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conoco

Mid-Continent Region
Exploration/Production

Conoco Inc.
10 Desta Drive, Suite 100W
Midland, TX 79705-4500
(915) 686-5400

6-36-31N-09W

October 1, 1997

Mr. Ernie Busch
New Mexico Oil Conservation Division
1000 Rio Brazos Rd.
Aztec, NM 87410

Subj.: Well Status of State Com J #6

Dear Mr. Busch:

According to the chromatographic gas analysis report (attached) performed by the El Paso Natural Gas Company, the content of carbon dioxide (CO_2) is 1.31 % by mole. With a bottom hole pressure of approximately 400 pounds, the partial pressure of CO_2 is less than 7 psi and the well environment is generally considered as non-corrosive* (attached). This is further supported by a water analysis (attached) performed on September 9, 1997 by BJ Services Company. Though the results of the water analysis indicate some corrosion activity with a pH of 6.62, the level of iron count (Fe^{++}) is below measurable limit.

Based on the available information about State Com J #6, my best judgement is that the degree of corrosion on current wellbore equipment is fairly insignificant. Corrosion on the casing string has also been mitigated externally by the application of cathodic protection.

Sincerely,

Steve C.K. Tsai

Steve C.K. Tsai
Chemical/Corrosion Advisor
Operations & Services

RECEIVED
OCT - 1 1997
OIL CON. DIV.
DIST. 3

/Attachment

* Reference: L. Garverick, eds. Corrosion in the Petroleum Industry. ASM International, Metals Park, Ohio, 1994.

RECEIVED

[illegible] 1987

PRODUCTION RECORDS

07-08-87

EL PASO NATURAL GAS COMPANY
MEASUREMENT DEPARTMENT
POST OFFICE BOX 1492
EL PASO, TEXAS 79978

MAILEE
04515

CHROMATOGRAPHIC GAS ANALYSIS REPORT

MESA OPERATING LTD PARTNERSHIP
P. O. BOX 2009
AMARILLO, TX 79189

ANAL DATE 00-00-00

METER STATION NAME
STATE COM J #6

METER STA 70137
OPER 6014

TYPE CODE	SAMPLE DATE	EFF. DATE	USE MOS	H2S GRAINS	LOCATION
00 ***	06-18-87	06-28-87	06	0	4 F 12

	NORMAL MOL%	GPM
CO2	1.31	.000
H2S	.00	.000
N2	.28	.000
METHANE	85.56	.000
ETHANE	7.48	2.001
PROPANE	3.10	.854
ISO-BUTANE	.56	.183
NORM-BUTANE	.76	.240
ISO-PENTANE	.27	.099
NORM-PENTANE	.20	.072
HEXANE PLUS	.48	.209
	100.00	3.658

SPECIFIC GRAVITY	.677
MIXTURE HEATING VALUE (BTU/CF @14.73 PSIA, 60 DEGREES,DRY)	1167
RATIO OF SPECIFIC HEATS	1.288

NO TEST SECURED FOR H2S CONTENT

*** TYPE CODE EXPLANATION SINGLE METER ANALYSIS

GXC

DATE 8/10/87
REGULATORY
MARKETING
WF

RULES OF THUMB FOR EVALUATING CORROSION IN WILDCAT GAS/CONDENSATE DISCOVERIES

Generally when a discovery is remote from a pipeline connection, after testing, the well will be closed-in for an extended period. This is to determine the required processing plant for producing the reservoir and sizing the pipeline after reservoir evaluation, and possibly includes the drilling of additional wells. The major problem for the corrosion engineer is to obtain enough data in the well testing to evaluate the corrosivity of the well. This can be particularly important if a long closed in period is anticipated. With highly corrosive well fluids, an optimum corrosion inhibitor "mothballing" program may be required for protecting the wellbore equipment. Also, where additional wells are required for reservoir evaluation, and highly corrosive gas is produced, special alloys may be necessary for wellhead and wellbore equipment.

The primary objective of the operator in testing is to determine a well's productive capacity. Tests usually consist of measuring producing rates at various choke settings. If a major discovery is anticipated, tests will also determine approximations of the water and condensate to gas ratios. Frequently the produced gas is analyzed.

In addition to this test data measurements or reasonable estimates are available on surface and bottomhole pressure and temperature conditions. Generally this is the most data the corrosion engineer can expect for his corrosivity evaluation.

In a corrosion evaluation the volume of acid gas components, (H_2S and/or CO_2) are of major concern. These will normally be included in the analysis of the test gas. The following reviews the "rules of thumb" used in estimating the corrosivity of these acidic gas components.

I - CARBON DIOXIDE

The most generally quoted "rules of thumb" for predicting corrosion in sweet (CO_2) gas wells were first published in the late fifties in the API Vocational Training Series, Book 2:

GAS/CONDENSATE WELLS GUIDELINES FOR PREDICTING CORROSION

1. Partial Pressure of CO_2 over 30 psi Indicates Corrosion
2. Partial Pressure of CO_2 Between 7 & 30 psi May Indicate Corrosion
3. Partial Pressure of CO_2 Below 7 psi Considered Non-corrosive

Field experience has established the below 7 psi P.P. is generally valid. Unfortunately many of the wells drilled today have a 7 to 30 psi P.P., the range of uncertainty. Considering drilling and workover costs of today's wells, until proven otherwise, most corrosion engineers will assume wells are corrosive in the 7 to 30 psi P.P. range.

Another factor to be considered in applying the 7 psi P.P. limitation is the increase in Partial Pressure with increasing well depth and pressure. When available the Partial Pressure calculation should be based on bottomhole pressure. When not available this pressure can be estimated from Figure 1.

Using the example of the curve and a gas analysis indicating 0.23 Mol Percent CO_2;

Wellhead Partial Pressure = 0.0023 X 3000 = 6.9 psi

Bottomhole Partial Pressure = 0.0023 X 3630 = 8.4 psi

Based on Partial Pressure at Bottomhole conditions this well would be classified as corrosive.

Discounting stress cracking as a possibility, sweet corrosion (CO_2), is the more serious of the acidic gas type attacks. It will generally initiate as large, deep isolated pitting, frequently progressing to the typical ringworm form. When not controlled, tubing failures due to pit penetration can be very premature. Fortunately, sweet corrosion is easy to control with an adequate corrosion inhibition program.

II - HYDROGEN SULFIDE

Unfortunately from only gas analyses the seriousness of sour corrosion (H_2S) is more difficult to predict. This reflects the variety of forms in which it may occur. Corrosion affects can vary from a thin, impermeable, inhibiting film of iron sulfide (Fe_xS_y) through a general attack, to isolated, deep pitting. Also, in pitting, the tenacity and permeability of the corrosion product formed can vary widely. It may either reduce the rate of metal loss or with deep pitting increase the rate of penetration. Also, as reported in the 2nd Quarter issue in the item titled, "Iron Sulfide Precipitated as a Scale in Sour Gas Wells", occasionally a very serious type corrosion may occur in the lower tubing section.

In a sour gas well discovery, where the question is the degree of protection required during an extended shut-in period, and only a gas analysis is available, the following are suggested as the basis of judging corrosivity:

0 - 250 ppm H_2S = mild corrosion

250 & up ppm H_2S = serious corrosion

These limits are based on the curve in Figure 2, and the following assumptions.

While the pH of the produced water is unknown, most discovery wells will be completed above the water table. The water produced during testing, and probably for a reasonable period after the well is placed on production, will generally be the condensate type. The evolved condensate water is solids free with a neutral (pH = 7.0).

In all/gas condensate wells trace amounts of interstitial water are produced. This water is frequently high in solids and can have a low pH. However in new wells the volume is small compared to the condensate water and the pH of the mixture will generally be in the 6.0 - 7.0 range.

As noted from the curve in this pH range, the relative corrosion is low for 250 ppm of H_2S. With only a gas analysis available as a basis for predicting corrosion the allowable of up to 250 ppm H_2S is considered reasonable.

III - PRODUCED WATER INFORMATION

While a complete analysis of produced water is always desirable the two items that are particularly important in an initial corrosivity evaluation are pH and salinity.

The important of pH's is that when used in conjuction with the acidic components in the gas analyses it will further confirm the possibilities of corrosion.

As noted above, with sweet corrosion (CO_2), it is probable the attack will be of the deep pitting type. Also the corrosion product formed is often soft and flocculant. This is readily eroded by the flowing gas and liquids, increasing the possibility of a corrosion/erosion type attack. For this reason unless the Partial Pressure of the CO_2 is markedly below the 7 psi limit (P.P. = ±5 psi) it is suggested that:

Sweet Gas - pH below 7.0 indicates significant corrosion

With sour gas (H_2S) the pH can be directly related to the data of Figure II. For this type analysis it is suggested:

Sour Gas - pH below 6.5 indicates significant corrosion

The salinity of the produced water is an indication of amount of interstitial water being entrained in the gas as it enters the wellbore. The Slip and Hold-up of condensate water assures its presence, and dilution of interstitial water at the bottom of the hole. A salinity over 500 ppm indicates interstitial water will predominate in the lower section of the producing string. Under these conditions corrosion could be occurring in the bottom of the well even when other guidelines indicate no significant corrosion.

IV - WATER/GAS RATIO

Initial well tests are frequently through test separators to obtain approximations of the rates of condensate and water production. While individual measurements can vary widely, if a reasonable average can be obtained the

FW01W210

BJ SERVICES COMPANY

WATER ANALYSIS #FW01W210

FARMINGTON LAB

GENERAL INFORMATION

OPERATOR:	CONOCO INC.	DEPTH:	
WELL:	STATE J-6	DATE SAMPLED:	05/19/97
FIELD:		DATE RECEIVED:	05/19/97
SUBMITTED BY:	TOMMY BROOKS	COUNTY:	STATE:NM
WORKED BY	:D. SHEPHERD	FORMATION:	
PHONE NUMBER:			

SAMPLE DESCRIPTION

SEPARATOR SAMPLE

PHYSICAL AND CHEMICAL DETERMINATIONS

SPECIFIC GRAVITY: 1.000 @ 74°F PH: 6.62

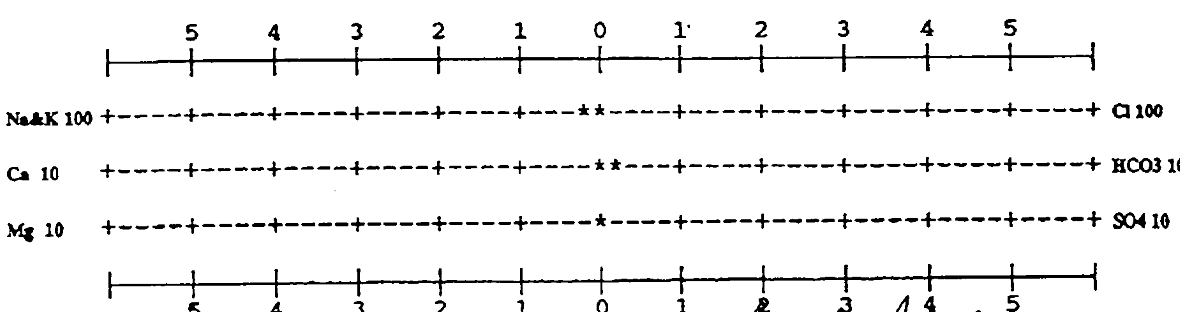
RESISTIVITY (MEASURED): 10.000 ohms @ 75°F

IRON (FE++) :	0 ppm	SULFATE:	0 ppm
CALCIUM:	20 ppm	TOTAL HARDNESS	60 ppm
MAGNESIUM:	2 ppm	BICARBONATE:	134 ppm
CHLORIDE:	355 ppm	SODIUM CHLORIDE(Calc)	583 ppm
SODIUM+POTASS:	253 ppm	TOT. DISSOLVED SOLIDS:	802 ppm
H2S: NO TRACE		POTASSIUM CHLORIDE: 11 PPM	

REMARKS

SEPARATOR SAMPLE APPROX. 90% OIL
WELLHEAD SAMPLE CONSISTS OF PARRAFIN & EMULSIONS

STIFF TYPE PLOT (IN MEQ/L)



ANALYST D. Shepherd
D. SHEPHERD

API_WELL_N	LEASE_NAME	**CURR_WEL	PROD_DATE_	AYS_PROD	GAS_-_PROD	OIL_-_PROD	WATER_-_PR
00451007000	STATE COM J	6	9708	31	63781	11	11
00451007000	STATE COM J	6	9707	27	61902	110	110
300451007000	STATE COM J	6	9706	26	59123	49	49
300451007000	STATE COM J	6	9705	25	71151	138	69
300451007000	STATE COM J	6	9704	18	43031	93	186