USE OF CAPILLARY INJECTION SYSTEM FOR CONTINUOUS CORROSION INHIBITION

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ABSTRACT

Shell Exploration & Production Company (SEPCo) is currently utilizing capillary injection systems to deliver corrosion inhibition chemicals in several gas wells in their South Texas fields. Traditional methods to handle corrosive production wellbores has been to use Corrosion Resistant Alloys (CRA's) or periodic batch treatments with corrosion inhibition chemicals. The installation of CRA materials has been the preferred method especially in the more corrosive environments but the high cost of these materials can be prohibitive in some installations. Periodic batch treatments have also been widely utilized to protect wells where less corrosive conditions are expected.

The current preferred method to protect wellbore tubulars is to install traditional carbon steel tubulars and install a capillary injection system to continuously deliver corrosion inhibition chemicals. Upon completion of a newly drilled well, a capillary injection string is installed and continuous corrosion inhibition chemical injection begun. Corrosion rates are monitored in the new installation and chemical injection volumes are adjusted to keep corrosions rates under control.

BACKGROUND

SEPCO operates over 300 gas wells in the South Texas counties of Starr and Hidalgo. The majority of these wells produce from the Vicksburg formation at depths from 10,000 to 15,000'. These Vicksburg reservoirs are sandstone reservoirs in a highly faulted region with numerous accumulations typically found in layers bounded by faults. Average reservoir conditions include temperatures from 280 degrees up to 325 degrees Fahrenheit. Initial reservoir pressures are in the 11,000 psi range and are typically produced to a nominal reservoir pressure at abandonment of 2000 psi. Porosity in the pay intervals range from 11-18% and permeability ranges from 0.01-0.05 md.

Drilling began in these fields in the early 1960's and the typical completion consisted of a 5" or 5 ½" production casing with a conventional tubing and packer assembly. The permanent packer would be located several hundred feet above the pay intervals and the individual zone completions would be performed without a workover rig and would be executed through tubing. Hydraulic fractures are typically required to make an economic completion. In the mid 1990's, drilling programs changed and the typical completion design consists of an intermediate casing string (typically 7 5/8") and the production casing is a "drilled in" string of either 3 ½" or 2 7/8" tubing that is cemented in the wellbore and completed as a tubingless completion. Early completions typically consisted of a single pay interval being produced at a time but since the early 1990's, commingling of several intervals has become common.

WELLBORE FLUIDS

Gas production from these wells varies from 5-15 MMCFD for new completions in virgin pressure areas to 2-5 MMCFD for completions in areas with less than original pressure. Flowing tubing pressures for these new completions range from 2,000-10,000 psi and flowing tubing temperatures in the 120-175 degree Fahrenheit range. Light gravity condensate (50-54 degree API) is typically produced with these wells at the rate of 0-25 bbl/mmcf of gas. Produced water is typically of low salinity (<20,000 ppm chlorides) and is produced at rates of 0-50 bbl/mmcf. The gas composition is usually greater than 90% methane with H_2S levels of <30 ppm and CO_2 content of <3%.

CORROSION MONITORING

Current practices utilized for the identification of potentially corrosive wellbores include comparison with offsetting wellbores and their production characteristics and an active monitoring program to measure the presence of iron in the produced water and predict a general corrosion rate based on these measurements. Upon completion of a new wellbore, produced fluids are periodically sampled and a calculation performed to predict a general corrosion rate. The equation used for this calculation is:

$$Fe = (3.5 \times 10^{-4}) \times (bw/mmcf) \times (mmcfd) \times (PPM\ Fe)$$

Where: Fe = iron loss (#/day)
Bw/mmcf = bbls water per mmcf gas
Mmcfd = gas production per day

If this rate is calculated to be greater than our threshold value of 0.5 #/day in 2 7/8" tubing or 0.6 #/day in 3 ½" tubing, an evaluation is done to compare the cost and relative effectiveness of either batch treating or continuous chemical inhibition. If the general corrosion rate is less than our threshold value, the monitoring frequency is reduced and the well production is monitored at less frequent intervals until the well is deemed to be non-corrosive and monitoring ceases. An example of this calculation is found in Table 1 and the plot of the data is shown in Figure 1.

PERIODIC BATCH TREATMENTS

Historically, the periodic batch treatment method is the most common treatment method utilized to inhibit wellbores against modest corrosive environments. In this method, the well is shut in and then a pump truck is utilized to pump the corrosion inhibitor followed by a small flush volume into the wellbore (typically 2 drums of corrosion inhibitor followed by 3 bbls flush). The well is left shut in and the inhibitor treatment is allowed to fall until it has reached the targeted treatment depth. This targeted depth may only be to a certain depth but is typically to the perforations. Upon the batch treatment reaching this target, the well is opened to production and the wellbore energy is used to produce the fluids to surface and the batch is directed down the flowline where it will provide some residual treatment to the flowline.

This type of treatment typically uses a batch treating truck outfitted with a small pump and chemical tankage that is suitable for treatment volumes <10 bbls and pressures less than 3000 psi. For larger volumes, additional tankage is required and for higher pressure applications, a high pressure pump truck is required. The cost for a typical batch treatment is less than $100 + the cost of the chemical. The cost for a high pressure batch treatment with volume greater than 10 bbls is typically in the $3000 range for the equipment alone.

Disadvantages of the batch treatment method include the shutting in of active production, labor intensive, operational upsets and potentially damaging to the near wellbore region. The cessation of production from a given well can cause upsets in compression systems and larger than normal fluid slugs can cause problems with separation systems. The batch treatment method also requires manpower to shut in, perform and re-open the well to production. Damage can also be done to the near wellbore region by reducing effective permeability in the perforations if the corrosion inhibitor is allowed to form a film in this area. Batch inhibition treatments also become less effective in high rate wells because of the breakdown of the corrosion inhibitor film in high velocity applications.

CAPILLARY STRING INJECTION

Another method used to provide corrosion inhibition is to install a capillary injection string in the wellbore and continuously pump small volumes of corrosion inhibition chemicals down the capillary string and allow it to mix with the production fluids in the wellbore near the perforations. The well's energy is then used to continuously deliver corrosion inhibition chemicals to treat the well tubulars and the treatment volume can also be monitored to provide protection to the flowline.

A capillary injection system is purchased from a vendor and installed utilizing a hookup similar to a coiled tubing setup. Historically, 3/8" stainless steel capillary strings were installed to accommodate the viscous quality of the corrosion inhibitor chemical but recent modifications in chemical usage has resulted in a transition to ¼" stainless steel capillary strings. This change has been made possible by using a combination of corrosion inhibition chemical reduced with a solvent. The transition to ¼" capillary injection system has allowed us to standardize our field installation procedure for injection systems for corrosion inhibition service with injection systems designed for production enhancement through foamer injection. The capillary injection string is suspended in the wellbore by a hanger/pack off assembly located on the top of the tree. The capillary string is typically run into the well to a depth 300' above the top perforation.

A semi-annual maintenance program has been established to check the condition of the capillary injection system. A complete inspection of the system is performed and the installation unit is used to tie into the capillary injection string and check the weight of the string and to spool up approximately 300' of the string to confirm the integrity of the string and to make sure that the string has not become stuck in the wellbore.

Standard installation equipment for capillary injection systems has typically consisted of a hanger/packoff system rated for 5,000 psi pressure maximum but recent installations of a hanger/packoff system designed for 10,000 psi pressure maximum have been utilized in new well completions. Upgraded surface equipment is also utilized for these higher pressure rated systems. This higher pressure rated system is designed for use to treat new well completions eliminating the need for periodic batch treatments. An example of the results of a high pressure installation are contained in Table 2 and Figure 2. This data is from a recent installation that shows a high initial corrosion rate in a new well completion that was treated one time with a batch treatment and then a capillary injection system was installed for continuous corrosion inhibition.

SUMMARY

There are currently two methods being utilized to treat wells for corrosion inhibition in the Vicksburg wells located in Starr and Hidalgo Counties in the South Texas area operated by SEPCo. Each method has advantages and disadvantages. Experience has proven that the batch treating method is less expensive (for low pressure applications) but provides a lesser degree of protection and requires increasing treatment frequency as production volumes increase. Batch treated wellbores also typically require continuous inhibitor injection for protection of the flowline and other surface equipment, downhole continuous corrosion inhibition systems will typically protect the flowline and surface equipment without additional equipment. Continuous corrosion inhibition utilizing a capillary injection system has a higher initial cost with a higher daily operating cost but provides a much greater degree of protection that is less disruptive to production operations. A variation of this treatment method is the high pressure treatment system that is significantly less expensive and much more effective than the batch treatment option for higher pressured wellbores. The higher initial cost of the capillary injection systems can be reduced by converting the wells to batch treatments after production volumes and pressures have declined to a point where periodic batch treatments can be utilized and the capillary injection system can be removed and utilized in another new high pressure installation.

TABLE 1

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IRON COUNT DATA

DATE:	PPM IRON	GAS PROD	H2O /MMCF	WATER PROD	MPY CONTROL	MPY RATE	4 SAMPLE AVERAGE	REMARKS OR TREATED	Treated Y or N	CO^2 P.P.
11/07/03	12.50	4.044	10.5	42.5	0.60	0.109	0.036		N	
11/14/03	85.75	4.044	10.5	42.5	0.60	0.746	0.214		N	
11/21/03	33.00	4.044	10.5	42.5	0.60	0.287	0.286	11/6 cap	Y	
11/25/03	76.50	4.044	10.5	42.5	0.60	0.666	0.452	12/1 cont inj	Y	
12/03/03	59.25	4.044	10.5	42.5	0.60	0.516	0.554		Y	
12/08/03	22.50	4.044	10.5	42.5	0.60	0.196	0.630		Y	
12/12/03	22.50	4.044	10.5	42.5	0.60	0.196	0.679		Y	
12/19/03	13.50	4.044	10.5	42.5	0.60	0.118	0.708		Y	
12/23/03	12.75	4.044	10.5	42.5	0.60	0.111	0.155		Y	
12/29/03	24.00	4.044	10.5	42.5	0.60	0.209	0.158		Y	
01/07/04	29.75	4.044	10.5	42.5	0.60	0.259	0.174		Y	
01/14/04	22.25	4.044	10.5	42.5	0.60	0.194	0.193		Y	
01/19/04	32.25	4.044	10.5	42.5	0.60	0.281	0.236		Y	
01/26/04	25.25	4.044	10.5	42.5	0.60	0.220	0.238		Y	
02/06/04	24.50	3.145	10.5	33.0	0.60	0.166	0.215		Y	
02/12/04	23.50	3.145	10.5	33.0	0.60	0.159	0.206		Y	
02/19/04	24.25	3.145	10.5	33.0	0.60	0.164	0.177		Y	
02/25/04	25.50	3.145	10.5	33.0	0.60	0.173	0.165		Y	
03/05/04	24.00	3.145	10.5	33.0	0.60	0.162	0.165		Y	
03/17/04	21.25	2.837	10.5	29.8	0.60	0.130	0.157		Y	
03/22/04	19.25	2.837	10.5	29.8	0.60	0.118	0.146		Y	
04/02/04	22.75	2.837	10.5	29.8	0.60	0.139	0.137		Y	
04/08/04	34.00	2.837	10.5	29.8	0.60	0.208	0.148		Y	
04/15/04	26.75	2.837	10.5	29.8	0.60	0.163	0.157		Y	
04/22/04	18.25	2.837	10.5	29.8	0.60	0.111	0.155		Y	
04/29/04	20.00	2.837	10.5	29.8	0.60	0.122	0.151		Y	
05/05/04	14.50	2.837	10.5	29.8	0.60	0.089	0.121		Y	
05/12/04	11.25	2.716	10.5	28.5	0.60	0.066	0.097		Y	
05/19/04	15.00	2.716	10.5	28.5	0.60	0.088	0.091		Y	
05/26/04	16.00	2.716	10.5	28.5	0.60	0.094	0.084		Y	
06/03/04	18.00	2.596	10.5	27.3	0.60	0.101	0.087		Y	
06/09/04	8.25	2.596	10.5	27.3	0.60	0.046	0.082		Y	
06/15/04	16.75	2.596	10.5	27.3	0.60	0.094	0.083		Y	
06/22/04	15.00	2.596	10.5	27.3	0.60	0.084	0.081		Y	
07/01/04		2.596	10.5	27.3	0.60			R&R		
07/15/04	64.00	2.388	10.5	25.1	0.60	0.329	0.169		Y	
07/21/04	65.25	2.388	10.5	25.1	0.60	0.335	0.249		Y	
08/06/04	17.75	1.961	10.5	20.6	0.60	0.075	0.246		Y	
08/12/04	13.50	1.961	10.5	20.6	0.60	0.057	0.199		Y	
08/20/04	21.25	1.961	10.5	20.6	0.60	0.090	0.139		Y	
08/25/04	18.50	1.961	10.5	20.6	0.60	0.078	0.075		Y	

Table 2

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IRON COUNT DATA

DATE:	PPM IRON	GAS PROD	H2O /MMCF	WATER PROD	MPY CONTROL	MPY RATE	4 SAMPLE AVERAGE	REMARKS OR TREATED	Treated Y or N	CO^2 P.P.
		0.000	0.0							
07/20/04	37.25	9.188	11.8						N	
08/04/04	68.50	9.188	11.8	108.4	0.50	2.935	2.935		N	
08/10/04	63.50	9.188	11.8	108.4	0.50	2.721	2.828		N	
08/19/04	60.25	11.220	11.8	132.4	0.50	3.152	2.936		N	
08/23/04	44.75	11.220	11.8	132.4	0.50	2.341	2.787		N	
09/02/04	43.50	11.220	11.8	132.4	0.50	2.276	2.623		N	
09/08/04	51.00	10.483	7.1	74.4	0.50	1.500	2.317		N	
09/13/04	61.50	10.483	7.1	74.4	0.50	1.809	1.982		N	
09/20/04	42.00	10.483	7.1	74.4	0.50	1.235	1.705		N	
09/30/04	44.75	10.483	7.1	74.4	0.50	1.316	1.465		N	
10/07/04	47.50	9.873	7.1	70.1	0.50	1.316	1.419		N	
10/11/04	46.75	9.873	7.1	70.1	0.50	1.295	1.291		N	
10/18/04	40.25	9.873	7.1	70.1	0.50	1.115	1.261		N	
10/29/04	44.50	9.582	7.1	68.0	0.50	1.196	1.231		N	
11/08/04	42.50	9.582	7.1	68.0	0.50	1.143	1.187		N	
11/15/04	12.50	9.582	7.1	68.0	0.50	0.336	0.948		Y	
11/29/04	22.75	9.582	7.1	68.0	0.50	0.612	0.822		Y	

Recommended Shut in Time (Hours) = 5.82

IRON LOSS FACTOR =	0.88261	bbls Oil/Day	169.1223
Well Depth To Perfs=	11330	FTP	4150
Shut in Tubing Pressure=	8300		
Fall Rate (ft/hr)=	1947.88		
Tubing Size =	2.875		
MPY Factor =	89.00		
intercept =	6157.14	Oil Factor	0.01765
slope =	-0.5071		
CO2=	0.2		

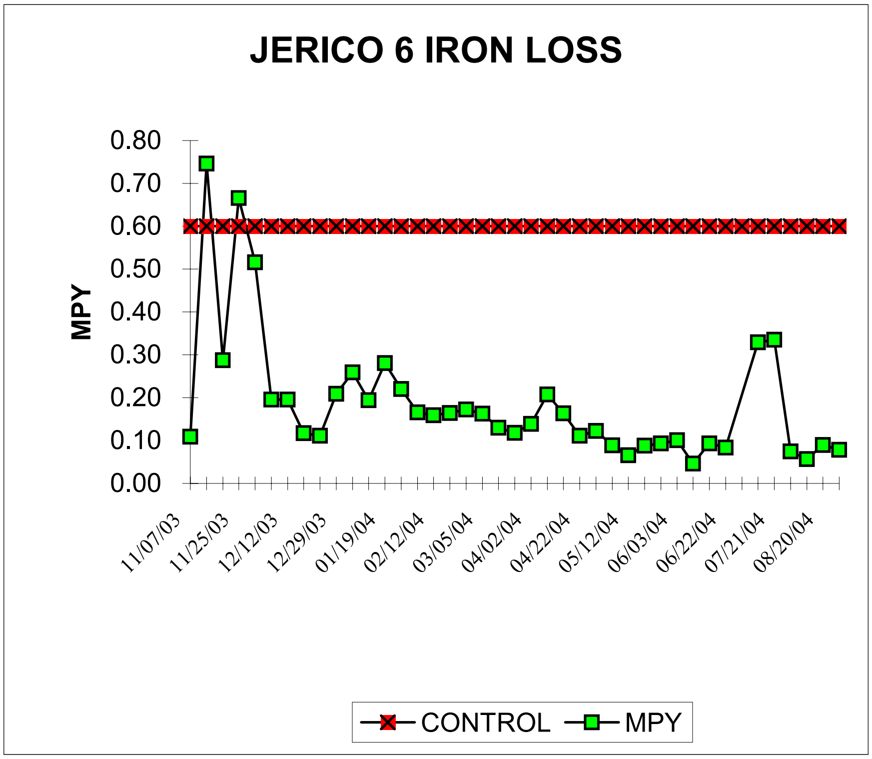

Figure 1

Woods Christian 45 Iron Loss

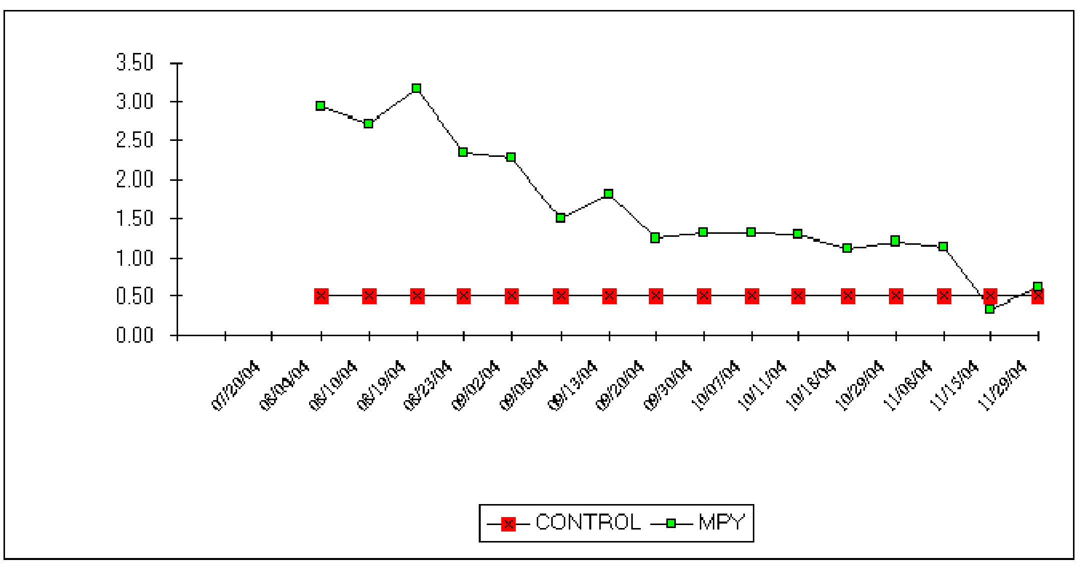

Figure 2