

RMOTC TEST REPORT
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CRYOGENIC TREATMENT OF PRODUCTION COMPONENTS IN HIGH-WEAR RATE WELLS

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Rocky Mountain Oilfield Testing Center

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CRADA 2000-010
DOE Project Code 6730.02.0138
Mark Milliken, Project Coordinator
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RMOTC

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Summary of results. Deep Cryogenic Tempering (DCT) is a specialized process whereby the molecular structure of a material is “re-trained” through cooling to -300°F and then heating to $+175\text{-}1100^{\circ}\text{F}$. Cryocon, Inc. (hereafter referred to as Cryocon) and RMOTC entered an agreement to test the process on oilfield production components, including rod pumps, rods, couplings, and tubing. Three Shannon Formation wells were selected (TD about 500 ft) based on their proclivity for high component wear rates.

Phase 1 of the test involved operation for a nominal 120 calendar day period with standard, non-treated components. In Phase 2, treated components were installed and operated for another nominal 120 calendar day period. Different cryogenic treatment profiles were used for components in each well. Rod pumps (two treated and one untreated) were not changed between test phases. One well was operated in pumped-off condition, resulting in abnormal wear and disqualification from the test. Testing shows that cryogenic treatment reduced wear of rods, couplers, and pump barrels. Testing of production tubing produced mixed results.

The problem. High wear rates in production components, including rods, couplings, pumps, pump valve rods, and tubing, can be caused by inclined well bores, hard tagging of rod pumps, improperly designed rod and tubing strings, high water-cut, and abrasive sediment loads. During normal operations, the effects include parted rod strings, poor pump performance, and perforated tubing, resulting in increased costly well maintenance and lost production.

Mitigation of the problem could save NPR3 tens of thousands of dollars per year in production, component, and labor costs. Within the industry as a whole, the cost savings could be on the order millions of dollars per year. With these potential benefits in mind, RMOTC entered into a cost sharing partnership with Cryocon in anticipation that the investment would ultimately be recovered through reduced operating costs at NPR3.

Cryocon and their technology. Cryocon is a publicly traded company specializing in a proprietary material treatment process called Deep Cryogenic Tempering (DCT). DCT is

a computer-controlled tempering process that, according to Cryocon, improves the wear and performance characteristics of many types of metals, alloys, and synthetic materials. DCT utilizes liquid nitrogen that is flashed to a gas to achieve temperatures of minus 300° F. This technique is completely dry and eliminates the condition known as thermal shock, which is a problem related to traditional cryogenic applications involving spraying or dipping. Cryocon reports that some treated items show dramatic increases in wear resistance, toughness, machinability, and thermal and dimensional stability.

Deep Cryogenic Tempering is a specialized process whereby the molecular structure of a material is “re-trained” through cooling to –300° F and then heating to +175-1100° F. Steel undergoes additional changes during Deep Cryogenic Tempering. One component of steel is austenite, a soft form of iron that lacks strength and durability. Traditional heat/quench tempering converts some of the austenite – but not all – into martensite, a harder form of iron. Deep Cryogenic Tempering converts nearly all the remaining austenite to martensite. The process can be used on most steel alloy that is heat-treatable, including cobalt, carbide, and carbon steels.

Cryogenic cooling pumps kinetic energy out of molecules. As temperatures approach minus 300° F, a number of molecular changes take place:

- Super cooled molecules realign. Residual material stress is relieved during this molecular “settling.”
- Super cooled molecules form stronger bonds, which yield improved material cohesion and resulting gains in performance and durability.

The heating phase is equally important because it:

- Further relieves residual stresses
- Reduces brittleness

During Deep Cryogenic Tempering, micro-fine carbide particles are formed, further strengthening the steel by filling micro-voids within the martensitic structure. According to Cryocon, the net result is a stronger, thermally stabilized material with a coherent, improved microstructure that exhibits outstanding wear resistance and improved performance. Not all cryogenic treatments are equally effective; improper super-cooling can damage or destroy an item. Cryocon has developed several optimal treatment profiles for numerous metals and alloys. Each treatment profile is controlled by computer to accuracy within 0.01° F.

For the RMOTC test, Cryocon constructed a special modular cryogenic processor to contain the rods and tubing (Figures 1 and 2). The modular design allows easy adaptation to different sizes of oil field components.



Figure 1. Cryocon's prototype cryogenic processor.



Figure 2. Rods and tubing in cryogenic processor.

Cryogenic processor walls consist of a one inch layer of perlite insulation with sheet metal covering. The entire cryogenic processor is wrapped in a four inch layer of foam insulation. Thermocouples within the cryogenic processor ensure even dispersal of liquid N₂. Ceramic blocks provide support for the components within the cryogenic processor.

Well selection. Three wells were initially selected, based on histories of production component failures due to abnormal wear: 52-2-SX3, 62-16-SX3, and 73-3-SX3. These wells produce from the Shannon Formation at depths of about 500 ft. During testing, well 62-16-SX3 was accidentally pumped off and operated dry for a period time, resulting in

abnormal wear rates. RMOTC recommended that test data from this well be reserved, and Cryocon concurred. Raw data for well 62-16-SX3 are included in the appendices.

Production data for the test wells are as follows:

API	Well #	Oil Cum BBLs	Water Cum BBLs
4902522510	73-3-SX3	11,741	223,240
4902522514	52-2-SX3	8,468	105,173

Nominal production at the start of the test period was:

- 52-2-SX3: 5 BOPD 36API, 78 BWPD
- 73-3-SX3: 1 BOPD 36 API, 23 BWPD

Test procedure. CRADA # 2000-010 was executed on 9/18/00. The Joint Work Statement (JWS) specified that RMOTC provide rods, couplings, pumps, and tubing, and that Cryocon provide the treatment. Each well had four joints of tubing, five rods, and five couplings each for Phases 1 and 2, for a total (for three wells) of 12 joints of tubing, 15 rods, and 15 couplings. On 9/19/00, an order was placed with Wilson Supply for components with these specifications:

- Rods: API Grade D, AISI 4720 nickle-chromium-moly alloy steel, 0.75 X 25'.
- Couplings: API Class T, 8630 alloy steel.
- Tubing: API Class J-55, 4.70 lb./ft, 2 3/8" OD, gage 0.190 wall, nominal 31 ft. length.
- Pumps (provided by Rex Bell of Harbison Fischer):
 - 52-2-SX3: Serial HF-9, 108" untreated chrome barrel, 54" valve rod.
 - 73-3-SX3: Serial HFTRT-1, 108" treated chrome barrel, 54" treated valve rod.
 - 62-16-SX3: Serial HFTRT-2, 120" treated carburized barrel, 72" valve rod.

Welded tubing provides more uniform wall thickness manufacturing tolerances. Some problems were encountered in ordering the tubing. The initial shipment contained 2 7/8" tubing. The second shipment had the correct 2 3/8" tubing, but was one joint short. The 24th joint was eventually shipped, but was destroyed in an accident during handling.

Bob Phegley and Larry Castleman of ICO in Casper provided pre-and post-test tubing inspections. Upon receipt, the tubing was taken to the Casper ICO yard, where it was inspected on 10/24/01. No defective tubing was found during pre-test inspections. ICO uses NDT 5700 four function Electro Magnetic Induction measurement equipment to obtain wall thickness dimensions within a tolerance of 0.001".

Sucker rods and couplings were acquired locally from Weatherford through Wilson Supply. API Grade D rods were not ideal for this test given their hardness. But the more desirable softer Grade C rods (AISI 1536 carbon-manganese steel) are not widely used and were not available within the time requirements of the test.

Each test component was stamped with a "T" or "U" for treated and untreated. Components to be treated ("T") were shipped to Cryocon, while untreated components

("U") were moved to the field for use in the baseline testing phase. Cryocon applied different treatment profiles to components in each of the three wells, Profile #1 (52-2-SX3), Profile #2 (62-16-SX3), and Profile #3 (73-3-SX3). Cryocon did not identify with a stamping the individual components treated with each profile.

Accurate alloy information is critical to the design of Cryocon's descent and ascent profiles. Mark Quinn of Wilson Supply in Casper ensured that all components were manufactured in the same mill runs with identical Material Test Reports (MTR). MTRs provide data on alloy composition (see Appendix 1).

Initially, the plan was to test untreated components in Phase 1, with wells operating 24/7 for a nominal 90 calendar day period. Phase 2 would use treated components for another nominal 90 day period. Phase 1 (baseline untreated components) field testing began on 10/25/00, when well 52-2-SX3 was put on production. Baseline testing on well 73-3-SX3 started 12/6/00. The late start for well 73-3-SX3 was due to delays in receiving the cryogenically treated rod pump and valve rod. The same rod pumps were used continuously throughout Phases 1 and 2. Both wells were operated at 12 RPM with a 54" stroke. The wells were shut-in for 3 days on 1/13/01 to accommodate 3D seismic acquisition.

Well 52-2-SX3 operated on a 24 hour clock until being pulled on 2/5/01. Very little wear was noted on the untreated couplings and rods, so the testing periods for wells 52-2-SX3 and 73-3-SX3 were extended to a nominal 120 calendar days. (*Note: Actual test periods are ± 120 calendar days due to other oil field activity, manpower availability, mechanical problems, and weather.*)

Well 52-2-SX3 continued on a 24 clock until being pulled on 3/13/01 with 118 calendar days of operation. Phase 2 treated components were installed. Well 73-3-SX3 was put on a 50% clock due to low fluid levels, and pulled on 4/9/01 after 118 calendar days of operation. Phase 2 treated components were installed. The baseline untreated rods and couplings were moved to the water treatment building and measured.

The three test wells are located in a depleted ex-steamflood area of high water cut. In early June, well 62-16-SX3 pumped off and operated dry, leading to its disqualification from the test. Production Operations, added chase water to a nearby idle steam injection well. Production from well 62-16-SX3 quickly went to 100% water. There was no reported oil/water ratio change in the other two wells. The duty cycle for well 73-3-SX3 was increased from 50% to 65% on 6/8/01.

Phase 2 well pulls were conducted on 7/27/01 for well 52-2-SX3 after 127 calendar days of operation, and 8/8/01 for well 73-3-SX3 after 118 days. The treated rods and couplings were moved to the water treatment building and measured. On 8/13/01, all tubing was moved to ICO for measurement. A delay resulted as ICO awaited the ir plant's changeover to 2 3/8" tubing capability. On 8/30/01, ICO inspected 24 joints of tubing.

Wear data acquisition and normalization. Rod and coupling OD dimensions were measured with a digital caliper to a tolerance of 0.01”.

Nominal dimensions are:

- Coupling nominal OD (Figure 3): 1.63”
- Rod shoulder nominal OD (Figure 4): 1.49”
- Rod shank OD: 0.75”



Figure 3. Typical rod coupling.



Figure 4. Typical rod end with shoulder.

Coupling wear was measured at the smallest OD. Rods were measured at the shoulder and mid-shank, where most wear occurs as the rod string spirals under compression. Excessive compression occurs when the rod string is improperly designed, or adjusted to tag the pump hard in order to break gas locks. Rod shoulders start wearing when the coupling OD has worn to the shoulder’s OD.

Because of various operating constraints, the test wells did not operate for similar periods of time or duty cycles. Calendar days of operation were factored with duty cycles to arrive at total hours of operation in Table 1:

TABLE 1. CRYOCON WELLS HOURS OF OPERATION		
WELL	PHASE 1	PHASE 2
52-2-SX3	3048	3048
73-3-SX3	1416	1632

Measured wear was normalized in order for wear character between components in each well and test phase to be compared with operation time factored out. The theoretical wear rate in inches per hour was multiplied by 10,000 hours, yielding an extrapolated wear amount over 10,000 hours. This computation is for comparison purposes only, and is not a prediction of true wear amounts over 10,000 hours.

Each component was assigned a number based on its position in the string, starting at the bottom. The rods were labeled 1-5, with #1 being the lowest in the string and first to be run in the hole. Tubing used the same convention. Couplings were labeled 1PUMP, 1, 2, 3, 4, 5. Coupling #1PUMP connected the lowermost rod (#1) to the pump valve rod. Coupling #1 was positioned at the top of rod #1, and so on.

Coupling wear analysis. Cryocon's treatment showed improved durability. The raw coupling measurements for Phases 1 (baseline) and 2 (treated) are listed in Appendix 2. Tables 2 and 3 show the improvements in wear between Phases 1 and 2 in wells 52-2-SX3 and 73-3-SX3 respectively. Wear data for well 73-3-SX3 are normalized to 10,000 hours because of the change in duty cycle during Phase 2 testing.

TABLE 2. 52-2-SX3 COUPLING WEAR			
COUPLING	PHASE 1	PHASE 2	% IMPROVEMENT
4	0.16	0.01	95%
3	0.06	0.01	89%
2	0.03	0.03	0%
1	0.27	0.07	75%
1PUMP	0.11	0.08	25%
AVERAGE IMPROVEMENT:			57%

TABLE 3. 73-3-SX3 COUPLING WEAR			
	PHASE 1	PHASE 2	
	NORMALIZED	NORMALIZED	
COUPLING	TO 10K HOURS	TO 10K HOURS	% IMPROVEMENT
1PUMP	0.12	0.03	74%
1	0.47	0.04	91%
2	0.41	0.02	94%
3	0.24	0.07	72%
4	0.37	0.39	-3%
5	0.90	0.47	48%
AVERAGE IMPROVEMENT:			63%

Figure 5 summarizes wear improvement with cryogenically treated components. The poor responses for couplings #2 in 52-2-SX3 and #1 in 73-3-SX3 are unexplained at this time.

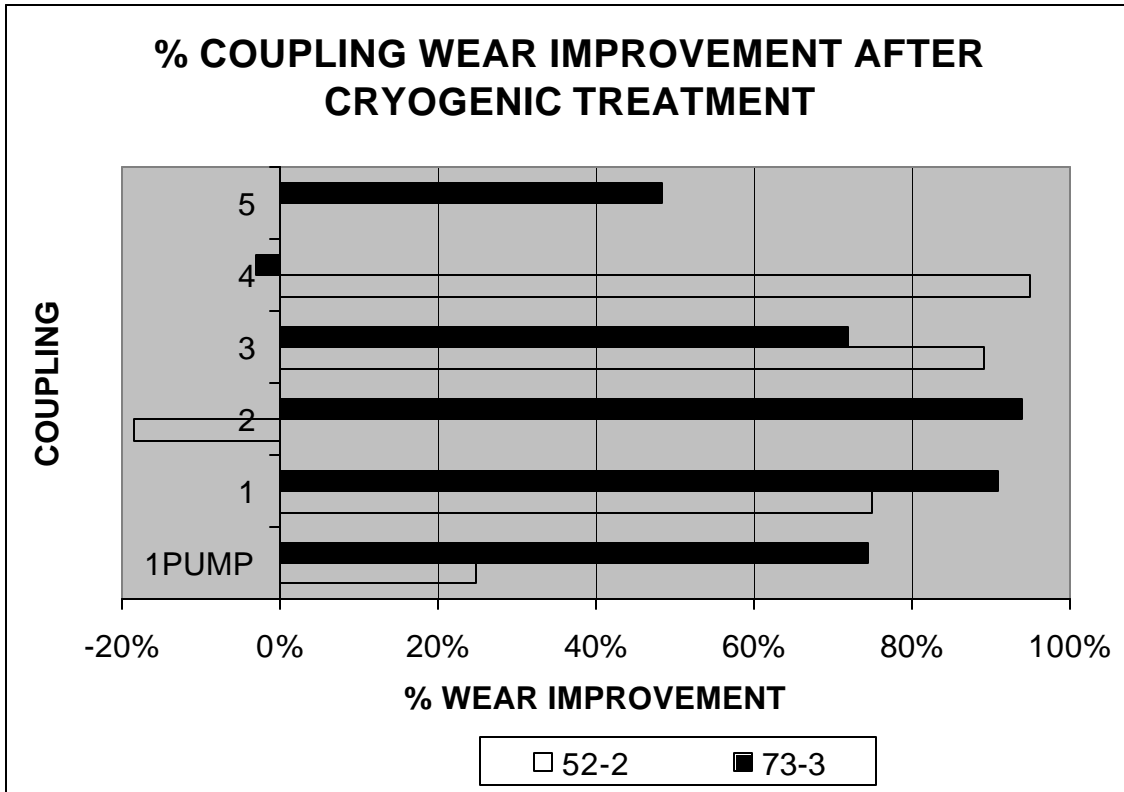


Figure 5. Coupling wear improvement in percent between Phase 1 and Phase 2.

Rod wear analysis. Phase 1 baseline rod wear was small in well 52-2-SX3, and essentially zero in well 73-3-SX3. Phase 2 cryogenically treated rods showed no wear in both wells, indicating improved wear character in well 52-2-SX3 (Tables 4). No table is included for well 73-3-SX3 since there was no wear in either test phase. The raw measurements are included in Appendix 3.

TABLE 4. WELL 52-2-SX3 ROD WEAR						
ROD	UPPER SHOULDER		MID SHANK		LOWER SHOULDER	
	UN-TREATED	TREATED	UN-TREATED	TREATED	UN-TREATED	TREATED
5	0.08	0.00	0.02	0.00	0.00	0.00
4	0.02	0.00	0.01	0.00	0.02	0.00
3	0.00	0.00	0.01	0.00	0.04	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00
1	0.13	0.00	0.00	0.00	0.00	0.01

Pump wear analysis. Well 52-2-SX3 operated with an untreated chrome barrel for a period of 6096 hours, and well 73-3-SX3 with a treated chrome barrel for 3048 hours. Raw measured data is included in Appendix 4. Because of the difference in operating time, barrel and valve rod wear data are normalized to 10,000 hours so a direct comparison of treated vs. untreated can be made (Table 5). As mentioned earlier, the treated carburized pump in well 62-16-SX3 had unusually high wear because of the well's operating condition.

Rex Bell of Harbison Fischer disassembled each pump and measured the barrel at six inch increments, and plungers and valve rods every three inches. Measurement accuracy was 0.0001” on the barrel ID, and 0.001” on the plunger and valve rod ODs. Nominal plunger-barrel clearance is 0.001”, and valve rod OD is 0.688.

There was no difference in wear on the plungers between the two wells. The untreated chrome barrel (well 52-2-SX3) exhibited slightly more wear than the treated chrome barrel (well 73-3-SX3). Conversely, the treated valve rod (well 73-3-SX3) showed significantly more wear than the untreated rod (well 52-2-SX3). Chuck Tarr of Harbison Fischer had the pump components analyzed in the H-F metallurgy lab. They found the difference in wear character was due to corrosion, and that the cryogenic treatment had "little or no effect" on component wear resistance.

TABLE 5. PUMP BARREL WEAR COMPARISON			
NORMALIZED TO 10,000 HOURS			
STA (IN.)	UNTREATED 52-2-SX3 /10K HR	TREATED 73-3-SX3 /10K HR	IMPROVEMENT
6	0.0000	0.0000	0.0000
12	0.0008	0.0000	0.0008
18	0.0008	0.0000	0.0008
24	0.0003	0.0010	-0.0007
30	0.0003	0.0000	0.0003
36	0.0003	0.0000	0.0003
42	0.0003	0.0000	0.0003
48	0.0003	0.0000	0.0003
54	0.0003	0.0000	0.0003
60	0.0003	0.0000	0.0003
66	0.0003	0.0000	0.0003
72	0.0008	0.0000	0.0008
78	0.0008	0.0000	0.0008
84	0.0008	0.0000	0.0008
90	0.0008	0.0000	0.0008
96	0.0008	0.0000	0.0008
102	0.0033	0.0000	0.0033
108	0.0008	0.0000	0.0008

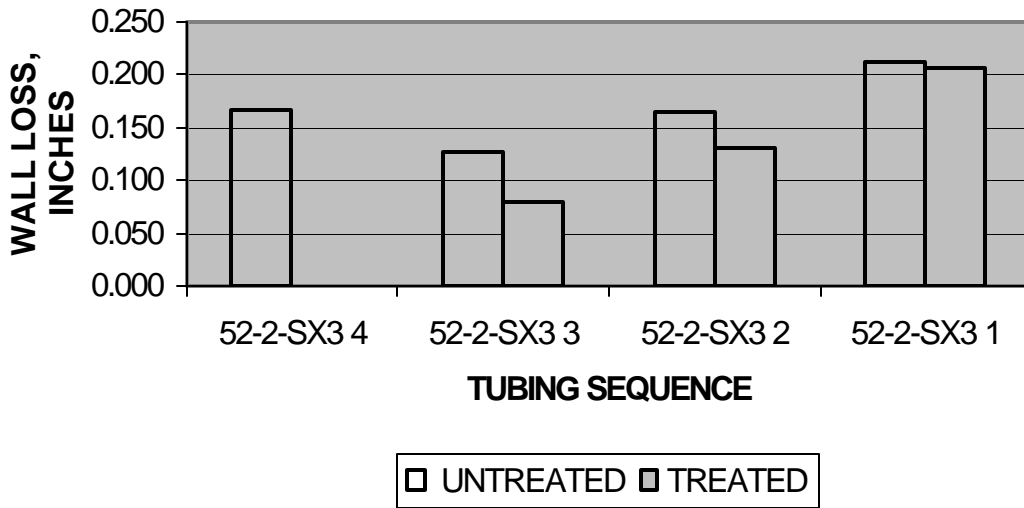
Pump valve rod wear analysis. Pump valve rods and guides have unusually high wear rates at NPR3, and so were added to the test at a late date. As with the pump barrels, valve rod wear is normalized to 10,000 hours so the two wells can be compared directly (Table 6). The results were a surprise, as the treated valve rod (well 73-3-SX3) exhibited generally more wear than the untreated rod (well 52-2-SX3). The possibility of the treated and untreated valve rods being accidentally switched has been ruled out. Due to a delay in receiving the treated valve rod, well 73-3-SX3 was the last to be put on test. No other valve rod was available to accidentally exchange.

TABLE 6. PUMP VALVE ROD WEAR COMPARISON			
NORMALIZED TO 10K HOURS			
STA (IN.)	UNTREATED 52-2-SX3 /10K HR	TREATED 73-3-SX3 /10K HR	IMPROVEMENT
3	0.121	0.440	-0.3182
6	0.148	0.502	-0.3543
9	0.125	0.558	-0.4331
12	0.148	0.574	-0.4265
15	0.159	0.571	-0.4117
18	0.159	0.604	-0.4446
21	0.157	0.571	-0.4134
24	0.169	0.558	-0.3888
27	0.172	0.525	-0.3527
30	0.169	0.420	-0.2510
33	0.164	0.338	-0.1739
36	0.169	0.259	-0.0902
39	0.169	0.187	-0.0180
42	0.159	0.115	0.0443
45	0.159	0.079	0.0804
48	0.146	0.036	0.1099
51	0.116	0.000	0.1165
54	0.075	0.000	0.0755

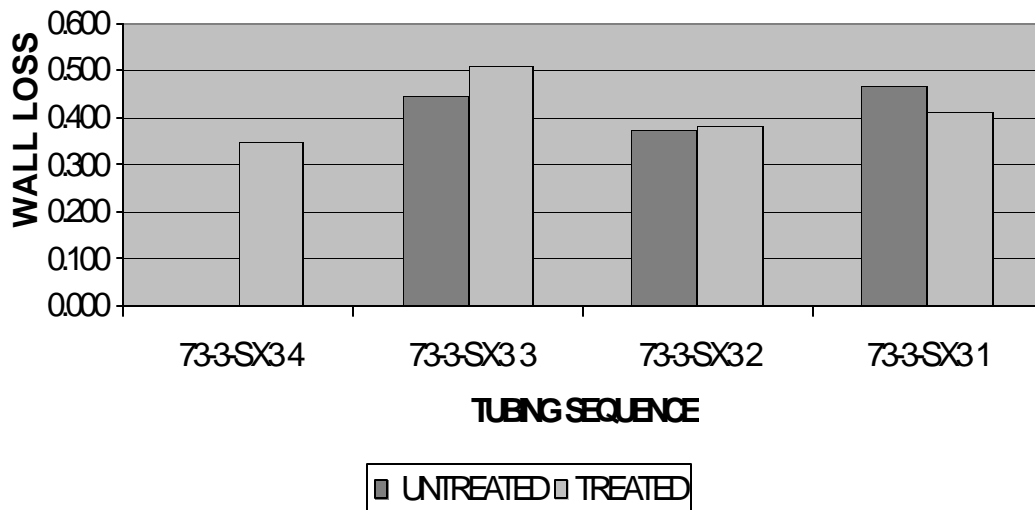
Tubing wear analysis. Larry Castleman of ICO reported that all tubing wall loss measured by their equipment was due to rod wear. Appendix 5 includes the raw wear data as recorded by ICO. Logs of internal wear locations were recorded and are included in Appendix 6. The treated and untreated tubing logs are presented adjacent to each other for a direct comparison of internal wear location. ICO rejects tubing with wall loss greater than 30%. For a 0.190" wall, the rejection threshold would be a wall thickness of 0.133" or less.

Tables 7 and 8 depict treated and untreated tubing wear in each well normalized to 10,000 hours for easy comparison. Treated tubing in well 52-2-SX3 shows a distinct improvement in wear, especially joint #4 where no wear was noted. The treated tubing in well 73-3-SX3 showed no advantage over untreated.

**TABLE 7. 52-2-SX-3 TUBING WALL WEAR
NORMALIZED TO 10,000 HOURS**



**TABLE 8. 73-3-SX-3 TUBING WALL WEAR NORMALIZED
TO 10,000 HOURS**



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APPENDICES

Appendix 1: Material Test Reports

Appendix 2: Coupling Wear Data

Appendix 3: Rod Wear Data

Appendix 4: Pump Wear Data

Appendix 5: Tubing Wear Data

Appendix 6: Tubing Wear Logs

APPENDIX 1

Material Test Reports

APPENDIX 2

Coupling Wear Data

CRYOCON TEST: COUPLING WEAR											
MILLIKEN 8/01				UNTREATED			TREATED				
WELL	C. DAYS	O. HRS	COUP*	MIN DIA**	WEAR	"/10K HR	MIN DIA**	WEAR	"/10K HR	DIFF	% IMP
52-2-SX3	127	3048	1PUMP	1.52	0.11	0.36	1.55	0.08	0.27	0.09	25%
52-2-SX3	127	3048	1	1.36	0.27	0.88	1.56	0.07	0.22	0.66	75%
52-2-SX3	127	3048	2	1.60	0.03	0.09	1.60	0.03	0.10	-0.02	-19%
52-2-SX3	127	3048	3	1.57	0.06	0.21	1.62	0.01	0.02	0.19	89%
52-2-SX3	127	3048	4	1.47	0.16	0.53	1.62	0.01	0.03	0.50	95%
62-16-SX3	118	2832	1PUMP	1.62	0.01	0.03	1.46	0.17	0.60	-0.16	-2025%
62-16-SX3	118	2832	1	1.61	0.02	0.07	1.49	0.14	0.49	-0.12	-637%
62-16-SX3	118	2832	2	1.62	0.01	0.04	1.60	0.03	0.11	-0.02	-167%
62-16-SX3	118	2832	3	1.62	0.01	0.05	1.57	0.06	0.20	-0.04	-346%
62-16-SX3	118	2832	4	1.63	0.00	0.00	1.59	0.04	0.14	-0.04	-3900%
73-3-SX3	118	1416	1PUMP	1.61	0.02	0.12					
73-3-SX3	118	1416	1	1.56	0.07	0.47					
73-3-SX3	118	1416	2	1.57	0.06	0.41					
73-3-SX3	118	1416	3	1.60	0.03	0.24					
73-3-SX3	118	1416	4	1.58	0.05	0.37					
73-3-SX3	118	1416	5	1.50	0.13	0.90					
73-3-SX3	118	1632	1PUMP				1.63	0.00	0.03	0.01	74%
73-3-SX3	118	1632	1				1.62	0.01	0.04	0.06	91%
73-3-SX3	118	1632	2				1.63	0.00	0.02	0.05	94%
73-3-SX3	118	1632	3				1.62	0.01	0.07	0.02	72%
73-3-SX3	118	1632	4				1.57	0.06	0.39	-0.01	-3%
73-3-SX3	118	1632	5				1.55	0.08	0.47	0.05	48%

APPENDIX 3

Rod Wear Data

ROD WEAR DATA

WELL	DAYS	ROD	U/U SHOULDER		T/U SHOULDER		U/MID SHANK		T/MID SHANK		U/L SHOULDER		T/L SHOULDER	
			MIN DIA**	WEAR	MIN DIA**	WEAR	MIN DIA**	WEAR	MIN DIA**	WEAR	MIN DIA**	WEAR	MIN DIA**	WEAR
52-2-SX3	127	1	1.36	0.13	1.49	0.00	0.75	0.00	0.75	0.00	1.49	0.00	1.48	0.01
52-2-SX3	127	2	1.49	0.00	1.49	0.00	0.75	0.00	0.75	0.00	1.49	0.00	1.49	0.00
52-2-SX3	127	3	1.49	0.00	1.49	0.00	0.74	0.01	0.75	0.00	1.45	0.04	1.49	0.00
52-2-SX3	127	4	1.47	0.02	1.49	0.00	0.74	0.01	0.75	0.00	1.47	0.02	1.49	0.00
52-2-SX3	127	5	1.41	0.08	1.49	0.00	0.73	0.02	0.75	0.00	1.49	0.00	1.49	0.00
62-16-SX3	118	1	1.49	0.00	1.46	0.03	0.75	0.00	0.604	0.15	1.49	0.00	1.44	0.05
62-16-SX3	118	2	1.49	0.00	1.49	0.00	0.75	0.00	0.75	0.00	1.49	0.00	1.46	0.03
62-16-SX3	118	3	1.49	0.00	1.49	0.00	0.74	0.01	0.75	0.00	1.49	0.00	1.49	0.00
62-16-SX3	118	4	1.49	0.00	1.48	0.01	0.75	0.00	0.75	0.00	1.49	0.00	1.49	0.00
62-16-SX3	118	5	1.49	0.00	1.45	0.04	0.75	0.00	0.75	0.00	1.49	0.00	1.48	0.01
73-3-SX3	118	1	1.49	0.00			0.75	0.00			1.49	0.00		
73-3-SX3	118	2	1.49	0.00			0.75	0.00			1.49	0.00		
73-3-SX3	118	3	1.49	0.00			0.75	0.00			1.49	0.00		
73-3-SX3	118	4	1.49	0.00			0.75	0.00			1.49	0.00		
73-3-SX3	118	5	1.48	0.01			0.75	0.00			1.49	0.00		
NOMINAL DIA:			1.49				0.75				1.49			

APPENDIX 4

Pump Wear Data

CRYOCON PUMP TEST

PREPARED BY MARK MILLIKEN 8/01 DATA FROM REX BELL OF HARBISON FISCHER 8/01

52-2-SX3

PUMP: HF9		UNTREATED CHROME BARREL, UNTREATED VALVE ROD									
HOURS OF OPERATION: 6096		12 RPM, 54" STROKE, 100% CLOCK									
BARREL (CLEAR.: 0.0010)				PLUNGER (CLEAR.: 0.003)			VALVE ROD (NOM. OD: 0.688)				
STA (IN.)	TEST CL	WEAR	*/10M HR	STA (IN.)	TEST CL	WEAR	STA (IN.)	TEST OD	WEAR	*/10M HR	
6	0.0010	0.0000	0.0000	3	0.004	0.001	3	0.614	0.074	0.121	
12	0.0015	0.0005	0.0008	6	0.004	0.001	6	0.598	0.090	0.148	
18	0.0015	0.0005	0.0008	9	0.004	0.001	9	0.612	0.076	0.125	
24	0.0012	0.0002	0.0003	12	0.004	0.001	12	0.598	0.090	0.148	
30	0.0012	0.0002	0.0003	15	0.004	0.001	15	0.591	0.097	0.159	
36	0.0012	0.0002	0.0003	18	0.004	0.001	18	0.591	0.097	0.159	
42	0.0012	0.0002	0.0003	21	0.004	0.001	21	0.592	0.096	0.157	
48	0.0012	0.0002	0.0003	24	0.004	0.001	24	0.585	0.103	0.169	
54	0.0012	0.0002	0.0003				27	0.583	0.105	0.172	
60	0.0012	0.0002	0.0003	NOTE: PLUNGER WEAR			30	0.585	0.103	0.169	
66	0.0012	0.0002	0.0003	IS MINIMAL			33	0.588	0.100	0.164	
72	0.0015	0.0005	0.0008				36	0.585	0.103	0.169	
78	0.0015	0.0005	0.0008				39	0.585	0.103	0.169	
84	0.0015	0.0005	0.0008				42	0.591	0.097	0.159	
90	0.0015	0.0005	0.0008				45	0.591	0.097	0.159	
96	0.0015	0.0005	0.0008				48	0.599	0.089	0.146	
102	0.0030	0.0020	0.0033				51	0.617	0.071	0.116	
108	0.0015	0.0005	0.0008				54	0.642	0.046	0.075	

*NOTE: WEAR AMOUNTS ARE NORMALIZED TO 10,000 HOURS. VALVE ROD AND GUIDE WORN SEVERELY

62-16-SX3

PUMP: HF TRT-2		TREATED CARBURIZED BARREL, UNTREATED VALVE ROD									
HOURS OF OPERATION: 5664		12 RPM, 54" STROKE, 100% CLOCK									
BARREL (CLEAR.: 0.0010)				PLUNGER (CLEAR.: 0.003)			VALVE ROD (NOM. OD: 0.688)				
STA (IN.)	TEST CL	WEAR**	/10M HR	STA (IN.)	TEST CL	WEAR	STA (IN.)	TEST OD	WEAR	/10M HR	
6	>0.005	>0.004	N/A	3	0.004	0.001	6	0.612	0.076	0.134	
12	>0.005	>0.004	N/A	6	0.004	0.001	12	0.588	0.100	0.177	
18	>0.005	>0.004	N/A	9	0.004	0.001	18	0.596	0.092	0.162	
24	>0.005	>0.004	N/A	12	0.003	0.000	24	0.588	0.100	0.177	
30	>0.005	>0.004	N/A	15	0.003	0.000	30	0.576	0.112	0.198	
36	>0.005	>0.004	N/A	18	0.003	0.000	36	0.580	0.108	0.191	
42	>0.005	>0.004	N/A	21	0.003	0.000	42	0.661	0.027	0.048	
48	>0.005	>0.004	N/A	24	0.004	0.001	48	0.583	0.105	0.185	
54	>0.005	>0.004	N/A				54	0.601	0.087	0.154	
60	>0.005	>0.004	N/A	NOTE: PLUNGER WEAR			60	0.632	0.056	0.099	
66	>0.005	>0.004	N/A	IS MINIMAL			66	0.688	0.000	0.000	
72	>0.005	>0.004	N/A				72	0.688	0.000	0.000	
78	>0.005	>0.004	N/A								
84	>0.005	>0.004	N/A								
90	>0.005	>0.004	N/A								
96	>0.005	>0.004	N/A								
102	>0.005	>0.004	N/A								
108	>0.005	>0.004	N/A								
114	>0.005	>0.004	N/A								
120	>0.005	>0.004	N/A								

**NOTE: CARBURIZED BARREL WAS HIGHLY SUSCEPTIBLE TO CORROSION IN THIS H2S AND CO2 ENVIRONMENT. ALSO, WELL WAS PUMPED OFF AND OPERATED DRY. VALVE ROD AND GUIDE WORN SEVERELY

73-3-SX3

PUMP: HF TRT-1		TREATED CHROME BARREL, TREATED VALVE ROD									
HOURS OF OPERATION: 3048		12 RPM, 54" STROKE, 50%-60% CLOCK									
BARREL (CLEAR.: 0.0010)				PLUNGER (CLEAR.: 0.003)			VALVE ROD (NOM. OD: 0.688)				
STA (IN.)	TEST CL	WEAR	/10M HR	STA (IN.)	TEST CL	WEAR	STA (IN.)	TEST OD	WEAR	/10M HR	
6	0.001	0.0000	0.000	3	0.003	0.000	3	0.554	0.134	0.440	
12	0.001	0.0000	0.000	6	0.004	0.001	6	0.535	0.153	0.502	
18	0.001	0.0000	0.000	9	0.004	0.001	9	0.518	0.170	0.558	
24	0.002	0.0005	0.001	12	0.004	0.001	12	0.513	0.175	0.574	
30	0.001	0.0000	0.000	15	0.004	0.001	15	0.514	0.174	0.571	
36	0.001	0.0000	0.000	18	0.004	0.001	18	0.504	0.184	0.604	
42	0.001	0.0000	0.000	21	0.004	0.001	21	0.514	0.174	0.571	
48	0.001	0.0000	0.000	24	0.004	0.001	24	0.518	0.170	0.558	
54	0.001	0.0000	0.000				27	0.528	0.160	0.525	
60	0.001	0.0000	0.000	NOTE: PLUNGER WEAR			30	0.560	0.128	0.420	
66	0.001	0.0000	0.000	IS MINIMAL			33	0.585	0.103	0.338	
72	0.001	0.0000	0.000				36	0.609	0.079	0.259	
78	0.001	0.0000	0.000				39	0.631	0.057	0.187	
84	0.001	0.0000	0.000				42	0.653	0.035	0.115	
90	0.001	0.0000	0.000				45	0.664	0.024	0.079	
96	0.001	0.0000	0.000				48	0.677	0.011	0.036	

APPENDIX 5

Tubing Wear Data

CRYOCON TUBING INSPECTION RESULTS					
MILLIKEN 9/01					
STAMP	SEQ	WELL	WT	% LOSS	REJECT
UA1	1	52-2-SX3	0.125	34%	X
TA1	1	52-2-SX3	0.127	33%	X
UA2	2	52-2-SX3	0.140	26%	
TA3	2	52-2-SX3	0.150	21%	
UA3	3	52-2-SX3	0.151	21%	
TB3	3	52-2-SX3	0.166	13%	
UA4	4	52-2-SX3	0.139	27%	
TB4	4	52-2-SX3	0.190	0%	
UB4	1	62-16-SX3	0.159	16%	
TA2	1	62-16-SX3	0.123	35%	X
UB3	2	62-16-SX3	0.190	0%	
TC4	2	62-16-SX3	0.117	38%	X
UB2	3	62-16-SX3	0.190	0%	
TC2	3	62-16-SX3	0.123	35%	X
UB1	4	62-16-SX3	0.190	0%	
TA4	4	62-16-SX3	0.141	26%	
UC1	1	73-3-SX3	0.124	35%	X
TC1	1	73-3-SX3	0.123	35%	X
UC2	2	73-3-SX3	0.137	28%	
TC3	2	73-3-SX3	0.128	33%	X
UC3	3	73-3-SX3	0.127	33%	X
TB1	3	73-3-SX3	0.107	44%	X
UC4	4	73-3-SX3	0.190	0%	X
TB2	4	73-3-SX3	0.133	30%	X

APPENDIX 6

Tubing Wear Logs

