M

Coiled-Tubing Technology (1993-1994)

DEA-67
Phases I and II

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

By

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TR95-11
May 1995

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1. Artificial Lift

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1. Artificial Lift

1.1 BP ALASKA/NOWCAM (SPOOLABLE GAS LIFT)

BP Exploration and Nowcam installed the first spoolable coiled-tubing gas-lift completion at Prudhoe Bay in November 1992 (Walker et al., 1993). Significant cost savings were achieved despite several aspects of the job that can be improved in future efforts. The system consisted of special gas-lift valves attached inside a string of coiled tubing. The recompletion was capable of being run in under pressure without stopping to install valves.

Previously, standard side-pocket slim-hole eccentric or concentric mandrels have been run on coiled-tubing strings. These mandrels have had a larger diameter than the coiled tubing, requiring that the coiled tubing be cut during installation at each gas-lift station. An access window below the injector (Figure 1-1) is used for installing the mandrels.

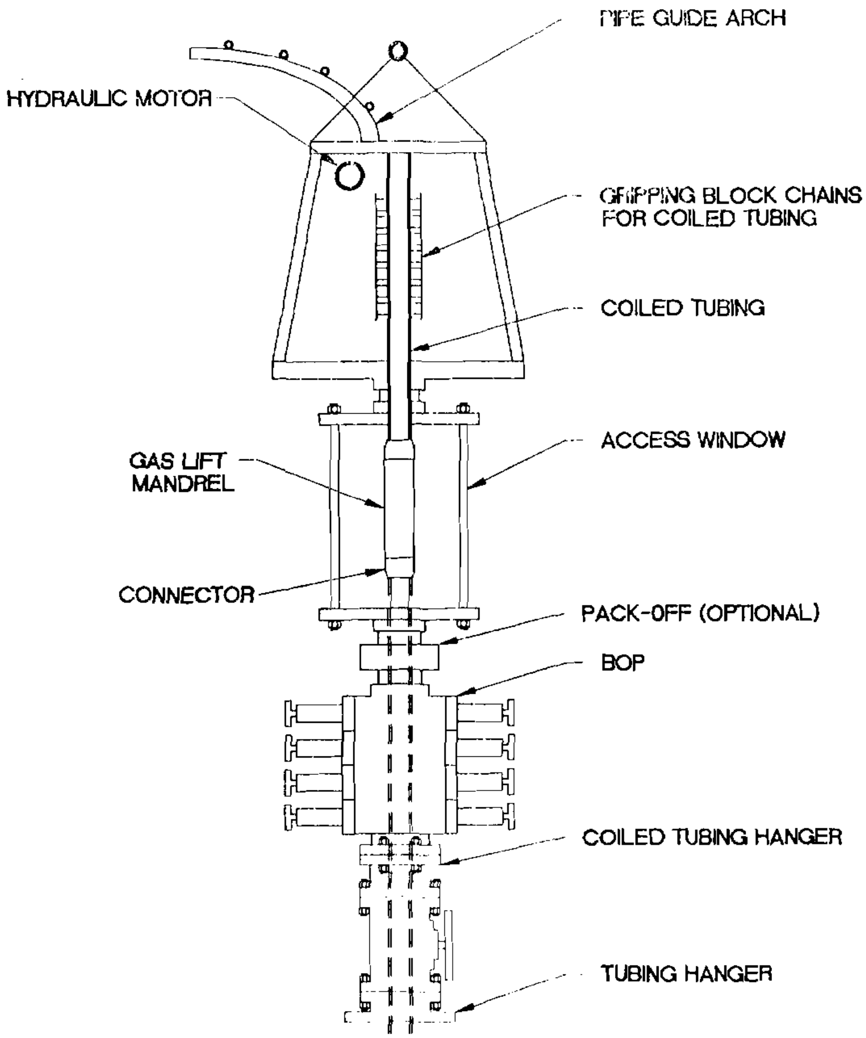


Figure 1-1. Access Window for Installing Side-Pocket Gas-Lift Mandrels on Coiled Tubing (Moore et al., 1993)

BP Alaska and Nowcan developed a system that eliminated the external upsets from the mandrels to allow spooling and rapid deployment. The first well so equipped (Well R-12) had declined and become unable to sustain stable flow. The well was completed with a 7 x 5½-in. tapered production string (Figure 1-2) with existing side-pocket gas-lift mandrels.

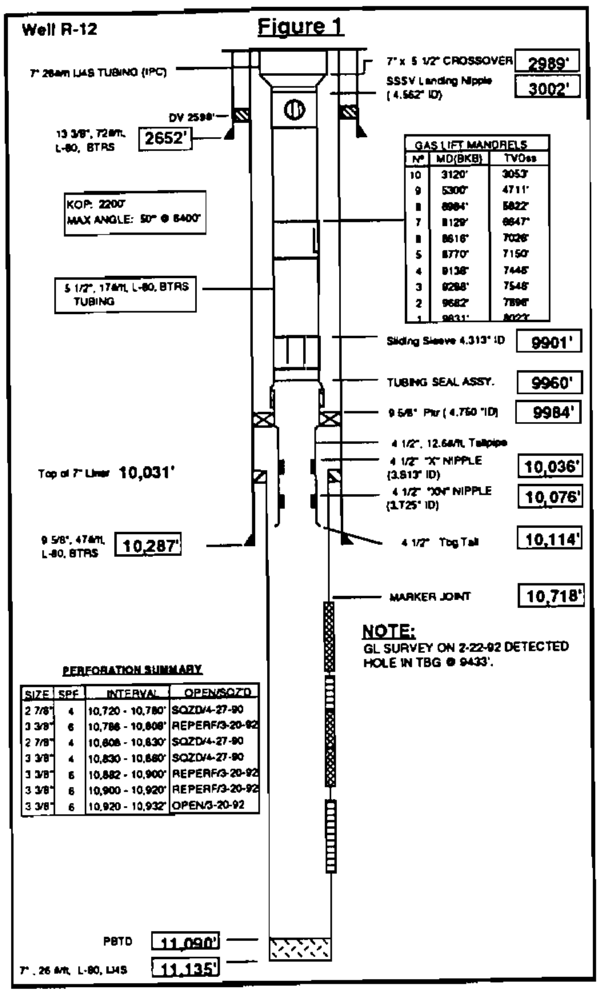


Figure 1-2. Well R-12 Wellbore Schematic (Walker et al., 1993)

For this first job, a 1-in. diameter gas-lift valve was fitted inside 2⅜-in. coiled tubing. These were chosen to provide an optimum balance between flow restrictions within the coiled tubing and gas-lift valve performance. The completion was designed so that the receptacle of the valve could remain rigid during spooling. The rest of the mandrel was flexible enough to assume the radius of curvature (Figure 1-3).

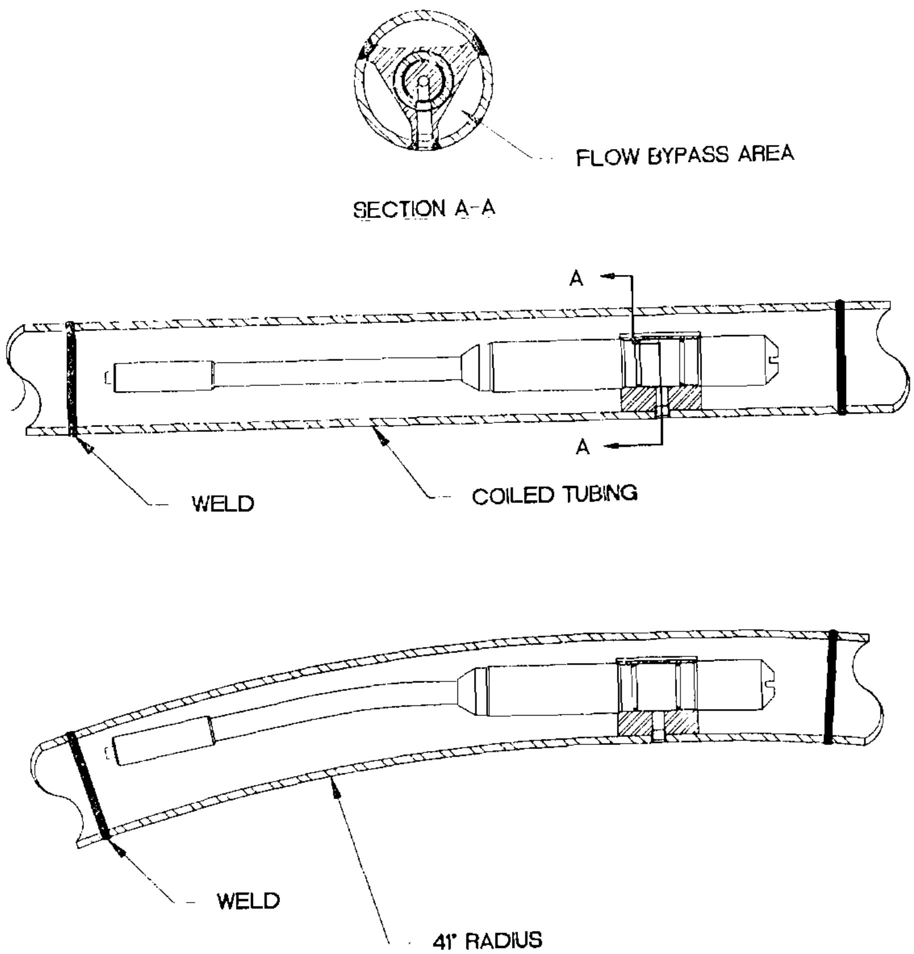
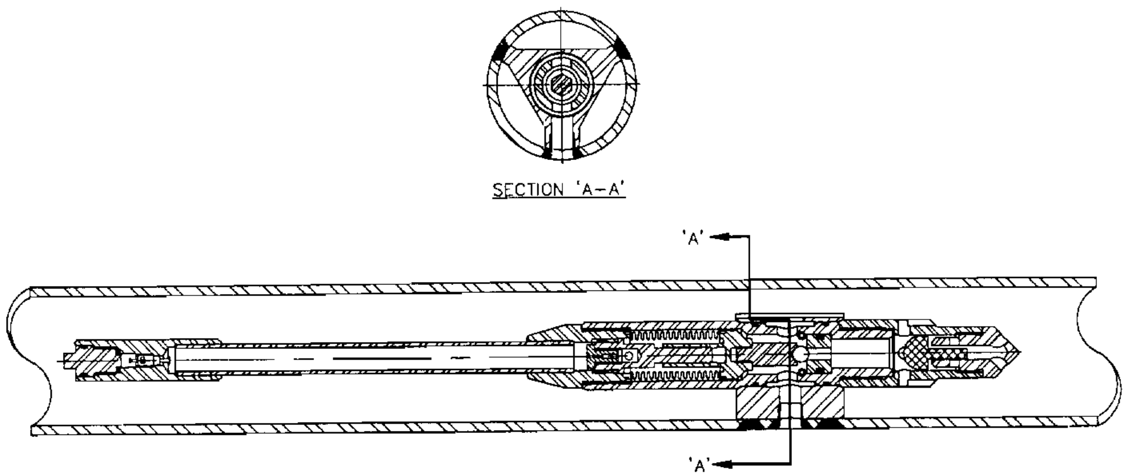


Figure 1-3. Spoolable Gas-Lift Valve Design (Moore et al., 1993)

Nowcam's design testing showed that spoolable gas-lift valves are feasible in 1½-in. and larger coiled tubing. Due to flow restrictions, best performance is obtained within 2-in. and larger coiled tubing. Specifications for the initial system are shown in Figure 1-4.



ENGINEERING DATA	
MAXIMUM OUTSIDE DIAMETER (GAS LIFT VALVE)	1.073 IN.
FLOW BYPASS EQUIVALENT DIAMETER	1.417 IN.
OVERALL LENGTH (GAS LIFT VALVE)	15.230 IN.
COILED TUBING SIZE	2-3/8" O.D. X .156" WALL
WORKING PRESSURE (MANDREL)	5,000 PSI

Figure 1-4. Spoolable Gas-Lift Valve Specifications (Moore et al., 1993)

Full-scale spooling tests were conducted with the prototype. Ten spooling cycles were performed. Valve opening pressure did not deviate as a result of spooling. Likewise, tensile strength of the mandrel was unaffected by spooling.

For recompleting well R-12, four spoolable valves were installed in a 10,076-ft string of 2⅜ x 0.156-in. coiled tubing. Before the coiled tubing was deployed, wireline was used to set a 10-ft polished bore with a flapper valve in the existing landing nipple (Figure 1-5).

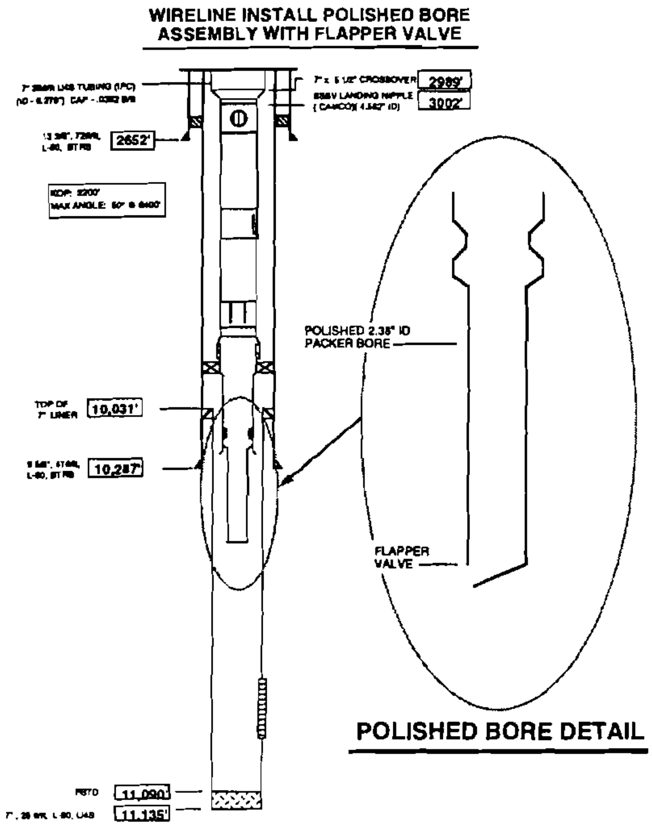


Figure 1-5. Polished Bore with Flapper Valve (Moore et al., 1993)

A 10-ft seal assembly and 10-ft production tube were attached to the coiled-tubing string. This assembly was stabbed into the polished bore, holding the flapper valve open. The coiled tubing had to be cut in the field for installation of the SSSV. A spoolable SSSV was not available in time for this job.

Major problems during this first job included:

- Fine threads on the coiled-tubing connectors cost too much time while installing the SSSV. Later designs will remedy this problem.
- Ice build-up on the gripper blocks threatened job safety by causing the coiled tubing to slide. This can be avoided in future jobs by running a check valve on the bottom that will allow circulation of warm fluid during run-in.
- After unloading the well, the lowest gas-lift valve was apparently plugged. In the future, production tubing should be pickled to ensure clean tubing.

After the recompletion, well R-12 stabilized at 750 BFPD at a 65% water cut with a lift gas rate of 1.5 MMscfd. Total running time in the field was 18 hours. Six hours were needed to install the SSSV; 4 hours was downtime due to gripper-block icing.

Costs for this job were 32% of conventional costs (Walker et al., 1993). BP Alaska planned to continue using this system and improve the design by adding a spoolable SSSV system, thus making the entire system "slick".

1.2 MOBIL E&P (ESP ON COILED TUBING)

The first electric submersible pump (ESP) deployed on coiled tubing was installed by Mobil E&P (Lidisky et al., 1993). Other team members included Nowcam Services, Reda and Quality Tubing. The viability of this method was demonstrated for installing and servicing ESPs in areas where conventional rigs are not an economic option for servicing these wells.

The ESP system consists of a pump, power cable, and surface electrical controls (Figure 1-6). This method has the broadest range of capacities for artificial lift. Flow rates can range from 100 to 95,000 BPD at depths up to 15,000 ft and at temperatures up to 450°F (Lidisky et al., 1993).

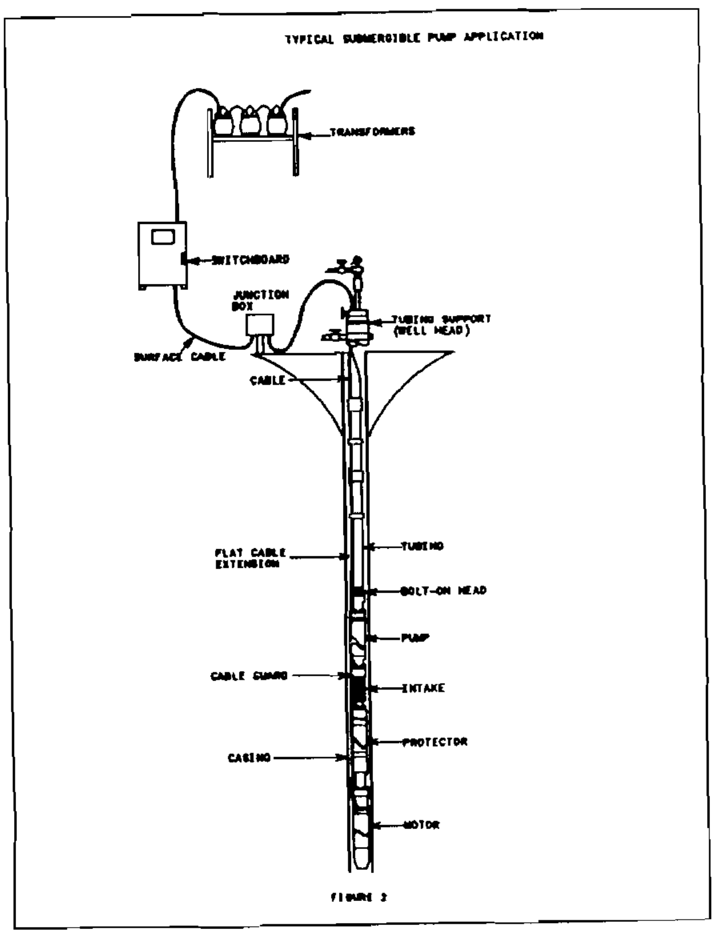


Figure 1-6. ESP Application (Lidisky et al., 1993)

The primary variation for this method as compared to typical coiled-tubing operations is the use of a work window (Figure 1-7). This is used provide room below the injector and above the wellhead to pick up the pump assembly and to band the power cable to the coiled tubing during run-in.

The pump was designed to lift 1400 BFPD through 1¾ x 0.109-in. coiled tubing. The increase in friction due to using a smaller tubular than a typical 2⅜ or 2⅞-in. string was calculated as 153 psi (353 ft of hydrostatic head) based on Hagedorn and Brown correlations (Figure 1-8). To account for this extra pressure drop, the pump was designed with 18 additional stages. The motor size was increased by 13 hp, resulting in an increase in cost of $1596. Power for the additional hp was estimated to cost over $1800/yr.

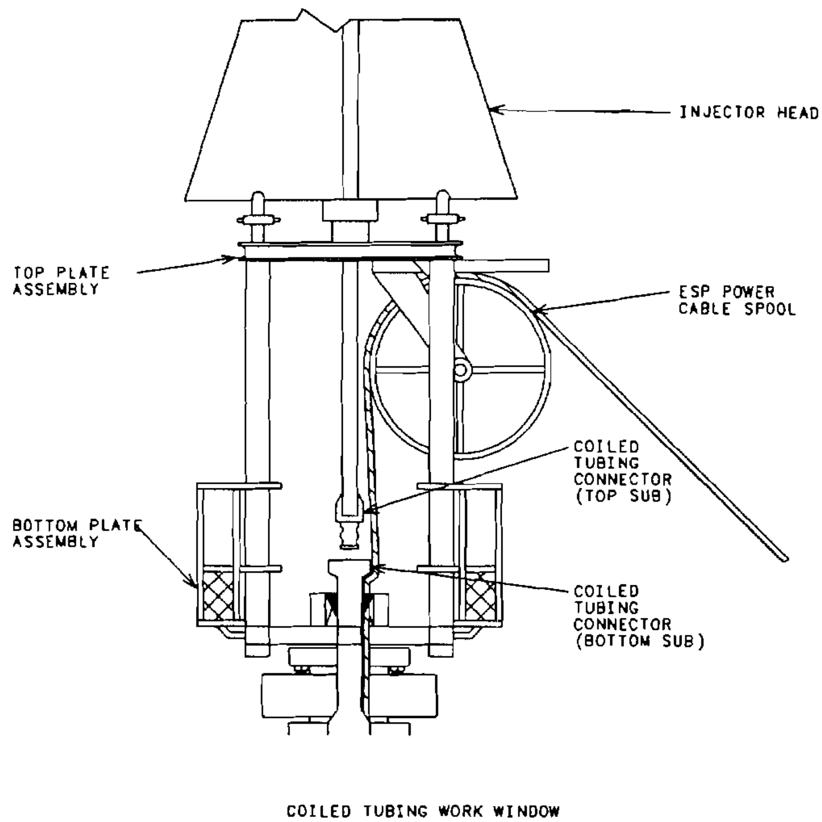


Figure 1-7. Work Window for Deployment (Lidisky et al., 1993)

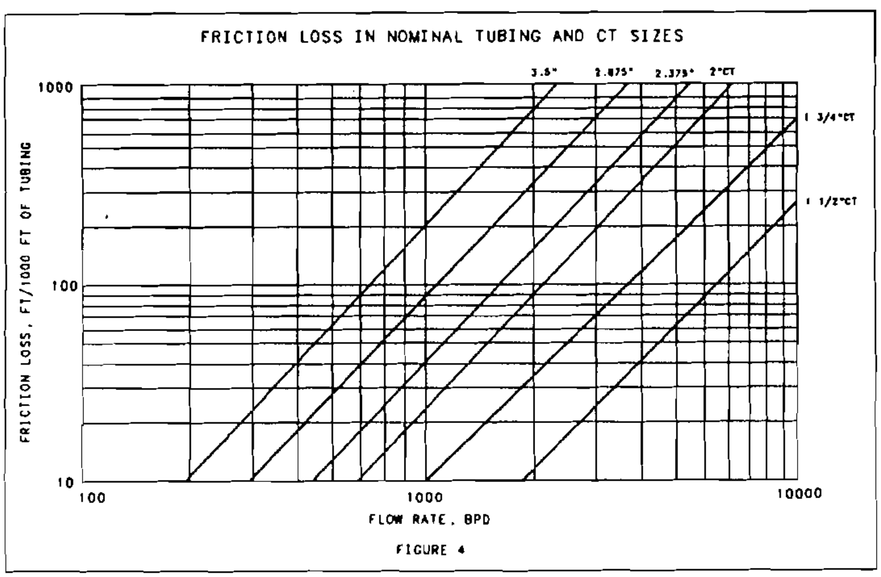


Figure 1-8. Friction Loss in Coiled Tubing (Lidisky et al., 1993)

A structural analysis was performed to determine the capacity of the coiled tubing for the ESP operations. The tubing was not constrained downhole so that it could move up and down. The structural cases were modeled: 1) base case—buoyed weight of the tubing, power cable and ESP, 2) flowing load case—discharge pressure of 1140 psi results in added tension load of 2100 lb, 3) shut-in load case—with pump still running, a maximum head of 3355 psi is developed. Results of running these three cases (Table 1-1) show that all loads are within required working limits and safety factors.

TABLE 1-1. Coiled-Tubing Load Capacity Calculations (Lidisky et al., 1993)

Loads and Load Capacity Design Factors
1-3/4 inch O.D., 0.109 inch wall thickness Coiled Tubing

Base Case: As Landed, Tubing Hanging Open Ended

			Pressure			Axial forces		API Load Capacity Design Factors				VME Stress	
Node	Depth	Temp	External	Internal	Difference	Above	Below	Axial Tension Force		Pressure		Intensity Design Factor	
#	MD=TVD (ft)	(F)	psi	psi	psi	(lbs)	(lbs)	Above	Below	Above	Below	Above	Below
1	0	80	0	0	0		6800		5.8				5.6
1a	1500	94	0	0	0	2600	2600	14.9	14.9			14.3	14.3
1b	1970	99	215	215	0	1400	1400	29.0	29.0			25.8	25.8
2	2078	100	264	264	0	1100	1100		37.2			31.6	31.6
2a	2079	100	265	265	0	500	500		86.6			63.4	63.4
3	2080	100	265	265	0	-100		>100.0				>100.0	

Load Case 2: ESP Pumping - Flowline Open

			Pressure			Axial forces		API Load Capacity Design Factors				VME Stress	
Node	Depth	Temp	External	Internal	Difference	Above	Below	Axial Tension Force		Pressure		Intensity Design Factor	
#	MD=TVD (ft)	(F)	psi	psi	psi	(lbs)	(lbs)	Above	Below	Above	Below	Above	Below
1	0	85	0	60	60		8900		4.4		>100		4.3
1a	1500	96	0	839	839	4800	4800	8.2	8.2	9.9	9.9	8.0	8.0
1b	1970	99	0	1083	1083	3500	3500	11.3	11.3	7.7	7.7	7.9	7.9
2	2078	100	49	1139	1090	3200	1100	12.3		7.6		8.0	
2a	2079	100	50	1139	1089	500	2600		15.2		7.6		8.2
3	2080	100	50	1140	1090	2000		19.8		7.8		8.3	

Buckling does not occur   Length change at bottom = 3 inches (down)

Load Case 3: ESP Pumping - Well Shut-in

			Pressure			Axial forces		API Load Capacity Design Factors				VME Stress	
Node	Depth	Temp	External	Internal	Difference	Above	Below	Axial Tension Force		Pressure		Intensity Design Factor	
#	MD=TVD (ft)	(F)	psi	psi	psi	(lbs)	(lbs)	Above	Below	Above	Below	Above	Below
1	0	80	0	2391	2391		13000		3.0		3.5		2.9
1a	1500	94	0	3086	3086	8900	8900	4.4	4.4	2.7	2.7	2.8	2.8
1b	1970	99	0	3304	3304	7600	7600	5.2	5.2	2.5	2.5	2.7	2.7
2	2078	100	49	3354	3305	7300	1100	5.4		2.5		2.7	
2a	2079	100	50	3355	3305	500	6700		5.9		2.5		2.7
3	2080	100	50	3355	3305	6100		6.5		2.5		2.7	

Buckling does not occur   Length change at bottom = 4 inches (down)

Nodes.
1) 0.0 feet coiled tubing at the wellhead
1a) 1500.0 feet depth at static fluid level with the ESP shut off
1b) 1970.0 feet depth at producing fluid level ESP pumping
2) 2078.0 feet depth at the pump
2a) 2079.0 feet depth below the pump
3) 2080.0 feet depth below entire ESP assembly

Fatigue life was considered as it impacted the ESP service life. A running feet limit of 200,000 to 300,000 ft was established based on recommendations of service companies. For this particular case, the string could be run 96 to 144 times before the fatigue limit was exceeded. Thus, with a safety factor of 4, this string would last about 24 yr in this application. More likely failure mechanisms are mechanical damage to the string or localized corrosion.

Torque requirements were also checked. The capacity of the coiled tubing was more than sufficient. However, the coiled-tubing connector was modified to increase its torque capacity.

The final downhole assembly is shown in Figure 1-9.

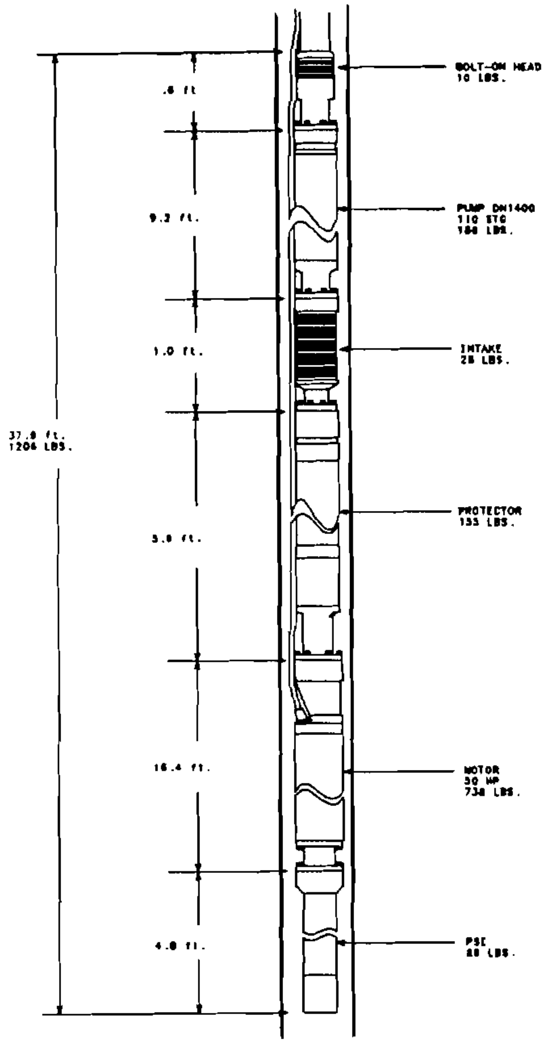


Figure 1-9. ESP Downhole Assembly (Lidisky et al., 1993)

The ESP was run to a depth of 2080 feet. Total installation time was 11 hours (Table 1-2). Mobil stated that this installation took longer than normally required due to necessary rework on the work window. Without this element, the overall time spent installing the ESP could be reduced by 2 hours.

TABLE 1-2. Coiled-Tubing-Deployed ESP Installation (Lidisky et al., 1993)

Installation Task	Hours
1. Initial spotting of equipment and rig-up	1.9
2. Reda equipment make-up	1.0
3. Final rig-up	3.1
4. Install connector and pull test	1.7
5. Run tubing and band cables together	1.6
6. Make up tubing hanger and pull test	1.3
7. Land tubing hanger	0.2
8. Rig down work window	0.2
TOTAL	11.0

The use of coiled tubing to deploy this ESP was considered a success. The single problem observed after installation was the inability to shoot fluid height down the annulus. Since there are no tubing collars, it is impossible to read the fluid depth.

Conclusions reached by participants in this effort include the following:

- The design of the work window was effective, allowing safe and efficient installation
- Modeling/calculation of the loads and forces is required to properly size the coiled tubing
- Due to the differences in standard coiled-tubing operations and ESP installation, a crew experienced in both fields is recommended
- ESPs deployed on coiled tubing offer an economic alternative in many marginal prospects

1.3 MARATHON OIL (JET PUMP)

Marathon Oil designed a concentric coiled-tubing jet pump for well Ezzaouia #8 in eastern Tunisia (Nirider, 1994). After original completion, the well was never able to sustain steady production. Completion design (Figure 1-10) included 9⅝-in. casing plugged back with 3½-in. tubing and a production packer.

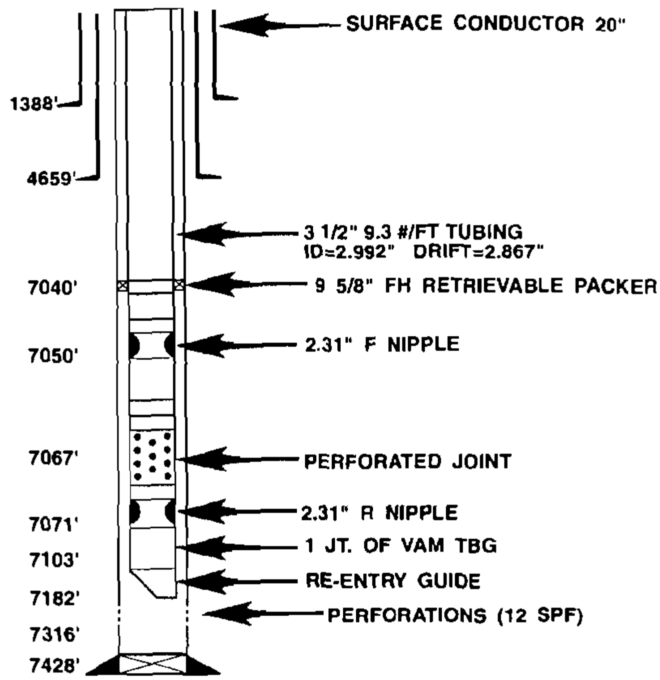


Figure 1-10. Ezzaouia #8 Wellbore Schematic (Nirider, 1994)

Modeling analyses indicated that the well could flow with smaller tubing or artificial lift. Lack of availability of workover rigs prevented the most obvious remediation: tubing change-out and installation of rod-pumping equipment. Instead, Marathon chose an innovative artificial lift system consisting of a jet pump run on coiled tubing. Their design is shown in Figure 1-11.

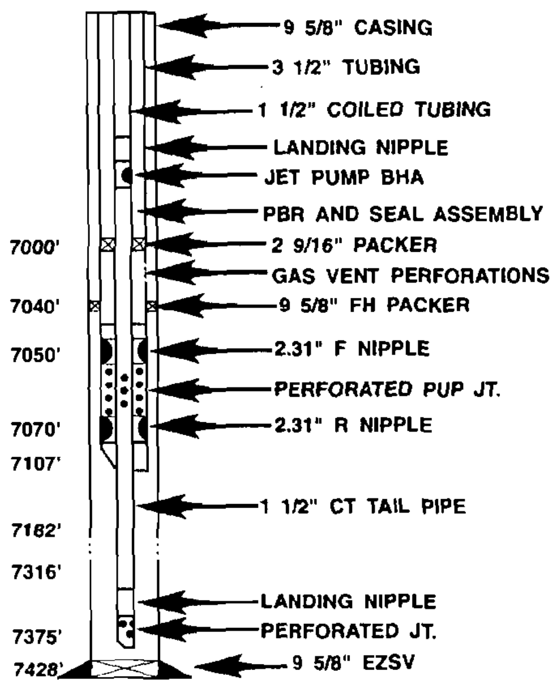


Figure 1-11. Wellbore with Coiled-Tubing Jet Pump (Nirider, 1994)

To install the slim-hole jet pump, 375 ft of 1½-in. coiled tubing tail pipe will be run and set with a hydraulic packer above the holes in the 3½-in. tubing. After the packer is set, a disconnect releases the setting tool and leaves a polished bore receptacle looking up. The stinger seal assembly, jet-pump housing and landing nipple are stung into the polished bore receptacle and packed off and hung at the surface.

Normal operating parameters for the jet pump (Figure 1-12) are 3500 psi and 300 BPD of power fluid. Throat and nozzle combinations can be changed by reversing flow and pumping the assembly into the catcher.

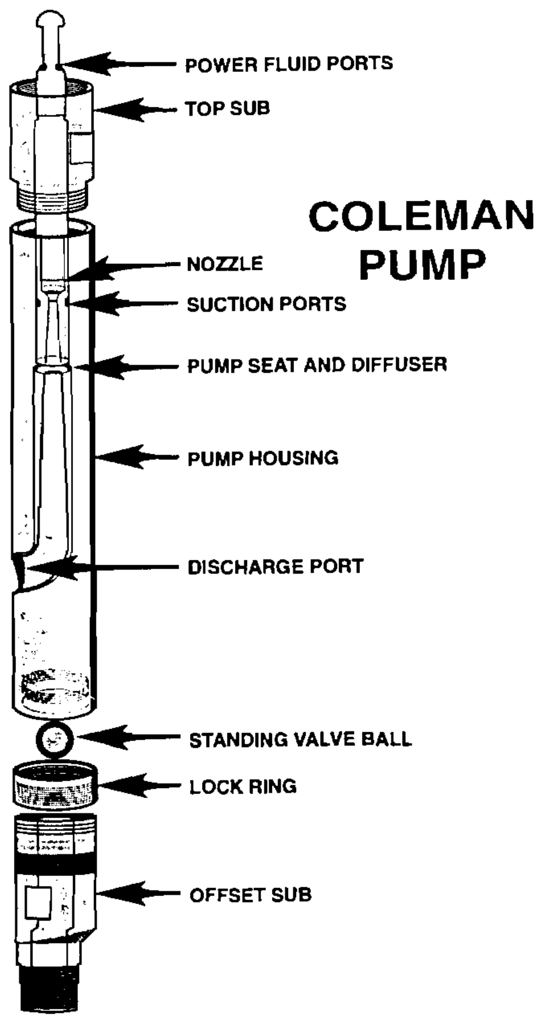


Figure 1-12. Slim-Hole Jet Pump (Nirider, 1994)

Primary obstacles in the design included locating a small jet pump with high flow capacity. Only one potential product was found, and it has been used primarily to de-water coalbed methane wells. Other difficulties were in selecting a packer that would allow predicted tubing movement. Unbalanced forces were expected to create a significant downward force during operation. A hydraulic single-grip packer with a polished bore receptacle and seal assembly was chosen for this application.

1.4 REFERENCES

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Moore, B.K., Laflin, W.J. and Walker, E.J., 1993: "Rigless Completions: A Spoolable Coiled-Tubing Gas Lift System," OTC 7321, paper presented at the 25th Annual Offshore Technology Conference held in Houston, Texas, May 3-6.

Nirider, Lee, 1994: "Marathon Oil Company's Proposed Concentric Coiled Tubing Jet Pump Installation Ezzaouia No. 8, Tunisia," paper presented at the Second International Conference and Exhibition on Coiled Tubing Technology: Operations, Services, Practices held in Houston, Texas, March 28-31.

Walker, E.J. et al., 1993: "A Spoolable Coiled-Tubing Gas-Lift Completion System," SPE 26538, paper presented at the 68th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in Houston, Texas, October 3-6.

2. Buckling

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2. Buckling

2.1 THEORY

2.1.1 Maurer Engineering/Texas A&M

Maurer Engineering and Texas A&M (Wu and Juvkam-Wold, 1993) analyzed coiled-tubing buckling and drag with special consideration for drilling and completion operations. They derived modified equations for helical buckling forces, bit weights attainable, and maximum horizontal length that can be drilled with coiled tubing. Full details of their mathematical models are presented in their paper.

A sample of results obtained with their buckling models is presented in Table 2-1 for vertical and horizontal wells. Loads shown for vertical wells include $F_{cr,b}$ = critical (sinusoidal) buckling load at bottom of tubing; $F_{hel,b}$ = helical buckling load at bottom of tubing; and $F_{hel,t}$ = buckling load at top of helically buckled tubing section. For horizontal wellbores, critical (sinusoidal) and helical buckling loads are shown.

TABLE 2-1. Buckling Loads for Coiled Tubing in 3⅞-in. Well (Wu and Juvkam-Wold, 1993)

Coiled Tubing			Vertical Wellbore			Horizontal Wellbore	
O.D. (in.)	I.D. (in.)	Weight (lb/ft)	$F_{cr,b}$ (lbf)	$F_{hel,b}$ (lbf)	$F_{hel,t}$ (lbf)	F_{cr} (lbf)	F_{hel} (lbf)
2.375	2.063	3.7	288	628	16	5369	9817
2	1.688	3.07	212	461	12	3317	6066
1.75	1.438	2.66	167	363	9	2334	4268
1.5	1.376	2.24	125	273	7	1572	2874

The data in Table 2-1 show that, once coiled tubing is in compression in a vertical well, little added load is required to initiate buckling. Loads to initiate buckling in horizontal wells are significantly higher than in vertical wells.

Wu and Juvkam-Wold found that curved sections have increased buckling limits. Figure 2-1 compares critical buckling loads for 2-in. coiled tubing in the build section of a 3⅞-in. well for various build rates. In typical coiled-tubing operations, compressive loads will usually not exceed these critical values; consequently, coiled tubing in the build section does not usually buckle.

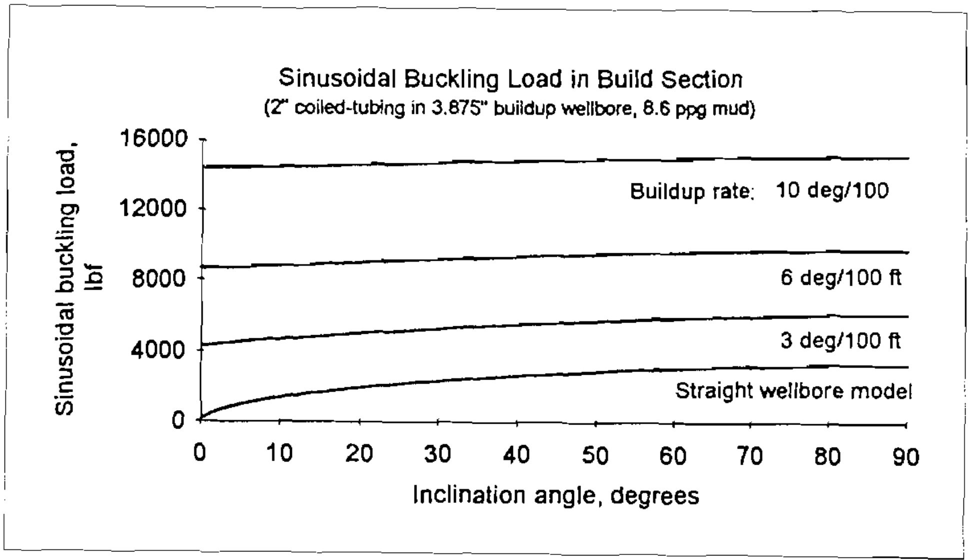

Figure 2-1. Critical Buckling Load in Build Section (Wu and Juvkam-Wold, 1993)

While drilling a vertical well with coiled tubing, all of the string weight will not be available at the bit. A portion of the weight is offset by friction losses due to buckling. The maximum load transmitted to the BHA is shown in Figure 2-2 for a 4.052-in. vertical well with several sizes of coiled tubing. Load at the bottom approaches a limiting value for each wellbore/tubing combination for a zero hook load.

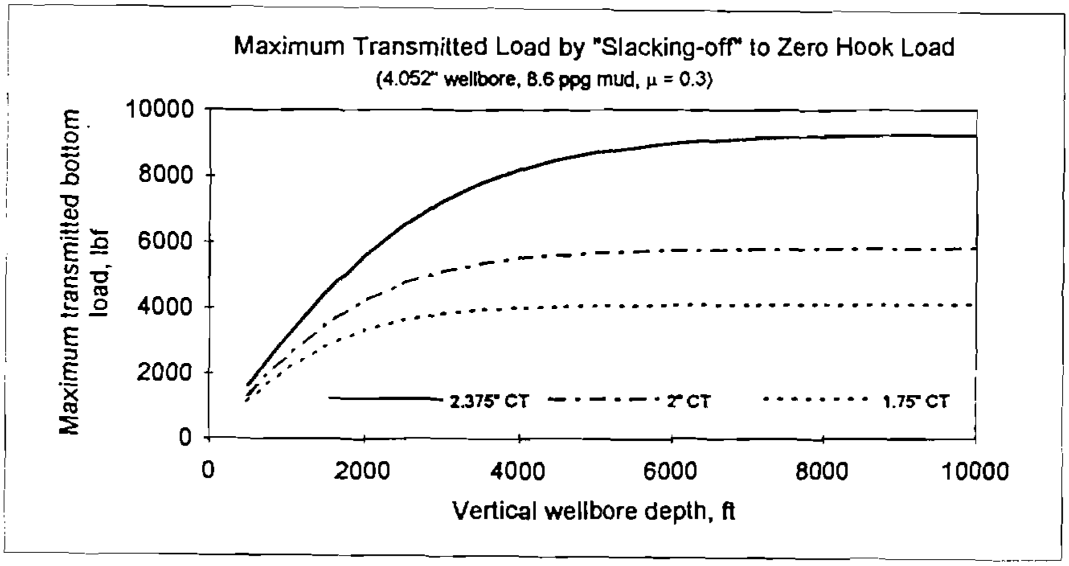

Figure 2-2. Maximum Transmitted Load in Vertical Well (Wu and Juvkam-Wold, 1993)

"Lock-up" of coiled tubing in a horizontal well occurs when no additional load is transferred to the bottom even though the pushing load increases. The tubing will yield before the pushing load approaches infinity. The maximum compressive load that will yield 70-ksi coiled tubing is plotted in Figure 2-3. These data show that coiled tubing will yield at relatively low loads after buckling helically in large wellbores.

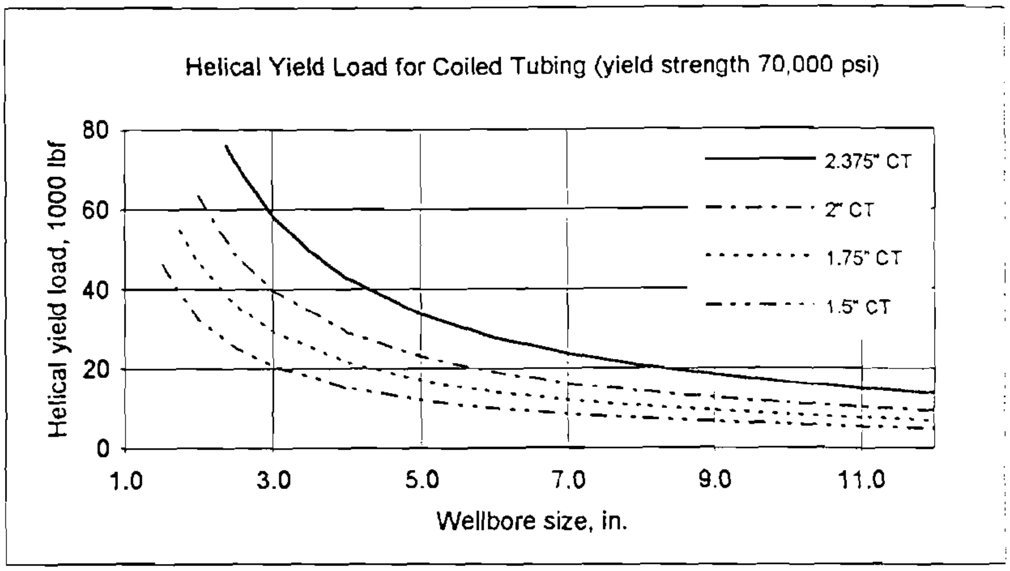

Figure 2-3. Yield Loads for Buckled Coiled Tubing (Wu and Juvkam-Wold, 1993)

Lock-up is evident when the hook load goes to zero (ignoring any snubbing loads). Figure 2-4 shows an example hook-load plot for drilling a horizontal well. For the case where a 2000-lb WOB is required, the maximum depth attained is 7660 ft when the hook load goes to zero.

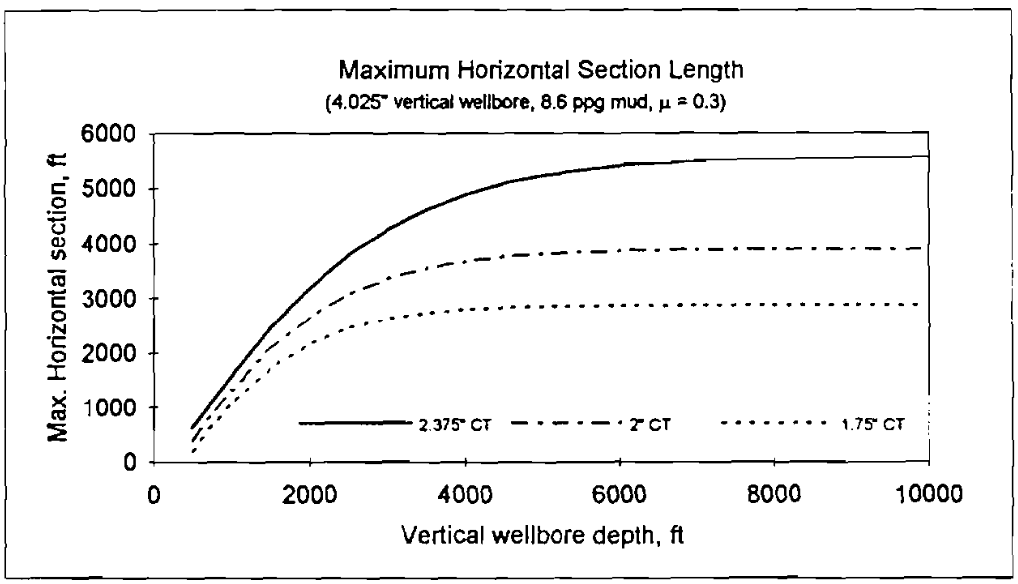

Figure 2-4. Hook Loads for Drilling a Horizontal Well with Coiled Tubing (Wu and Juvkam-Wold, 1993)

The length of horizontal section that can be drilled before coiled tubing yields (Figure 2-5) is limited due to buckling forces in both the vertical and horizontal sections. These data assume a 4.052-in. wellbore, 1000-lb WOB, 15°/100 ft build rate, and friction coefficient of 0.3. Snubbing forces from the injector were not considered.

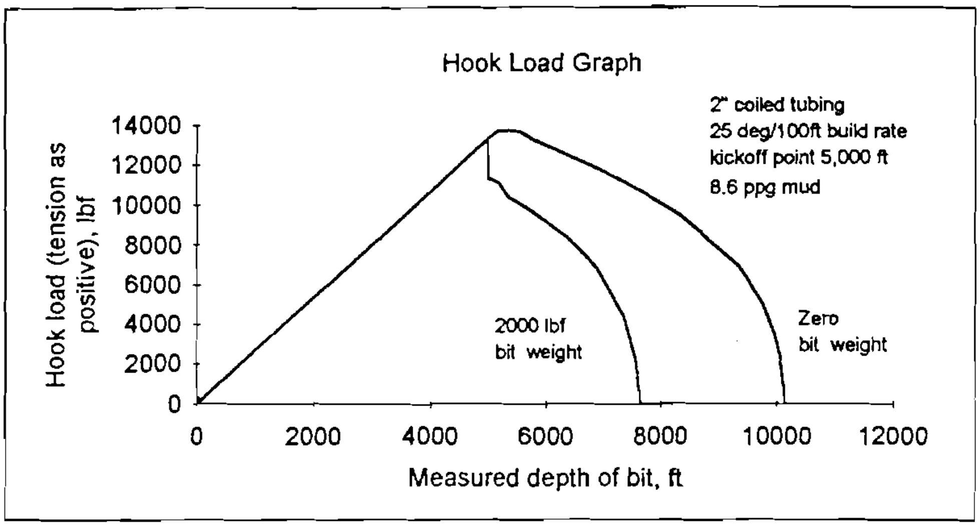

Figure 2-5. Maximum Length of Horizontal Section Drilled with Coiled Tubing (Wu and Juvkam-Wold, 1993)

Wu and Juvkam-Wold presented several conclusions regarding their analyses of coiled-tubing drilling limits:

- In wells from 0-70° inclination, buckling is initiated near the bit and progresses upward. In 70-90° wells, buckling starts where critical loads are first exceeded, often at the heel of the well, and then progresses toward the bit.
- Coiled tubing rarely buckles in curve sections of horizontal wells due to effect of curvature.
- Wall contact force and frictional drag increase substantially after tubing helically buckles.
- Coiled tubing may yield before lock-up occurs.
- Buckling, yielding and lock-up are less with smaller holes or larger tubing.

2.1.2 Rogaland Research

Rogaland Research (He and Kyllingstad, 1993) derived an improved formula for predicting critical buckling loads for coiled tubing. Their analysis takes into account wellbore curvature. Their mathematical model compared favorably with laboratory test results using a small scale model. They also compared model predictions with results from a horizontal well in the North Sea.

The experiences of many in the coiled-tubing service industry showed that coiled tubing can be used successfully at forces exceeding the Dawson and Chen et al. formulas for critical buckling and helical buckling, respectively. The use of the critical buckling load as an operational limit is deemed as too conservative.

He and Kyllingstad state that two problems exist with the use of these accepted formulas: 1) these formulas do not account for the effect of wellbore curvature and 2) it is assumed that operations are not feasible if the critical buckling force is exceeded. They developed a new formula that included inclination and azimuth build rates in the buckling calculation. Their mathematics are described and presented in detail in their paper. Trends predicted by their models are shown below.

He and Kyllingstad considered normalized inclination and azimuth build rates and their impact on the normalized critical buckling force. In Figure 2-6, critical buckling force is plotted as a function of inclination build rate for three values of normalized azimuth build rate (a_2). The solid curve ($a_2 = 0$) is for the case of no azimuth change.

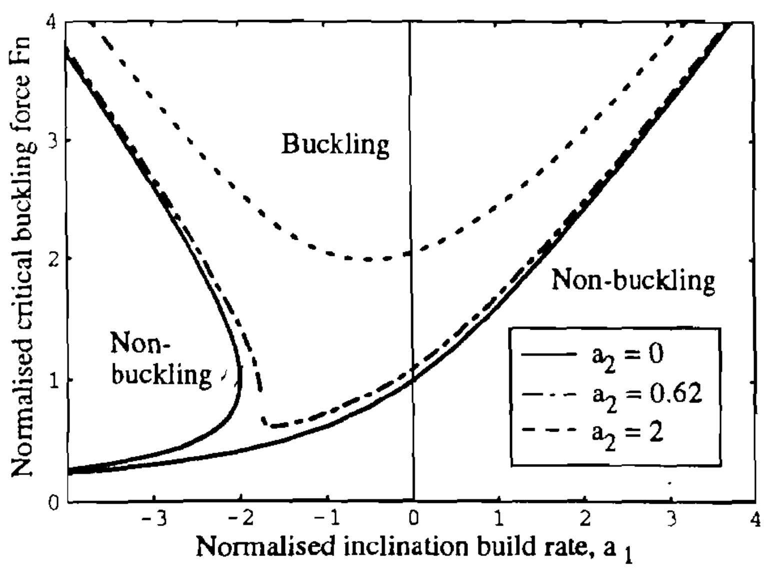

Figure 2-6. Curvature and Critical Buckling Load (He and Kyllingstad, 1993)

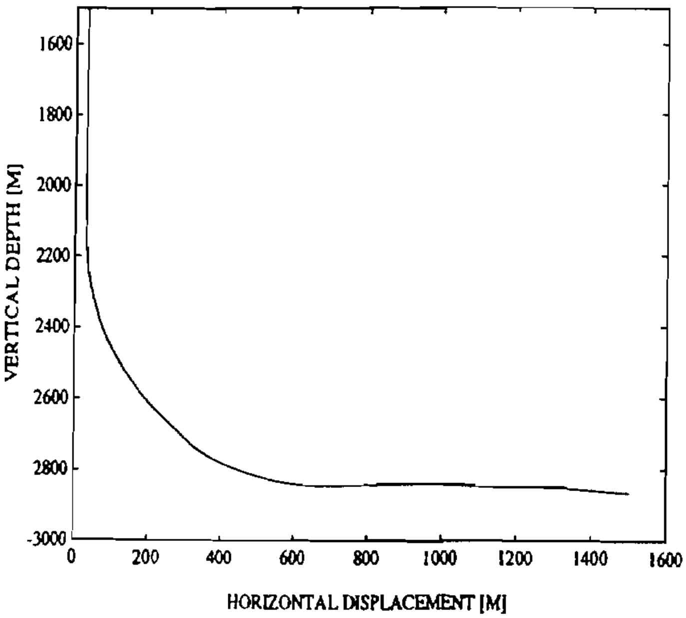

Figure 2-7. Example Horizontal Well Profile
(He and Kyllingstad, 1993)

Their analysis suggested that buckling limits are very sensitive to wellbore curvature rates. An example horizontal well profile (Figure 2-7) was used to compare buckling forces with and without considering curvature (Figure 2-8). In the build section, buckling forces are up to 40% higher when the curvature is considered.

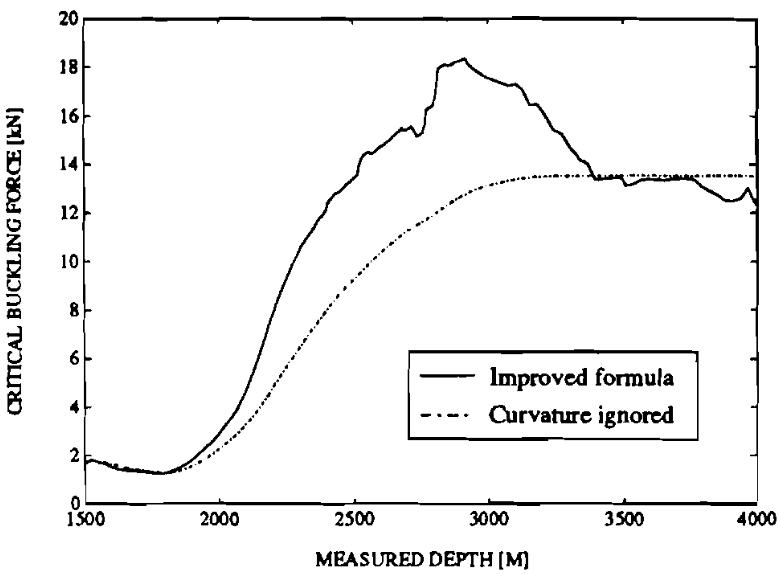

Figure 2-8. Critical Buckling Forces in Example Horizontal Well (He and Kyllingstad, 1993)

He and Kyllingstad's formula predicts a longer reach before coiled tubing buckles than do standard formulas. Slack-off forces in the example horizontal well (Figure 2-9) show that the tubing can be pushed an additional 290 meters if curvature is taken into account. Coiled tubing used in the example is 1¾ x 0.134 in.

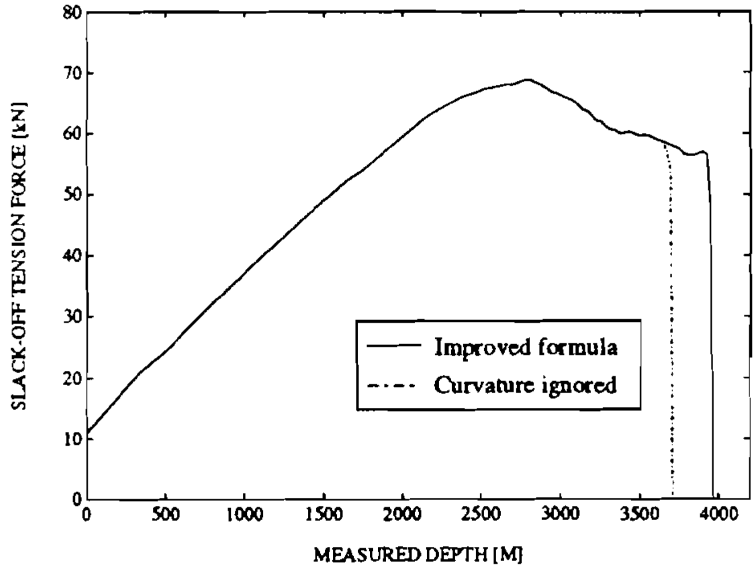

Figure 2-9. Slack-Off Forces in Example Horizontal Well (He and Kyllingstad, 1993)

Simulated axial force transmitted through a string of coiled tubing in a horizontal well is plotted in Figure 2-10. The steep, straight sections of the curves represent force transmission before buckling occurs. The critical buckling load is 5.5 kN (1.2 kip) for this 1¼ x 0.125-in. tubing in a 5-in. wellbore.

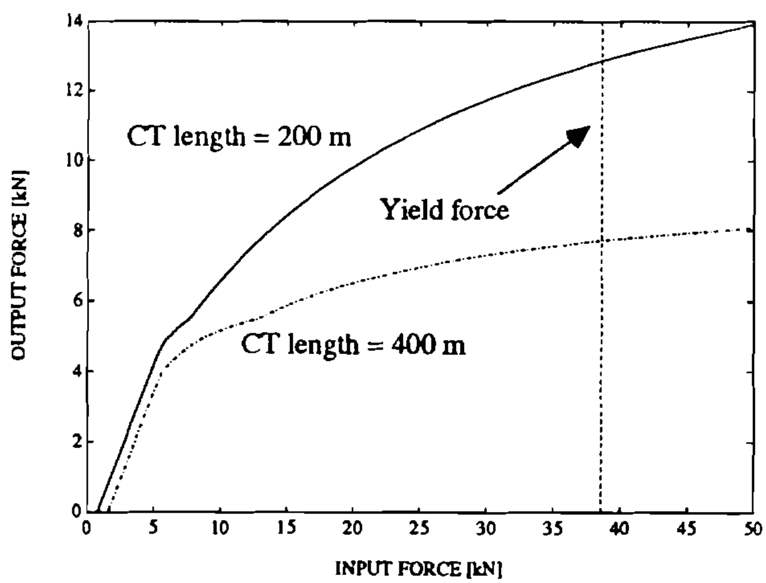

Figure 2-10. Force Transmission in Horizontal Well (He and Kyllingstad, 1993)

He and Kyllingstad concluded that wellbore curvature has a significant effect on critical buckling loads for coiled tubing and should be considered in the analysis. They found that a positive inclination build rate generally increases the critical buckling load; moderate negative inclination build rates decrease critical buckling load. Azimuth build rates also increase critical buckling load.

2.1.3 Schlumberger Dowell (Limits for Extended-Reach Operations

Schlumberger Dowell (van Adrichem and Spruill, 1993) conducted a study to investigate the feasibility of running coiled tubing to a measured depth of 30,000 ft. Justification for considering such a large displacement comes from operators planning ultralong-reach wells. If a well with a 30,000-ft displacement were drilled, could it be entered to TD with coiled tubing? Cost savings push the drive to achieve greater displacements from the surface location, especially in the offshore environment, where fewer platforms might be required to develop a field.

Impressive depth records have been set in coiled-tubing workover operations, including 1-in. strings to about 25,000 ft and 2-in. strings to 10,000 ft. For a well with a 30,000-ft displacement to be economic, it must be able to be worked over with standard equipment.

Schlumberger Dowell ran numerous simulations with their coiled-tubing models to calculate drag and buckling limits for an example well. The profile used in the analyses is shown in Figure 2-11. The well is vertical down to 1800 ft, then turned to 72° inclination at a rate of 15°/100 ft. Production tubing (3½ in.) is set from surface to 25,000 ft. The final 5000 ft is 7-in. casing.

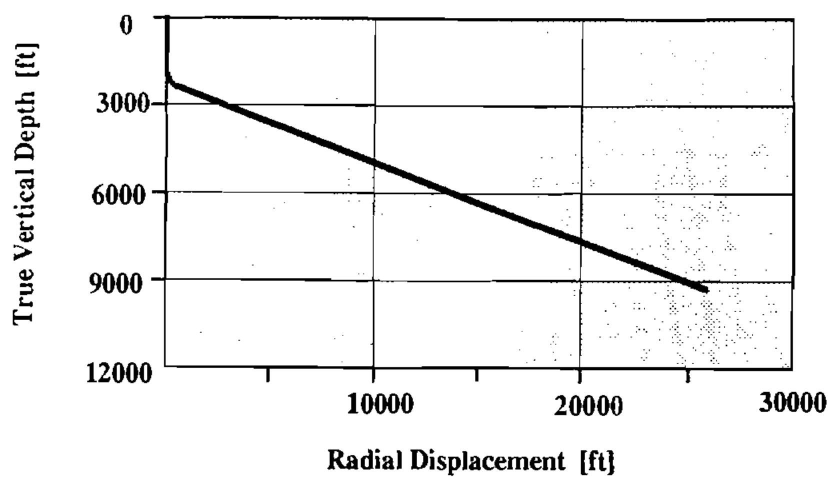

Figure 2-11. Well Profile Used in Simulations (van Adrichem and Spruill, 1993)

Maximum hanging depth for coiled tubing to not exceed 80% of material yield strength in a vertical well is about 16,000 ft (70-ksi tubing). Longer lengths can be run in inclined wells. Figure 2-12 shows the percentage of yield achieved for a 16,000-ft string as a function of wellbore inclination. A crossover from tension to compression occurs at the critical angle of about 72°. Wellbores at this angle allow the greatest lateral reach.

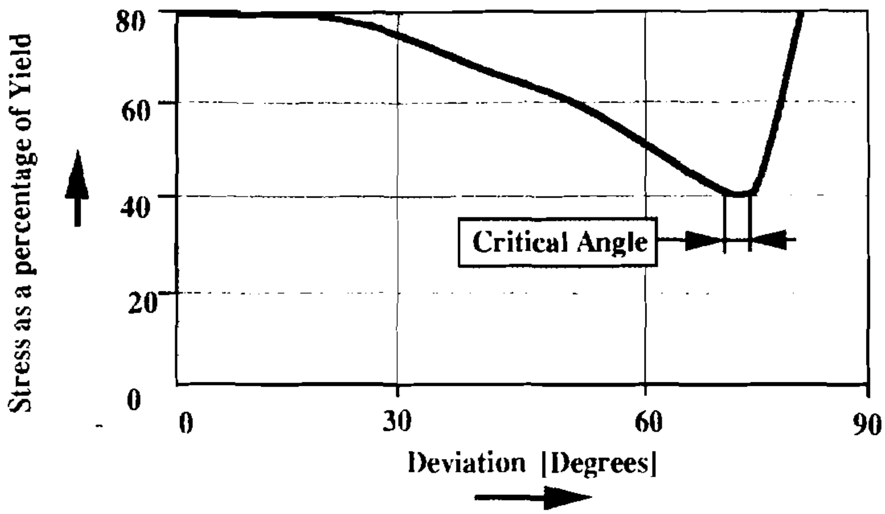

Figure 2-12. Yield Stress in a 16,000-Ft String (van Adrichem and Spruill, 1993)

The expected loads for running in and out of a 72° wellbore (Figure 2-13) show that during run-in (dashed line) the increasing weight of the tubing is offset by frictional drag.

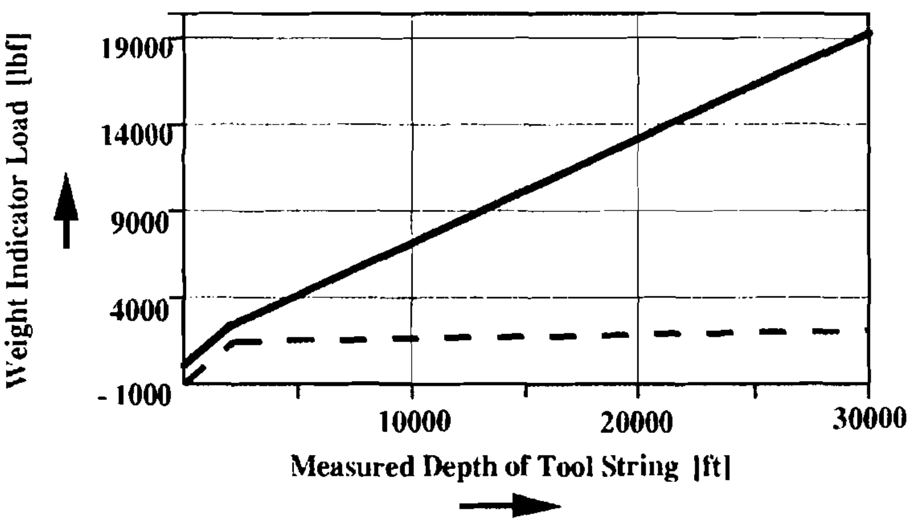

Figure 2-13. Weight Indicator Loads for 72° Well (van Adrichem and Spruill, 1993)

Modeling runs showed that a string of coiled tubing could be run to bottom in the 30,000-ft example well. However, stress levels would reach 82% of yield, exceeding the standard 80% safety limit. A tapered string was designed to prevent stress levels from exceeding the 80% maximum. String design consisted of 12,000 ft of 0.095-in. wall; 8000 ft of 0.102-in. wall; 4000 ft of 0.109-in. wall; 2000 ft of 0.125-in. wall; 2000 ft of 0.134-in. wall; and 2000 ft of 0.156-in. wall.

This optimized tapered design causes the maximum stress to be decreased to 62% of yield (Figure 2-14). The use of 100,000-psi yield material in a tapered string would allow the maximum stress to be reduced to 42% yield in the example well.

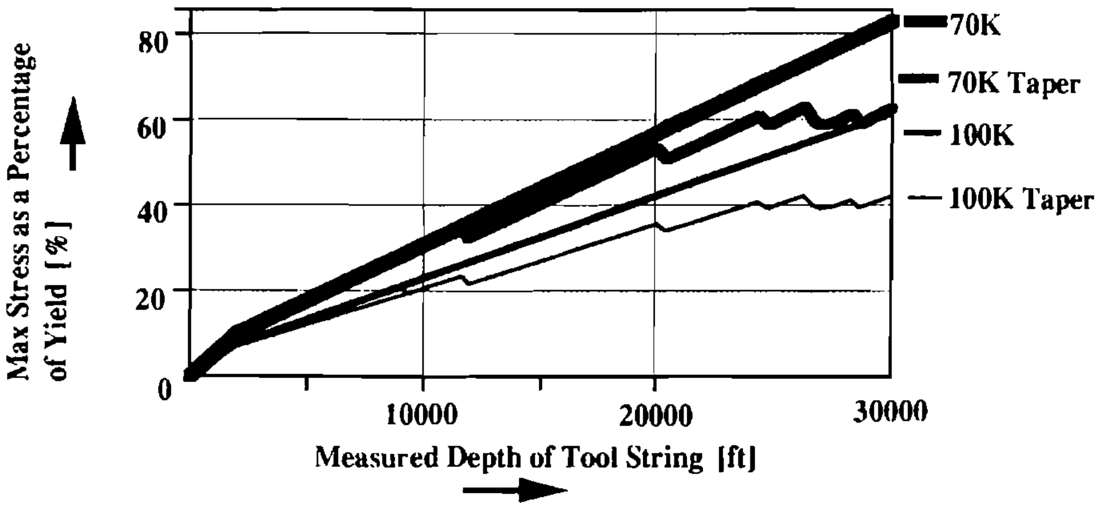

Figure 2-14. Tensile Stress for Uniform and Tapered Coiled-Tubing Strings (van Adrichem and Spruill, 1993)

As noted, the maximum penetration is achieved in a wellbore inclination of 72°. At higher angles (Figure 2-15), maximum penetration decreases to about 8000 ft in a horizontal (90°) wellbore.

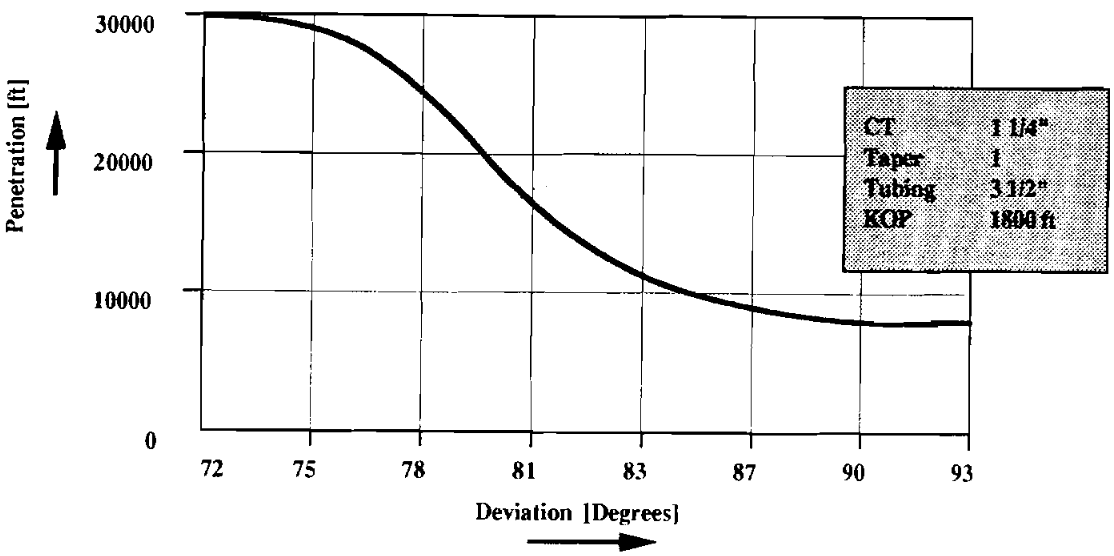

Figure 2-15. Maximum Penetration Versus Inclination Angle (van Adrichem and Spruill, 1993)

Build rate in the curve section also impacts maximum penetration. Schlumberger Dowell ran simulations with build rates from 1°/100 ft up to 100°/100 ft (Figure 2-16). The maximum loss of penetration due to shorter radius build rates was 2200 ft at an inclination of 81°. It is interesting to note that build rate has almost no effect on achievable penetration for wellbores with inclinations near 72° or 90°.

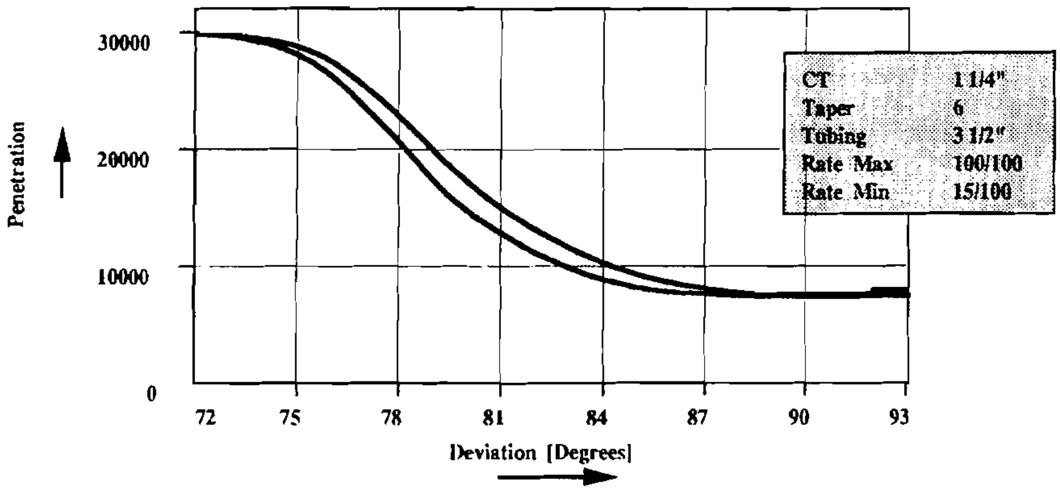

Figure 2-16. Maximum Penetration Versus Curve Section Build Rate (van Adrichem and Spruill, 1993)

The effect of larger casing below the production tubing was analyzed. Simulation runs showed no difference for either 5- or 9⅝-in. casing. Apparently, this relatively short 5000-ft interval of casing does not impact buckling to a significant degree.

The effect of changing production-tubing diameter is more significant (Figure 2-17). Deeper penetration is achieved with smaller production tubing, especially in the range of 75-87° inclination. The maximum difference is at an angle of 79° (6600 ft less with 3½-in. than with 2⅜-in.).

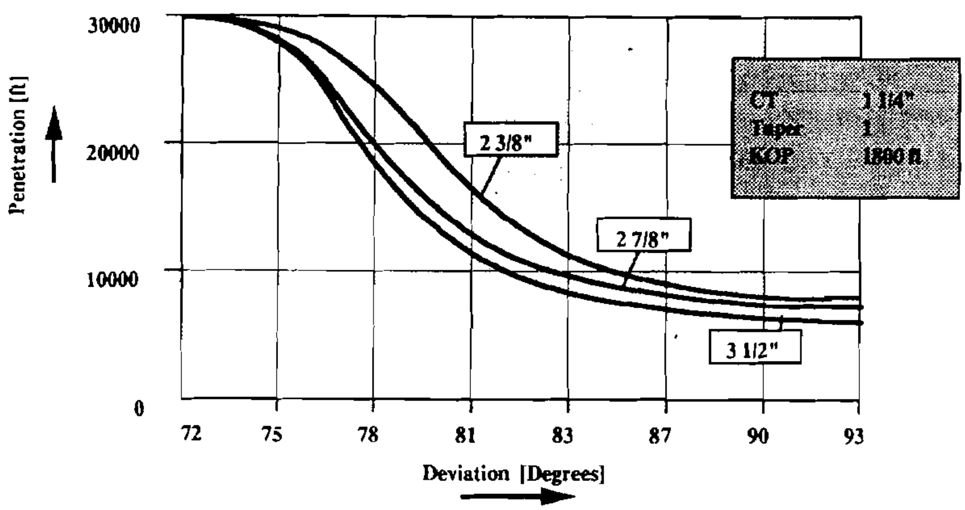

Figure 2-17. Maximum Penetration Versus Production Tubing Size (van Adrichem and Spruill, 1993)

A final geometric variable considered was depth of the kick-off point (Figure 2-18). At inclinations of 83° and greater, every 1000-ft increase in kick-off depth resulted in a 1000-ft increase in penetration.

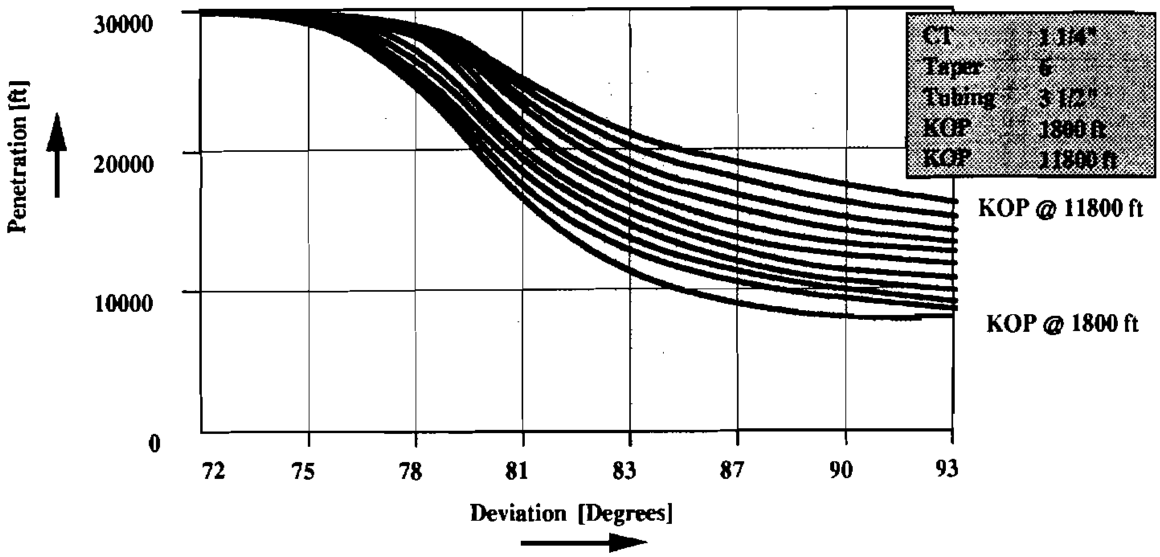

Figure 2-18. Maximum Penetration Versus Kick-Off Point Depth (van Adrichem and Spruill, 1993)

Beyond wellbore design considerations, other concerns must be addressed to determine the practicality of coiled-tubing operations in a 30,000-ft well. Spool weights are compared for various sizes and metallurgies in Table 2-2.

TABLE 2-2. Spool Weights for 30,000-Ft String (van Adrichem and Spruill, 1993)

Tubing (O.D.)	70K (lbs)	70K Taper (lbs)	100K (lbs)	Titanium (lbs)
1¼ in.	35,160	39,230	32,430	18,780
1½ in.	42,750	47,700	39,390	24,750
1¾ in.	57,360	63,930	57,300	33,180
Empty reel package weight: 16,000 lb				

Pump rates that could be achieved were also considered. Pressure drops for fresh water and brine (11.6 ppg) were calculated (Figure 2-19). Maximum allowable tubing pressure is 5000 psi. The lower bound in the figure for each size of coiled tubing corresponds to fresh water. The maximum pump rate for 1¼-in. tubing would be about 0.6 BPM with fresh water at 5000 psi.

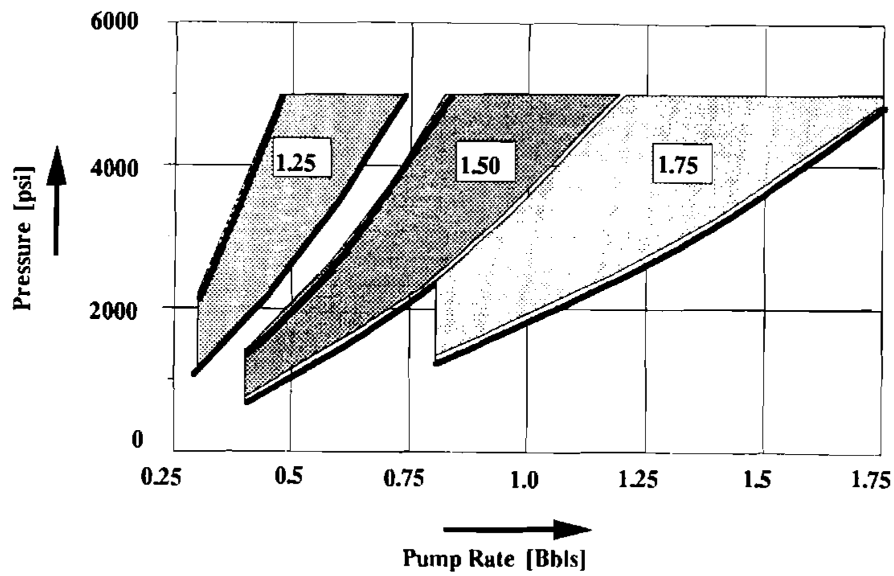

Figure 2-19. Pressure Drop and Pump Rate Through 30,000-Ft String (van Adrichem and Spruill, 1993)

The final parameter considered in the feasibility analyses was whether any useful capacity was available to perform work after reaching 30,000 ft. Both WOB tensile and pulling capacity are summarized in Table 2-3.

TABLE 2-3. WOB and Pulling Force at 30,000 Ft (van Adrichem and Spruill, 1993)

	WOB	PULL
1¼ In.	625 lbs	7500 lbs
1½ In.	1200 lbs	7500 lbs
1¾ In.	2350 lbs	7500 lbs

Schlumberger Dowell concluded that it is feasible to run coiled tubing to 30,000 ft under certain conditions. These include a wellbore inclination of 72-74° and a tapered work string.

2.1.4 Schlumberger Dowell (Residual-Bending Model)

Schlumberger Dowell (Bhalla, 1994) developed a coiled-tubing buckling model that accounts for the effects of residual bends in the tubing string. Comparison of results with the model to field measurements and Schlumberger Dowell's previous buckling model showed good agreement.

After coiled tubing is plastically deformed across the reel and gooseneck, it cannot be completely straightened. Coiled tubing hangs in the well with a helical curvature after passing through the injector. This residual curvature results in the generation of lateral loads against the wellbore, which increase friction and resist forward movement of the tubing.

The effects of residual bends in coiled tubing have been ignored in most buckling models. Residual bending results in premature buckling while running in hole. The method most often used to account for this generally observed tendency is to use different friction coefficients for running in and pulling out of hole. Schlumberger Dowell has commonly used a friction coefficient of 0.30 for slack off and 0.18 for pick up, assuming steel-on-steel in an oil-wet environment.

A nondimensional curvature variable versus applied bending moment is plotted for the general run-in case in Figure 2-20. The elastic unloading as the tubing leaves the reel is represented as path BC in the figure. After the tubing is plastically bent across the gooseneck, it is again unloaded, this time along path DE. The final residual curvature is shown by OE (along the x-axis).

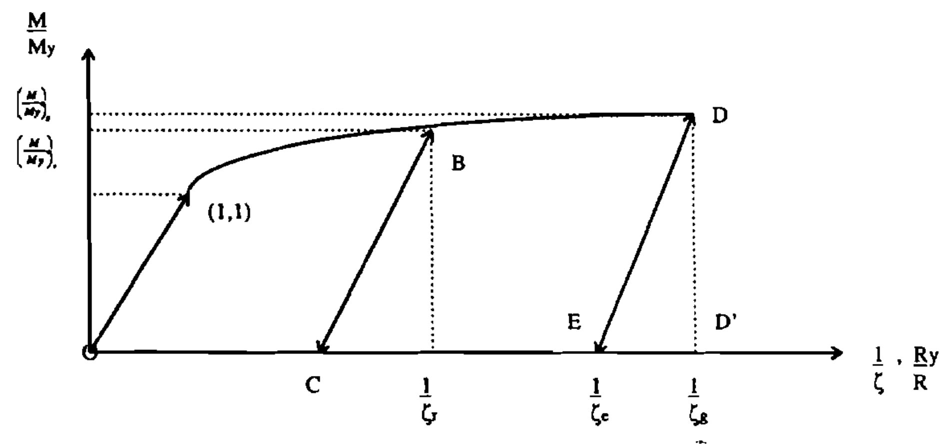

Figure 2-20. Moment/Curvature Plot for Bending Coiled Tubing (Bhalla, 1994)

Results with the residual-bending model are compared to output from Schlumberger Dowell's standard buckling model (CoilCADE) in Figure 2-21. The friction coefficient is set at 0.18 for both pick-up and slack-off with the residual-bending model. For CoilCADE, 0.30 is used for slack-off and 0.18 for pick-up. These two approaches compare favorably for this horizontal well.

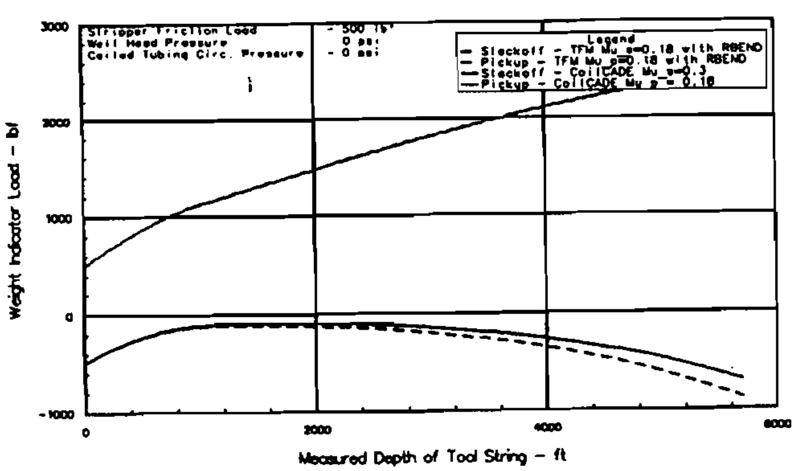

Figure 2-21. Predicted Weight Indicator With and Without Residual Bend (Bhalla, 1994)

Bending radius has an important impact on the magnitude of residual bending. Bhalla modeled the effect of varying reel and gooseneck radii on coiled-tubing buckling. For small radii (e.g., 30-in. reel radius; 72-in. gooseneck radius), lock-up of the coiled tubing occurs much earlier than for larger radii (Figure 2-22). For large radii (e.g., 200-in. reel radius; 100-in. gooseneck radius), slack-off loads asymptotically approach the CoilCADE prediction for friction factor of 0.18 (dot-dash curve).

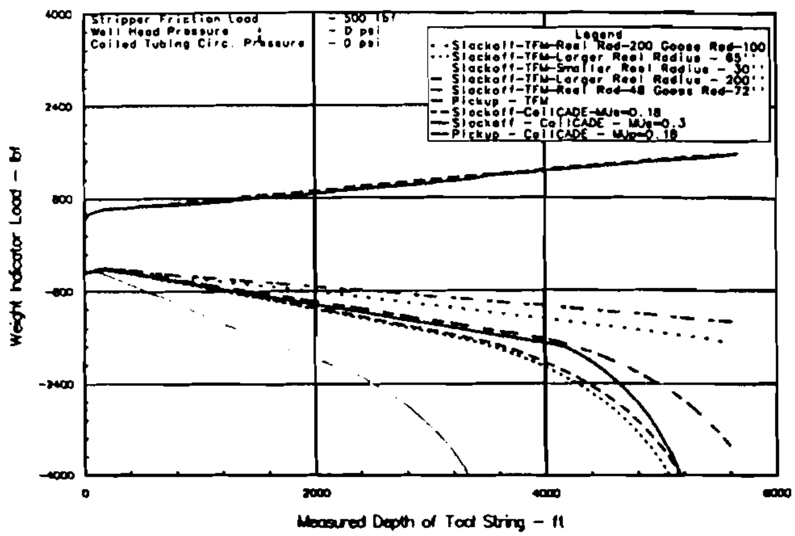

Figure 2-22. Effect of Reel and Gooseneck Radii (Bhalla, 1994)

Schlumberger Dowell investigated the impact of tubing yield strength on residual bending. Less plastic deformation occurs at a given bending radius as yield strength is increased; thus, higher yield strengths should decrease residual bending and increase penetration. Results are shown in Figure 2-23 for 70-ksi, 87.5-ksi and 105-ksi tubing. The three predicted weight indicator curves are similar. Yield strength does not appear to strongly affect residual bending and tubing penetration.

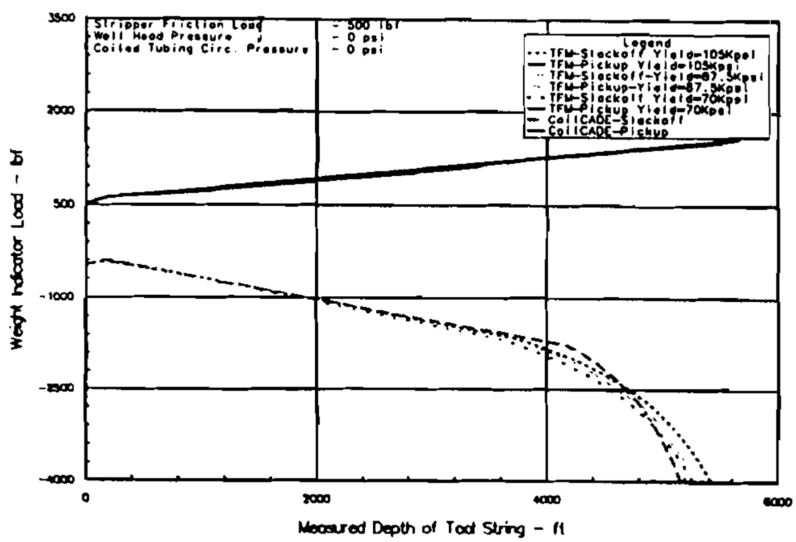

Figure 2-23. Effect of Tubing Yield Strength (Bhalla, 1994)

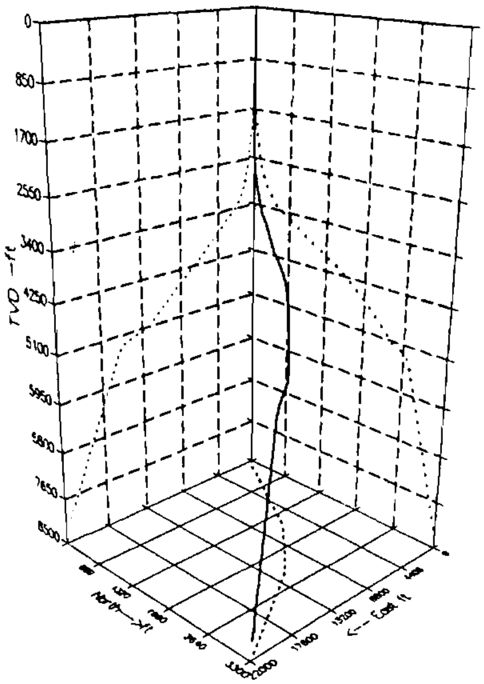

Figure 2-24. Profile of Example Well (Bhalla, 1994)

The residual-bending model was compared to results from a field operation. The subject well had a diameter of 4.89 in. to a T.D. of 25,000 ft (Figure 2-24). A four-section tapered coiled-tubing string was used to enter the well. Tubing O.D. was 1¾ in., reel diameter was 120 in., and gooseneck radius was 72 inches.

Measurements and predictions, with both residual-bending model and CoilCADE, compare favorably for operations in this well (Figure 2-25). As was true for other cases, a friction factor of 0.18 was used for both slack-off and pick-up calculations with the residual-bending model. For CoilCADE, 0.30 was used for slack-off and 0.18 for pick-up.

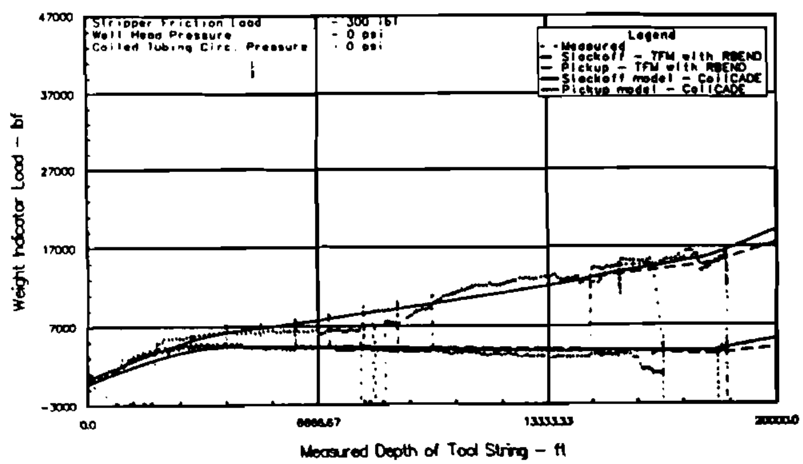

Figure 12-25. Modeled and Measured Results for Example Well (Bhalla, 1994)

Schlumberger Dowell's developments and analyses showed that the new residual-bending model for use in predicting coiled-tubing buckling is in good agreement with their older model (which uses empirical fixes to match field observations), as well as data measured in the field. The use of the new residual-bending model allows the use of the same friction factor for both run-in and pull-out operations.

2.2 FIELD STUDIES/APPLICATIONS

2.2.1 BP Exploration Operating (Wytch Farm Operations)

BP Exploration Operating Co. Ltd. (Summers et al., 1994) discussed the use of coiled tubing to service extended-reach wells in the Wytch Farm field on the southern coast of England. Three extended-reach wells have been drilled with departures as great as 5001 m (16,400 ft) (Table 2-4). Well profile designs were modified as the development progressed to optimize both drilling conditions and coiled-tubing penetration during completion and servicing.

TABLE 2-4. Wytch Farm Extended-Reach Wells (Summers et al., 1994)

Well	Departure (m)	Departure (ft)	TVD (m)	TVD (ft)	Measured Depth (m)	Measured Depth (ft)	Tangent Angle (degrees)
F18	3,857	12,655	1,670	5,479	4,450	14,600	72
F19	5,001	16,408	1,675	5,496	5,757	18,889	82
F20	4,486	14,719	1,667	5,469	5,300	17,389	80

Development at Wytch Farm began in the late 1970s with the onshore areas of the field. Currently, about 80 wells produce over 85,000 BOPD. Development of reserves located offshore was planned beginning in 1990. An artificial island was first considered to be the most practical approach. In late 1991 as a result of technological developments within the industry, the development plan was changed to extended reach wells drilled onshore. Cost savings with this approach were about 50%.

These extended-reach wells are each equipped with an ESP. The completion includes 5½-in. production tubing. Access to the liner with coiled tubing is by means of a 2⅞-in. logging bypass (Figure 2-26).

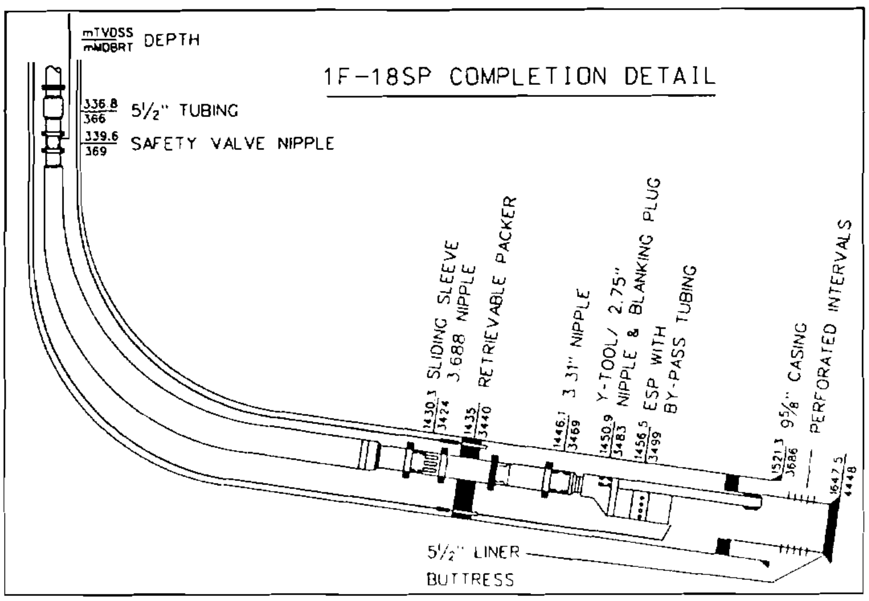

Figure 2-26. Extended-Reach Well Completion (Summers et al., 1994)

The first extended-reach well (F18) was drilled with a tangent angle of 72° (Figure 2-27), which was considered the optimum angle for minimizing torque and drag while drilling. The second well (F19) was designed with a catenary profile and tangent angle of 82°. This design successfully decreased drilling torque and drag. However, coiled-tubing access was limited. The third well (F20) was designed for an optimum compromise between low torque and drag while drilling and extended coiled-tubing penetration.

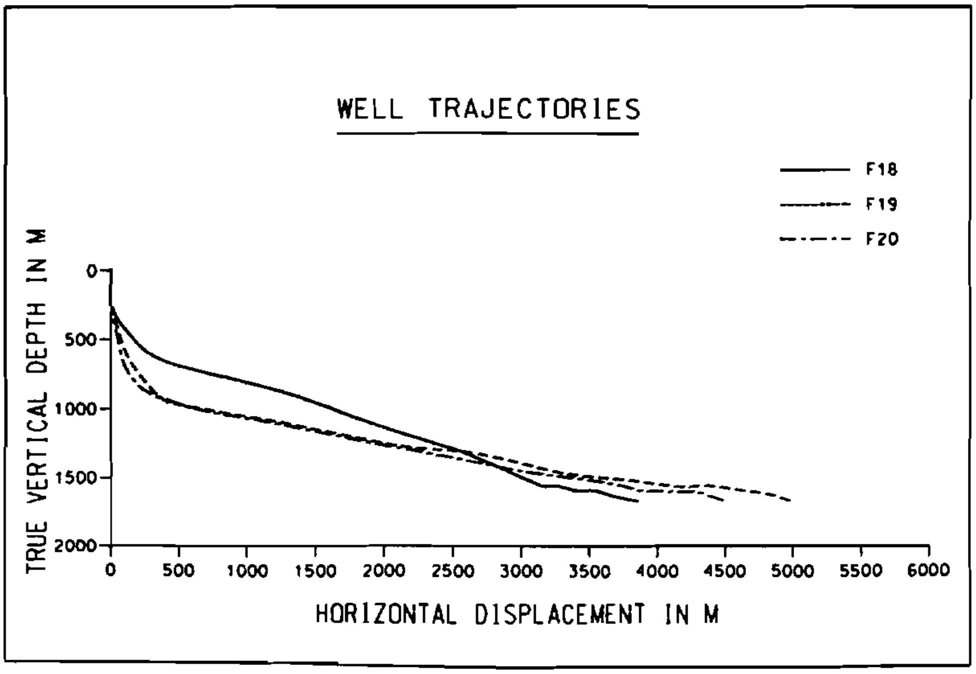

Figure 2-27. Wytch Farm Extended-Reach Well Profiles (Summers et al., 1994)

BP Exploration Operating carefully planned the design and implementation of coiled-tubing operations in these wells. Schlumberger Dowell's standard model was used to predict buckling and penetration limits. Typical values for friction factor were assumed in initial runs: 0.30 for slack-off and 0.18 for pick-up. These values were later modified based on ongoing measurements.

In the first well (F18), post-job analysis of the cement-bond logging run showed the slack-off friction factor to be equivalent to about 0.21 (Figure 2-28). Residual bending was surmised to have less effect than expected; thus, the friction factor while running in was closer to the ideal value of 0.18. Later runs of coiled tubing inside production tubing exhibited a slack-off friction factor of about 0.26. Residual bending had a greater impact on drag inside the smaller diameter production tubing.

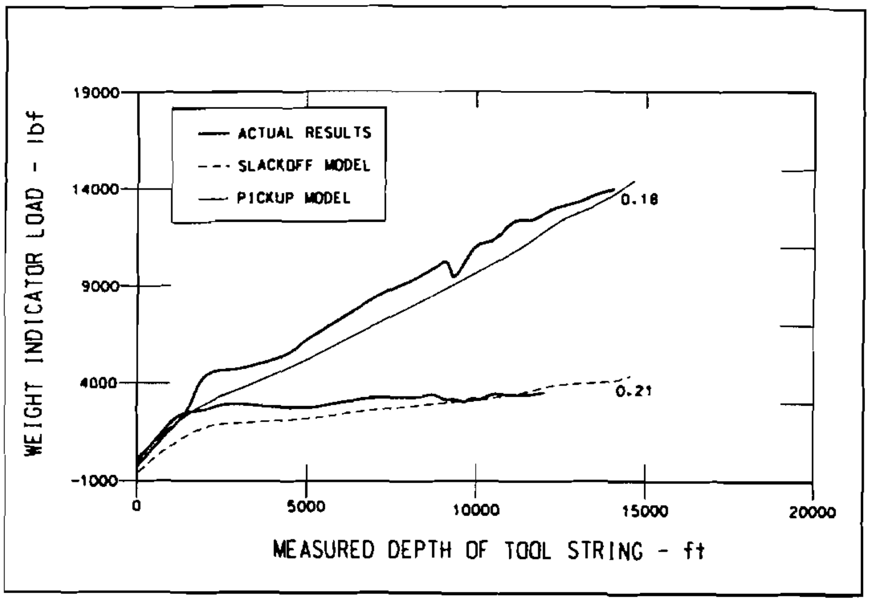

Figure 2-28. Weight Indicator from CBL in Well F18 (Summers et al., 1994)

The second well (F19) was modeled based on results with the first well. Lock-up was predicted at 4966 m (16,293 ft), that is, 791 m (2595 ft) short of TD. During initial run-in, the string locked up about 3% deeper than predicted. A friction reducer was used to increase penetration. After 400+ bbl of friction-reducer fluid was pumped, friction decreased about 15% and TD was reached successfully.

Post-job analysis showed friction factors to have been reduced to 0.18 for slack-off and 0.15 for pick-up (Figure 2-29).

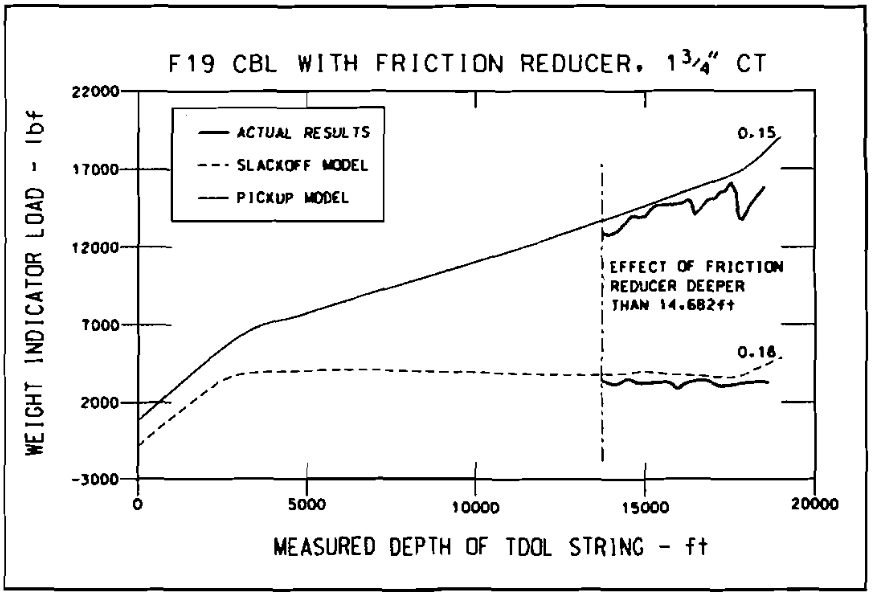

Figure 2-29. Weight Indicator from CBL in Well F19 (Summers et al., 1994)

Friction-factor predictions for the third well (F20) were accurate, and TD was reached without difficulty.

BP Exploration Operating plans to drill a fourth extended-reach well out to a departure of 5700 m (18,700 ft). Modeling predictions suggest that friction reducer will be required to reach TD along with displacing the coiled tubing to nitrogen to increase buoyancy. BP's experience has convinced them that wellbore tangent angles must be optimized both for drilling and coiled-tubing penetration. They believe the industry needs to develop alternative methods to increase penetration, such as pump-down systems and tractors. They also cite the need for improved coiled-tubing buckling models, especially for wells flowing at high rates.

2.2.2 Mobil Erdgas-Erdöl GmbH (Open-Hole Logging)

Based on the results of two series of field trials in open-hole shallow horizontal wells, Mobil Erdgas-Erdöl GmbH (Van den Bosch, 1994) found that coiled-tubing logging operations did not offer advantages as compared to drill-pipe-conveyed methods due primarily to coiled-tubing lock-up. They found that buckling simulation programs were unreliable for calculating penetration limits for coiled tubing in the open hole.

Mobil completed and logged eight shallow medium- to short-radius horizontal wells. More details are presented on these projects in the Chapter *Logging*. Mobil used both coiled-tubing-conveyed and drill-pipe-conveyed logging for these programs.

TABLE 2-5. Mobil Horizontal Well Logging Program (Van den Bosch, 1994)

Well	Horizontal Length, m	True Vertical Depth, m	Build-Up Radius, m	Dogleg, °/30 m	Formation	Application
R-302	128	638	28	62	Chalk	Gas Storage
R-303	298	905	30	58	Chalk	Gas Storage
R-304	390	890	29	60	Chalk	Gas Storage
R-305	432	958	34	52	Chalk	Gas Storage
R-306	426	693	28	62	Chalk	Gas Storage
Well A	414	660	146	12	Sandstone	Oil Well
Well B	715	1,172	194	9	Sandstone	Oil Well
Well C	161	948	125	14	Sandstone	Oil Well

Wellbore profiles are summarized in Figure 2-30.

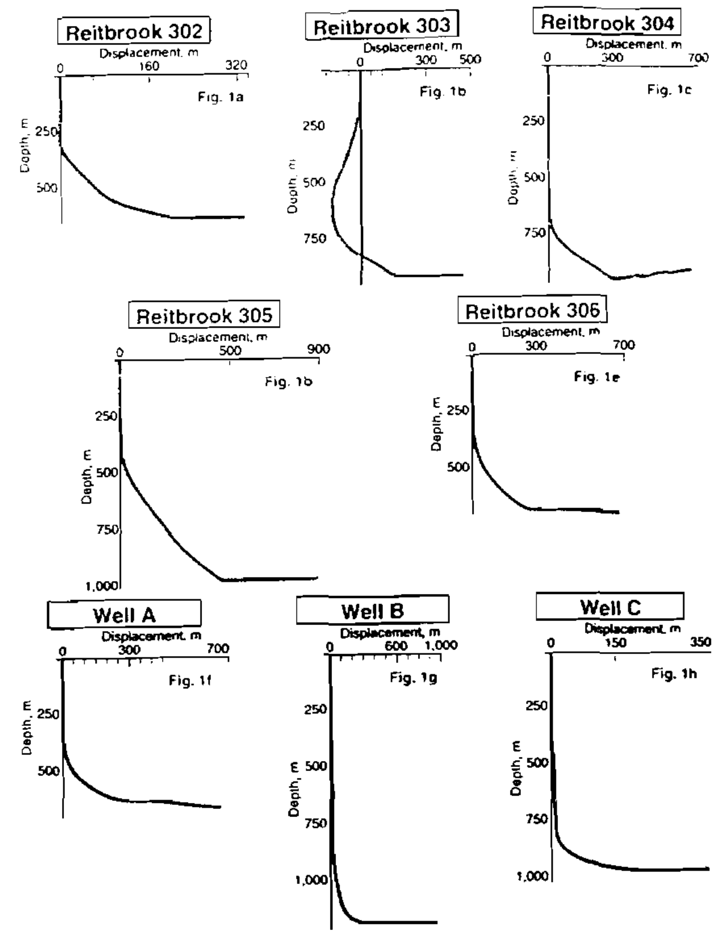

Figure 2-30. Mobil Horizontal Well Profiles (Van den Bosch, 1994)

The wells were entered with a dummy logging tool on coiled tubing prior to running logging tools. The dummy run was to determine whether total depth could be reached without lock-up. On the first well (R-303), the dummy tool reached total depth without problems. The logging run locked up 170 m (560 ft) into the horizontal section. In well R-304, only 60 m (200 ft) of open hole could be penetrated before lock-up. Later, both wells were successfully logged with drill pipe.

In R-306, larger coiled tubing (1¾ in.) was used in an attempt to increase penetration. However, lock-up occurred after 290 m (950 ft) of the 426-m open-hole section. Forces measured at the surface and downhole are compared in Figure 2-31. Since the compression force at the tool is not increasing at lock-up (1068 m MD), wellbore friction was determined to be causing buckling. As before, drill-pipe-conveyed tools were later run to TD without problems.

In the first oil well (Well A), neither logging run on coiled tubing reached TD. On Well B, buckling lock-up was predicted due to the long horizontal section, so coiled tubing was not run.

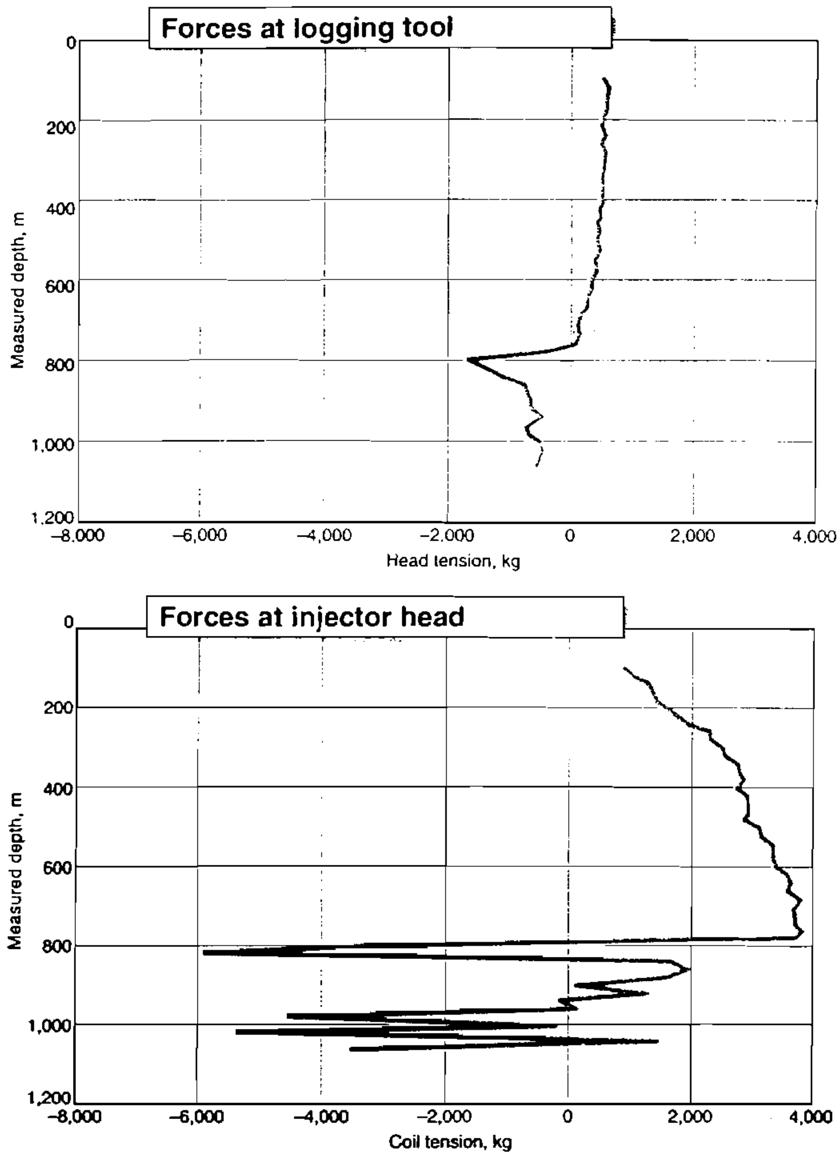

Figure 2-31. Well R-306 Downhole and Surface Loads (Van den Bosch, 1994)

Success of the coiled-tubing and drill-pipe runs is summarized in Figure 2-32. Coiled-tubing conveyance was successful to an average of 62%; drill-pipe conveyance was 100% successful.

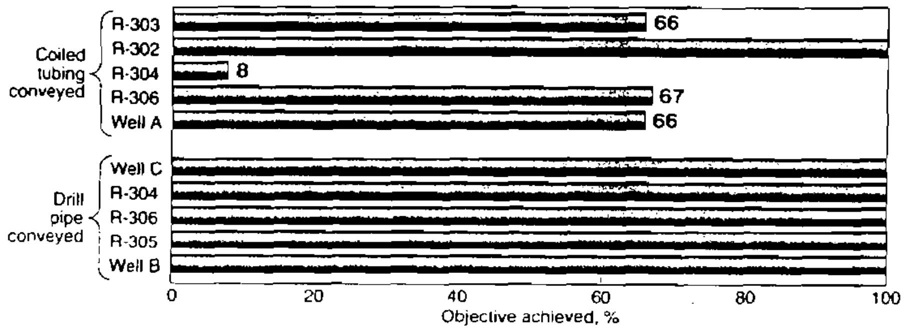

Figure 2-32. Success of Coiled-Tubing Versus Drill-Pipe Logging (Van den Bosch, 1994)

Mobil Erdgas-Erdöl GmbH reached several conclusions after this field trial comparing coiled-tubing- to drill-pipe-conveyed logging. Problems with coiled-tubing operations included:

- Buckling and lock-up was a significant problem in the open-hole environment. Maximum penetration was about 290 m (950 ft) with 1¾-in. tubing.
- Successful runs to TD with a dummy logging tool do not guarantee success with actual logging tools.
- Buckling prediction software was inadequate for these projects.

The author does note that Mobil believes that these problems will be overcome, buckling prediction will be improved, and that coiled-tubing logging in open hole will in the future be more efficient than using drill pipe.

2.2.3 PEA-13 Joint-Industry Project (Full-Scale Buckling Tests)

Six operating companies and six service companies joined efforts in a joint-industry project (PEA-13) to investigate coiled-tubing buckling behavior in full-scale tests (Tailby et al., 1993). They considered the effects of residual bends in tubing, tip loads on the string, and well profile. Data recorded during several series of tests showed that classic buckling theory derived for straight drill pipe is too conservative for coiled tubing.

Primary objectives of PEA-13 included to observe full-scale behavior of coiled tubing under buckling conditions and compare these to theory; to identify penetration limits for use of coiled tubing in horizontal wells; and measure force transmission (F_{in}/F_{out}) for a range of conditions. Many of the tests were conducted in a 4-in. through-flow-line test loop. The vertical undulations of the test section (Figure 2-33) represent conditions in a horizontal well with poor depth control.

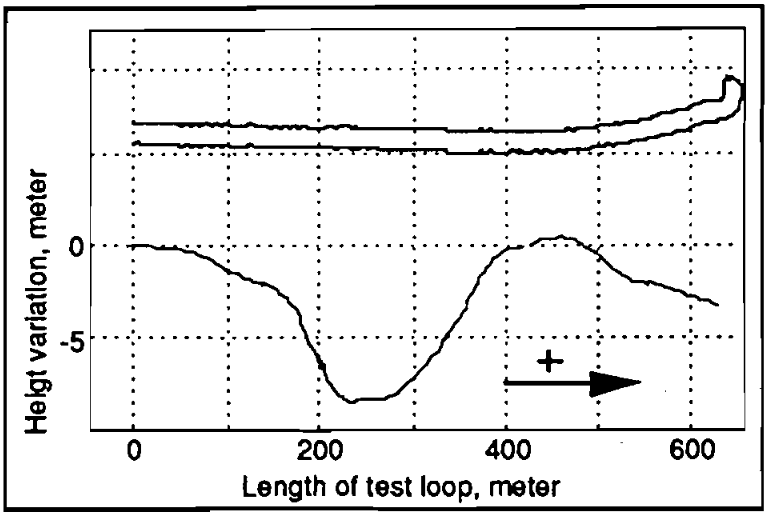

Figure 2-33. PEA-13 Test Loop Overhead View and Profile (Tailby et al., 1993)

Through flow-line locomotives were used to provide compression forces in many of the tests. Forces were calculated by measuring pressures above/below the locomotive and in a static load cell at the tip of the coiled tubing (Figure 2-34). In later tests, a coiled-tubing injector and a double-acting cylinder were used to apply compressive force to the tubing.

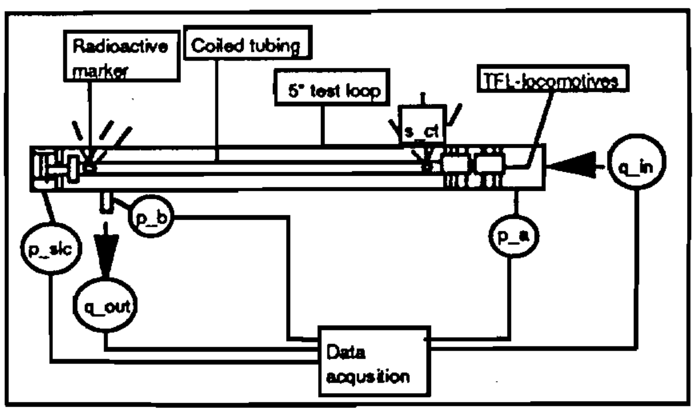

Figure 2-34. PEA-13 Test Loop Schematic (Tailby et al., 1993)

Typical results from tests with the through flow-line locomotive are shown in Figure 2-35. Casing ID was 4 in.; coiled tubing was 1½ x 0.134 in. Length of coiled-tubing string is shown in the figure.

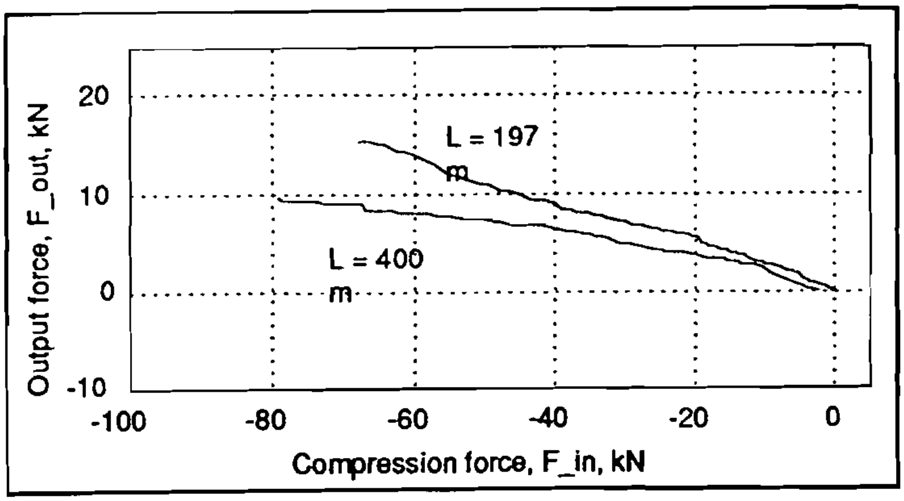

Figure 2-35. Compressive Force and Output Force for 1½-in. Tubing (Tailby et al., 1993)

Coiled tubing clearly continued to transmit force for a range above the helical buckling limit. Concerns about the design of the testing apparatus led to the use of a double-acting cylinder as the locomotive. Typical results with this test set-up are shown in Figure 2-36 for 1¾ x 0.125-in. tubing.

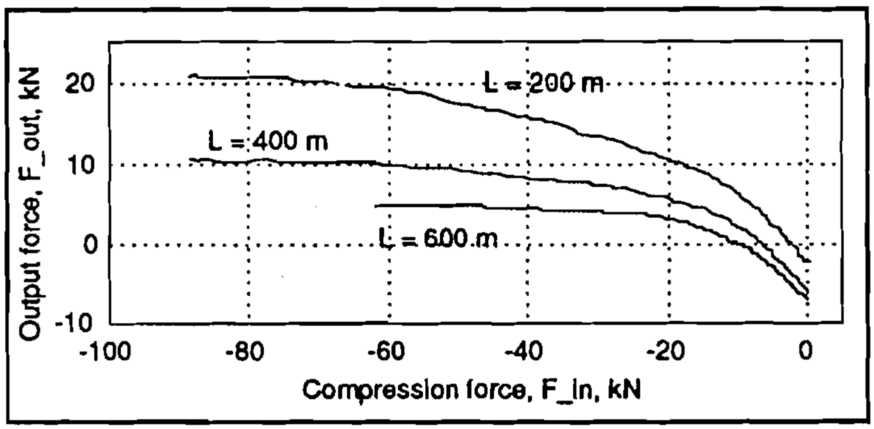

Figure 2-36. Compressive Force and Output Force for 1¾-in. Tubing (Tailby et al., 1993)

The effect of coiled-tubing length on force output is summarized in Figure 2-37 for a range of input compression forces. For longer lengths of tubing, large changes in the input force have only a small impact on the tip load.

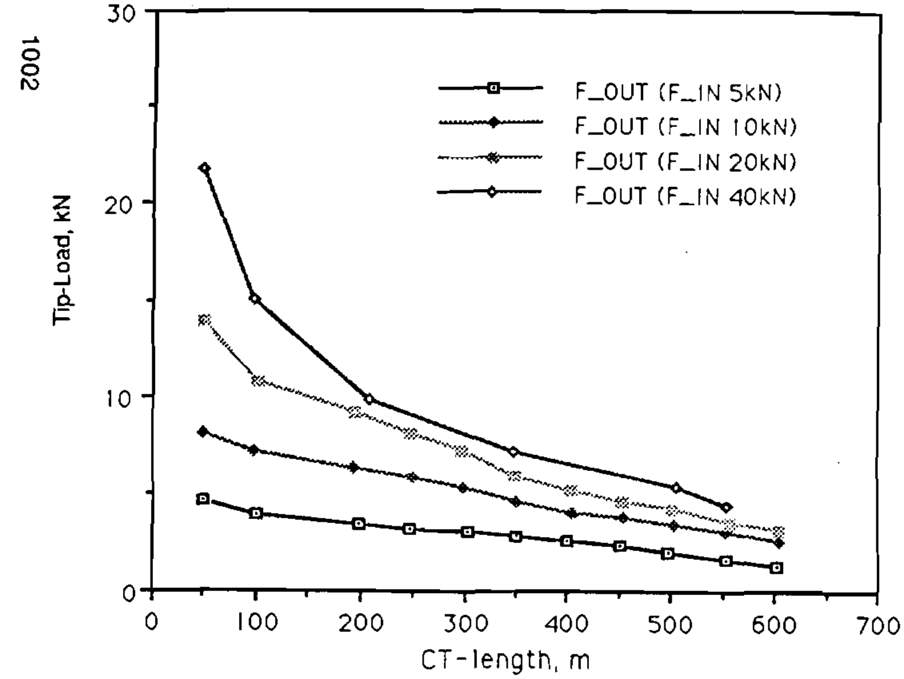

Figure 2-37. Coiled Tubing Length and Output Force for 1¾-in. Tubing (Tailby et al., 1993)

Residual bending effects were observed to cause friction force to build with each insertion of a particular section of coiled tubing into the test casing. An example of changing friction force is shown in Figure 2-38 for 1¼ x 0.125-in. coiled tubing with the double-acting cylinder locomotive.

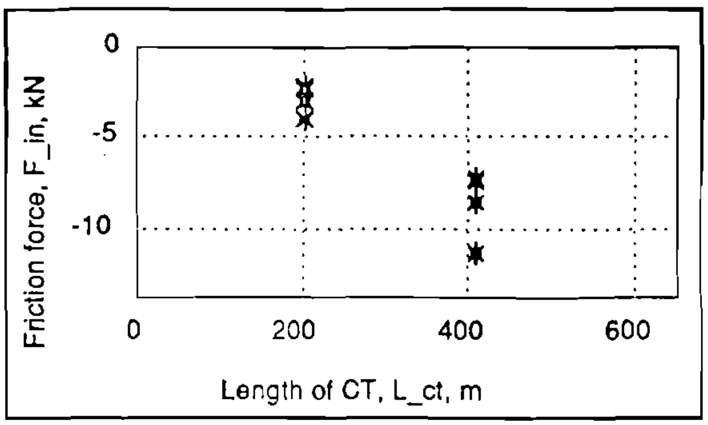

Figure 2-38. Change in Static Friction Force for 1¼-in. Tubing (Tailby et al., 1993)

PEA-13 experiments with friction forces indicated that a friction coefficient of 0.18 is appropriate for an oil environment and 0.2-0.3 for a water environment.

Conclusions from this investigation of coiled-tubing buckling and force transmission include:

- Transmitted force is affected by residual bends in coiled tubing.
- No anomaly was observed at the helical buckling limit.
- Tip loads can lead to premature lock-up of coiled tubing. This is of special concern for entering inverted wells.

2.2.4 Schlumberger Dowell (Verifying Model Predictions)

Schlumberger Dowell (van Adrichem and Newman, 1993) presented a comparison of drag and buckling model predictions with results from several jobs performed in the field. Their observations from both laboratory and field work highlighted several characteristics of helically buckled tubing:

- Helical buckling sets up only in the section(s) of the pipe where the helical buckling load is exceeded
- Helical buckling does not damage the tubing
- The tubing helix reverses direction every few periods
- Helical buckling increases wall contact forces, leading to increased friction
- Once initiated, helical buckling does not necessarily halt tubing penetration. Lock-up occurs when input forces cannot overcome friction forces
- Tubing is not usually damaged by helical lock-up

A summary of results from several coiled-tubing field operations is presented in Table 2-6. Predicted and actual lock-up depths are generally in good agreement. Errors also tend to be conservative (the tubing went deeper into the well than predicted).

TABLE 2-6. Predicted and Actual Lock-up Depths (van Adrichem and Newman, 1993)

Job Type	Completion Size (In.) (Open Hole)	TD (Ft)	Horizontal Section (Ft)	Predicted Lockup MD (ft)	Actual Lockup MD (ft)	Actual vs. Predicted (%)
CTL	8½	4,180	1,558	3,963	3,940	-0.6
CTL	8½	8,390	3,379	6,593	6,240	-5.7
Acid+N_2	6⅛	10,256	3,356	10,100	10,256	1.5
Acid+N_2	6⅛	10,971	3,971	9,819	10,387	5.5
Acid+N_2	6⅛	11,306	3,656	9,900	11,300	12.4
Acid	6⅛	8,962	2,064	8,962	8,825	-1.6
Acid+N_2	8½	13,402	3,802	12,990	12,720	-2.1
Acid	8½	10,801	4,200	9,100	8,970	-1.4
Acid	8½	11,481	4,800	11,200	11,000	-1.8

Schlumberger Dowell's model does not account for residual bend in coiled tubing, but is based on straight-pipe theory with an empirical correction. Development has continued to incorporate the effects of residual bends on tubing buckling behavior.

A generic tubing hook-load plot for running coiled tubing in a horizontal well is shown in Figure 2-39. At point 1, weight at surface is negative since the injector has to push against well pressure, stripper friction, etc. The weight begins to decrease at point 3 (the start of the curved section) as friction forces increase. The pipe locks up due to helical buckling at point 5, and the weight indicator goes to zero.

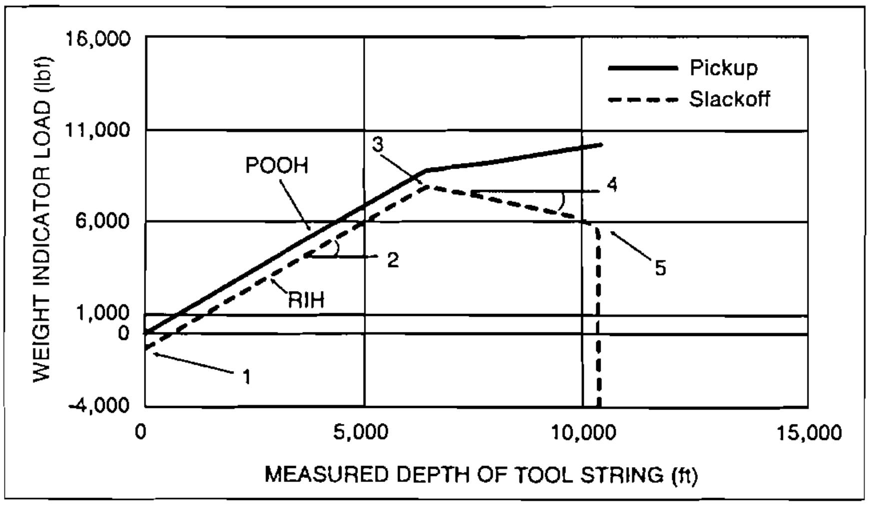

Figure 2-39. Generic Weight Indicator Readout for Job in Horizontal Well
(van Adrichem and Newman, 1993)

Among the most difficult parameters to estimate are hole size and friction coefficient in open-hole conditions. Values must be estimated based on previous jobs in the same formation. Improved estimates are calculated after the job is performed.

Field results from a coiled-tubing logging job are compared with model predictions in Figure 2-40. The well was vertical down to 1600 ft, then kicked off to 72° all the way to TD. Surface weight became positive at about 1800 ft, rose to about 500 lb and remained nearly constant out to TD.

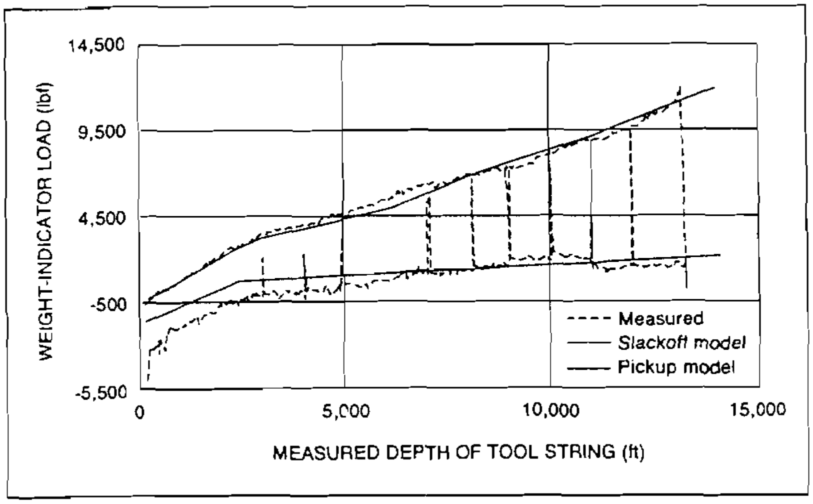

Figure 2-40. Coiled-Tubing Logging Run in Horizontal Well (van Adrichem and Newman, 1993)

Results from an acid wash in a horizontal well (Figure 2-41) illustrate a successful attempt to increase penetration beyond initial lock-up. Model calculations predicted lock-up 50 ft short of TD. While running in, nitrogen was circulated, resulting in increased drag after wellbore fluids were displaced. The string locked up at 9600 ft. Water was then pumped into the well and the coiled tubing reciprocated. Final lock-up occurred 120 ft short of predicted depth. Actual pick-up loads are higher than predictions because calculations were performed assuming nitrogen inside the tubing. After acid was circulated, nitrogen was pumped through the string, and the weight returned to near predictions.

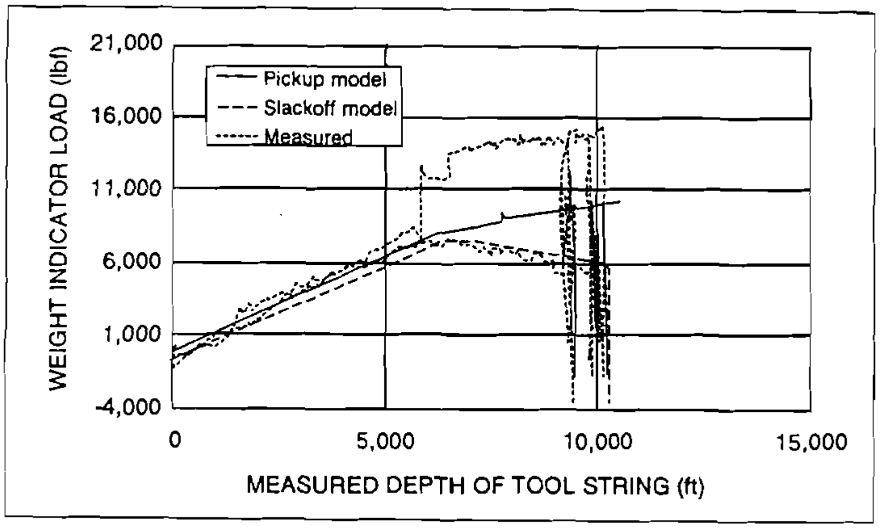

Figure 2-41. Coiled-Tubing Acid-Wash Job in Horizontal Well (van Adrichem and Newman, 1993)

2.2.5 Statoil (Pump-Assistance Conveyance)

Statoil (Tailby, 1993) described the design and development of pump-assistance conveyance for extending the reach of coiled tubing in extended-reach wells. Horizontal wells are being drilled or planned that are beyond the capability of conventional coiled-tubing systems. The pump-assist concept is designed to extend these limits.

Coiled-tubing-assisted pumpdown was first conceived by Statoil. This approach involves the use of leading and trailing locomotives attached to a length of coiled tubing that is pumped down to the production zone. The leading locomotive stops at a no-go nipple just above the production packer. "Scoping" of the coiled tubing may occur (Figure 2-42) after the seals on the locomotive enter the nipple bore. Since the leading locomotive is free to slide along the coiled tubing, the tubing will advance deeper into the well after being pressurized.

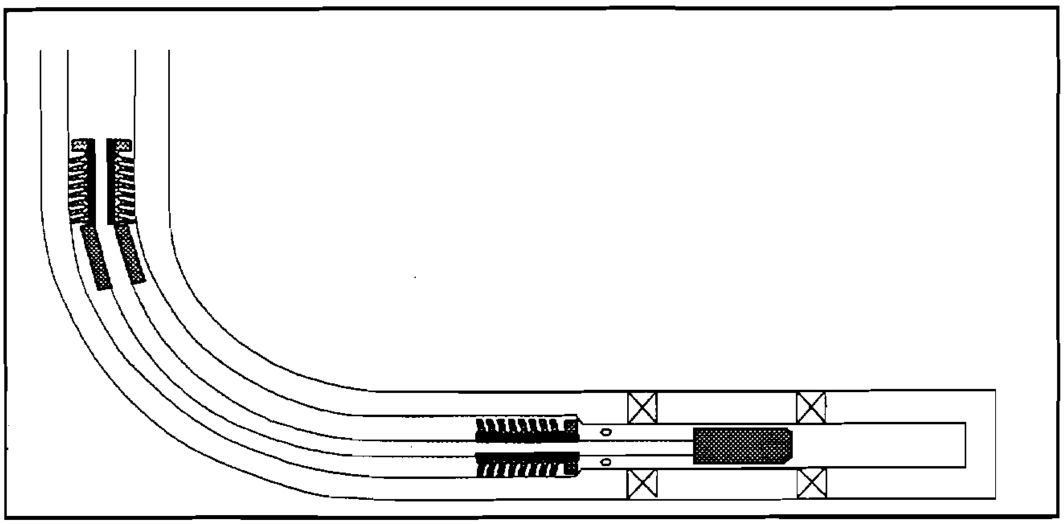

Figure 2-42. Scoping with Coiled-Tubing-Assisted Pumpdown (Tailby, 1993)

Statoil modified the coiled-tubing-assisted pumpdown approach into a less radical design that takes advantage of scoping. The second concept is termed pumpdown-assisted coiled tubing. It involves running conventional coiled tubing to a no-go nipple located close to the top of perforations. A seal adaptor (Figure 2-43) is run behind the BHA.

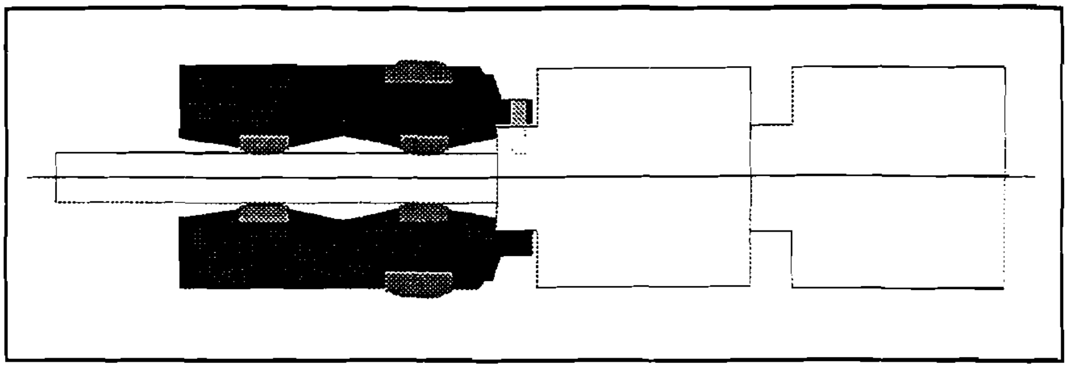

Figure 2-43. Pumpdown-Assisted Coiled-Tubing Seal Adaptor (Tailby, 1993)

After the BHA end of the coiled tubing is isolated from the rest of the string, slacking off weight at surface (or snubbing) will cause coiled tubing to move through the seal adaptor and deeper into the well (Figure 2-44), providing the annular pressure is greater than bottom-hole pressure.

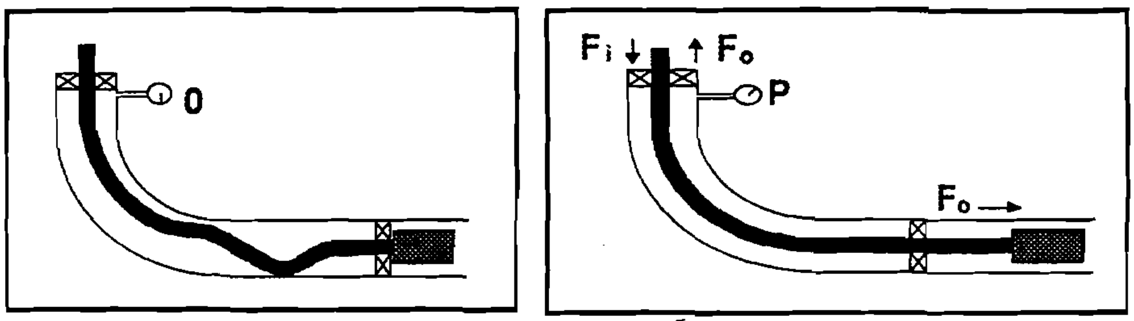

Figure 2-44. Pumpdown Assist Used to Increase Coiled Tubing Reach (Tailby, 1993)

An example was provided by Tailby (1993) to illustrate the potential benefit of pumpdown-assisted coiled tubing. At a depth of 4595 m (15,075 ft), one meter of string movement causes substantial loss of surface weight (Figure 2-45).

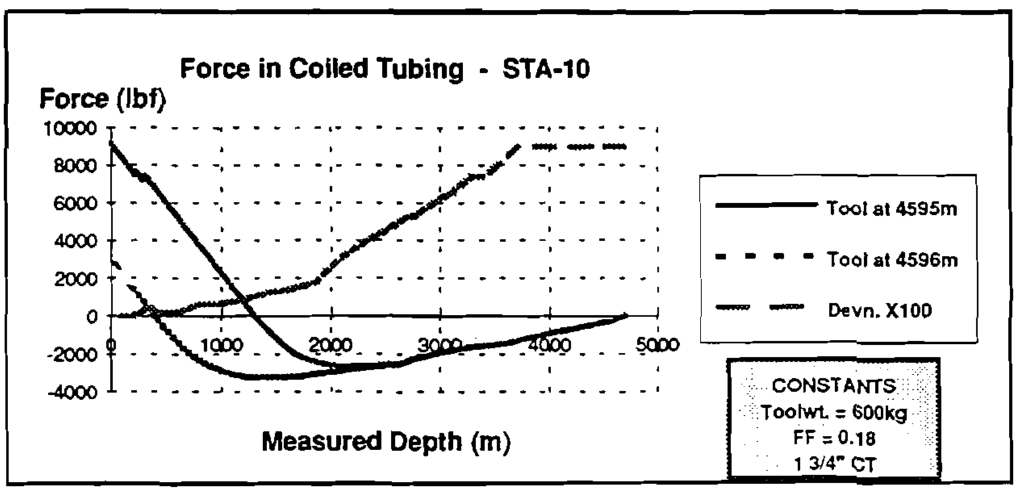

Figure 2-45. Coiled Tubing Lock-Up in Example Extended-Reach Well (Tailby, 1993)

If a no-go nipple were installed above the perforations, the section of coiled tubing that was under the largest compressive forces could be unbuckled by pumpdown assist. In Statoil's simulation, a no-go nipple was placed at 3900 m and the annulus pressurized to 500 psi. Compressive forces were greatly reduced and coiled-tubing reach extended (Figure 2-46).

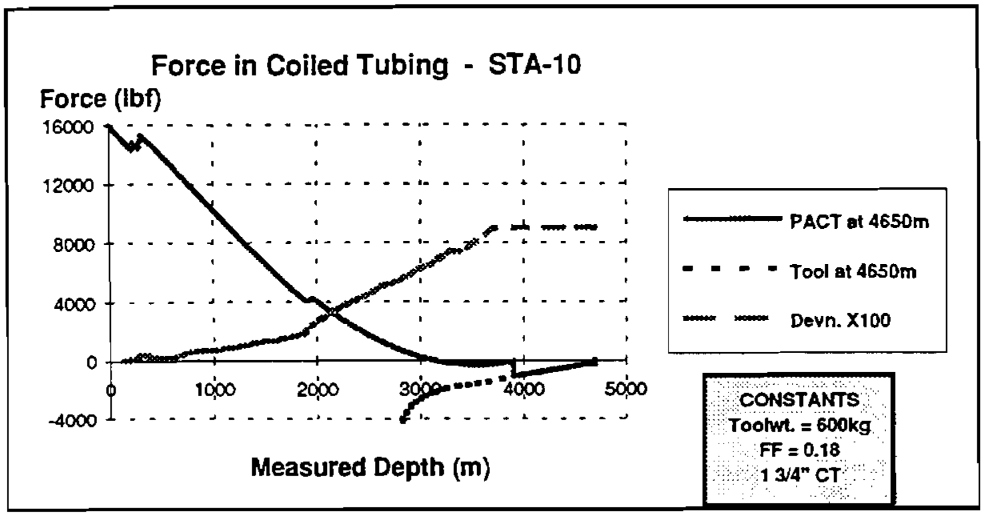

Figure 2-46. Benefit of Pumpdown Assist in Example Extended-Reach Well (Tailby, 1993)

Statoil pointed out that the principle of pumpdown assist may have already been applied (unintentionally) in production logging of wells with ESPs. For these wells, a bypass is used to direct coiled-tubing tools past the ESP (Figure 2-47).

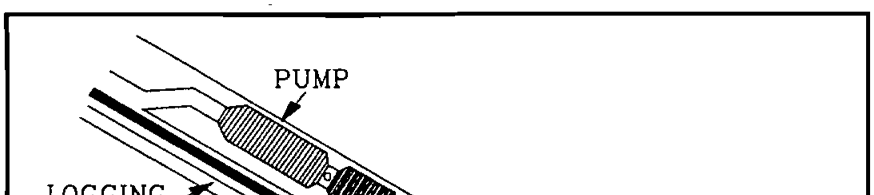

Figure 2-47. Pumpdown Assist Concept: Production Logging with ESP (Tailby, 1993)

A sliding seal in a no-go nipple is used to pack off the bypass during production logging operations. This pack-off ensures that fluids pumped by the ESP do not circulate back down the bypass.

2.2.6 Statoil (Ultralong-Reach Well)

Statoil (Ostvang et al., 1994) described the feasibility determination, planning, and execution of coiled-tubing operations in an ultralong-reach well. The well had a catenary build-up profile (well A in Figure 2-48) and a sail angle of 82-85°, which was maintained for 4000 m (13,000 ft). A catenary profile is advantageous during drilling operations in that it minimizes torque by reducing wall contact. A conventional extended-reach well is also shown in Figure 2-48 (ERD well).

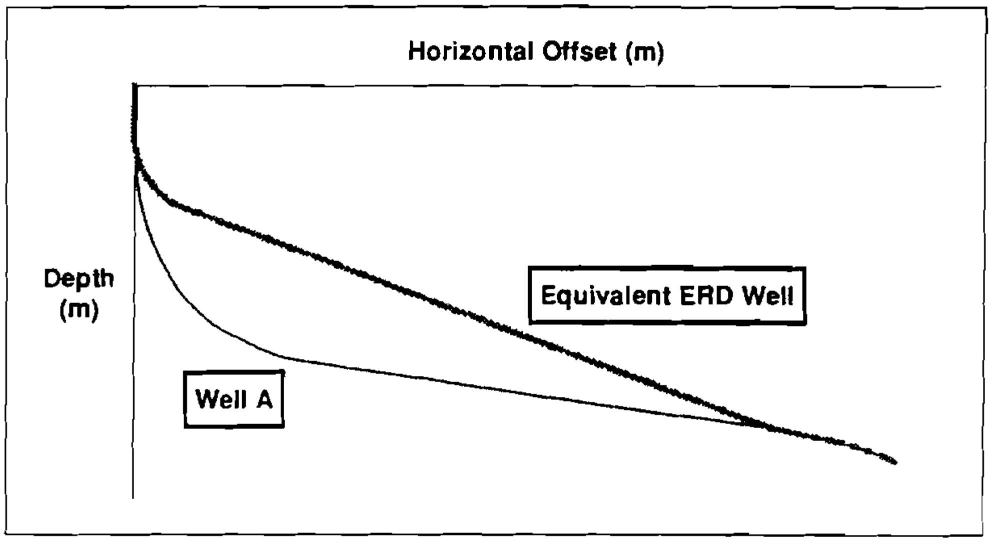

Figure 2-48. Profile of Catenary Well (Ostvang et al., 1994)

Very large displacements have been achieved in the offshore environment through the use of extended-reach technologies. The longest is about 7200 m (23,600 ft), and reaches of 10,000 m (32,800 ft) are being planned. Workovers on the wells are dependent on coiled tubing for efficient cost-effective servicing. The primary problems with the use of coiled tubing are buckling and the logistics of transporting and using long, heavy spools.

Statoil compared their in-house model (modified to incorporate findings from PEA-13) to services companies' models to determine whether coiled-tubing operations could be carried out in the catenary well. Service company models originally predicted lock-up far before reaching TD. Statoil's model suggested that, under ideal conditions, TD could be reached.

Statoil's model considers the effect of residual bending on buckling limits. They found that 1½-in. coiled tubing has a residual bend of about an 8-m (26-ft) radius after passing through an injector, and would lie in a circle if unconstrained (Figure 2-49).

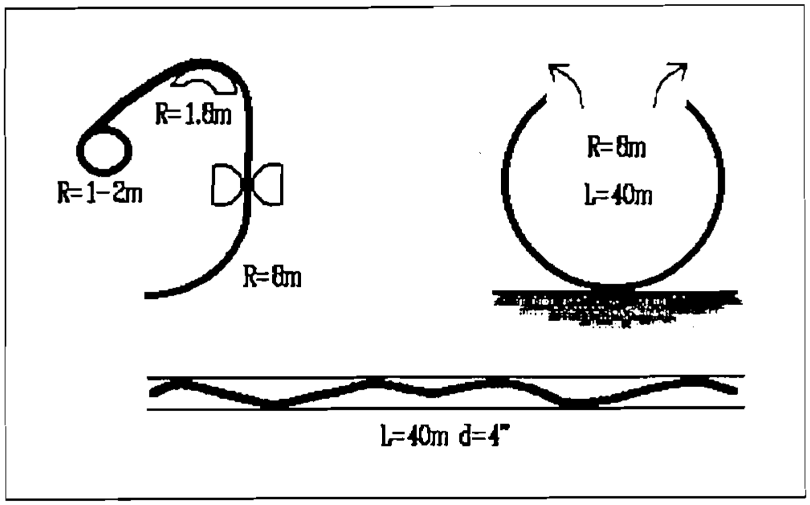

Figure 2-49. Residual Bending in 1½-in. Coiled Tubing (Ostvang et al., 1994)

According to full-scale test measurements (Figure 2-50), tubing injected into a horizontal casing becomes stable after 20-25 m (66-82 ft). Thus, the transition to helical buckling is a function of tubing length, not compressional force.

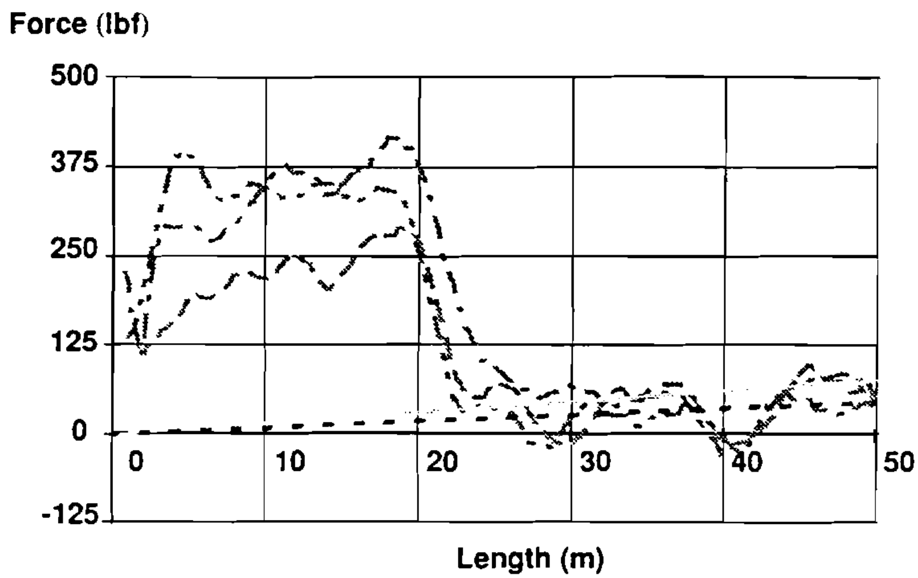

Figure 2-50. Injection Load While Running Coiled Tubing into Horizontal Casing (Ostvang et al., 1994)

Statoil's calculations showed that there was a critical depth for the BHA (between 200 and 250 m) where compression forces would be maximum (Figure 2-51). Once past this zone, maximum compression decreases (note curve at BHA at 900 m).

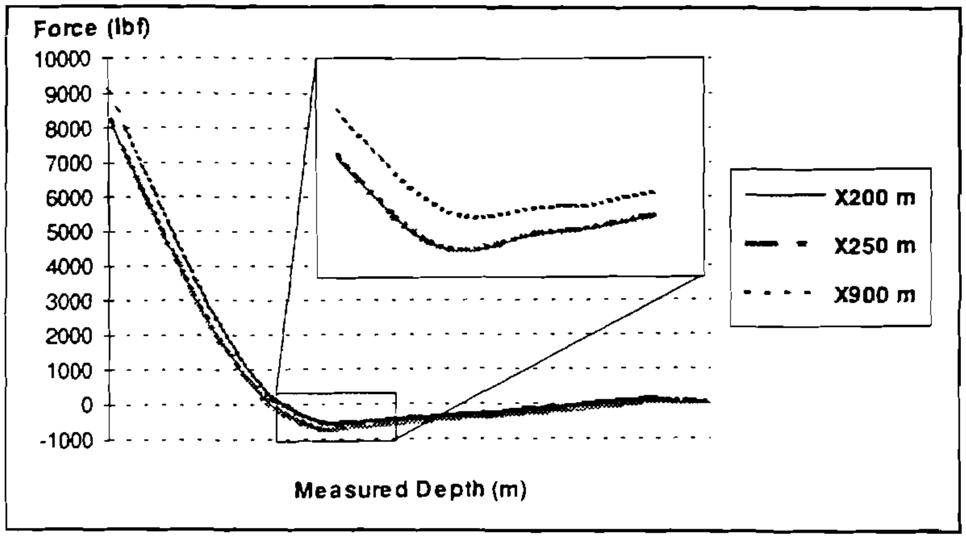

Figure 2-51. Compression Along the Coiled Tubing for BHA at Various Depths (Ostvang et al., 1994)

The sensitivity to several parameters was investigated to increase the probability of a successful run and job execution. Fluids in the well and coiled tubing were determined to be of relatively minor significance. Tool weight was also shown to have only a small impact for a realistic range of values. The most important variable was friction factor (Figure 2-52), with only a very small increase (from 0.18 up to 0.186) leading to premature lockup.

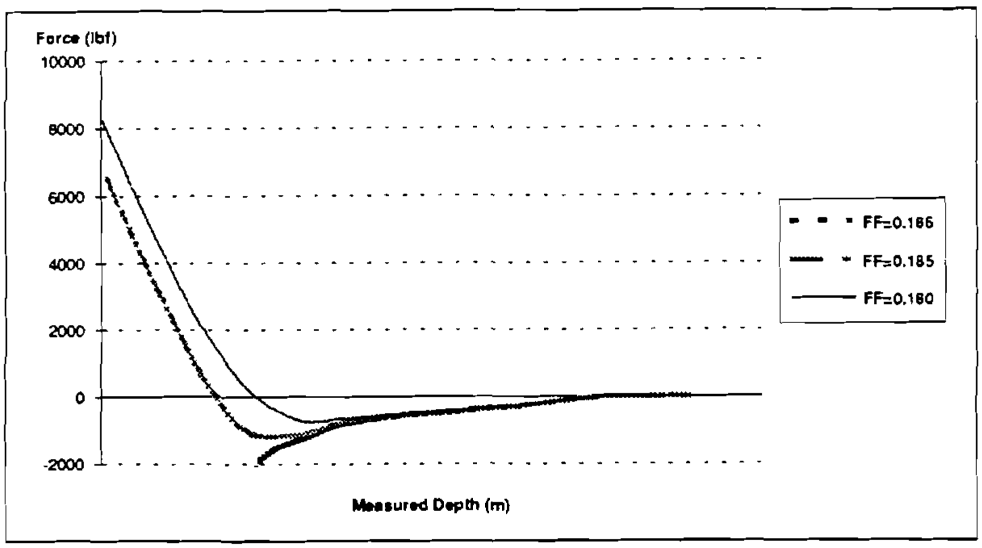

Figure 2-52. Effect of Friction Factor on Coiled-Tubing Lock-up (Ostvang et al., 1994)

A string of 1½-in. coiled tubing was the only string available for the job. The operation was planned based on the addition of friction reducer to the brine. Brine weight was designed to permit underbalanced perforating.

During field operations, the first trip into the well went to operational depth without incident. However, after stopping the string, it was not possible to go deeper. Next, after tripping out of the well for adjustments to the BHA, three passes were made without incident. Several additional runs were also completed.

During the final runs to the formation, the string began to lock up above TD. In a final attempt, a lighter BHA was substituted and the coiled tubing was filled with diesel. Lock-up prevented success. A snubbing unit had to be brought in to complete the operation.

Although not an economic success, this job provided significant beneficial experience for the players involved. Post-job analyses showed that friction factor in the final unsuccessful runs may have been as high as 0.1975. Both Statoil's and the service company's models indicated that sand in the wellbore was the cause of lock-up in the final runs.

A final analysis shows the difference in tubing forces between Statoil's catenary well and an equivalent extended-reach well (see Figure 2-48). For the extended-reach (ERD) well, the coiled tubing will never be in compression (Figure 2-53), and would be expected to run to TD without problems.

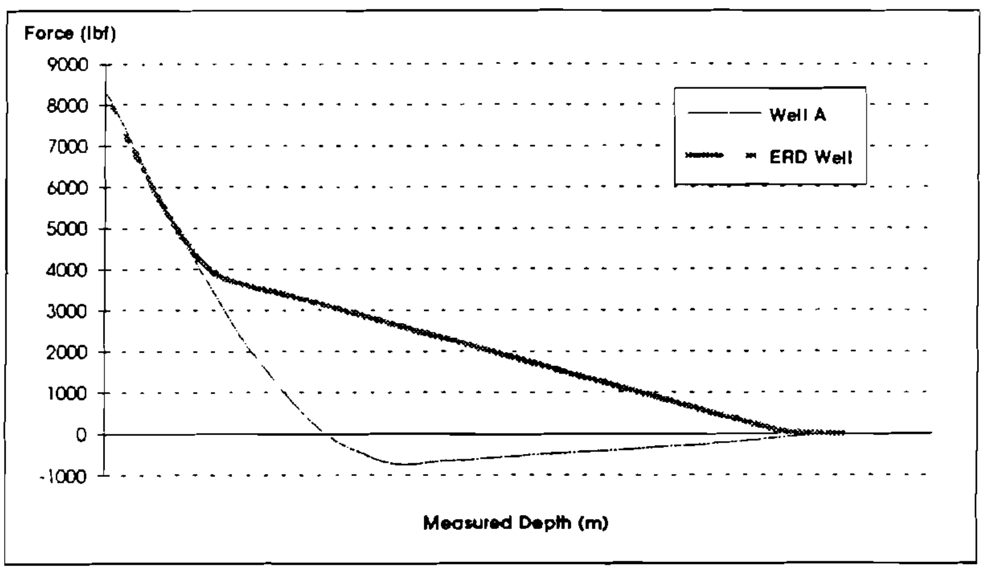

Figure 2-53. Compressive Forces on Coiled Tubing in Catenary and Extended-Reach Wells (Ostvang et al., 1994)

2.2.7 Transocean Well Services (Extended-Reach Operations)

Transocean Well Services (Dickson and Smith, 1994) detailed the requirements and considerations for coiled-tubing operations in extended-reach applications. As is particularly true for the North Sea area, drilling designs have become more innovative, greater inclinations have been used, greater displacements from platforms are being achieved, and casing and liner strings have become slimmer. It has been clearly demonstrated that design innovations to decrease drilling costs do not necessarily lead to an efficient workover environment. Only recently have workover options been considered in well design.

Coiled tubing's buckling characteristics are determined by the well path, completion design, conditions within the wellbore, tubing metallurgy, design of the coiled-tubing string (diameter, thickness, taper, etc.), and BHA weight. Higher strength tubing (80 ksi up to 100 ksi) has increased the potential for coiled tubing in extended-reach operations.

Equipment requirements usually include an injector with at least 60-ksi overpull capacity. Long running times require a dual stripper assembly with a side-door design for rapid change-out of elements. High capacity tubing reels can exceed practical size and weight limits. A spool with 26,000 ft of 1½-in. coiled tubing weighs about 30 tonnes (66 kips), far in excess of crane capacity on many platforms. One solution developed for this weight problem is a reel that splits into three parts: crash frame, drum, and base frame. This allows a reduction in spool weight of 10 tonnes (22 kips).

Coiled-tubing string design is impacted by several parameters. For buckling prevention, thicker walls are needed in areas with maximum compression. Wall thickness must have sufficient capacity for string weight and overpull. Transocean Well Services described a straightforward process to design a tapered string to meet these requirements with the lightest overall weight possible.

The buckling model is run assuming the use of a string of the thinnest wall tubing available (Figure 2-54). This run shows up to what depth from TD the thin wall pipe is sufficient.

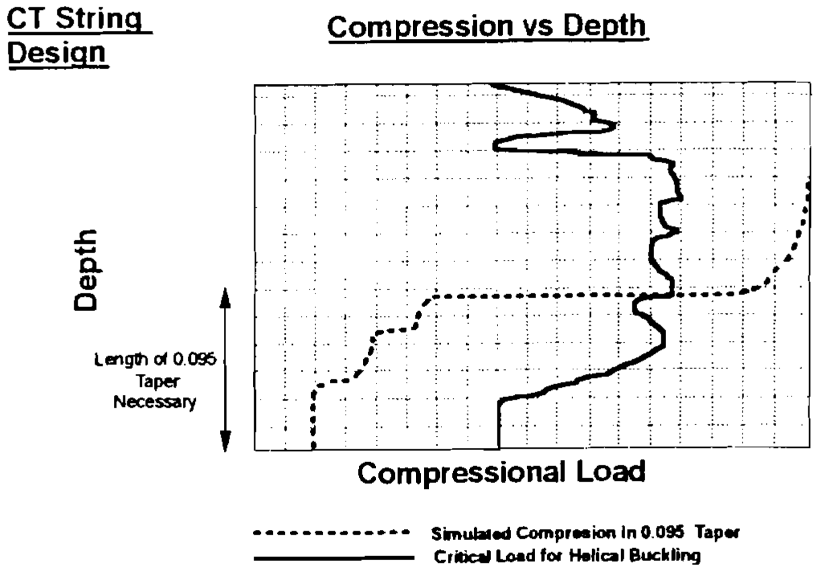

Figure 2-54. Buckling Simulation with Thinnest (0.095-in.) Coiled Tubing (Dickson and Smith, 1994)

Another run of the buckling model is made with thicker-walled coiled tubing (0.102 in. for this case) to determine the minimum required length of the second section of the taper (Figure 2-55).

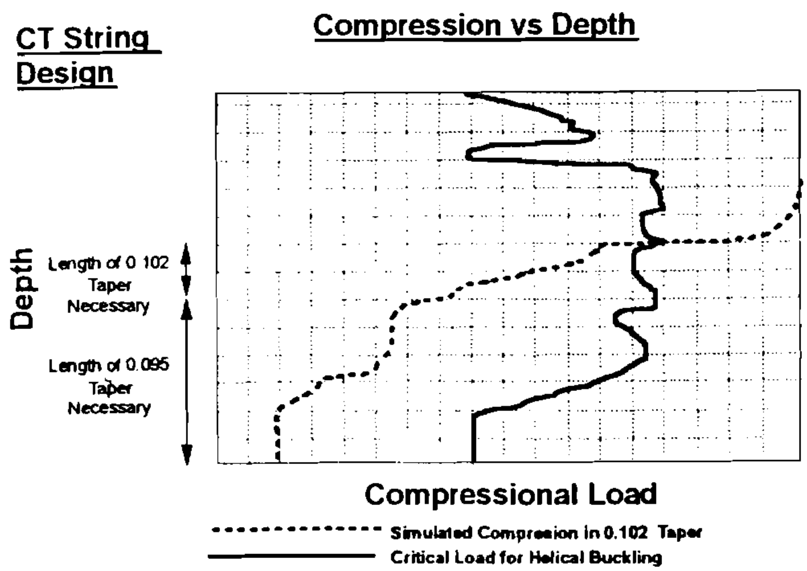

Figure 2-55. Buckling Simulation with 0.102-in. Coiled Tubing (Dickson and Smith, 1994)

This iterative process is repeated (Figure 2-56) until the tubing is capable of running all the way to surface without buckling.

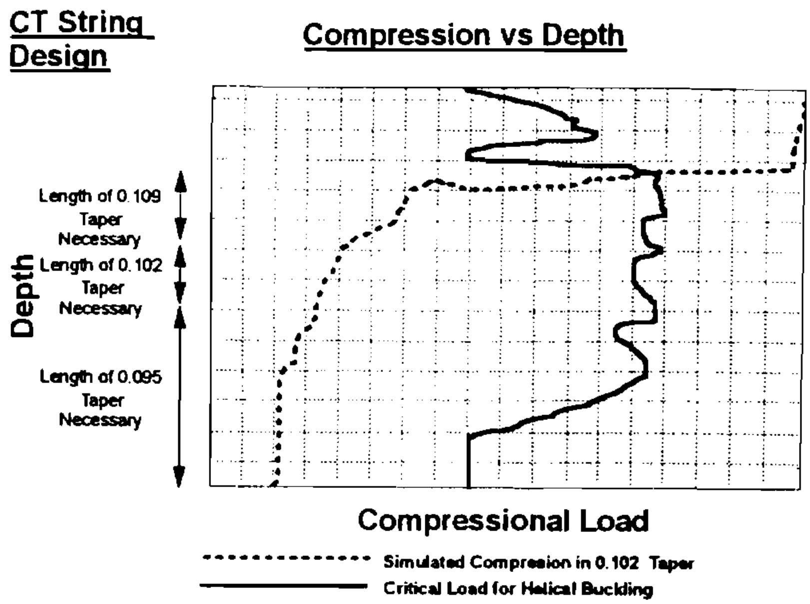

Figure 2-56. Buckling Simulation with 0.109-in. Coiled Tubing (Dickson and Smith, 1994)

A final check is required for the complete tapered string after design. The uppermost section of the tapered string (the thickest wall) must be able to support the string weight component and overpull. Note that the tubing does not need to be able to support the entire vertical hanging weight of the string, only the expected surface load during the job.

Procedures to optimize the reach of the coiled-tubing string include running in with nitrogen inside the tubing and circulating a friction reducer prior to run-in. Systems to increase the working forces available at the BHA include rollers in the BHA, hydraulic hammers for opening sliding sleeves, pistons and anchoring mechanisms for downhole force generation, downhole tractors, and control lines inside the string to activate/power tools.

After job completion, a comparison of actual versus predicted hook loads (Figure 2-57) can provide additional important information about the operation. Friction-reducing agent dispersal can be charted. The quality of the clean-up operations can be gauged. Actual bottom-hole pressures can be compared to predictions.

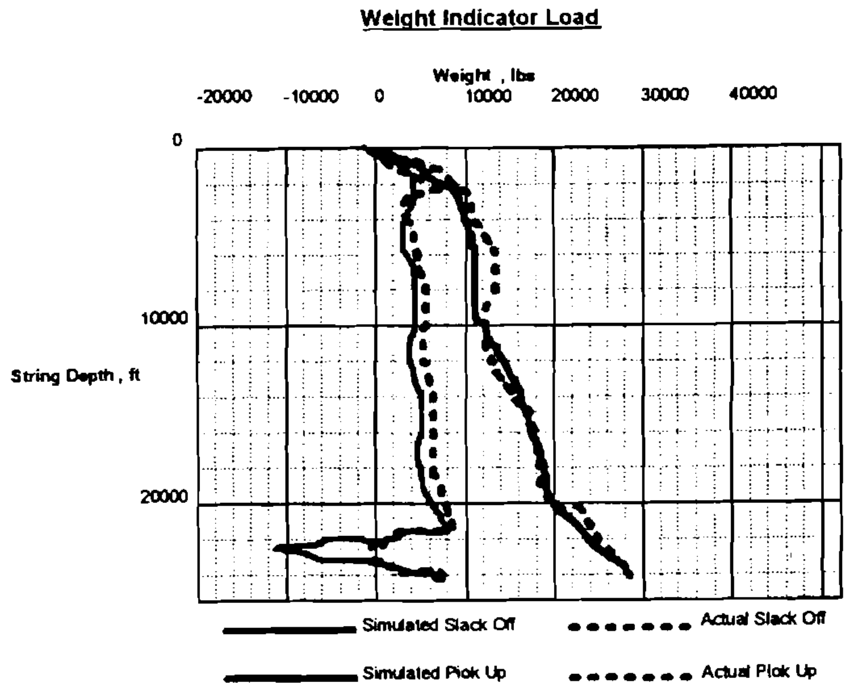

Figure 2-57. Post-Job Weight Indicator Load Simulation (Dickson and Smith, 1994)

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3. Cementing

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3. Cementing

3.1 ARCO ALASKA (CEMENTING AT PRUDHOE BAY)

Many significant advances in squeeze cementing with coiled tubing have been implemented by operators at Prudhoe Bay. The technology was first implemented there in 1983. Since then, over 1000 coiled-tubing cementing operations have been performed on the 1200 wells in the field.

Gantt and Smith (1994) summarized the variety and success of coiled-tubing squeeze cementing operations at Prudhoe Bay. Through-tubing well remediation technology was recognized as having tremendous potential in the field. Through-tubing techniques have been found to have several advantages over conventional, including allowing problem diagnosis based on production performance rather than on logs alone; allowing more thorough planning, design and performance of a remedial operation without the cost of the rig waiting on site; placing the well on production prior to remedial cementing allows improved cleanup of channels and perforations; and coiled tubing allows more controlled placement of the cement with less dilution and contamination.

Liquid latex cement blends (Table 3-1, LARC = Latex Acid-Resistant Cement) were developed to combat dissolution of cement during acid jobs. These provide improved acid resistance as compared to class "G"' blends. Additionally, latex makes the cement more resilient and less susceptible to thermal-shock damage.

TABLE 3-1. Typical Cement Slurry Properties (Gantt and Smith, 1994)

Slurry	Density (lb/gal)	Fluid-Loss (cc/30 min)	Filter Cake (in.)	PV (cp)	YP (lb/100 ft^2)	Thickening Time (Hrs)
LARC	15.6	50–90	.75–1.0	20–50	5–20	6–11
Fine-Grain	12	10–20	*.05–0.1	5–10	*1–5	6–11
Fine-Grain	12–14	40–90	0.4–.75	5–20	*1–10	6–11
			*Film		*No Settling	

Fine-grained cement has been applied successfully in narrow geometries including channels behind pipe, fractures, faults, and voids prepacked with sand or proppant. Particle-size distributions for fine-grained and class "G" are shown in Figure 3-1.

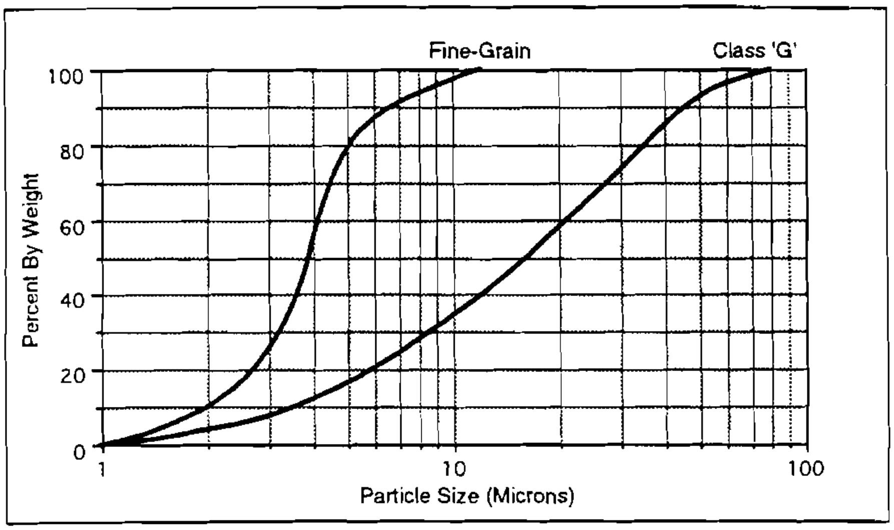


Figure 3-1. Fine and Class "G" Cement Grind Size (Gantt and Smith, 1994)

Fiber-reinforced cement has been used for additional resistance to fragmentation. This is most beneficial when cement sheath remains in the well as part of the repair. Rectangular polypropylene fibers (12 x 0.7 x 0.025mm) are added at a concentration of 1% by weight.

For certain situations, such as damaged casing, severe corrosion/erosion, thief zones or voids, coiled-tubing-conveyed scab liners have been effective. A threaded flush-joint pipe is used as the liner. Running the liner is faster if the well is loaded with kill-weight fluids (3 min/joint versus 10-20 min/joint for live well). Installation procedures are summarized in Figure 3-2.

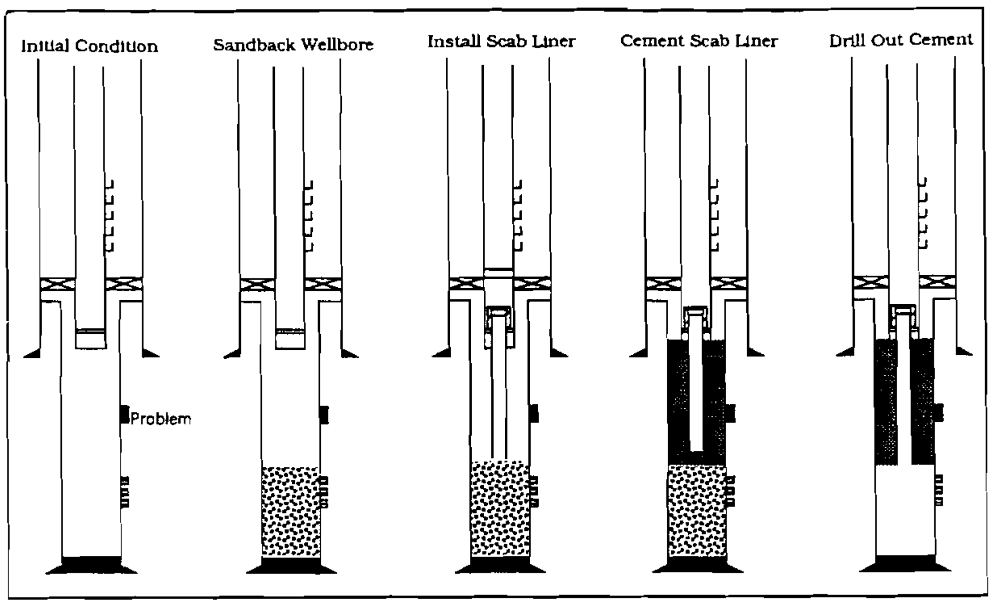


Figure 3-2. Scab Liner Installation with Coiled Tubing (Gantt and Smith, 1994)

Failed packers have been repaired via coiled tubing without killing the well. For this procedure (Figure 3-3), returns are taken behind the production tubing to place cement around the tailpipe.

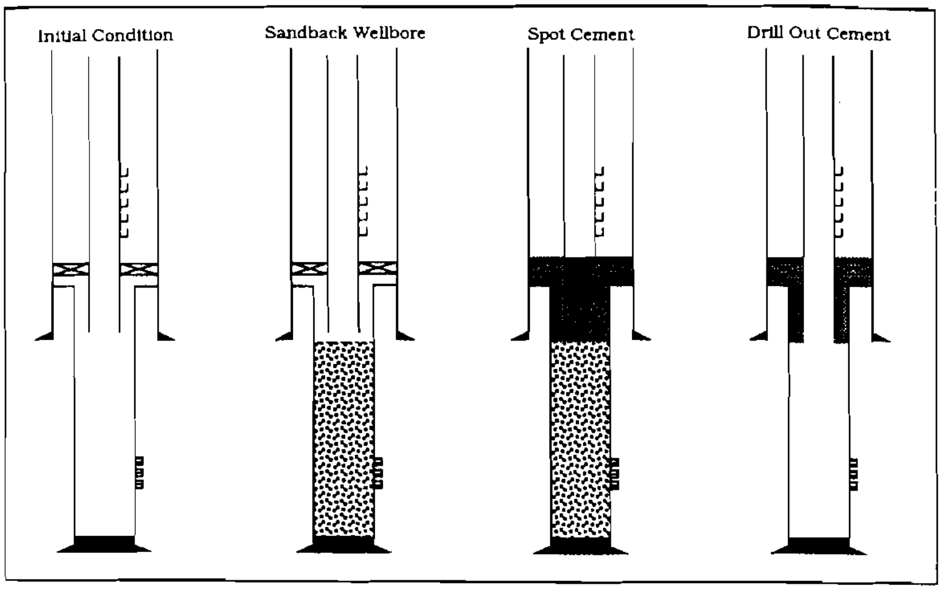


Figure 3-3. Repairing Failed Packer with Coiled Tubing (Gantt and Smith, 1994)

Sand pack injection squeezes, consisting of injecting resin-coated proppant behind pipe, have allowed successful squeezes in cases of void space, faults, or coarse-grained rock. The injected proppant serves as a matrix for the cement slurry to bridge against.

Previously unsuccessful squeeze attempts have been treated with polymer gel squeezes. These gels form a rigid cross-linked structure after injection into the formation. Typical treatments are sized to saturate the formation to about 10 ft from the wellbore. This treatment is considered to be a permanent abandonment of the particular problem zone.

Higher squeeze pressures have been adopted to allow fracing the well after the squeeze job. Results from high-pressure squeeze jobs performed in 1991 show an 89% success rate (Krause and Reem, 1993). Squeeze life also appears to be increased with high-pressure squeezes. Several mechanisms have been proposed as contributing to the high success rates with these operations:

- Cement may be forced into perforations that would not take cement otherwise
- High pressure may form harder, drier nodes that withstand higher stress
- Resiliency due to latex additive may allow the cement to withstand higher differential pressures

A basic procedure for high-pressure cement squeezes was given by Krause and Reem (1993):

1. After the well is fluid-packed with heated seawater, cement is spotted across the perforations.
2. A low pressure differential of about 1500 psi (less than the fracture gradient) is placed across the formation for about 15 minutes.
3. Pressure is incrementally increased (500-psi steps, 10 minutes each) to a 3500-psi differential, which is then held for an hour.
4. If pressure breaks back, step 3 is repeated to rebuild cement nodes.
5. Pressure is reduced to a 500-psi differential. Slurry contaminant is pumped and wellbore cement washed out. A cement accelerator is then left in the wellbore across the perforations.
6. The cement is allowed to set for a minimum of 2 days before the well is reperforated.

Cementing challenges that remain were described by Gantt and Smith (1994). Leaking perforations that were previously squeezed are a problem, especially in wells that have had multiple intervals squeezed on separate occasions. Treating leaks remains an ongoing process. Soon after treating one zone, new leaks often develop elsewhere in the well. Severely eroded or corroded liners are becoming more common. These are not easily patched with squeeze techniques, in that filter cake does not build adequately across large voids. Channeling behind casing is a significant problem, comprising 25% of squeeze jobs. Squeeze pressure cannot be attained in some wells, probably due to voids or coarse-grained rock behind the pipe. Another challenge is technology to shut off all or part of a propped hydraulic fracture for modifying the production profile.

3.2 HALLIBURTON ENERGY SERVICES/CONOCO (MIXING ENERGY)

A study was performed by Halliburton Energy Services (Heathman et al., 1993) to investigate the effects of mixing energy on cement. Three separate aspects of coiled-tubing cementing operations were addressed: 1) the effects of mixing energy over time on various cement slurries, 2) the impact of a cement particle's wetting efficiency on final cement performance, and 3) the effects of pumping cement slurry through a string of coiled tubing.

These tests were designed to reflect actual field operations as closely as possible. Cementing materials, mixing equipment, and operators were acquired from the field. A new 10,000-ft spool of coiled tubing was used for the tests. Batch-mixing procedures were used, since this approach represents a majority of coiled-tubing cementing operations. A primary question considered was the impact of cement residence time after mixing during quality control procedures or while being pumped.

Pressure, temperature, density, and flow rate were measured at several points in the test equipment (Figure 3-4).

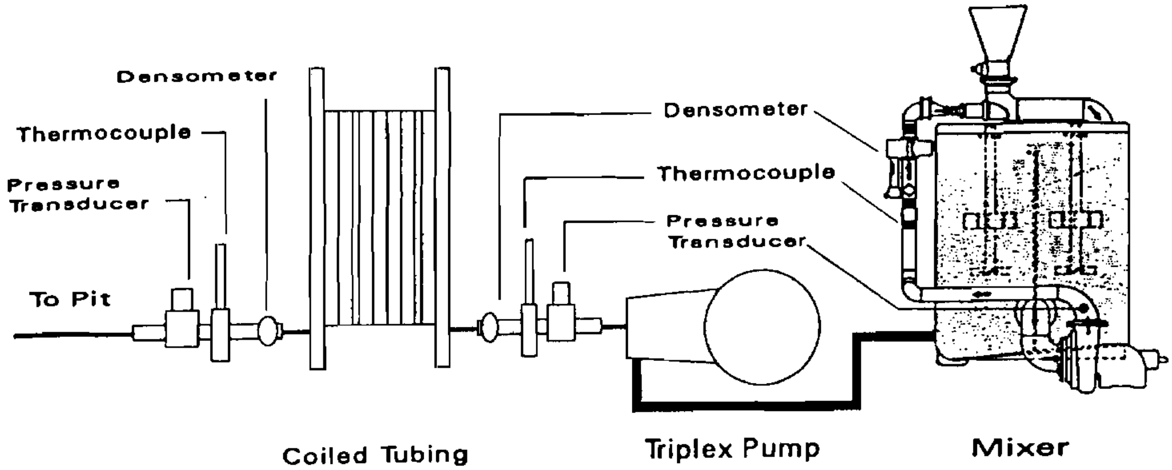


Figure 3-4. Cement Slurry Test Equipment (Heathman et al., 1993)

Cement slurries that were tested (Table 3-2) included three fluid-loss systems: a synthetic fluid-loss additive slurry, a latex slurry, and a hydroxyethyl cellulose slurry (HEC). Fluid loss was specified in the range of 50-125 cc. A minimum dynamic thickening time of 4 hours was used.

TABLE 3-2. Cement Slurries (Heathman et al., 1993)

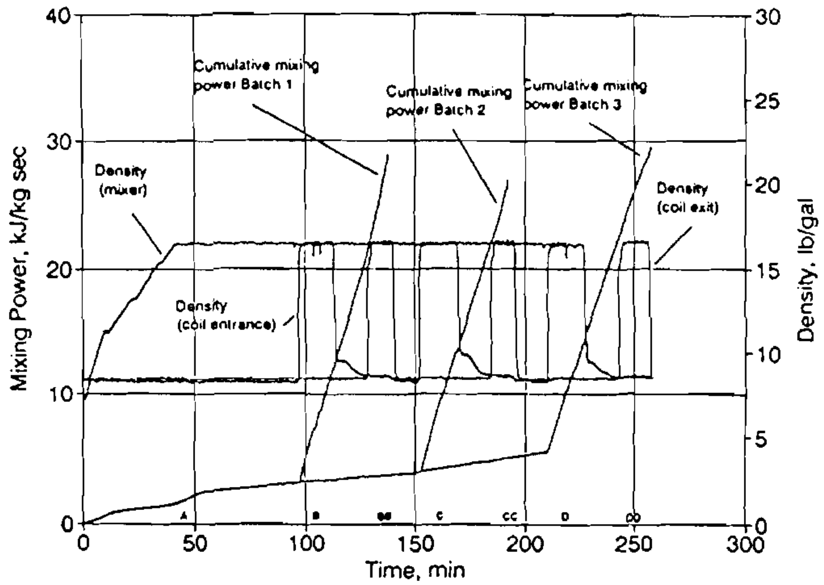
Slurry Series	Density (lb/gal) and Yield (ft^3/sk)	Class H Cement with add-mixtures
N, T, & NX	16.4 1.07	0.5 gal/sk proprietary synthetic fluid loss additive, 0.15 gal/sk aqueous solution of calcium lignosulfonate, and 0.08 gal/sk defoamer
L, TL, & LX	16.4 1.06	1.25 gal/sk latex, 0.2 gal/sk stabilizer, 0.12 gal/sk aqueous solution of calcium lignosulfonate, and 0.08 gal/sk defoamer
A	16.0 1.12	0.15 gal/sk non-aqueous dispersion of HEC, 0.17 gal/sk aqueous solution of calcium lignosulfonate, and 0.05 gal/sk defoamer

Tank residence time was simulated by holding each slurry in the batch mixer under normal agitation for a minimum of one hour before commencing pumping through the coiled tubing. Tests were then conducted at 1-hour intervals (Table 3-3).

TABLE 3-3. Cement Slurry Sampling Sequence (Heathman et al., 1993)

Sample Pt.	Description
Pilot	Laboratory pilot tests with isolated materials.
Blend	Laboratory mixed slurry using mixing fluid prepared in batch mixing equipment.
A	10 minutes after reaching density.
B	50 minutes after "A"; taken when 3 bbls had entered the coil.
BB	Mate to sample B, slurry exiting coiled tubing; taken after 3 bbls had exited coil.
C	60 minutes after sample B (where applicable) taken when 3 bbls had entered the coil.
CC	Mate to sample C, slurry exiting coiled tubing; taken after 3 bbls had exited coil.
D	60 minutes after sample C (where applicable) taken when 3 bbls had entered the coil.
DD	Mate to sample D, slurry exiting coiled tubing; taken after 3 bbls had exited coil.

An example plot of output data is shown in Figure 3-5 for slurry N (see Table 3-2). Dynamic thickening times to 70 Bearden Units of Consistency are shown in the table below Figure 3-5.



Sample Point	Arrival Temp.(°F)	PV (cp) (Arrival)	YP (lb/100 ft²) (Arrival)	PV (cp) 150°F	YP (lb/100 ft²) 150°F	70 Bc (HR:MIN) 120°F @ [illegible]	Fluid Loss (cc's) 190°F
Blend	81	116	5	74	12	8:08	52
A	89	143	16	90	18	7:19	28
B	93	131	11	88	10	6:57	20
BB	98	113	11	91	10	6:55	16
C	96	142	12	85	11	6:36	20
CC	98	117	13	80	11	6:46	16
D	98	112	14	78	11	9:15	16
DD	98	123	12	80	9	8:17	16

Test 2N (21 bbl)

Figure 3-5. Mixing Power and Density for Slurry Test 2N (Heathman et al., 1993)

The mean thickening time and variance for each test series (Figure 3-3) showed little variation with respect to each measurement point. Heathman et al. concluded that cement slurry performance is not significantly affected by batch size or mixing pumps, or by being pumped through a string of coiled tubing. Additionally, they point out that a lack of adequate cement particle wetting efficiency when dry cement is first wetted can lead to erratic slurry performance.

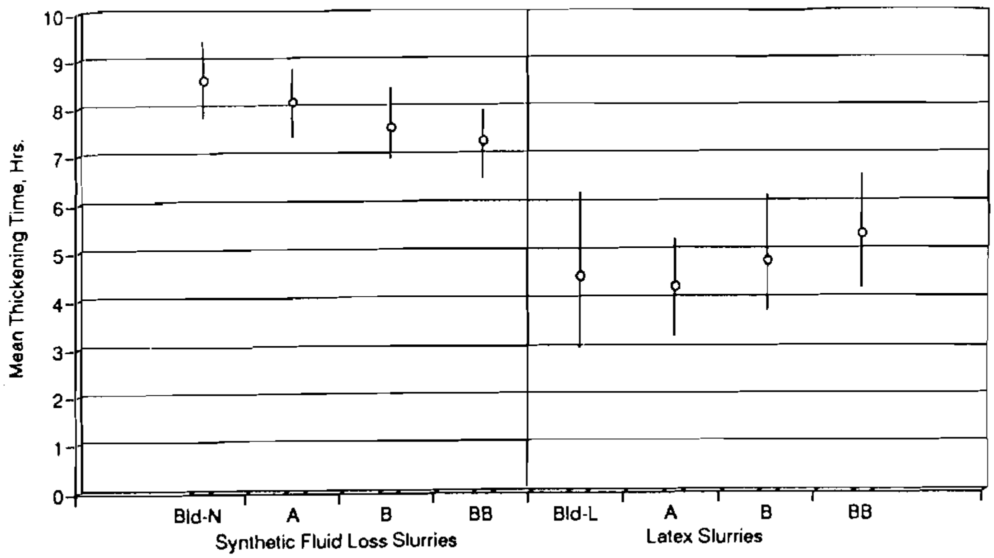


Figure 3-6. Mean Thickening Times for Slurry Tests (Heathman et al., 1993)

3.3 MOBIL NORTH SEA LTD/NOWSCO WELL SERVICES (BERYL BRAVO)

Mobil North Sea Ltd performed a cement squeeze in well B24 on the Beryl Bravo platform in the northern sector of the North Sea (Oliver et al., 1994). In Unit I Eastern Sector, the single producing well (B21) was supported by water injection from B24. A significant reduction in production from B21 due to scaling and water breakthrough led Mobil to design a squeeze treatment for the injector B24 to shut off water to a high-permeability zone. As a consequence, it was hoped that water would be forced to sweep a low-permeability zone and increase oil production (Figure 3-7). Large cement channels behind 7-in. casing also needed to be addressed in the design of the recompletion.

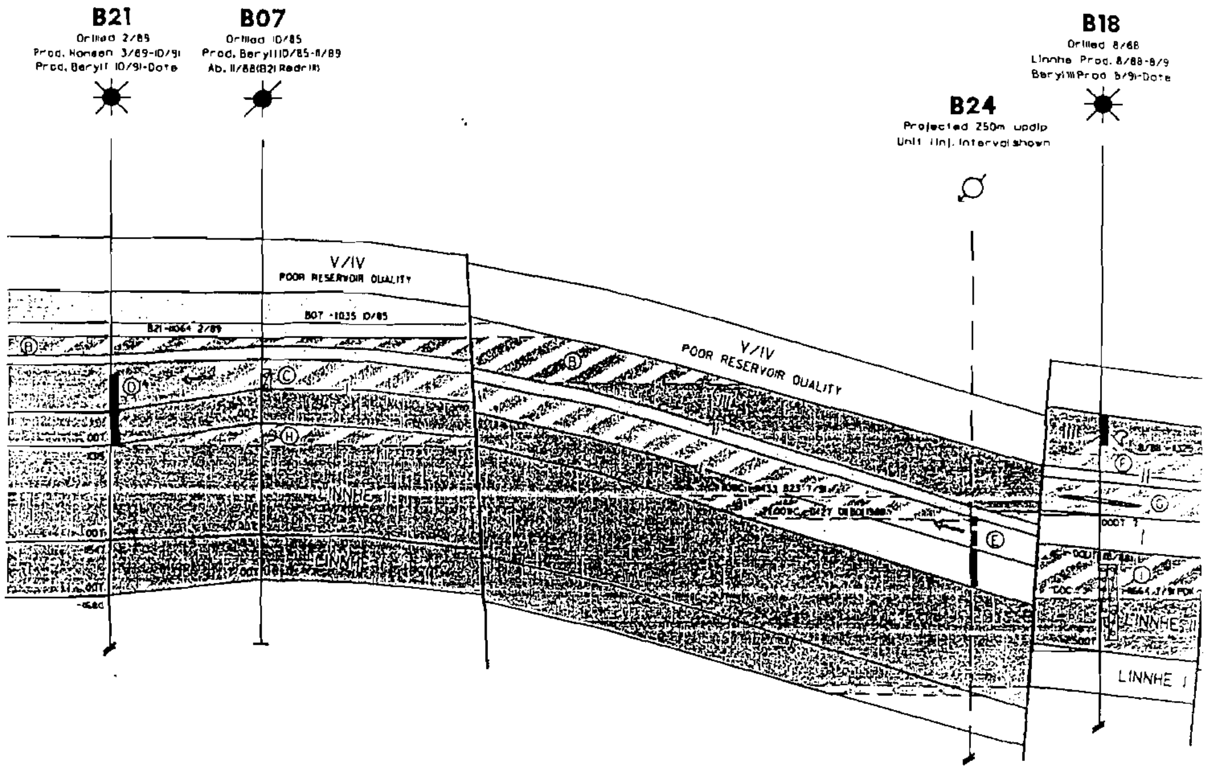


Figure 3-7. Beryl Formation Cross Section (Oliver et al., 1994)

Three approaches were considered for treating B24: a polymer squeeze, a conventional workover, and a through-tubing recompletion with coiled tubing. A polymer squeeze was rejected due to the possibility of polymer migration into the low-permeability zone. An economic risk analysis showed that the coiled-tubing squeeze would cost about £450,000 versus £1,000,000 for a conventional operation. However, the coiled-tubing operation included more risk.

Due to the impact of temperature on cement thickening time, a temperature survey was run across the zone to be cemented. Surveys were recorded under shut-in conditions and after circulation similar to that expected during the squeeze job.

Yard tests were also conducted to verify cement properties under simulated field conditions. Thickening time, fluid loss and filter cake were compared before and after pumping slurry through the 1½-in. reel of coiled tubing. Fluid compatibility was checked between the cement slurry and the fluid that would be used to support the slurry. An estimate of batch mixing time was also developed by rehearsing the process in the yard.

Slurry properties were designed as follows:

Thickening Time	6-8 hr
Fluid Loss	65-75 cc/30 min
Filter Cake	0.5-0.75 in.
Compressive Strength	500 psi min

The slurry consisted of Class "G" cement with 0.75% T-10 dispersant and 0.8% D-42 fluid-loss additive. Final slurry density was 15.9 ppg.

A 16.5 ppg gel pill was spotted below the perforations. The well was then circulated and cooled to the temperature observed in the previous survey. After the 30 bbl of slurry were pumped, a squeeze pressure of 1500 psi was attained and held for 1 hr. Biozan contaminant was then circulated at 500 psi. Squeeze pressure was then returned to 1500 psi.

The cleanout BHA (Figure 3-8) was run in hole with the underreamer blades spot-soldered to prevent blade engagement below a certain pressure. The well was cleaned out successfully, though was much more time-consuming than anticipated.

The cement squeeze operation required a total of 10.5 days to complete (Table 3-4). Trouble time was primarily during the cleanout operation; 48 hours were lost trying to enter the well with the BHA shown in Figure 3-8. The blades were switched to a banana-blade design, resulting in a further loss of 24 hours.

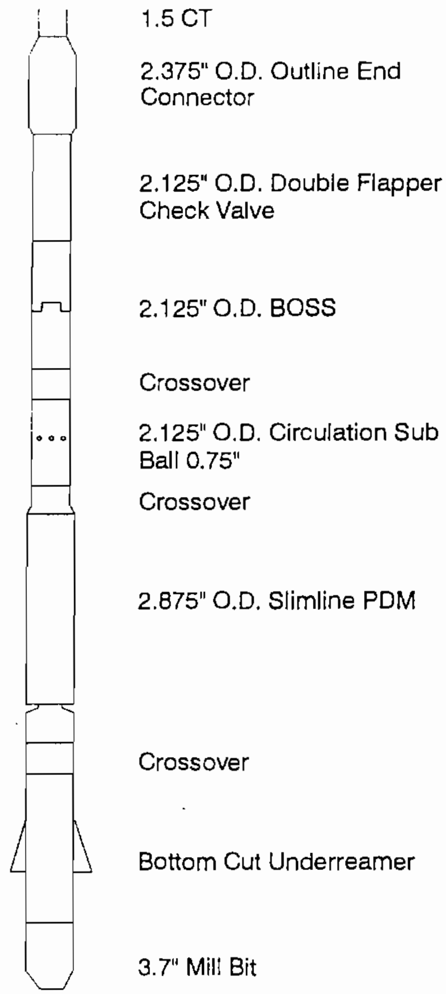


Figure 3-8. Underreaming BHA (Oliver et al., 1994)

TABLE 3-4. Planned and Actual Times (Oliver et al., 1994)

	Operation	Duration		
		Planned (hours)	Actual (hours)	Variance (hours)
1.	Rig up Coiled Tubing	10.00	14.50	4.50
2.	RIH and Spot Gel Pill	8.00	9.75	1.75
3.	Cool Well	6.00	2.50	-3.50
4.	Mix and Pump Slurry	9.00	3.25	-5.75
5.	Squeeze Cement	5.00	2.00	-3.00
6.	Clean Out Cement	10.00	6.75	-3.25
7.	WOC. POOH. Change BHA. RIH	19.00	24.75	5.75
8.	Clean Out Tubing	12.00	111.00	99.00
9.	POOH. Rig Down Coiled Tubing	8.00	7.50	-0.50
10.	Pressure Test Tubing	2.00	2.00	0.00
11.	Slickline Drift Run	4.00	4.00	0.00
12.	R/U Atlas. Reperf. well (3 runs) R/D	24.00	24.50	0.50
13.	R/U CT. RIH backflow well	22.00	18.50	-3.50
14.	POOH. R/D Coiled Tubing	12.00	6.00	-6.00
	TOTAL	151.00	237.00	86.00

Mobil successfully completed the operation at a cost of £460,000. The final wellbore status is shown in Figure 3-9.

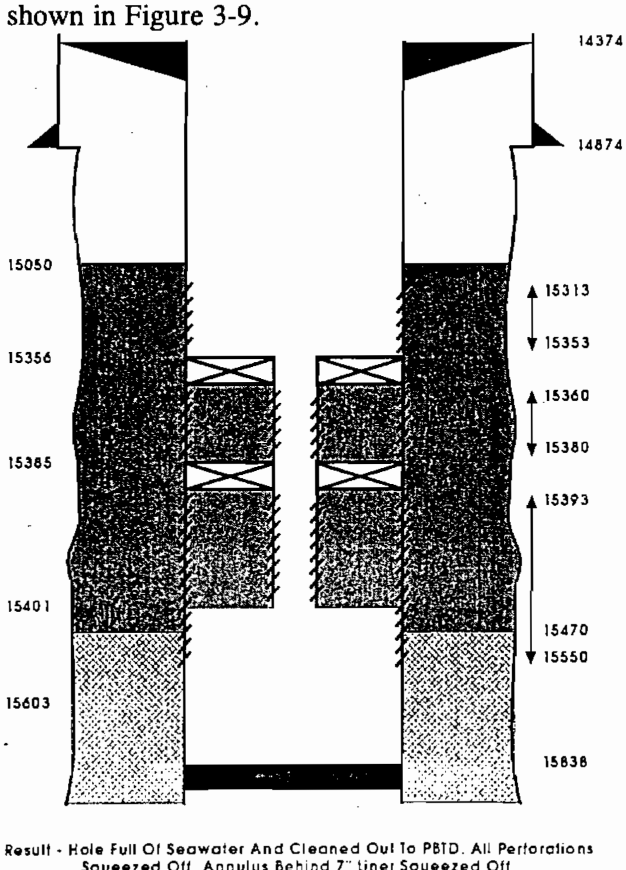


Figure 3-9. Completed Squeeze (Oliver et al., 1994)

3.4 SCHLUMBERGER/ARCO ALASKA (SLURRY PROPERTIES)

Squeeze cementing research and development has been an important aspect of coiled-tubing operations at Prudhoe Bay. Recent developments and improvements were incorporated after aggressive fracturing was implemented in 1990. High differential pressures were used in the fracture program, resulting in failures of previously squeezed perforations. Final cement squeeze pressures were increased from 1500 to 3500 psi (Vorkinn and Sanders, 1993).

Adequate slurry stability was found to alleviate several potential problems, including plugging of nozzles and pipe, inconsistent filter cake, variation in fluid loss, reduction in available working time, and problems during cement cleanout. A slurry stability test has been devised for Alaskan operations.

Filter cake performance is measured by its firmness and height (Figure 3-10). Desired performance for a filter cake test includes liquid slurry in the fluid-loss cell (facilitates clean-out operations), firm filter cake, and reproducibility of properties (±0.1 in. cake height; ±5 ml/30 min fluid loss).

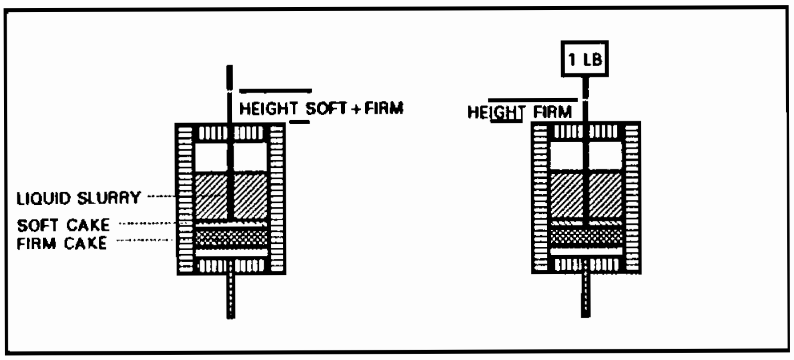


Figure 3-10. Cement Filter-Cake Test Fixture (Vorkinn and Sanders, 1993)

A thickening time schedule used for cement squeezes at Prudhoe Bay is shown in Table 3-5. Success is highly dependent on final squeeze pressure and the length of time it is maintained. To make cleanout possible, slurries are designed with thickening times of 7-10 hours.

TABLE 3-5. Cement Squeeze Thickening Schedule (Vorkinn and Sanders, 1993)

ACTIVITY	TIME (min)	TEMP (° F)	PRESSURE (psi)
Batch mix time	0-120	90	atmosphere
Start slurry placement	@ 120	90	0-4,000
Slurry placement	120-150	90-BHST	4,000
Squeezing	150-165	BHST	4,000-7,500
Holding squeeze pressure	165-210	BHST	7,500
Reducing pressure	210-225	BHST	7,500-5,000
Cleaning out	225-end	BHST	5,000

Investigations of fluid loss and mixing energy showed that slurry consistencies are sensitive to shear energy. Laboratory test results are shown for a latex cement system in Figure 3-11 and a copolymer system in Figure 3-12. Cake thickness and fluid loss are relatively constant for mixing times above about 120 seconds. Based on these observations, the standard shear time at 12,000 rpm was set at 180 seconds.

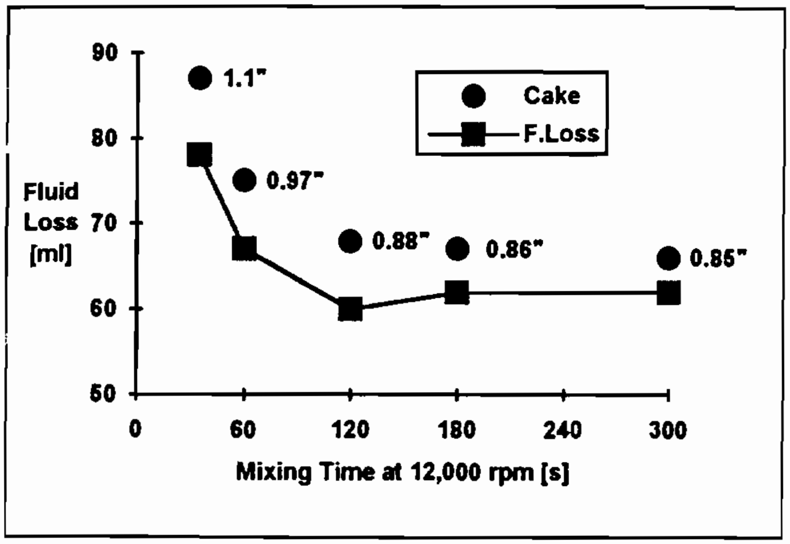


Figure 3-11. Filter Cake and Fluid Loss for Latex Slurry (Vorkinn and Sanders, 1993)

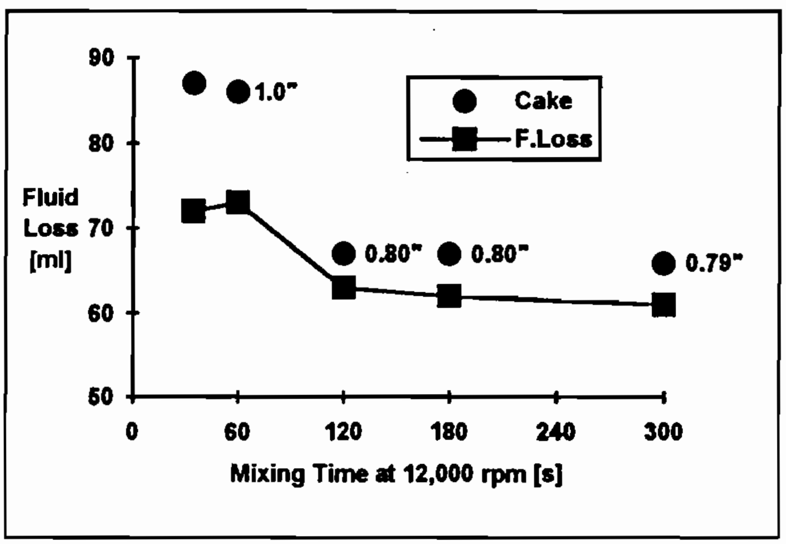


Figure 3-12. Filter Cake and Fluid Loss for Copolymer Slurry (Vorkinn and Sanders, 1993)

At Prudhoe Bay, the latex system is commonly used in squeeze operations. The copolymer system is often used for well abandonment.

Earlier R & D efforts had indicated that mixing energy imparted to the slurry was a critical parameter. As a result, field procedures were developed that ensured an adequate energy input level. Vorkinn and Sanders' data confirm earlier studies that concluded that thickening time is reduced as total shear is increased. Mixing energy and thickening time are compared for the latex system in Figure 3-13.

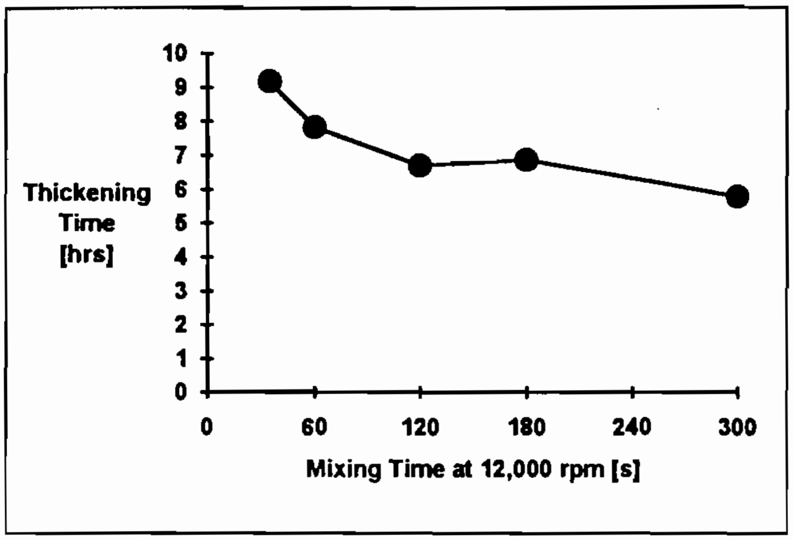


Figure 3-13. Mixing Energy and Thickening Time for Latex Slurry (Vorkinn and Sanders, 1993)

These data show that, at the early stages, increased shear can result in significantly reduced thickening time. Above 120 seconds, however, thickening time remains relatively stable.

Vorkinn and Sanders did not directly measure the effect of pumping slurry through coiled tubing. They did note that several jobs in the field have extended into the last hour of the slurry working time, and early thickening has not been observed. These experiences indicate that additional mixing energy from pumping through 1¾-in. coiled tubing does not alter thickening time to a significant degree.

The laboratory and field data led them to conclude that slurry properties are affected by mixing energy, but tend to stabilize above a certain level.

3.5 SHELL WESTERN E&P/HALLIBURTON (THERMAL WELL ABANDONMENT)

Shell Western E&P sought ways to decrease the cost of plugging and abandoning shallow thermal wells in the South Belridge Field (Fram and Eberhard, 1993). Shell found that the use of coiled tubing as part of a more efficient use of equipment and personnel increases efficiency and reduces costs. Coiled tubing was used to spot cement plugs for half the jobs performed in 1992. Job costs were reduced by $2000/well with this method.

Well abandonment is a routine operation in a thermal project such as South Belridge. Large numbers of up-dip wells become desaturated and uneconomical. Typical producer and injector completions are shown in Figure 3-14. Two hundred wells were abandoned in 1992. Savings by use of coiled tubing were due to more efficient use of equipment and personnel.

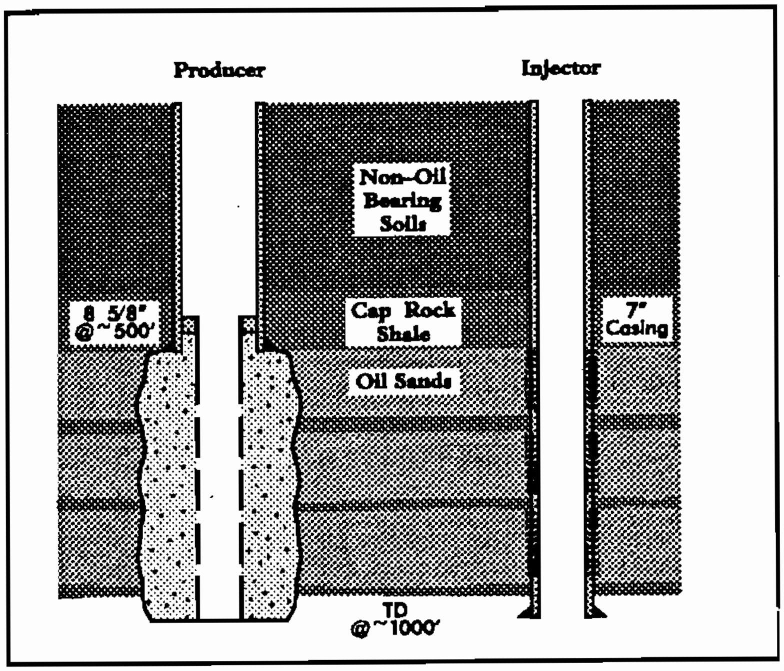


Figure 3-14. Typical South Belridge Completions (Fram and Eberhard, 1993)

Equipment used for well abandonments using coiled tubing is shown in Figure 3-15. Before the coiled-tubing unit is used, wells are cleaned out and their production tubing and packers removed by a workover rig. After the coiled-tubing unit is rigged up, the well is quenched while running the tubing into the well. The bottom cement plug is spotted next. The unit is then rigged down and moved to the next well. Five or six bottom plugs can be set in an 8-hour day.

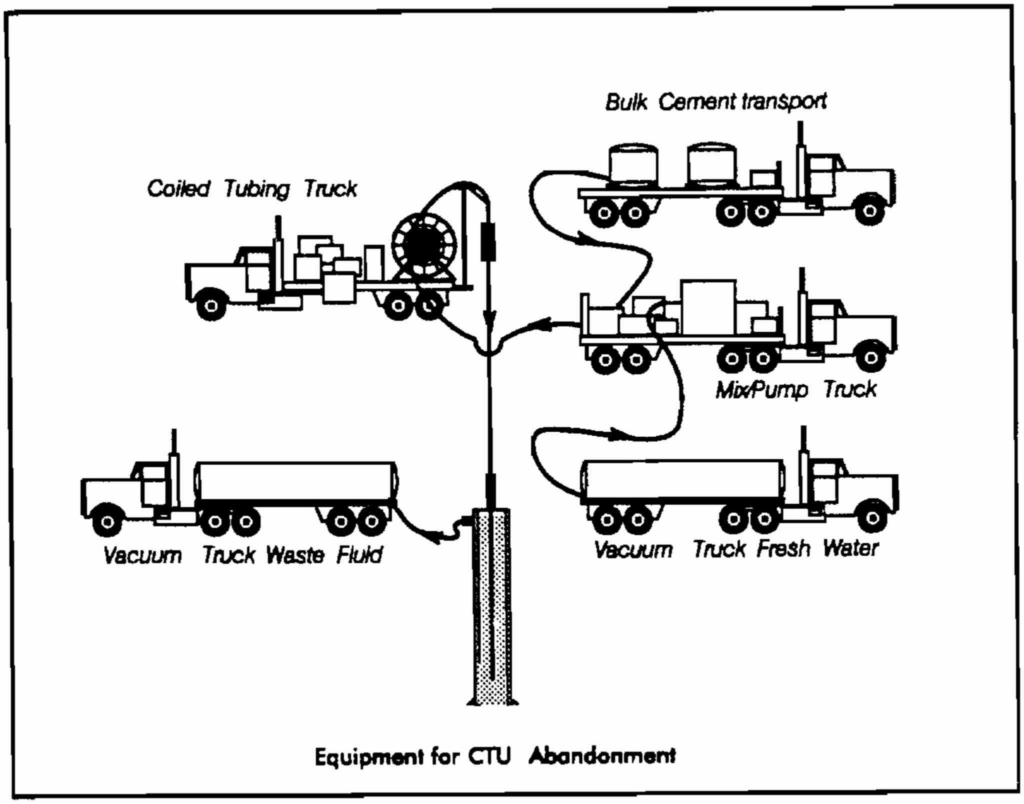


Figure 3-15. Equipment for Coiled-Tubing Abandonment (Fram and Eberhard, 1993)

A small wireline perforating unit next tags the top of cement and perforates the casing across from the caprock overlying the reservoir. Later, the coiled-tubing equipment is again rigged up and used to fill the remaining wellbore with cement.

Savings are seen with the coiled-tubing procedure by more efficient use of equipment, a reduction in the number of tags at the wrong depth, and far fewer instances of unintentionally fracturing the wellbore while pumping cement, as compared to conventional procedures with a workover rig.

The project team also sought ways to decrease the cost of cement material, one of the major expenses. A Premium cement slurry was used previously (Figure 3-16, Slurry 2). The addition of pozzolan reduced costs by 40%, while still providing acceptable properties. Pozzolan blend has an increased set-up time; however, since the equipment is moved off the well after the cement is spotted, longer WOC times are not a problem. The pozzolan blend (Figure 3-16, Slurry 3) is also less viscous and can be pumped at a rate of 1½ bpm versus about 1 bpm for Premium. As a consequence, pumping times are reduced.

	Slurry 1	Slurry 2	Slurry 3	
Yield	2.35	1.65	1.9	cft/sk
Weight	16.7	15.6	13.0	lb/gal
Water	7.9	6.6	9.7	gal/sk
Relative Cost Factor	.9	1.0	.6	$/cft
All test are at a BHCT of 100 °F				
Free Water – %	0.0	0.5	1.0	
Fluid Loss – cc/30min	800	750	1000	
Rheolgy				
600 rpm	130	150	132	
300 rpm	105	100	110	
200 rpm	96	81	101	
100 rpm	83	60	91	
Thickening Time – Hr:Min	3:00+	1:30	5:21	

Compressive Strength – psi	Slurry 1 100	Slurry 1 200	Slurry 1 300	Slurry 2 100	Slurry 2 200	Slurry 2 300	Slurry 3 100	Slurry 3 200	Slurry 3 300 °F
24 hr	900		2000	2000	2500	3600			
48 hr				2700	3500	5000			
72 hr	1700		4000				250	800	2550
5 day				3000	3500	5400	450	1500	3000
7 day	2100		4500	4000	4800	6000	600	1750	3200

Slurry 1 – 1:1 Sand/Premium cement with 35% silica flour, 2% gel
Slurry 2 – Premium cement with 35% silica flour, 3% calcium chloride
Slurry 3 – 50:50 Pozzolan/Premium cement with 35% silica flour (BWOC), 5% gel

Figure 3-16. Cement Slurry Properties (Fram and Eberhard, 1993)

Shell Western concluded that this type of review and revision of routine tasks as new technology becomes available, can result in significantly decreased costs.

3.6 REFERENCES

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4.1 COILED-TUBING PROPERTIES AND PERFORMANCE

During the first 25 years of its existence, coiled tubing was typically manufactured in strings of 1- or 1¼-in. diameter. Work strings of up to 15,000 ft were transportable on a single compact rig. Pump rates were generally limited to about 1 BPM. Larger tubing of 1½- and 1¾-in. were introduced in the mid-1980s to allow higher pump rates for various operations.

Coiled tubing has since been made available (Figure 4-1) in several additional diameters: 2, 2⅜, 2⅞, and 3½ in. Wall thicknesses range from 0.109 in. for light-wall 2-in. tubing to 0.204 in. for 3½-in. tubing (Smith, 1993).

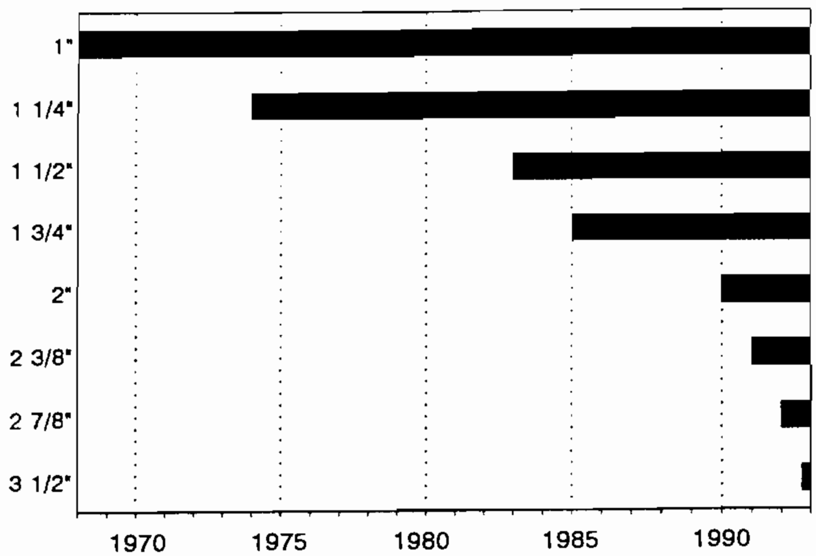

Figure 4-1. Introduction of Coiled Tubing Sizes

Ratios of outer diameter to wall thickness have ranged from 8:1 up to 20:1, based on the intended service. Work strings that will be cycled repeatedly under pressure perform best in the range of 12:1 to 14:1. Strings that will not be cycled (flow lines, etc.) have used thickness ratios in the range of 16:1 to 19:1.

Coiling diameter is the ratio of spool hub diameter to tubing diameter. Industry's experience has shown that coiling diameter for strings that will be cycled repeatedly can range from a minimum of 40:1 to a more optimum 48:1 (Smith, 1993). Again, more leeway is available for strings that will not be cycled. For these strings, a coiling diameter as low as 36:1 has been found to be acceptable.

Shipping constraints become an important consideration for larger sizes of coiled tubing (Table 4-1). Typical maximum spool dimensions to avoid special permits for over-road shipment are: 70 in. flange width, 150 in. height, and 45,000 lb total weight. Note in Table 4-1 that these 2⅞- and 3½-in. spools are constrained by height rather than weight.

TABLE 4-1. Typical Tubing Shipping Limits (Smith, 1993)

Tubing (in.)	Weight (lb/ft)	Core OD (in.)	Capacity (ft)	Weight (lb)
2 x 0.109	2.2	80	17,000	41,000
2⅜ x 0.156	3.7	95	11,000	44,000
2⅞ x 0.175	5.1	110	5,300	30,000
3½ x 0.190	6.7	130	2,400	20,000

Larger diameter coiled tubing (2 in. and greater) has found considerable application as production tubing and flowline. Industry's experiences in these areas are discussed in the chapters *Pipelines* and *Production Strings*.

Sizes, dimensions, and ratings of 80-ksi tubing are summarized in Tables 4-2 (English units) and 4-3 (metric units). These data are for QT-800® tubing, Quality Tubing's 80-ksi bias-welded material. This product represents the majority of strings currently in service.

TABLE 4-2. 80-Ksi Coiled Tubing — English Units (Quality Tubing, 1993)

QT-800' COILED TUBING DATA

TUBE DIMENSIONS (INCHES)				TUBE AREA (SQ. IN)		WEIGHT (LB/FT)	LOAD CAPACITY (LBS)		PRESSURE CAPACITY (PSI)				TORQUE (LB-FT)		INTERNAL CAPACITY PER 1000 FT		EXTERNAL DISPLACEMENT PER 1000 FT	
O.D. NOM.	WALL NOM.	WALL MIN.	I.D. NOM.	WALL NOM.	I.D. NOM.	NOM.	YIELD MIN.	ULTIMATE MIN.	YIELD MIN.	TEST 80%	BURST MIN.	COLLAPSE MIN.	YIELD NOM.	ULTIMATE NOM.	GALS.	BBLS.	GALS.	BBLS.
1.000	0.080	0.198	0.840	0.231	0.554	0.786	16185	18497	11200	8960	14229	5890	288	383	28.79	0.690	40.80	0.971
1.000	0.087	0.082	0.826	0.250	0.536	0.848	19960	22450	13110	10400	16430	12700	350	466	27.84	0.663	40.80	0.971
1.000	0.095	0.090	0.810	0.270	0.515	0.918	21600	24300	14400	11500	18150	13750	373	497	26.77	0.637	40.80	0.971
1.000	0.102	0.097	0.796	0.288	0.498	0.978	23020	25890	15510	12400	19660	14650	392	522	25.85	0.616	40.80	0.971
1.000	0.109	0.104	0.782	0.305	0.480	1.037	24400	27450	16640	13300	21190	15530	410	546	24.95	0.594	40.80	0.971
1.250	0.080	0.198	1.090	0.294	0.933	1.000	20583	23524	8960	7168	11230	7134	472	629	48.47	1.150	63.75	1.518
1.250	0.087	0.082	1.076	0.318	0.909	1.081	25420	28600	10490	8300	12960	9800	576	769	47.24	1.125	63.75	1.518
1.250	0.095	0.090	1.060	0.345	0.882	1.172	27570	31020	11520	9200	14310	11230	617	823	45.84	1.091	63.75	1.518
1.250	0.102	0.097	1.046	0.368	0.859	1.251	29420	33100	12410	9900	15490	11990	652	869	44.64	1.063	63.75	1.518
1.250	0.109	0.104	1.032	0.391	0.836	1.328	31250	35160	13310	10600	16690	12730	684	913	43.45	1.035	63.75	1.518
1.250	0.125	0.120	1.000	0.442	0.785	1.502	35340	39760	15360	12200	19440	14400	755	1006	40.80	0.971	63.75	1.518
1.250	0.134	0.129	0.982	0.470	0.757	1.597	37580	42280	16510	13200	21010	15310	791	1055	39.34	0.937	63.75	1.518
1.250	0.156	0.151	0.938	0.536	0.691	1.823	42890	48250	19320	15400	24870	17470	873	1164	35.90	0.855	63.75	1.518
1.500	0.095	0.090	1.310	0.419	1.348	1.426	33540	37730	9600	7600	11800	8260	924	1232	70.02	1.667	91.80	2.186
1.500	0.102	0.097	1.296	0.448	1.319	1.523	35830	40310	10340	8200	12770	9410	978	1304	68.53	1.632	91.80	2.186
1.500	0.109	0.104	1.282	0.476	1.291	1.619	38100	42860	11090	8800	13740	10560	1030	1374	67.06	1.597	91.80	2.186
1.500	0.125	0.120	1.250	0.540	1.227	1.836	43190	48590	12800	10200	16000	12220	1144	1525	63.75	1.518	91.80	2.186
1.500	0.134	0.129	1.232	0.575	1.192	1.955	46000	51750	13760	11000	17290	13010	1204	1605	61.93	1.474	91.80	2.186
1.500	0.156	0.151	1.188	0.659	1.108	2.239	52690	59280	16100	12800	20460	14900	1340	1786	57.58	1.371	91.80	2.186
1.750	0.109	0.104	1.532	0.562	1.843	1.910	44950	50570	9500	7600	11680	8010	1448	1930	95.76	2.280	124.95	2.975
1.750	0.125	0.120	1.500	0.638	1.767	2.169	51050	57430	10970	8700	13580	10230	1614	2152	91.80	2.186	124.95	2.975
1.750	0.134	0.129	1.482	0.680	1.725	2.313	54420	61220	11790	9400	14670	11310	1704	2271	89.61	2.134	124.95	2.975
1.750	0.156	0.151	1.438	0.781	1.624	2.656	62490	70300	13800	11000	17350	12990	1908	2545	84.37	2.009	124.95	2.975
1.750	0.175	0.170	1.400	0.866	1.539	2.944	69270	77930	15540	12400	19690	14400	2071	2761	79.97	1.904	124.95	2.975
2.000	0.109	0.104	1.782	0.648	2.494	2.201	51800	58270	8320	6600	10150	6090	1936	2581	129.56	3.085	163.20	3.886
2.000	0.125	0.120	1.750	0.736	2.405	2.503	58900	66260	9600	7600	11800	8060	2167	2889	124.95	2.975	163.20	3.886
2.000	0.134	0.129	1.732	0.786	2.356	2.671	62840	70690	10320	8200	12730	9160	2291	3055	122.39	2.914	163.20	3.886
2.000	0.156	0.151	1.688	0.904	2.238	3.072	72290	81330	12080	9600	15050	11500	2579	3439	116.25	2.768	163.20	3.886
2.000	0.175	0.170	1.650	1.003	2.138	3.411	80260	90300	13590	10800	17070	12770	2810	3747	111.08	2.645	163.20	3.886
2.000	0.188	0.183	1.624	1.070	2.071	3.638	85610	96310	14640	11700	18470	13620	2960	3946	107.60	2.562	163.20	3.886
2.000	0.203	0.198	1.594	1.146	1.996	3.896	91680	103140	15840	12600	20100	14590	3123	4164	103.67	2.468	163.20	3.886
2.375	0.109	0.104	2.157	0.776	3.654	2.638	62070	69830	7000	5600	8480	3980	2802	3737	189.83	4.520	230.14	5.479
2.375	0.125	0.120	2.125	0.884	3.547	3.004	70680	79520	8080	6400	9850	5630	3149	4198	184.24	4.387	230.14	5.479
2.375	0.134	0.129	2.107	0.943	3.487	3.207	75470	84900	8690	6900	10620	6570	3337	4449	181.13	4.313	230.14	5.479
2.375	0.156	0.151	2.063	1.088	3.343	3.697	87000	97870	10170	8100	12540	8840	3776	5035	173.64	4.134	230.14	5.479
2.375	0.175	0.170	2.025	1.210	3.221	4.112	96760	108850	11450	9100	14220	10810	4134	5512	167.31	3.983	230.14	5.479
2.375	0.188	0.183	1.999	1.292	3.138	4.391	103330	116250	12320	9800	15380	11660	4368	5823	163.04	3.882	230.14	5.479
2.375	0.203	0.198	1.969	1.385	3.045	4.709	110810	124660	13330	10600	16720	12500	4626	6168	158.18	3.766	230.14	5.479
2.875	0.125	0.120	2.625	1.080	5.412	3.671	86390	97190	6670	5300	8070	3470	4744	6326	281.14	6.694	337.24	8.029
2.875	0.134	0.129	2.607	1.154	5.338	3.923	92310	103840	7170	5700	8700	4150	5038	6717	277.29	6.602	337.24	8.029
2.875	0.156	0.151	2.563	1.333	5.159	4.530	106600	119920	8400	6700	10260	6030	5730	7640	268.01	6.381	337.24	8.029
2.875	0.175	0.170	2.525	1.484	5.007	5.046	118750	133590	9460	7500	11620	7660	6300	8399	260.12	6.193	337.24	8.029
2.875	0.188	0.183	2.499	1.587	4.905	5.395	126950	142820	10180	8100	12560	8770	6675	8900	254.80	6.067	337.24	8.029
2.875	0.203	0.198	2.469	1.704	4.788	5.793	136320	153360	11010	8800	13650	10050	7094	9458	248.71	5.922	337.24	8.029
3.500	0.134	0.129	3.232	1.417	8.204	4.817	113350	127520	5890	4700	7090	2640	7657	10209	426.19	10.147	499.80	11.900
3.500	0.156	0.151	3.188	1.639	7.982	5.571	131100	147490	6900	5500	8350	3650	8746	11661	414.66	9.873	499.80	11.900
3.500	0.175	0.170	3.150	1.828	7.793	6.215	146240	164520	7770	6200	9450	4990	9650	12867	404.84	9.639	499.80	11.900
3.500	0.188	0.183	3.124	1.956	7.665	6.650	156490	176050	8360	6600	10210	5900	10251	13668	398.18	9.481	499.80	11.900
3.500	0.203	0.198	3.094	2.103	7.518	7.148	168210	189230	9050	7200	11090	6950	10925	14567	390.57	9.299	499.80	11.900

NOTES: 1. The effect of Axial Tension on Pressure Rating has **not** been applied to the above data.
2. Above data is for new tubing at minimum strength.

Maximum Working Pressure is a function of tube condition and is determined by the user.

TABLE 4-3. 80-Ksi Coiled Tubing — Metric Units (Quality Tubing, 1993)

QT-800' COILED TUBING METRIC DATA

TUBE DIMENSIONS (mm)				TUBE AREA (mm²)		WEIGHT (KG/M)	LOAD CAPACITY (KG)		PRESSURE CAPACITY (N/mm²)				TORQUE (N-M)		INTERNAL CAPACITY	EXTERNAL DISPLACEMENT
O.D. NOM.	WALL NOM.	WALL MIN.	I.D. NOM.	WALL NOM.	I.D. NOM.	NOM.	YIELD MIN.	ULTIMATE MIN.	YIELD MIN.	TEST 80%	BURST MIN.	COLLAPSE MIN.	YIELD NOM.	ULTIMATE NOM.	LITERS PER METER	LITERS PER METER
25.40	2.03	1.91	21.34	149.2	357.5	1.171	8390	9440	82	66	103	81	446	594	0.358	0.507
25.40	2.21	2.08	20.98	161.0	345.7	1.264	9060	10190	90	71	113	87	474	632	0.346	0.507
25.40	2.41	2.29	20.57	174.3	332.5	1.368	9805	11030	99	79	125	94	505	674	0.332	0.507
25.40	2.59	2.46	20.22	185.6	321.1	1.457	10450	11750	106	85	135	101	531	708	0.321	0.507
25.40	2.77	2.64	19.86	196.8	309.9	1.545	11075	12460	114	91	146	107	556	741	0.310	0.507
31.75	2.03	1.91	27.69	189.7	602.0	1.489	10675	12010	66	52	81	58	731	975	0.602	0.792
31.75	2.21	2.08	27.33	205.1	586.7	1.610	11540	12980	72	57	89	67	782	1042	0.587	0.792
31.75	2.41	2.29	26.92	222.4	569.3	1.746	12515	14080	79	63	98	77	837	1116	0.569	0.792
31.75	2.59	2.46	26.57	237.3	554.4	1.863	13355	15025	85	68	106	82	883	1178	0.554	0.792
31.75	2.77	2.64	26.21	252.1	539.7	1.978	14185	15960	91	73	115	87	928	1237	0.540	0.792
31.75	3.17	3.05	25.40	285.0	506.7	2.237	16040	18050	105	84	134	99	1023	1364	0.507	0.792
31.75	3.40	3.28	24.94	303.1	488.6	2.379	17060	19195	113	91	144	105	1073	1431	0.489	0.792
31.75	3.96	3.84	23.83	345.9	445.8	2.715	19470	21905	133	106	171	120	1184	1578	0.446	0.792
38.10	2.41	2.29	33.27	270.5	869.6	2.123	15225	17125	66	52	81	56	1253	1670	0.870	1.140
38.10	2.59	2.46	32.92	289.0	851.1	2.268	16265	18300	71	56	88	64	1326	1768	0.851	1.140
38.10	2.77	2.64	32.56	307.3	832.8	2.412	17295	19455	76	60	94	72	1397	1863	0.833	1.140
38.10	3.17	3.05	31.75	348.4	791.7	2.734	19605	22055	88	70	110	84	1551	2067	0.792	1.140
38.10	3.40	3.28	31.29	371.0	769.1	2.912	20880	23490	94	75	119	89	1632	2176	0.769	1.140
38.10	3.96	3.84	30.18	425.0	715.1	3.335	23920	26910	111	88	141	102	1817	2422	0.715	1.140
44.45	2.77	2.64	38.91	362.5	1189.3	2.845	20405	22955	65	52	80	55	1963	2617	1.189	1.552
44.45	3.17	3.05	38.10	411.7	1140.1	3.231	23175	26070	75	59	93	70	2189	2918	1.140	1.552
44.45	3.40	3.28	37.64	438.9	1112.9	3.445	24705	27790	81	64	101	77	2310	3080	1.113	1.552
44.45	3.96	3.84	36.53	504.0	1047.8	3.956	28370	31915	95	75	119	89	2588	3450	1.048	1.552
44.45	4.44	4.32	35.56	558.6	993.1	4.385	31445	35380	107	85	135	99	2808	3744	0.993	1.552
50.80	2.77	2.64	45.26	417.8	1609.1	3.279	23515	26450	57	45	69	41	2625	3500	1.609	2.027
50.80	3.17	3.05	44.45	475.0	1551.8	3.728	26740	30080	66	52	81	55	2938	3917	1.552	2.027
50.80	3.40	3.28	43.99	506.8	1520.0	3.978	28525	32090	71	56	87	63	3106	4142	1.520	2.027
50.80	3.96	3.84	42.88	583.0	1443.8	4.576	32815	36920	83	66	103	79	3497	4662	1.444	2.027
50.80	4.44	4.32	41.91	647.3	1379.5	5.081	36435	40995	93	74	117	88	3810	5081	1.379	2.027
50.80	4.78	4.65	41.25	690.5	1336.4	5.419	38865	43720	100	80	127	93	4013	5350	1.336	2.027
50.80	5.16	5.03	40.49	739.4	1287.5	5.803	41620	46825	109	86	138	100	4235	5646	1.287	2.027
60.33	2.77	2.64	54.79	500.6	2357.5	3.929	28175	31700	48	38	58	27	3800	5066	2.357	2.858
60.33	3.17	3.05	53.98	570.0	2288.1	4.474	32085	36100	55	44	67	38	4269	5692	2.288	2.858
60.33	3.40	3.28	53.52	608.6	2249.5	4.777	34260	38540	59	47	73	45	4524	6032	2.249	2.858
60.33	3.96	3.84	52.40	701.6	2156.5	5.507	39495	44430	70	55	86	60	5120	6827	2.156	2.858
60.33	4.44	4.32	51.43	780.3	2077.8	6.125	43925	49415	78	62	98	74	5605	7473	2.078	2.858
60.33	4.78	4.65	50.77	833.3	2024.8	6.541	46910	52775	84	67	106	80	5922	7895	2.025	2.858
60.33	5.16	5.03	50.01	893.7	1964.5	7.014	50305	56595	91	73	115	86	6272	8362	1.964	2.858
73.03	3.17	3.05	66.67	696.7	3491.5	5.468	39220	44120	45	36	55	23	6432	8576	3.491	4.188
73.03	3.40	3.28	66.22	744.4	3443.8	5.843	41905	47140	49	39	59	28	6830	9107	3.443	4.188
73.03	3.96	3.84	65.10	859.7	3328.5	6.748	48395	54440	57	46	70	41	7769	10358	3.328	4.188
73.03	4.44	4.32	64.13	957.7	3230.6	7.517	53910	60645	65	51	80	52	8541	11388	3.230	4.188
73.03	4.78	4.65	63.47	1023.9	3164.4	8.036	57635	64840	70	55	86	60	9050	12067	3.164	4.188
73.03	5.16	5.03	62.71	1099.4	3088.9	8.629	61885	69625	75	60	94	69	9618	12823	3.088	4.188
88.90	3.40	3.28	82.09	914.2	5293.0	7.175	51460	57890	40	32	48	18	10382	13842	5.292	6.207
88.90	3.96	3.84	80.98	1057.3	5149.8	8.299	59515	66960	47	37	57	25	11858	15810	5.149	6.207
88.90	4.44	4.32	80.01	1179.4	5027.8	9.257	66390	74690	53	42	65	34	13084	17446	5.027	6.207
88.90	4.78	4.65	79.35	1262.0	4945.1	9.905	71045	79925	57	45	70	10	13898	18531	4.945	6.207
88.90	5.16	5.03	78.59	1356.5	4850.6	10.647	76365	85910	62	49	76	17	14812	19750	4.850	6.207

NOTES: 1. The effect of Axial Tension on Pressure Rating has **not** been applied to the above data.
2. Above data is for new tubing at minimum strength.

Maximum Working Pressure is a function of tube condition and is determined by the user.

The range of tubing wall thicknesses currently available varies for each size of tubing. For 1 in., wall thickness ranges from 0.080-0.109 (Quality Tubing); 0.075-0.109 (Precision Tube); and 0.087 (Southwestern Pipe). For 3½-in. tubing, wall thickness ranges from 0.134-0.203 (Quality Tubing); and 0.175-0.190 (Precision Tube).

Wall thickness has increased along with tubing size due to the need to maintain a practical level of burst resistance with larger pipe. The average wall thickness available from Quality Tubing is shown for each coiled-tubing diameter in Figure 4-2.

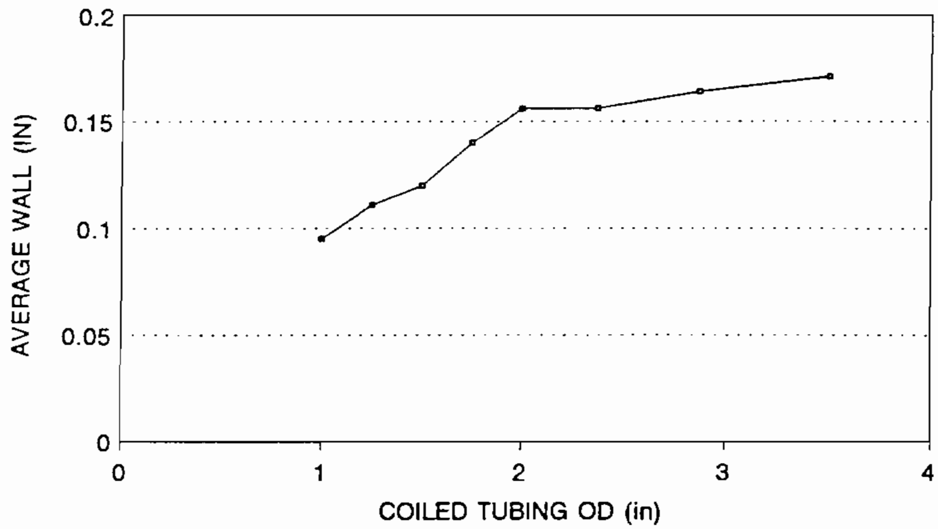

Figure 4-2. Coiled-Tubing Wall Thickness (Quality Tubing, 1993)

Due to the strong dependence on the tube diameter, burst strength does generally decrease for larger tubing, despite increased thickness (Figure 4-3). Average burst strength of 1-in. tubing is almost double that of 3½ in.: 16,100 psi versus 8400 psi. Note that the bump in the curves for burst strength for 2-in. tubing is due to the fact that the increase in average wall thickness offered by Quality Tubing outpaces the increase in tube diameter from 1¾ to 2 inches.

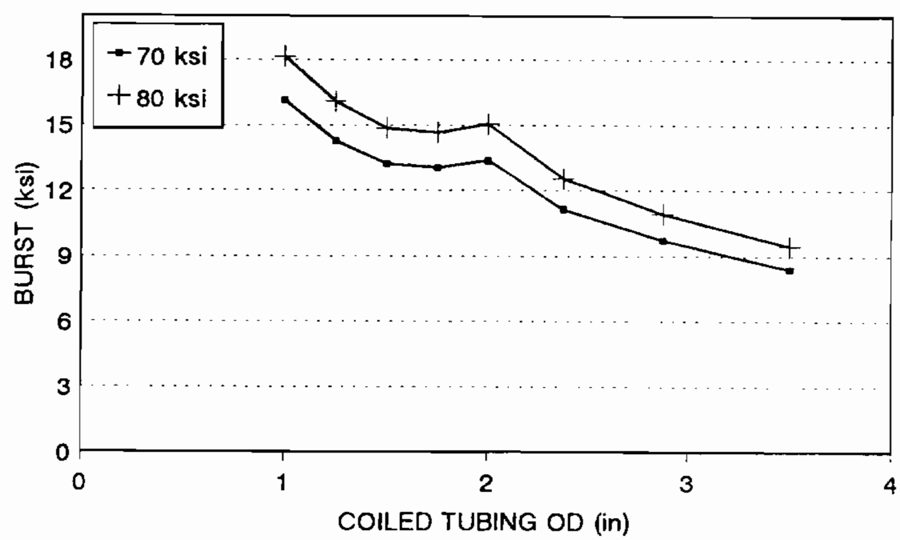

Figure 4-3. Coiled-Tubing Burst Strength (Quality Tubing, 1993)

Torque capacity increases as the square of tubing diameter. Average maximum torque data (Figure 4-4) illustrate why tubing less than 2 in. is poorly suited for drilling operations.

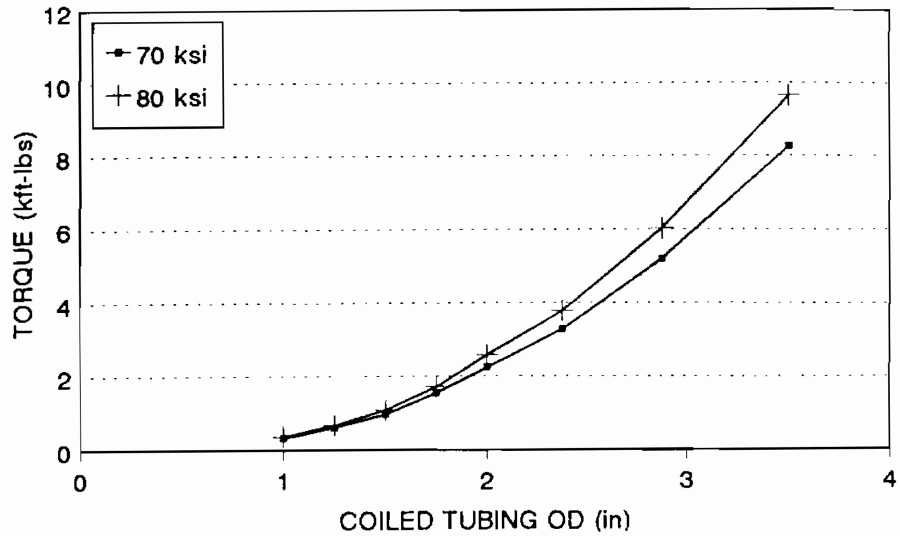

Figure 4-4. Coiled-Tubing Torque Capacity (Quality Tubing, 1993)

Tensile loads at pipe yield are compared in Figure 4-5. Average maximum load capacity is about 19,000 lb for 1 in., 49,000 lb for 1¾ in., and 125,000 lb for 3½ in. This increased capacity with larger sizes is offset to a degree by the increased weight of the tubing string at any given depth.

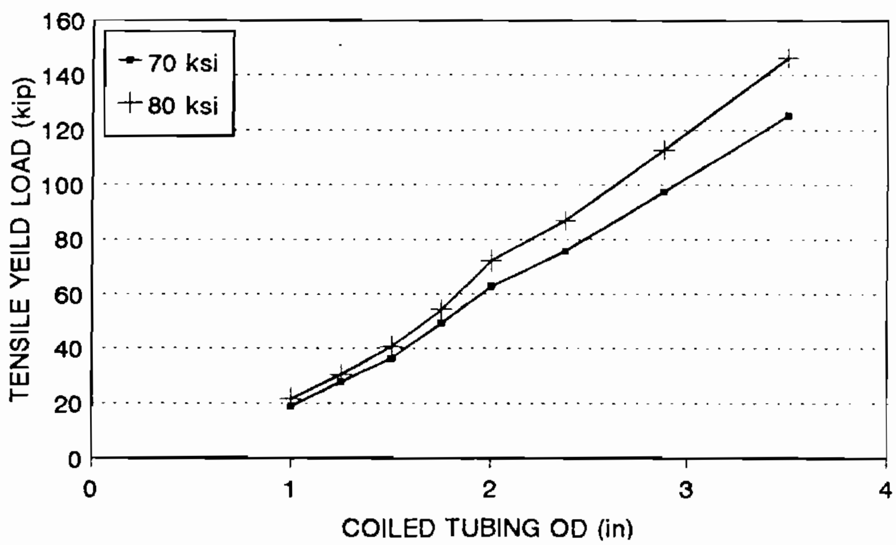

Figure 4-5. Coiled-Tubing Tensile Load Capacity (Quality Tubing, 1993)

Internal flow area also varies significantly (Figure 4-6). There is over 15 times more flow area in a 3½-in. string as in a 1-in. string. It is also interesting to note that 1½- and 1¾-in. tubing have about

50% and 100% more area, respectively, than 1¼-in. This explains why the introduction of these medium sizes satisfied most of the needs of traditional hydraulic service operations.

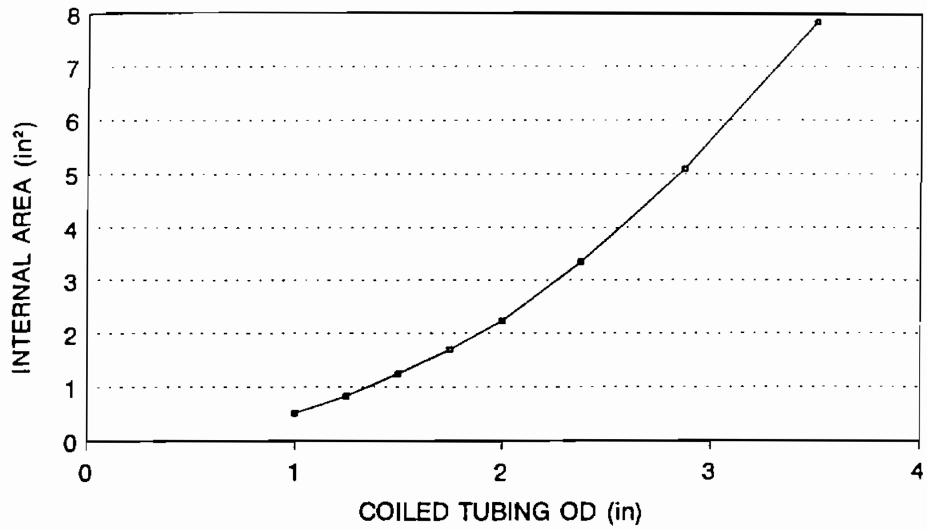

Figure 4-6. Coiled Tubing Internal Capacity (Quality Tubing, 1993)

The weight of coiled tubing is shown in Figure 4-7. Weight increases almost linearly for the range of tubings available. The cost of coiled tubing is on the order of $1/lb/ft, especially for the smaller sizes. Larger O.D. typically costs more than $1/lb/ft.

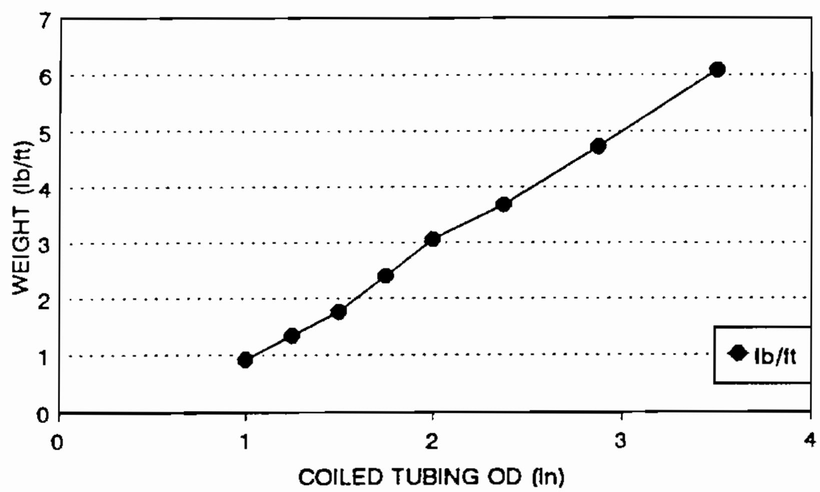

Figure 4-7. Coiled-Tubing Weight (Quality Tubing, 1993)

Traditional diameters (i.e., less than 2 in.) continue to represent a solid majority of coiled tubing production. Figure 4-8 presents an overview of recently manufactured tubing diameter.

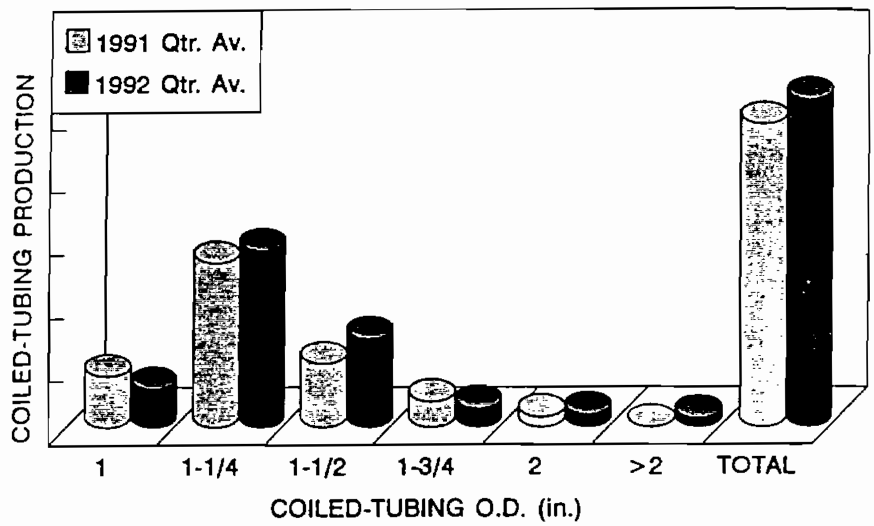

Figure 4-8. Recent Coiled-Tubing Production (Quality Tubing, 1993)

4.2 CORROSION OF COILED TUBING

4.2.1 Halliburton

Halliburton (Walker and Lancaster, 1993) reported the results of various tests of the susceptibility of coiled tubing to corrosion by inhibited acid. Early in the history of coiled-tubing field operations, excessive corrosion was observed after acid jobs. Operators began to use higher concentrations of inhibitors, special inhibitors, as well as pump slugs of inhibitor ahead of the acid. Although somewhat successful, these types of fixes increased the potential to damage the formation.

The primary differences in the metallurgy of coiled tubing and N-80 jointed tubulars are reduced carbon and sulfur in coiled tubing (Table 4-4). From a metallurgical analysis, these differences in recipe should make coiled tubing *less* susceptible to corrosion than N-80.

TABLE 4-4. Metallurgy of Coiled Tubing, N-80, and L-80 (Walker and Lancaster, 1993)

Elements	Coiled Tubing	N-80 Steel*	L-80
Carbon	0.10 - 0.14	-	0.43 Max
Manganese	0.70 - 0.90	-	1.90 Max
Phosphorus	0.0025 Max	0.040 Max	0.040 Max
Sulfur	0.005 Max	0.060 Max	0.060 Max
Silicon	0.30 - 0.5	-	0.45 Max
Chromium	0.50 - 0.70	-	--
Copper	0.25 Max	-	0.35 Max
Nickel	0.20 Max	-	0.25 Max
Iron	Balance	Balance	Balance

*NOTE: Specification 5A: Casing, tubing, and drill pipe from API show only maximum content allowed of phosphorus at 0.040% and sulfur at 0.060% required for composition of material to make tubulars of grades H-40 to N-80. For L-80 grade tubing, see above composition.

Halliburton conducted tests where tubing was placed in inhibited 15% HCl for 6 hr at temperatures ranging from 200 to 300°F. These results showed no significant differences between coiled tubing or N-80 tubing (Figure 4-9).

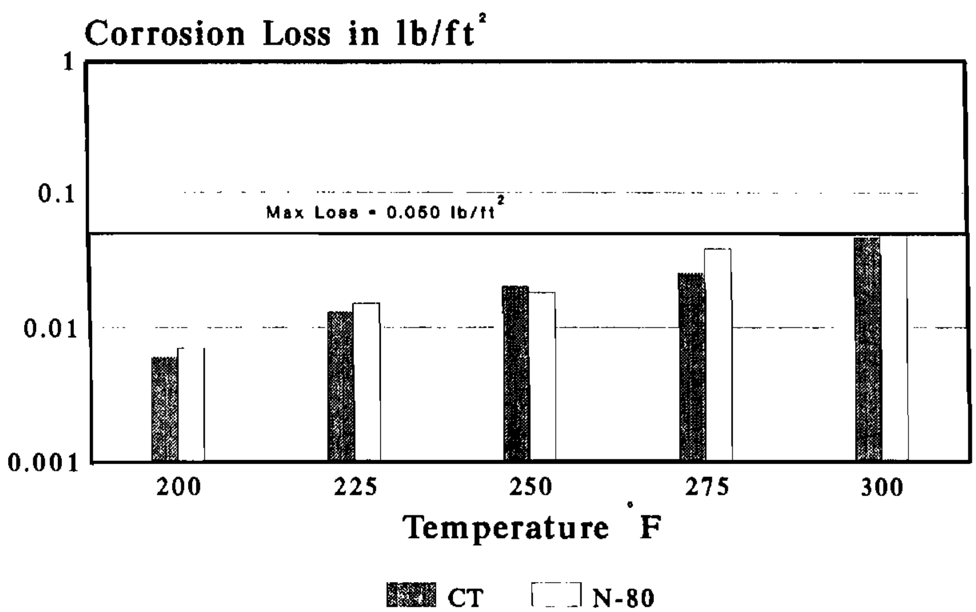

Figure 4-9. Inhibited Acid Immersion Tests (Walker and Lancaster, 1993)

Corrosion was further evaluated under cycling conditions designed to simulate field usage of coiled tubing. Tubing was exposed to inhibited acid for 8 hr and then to either moist air or moist nitrogen for 16 hours. This cycle was repeated 60 times. Results showed that corrosion was significantly greater on the aerobic tests (Figure 4-10). A control sample was kept immersed in acid throughout the 60-day test period ("immersion" data in Figure 4-10).

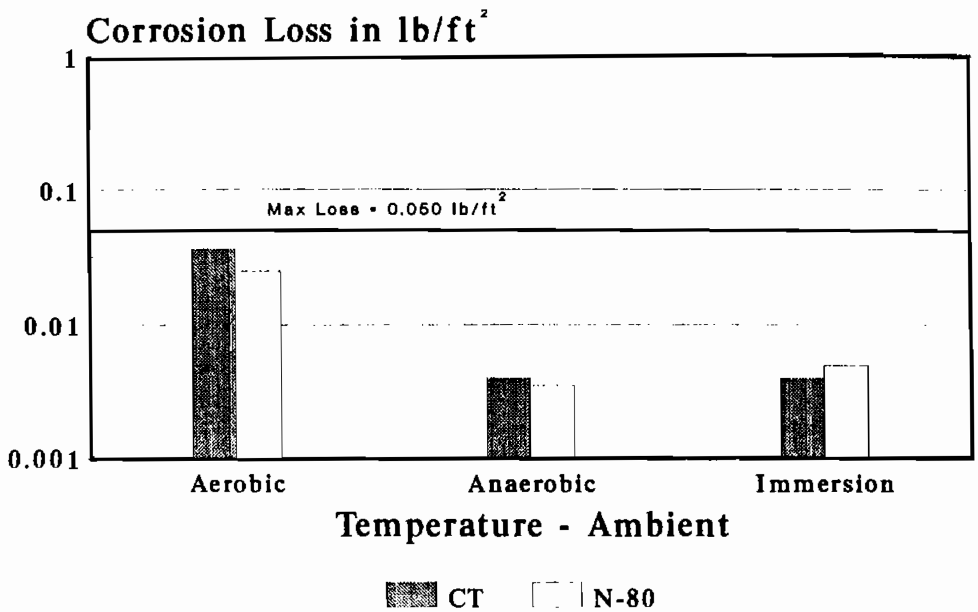

Figure 4-10. Aerobic and Anaerobic Cycle Tests (Walker and Lancaster, 1993)

These results indicate that the formation of iron oxides (rust) between acid baths led to exposure of new metal after dissolution of each cycle's rust by the acid. Corrosion by exposure to oxygen cannot be easily avoided during typical coiled-tubing field usage. Rust is best prevented by programs of rinsing, cleaning, and atmospheric corrosion inhibitors.

Another series of tests was conducted in which the inhibited acid was pumped through the tubulars during the tests. These tests were designed to investigate whether flow regimes or velocity profiles increased the rate of corrosion. Acid was pumped at 0.5 BPM through 1¼ x 0.090 x 10 ft coiled tubing for 8 hours at 150°F and 500 psi. Sonic wall thickness measurements (Table 4-5) showed that no unusual wall loss occurred.

TABLE 4-5. Wall Thickness After Acid Flow Tests (Walker and Lancaster, 1993)

Acid System	Before Test Thin (in.)	Before Test Thick (in.)	After Test Thin (in.)	After Test Thick (in.)
1	0.089	0.092	0.087	0.090
2	0.091	0.093	0.087	0.089
3	0.089	0.092	0.085	0.090

Coiled tubing samples 10 ft. x 1.25 in. x 0.090 in. coiled tubing exposed to (1) 15% HCl + 0.3% inhibitor; (2) 7.5-1.5 HCl-HF + 0.3% inhibitor and (3) 15% HCl + 0.3% inhibitor for 8 hours followed by 7.5-1.5 HCl-HF + 0.3% inhibitor for 8 hours. Tests were conducted at 150°F for 8 hours.

Halliburton planned additional tests to include the impacts of cold working and pressure cycling on corrosion.

4.3 HIGH-STRENGTH COILED TUBING

4.3.1 CYMAX/Halliburton

A discussion of the theoretical benefits and early field experiences with 100-ksi quenched and tempered coiled tubing was provided by Thompson et al. (1994). Several strings of CYMAX 100-ksi coiled tubing have been delivered to the field and a database of operational experience is forming.

There are several theoretical performance improvements that would result from increased material strength. Among the most important is fatigue life. Materials with higher yield strength will be stressed to a lower percentage of hoop stress under the same operating conditions. Thus, for the same bending radius, high-strength materials will have a longer life (Figure 4-11).

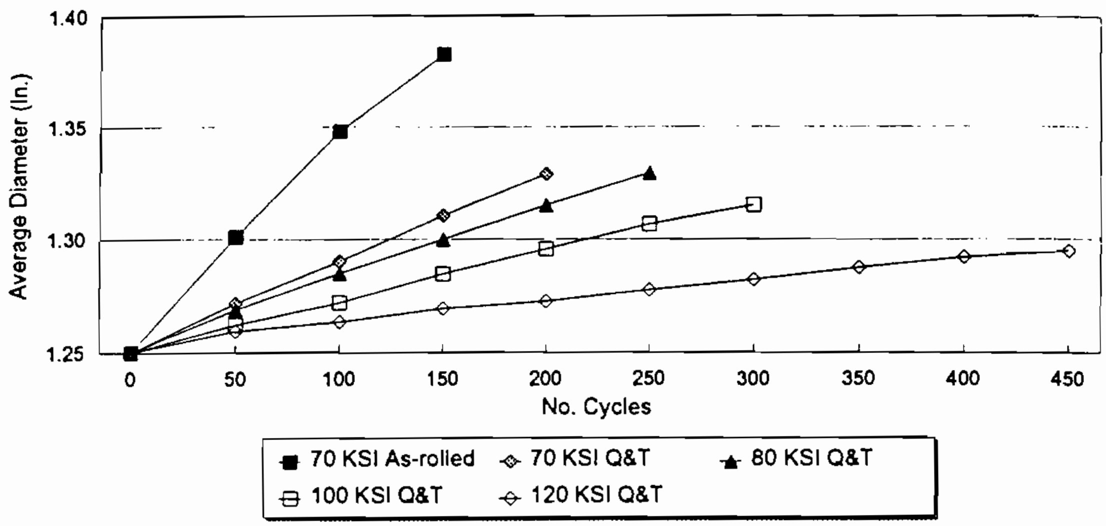

Figure 4-11. Coiled-Tubing Cycle Life and Strength (Thompson et al., 1994)

Few failures of high-strength coiled tubing have occurred as a result of fatigue failure. Several strings have been run over 1 million running feet. Service company experiences indicate that field life of these high-strength strings exceed that predicted in laboratory tests. It is surmised that the constraining effect of the gripper blocks and gooseneck slow the ballooning of the tubing and contribute to a fatigue life greater than predicted.

Increased overpull capacity is an important benefit of higher strength. Four string designs are compared in Table 4-6: 1) 70-ksi tubing with standard wall thickness, 2) 70-ksi tubing with thicker wall, 3) 70-ksi tubing tapered across four sections, and 4) 100-ksi tubing with standard wall thickness. Increased overpull can be derived from each of the three alternative designs; however, high-strength tubing provides the greatest overpull at the least string weight.

TABLE 4-6. Overpull of 1¼ x 15,000 ft Coiled Tubing (Thompson et al., 1994)

Tubing Material	Wall (in.)	Length (ft)	Weight (lb)	Overpull (lb)
Standard 70 ksi	0.087	15,000	16,210	1590
Thicker-wall 70 ksi	0.109	15,000	19,920	1960
Tapered 70 ksi	0.109 0.102 0.095 0.087	2500 2500 5000 5000	17,710	4170
Standard 100 ksi	0.087	15,000	16,210	9220

Burst and collapse pressure should increase with yield strength. Test results compared to calculated results are shown for burst in Table 4-7. Calculated collapse predictions are shown in Table 4-8.

TABLE 4-7. Burst Tests of High-Strength Coiled Tubing (Thompson et al., 1994)

Description	Actual Tensile (PSI)	Calculated Burst (PSI)	Tested Burst (PSI)
1¼" X .087"(.089) X 70 KSI As Rolled	81,500	12,400	12,800
1¼" X .087"(.088) X 100 KSI Quenched & Tempered	109,600	16,500	17,900

TABLE 4-8. Collapse Predictions for High-Strength Coiled Tubing (Thompson et al., 1994)

	70 KSI As Rolled	100 KSI Q&T
Weight (Lbs)	21,250	21,250
Yield Load (Lbs)	27,350	39,070
% of Yield	78%	54%
Collapse (PSI) of Round Tube	4,500	10,300
Collapse (PSI) of 1% out of Round	2,900	6,700

Field experience also indicates that high-strength tubing is not ovalled as rapidly as 70-ksi tubing under the same bending conditions.

The question of the detrimental effects of field welds has been asked by many in industry. CYMAX performed a series of tests comparing cycle life of a tube to that of a field repair weld (Table 4-9). These results show that field welds fail much more rapidly than tube body.

TABLE 4-9. Effect of Field Welds on High-Strength Coiled Tubing (Scott, 1994)

SAMPLE	No. of CYCLES	BREAK POINT
70 Tube	150	Tube
70 Weld	75	HAZ
80 Tube	210	Tube
80 Weld	135	HAZ
100 Tube	310	Tube
100 Weld	165	HAZ

Field repair welds were made using an orbital TIG welder with no post heat treatment.

Another important consideration with field welds is the reduced tensile capacity due to the inability to duplicate quench and temper processes in the field. CYMAX's tests (Scott, 1994) suggest that 100-ksi quenched and tempered coiled tubing should be downrated to 90 ksi following field welds. Neither 70-ksi or 80-ksi strings need to be down rated.

4.3.2 Halliburton/Amoco

High-strength coiled tubing was successfully used to clean out scale from three high-pressure gas wells in the Gulf of Mexico (Coats and Tatarski, 1993). Zinc sulfide had plugged off the wells and was removed using jetting and impact drilling operations run on coiled tubing. Significant cost savings were enjoyed by the operator (Amoco) for these workovers.

Due to the high shut-in pressures (>7000 psi), high-strength coiled tubing was required for these jobs. Prior to the field work, jetting parameters were modeled, which indicated that injection pressure would be in the range of 7500 psi and require 100-ksi coiled tubing.

Surface equipment for these three jobs included some modifications to the basic set-up due to the high surface pressures. A guide tube (Figure 4-12) was added below the injector to provide support for the tubing between the bottom of the chains and the stuffing box.

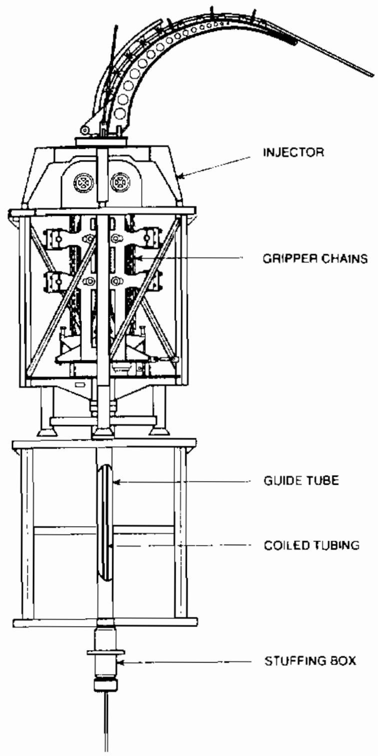

Figure 4-12. Tubing Guide for High-Pressure Workover (Coats and Tatarski, 1993)

A combination of jetting, acid soaking, and impact drilling was used to successfully clean out three wells. Production rates and coiled-tubing workover costs are summarized in Table 4-10. Cost estimates for conventional workovers for wells 5 and C-6 totaled almost $6 million. Coiled-tubing operations were performed at a cost of 5-6% of conventional.

TABLE 4-10. Production Rates and Costs for Three Wells (Coats and Tatarski, 1993)

Well Number	Original Production	Production Before Repair	Production After Repair	Cost of Repair
C-1	13 MMscfd	0	25.7 MMscfd	$ 80,000
5	20 MMscfd	.3 MMscfd	23.4 MMscfd	$152,000
C-6	11 MMscfd	3 MMscfd	19.5 MMscfd	$125,000
Cumulative Totals	44 MMscfd	3.3 MMscfd	68.6 MMscfd	$357,000

Additional discussion of these high-pressure scale removal operations is presented in the chapter *Workovers*.

4.4 TITANIUM COILED TUBING

4.4.1 Titanium Tube Technology

Titanium coiled tubing has recently been made available to the oil industry. RMI Titanium Co. and Precision Tube Technology have formed a joint-venture company called Titanium Tube Technology to offer this product. The first string was shipped in early 1993. CYMAX has also begun offering titanium tubing (see next section).

Several basic properties of all titanium alloys make them suited for specific oil-field applications. These include a high strength/weight ratio of about 2:1, excellent corrosion resistance in H_2S environments, low modulus of elasticity (about half that of steel: 16 MMpsi), and excellent fatigue properties. Elastic bend radius is inversely proportional to modulus of elasticity; thus, a lower modulus as with titanium will result in less plastic bending strain at a given spool or gooseneck radius. This will result in increased cycle life as compared to steel.

Two alloys are of current interest for use as coiled tubing (Table 4-11).

TABLE 4-11. Properties of Titanium Alloys (Klink, 1993)

PROPERTY	GRADE 12	GRADE 9
Minimum Yield	70 ksi (483 MPa)	90 ksi (621 MPa)
Minimum Tensile	80 ksi (552 MPa)	100 ksi (690 MPa)
Elastic Modulus	16,000 ksi (110 GPa)	16,000 ksi (110 GPa)

Grade 12 is composed of 99% titanium with 0.7% nickel and 0.3% molybdenum. The higher strength of Grade 9 is a result of a higher alloy content: 3% aluminum and 2.5% vanadium. Properties and capacities for Grade 12 coiled tubing are presented in Table 4-12, and for Grade 9 coiled tubing in Table 4-13.

TABLE 4-12. Properties of Grade 12 Titanium Coiled Tubing (Klink, 1993)

DIMENSIONS (INCHES)			WEIGHT LBS/FT	LOAD CAPACITY	BURST RATING	COLLAPSE RATING	INTERNAL PER	CAPACITY 1000FT	EXTERNAL PER	DISPLACEMENT 1000FT
OD NOM	WALL NOM	ID NOM	NOM	LBS	PSI	PSI	GALLONS	BBLS	GALLONS	BBLS
1.00	0.087	0.826	0.491	17468	13703	14298	27.83	0.66	40.8	0.97
1.00	0.095	0.81	0.532	21358	14963	15476	26.77	0.64	40.8	0.97
1.25	0.087	1.076	0.626	22251	10962	11815	47.23	1.12	63.75	1.52
1.25	0.095	1.06	0.678	24130	11970	12640	45.84	1.09	63.75	1.52
1.25	0.109	1.032	0.769	27350	13734	14327	43.45	1.03	63.75	1.52
1.50	0.095	1.31	0.825	29353	9975	10102	70.01	1.67	91.79	2.19
1.50	0.109	1.282	0.937	33343	11445	12130	67.05	1.6	91.79	2.19
1.50	0.125	1.25	1.063	37797	13125	13750	63.75	1.52	91.79	2.19
1.75	0.109	1.532	1.106	39335	9810	9816	95.75	2.28	124.94	2.97
2.00	0.09	1.82	1.506	37803	5513	3592	135.14	3.22	163.19	3.89
2.00	0.109	1.782	1.274	58279	8584	7687	129.55	3.08	163.19	3.89
2.375	0.109	2.157	1.518	54317	5622	3782	189.81	4.52	230.12	5.48
2.375	0.125	2.125	1.739	79522	8289	7177	184.22	4.39	230.12	5.48
2.375	0.134	2.107	1.857	66038	6912	6020	181.12	4.31	230.12	5.48
2.375	0.156	2.063	2.14	76126	8046	7989	173.63	4.13	230.12	5.48

Properties based on 70,000 psi min. yield and nominal dimensions

TABLE 4-13. Properties of Grade 9 Titanium Coiled Tubing (Klink, 1993)

DIMENSIONS (INCHES)			WEIGHT LBS/FT	LOAD CAPACITY	BURST RATING	COLLAPSE RATING	INTERNAL PER	CAPACITY 1000FT	EXTERNAL PER	DISPLACEMENT 1000FT
OD NOM	WALL NOM	ID NOM	NOM	LBS	PSI	PSI	GALLONS	BBLS	GALLONS	BBLS
1.00	0.087	0.826	0.491	22459	13703	14298	27.83	0.66	40.8	0.97
1.00	0.095	0.81	0.532	24309	14963	15476	26.77	0.64	40.8	0.97
1.25	0.087	1.076	0.626	28608	10962	11815	47.23	1.12	63.75	1.52
1.25	0.095	1.06	0.678	31024	11970	12640	45.84	1.09	63.75	1.52
1.25	0.109	1.032	0.769	35165	13734	14327	43.45	1.03	63.75	1.52
1.25	0.125	1	0.869	39761	15750	16200	40.8	0.97	63.75	1.52
1.50	0.095	1.31	0.825	37739	9975	10102	70.01	1.67	91.79	2.19
1.50	0.109	1.282	0.937	42869	11445	12130	67.05	1.6	91.79	2.19
1.50	0.125	1.25	1.063	48597	13125	13750	63.75	1.52	91.79	2.19
1.75	0.109	1.532	1.106	50574	9810	9818	95.75	2.28	124.94	2.97
1.75	0.125	1.5	1.256	57432	11250	12315	91.79	2.19	124.94	2.97
2.00	0.109	1.782	1.274	58279	8584	7687	129.55	3.08	163.19	3.89
2.00	0.125	1.75	1.449	66268	9844	9874	124.94	2.97	163.19	3.89
2.375	0.125	2.125	1.739	79522	8289	7177	184.22	4.39	230.12	5.48
2.875	0.125	2.625	2.125	97193	6848	4675	281.12	6.69	337.21	8.03

Properties based on 90,000 psi and nominal dimensions

Applications for titanium coiled tubing include workovers, velocity strings, injection strings, production tubulars, and flow lines.

Titanium's high strength/weight ratio allows greater depth capacity than steel tubing and lighter overall string weight. Maximum string length (string will break under its own weight) for titanium is considerably longer than for nontapered steel strings (Figure 4-13).

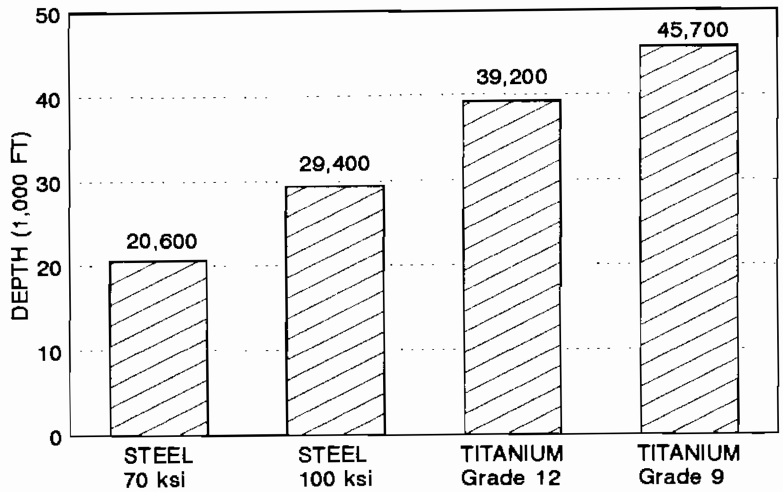

Figure 4-13. Maximum Hanging Length (Klink, 1993)

Another measure of the difference in load capacity for various tubing materials is shown in Figure 4-14. The available overpull for a 22,000-ft string of each material ranges from 9850 lb for 100 ksi steel to 18,200 lb for Grade 9 titanium.

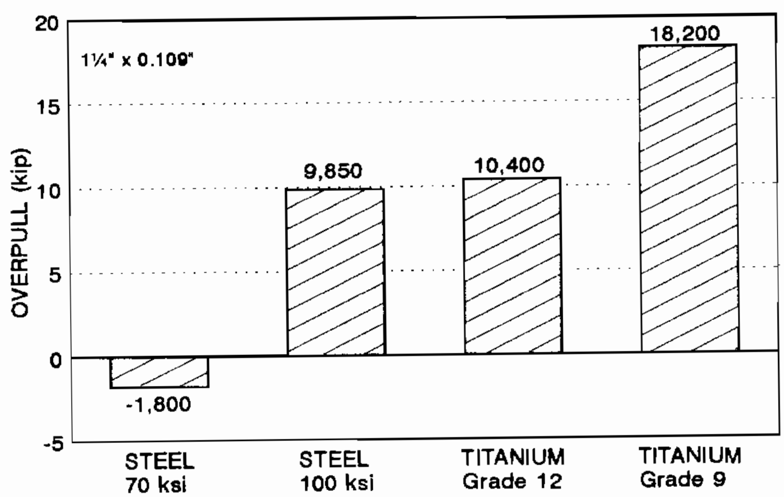

Figure 4-14. Maximum Overpull for 22,000-ft String (Klink, 1993)

Titanium offers advantages for velocity and injection string applications including greater depth capacity, and corrosion resistance in hostile, sour, and CO_2 environments. As production tubing, titanium offers corrosion resistance, the elimination of threaded connections, and reduced installation time.

Titanium also presents an effective alternative to clad flow lines, especially steel flow lines clad internally with a high nickel alloy for corrosion resistance. For subsea installations, extended fatigue life with titanium may be another distinct advantage.

The principal disadvantage of titanium is cost: about 6 to 7 times the cost of steel for 70 ksi strings. Other disadvantages include titanium's weakness to HCl acid, HF acid, and anhydrous methanol. Inhibitors are available for HCl. Effects of anhydrous methanol are reduced with 2% water addition.

Various other titanium alloys are under consideration for coiled tubing. Significantly increased yield strengths are possible. Titanium Tubing Technology is developing a high-strength alloy called βc. Its yield strength of 140 ksi will increase the tubing's working range for all types of applications.

4.5.2 CYMAX/TIMET

CYMAX (Zernick, 1994) has been considering the use of several titanium alloys (Figure 4-15) displaying a variety of yield strengths.

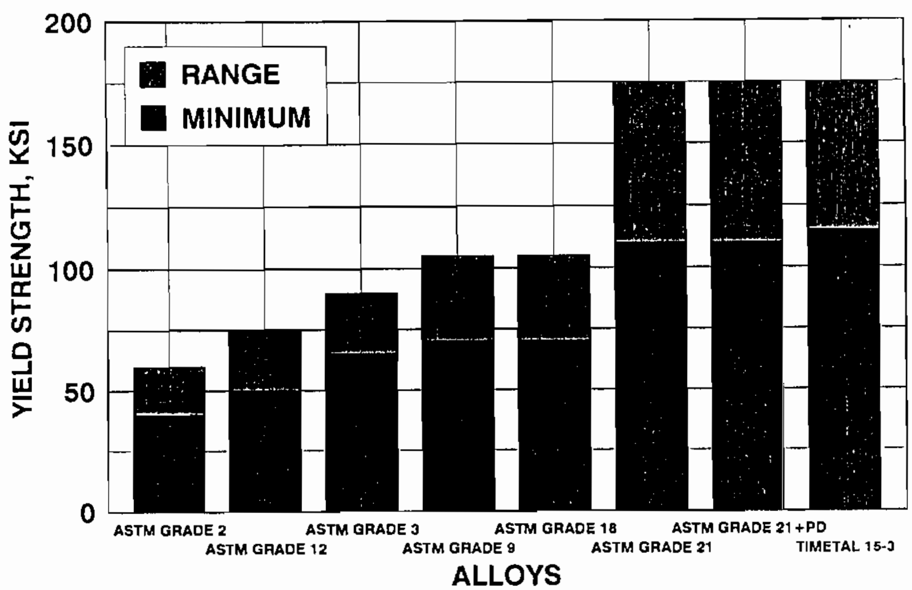

Figure 4-15. Titanium Alloy Yield Strengths (Zernick, 1994)

CYMAX reported the results of a series of fatigue life tests comparing titanium to steel. Their data show that ballooning (diametral growth) is much less for titanium at similar load stresses (Figure 4-16).

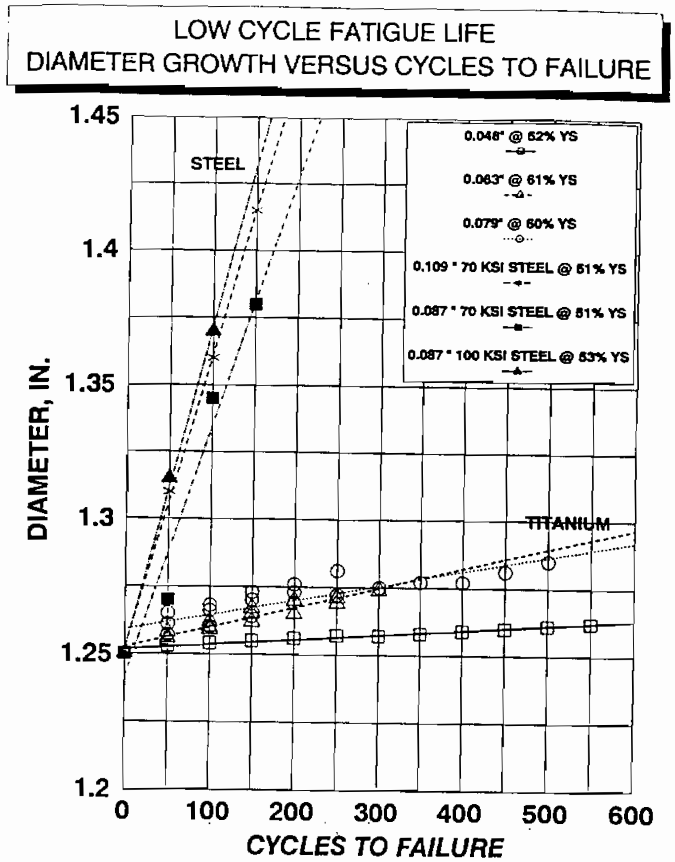

Figure 4-16. Ballooning of Titanium and Steel (Zernick, 1994)

Fatigue life of high-strength titanium is greater than both 70-ksi and 100-ksi steel for a range of wall thicknesses (Figure 4-17). Note that, for CYMAX's fatigue test fixture, each bending/unbending cycle is counted as one cycle. To compare with cycle life on a rig, these data should be divided by three.

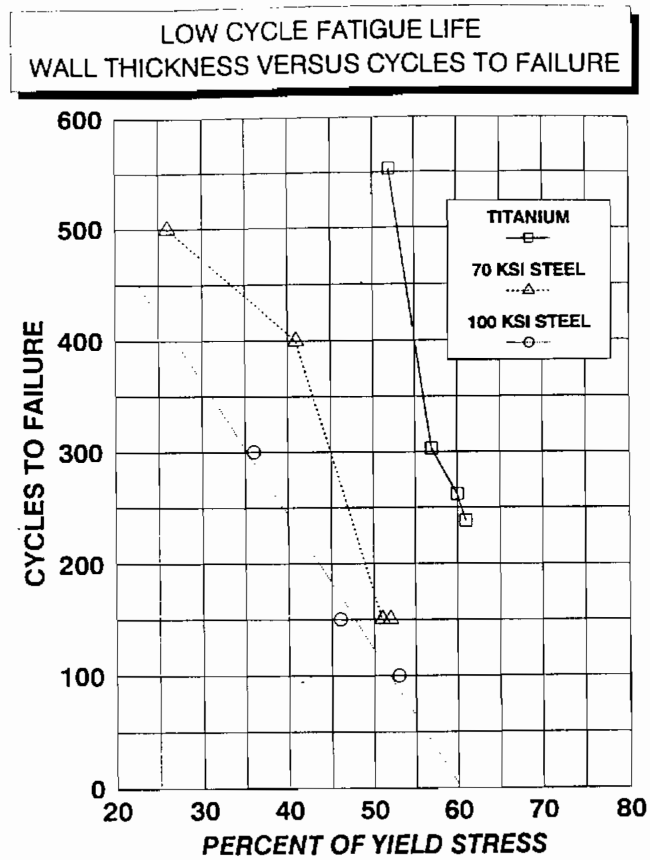

Figure 4-17. Titanium Fatigue Life (Zernick, 1994)

4.5 COMPOSITE COILED TUBING

4.5.1 Conoco

Various materials have been suggested as alternatives to HSLA (high-strength low-alloy) steel to improve the product's performance in field operations. Quench and tempered processes have been used to increase strength. New steel alloys with higher yield strengths are being developed.

Composite coiled tubing has been investigated and shown to offer the potential for performance exceeding that of metal tubing (Sas-Jaworsky and Williams, 1993). Fibrous composite construction can be customized anisotropically to address specific requirements for tensile, compressive, collapse and burst loads. Important benefits for these materials include resistance to most chemicals used in the oil-field and operational ranges from 225° to 350°F.

Representative stress-strain curves for unidirectional laminates in epoxy matrices are shown in Figure 4-18.

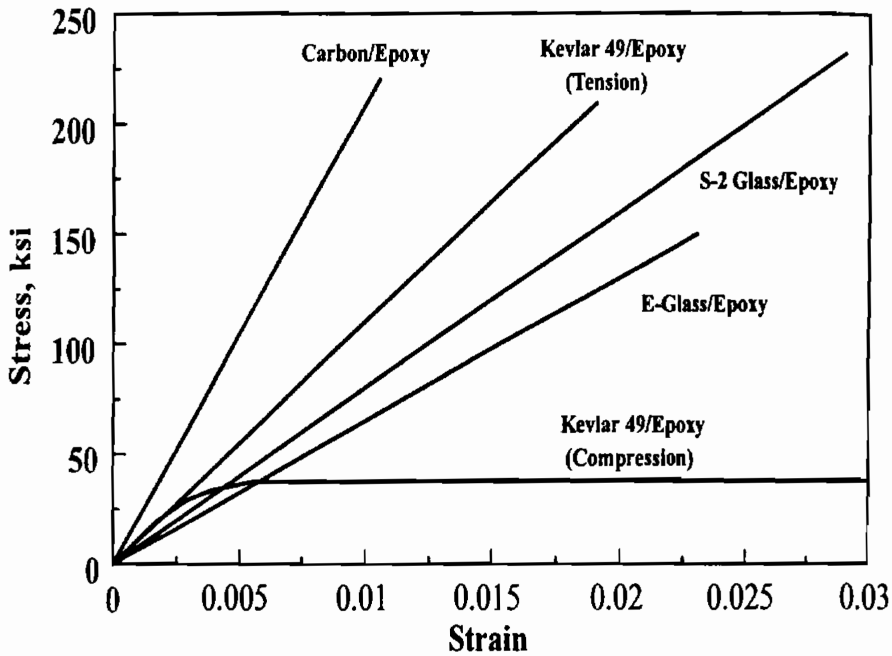

Figure 4-18. Stress-Strain Curves for Unidirectional Composites
(Sas-Jaworsky and Williams, 1993)

Conoco began examining composites for use in high-pressure tubulars for onshore water injection lines in 1988. The following year, an effort was directed toward the fabrication and testing of composite coiled tubing. The strains imposed on coiled tubing during routine field usage presented significant design challenges for composite construction. For example, the strain imposed by spooling 1½-in. tubing on a 6-ft spool is about 4 times greater than that on commercial aircraft wings.

These high strains will exceed the ultimate stress of most composites arranged in a unidirectional laminate along the tubing axis. However, studies by NASA and others have shown that cross-plied laminates with fiber from about 35° to 55° relative to the high strain load can withstand much higher strains without failure (Figure 4-19).

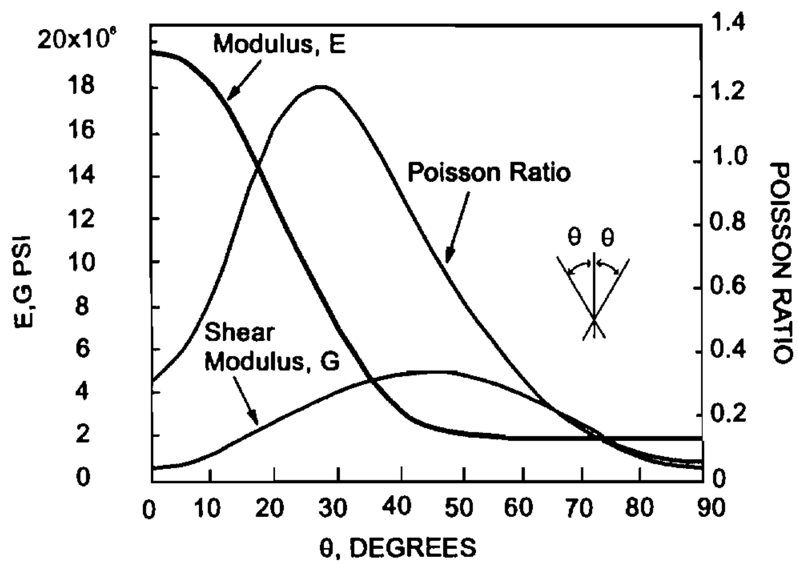

Figure 4-19. Properties of Cross-Ply Laminate Composite (Sas-Jaworsky and Williams, 1993)

Mechanical properties for 45° laminates are compared in Table 4-14. Conoco fabricated several tubing prototypes from these composites using three manufacturing processes: pultrusion, filament winding and braiding.

TABLE 4-14. Properties of 45° Laminate Composites (Sas-Jaworsky and Williams, 1993)

	E-Glass /Epoxy	S-2 Glass /Epoxy	Carbon /Epoxy	KEVLAR® 49 /Epoxy
Axial Modulus, Msi	2.38	2.77	3.12	1.09
Transverse Modulus, Msi	2.38	2.77	3.12	1.09
Shear Modulus, Msi	1.88	2.35	5.44	2.84
Poisson Ratio, (Axial-Transverse)	0.49	0.54	0.73	0.82
Axial Coef. Thermal Expansion, Microstrain/°F	6.95	7.37	0.92	0.77

Mechanical Properties for [+-45/-+45] Cross-Ply Laminates in an Epoxy Matrix.

Conoco chose to do more extensive testing with Kevlar® composite tubing fabricated by the braiding process (Figure 4-20).

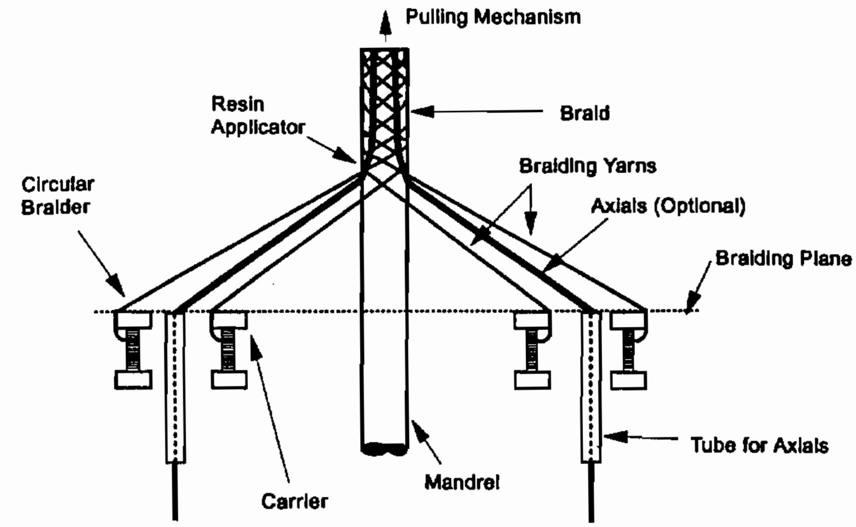

Figure 4-20. Braider for Composite Coiled Tubing (Sas-Jaworsky and Williams, 1993)

Design parameters for the 45° Kevlar® tube are shown in Table 4-15.

TABLE 4-15. Design Specifications for Prototype Composite Tubing (Sas-Jaworsky and Williams, 1993)

CCT SPECIFICATIONS

1. 1.0-inch I.D.
2. 1.5-inch O.D.
3. 5000-psig Operating Pressure
4. 2000-lb Axial Compression
5. Tension: 1.5 x Air Weight/Unit Length x Length
6. 1500-psig Collapse Resistance
7. 180° F Maximum Operating Temperature
8. 7-ft. Minimum Diameter Spool
9. Minimum of 2500 Bending Cycles
10. Smooth, Tough, Abrasion Resistant Interior and Exterior Surfaces
11. Simultaneous Loads: 3+4, 3+5, 3+8
12. Damage Tolerant
13. Producible in 10,000-ft. Lengths

Preliminary Design Specifications for Initial CCT Prototype Specimens.

A simple bending fixture (Figure 4-21) was fabricated to test the fatigue life of composite coiled tubing. The radius of curvature for these tests was 29 in. After being subjected to 50,000 bending cycles with no internal pressure, the sample was pressurized until it burst at 19.5 ksi.

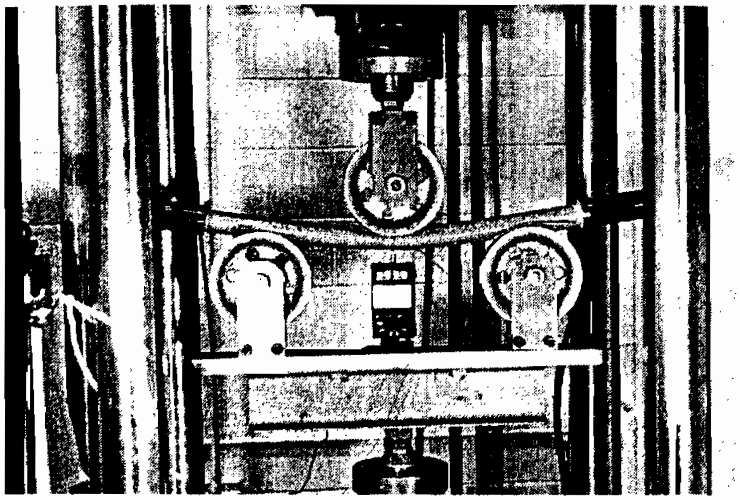

Figure 4-21. Bending Test Fixture for Composite Coiled Tubing
(Sas-Jaworsky and Williams, 1993)

Bending tests with internal pressure were conducted with several samples. Results of three tests are shown in Figure 4-22. Square symbols in the figure indicate that the tubing did not fail during the test; star symbols indicate failures (loss of pressure). A multistage test is represented with arrows. In one test, the sample was cycled 80,000 times at 5000 psi then tested again at 7500 psi, finally failing after an additional 20,000 cycles. One high-pressure test was performed at 10,000 psi; failure occurred near 80,000 cycles.

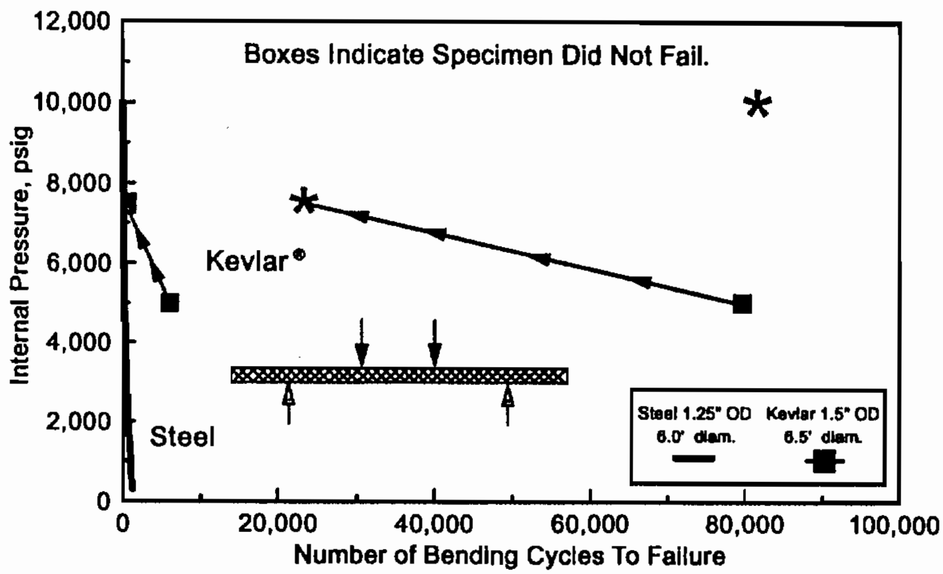

Figure 4-22. Bending Test Results (Sas-Jaworsky and Williams, 1993)

Tension and compression test results (Figure 4-23) show that tension strains are nonlinear above about 0.8% for the 45° laminate. A sample was constructed with two sets of additional fibers placed along the direction of the tubing axis, which significantly increased tension and compression capacity. This sample is indicated as [±45/0] in the figure.

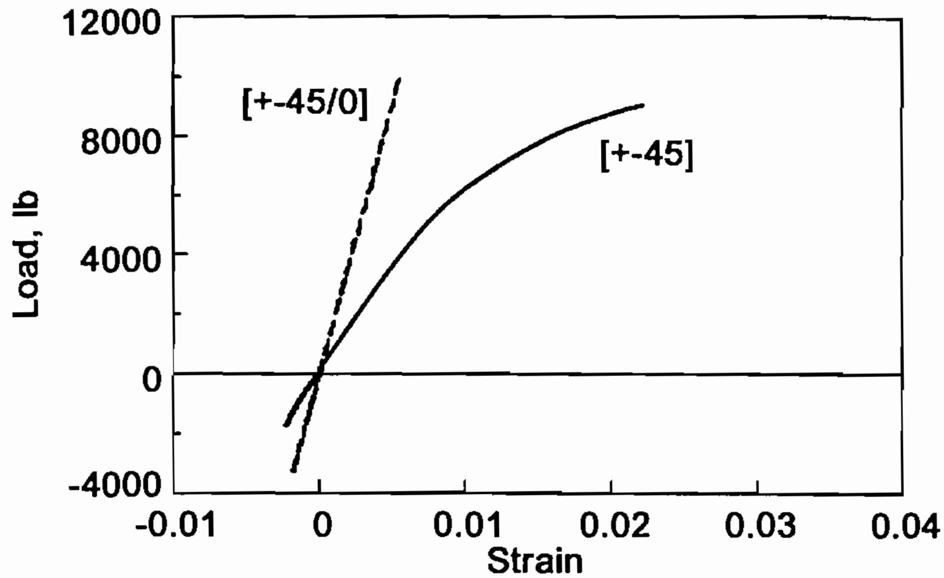

Figure 4-23. Tension/Compression Test Results (Sas-Jaworsky and Williams, 1993)

Tests were conducted under simulated field conditions with a guide arch and injector on a test well. A 20-ft section of composite tubing was cycled across the arch and through the injector and stripper. A total of 1500 trips was performed at 2500 psi internal tubing pressure. The tubing did not fail during these tests.

Advantages of composite coiled tubing as determined by Conoco's tests include:

- Composite tubing has a significantly increased cycle life as compared to steel (about two orders of magnitude greater)
- Burst and collapse can be tailored through fiber orientation without increasing tubing weight
- Inhibitors are not needed for pumping acid
- Laminate construction allows tailored surfaces, such as wear-resistant exterior layers
- Conductors can be incorporated into the matrix to provide wireline capability without an internal cable
- Weight of tubing is 60-75% less than steel, providing extended reach capabilities

Areas that need to be investigated in the future include the effects of tubing damage by wear, impacts, and high gripper-block loads.

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5. Drilling

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5. Drilling

5.1 BENEFITS OF COILED-TUBING DRILLING

5.1.1 History of Drilling with Continuous Strings

Drilling with coiled tubing has received considerable interest from the industry in recent years, probably more than any other area of coiled-tubing technological development. With the ability to be rapidly tripped under pressure, coiled tubing holds promise to provide a cost-saving alternative to conventional rotary drilling when applied under appropriate conditions.

Drilling with a continuous string had been considered prior to the current boom. A drilling system based on a continuous drill string was developed by Roy H. Cullen Research in 1964 (Gronseth, 1993). The flexible drill string was constructed of multiple-wire tension members and had an O.D. of 2⅝ inches. The drill string was advanced and retracted by a hydraulic injector with gripper blocks. The system was used to drill a 4¾-in. test well through 1000 ft of granite near Marble Falls, Texas. Penetration rates of 5-10 ft/hr were reported.

Another system was developed by the Institut Français du Pétrole (IFP), which used 5-in. O.D., 2½- to 3-in. I.D. flexible drill strings containing several electrical conductors. Downhole electric motors or turbines were used to rotate the bit. Their injector was operated either electrically or hydraulically, and could be run in an "auto-driller" mode controlled by feedback from bit power consumption.

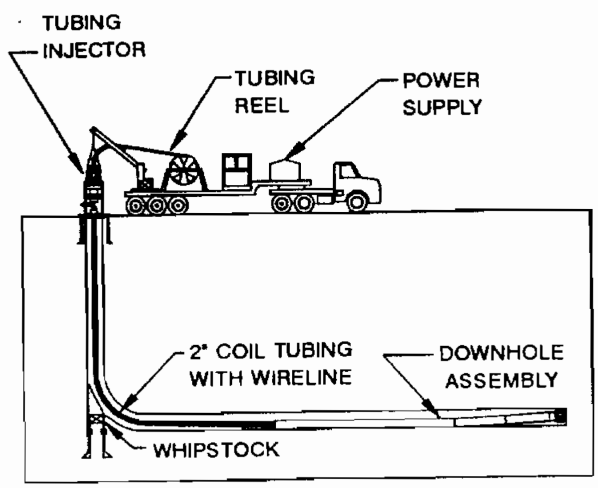


Figure 5-1. Open-Hole Drilling with Coiled Tubing (Ramos et al., 1992)

The IFP system could be used to drill holes from 6¾ to 12¼ in. to depths of 3300 ft (1000 m). By 1965, more than 20,000 ft (6000 m) of hole had been drilled with the system.

FlexTube Service Ltd. developed another system in the mid-1970s that used 2⅜-in. continuous tubing. They drilled shallow gas wells with the system in Alberta, Canada. Initial tubing strings were fabricated from butt-welded X-42 line pipe. They later developed the first aluminum coiled tubing in conjunction with Alcan Canada.

FlexTube's system used 4¾-in. drill collars, a positive-displacement motor, and conventional 6¼-in. bits. Penetration rates were comparable to those with conventional rigs.

Bottom-hole assemblies designed for drilling operations have also been run on conventional steel coiled tubing for some time. Most coiled-tubing drilling operations have been performed as part of workover applications, such as cement and scale removal, milling, and underreaming. More recently, coiled tubing has been used to drill vertical and horizontal re-entries and new wells. The industry has been watching these developments in coiled-tubing drilling with high interest.

Since 1991, almost 200 wells have been drilled with coiled-tubing rigs and positive-displacement motors (Figure 5-1). Although there has been considerable activity and interest, coiled-tubing drilling technology is still immature, and the potential cost savings predicted for these operations have not yet been widely realized.

Halliburton, Cudd Pressure Control, NOWSCO, and Schlumberger Dowell have each organized specialty teams devoted to developing systems and techniques for coiled-tubing drilling. Field activity continues at a healthy pace.

Mud motors and various types of bits have historically been run on coiled tubing, including drilling open hole, drilling cement and scale, milling, and underreaming. Drilling with coiled tubing is obviously not a new concept; however, recent advances in both coiled-tubing and drilling technology have significantly increased the depth limitations and directional-control capabilities of these systems.

The driving force behind the development of coiled-tubing drilling is, not surprisingly, the need to reduce drilling costs. The economic advantages of slim-hole operations are shared by coiled-tubing drilling. Smaller rigs and surface locations result in less environmental impact and lower civil engineering costs. Lower mobilization costs and faster rig-up are also expected. Smaller scale operations lead to savings in mud, casing, and other consumables.

Fewer personnel and equipment should decrease day-rate costs. Unfortunately, the potential savings in equipment costs have generally not been realized as of yet. An important factor shifting the economic equation is that coiled-tubing rigs normally must compete against fully depreciated workover and drilling rigs, as well as steep discounts in slow conventional markets.

Coiled tubing has been used for several years to drill out scale and cement in cased wellbores. Recent applications have included both vertical and horizontal open-hole sections. The industry's attention has been focused on the cost-saving potential of drilling grassroots and re-entry wells with coiled tubing.

5.1.2 Advantages/Disadvantages of Coiled-Tubing Drilling

Several authors have listed and discussed a variety of advantages and disadvantages of drilling with coiled tubing in numerous journal and magazine articles, as well as conference presentations. In the following paragraphs, the principal advantages and disadvantages of coiled-tubing drilling are summarized. More detailed discussion appears in the sections that follow.

Advantages

Costs are reduced with coiled-tubing operations. Many of the cost savings attainable with coiled-tubing drilling arise from the small size of the rig, the inherent automation of coiled-tubing rigs, and other savings enjoyed in slim-hole operations. Costs other than drilling time, such as mobilization, site size and preparation, and expendables, often account for more than 50% of conventional costs.

Coiled-tubing drilling operations have smaller surface lease requirements than most conventional rigs due to a smaller footprint (usually less than 50% conventional) for the coiled-tubing system (Figure 5-2). Costs in several categories can be significantly reduced with coiled-tubing slim-hole systems.

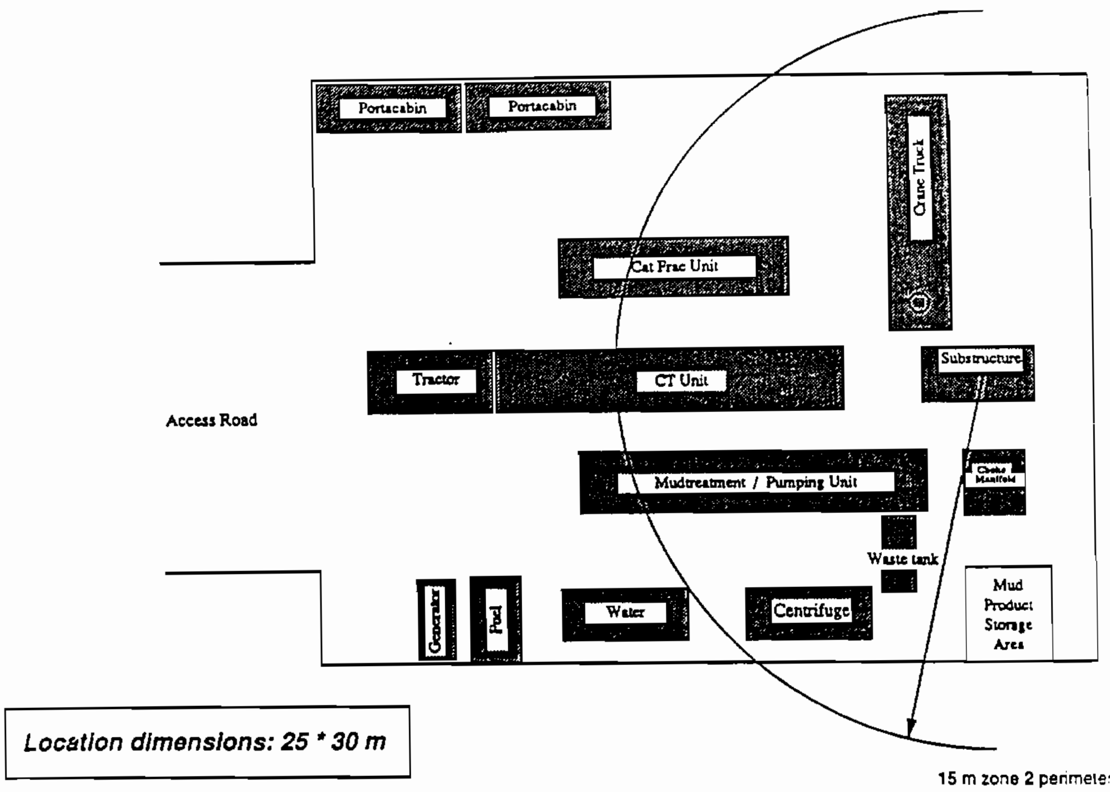


Figure 5-2. Coiled-Tubing Drilling Land Rig Layout (Schlumberger Dowell)

Drill-string trip time is reduced. Continuous tubing eliminates the need for drill-string connections, thus reducing trip times and increasing safety. Many rig-floor accidents and stuck-pipe incidents occur when drilling is stopped to make a connection.

Underbalanced drilling is practical with coiled tubing. The design of coiled-tubing pressure-control equipment and systems allows the tubing to be run safely in and out of live wells. Drilling can be performed in underbalanced conditions, which minimizes formation damage, increases rate of penetration, and eliminates differential sticking. Reducing formation damage can lead to increased well productivity and eliminate the need for stimulation or damage removal treatments during completion operations.

Coiled tubing allows continuous circulation. A fluid swivel joint installed on the axle of the tubing reel allows circulation through coiled tubing while tripping. This design simplifies well-control techniques and helps maintain good hole conditions. Continuous circulation also allows continuous drilling, facilitating the use of foam as a low-weight drilling fluid when appropriate.

Coiled tubing has no joints to make and break. There are several benefits to eliminating tool joints in the drill string. Among them are no mud spillage while making joints, elimination of noise from pipe-handling equipment, and increased safety on the rig floor.

Coiled tubing is readily adapted for wireline telemetry. Wireline is routinely installed inside coiled tubing. High-speed continuous telemetry is practical with coiled tubing for MWD (measurement-while-drilling) and FEMWD (formation evaluation MWD). The same wireline can also be used for steering-tool data and orientation-tool control.

Disadvantages

Coiled-tubing drilling, of course, is not a panacea for the oil industry. There are currently several disadvantages for using coiled tubing as a drill string in open hole. Some of the disadvantages are being successfully addressed by new developments and tools. Others will remain as limits that define the ultimate range of economic application of the technology.

Coiled tubing cannot be rotated. Downhole motors, an expensive component, are required when drilling with coiled tubing. Consequently, slide drilling is the only mode of operation, which results in increased friction losses and reduced WOB. Separate BHAs must be run for straight hole sections and for angle building sections. Basic BHAs are shown in Figure 5-3.

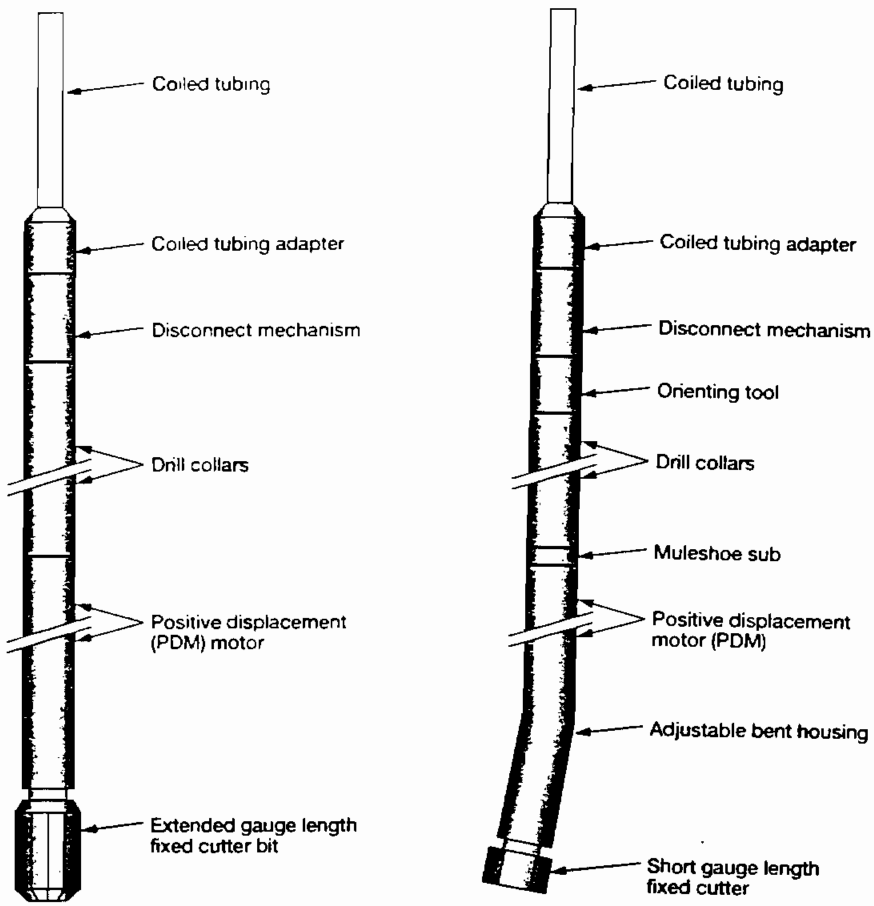


Figure 5-3. Coiled-Tubing BHAs for Holding Angle (Left) and Building Angle (Right) (Gronseth, 1993)

Downhole orientation tools are required to direct the bit along the designed well path. Orientation tools for use on coiled tubing are expensive, and the technology is not yet mature.

Coiled-tubing drilling is limited to small hole sizes. Coiled-tubing O.D. and torque capacity place limits on the size of hole that can be drilled. The largest hole that can be drilled with coiled tubing is about 6¼ inches. Most jobs have been performed with 1¾- or 2-in. coiled tubing. Larger tubing is available. However, lack of rigs with capability to run larger ODs hinders their use, as well as logistical difficulties of working with large reels.

Coiled-tubing drilling is limited to relatively shallow holes. Depth limitations for the technology are governed by the size and weight restrictions of the tubing reel and the reel trailer rather than by the mechanical strength of the tubing itself. The larger the coiled-tubing OD, the shorter the length of the string that can be legally transported. Work is underway in the development of reliable tubing connectors that can by used to join two or more reels of tubing on location, without sacrificing mechanical strength or life.

Coiled-tubing drilling is a new technique. The learning curve for coiled-tubing drilling has begun to fall; however, there is considerable development and industry experience required before the technology can be considered routine. As was the case for horizontal drilling, it can be expected that coiled-tubing drilling costs will decrease when operating companies and drilling contractors become more familiar with the technology.

Coiled-tubing drilling rigs and equipment are expensive. Coiled-tubing rigs must compete against fully depreciated workover and drilling rigs. In areas with low utilization rates for conventional systems, daily rates of coiled-tubing systems are often not competitive. This new technology has also required the development of new tools and assemblies, further increasing costs.

Coiled-tubing rigs cannot run or pull casing or completions. Conventional rig assistance is normally required for well preparation, unsetting production packers, pulling production tubing, and running completions. An exception to this restriction is coiled production tubing or liners. The inability to run jointed tubulars continues to limit the application of coiled-tubing drilling techniques. Although hybrid rigs have been developed and deployed, they are not yet widely available.

It should be noted that the use of more than one rig for drilling operations is not unique to coiled-tubing drilling. Drilling rigs and service rigs are commonly used to drill and complete conventional wells. Re-entry operations commonly use a service rig to prepare the well for drilling, a drilling rig to drill new hole, and a service rig for recompletion operations and to bring the well on production.

Coiled-tubing life in drilling operations is not well defined. Open-hole drilling can subject coiled tubing to loading conditions not typically encountered in cased-hole operations. The earliest drilling field applications in the Austin Chalk had problems with pin-hole leaks in the tubing. The tubing is subjected to high forces when buckling occurs that can damage the tubing wall by forcing it into irregularities or washouts downhole.

Techniques to maximize the life of a coiled-tubing drilling string include avoiding pumping corrosive fluids through the tubing, minimizing solids in the mud, using techniques that minimize the number of plastic deformations for any given section of tubing, and avoiding stacking the weight of the coiled-tubing string on the bit.

5.1.3 Halliburton Energy Services (Applications of Coiled-Tubing Drilling)

Halliburton Energy Services (Rutland and Fowler, 1994) discussed the most economic applications for coiled-tubing drilling in the current market. They surmised that the technology is of economic advantage when some or all of certain factors are true:

- Surface conditions favor a small rig footprint
- Price of a conventional drilling rig is high
- Expected production gains (i.e., re-entry applications) do not justify shipping in a conventional rig
- Underbalanced drilling operations (Figure 5-4) are preferred

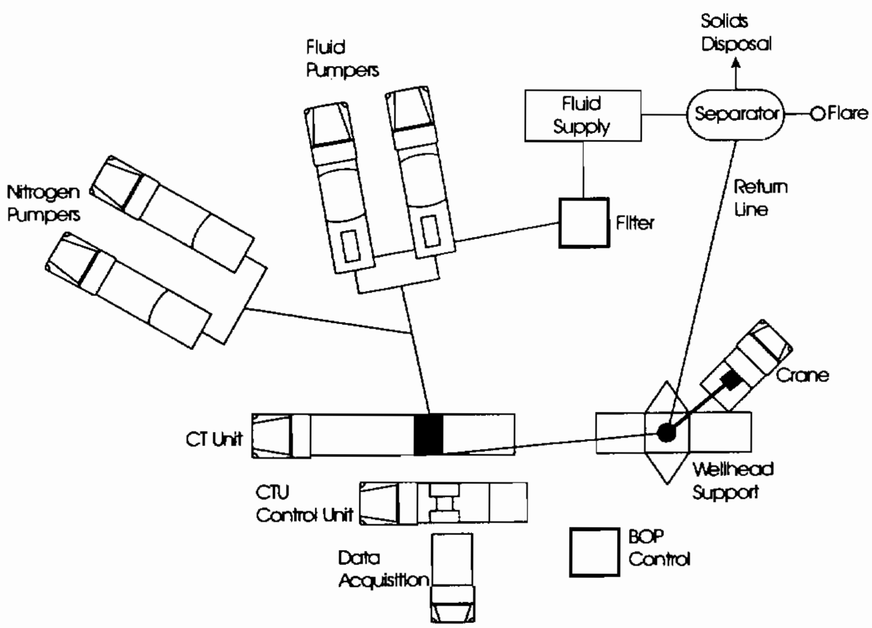


Figure 5-4. Surface Equipment for Coiled-Tubing Drilling with Nitrified Fluid (Rutland and Fowler, 1994)

Clearly, in the current market, there is no single answer for all drilling environments, and operators should compare costs for all systems. Costs vary widely. For example, a North Slope operator may reduce drilling costs by 50% by using coiled tubing. A Mid-Continent operator, however, would probably spend more money with a coiled-tubing rig than by using a fully-depreciated conventional rig.

Hole size, currently restricted to a maximum of about 6¼ in., is among the most important limitations. Horizontal penetration in horizontal applications may also be a limiting factor. Penetration limits are affected by casing and hole size, coiled-tubing size (Table 5-1), build radius, and fluids.

TABLE 5-1. Penetration Limits for Coiled-Tubing Drilling in Horizontal Holes (Rutland and Fowler, 1994)

	Maximum Horizontal Length (Ft)	
Casing x Hole (In.)	2-In. Tubing	2⅜-In. Tubing
4½ x 3⅞	2,700	4,600
5½ x 4½	1,000	2,600
7 x 4½	200	1,600

5.1.4 Nederlandse Aardolie Maatschappij (Evolution of Coiled-Tubing Drilling)

A long-lived dream of the drilling industry, the use of continuous tubing for drilling operations, is now feasible due to recent advances and developments in coiled-tubing technology. The earliest coiled-tubing drilling projects are summarized in Table 5-2. Almost all of these wells were drilled onshore where competing rig costs were low. Economics should be even more favorable offshore where reduced mobilization/demobilization costs are significant.

TABLE 5-2. Early Coiled-Tubing Drilling Projects (Simmons and Adam, 1993)

Date	Location	Operator	Wellbore	Deviation	CT Size, In.	Hole Size, In.
June 1991	Paris	Elf	Re-entry	Vertical	1.50	3.875
June 1991	Texas	Oryx	Re-entry	Horizontal	2.00	3.875
August 1991	Texas	Oryx	Re-entry	Horizontal	2.00	3.875
December 1991	Texas	Chevron	Re-entry	Horizontal	2.00	3.875
May 1992	Canada	Lasmo	New	Vertical	2.00	4.750
July 1992	Texas	Chevron	Re-entry	Horizontal	2.38	3.875
July 1992	Canada	Gulf	Re-entry	Horizontal	2.00	4.125
July 1992	Canada	Imperial	New	Vertical	2.00	4.750
July 1992	Texas	Arco	Re-entry	Horizontal	1.75	3.750
September 1992	Canada	Pan Canadian	Re-entry	Vertical	2.00	4.750
October 1992	Canada	Can. Hunter	Re-entry	Vertical	1.75	3.875
October 1992	Paris	Elf	New	Vertical	1.75	3.875

Date	Location	Operator	Wellbore	Deviation	CT Size, In.	Hole Size, In.
November 1992	Canada	Gulf	Re-entry	Vertical	2.00	4.750
November 1992	Austria	RAG	Re-entry	Vertical	2.00	6.125
December 1992	Alaska	Arco	Re-entry	Deviated	2.00	3.750
January 1993	Canada	Petro Canada	Re-entry	Vertical	2.00	3.875
February 1993	Holland	Shell-NAM	Re-entry	Horizontal	2.00	4.125
February 1993	North Sea	Phillips	Re-entry	Deviated	1.75	3.750
February 1993	Canada	Petro Canada	Re-entry	Horizontal	2.00	4.750
March 1993	Alaska	BP	Re-entry	Deviated	2.00	3.750*
April 1993	California	Berry	New	Vertical	2.00	6.250
April 1993	California	Berry	New	Vertical	2.00	6.250
May 1993	Alaska	Arco	Re-entry	Deviated	2.00	3.750
June 1993	Alaska	Arco	Re-entry	Deviated	2.00	3.750*
*Underreamed						

The first practical attempts at drilling with coiled tubing were made in the mid-1970s in Canada. No further attempts with the technology were recorded between 1976 and 1991. This lack of use of the technology underscores technical and economic hurdles encountered with early systems.

NAM (Simmons and Adam, 1993) listed important advantages and disadvantages of coiled-tubing drilling (Figure 5-5). They emphasized that operators analyzing coiled-tubing drilling technology must consider the long-term benefits of this approach. Underbalanced drilling, a key benefit of coiled-tubing operations, impacts the economics of the well far into its production lifetime. The long-term economic benefits of underbalanced drilling have potential to outweigh most near-term technical disadvantages of coiled-tubing drilling.

ADVANTAGES	DISADVANTAGES
Underbalanced Drilling and Improved Well Control • Full pressure control possible throughout drilling operations • Underbalanced tripping, drilling, and completion reduces formation damage and permits faster penetration with reduced risk of differential sticking.	**Drill String Cannot Be Rotated** • Downhole motors required, even for vertical wells. • An orienting tool is required for steering. • Higher friction with the borehole wall.
Continuous Drill String • Allows continuous circulation while tripping. • Eliminates joint-related problems and allows faster tripping. • No pipe handling, which improves safety and reduces noise. • Reduced environmental impact. No spillage at joints. • Simplified automation, reduced manpower.	**Limited to Slim-Hole Applications** • Largest hole to date is 6¼ in., larger holes technically are feasible. • Small hole size limits the number of casing strings and liners that can be run.
Compact Unit and Equipment Configuration • Reduced drill site size and associated costs. • Reduced mobilization and demobilization costs.	**Wireline Inside the CT Drill String** • Fatigued or damaged sections of CT cannot be removed from the drill string.
Wireline Inside the CT Drill String • Allows high-speed telemetry for measurement and logging-while-drilling (MWD, LWD) • CT protects wireline and simplifies operations through simultaneous spooling of tubing and wireline. • Electrically operated directional control is possible.	**New Technique** • Currently in the learning curve.

Figure 5-5. Coiled-Tubing Drilling Advantages/Disadvantages (Simmons and Adam, 1993)

Hybrid rigs designed to run both coiled and jointed tubing will speed the applications of coiled-tubing drilling. The added ability to run and cement casing after drilling operations is beneficial. In addition, having the option to pull existing production strings, work the well, and then recomplete with coiled or jointed tubing should result in cost savings.

The use of large-diameter coiled tubing for completions (Figure 5-6) has shown potential for decreasing overall future costs.

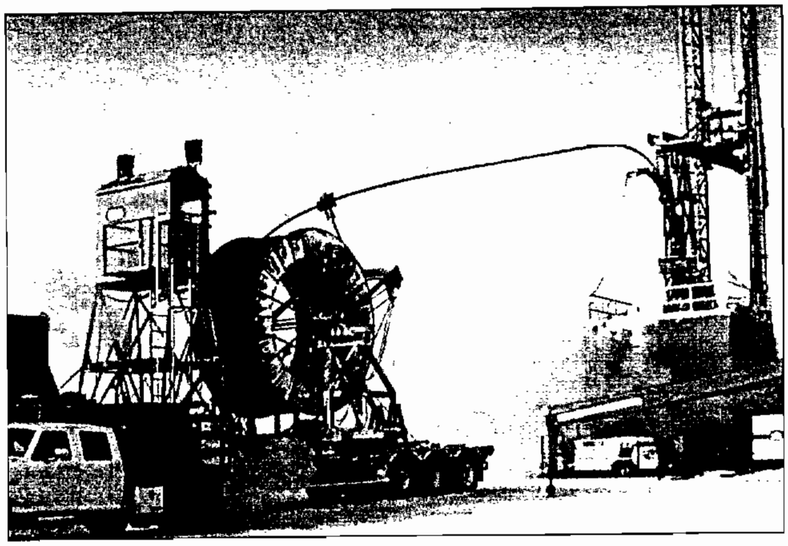


Figure 5-6. Running Large Coiled Completions (Simmons and Adam, 1993)

5.1.5 Schlumberger Dowell (Limits of Coiled-Tubing Drilling)

Schlumberger Dowell (Leising and Newman, 1993) described the applications of coiled-tubing drilling, and analyzed its potential and limits. Limits were considered with respect to basic parameters including tubing weight and size, achievable down-hole force and life, and hydraulic limits.

Leising and Newman highlighted four major categories of applications for drilling with coiled tubing (Table 5-3). Wells have been drilled in each of these four categories. The least used applilcation has been new deviated wells.

TABLE 15-3. Applications for Coiled-Tubing Drilling (Leising and Newman, 1993)

	VERTICAL	DEVIATED
Re-Entry Drilling	• Deepening of existing wells	• Lateral drainholes
New Well Drilling	• Disposable exploration wells • Observation & delineation wells • Slim-hole prod./injection wells	• Steam injection • Environmental observation

In many conventional applications, the fact that coiled-tubing drilling can be safely performed underbalanced is beneficial. Coiled-tubing systems can be used in conjunction with a conventional rig in several applications including:

- Drilling in or below lost-circulation zones
- Coring pay zones
- Underbalanced drilling through pay zones

For these multirig applications, a conventional rig would be used to drill most of the hole. A coiled-tubing rig would be used to drill critical zones only.

The first coiled-tubing services were developed for workover operations. Consequently, re-entry drilling was the first application with coiled tubing. Operations in existing wells do not require setting surface casing, which cannot be performed with existing coiled-tubing units.

Vertical well deepening with a pendulum BHA is the most straight-forward drilling application for coiled tubing. In most cases a long BHA with a few drill collars provides the WOB. Buckling is minimized because the neutral point is in the BHA and the tubing string is kept in tension.

Deviated or horizontal drilling is performed with coiled tubing after a window is cut in casing. A downhole survey system is required for directional drilling applications with coiled tubing. Steering tools or MWD systems can be utilized. These tools provide the operator with updated data describing the inclination and azimuth of the wellbore. A muleshoe sub is normally placed above the mud motor and used to align the survey tool with the tool face at the bit.

Photographic survey tools, either single or multishot, are usually impractical except for widely spaced survey stations because the BHA must be tripped for each survey.

During planning of a deviated or horizontal well drilling program, computer modeling of drag should be performed to determine whether the coiled tubing and BHA will achieve the intended penetration.

There are currently limitations for coiled-tubing drilling based on rig capabilities, tubing mechanical limits, tubing weight and transportation limits, tubing life limits, and hydraulic flow-rate limits, among others. Together these parameters define the boundaries of the application of this "new" technology.

Leising and Newman (1993) performed an engineering analysis of the factors that limit what can and cannot be done with coiled-tubing drilling. Their analyses were based on available equipment, basic engineering calculations, and computer models from various drilling applications.

Example coiled-tubing weights and capacities are given in Table 5-4. Greater wall thicknesses and higher capacities are available than those given, especially for larger tubing sizes.

TABLE 5-4. Coiled-Tubing Weights and Capacities (Leising and Newman, 1993)

Diameter (in.)	Wall Thickness (in.)	Weight (lbm/ft)	Maximum Tension (lbf)	Maximum Allowable Working Torque (lbf-ft)	Maximum Allowable Working Pressure (psi)	Reel Core Diameter (in.)
1.500	0.156	2.24	32,000	1,044	7,700	76
1.750	0.156	2.66	37,900	1,484	6,700	76
2.000	0.156	3.07	43,900	2,002	5,900	84
2.375	0.156	3.70	78,100	2,926	5,300	84
2.875	0.156	4.53	95,000	4,431	4,400	96

Note: 70,000-psi yield stress material for all CT sizes.

Dimensions and mechanical properties of API jointed drill strings are compared to those of coiled tubing in Table 5-5. The jointed drill-pipe data are for the lightest weight pipe of the same O.D. as coiled tubing. Coiled-tubing wall thickness was chosen for these examples to be as close as possible to the drill pipe.

TABLE 5-5. Comparison of Properties of Coiled Tubing and API Drill Pipe (Gronseth, 1993)

	CT	Drill Pipe*	CT	Drill Pipe*	CT	Drill Pipe*
Nominal O.D., In.	2.375	2.375	2.875	2.875	3.50	3.50
Tool Joint O.D. In.	None	3.37	None	4.126	None	4.75
Nominal I.D., In.	1.969	1.995	2.495	2.441	3.12	2.992
Wall Thickness, In.	0.203	0.192	0.19	0.217	0.19	0.254
Weight, ppf	4.71	4.85	5.46	6.85	6.73	9.50
Yield Strength, kips	96.9	97.7	106.7	136.0	131.4	194.0

*Grade E Drill pipe

The maximum length of a string of coiled tubing based on various allowable spool weights (Figure 5-7) shows that spool size limitations dominate for large-diameter tubing. A typical coiled-tubing trailer and reel can carry about 40,000 lb of tubing and still be legal for U.S. roads. Length limitations can be overcome by connecting or welding multiple spools of coiled tubing at the job-site. However, the cost of this type of solution, which requires the fabrication of larger-than-legal reels on site, often cannot be justified.

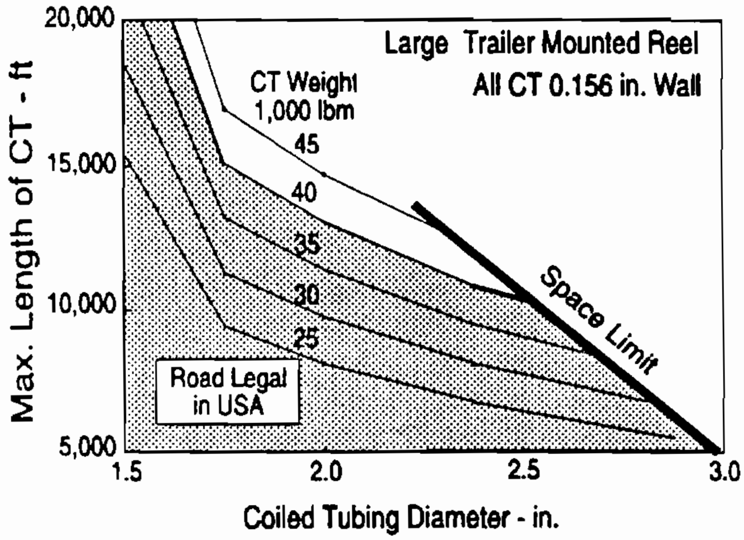


Figure 5-7. Maximum Coiled-Tubing String Length (Leising and Newman, 1993)

Maximum hanging length for a coiled-tubing drilling string is dependent on material strength, wellbore fluid density, and whether or not the string is tapered. For a non-tapered string, the hanging length at 80% yield stress is given by:

$$D = \frac{\sigma_y}{4.245 - 0.065W_m}$$

where: D = hanging length at 80% yield (ft)

σ_y = tubing yield stress (psi)

W_m = wellbore fluid weight (lb/gal)

For example, 70,000 psi tubing in 8.6 lb/gal mud will reach 80% yield at just less than 19,000 ft. It is interesting to note that this calculation is independent of tubing diameter or wall thickness. As more steel is added to the tube either by increasing the diameter or using thicker walls, the weight of the string increases in direct proportion, canceling the benefit of the additional steel.

The use of tapered tubing strings with thicker walls high up in the hole is the most common technique to increase hanging length. Using this approach, conventional coiled-tubing service operations have been performed at depths greater than 23,000 ft.

BHAs for drilling deviated wells with coiled tubing are designed based on the set-down weight available in the vertical section to provide WOB. In vertical hole sections, maximum set-down weight is reached after the tubing buckles into a helix.

Set-down weight for various coiled-tubing sizes was calculated with Schlumberger Dowell's Tubing Forces Model (Figure 5-8). The results show that greater set-down weights can be achieved with larger coiled tubing and in smaller casing. The model predicts that maximum set-down weight does not vary significantly with depth.

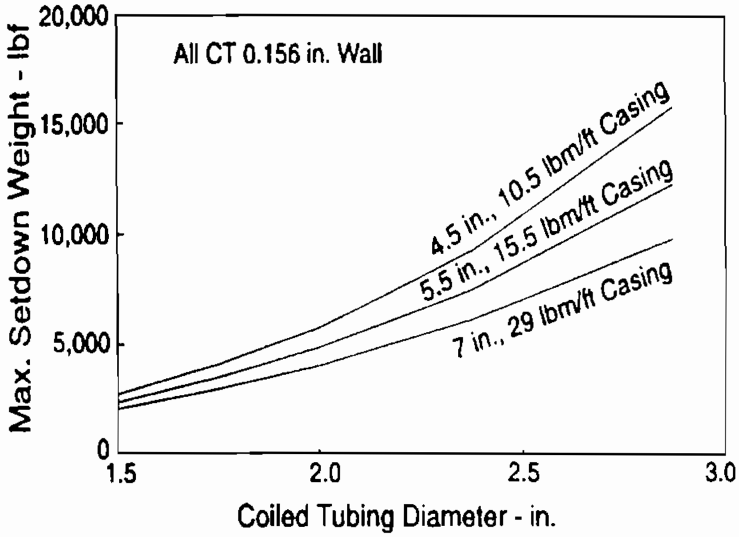


Figure 5-8. Maximum Coiled-Tubing Set-Down Weight in Vertical Sections (Leising and Newman, 1993)

Friction forces generated in build sections or doglegs also work to reduce the effective WOB. Friction losses for three example BHAs are plotted in Figure 5-9. All BHAs are 60 ft in length. It is seen that the build section friction of a deviated hole can prevent any weight from reaching the bit and limit additional horizontal penetration.

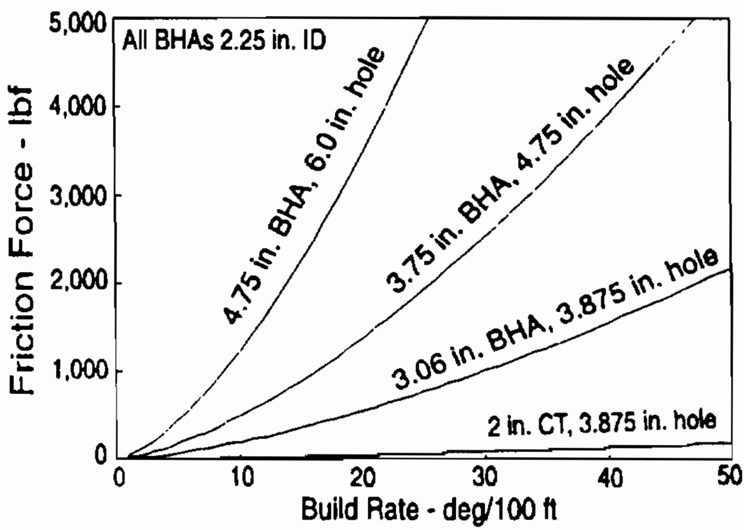


Figure 5-9. Friction Force on 60-ft BHAs in Build Sections (Leising and Newman, 1993)

Friction force can be decreased by using flex joints or articulated BHAs. The frictional loss of 2-in. coiled tubing in a 3⅞-in. borehole is shown as the lowest trace in Figure 5-9.

Five example horizontal re-entry scenarios (Figure 5-10) were devised to demonstrate basic trends and penetration limits with coiled-tubing drilling. Casing size, bit diameter, BHA size, and downhole weight on bit (DWOB) for the five cases are summarized in Table 5-6. Cases 1, 2, and 3 drill out of 4½-, 5½-, and 7-in. casing, respectively, with the largest bit possible. Cases 4 and 5 use smaller bits in 5½- and 7-in. casing.

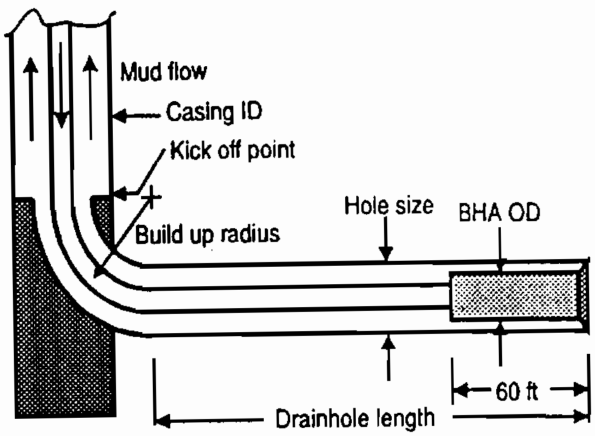


Figure 5-10. Horizontal Re-Entry Model (Leising and Newman, 1993)

TABLE 5-6. Example Horizontal Re-entries Drilled With Coiled Tubing (Leising and Newman, 1993)

	Case				
	1	2	3	4	5
Casing					
Diameter, in.	4.5	5.5	7	5.5	7
Weight, lbm/ft	10.5	15.5	29	15.5	29
ID, in.	4.052	4.950	6.184	4.950	6.184
Hole size, in.	3.875	4.750	6.000	3.875	4.750
BHA OD, in.	3.060	3.750	4.750	3.060	3.750
DWOB, lbf	2,000	2,500	3,100	2,000	2,500

Assumptions used in the computer calculations include 15°/100 ft build rates, 8.6 lb/gal brine drilling fluid, and that drilling continues until DWOB requirements cannot be maintained. Calculations were made for each re-entry case (Figure 5-11) with the coiled tubings listed in Table 5-4.

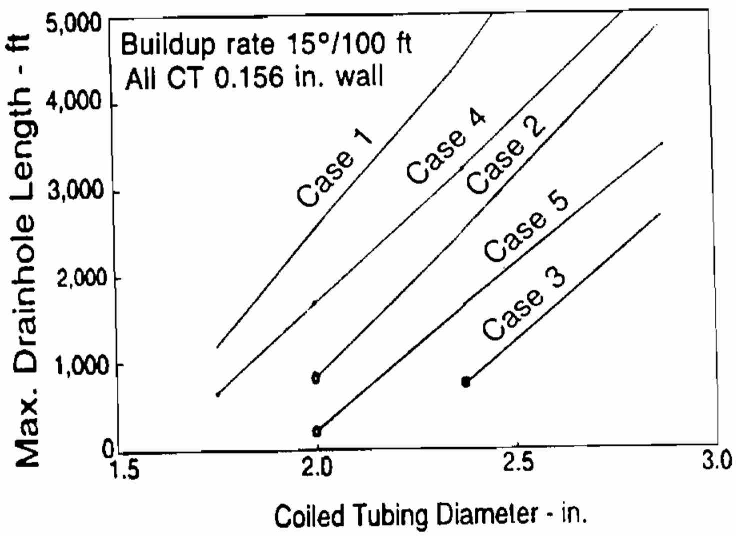


Figure 5-11. Maximum Horizontal Length for Example Coiled-Tubing Re-entries (Leising and Newman, 1993)

The circled points in Figure 5-11 are cases where the tubing would lock up in the vertical section before any horizontal hole was drilled.

Coiled-tubing fatigue life is another serious concern in drilling operations. Larger tubing diameters and high pressures resulting from high flow-rate requirements lead to a decrease in coiled-tubing life. Calculations with Schlumberger Dowell's CoilLife Model (Figure 5-12) show the effects of flow rate and high pressure in 8000-ft wells.

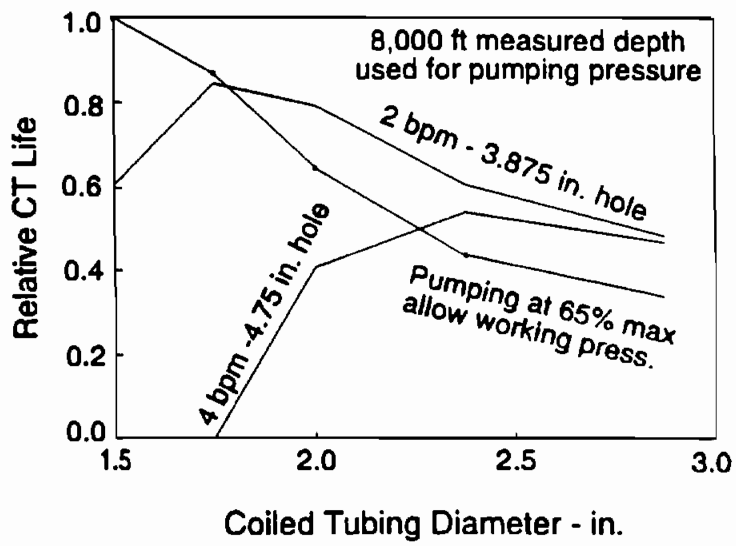


Figure 5-12. Effect of High Flow Rates on Tubing Life (Leising and Newman, 1993)

The data at 65% maximum allowable working pressure show that larger diameter coiled tubing had significantly less life than 1½- and 1¾-in. under these conditions.

Limits in hydraulics must be considered for coiled-tubing drilling. Circulation rates must provide sufficient velocity to carry cuttings from the hole. However, there are other factors that may limit maximum fluid pump rates. Pressure drops through the coiled-tubing string and in the annulus increase significantly at high circulation rates. Another factor is that the maximum flow rate for the downhole motor may fix circulation rate.

Maximum and minimum (critical) flow rates for vertical hole drilling with coiled tubing are shown in the upper two plots of Figure 5-13 for 3⅞-, 4¾-, and 6-in. wellbores. Fluid density of 8.6 lb/gal and annulus velocity of 100 ft/min are assumed. Results for a 5000-ft vertical well are shown in the upper left plot and for an 8000-ft vertical well in the upper right plot.

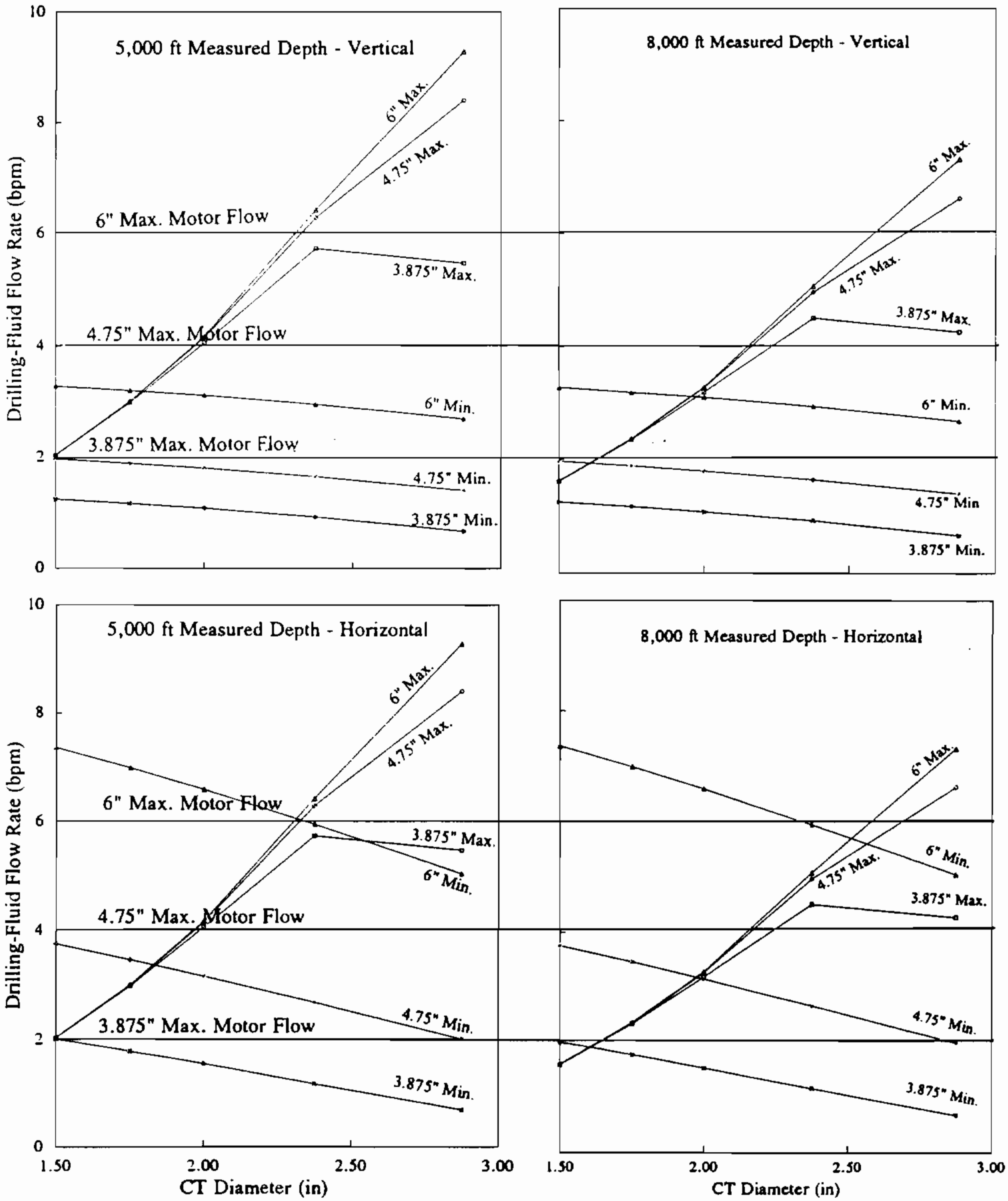


Figure 5-13. Hydraulic Limits for Wells Drilled With Coiled Tubing (Leising and Newman, 1993)

Flow rates for wells with a horizontal section are shown in the lower two plots in Figure 5-13. Critical flow rates, shown as minimum rates in the figure, are much higher than for similar vertical-well data. For example, a 4¾-in. horizontal drilled with 2-in. coiled tubing requires a minimum flow of 3.2 bpm, which corresponds to 180 ft/min. The same vertical well requires about 1.8 bpm (100 ft/min).

The lines in Figure 5-13 marked "Max. Motor Flow" represent typical maximum allowable flow rates of 3.06-, 3¾-, and 4¾-in. motors.

Reactive torque is another concern in directional drilling because torsional winding of the tubing affects the tool-face orientation. The maximum wind-up due to torsion is easy to calculate. However, friction along the wellbore can significantly reduce the number of turns. This has been shown to be true in field applications. For example, Oryx reported a reactive twist of 280° on their first well, and did not observe the multiple twists predicted by theoretical calculations.

5.1.6 Schlumberger Dowell (Well Control, Stuck Pipe, Underbalanced Operations)

Schlumberger Dowell (Rike, 1993) discussed several planning aspects of coiled-tubing drilling operations. Benefits addressed included increased safety, smaller environmental impact, improved well control, lower incidence of stuck pipe, and the ease of incorporating underbalanced drilling.

The components of a typical coiled-tubing drilling unit include a coiled-tubing rig with tubing spool and operator's cabin, a trailer-mounted mud handling unit with high-pressure pump, a crane, required fluid tanks, and storage space for drilling assembly components.

The maintenance of well control is more efficient in coiled-tubing drilling operations. Over half of well-control situations in conventional systems occur during tripping operations. The circulation path is broken during tripping and repeated surging and swabbing of the formation occurs. With coiled tubing, the circulation path remains intact during trips. Circulation is normally continued at a reduced rate during trips.

A flow meter on the flow line can be used to measure returns. This information can be compared to flow being pumped into the well, making an accurate delta flow measurement possible. With this approach, kicks and lost circulation zones can be detected quickly.

The circulation pressure drop remains almost the same throughout the operation regardless of depth. Circulated fluid must travel through the entire string of coiled tubing at all depths. Normally, only relatively minor increases in circulating pressure are noted due to pressure losses in the annulus as the operating depth increases.

Most operators assume that the chances of a nonrotating pipe becoming stuck are greater than for a rotating drill string. According to Rike (1993), this is not usually the case. Since coiled tubing is continuously attached to the surface equipment, the operator can more readily determine whether the string continuously attached to the surface equipment, the operator can more readily determine whether the string is tending to stick or remain free. Stuck-pipe conditions can be recognized more easily and remedial action taken prior to problems. Continuous circulation through coiled tubing also helps prevent cuttings build-up.

Filter cakes for coiled-tubing drilling procedures should be thin and tough and not create high sliding friction. For overbalanced drilling conditions, fluid loss values of 5-8 cc are common.

Jars are sometimes run on drilling assemblies if sticking is predicted. Extended jarring is not practical due to the excessive fatigue wear that results from numerous tubing reversals. Nitrogen can be pumped to increase tubing buoyancy prior to firing the jars. Schlumberger Dowell has successfully used this approach to free stuck strings.

Underbalanced drilling is well suited for coiled-tubing operations. The drilling assembly is deployed through a lubricator into the pressurized wellbore (Figure 5-14).

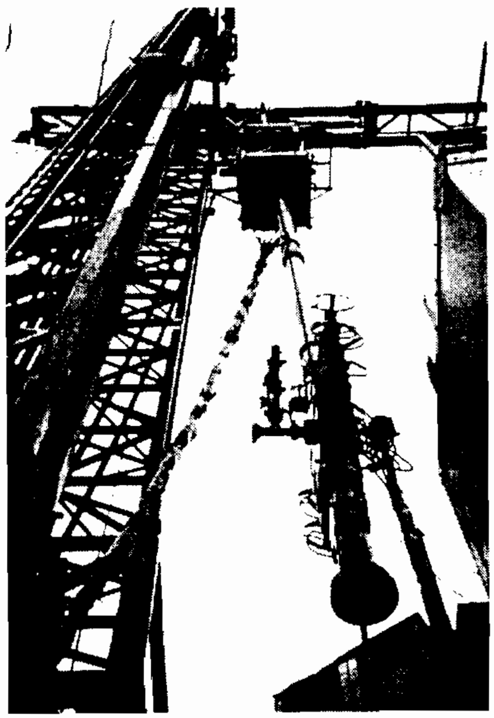


Figure 5-14. Lubricator Used for Underbalanced Drilling (Rike, 1993)

Underbalanced conditions can be achieved by use of several approaches. Aerated fluid can be created by adding air or nitrogen into the fluid pumped down the tubing string. In directional drilling, this approach requires the use of a wireline steering tool, since mud-pulse systems will suffer from signal loss in the aerated fluid.

Other techniques to maintain underbalanced conditions allow the use of mud-pulse technology, including parasitic string injection and gas-lift valves. Since the column of fluid inside the coiled tubing is not aerated for these techniques, either MWD or wireline tools can be used.

5.1.7 Shell Research (Environmental Impact)

Shell Research (Faure et al., 1994) discussed the environmental impact of drilling operations, with special attention to the potential benefits of coiled-tubing drilling in this and related areas. Many established technical processes within the oil and gas industry around the globe have reached limits with respect to environmental impact, economic feasibility, or public acceptance in light of these concerns. Since coiled-tubing drilling represents a departure from established practice, this technology may be an excellent venue to rethink the drilling process while incorporating current concerns for health, safety and the environment.

Faure et al. cited the North Sea as an area with increased environment concerns. In that area, the offshore oil and gas industry is credited with about half of the hydrocarbon pollution each year (Figure 5-15).

Environmental Control Technology (ECT) is being developed to counteract increasing limitations of traditional waste management. A primary objective of ECT is to use new approaches and techniques to avoid or minimize waste generation (Figure 5-16). Novel mud systems are being developed and applied to control offshore discharges. Slim-hole projects are also proving to yield impressive environmental benefits.

Environmental benefits from coiled-tubing drilling are complemented by other advantages including safe and efficient underbalanced operations.

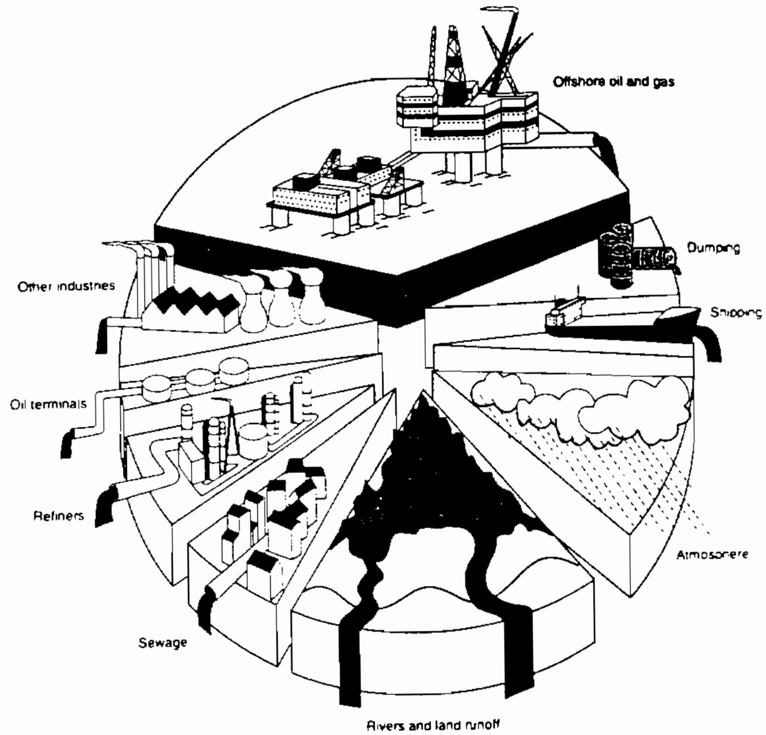


Figure 5-15. Sources of Hydrocarbon Pollution in the North Sea (Faure et al., 1994)

A potential technique to minimize generated wastes is to use crude oil and nitrogen lift to create an underbalanced condition. After circulation, the crude oil is returned to the production facilities, eliminating environmental concerns and costs of drilling fluid disposal.

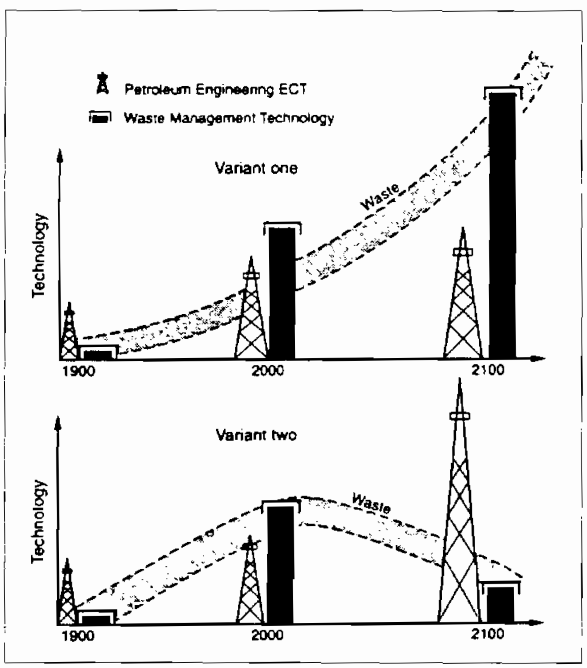


Figure 5-16. Using Control Technology to Reduce Environmental Impact (Faure et al., 1994)

The ease with which high-rate real-time data can be relayed to surface in coiled-tubing operations could lead to greater automation of the drilling process than may be possible with jointed pipe. During drilling operations, there is no need for personnel to be stationed near the wellhead or reel. Exposure of rig personnel to dangerous conditions is greatly reduced.

Safety and costs are also positively affected by a reduction in personnel required to operate the rig. Typical crews consist of a drilling supervisor, coiled-tubing operator, and two helpers for a coiled-tubing drilling operation, compared to a driller, assistant driller, derrickman and three floor hands.

Environmental impact on land is less with a coiled-tubing rig due to a greatly reduced footprint (Figure 5-17) compared to conventional rigs. A consequent benefit is that locations are more easily restored. In addition, mud spillage is much less likely with coiled tubing, and no hole is required for the kelly, both factors reducing the risk of contamination of the surface soil.

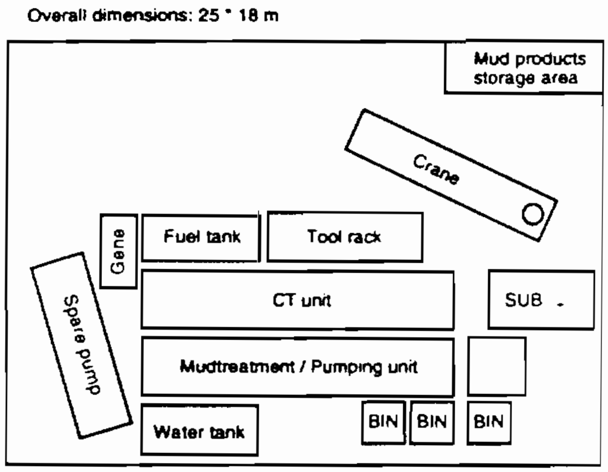


Figure 5-17. Footprint of Coiled-Tubing Drilling Operation (Faure et al., 1994)

Another benefit of special concern in many areas is the reduction in noise with coiled-tubing operations. Noise produced by a coiled-tubing rig and conventional rig is compared in Figure 5-18. Note that a reduction of 10 dB is reported for a radius of about 400 ft, which corresponds to a 90% reduction in acoustic energy.

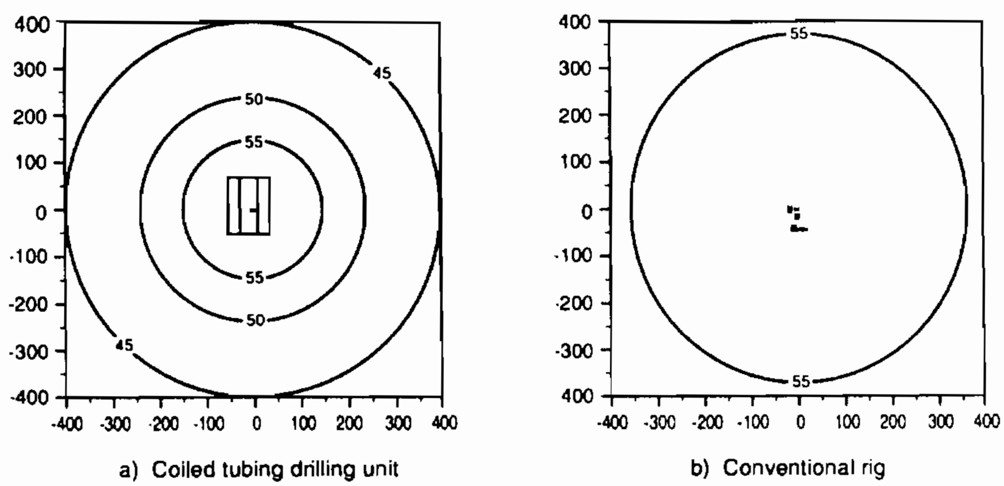


Figure 5-18. Noise Levels for Coiled-Tubing Drilling (Faure et al., 1994)

Other benefits for noise generation include a significant reduction in intermittent (and thus more annoying) noise from pipe bangs during making/breaking operations or squealing breaks. The smaller size of a coiled-tubing rig also makes the unit more amenable to noise enclosures or barriers if further noise reduction is required.

Waste reduction has received considerable attention as a response to the increasing costs associated with waste remediation and disposal. Coiled-tubing operations can take advantage of significant reductions in fluid and cuttings volumes through slim-hole design. Fluid volume reductions of about 70% are achievable (Figure 5-19). Waste transportation and environmental concerns are therefore less.

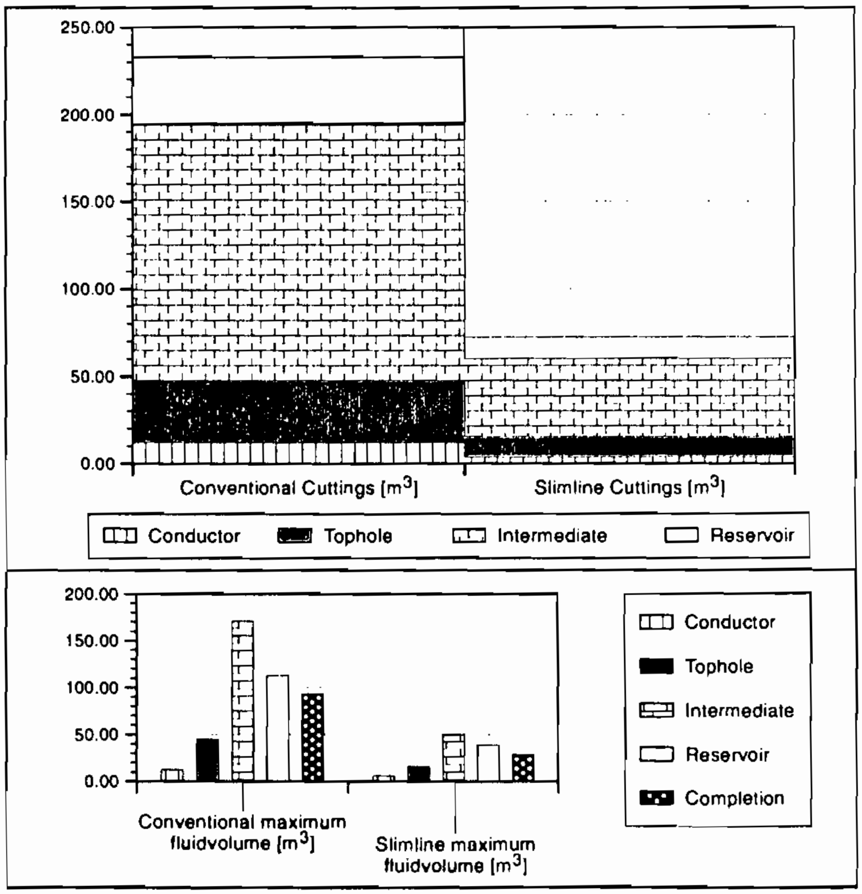


Figure 5-19. Cuttings and Mud Volumes with Slim Coiled-Tubing Drilling (Faure et al., 1994)

Another environmental benefit for coiled-tubing drilling is a reduction in fuel consumption and exhaust gas emission (Table 5-5).

TABLE 5-5. Rig Fuel Usage and Exhaust Emissions (Faure et al., 1994)

		Medium Workover Rig	Land Drilling Rig	CTD Unit
Diesel (m^3/month)		35	160	25
Gas emissions (kg/day)	CO_2	3293	15,055	2,122
	CO	3.7	16.8	2.5
	NOx	4.6	21	2.1
	HC	3.9	17.8	2.8
	HC (gas)	1.83	8.4	1.1
	SO_2	4.2	19.4	2.2

Early inefficiencies with coiled-tubing drilling were described by Faure et al. (1994). The inability for a conventional coiled-tubing rig to run casing has been among the prime deficiencies of these operations. The industry has begun moving along several avenues to address this need. Hybrid rigs with casing snubbing capability are currently in the field-testing phase.

Another avenue is the use of continuous composite casing systems that are hardened in place. Diameters up to 14 in. are possible. These casings are stored folded on a reel. Novel approaches such as composite casing may solve the problems in running conventional casing with a coiled-tubing rig and do so in an environmentally beneficial way.

5.2 TECHNIQUES AND EQUIPMENT FOR COILED-TUBING DRILLING

5.2.1 Anadrill (Directional BHAs)

Anadrill and Schlumberger Dowell (Tracy and Rike, 1994) discussed equipment design, primary advantages and the future of coiled-tubing drilling. They state that the future of coiled-tubing technology is inexorably tied to horizontal drilling.

Early efforts in coiled-tubing drilling yielded important technical successes, but economic success was rare. Since about 1993, several wells drilled with coiled tubing have proven to be economic successes, and more companies are dedicating resources to developing this technology.

Design of drilling BHAs must consider the functioning of the entire assembly. Several special components have been developed for directional drilling applications (Figure 5-20).

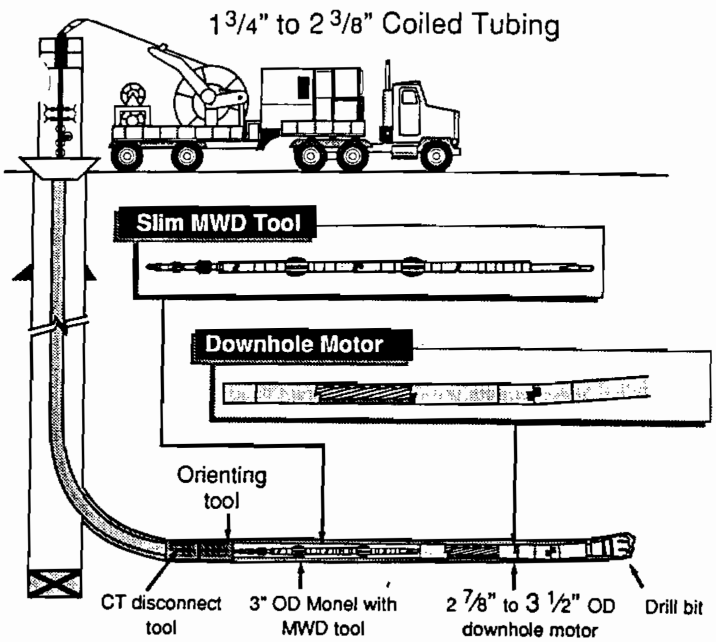


Figure 5-20. Assembly for Directional Drilling with Coiled Tubing (Tracy and Rike, 1994)

Motors are selected to provide the best combination of rotational speed and torque for the formations to be encountered. The majority of drilling operations have been performed with motors smaller than 3½ inches (Figure 5-21).

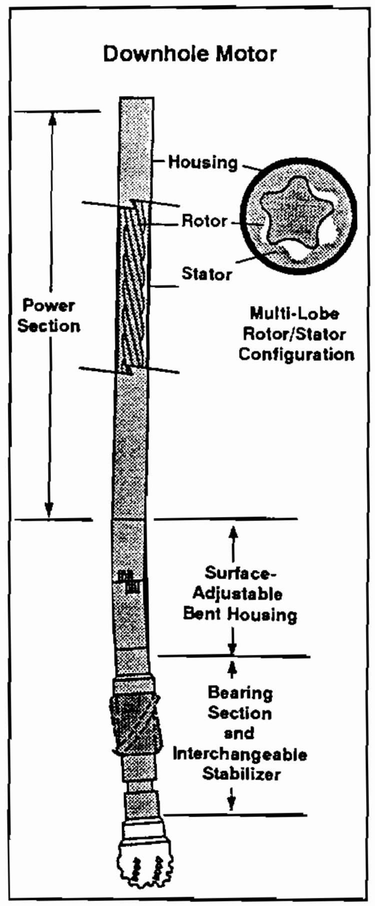


Figure 5-21. Downhole Motor Assembly (Tracy and Rike, 1994)

Directional data are measured with a slim MWD tool (Figure 5-22). Some of these tools provide geologic data for guiding the borehole. Systems have been developed based on mud-pulse or wireline telemetry.

The North Slope is one area that holds particular promise for coiled-tubing drilling. Conventional new wells cost about $2.5 million and re-entries about $1.7 million. It is estimated that a through-tubing re-entry on coiled tubing could save as much as $1 million per well. This approach could result in a considerable increase in reserves and a lengthening of the economic life of these fields.

Liners have been successfully run into five Alaskan wells for casing horizontal sections or repairing leaks. In addition, at least four hybrid rigs have been built to pull and run production tubulars. Other pilot projects are evaluating the feasibility of combination rotary/coiled-tubing rigs, with rotary systems being used to drill surface holes and set casing and coiled-tubing units used for underbalanced drilling of the target zones.

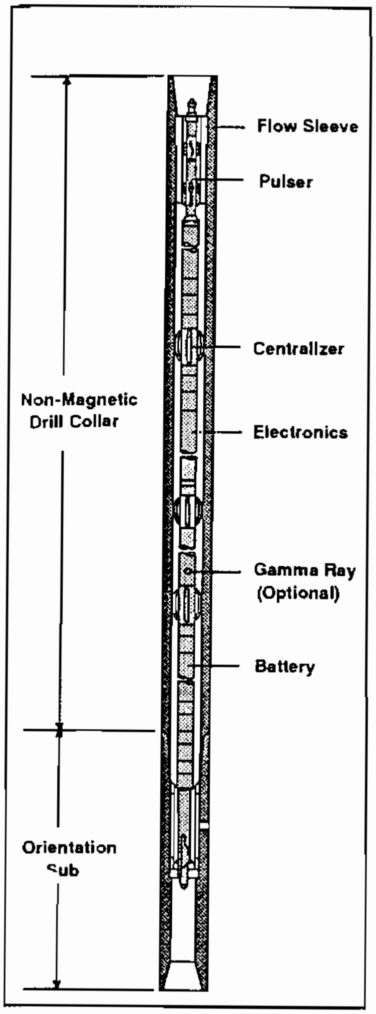


Figure 5-22. Slim MWD Tool for Coiled Tubing (Tracy and Rike, 1994)

5.2.2 Baker Hughes INTEQ (Milling Assemblies)

Baker Hughes INTEQ (Burge and Mieting, 1994) summarized recent activity in designing drilling and milling assemblies for coiled-tubing drilling. Modified technology was demonstrated by the project team in February 1994 in drilling the first coiled-tubing re-entry performed without any intervention from a conventional rig.

The current practical limits for coiled-tubing wells are summarized in Table 5-6. These limits are defined by several factors, especially the required drilling method of slide drilling. For horizontal drilling, the upper limit of hole size is about 5⅞ inches. Hole cleaning becomes much more difficult above this range.

TABLE 5-6. Practical Limits of Coiled-Tubing Drilling (Burge and Mieting, 1994)

	Vertical	Horizontal
HOLE SIZE		
Maximum	6¼	5⅞" Curve 4¾" Horizontal
Minimum	3½"	3½"
Depth	4000 m	3500 m
BUR		60 m radius
Casing Size		
Maximum	9⅝"	7"
Minimum	4½"	4½"

A basic drilling BHA (Figure 5-23) includes connections and crossovers unique to coiled-tubing drilling.

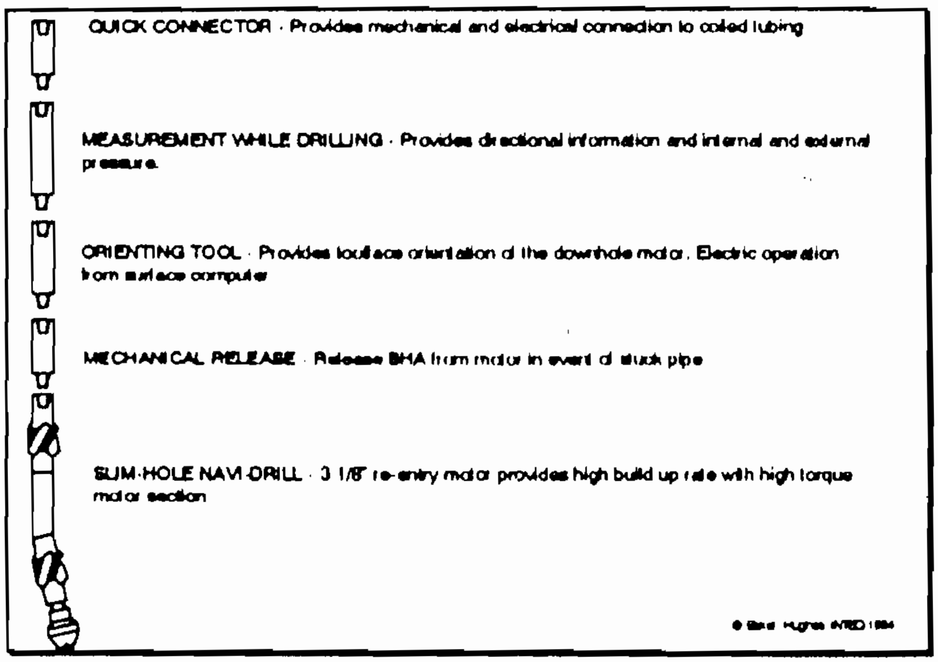


Figure 5-23. BHA for Coiled-Tubing Drilling (Burge and Mieting, 1994)

Guidance data can be conveyed by wireline or mud-pulse systems. The MWD wireline system has advantages for coiled-tubing operations (Figure 5-24). Additional sensors (internal/external pressure) can be added to the wireline system to control underbalanced drilling.

FEATURE	WIRELINE	MUD PULSE
Directional Control	Independent of WOB Continuous orientation Analog orientation Smooth well path	Interrupts drilling process Difficult with aggressive bits Higher total DLS
Information	High data rates Additional sensors	Low data rates Limited potential to add sensors
Two-Way Communication	Control of DHT	Limited control
Drilling Fluid	No limit	Limited to fluid
Operations	Additional weight of coil Additional pressure drop Cementing	

Figure 5-24. Comparison of Wireline and Mud Pulse (Burge and Mieting, 1994)

Special procedures are used in the event of stuck pipe. A ball cannot be dropped due to the presence of the wireline. Baker designed an adjustable mechanical release for use with this assembly. Another solution is an electrically activated release sub.

This system was used to drill a horizontal re-entry without assistance with a conventional rig. A window was cut with a coiled-tubing-deployed assembly (see Section 5.2.11). Cutting the window took 42 hours. A 5⅞-in. 600-ft curve was then drilled. Geologic problems required that the curve then be cemented back and redrilled. Cement was pumped through the wireline-equipped string without problems. After redrilling, a 950-ft horizontal section was completed, with the final portion drilled at 33 ft/hr. All operational problems encountered were successfully solved with coiled tubing.

5.2.3 Dresser Industries (Bit Selection)

A discussion of the parameters impacting drill-bit selection for coiled-tubing drilling was presented by Dresser Industries (King, 1994). It is emphasized that drill system components must be analyzed together, and that drill-bit design and compressive strength of the formation are both critical components.

Motor and bit selection are integrally related. The most common motors used on coiled tubing are high-speed, low-torque motors and medium-speed, medium-torque motors. Greater rotational speeds usually result in increased ROP. In general, roller-cone bits are run on medium-speed, medium-torque motors. Rotational capabilities of the bit should be matched to motor performance.

WOB (weight-on-bit) is generally less than optimal in coiled-tubing drilling, both vertical and directional. The use of drill collars is often limited due to tubing and surface handling constraints. They usually cannot be used in directional applications; WOB is provided by string weight and snubbing forces.

A relatively small proportion of system pressure drop occurs across the bit. Annular pressure drop, frictional pressure drop inside coiled tubing, and pressure drop across the BHA consume most of the available hydraulic energy.

A summary of coiled-tubing and bit sizes for several drilling jobs is presented in Table 5-7. The most common bit size has been 3⅞ in., with 2-in. coiled tubing the most common string.

TABLE 5-7. Bit and Coiled-Tubing Sizes* (King, 1994)

BIT DIAMETER, IN.	JOBS	COILED-TUBING DIAMETER, IN.	JOBS
3.750	6	1.500	6
3.875	15	1.750	4
4.125	2	2.000	25
4.500	1	2.375	3
4.750	9	TOTAL	38
6.125	1		
6.250	4		
TOTAL	38		

* Through late 1993

King (1994) designed three typical matched drilling systems for coiled tubing (Table 5-8). Systems are designed with 3⅞-, 4¾-, and 6¼-in. bits. King believes that both 2⅜-in. coiled tubing and 6¼-in. bits will see increased use in the future.

TABLE 5-8. Matched Coiled-Tubing Drilling Systems (King, 1994)

Coiled tubing diameter, in.	Bit diameter, in.	Motor OD, in.	Motor type	Flow rates, gpm	Rotational speed, rpm	Torque output, ft-lb	Differential pressure, psi
1.750	3.875	2.875	HSLT	20-70	225-800	20-160	100-700
			MSMT	30-70	60-375	40-280	100-600
2.000	4.750	3.500	HSLT	120-180	640-950	30-250	100-800
			MSMT	70-120	170-310	30-480	100-600
2.375	6.250	4.750	HSLT	150-250	325-550	50-440	100-800
			MSMT	150-400	175-475	50-1,100	100-700

Each of the bit types (Figure 5-25) should receive consideration. Bit type should not be chosen by default without proper analysis of economics and mechanics.

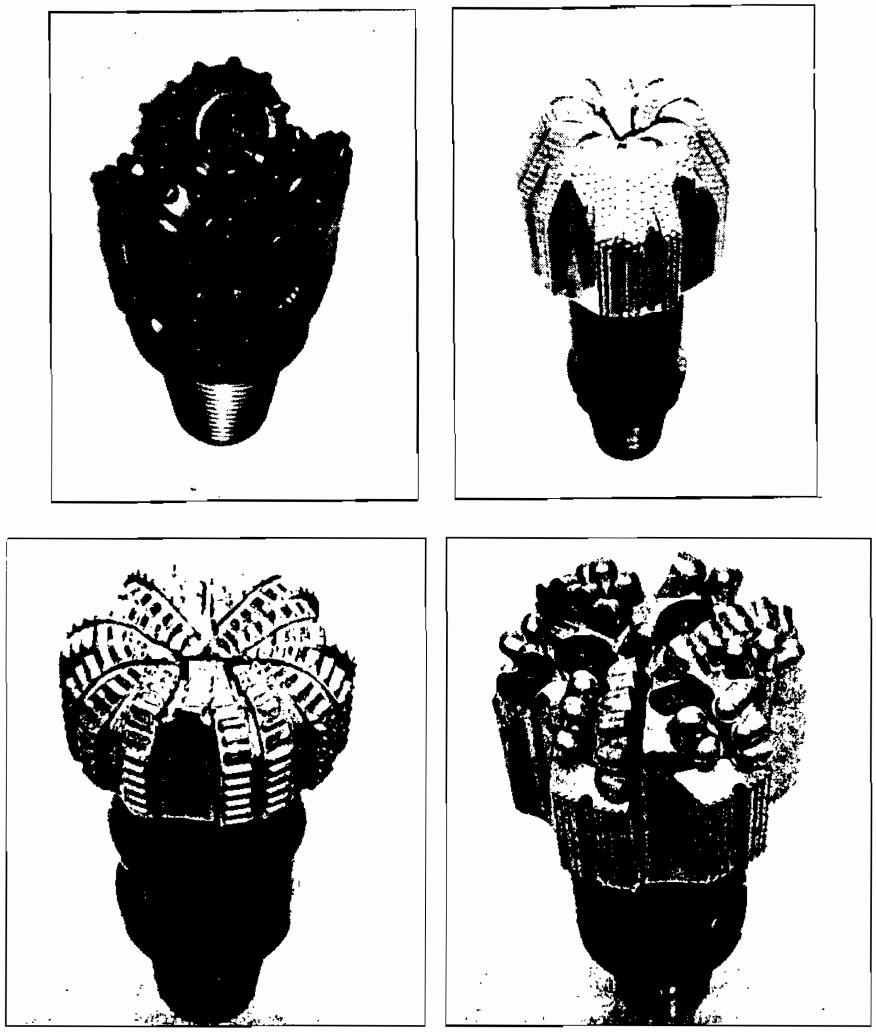


Figure 5-25. Bit Types: Roller Cone (upper left), Natural Diamond (upper right), TSP (lower left), and PDC (lower right) (King, 1994)

Roller-cone bits are available in diameters as small as 3⅞ in. with either sealed or nonsealed bearings (Table 5-9). Nonsealed bits are used for drilling out cement and for workovers. Sealed bits are used in drilling applications. Advantages of roller-cone bits in certain situations include almost no problems with stalling. However, these slim-hole bits lack the strength and capacity for lubrication available with larger bits.

TABLE 5-9. Slim-Hole Roller-Cone Bits (King, 1994)

IADC code			1 Standard roller bearing	2 Roller bearing air cooled	6 Sealed fiction bearing	7 Sealed friction bearing gauge protection
1	Steel tooth soft	1			▲	
		2	▲		■▲	
		3	■▲		■▲	
2	Steel tooth medium	1	▲		■	
		2	●■			
		3				
3	Steel tooth hard	1	■▲			
		2				
		3				
4	Insert very soft	2				
		3				
		4				■
5	Insert soft	1				■▲
		3				●■▲
		4				■
6	Insert medium	1				▲
		2				■▲
		3				■▲
7	Insert hard	3				▲
		4		▲		

● 3.875 in. ■ 4.750 in. ▲ 6.250 in.

The popularity of natural-diamond bits has lessened with the increased availability of TSP and PDC technology. Relatively low torque is generated with natural diamond bits due to less aggressive cutting action. Natural-diamond bits may be used to drill an angular tight sand or other applications where the life of other bits may be too limited.

TSP (thermally-stable polycrystalline) bits are long-lived but generally drill slower than comparable PDC or roller-cone bits. The torque consistency in TSP bits is helpful for overcoming difficulties with tool-face orientation and motor stalling. For some operators, TSP bits are the first choice because of life expectancy and torque consistency. However, if bit selection is based only on these considerations, potential benefits of higher ROP with other bits may never be enjoyed.

In many cases, PDC (polycrystalline diamond compact) bits are considered as too aggressive for coiled-tubing drilling, leading to erratic and excessive torque generation. However, recent developments to minimize axial and lateral vibrations have led to more consistent torque performance with these bits. With reduced vibrations and relatively consistent torque, improved PDC bits can be ideal for coiled-tubing applications.

Torque performance with WOB is compared for the four bit types in Figure 5-26.

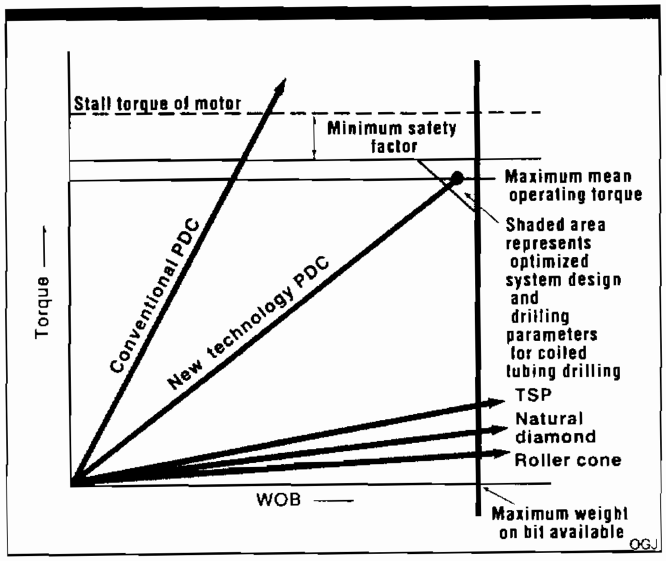


Figure 5-26. Torque and WOB for Bit Types (King, 1994)

Torque amplitudes are compared in Figure 5-27. Improved PDC bits have been shown to perform with significantly less torque cycling than conventional PDC bits.

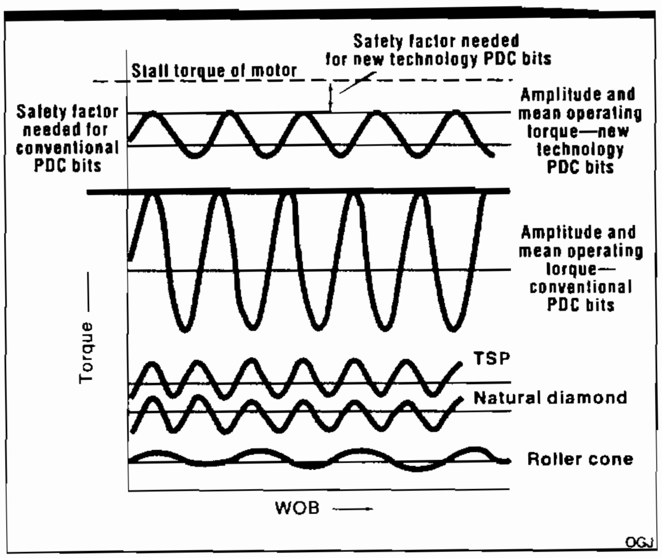


Figure 5-27. Torque Amplitude for Bit Types (King, 1994)

A comparison of general performance of bit types with respect to WOB, torque generation, torque cycling, and potential ROP for coiled-tubing drilling is shown in Table 5-10.

TABLE 5-10. Ranking of Bits for Coiled-Tubing Drilling (King, 1994)

AMOUNT OF WEIGHT REQUIRED TO DRILL (Ranked Highest to Lowest)

1. Roller cone
2. Natural diamond
3. TSP
4. New technology PDC
5. Conventional PDC

TORQUE GENERATION WHILE DRILLING (Ranked Most to Least)

1. Conventional PDC
2. New technology PDC
3. TSP
4. Natural diamond
5. Roller cone

HIGH-AMPLITUDE TORQUE VARIANCE WHILE DRILLING (Ranked Most to Least)

1. Conventional
2. New technology PDC
3. TSP
4. Natural diamond
5. Roller cone

ROP POTENTIAL AT HIGH ROTATIONAL SPEED WITHIN COILED TUBING DRILLING SYSTEM CONSTRAINTS (Ranked Highest to Lowest)

1. New technology PDC
2. Conventional PDC
3. Roller cone
4. TSP
5. Natural diamond

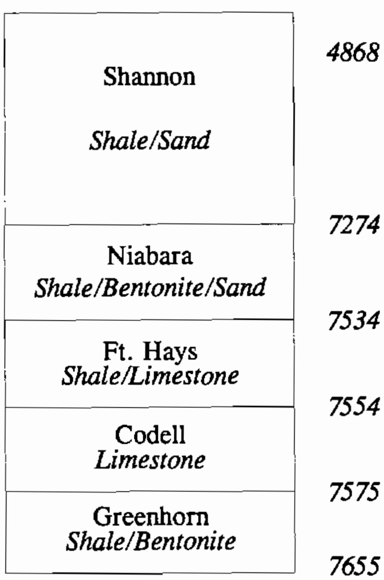


Figure 5-28. Formation Tops for Well Deepening (Mensa-Wilmot and Coolidge, 1994)

5.2.4 Dresser Industries (Optimizing PDC Bits)

Dresser Industries (Mensa-Wilmot and Coolidge, 1994) described the need to integrate bit design for coiled-tubing drilling with all other components. Proper bit selection can greatly impact the success of coiled-tubing drilling. Experience has shown that small changes in bit design can have considerable effect on bit performance.

In one specific project, a well in the Spindle Field in Weld Colorado was to be deepened with a 4¾-in. bit. Drilling was to commence through a cement column starting at 4554 ft down to the Greenhorn formation at 7655 ft (Figure 5-28).

Coiled-tubing equipment design for this project included 2⅜ x 0.188-in. tubing and a 3⅞-in. motor with a 1/2-lobe configuration (Table 5-11). Drill collars (3½ x 1½ in.) were also used, with a maximum of nine allowable based on mechanical limits.

TABLE 5-11. Motor Specifications for Coiled-Tubing Drilling (Mensa-Wilmot and Coolidge, 1994)

Flow Rate	-	75-125-175 gpm
Rotation Rate	-	320-530-745 rpm
$\Delta P_{(motor)}$ -	-	750 psi
Operational Torque	-	455 ft-lb
Stall Torque	-	910 ft-lb
Motor HP	-	28-46-65 hp
$\Delta P_{(bit)}$	-	200-1000 psi

Examination of rock mechanics data showed that different bits would be required for optimum ROP in the Shannon and Codell formations. A bit with a tracking ridge was suggested for the Shannon and Niobrara. For the Codell, a track-set structure was specified (Figure 5-29). This design reduces vibration, lowers impact loads, and improves the life of the cutting elements.

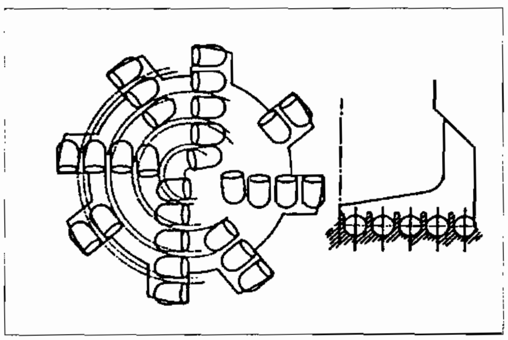


Figure 5-29. PDC Bit with Track-Set Design (Mensa-Wilmot and Coolidge, 1994)

Target ROPs for coiled-tubing drilling with the tracking-ridge bit were set based on historic roller-cone performance as 70 ft/hr in the Shannon and 30 ft/hr in the Niobrara. An assumed 90% of WOB was to be provided by drill collars so that the tubing string will always be in tension. Calculations showed that seven drill collars were needed for these formations.

Operations with the track-set bit in the Codell were modeled based on the same WOB. An ROP of 32 ft/hr was established.

Bit performance (tracking-ridge bit) in the Shannon is summarized in Figure 5-30.

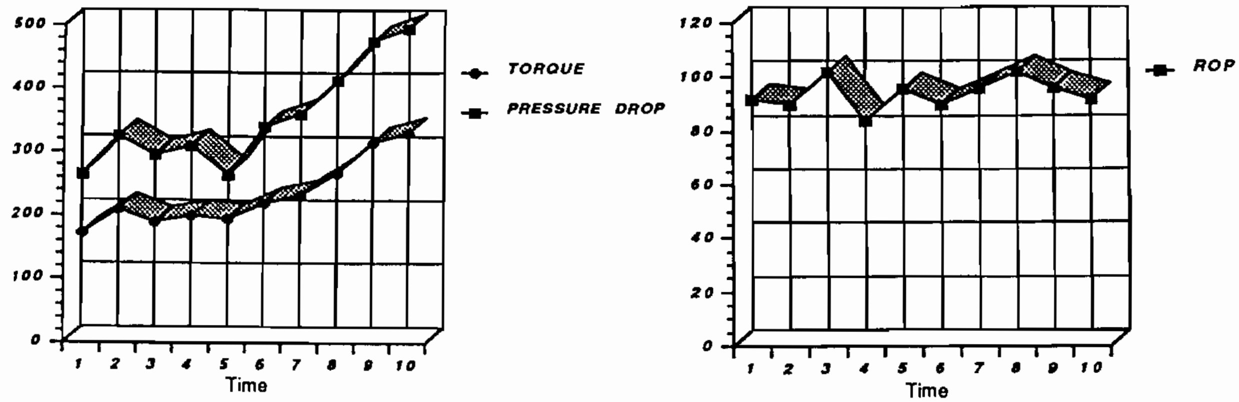


Figure 5-30. Torque, ΔP and ROP for PDC Tracking-Ridge Bit (Mensa-Wilmot and Coolidge, 1994)

The bit drilled 1706 ft of formation before it was tripped out and replaced with the track-set bit so that their performance could be compared within the same formation. Average ROP with the tracking ridge bit was 94 ft/hr (Table 5-12).

TABLE 5-12. Performance of the PDC Tracking-Ridge Bit (Mensa-Wilmot and Coolidge, 1994)

	WOB(lbs)	Torque (lb-ft)	Pressure Drop (psi)	ROP(ft/hr)
Mean	3981	233	354	94.0
Std.Dev.	349	53.6	81	5.5

The track-set bit was tripped in, and drilled through the bottom of the Shannon at an average ROP of 50 ft/hr. Within the Codell, the track-set bit drilled at an ROP of 22 ft/hr. However, no historic data were available to compare to this rate. Track-set bit performance in the Codell is summarized in Figure 5-31.

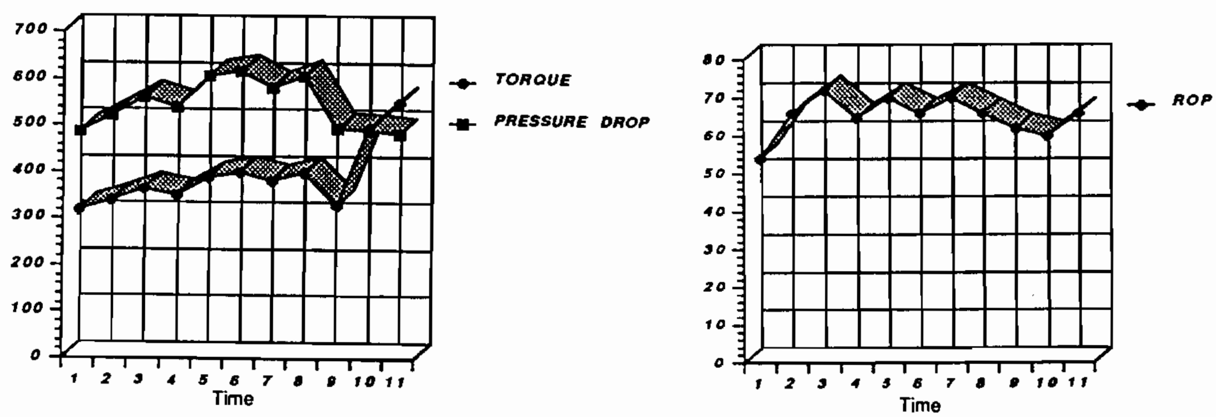


Figure 5-31. Torque, ΔP and ROP for PDC Track-Set Bit (Mensa-Wilmot and Coolidge, 1994)

This successful field trial showed that properly designed and selected PDC bits are effective for drilling on coiled tubing. Consideration of the mechanisms of formation removal and vibration tendencies is necessary for proper bit design.

5.2.5 Drexel Oilfield Services (Hybrid Coiled-Tubing/Snubbing Rig)

Industry's experience with early coiled-tubing drilling applications demonstrated that a system was needed that could run both coiled and jointed pipe. In many cases, existing jointed production tubing needs to be pulled and run, or casing/liners need to be run after drilling is completed.

Drexel Oilfield Services (Newman and Doremus, 1994) considered several basic designs for hybrid coiled/jointed pipe operations. The first approach involved adding coiled-tubing subsystems to a conventional rig, including the control panel, injector, reel and accumulator. Power for coiled-tubing operations could be taken from the rig power.

Another approach to the design of a hybrid rig is to add a mast to a basic coiled-tubing rig. The mast would be used for pulling jointed pipe, and, if required, a top drive could be used to rotate jointed pipe.

The third approach is to add snubbing jacks to a basic coiled-tubing rig. If rotation were required, a rotary table could be added.

These three approaches are compared in Table 5-13.

TABLE 5-13. Coiled/Jointed Pipe Hybrid Systems (Newman and Doremus, 1994)

TYPE	ADVANTAGES	DISADVANTAGES
Rig + CTU Subsystems	◆ Fast running/pulling of jointed pipe ◆ Full rig capabilities	◆ Expensive –Cost of full rig + CTU ◆ Large amount of equipment ◆ Large location size ◆ Large crew size needed ◆ Cannot run jointed pipe underbalanced ◆ Transmits load only through substructure
CTU + Mast	◆ Fast running/pulling of jointed pipe	◆ Cannot run jointed pipe underbalanced ◆ Large crew size ◆ Transmits load only through substructure
CTU + Snubbing Jacks	◆ Can run jointed pipe underbalanced ◆ Small crew size ◆ Less equipment ◆ Small location ◆ Transmits load through either the substructure or the wellhead	◆ Slow running/pulling of jointed pipe

Drexel weighed the advantages/disadvantages of these three approaches and settled on the third: snubbing capability added to a coiled-tubing rig. The ability to run jointed tubing under pressure for underbalanced operations was an important factor favoring this design. Another important element was the ability to transmit axial loads through the wellhead, an important attribute for operations on some offshore platforms.

Drexel designed and manufactured a hybrid rig capable of running both continuous and jointed pipe (Figure 5-32). Some of the design features of the system are:

- Includes two snubbing jacks with 11-ft stroke capable of pulling 170,000 lb
- A trolley is used to move the injector on/off the well
- The jacks are used to lift the injector off the trolley and hold it while coiled tubing is run in. This design lessens fatigue life by allowing small pipe movements to be made by raising/lowering the injector, provided a telescoping lubricator is used.
- Height of the drilling floor adjusts between 14 to 18 ft above ground level
- Jointed pipe ranging from 2⅜ to 7⅝ in. can be run. A crane is used to handle pipe joints
- Operations can be switched between continuous and jointed pipe rapidly by moving the injector on or off the wellhead

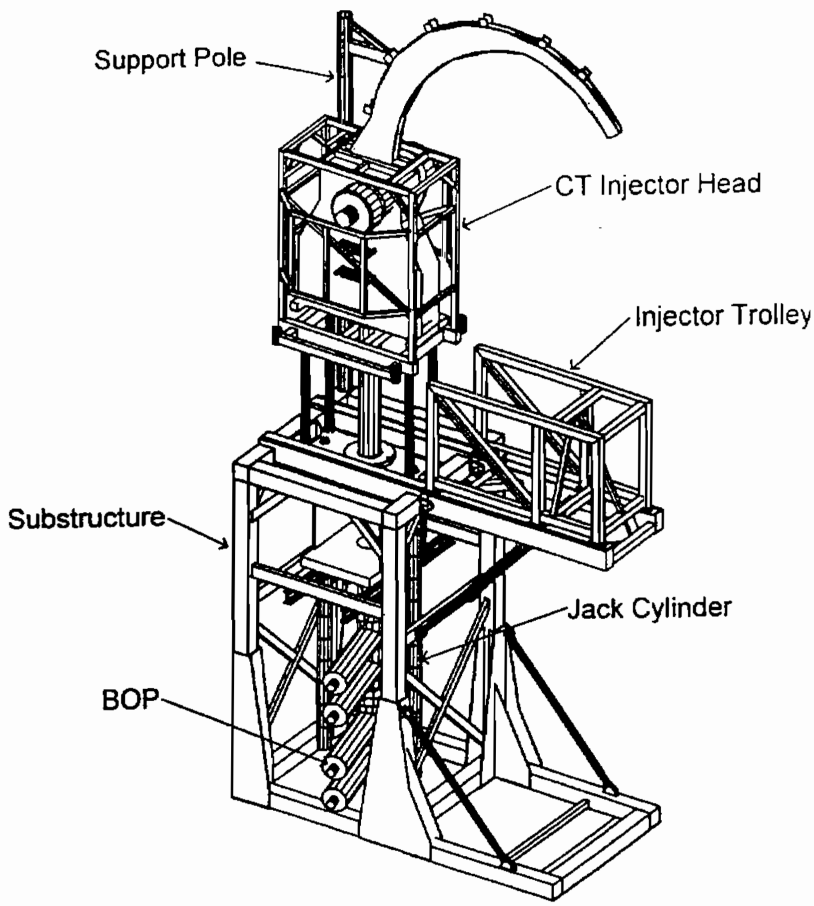


Figure 5-32. Drexel's Hybrid Coiled/Jointed-Pipe System (Newman and Doremus, 1994)

The first field use of the hybrid system was to drill a shallow gas well. After a water-well rig was used to drill the pilot hole and set surface casing, the hybrid rig drilled a 6½-in. hole to 2290 ft. Conventional casing (4½ in.) was run to complete the well. While lowering the casing, two bridges were encountered. The first bridge was pushed through by snubbing forces. The second bridge could not be overcome. A conventional rig was brought in to ream the hole and set the casing. Drexel believes that the job could have been completed with the hybrid rig if the casing could have been rotated.

5.2.6 Drilex Systems (Motor Selection)

Fothergill (1994) of Drilex Systems discussed the special concerns for running downhole motors on coiled tubing. Many difficulties that are experienced in the field can be avoided with appropriate design of the equipment and good operational practices.

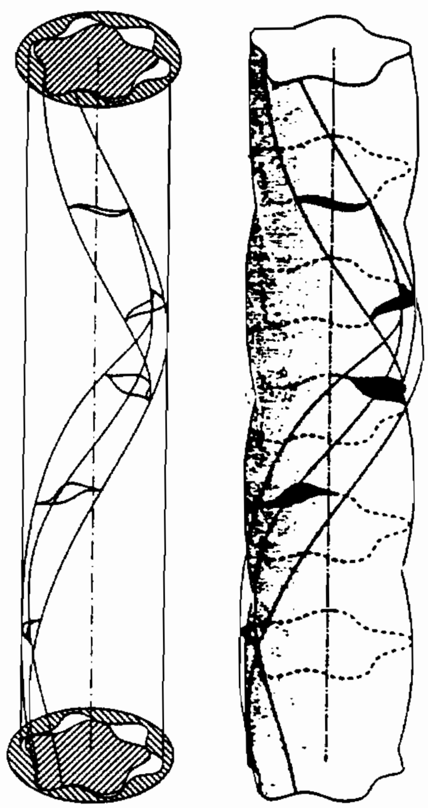


Figure 5-33. Fluid Path in Downhole Motor (Fothergill, 1994A)

Power to rotate cutting elements on coiled tubing is generated as fluid is pumped through a helical pathway (Figure 5-33) in the motor. Additional torque is generated by an increased number of stages.

The configuration of the rotor and stator (Figure 5-34) determines operating characteristics including flow rate, rotational speed, pressure drop and torque. Multilobe designs act as a gear reducer, providing high torque at reduced rotational speed.

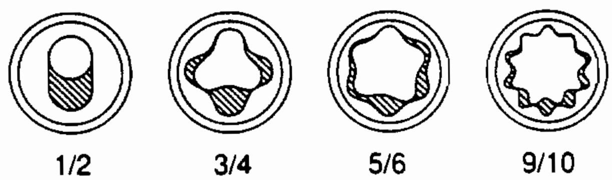


Figure 5-34. Rotor/Stator Configurations (Fothergill, 1994A)

Flow rate dictates motor rotational speed, unless weight is placed on the bit. Torque demand increases pressure drop through the motor. A typical torque/speed performance curve is shown in Figure 5-35.

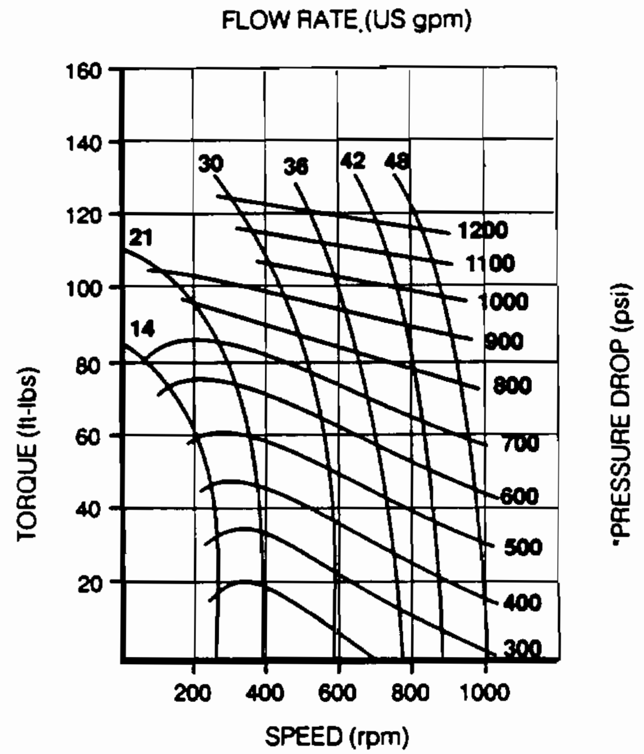


Figure 5-35. Motor Performance Curves (Fothergill, 1994A)

A typical bottom-hole assembly run above the motor is shown in Figure 5-36. Additional concern is warranted in the design of these components. Operators not familiar with coiled-tubing motor jobs often underestimate the effects of torque and vibration. Failures have occurred, most often in the hydraulic disconnect or tubing connector.

BHA components must be able to withstand the maximum reactive torque produced at stall. A common safety factor for tubing yield is that maximum motor stalling torque not exceed 40% of coiled-tubing yield.

Gel sweeps should be pumped periodically if annular velocities are restricted by BHA hydraulics. In addition, a conservative penetration rate should be adopted.

Drilex designed a selective flow sub (Figure 5-37) for coiled-tubing motor operations. The sub functions as a flow bypass tool that is closed at lower pressure differentials, and then opens to

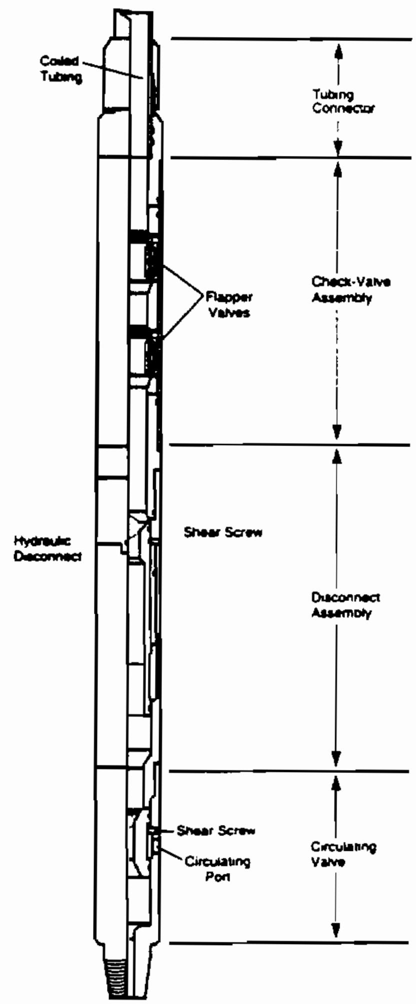


Figure 5-36. Typical Assembly for Running a Motor on Coiled Tubing (Fothergill, 1994A)

bypass flow at stall pressures. Excessive torques can thus be prevented. Bypass rates can be preset and changed in the field.

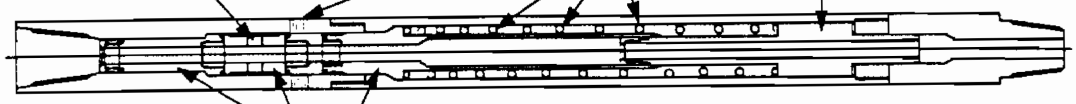


Figure 5-37. Selective Flow Sub (Fothergill, 1994B)

The prototype selective flow sub was 3⅛-in. for use with a 2⅞- or 3½-in. motor. In early tests the sub was configured to allow bypass of 42 gpm for maximum pump rate of 126 gpm. The operational window was designed as 100 psi between closed to full open.

Examples of uses of a selective flow sub are shown in Table 5-14. Various motors are listed in the left column; their model number refers to their diameter. Motor/coiled-tubing combinations that are within safety limits are marked with a check; impractical combinations are marked with an x. Matches that are possible with a selective flow sub show the necessary pressure limitation and the flow bypass area (TFA) required.

TABLE 5-14. Motor/Coiled-Tubing Combinations (Fothergill, 1994B)

Motor Size		Coiled Tubing Size							
		1.50"		1.75"		2.00"		2.38"	
	Wall Nom	.095	.156	.109	.156	.109	.203	.109	.203
D287	Max Pres Diff	500	700	✓	✓	✓	✓	✓	✓
	TFA	.155	.141						
D350	Max Pres Diff	500	883	✓	✓	✓	✓	✓	✓
	TFA	.136	.102						
D375	Max Pres Diff	412	600	612	864	874	1409	1265	✓
	TFA	.206	.169	.168	.141	.140	.110	.117	
DIR475	Max Pres Diff	x	x	x	x	346	576	514	869
	TFA					.371	.288	.305	.234
D475	Max Pres Diff	x	x	x	x	347	497	475	971
	TFA					x	.310	.317	.222

Fothergill (1994) listed a number of general operational guidelines for coiled tubing/motor procedures. Readers are referred to his papers for more details.

Motor stalls are detected by a significant increase in pressure (Figure 5-38). The tubing should be advanced at a rate to maintain a 300-400 psi differential above the pressure recorded during circulation while off bottom.

Common problems/mistakes during coiled-tubing motor operations include:

- Premature motor failure, caused by pump rates above specifications, high temperatures, poor solids control, excessive stalling or harsh chemicals
- Failure of hydraulic disconnect, caused by poor design or use of undersized disconnect
- Failure of tubing connector, caused by poor make-up or testing
- Tools stuck in hole, caused by not keeping the hole clean

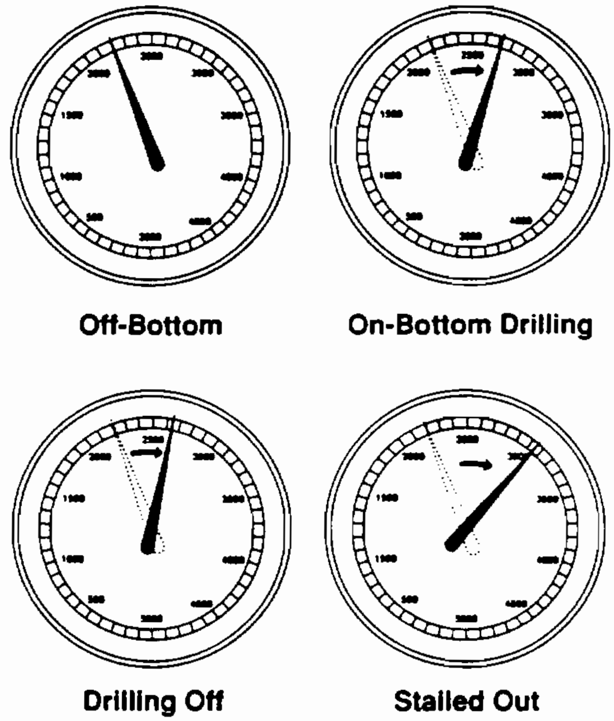


Figure 5-38. Pump Pressure for Motor Operations (Fothergill, 1994A)

5.2.7 Ensco Technology (BHAs for Coiled-Tubing Drilling)

From the perspective of directional drilling, coiled-tubing drilling can be considered another of the innovative techniques and procedures developed over the last decade to drill horizontal and high-angle wells. Ensco Technology (Lenhart, 1994) summarized the differences between directional drilling with coiled tubing as compared to conventional systems based on workover or drilling rigs.

Basic technology for directional drilling assemblies is similar for coiled tubing (Figure 5-39) and slim-hole jointed-pipe systems (Figure 5-40). Bit requirements are the same and both BHAs contain a PDM and nonmagnetic collars. The primary differences are the assembly connector, orienting tool, and running gear for the steering tool.

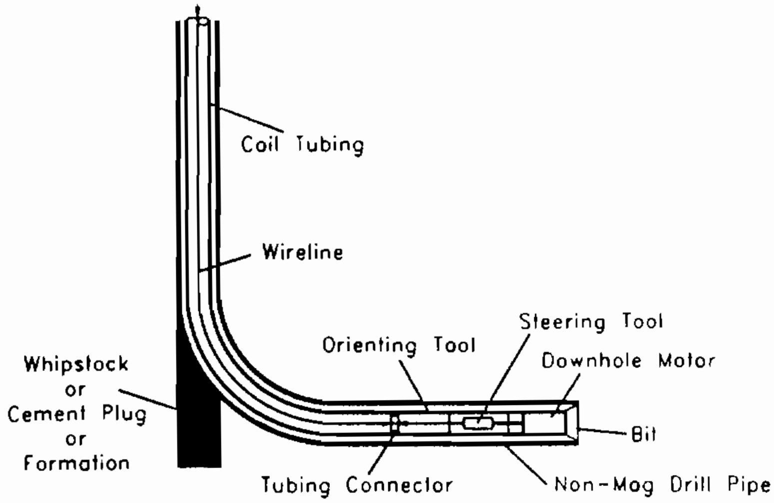


Figure 5-39. BHA for Directional Drilling with Coiled-Tubing (Lenhart, 1994)

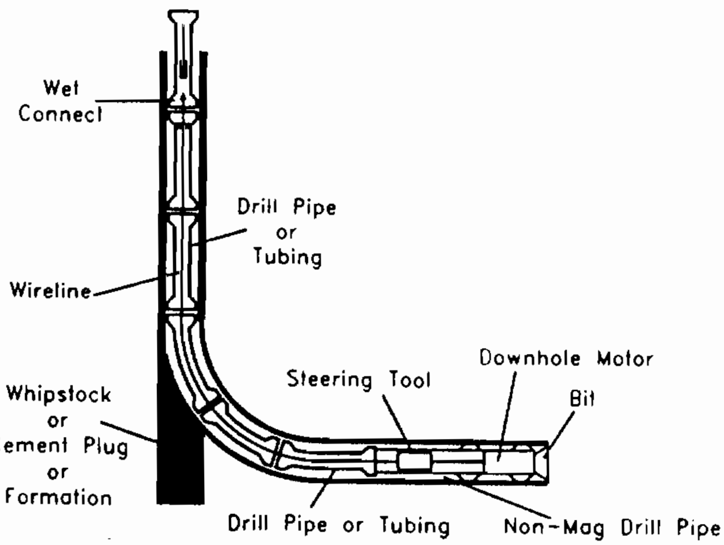


Figure 5-40. BHA for Directional Drilling with Jointed Tubing (Lenhart, 1994)

The assembly connector for a coiled-tubing BHA performs two functions: mechanically connects BHA to the string as well as connects wireline to BHA components. The orienting tool for coiled-tubing drilling takes the place of string rotation with jointed-pipe systems for orienting the tool face. The orienting tool used in early coiled-tubing drilling efforts rotated the BHA with respect to the coiled-tubing string as the tool was telescoped. The steering tool for coiled-tubing drilling uses an improved centralization system, which is practical since the tool does not have to be tripped through the string.

Conventional slim-hole drilling has evolved to an efficient practice is many areas using a workover rig, power swivel and portable mud system. Coiled-tubing drilling has normally been performed with conventional coiled-tubing rigs designed for workovers. Drilling efficiency has not generally been competitive with a conventional workover rig.

Coiled-tubing rig arrangements have varied in the method of supporting the injector and in the work floor area. A design used in early wells included a trailer-mounted mast that supported a frame to move the injector in three dimensions (Figure 5-41). A platform is positioned at the top of the BOP for handling the BHA and other equipment.

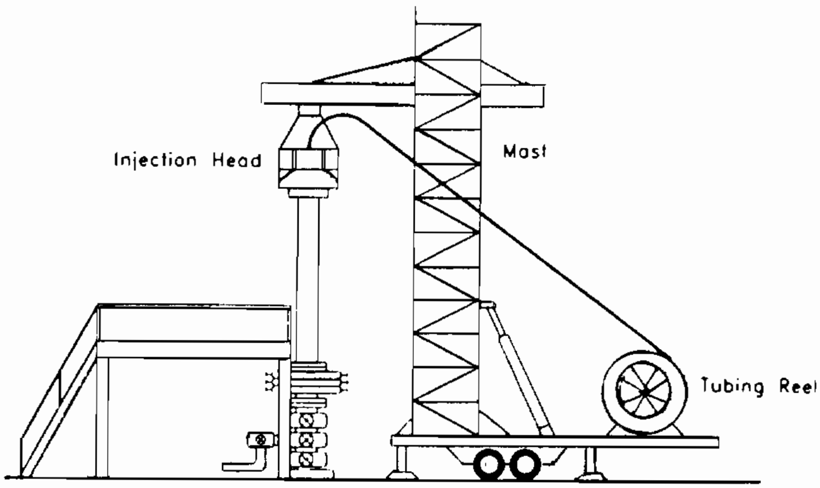


Figure 5-41. Mast-Supported Drilling Rig (Lenhart, 1994)

A design used on some later wells was based on a small substructure assembly to support the injector and provide a work floor for handling equipment (Figure 5-42). A trolley is used to move the injector off the wellhead for access.

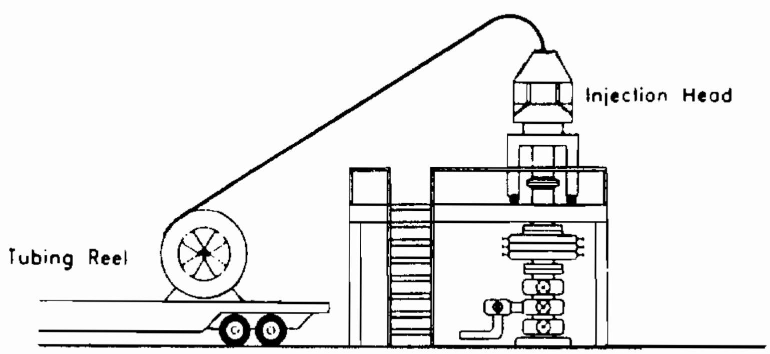


Figure 5-42. Drilling Rig with Substructure (Lenhart, 1994)

One advantage of coiled tubing for directional drilling applications is increased flexibility of build rate. Build rate can be increased to 50-60°/100 ft on coiled tubing without danger for failure as may be the case for jointed pipe in rotation. These bending stresses are within the elastic limits of coiled tubing.

Lateral departures for several directional wells are shown in Table 5-15. Experience has shown that greater departures were achieved with rotating drill strings than with coiled tubing. However, economic results can be achieved with slide-drilling systems, including coiled tubing.

TABLE 5-15. Lateral Departures for Coiled-Tubing and Rotary Wells (Lenhart, 1994)

Well Name	Drilling System	Hole Size (In.)	Footage Drilled (Ft)	Departure (Ft)	Reason for T.D.
Shelton #3	Coiled Tubing	3⅞	1,978	1,458	Well producing oil, spent AFE
Lasater #1	Coiled Tubing	3⅞	963	699	Equipment problems, wireline
McKinney #1	Coiled Tubing	3⅞	1,396	1,011	Could not get WOB to drill
Holubec Unit #1	Coiled Tubing	4½ 3⅞	1,452 93	1,327 1,420	High project cost, tubing failures
Berkel #58	Coiled Tubing	4½	1065	861	T.D. as planned
Poellnitz #1	Steerable	4¾	2923	2,885	T.D. as planned
Booth #4	Steerable	3⅞	2651	2,456	T.D. as planned

Directional coiled-tubing wells have been limited to slim sizes (Table 5-16), i.e., generally 4¾ in. or less. Tubing mechanical strength limits BHA weight and reactive torque capacity. Additionally, larger holes reduce critical buckling loads, which lead to early lock-up of the string.

TABLE 5-16. Wellbore Diameter for Coiled-Tubing and Rotary Wells (Lenhart, 1994)

Well Name	Drilling System	Casing Size (In.)	Hole Size (In.)	Tubing Size (In.)	Comments
Shelton #3	Coiled Tubing	4½	3⅞	2	Good controllability of BHA
Lasater #11	Coiled Tubing	4½	3⅞	2	Good controllability of BHA
McKinney #1	Coiled Tubing	5½	3⅞	2	Difficult to get WOB, buckling
Holubec #1	Coiled Tubing	5½	4½ & 3⅞	2⅜	High drag, difficult to get WOB
Berkel #58	Coiled Tubing	5 & 7⅝	4½	2	No apparent problem; good controllability
Poellnitz #1	Steerable	5½	4¾	2⅞	No apparent problem; good controllability
Booth #4	Steerable	4½	3⅞	2⅜	No apparent problem; good controllability

Slide drilling, as with coiled tubing, has generally performed at an ROP about half that with rotation. However, this is offset to an extent by increased efficiency from tripping and other time savings from coiled tubing. Average daily footage should be compared, rather than instantaneous rate of penetration. ROP in the curve and in the horizontal section are compared for coiled-tubing and rotary wells in Table 5-17.

TABLE 5-17. ROP for Coiled-Tubing and Rotary Wells (Lenhart, 1994)

Well Name	Drilling System	Rate of Penetration: Curve Ft/Hr	Rate of Penetration: Horizontal Ft/Hr	Lithology	Comments
Shelton #3	Coiled Tubing	11	15	Limestone	WOB not a problem
Lasater #11	Coiled Tubing	8	20	Limestone	Tool problems; lost circulation; WOB no problem
McKinney #1	Coiled Tubing	9.2	11	Limestone	Hard to get WOB
Holubec #1	Coiled Tubing	9.4	5.9	Limestone	Hole problems; hard to get WOB; bit damage
Berkel #58	Coiled Tubing	9.8	16.4	Sandstone	No apparent problems
Poellnitz #1	Steerable	12.7	22	Limestone very hard	10% Slide; 90%Rotary
Booth #4	Steerable	12.3	31.3	Limestone	40% Slide; 60% Rotary

Lenhart (1994) listed several applications most likely to benefit from coiled-tubing drilling:

- Environmentally sensitive areas, especially those with noise concerns or strict well-control regulations
- Underbalanced applications where special permitting is required and difficult to obtain for conventional systems, or where high working pressures exceed conventional equipment capabilities
- Offshore re-entries where the platform cannot support a workover rig, or where a retrofit is too costly
- Through-tubing drilling where the cost of pulling production tubing makes the project uneconomical.

5.2.8 Halliburton Services (Coiled-Tubing/Workover-Rig Drilling System)

A coiled-tubing drilling system that does not require a derrick has been described by Halliburton (Courville and Maddox, 1993). Their approach combines coiled-tubing and hydraulic workover-rig technologies. The principal shortcoming of a coiled-tubing rig in drilling applications—the inability to set casing—is readily performed by the hydraulic workover unit. This combination can thus perform complete slim-hole drilling operations without any need for a conventional derrick-based drilling rig.

The coiled-tubing/hydraulic-workover system can work under pressure, allowing underbalanced drilling and providing protection against formation damage. Other advantages of the system are cited by Halliburton:

- Small size, resulting in less environmental impact and ready access to remote locations
- Inherent capability to safely handle unexpected pressures
- Eliminates need for load-bearing structures such as concrete pads
- Faster trip times allow rapid adjustments to the BHA

Hydraulic workover units were originally introduced in the 1960s. They have been used primarily to move pipe inside production tubing or for setting and retrieving small production strings. Modern load capacity is significantly above that of early units: maximum pulling forces up to 600,000 lb and snubbing forces up to 300,000 lb. Larger units can handle 9⅝-in. casing (Table 5-18).

TABLE 5-18. Hydraulic Workover Jack Capacities (Courville and Maddox, 1993)

Specifications of Typical Hydraulic Workover Jacks				
Bore Size	*Maximum Pulling Force*	*Maximum Snub Force*	*Maximum Pipe Size*	*Jack Weight*
4 1/16"	*120,000 lbs*	*60,000 lbs*	*2 7/8"*	*7,000 lbs*
7 1/16"	*200,000 lbs*	*100,000 lbs*	*5 1/2"*	*9,000 lbs*
11"	*600,000 lbs*	*300,000 lbs*	*9 5/8"*	*16,000 lbs*

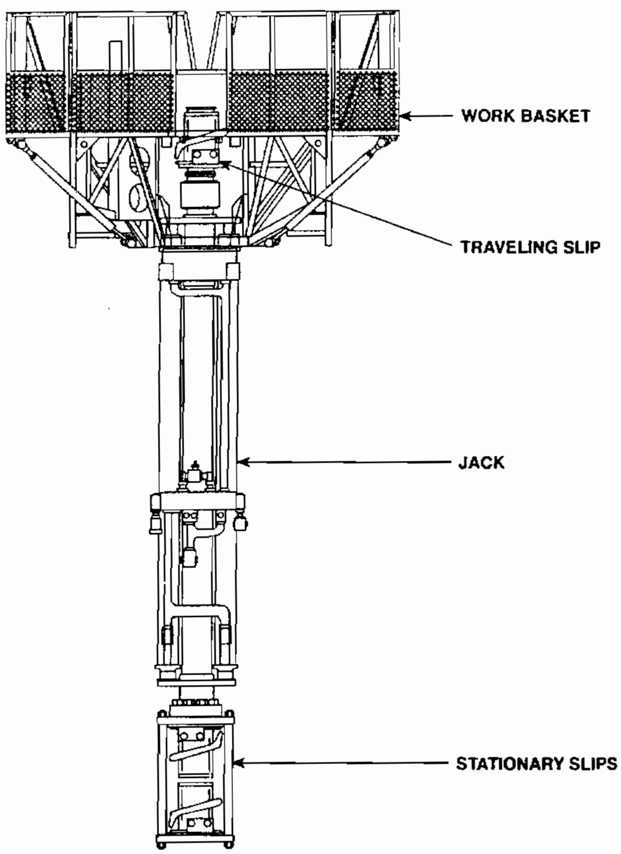


Figure 5-43. Hydraulic Workover Unit Pipe Handling System (Courville and Maddox, 1993)

Pipe-handling systems on hydraulic workover units consist of a set of opposing stationary slips, a hydraulic jack, a traveling slip bowl, a small winch and gin pole combination, and related workbasket and controls (Figure 5-43). Forces resulting from pipe weight and workover unit weight are transferred to the wellhead. No additional load-bearing structure is necessary.

Pressure control can be maintained by either a conventional approach using drilling mud and normal BOPs, or by additional BOPs configured to allow pipe movement under pressure (Figure 5-44).

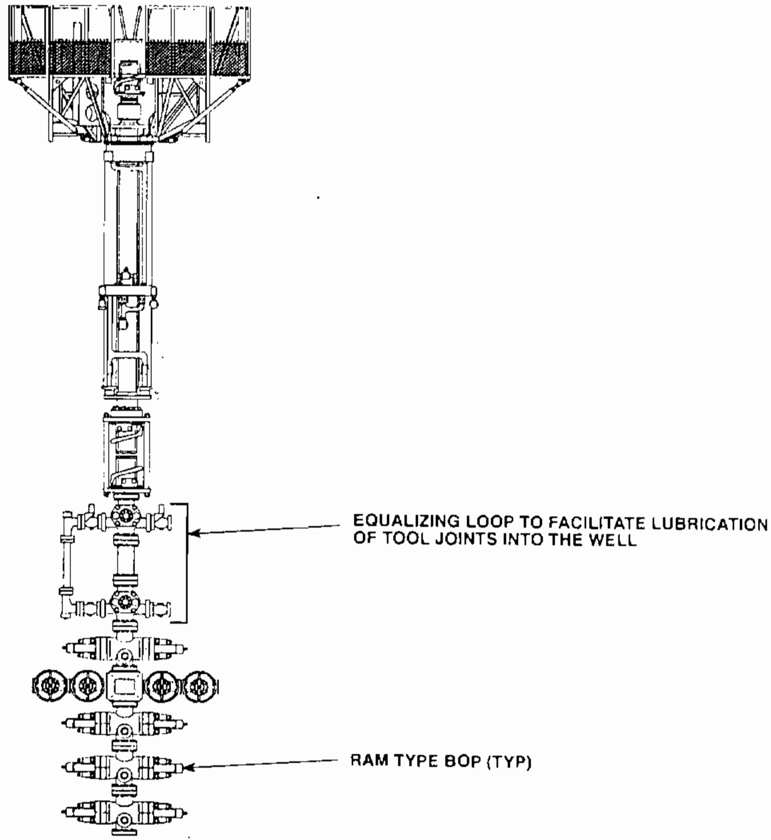


Figure 5-44. Hydraulic Unit Rigged to Allow Pipe Movement Under Pressure
(Courville and Maddox, 1993)

The standard pressure seal for coiled-tubing operations is the stuffing box. Halliburton's coiled-tubing pressure system design for work on live wells (Figure 5-45) uses an annular BOP arranged so that the same BOPs can be used by both the hydraulic-workover rig and coiled-tubing rig.

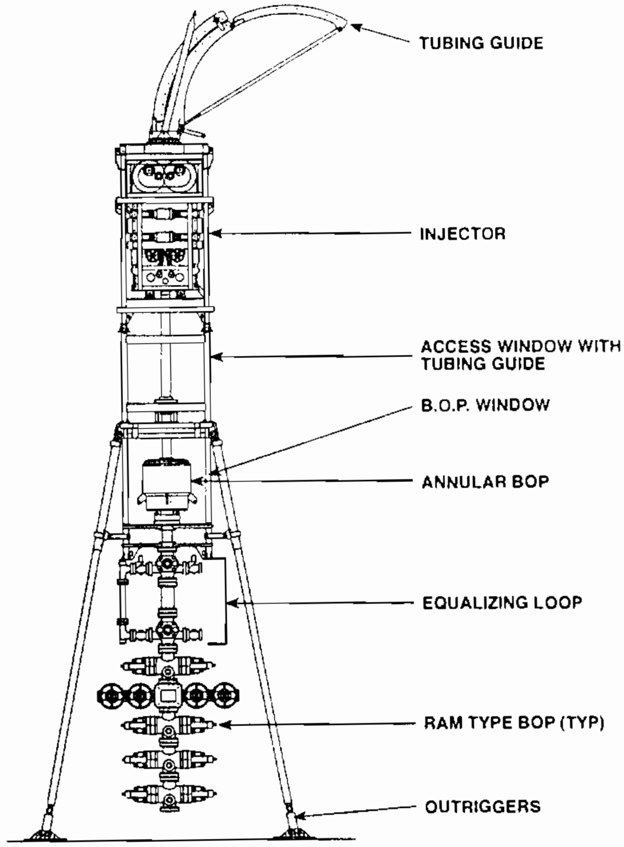


Figure 5-45. Coiled-Tubing Injector and BOPs for Drilling Live Wells (Courville and Maddox, 1993)

A general arrangement of the coiled-tubing drilling rig and equipment is shown in Figure 5-46.

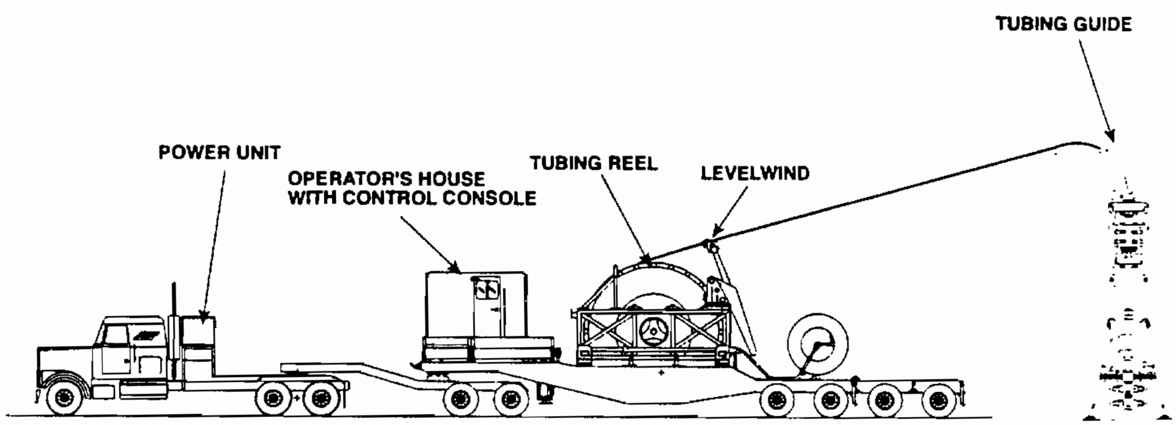


Figure 5-46. Coiled-Tubing Rig Set-Up for Drilling Operations (Courville and Maddox, 1993)

In a field application, the first operation is to drive the surface pipe into the ground with typical impact-type driving equipment. Drilling is then initiated with the coiled-tubing rig and a downhole motor. After the first casing set-depth is reached, the coiled tubing is pulled out of hole and the coiled-tubing unit is rigged down.

The hydraulic-workover unit is then rigged onto the wellhead, and the string of casing is run and cemented. The workover unit can rotate and reciprocate the casing string to ensure a good cement bond. Next, the hydraulic workover unit is replaced with the coiled-tubing unit, and drilling is continued.

The completion string is run after drilling is complete. Casing or liner can be run by the hydraulic workover unit. Another option is to run a coiled completion with the coiled-tubing rig.

5.2.9 Petro-Canada (Balanced Drilling with Coiled Tubing)

Petro-Canada Inc. (MacDonald and Crombie, 1994) investigated the use of foam to maintain near-balanced conditions for coiled-tubing drilling operations. Calculations, computer modeling, and field tests were conducted in conjunction with Nowsco Well Service to determine whether the benefits of near-balanced drilling could be economically obtained.

The industry has recognized that horizontal re-entries into low-pressure reservoirs represent an area of great opportunity for coiled-tubing drilling. Many have advocated the advantages of underbalanced drilling for these projects. To justify using underbalanced techniques, the costs for overbalanced drilling and any necessary clean-up costs should exceed underbalanced costs.

A third option is balanced drilling. The principal advantage for balanced as compared to underbalanced is less wellbore fluids are produced during the operation, with a consequent reduction in danger to personnel and equipment. Petro-Canada and Nowsco sought to test techniques for balanced drilling and investigate the economic advantages/disadvantages of this approach.

Test conditions were designated as reservoirs with BHPs equivalent to 4.2 ppg (500 kg/m^3). Computer runs (Table 5-19) were conducted to determine the utility of nitrified water in these conditions. Annular velocities of 3 ft/sec (0.9 m/sec) were required.

TABLE 5-19. Computer Runs with Nitrified Water (MacDonald and Crombie, 1994)

Circulation Water (m^3/min)	N^2 Rates (m^3/min)	Gooseneck Pressure (MPa)	Annulus Backpressure (MPa)	Liquid Velocity (m/min)
0.08	30	8.1	0.50	0.40
0.08	32	8.5	0.57	0.41
0.08	34	8.9	0.63	0.42
0.08	36	9.3	0.70	0.43
0.08	38	9.7	0.76	0.45
0.12	30	8.8	0.41	0.56
0.12	32	9.2	0.48	0.58
0.12	34	9.6	0.54	0.60
0.12	36	10.1	0.61	0.62
0.12	38	10.5	0.67	0.64
0.16	30	9.6	0.32	0.72
0.16	32	10.1	0.39	0.74
0.16	34	10.5	0.45	0.77
0.16	36	11.0	0.51	0.79
0.16	38	11.4	0.57	0.82
0.20	30	10.5	0.22	0.86
0.20	32	11.0	0.28	0.89
0.20	34	11.5	0.34	0.92
0.20	36	12.0	0.40	0.95
0.20	38	12.5	0.46	0.98

Modeling results with nitrified water suggested that fluid and gas rates would need to be higher than was desired. Additionally, operating range for surface annular pressure was more narrow than desired (Figure 5-47).

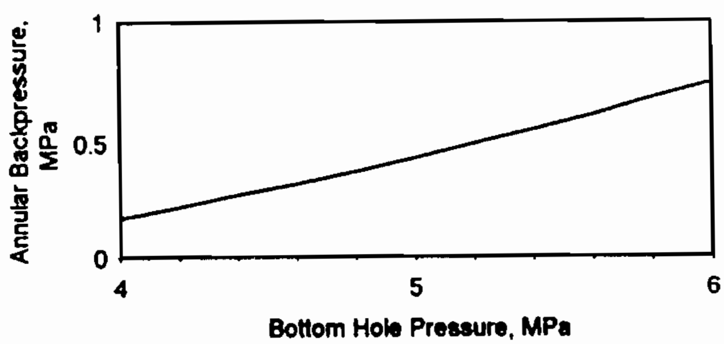


Figure 5-47. Annular Pressure Vs. BHP with Nitrified Water (MacDonald and Crombie, 1994)

As a result of the limitations with nitrified water as a drilling fluid, the use of foam was investigated. Calculations showed an increased annular pressure operating range (Figure 5-48) and lower liquid and gas requirements.

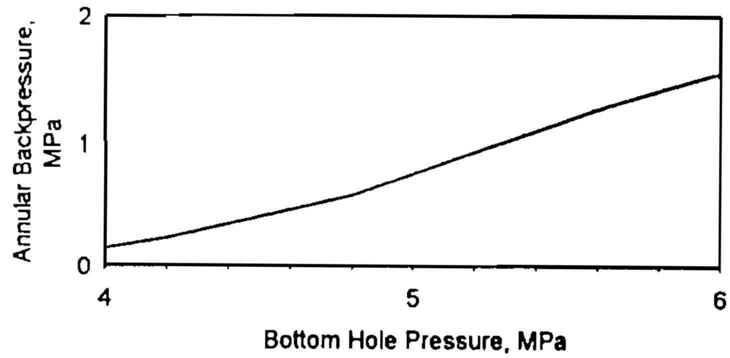


Figure 5-48. Annular Pressure vs. BHP with Foam (MacDonald and Crombie, 1994)

Petro-Canada and Nowsco considered a large range of fluid and gas combinations. One of the most limiting parameters was coiled-tubing diameter. Most drilling operations are conducted with 2-in. (or less) coiled tubing, and this choice has a significant impact on foam hydraulics design.

Equipment was designed for balanced foam drilling with coiled tubing (Figure 5-49). Three concepts were required to be feasible before this balanced drilling system could be pursued. Firstly, monitoring of downhole pressures must be possible in real time. Next, the surface equipment should be able to handle well fluids and gases. Lastly, the model design had to show good agreement with results.

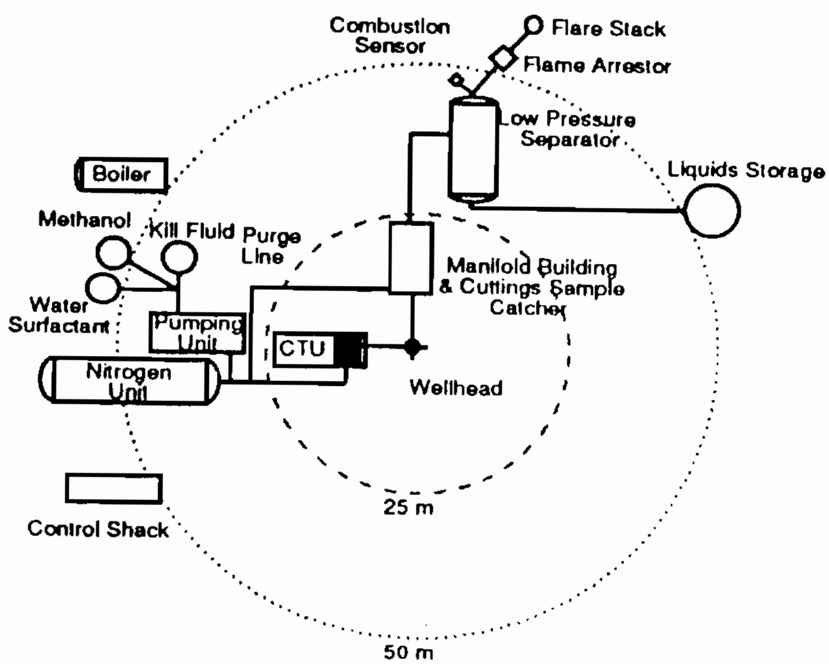


Figure 5-49. Equipment for Balanced Drilling with Foam (MacDonald and Crombie, 1994)

Two wells were used as test cases for this system, one with 2.4 ppg equivalent reservoir pressure and one with 3.5 ppg (Table 5-20).

TABLE 5-20. Test Wells for Balanced Foam System (MacDonald and Crombie, 1994)

WELL	DEPTH (m)	HOLE SIZE (mm)	BHP (MPa)	BALANCE DENSITY (Kg/m^3)
Shallow Gas	460-510	98	1.9	420
Oil Horizontal	1780 TVD 1840 MD	120	5.1	290

Downhole pressure sensors were situated in an assembly positioned between the coiled-tubing connector and drilling BHA (Figure 5-50). Both annulus and coil pressure were measured at 1-sec intervals.

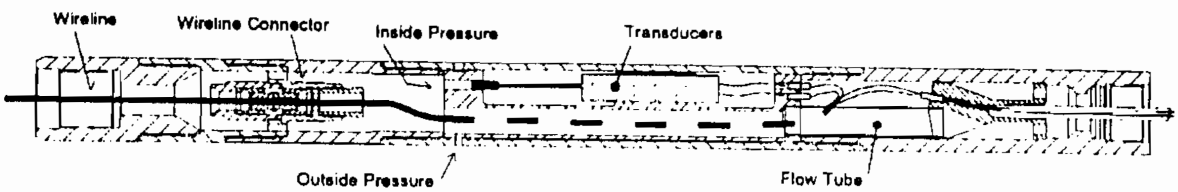


Figure 5-50. Pressure Sensor Sub (MacDonald and Crombie, 1994)

Results in the test wells showed the importance of monitoring downhole pressure. Figure 5-51 compares pressure measured downhole inside the coil to that at the surface during motor stalling.

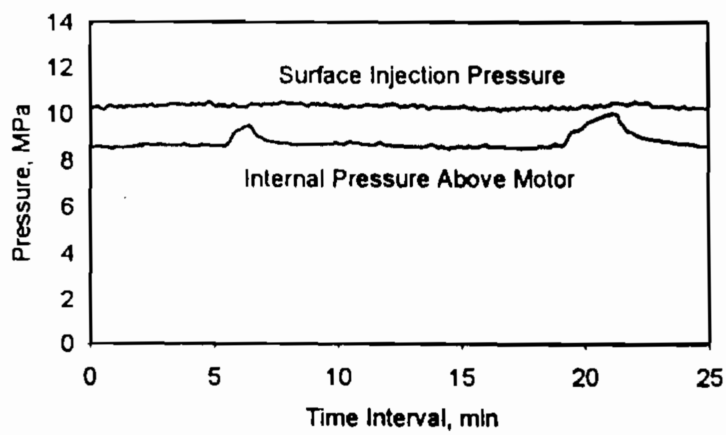


Figure 5-51. Downhole Vs. Surface Pressure (MacDonald and Crombie, 1994)

Predicted pressure above the motor compared favorably with measurements for the test wells (Figure 5-52). Motor stalls, indicated as spikes in the measured data, were not accounted for in the calculation.

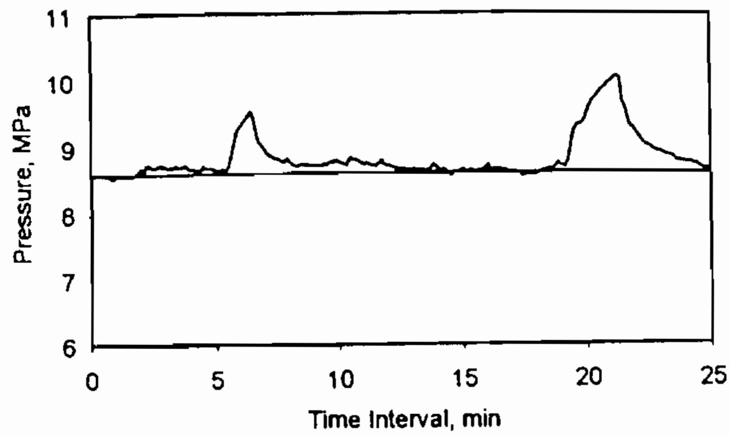


Figure 5-52. Measured Vs. Calculated Downhole Pressure (MacDonald and Crombie, 1994)

A closed system was required for foam returns (Figure 5-53). Mechanical degassing was used to break down the foam. A polyurethane hydrocyclone was installed inside a low-pressure separator and a defoamer sprayer was added at the top of the unit. Additional new components included a cuttings sample catcher, gas analyzers and a flame arrester.

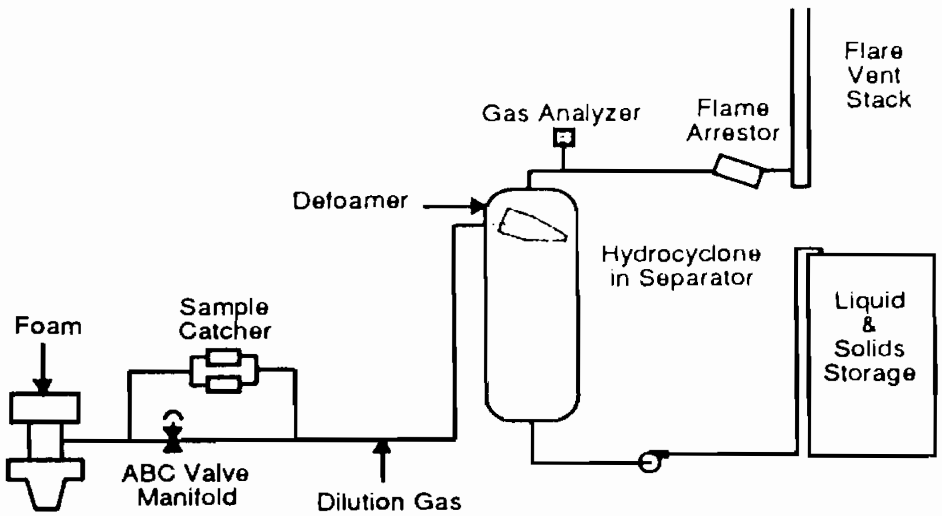


Figure 5-53. Foam Treatment Equipment (MacDonald and Crombie, 1994)

Test results showed that balanced conditions could be maintained in low-pressure reservoirs with foam circulated with coiled tubing. Petro-Canada and Nowsco suggest that additional consideration should be given to the benefits of drilling near balance. They also note that foam stability and rheology need more evaluation for directional drilling applications.

5.2.10 Petrolphysics (Coiled-Tubing-Jetted Radials)

Petrolphysics (Dickinson, 1994 and Dickinson et al., 1993) described the operation of and field results with a coiled-tubing jetting system to drill multiple short (25-150 ft) radials in one or more layers of a producing zone (Figure 5-54). Experience in both light- and heavy-oil applications has shown an average production improvement of 2 to 4 times conventional.

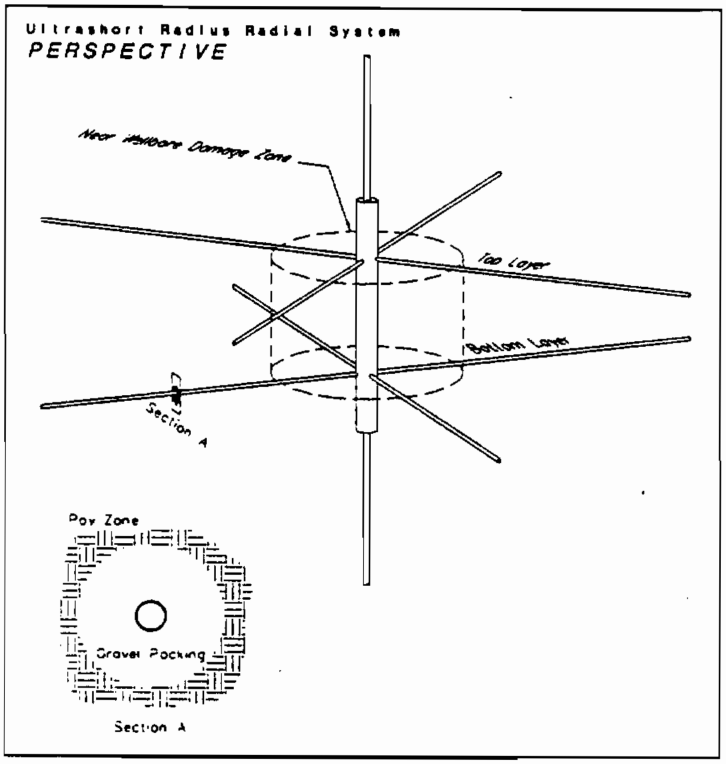


Figure 5-54. Jetted Radials in Multiple Layers (Dickinson et al., 1993)

Formation damage can be overcome through wellbore stimulation (acidizing or fracturing) or by drilling horizontal laterals past the zone. Production improvement with jetted radials can be significant in a well with formation damage (Table 5-21).

TABLE 5-21. Production Improvement from Jetted Radials in Damaged Vertical Well (Dickinson et al., 1993)

Formation Thickness, ft	Damaged Zone, ft	Length of Radials, ft	Jh/Jv for Number of Layers of Radials			
			1	2	3	4
25	6.25	25	14.4			
		50	20.4			
		75	24.6			
		100	27.4			
25	12.50	25	13.7			
		50	21.6			
		75	27.4			
		100	31.7			
100	6.25	25	5.8	10.0	12.5	14.4
		50	10.3	15.6	16.9	20.4
		75	14.0	20.5	23.5	24.6
		100	17.3	24.5	27.2	27.4
100	12.50	25	5.7	9.5	12.0	13.7
		50	10.8	17.2	20.1	21.8
		75	15.5	22.9	26.2	27.4
		100	19.7	27.5	31.2	31.7

Note:
K/K-damaged = 25
R-wellbore = 0.49 feet
R-damaged = 6.25 feet
R-outter boundary = 500 feet

Petrolphysics described two systems for jetting short laterals. The Ultrashort Radius Radial System (Figure 5-55) has been used in several fields around the world. The system uses a 100–200 ft length of 1¼-in. coiled tubing with a special conical fluid jet. Radials are jetted from a 2-ft diameter by 10-ft high window. High-velocity water particles (8000–10,000 psi) jet a 2–4 in. borehole.

Gravel packing is used to complete the radials in unconsolidated formations. The ultrashort radius allows produced oil to flow by gravity directly to a conventional pump (Figure 5-56).

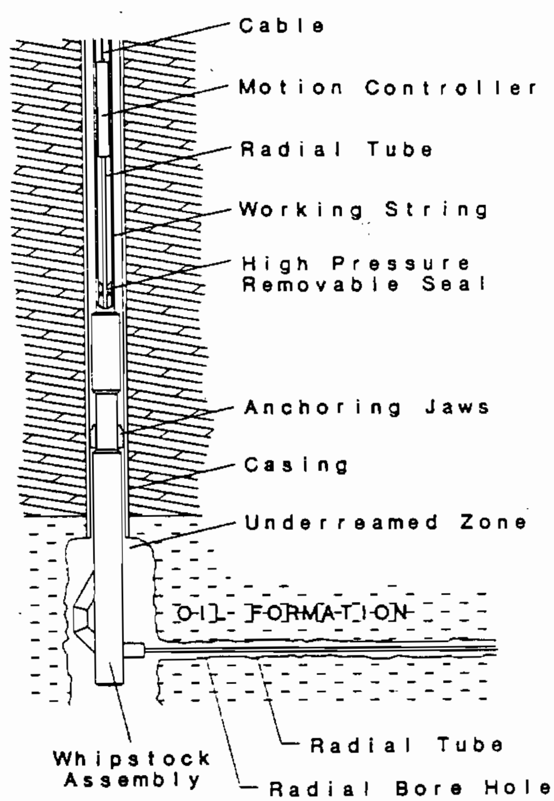


Figure 5-55. Petrolphysics' Ultrashort Radius Radial System (Dickinson et al., 1993)

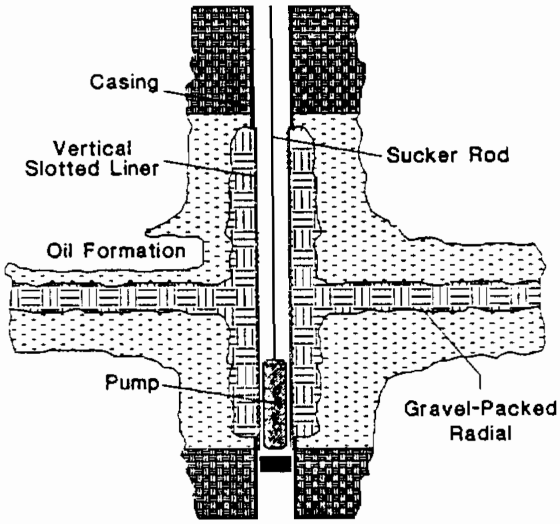


Figure 5-56. Gravel-Pack Completion of Ultrashort Radius Radial (Dickinson et al., 1993)

Another jetting system, the Quick Radial System (Figure 5-57), is under development. This system requires a workover unit to orient a whipstock. All other operations can be accomplished with a coiled-tubing rig. An advantage of this system is the use of pressures (3500–5000 psi) lower than with the Ultra-short Radius Radial System.

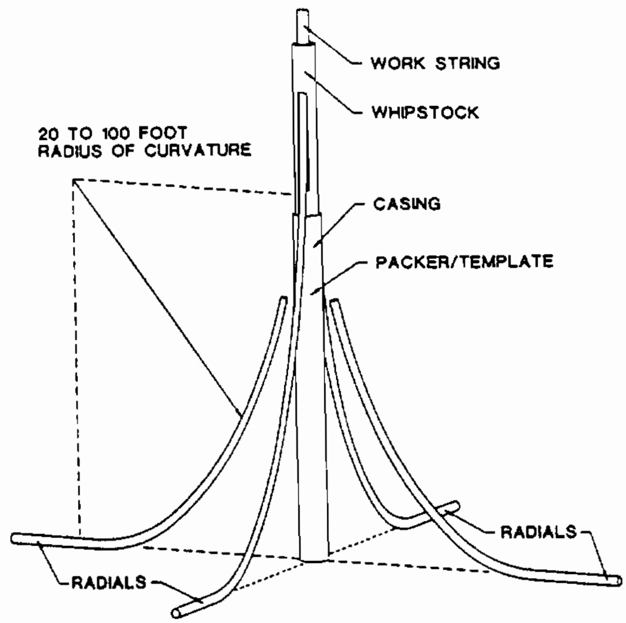
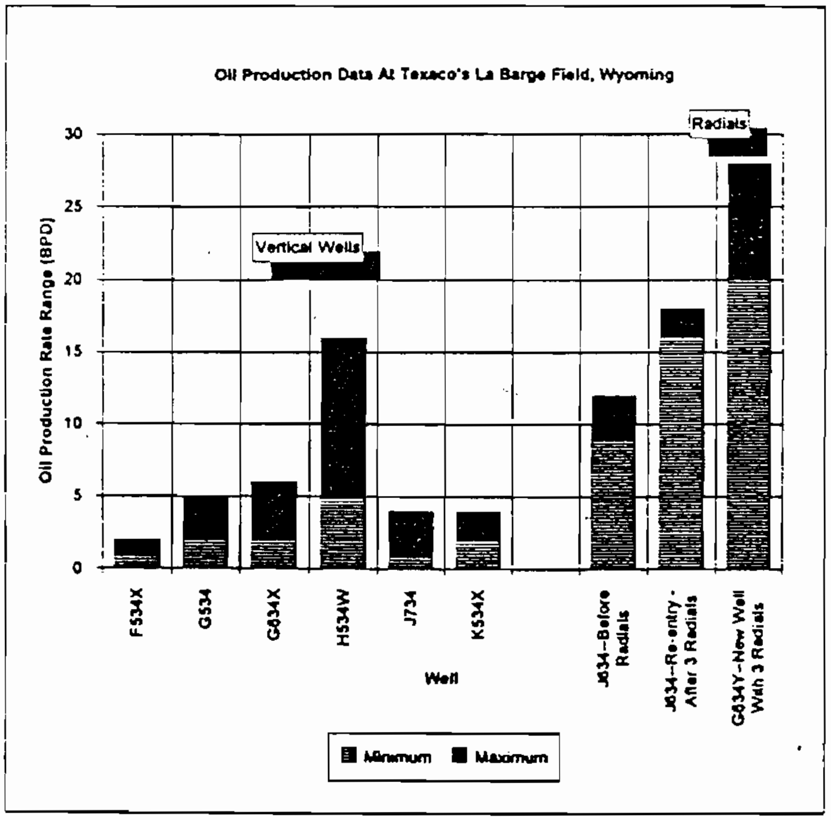


Figure 5-57. Quick Radial System (Dickinson et al., 1993)

Field results with the Ultrashort Radius Radial System are presented in Figure 5-58. These data are from wells in Texaco's LaBarge Field in Wyoming. Well J634 is a re-entry with three radials ranging from 54–70 ft. Production data are shown before and after radial drilling. Well G634Y is a new well with three radials from 68–151 ft in length.



Wells	Water Production	Oil Production Declining Rate
F534X	Nearly Clean	
G534	Declining from 200 bwpd to 36 bwpd	
G634X	Declining from 160 to 25 bwpd	
H534W	Fluctuating from 1 bwpd to 2 bwpd	
J734	Fluctuating from 10 bwpd to 100 bwpd	
K534X	Fluctuating from 30 bwpd to 80 bwpd	
J634—Before radials	Fluctuating from 2 bwpd to 5 bwpd	Declining 63% over 10 months
J634—Entry after 3 radials	Nearly Clean	Declining 33% over 18 months
G634Y—New well with 3 radials	Increasing to 7 bwpd	Declining 49% over 18 months

Figure 5-58. Production From Texaco Wells with Multiple Radials (Dickinson et al., 1993)

Overall trends show about a doubling of oil production rate and a halving of the rate of decline.

5.2.11 Shell Research B.V./INTEQ (Window-Cutting Systems)

Shell Research and Baker Hughes INTEQ (Faure et al., 1994) described progress in the ongoing development of a one-trip window cutting system that can be deployed on coiled tubing. Early coiled-tubing re-entries have required a conventional rig to cut the window. For coiled-tubing drilling to become economic, a window-cutting system for coiled tubing is needed. Shell and INTEQ developed and tested a prototype window-cutting system that required three runs for milling. Development continues to reduce the number of milling runs to one.

In re-entry applications, cutting a window in the casing can be an option to section milling. The most important innovation in window-cutting techniques are systems that allow setting the packer and whipstock, and milling the window in one run. Another approach is to set the packer on wireline or drill pipe, then run the whipstock and milling assembly (Figure 5-59). This modified approach addresses concerns about premature setting of the packer.

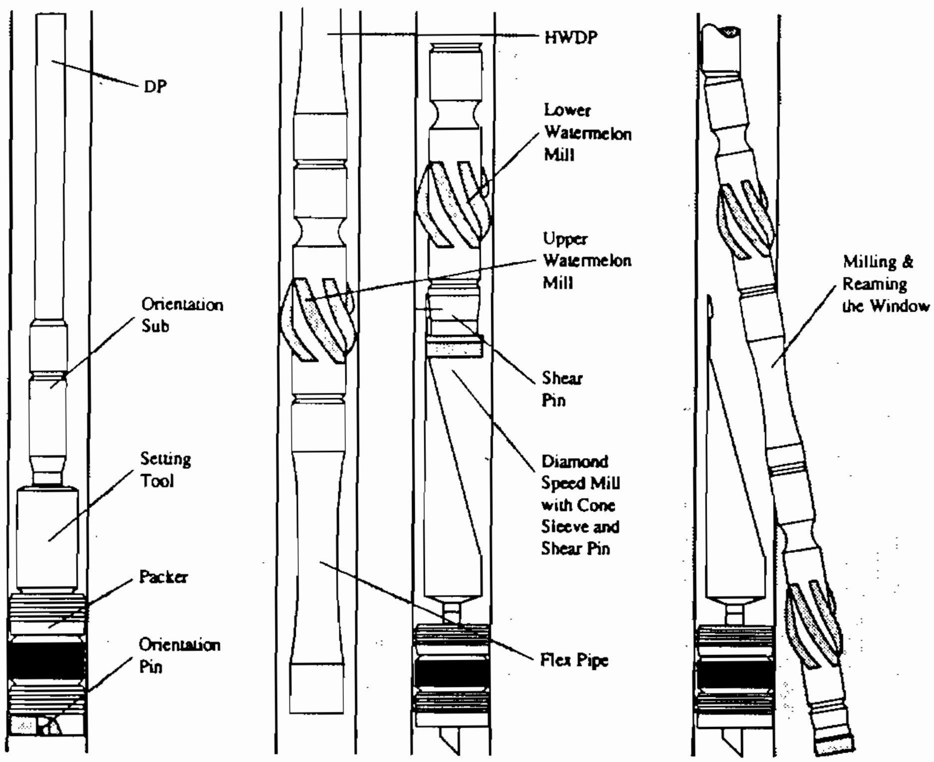


Figure 5-59. Two-Trip Window Cutting in Slim Hole (Faure et al., 1994)

Coiled-tubing systems hold promise for benefits in underbalanced and through-tubing re-entries. With this method, there is a need for an assembly that does not require rotation. Shell's system combines mud motors with hydraulic thrusters for control of WOB.

A series of laboratory tests was conducted toward the development of a new window-cutting system (Figure 5-60). The performance characteristics of diamond speed mills and tungsten-carbide mills were compared. Early results showed that tungsten-carbide mills were faster than diamond; however, stalling problems were much less severe with diamond.

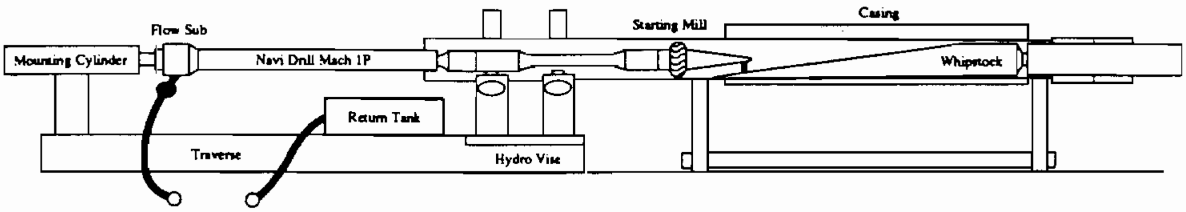


Figure 5-60. Laboratory Testing of Slim-Hole Window-Cutting System (Faure et al., 1994)

A full-scale field trial was conducted on a re-entry in Germany. Objectives included cutting a 5⅞-in. window in 6⅝-in. casing, drilling a 4¾-in. hole along a 330-ft radius, and drilling a short horizontal section (100-130 ft). Three BHAs were used (Table 5-22). Each BHA incorporated a modified tungsten-carbide mill.

TABLE 5-22. BHAs for Cutting Window on Coiled Tubing (Faure et al., 1994)

Starting Mill Assembly	Window Mill Assembly	Reaming Assembly
5⅞" Starting mill	5⅞" Window Mill	5⅞" Taper Mill
3½" Flex pipe	3½" Flex pipe	5⅞" Watermelon mill
4¾" Navi-Drill	4¾" Navi-Drill	3½" Flex pipe
2 x 5⅞" Chip Catcher	2 x 5⅞" Chip Catcher	4¾" Navi-Drill
3¾" Release tool	3¾" Release tool	2 x 5⅞" Chip Catcher
3¾" Lower quick connect	3¾" Lower quick connect	3¾" Release tool
3¾" Upper quick connect	3¾" Upper quick connect	3¾" Lower quick connect
3½" Grapple connector	3½" Grapple connector	3¾" Upper quick connect
		3½" Grapple connector

The tools performed well with few problems. One fish was successfully caught on the first attempt. Times to complete various components of the operation are shown in Table 5-22.

TABLE 5-22. Operational Times for Cutting Window on Coiled Tubing (Faure et al., 1994)

ACTIVITY	TOTAL TIME	COMMENTS
Well Preparation - casing scraper - CCL/CBL/gyro	23 hours	Remove paraffin, circulate hot water
CCL/CBL/Gyro Survey	7 hours	
Set Packer/Gyro Survey	8 hours	
Set Whipstock	6 hours	

CUT WINDOW		TOTAL TIME	MILLING TIME	COMMENTS
BHA #1	Starting mill	8 hours	¾ hour	4-hour rig maintenance
BHA #2	Window mill	9¾ hours	3¼ hour	plus 5m formation
BHA #3	Reaming assembly	15½ hours	7½ hours	6 hours circulate
TOTAL		33¼ hours	11 hours	

Following these successful field trials, Shell and INTEQ plan to continue development in an effort to design a reliable through-tubing coiled-tubing window-cutting system.

5.2.12 Sun Drilling Products (Copolymer Beads for Friction Reduction)

Sun Drilling Products (Brookey et al., 1994) described the potential use of copolymer beads for friction reduction in coiled-tubing drilling and workover operations. Friction reduction is accomplished by introducing beads between the coiled tubing and borehole wall. Mechanisms of friction reduction include decreasing capillary forces by increasing the distance between the coiled tubing and borehole, and the effect of rolling bearings between the string and borehole.

Sun Drilling Products' copolymer beads are a spherical (Figure 5-61) free-flowing, inert solid. Particle size ranges from 260-550 μm (0.0009-0.0018 in.). Beads are of low density (1.13 SG) with compressive strength of 11-16 ksi. Their spherical shape ensures that they will continue to provide lubricity while remaining nonabrasive, and that they will not plug the formation.

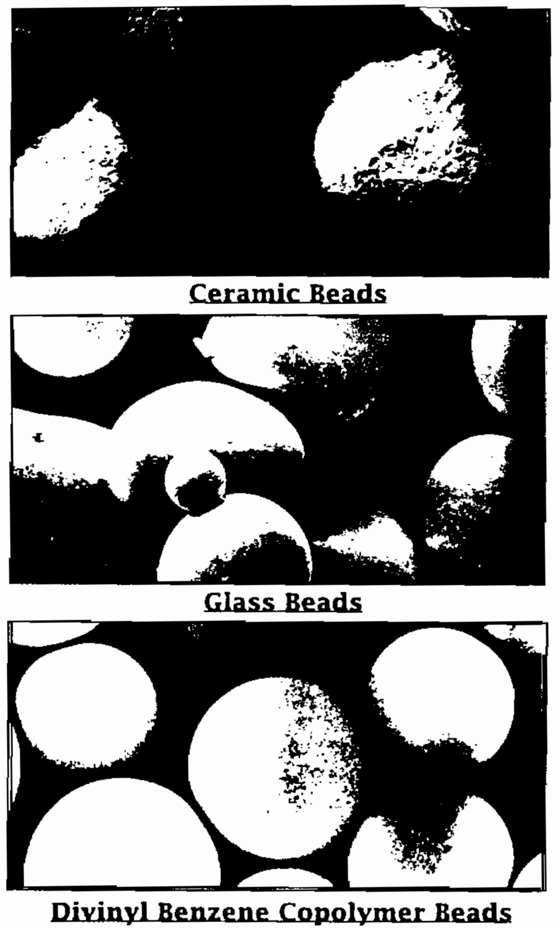


Figure 5-61. Electron Micrographs of Copolymer Beads (Brookey et al., 1994)

Friction problems are normally more pronounced in operations in horizontal wells. This is due to the increased contact area and normal forces. Various techniques can be used to place the beads across the problem zones. Most often, sweeps are used to pave the lateral and build section with beads (Figure 5-62). Beads normally settle to the low side of the hole and are worked into the wallcake by string reciprocation.

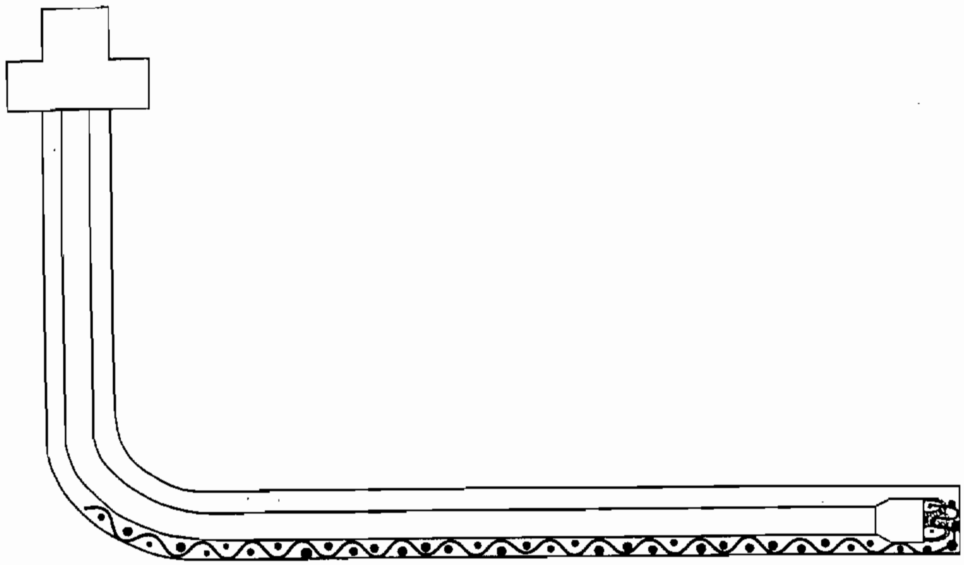


Figure 5-62. Bead Sweeps to Treat Wellbore (Brookey et al., 1994)

If friction problems are isolated to specific sections along the wellbore, pills with beads can be spotted across the problem zone, circulation stopped, and the string reciprocated to work the beads into the wall.

Under some conditions, operations are conducted with full or partial lost returns. To reduce friction in these applications, pills with beads can be pumped down the annulus (Figure 5-63) to place them across the problem zones.

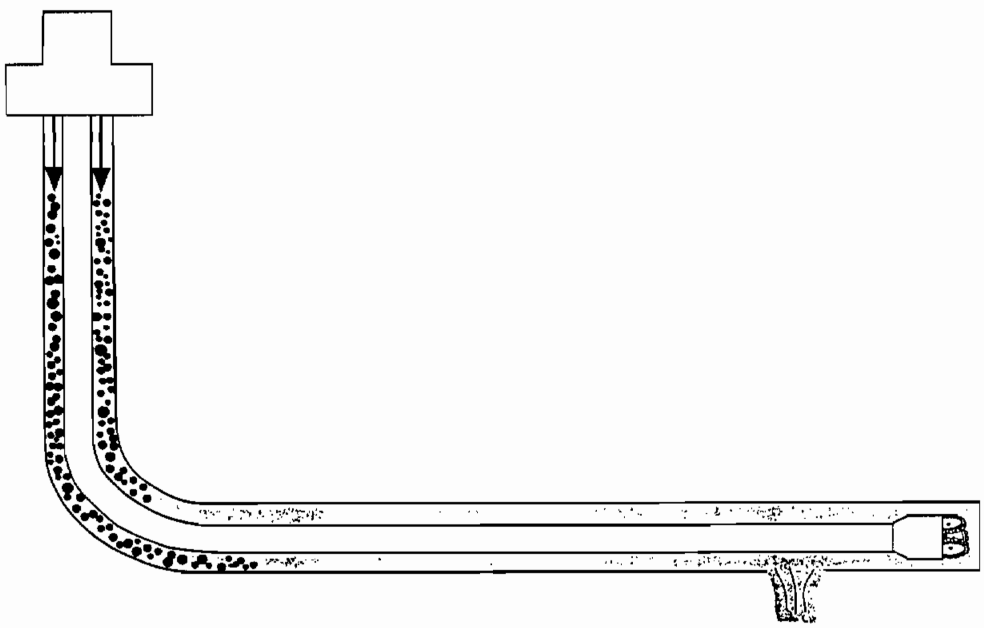


Figure 5-63. Spotting Beads Down the Annulus (Brookey et al., 1994)

These beads have been used in several areas of the world to reduce friction in conventional horizontal wells. In one Austin Chalk well, pick-up weight was reduced 30,000 lb (from 220,000 to 190,000 lb) after beads were placed across the open-hole interval. ROP increased from 4 ft/hr before beads to 25 ft/hr after beads were placed along the wellbore.

5.3 CASE HISTORIES

5.3.1 <u>ARCO E&P Technology (Slaughter Field)</u>

ARCO E&P (Hightower et al., 1993) used coiled tubing to drill a successful sidetrack of a well in the Slaughter Field in West Texas. Several aspects of the job represent the first time coiled tubing was used in these procedures. These include:

- Setting a whipstock in casing
- Milling a window
- Using MWD
- Using a pressure-activated orientation tool
- Using an autodriller system to maintain WOB

Although problems prevented the well from being drilled as planned, project results and well production were successful.

The original wellbore (H.T. Boyd 59X) was drilled to 5245 TD in 1989. Despite acid stimulation and fracture treatment, original production was poor (64 BFPD with 94% water cut). ARCO planned to sidetrack the well, build angle at a rate of 15°/100 ft, and drill about 500 ft of new horizontal section (Figure 5-64). The 3¾-in. borehole was to be completed open-hole and produced on rod pump.

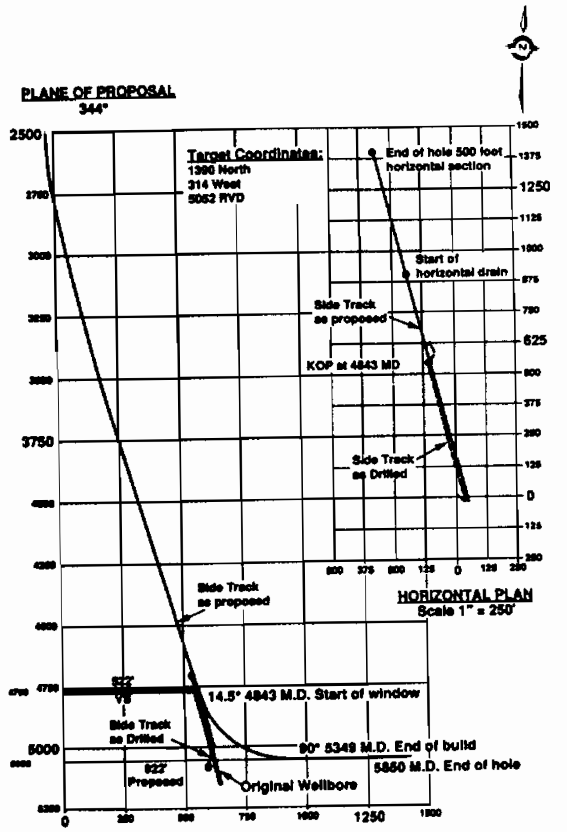


Figure 5-64. ARCO Re-entry Well Plan (Hightower et al., 1993)

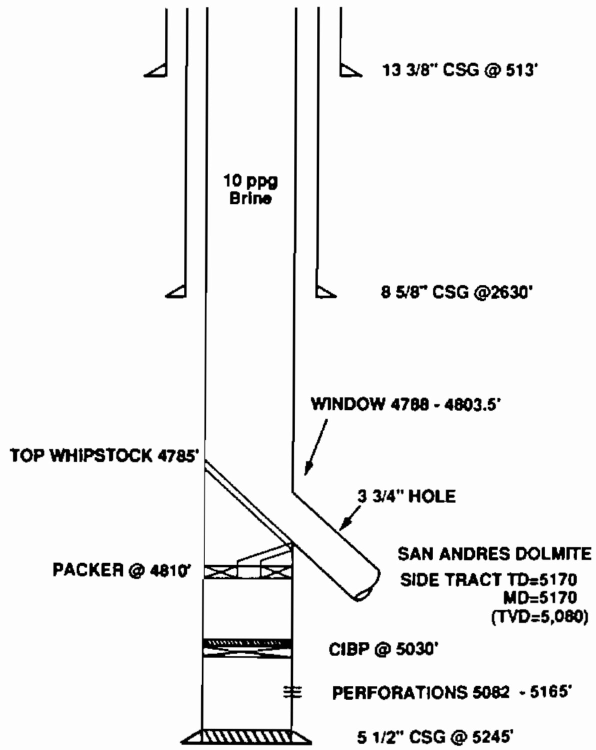


Figure 5-65. ARCO Re-entry Well Schematic (Hightower et al., 1993)

Wellbore inclination was about 14° at the planned kick-off depth (Figure 5-65).

Drilling system design was based on 1¾ x 0.156-in. 70 ksi coiled tubing. The orienting tool was hydraulically controlled, adjusting about 45° for each pump on/off cycle. The wellhead arrangement for drilling operations is shown in Figure 5-66. A small substructure was used to provide a work platform 11 ft above ground level.

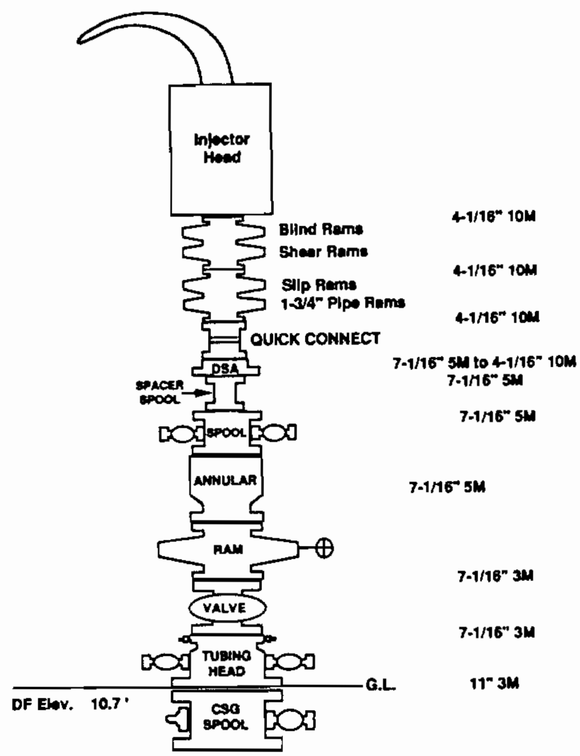


Figure 5-66. Wellhead Equipment (Hightower et al., 1993)

Prior to bringing the coiled-tubing rig on location, wireline was used to set a permanent packer with orientation lug. The whipstock was then run on coiled tubing and stung into the packer. A window was milled (Figure 5-67) and several feet of new hole drilled.

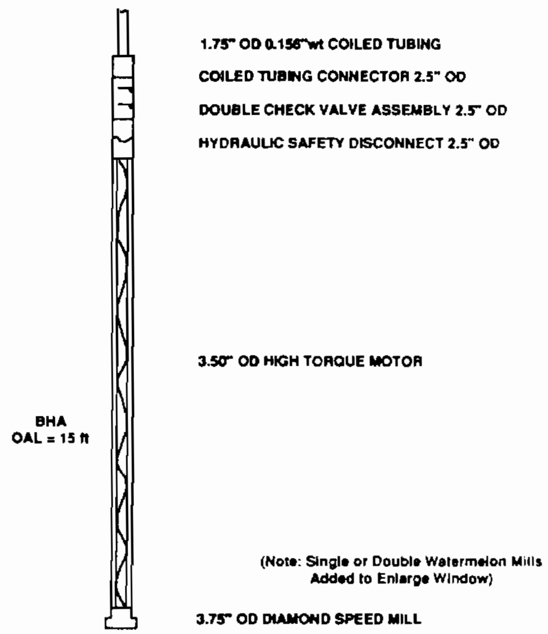


Figure 5-67. Typical Window Milling BHA (Hightower et al., 1993)

The drilling BHA (Figure 5-68) was then run in with a 3¾-in. TSD bit. A total of 366 ft of new hole was drilled.

Significant problems were encountered in trying to build angle. Angle remained relatively constant despite several trips for new bits, mills, assemblies, etc. (Table 5-23). Later, ARCO discovered that the program used to process the MWD data was flawed, resulting in false indications of tool-face angle.

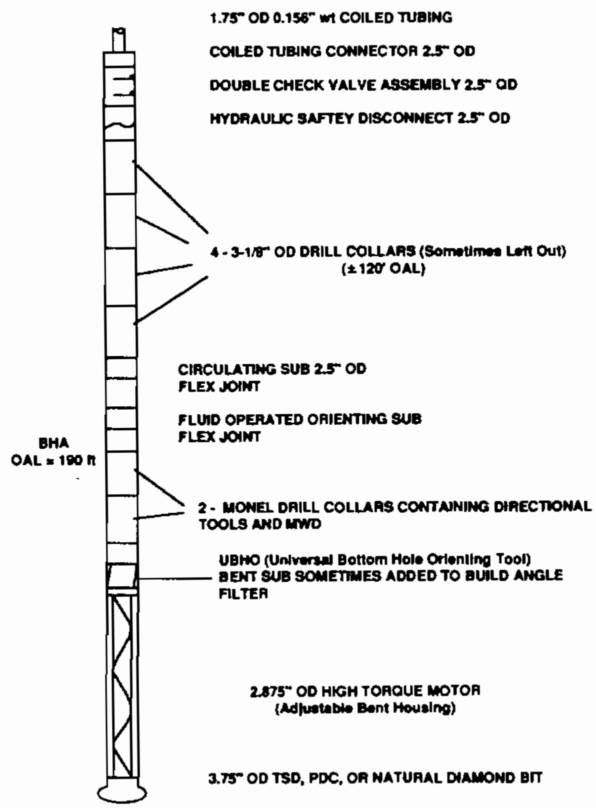


Figure 5-68. Typical Coiled-Tubing Drilling BHA (Hightower et al., 1993)

TABLE 5-23. Summary of Drilling BHAs (Hightower et al., 1993)

BHA NO	3.75" BIT TYPE	MOTOR	HOUSING	BENT SUB	COLLARS	FOOTAGE	ROP	REMARKS
1	DSM	3.500" HT	Straight	None	None	NA	NA	Window
2	DSM w/ single WMM	3.500" HT	Straight	None	None	NA	NA	Window
3	DSM w/ double WMM	3.500" HT	Straight	None	None	NA	NA	Window
4	DSM w/ double WMM	3.500" HT	Straight	None	None	16 ft	5.8 FPH	Window/ FM
5	TSD	2.875" HT	1.9 °	None	None	21 ft	9.1 FPH	FM
6	DSM	2.875" HT	Straight	None	None	None	NA	Stop @ window
7	DSM	2.875" HS	1.4 °	None	None	4 ft	16 FPH	Cut into casing
8	TSD	2.875" HS	1.4 °	None	None	19 ft	NA	Inside casing
9	PDC	2.875" HS	1.4 °	None	None	26 ft	NA	Inside casing
10	nozzle (2.125 ")	None	NA	None	None	NA	NA	Cementing
11	DSM	3.500" HT	Straight	None	None	None	NA	Stop @ WS
12	Tapered mill	3.500" HT	Straight	None	None	None	NA	Stop @ WS
13	Round nose TSD	3.500" HT	Straight	None	None	None	NA	Stop @ WS
14	DSM w/ single WMM	3.500" HT	Straight	None	None	26 ft	NA	CO to TOC
15	Sidetrack bit	2.875" HT	2 °	None	124'-3-1/8"	12 ft	1.3 FPH	15.4 ° Incl
16	TSD	2.875" HT	2 °	None	124'-3-1/8"	53 ft	3.7 FPH	12.3 ° Incl
17	PDC	2.875" HT	2 °	None	124'-3-1/8"	16 ft	1.5 FPH	13.6 ° Incl
18	Natural diamond bit	2.875" HS	1.25 °	None	124'-3-1/8"	55 ft	2.7 FPH	19.2 ° Incl
19	Exposed diamond bit	2.875" HS	1.25 °	None	None	20 ft	3.2 FPH	19.7 ° Incl
20	Natural diamond bit	2.875" HS	2 °	None	None	41 ft	6.8 FPH	16.6 ° Incl
21	Ballaset diamond bit	2.875" HS	2 °	1.25 °	124'-3-1/8"	74 ft	4.0 FPH	8.3 ° Incl
22	Ballaset diamond bit	2.875" HS	1.25 °	None	None	69 ft	13.0 FPH	11.1 ° Incl
23	Nozzle	None	NA	None	None	NA	NA	Circulation
DSM = diamond speed mill, WMM = watermelon mill, TSD = thermally stable diamond, PDC = polycrystalline diamond compact,								
HT = high torque, HS = high speed, WS = whipstock, CO = cleanout, TOC = top of cement, FM = formation, FPH = feet / hour								

ARCO found that the MWD tools performed well, with readings accurately confirmed by gyro surveys. The orienting tool also performed well.

The use of the autodriller was also counted a success. Sensitivity of the system to maintenance of WOB was judged as better than an experienced coiled-tubing operator.

Fatigue was found to be an important element requiring careful tracking in these operations. As a result of many trips and extended operations at depth, about 80% of coiled-tubing fatigue life was used for this project (Figure 5-69).

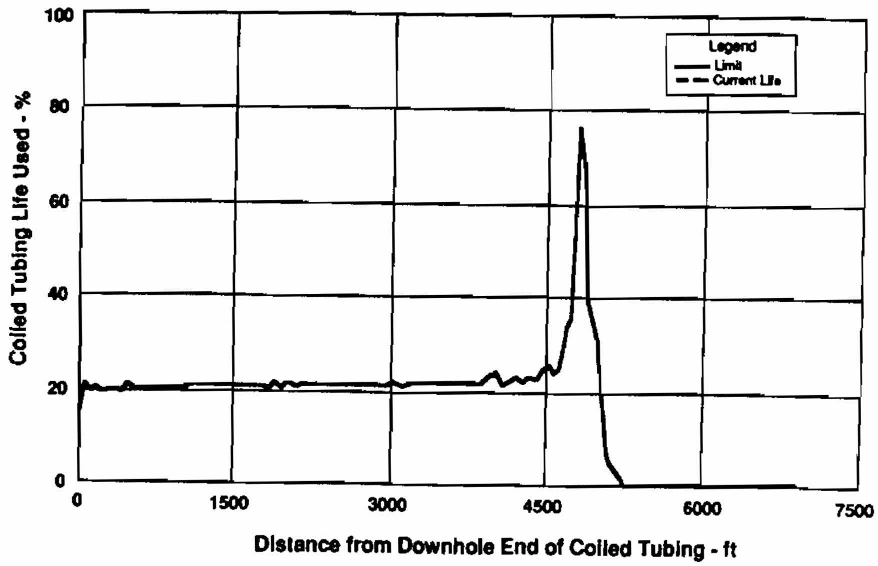


Figure 5-69. Coiled-Tubing Life for Drilling Project (Hightower et al., 1993)

ARCO estimated that the overall cost of this operation was 50% greater than for a conventional workover rig. However, they believe that, in the absence of the software bug, costs would have been competitive with conventional, and that operations could have been completed in 10 days, rather than 17.

ARCO's experience demonstrated that drilling with coiled tubing is here to stay, and that the tools and technologies required are available and improving steadily.

5.3.2 Berry Petroleum (McKittrick Field)

Berry Petroleum and Schlumberger Dowell (Love et al., 1994) drilled two shallow vertical wells with coiled tubing in the McKittrick Field in California. These wells are believed to be the first grass-roots wells drilled with coiled tubing. In addition, these wells were the first medium-diameter (6¼ in.) boreholes drilled using motors on coiled tubing.

A two-well project was designed to provide data on reservoir extent and evaluate the use of coiled tubing as a means of conveying drilling assemblies in this area. Completion operations were not included in original project plans. Secondary objectives of this project were to test coiled-tubing drilling in the context of slim (6¼ in.) vertical wells with conventional muds, and evaluate economic potential for coiled-tubing drilling for other applications. A hole size of 6¼ in. was chosen based on logging considerations (using conventional tools) and available motor/bit combinations.

The production horizon of interest was the Tulare tar zones, located at depths between 600–900 ft. Two wells, BY20 and BC4, were drilled in different edges of the reservoir.

A 4¾-in. medium speed motor was used for drilling operations (Figure 5-70). Rotational speed was 150-200 rpm at a flow rate of 150 gpm.

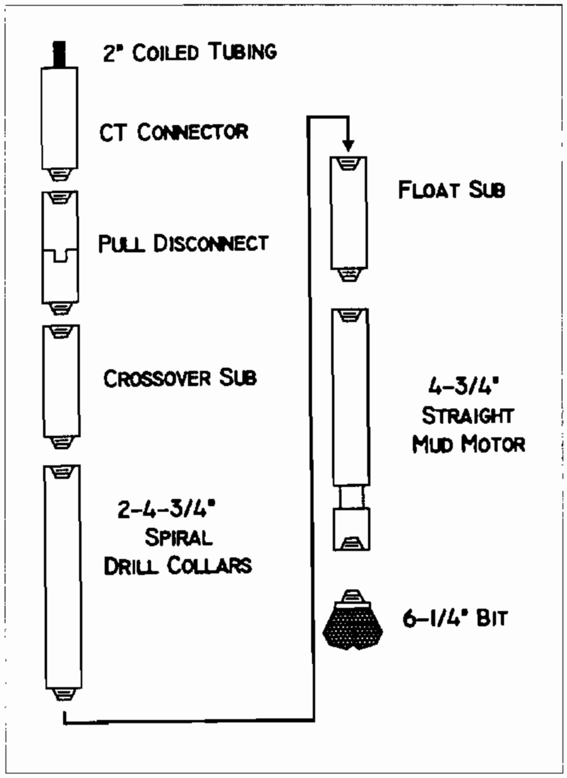


Figure 5-70. Drilling BHA
(Love et al., 1994)

A 3500-ft string of 2 x 0.156-in. coiled tubing was used for both wells. Drilling fluid was a cypan-based system. The location was about 90 ft on a side (Figure 5-71). Love et al. stated that reorganization would permit the location to be reduced to 90 x 70 ft, and that it need not be rectangular.

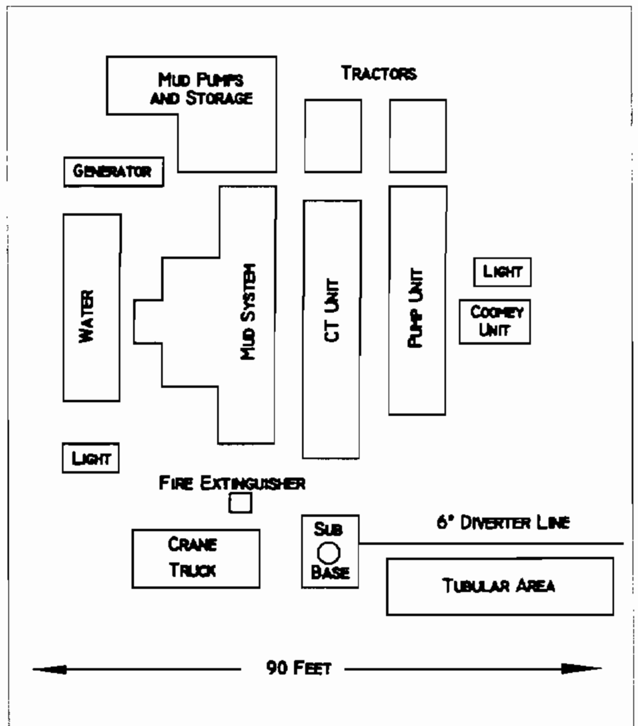


Figure 5-71. Surface Equipment Layout
(Love et al., 1994)

The first well was spudded using two drill collars (Table 5-24). Deviation was checked at 259 ft MD. During this trip, a third drill collar was added to the BHA. Drilling continued successfully to TD at 1257 ft. Deviation along the wellbore was a maximum of 1¼°.

TABLE 5-24. Drilling Operations on Well BY20 (Love et al., 1994)

Hole Size	6¼"
CT Size	2" nominal, 0.156 wall thickness
Drill Collars	3
Spudding Depth	78', Below conductor
Total Measured Depth (TD)	1257'
Maximum Deviation	1¼°
Hole Length Drilled	1179'
Avg. Rate of Penetration	32 ft/hr
Avg. Drilling Rate	51 ft/hr

Total drilling time was 35 hr, 10 hr of which were spent checking the survey with a conventional tool (Figure 5-72). Logging was performed successfully. A cement plug was placed on bottom.

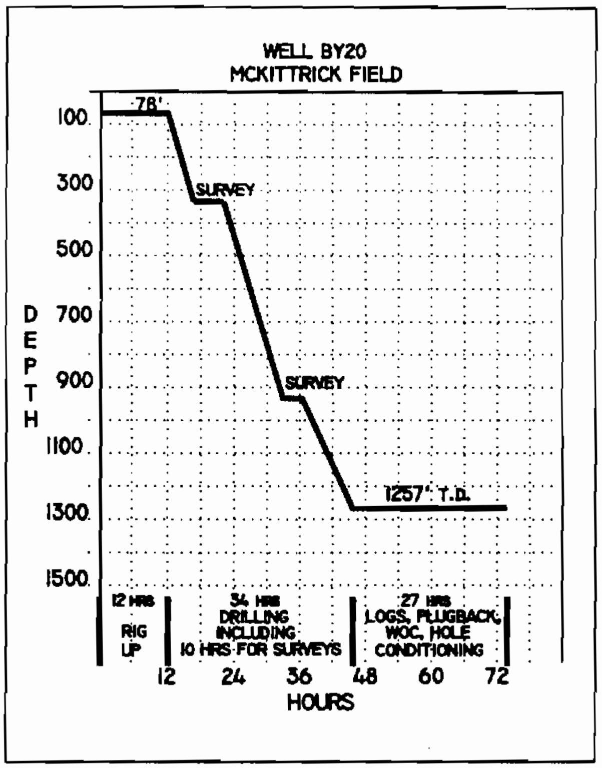


Figure 5-72. Time Summary for Well BY20 (Love et al., 1994)

A second well (BC4) was spudded from 80 ft with two drill collars (Table 5-25). Good penetration rates were achieved all the way to TD.

TABLE 5-25. Drilling Operations on Well BC4 (Love et al., 1994)

Hole Size	6¼"
CT Size	2" Nominal, 0.156 Wall Thickness
Drill Collars	2
Spudding Depth	78', Below Conductor
Total Measured Depth (TD)	1500'
Maximum Deviation	1°
Hole Length Drilled	1422'
Avg. Rate of Penetration	68 ft/hr*
Avg. Drilling Rate	70 ft/hr**

* includes all time, spud to TD
** 200'/hr 78-180'
100'/hr 180'-860'
50'/hr 860'-1500'

No intermediate directional surveys were taken on the second well due to the low deviation noted on the first well. Total drilling time was 21 hr (Figure 5-73). Dipmeter logs after drilling showed a maximum deviation of 1°.

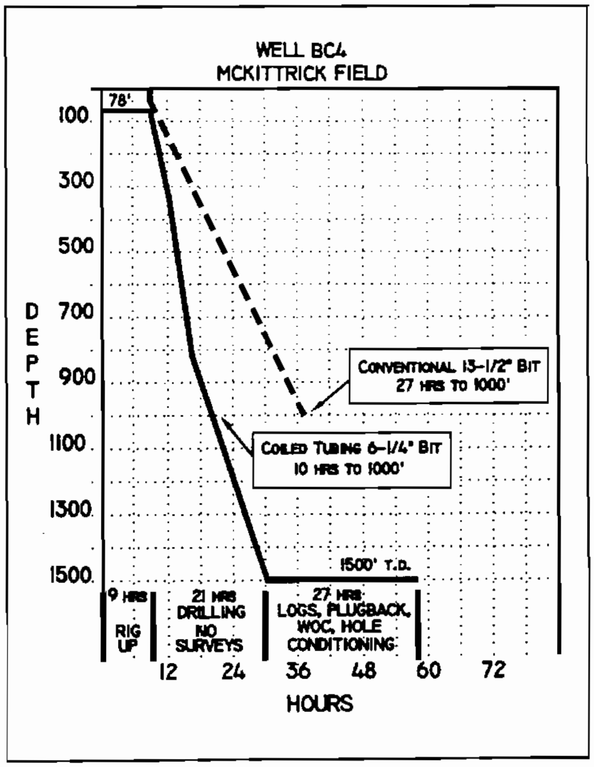


Figure 5-73. Time Summary for Well BC4 (Love et al., 1994)

Post-drilling analyses showed that drilling time for the second well was about 60% faster than for a conventional (larger diameter) well. Most of the time savings were attributed to faster ROP in the slimmer hole.

An additional benefit was a reduction in hole wash-out (Figure 5-74). Berry Petroleum believed that improved hole conditions were the result of continuous circulation with the coiled-tubing system, reduced pumping rates, and slimmer hole.

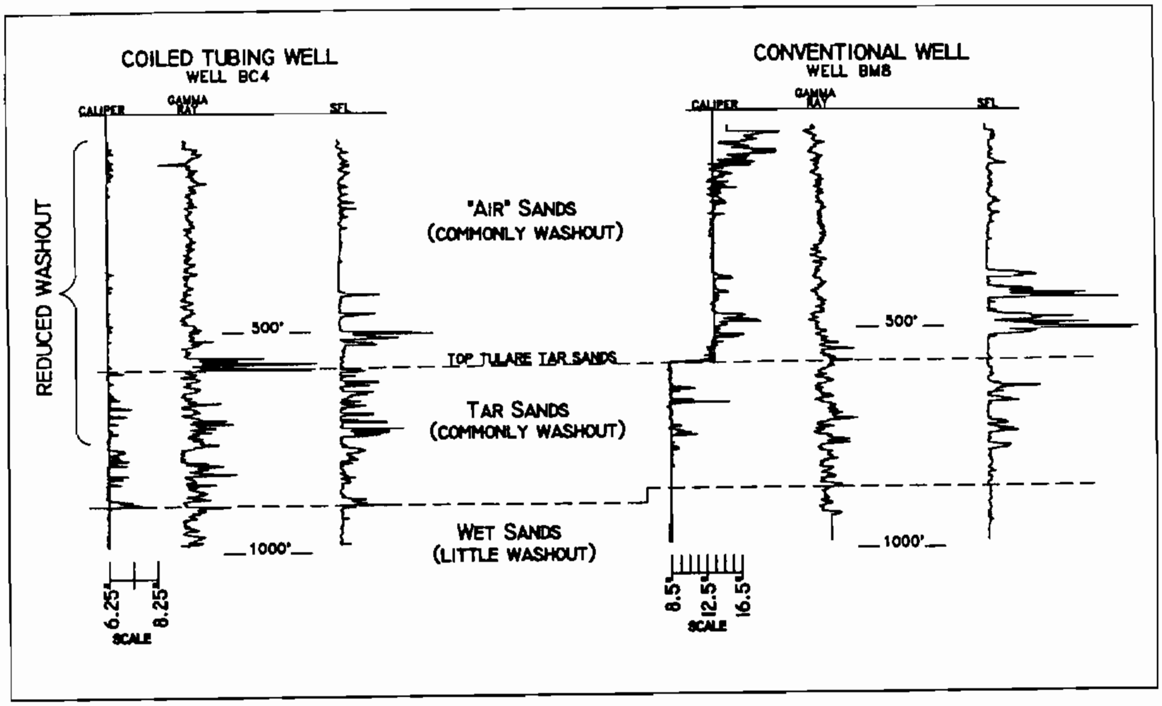


Figure 5-74. Coiled-Tubing and Conventional Hole Calipers (Love et al., 1994)

Fatigue life consumption of the string during these operations was moderate. For all operations on both wells, modeling indicated that a maximum of 18% of string life was used (Figure 5-75).

Berry Petroleum found that costs with coiled-tubing drilling were comparable or less than conventional rigs for this application. Costs would be even more favorable for deviated holes where conventional systems would also have to use motors.

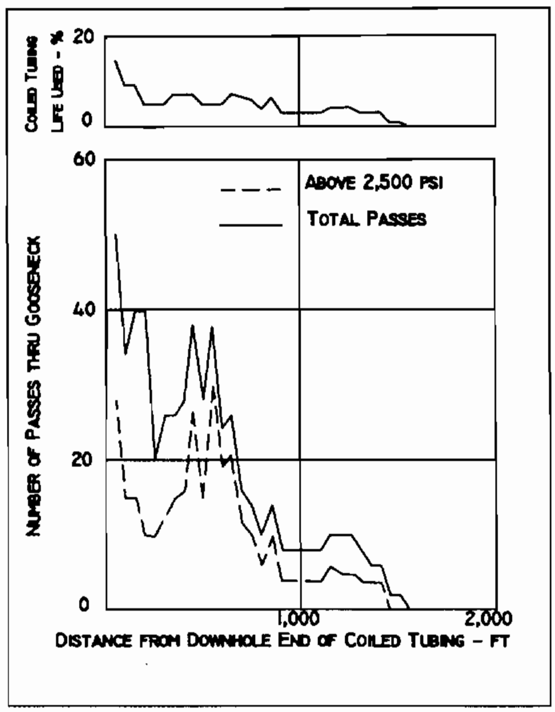


Figure 5-75. Coiled-Tubing Fatigue for Two-Well Project (Love et al., 1994)

5.3.3 Cudd Pressure Control (Chevron Wells)

Cudd Pressure Control drilled two wells for Chevron in Texas, one in late 1991 and one in mid-1992. Wesson (1993) described the well design and coiled-tubing drilling operations.

The first well (Table 5-26) was a horizontal re-entry out of 5½-in. casing. The pilot hole in the curve was drilled with a 4¾-in. bit by a conventional hydraulic workover rig. The borehole was downsized to 3⅞ in. while still in the curve after the coiled-tubing unit was rigged up. A horizontal section length of 765 ft was attained from the end of the curve (EOC) to TD (9568 ft MD).

TABLE 5-26. Drilling Data for Chevron Well #1 (Wesson, 1993)

Casing:		5½ inch	ROP		
Wellbore				Curve:	9.2 ft./hr
	Curve:	4¾ inch		HOR.:	11 ft./hr
	HOR.:	4½ inch			
Downsized to:		3⅞ inch			
			Drilling Hours		
KOP:		8,377 ft. TVD		Curve:	44 hrs
EOC:		8,803 ft. MD		HOR.:	72 hrs
		8,783 ft. TVD			
EOH:		9,568 ft. MD	TIH		
				Curve:	5 - 3⅜ assembly
Departure:		1,200 ft.			3 - 2⅞ assembly
				HOR.:	7 - 2⅞ assembly
BUR					
	Planned:	28°/100'	St./Wc. Tool:		Ensco
	Actual:	23°/100'	Motor:		Ensco
	Range:	16 to 45°/100'			
Inclination:		91.5°			
Kickoff:		Whipstock Window			
Tubing					
	Size:	2.0 inch X 0.156 wall			
	Length:	11,600 ft.			

Operational problems on the first Chevron well included cutting the window in the wrong place due to unplanned movement of the whipstock. When the sidetrack was kicked off, the azimuth was off by 166°. As the wellbore was turned back on course, it intersected and drilled through the old casing.

Electrical problems continued to hinder operations. There were multiple internal breaks in the steering package, and shorts at the reel slip ring and wet-connect sub. Drag forces were higher than anticipated, and it was difficult to keep the necessary weight on bit.

Drilling operations placed significant stresses on the coiled-tubing string and led to uncertainties with tubing life. Cudd stated that tubing damage occurred downhole when buckling forced the tubing against discreet rough spots and produced very high point loads. Lateral cracks appeared on the low side of the tubing as it was run across the gooseneck.

The drilling and wellbore data for Chevron Well #2 are shown in Table 5-27. This well was the first drilling operation with Cudd's purpose-built coiled-tubing drilling rig. The rig was designed for 2⅜-in. tubing, which has twice the moment of inertia of 2-in. tubing.

TABLE 5-27. Drilling Data for Chevron Well #2 (Wesson, 1993)

Casing:	5½ inch	ROP	
Wellbore		Curve:	9.4 ft./hr
Curve:	4¾ inch	HOR.:	5.9 ft./hr
HOR.:	4½ inch		
Downsized to:	3⅞ inch		
		Drilling Hours	
KOP:	8,076 ft. TVD	Curve:	43.5 hrs
EOC:	8,284 ft. MD	HOR.:	195 hrs
	8,485 ft. TVD		
EOH:	8,249 ft. TVD		
	9,621 ft. MD	TIH	
		Curve:	6 - 3⅜ assembly
Departure:	1,553 ft.	HOR.:	6 - 3⅜ assembly
			4 - 2⅞ assembly
BUR			
Planned:	23°/100'	Bits:	
Actual:	21.2°/100'	Cone:	2
Range:	19 to 26°/100'	PDC:	4
Inclination:	92°	TSP:	1
Kickoff:	Whipstock Window	St./Wc. Tool:	Ensco
		Motor:	Ensco
Tubing			
Size:	2⅜ inch X 0.156 wall		
Length:	12,000 ft.		

Wellbore kick-off was accomplished at the desired orientation. There were problems with formation wash-out at the casing window. The wireline connectors continued to have intermittent problems with shorting.

The BHA was dropped from the surface, leading to fishing operations, which were ultimately successful. Junk in the hole, presumably from window-cutting operations, damaged four TSD bits. The junk was buried by a two-step operation: 1) drilling an oblong hole at the top of the curve by orienting the bent assembly downward, and 2) orienting the bit against the roof of the curve, running over the junk and plowing it into the wellbore wall.

Tubing problems included breaking the tubing string by catching on the whipstock, which had accidently been shifted during BHA fishing operations. There were significant vibration problems with the BHA that led to multiple steering-tool failures and backoff of a nut on the orienting tool.

5.3.4 Petro Canada (Medicine Hat Re-entry)

Petro Canada (McMechan and Crombie, 1994) tested modified equipment and drilling techniques by deepening, completing and fracturing a vertical gas well with coiled tubing. The deepening of the well near Medicine Hat, Alberta was the first field operation in a larger project to evaluate balanced drilling of horizontal wells in sour reservoirs with coiled tubing. This first site was purposely chosen as a safer environment to test fluids handling systems, a new pressure sensor sub, and foam model accuracy.

The subject well (PEX WINCAN MEDHAT 10-9MR-17-3 W4M) was to be deepened from 448 m to 530 mMD (1470 ft to 1740 ft) with a 3⅞-in. hole. Drilling was to be conducted at balanced conditions with foam to avoid formation damage in the currently producing Milk River zone and the target Medicine Hat zone. Fluid modeling showed that foam rates of 33 gpm of water and 440 scfm of nitrogen would be required.

Drilling BHA components are listed in Table 5-28. Components were assembled to reflect the requirements for horizontal drilling in later phases. However, directional equipment (steering tool etc.) was not used.

TABLE 5-28. Coiled-Tubing Drilling BHA (McMechan and Crombie, 1994)

COMPONENT	O.D.(In.)	LENGTH (m)	TOTAL LENGTH (m)
Junk Mill	3⅞	0.46	0.46
Crossover Sub	3⅛	0.12	0.58
Motor	3⅛	3.80	4.38
Crossover Sub	3⅛	0.12	4.50
Thruster	2⅜	2.84	7.34
Crossover Sub	3⅛	0.24	7.58
Crossover Sub	3⅛	0.18	7.76
Drilling Release Tool	3⅛	1.77	9.53
Quick Latch, Pressure Sensor, Coil Connector	3⅛	1.97	11.50

The maintenance of balanced conditions with foam required accurate measurement of downhole pressures. A special sub was designed with two pressure sensors (Figure 5-76), one measuring pressure in the coiled tubing above the motor and one measuring pressure in the annulus. Pressure in the annulus ranged from about 245-320 psi during drilling operations.

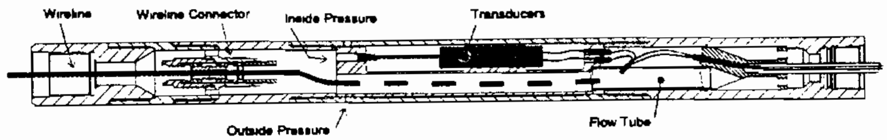


Figure 5-76. Pressure Sensor Sub (McMechan and Crombie, 1994)

Petro Canada and Nowsco wanted to obtain pressure data from drilling operations that could be compared with computer simulation data (Table 5-29) so that any appropriate empirical corrections could be determined and applied in later phases of the development.

TABLE 5-29. Predicted/Actual Drilling Pressures (McMechan and Crombie, 1994)

PRESSURE AT:	PREDICTED (MPa)	ACTUAL (MPa)
Rotating Joint	13	13.0–13.4
Gooseneck	7.5	N/A
Above motor	9.5	9.3–9.5
Annulus (surface)	0.49	0.40–0.45

Considerable design effort was directed toward a system to handle the foam (Figure 5-77). Calculated foam quality was 79% at bottom hole and 90% for returns at surface. Tests indicated that these foams could be broken down mechanically. However, in the field the system broke down only about 98% of the foam. A chemical breaker was used for the remainder.

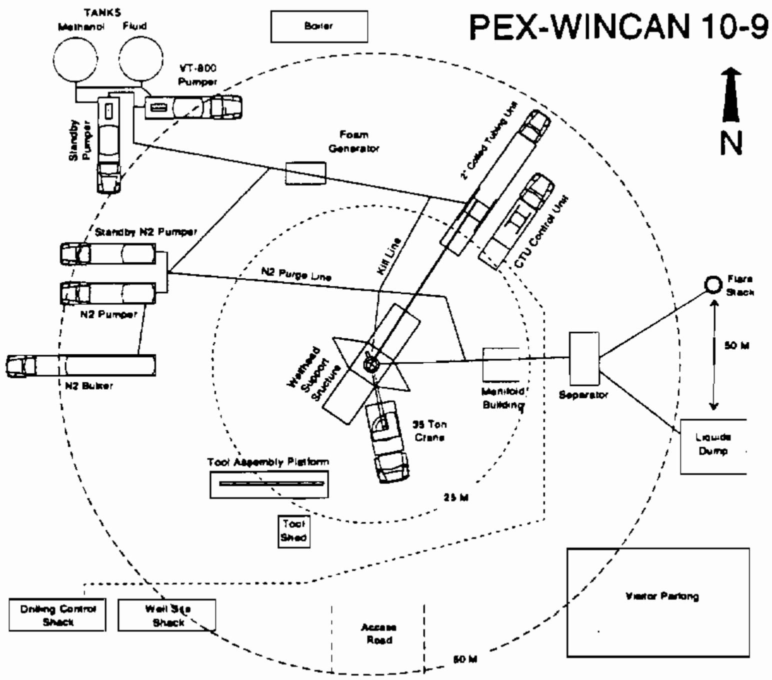


Figure 5-77. Surface Equipment with Foam Treatment (McMechan and Crombie, 1994)

Drilling operations progressed relatively smoothly. To drill out the shoe joint, a junk mill was substituted for the 3⅞-in. TSP bit run initially. The bit was reinstalled to drill the new hole. Drilling time was 9½ hr for 224 ft, for an average ROP of 27 ft/hr.

After drilling was complete, a string of 2⅞-in. coiled tubing was cemented in place as a production liner. After logging and perforating operations, a 55,000-lb frac job was pumped and the well put on production. The final wellbore status is shown in Figure 5-78.

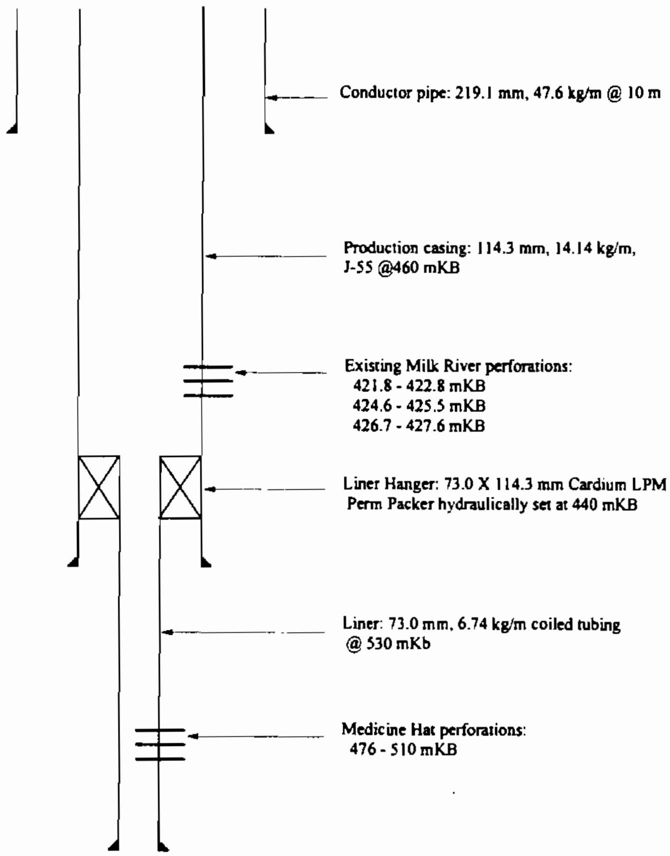


Figure 5-78. Final Completion of 10-9MR-17-3 W4M (McMechan and Crombie, 1994)

5.3.5 Schlumberger Dowell (Summary of Industry Experience)

Schlumberger Dowell has been involved in many of the developments of techniques and technologies related to coiled-tubing drilling. Several publications (for example, Newman, 1993; Doremus, 1994; Leising and Rike, 1994) summarize industry's efforts in modern coiled-tubing drilling. The most recent well counts are shown in Figure 5-79. For 1995, about 70 directional wells are predicted; the number of vertical jobs was not predicted, but is expected to continue to grow.

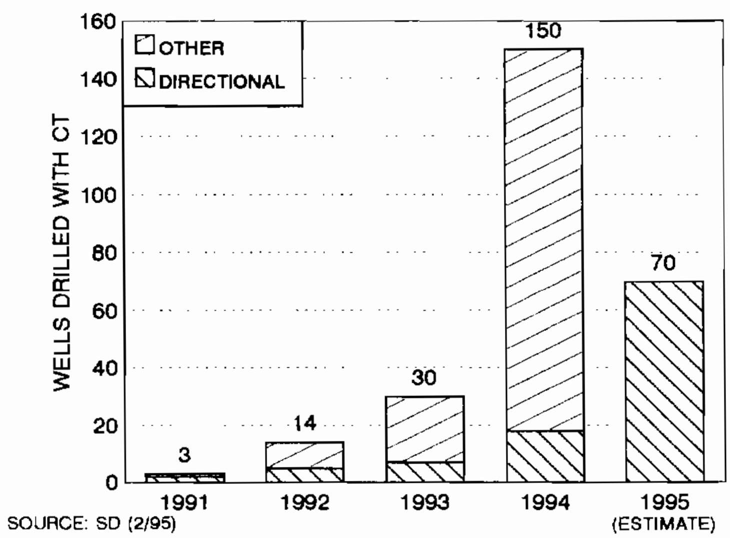


Figure 5-79. Job Counts for Coiled-Tubing Drilling (Gary, 1995)

Newman (1993), along with enumerating the advantages and disadvantages coiled-tubing drilling, presented a list of coiled-tubing drilling jobs as of February 1993 (Table 5-30). He noted that these attempts were not all successful.

TABLE 5-30. Coiled-Tubing Drilling Jobs as of 02/93 (Newman, 1993)

Date	Location	Client	New Re-entry	Vert. Dev.	CT Size	Hole Size
Jun 91	Paris	Elf	Re-entry	Vert.	1.50	3.875
Jun 91	Texas	Oryx	Re-entry	Devi.	2.00	3.875
Aug 91	Texas	Oryx	Re-entry	Devi.	2.00	3.875
Dec 91	Texas	Chevron	Re-entry	Devi.	2.00	3.875
May 92	Canada	Lasmo	New	Vert.	2.00	4.750
July 92	Texas	Oryx	Re-entry	Devi.	2.00	3.875
July 92	Canada	Gulf	Re-entry	Devi.	2.00	4.125
July 92	Canada	Imperial	New	Vert.	2.00	4.750
July 92	Texas	Arco	Re-entry	Devi.	1.75	3.750
Sept 92	Canada	Pan Can.	Re-entry	Vert.	2.00	4.750
Oct 92	Canada	Can. Hunt	Re-entry	Vert.	1.75	3.875
Oct 92	Paris	Elf	New	Vert.	1.75	3.875
Nov 92	Canada	Gulf	Re-entry	Devi.	2.00	4.750
Nov 92	Canada	Gulf	Re-entry	Vert.	2.00	4.750
Nov 92	Austria	RAG	Re-entry	Vert.	2.00	6.125
Dec 92	Alaska	Arco	Re-entry	Devi.	2.00	3.875
Feb 93	Holland	NAM	Re-entry	Devi.	2.00	3.875

Based on the data in Table 5-30, 2-in. coiled tubing is the most popular drill string and most holes are about 4 inches.

Schlumberger Dowell (Leising and Rike, 1994) discussed their own experience drilling wells with coiled tubing around the world. In addition, they presented data describing two of these wells in more detail. The number of coiled-tubing drilling jobs has increased significantly in recent years, with the annual percentage of vertical wells (versus deviated) increasing through 1993 (Figure 5-80).

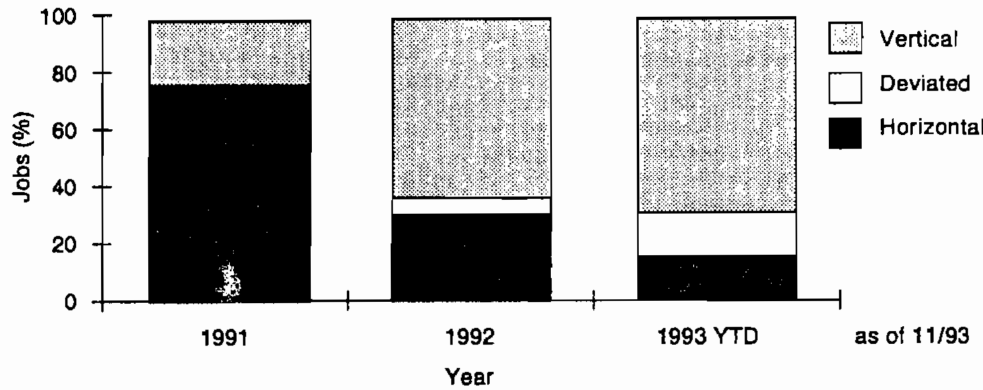


Figure 5-80. Orientation of Coiled-Tubing Wells (Leising and Rike, 1994)

A variety of operations have been proven during the jobs, including coring, setting whipstocks, cutting windows, MWD mud-pulse with gamma-ray, using new steering tools, running liners and hangers, using tricone and diamond bits, underbalanced drilling with artificial lift and lightweight fluids, air/mist drilling, drilling through 3½-in. tubing, and off-pad remote drilling.

Schlumberger Dowell's projects are summarized in Table 5-31. The footage drilled on a typical coiled-tubing drilling project was about 900 ft. The maximum is 4370 ft. WOB has ranged from 500-1000 lb per inch of bit diameter.

TABLE 5-31. Coiled-Tubing Wells by Schlumberger Dowell (Leising and Rike, 1994)

WELL #	DATE	LOCATION	CLIENT	TECH SUCCESS	DRILLED FT	COMMENTS	PROBLEMS
D-1	6-91	Paris	Elf	Yes	896	Cored	
D-2	7-92	Texas	Arco	No	382	Whipstock set/drilled, MWD	Software error
D-3	10-92	Canada	Can. Hunter	No	3	Gel diesel mud	Hard stringer below shoe
D-4	10-92	Paris	Elf	Partial	4370		Motors, differential sticking, bit balling, disconnects
D-5	2-93	Holland	Shell-NAM	Yes	1060	Liner, 11 times production increase	Orienting tool
D-6	4-93	California	Berry	Yes	1179	Washout 1/4 of Rotary	Bit balling
D-7	4-93	California	Berry	Yes	1422		
D-8A,B	6-93	Alaska	Arco	Yes	135	Underbalanced, TT[1]	Underreamer blade wear
D-9	8-93	Alaska	Arco	Yes	199	3½ times production increase	Weight transfer
D-10	9-93	Texas	Amoco	Yes	416	Air/mist	Motors
D-11	9-93	Texas	Amoco	Yes	467	Air/mist	CT scale
D-12	10-93	Texas	Amoco	Yes	424	Air/mist	Motor
D-13	10-93	California	Chevron	Yes	880		Mud handling
D-14	10-93	California	Chevron	Yes	872		
D-15	10-93	Venezuela	Lagoven	Yes	1000	Off pad drilling	
D-16	11-93	Venezuela	Lagoven	Yes	1000	Off pad drilling	
D-17	11-93	Venezuela	Lagoven	Yes	1005	Off pad drilling	
D-18	11-93	Venezuela	Lagoven	Yes	1000	Off pad drilling	Clay swelling/BHA LIH[2]
D-19	11-93	Venezuela	Lagoven	Yes	1000	Off pad drilling	
				TOTAL	17,710		

A problem with weight transfer is illustrated in Figure 5-81, which is a log from well D-4 (see Table 5-31). Although surface weight was increased over 2000 lb between 16:45 and 16:52, motor pressure did not increase significantly due to differential sticking. Logging was also a problem; tools could only pass the top third of the hole. Overall, well D-4 was listed as a partial success.

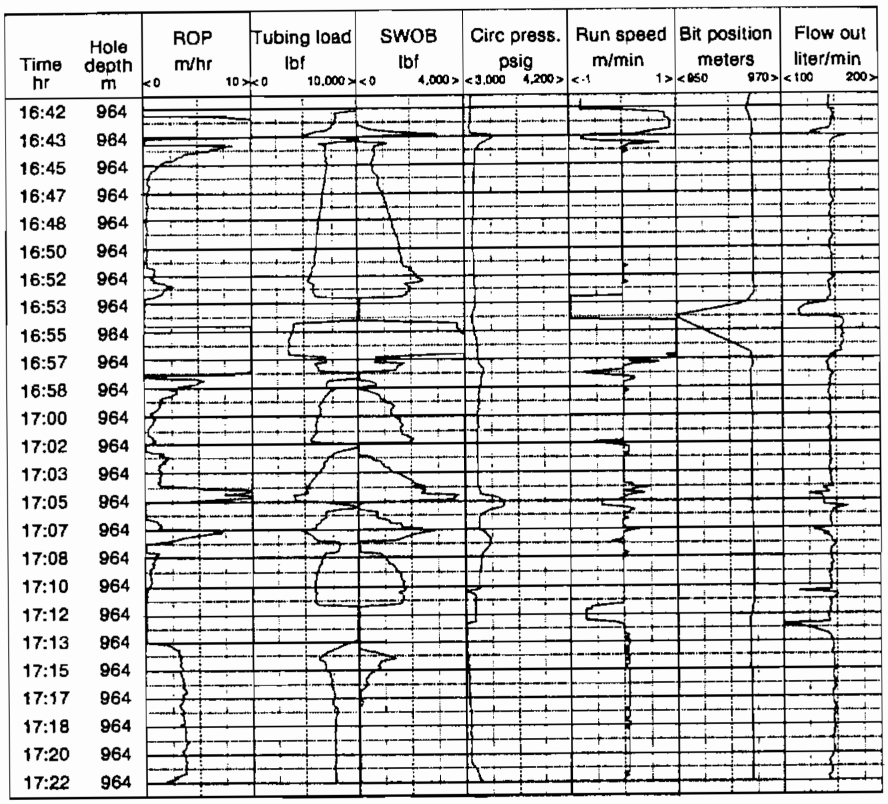


Figure 5-81. Drilling Log From Well D-4 (Leising and Rike, 1994)

Well D-9 was a horizontal well deepening operation. This Prudhoe Bay well was originally completed with a 4½-in. slotted liner and 4½ x 3½ production tubing (Figure 5-82). Formation damage during original drilling operations was suspected as the cause of the well's poor production (less than 300 BOPD).

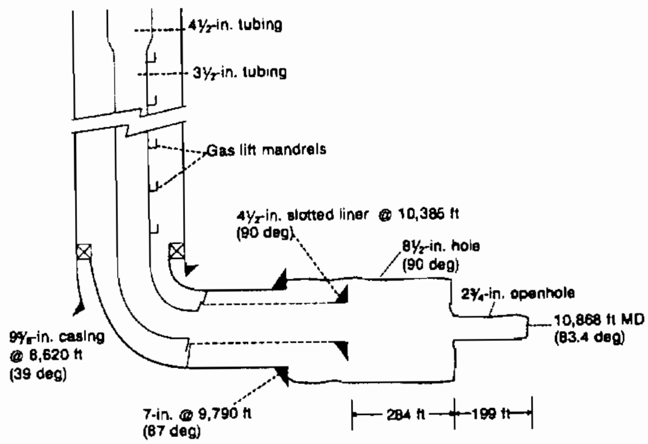


Figure 5-82. Well D-9 (Leising and Rike, 1994)

The deepening was performed underbalanced with gas lift. Wellhead equipment included a $7^{1}/_{16}$ BOP stack (Figure 5-83). Biozan drilling fluid (2.5 lb/bbl) was used for the operation. The drilling BHA consisted of a 2¾-in. bit, motor, drop-ball circulation sub, drop-ball disconnect, dual check valves, and weld-on connector.

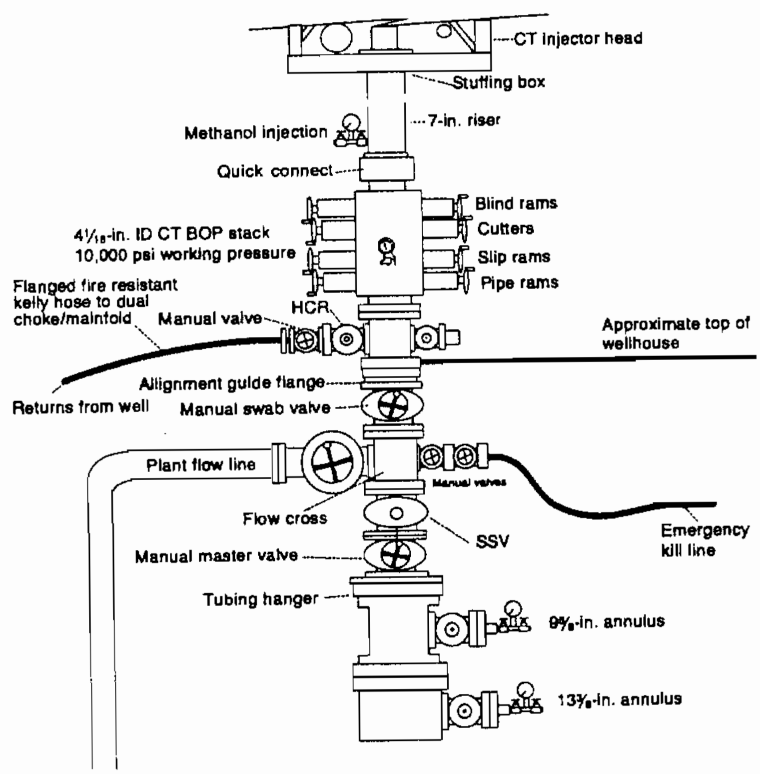


Figure 5-83. Wellhead Equipment for Well D-9 (Leising and Rike, 1994)

A two-phase separator was used along with collection tanks to store the usable fluid before returning it to the suction tanks. A layout of the surface equipment is shown in Figure 5-84.

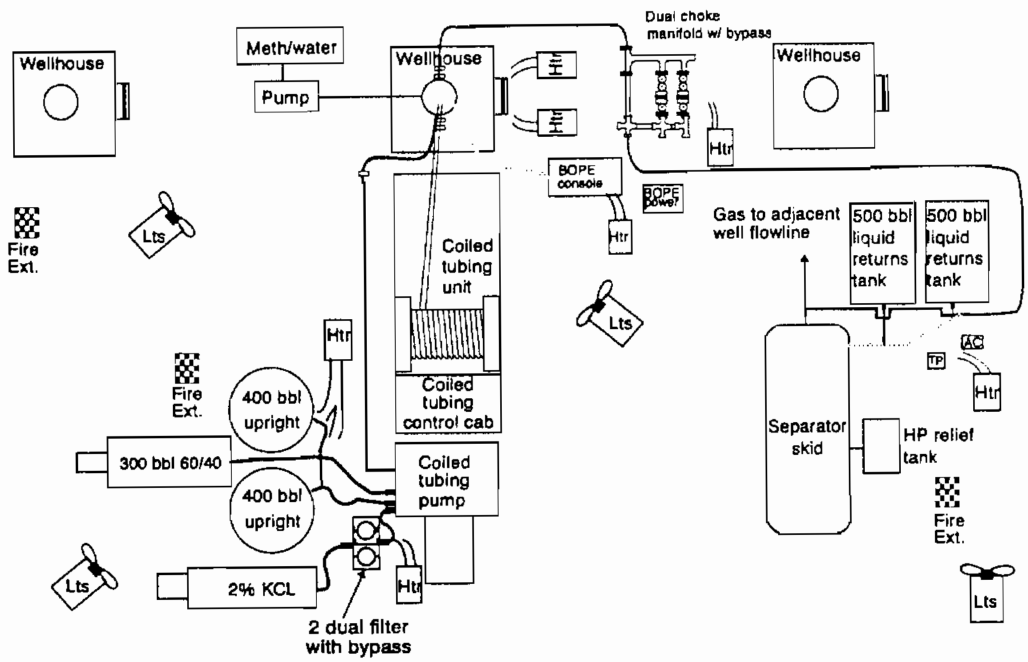


Figure 5-84. Surface Equipment for Well D-9 (Leising and Rike, 1994)

After a profile nipple was milled out, the BHA was run to the old TD and the hole lengthened 199 ft (Figure 5-85). A final survey showed that the new wellbore dropped angle along its length at a rate of about 3½°/100 ft. Guidance was not critical for this interval so no attempt was made to measure changes in inclination while drilling.

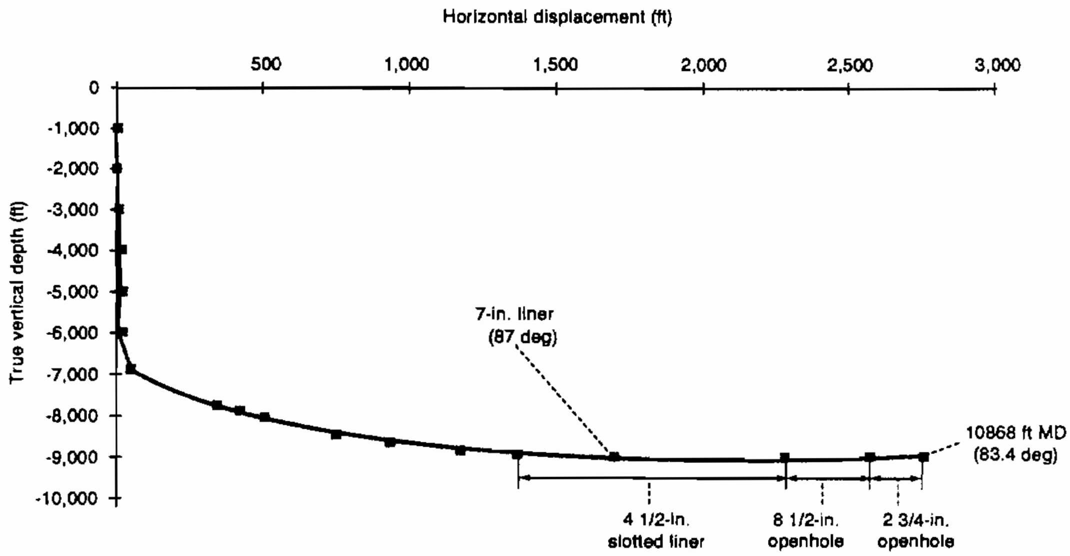


Figure 5-85. Final Survey for Well D-9 (Leising and Rike, 1994)

Problems with job design included difficulty achieving desired underbalanced conditions. The size of the annulus (2-in. coiled tubing in 3½-in. production tubing) resulted in high pressure losses in the annulus. Smaller coiled tubing (1¾ in.) was not considered feasible due to the large diameter of the original wellbore (8½ in.).

Unidentified fluid contamination and a large wellbore diameter led to stick/slip behavior of the coiled-tubing string, resulting in difficulty getting weight to the bit. ROP ranged from 6–18 ft/hr; the average was about 10 ft/hr.

Production from well D-9 was increased by a factor of 3½ by the coiled-tubing lengthening. The cost for this operation was about 75% less than if a conventional rig were used.

Doremus (1994) summarized Schlumberger Dowell's work with Lagoven in drilling top holes with coiled tubing in Lake Maracaibo, Venezuela. There was a risk in drilling these wells from gas-bearing sands at depths of 400-1000 ft. The conventional approach in this field was to place the diverter lines for piping away flowing gas on barges tied next to the platform. An effective coiled-tubing rig-up allowed most of the equipment and all of the personnel to be positioned over 100 ft from the platform (Figure 5-86). Consequently, diverter lines could be positioned normally on the platform.

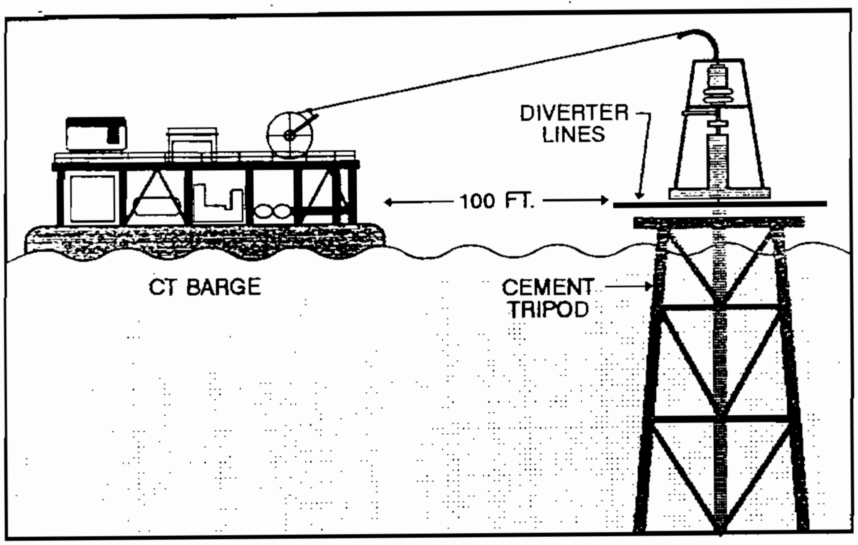


Figure 5-86. Lagoven Coiled-Tubing Rig-Up (*Offshore* Staff, 1994)

After the 24-in. conductor and cement tripod platform were installed, the BOP and injector were rigged up on the conductor. Pilot holes (3⅞ in.) were drilled on 1½-in. coiled tubing. A 5-in. flow conductor was used inside the 24-in. conductor to maximize ROP.

Coiled-tubing TD was about 1000 ft. Afterwards, a conventional system reamed out the pilot hole and completed the top hole to 3500 ft.

The coiled-tubing system proved very effective for this application. Four early pilot holes were drilled in 10 days. Cost savings were estimated at 70% for top-hole costs.

Doremus (1994) presented a summary of current coiled-tubing drilling capabilities for hole sizes and depths (Table 5-32). For through-tubing applications, the maximum diameter of production tubing that can be worked through is given. For other applications, the maximum hole diameter that can be drilled is presented. Obviously, these stated limits are contingent on site-specific conditions; however, these are given as a general indication of industry's capabilities.

TABLE 5-32. Current Coiled-Tubing Drilling Capability (Doremus, 1994)

Application	Max. Hole Size (in.)	Depth (ft)
Conventional Re-entry	3½-4¾	15,000
New Shallow Well	8½	6000
Through-Tubing Re-entry	**Min. Tubing Size (in.)**	
Vertical Deepening	3½	
Directional	4½	

5.3.6 Shell Research B.V. (Berkel Field)

Shell Research B.V. (Faure et al., 1993) described coiled-tubing drilling operations for a horizontal sidetrack in the Berkel Field in the Netherlands. Results demonstrated that drilling with coiled tubing is well suited for optimizing mature North Sea fields. Underbalanced drilling is a prime advantage in mature fields (Figure 5-87).

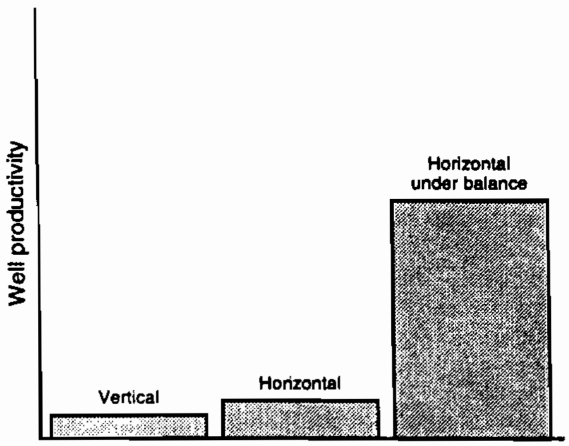


Figure 5-87. Production Advantage with Underbalanced Drilling (Pan-Canadian Oil Experience) (Faure et al., 1993)

Shell Research expects coiled-tubing drilling to become a more cost-effective approach than conventional after further develop and wider availability of coiled-tubing systems. Costs are reduced through lower initial capital investment and reduced manpower requirements. Improved health, safety, and environment concerns are other benefits anticipated in Shell's operations.

Lower drilling footprint (Figure 5-88), exhaust emissions, waste generation, noise, and visual disturbance are important benefits of this approach, especially in populated areas.

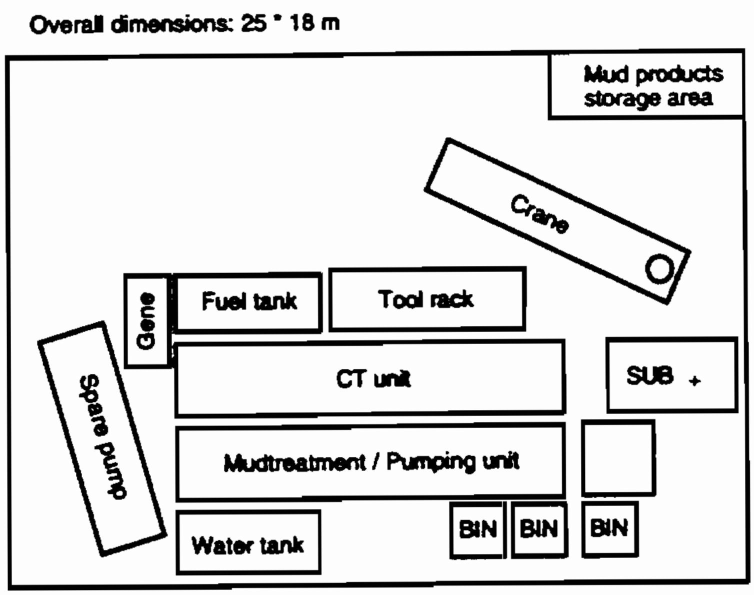


Figure 5-88. Shell Research Coiled-Tubing Drilling Site (Faure et al., 1993)

Part of the ultimate promise of coiled-tubing drilling is in the potential for automation. Continuous data relayed through integral wireline will allow a fully automatic drilling system, possibly based on alternative rock-destruction mechanisms.

Shell Research and NAM tested the potential of coiled-tubing drilling in the Berkel oil field in 1993. The Berkel 5 was drilled in 1978 with an "S" profile (Figure 5-89). Principal objectives of the re-entry included proving the use of coiled tubing for drilling horizontal re-entries, making progress toward a comprehensive coiled-tubing drilling unit not requiring assistance from a conventional rig, and identifying technology areas in need of further R&D.

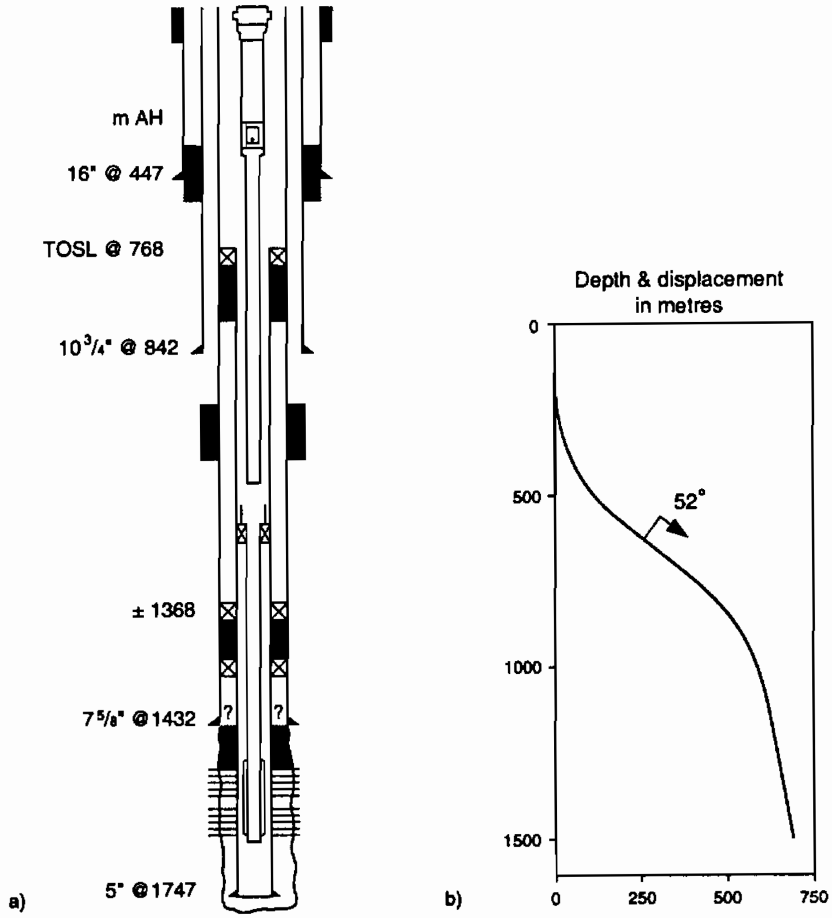


Figure 5-89. Berkel 5 Casing Program and Profile (Faure et al., 1993)

The drilling plan called for a medium-radius curve with 4⅛-in. borehole 30 m above the oil/water contact. An uncemented annulus required that the window be drilled higher than the ideal position. A workover rig pulled the existing completion, abandoned the lower wellbore and milled the window. Window milling was conducted without rotation, using mud motors and hydraulic thrusters.

Planned and achieved well paths are shown in Figure 5-90. Total drilled hole length was 321 m (1050 ft). Maximum build rate was 34°/100 ft; maximum inclination 96°. ROPs were 3 m/hr (10 ft/hr) in shale and 10 m/hr (33 ft/hr) in sandstone.

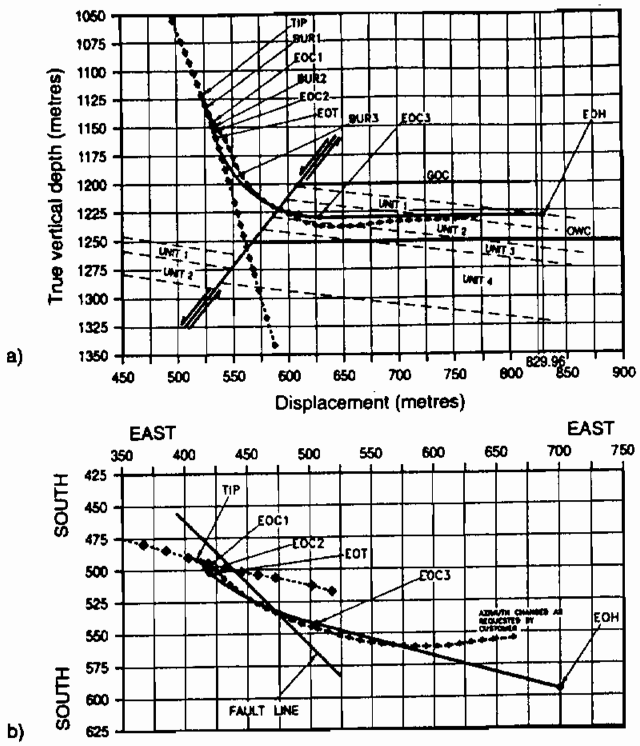


Figure 5-90. Berkel 5 Re-entry Well Path
(Faure et al., 1993)

The drilling BHA (Figure 5-91) included both single- and double-bend motors. The coiled-tubing string was 7200 ft of 2 x 0.156 in. with an integral 0.5-in. multiconductor wireline. The orienting tool was adjusted by string reciprocation.

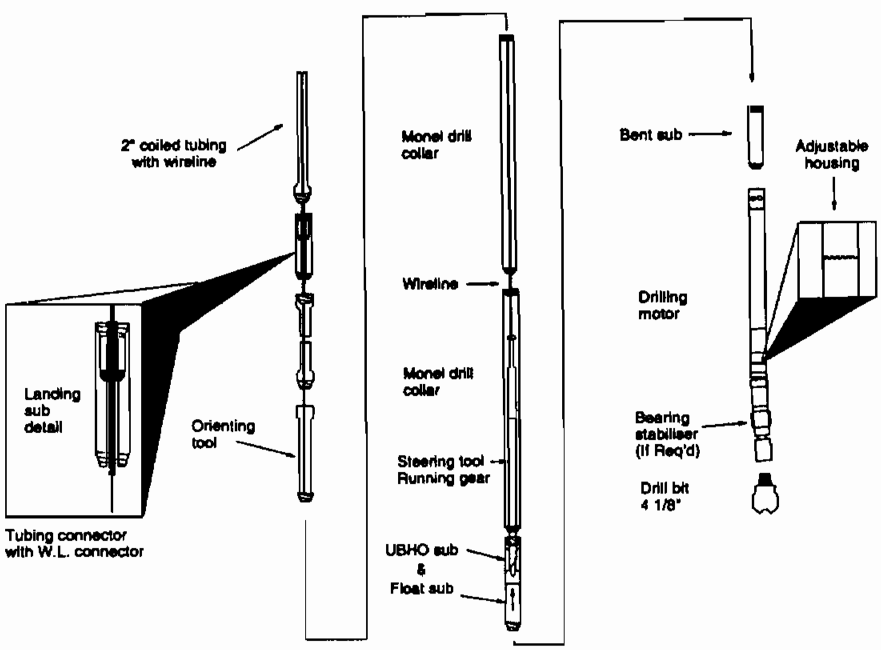


Figure 5-91. Berkel 5 Re-entry BHA (Faure et al., 1993)

The BHA and jointed tubulars were made up on a special substructure with slips and power tongs. Drilling fluids were treated in a trailer-mounted mud system (Figure 5-92) with a capacity of 170 bbl.

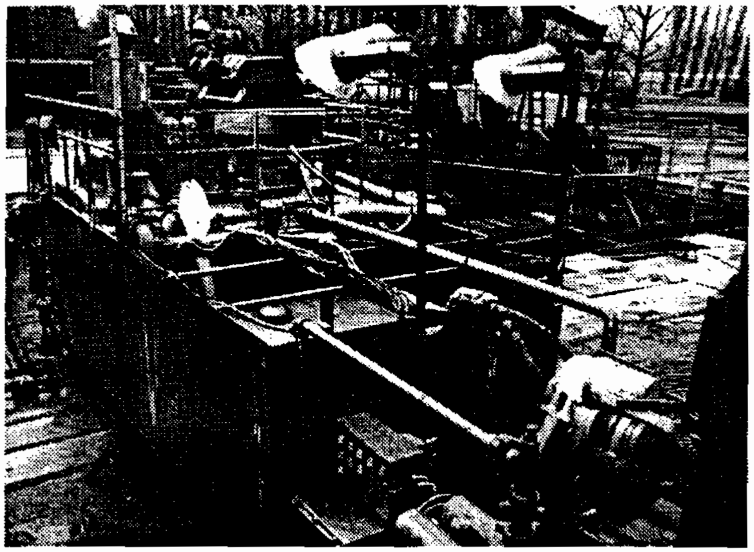


Figure 5-92. Mud System (Faure et al., 1993)

Drilling problems included a dropped bit and bit sub, total circulation losses after penetrating the reservoir, an accidental sidetrack after a BHA change, and other normal equipment failures. The fish were retrieved successfully on coiled tubing. Lost-circulation material was spotted to reduce circulation losses. The orienting tool was jammed by lost-circulation material. TD was declared after the motor twisted off at 1700 m (5577 ft).

All problems were readily corrected. Most of the difficulties encountered were not caused by the coiled-tubing system, but resulted from the lack of experience with horizontal slim-hole drilling in this field.

The producing zone was completed open-hole (Figure 5-93). Liner (3½ x 679 ft of 13 CR Hydril 511) was made up using a boom crane and the coiled-tubing rig substructure. A completion packer and 2⅞-in. tailpipe were also run in on coiled tubing. After this, a light pulling hoist was used to run a 3½ x 2⅞-in. single-string completion with SSSV.

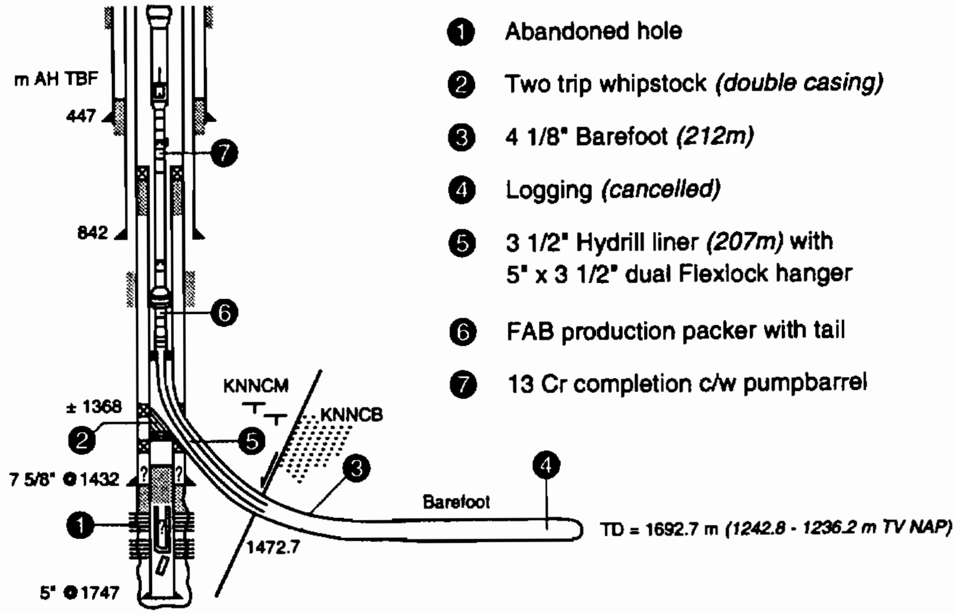


Figure 5-93. Berkel 5 Final Completion (Faure et al., 1993)

Costs of coiled-tubing operations on this re-entry were only slightly more expensive than workover-rig operations. Comparative costs for the whole project were not available since this re-entry was the first horizontal slim hole in this field. Production gains were significant: 82 BPD (40% water cut) before re-entry; 692 BPD (25% water cut) after re-entry.

Shell Research suggested that these coiled-tubing techniques have important applications in North Sea oil and gas fields. Many gas fields are significantly depleted, and horizontal re-entries would extend production and increase drainage area. For example, the Leman field cannot be re-entered with conventional systems and fluids. The life of this depleted field (435 psi at 5900 ft TVD) may be economically extended by laterals drilled underbalanced. Induced fractures have created paths for water invasion in some of these fields. Lateral re-entries could be used to bypass these fractures and decrease water production.

Mature North Sea oil fields also present significant opportunities for coiled-tubing drilling. Multiple drainholes can be used to access undrained fault blocks, as well as bypass damaged zones near the wellbore. Through-tubing operation is considered a necessary technology to achieve economic results in these fields.

According to Shell, near-term needs for coiled-tubing drilling in the North Sea include a comprehensive system for drilling and completing re-entries and deepenings that does not require assistance from a workover rig. Through-tubing window systems and short-radius BHAs are in need of further refinement. Tools and techniques for drilling multiple laterals from a single wellbore are needed.

5.3.7 Shell Western E&P (McKittrick Field)

Shell Western E&P used coiled tubing to drill 68 slim-hole injector wells in the McKittrick Field near Bakersfield, California (Figure 5-94). This project represents the largest coiled-tubing drilling program yet conducted. Costs were reduced significantly for this application. Background and results of this effort are described in detail in DEA-67 *Topical Report No. 1: Shell California Slim-Hole and Coiled-Tubing Drilling Operations*. A summary is presented in this section.

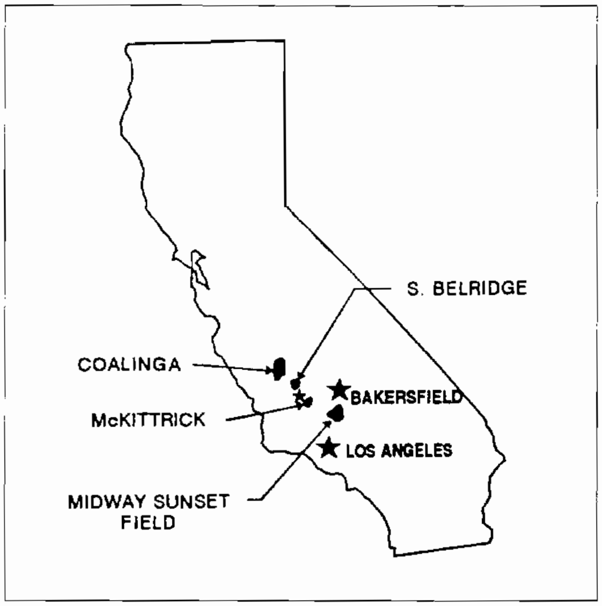


Figure 5-94. McKittrick Field

Shell drilled the slim-hole injection wells to improve thermal efficiency, production and economics of the McKittrick field. Steam is injected into these wells in the Tulare reservoir. Prior to project implementation, the field was shut in for several years due to poor economics. The redevelopment plan was to decrease well spacing by infill drilling 115 new injectors in thirty 5-acre inverted 9-spot patterns to increase thermal efficiency of the reservoir and increase production through existing or reworked conventional production wells.

The McKittrick field has a complex system of pumping equipment, steam distribution, production, and power lines that restrict the space available for conventional rotary drilling. Figure 5-95 shows the heavy congestion in the field.

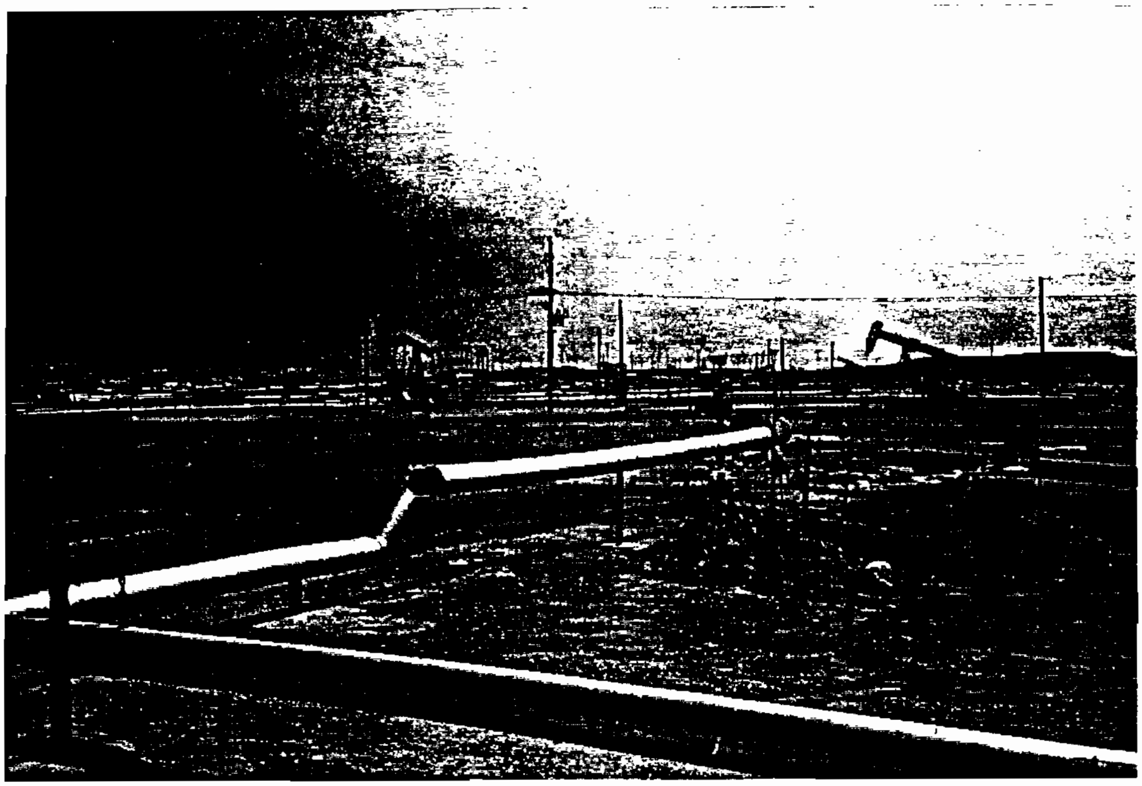


Figure 5-95. McKittrick Field Project Site

The slim-hole wells were drilled for primarily two reasons. First, by reducing hole and casing sizes, vertical slim-hole wells could be drilled and completed for approximately half the cost of conventional vertical wells. Secondly, coiled-tubing drilling allowed slim-hole infill wells to be drilled on the required precise patterns in this crowded field. These wells could not have been drilled with workover rigs because of their locations and would have required expensive directional drilling with conventional rigs.

Many of the new well locations were directly under existing power lines and very close to existing facilities. In addition, drilling conventional directional wells would have been relatively expensive since 68 wells had to be drilled.

Other benefits of using coiled-tubing drilling were:

1. Low mobilization and de-mobilization costs between wells.
2. Safer working environment (i.e., no couplings to make or break)
3. Decreased noise and emission levels.

A Halliburton coiled-tubing unit with 2-in. coiled tubing, 5-in. motor and 6⅛-in. bits was used to drill 68 injector wells. Mud and cement were pumped using a Halliburton 75TC4 cement pump truck. A portable trailer-mounted mud tank, shakers, mud mixer, centrifuge, and desanders were used. Shell supplied the mud tanks, bits, and the drilling mud. A typical wellbore schematic is shown in Figure 5-96.

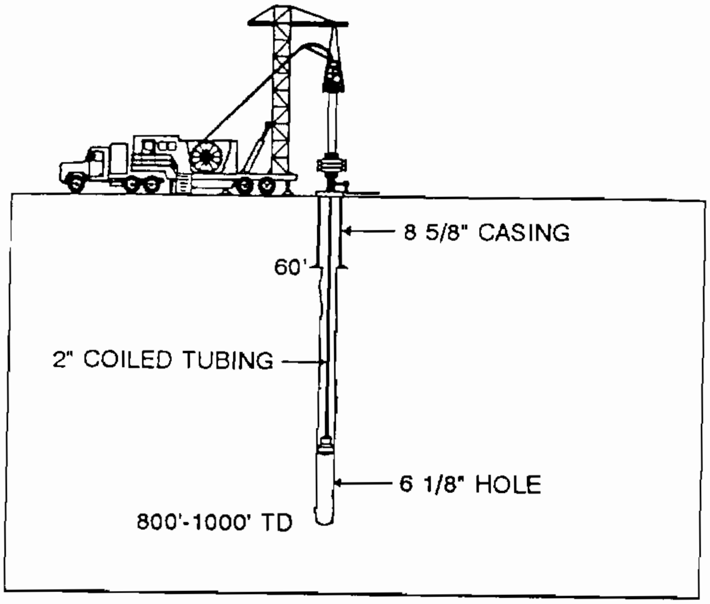


Figure 5-96. Shell Injector Well Schematic

After the wells were drilled, 2⅞-in. tubing was cemented to surface and perforated (Figure 5-97). Some wells will be acidized at a later date.

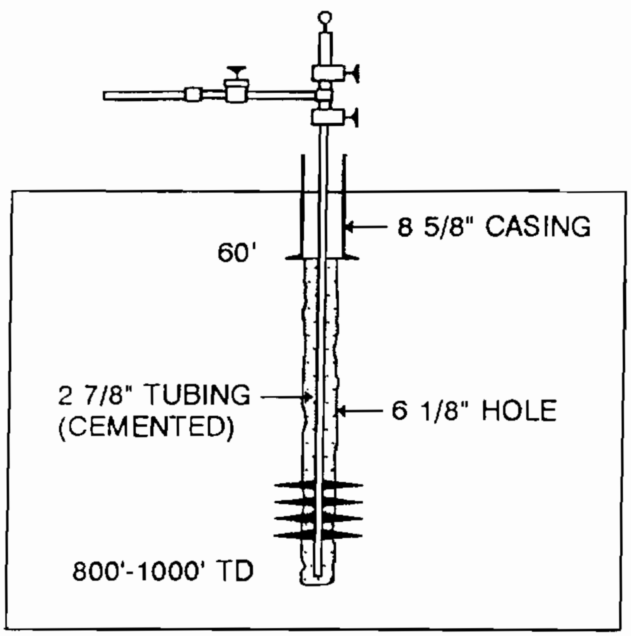


Figure 5-97. Shell Injector Completion

Prior to drilling operations, an 8 ft x 8 ft jacking framework floor was set by crane and a 6-in. diverter line and a 4-in. return line were installed (Figure 5-98). Power and backup tongs were installed on the working floor. A pump truck, coiled-tubing unit, and trailer-mounted mud system were rigged up on location and a small pit was dug next to the mud unit to handle cuttings and cement returns.

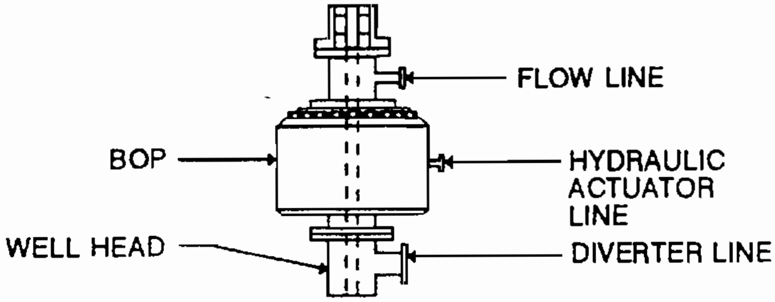


Figure 5-98. Wellhead Installation and Diverter Lines

An 8⅝-in. conductor was set at 60 ft to allow the BHA (6⅛-in. rock bit, 5-in. motor and 2-in. spiral drill collars) to be run before installing the injector. A fresh-water bentonite mud was used initially. Portable mud mixing facilities (Figure 5-99) were provided by Shell.

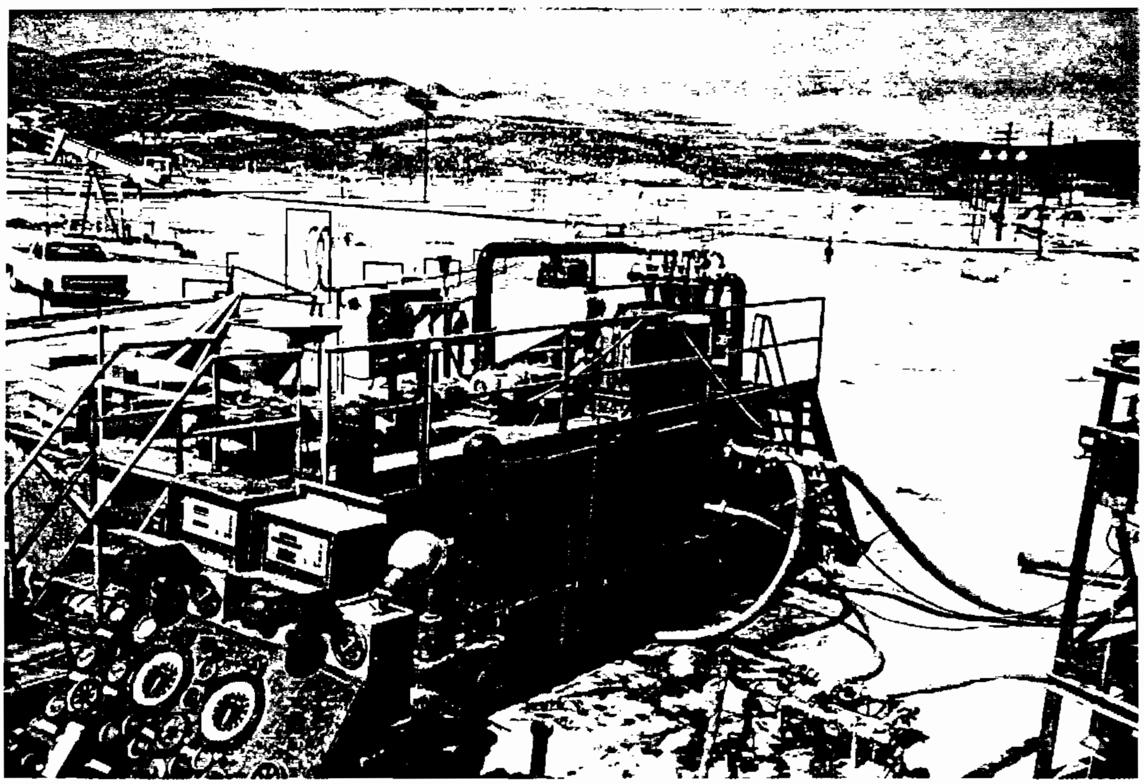


Figure 5-99. Portable Mud Tank

The workover and coiled tubing drilled slim-hole injectors took less time and cost to drill than conventional 8¾-in. injectors (Table 5-33). The workover and coiled-tubing rigs were used primarily due to surface constraints. The coiled-tubing rig proved to be ideal for drilling the shallow injectors due to the small location size and ease of mobilization.

TABLE 5-33. Shell Cost Comparison

	CONVENTIONAL OFFSET WELL	COILED TUBING WELL	WORKOVER RIG WELL
No. Of Wells	2(100)	68	45
Drill Pipe Size	3½ in.	–	2⅞ in.
Coiled-Tubing Size	–	2 in.	–
Hole Size	8¾ in.	6⅛	6⅛
Casing/Tubing Size	7(2⅞) in.	2⅞ in.	2⅞ in.
ROP	120 ft/hr	50–180 ft/hr	70–80 ft/hr
Days	7	1.25	4
Cost	100%	65%	55%

There was a steep learning curve with coiled-tubing wells, with costs on initial wells being similar to conventional wells and then declining to 65% of the cost of conventional. Coiled-tubing drilling costs should continue to decline as more experience is gained and as better tools are developed.

5.3.8 Zeeland Horizontal Ltd. (Canadian Applications)

Zeeland Horizontal and Audryx Petroleum (Hatala et al., 1994) presented an overview of the use of coiled-tubing drilling in Canada. A wide variety of applications have been performed there, including the pioneering effort in drilling new wells with coiled tubing. The increase in usage of coiled-tubing technology has followed closely behind the significant activity in horizontal drilling.

Uniflex Rig Co. began manufacturing coiled-tubing rigs in 1975, building around 70 units for Canadian and international customers. Flex-Tube of Alberta used a Uniflex Rig to drill new vertical wells in Alberta and Texas. A drill string butt-welded from line pipe was used to drill 6¼-in. holes. Interestingly, a spool of 2-in. aluminum coiled tubing was manufactured to increase depth and weight limits. A tricone bit was run on a 5-in. motor at 300 rpm.

Ten wells were drilled with this system before it was retired in 1977. The lack of industry support and sponsorship is the primary reason Flex-Tube's system declined. The spool of aluminum coiled tubing was never used.

A summary of coiled-tubing drilling projects in Canada is presented in Table 5-34. The modern revival of coiled-tubing drilling began in Canada in 1992 with Elan Energy's new vertical well at Cactus Lake. This well met drilling objectives, but could not be fully logged. Costs were not less than competing systems.

TABLE 5-34. Canadian Coiled-Tubing Drilling Projects (Hatala et al., 1994)

Date	No.	Location	Operator	Wellbore	Type	CT size (mm)	Hole size (mm)	Depth (m)
1974	2	Keg River, AB	Canadian Montana Gas	Re-entry	Vertical	25.4	114.3	285
1975	1	Oyen, AB	(?)	Re-entry	Vertical	25.4	114.3	443
1975	4	Bantry, AB	Alberta Eastern Gas Ltd	New	Vertical	60.3	139.7	486
1975	1	Lloydminster, AB	Husky Oil Ltd	Re-entry	Vertical	25.4	73.0	125
1976	4	Lougheed, AB	Sedger Resources Ltd	New	Vertical	60.3	139.7	500
1976	1	Alderson, AB	Pan Canadian Petroleum	Re-entry	Vertical	25.4	114.3	390
1978	1	Alderson, AB	Pan Canadian Petroleum	Re-entry	Vertical	25.4	114.3	387
1980	1	Medicine Hat, AB	Gascan Resources Ltd	Re-entry	Vertical	25.4	114.3	418
1981	1	Alberta	Petro Canada	Re-entry	Vertical	25.4	114.3	328
Jan, '88	1	Liege, AB	Paramount Resources	Re-entry	Vertical	31.75	114.3	460
Mar,'92	1	Bellis, AB	North Canadian Oils ltd	Re-entry	Vertical	38.1	114.3	555
Jun, '92	1	Cactus Lake, Sask	Elan Energy Inc.	New	Vertical	50.8	121.0	876
Jun, '92	1	Big Valley, AB	Gulf Canada Resources Inc	Re-entry	Horizontal	50.8	104.8	670
Aug, '92	1	Bellis, AB	Chauvco Resources Ltd	Re-entry	Vertical	31.75	114.3	570
Sep, '92	1	Irricana, AB	Pan Canadian Petroleum	New	Vertical	50.8	121.0	2100
Oct,'92	1	Canada	Canadian Hunter Ltd	Re-entry	Vertical	44.45	98.4	?
Nov','92	1	Strachan, AB	Gulf Canada Resources Inc	Re-entry	Vertical	50.8	152.0	4000
Jan, '93	1	Algar, AB	Rio Alto Oil & Gas Ltd	Re-entry	Vertical	31.75	114.3	455
Feb,'93	1	Medicine Hat, AB	Petro Canada Ltd	Re-entry	Vertical	50.8	104.0	600
Mar,'93	1	Shekilie, AB	Petro Canada Ltd	New	Horizontal	50.8	121.0	1800
Mar, '93	1	Bellis, AB	Talisman Energy Ltd	Re-entry	Vertical	38.1	114.3	570
Aug, '93	9	Brooks, AB	Pan Canadian Petroleums	Re-entry	Vertical	31.75	114.3	655
Aug,'93	1	Lovett River, AB	Conoco	New	Vertical	50.8	121.0	1750
Oct,'93	1	Wilson Crk, AB	Imperial Oil Resources	New	Vertical	60.3	156	1450
Nov,'93	1	Delia, AB	Poco Petroleums Ltd	Re-entry	Vertical	50.8	95.2	260
Dec,'93	1	Sinclair, AB	Imperial Oil Resources	Re-entry	Vertical	60.3	121.0	1775
Jan,'94	1	Kaybob, AB	Co-enerco	New	Vertical	38.1	98.0	1400
Jan,'94	1	Fox Creek, AB	Amerada	Re-entry	Vertical	50.8	152.0	2600
Jan,'94	1	Doe Creek, AB	Talisman	Sidetrack	Deviated	50.8	98.0	2500

Two horizontal wells have been drilled in Canada with coiled tubing, one new well at Shekilie for Petro Canada and one re-entry for Gulf in Big Valley. Petro Canada's well was drilled underbalanced with coiled tubing due to the depleted nature of the target formation. The well was judged unsuccessful due to failure of the MWD system. Rather than drill the well blind, operations were suspended.

The horizontal re-entry for Gulf was designed to bypass near-wellbore damage. Drilling operations were conducted with 2-in. coiled tubing, nitrified drilling foam, and an MWD system. A 4¾-in. hole was drilled through a window in the 5½-in. casing. Problems were experienced with directional control. A significant increase in ROP due to underbalanced conditions resulted in low WOB and poor ability to control direction. The wellbore did not remain in the target formation and the project was not deemed a success.

Development in coiled-tubing drilling is proceeding rapidly in Canada. New operations, such as setting whipstocks, cutting windows, directional drilling, coring, evaluating, and testing, are being planned with coiled tubing. Special tools under development include thrusters for applying WOB, torque reactors, and rotators to allow rotating the BHA.

A typical coiled-tubing drilling surface location is shown in Figure 5-100. Canadian highway load limits dictate a maximum spool length of about 20,000 ft of 1½-in., 12,000 ft of 2-in., and 9000 ft of 3½-in. coiled tubing.

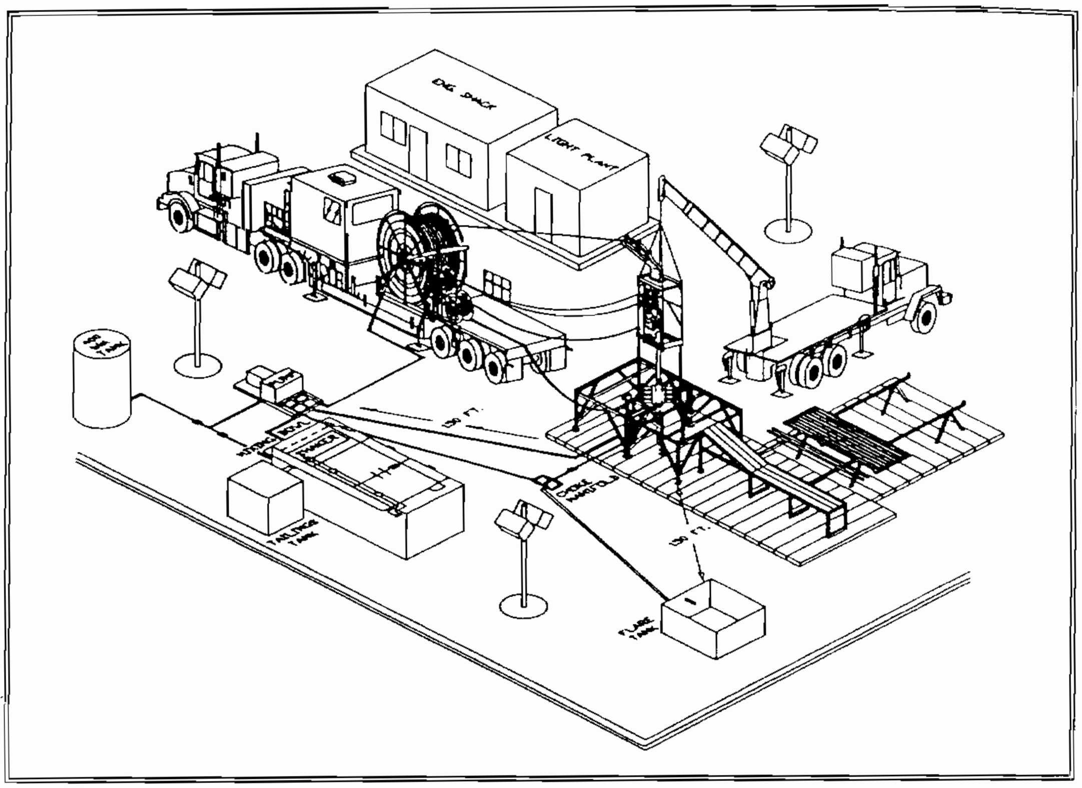


Figure 5-100. Surface Equipment for Coiled-Tubing Drilling (Hatala et al., 1994)

Hatala et al. estimated the growth of coiled-tubing drilling in Canada in 1994 and beyond. They estimated that a total of 90 coiled-tubing drilling operations would be conducted in 1994, including 65 vertical deepenings, 15 new vertical wells, and 10 horizontal re-entries. They assumed that 670 horizontal re-entries will be performed annually over the next several years, and that coiled tubing's share of that market will increase. According to their forecast (Table 5-35), demand will exceed supply until 1998.

TABLE 5-35. Forecast of Canadian Coiled-Tubing Drilling (Hatala et al., 1994)

	1992	1993	1994	1995	1996	1997	1998
• Conventional HZ Re-Entries	110	150	195	255	330	430	560
• CT HZ Re-Entries	2	0	10	35	70	105	140
SUB-TOTAL	**112**	**150**	**205**	**290**	**400**	**535**	**700**
• Supply Less Demand (670 per yr)	*(558)	(520)	(465)	(380)	(270)	(135)	30
• CT Vertical Deepenings	40	50	65	80	100	125	150
• CT Vertical Grassroots	1	3	15	20	30	40	50
TOTAL CTD OPERATIONS	**43**	**53**	**90**	**135**	**200**	**270**	**340**

Note: * ( ) brackets indicate a shortfall of services to meet the perceived demand.

According to the experience of the Canadian industry, improvements are needed in four areas of coiled-tubing drilling technology: 1) tubing materials and performance, 2) integration of drilling equipment and systems, 3) directional tools (orienting tools, thrusters, etc.), and 4) improved motor and bit performance in various fluids. Hatala et al. point to the orienting tool as the greatest current need. Orienting tools are needed that are based on servomotor control to allow the development of joystick drilling.

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6. Fatigue

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6. Fatigue

6.1 THEORY

6.1.1 Exxon Production Research Company

Sisak of Exxon Production Research and Crawford of Stanford University developed a model for fatigue of coiled tubing (Sisak and Crawford, 1994). Their model is based on full-scale testing results, published fatigue data, and general industry experience and observations. A separate failure mechanism is assumed to control fatigue under low versus high internal pressure. Under conditions of high internal pressure, fatigue is controlled by the net cumulative axial plastic strain, with failure occurring when the strain reaches a critical value. For fatigue with low internal pressure, the model is based on standard low-cycle fatigue theory.

Laboratory testing of fatigue and material properties was conducted toward the development of the model. Most tests were performed with new 1¼ x 0.087-in. 70 ksi tubing. Full-scale bending tests were conducted on a test fixture with a 6-ft diameter wheel. (This test stand was built by Southwestern Pipe and has been described previously in the literature.) Bending strain amplitudes of about 1.1%/cycle were measured on the test specimens. A theoretical maximum strain value of 1.7%/cycle was calculated for this bending geometry.

Failures were observed on the outside of the pipes on surfaces both against the bending wheel and opposed to the wheel. Most failures in the field are reported to occur on the pipe surface in contact with the gooseneck. Examples of pipes that failed in the laboratory are shown in Figure 6-1. Undulating bulges are commonly observed in the laboratory and field, and tend to grow larger at higher internal pressures. These are believed to result from local buckling of unsupported sections of pipe while it is being straightened (Sisak and Crawford, 1994).

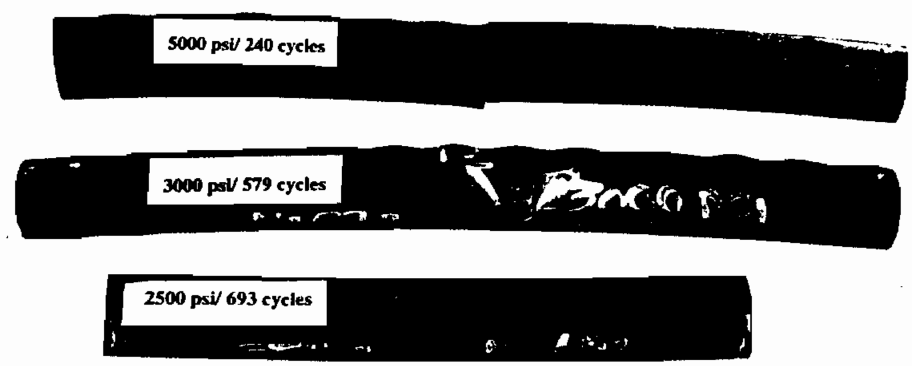

Figure 6-1. Fatigued Coiled Tubing (Sisak and Crawford, 1994)

Uniaxial tensile properties were measured for coiled tubing material. Small cylinders (⅛-in. OD) were machined from 0.156-in. wall tubing and tested to failure in tension. The local axial strain at failure was estimated as 150%, assuming a Poisson's ratio of 0.5. Next, fatigued tubing samples were examined (Figure 6-2). These showed crack growth and necking in the failure zone in a manner consistent with a ductile overload failure, similar to a uniaxial tension failure.

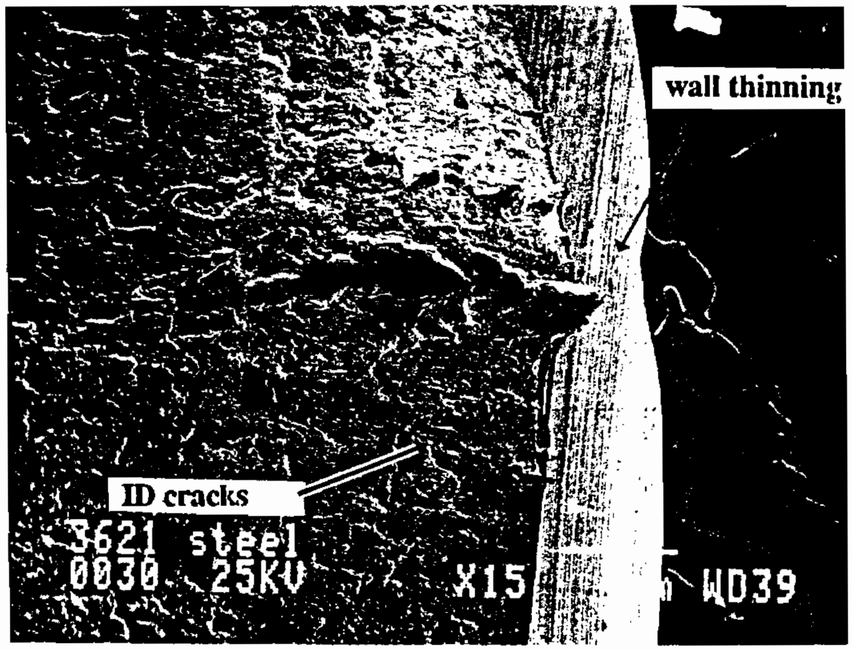

Figure 6-2. Cross-Section of Coiled-Tubing Failure
(Sisak and Crawford, 1994)

Fatigue test results are summarized in Figure 6-3 for internal pressures ranging from 1000 to 6000 psi. An interesting trend in the data is that failures at 3000 psi and greater occur at about the same final diameter. Failures at high pressures are apparently controlled by ballooning rather than number of cycles. Sisak and Crawford determined that these high pressure failures occurred when the net strain per cycle summed to a local fracture strain of 150%, just as for the uniaxial tensile tests.

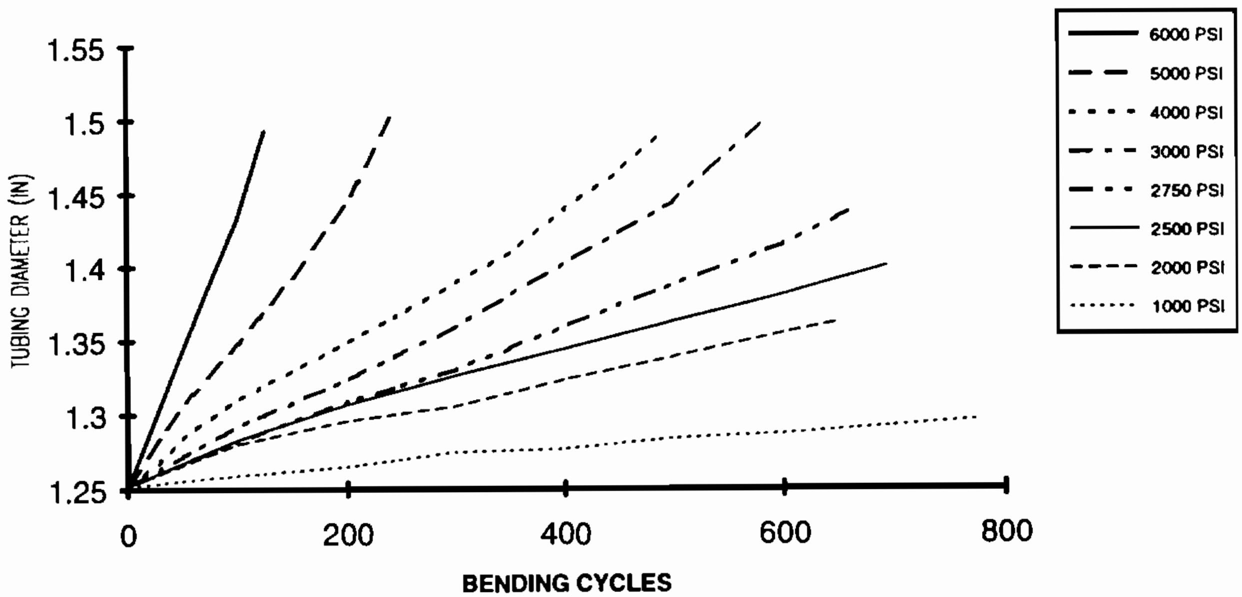

Figure 6-3. Bending Cycles and Diametral Growth (Sisak and Crawford, 1994)

Diametral growth during bending can be qualitatively interpreted as shown in Figure 6-4. The "A" vectors depict strain for bending with no internal pressure. These are roughly equal and opposite. However, with internal pressure (the "B" vectors), the strains are not equal and opposite, a net hoop strain results, and the tubing diameter increases with each bending cycle.

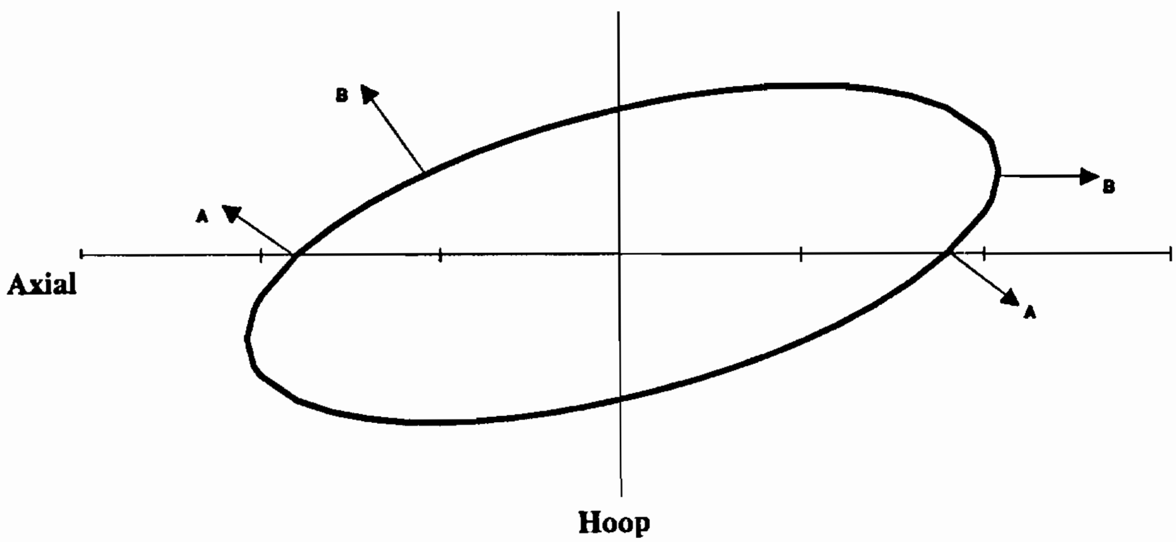

Figure 6-4. Diametral Growth due to Axial Strain and Pressure (Sisak and Crawford, 1994)

Tubing failures at pressures below 3000 psi were found to be relatively insensitive to the number of bending cycles. These failures can be predicted by summing the accumulated plasticity, with 475% the approximate critical value.

In addition to the tests with new tubing, two tests were conducted with used tubing. One pipe had been exposed to the elements for six months and had surface gouges of about 0.5 x 0.01 in. These surface defects decreased the fatigue life by 43%.

A model of a deforming section of coiled tubing was developed using finite-element analysis. A generalized plane strain element was devised to simulate fatigue. A comparison of measured growth rates to those predicted by the finite-element model is shown in Figure 6-5.

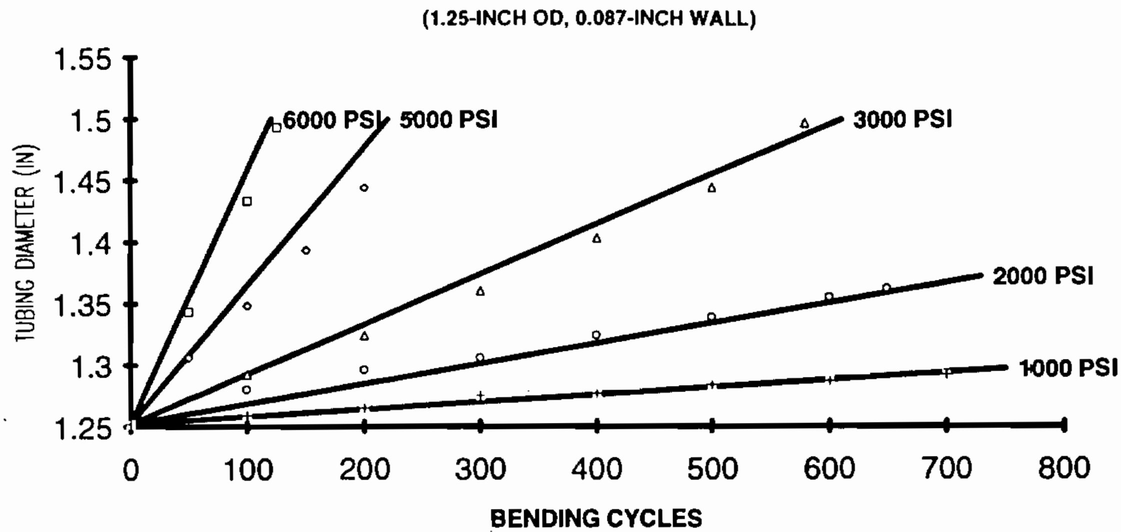

Figure 6-5. Diametral Growth Measurements and Model Predictions (Sisak and Crawford, 1994)

Predicted and measured cycles to failure are compared in Table 6-1.

TABLE 6-1. Cycles to Failure Measurements and Model Predictions (Sisak and Crawford, 1994)

INTERNAL PRESSURE psi	CYCLES TO FAILURE		
	Measured	Predicted	Error
6,000	125	132	+5.6%
5,000	240	247	+2.9%
4,000	487	486	-0.2%
3,000	579	591	+2.1%
2,000	649	728	+12.1%
1,000	772	730	-5.4%

The finite element model was used to relate hoop stress to fatigue life. Hoop stress was used as the critical parameter instead of pressure, diameter, and/or thickness. Hoop stress and strain amplitude are related to cycle life in Figure 6-6. These results are for 70-ksi tubing.

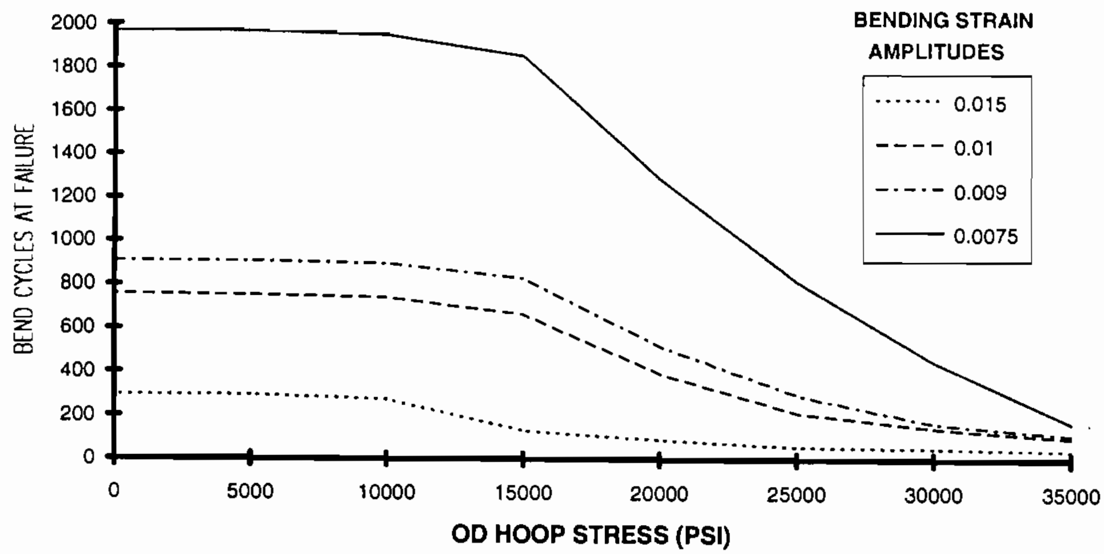

Figure 6-6. Hoop Stress and Cycle Life (Sisak and Crawford, 1994)

Sisak and Crawford gave examples of the use of Figure 6-6 to compare fatigue life for various conditions. For 1¼-in. coiled tubing, the bending strain was 1.04%. At 1000 psi internal pressure, the hoop stress is 7184 psi; at 5000 psi pressure, the hoop stress is 35,919 psi. The life predicted in the figure is 780 cycles at 1000 psi and 110 cycles at 5000 psi.

Fatigue life, as predicted by Sisak and Crawford's model, is relatively insensitive to hoop stress below a critical range. Above this range (e.g., 15,000 psi hoop stress at 0.0075 strain), fatigue life decreases rapidly.

6.1.2 Halliburton

Halliburton (Avakov et al., 1993) developed a mathematical model for coiled-tubing life prediction. Their model is based on an algorithm that relates equivalent strains to principal strains. Full-scale laboratory testing was used to test the accuracy of the model. A correlation coefficient of 0.973 was reported between predicted and measured fatigue life.

The majority of engineering problems in the prediction of fatigue life relate to high-cycle failure. Both the Tresca criterion (maximum shear stress failure theory) and von Mises criterion (distortion energy failure theory) are widely used for high-cycle fatigue of ductile metals under multiaxial stress. In problems of low-cycle fatigue, such as for coiled tubing, basic theories do not correlate with observed behavior.

Avakov et al.'s approach to the prediction of low-cycle fatigue life was based on Collins' techniques, which 1) define an equivalent stress and equivalent total strain range, 2) estimate life using equivalent strain range and low-cycle fatigue lines defined under uniaxial stress state, and 3) convert equivalent uniaxial mean stress cycles to equivalent reversed cycles by an empirical expression based on material data. Although questions remain regarding the validity of this technique, it is considered the best approach available.

The basic strain-life curve for coiled tubing takes the form:

$$\frac{N}{N_M}\left(\frac{S}{S_M}\right)^2 = 1$$

where: N is tubing life, cycles

N_M is median fatigue line reference, cycles

S is total applied stress

S_M is median fatigue line reference (strength/stress)

As a consequence, the quantity $N_M S_M^2$ is a constant for a given material. For QT-700 70-ksi material, $N_M S_M^2$ is about $130 \bullet 10^6$ (Avakov and Foster, 1994). With this material property defined, other stress ranges and cycles lives are normalized with the quantity NS^2. Tubing life is thus proportional to the square of the equivalent stress.

Typical stresses for 1¼ x 0.087-in. 70-ksi coiled tubing as it is run from the reel to the well are shown in Table 6-2. Internal pressure is 5000 psi, and bending radii are 72 in. for the gooseneck and 42 in. for the reel. The unit loading from the injector's pressure beam is 1287 lb/in. Experience has shown that stresses due to hoisting loads and injector gripper pressure are small enough to be neglected in the analysis of low-cycle fatigue life.

TABLE 6-2. Typical Stresses in Coiled Tubing During Pressure Cycling (Avakov et al., 1993)

Section location: *source of loading*		INNER TUBING SURFACE & OUTER RADIUS	INNER TUBING SURFACE & INNER RADIUS	OUTER TUBING SURFACE & OUTER RADIUS	OUTER TUBING SURFACE & INNER RADIUS
1. On the reel: *inner pressure &* *bending over reel*	σ_r σ_t σ_a	$\sigma_3 =$ -5000 $\sigma_2 =$ 33607 $\sigma_1 =$ 382012	$\sigma_2 =$ -5000 $\sigma_1 =$ 33607 $\sigma_3 =$ -382012	$\sigma_3 =$ 0 $\sigma_2 =$ 28607 $\sigma_1 =$ 443787	$\sigma_2 =$ 0 $\sigma_1 =$ 28607 $\sigma_3 =$ -443787
2. Space reel- -gooseneck & 4. gooseneck-p.beams: *inner pressure*	σ_r σ_t σ_a	$\sigma_3 =$ -5000 $\sigma_1 =$ 33607 $\sigma_2 =$ 0	$\sigma_3 =$ -5000 $\sigma_1 =$ 33607 $\sigma_2 =$ 0	$\sigma_3 =$ 0 $\sigma_1 =$ 28607 $\sigma_2 =$ 0	$\sigma_3 =$ 0 $\sigma_1 =$ 28607 $\sigma_2 =$ 0
3. Gooseneck: *inner pressure &* *bending over* *gooseneck*	σ_r σ_t σ_a	$\sigma_3 =$ -5000 $\sigma_2 =$ 33607 $\sigma_1 =$ 224167	$\sigma_2 =$ -5000 $\sigma_1 =$ 33607 $\sigma_3 =$ -224167	$\sigma_3 =$ 0 $\sigma_2 =$ 28607 $\sigma_1 =$ 260416	$\sigma_2 =$ 0 $\sigma_1 =$ 28607 $\sigma_3 =$ -260416
5. Between p.beams: *inner pressure &* *V-block load* *(upper sections)*	σ_r σ_t σ_a	$\sigma_3 =$ -5000 $\sigma_1 =$ 1822 $\sigma_2 =$ 0	$\sigma_3 =$ -5000 $\sigma_1 =$ 1822 $\sigma_2 =$ 0	$\sigma_2 =$ 0 $\sigma_1 =$ 60392 $\sigma_3 =$ 0	$\sigma_2 =$ 0 $\sigma_1 =$ 60392 $\sigma_3 =$ 0
6. Between p.beams: *inner pressure,* *hoisting load &* *V-block load*	σ_r σ_t σ_a	$\sigma_3 =$ -5000 $\sigma_2 =$ 1822 $\sigma_1 =$ 56000	$\sigma_3 =$ -5000 $\sigma_2 =$ 1822 $\sigma_1 =$ 56000	$\sigma_3 =$ 0 $\sigma_1 =$ 60392 $\sigma_2 =$ 56000	$\sigma_3 =$ 0 $\sigma_1 =$ 60392 $\sigma_2 =$ 56000
7. Below pressure beams: *inner* *pressure and* *hoisting load*	σ_r σ_t σ_a	$\sigma_3 =$ -5000 $\sigma_2 =$ 33607 $\sigma_1 =$ 56000	$\sigma_3 =$ -5000 $\sigma_2 =$ 33607 $\sigma_1 =$ 56000	$\sigma_3 =$ 0 $\sigma_2 =$ 28607 $\sigma_1 =$ 56000	$\sigma_3 =$ 0 $\sigma_2 =$ 28607 $\sigma_1 =$ 56000

σ_a - axial stress due to hoisting load or bending over reel and gooseneck; bending stress is defined as $\sigma_a = \sigma_b = \pm\varepsilon E \approx \pm dE/(2R)$, where R is bending radius over reel or gooseneck; σ_r - radial stress; σ_t - tangental stress; $\sigma_1, \sigma_2, \sigma_3$ - principal stresses.

Coiled tubing's operational conditions are relatively unique and characterized by alternating plastic strains along the longitudinal axis (bending over the reel and gooseneck) and static biaxial stress (due to internal pressure). Bending strains are far beyond elastic limits and are the most damaging. Stress due to pressure is normally not damaging unless alternating axial stress is also applied.

In Halliburton's fatigue model, low-cycle fatigue life is defined by the Coffin-Manson equation (Figure 6-7). The strain/life curve is the sum of two lines, one for plastic strain and one for elastic. Clearly, for short-lived materials like coiled tubing (almost always less than 300 cycles), the plastic strain term (second term on right side of equation in Figure 6-7) dominates.

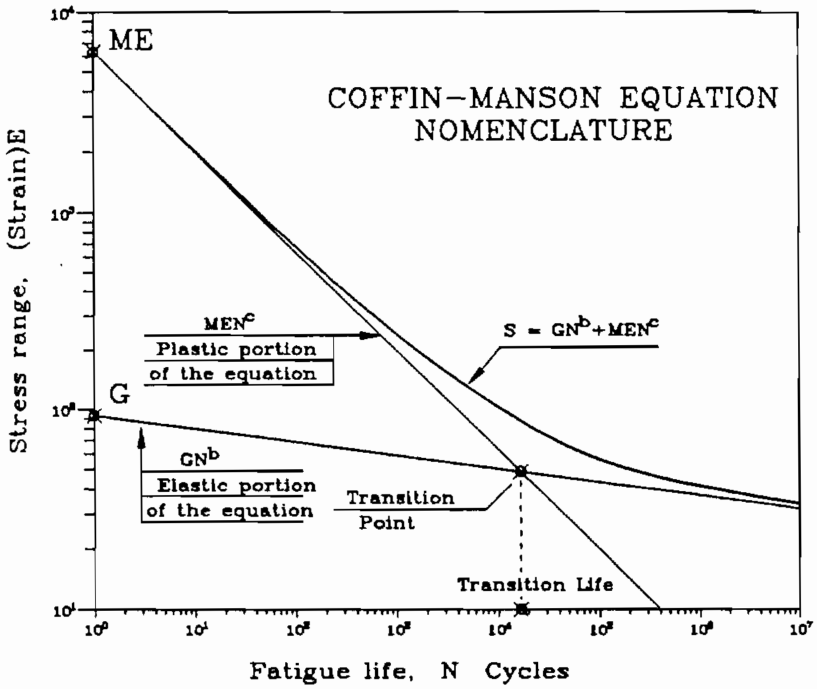

Figure 6-7. Coffin-Manson Low-Cycle Fatigue Stress/Life (Avakov et al., 1993)

Halliburton's fatigue model was compared to measure cycle life in a series of 28 tests performed on a shallow test well with a standard coiled-tubing unit. Tests were performed with strings of 70-, 80-, and 100-ksi 1¼ x 0.087-in. coiled tubing. Gooseneck radius was 70 in. and spool diameter ranged from 82-95 inches. Strokes to failure, usually manifested by the development of a pinhole leak, were recorded for each test run.

Results of the tests are summarized in Table 6-3. A stroke was defined as one complete trip in and out of the hole; thus, these data can be compared directly to other field results.

TABLE 6-3. Halliburton Fatigue Cycle Tests (Avakov et al., 1993)

COILED TUBING TEST DATA
1.25 *in.* OD, 0.087 *in.* wall thickness
m=1.895

SAMPLE	Ultimate Strength S_u *kpsi*	Bending Stress $S_{ag}=E\varepsilon_{ag}$ *kpsi*	Pressure P *psi*	Hoop Stress S_t *kpsi*	Predicted Life M_r *Strokes*	Recorded Life M *Strokes*	S-N Line Constant $N_M S_M^2$
1	85.7	436	200	1.1	321	240*	105645726
2	85.7	436	3000	17.2	145	143	139366392
3	85.7	436	5000	28.6	61	37	85365141
4	85.7	436	3000	17.2	145	135	131569671
5	85.7	436	4000	22.9	95	86	128692386
6	85.7	436	5000	28.6	61	56	129201294
7	85.7	446	4000	22.9	95	86	128692386
8	85.7	446	3000	17.2	145	141	137417211
9	85.7	446	5000	28.6	61	51	117665464
10	113	431	5000	28.6	107	115	152609453
11	113	431	6000	34.3	70	71	143230382
12	113	431	7500	42.9	39	40	144978886
13	113	431	3000	17.2	252	216	121082262
14	113	431	5000	28.6	107	102	135357949
15	113	431	7500	42.9	39	42	152227830
16	113	431	6000	34.3	70	66	133143735
17	101	395	6000	34.3	56	43	108582390
18	101	395	6000	34.3	56	49	123733421
19	101	395	5000	28.6	85	90	149499673
20	101	395	5000	28.6	85	82	136210813
21	101	395	4000	22.9	131	126	135751252
22	101	395	4000	22.9	131	112	120667780
23	85.7	457	3000	17.2	145	140	136442621
24	85.7	446	5000	28.6	61	60	138429958
25	85.7	446	3000	17.2	145	132	128645900
26	85.7	457	5000	28.6	61	50	115358298
27	85.7	457	5000	28.6	61	54	124586962
28	85.7	446	3000	17.2	145	140	136442621
						Mean	**130021352**
						STD	**14449594**
						STD/Mean	**0.111**

* Test halted after 240 strokes

Tubing strength, pressure, and life are compared in Figure 6-8. Higher strength tubing performed more cycles before failure. However, increased pressure significantly shortened fatigue life for all samples.

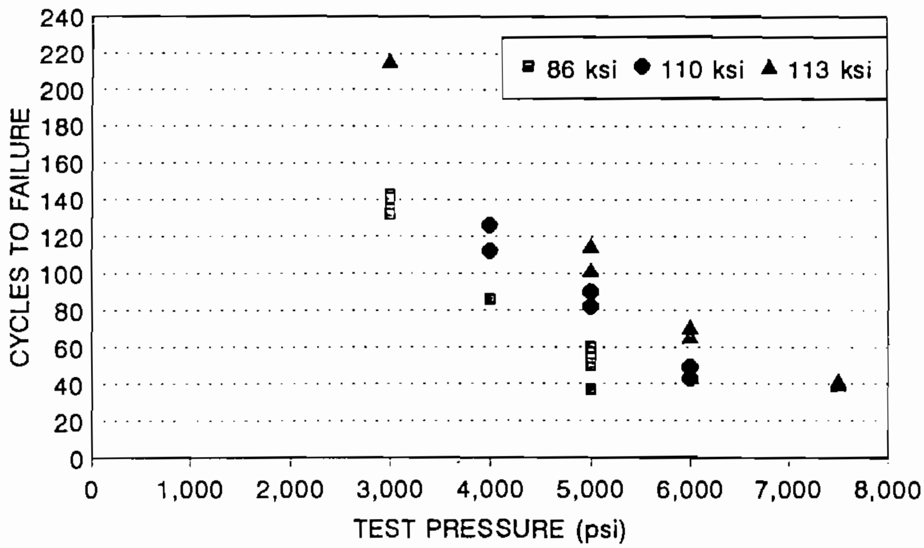

Figure 6-8. Fatigue Life, Tubing Strength and Pressure (Avakov et al., 1993)

Measured and predicted cycle life are compared in Figure 6-9. The line in the figure represents perfect correlation (y=x). It can be seen that the predicted results are on average slightly less than measured cycle life.

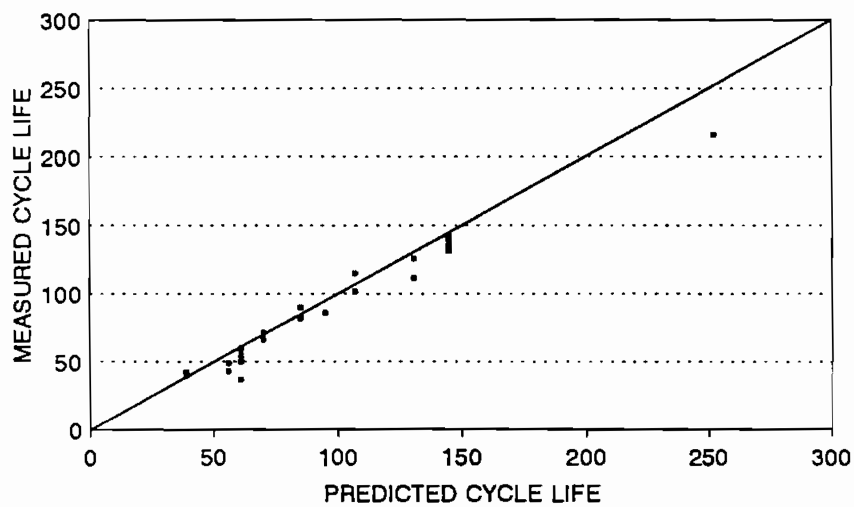

Figure 6-9. Predicted and Measured Cycle Life (Avakov et al., 1993)

Avakov et al. concluded that further verification of the model in the laboratory and field is needed. More tests are planned with tubings of various diameter and thickness. For more details on Halliburton's model for fatigue-life prediction, the reader is directed to the papers Avakov et al. (1993) and Avakov and Foster (1994).

6.2 FATIGUE TESTING

6.2.1 CYMAX/TIMET (Titanium Coiled Tubing)

CYMAX (Zernick, 1994) reported the results of a series of fatigue life tests comparing titanium to steel. Their data show that ballooning (diametral growth) is much less for titanium at similar load stresses (Figure 6-10).

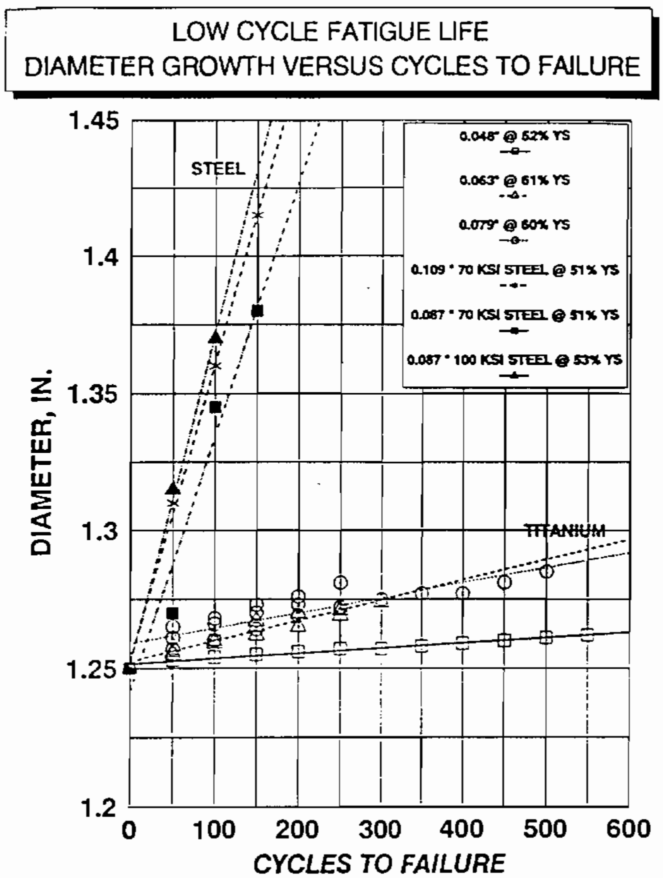

Figure 6-10. Ballooning of Titanium and Steel (Zernick, 1994)

Fatigue life of high-strength titanium is greater than both 70-ksi and 100-ksi steel for a range of wall thicknesses (Figure 6-11). Note that, for CYMAX's fatigue test fixture, each bending/unbending cycle is counted as one cycle. To compare with cycle life on a rig, these data should be divided by three.

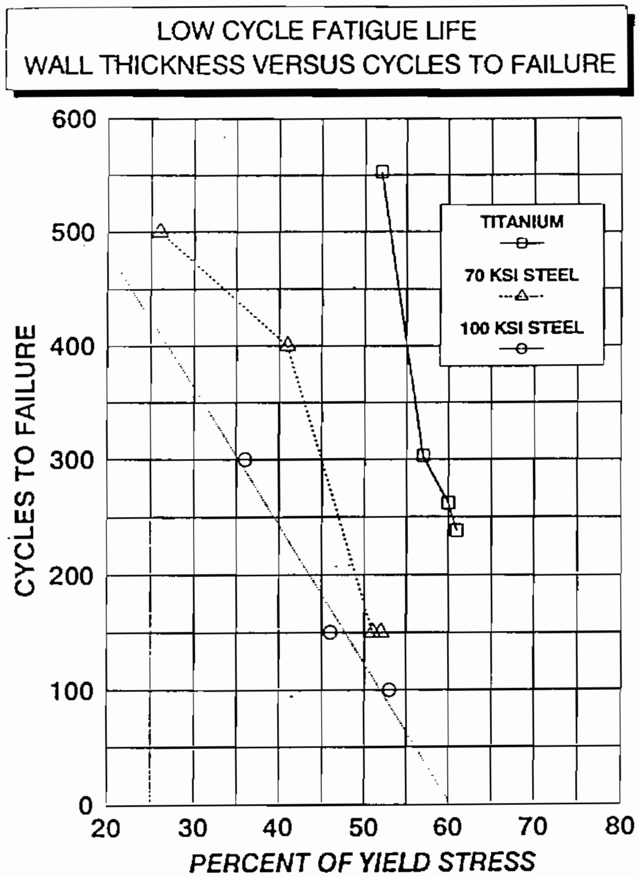

Figure 6-11. Titanium Fatigue Life (Zernick, 1994)

6.2.2 Schlumberger Dowell (Oval Coiled Tubing)

Schlumberger Dowell (Newman, 1992) reported the results of the effects of ovality on the collapse rating of coiled tubing. During cycling operations, coiled tubing becomes out-of-round due to bending around the reel and across the gooseneck. Ovality is known to have a detrimental effect on collapse rating of tubing.

Ovality can be defined as:

$$\text{Ovality \%} = 100\left(\frac{\text{Major OD}}{\text{Minor OD}} - 1\right)$$

Just before coiled tubing collapses (obviously a plastic deformation), plastic hinges form at the major and minor axes, with stress concentrations assumed as shown in Figure 6-12.

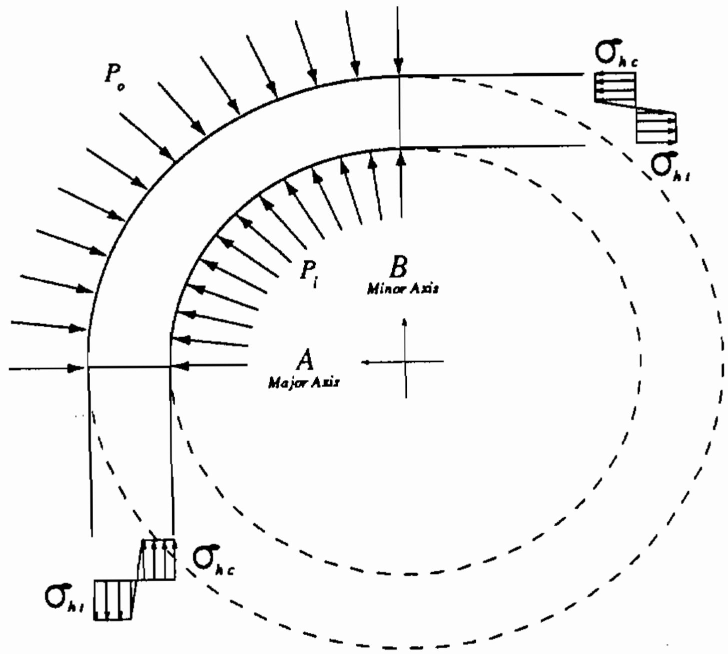

Figure 6-12. Plastic Stress Distribution Before Collapse (Newman, 1992)

Newman (1992) developed an equation to estimate the external pressure that will cause collapse. Next, theoretical predictions were compared to laboratory test results. A special fixture was devised to subject coiled tubing to increasing external pressures (Figure 6-13).

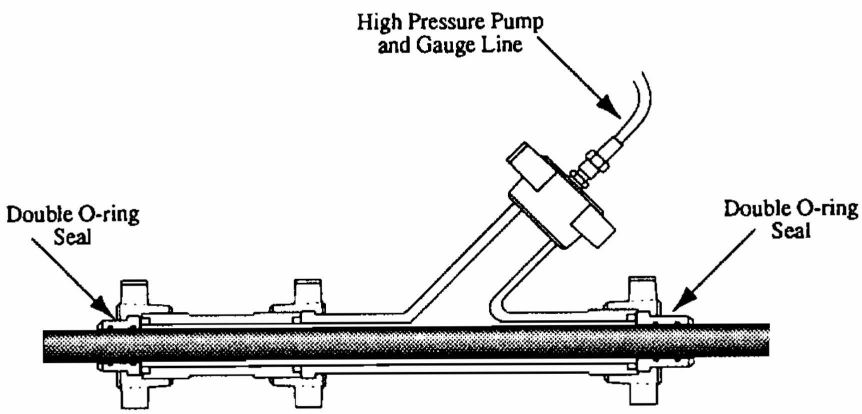

Figure 6-13. Coiled Tubing Collapse Test Fixture (Newman, 1992)

New tubing was ovaled by pressing it between two plates. Twelve-inch samples were placed in the fixture and subjected to increasing pressures until collapse. For two cases, an axial load of 20,000 lb was placed on the sample during the tests. Test results are summarized in Table 6-4.

TABLE 6-4. Ovality and Collapse-Pressure Tests (Newman, 1992)

OVALITY (%)	AXIAL FORCE (lbf)	MEASURED COLLAPSE PRESSURE (psi)	CALCULATED COLLAPSE PRESSURE (psi)	% DIFF
0.4	0	8,130	9,076	11.6
2.7	0	7,740	7,752	0.2
2.7	20,000	5,090	3,916	-23.1
4.4	0	6,690	6,931	3.6
4.8	0	6,310	6,757	7.1
7.2	0	5,760	5,831	1.2
7.4	20,000	4,180	2,998	-28.3
9.3	0	5,160	5,175	2.9
9.9	0	4,770	5,010	5.0
12.9	0	4,260	4,305	1.1

Most of the collapsed samples assumed the shape of an '8', suggesting the formation of all four plastic hinges. Test results and theoretical predictions are compare in Figure 6-14. Based on assumptions used in developing the mathematical prediction, it was expected that actual results would be below estimations. A curve is also presented for 75-ksi yield stress since pull tests of test tubing showed this value.

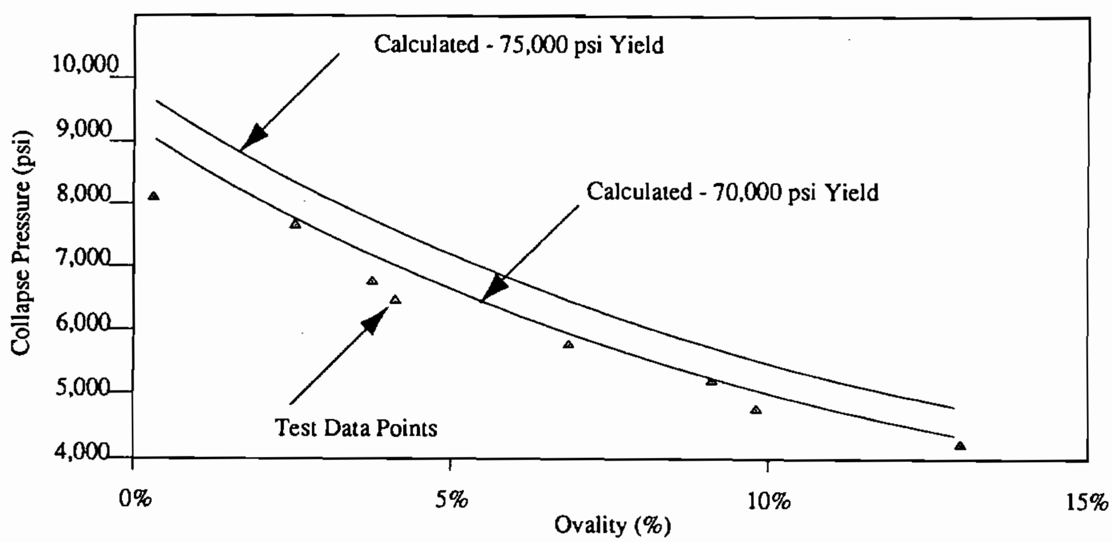

Figure 6-14. Coiled-Tubing Collapse Pressure and Ovality (Newman, 1992)

6.2.3 Schlumberger Dowell (Fatigue Test Fixture)

Schlumberger Dowell (Newman and Brown, 1993) led a multiparticipant development of a method and testing apparatus to simplify and standardize coiled-tubing fatigue testing. A simple testing method was desired for several reasons, including the high cost of full-scale testing with a coiled-tubing rig, the lack of a standard approach by the companies previously addressing fatigue, and the lack of standard quality-control tests for new tubing.

Based on previous results of coiled-tubing fatigue tests, the test fixture was designed to account for only the major causes of fatigue damage: plastic deformation on the reel and gooseneck, and internal pressure. Other factors and types of damage were assumed to have a small impact and were ignored, including gooseneck rollers and roller spacing, and axial tension.

The operational principle of the test fixture (Figure 6-15) involves bending a sample of coiled tubing across a fixed radius, and then straightening it back to its original position. Both bending surfaces have "V" profiles. The bending arm is equipped with rollers to prevent axial loads from being applied to the sample.

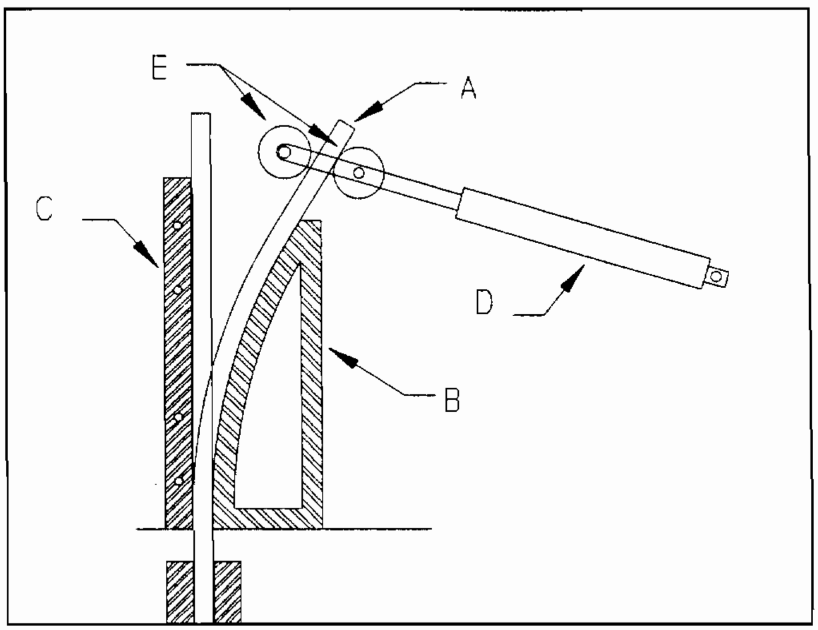

Figure 6-15. Fatigue Test Fixture Schematic (Newman and Brown, 1993)

A view of the complete fixture is shown in Figure 6-16. During testing, the sample is filled with water and pressurized to the test pressure. Fatigue failure is detected as a drop in pressure inside the tubing. Size, weight and cost of the design were kept low to encourage the widespread adoption and use of the system.

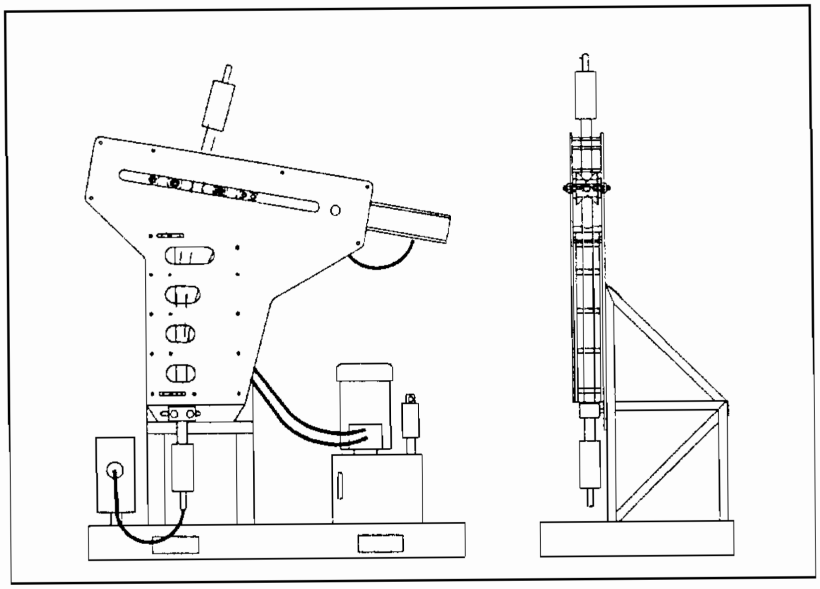

Figure 6-16. Complete Fatigue Test Fixture (Newman and Brown, 1993)

Test results (Table 6-5) show relatively good agreement between measurements with the fixture, full-scale tests (with a rig) and model predictions. Note that each run-in and pull-out sequence with a rig consists of three cycles as reported here, assuming the gooseneck and reel bending radii are equivalent to the fixture. Crack initiation, as predicted by Schlumberger's model, is considered the end of tubing working life. The rate of crack propagation, once formed, is a function of internal pressure and wall thickness.

TABLE 6-5. Fatigue Test Results (Newman and Brown, 1993)

CT Dia. (in)	Wall Thickness (in)	Bending Radius (in)	Internal Pressure (psi)	Predicted Crack Init. (cycles)	Predicted Failure (cycles)	Observed Full-Scale (cycles)	Observed Fixture (cycles)
1.25	0.087	48	250	447	597	597	522
1.25	0.087	48	1500	399	528	525	517
1.25	0.087	48	3000	336	432	423	333
1.25	0.087	48	4000	228	282	n/a	212
1.25	0.087	48	5000	111	129	123	128
1.75	0.109	48	250	252	330	n/a	362
1.75	0.109	48	1000	231	309	n/a	262
1.75	0.109	48	2000	213	279	n/a	216
1.75	0.109	48	3000	174	225	n/a	170
1.75	0.109	48	4000	99	117	n/a	99
1.75	0.109	48	5000	42	45	n/a	49
1.75	0.156	48	2000	225	300	n/a	311
1.75	0.156	48	4000	195	252	n/a	235

Test results are shown graphically in Figure 6-17, which compares predicted crack initiation, predicted failure, and measured failure. For most cases, measured failure falls between predicted initiation and failure. Schlumberger's recommended practice, based on these and other results, is to consider 80% of predicted crack initiation as a conservative service life for a string of tubing.

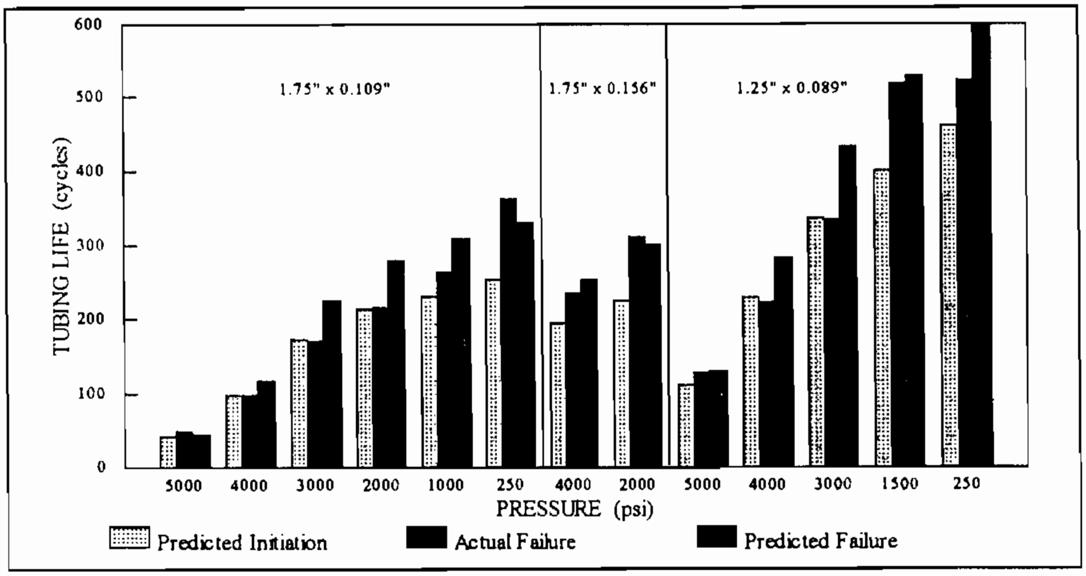

Figure 6-17. Fatigue Test Results and Predictions (Newman and Brown, 1993)

6.2.4 <u>Schlumberger Dowell (Coiled-Tubing Diameter Growth)</u>

Schlumberger Dowell (Brown, 1994) investigated the diameter growth of coiled tubing during plastic cycling. In many cases, a practical limit is reached for increasing coiled-tubing diameter because the tubing will no longer pass through the stripper brass. One potential solution short of retiring the string is to cut out ballooned sections from the string. Unfortunately, butt welds to spice the string in the field also introduce a reduced life expectancy.

Schlumberger Dowell's recommended practice is to allow a maximum diameter growth of 6% (Brown, 1994). With this limit, a string may be retired even though significant fatigue life remains. Data in Table 6-6 show that about half the fatigue life remains after a 1¾-in. tubing cycled at 6000 psi has grown in diameter by 6% (i.e., to 1.855 in.). Several researchers have confirmed that diameter growth is strongly influenced by internal pressure. In addition, the relationship is not linear.

TABLE 6-6. Working Life of 1¾-in. Coiled Tubing for 6% Growth (Brown, 1994)

Pressure (psi)	Fatigue Life (cycles)	Final Diameter (in)	Observed Cycles at 6%	Predicted Cycles at 6%	Working Life (% of fatigue life)
1000	435	1.85	(not reached)	(457)	100%
2000	219	1.90	150	153	68%
4000	63	1.93	35	37	56%
6000	21	1.87	10	18	48%

When possible, cycling coiled tubing under pressure is avoided. However, in many circumstances this situation is difficult to avoid. In one important example, frequent cycling is required at pressures from 2000-4000 psi in a typical coiled-tubing drilling operation.

Primary parameters controlling diameter growth are internal pressure, tubing diameter, wall thickness, bending radius, and material properties. Coiled tubing becomes oval in cross-section when bent around a spool or gooseneck. Wall thickness decreases as the diameter grows, with more thinning at the top and bottom than on the sides (which are near the neutral bending axis).

The fatigue test fixture described in the preceding section was used by Schlumberger Dowell in the investigation of coiled-tubing diameter growth. This machine significantly accelerated testing procedures. A series of 300 fatigue cycles can be completed in about 2½ hours, as compared to several days with a rig.

Results with the fatigue test fixture were seen to compare favorably with full-scale tests. One consideration not accounted for by the testing procedure is the effect of gripper blocks on diameter growth. Gripper blocks may reduce the rate of ballooning since they serve to constrain the tubing. No diametral constraint is placed on the tubing in Schlumberger's test fixture.

Schlumberger Dowell has performed over 250 fatigue tests in the fixture. As testing proceeds, major and minor axes are measured at regular intervals. These data are analyzed to discern trends in ballooning and ovality as a function of pressure.

Diametral growth and cycle life are compared in Figure 6-18 for 1¾ x 0.109-in. tubing at a 48-in. bend radius for pressures from 250 to 8000 psi. Fatigue cycle life is shown above the data points. The greatest growth in diameter occurred at pressures in the range of 4000-5000 psi. At higher pressures, the tubing failed before extreme diametral growth could occur.

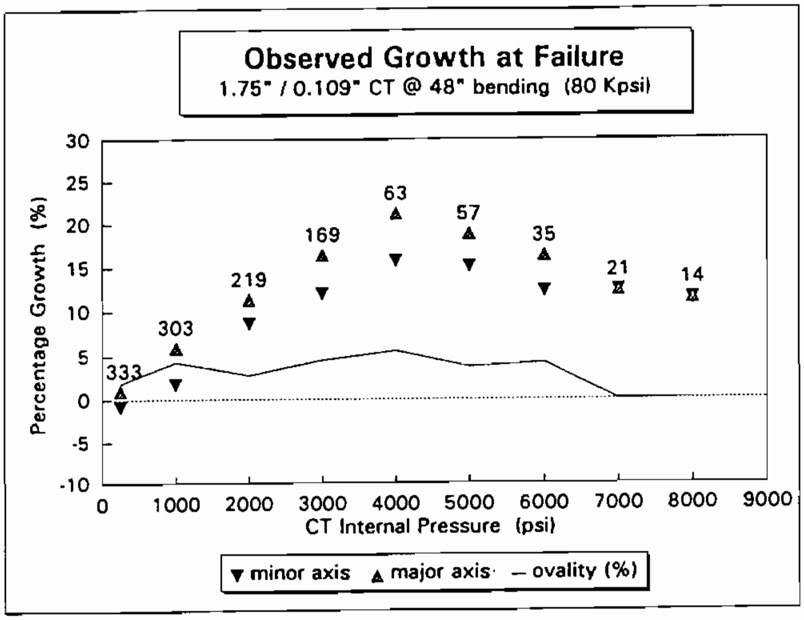

Figure 6-18. Diametral Growth for 1¾ x 0.109-in. Tubing (Brown, 1994)

The rate of growth in diameter, expressed as percent increase per cycle, is illustrated in Figure 6-19 for two thicknesses of 1½-in. coiled tubing. The thicker tubing grows significantly less at pressures of 4000 psi and above.

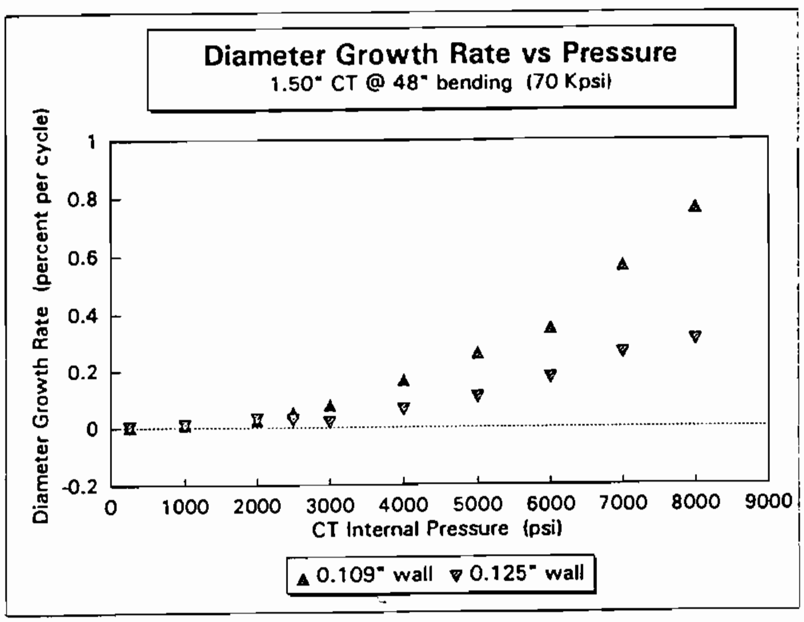

Figure 6-19. Diametral Growth Rate and Wall Thickess (Brown, 1994)

Test data are shown for a section of 3½-in. coiled tubing in Figure 6-20. Significant growth occurs with each cycle, and it is readily apparent that a limit of 6% growth would be quickly surpassed. However, on the other hand, 3½-in. tubing is not likely to be used in high-pressure, high-cycle operations.

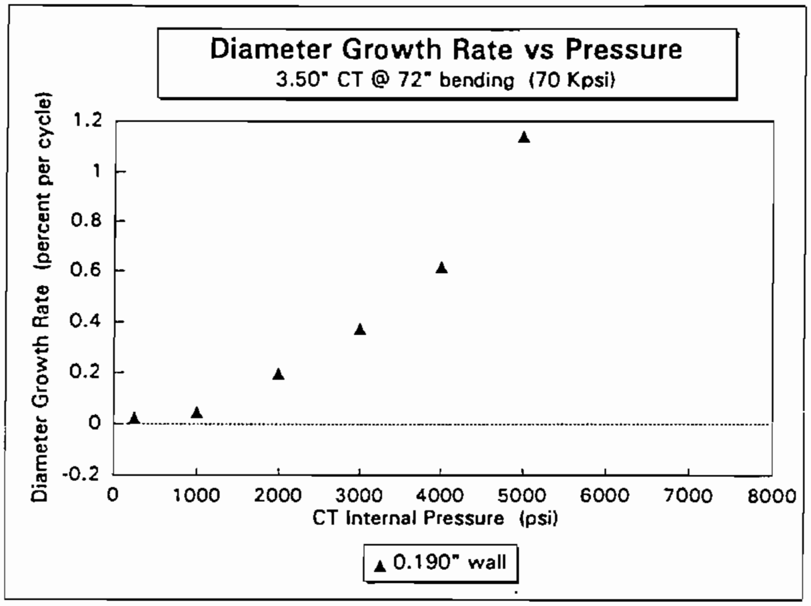

Figure 6-20. Diametral Growth Rate for 3½-in. Tubing (Brown, 1994)

Tubing material strength affects tubing growth (Figure 6-21), with 100 ksi tubing showing much less growth than 70 ksi as-rolled material. These data are for 1½ x 0.109-in. tubing bent on a 48-in. radius.

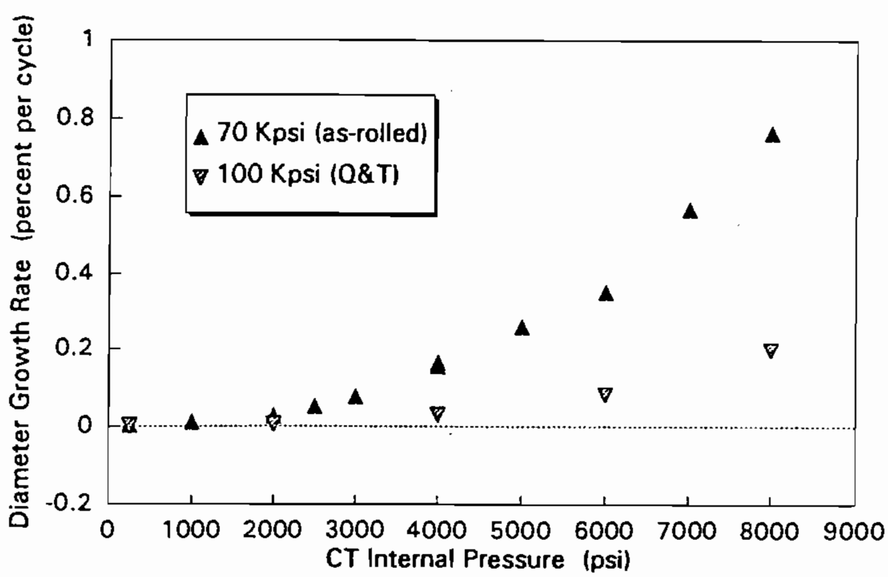

Figure 6-21. Diametral Growth Rate and Tubing Strength (Brown, 1994)

Based on a practical growth limit of 6%, tubing may need to be retired before the complete fatigue life is expended. At medium to high pressures, the difference between 6% working life and fatigue failure life can be substantial (Figure 6-22). At pressures above 2000 psi, growth limits dictate that the tubing be retired at a cycle life of less than half the fatigue limit. These data are for 1½ x 0.109-in. 70-ksi tubing bent on a 48-in. radius.

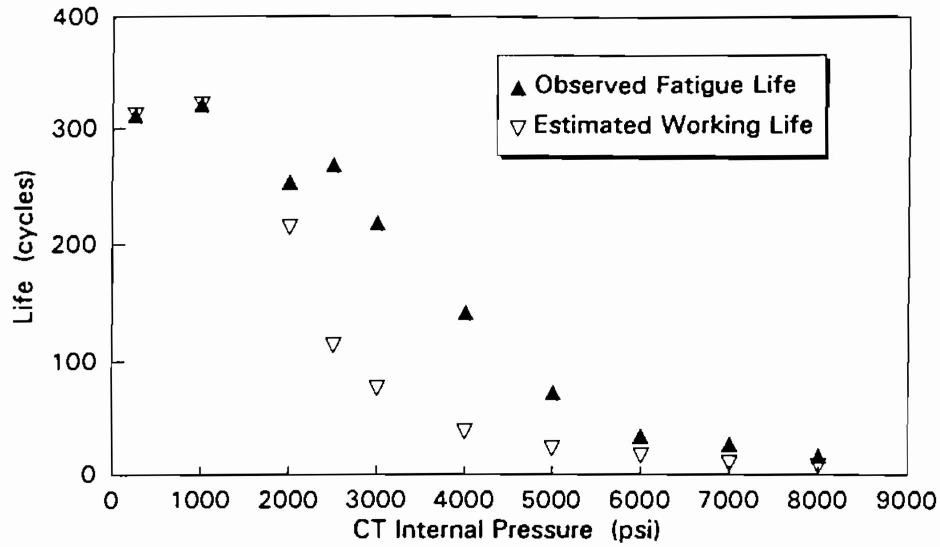

Figure 6-22. Tubing Working Life and Ultimate Life (Brown, 1994)

Schlumberger Dowell derived several conclusions from these tests, including the following:

- Pressure has a significant impact on diametral growth rate
- Growth rates are higher for larger diameter tubing; increased wall thickness can offset this tendency
- High-strength tubing has a lower growth rate than standard tubing
- Working life of a tubing string may be significantly less than total fatigue life, due to diameter growth limitations

6.3 FIELD APPLICATION

6.3.1 ARCO E&P Technology (Slaughter Field Well)

ARCO E&P (Hightower et al., 1993) used coiled tubing to drill a successful sidetrack of a well in the Slaughter Field in West Texas. Several aspects of the job represent the first time coiled tubing was used in these procedures. These include:

- Setting a whipstock in casing
- Milling a window
- Using MWD
- Using a pressure-activated orientation tool
- Using an autodriller system to maintain WOB

Although problems prevented the well from being drilled as planned, project results and well production were successful.

Fatigue was found to be an important element requiring careful tracking in these operations. As a result of many trips and extended operations at depth, about 80% of coiled-tubing fatigue life was used for this project (Figure 6-23).

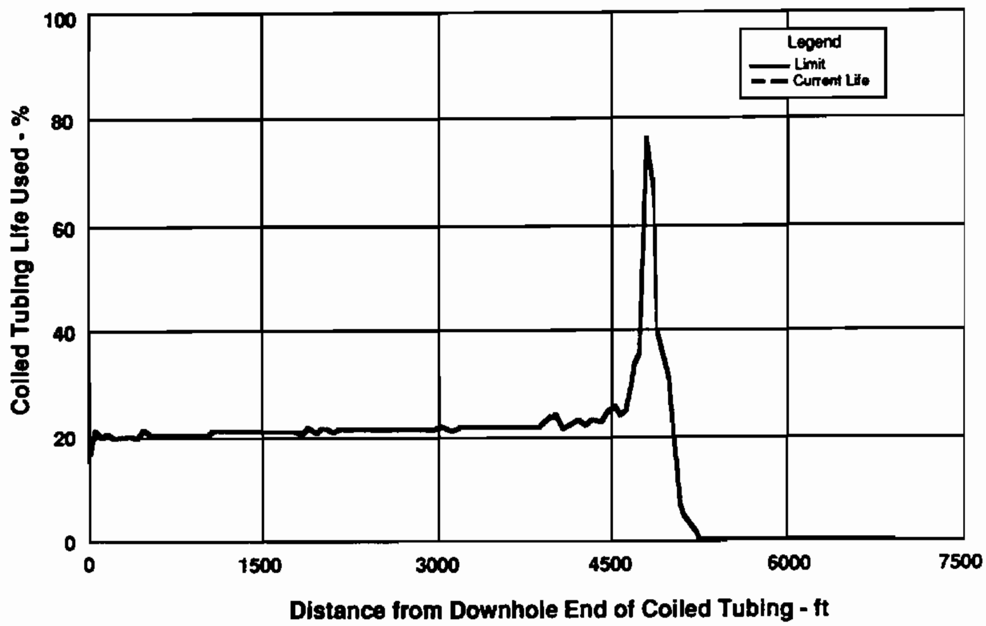

Figure 6-23. Coiled-Tubing Life for Drilling Project (Hightower et al., 1993)

ARCO's experience demonstrated that drilling with coiled tubing is here to stay, and that the tools and technologies required are available and improving steadily. Detailed discussion of this project is presented in the Chapter *Drilling*.

6.3.2 Berry Petroleum (McKittrick Field)

Berry Petroleum and Schlumberger Dowell (Love et al., 1994) drilled two shallow vertical wells with coiled tubing in the McKittrick Field in California. These wells are believed to be the first grass-roots wells drilled with coiled tubing. In addition, these wells were the first medium-diameter (6¼ in.) boreholes drilled using motors on coiled tubing.

A two-well project was designed to provide data on reservoir extent and evaluate the use of coiled tubing as a means of conveying drilling assemblies in this area. Completion operations were not included in original project plans.

A 3500-ft string of 2 x 0.156-in. coiled tubing was used for both wells. Drilling fluid was a cypan-based system. Total drilling time on the first well was 35 hr, 10 hr of which were spent checking the survey with a conventional tool. Logging was performed successfully. A cement plug was placed on bottom.

Fatigue-life consumption of the string during these operations was moderate. For all operations on both wells, modeling indicated that a maximum of 18% of string life was used (Figure 6-24).

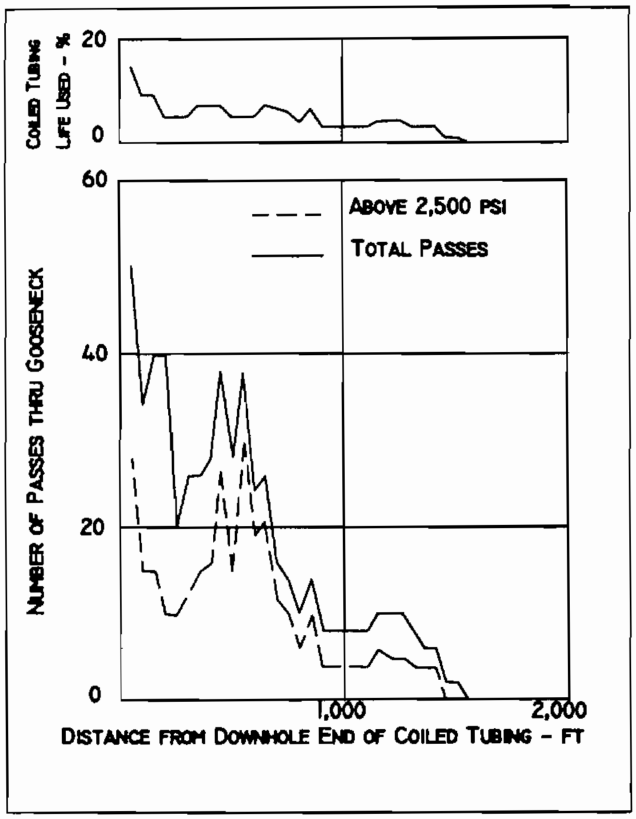

Figure 6-24. Coiled-Tubing Fatigue for Two-Well Project (Love et al., 1994)

Berry Petroleum found that costs with coiled-tubing drilling were comparable or less than conventional rigs for this application. Additional description of this project is presented in the Chapter *Drilling*.

6.3.3 Corrosion Resistance

The wide range of new applications for coiled tubing has generated increased interest in its serviceability. In addition to concerns relative to low-cycle fatigue failure, other issues of mechanical integrity and corrosion resistance are under consideration. Kane and Cayard (1993) presented a list of current concerns for coiled tubing compiled during a meeting of producers, service companies, and manufacturers. These included:

1. Assessment of mechanical integrity and fatigue damage
2. Corrosion resistance, especially effects of H_2S and other corrosives with respect to metallurgy, heat treatment, grade, etc.
3. Categorization of coiled tubing failures and defects
4. Establishment of limits for used coiled tubing regarding corrosion, handling, and fatigue
5. QA/QC and inspection requirements for new and used coiled tubing
6. Fitness-for-service evaluation of coiled tubing
7. Effects of shop and field welds on fatigue and corrosion
8. Methods to keep records for assessment of used coiled tubing

Determining the effects of H_2S on the integrity of coiled tubing was a principal concern of users and manufacturers. The development of high-strength coiled tubing raises questions regarding fracture resistance and susceptibility to sulfide stress cracking.

Data from conventional tubulars exposured to H_2S (Figure 6-25) show that high-strength steels have significantly lower threshold stress (stress where cracking is initiated) than lower strength steels.

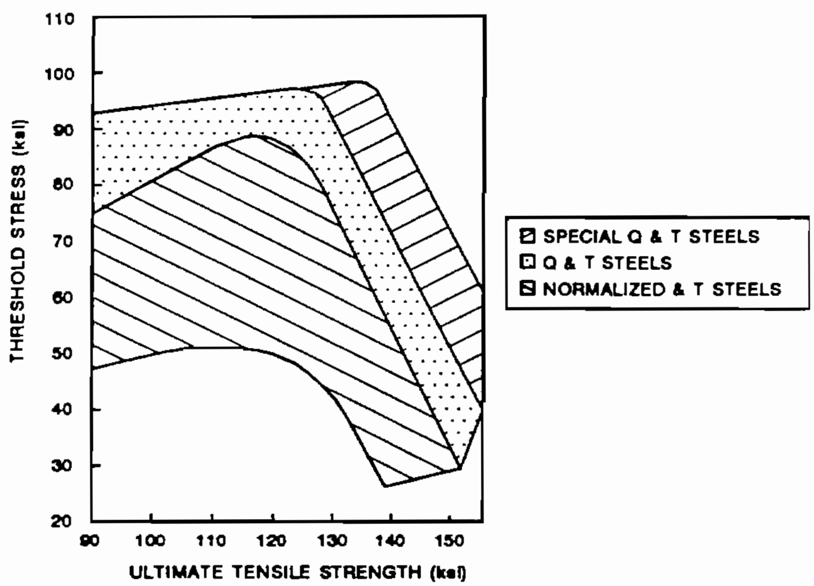

Figure 6-25. Sulfide Stress Cracking in Steels (Kane and Cayard, 1993)

Cortest Laboratories initiated an industry-supported study to investigate the effects of H_2S on coiled tubing. They are addressing methods to evaluate used coiled tubing that has been in corrosive environments, looking at the combined effect of fatigue cycling and H_2S exposure, and investigating the impact of various manufacturing processes on resistance to sulfide stress cracking.

6.3.4 Halliburton Energy Services (Mechanical Limits of Coiled Tubing)

Halliburton (Courville and Avakov, 1994) published a compilation of equations to predict mechanical limits of coiled tubing with respect to internal and external pressures, axial loads, ovality, and other factors. Modern operations are being performed under increasingly challenging conditions, and former rules-of-thumb concerning depths and pressures, which provided more than adequate safety factors in the past, may need to be updated.

Collapse pressure rating is an important concern in many operations. This is particularly true with the larger tubing now readily available. A comparison of collapse pressures for a range of material strengths is shown in Figure 6-26.

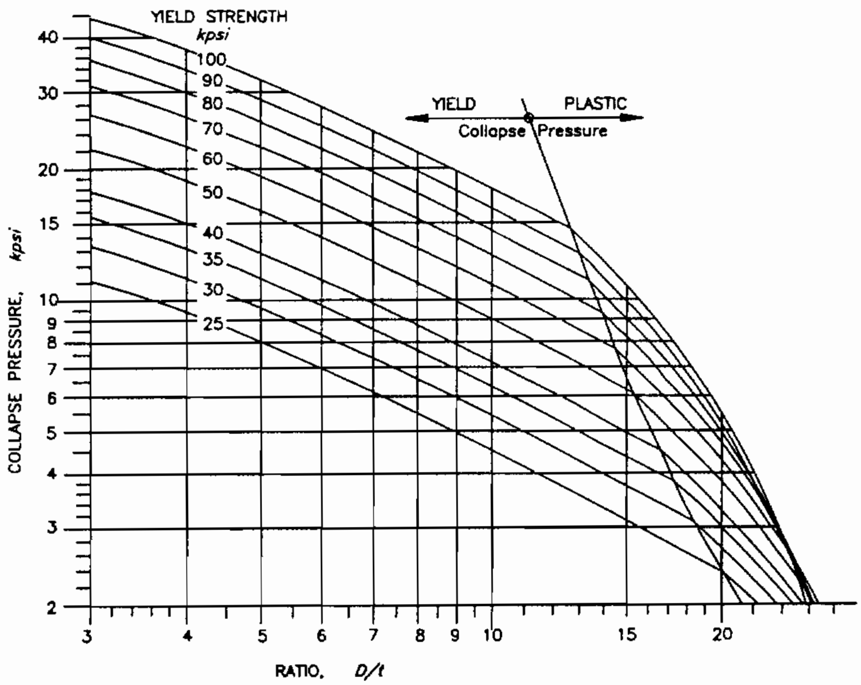

Figure 6-26. API Collapse Rating of Tubing (Courville and Avakov, 1994)

Axial load can serve to derate collapse ratings (Figure 6-27). In the example shown in the figure (dotted lines and arrows), 80-ksi 1¼ x 0.095-in. coiled tubing is loaded with 9 kips. The yield strength correction is found by entering the chart at the bottom at 9 kips, moving up to the line of tubing area (0.345 in^2 for this example), moving horizontally to the 80 ksi line, and finally moving vertically to the corrected yield strength. For this example, collapse rating should be determined based on a yield strength of 64 ksi rather than 80 ksi for an unloaded condition.

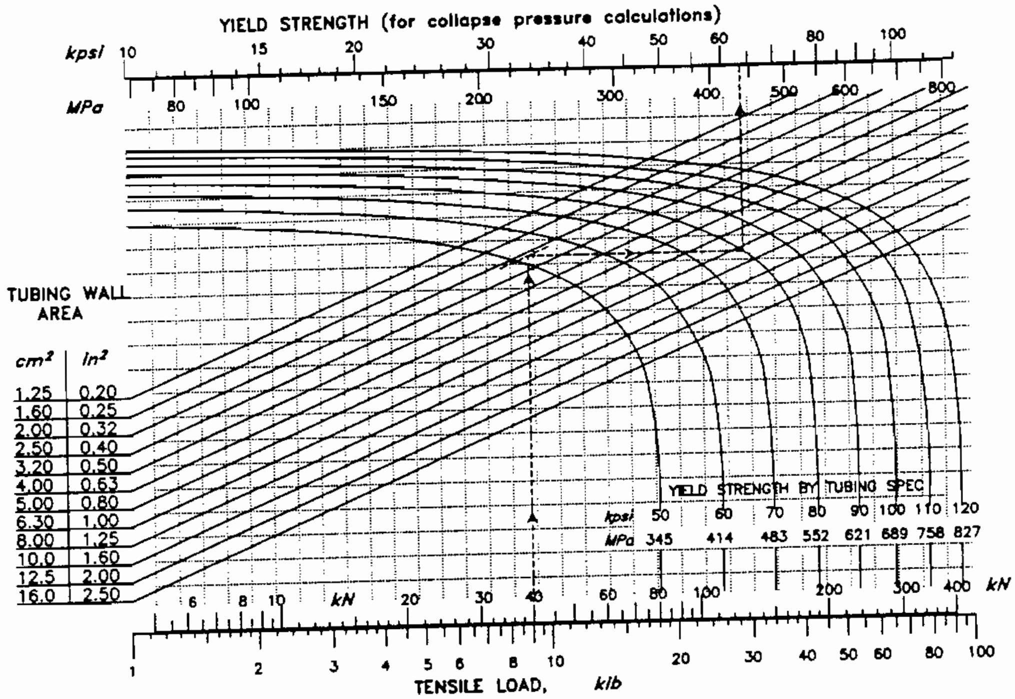

Figure 6-27. Collapse Pressure Correction Due to Axial Load (Courville and Avakov, 1994)

Ovality can also have a significant negative impact on collapse ratings. A chart is shown in Figure 6-28 for 80-ksi tubing. Actual collapse pressure is shown as a function of ovality and thickness ratio.

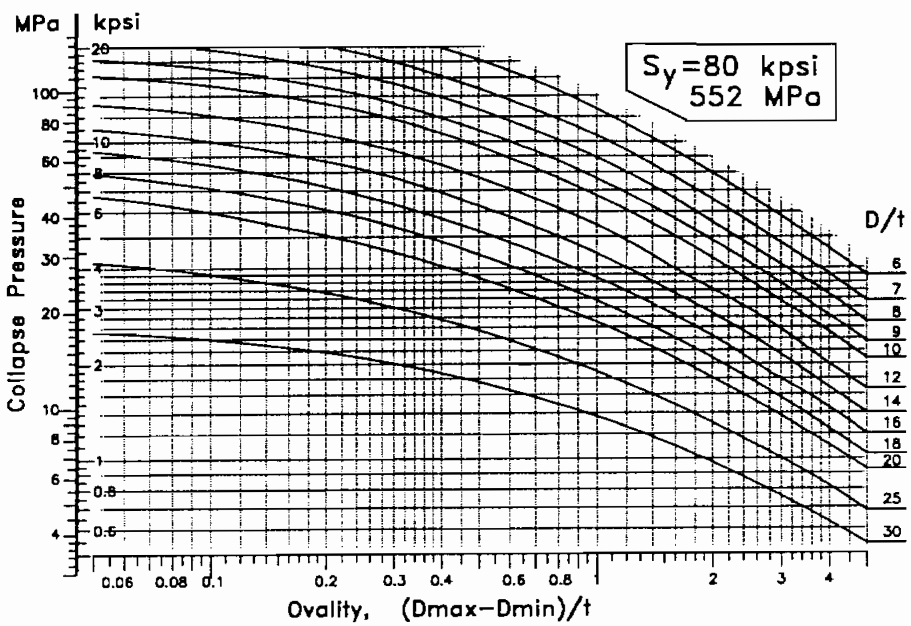

Figure 6-28. Collapse Pressure Due to Ovality (Courville and Avakov, 1994)

6.3.5 Schlumberger Dowell (CoilLIFE Model)

As part of a joint-industry project, Schlumberger Dowell's fatigue model (CoilLIFE) was further refined based on fatigue fixture tests as described in previous sections. Tipton (The University of Tulsa) and Brown (Dowell) described the application of the model to field operations (Tipton and Brown, 1994). CoilLIFE's operation is depicted in Figure 6-29. Material data and constant-pressure tests on the fatigue fixture are used to obtain stress/strain relations. The plasticity routine then formulates a dimensionless coiled-tubing parameter. Lastly, the model is used to chart the life of a string as a function of actual field loading history.

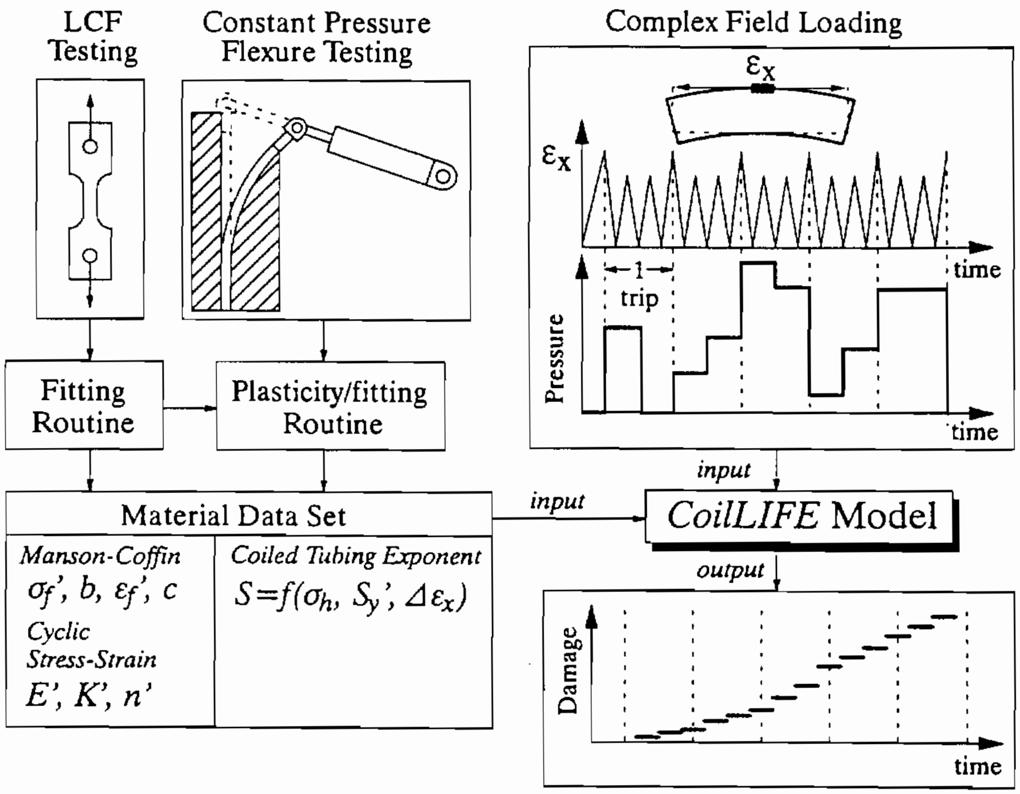

Figure 6-29. CoilLIFE Fatigue Model Algorithm (Tipton and Brown, 1994)

Specific mathematical details of the model remain confidential. CoilLIFE was used to predict fatigue resulting from complex loadings and pressures as is typical of field use. Several of the complex pressure profiles tested are shown in Figure 6-30.

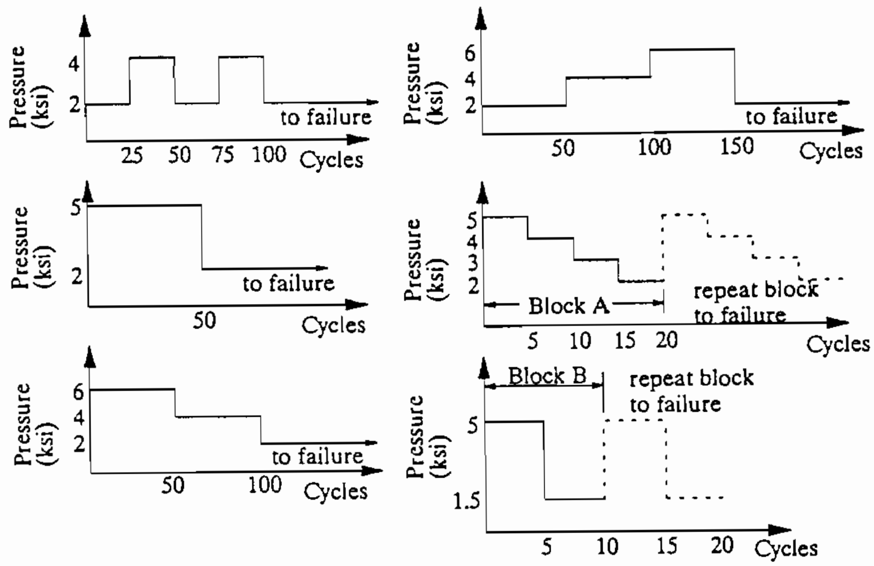

Figure 6-30. Complex Pressure Profiles for Fatigue Tests (Tipton and Brown, 1994)

Model predictions for complex-pressure testing are compared to actual results in Figure 6-31. Three cases are reported: a simple linear fatigue model, fracture (failure) as predicted by CoilLIFE, and crack initiation as predicted by CoilLIFE.

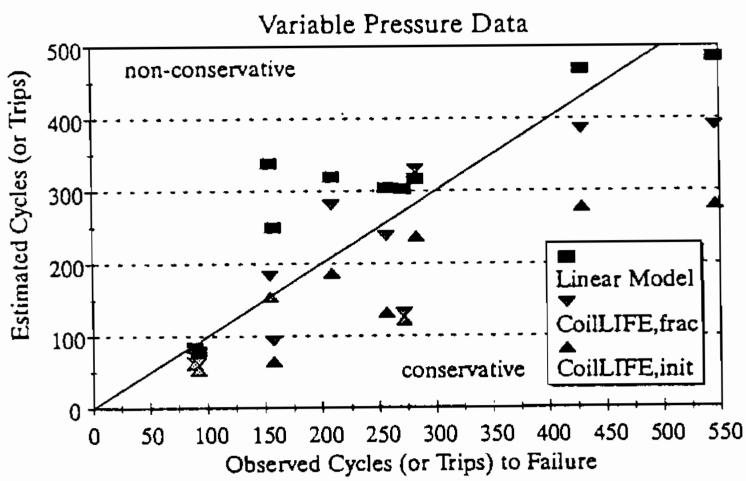

Figure 6-31. Complex Pressure Profile Predictions (Tipton and Brown, 1994)

6.3.6 Spooling Diameter

The diameters of the spool and gooseneck around which coiled tubing is plastically deformed have a significant effect on cycle life. In addition, the ratio of bending diameter to tube O.D. must be considered. On a given size spool, a large-diameter string of coiled tubing undergoes more plastic deformation than a smaller diameter string.

The minimum elastic bending radius to avoid plastic deformation of tubing is given by the following equation:

$$R_y = \frac{E\ r_0}{\sigma_y}$$

where:

r_0 = outside radius of tube

E = Young's Modulus

σ_y = Yield stress

Calculated minimum radius for elastic bending for various tube diameters is presented in Table 6-7. These calculations are based on a nominal yield stress of 80,000 psi.

TABLE 6-7. Minimum Elastic Bending Radius for Coiled Tubing

COILED-TUBING DIAMETER (IN)	BENDING RADIUS R_Y (FT)
1.00	16
1.25	20
1.50	23
1.75	27
2.00	31
2.38	37
2.88	45
3.50	55

Typical bending radii used by the coiled-tubing service industry range from 4 to 6 ft. The need for the tubing to undergo such significant plastic deformation is dictated by storage and transportation constraints. Thus, coiled-tubing life is normally limited by fatigue damage which accumulates as the tubing is yielded around the reel and the tubing guide.

Since elastic bending radii represent generally impractical limits, the coiled-tubing industry has accepted plastic deformation as a necessary part of operations, and tried to find an optimum compromise between spool capacity and tubing cycle life. Historical experience has suggested various rules-of-thumb for the ratio between coiling diameter and tubing OD, that is, the *coiling ratio*.

Both Quality Tubing and Precision Tube suggest that a coiling ratio of 48:1 provides a good balance between spool capacity and tubing life for most applications. Note that the coiling ratio for elastic bending is 375:1. The 48:1 ratio prescribes a 48-in. (4-ft) spool core for 1-in. tubing, 72-in. (6-ft) core for 1½-in. tubing, a 114-in. (9½-ft) core for 2⅜-in. tubing, and a 168-in. (14-ft) core for 3½-in. tubing. It is apparent that it is only practical to maintain a 48:1 coiling ratio with smaller OD tubing.

If the 48:1 rule is too restrictive, the manufacturers suggest that a string that will be cycled repeatedly should not be placed on a spool with less than a 40:1 coiling ratio. A ratio of 36:1 is about the lowest ratio that is recommended under any circumstance and should only be used with strings that will not be fatigue cycled repeatedly, such as production tubing and flow lines.

Spooling coiled tubing at low coiling ratios will cause ovaling, lower collapse rating and lead to rapid fatigue.

A brief survey was conducted of the service industry to determine typical coiling diameters used on modern service rigs. The Houston offices of three service companies were contacted for the information. Service company responses are summarized in Table 6-8. The values given and presented in the table are only intended as representative since spool sizing might vary according to application, area of operations, and other factors.

TABLE 6-8. Representative Coiling Diameter Ratios

Company	Tubing O.D. (In.)	Spool Core (In.)	Spool Flange (In.)	Coiling Ratio	Comments
Schlumberger	1¼	72	108	58	
Dowell	1½	72	108	48	
	1¾	84	127	48	81" Wide
Cudd	1¼	60	96	48	Min - OD x 40
	1½	60	96	40	
	1¾	72	108	41	
	2	84	-	42	
	2⅜	84	-	35	
	3½	110	-	31	Experimental
Halliburton	1	72	115	72	43.8" Wide
	1¼	72	115	58	
	1½	72	115	48	
	1¾	72	115	41	
	2	-	-	-	None in Service
	2⅜	84	145	35	76" Wide

6.3.7 Stylwan (Inspection of Coiled Tubing)

Stylwan (Papadimitriou and Stanley, 1994) has begun development of a coiled-tubing inspection system to detect flaws. Imperfections in coiled tubing are of three types: microcracks between grains due to accumulated fatigue, transverse cracking as microcracks grow, and three-dimensional imperfections (pits, gouges, etc.).

Guidelines are established for the downgrading of oil-field tubulars based on remaining wall thickness (Table 6-9). Electromagnetic methods are most often used to inspect pipe. Ultrasonic methods are normally impractical due to inherent difficulty in coupling the transducer to the pipe surface in the presence of rust, scale, slip/tong marks, and other imperfections.

TABLE 6-9. API Tubular Downgrade Criteria (Papadimitriou and Stanley, 1994)

Wall Loss	Remaining Wall	Color Band	Condition
0 – 15%	> 85%	Yellow	Acceptable
15.1 – 30%	70 – 84.9%	Blue	
30.1 – 50%	50 – 70.1%	Green	
> 50%	> 50%	Red	Reject

A system to inspect coiled tubing would need to operate continuously during spooling operations, be responsive to all types of flaws, be unaffected by debris on the pipe surface, be independent of tubing speed, and cover 100% of the material volume. A prototype sensor system developed to meet these requirements is shown in Figure 6-32 attached to a level wind on a 1½-in. tubing spool.

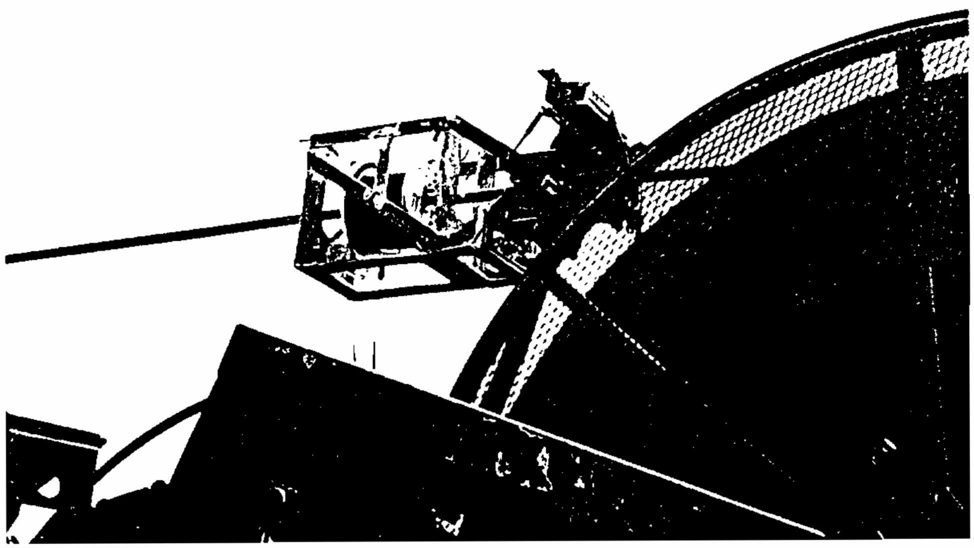

Figure 6-32. Electromagnetic Inspection System Sensor (Papadimitriou and Stanley, 1994)

Computation equipment, located inside the operator cabin, converts the data to useful output. A typical inspection screen (Figure 6-33) presents transverse flaws (TDS) and wall inspection data (WDS). One obvious imperfection is present in this example.

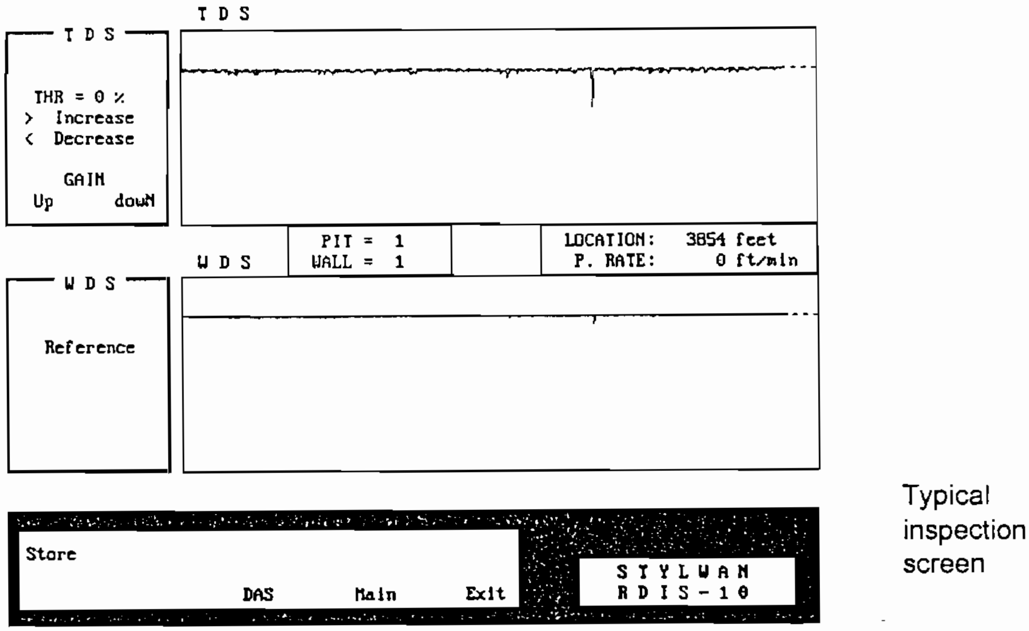

Figure 6-33. Electromagnetic Inspection System Output Screen (Papadimitriou and Stanley, 1994)

6.4 REFERENCES

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7. Fishing

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7. Fishing

7.1 BAKER OIL TOOLS (TOOLS AND TECHNIQUES)

Baker Oil Tools (Coronado, 1993) presented a summary of tools and techniques for fishing with coiled tubing. An important advantage for fishing with coiled tubing is the ability to perform through-tubing operations (including fishing) without necessarily needing to pull the production tubing or recomplete the well after the job.

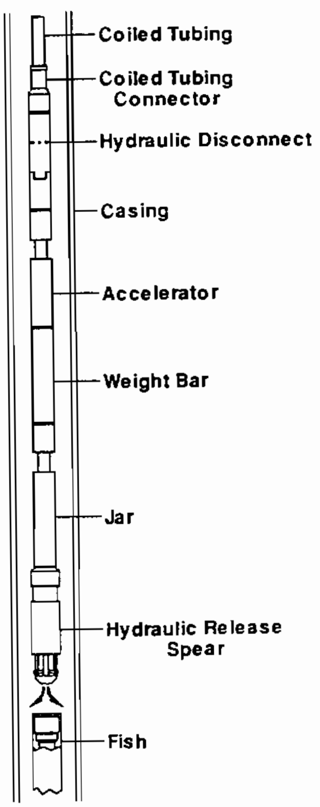

Figure 7-1. Coiled-Tubing Work String for Fishing Internal Fishing Neck (Coronado, 1993)

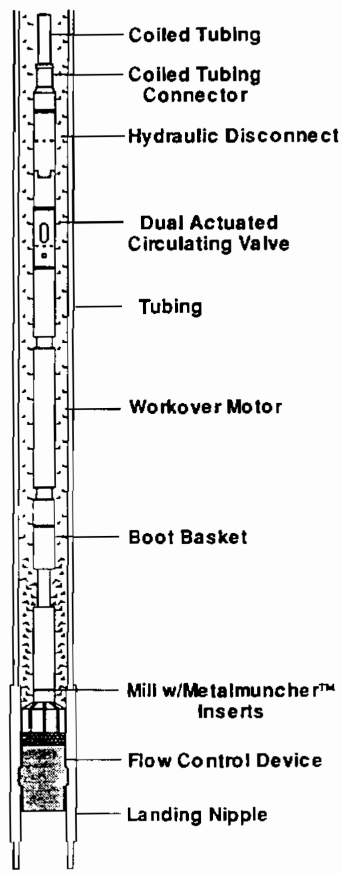

Figure 7-2. Coiled-Tubing Work String for Fishing Stuck Flow Control (Coronado, 1993)

Early attempts to use coiled tubing for fishing used wireline fishing tools. Since these tools were designed for wireline, the advantages of coiled tubing could not always be used, including circulation through the tool and the capacity for high impact loads.

A fishing assembly with a hydraulic release spear is used when an internal fishing neck is looking up (Figure 7-1). The spear can be released in the event the fish cannot be freed. The standard hydraulic disconnect serves as a backup in this configuration.

An assembly to mill out a stuck flow-control device is shown in Figure 7-2. The largest chips that cannot be circulated out of the hole are caught in a boot basket. The dual-activated circulating valve provides a bypass for flow around the motor for enhanced flow rates, or in the event the motor becomes plugged.

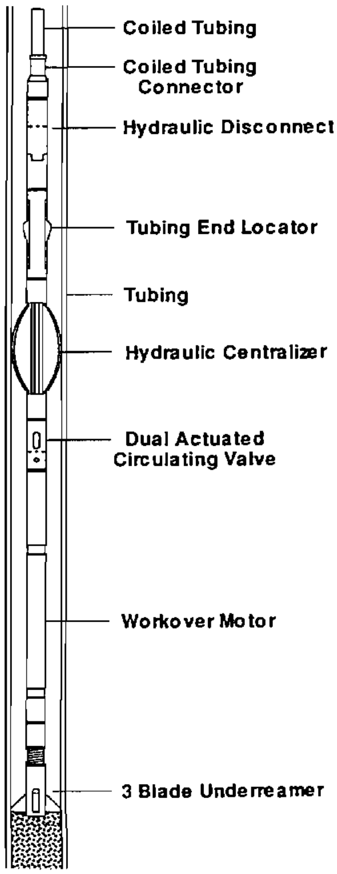

Figure 7-3. Coiled-Tubing Work String for Underreaming (Coronado, 1993)

A work string for underreaming operations (Figure 7-3) may contain a tubing-end locator for more accurate depth correlation. When the tubing-end locator is pulled up through landing nipples in the production tubing tailpipe, a slight overpull is noted, which can then be correlated with wireline logs of the well.

When fishing in highly deviated holes, latching the fish is often difficult. Experiences have shown that the top of the fish can be anywhere, including the high side of the casing. A hydraulic centralizer can be used to adjust the position of the fishing tool (Figure 7-4). The centralizer can be expanded to varying positions by changing the circulation rate through the string. A knuckle joint allows the centralizer to raise the work string without having to lift the coiled tubing.

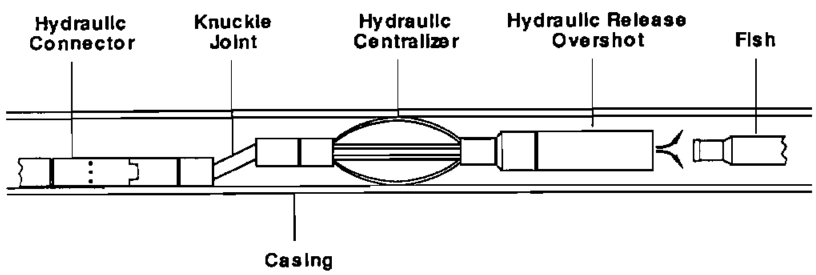

Figure 7-4. Coiled-Tubing Work String for Fishing in Deviated Hole (Coronado, 1993)

7.2 BP EXPLORATION (FISHING IN MAGNUS FIELD)

BP Exploration (Bedford and Divers, 1994) has increasingly used coiled-tubing workovers in the Magnus Field in the northern North Sea. The field was developed initially between 1983 and 1986. Twenty wells have been drilled to date. Most wells are prolific, ranging from 20,000 to 60,000 BPD. A typical completion for the field is shown in Figure 7-5.

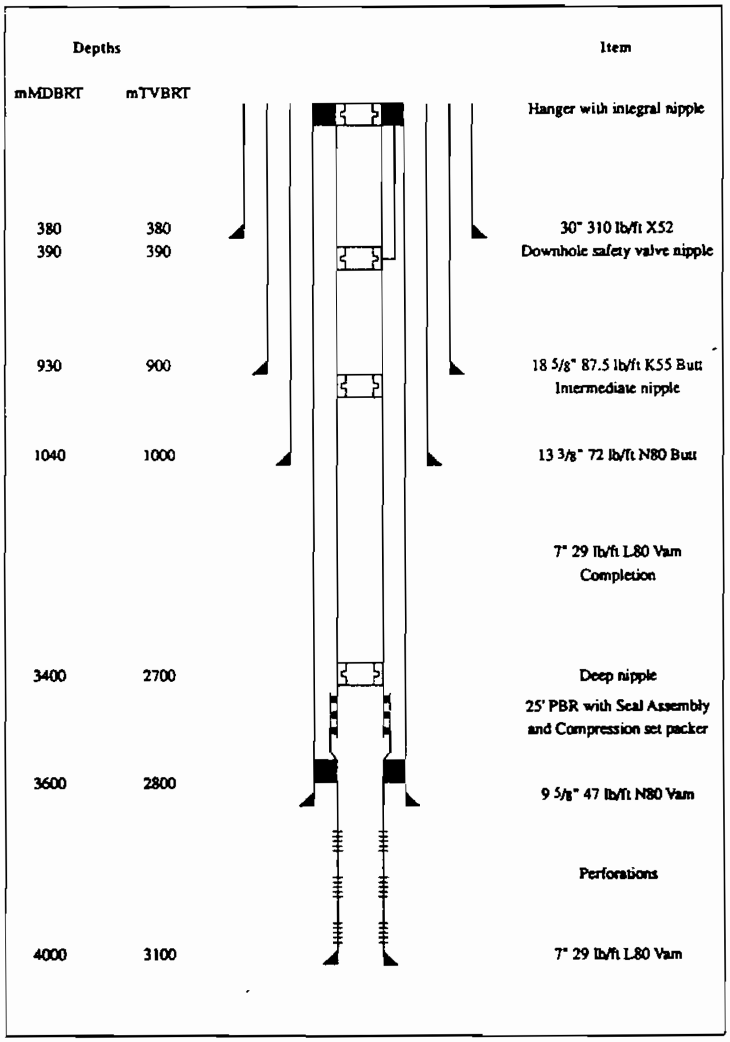

Figure 7-5. Magnus Field Typical Completion (Bedford and Divers, 1994)

During the past couple of years, the number and variety of well interventions in the Magnus Field using coiled tubing have increased dramatically. Coiled tubing has been used for fishing operations for cases where wireline has had insufficient capacity or where circulation was desired.

In BP Exploration's first coiled-tubing fishing job, 21 m (69 ft) of perforating guns were retrieved. The fish was caught with an overshot and recovered from 4831 m (15,850 ft) on the first attempt.

A second fishing job was to recover a wireline lock from a zone with heavy corrosion. Coiled tubing was used to remove the debris from the fish; however, the fish could not be latched with coiled tubing. The fish was then removed with slickline. The operator states that slickline provided better control ("feel") than did coiled tubing.

7.3 HALLIBURTON ENERGY SERVICES (OVERVIEW)

Halliburton presented an overview of considerations for using coiled tubing in fishing operations (Hilts et al., 1993). Coiled tubing has become an important technique for retrieving fish, especially in cases requiring high forces downhole or circulation to remove fill or clean scale/debris.

Before 1980, most fishing jobs involving coiled tubing were to fish lost sections from the hole due to tubing failures. Along with the significant improvements in tubing strength and reliability, the use of coiled tubing as a fishing tool has increased significantly, due in large part to the horizontal drilling boom. The availability of coiled tubing has allowed more fish to be removed from live wells, in many cases eliminating the need for a conventional rig or workover unit.

Where its use is feasible, wireline is normally the most efficient fishing approach. Coiled tubing has certain advantages over wireline that are important in certain situations, including:

- Coiled tubing can circulate fluids (acid, nitrogen) to wash sand from top of the fish
- Coiled tubing can be used to apply large pulling forces in both straight and inclined holes
- Coiled tubing can clean debris and pull on the same trip

The axial load capacity of coiled tubing is significantly greater than standard wireline (Figure 7-6). In addition, higher strength coiled tubing (80 ksi, 100 ksi) increases the tensile capacity available to retrieve fish.

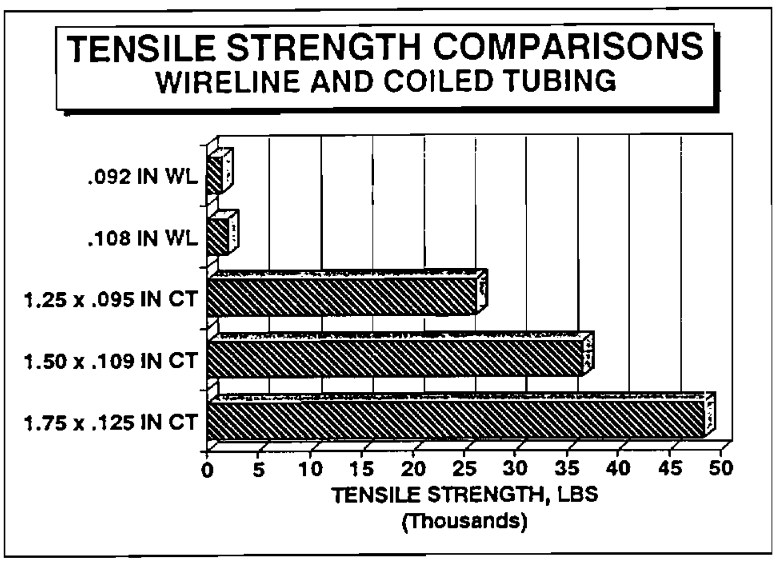

Figure 7-6. Tensile Strength of Wireline and Coiled Tubing (Hilts et al., 1993)

The internal strain energy available to deliver impact forces to a fish is compared for coiled tubing and wireline in Table 7-1. The surface load capacity of coiled tubing is eighteen times greater than wireline in this comparison. However, the proportion of surface load capacity expended to support the weight of the string is about twice as high for coiled tubing.

TABLE 7-1. Mechanical Properties of Wireline and Coiled Tubing (Hilts et al., 1993)

Property	0.108-in. Wireline		1¼ x 0.095-in. Coiled Tubing	
	500 ft	10,000 ft	500 ft	10,000 ft
Weight (lbs)	15.6	311	586	11,720
Max Surface Load (lb)	1000	1000	18,000	18,000
Deflection (in)	22	301	10	73
Spring Rate (lb/in)	45.8	2.3	1723	86
Internal Energy (ft-lb)	881	8634	7331	19,068

Internal energy is compared graphically in Figure 7-7. These data reflect the stored energy available. Transferring this energy to jarring force depends on jar stroke, stem weight, accelerator design, etc.

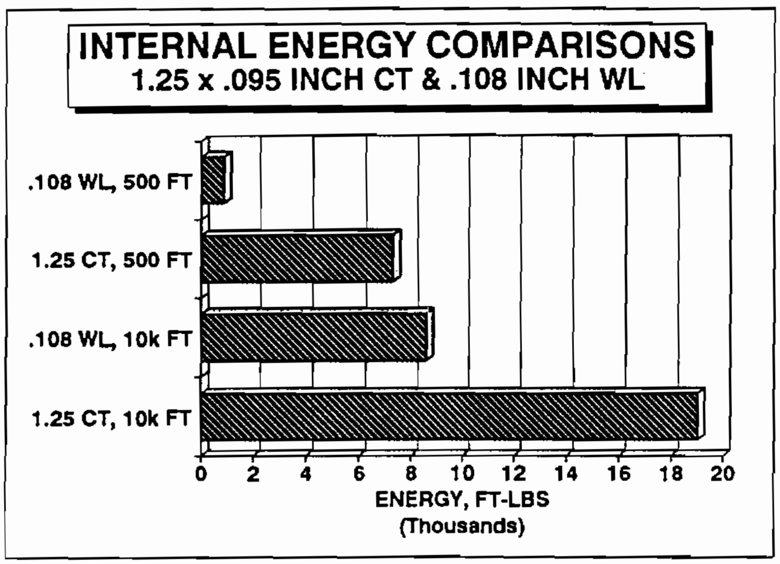

Figure 7-7. Internal Energy of Wireline and Coiled Tubing (Hilts et al., 1993)

The design of the BHA for fishing with coiled tubing will vary with each specific application. A typical fishing string is shown in Figure 7-8. Basic components are:

1. Coiled-tubing connector; threaded, set-screw, swedge or slip-type. Slip connectors are generally superior for fishing applications, and the connection is stronger than the body of the coiled tubing.

2. Emergency disconnect sub; activated by circulating a ball in the event the fishing assembly becomes stuck. The disconnect is rotationally locked so it can be used in torque-producing operations such as milling and underreaming.

3. Back-pressure valve; prevents wellbore fluids from flowing up the coiled-tubing string.

4. Ported-knuckle joint; removes the influence of side loads due to residual bending in the coiled tubing.

5. Accelerator; stores energy in a spring to accelerate the weighted stem for impact loads. Additionally, it serves to isolate the coiled-tubing string from the shock loads generated during jarring.

6. Weighted stem; provides mass to develop high impact loads for jarring the fish.

7. Hydraulic jars; time-delay device that allows the accelerators to fully extend or contract before releasing. A fluid-metering design is used to regulate the transfer of fluid within cavities after the coiled tubing is placed in tension.

8. Fishing tool; as required to grab the fish, e.g., overshots, spears, pulling tools, junk baskets, etc.

Halliburton outlined several steps in planning a coiled-tubing fishing job to maximize economic benefits. For example, video cameras can provide important information on the condition of the fish that can save days of fishing time. Additionally, wireline can be used in conjunction with coiled tubing to speed the job. Fast trip times with wireline can save time while running drifts, impression blocks, baiting the fish, etc.

The surface rig-up has to be designed for safety with live-well operations and to allow removal of the fish once retrieved to the surface. A typical rig-up for land operations (Figure 7-9) includes a flanged wireline BOP connected directly to the tree. Above a gate valve, enough lubricator is provided to cover the fishing work string.

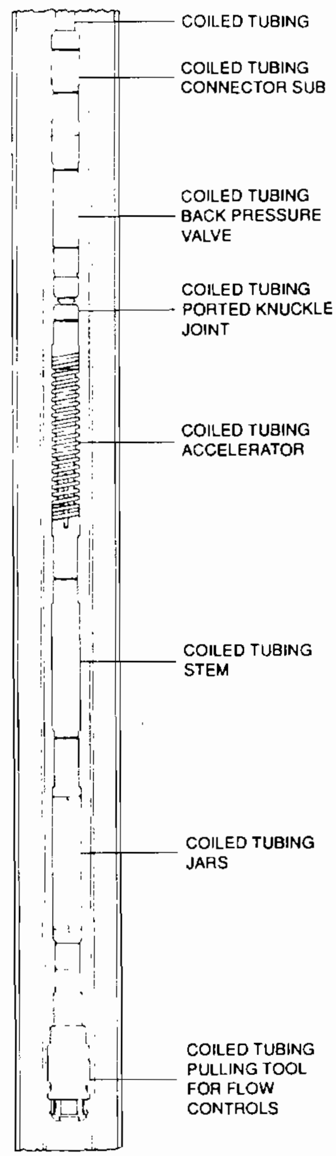

Figure 7-8. Fishing Assembly for Coiled Tubing (Hilts et al., 1993)

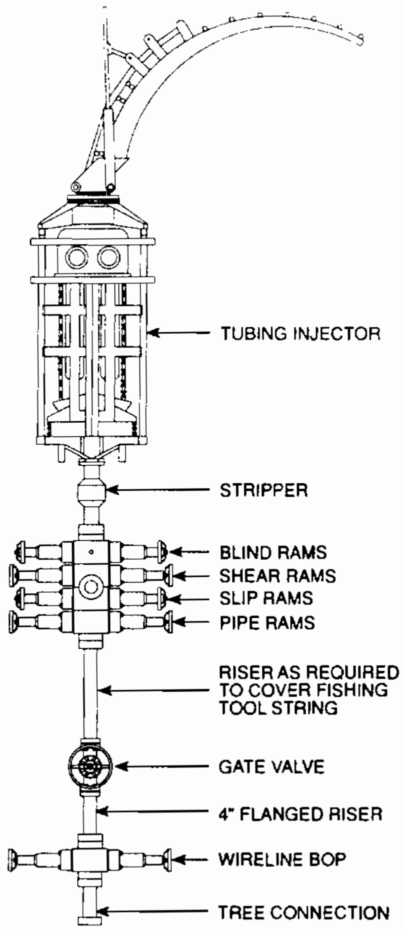

Figure 7-9. Surface Rig-Up for Fishing with Coiled Tubing on Land (Hilts et al., 1993)

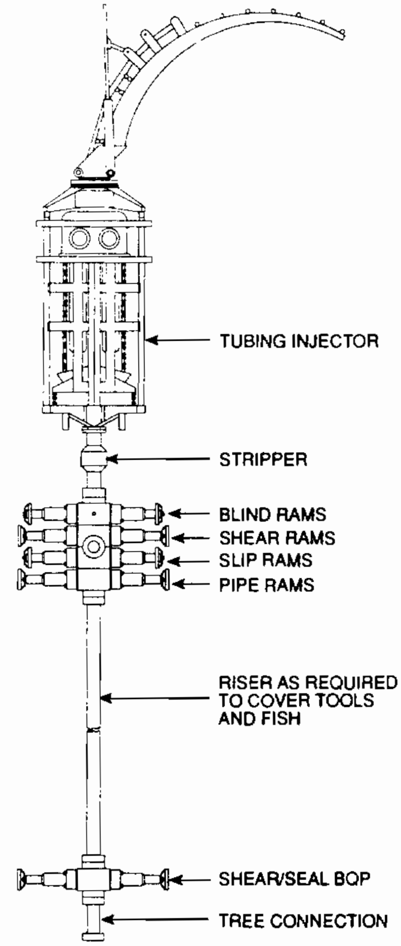

Figure 7-10. Surface Rig-Up for Fishing with Coiled Tubing Offshore (Hilts et al., 1993)

After the fish is pulled to surface with coiled tubing, a typical procedure would be to secure the fish with the wireline BOP, disconnect the coiled tubing via the hydraulic disconnect, pull the coiled tubing, close the gate valve, rig down the coiled-tubing equipment, rig-up a wireline lubricator long enough to enclose the whole fish, and remove the fish with wireline. Of course, if the fish cannot be sealed off or is extremely long, the well must be killed before the fish can be removed.

An offshore rig-up may provide sufficient distance to contain the fish in the riser between the tree and rig floor (Figure 7-10).

Fatigue may be a special concern in coiled-tubing fishing operations. Extended jarring may require many cycles across a short section of the string. Low-cycle fatigue can be reduced by increasing the bend radius while jarring. This can be accomplished by bypassing the gooseneck, looping the tubing between the injector and spool, setting the spool brake, and using a crane to support the loop of tubing.

In difficult fishing operations, the tubing should be retrieved to the surface after 50–150 cycles and a length of tubing (several hundred ft) removed from the end. This will limit the fatigue and shock loads each section of the string receives.

7.4 REFERENCES

Bedford, S.A. and Divers, P., 1994: "Coiled Tubing Operations in the Northern North Sea, Magnus Field," presented at Second International Conference and Exhibition on Coiled Tubing Technology: Operations, Services, Practices, Houston, Texas, March 29-31.

Coronado, Martin P., 1993: "Coiled Tubing Conveyed Fishing Systems," presented at 1st Annual Conference on Coiled Tubing Operations & Slim Hole Drilling Practices, Houston, TX, March 1-4.

Hilts, R.L., Fowler, S.H., Jr. and Pleasants, C.W., 1993: "Fishing With Coiled Tubing," SPE 25499, paper presented at the Production Operations Symposium held in Oklahoma City, Oklahoma, March 21-23.

8. Logging

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8. Logging

8.1 WIRELINE LOGGING

8.1.1 Atlas Wireline Services

Atlas Wireline Services (Nice, 1994) summarized the advantages and disadvantages of using coiled tubing as a means of conveying logging tools. The increase in horizontal drilling has been a significant catalyst for the development of coiled-tubing logging technology. The flexibility of coiled tubing allows conveyance of logging assemblies into short-radius wellbores. The ability to log wellbores at a constant rate without stopping to make or break pipe leads to more efficient operations.

A basic coiled-tubing logging system (Figure 8-1) includes a standard coiled-tubing rig outfitted with a spool of tubing with wireline installed inside. A rotating electrical connector on the axle of the spool feeds data from the wireline to the logging instrumentation.

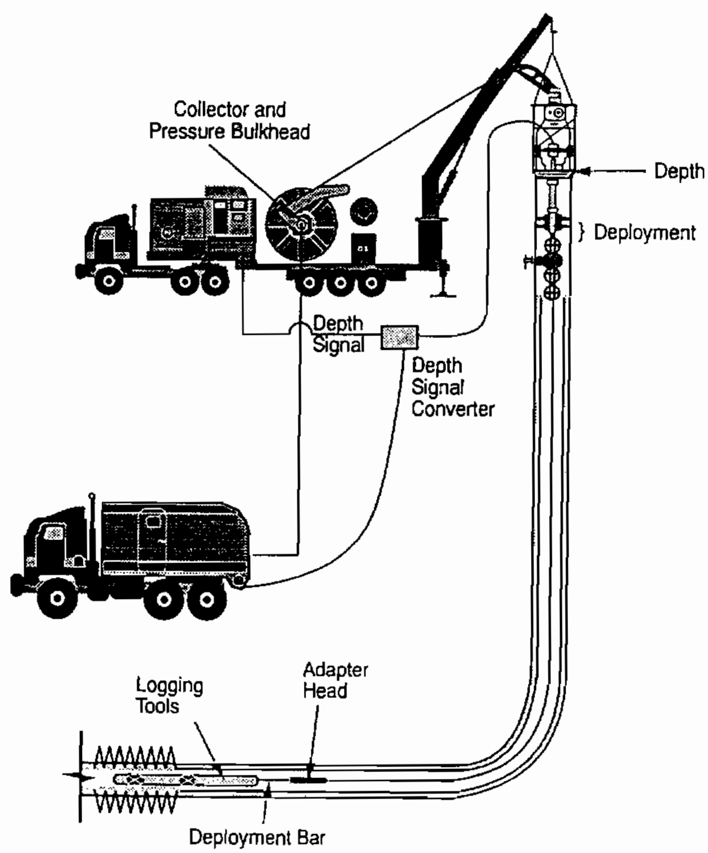

Figure 8-1. Logging with Coiled Tubing (Chauvel and Clayton, 1993)

All conventional wireline logging services can be performed on coiled tubing. Perforating guns, packers, bridge plugs, and jet and chemical cutters are routinely conveyed on coiled tubing.

Nice (1994) listed many of the advantages gained by the use of coiled tubing for logging tool conveyance:

- High-angle wellbores (open-hole and cased) can be entered
- Operations possible in short-radius wells, as well as slim holes
- Can run tools through cork-screwed production tubing
- Safe operations possible with high wellhead pressures
- Perforation can be performed in underbalanced conditions, leading to improved formation clean-up
- Artificial lift readily available during production logging operations
- Operational temperature range can be increased by injecting cooler fluids through coiled tubing
- Capability for both electric and hydraulic control of downhole tools
- Workover rig not required

Disadvantages for coiled-tubing logging services also exist. Among them are:

- Higher costs than conventional wireline systems
- Longer operating time than conventional wireline systems
- Spools of coiled tubing equipped with wireline not widely available
- Coiled tubing buckling may limit penetration

In one application described by Nice (1994), a horizontal well on a platform in the Gulf of Mexico had a 1300-ft lateral section with five prepacked screens. Oil production declined from 1300 to 350 BOPD while water production increased from 300 to 1700 BWPD. A coiled-tubing-conveyed logging assembly measured flowing and shut-in BHP, borehole integrity, total flow, and water-only profile. After a blank section of pipe was installed, flow logs were rerun (Figure 8-2) showing that production improved to 850 BOPD with 500 BWPD.

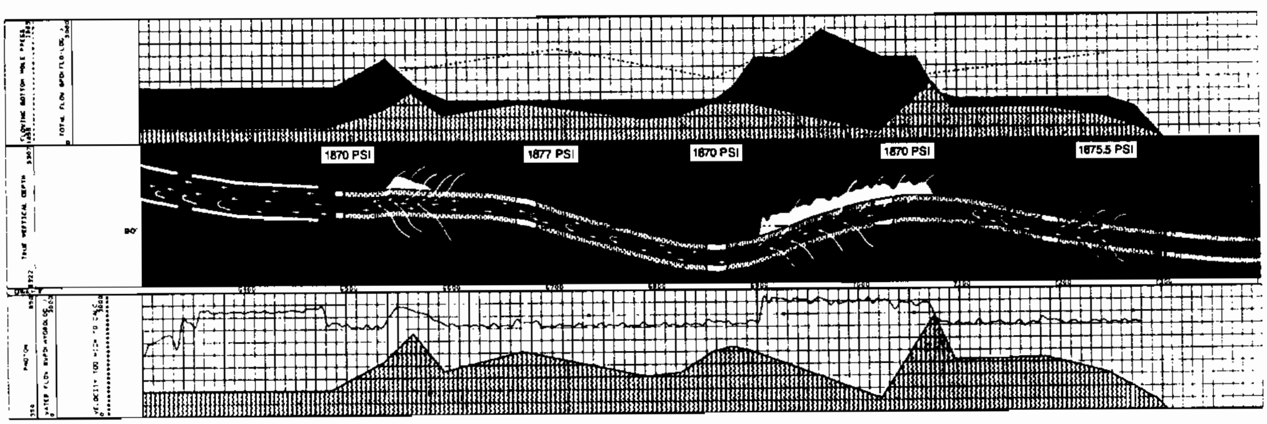

Figure 8-2. Flow Profile Logs with Coiled Tubing (Nice, 1994)

8.1.2 Halliburton Energy Services (Video Logging)

Halliburton Energy Services (Rademaker et al., 1993) described the development and use of a coiled-tubing-deployed downhole video logging system. These systems can be beneficial in many applications including:

- Leak detection; identified through observation of turbulence or entrance of different fluid
- Damaged tubulars; parted or collapsed tubing or casing
- Scale buildup
- Formation fractures; visualization of size and extent, and with gyroscopic data, direction of fractures
- Fishing operations; rapidly identifies fish and its orientation
- Perforation inspection; performance and plugging of perforations can be identified
- Corrosion surveys
- Lost production; causes for lost production (sand bridges, non-operative flow controls, etc.) can be identified.

Video logging has become a practical technology in the past few years. Downhole video was first applied in shallow water wells after 1970. Oil-field applications brought many problems to be solved including telemetry, elevated pressure, high temperature, lighting, opaque fluid media, and condensation. Previously, the rugged conditions of the downhole environment have limited the application of video logging.

Recently developed equipment can be operated down hole in temperatures up to 300°F, pressures up to 10,000 psi, wellbores from 4 to 20 in., and depths up to 20,000 ft. Typical cameras produce high-resolution, black-and-white images in low light conditions. Power is conveyed down hole and data to the surface on a double-armored ½- to 9/16-in. coaxial cable. Newer systems take advantage of recent advances in fiber-optic components and systems. Armored fiber-optic cable can transmit over greater distances from wireline. Weight savings are also considerable: 0.4 lb/ft for wireline versus 0.085 lb/ft for fiber-optic cable. A typical coiled-tubing-conveyed video logging system is shown in Figure 8-3.

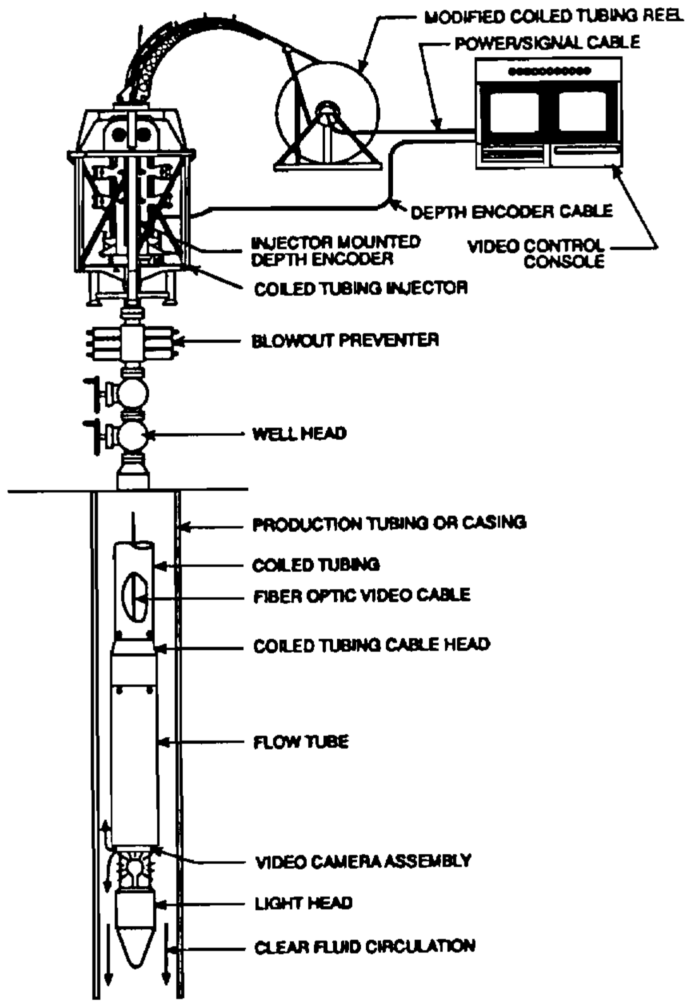

Figure 8-3. Coiled-Tubing-Conveyed Video Logging
(Rademaker et al., 1993)

Video camera systems can be conveyed with wireline if the wellbore contains gas or clear fluid and the wellbore deviation is minimal. For other cases, coiled tubing is used to displace the wellbore fluids at the depth of interest with a clear fluid, typically a gelled liquid. In addition, coiled-tubing allows inspection of high-angle and horizontal wells.

In addition to standard real-time cameras, new cameras are under development that can be run on monoconductor wireline. These units will transmit a new still image every 15 seconds to replace the previous one. These systems will provide an additional choice to operators in areas where multiconductor video coiled-tubing logging units are not readily available.

Video picture quality may be impaired in deeper wells due to transmission losses. Coaxial cable is capable of functioning to depths not much greater than 10,000 ft. The large diameter of the coaxial cable has required the addition of cumbersome sinker bars to overcome even modest wellbore pressures.

To address these problems and extend the applicability of video logging, fiber-optic transmission cables have recently been developed. Fiber-optic images degrade only about half as rapidly as with coaxial cable. The smaller cable, usually 7/32 in., requires significantly less sinker weight and can transmit high-resolution images in excess of 20,000 ft. The drawbacks of fiber-optic cables are some sensitivity to high temperatures and the difficulty of splicing damaged cable.

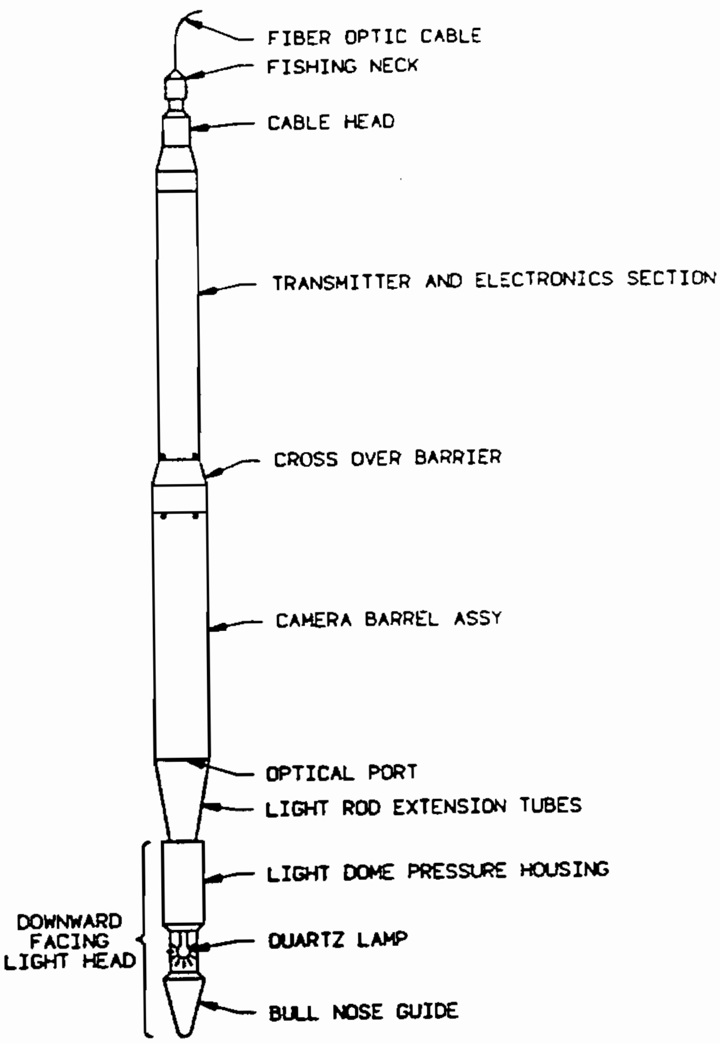

Figure 8-4. Otis Fiber-Optic Video System (Cobb and Schultz, 1992)

Halliburton has successfully used the fiber-optic video assembly shown in Figure 8-4 in numerous field applications. Four subassemblies are required: the cable head, electronics tray, pressure housing and light head. The light head and electronics are usually powered from the surface.

Light heads are available in several designs. A ring light (Figure 8-5) consists of a series of small lamps placed around the lens. It is generally not well suited for use in fluid, since any particulate material can cause glare.

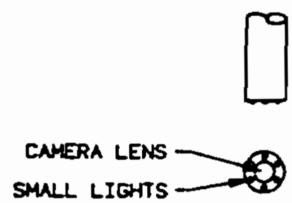

Figure 8-5. Video Ring Light Head (Cobb and Schultz, 1992)

The most common light head has a single lamp positioned in front of the lens (Figure 8-6). It is suitable in fluid for tubular inspection. The distance between the optical port and the lens is adjusted based on the ID to be viewed.

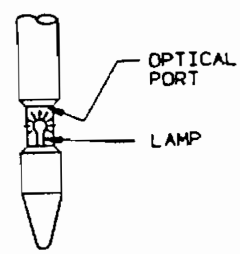

Figure 8-6. Standard Video Light Head (Cobb and Schultz, 1992)

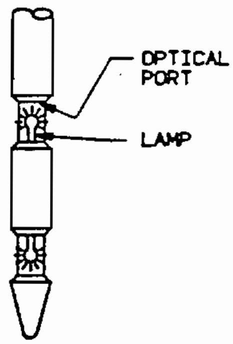

Figure 8-7. Dual-Light Video Head (Cobb and Schultz, 1992)

A dual-light design (Figure 8-7) can be used to view two different tubulars on the same run, such as production tubing and casing. The light closest to the optical port is used in production tubing and the downward light in casing. Light intensity is adjustable from the surface.

The downhole components of the camera assembly are shown in more detail in Figures 8-8 and 8-9. The upper two sections of the assembly are shown in Figure 8-8; the lower two sections are shown in Figure 8-9.

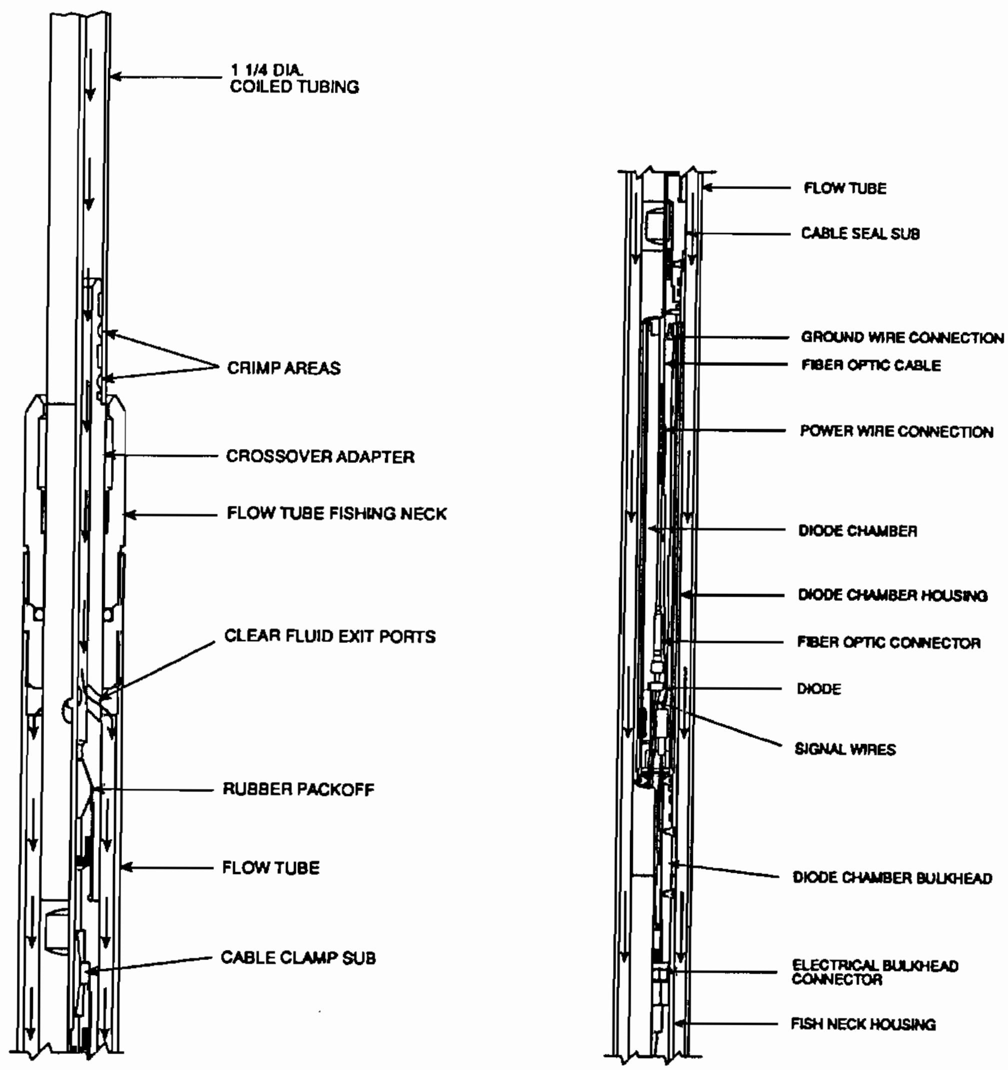

Figure 8-8. Halliburton Camera Assembly (Upper Sections) (Rademaker et al., 1993)

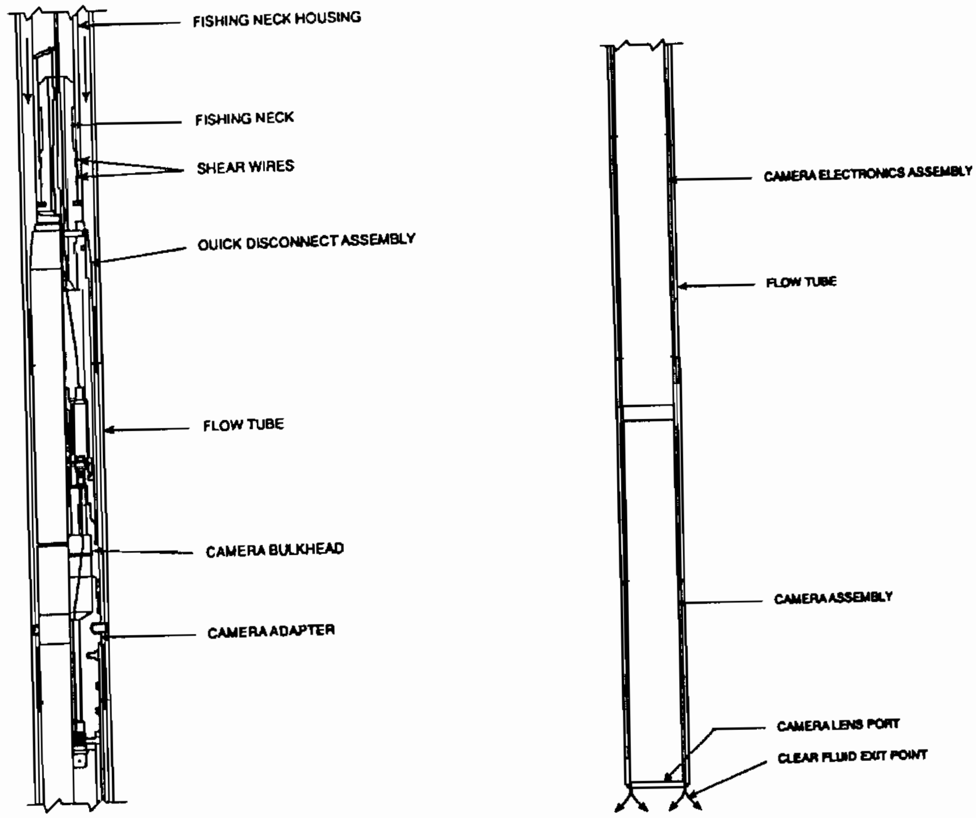

Figure 8-9. Halliburton Camera Assembly (Lower Sections) (Rademaker et al., 1993)

Some operating areas require the use of a check valve on the bottom-hole assembly to prevent accidental backflow of well fluids to the surface. A standard check valve cannot be used due to the coaxial cable. A special check valve (Figure 8-10) uses spring-loaded ball valves to allow flow out of the assembly but not back in.

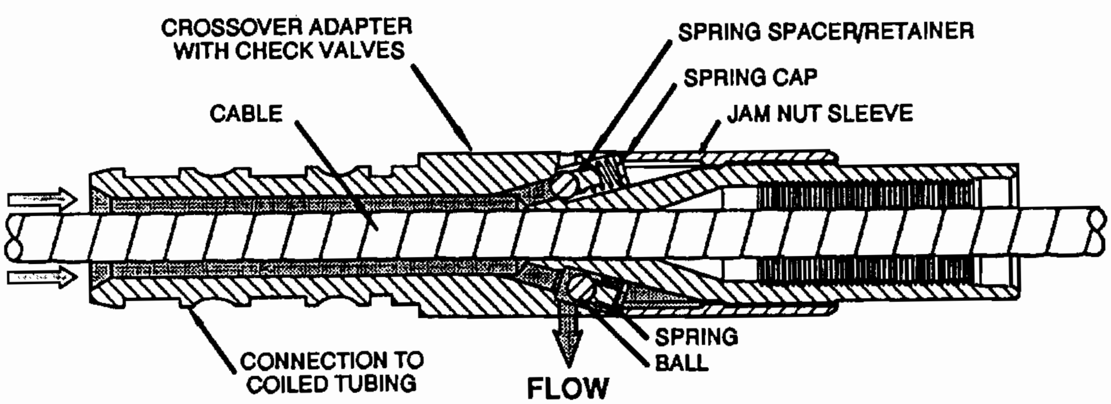

Figure 8-10. Check Valve for Video Logging (Rademaker et al., 1993)

Surface equipment with Halliburton's system consists of a modified coiled-tubing reel and a video control console. The armored fiber-optic cable is placed inside a 17,000-ft spool of 1¼-in. tubing, the core of which contains a fiber-optic video receiver to convert the optic signal to electronic, and associated hardware to carry the signal to the electrical slip rings (Figure 8-11). The difficulties in designing an optical slip-ring assembly are avoided by placing the converter within the rotating spool.

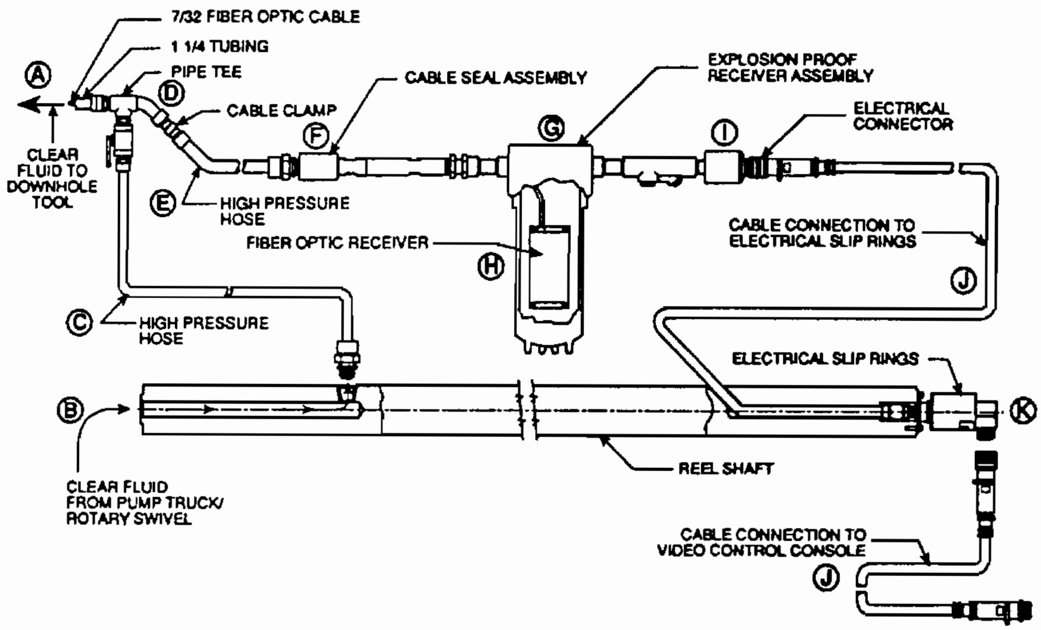

Figure 8-11. Hardware Inside Tubing Reel for Fiber-Optic Video System (Rademaker et al., 1993)

The video control console (Figure 8-12) contains the power supply, a communications processor, a character generator, a video typewriter, video monitors, and video recorders.

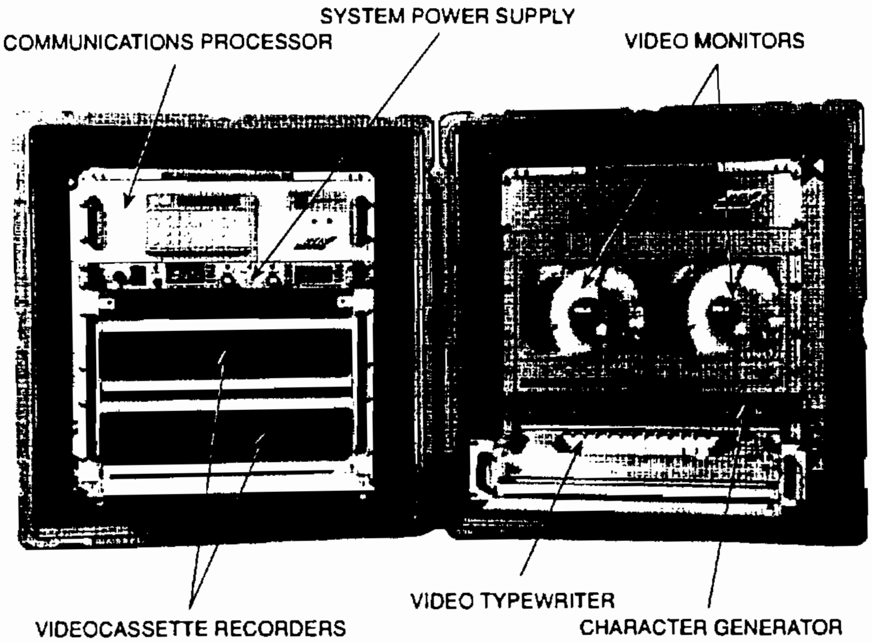

Figure 8-12. Fiber-Optic Video Control Console (Rademaker et al., 1993)

8.1.3 Institut Français du Pétrole (Semirigid Wireline)

Institut Français du Pétrole (Fay et al., 1993) developed and tested in the laboratory a semirigid wireline for use in deviated wells. By using a shell of composite material around a central conductor, the semirigid stem can transmit thrust to push a tool into a highly deviated wellbore without the use of coiled tubing. When installed inside a string of coiled tubing, the composite stem protects the wireline from damage and can be subjected to bending cycles without damage.

Institut Français du Pétrole fabricated two prototype strings of semirigid wireline: 1) 25-mm (1-in.) diameter by 100-m long and 2) 16-mm (⅝-in.) diameter by 230-m long (Figure 8-13). The ability of the string to withstand repeated winding/unwinding cycles was a primary concern during design. Thermal and chemical stresses also had to be addressed.

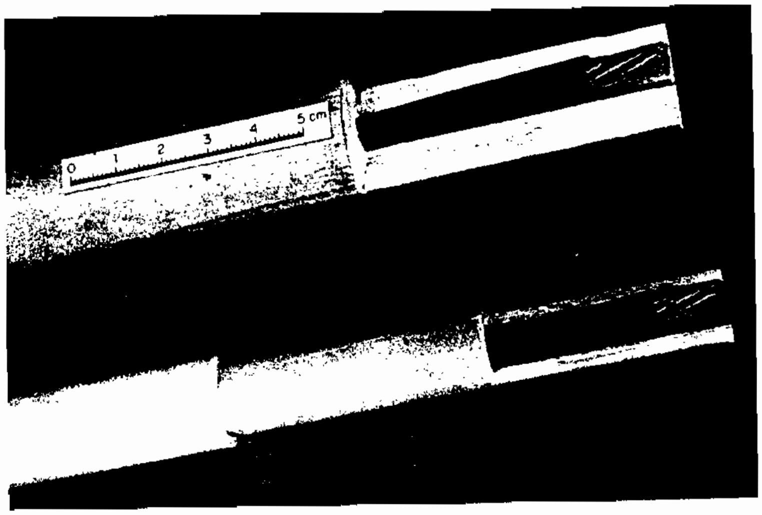

Figure 8-13. Prototype Semirigid Wireline (Fay et al., 1993)

Potential materials were considered for the semirigid sheath (Table 8-1) including steel, high-modulus carbon fiber (HMC), high-strength carbon fiber (HSC), and glass fiber (GF). Glass fiber is the only material that allows a large enough sheath to enclose the wireline while meeting the winding stress safety factor.

TABLE 8-1. Semirigid Wireline Candidate Materials (Fay et al., 1993)

Material	Ultimate Strain ($\Delta l/l$)	Working Strain ($\Delta l/l$)	Outside Stem Diameter (2000 $\Delta l/l$) (mm)	Inertia I (mm^4)	Modulus E (MPa)	Bending Stiffness EI ($N{\cdot}mm^2$)
Steel	0.00286	0.00095	1.90		210,000	
HMC	0.005	0.00167	3.33		200,000	
HSC	0.01	0.00333	6.67		110,000	
GF	0.025	0.00833	16.67	3587	43,000	154,221,433

Pultrusion, by which the product is drawn through a die, was the manufacturing method chosen to produce the semirigid wireline. A vinylester resin was used due to its good resistance to chemicals and good mechanical properties. After pultrusion, a 2-mm thick coating of polyethylene was extruded onto the wireline for extra protection of the whole system.

Long-term bending tests of the composite stem (Figure 8-14) were conducted to determine the optimum spool diameter. Results for the 25-mm system showed immediate failure for 0.8-m radius spool, failure after 4 hr for 1.1-m radius, failure after 48 hr for 1.25-m radius, and failure after 2900 hr for 1.30-m radius.

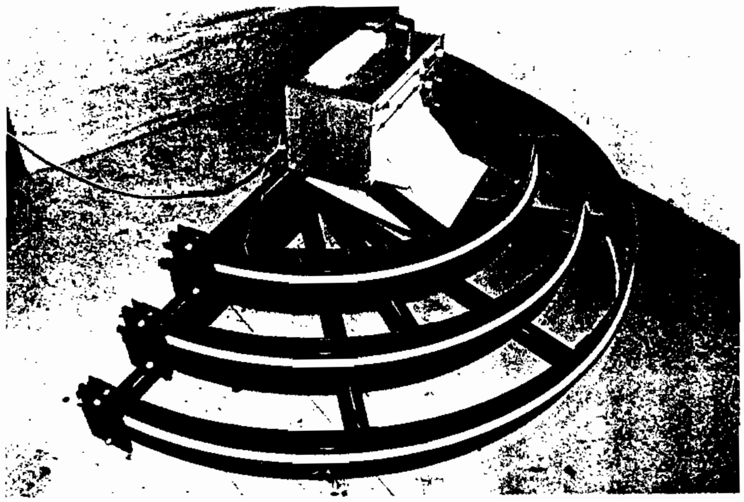

Figure 8-14. Long-Term Bending Test of Semirigid Wireline (Fay et al., 1993)

For the 16-mm system, no failure occurred for 5000 cycles on and off a 1-m radius spool (Figure 8-15).

Figure 8-15. Fatigue Bending Test of Semirigid Wireline (Fay et al., 1993)

Institut Français du Pétrole concluded that semirigid wireline systems fabricated from glass fiber in vinylester resin showed promise for oil-field use. These systems can withstand winding/unwinding cycles without damage and exhibit mechanical properties useful for operations in deviated wellbores.

8.1.4 Mobil Erdgas-Erdöl GmbH (Penetration Limits)

Based on the results of two series of field trials in open-hole shallow horizontal wells, Mobil Erdgas-Erdöl GmbH (van den Bosch, 1994) found that coiled-tubing logging operations did not offer advantages as compared to drill-pipe-conveyed methods. They found that buckling simulation programs were unreliable for calculating penetration limits for coiled tubing in the open hole.

Mobil completed and logged eight shallow medium- to short-radius horizontal wells. Average horizontal reach of these wells is 350 m (1150 ft) (Table 8-2); TD ranged from 850 to 2000 m (2790 to 6660 ft). Mobil used both coiled-tubing-conveyed and drill-pipe-conveyed logging for these programs.

TABLE 8-2. Mobil Horizontal Well Logging Program (van den Bosch, 1994)

Well	Horizontal Length, m	True Vertical Depth, m	Build-Up Radius, m	Dogleg, °/30m	Formation	Application
R-302	128	638	28	62	Chalk	Gas Storage
R-303	298	905	30	58	Chalk	Gas Storage
R-304	390	890	29	60	Chalk	Gas Storage
R-305	432	958	34	52	Chalk	Gas Storage
R-306	426	693	28	62	Chalk	Gas Storage
Well A	414	660	146	12	Sandstone	Oil Well
Well B	715	1172	194	9	Sandstone	Oil Well
Well C	161	948	125	14	Sandstone	Oil Well

Five wells (R-302 to R-306) were drilled as part of an expansion of a gas-storage project. Another three (Well A, B, and C) were new oil wells.

Each of the gas-storage wells had two logging runs. Wellbore profiles are summarized in Figure 8-16. On the first run, the wells were entered with formation micro-scan, gamma ray, and compression/tension tool. The second run included a dual induction tool, gamma ray and compression/tension.

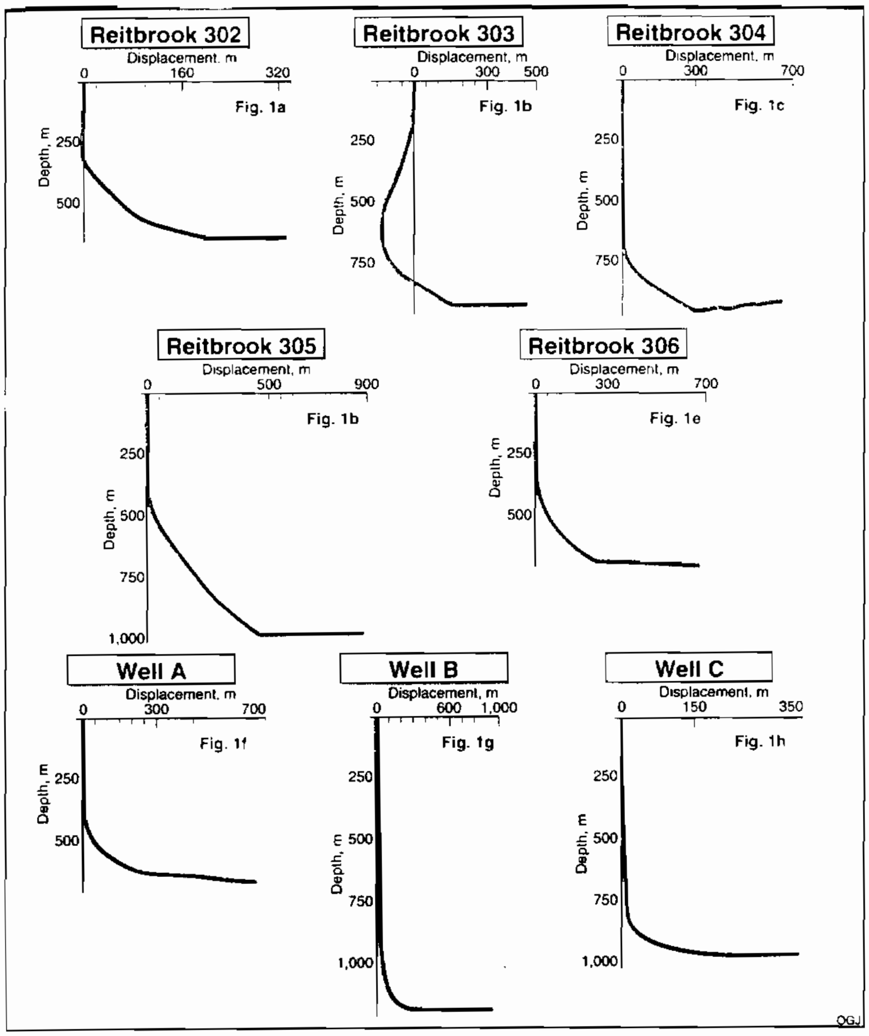

Figure 8-16. Mobil Horizontal Well Profiles (van den Bosch, 1994)

The wells were entered with a dummy logging tool on coiled tubing prior to running logging tools. The dummy run was designed to determine whether total depth could be reached. On the first well (R-303), the dummy tool reached total depth without problems. However, the logging run locked up 170 m (560 ft) into the horizontal section. In well R-304, only 60 m (200 ft) of open hole could be penetrated before lock-up. Later, both wells were successfully logged with drill pipe.

In R-306, larger coiled tubing (1¾ in.) was used in an attempt to increase penetration success. However, lock-up occurred after 290 m (950 ft) of the 426-m open-hole section. Forces measured at the surface and downhole are compared in Figure 8-17. Since the compression force at the tool is not increasing at lock-up (1068 m MD), wellbore friction was determined to be causing buckling. Drill-pipe-conveyed tools were later run to TD without problems.

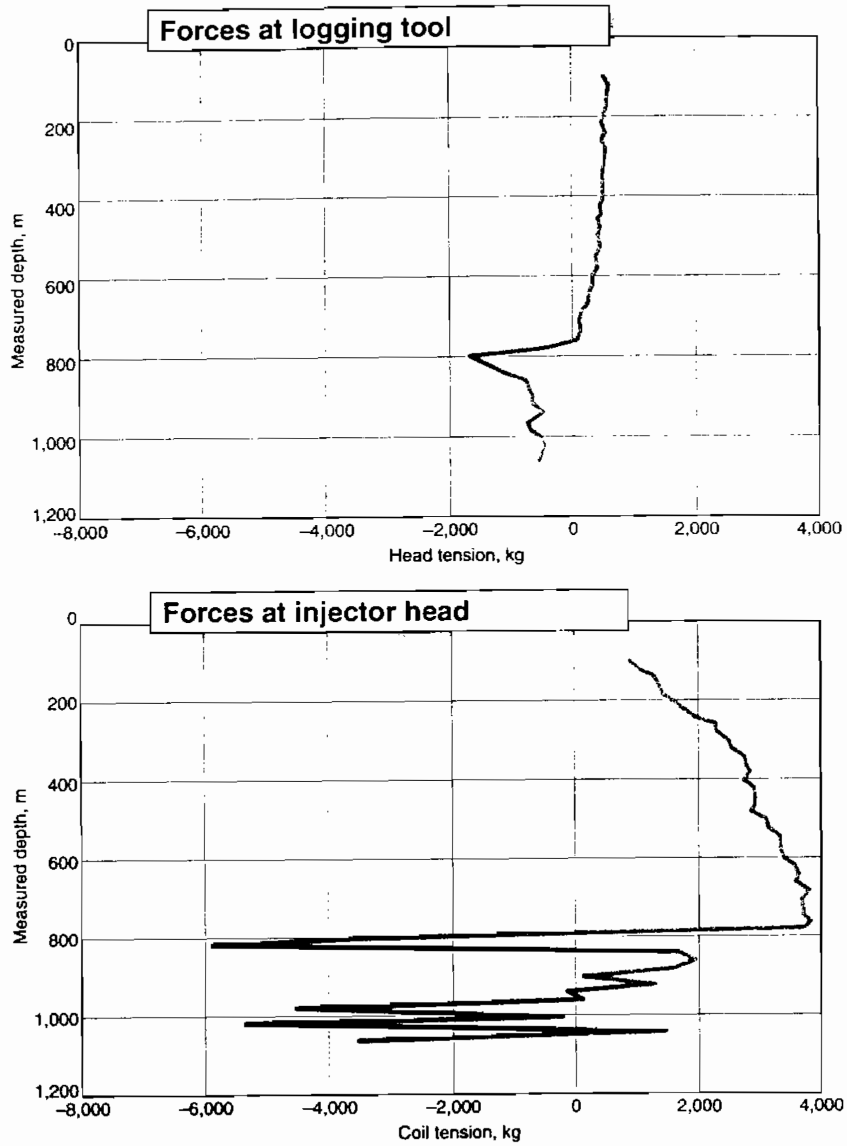

Figure 8-17. Well R-306 Downhole and Surface Loads (van den Bosch, 1994)

In the first oil well (Well A), neither logging run on coiled tubing reached TD. On Well B, coiled-tubing lock-up was predicted due to the long horizontal section, so coiled tubing was not run.

Success of the coiled-tubing and drill-pipe runs is summarized in Figure 8-18. Coiled-tubing conveyance was successful to an average of 62% of the horizontal section; drill-pipe conveyance was 100% successful in reaching TD.

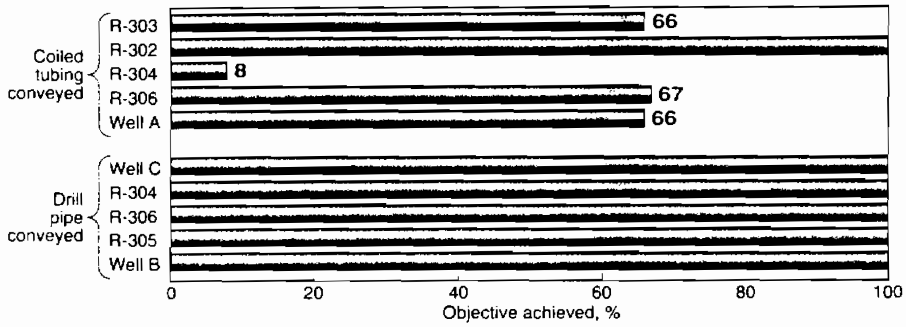

Figure 8-18. Success of Coiled-Tubing Versus Drill-Pipe Logging (van den Bosch, 1994)

Costs averaged \$304/m (\$93/ft) for the R-series wells (Figure 8-19). Note that costs for R-304 coiled-tubing logging are estimated, as the job was unsuccessful and not actually charged. Drill-pipe logging costs averaged \$105/m (\$32/ft). Higher costs for coiled tubing were attributed to higher day rates for the coiled-tubing rig and increased time needed for coiled-tubing operations.

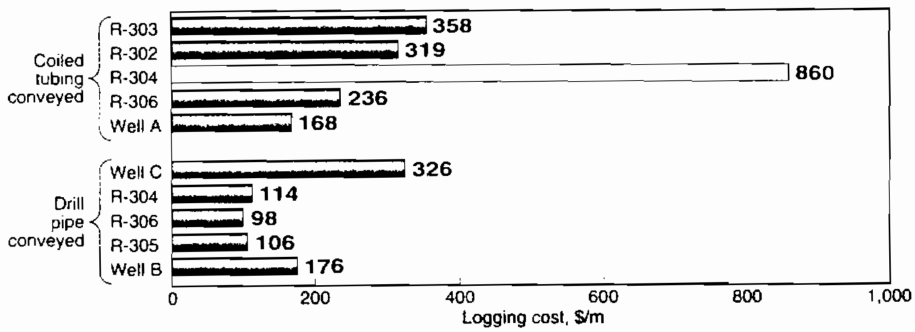

Figure 8-19. Cost of Coiled-Tubing Versus Drill-Pipe Logging (van den Bosch, 1994)

Job time for the two logging techniques is compared in Figure 8-20. An average of 7.8 min/m was required for coiled-tubing logging, compared to only 3.6 min/m for drill-pipe logging. Differences included 4 hr rig-up/rig-down time for coiled tubing competing against a conventional rig that was already in place and could begin logging immediately. Dummy runs to test coiled-tubing penetration also added significantly to run time.

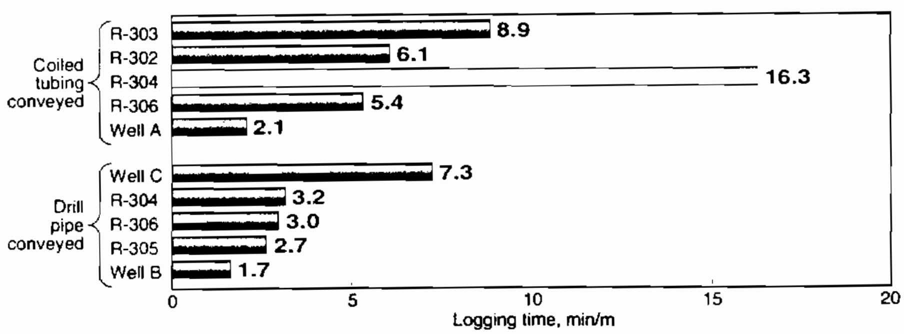

Figure 8-20. Job Time for Coiled-Tubing Versus Drill-Pipe Logging (van den Bosch, 1994)

Coiled tubing showed a slight advantage in data quality. FMS (formation micro-scan) data were adversely affected when the drill pipe was stopped to remove a joint.

Mobil Erdgas-Erdöl GmbH reached several conclusions after this field trial comparing coiled-tubing- to drill-pipe-conveyed logging. For open-hole logging of shallow horizontal wells, logging with drill pipe is more successful, twice as fast, and less expensive than coiled tubing. Problems with coiled-tubing operations included:

- Buckling and lock-up was a significant problem in the open-hole environment. Maximum penetration was about 290 m (950 ft) with 1¾-in. tubing.
- Successful runs to TD with a dummy logging tool do not guarantee success with actual logging tools.
- Coiled-tubing rig-up/rig-down time could not be offset by faster trip time in these shallow wells.
- Buckling prediction software was inadequate for these projects.

The author does note that Mobil believes that these problems will be overcome and that coiled-tubing logging in open hole will in the future be more efficient than using drill pipe.

8.2 PRODUCTION LOGGING

Production logging is a principle division of cased-hole logging and evaluation services. These services confirm or identify characteristics of the reservoir or completion. The most common cased-hole logging services are:

- Production logging, which includes measurement of temperature, pressure, density, flow velocity, fluid sampling, noise tools and gravel-pack tools
- Reservoir monitoring, which includes gamma-ray spectroscopy and thermal decay-time logs
- Corrosion monitoring, including the use of multifinger calipers and borehole televiewers
- Cement evaluation, including cement-bond logs, cement evaluation tools, and ultrasonic imaging tools
- Gyro compass
- Free-point indicator
- Downhole seismic array

Cased-hole logging services are most often conducted on wells that are producing. Coiled tubing is an ideal method of conducting safe and efficient operations on live wells.

8.2.1 Atlas Wireline Services

Atlas Wireline Services (Copoulos et al., 1993) summarized the issues involved in planning a coiled-tubing-conveyed production logging job in a horizontal well. Experience has shown the vital importance of planning for each project's success. All concerned parties (production engineer, reservoir engineer, and field supervisor from the operating company; field engineers from logging and coiled-tubing service companies) should be involved in advance planning efforts. Costs, rig-up technique, tool length, data acquisition need should be determined jointly to minimize downtime and clearly define the project's objectives.

Logging with coiled tubing is usually performed to address unwanted gas or water influx. Operators inexperienced in coiled-tubing logging programs in horizontal wells have assumed these are as straightforward as conventional wells. Previous experiences have shown that these jobs require considerably more planning than conventional.

Regional reservoir performance characteristics should be identified. These parameters will allow clearer definition of job needs and data analysis.

Faults and fractures need to be identified. Open-hole acoustic imaging logs can be used for this purpose. In one example, an acoustic imaging log was used to identify both faulting and fracturing in a horizontal well (Figure 8-21).

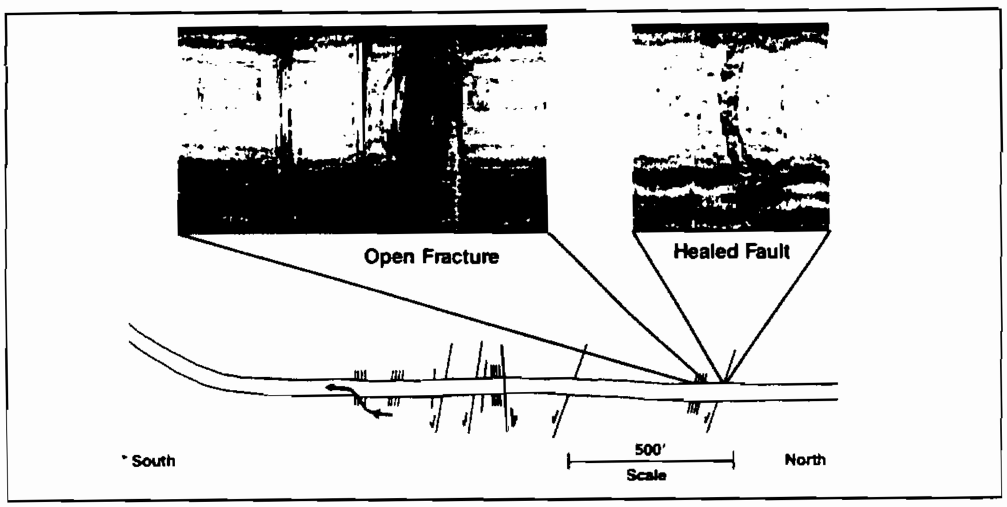

Figure 8-21. Identifying Faults and Fractures (Copoulos et al., 1993)

As a check of a horizontal well's productivity, data from offset vertical wells in similar producing horizons should be compared. Horizontal well productivity is usually 2–3+ times that of vertical wells.

Logging concerns in horizontal wellbores include multiphase production regimes, gravity segregation, tool centralization, changes in wellbore deviation, and flow inside and outside of slotted liners. Unfocused or radial measurements in horizontal wellbores have become common to address these problems. Instrument response for these tools is average over the borehole cross section.

Pulsed neutron logs have been used to identify cement channeling (Figure 8-22). Injection of boron-laden fluids is used to identify channels through large changes in formation sigma.

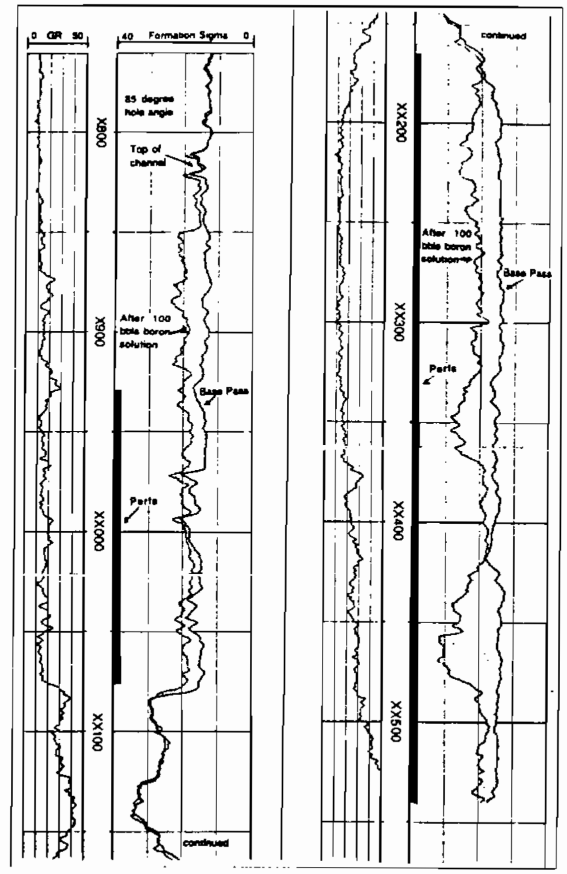

Figure 8-22. Identifying Cement Channeling (Copoulos et al., 1993)

Undulating horizontal wellbore trajectories can lead to premature gas or water breakthrough (Figure 8-23). Evidence of this situation has been seen in several cases, and its effects should be considered prior to performing a logging job.

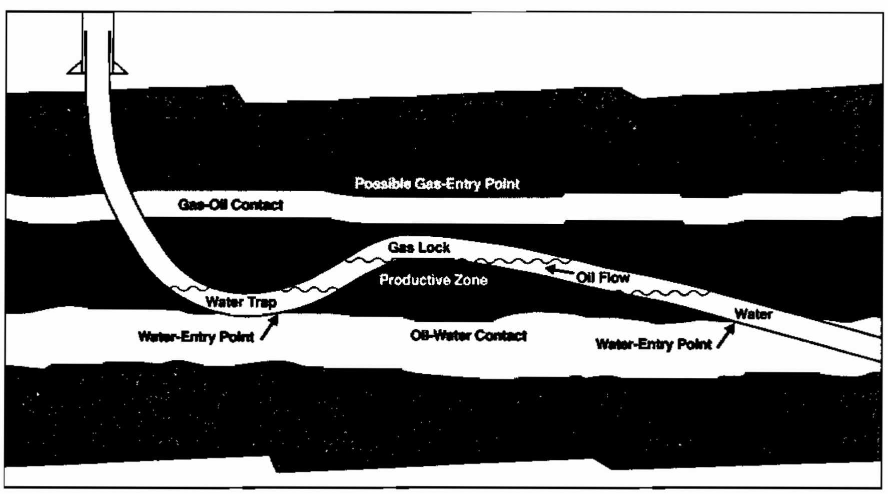

Figure 8-23. Undulating Horizontal Wellbore Production Problems (Copoulos et al., 1993)

Techniques to rig-up the coiled-tubing unit need to be considered before field operations begin. A specific rig-up will affect the number of trips required, overall job cost, and choice of logging instruments. Three rig-up techniques are common:

1. A conventional rig-up where the tool string is lubricated between the injector and the wellhead. Primary disadvantage is the limit placed on tool string length. Multiple runs may be justifiable since incremental cost of added runs is usually low.
2. Hanging the injector from a large construction crane allows the use of a long lubricator. However, the cost of the crane may substantially increase job costs.
3. Tools of great lengths can be hung off in the BOP stack. This approach is useful when the wellhead cannot support the lubricator and injector.

Tool centralization is accomplished by three common methods. In-line or slip-over bow springs, in-line centralizers with hinges and rollers, and in-line motorized centralizers are the most common systems. These tools provide rigidity as needed in horizontal operations, and add significantly to tool-string length.

Western Atlas also recommends that a torque and drag program be run before the job is performed. Program results should be used to determine limits for pull-up and slack-off weights while running into the well.

8.2.2 Schlumberger Dowell (Analyzing Three-Phase Flow)

Production logging with coiled tubing was used to analyze complex three-phase flow in a horizontal well (Chauvel and Clayton, 1993). Coiled-tubing logging techniques have been used for flow profiling horizontal wells for the last few years, although the technique is usually restricted to single-phase analyses due to a lack of appropriate data and understanding of the fluid mechanics.

A successful coiled-tubing production logging job was conducted by Schlumberger and Brunei Shell on a prolific well in Malaysia. The well produced 3650 BOPD (through a 48/64-in. choke) with a 30% water cut and a GOR of 2200 scf/bbl. The horizontal section was about 500 m (1640 ft) in length. The 7-in. liner completion was perforated across 30 intervals over a total length of 244 m (800 ft).

Production logging was performed to map the flow profile and to obtain data for designing possible remedial actions. Profile modifications were not required at the present time; however, the water and gas influxes were rising and a future workover was highly likely. The logging program included Schlumberger's Production Logging Tool (with two spinner flow meters, nuclear fluid densimeter, pressure, and temperature) and Water Flow Log (dual-burst thermal decay time tool).

Production data from the horizontal section of the well are shown in Figure 8-24. The left trace is from the end of the wellbore (the toe of the well) and the right trace begins at the end of the curve (the heel of the well).

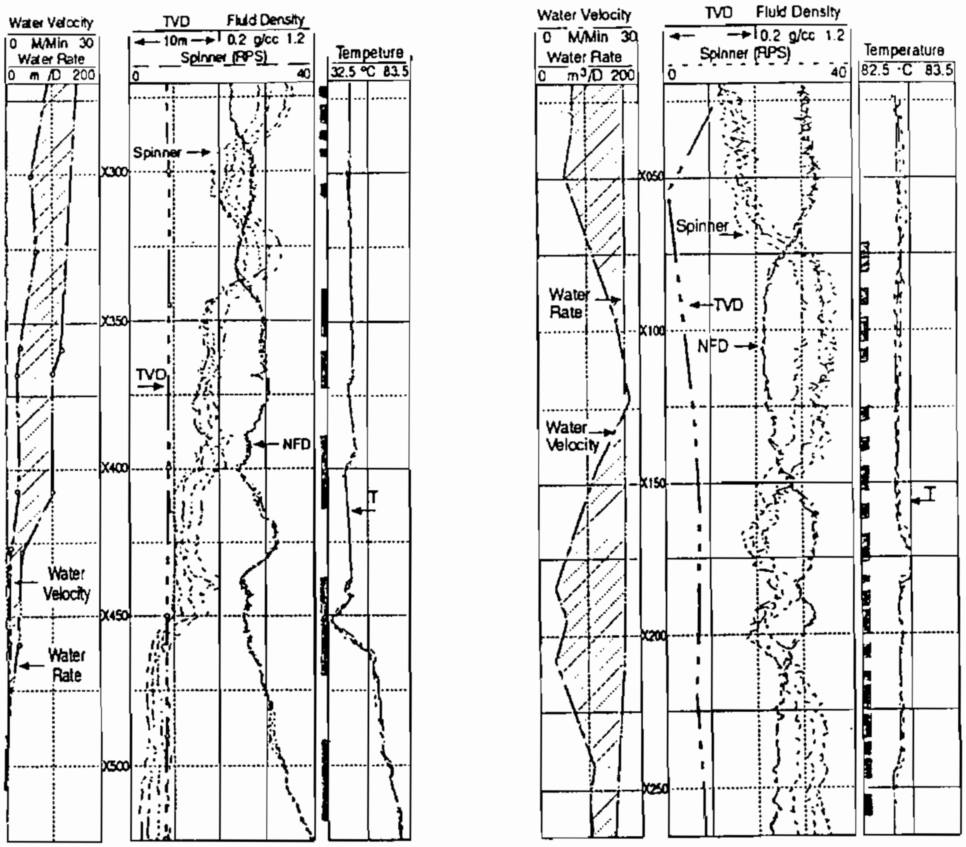

Figure 8-24. Production Logs Run on Coiled Tubing (Chauvel and Clayton, 1993)

Through this coiled-tubing logging operation, a complex diagnosis of three-phase flow was performed successfully. Even though the flow was stratified, spinner flow meter data were obtained and successfully corrected with appropriate correction factors.

8.3 PERFORATING

Coiled-tubing perforation is an extension of established coiled-tubing logging services. Coiled tubing's rigidity and strength are useful when perforating deviated wellbores and when long and heavy gun assemblies are deployed. Coiled tubing also allows safe perforation operations in live and underbalanced wells.

Perforating guns can be categorized by type of application:

- *Casing guns* are large guns (generally 3⅜ to 7 in.) run on wireline, jointed pipe or drill pipe.

- *Through-tubing guns*, generally $1^{11}/_{16}$ to $2^{7}/_{8}$ in., are most often run on coiled tubing.
- Expendable guns can be run on coiled tubing and are designed to be left in the hole after firing. They are only used in applications where debris of large size can be tolerated.
- *Semi-expendable guns* can be used where moderate debris can be tolerated.
- *Retrievable guns* are housed in a rugged carrier that confines the gun debris after firing. The carrier normally expands after firing. Thus, the anticipated OD of the assembly after firing must be less than the minimum wellbore restriction.

Perforation geometry significantly affects productivity of a perforated interval. Penetration must extend beyond the zone damaged by fluid invasion. The perforation channel must be cleaned of charge and formation debris, which is best accomplished by perforating in an underbalanced condition. Perforation density must be carefully designed to avoid excessive pressure drop across the perforation. Phasing of the individual shots of often desirable to maintain casing/liner strength.

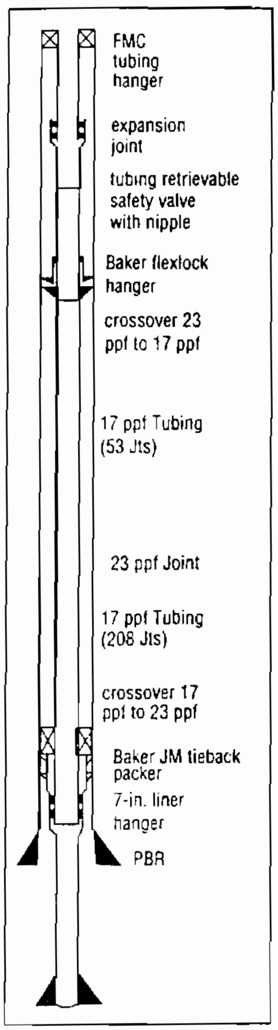

Figure 8-25. Amoco North Everest Well (Hennington and Jones, 1994)

Perforation diameter must be designed based on several factors. Perforations of ⅜-in. diameter are adequate in many applications, delaying the onset of plugging with scale or asphalt. Gravel-packed perforations usually must be about ¾ in. to minimize pressure drop across the packed tunnel.

Coiled-tubing-conveyed perforation systems can be fired by one of two methods: electrical actuation by wireline or hydraulic actuation by internal pressure. Pressure-actuated systems have the advantage of not requiring a wireline in the coiled tubing. Their principal disadvantage is that correlation logging tools cannot be run prior to firing to confirm gun position.

8.3.1 Amoco UK Exploration Company (Long Assemblies)

Amoco UK Exploration (Hennington and Jones, 1994) used coiled tubing to run perforating guns into several wells, including one that represented the longest perforated interval (almost 700 ft) ever shot on coiled tubing. The project team successfully perforated ten wells in the North Sea, all of which were 5½-in. monobore completions and at deviations of up to 65°. A typical completion is shown in Figure 8-25.

Amoco considered three options for perforation conveyance: wireline, jointed tubing, and coiled tubing. Wireline was rejected since coiled tubing would still be required to establish an under-balance across the zone. Jointed tubing was viable, but considered too slow and tedious. Since speed of operations and safety were primary concerns, coiled tubing was chosen as the conveyance method.

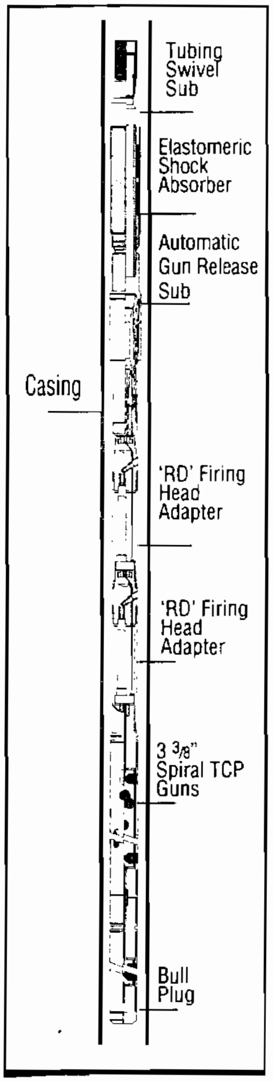

Figure 8-26. Coiled-Tubing-Conveyed Perforation Assembly (Hennington and Jones, 1994)

The coiled-tubing BHA for conveying the perforation assembly included a cross-over, two hydraulic disconnects, a dual flapper valve, a tubing connector, and a ported nipple that provided for flow from the tubing to annulus while displacing. One and one-half in. coiled tubing was used, since it had sufficient capacity to support 850 ft of 3⅜-in. guns.

The perforation BHA (Figure 8-26) allowed the guns to rotate freely. An automatic gun release dropped the guns into the rathole after firing. Rupture-disk hydraulic firing heads were used. They are actuated by elevated pressure. After the disk breaks, the guns fire after a 30-min delay. This delay provides time to unload the well pressure for underbalanced perforation.

These wells were perforated across multiple zones on single runs using a combination of gun sections and blank intervals. Each section was stabbed into the BOP stack and secured, the lift sub removed and the next section picked up. After complete assembly of the perforation assembly, the coiled tubing was made up.

The perforation assembly was run down hole to a depth of 5000 ft at about 50 ft/min. The wellbore fluids were then displaced with nitrogen at pump rates of 250–750 scfm. Pressure downhole was maintained at least 1000 psi below firing pressure. Fluid displacement average less than 100 bbl. The guns were then run to TD and then picked up to the desired position.

Pressure at the wellhead increased 200–600 psi when the guns fired. Immediately thereafter, string weight decreased as the gun assembly dropped down the well.

Logging runs conducted after perforation showed the perforations to be accurate. All aspects of these operations were successful, including a record-length 680-ft of perforations in one well.

8.3.2 Amoco UK Exploration Company (Extended-Reach Well)

Amoco UK, along with several service companies (Hennington et al., 1994), planned the use of coiled tubing to log and perforate a high-angle extended-reach well. Beyond the work described in the previous section, a new wellbore profile called for a TD of greater than 25,000 ft at an angle of 78° (Figure 8-27).

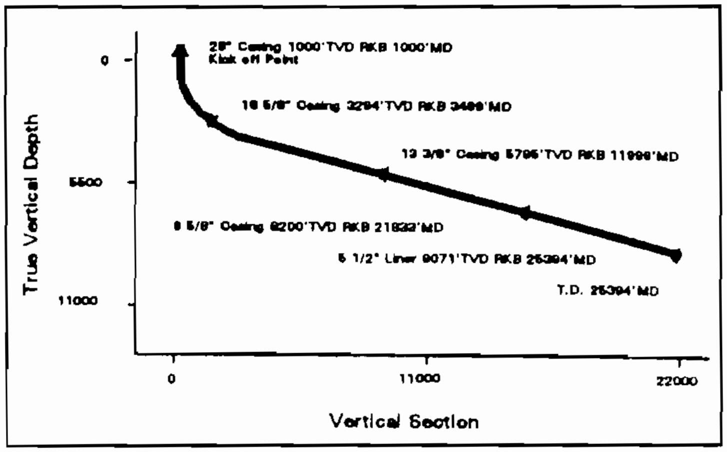

Figure 8-27. Amoco UK High-Angle Well (Hennington et al., 1994)

Completion design called for a monobore completion with 5½-in. chrome tubing from TD to surface (Figure 8-28).

Planned logging operations involved two separate runs. The first run would be made before perforating the well to measure liner cement quality and plug-back total depth (PBTD). After perforation and clean-up, a second logging run would include pressure, temperature, flow profile, confirmation of perforation depths, and pulsed neutron.

Depth control for the operations was planned to be by means of two encoders on the coiled-tubing injector. Thus, if one unit fails, a back-up is already available.

Perforating operations were designed to combine underbalancing the well with injected nitrogen along with perforation. This approach has been successful in previous development phases of this field. However, this well was at a greater angle than previous wells, and the removal of completion fluid with nitrogen became much less efficient.

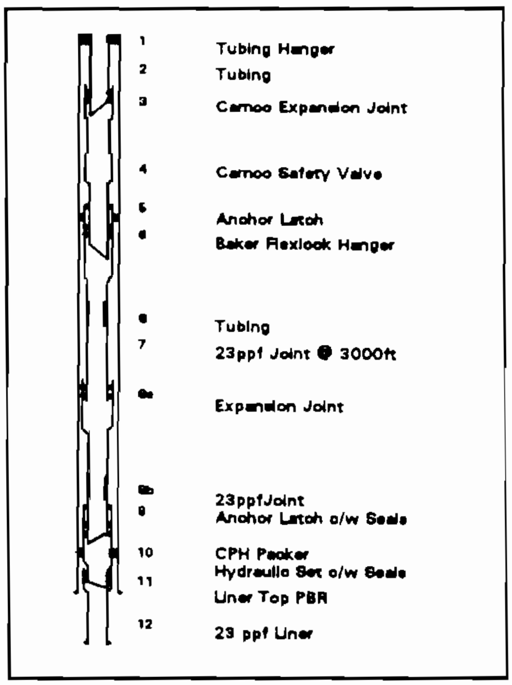

Figure 8-28. High-Angle Well Completion Design (Hennington et al., 1994)

Stresses and buckling forces in the coiled tubing were modeled in detail for this well. After a tapered string was designed, compressive forces along the string were modeled (Figure 8-29). A 1¼-in. string of coiled tubing with seven tapers was seen to reach bottom, according to the model.

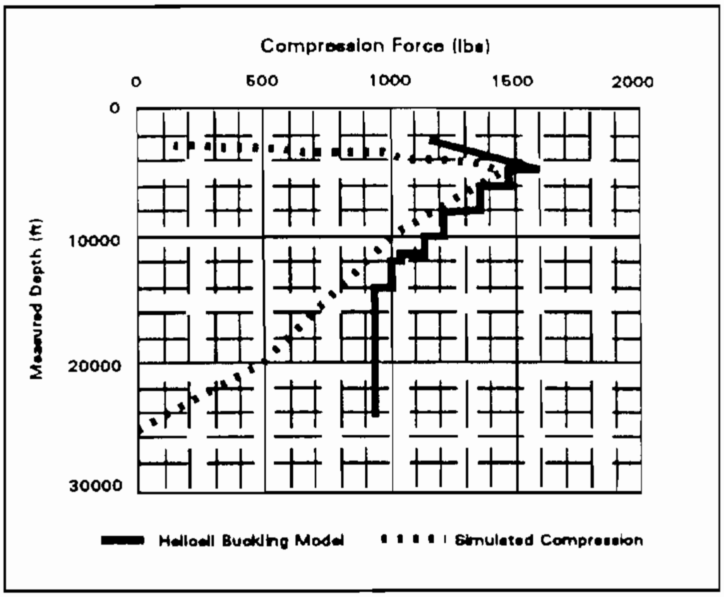

Figure 8-29. Compression Modeling for Coiled-Tubing Logging (Hennington et al., 1994)

After logging operations with a 1¼-in. string, a second string (1½ in. with five tapers) will be used for running the perforating assembly. The modeled weight indicator load at surface is shown in Figure 8-30. Safe operations are indicated by the model, which assumes both wellbore and coiled tubing are filled with gas for worst-case conditions.

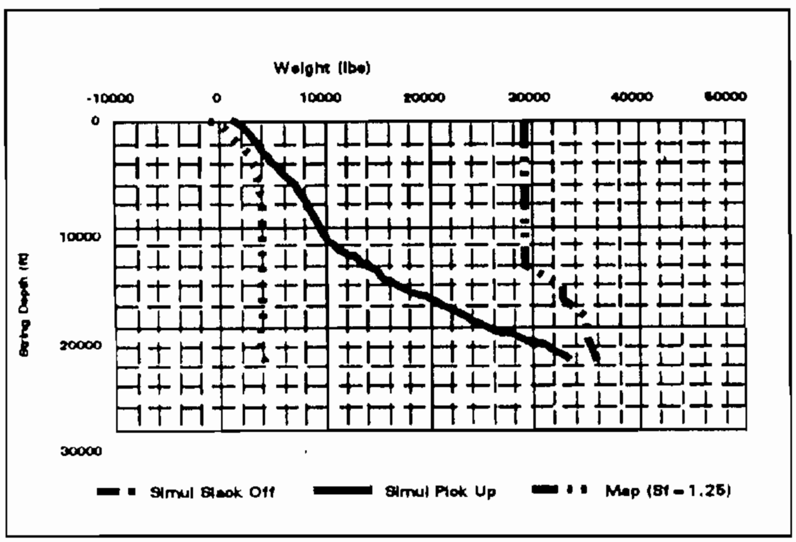

Figure 8-30. Surface Load for Coiled-Tubing Perforating (Hennington et al., 1994)

Coiled-tubing conveyed perforation was very successful in earlier phases of development. Guns up to 700 ft have been deployed. A similar perforation assembly as used previously by the team will be used in the new well (Figure 8-31). Estimated assembly length is 500 ft.

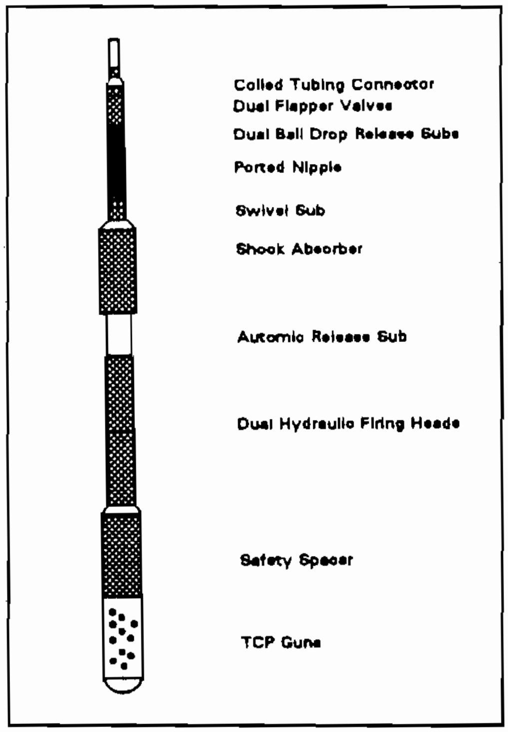

Figure 8-31. Coiled-Tubing Perforating Assembly (Hennington et al., 1994)

Due to the high angle of the wellbore, the perforation assembly will need to be pushed into the rathole after firing. Assuming friction factors for steel on steel, a force of 3300 lb will be needed to push the assembly down the hole. Previous runs in other wells show this modeling approach to be conservative. Buckling models suggest that sufficient force would be available down hole to perform the operation.

8.3.3 Enterra UK (Hydraulic Control System)

Enterra UK (Murry, 1994) developed and tested a hydraulic control system for coiled-tubing perforation. This system was tested for use on an assembly about 400 ft in length to be deployed in a North Sea horizontal well. Depth correlation was accomplished using a memory casing-collar locator.

System design requirements included circulation during run-in, perforation and pull-out. System operation is depicted in Figure 8-32. After reaching target depth, a ball is dropped and pins are sheared at 500 psi to close the circulation ports. The sequence valve is next opened with a pressure differential of 1000 psi. The open valve allows pressure to reach the detonation system, and detonation is activated at 2000 psi. After the guns are fired, further pressure is used to burst a rupture disk to re-establish circulation for pulling out of hole or dropping a ball to activate a hydraulic disconnect.

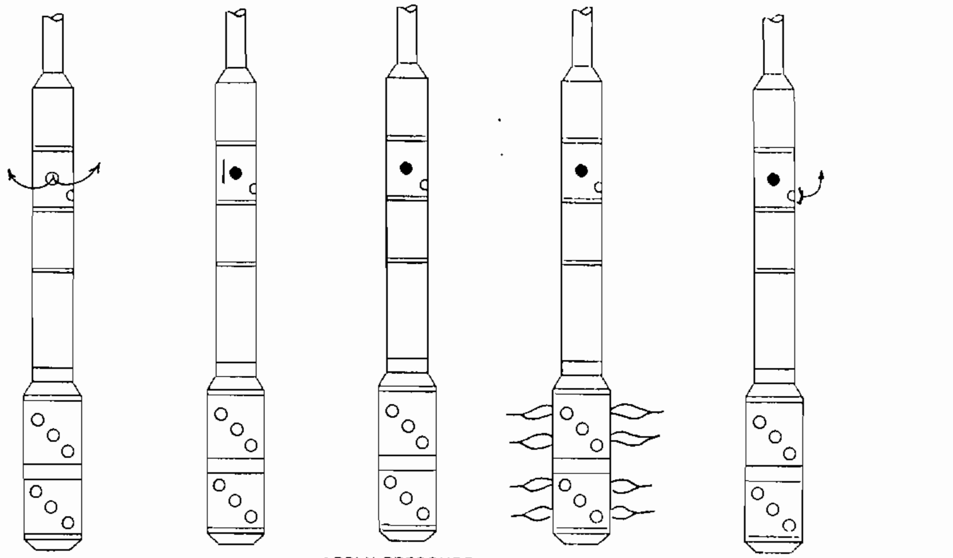

Figure 8-32. Perforation Assembly Operational Sequence (Murry, 1994)

8.3.4 Halliburton Energy Services

Halliburton Energy Services (Bond and Courville, 1994) summarized the factors to be considered for coiled-tubing-conveyed perforation operations. Conveying perforation assemblies with coiled tubing is an extension of (jointed) tubing conveyance. Most of the benefits of jointed-tubing conveyance are maintained with coiled tubing. Additional benefits with coiled tubing over jointed pipe are faster run-in, no rig needed, through-tubing operation, and the capability of working under pressure.

Halliburton states that three factors have primary impact on job success when running perforating guns on coiled tubing. These factors are the length of rathole, the firing sequence, and shock absorbers. These conclusions are based on the results from many jobs in the field.

Rathole depth affects the time of the reflected shock wave after firing. Deeper ratholes allow the initial shock to be attenuated before the reflection returns, thereby lessening damage to the tubing.

A belief commonly held by field engineers involved in perforating is that firing from the top down stresses the tubing more than firing from the bottom up. However, this observation has not been verified in controlled studies.

Shock absorbers have been used in some form on all successful jobs. Four basic options are:

- Accelerator placed between the coiled-tubing assembly and guns. Shock loads as great as 800 lb can be absorbed by the spring.
- Force generator. Slips are hydraulically activated to engage the casing ID, thereby greatly reducing transmitted shock.

- Radial shock absorbers incorporate a spring that absorbs radial forces.
- Impact subs use a hydraulic chamber and piston mandrel to damp shock load.

Firing heads for perforating assemblies run on coiled tubing are of several designs. Hydraulically actuated firing heads are activated by pumping a ball through the coiled tubing. Circulation is blocked after the ball seats, and pressure is increased to shear pins and fire the gun. Pressure-actuated firing heads are run in without circulation. To fire these heads, pressure is increased to shear pins holding a piston in place. Circulation is established after the pins are sheared. Both hydraulically actuated and pressure-actuated heads can incorporate a time delay before detonation to allow time to achieve underbalanced conditions.

Another method of firing the guns is with a slickline-retrievable firing device. Perforating guns can be run in on coiled tubing, and pressure tests and circulation established. When all conditions are ready, the firing head can be run in separately on coiled tubing or wireline. The heads are fired by increasing well pressure.

When running long gun sections into the hole, pressure isolation subs are made up between gun sections (Figure 8-33). These allow snubbing in each section through the lubricator and maintaining control by sealing on these subs.

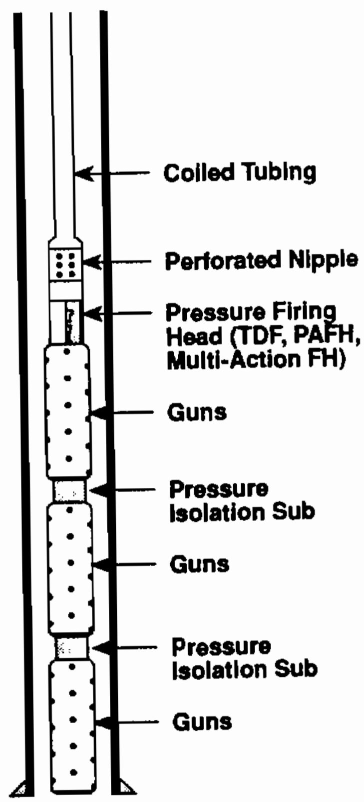

Figure 8-33. Pressure Isolation Subs for Long Assemblies (Bond and Courville, 1994)

Automatic-release gun hangers (Figure 8-34) allow the coiled tubing to be disconnected from the guns before they are fired. This approach greatly reduced shock damage to the tubing. After firing, the guns are dropped to the bottom. An additional coiled-tubing run to push the spent guns down to the rathole would be required in horizontal boreholes.

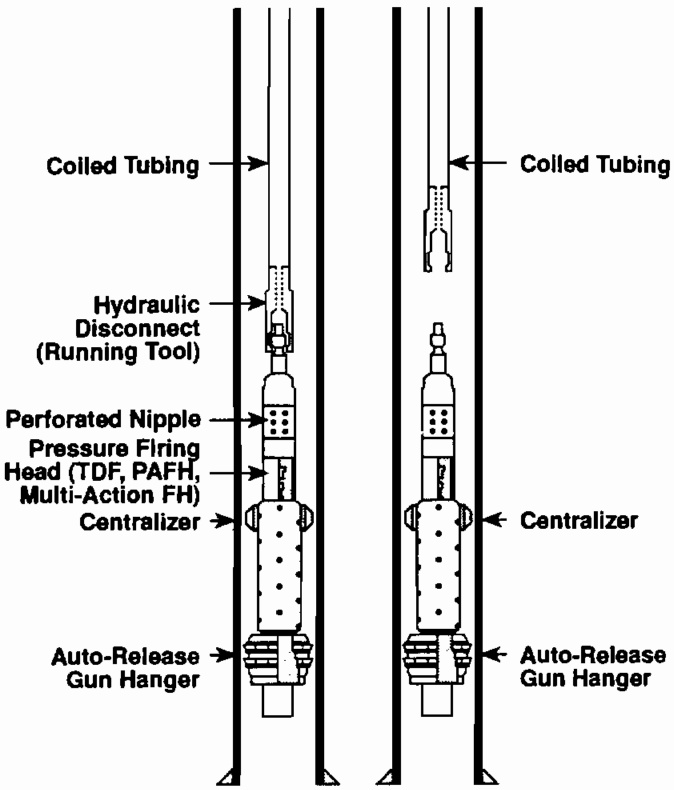

Figure 8-34. Automatic-Release Gun Hanger (Bond & Courville, 1994)

Retrievable firing heads (Figure 8-35) allow pressure tests of the casing and tubing before the firing head is run in.

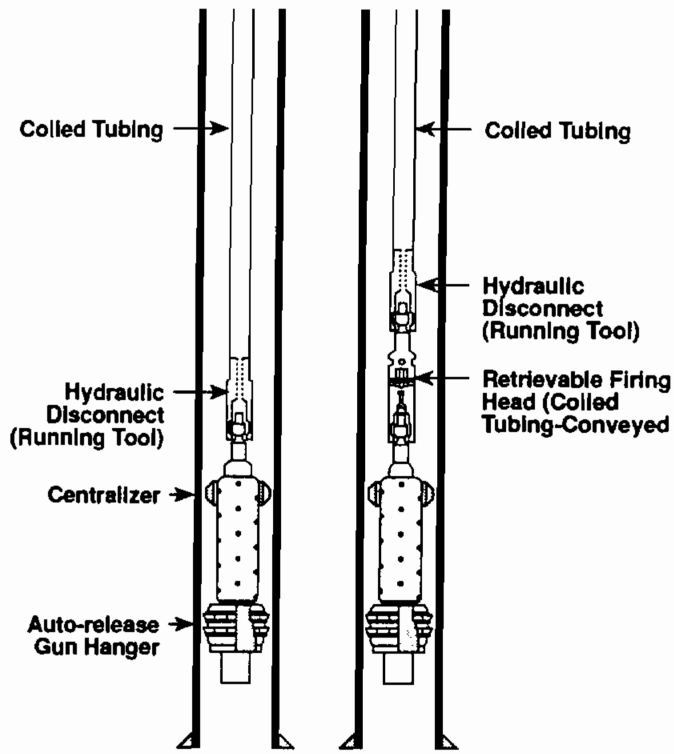

Figure 8-35. Retrievable Firing Head (Bond and Courville, 1994)

Firing heads conveyed on coiled tubing can be used for other tasks in addition to perforating. Cutting tools can be detonated (Figure 8-36) to sever casing or tubing.

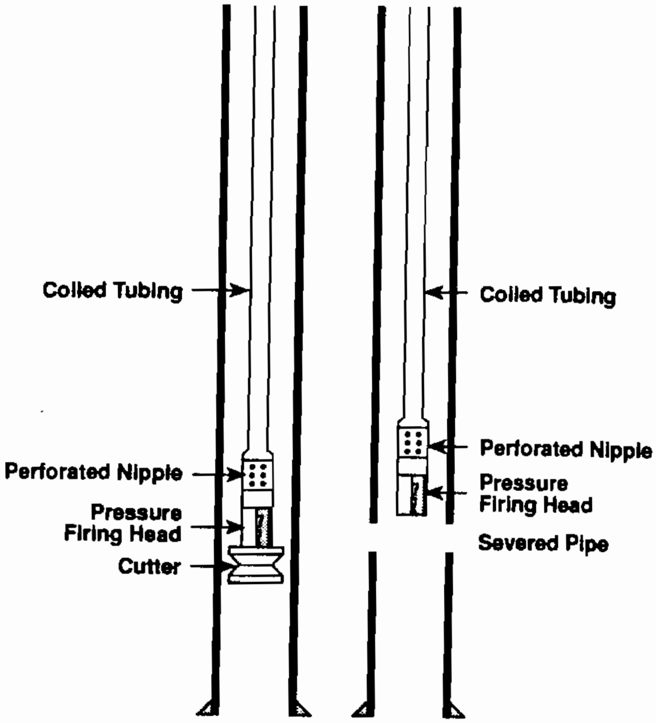

Figure 8-36. Retrievable Firing Head
(Bond and Courville, 1994)

Extremely long gun systems can be conveyed on coiled tubing through the use of modular gun systems (Figure 8-37). Gun sections are run in and stacked until total length is achieved.

Depth correlation for positioning perforating guns with coiled tubing can be accomplished by several techniques:

- Tubing end locator. Accuracy is about ± 1 ft at 10,000 ft. Used for situations where tubing end is near area to be perforated.
- Tagging bottom or other restriction at known depths with the assembly. Accuracy similar to tubing end locator.
- Electric line correlation via casing collar locator or gamma-ray collar locator.

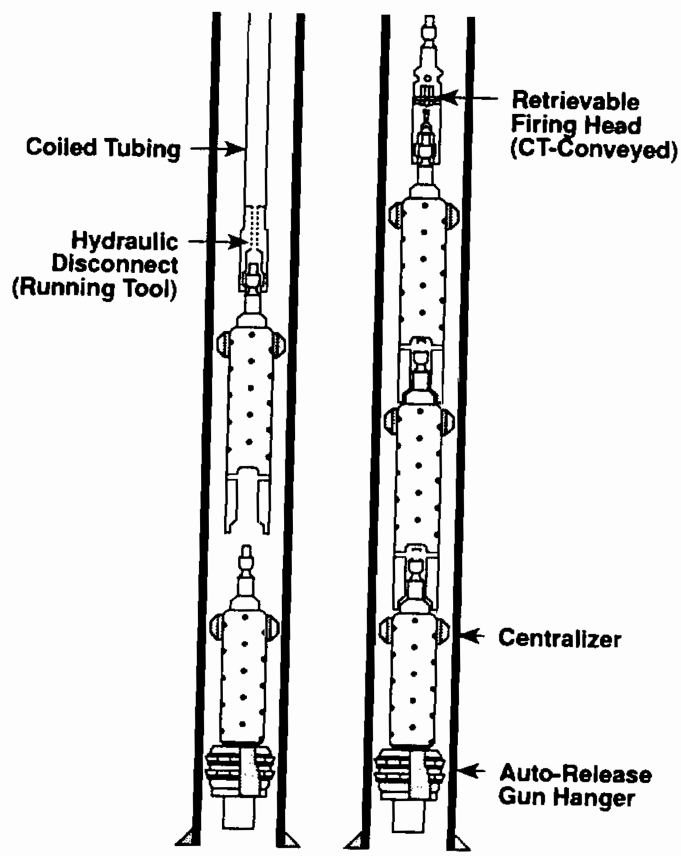

Figure 8-37. Modular Perforating Gun System
(Bond and Courville, 1994)

- Mechanical/electric counters on coiled-tubing rigs. This method is less accurate ($\pm$10 ft at 10,000 ft), but is simple and inexpensive.
- Using nipples in the completion string. Useful only if a nipple is near area to be perforated.

Halliburton has shown through their field experience that coiled tubing is an effective and economic means of conveying perforating assemblies. Almost all techniques used for jointed-tubing-conveyed operations are possible with coiled-tubing conveyance.

8.4 REFERENCES

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9. Overview

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9.1 COILED-TUBING RECORDS

Records for coiled-tubing operations were compiled and updated by *Petroleum Engineer International* for their Drilling and Production Yearbook (*Petroleum Engineer International* Staff, 1994). The records describing coiled-tubing jobs and record string lengths are summarized in Table 9-1.

TABLE 9-1. Coiled-Tubing Records (*Petroleum Engineer International* Staff, 1994)

Description	Length (ft)	O.D. (in.)	Year	Location	Operator	Service Co.
Horizontal Drilling	1,458	2	1991	Frio Co., TX	Oryx	Cudd
Horizontal Displacement (Coiled-Tubing Well)	6,841	2	1993	North Slope	ARCO	SD
Longest Drilled Section	4,182	1¾	1992	Paris Basin	Elf	SD
Offshore Drilling	1,000	1½	1993	Venezuela	Lagoven	SD
Largest Drilled Hole	–	6¼	1993	California	Berry Pet.	SD
Offshore N_2 Kickoff	20,797	1¼	1991	Gulf of Mexico	Pemex	SD
Cement Plug	19,261	1¼	1991	Mexico	Pemex	SD
Longest String	23,312	1¼	1991	Mexico	(Precision Tube)	SD
Longest Stiffline	22,800	1¼	1991	North Sea	(Precision Tube)	Transocean
Jet Cleaning	19,426	1¼		Tomlinson		Halliburton
Production Tubing	17,000	1	1987	Wheeler Co., TX		Halliburton
Production Tubing	20,500	1¼	1991	West Texas	Chevron	Nowcam
Production Tubing	21,700	1½	1992	West Texas		
Perforation	708	–	1993	North Sea	Amoco	Baker

9.2 CHALLENGES FOR THE INDUSTRY

Blount of Arco Alaska reviewed (Blount, 1994) the technical challenges facing the coiled-tubing industry and current progress toward meeting these needs. He listed seventeen areas of technical need that were highlighted by the attendees of the August 1992 SPE Forum on Coiled-Tubing Technology. Advances in most of these areas are discussed within other chapters of this report. In order of priority, the most significant technical needs are:

- *Coiled-Tubing Drilling.* Interest in coiled-tubing drilling remains high, although economics are not currently attractive in most applications. Niche markets do exist and the technological advantages of coiled tubing for drilling may make the development of this approach very worthwhile. Re-entry applications are a primary focus, along with underbalanced operations and deepenings, which are cost competitive in many areas.

- *Standardized Coiled-Tubing Fatigue Testing and Modeling*. Joint-industry projects have been performed to address these issues. One project developed a standard test fixture and testing method. Another has been proposed to address shortcomings in modeling. Advances have been made toward complete understanding of these areas.

- *Material, Equipment, Safety and Maintenance Standards*. An API task force is currently developing domestic standards covering a variety of aspects concerning coiled-tubing operations. API Committee 5's task force is expected to have a final document ready by Spring 1995.

- *Well-Control Equipment*. Recommended practices in well control will also be addressed by the efforts of the API Task Group. In addition, well control is guided by special requirements of local commissions and federal agencies.

- *Completion and Production Equipment*. Larger coiled tubing has led to high interest in coiled-tubing completions. The equipment to perform these operations is among the most significant needs. Recently, injector and gooseneck failures have caused problems in 3½-in. completions. Coiled tubing itself is not always well suited for production applications that may include sour, corrosive, or high-pressure service. New materials may be needed at the manufacturing stage to address these issues.

- *Coiled-Tubing Materials*. The industry's development of new materials for coiled tubing remains very active. High-strength tubing resulting from both changes in metallurgy and quench-and-temper processes is available. Titanium tubing has been delivered to the industry. Work continues on the development of corrosion-resistant alloys that are compatible with current coiled-tubing manufacturing processes. Composite coiled tubing is also being rapidly developed, with initial field trials to be conducted in the near future.

- *Cleanout Technology*. Although cleanouts represent the earliest use of coiled tubing, this aspect of coiled-tubing operations still requires innovative solutions in some areas. Reports of unsuccessful cleanout operations are not uncommon. One successful solution developed for a Canadian job involved a concentric reel of tubing (1¼-in. tubing inside 2⅜-in.). The smaller string was used to power a jet pump, which vacuumed fill from the wellbore.

- *Special Tools and Equipment*. Job requirements and equipment needs specific to particular regions drive the development of special technologies. The North Slope and the North Sea are prime examples of areas where potential economic savings and relatively large numbers of applications drive coiled-tubing technology into new areas. Ongoing development efforts will produce technologies that will eventually spread to other geographic areas.

- *High-Pressure Abrasive Jet Technology.* Renewed interest has been shown by the industry in abrasive and high-pressure jet drilling with coiled tubing. Extremely short-radius turns are a primary advantage of these techniques. Substantial design and development efforts are required for these technologies to become a part of standard through-tubing operations. Composite coiled tubing may play an important role here.

- *Hybrid Rigs.* New rig equipment is under design that combines the function of a workover rig and coiled-tubing unit. Prototype rigs have been tested in the field. One important challenge is to not design away the primary advantages of coiled-tubing operations.

- *Equipment for High-Pressure Operations.*

- *Information Exchange.* Information exchange remains a strong attribute within the coiled-tubing industry. Major forums to share experiences are common, and the published literature contains a significant increase in coiled-tubing technology in recent years. Lessons learned in the most active areas can be applied in new areas.

- *Job Planning/Operating Guidelines.* An increasing number of guidelines have been assembled, from sources including users and providers of coiled-tubing services, forums centered on coiled-tubing technology, technical articles, and an API task force currently developing domestic standards. API Committee 5's task force is expected to have a final document ready by Spring 1995.

- *Large-Diameter Tubing.* Clear progress has been made with the introduction of 3½-in. tubing and the soon-completed development of 4½ inch.

- *Simplified Hydraulics.* Gradual improvement has occurred, but more remains to be gained.

- *Floating Operations Technology.* Work remains in developing equipment and procedures for these applications.

- *Electronic Monitor/Control for Rigs.* Off-the-shelf electronics have become available for monitoring job parameters and controlling some aspects of coiled-tubing procedures. Several computer models are available for planning operations.

greatly reduced costs. In the North Sea, highly portable equipment for 1- and 1¼-in. tubing can be positioned on the lower decks of offshore platforms.

The use of coiled tubing as flow lines and service lines is another area of high potential not foreseen just a couple of years ago. Many new players are examining this use of the technology, and tremendous growth in this area is expected in the coming years (see also the Chapter *Pipelines*).

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10. Pipelines

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10. Pipelines

10.1 BT OPERATING (GAS INJECTION LINE)

In an application that represents the very first use of 3½-in. coiled tubing, BT Operating Company laid 5000 ft of tubing as a gas injection line between two platforms offshore Southern Louisiana in August of 1992 (American Oil & Gas Reporter Staff, 1993). Costs were reduced almost 50% as compared to a conventional welded-pipe installation. Tubing costs were comparable for 3½-in. coiled tubing and 3-in. Schedule pipe. Savings in time, labor and transportation amounted to about $100,000 ($283,000 conventional versus $178,000 coiled).

Quality Tubing manufactured the 3½-in. x 0.134-in. wall x 5200 ft string. It was coated with high-density polyethylene to improve corrosion and abrasion resistance. Pressure tests were conducted at the mill at 2150 psi. After installation, the string was pressure tested again at 2150 psi. Operating pressure is near 1440 psi.

BT Operating stated that the most difficult aspect of the job was convincing the Minerals Management Service (MMS) to approve use of the new product. Their primary concern was that the 3½-in. coiled tubing had a thinner wall than conventional Schedule 80 pipe. Technical data and analysis showed the coiled tubing to be as strong as conventional.

Conventional installation for this application normally requires about 10 days. The coiled pipeline was installed in 2½ days. In addition, a significant intangible benefit was in decreased exposure to potentially volatile Gulf of Mexico weather.

Five thousand ft of ⅝-in. cable was pulled from a supply boat and used to pull the coiled tubing to the platform (Figure 10-1). Divers then located the end of the tubing, which was pulled up to the work area for tie-in fabrication.

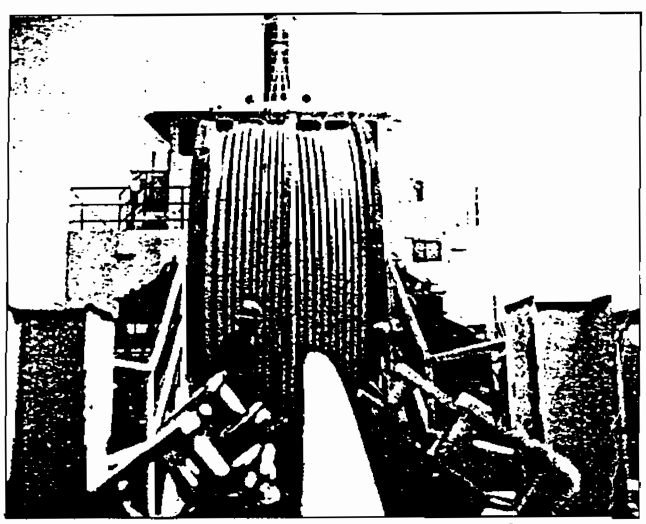

Figure 10-1. 3½-in. Coiled-Tubing Gas Injection Line

Two pre-job concerns were raised regarding this new application. The first concern was whether the coiled tubing would lay in a straight line during burial in the sea bed. There were no problems with residual bends after the tubing was unspooled. The second concern was the buoyancy of the string, given that the coiled tubing was lighter than conventional Schedule 80. Pre-job calculations indicated very little tolerance. However, the tubing lay straight on the bottom and there were no complications during installation.

BT Operating was very pleased with the results of the application. They hope that 4½-in. coiled tubing is available in time for a future job installing an offshore gas products line.

10.2 HALLIBURTON ENERGY SERVICES (GAS INJECTION FLOW LINE)

Halliburton installed a recyclable gas flow line in an environmentally restrictive swamp area for Zeit Exploration (Coats et al., 1993). Production decreases on two outlying wells in a south Louisiana field were remedied by gas lift installation. A coiled-tubing flow line was rapidly installed between the well and gas source. Costs were about 33% of those for a conventional jointed-pipe job. Production increased 80% after the job, and one day of production paid for the work.

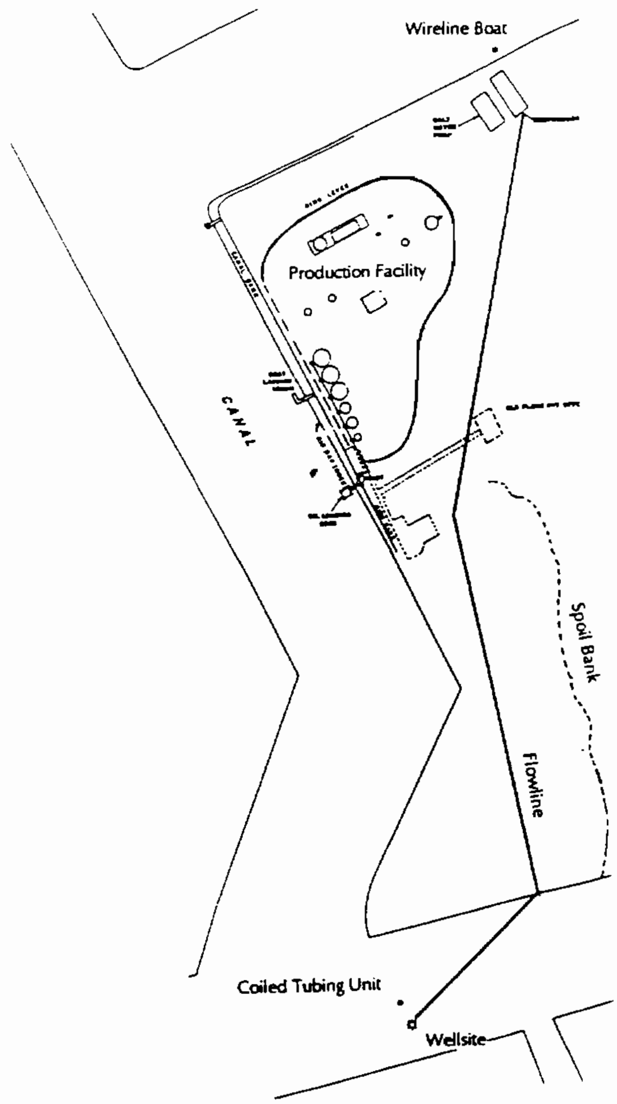

Figure 10-2. Gas Injection Flow-Line Job Site (Coats et al., 1993)

The nearest gas source to the well undergoing decline was about 2200 ft upstream from the well across dense cyprus swamp. A gas injection line to the well site was required. Economic and environmental constraints, including the effects of mobilization of large welding and X-ray equipment, and the need for numerous trained personnel to prepare the right-of-way and lay the pipe, led to the consideration of coiled tubing as an alternative.

To reduce installation efforts, the job was designed with the smallest coiled tubing size possible. Computer software was used to calculate gas-lift requirements and friction loss through the flow line. One-inch x 0.087-inch wall tubing was chosen for the job.

The flow line was installed by walking a wireline from the compressor station to the wellhead (Figure 10-2) along an existing spoil bank. The wireline was then used to pull the coiled tubing back to the hookup site.

10.3 HALLIBURTON ENERGY SERVICES (PRODUCTION FLOW LINE)

Halliburton (Coats and Marinello, 1993) described the use of 2-in. coiled tubing as a production flow line on a new well in the Deer Island area of South Louisiana. Coiled tubing was used as part of the well-site production facility hook-up as well as for a flow line to cross about 2000 ft of swamp to connect with the existing sales transmission line.

The first step in the field installation was to move a production barge along side the well and stabilize it. Next, three 2-in. coiled-tubing lines 250 ft in length were run to connect the wellhead to the barge. Finally, an 1800-ft string of coiled tubing was pulled through the swamp via swamp buggy to the transmission tie-in point.

A connection flange was welded onto the tubing (Figure 10-3) before the production line was pulled across the swamp.

The use of coiled tubing resulted in significant time savings. Installation and hook-up of the four coiled-tubing lines took about 18 hours. Conventional jointed pipe would have required 8 days.

Figure 10-3. Coiled-Tubing Connection Flange (Coats and Marinello, 1993)

10.4 HALLIBURTON ENERGY SERVICES (PRODUCTION FLOW LINE REPLACEMENT)

Halliburton (Coats and Marinello, 1993) described a field case history where 3½-in. coiled tubing was run to replace an existing jointed production line in a swamp area (Bayou Sale) of South Louisiana. The area was designated as an eagle habitat; consequently, replacement operations needed to be efficient.

The existing production line ran 1500 ft from the wellhead to production facilities. It was cut at both ends and pulled from the production facility out of the swamp area. A hook-up was designed that allowed new coiled tubing to be pulled in place as the existing line was removed.

Installation took about 8 hours. No additional excavation was required to complete the job.

10.5 MEWBOURNE OIL (HIGH-PRESSURE GAS INJECTION LINE)

Coiled tubing was recently used as a high-pressure natural gas pipeline in a pressure-maintenance project in northwest Oklahoma (Hoover and Benge, 1993). The installation was much more rapid than with conventional line pipe, and the project yielded substantial cost savings for the operator, Mewbourne Oil Company. Project costs were reduced by more than $7/ft.

Seven injection wells in the field are used to re-inject about 30 MMscfd at pressures up to 6000 psi (41 MPa). After a producing well was converted to an injector, a 4300-ft (1311-m) high-pressure pipeline was required for connection to the existing pipeline network. Work done previously in the field had used 3- and 4-in. XXH Grade B SMLS line pipe. Welding operations during conventional laying operations limited progress to about 500 ft/day.

A string of 3½-in. coiled tubing was manufactured by Precision Tube Technology for the application. External corrosion resistance was provided by a tape wrap at the mill. A 50% overlap 50-mm coating was used. Internal weld flash was removed during milling, providing a smooth internal bore.

The entire spool of coiled tubing was laid in 3 hours. Overall installation time was reduced by 80% as compared to conventional line pipe.

Additional benefits of the operation include minimizing the use of heavy equipment on-site for welding, inspection, and pipe coating. This is especially important in environmentally sensitive marsh lands and coastal waters.

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11. Production Strings

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11.1 PRODUCTION TUBING

11.1.1 ARCO E&P Technology (Production Applications)

Hightower of ARCO Exploration and Production Technology summarized (Hightower, 1992) the production applications of coiled tubing in oil and gas operations. Production applications have grown dramatically in recent years as new uses have been envisioned and tools and techniques to implement them have been developed.

The introduction of larger coiled-tubing sizes (2 in. and greater) marks a new era in the use of coiled tubing for traditional production operations. As coiled-tubing units equipped to run larger sizes become more readily available, the market for coiled-tubing production strings will increase dramatically. A recent market survey performed by Resource Marketing indicates that two of the most promising areas for near-term growth of the coiled-tubing market are velocity strings and production tubing installation.

Even though the use of coiled tubing for production strings has received most of the recent attention, coiled tubing has been used successfully for years as production velocity strings. In most cases, once a service company has "worn out" a string of coiled tubing, it is sold to a production company for further use as a velocity string. According to ARCO, an estimated 700 of these velocity strings were installed in 1992.

As a comparison, it is estimated that only 20 to 30 strings of large diameter coiled tubing have been run as either production or injection strings over the past 2–3 years. In fact, it was 1990 before the first string of 2-in. OD coiled tubing was installed inside a 4½-in. production string by ARCO Alaska.

There are several benefits and drawbacks that should be considered when comparing jointed-pipe completions to coiled-tubing completions. A few of the specific benefits of running larger (greater than 2 in.) coiled-tubing strings are as follows:

1. Killing the well not required
2. Reduced formation damage
3. Quicker installation times
4. Elimination of pin-end corrosion
5. Elimination of joint seal problems
6. Elimination of a workover rig
7. No joint clearance problems
8. Compatible with many artificial lift methods
9. Preferred for many slim-hole completions

In many cases, these production strings are run inside existing production tubulars. Figure 11-1 shows a typical coiled-tubing production string run by ARCO Alaska. Most of these strings are hung from the surface with a landing nipple at the lower end of the coiled tubing for setting plugs as needed. More recently, several strings have included retrievable packers that are capable of setting and releasing without rotation.

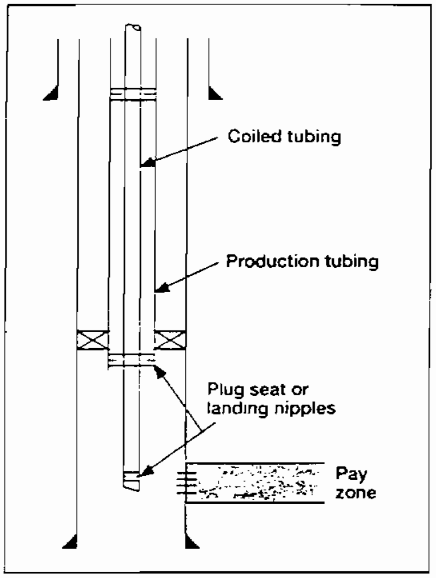


Figure 11-1. Typical Coiled-Tubing Production String (Hightower, 1992)

Even though the future of coiled-tubing production strings looks very bright, there are currently several drawbacks associated with running coiled-tubing as a production string:

1. Large coiled tubing requires a specialized running unit
2. Significant lead time required
3. Repair can be difficult
4. Long-term life uncertain
5. Minimal drift diameter data
6. Lack of downhole inspection tools
7. Plunger lift unavailable
8. Special welder required for field work

Most of the drawbacks associated with coiled-tubing production strings relate to the lack of experience and/or long-term integrity considerations. As larger coiled tubing and units to run it become more commonplace, many of the drawbacks associated with coiled-tubing production strings will lessen.

There are many methods and variations in procedures for installing coiled-tubing production strings. One of the most concise listings of installation procedures was published by ARCO (Hightower, 1992). The following installation procedure represents the standard procedure that ARCO Alaska uses for coiled-tubing installation:

1. Rig-up coiled-tubing unit and kill well if necessary.
2. Install coiled-tubing tubinghead. This may already be in place or may be an addition to existing wellhead equipment. In many cases, the tubing head will be installed on the lower master valve.
3. Nipple up blowout preventers (BOPs) with window on tubing head (Figure 11-2).

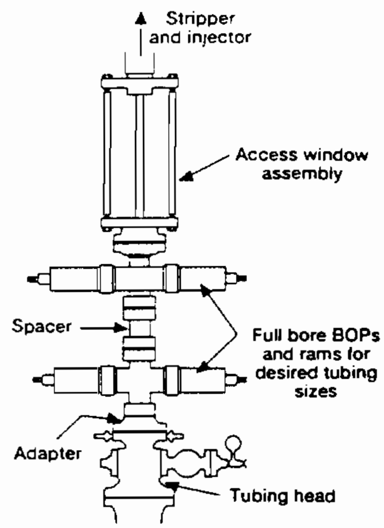


Figure 11-2. Coiled-Tubing Rig-Up for Completion Work on Live Wells (Hightower, 1992)

4. Run coiled tubing with shear-out or pumpout plug on the end (to prevent possible well flow back through the coiled tubing), accessories such as seals for a packer installation, and landing nipples or gas lift mandrels as needed. Use BOPs or tubing stripper for annular well control.
5. When end of coiled tubing is at desired depth, close lower set of BOPs and check for leaks.
6. Carefully measure distance from bottom flange of access window to tubing head lock screws to insure that, while landing hanger, the assembly sets completely in the hanger profile (Figure 11-3).

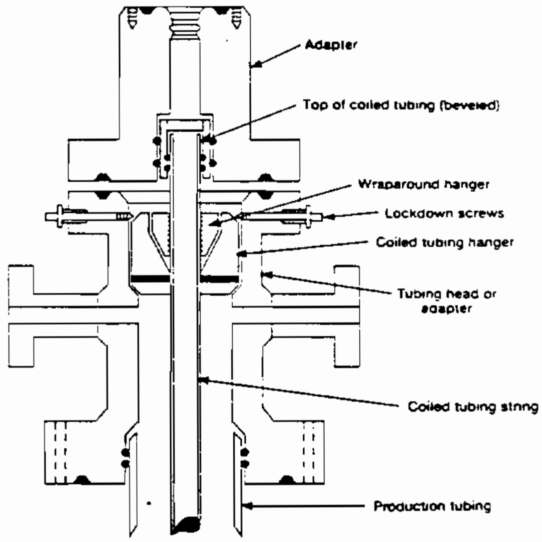


Figure 11-3. Tubing Head and Adapter for Hanging Coiled Tubing
Off From Surface (Hightower, 1992)

7. Attach hanger and slips to coiled tubing (both are wraparound style) and slowly lower assembly to top of the lower set of BOP rams.
8. Close upper BOPs, open lower BOPs and allow pressure to equalize across the spool.
9. Lower hanger to depth of bowl and land tubing with weight on hanger. Carefully engage lock-down screws. Pressure test hanger.
10. Rough cut coiled tubing at the window, and nipple down BOPs and window assembly.
11. Make a final (smooth) cut on the coiled tubing, and bevel to fit adapter and avoid damaging adapter seals. Install remaining wellhead equipment (Figure 11-4) and connect flowline.
12. Pressure up on coiled tubing to shear out bottom plug.
13. Place well in service.

Production applications in horizontal wells are also increasing. Coiled tubing has been run as liners and casing. Other potential uses include pre-perforated liners (Figure 11-5) and pre-packed screens.

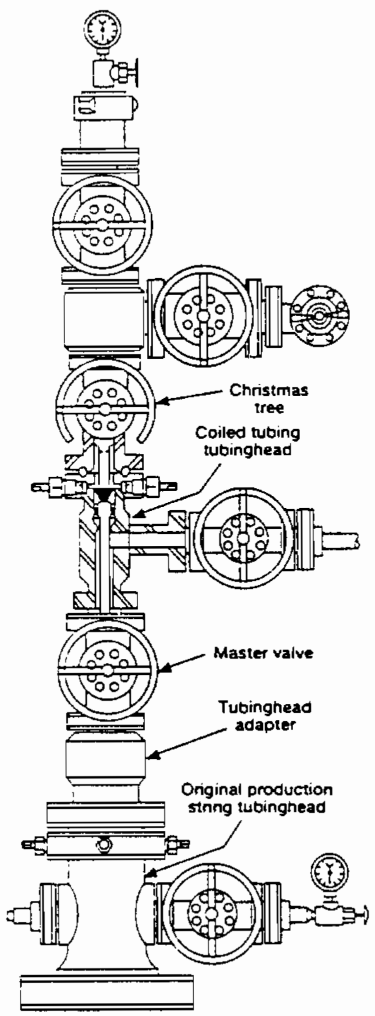


Figure 11-4. Wellhead Configuration for Coiled Production Tubing (Hightower, 1992)

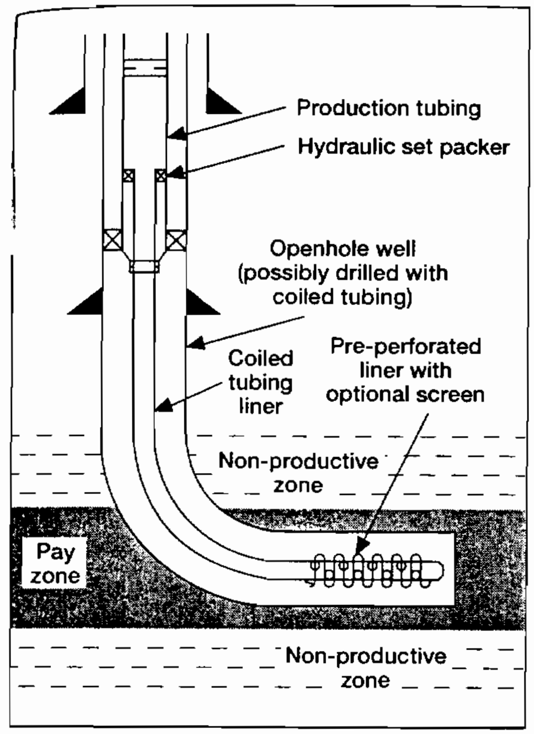


Figure 11-5. Coiled-Tubing Liner in Horizontal Well (Hightower, 1992)

Future production applications for coiled tubing will be enhanced by several developments. A wider availability of coiled-tubing units to handle large pipe will accelerate its use. Better methods of joining tubing sections in the field are needed. Spool lengths of large coiled tubing are restricted due to weight limits for transportation. Life and corrosion resistance of coiled tubing in production environments need to be better established. Lastly, installation costs need to be reduced.

In a recent publication, Hightower (1994) provided an update of the use of coiled tubing in production applications. The first downhole use of 3½-in. coiled tubing was a production string installed in a North Slope exploration well in March 1993 (see next section). Several more wells have been completed this way since that first installation.

Manufacturers reported that several hundred thousand feet of 3½-in. coiled tubing were milled or on order as of late 1993. Many strings of 2-, 2⅜-, and 2⅞-in. coiled production tubing have also been installed around the world. Several of these strings were installed without packers (see Figure 11-1).

Where required, retrievable packers have been run in a manner similar to jointed production tubing. Of course, these packers must be set without pipe rotation.

Coiled tubing in artificial lift is another type of production application. Several strings of 2⅜-in. coiled tubing with side-pocket gas-lift mandrels have been installed on the North Slope. Gas-lift valves were installed inside these strings with wireline without difficulty. The use of spoolable gas-lift valves was pioneered in late 1992.

Marathon has developed plans to install a jet pump on 1½-in. coiled tubing at 7000 ft in Tunisia. The design will permit changing the pump by circulating it out of the well. Additional details on Marathon's plans are presented in the Chapter *Artificial Lift*.

11.1.2 ARCO Alaska (3½-in. Production Tubing)

ARCO Alaska (Prestridge and Mahoney, 1994) ran the first string of 3½-in. coiled tubing used as production tubing in an exploration well on the North Slope. New equipment, tools and techniques were developed for this pioneering effort, which was completed in April 1993. Tubing performance successfully met all job criteria, including its use in a frac job.

ARCO Alaska considered whether coiled tubing could be a practical replacement for jointed completions. Due to flow rates typical of these wells, tubing at least as large as 3½-in. was required. Since this was a novel application for coiled tubing, inquiries were made to the manufacturers (tubing and rigs) and service companies followed by careful planning of the job.

An exploration well was chosen for this operation based on several considerations. For example, the lifetime of these completions was only intended to be a few weeks, allowing analysis of project results relatively quickly.

The surface equipment is shown schematically in Figure 11-6. A new injector, capable of running tubing ranging from 1 to 3½ in., was used on this project.

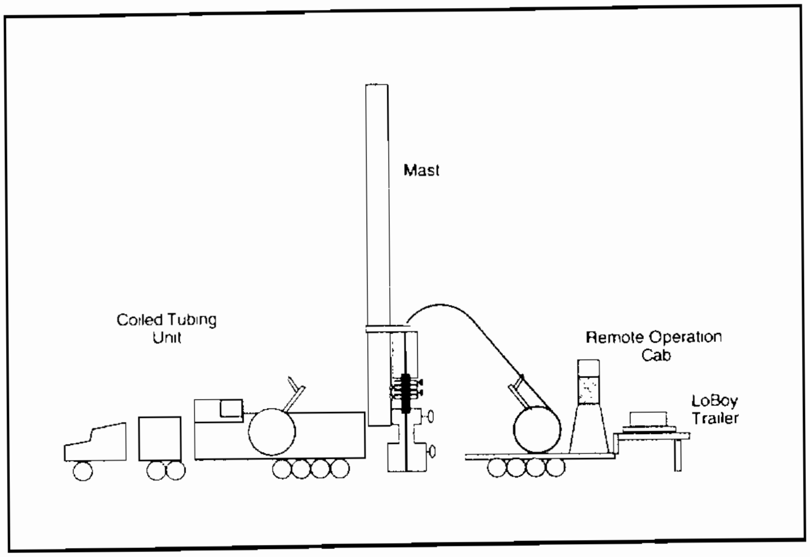


Figure 11-6. Surface Equipment for 3½-in. Completion (Prestridge and Mahoney, 1994)

The coiled tubing ordered was the heaviest wall available at that time. Compared to conventional 3½-in. jointed tubing, coiled tubing is stronger in some parameters and weaker in others, although generally comparable (Table 11-1).

TABLE 11-1. Properties of Coiled and Jointed Tubing (Prestridge and Mahoney, 1994)

	GRADE	O.D.	I.D.	DRIFT I.D.	WALL THICKNESS	LB/FT	BURST	COLLAPSE	TENSILE YIELD
3½" Coiled Tubing	QT-800	3.500	3.094	2.867	0.203	7.148	10,250 psi	6,950 psi	168,210 lb
3½"T&C Tubing	L-80	3.500	2.992	2.867	0.254	9.300	10,160 psi	10,530 psi	142,460 lb

Spool size was limited to a diameter of 15 ft. About 6500 ft of tubing could be placed on the 7-ft wide spool. The spool was positioned on a low-boy trailer separate from the rig. A remote cab was used for equipment operation (Figure 11-7).

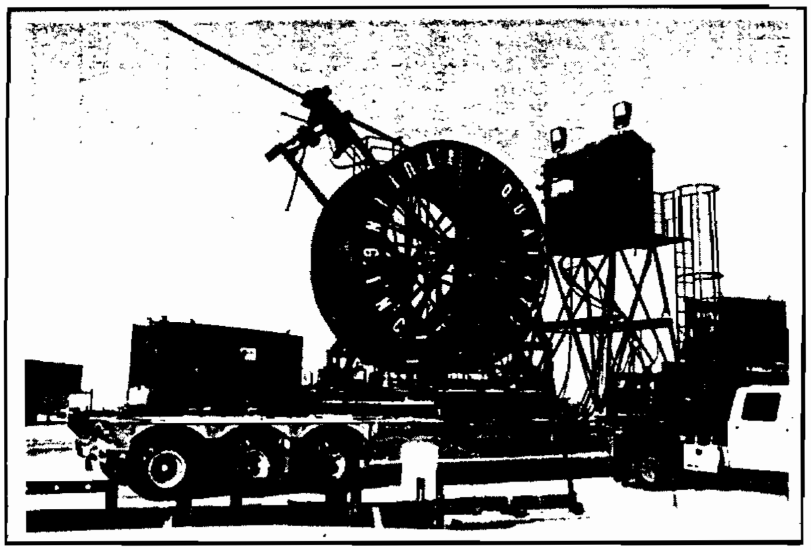


Figure 11-7. Tubing Spool and Remote Cab (Prestridge and Mahoney, 1994)

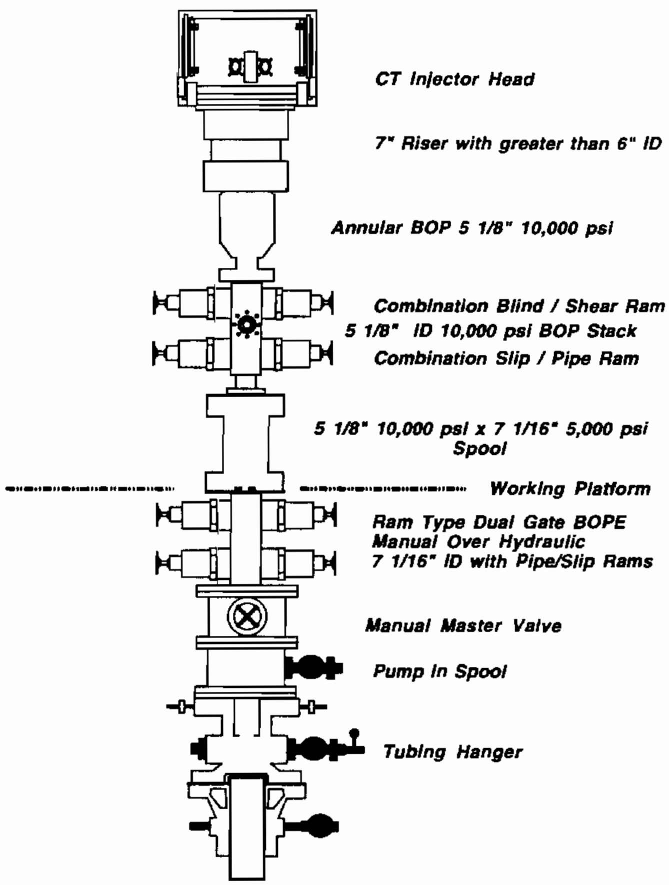


Figure 11-8. Wellhead Assembly (Prestridge and Mahoney, 1994)

Prior to conducting the job, the equipment was rigged up for a test run on another well slated for abandonment. Techniques for threading the tubing into the injector were practiced over several days. Several lessons were learned during the test runs that saved time on the actual job.

The BOP stack included two sets of rams and an annular BOP (Figure 11-8). Larger rams ($7^{1}/_{16}$ in.) were required so that tools could be run through the BOPs into the 7-in. casing.

Completion design included a single permanent packer, which was set by wireline after the drilling rig was moved off location. A large coiled-tubing unit was rigged up and a work stand was fabricated over the wellhead. Drill-stem test (DST) tools were run in on the coiled tubing and sealed in the packer. Run-in speeds of 50-70 ft/min and retrieval speeds of 70-100 ft/min were easily achieved. After cutting and landing the coiled tubing, a production test was performed. The coiled tubing was later reconnected to tubing on the spool and pulled out of the well. The process was then repeated on the next zone to be tested.

Some of the zones tested were perforated with guns conveyed with the completion string below the packer (Figure 11-9). Other zones were perforated with through-tubing guns.

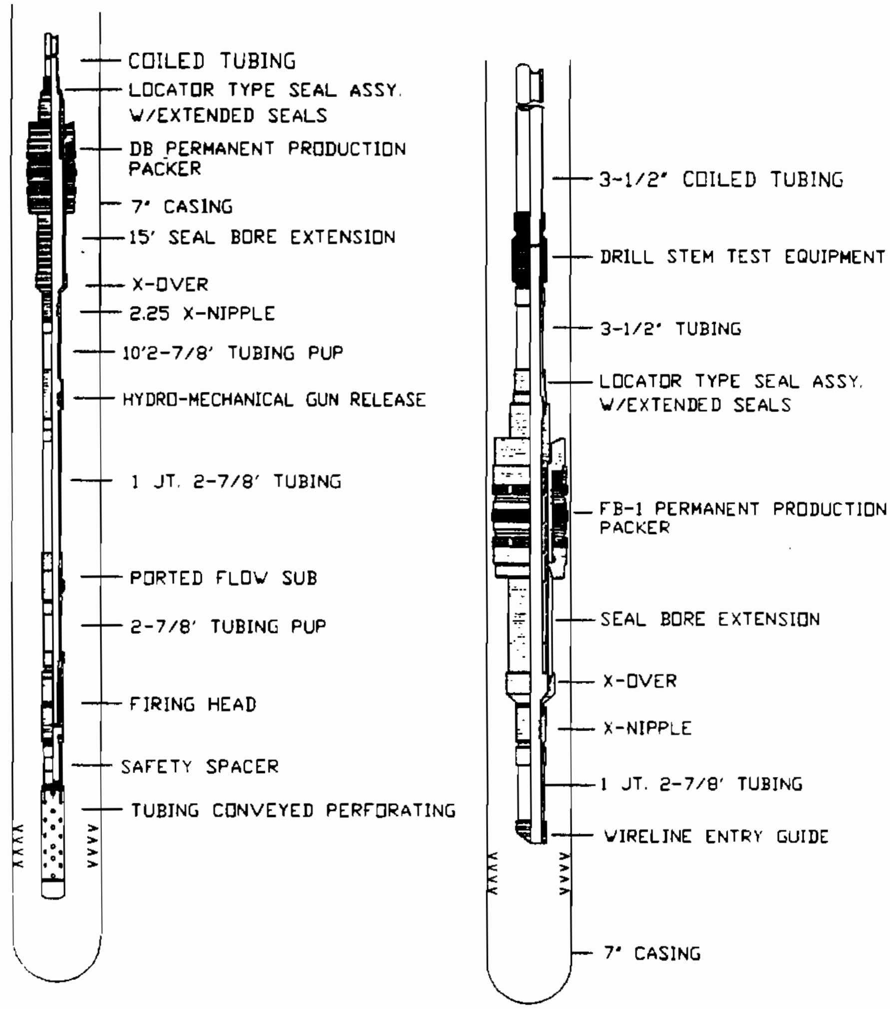


Figure 11-9. Completion Assemblies With Perforating Guns (left) and Without (right) (Prestridge and Mahoney, 1994)

The completion string was retrieved from the well after the production testing of each zone was complete. On the first attempt, a splice consisting of 6 ft of coiled tubing with a fishing spear on each end was used to join the completion string back to the tubing on the spool. A crack developed when wrapping the splice around the spool. On the next retrieval, the tubing was butt-welded back together. A welding jig was used to align the tubing. Chill blocks were used to dissipate heat (Figure 11-10). This approach was successful.

The tubing string was subjected to a pressure differential of 6400 psi as a result of a screen-out during a frac operation. However, tubing metallurgy allowed it to withstand this stress without damage.

Tubing cost on location was \$11.25/ft. Comparable jointed tubing costs \$10.25/ft on location. ARCO spent \$210,000 on specialized equipment for this job (which can be used again in later efforts). Before the job was performed, cost estimates indicated that for a one-well campaign, coiled tubing would cost \$10,000 more than conventional. For a two-well campaign, coiled tubing would cost \$190,000 less than conventional.

Unfortunately, actual costs were about \$290,000 more than conventional. Future jobs are expected to cost about the same as conventional due to the impact of a rapidly developing learning curve. For longer production tests, coiled tubing should be cheaper than conventional.

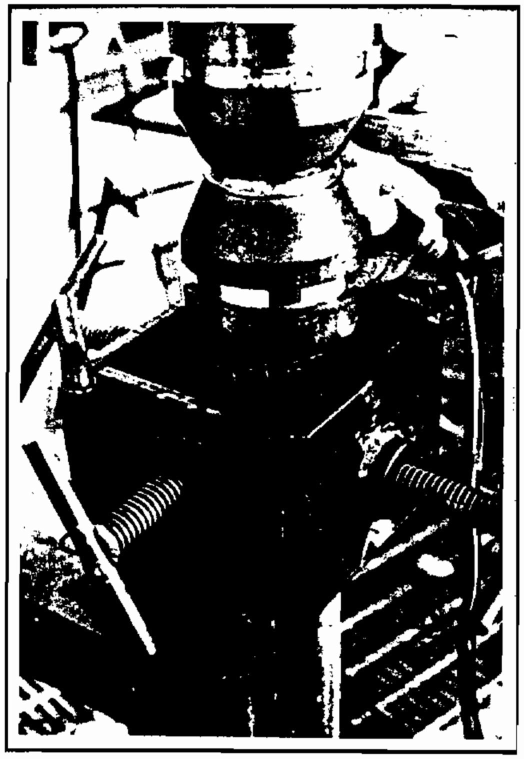


Figure 11-10. Coiled-Tubing Welding Jig (Prestridge and Mahoney, 1994)

Project benefits that ARCO found to favor 3½-in. coiled-tubing completions include lower work-over costs, lower production facility costs (if ESPs are run), testing program flexibility, feasibility of longer well tests in winter, and lower costs on exploration wells. This first application was very successful. In addition, this is the first time coiled tubing has been used as a frac string.

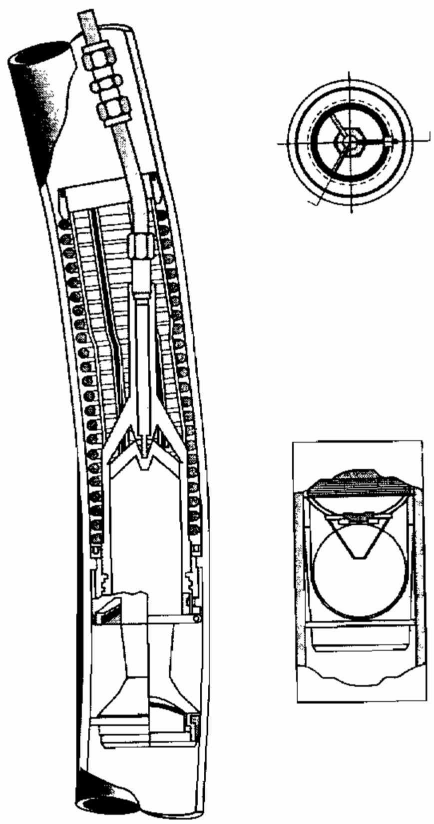


Figure 11-11. Spoolable SSSV (Teel, 1994)

11.1.3 Camco/Nowcam (Spoolable SSSV)

A spoolable surface-controlled subsurface safety valve (SSSV) was recently designed and patented by Camco/Nowcam (Teel, 1994). The SSSV (Figure 11-11) is manufactured in a housing of coiled tubing and the valves can conform to reel radius during deployment. Rigid components (flapper, hydraulic piston actuator) are designed as short as possible so that they do not make contact when the assembly is bent.

A stainless-steel control line is connected to the assembly before the valve is welded into a string of coiled tubing. The valve closes when hydraulic pressure is lost.

A 2⅜-in. version of the valve has been tested. It is designed for a maximum working depth of 2600 ft and working pressure of 5000 psi. The first string is to be installed in the Gulf of Mexico.

11.1.4 Petro Canada (Coiled-Tubing Liner)

Petro Canada (McMechan and Crombie, 1994) tested modified equipment and drilling techniques by deepening, completing and fracturing a vertical gas well with coiled tubing. The operations on a well near Medicine Hat, Alberta was the first phase in a larger project to evaluate balanced drilling of horizontal wells in sour reservoirs with coiled tubing. This first site was purposely chosen as a safer environment to test fluids handling systems, a new pressure sensor sub, and foam model accuracy.

The subject well (PEX WINCAN MEDHAT 10-9MR-17-3 W4M) was deepened from 448 m to 530 m (1470 ft to 1740 ft) with a 3⅞-in. hole. Drilling was conducted at balanced conditions with foam to avoid formation damage in the currently producing Milk River zone and the target Medicine Hat zone.

After drilling operations were complete, a production liner of 2⅞-in. 70 ksi coiled tubing was installed. No injector could be found in Canada outfitted for 2⅞-in. tubing. A small-capacity (20 kip) 1-in. injector was obtained from the North Sea and converted for the task. Spools had to be mocked up from shipping spools. Because there was no swivel joint on the shipping spool, circulation was not possible while running in the liner.

The liner assembly (Figure 11-12) included a hydraulically actuated seal-bore permanent packer as the liner hanger. The cement plug caused actuation of the setting tool after the plug landed in the bottom of the liner. The top of the liner was left with a standard seal bore for use in stimulation operations.

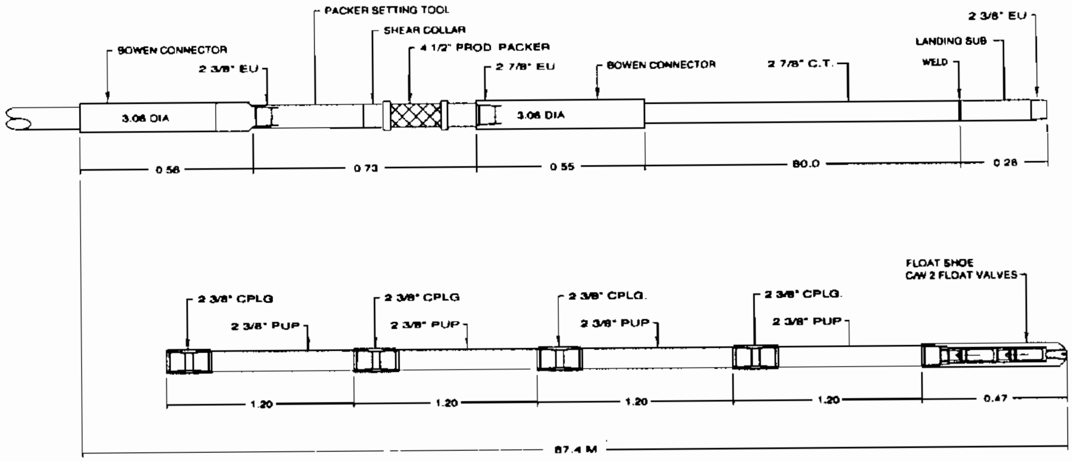


Figure 11-12. Running Assembly for Coiled-Tubing Liner (McMechan and Crombie, 1994)

Installation and cementing operations were completed in less that 3 hours. After the cement plug was bumped, pressure was increased to 2030 psi, shearing the coiled-tubing string off the liner. Throughout the operation, the upper producing zone was kept in a balanced or under-balanced condition.

After logging and perforating operations, a 55,000-lb frac job was pumped and the well put on production. The final wellbore status is shown in Figure 11-13.

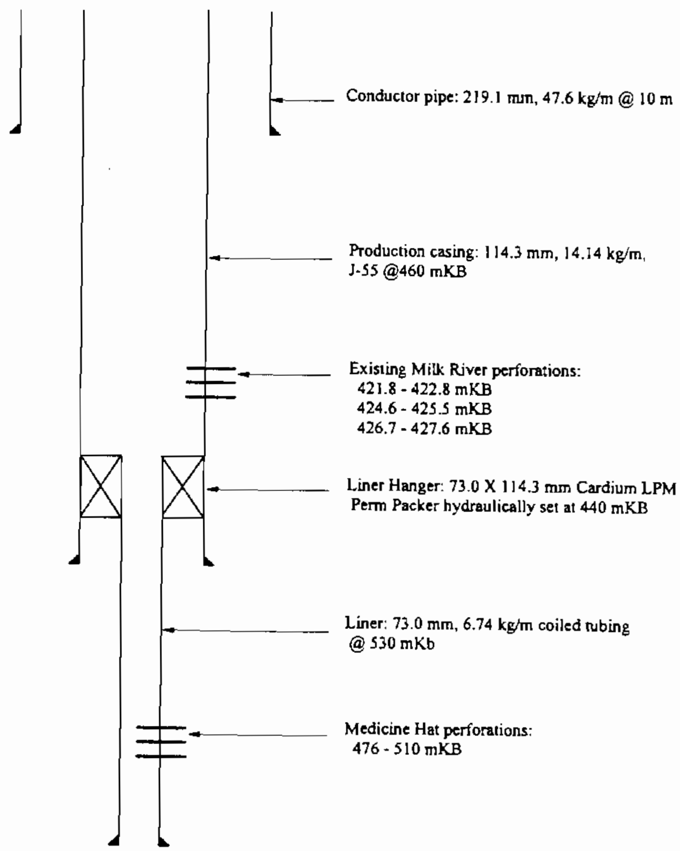


Figure 11-13. Final Completion of 10-9MR-17-3 W4M (McMechan and Crombie, 1994)

11.2 VELOCITY STRINGS

11.2.1 Chevron USA Production Company

Adams (1993) of Chevron USA Production discussed several practical aspects of velocity string design for keeping gas wells unloaded. He reviewed methods to select appropriate candidates, to design the string, and to install the string. Improvements in coiled-tubing technology, manufacturing, and equipment (surface and downhole) have enhanced the utility of coiled tubing in these applications.

The flow area of a gas well's production string impacts its ability to unload fluids. Surface back pressure is another parameter that can be lowered to accomplish fluid unloading. However, this approach, when feasible, is usually only a temporary fix.

It is often difficult to determine whether liquid loading is occurring. Symptoms strongly suggesting liquid loading include dramatic drops in daily production, intermittent production, or the need for pumps or swab units to maintain production. It is important to identify and remediate liquid loading as quickly as possible since it can result in permanent damage to the reservoir.

A well's production history is the most important tool for identifying liquid loading. This can be a problem even in wells that have never produced fluid. Due to initial completion design, velocities sufficient to unload fluids may have never been achieved. As an example, a well that appeared to have a normal decline was actually suffering from liquid loading since 1971 (Figure 11-14).

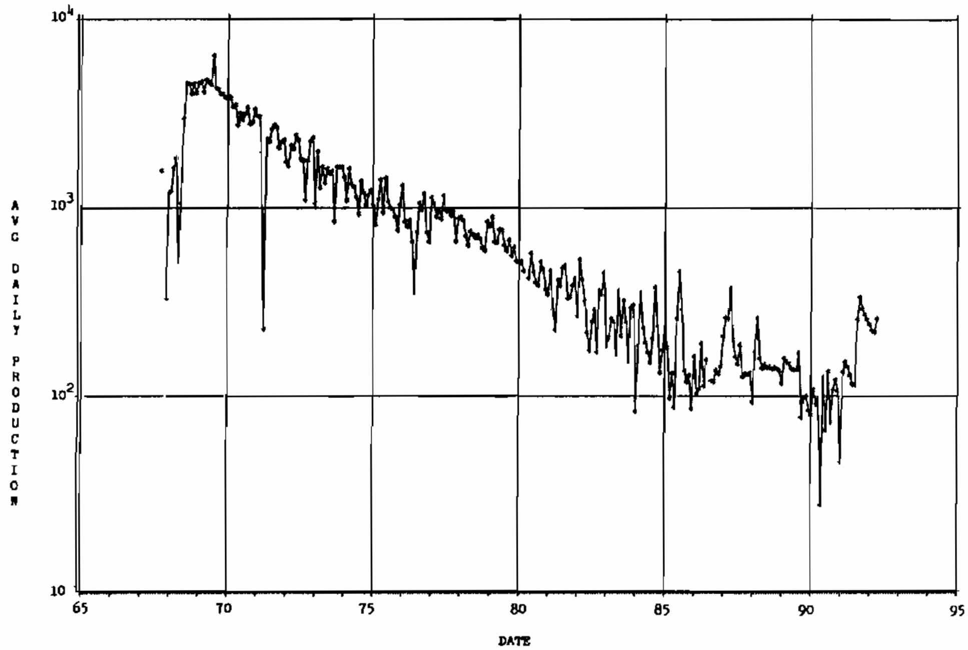


Figure 11-14. Well Production Decline With Liquid Loading (Adams, 1993)

The most accurate data for pinpointing liquid loading are flowing and shut-in bottom-hole pressures. P/Z data, production history, and offset well performance should also be considered.

The use of conventional theory (Turner, Hubbard, and Duckler equation) is not recommended by Chevron USA. Significant error can be introduced into these calculations through variations in temperature, pressure, and reservoir inflow effects. Nodal analysis is recommended. A history match of the well's current configuration should be performed to verify parameters.

Design procedures for wells with unsteady flow are more complicated. For these cases, the velocity string should be able to unload liquid at rates higher than reservoir inflow until accumulated fluids are produced. Split-stream surface compression can be used (Figure 11-15) until fluids are reduced.

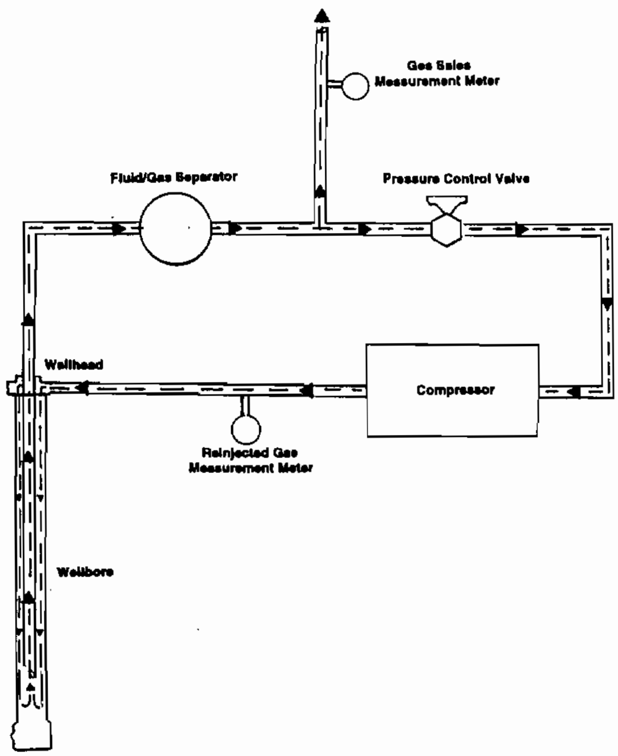
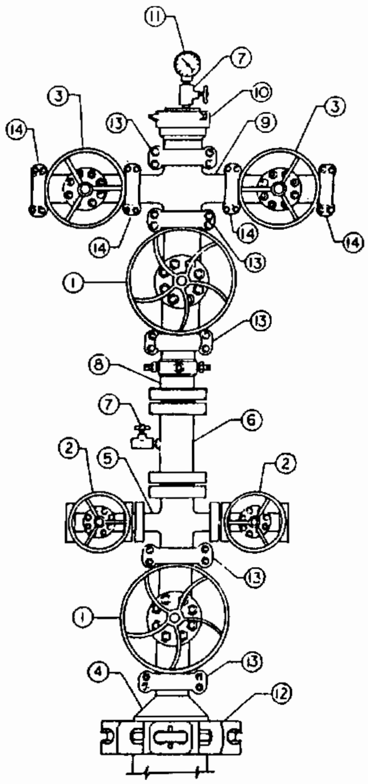


Figure 11-15. Single-Point Gas Lift to Unload Liquids
(Adams, 1993)

The properties of the velocity string should be compared to job requirements. The tubing metallurgy must be suited for exposure to the downhole environment. Overpull, burst, and collapse should be checked for each section of the string. Buckling should also be modeled if appropriate.

The coiled-tubing velocity string should be installed without using kill fluids or shutting in the well. One installation method is to place a master control preventer between the flow spool and coiled-tubing hanger (Figure 11-16).



ITEM	QTY	DESCRIPTION
	2	D31 Grayloc Seal Ring
	5	F40 Grayloc Seal Ring
	1	P87 Grayloc Seal Ring
	2	R24 Ring Gasket
	2	BX155 Ring Gasket
	16	7/8" Dia. x 6 1/4" Long B7 Studs w/2 Nuts
	16	1 3/8" Dia. x 8 3/8" Long B7 Studs w/2 Nuts
1	2	4 1/16" 10M WKM Gate Valve, F40 Grayloc
2	2	2 1/16" 5M WKM Gate Valve, Flanged
3	2	2 9/16" 10M WKM Gate Valve, D31 Grayloc
4	1	P87 x F40 Grayloc Tubing Head Adap
5	1	F40 Grayloc x 4 1/16" 10M Flanged Diverter Spool w/2-2 1/16" 5M Flg'd. Outs.
6	1	4 1/16" 10M Studded Master Control Valve
7	2	1/2" NPT Needle Valve, M x F
8	1	4 1/16" 10M Flange x F40 Grayloc Coiled Tubing Hanger Spool
9	1	F40 x D31 Grayloc Cross
10	1	F40 Grayloc Tree Cap
11	1	1/2" NPT Pressure Gauge 0-10M
12	1	P87 Grayloc Clamp Assembly
13	5	F40 Grayloc Clamp Assembly
14	4	D31 Grayloc Clamp Assembly

Figure 11-16. Wellhead Equipment for Installing Velocity String (Adams, 1993)

11.2.2 Cudd Pressure Control

Cudd Pressure Control (Wesson, 1993) outlined the steps in velocity-string design. As of early 1993, Cudd had hung off more than 3 million ft of coiled tubing as velocity strings. Ninety percent of these applications have been successful. The payout time for these operations is short: 4-6 months on average. A listing of results from several typical jobs is presented in Table 11-2.

TABLE 11-2. Coiled-Tubing Velocity Strings (Wesson, 1993)

Well	Production String Size (In.)	Perforation Depth (Ft.)	Pre-Production	Velocity String Size	Post Production
1	2⅞	8,200	40 Mcfd–4 BLPD	1¼	500 Mcfd–8 BLPD
2	2⅞	12,600	80 Mcfd–1-2 BLPD	1¼	200 Mcfd–10 BLPD
3	2⅞	13,000	50 Mcfd–2 BLPD	1¼	350 Mcfd–10 BLPD
4	2⅞	13,300	150 Mcfd–3 BLPD	1¼	300 Mcfd–6 BLPD
5	2⅞	13,300	Dead	1¼	250 Mcfd
6	2⅞	11,380	150 Mcfd–6 BOPD	1¼	155 Mcfd–12 BOPD
7	3½	11,860	8 Mcfd–2 BLPD	–	225 Mcfd–26 BOPD
8	2⅞	11,850	25 Mcfd–4 BOPD	1¼	419 Mcfd–19 BOPD

11.2.3 Shell U.K. E&P/Nowsco Well Service U.K.

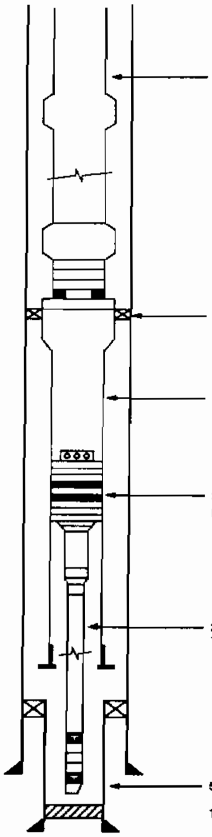


Figure 11-17. Recompletion with 2⅞-in. Tailpipe (Campbell and Bayes, 1994)

Coiled tubing was used as tailpipe extensions to extend the life of gas wells in the Leman field offshore U.K. (Campbell and Bayes, 1994). Use of coiled tubing for these operations saved the operators about half of conventional costs using jointed tubing and a rig.

Formation pressures in the Leman field have declined such that wells cannot support a column of fluid during workovers. This has resulted in formation damage from fluid losses during workovers. Liquid loading has also become a problem in the field. Tailpipes were needed, but could only be installed under live conditions. A conventional wireline approach would handle a tailpipe of about 50 ft maximum. Tailpipes were needed with lengths in the range of 500-700 ft.

A modified recompletion using a 2⅞-in. coiled-tubing tailpipe (Figure 11-17) below the existing production packers was implemented to increase production rates and overall cumulative production. The necessary length of tailpipe could easily be run with available systems.

In addition to the tailpipe, the original 5½-in. production tubing was exchanged for 3½ in., providing a higher velocity from the perforations to the surface. The recompletion procedure called for installing the tailpipe first, setting plugs above the tailpipes to isolate the formation, and then replacing the production tubing conventionally. This approach promised several benefits:

- Tailpipe installation prior to rigging up the workover rig saved costly rig time
- Tailpipe installation with a coiled-tubing unit could be performed under live well conditions
- The use of plugs above the tailpipes would allow the wells to be left suspended until the conventional workover.

Shell U.K. and Nowsco developed an efficient procedure for performing the two-part recompletion. The surface rig-up for running the coiled-tubing tailpipe (Figure 11-18) included both 1½- and 2⅞-in. BOPs.

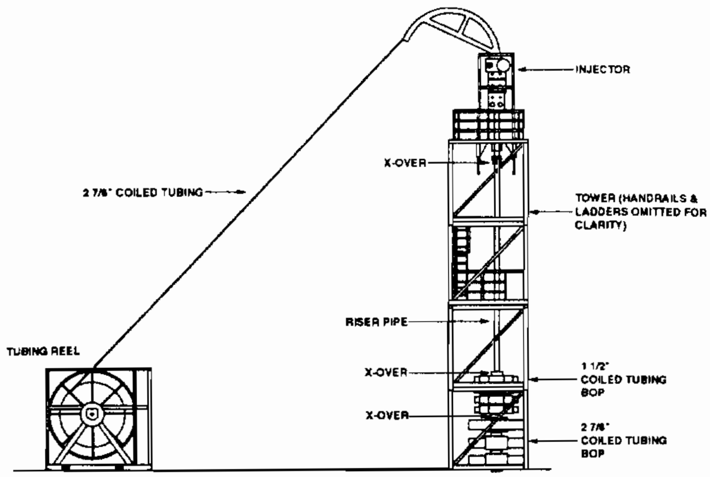


Figure 11-18. Surface Rig-Up for Recompletion (Campbell and Bayes, 1994)

The required length of tailpipe was hung off in the 2⅞-in. BOP. The tubing was then cut and a permanent packer installed on top (Figure 11-19).

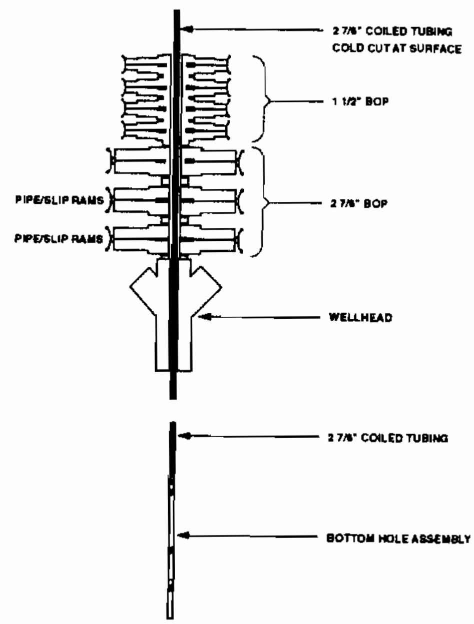


Figure 11-19. 2⅞-in. Tailpipe Hung Off at Surface (Campbell and Bayes, 1994)

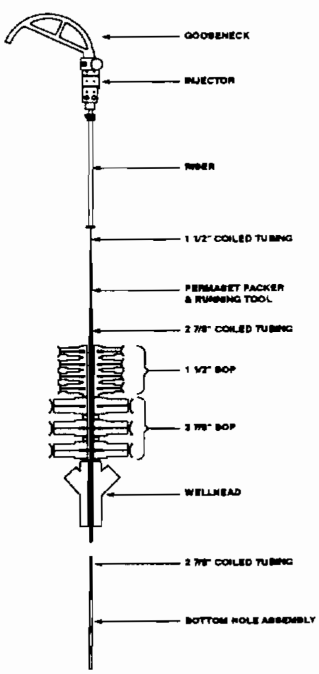


Figure 11-20. Tailpipe Connected to 1½-in. Coiled Tubing (Campbell and Bayes, 1994)

Next, the injector equipped for 2⅞-in. tubing was rigged down and exchanged for a 1½-in. unit. Coiled tubing (1½ in.) was connected to the tailpipe packer (Figure 11-20).

The tailpipe was then run to depth (Figure 11-21). Depth was correlated by tagging the no-go nipple. The packer was set, the running tool released, and the 1½-in. coiled tubing pulled out.

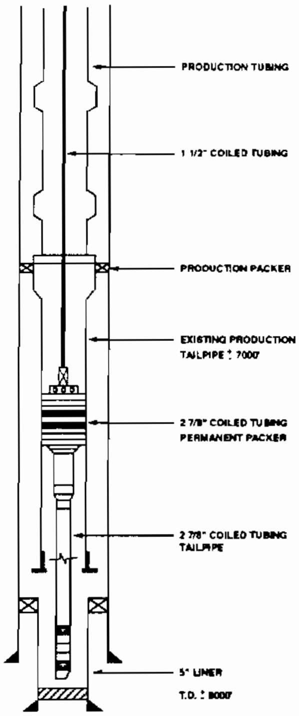


Figure 11-21. Tailpipe Run to Depth on 1½-in. Coiled Tubing (Campbell and Bayes, 1994)

The coiled-tubing equipment can now be rigged down. Later, the production tubing was replaced by a cantilever rig.

The injector used to run the 2⅞-in. coiled tubing was a 1-in. unit with modified gripper blocks. Since the maximum pick-up load was estimated to be about 5000 lb, this smaller unit could easily perform the job.

The first campaign included three wells. These first three applications required 5 days, 7 days, and 2 days, respectively. Over the next few months, an additional five jobs were performed. Average time for these wells was 3 days each.

After the original production tubing had been replaced, in some cases the operator found significant debris on top of the tailpipe packer. This was successfully circulated out with coiled tubing. In later wells, debris was not a problem. The plugs were removed readily with wireline and the wells put back on production.

In one well, the tailpipe packer set prematurely and the existing production tubing could not be removed without killing the well. This was solved by installing a 2⅞-in. velocity "insert" string inside the existing completion (Figure 11-22). Since welding sections of coiled tubing together was not feasible, special connectors were used to join three 2000-ft sections.

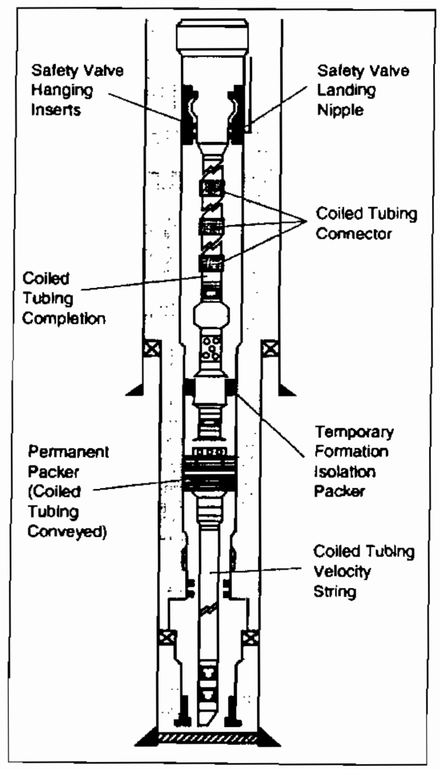


Figure 11-22. Recompletion with 2⅞-in. Coiled Tubing (Campbell and Bayes, 1994)

Every well treatment successfully increased the production and productive life of the well. A typical production decline (Figure 11-23) indicates the recompletion added from 4 to 9 years to the well's life.

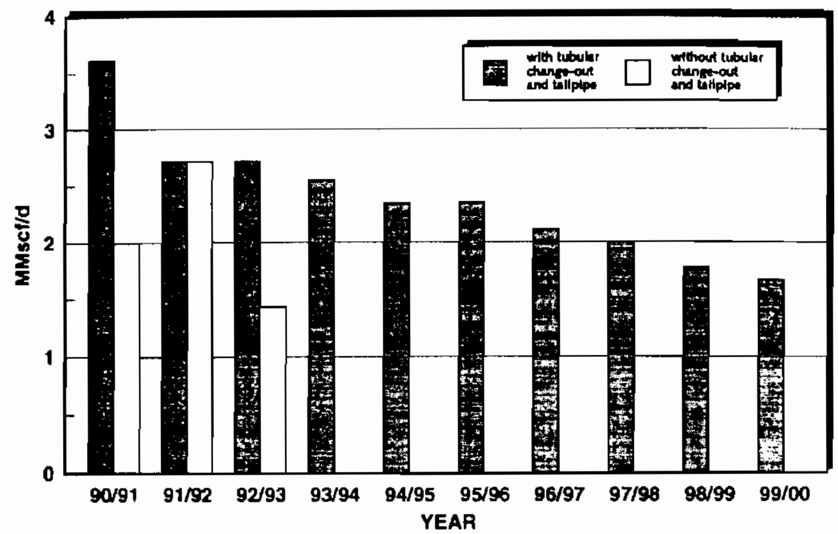


Figure 11-23. Typical Leman Well Production Forecast After Recompletion (Campbell and Bayes, 1994)

11.2.4 Texaco Exploration and Production

Texaco Exploration and Production (Brown and Wimberly, 1992) presented a detailed description of the theory and practice of using coiled tubing for velocity strings. Experiences within the industry show this technique to be a viable and effective way to return wells to production that are experiencing liquid loading.

Liquid loading is a problem in many older and some newer gas wells, particularly in pressure-depletion type reservoirs. If steps are not taken to minimize liquid loading, it will severely limit the producing capacity of the well, and eventually kill the well. Various methods are available to reduce the severity of liquid loading, including the use of foaming agents, plunger lift, gas lift, intermittent lift, venting or blow down, rod pumps, jet pumps, electric submersible pumps, and velocity strings.

Using coiled tubing as a velocity (siphon) string has proven to be an economical alternative to allow continued production for wells with liquid loading problems. Coiled tubing run inside of the existing production tubing reduces the flow area (Figure 11-24). The well can be produced up the coiled tubing or up the coiled-tubing/production-tubing annulus.

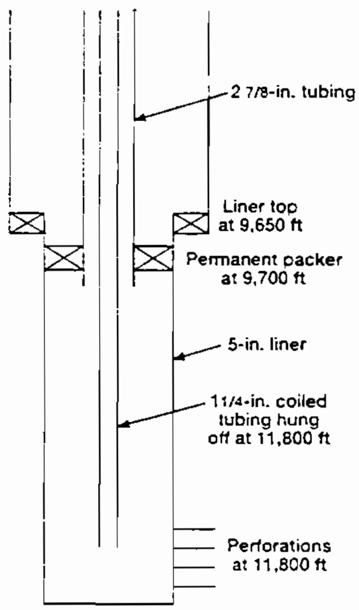


Figure 11-24. Coiled Tubing As a Velocity String (Brown and Wimberley, 1992)

A reduction in flow area causes an increase in flow velocity for a given flow rate. Provided that the reservoir is capable of producing at this rate and resulting bottom-hole flowing pressure, this increase in flowing velocity will result in an increase in the well's ability to unload fluids.

Restoring wells to flowing condition at a sustainable rate is achieved by choosing a tubing performance curve that intersects the formation inflow performance curve. Several factors influence tubing performance characteristics. The most influential factor affecting tubing performance is tubing diameter.

Figure 11-25 shows four Inflow Performance Relationship (IPR) curves and two Tubing Performance Curves (TPC). The IPR curve characterizes the flow capacity of the reservoir. It depends on the reservoir and fluid properties. The four curves correspond to four different stages in the life of the reservoir. As the reservoir depletes, the IPR curve will shift toward the left until it is just tangent to the TPC curve. If reservoir continues to deplete beyond this stage, the well will cease production. However, a tubing of smaller diameter will restore the well to flowing conditions as shown by the second TPC (1.25 in.). The selection of tubing size depends on the degree of the reservoir depletion and the desired production rate.

As mentioned above, the proper selection of tubing size depends on the correct interpretation of the reservoir inflow performance. One of the most common prediction tools is the back-pressure equation.

$$Q = C(P_r^2 - P_{wf}^2)^n$$

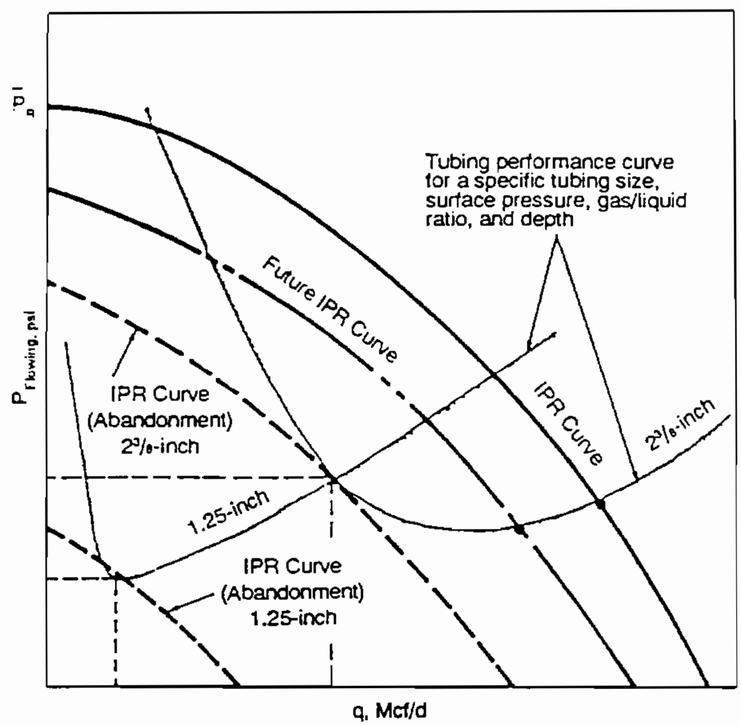


Figure 11-25. Example IPR/TPC Plot for Velocity String Production (Wesson, 1993)

where

Q	=	Rate (Mscfd)
P_r	=	Average Reservoir Pressure (psi)
P_{wf}	=	Well flowing pressure (psi)
C	=	Coefficient from well data (Mscfd/psi)
n	=	Exponent obtained from well tests

C and n can be calculated from a log-log plot of Q versus $P_r^2 - P_{wt}^2$, a four-point back-pressure test. This can be accomplished by:

$$\ln Q = \ln C + n \ln(P_r^2 - P_{wt}^2)$$

On the log-log plot, n is the slope of the line and ln C is the Y-intercept. Future IPR curves can be generated by reducing reservoir pressure.

$$Q = C(P_r/P_i)(P_r^2 - P_{wf}^2)^n$$

Using a method such as this allows any testing to be limited to a bottom-hole pressure build-up test to determine what the current reservoir pressure is. Once the IPR curve has been determined, it can be cross plotted on the tubing performance curve. The intersection of these two curves indicates where the well will produce with that particular set of tubulars and conditions.

The point of intersection of the IPR curve and TPC indicates at what rate a well will flow. An example intersection point is shown in Figure 11-26. If the IPR curve and TPC do not intersect, it means that bottom-hole flowing pressure is too low and the well will not flow at the designated tubing pressure. Also, even if the two curves cross, the intersection point may be at a rate below minimum critical gas rate (to the left of the loading point). In this situation, loading will occur because flow is unstable and the well will eventually die. Tubing performance curves for smaller tubing sizes need to be prepared until an intersection located to the right of the liquid-loading point is achieved.

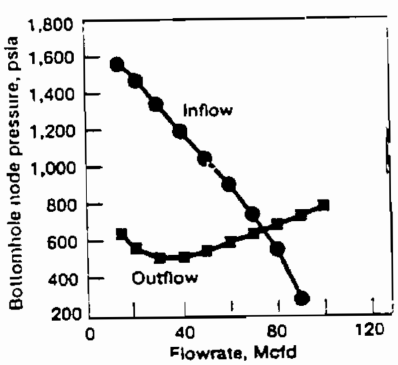


Figure 11-26. IPR and TPC Curves (Brown and Wimberley, 1992)

Undersized tubing can also be detrimental to the well's performance by creating excessive friction drop. If more than one tubing curve intersects the IPR curve, an economic decision will need to be made, weighing factors of increased production and tubing cost with larger tubing versus lower production, but reduced subsequent tubing changeouts, with smaller tubing. Future tubing reduction may be required as reservoir pressure declines.

The components of a coiled-tubing velocity string are the coiled tubing and tubing hanger. tubing hanger consists of segmented tubing slips and packing elements with flanged or threaded connections. A coiled-tubing hanger installed in a wellhead and a cut-away schematic are shown in Figure 11-27.

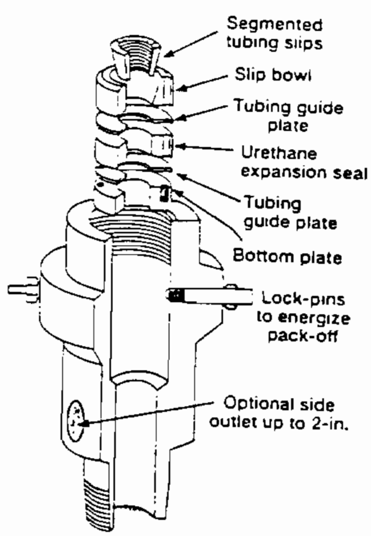


Figure 11-27. Coiled-Tubing Hanger (Brown and Wimberley, 1992)

A detailed installation procedure is presented in Brown and Wimberley (1992).

To remove a velocity string after its effective life, the well must be killed, the tubing hanger unbolted, and the string pulled out with a coiled-tubing rig. If the well is not killed, the string needs to be plugged off prior to removal. Hot oil should be used if paraffin sticking is a concern.

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12. Rigs

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12. Rigs

12.1 DREXEL COILED-TUBING PRODUCTS GROUP (SPECIALIZED DRILLING EQUIPMENT)

New equipment is being developed and manufactured as a result of the record activity levels in coiled-tubing technology. New services are being introduced, although drilling, completions, and flowlines (the most exciting new areas) still represent a small proportion of all coiled-tubing jobs.

Drexel Coiled Tubing Products Group (Newman et al., 1994) has designed new rig equipment for advanced operations including drilling and completion. Industry's needs with respect to new equipment are not clearly defined. Several new types of equipment, much of it for larger sizes of coiled tubing, are being developed and more is expected in the near future.

Coiled-tubing reels are being designed to maximize transportable lengths of larger tubing. In most cases, a spooling diameter of 44-48 times the tube diameter is preferred. Lower spooling diameters have been used for shipping and storage reels. It is possible to accommodate a reel of 146-in. outer diameter with a recessed drum trailer. Maximum weight of tubing is usually limited to about 35,000 lb. Tubing lengths transportable on this special trailer are summarized in Table 12-1.

TABLE 12-1. Coiled-Tubing Transportable on 146-in. Spool (Newman et al., 1994)

CT Diameter (In.)	Nominal Wall (In.)	Core Diameter (In.)	Length Capacity (ft)	Length by Weight (ft)
1.75	0.134	77	22,000	15,100
2.00	0.109	88	15,000	15,850
2.375	0.156	104	8,000	9,444
2.875	0.19	126	2,500	na
3.50	0.203	130*	1,500	na

* Smaller core than 44 multiple

Bending forces for spooling coiled tubing increase substantially for larger sizes of tubing. As an example, Newman et al. mentioned that almost 10 times more force is required to spool 3½-in. tubing than 2-in. tubing. These increased loads require increased reel torque and a larger level wind. In addition, the rig control cabin must be enlarged for more systems (and personnel), and the power pack for increased power output.

Specialized equipment is required especially for drilling operations. Current drilling practices normally require the ability to run both continuous and jointed tubing. Most recent drilling operations require that a workover rig be used to complete the well. This approach is inefficient.

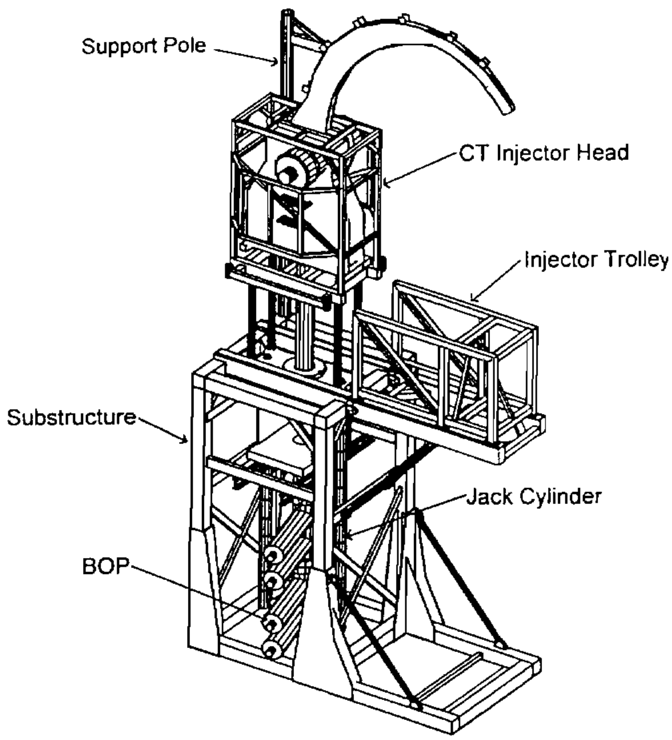


Figure 12-1. Coiled-Tubing Drilling Substructure (Newman et al., 1994)

A substructure that will allow both types of operations has been recently fabricated by Hydra Rig (Figure 12-1). The structure contains a set of casing jacks capable of pulling 150,000 lb with an 11-ft stroke.

Another development is an integrated mud skid for coiled-tubing drilling. This unit combines a shaker, centrifuge, degasser, mixing system, and mud tanks.

Underbalanced drilling operations are one of the benefits of using coiled tubing. Well control is an important consideration, as it is for most drilling operations. A new BOP capable of operating with jointed or continuous pipe in the well has been developed (Figure 12-2). These systems have sealing rams for both types of tubulars, variable-bore rams, and side doors for easy ram change.

A radial stripper has been developed (Figure 12-3) that will work with all sizes of coiled tubing. Stripper height is kept at a minimum by use of an opposing actuator system similar to that of a BOP.

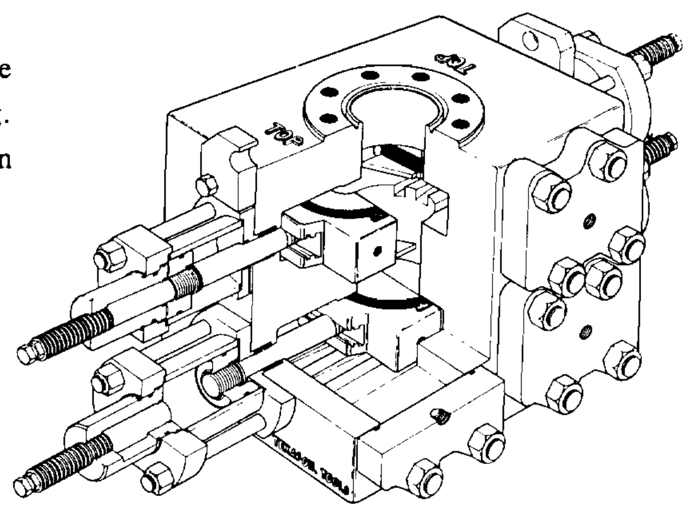


Figure 12-2. Coiled-Tubing/Jointed-Tubing BOP (Newman et al., 1994)

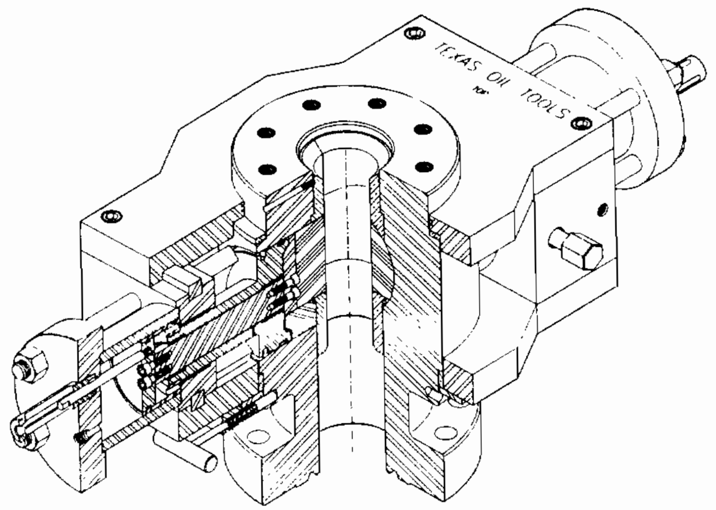


Figure11-3. Radial Coiled-Tubing Stripper (Newman et al., 1994)

A safer deployment method can be used for operations that require the use of long BHAs (Figure 12-4). A wireline system is used to load the BHA into the BOP. Then the injector is rigged up, and coiled tubing is stabbed into the quick connect.

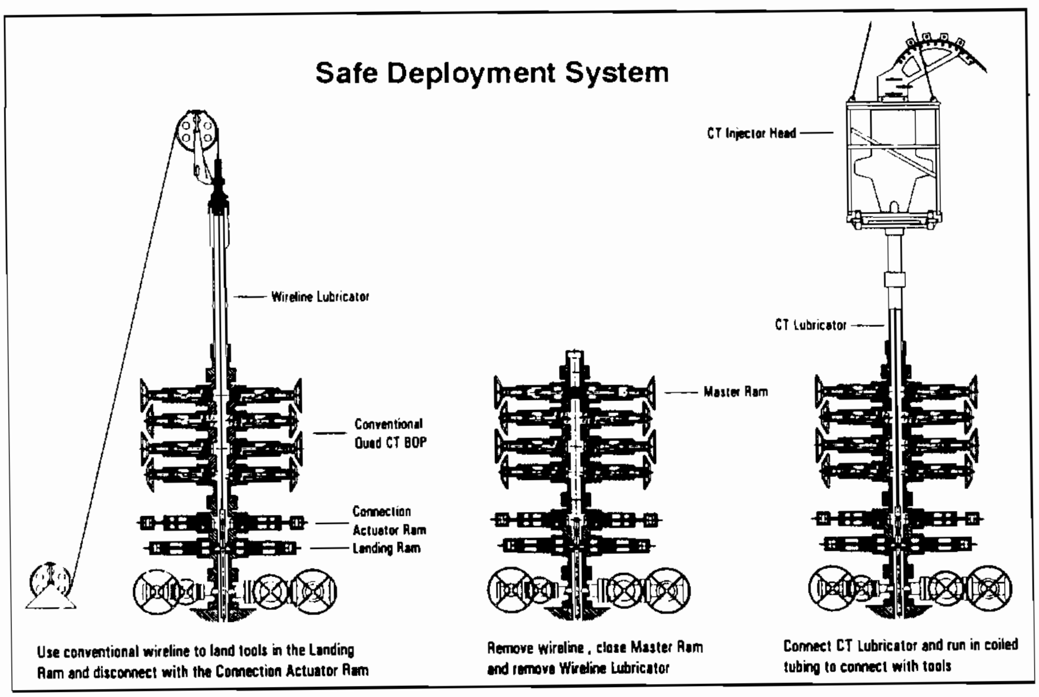


Figure 12-4. Safe Deployment of Long BHAs (Newman et al., 1994)

Future developments under consideration include drilling platforms with huge multisection reels built in. These would be designed for coiled tubing operations as the primary mode, with jointed-piped capability for special circumstances.

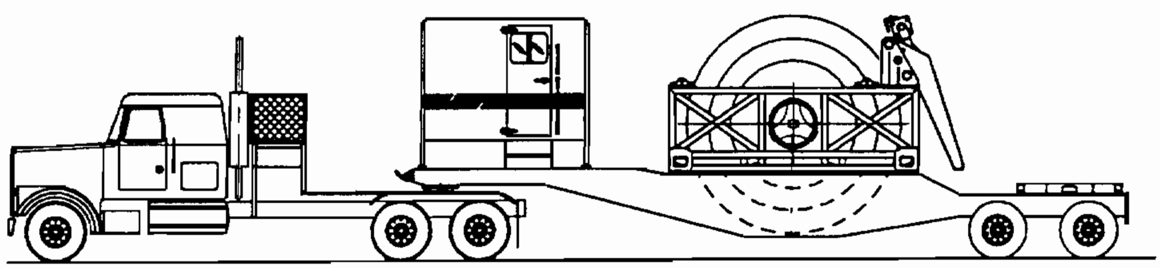
12.2 HALLIBURTON ENERGY SERVICES (80K RIG)

Halliburton built a large-capacity coiled-tubing unit for use in operations in Oman (PEI staff, 1993). Referred to as an 80K unit, the injector has a capacity of 100 kip in tension and 40 kip in snubbing. Initially to be used for cementing and stimulation jobs, the large unit will eventually be used for logging, completion work, and drilling.

Two trailer-mounted reels were fabricated as part of the package. One spool has capacity for 15,000 ft of 2⅜-in. coiled tubing, 9500 ft of 2⅞-in., or 7000 ft of 3½-in.

12.3 HALLIBURTON ENERGY SERVICES (EQUIPMENT FOR LARGE COILED TUBING)

Halliburton Energy Services (Courville, 1994) described the requirements for rigs and equipment to handle large-diameter coiled tubing. Halliburton's reel trailer for large coiled tubing (Figure 12-5) is built on a modified trailer and carries the reel, control house, a fold-down gooseneck, and hydraulic hook-up hoses. The hydraulic power unit is mounted behind the truck cab on another trailer, and can be powered by the 425-hp diesel truck engine.



REEL TRAILER COILED TUBING UNIT

Figure 12-5. Halliburton Large-Diameter Coiled-Tubing Trailer (Courville, 1994)

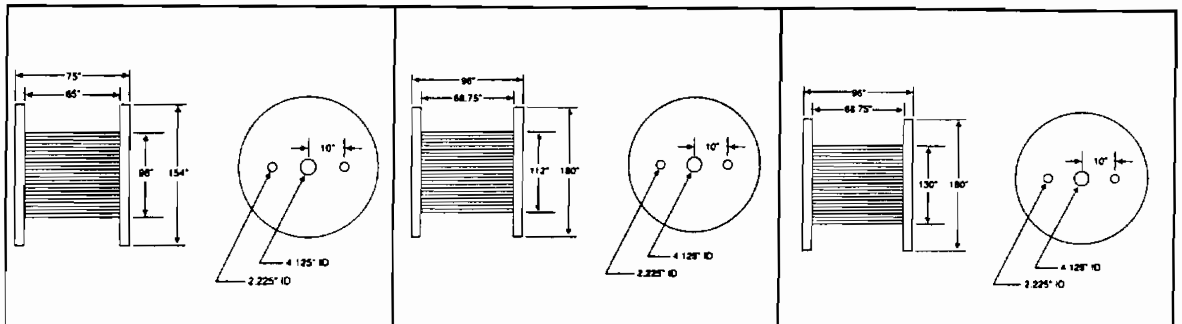
Reel capacities for Halliburton's 80K and 100K rigs are compared in Table 12-2.

TABLE 12-2. Halliburton Rig Tubing Capacity (Courville, 1994)

80K			100 K Unit		
Tubing O.D.	Full Reel	One Diameter Low	Tubing O.D.	Full Reel	One Diameter Low
1.75	26,793	25,079	1.75	34,415	31,907
2.00	19,956	18,464	2.00	26,639	24,423
2.38	13,300	12,127	2.38	17,090	15,301
2.88	9,684	8,661	2.88	11,389	9,936
3.5	6,452	5,715	3.5	8,604	7,361

The tubing injector is driven by two 6000-psi variable-volume axial piston pumps. Halliburton's V-shaped gripper blocks can be used to run tubing sizes from 1½ to 3½ in.

Standard shipping spools (Figure 12-6) can store about 6500 ft of 3½-in. tubing. This spool (15-ft flange and 8 ft wide) may required special road permits for transportation.



Spool Measurements (in.)	Tubing Capacities (in./ft)	Spool Weight (lb)	Spool Measurements (in.)	Tubing Capacities (in./ft)	Spool Weight (lb)	Spool Measurements (in.)	Tubing Capacities (in./ft)	Spool Weight (lb)
Flange height: 154	1.50 25,000	Empty:	Flange height: 180	1.50 49,000	Empty:	Flange height: 180	1.50 37,800	Empty:
Inside width: 65	1.75 19,200	5,700	Inside width: 88.75	1.75 35,800	13,500	Inside width: 88.75	1.75 28,100	13,500
Outside width: 75	2.00 14,300	Exp Crtd:	Outside width: 96	2.00 28,200		Outside width: 96	2.00 21,000	
Core diameter: 98	2.375 9,500	7,000	Core diameter: 112	2.375 19,000		Core diameter: 130	2.375 14,400	
Center hole: 4.125	2.875 6,300		Center hole: 4.125	2.875 12,400		Center hole: 4.125	2.875 9,600	
Drive holes: 2.225			Drive holes: 2.225			Drive holes: 2.225		
Drive hole radii 10			Drive hole radii: 10			Drive hole radii: 10		

Figure 12-6. Shipping Spool Capacity (Courville, 1994)

Fluid inside a spool of coiled tubing can significantly impact shipping weight. Even after evacuating the spool with nitrogen or air, there is a significant chance of leaving some fluid inside the spool. Consequently, allowance is needed for residual fluid weight when calculating total weight.

12.4 HALLIBURTON ENERGY SERVICES (LARGE COILED-TUBING CUTTER FOR JACKUP RIG)

Halliburton Energy Services developed and tested a ball and seat safety valve for increased safety during offshore well test procedures (Allred and Clark, 1994). During emergency conditions when it is desired to shut in the well, an operator normally must cut the coiled tubing in the well before he can close the emergency valve. Pulling the tubing out of the well is usually too slow to be an option.

The method preferred by operators has been to cut the coiled tubing with cutters at the safety valve and reserve the coiled-tubing BOP as a back-up system. Cutting systems at the safety valve have only been capable of cutting up to 1¼ x 0.095-in. tubing.

Halliburton designed a 3-in. 15,000-psi ball and seat mechanism to cut tubing up to 1½ x 0.125 in. In one common application, the new mechanism has been incorporated into a 15,000-psi safety valve (Figure 12-7) for use on a jackup or land rig.

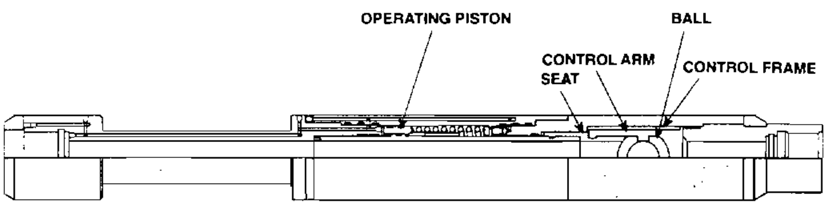


Figure 12-7. Jackup Safety Valve With Cutter (Allred and Clark, 1994)

The safety valve used for floater rig- or drillship-based operations is normally located in the subsea test tree (Figure 12-8). This set-up allows the operator to unlatch from the test string in an emergency (drive-off of the drillship).

For offshore environments using a jackup rig, the safety valve is in the BOP below the rig floor (Figure 12-9). The valve does not need to allow disconnecting from the test string since the rig will not move.

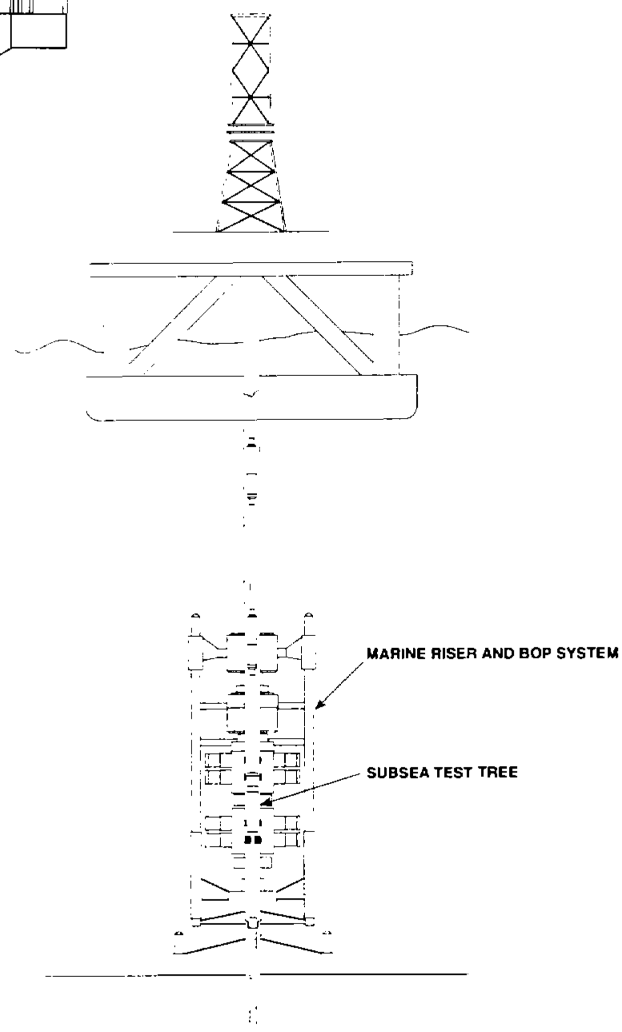


Figure 12-8. Subsea Test Tree for Floater Rig (Allred and Clark, 1994)

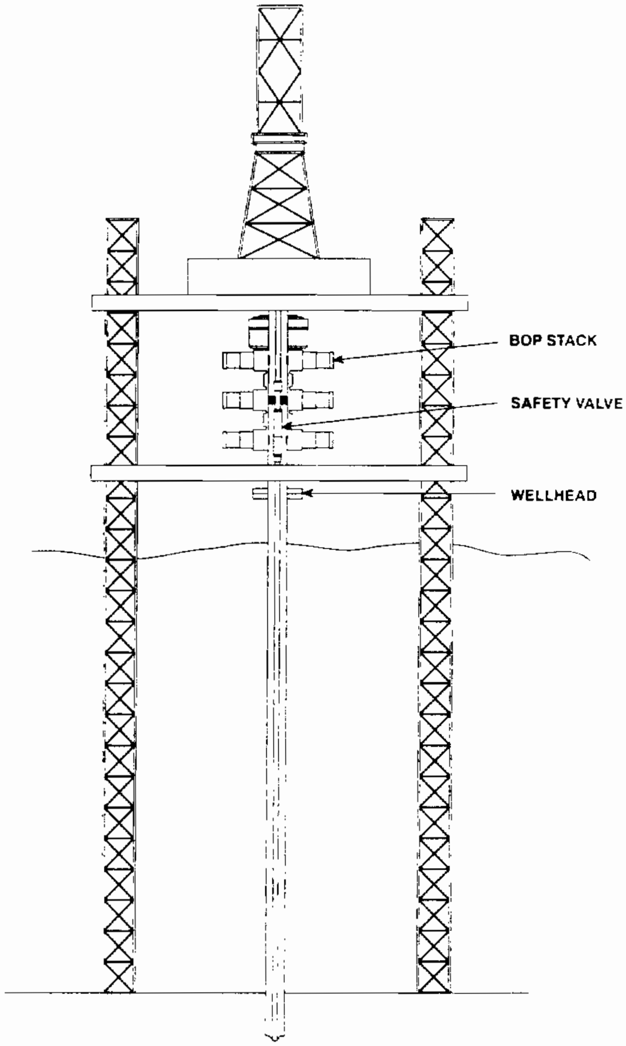


Figure 12-9. Safety Valve for Jackup Rig (Allred and Clark, 1994)

Larger-diameter coiled tubing has become more common in these environments, and enhancements to the safety systems have become necessary. The enhanced ball and seat mechanism consists of a ball, seat, and two control arms, control frames, alignment sleeves, and control pins (Figure 12-10). Coiled tubing is cut after control line pressure is bled off, and the spring and precharged nitrogen force the ball and seat to the closed position.

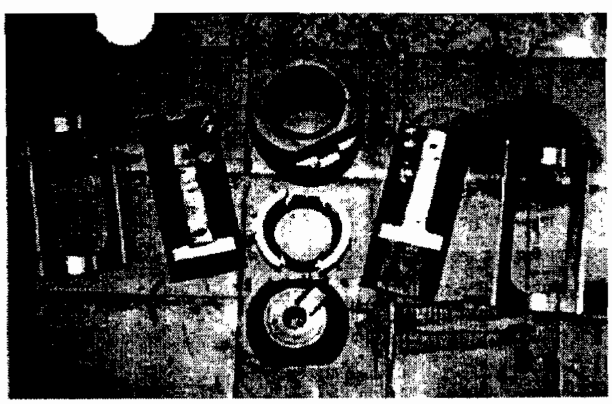


Figure 12-10. Ball and Seat Mechanism (Allred and Clark, 1994)

A test fixture was developed (Figure 12-11) to test the new mechanism. The complete 3-in. 15,000-psi jackup safety valve is being developed.

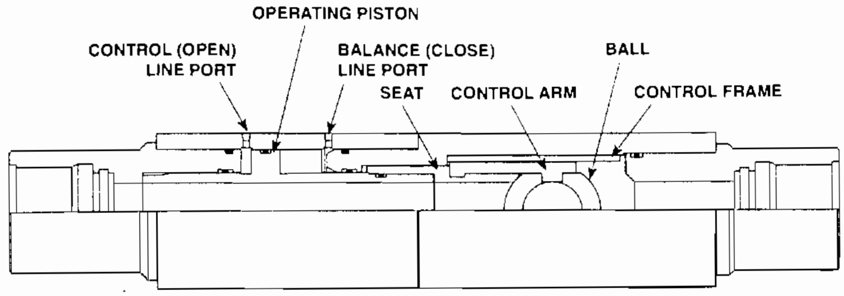


Figure 12-11. Ball and Seat Mechanism Test Fixture (Allred and Clark, 1994)

Test results are shown in Figure 12-12. Predicted and measured cutting pressures showed good agreement for the first two tests. A divergence in the third test was attributed to internal damage sustained during the second test. In the field, a cutter mechanism would not be reused after a cutting operation.

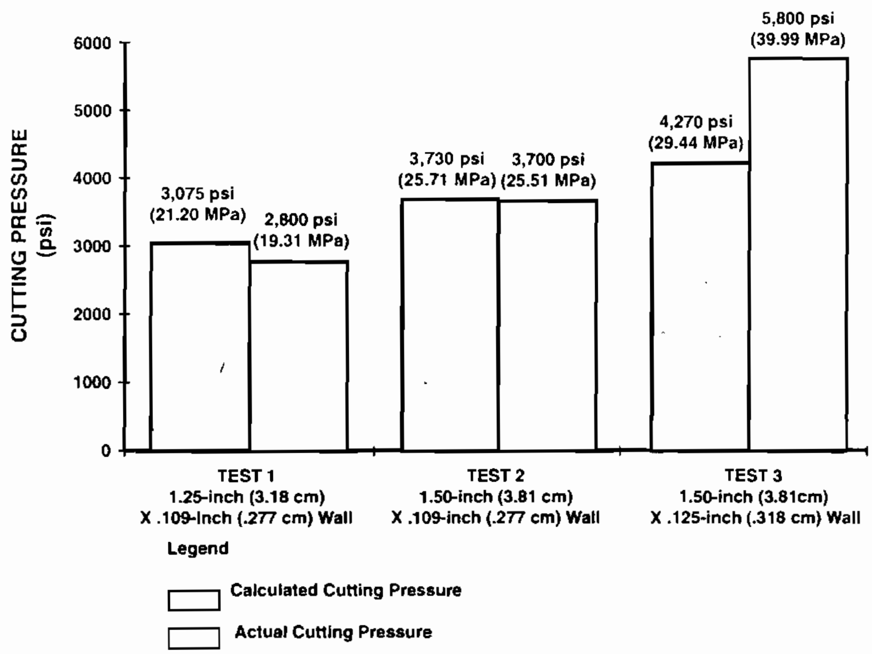


Figure 12-12. Ball and Seat Mechanism Test Results (Allred and Clark, 1994)

Tests with this improved subsea cutter showed that it can provide greater assurance of operational and environmental safety in offshore operations using coiled tubing as large as 1½ x 0.134 in.

12.5 HALLIBURTON ENERGY SERVICES (RIG DATA ACQUISITION SYSTEM)

Halliburton Energy Services (Eriken and Foster, 1993) described the design of a data acquisition system for coiled-tubing units. This system is capable of digitally displaying real-time data from sensors and transducers in engineering units. Stresses in the coiled-tubing string are calculated and displayed in relation to the desired safety margin. Data for string management and fatigue life are gathered and stored continuously.

In the past, pre-job planning for coiled-tubing operations has been done in the office. Assumptions made in planning have been found in many cases to be inappropriate, based on conditions encountered later in the field. A field-based system allows the operator to adapt job design in real-time based on ongoing circumstances.

Halliburton sought to design a data acquisition system that would meet several criteria including easy to operate, inherently safe, flexible, conveniently packaged, modular, battery operated, compatible with other computers, reliable, low cost, and easily upgraded.

Their system consists of two major subsystems. Data are gathered by the Digital Panel Meter along with sensors mounted on the reel and injector. Parameters monitored include tubing weight, tubing speed, tubing depth, wellhead pressure, tubing pressure, flow rate and flow volume. The Data Acquisition Control consists of a laptop PC, printer, and interface electronics for additional sensors. The system is packaged in a single case for portability between the office and field.

A field example using the data acquisition system was presented by Halliburton. An acid-wash job was performed in a horizontal well. The measured depth and weight (Figure 12-13) can be plotted at the job site.

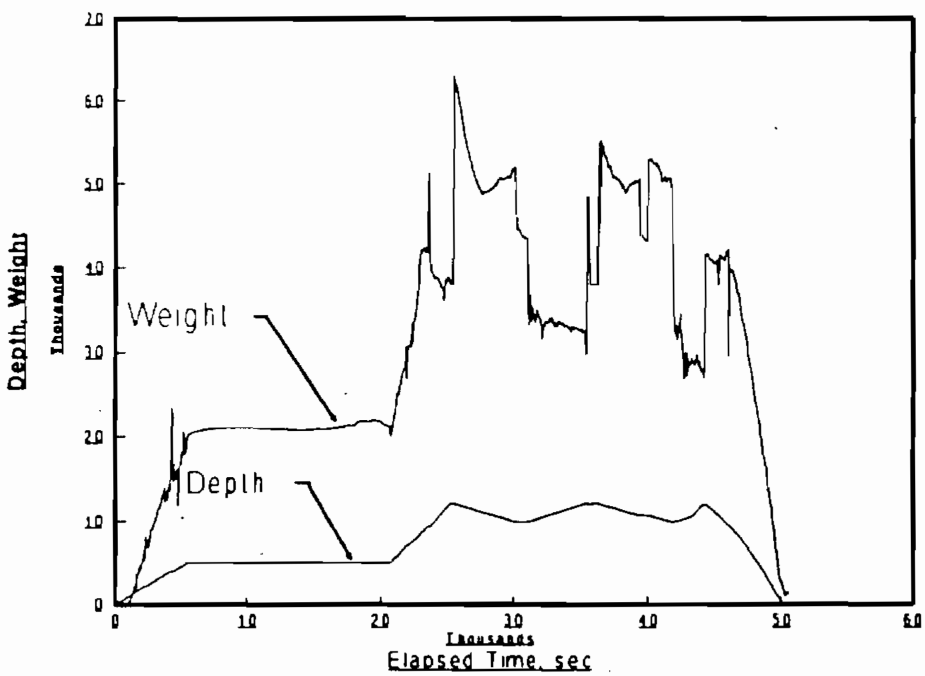


Figure 12-13. Acid-Wash Job: Tubing Weight and Depth Versus Time (Eriken and Foster, 1993)

Tubing weight and depth are compared in Figure 12-14. These results show trends typical for a horizontal well operation.

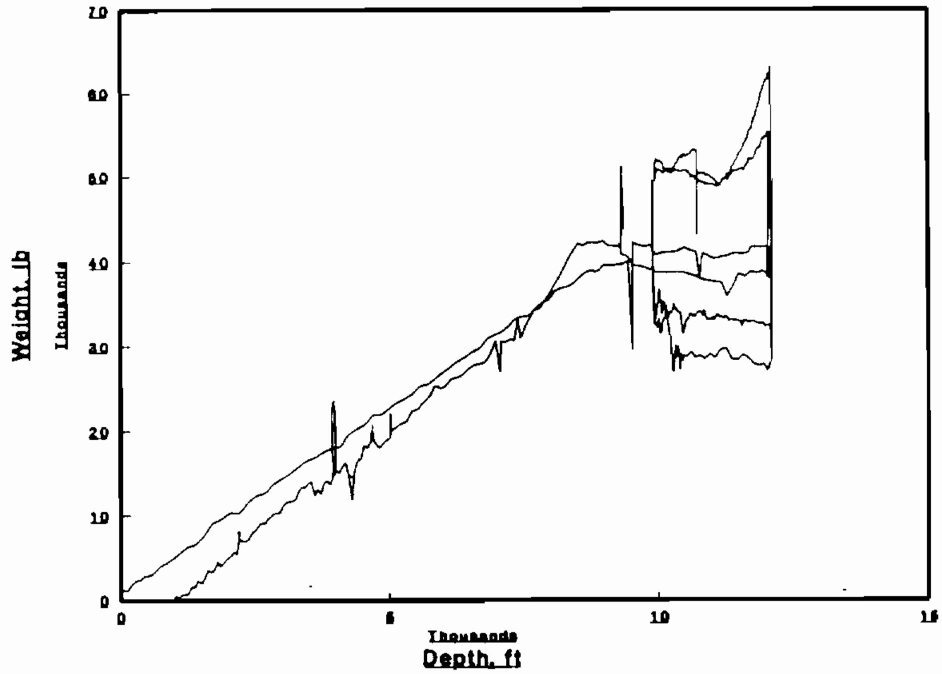


Figure 12-14. Acid-Wash Job: Tubing Weight Versus Depth (Eriken and Foster, 1993)

Computer predictions of weight at depth (Figure 12-15) compare favorably to measured loads. A friction factor of 0.35 was used, giving good agreement.

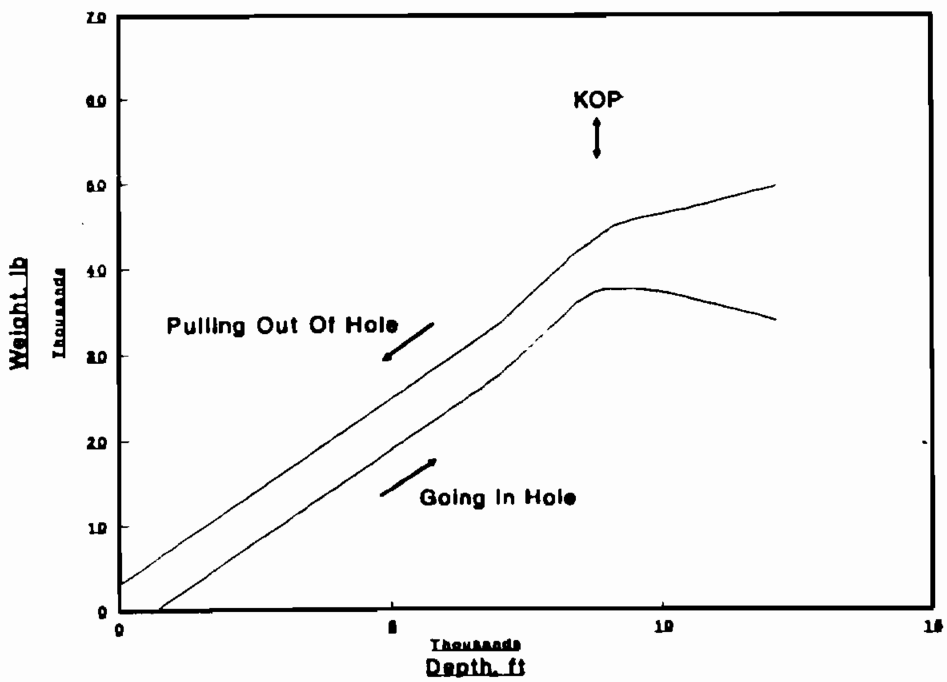


Figure 12-15. Predicted Tubing Weight Versus Depth (Eriken and Foster, 1993)

12.6 SCHLUMBERGER DOWELL (SIZE OF COILED-TUBING RIG FLEET)

Schlumberger Dowell (Adam et al., 1992) reported the distribution of the fleet of coiled-tubing rigs as of late 1992. The fleet capacity was far greater than demand, as was the case for drilling and workover rigs.

Demand for coiled-tubing rigs was expected to increase due to several factors:

- The rapid development for new applications for coiled-tubing technology
- Growth in the overall market for coiled-tubing services
- Industry's expectations of improved equipment capability and reliability will hasten retirement of older units
- Large diameter-capable units are required for many new applications

Schlumberger Dowell's survey documented 533 units around the world. The geographic distribution is summarized in Table 12-3.

TABLE 12-3. Coiled-Tubing Rigs by Region (Adam et al., 1992)

Regional Coiled-Tubing Units					
NORTH AMERICA	**245**	**SOUTH AMERICA**	**59**	**MIDDLE EAST**	**55**
Alaska	13	Argentina	3	Egypt	9
Canada	43	Brazil	8	Iran	4
Lower 48 States	189	Colombia	2	Kuwait	2
		Ecuador	3	Oman	6
		Mexico	28	Qatar	3
		Trinidad	7	Saudi Arabia	5
		Venezuela	8	Syria	3
				UAE	19
				Yemen	2
				Other	2
EUROPE	**90**	**FAR EAST**	**54**	**AFRICA**	**30**
Denmark	3	Australia	6	Algeria	7
France	3	Brunei	1	Angola	2
Germany	6	China	15	Congo	1
Holland	13	India	7	Gabon	3
Italy	12	Indonesia	14	Libya	3
Norway	6	Malaysia	5	Nigeria	10
Russia	6	Pakistan	1	Tunisia	2
UK	35	Thailand	1	Other	2
Other	6	Other	2		
TOTAL	533				

Coiled-tubing units were also broken down by ownership. Of the total fleet, 409 (75%) are operated by integrated service companies (Figure 12-16). Small independents own 87 units. The remaining 37 units belong to state-owned companies around the globe.

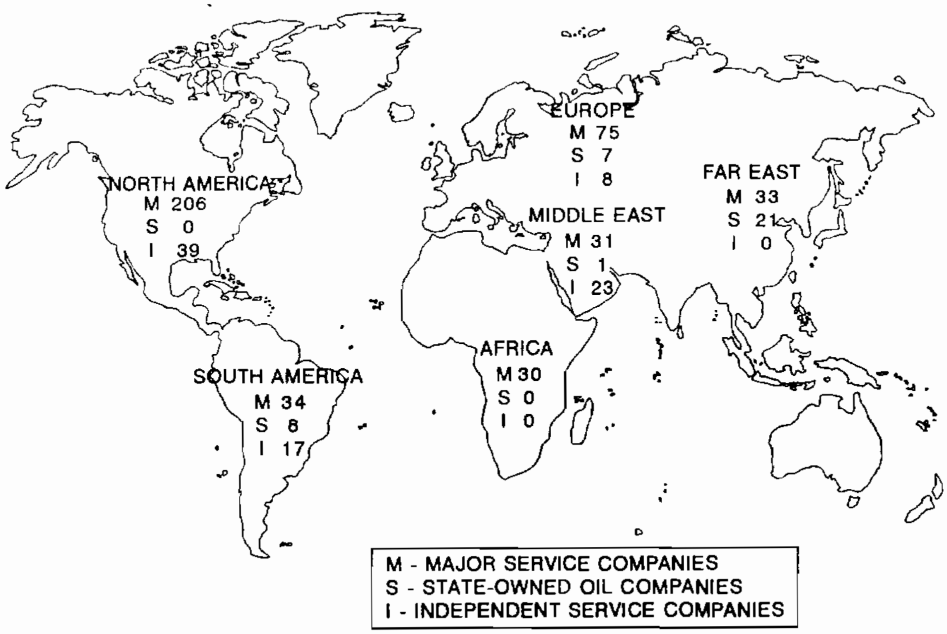


Figure 12-16. Coiled-Tubing Rigs by Region (Adam et al., 1992)

Areas where operating costs are especially high, such as the North Sea, are prime targets for coiled-tubing services. About 70% of Europe's units are engaged in North Sea operations.

The average diameter of coiled tubing in use has been steadily increasing. Less than 20% of the fleet is designed for use with 1-in. and smaller tubing. About 50% of rigs are equipped for 1¼-in. tubing. One-fourth of world rigs are sized for 1½-in. tubing. The remaining 5% of the fleet runs 1¾-in. and greater.

The fleet's tubing diameter is increasing. The rate of production of 1-in. tubing fell dramatically between 1991 and 1992 (Figure 12-17). On the other end of the spectrum, the number of tubing work strings 2 in. and greater is growing rapidly.

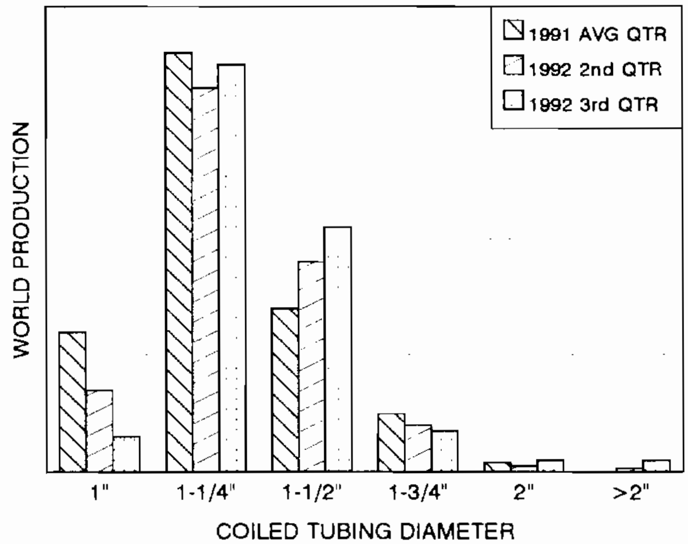


Figure 12-17. Production of Coiled Tubing (Adam et al., 1992)

12.7 STEWART & STEVENSON SERVICES (INJECTOR FOR DRILLING/COMPLETION)

Stewart & Stevenson Services (Dearing, 1994) described the design features of their coiled-tubing injectors that make them suitable for drilling and completion operations. Features that they believe are important in these operations include operational flexibility, the capability to pass tools through the chains, improved performance and reduced system weight.

Gripper block design can enhance flexibility of injector operation. Stewart & Stevenson's design uses replaceable inserts that can be changed out by two men in about 30 minutes. This feature allows rapid change-out of tubing size; for example, one size of coiled tubing for drilling operations and a larger size for completion operations.

Coiled-tubing drilling and completion operations are also enhanced if tools can be passed through the injector chains. Stewart & Stevenson's design allows the chains to retract toward the spines, providing an extra 1.8 in. clearance with tubing up to 2⅜ inches. Tools can be fed through the injector with insert corner grip supporting the relatively light loads during tool installation. In some cases, this allows operations without a lubricator and/or a reduction in rig-up height.

Improved pull/weight ratio makes transportation and field operations easier and safer. Stewart & Stevenson's 80-kip injector has a pull/weight ratio of 14.5 lb/lb.

Snubbing capability can be important in underbalanced operations. Required snubbing forces increase substantially for larger coiled tubing (Figure 12-18).

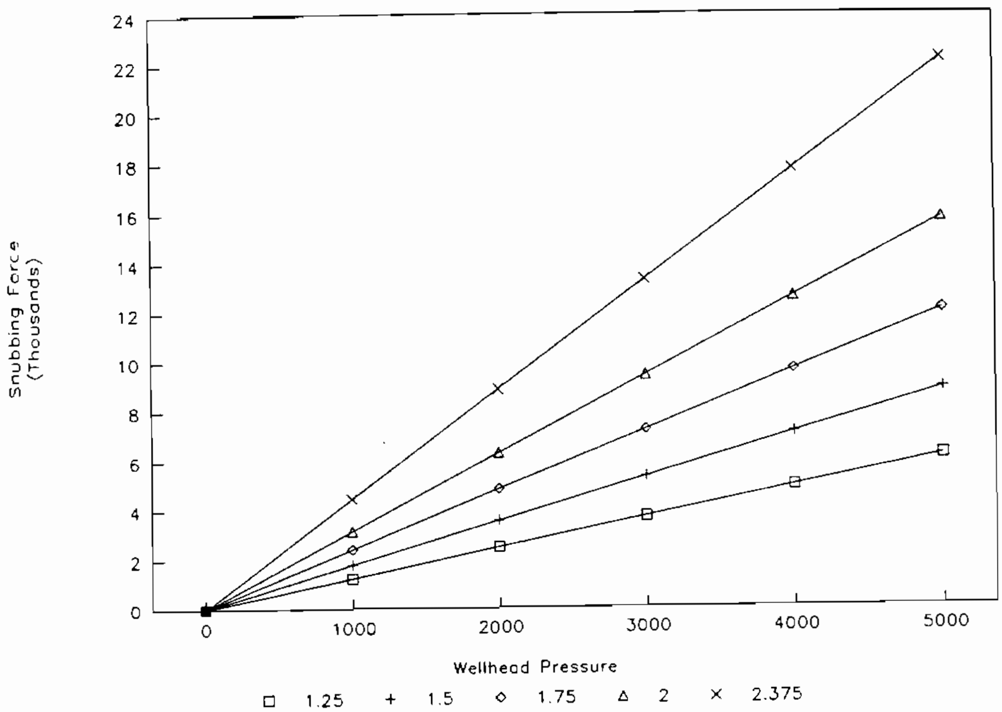


Figure 12-18. Snubbing Forces for Coiled Tubing (Dearing, 1994)

For snubbing, injector chains must be kept tight while pulling with the lower sprockets (Figure 12-19).

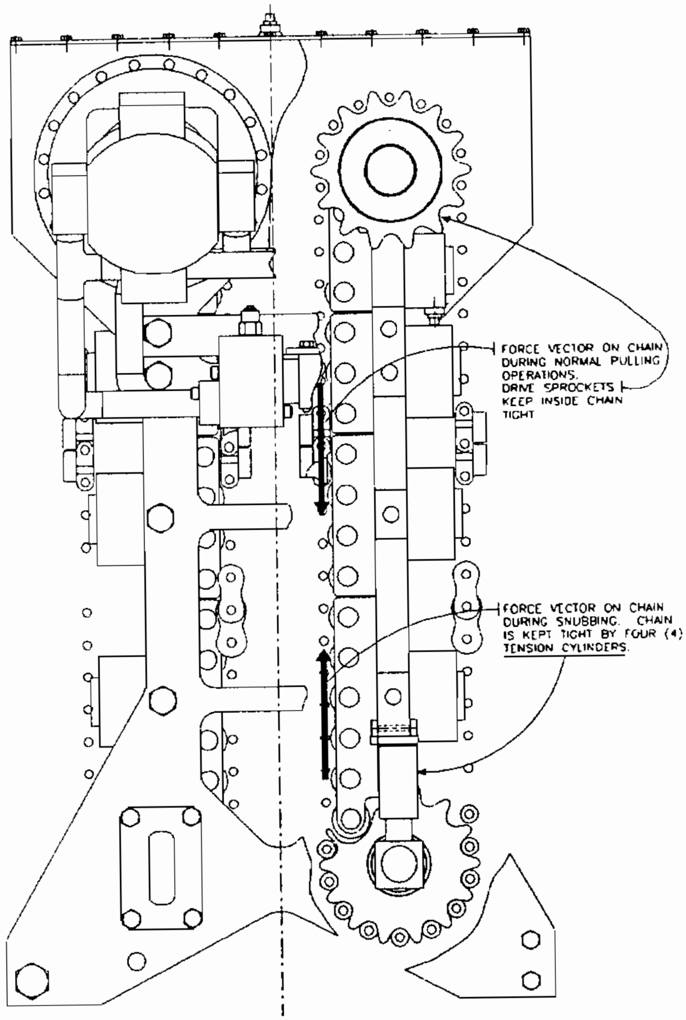


Figure 12-9. Injector Chain Forces (Dearing, 1994)

12.8 REFERENCES

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13. Stimulation

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13. Stimulation

13.1 BAKER OIL TOOLS (SELECTIVE STIMULATION TOOL)

An inflatable selective stimulation tool has been developed by Baker Oil Tools (Coronado and Mody, 1993) for use on coiled tubing. The system can be used for stimulating multiple zones without pulling the production string or killing the well. Through-tubing operations have led to significant cost savings for operators, as well as other benefits.

Dramatic increases in pressure and temperature capability of inflatable elements have made many new applications possible. One of the most critical was a system to stimulate selected perforated intervals below the tailpipe (Figure 13-1), eliminating the need for mechanical or chemical diverting systems.

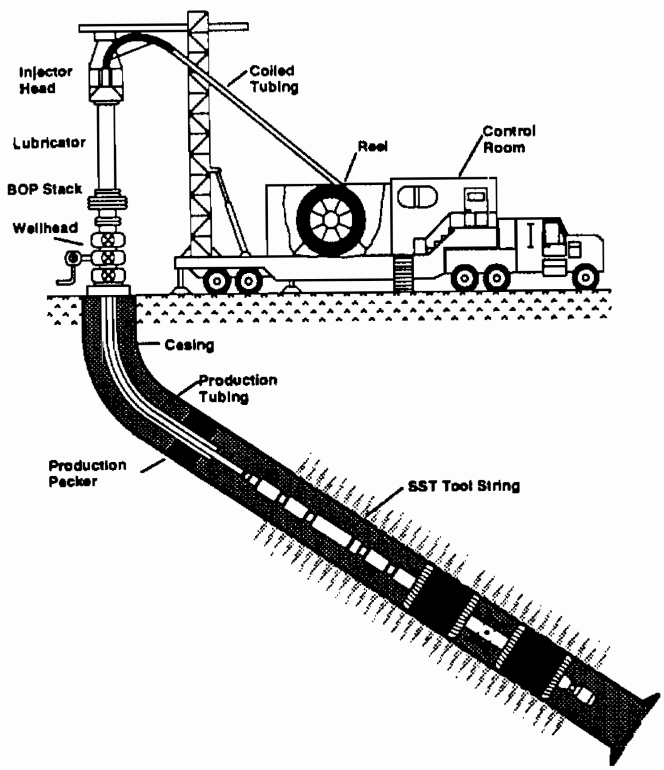

Figure 13-1. Selective Stimulation with Coiled Tubing (Coronado and Mody, 1993)

System requirements for a selective stimulation tool (Figure 13-2) include dual packer elements to isolate the zone of interest, the ability to be reset multiple times on the same trip, operation without tubing rotation, and the ability to be used in deviated wellbores. Baker Oil Tools launched several development projects (e.g., elastomer development, valve design, etc.) to address the technologies required for the new tool.

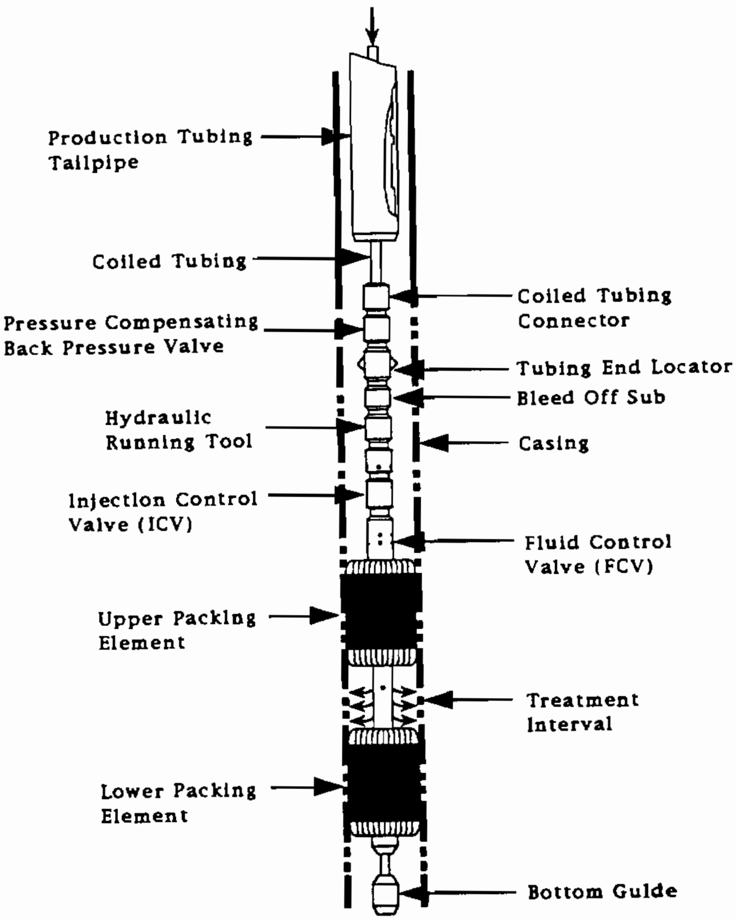

Figure 13-2. Selective Stimulation Tool
(Coronado and Mody, 1993)

The packer elements are set with coiled-tubing pressure after circulating a ball. A spotting setting of the valve assembly allows circulation above the set tool. In this way, non-treatment fluids do not need to be pumped into the formation ahead of the treatment fluids. After treatment fluids arrive at the tool, the valves are switched to channel fluids only into the formation between the packers. Valves are controlled by tension in the coiled tubing.

The tool is of modular design, in sections of about 8 ft each. Lubricator length may limit the amount of spacer pipe that can be run between the two packers. Current tool sizes are a 3-in. tool for 4-in. production tubing and a 3⅜-in. tool for 4½-in. production tubing. Baker is developing a 2⅛-in. tool for use through 2⅞- and 3½-in. production tubing.

The inflatable elements were specifically designed to be set in perforated casing. Testing has been successful in perforations as large as 1¼ in. The 3-in. tool can be set 35 times at 3500 psi in 7-in. casing. The 3⅜-in. tool can be set 40 times at 4000 psi in 7-in. casing. One-time inflation pressure limits in 7-in. casing are about 7000 and 8000 psi for the 3-in. and 3⅜-in. tools, respectively.

Prior to field deployment, the selective stimulation tool was tested at simulated downhole conditions (temperature, oil environment). The test fixture (Figure 13-3) has 1¼-in. perforations at 4 shots/ft, and is oriented horizontally to simulate worst-case centering conditions.

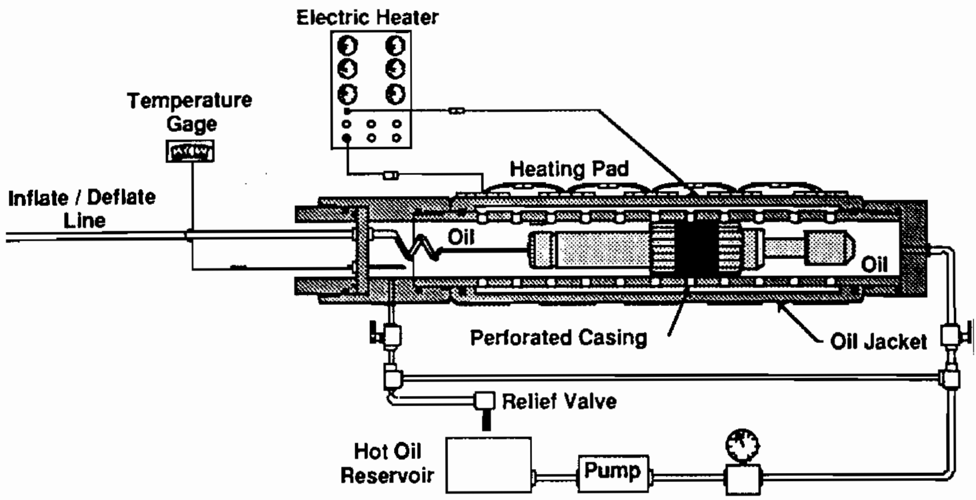

Figure 13-3. Test Set-up for Selective Stimulation Tool (Coronado and Mody, 1993)

Working pressure limits for field operations are derived from these and other tests. Results for the 3- and 3⅜-in. tools are shown in Figure 13-4.

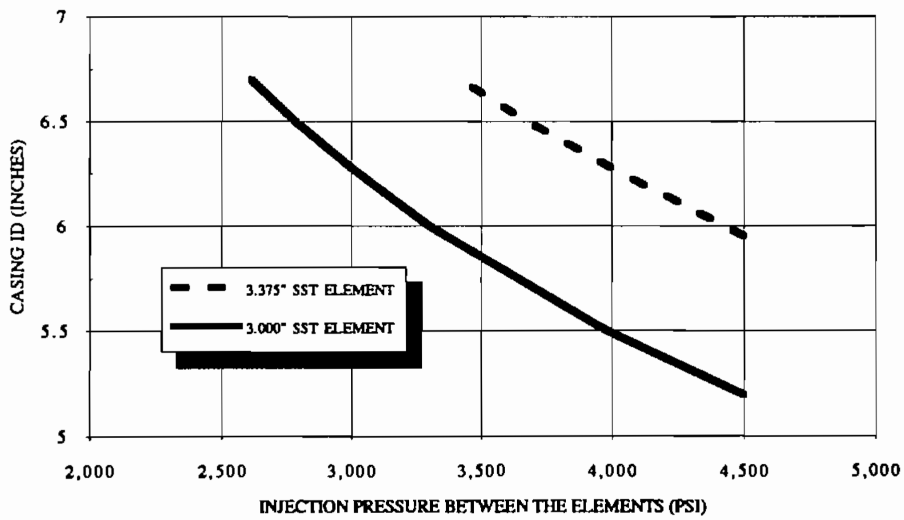

Figure 13-4. Pressure Limits for Selective Stimulation Tool (Coronado and Mody, 1993)

Field testing of the tools began in 1989 at Prudhoe Bay. Overall, these tools have been run 39 times at a success rate of 44%. Since early 1992, the success rate is much greater (16 runs with 81% successful) due principally to improvements in the tools' design.

The most extensive field jobs required setting the tool 11 times in 7-in. casing and 20 times in 5½-in. casing. The highest injection rate during stimulation was 4.2 bbl/min.

The flow paths through the tools' valves are curved and restricted. As a consequence, the manufacturer does not recommend using the tool for services with high-solids fluids, such as cementing or fracturing.

13.2 CONOCO (BASIC COILED-TUBING STIMULATION DESIGN)

Sas-Jaworsky (1993) of Conoco presented an overview of the considerations for designing, planning, and implementing stimulation treatments using coiled tubing (Figure 13-5).

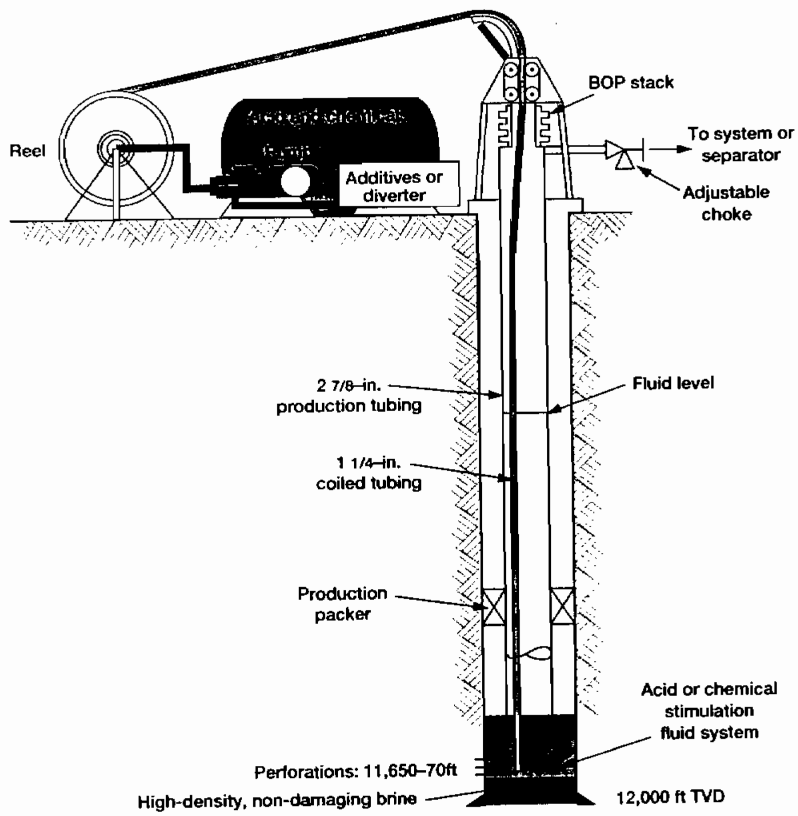

Figure 13-5. Stimulation Treatment Using Coiled Tubing (Sas-Jaworsky, 1993)

Four general mechanisms are responsible for formation damage: solids plugging, water blockage, clay swelling, and fines migration. These mechanisms may act singly or in combination. Specific mechanisms must be identified before the best stimulation program can be designed.

Chemical stimulation treatments are especially suitable for coiled tubing. These treatments generally do not require high pump rates or pressures. Coiled tubing has several advantages when compared to jointed tubing for performing stimulation treatments. Coiled-tubing rigs require less space and conventional rigs are not needed. Additional formation damage can be avoided if coiled tubing is used. Coiled tubing can be deployed under pressure; thus, kill-weight fluids (potentially damaging to the formation) are not needed. Also, production tubing can be left in place, thereby avoiding exposing the formation to fluids and debris behind the production tubing.

Pumping debris from the wall of the coiled tubing into the formation can be avoided by pickling the string with acid prior to performing the job. Acid volumes required to clean 12,500 ft of coiled tubing are shown in Table 13-1.

TABLE 13-1. Acid Volume to Pickle 12,500 Ft of Coiled Tubing (Sas-Jaworsky, 1993)

Pipe OD (in.)	Pipe ID (in.)	Area (sq ft)	Rust (lb)	15% HCl (gal)
1.000	0.826	2,703	130	378
1.250	1.060	3,469	167	486
1.500	1.282	4,195	201	588

Acid can also be placed selectively with coiled tubing. Coiled tubing can be used to unload the well after stimulation procedures are complete, thereby minimizing the time spent acid remains in the wellbore.

Coiled-tubing diameter should be chosen after pump rates are determined. The largest practical diameter should be used to minimize friction pressure drops during pumping.

Sas-Jaworsky listed general procedures for stimulation jobs using coiled tubing. These include:

1. Design wash tool based on required hydrodynamic action for proposed operation.
2. Circulate completion fluid and run in with coiled tubing to below zone to be stimulated.
3. Pump pre-wash treatment fluid. Pull up coiled tubing while pumping at a rate to provide complete displacement of borehole fluid.
4. After interval is displaced, stop coiled tubing movement, close off annulus, and displace solvent into interval.
5. Pump primary acid stage while reciprocating nozzle to ensure uniform coverage.
6. Pump first diverter stage while continuing reciprocation.
7. Continue for remaining acid and diverter stages.
8. Pump flush volume to displace treatment fluids from coiled tubing.
9. Run coiled tubing below treatment interval and displace downhole wellbore with clean fluid.
10. Pull up coiled tubing to depth as required for unloading well, else pull out of well.

13.3 MOBIL E&P U.S. (COILED-TUBING-ASSISTED FRACTURING)

Mobil E&P U.S. (Harms, 1994) modified their completion operations at the Lost Hills field to include the use of coiled tubing for cleaning out and placing sand plugs, and to monitor bottom-hole pressure during fracturing. Overall completion costs were reduced 21% as compared to a conventional approach using a workover rig/snubbing unit.

Fracturing costs account for the majority (65%) of total costs for the wells in this field. The reservoir thickness ranges from 600-800 ft. Multiple fracturing procedures are required due to variation in mechanical properties throughout the interval. Charges for an average well completion in 1992 (before coiled tubing was used) are summarized in Figure 13-6.

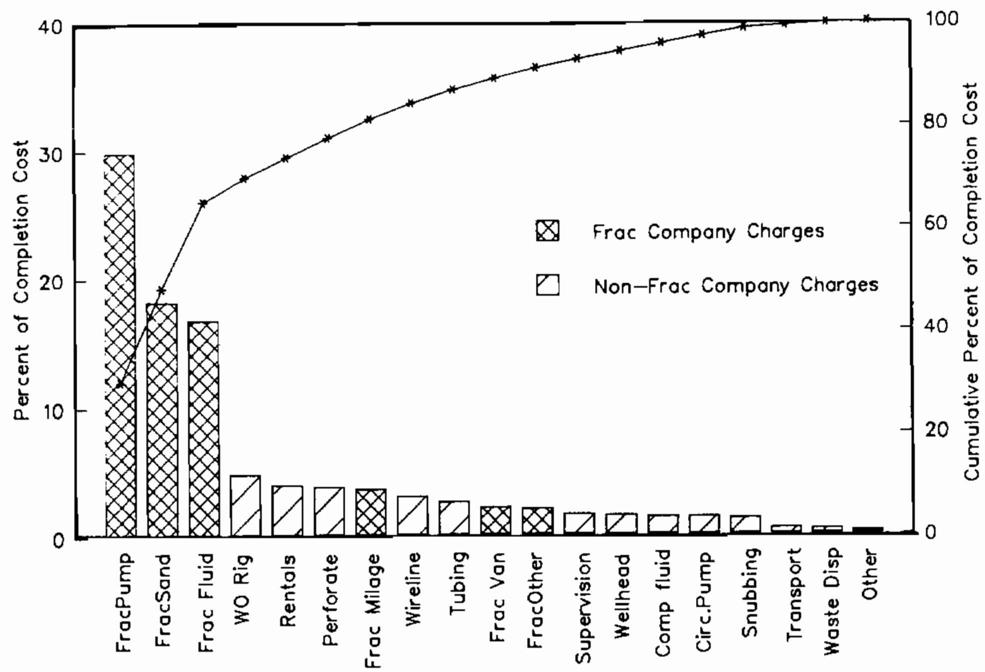

Figure 13-6. Completion Costs for Conventional Program (Harms, 1994)

Fracturing costs accounted for 73% of total completion costs. There were important inefficiencies in the time required to perform the operations. Fracture pumping operations were completed in 1-1.5 hr. Conventional procedures allowed only one interval to be stimulated each day. Consequently, 65-75% of the 4-hr minimum pumping charges were wasted. A typical well with five fractured intervals required 8 days to complete.

Mobil's completion operations were modified in 1993 to include the use of a coiled-tubing unit. Coiled tubing was used in place of conventional tubing for cleaning out and placing sand plugs between the intervals, and as a dead string during fracturing. The modified completion operation is summarized in Figure 13-7.

Step 1. Move in coiled tubing unit, install necessary equipment.
Step 2. Perforate interval to be fracture stimulated.
Step 3. Run coiled tubing in hole.
Step 4. Fracture stimulate down tubing/casing annulus (with coiled tubing used to monitor bottom hole pressure).
Step 5. Force close fracture with limited flowback and allow time for sand to settle.
Step 6. Clean out sand to bottom of next perforated interval, or place sand through coiled tubing if necessary.
Step 7. Pull coiled tubing out of hole.

Repeat steps 2 through 7 for each stage.

Step 8. Rig down coiled tubing unit and equipment.
Step 9. Move in production rig, install necessary equipment.
Step 10. Run conventional tubing in hole, circulate out sand to total depth.
Step 11. Land production string.

Figure 13-7. Completion Procedure Using Coiled Tubing (Harms, 1994)

Costs for the modified completion procedure (Figure 13-8) were reduced for fracture pumping charges (a 33% reduction from conventional). The costs of a coiled-tubing rig versus a workover rig did not have a significant impact on project costs since both were small compared to fracturing costs.

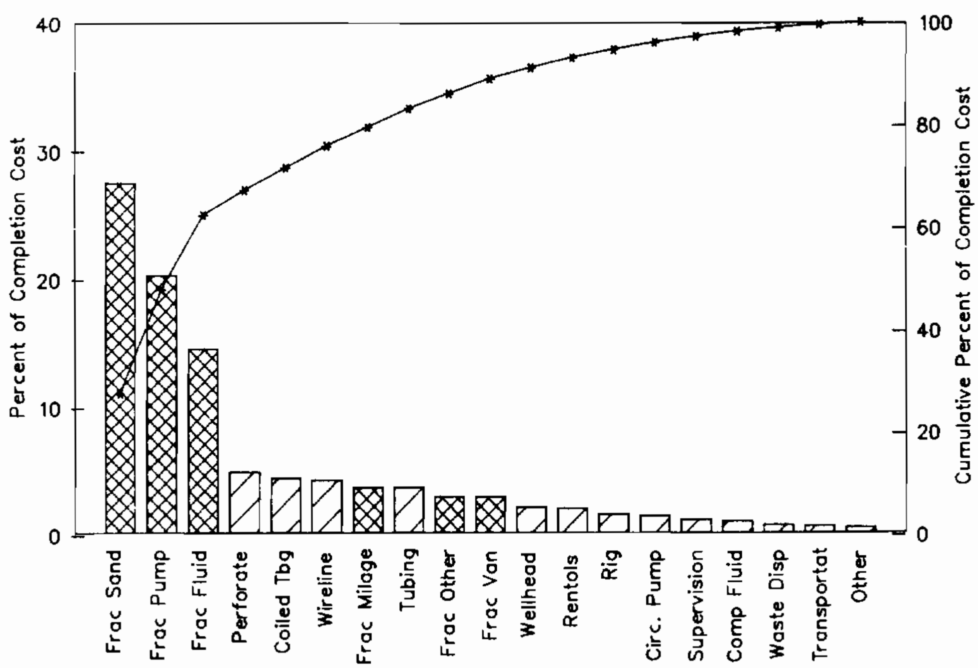

Figure 13-8. Completion Costs Using Coiled Tubing (Harms, 1994)

Coiled tubing (1½ in.) was used to clean out sand in 7-in. casing. Gelled KCl water was used as the circulating fluid. Sometimes additional sand was required to complete a plug. Sand at 1-2 lb/bbl was pumped through the coiled tubing without problems.

Coiled tubing was also used to monitor bottom-hole pressure during fracturing. A blast joint was used in the wellhead (Figure 13-9) to protect the coiled tubing from erosion by sand entering the wellhead. Post-job measurements showed that the blast joint was significantly worn and that the coiled tubing was protected.

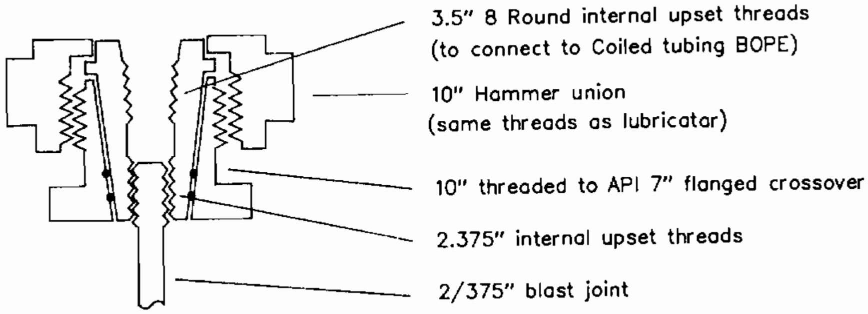

Figure 13-9. Blast Joint in Tree Cap (Harms, 1994)

A hammer-union tree cap was placed below the coiled-tubing BOP equipment. This design allowed rapid removal of the tree cap and blast joint when switching over to a lubricator for other operations.

Operations with the coiled-tubing rig were more efficient. Placing plugs was much more rapid, so that a fracture stimulation could be performed every 3 hours, as compared to once a day. A typical well with five fracture intervals can be placed on production in 4 days (half of time required for conventional). The ability to effectively use the minimum 4-hour pumping charges led to large cost savings.

The costs for conventional and coiled-tubing-assisted fracturing programs are compared in Table 13-2. Overall completion costs were reduced by about $60,000 through the use of coiled tubing. Additional areas of savings were reduced rental times, not using bridge plugs, and not renting the snubbing-assist unit.

TABLE 13-2. Conventional and Coiled-Tubing Completion Costs (Harms, 1994)

	Conventional Completion (1992 Average) Cost (M$)	Percent	Coiled Tbg Completion (1993 Average) Cost (M$)	Percent
Pump/Blender	71.5	29.9	36.2	20.3
Sand	43.6	18.2	49.1	27.5
Frac Fluid	40.1	16.8	25.9	14.5
Milage/Delivery	8.7	3.6	6.5	3.6
Frac Van	5.3	2.2	5.2	2.9
Other	5.1	2.1	5.2	2.9
Frac Subtotal	174.3	72.84	128.1	71.76
Rig	11.5	4.8	2.8	1.6
Coiled Tbg	0	0.0	7.8	4.4
Equipment Rentals	9.5	4.0	3.6	2.0
Perforate	9.2	3.8	8.7	4.9
Wireline	7.4	3.1	7.5	4.2
Tubing	6.3	2.6	6.5	3.6
Pump	3.5	1.5	2.6	1.5
Supervision	4	1.7	2	1.1
Wellhead	3.8	1.6	3.8	2.1
Snubbing Unit	3.2	1.3		0.0
Completion Fluid	3.5	1.5	1.8	1.0
Transportation	1.3	0.5	1.1	0.6
Waste Disposal	1.1	0.5	1.3	0.7
Location	0.7	0.3	0.9	0.5
Total	239	100	179	100

Completion costs using coiled tubing are 21% lower than the average for the preceding five years with conventional programs (Figure 13-10).

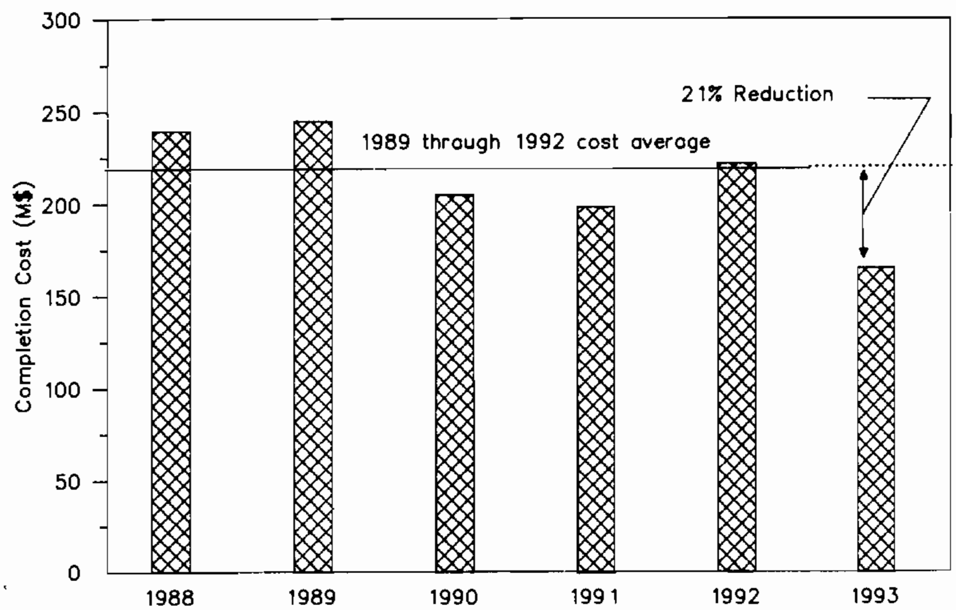

Figure 13-10. Average Completion/Stimulation Costs by Year (Harms, 1994)

13.4 PETRO CANADA (MEDICINE HAT RE-ENTRY)

Petro Canada (McMechan and Crombie, 1994) tested modified equipment and drilling techniques by deepening, completing and fracturing a vertical gas well with coiled tubing. The deepening of the well near Medicine Hat, Alberta was the first field operation in a larger project to evaluate balanced drilling of horizontal wells in sour reservoirs with coiled tubing. This first site was purposely chosen as a safer environment to test fluids handling systems, a new pressure sensor sub, and foam model accuracy.

The subject well (PEX WINCAN MEDHAT 10-9MR-17-3 W4M) was deepened from 448 m to 530 mMD (1470 ft to 1740 ft) with a 3⅞-in. hole. Drilling was conducted at balanced conditions with foam to avoid formation damage in the currently producing Milk River zone and the target Medicine Hat zone.

After drilling was complete, a string of 2⅞-in. coiled tubing was cemented in place as a production liner. The liner assembly included a hydraulically actuated seal-bore permanent packer as the liner hanger. The cement plug caused actuation of the setting tool after the plug landed in the bottom of the liner. The top of the liner was left with a standard seal bore for use in fracturing operations.

The target formation (Medicine Hat) is a tight gas sand that requires fracing to obtain economic production rates. This is true even if formation damage is avoided during drilling operations. Energized fluids were required for clean up of the low-pressure zone. The proppant schedule is summarized in Table 13-3.

TABLE 13-3. Proppant Schedule for Coiled-Tubing Fracture (McMechan and Crombie, 1994)

Fluid per Stage m3	Out of Tanks m3	Slurry per Stage m3	Total Slurry m3	Proppant Conc kg/m3	Total Proppant tonnes	Remarks
1.0						Acid spearhead
3.2	3.2	3.2	3.2			Displace/ISIP
19.0	22.2	19.0	22.2			Pad
2.0	24.0	2.2	24.4	300	0.60	20/40 mesh sand
2.0	26.0	2.4	26.8	500	1.60	20/40 mesh sand
2.5	28.5	3.2	30.0	700	3.35	20/40 mesh sand
2.5	31.0	3.3	33.3	900	5.60	20/40 mesh sand
2.5	33.5	3.5	36.9	1100	8.35	20/40 mesh sand
3.0	36.5	4.5	41.3	1300	12.25	20/40 mesh sand
3.2	39.6	5.0	46.3	1500	17.00	20/40 mesh sand
5.3	44.9	8.4	54.6	1500	25.00	12/20 mesh sand
1.9	46.8	1.9	56.5			Flush

The operator found that stinging the 2⅞-in. coiled tubing into the liner was difficult, due presumably to residual curvature. This problem was solved by adding 16 ft of EUE pup joints to the end of the coiled-tubing string.

The frac job was pumped at an average 21 bpm. Formation breakdown pressure was 1740 psi and treating pressure ranged from 1160 to 3850 psi.

After the proppant was pumped, fluids were produced up the frac string until the well died due to fluid loading. Next, the coiled-tubing frac string was pulled out of the liner hanger and nitrogen circulated through the well to unload fluids and initiate production. The final wellbore status is shown in Figure 13-11.

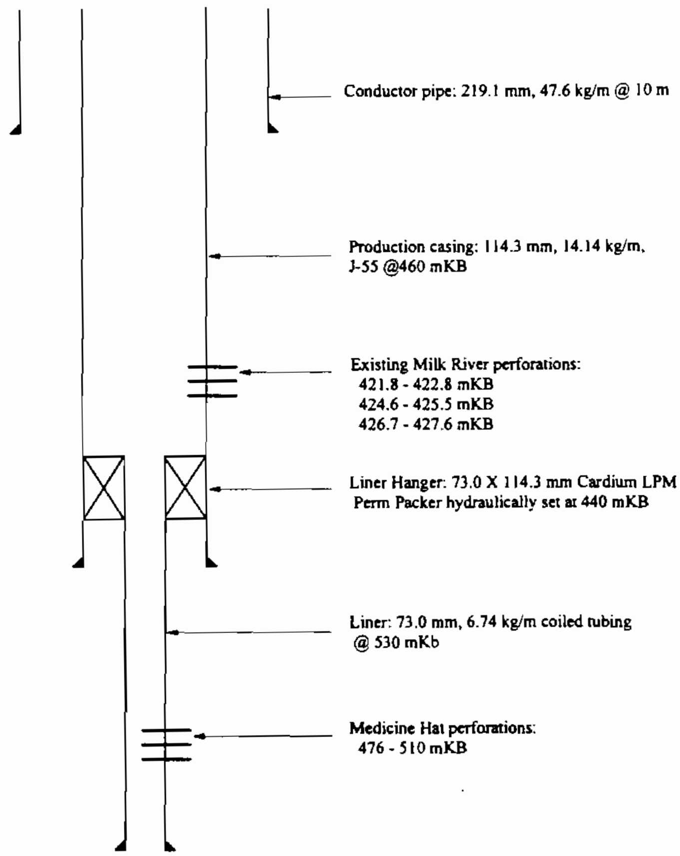

Figure 13-11. Final Completion of 10-9MR-17-3 W4M (McMechan and Crombie, 1994)

13.5 SCHLUMBERGER DOWELL (CARBONATE MATRIX STIMULATION)

Schlumberger Dowell in Saudi Arabia (Thomas and Milne, 1993) performed laboratory and field studies to develop improved techniques for acidizing horizontal wells with coiled tubing. Results suggest that, in carbonate reservoirs, acid placed via coiled tubing with foam diversion is the preferred method for damage removal.

Matrix acidizing techniques are often more economic than other stimulation methods (hydraulic fracturing, acid fracturing, etc.). Fracturing techniques have limited success in naturally fractured formations, in which horizontal drilling is popular. Operators commonly use bullheading as well as coiled-tubing placement techniques for matrix stimulation. The use of foam diverters has become more common in these operations.

An example of the removal of formation damage by bullheading acid without diverter is shown in Figure 13-12. The data represent a 1000-ft well in a sandstone formation with a 2 in. damaged zone in the upper and lower zones. The mid 200 ft are the undamaged thief zone.

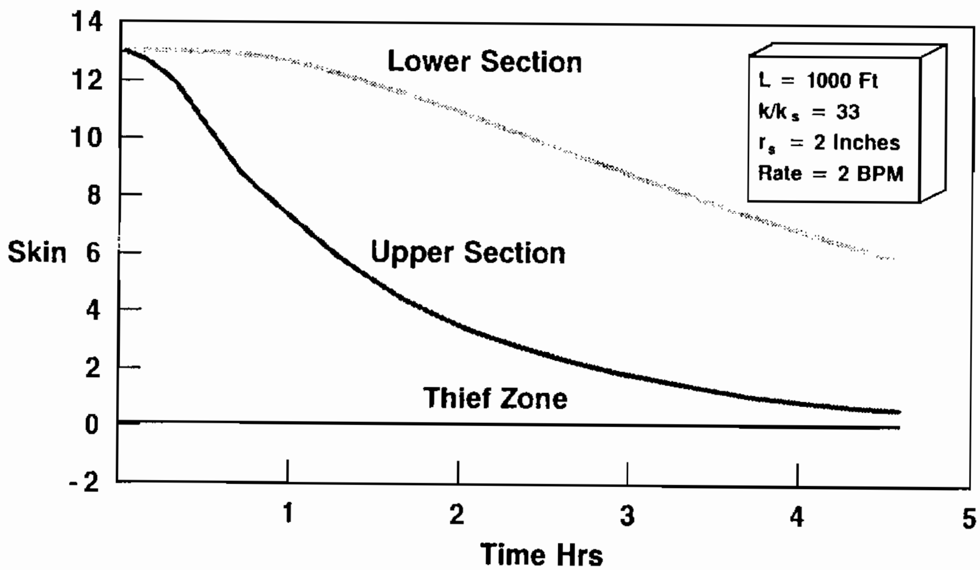

Figure 13-12. Treating Horizontal Well with Thief Zone by Bullheading Acid (Thomas and Milne, 1993)

After 5 hours, damage is removed in the upper section preceding the thief zone. In the lower zone, significant damage remains after treatment. This treatment can be improved by staging acid and diverter. If ten acid/diverter stages are injected, the lower zone beyond the thief zone can be effectively treated (Figure 13-13).

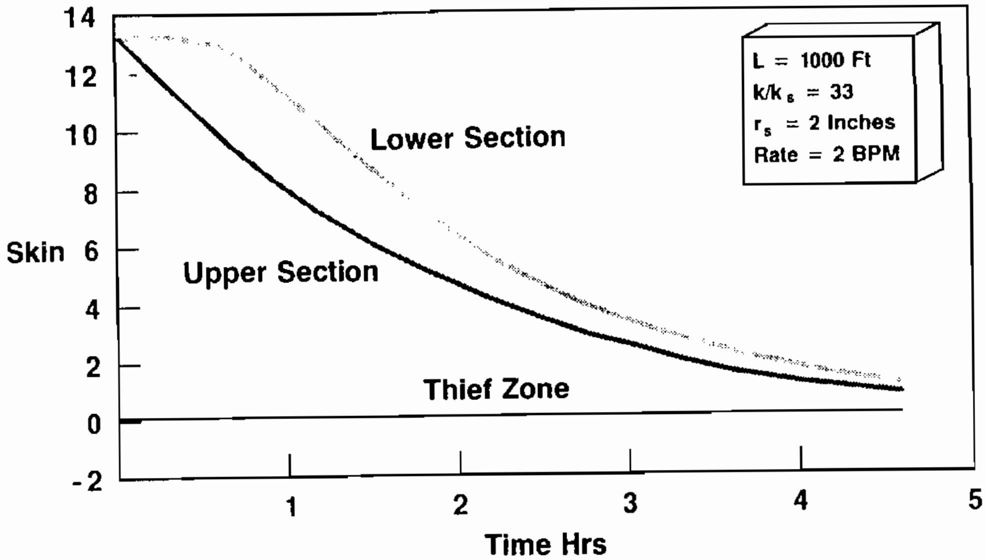

Figure 13-13. Treating Horizontal Well with Thief Zone by Staged Bullheading of Acid and Diverter (Thomas and Milne, 1993)

The flow rate into each zone varies over time (Figure 13-14). Flow into the thief zone is reduced after the first diverter stage is pumped.

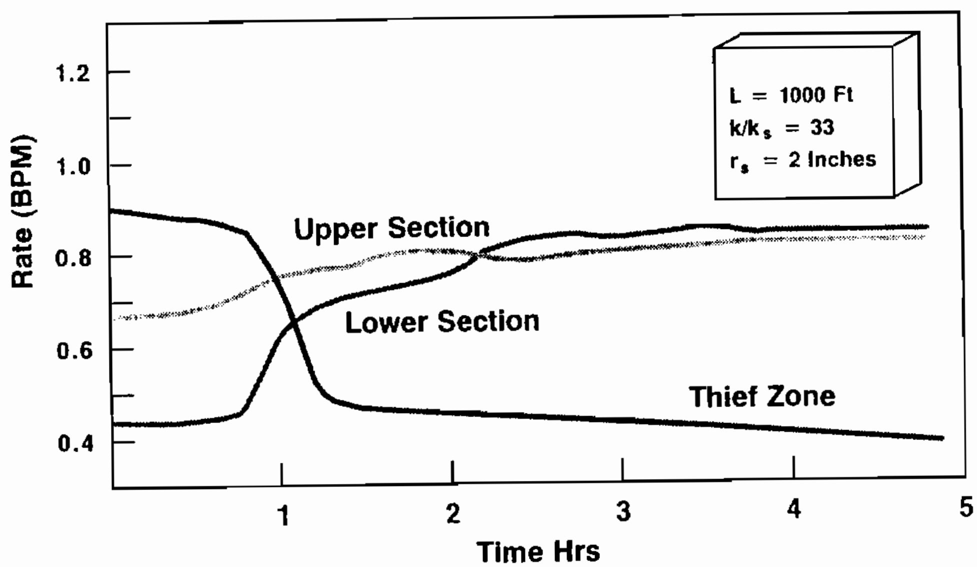

Figure 13-14. Flow Rates into Zones (Thomas and Milne, 1993)

Coiled tubing can be used effectively to place a staged acid/diverter treatment. For one simulation (Figure 13-15), diverter is placed at the thief zone for the first 20 minutes. Next, acid/diverter stages are run while the coiled tubing is slowly withdrawn starting from TD. Permeability is almost completely restored.

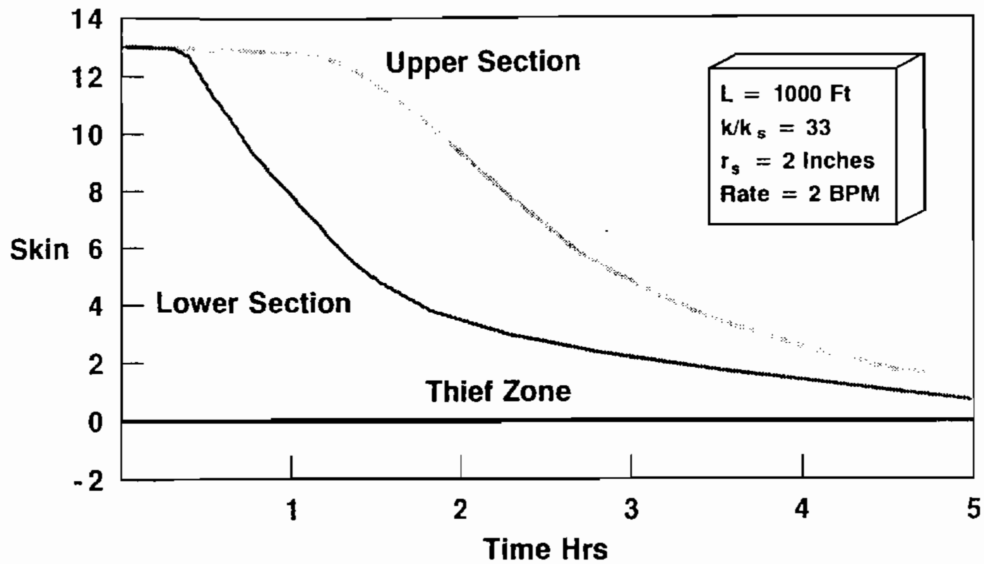

Figure 13-15. Coiled-Tubing Treatment of Horizontal Well with Thief Zone (Thomas and Milne, 1993)

Fractured formations can also be treated successfully with acid. A simulation was conducted of bullheading acid into a horizontal well with three severely damaged fractures spaced 200 ft apart. Results indicated that acid never reaches the lower fracture (Figure 13-16).

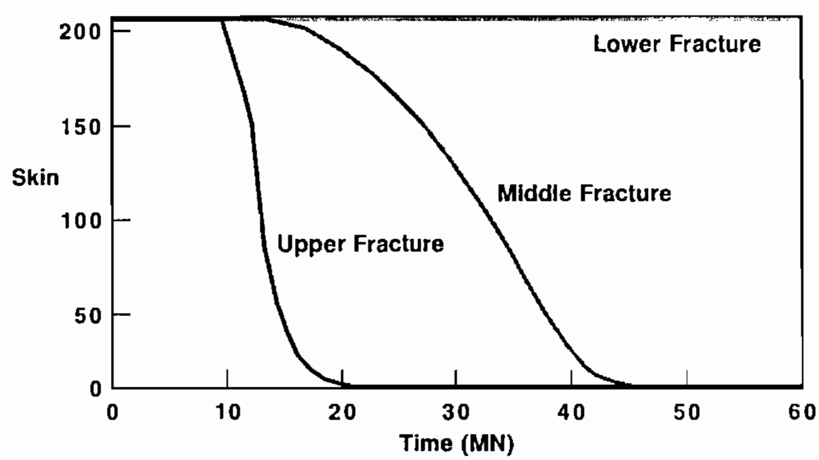

Figure 13-16. Treating Horizontal Well with Damaged Fractures by Bullheading (Thomas and Milne, 1993)

Using staged acid and diverter is more effective for treating all three fractures in the horizontal wellbore (Figure 13-17). However, bullheading the treatment normally results in poor coverage beyond 200-300 ft.

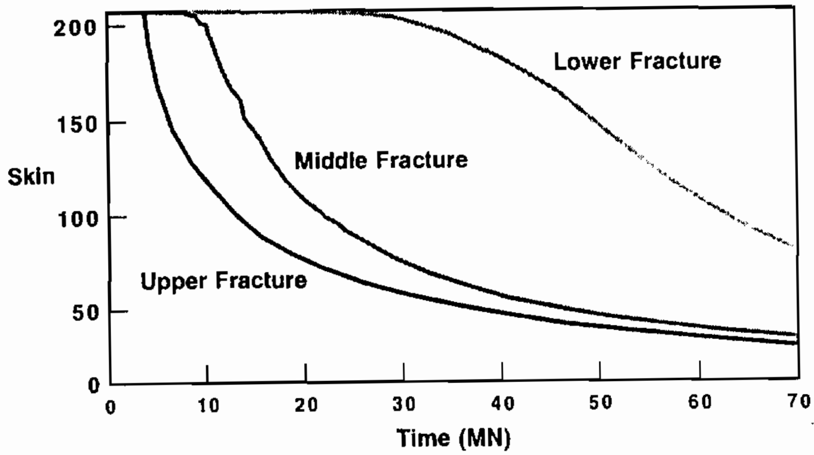

Figure 13-17. Treating Horizontal Well with Damaged Fractures by Bullheading Staged Acid and Diverter (Thomas and Milne, 1993)

In one field operation, coiled tubing was used to acidize a 1500-ft horizontal section with HCl at 25 gal/ft. Acid was pumped at 10 gal/ft while pulling the coiled tubing out of hole. Next, 15 gallons was bullheaded into the section. The production logs after the treatment (Figure 13-18) show that most of the improvement occurred in the first 300 ft of the well. Schlumberger Dowell suggested that a thief zone was created in the first section of the wellbore by the wormholing effect of the acid.

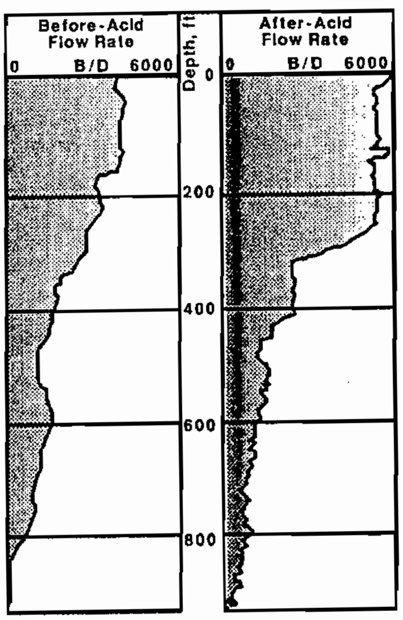

Figure 13-18. Production Logs Before and After Coiled Tubing Acidizing (Thomas and Milne, 1993)

Another horizontal was treated with coiled tubing with foam diversion. Production logs (Figure 13-19) showed that the heel and toe of the well were not producing as expected. The post-treatment temperature log shows that injection was improved in the treated zones.

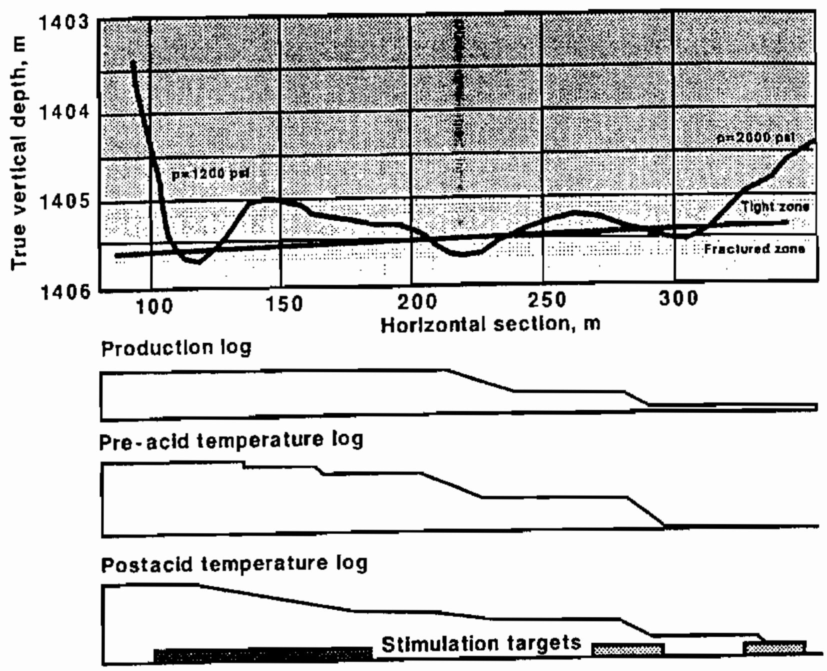

Figure 13-19. Acid Treatment with Coiled Tubing and Foam Diversion (Thomas and Milne, 1993)

Schlumberger Dowell recommends that the most successful acid treatments in horizontal wells are obtained with foam diversion and the use of coiled tubing placement.

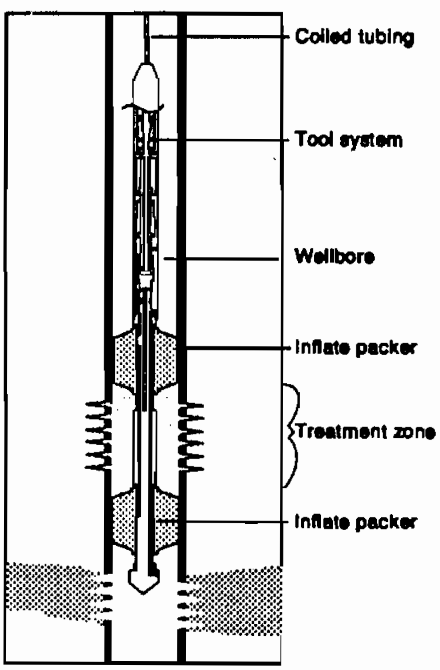

Figure 13-20. Stimulation BHA with Real-Time Measurements (Thomeer and Willauer, 1994)

13.6 SCHLUMBERGER DOWELL (REAL-TIME MEASUREMENTS)

Schlumberger Dowell (Thomeer and Willauer, 1994) added a special tool system to a selective stimulation tool (Figure 13-20), improving the ability to optimize stimulation procedures based on conditions actually encountered. Real-time measurements of pressure and temperature at bottom hole are used to evaluate reservoir and wellbore conditions before, during and after a stimulation treatment. This ability to evaluate and treat in a single run greatly increases efficiency.

Conventional approaches to designing job pressures and fluid volumes rely on gauges conveyed on wireline or jointed pipe, or on the use of surface data to predict downhole conditions. Bottom-hole pressure is usually extrapolated from wellhead data by accounting for friction pressure and hydrostatic head.

Significant errors can arise through this approach, particularly when non-newtonian fluids are used. Chemical reactivity of the treating fluids can change the surface roughness of coiled tubing, affecting friction pressure.

In one example job, calculated bottom-hole pressures were compared to those recorded on memory gauges during the job (Figure 13-21). Predictions were relatively accurate when the pumps were off. During pumping operations, errors in frictional losses and tool pressure drops result in a significant variation between predictions and reality.

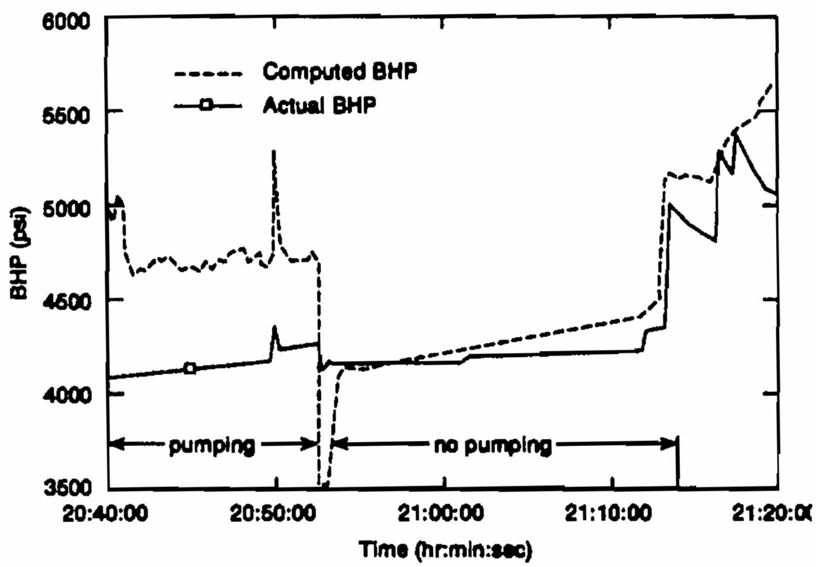

Figure 13-21. Downhole Pressure Predictions and Memory-Gauge Measurements
(Thomeer and Willauer, 1994)

The real-time tool system can be used in the design of a stimulation treatment by identifying highly permeable zones. One technique is to inject cool fluid down the annulus. Afterwards, the tool string with temperature gauge is moved up the well. Theoretical results in a homogeneous horizontal wellbore are shown in Figure 13-22.

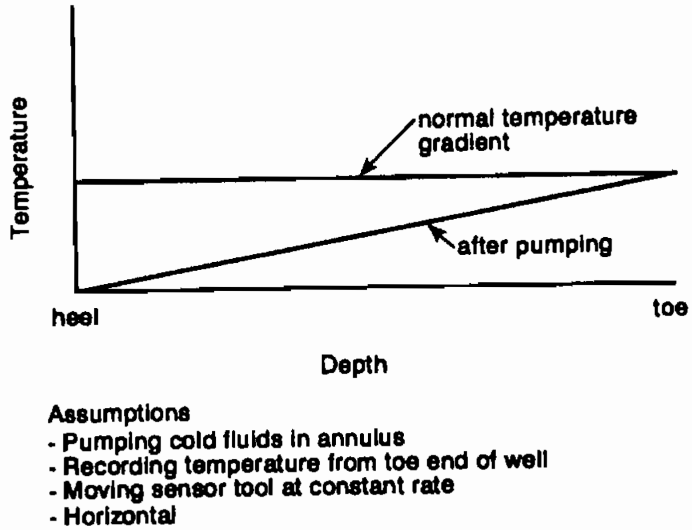

Figure 13-22. Temperature Profile in Homogeneous Horizontal Wellbore (Thomeer and Willauer, 1994)

If this procedure were performed in a horizontal well with a single permeable zone, the temperature profile would contain a dip (Figure 13-23). The center of the zone can be located by plotting the rate of change of temperature. The center of the zone has zero slope.

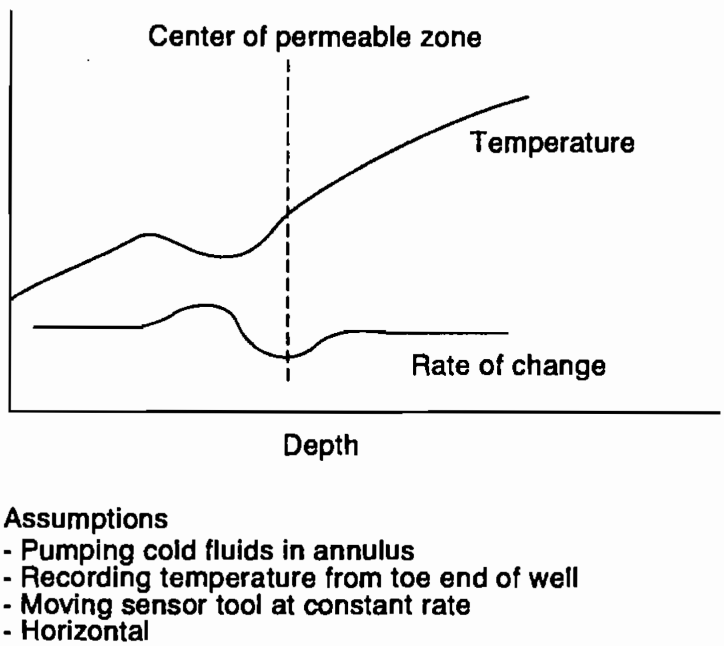

Figure 13-23. Temperature Profile in Horizontal Wellbore with Permeable Zone (Thomeer and Willauer, 1994)

The entire data acquisition system is shown in Figure 13-24. These data can be obtained on monoconductor cable. For stimulation jobs, the cable and tools must be acid-resistant.

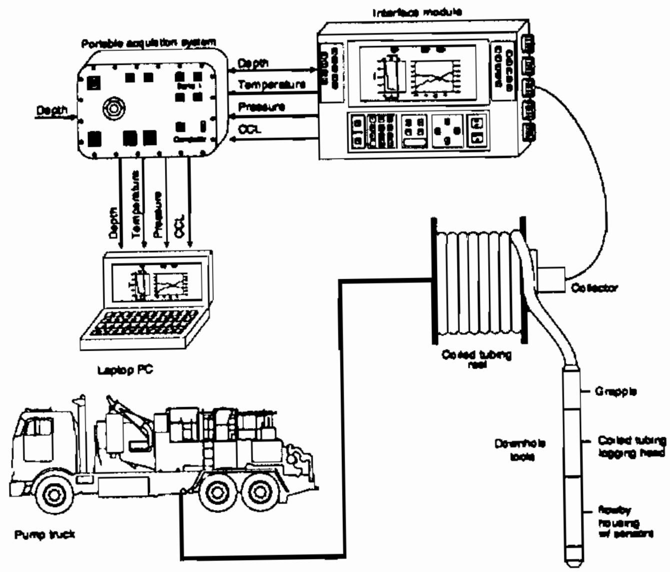

Figure 13-24. Real-Time Data Acquisition System (Thomeer and Willauer, 1994)

Schlumberger Dowell presented results from an acid stimulation of a horizontal oil well in Canada. Objectives were to locate permeable zones before treatment, treat the well, and verify results by locating new permeable zones. A temperature survey run before treatment is shown in Figure 13-25. The smoother line is the temperature survey; the rougher line is the rate of change of temperature.

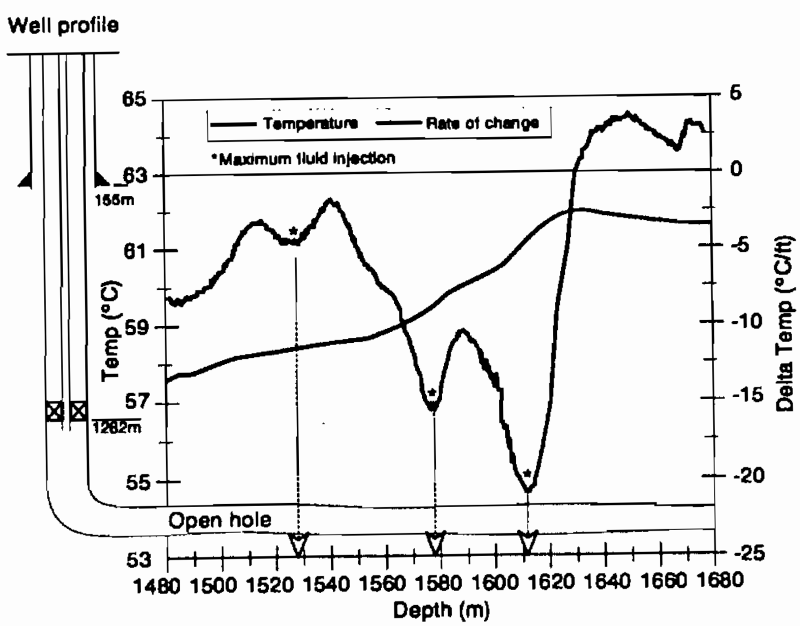

Figure 13-25. Temperature Profile Before Acid Stimulation (Thomeer and Willauer, 1994)

After stimulation, another temperature log was run (Figure 13-26). It is clear that new permeable zones were created by the stimulation treatment. Actual temperatures vary from pre- to post-treatment because water was injected at the heel initially and at the toe after stimulation.

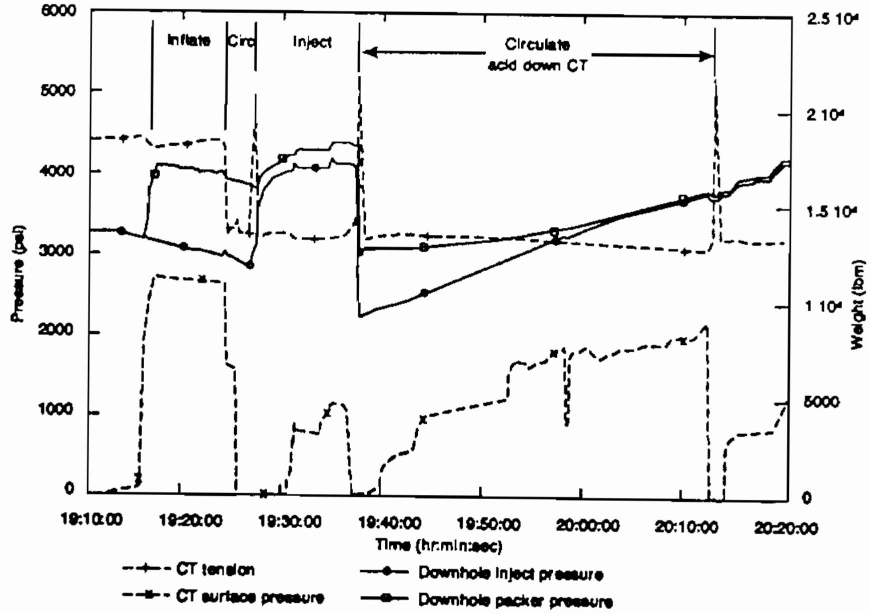

Figure 13-26. Temperature Profile After Acid Stimulation (Thomeer and Willauer, 1994)

The selective treatment tool was used without real-time measurement capability in an African oil well. Downhole data were recorded on memory gauges (Figure 13-27). The packer pressure trace revealed that the packer's working differential pressure was exceeded during the job. Surface data did not indicate that bottom-hole pressure was dropping. Experiences with this well emphasize the importance of real-time monitoring of bottom-hole conditions.

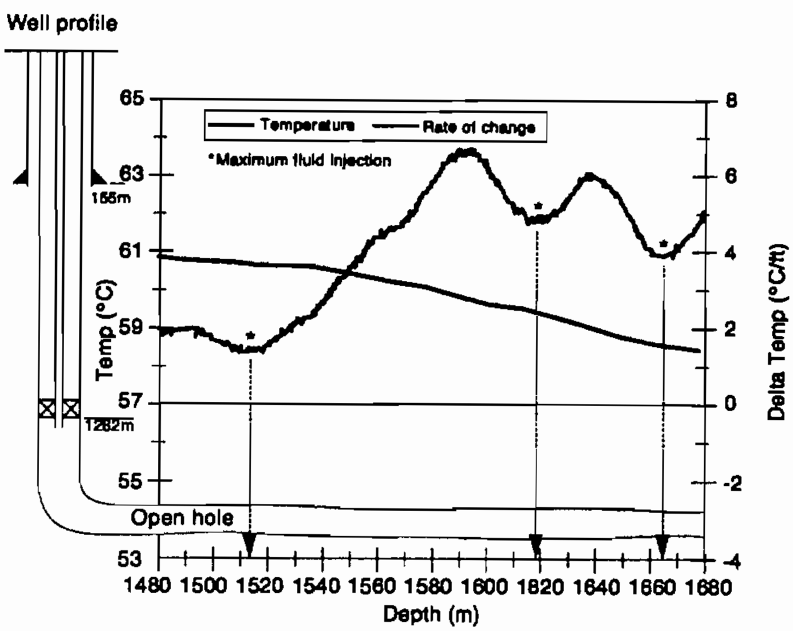

Figure 13-27. Stimulation Job Without Real-Time Measurements (Thomeer and Willauer, 1994)

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14. Tools

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14. Tools

14.1 ARCO ALASKA (SPECIAL TOOLS)

Along with the development of higher-strength, more reliable, and larger coiled tubing and surface equipment, tools are being developed and perfected for new applications and techniques. The coiled-tubing applications that are receiving the most attention include drilling (sidetracking and wellbore extensions), cleanouts, one-day recompletion workovers, and exploration.

Blount (1993) of ARCO Alaska discussed many of the most interesting coiled-tubing tools recently developed. Additionally, he described several tools needed by the industry to perform a variety of coiled-tubing operations more efficiently.

Blount mentions the need for lightweight power tongs for making up motors onto coiled tubing. In the past, North Slope operators have used a thread sealant to prevent the connection from slipping. The difficulty in breaking the seal after the operation is completed makes this approach less than ideal. Power tongs for this operation would not need to be especially fast since only a small number of connections need to be made each trip.

The push toward the use of larger coiled tubing equipment raises conflicting requirements. Larger tubing requires larger rigs, larger footprints at the site, more rig-up time, and higher operating costs. These requirements serve to erode the basic advantages of coiled-tubing operations. Blount warns that equipment design should be carefully planned and matched to essential requirements to maintain the basic benefits of coiled tubing.

Hydraulically operated re-engageable tools are recent innovations in coiled-tubing fishing operations. These tools operate by a visco-jet orifice that cycles the tool between engage and disengage. Increased pressure (above a preset limit) causes the tool to release from the fish. More of this type of tool is needed for fishing operations.

Tools that have proved useful in fishing operations include the orienter and the adjustable bent sub, which were initially developed for drilling applications. The orienting tool can be used to rotate the fishing assembly by 30-45° each time the circulating pumps are cycled. The adjustable bent sub bends to a preset or variable angle when pressure is applied. These tools have been shown to be extremely useful for engaging fish.

Abrasive jet drilling with coiled tubing is under serious consideration. Many new tools need to be developed for this technology. Coiled tubing strings of high-strength alloys or composites may have a substantially increased life in high-pressure abrasive drilling.

New packers have been designed for coiled-tubing operations. These can allow pumping while running in the hole and after setting. They are expandable for use below restrictions, such as landing nipples.

Spoolable equipment is expected to increase in variety in the future. Surface equipment that is more flexible will be able to run tubing with external upsets. Spoolable gas-lift valves were recently installed successfully in a string of 2⅜-in. coiled tubing.

14.2 BOCK SPECIALTIES INC. (COILED-TUBING PACKERS)

Bock Specialties Inc. (Lacy, 1994) described the design and use of coiled-tubing packers, bridge plugs, and cementing tools. These tools are activated by hydraulic pressure or reciprocation of the coiled tubing.

A newly-designed setting mechanism was used in a multiple-set coiled-tubing tension packer. The packers setting mechanism engages every time the tubing's direction of motion reverses. The packer is set by running in hole and then picking up at the desired depth. The mechanism is released by slacking off on the packer and then picking up again.

Another design that includes an equalizing valve was derived for testing applications. This system is set initially with tension. After being set, the tool holds pressure from above or below without moving. The equalizing valve equalizes pressure across the tool before the tool is released and retrieved.

14.3 HALLIBURTON ENERGY SERVICES (HORIZONTAL COMPLETION TOOLS)

Horizontal drilling technology has been well served by coiled tubing. Industry's focus has shifted toward development of technologies that allow more control over production. New tools designed to be run and operated on coiled tubing are being developed to address these needs (Robison et al., 1993).

Zonal isolation is now practical in horizontal wellbores due to the availability of coiled tubing services. It is now routine to complete horizontal wells with zonal isolation capability and within a reasonable cost.

Open-hole completions have been the most common and least expensive option for horizontal wells. The principal disadvantage is the lack of control this provides over the producing interval. External casing packers can be used in these wells. Coiled tubing can be used to set inflatable elements that have a low-pressure seal, usually adequate to isolate adjoining zones. Between the packers, either slotted liners or sliding sleeves (Figure 14-1) can be installed.

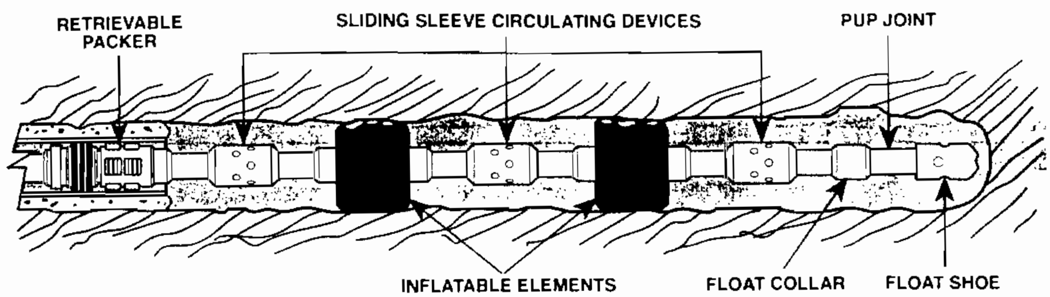


Figure 14-1. Open-Hole Zone Isolation With Packers and Sliding Sleeves (Robison et al., 1993)

Sliding sleeves provide more positive control of the production interval. They can be opened or closed by a simple coiled-tubing procedure.

Sliding sleeves are also an option in cased-hole completions (Figure 14-2). For these cases, conventional production packers can be used for zone isolation.

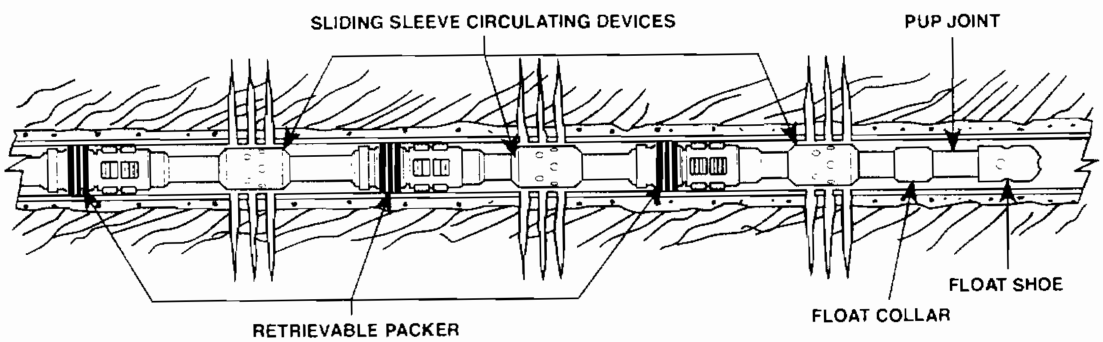


Figure 14-2. Cased-Hole Zone Isolation With Packers and Sliding Sleeves (Robison et al., 1993)

The hydraulic capability of coiled tubing adds significantly to the operational options available. Downhole tools can be manipulated hydraulically without needing to rely on set-down weight. A special hydraulic shifting tool (Figure 14-3) provides more positive control than a conventional shifting tool with set-down weight. No tubing manipulation is required. When shifting is accomplished, flow ports open, signaling successful operation.

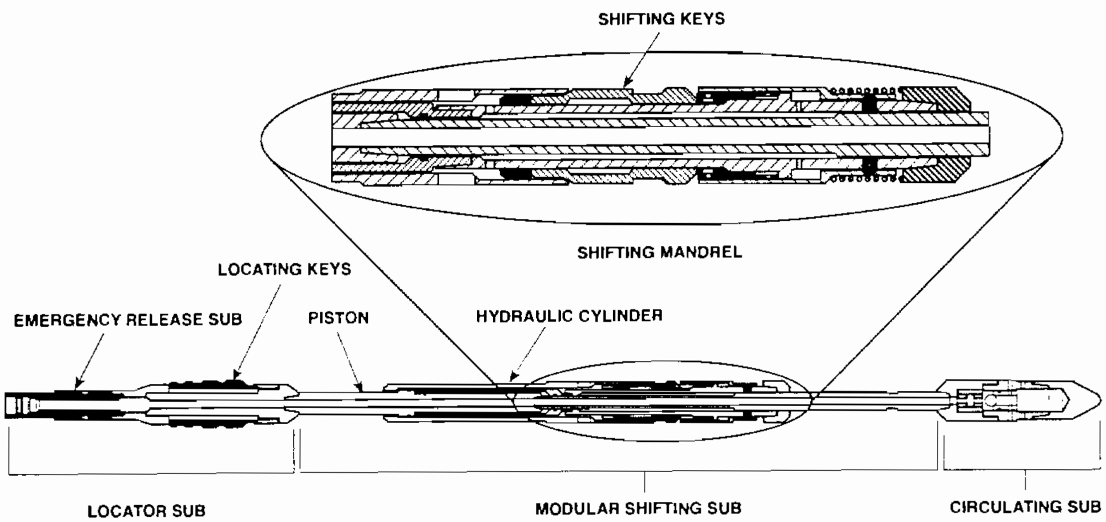


Figure 14-3. Hydraulic Shifting Tool (Robison et al., 1993)

Significant forces can be generated by the hydraulic shifting tool for shifting sliding sleeves (Table 14-1). Wireline inside the coiled tubing can relay data describing the forces applied and the position of the sliding sleeve.

TABLE 14-1. Hydraulic Shifting Tool Force (Robison et al., 1993)

Tubing Size (In.)	Shifter O.D.(In.)	Piston Area (Sq.In.)	Force Available (LBF)
2⅜	1.84	1.57	7,800
2⅞	2.23	1.90	9,500
3½	2.72	2.32	11,600
4½	3.50	2.98	14,900
5	3.89	3.31	16,500

Advanced shifting tools have multi-position settings that allow fine control of the flow area (Figure 14-4) and the flow profile along the wellbore. This ability can be very useful in water coning avoidance and injection wells where precise flow control is required.

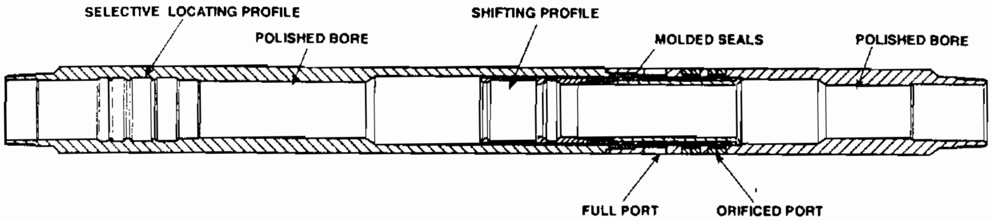


Figure 14-4. Multiposition Sliding Sleeve (Robison et al., 1993)

14.4 SONOMA CORPORATION (IMPACT DRILL)

The HIPP-TRIPPER® is a rotating impact drill that operates with any fluid including diesel and xylene. This patented tool combines bit rotation, impact force, and a high-pressure pulse at each cycle for effectively drilling fill, removing obstructions, freeing stuck tools, and a variety of other tasks. A basic tool schematic is shown in Figure 14-5.

The tool is used primarily in coiled-tubing operations to remove scale, gravel, resin sand, and paraffin; to drill out cement; and to break ceramic disks in zone isolation systems. A bidirectional version of the HIPP-TRIPPER® can impact both up and down, and is used for fishing operations, removing tubing obstructions, and shifting sliding sleeves. Typical tool specifications are shown in Table 14-2.

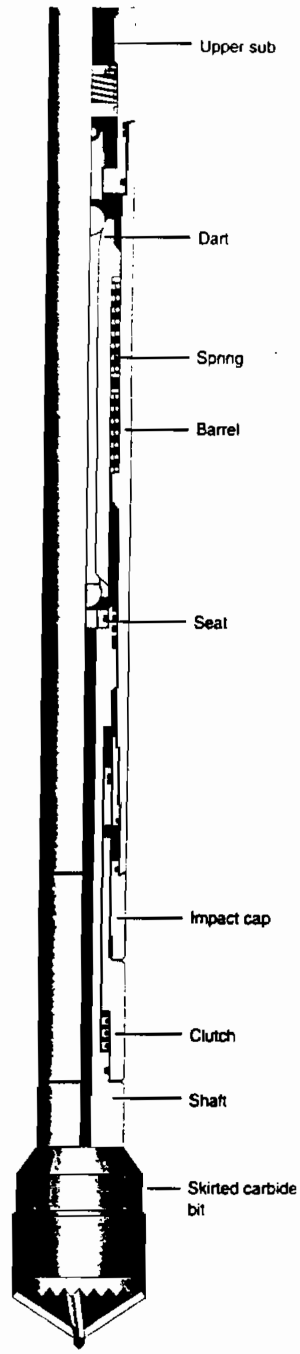


Figure. 14-5. HIPP-TRIPPER® Impact Drill

TABLE 14-2. Specifications of HIPP-TRIPPER® Impact Drill

Typical Specifications**

Tool Size (In.)	$1^{11}/_{16}$ Single Directional	2⅛ Bidirectional*
Diameter (In.)	1.688	2.125
Flow Rate (bbl/min)	0.25 – 1.00	0.25 – 1.50
Torque Range (ft-lbf)	100 – 250	120 – 360
Rotation Speed (rpm)	7 – 30	7 – 30
Blow Frequency (blows/ min)	50 – 800	50 – 500
Tool Size (In.)	**4¾ Single Directional**	**3⅛ Bidirectional***
Diameter (In.)	4.75	3.125
Flow Rate (bbl/min)	0.25 – 3.00	0.25 – 1.50
Torque Range (ft-lbf)	50 – 750	50 – 750
Rotation Speed (rpm)	7 – 30	7 – 30
Blow Frequency (blows/ min)	50 – 200	50 – 500

*Also available in single-directional version

**All tools operate at a maximum temperature of 600°F and 5000 psi

The HIPP-TRIPPER® does not rotate or reciprocate unless the bit meets resistance; thus, fluid can be circulated while the tool is run in and out of the well without damaging wellbore tubulars. The impact frequency is dependent on the weight on bit and fluid pump rate, and varies between 50 and 800 blows/min. The stroke length varies between ¼ and 1½ in., and depends on tool size and weight on bit.

Various bits and tools are available for the tool for drilling different materials and performing other tasks. Several operators and service companies have reported good success with the HIPP-TRIPPER®.

14.5 REFERENCES

Blount, C.G., 1993: "Coiled Tubing...Operations and Services, Part 15—Special Tools," *World Oil*, May.

Lacy, Rodger, 1994: "Tools Open Way for Growing Coiled Tubing Use," *The American Oil & Gas Reporter*, July.

Robison, C.E., Mashaw, H.R. and Welch, H.R., 1993: "Zone Isolation of Horizontal Wells by Coiled-Tubing-Actuated Tools," OTC 7354, paper presented at the 25th Annual Offshore Technology Conference held in Houston, Texas, May 3-6.

15. Workovers

15. Workovers

15.1 GENERAL

15.1.1 BP Exploration (Success of Coiled-Tubing Workovers)

BP Exploration (Pucknell and Broman, 1994) assessed the success of horizontal wells in the Prudhoe Bay field. They analyzed five years of production data and compared fourteen horizontal and high-angle wells to conventional offset wells. Completed intervals in these horizontal wells ranged from 430 to 2166 ft. Additionally, they described the success of coiled-tubing workovers on these non-conventional wells.

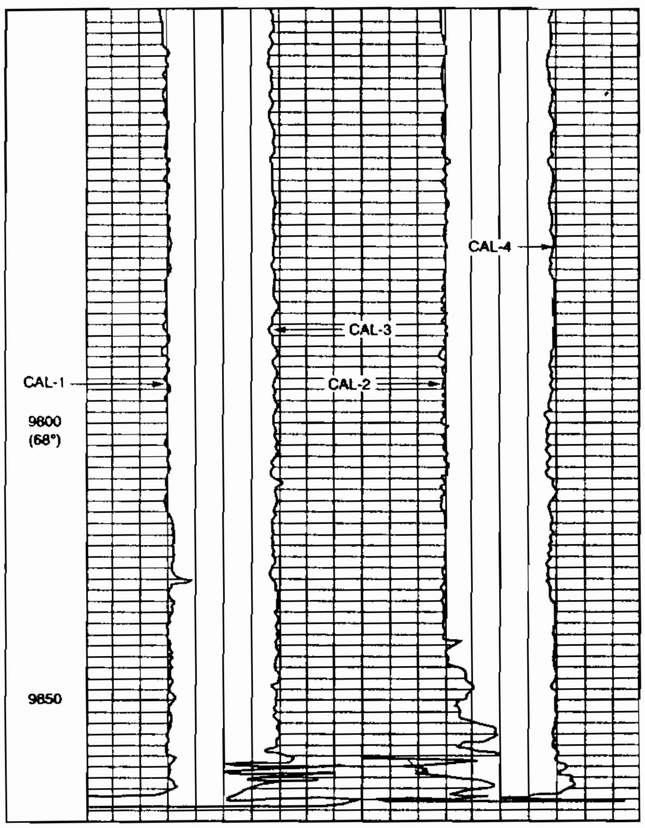


Figure 15-1. Caliper from Cement Evaluation Log in Horizontal Well (Pucknell and Broman, 1994)

North Slope operators have extensive experience with coiled-tubing workovers. In these nonconventional wells, coiled tubing has been used successfully to run flow meters and other logs. Problems have occurred in running a bridge plug to shut off gas and in opening/closing sliding sleeves. BP Exploration believes these problems are the result of debris in the hole and completion jewelry in doglegs.

Junk has been seen to accumulate on the low side of the hole in wells with deviations greater than 60-76°. In one well, a cement caliper log (Figure 15-1) indicates the presence of junk starting about 15 ft before the tool stopped advancing. Caliper 2 showed the debris on the low side of the hole.

Problems with debris in 4.9-in. liners occurred most often with tools larger than 3 inches. Coiled-tubing jetting was successfully used to clean out the debris. BP Exploration recommends performing a clean-out operation before running large-diameter tools in horizontal wells.

Another problem encountered in coiled-tubing workovers in horizontal wells was tools hanging up at specific locations even though the well was clean. Analysis pointed to tools hanging in the seal assembly (Figure 15-2). The tools can normally pass through this geometry; however, when the assembly is located in a dogleg, the tool edges can catch. BP Exploration suggested that this problem could be avoided by locating completion jewelry in positions other than doglegs.

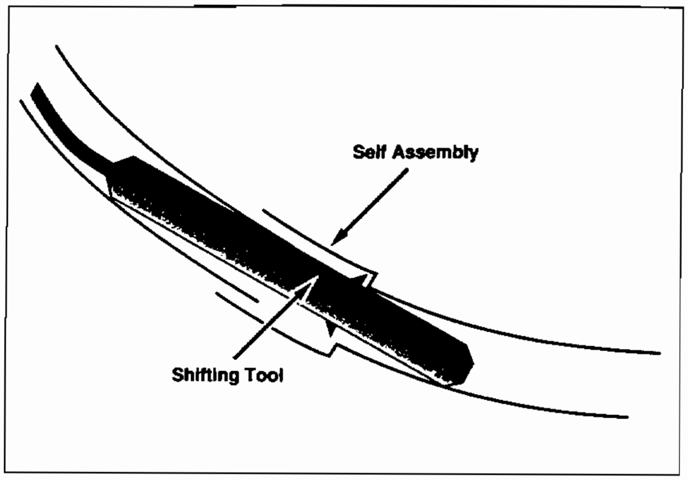


Figure 15-2. Logging Tools Catching in Completion Jewelry (Pucknell and Broman, 1994)

15.1.2 Maurer Engineering Inc. (Advanced Workover Applications)

Maurer Engineering (Adkins and Deskins, 1994) reviewed coiled-tubing workover applications, discussing job distributions in the past and future. About two-thirds of the entire coiled-tubing market relates to workover/stimulation activities (Figure 15-3). In fact, approximately 60% of worldwide coiled-tubing units are owned by pressure-pumping companies.

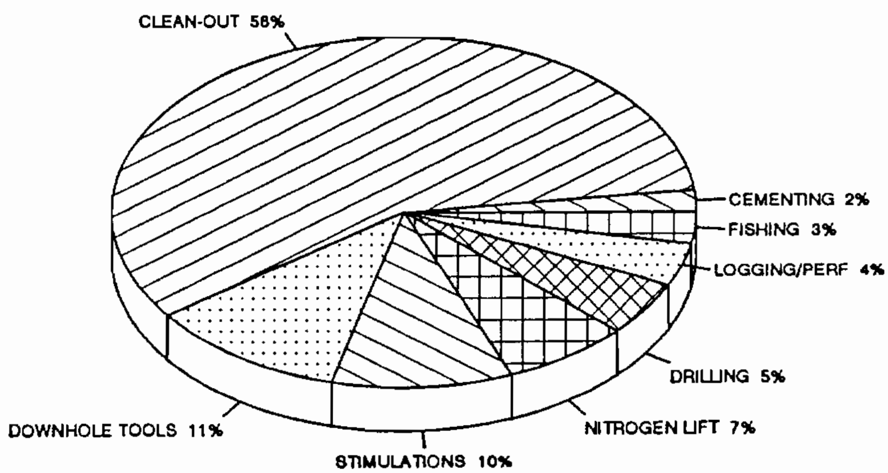


Figure 15-3. Coiled-Tubing Workover Applications (Adkins and Deskins, 1994)

Coiled-tubing rigs have found widespread use in the oil field for workovers, drilling, and completion operations. Reduced rig costs and trip times with coiled-tubing rigs have reduced costs by as much as 50-70% when compared to conventional workovers. Coiled tubing has also proven to be more versatile than other conventional systems. The advantages and disadvantages of coiled-tubing systems as compared to conventional systems (i.e., jointed pipe and wireline) are shown in Figures 15-4 and 15-5.

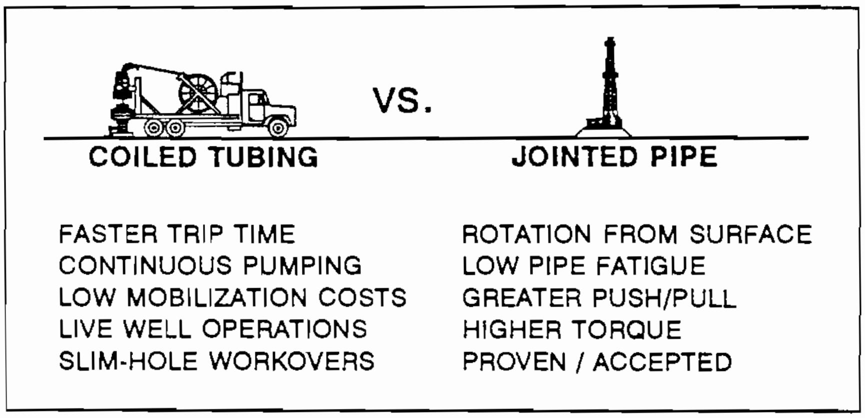


Figure 15-4. Coiled-Tubing Versus Jointed-Pipe Operations (Adkins and Deskins, 1994)

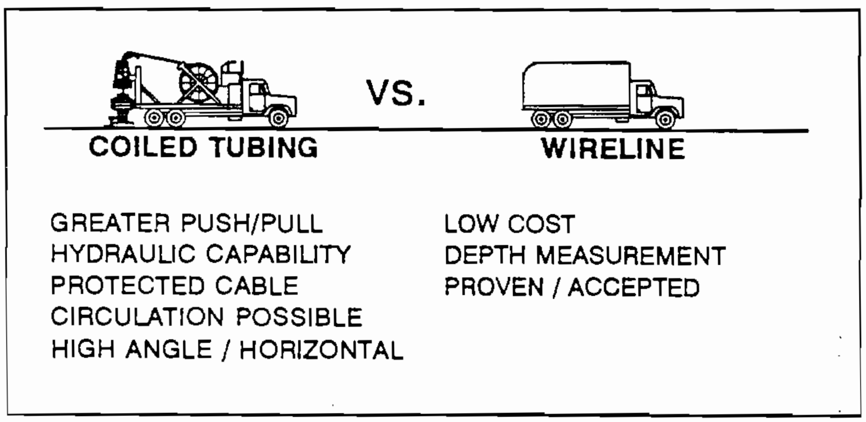


Figure 15-5. Coiled-Tubing Versus Wireline Operations (Adkins and Deskins, 1994)

In addition to "conventional" workovers with coiled tubing, new applications are under development. One of these is the use of coiled tubing as a production flow line. One of the earliest of these jobs involved laying a pipeline in the Gulf of Mexico between two platforms. Substantial cost savings resulted from significantly less installation time as compared to welded pipelines. The market for the newest applications is expected to gradually expand as the industry becomes more comfortable with the quality of the new generation of coiled-tubing tubulars, equipment and services.

15.2 SAFETY

15.2.1 Introduction

The full potential of the technical and economic advantages of live-well operations will never be achieved unless these operations are conducted safely. The coiled-tubing service industry has recognized this fact and has improved operational safety rapidly and dramatically in recent years. Coiled-tubing technologies are also being increasingly adopted by safety-conscious operators and integrated into their operations.

In early coiled-tubing field operations, tubing reliability was the principal area of operator concern. Fortunately, recent developments in manufacturing quality and improvements in tubing materials have largely alleviated the industy's concern. Along with improvements in the tubing itself, a large body of research has been conducted to increase the industry's understanding of the mechanical and fatigue performance limits of the product.

Tubing-life prediction models have been developed based on theoretical analyses and empirical data. These models can normally predict with good accuracy the life of a string of coiled tubing. Input data for the life models are taken in real time during each operation with a particular string of tubing.

Pressure, tension, and compression limitations are now understood much more accurately. Operations are now designed to be completed safely within these limitations, further reducing the chances of unexpected failure. Some operators' perceptions about tubing safety lag behind the industry's advancements, but should converge as information and data are made widely available.

Well-control systems and BOPs have been improved to safely handle any emergency condition. Larger coiled-tubing BOPs with improved capabilities are being developed to handle larger tubing diameter and wall thickness. Special surface equipment and techniques have been developed for running long BHAs. These new techniques allow a lower, safer injector height.

Injector designs are becoming refined to minimize stress, scarring, and deformation of the tubing as it passes through the grippers and gooseneck.

The experience and competence of the equipment operator have a strong impact on job safety. Major service companies have instituted major training programs for basic and advanced operations. Sophisticated simulators (Figure 15-6) raise the safety awareness and response of operators for a variety of emergency conditions. Responses can be practiced under controlled conditions for normal, unusual, and emergency situations.

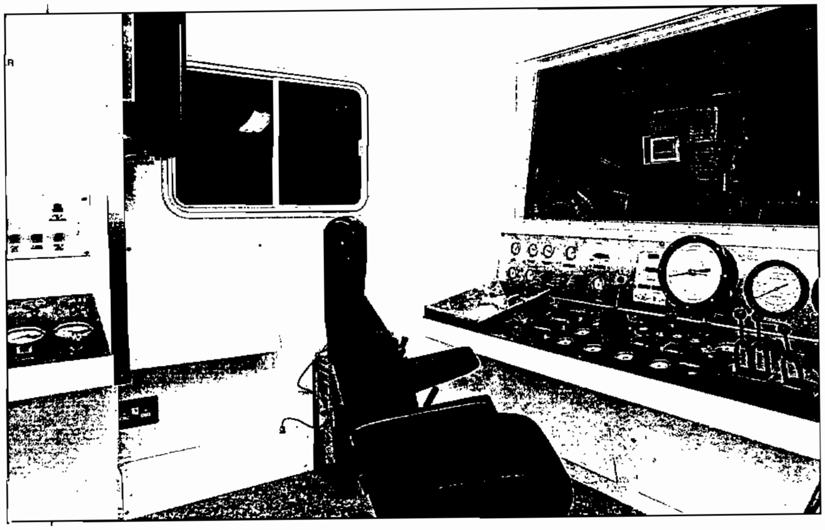


Figure 15-6. Coiled-Tubing Simulator (Adam et al., 1992)

An additional important development is the establishment of an API committee to study and formulate recommended practices for coiled-tubing operations. Five divisions are under consideration:

1. Coiled tubing
2. Surface equipment
3. Downhole equipment
4. Safety and environmental issues
5. Operating procedures

Environmental safety has become a critical concern for both operators and service companies. Coiled-tubing operations have advantages over other technologies, including a smaller well-site footprint, less equipment to transport, lower fluid volumes, and less waste requiring disposal.

15.2.2 Schlumberger Dowell (Operational Limits)

Operational limits for coiled-tubing usage should ultimately be determined based on the specifications and condition of the string. Schlumberger Dowell (van Adrichem and Adam, 1993) formulated suggested overall operational limits for coiled tubing jobs (Table 15-1).

TABLE 15-1. Suggested Operating Limits for Coiled Tubing (van Adrichem and Adam, 1993)

MAXIMUM	
Circulating pressure with tubing static:	5,000 psi
Circulating pressure with tubing moving:	4,000 psi
Outside to inside pressure differential:	1,500 psi
Wellhead pressure:	3,500 psi
Tubing speed RIH:	75 ft/min
Tubing speed POOH:	100 ft/min
Tubing speed RIH @ 100 feet from bottom	10 ft/min
Tensile stress in coiled tubing:	80% of yield point
Ovality of coiled tubing:	6%
MINIMUM	
Clearance for tools to pass restrictions:	4% (ID/OD)
Clearance for tools while sand washing:	16%
H_2S producing wells:	No butt welds

Operational limits become increasingly important as coiled-tubing applications become more rigorous and equipment capacities increase. The pulling capacity of many injector heads can exceed the tensile strength of tubing. Pumping equipment may also be capable of exceeding tubing limits.

Some of the limits listed in Table 15-1 seem to be conservative when considered independently. However, some parameters interact synergistically, and conservative limits are a practical way to address their interaction. As an example, a slight increase in tubing ovality leads to a decrease in collapse pressure. Consequently, a collapse pressure rating of 1500 psi takes into account the presence of some tubing ovality.

Interaction of Von Mises stresses in setting tension, burst, and collapse limits is depicted in Figure 15-7. The operating range (the cross-hatched portion) is based on limiting tension and burst to 80% of yield and collapse to 65% of yield (again taking into account the effect of ovality on collapse).

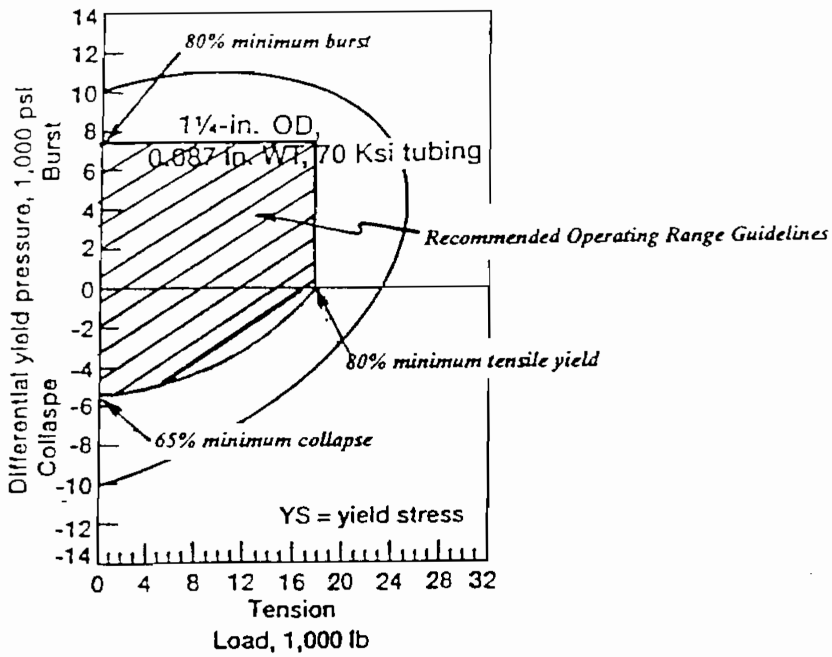


Figure 15-7. Example Operating Range for Tension, Burst, and Collapse

Safety is an increasingly critical factor in the job-design equation. Coiled-tubing operations are generally considered as inherently safer than operations with conventional workover rigs or snubbing units. The primary advantage of coiled tubing is the absence of joints, which eliminates hazardous pipe-handling operations. However, other aspects of coiled-tubing operations can pose hazards and must be given appropriate attention both before and during job execution.

Live-well operations always present the potential for danger and must be handled with appropriate respect. Coiled-tubing operations require the use of heavy equipment by personnel who must often work extended hours.

Engineering efforts to understand and predict tubing fatigue and behavior have resulted in a significant decrease in the incidence of tubing failure. However, a frustrating aspect of tubing behavior is the lack of any repeatable warning sign as an indicator of imminent failure. For example, a work string can rate "as new" by pressure testing, and fail during job execution soon thereafter.

Coiled-tubing technology shares pitfalls in equipment design, as does any rapidly developing technology. As new applications are constantly developed, existing equipment is often extensively modified and adapted. Occasionally during these efforts the design limitations of the original tools are inadvertently exceeded.

Early fishing tools run on coiled tubing were adapted from common wireline tools. To allow circulation in these tools, holes were drilled in mandrels, resulting in weakening of the tool body. Higher forces could be applied by the coiled tubing for fishing operations. The combination of higher forces and weaker tools resulted in lower reliability of coiled-tubing fishing operations. Fortunately, purpose-designed coiled-tubing fishing tools are currently available and reliable.

Preventative maintenance of coiled-tubing equipment must include monitoring and recording equipment usage. Three factors prescribe maintenance and replacement procedures:

1. *Time*. Coiled-tubing rig systems are monitored by operating hours. Additional influences must also be accounted for, including equipment life, climatic conditions, and logistics.
2. *Footage*. The footage of coiled tubing run by the rig is a strong indicator of wear and fatigue in the gripper components of the injector and the tubing reel. Footage records and periodic inspections can provide early warning of failure.
3. *Cyclic stress*. The safe working life of a coiled-tubing string is dependent on the plastic stresses to which it is subjected. Plastic stress with internal pressure increases tubing damage. Computerized monitoring of tubing life is becoming more common on rigs to ensure safe operations.

Human error remains an important part of the safety equation in coiled-tubing operations as it does for other technologies. Minor incidents resulting from human error have snowballed into major job failures. Education and training are seen as the principal methods for reducing this problem.

15.2.3 Schlumberger Dowell (Deployment of Long BHAs)

As the use of coiled tubing has expanded into logging, selective stimulation, drilling, coiled-tubing completions, and artificial lift, long specialized BHAs exceeding 30 ft in length have become more common. Conventional deployment of coiled-tubing strings in live wells poses several safety hazards. Placing the injector on top of the lubricator (Figure 15-8) is hazardous because a large crane is required and the injector often cannot be seen easily from the control house.

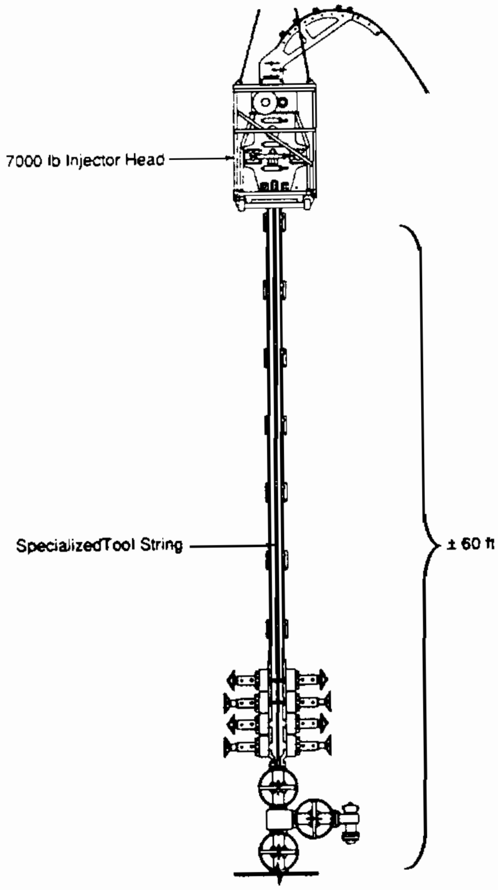


Figure 15-8. Conventional Deployment of Long BHAs (Thomeer and Eslinger, 1992)

Any repair or service to the injector would require working at an unsafe height.

Schlumberger Dowell developed a deployment method that avoids unsafe injector heights (Thomeer and Eslinger, 1992). Their method makes use of a special deployment bar that is positioned on top of the long tool string. The deployment bar has a section whose diameter is identical to that of the coiled tubing.

The modified deployment method is described in Figure 15-9. Step 1 involves lowering the BHA into the well through a wireline lubricator. The string is lowered until the deployment bar is located across from the BOP tubing rams.

The tubing and slip rams are closed around the deployment bar to support the BHA and seal off wellhead pressure (Step 2). Then the wireline lubricator and connector are removed, and the end of the deployment bar is accessible.

The injector is fitted with a short riser and wireline or fluid connector and positioned above the wellhead (Step 3). The connectors are then made up to the deployment bar. The injector is lowered so that the short riser can be made up (Step 4). Pressure testing is performed. Finally, the BOP is opened and the tool string is RIH.

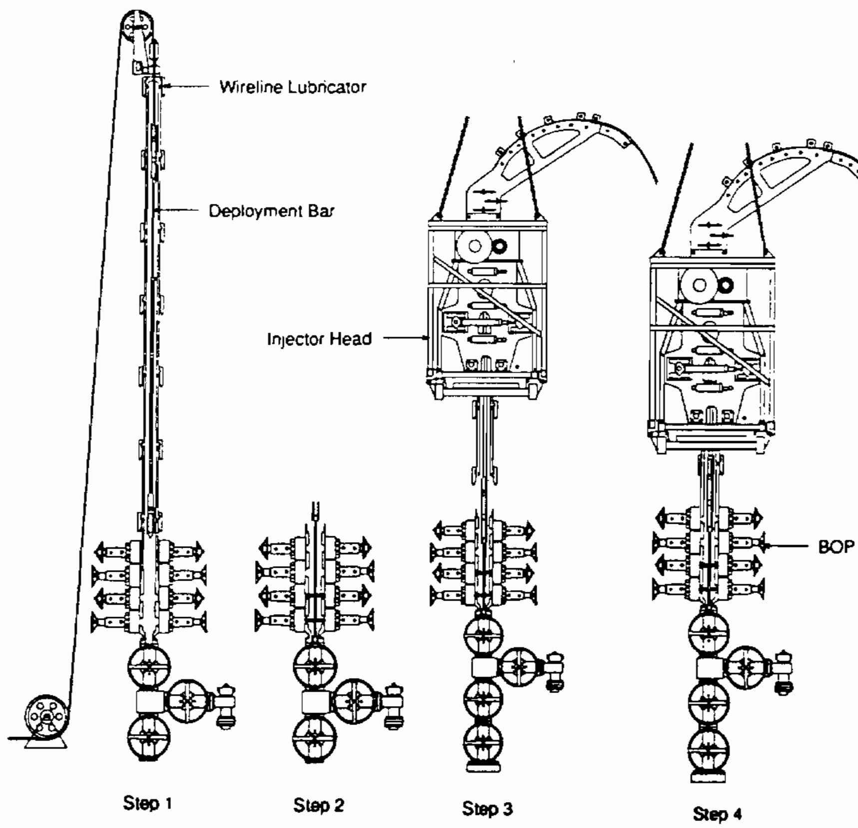


Figure 15-9. Safer Method of Deploying Long BHAs (Thomeer and Eslinger, 1992)

Additional improvements were made to the design of this deployment technique (Figure 15-10). The surface equipment was modified to include a quick-latch connector, side-door deployment tool, annular BOP and hydraulic control panel. The quick-latch connector is self-aligning and requires no operator to help stab or make up a threaded union.

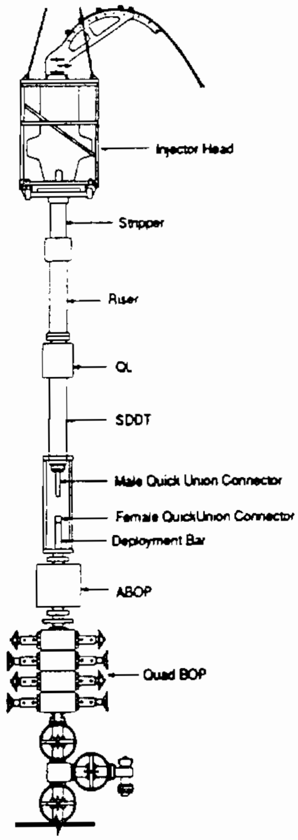


Figure 15-10. Improved Coiled-Tubing Deployment System (Thomeer and Eslinger, 1992)

The side-door deployment tool provides a way to ground the injector to the wellhead before the coiled tubing is connected. The annular BOP provides a redundant wellhead seal for the conventional quad BOP.

The hydraulics control panel (Figure 15-11) operates the side-door deployment tool, the quick-latch and the annular BOP. Stripper pressure is monitored to disable the control valves and prevent unintentional opening of the side-door and quick-latch.

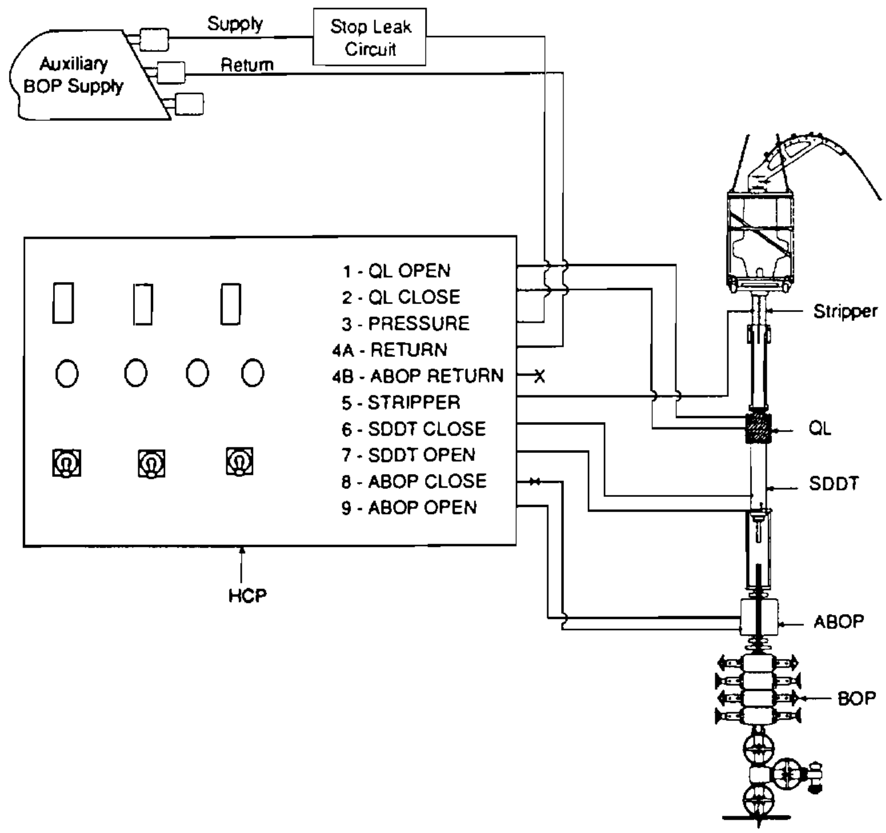


Figure 15-11. Improved Hydraulics Control Panel (Thomeer and Eslinger, 1992)

Downhole tools in the improved design include the deployment bar, a dual-ball deployment valve, and quick-union connector.

Running a long BHA with the improved deployment system begins with latching the wireline lubricator to the quick-latch and closing the side-door deployment tool. After the blind ram is opened and lubricator pressure equalized, the string is lowered to the tubing and slip rams (Figure 15-12, Step 1). The rams are closed on the deployment bar and, after the pressure in the lubricator is bled through the kill line, the annular BOP is closed.

Next, the side door is opened and the male quick-union connector is removed. After the quick-latch is unlocked, the wireline lubricator is removed from the wellhead (Step 2).

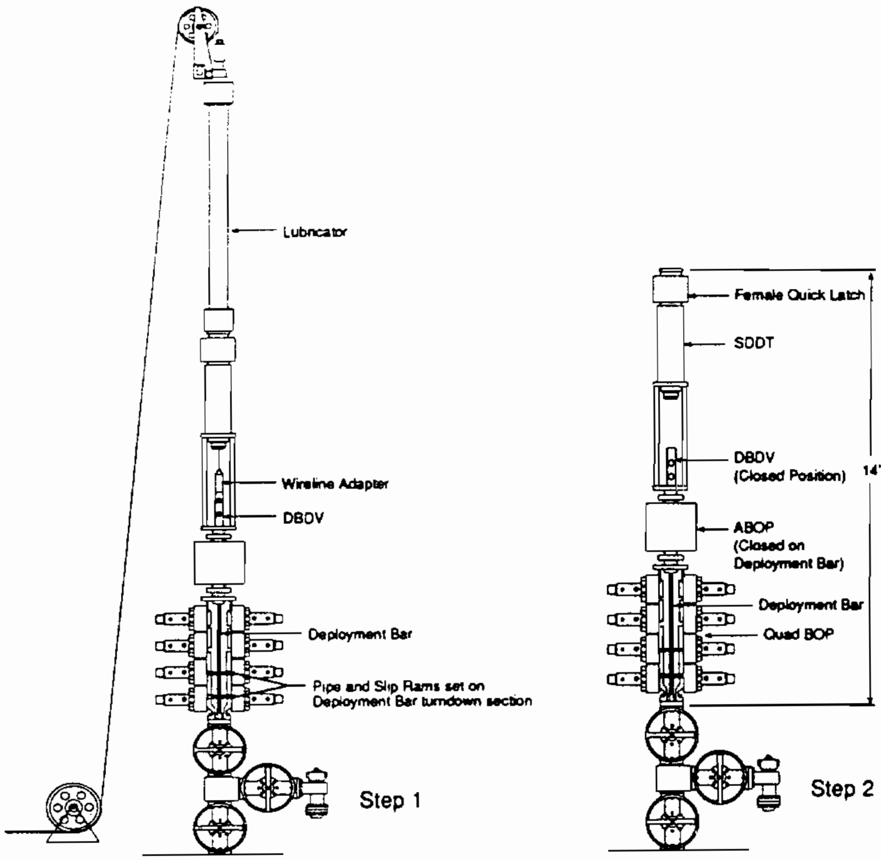


Figure 15-12. Improved Deployment Procedure (Thomeer and Eslinger, 1992)

The male quick-latch and riser are installed on the injector, and the coiled-tubing connector, check valves, release joint, and quick-union are made up to the coiled tubing. The injector and riser assembly are latched to the female quick-latch and stabilized (Figure 15-13, Step 3).

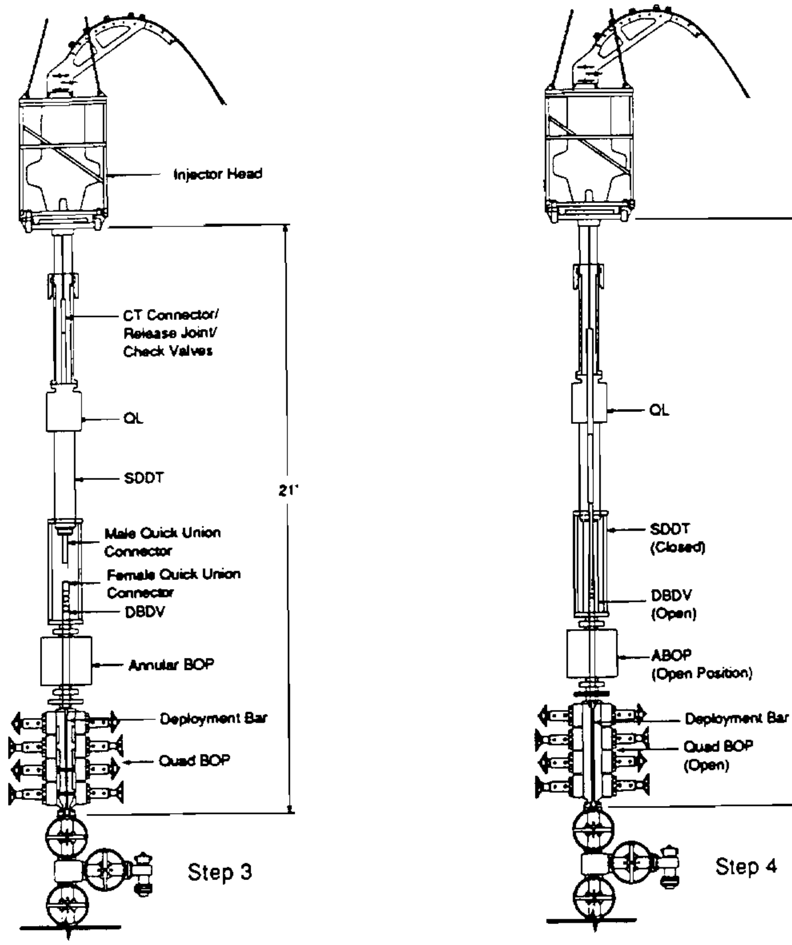


Figure 15-13. Improved Deployment Procedure (Thomeer and Eslinger, 1992)

An operator now moves in under the secured injector, opens the side door, removes the guide tool, and threads the quick-union connector (Figure 15-14).

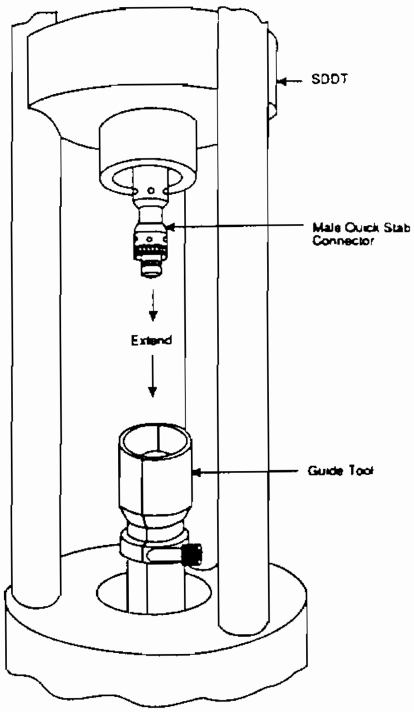


Figure 15-14. Deployment Guide Tool and Connector (Thomeer and Eslinger, 1992)

After the side door window is closed and locked, the annular BOP is opened. The stripper is pressured and tested (Figure 15-13, Step 4). The riser pressure is equalized with the well and the quad BOP rams opened.

Schlumberger Dowell states that this improved system is safer, more reliable, and faster. Minimum operator involvement beneath the injector results in improved safety. Wellhead pressure is controlled by a dual barrier throughout the job with the annular BOP as the second seal.

15.2.4 Schlumberger Dowell (High-Pressure Wells)

Coiled-tubing services are being increasingly performed in high-pressure wells, i.e., those with wellhead pressures above 3500 psi. Safe operations in these wells are possible with coiled tubing. A few special considerations are required for these jobs, however. These considerations were reviewed by Newman and Allcorn (1992).

A standard quad coiled-tubing BOP has four sets of rams (Figure 15-15). Blind rams seal the wellbore when the string is not in the BOP body. Shear rams are used to cut through the tubing in emergencies. Slip rams support the string weight. Pipe rams close and hold pressure when coiled tubing is in the BOP.

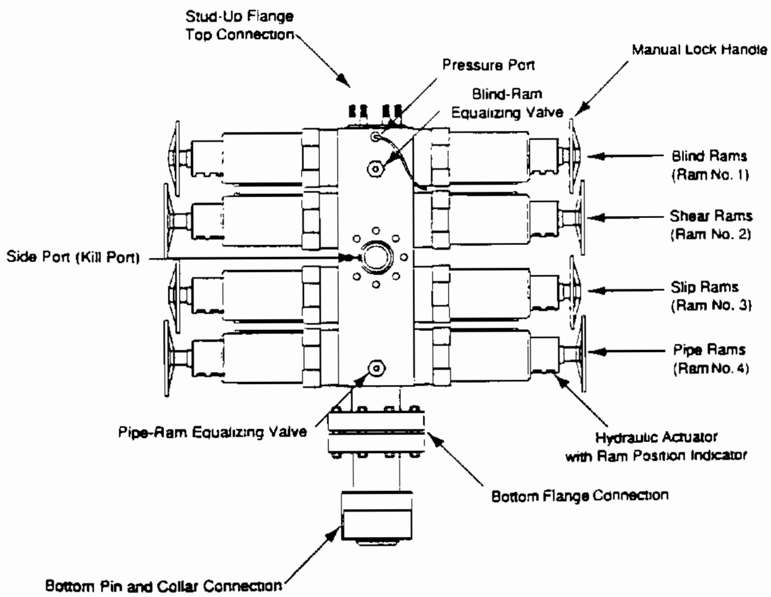


Figure 15-15. Typical Quad Coiled-Tubing BOP (Newman and Allcorn, 1992)

The BOP can be activated both hydraulically and manually in case either system fails. Most BOPs are rated for 10,000 psi maximum working pressure. This rating does not, however, ensure that the BOP can perform its functions with a 10,000-psi wellhead pressure.

If the hydraulic systems fail, the accumulator is used to operate the BOP. Accumulator pressure decreases after each close-open cycle (Figure 15-16), with four cycles required to close and open all rams. Accumulator capacity must be sufficient based on required closing pressure on high-pressure wellheads.

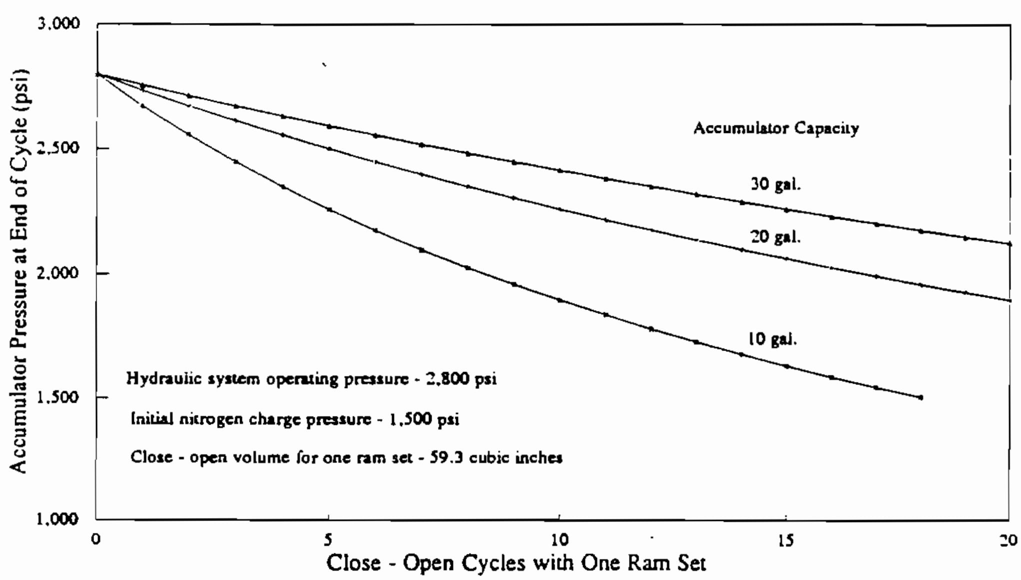


Figure 15-16. Accumulator Pressure After Closing BOP Ram (Newman and Allcorn, 1992)

The required hydraulic system pressure to shear coiled tubing increases with higher wellhead pressures. Table 15-2 gives examples of shearing pressure at various wellhead pressures.

TABLE 15-2. Hydraulic Pressure to Shear Coiled Tubing (Newman and Allcorn, 1992)

CT OD (In.)	Wall Thickness (In.)	Pressure Required to Shear 0 psi WHP	Pressure Required to Shear 5,000 psi WHP	Pressure Required to Shear 10,000 psi WHP
1.25	0.109	1,500	2,056	2,611
1.25	0.134	2,400	2,956	3,511
1.50	0.109	1,900	2,456	3,011
1.50	0.125	2,100	2,656	3,211
1.50	0.134	2,750	3,306	3,861

Schlumberger Dowell recommends that threaded connections not be used in coiled-tubing BOP equipment. Their structural and sealing capacity is less than those of flanged connections or integral pin/collar unions.

Considerations for the stripper in high-pressure operations include the magnitude of frictional force placed on the coiled tubing by the stripper, the durability of the sealing element in high-pressure use, and redundancy of the annular sealing system.

In normal operations, the stripper element can be replaced by closing the pipe rams. A back-up seal is recommended in high-pressure situations, such as the back-up stripper shown in Figure 15-17. The backup stripper and pipe rams provide a dual annular seal while the primary stripper element is being replaced.

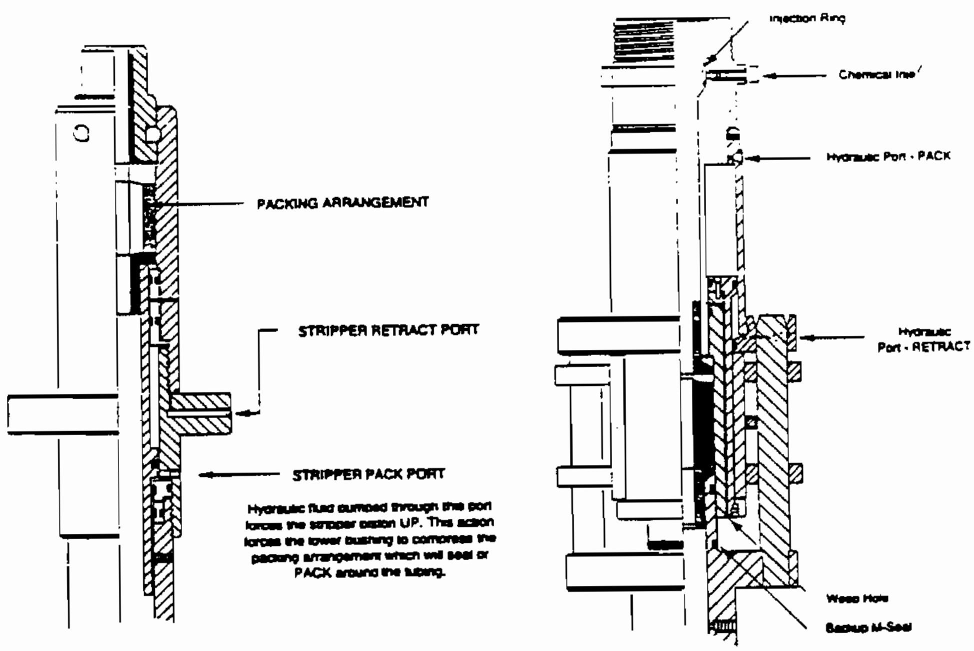


Figure 15-17. Standard and Back-Up Coiled-Tubing Stripper (Newman and Allcorn, 1992)

Concerns of tubing collapse are increased in high-pressure operations. Tubing that has become oval through fatigue cycling is more susceptible to collapse (Figure 15-18). Three techniques can be used to minimize the possibility of tubing collapse:

1. Use small-diameter heavy-wall tubing
2. Adjust pressure inside the tubing so that differential pressure is above collapse pressure
3. Run the coiled tubing without a check valve on the BHA so that the tubing is pressurized by the well pressure

The third option is normally not recommended, since it requires that the tubing on the reel and the reel manifold become well-control equipment. Should a leak occur, BOP shear and blind rams would be the only way to control a failure in the coiled-tubing surface equipment.

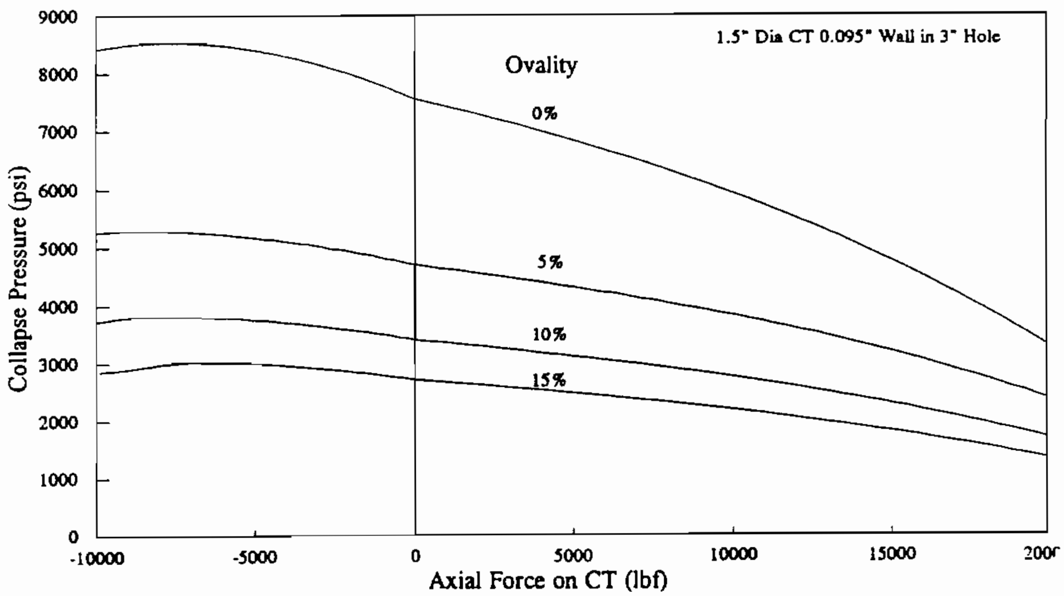


Figure 15-18. Effect of Ovality on Collapse Pressure (Newman & Allcorn, 1992)

Injector snubbing capacity is another consideration in high-pressure wells. The compressive force pushing the coiled tubing out of the well increases with well pressure and coiled-tubing diameter (Figure 15-19).

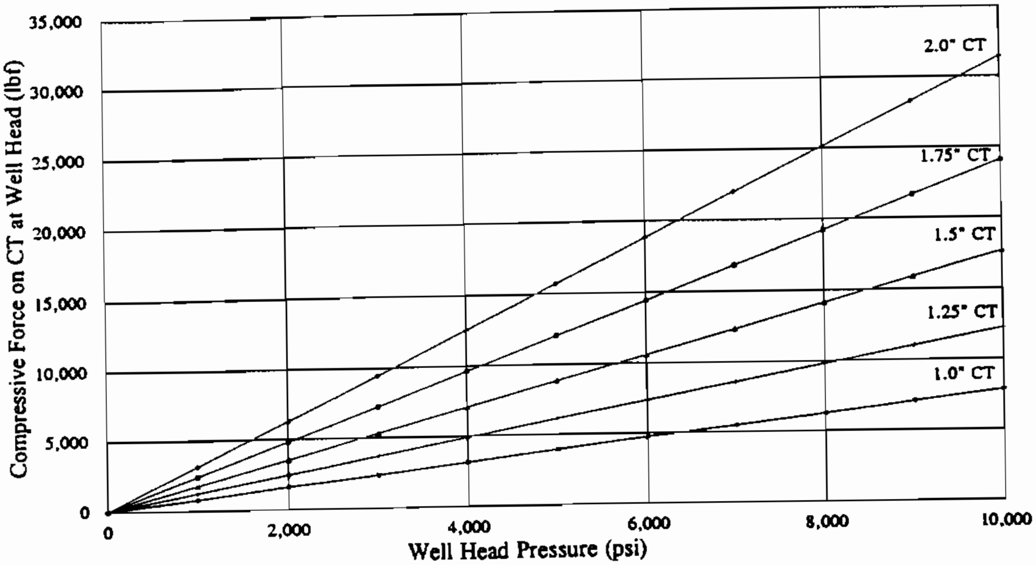
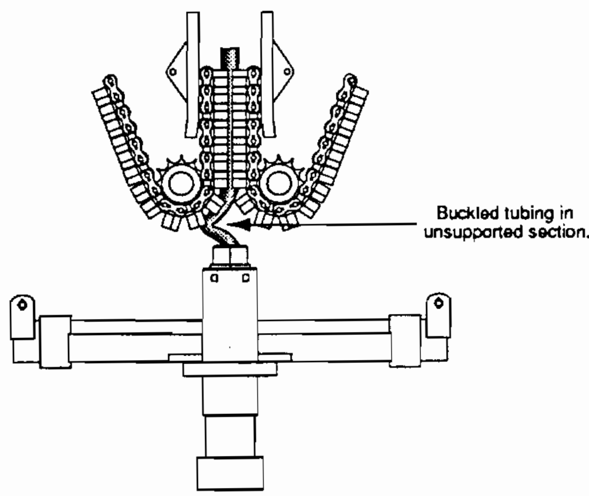


Figure 15-19. Wellhead Pressure and Snubbing Force (Newman and Allcorn, 1992)

Most injector heads have a lower snubbing capacity than pulling capacity due to limitations in the chain tensioning system. A typical 40,000-lb injector is capable of generating about a 14,000-lb snubbing force.

High snubbing forces have created another problem in some high-pressure operations: buckling of the tubing between the chains and the stripper (Figure 15-20). This tendency can be increased when a single-acting load cell is used.

Figure 15-20. Buckled Tubing Between Injector and Stripper (Newman and Allcorn, 1992)



The buckling load varies as a function of the distance between the chains and stripper, the amount of misalignment, and the tubing wall thickness. A buckling guide (Figure 15-21) lessens the possibility of tubing buckling in operations with high snubbing loads.

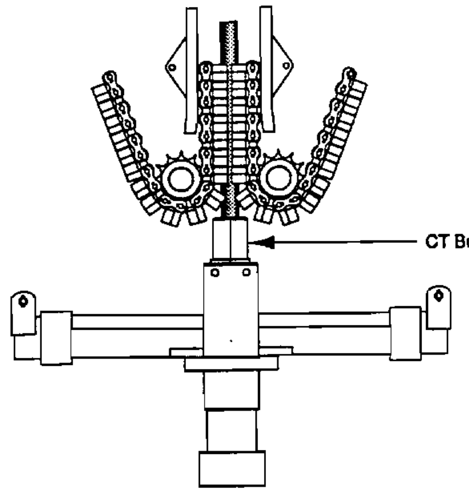


Figure 15-21. Buckling Guide Between Injector and Stripper (Newman and Allcorn, 1992)

15.3 SAND CONTROL

15.3.1 ARCO Oil & Gas (Coiled-Tubing Sand Control)

ARCO Oil & Gas (Rich and Blue, 1993) presented an overview of sand control techniques using coiled tubing and through-tubing techniques. Improvements in coiled tubing, equipment and tools have led to increased acceptance and wider application of through-tubing sand control.

Through-tubing sand control was first developed in the 1960s before the development of modern gravel-packing techniques. The success with modern methods resulted in the abandonment of the early through-tubing techniques. Improvements in coiled-tubing technology have revived interest in through-tubing methods. The most appropriate applications for this approach include:

- Locations with remote or harsh conditions that make conventional methods impractical
- Wells with reserves insufficient to pay back conventional gravel-pack costs
- Wellbores consisting of multiple or thin zones
- Wells that require heavy-weight kill fluids to control reservoir pressure, with the consequent danger of formation damage

The principal types of through-tubing sand control are mechanical gravel packs (small-diameter and prepacked screens), chemical formation consolidation, and resin-coated sand slurry packs. Basic techniques and applications are summarized in Table 15-3. Each method has both advantages and disadvantages, as discussed in the following paragraphs.

TABLE 15-3. Through-Tubing Sand-Control Techniques (Rich and Blue, 1993)

RECOMMENDED TREATMENT	COMMENTS	APPLICATIONS
Through-Tubing Mechanical Gravel Packs	Often must kill well. Pressure drop through small IDs can limit flow rates and it may be hard to prevent pack voids in long (over 20 ft) intervals. Future wellbore utility may be restricted.	Intervals up to and greater than 20 ft and repair of conventional mechanical gravel pack screens that fail
Chemical formation application	Simple with a good success record for short intervals (under 10 ft)	Intervals less than 10 ft and repair of conventional mechanical gravel pack screens that fail.
Resin-coated sand slurry packs	Drilling a pilot hole may be required to fully deplete lower zones. Not drilling a hole increases the chance of successful sand control, but limits flow rates. Good grain-to-grain contact and adequate compressive strength throughout the pack is difficult to obtain.	Intervals up to and greater than 20 ft and repair of conventional mechanical gravel pack screens that fail.

The *over-the-top squeeze pack* utilizes a gravel-pack screen, blank pipe, and a wireline set plug to place the assembly. The procedure (Figure 15-22) as described by ARCO is as follows:

- Set screen and blank pipe on hard bottom, plug back if necessary with or without tieback to EOT or hang BHA from a production tubing nipple.
- Set a retrievable plug in top of blank pipe.
- Establish injection and bullhead gravel-pack sand slurry down production or coiled tubing into perforations and annulus around screen until sandout occurs.
- Wash out excess sand to top of blank pipe using coiled tubing.
- Dump bail cement to seal sand top if BHA is not tied back into the production tubing.
- Retrieve plug from top of blank pipe.
- Set packoff and hold-down to seal top of blank pipe in production tubing if BHA is tied back into production tubing or hung-off in a nipple.

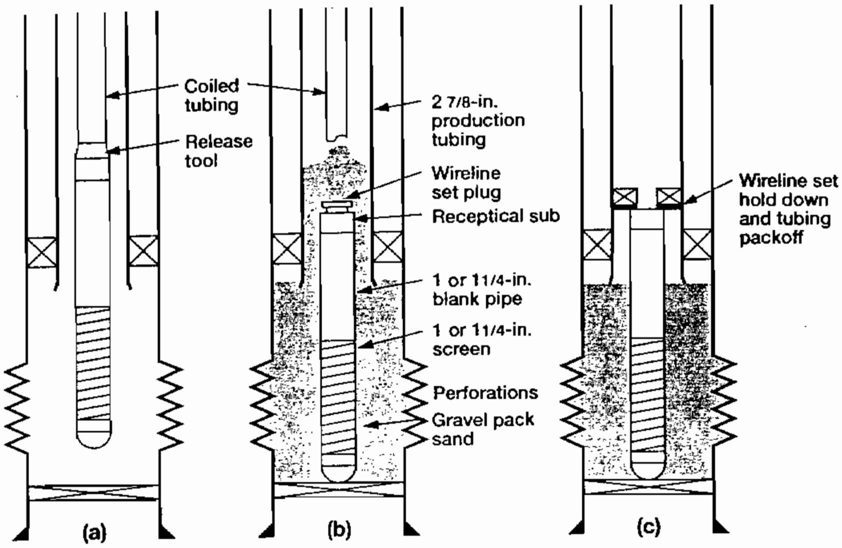


Figure 15-22. Over-the-Top Squeeze Pack Method (Rich and Blue, 1993)

A *wash-down pack* (Figure 15-23) places the gravel-pack sand or, more commonly, ceramic beads across the perforations before running the screen into the well. Once the ceramic beads are placed across the perforation interval, the well is killed and the bottom-hole assembly is run to the top of the ceramic beads. A wash pipe and circulating shoe are used to wash the screen assembly down into the ceramic beads until it reaches bottom or the tubing hangoff location. This method is limited to treatment intervals of 50 to 60 ft due to the need to keep the prepack fluidized during washdown.

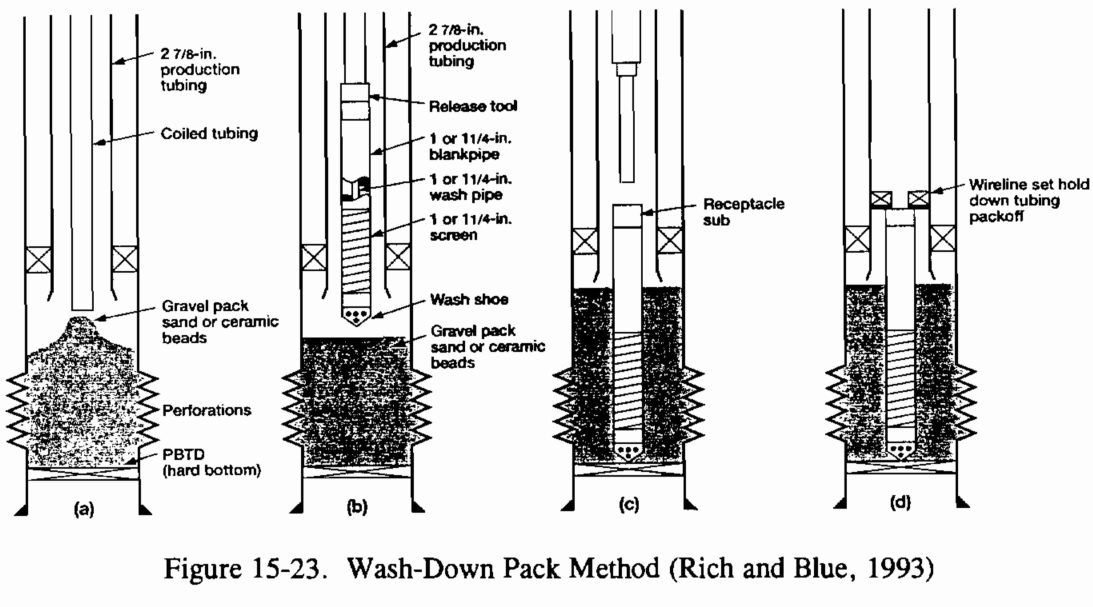


Figure 15-23. Wash-Down Pack Method (Rich and Blue, 1993)

Chemical methods of through-tubing sand control offer an economic option for wells with the following attributes: small reservoirs (1–2 BCF), minimal wellbore ID, bottom-hole temperatures in the range 60-400°F, and bottom-hole pressures of less than 11.6 ppg.

Furan resins have been used effectively for formation consolidation (Figure 15-24) out to a radius of over 3 ft. After the wellbore is cleaned, salt water is pumped into the formation, followed by the resin, a saltwater spacer, an acid catalyst, and a final brine flush. After the resin is cured, a solid sand filter is formed with a permeability of about 85-90% of the native permeability.

The main advantage of this type of system is that no specialized downhole equipment is required and the job can be pumped without killing the well. Recent advancements in coiled-tubing equipment and services now allow good resin placement, better zone coverage, and easy wellbore cleanout. Generally there is a minimal loss in productivity associated with these types of operations.

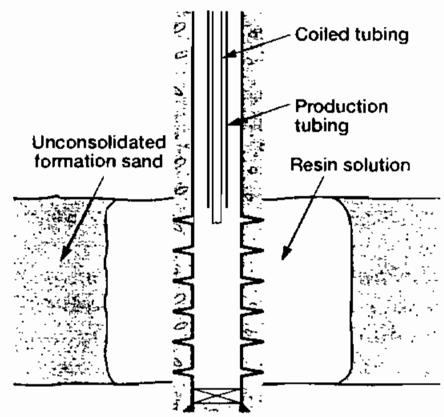


Figure 15-24. Chemical Formation Consolidation (Rich & Blue, 1993)

Because there is no sand or "junk" equipment in the well, this type of sand control makes it much easier to perform routine remedial workover operations. The lack of obstructions also make high sand-free flow rates more easily attainable than with the small diameter gravel packs.

The main disadvantage of this technique is that it is generally considered the least effective of any of the through-tubing sand-control methods available. Volatile chemicals and complicated pump schedules are required and diversion is considered a significant problem since several stages are required for successful resin setting.

Although there are other resins available (epoxies and thenolic resins), the furan resins have proven to be most effective. Simpler pump schedules, pre-mixing ability, and external catalyzation make the furan resin much more operationally attractive. Additionally, laboratory work has indicated that furan systems can achieve compressional strengths of 2200 psi as opposed to 1700 psi or less for the other types of systems. Generally a 15–25% reduction in permeability is used for calculating post chemical-consolidation flow rates.

A hybrid of the mechanical and chemical consolidation methods is a method called resin-coated sand slurry packs. This method as shown in Figure 15-25 involves pumping a resin-coated sand across a perforated interval in a manner very similar to the initial step of the wash-down method. Time and temperature cause the resin-coated sand to set up as a permeable plug. If it performs as designed, this plug has excellent strength and very high permeability. Once the sand pack has set up, then it can be left as is or drilled out as flow rates require.

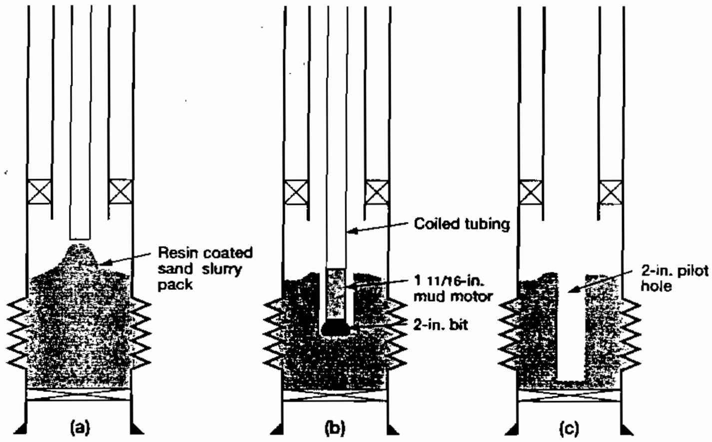


Figure 15-25. Resin-Coated Slurry Pack (Rich and Blue, 1993)

The resin-coated sand pack method has all the advantages of a chemical consolidation method and yet is generally considered a much more effective method of permanently controlling sand production. Advantages include:

1. No screen, blank pipe, or junk left in the hole
2. Easy remedial operation
3. No need to kill the well
4. High flow rate potential with minimal frictional pressure drop

The main disadvantage of this technique is the expense associated with drilling out the plug if flow rates are unacceptable. Another disadvantage is in the placement technique used to ensure a dense pack with sufficient grain-to-grain contact for high compressor strength throughout the entire interval. This is a significant concern because, as a resin-coated sand slurry is pumped across the producing interval, certain perforations will preferentially take fluid. As the slurry packs off against these high rate perforations, it will begin to dehydrate and bridge off (like a cement squeeze), leaving the lower perforation ineffectively covered.

When drilling out a "donut" within the resin-coated sand, the vibration forces can compromise the pack's compressional strength, thus leading to pack failure. Also, any well deviation can cause the plugs to be drilled out along the low side of the casing, thus exposing the perforations and causing a pack failure. For this reason it is often recommended that the pilot holes be drilled only to within several feet of the top perforation. If the production interval is very long, however, the large frictional pressure drop caused by the sand pack may result in unacceptable flow rates.

15.3.2 Chevron Production Company USA (Single-Trip Gravel Pack)

Chevron USA and Western Sand Control (Dorman et al., 1994) developed and installed a single-trip gravel pack through tubing in a well offshore Louisiana. The well was completed initially with a conventional circulating gravel pack in 1983. Sand production began in 1992. The high angle of the completion interval (Figure 15-26) would not allow the use of slickline or wireline operations for sand isolation.

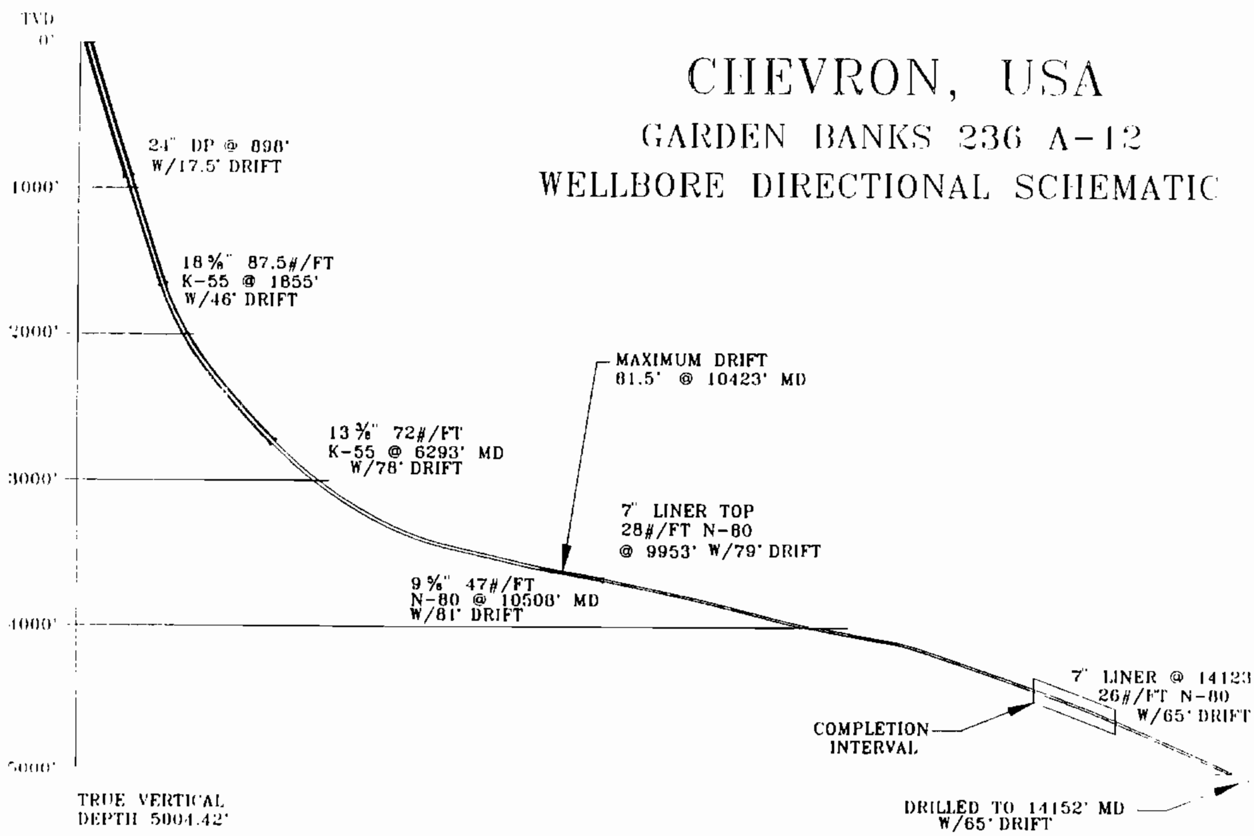


Figure 15-26. Chevron Well Offshore Louisiana (Dorman et al., 1994)

The original gravel pack failed after a path was opened through the 4-in. production screen near the upper lobe of the low-side perforations. Several cleanouts were attempted with 1½- and 1¼-in. coiled tubing. These were unsuccessful. Resin-coated sand was next placed via coiled tubing, again with little success.

A through-tubing gravel-pack treatment was considered as the next option. Gravel would be placed inside the original screen outside of a new screen. A special design was deemed necessary, which included a packer for the top seal of the pack rather than a wireline- or coiled-tubing-set pack off. The through-tubing gravel-pack assembly for this application is shown in Figure 15-27.

SINGLE TRIP THRU-TUBING GRAVEL PACK ASSEMBLY			
NO	FROM	TO	DESCRIPTION
1	13241.02	13241.71	RELEASE SUB
2	13241.71	13244.66	CT-1 PACKER ASSEMBLY
3	13244.66	13247.83	CT-1 CLOSING SLEEVE
4	13247.83	13258.33	LONG STROKE EXTENSION
5	13258.33	13258.85	1.990 AFJ X 1.5 CS BOX CROSSOVER
6	13258.85	13470.12	1.990 AFJ BLANK PIPE
7	13470.12	13470.60	2.375" FJ X 1.990" AFJ CROSSOVER
8	13470.60	13560.58	SCREEN ULTRA PACK 40-60 PRE-PACK
9	13560.58	13561.00	BULLPLUG

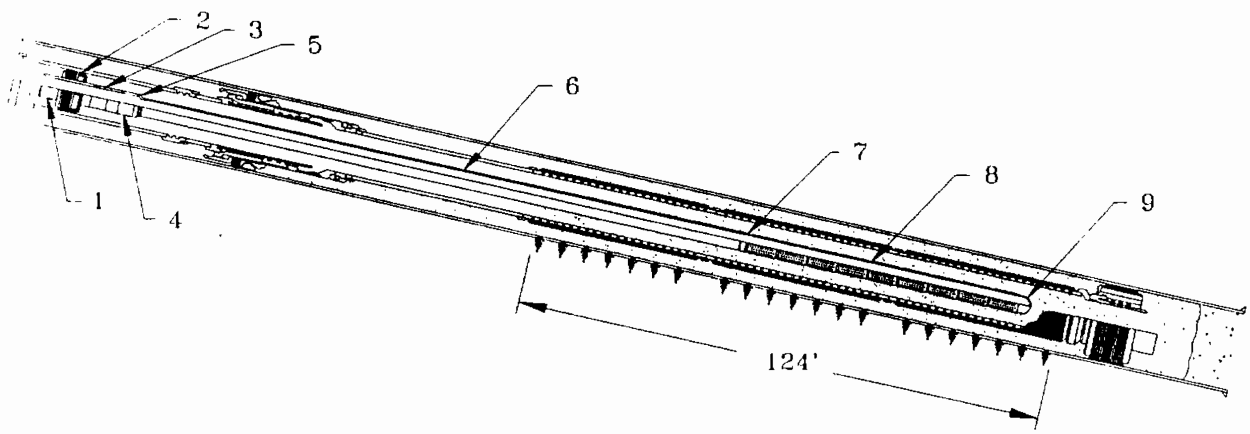


Figure 15-27. Through-Tubing Gravel Pack (Dorman et al., 1994)

Buckling models indicated that coiled tubing would be unable to convey the required 330-ft assembly into place in this high-angle well. For this particular well, a snubbing unit and concentric work string were required.

A service assembly (Figure 15-28) was used to run the completion assembly into the well. The service assembly allowed setting the packer hydraulically, provided a path for pumping sand slurry, and closed the sliding sleeve after the pack was complete.

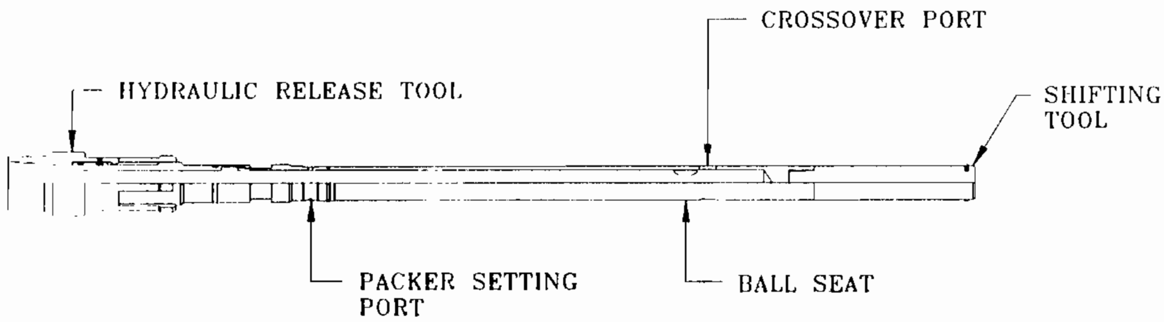


Figure 15-28. Gravel-Pack Service Assembly (Dorman et al., 1994)

The completion assembly (Figure 15-29) was attached to the service assembly by a release sub. The packer used was a mechanical-type packer activated by tubing pressure. A sliding sleeve below the packer seals the gravel-pack ports and locks closed after completion.

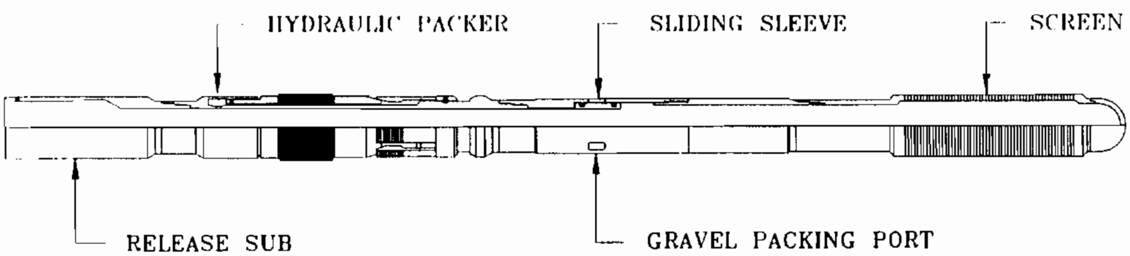


Figure 15-29. Gravel-Pack Completion Assembly (Dorman et al., 1994)

After the assembly is run into position, a ball is circulated downhole. The hydraulic packer is activated at 3000 psi. At 3200 psi, the release sub is activated, disconnecting the service and completion assemblies. At 3500 psi, the ball seat is sheared and a communication path is opened through the port (Figure 15-30), allowing gravel packing.

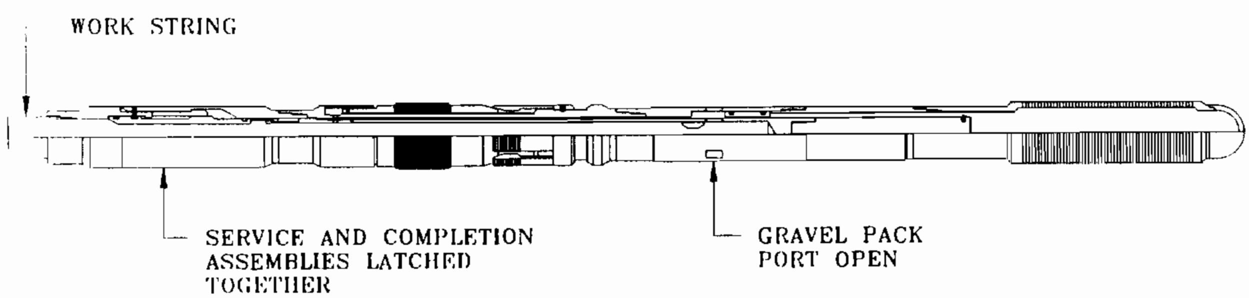


Figure 15-30. Run-In Configuration for Completion and Service Assemblies (Dorman et al., 1994)

This through-tubing gravel pack successfully eliminated sand production. In future activity, Chevron plans to work over several wells at smaller angles and intends to run this system on coiled tubing.

15.3.3 Nowcam Services (Through-Tubing Gravel Packs)

Nowcam Services (Pursell et al., 1993) has had excellent success running gravel-pack assemblies on coiled tubing through production tubing (Figure 15-31). Of a reported 119 jobs performed with their system, over 71% were completed successfully. Most of the failures were due to tight spots in the tubing. Of those placed successfully, 95% were successful producers, that is, exhibited sand-free production sufficient to pay for the workover.

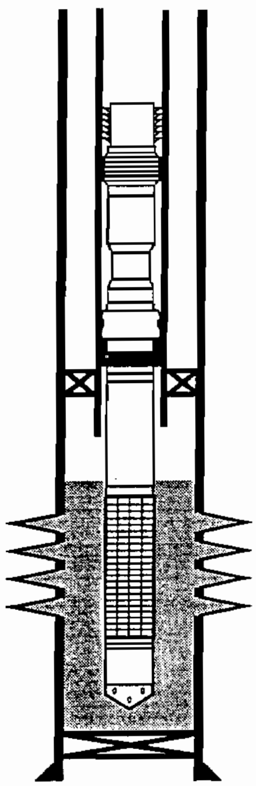


Figure 15-31. Coiled-Tubing Gravel-Pack Assembly (Pursell et al., 1993)

Gravel-pack installation through tubing can be a viable option for wells completed conventionally that later suffer from sand production. In some cases, gravel packs run through tubing are economically justifiable where a conventional gravel-pack installation is not.

Specific parameters must be customized for each installation, based on bottom-hole pressure, existing completion, gravel material, fluids and screen design. Prior to installing the system, the wellbore is cleaned, formation damage is evaluated, and any necessary stimulation performed.

Gravel-pack material is often composed of ceramic beads. Their spherical shape increases mobility of the material and reduces the potential for bridging. The appropriate gravel-pack material is placed across from the formation with either a gel slurry or a downstream injector (Figure 15-32).

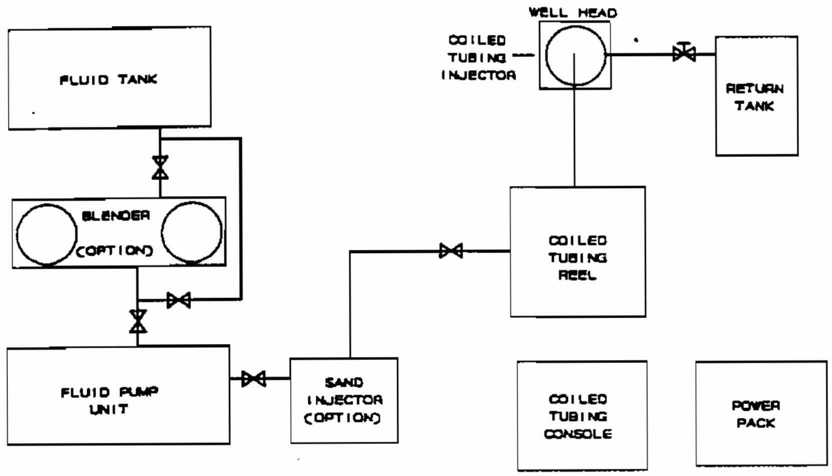


Figure 15-32. Coiled-Tubing Gravel-Pack Surface Equipment (Pursell et al., 1993)

If gel is used to place the material, gel properties should be designed to allow the material to settle in a reasonable time. A downstream injector is another possibility, such that the gravel material is added to the high-pressure fluid before entering the coiled-tubing spool. This method is possible if sufficient velocities can be maintained within the tubing. Significant advantages of the downstream injection method are greatly decreased time waiting for the gravel pack to settle, and reduced formation damage potential.

One of the first steps to install a through-tubing gravel pack on coiled tubing is to make a dummy run to ascertain that the assembly can be run to depth. Next, the gravel-pack material is placed across the perforated interval (Figure 15-33) and squeezed.

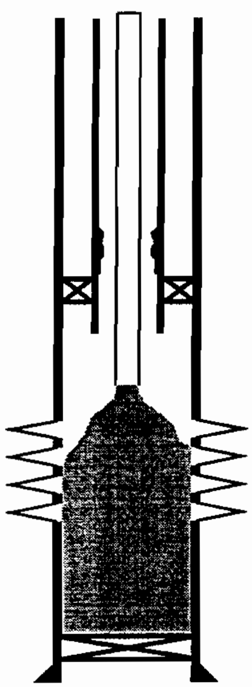


Figure 15-33. Placing Gravel-Pack Material (Pursell et al., 1993)

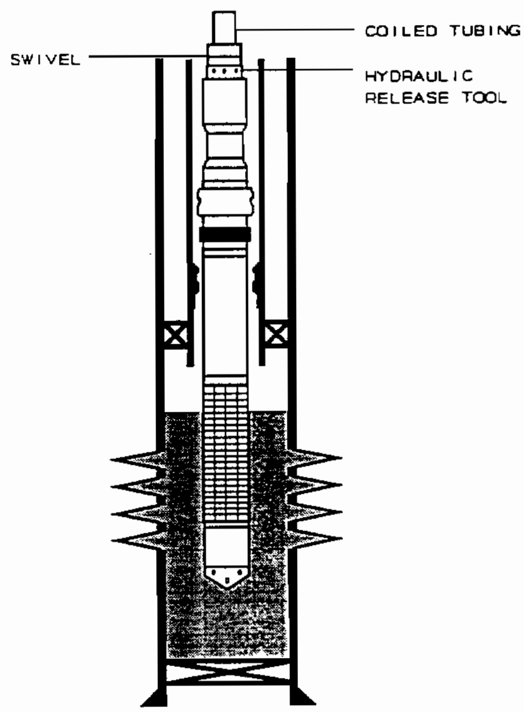


Figure 15-34. Washing Gravel-Pack Assembly into Place (Pursell et al., 1993)

The gravel-pack assembly is then picked up and washed into the gravel (Figure 15-34) until the prepacked screen is across from the perforations. After the assembly is seated, the hydraulic release is activated and the wash pipe is retrieved from the well.

A pack-off and hold-down are then run and stung into the assembly (Figure 15-35). The hold-down serves to keep the assembly in the correct position.

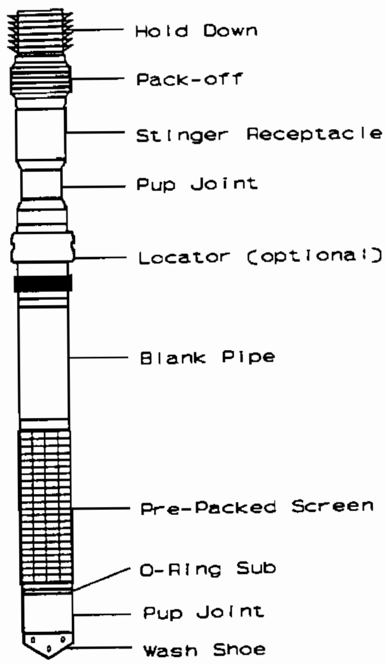


Figure 15-35. Final Gravel-Pack Assembly (Pursell et al., 1993)

15.3.4 Oryx Energy Company (Gravel Packs in GOM)

Oryx Energy Company and Santa Fe Minerals (Plummer et al., 1994) described the success of coiled-tubing gravel-pack operations on several wells in the Gulf of Mexico. Reservoirs in the area have proved to be prone to sand production and often require sand-control treatment. Options available to Oryx include limiting production below sand threshold, conventional workovers for which production tubing is removed, and through-tubing operations using a coiled-tubing rig, hydraulic workover unit, or wireline system.

Oryx worked over twelve wells in 1992 and 1993 using coiled-tubing sand control (Table 15-4). Results were generally positive. Six of these operations were economic successes; two more were mechanical successes. The total project costs were paid out in 40 days. The most cost-efficient offshore job was performed for less than $58,000.

TABLE 15-4. Oryx Coiled-Tubing Gravel-Pack Jobs (Plummer et al., 1994)

WELL	COST M$	BEFORE			AFTER			INCREMENTAL		
		MCFPD	BOPD	BWPD	MCFPD	BOPD	BWPD	MCFPD	BOPD	PAYOUT (DAYS)
VERM 320 A-5	145	Shut-In			Shut-In					-
WC 639 A-20D	85	750	0	17	Shut-In			-750	0	-
HUMPREYS #7	18	Shut-In			120	10	53	120	10	46
EI 380 A-3Z	63	500	0	0	1,000	0	0	500	0	77
EI 380 A-10D	84	200	0	1	Shut-In			-200	0	-
WC 648 A-10	175	Shut-In			1,400	29	1	1,400	29	62
HI 166 A-4	58	Shut-In			6,500	53	590	6,500	53	5
HI 120 A-1	160	Shut-In			5,500	19	8	5,500	19	17
HI 167 A-2	200	Shut-In			5,600	17	13	5,600	17	22
HI 167 A-3	55	Shut-In			Shut-In					-
HI 134 A-3	105	Shut-In			Shut-In					-
HI 166 A-4	155	Shut-In			Shut-In					-
TOTAL	1,303	1,450	0	18	20,120	128	665	18,670	128	40

PAYOUT CALCULATIONS BASED ON $1.60/MCF AND $20/BO

The through-tubing gravel-pack (Figure 15-36) installation technique used was the wash-in method. This technology was chosen based on mechanical reliability and integrity, cost, and flexibility. Additionally, uniform treatment of the interval is not essential.

The primary advantage of through-tubing gravel packs is cost. In some cases, the total cost to install a gravel pack with coiled tubing is less than mobilization costs for a workover rig. Disadvantages of through-tubing packs include sensitivity to wellbore conditions and flow restrictions caused by small screens.

The wells chosen by Oryx and Santa Fe for through-tubing gravel packs were sanded up or severely restricted due to sand. These wells represented a broad range of reservoir and wellbore conditions. Reservoir pressures ranged from about 1000 to 4600 psi; equivalent fluid weights were between 3.7 and 10.4 ppg.

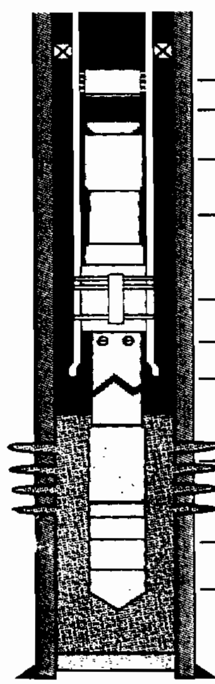


Figure 15-36. Oryx Through-Tubing Gravel Pack (Plummer et al., 1994)

Specific results for several of the through-tubing gravel pack jobs are detailed in Plummer et al. (1994). A few example results are presented below.

Humphreys #7 (see Table 15-4) had been shut in due to sand production. A resin consolidation treatment was performed but failed within a few weeks. Bailing runs before a through-tubing gravel pack showed that the casing was full of the gravel pumped in for the resin procedure. The operator decided to wash the gravel pack into the sand already in place. Total workover cost was $18,000 and the procedure was successful (Figure 15-37).

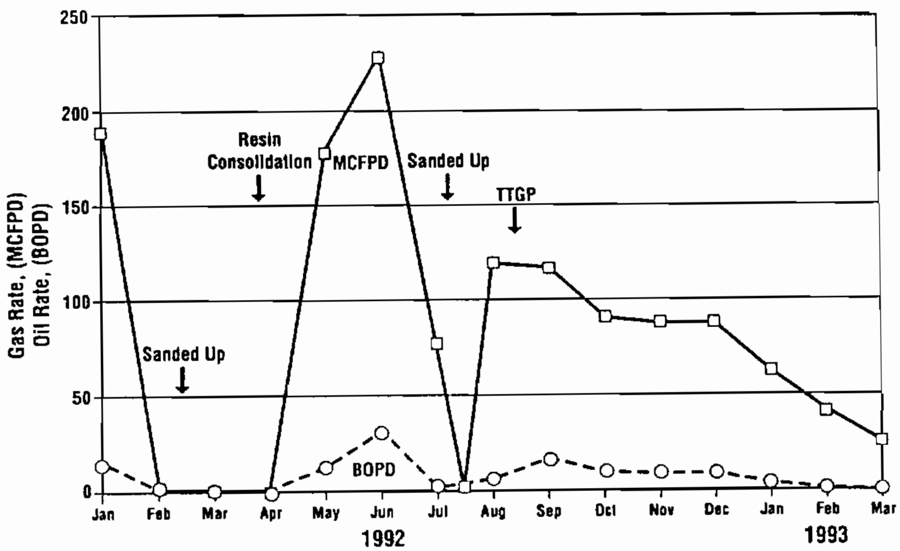


Figure 15-37. Humphreys #7 Through-Tubing Gravel-Pack Results (Plummer et al., 1994)

In another well, a through-tubing gravel pack initially increased production by 500 Mscfd (Figure 15-38). Later, a pressure transient test showed a relatively high pressure drop across the completion. After the formation was acidized, production increased substantially.

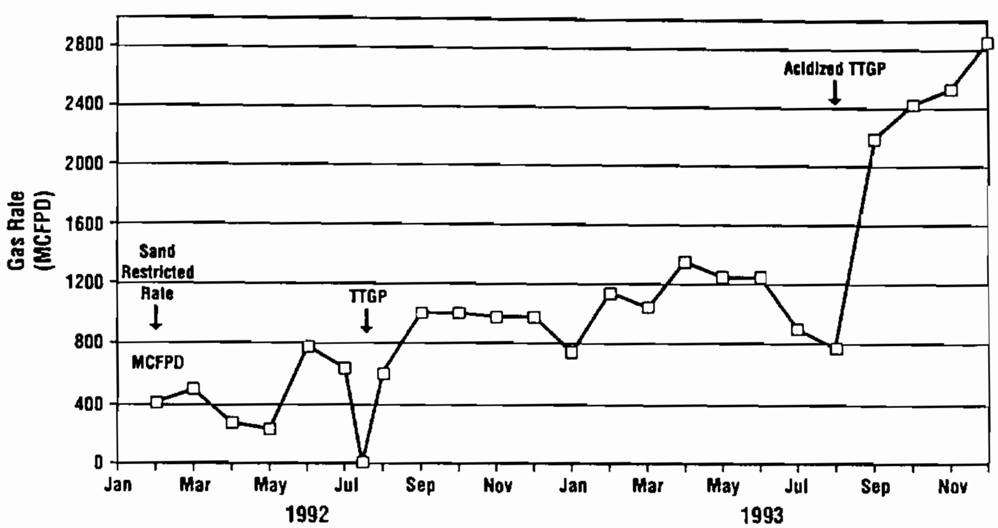


Figure 15-38. EI 380 A-3Z Through-Tubing Gravel-Pack Results (Plummer et al., 1994)

The well HI 166 A-4 had been shut in due to sand production. Intermediate strength proppant was placed in the well and a sintered metal-wrapped screen was washed into place. Production was significantly improved (Figure 15-39). Later, the screen failed after cumulative production of 2.9 Bcf. The through-tubing gravel pack was pulled and another assembly run in.

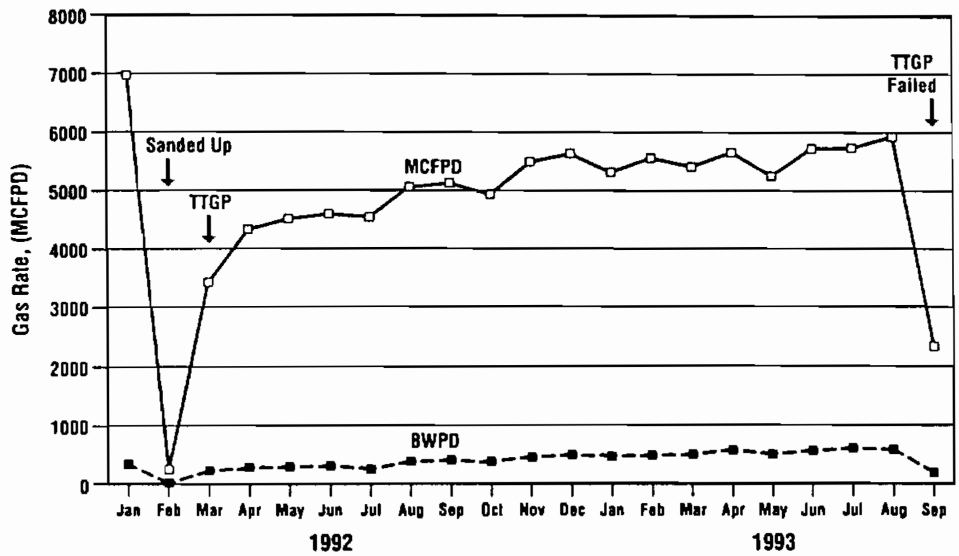


Figure 15-39. HI 166 A-4 Through-Tubing Gravel-Pack Results (Plummer et al., 1994)

15.4 SCALE REMOVAL

15.4.1 <u>BP Exploration (Coiled Tubing in Magnus Field)</u>

BP Exploration (Bedford and Divers, 1994) have increasingly used coiled-tubing workovers in the Magnus Field in the northern North Sea. The field was developed initially between 1983 and 1986. Twenty wells have been drilled to date. Most wells are prolific, ranging from 20,000 to 60,000 BPD. A typical completion for the field is shown in Figure 15-40.

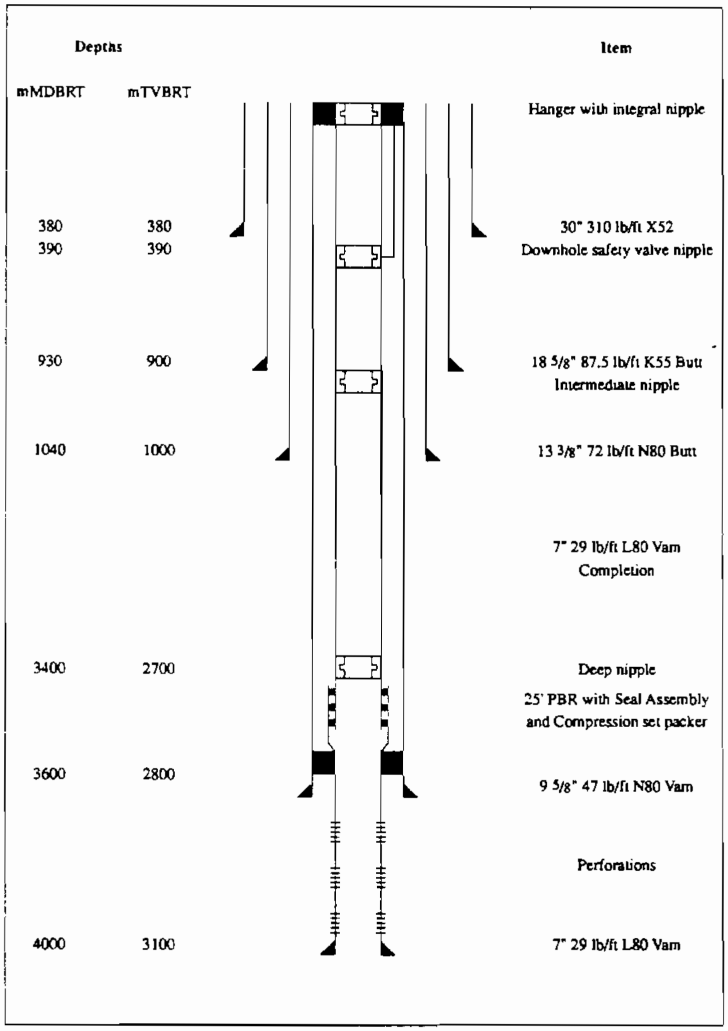


Figure 15-40. Magnus Field Typical Completion (Bedford and Divers, 1994)

During the past several years, the number and variety of well interventions in the Magnus Field using coiled tubing have increased dramatically (Table 15-5).

TABLE 15-5. Coiled-Tubing Operations in Magnus Field (Bedford and Divers, 1994)

Well	Job	Start Date	Depth m/MDBRT	Runs Plan	Runs Actual	Objectives Met	Objectives Set	Oil Recov. (BBL)
B7	Diesel Lift	22/11/87	3000	1	1	1	1	
B1	Diesel Lift	20/03/88	3750	1	1	1	0	
	Acid Wash			1	1	1	0	
A5	Nitrogen Cushion	08/12/88	3034	1	1	1	1	
A2	Nitrogen Lift	27/02/89	1829	1	1	1	1	
C6	Nitrogen Lift	06/12/89	2100	1	1	1	1	
C5	Nitrogen Lift	31/05/90	2000	1	1	1	1	
B5	Nitrogen Lift	17/12/90	2070	1	1	1	1	
A4	Nitrogen Cushion	15/02/91		1	2	1	1	
A4	Nitrogen Lift	19/02/91		1	1	1	1	
B5	Nitrogen Lift	21/02/91	2000	1	2	1	1	
A6	Sand Cleanout	20/04/91	3830	1	3	1	1	
A1	Sand Cleanout	22/06/91	5257	1	1	1	1	
B5	Nitrogen Lift	10/09/91	3289	1	1	1	1	
	Cement Plug	12/09/91	3289	1	1	1	1	
	Millout Cement	14/09/91	3174	1	3	1	1	
	Nitrogen Lift	21/09/91	2500	1	1	1	1	
A7	Nitrogen Cushion	16/03/92	1600	1	3	1	1	
	Nitrogen Lift	30/03/92	2700	1	1	1	1	
B1	Cement Plug	12/04/92	4394	1	1	2	2	
B1	Reverse Cleanout	28/08/92	4394	1	3	1	1	
	Nitrogen Cleanout	31/08/92	4000	1	1	2	2	
B7	Barium Millout	12/02/93	4470	1	2	1	1	1,300,000
B1	Sand Cleanout	23/02/93	4831	1	1	1	1	64,100
	Fish Perf Gun	25/02/93	4831	1	2	1	1	
B7	Barium Millout	16/05/93	5120	1	1	1	1	281,430
A1	Barium Millout	22/05/93	5158	1	1	1	0	-70,000
	Isolate W/packer	31/05/93	5120	1	1	1	1	
	Nitrogen Lift	01/06/93	4000	1	1	1	1	
A1	Nitrogen Lift	18/07/93	4000	1	1	1	1	
B5	Abandon	15/08/93	3148	2	2	3	3	
B5	Perforate	01/11/93	5187	4	4	3	3	
B7	Scale Millout	14/11/93		1	4	2	2	200,000
C7	Scale Cleanout	03/12/93	3120	1	1	1	1	
	Fish Lock	05/12/93	3120	1	4	1	0	
	Isolate W/Packer	10/12/93	3246	1	1	1	1	
	Punch & Kill Well	11/12/93	3098	1	1	1	1	

Most of these jobs have been at considerable depths, ranging from about 3000–5257 m (9840–17,247 ft). A total of 37 jobs have been performed with a combined total of 59 runs. Within these 37 jobs, 45 objectives were defined. Of these objectives, 91% were met successfully.

Water injection is used for pressure maintenance. Thermal fracturing and variations in permeability have resulted in water breakthrough in discrete intervals. Water breakthrough has also caused increased sand production, which loads the liner and surface facilities and erodes piping.

Water production also leads to the formation of barium sulphate, which collects across the perforations and at flow restrictions (SSSVs, wireline profiles, etc.). Scaling can cause production to drop from 30,000 to 5000 BPD in the space of a few days.

Water production also increases the hydrostatic pressure of the wellbore fluid column. If the water cut exceeds 40-60%, the well can become loaded and die. Corrosion and erosion have also been problems, especially in injection wells. All injection wells have developed holes in the completion tubing, and wall loss in the upper half can range from 20-60%.

These production problems have been addressed by an increasing number of coiled-tubing workovers (Figure 15-41). Significant working depths and crane limitations have led to the use of relatively small coiled tubing: 1¼- and 1½-in. 70- and 80-ksi tapered strings.

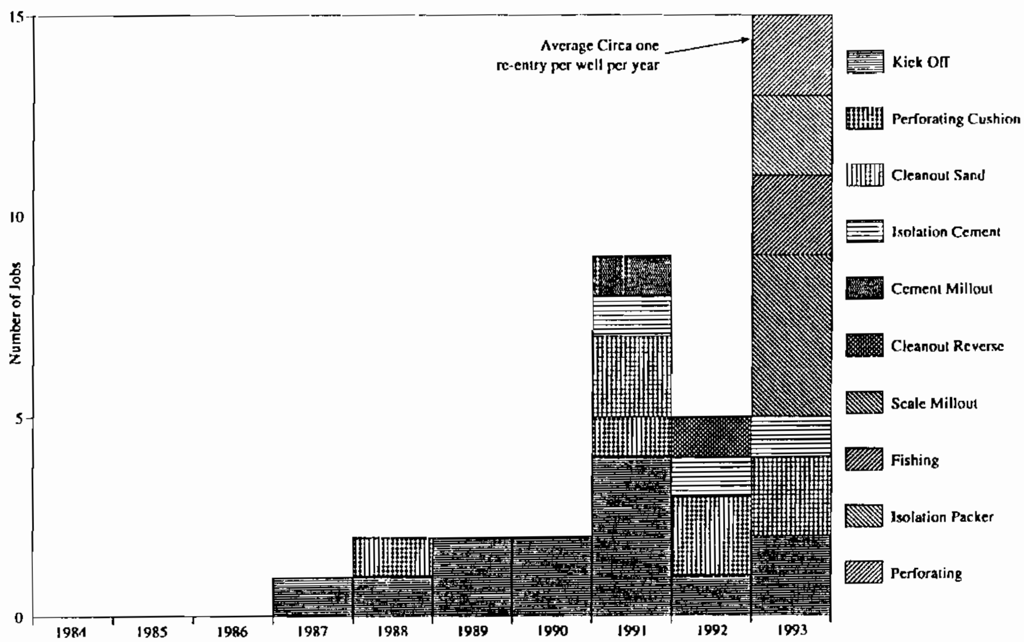


Figure 15-41. Frequency of Coiled-Tubing Operations (Bedford and Divers, 1994)

The formation of barium sulphate scale has proved to be at times a problem and at other times of benefit. In some cases, zones where water has broken through have been naturally shut off by scale formation. In other wells, scale has shut off oil production.

The first scale underreaming job was performed in February 1993. Four jobs have been performed in two wells. In one well, production became erratic following water breakthrough in 1989. Production fell dramatically in October 1992 (Figure 15-42).

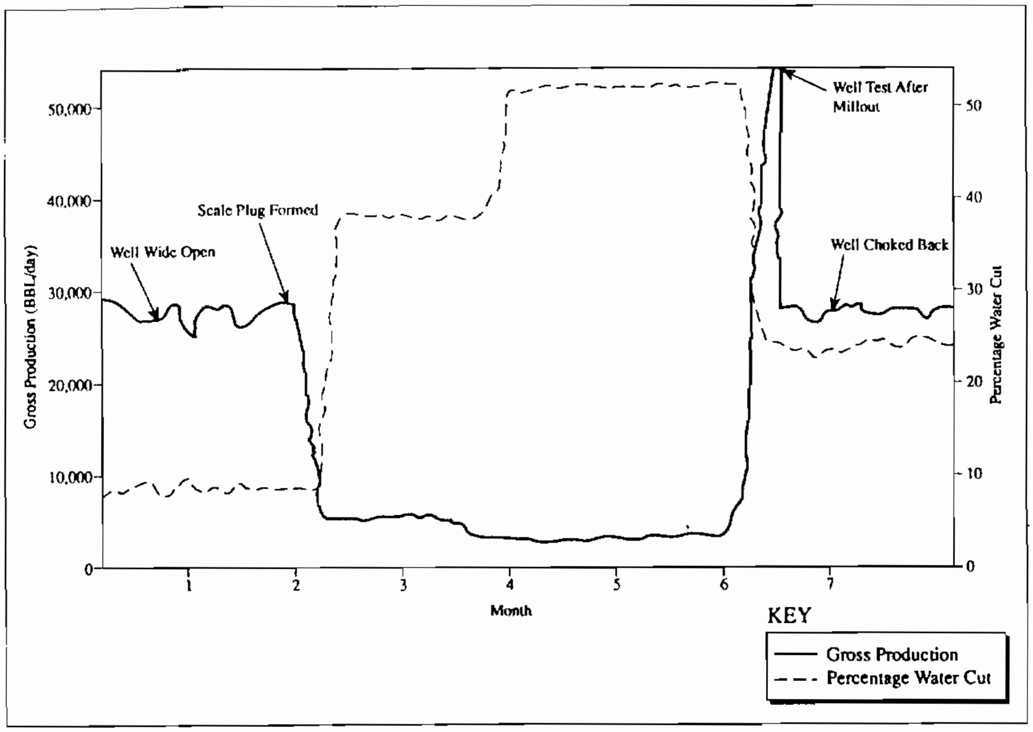


Figure 15-42. Production of Well With Barium Sulphate Scale (Bedford and Divers, 1994)

A production log was run to plan remedial action. The log showed that all production was coming from the uppermost zone (Figure 15-43). Barium sulphate was identified at a nipple.

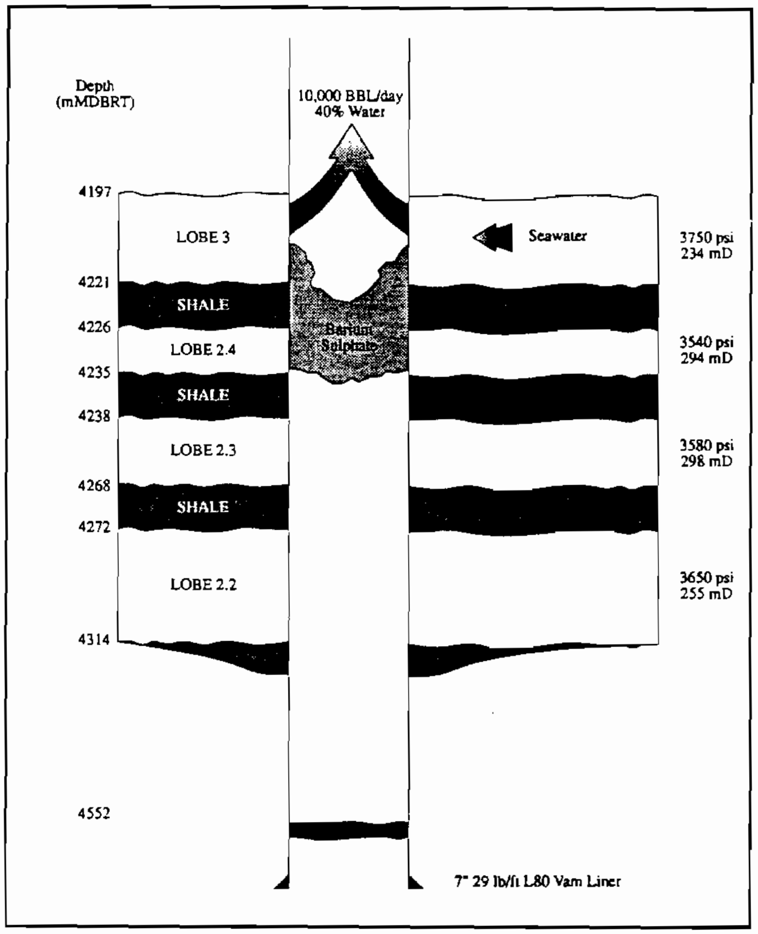


Figure 15-43. Scaling From Water Breakthrough
(Bedford and Divers, 1994)

To remove the scale, a 2⅛-in. bottom-hole assembly consisting of connector, dual flapper valves, hydraulic disconnect, 2⅞-in. motor and 3.2-in. diamond bit was run on a 1½-in. string of 80 ksi coiled tubing with four tapers. After tagging the scale, the coiled tubing was pulled up 5 m. Production was established at a rate of about 10,000 BPD. The assembly was then run slowly through the scale, alternating with frequent wiper trips.

Underreaming was performed along about 400 m of the wellbore. About 32 m were classified as hard milling. The operation was very successful. The well flowed at over 53,000 BPD during a well test after the job (see Figure 15-42).

After the scale removal, the well produced at 28,000 BPD for two months. Scale formed again and production was cut off. Two more scale removal jobs have been successfully performed in this well to re-establish production.

BP Exploration reached several conclusions as a result of the coiled-tubing operations at Magnus Field:

- Rather than using nitrogen injection to assist with hole cleaning, BP found that well production of 10,000+ BPD combined with pills have been successful. Nitrogen was seen to dry out motor bearings on one of the earliest jobs.
- Barium sulphate returns have caused no problems at surface or in processing facilities.
- Performance of downhole motors has been erratic.

Economics of these coiled-tubing workovers has been very favorable. The impact of these jobs on the field's production has been dramatic due to the relatively small number of high-productivity wells. Rig costs deferred by coiled-tubing operations have been substantial (Figure 15-44).

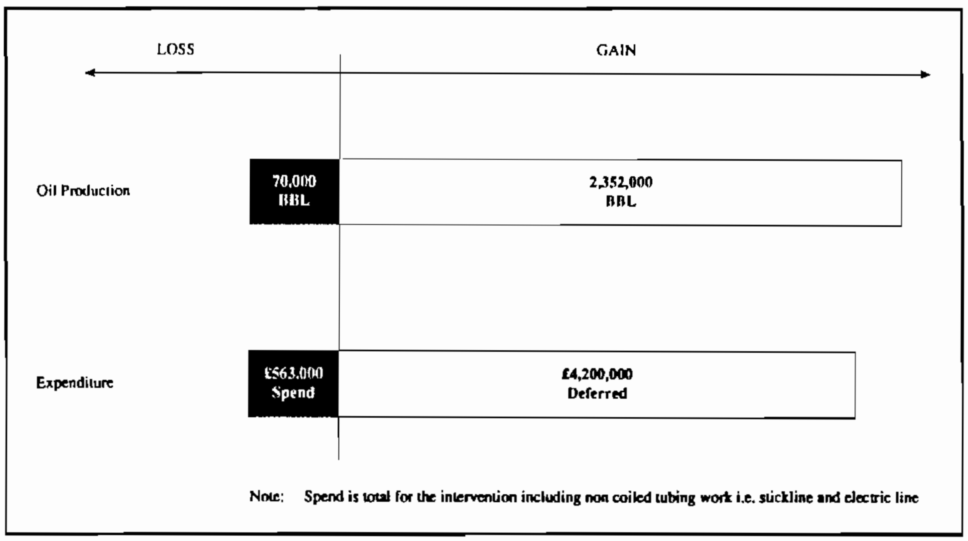


Figure 15-44. Economics of Coiled-Tubing Workovers (Bedford and Divers, 1994)

An analysis of cost data indicates a cost/benefit ratio of about $0.37/bbl oil production added. Lost production in Figure 15-44 was caused by high water production following a barium sulphate underreaming job. The mill uncovered a previously scaled-over water interval, which then produced enough water to kill the well.

15.4.2 Halliburton/Amoco (Scale Removal from High-Pressure Wells)

High-strength coiled tubing was successfully used to clean out scale from three high-pressure gas wells in the Gulf of Mexico (Coats and Tatarski, 1993). Zinc sulfide had plugged off the wells and was removed using jetting and impact drilling operations run on coiled tubing. Significant cost savings were enjoyed by the operator (Amoco) for these workovers.

Due to the high shut-in pressures (>7000 psi), high-strength coiled tubing was required for these jobs. Tubing specifications are summarized in Table 15-6. Prior to the field work, jetting parameters were modeled, which indicated that injection pressure would be in the range of 7500 psi. For reasons of safety, 100-ksi coiled tubing was required.

TABLE 15-6. Properties of High-Strength Coiled Tubing (Coats and Tatarski, 1993)

O.D. (In.)	Wall (In.)	I.D. (In.)	Weight (lb/ft)	Area (Sq.-In.)	Yield Load (Lb)	Yield Press (PSI)	Burst Press (PSI)
1.250	0.087	1.076	1.081	0.318	31,790	13,900	14,500
Torque (Ft-Lb)	**Capacity Gal/1000'**	**Capacity BBL/1000'**	**Collapse Pressure (PSI)**				
			Axial Load	**% Yield**	**Round**	**1% OD TIR**	**2% OD TIR**
721	47.24	1.125	None	0%	13,300	8,600	4,400

Surface equipment for these three jobs (Figure 15-45) included some modifications to the basic set-up due to the expected high pressures. A guide tube was added below the injector to provide support for the tubing between the bottom of the chains and the stuffing box.

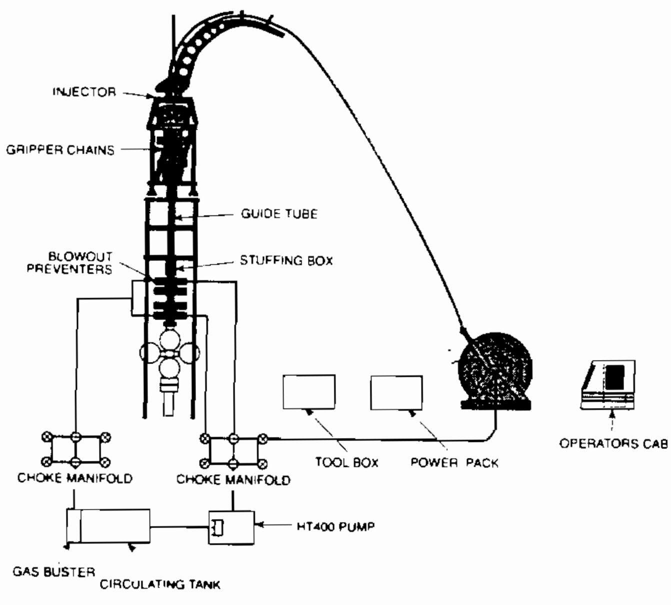


Figure 15-45. Surface Equipment for High-Pressure Workover (Coats and Tatarski, 1993)

A standard 10,000 psi coiled tubing BOP stack was used as a secondary BOP system in conjunction with a 15,000 psi stack placed on the tree (Figure 15-46).

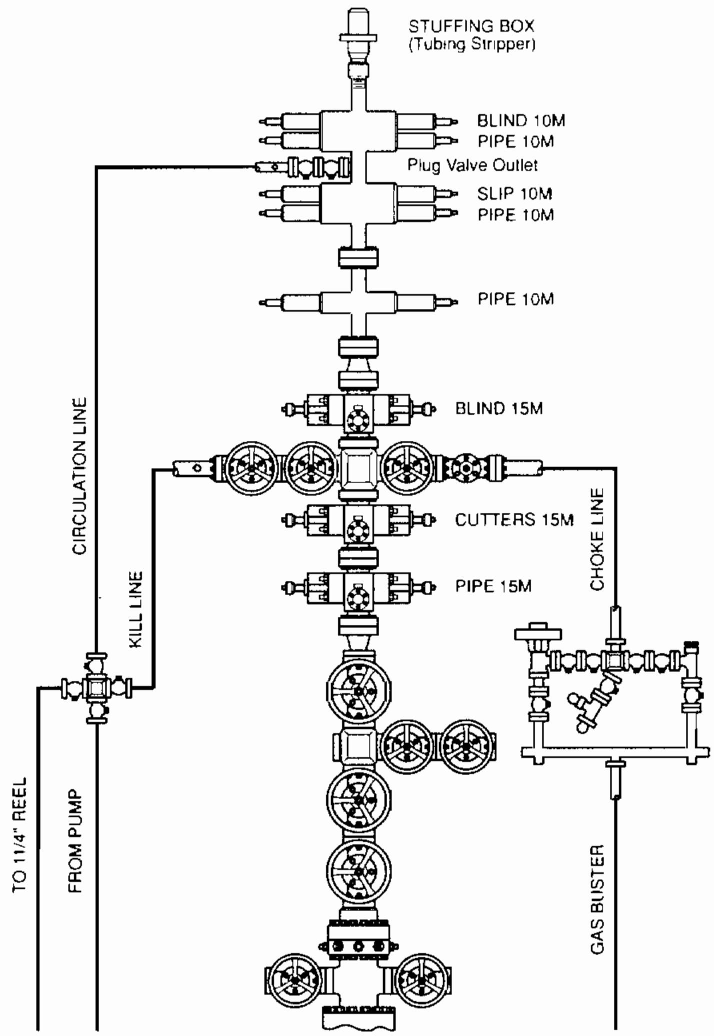


Figure 15-46. Surface Well-Control Equipment (Coats and Tatarski, 1993)

The first well treated had declined in production from 13 MMscfd to 0 during a 2-week period. The wellbore schematic is shown in Figure 15-47.

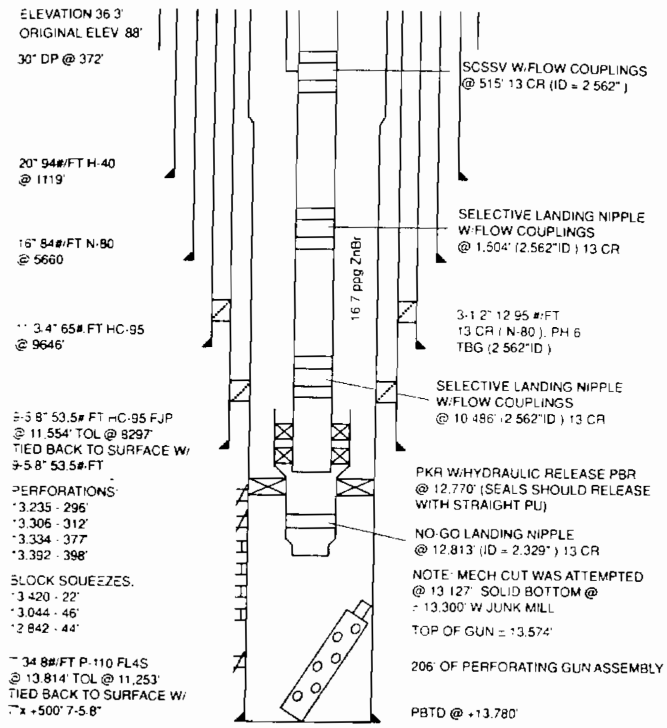


Figure 15-47. Wellbore Schematic (Coats and Tatarski, 1993)

As a first step, the well was loaded with 9.2 ppg NaCl water, which lowered the shut-in surface pressure to 2500 psi. A jetting assembly was run in to clean out scale. Pumping rates of about 1 BPM at 7500 psi were used. Next, an impact drill (Figure 15-48) was used to speed scale removal.

HCl was spotted across the formation for final clean-up. After the well was put back on production, a stabilized rate of 26 MMscfd was measured with a flowing tubing pressure of 6150 psi.

The second well that was treated had been gravel packed and pulled back from 40 to 20 MMscfd to decrease sand production. Later, the well scaled over with zinc sulfide and required a workover. A major conventional workover was considered at an estimated cost of $3.3 million.

A coiled-tubing workover was performed instead. This well could not be loaded by bullheading. Fluid had to be circulated with coiled tubing against a shut-in surface pressure of 5100 psi. Halliburton found that this operation would not have been possible without high-strength coiled tubing.

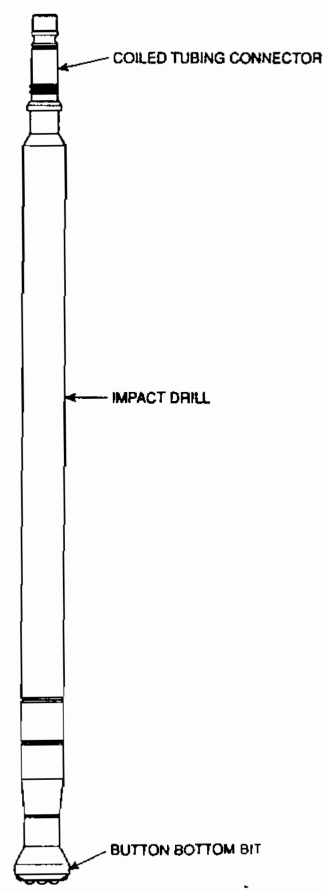


Figure 15-48. Impact Drill BHA (Coats and Tatarski, 1993)

After jetting and acidizing the well, production improved to 23 MMscfd with 6160 psi flowing tubing pressure. Workover costs with coiled tubing totaled $152,000.

A combination of jetting, acid soaking, and impact drilling was used to successfully clean out a third well. Production was restored to over 19 MMscfd at a cost of $125,000.

Production rates and coiled-tubing workover costs are summarized in Table 15-7. Cost estimates for conventional workovers for wells 5 and C-6 totaled almost $6 million. Coiled-tubing operations were performed at a cost of 5-6% of conventional.

TABLE 15-7. Production Rates and Costs for Three Wells (Coats and Tatarski, 1993)

Well Number	Original Production	Production Before Repair	Production After Repair	Cost of Repair
C-1	13 MMscfd	0	25.7 MMscfd	$ 80,000
5	20 MMscfd	0.3 MMscfd	23.4 MMscfd	$152,000
C-6	11 MMscfd	3 MMscfd	19.5 MMscfd	$125,000
Cumulative Totals	44 MMscfd	3.3 MMscfd	68.6 MMscfd	$357,000

15.4.3 SlimDril International (Underreaming)

Underreaming on coiled tubing has been very successful for cement squeeze/reperforation operations in various areas, particularly remote locations (Werner and Pittard, 1993). The primary advantage is that this approach eliminates the need to remove production tubulars. As a result, the well can be placed back on production much faster.

Underreaming with coiled tubing increases operational safety by removing almost all residual cement after several passes with the assembly. The risk of losing tools (guns, etc.) in the hole due to cement collapse is greatly reduced.

Natural diamond bits are used extensively in coiled-tubing underreaming. These improve hole stability and reduce vibration as compared to tungsten-carbide mills. For drilling metal or junk, a tungsten-carbide wavy-bottom mill (Figure 15-49) has been used successfully. Its low profile lowers the tendency to stall the motor.

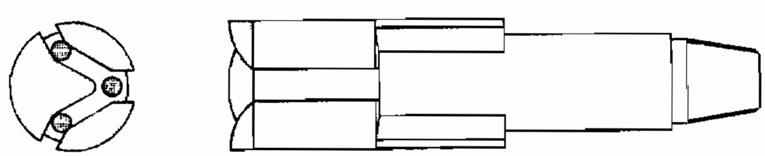


Figure 15-49. Wavy-Bottom Mill (Werner and Pittard, 1993)

Underreamers run on coiled tubing are most often designed with four blades (Figure 15-50). The upper blade set serves to stabilize the underreamer. The blades are usually tipped with tungsten carbide. Hard materials can be cut with diamond-tipped blades (either natural or synthetic).

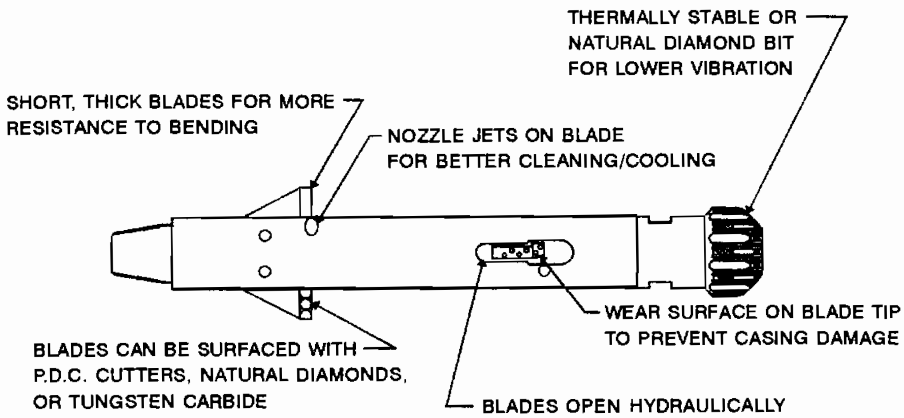


Figure 15-50. Four-Bladed Underreamer (Werner and Pittard, 1993)

Positive-displacement motors are used to power the underreamer. In coiled-tubing operations, high-speed low-torque motors are generally preferred. These provide a high rate of penetration with low weight on bit.

A circulating sub (Figure15-51) is run above the motor to allow fluid to bypass the motor both during underreaming (partial bypass) and after the operation (complete bypass).

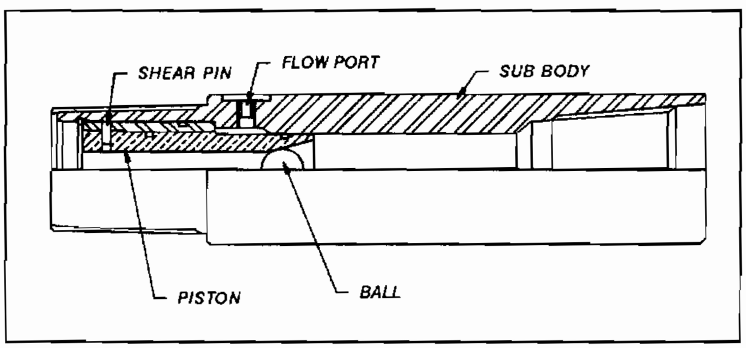


Figure 15-51. Circulating Sub (Werner and Pittard, 1993)

Typical coiled-tubing underreamer sizes and hole capability are summarized in table 15-7.

TABLE 15-7. Coiled-Tubing Underreamers (Werner and Pittard, 1993)

Underreamer Size	Minimum Restriction	Maximum Hole Size
3⅝ in.	4½ in.	6–8⅝ in.
1¾ in.	2⅞ in.	4½ in.

A typical coiled-tubing underreaming bottom-hole assembly is shown in Figure 15-52. Most projects have used either 1½- or 1¾-in. coiled tubing. Over 120 wells have been underreamed with coiled-tubing in Prudhoe Bay. Other areas where the technology has been used include West Texas, Brunei, Malaysia and Indonesia.

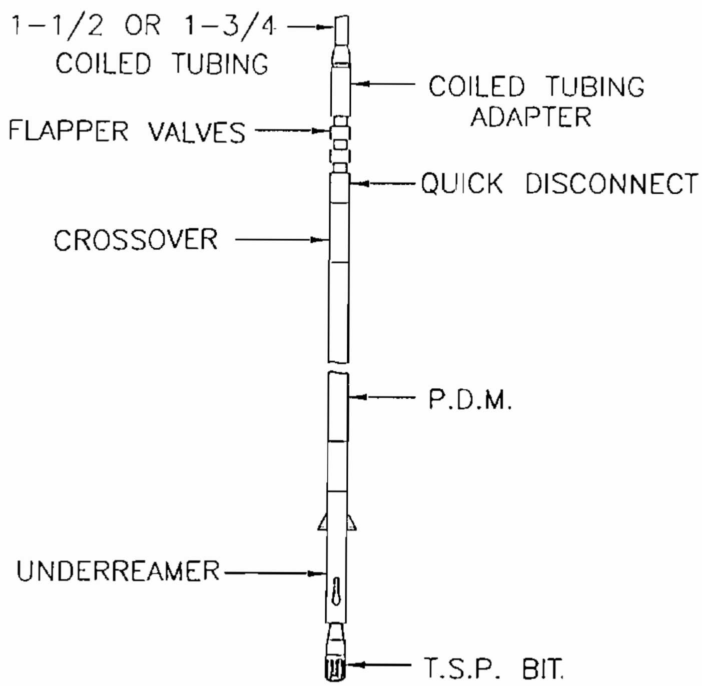


Figure 15-52. Coiled-Tubing Underreaming BHA (Werner and Pittard, 1993)

Overall experience with coiled-tubing underreaming suggests that the most cost-effective operations are in the most remote locations. For areas particularly suited to coiled-tubing operations, such as the North Slope, cost savings of up to 85% over conventional procedures have been demonstrated. In areas where workover rigs are abundant and coiled-tubing rigs are scarce, cost savings may only be minimal.

15.5 WASHING/JETTING

15.5.1 BP Exploration (Fill Cleanouts)

BP Exploration (Melvan, 1994) described the design and equipment used for wellbore cleanouts with coiled tubing in their North Slope operations. Coiled tubing has been used for cleanouts in a wide range of tubing sizes (up to 9⅝ in.) in vertical, horizontal, producers, injectors, and hydraulically fractured wells. The parameters that BP Exploration has found to be most important in job design are: coiled-tubing size, type of fill, fluid selection, friction reducers, nozzles, gas requirements for lifting, and high-viscosity sweep agents.

Two principal methods have been used by operators on the North Slope. These are:

- Long-way circulation—conventional circulation down the coiled tubing and up the annulus. This is performed on live wells.
- Reverse outs—circulation down the coiled tubing by production tubing annulus and up the coiled-tubing string. These are only performed on dead wells. The most common of these operations is in wells that have been hydraulically fractured and have large amounts of proppant remaining in the wellbore.

Reverse outs are not performed in live wells to avoid excessive discharge of oil and gas to surface fluid tanks. If performed on a live well, high velocities in the coiled-tubing string could cause severe erosion of the interior of the string. Reverse-out jobs are maintained at a maximum collapse pressure of 2000 psi.

For cleanout jobs in production tubing of 4½ in. or larger, BP Exploration normally uses 1¾-in. coiled tubing to maximize circulation rate and annular velocity. One and one-half in. tubing is also used, and more time is allowed to safely clean out a comparable amount of fill. Properties of these strings are summarized in Table 15-9

TABLE 15-9. Coiled Tubing for Cleanouts (Melvan, 1994)

TUBE DIMENSIONS (Inches)			WEIGHT (LB/FT)	LOAD CAPACITY (LBS)		PRESSURE CAPACITY (PSI)		
O.D.	I.D.	WALL		YEILD	ULTIMATE	YIELD	BURST	COLLAPSE
NOM.	NOM.	NOM.	NOM.	MIN.	MIN.	MIN.	MIN.	MIN.
1.50	1.282	0.109	1.619	33340	38100	9700	12220	9430
1.75	1.532	0.109	1.910	39330	44950	8320	10380	7260

TUBE DIMENSIONS (Inches)			TORQUE (LB-FT)		INTERNAL CAPACITY (PER 1000 FT)		EXTERNAL DISPLACEMENT (PER 1000 FT)	
O.D.	I.D.	WALL	YIELD	ULTIMATE				
NOM.	NOM.	NOM.	NOM.	NOM.	GALS.	BBLS.	GALS.	BBLS.
1.50	1.282	0.109	902	1202	67.06	1.597	91.80	2.186
1.75	1.532	0.109	1267	1689	95.76	2.280	124.95	2.975

Notes: 1. The effect of Axial Tension on Pressure Rating has not been applied to the above data.
2. Above data is for new tubing at minimum strength.

Jetting nozzles are designed for the particular type of operation. For cleanouts in live wells, swirl nozzles are used. These usually include upward-pointing jets for back jetting while pulling out of hole. Typical nozzle performance for long-way circulation is shown in Table 15-10.

TABLE 15-10. Cleanout Nozzle for Long-Way Circulation (Melvan, 1994)

Jetting Nozzle:

HOLE DIAMETER 1	0.125 IN.	Nº OF HOLES	4
HOLE DIAMETER 2	0.1875 IN.	Nº OF HOLES	4
HOLE DIAMETER 3	0.125 IN.	Nº OF HOLES	4
FLUID DENSITY:	8.55 PPG	Seawater	
AREA THROUGH NOZZLES:		0.20862 SQ IN.	

Pump Rate (BPM)	Jet Velocity (Ft/Sec)	Press Drop (psi)	Impact Force (Lbf)
0.25	16	2	1
0.50	32	8	3
0.75	48	18	7
1.00	65	32	12
1.25	81	50	19
1.50	97	72	27
1.75	113	98	37
2.00	129	128	48
2.25	145	162	61
2.50	161	199	75
2.75	177	241	91
3.00	194	287	108

BP Exploration recommends that nozzle diameter not exceed 2¾ in. for long-way circulation. Solids bridging above a larger nozzle can result in high overpulls during retrieval.

For reverse-out jobs, a nozzle from 2¾ to 3¼ in. is normally used. Larger jets (Table 15-11) are required since the solids have to pass through the jet into the coiled tubing. Jets on the side of the nozzle (¼ in.) allow reverse circulation to continue even if the tool is set down on the fill.

TABLE 15-11. Cleanout Nozzle for Reverse Outs (Melvan, 1994)

Reversing Nozzle:

HOLE DIAMETER 1	0.25 IN.	Nº OF HOLES	4
HOLE DIAMETER 2	0.75 IN.	Nº OF HOLES	1
HOLE DIAMETER 3	0.156 IN.	Nº OF HOLES	0
FLUID DENSITY:	8.55 PPG	Seawater	
AREA THROUGH NOZZLES:		0.63814 SQ IN.	

Pump Rate (BPM)	Jet Velocity (Ft/Sec)	Press Drop (psi)	Impact Force (Lbf)
0.25	5	0	0
0.50	11	1	1
0.75	16	2	2
1.00	21	3	4
1.25	26	5	6
1.50	32	8	9
1.75	37	10	12
2.00	42	14	16
2.25	47	17	20
2.50	53	21	25
2.75	58	26	30
3.00	63	31	35

Water-soluble polymer friction reducers are recommended to reduce the pressure drop in the circulation system (Figure 15-53. Typical concentrations are 10-15 gal per 300 bbl for 1½-in. tubing and 5-10 gal per 300 bbl for 1¾-in. tubing.

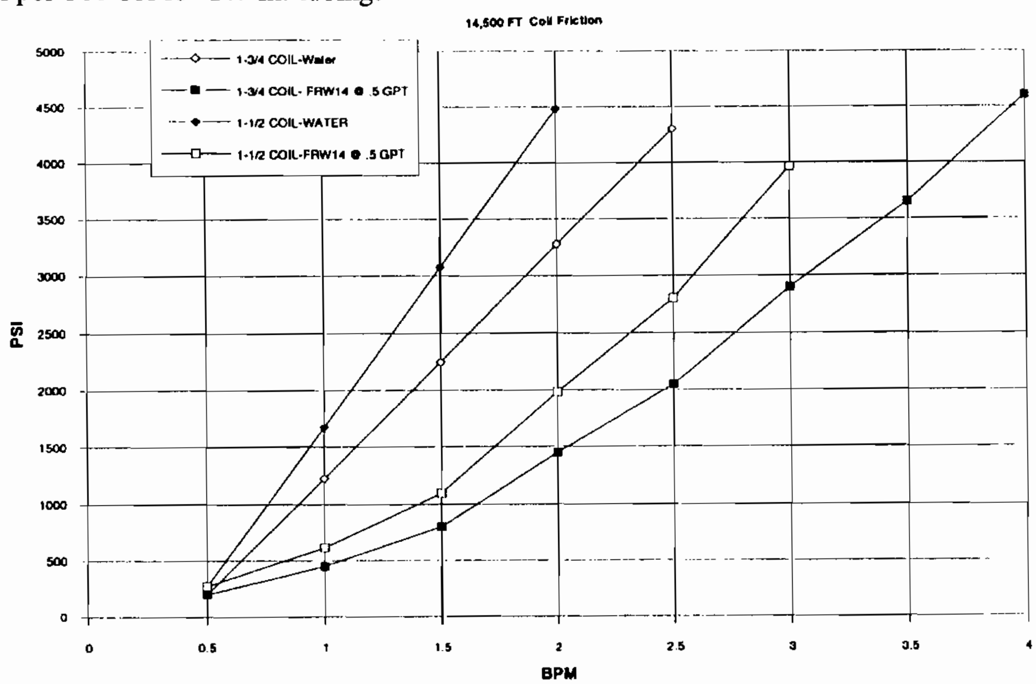


Figure 15-53. Pressure Drops with Friction Reducers (Melvan, 1994)

Water often lacks sufficient carrying capacity for removing solids. BP Exploration recommends adding biozan, a high-viscosity polymer that is shear-thinning. Concentrations of 3–3½ lb/bbl are typical.

Gas lift is necessary on wells with low GOR when circulating up the annulus. A flow-back separator (Figure 15-54) is used to take well returns and permit recirculation of some of the treatment fluids.

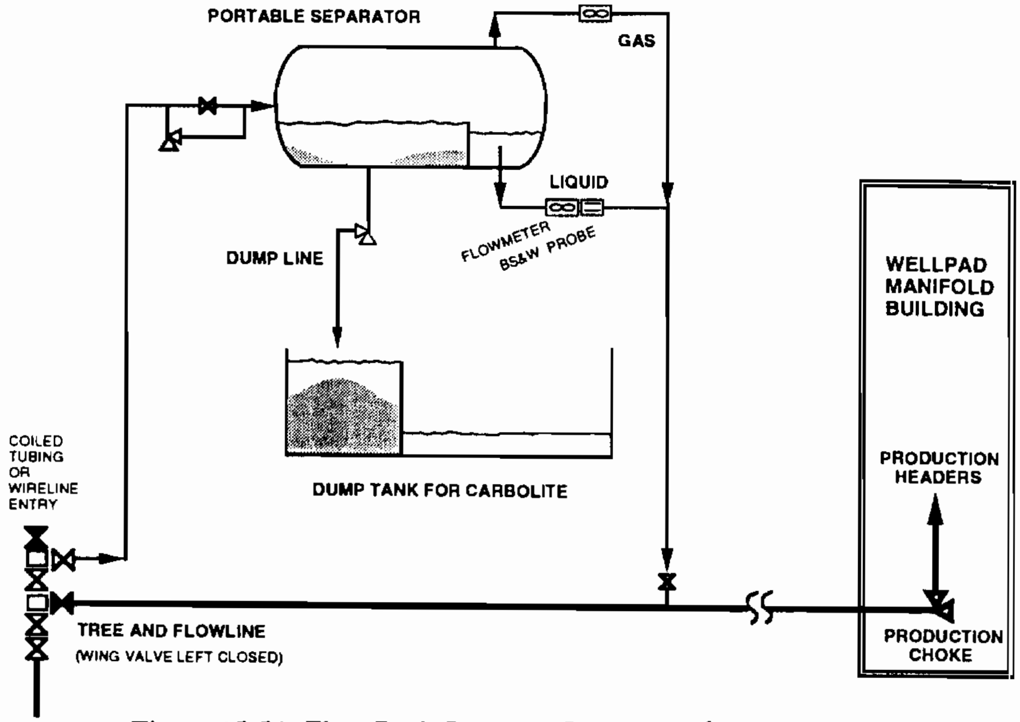


Figure 15-54. Flow-Back Separator Layout (Melvan, 1994)

15.5.2 Nowsco Well Service (Rotary Jetting Tool)

Nowsco Well Service (Latos, 1994) described the parameters affecting jetting tool performance. Limitations in current tools led to the development of a rotary tool. Laboratory and field tests have shown this tool to be very successful when applied appropriately.

Medium-pressure jetting (2000-3000 psi for 70-ksi tubing) has been used to clean out a variety of deposits from wellbore tubulars including particulates, muds/gels, waxes/complexes, coke/tar, iron sulphide, gypsum, sulphur, and calcium carbonate. Hardness can vary dramatically between materials. Hard calcium carbonate represents the limit for economic jetting performance on coiled tubing.

Four principal mechanisms account for the ability of fluid jets to break down deposits. Erosion is a powerful mechanism, even under submerged conditions. Abrasion is an important component when solids are pumped with the fluid or entrained by the jet from debris. Stress cycling can also remove deposits whereby the jet induces a stress pattern around fine surface cracks in the deposit. Cavitation can play a significant role in jetting operations at the surface. However, high pressures downhole counteract the effects of cavitation, so that it has little impact in coiled tubing jetting.

Designing jetting operations for specific requirements can be difficult. Small changes in scale composition can result in significant changes in hardness of the deposit. The primary performance objectives of a jetting tool are (Latos, 1994):

- Effective cleaning in a single pass
- Economic tool travel speed
- Versatility for varying conditions
- Reliability
- Tool economy

Orifice shape and pressure drop dictate jet velocity. Minimum jet velocities for cleaning operations vary from about 300 ft/sec for scale to at least 500 ft/sec for calcium carbonate.

Rotary jetting tools can have advantages over conventional (nonrotating) designs. Complete cleanout in a single pass is much more readily achieved with a rotating tool. Rotation also induces low-frequency pressure pulsation, which enhances scale removal. Preferred rotational velocities range from 100 to 1000 rpm. Hard scales are best removed with lower rates of rotation.

Controlling rotation has been found to be difficult. Many tools spin up to rates as high as several thousand rpm, at which cleaning performance is often not superior to non-rotating tools.

Nowsco developed a new 2⅛-in. rotary jetting tool (Figure 15-55). Jet diameter and orientation are chosen to suit specific deposit parameters and pump rates.

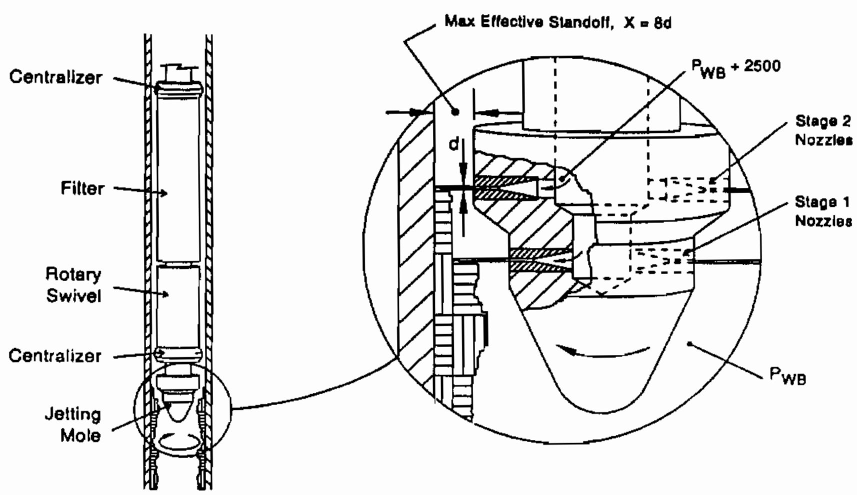


Figure 15-55. Rotary Jetting Tool (Latos, 1994)

Laboratory tests were conducted on three types of deposits in a simulated downhole environment (Table 15-12). Bore size for these tests was approximately that of 2⅞-in. production tubing. Gas production (1 MMscfd) during the operation was simulated for the calcium carbonate tests.

TABLE 15-12. Laboratory Tests of Rotary Jetting Tool (Latos, 1994)

Sample Composition	Jet Velocity (ft/sec)	Tool Travel Rate (ft/min)
Gypsum Cement	300	3
Sulphur	300	3
Calcium Carbonate	450	0.6

The rotary tool has been used in twenty jobs, as summarized in Table 15-13. Seventeen of these jobs were deemed successful. Wells with "scale" contained unknown deposits. For one of these, a 450-ft cap of pebble-sized shale in an asphalt matrix was jetted at a penetration rate of 84 ft/hr. After the customer demanded switching to a drill to speed up the operation, the final 30 ft of the deposit were drilled out at about the same ROP as the jetting tool.

TABLE 15-13. Field Tests of Rotary Jetting Tool (Latos, 1994)

Deposit Composition	Number of Wells	Jet Velocities (ft/sec)	Tool Travel Rates (ft/min)
Sulphur	4	375–400	1–4
Gypsum	2	425–480	0.75–3
Iron Sulphide	7	240–370	1.5–6
"Scale"	2	220–250	3
Shale/Sand in Asphalt	3	325–360	1.5–3
Compressor Residue	2	470–570	9–11

Nowsco found that the rotary jetting tool was a very successful design. However, they suggest that the tool may be too complex and costly for its use to be warranted in softer deposits. The use of high-strength coiled tubing will also increase the effectiveness of the rotary tool by allowing higher pressures at the tool without undue fatigue stress of the pipe.

15.6 ZONE ISOLATION

15.6.1 BP Exploration (Gel Placement for Water Shut-Off)

BP Exploration (Wigg, 1994) described a successful operation placing cross-linked gel with coiled tubing to isolate a water-producing zone. The well is located in the Thistle Field in the Northern North Sea off the Shetland Islands.

The well's completion is a single-packer design (Figure 15-56), and includes 5½-in. production tubing and 9⅝-in. casing at depth with no liner.

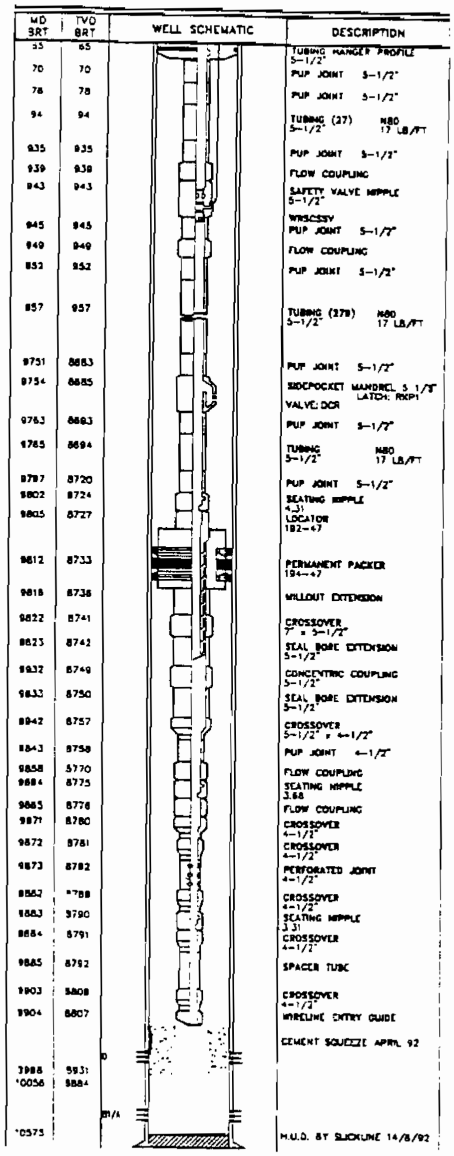


Figure 15-56. A35Z(44) Completion (Wigg, 1994)

The original producing zone with 58 ft of perforations had gradually watered out. In 1992, a cement squeeze was performed to close off this zone. A lower zone was then perforated and the well produced at a water cut of 55% for a time. By 9 months, the squeeze broke down and the water cut increased. Due to surface constraints, the well was returned to intermittent production (Figure 15-57).

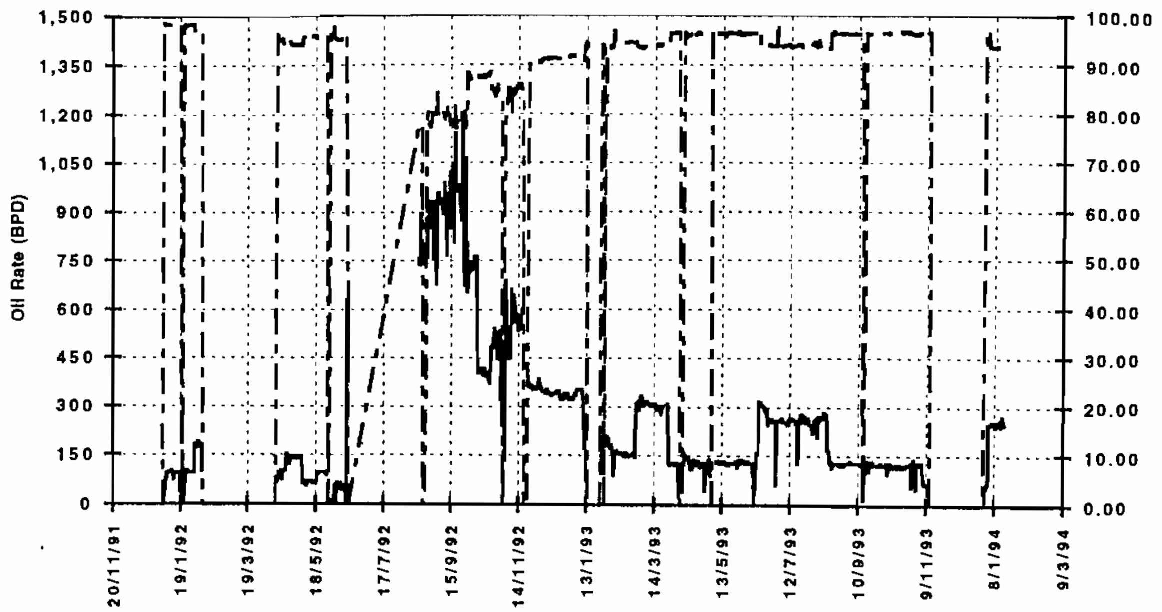


Figure 15-57. A35Z(44) Production History (Wigg, 1994)

Options for shutting off the watered-out zone were considered, including another cement squeeze. However, the limited success with the first treatment suggested an alternate approach should be considered. Mechanical isolation was not practical since the producing zone was below the watered-out zone. BP Exploration chose the placement of a gel treatment (Maraseal) to permanently isolate the zone. Developed by Marathon, this gel consisted of a copolymer of polyacrylamide and sodium acrylate crosslinked with chromium acetate.

The gel treatment chosen had been previously used on jobs at Prudhoe Bay. While the Alaskan jobs involved shutting off gas zones in relatively short intervals, the proposed job was to treat a 105-ft interval.

Perforations in the oil-producing zone had to be isolated during the treatment operation. BP Exploration considered a through-tubing plug, but rejected that approach due to the high expansion ratio required and the lack of a suitable rathole should the assembly not come out of the hole after the operation.

Pumping a sand plug was also rejected as an option. The plug would need to be removed before the gel had completely set. Thus, during removal of the sand plug, the well could not be flowing to assist with carrying solids from the well. Tubing and casing size were such that sufficient velocity could not be attained without assist.

BP Exploration chose a calcium carbonate plug to isolate the lower perforations. This material was light enough to be washed from the well without assist. A problem after the plug was placed was that tagging the top of the plug was difficult, with little resistance as the BHA passed into the fill.

A tapered string of 1¾-in. coiled tubing was used for the operations. A large volume of seawater (1500 bbl) was pumped to cool the watered-out zone to increase gel set-up time. Gel was pumped at 1½ bbl/min for 250 bbl, and then at a low rate for 80 bbl. A Hall plot recorded during injection operations is shown in Figure 15-58.

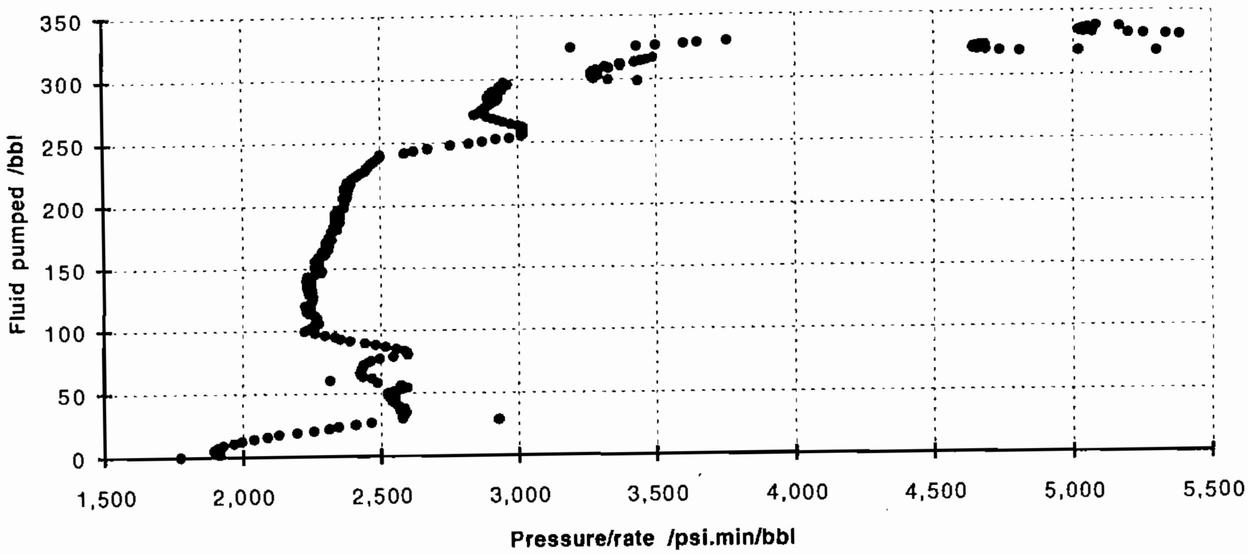


Figure 15-58. Gel Injection Hall Plot (Wigg, 1994)

Plans called for a 14-day wait for gel setting before returning to production. For the future, the operator believes that this period can be reduced.

The well was brought back on production at about 800 BOPD. Initial water cuts were high, but declined rapidly to about 10%. The operation was deemed a success, and additional jobs are being planned for other wells in this and other fields.

15.6.2 BP Exploration (Remedial Straddle Completions)

Corrosion and erosion can result in failure of production liners and tubulars, especially in mature fields. BP Exploration (Stephens and Welch, 1994) has developed techniques using coiled tubing to straddle and isolate these types of problems. These operations have been found to be much less expensive than conventional replacement techniques or scab liner installation.

Problems in completions that may be addressed with coiled-tubing techniques include damaged gas-lift valves, stuck sliding sleeves, corrosion and erosion of tubing. Treating corrosion/erosion normally requires installing long sections of tubing. Other problems are more localized and can often be repaired with conveyed tubing patches.

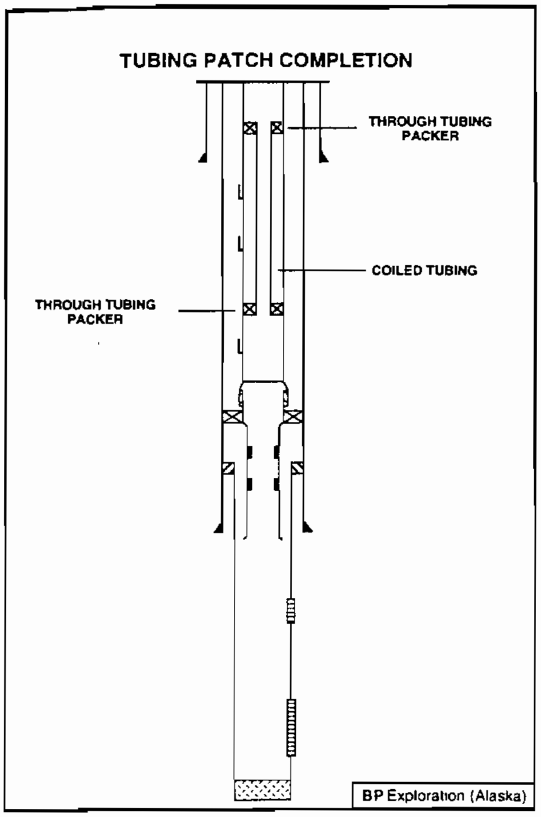


Figure 15-59. Straddle Patch Within Production Tubing (Stephens and Welch, 1994)

Installing straddles within production liner is made difficult by the need for the assembly to pass through tubing profiles. This results in reduced internal diameter of the assembly and makes workovers below the straddle difficult (or impossible). Straddles within production tubing are complicated by gas-lift valves below or behind behind the straddle (Figure 15-59), and production restrictions. Fortunately, many candidates for coiled-tubing straddles are low-rate wells anyway, so that reduced production area may be insignificant.

Straddle patches can be designed as retrievable or nonretrievable, incorporate various packers, be hung off tubing tails, and incorporate polished bore receptacles, gas-lift valves, or SSSVs. If designed to straddle the upper section of a liner, the assembly can be hung from the no-go nipple and require only one packer (Figure 15-60).

For some cases, the coiled tubing patch must be allowed to move for expansion and contraction. A polished bore receptacle is used in these wells (Figure 15-61). Spoolable gas-lift valves can be incorporated into the assembly if required. These valves are not retrievable and should be designed with future production needs in mind.

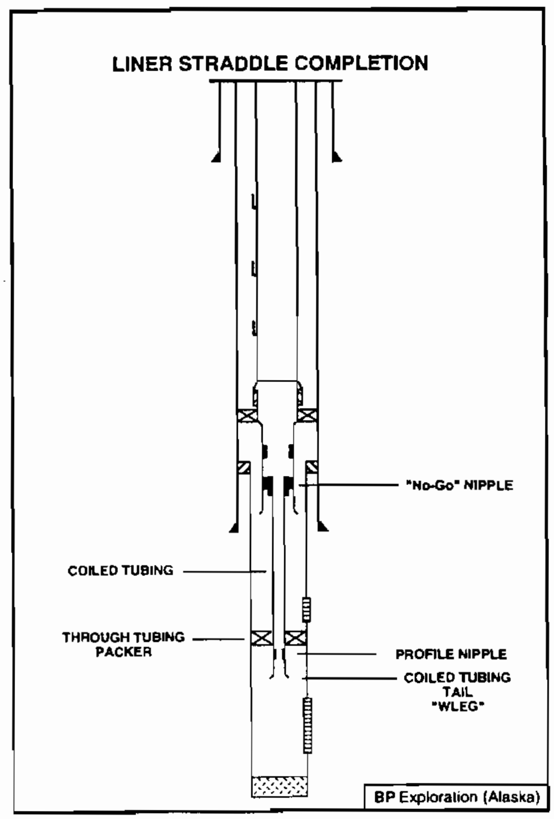


Figure 15-60. Straddle Patch for Upper Liner (Stephens and Welch, 1994)

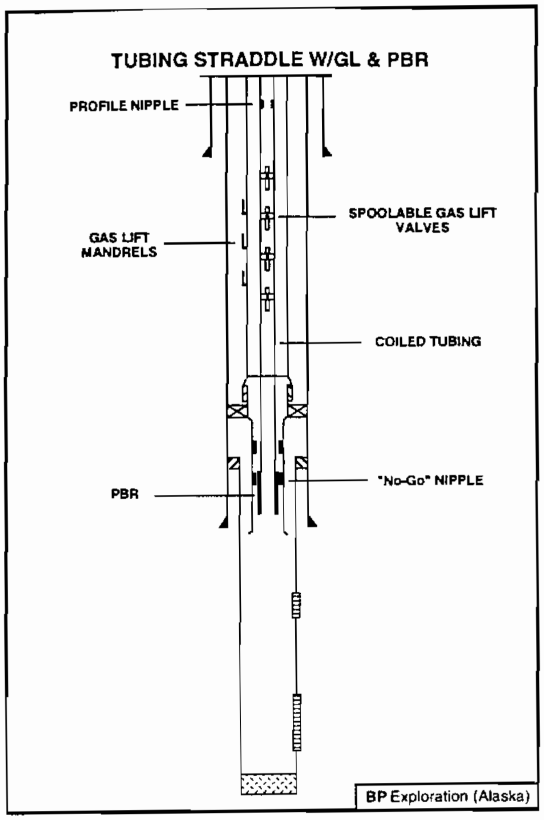


Figure 15-61. Straddle Patch With Polished Bore Receptacle (Stephens and Welch, 1994)

BP Exploration presented an example running procedure for a coiled-tubing straddle assembly. The reader is referred to Stephens and Welch (1994) for details on their procedures.

Several advantages have resulted from using coiled-tubing straddle techniques. Primarily, economics allow working over wells for which conventional rig workovers are not justified (Table 15-14). Other benefits are improvements to the well's production as a result of increased velocity due to smaller production area (velocity-string effect) or gas-lift valves where none existed previously.

TABLE 15-14. Coiled-Tubing Straddle-Patch Operations (Stephens and Welch, 1994)

WELL	COILED TUBING WORK PERFORMED	TOTAL CT COMPL. COST $M	ALTERNATIVE RIG WORK	EST. TOTAL RWO COST $M	ESTIMATED SAVINGS $M
1	Straddled Prod Tbg (10,063') Equip.: CT hanger, GLV, & PBR	283	Pull 7"X 5 1/2" Tbg and Packer Install 4 1/2" Tbg/GL Mandrels	835	552
2	Patched Prod Tbg (3,814') Equip.: Tbg Pkr and PBR	274	Pull 5 1/2" Tbg and Packer Install 4 1/2" Tbg	750	476
3	Patched Prod Tbg (3,132') Equip.: Tbg Pkr and PBR	103	Pull 4 1/2" Tbg and Packer Install 4 1/2" Tbg/GL Mandrels	750	647
4	Straddle Prod Liner (170') Equip.: Thru Tbg Pkr and "X" Lock	Run Cost 130 Pull Cost 86	Pull 4 1/2" Tbg, Pkr, and Sidetrack Install 7" Liner, 4 1/2" Tbg/Mandrels	1,200	-
5	Patch Prod Tbg (5250') Equip.: Two Thru Tbg Pkr w/Slips	Est. Cost 150	Pull 3 1/2" Tbg and Packer Install 3 1/2" Tbg/GL Mandrels	750	600

The disadvantages of these techniques arise from the difficulty in performing future workovers through the assembly. Problems encountered in previous jobs include failures of through-tubing packers, plugging of spoolable gas-lift valves, and lack of availability of specialized equipment. Success has improved as the problem areas are addressed.

15.6.3 BP Exploration (Laying Sand Plugs)

Numerous field operations involving laying sand plugs with coiled tubing have been conducted on Alaska's North Slope. Chambers (1993) described BP Exploration's experiences in the Western Operating Area of Prudhoe Bay. Their experiences show that a sand plug can be laid in one operation using coiled tubing and a multistage pumping schedule. Live well operations are also a benefit of this technique.

Plugs are used at Prudhoe Bay to temporarily isolate lower zones from stimulation or cement-squeezing of upper zones (Figure 15-62). Since these lower zones are not to be abandoned, the isolation technique must be readily removable and not damage perforations. Inflatable bridge plugs, first set above the zone to be isolated and then covered with sealing material, have been successfully used for these applications. However, BP Exploration's experience has shown that laying a sand plug can be less expensive than the use of an inflatable bridge plug.

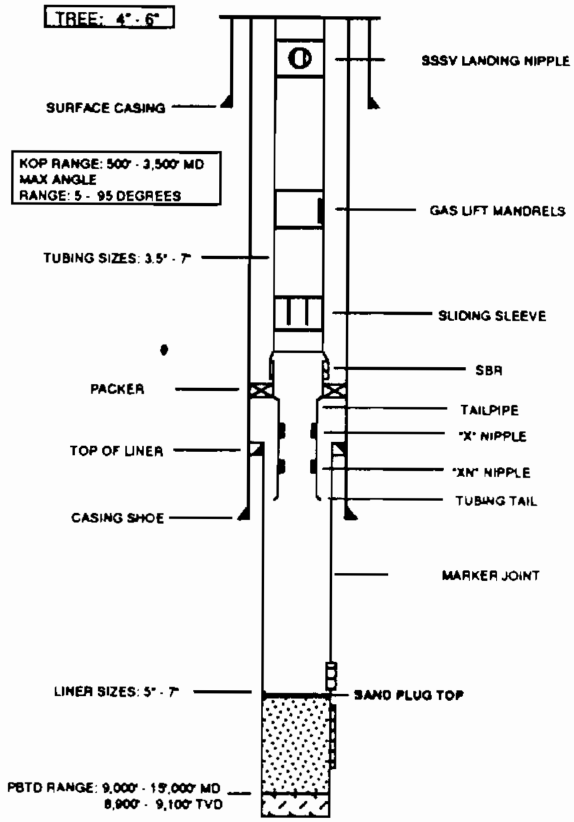


Figure 15-62. Use of a Sand Plug for Zone Isolation (Chambers, 1993)

Other advantages to the use of sand plugs include the ability to cover long intervals quickly, accurately control depth, and change the strength of the plug through choice of materials (Table 15-15). Spherical plug material has less tendency to plug the BHA. For more permanent zone isolation, 20/40 Ottowa sand is used to form a tighter plug.

TABLE 15-15. Plug Materials (Chambers, 1993)

BULK AND TRUE VOLUME MEASUREMENTS OF VARIOUS PROPPANTS

UNITS OF MEASURE	20/40 SAND	20/40 CARBOLITE*	20/40 LWP
BULK VOLUME			
LB/CU FT	107.0	100.0	92.47
LB/BBL	600.6	560.45	518.45
LB/GAL	14.3	13.34	12.34
SP. GRAVITY	1.72	1.6	1.48
TRUE VOLUME			
GAL/LB	0.0456	0.0441	0.0466
LB/GAL	21.93	22.68	21.46
LB/BBL	921.0	952.4	901.3
SP. GRAVITY	2.63	2.72	2.573

The true (absolute) volume of a granular material is the actual volume occupied by the grains. The bulk volume is the true volume plus the void space between the grains. The bulk volume, therefore, is always greater than the true volume.

In proppant-fluid slurry calculations, the true volume density of the proppant must be used. In proppant fill-up calculations, the bulk volume density of the proppant must be used.

* Carbolite is a product of CarboCeramics

BP Exploration has developed operational procedures for efficiently laying sand plugs with coiled tubing. Jobs are performed in two or three stages, with about 80% of the target pumped in the first stage. After the first stage settles, the sand top is tagged with the coiled tubing. The second-stage sand volume is then adjusted to account for the behavior of the first stage. A third stage is pumped if necessary. After the plug is laid, the well is allowed to stabilize for 12 hours. A final depth tag is run with wireline before the operation proceeds.

A typical tool assembly for laying sand plugs is shown in Figure 15-63. If depth control is needed, a tubing end locator should be run rather than rely on tags in soft fill. A hydraulic disconnect is included in case the end locator springs become jammed and cannot enter the tubing tail.

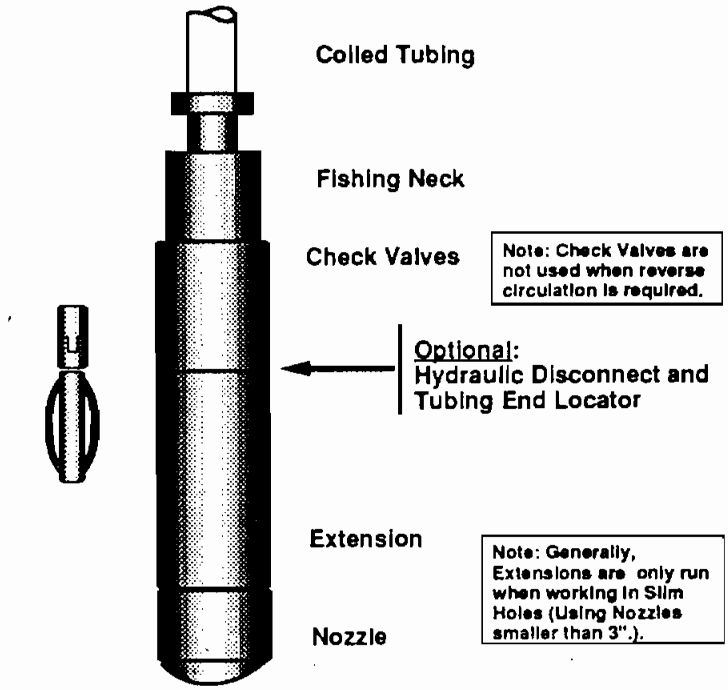


Figure 15-63. BHA for Laying Sand Plugs (Chambers, 1993)

Sand-nozzle design includes a center hole of at least ½ in. and five smaller holes around the circumference (Figure 15-64).

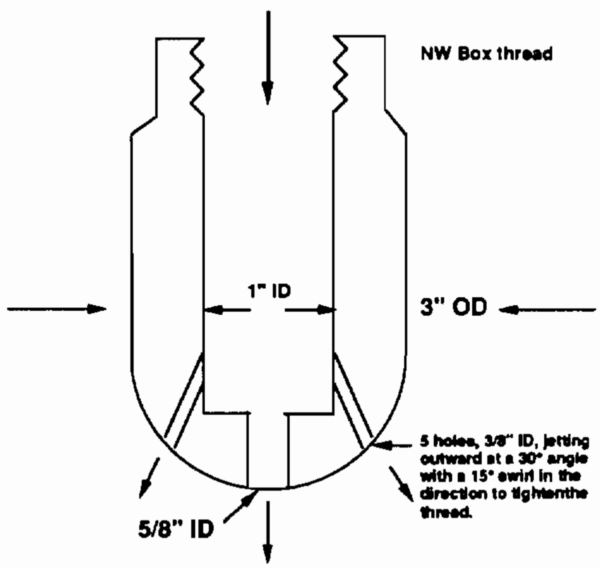


Figure 15-64. Nozzle for Laying Sand Plugs (Chambers, 1993)

After a plug stage is laid, the sand top is tagged every 5-10 minutes with the coiled tubing. Operations proceed after the sand top remains stationary. Typical problems encountered in deviated wells are shown in Figure 15-65. If the sand top is consistently below expected depth, sand may be strung out in dunes. This is remedied by washing across the liner with sea water. If the sand top is consistently above expected depth, voids or bridges may be present in the column. A jet pass should be made into the column with sea water to determine whether the sand top changes.

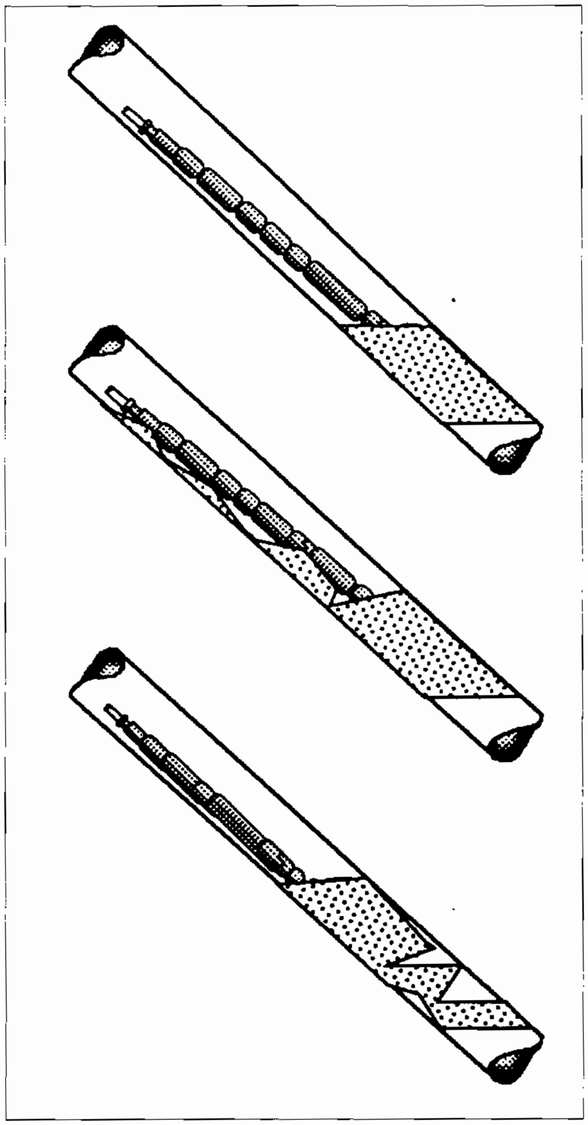


Figure 15-65. Sand Plug Problems: Good Plug (Top), Sand Dunes (Middle), Voids (Bottom) (Chambers, 1993)

In one case history described by BP Exploration, a fracture candidate required a 69-ft plug to protect lower perforations. Three stages were planned to lay the plug. The first stage was intended to cover 80% of the interval. After the well was killed with sea water, the first stage was pumped at 1 bpm. The sand top was tagged after 2 hrs at a height equivalent to 33% of the interval.

Enough sand was pumped in the second stage to fill the interval, according to initial volume calculations. The sand top was tagged after 1 hr at 88% of the 69-ft interval. Ten more feet of sand were pumped in the third stage, increasing the total pumped to 110 ft of sand (calculated) into the interval.

Wireline was used to tag the plug on the next day. The plug was found to be 10 ft too long. Excess sand was bailed out via wireline. The operator believed that the second stage was strung up the hole, and that the third stage was unnecessary.

BP Exploration's experiences with sand plugs showed that this approach allows effective isolation in one operation, and reduces the effects of wellbore deviation, liner condition, and sand behavior.

15.6.4 Halliburton Energy Services (Horizontal Completion Tools)

Zonal isolation is now practical in horizontal wellbores due to the availability of coiled tubing services. New tools designed to be run and operated on coiled tubing are being developed to address the needs of horizontal completions (Robison et al., 1993). It is now routine to complete horizontal wells with zonal isolation capability and within a reasonable cost.

The hydraulic capability of coiled tubing adds significantly to the operational options available. Downhole tools can be manipulated hydraulically without needing to rely on set-down weight. A special hydraulic shifting tool (Figure 15-66) provides more positive control than a conventional shifting tool with set-down weight. No tubing manipulation is required. When shifting is accomplished, flow ports open, signaling successful operation.

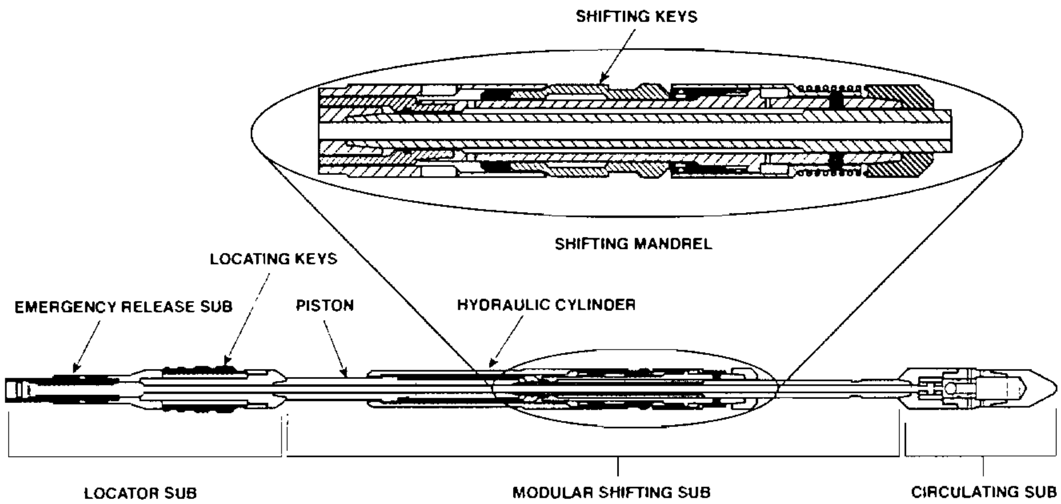


Figure 15-66. Hydraulic Shifting Tool (Robison et al., 1993)

Significant forces can be generated by the hydraulic shifting tool for shifting sliding sleeves (Table 15-16). Wireline inside the coiled tubing can relay data describing the forces applied and the position of the sliding sleeve.

TABLE 15-16. Hydraulic Shifting Tool Forces (Robison et al., 1993)

Tubing Size (In.)	Shifter O.D. (In.)	Piston Area (Sq. In.)	Force Available (lbf)
2⅜	1.84	1.57	7,800
2⅞	2.23	1.90	9,500
3½	2.72	2.32	11,600
4½	3.50	2.98	14,900
5	3.89	3.31	16,500

More discussion of advanced coiled-tubing tools for horizontal completions is presented in the Chapter *Tools*.

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