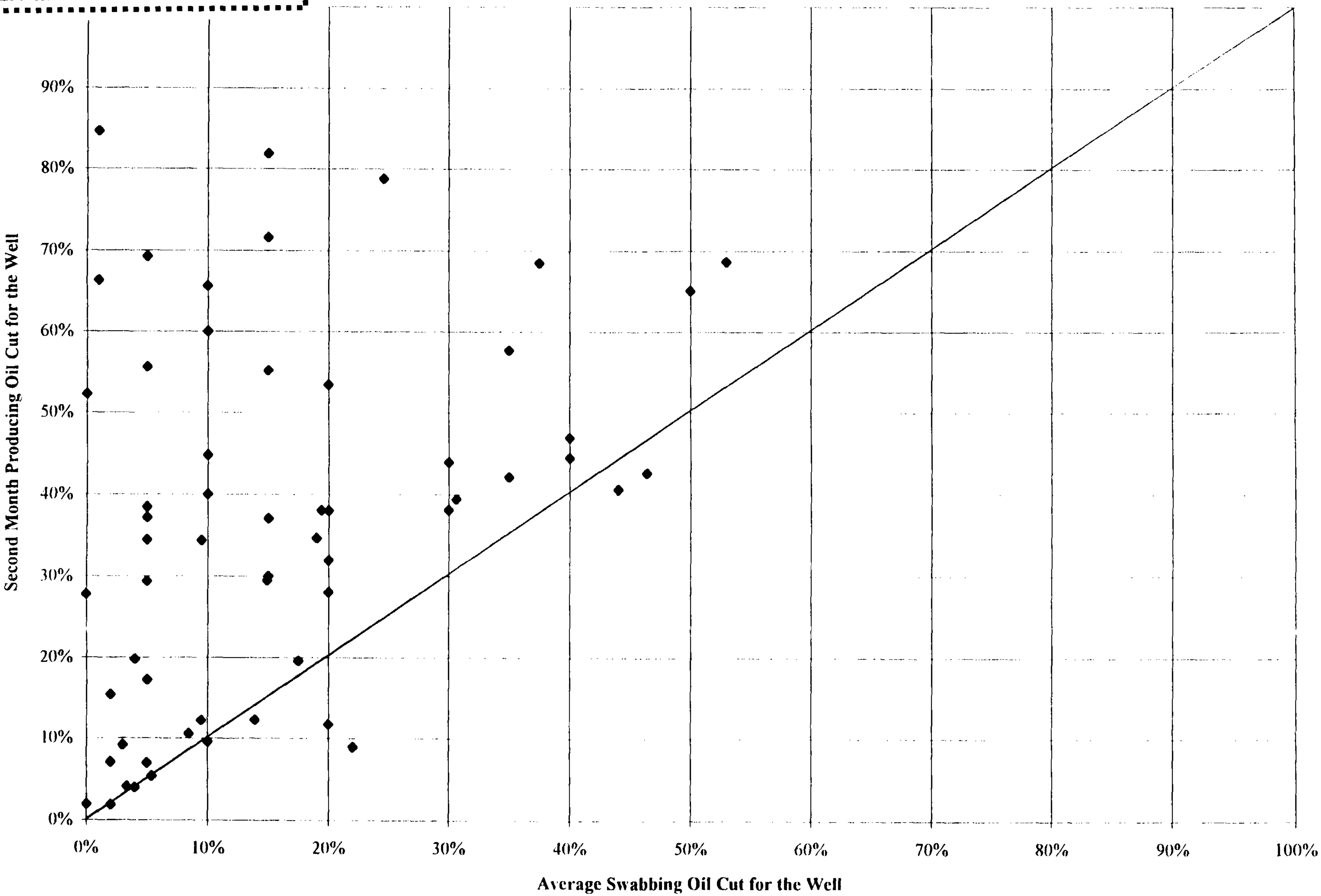
Examiner

Case No. 11525 + 11526

EXHIBIT NO. 8

ping Oil Cut Versus Second Month Producing Oil Cut for 58 Wells in Dagger Draw



Robert S. Fant

4/30/96

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

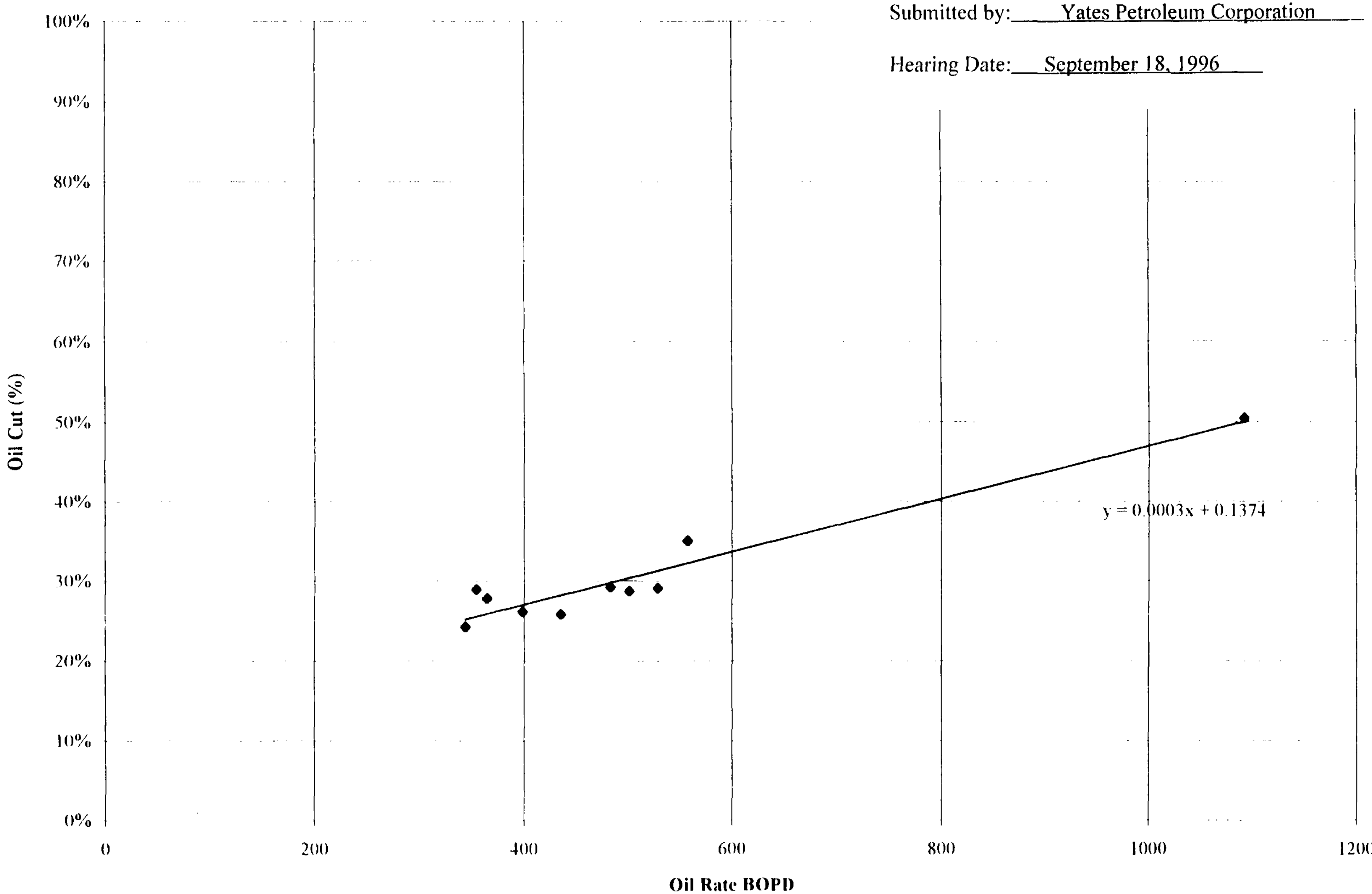
Case Nos. 11525 and 11526 Exhibit No. 8
(De Novo)
Submitted by: Yates Petroleum Corporation

Hearing Date: September 18, 1996

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

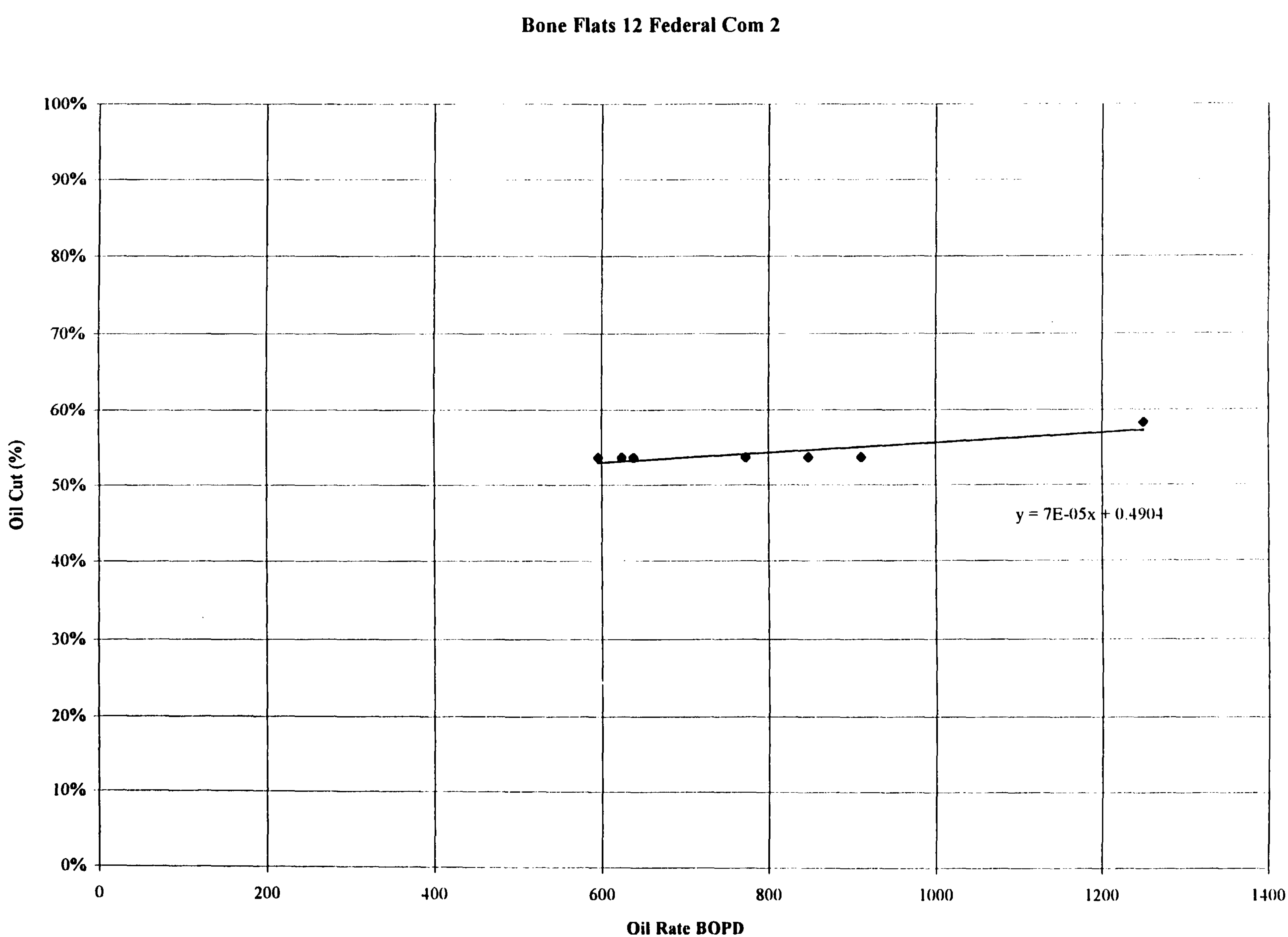
Case Nos. 11525 and 11526 (De Novo) Exhibit No. 9
Submitted by: Yates Petroleum Corporation
Hearing Date: September 18, 1996

APAREJO APA ST. COM. #3

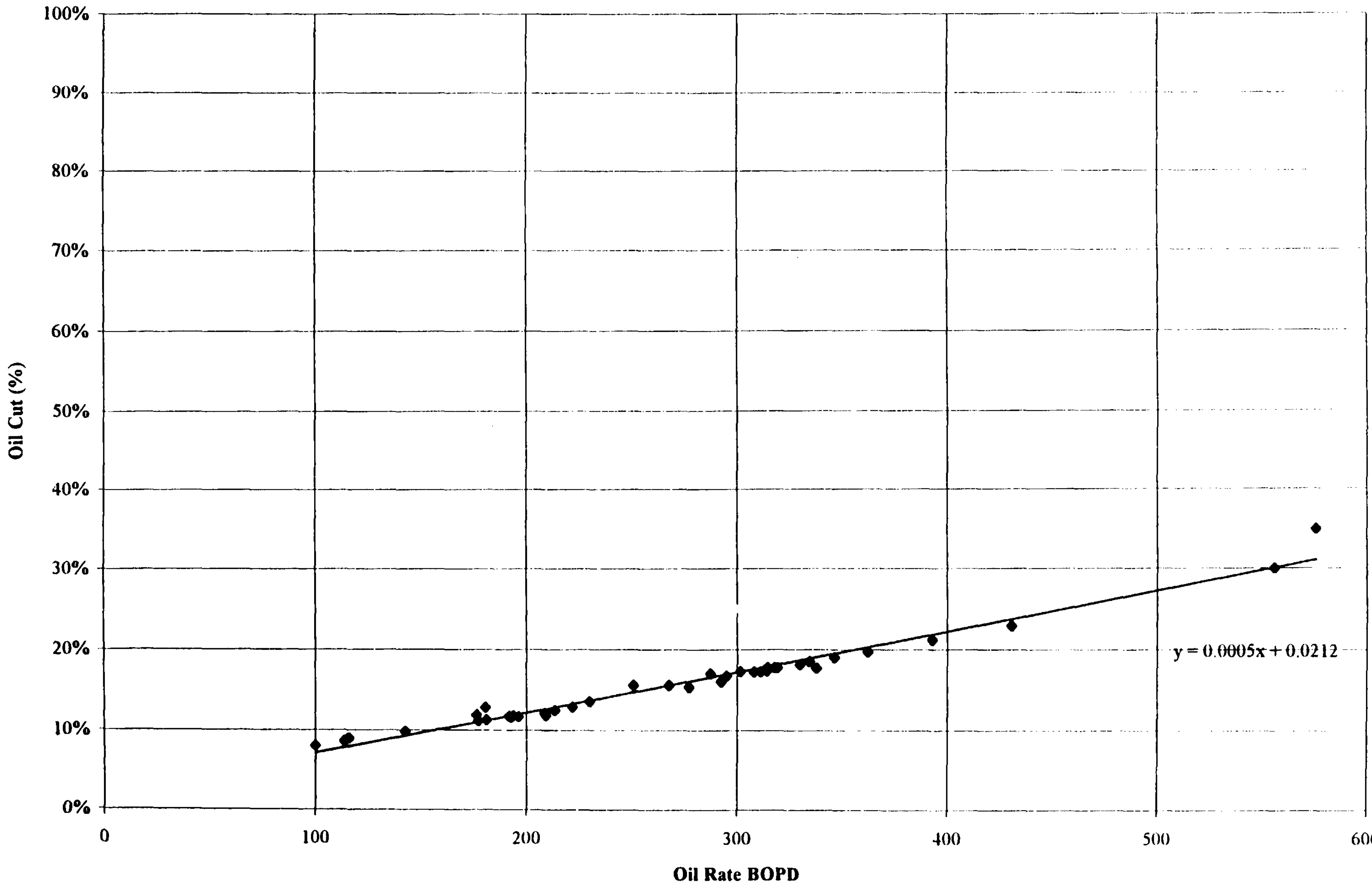


Robert S. Fant

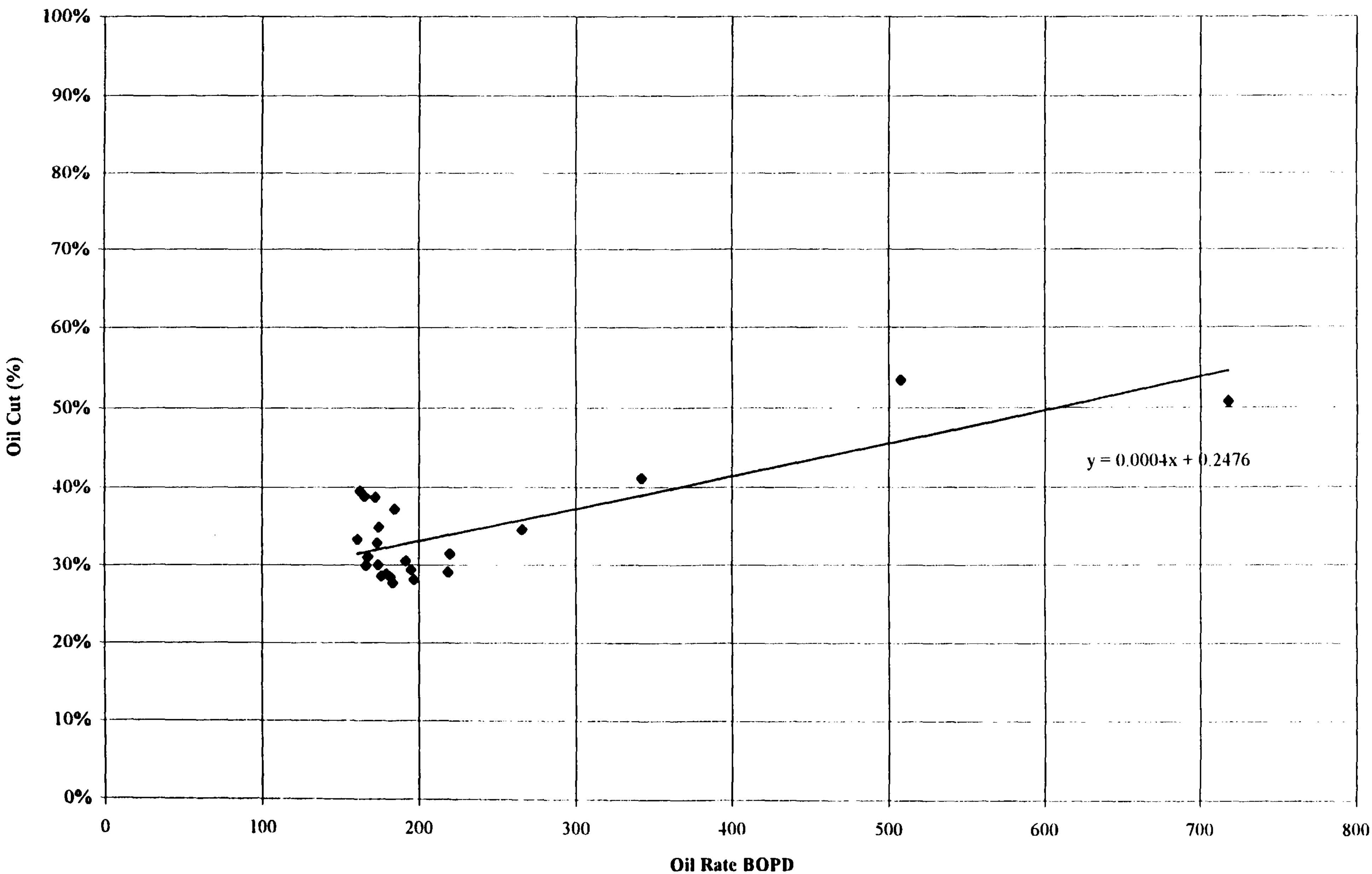
4/30/96


Bone Flats 12 Federal Com 2
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Oil Cut (%)
0
200
400
600
800
1000
1200
1400
Oil Rate BOPD
y = 7E-05x + 0.4904

BOYD X ST COM #2

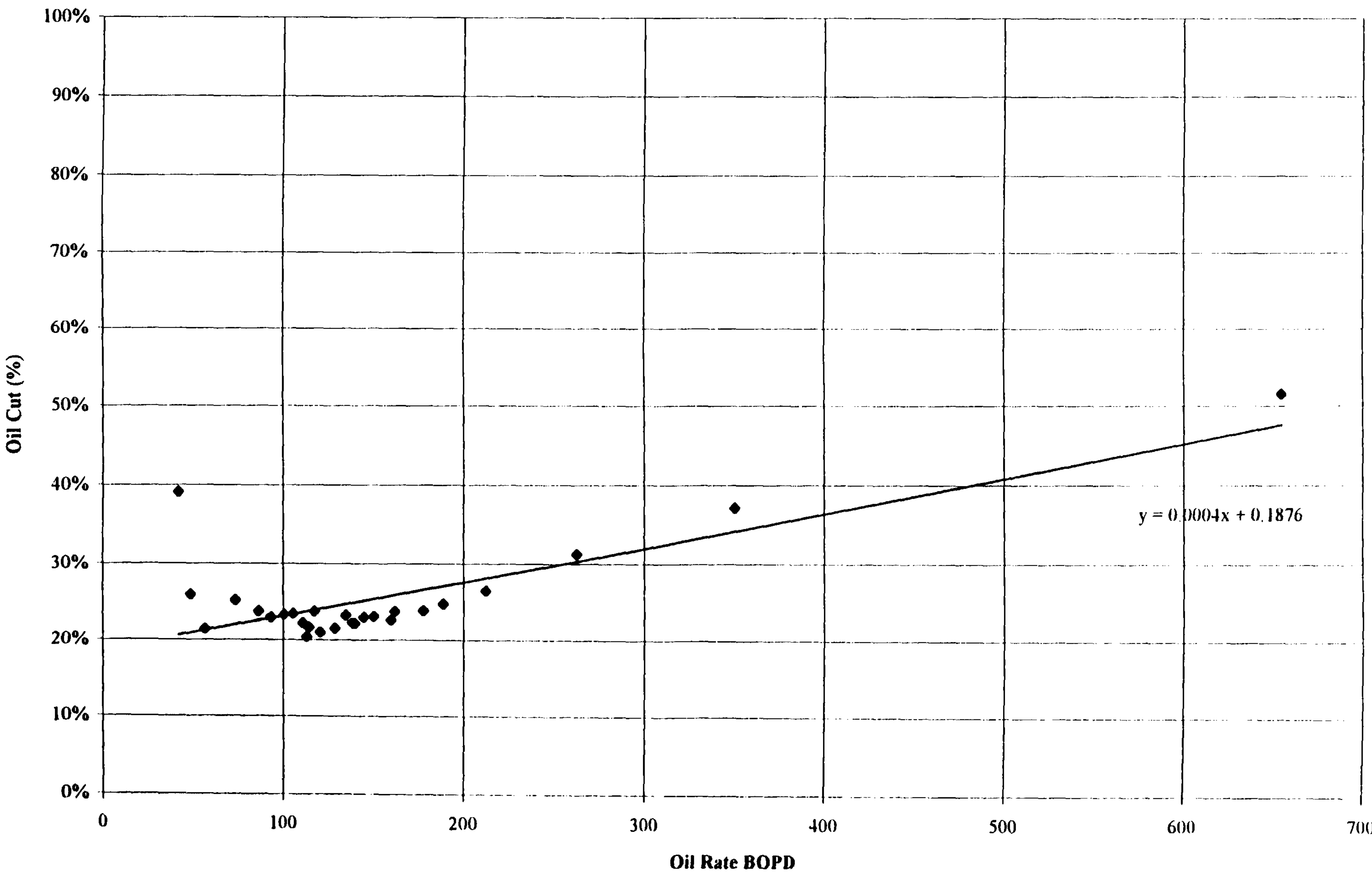


BOYD X ST COM #3



4/30/96

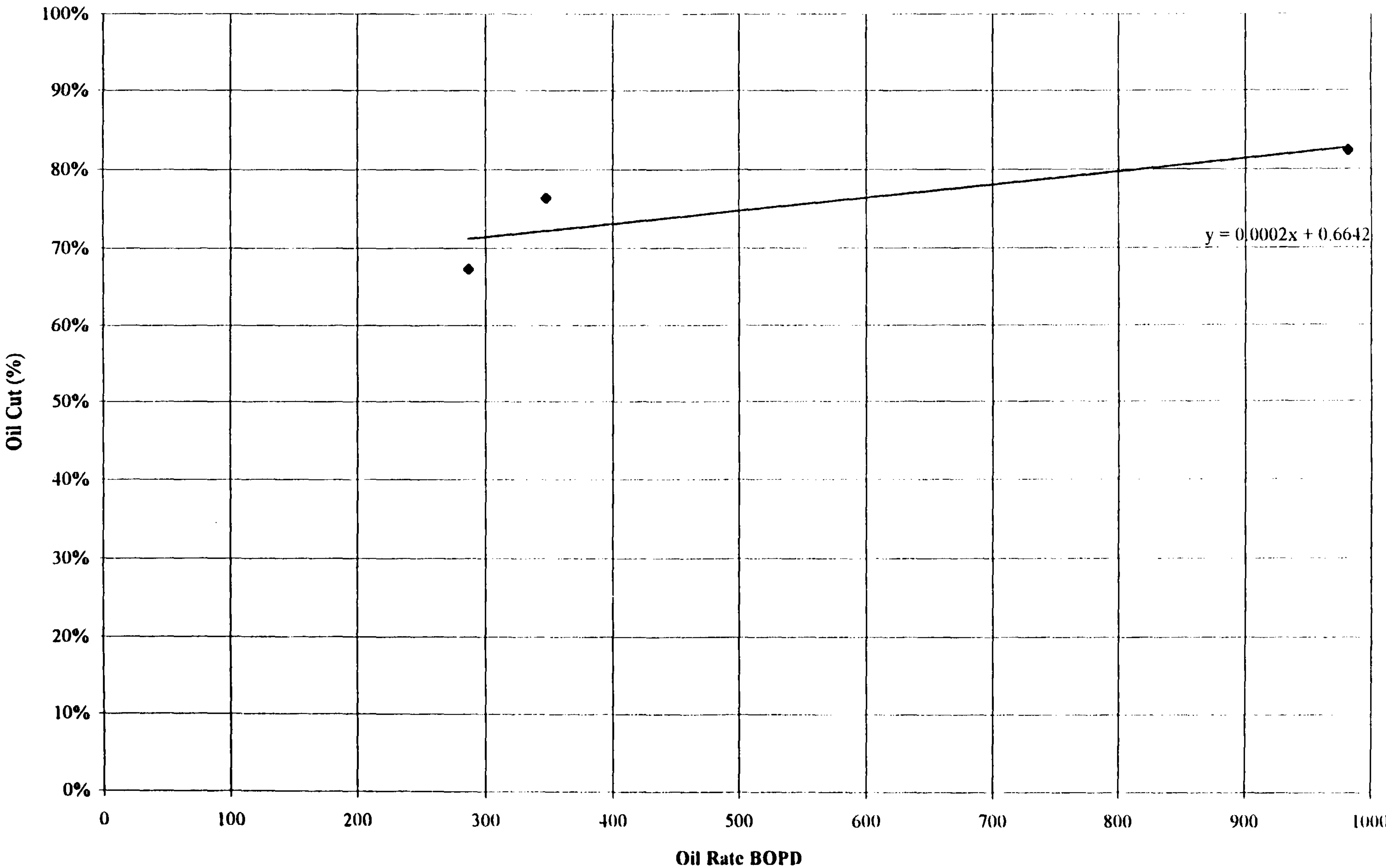
BOYD X ST COM #4



Robert S. Fant

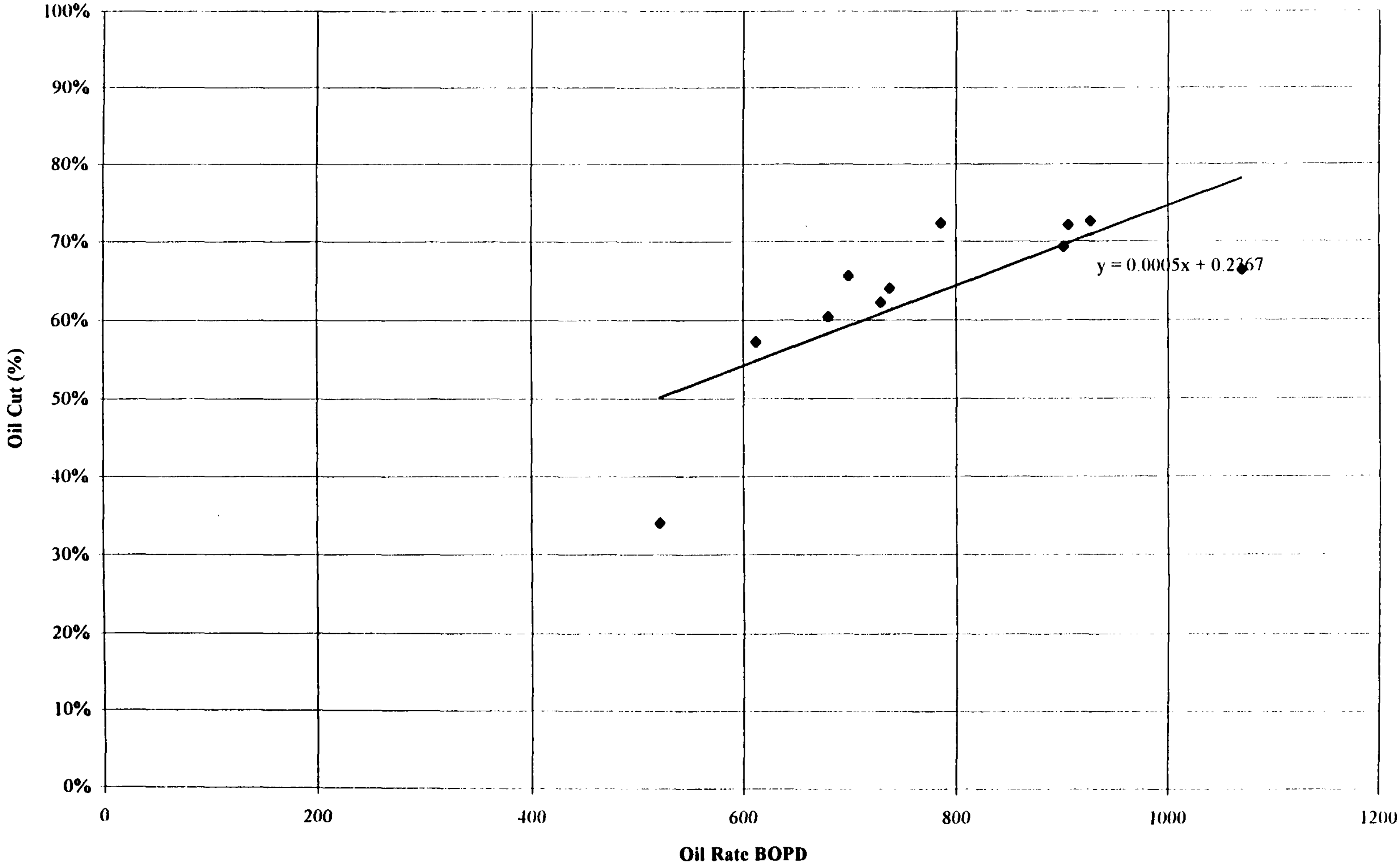
4/30/96

BOYD X #5

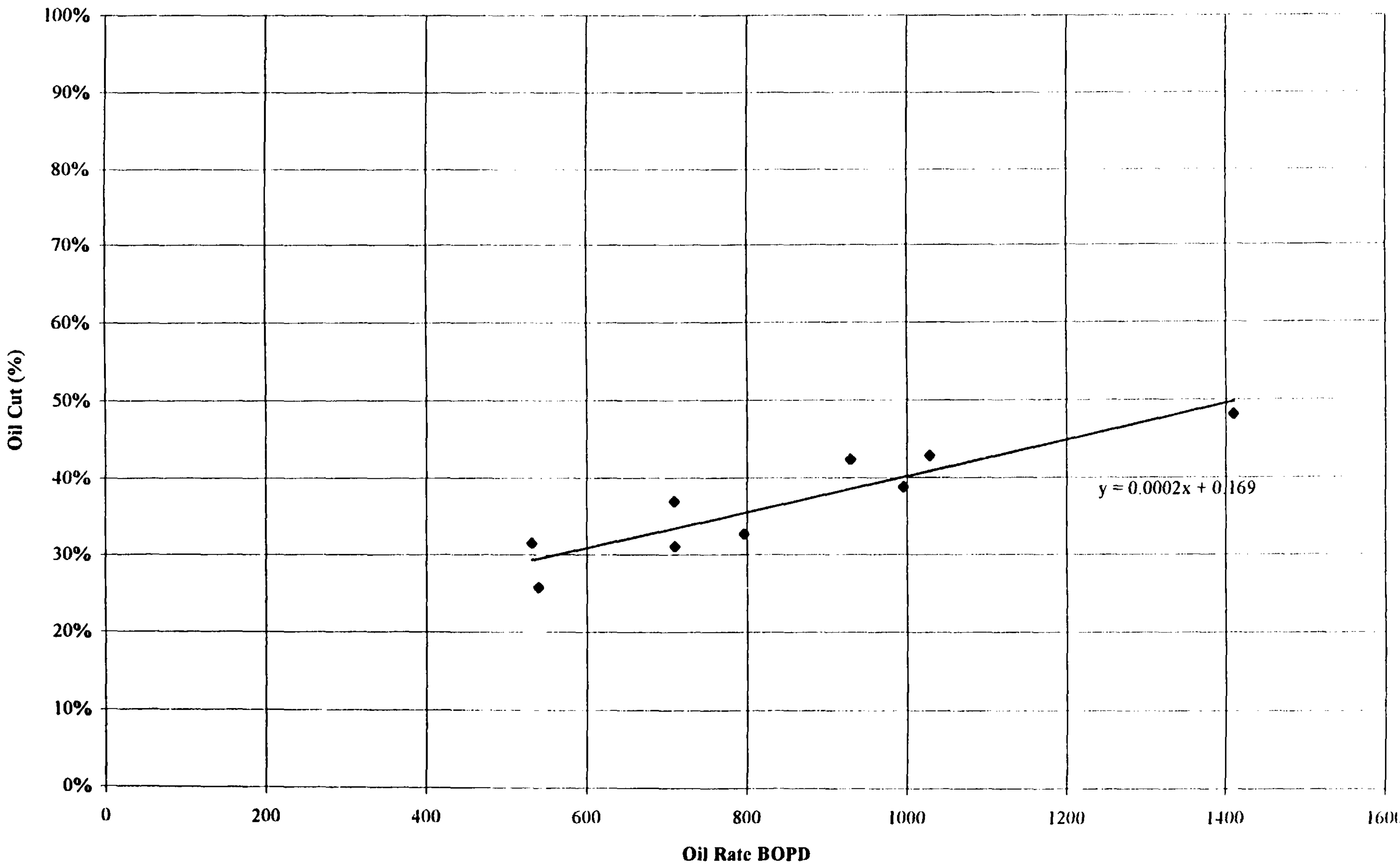


100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Oil Cut (%)
y = 0.0002x + 0.6642
0
100
200
300
400
500
600
700
800
900
1000
Oil Rate BOPD

BOYD X ST COM #6



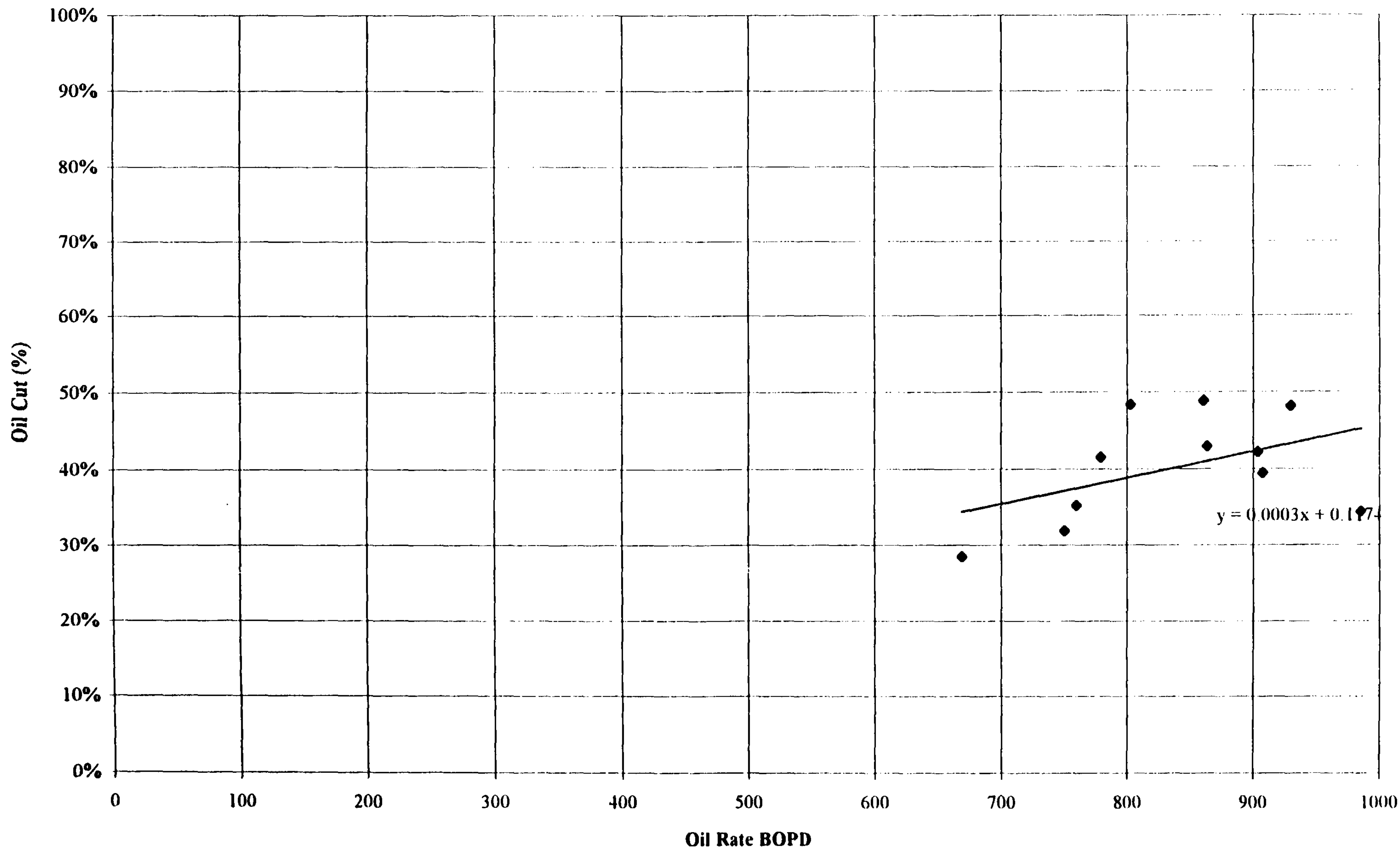
CUTTER APC #1



Robert S Fant

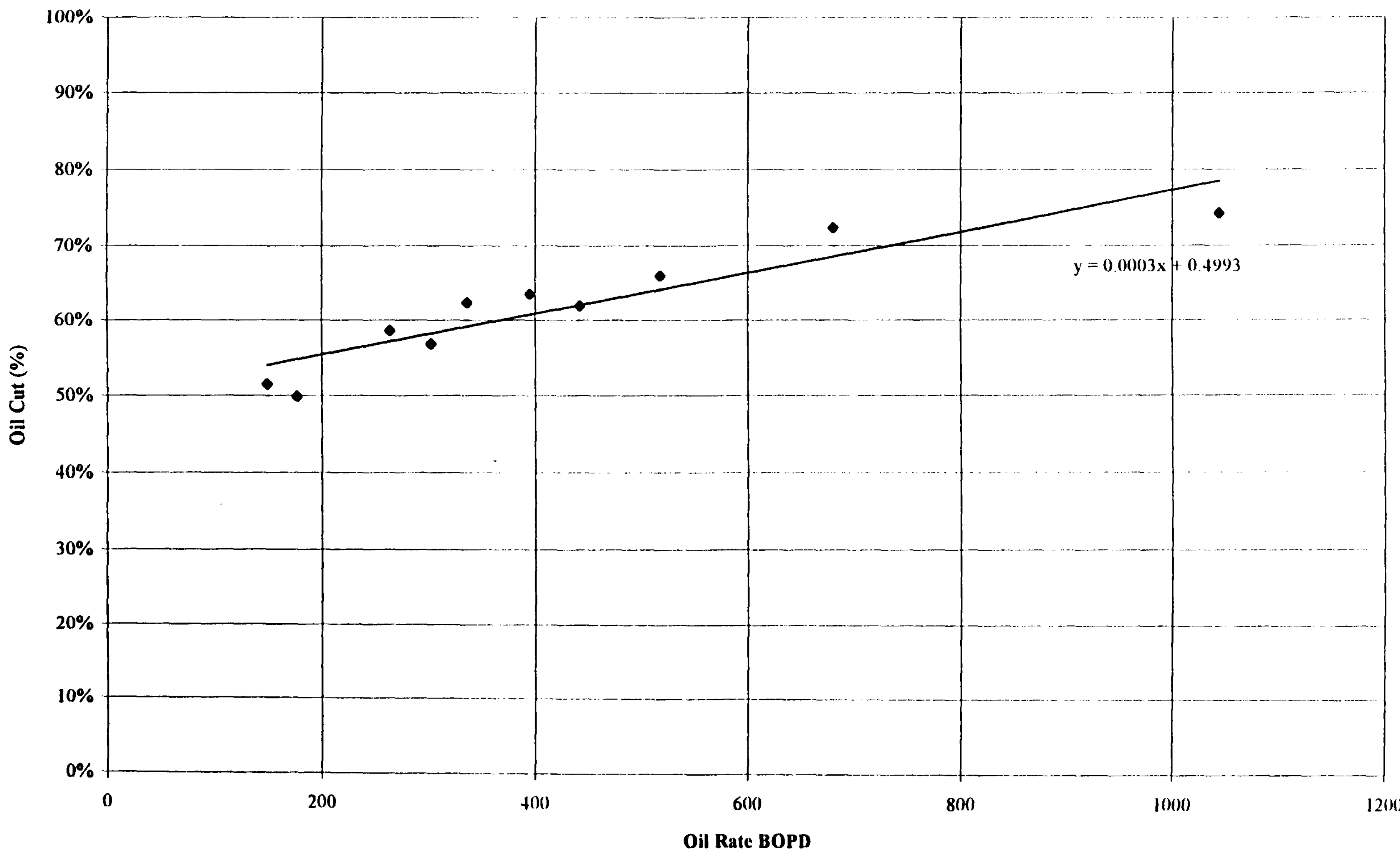
4/30/96

HINKLE ALD #2



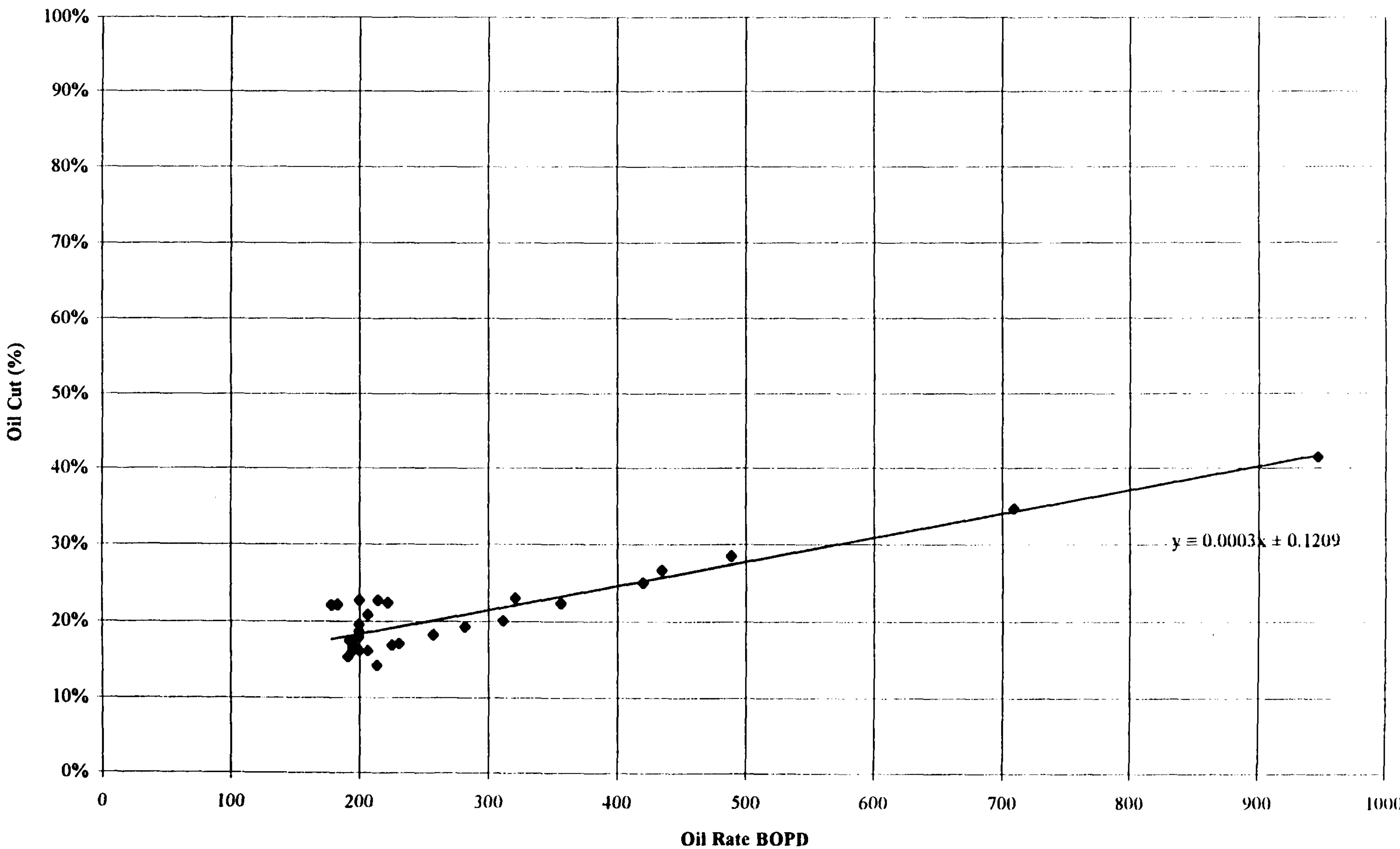
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Oil Cut (%)
y = 0.0003x + 0.1
0
100
200
300
400
500
600
700
800
900
1000
Oil Rate BOPD

HOOPER AMP #4



100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Oil Cut (%)
y = 0.0003x + 0.4993
0
200
400
600
800
1000
1200
Oil Rate BOPD

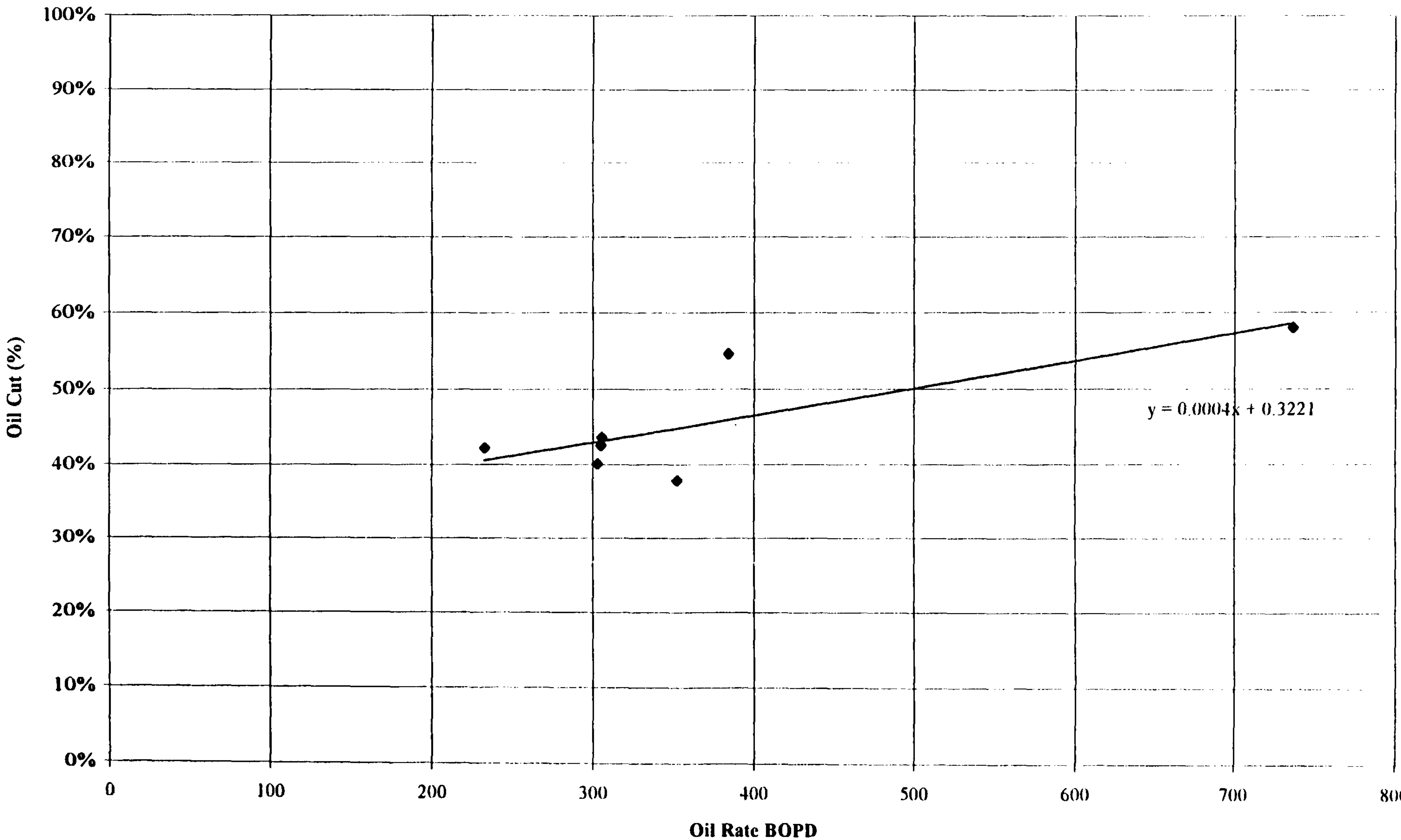
PATRIOT AIZ COM #3



Robert S. Fant

4/30/96

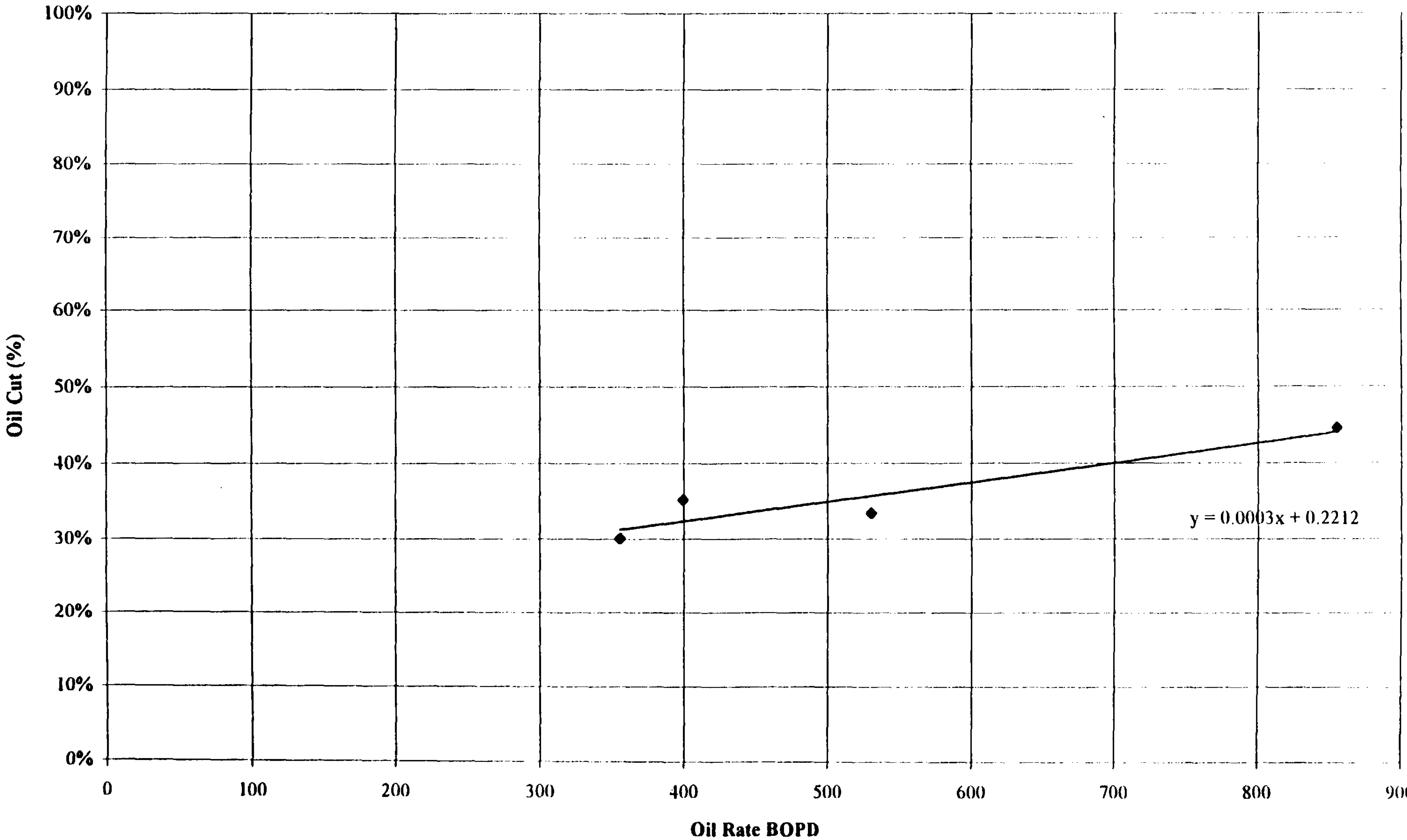
POLO AOP FEDERAL #3



Robert S. Fant

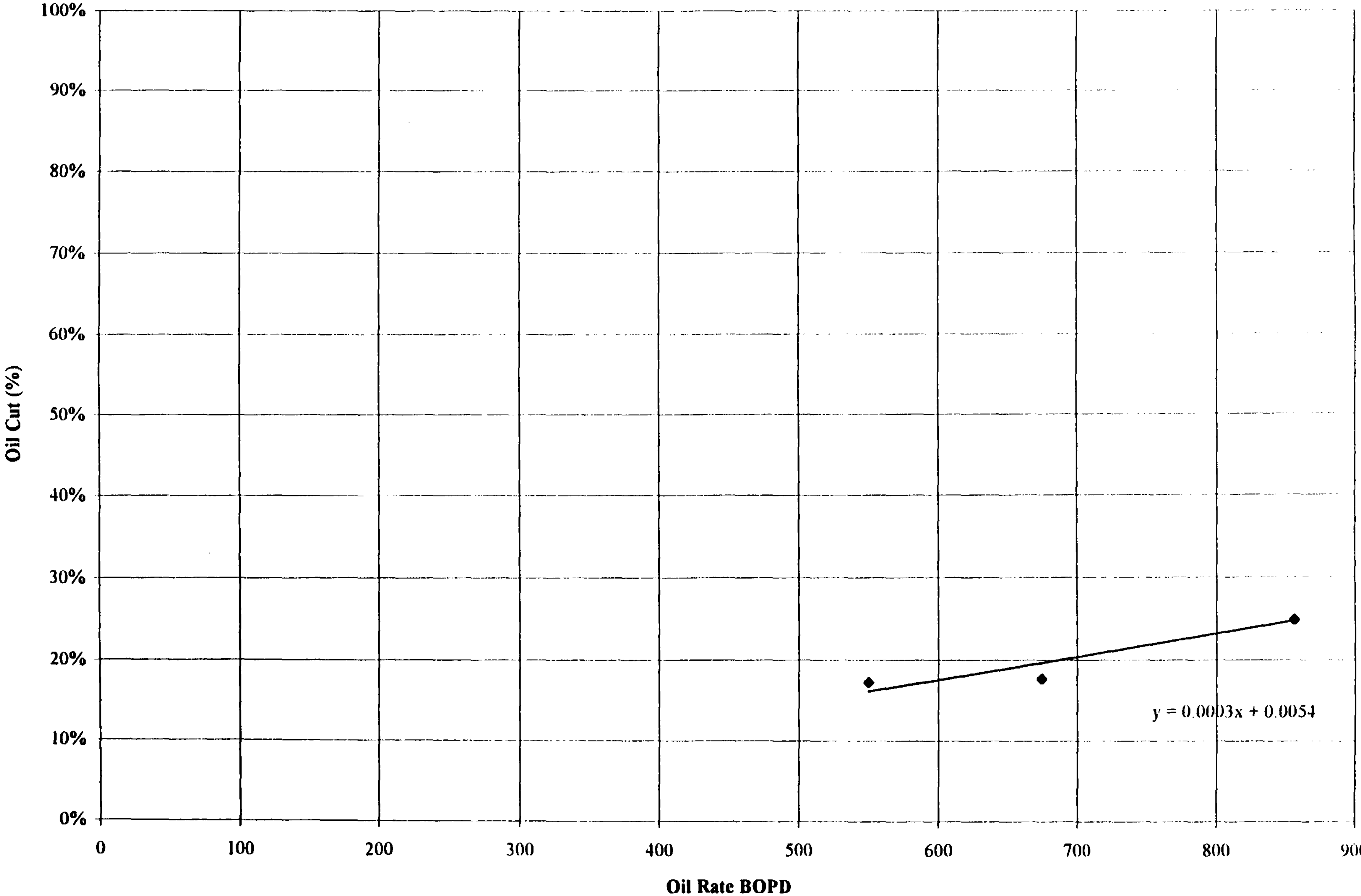
4/30/96

ROSS EG #14



100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Oil Cut (%)
0
100
200
300
400
500
600
700
800
900
Oil Rate BOPD
y = 0.0003x + 0.2212

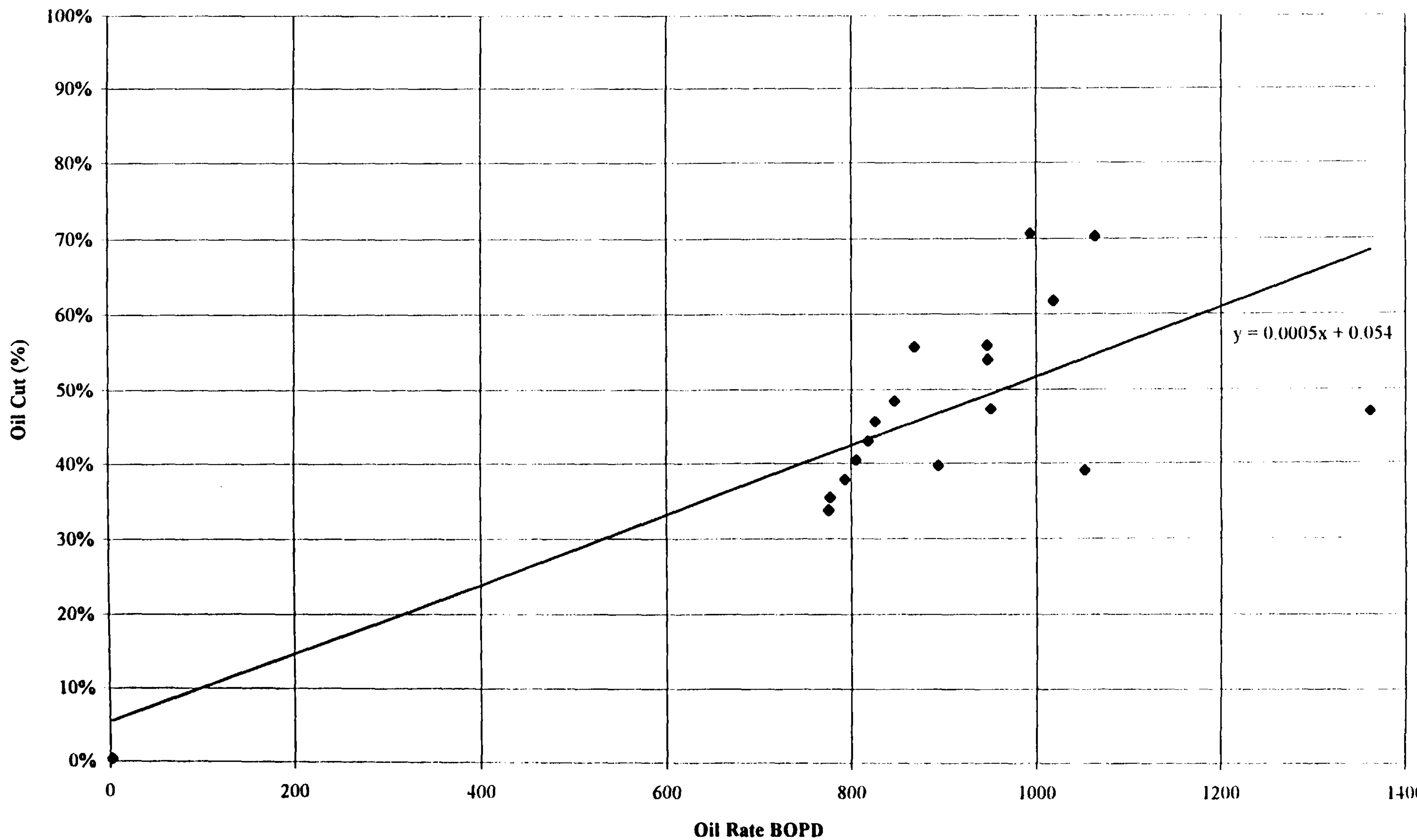
South Boyd 27 3



Robert S. Fant

4/30/96

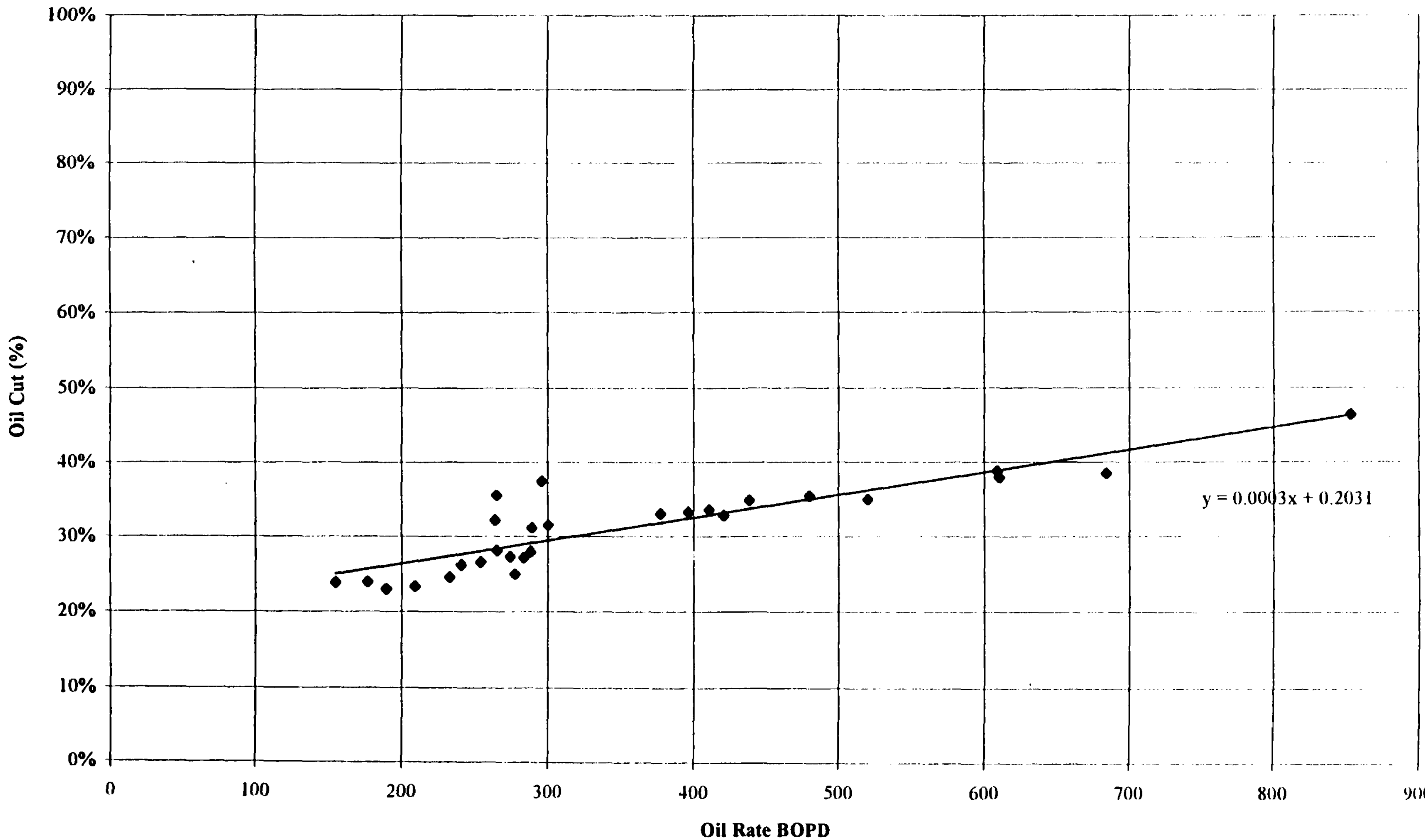
STATE K #3



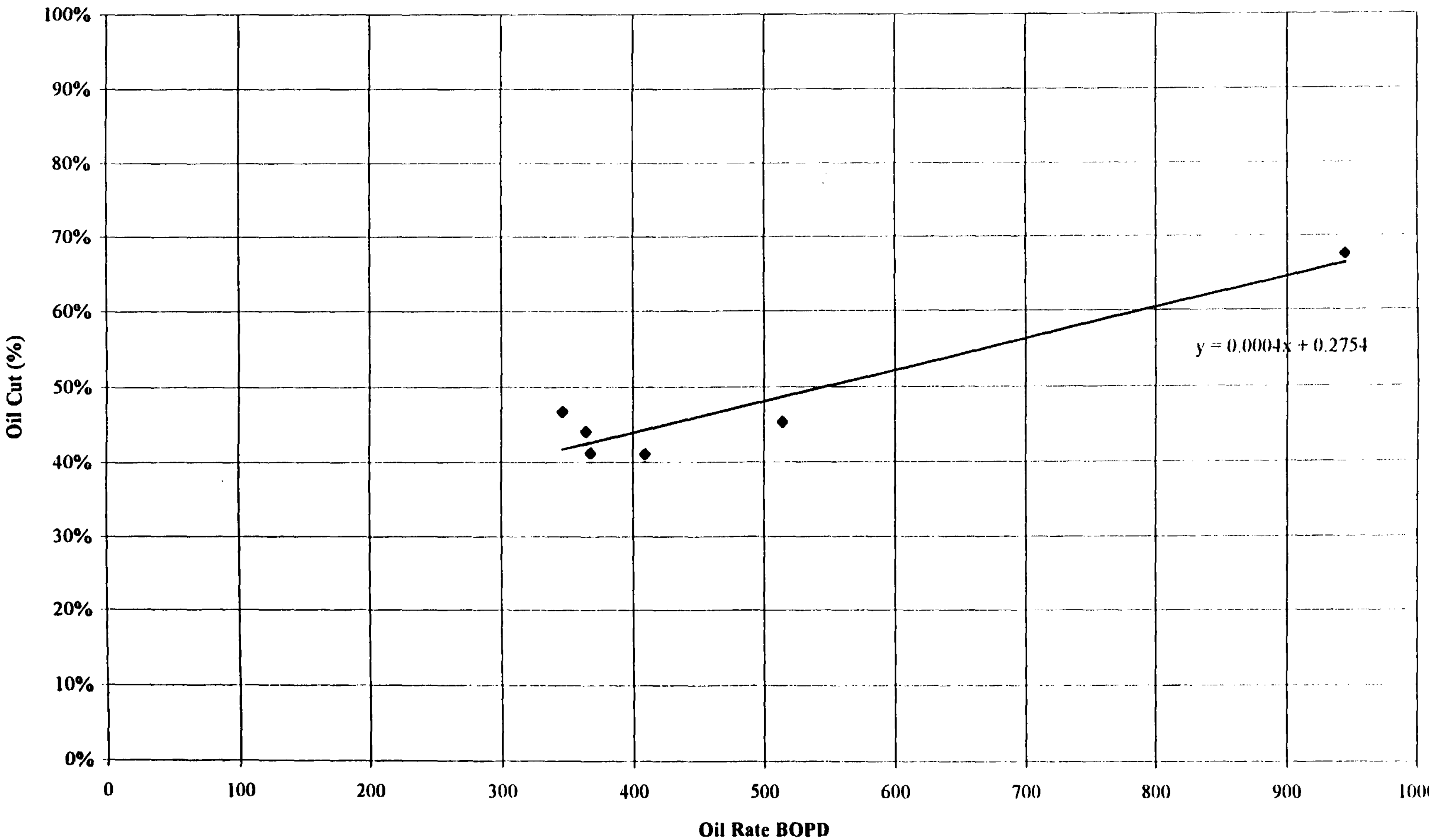
Robert S. Fant

4/30/96

VOIGHT AJD COM #3



WARREN ANW #3



4/30/96

WellName	Operator	Unit	Section	Township	Range	Oil Cut Slope	GOR Slope
ALEXANDRE AHX FED #1	Yates Petroleum	C	33	19S	24E	0.048166385	27195.25541
ALGERITA AHR ST #1	Yates Petroleum	H	16	20S	24E	0.00583123	-1615.411247
ALLISON CQ FED #10	Yates Petroleum	H	13	19S	24E	0.021929806	9346.139859
AMOLE AMM ST COM #1	Yates Petroleum	M	16	19S	25E	0.00096623	12.7424447
AMOLE AMM ST COM #2	Yates Petroleum	K	16	19S	25E	0.000457863	-57.57266548
APAREJO APA ST. COM. #1	Yates Petroleum	D	16	19S	25E	0.000244399	-0.887498863
APAREJO APA ST. COM. #2	Yates Petroleum	F	16	19S	25E	0.000364895	-7.024728317
APAREJO APA ST. COM. #3	Yates Petroleum	B	16	19S	25E	0.000331833	-0.004706601
ASPDEN AOH FED #2	Yates Petroleum	N	29	19S	25E	-2.68908E-05	0.543472492
ASPDEN AOH FED COM #1	Yates Petroleum	M	29	19S	25E	0.000114316	0.844177224
ASPDEN AOH FED COM #3	Yates Petroleum	F	29	19S	25E	0.000145969	-2.00547877
Barbara 17 SE Com 18	Conoco Inc	P	17	19S	25E	0.004810691	-44.74090022
Barbara 17 SW Com 10	Conoco Inc	M	17	19S	25E	0.003698494	-163.1691841
Barbara 17 SW Com 17	Conoco Inc	K	17	19S	25E	0.008467401	60.01945564
Barbara 18 SE Federal 12	Conoco Inc	O	18	19S	25E	0.001951929	4.365052479
Barbara 18 SE Federal 8	Conoco Inc	P	18	19S	25E	0.00021868	-5.940123925
Barbara Federal 1	Conoco Inc	H	18	19S	25E	0.000775559	5.2028666
Barbara Federal 2	Conoco Inc	K	18	19S	25E	0.005099873	13.28680043
Barbara Federal 3	Conoco Inc	F	17	19S	25E	0.002851436	-10.84430379
Barbara Federal 4	Conoco Inc	L	17	19S	25E	0.002080989	-2.510561181
Barbara Federal 5	Conoco Inc	F	18	19S	25E	0.001636043	-1077.167634
Barbara Federal 6	Conoco Inc	J	18	19S	25E	0.001087722	-3.099875975
Barbara Federal 7	Conoco Inc	J	17	19S	25E	0.001502151	-471.9998438
BINGER AKU #2	Yates Petroleum	G	29	19S	25E	-7.93056E-05	0.148535776
BINGER AKU COM #1	Yates Petroleum	B	29	19S	25E	-8.23906E-06	-0.554720615
Bone Flats 12 Federal 1	Marathon Oil Co	D	12	21S	23E	0.002198029	9.649921763
Bone Flats 12 Federal Com 2	Marathon Oil Co	E	12	21S	23E	6.52048E-05	-0.202875156
BOYD BN #2	Yates Petroleum	J	15	19S	25E	0.00043326	-0.790264438
BOYD X #5	Yates Petroleum	I	29	19S	25E	0.00016604	0.56440182
BOYD X ST COM #1	Yates Petroleum	A	16	19S	25E	0.000581669	0.183613499
BOYD X ST COM #2	Yates Petroleum	L	29	19S	25E	0.000502053	-1.679832919
BOYD X ST COM #3	Yates Petroleum	J	29	19S	25E	0.000414547	0.934744868
BOYD X ST COM #4	Yates Petroleum	K	29	19S	25E	0.000511665	-1.606590401
BOYD X ST COM #6	Yates Petroleum	O	29	19S	25E	0.000508904	-4.174594867
CACTI AGB STATE COM #1	Yates Petroleum	J	2	20S	24E	0.006540771	-76.41075045
CANDELILLA AKD ST COM #1	Yates Petroleum	O	2	20S	24E	0.001047056	-13.35520275
CANDELILLA AKD ST COM #2	Yates Petroleum	N	2	20S	24E	0.002875374	-66.00594274
CARL TP COM #1	Yates Petroleum	I	22	20S	24E	0.008312369	-6998.15442
CARL TP COM #2	Yates Petroleum	K	22	20S	24E	0.005392019	-37451.44487
CARL TP COM #3	Yates Petroleum	C	22	20S	24E	0.000615431	-55402.06326
CARL TP COM #4	Yates Petroleum	A	22	20S	24E	0.000691982	-1002.488205
CATCLAW AGM ST #1	Yates Petroleum	F	2	20S	24E	0.003789958	-83.95677111
CATCLAW AGM ST COM #3	Yates Petroleum	G	2	20S	24E	0.000464171	-72.84544471
CATCLAW AGM ST COM #4	Yates Petroleum	A	2	20S	24E	0.002222751	-61.63850428
CENIZA AGZ COM #1	Yates Petroleum	P	2	20S	24E	0.000325393	-4.816818748
CENIZA AGZ COM #2	Yates Petroleum	M	12	20S	24E	0.002407025	-53.06539415
CENIZA AGZ COM #3	Yates Petroleum	E	13	20S	24E	0.000966722	410.8217321
CENIZA AGZ COM #4	Yates Petroleum	L	12	20S	24E	0.000489391	-22.20005002
CENTURY PLANT AHT #1	Yates Petroleum	P	34	19S	24E	0.008072826	-28557.97303
CHAMIZA AJC COM #1	Yates Petroleum	O	19	19S	25E	0.000641462	-16.65658758
Charolette McKay Fed Com 2	McKay Oil Corp	D	25	20S	24E	0.001207441	-137.4067185
Charolette McKay Fed Com 4	McKay Oil Corp	E	25	20S	24E	0.000408525	-292.1154147
CHOLLA AGE FED. #1	Yates Petroleum	I	3	20S	24E	0.002605033	718.9912861
CLIFFORD ADD #1	Yates Petroleum	P	35	19S	24E	0.001013519	-83.80549113
CLIFFORD ADD #2	Yates Petroleum	I	[illegible]	[illegible]	[illegible]	[illegible]8	-2933.476097

Examiner ____

Case No. 11525 + 11526

EXHIBIT NO. 10

WellName	Operator	Unit	Section	Township	Range	Oil Cut Slope	GOR Slope
CONOCO AGK FED #1	Yates Petroleum	C	11	20S	24E	0.000759604	-16.66718356
CONOCO AGK FED #11	Yates Petroleum	J	26	20S	24E	0.001329561	-49.31151315
CONOCO AGK FED #12	Yates Petroleum	E	11	20S	24E	0.001341897	-95.18612344
CONOCO AGK FED #2	Yates Petroleum	G	26	20S	24E	0.002316507	-114.7656511
CONOCO AGK FED #3	Yates Petroleum	I	26	20S	24E	0.000766087	-27.11574906
CONOCO AGK FED #4	Yates Petroleum	A	26	20S	24E	0.000746649	-11.98482047
CONOCO AGK FED #5	Yates Petroleum	B	26	20S	24E	0.001156028	-40.98500378
CONOCO AGK FED #7	Yates Petroleum	F	11	20S	24E	0.001568802	-21.07206338
CONOCO AGK FED COM #10	Yates Petroleum	J	11	20S	24E	0.002435247	-161.8013433
CONOCO AGK FED COM #14	Yates Petroleum	M	15	20S	24E	0.000417353	13201.28055
CONOCO AGK FED COM #15	Yates Petroleum	O	26	20S	24E	0.001658928	-33.39478086
CONOCO AGK FED COM #6	Yates Petroleum	K	26	20S	24E	0.002530155	-23.03060595
CONOCO AGK FED COM #8	Yates Petroleum	H	26	20S	24E	0.000936403	-9.072593532
CONOCO AGK FED COM #9	Yates Petroleum	P	26	20S	24E	0.000812446	-423.1167799
Conoco Com 1	Conoco Inc	A	18	19S	25E	0.003181582	2.03219016
Conoco Com 9	Conoco Inc	G	18	19S	25E	-0.00037132	-16.65033098
COOPER AHH #1	Yates Petroleum	F	1	20S	24E	0.000845106	-35.37034404
COOPER AHH #2	Yates Petroleum	E	1	20S	24E	0.001934401	-17.79270464
Covert Com 2	Nearburg Producing Co	D	6	20S	25E	0.000408861	-1.331397614
CUTTER APC #1	Yates Petroleum	P	21	19S	25E	0.000232769	-0.347061392
D D Federal 24 1	Texaco Expl & Prod Inc	P	24	19S	24E	0.002584174	-43.74801309
D D Federal 24 2	Texaco Expl & Prod Inc	I	24	19S	24E	0.001260427	-60.05699005
D D Federal 24 3	Texaco Expl & Prod Inc	O	24	19S	24E	0.004309221	-637.948755
D D Federal 24 4	Texaco Expl & Prod Inc	J	24	19S	24E	0.001229702	-208.337586
D D Federal 25 1	Texaco Expl & Prod Inc	H	25	19S	24E	0.002736717	-72.84628625
D D Federal 25 2Y	Texaco Expl & Prod Inc	G	25	19S	24E	0.002935078	-163.3367898
D D Federal 25 3	Texaco Expl & Prod Inc	A	25	19S	24E	0.001884015	-57.16988463
D D Federal 25 4	Texaco Expl & Prod Inc	B	25	19S	24E	0.001493792	-48.27515979
Dagger Draw 19 SW 10	Conoco Inc	M	19	19S	25E	0.001440012	-14.64589334
Dagger Draw 19 SW 14	Conoco Inc	N	19	19S	25E	0.002547616	-12.72289802
Dagger Draw 19 SW 4	Conoco Inc	L	19	19S	25E	0.000261345	-7.674014954
Dagger Draw 2	Conoco Inc	I	30	19S	25E	0.001665016	-23.62610825
Dagger Draw 30 N Com 1	Conoco Inc	D	30	19S	25E	0.001992355	-30.025047
Dagger Draw 30 N Com 12	Conoco Inc	G	30	19S	25E	0.001195355	4.312798714
Dagger Draw 30 N Com 13	Conoco Inc	F	30	19S	25E	0.000918172	-43.72484666
Dagger Draw 30 N Com 17	Conoco Inc	H	30	19S	25E	0.002427864	-88.71704325
Dagger Draw 30 N Com 5	Conoco Inc	B	30	19S	25E	0.000340327	-19.12725507
Dagger Draw 30 N Com 9	Conoco Inc	E	30	19S	25E	0.001142717	-62.57081203
Dagger Draw 30N Com 15	Conoco Inc	A	30	19S	25E	0.00557057	-2.23204399
Dagger Draw 30SE Com 11	Conoco Inc	O	30	19S	25E	0.000852987	1.766724785
Dagger Draw 30SE Com 16	Conoco Inc	P	30	19S	25E	0.002368458	-1.241972336
Dagger Draw 30SE Com 8	Conoco Inc	J	30	19S	25E	0.001237574	7.209346493
Dagger Draw 31 Federal 1	Nearburg Producing Co	D	31	19S	25E	0.000342063	-8.951553508
Dagger Draw 31 Federal 2	Nearburg Producing Co	B	31	19S	25E	0.000158696	-6.467999211
Dagger Draw 31 Federal 4	Nearburg Producing Co	E	31	19S	25E	0.001253633	-7.039632056
Dagger Draw 31 Federal 5	Nearburg Producing Co	C	31	19S	25E	0.002136926	-16.23714998
Dagger Draw 31 Federal 6	Nearburg Producing Co	A	31	19S	25E	0.000253408	5.480331733
Dagger Draw A 1	Southwest Royalties Inc	G	17	19S	25E	0.003093954	13.47720824
DAGGER ZW #1	Yates Petroleum	K	30	19S	25E	0.0005037	-15.09327823
DAGGER ZW #2	Yates Petroleum	I	25	19S	24E	0.001068939	-31.99946052
DAGGER ZW #3	Yates Petroleum	L	30	19S	24E	0.001116529	-22.5089283
DAHLIA ALA COM #1	Yates Petroleum	L	25	20S	25E	0.000749192	-13.22848112
Dee 36 SE State 1	Conoco Inc	J	36	19S	24E	0.000311105	-670.437104
Dee 36 SE State 10	Conoco Inc	M	17	19S	25E	0.002196868	-23.79210246
Dee 36 SE State 3	Conoco Inc	J	36	19S	24E	0.000476145	0.013703391

WellName	Operator	Unit	Section	Township	Range	Oil Cut Slope	GOR Slope
Dee 36 SE State 5	Conoco Inc	P	36	19S	24E	0.000857037	-1.763340936
Dee 36 SE State 6	Conoco Inc	I	36	19S	24E	0.001082143	-77.47601009
Dee 36 SW State 2	Conoco Inc	M	36	19S	24E	0.000289212	-86.12748835
Dee 36 SW State 4	Conoco Inc	K	36	19S	24E	0.002766113	-27.07266124
EE 24 Federal 1	Texaco Expl & Prod Inc	H	24	19S	24E	0.001942696	-136.9770875
EE 24 Federal 2	Texaco Expl & Prod Inc	A	24	19S	24E	0.001547506	-82.02133995
ENG TX FED #1	Yates Petroleum	E	35	19S	24E	0.024981349	8594.87157
ENG TX FED #2	Yates Petroleum	N	26	19S	24E	0.009071115	-28482.37844
Fairchild 24 1	Nearburg Producing Co	E	24	19S	25E	0.000156159	1.784731178
Foster 31 Federal 1	Nearburg Producing Co	N	31	19S	25E	0.000851002	-2.786918277
Foster 31 Federal 2	Nearburg Producing Co	L	31	19S	25E	-1.83177E-05	-3.237931496
Foster 31 Federal 3	Nearburg Producing Co	M	31	19S	25E	0.000224924	-12.08744519
FOSTER AN #1	Yates Petroleum	D	1	20S	24E	0.00049314	-24.45138917
FOSTER AN #2	Yates Petroleum	B	1	20S	24E	0.000490457	-10.82782977
FOSTER AN #3	Yates Petroleum	A	1	20S	24E	0.000483188	-2.254396044
FOSTER AN #4	Yates Petroleum	C	1	20S	24E	0.004775859	-66.42388007
FOSTER FF COM #1	Yates Petroleum	J	1	20S	24E	0.001409759	0.158692087
FOSTER FF COM #2	Yates Petroleum	L	1	20S	24E	0.001242535	-15.83462948
FOXTAIL AJX FED COM #1	Yates Petroleum	M	1	20S	24E	0.000929416	-15.89134681
HILL VIEW AHE COM #10	Yates Petroleum	H	23	20S	24E	0.000771795	-249.841518
HILL VIEW AHE COM #11	Yates Petroleum	K	23	20S	24E	0.001143125	-86.11776729
HILL VIEW AHE COM #12	Yates Petroleum	I	23	20S	24E	0.000776984	-51.60557658
HILL VIEW AHE COM #7	Yates Petroleum	M	13	20S	24E	0.001204256	161.8495476
HILL VIEW AHE COM #8	Yates Petroleum	P	14	20S	24E	0.000429845	-33.9188754
HILL VIEW AHE FED #1	Yates Petroleum	D	12	20S	24E	4.35102E-05	-13.5365953
HILL VIEW AHE FED #9	Yates Petroleum	E	12	20S	24E	0.000954159	-9.401289345
HILL VIEW AHE FED COM #13	Yates Petroleum	I	14	20S	24E	0.000928446	-46.59070904
HILL VIEW AHE FED COM #16	Yates Petroleum	M	14	20S	24E	0.005823606	-161.3506946
HILL VIEW AHE FED COM #17	Yates Petroleum	O	23	20S	24E	0.002659012	-58.22262947
HILL VIEW AHE FED COM #2	Yates Petroleum	G	23	20S	24E	0.000797898	-11.83279052
HILL VIEW AHE FED COM #3	Yates Petroleum	N	23	20S	24E	0.000735107	-38.5148288
HILL VIEW AHE FED COM #4	Yates Petroleum	J	23	20S	24E	0.000632682	-46.07436535
HILL VIEW AHE FED COM #5	Yates Petroleum	A	23	20S	24E	0.000421463	-170.4922475
HILL VIEW AHE FED COM #6	Yates Petroleum	B	23	20S	24E	0.001124075	-37.05231907
HINKLE ALD #1	Yates Petroleum	G	28	19S	25E	-0.000159528	0.542487914
HINKLE ALD #2	Yates Petroleum	B	28	19S	25E	0.000339128	-0.926642899
HOOPER AMP #1	Yates Petroleum	M	21	19S	25E	2.18418E-05	-20.87858782
HOOPER AMP #2	Yates Petroleum	F	21	19S	25E	-0.002098466	4.122223041
HOOPER AMP #4	Yates Petroleum	A	20	19S	25E	0.000273521	-0.720863836
HOOPER AMP COM. #3	Yates Petroleum	H	20	19S	25E	2.96768E-05	1.238217607
HUISACHE AHI ST COM #1	Yates Petroleum	H	2	20S	24E	0.000653643	-10.46892404
HUISACHE AHI ST COM #2	Yates Petroleum	I	2	20S	24E	0.00247783	-26.67806875
Indian Hills State Comm 1	Marathon Oil Co	G	36	20S	24E	0.017715027	-1113.04865
Indian Hills State Comm 3	Marathon Oil Co	D	36	20S	24E	0.000521636	-82.71057928
Indian Hills State Comm 4	Marathon Oil Co	E	36	20S	24E	-0.000289043	-18.08683834
Indian Hills State Comm 5	Marathon Oil Co	L	36	20S	24E	0.000802219	-71.18447909
Indian Hills State Comm 6	Marathon Oil Co	K	36	20S	24E	-0.001293057	-1203090.347
Indian Hills State Comm 8	Marathon Oil Co	M	36	20S	24E	0.002276034	-2767.692615
Jenny Com 1	Conoco Inc	E	17	19S	25E	0.001614724	-1263.94568
Jenny Com 2	Conoco Inc	C	17	19S	25E	0.00362235	-857.9139752
JOHN AGU #1	Yates Petroleum	C	14	20S	24E	0.000747491	-5.620596869
JOHN AGU #2	Yates Petroleum	A	14	20S	24E	0.00086213	-2.750805973
JOHN AGU #3	Yates Petroleum	G	14	20S	24E	0.001679598	134.3848856
JOHN AGU #4	Yates Petroleum	H	14	20S	24E	0.000612091	-10.97367048
JOHN AGU #5	Yates Petroleum	F	14	20S	24E	0.000759199	-9.538117216

WellName	Operator	Unit	Section	Township	Range	Oil Cut Slope	GOR Slope
JOHN AGU #6	Yates Petroleum	B	14	20S	24E	0.002225425	-17.95215288
JOHN AGU #7	Yates Petroleum	E	14	20S	24E	0.001744406	-26.33509503
JOHNSTON BE FED COM #1	Yates Petroleum	A	8	19S	25E	0.001149972	4.26847474
Joyce Federal Com 1	Conoco Inc	D	32	19S	25E	0.00121558	1.21394287
Joyce Federal Com 2		C	32	19S	25E	0.000134038	1.230575507
JUDITH AIJ FED #1	Yates Petroleum	P	9	20S	24E	0.008481282	-21009.68107
Julie 2	Conoco Inc	B	17	19S	25E	0.004306059	6.814619633
Julie Com 1	Conoco Inc	H	17	19S	25E	0.001555763	-138.0317613
Kathy Eyre Federal 1	Nearburg Producing Co	C	31	19S	25E	0.001337016	-2046.878181
Kincaid State Com 1	Yates Petroleum	F	16	19S	25E	0.001365103	7610.789646
LARUE XX FED #1	Yates Petroleum	F	3	20S	24E	0.005453612	-8175.114769
Lehman Com 1	Conoco Inc	M	18	19S	25E	0.001164951	-28.16979326
Lehman Com 11	Conoco Inc	L	18	19S	25E	0.000706162	-2.264628397
Lodewick A 1	Conoco Inc	C	19	19S	25E	0.000287595	-15.56593545
Lodewick A 2	Conoco Inc	E	19	19S	25E	0.002145556	-15.01679712
Lodewick A 3	Conoco Inc	D	19	19S	25E	0.004565016	34.34695582
LORENE ANN #1	Yates Petroleum	D	28	19S	25E	-0.000245335	4.023800397
MARCH AMT FED COM #1	Yates Petroleum	N	25	19S	24E	0.006858682	-913.076129
MARSHALL APH #1	Yates Petroleum	F	9	19S	25E	0.00010608	-3.610125454
Mayer 24 1	Nearburg Producing Co	E	24	20S	24E	0.000994832	3.563905662
Mayer 24 2	Nearburg Producing Co	D	24	20S	24E	0.001038932	-7.378715804
MOBIL AOB #1	Yates Petroleum	G	1	20S	24E	0.00146035	-13.04003251
MOJAVE AJY COM #1	Yates Petroleum	I	35	20.5	23E	0.004847165	10438.76068
MOJAVE AJY COM #2	Yates Petroleum	O	35	20.5	23E	0.000358903	-21.72828697
Molly Com 1	Yates Petroleum	P	13	19S	24E	0.004481639	193.843478
MOLLY QD COM #1	Yates Petroleum	P	13	19S	24E	0.001066832	-10.61415733
MOLLY QD COM #2	Yates Petroleum	I	13	19S	24E	0.000915972	-9.180469095
NOPAL AFP FED COM #1	Yates Petroleum	N	35	19S	24E	0.01119543	684.9146543
North Indian Basin Unit 10	Marathon Oil Co	C	11	21S	23E	0.003085199	-95.92207409
North Indian Basin Unit 16	Marathon Oil Co	I	11	21S	23E	0.002990456	9.334120638
North Indian Basin Unit 19	Marathon Oil Co	C	11	21S	23E	0.00106215	-28.00123223
North Indian Basin Unit 7	Marathon Oil Co	K	11	21S	23E	0.00204528	627.3026547
OAKASON NV FED #3	Yates Petroleum	G	34	19S	24E	0.008540988	-79499.70763
OCOTILLO ACI FED #1	Yates Petroleum	A	10	20S	24E	0.005836982	6283.806719
OCOTILLO ACI FED #3	Yates Petroleum	G	10	20S	24E	0.027864893	-228637.8602
OCOTILLO ACI FED COM #2	Yates Petroleum	P	10	20S	24E	0.000508683	75306.02047
OTTAWA AOW #1	Yates Petroleum	K	3	19S	25E	0.000628224	6.319557907
PALO VERDE AJV FED COM #1	Yates Petroleum	M	24	20S	24E	0.002377301	-28.69002757
PARISH IV COM #1	Yates Petroleum	J	19	19S	25E	0.000827036	-314.1358301
PARISH IV COM #2	Yates Petroleum	F	26	19S	24E	0.00376422	-40199.0275
PARISH IV COM #3	Yates Petroleum	F	25	19S	24E	0.003168119	4.352833498
PARISH IV COM #4	Yates Petroleum	G	19	19S	25E	0.000972544	-22.60748566
PARISH IV COM #5	Yates Petroleum	P	19	19S	25E	0.000669905	-141.4524476
PATRICK API #1	Yates Petroleum	D	10	19S	25E	0.000374028	-3.88995642
PATRIOT AIZ #10	Yates Petroleum	N	21	19S	25E	-6.22639E-05	0.117253359
PATRIOT AIZ COM #1	Yates Petroleum	M	20	19S	25E	0.00055006	-6.233131094
PATRIOT AIZ COM #2	Yates Petroleum	O	20	19S	25E	0.000192803	-3.397141964
PATRIOT AIZ COM #3	Yates Petroleum	P	20	19S	25E	0.000312366	0.275159523
PATRIOT AIZ COM #4	Yates Petroleum	N	20	19S	25E	9.86926E-06	-3.39869687
PATRIOT AIZ COM #5	Yates Petroleum	O	21	19S	25E	0.000566677	-110.9899291
PINCUSHION AHN #1	Yates Petroleum	M	30	19S	25E	0.00112856	-31.49048013
PINCUSHION AHN #2	Yates Petroleum	J	25	19S	24E	0.001015257	-18.18132338
PINCUSHION AHN #3	Yates Petroleum	N	30	19S	25E	0.001120317	-47.70574759
POLO AOP #2	Yates Petroleum	J	10	19S	25E	0.000445286	-62.85818048
POLO AOP FEDERAL #1	Yates Petroleum	K	10	19S	25E	0.002948434	-199.903547

WellName	Operator	Unit	Section	Township	Range	Oil Cut Slope	GOR Slope
POLO AOP FEDERAL #3	Yates Petroleum	M	10	19S	25E	0.000357479	1.496829819
Preston 35 N Federal 8	Conoco Inc	H	35	20S	24E	0.001577328	-1.563111919
Preston 35 N Federal 9	Conoco Inc	B	35	20S	24E	0.002296768	-6.337569625
Preston Federal 1	Conoco Inc	L	35	20S	24E	0.002272424	-4751.872838
Preston Federal 10	Conoco Inc	P	35	20S	24E	-0.000733601	37.97956573
Preston Federal 5	Conoco Inc	O	34	20S	24E	0.000517887	-4.00889418
Preston Federal 7	Conoco Inc	O	35	20S	24E	0.001201803	17.95389001
PRICKLY PEAR AIE #1	Yates Petroleum	P	23	20S	24E	0.001319637	-475.351899
Roaring Springs 14 Federal Com 2	Santa Fe Energy Res Inc	B	14	21S	23E	0.000500872	-1286.318266
Roaring Springs Federal 1	Santa Fe Energy Res Inc	E	14	21S	23E	0.00060525	-72.07333468
RODEN GD FED #1	Yates Petroleum	I	23	19S	24E	0.004609146	-1119.448118
RODEN GD FED #2	Yates Petroleum	K	25	19S	24E	0.000992237	-260.7029166
RODEN GD FED #3	Yates Petroleum	F	24	19S	24E	0.020263584	20417.12283
RODEN GD FED #4	Yates Petroleum	G	35	19S	24E	0.004720611	-4724.347368
RODEN GD FED #5	Yates Petroleum	N	24	19S	24E	0.000386551	-284.4275052
RODEN GD FED #6	Yates Petroleum	H	35	19S	24E	0.000726706	-51.28428081
ROSS EG #14	Yates Petroleum	B	21	19S	25E	0.000255303	-1.885074694
ROSS EG COM #1	Yates Petroleum	K	20	19S	25E	0.000557182	-20.52409944
ROSS EG FED #10	Yates Petroleum	G	20	19S	25E	9.76097E-05	-20.26212204
ROSS EG FED #12	Yates Petroleum	H	19	19S	25E	0.003067177	-91.48474421
ROSS EG FED #3	Yates Petroleum	D	20	19S	25E	0.001060413	6.184764239
ROSS EG FED #4	Yates Petroleum	E	20	19S	25E	0.000698927	-8.279766962
ROSS EG FED #6	Yates Petroleum	C	20	19S	25E	0.001333724	-3.246108184
ROSS EG FED #7	Yates Petroleum	F	20	19S	25E	0.001012208	12.42208257
ROSS EG FED COM #13	Yates Petroleum	I	19	19S	25E	0.001540776	151.2795504
ROSS EG FED COM #2	Yates Petroleum	B	19	19S	25E	0.00094854	-30.88187082
ROSS EG FED COM #5	Yates Petroleum	A	19	19S	25E	0.001016623	-9.207595299
ROSS EG FED COM #8	Yates Petroleum	L	20	19S	25E	0.001864943	1.704033935
ROSS EG FED COM #9	Yates Petroleum	I	19	19S	25E	0.001497954	-27.70054077
ROSS IZ COM. #1	Yates Petroleum	F	28	19S	25E	-0.000281117	1.39733891
Ross Ranch 22 2	Nearburg Producing Co	E	22	19S	25E	0.000259474	-1162.661624
ROY AET #1	Yates Petroleum	N	8	19S	25E	0.000478434	6.071682624
ROY AET #2	Yates Petroleum	M	8	19S	25E	0.000734368	-8.845605568
ROY AET #4	Yates Petroleum	O	8	19S	25E	0.000228161	-0.83833914
ROY AET #5	Yates Petroleum	P	8	19S	25E	0.002714428	2.509120051
SAGUARO AGS FED COM #1	Yates Petroleum	F	11	20S	24E	0.00078741	-60.73484218
SAGUARO AGS FED COM #10	Yates Petroleum	C	26	20S	24E	0.000776269	-158.6475893
SAGUARO AGS FED COM #12	Yates Petroleum	L	14	20S	24E	0.001044192	-23.81696551
SAGUARO AGS FED COM #13	Yates Petroleum	B	11	20S	24E	0.000829875	-10.20810852
SAGUARO AGS FED COM #2	Yates Petroleum	F	15	20S	24E	0.001707811	-19989.82749
SAGUARO AGS FED COM #3	Yates Petroleum	F	26	20S	24E	0.002058353	-832.76847
SAGUARO AGS FED COM #4	Yates Petroleum	J	14	20S	24E	0.000793078	-15.22623834
SAGUARO AGS FED COM #5	Yates Petroleum	F	23	20S	24E	0.001302794	-134.1733703
SAGUARO AGS FED COM #6	Yates Petroleum	G	11	20S	24E	9.91058E-05	-16.3472957
SAGUARO AGS FED COM #8	Yates Petroleum	D	14	20S	24E	0.001463124	-10.81889072
SAGUARO AGS FED COM #9	Yates Petroleum	C	23	20S	24E	0.000539282	-22.59478095
SARA AHA #2	Yates Petroleum	H	15	20S	24E	0.001534173	-18164.54733
SARA AHA COM #1	Yates Petroleum	I	11	20S	24E	0.001181244	-0.866625841
SARA AHA COM #3	Yates Petroleum	A	11	20S	24E	0.000283312	-9.791203341
SARA AHA COM #4	Yates Petroleum	O	11	20S	24E	0.000528649	-14.99652222
SARA AHA COM #5	Yates Petroleum	N	11	20S	24E	0.000758381	-11.73322368
SARA AHA COM #6	Yates Petroleum	P	11	20S	24E	0.001201532	-12.06493401
SARA AHA COM #8	Yates Petroleum	H	11	20S	24E	0.002308823	-50.88384315
SARA AHA COM #9	Yates Petroleum	J	15	20S	24E	0.000529387	-668.6833448
SENITA AIP FED COM #1	Yates Petroleum	K	14	20S	24E	0.002150714	-17.36789909

WellName	Operator	Unit	Section	Township	Range	Oil Cut Slope	GOR Slope
SENITA AIP FED COM #2	Yates Petroleum	N	14	20S	24E	0.003797921	-126.7369446
South Boyd 1	Nearburg Producing Co	F	27	19S	25E	0.000351448	14.01399794
South Boyd 27 3		E	27	19S	25E	0.0002604	0.668972139
South Boyd 27 4		L	27	19S	25E	0.000414892	-6.474736856
STAGHORN AJG FED COM #1	Yates Petroleum	M	25	20S	24E	0.000548478	-2.158569163
STAGHORN AJG FED COM #2	Yates Petroleum	N	25	20S	24E	0.007949202	-21.79910971
STATE CO COM #2	Yates Petroleum	G	36	19S	24E	0.000380325	-9.47647842
STATE CO COM #3	Yates Petroleum	D	36	19S	24E	0.001622065	-767.3729262
STATE CO COM #4	Yates Petroleum	F	36	19S	24E	0.000804682	-36.75428363
STATE CO COM #5	Yates Petroleum	A	36	19S	24E	0.000347164	-2.598203887
STATE CO COM #6	Yates Petroleum	H	36	19S	24E	0.002137121	1.995842312
STATE CO COM #7	Yates Petroleum	B	36	19S	24E	0.001378102	-15.33343901
STATE CO COM #8	Yates Petroleum	C	36	19S	24E	0.001123904	-70.56802049
STATE K #3	Yates Petroleum	K	28	19S	25E	0.000462994	-26.66537211
Stinking Draw 2	Marathon Oil Co	F	36	20S	23E	0.000653207	-1296.552423
Stinking Draw 3	Marathon Oil Co	D	36	20S	23E	0.000727793	-1290.878101
TACKITT AOT #1	Yates Petroleum	I	28	19S	25E	0.000938654	-22.88616126
TACKITT AOT #2	Yates Petroleum	J	28	19S	25E	0.000595351	-176.7452407
TACKITT AOT #3	Yates Petroleum	O	28	19S	25E	-0.001493136	1.044857586
THOMAS AJJ #3	Yates Petroleum	J	8	19S	25E	0.000534978	2.248916441
THOMAS AJJ #6	Yates Petroleum	I	8	19S	25E	0.000339162	0.988985007
THOMAS AJJ COM #4	Yates Petroleum	H	8	19S	25E	0.000896083	8.203176842
THOMAS AJJ COM #5	Yates Petroleum	G	8	19S	25E	0.002177142	6.047741548
VANN APD #1	Yates Petroleum	D	21	19S	25E	0.000201358	2.135283728
VOIGHT AJD COM #1	Yates Petroleum	D	29	19S	25E	0.00017966	-5.259408845
VOIGHT AJD COM #2	Yates Petroleum	E	29	19S	25E	0.000440449	-2.82633403
VOIGHT AJD COM #3	Yates Petroleum	C	29	19S	25E	0.000304501	-1.765371532
WARREN ANW #3	Yates Petroleum	O	9	19S	25E	0.0004101	0.042943998
WARREN ANW FED #1	Yates Petroleum	L	9	19S	25E	0.000256316	2.667458276
WARREN ANW FED #2	Yates Petroleum	M	9	19S	25E	0.001748662	2.155327989
ZORRILLO ANZ FED COM #2	Yates Petroleum	N	10	20S	24E	0.040473869	-47072.37045

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

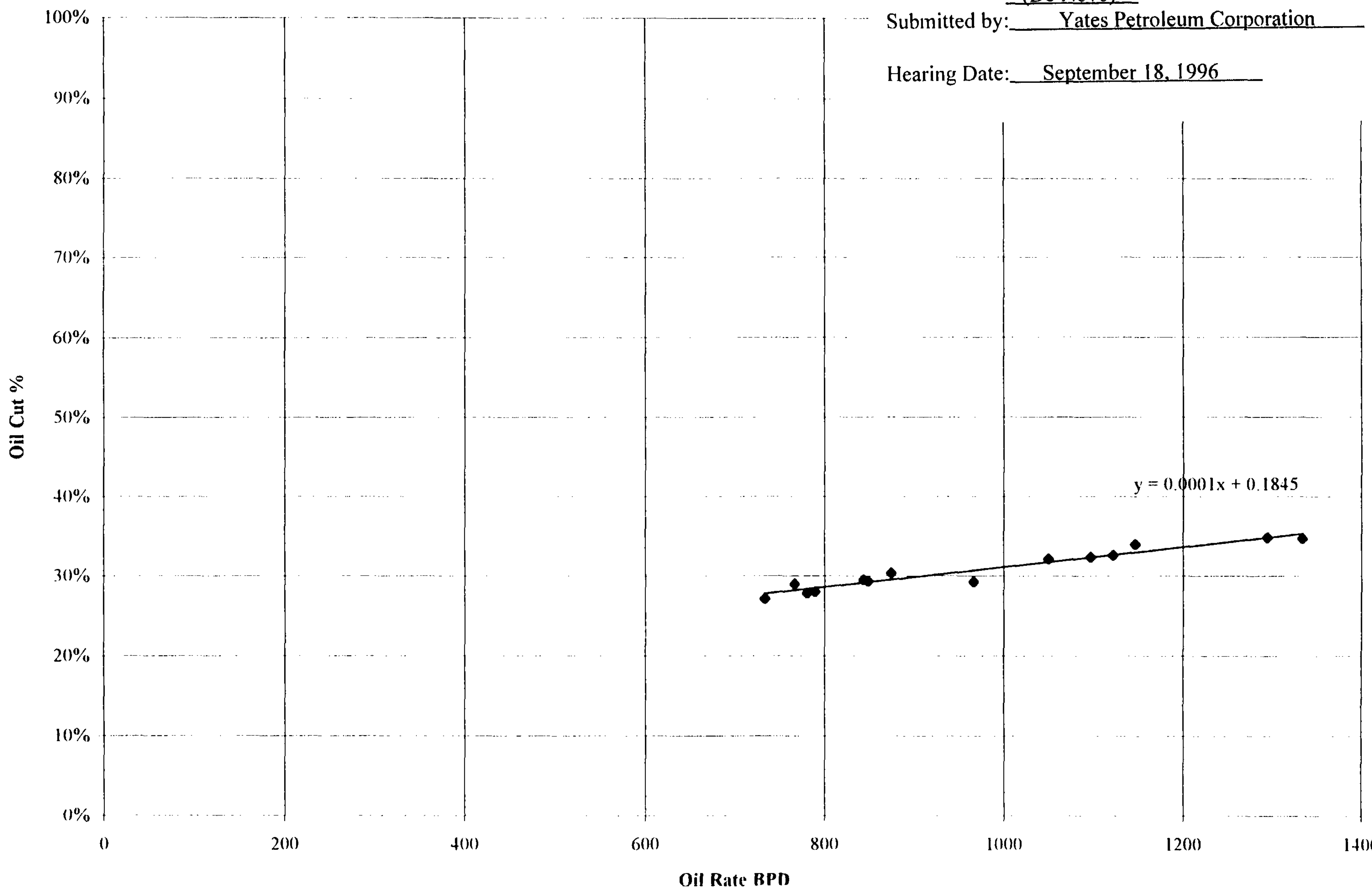
Case Nos. 11525 and 11526 Exhibit No. 10
(De Novo)
Submitted by: Yates Petroleum Corporation

Hearing Date: September 18, 1996

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case Nos. 11525 and 11526 (De Novo) Exhibit No. 11
Submitted by: Yates Petroleum Corporation
Hearing Date: September 18, 1996

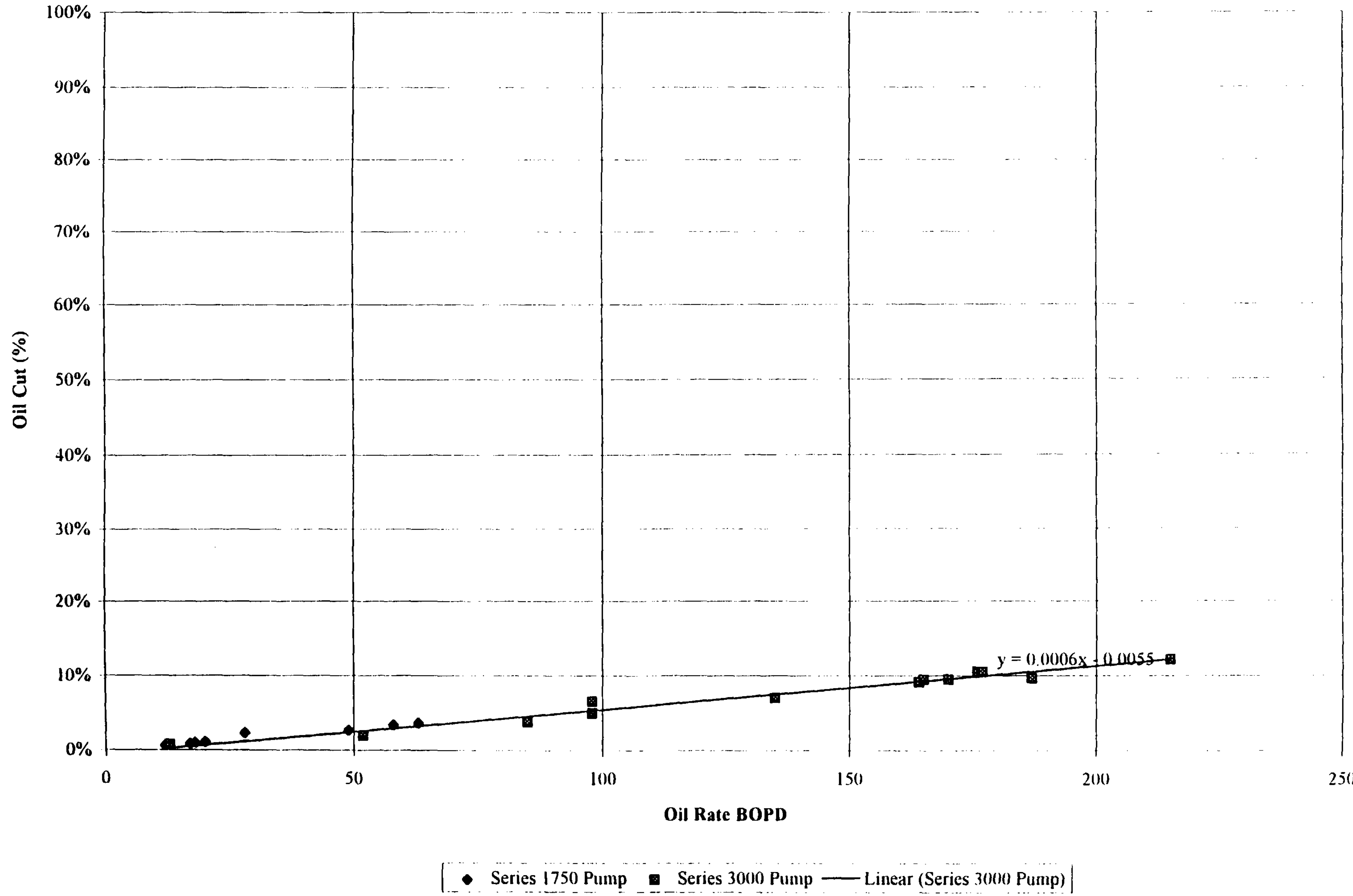
Diamond AKI #1



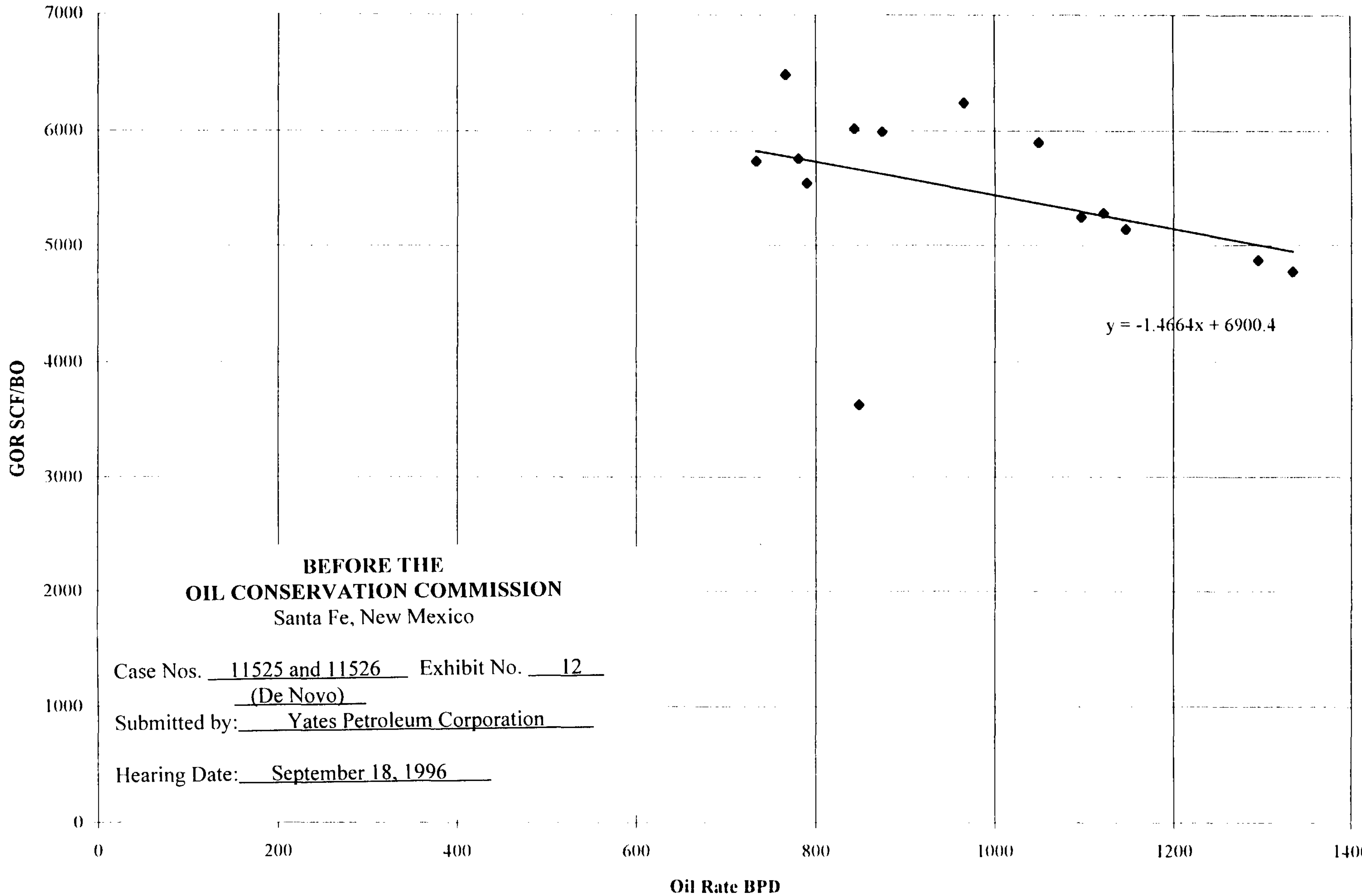
Robert S. Fant

4/30/96

Aparejo APA #5



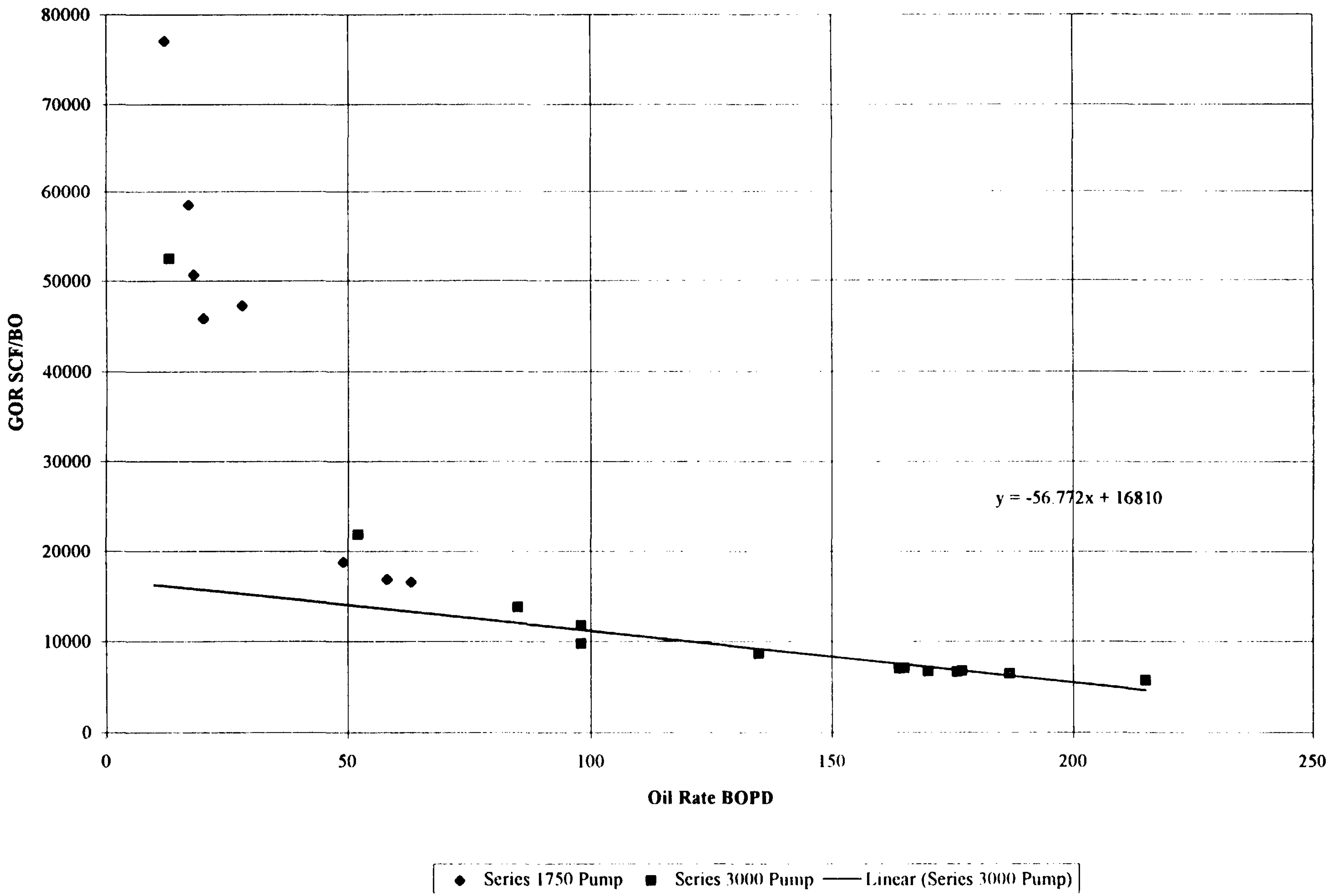
Diamond AKI #1



BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

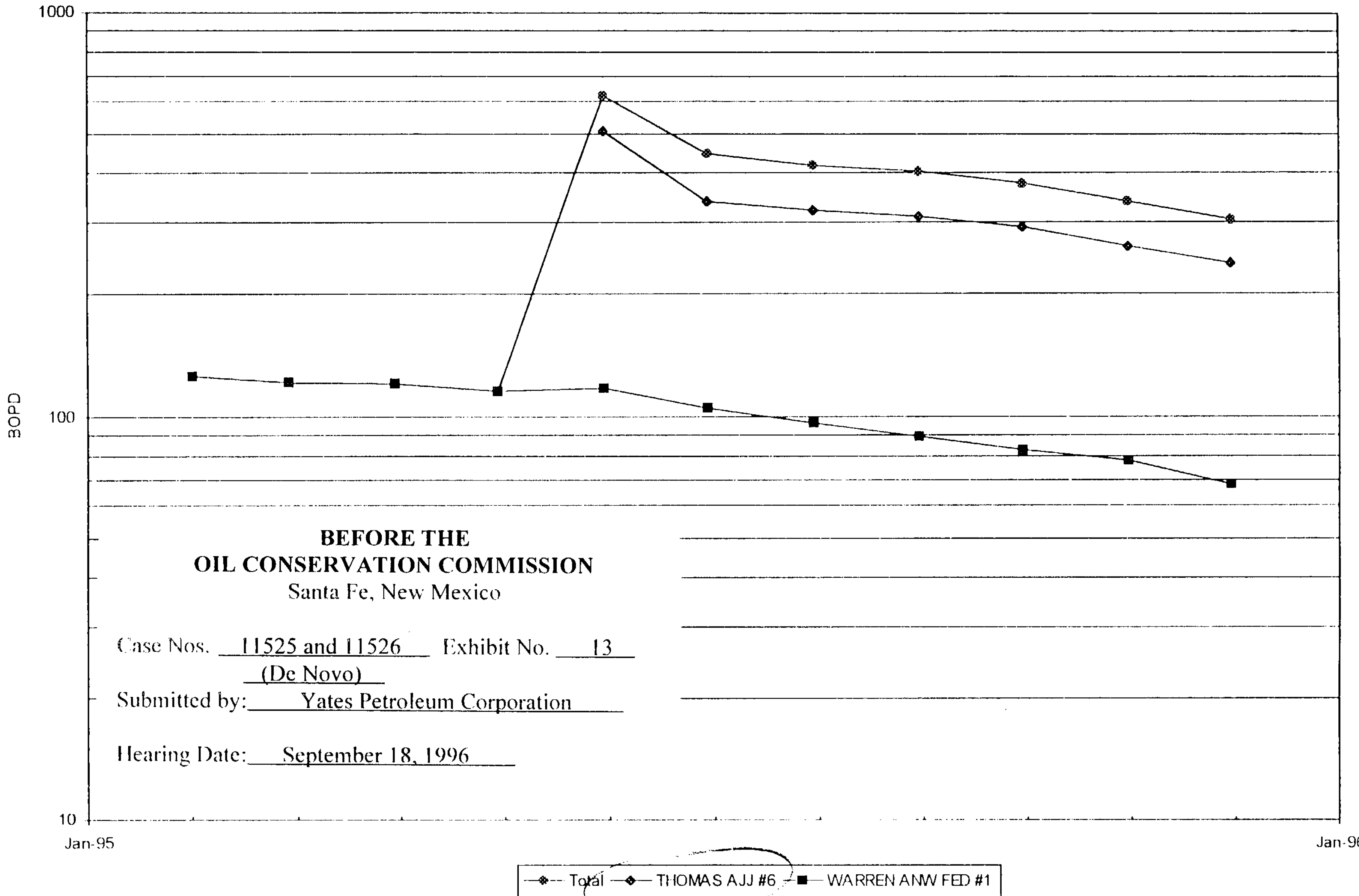
Case Nos. 11525 and 11526 (De Novo) Exhibit No. 12
Submitted by: Yates Petroleum Corporation
Hearing Date: September 18, 1996

Aparejo APA #5



Withdrawal Comparison on Oil Production

WARREN ANW FED #1



BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case Nos. 11525 and 11526 (De Novo) Exhibit No. 13

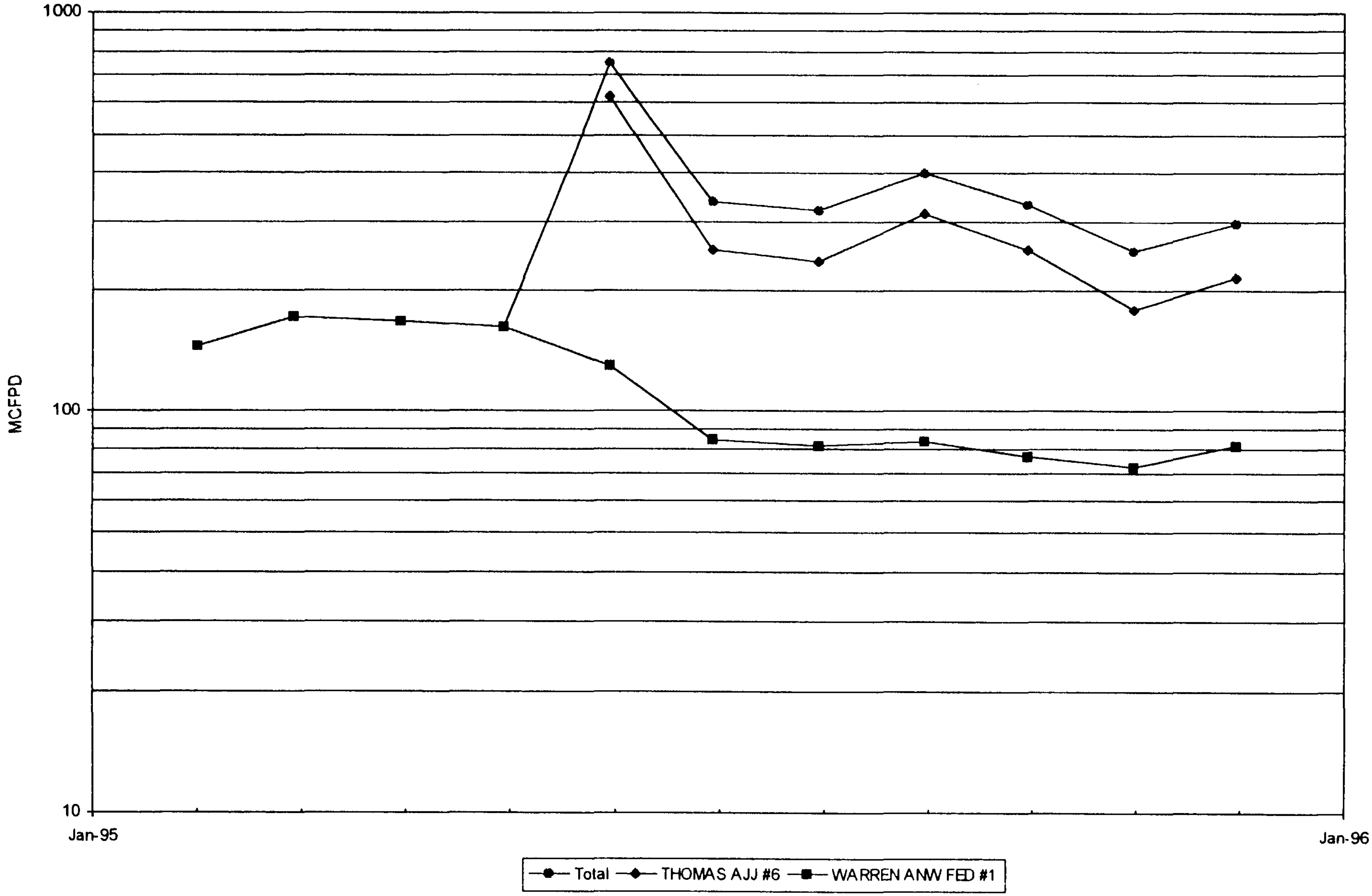
Submitted by: Yates Petroleum Corporation

Hearing Date: September 18, 1996

01-May-96

Withdrawal Comparison on Gas Production

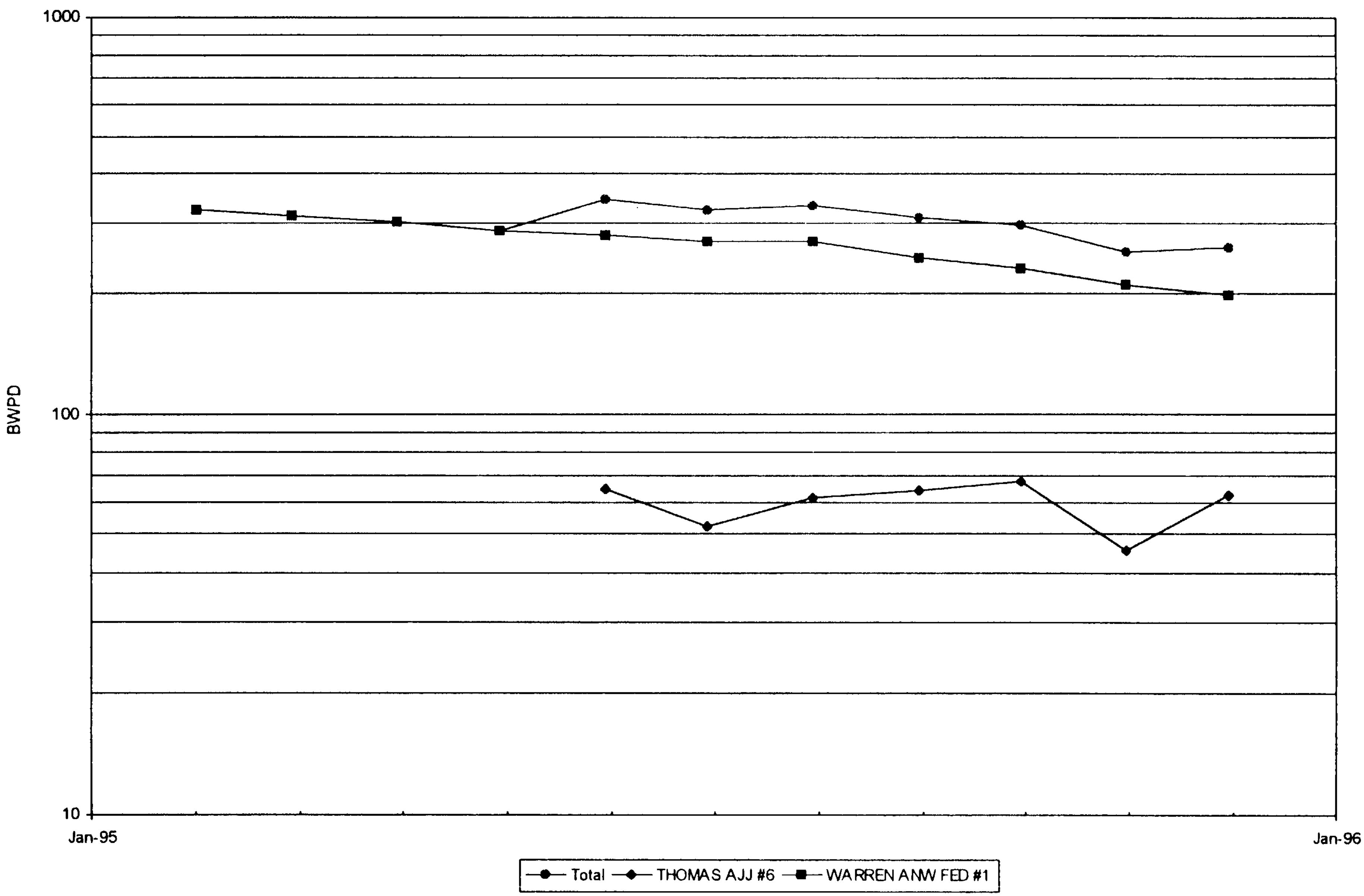
WARREN ANW FED #1



01-May-96

Withdrawal Comparison on Water Production

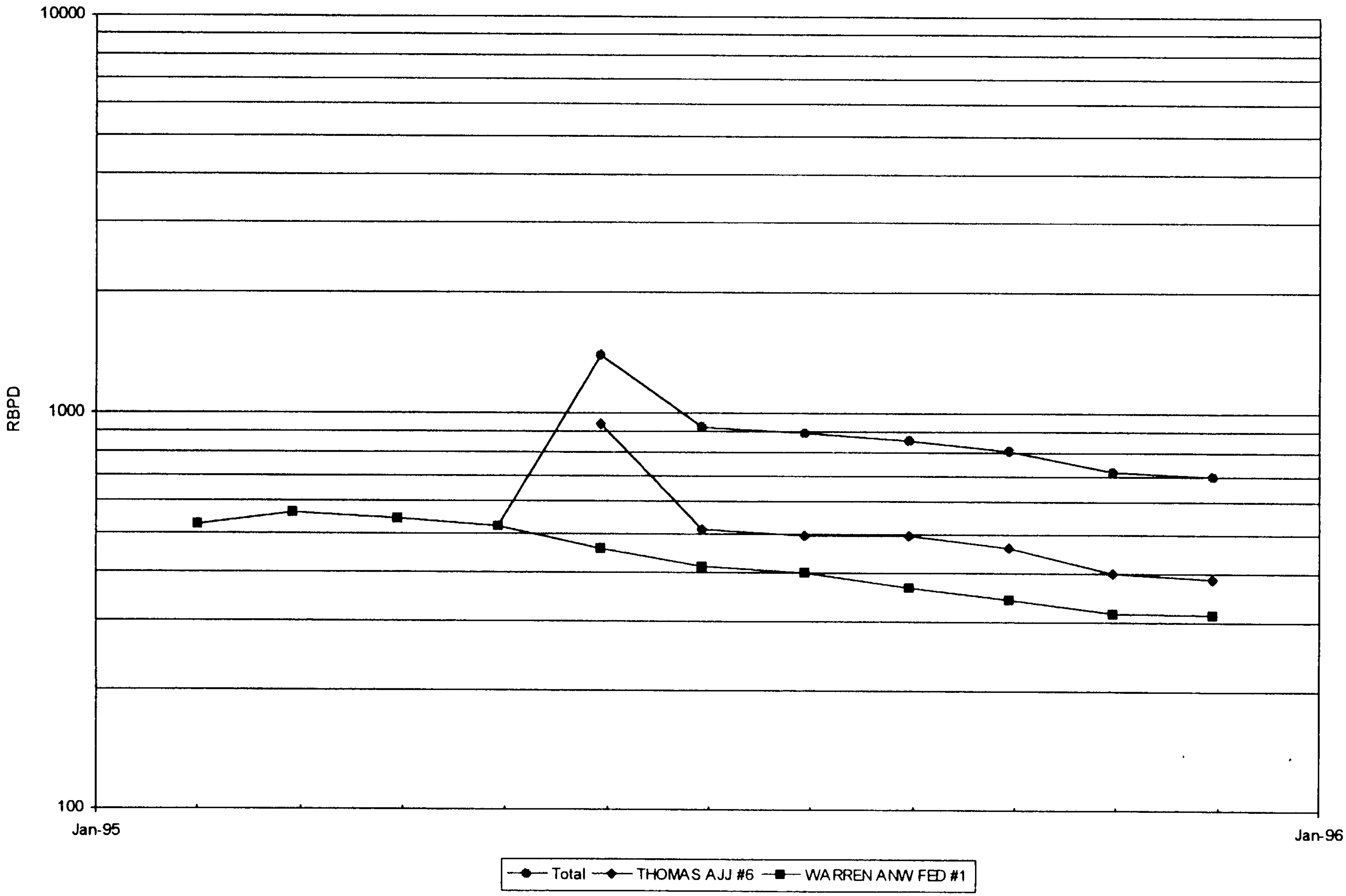
WARREN ANW FED #1



01-May-96

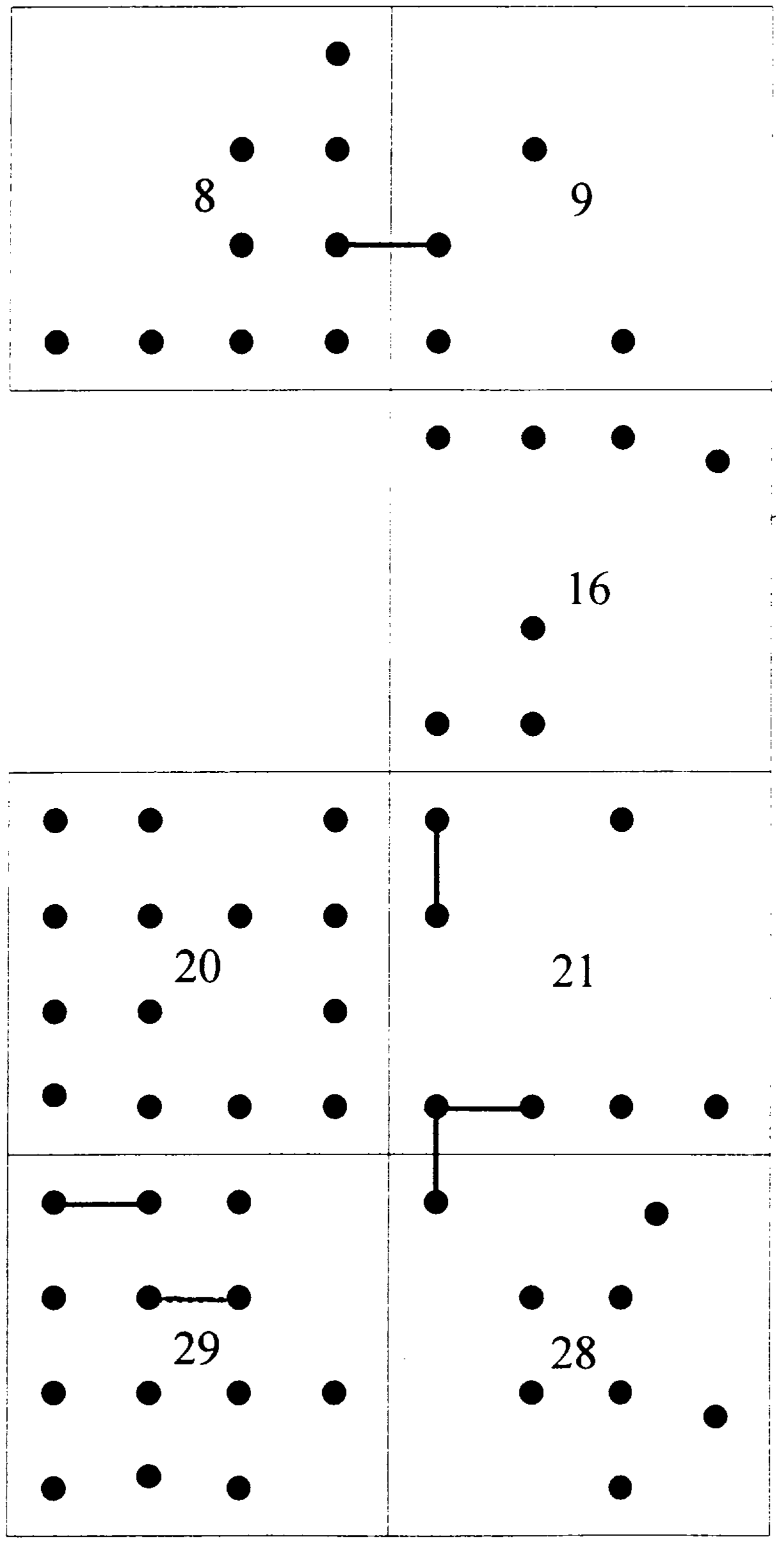
Withdrawal Comparison on Total Fluid Production

WARREN ANW FED #1



01-May-96

Known Instances of Interference in the Areas of New Development



T 19 S - R 25 E

Conclusions
1) Poor wells draining
Good wells
2) Need to correct development

137 [illegible]
6 Known instances
of Communication

Examiner
Case No. 11325
EXHIBIT NO. 14

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

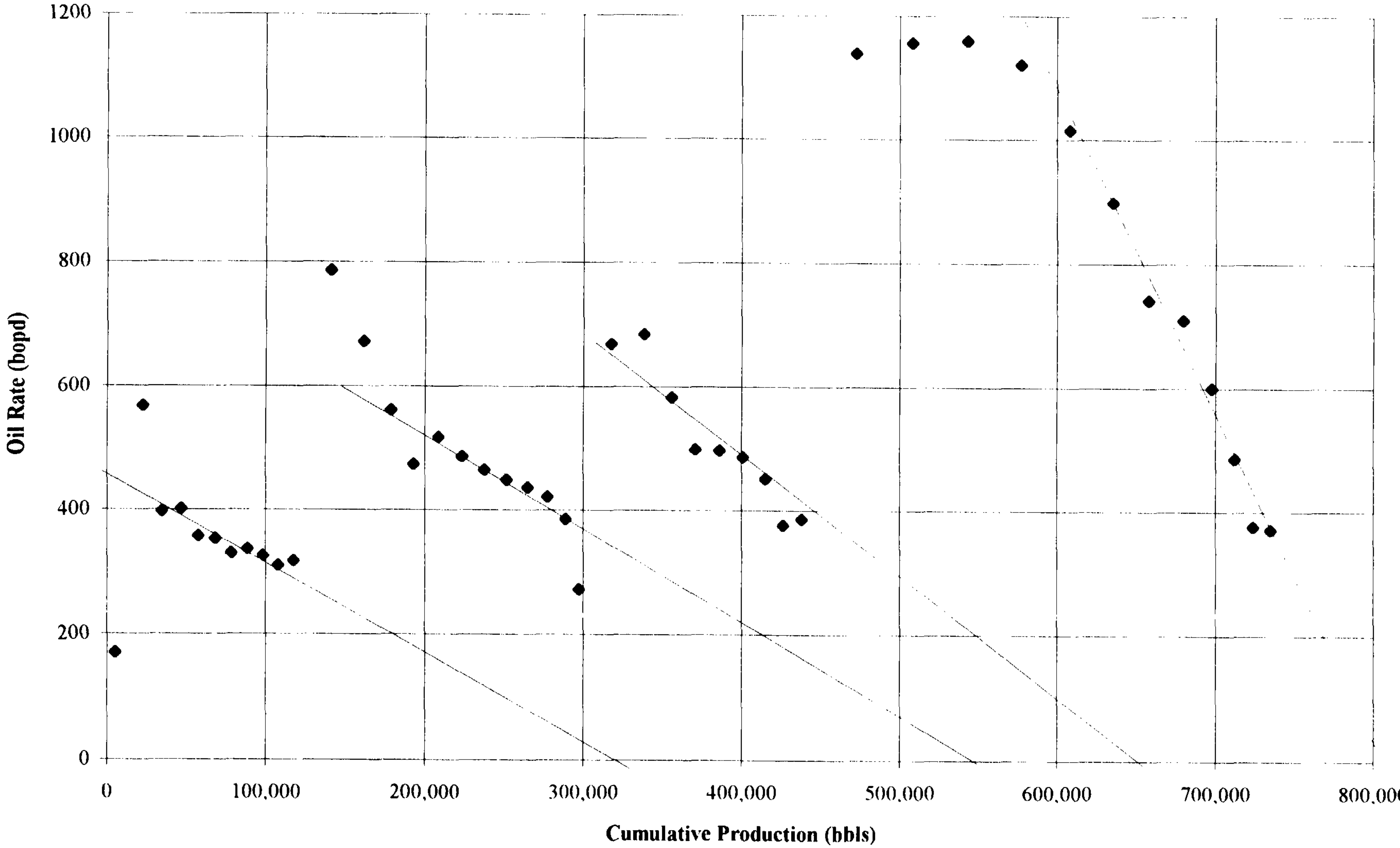
Case Nos. 11525 and 11526 Exhibit No. 14
(De Novo)
Submitted by: Yates Petroleum Corporation

Hearing Date: September 18, 1996

SW29

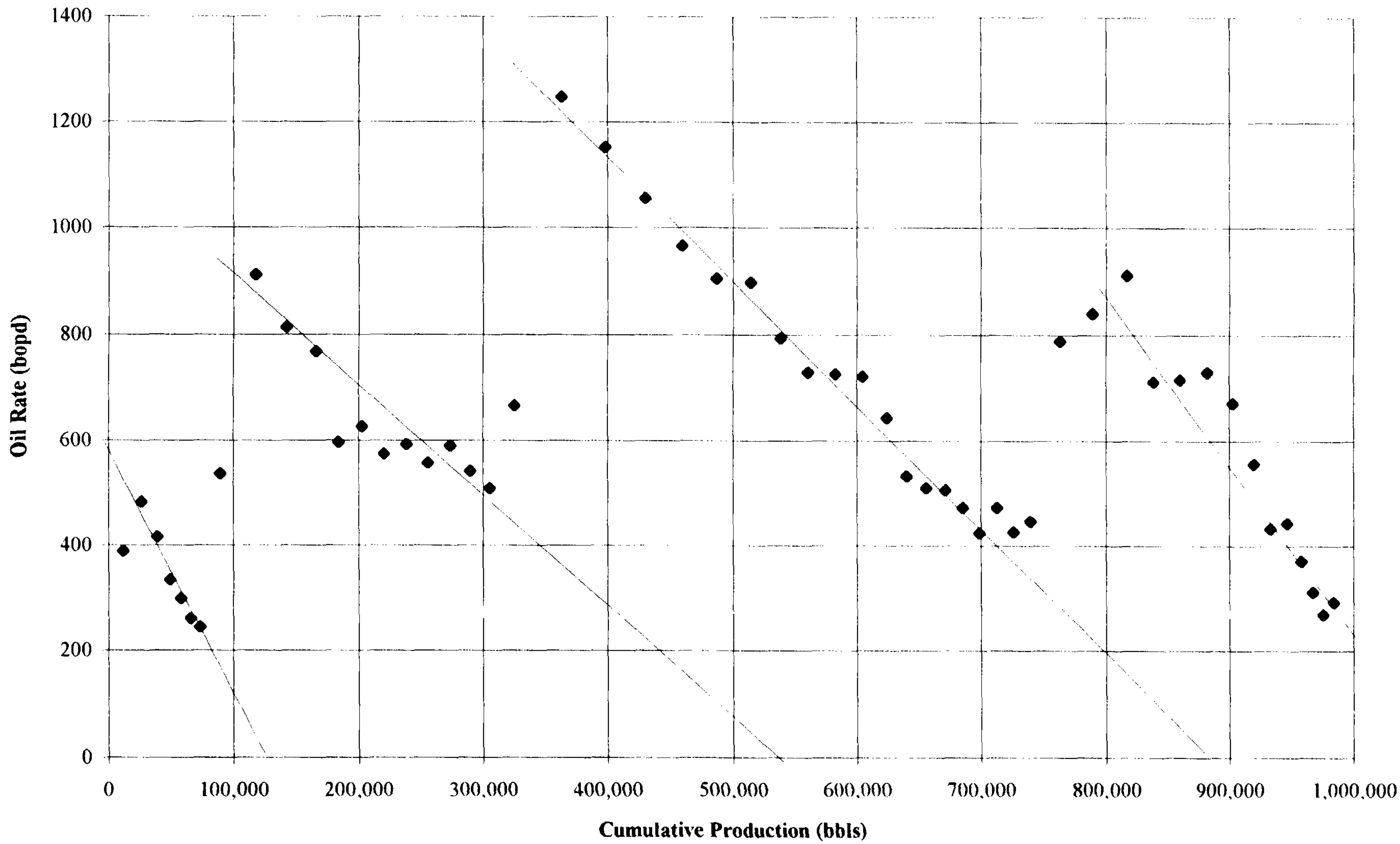
SW/4 Section 29 T19S - R25E

Examiner ____
Case No. 11525
EXHIBIT NO. 15



NW29

NW/4 Section 29 T19S - R25E



BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case Nos. 11525 and 11526 Exhibit No. 15
(De Novo)
Submitted by: Yates Petroleum Corporation

Hearing Date: September 18, 1996

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case Nos. 11525 and 11526 (De Novo) Exhibit No. 17
Submitted by: Yates Petroleum Corporation
Hearing Date: September 18, 1996

SPE

Society of Petroleum E

SPE 24356

Well Performance Evidence for Compartmented Geometry of Oil and Gas Reservoirs

J.E. Junkin, M.A. Sippel, R.E. Collins, and M.E. Lord, Research & Engineering Consultants Inc.
SPE Members

This paper was prepared for presentation at the SPE Rocky Mountain Regional Meeting held in Casper, Wyoming, May 18–21, 1992.

ABSTRACT

Well pressure and production histories and transient pressure tests, evaluated by conventional well testing techniques and simulation, are shown to indicate compartmented reservoir geometry arising by depositional and diagenetic processes. Examples are cited of both clastic and carbonate reservoirs but the central focus of this study is on fluvial deposits exhibiting stratigraphic compartmentation. Field examples of compartmented behavior in such reservoirs are demonstrated by wells with spacing corresponding to separations as small as 1/4 mile. Furthermore, directly drained compartments with radii as small as 60 feet are demonstrated. The impact of such compartmentation on development strategies is examined.

INTRODUCTION

The last two decades have witnessed increasing evidence for compartmented geometry in oil and gas reservoirs. Abnormally high completion pressures and anomalous well tests are often attributed to reservoir heterogeneity with compartmentation being a dominant characteristic. Ten years ago, Exxon completed an evaluation of reserve additions from infill development (Barber, et al[1]). This study demonstrated compartmented behavior in nine oil fields, including carbonate and sandstone reservoirs, which realized significant additions in recoverable reserves through reductions in well spacing. This paper reported significant increased recovery of OOIP in the 40 acre tracts where 20 acre infill wells were drilled. More recently, Sippel and Levey[2] have similarly shown that significant increases in recoverable reserves are also possible in gas reservoirs by infill development. Their study in Stratton Field in south Texas showed that reserve additions by infill development can occur in certain fluvial reservoirs of the Middle

References and figures at end of paper.

Frio Formation even after 50 years of production. T reported recoverable reserve additions where aver spacing had been reduced from about 160 acres to for completions at a common reservoir level in frame from 1970 to 1990.

The compartmentation observed in fluvial sys primarily depositional in origin. Such depositional p are depicted in Figure 1. This shows a hyp meandering fluvial system. The channel system meander belt with periods of channel fill alternating silt and permeable sand. Such a system could continuous and relatively homogeneous in well-lo section or isopach map views, but this process is be produce stratigraphic barriers. Subsequent di processes may also contribute to barrier formation.

The present paper addresses engineering techniq can be used to identify and quantify compa reservoir behavior in such gas reservoirs. Exam data are all from the Middle Frio Formation of the Te Coast, but these are similar to many other fluvial sys

The engineering techniques to be described production history matching by simulation and eval transient well tests by simulation as well as con analysis. The simulation system used to compartments in a gas reservoir from production simple material balance model described by Ho Collins[3] and by Lord and Collins[4]. This model trea reservoir as a collection of tank-like chambers w barriers allowing flow communication between th most instances, evaluation of production data a pressure history can be accomplished for a single w a simple two compartment version of this model as Figure 2. However, the supporting volume, which the primary, or directly drained volume through permeability barrier, may not actually be contiguou this is a *functional* model not an *anatomical* model for the reservoir. This compartment model has proved effective in evaluating compartmented reservoir behavior where permeabilities are greater than 5 md and has now been well validated. Lord, et al[5] have shown through detailed comparisons to precise finite element simulations that the model does accurately simulate pressure-production histories of compartmented reservoirs with diverse geometries.

Development of the log-log pressure derivative plot[6] for analysis of transient well test data in infinite reservoirs has provided a new tool for detection and evaluation of reservoir heterogeneities. Proano and Lilley[7] demonstrated the use of log-log derivative analysis of drawdown and buildup data to characterize a variety of boundary effects. Stewart and Whaballa[8] presented theoretical pressure behavior for several idealized compartmented systems and suggested transient test techniques to determine formation parameters. Both extended drawdown and buildup tests are required to develop the patterns necessary to completely describe compartmented reservoir parameters. Such extended tests are not usually economically feasible and therefore few field applications of these techniques have been presented.

Simulations of transient well tests are accomplished with finite element simulations as described by Kocberber and Collins[9]. This type of simulation is the method of choice because reservoirs with heterogeneities in permeability and complex geometry can be modeled with precision.

While the compartmented simulator has proved to be an ideal tool for determining reservoir compartment pore volumes, it is not always practical to use. When well rate and reservoir pressure data are not of sufficient quantity or quality, the data cannot be treated with this model. Thus, transient well testing with evaluation by simulation then becomes the method of choice.

GAS RESERVOIR COMPARTMENT SIZES IN A FLUVIAL SYSTEM

A large number of gas completions in fluvial reservoirs of the Middle Frio Formation in Stratton Field, south Texas were studied using the compartment model simulator described above. The simulator uses monthly production data as input and matches observed static pressure history by adjusting compartment volumes and inter-compartment transmissibility. A typical pressure history match is shown in Figure 3. Production and pressure data for these studies were obtained from public domain sources. The reservoir parameter most precisely determined with this simulator is the primary, or directly drained, compartment volume. Volumes determined by these compartment model studies for one Frio reservoir are shown in Figure 4 as a cumulative frequency plot for the logarithm of primary pore volume. An approximate equivalent area (determined for average thickness and porosity) is also shown. This trend indicates that compartment volumes have a log-normal distribution with a geometric mean of 3.1×10^6 ft^3 for primary compartment volume. The standard deviation of the logarithm of compartment volume is 0.65. The mean compartment volume corresponds to an area of s acres using average porosity and thickness for the r Well spacing for these completions is variable bu from about 80 acres to 160 acres.

These gas completions are in conventional per sandstone having a permeability between 10 md md. Clearly, such permeabilities would allow dra very large areas in the absence of compartmented r geometry.

WELL TEST EXAMPLES

Evidence of compartmented reservoir geometry i reservoir is demonstrated in this study by well te production performance.

The example gas wells are completed in a fluvial sa reservoir of the Middle Frio Formation which covers square miles of Stratton Field in south Texas. Even this reservoir has been produced since 1954, the been several new completions exhibiting almost pressure (3,200 psi) in close proximity to deple abandoned completions in this reservoir. Water-dri a characteristic of this reservoir. The reservoir co up to four, stacked channel sandstones vertically s by only a few feet of shale or silt. Gross reservoir t is typically between 30 ft and 50 ft. The permeabili reservoir ranges from 10 md to 100 md based o transient well tests. The example wells demonst scale of effective heterogeneity which may be ty fluvial reservoir systems.

Conventional permeability is demonstrated from we but bounded behavior is frequently indicated by th tests. Calculation of appropriate well or completion using the near-well permeability would result in ve spacing indeed. Experience in this field has sho reserve additions have been found at 40 acre infill between depleted and abandoned completions in reservoirs. This spacing is possible because of the of closely spaced wells which are necessary to dev many stacked reservoirs in the Stratton Field.

Long-term production histories of these example w development history of the whole reservoir, indicate of reservoir compartments on the order of 40 to 8 (1,000 ft to 2,000 ft). Examination of extended w from this reservoir indicates that the scale of heterogeneity, or barriers is sometimes much smalle

Many types of pressure transient tests were pe during the present study. Both conventional and ty analysis techniques were used to evaluate f properties and heterogeneity. A finite element simul used to evaluate well tests in the presence of heter and compartmentation. When production da available, the compartmented gas reservoir s described above was also used to estimate f parameters.

Well A

This well was completed in 1989 with a static bottomhole pressure of 2,050 psi. The original pressure for this reservoir was about 3,200 psi. Well A is a quarter-mile offset to a completion made in the same reservoir in 1964. That completion produced a total cumulative of 2.3 bcf and was depleted to 600 psi by 1977. Prior to completion of Well A, the nearest completion to the older well was 3,000 ft distant. Analysis of the pressure and production data for Well A indicate a total drainage area of less than 120 acres (drainage radius of 1,300 ft). The nearest producing well to Well A is more than 3,000 ft distant. Based on well logs, there appears to be sandstone continuity between these wells yet pressures clearly indicate permeability barriers between the wells. The well control is about one well per quarter mile (40 acres).

Well A demonstrates reservoir heterogeneity on several scales. First, the well demonstrates a strong reservoir barrier exists which is sufficient to have preserved more than 1,500 psi differential between two wells, with similar permeabilities, that are 1,320 ft apart. Second, the volumetric drainage of Well A is only 120 acres when the reservoir sandstone appears continuous to the nearest completions which are 3,000 ft to the north and south. Third, the transient tests of this well show that the higher permeability reservoir rock near the well has volume that corresponds to an equivalent radius of only 64 feet.

Transient Pressure Test Analysis. Figure 5 shows a Horner plot of a buildup test for Well A which was performed with a bottomhole shut-in tool. Figure 5 indicates two straight line segments. Permeability of the region near the well, determined from the slope of the early straight line region, was found be 22 md. For the case of a composite system in which the ratio of the outer zone radius to the inner zone radius is sufficiently large, Hurst[10] has suggested that the outer zone permeability can be determined from the slope of the later straight line segment. A permeability of 1.85 md for the region more distant from the well was obtained using the slope of the second straight line segment.

A log-log graph of data from this buildup test is shown in Figure 6. Reservoir pressure and derivative response characteristic of a heterogeneous reservoir are evident in this figure. Note that the pressure derivative curve has an inverted shape as compared to a naturally fractured reservoir response as described by Bourdet, et. al.[11]. The radius of investigation at the inflection point (marked with a vertical dashed line) on the derivative curve, calculated by the equation given by Lee [12],

$$r_i = \sqrt{\frac{kt}{948\,\phi\,\mu c_t}}$$

was found to be 64 feet.

Computer Simulations. The finite element grid sh Figure 7 was used for this analysis. Local grid refir corresponds to regions of high pressure gradient arou well. Using an inner compartment radius of 6 permeability of 22 md and no skin or well bore stora outer compartment radius and permeability were dete by history matching flow rate and pressure data co from Well A during an extensive series of transien Bottom hole pressure response from the co simulation is compared to actual field data collected d 10 day test period in Figure 8. Figure 9 shows a log-l comparing the finite element model response to fiel obtained during the previously described buildup These figures demonstrate excellent agreement b the actual well response and computed results usi finite element model.

Figure 10 shows a comparison of field results with sin reservoir responses for varying outer region radius discriminating power of the pressure derivative is evident in this figure. The prior drawdown w sufficiently long to accurately model the outer v However, the outer compartment radius appears to least 1000 feet.

The production history for Well A was used compartmented reservoir simulator described ab determine the primary and secondary compa volumes. These results are compared to the w results in Table 1.

These results demonstrate that each type of a reveals certain information about the compart system. Excellent agreement between well test a and simulation results provides a level of confide estimates of compartment permeabilities and p compartment area. Global pseudo steady state flow w achieved during well testing and so the estim secondary compartment size can only be termed a m area. This did not contradict the compartment simulation results which were obtained using longe production data. Due to the extremely small p compartment volume the compartmented simulato only give an estimate of primary compartment volume was consistent, however, with results obtained fro testing. It should be noted that the results fro compartment model using production data were obta a small fraction of the cost of extensive well testing r for the other methods.

Well B

Well B was completed in January, 1990 with a bottomhole pressure of 2,300 psi, which is only 900 than the original reservoir pressure. This is notable b it is between and less than one-half mile (2,500 completions which were abandoned with less than static reservoir pressure after producing more than 1 gas, combined.

Transient Pressure Test Analysis. Multiple con drawdown and buildup tests show sufficient p depletion to demonstrate that the primary drainage volume near the well is less than 10 acres and has a permeability to gas of about 3-4 md. The initial drawdown was started from stabilized conditions after a one-month shut-in. Multiple buildup tests indicated depletion from 1,733 psia to 1,604 psia after producing 5,358 mcf (using Horner P*). The Horner plots are shown on Figure 11. This well was utilized in an interference test, which is the reason for the short drawdown and buildup times. The dramatic depletion of Well B is shown on Figure 12, which is a plot of the extrapolated pressures from these buildup tests with cumulative withdrawal. The primary drainage area, determined from these pressures by material balance and 14 ft of net pay, is about 10 acres (radius of about 400 ft). This method of analysis does not account for gas influx from the outer region, however, and causes an over-estimate of the primary compartment volume. It is not possible to make a determination of the outer region volume or transmissibility from the short buildup tests alone. Simulation of this series of tests was necessary to determine additional compartment parameters.

Computer Simulations. A history match of the month-long testing of Well B with the finite element simulator established an inner compartment radius of at least 100 ft and a total drainage radius of 900 ft. The inner region permeability was matched to the results from the buildup tests at 3 md. An outer region permeability of 0.5 md produced successful matches of rate and pressure data.

In order to determine the nature of the outer region, one must look to external reservoir information. The offset wells, at distances of about one quarter-mile, exhibit similar sandstone development on logs. The permeabilities of the two offset completions were determined to be 30 md and 80 md. A well that is only 200 ft away from Well B was completed and tested by buildup after a short flow and was found to have permeability of less than 1 md. Alternating regions of high and low permeability appear to create the conditions which cause the compartmented behavior of this reservoir.

IMPLICATIONS FOR RESERVOIR MANAGEMENT

The execution of both drawdown and buildup tests during the initial completion of a well provides the best description of the reservoir. Drawdown testing provides a means to determine the limits of the primary compartment volume and the barrier strength. A buildup test may provide only an estimate of the distance to the nearest boundary, but it is better suited for evaluation of completion efficiency and near-well permeability.

An important question in well test design is how long flowing and shut-in time should be in order to determine barrier strength and reserves in both inner and outer zones of a compartmented reservoir. The drawdown should be long enough to determine the limits of the primary compartment volume followed by evidence of support. If pressure data are available in real time at the surface during the test, the log-log pressure derivative plot can be an important road map to determine how the test is proceeding. The pressure derivative should respond initially as if the rese homogeneous, but later time response can revea heterogeneities. The time to observe this respon prohibitively long when the barrier is significan from the well or if the barrier transmissibility is sn an extended test would be attempted in only the m development situations. Another consideratio difficulty of maintaining a constant rate during an drawdown test.

The primary drainage volume of the inner zor transmissibility can be readily determined from te the well is initially completed. The boundary tran can be determined to some degree from the initia However, looking beyond the boundary or barrie extended testing time. After the primary drainag and transmissibility have been established by init a long-term evaluation strategy can be developed shut-in static gradient tests can be substitut continuous extended drawdown test. Thes pressure measurements should be made afte sufficiently long to establish the average press primary drainage volume. The determination of initial in-place hydrocarbons after subsequent implies compartmented behavior in a depl reservoir. This method of evaluation is readily pe conventional permeability gas reservoirs compartment model described earlier.

The outer zone or supporting volume of a compartmented reservoir may be a large low-p region or permeable reservoir compartments se low-permeability barriers. The question of "whic not resolvable without external geologic informat knowledge of the probable structure of the rese geology, geophysics, cores and logs) becomes e enable the engineer to determine the best moc particular reservoir.

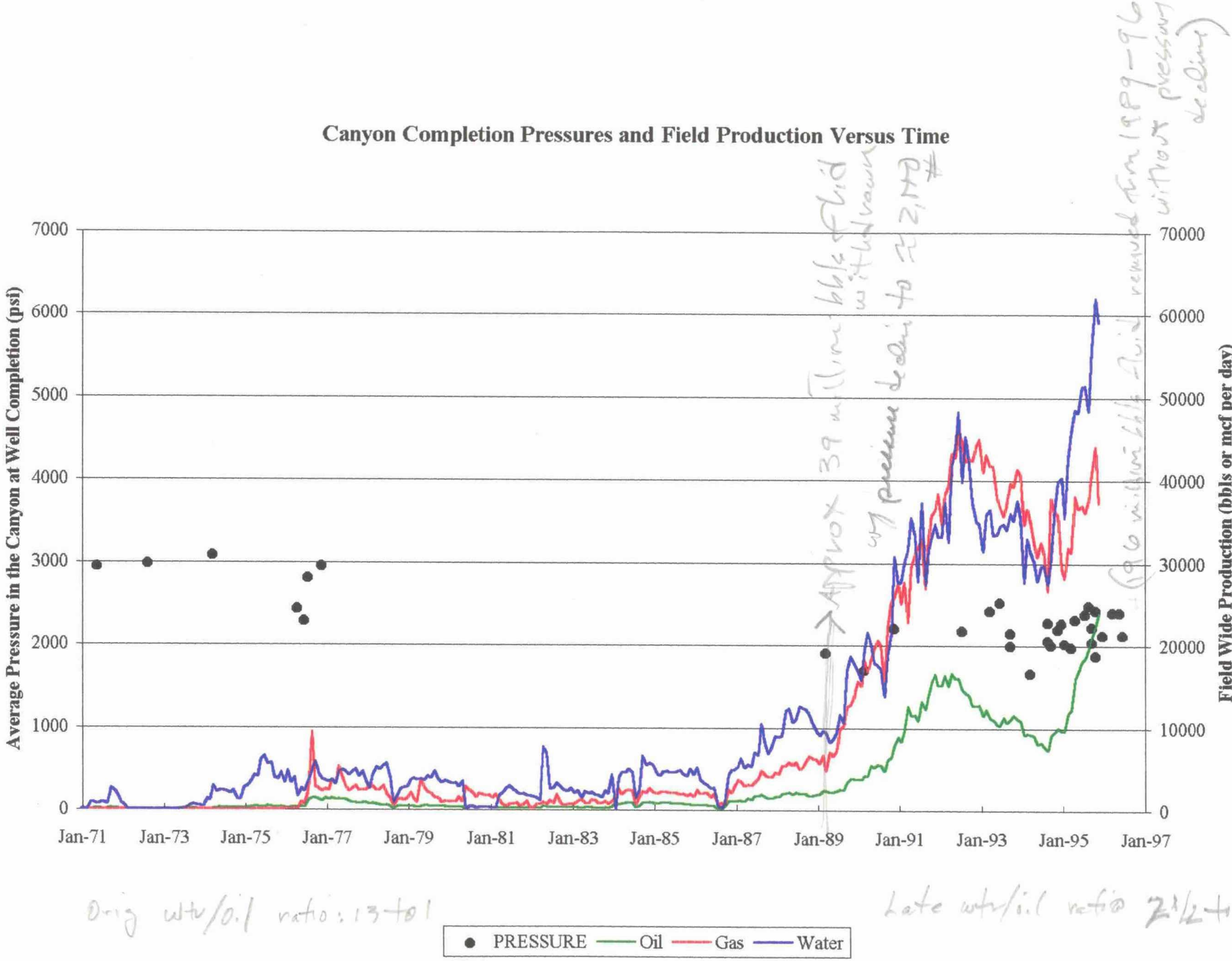
IMPLICATIONS FOR OIL RESERVOIRS IN SYSTEMS

The well test examples and primary compart distribution reported in this paper were from reservoirs in which the principal cause of heter believed to be the fluvial depositional proc heterogeneity exhibited in these gas reservoir would be magnified in an oil system since fluid would be orders of magnitude greater than Heterogeneities might remain undetected until a recovery project is initiated, but this may be t corrections to effectively recover the secondar best opportunity to identify and quantify importa compartments will have been lost if this is the cas

CONCLUSIONS

Compartmented reservoir behavior in moderate p gas reservoirs has been shown by well test exa analysis of production histories using a comp reservoir model. The examples show that permeability should not be used as the sole

Canyon Completion Pressures and Field Production Versus Time



Examiner____________

Case No. 11585

EXHIBIT NO. 16

Robert S. Fant

9/13/96

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case Nos. 11525 and 11526 (De Novo) Exhibit No. 16

Submitted by: Yates Petroleum Corporation

Hearing Date: September 18, 1996

SPE 11023

Infill Drilling To Increase Reserves—Actual Experience in Nine Fields in Texas, Oklahoma, and Illinois

by A.H. Barber Jr., C.J. George, L.H. Stiles, and B.B. Thompson, *Exxon Co., U.S.A.*

Members SPE

This paper was presented at the 57th Annual Fall Technical Conference and Exhibition of the Society of Petroleum Engineers of AIME, held in New Orleans, LA, Sept. 26-29, 1982. The material is subject to correction by the author. Permission to copy is restricted to an abstract of not more than 300 words. Write: 6200 N. Central Expressway, P.O. Drawer 64706, Dallas, Texas 75206.

ABSTRACT

Evaluation of reservoir discontinuity has been used by industry to estimate potential oil recovery to be realized from infill drilling. That this method may underestimate the additional recovery potential is shown by continuity evaluation in a West Texas carbonate reservoir, as infill drilling progressed from 40-acre (16.2-ha) wells to 20-acre (8.1-ha) wells and eventually to 10-acre (4.1-ha) wells.

Actual production history from infill drilling in nine fields, including carbonate and sandstone reservoirs, shows that additional oil recovery was realized by improving reservoir continuity with increased well density.

INTRODUCTION

One objective of an orderly field development program is to determine the maximum well spacing that will effectively drain oil and gas reserves. While wide spacing has proved effective in many oil field applications, there are a growing number of examples where infill drilling, combined with water injection pattern modifications, has provided substantial additional oil reserves. This paper deals with such fields; Means, Fullerton, Robertson, IAB, Howard-Glasscock, Dorward and Sand Hills Fields in West Texas, Hewitt Field in Southern Oklahoma, and Loudon Field, Illinois. The paper will quantify the contribution to current production and the additional reserves attributable to the above action, using data available through October, 1981. Infill drilling has continued in most of these fields. Also revealed by infill drilling is the fact that the West Texas carbonate reservoirs are more stratified and porous stringers are more discontinuous than revealed by initial studies.

BACKGROUND

The theoretical concepts indicating that infill drilling will increase reservoir continuity and improve waterflood pattern conformance in heterogeneous West Texas carbonate reservoirs was researched and published in the early 1970's by W. K. Ghauri (1), et al (2), L. H. Stiles(3),(4), C. J. George(4), and V. J. Driscoll(5).

References and illustrations at end of paper.

Detailed field studies recommending infill drilling and waterflood pattern modifications were made for the Means, Fullerton, and Robertson fields by Stiles(3)(4), and George (4). Unpublished studies were made for the other reservoirs prior to infill drilling.

Borrowing from a previous work by George and Stiles (4), Figure 1 is a type cross section in the Fullerton Field Clearfork reservoir that illustrates the concept of continuity, which term is defined as the percentage of pay in a well that is continuous to another well. The two original wells "A" and "B" are 40-acre (16.2-ha) locations, and the center well is an infill location 660 ft (201.2 m) from either original well. Note the discontinuous nature of the porosity stringers and that correlation before drilling the infill well would have been considerably different than it is after drilling the infill well. The increase in net pay in the infill well, especially in the upper part of the Clearfork formation, illustrates the fact that the more wells that are drilled, the more highly stratified, discontinuous and complex a given West Texas carbonate reservoir is found to be. This fact leads to a conservative evaluation of the potential increased recovery from an infill well.

CONSIDERATIONS IN INFILL DRILLING

A progression of continuity improvement was revealed by infill drilling in the Means San Andres Field. Figure 2 is a statistical plot of continuous pay vs. horizontal distance between wells for an area at Means that has been infill drilled to 10-acre (4.1-ha) density. This technique was used by Shell Oil Company (6) and was discussed by Stiles (3) in a previous paper. The top curve, made prior to infill drilling, shows the increase in apparent continuity between wells with increasing well density. Subsequent curves, made after infill drilling, shows the pay development to be more discontinuous than would have been predicted. As shown by the upper curve, based on 40-acre (16.2-ha) wells alone, an increase in continuity of 3% would be expected as spacing decreased from 20 acres (8.1 ha) to 10 acres (4.1 ha). The second curve, after drilling 20-acre (8.1-

ha) wells, shows that using only 40-acre (16.1-ha) and 20 acre (8.1-ha) wells, an increase in continuity of 4% would be anticipated as spacing decreased from 20 acres (8.1 ha) to 10 acres (4.1 ha). The analysis including the 10-acre (4.1-ha) wells, shown by the lower line, indicates an apparent 14% improvement in continuity. The absolute values obtained for this particular area of the field are not necessarily typical of what would be expected throughout the field, but do illustrate the concept of progressive increase in continuity with closer well spacing.

The complexity of stringerization is even more obvious after examining Figure 3. This is a cross section through three wells in a tertiary pilot in the Means San Andres reservoir. The wells are located approximately 150 ft (45.7 m) apart, and core porosity and permeability have been correlated over the same stratigraphic interval. Porosity is plotted to the left and permeability is plotted on a log scale to the right. The pay intervals are relatively continuous between wells, but the porosity variations are significant in an individual stringer between wells. Permeability variations are even more severe. With injected fluids taking the path of least resistance, this plot serves to illustrate why even in stringers that are continuous between wells, recovery may be lower than anticipated.

In a previous paper[3], it was stated that to be waterflooded, a pay interval must meet the following three requirements:

1. It must be continuous and reasonably homogeneous between an injection well and the offset producing wells.
2. It must be injection supported.
3. It must be effectively completed in the offset producing well.

In many West Texas Permian carbonate reservoirs there may be 50 or more individual pay stringers. Only rarely will all of the stringers be effectively completed in a specific well. When a pay stringer is not effectively completed in a given well, a partial pattern exists for that stringer, and recovery will be less than for a complete pattern. These considerations were used to evaluate infill drilling and pattern modifications in several fields.

INFILL DRILLING RESULTS

Major infill drilling programs were implemented in nine Exxon-operated fields in West Texas, Oklahoma, and Illinois. These fields include dolomite, limestone, and sandstone reservoirs with porosities varying from 4% to 21% and with average permeabilities varying from 0.65 md to about 184 md. Two of the fields are still on primary production, the other seven are waterflood fields. A detailed discussion of each of these fields follows.

Means San Andres Unit

One of the first fields studied was the Means San Andres reservoir in Andrews County, Texas. Production is from a depth of 4400 ft (1341 m). The San Andres is over 1400 ft (427 m) thick, but only the upper 200 to 300 ft (61 to 91 m) is productive at Means. It is predominately dolomite with minor shale and anhydrite. Average porosity and permeability are 9% and 20 md, respectively. The reservoir was discovered in 1934 and drilled to 40 acre (16.2-ha) spacing. Waterflooding began in 1963 with a peripheral pattern which was expanded to a 3-to-1 line drive in 1970. Following a detailed reservoir study in 1975, a large scale infill drilling and pattern modification program was begun. By the 1981 study cutoff date, 141 20-acre (8.1-ha) and 16 10-acre (4.1-ha) infill wells had been drilled. During this period the pattern was gradually changed, generally to an 80-acre (32.4-ha) inverted 9-spot.

Actual production from the 40-acre (16.2-ha) wells is shown by the lower line in Figure 4. Production from the total unit is shown by the upper line. The area between these lines is wellbore oil production from the infill wells. The area between the dashed line and actual 40-acre (16.2-ha) well production is interference oil. Increased recovery resulting from infill drilling is that production represented by the area between the dashed line and the total unit production. Increased recovery is calculated to be 15.4 million barrels ($2.4 \times 10^6 m^3$) of oil, or 66% of the total oil produced by the infill wells. Additional recovery from 20-acre (8.1-ha) infills has been from 5% to 8% of the original oil in place in various areas of the field. The infill wells account for 68% of the unit daily production.

Looking at a smaller area in the Means Field, sixteen 10-acre (4.1-ha) wells were drilled in two pilot areas in 1979 and 1980. Figure 5 shows the impact of the 10-acre (4.1-ha) infills on the production in the pilot areas. Decline curve analysis indicates that additional recovery from the 10-acre (4.1-ha) infills will be 1.2 million barrels ($1.9 \times 10^5 M^3$) of oil or 67% of the wellbore recovery. Additional recovery from 10-acre (4.1-ha) drilling in this area of Means is estimated to be from 2% to 5% of the original oil in place.

Fullerton Field

The Fullerton Clearfork unit, also located in Andrews County, Texas, produces from the Permian Clearfork and Wichita formations, which are predominately dolomite interbedded with limestone, anhydrite and shale. Production is from an average depth of 7000 ft (2133 m), and the reservoir averages 10% porosity and 3 md permeability.

Fullerton was discovered in 1942, and was originally developed on 40-acre (16.2 ha) spacing. The Fullerton Clearfork Unit has been under water injection since 1961. The original pattern used in the largest portion of the field, the North dome, was a 3-to-1 line drive, with the injectors oriented north-south. The original north-south injection rows are shown in Figure 6. Note the 80 acres (32.4 ha) outlined by the dashed line. An 80-acre (32.4-ha) tract in this position will be discussed further.

Based on the recommendations of a 1973 study reported by Stiles[3], a program later called the Phase I Infill Program was initiated. Under this program the wells shown by the solid dots in Figure 6 were drilled as infill producers, and half of the adjacent row producers were converted to injection wells as shown by the solid triangles. Sixty-one Phase I wells were drilled. At the conclusion of the Phase I drilling in 1976, the average production of the Phase I wells was 88 BOPD (14 m^3/d oil) with a 46% water cut. Average production for the offset wells was about half, or 46 BOPD (7.3 m^3/f oil), with a 68% water cut. The fact that these infill wells performed better than the offsets indicated that additional pay was being opened up, which in turn implied that less than all of the pay was being flooded.

An 80-acre (32.4-ha) tract, that was outlined in Figure 6, has been enlarged and is shown in Figure 7. The original north-south injection row is to the left and the black dot to the right fixes the location of the 61 Phase I wells. The solid triangle shows the location of the Phase I injection conversion. Prior to the Phase I program, seven wells had been drilled between 1970 and 1972 in the positions shown by the hexagons. These wells had average initial potentials of 221 BOPD (35.1 m^3/d oil), and in July, 1976 they were producing an average of 92 BOPD (14.6 m^3/d oil) and 70% water. Their offset wells were producing an average of 26 BOPD (4.1 m^3/d oil). The performance of the Phase I wells and the seven earlier wells suggested that additional recovery might be obtained if wells were drilled anywhere within the pattern. In 1976 three wells were drilled in the position shown by the square. They produced an average of 115 BOPD (18.3 m^3/d oil) with a 74% water cut. Four of the six direct offsets to these wells had been shut-in from 4 to 9 years earlier as uneconomic to produce. One was a producer testing 1 BOPD (0.16 m^3/d oil) and 500 BWPD (79.5 m^3/d water). The sixth was an injector which had been converted in 1975 while producing 38 BOPD (6 m^3/d oil).

As a result of these 10 pilot wells, a 151-well Phase II infill drilling program at Fullerton was undertaken. Phase II wells have been drilled in the position shown by the square in Figure 8. Wells in the position captioned "Phase II Conversion" are being converted to injection as part of the Phase II program. Of the 171 wells in this conversion location, 111 were watered out by 1976. Most others were at very low producing rates. It can be concluded that Phase II wells are mostly additional recovery. The production contribution from these infill drilling programs can be seen in Figure 9. This datagraph shows the impact of the Phase I, Phase II, and other infill wells. These wells account for 71% of the unit's current production and will result in additional recovery of 24.6 million barrels (3.9 x $10^6 m^3$) of oil. Fifty-six percent of the wellbore reserves are increased recovery and will average about 97,000 barrels (15.4 x $10^3 m^3$) per infill well.

Robertson Field

The Robertson Clearfork Unit in Gaines County, Texas, produces from the Permian Glorieta, Upper Clearfork, and Lower Clearfork formations, at an average depth of 6500 ft (1981 m). The reservoir is about 1400 ft (427 m) thick with actual net pay of about 200 to 300 ft (61 to 91 m), broken vertically into as many as 50 to 60 separate porosity stringers in any given well. Figure 10, a cross section between two 40-acre (16.2-ha) wells, better illustrates the extreme stringerization. The reservoir rock is predominately dolomite with anhydrite and shale. Porosity averages 6.3% and permeability averages 0.65 md. Beginning in 1942, the area was drilled on 40-acre (16.2-ha) locations. In 1969, the unit was formed for waterflooding. From 1976 through 1980, 107 infill wells were drilled on 20-acre (8.1-ha) spacing. A 10-acre (4.1-ha) drilling program has begun with 31 wells completed through October, 1981.

The contribution of the 20-acre (8.1-ha) and 10-acre (4.1-ha) wells is shown in Figure 11. The dashed line represents the expected production from the 40-acre (46.2-ha) wells had there been no infills. Infill wells provide 73% of the current production. They are expected to add additional reserves of 10.7 million barrels (1.7 x $10^6 m^3$). Increased recovery represents 79% of the wellbore reserves and is about 73,000 barrels (11.6 x $10^3 m^3$) per well.

IAB Field

The IAB (Menielle Penn) field is located in Coke County, Texas. The Menielle Penn reservoir produces from a depth of 5800 ft (1768 m) and is a coarse skeletal limestone buildup with an average of 7% porosity and 27 md permeability. The reservoir was discovered in 1958 and was drilled initially on 80-acre (32.4-ha) spacing. Waterflooding began in 1962 with an initial pattern which was essentially a 3-to-1 line drive. Figure 12 is the production datagraph showing the impact from a 17-well 40-acre (16.2-ha) infill drilling program which began in 1978. The dashed line is an extrapolation of what the 80-acre (32.4-ha) wells would have done if the infill wells had not been drilled. The lower solid line shows the actual and forecasted performance of the old wells. Based on this analysis, the infill wells will increase the field's reserves by 1.7 million barrels (2.7 x $10^6 m^3$). This represents additional recovery of 100,000 barrels (1.59 x $10^5 m^3$) per well, which is 58% of the wellbore reserves and 4% of original oil in place in the affected area.

Howard-Glasscock Field

The Douthit Unit, located in Howard and Sterling Counties, Texas, was formed for waterflooding the Permian Seven Rivers reservoir in the Howard-Glasscock Field. The reservoir is approximately 1400 ft (427 m) deep and is a sandstone with a porosity of 18% and a permeability of 44 md. Development of the Seven Rivers reservoir in this area began in 1957, and it was originally drilled on 40-acre (16.2-ha) locations. Waterflooding began in 1968 with a peripheral injection pattern. Ten-acre (4.1-ha) development began in 1976, and by the 1981 study cutoff date, 52 infill wells had been drilled. The production datagraph, Figure 13, shows the additional production from the infills, along with production from the older wells. The infill wells account for 75% of the current production, and wellbore production is 88% additional recovery. Total additional recovery of 1.0 million barrels (1.59 x $10^6 m^3$) is expected.

Dorward Field

The Dorward Field is located in Scurry and Garza Counties, Texas. Production is commingled from the Permian San Angelo and San Andres formations at average depths of 2350 ft (716 m) and 2100 ft (640 m), respectively. The San Angelo formation is mostly dolomite interbedded with shale and sandstone. The San Andres consists of dolomite, anhydrite, and shale. Apparent porosity for the San Angelo and San Andres are 15% and 13.5%, respectively. Actual porosities are probably less because of the presence of gypsum, which causes optimistic measurements of porosities in cores and logs. Average permeability is about 3 md in both reservoirs.

The field was discovered in 1950 and drilled on 40-acre (16.2-ha) spacing. Although waterflooding began in 1958 in a portion of the field, most of the field has been and is currently producing primary oil by dissolved gas drive. Peripheral and 80-acre (32.4-ha) 5-spot patterns were tried. Early water breakthrough, caused by directional permeability and severe stratification, discouraged expansion of waterflooding to other areas.

Infill drilling began in 1971. At that time, 149 wells on 40-acre (16.2-ha) spacing had been drilled. They had accumulated an average of 49,400 barrels (7850 m^3) of oil per well and production had declined to an average of 4.8 BOPD (0.76 m^3/d oil) per well for the 107 wells still producing at that time. From 1971 through 1980, there were 123 20-acre (8.1-ha) infill wells drilled. Ten acre (4.1-ha) drilling began in 1979, and 17 wells had been drilled by the end of 1980. Figure 14 shows the results.

Since production at start of infill drilling was nearing the economic limit, essentially all production from the infill wells is considered increased recovery. The infill wells will provide additional recovery of 4.6 million barrels (7.3 x $10^5 m^3$) of oil or 33,000 barrels (5244 m^3) per well. The field is now being studied for further 10-acre (4.1-ha) development and to determine if waterflooding is feasible with increased well density.

Sand Hills

Exxon's infill drilling in the Sand Hills area of Crane County, Texas has been concentrated in the Sand Hills (Tubb) and Sand Hills (McKnight) Fields. The Tubb reservoir produces from the Permian Lower Clearfork formation at a depth of 4250 ft (1295 m) and is anhydritic dolomite with a minor amount of limestone. Average porosity and permeability are 4% and 12 md, respectively. The McKnight reservoir produces from the Permian Lower San Andres at a depth of 3200 ft (975 m) and is also mostly anhydritic dolomite. In this reservoir, average porosity and permeability are 5% and 1.3 md, respectively. Gross productive interval is approximately 400 ft (122 m) in the Tubb and 350 ft (107 m) in the McKnight. Both reservoirs are highly stringerized with indications of poor reservoir continuity. They are both productive throughout the area of interest.

The Sand Hills (Tubb) Field was discovered in 1931 and was generally developed on 40-acre (16.2-ha) spacing. In the area of interest, most of the Tubb 40-acre (16.2-ha) drilling was between 1936 and 1941. Exxon's development of the McKnight Reservoir did not begin until 1955. McKnight development was erratic, depending largely on recompletions from the depleting Tubb reservoir; however, there was some drilling along with the workovers. Most of the 40-acre (16.2-ha) McKnight activity was from 1955 to 1965 and later during the 1970's.

A 20-acre (8.1-ha) infill program was begun in 1979. By the 1981 cutoff date, 56 infill wells had been drilled, with most of them being dually completed in both reservoirs. As expected, these wells found stringers that were pressure depleted but also found stringers that were only partially depleted or had not been penetrated by other wells. Forty-acre (16.2-ha) development had continued until the time when the 20-acre (8.1-ha) infill program began. Thus a substantial amount of total production was flush production from recently drilled wells. Production from the older 40-acre (16.2-ha) locations, those drilled before 1975, was 5.5 BOPD (0.87 m^3/d oil) from the McKnight and 5.3 BOPD (0.84 m^3/d oil) from the Tubb. Remaining reserves from these wells were about 9,000 barrels (1431 m^3) per well.

Figure 15 shows both the performance of the 20-acre (8.1-ha) infills and offset 40-acre (16.2-ha) wells, including the recently drilled ones. During 1981, they produced 45% of the total production. Performance to date indicates they will ultimately produce 1.6 million barrels (2.5 x $10^5 m^3$) of additional oil or 28,400 barrels (4516 m^3) per well. This recovery compares favorably with the estimated remaining 9,000 barrels (1430 m^3) per well from the older 40-acre (16.2-ha) wells. Because of the extreme lenticularity of these reservoirs and difficulty in obtaining reliable porosity data, good values for original oil in place are not available.

Hewitt Field

The Hewitt Field located in Carter County, Oklahoma, was discovered in 1919. Production is from 22 Pennsylvanian Hoxbar and Deese sand intervals, with a gross thickness of over 1500 ft (457 m). The many sand intervals are separated by shale zones. Average depth to the top of the first pay interval is about 2000 ft (610 m). The sands have an average porosity of 21% and an average permeability of 184 md. In the area of infill drilling, the original spacing was 2.5 acres (1 ha). After the field was unitized for secondary recovery operations, many of the old wells were plugged and the field was redrilled on 10-acre (4.1 ha) spacing. A fieldwide 20-acre (8.1-ha) 5-spot water injection project was begun. Fifteen 5-acre (2-ha) infills have been drilled and their impact is shown on Figure 16. The infills account for 23% of current unit production. Our analysis indicates about 60% of the wellbore reserves will be increased recovery and will total about 400,000 barrels (6.4 x $10^4 m^3$) from the 15 wells.

The performance of the best well of these infills is a good example of the erratic nature of the porosity development and fluid flow characteristics of this reservoir. This well potentialed for 414 BOPD (65.8 M^3/d oil) with a 50% water cut, although one offset was producing 44 BOPD (7.0 m^3/d oil) with a 96% water cut, and the other was producing only 7 BOPD (1.1 m^3/d oil) with a 99% water cut. Overall project water cut is 97%. This type of result was obtained in a reservoir that was developed on 2.5 acre (1-ha) spacing with a 20-acre (8.1-ha) 5-spot pattern.

Loudon Field

The Loudon Field, discovered in 1937, is located in Fayette and Effingham Counties, Illinois, and produces from four Pennsylvanian sandstones, the Weiler, Paint Creek, Bethel and Aux Vases, at an average depth of 1500 ft (457 m). Average porosity is 19% and average permeability is about 100 md. The northern half of the field was drilled on 20-acre (8.1-ha) spacing in a sunflower pattern. The southern half of the field was drilled on 10-acre (4.1-ha) spacing. Waterflooding began in the early 1950's, with the north half of the field on a 70-acre (28.3-ha) 9-spot pattern and the south half on a 20-acre (8.1-ha) 5-spot pattern. Subsequently, injection wells were drilled in 10-acre (4.1-ha) "dead" spots which are characteristic of the sunflower pattern, thus creating 10-acre (4.1-ha) 5-spot patterns. Producing water cut is now 98%.

Beginning in 1979, 50 infill wells have been drilled in the 20-acre (8.1-ha) development area. These infills were drilled at the intersection of a line between 20-acre (8.1-ha) producing wells and a line connecting offset injection wells. This is a "dead" area in the flood pattern, and the thought was that these areas had been inadequately flooded. Initial production ranged from 131 BOPD (20.8 m^3/d oil) to 3.4 BOPD (0.54 m^3/d oil), with the average being 25 BOPD (4.0 m^3/d oil). Offsets were producing less than 4 BOPD (0.6 m^3/d oil) average prior to the drilling of the infill wells. Figure 17 shows the impact of drilling these 50 infills. At the time of analysis these wells were producing about 600 BOPD (95.4 m^3/d oil) or 18% of Exxon's total field production. Because of their location, and the stage of depletion of the field, essentially all production from these wells is considered increased recovery. These infills are expected to increase oil reserves by 970,000 barrels ($1.5 \times 10^5 m^3$).

CONCLUSIONS

The conclusions formulated from this infill drilling study are as follows:

1. Infill drilling in nine Exxon-operated fields has resulted in per well recovery improvements that are attractive under current economic conditions.

2. Increased oil recovery from the drilling of 870 infill wells in nine fields, ranges from 56% to 100% of their well bore production.

3. Total additional reserves from these wells will be 60.8 million barrels ($9.7 \times 10^6 m^3$) of oil.

4. Continuity calculations made after infill drilling indicated the pay zones to be more discontinuous than when calculations were made before infill drilling.

5. As indicated by the experience in these nine fields, the ultimate well density in any given field can only be determined after several years of field performance provides sufficient information on reservoir continuity and recovery efficiencies.

ACKNOWLEDGEMENTS

The authors thank the many persons who made this paper possible by supplying data, preparing graphics, and typing the manuscript.

REFERENCES

1. Ghauri, W. K., "Production Technology Experience in a Large Carbonate Waterflood, Denver Unit, Wasson San Andres Field, West Texas", J. Pet. Tech. (September 1980), pp 1493 - 1502.

2. Ghauri, W. K., Osborne, A. F. and Magnuson, W. L.: "Changing Concepts in Carbonate Waterflooding, West Texas Denver Unit Project - An Illustrative Example", J. Pet. Tech. (June 1974) pp 595 - 606.

3. Stiles, L. H., "Optimizing Waterflood Recovery in a Mature Waterflood, The Fullerton Clearfork Unit", Paper SPE 6198 presented at SPE 51st Annual Fall Technical Conference, New Orleans, October 3-6, 1976.

4. George, C. J. and Stiles, L. H.: "Improved Techniques for Evaluating Carbonate Waterfloods in West Texas", J. Pet. Tech. (November 1978) pp 1547 - 1554.

5. Driscoll, V. J.: "Recovery Optimization Through Infill Drilling Concepts, Analysis and Field Results" Paper SPE 4977 presented at SPE 49th Annual Fall Meeting, Houston, October 6-9, 1974.

6. Hearing Testimony RE: "Application for Waterflood Response Allowable for Wasson Denver Unit:, before Texas Railroad Commission by Shell Oil Co., March 21, 1972, Docket 8-A-61677.

7. Ruble, David B., "Case Study of a Multiple Sand Waterflood, Hewitt Unit, OK.", J. Pet. Tech. (March, 1982) pp 621 - 627.

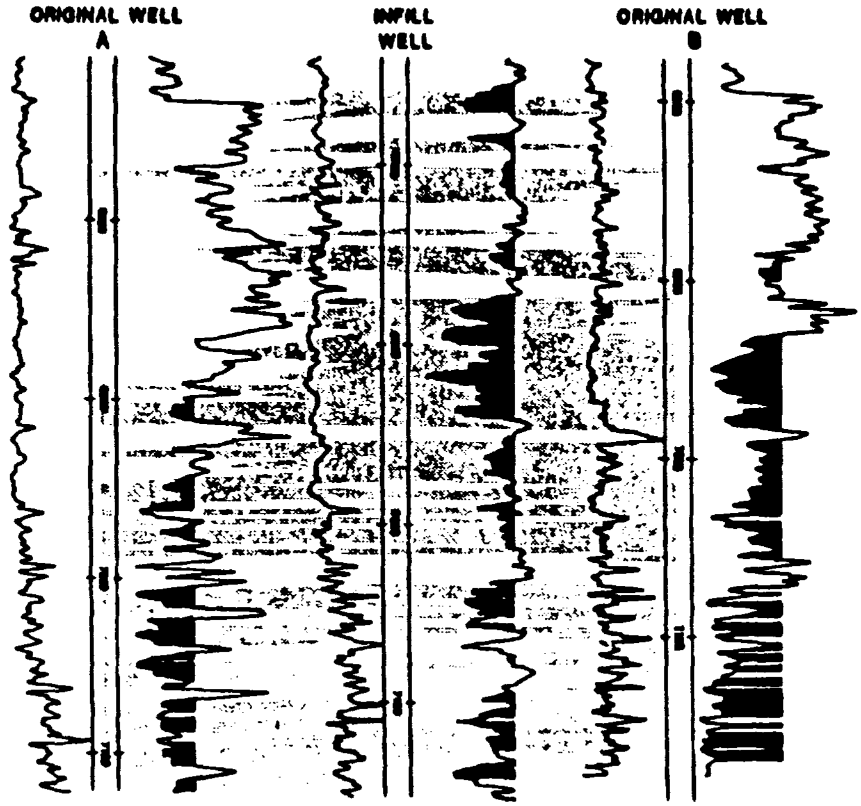


Fig. 1—Type cross section—Fullerton Clearfork reservoir.

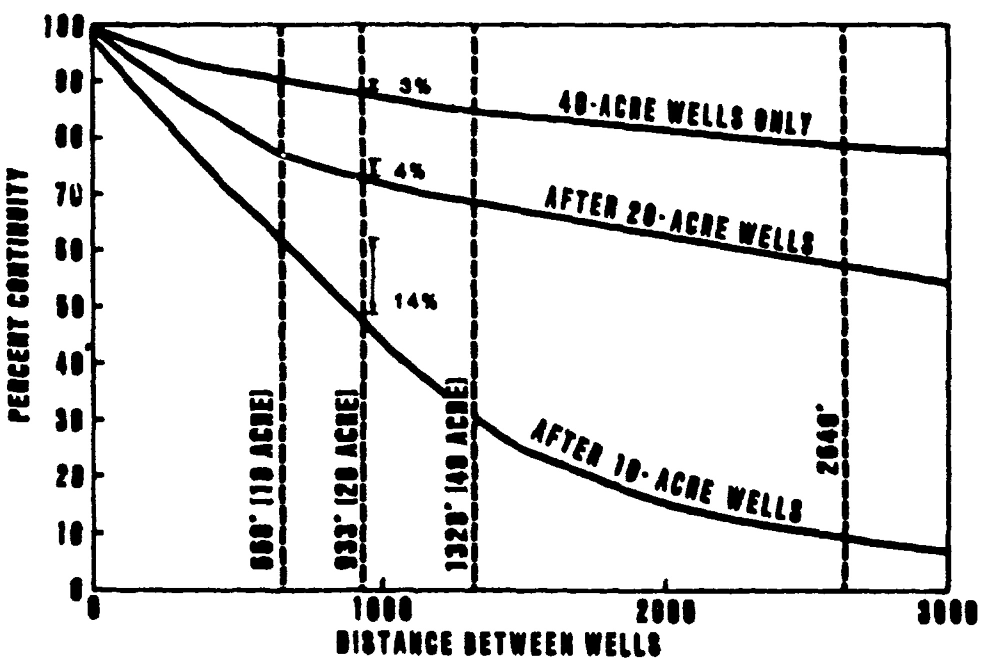


Fig. 2—Continuity progression—Means San Andres Unit.

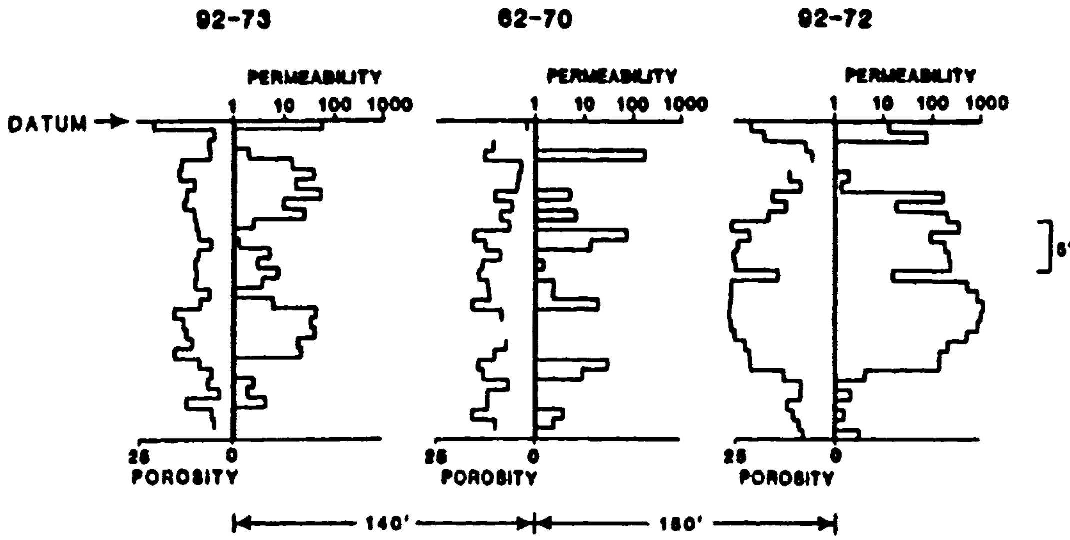


Fig. 3—Porosity and permeability variations—Means tertiary pilot.

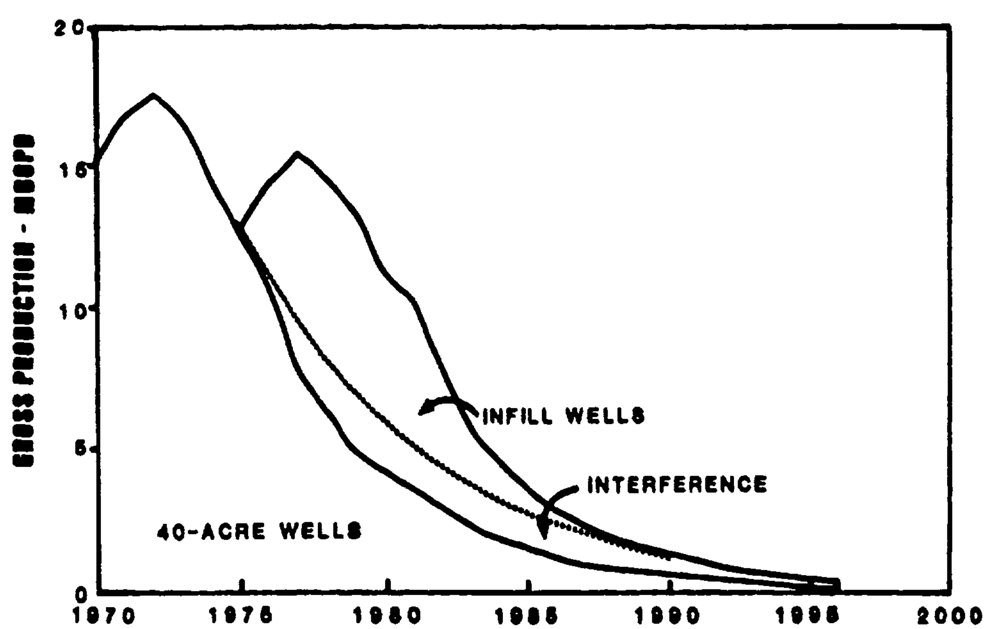


Fig. 4—Production datagraph—Means San Andres Unit.

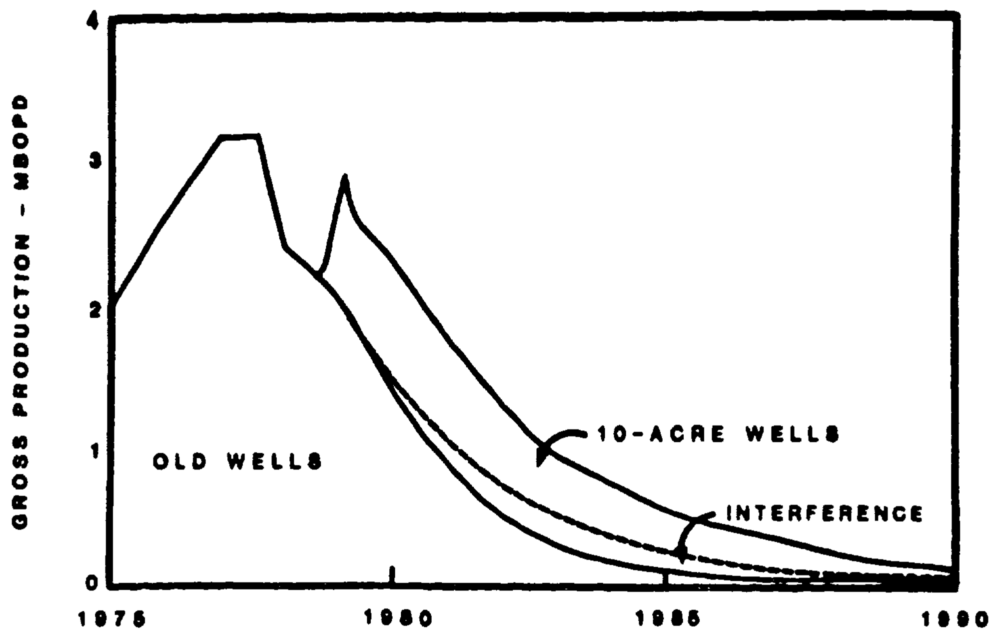


Fig. 5—Production datagraph—10-acre pilot, Means San Andres Unit.

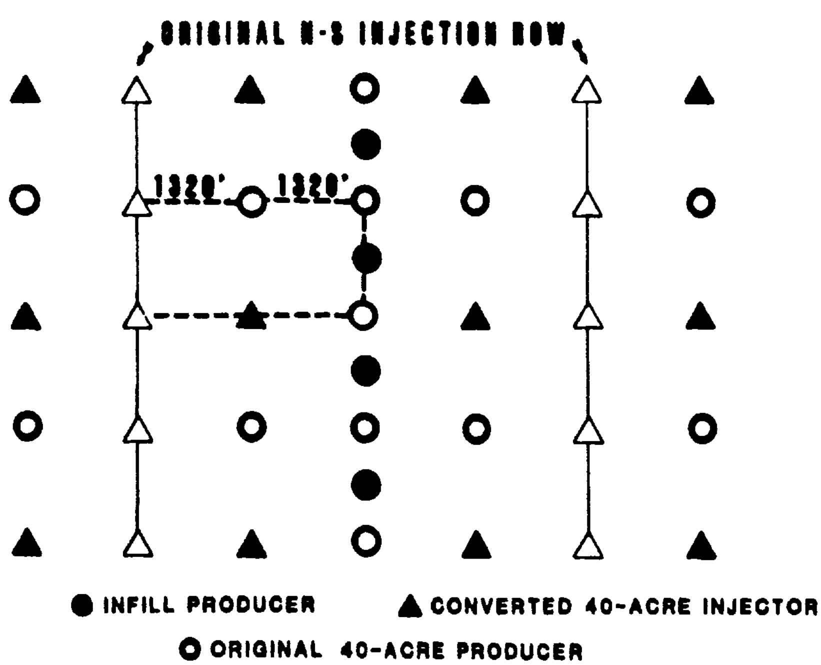


Fig. 6—Phase I infill drilling—Fullerton Clearfork Unit.

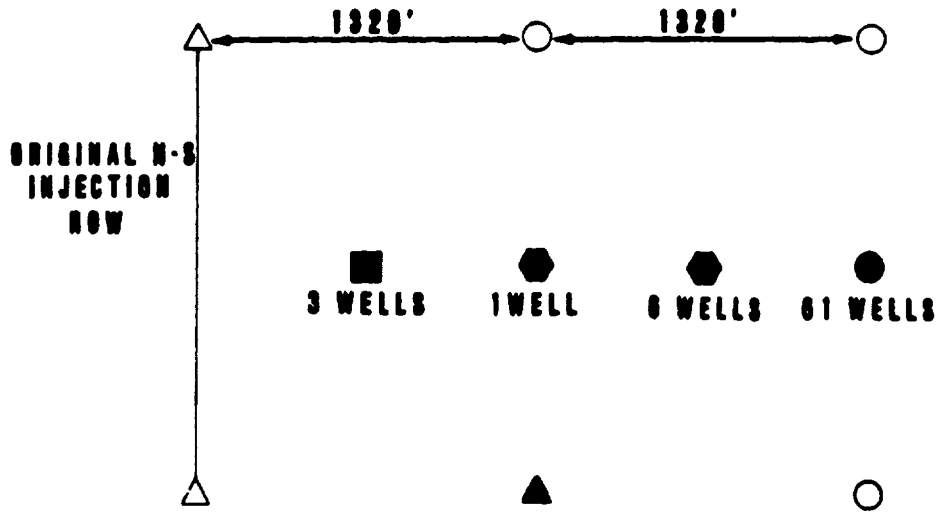


Fig. 7—Pilot infill drilling—Fullerton Clearfork Unit.

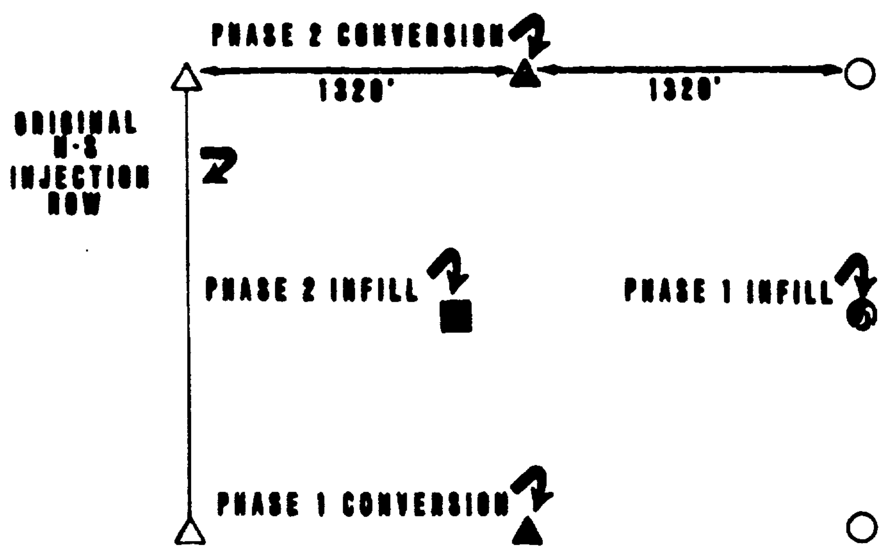


Fig. 8—Phase II infill drilling—Fullerton Clearfork Unit.

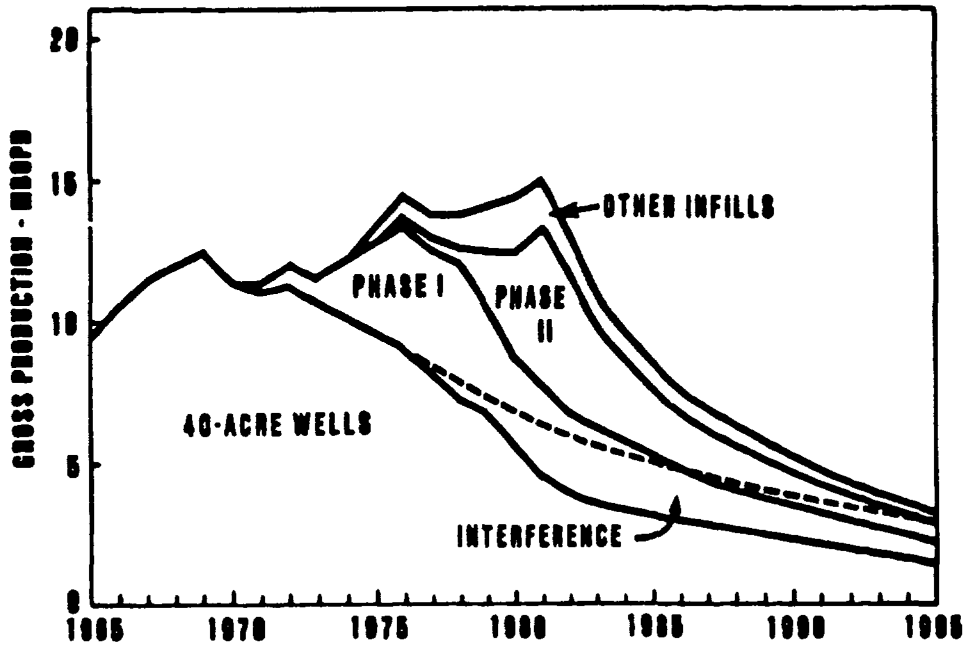


Fig. 9—Production datagraph—Fullerton Clearfork Unit.

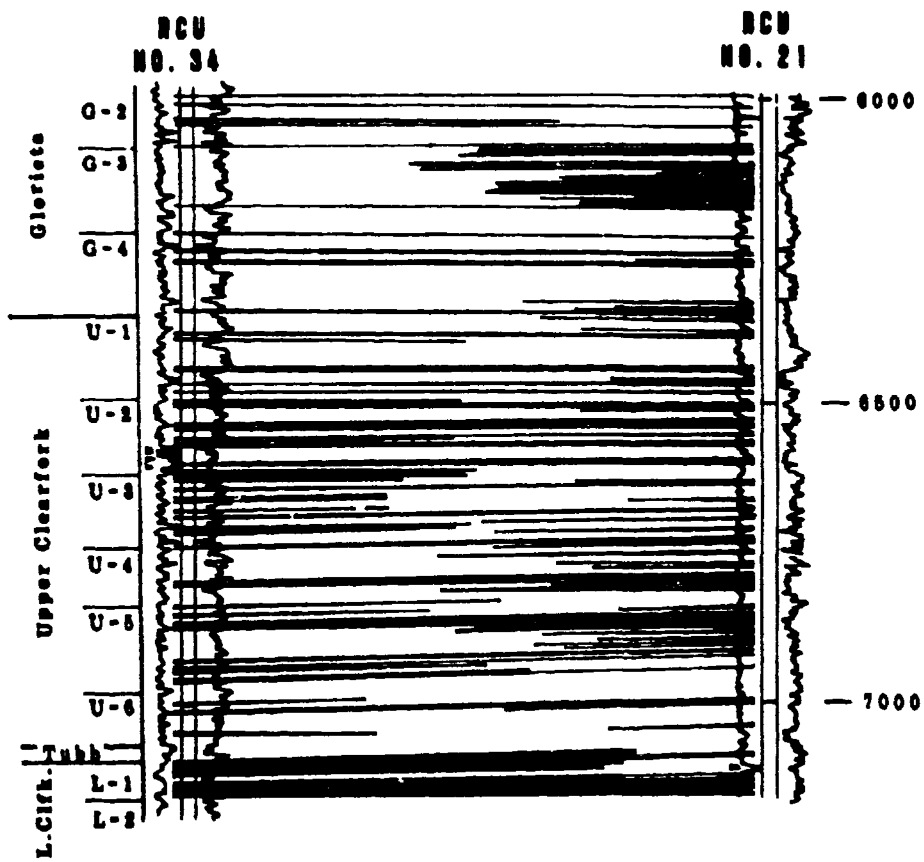


Fig. 10—Cross section—Robertson Clearfork Unit.

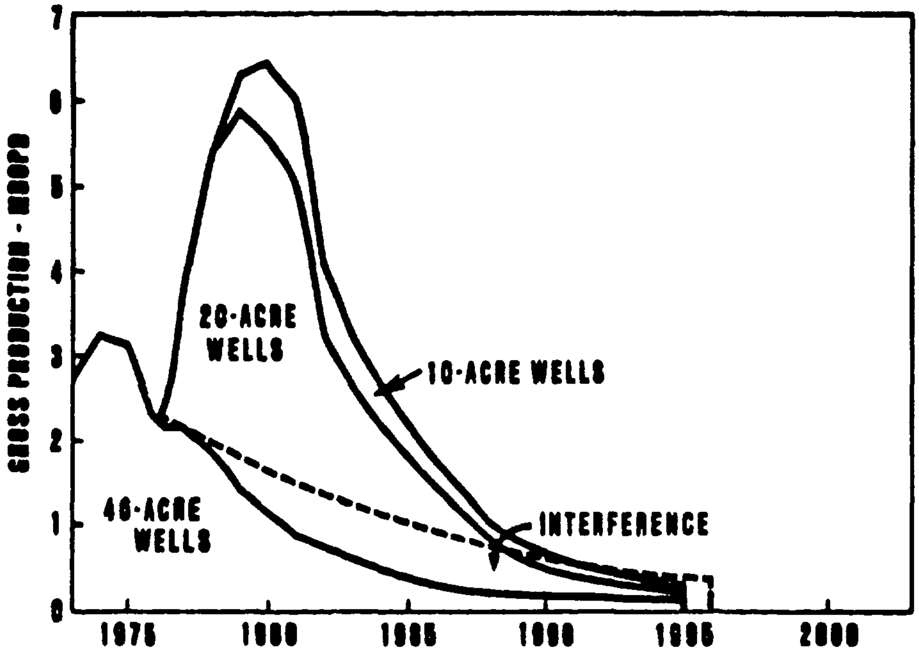


Fig. 11—Production datagraph—Robertson Clearfork Unit.

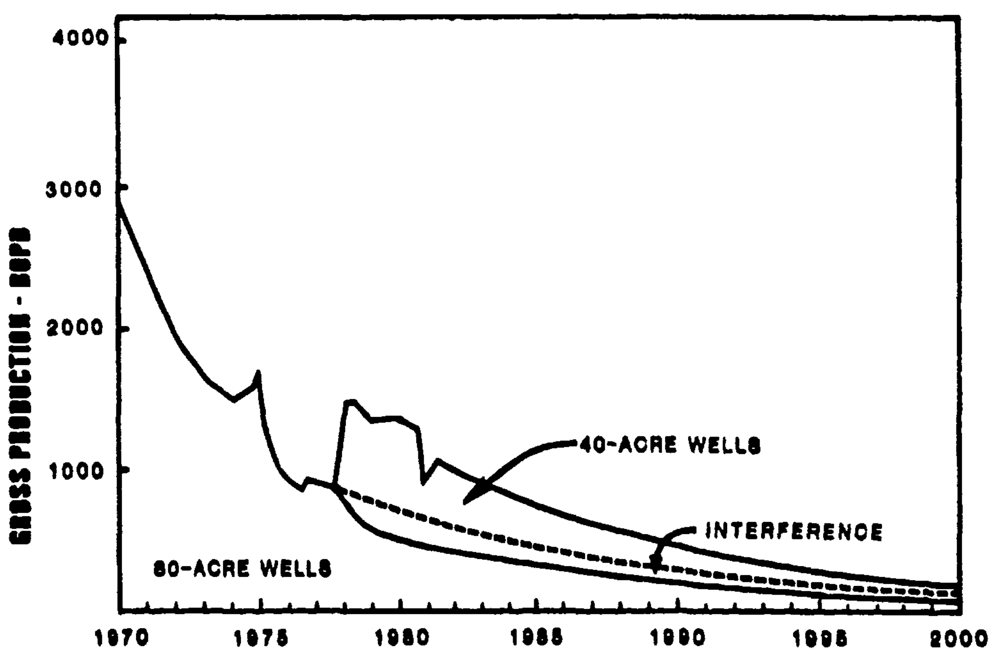


Fig. 12—Production datagraph—IAB (Menielle Penn) field.

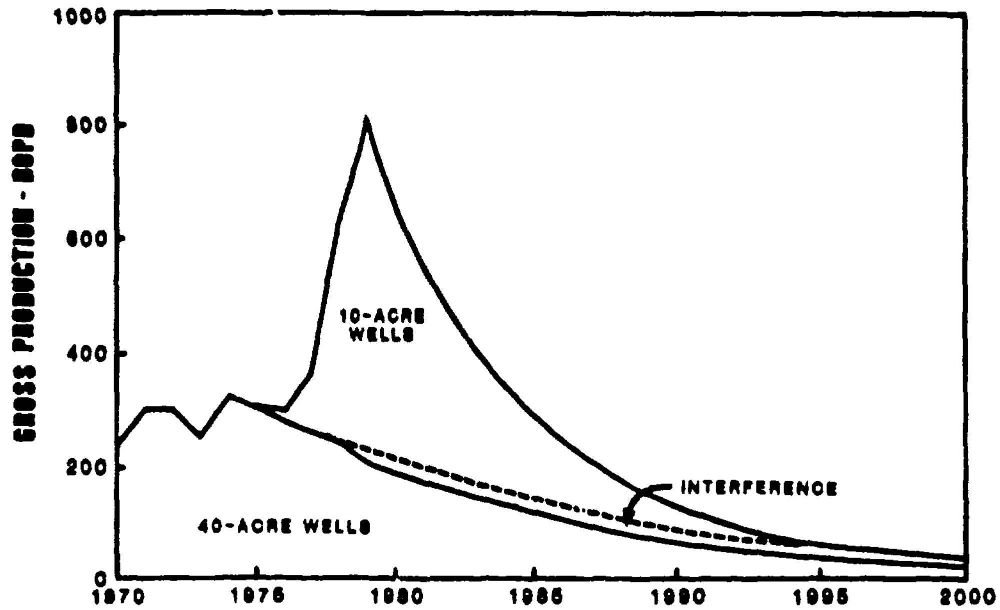


Fig. 13—Production datagraph—Douthit Unit, Howard-Glassc‹ ck field.

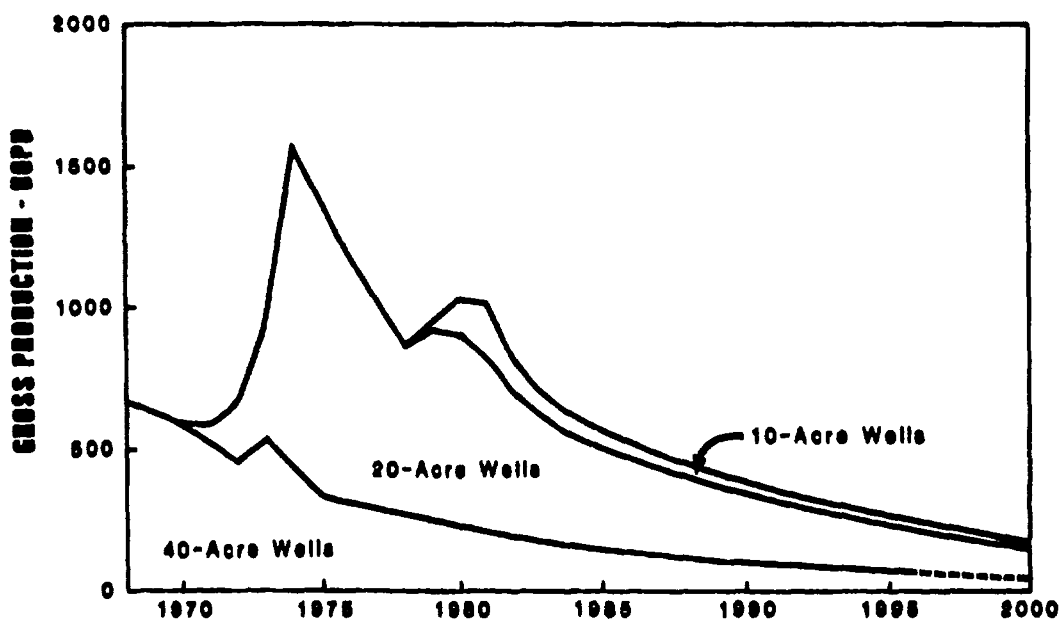


Fig. 14—Production datagraph—Dorward field.

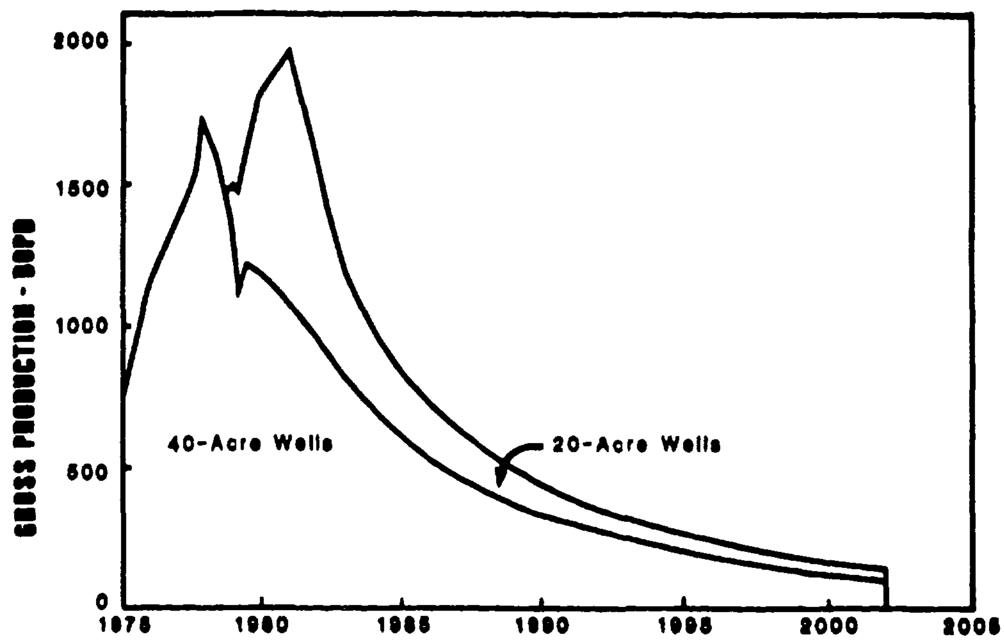


Fig. 15—Production datagraph—Sand Hills area.

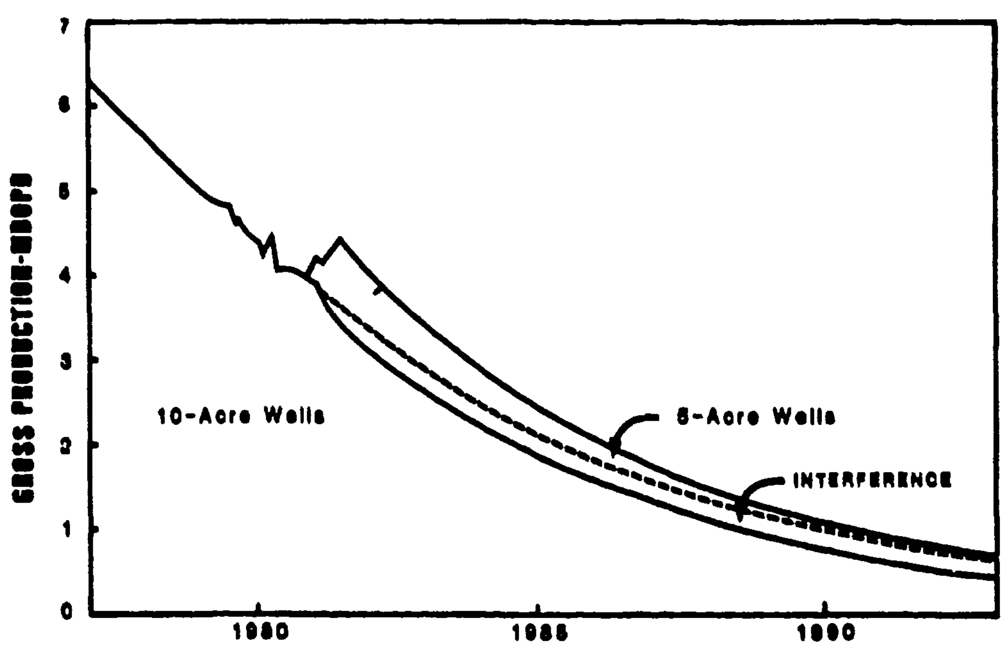


Fig. 16—Production datagraph—Hewitt Unit—Hewitt field, Oklahoma.

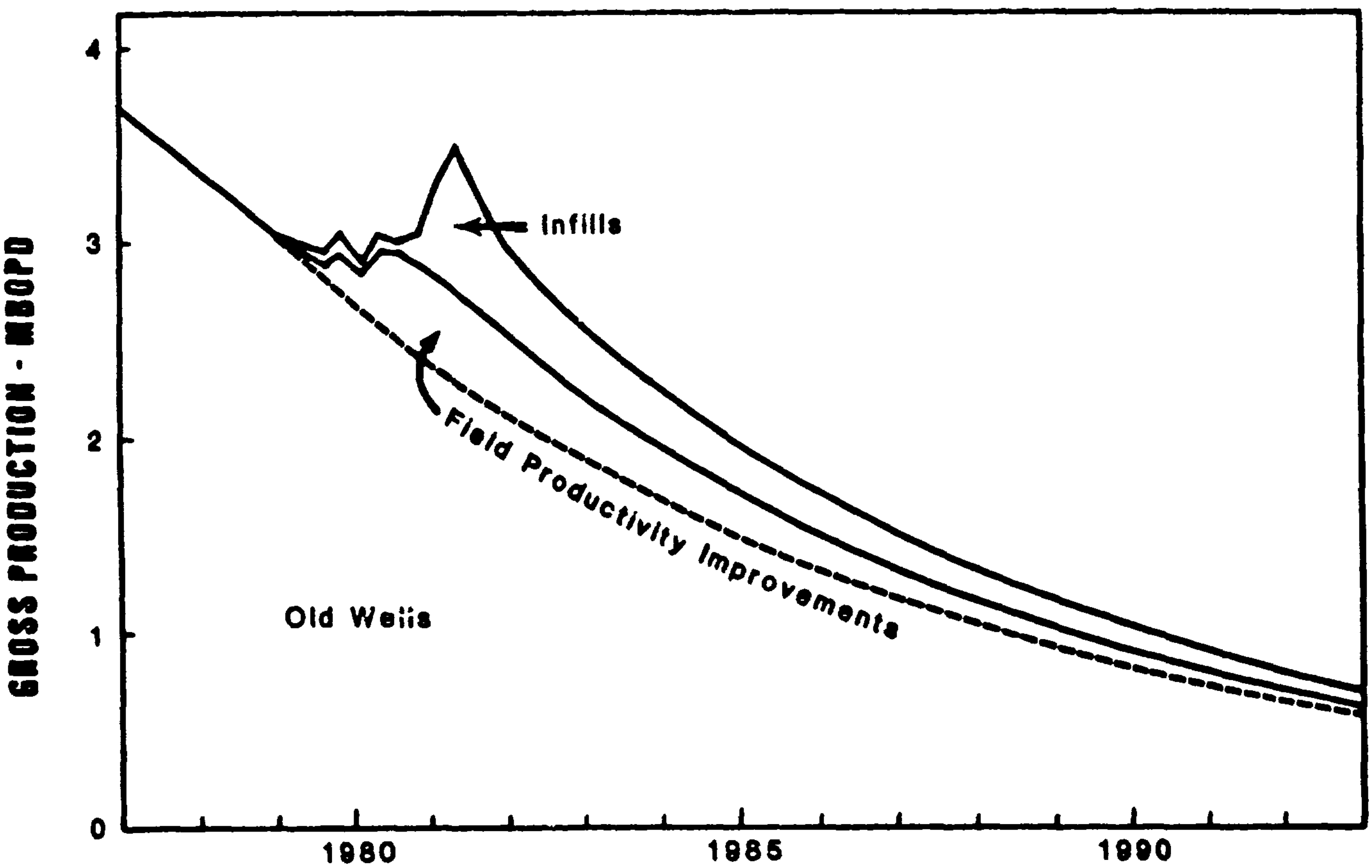
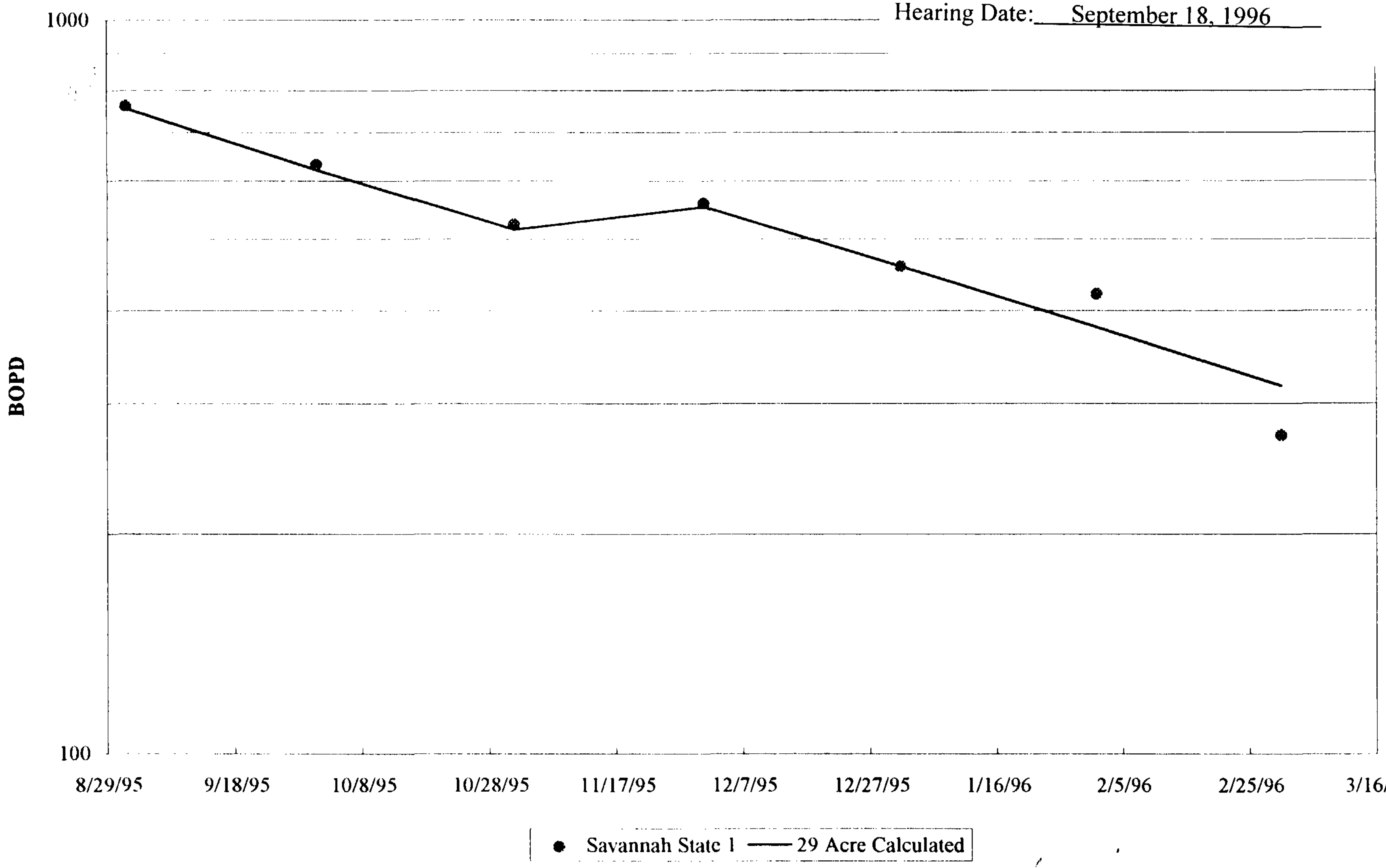


Fig. 17—Production datagraph—Loudon field, Illinois.

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case Nos. 11525 and 11526 (De Novo) Exhibit No. 19
Submitted by: Yates Petroleum Corporation
Hearing Date: September 18, 1996

Savannah State 1



Robert S. Fant

9/13/96

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case Nos. 11525 and 11526 (De Novo) Exhibit No. 18
Submitted by: Yates Petroleum Corporation

Hearing Date: September 18, 1996

Society of Petroleum Engineers

SPE 26437

Control of Fractured Reservoir Permeability by Spatial and Temporal Variations in Stress Magnitude and Orientation

L.W. Teufel,* Sandia Natl. Laboratories, D.W. Rhett, Phillips Petroleum Co., H.E. Farrell, Phillips Petroleum Co., and J.C. Lorenz,* Sandia Natl. Laboratories

* SPE Member

This paper was prepared for presentation at the 68th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in Houston, Texas, 3–6 October 1993

Abstract

A case study of the Ekofisk field, a naturally fractured chalk reservoir in the North Sea, demonstrates the strong influence of horizontal stress anisotropy on fracture conductivity and reservoir permeability. Directions and magnitudes of horizontal in situ stresses, as well as the distribution and orientations of natural fractures, vary locally across the structural dome that forms the Ekofisk reservoir. Fracture permeability is stress-sensitive and decreases as effective stresses in the reservoir increase due to pore pressure reduction resulting from production of oil and gas. Changes in fracture permeability also depend on the orientation of fractures relative to the evolving anisotropic stress field in the reservoir. Steeply dipping fractures aligned parallel to the local maximum horizontal stress direction show the smallest decline in permeability as the reservoir is depleted and can control permeability anisotropy in a naturally fractured reservoir containing multiple fracture sets.

Introduction

Fractures are present in almost all hydrocarbon reservoirs, but it is only when fractures form an interconnected network that their effect on fluid flow becomes important. Fractures not only enhance the overall permeability of many reservoirs, they also create significant permeability anisotropy. Knowledge of the orientation and magnitude of the horizontal permeability anisotropy has significant economic importance in developing and managing a reservoir. Such knowledge allows optimization of (1) location of production wells for maximum primary oil recovery and drainage of the reservoir with the fewest number of wells, and (2) placement of waterflood injection wells to prevent early water breakthrough in producing wells, thereby achieving optimum sweep efficiency and maximum oil recovery.

References and illustrations at end of paper.

In order to assess the role of fractures on hydrocarbon production and permeability anisotropy, characterization of naturally fractured reservoirs has focused primarily on the distribution and orientation of fractures and the fluid-flow properties of individual representative fractures in a given reservoir volume. For reservoirs with only one set of fractures (e.g., regional vertical extension fractures across a sedimentary basin) the horizontal direction of preferred fluid flow is parallel to the trend of the fractures.[1] For reservoirs with more than one set of fractures in different orientations it is often assumed that the intensity of fracturing controls reservoir permeability anisotropy and that maximum permeability direction is closely aligned with the dominant fracture trend. Considerable work has been conducted over the past decade to develop new statistical techniques and numerical simulations to predict distributions and orientations of subsurface fractures from cores and geophysical logs. The assumption being that a better statistical description of a reservoir's fracture system provides a better prediction of fracture interconnectivity and fluid-flow characteristics of the reservoir.

However, fluid flow in a naturally fractured reservoir is not only a function of the spacing and interconnectivity of the fracture system, it is also dependent on the conductivity of individual fractures. Fracture conductivity is directly related to the morphology (e.g., surface roughness and filling) of the fracture and the applied stress on the fracture. Fracture apertures close and conductivity decreases as the effective normal stress across the fracture increases.[2] This response can severely limit the productivity of naturally fractured reservoirs during reservoir depletion and affect reservoir permeability anisotropy.

Hydrostatic (isotropic) loading is the conventional test procedure used by the petroleum industry to determine the stress dependence of fracture conductivity (as well as other reservoir properties). However, in most reservoirs the *in situ* stress state is anisotropic. Hydrostatic tests, therefore, do not truly reflect the stress anisotropy and deviatoric stress state that exists in most reservoirs and they do not adequately simulate the evolution of stresses in a reservoir during production. *In situ* stress measurements made during pore pressure drawdown show that many reservoirs follow a stress path, K, (defined as the change in effective horizontal stress/change in effective overburden stress from initial reservoir conditions) that is significantly different than either a constant total stress boundary condition (isotropic loading) or a uniaxial strain boundary condition (i.e., no lateral displacement of the reservoir boundaries).[3]

This paper describes a case study of the Ekofisk field, a naturally fractured chalk reservoir in the North Sea, that demonstrates the strong influence of anisotropic horizontal stresses on fracture conductivity and horizontal permeability anisotropy in the reservoir. Following a brief review of the natural fracture system and *in situ* stress state in the field, the paper focuses on a waterflood pilot area on the north-northwest flank of the field where a series of interference tests were conducted prior to waterflooding to determine the local horizontal permeability anisotropy in the reservoir. The interference tests and subsequent waterflood response indicate a strong preferred direction for the horizontal permeability. The maximum permeability direction is closely aligned with fractures that are parallel to the local maximum horizontal stress direction. Laboratory experiments conducted on representative fractures from the reservoir show that fracture conductivity is extremely stress-sensitive and changes in fracture conductivity depend on the reservoir stress path.

Description of Ekofisk Field and Fracture System

The Ekofisk field is the largest of nine chalk reservoirs that lie within the Central Graben in the southern part of the Norwegian sector of the North Sea. It is an elliptical dome, elongate in a north-south direction, with dimensions of approximately 7.8 km by 13.3 km. The top of the reservoir is at a depth of 2.9 km. Total reservoir thickness is 305 m. The reservoir consists of two fractured chalk intervals separated by a relatively impermeable layer of argillaceous, siliceous, and cherty chalk.[4] The chalks are of Danian and Maastrichtian age. These chalks are draped over what may be a salt diapir, although salt has not been penetrated by any wells.

More than 20 years of petroleum production has resulted in a 24 MPa reduction in reservoir pore pressure throughout the field. The decline in pore pressure has led to an increase in the fraction of the overburden load that must be supported by the structurally weak chalk matrix, which in turn has caused significant reservoir compaction and more than five meters of seafloor subsidence.

The Ekofisk field contains an extensive natural fracture system. Hydrocarbon production, reservoir permeability, and waterflood response are controlled by conductive fractures. Permeabilities inferred from the analysis of well tests are as high as 150 md,[5] which is two orders of magnitude greater than matrix permeabilities of about 1 md measured in cores.[6]

Natural fracturing in Ekofisk cores is dominated by tectonic fractures,[7] which are through-going, subplanar features that form well developed parallel sets that dip from 65° to 80°. Their geometry indicates that they are shear fractures, although offsets are rarely seen in cores either because the displacements are too small or because marker horizons are absent. These fractures rarely have slickensides or mineralization along their surfaces. Where fracture intensity is high, fractures conjugate to the dominant set are also seen. Fracture spacing, measured perpendicular to the fracture surface, is highly variable throughout the field. In the most highly fractured zones, the spacing of fractures in the dominant set is typically as small as 5 cm. In these zones, the spacing of the conjugate set may also be as small as 15 cm. Elsewhere, fracture spacings of 15 - 100 cm are more common. Spacing of the dominant set of fractures rarely exceeds 100 cm at any point in the Ekofisk field.

Stylolite-associated extension fractures are also present in the reservoir and contribute to the reservoir permeability. These fractures usually form sub-parallel, anastomosing networks. Within each network the fractures are well interconnected. The lengths of the stylolite associated fractures are generally shorter than the distance between adjacent stylolites. This means that where stylolite-associated fractures occur alone, there is poor interconnection between individual networks. They form bedding parallel (sub-horizontal) zones of enhanced permeability, but do not form a pervasive network throughout the formation unless they occur in combination with the tectonic fractures.

At least two sets of fractures cut the Ekofisk field.[7] One set trends NNE-SSW throughout the field and is most prominent in the northwest part of the field. These fractures are thought to have resulted from an episode of regional tectonic faulting that is associtated with extension of the North Sea basin and formation of the Central Graben. The second set of fractures cutting the field are genetically related to doming, and probably formed under a radial and tangential stress system that evolved during the doming process.

The orientation of tectonic fractures in the waterflood pilot area on the north-northwest flank of the field is shown in Figure 1. In this area of the field the regional NNE-SSW fracture trend and radial fractures are nearly orthogonal. The resulting distribution of tectonic fractures is dominated by these two orthogonal sets of steeply dipping, conjugate shear fractures.

In Situ Stress State

In situ stress measurements have been made using hydraulic fractures, anelastic strain recovery measurements of oriented core, and wellbore breakouts.[2,7] In general, the azimuth of the maximum horizontal *in situ* stress is not uniform across the field, but is oriented roughly perpendicular to the structural contours around the dome (Figure 2).[11] The minimum horizontal stress magnitudes, as determined from closure stresses derived from shut-in pressure data of hydraulic fractures, have decreased temporally as a function of reservoir depletion and pore pressure drawdown and vary spatially across the field as a function of position on the structure.[7] More than 20 years of production has reduced the original reservoir pore pressure of 48.3 MPa to about 24 MPa. The total minimum stress has decreased linearly with pore pressure drawdown, and the change in minimum stress is about 80 percent of the net change in pore pressure. The lowest magnitudes of the minimum stress are on the crest of the structure and the highest magnitudes are on the outer flanks. The present minimum stress magnitudes range from about 34 MPa on the crest to 40 MPa on the outer flanks of the structure, compared to an average overburden stress of about 62 MPa. An open-hole hydraulic fracture conducted at the crest of the structure indicates that the difference between the maximum and minimum horizontal stresses is about 7 MPa.

Measurements of the total minimum horizontal stress as a function of pore pressure drawdown have been used to provide an understanding of the boundary conditions on the reservoir and the stress path followed by reservoir rock during the production history of the Ekofisk field.[7] With pore pressure drawdown the effective stresses in the reservoir increase, but at different rates. Following Rice and Cleary,[8] effective stress is defined by

$$\sigma = S - \alpha P$$

where σ is the effective stress, S is the total stress, P is the pore pressure, and α is a poroelastic parameter. Laboratory poroelastic-deformation experiments on Ekofisk chalk have shown that α is approximately unity for high porosity chalks.[9]

Figure 3 is a plot of effective minimum horizontal stress, σ_{Hmin}, versus effective vertical stress, σ_V, during primary production from the Ekofisk reservoir. For this plot the total vertical stress in the reservoir is assumed to be constant during the production history of the reservoir and equal to the total stress exerted by the weight of the overburden. Accordingly, an incremental reduction in pore pressure corresponds directly to an incremental increase in effective vertical stress of the same magnitude.

The ratio of effective minimum horizontal stress to effective overburden stress varies spatially across the field with the lowest ratios occurring on the crest and the highest ratios occurring on the outer flanks of the structure. In general, the incremental change in effective minimum horizontal stress with an incremental increase in effective overburden stress is nearly constant over the entire reservoir. Using a linear regression analysis, this ratio, K, is approximately 0.20. Hence, with pore pressure drawdown the effective minimum horizontal stress has increased at a much lower rate than the effective vertical stress.

Reservoir Permeability Anisotropy

Interference tests were conducted prior to waterflooding a pilot area on the north-northwest flank of the field to determine if a permeability anisotropy exists in the reservoir.[10] The interference tests utilized a triangul: pattern of four wells with a central active well (B16a) and three observation wells (B19a, B22c, and B24a) with bottom-hole locations that are approximately 110° to 130° apart and from 341 m to 412 m away from the central B16a well (Figure 4). Pressure responses were measured in the observation wells while the B16a well was produced for 121 hours and then shut-in for 168 hours. A static period of 72 hours was monitored prior to the activation of the B16a well. The results indicate a rapid response of 12 hours between the B16a and B22a wells, a slower response of 32 hours between the B16a and B19a wells, and the slowest response of more than 120 hours between the B16a and B24a wells. Interwell permeability was calculated using a line source solution technique for anisotropic formations.[11] The calculated permeability between the central B16a well and the three observation wells ranged from 153 md in the direction of the B22c well, to 82 md in the direction to the B19a well, to less than 40 md in the direction of the B24a well. The maximum and minimum horizontal permeability in the pilot area was calculated using the interwell permeabilities determined in the three different directions. The maximum permeability is 159 md in a direction of N162°E and the minimum permeability is 36 md in a direction of N72°E. The reservoir permeability is clearly anisotropic, with the ratio of maximum to minimum permeability greater than four to one.

The relationship between the maximum horizontal stress direction and horizontal permeability anisotropy in the pilot area is also shown in Figure 4. The maximum horizontal permeability direction is parallel to the local maximum horizontal stress direction and is closely aligned with the local trend of the radial fracture pattern; one of two nearly orthogonal sets of steeply dipping, conjugate shear fractures in the pilot area (Figure 1). These results suggest that fracture conductivity and horizontal permeability anisotropy in the Ekofisk reservoir are stress-sensitive (i.e., the most conductive fractures are steeply dipping fractures perpendicular to the minimum horizontal stress) and are strongly influenced by the anisotropic horizontal stresses in the reservoir.

Following the interference tests the B16a well was used as a waterflood injector and the three observation wells were produced. Water was injected into the B16a well at rate of over 3100 m^3/day at a bottomhole pressure of about 47 MPa. The waterflood response in the pilot area is in good agreement with the directions and relative magnitudes of the permeability anisotropy determined from the interference tests. Water breakthrough occurred first in the B22a after 69 days of water injection, second in the B19a well after 334 days of injection, and in the B24a well after more than 700 days of injection.

Relationship Between In Situ Stress and Natural Fractures

The relationship between the anisotropic *in situ* stress state and the orientation of two orthogonal, conjugate sets of steeply dipping tectonic fractures is shown in Figure 5. Effective normal (σ_N) and shear (τ) stresses on these steeply dipping fractures are determined by the magnitudes of the principal stresses, pore pressure, and the orientation of the fractures relative to principal stress directions. Vertical fractures aligned with the maximum horizontal stress (σ_{Hmax}) will have the least normal stress across the fracture.

As the reservoir pore pressure is drawn down the effective principal stresses in the reservoir increase, but at different rates as determined by the reservoir stress path. Consequently, changes in the effective normal stress and shear stress on a fracture are a function of the reservoir stress path as well as the orientation of the fracture relative to the evolving anisotropic stress field. Because the Ekofisk reservoir follows a stress path of 0.2, vertical fractures aligned with the maximum horizontal stress will have the smallest increase in normal stress across the fracture and horizontal fractures will have the largest increase in normal stress (Figure 6). This is in sharp contrast to hydrostatic loading (K equals 1.0) where the change in the effective normal stress on a fracture is equal to the magnitude of the pore pressure drawdown for all fractures regardless of orientation (Figure 7).

Tectonic fractures in the Ekofisk reservoir are steeply dipping, sub-planar discontinuities that dip from 65° to 80°. Production-induced changes in the effective normal stress and shear stress on a 75° fracture aligned with the maximum horizontal stress for stress paths of K equals 0.2 and K equals 1.0 are shown in Figure 8. The fracture loaded along a stress path of K equals 0.2 has a much smaller increase in effective normal stress and a larger increase in shear stress than a fracture that is hydrostatically loaded. In fact, shear stress remains constant during hydrostatic loading.

Effect of Reservoir Stress Path on Fracture Permeability

Although many studies have been made on the influence of normal stress on fracture permeability,[12-16] little experimental work has been done on the influence of shear stress and shear displacement on fracture permeability.[15,16] Non-hydrostatic stress paths cause changes in both the normal and shear stress on a fracture as the reservoir pore pressure is drawn down. A series of triaxial-compression tests were conducted on chalk samples having sub-planar natural fractures to determine the effect of reservoir stress path on fracture permeability. In these compression tests the pore pressure and confining pressure were continuously changed from initial reservoir conditions, while maintaining a constant axial (overburden) stress, so that the stress state applied to each sample evolved along a prescribed stress path.

Experimental Procedure

Permeability was measured during hydrostatic and triaxial compression tests on cylindrical samples of Tor Formation chalk from the Ekofisk Field that had a single, sub-planar fracture. Fractures in the samples were oriented at angles less than 17° to the maximum stress. Samples were 47.6 mm in diameter and 114 to 122 mm long. Polyolefin jackets were used to isolate the fractured samples from the confining fluid. Matrix porosity of these samples was about 28-32%.

In the triaxial-compression tests the axial stress was held constant at 62.1 MPa, initial confining stress was 55.2 MPa and the pore pressure was 48.3 MPa. Pore fluid was a low viscosity, pure mineral oil. Effective stresses were applied by reducing pore pressure in increments of 3.45 MPa over a two hour interval while maintaining the total axial stress constant and adjusting the confining pressure so that the stress applied to each sample evolved along a constant stress path of K = 1.0, 0.5, or 0.2, respectively.

Following each incremental increase in stress for both the hydrostatic and triaxial-compression tests, the samples were equilibrated for about 12 hours at the new stress condition. During each test, specific permeability was measured at increments of 3.45 MPa effective overburden stress by flowing mineral oil through the fractured sample at a constant rate and adjusting the downstream pore pressure valve until the pressure difference along the length of the sample had stabilized. Flow was parallel to the load axis. Once conditions were stable, the flow rate and the pressure difference were recorded every minute for 20 - 30 minutes. Permeability was calculated for each data set using the standard permeability equations.[12]

In order to compare changes in permeability observed along the stress path tests all permeabilities were normalized by dividing each permeability by the initial permeability measured under initial reservoir conditions.

Experimental Results of Hydrostatic Stress Tests

Results of permeability measurements made during hydrostatic stress tests on matrix and fractured chalk are shown in Figure 9. Matrix permeability decreased from about 1.2 md to 0.5 md as the hydrostatic stress increased from 6.9 to 41.4 MPa. Permeability of a sample with an unfilled planar fracture was initially much higher than the intact sample and it showed a larger reduction in permeability with increasing hydrostatic stress. Under hydrostatic loading an increase in effective stress of about 20 MPa reduced fracture permeability by more than an order of magnitude until it was equal to the matrix permeability. A chalk sample containing a vertical, partially-filled, stylolite-associated, extension fracture was also tested. This sample had the highest permeability. Increasing hydrostatic stress reduced the permeability of this fractured sample much less than the unfilled fracture.

Experimental Results of Stress Path Tests

Results of permeability measurements made during stress path tests on chalk samples with unfilled, sub-planar fractures are shown in Figure 10. Changes in fracture permeability varied markedly with stress path. As K diminished the reduction in fracture permeability with pore pressure drawdown also diminished.

For a stress path of K equals 0.2, fracture permeability decreased only slightly and then increased as the pore pressure was reduced. The resulting small increase in effective normal stress and large increase in shear stress is probably responsible for this behavior. Increasing shear stress likely produced local slippage along the fracture, causing the fracture to dilate as asperities on one fracture surface were displaced up and over asperities on the opposing fracture surface. Although macroscopic shear displacement did not occur along the fracture, displacement measurements on the sample indicate that nonlinear deformation did occur across and along the fracture, suggesting that microscopic displacements on the scale of surface asperities probably occurred during loading. Frictional wear damage was observed locally on the fracture surface after the test, supporting this conclusion.

Discussion

Reservoirs are dynamic systems that are constantly changing during their production history. Primary hydrocarbon production of a reservoir will reduce the pore pressure, increase the effective stresses, and change the three dimensional effective stress field. *In situ* stress measurements made during pore pressure drawdown of the Ekofisk field show that the reservoir follows a stress path of about 0.2. This stress path is significantly less than either a constant total stress boundary condition (hydrostatic loading), or a uniaxial strain boundary condition (i.e., no lateral displacement of the reservoir boundaries and K equal to 0.4 - 0.6, as determined from uniaxial strain tests on reservoir chalk). Two other naturally fractured chalk reservoirs in the area exhibit similar stress paths.

Reservoirs in different geologic environments can follow different stress paths during pore pressure drawdown. Figure 11 is a plot showing stress paths followed by reservoir rocks in the Rulison field (tight lenticular Measverde sands in western Colorado), in the McAllen Ranch field (tight blanket Vicksburg sands in south Texas)[19], and the Ekofisk field. In all three reservoirs the stress path is less than isotropic loading, ranging from 0.76 for the Rulison field, to 0.52 for the McAllen Ranch field, to 0.20 for the Ekofisk field. The significance of stress path is that shear stresses increase more rapidly with pore pressure drawdown for reservoirs following low stress paths than for reservoirs following high stress paths.

What controls reservoir stress path is poorly understood at present. It is determined by boundary conditions on the reservoir, size and geometry of the reservoir, reservoir depth, poroelastic deformation behavior of reservoir rock and bounding formations, and other parameters. At present, the only way to determine the stress path is to measure the *in situ* stress at two or more different drawdown pressures.

Natural fractures are the primary conductive paths for produced hydrocarbons in the Ekofisk field, as well as most chalk fields in the North Sea. Deformation and permeability of matrix chalk and fractured chalk are stress-sensitive and will change with variations in effective stress as reservoir pore pressure changes during production. A pore pressure drawdown of 24 MPa in the Ekofisk reservoirs has caused significant reservoir compaction and more than five meters of seafloor subsidence. In general, reservoir compaction leads to a reduction of porosity, decrease in permeability, and a decline in productivity. However, deformation of the natural fracture system in these compacting reservoirs has not reduced reservoir productivity. At Ekofisk there has been good maintenance of productivity and reservoir permeability appears to have remained essentially unchanged. In reviewing the first 20 years of Ekofisk production Sulak[20] wrote: "Even though the Ekofisk reservoirs had compacted by some 15 ft by the time subsidence was recognized in late 1984, loss of reservoir productivity (absolute permeability) was not observed."

The apparent paradox of a compacting reservoir maintaining reservoir permeability and productivity can be explained by considering the evolution of the effective stress state during reservoir depletion and the resulting deformation response of the reservoir's fractured rock mass. Previous work has shown that stress path has a marked effect on matrix properties of porous rocks.[21] Laboratory measurements in the present study have shown that permeability of natural fractures is also strongly influenced by the reservoir stress path. Under hydrostatic loading the permeability of fractured chalk sample decreased rapidly as increasing normal stress closed the fracture aperture. However, when th stress path was 0.2 the permeability along a steeply inclined fracture decreased only slightly. The small increase in normal stress across the fracture and shear-enhanced dilation of the fracture aperture is the most likely mechanism for maintaining fracture permeability. Dilation of a fracture can only occur when the normal stress across the fracture is low, allowing the fracture to ride over surface asperities.[22] At higher normal stress asperities are usually sheared off, creating wear damage and gouge along the fracture surface, which reduces fluid flow along the fracture.[23]

In the Ekofisk reservoir the natural fracture system is dominated by conjugate sets of sub-planar tectonic fractures that dip from 65° to 80°. These steeply dipping fractures, together with the low stress path, likely result in low normal stress across the fractures and shear-enhanced fracture dilation that has helped maintain reservoir permeability and productivity in spite of compaction.

It is important to note that reservoir response to depletion would have been considerably different if fractures in the Ekofisk reservoirs were sub-horizontal instead of steeply dipping. The increase in normal stress across horizontal fractures is much greater than steeply dipping fractures (Figure 6) and is equal to the increase in effective overburden stress (i.e. equal to the magnitude of the pore pressure reduction, 24 MPa). This increase in normal stress would have been more than sufficient to close sub-horizontal fractures and reduce fracture permeability to matrix permeability values (Figure 9). Hence, the net result for a reservoir with sub-horizontal fractures would have been a large and dramatic decline in reservoir permeability and productivity accompanying reduction in pore pressure.

Previous work has shown that the increase in shear stress during production of the Ekofisk reservoirs is also sufficient to cause shear failure of high porosity chalk.[2] Production-induced shear fractures enhance local permeability as they become incorporated into the natural fracture system. Increasing shear stress will also cause local slippage of natural and induced fractures. Shear displacement and interaction of intersecting fracture and fracture blocks in this intensely fractured rock mass may close some fractures, but will open others.[24] The resulting deformation response of the fractured-reservoir rock mass has been to maintain reservoir permeability and productivity. The key factors in this positive reservoir response are (1) the stress path followed by the reservoir is low, with a K value of 0.2 and (2) conjugate fractures are steeply dipping.

Other reservoirs may follow different stress paths and the deformational response to drawdown may lead to increasing formation damage and a reduction in permeability and productivity. For example, naturally fractured tight-gas-sand reservoirs in the Rulison field, which are following a relatively high stress path of 0.76 (Figure 11), show significant sensitivity to changes in stress. Reductions in pore pressure have caused fracture closure of near-vertical extension fractures and large reductions in reservoir permeability and productivity.[25]

In Ekofisk, steeply dipping fractures aligned parallel to the maximum horizontal stress will have the smallest decline in permeability during production. These fractures are also likely to be the most conductive fractures in the reservoir. Moreover, their influence on reservoir permeability and permeability anisotropy will increase as the reservoir is depleted. Interference tests in a pilot area on the north-northwest flank of the field indicate a significant permeability anisotropy is present following a reduction in reservoir pore pressure by about 16 MPa. The horizontal permeability anisotropy reflects both the stress-sensitive conductivity of the local fracture system and the local anisotropic horizontal stress state.

The directions and magnitudes of the horizontal *in situ* stresses, as well as the distribution and orientations natural fractures, vary locally across the structural dome that forms Ekofisk. The azimuth of the maximum horizontal *in situ* stress is not uniform across the field, but is oriented roughly perpendicular to the structural contours around the dome. The present *in situ* stress magnitudes are also not uniform across the field. The lowest magnitudes of the minimum horizontal stress occur at the crest of the structure and the highest magnitudes occur on the outer flanks of the structure.

Differences in stress directions and magnitudes at different positions on the structure will affect the conductivity of natural fractures and reservoir permeability across the field. Radial fractures are closely aligned with the local maximum horizontal stress direction on the flanks of the structure and probably were created by structurally-induced stresses during vertical doming. Radial fractures will have the highest conductivity and the azimuth of the reservoir horizontal permeability anisotropy will vary across the field, with the loca[l] maximum flow direction being radial around the flanks of th[e] dome. The magnitude of the reservoir horizontal permeabil[ity] anisotropy is a function of the local fracture system'[s] spacing and interconnectivity, as well as the stress-sensitiv[e] conductivity of the fractures, which is determined largely b[y] the local anisotropic stress state.

In general, reservoir permeability at Ekofisk is higher o[n] the crest than on the flanks of the field, which is typical [of] most reservoirs that are folded structural traps. Higher pe[r]meability in the crestal area is attributed not only to high[er] fracture intensity, but also to higher fracture conductivit[y]. Steeply dipping, stress-sensitive fractures are more condu[c]tive at the crest than on the flanks because the magnitud[es] of the minimum horizontal stress are lowest at the crest a[nd] increase towards the outer flanks of the field.

Conclusions

A case study of the Ekofisk field has demonstrated t[he] strong influence of anisotropic horizontal stresses on fr[ac]ture conductivity and reservoir permeability anisotropy. [...]

stress-sensitive naturally fractured reservoirs having more than one set of fractures, *in situ* stress can be a controlling factor in determining reservoir permeability anisotropy. The study indicates that accurate prediction of permeability anisotropy in naturally fractured reservoirs must involve not only fracture characterization, but also local stress measurements across the reservoir.

This study has also demonstrated that predictions of changes in fracture permeability during reservoir depletion should not be based on measurements made under hydrostatic loading conditions. Instead, predictions should be based on variations in fracture permeabilities measured under deviatoric stresses that simulate the stress path followed by the reservoir during production and on the orientation of natural fractures relative to the evolving *in situ* stress field. Steeply dipping fractures aligned with the maximum horizontal stress direction will have the smallest decline in permeability during production. These fractures will likely dominate reservoir permeability as the reservoir is depleted.

Acknowledgments

Some of this work was performed at Sandia National Laboratories, which is operated for the U.S. Department of Energy under contract number DE-AC04-76DP00789, and is part of a cooperative USDOE/industry research program with Phillips Petroleum Company. The authors acknowledge permission from Phillips Petroleum Company Norway and CoVenturers, including Fina Exploration Norway, Norsk Agip A/S, Elf Aquitaine Norge A/S, Norsk Hydro a.s., Den norske stats oljeselskap a.s., and Total Norge A/S to publish this paper. The opinions presented are those of the authors and do not necessarily represent those of the Phillips Petroleum Norway Group.

References

1. Branagan, P. T.: "Interference Testing of the Natural Fractured Cozzette sandstone: A Case Study at the DOE MWX Site," SPE paper 12869, SPE Unconventional Gas Recovery Symp., Pittsburg, 359-366, 1984.
2. Tsang, Y. W. and P. A. Witherspoon: "Hydromechanical Behavior of a Defomable Rock Fracture Subject to Normal Stress," J. Geophys. Res., 86, 9287-9298, 1981.
3. Teufel, L. W. and D. W. Rhett: "Geomechanical Evidence for Shear Failure of Chalk During Production of the Ekofisk Field," SPE paper 22755, SPE Tech. Conf., Dallas, TX, Oct. 6-9, 1991.
4. Feazel, C. T., I. A. Knight, and L. J. Pekot: "Ekofisk Field, Norwegian Sector, North Sea," in Am. Assoc. Petro. Geol. Atlas of Petroleum Geology, 1990.
5. Brown, D.: "The Flow of Water and Displacement of Hydrocarbons in Fractured Chalk Reservoirs," in Fluid Flow in Sedimentary Basins and Aquifers (J. C. Goff an B. P. Williams, eds), Geological Society London Specia Publication, 34, 201-208, 1987.
6. Thomas, L., T. Dixon, C. Evans, and M. Vienot: "Ekofi Pilot Waterflood," J. Petrol. Tech., 39, 221-230, 1987
7. Teufel, L. W. and H. E. Farrell: "Distribution of In Sit Stress and Natural Fractures in the Ekofisk Field, Nort Sea," in Proc. Third North Sea Chalk Symp., Copen hagen, Denmark, 1990.
8. Rice, J. and M. Cleary: "Some Basic Stress Diffusio Solutions for Fluid-Saturated Elastic Porous Media wit Compressible Constituents," Rev. Geophys. and Spac Phys., 14, 227-241, 1976.
9. Teufel, L. W. and N. R. Warpinski: "Laboratory Dete mination of Effective Stress Laws for Deformation an Permeability of Chalk," in Proc. Third North Sea Chal Symp., Copenhagen, Denmark, 1990.
10. Sylte, J. E., L. D. Hallenbeck, and L. K. Thomas, "Ekof Formation Pilot Waterflood," SPE paper 18276, in Proc. 63rd Annual SPE Tech. Conf., Housto TX, October 2-5, 1988.
11. Ramey, H. J., "Interference Analysis for Anisotropic Fo mations - A Case History," J. Petro. Tech., 22, 129 1298, 1975.
12. Nelson, R. A. and J. Handin: "Experimental Study Fracture Permeability in Porous Rock," Am. Asso Petrol. Geol. Bull., 61, 227-236, 1977.
13. Raven, K. G. and J. E. Gale: "Water Flow in a Natur Rock Fracture as a Function of Stress and Sample Size Int. J. Rock Mech. Min Sci. & Geomech. Abstr., 2 251-261, 1985.
14. Jones, F. O.: "A Labortory Study of the Effects of Co fining Pressure on Fracture Flow and Storage Capaci in Carbonate Rocks," J. Petrol. Tech., 25, 21-27, 197
15. Kranz, R. L., A. D. Frankel, T. Engelder, and C. Scholz: "The Permeability of Whole and Jointed Ba Granite," Int. J. Rock Mech. Min. Sci & Geomec Abstr., 16, 225-234, 1979.
16. Trimmer, D., B. Bonner, H. C. Heard, and A. Dut "Effect of Pressure and Stress on Water Transport Intact and Fractured Gabbro and Granite," J. Geoph Res., 85, 7059-7071, 1980.
17. Makurat, A., N. Barton, and N. S. Rad: "Joint Cond tivity Variation Due to Normal and Shear Deformati in Rock Joints," edited by N. Barton and O. Stepha son, A. A. Balkema, Brookfield, 535-540, 1990.
18. Olsson, W. A.: "The Effect of Slip on the Flow of Fl Through a Fracture," Geophys. Res. Letters, 19, 5 543, 1992.

19. Salz, B.: "Relationship Between Fracture Propagation Pressure and Pore Pressure, SPE paper 6870, in Proc. 52nd SPE Annual Conf., Denver, Oct. 9-12, 1977.

20. Sulak, R. M.: "Ekofisk Field, The First 20 Years," J. Petrol. Tech., 41, 1265-1271, 1991.

21. Rhett, D. W. and L. W. Teufel: "Stress Path Dependence of Matrix Permeability of North Sea Sandstone Reservoir Rock," in Proc. 33rd U.S. Symp. Rock Mech., edited by J. Tillerson and W. Wawersik, Sante Fe, NM, 1992.

22. Goodman, R. E. and J. Dubois: "Duplication of Dilatancy in Analysis of Jointed Rocks," J. Soil Mech. Foundations Div, ASCE SM4, 399-422, 1972.

23. Teufel, L. W.: "Permeability Changes during Shear Deformation of Fractured Rock," in Proc. 28th U. S. Symp. Rock Mech., edited by I. Farmer, J. Daemen, C. Desai, C. Glass, and S. Neuman, Tucson, AZ, 473-480, 1987.

24. Barton, N., L. Harvik, M. Christianson, S. Bandis, A. Makurat P. Chryssanthakis, P., and G. Vik: "Rock Mechanics Modelling of the Ekofisk Reservoir Subsidence," in Proc. 27th U. S. Symp. Rock Mech., edited by H. Hartman, Tuscaloosa, AL, 267-277, 1986.

25. Warpinski, N. R.: "Hydraulic Fracturing in Tight Fissured Media," J. Petro. Tech., 43, 146-152, 1991

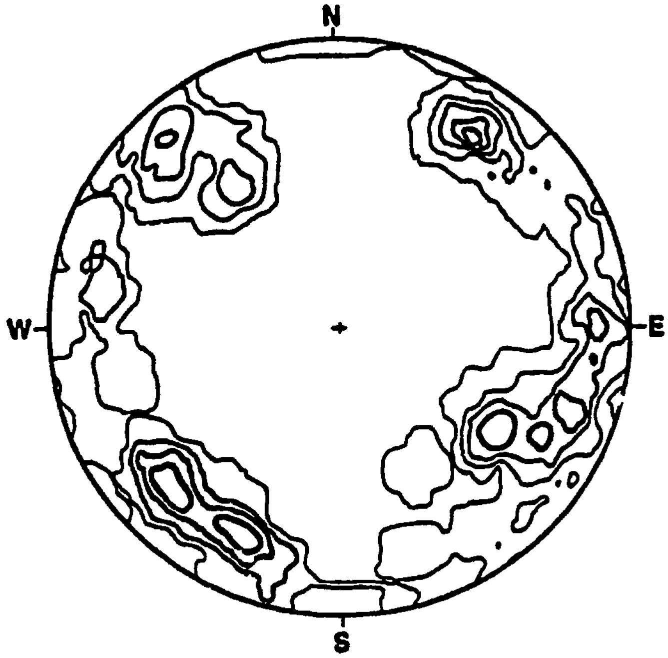


Figure 1. Lower hemisphere equal area plot showing distribution and orientation of tectonic fractures in the waterflood pilot area on the north-northwest flank of the Ekofisk field. Contour intervals are two percent of total (78 fractures).

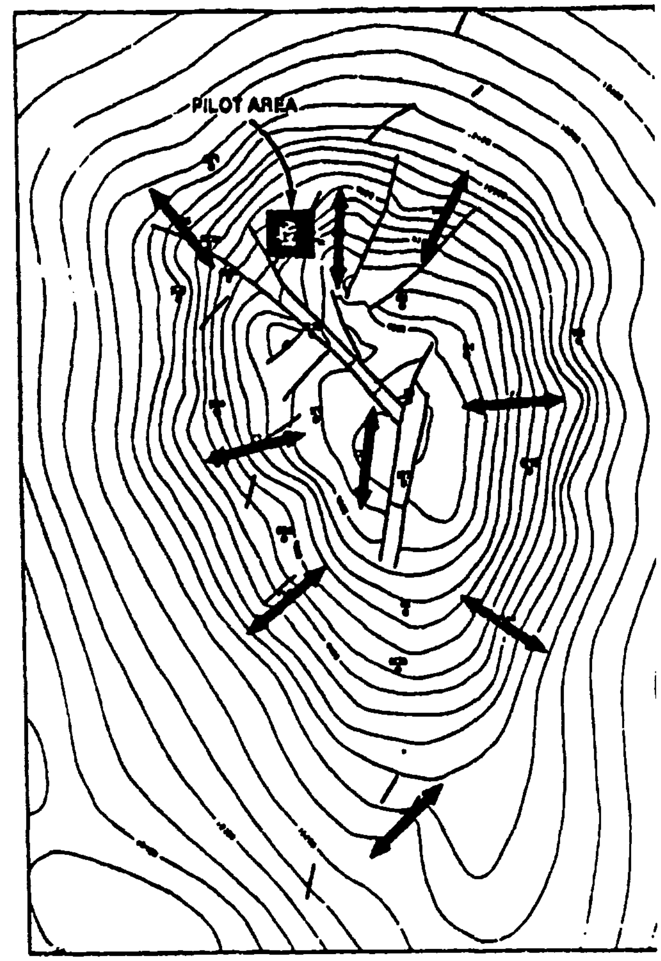


Figure 2. Structural contour map for the top of the Ek
formation showing the azimuth of the maximum horiz
stress (large arrows) in the Ekofisk field[7] and the locatio
the waterflood pilot area.

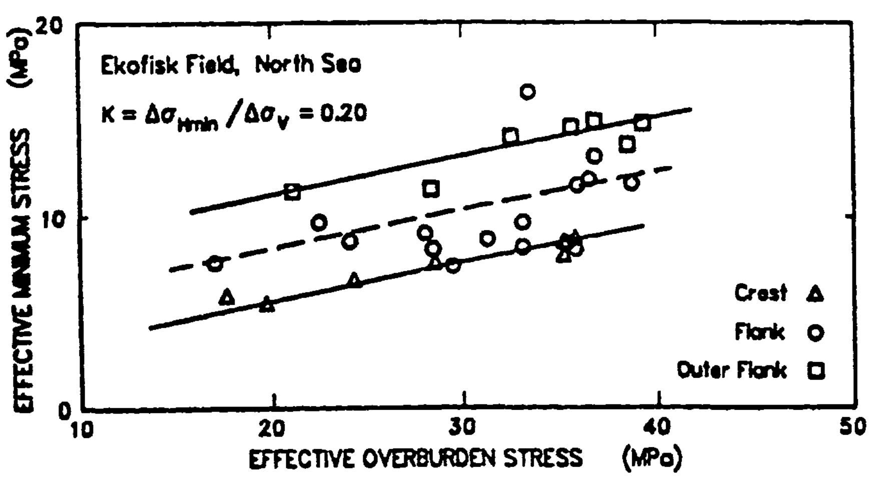


Figure 3. Plot of effective minimum horizontal stress versus effective overburden (vertical) stress in the Ekofisk field.

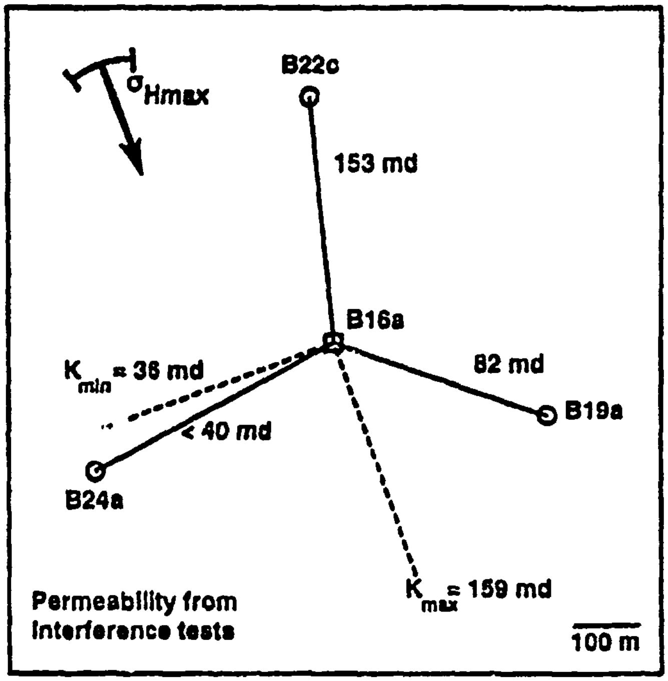


Figure 4. Map showing location of the four wells in the waterflood pilot area and directional permeability between wells determined from interference tests. Relationship between the local maximum horizontal stress direction and calculated permeability anisotropy is also shown.

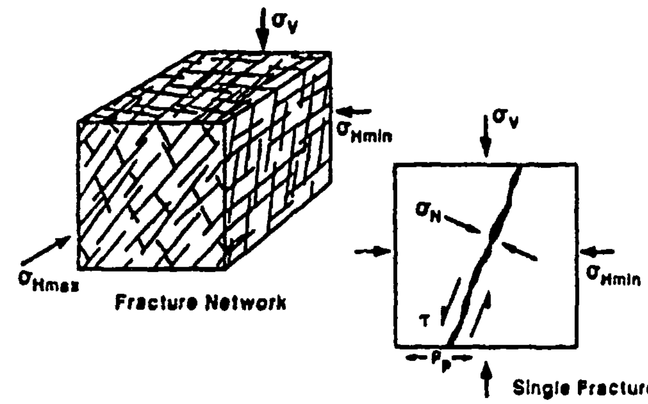


Figure 5. Schematic diagrams showing the *in situ* stress state on a fracture network and on a single fracture that aligned with the maximum horizontal stress.

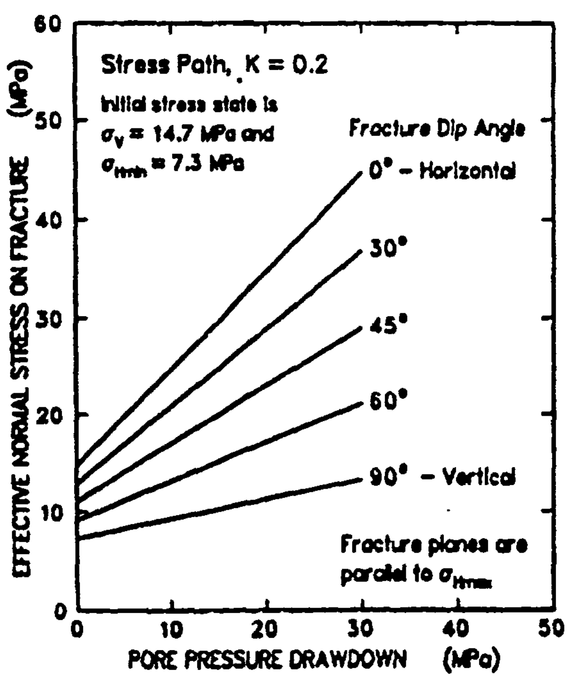


Figure 6. Effect of pore pressure drawdown on effective normal stress across fractures with different orientations for a reservoir stress path of K equals 0.2.

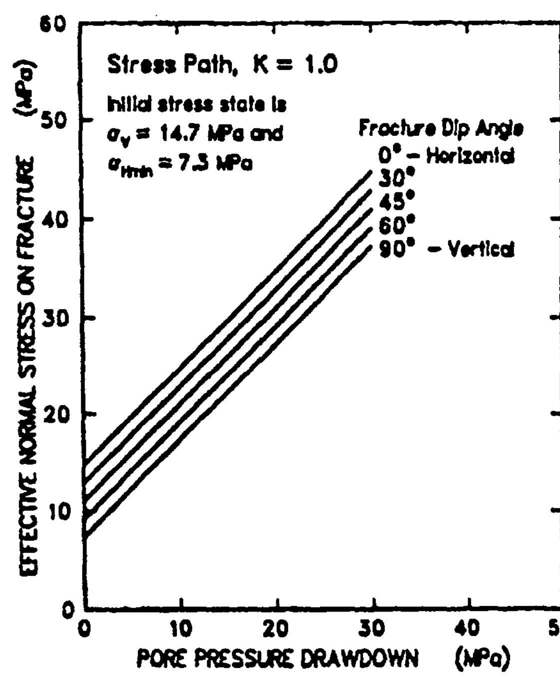


Figure 7. Effect of pore pressure drawdown on effective normal stress across fractures with different orientations for a reservoir stress path of K equals 1.0.

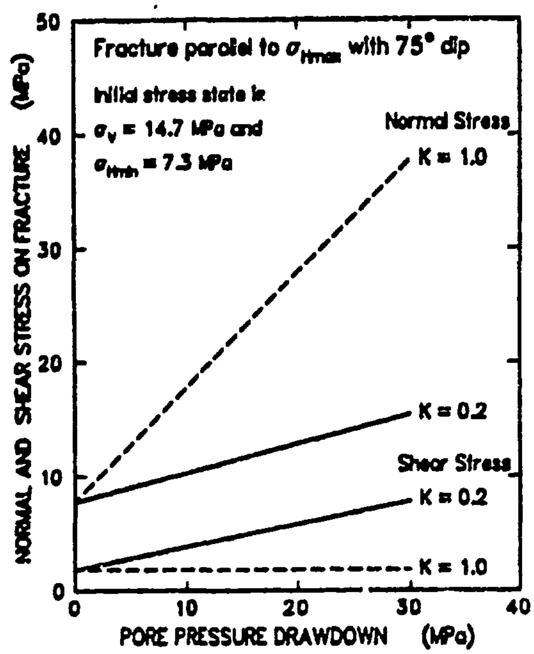


Figure 8. Effect of pore pressure drawdown on effective normal and shear stress for reservoir stress paths equal to 0.2 and 1.0. Fracture is dipping 75° and is aligned the maximum horizontal stress.

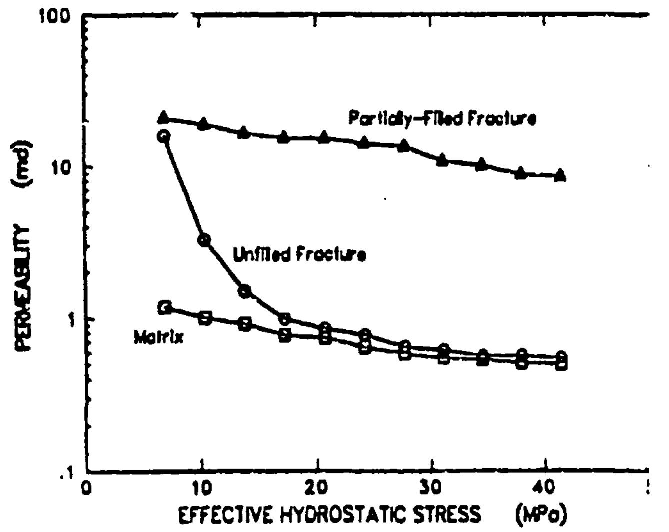


Figure 9. Effect of hydrostatic loading on permeability matrix and fractured chalk samples.

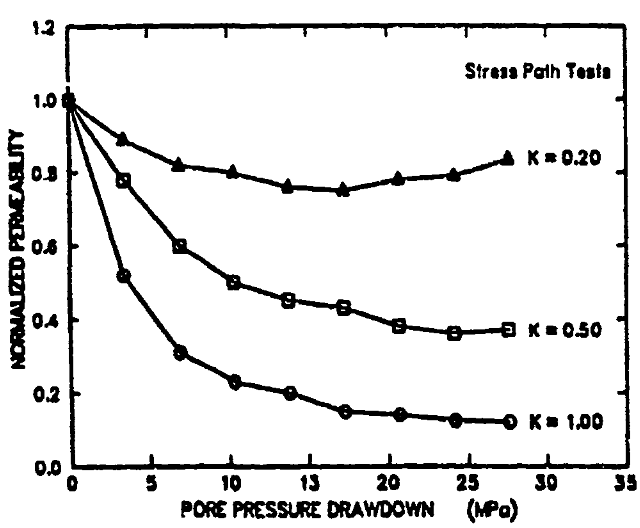


Figure 10. Effect of stress path loading on permeability of fractured chalk samples.

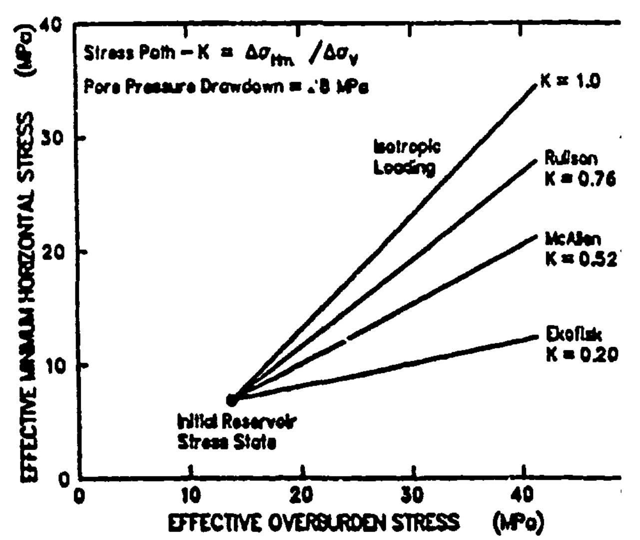
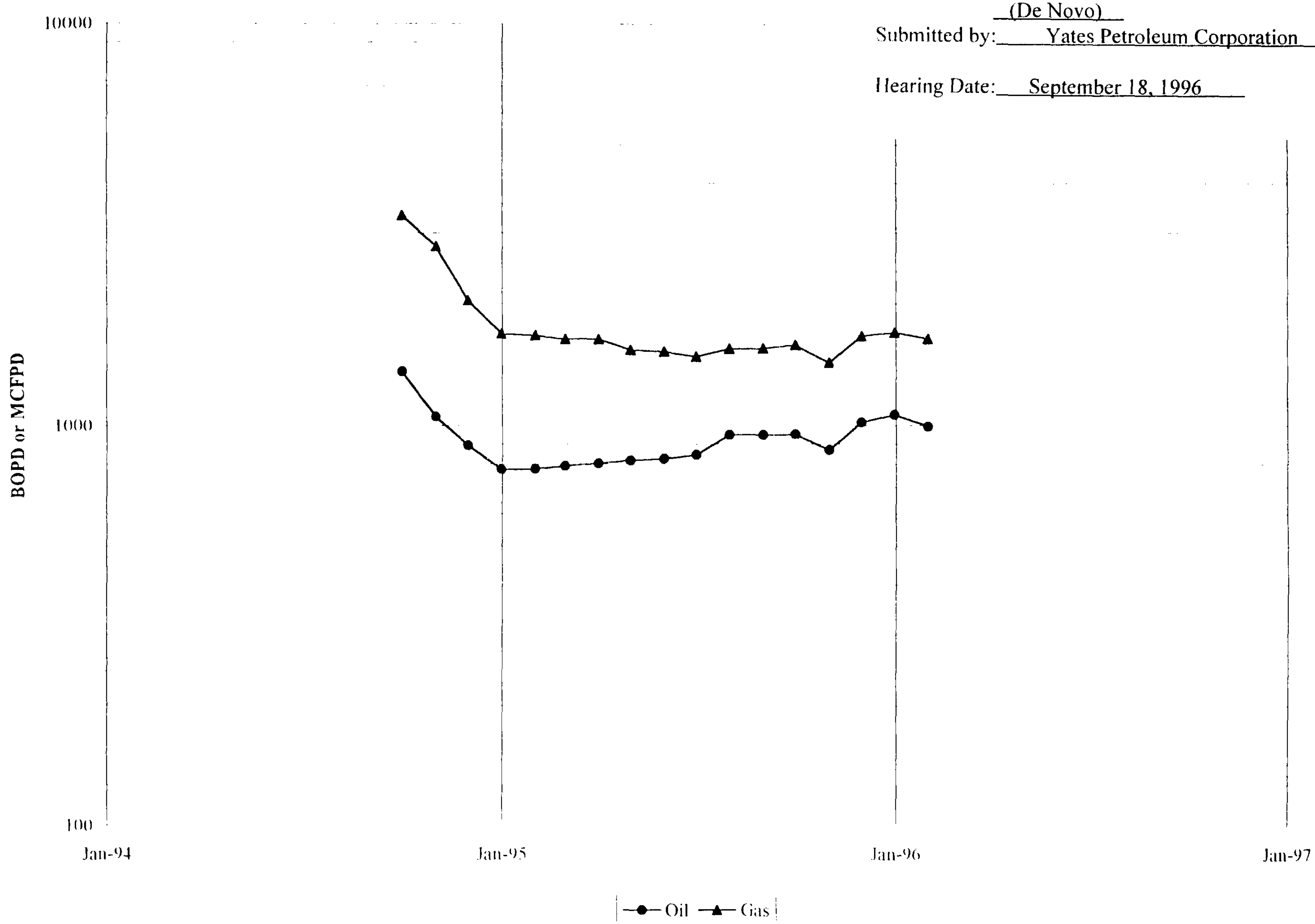


Figure 11. Plot of effective minimum horizontal stress ver effective overburden (vertical) stress in the Rulison, McA Ranch, and Ekofisk fields. Stress path for isotropic load is also shown.

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case Nos. 11525 and 11526 (De Novo) Exhibit No. 20
Submitted by: Yates Petroleum Corporation
Hearing Date: September 18, 1996

State K #3



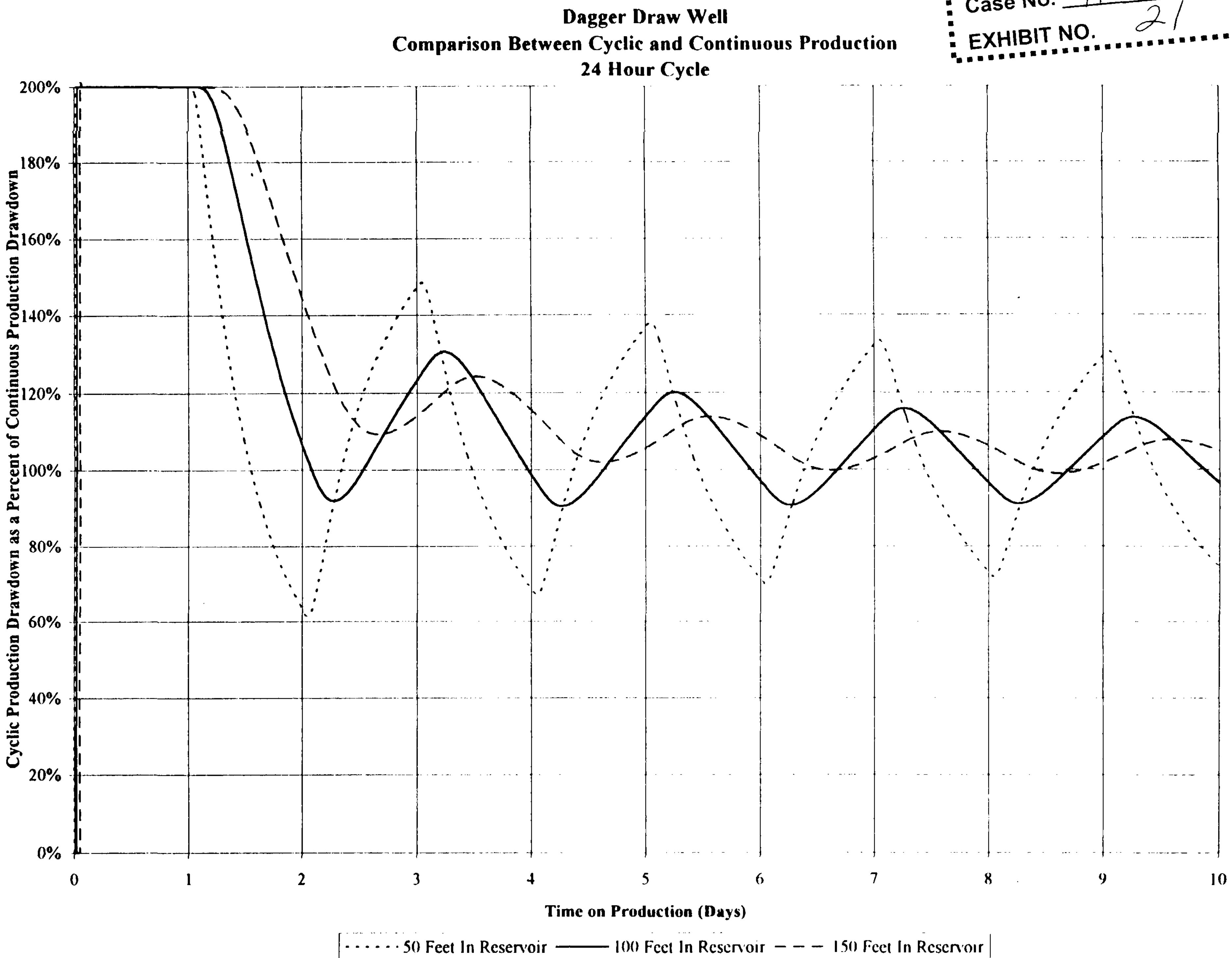
Robert S. Fant

5/1/96

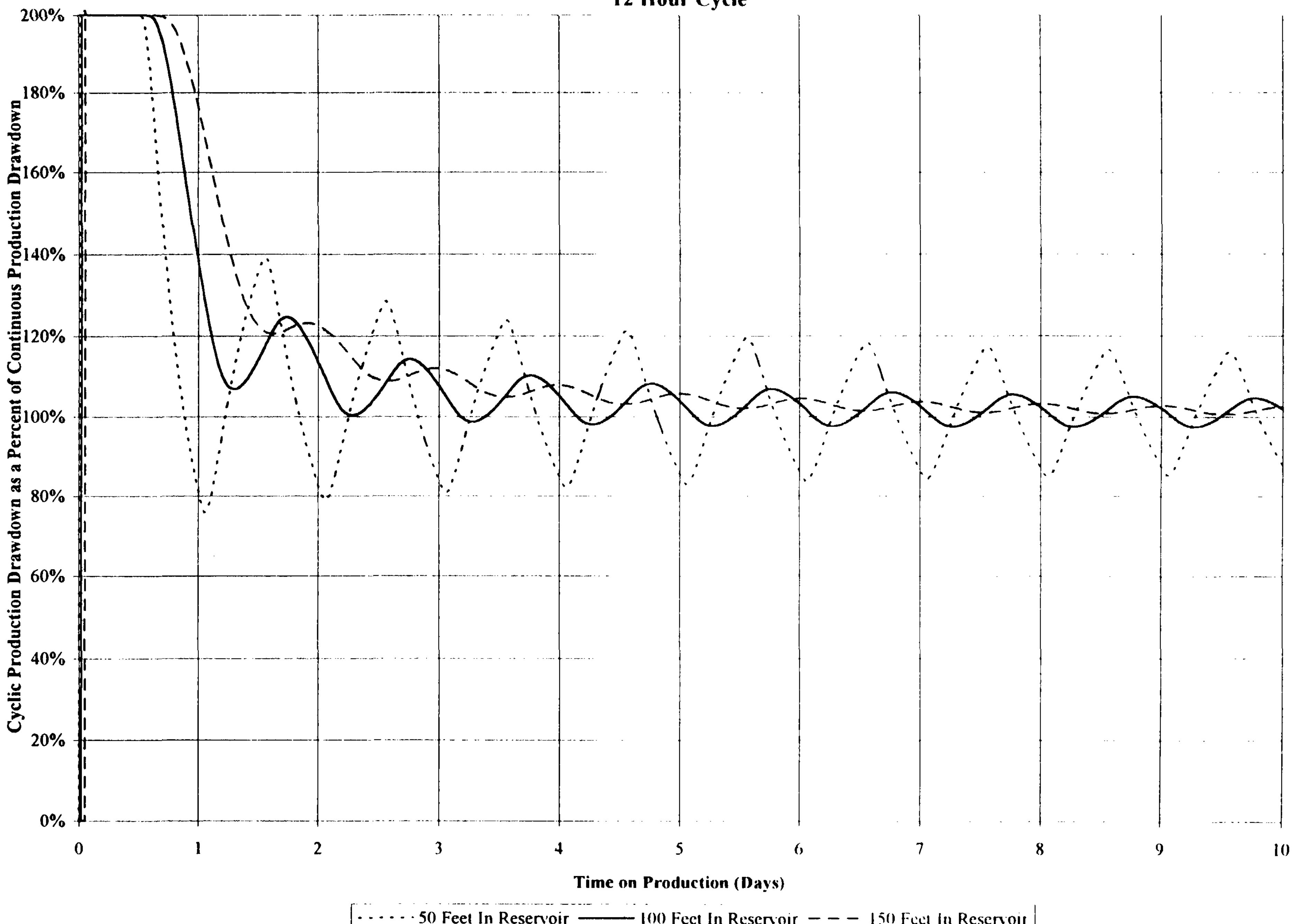
Examiner

Case No. 11525

EXHIBIT NO. 21



Dagger Draw Well
Comparison Between Cyclic and Continuous Production
12 Hour Cycle



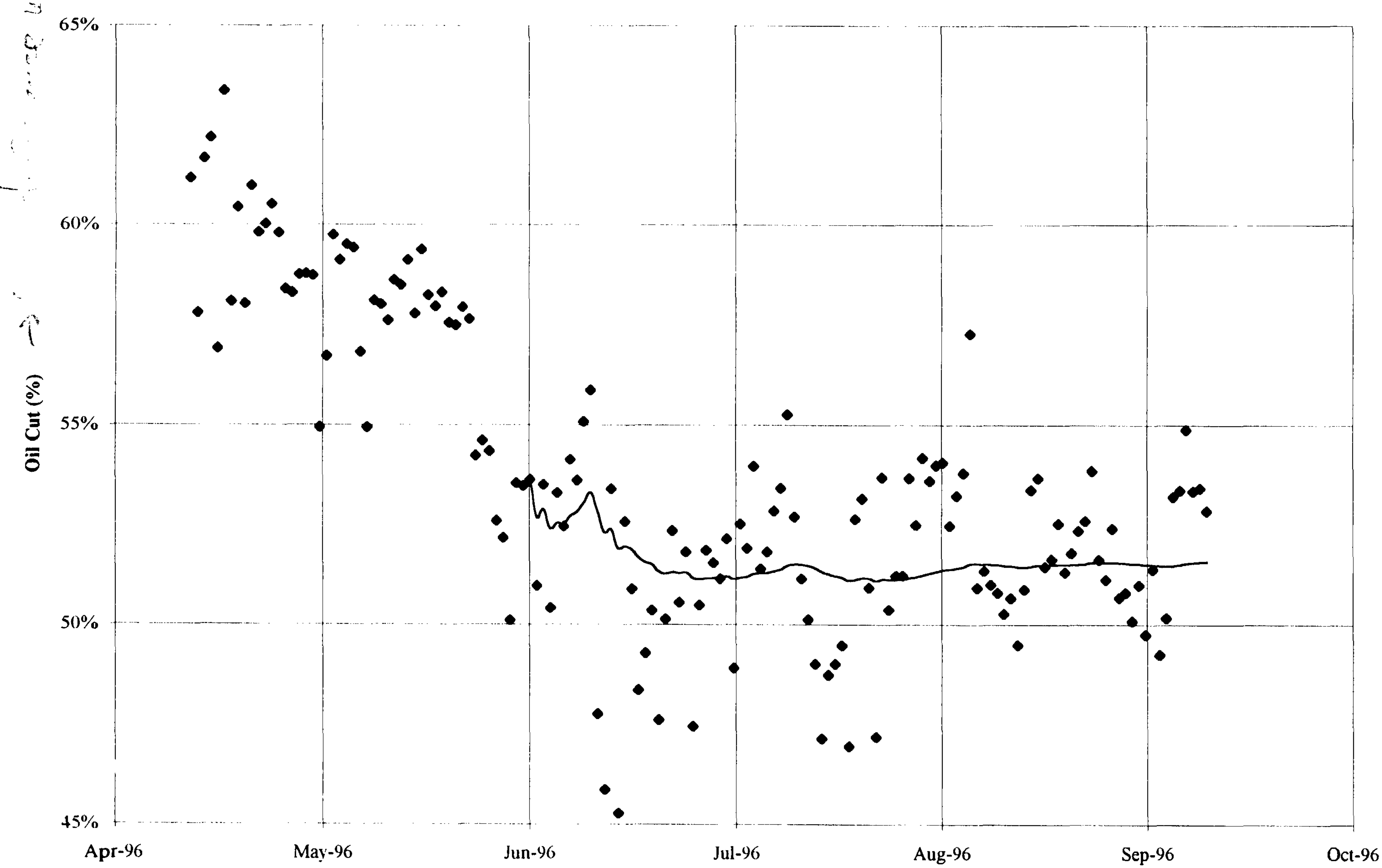
BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case Nos. 11525 and 11526 Exhibit No. 21
(De Novo)
Submitted by: Yates Petroleum Corporation

Hearing Date: September 18, 1996

Oil Cut Versus Time for Restricted Proration Units

Examiner
Case No. 11525
EXHIBIT NO. 22



BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case Nos. 11525 and 11526 Exhibit No. 22
(De Novo)
Submitted by: Yates Petroleum Corporation

Hearing Date: September 18, 1996

MEMO

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case Nos. 11525 and 11526 (De Novo) Exhibit No. 23
Submitted by: Yates Petroleum Corporation
Hearing Date: September 18, 1996

July 12, 1996

From: R.S. Fant

To: Brian Collins

Subject: Dagger Draw Lost Production and Revenues

During the week of April 8, 1996, we filed applications with the NMOCD (cases 11525 and 11526) to increase the allowables in the Dagger Draw (Upper Penn) fields. The NMOCD set these applications for hearing on May 2, 1996. Conoco opposed the applications while Marathon took a neutral position. Nearburg supported our application.

On April 10, 1996, Brian Collins, Pinson McWhorter, and I met with Tim Gum of the Artesia NMOCD office and proposed that we restrict the production on 7 proration units in Dagger Draw to the current allowable of 700 bopd per proration unit. Tim agreed to the proposal partially because we promised to move quickly with our allowable increase applications. At our meeting with Mr. Gum, I presented calculations to Mr. Gum showing that restricting the wells will cause a reduction in oil cut to approximately 52% (from the current 59%). I also showed calculations that approximately this action would waste 7% of the delayed oil. We also conveyed to Mr. Gum that well failures would increase due to the restrictions in produced volumes.

On April 12, 1996, we implemented the production restriction plan. Since that time, we have been carefully monitoring the daily oil cuts on each well, proration unit, and on the total for the restricted proration units.

We presented our case before Michael E. Stogner of the NMOCD on May 3, 1996. I presented testimony that restricting the well would reduce the oil cut and that it would take time to see these effects due to the specific method of restricting these wells. I also testified that well failures would significantly increase.

My original calculations predicted an oil cut of 52% when we restricted the 7 proration units to a total of 4900 bopd. Attachment 1 contains the results of these calculations. Producing the wells at 4900 bopd would require 127 days to produce as much oil as the unrestricted production would produce in 92 days. During the additional 35 days of production we would produce an additional 102,865 barrels of water. This volume of water represents a fluid volume that we will not produce later in the life of the well. The oil represents 26% of the produced fluid stream. Consequently, 26% of the additional water volume represents wasted oil. Corrected for B_o (estimated at 1.27), this represents 21 MBO.

Attachment 2 shows the oil cut as a function of time for the restricted wells since we implemented the production restrictions. As I predicted in my testimony before the NMOCD, the oil cut fell gradually over time. After approximately 6 weeks, the cut leveled out at approximately 52% (the same value we predicted). Attachment 3 shows the same type of calculations presented in Attachment 1 based upon the actual production numbers. It is obvious that the oil cut has not average 52% since the restrictions began. However, I believe that the damage to the reservoir is at some depth and even if we increase production, oil cut will increase in a manner similar to the original decreases. Consequently I believe that using 52% as the bottom oil cut is accurate.

I included a table showing some of the delayed and wasted volumes and values. I used an oil price of $20/bbl and a gas price of $2/mcf. These values are conservative as compared to actual booked prices for this period.

Daily Oil Allowable	4900 BOPD
Daily Average Oil Production	4608 BOPD
Daily Gas Allowable	49 MMCFGPD
Daily Average Gas Production	6.7 MMCFGPD
Total Oil Delayed	272 MBO
Total Oil Lost	21 MBO
Total Gas Delayed	343 MMCFG
Value of Delayed Oil	$5,440,000
Value of Lost Oil	$420,000
Value of Delayed Gas	$686,000
State Royalty Oil Delayed	9 MBO
State Royalty Oil Lost	1 MBO
State Royalty Gas Delayed	11 MMCFG
Value of State Royalty Oil Delayed	$180,000
Value of State Royalty Oil Lost	$20,000
Value of State Royalty Gas Delayed	$22,000
State Production Taxes Delayed (8%)	$474,000
State Production Taxes Lost (8%)	$32,000
Ad Valorem Taxes Delayed (1.5%)	$89,000
Ad Valorem Taxes Lost (1.5%)	$6,000
Estimated NM State Income Taxes Delayed (5%)	$268,000
Estimated NM State Income Taxes Lost (5%)	$18,000
Total NM Revenue Losses for 1996	$1,109,000

Delayed volumes represent volumes that we will recover over the remaining life of the well while lost volumes represent wasted volumes of oil. YPC interests in these wells averages between 50% and 60%. Consequently, all of the production and revenue loss is not borne by YPC et al.

I hope these numbers are of value to you and if you have any questions about this analysis, please let me know.

RSF/rsf

XC

Pinson McWhorter
Randy Patterson

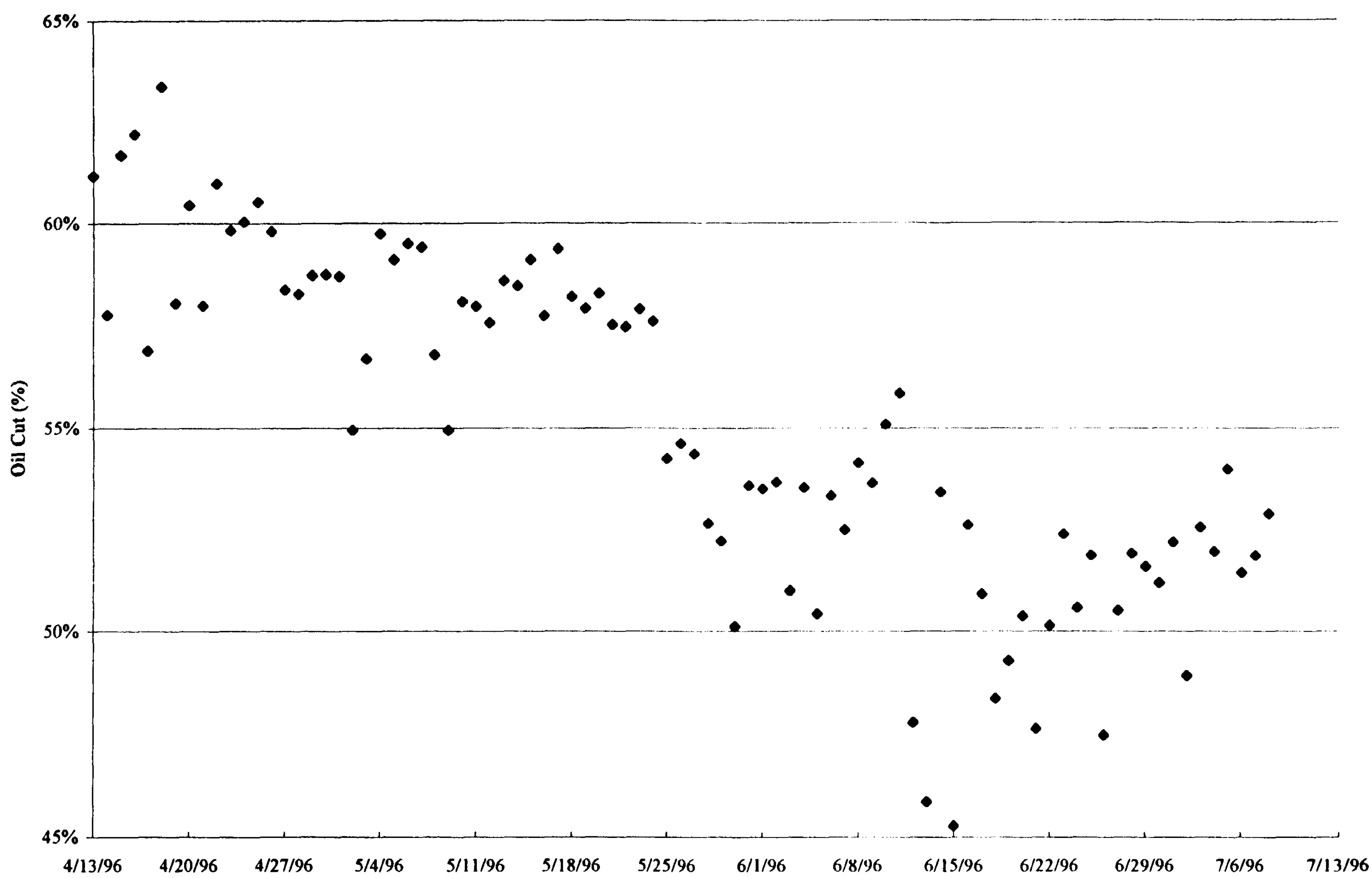
Lost Oil

	Before	After	Delta	
Oil	7933	4900	3033	BPD
Gas	10571	6463	4108	MCFPD
Water	5506	4519	987	BPD
Oil Cut	59%	52%		
GOR	1333	1320		SCF/STB
GLR	787	686		SCF/STB
Liquid	13439	9419	4020	BPD
Days Restricted			92	Days
Additional Days			35	Days
Additional Gas Produced			371825	MCF
Additional Water Produced			193669	BW
Original Oil			729836	STB
Origina Gas			972532	MCF
Original Water			506552	BW
Total Oil			729836	STB
Total Gas			966421	MCF
Total Water			609417	BW
Extra Oil			0	STB
Extra Gas			0	MCF
Extra Water			102865	BW
Bg			2.87	RB/MCF
Bo			1.27	RB/STB
Rs			300	SCF/STB
% Stream as Oil			26%	
Water Based Loss			20890	STB
% Loss of Delayed Production			7%	

Original Calculations In April 1996

Attachment 1

Oil Cut Versus Time for Restricted Proration Units



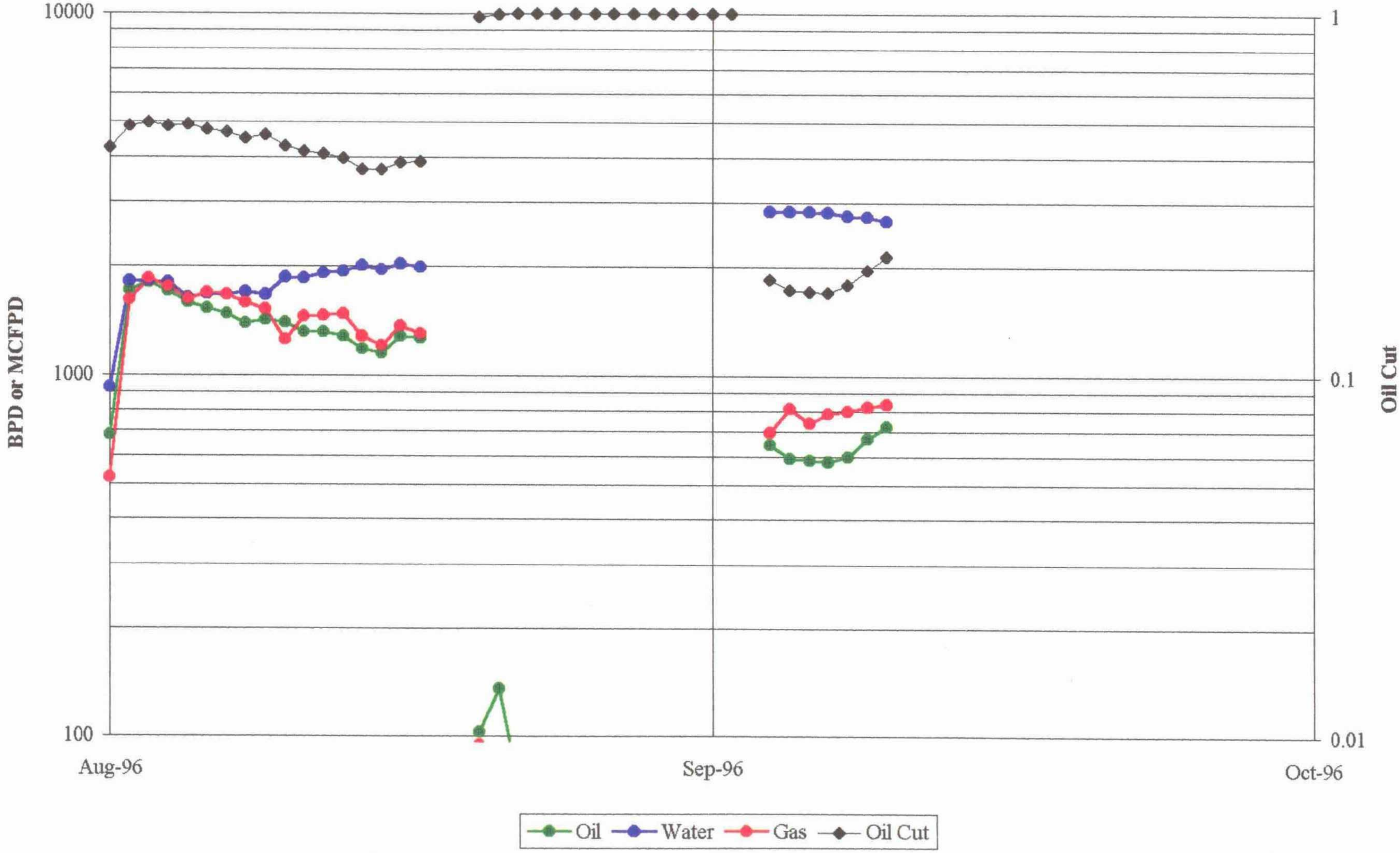
Lost Oil

	Before	After	Delta	
Oil	7933	4608	3325	BPD
Gas	10571	6083	4488	MCFPD
Water	5506	4326	1180	BPD
Oil Cut	59%	52%		
GOR	1333	1320		SCF/STB
GLR	787	681		SCF/STB
Liquid	13439	8934	4505	BPD
Days Restricted			92	Days
Additional Days			39	Days
Additional Gas Produced			407655	MCF
Additional Water Produced			212331	BW
Original Oil			729836	STB
Origina Gas			972532	MCF
Original Water			506552	BW
Total Oil			729836	STB
Total Gas			967313	MCF
Total Water			610342	BW
Extra Oil			0	STB
Extra Gas			0	MCF
Extra Water			103790	BW
Bg			2.87	RB/MCF
Bo			1.27	RB/STB
Rs			300	SCF/STB
% Stream as Oil			25.79%	
Water Based Loss			21078	STB
% Loss of Delayed Production			6.89%	

Calculations Based Upon Actual Data
Attachment 3

7/12/96

Polo AOP #6



Robert S. Fant

9/13/96

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case Nos. 11525 and 11526 Exhibit No. 24
(De Novo)
Submitted by: Yates Petroleum Corporation

Hearing Date: September 18, 1996

Revenue Loss in the Next 18 Months if Examiner Order Implemented

Cost of Delayed and Lost Production

July 12, 1996 memo to Brian Collins illustrates that New Mexico revenue in 1996 will be reduced by $1,109,000 due to the restriction of 3325 bopd for 92 days.

$$\frac{\$1{,}109{,}000}{3{,}325 bopd \times 92 days} = \frac{\$3.62}{bopd \times day}$$

The memo further states that 93% of the revenue is delayed and 7% is permanently lost.

$$\text{Delayed Revenue} = \frac{\$3.37}{bopd \times day}$$

$$\text{Permanently Lost Revenue} = \frac{\$0.25}{bopd \times day}$$

Amount of Delayed Production

The total overproduction for the field is in excess of 1,000,000 bbls (all operators). By prorating this overproduction over the next 18 months, an average daily restriction of 1827 bopd is calculated.

$$\frac{1{,}000{,}000 bbls}{547 days} = 1828 bopd$$

This value does not represent the total restriction on the field because there are at least 4 other proration units that are capable of producing in excess of the 700 bopd allowable with the existing wells. I conservatively estimate that at least another 1000 bopd would be restricted. This brings the total restriction for the 18 month period to 2828 bopd.

Revenue Impact Over the Next 18 Months

Delayed Revenue	$547 days \times 2828 bopd \times \frac{\$3.37}{bopd \times days}$	$5,213,000
Lost Revenue	$547 days \times 2828 bopd \times \frac{\$0.25}{bopd \times days}$	$387,000
Revenue Already Delayed	$\frac{\$1{,}031{,}370}{92 days} \times 153 days$	$1,715,000
Revenue Already Lost	$\frac{\$77{,}630}{92 days} \times 153 days$	$129,000
Total		$7,444,000

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case Nos. 11525 and 11526 Exhibit No. 25
(De Novo)
Submitted by: Yates Petroleum Corporation

Hearing Date: September 18, 1996

List of wells proposed by Yates to Nearburg et. al. from February 23, 1995 to March ~~9~~, 1995.
22

1) Ross E. G. Com #14
2) Rodke "AOY" Com #1
3) Aspden "AOH" Federal Com #2
4) Foster Fee 31 Com #1
5) B&B #4
6) B&B #5
7) B&B #6
8) Ross Ranch #4
9) Ross Ranch #3
10) Boyd X #7
11) Boyd X #6
12) Tackitt #3
13) Tackitt #4
14) Aspden "AOH" Federal Com #3
15) Patriot "AIZ" #7
16) Daggar Draw 31 Federal #8
17) Ross "EG" Federal Com #15
18) Patriot "AIZ" #6
19) Cutter "APC" #1
20) Big Walt 2 State #4.
21) B&B #11
22) B&B #8

BEFORE THE
OIL CONSERVATION DIVISION
Case No. 11311 Exhibit No. 5
Submitted By:
Nearburg Exploration Company

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 11525 Exhibit No. A
Submitted by CONOCO
Hearing Date 9/18/96

List of wells proposed by Yates to Nearburg et. al. between February 23, 1995 and March 9, 1995, continued.

23) B&B #2

24) B&B #9

25) B&B #7

26) Voight "AJD #1; Rework

27) B&B #3

28) Hinkle "ALD" #4

29) Patriot "AIZ" #10

30) Patriot "AIZ" #12

31) Patriot "AIZ" #9

32) Patriot "AIZ" #8

33) Patriot "AIZ" #11

34) Amole "AMM" Com State

35) Vann "APD" #1

36) Hinkle "ALD" #3

37) Boyd X State Com #9

38) Boyd X State Com #8

39) Hooper "AMP" Com #4

C:\wordw in\bob\38wellex.doc

MARTIN YATES, III
1912 - 1985
FRANK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

S. P. YATES
CHAIRMAN OF THE BOARD
JOHN A. YATES
PRESIDENT
PEYTON YATES
EXECUTIVE VICE PRESIDENT
RANDY G. PATTERSON
SECRETARY
DENNIS G. KINSEY
TREASURER

(1)

February 23, 1995

FEB 27 1995

To: Working Interest Owners
Address List Attached

Re: Ross EG Com. #14
Township 19 South, Range 25 East
Section 21: NE/4
Eddy County, New Mexico

Gentlemen:

Pursuant to Nearburg's request and our concerns about the Alto AOL Com. #1 location being between two SWD wells, Yates Petroleum Corporation is proposing the Ross EG Com. #14 at a location of 660' FNL and 1980' FEL of Section 21-T19S-R25E to test the Canyon formation. Enclosed are two (2) copies of an Authority for Expenditure for your review.

We will be furnishing you in the near future with a revised page 4 and Exhibit A to the August 23, 1994 Operating Agreement to reflect the new proposal.

If the AFE is acceptable and you would like to participate in the drilling of this well, please sign and return one (1) executed copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Mecca Mauritsen

Mecca Mauritsen
Landman

MM:dke
enclosure(s)

M/ I YATES, III
.2 - 1985
FRANK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION

105 South Fourth Street
ARTESIA, NEW MEXICO 88210
Telephone (505) 748-1471

RECEIVED
MAR - 6 1995

March 3, 1995

Nearburg Exploration Company
3300 North "A" Street
Building 2, Suite 120
Midland, Texas 79705

Attention: Mr. Bob Shelton

Re: B&B #5
Section 22-T19S-R25E
Eddy County, New Mexico

Gentlemen:

Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation proposes the drilling of the captioned well. The proposed footage location is 660' FNL and 1980' FWL of Section 22-T19S-R25E to test the Canyon formation. Authority for Expenditure costs for the 8300' test are $253,700 dry hole and $685,700 completed. Enclosed for your review are two (2) copies of the detailed AFE.

Please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson

Randy G. Patterson
Land Manager

RGP/mw

Enclosures

MARTIN YATES, III
1912 - 1985
NK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

S. P. YATES
CHAIRMAN OF THE BOARD
JOHN A. YATES
PRESIDENT
PEYTON YATES
EXECUTIVE VICE PRESIDENT
RANDY G. PATTERSON
SECRETARY
DENNIS G. KINSEY
TREASURER

RECEIVED
MAR - 6 1995

March 3, 1995

Nearburg Exploration Company
3300 North "A" Street
Building 2, Suite 120
Midland, Texas 79705

Attention: Mr. Bob Shelton

Re: B&B #6
Section 22-T19S-R25E
Eddy County, New Mexico

Gentlemen:

Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation proposes the drilling of the captioned well. The proposed footage location is 1980' FNL and 1980' FWL of Section 22-T19S-R25E to test the Canyon formation. Authority for Expenditure costs for the 8300' test are $253,700 dry hole and $685,700 completed. Enclosed for your review are two (2) copies of the detailed AFE.

Please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson
Land Manager

RGP/mw

Enclosures

MARTIN YATES, III
1912 - 1985
FRANK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

March 3, 1995

MAR - 6 1995

Nearburg Exploration Company
3300 North "A" Street
Building 2, Suite 120
Midland, Texas 79705

Attention: Mr. Bob Shelton

Re: Ross Ranch #4
Section 22-T19S-R25E
Eddy County, New Mexico

Gentlemen:

Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation proposes the drilling of the captioned well. The proposed footage location is 660' FSL and 660' FWL of Section 22-T19S-R25E to test the Canyon formation. Authority for Expenditure costs for the 8300' test are $253,700 dry hole and $685,700 completed. Enclosed for your review are two (2) copies of the detailed AFE.

Please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson
Land Manager

RGP/mw

Enclosures

Enclosures

YATES PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

March 3, 1995

Nearburg Exploration Company
3300 North "A" Street
Building 2, Suite 120
Midland, Texas 79705

Attention: Mr. Bob Shelton

RECEIVED
MAR - 6 1995

Re: Ross Ranch #3
Section 22-T19S-R25E
Eddy County, New Mexico

Gentlemen:

Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation proposes the drilling of the captioned well. The proposed footage location is 660' FNL and 660' FWL of Section 22-T19S-R25E to test the Canyon formation. Authority for Expenditure costs for the 8300' test are $253,700 dry hole and $595,700 completed. Enclosed for your review are two (2) copies of the detailed AFE.

Please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson

Randy G. Patterson
Land Manager

RGP/mw

Enclosures

10

YATES PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

MAR - 6 1995

March 3, 1995

Nearburg Exploration Company
3300 North "A" Street
Building 2, Suite 120
Midland, Texas 79705

Attention: Mr. Bob Shelton

Re: Boyd X #7
Section 29-T19S-R25E
Eddy County, New Mexico

Gentlemen:

Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation proposes the drilling of the captioned well. The proposed footage location is 660' FSL and 660' FEL of Section 29-T19S-R25E to test the Canyon formation. Authority for Expenditure costs for the 8300' test are $253,700 dry hole and $595,700 completed. Enclosed for your review are two (2) copies of the detailed AFE.

Please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson
Land Manager

RGP/mw

Enclosures

11

M~~TIN YATES, III
~912 - 1985
F... NK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

S. P. YATES
CHAIRMAN OF THE BOARD
JOHN A. YATES
PRESIDENT
PEYTON YATES
EXECUTIVE VICE PRESIDENT
RANDY G. PATTERSON
SECRETARY
DENNIS G. KINSEY
TREASURER

MAR - 6 1995

March 3, 1995

Nearburg Exploration Company
3300 North "A" Street
Building 2, Suite 120
Midland, Texas 79705

Attention: Mr. Bob Shelton

Re: Boyd X #6
Section 29-T19S-R25E
Eddy County, New Mexico

Gentlemen:

Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation proposes the drilling of the captioned well. The proposed footage location is 660' FSL and 1980' FEL of Section 29-T19S-R25E to test the Canyon formation. Authority for Expenditure costs for the 8300' test are $253,700 dry hole and $595,700 completed. Enclosed for your review are two (2) copies of the detailed AFE.

Please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson
Land Manager

RGP/mw

Enclosures

M**TIN YATES, II
1912 - 1985
F. NK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

S. P. YATES
CHAIRMAN OF THE BOARD
JOHN A. YATES
PRESIDENT
PEYTON YATES
EXECUTIVE VICE PRESIDENT
RANDY G. PATTERSON
SECRETARY
DENNIS G. KINSEY
TREASURER

March 3, 1995

MAR - 6 1995

Nearburg Exploration Company
3300 North "A" Street
Building 2, Suite 120
Midland, Texas 79705

Attention: Mr. Bob Shelton

Re: Tackitt AOT #3
Section 28-T19S-R25E
Eddy County, New Mexico

Gentlemen:

Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation proposes the drilling of the captioned well. The proposed footage location is 660' FSL and 1980' FEL of Section 28-T19S-R25E to test the Canyon formation. Authority for Expenditure costs for the 8300' test are $253,700 dry hole and $595,700 completed. Enclosed for your review are two (2) copies of the detailed AFE.

Please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson
Land Manager

RGP/mw

Enclosures

MARTIN YATES, III
1912 - 1985
FRANK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

S. P. YATES
CHAIRMAN OF THE BOARD
JOHN A. YATES
PRESIDENT
PEYTON YATES
EXECUTIVE VICE PRESIDENT
RANDY G. PATTERSON
SECRETARY
DENNIS G. KINSEY
TREASURER

March 3, 1995

RECEIVED
MAR - 6 1995

Nearburg Exploration Company
3300 North "A" Street
Building 2, Suite 120
Midland, Texas 79705

Attention: Mr. Bob Shelton

Re: Tackitt AOT #4
Section 28-T19S-R25E
Eddy County, New Mexico

Gentlemen:

Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation proposes the drilling of the captioned well. The proposed footage location is 660' FSL and 660' FEL of Section 28-T19S-R25E to test the Canyon formation. Authority for Expenditure costs for the 8300' test are $253,700 dry hole and $595,700 completed. Enclosed for your review are two (2) copies of the detailed AFE.

Please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson
Land Manager

RGP/mw

Enclosures

OTAL COSTS

MARTIN YATES, III
1912 - 1985
FRANK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

S. P. YATES
CHAIRMAN OF THE BOARD
JOHN A. YATES
PRESIDENT
PEYTON YATES
EXECUTIVE VICE PRESIDENT
RANDY G. PATTERSON
SECRETARY
DENNIS G. KINSEY
TREASURER

RECEIVED
MAR - 8 1995

March 6, 1995

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

TO WORKING INTEREST OWNERS
ADDRESSEE LIST ATTACHED

RE: **Aspden "AOH" Federal Com #3**
Township 19 South, Range 25 East
Section 29: NW/4
Eddy County, New Mexico

Gentlemen:

Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation proposes the drilling of the captioned well at a location 1,980' FNL and 1,980' FWL of Section 29, T19S-R25E to a depth of 8,300' to test the Canyon formation. Authority for Expenditure costs for the 8,300' test are $238,745 dry hole and $508,745 completed. We invite you to join with us in drilling this well. Enclosed for your consideration are two copies of the detailed AFE.

If satisfactory, please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson
Land Manager

RGP/dep
Encl.

15

MARTIN YATES, III
1912 - 1985
FRANK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION
105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

S. P. YATES
CHAIRMAN OF THE BOARD
JOHN A. YATES
PRESIDENT
PEYTON YATES
EXECUTIVE VICE PRESIDENT
RANDY G. PATTERSON
SECRETARY
DENNIS G. KINSEY
TREASURER

RECEIVED
MAR - 8 1995

March 6, 1995

To: Working Interest Owners
Addressee List Attached

Re: Patriot AIZ #7
Township 19 South, Range 25 East
Section 21: SE/4
Eddy County, New Mexico

Gentlemen:

Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation proposes the drilling of the captioned well. The proposed footage location is 1980' FSL and 1980' FEL of Section 21-T19S-R25E to test the Canyon formation. Authority for Expenditure costs for the 8300' test are $253,700 dry hole and $595,700.00 completed. Enclosed for your review are two (2) copies of the detailed AFE.

Please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson
Land Manager

RGP:de
enclosure(s)

MARTIN YATES, III
1912 - 1985
FRANK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

MAR - 8 1995

March 7, 1995

Attention: Bob Shelton
Nearburg Exploration Company
3300 North "A" Street
Building 2, Suite 120
Midland, Texas 79705

Attention: District Manager
Conoco, Inc.
10 Desta Drive, Suite 100 West
Midland, TX 79705-4500

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

RE: Dagger Draw 31 Federal #8
Township 19 South, Range 25 East, NMPM
Section 31: NE/4
Eddy County, New Mexico

Gentlemen:

Pursuant to that certain Operating Agreement dated March 8, 1991, Yates Petroleum Corporation proposes the drilling of the captioned at a location of 1980' FNL and 1980' FEL of Section 31, Township 19 South, Range 25 East. Approximate Authority for Expenditure costs for the 8,300' Canyon test are $253,700 dry hole and $685,700 completed.

Enclosed for your review are two (2) copies of the AFE. If this meets with your approval, please execute and timely return one (1) copy to our office if you desire to join and drill.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson
Land Manager

RGP/jrw
Enclosures

MARTIN YATES, III
1912 - 1985
FRANK W. YATES
1936 - 1986

PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

PRESIDENT
PEYTON YATES
EXECUTIVE VICE PRESIDENT
RANDY G. PATTERSON
SECRETARY
DENNIS G. KINSEY
TREASURER

RECEIVED
MAR - 8 1995

17

March 7, 1995

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

TO WORKING INTEREST OWNERS
ADDRESSEE LIST ATTACHED

RE: **Ross "EG" Federal Com #15**
Township 19 South, Range 25 East
Section 20: NE/4
Eddy County, New Mexico

Gentlemen:

Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation proposes the drilling of the captioned well at a location 860' FNL and 1,780' FEL of Section 20, T19S-R25E to a depth of 8,300' to test the Canyon formation. Authority for Expenditure costs for the 8,300' test are $253,700 dry hole and $595,700 completed. We invite you to join with us in drilling this well. Enclosed for your consideration are two copies of the detailed AFE.

If satisfactory, please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson
Land Manager

RGP/dep
Encl.

TOTAL COSTS	253,700	595,700

APPROVAL OF THIS AFE CONSTITUTES APPROVAL OF OPERATOR'S OPTION TO CHARGE THE JOINT ACCOUNT WITH TUBULAR GOODS FROM THE OPERATOR'S WAREHOUSE STOCK AT THE RATES STATED ABOVE.

10

MARTIN YATES, III
1912 - 1985
FRANK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

S. P. YATES
CHAIRMAN OF THE BOARD
JOHN A. YATES
PRESIDENT
PEYTON YATES
EXECUTIVE VICE PRESIDENT
RANDY G. PATTERSON
SECRETARY
DENNIS G. KINSEY
TREASURER

RECEIVED
MAR - 8 1995

March 6, 1995

To: Working Interest Owners
Addressee List Attached

Re: Patriot AIZ #6
Township 19 South, Range 25 East
Section 21: SE/4
Eddy County, New Mexico

Gentlemen:

Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation proposes the drilling of the captioned well. The proposed footage location is 1980' FSL and 660' FEL of Section 21-T19S-R25E to test the Canyon formation. Authority for Expenditure costs for the 8300' test are $253,700 dry hole and $595,700.00 completed. Enclosed for your review are two (2) copies of the detailed AFE.

Please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson
Land Manager

RGP:de
enclosure(s)

186

MARTIN YATES, III
1912 - 1985
FRANK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

S. P. YATES
CHAIRMAN OF THE BOARD
JOHN A. YATES
PRESIDENT
PEYTON YATES
EXECUTIVE VICE PRESIDENT
RANDY G. PATTERSON
SECRETARY
DENNIS G. KINSEY
TREASURER

RECEIVED
MAR - 8 1995

March 7, 1995

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

TO WORKING INTEREST OWNERS
ADDRESSEE LIST ATTACHED

RE: **Hooper "AMP" Com #4**
Township 19 South, Range 25 East
Section 20: NE/4
Eddy County, New Mexico

Gentlemen:

By letter dated March 1, 1995 we received Nearburg's proposal for the drilling of a well at a location 660' FNL and 660' FEL of Section 20, T19S-R25E. Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation, as operator, hereby proposes the drilling of the captioned well at a location 660' FNL and 660' FEL of Section 20, T19S-R25E to a depth of 8,300' to test the Canyon formation. Authority for Expenditure costs for the 8,300' test are $253,700 dry hole and $595,700 completed. We invite you to join with us in drilling this well. Enclosed for your consideration are two copies of the detailed AFE.

If satisfactory, please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson
Land Manager

RGP/dep
Encl.

MARTIN YATES, III
1912 - 1985
FRANK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION
105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

S. P. YATES
CHAIRMAN OF THE BOARD
JOHN A. YATES
PRESIDENT
PEYTON YATES
EXECUTIVE VICE PRESIDENT
RANDY G. PATTERSON
SECRETARY
DENNIS G. KINSEY
TREASURER

March 6, 1995

RECEIVED
MAR - 8 1995

To: Working Interest Owners
Addressee List Attached

Re: Cutter APC #1
Township 19 South, Range 25 East
Section 21: SE/4
Eddy County, New Mexico

Gentlemen:

Pursuant to the Operating Agreement covering the captioned acreage, Yates Petroleum Corporation proposes the drilling of the captioned well. The proposed footage location is 660' FSL and 660' FEL of Section 21-T19S-R25E to test the Canyon formation. Authority for Expenditure costs for the 8300' test are $253,700 dry hole and $685,700.00 completed. Enclosed for your review are two (2) copies of the detailed AFE.

Please indicate your election to join by signing and returning one copy of the AFE to our office.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G. Patterson
Land Manager

RGP:de
enclosure(s)

TOTAL COSTS	253,700	685,700

MARTIN YATES, III
1912 - 1985
FRANK W. YATES
1936 - 1986

YATES PETROLEUM CORPORATION

105 SOUTH FOURTH STREET
ARTESIA, NEW MEXICO 88210
TELEPHONE (505) 748-1471

S. P. YATES
CHAIRMAN OF THE BOARD
JOHN A. YATES
PRESIDENT
PEYTON YATES
EXECUTIVE VICE PRESIDENT
RANDY G. PATTERSON
SECRETARY
DENNIS G. KINSEY
TREASURER

March 9, 1995

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

RECEIVED
MAR 10 1995

Nearburg Exploration Company
3300 North 'A' Street
Bldg 2 Suite 120
Midland, Texas 79705

RE: Big Walt 2 State Com #4
Township 22 South, Range 24 East
Section 2: E/2
Eddy County, New Mexico

Gentlemen:

Yates Petroleum Corporation proposes drilling the Big Walt 2 State Com #4 well to a depth of 8,800' to test the Canyon formation at a location 1,980' FNL and 660' FEL of Section 2, T22S-R24E, Eddy County, New Mexico. Estimated costs for drilling this test are $408,800 dry hole and $832,600 completed. An Authority for Expenditure in duplicate is enclosed for your consideration. We invite you to join with us in drilling this well.

If satisfactory, please sign and return one copy of the enclosed AFE.

Thank you.

Very truly yours,

YATES PETROLEUM CORPORATION

Randy G Patterson

Randy G. Patterson JR
Land Manager

RGP/dep
Encl.

TOTAL COSTS	408,800	832,600