FORREST A. GARB & ASSOCIATES, INC.

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November 29, 2006

Mr. Patrick McKinney
Cano Petroleum, Inc.
Burnett Plaza
801 Cherry Street, Unit 25, Suite 3200
Fort Worth, Texas 76102

Re: Negative Gas Reserves Revision

Dear Mr. McKinney:

In response to the letter dated November 9, 2006, from the United States Securities and Exchange Commission (SEC) to Cano Petroleum, Inc. (Cano) concerning Cano's registration statement filed on October 13, 2006, Forrest A. Garb & Associates, Inc. (FGA) submits the following comments. These comments only address item 11 of this letter relating to the negative revision of gas reserves from July 1, 2005, to July 1, 2006.

The 7.2 billion cubic feet (Bcf) of proved gas reserves were included as of July 1, 2005, because Cano was, at that time, producing and was capable of selling the gas through leased processing equipment that removed excess oxygen from the gas, thus allowing it to meet a maximum oxygen content quality specification contained in the then gas contract. By July 1, 2006, Cano had elected not to renew its lease of the equipment and had canceled its gas contract, thus no gas was being sold. As-of July 1, 2006, Cano had a new gas contract; however, a minimum gas quality remained in the contract. The produced gas did not meet the minimum requirements; therefore, the gas could not be included as proved reserves. As-of July 1, 2006, Cano planned recompletions to the Duffer gas zone to improve the overall gas quality in the field, but the reserves associated with the Duffer gas zone could not be considered proved by July 1, 2006.

The remainder of the 16.4 Bcf of negative revision can be attributed to gas production from the Panhandle field. As the Panhandle field was acquired after the July 1, 2005 reporting period, it was not included in the July 1, 2005 report; however, reserves were determined at the time of acquisition. The gas reserves reported at the time of acquisition decreased from the time of acquisition to July 1, 2006, primarily due to a significantly lower gas price used for the latter reserves determination at July 1, 2006.

This letter is submitted in place of our letter dated November 13, 2006. If you have any questions or need clarification on any of these points, please do not hesitate to contact us.

Yours truly,

Forrest A. Garb & Associates, Inc.

Forrest A. Garb & Associates, Inc.

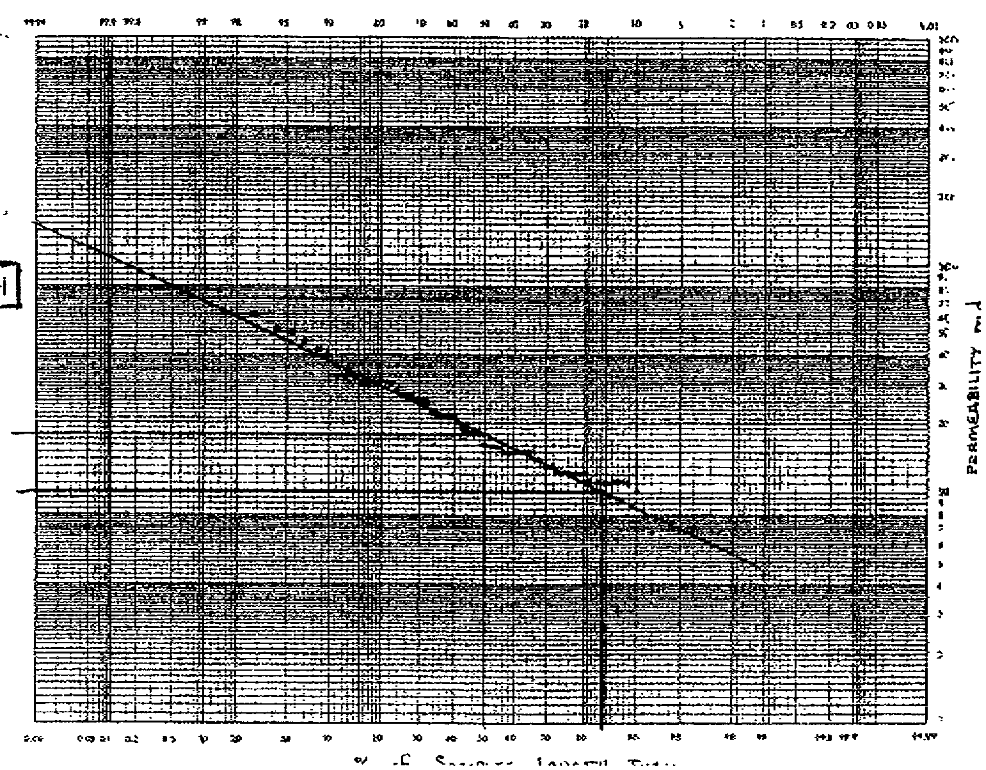
Appendix A: Background Information

PROPERTY	FIELD			
	NOWATA	PANHANDLE	DAVENPORT	DESDEMONA
RESERVOIR:				
Dimensions (ft): Depth of reservoir top (DT) Dimensions of pay zone	DT = ~650 ft Thickness = ~25	DT = 3100 deep Thickness = ~34 ft	DT = 3300 deep Thickness = ~27 ft	DT = 2000 deep Thickness = ~14 ft
Permeability (md)	30	133	90	344
Porosity (%)	18	15	20	13
Composition	Sandstone	Dolomite	Sandstone	Sandstone
Wettability				
Fracture		Some vugs		
Temperature (oC)	26	49	52	49
Pressure (psi)	300	10	1600	120
History	Water flooded	Not water flooded	Water flooded Primary: 22% OOIP Secondary: 15% OOIP	Not water flooded
WELL				
Spacing (acre)	5	40	20	10
Completion	Cased/Perforated	OH	Cased/Perf & OH	Cased/Perf
Others				
CRUDE OIL:				
Viscosity (cp)				
Density (API)	34	38	48	37
Acid number				
FORMATION WATER				
Salinity			150000	
Multivalent cations				
Others				
INJECTION WATER				
Salinity	Same as Produced	Fresh	Same as Produced	Unknown
Multivalent cations				
Others				

SPE 1801)

Dykstra-Parson's Plot

Cockrell Ranch #34



& SPE 1801 Data
Cockrell Ranch #67

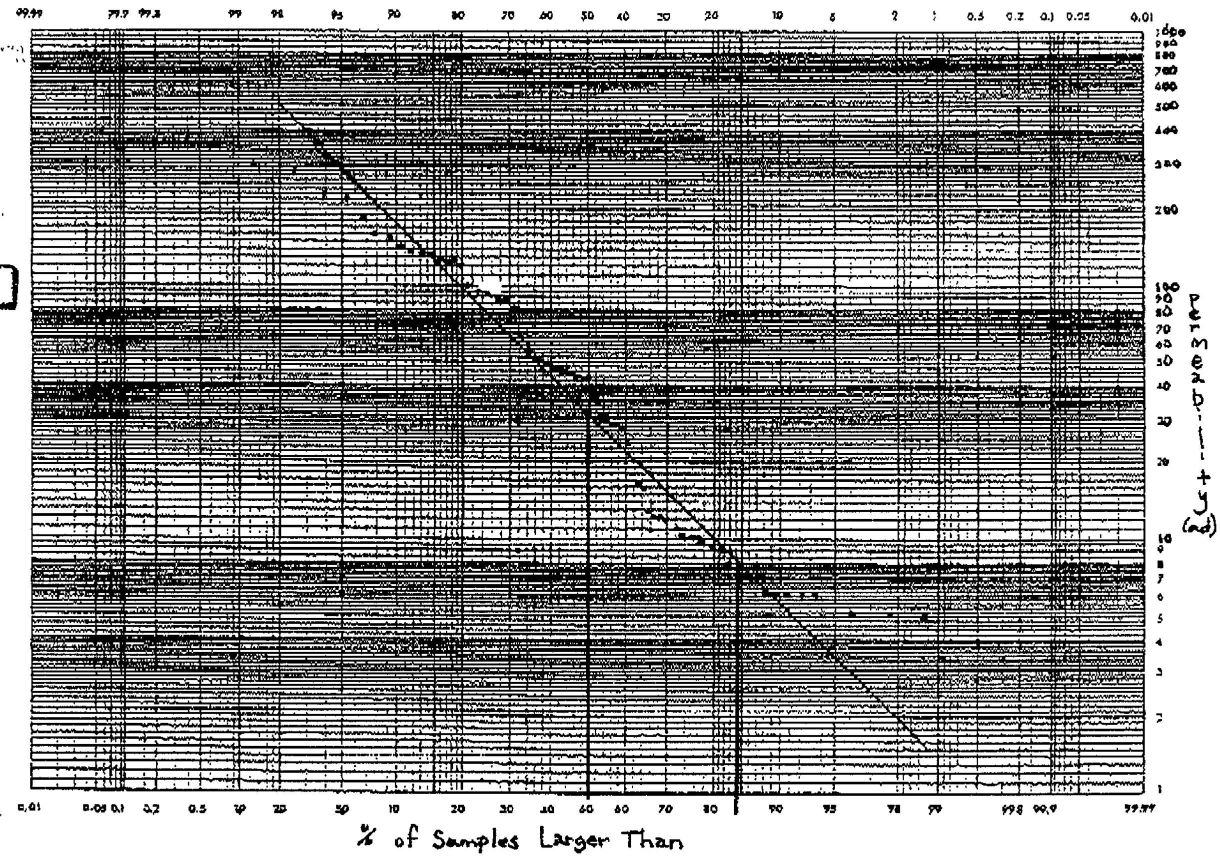
$V = \frac{k_{50} - k_{84.1}}{k_{50}}$

$k_{50} = 31$

$k_{84.1} = 8.5$

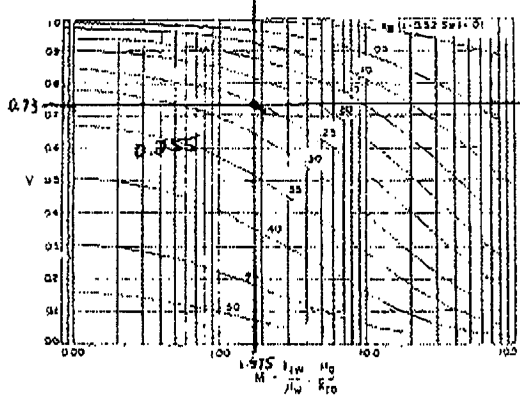
$V = \frac{31 - 8.5}{31}$

$\boxed{V = 0.73}$



COCKRELL RANCH #67

Givens
$V = 0.73$
$M = 1.875$
$S_w = 0.40$
Primary Recovery = 25%



$E_R(1-0.52S_w)=0.255$

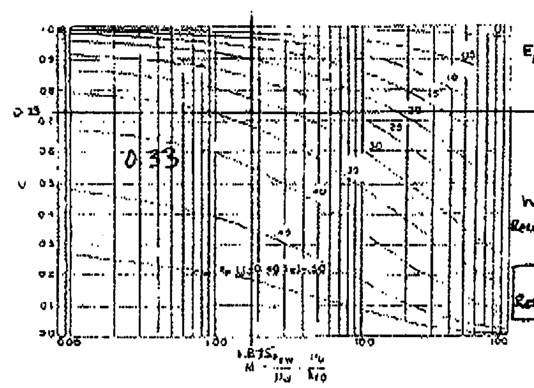
$E_R = \frac{0.255}{1-0.52(0.40)}$

$E_R = 0.322$

WF Recovery = 0.322 − 0.25

$\boxed{\text{WF Recovery} = 7.2\%}$

Fig. 8.3 Permeability variation plotted against mobility ratio, showing lines of constant $E_R(1-0.52\,S_w)$ for a producing WOR of 25.[14]



$E_R(1-0.4S_w)=0.33$

$E_R = \frac{0.33}{(1-0.4(0.4))}$

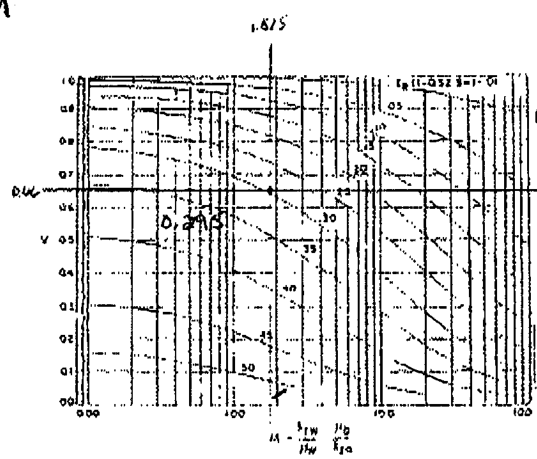
$E_R = 0.393$

WF Recovery = 0.393 − 0.25

$\boxed{\text{WF Recovery} = 14.3\%}$

Fig. 8.4 Permeability variation plotted against mobility ratio, showing lines of constant $E_R(1-0.40\,S_w)$ for a producing WOR of 100.[14]

#79



$E_R(1-0.52\,S_w) = 0.295$

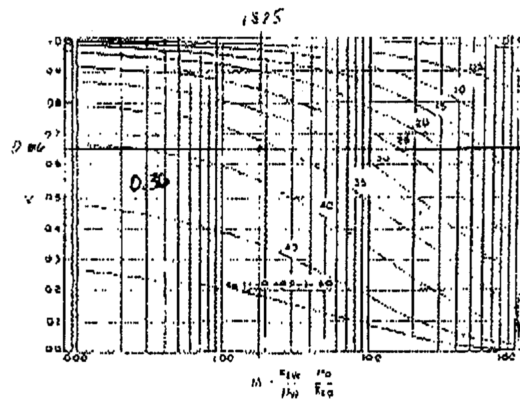
$E_R = \frac{0.295}{(1-0.52(0.4))}$

$E_R = 0.372$

WF Recovery $0.372 - 0.25$

NF Recovery 0.122

Fig. 8.3 Permeability variation plotted against mobility ratio, showing lines of constant $E_R\,(1-0.52\,S_w)$ for a producing WOR of 25.[11]



$E_R(1-0.4\,S_w) = 0.36$

$E_R = \frac{0.36}{(1-0.4(0.4))}$

$E_R = 0.429$

WF Recovery $= 0.429 - 0.25$

NF Recovery 0.179

Fig. 8.4 Permeability variation plotted against mobility ratio, showing lines of constant $E_R\,(1-0.40\,S_w)$ for a producing WOR of 100.[11]

Panhandle Waterflood

722

30

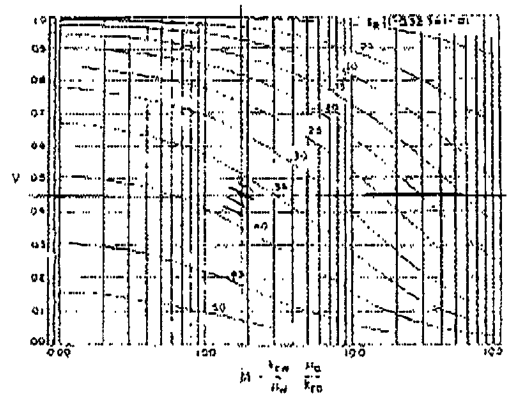
Lease	NRI (%)	GOR (scf/Bbl)	Btu factor	Avg Current Water Cut	Acres	Patterns	CumPats	Primary Remain Oil (MBbl)	Primary Remain Gas (MBbl)	Primary Ultimate Oil (MBbl)	Primary Ultimate Gas (MBbl)	OOIP (Assume 20% Recovery) (MBO)	OOIP/Acres	WF Reserves (7% of OOIP) Unrisked (MBO)	Risk WF Reserves/Acres	WF Reserves (7% of OOIP) Risked*NRI (MBO)	WF Reserves (7% of OOIP) Risked*NRI+BtuGas (MBO)	WF Reserves (7% of OOIP) Risked (MBO)	cum wf mbo	Comments
SCHAFER MULTI	87.50%	3500	0.812	0.85	3076	103	103	7.13	0	885.35	150.25	107392	35	7511	2.44	6578	8035	7517	7517	
FEE -244- 172R	81.25%	2500	0.788	0.85	2880	96	199	315.81	797.42	18792.03	13014.11	93980	33	6577	2.28	5344	6563	6577	14095	
COCKRELL RANCH T-K A&B MULTI	74.75%	5000	1.028	0.75	1499	50	248	93.65	442.01	9224.77	12458.69	46124	31	3229	1.08	1207	1980	1614	15709	Risk adjusted for high initial water cut (50%)
HARVEY UNIT MULTI	64.56%	1500	0.968	0.8	1321	44	292	62.88	57.11	4861.31	7225.78	24307	18	1701	0.64	549	811	851	16560	Risk adjusted for high initial water cut (50%)
KINGSLAND -B- MULTI	87.50%	5000	1.400	0.8	1099	37	329	70.7	91.81	1500.28	1345.61	9621	9	673	0.31	295	455	337	16896	Risk adjusted for high initial water cut (50%)
HUTCH-O JORDAN MULTI	75.00%	1500	0.951	0.7	1023	34	363	61.32	64.5	1469.93	899.04	7350	7	514	0.50	385	429	514	17411	
COCKRELL -B- 6 L	87.50%	1070	1.429	0.4	911	30	393	17.38	0	105.71	5.22	4828	5	338	0.22	174	185	199	17610	Not identified on Cano map, but assumed to be on major trend & included in WF PUD
BRYAN E F MULTI	81.25%	3500	0.770	0.55	701	23	417	15.53	32.37	268.49	414.92	1442	2	101	0.14	82	99	101	17711	
LONG MULTI	81.25%	7500	1.307	0.75	679	23	439	24.95	169.68	1414.88	2006.31	7070	10	495	0.38	201	355	247	17958	Risk adjusted for high initial water cut (50%)
QUINN MULTI	75.00%	5700	1.233	0.7	640	21	461	102.48	238.2	2068.35	1027.73	10340	16	724	1.13	543	632	724	18682	
HARRAH W W (T) MULTI	87.50%	6000	1.519	0.4	608	20	481	12.76	108.35	2763.21	1831.92	27786	46	1944	3.20	1701	2909	1944	20626	
COOPER E NCT-C MULTI	75.00%	800	1.135	0.73	571	19	500	111.28	320.81	392.22	563.9	1961	3	137	0.24	108	110	137	20763	
BLOCK ABC MULTI	72.98%	3898	1.164	0.36	516	17	517	57.37	204.22	851.82	609.3	4309	8	302	0.58	220	298	302	21064	
SACKETT RUBY MULTI	87.50%	4000	0.904	0.6	446	15	532	24.7	93.84	1356.94	1834.15	6780	15	475	1.06	415	532	475	21539	
HALE MULTI	75.00%	10	1.101	0.8	419	14	546	12.93	60.12	1528.57	1648.19	7643	18	535	0.65	201	201	267	21807	Risk adjusted for high initial water cut (50%)
NEWBLOCK-LANGDON MULTI	75.00%	1500	1.285	0.8	405	14	559	98.55	144.82	896.1	392.28	4476	11	313	0.39	117	135	157	21963	Risk adjusted for high initial water cut (50%)
COOPER B & E MULTI	70.32%	4000	1.059	0.7	368	12	572	31.37	125.49	1818.38	603.2	9092	25	636	1.73	448	590	636	22600	
PITCHER H C ETAL MULTI	75.00%	2500	0.927	0.75	331	11	583	49.53	123.83	1889.98	1788.7	9450	29	661	1.00	248	293	331	22930	Risk adjusted for high initial water cut (50%)
POPE DAVE MULTI	87.50%	7000	0.908	0.8	331	11	594	10.2	172.7	936.06	2454.3	4680	14	328	0.49	143	214	164	23094	Risked due to small isolated lease (50%)
SOUTHLAND -B- 7 L	75.00%	13000	0.618	0.95	324	11	605	18.47	0	73.58	2.55	1646	5	108	0.15	36	87	48	23142	Risk adjusted for possible gas cap plus high initial water cut (25%)
COOPER E NCT-A MULTI	75.00%	10000	1.448	0.7	289	10	615	53.83	484.46	227.09	1044.51	1136	4	78	0.13	30	83	40	23182	Risk adjusted for possible gas cap (50%)
SIN-HARRAH MULTI	87.50%	4500	1.124	0.8	265	9	623	11.73	52.77	1165.92	1715.42	5830	22	408	0.77	179	249	204	23386	Risked due to small isolated lease (50%)
BONEY T J NCT-1 MULTI	74.75%	1000	1.000	0.8	265	9	632	43.81	0	1082.96	1297.81	5415	20	379	0.72	142	153	190	23575	Risk adjusted for high initial water cut (50%)
CITIES SERVICE -C- MULTI	87.50%	7000	0.550	0.75	265	9	641	28.89	237.31	544.12	898.1	2721	10	190	0.36	83	108	95	23670	Risk adjusted for high initial water cut (50%)
MOORE J W MULTI	87.50%	1500	1.622	0.7	285	9	650	10.05	20.06	137.59	374.81	688	3	48	0.09	21	25	24	23694	Risked due to small isolated lease (50%)
MCCONNELL J C -A- MULTI	75.00%	3000	0.999	0.7	239	8	658	110.87	254.54	468.8	905.28	2344	10	164	0.69	123	152	164	23858	
VAHIMAN F A MULTI	87.50%	7000	0.713	0.5	172	6	664	46.73	233.63	288.16	1512.29	1441	8	101	0.29	44	51	50	23909	Risked due to small isolated lease (50%)
BONEY T J NCT-4 MULTI	81.25%	5000	0.650	0.75	182	5	669	5.85	31.31	366.29	519.05	1831	11	128	0.40	52	65	64	23973	Risk adjusted for high initial water cut (50%)
COOPER -C- MULTI	63.07%	18000	1.609	0.85	160	5	674	97.63	177.06	2110.00	981.04	10550	66	739	2.31	307	956	369	24342	Risk adjusted for possible gas cap (50%)
BLOCK B F MULTI	75.07%	4650	1.218	0.75	160	5	680	12.19	106.48	1763.41	707.33	8817	55	617	1.93	232	334	309	24651	Risk adjusted for high initial water cut (50%)
COOPER E NCT-B MULTI	75.00%	1400	0.856	0.86	160	5	685	113.8	170.7	662.75	825.67	3314	21	232	1.45	174	190	232	24883	
																				Not identified on Cano map, but assumed to be on major trend & included in WF PUD.
BONEY T J NCT-2 MULTI	81.25%	3000	0.743	0.8	160	5	690	5.05	155.73	599.15	1175.46	2996	19	210	0.66	85	100	105	24988	Risk adjusted for high initial water cut (50%)
COOPER -A- MULTI	73.09%	2000	1.132	0.7	142	5	695	30.06	55.22	1022.17	440.11	5111	36	358	2.52	261	308	358	25345	
CASTLEBERRY -B- MULTI	87.50%	4500	1.584	0.3	142	5	700	3.79	39.95	589.61	875.27	2949	21	206	0.73	90	140	103	25449	Risked due to small isolated lease (50%)
BLOCK MULTI	75.00%	15000	0.989	0.7	133	4	704	2.16	16.85	480.52	408.37	2403	18	168	0.83	63	135	84	25533	Risk adjusted for possible gas cap (50%)
COOPER -B- MULTI	62.50%	1000	1.159	0.8	128	4	708	8.47	3.16	217.58	200.51	1088	8	76	0.59	48	52	76	25609	
COOPER OLIVE MULTI	87.50%	1200	1.340	0.7	116	4	712	136.18	163.42	1505.62	467.57	7528	65	527	4.54	461	519	527	26135	
COCKRELL -F- 8 L	87.50%	5000	1.000	0.85	118	4	716	5.01	0	1708	9.45	2055	18	144	0.52	63	87	72	26206	Risk adjusted for high initial water cut (50%)
SEIBOLD MULTI	75.00%	2400	1.072	0.75	99	3	720	33.98	83.92	1786.49	560.88	8932	90	625	3.16	234	282	313	26520	Risk adjusted for high initial water cut (50%)
ARNOLD RALPH MULTI	87.50%	5840	1.091	0.7	80	3	722	13.81	95.79	1291.94	1580.94	6460	81	452	2.83	198	298	226	26747	Risked due to small isolated lease (50%)
COCKRELL -B- MULTI				0.6		0	722	14.38	0	64.99	74.04					0	0			Not identified on Cano map, but assumed to be on major trend & included in WF PUD
COCKRELL -D- MULTI				0.8		0	722	14.41	23.15	794.49	530.07					0	0			Risk adjusted for high initial water cut (50%)
COCKRELL -F- MULTI		1000		0.7		0	722	23.85	0	240.34	109.85					0	0			Risked due to small isolated lease (50%)
HARRAH W W MULTI		2510		0.25		0	722	42.58	145.22	2769.31	2075.3					0	0			
KINGSLAND MULTI				0.75		0	722	55.88	65.23	301.44	290.1					0	0			Risk adjusted for high initial water cut (50%)
MAGIC MULTI				0.75		0	722	19.71	58.08	122.47	265.43					0	0			Risk adjusted for high initial water cut (50%)
SCHAFER RANCH 71		3500		0.8		0	722			31116.5	18173.81					0	0			From Tom: 34,913 OOIP/Acre * 3,076 Acres
SOUTHLAND -B- MULTI				0.6		0	722	14.64	162.87	235.63	703.8					0	0			Risk adjusted for possible gas cap (50%)
Eco Line 1					35													10		
Eco Line 2					10000	722												10000		
Eco Line 3					35													10		
Eco Line 4					10000													5500		
Eco Line 5					23													10		
Eco Line 6					10000													4900		
Eco Line 7					23													10		
Eco Line 8					10000													5500		

CF1-00048118

COCKRELL RANCH #34

V-0.44 M-1.375

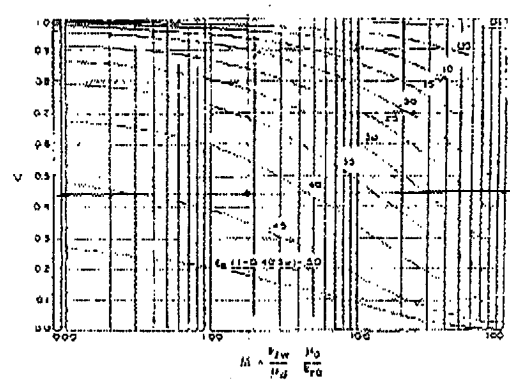
Waterflood Recovery = 22%



0.372

Fig. 8.3 Permeability variation plotted against mobility ratio, showing lines of constant E_R $(1 - 0.52\,S_w)$ for a producing WOR of 25.[14]

Waterflood Recovery* = 25.6%



0.425

Fig. 8.4 Permeability variation plotted against mobility ratio, showing lines of constant E_R $(1 - 0.40\,S_w)$ for a producing WOR of 100.[14]

COCKRELL RANCH #34

Y= 0.44

M= 1.875

method as we know them today, operating engineers used these values in their estimates of waterflood recovery.

Hurst Method

Hurst[17] extended Muskat's earlier work for the five-spot pattern to consider the existence of an initial gas saturation prior to water injection. His mathematical studies considered the formation of an oil bank, but assumed the oil and water had equal mobilities. His was the first study to show the increase in areal sweep obtainable after water breakthrough by continued water injection.

Caudle et al. Method

Caudle and a series of coworkers[18-23] devoted a great deal of effort to the experimental studies of areal sweep-out in a wide variety of flooding patterns. These patterns include the four-spot, five-spot, nine-spot, and

line drive patterns. The work was extended[24] to the seven-spot pattern as well as the nine-spot. Using miscible fluids and the X-ray shadowgraph technique, they obtained values of four measures of performance: (1) areal sweep efficiency, (2) mobility ratio, (3) injected volume, and (4) portion of the production coming from the swept area. The injectivity variation during flooding was measured for many of these patterns. (See Section 5.6 for more details on these measures.) Because the studies were restricted to the use of miscible fluids, they apply for waterflood conditions in which there is no flowing oil behind the flood front. Other authors[25-26] have applied this basic technique to prediction of miscible fluid displacement projects.

Aronofsky Method

This method is based on potentiometric model studies[27-28] of the five-spot and line drive well arrange-

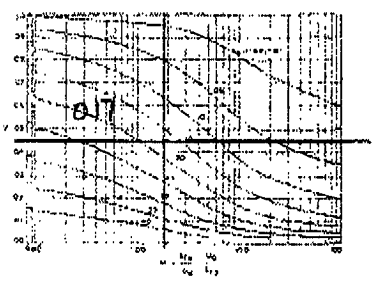


Fig. 8.1 Permeability variation plotted against mobility ratio, showing lines of constant E_A $(1 - S_w)$ for a producing WOR of 1.[15]

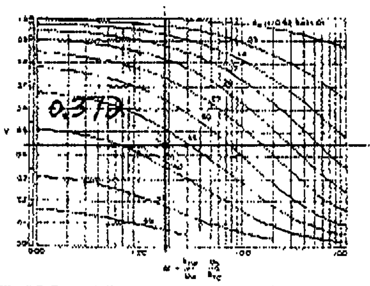


Fig. 8.3 Permeability variation plotted against mobility ratio, showing lines of constant E_A $(1 - 0.52\,S_w)$ for a producing WOR of 25.[15]

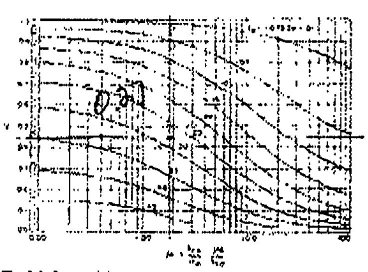


Fig. 8.2 Permeability variation plotted against mobility ratio, showing lines of constant E_A $(1 - 0.72\,S_w)$ for a producing WOR of 5.[15]

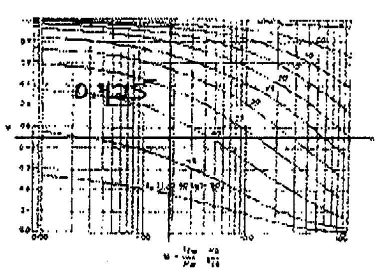
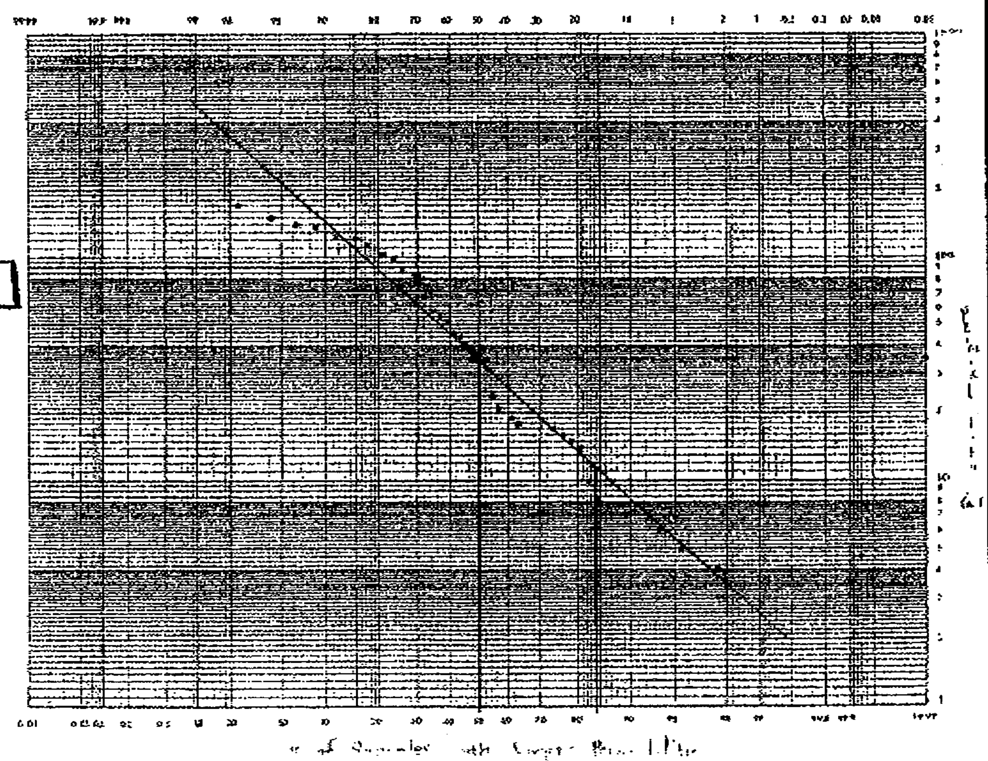


Fig. 8.4 Permeability variation plotted against mobility ratio, showing lines of constant E_A $(1 - 0.40\,S_w)$ for a producing WOR of 100.[15]

Cockrell Ranch
(#79) & SPE 1801 Data



CF1-00048121

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Producing oil & gas
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for the USA

Monday December 11, 2006

RE: Cockrell Ranch Waterflood Model, Phase 1

To Whom It May Concern:

This report and enclosed documents contain information regarding the evaluation of converting proved undeveloped waterflood reserves for the Cockrell Ranch Phase 1 (783 Acres) to the proved producing category. Gross waterflood recoverable oil reserves are 2,722,790 barrels. First response to water injection will be seen after 0.25 pore volumes of injection. Reserves are recovering an additional 14.6 percent of the original oil in place.

The model was developed to reflect the response shown in the Schafer Ranch waterflood pilot (See SPE Paper # 1801). An initial flush production of two months occurs as a direct result of fillup. Once fillup is complete and the flush production has passed, oil production continues in relation to the pore volumes of water injected, as also seen in the Schafer Ranch pilot.

Table 1 outline the reservoir data used for the model.

Table 1: ReservoirData

Analysis Acreage	783
Number of Injectors	39
Number of Producers	39
Net Pay Thickness (Feet)	36
Porosity (Percentage)	16.4
Original Oil Saturation (Fraction)	0.65
Original Water Saturation (Fraction)	0.35
Ratio of Injectors to Producers	1:1
Injection Rate (Barrels per Day Per Well)	600
Time to Response (Days)	200
Initial Oil Production Rate (BO per Day per Producer)	135
Time of Peak Production (Months)	2
Oil Formation Volume Factor (Reservoir Barrels per Stock Tank Barrel)	1.25
Fill-Up at Time at Response (PV)	0.25

Appendix E of the Waterflooding Monograph by Forrest Craig was used as a basis for determining the recovery characteristics of the Cockrell Ranch project. The model was performed assuming four nine-foot layers. A sample for the highest permeability layer is shown in Tables 2, 3 and 4 below which indicates fillup occurrence in 200 days and water break through at 247 days with recovery prior to breakthrough of 4.8 percent OOIP.

Stiles calculations were used for the period after water breakthrough to arrive at the final pattern recovery of 14.6 percent.

Table 2: Basic Pattern Data for 9 Foot Layer

Area	20		PV	229016.16	
Layer h	9		OOIP	119088.4032	
Porosity	0.164		Wii	45042.95913	
Swi	0.35		Wif	57254.04	
Soi	0.65		Ea	1.09163E-05	*Wi
Boi	1.25		Re^2	4.84180001	*Wi
Uo	3		R	0.790569415	*Re
Uw	0.8		Wibt	64124.5248	
Kro	1		Ibase	144	k=133
Krw	0.3		Rw	1	
M	1.125		Bowf	1.2	
Eabt	0.7		OIPwf	87244.25143	
Swbt	0.75		Soiwf	0.4	
Sgi	0.25		DelP	600	
Rei	466		Bowfi	1.05	
Swbt-Swc	0.4		Total h	36	

Table 3: 4 Layer Performance Prior to Interference (K = 133)

Wi	Re^2	Re	R	2.67*lnR/Rw	3*lnRe/R	F+G	Iw	Time	
5000	24209	155.5924164	123.00661	12.83263482	0.705005444	13.53764	375.0782	13.33055	
7000	33892.6	184.0994299	145.54338	13.28126447	0.705005444	13.98627	363.047	19.28125	
9000	43576.2	208.749132	165.03068	13.61635038	0.705005444	14.32136	354.5526	25.3841	
11000	53259.8	230.7808487	182.44828	13.8839113	0.705005444	14.58892	348.0501	31.60465	
13000	62943.4	250.885233	198.34219	14.10665008	0.705005444	14.81166	342.8161	37.92121	
15000	72627	269.4939705	213.05369	14.29745121	0.705005444	15.00246	338.4562	44.31888	
45042.96	218089	467	369.19592	15.76353985	0.705005444	16.46855	308.3256	146.0889	Fillup

Table 4: Performance Fill up to Water Breakthrough

53.9524533 Interim Interference

Performance Fill up to Water Breakthrough

Wi	Ea	Gamma	Iw	DelT	Time	Qo	Wi-Wif	Np	ErWFOIP	ER OOIP
57254.04	0.625	1	144.33523		200.0413934	120.2794	0			
60689.28	0.6625	1	144.33523	23.80044353	223.8418369	120.2794	3435.242	2862.702	0.032813	0.024038
62406.9	0.68125	1	144.33523	11.90022176	235.7420586	120.2794	5152.864	4294.053	0.049219	0.036058
64124.52	0.7	1	144.33523	11.90022176	247.6422804	120.2794	6870.485	5725.404	0.065625	0.048077
				47.60088706						

Lease operating expenses were estimated at 26 cents per barrel of injected water was approximately the value was used on the April 1, 2006 reserve report performed by Forrest A. Garb and Associates. The operating expense of 26 cents per injected barrel correlates well with the expenses seen at the Davenport Field (OK) waterflood. The depth of the producing interval at Davenport is similar to that of Cockrell Ranch.

Figure 1 shows the incremental oil equivalent production seen by the implementation of the waterflood during the first two and one half years of the project.

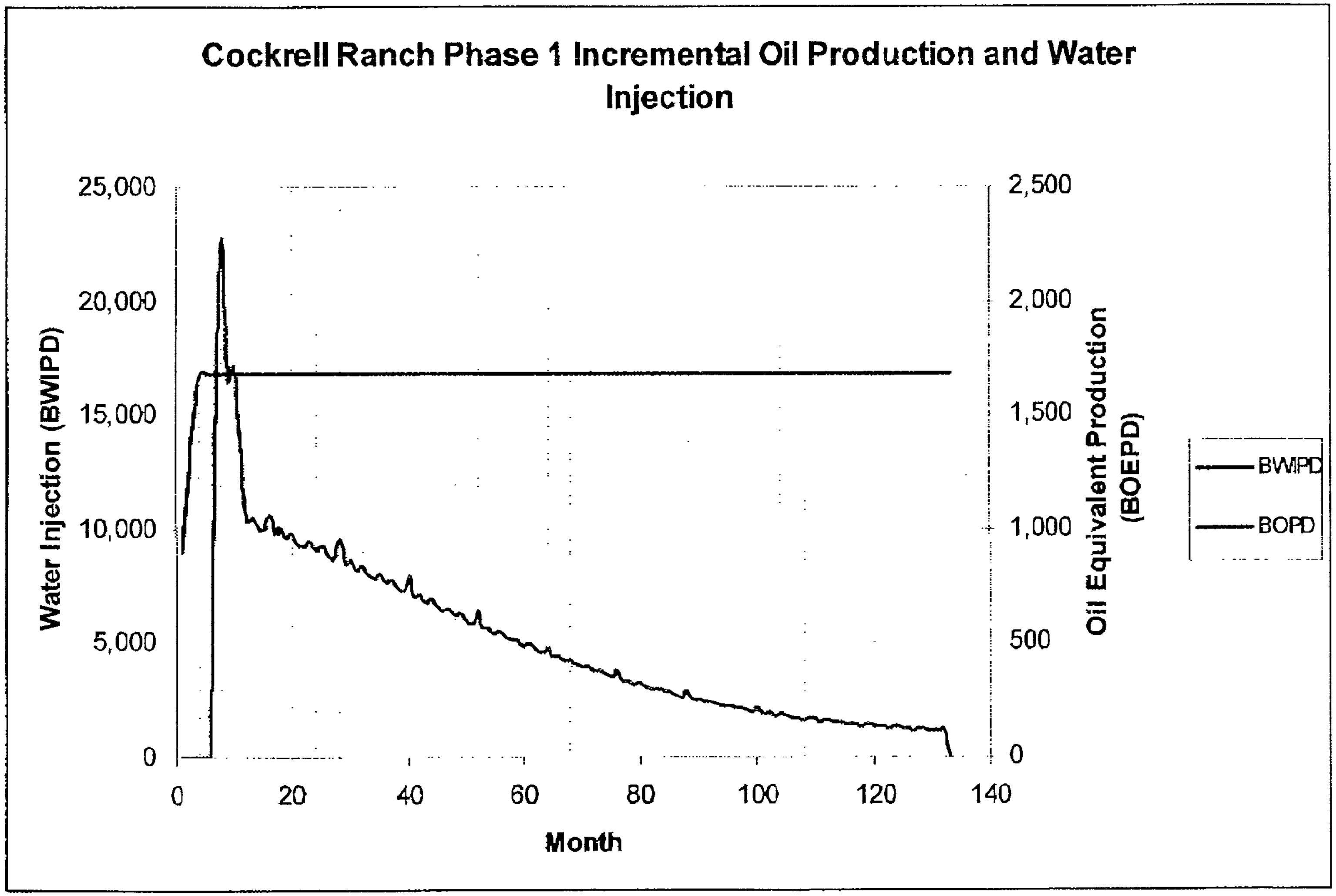

Figure 1: Daily Production by Month

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Pilot Waterflood Evaluation - Panhandle Field

By

J. C. Henry, Junior Member AIME, Skelly Oil Co., Tulsa, Okla., and
J. D. Moring, Junior Member AIME, Skelly Oil Co., Pampa, Tex.

ABSTRACT

In July, 1963, a five-spot pilot waterflood was initiated in the Brown Dolomite of Skelly Oil Company's Schafer Ranch lease in the Panhandle Field, Carson County, Texas.

Two years later response had not yet occurred even though 1,300,000 barrels of water had been injected. Injectivity surveys indicated that the water was entering the producing formation at the well bore but what happened to it after that remained a mystery.

A decision was made to find out if the water was actually staying in the formation. This was to be done by drilling a test well half way between one of the four injection wells and the center production well.

Analysis of test data indicated that the advance portion of the flood front had already passed this position and must be close to the center producing well. The flood was behaving admirably - water was going into the formation and not channeling. Fracture treatment of the center producing well resulted in the long-awaited response.

References and illustrations at end of paper.

INTRODUCTION

This paper is about an evaluation of a pilot waterflood. However, it is not a theoretical evaluation based on hypothetical data. It is based on actually drilling a well in the middle of a pilot, coring, logging and testing it, and then analyzing this data. We did what many of us that try to deal in abstract reservoir engineering would love to do. In effect, we went down and took a chunk out of the reservoir while it was in the process of being flooded.

PANHANDLE FIELD

The pilot (Figure 1) is located in the Texas Panhandle Field; the second largest field in terms of cumulative production in the United States. Only the East Texas Field is larger, with a cumulative production of 3.7 billion barrels compared to the Panhandle Field's 1.2 billion barrels. This field is over 100 miles long and extends into five counties. Just to the south of the field is a buried granite mountain ridge, called the Amarillo Mountains, which extends into Oklahoma where it becomes the Wichita Mountains.

There have been many attempts to wrestle additional oil, over primary, from this field but most attempts have met with failure. Conventional waterflooding is hampered by an unfavorable mobility ratio, inadequate cement behind casing, open hole completions, low oil saturation at start of flood and a poor permeability distribution.

Original reservoir pressure was abnormally low; about 430 psig. Gas injection was initiated approximately thirty years ago but even so the reservoir pressure has dropped to about 100 psig.

Various methods besides water or gas injection have been tried. LPG injection, in situ combustion and steam injection have met with limited success.

There are now about 27 active waterfloods in the Panhandle Field. For some reason almost all of the floods in eastern Gray County are successful, whereas those in western Gray, Carson and Hutchinson Counties are generally unsuccessful.

Several reasons have been cited for these waterflood failures. Most of the reasons involve not getting the water where it is needed. Injectivity profiles show that the injected water in some cases leaves the well bore above or below the pay zone, while in other cases it enters a watered-out zone and channels to nearby production wells. Also it is possible that the water travels through fractures up to the gas cap or down to the water leg.

GEOLOGY

Figure 2 is a schematic cross-section of the Panhandle Field. The miniature pumping unit denotes the approximate location of the pilot waterflood.

Production is from the Brown Dolomite at about 3000 feet. A gas-oil contact exists to the south and a water-oil contact to the north. Hydrocarbons are trapped by truncation of the formation against the buried Amarillo Mountains.

The top of the Brown Dolomite is usually defined by the First Chert. Below this is an Oolitic section which has high permeability, then additional pay; next the base which is defined by the Second Chert.

Porosity was formed by dolomitization of calcareous material. This resulted in zones of porosity separated by dense dolomite. Some of the dolomite has as high as 10 percent porosity without any permeability - which makes log interpretation difficult.

PILOT WATERFLOOD

Skelly's Schafer Ranch lease is located in an area of the field which has not yet been successfully waterflooded. For this reason, we thought it would be judicious to start out with a pilot rather than a full scale waterflood.

Figure 3 is an illustration of the five-spot waterflood which was initiated in July, 1963. The four injection wells and center producing well are all completed in open hole at about 3000 feet, and are on 17.8 acre spacing. All of these wells have been fraced at least once.

Initial operations were trouble-free. Injectivity surveys showed that most of the water was entering the pay zone, at least at the well bore. About 500 barrels of water per day were being injected into each well. But by June, 1965, 1,300,000 barrels of water had been injected and no response of any kind had been noted. Fill-up calculations indicated that some kind of response should have occurred by now. Since millions of barrels of oil were at stake we felt that it was necessary to find out what was going on.

TEST WELL

A decision was made to drill a test well halfway between the north injection well and the center production well. If the well encountered injected water in the Brown Dolomite, then the flood front had already passed this location and the flood was progressing satisfactorily. If the well encountered connate water and free oil, then the flood front had not yet passed and something was wrong. This was one of the few times when we would rather find water than oil.

The location between the north injection well and the center production well was chosen because only fresh water had been injected into the north injection well. Some produced water had been injected into the other three injection wells. This way if the test well produced fresh water we could be sure it was injected water and not formation water.

The well was drilled down to the top of the Brown Dolomite, approximately 3000 feet, and seven-inch casing was set so that the drilling fluid could be switched from mud to natural gas. The next 264 feet were cored with a 3½-inch core barrel. About 225 feet were recovered. Natural gas was used in cutting the core in an attempt to obtain more reliable water saturations. Total depth was reached on June 15, 1965.

Figure 4 illustrates graphically the results of the core analysis. At about 3100 feet the top of the Oolitic Section was encountered. Because this section is somewhat friable, we were unable to retain it in the core barrel and the core was lost. While drilling through the Oolitic Section water started entering the well bore, so the rest of the core was cut with a mist of water and natural gas. This undoubtedly increased the water saturation in the remainder of the core.

After coring the well, five logs were run; (1) Epithermal Neutron, (2) Formation Density-Gamma Ray Caliper; (3) Microlaterolog, (4) Sonic Dual Induction, and (5) Gamma Ray-Neutron.

In order to production test the well, a liner was installed and cemented in the cored interval.

The cores and logs indicated five different zones of porosity. Zone 2 through 5 are shown in Figure 4. Zone 1 is just below 3200 feet. Each zone was perforated, swab tested, acidized and then swabbed again. Unfortunately not enough fluid was produced during these five tests to make the results conclusive.

With all the zones commingled the well was put on pump and tested for 18 days. Then a bottom hole pressure reading was taken and the chloride content of the produced water was measured. From this data the following three factors emerged as proof that the flood front had already passed this well.

(1) High reservoir pressure: Most of the wells in the vicinity of the test well have bottom hole pressures close to 100 pounds. When the test well was shut-in for 72 hours, a bottom hole pressure of 181 psi was measured. Two and a half months later the pressure was 228 psi and eight months later it was 290 psi. This is one of the best indications that the flood front had passed the test well at the time it was drilled.

(2) High water cut: The well was production tested for 18 days and it averaged 4 barrels of oil per day and 20 barrels of water per day - a water cut of 83 percent. This is significant because the offset wells had never produced any water.

(3) Low produced water chloride content: The produced water was analyzed two different times, once on August 2, and again on August 27, 1965. On the first test the chloride content was 24,000 ppm and on the second test it was 29,000 ppm. Normally the chloride content of the produced water from the Brown Dolomite will run well over a hundred thousand parts per million.

POSITION OF FLOOD FRONT

1. Statement of Problem and Assumptions

The question still remains - has the flood front advance far enough to affect the center production well. In an attempt to answer this, a modification of the Stiles approach was devised.

According to the core analysis there were 62 feet of pay (including estimated pay from the missing core) with a permeability exceeding 10 mds. These 62 feet were arranged in order of decreasing permeability and are listed in Table 1.

The problem is to calculate the radial distance, r_i, that water had advanced into each foot of permeability. Connecting these distances together results in a profile of the flood front (See Figure 5).

Implicit in the Stiles approach is the assumption that each foot of permeability reacts independently of the rest of the pay - that is, as if it were in its own small reservoir. If the reader will accept this assumption, recognizing its limitations, then the following equations can be developed.

2. Derivation of Equations

From the equation for the volume of a cylinder:

$$\text{Volume} = \pi r^2 h \quad \ldots \ldots \ldots (1)$$

the equation for the volume of water injected, W_i, can be developed:

$$W_i = \pi r^2 h \phi(1 - S_{or} - S_{gr} - S_{wc}) \quad \ldots \ldots \ldots (2)$$

Where:

W_i = volume of water injected - barrels
r = radial distance from the injection well - feet
h = formation thickness - feet
ϕ = porosity - fraction
S_{or} = residual oil saturation - fraction
S_{gr} = residual gas saturation - fraction
S_{wc} = connate water saturation - fraction

In all probability, the injected water bypasses some of the reservoir, so a conformance factor, C_i, must be included.

$$W_i = \pi r^2 h \phi(1 - S_{or} - S_{gr} - S_{wc})C_i \quad \ldots \ldots \ldots (3)$$

Considering just one foot of pay:

$$(W_i)_1 = \pi r_1^2 \phi(1 - S_{or} - S_{gr} - S_{wc})C_i \quad \ldots \ldots \ldots (4)$$

Since the amount injected into one foot pay is unknown, but the total injection is known, we must take the sum of Equation (4).

$$\sum_{i=1}^{h}(W_i)_i = \sum_{i=1}^{h}\pi r_i^2\phi(1 - S_{or} - S_{gr} - S_{wc})C_i \;\ldots\ldots (5)$$

Substituting W_1 for $\sum_{i=1}^{h}(W_i)_i$ and moving all constants in front of the summation sign results in the equation:

$$W_1 = [\pi\phi(1 - S_{or} - S_{gr} - S_{wc})C_i][\sum_{i=1}^{h} r_i^2] \;\ldots\ldots (6)$$

Assuming that the distance from the injection well, r_i, is directly proportional to the permeability, k_i, for that foot of pay, then:

$$r_i = Ck_i \;\ldots\ldots (7)$$

Where C is a proportionality constant.

Substituting Ck_i for r_i in Equation (6)

$$W_1 = [\pi\phi(1 - S_{or} - S_{gr} - S_{wc})C_i][\sum_{i=1}^{h}(Ck_i)^2] \;\ldots\ldots (8)$$

Moving C in front of the summation sign

$$W_1 = [\pi\phi(1 - S_{or} - S_{gr} - S_{wc})C_i][C^2\sum_{i=1}^{h}k_i^2] \;\ldots\ldots (9)$$

3. Substituting Values in the Derived Equations

From Table 1 the summation of permeabilities squared was obtained, and this was substituted in Equation (9). Also substitued were values from Table 2 and the conversion constant 5.615 cubic feet per barrel.

$$W_1 = [(3.14)(0.154)(1 - 0.30 - 0.05 - 0.40)(0.80)/5.615] \times [(C^2)(4,710,700)] \;\ldots\ldots (9)$$

$$W_1 = 81,118\,C^2 \;\ldots\ldots (9)$$

With this equation and Equation (7), we can now calculate where the flood front is with any cumulative injection, W_1.

At the time the test well, No. 259, was drilled, 301,000 barrels had been injected into the north injection well, No. 157. However injectivity surveys showed that only 80 percent, or 240,800 barrels, went into the Brown Dolomite. Substituting in Equation (9):

$$240,800 = 81,118\,C^2 \;\ldots\ldots (9)$$

$$C = 1.722$$

Substituting in equation (7)

$$r_i = 1.722\,k_i \;\ldots\ldots (7)$$

4. Calculation of the Flood Front Profile

Now the distance to the flood front, r_i, in any permeability layer, k_i, can be calculated. For example, referring to Table 1, the highest permeability, 1040 md, has traveled a distance of 1.722 times 1040 or 1791 feet. This distance was calculated for each of the 62 permeabilities and plotted in Figure 5.

5. Check of Calculated Flood Front

We know that when Well No. 259 was production tested it produced 20 barrels of water and 4 barrels of oil, which is a water cut of 83.3%. If we can calculate this water cut, based on the position of the flood front, then this should be a fairly good check.

Figure 5 shows that the seven highest permeabilities have passed the test well. The sum of these permeabilities is 5265 md. This is the capacity of the formation that is producing water in Well No. 259 The capacity that is producing oil is 8263 minus 5265 or 2998 md.

According to Stiles:

$$f_w = \frac{(5265)(B_o\mu_o k_{rw}/\mu_w k_{ro})}{(5265)(B_o\mu_o k_{rw}/\mu_w k_{ro}) + 2998} \;\ldots\ldots (10)$$

f_w = Surface water cut - fraction
B_o = Oil formation volume factor - fraction
μ_o = Oil viscosity - cp
k_{rw} = Relative permeability to water at residual oil saturation - fraction
μ_w = Water viscosity - cp
k_{ro} = Relative permeability to oil at connate water saturation - fraction

Substituting values from Table 2

$$f_w = \frac{(5265)(1.05 \times 5 \times 0.4/0.8 \times 0.8)}{(5265)(1.05 \times 5 \times 0.4/0.8 \times 0.8) + 2998} \;\ldots\ldots (10)$$

f_w = 0.852 or 85.2%

Since this only differs by 1.9 percent from 83.3, it is considered a good match.

6. Water Production From the Oolitic Section

It is interesting to note that all of the seven feet producing water in Well No. 259 are located in the Oolitic Section. In other words, if we could have obtained reliable water saturations from the core analysis we should have found connate water saturations (about 40%) everywhere except in the Oolitic Section.

PERFORMANCE OF THE CENTER PRODUCING WELL

We may conclude from Figure 5 that some stimulation of oil production should have already occurred in Well No. 197, in fact, it should have already been producing some water. Since it was possible that skin damage was preventing response, the well was fraced on August 21, 1965. Immediately after treatment production increased from ten barrels of oil per day, zero water, to 35 barrels of oil per day and 12 barrels of water, it remained at that level for about a month, then jumped to close to 200 barrels of oil per day plus 58 bbls. of water. This is only a water cut of 22.5%. Based on Figure 5, five feet should have already been flooded out and the water cut should have been 79.2%. However, one reason the well did not produce more water is that interference from the other injection wells prevented the flood front from advancing further than the center production well. Had there been only one injection well, the water cut would probably have been about 79%. This is a good argument for a confined waterflood in the Brown Dolomite.

Figure 6 shows the production performance of this well. There is some argument that the increase in production might have been caused by the frac treatment. However, most frac jobs in the Brown Dolomite drop off to less than one half the peak rate within a few months after the treatment. Also, the peak rate seldom exceeds 100 barrels of oil per day.

CONCLUSIONS:

1. Location of the flood front, at the time the test well was drilled, was calculated with a fair degree of accuracy using a modified Stiles approach.

2. At the time the test well was drilled, response should have already occurred in the center production well, Well No. 197.

3. Skin damage in Well No. 197 prevented response from occurring sooner. Also from this we may conclude that some of the other production wells in the Brown Dolomite will have to be fraced before response will occur.

4. Water production in the test well was from the Oolitic Section only.

5. Due to the high and variable permeability in the Oolitic Section, a large amount of water will have to be produced before the flood is abandoned.

6. In the Brown Dolomite, a confined flood, such as a five-spot, will be more efficient than an unconfined flood, such as a line-drive.

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TABLE 1
BROWN DOLOMITE PERMEABILITY FROM THE
CORE ANALYSIS ON WELL NO. 259

The following is the permeability for each foot of pay in the Brown Dolomite. It is arranged in descending order. A 10 md. cut-off was used.

Permeability - md.	Permeability - md.	Permeability - md.
1040^e	75	26
1015^e	73	25
990^e	70	25
740^e	60	24
660^e	59^e	23
470^e	51	23
350^e	49	20
232	49	18
176	49	18
164^e	46	14
152	45	14
146^e	43	14
121	43	14
120	36^e	14
100^e	32	14
98	32	13
94	30	12
82	30	11
79	28	11^e
76	26	11
76		10^e
	TOTAL	8263

e - Estimated from core analysis on Well No. 239

TABLE 2

FORMATION STATISTICS ON THE BROWN DOLOMITE IN WELL 259

Average permeability .... 133 md.

Average porosity 15.4%

Residual oil saturation 30%

Residual gas saturation .... 5%^{e}

Connate water saturation 40%

Conformance factor .... 80%^{e}

Reservoir water viscosity .... 0.8 cp.

Reservoir oil viscosity .... 5 cp

Relative permeability to water at residual oil saturation 0.4

Relative permeability to oil at connate water saturation 0.8

Present oil formation volume factor .... 1.05^e

LOCATION OF SKELLY'S
SCHAFER RANCH LEASE

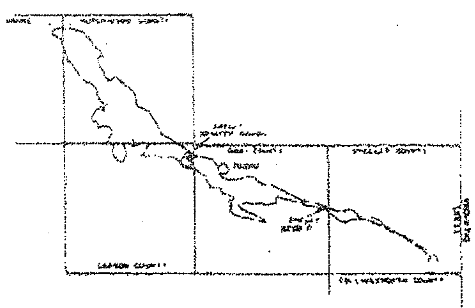

Fig. 1

SCHEMATIC CROSS-SECTION
TEXAS PANHANDLE FIELD

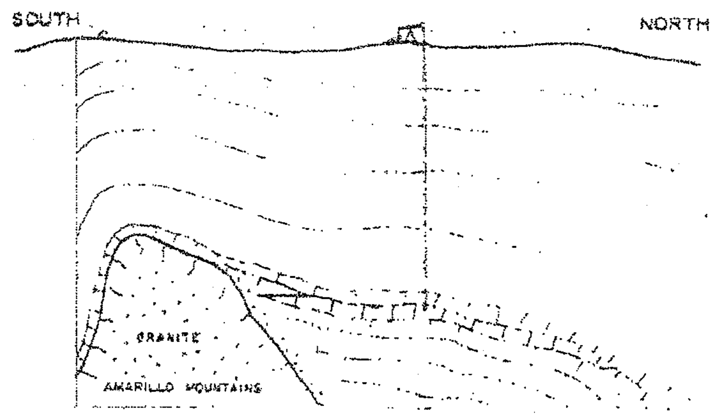

Fig. 2

PILOT WATERFLOOD
SCHAFER RANCH LEASE
TEXAS PANHANDLE FIELD

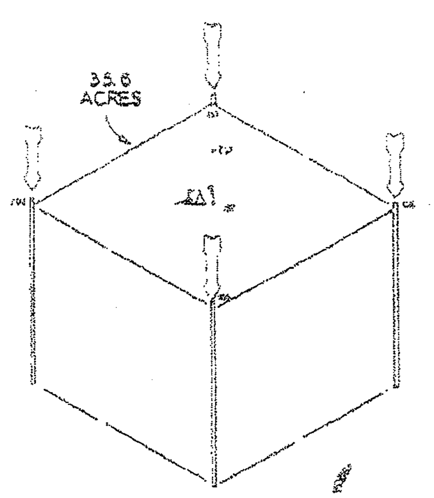

Fig. 3

CORE ANALYSIS
SCHAFER RANCH NO 259

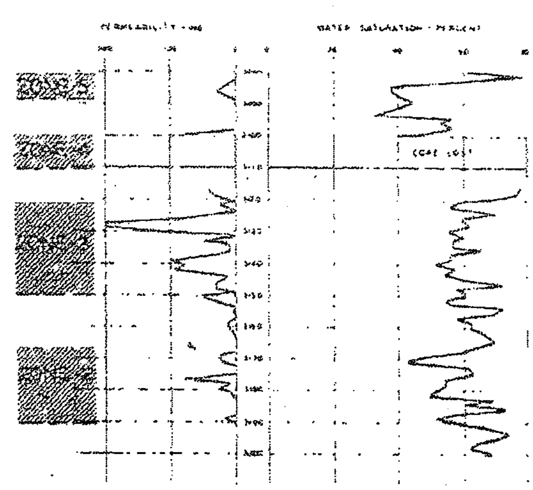

Fig. 4

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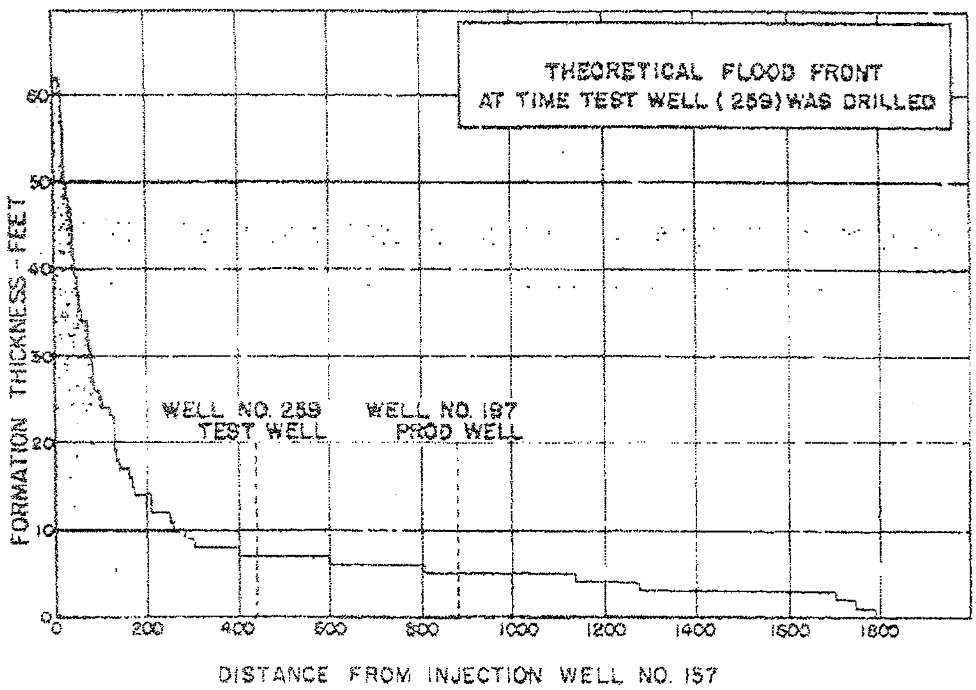
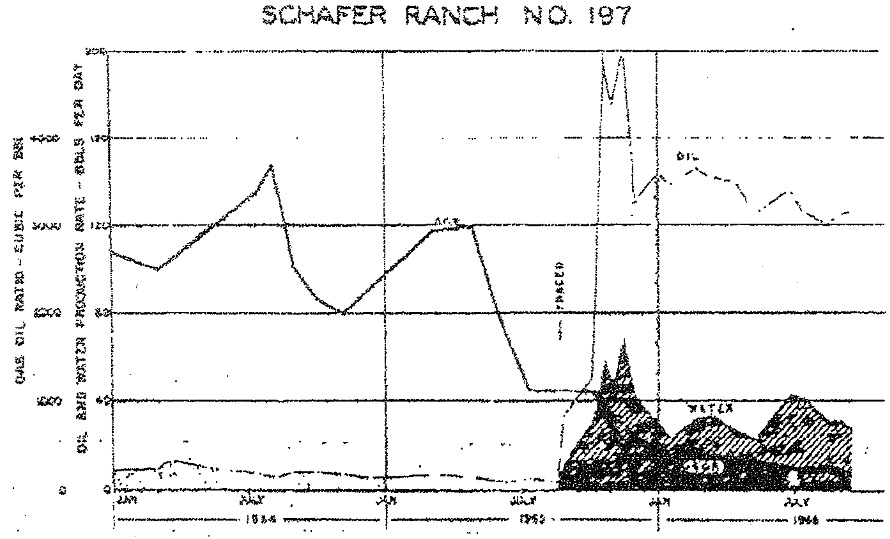


Fig. 5

PERFORMANCE CURVES
SCHAFER RANCH NO. 197



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DATE: December 11, 2006

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FAX NO.: 202.772.9368

FROM: James K. Teringo, Jr.

PAGES; 12, including cover page

RE:

CRUDE OIL AND NATURAL GAS PRODUCTION COMPANY
FOCUSED ON SECONDARY AND TERTIARY RECOVERY METHODS

SCHAFER RANCH WF
PRODUCTION AND INJECTION HISTORY

FIGURE 8C
COOPER/BLOCK AREA

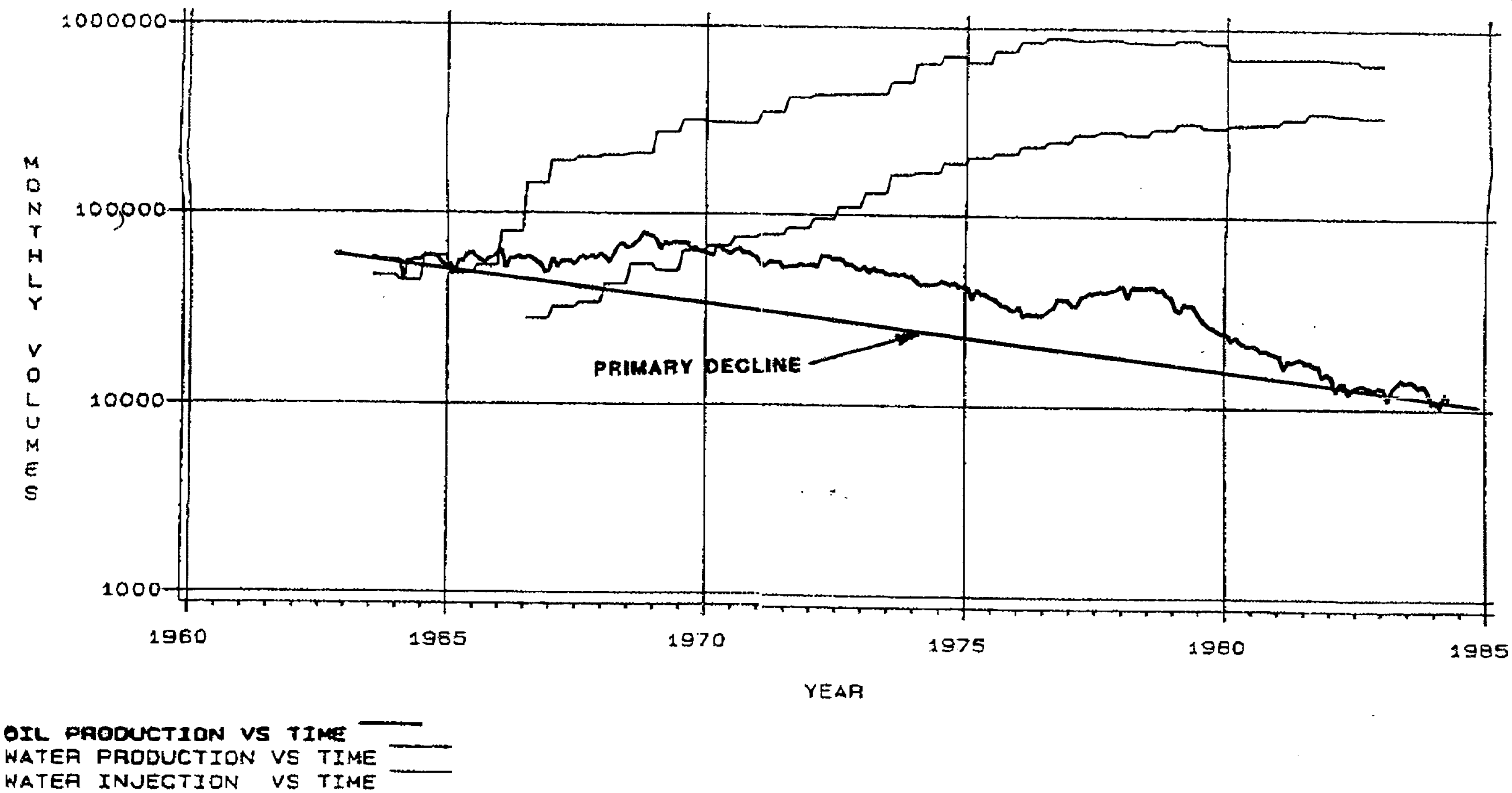

FIGURE 8
WATERFLOOD PERFORMANCES
COOPER/BLOCK AREA

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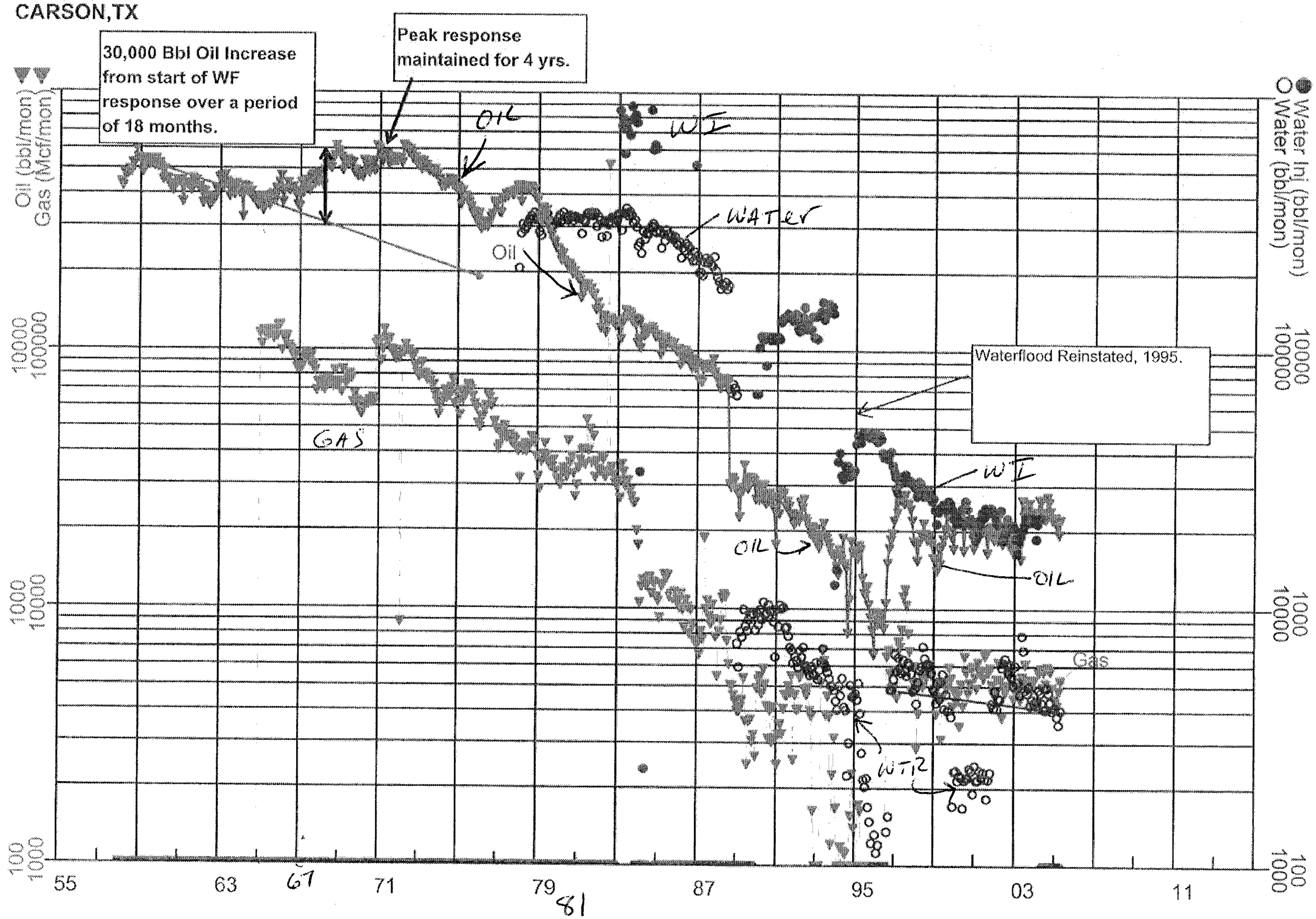
SCHAFER RANCH 71
WO OPERATING COMPANY
CARSON,TX



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The pilot (Figure 1) is located in the Texas Panhandle Field: the second largest field in terms of cumulative production in the United States. Only the East Texas Field is larger, with a cumulative production of 3.7 billion barrels compared to the Panhandle Field's 1.2 billion barrels. This field is over 100 miles long and extends into five counties. Just to the south of the field is a buried granite mountain ridge, called the Amarillo Mountains, which extends into Oklahoma where it becomes the Wichita Mountains.

There have been many attempts to wrestle additional oil, over primary, from this field but most attempts have met with failure. Conventional waterflooding is hampered by an unfavorable mobility ratio, inadequate cement behind casing, open hole completions, low oil saturation at start of flood and a poor permeability distribution.

Original reservoir pressure was abnormally low; about 430 psig. Gas injection was initiated approximately thirty years ago but even so the reservoir pressure has dropped to about 100 psig.

Various methods besides water or gas injection have been tried. LPG injection, in situ combustion and steam injection have met with limited success.

There are now about 27 active waterfloods in the Panhandle Field. For some reason almost all of the floods in eastern Gray County are successful, whereas those in western Gray, Carson and Hutchinson Counties are generally unsuccessful.

Several reasons have been cited for these waterflood failures. Most of the reasons involve not getting the water where it is needed. Injectivity profiles show that the injected water in some cases leaves the well bore above or below the pay zone, while in other cases it enters a watered-out zone and channels to nearby production wells. Also it is possible that the water travels through fractures up to the gas cap or down to the water leg.

GEOLOGY

Figure 2 is a schematic cross-section of the Panhandle Field. The miniature pumping unit denotes the approximate location of the pilot waterflood.

Production is from the Brown Dolomite at about 3000 feet. A gas-oil contact exists to the south and a water-oil contact to the north. Hydrocarbons are trapped by truncation of the formation against the buried Amarillo Mountains.

The top of the Brown Dolomite is usually defined by the First Chert. Below this is an Oolitic section which has high permeability, then additional pay; next the base which is defined by the Second Chert.

Porosity was formed by dolomitization of calcareous material. This resulted in zones of porosity separated by dense dolomite. Some of the dolomite has as high as 10 percent porosity without any permeability - which makes log interpretation difficult.

PILOT WATERFLOOD

Skelly's Schafer Ranch lease is located in an area of the field which has not yet been successfully waterflooded. For this reason, we thought it would be judicious to start out with a pilot rather than a full scale waterflood.

Figure 3 is an illustration of the five-spot waterflood which was initiated in July, 1963. The four injection wells and center producing well are all completed in open hole at about 3000 feet, and are on 17.8 acre spacing. All of these wells have been fraced at least once.

Initial operations were trouble-free. Injectivity surveys showed that most of the water was entering the pay zone, at least at the well bore. About 500 barrels of water per day were being injected into each well. But by June, 1965, 1,300,000 barrels of water had been injected and no response of any kind had been noted. Fill-up calculations indicated that some kind of response should have occurred by now. Since millions of barrels of oil were at stake we felt that it was necessary to find out what was going on.

TEST WELL

A decision was made to drill a test well halfway between the north injection well and the center production well. If the well encountered injected water in the Brown Dolomite, then the flood front had already passed this location and the flood was progressing satisfactorily. If the well encountered connate water and free oil, then the flood front had not yet passed and something was wrong. This was one of the few times when we would rather find water than oil.

The location between the north injection well and the center production well was chosen because only fresh water had been injected into the north injection well. Some produced water had been injected into the other three injection wells. This way if the test well produced fresh water we could be sure it was injected water and not formation water.

The well was drilled down to the top of the Brown Dolomite, approximately 3000 feet, and seven-inch casing was set so that the drilling fluid could be switched from mud to natural gas. The next 264 feet were cored with a 3½-inch core barrel. About 225 feet were recovered. Natural gas was used in cutting the core in an attempt to obtain more reliable water saturations. Total depth was reached on June 15, 1965.

Figure 4 illustrates graphically the results of the core analysis. At about 3100 feet the top of the Oolitic Section was encountered. Because this section is somewhat friable, we were unable to retain it in the core barrel and the core was lost. While drilling through the Oolitic Section water started entering the well bore, so the rest of the core was cut with a mist of water and natural gas. This undoubtedly increased the water saturation in the remainder of the core.

After coring the well, five logs were run: (1) Epithermal Neutron, (2) Formation Density-Gamma Ray Caliper; (3) Microlaterolog, (4) Sonic Dual Induction, and (5) Gamma Ray-Neutron.

In order to production test the well, a liner was installed and cemented in the cored interval.

The cores and logs indicated five different zones of porosity. Zone 2 through 5 are shown in Figure 4. Zone 1 is just below 3200 feet. Each zone was perforated, swab tested, acidized and then swabbed again. Unfortunately not enough fluid was produced during these five tests to make the results conclusive.

With all the zones commingled the well was put on pump and tested for 18 days. Then a bottom hole pressure reading was taken and the chloride content of the produced water was measured. From this data the following three factors emerged as proof that the flood front had already passed this well.

(1) High reservoir pressure: Most of the wells in the vicinity of the test well have bottom hole pressures close to 100 pounds. When the test well was shut-in for 72 hours, a bottom hole pressure of 181 psi was measured. Two and a half months later the pressure was 228 psi and eight months later it was 290 psi. This is one of the best indications that the flood front had passed the test well at the time it was drilled.

(2) High water cut: The well was production tested for 18 days and it averaged 4 barrels of oil per day and 20 barrels of water per day - a water cut of 83 percent. This is significant because the offset wells had never produced any water.

(3) Low produced water chloride content: The produced water was analyzed two different times, once on August 2, and again on August 27, 1965. On the first test the chloride content was 24,000 ppm and on the second test it was 29,000 ppm. Normally the chloride content of the produced water from the Brown Dolomite will run well over a hundred thousand parts per million.

POSITION OF FLOOD FRONT

1. Statement of Problem and Assumptions

The question still remains - has the flood front advance far enough to affect the center production well. In an attempt to answer this, a modification of the Stiles approach was devised.

According to the core analysis there were 62 feet of pay (including estimated pay from the missing core) with a permeability exceeding 10 mds. These 62 feet were arranged in order of decreasing permeability and are listed in Table 1.

The problem is to calculate the radial distance, r_i, that water had advanced into each foot of permeability. Connecting these distances together results in a profile of the flood front (See Figure 5).

Implicit in the Stiles approach is the assumption that each foot of permeability reacts independently of the rest of the pay - that is, as if it were in its own small reservoir. If the reader will accept this assumption, recognizing its limitations, then the following equations can be developed.

2. Derivation of Equations

From the equation for the volume of a cylinder:

$$\text{Volume} = \pi r^2 h \quad (1)$$

the equation for the volume of water injected, W_i, can be developed:

$$W_i = \pi r^2 h \phi (1 - S_{or} - S_{gr} - S_{wc}) \quad (2)$$

Where:

W_i = volume of water injected - barrels
r = radial distance from the injection well - feet
h = formation thickness - feet
ϕ = porosity - fraction
S_{or} = residual oil saturation - fraction
S_{gr} = residual gas saturation - fraction
S_{wc} = connate water saturation - fraction

In all probability, the injected water bypasses some of the reservoir, so a conformance factor, C_f, must be included.

$$W_i = \pi r^2 h \phi (1 - S_{or} - S_{gr} - S_{wc}) C_f \quad (3)$$

Considering just one foot of pay:

$$(W_i)_i = \pi r_i^2 \phi (1 - S_{or} - S_{gr} - S_{wc}) C_f \quad (4)$$

Since the amount injected into one foot pay is unknown, but the total injection is known, we must take the sum of Equation (4).

$$\sum_{i=1}^{i=h} (W_i)_i = \sum_{i=1}^{i=h} \pi r_i^2 \phi(1 - S_{or} - S_{gr} - S_{wc})C_f \ldots\ldots (5)$$

Substituting W_i for $\sum_{i=1}^{i=h}(W_i)_i$; and moving all constants in front of the summation sign results in the equation:

$$W_i = [\pi\phi(1 - S_{or} - S_{gr} - S_{wc})C_f][\sum_{i=1}^{i=h} r_i^2] \ldots\ldots (6)$$

Assuming that the distance from the injection well, r_i, is directly proportional to the permeability, k_i, for that foot of pay, then:

$$r_i = Ck_i \ldots\ldots (7)$$

Where C is a proportionality constant.

Substituting Ck_i for r_i in Equation (6)

$$W_i = [\pi\phi(1 - S_{or} - S_{gr} - S_{wc})C_f][\sum_{i=1}^{i=h}(Ck_i)^2] \ldots (8)$$

Moving C in front of the summation sign

$$W_i = [\pi\phi(1 - S_{or} - S_{gr} - S_{wc})C_f][C^2 \sum_{i=1}^{i=h} k_i^2] \ldots (9)$$

3. Substituting Values in the Derived Equations

From Table 1 the summation of permeabilities squared was obtained, and this was substituted in Equation (9). Also substitued were values from Table 2 and the conversion constant 5.615 cubic feet per barrel.

$$W_i = [(3.14)(0.154)(1 - 0.30 - 0.05 - 0.40)(0.80)/5.615] \times [(C^2)(4,710,700)] \ldots (9)$$

$$W_i = 81,118\,C^2 \ldots (9)$$

With this equation and Equation (7), we can now calculate where the flood front is with any cumulative injection, W_i.

At the time the test well, No. 259, was drilled, 301,000 barrels had been injected into the north injection well, No. 157. However injectivity surveys showed that only 80 percent, or 240,800 barrels, went into the Brown Dolomite. Substituting in Equation (9):

$$240,800 = 81,118\,C^2 \ldots (9)$$

$$C = 1.722$$

Substituting in equation (7)

$$r_i = 1.722\,k_i \ldots (7)$$

4. Calculation of the Flood Front Profile

Now the distance to the flood front, r_i, in any permeability layer, k_i, can be calculated. For example, referring to Table 1, the highest permeability, 1040 md, has traveled a distance of 1.722 times 1040 or 1791 feet. This distance was calculated for each of the 62 permeabilities and plotted in Figure 5.

5. Check of Calculated Flood Front

We know that when Well No. 259 was production tested it produced 20 barrels of water and 4 barrels of oil, which is a water cut of 83.3%. If we can calculate this water cut, based on the position of the flood front, then this should be a fairly good check.

Figure 5 shows that the seven highest permeabilities have passed the test well. The sum of these permeabilities is 5265 md. This is the capacity of the formation that is producing water in Well No. 259. The capacity that is producing oil is 8263 minus 5265 or 2998 md.

According to Stiles:

$$f_w = \frac{(5265)(B_o\mu_o k_{rw}/\mu_w k_{ro})}{(5265)(B_o\mu_o k_{rw}/\mu_w k_{ro}) + 2998} \ldots\ldots (10)$$

f_w = Surface water cut - fraction
B_o = Oil formation volume factor - fraction
μ_o = Oil viscosity - cp
k_{rw} = Relative permeability to water at residual oil saturation - fraction
μ_w = Water viscosity - cp
k_{ro} = Relative permeability to oil at connate water saturation - fraction

Substituting values from Table 2

$$f_w = \frac{(5265)(1.05 \times 5 \times 0.4/0.8 \times 0.8)}{(5265)(1.05 \times 5 \times 0.4/0.8 \times 0.8) + 2998} \ldots (10)$$

f_w = 0.852 or 85.2%

Since this only differs by 1.9 percent from 83.3, it is considered a good match.

6. Water Production From the Oolitic Section

It is interesting to note that all of the seven feet producing water in Well No. 259 are located in the Oolitic Section. In other words, if we could have obtained reliable water saturations from the core analysis we should have found connate water saturations (about 40%) everywhere except in the Oolitic Section.

PERFORMANCE OF THE CENTER PRODUCING WELL

We may conclude from Figure 5 that some stimulation of oil production should have already occurred in Well No. 197, in fact, it should have already been producing some water. Since it was possible that skin damage was preventing response, the well was fraced on August 21, 1965. Immediately after treatment production increased from ten barrels of oil per day, zero water, to 35 barrels of oil per day and 12 barrels of water, it remained at that level for about a month, then jumped to close to 200 barrels of oil per day plus 58 bbls. of water. This is only a water cut of 22.5%. Based on Figure 5, five feet should have already been flooded out and the water cut should have been 79.2%. However, one reason the well did not produce more water is that interference from the other injection wells prevented the flood front from advancing further than the center production well. Had there been only one injection well, the water cut would probably have been about 79%. This is a good argument for a confined waterflood in the Brown Dolomite.

Figure 6 shows the production performance of this well. There is some argument that the increase in production might have been caused by the frac treatment. However, most frac jobs in the Brown Dolomite drop off to less than one half the peak rate within a few months after the treatment. Also, the peak rate seldom exceeds 100 barrels of oil per day.

CONCLUSIONS:

1. Location of the flood front, at the time the test well was drilled, was calculated with a fair degree of accuracy using a modified Stiles approach.

2. At the time the test well was drilled, response should have already occurred in the center production well, Well No. 197.

3. Skin damage in Well No. 197 prevented response from occurring sooner. Also from this we may conclude that some of the other production wells in the Brown Dolomite will have to be fraced before response will occur.

4. Water production in the test well was from the Oolitic Section only.

5. Due to the high and variable permeability in the Oolitic Section, a large amount of water will have to be produced before the flood is abandoned.

6. In the Brown Dolomite, a confined flood, such as a five-spot, will be more efficient than an unconfined flood, such as a line-drive.

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3. Neslage, Fred J.: Report of Watkins Operators Committee, Panhandle Field (Sept., 1966).

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TABLE 1
BROWN DOLOMITE PERMEABILITY FROM THE
CORE ANALYSIS ON WELL NO. 259

The following is the permeability for each foot of pay in the Brown Dolomite. It is arranged in descending order. A 10 md. cut-off was used.

Permeability - md.	Permeability - md.	Permeability - md.
1040^e	75	26
1015^e	75	25
990^e	70	25
740^e	60	24
660^e	59^e	23
470^e	51	23
350^e	49	20
232	49	18
176	49	18
164^e	46	14
152	45	14
146^e	43	14
121	43	14
120	36^e	14
100^e	32	14
98	32	13
94	30	12
82	30	11
79	28	11^e
76	26	11
76		10^e
	TOTAL	8263

e - Estimated from core analysis on Well No. 239

TABLE 2

FORMATION STATISTICS ON THE BROWN DOLOMITE IN WELL 259

Average permeability	133 md.
Average porosity	15.4%
Residual oil saturation	30%
Residual gas saturation	$5\%^e$
Connate water saturation	40%
Conformance factor	$80\%^e$
Reservoir water viscosity	0.8 cp
Reservoir oil viscosity	5 cp
Relative permeability to water at residual oil saturation	0.4
Relative permeability to oil at connate water saturation	0.8
Present oil formation volume factor	1.05^e

LOCATION OF SKELLY'S
SCHAFER RANCH LEASE

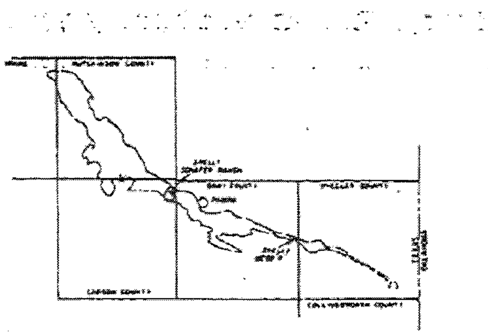

Fig. 1

SCHEMATIC CROSS-SECTION
TEXAS PANHANDLE FIELD

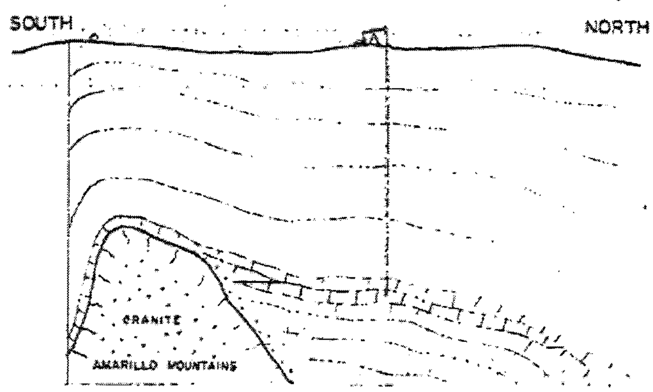

Fig. 2

PILOT WATERFLOOD
SCHAFER RANCH LEASE
TEXAS PANHANDLE FIELD

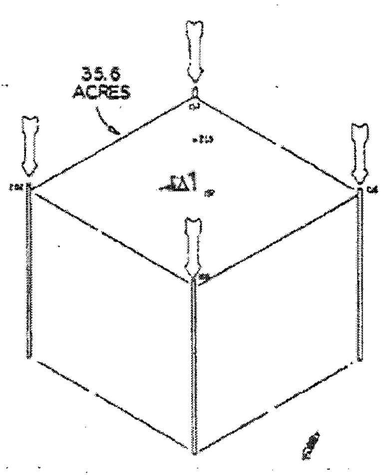

Fig. 3

CORE ANALYSIS
SCHAFER RANCH NO. 259

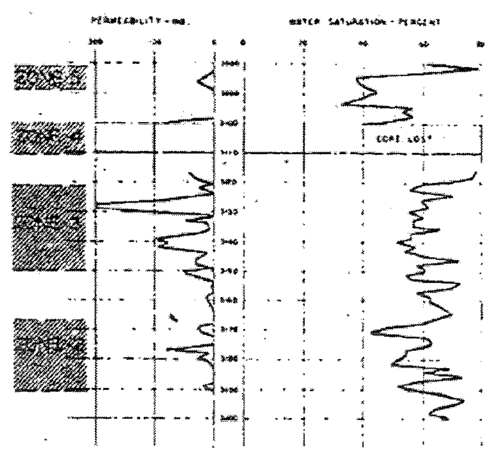

Fig. 4

Murphy, James

From: Patrick McKinney [patrick@canopetro.com]
Sent: Friday, December 08, 2006 6:53 PM
To: Murphy, James
Cc: Sam Smith; Jeff Johnson; Bruce.Newsome@haynesboone.com; Jimmy Teringo
Subject: Cano Panhandle Field Source Data
Attachments: SPE Papers 1801-WF Evaluation on Panhandle.pdf

Dear Mr. Murphy:

Pursuant to our discussion today, attached please find the detailed production graph (from public data) of the analog E. Schafer Ranch water flood. It will allow you to see more granularity of the waterflood response timing. Mover, it is interesting to note that the flood was re-instated in 1995 and continued to respond to water injection some 30 years after the initial flood.

Additionally, the PDF file contains the SPE Paper (#1801) that details the injection and response characteristics at the E. Schafer Ranch Waterflood upon which we based our analog responses.

Lastly, I will be forwarding on Monday a write-up and summary of the simulation that we performed on our Cockrell Phase I project to give you more color on the timing and response characteristics that are portrayed in our PUD reserves.

Best Regards,

Pat

,

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