CASE 7426: PHILLIPS PETROLEUM COMPANY FOR AMENDMENT OF DIVISION ORDER NO. R-5897 AND CERTIFICATION OF A TERTIARY RECOVERY PROJECT, LEA COUNTY, NEW MEX. any

DOCKET MAILED

Date 11/6/81

CASE NO.

7426

APPLICATION,
Transcripts,
mall Exhibits,

ETC.

PHILLIPS PETROLEUM COMPANY

ODESSA, TEXAS 79762
4001 PENBROOK

EXPLORATION AND PRODUCTION GROUP

RECEIVED
OCT 20 1986
OIL CONSERVATION DIVISION
SANTA FE

October 8, 1986

East Vacuum Grayburg-San Andres Unit
Carbon Dioxide Injection Project
Lea County, New Mexico

Case File 7426

New Mexico Oil Conservation Division
Attn: Mr. Jerry Sexton
P. O. Box 1980
Hobbs, New Mexico 88240

Dear Mr. Sexton:

As authorized by New Mexico Oil Conservation Division Order No. R-6856, carbon dioxide injection is presently in progress in the East Vacuum Grayburg-San Andres Unit.

CO_2 injection into WAG Area C began in June of this year and we are currently in the process of transferring CO_2 back to WAG Area A. While CO_2 was being injected into Area C, bottom hole injection pressure surveys were run. The results of these surveys are attached. Please note that, with one exception, these injectors have bottom hole injection pressures below the formation parting pressure or the bottom hole pressure limitation of 3150 psi, whichever is applicable. (Three of these wells have a bottom hole pressure limitation of 4000 psi, as approved by Mr. Stamets' letter of May 27, 1986.)

The one exception is Tract 3202, Well No. C011. The data shows the bottom hole injection pressure to be 3302 psi. We have restricted injection into this well to get back within the limitation of 3150 psi. A step-rate test run in May of this year showed this well to have a formation parting pressure of 4300 psi. For this reason, it is felt that we have not damaged the formation as yet and we are making application to the Director of the NMOCD to increase the pressure limitation in this well. Until such approval is received for this increase, we will continue to restrict CO_2 injection into this well.

If you have any questions concerning this matter, please contact Mr. Mike Brownlee in Odessa at (915) 367-1413.

Very truly yours,

G. R. Smith

G. R. Smith, Director
Reservoir Engineering

MHB:jj

Attachments

cc: New Mexico Oil Conservation Division
Attn: Mr. R. L. Stamets
P. O. Box 2088
Santa Fe, New Mexico 87501

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Summary of CO_2 Injection BHP Survey Results
WAG Area C

TRACT-WELL	CO_2 INJ. RATE MSCF/D	DEPTH OF TOP PERFORATION	INJECTION PRESSURE, PSI SURFACE	INJECTION PRESSURE, PSI BOTTOM HOLE*	BOTTOM HOLE* PARTING PRESSURE** PSI
0524C001	3167	4400'	792	2350	3613
2913C007****	651	4508'	1574	3221	4760
2913C008	549	4504'	856	2320	3675
2913C009	63	4520'	989	2516	3975
2941C001	491	4492'	1475	3093	4085
2947C001****	234	4552'	1093	2655	4700
2963C004	257	4395'	526	1804	3463***
2980C003****	246	4580'	1723	3398	4090
3202C008	3481	4366'	939	2458	3540
3202C009	1759	4395'	1387	2978	3650
3202C011	848	4354'	1508	3302	4300
3229C006	3615	4365'	1146	2424	4000
3229C007	1663	4345'	729	2120	3732***
3229C008	4033	4330'	1113	2631	3710
3236C006	3615	4383'	1080	2404	4171***

* At depth of top perforation

** Parting pressures obtained from step rate tests, run using water as the injection fluid

*** No identifiable parting pressure was observed; this is the maximum bottom hole pressure achieved during the step rate test.

**** These wells have bottom hole injection (CO_2) pressure limitations of 4000 psi.

MB/sdb
RE6.2/evg24

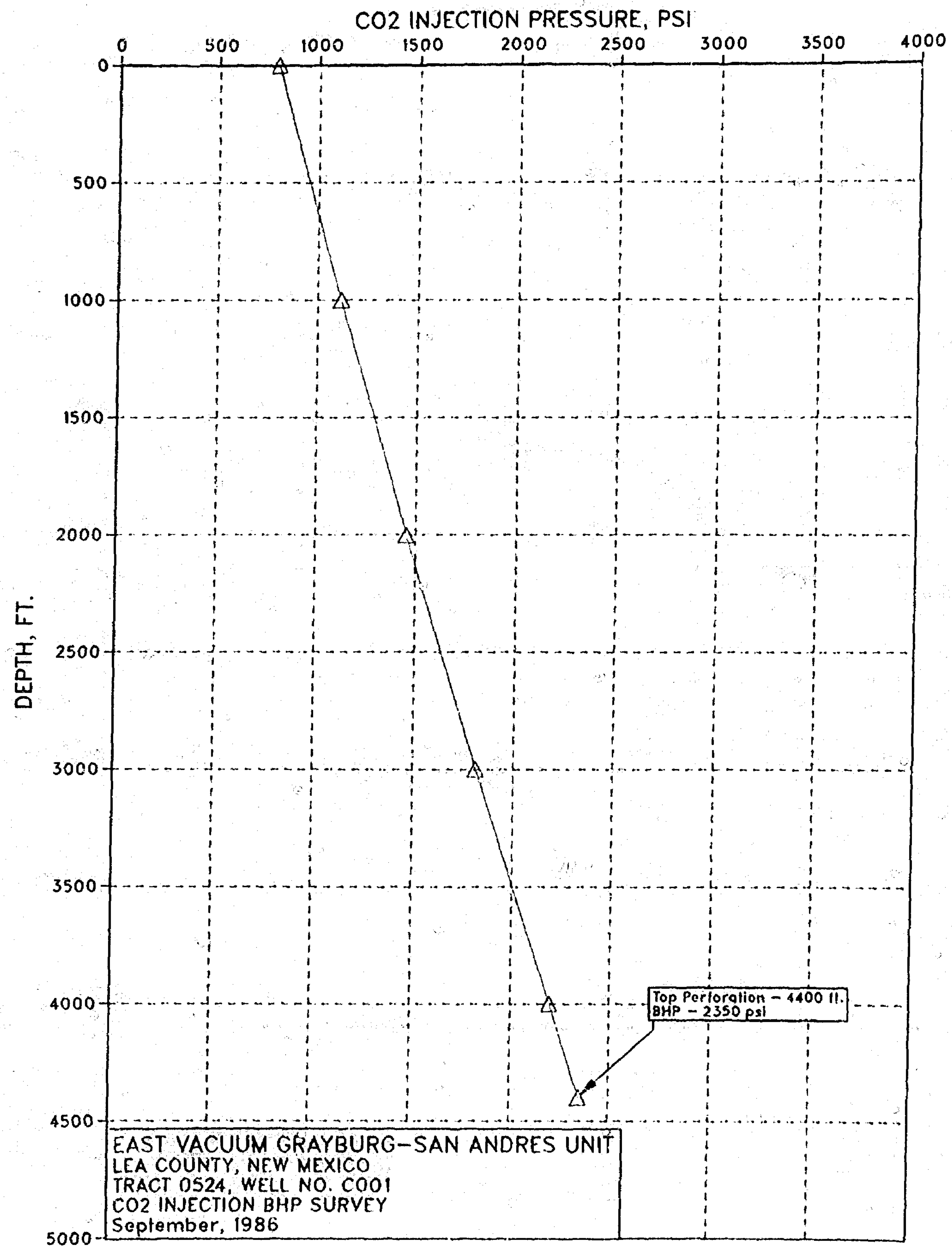
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 0524, Well No. C001

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	792	
1,000	1,113	0.321
2,000	1,453	0.340
3,000	1,808	0.355
4,000	2,196	0.388
4,400 (Top Perf)	2,350	0.395

CO_2 Injection Rate = 3167 MSCF/D

RE6.2/evg5


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation – 4400 ft.
BHP – 2350 psi
EAST VACUUM GRAYBURG–SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 0524, WELL NO. C001
CO2 INJECTION BHP SURVEY
September, 1986

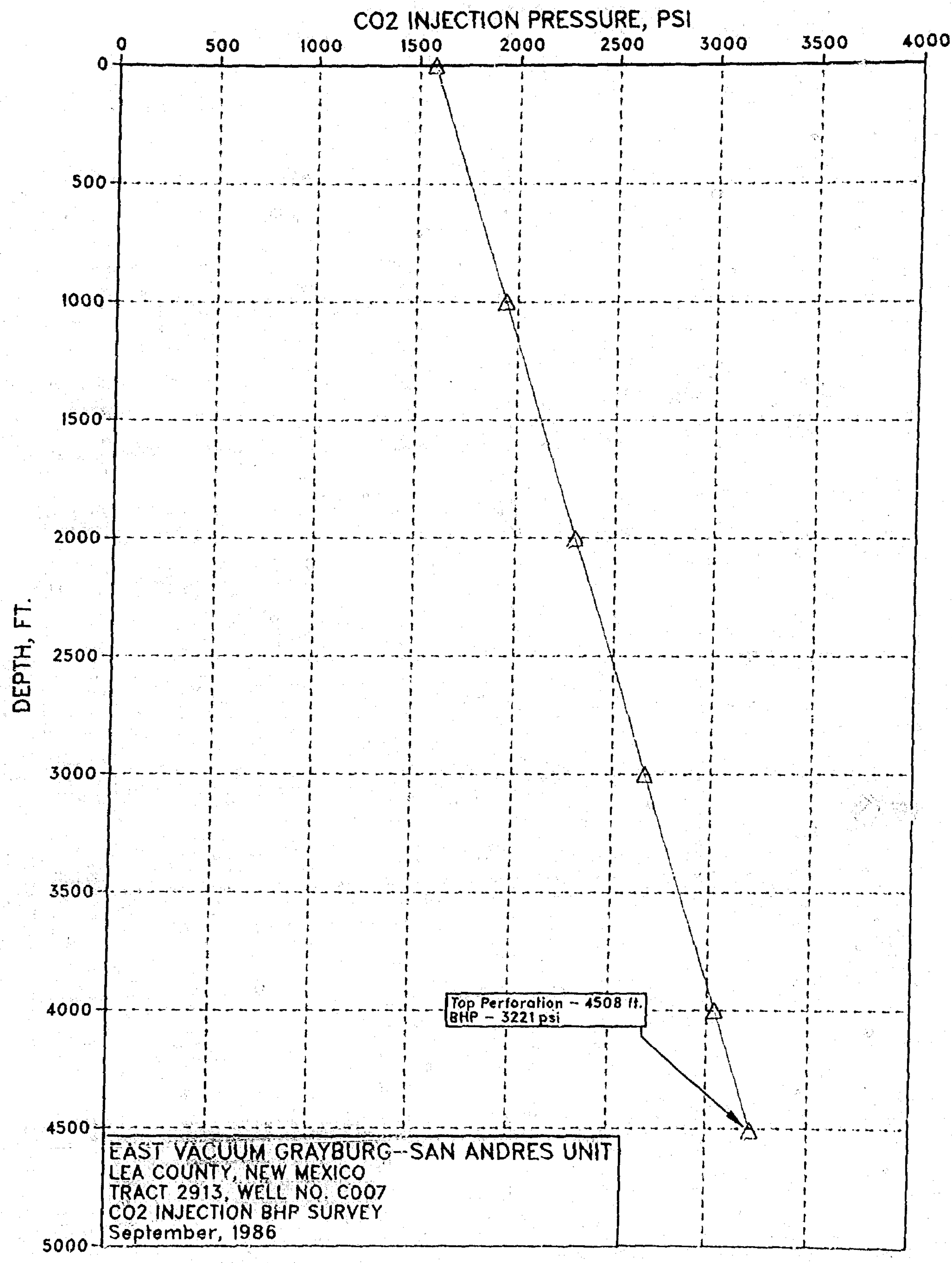
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 2913, Well No. C007

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,574	
1,000	1,940	0.366
2,000	2,303	0.363
3,000	2,669	0.366
4,000	3,038	0.369
4,508 (Top Perf)	3,221	0.368

CO_2 Injection Rate = 651 MSCF/D

RE6.2/evg6


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation – 4508 ft.
BHP – 3221 psi
EAST VACUUM GRAYBURG–SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2913, WELL NO. C007
CO2 INJECTION BHP SURVEY
September, 1986

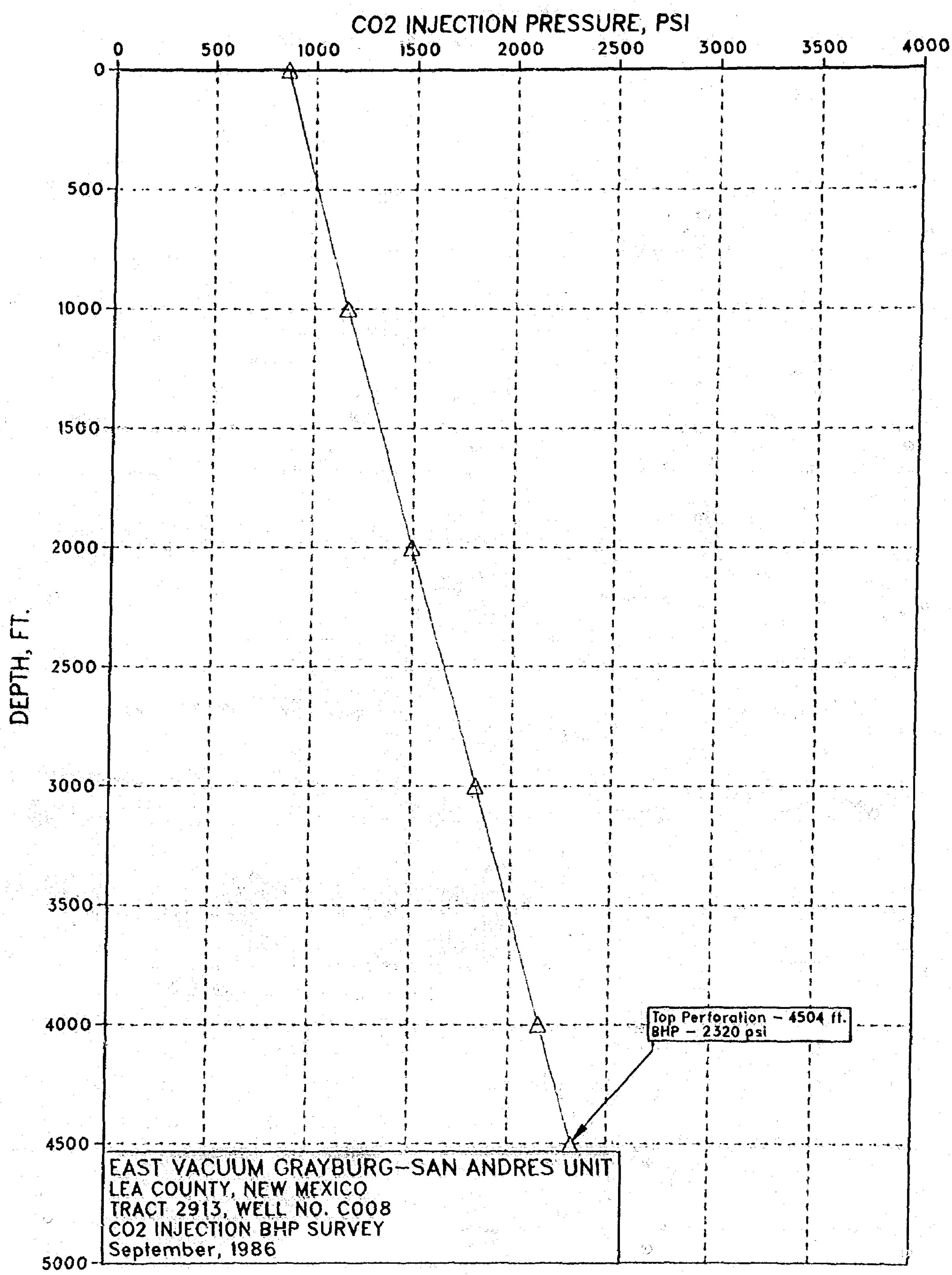
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 2913, Well No. C008

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	856	
1,000	1,165	0.309
2,000	1,495	0.330
3,000	1,821	0.326
4,000	2,152	0.331
4,504 (Top Perf)	2,320	0.339

CO_2 Injection Rate = 549 MSCF/D

RE6.2/evg7


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation - 4504 ft.
BHP - 2320 psi
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2913, WELL NO. C008
CO2 INJECTION BHP SURVEY
September, 1986

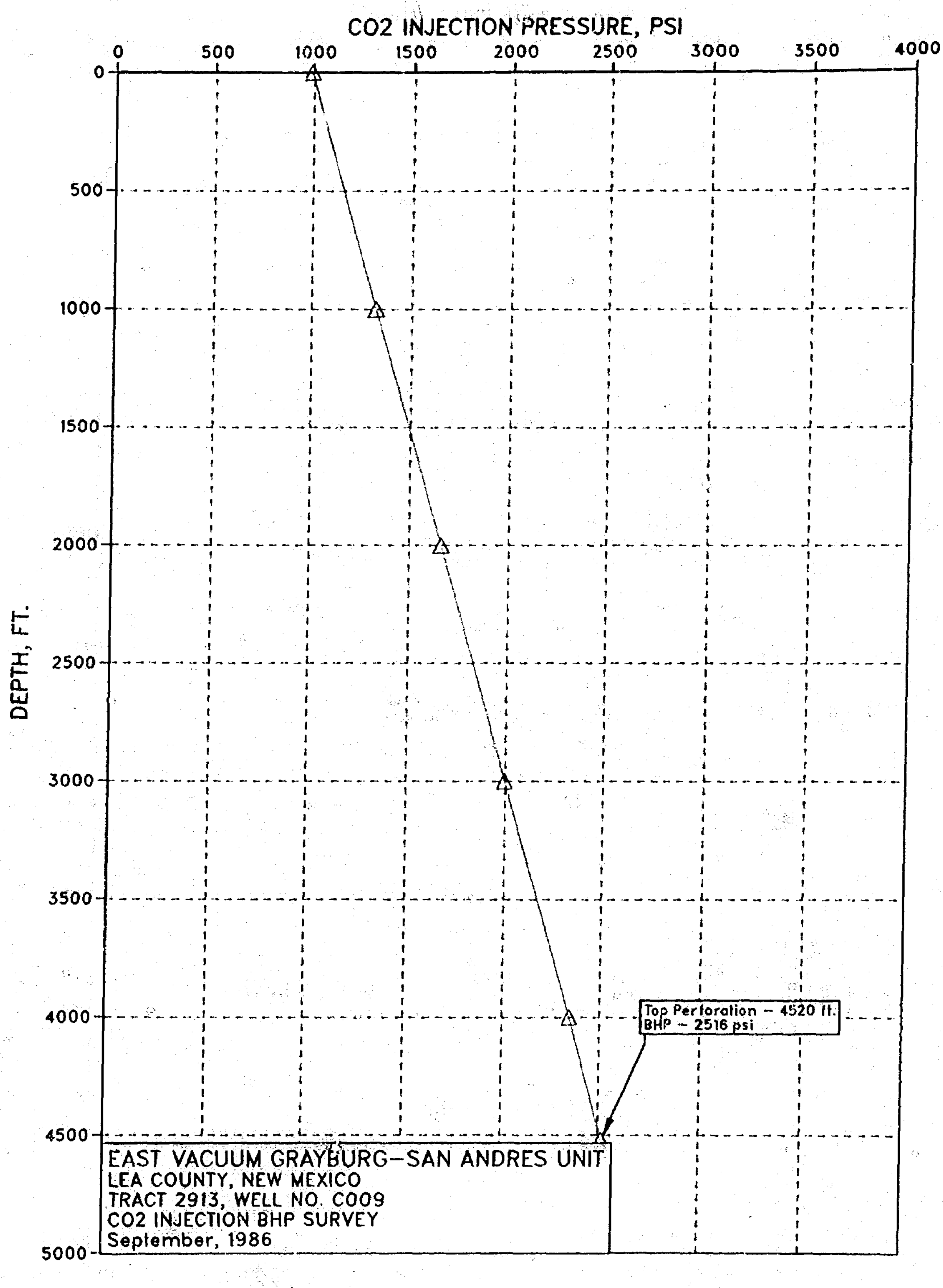
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 2913, Well No. C009

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	989	
1,000	1,324	0.335
2,000	1,659	0.335
3,000	1,995	0.336
4,000	2,339	0.344
4,520 (Top Perf)	2,516	0.349

CO_2 Injection Rate = 63 MSCF/D

RE6.2/evg8


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation – 4520 ft.
BHP – 2516 psi
EAST VACUUM GRAYBURG–SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2913, WELL NO. C009
CO2 INJECTION BHP SURVEY
September, 1986

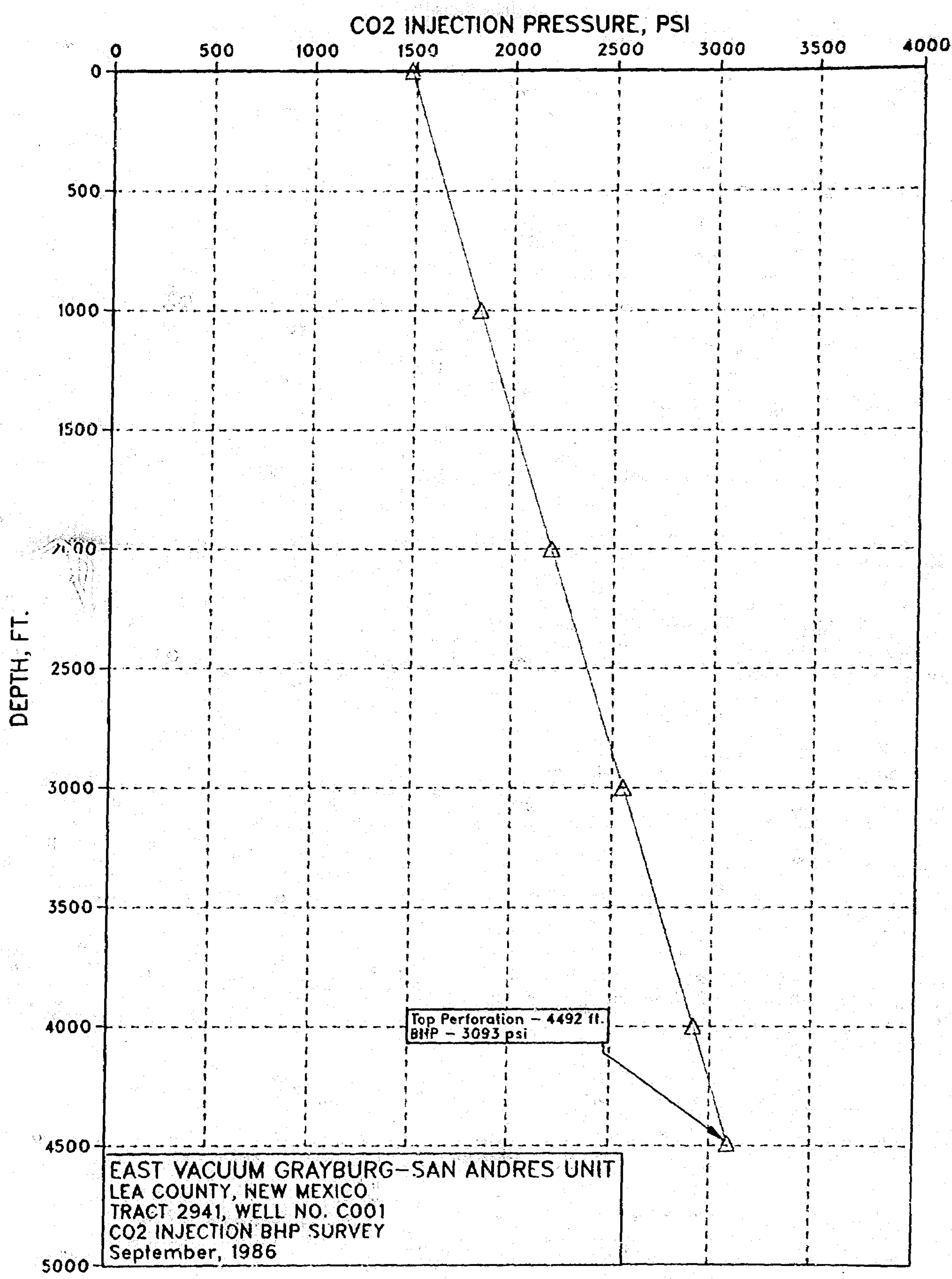
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 2941, Well No. C001

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,475	
1,000	1,832	0.357
2,000	2,193	0.361
3,000	2,551	0.358
4,000	2,915	0.364
4,492 (Top Perf)	3,093	0.370

CO_2 Injection Rate = 491 MSCF/D

RE6.2/evg9


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation – 4492 ft.
BHP – 3093 psi
EAST VACUUM GRAYBURG–SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2941, WELL NO. C001
CO2 INJECTION BHP SURVEY
September, 1986

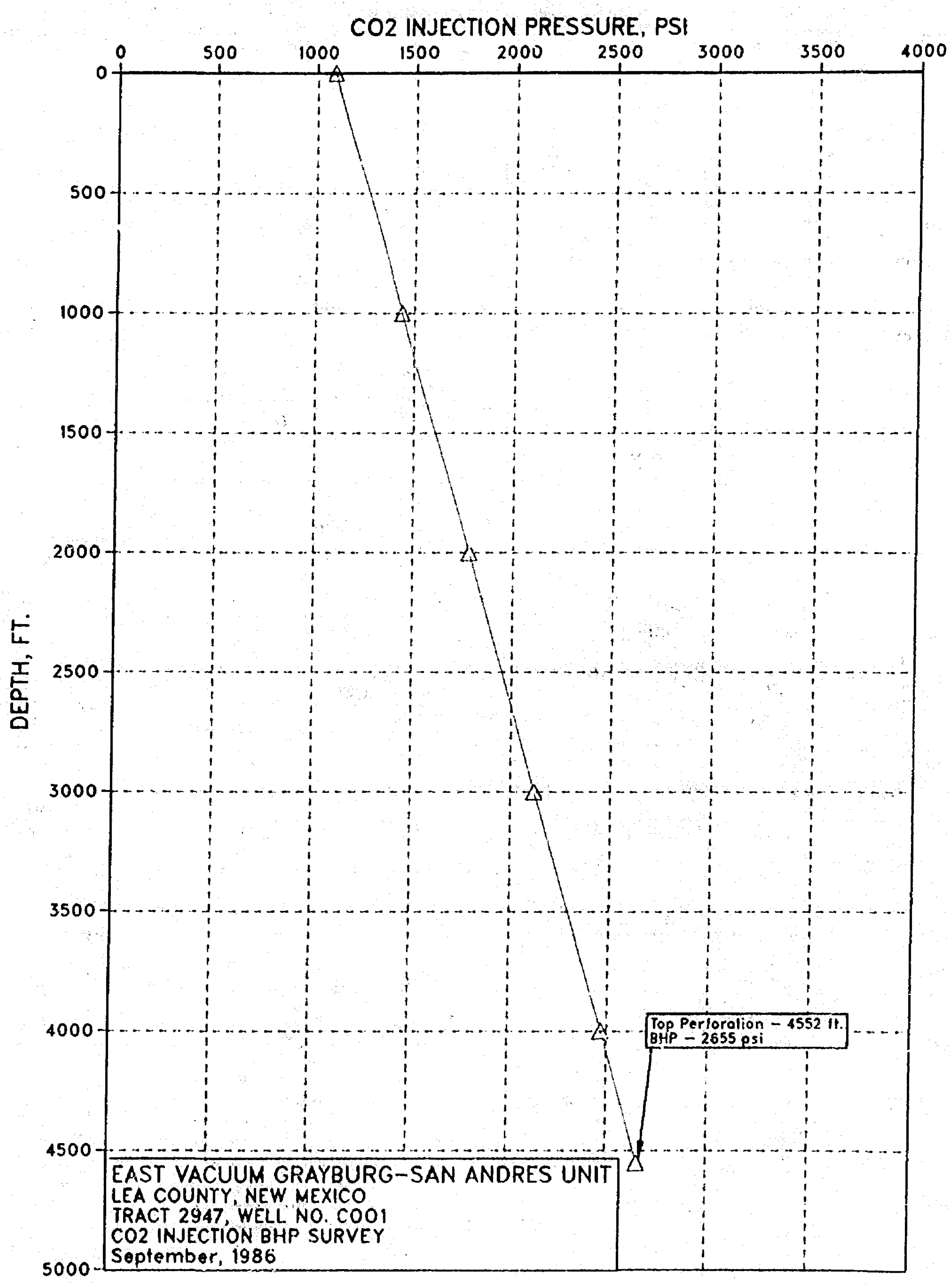
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 2947, Well No. C001

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,093	
1,000	1,434	0.341
2,000	1,780	0.346
3,000	2,121	0.341
4,000	2,471	0.350
4,552 (Top Perf)	2,655	0.341

CO_2 Injection Rate = 234 MSCF/D

RE6.2/evg10



CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation – 4552 ft.
BHP – 2655 psi
EAST VACUUM GRAYBURG–SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2947, WELL NO. C001
CO2 INJECTION BHP SURVEY
September, 1986

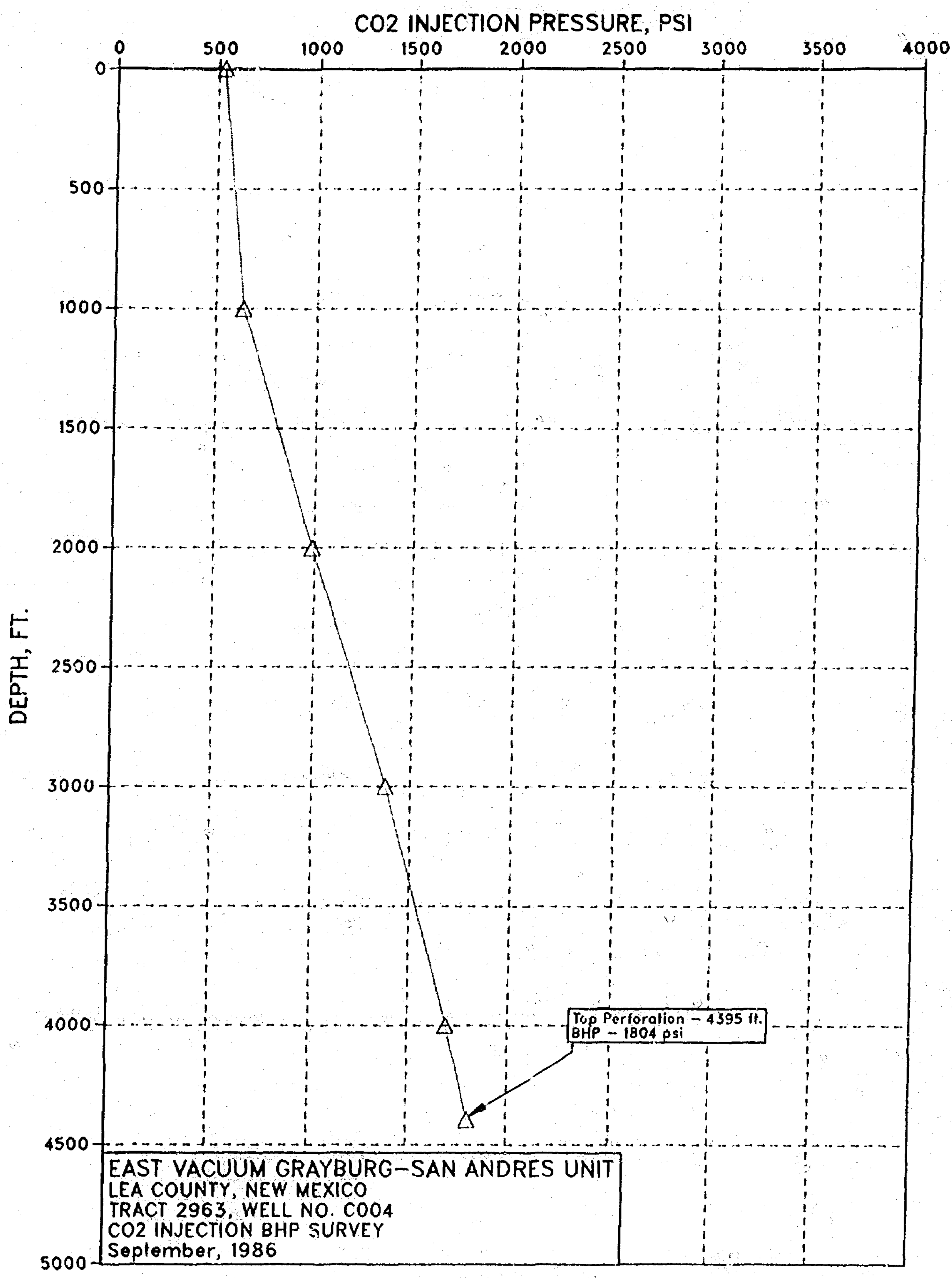
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 2963, Well No. C004

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	526	
1,000	632	0.106
2,000	986	0.354
3,000	1,374	0.388
4,000	1,690	0.316
4,395 (Top Perf)	1,804	0.298

CO_2 Injection Rate = 257 MSCF/D

RE6.2/evg11


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation – 4395 ft.
BHP – 1804 psi
EAST VACUUM GRAYBURG–SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2963, WELL NO. C004
CO2 INJECTION BHP SURVEY
September, 1986

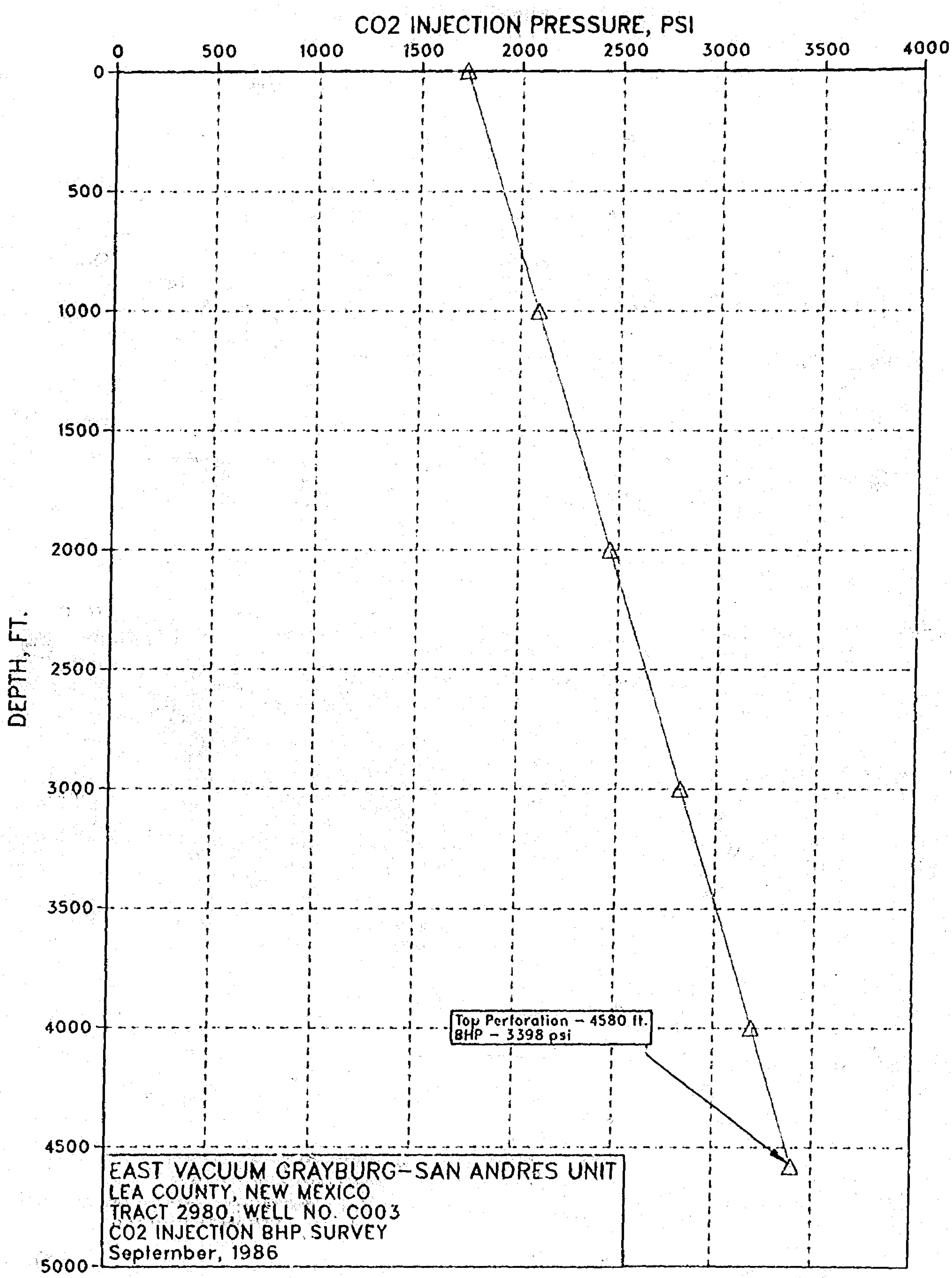
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 2980, Well No. C003

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,723	
1,000	2,091	0.368
2,000	2,457	0.366
3,000	2,824	0.367
4,000	3,192	0.368
4,580 (Top Perf)	3,398	0.361

CO_2 Injection Rate = 246 MSCF/D

RE6.2/evg12


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation – 4580 ft.
BHP – 3398 psi
EAST VACUUM GRAYBURG–SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2980, WELL NO. C003
CO2 INJECTION BHP SURVEY
September, 1986

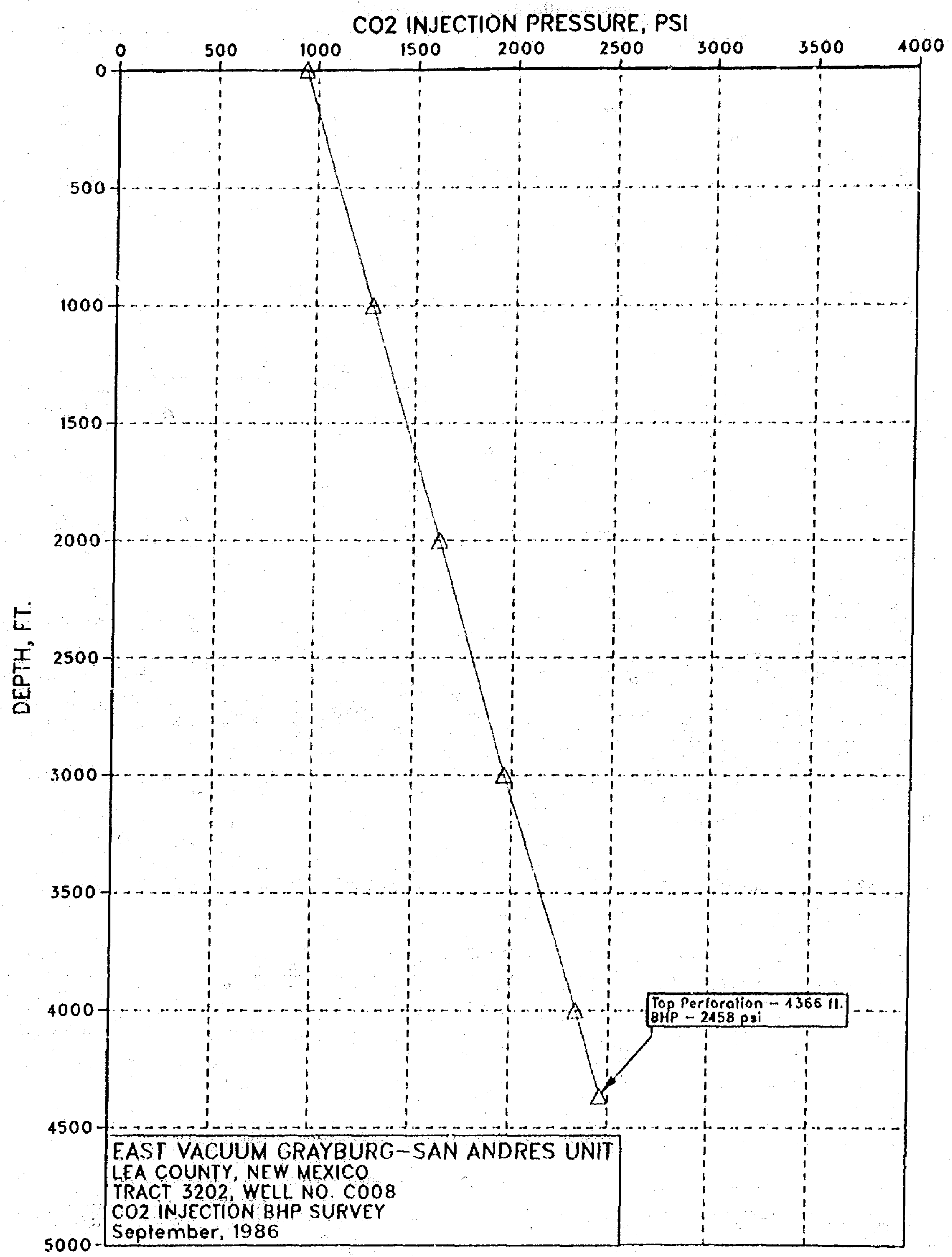
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3202, Well No. C008

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	939	
1,000	1,280	0.341
2,000	1,629	0.349
3,000	1,962	0.333
4,000	2,331	0.369
4,366 (Top Perf)	2,458	0.359

CO_2 Injection Rate = 3481 MSCF/D

RE6.2/evg13


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation - 4366 ft.
BHP - 2458 psi
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 3202, WELL NO. C008
CO2 INJECTION BHP SURVEY
September, 1986

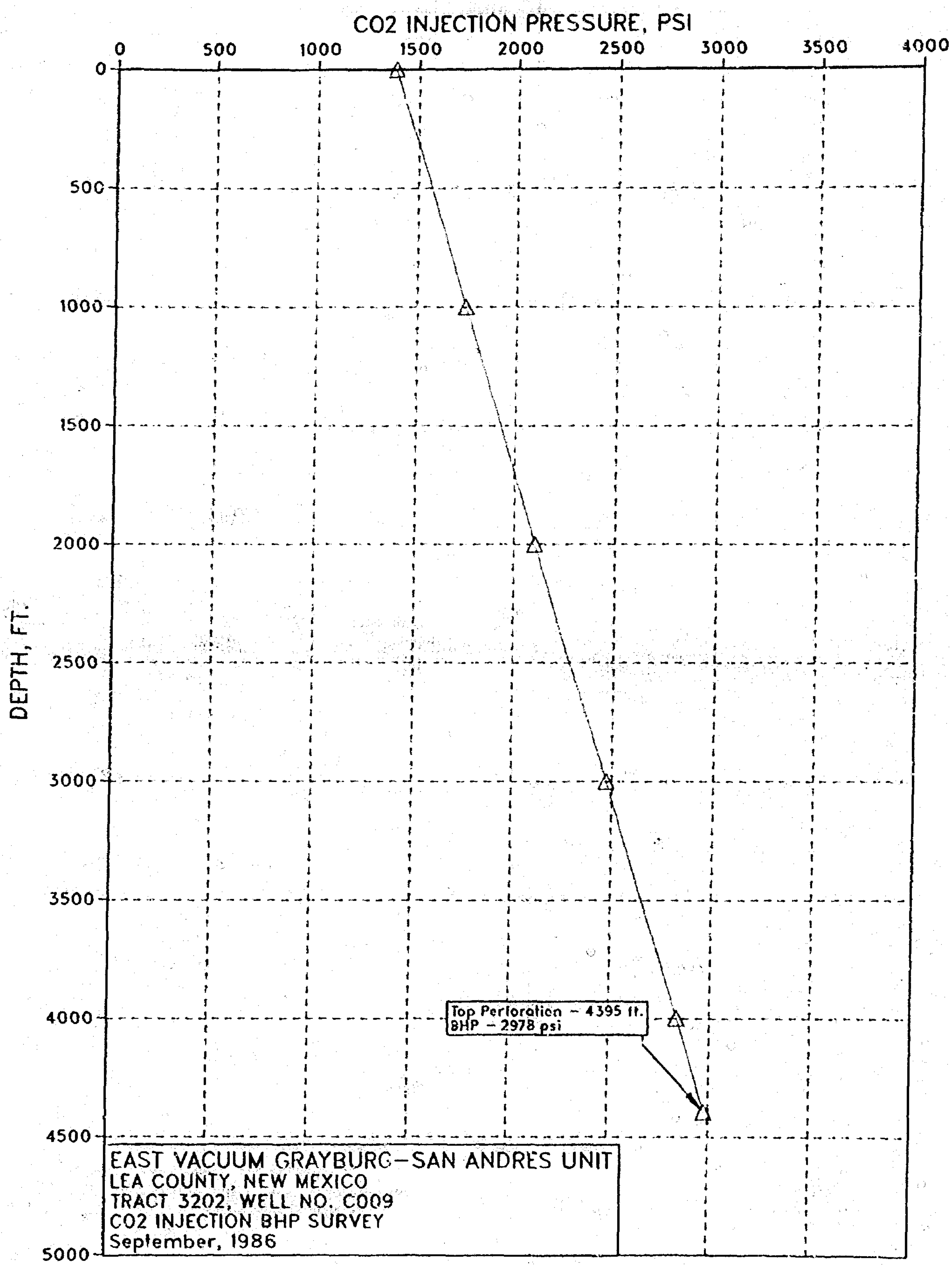
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3202, Well No. C009

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,387	
1,000	1,747	0.360
2,000	2,107	0.360
3,000	2,471	0.364
4,000	2,835	0.364
4,395 (Top Perf)	3,041	0.371

CO_2 Injection Rate = 1759 MSCF/D

RE6.2/evg14


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation - 4395 ft.
BHP - 2978 psi
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 3202, WELL NO. C009
CO2 INJECTION BHP SURVEY
September, 1986

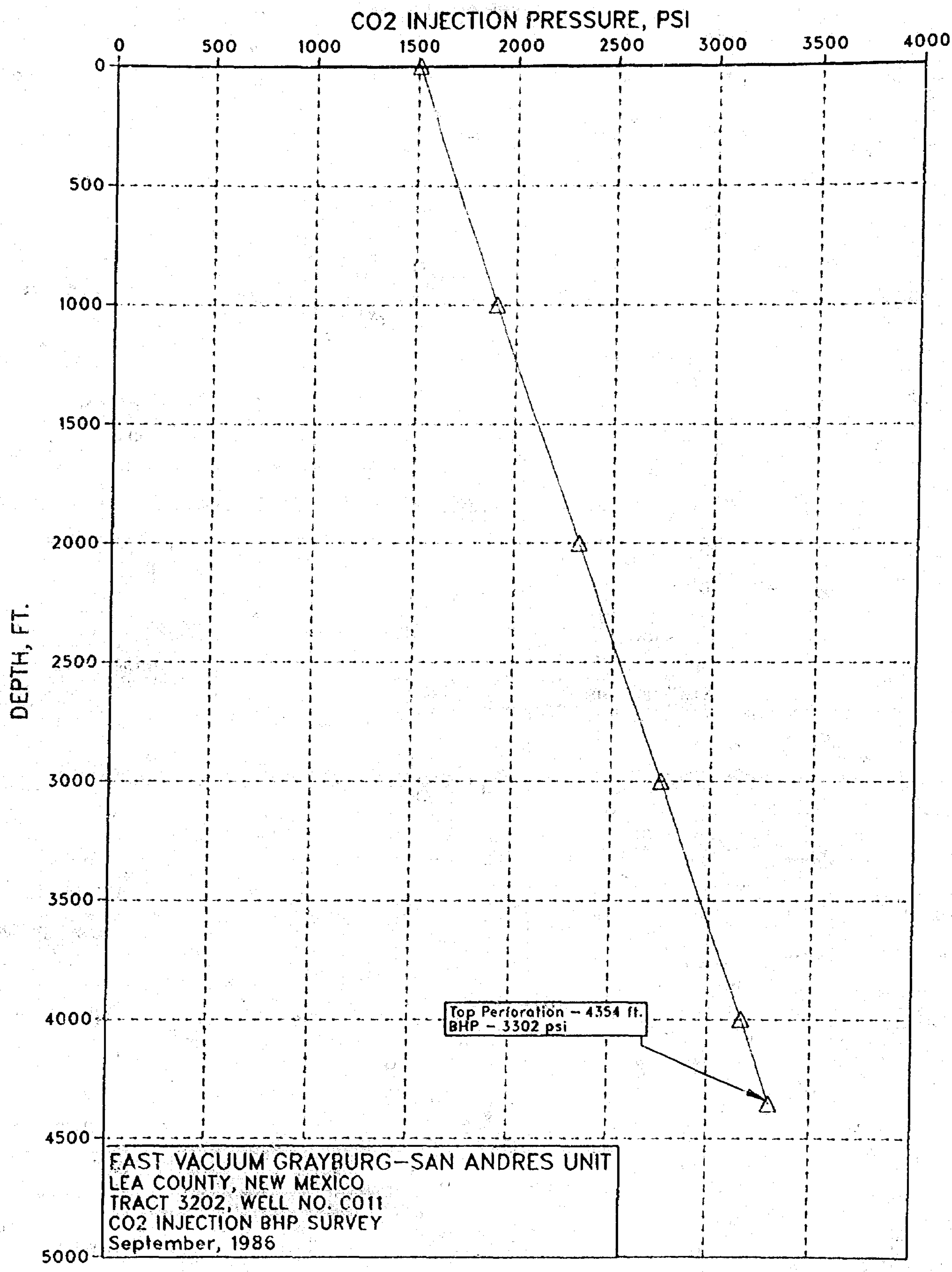
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3202, Well No. C011

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,508	
1,000	1,898	0.391
2,000	2,322	0.424
3,000	2,747	0.425
4,000	3,162	0.415
4,354 (Top Perf)	3,302	0.408

CO_2 Injection Rate = 848 MSCF/D

RE6.2/evg15


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation - 4354 ft.
BHP - 3302 psi
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 3202, WELL NO. C011
CO2 INJECTION BHP SURVEY
September, 1986

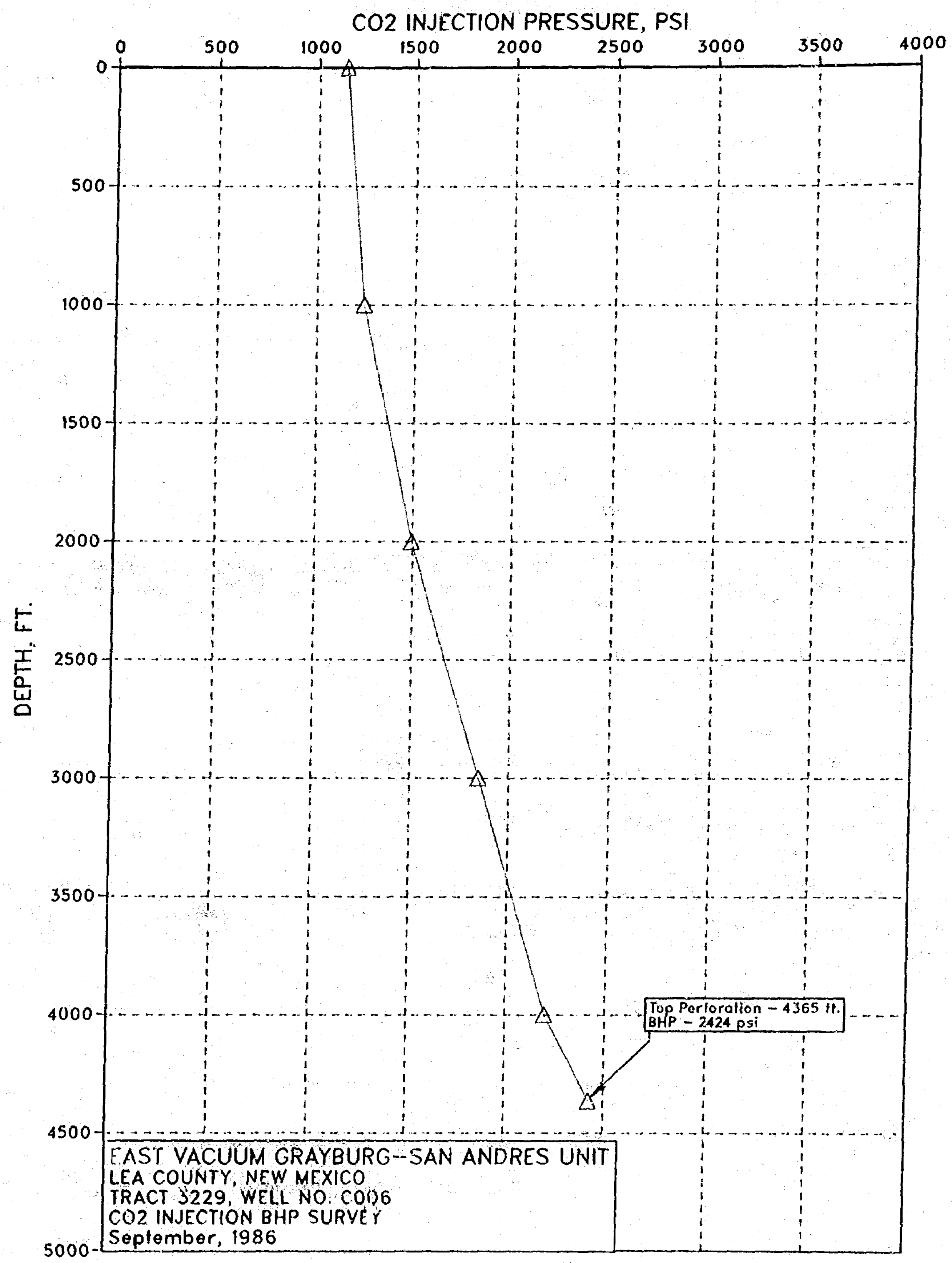
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3229, Well No. C006

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,146	
1,000	1,245	0.099
2,000	1,497	0.252
3,000	1,849	0.352
4,000	2,201	0.352
4,365 (Top Perf)	2,424	0.627

CO_2 Injection Rate = 3615 MSCF/D

RE6.2/evg16


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation – 4365 ft.
BHP – 2424 psi
EAST VACUUM GRAYBURG--SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 3229, WELL NO. C006
CO2 INJECTION BHP SURVEY
September, 1986

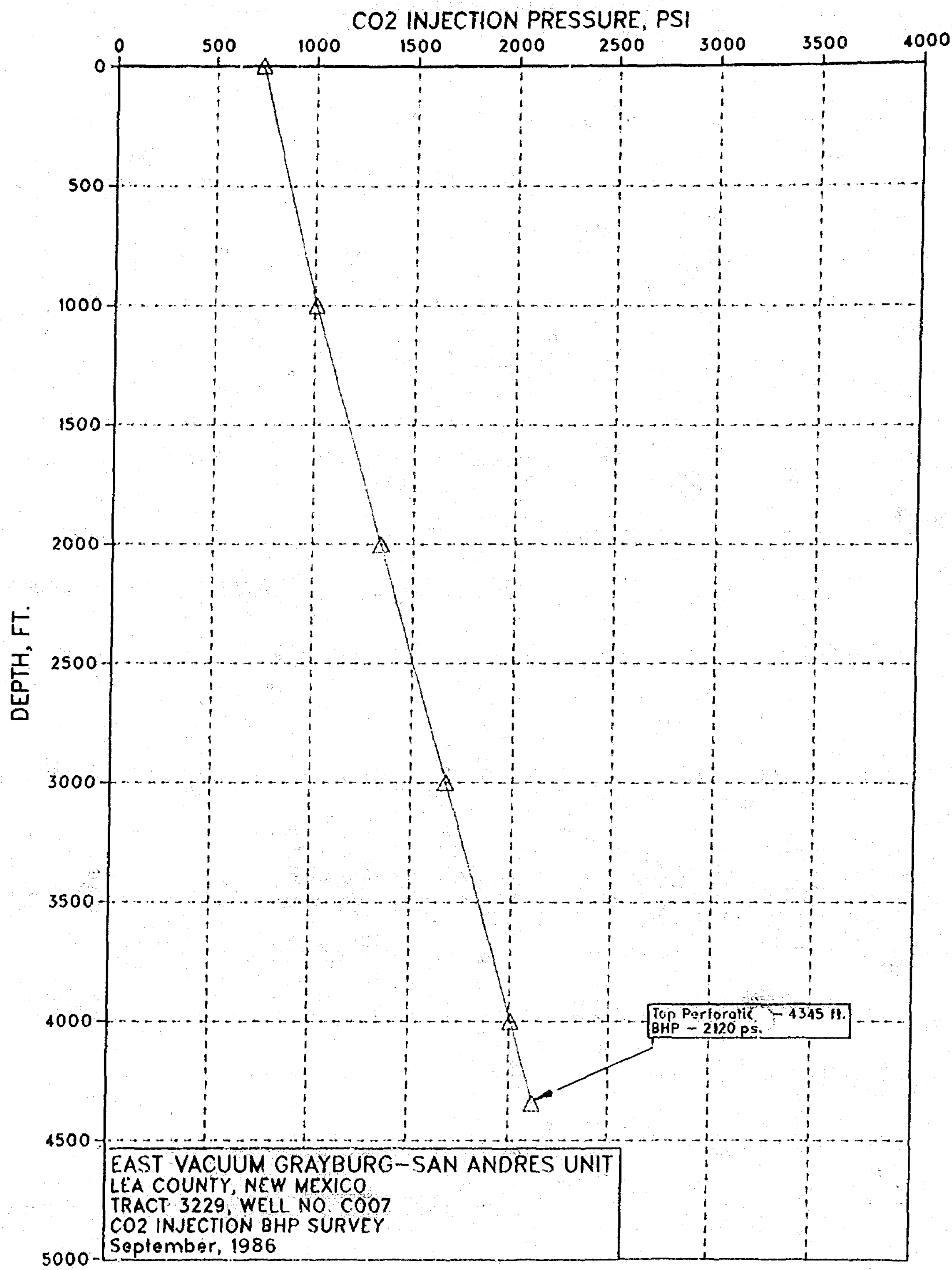
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3229, Well No. C007

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	729	
1,000	1,008	0.279
2,000	1,338	0.330
3,000	1,670	0.332
4,000	2,006	0.336
4,345 (Top Perf)	2,120	0.342

CO_2 Injection Rate = 1863 MSCF/D

RE6.2/evg17


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforatic — 4345 ft.
BHP — 2120 ps.
EAST VACUUM GRAYBURG–SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 3229, WELL NO. C007
CO2 INJECTION BHP SURVEY
September, 1986

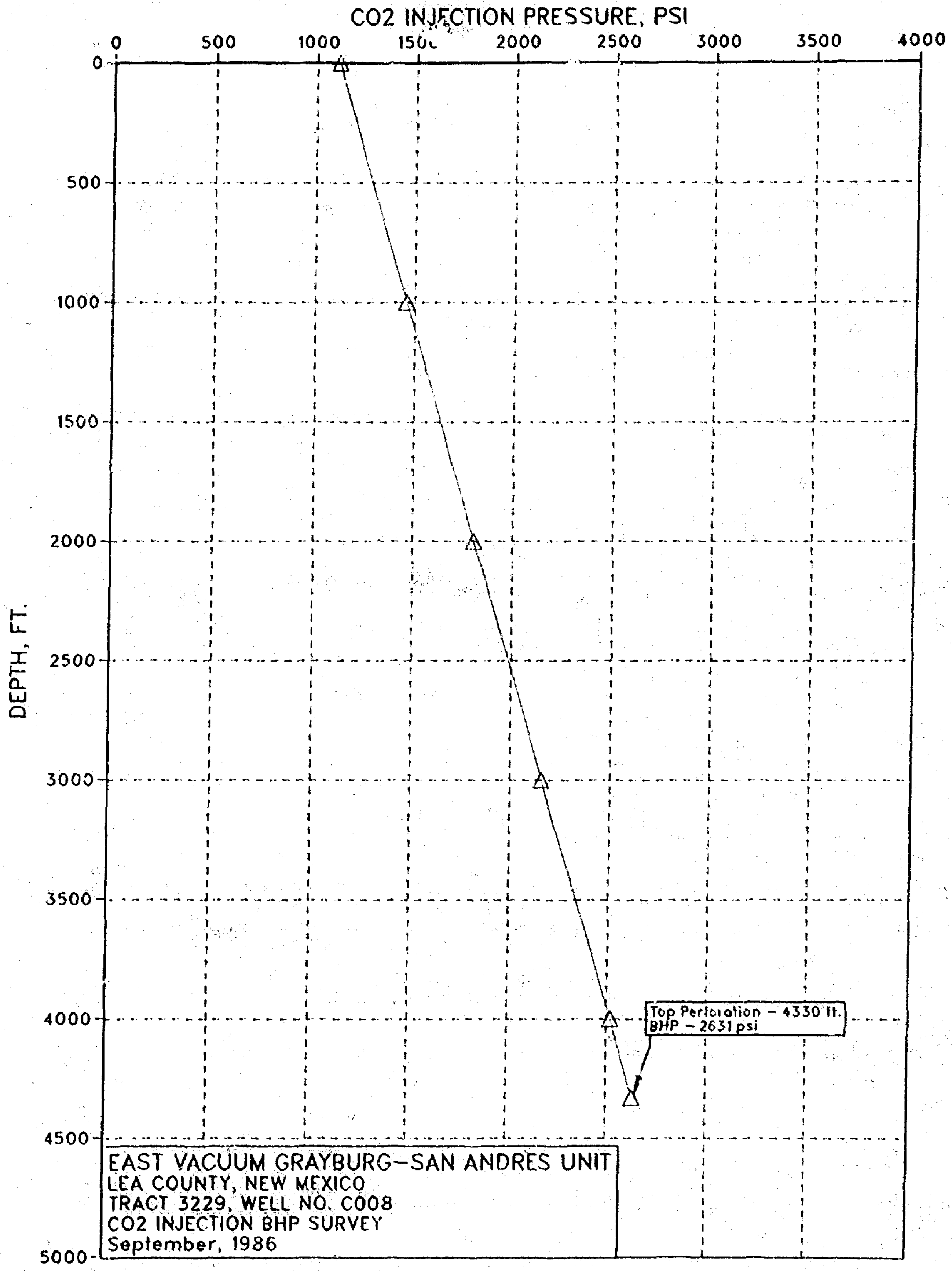
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3229, Well No. C008

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,113	
1,000	1,459	0.346
2,000	1,810	0.351
3,000	2,163	0.353
4,000	2,518	0.355
4,330 (Top Perf)	2,631	0.353

CO_2 Injection Rate = 4033 MSCF/D

RE6.2/evg18


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation - 4330 ft.
BHP - 2631 psi
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 3229, WELL NO. C008
CO2 INJECTION BHP SURVEY
September, 1986

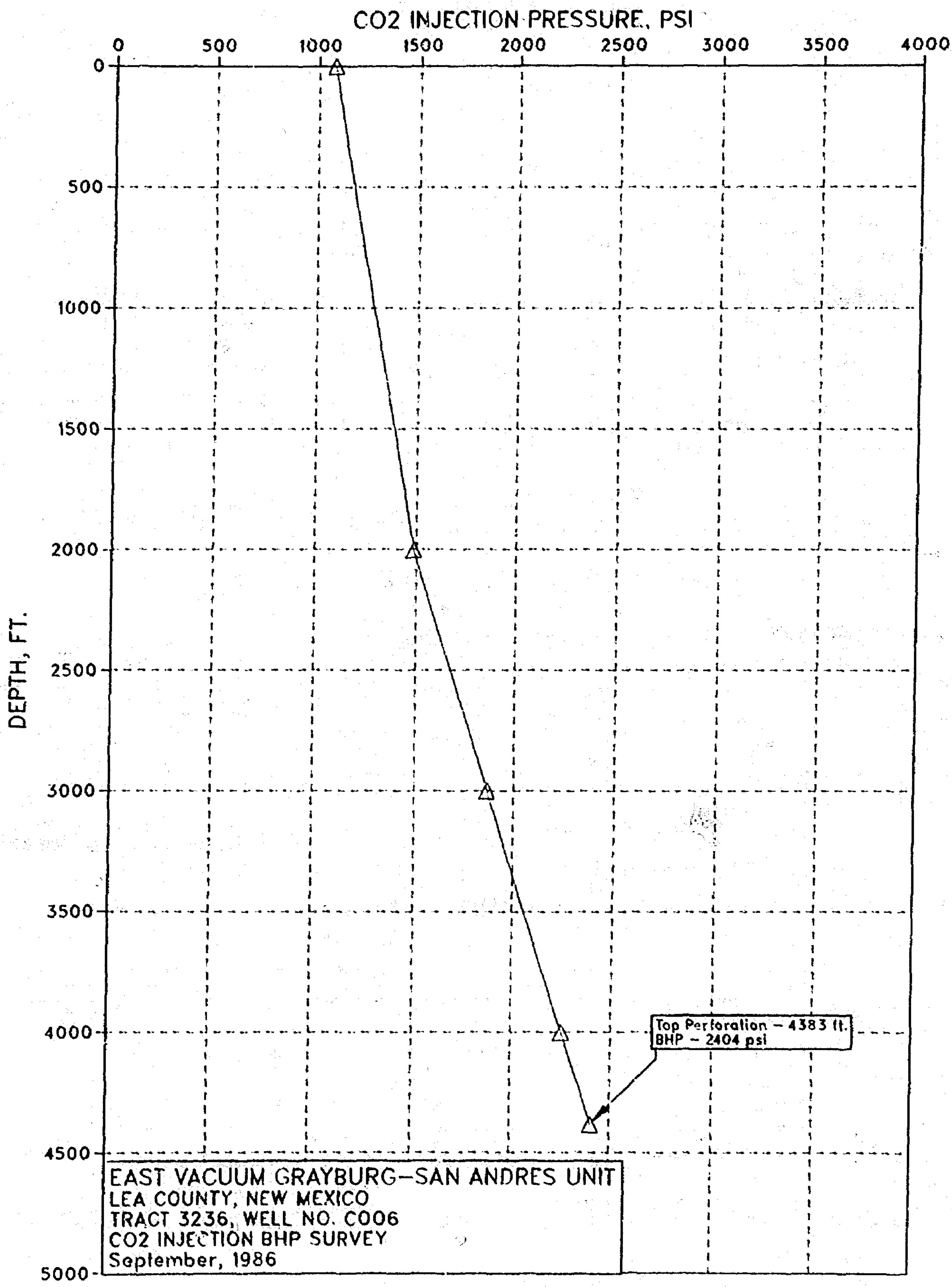
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3236, Well No. C006

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,080	
1,000	1,431	0.351
3,000	1,863	0.379
4,000	2,251	0.388
4,383 (Top Perf)	2,404	0.410

CO_2 Injection Rate = 3615 MSCF/D

RE6.2/evg19



CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT.
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation – 4383 ft.
BHP – 2404 psi
EAST VACUUM GRAYBURG–SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 3236, WELL NO. C006
CO2 INJECTION BHP SURVEY
September, 1986

PHILLIPS PETROLEUM COMPANY
ODESSA, TEXAS 79762
4001 PENBROOK

EXPLORATION AND PRODUCTION GROUP

October 8, 1986

East Vacuum Grayburg-San Andres Unit
Carbon Dioxide Injection Project
Lea County, New Mexico

Case-7426

New Mexico Oil Conservation Division
Attn: Mr. Jerry Sexton
P. O. Box 1980
Hobbs, New Mexico 88240

Dear Mr. Sexton:

My letter to you on this subject dated June 9, 1986, presented fourteen step-rate tests run in WAG Area C. That letter also stated that two injectors were currently shut in pending remedial work. That work has subsequently been completed and step-rate tests have been run on those two wells: Tract 3127, Well No. 004 and Tract 3202, Well No. 010. With the submission of the attached results of these tracts, a step-rate test has been run on every WAG injector.

The bottom hole formation parting pressure identified for 3127-004 is 3250 psi. We shall restrict the bottom hole injection pressure so as not to exceed the pressure limitation of 3150 psi. Notice, however, that the bottom hole parting pressure for 3202-010 is less than the limitation. In order to keep from parting the formation during injection, we will restrict CO_2 injection to a bottom hole parting pressure of less than 3050 psi. You will also note that the surface parting pressure is 1250 psi. Since this test was run with water and the resulting surface parting pressure is less than our limitation of 1350 psi, we will restrict water injection to a surface injection pressure of 1250 psi or less in this well.

If you have any questions concerning this matter, please call Mr. Mike Brownlee at (915) 367-1413.

Very truly yours,

G. R. Smith

G. R. Smith, Director
Reservoir Engineering

MHB:jj

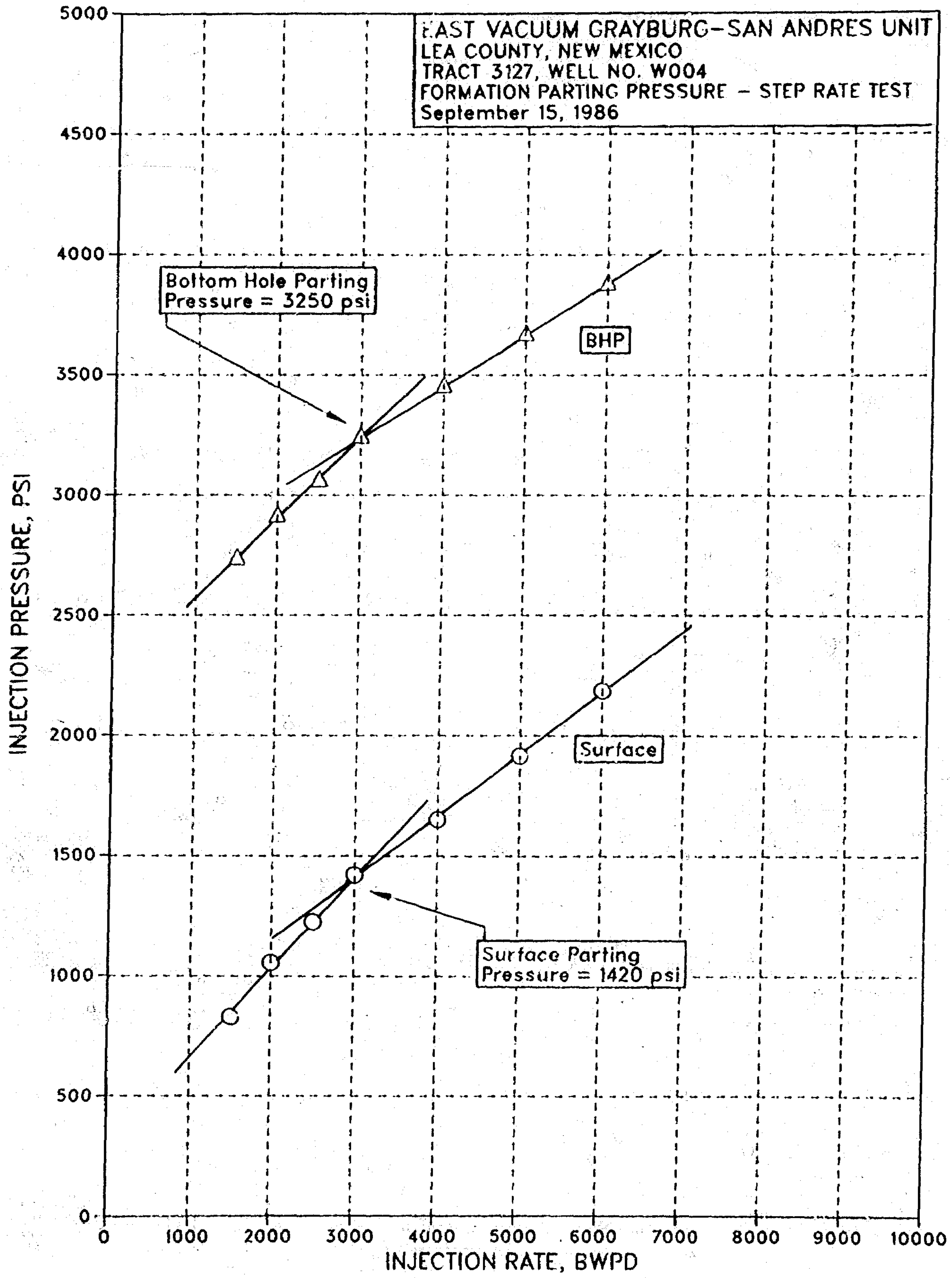
Attachments

cc: New Mexico Oil Conservation Divison
Attn: Mr. R. L. Stamets
P. O. Box 2088
Santa Fe, New Mexico 87501

EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Summary of Formation Parting Pressure Results
for Wag Area C

Tract-Well	Depth of Top Perforation	Tubing Size	Bottom Hole Parting Pressure, PSI	Injection Rate at Parting Pressure, BPD
3127W004	4310'	2-7/8"	3250	3,000
3202W010	4436'	2-7/8"	3050	5,625

MB/sdb
RE6.2/evgsau.t17


EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 3127, WELL NO. W004
FORMATION PARTING PRESSURE - STEP RATE TEST
September 15, 1986
Bottom Hole Parting Pressure = 3250 psi
BHP
Surface
Surface Parting Pressure = 1420 psi
INJECTION PRESSURE, PSI
INJECTION RATE, BWPD
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000

EAST VACUUM GRAYBURG-SAN ANDRES UNIT

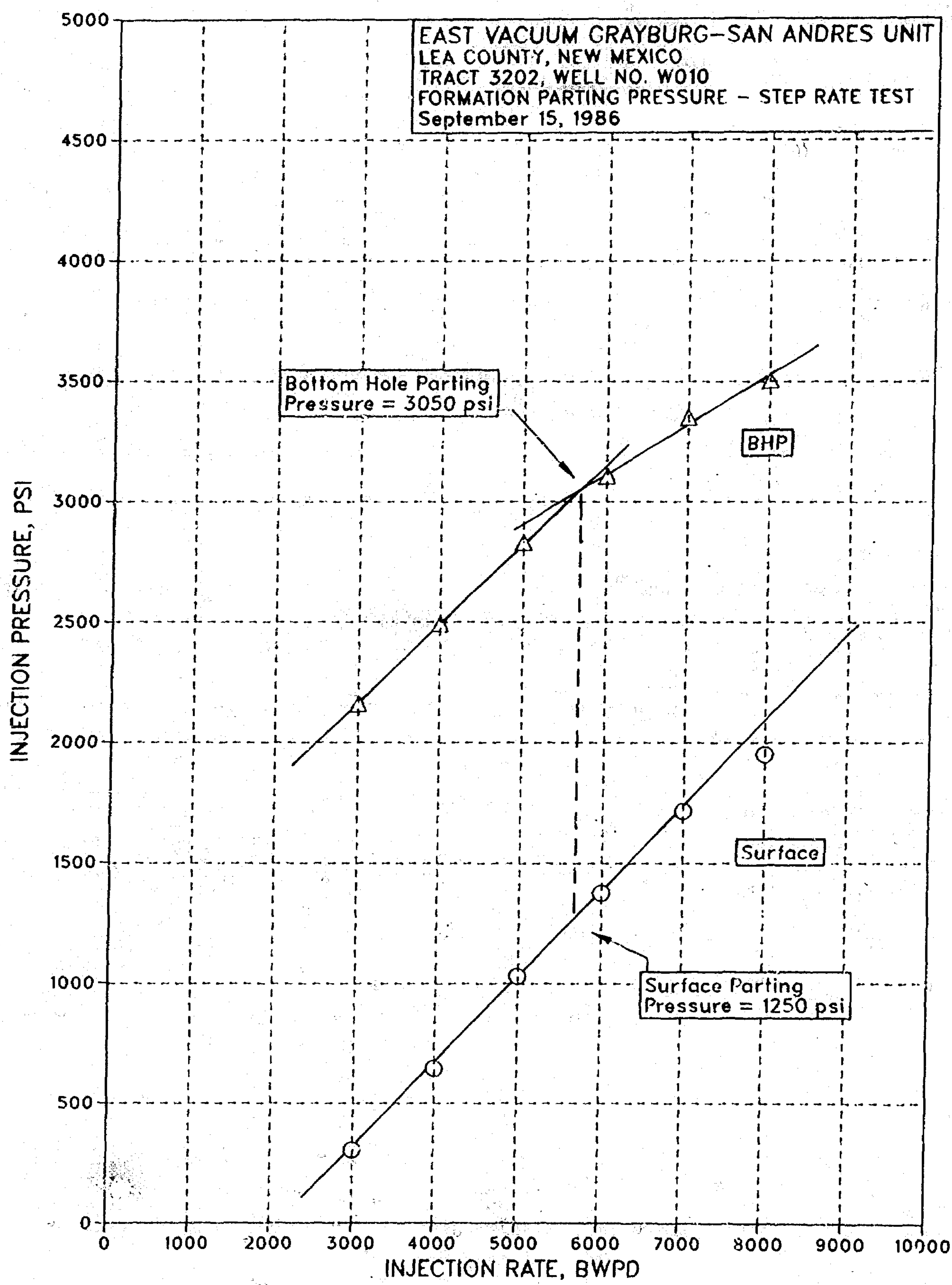
Tract 3127, Well No. W004

FORMATION PARTING PRESSURE TEST DATA

INJECTION RATE BPD	PRESSURE (PSI) SURFACE	BOTTOM HOLE *
1500	835	2744
2000	1055	2922
2500	1225	3070
3000	1420	3250
4000	1650	3460
5000	1915	3484

*Measured at top perforation.

RE6.2/evgsau.t19



EAST VACUUM GRAYBURG–SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 3202, WELL NO. W010
FORMATION PARTING PRESSURE – STEP RATE TEST
September 15, 1986
Bottom Hole Parting Pressure = 3050 psi
BHP
Surface
Surface Parting Pressure = 1250 psi
INJECTION PRESSURE, PSI
INJECTION RATE, BWPD
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000

EAST VACUUM GRAYBURG-SAN ANDRES UNIT

Tract 3202, Well No. W010

FORMATION PARTING PRESSURE TEST DATA

INJECTION RATE BPD	PRESSURE (PSI) SURFACE	BOTTOM HOLE *
3000	305	2161
4000	645	2494
5000	1030	2833
6000	1375	3108
7000	1715	3351
8000	1950	3505

*Measured at top perforation.

RE6.2/evgsau.t18

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

TONEY ANAYA
GOVERNOR

50 YEARS
1935 - 1985

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501
(505) 827-5800

May 27, 1986

Phillips Petroleum Company
4001 Penbrook
Odessa, Texas 79762

Attention: G. R. Smith

Re: Injection Pressure Increase
E. Vacuum G-SA Unit
Lea County, New Mexico

Dear Sir:

Reference is made to your request of May 12, 1986 to increase the bottom-hole injection pressure on three wells in your East Vacuum Grayburg-San Andres Unit Waterflood Project. It is our understanding that these wells are water-alternate-Co_2 injectors and that the previously approved bottom-hole pressure limit was 3150 p.s.i. set in Division Order No. R-6856. The request for pressure increase is based on a step rate tests performed on these wells during January, 1986. The results of the tests have been reviewed by my staff and we feel an increase in bottom-hole injection pressure is justified at this time.

You are therefore authorized to increase your bottom-hole injection pressure to 4000 p.s.i. on the following wells:

Well No.	Location
Tract 2913 No. 007	Sec. 29, T-17S, R-35E
Tract 2947 No. 001	Sec. 29, T-17S, R-35E
Tract 2980 No. 003	Sec. 29, T-17S, R-35E

All Wells located in Lea County, New Mexico

The Division Director may rescind this injection pressure increase if it becomes apparent that the injected water is not being confined to the injection zone or it is endangering any fresh water aquifers.

Sincerely,

R. L. STAMETS
Director

RLS/DRC/et

xc: Oil Conservation Division - Hobbs
Case File - 7426
Donna McDonald
D. Catanach

May 26, 1986

Phillips Petroleum Company
4001 Penbrook
Odessa, Texas 79762

Attention: C.R. Smith

Re: Injection Pressure Increase
E. Vacuum G-SA Unit
Lea County, New Mexico

Dear Sir:

Reference is made to your request of May 12, 1986 to increase the bottom-hole injection pressure on three wells in your East Vacuum Grayburg-San Andres Unit Waterflood Project. It is our understanding that these wells are water-alternate-CO_2 injectors and that the previously approved bottom-hole pressure limit was 3150 p.s.i. set in Division Order No. R-6856. The request for pressure increase is based on step rate tests performed on these wells during January 1986. The results of the test have been reviewed by my staff and we feel an increase in bottom-hole injection pressure is justified at this time.

You are therefore authorized to increase your bottom-hole injection pressure to 4000 p.s.i. on the following wells:

Well No.	Location
Tract 2913 No. 007	Sec. 29, T-17S, R-35E
Tract 2947 No. 001	Sec 29, T-17S R-35E
Tract 2980 No. 003	Sec 29, T-17S, R-35E

All wells located in Lea County, New Mexico.

The Division Director may rescind this injection pressure increase if it becomes apparent that the injected water is not being confined to the injection zone or it is endangering any fresh water aquifers.

Sincerely,

R.L. Stamets
Director

xc: OCD - Hobbs
Case File - 7426
Donna McDonald
D. Catanach

PHILLIPS PETROLEUM COMPANY

ODESSA, TEXAS 79762
4001 PENBROOK

EXPLORATION AND PRODUCTION GROUP

May 12, 1986

East Vacuum Grayburg-San Andres Unit
Carbon Dioxide Injection Project
Bottom Hole Injection Pressure Limitation
Lea County, New Mexico

New Mexico Oil Conservation Division
Attn: Mr. R. L. Stamets
P. O. Box 2088
Santa Fe, New Mexico 87501

Dear Mr. Stamets:

Phillips Petroleum Company, as operator of the subject unit, requests administrative approval of an increased bottom hole carbon dioxide injection pressure limitation of 4000 psi for three injection wells; Tract 2913, Well No. 007, Tract 2947, Well No. 001 and Tract 2980, Well No. 003. These three wells are identified as approved water-alternate-carbon dioxide injectors in Exhibit A of NMOCD Order No. R-6856, and are therefore subject to the bottom hole injection pressure limitation set out in that order of 3150 psi.

Formation parting pressure tests were run on these wells in January of this year. These tests were submitted to Mr. Jerry Sexton by letter dated February 11, 1986. (A copy was also sent to you.) Copies of these three tests are attached for your convenience. Note from these tests that the bottom hole parting pressures were 4090, 4700, and 4760 psi. Our request would not allow for formation parting in any of these wells.

After CO_2 injection was begun in these wells, BHP surveys were run. The results of those surveys are attached. Because of the low injectivity of the reservoir in the area around these wells, the rate of CO_2 injected into each of them is relatively low. Please note from the BHP surveys that the surface injection pressures in all three wells are very near our CO_2 delivery pressure of 1800 psi. This means that the bottom hole injection pressures should not rise appreciably above those shown on these surveys.

We request that the bottom hole injection pressure limitation for these three wells be increased to allow maximum CO_2 injection. We have ceased CO_2 injection into these wells at this time, so your earliest consideration is appreciated.

Very truly yours,

G. R. Smith

G. R. Smith, Director
Reservoir Engineering

MHB:jj

Attachments

cc: New Mexico Oil Conservation Division
Attn: Mr. Jerry Sexton
P. O. Box 1980
Hobbs, New Mexico 88240

EAST VACUUM GRAYBURG - SAN ANDRES UNIT
CO_2 Injection BHP Survey Results
WAG Area B

TRACT-WELL	SURFACE INJ. PRESSURE PSI	CO_2 INJECTION RATE AT TOP PERF.,MSCFD	DEPTH OF TOP PERFORATION	*BOTTOM HOLE PRESSURE AT INJECTION RATE, PSI	+BOTTOM HOLE PARTING PRESSURE PSI
2913-W007	1681	471	4,508'	3,381	4,760
2947-W001	1802	93	4,552'	3,505	4,700
2980-W003	1780	601	4,580'	3,492	4,090

* Pressure at top perforation

+ Parting pressure obtained from step rate tests, using water as the injection fluid, performed in January, 1986.

RE6.2/evg4.1

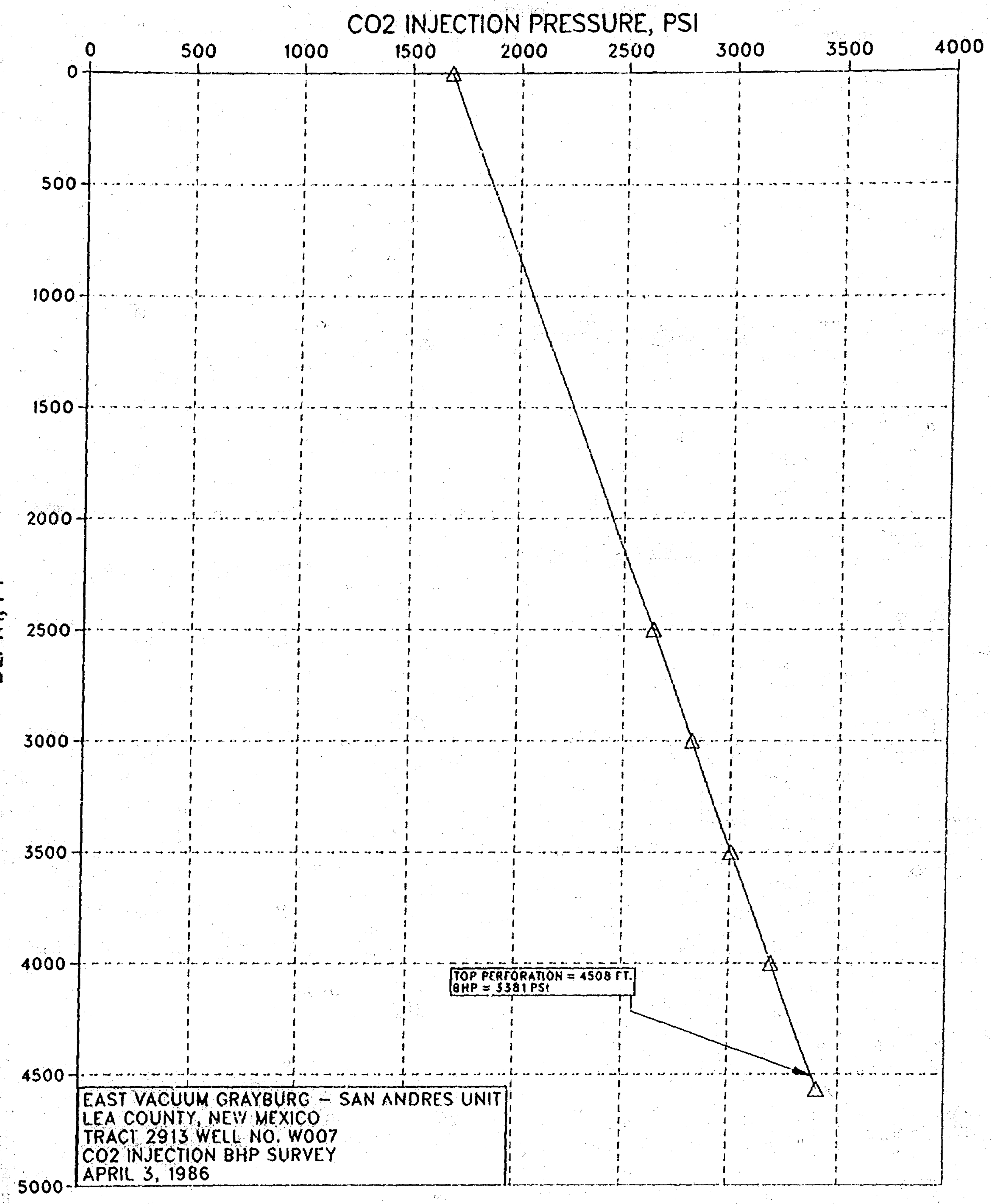
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2913, Well No. W007

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,681	
2,500	2,636	0.382
3,000	2,821	0.370
3,500	3,005	0.368
4,000	3,192	0.374
4,508 (Top Perf)	3,381	0.372
4,568	3,403	0.372

CO_2 Injection Rate at Top Perforation = 0.471 MMSCFD

RE6.2/evg21


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4508 FT.
BHP = 3381 PSI
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2913 WELL NO. W007
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

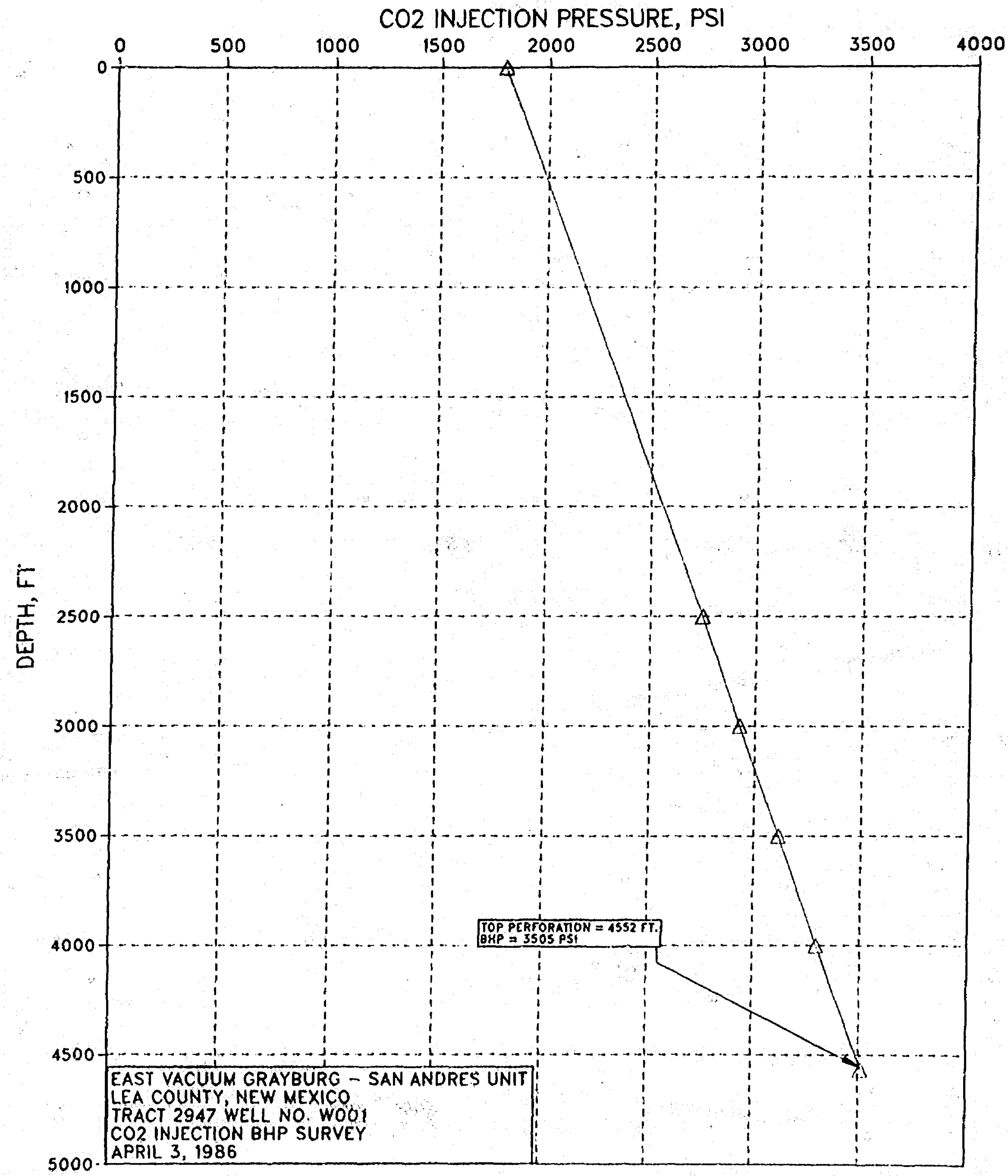
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2947, Well No. W001

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,802	
2,500	2,744	0.377
3,000	2,928	0.368
3,500	3,112	0.368
4,000	3,299	0.374
4,552 (Top Perf)	3,505	0.373
4,566	3,510	0.373

CO_2 Injection Rate at Top Perforation = 0.093 MMSCFD

RE6.2/evg22


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4552 FT.
BHP = 3505 PSI
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2947 WELL NO. W001
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

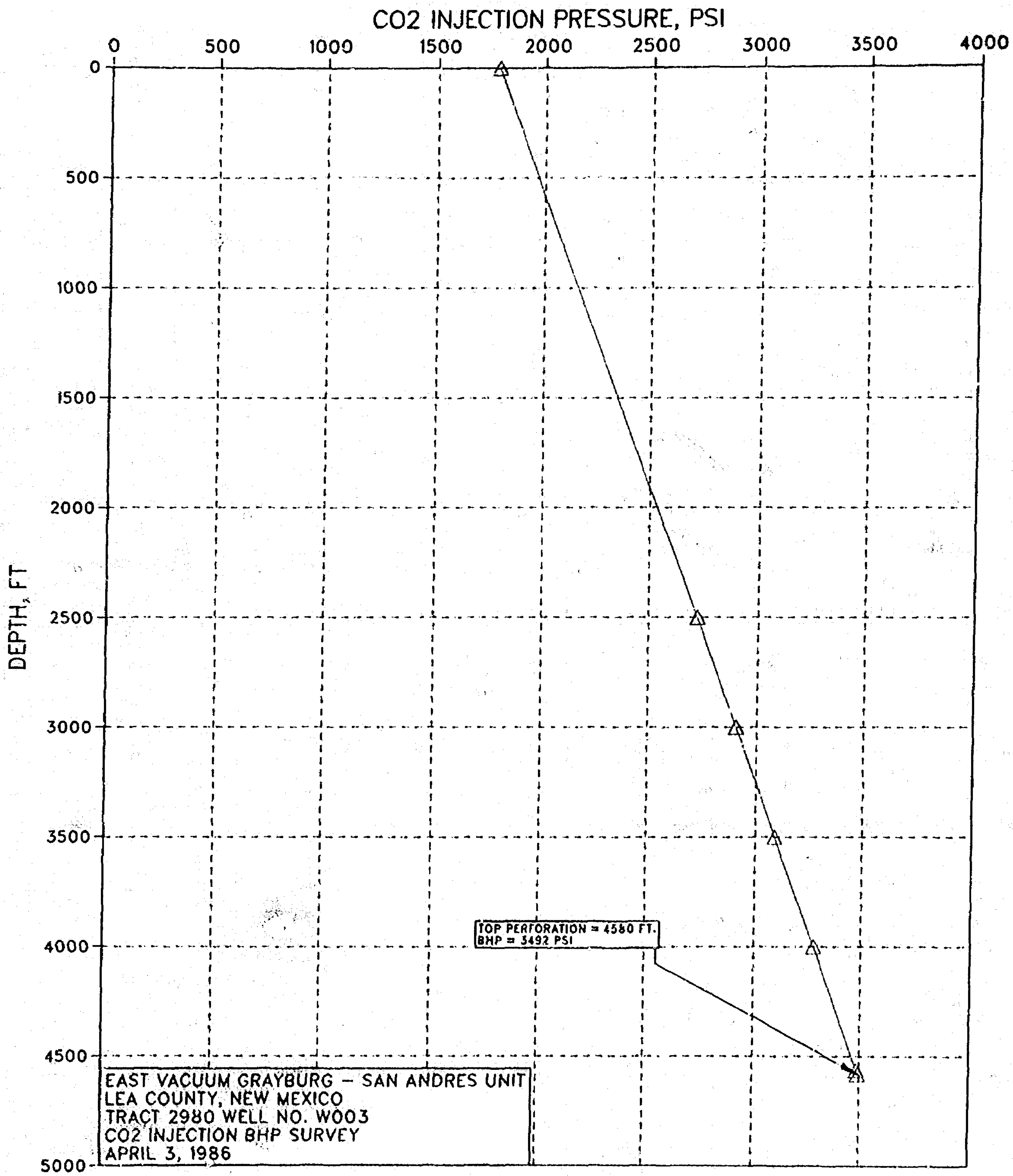
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2980, Well No. W003

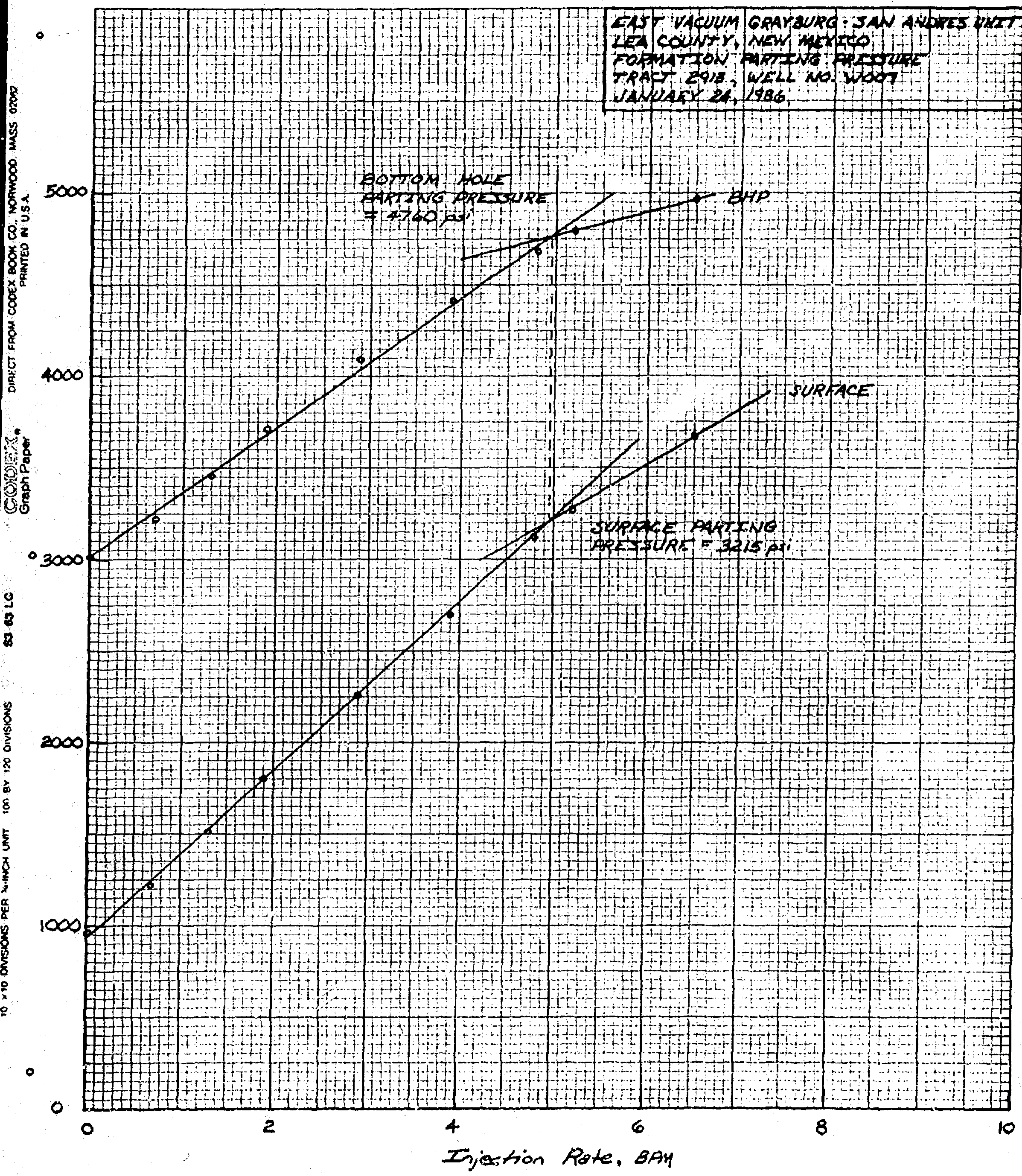
CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,780	
2,500	2,722	0.377
3,000	2,906	0.368
3,500	3,090	0.368
4,000	3,277	0.374
4,562	3,485	0.370
4,580 (Top Perf)	3,492	0.371

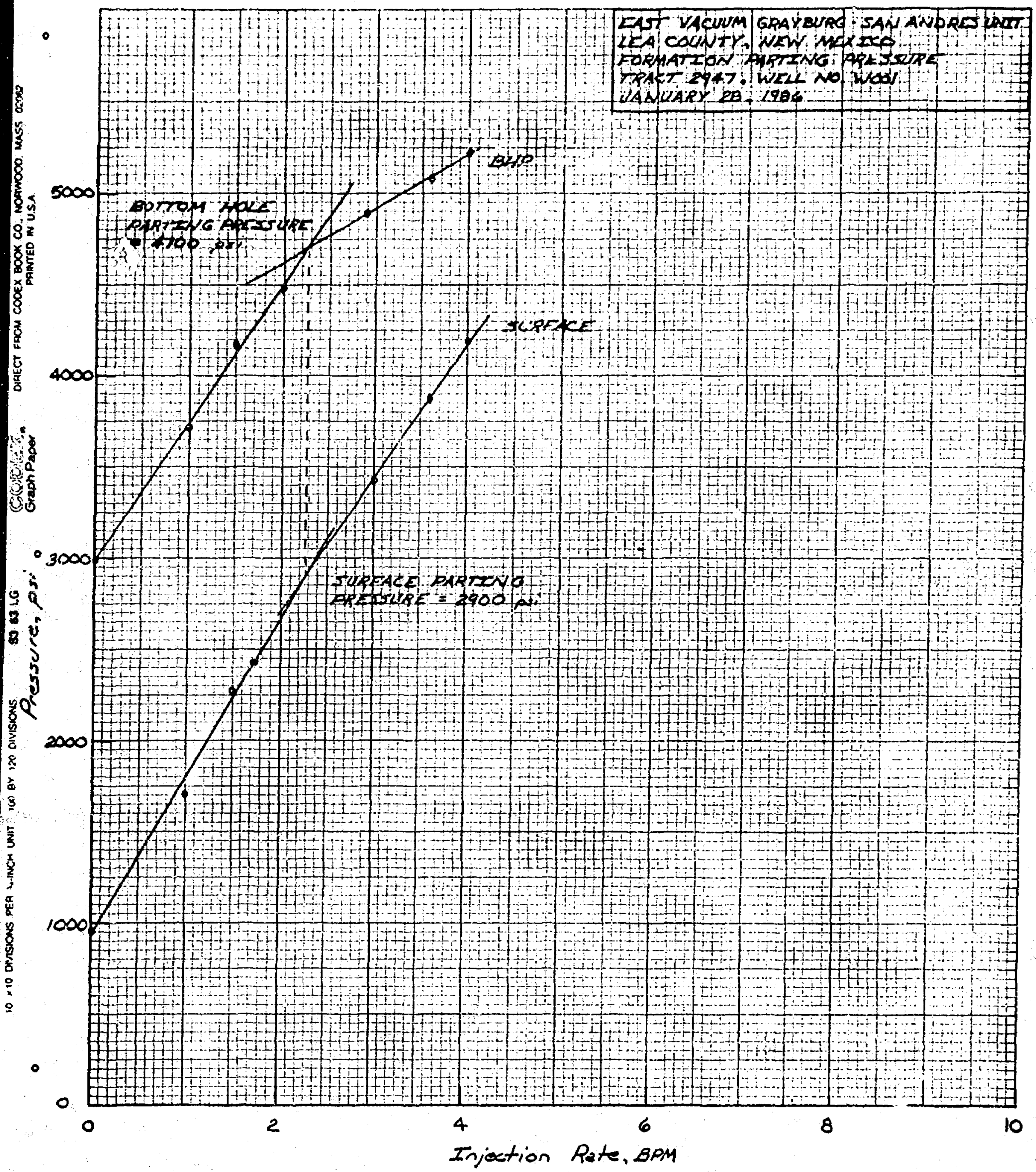
CO_2 Injection Rate at Top Perforation = 0.601 MMSCFD

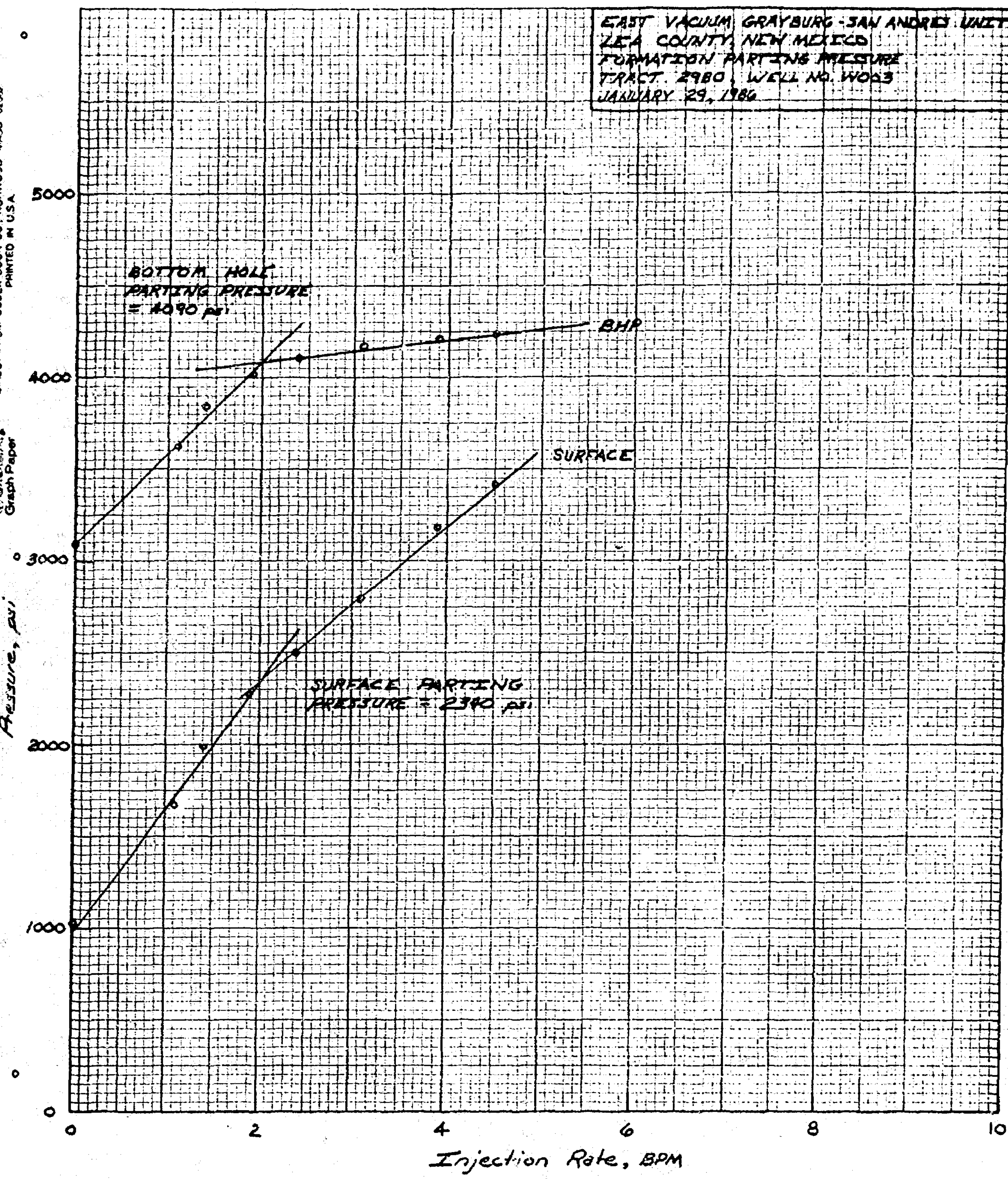
RE6.2/evg23


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4580 FT.
BHP = 3492 PSI
EAST VACUUM GRAYBURG – SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2980 WELL NO. W003
CO2 INJECTION BHP SURVEY
APRIL 3, 1986



EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
FORMATION PARTING PRESSURE
TRACT 2913, WELL NO. W007
JANUARY 24, 1986
BOTTOM HOLE PARTING PRESSURE = 4760 psi
BHP
SURFACE
SURFACE PARTING PRESSURE = 3215 psi
0
1000
2000
3000
4000
5000
0
2
4
6
8
10
Injection Rate, BPM
CODEX Graph Paper
DIRECT FROM CODEX BOOK CO., NORWOOD, MASS 02062 PRINTED IN U.S.A.
10 x 10 DIVISIONS PER ½-INCH UNIT 100 BY 120 DIVISIONS 33 63 LG


EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
FORMATION PARTING PRESSURE
TRACT 2947, WELL NO. W001
JANUARY 28, 1986
BHP
BOTTOM HOLE PARTING PRESSURE = 4700 psi
SURFACE
SURFACE PARTING PRESSURE = 2900 psi
Pressure, psi
Injection Rate, BPM
0
1000
2000
3000
4000
5000
0
2
4
6
8
10
10 x 10 DIVISIONS PER ½-INCH UNIT 100 BY 120 DIVISIONS 83 83 LG
CODEX Graph Paper
DIRECT FROM CODEX BOOK CO. NORWOOD, MASS 02062 PRINTED IN U.S.A.


EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
FORMATION PARTING PRESSURE
TRACT 2980, WELL NO. W003
JANUARY 29, 1986
BOTTOM HOLE PARTING PRESSURE = 4090 psi
BHP
SURFACE
SURFACE PARTING PRESSURE = 2340 psi
Pressure, psi
Injection Rate, BPM
0
1000
2000
3000
4000
5000
0
2
4
6
8
10
10 × 10 DIVISIONS PER ½-INCH UNIT 100 BY 120 DIVISIONS
DIRECT FROM CODEX BOOK CO. NORWOOD MASS. 02062 PRINTED IN U.S.A.
Graph Paper

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

May 27, 1986

TONEY ANAYA
GOVERNOR

50 YEARS
1935 - 1985

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501
(505) 827-5800

Phillips Petroleum Company
4001 Penbrook
Odessa, Texas 79762

Attention: G. R. Smith

Re: Amendment to Order PMX-118

Dear Sir:

Reference is made to your request of May 12, 1986 for an amendment to Administrative Order PMX-118, which authorized water injection into two wells on your East Vacuum Grayburg-San Andres Unit. It is our understanding that you wish these wells to be now classified as water-alternate-CO_2 injection wells. It is also our understanding that these two wells are currently equipped for CO_2 injection.

You are therefore authorized to utilize the following wells as water-alternate-CO_2 injection wells on your East Vacuum Grayburg-San Andres Unit, previously approved by Division Order No. R-6856 for CO_2 injection.

Tract - Well	Location
3202-011	2600 FSL & 200 FEL Sec. 32, T-17S, R-35E
3229-007	2600 FSL & 2500 FWL Sec. 32, T-17S, R-35E

Both wells in Lea County, New Mexico.

Sincerely,

R. L. STAMETS
Director

RLS/DRC/et

xc: Oil Conservation Division - Hobbs
File PMX-118
Donna McDonald
Case File- 7426

May 26, 1986

Phillips Petroleum Company
4001 Penbrook
Odessa, Texas 79762

Attention: C. R. Smith

Re: Amendment to Order PMX-118

Dear Sir,

Reference is made to your request of May 12, 1986 for an amendment to Administrative Order PMX-118, which authorized water injection into two wells on your East Vacuum Grayburg-San Andres Unit. It is our understanding that you wish these wells to be now classified as water-alternate-CO_2 injection wells. It is also our understanding that these two wells are currently equipped for CO_2 injection.

You are therefore authorized to ~~use~~ utilize the following wells as water-alternate-CO_2 injection wells on your East Vacuum Grayburg-San Andres Unit, previously approved by Division Order No. R-6856 for CO_2 injection.

Tract-Well	Location
3202-011	2600 FSL & 200 FEL Sec 32, T-17S, R-35E
3229-007	2600 FSL & 2500 FWL Sec 32, T-17S, R-35E

Both wells in Lea County, New Mexico.

Sincerely

R.L. Stamets
Director

xc: OCD-Hobbs
File - PMX-118
Donna McDonald
Case File - 7426

PHILLIPS 66
PHILLIPS PETROLEUM COMPANY
ODESSA, TEXAS 79762
4001 PENBROOK

EXPLORATION AND PRODUCTION GROUP

May 12, 1986

East Vacuum Grayburg-San Andres Unit
Carbon Dioxide Injection Project
Conversion of Water Injectors to
Water-Alternate-CO_2 Injectors
Lea County, New Mexico

New Mexico Oil Conservation Division
Attn: Mr. R. L. Stamets
P. O. Box 2088
Santa Fe, New Mexico 87501

Dear Mr. Stamets:

Phillips Petroleum Company, as operator of the East Vacuum Grayburg-San Andres Unit, requests approval to convert the following water injection wells to water-alternate-CO_2 injection; Tract 3229, Well No. 007 and Tract 3202, Well No. 011. Locations of the wells and a plat are attached.

Exhibit A to NMOCD Order No. R-6856, dated December 16, 1981, lists forty-five wells approved for water-alternate-CO_2 injection. Subsequently, the two subject wells were approved for water injection July 27, 1982 under NMOCD Order No. PMX-118. The two wells are equipped for CO_2 injection service and are presently injecting water. Conversion of these wells will not serve to alter the CO_2 Project Area. Therefore, conversion of these wells consists simply of inclusion in the list of already approved water-alternate-CO_2 injectors.

As these wells are due to commence CO_2 injection June 2, your earliest reply is appreciated.

Very truly yours,

G. R. Smith

G. R. Smith, Director
Reservoir Engineering

MHB:jj

Attachment

cc: New Mexico Oil Conservation Division
Attn: Mr. Jerry Sexton
P. O. Box 1980
Hobbs, New Mexico 88240

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Proposed Conversions of Water Injection
Water-Alternate-CO_2 Injectors
Lea County, New Mexico

Tract-Well	Location
3202-011	2600' FSL & 200' FEL, Sec. 32, T-17-S, R-35-E
3229-007	2600' FSL & 2500' FWL, Sec. 32, T-17-S, R-35-E

PHILLIPS PETROLEUM COMPANY
ODESSA, TEXAS 79762
4001 PENBROOK

EXPLORATION AND PRODUCTION GROUP

May 8, 1986

East Vacuum Grayburg-San Andres Unit
Carbon Dioxide Injection Project
Lea County, New Mexico

Case 7426

MAY 13 1986

New Mexico Oil Conservation Division
Attn: Mr. Jerry Sexton
P. O. Box 1980
Hobbs, New Mexico 88240

Dear Mr. Sexton:

As authorized by New Mexico Oil Conservation Division Order No. R-6856, carbon dioxide injection is presently in progress in the East Vacuum Grayburg-San Andres Unit.

Currently, CO_2 is being injected into WAG Area B as outlined in our correspondence dated February 11, 1986. Attached are the injection bottom hole pressure surveys for sixteen of the nineteen CO_2 injectors in Area B. The data show that these injectors have bottom hole injection pressures below the formation parting pressure or the bottom hole pressure limitation of 3150 psi, whichever is applicable. The remaining three pressure surveys will be forwarded to you shortly.

If you have any questions concerning this matter, please contact Mr. Mike Brownlee in Odessa at (915) 367-1413.

Very truly yours,

G. R. Smith

G. R. Smith, Director
Reservoir Engineering

MHB:jj

Attachments

cc: New Mexico Oil Conservation Division
Attn: Mr. R. L. Stamets
P. O. Box 2088
Santa Fe, New Mexico 87501

EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Summary of CO_2 Injection BHP Survey Results
for WAG Area B

TRACT-WELL	SURFACE INJ. PRESSURE PSI	CO_2 INJECTION RATE AT TOP PERF., MMSCFD	DEPTH OF TOP PERFORATION	*BOTTOM HOLE PRESSURE AT INJECTION RATE, PSI	+BOTTOM HOLE PARTING PRESSURE PSI
2622-W004	682	2.199	4,435'	2,244	3,128@
2622-W006	794	0.920	4,480'	2,368	3,570
2717-W003	606	0.228	4,394'	1,985	3,625
2717-W005	778	0.713	4,441'	2,382	3,488@
2717-W007	702	1.808	4,371'	2,242	3,250
2720-W006	787	0.863	4,410'	2,330	3,515
2721-W001	1,474	1.847	4,352'	3,116	3,370
2721-W002	790	1.858	4,376'	2,046	3,116@
2738-W007	621	1.655	4,362'	2,074	3,290
2738-W008	717	0.889	4,367'	2,233	3,440
2801-W005	524	1.213	4,488'	1,742	3,015@
2801-W006	643	1.154	4,411'	2,082	3,195
2801-W007	577	2.296	4,404'	1,996	3,000@
2801-W012	673	1.138	4,455'	2,204	3,435
2801-W015	1,033	1.597	4,433'	2,657	3,450
2865-W001	1,374	0.896	4,488'	3,035	4,070

* Pressure at top perforation

+ Parting pressure obtained from step rate tests, using water as the injection fluid, performed in January, 1986.

@ No identifiable parting pressure was observed, this is the maximum bottom hole pressure observed during the test.

RE6.2/evg4.1

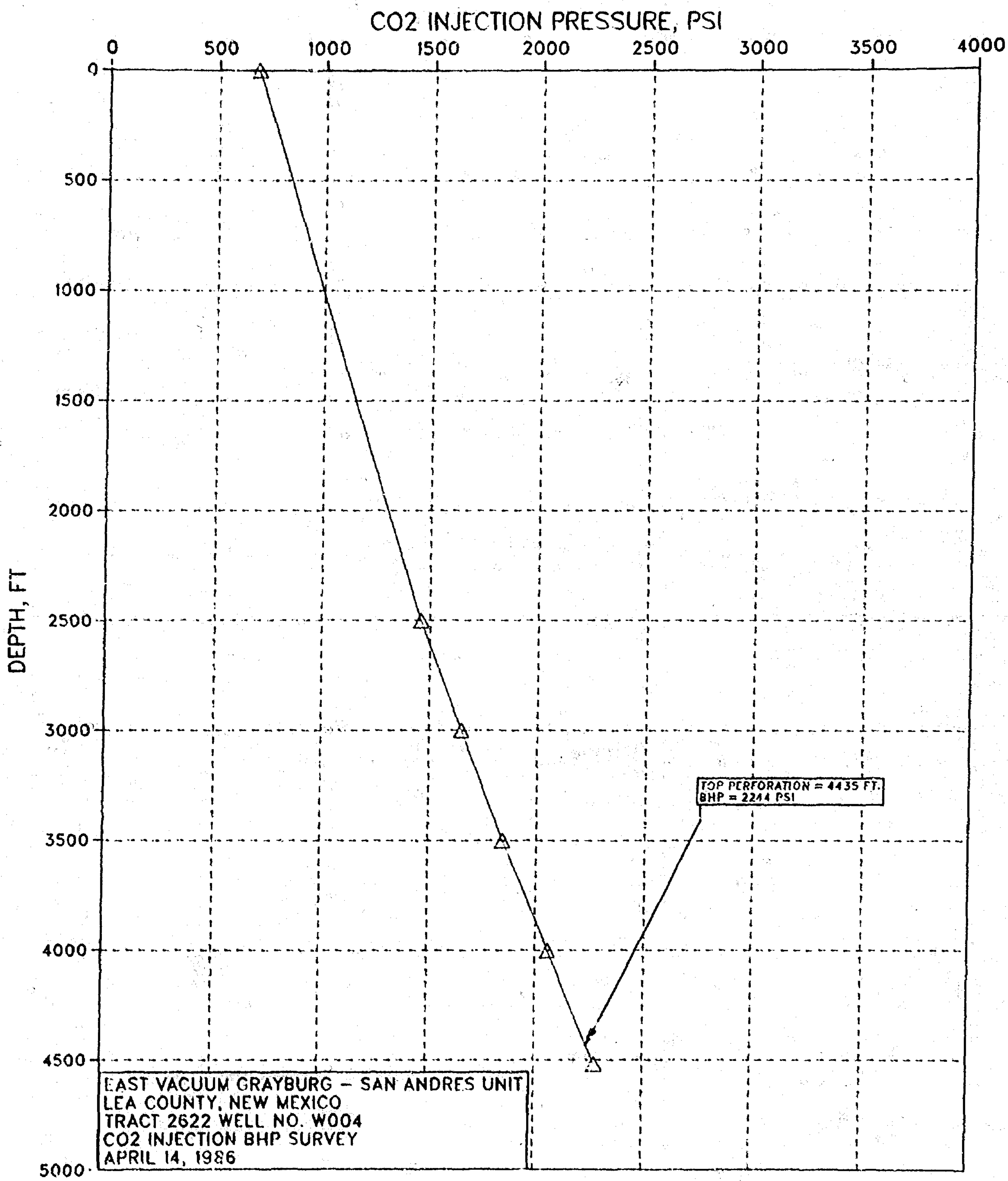
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2622, Well No. W004

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	682	
2,500	1,458	0.310
3,000	1,647	0.378
3,500	1,846	0.398
4,000	2,059	0.426
4,435 (Top Perf)	2,244	0.425
4,519	2,280	0.426

CO_2 Injection Rate at Top Perforation = 2.199 MMSCFD

RE6.2/evg5


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4435 FT.
BHP = 2244 PSI
EAST VACUUM GRAYBURG – SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2622 WELL NO. W004
CO2 INJECTION BHP SURVEY
APRIL 14, 1986

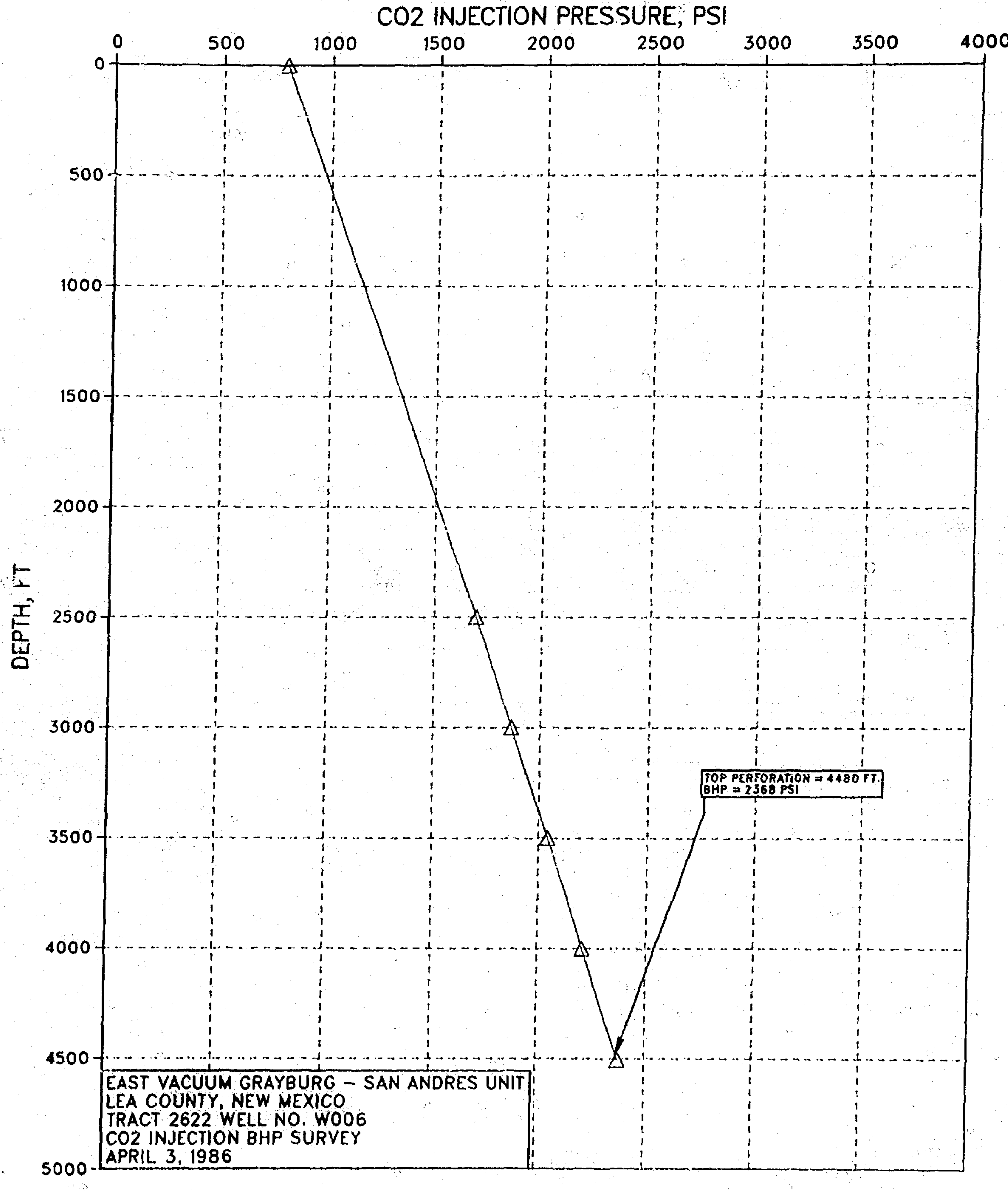
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2622, Well No. W006

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	794	
2,500	1,695	0.360
3,000	1,868	0.346
3,500	2,041	0.346
4,000	2,212	0.342
4,480 (Top Perf)	2,368	0.325
4,506	2,376	0.325

CO_2 Injection Rate at Top Perforation = 0.920 MMSCFD

RE6.2/evg6


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4480 FT.
BHP = 2368 PSI
EAST VACUUM GRAYBURG – SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2622 WELL NO. W006
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

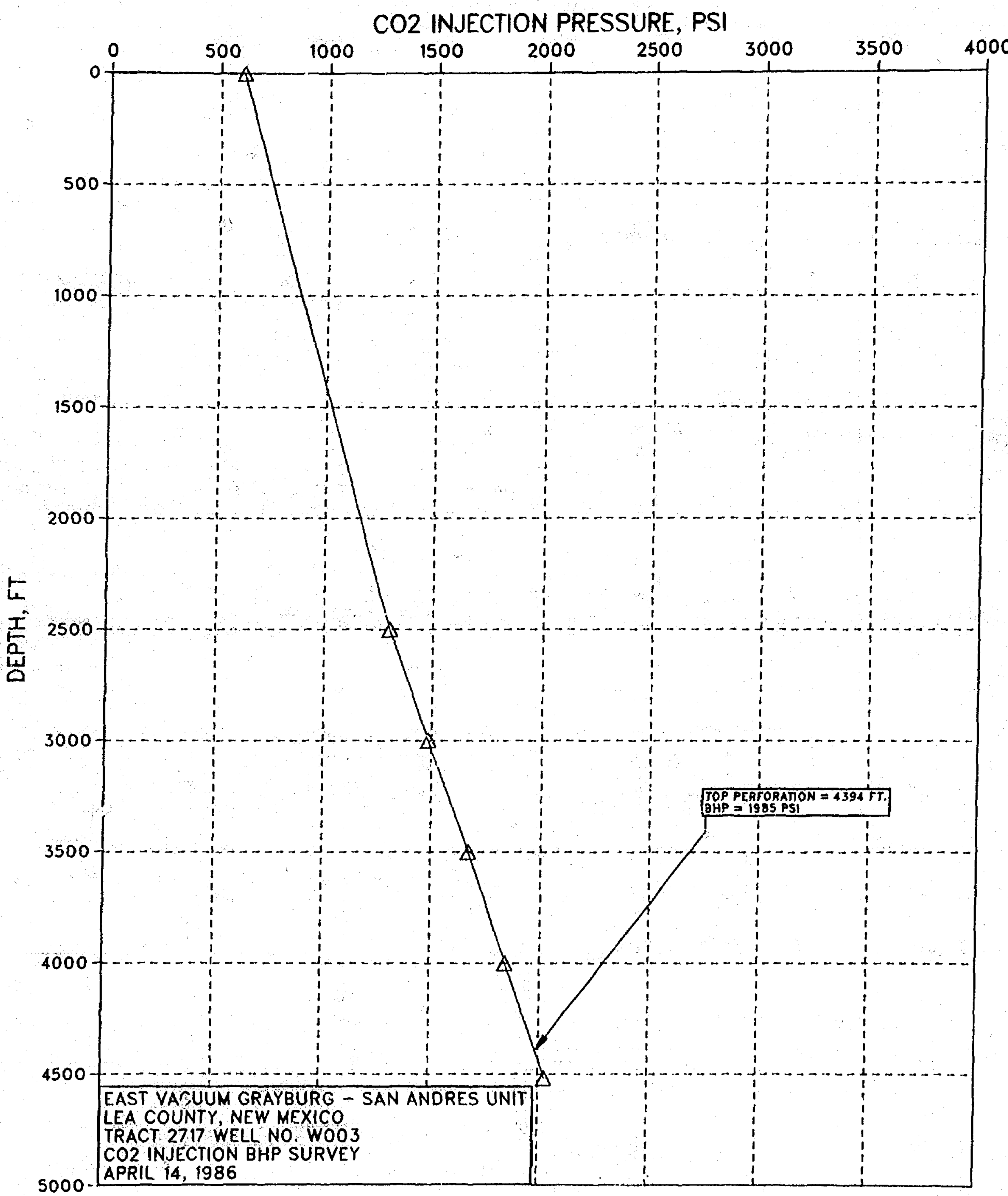
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2717, Well No. W003

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	606	
2,500	1,302	0.278
3,000	1,484	0.364
3,500	1,669	0.370
4,000	1,846	0.354
4,394 (Top Perf)	1,985	0.353
4,517	2,028	0.352

CO_2 Injection Rate at Top Perforation = 0.228 MMSCFD

RE6.2/evg7


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4394 FT.
BHP = 1985 PSI
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2717 WELL NO. W003
CO2 INJECTION BHP SURVEY
APRIL 14, 1986

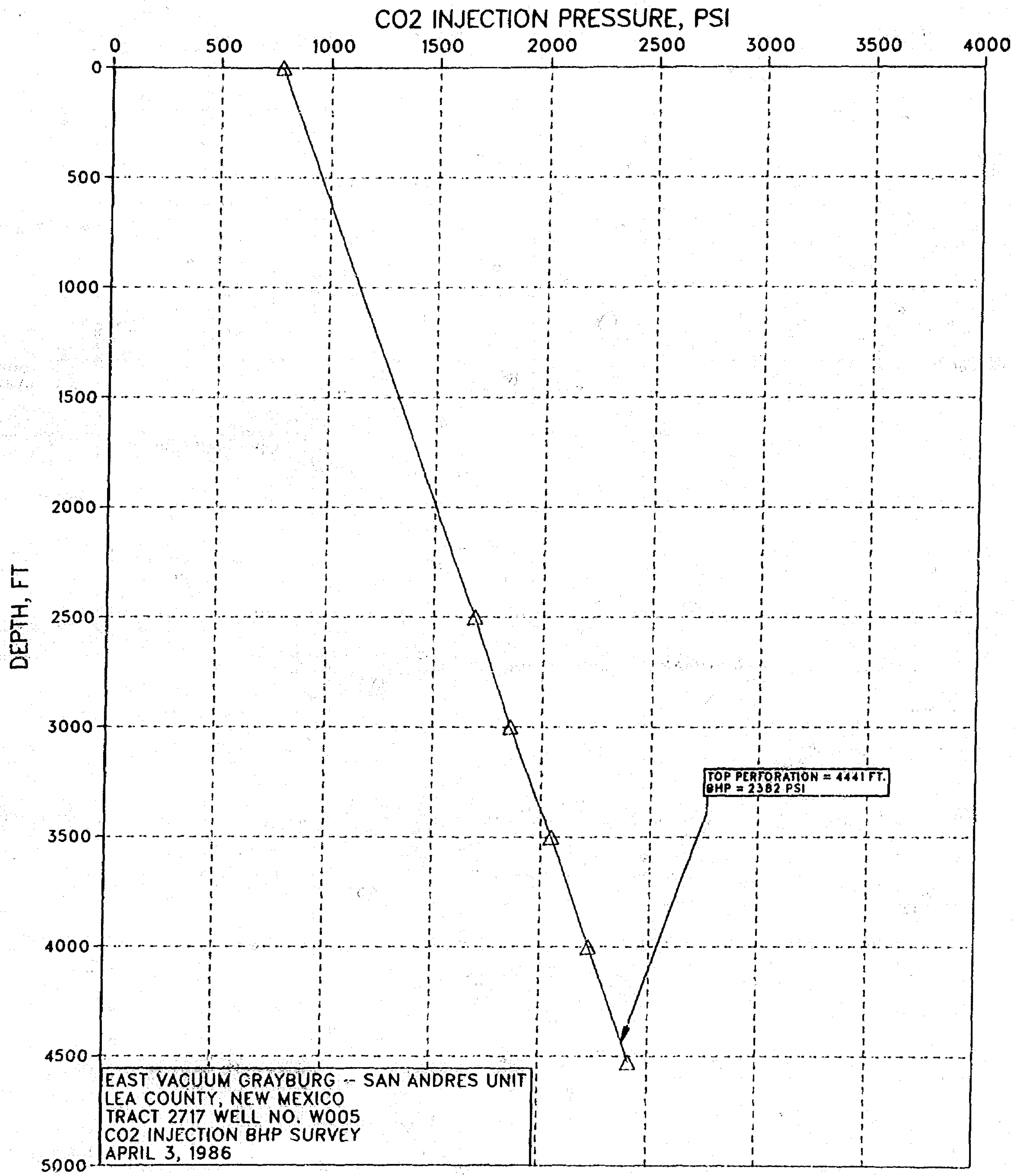
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2717, Well No. W005

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	778	
2,500	1,688	0.364
3,000	1,858	0.340
3,500	2,046	0.376
4,000	2,225	0.358
4,441 (Top Perf)	2,382	0.356
4,527	2,413	0.356

CO_2 Injection Rate at Top Perforation = 0.713 MMSCFD

RE6.2/evg8


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4441 FT.
BHP = 2382 PSI
EAST VACUUM GRAYBURG -- SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2717 WELL NO. W005
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

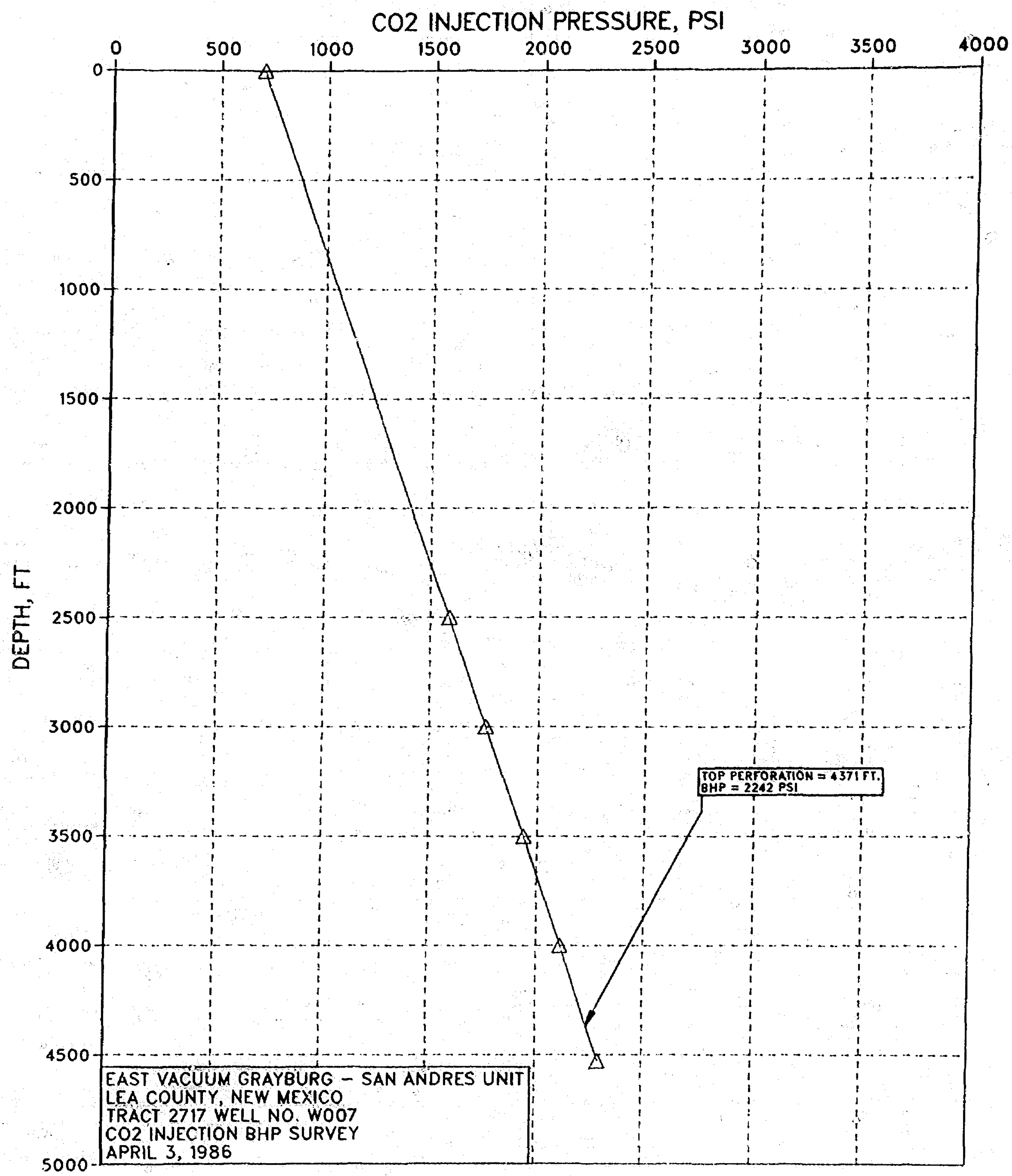
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2717, Well No. W007

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	702	
2,500	1,585	0.353
3,000	1,759	0.348
3,500	1,936	0.354
4,000	2,113	0.354
4,371 (Top Perf)	2,242	0.348
4,529	2,297	0.348

CO_2 Injection Rate at Top Perforation = 1.808 MMSCFD

RE6.2/evg9


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4371 FT.
BHP = 2242 PSI
EAST VACUUM GRAYBURG – SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2717 WELL NO. W007
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

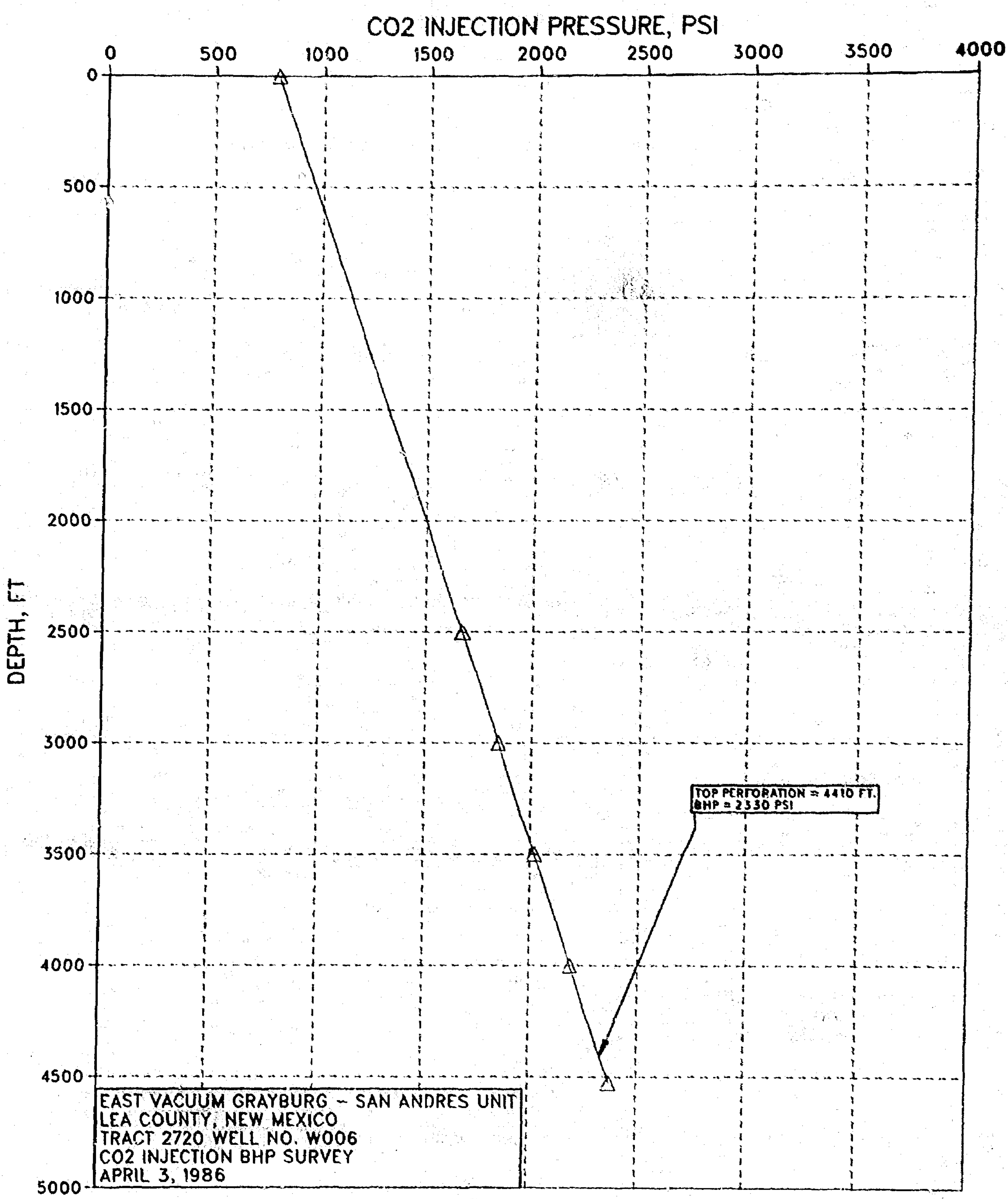
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2720, Well No. W006

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	787	
2,500	1,676	0.356
3,000	1,846	0.340
3,500	2,018	0.344
4,000	2,188	0.340
4,410 (Top Perf)	2,330	0.346
4,528	2,371	0.346

CO_2 Injection Rate at Top Perforation = 0.863 MMSCFD

RE6.2/evg10


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4410 FT.
BHP = 2330 PSI
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2720 WELL NO. W006
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

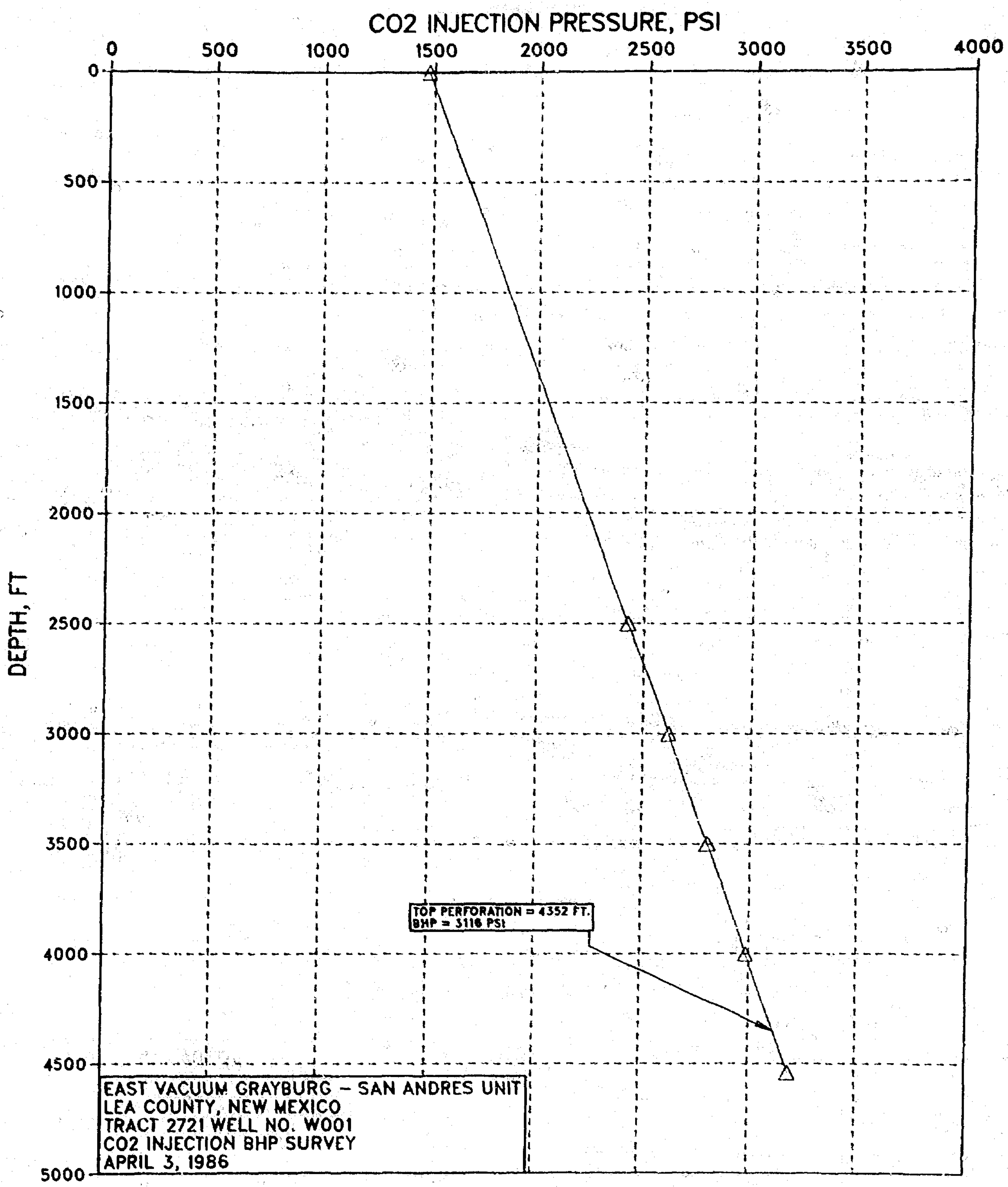
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2721, Well No. W001

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,474	
2,500	2,430	0.382
3,000	2,620	0.380
3,500	2,805	0.370
4,000	2,984	0.358
4,352 (Top Perf)	3,116	0.375
4,540	3,186	0.374

CO_2 Injection Rate at Top Perforation = 1.847 MMSCFD

RE6.2/evg11


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4352 FT.
BHP = 3116 PSI
EAST VACUUM GRAYBURG – SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2721 WELL NO. W001
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

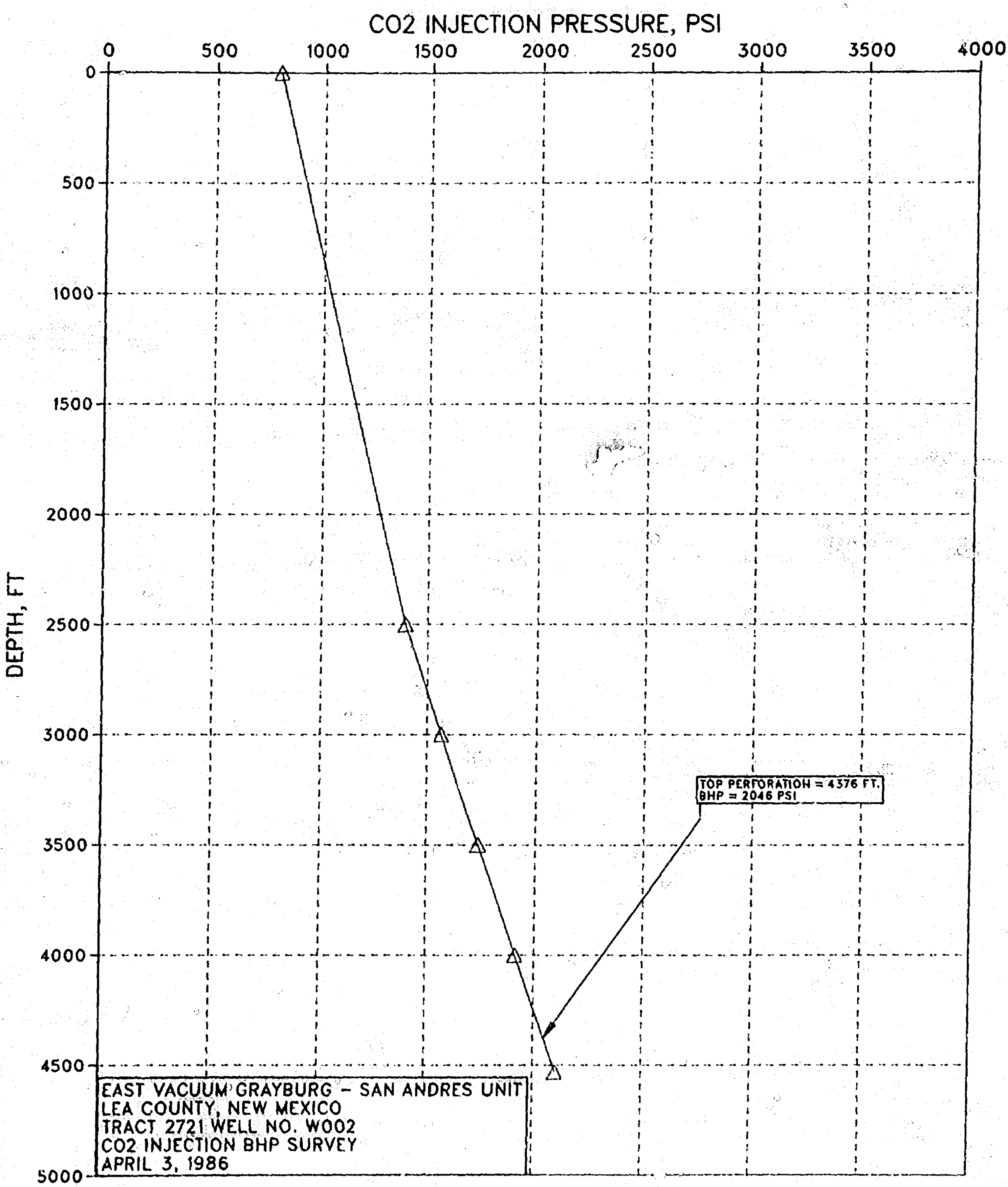
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2721, Well No. W002

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	790	
2,500	1,396	0.242
3,000	1,568	0.344
3,500	1,741	0.346
4,000	1,914	0.346
4,376 (Top Perf)	2,046	0.351
4,531	2,101	0.352

CO_2 Injection Rate at Top Perforation = 1.858 MMSCFD

RE6.2/evg12


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4376 FT.
BHP = 2046 PSI
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2721 WELL NO. W002
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

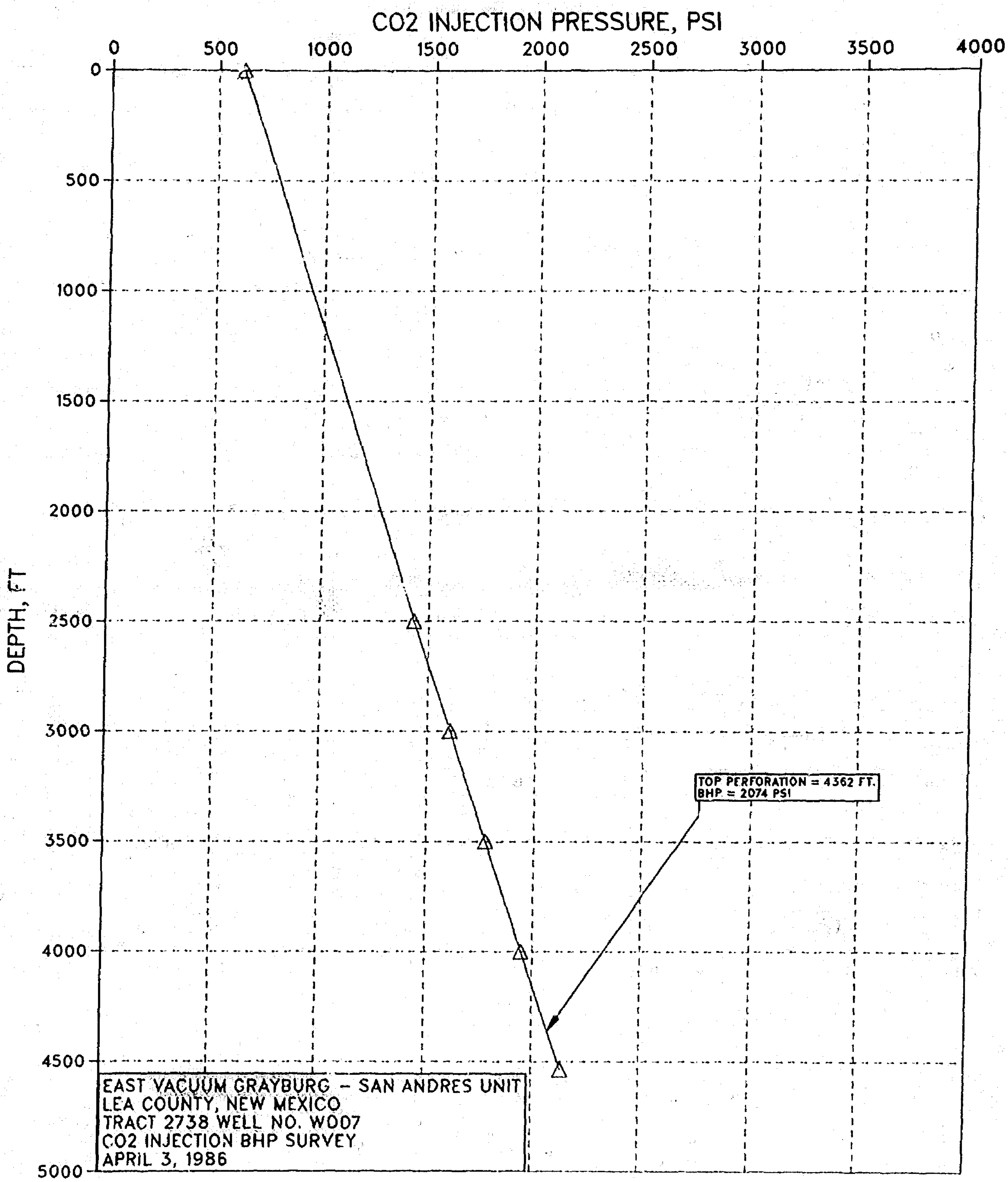
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2738, Well No. W007

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	621	
2,500	1,432	0.324
3,000	1,605	0.346
3,500	1,776	0.342
4,000	1,945	0.338
4,362 (Top Perf)	2,074	0.357
4,537	2,137	0.358

CO_2 Injection Rate at Top Perforation = 1.655 MMSCFD

RE6.2/evg13


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4362 FT.
BHP = 2074 PSI
EAST VACUUM GRAYBURG – SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2738 WELL NO. W007
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

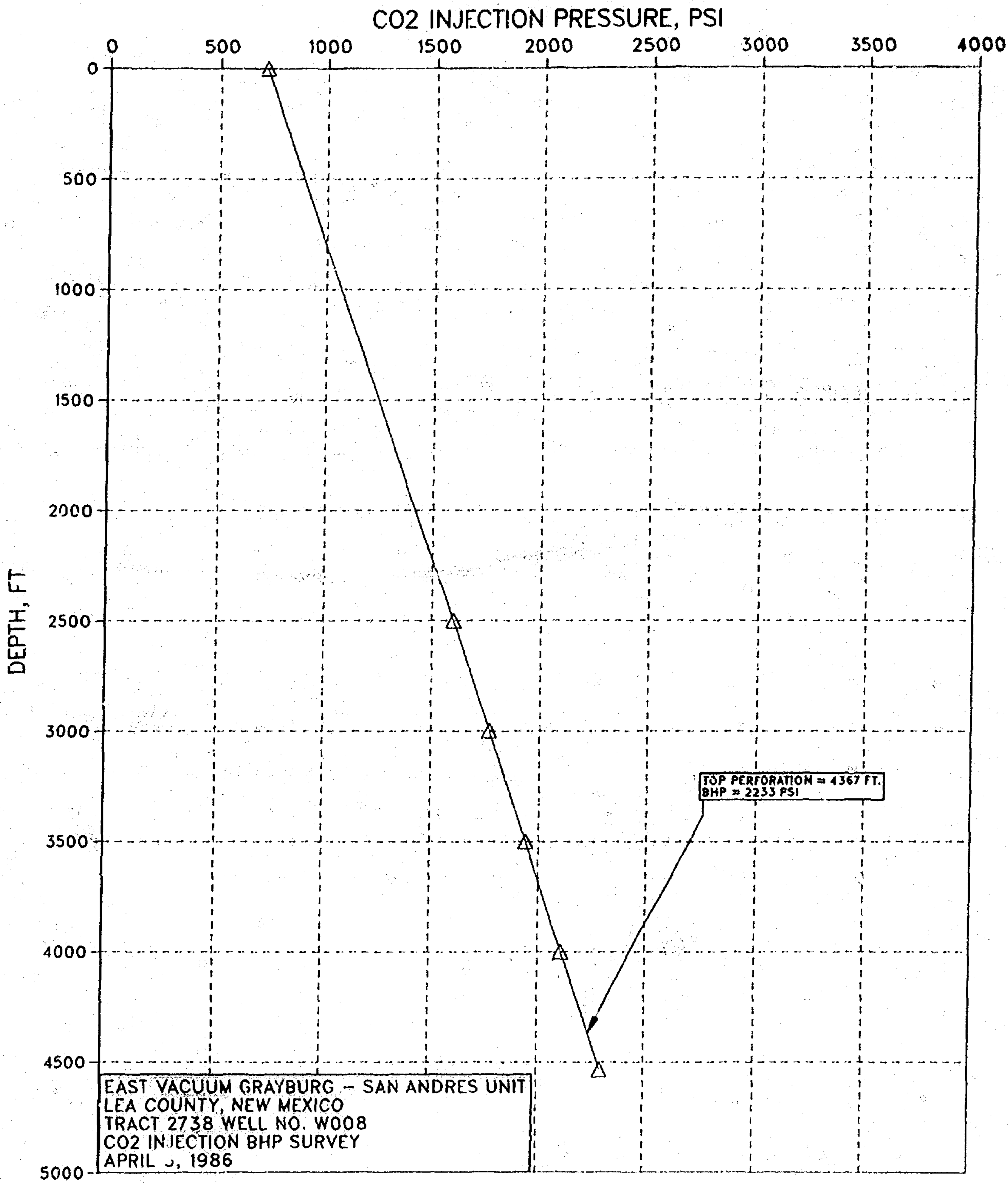
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2738, Well No. W008

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	717	
2,500	1,597	0.352
3,000	1,768	0.342
3,500	1,938	0.340
4,000	2,107	0.338
4,367 (Top Perf)	2,233	0.343
4,535	2,290	0.342

CO_2 Injection Rate at Top Perforation = 0.889 MMSCFD

RE6.2/evg14


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4367 FT.
BHP = 2233 PSI
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2738 WELL NO. W008
CO2 INJECTION BHP SURVEY
APRIL 5, 1986

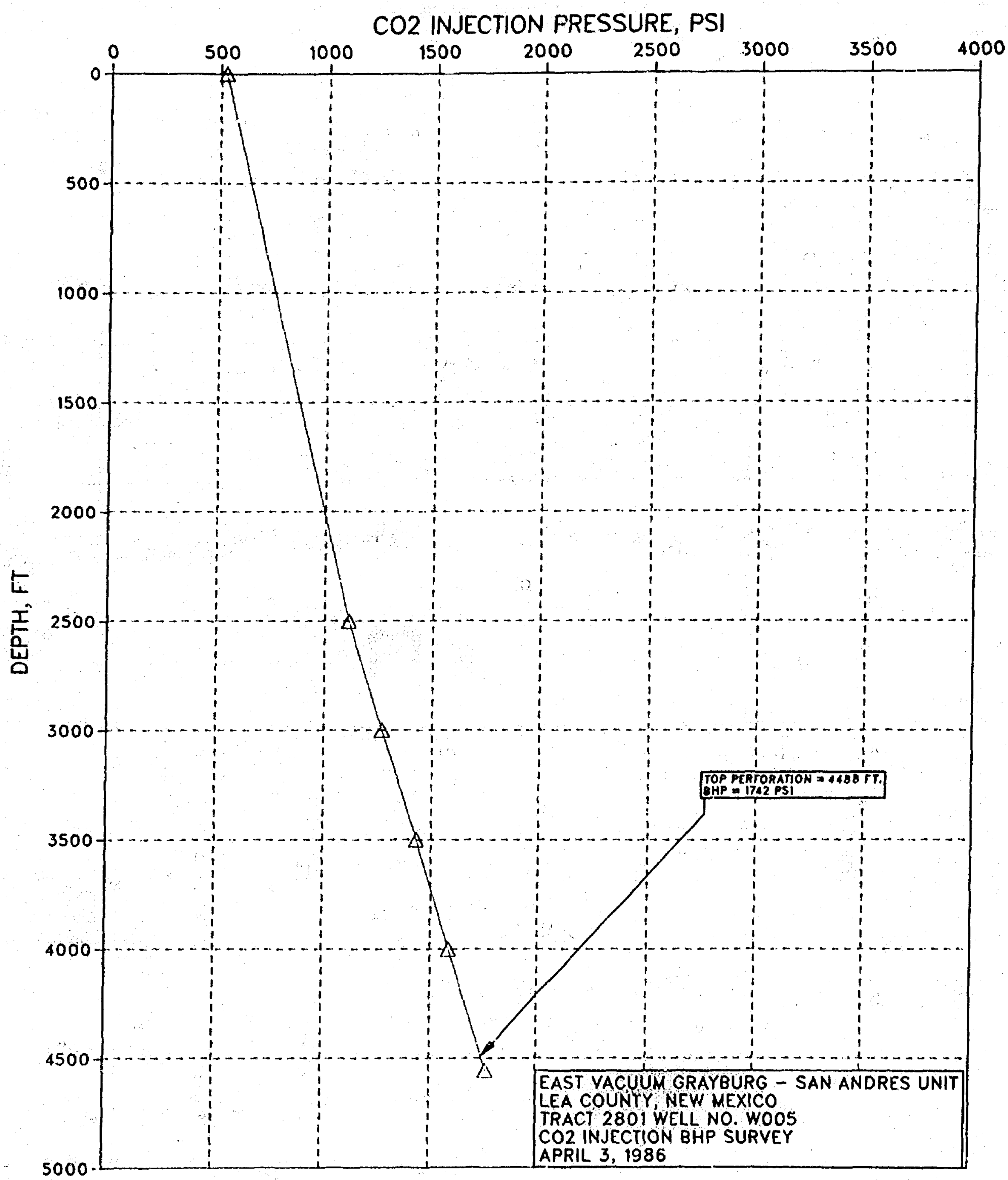
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2801, Well No. W005

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	524	
2,500	1,112	0.235
3,000	1,271	0.318
3,500	1,430	0.318
4,000	1,586	0.312
4,488 (Top Perf)	1,742	0.319
4,555	1,763	0.319

CO_2 Injection Rate at Top Perforation = 1.213 MMSCFD

RE6.2/evg15


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4488 FT.
BHP = 1742 PSI
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2801 WELL NO. W005
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

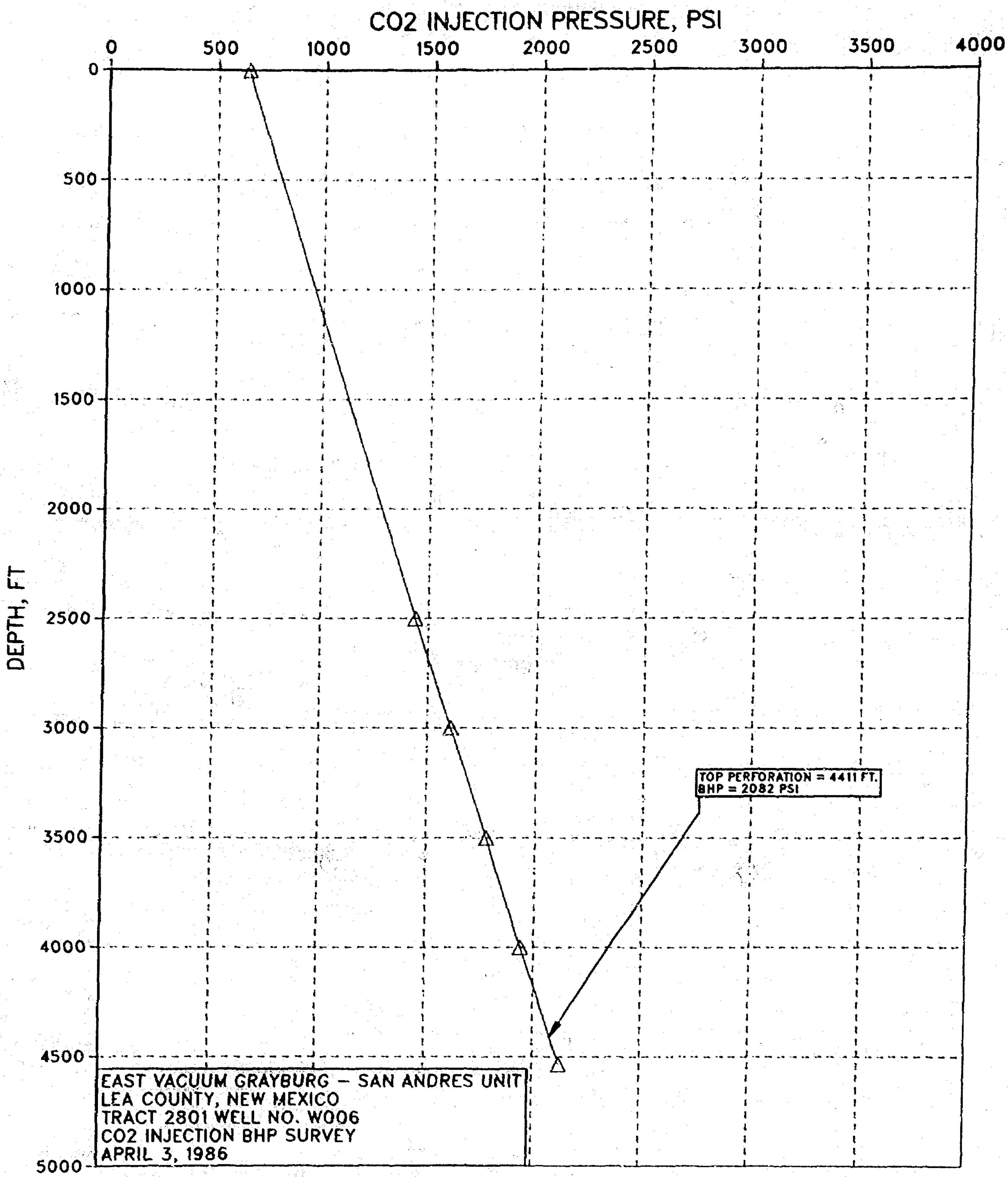
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2801, Well No. W006

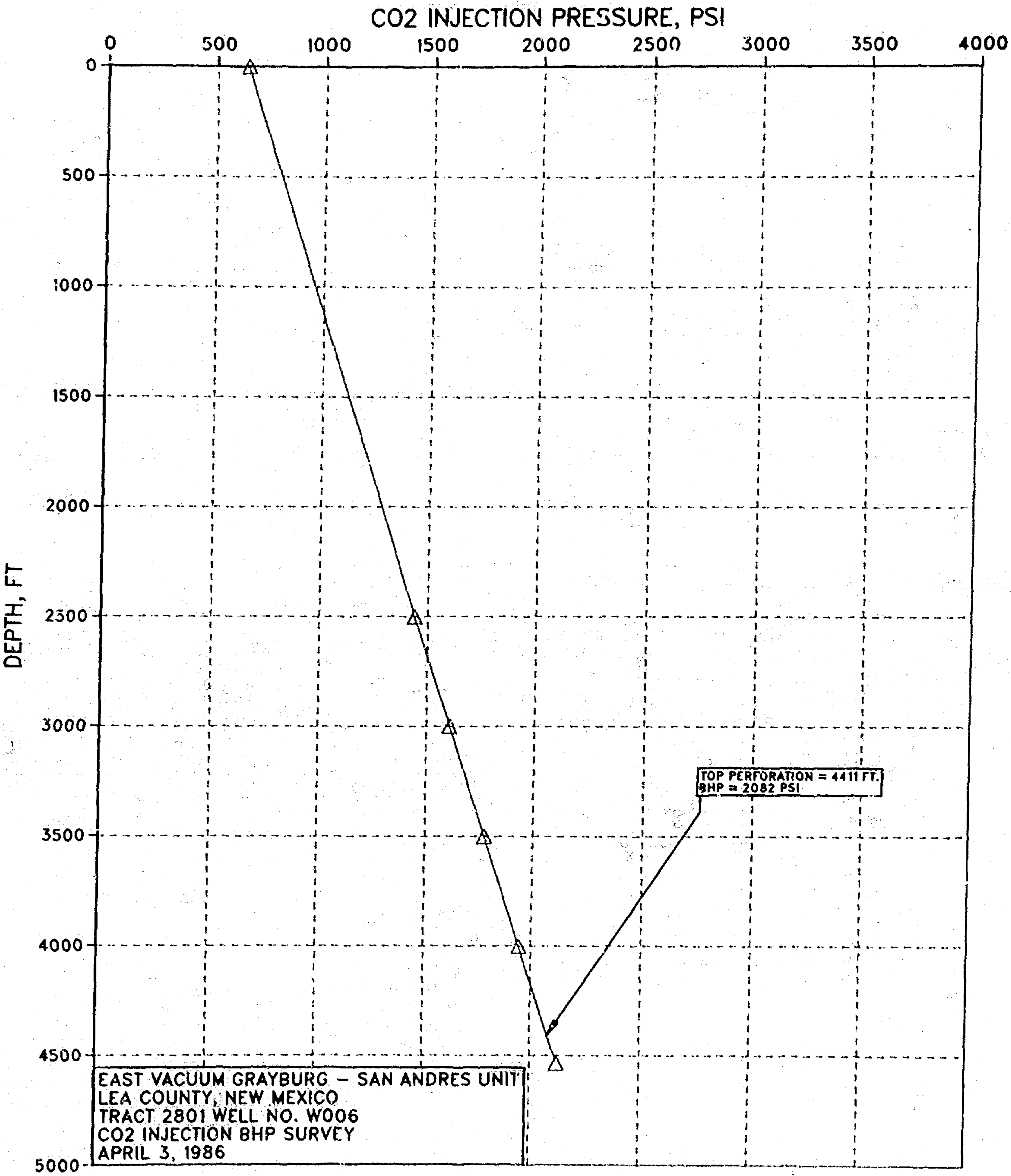
CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	643	
2,500	1,440	0.319
3,000	1,608	0.336
3,500	1,776	0.336
4,000	1,941	0.330
4,411 (Top Perf)	2,082	0.343
4,534	2,124	0.343

CO_2 Injection Rate at Top Perforation = 1.154 MMSCFD

RE6.2/evg16


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4411 FT.
BHP = 2082 PSI
EAST VACUUM GRAYBURG – SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2801 WELL NO. W006
CO2 INJECTION BHP SURVEY
APRIL 3, 1986


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4411 FT.
BHP = 2082 PSI
EAST VACUUM GRAYBURG – SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2801 WELL NO. W006
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

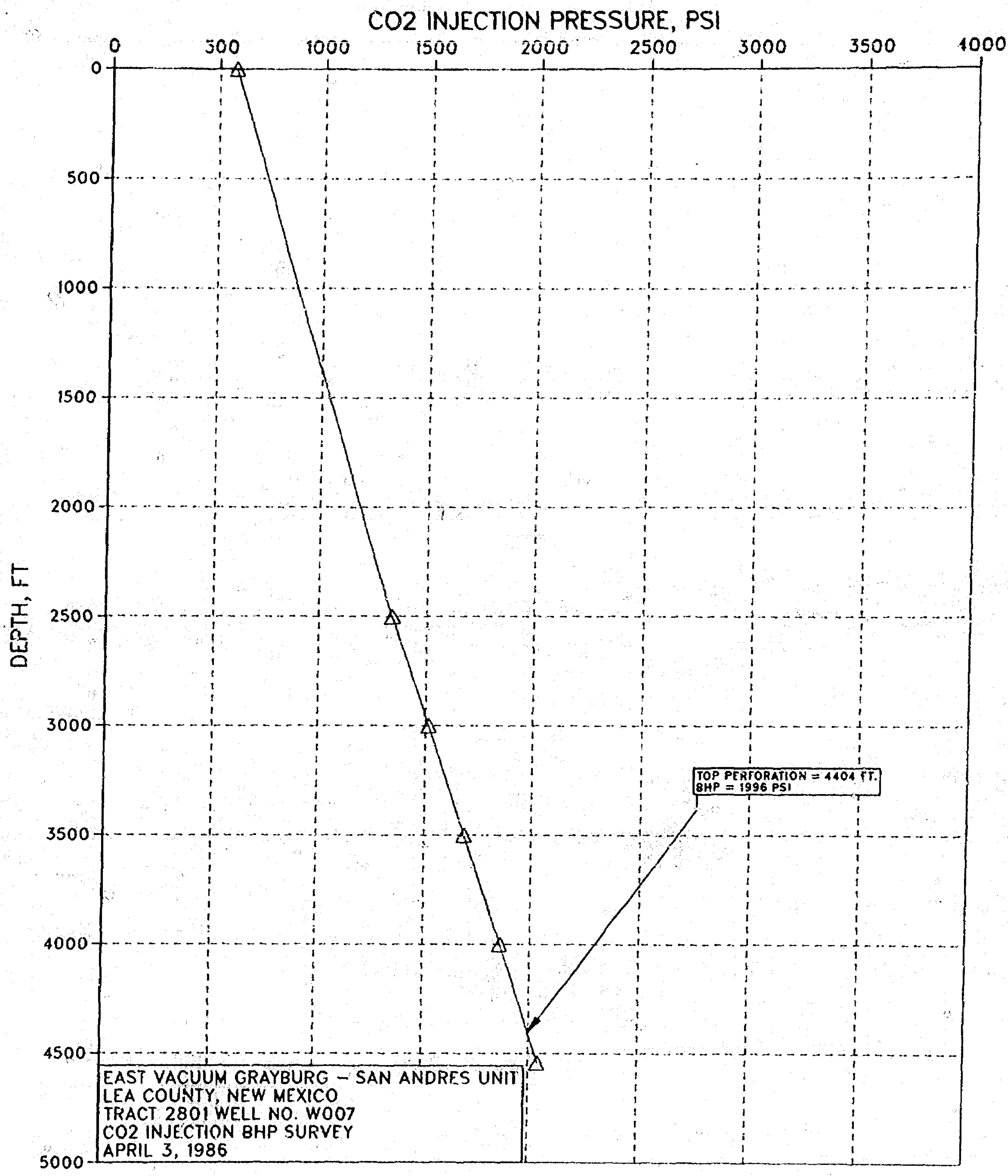
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2801, Well No. W007

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	577	
2,500	1,344	0.307
3,000	1,515	0.342
3,500	1,688	0.346
4,000	1,858	0.340
4,404 (Top Perf)	1,996	0.342
4,543	2,044	0.343

CO_2 Injection Rate at Top Perforation = 2.296 MMSCFD

RE6.2/evg17


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4404 FT.
BHP = 1996 PSI
EAST VACUUM GRAYBURG – SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2801 WELL NO. W007
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

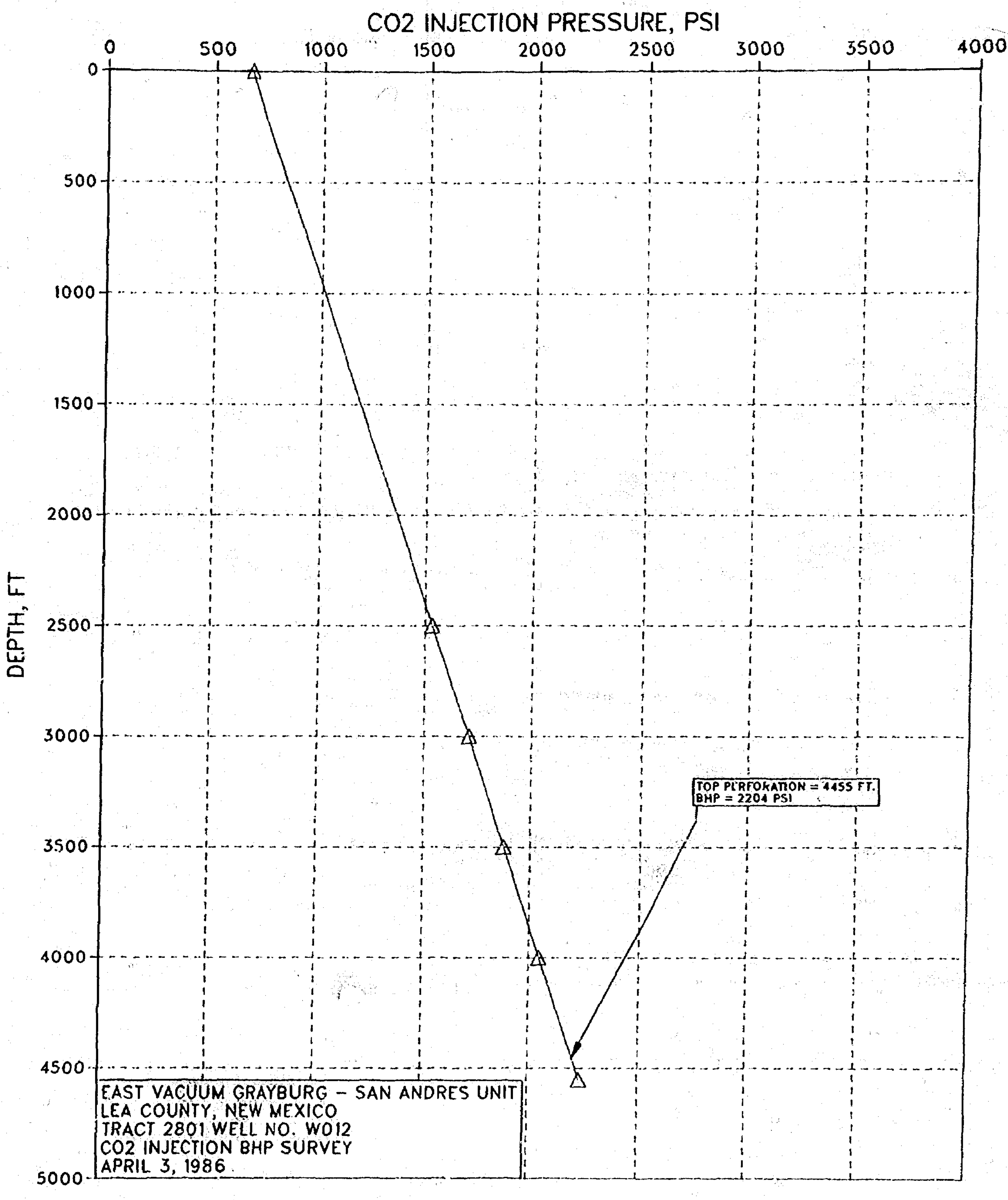
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2801, Well No. W012

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	673	
2,500	1,533	0.344
3,000	1,708	0.350
3,500	1,877	0.338
4,000	2,048	0.342
4,455 (Top Perf)	2,204	0.343
4,552	2,238	0.344

CO_2 Injection Rate at Top Perforation = 1.138 MMSCFD

RE6.2/evg18



CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4455 FT.
BHP = 2204 PSI
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2801 WELL NO. W012
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

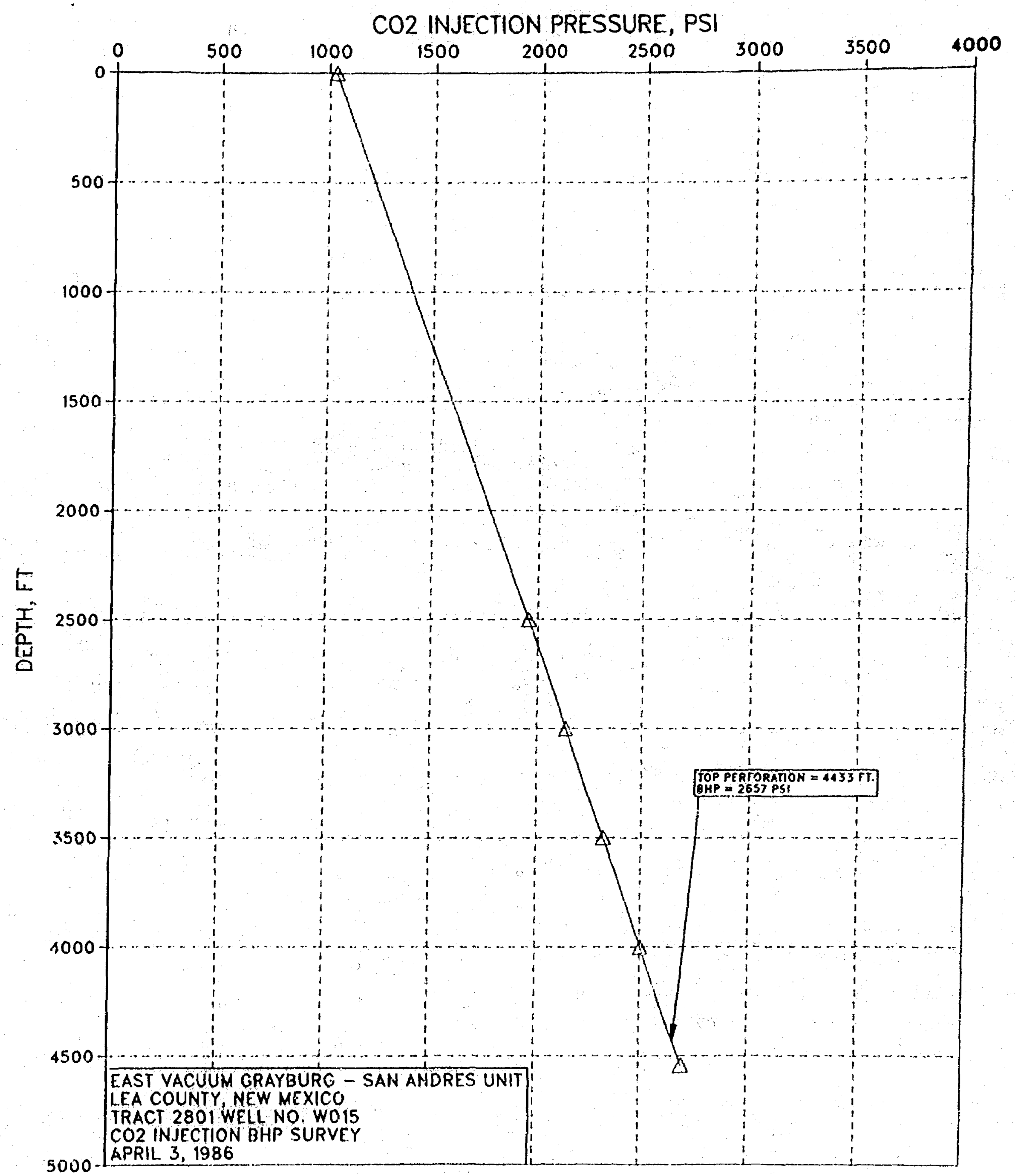
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2801, Well No. W015

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,033	
2,500	1,958	0.370
3,000	2,138	0.360
3,500	2,319	0.362
4,000	2,502	0.366
4,433 (Top Perf)	2,657	0.358
4,544	2,697	0.358

CO_2 Injection Rate at Top Perforation = 1.597 MMSCFD

RE6.2/evg19


CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4433 FT.
BHP = 2657 PSI
EAST VACUUM GRAYBURG – SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2801 WELL NO. W015
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

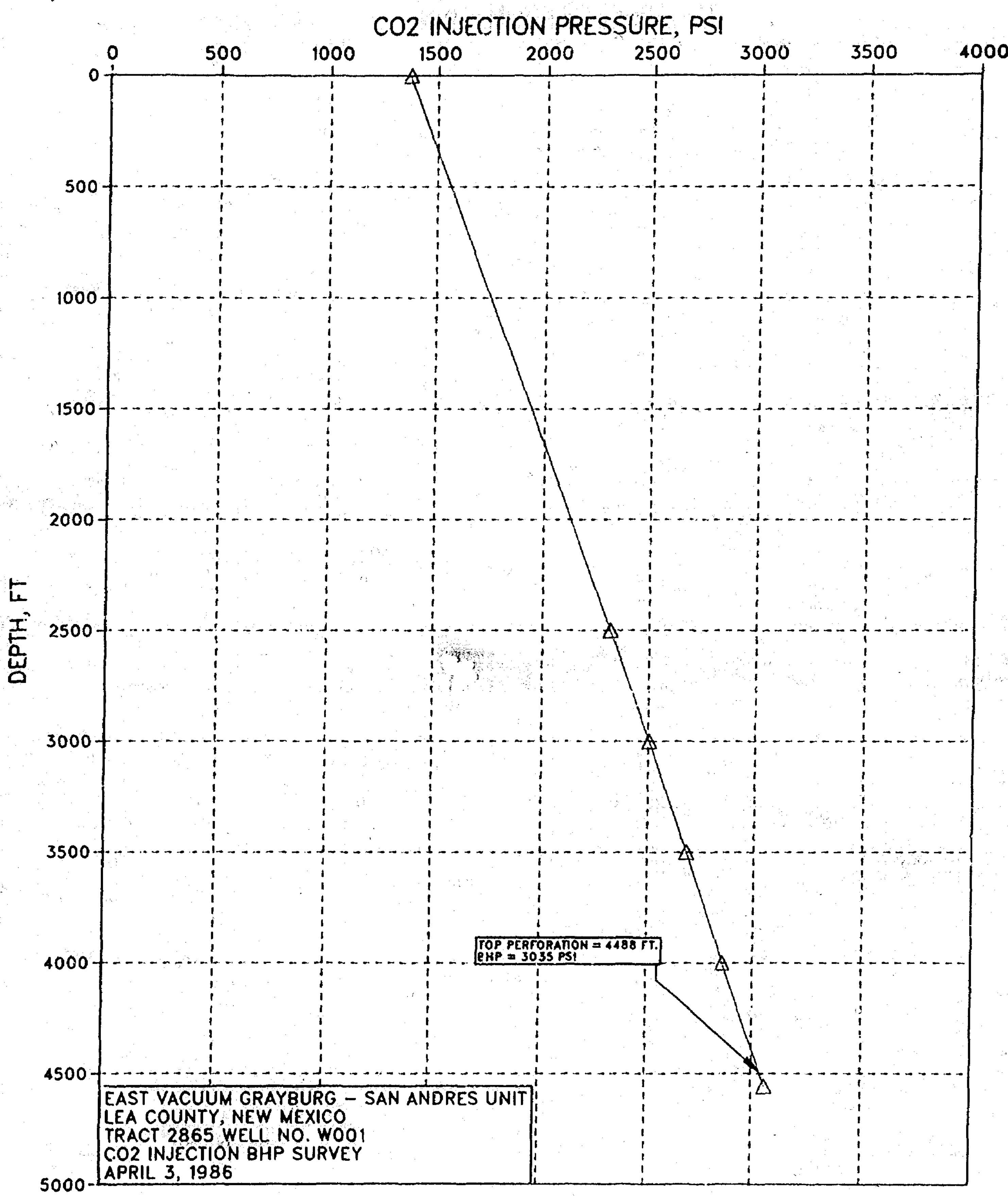
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 2865, Well No. W001

CO_2 Injection BHP Survey Data

Depth, ft.	CO_2 Injection Pressure, psi	Gradient, psi/ft
0	1,374	
2,500	2,317	0.377
3,000	2,504	0.374
3,500	2,682	0.356
4,000	2,859	0.354
4,488 (Top Perf)	3,035	0.361
4,556	3,059	0.360

CO_2 Injection Rate at Top Perforation = 0.896 MMSCFD

RE6.2/evg20



CO2 INJECTION PRESSURE, PSI
0
500
1000
1500
2000
2500
3000
3500
4000
DEPTH, FT
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
TOP PERFORATION = 4488 FT.
BHP = 3035 PSI
EAST VACUUM GRAYBURG – SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO
TRACT 2865 WELL NO. W001
CO2 INJECTION BHP SURVEY
APRIL 3, 1986

PHILLIPS PETROLEUM COMPANY
ODESSA, TEXAS 79762
4001 PENBROOK

EXPLORATION AND PRODUCTION GROUP

February 3, 1986

East Vacuum Grayburg - San Andres Unit
Carbon Dioxide Injection Project
Lea County, New Mexico

Case 7426

New Mexico Oil Conservation Division
Attn: Mr. Jerry Sexton
P. O. Box 1980
Hobbs, New Mexico 82240

Dear Mr. Sexton:

As authorized by the New Mexico Oil Conservation Division Order No. R-6856, carbon dioxide injection is presently in progress in the East Vacuum Grayburg - San Andres Unit.

Currently, CO_2 is being injected into WAG (water-alternate-gas) Area A as outlined in our correspondence dated September 24, 1985. Attached are the injection bottom hole pressure surveys performed in the WAG Area A injectors. The data reveal that all of the CO_2 injectors are below the bottom hole parting pressure or the bottom hole pressure limitation of 3150 psi, whichever is applicable.

If you have any questions concerning this matter, please contact Mr. Mike Brownlee in Odessa at (915) 367-1413.

Very truly yours,

G. R. Smith

G. R. Smith, Director
Reservoir Engineering

GRS/MAA/sdb
PR.E/evgsau14

Attachments

cc: New Mexico Oil Conservation Division
Attn: Mr. R. L. Stamets
P. O. Box 2088
Santa Fe, New Mexico 87501

EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Summary of CO_2 Injection BHP Survey Results
for WAG Area A

Tract-Well	Surface Injection Pressure Psi	CO_2 Injection Rate at Top Perf. MMSCFD	Depth of Top Perforation	*Bottom Hole Pressure at Injection Rate Psi	+Bottom Hole Parting Pressure Psi
3315-W006	776	2.238	4397'	2348	3500
3315-W008	514	1.394	4450'	1615	3166@
3328-W003	548	1.841	4458'	2102	2840
3332-W001	679	2.508	4449'	2243	3074@
3333-W005	1,074	2.435	4394'	2672	3617@
3333-W006	745	2.350	4387'	2302	3283@
3373-W001	862	2.288	4462'	2474	4148@
3374-W002	615	3.002	4360'	2111	3385@
3456-W006	552	2.187	4376'	1892	2414@
3456-W007	515	3.298	4509'	1819	2445@
3456-W009	621	2.292	4446'	2160	2732@

* - Pressure at Top Perforation

+ - Parting pressure obtained from step rate tests, using water as the injection fluid, performed in August, 1985

@ - No identifiable parting pressure was observed, this is the maximum bottom hole pressure observed during the test.

PR.E/east.wag

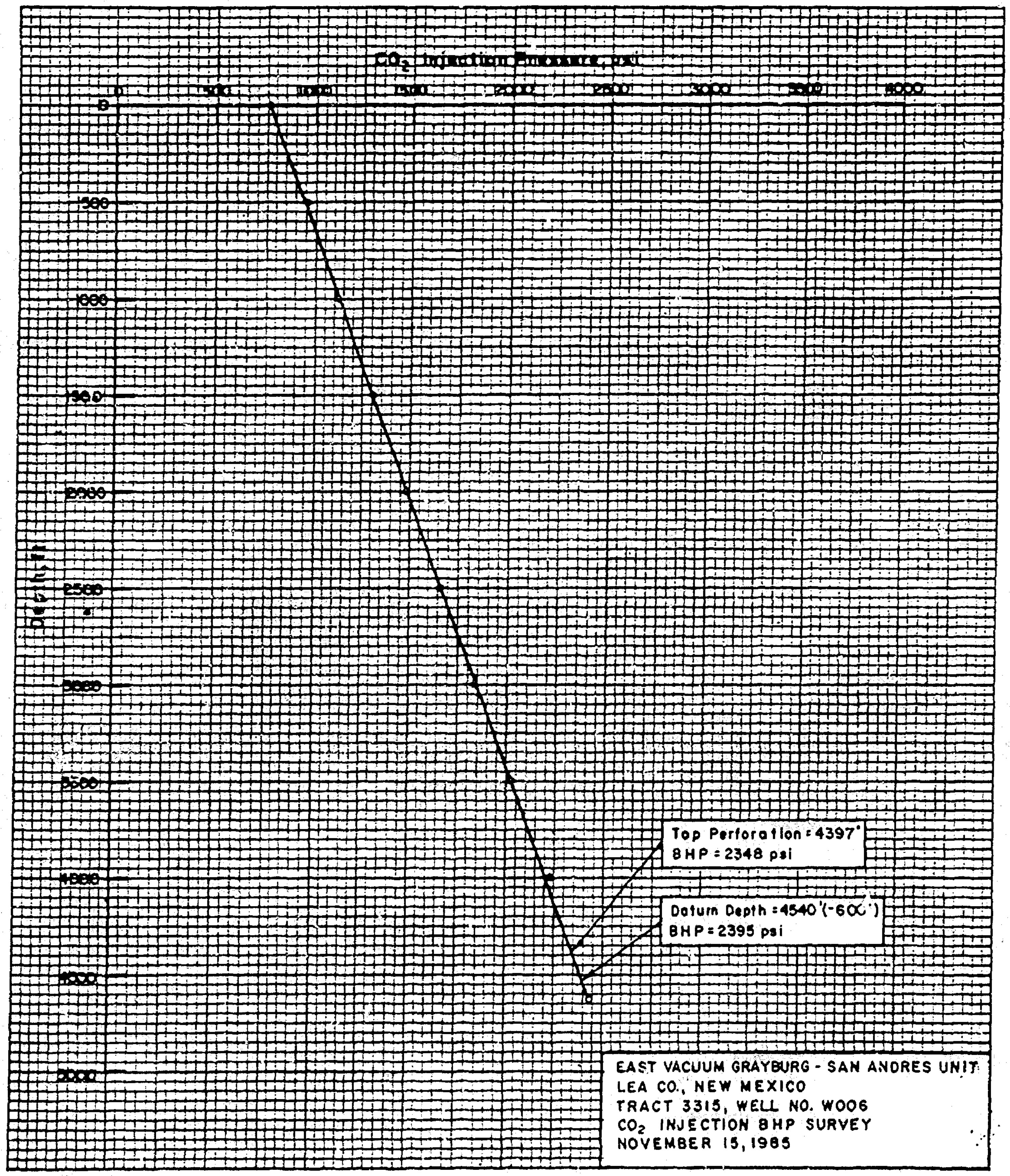
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 3315, Well No. W006

CO_2 Injection BHP Survey Data

Depth, Ft.	CO_2 Injection Pressure, Psi	Gradient, Psi/Ft
0	776	
500	958	0.364
1,000	1,129	0.342
1,500	1,310	0.362
2,000	1,489	0.358
2,500	1,665	0.352
3,000	1,841	0.352
3,500	2,014	0.346
4,000	2,218	0.408
4,397 (Top Perf)	2,348	0.328
4,540 (Datum Depth, - 600')	2,395	0.328
4,628	2,424	0.328

CO_2 Injection Rate at Top Perforation = 2.238 MMSCFD

PR.E/east.wagl



CO2 Injection Pressure, psi
0
500
1000
1500
2000
2500
3000
3500
4000
Depth, ft
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation = 4397'
BHP = 2348 psi
Datum Depth = 4540' (-600')
BHP = 2395 psi
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA CO., NEW MEXICO
TRACT 3315, WELL NO. W006
CO2 INJECTION BHP SURVEY
NOVEMBER 15, 1985

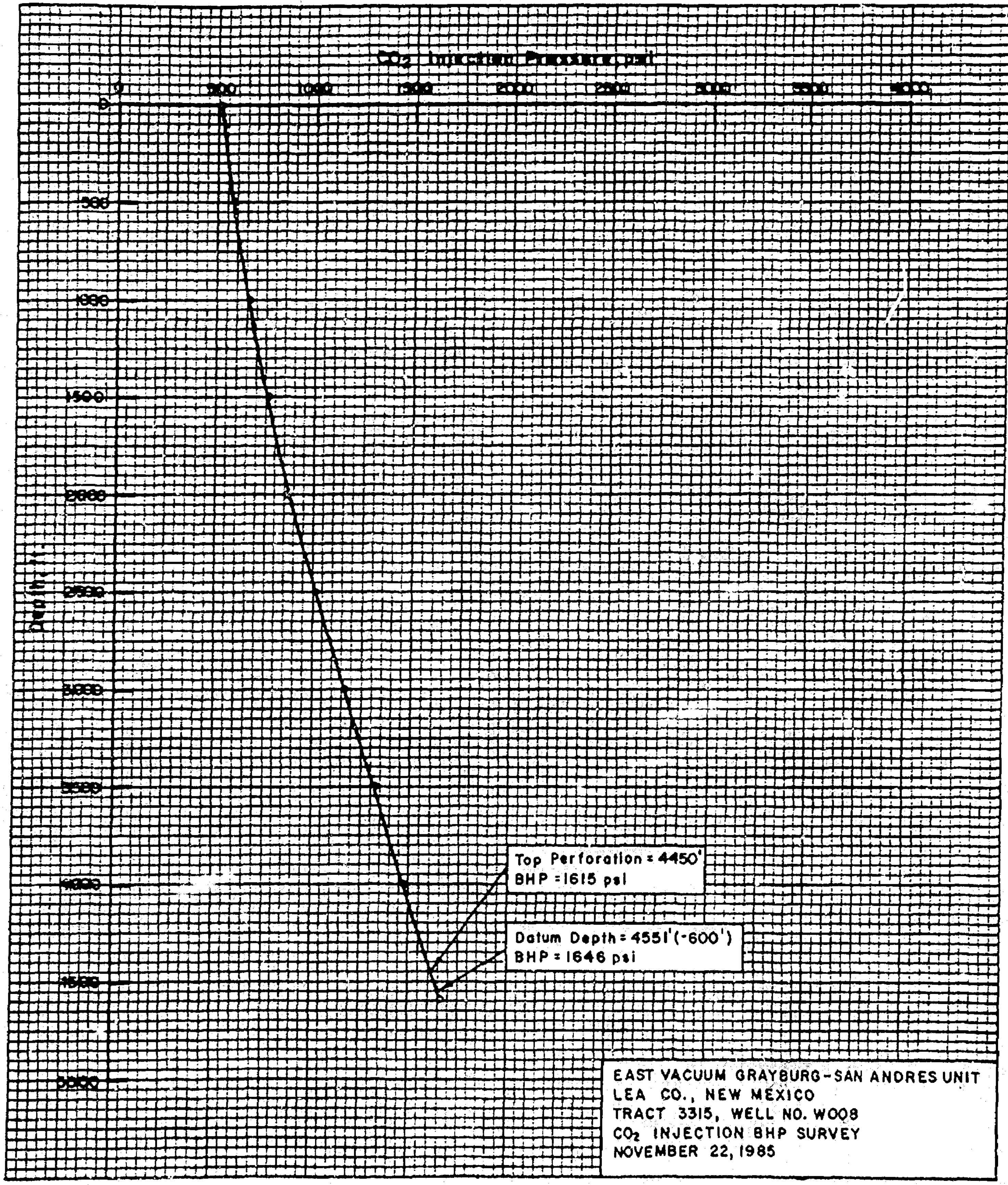
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 3315, Well No. W008

CO_2 Injection BHP Survey Data

Depth, Ft.	CO_2 Injection Pressure, Psi	Gradient, Psi/Ft.
0	514	
500	583	0.138
1,000	661	0.156
1,500	758	0.194
2,000	875	0.234
2,500	1,020	0.290
3,000	1,170	0.300
3,500	1,323	0.306
4,000	1,477	0.308
4,450 (Top Perf)	1,615	0.307
4,551 (Datum Depth, - 600')	1,646	0.307
4,593	1,659	0.307

CO_2 Injection Rate at Top Perforation = 1.394 MMSCFD

PR.E/east.wag2



EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA CO., NEW MEXICO
TRACT 3315, WELL NO. W008
CO_2 INJECTION BHP SURVEY
NOVEMBER 22, 1985

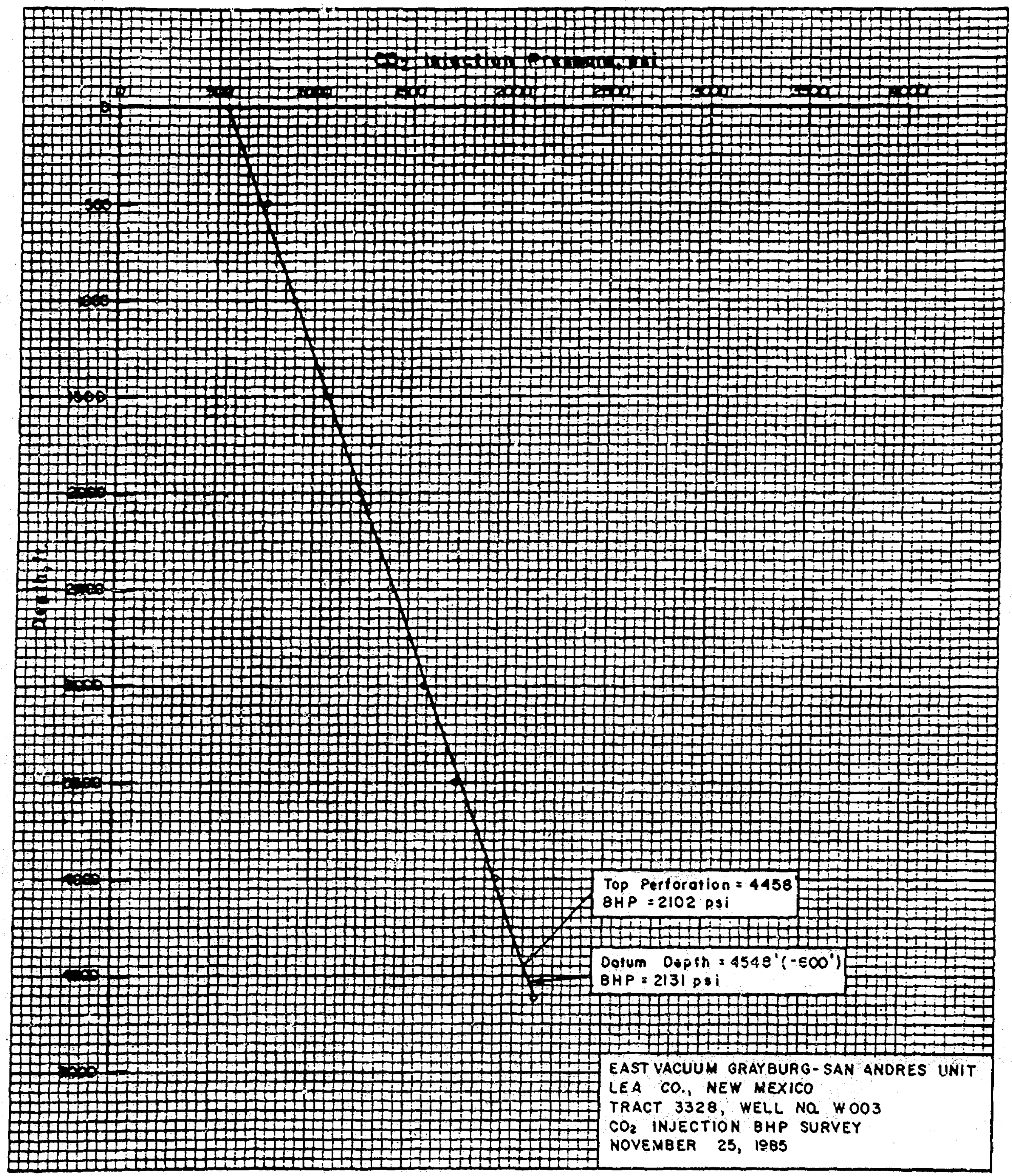
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 3328, Well No. W003

CO_2 Injection BHP Survey Data

Depth, Ft	CO_2 Injection Pressure, Psi	Gradient, Psi/Ft.
0	548	
500	753	0.410
1,000	903	0.300
1,500	1,077	0.348
2,000	1,242	0.330
2,500	1,409	0.334
3,000	1,580	0.342
3,500	1,745	0.330
4,000	1,950	0.410
4,458 (Top Perf)	2,102	0.332
4,548 (Datum Depth, - 600')	2,131	0.330
4,610	2,152	0.331

CO_2 Injection Rate at Top Perforation = 1.841 MMSCFD

PR.E/east.wag3


Top Perforation = 4458'
BHP = 2102 psi
Datum Depth = 4548'(-600')
BHP = 2131 psi
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA CO., NEW MEXICO
TRACT 3328, WELL NO. W003
CO_2 INJECTION BHP SURVEY
NOVEMBER 25, 1985

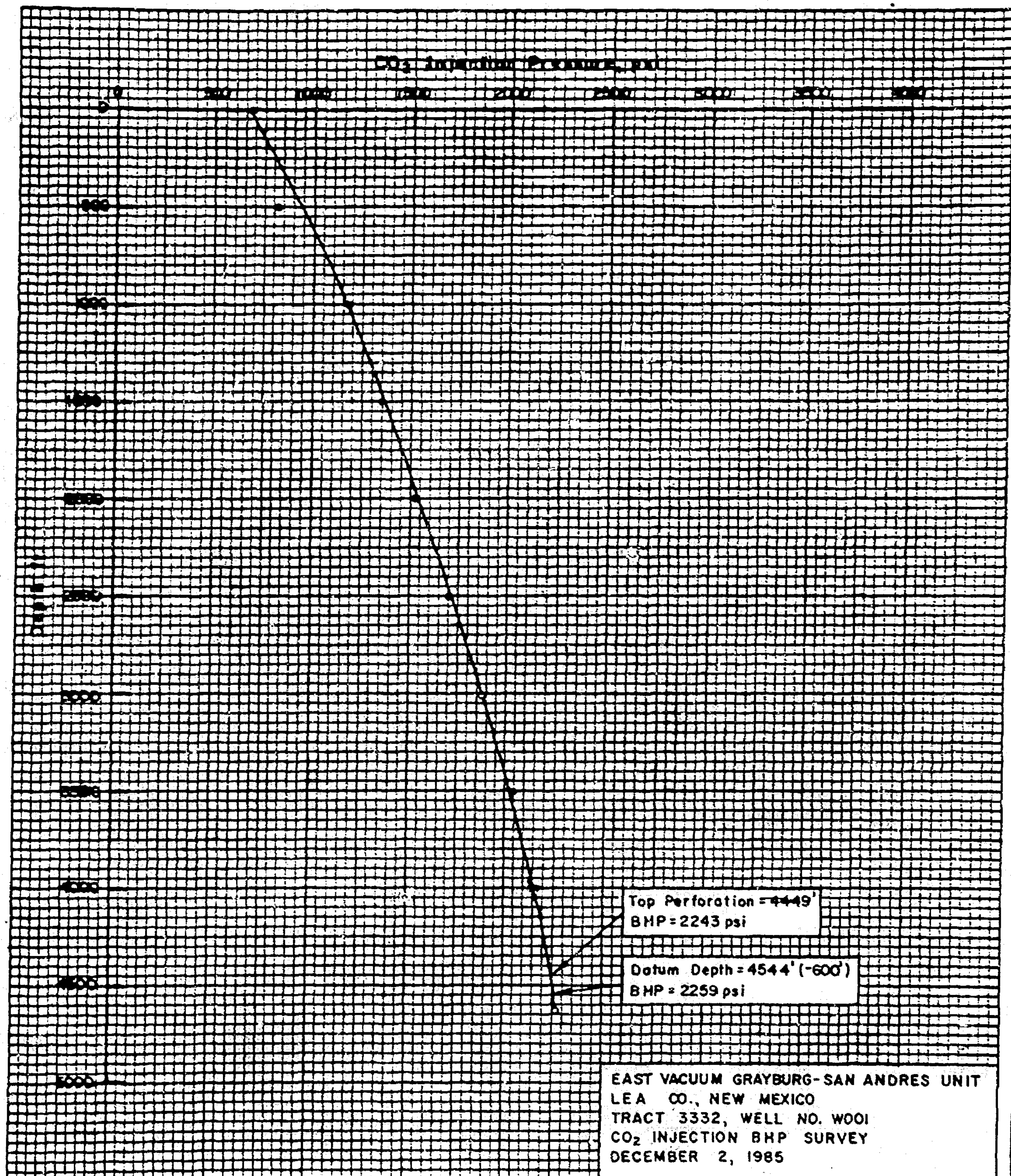
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 3332, Well No. W001

CO_2 Injection BHP Survey Data

Depth, Ft	CO_2 Injection Pressure, Psi	Gradient, Psi/Ft.
0	679	
500	823	0.288
1,000	1,181	0.716
1,500	1,357	0.352
2,000	1,527	0.340
2,500	1,706	0.358
3,000	1,882	0.352
3,500	2,052	0.340
4,000	2,168	0.232
4,449 (Top Perf)	2,243	0.167
4,544 (Datum Depth, - 600')	2,259	0.167
4,631	2,273	0.166

CO_2 Injection Rate at Top Perforation = 2.508 MMSCFD

PR.E.east.wag.4



Top Perforation = 4449'
BHP = 2243 psi
Datum Depth = 4544' (-600')
BHP = 2259 psi
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA CO., NEW MEXICO
TRACT 3332, WELL NO. W001
CO_2 INJECTION BHP SURVEY
DECEMBER 2, 1985

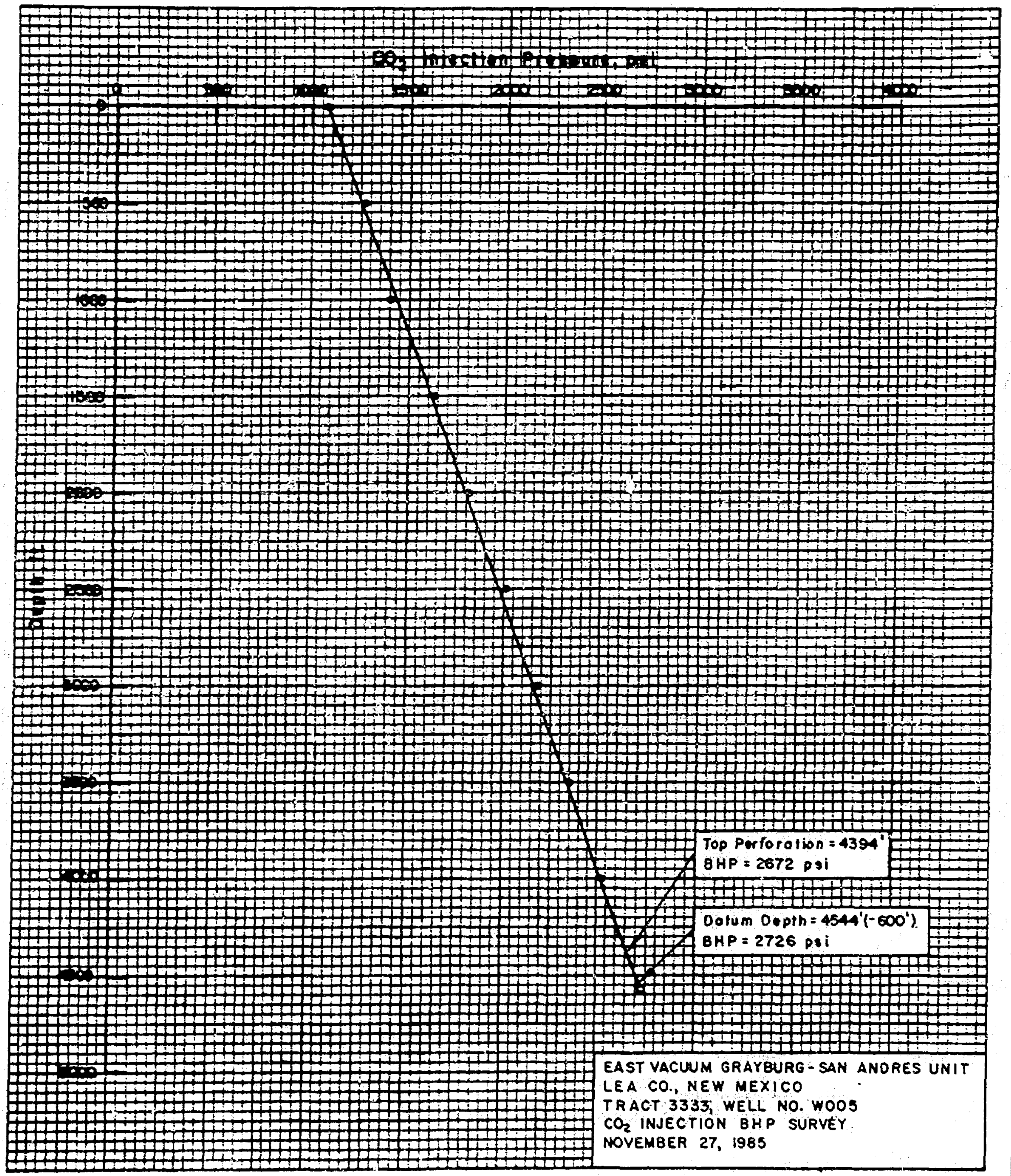
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 3333, Well No. W005

CO_2 Injection BHP Survey Data

Depth, Ft	CO_2 Injection Pressure, Psi	Gradient, Psi/Ft.
0	1,074	
500	1,261	0.374
1,000	1,407	0.292
1,500	1,626	0.438
2,000	1,810	0.368
2,500	2,011	0.402
3,000	2,174	0.326
3,500	2,350	0.352
4,000	2,532	0.364
4,394 (Top Perf)	2,672	0.355
4,544 (Datum Depth, - 600')	2,726	0.357
4,564	2,733	0.356

CO_2 Injection Rate at Top Perforation = 2.435 MMSCFD

PR.E/east.wag5


Top Perforation = 4394'
BHP = 2672 psi
Datum Depth = 4544'(-600')
BHP = 2726 psi
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA CO., NEW MEXICO
TRACT 3333, WELL NO. W005
CO2 INJECTION BHP SURVEY
NOVEMBER 27, 1985

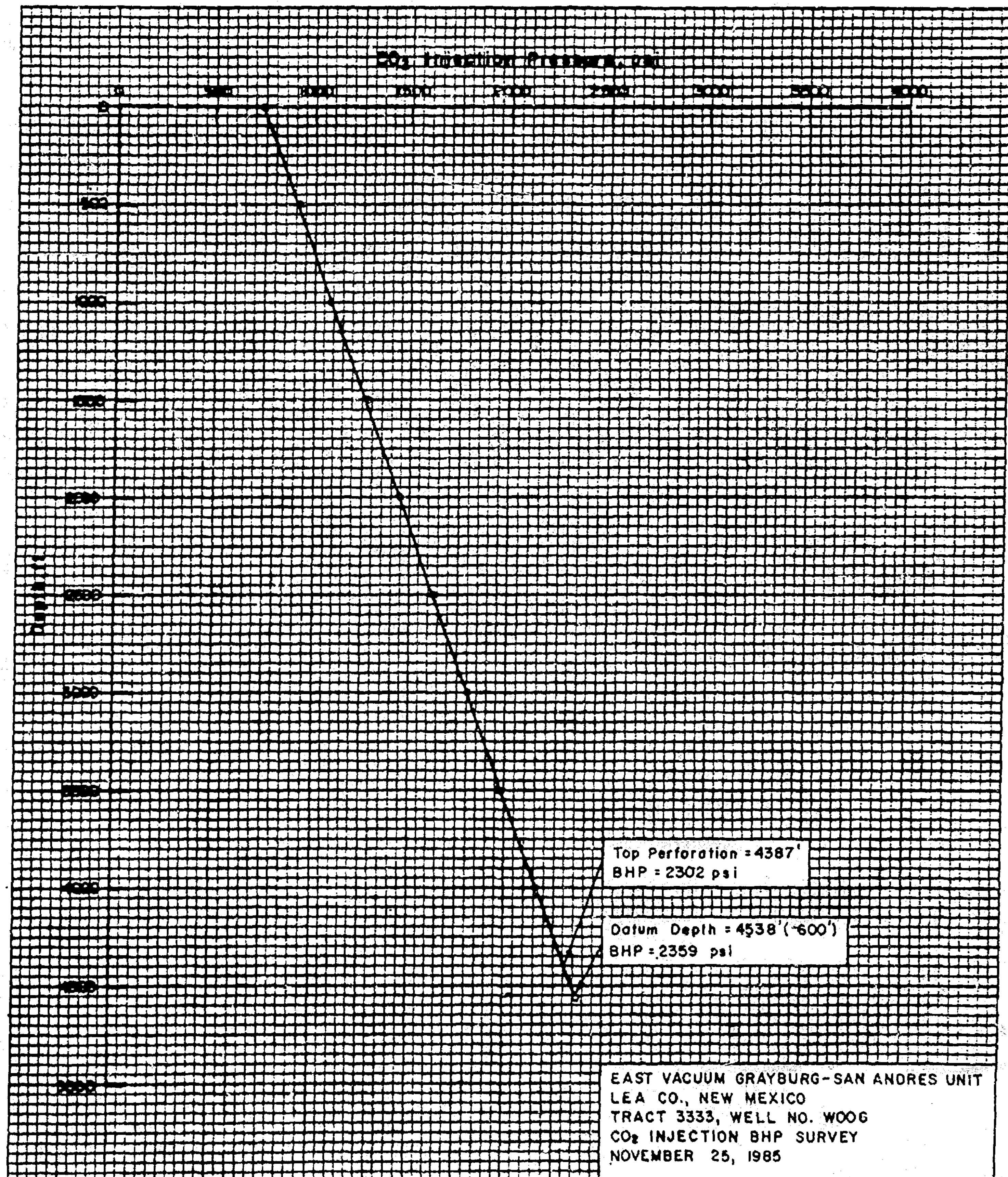
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 3333, Well No. W006

CO_2 Injection BHP Survey Data

Depth, Ft	CO_2 Injection Pressure, Psi	Gradient, Psi/Ft.
0	745	
500	917	0.344
1,000	1,096	0.358
1,500	1,272	0.352
2,000	1,453	0.362
2,500	1,629	0.352
3,000	1,808	0.358
3,500	1,983	0.350
4,000	2,157	0.348
4,387 (Top Perf)	2,302	0.375
4,538 (Datum Depth, - 600')	2,359	0.375
4,572	2,372	0.376

CO_2 Injection Rate at Top Perforation = 2.350 MMSCFD

PR.E/east.wag6


Top Perforation = 4387'
BHP = 2302 psi
Datum Depth = 4538' (-600')
BHP = 2359 psi
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA CO., NEW MEXICO
TRACT 3333, WELL NO. WOOG
CO2 INJECTION BHP SURVEY
NOVEMBER 25, 1985

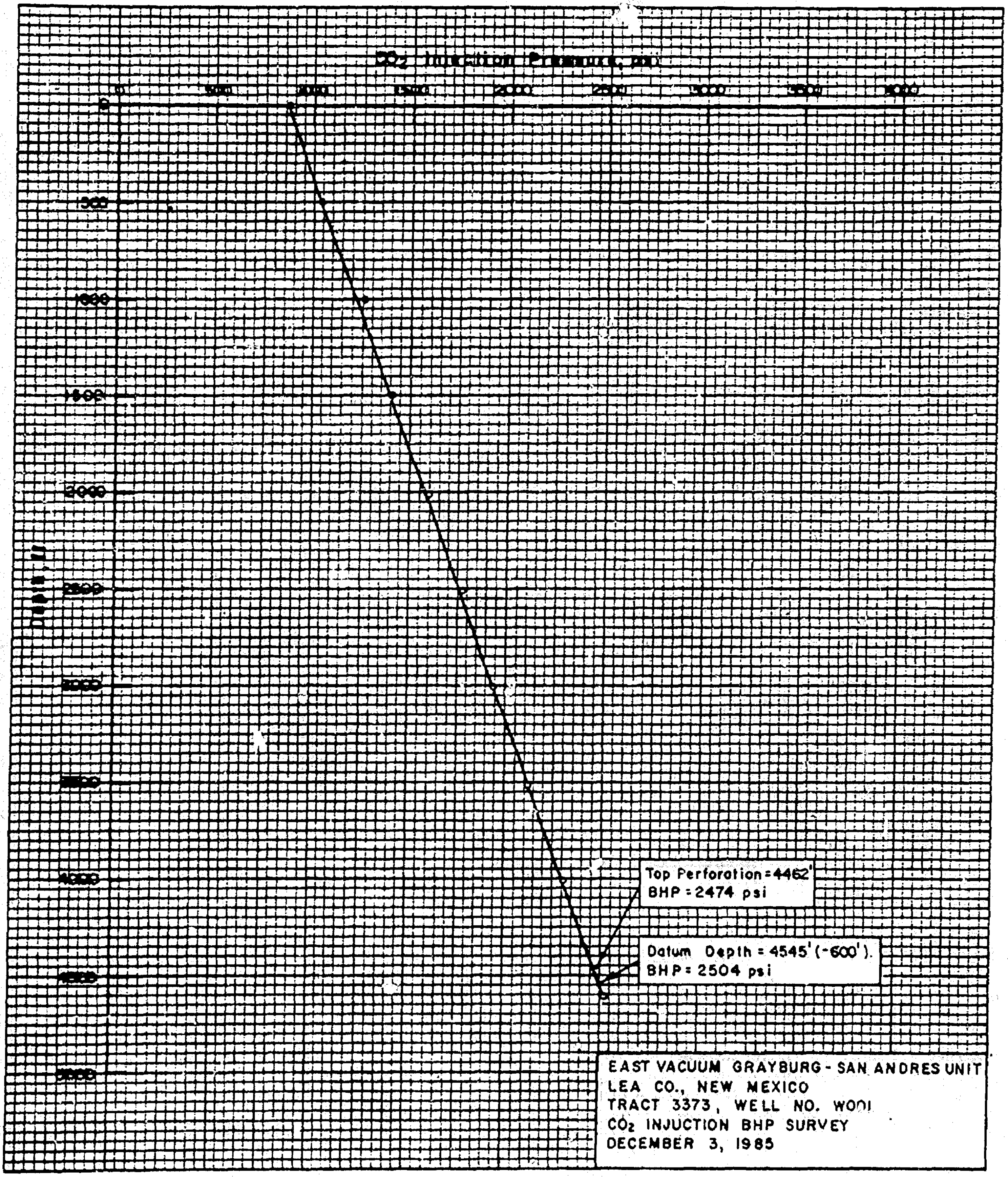
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 3373, Well No. W001

CO_2 Injection BHP Survey Data

Depth, Ft	CO_2 Injection Pressure, Psi	Gradient, Psi/Ft.
0	862	
500	1,044	0.364
1,000	1,261	0.434
1,500	1,409	0.296
2,000	1,591	0.364
2,500	1,769	0.356
3,000	1,948	0.358
3,500	2,129	0.362
4,000	2,306	0.354
4,462 (Top Perf)	2,474	0.363
4,545 (Datum Depth, - 600')	2,504	0.363
4,598	2,523	0.363

CO_2 Injection Rate at Top Perforation = 2.288 MMSCFD

PR.E/east.wag7



CO_2 Injection Pressure, psi
0
500
1000
1500
2000
2500
3000
3500
4000
Depth, ft
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation = 4462'
BHP = 2474 psi
Datum Depth = 4545' (-600').
BHP = 2504 psi
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA CO., NEW MEXICO
TRACT 3373, WELL NO. W001
CO_2 INJUCTION BHP SURVEY
DECEMBER 3, 1985

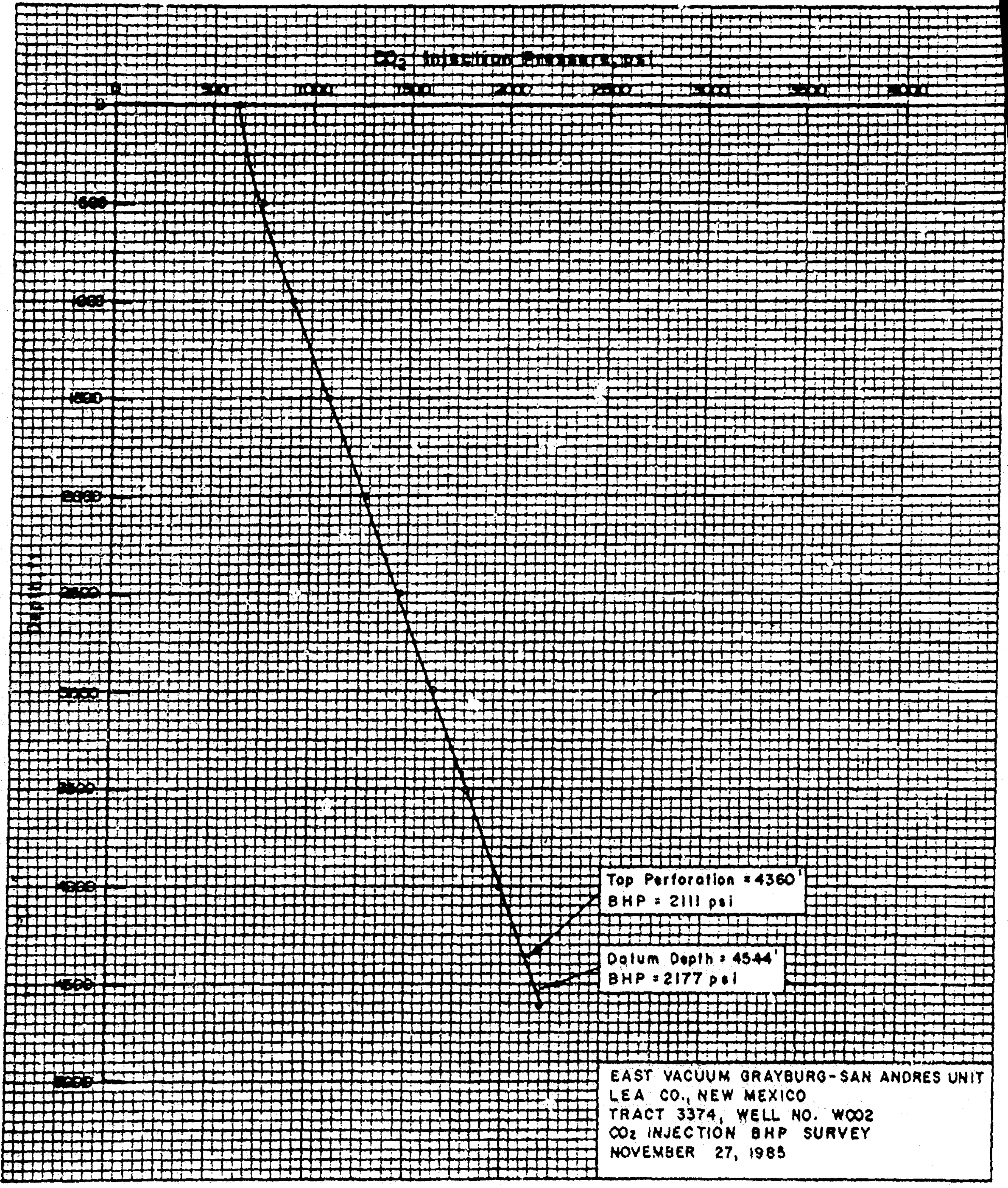
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 3374, Well No. W002

CO_2 Injection BHP Survey Data

Depth, Ft	CO_2 Injection Pressure, Psi	Gradient, Psi/Ft.
0	615	
500	747	0.264
1,000	919	0.344
1,500	1,098	0.358
2,000	1,275	0.354
2,500	1,451	0.352
3,000	1,630	0.358
3,500	1,803	0.346
4,000	1,982	0.358
4,360 (Top Perf)	2,111	0.358
4,544 (Datum Depth, - 600')	2,177	0.358
4,620	2,204	0.358

CO_2 Injection Rate at Top Perforation = 3.002 MMSCFD

PR.E/east.wag8


Top Perforation = 4360'
BHP = 2111 psi
Datum Depth = 4544'
BHP = 2177 psi
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA CO., NEW MEXICO
TRACT 3374, WELL NO. W002
CO2 INJECTION BHP SURVEY
NOVEMBER 27, 1985

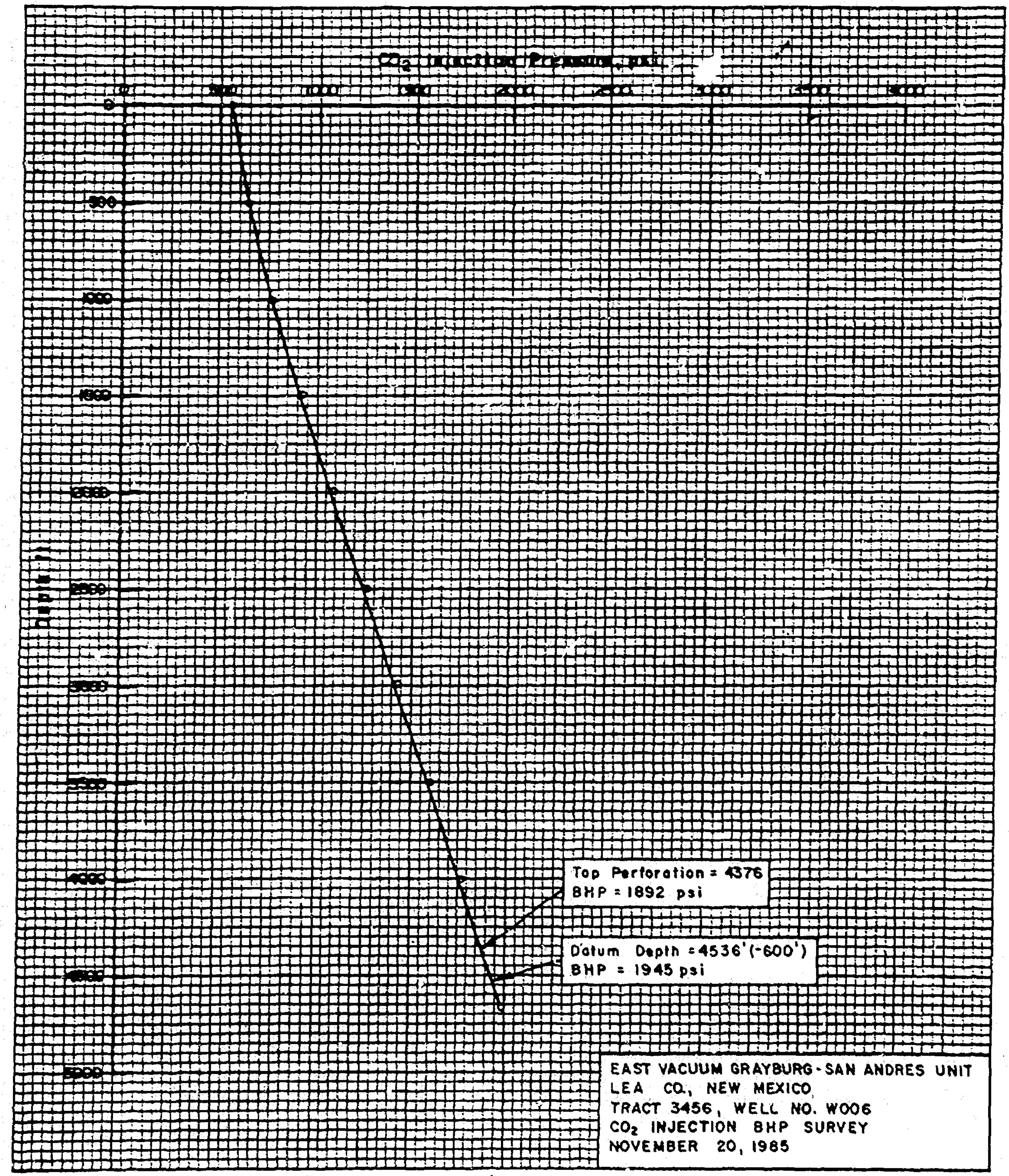
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 3456, Well No. W006

CO_2 Injection BHP Survey Data

Depth, Ft	CO_2 Injection Pressure, Psi	Gradient, Psi/Ft.
0	552	0.190
500	647	0.242
1,000	768	0.242
1,500	927	0.318
2,000	1,096	0.338
2,500	1,265	0.338
3,000	1,432	0.334
3,500	1,601	0.338
4,000	1,768	0.334
4,376 (Top Perf)	1,892	0.330
4,536 (Datum Depth, - 600')	1,945	0.330
4,661	1,986	0.330

CO_2 Injection Rate at Top Perforation = 2.187 MMSCFD

PR.E/east.wag9



Top Perforation = 4376
BHP = 1892 psi
Datum Depth = 4536'(-600')
BHP = 1945 psi
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA CO., NEW MEXICO
TRACT 3456, WELL NO. W006
CO_2 INJECTION BHP SURVEY
NOVEMBER 20, 1985

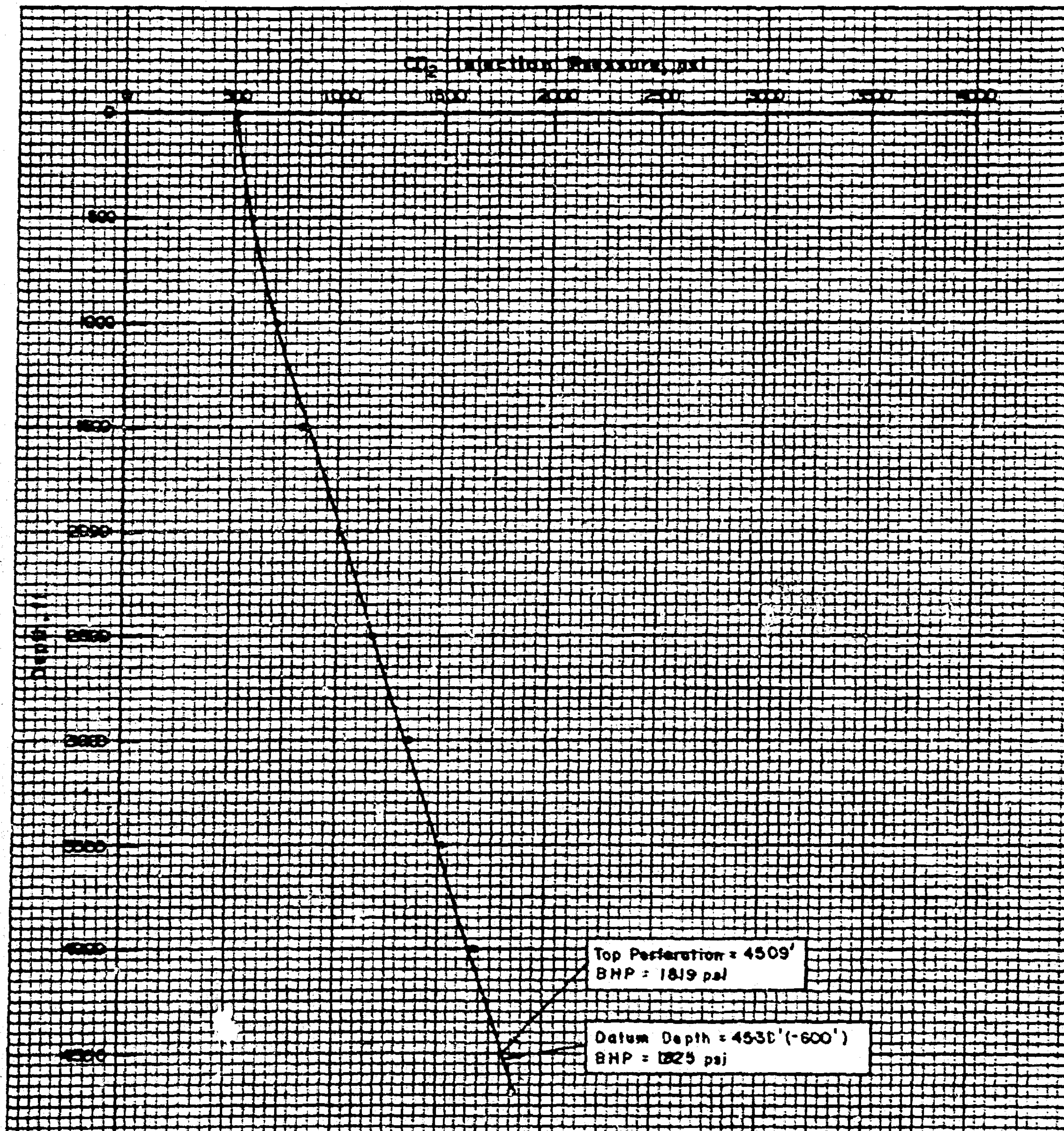
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 3456, Well No. W007

CO_2 Injection BHP Survey Data

Depth, Ft	CO_2 Injection Pressure, Psi	Gradient, Psi/Ft.
0	515	
500	598	0.166
1,000	704	0.212
1,500	842	0.276
2,000	1,011	0.338
2,500	1,181	0.340
3,000	1,352	0.342
3,500	1,522	0.340
4,000	1,692	0.340
4,509 (Top Perf)	1,819	0.250
4,531 (Datum Depth, - 600')	1,825	0.250
4,691	1,865	0.250

CO_2 Injection Rate at Top Perforation = 3.298 MMSCFD

PR.E/east.wag10



EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA CO., NEW MEXICO
TRACT 3456, WELL NO. W007
CO_2 INJECTION BHP SURVEY
NOVEMBER 15, 1985

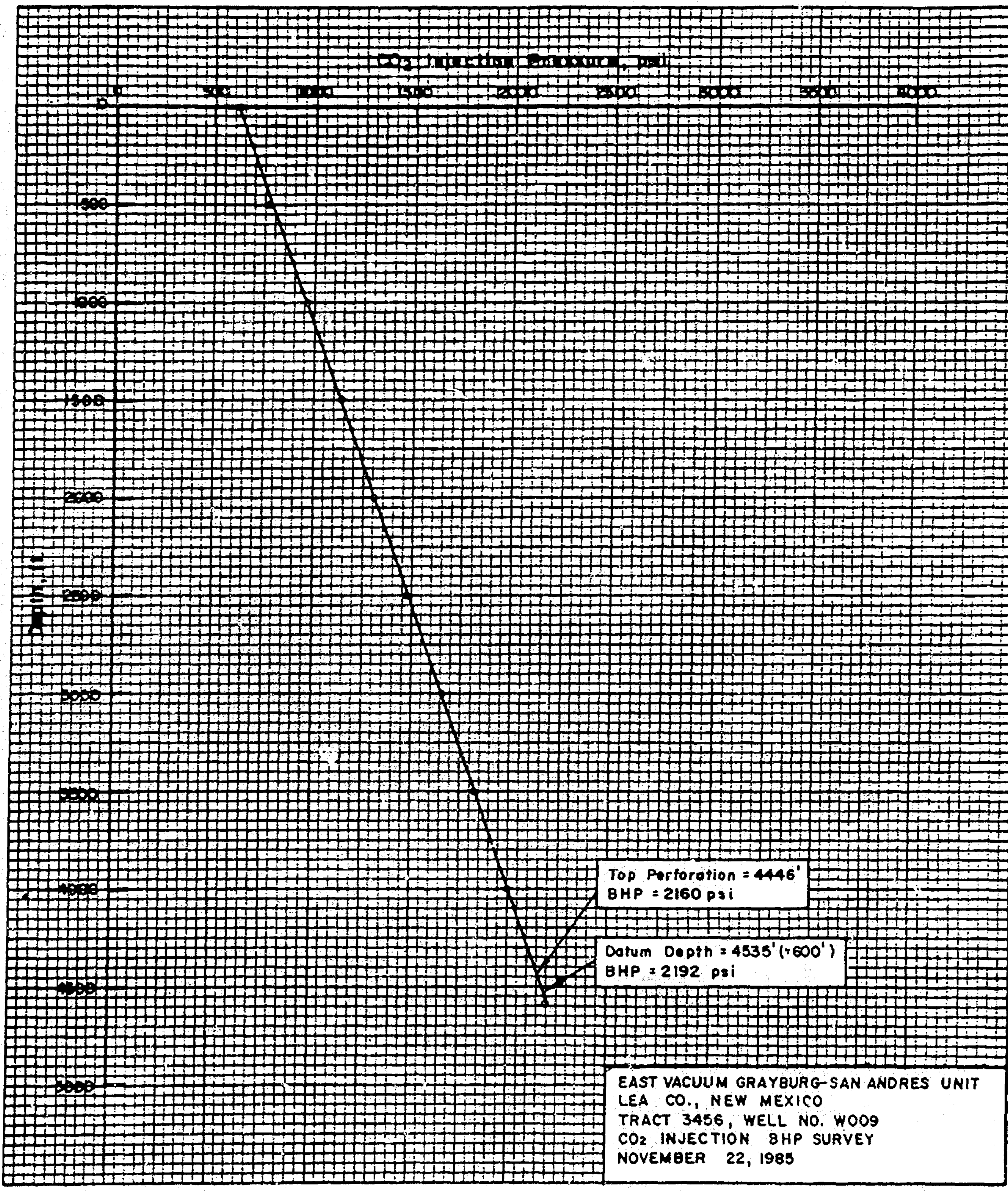
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
Tract 3456, Well No. W009

CO_2 Injection BHP Survey Data

Depth, Ft	CO_2 Injection Pressure, Psi	Gradient, Psi/Ft.
0	621	
500	775	0.308
1,000	954	0.358
1,500	1,134	0.360
2,000	1,308	0.348
2,500	1,484	0.352
3,000	1,660	0.352
3,500	1,834	0.348
4,000	2,002	0.336
4,446 (Top Perf)	2,160	0.354
4,535 (Datum Depth, - 600')	2,192	0.355
4,590	2,212	0.356

CO_2 Injection Rate at Top Perforation = 2.292 MMSCFD

PR.E/east.wag11



CO2 Injection Pressure, psi
0
500
1000
1500
2000
2500
3000
3500
4000
Depth, ft
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Top Perforation = 4446'
BHP = 2160 psi
Datum Depth = 4535' (-600')
BHP = 2192 psi
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
LEA CO., NEW MEXICO
TRACT 3456, WELL NO. W009
CO2 INJECTION BHP SURVEY
NOVEMBER 22, 1985

PHILLIPS PETROLEUM COMPANY
ODESSA, TEXAS 79762
4001 PENBROOK

EXPLORATION AND PRODUCTION GROUP
Permian Basin Region

September 24, 1985

East Vacuum Grayburg-San Andres Unit
Carbon Dioxide Injection Project
Lea County, New Mexico

New Mexico Oil Conservation Division
Attn: Mr. Jerry Sexton
P. O. Box 1980
Hobbs, New Mexico 82240

Dear Mr. Sexton:

Carbon dioxide injection is to commence in the East Vacuum Grayburg-San Andres Unit during October, 1985. This action was authorized by New Mexico Oil Conservation Division Order No. R-6856.

For operational purposes, we have split the CO_2 project area into three segments (see attached map) and will be injecting CO_2 into each segment in sequence. We shall begin injection of 30 MMCF/D of CO_2 into the eleven (11) WAG (water-alternate-gas) injectors in area A. After approximately four months, we will begin CO_2 injection into area B, returning area A to water injection. After another four months, we will begin CO_2 injection into area C, returning area B to water injection. After four months of CO_2 injection into area C, the cycle will start over again. This rotation will not affect the water injection into the unit's periphery injectors within the project area or those injectors outside the CO_2 project area.

During the time a well is on CO_2 injection service, we will be injecting at up to 3150 psi bottom hole pressure, as authorized by Order No. R-6856. We do not, however, wish to exceed parting pressure. We have, therefore, been performing step-rate tests on our WAG injectors to determine the parting pressure in each well. Copies of the tests for the first eleven injectors (area A) are attached. Note that only two of these wells showed a parting pressure within the range of our tests; Tract 3315, Well No. W006 at 3500 psi and Tract 3328, Well No. W003 at 2840 psi. Bottom hole injection pressure will be kept at or below 2840 psi in Tract 3328, Well No. W003. The other ten wells in area A will be restricted to the 3150 psi bottom hole injection pressure authorized by the New Mexico Oil Conservation Divison.

Since the attached step-rate tests were run using water as the injection fluid, we do not know exactly what the surface injection pressure is for CO_2 that corresponds to our bottom hole pressure limit. Once we begin CO_2 injection, we will run BHP surveys in these wells to make sure we are not exceeding our bottom hole injection pressure limit and to determine the surface injection pressure that corresponds to it. We will submit these data to you as soon as the tests are run.

We will begin running step-rate tests in area B once we start CO_2 injection into area A. We will submit these data to you before starting CO_2 injection into that area. If you have any questions on this matter, please call Mr. Mike Brownlee in Odessa at (915) 367-1413.

Very truly yours,

G. R. Smith, Chairman
Working Interest Owners Committee

MHB:jj

Attachments

cc: New Mexico Oil Conservation Divison
Attn: Mr. R. L. Stamets
P. O. Box 2088
Santa Fe, New Mexico 87501

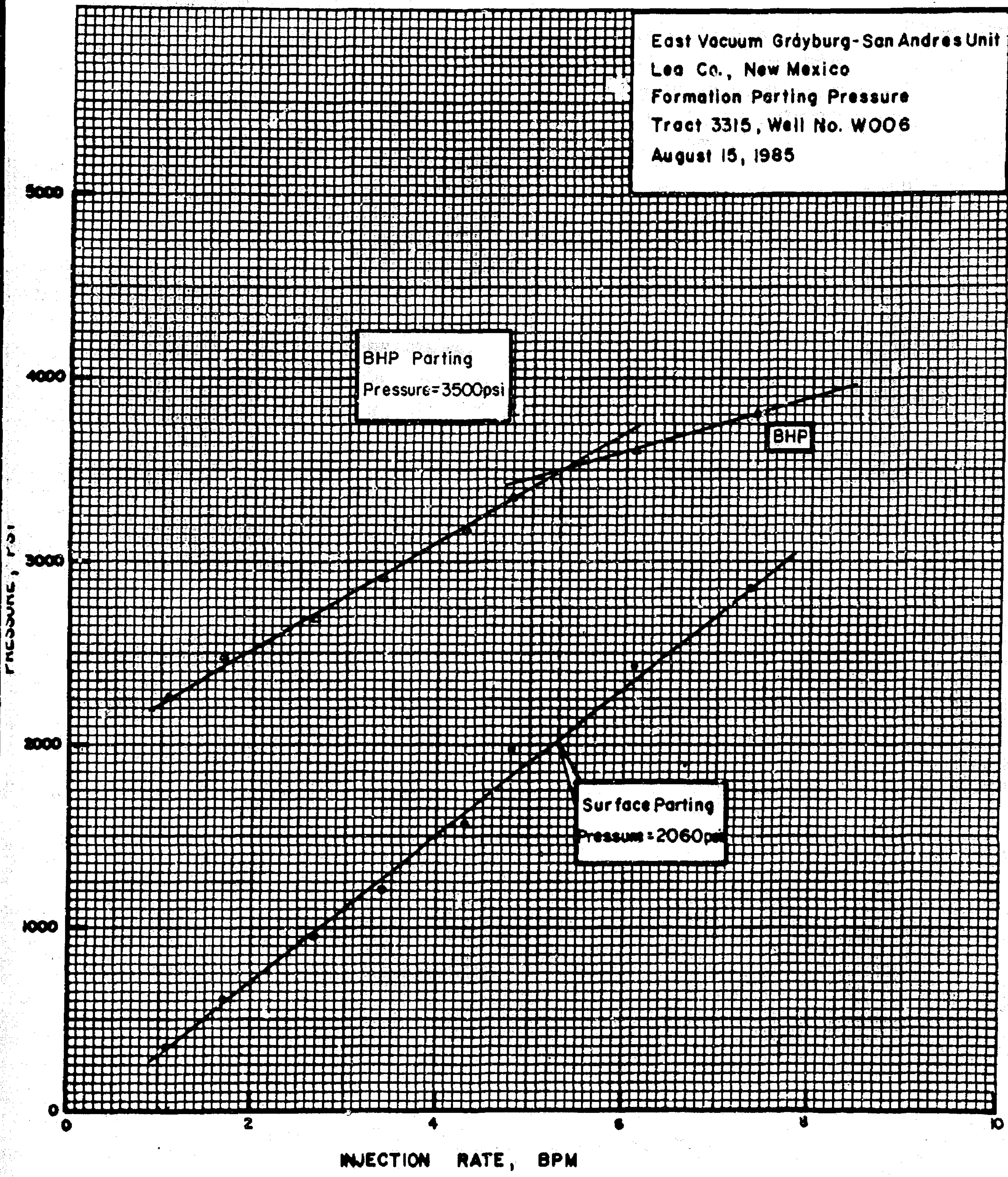
EAST VACUUM GRAYBURG-SAN ANDRES UNIT
SUMMARY OF FORMATION PARTING PRESSURE RESULTS
FOR WAG AREA A

Tract-Well	Depth of Top Perforation	Tubing Size	Bottom Hole Parting Pressure, psi.	Inj. Rate at Parting Pressure, BPD
3315-W006	4397'	2 7/8"	3500	7632
3315-W008	4450'	2 7/8"	NIPP	12240+
3328-W003	4458'	2 7/8"	2840	9922
3332-W001	4449'	2 7/8"	NIPP	11851+
3333-W005	4394'	2 7/8"	NIPP	9936+
3333-W006	4387'	2 7/8"	NIPP	11376+
3373-W001	4462'	2 7/8"	NIPP	9360+
3374-W002	4360'	2 7/8"	NIPP	10944+
3456-W006	4376'	2 7/8"	NIPP	10166+
3456-W007	4509'	2 7/8"	NIPP	12096+
3456-W009	4446'	2 7/8"	NIPP	8640+

NIPP - No identifiable parting pressure.

\+ - Where no identifiable parting pressure is shown, the maximum injection rate attained during the test is given.

RE6/evgsau35

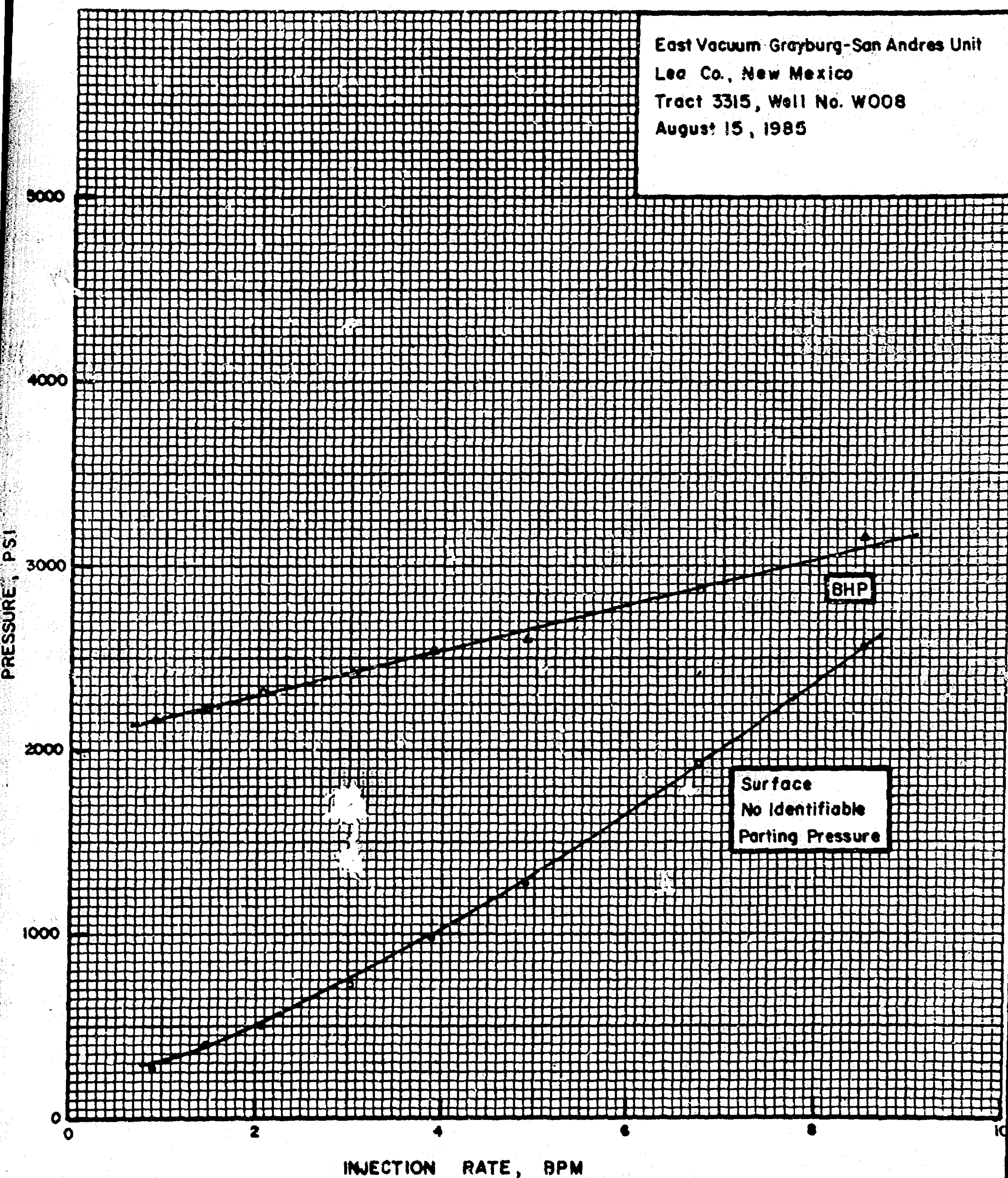

East Vacuum Grayburg-San Andres Unit
Lea Co., New Mexico
Formation Parting Pressure
Tract 3315, Well No. W006
August 15, 1985
BHP Parting
Pressure=3500psi
BHP
Surface Parting
Pressure=2060psi
5000
4000
3000
2000
1000
0
PRESSURE, PSI
0
2
4
6
8
10
INJECTION RATE, BPM

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3315, Well No. W006

FORMATION PARTING PRESSURE
TEST DATA

Injection Rate		Pressure, psi	
BPM	BPD	Surface	BHP
1.07	1541	350	2277
1.70	2448	600	2483
2.67	3845	890	2696
3.40	4896	1215	2922
4.30	6192	1565	3181
4.80	6912	1970	3377
6.10	8784	2420	3609
7.37	10613	2850	3821

RE6/evgsau35.1

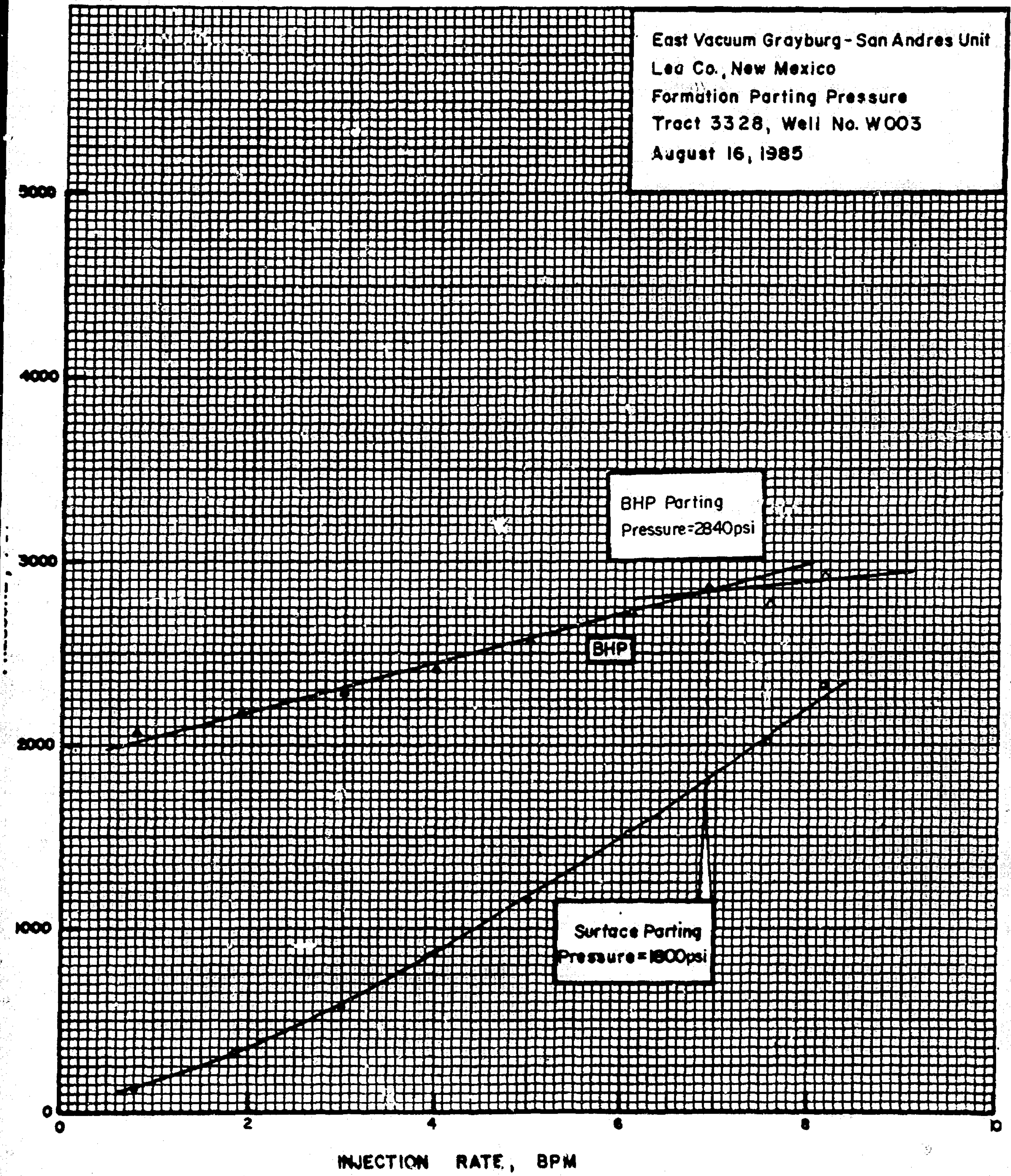

East Vacuum Grayburg-San Andres Unit
Lea Co., New Mexico
Tract 3315, Well No. W008
August 15, 1985
BHP
Surface
No Identifiable
Parting Pressure
PRESSURE, PSI
5000
4000
3000
2000
1000
0
0
2
4
6
8
10
INJECTION RATE, BPM

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3315, Well No. W008

FORMATION PARTING PRESSURE
TEST DATA

Injection Rate BPM	Injection Rate BPD	Pressure, psi Surface	Pressure, psi BHP
0.93	1339	270	2186
1.46	2102	385	2241
2.04	2938	510	2305
3.03	4363	725	2409
3.90	5616	980	2539
4.90	7056	1280	2612
6.73	9691	1930	2872
8.50	12240	2560	3166

RE6/evgsau35.2

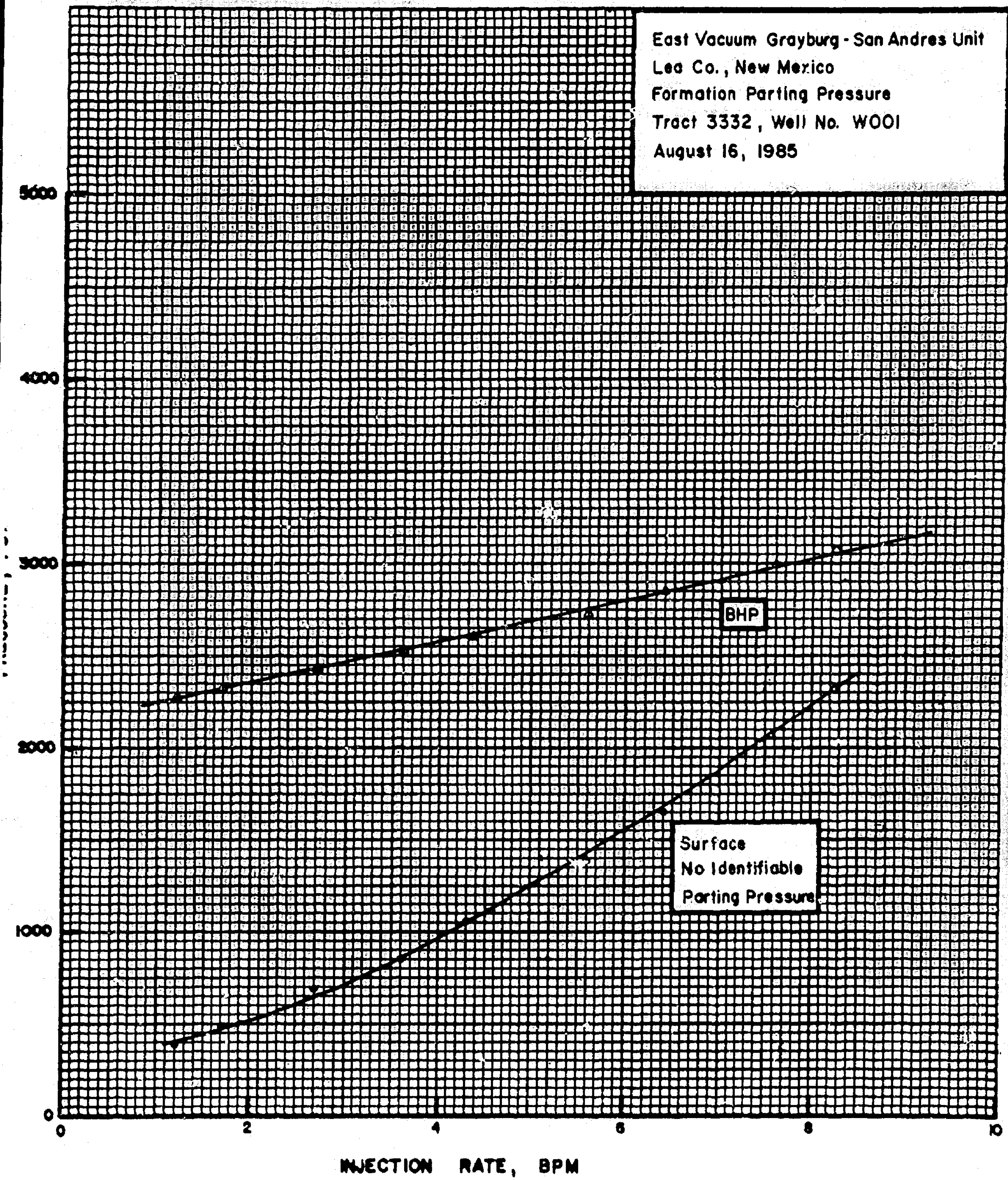

East Vacuum Grayburg - San Andres Unit
Lea Co., New Mexico
Formation Parting Pressure
Tract 3328, Well No. W003
August 16, 1985
BHP Parting
Pressure=2840psi
BHP
Surface Parting
Pressure=1800psi
5000
4000
3000
2000
1000
0
0
2
4
6
8
10
INJECTION RATE, BPM

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3328, Well No. W003

FORMATION PARTING PRESSURE
TEST DATA

Injection Rate BPM	Injection Rate BPD	Pressure, psi Surface	Pressure, psi BHP
0.80	1152	130	2069
1.86	2678	330	2175
2.99	4306	570	2292
3.96	5702	870	2424
5.00	7200	1150	2569
6.08	8755	1530	2719
6.90	9936	1795	2859
7.57	10901	2020	2811
8.12	11693	2340	2925

RE6/evgsau35.3

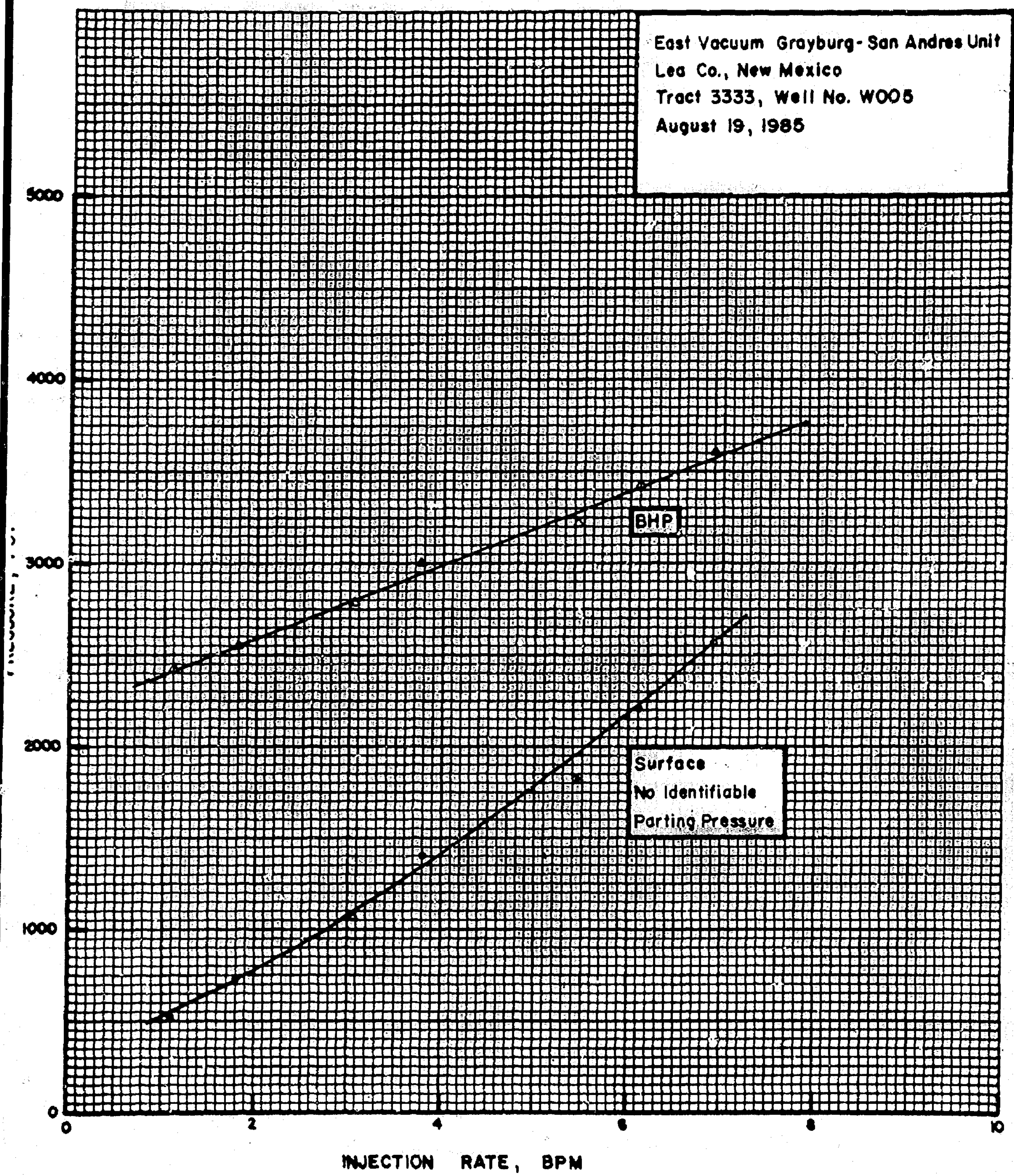

East Vacuum Grayburg - San Andres Unit
Lea Co., New Mexico
Formation Parting Pressure
Tract 3332, Well No. W001
August 16, 1985
BHP
Surface
No Identifiable
Parting Pressure
5000
4000
3000
2000
1000
0
0
2
4
6
8
10
INJECTION RATE, BPM

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3332, Well No. W001

FORMATION PARTING PRESSURE
TEST DATA

Injection Rate		Pressure, psi	
BPM	BPD	Surface	BHP
1.20	1728	375	2285
1.69	2434	495	2338
2.70	3888	685	2422
3.60	5184	860	2516
4.32	6221	1055	2610
5.60	8064	1390	2742
6.39	9202	1655	2856
7.59	10930	2075	2996
8.23	11851	2330	3074

RE6/evgsau35.4

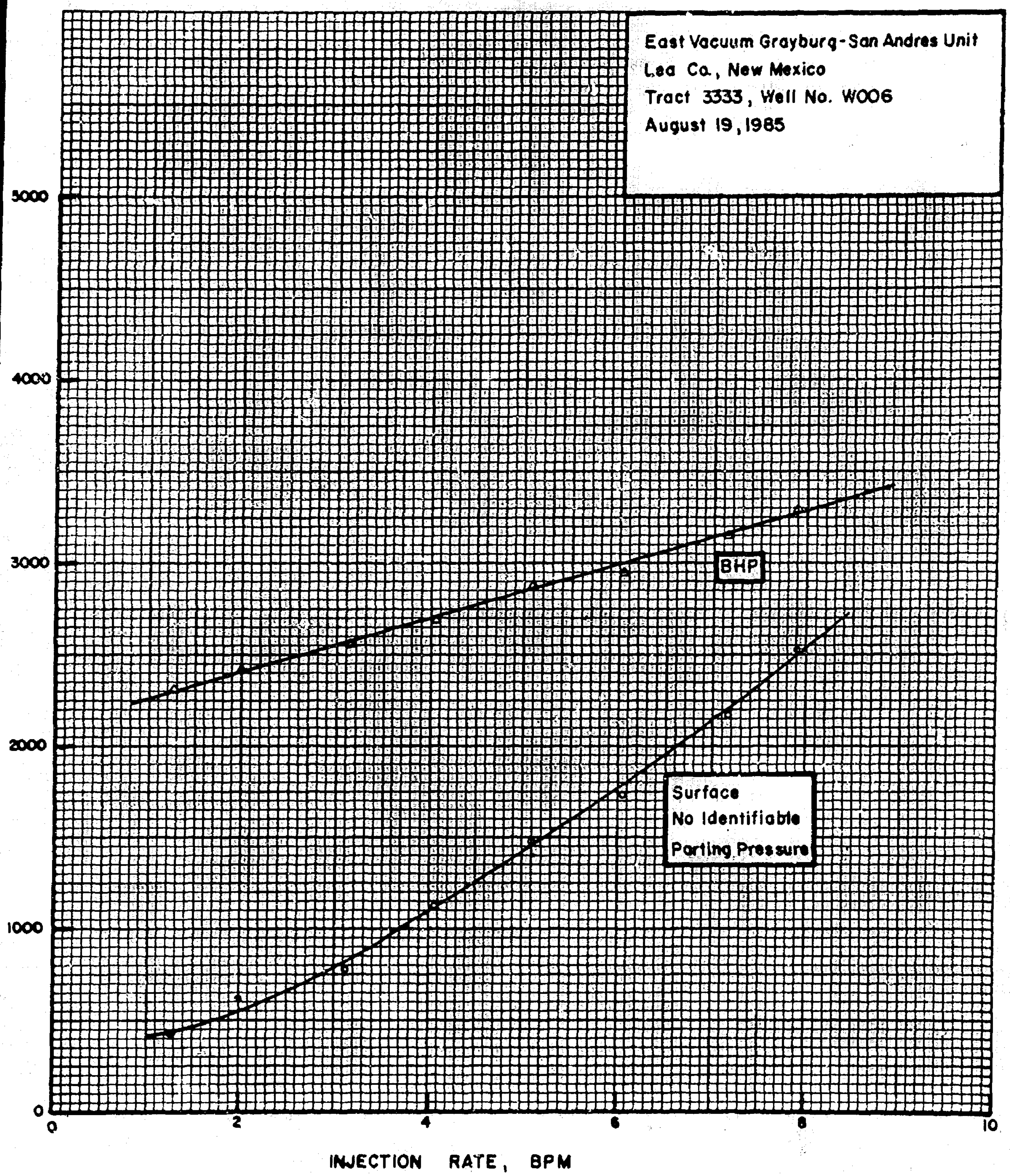

East Vacuum Grayburg-San Andres Unit
Lea Co., New Mexico
Tract 3333, Well No. W005
August 19, 1985
BHP
Surface
No Identifiable
Parting Pressure
5000
4000
3000
2000
1000
0
0
2
4
6
8
10
INJECTION RATE, BPM

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3333, Well No. W005

FORMATION PARTING PRESSURE
TEST DATA

Injection Rate		Pressure, psi	
BPM	BPD	Surface	BHP
1.08	1555	510	2427
1.80	2592	730	2557
3.05	4392	1060	2793
3.78	5443	1400	3000
5.45	7848	1830	3230
6.09	8770	2215	3439
6.90	9936	2560	3617

RE6/evgsau35.5



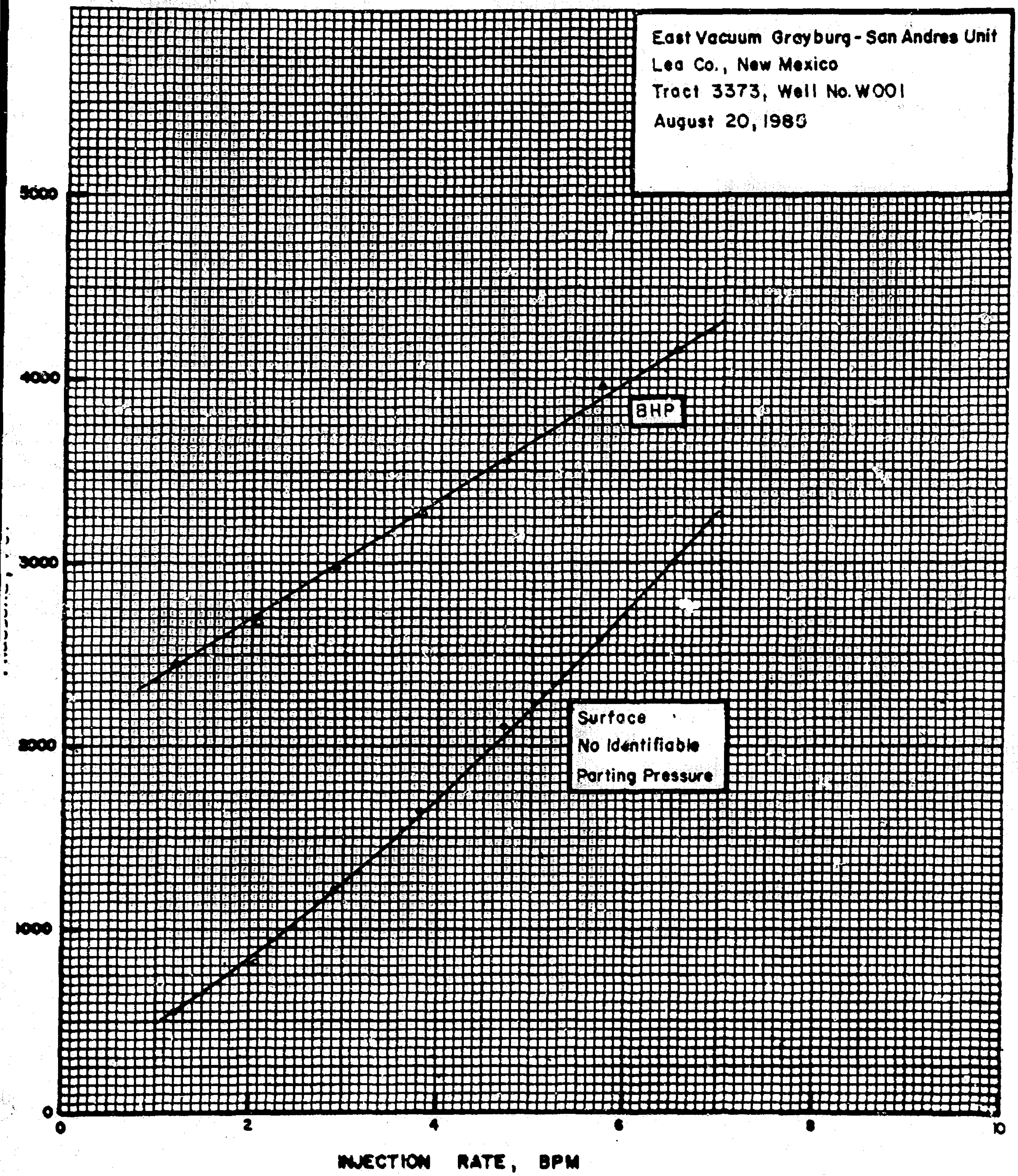
East Vacuum Grayburg-San Andres Unit
Lea Co., New Mexico
Tract 3333, Well No. W006
August 19, 1985
5000
4000
3000
2000
1000
0
0
2
4
6
8
10
BHP
Surface
No Identifiable
Parting Pressure
INJECTION RATE, BPM

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3333, Well No. W006

FORMATION PARTING PRESSURE
TEST DATA

Injection Rate BPM	Injection Rate BPD	Pressure, psi Surface	Pressure, psi BHP
1.27	1829	430	2328
2.00	2880	615	2435
3.10	4464	820	2562
4.04	5818	1110	2699
5.10	7344	1475	2882
6.03	8683	1735	2963
7.15	10296	2175	3156
7.90	11376	2520	3283

RE6/evgsau35.6

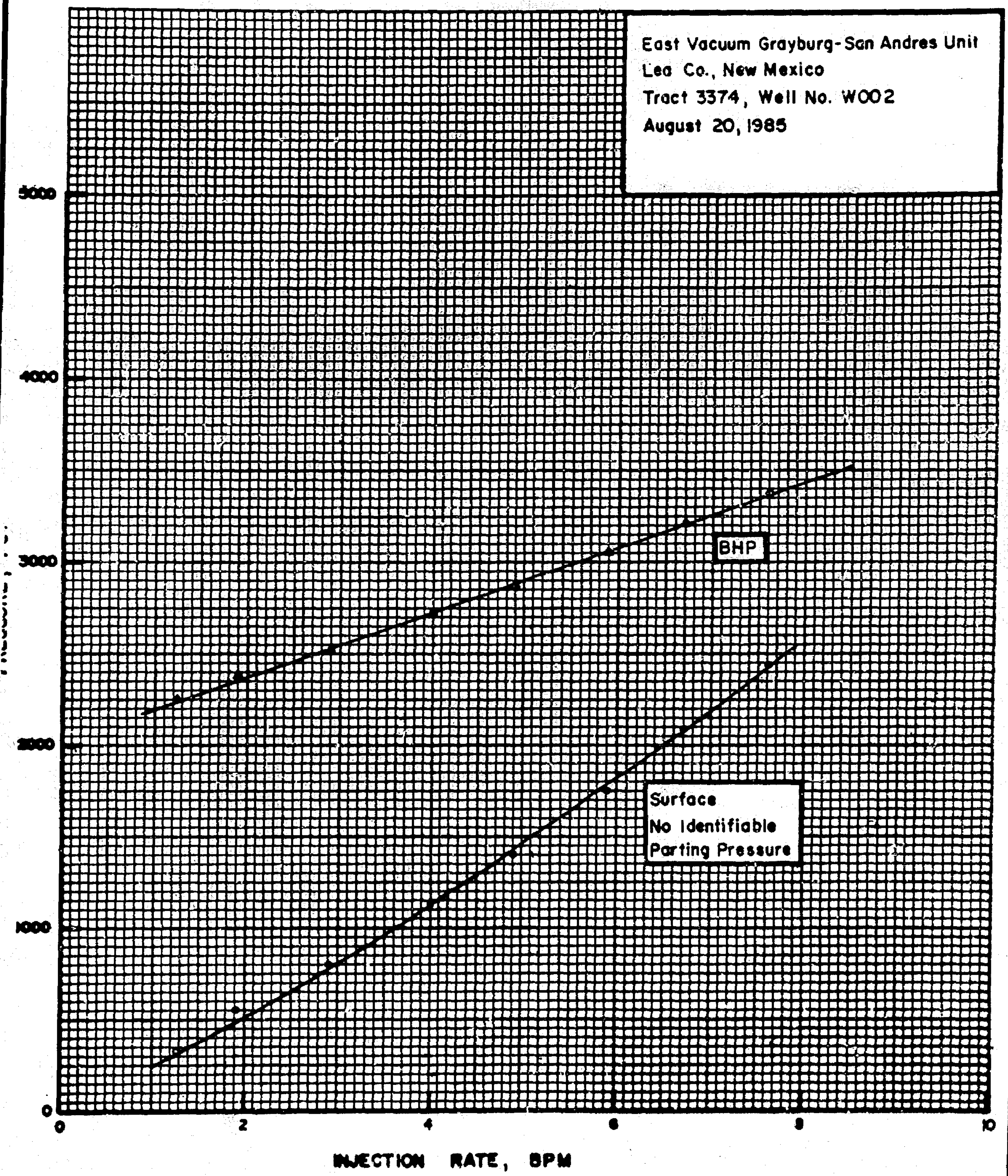

East Vacuum Grayburg - San Andres Unit
Lea Co., New Mexico
Tract 3373, Well No. W001
August 20, 1985
BHP
Surface
No Identifiable
Parting Pressure
5000
4000
3000
2000
1000
0
0
2
4
6
8
10
INJECTION RATE, BPM

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3373, Well No. W001

FORMATION PARTING PRESSURE
TEST DATA

Injection Rate BPM	Injection Rate BPD	Pressure, psi Surface	Pressure, psi BHP
1.20	1728	550	2457
2.07	2981	820	2686
2.99	4306	1210	2996
3.80	5472	1630	3298
4.70	6768	2110	3561
5.70	8208	2580	3951
6.50	9360	3005	4148

RE6/evgsau35.7



East Vacuum Grayburg-San Andres Unit
Lea Co., New Mexico
Tract 3374, Well No. W002
August 20, 1985
BHP
Surface
No Identifiable
Parting Pressure
5000
4000
3000
2000
1000
0
0
2
4
6
8
10
INJECTION RATE, BPM

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3374, Well No. W002

FORMATION PARTING PRESSURE
TEST DATA

Injection Rate BPM	BPD	Pressure, psi Surface	BHP
1.26	1814	340	2267
1.90	2736	555	2386
2.90	4176	790	2539
4.00	5760	1125	2732
4.90	7056	1400	2872
5.90	8496	1760	3041
6.70	9648	2085	3209
7.60	10944	2440	3385

RE6/evgsau35.8

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3374, Well No. W002

FORMATION PARTING PRESSURE
TEST DATA

Injection Rate		Pressure, psi	
BPM	BPD	Surface	BHP
1.26	1814	340	2267
1.90	2736	555	2386
2.90	4176	790	2539
4.00	5760	1125	2732
4.90	7056	1400	2872
5.90	8496	1760	3041
6.70	9648	2085	3209
7.60	10944	2440	3385

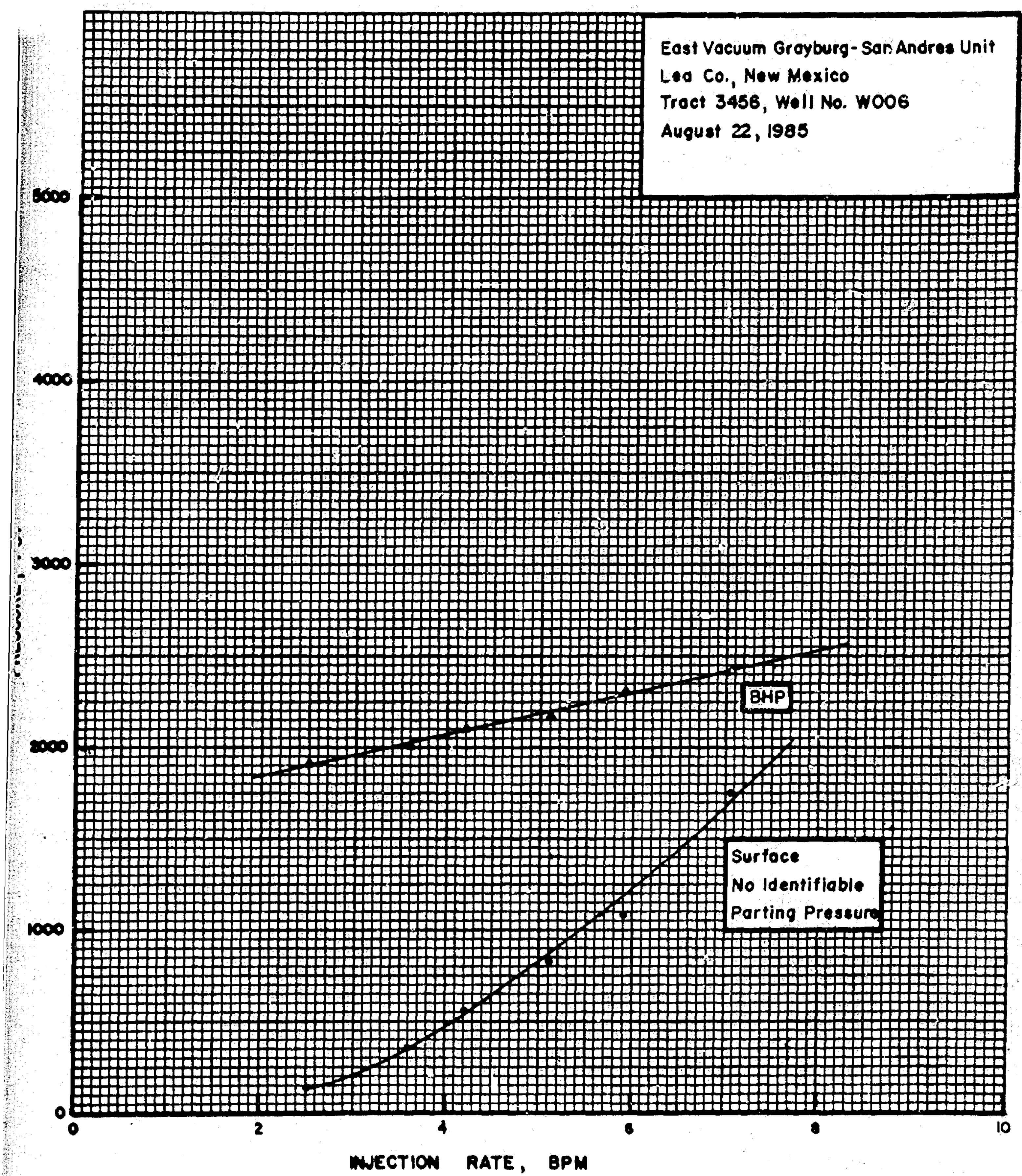
RE6/evgsau35.8

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3456, Well No. W006

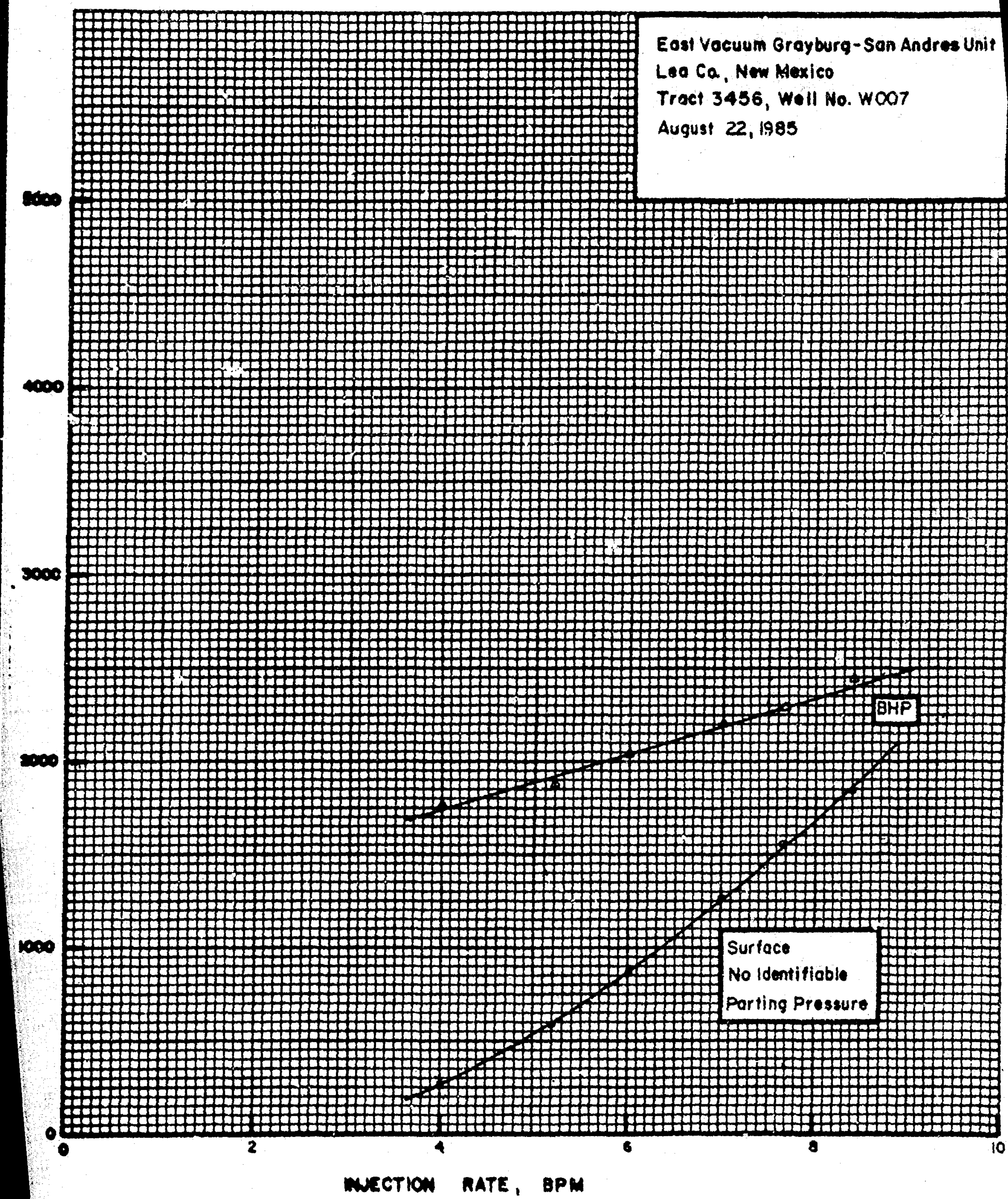
FORMATION PARTING PRESSURE
TEST DATA

Injection Rate BPM	BPD	Pressure, psi Surface	BHP
2.50	3600	145	1919
3.60	5184	355	2018
4.20	6048	560	2107
5.10	7344	825	2216
5.90	8496	1090	2305
7.06	10166	1750	2414

RE6/evgsau35.9



East Vacuum Grayburg - San Andres Unit
Lea Co., New Mexico
Tract 3456, Well No. W006
August 22, 1985
5000
4000
3000
2000
1000
0
BHP
Surface
No Identifiable
Parting Pressure
0
2
4
6
8
10
INJECTION RATE, BPM

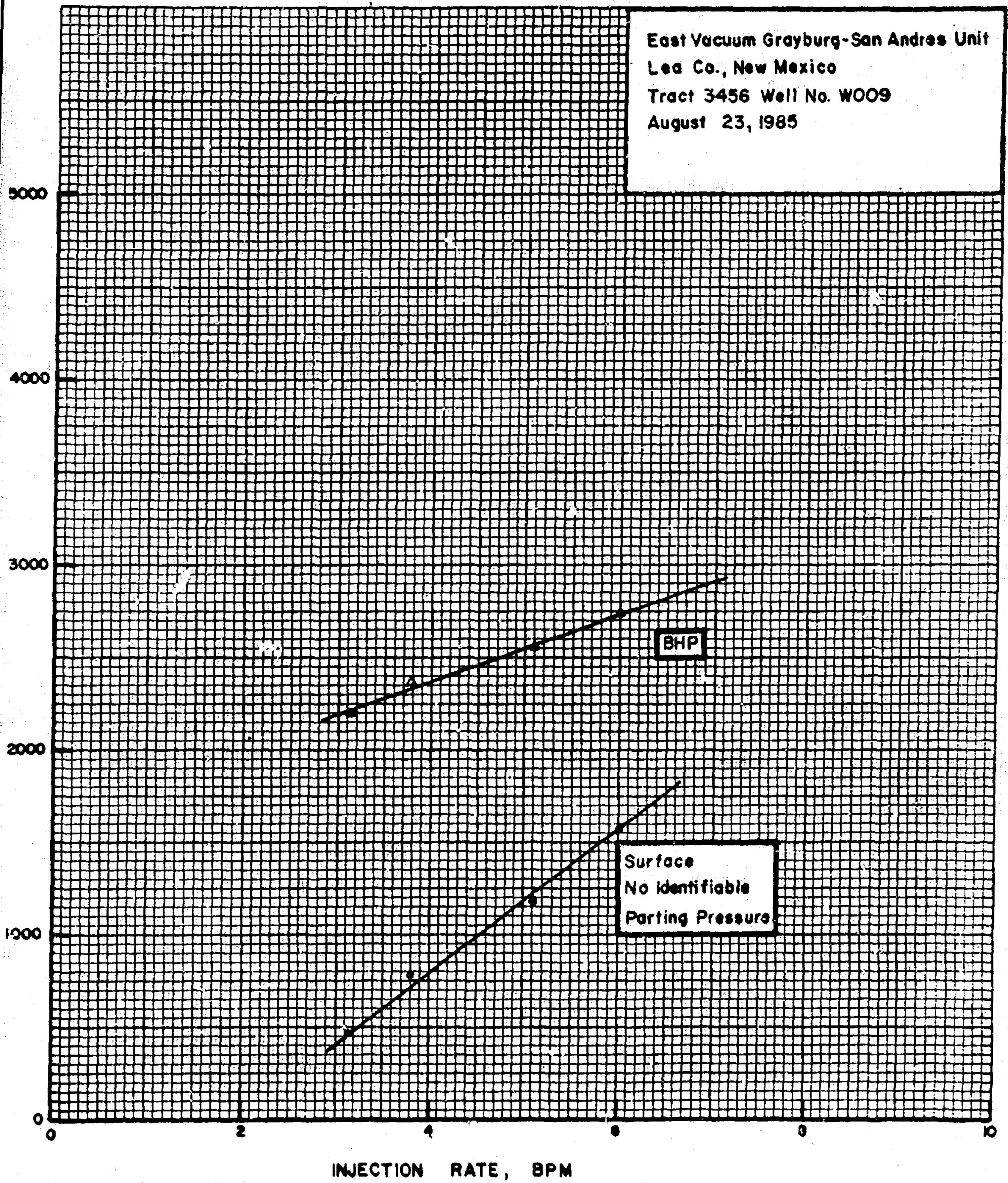

East Vacuum Grayburg-San Andres Unit
Lea Co., New Mexico
Tract 3456, Well No. W007
August 22, 1985
5000
4000
3000
2000
1000
0
0
2
4
6
8
10
INJECTION RATE, BPM
BHP
Surface
No Identifiable
Parting Pressure

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3456, Well No. W007

FORMATION PARTING PRESSURE
TEST DATA

Injection Rate		Pressure, psi	
BPM	BPD	Surface	BHP
4.0	5760	265	1770
5.19	7474	595	1832
5.95	8568	870	2043
6.95	10008	1270	2150
7.67	11045	1555	2292
8.40	12096	1840	2445

RE6/evgsau36


East Vacuum Grayburg-San Andres Unit
Lea Co., New Mexico
Tract 3456 Well No. W009
August 23, 1985
5000
4000
3000
2000
1000
0
0
2
4
6
8
10
BHP
Surface
No Identifiable
Parting Pressure
INJECTION RATE, BPM

EAST VACUUM GRAYBURG-SAN ANDRES UNIT
Tract 3456, Well No. W009

FORMATION PARTING PRESSURE
TEST DATA

Injection Rate		Pressure, psi	
BPM	BPD	Surface	BHP
3.13	4507	470	2201
3.79	5458	780	2379
5.20	7488	1185	2557
6.00	8640	1560	2732

* Dowell's pump truck overheated. Only four rates could be obtained.

RE6/evgsau36.1

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
STATE LAND OFFICE BLDG.
SANTA FE, NEW MEXICO
19 November 1981

EXAMINER HEARING

IN THE MATTER OF:

Application of Phillips Petroleum Company for amendment of Division Order No. R-5897 and certification of a tertiary recovery project, Lea County, New Mexico.

CASE 7426

BEFORE: Richard L. Stamets

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division:
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Legal Counsel to the Division
State Land Office Bldg.
Santa Fe, New Mexico 87501

For the Applicant:
W. Thomas Kellahin, Esq.
KELLAHIN & KELLAHIN
500 Don Gaspar
Santa Fe, New Mexico 87501

I N D E X

E X H I B I T S

MR. STAMETS: We'll call next Case 7426.

MR. PEARCE: Application of Phillips Petroleum Company for amendment of Division Order No. R-5897 and certification of a tertiary recovery project, Lea County, New Mexico.

MR. KELLAHIN: If the Examiner please, I'm Tom Kellahin of Santa Fe, New Mexico, appearing on behalf of the applicant, and I have two witnesses to be sworn.

MR. STAMETS: Are there any other appearances in this case?

(Witnesses sworn.)

MR. KELLAHIN: If the Examiner please, the applicant in this case is seeking two things from the Division.

First of all is the inclusion of approval to use CO_2 injection in their pressure maintenance project for the East Vacuum Grayburg-San Andres Unit. As the Examiner may recall, the East Vacuum San Andres Unit operated by Phillips is a pressure maintenance project. The only change anticipated at this point with regards to additions or modifications of the pressure maintenance order would be the inclusion of a plan or procedure to use CO_2 as an enhanced tertiary recovery project.

The second portion of the case is to have the Division certify the use of CO_2 and the method of enhanced recovery as qualifying for a tertiary oil recovery project under the Crude Oil Windfall Profit Tax Act of 1980.

As you may know, this is the first case in New Mexico where an operator has asked the Division for that certification. A similar case has been presented to the Railroad Commission of Texas and an order has been entered and we have some specific testimony with regards as to what is required in order to comply or be approved for certification, and we propose to submit to you subsequent to the hearing a draft of a proposed order that would accomplish that result if you so agree.

We have two witnesses this afternoon. Both of them are petroleum engineers. Both gentlemen have worked on this project.

The first gentleman is Mr. Bill Berry and he will talk in general terms about this project.

Mr. Terry Christian is the second petroleum engineer and he will talk specifically about the model study that was done in order to demonstrate to you that this is a viable project, and his comparison with other pilot projects in the area.

And both men are available to answer questions, and my first witness is Mr. Bill Berry.

MR. STAMETS: Let's go off the record a minute.

(Thereafter a discussion was had off the record.)

MR. STAMETS: Back on the record. Let's proceed.

BILL BERRY

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q. Mr. Berry, let me ask you your name and occupation, sir.

A. My name is Bill Berry. I'm the Senior Division Reservoir Engineer for west Texas and New Mexico for Phillips Petroleum Company, based in Houston, Texas.

Q. Would you summarize for the Examiner when and where you obtained your degree in engineering?

A. Yes. I obtained a BS and MS degree in petroleum engineering from Mississippi State University in 1974 and 1975.

Q. Subsequent to graduation, Mr. Berry, where have you been employed as a petroleum engineer?

A. I've been employed in Texas, Arkansas, the Ivory Coast, which is in West Africa, Norway, and England.

Q. Would you describe generally to the Examiner what your studies have been of the East Vacuum Grayburg-San Andres Unit in terms of this tertiary recovery project? When did you start working on this, that sort of thing?

A. We started preparing the work for the testimony approximately three or four months ago. Prior to that I worked out in Odessa on the East Vacuum Grayburg-San Andres Unit in connection with the waterflood project, the water injection project, approximately three years ago.

On the carbon dioxide tertiary project I started work on it approximately three months ago.

Q. Are you familiar with the pressure maintenance order of the Oil Conservation Division that regulates and controls the pressure maintenance for this area?

A. I am.

Q. And have you made a study of the rules and regulations of the Secretary of IRS with regards to the

Crude Oil Windfall Profits Tax Act?

A. I have.

MR. KELLAHIN: We tender Mr. Berry as an expert petroleum engineer.

MR. STAMETS: He is considered qualified.

Q Mr. Berry, let me direct your attention to the packet of exhibits and have you turn, first of all, to about a third of the way through the packet where there is a tabulation of the exhibits. The exhibit list follows page 19.

Let's look at the exhibit list for a moment, Mr. Berry, and if you'll identify for us what exhibits you're going to be talking about, and identify for the Examiner what exhibits Mr. Christian is going to be talking about.

A. Okay. I'll be discussion the first six exhibits, which have to do with location and geology and production history and the forecast of the East Vacuum Unit, and I will continue the discussion starting with Exhibit Number Thirteen through Nineteen, which have to deal with the comparison of the CO project area and the total unit, and also presentation of Texas Oil Commission's order and IRS Self-Certification forms.

Mr. Christian will be discussing the

slim tube recovery processes, which will be Exhibit Seven, through and including Exhibit Thirteen.

Q. All right, sir, let's turn to Exhibit Number One and have you identify Exhibit Number One for us and give us a little background about this East Vacuum Field.

A. Exhibit One is a location plat, showing the location of the Vacuum Field in Lea County, New Mexico. It was originally discovered in 1924 by Socony Vacuum Oil Company, Bridges State No. 1 Well.

The development began in 1939. First water injection project was in 1958 in the Mobil Bridges State Lease project. The most recent water injection project is the East Vacuum Grayburg-San Andres Unit project, which began injection in December of 1979.

Q. That's the one operated by Phillips?

A. That's right.

Q. All right, sir, let's turn to Exhibit Number Two. What does this show us?

A. This is just a location plat of the various water injection projects in the Vacuum Grayburg-San Andres Field. The Phillips East Vacuum Unit is the one to the far right.

Q. All right, sir, and let's go to Exhibit Number Three.

A. Exhibit Three is a structural map of the top of the San Andres, the main pay in the East Vacuum Grayburg-San Andres Unit. The East Vacuum Grayburg-San Andres Unit is outlined in red on this plat.

I'd like to point out that there's approximately 400 feet of closure of this east/west trending anticline down to -700 feet subsea, which was the original oil/water contact.

I'd like to continue talking about the geology on Exhibits Four and Five, which are cross sections.

Q. All right, sir.

A. Exhibit Four is a west/east cross section. Exhibit Five are north/south cross sections. I'll talk about both of them in the same context.

The black zones illustrated here are the impermeable strata and the white zones are the main pay. The San Andres formation is a medium crystalline and oolitic dolomite, with the pay having fractures and vugs.

I'd like to point out that the impermeable strata here is widespread and does offer an effective cross flow, which in the case of CO_2 injection is beneficial, in that it prevents CO_2 override of the oil.

Q. Is there anything else you'd like to tell us, Mr. Berry, about the general geology that you have found in this unit?

A. No, sir.

Q. All right, sir. Let's go on to Exhibit Number Fourteen. What is Exhibit Number Fourteen?

A. Exhibit Fourteen is a delineation of the CO_2 project area within the East Vacuum Grayburg-San Andres Unit.

Q. All right, now that's different than what the total East Vacuum Unit is.

A. Correct. The CO_2 project area is in the lower southeast corner of the unit, and it's outlined by the cross hatched, and the blue water injection wells that surround it.

Q. What would be the total outer boundary for the unit itself as opposed to the project area, how is that shown?

A. The total unit boundary is the dashed line that goes to the north and over a little further to the west than the project, CO_2 project area.

Q. All right.

MR. STAMETS: I'm a little confused on that, Tom. Am I missing some lines on this?

MR. KELLAHIN: They're hard to see.

Q. While we're on this point, Mr. Berry, tell me a little something about the East Vacuum Unit itself.

What kind of acreage composes that unit?

A. I'd like to refer to Exhibit Number Thirteen, which has a tabulation of the comparison of the CO_2 flood project area parameters and the total East Vaccum Unit.

Q. No, sir, you're a little bit ahead of me. What I'm talking about is in terms of ownership of the acreage that composes the unit area itself. Is that fee land, Federal land, or State Land, or a combination?

A. State land.

Q. It's all State land, all right. The unit agreement, does it have provisions in it to allow you to dedicate as a project area for purpose of CO_2 an area that's less than the total area for the unit?

A. It doesn't specifically address allocating less than the total unit area to a project area; however, in the original unit agreement the verbiage was that the unit was formed for enhanced recovery processes, which CO_2 injection is an enhanced recovery process.

The reason for using the project area rather than the total unit is that the reservoir quality rock is better in the CO_2 project area than in the northern portion of the reservoir and that is required to support the higher production rates that are required to support the higher operating costs associated with CO_2 injection and operation.

Q One of the elements necessary for approval of an enhanced tertiary recovery project is the clear delineation of the boundaries of the project, is it not?

A. Yes.

Q And your attempt to locate this project area, I assume, is your effort to clearly define an area that is suitable for the tertiary recovery project.

A. That's right. The economics dictate that we at this time only CO_2 flood the area delineated in Exhibit Number Fourteen.

We will periodically review in the future expanding this CO_2 injection process to include the remainder of the unit.

Q All right. Describe for me then how -- or what reasons you have used to justify the delineation of the project as depicted on Exhibit Fourteen.

A. It's primarily the productivity of the wells in this area and the reservoir quality. There were two reasons that we picked this. As I mentioned earlier, the productivity is needed to support the higher operating costs and the better reservoir quality rock is found in this area, which will -- which is required for a better CO_2 flood performance.

Q All right, sir. Let's compare, then, Fourteen with Exhibit Thirteen, and have you describe that for me, please.

A. Exhibit Thirteen is a comparison of the East Vacuum total unit and the flood -- CO_2 flood project area, as well as the Denver Unit.

I'd like to concentrate on the comparison of the CO_2 flood project area and the total East Vacuum Grayburg-San Andres Unit, paying particular attention to the net pay, porosity, and permeability.

I might point out the net pay of the CO_2 project area is 108 feet versus 71 feet for the total unit; that the porosity is approximately 12 percent versus 11.7 percent; and that the permeability is 12.2 versus 11.

The total acreage of the CO_2 project area is 4,997 acres, as opposed to 7,025 acres within the entire unit.

These are the main parameters which affect CO_2 performance, or flooding performance.

Q Let's go back now, Mr. Berry, and have you give us some of your general comments with regards to, first of all, why you believe that the East Vacuum Grayburg-San Andres project area is a suitable project for this enhanced recovery project.

A. We feel that the San Andres is a suitable formation for CO_2 flooding in that there have been several pilots operated by other operators in the San Andres within the west Texas-New Mexico area that indicate that recoveries can be expected anywhere from 10 to 18 percent of original oil in place by CO_2 miscible flooding.

Q. Have you made any calculations to determine what is going to be the additional recoveries of oil from the project area as a result of the use of this enhanced recovery technique?

A. Yes, we have. I would like to back up and give the recoveries that we expect from primary and secondary, also, to shed light on the significance of this process.

We produced as of December of 1980 approximately 2-million barrels from the entire unit. The anticipated ultimate primary was 78-million barrels. The waterflood was anticipated to recover an additional 41-million barrels, and on top of this, we'll expect to recover 26-million barrels from the tertiary CO_2 flood.

This represents an increase of approximately 22 percent of the remaining recoverable reserves.

Q. When do you anticipate the actual injection of CO_2 into the project area?

A. The injection of CO_2 is dictated by the time at which we reach miscibility pressure, which for the CO_2 that we anticipate injection will be about 1369 psi, which we anticipate reaching the beginning of 1984.

We are currently over injecting voidage in order to achieve that miscibility pressure. The current pressure is approximately 577 psi as of March of last year.

Q. All right, let me -- let me understand some numbers.

What is the current pressure in the formation?

A. As of March of last year it's 500 -- excuse me, as of March of this year it's 577 psi.

Q. And before you can start the -- by what points do you reach the optimum miscibility pressure? What is that number?

A. The miscibility pressure is a function of the oil composition and CO_2 gas composition that we inject. With the gas composition that we think we'll be able to obtain, it's 1369 psi, according to miscibility studies.

Q. When, at what point did you commence the injection of more water than the amount of fluids that's drawn from the project area?

A. Okay, I'd like to refer to Exhibit Number Sixteen at this time, which has a tabulation of the injection to voidage ratio from March, 1980, through August, 1981.

As can be seen here, in February, 1981, we overinjected voidage at the ratio of 1.0264. This is a time at which we injected more water than we extracted hydrocarbons, gas, oil, and water. This is what we define as the project beginning date, because the injection of water in excess of voidage to repressure the reservoir to miscibility pressure is a necessary, integral, and inseparable part of the CO_2 flooding process.

The injection rates in January of this year were approximately 33,000 barrels per day; in August, 61,000 barrels per day; and currently we're injecting at a rate approximately 85,000 barrels per day.

The maximum rate that we anticipate injecting at is 90,000 barrels per day, and with the 90,000 barrels per day injection rate we anticipate reaching miscibility pressure the first part of 1984.

Q All right, sir. For purposes of understanding the implementation of the Windfall Profits Tax Act, and the qualification of this project as an acceptable enhanced tertiary oil recovery project, would you describe generally what your understanding is as to the requirements that are necessary for the Examiner to find in order that this project may be approved?

The requirements are, one, that the project began after May of 1979. This project clearly qualified there, in that injection of water was initiated in December of '79. Overinjection of voidage, which is the start of the CO_2 miscible process, began in February of 1981.

Secondly, the tertiary project has to be defined by the DOE -- Department of Energy Regulation 212.78-C, which -- miscible CO_2 flooding is clearly defined there.

And third, that it recover more than an insignificant amount of oil, which I've stated earlier that we will be recovering 26-million barrels of oil from the CO_2 process, which is approximately 10 percent of original oil in place, which is more than an insignificant amount of oil.

Q. Basically those are the three criteria or essential findings of fact that are going to be required of the Examiner in order to approve this, approve this project.

A. That's right.

Q. All right, sir.

We have skipped Exhibit Fifteen. If you'll go back for a moment, Mr. Berry, and let's look at the schematic, which is Exhibit Fifteen.

Would you summarize for us the information contained on that exhibit?

A. Yes, this is a schematic of the typical injection well in the East Vacuum Grayburg-San Andres Unit. This is completed and complies with the pressure maintenance Order R-5897 with regard to the packer setting depth within 100 feet of top of the perforations, and that inert fluid be placed in the tubing-casing annulus.

I'd also like to point out that cement in all the injection wells in the East Vacuum Grayburg-San Andres Unit that have been drilled have been circulated to surface, as is described in this exhibit.

The only difference that will be mechanically involved in a CO_2 injection well and a water injection well is that there will be a different lining, which will be a plastic-coated TK-69 product by Tubescope, and that will have nickel-plated Baker Loc lefthand on/off tool threads, packer set within 100 feet of the top perforation.

Currently we have sixteen out of the 45 wells that we will be using for water/alternate/gas, it's -- an acronym used is WAG, and 16 of the 45 WAG wells are currently completed in this manner and are ready for CO_2 injection, and prior to injecting in the other wells we will convert them over in this manner.

Q. To make sure I'm sure on that point, the existing pressure maintenance order has approved certain water injection wells and this is simply going to be a conversion of those wells that are already permitted or approved to drill --

A. That's correct.

Q. -- for CO_2 injection, also.

A. That's correct. We, at this time, anticipate no need for any additional wells other than the wells that we currently have drilled or planned for the pressure maintenance project.

Q. Let me ask you some questions about that pressure maintenance order itself.

There is a method in the pressure maintenance order that establishes a bonus allowable for water injected. What, if any, change is going to be required with regards to how that bonus allowable is calculated because of the use of CO_2?

A. At the time that we inject CO_2 and produce CO_2 and gas, we will have to modify the bonus allowable calculation.

Q. You're not seeking to have the Division approve that portion at this hearing?

A. No, we're not.

Q. All right, sir, let's go on to Exhibit Number Seventeen, I believe it is.

A. Exhibit Seventeen is a tabulation of the CO_2 production and injection schedule, and at this time I'd like to refer back to Exhibit Six also, which is the production history and forecast.

We have three curves presented on Exhibit Six. One is the continued primary which is the estimated continued primary production that we would have recovered if we had not implemented a pressure maintenance order.

The second line is the primary plus waterflood. This is the anticipated production forecast that will be achieved if we continue under our pressure maintenance program.

And the third dashed curve is the primary plus waterflood, plus CO_2 flood, which is the production profile that we anticipate with a tertiary CO_2 flood.

Note that the difference between the primary, the waterflood, the primary and waterflood plus CO_2 flood is 26-million barrels additional recovery.

Back to Exhibit Number Seventeen, the injection of CO_2 that we anticipate will be approximately 40-million cubic feet per day for 19 years. This represents a 40 percent of the original hydrocarbon pore volume of the reservoir within the CO_2 project area.

Note that approximately 126-million of the 227 -- excuse me, 226-billion of the 277-billion cubic feet of CO_2 required will be produced and re-injected.

Anticipated costs for the total CO_2 will be approximately $400,000,000 over the nineteen year life. The investments for this CO_2 project will be approximately $81,000,000, which will be made in 1982 and 1983.

MR. STAMETS: Now you gave me two figures there. The $400,000,000 was CO_2 cost.

A. Yes, sir, that's the cost of purchasing make-up CO_2 and of recovering the CO_2 and re-injecting it from the produced stream.

MR. STAMETS: And the other cost was $80-how many million?

A. $81,000,000 will be our investment cost for distribution systems, processing equipment, and pipelines.

MR. STAMETS: To handle the CO_2.

A. Yes, sir.

Q. So we're clear on this point, Mr. Berry, let me have you explain to us why an operator such as Phillips for this project would not wait until they had completed secondary recovery by waterflood alone before initiating a tertiary recovery by the use of CO_2?

A. I'd like to quote a statement by Mr. Brian Sullivan, while he was with the Railroad Commission, if I could at this time, which I think highlights this point. This was stated in the February 2, 1981, Oil & Gas Journal, quote:

> The fact that a field is not amenable to secondary recovery methods, or that secondary methods would destroy the potential use of tertiary methods, would seem to be satisfactory for going directly from primary to tertiary -- tertiary production.

The continued operation -- oh, excuse me, unquote.

The continued operation of the secondary waterflood to its conclusion in the East Vacuum Grayburg-San Andres Unit would destroy the potential use of the CO_2 tertiary project because the economics dictate that the tertiary and secondary projects be operated concurrently.

Q. Based upon your studies of this reservoir and your knowledge of the tertiary recovery projects, Mr. Berry, is it true and correct to state that for this project there is a higher probability of success if the tertiary project is initiated early in the life of the reservoir, as opposed to waiting until you completed the waterflood portion?

A. Yes, that's correct, and it's industry-recognized that the earlier you can implement a tertiary process the better it is and the more likely that it will -- chance it will have of succeeding, both from recovery of additonal oil and from an economic point of view.

Q. In your opinion is this particular project area in the Vacuum San Andres Reservoir well suited for the miscible displacement by carbon dioxide injection for the enhanced recovery project?

A. Yes, I feel this is an excellent candidate for CO_2 injection.

Q. Do you have any reasons why you believe that?

A. Several reasons. One is that the miscibility pressure is at an achieveable level, that of 1369 psi, which we believe we can reach in a timely manner.

Secondly that we at this time feel there will be no adverse effect from asphalting precipitation (sic) which is a sometimes occurrence with CO_2 when it commingles with oil, depending on the composition of the oil.

And third is that we feel that the current rates of production will help to sustain the high operating costs associated with the CO_2 miscible process.

Q. In your opinion, Mr. Berry, would there be any detrimental effect upon any offset operator if the tertiary project is approved as you propose?

A. No, none whatsoever, and I'd like to refer back to Exhibit Fourteen at this time, to illustrate -- where it illustrates that we have water injection wells around the perimeter of the CO_2 project area, and we feel that operating these water injection wells will adequately contain the CO_2 flood to the CO_2 project area.

Q. In your opinion, then, correlative rights of none of the offset interest owners are going to jeopardized by approval of this project?

A. No.

Q. What do you anticipate to be the source of your carbon dioxide, Mr. Berry?

A. We've made preliminary contacts with several conventional suppliers and have come to the conclusion that it will be one of two sources in New Mexico, either from large industrial plant by-products streams or from natural sources in southern Colorado via pipeline down through the area near East Vacuum.

Q. In summary, then, Mr. Berry, let me ask you a series of questions.

In your opinion will the injection of

the CO_2 as you've described cause any damage or waste in the reservoir?

A. No, it will not; definitely will not cause any damage, and that there will be no waste because of recovery of an additional 26-million barrels of oil.

Q. In your opinion is this carbon dioxide injection tertiary recovery project designed in accordance with sound engineering principles?

A. Yes, it is.

Q. And in your opinion is the project you've describe an immiscible displacement enhanced recovery -- oil recovery technique, as defined in DOE Regulation 212.78-C?

A. Yes, it is.

Q. In the project, as you've described it, in your opinion will the injected fluid measured at reservoir temperature and pressure be more than 10 percent of the reservoir pore volume being served by the injection wells?

A. Yes.

Q. In your opinion does the project, as you have described it, involve the application in accordance with sound engineering principles of one or more tertiary recovery methods which can reasonably be expected to result in more than an insignificant increase in the amount of crude oil which will ultimately be recovered?

A. Yes, it will.

Q. Does the project you have described, or as you've described it, have a beginning date of after May of 1979?

A. Yes, it does.

Q. And again what is the beginning date of the project?

A. February, 1981, which was the first month of overinjection of voidage with water.

Q. And finally, in your opinion do your exhibits and testimony clearly delineate the portion of the property to be affected by the project?

A. Yes, it does.

I'd like to also present Exhibits Eighteen and Nineteen to the Examiner.

Q. Let's go to Exhibit Eighteen while we're at that point, Mr. Berry, and have you identify for me what that is.

A. This is a copy of the order from the Texas Railroad Commission on the certification of the Kurten (Woodbine) Field as a qualified tertiary oil recovery project. This project consists of proceeding directly from primary recovery to a tertiary CO_2 process with an intermediate phase of repressuring by water.

Q. That is very much like the project you have anticipated for the East Vacuum Grayburg-San Andres Unit.

A. Yes, it is.

Q. All right, sir. In terms of the findings and conclusions of the Railroad Commission's order, are there any additions, modifications, corrections, that you would like to suggest to this Examiner for purposes of your project?

A. Yes, I'd like to state that in addition to the Conclusions of Law mentioned in the order by the Railroad Commission, that the Oil Conservation Division state the project beginning date.

Q. Other than that addition to the types of Findings and Conclusions in the Railroad Commission order, are there any other additions that you'd like to suggest?

A. No.

Q. Let's go to Exhibit Number Nineteen and have you identify that for me.

A. This is a copy of the forms that are required by the IRS for self-certification of a qualified tertiary recovery project. They're provided to the Commission at this time for your convenience in establishing the qualifications of the project.

Q. If you were to elect to make a self-certification of this project to the Secretary of IRS, this is the way you would have completed the form.

A. That's correct.

Q. And why have you not sought to do that, Mr. Berry?

A. The reason we have not sought to self-certify this project is because the option of having a self-certified project reviewed and acted on by the Secretary of Internal Revenue Service is not available, whereas supplying the IRS Secretary with a copy of an order from a jurisdictional agency, such as the Oil Conservation Division, is available in that the IRS Secretary has to rule on it within 180 days.

Q. All right, sir, are there any other points that you'd like to discuss with regards to your testimony or exhibits, Mr. Berry?

A. No, sir, there are not.

Q. Were Exhibits One through Six and Thirteen through Nineteen, excluding the Oil Conservation -- the Texas Railroad Commission order, prepared by you or compiled under your direction and supervision?

A. Yes, they were.

MR. KELLAHIN: That concludes my examination of Mr. Berry.

MR. STAMETS: Any questions of this witness?

MR. PEARCE: Yes, Mr. Examiner, if I may.

CROSS EXAMINATION

BY MR. PEARCE:

Q. Mr. Berry, on the beginning date of the project, February of 1981, being the data that you first achieved overvoidage, can you explain to me what caused that on that date? Did you -- did you simply take less or this a formation characteristic that caused overvoidage on that date?

A. No, this is a continued effort on our part to accelerate our injection program to inject more water to actively repressure the formation. It was be design that we did overinject.

Q. Just because I kept missing the numbers, the figure of the DOE regulation is 212.187-C, is that correct?

A. 212.78.

Q. .78, not 187.

A. Yes.

Q. Could you give me some indication, Mr. Berry, of how the cost of the CO_2 for this project was arrived at? I noticed in one of your exhibits you were estimating, as I read it, $277,000,000 plus mcf.

A. Yes, sir. The cost was arrived at by

preliminary contacts with suppliers on what they would be charging in this area for CO_2.

Q Okay. Did you make any effort to -- those figures are running through the year 2000, or whatever, is there any adjustment in there for time or is that simply the number they gave you multiplied?

A. No, that is escalated.

Q It is escalated. Do you have any idea what factor they used to escalate it?

A. If I could consult with somebody at this time that would know?

Q Please.

MR. KELLAHIN: Perhaps our second witness could answer that question.

A. I'd like to retract that statement that it was escalated. It was not.

Q I'll ask again. Thank you.

MR. PEARCE: That's all I have.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Berry, would you reiterate why Phillips choses not to wait at this time to complete the secondary phase before going into the tertiary phase?

A. Yes, sir. There are two reasons. One is that we feel that we have initiated this CO_2 project by overinjection of voidage to achieve miscibility pressure, and secondly, the operation of a tertiary project is more beneficial if it's conducted in the early phases or early life of the reservoir where the high operating costs associated with the tertiary process can be borne by both tertiary and secondary or primary oil.

Q. Okay. Why have you chosen not to do this in a pilot project, just to go ahead with the entire project, or the majority of the project at one time?

A. We feel that there's adequate supporting information from other operators in the San Andres in pilots and field -- full field floods. Mr. Christian will be discussing that in further detail or I can go into it now, if you like.

Q. We'll wait for the next witness.

A. Okay.

MR. STAMETS: Are there other questions?

MR. STOGNER: I have one thing that bothered me.

QUESTIONS BY MR. STOGNER:

Q. In Exhibit Number Fifteen you show the modification and drawn up plans for your present injection well to accommodate CO_2 injection.

Do you have any plans for modifications on the present producing wells to handle the produced CO_2 coming out with your water?

A. At this time we have no set plans as far as whether we will be doing some type of corrosion inhibition or modifying to this type plastic-coated tubing, but we will be monitoring it on a continuous basis.

Q Okay. All your producing wells, are they also cemented in the same manner, circulated?

A. Yes.

MR. STAMETS: Any other questions of this witness? He may be excused.

TERRY CHRISTIAN

being called as a witness and being duly sworn upon his oath, testified as follows, to-wit:

DIRECT EXAMINATION

BY MR. KELLAHIN:

Q Mr. Christian, for purposes of the record would you please state your name and occupation?

A. My name is Terry Christian. I'm a petroleum engineer with Phillips Petroleum.

Q When and where did you obtain your degree in petroleum engineering?

A. I graduated in December of 1977 from Texas Tech with a Bachelor of Science in petroleum engineering.

Q Subsequent to graduation when and where have you been employed as a petroleum engineer?

A. I have worked in Houston, Texas, with Phillips, and also in Bartlesville, Oklahoma, and Odessa, Texas.

Q As a petroleum engineer have you made a study of the facts surrounding Phillips' application for an enhanced tertiary oil recovery project for this particular unit?

A. Yes, quite a few of them.

Q And pursuant to those studies have you compiled certain exhibits for presentation today?

A. Yes, sir.

MR. KELLAHIN: We tender Mr. Christian as an expert petroleum engineer.

MR. STAMETS: He is considered qualified.

Q Mr. Christian, let me direct your attention, first of all to Exhibit Number Seven.

MR. STAMETS: I think we'd better take

about a fifteen minute recess before we go further into Mr. Christian's testimony.

(Thereupon a recess was taken.)

MR. STAMETS: The hearing will please come to order and you may proceed.

Q Mr. Christian, so that we might follow your testimony, would you take a minute here and describe generally what the areas are that you're going to discuss with regards to the hearing today?

A. Well, I want to try to clarify the miscible CO_2 flooding process a little bit and maybe explain it enough, how we arrived at our numbers somewhat, and give some technical support for what we're telling you.

Q Okay. Let's start off, then, and have you explain why you have chosen a combination of CO_2 and water as an enhanced recovery process for this particular reservoir and project area.

A. Well, one of the primary reasons is the fact that pilots in the Permian Basin have recently indicated that the process could be feasible and successful on a large scale basis. There have been very encouraging pilots performed and data released in thos recently.

Q. Let's identify for the Examiner what specific pilot projects you have studied and that you're talking about.

A. Well, there is a pilot operated by Shell in the Denver Unit in the Wasson Field near Denver City, Texas.

There is a -- I can't think of all the names of them. There is the Slaughter Estate, operated by Amoco, which is west of Lubbock in another San Andres flood.

There is the Willard Unit pilot, operated by ARCO, also in the Wasson-San Andres Field.

Q. The study of those pilot projects are discussed in your written summary of the exhibits?

A. Yes.

Q. All right. As I understand your study, you developed a model. Would you describe for us how you developed the model and what it shows us?

A. Well, the model is one that we use fairly regularly in Phillips for miscible CO_2 forecasts. I did not build the model. Research and Development built the model. I am the one who uses the model for projections and estimates based upon geological data from the East Vacuum Unit.

The model uses -- well, suffice it to say that it uses a miscible flood technique that is well accepted in the industry.

Okay, I don't know if I need to give you any more detail than that.

Q Okay. The calculations or studies came -- you reached some conclusion with regards to what was the optimum miscible pressure for use in this project. I would like for you to spend some time and describe for me generally how you got to get to that pressure.

A. Okay. CO_2 and oil are not directly miscible at low pressures. The interfacial tension in that system seems to lower as pressure is increased, meaning that more oil can be swept out with CO_2. So it is unique as an enhanced recovery process in that we need to be careful at what pressures we operate the flood.

It does help recovery at, let's say, pressures below the miscibility pressure. We would call that an immiscible CO_2 flood; however, those floods have not given as great a recovery as a miscible CO_2 flood.

We use a standard laboratory apparatus called a slim tube to measure what pressures we should operate the flood at. Our Research and Development people have spent -- have run numerous tests, not only on this, but other fields, and they're very well versed on how to use the apparatus.

The miscibility of CO_2 and oil is dependent on several things. One of them is the oil composition; the other is the composition of the injection gas; the other would be the temperature, which in this case is fixed at reservoir temperature. We don't consider that a variable.

When we began to plan for this Vacuum Unit, we needed to know what composition of gas was available, so we called several possible suppliers and asked them, and we got what we thought was a reasonable range of maybe 94 percent CO_2 with 6 percent nitrogen, up to, like, even 99 percent CO_2, and I've covered that in here.

We found that in lab tests that nitrogen is detrimental to CO_2 flooding in that it seems to cause the CO_2 and oil miscibility pressure to increase. The more nitrogen that's there, the higher the miscibility pressure.

So what we did is asked ourselves the question, at 6 percent nitrogen, how does that affect the operation of our flood? Can we reasonably expect to operate this flood with 6 percent nitrogen?

This is a small contamination but it in some cases could have a large effect. So we ran slim tube tests, a series of them, to show this effect, to be certain that we had the right numbers.

We also considered the effect of stock tank oil and reservoir or live oil. Again, the composition of the oil is important, so we wanted to bracket it as much as possible, and let me just say that -- let me find the spot here, I want to make sure I say it right -- that we had two objectives. One of them was to determine the influence of the state of depletion and the injectant composition on the minimum miscibility pressure, and the other was to quantify the range in necessary operating pressures.

Q. Have you demonstrated those pressure results on an exhibit, Mr. Christian?

A. Yeah, let's --

Q. Let's look at Exhibit Number Seven, then.

A. Okay. Exhibit Seven is a typical plot of the data that we get from the slim tube test. I've picked this one in that it has a particular significance in that this is the MMP we have designed our project for.

But as you can see, the recovery, which is shown on the lefthand, or the vertical axis, increases with increasing pressure up to a point and then you see a breakover in the curve and that is what we call the minimum miscibility pressure.

MR. STAMETS: I can't read that very well.

because it's down in the crack of the book. What does that --

A. Okay.

MR. STAMETS: -- lefthand side mean?

A. Okay. Effective recovery percent of original oil in place.

MR. STAMETS: Okay.

A. Now, the slim tube test doesn't tell us that we expect to recover 90 percent of the oil in place. What it does tell us is that operating above 1369 psia we should obtain the maximum benefit from the CO_2 flood.

If I could --

Q. All right, let's look at Exhibit Eight, I believe, is the next one.

A. Okay. If I could continue, Exhibit Eight and Nine are really basically the same data; one is in graphical form and the other is tabulated, but this just demonstrates our findings of the miscibility pressure that we measured for various gas compositions and for light oil and stock tank oil.

As you can see, the minimum miscibility pressure ranged for live oil was a minimum of 1190 and up to 1369, for 6 percent nitrogen in the CO_2.

We felt that the flood could be safely operated at these pressures because the original reservoir pressure was over 1600 pounds, so there should be no danger as long as the bottom hole injection pressure is maintained at the proper pressure.

Q. All right. The initial pressure in the Vacuum Field, according to your summary here, Mr. Christian, shows 1613 psig. You're going to maintain a pressure of something less than that in the project, the 1369 figure?

A. The 1369 is saying we need to operate above that pressure.

Q. All right.

A. If the CO_2 actually contract actually has that much nitrogen in it. That will be something to be determined exactly later, but you can see from this data that there's no reason to suspect that it can't be done successfully without parting the formation.

Q. All right. I want to spend a moment and make sure we understand this particular point.

The Division has established by policy and regulation a fracture gradient based upon .2 psi per foot of depth, and that's for water, so that they can have a way to regulate the bottom hole pressure in the formation.

Now how are we going to make that formula work when you've also now using CO_2 injection?

A. Okay. CO_2 is not -- does not necessarily have the same density as water, so what we would like to do is operate the injectors at the same bottom hole injection pressure as we have set forth by pressure maintenance order R-5897.

At this time we're not asking for any change in the bottom hole injection pressure; however, to get to that point the wellhead surface pressure that goes along with that will need to be changed for CO_2, and this is only -- we ask this only to optimize the injection of WAG, the WAG injection during flooding.

Q. All right, what is the bottom hole pressure for the project, using the water calculation?

A. 3150 psig.

Q. That's the 3150 psig?

A. Yes.

Q. We can't use the equivalent .2 psi per foot of depth for the CO_2 because in order to get the 3150 in the bottom by using CO_2, it's going to have to have a surface pressure of something in excess of .2.

A. Yes.

Q. All right, sir. All right, let's discuss generally what conclusions you have drawn by the use of your model and the comparison of the model to the different pilot projects operated by some of these other operators in terms of what you anticipate to be the additional recovery of oil from this project.

A. One of the conclusions that we derive from the model is that the model suggests that CO_2 injected alternately with water recovers more than just CO_2 injection. This would probably be due to mobility control.

So based on that, we plan to inject them alternately, as Bill has discussed, in a water/alternate/gas process.

Also based on the model, we make projection of 26-million barrels as the incremental recovery. We wouldn't stand on that alone if there weren't -- wasn't pilot data to support it, based on other San Andres floods, but we feel fairly comfortable with that.

Q What is your next exhibit, Mr. Christian? I've lost my place. Exhibit Number Ten, I believe, is the next one we'll look at.

A. Yes. Exhibit Ten is a standard gas compressibility curve for 100 percent carbon dioxide, and I included this to show that this was what we used to calculate the complementary wellhead pressures, or fluid densities necessary to get the 3150 psig bottom hole pressure.

Q All right, sir, let's go on to Exhibit Number Eleven and have you identify that.

A. Exhibit Eleven is the wellhead injection pressure limit curve. At this time we would consider this an approximation of what pressures we would expect to operate the wellhead at to achieve that 3150.

You might note that the bottom, or horizontal axis is temperature. We did it this way because the density of CO_2 is quite dependent on the temperature that it arrives at the wellhead, and also your profile in the well. So we have investigated some other projects and tried to give our best guess at this time, and I feel like that this is a reasonable estimate of where we will be operating; however, we do also plan to measure it in the field once CO_2 injection starts to make sure that we're -- we can calibrate this curve and operate correctly.

Q. All right, let's go on to Exhibit Number Twelve.

A. This exhibit is a representation of the layers I used in the model. It is an average representation out there in the East Vacuum San Andres Unit of the porosity intervals as they occur.

Q. All right, sir, and are there any comments you'd like to make with regards to Exhibit Number Thirteen?

A. Well, I've already suggested that the other San Andres pilots were helpful in allowing us to evaluate the feasibility of CO_2 flooding, and Exhibit Thirteen is one tabulation of data available on the Denver Unit in the Wasson San Andres Field.

You can see that the porosity is very similar to ours and we feel like the Permian San Andres reservoirs are fairly similar.

Q. All right, sir, is there anything else you would like to discuss with regards to your testimony?

A. I don't believe so.

Q. Were Exhibits Seven through Thirteen prepared by you or compiled under your direction and supervision?

A. Yes.

MR. KELLAHIN: If the Examiner please, we move the introduction of Phillips' Exhibits One through Nineteen.

MR. STAMETS: These exhibits will be admitted.

MR. KELLAHIN: That concludes our examination of Mr. Christian.

CROSS EXAMINATION

BY MR. STAMETS:

Q Mr. Christian, the additional oil in -- that would be recovered by CO_2 injection was based on the model?

A. The number I gave you was based on the model.

Q Okay, could you just give us a brief rundown of what the model amounts to, what factors go into it, and what -- how it works?

A. Okay. Basically, one of the key things in a model is you have to determine a new residual oil saturation after waterflooding, and again this is based on the pilot data from the other fields. We don't see that much variation.

The model is segmented, as you may be aware, in any simulation technique, where the fluid is allowed to flow from one block to another to account for saturation gradient, and this type of thing. It is a miscible process model in that the fluids are allowed to mix with the oil. It does assume -- it does assume that you're operating above the miscibility pressure. So all projections made by the model were assuming that we start injection above the miscibility pressure.

Q. Part of the variation in expected recovery out there, would that be because of the -- well, let me go back and start over on this.

The effect of CO_2 at various residual oil saturations, was that based on actual measured detail from the field in other projects, or is that a theoretical set of figures, or is that based on laboratory tests?

A. Okay. The number I used in the model was before we had measured it in the lab. We're still in the process of measuring it to confirm it, but it is based on pilot data from Shell in the Denver Unit, so it is measured in the field.

Q. Okay. What I'm trying to find out is, obviously, if you've waterflooded a project all the way through, you're going to have a lot more residual oil saturation than if your --

A. Oh, okay.

Q. -- than if your waterflood is in the early stage, or the stage that this project is in. And I would assume that in the modeling that residual oil saturation does make a difference as to what you come out with at the end.

A. You're talking about whether we start the project now or at the end of waterflooding.

Q. Yes.

A. Well, it certainly has an economic effect and there's no way to get residual oil saturation away from that, but it -- several people have suggested it has effect; however, I didn't investigate the specific answer to your question.

What I did do, is I flooded the model with water up until the point where we felt like we would be at the miscibility pressure and then started injection of CO_2. Is that answering?

Q. Well, sort of. At this point, though, it seems like one of the exhibits Mr. Berry presented indicated that there probably would be about as much oil recovered as a result of CO_2 flooding whether it was done now or done later.

MR. KELLAHIN: Is that Exhibit Thirteen?

MR. STAMETS: I don't know. Yes, that's Exhibit Thirteen. It's that final -- well, I'm not sure that that's what that shows.

It's the bottom line on there showing estimated tertiary millions of barrels; shows the Denver Unit, East Vacuum Unit, and CO_2 Area, but I don't know that that's what that shows.

Mr. Berry, let me ask this question of

the appropriate person, whoever that turns out to be.

Were any calculations made as to how much oil would be recovered by -- how much tertiary oil would be recovered by starting tertiary now as opposed to starting tertiary after the secondary?

MR. BERRY: I'd like to respond to that. The incremental recovery for tertiary will be between 6-million whether we implement it now or later. As far as injecting CO_2 at the miscibility point in 1984 or at miscibility point at some time later than that, there is no recovery of oil from -- that is attributable to the waterflood in our testimony that is attributable to the tertiary recovery.

So if I understand your question, that you're wondering if the residual oil saturation if we flooded it down to a lower residual oil saturation would we expect the same amount of recovery.

MR. STAMETS: Right.

MR. BERRY: And the answer to that is that the two processes, although operating simultaneously, that with the CO_2 process we will recover the 41-million that I quoted earlier, plus the additional 26-million.

MS. STAMETS: So you're not stating that because you're starting this now you're going to recover any more oil; you will just do it more economically.

MR. BERRY: That's -- that's correct, and that the economics also enter to this in that, as we mentioned earlier, the operating costs are high for a tertiary project and that the implementing of this project at an early date is necessary in order that the operating costs be borne by both tertiary and secondary, or that the economics become very unfavorable if the project is started at a later date.

Q Exhibit Number Seven seems to show that there is some scaling off of the effectiveness of the CO_2 injected above the miscible pressure.

A. I wouldn't say that that's really a conclusion we should draw from that. It has to do with the swelling and pore volume of the oil as you increase the pressure. There's no additional help and it compresses the fluid more.

Typically in these lab tests it can slightly drop or it can be parallel, horizontal, or it can go up a little bit. I'm not sure that that's a conclusion that is really -- that we could really say that that's -- that it's going to decrease.

In fact, we don't expect it to decrease.

Q Now, under normal injection processes the pressure that you would have in the formation front would decline as you move away from the wellbore. Will you be restricting production in any way to try and achieve a more uniform pressure throughout the reservoir than under normal secondary processing?

A. The only restriction might be if there were high gas breakthrough volumes of CO_2. Really what we hope to do is maintain an injection pressure high enough to keep most of the reservoir above the miscibility pressure. There is no way to keep it all above it, because average pressure in a producer is very low.

Q. Will there be any monitoring done in the area to see how effective this is during the course of the project?

A. You're talking about, what, pressure or something else?

Q. Is Phillips going to drill any monitor wells in the area between existing injection wells, producing wells, to see how effective the CO_2 is, and how effective you are at keeping the pressure up?

A. It's a possibility, although I can't say that we are definitely, have committed ourselves to that.

Q. Is it possible to operate this kind of a project and know what you're doing without that type of monitoring process?

A. Well, we think so. We certainly don't know everything involved in the mechanism of the recovery. I'm not sure anybody does, but we fully anticipate that the recovery we projected can be achieved and whether or not we will have to drill some additional wells, that will depend on more data as it becomes available.

MR. STAMETS: Are there other questions of this witness?

MR. PEARCE: Yes, sir, if I may.

CROSS EXAMINATION

BY MR. PEARCE:

Q It may be that Mr. Berry is the person to answer this.

Do I understand you correctly that you believe there is no requirement in the Windfall Profits Tax Act which requires that secondary recovery methods be exhausted prior to institution of tertiary recovery methods? Is that your understanding, that there is no such requirement?

MR. BERRY: Although tertiary by definition implies after secondary, that the tertiary project, or process, is defined by the Department of Energy Regulation 212.78, in which they do not specify that they must follow a secondary process.

In fact, the implementation of a tertiary project early, also, as I mentioned earlier, improves your economic limit, and if you implement a tertiary project at the conclusion of the secondary project, if it was economically viable at that time your economic limit would indicate that you probably not recover as much reserves as you would if you operated these simultaneously.

Q And for Mr. Christian, I asked this of Mr. Berry earlier, and I'm hoping you can give me some clarification.

If you would explain to me whatever you can about the way you arrived at the cost of CO_2 projected for this project over the life of the project.

A Really the cost is based on the volume and in talking to suppliers we have taken a range and taken an average. There is no guarantee that we'll be able to get it for that price. We may be able to get it for less or for more, and we have just used that, I guess Bill used that as a demonstration point.

MR. STAMETS: Mr. Berry, I believe you indicated that there were 78-million barrels of primary production expected out of East Vacuum. What was the calculated original oil in place?

MR. BERRY: 296-million for the entire unit. There's a tabulation, I believe, with these pertinent numbers on Exhibit Thirteen, I believe.

MR. STAMETS: Okay.

MR. BERRY: There's 296.6, rounded off to 297-million barrels original oil in place in the East Vacuum Unit; 260-million in the CO_2 project area.

MR. STAMETS: Any other question of either witness? They may be excused.

Anything further in this case?

MR. KELLAHIN: No, sir.

MR. STAMETS: The case will be taken under advisement.

(Heqring concluded.)

CERTIFICATE

I, SALLY W. BOYD, C.S.R., DO HEREBY CERTIFY that the foregoing Transcript of Hearing before the Oil Conservation Division was reported by me; that the said transcript is a full, true, and correct record of the hearing, prepared by me to the best of my ability.

Sally W. Boyd CSR

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 7426, heard by me on 11-19 1981.

Richard L. Stamets, Examiner
Oil Conservation Division

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ENERGY AND MINERALS DEPARTMENT

OIL CONSERVATION DIVISION

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December 28, 1981

Mr. Thomas Kellahin
Kellahin & Kellahin
Attorneys at Law
Post Office Box 1769
Santa Fe, New Mexico

Re: CASE NO. 7426
ORDER NO. R-6856

Applicant:

Phillips Petroleum Company

Dear Sir:

Enclosed herewith are two copies of the above-referenced Division order recently entered in the subject case.

Yours very truly,

JOE D. RAMEY
Director

JDR/fd

Copy of order also sent to:

Hobbs OCD x
Artesia OCD x
Aztec OCD ____

Other ____

RECEIVED
DEC 21 1981
OIL CONSERVATION DIVISION
SANTA FE

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
DIVISION FOR THE PURPOSE OF
CONSIDERING:

CASE NO. 7426
Order No. R-6856

APPLICATION OF PHILLIPS PETROLEUM COMPANY FOR AMENDMENT OF DIVISION ORDER NO. R-5897 AND APPROVAL OF A QUALIFIED TERTIARY OIL RECOVERY PROJECT UNDER THE CRUDE OIL WINDFALL PROFITS TAX ACT OF 1980, LEA COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 9:00 a.m. on November 19, 1981, at Santa Fe, New Mexico, before Examiner Richard L. Stamets.

NOW, on this 14th day of December, 1981, the Division Director, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Division has jurisdiction of this cause and the subject matter thereof.

(2) That the applicant, Phillips Petroleum Company, seeks the Amendment of Division Order No. R-5897, to include the injection of carbon dioxide in its previously authorized pressure maintenance project in the East Vacuum Grayburg-San Andres Unit, for conversion of existing injectors to water/carbon dioxide injection, and for the approval of a portion of the East Vacuum Grayburg-San Andres Unit as a Qualified Tertiary Oil Recovery Project under the Crude Oil Windfall Profits Tax Act of 1980.

(3) That said pressure maintenance project lies within the Vacuum Grayburg San Andres Pool, Lea County, New Mexico.

(4) That said pool was discovered May 5, 1924, by Socony Vacuum Oil Company, experienced substantial development thereafter with waterflooding being initiated in a project during 1958.

(5) That the Phillips Petroleum Company East Vacuum Unit Pressure Maintenance Project consisting of approximately 7025 acres was approved by said Division Order No. R-5897 on January 16, 1979, and water injection was commenced within said project during December, 1979.

(6) That the applicant now seeks approval for the injection of carbon dioxide and water into 45 project wells and the designation of a qualifying tertiary recovery project area within said pressure maintenance project.

(7) That the proposed Qualifying Tertiary Project Area (QTP Area) lies wholly within said East Vacuum Unit Pressure Maintenance Project and consists of the following described acreage:

TOWNSHIP 17 SOUTH, RANGE 35 EAST, NMPM
Section 26: W/2, NE/4; W/2 SE/4; and NE/4 SE/4
Section 27: All
Section 28: All
Section 29: All
Section 31: N/2 SE/4 and SE/4 SE/4
Section 32: All
Section 33: All
Section 34: N/2; SW/4; and NW/4 SE/4
Section 35: N/2 NW/4

TOWNSHIP 18 SOUTH, RANGE 35 EAST, NMPM
Section 4: N/2 NW/4 and NW/4 NE/4
Section 5: N/2 and NW/4 SW/4

containing 4997 acres more or less.

(8) That the QTP Area is adequately delineated and that the entire area will be affected.

(9) That the New Mexico Oil Conservation Division has been designated by the Governor of the State of New Mexico as the appropriate agency to approve Qualified Tertiary Recovery Projects in New Mexico for purposes of the Crude Oil Windfall Profits Tax Act of 1980.

(10) That the tertiary oil recovery method used in the Phillips QTP Area is a carbon dioxide miscible displacement method which is a recognized tertiary oil recovery method described in Section 212.78(c) of the Department of Energy Regulations in effect in June, 1979.

(11) That the Tertiary Recovery method includes overinjection of voidage with water at maximum rates to achieve a miscibility pressure in the formation.

(12) That slim-tube tests have determined such miscibility pressure to be approximately 1369 psia.

(13) That overinjection began on February 1, 1981, and carbon dioxide injection will begin after miscibility pressure has been achieved.

(14) That under the tertiary recovery method to be used, it is anticipated that the volume of injected carbon dioxide measured at reservoir temperature and pressure will be more than 10 percent of the reservoir pore volume being served by the injection wells.

(15) That because of the geological and reservoir characteristics of the effected reservoir, the QTP Area is well suited for miscible fluid displacement by carbon dioxide as an enhanced recovery process.

(16) That the estimated primary production from the East Vacuum Unit Pressure Maintenance Project Area is 72 million barrels and that water flooding secondary recovery operations will recover an additional 38 million barrels.

(17) That an estimated 26 million barrels of additional oil (which is 10 percent of the original oil in place within the project area) will be recovered as a result of the tertiary recovery operations, which is more than an insignificant increase in the amount of crude oil which will ultimately be recovered.

(18) That the QTP Area tertiary recovery operations beginning date is after May, 1979.

(19) That the QTP Area tertiary recovery operations beginning date (i.e., the date on which the injection of liquids, gases or other matter begins) was February 1, 1981.

(20) That the proposed tertiary recovery operations within said QTP Area meet all requirements of Section 4993 of the Internal Revenue Code.

(21) That the Phillips QTP Area project is designated in accordance with sound engineering principles.

(22) That the approval of this application will prevent waste, protect correlative rights and promote conservation.

IT IS THEREFORE ORDERED:

(1) That effective December 1, 1981, the Qualifying Tertiary Recovery Project Area, described in Finding No. (7) of this Order, of the Phillips Petroleum Company East Vacuum Unit Pressure Maintenance Project, Vacuum Grayburg-San Andres Pool, Lea County, New Mexico, is hereby approved as a Qualified Tertiary Recovery Project under the Crude Oil Windfall Profits Tax Act of 1980.

(2) That the applicant, Phillips Petroleum Company, is hereby authorized to inject water and carbon dioxide into the 45 wells listed on Exhibit "A" attached to this Order.

(3) That Order No. R-5897 is hereby amended to authorize injection of carbon dioxide up to an average maximum bottom hole pressure of 3150 psi.

(4) That jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

JOE D. RAMEY,
Director

S E

CASE NO. 7426
Order No. R-6856

EXHIBIT A

Approved Water-Alternate-Carbon Dioxide Injectors

Tract 2622 - Well 004
Well 006

Tract 2717 - Well 003
Well 005
Well 007

Tract 2720 - Well 006

Tract 2721 - Well 001
Well 002

Tract 2738 - Well 007
Well 008
Well 009

Tract 2801 - Well 005
Well 006
Well 007
Well 012
Well 015

Tract 2865 - Well 001

Tract 2913 - Well 007
Well 008
Well 009

Tract 2941 - Well 001

Tract 2947 - Well 001

Tract 2963 - Well 004

Tract 2980 - Well 003

Tract 3127 - Well 004

Tract 3202 - Well 008
Well 009
Well 010
Well 013

Tract 3229 - Well 006
Well 008

Tract 3236 - Well 006

Tract 3315 - Well 006
Well 008

Tract 3328 - Well 003

Tract 3332 - Well 001

Tract 3333 - Well 005
Well 006

Tract 3373 - Well 001

Tract 3374 - Well 002

Tract 3456 - Well 006
Well 007
Well 009

Tract 0524 - Well 001
Well 006

EAST VACUUM GRAYBURG-SAN ANDRES UNIT

CARBON DIOXIDE TERTIARY RECOVERY PROJECT

The objectives of Phillips Petroleum Company's presentation today on CO_2 flooding the East Vacuum Grayburg-San Andres Unit are: 1. To receive approval from the New Mexico Oil Conservation Division to expand the previously issued pressure maintenance Order 5897 to include CO_2 injection; and 2. To obtain certification from the New Mexico Oil Conservation Division of this project as a qualified tertiary oil recovery project under the Crude Oil Windfall Profits Tax Act of 1980.

The first part of the testimony that I will present will be a brief review of the history of the Vacuum Field in general and the East Vacuum Grayburg-San Andres Unit in particular. I will then call on Mr. Terry Christian to present the second part which will be a discussion of the technical data that have led Phillips to selecting CO_2 flooding as the tertiary method to be used in the East Vacuum Grayburg-San Andres Unit. I will then follow his presentation with a recapitulation of our testimony.

The Vacuum Field was discovered May 5, 1924, by Socony Vacuum Oil Company's Bridges State Well No. 1. Exhibit 1 shows the location of the Vacuum Field in Lea County, New Mexico. Development began in 1939 and by the end of 1941 there were 330 producers in the Field. As of June of this year there were 492 production wells and 181 injection wells in the field. The first waterflood project in the field, Mobil Oil Company's Bridges State Lease, began in 1958. The latest flood to be implemented in the field is the East Vacuum Grayburg-San Andres Unit. Exhibit 2 illustrates the relative location

BEFORE EXAMINER STAMETS
OIL CONSERVATION DIVISION
Phillips EXHIBIT NO. 1
CASE NO. 7426
Submitted by
Hearing Date

of the various waterfloods.

The Vacuum Grayburg-San Andres Field is an east-west trending anticline on the Artesia Lovington uplift. Exhibit 3 is a structure map of the eastern part of the Vacuum Field in which the East Vacuum Grayburg-San Andres Unit is outlined in red. The structure has more than 400' of closure above the original oil-water contact of 700 feet subsea.

The San Andres zone in the Vacuum Field is a dolomitized reef with permeable forereef charateristics to the south and poor quality back-reef and lagoonal deposits to the north. Exhibits 4 and 5 are west-east and north-south cross sections respectively for the East Vacuum Grayburg-San Andres Unit. Only zones that can be correlated over large areas of the unit are presented in these cross sections. The black zones represent the impermeable strata and the white zones are the pay. As can be seen in these cross sections, the impermeable strata are widespread and form effective cross flow barriers throughout the reservoir. The San Andres formation is a dense, medium crystalline and oolitic, white to gray dolomite with some anhydrite. The productive zones are composed of a fine to medium crystalline slightly fractured dolomite with some solution cavities.

The East Vacuum Grayburg-San Andres Unit encompasses 7025.36 acres with an average thickness of 71'. The original-oil-in-place for the unit was 296.99 million barrels of oil based on a lease by lease determination. The average porosity and initial water saturation for the unit were 11.7% and 15.9% respectively.

Exhibit 6 is a graphical representation of the last two years of production and the forecast for primary, secondary and tertiary production performance from the East Vacuum Grayburg-San Andres Unit. As of January 1, 1981 more than 72 million barrels of oil have been produced from the unit area. Ultimate primary recovery is expected to be 78 million barrels of oil or 26.3% of the original-oil-in-place. The incremental recovery attributable to secondary waterflooding will be 13.7% of the original-oil-in-place or 40.8 million barrels. The estimated additional recovery from the tertiary CO_2 flood will be 26 million barrels or 10% of the original-oil-in-place in the project area. An explanation of the tertiary forecast will be provided later in the testimony.

At this time if there are no questions, I would like to turn the testimony over to Mr. Terry Christian to present the premises and technical justification for conducting a tertiary CO_2 project in the unit.

Phillips has for some time considered the Vacuum San Andres reservoir to have good enhanced recovery potential. Several factors have caused us to accelerate our preparation for enhanced recovery. The major reason is that more pilot information has recently become available which strongly suggests that some processes may be technically and economically possible on a large scale basis. The performance of these pilots has been very encouraging.

Miscible flooding with CO_2 and water was chosen as the best enhanced recovery process due to the low permeability (1-20 md) of the pay, carbonate lithology, and high formation water salinity. This process was chosen instead of polymer, surfactant, and immiscible gas processes because of the above factors and because the incremental recovery for miscible CO_2 flooding would likely be greater. Thermal methods were excluded because the

Vacuum San Andres oil is a 35° API oil. The oil viscosity is low enough that thermal methods would not significantly benefit recovery, and the low porosity (11.7%) would require more heat than is considered feasible. Other processes may work, but the performance of various pilots have indicated the San Andres reservoirs of the Permian Basin are well suited to miscible CO_2 injection.

The miscible CO_2 process improves recovery by oil swelling, by oil viscosity reduction, and a method similar to the surfactant flood; by lowering the interfacial tension of the reservoir fluids. CO_2 is not directly miscible with most oils, but develops miscibility through multiple contacts. Very low interfacial tensions can be achieved if carried out at adequate pressures.

Generally as the system interfacial tension lowers, the residual oil saturation to CO_2 flooding lowers, indicating the system is approaching complete miscibility and that greater oil recoveries would be expected. Also the degree of miscibility for CO_2 and crude oil increases with increasing pressure, up to a certain minimum, above which there is little change for increasing pressure. At this point, the CO_2 and crude are considered a miscible system. The lowest pressure at which the CO_2 injectant and reservoir crude develop this miscibility is defined as the minimum miscibility pressure.

Since the minimum miscibility pressure may be different for each CO_2-oil system, the first matter of concern was the determination of the minimum miscibility pressure for the East Vacuum Unit crude.

We use a slim tube apparatus to determine the minimum miscibility pressure, which allows multiple contacts of CO_2 and oil to develop miscibility in a porous medium. Also, with the slim tube, the effects of adverse mobility ratios and viscous fingering can be minimized. The minimum miscibility pressure can be determined with a slim tube by comparing the relative displacement efficiencies of controlled flow experiments.

The slim tube process used for this study consists of a .25 inch x 50 ft. stainless steel column packed with 100-140 mesh glass beads. The tube is presaturated with oil before injection of the CO_2 stream begins. Basically, displacements are carried out at several pressures and the minimum miscibility pressure is the pressure where the recovery versus pressure curve breaks sharply and reaches an approximate maximum. Exhibit / is a typical curve. Note the sharp breakover. This is the minimum miscibility pressure. In this case it is 1369 psia.

The minimum miscibility pressure for pure CO_2 and East Vacuum reservoir oil at reservoir temperature is 1190 psia. However, the minimum miscibility pressure is affected by oil composition, injection gas composition and reservoir temperature. Two of the above variables could be expected to vary. First, almost no naturally occurring supply is pure CO_2. Second, the inplace oil composition may vary according to the present state of depletion in various areas of the field.

To determine the composition of the CO_2 injection stream, we contacted several of the possible suppliers. After discussions with these suppliers, it became apparent that the supply offered for sale would likely range from 3 to 6 mol % nitrogen and 0 to 2 mol % methane in CO_2. Our previous experience with slim tube tests indicated that small amounts of methane have little effect, so most of the work focused on the effect of nitrogen contamination. Exhibit 8 is a table summarizing our findings. With the maximum expected contamination of 6 mol % nitrogen, the minimum miscibility pressure increased to 1369 psia from 1190 psia for pure CO_2. Exhibit 9 is a plot showing the effect of nitrogen contamination on the minimum miscibility pressure. Note that the effect is small for up to 6 mol % nitrogen in the injected gas. This is considered nondetrimental. For all practical purposes this would delay the start of CO_2 injection at the East Vacuum Unit very little. However, if the supply were to contain 10 mol % nitrogen, a significant delay to repressure the reservoir to the miscibility level could be possible. Note on Exhibit 9 that the minimum miscibility pressure increased to 2120 psia for the 10 mol % nitrogen case.

All the previously discussed tests were conducted on live oil, or recombined oil to represent the crude as it occurs in the reservoir. As previously mentioned, the minimum miscibility pressure is also affected by the oil composition. Therefore, recombining stock tank oil to reproduce in situ reservoir oil is necessary to determine an accurate minimum miscibility pressure.

A gas composition was calculated which would combine with stock tank oil to simulate the reservoir oil, and this composition roughly agreed with recent produced gas analyses. This gas was recombined with stock tank oil to represent the current in-place oil. This oil was the live or recombined oil used for tests with the slim tube.

Also, slim tube tests were conducted with stock tank oil. Even though material balance calculations gave a good estimate of the average in-place oil composition, parts of the Unit are more depleted than this average representation. Stock tank oil represents the most severe case of gas depletion possible. Again on Exhibit 9 you can see that this had little effect on the ability of CO_2 to reach a miscible state with the oil. The minimum miscibility pressures for stock tank oil and the CO_2 and CO_2 plus nitrogen mixtures were nearly the same as those found for the recombined in-place oil.

The two objectives of this work were to: 1) determine the influence of the state of depletion and injectant composition on the minimum miscibility pressure and 2) quantify the range of necessary operating pressures. Having already discussed the first aspect, we concluded that the flood could be conducted successfully at reservoir pressures from 1100 psia and up. For planning purposes and to allow a margin of safety, we utilized the minimum miscibility pressure for CO_2 and 6 mol % nitrogen, 1369 psia, to establish a flood plan. Since the initial pressure in the Vacuum Field was 1613 psig, the flood could be safely operated at these pressures with little or no danger of rock parting and fluid migration, as long as proper bottomhole injection pressures are maintained.

Model results, which I will discuss later, indicated that the CO_2 flood would perform better if the CO_2 is injected alternately with water. To optimize the operation of a water-alternate-gas (WAG) process, the bottom-hole injection pressure should be maintained the same during water and CO_2 injection. However, the densities of these two fluids are different, requiring a different surface tubing pressure, depending on the fluid being injected. The surface tubing pressure limit for water injection has already been regulated, by Pressure Maintenance Order R-5897. The pressure was limited in order to prevent formation parting and fluid migration. Therefore, this same bottomhole pressure limitation should be used for gas injection.

The injection wellhead pressure limit was set by the Pressure Maintenance Order at 0.2 psi/ft to the top perforation. In the case of the East Vacuum Unit the maximum wellhead pressures by this formula range from 860 psig to 920 psig averaging 900 psig. The bottomhole pressure for a 900 psig wellhead pressure is near 3150 psig. The average wellbore system to represent this 3150 psig bottomhole pressure consists of: 1) a 900 psig surface pressure, and 2) 4500 feet of hydrostatic head.

Since CO_2 is a compressible fluid, it would be improper to assume one density for calculating the gravity head. The density is related to the temperature, pressure and composition. The ideal gas law can be used to calculate the density of CO_2 as a function of temperature and pressure if the proper compressibility factor is used. Using standard gas well pressure gradient calculation methods, a surface pressure-vs-surface temperature curve can be established. The surface pressure calculated is the pressure necessary to maintain a bottomhole injection pressure of 3150 psig. Exhibit 10 is a graph of the compressibility factors used in the calculation. Exhibit 11 is the resulting wellhead pressure versus wellhead temperature curve. Because the exact heat transfer attendant with the pipeline and tubing system cannot be calculated with a great deal of assurance, we hesitate to project a wellhead temperature and temperature profile for the injection gas. However, we reasonably expect the temperature to vary with atmospheric conditions and range from possibly 40° to 100° F.

Therefore the curve on Exhibit 11 can be used as an approximate operating guideline for wellhead injection pressures. This curve is for a composition of 100% carbon dioxide. In actuality, the composition will be slightly different. Also, Chevron has demonstrated that the actual compressibility factors may deviate from handbook values. We propose that the Division accept this as an approximate guideline until actual field measurements can be made with bottomhole pressure bombs with bottomhole injection pressures limited to 3150 psig. This can be done after the injection of CO_2 begins.

We plan to monitor and control wellhead pressures, temperatures, and rates by manual adjustment or by a computer controlled automated supervisory system. Since temperature and pressure must be measured to calculate rates, this wellhead curve can be loaded into the computer as a limiting pressure at any measured temperature.

With the preceding premises set for operating the flood, performance predictions can be made. Two approaches were used to predict the incremental oil production attributable to miscible CO_2 flooding. First, a review of present pilots and projects in operation was made. Second, a Phillips miscible process computer model was used to calculate performance. Both approaches gave results with acceptable agreement. Based on these two methods an additional 26 million barrels, or 10% of the original oil-in-place for the project area can be recovered with total CO_2 injection equivalent to 40% of the initial hydrocarbon pore volume.

The model used to predict miscible CO_2-waterflood performance is normally used for predictions when the reservoir is above the minimum miscibility pressure. It was therefore necessary to estimate the time necessary to repressure the reservoir by another means. Phillips compositional material balance model was used for this purpose. The compositional mode allowed us to account for the accelerated gas depletion history, as I discussed earlier, and more accurately estimate repressuring.

The model input data included original oil-in-place, original reservoir fluid composition, and original reservoir pressure. By supplying production history, the model calculates the reservoir pressure versus time. Using this method the reservoir primary depletion conditions prior to water injection could be simulated. By supplying the forecasted water injection and total production forecast, the future reservoir pressure can be predicted. The model predicted that repressuring will be slow during initial water injection until all the gas has collapsed into solution with the oil. After this, the system, as expected, will be fairly incompressible and repressuring will be more rapid. The model predicted that the average reservoir pressure will be 1400 psia in 1984. Once we determined that the reservoir pressure could be raised above the minimum miscibility pressure in a reasonable length of time, we began modeling to determine the effect of CO_2 injection. Production increases due to CO_2 flooding were predicted with a computer model developed by Phillips Research and Development. The model represents a linear, stratified reservoir with no cross flow. The permeability is assumed to be constant in each layer, but is allowed to vary from layer to layer. Within each layer, water, oil, and carbon dioxide are assumed to flow miscibly according to the miscible mixing relationships of Todd and Longstaff. This technique has been well accepted by the oil industry as a method for studying the effect of miscible CO_2 injection on reservoir performance. Provisions are made in the model for alternating water and carbon dioxide injection and for variable injection rates, as well as for viscosity reduction of oil mixing with CO_2. This model is adequate to compare various operating procedures and is useful in predicting CO_2 flood performance at the East Vacuum Unit. Input data for the model may be found in Exhibit 12. These data are representative of typical properties in the East Vacuum Unit, and have been previously used in waterflood studies. Waterflood performance to date, although small in extent, has indicated the representation is reasonably accurate.

By using the model we predicted ultimate incremental recovery would be 26 million barrels or 10% of the original oil-in-place for the CO_2 project area when areal heterogeneity and volumetric efficiencies are considered. This recovery is for the case of injecting a finite volume of CO_2 and then following this with the same effective volume of water, or 1 reservoir barrel of carbon dioxide per reservoir barrel of water.

Model results indicate that alternate injection of carbon dioxide and that the reservoir pressure could be raised above the minimum miscibility pressure in a reasonable length of time, we began modeling to determine the effect of CO_2 injection. Production increases due to CO_2 flooding were predicted with a computer model developed by Phillips Research and Development. The model represents a linear, stratified reservoir with no cross flow. The permeability is assumed to be constant in each layer, but is allowed to vary from layer to layer. Within each layer, water, oil, and carbon dioxide are assumed to flow miscibly according to the miscible mixing relationships of Todd and Longstaff. This technique has been well accepted by the oil industry as a method for studying the effect of miscible CO_2 injection on reservoir performance. Provisions are made in the model for alternating water and carbon dioxide injection and for variable injection rates, as well as for viscosity reduction of oil mixing with CO_2. This model is adequate to compare various operating procedures and is useful in predicting CO_2 flood performance at the East Vacuum Unit. Input data for the model may be found in Exhibit 12. These data are representative of typical properties in the East Vacuum Unit, and have been previously used in waterflood studies. Waterflood performance to date, although small in extent, has indicated the representation is reasonably accurate.

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Model results indicate that alternate injection of carbon dioxide and water recovers more oil than continuous injection of carbon dioxide. The water provides mobility control for the carbon dioxide and thereby improves recovery. We call alternate injection of water and gas (carbon dioxide) a WAG, or water alternate gas cycle. The combination of all the cycles gives the total amount of carbon dioxide necessary. For the previous oil forecast, the project will require 277 BSCF, or a total carbon dioxide slug equivalent to 40% of the initial hydrocarbon pore volume. Water will continue to be injected after the cyclic WAG injection ends to continue to displace the oil and carbon dioxide system. The model also suggested that the incremental recovery above waterflooding improved with decreasing cycle sizes, that is, injecting less CO_2 per cycle. It also suggested that there is a maximum benefit to be gained by this effect with approximate cycle slugs of 5% pore volume carbon dioxide per cycle. However, in view of problems reported at SACROC, we plan to use a smaller slug of carbon dioxide, equivalent to 2.1% of the initial hydrocarbon pore volume, with a WAG cycle ratio of 1.25 barrels of water per reservoir barrel of carbon dioxide. At SACROC, a large CO_2-water flood project near Snyder, Texas, the operators found it necessary in some cases to inject more water than carbon dioxide per WAG cycle in order to control mobility and restrict high volume breakthrough of carbon dioxide. This problem seems strongly related to heterogeneity of the reservoir and we are convinced that the reservoir at the East Vacuum Unit is generally less heterogeneous than at SACROC. This is due primarily to the extension of permeable layers and barriers over a greater amount of the field than at SACROC. The layers, as Mr. Bill Berry stated, appear to be continuous over fairly large portions of the East Vacuum Unit. This effect is beneficial in a horizontal flood because the tendency of carbon dioxide to override and bypass some oil is somewhat restricted.

At this point we felt the model had given us about as much information as could be expected without pilot history to match. A major problem in using the model is that not enough waterflood history is available to estimate the volumetric efficiency by history matching. Therefore, it was necessary to compare the model results to the actual performance of floods in other fields or to predictions from pilots in these fields. The possibility of initiating a pilot was precluded for two reasons. First, excellent information as to the success of the process is now available because of the recently completed pilot tests and the subsequent release of information of companies such as Amoco, Arco, and Shell. Second, as Mr. Berry will discuss, any appreciable delay will penalize the project economics, possibly making it uneconomic, or reducing the reserves by causing the economic limit to be reached earlier in the flood recovery life (at lower rates).

The basic conclusion of the review of other projects is that the model results are reasonable.

One comparison was with information given by Shell based on their forecast for miscible carbon dioxide flooding at the Denver Unit in the Wasson San Andres Field, near Denver City, Texas. Shell's results are from model studies based on pilot results. The expected ultimate incremental recovery is 13% of the original oil-in-place for a CO_2 slug of 40% of the initial hydrocarbon pore volume. This agrees fairly well with our prediction of 10% of the original oil-in-place for the East Vacuum Unit. Earlier engineering-geologic studies have indicated the reservoir properties of the Wasson San Andres are very similar to the Vacuum San Andres. Exhibit 13 is a tabulation of data to show this similarity. Therefore, the recovery factors due to enhanced recovery should be similar, and the model results suggest this also.

We also compared our results with a prediction released by Arco based on information from the Willard Unit pilot, also in the Wasson San Andres Field. The prediction of ultimate incremental recovery, 12.3% of the original oil-in-place, agrees very closely with Shell's forecast for the Denver Unit, 13% of the original oil-inplace.

A third case to indicate the success of miscible carbon dioxide flooding in San Andres reservoirs of the Permian Basin is the Slaughter Estate Unit pilot, operated by Amoco. In this pilot the actual recovery through December, 1980, of incremental tertiary oil was 104,700 stock tank barrels of 16.8% of the original oil-in-place for the pilot area. Amoco projects the ultimate incremental recovery to be no less than 20% of the original oil-in-place.

The performance of these pilots has been quite good and suggests that miscible CO_2 flooding of the Permian San Andres is a good process. The major difference, however, in conditions at these pilots and at the East Vacuum Unit is that the reservoir pressures were above the minimum miscibility pressure at onset. The average pressure in March of 1980 for the East Vacuum Unit was 561 psig, which is well below the minimum miscibility pressure. Therefore, the reservoir must be repressured. We considered injecting carbon dioxide with water to accelerate repressuring. The carbon dioxide would supply additional voidage replacement and could likely be injected under current wellhead pressure limitations. The injectivity is such that the carbon dioxide and available water could both be safely injected, thereby accelerating voidage replacement. Slim tube tests indicate that this could be done under certain conditions. The tests, however, also suggest that the ultimate incremental recovery of the miscible flood could be reduced. This would occur if significant volumes of carbon dioxide were injected under certain conditions into the reservoir before reaching the minimum miscibility pressure. The presence of free gas in the reservoir and high permeability streaks could allow the carbon dioxide to contact and pass through the oil rapidly and detrimentally affect ultimate performance. Apparently at pressures less than the minimum miscibility pressure, some of the intermediate hydrocarbons that are essential for obtaining miscibility are "stripped" and carried forward with the carbon dioxide. This reduces the ability of the carbon dioxide to later achieve miscibility with that oil when the minimum miscibility pressure is reached. For this reason, we have precluded the use of carbon dioxide as an additional repressuring agent and have chosen to wait until water injection has properly repressured the reservoir.

Pilot results, along with the model predictions, give us enough confidence to pursue enhanced recovery for the East Vacuum Unit. Due to high costs of the process, the earlier the better for project initiation. We expect the tertiary miscible carbon dioxide-water flood to recover an additional 26 million barrels from the project area. This increases the anticipated ultimate recovery of the Unit to 144.8 million barrels or 48.8% of the original oil-in-place. At this time, I will return the testimony to Mr. Bill Berry to discuss the project area and development plans.

Thank you Mr. Christian.

The tertiary CO_2 project will encompass most but not all of the East Vacuum Grayburg-San Andres Unit. Exhibit 14 shows the project area delineated within the Unit. This portion of the Unit was selected for CO_2 flooding because it would more likely be able to maintain the production rates required to support the high operating costs associated with a miscible CO_2 project. Exhibit 13 is a comparison of the project area and total unit parameters. This Exhibit clearly illustrates that the project area contains the better reservoir rock of the unit. The project area includes 4,997 acres out of 7,025 acres in the Unit and a reservoir volume that originally contained 260 million barrels or 88% of the original oil-in-place of the Unit. The economic viability of CO_2 flooding the rest of the unit will be periodically reviewed to determine if an expansion of the project is justified. The initial injection facilities will have the flexibility to be expanded as needed.

Initially 45 wells will be utilized as water-alternate-gas (WAG) injectors. All 45 WAG injectors are shown in red on Exhibit 14. These injectors are surrounded by currently completed or planned water injectors, colored in blue on this exhibit. These perimeter injectors will continue to inject water to confine the CO_2 within the project area. Sixteen of the forty-five wells that will be used for CO_2 and water injection are currently equipped with packers and tubing linings that can be used for CO_2 injection. The remaining twenty-nine wells will be converted prior to injecting CO_2 in them. All of these injection wells will be equipped and operated as specified in Pressure Maintenance Order 5897 with the exception of the surface pressure limitation for CO_2 injection as discussed by Mr. Christian.

A schematic of a typical injection well is included as Exhibit 15. The depths in this schematic are representative of the injectors throughout the Unit.

The injectors will be divided into two groups of approximately equal injection capacity. One group will receive CO_2 for 6 months while the other group takes water. At the end of 6 months, CO_2 injection will be rotated to the second group and vice-versa. This rotation will remain in effect unless field data indicate another plan will improve performance and economics.

The inverted nine-spot currently being used for waterflooding will also be used for WAG injection of water and CO_2. This pattern has a ratio of 3 producers to one injector, with each injector serving approximately 80 acres. At present, injectivity is high enough to expect adequate injection rates during WAG injection to maintain economical producing rates; however, should the injection rate become lower than expected, another pattern such as a five-spot, with a producer to injector ratio of 1 to 1 may be used. The inverted nine-spot offers the flexibility to convert to other patterns easily which is one of the reasons for using it as the initial pattern.

In order to repressure the reservoir to the miscibility pressure water injection in excess of voidage has been initiated and will be continued at an accelerated pace.

From January to August of this year the water injection has been increased from 33,000 to 61,000 barrels per day. As a result of this increased injection the injection to voidage ratio has increased from .77 to 1.59. A tabulation of the monthly ratios from March 1980 to August 1981 is presented in Exhibit 16. Note that the first overinjection of voidage occurred in February 1981.

The water injection rate during the repressuring stage is anticipated to be the maximum available rate of 90,000 BPD of which 80,000 BPD will be makeup water and 10,000 BPD will be produced water. Plans to maximize use of this injection water include 1) injection surveys, 2) pressure falloff tests, and 3) remedial work, if necessary. The injection surveys will be used to insure that all zones are being repressured. Pressure falloff surveys will be used to investigate the possible presence of formation damage, while remedial workovers will be conducted to improve vertical conformance and reduce scale. Also, the falloff surveys will be used concurrently with buildup data from producers to monitor the average reservoir pressure and revise operations as needed.

A separate distribution system will be constructed to inject CO_2 since the present surface water injection system is not compatible with CO_2. Also, the separate CO_2 injection system will provide the flexibility necessary to operate the field on a WAG process.

Based on reports of premature breakthrough at SACROC and on Phillips' reservoir model studies, Phillips has decided to start with an initial WAG ratio of 5 to 4 with approximately 2.1% of the initial hydrocarbon pore volume injected per CO_2 cycle. The WAG process was chosen to maximize mobility control. The CO_2 slug size will be kept small to reduce the possibility of early, high volume breakthrough. Both the WAG ratio and cycle slug size are intended to avoid the high operating costs and low oil recoveries resulting from early, high volume CO_2 production rates.

Model studies indicate that the cumulative injected CO_2 volume (including make-up and reinjection) over the project life may be as much as 40% of the initial hydrocarbon pore volume. The actual amount injected will depend on future oil prices and operating costs, but Phillips anticipates that at least 10% pore volume will be injected over the life of the project.

For a CO_2 volume equivalent to 40% of the initial hydrocarbon pore volume, total injection will be 277.6 BCF over a 19 year life. Approximately 62% or 171.2 BCF will be purchased, with reinjection of 106.4 BCF, accounting for the remaining 38% of the total. Due to the large volume of CO_2 required the supply will probably be delivered by pipeline from prolific natural sources or from large industrial by-product streams. Water injection will be continued for 8-12 years after the termination of CO_2 injection. A schedule of the forecast CO_2 injection and production over the 19-year period is included in Exhibit 17.

The cost of the 277.6 billion cubic feet of CO_2 that will be injected or reinjected will be more than $400 million over the 19-year injection period. The investment cost, which will be made in 1982 and 1983, for the pipelines, distribution systems and process equipment and modifications are estimated to be approximately $81.5 million.

EXHIBITS

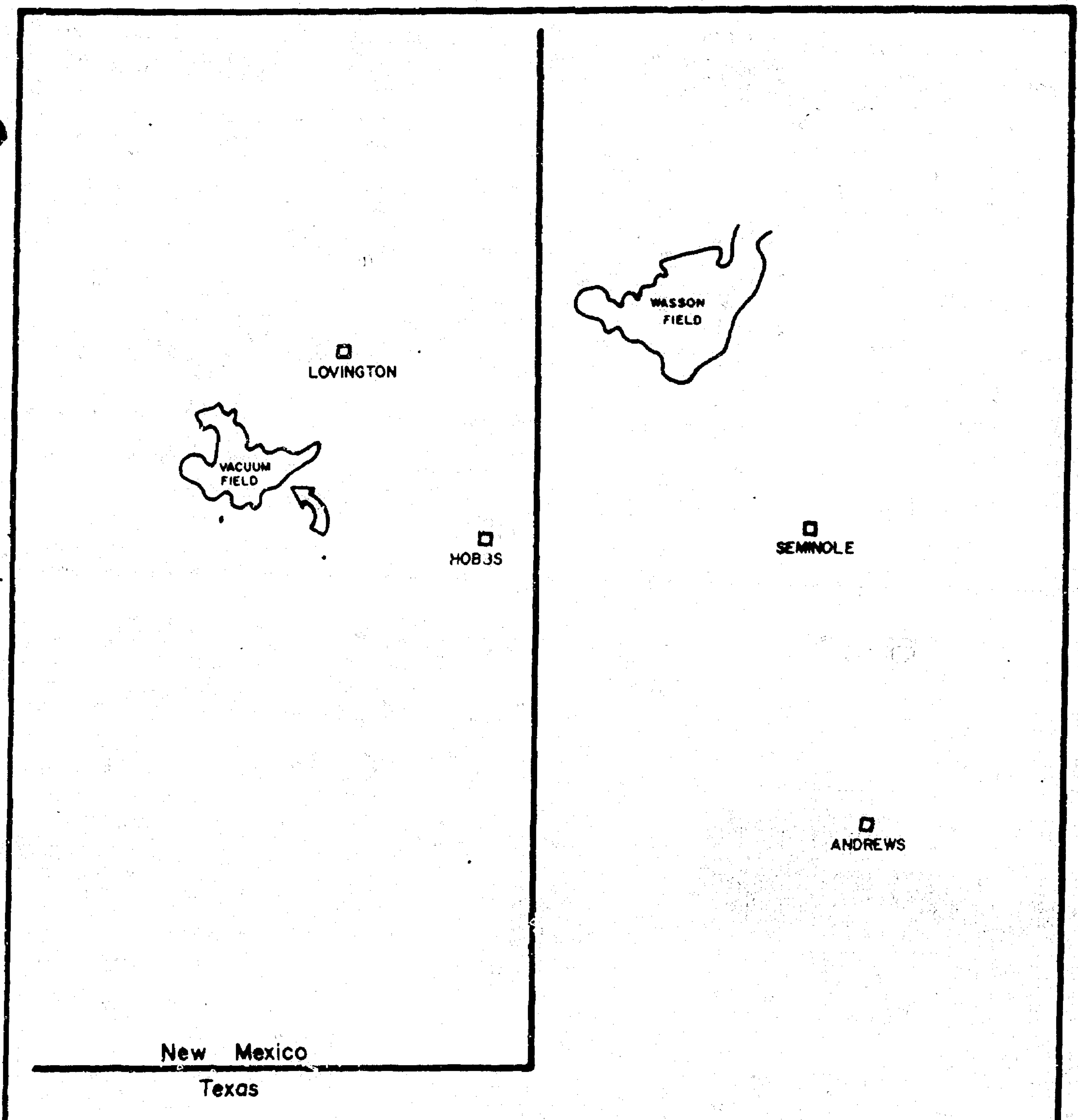


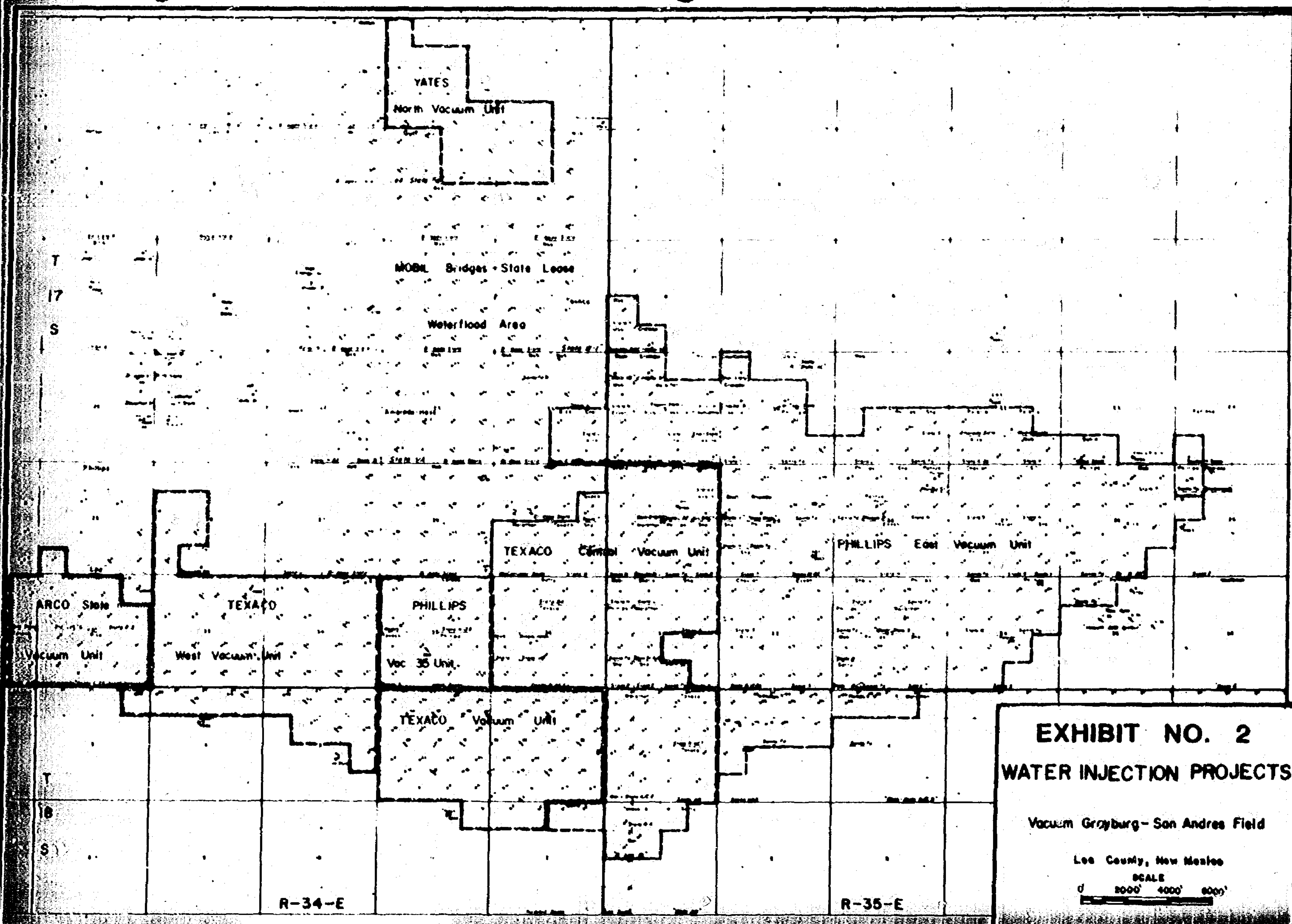
EXHIBIT No. 1

LOCATION PLAT

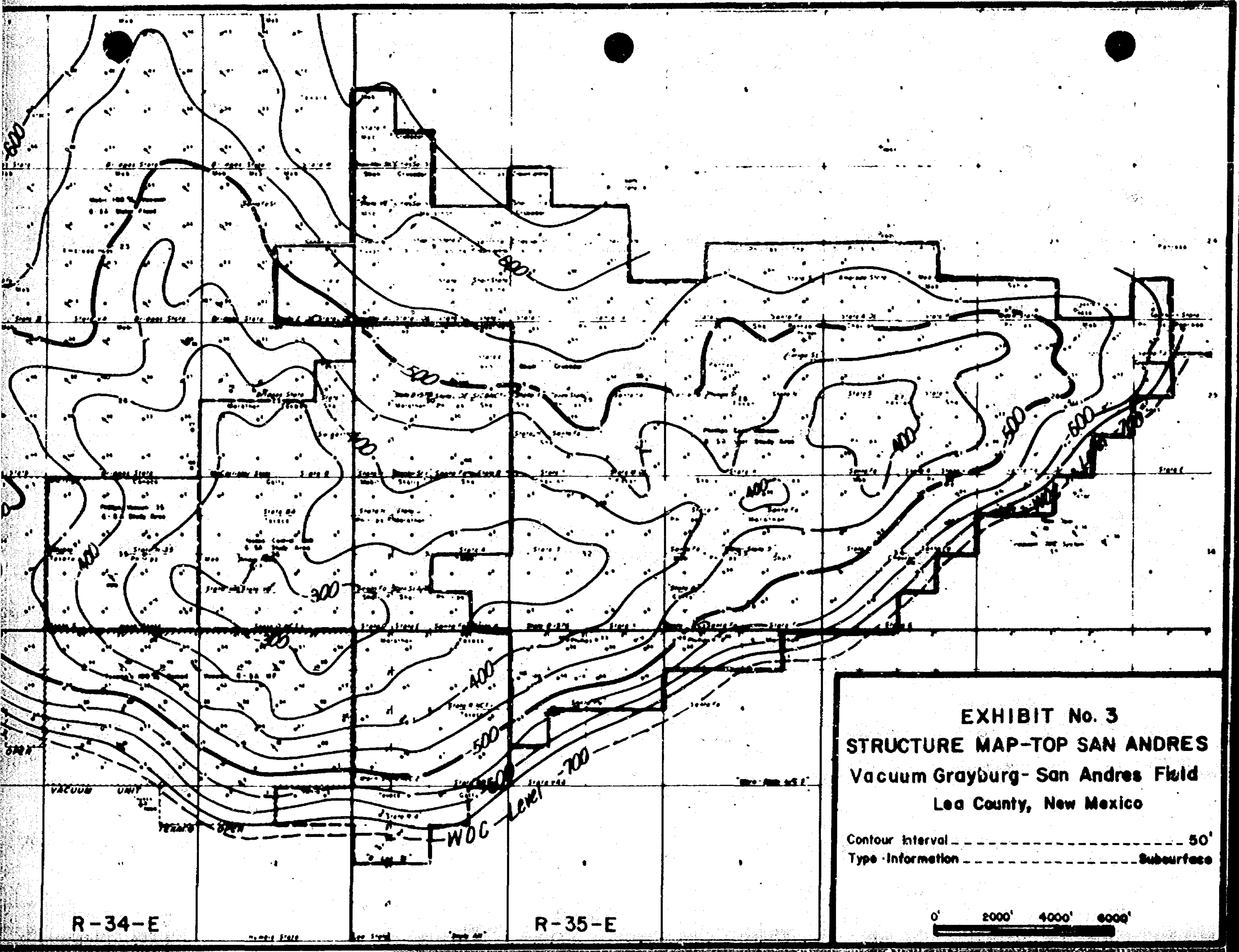
VACUUM FIELD

LEA COUNTY, NEW MEXICO

SCALE: 1" = 12.12 MILES



YATES
North Vacuum Unit
MOBIL Bridges - State Lease
Waterflood Area
T
17
S
TEXACO Central Vacuum Unit
PHILLIPS East Vacuum Unit
ARCO State
Vacuum Unit
TEXACO
West Vacuum Unit
PHILLIPS
Vac 35 Unit
TEXACO Vacuum Unit
T
18
S
R-34-E
R-35-E
EXHIBIT NO. 2
WATER INJECTION PROJECTS
Vacuum Grayburg - San Andres Field
Lea County, New Mexico
SCALE
0 2000' 4000' 6000'



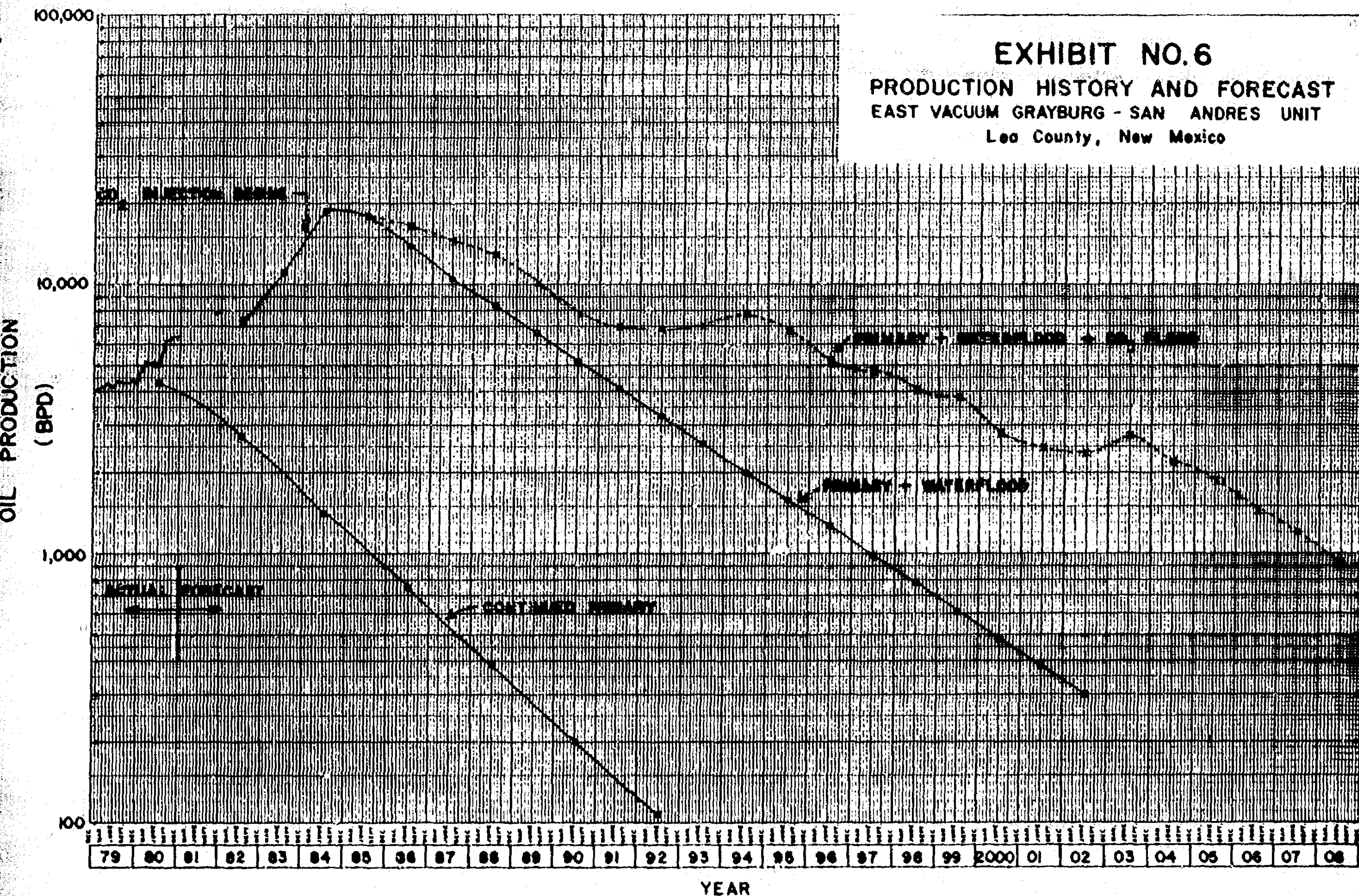
R-34-E
R-35-E
WOC Level -700
VACUUM UNIT
EXHIBIT No. 3
STRUCTURE MAP-TOP SAN ANDRES
Vacuum Grayburg- San Andres Field
Lea County, New Mexico
Contour Interval 50'
Type Information Subsurface
0' 2000' 4000' 6000'

EXHIBIT NO. 6

PRODUCTION HISTORY AND FORECAST

EAST VACUUM GRAYBURG - SAN ANDRES UNIT

Lea County, New Mexico



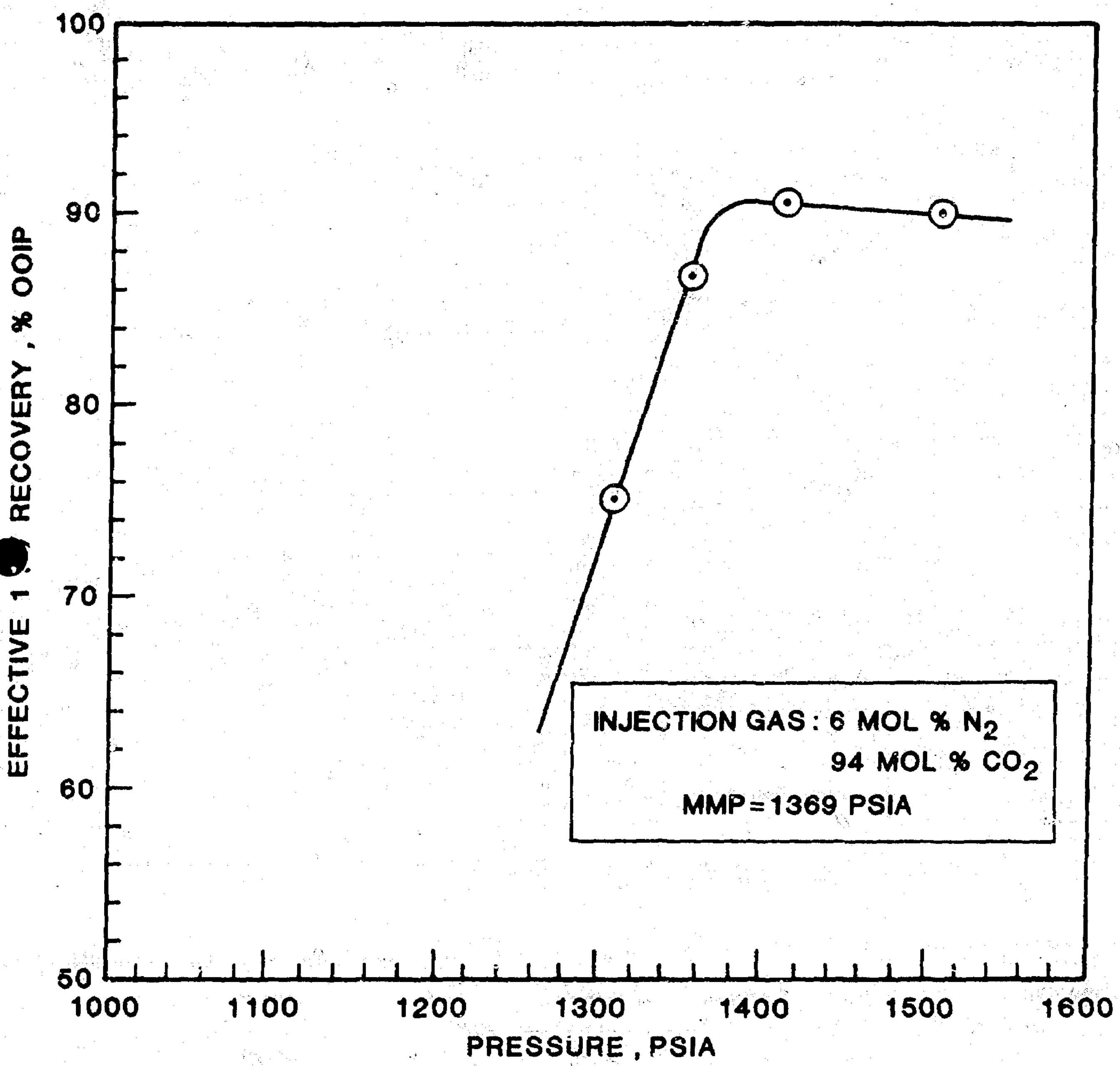


EXHIBIT NO. 7

SLIM TUBE RECOVERIES OF RECOMBINED
IN-PLACE EAST VACUUM GRAYBURG-SAN ANDRES OIL
AT 101 DEGREES F

EXHIBIT NO. 8

SUMMARY OF EAST VACUUM GRAYBURG-SAN ANDRES UNIT
SLIM TUBE DETERMINATIONS OF MINIMUM
MISCIBILITY PRESSURE

101° F

Oil Displaced	Injection Gas Composition (Mol %)	Minimum Miscibility Pressure (PSIA)
Recombined	100% CO_2	1190
Recombined	97% CO_2 3% N_2	1268
Recombined	94% CO_2 6% N_2	1369
Stock Tank Oil	100% CO_2	1230
Stock Tank Oil	97% CO_2 3% N_2	1275
Stock Tank Oil	90% CO_2 10% N_2	2120

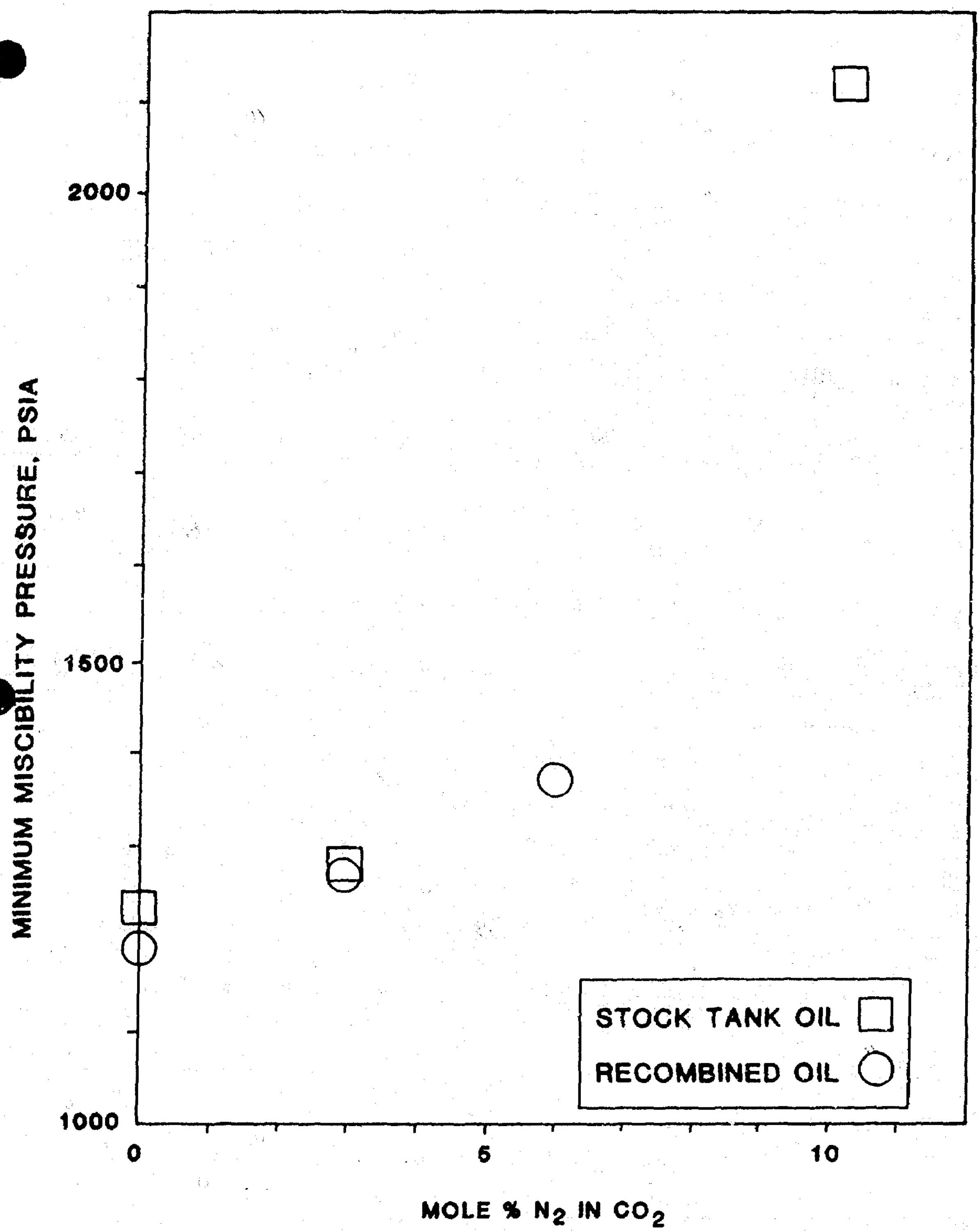


EXHIBIT NO. 9

MINIMUM MISCIBILITY PRESSURE VERSUS MOLE PERCENT N_2 IN CO_2 INJECTION GAS FOR EAST VACUUM GRAYBURG-SAN ANDRES RECOMBINED IN-PLACE OIL AND STOCK TANK OIL.

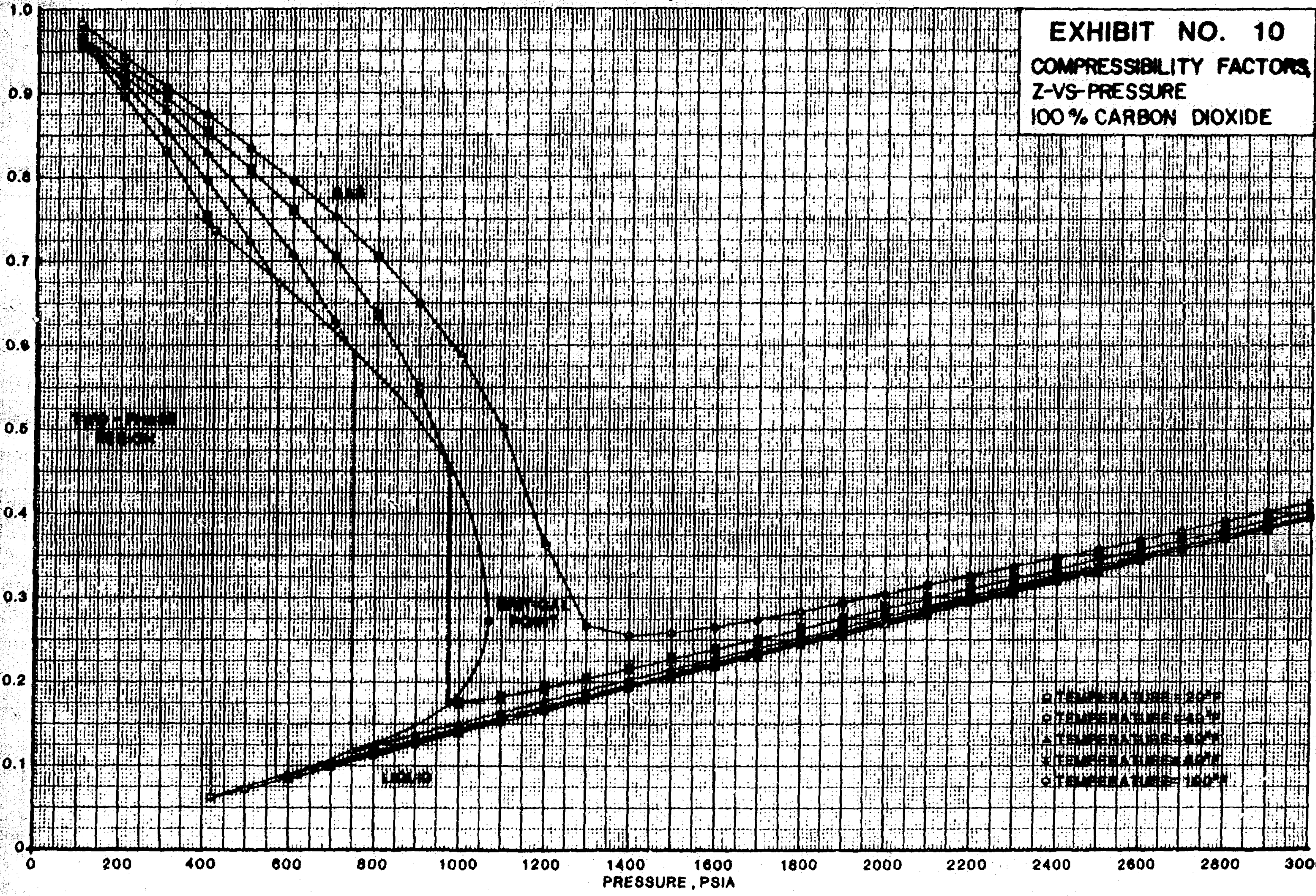


EXHIBIT NO. 10
COMPRESSIBILITY FACTORS,
Z-VS-PRESSURE
100 % CARBON DIOXIDE
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
2600
2800
3000
PRESSURE , PSIA

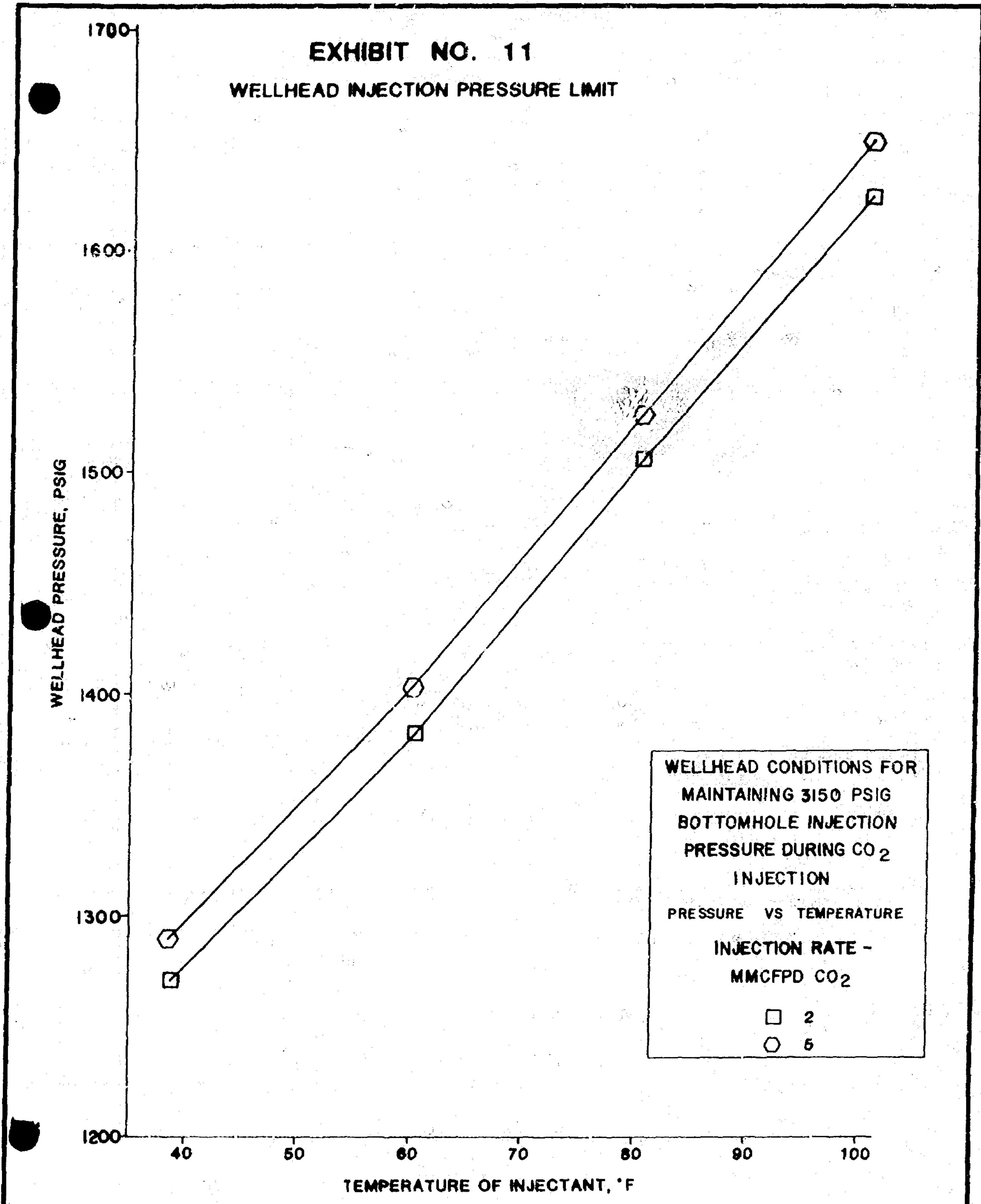


EXHIBIT NO. 11
WELLHEAD INJECTION PRESSURE LIMIT
WELLHEAD PRESSURE, PSIG
1700
1600
1500
1400
1300
1200
40
50
60
70
80
90
100
TEMPERATURE OF INJECTANT, °F
WELLHEAD CONDITIONS FOR MAINTAINING 3150 PSIG BOTTOMHOLE INJECTION PRESSURE DURING CO2 INJECTION
PRESSURE VS TEMPERATURE
INJECTION RATE - MMCFPD CO2
2
5

EXHIBIT NO. 12

LAYERS USED IN MODEL STUDY
(Average Net Pay in the South Area)

Zone	Thickness, Feet	Permeability, md.	Porosity, %
1	14.0	4.2	11.5
2	22.2	6.7	11.4
3	28.6	14.1	13.0
4	28.3	22.9	11.9
5	18.7	5.0	12.1
6	8.2	6.3	11.1
Average	120.0' (Total)	11.7	12.0

EXHIBIT NO. 13

DENVER GRAYBURG-SAN ANDRES UNIT,
EAST VACUUM GRAYBURG SAN ANDRES UNIT
AND
CO_2 FLOOD PROJECT AREA PARAMETERS

	DENVER UNIT	EAST VACUUM TOTAL UNIT	CO_2 FLOOD PROJECT AREA
Depth, Feet	5100	4,400	4,400
Type Formation	Dolomite	Dolomite	Dolomite
Bottom-Hole Temperature, °F	105	101	101
Original Bottom-Hole Pressure, psig	1805	1,613	1,613
Net Pay, Feet	129	71	108
Porosity, Percent	12.0	11.7	12.0
Permeability, Md.	3.5	11.0	12.2
Area, Acres	27,850	7,025	4,997
Connate Water, Percent	15.0	15.9	15.3
Original Oil Formation Volume Factor	1.312	1.288	1.288
Initial Solution Gas-Oil Ratio, cubic feet/stock tank barrel	588	465	465
Initial Viscosity of Oil, Centipoise	0.97	0.80	0.80
Stock Tank Oil Gravity, °API	33	35	35
Original Oil-in-Place, MM Barrels	2166	297	260
Ultimate Primary, MM Barrels	354	78	72
Estimated Secondary, MM Barrels	410	41	38
Estimated Tertiary, MM Barrels	281	26	26

EXHIBIT NO. 15
WATER-CO_2 INJECTION WELL SCHEMATIC
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
LEA COUNTY, NEW MEXICO

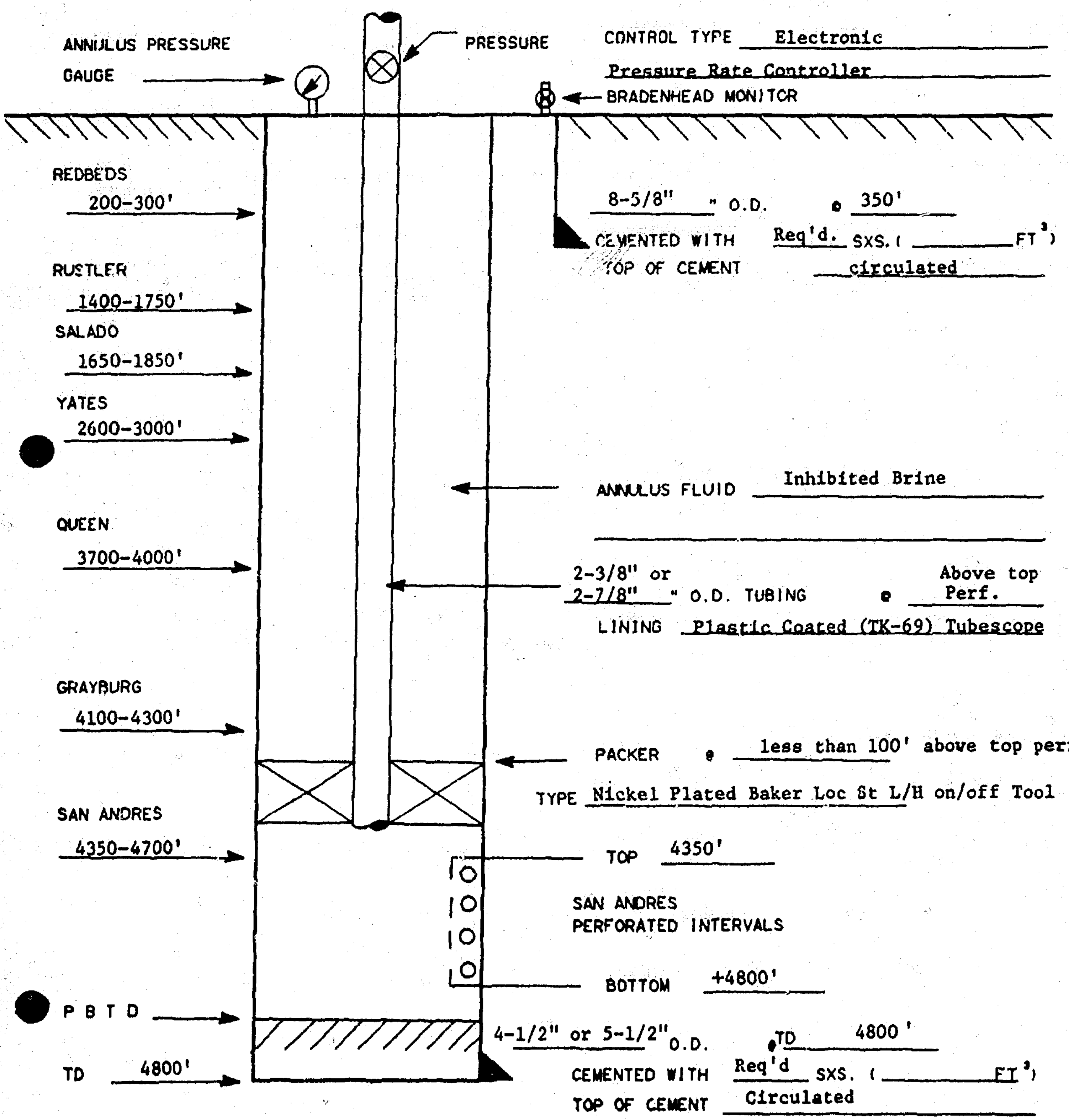


EXHIBIT NO. 16

WATER INJECTION TO VOIDAGE RATIO
EAST VACUUM GRAYBURG-SAN ANDRES UNIT

MONTH/YEAR	RATIO*
1980	
March	.0345
April	.0370
May	.1602
June	.2458
July	.2757
August	.3452
September	.3903
October	.3956
November	.2591
December	.1854
1981	
January	.7736
February	1.0624
March	1.2249
April	.9311
May	.9919
June	1.2446
July	1.4941
August	1.5850

*This ratio is calculated by the Equation $\frac{Wi}{Q_o\left(B_o + \frac{(Rp-Rs)}{(1000)}Bg\right) + Wp}$

Where:

- Wi = Water injection rate
- Wp = Water production rate
- Qo = Oil production rate
- Rp = Produced Gas oil Ratio
- Rs = Solution Gas Oil Ratio
- Bg = Gas Formation Volume Factor
- Bo = Oil Formation Volume Factor

EXHIBIT NO. 17

CO_2 PRODUCTION AND INJECTION SCHEDULE

EAST VACUUM GRAYBURG-SAN ANDRES UNIT

	TOTAL CO_2 INJECTED		PRODUCED AND RE-INJECTED CO_2	
YEAR	MCFPD	MMCFPY	MCFPD	MMCFPY
1982	0	0		
1983	0	0		
1984	40,000	14,610	720	260
1985	40,000	14,610	1,050	380
1986	40,000	14,610	2,200	800
1987	40,000	14,610	5,400	1,970
1988	40,000	14,610	10,800	3,950
1989	40,000	14,610	13,000	4,750
1990	40,000	14,610	13,400	4,890
1991	40,000	14,610	14,000	[illegible],110
1992	40,000	14,610	14,500	5,300
1993	40,000	14,610	15,200	5,550
1994	40,000	14,610	16,700	6,100
1995	40,000	14,610	18,100	6,610
1996	40,000	14,610	20,000	7,310
1997	40,000	14,610	21,300	7,780
1998	40,000	14,610	23,000	8,400
1999	40,000	14,610	24,000	8,770
2000	40,000	14,610	25,000	9,130
2001	40,000	14,610	26,000	9,500
2002	40,000	14,610	27,000	9,860
2003	0	0	26,000	9,500
2004			15,000	5,479
2005			7,500	2,740
2006			3,000	1,424
2007			2,000	732
2008			1,000	365
		277,590		126,660

40% Oil hydro carbon pore vol

$400 000 000 CO2 cost

$81 000 000 cost to handle CO2

EXHIBIT NO. 18

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

OIL AND GAS DOCKET NO. 3-75,828

IN RE: CONSERVATION AND PREVENTION OF WASTE OF CRUDE PETROLEUM AND NATURAL GAS IN THE STATE OF TEXAS

APPLICATION OF GULF OIL CORPORATION FOR A CERTIFICATION AS APPROVED QUALIFIED TERTIARY OIL RECOVERY PROJECT UNDER THE CRUDE OIL WINDFALL PROFITS TAX FOR THE KURTEN (WOODBINE) FIELD, BRAZOS COUNTY, TEXAS

OPINION AND ORDER

This is Gulf Oil Corporation's application for certification of the Kurten (Woodbine) Field enhanced recovery unit as a qualified tertiary oil recovery project under the Crude Oil Windfall Profits Tax (26 U.S.C. 4993). The Railroad Commission of Texas has been designated by Governor William Clements, Jr. as the proper agency to make these certifications.

The Kurten (Woodbine) Field was discovered in 1976 and developed with 131 wells on 160 acre units. The Woodbine is encountered at approximately 8100 feet. The pilot Jones Enhanced Recovery Unit proposed by Gulf contains 672 acres and has four existing producing wells. Gulf proposes to drill four new injection wells and one new producing well, number 6, on this unit. (Tr 15) The development pattern will be an assymetrical forty acre five-spot pattern. Gulf will drill its number 5 well to the Wilcox at 4000 feet as a water supply well.

The estimated primary production from this unit is one million barrels of oil or 11 percent of the oil in place. (Tr 14 and Tr 29). Gulf investigated waterflooding (Tr 19-22) as well as several methods of tertiary recovery for this field (Tr 14). Since the permeability of this Woodbine reservoir was low, 2 millidarcies, (Tr 25) the only feasible method of recovery was the CO_2 miscible displacement method. Tests show that miscibility could be obtained at a pressure of between 3000 and 3500 psi. It is estimated that this miscible displacement method will increase ultimate recovery by 1.2 million barrels of oil over the period from September, 1981 through September, 1986.

The Gulf plan calls for all new wells to be drilled and completed by April, 1981. At that point Gulf will repressure the reservoir by injecting approximately 400 barrels of water per day in each injection well for three months (Tr 16). In July, 1981, 40 tons per day per well of CO_2 will be injected for about nine months. Thereafter, Gulf will inject alternate slugs of CO_2 and water for three month periods until about 1986.

The result of this proposed tertiary oil recovery project will be to increase recovery from this field from 1 to 2.2 million barrels of oil. This is a 120 percent increase in ultimate recovery.

FINDINGS OF FACT

Based on the record evidence, the Commission makes the following findings of fact:

1. The Kurten (Woodbine) Field is located in Brazos County, Texas;

2. The Gulf Jones Enhanced Recovery Unit in the Kurten (Woodbine) Field consists of 672 acres;

3. The Gulf unit is in the later stages of primary depletion;

4. Gulf plans to go directly from primary to tertiary oil recovery because:
   (a) Secondary recovery by gas injection would eliminate CO_2 miscible flooding due to large remaining gas saturations which would cause CO_2 channelling and reduce sweep efficiency;
   (b) Comparisons with other Woodbine waterflood projects located near the Kurten (Woodbine) Field indicate waterflood recovery would be low;
   (c) Waterflooding is not a necessary prerequisite for CO_2 miscible flooding;
   (d) Tertiary recovery projects generally have a higher probability for success if initiated early in a reservoir's life;
   (e) Tertiary recovery would be reduced by a lengthy waterflood program;

5. The tertiary oil recovery method Gulf plans to use in the Kurten (Woodbine) Field is a CO_2 miscible displacement method;

6. The CO_2 miscible displacement method is a recognized tertiary oil recovery method described in Section 212.78(c) of the Department of Energy Regulations in effect on June 1, 1979;

7. The estimated primary production from the Gulf unit is one million barrels of oil or 11 percent of the oil in place;

8. The estimated total production after the tertiary oil recovery project is 2.2 million barrels of oil or 25 percent of the oil in place;

9. The increase in recovery is estimated to be 1.2 million barrels or 120 percent of primary recovery. This is more than an insignificant amount of oil recovery;

10. The Gulf plan calls for the drilling of four new injection wells, one new producing well and one new water supply well.

11. In April, 1981, Gulf will inject approximately 400 barrels of water per day into each injection well for approximately three months to repressure the reservoir to a miscible pressure of between 3000 and 3500 psi.

12. After the reservoir is repressured (July, 1981), Gulf will inject 40 tons of CO_2 per day per injection well for nine months. Thereafter, Gulf will alternate three month injections of CO_2 and water until 1986;

13. The project beginning date will be after May, 1979;

14. The Railroad Commission of Texas has been duly designated by the Governor of Texas as the jurisdictional agency authorized under state law to qualify tertiary recovery projects for purposes of the Crude Oil Windfall Profits Tax of 1980.

CONCLUSIONS OF LAW

1. The project proposed by Gulf involves a miscible fluid displacement process, which is one of the tertiary oil recovery methods described in Section 212.78(c) of the Energy Regulations of the D.O.E. in effect on 6-1-79.

2. The project proposed by Gulf will result in a more than insignificant amount of additional oil recovery from the Jones Enhanced Recovery Unit.

3. The project proposed by Gulf will begin after May, 1979.

4. The project proposed by Gulf will affect all of the 672 acre unit and such unit is adequately delineated.

5. The Railroad Commission of Texas has been designated as the appropriate agency to certify qualified tertiary oil recovery projects pursuant to Section 4993(d)(5)(A)(i) of the Internal Revenue Code.

6. The project meets, and the Commission approves the project as meeting, the requirements of subparagraphs (A), (B) and (C) of Section 4993 (C)(2) of the Code.

IT IS THEREFORE ORDERED BY THE RAILROAD COMMISSION OF TEXAS THAT the CO_2 miscible gas displacement by Gulf in its Jones Enhanced Recovery Unit in the Kurten (Woodbine) Field is hereby certified as a qualified tertiary oil recovery project under Section 4993 of the Internal Revenue Code.

Done this the 1st day of December, 1980.

RAILROAD COMMISSION OF TEXAS

John Barnes
CHAIRMAN

James E. (Jim) Nugent
COMMISSIONER

Mack Wallace
COMMISSIONER

ATTEST:

Elizabeth Mavrogoulis
SECRETARY

BRS:djl

WINDFALL PROFIT TAX ACT OF 1980
TERTIARY RECOVERY PROJECT CERTIFICATION

Field	Vacuum
Lease	East Vacuum Grayburg San Andres Unit
Reservoir	Grayburg San Andres

Name and address of the operator.

Phillips Petroleum Company
P. O. Box 1967
Houston, TX 77001

Employer I.D. Number

Name and telephone number of a person to whom questions may be directed regarding this certification.

Name ____________________

☐☐☐ ☐☐☐-☐☐☐☐
(Area Code)

1A. The tertiary method as defined in 10 CFR Part 212.78(c) of the Energy Regulations to be employed in the project. If the project employs a method not defined in 212.78, a description of the method is provided.	Miscible Fluid Displacement by CO_2
1B. Estimate of the amount of additional oil that will be recovered as a result of the tertiary project.	26,000,000 Barrels
2A. The applicable section is completed below: (a,b,c,d, or e)	
a. In-situ combustion projects: 1) Type of method used. The applicable box is marked.	☐ Wet ☐ Dry
2) The type(s) of additive(s) used For example: any agent used to increase mobility or sweep efficiency, such as foam, surfactants, etc.	
b. Cyclic steam and steam drive projects.	
1) The recovery mechanism used.	☐ Cyclic steam ☐ Steam drive ☐ Both cyclic steam and steam drive.
2) The type(s) of additive(s) used. For example: any agent used to increase mobility of sweep efficiency, such as foam, surfactants, etc.	
c. Microemulsion and alkaline flooding projects	
1) Water supply	
Source of the supply For example: ground water, lake, municipal water, etc.	
Salinity. Parts per million of total dissolved solids.	ppm tds
2) Preflush	
Type of agent used.	
Quantity of agent used.	Barrels
Size of the slug used.	Pore volume
Concentration used.	Parts per million

c. (Continued) Microemulsion or alkaline flooding projects.

3) Surfactant or alkaline slug

Type of slug used
The applicable box is marked.

☐ Surfactant

☐ Alkaline

Type(s) of chemical agent(s) used. ______

Concentration used. ______

Size of the slug used. ______ Pore volume

Estimate of the quantity of each chemical that will be injected during the project life. Pounds

Chemical	Quantity
	lbs.
	lbs.

4) Mobility buffer

Type of polymer used. ______

Estimate of the quantity of polymer to be used during the project life. ______ Pounds

d. Miscible fluid and immiscible non-hydrocarbon gas projects

1) Type of agent used. Carbon Dioxide

2) Level of miscibility expected to be achieved.

☐ Partial

☒ Complete

3) If complete miscibility is not expected, explanation. ______

4) Size of the slug used.
2.1% PV slug per year for 5 to 19 years. Total = 10% to 40% Pore volume

5) Estimate of the quantity of injected fluid to be used during the project life. Use appropriate units. 277,590 MMSCF

2A. (Continued)

d. (Continued) Miscible fuild and immiscible non-hydrocarbon gas projects.

6) Type(s) of drive fluid(s) used. Water

e. Polymer project.

1) The salinity of the water supply. Parts per million of total dissolved solids. ____ ppm tds

2) The preflush used, (if any).
- [ ] Yes - answer 3.
- [ ] No - skip to 4.

3) Type of preflush agent used. ____

4) Type of polymer used. ____

5) Estimate of the quantity of polymer to be used over the life of the project. ____ Pounds

2B. The information on the reservoir and crude oil characteristics that are present in the portion of the reservoir that will be affected by the tertiary enhanced recovery method is provided below.

a. Oil gravity
Report to the nearest whole degree. 35 ° API

	Original	Present
b. Original and present oil saturation This is the estimated portion of the pore value in the project area occupied by crude oil; give in percent.	84.7%	56.00%
c. Original and present water saturation percent	15.3%	34%
d. Original and present gas saturation percent.	0%	10%

e. Oil in place

1) Estimated original oil in place (STB) 260,000 Thousands of barrels

2) Estimated present oil in place (STB) 195,856 Thousands of barrels

f. Oil type
Mark the applicable box
- [X] Paraffinic
- [ ] Naphtenic
- [ ] Asphaltic

2B. (Continued)

g. Oil viscosity at reservoir temperature — 0.8 Centipoise

h. Reservoir Lithology
Mark the applicable box

- [ ] Sandstone
- [x] Carbonate
- [ ] Other (Specify) ______

i. Depth of the reservoir to the bottom of the perforations, or in the case of an open hole, to the bottom of the producing formation and measured along the well bore (as distinct from vertical depth). Note: measurement along the well bore is consistent with ERA published marginal well rule. — 5050 Feet

j. Average reservoir thickness

1) Gross above oil-water-contact at -700' — 300 Feet

2) Net pay — 108 Feet

k. Average reservoir porosity — 11.7 Percent

l. Reservoir temperature — 101 Degrees Fahrenheit

m. Present reservoir pressure — 561 Pounds per square inch

n. Permeability

1) Range to air — 12.2 Millidarcies

2) Variation
Use Lorenz Coefficient — 0.4 Lorenz Coefficient

o. Gas cap at present

- [ ] Yes - Answer p.
- [ ] No - Skip to q.

p. Gas cap is primary or secondary
Mark the applicable box

- [ ] Primary
- [ ] Secondary

2B. (Continued)

q. Active water drive.	[X] Yes Weak [ ] No
r. Reservoir Wettability Mark the applicable box.	[ ] Oil Wet /X/ Intermediate [ ] Water Wet
s. Degree of the dip. The applicable box is marked.	[X] 0-5° [ ] 16-25° [ ] 6-15° [ ] 25°
t. Current average salinity of the produced water in the project area. Parts per million of total dissolved solids.	250,000 ppm tds
u. Rock property. The applicable box is marked.	[X] Consolidated [ ] Unconsolidated
v. Clay Characteristics 1) Type(s) of clay(s)	______
2) Weight percent	______ Percent
w. Other reservoir or crude oil characteristics such as fractures, permeability, barriers, directional permeability, hydrogen sulfide, etc., which may affect the tertiary project.	Small amount of hydrogen sulfide present.

EXHIBIT NO. 19

3. Information to identify the property is provided below. This includes state, county(ies), field, reservoir, I.D. number, if available and legal description of the property affected by the project. Also, if different than the property identified above, delineate the portion of the property (the project area) that is expected to yield the increase in ultimate recovery. Attach maps as necessary.	State: New Mexico County: Lea Field: Vacuum Reservoir Identification Number

LEASE: The project area will be the portion of the East Vacuum Grayburg San Andres Unit described as follows: In T-17S-R-35E, all of Sections 27,28,29,32 and 33 plus all of Section 26 except the SW/4 of SW/4, all of Section 34 except the S/2 and W/2 of Section 26 except the SW/4 of SW/4, all of Section 34 except the S/2 and W/2 of the SW/4, the N/2 of NW/4 of Section 35 and the W/2 and N/2 of SW/4 of Section 31. Also in T-18S-R-35E the N/2 and the NW/4 of SW/4 of Sec. 05 and the N/2 of NW/4 and the NW/4 of the NE/4 of Sec. 04.

4. Estimated dates for the planned project time schedule are provided below.	From Month and Year	To Month and Year
a. Injection of preflush		
b. Injection of tertiary fluid	02/81*	12/1988 to 12/2002

5. Explanation of the number and frequency of injections to be made and the expected duration of the project.

1-6 month injection of CO_2 per injection well per year for 5 to 19 years for injection of 0.1 to 0.4 Pore Volumes of CO_2.

6. If the project involves a single injection, estimation of the time that the tertiary process is expected to affect the reservoir.

- [X] Not applicable
- [ ] Until depletion
- [ ] Other - give year process is expected to stop affecting the reservoir and expected year of reservoir depletion.

7. Estimated reserve data for the project area is included below.

a. Year of first production.	1981	
b. Year of initiation of tertiary operation.	1981	
c. Total reserves without the project. Do not use decimals.	110,201	Thousands of barrels
d. Total reserves with the project. Do not use decimals	136,201	Thousands of barrels

*Overinjection of voidage to achieve miscibility pressure started in February, 1981.

EXHIBIT NO. 19

T production history and estimate of future production from the project area. (Use attachments as required.)	Year	Crude & Condensate	Gas
SEE ATTACHED PAGE 10			

A. Number of existing ...

a. Producing Wells Wells which are temporarily out of production for maintenance or other reasons are included	189
b. Injection Wells Wells which are temporarily out of production for maintenance or other reasons are included.	54
c. Shut-in Wells Wells counted in 9A.a and b are excluded.	9

B. Planned total number of:

a. Production wells	8
b. Injection wells	24

A. Projected future income (thousands of dollars)	
B. Projected future expenses (thousands of dollars)	$81,500

The foregoing projection of future income is based on crude and gas prices currently in effect in the field. The future expenses are based on uninflated estimates.

I ______________________, as a duly registered or certified engineer, engaged in the duties normally assigned to a petroleum engineer, do hereby certify that the project described in the attached certification:

1) involves the application (in accordance with sound engineering principles) of one or more tertiary recovery methods which can reasonably be expected to result in more than an insignificant increase in the amount of crude oil which will ultimately be recovered;

2) that the "project beginning date" as defined in section 4993(d)(2) of the "Crude Oil Windfall Profit Tax Act of 1980" is after May, 1979; and

3) that the portion of the property to be affected by the project is adequately delineated.

Under penalties of perjury, I declare that to the best of my knowledge and belief, the information contained in the attached certification is true, correct and complete.

Signed this ______ day of __________________, 1980 and posted by United States mail to the District Director of the Internal Revenue Service Center at :, on this ______ day of __________________, 1980.

Signed by:

____
Signature

____
Title

EXHIBIT NO. 19

EAST VACUUM GRAYBURG SAN ANDRES UNIT CO_2 FLOOD PROJECT AREA

PRODUCTION HISTORY AND FORECAST

YEAR	OIL PRODUCTION (BBLS.)	GAS PRODUCTION (MCF)
HISTORY		
1979	1,488,608	2,175.843
1980	1,954,744	2,530,944
FORECAST		
1981	2,300,622	2,400,000
1982	2,369,033	1,864,423
1983	3,561,168	1,752,095
1984	6,098,658	1,347,803
1985	5,761,890	1,273,378
1986	5,469,470	1,207,872
1987	4,840,988	1,068,550
1988	4,432,747	978,026
1989	3,422,618	755,202
1990	2,636,446	581,771
1991	2,360,900	520,795
1992	2,368,003	522,088
1993	2,485,993	547,813
1994	2,780,435	612,414
1995	2,435,524	536,384
1996	1,859,520	409,539
1997	1,696,330	373,545
1998	1,473,110	324,363
1999	1,394,090	306,921
2000	1,014,265	223,313
2001	903,271	198,858
2002	851,244	187,383
2003	1,014,000	223,080
2004	806,000	177,320
2005	707,000	154,440
2006	546,000	120,120
2007	442,000	97,240
2008	338,000	74,360

purchaser on or in connection with an automobile bus, or is to be resold by the purchaser or a se[illegible]nd p[illegible]rch[illegible]r for suc[illegible] use.

(6) CLERICAL AMENDMENT.—Th[illegible] l[illegible]t sentence of section 48(a)(10)(B) is amended by striking out "51" and inserting in lieu thereof "5".

(7) EFFECTIVE DATE.—Any amendment made by this subsection shall take effect as if included in the provision of the Energy Tax Act of 1978 to which such amendment relates; except that the amendment made by paragraph (6) shall take effect on the first day of the first calendar month which begins more than 10 days after the date of the enactment of this Act.

[illegible]) AMENDMENTS RELATED TO PUBLIC LAW 95-472.—Subsection (c) [illegible]ection 6324B (relating to special lien for additional estate tax [illegible]ibutable to farm, etc., valuation) is amended to read as follows:

[illegible]c) CERTAIN RULES AND DEFINITIONS MADE APPLICABLE.—

"(1) IN GENERAL.—The rule set forth in paragraphs (1), (3), and (4) of section 6324A(d) shall apply with respect to the lien imposed by this section as if it were a lien imposed by section 6324A.

"(2) QUALIFIED REAL PROPERTY.—For purposes of this section, the term 'qualified real property' includes qualified replacement property (within the meaning of section 2032A(h)(3)(B))."

[illegible]ITLE II—GENERAL EFFECTIVE DATE

[illegible] 201. GENERAL EFFECTIVE DATE.

[illegible]xcept as otherwise provided in title I, any amendment made by [illegible] I shall take effect as if it had been included in the provision of the [illegible]nue Act of 1978 to which such amendment relates.

[illegible]pproved April 1, 1980.

[illegible]LATIVE HISTORY

[illegible]E REPORT No. 96-250 (Comm. on Ways and Means).
[illegible]TE REPORT No. 96-498 (Comm. on Finance).
[illegible]RESSIONAL RECORD:
Vol. 125 (1979): July 16, considered and passed House.
Vol. 126 (1980): Feb. 26, considered and passed Senate, amended.
Feb. 28, House concurred in certain Senate amendments and disagreed to Senate amendment No. 67.
Mar. 18, Senate receded from its amendment No. 67 and offered another am[illegible]ment to the House bill.
Mar. 19, House concurred in Senate amendment.

PUBLIC LAW 96-223 [H.R. 3919]; APRIL 2, 1980

CRUDE OIL [illegible]

For Legislative History of Act, see p. 1068

An Act to impose a windfall profit tax on domestic crude oil, and for other purposes.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

Crude Oil Windfall Profit Tax Act of 1980.

SECTION 1. SHORT TITLE; AMENDMENT OF 1954 CODE; TABLE OF CONTENTS.

(a) SHORT TITLE.—This Act may be cited as the "Crude Oil Windfall Profit Tax Act of 1980". 26 USC 1 note.

(b) AMENDMENT OF 1954 CODE.—Except as otherwise expressly provided, whenever in this Act an amendment or repeal is expressed in terms of an amendment to, or repeal of, a section or other provision, the reference shall be considered to be made to a section or other provision of the Internal Revenue Code of 1954. 26 USC 1 *et seq.*

(c) TABLE OF CONTENTS.—

TITLE I—WINDFALL PROFIT TAX ON DOMESTIC CRUDE OIL

SEC. 101. WINDFALL PROFIT TAX.

(a) IN GENERAL.—

(1) AMENDMENT OF SUBTITLE D.—Subtitle D (relating to miscellaneous excise taxes) is amended by adding at the end thereof the following new chapter:

"CHAPTER 45—WINDFALL PROFIT TAX ON DOMESTIC CRUDE OIL

"Subchapter A—Imposition and Amount of Tax

26 USC 4986. **"SEC. 4986. IMPOSITION OF TAX.**

"(a) IMPOSITION OF TAX.—An excise tax is hereby imposed on the windfall profit from taxable crude oil removed from the premises during each taxable period.

"(b) TAX PAID BY PRODUCER.—The tax imposed by this section shall be paid by the producer of the crude oil.

26 USC 4987. **"SEC. 4987. AMOUNT OF TAX.**

"(a) IN GENERAL.—The amount of tax imposed by section 4986 with respect to any barrel of taxable crude oil shall be the applicable percentage of the windfall profit on such barrel.

"(b) APPLICABLE PERCENTAGE.—For purposes of subsection (a)—

"(1) GENERAL RULE FOR TIERS 1 AND 2.—The applicable percentage for tier 1 oil and tier 2 oil which [illegible]

"Tier 1	70
"Tier 2	60

"(2) INDEPENDENT PRODUCER OIL.—The applicable percentage for independent producer oil which is tier 1 oil or tier 2 oil is—

"Tier 1	50
"Tier 2	30

"(3) TIER 3 OIL.—The applicable percentage for tier 3 oil is 30 percent.

"(c) FRACTIONAL PART OF BARREL.—In the case of a fraction of a barrel, the tax imposed by section 4986 shall be the same fraction of the amount of such tax imposed on the whole barrel.

"SEC. 4988. WINDFALL PROFIT; REMOVAL PRICE. 26 U

"(a) GENERAL RULE.—For purposes of this chapter, the term 'windfall profit' means the excess of the removal price of the barrel of crude oil over the sum of—

"(1) the adjusted base price of such barrel, and

"(2) the amount of the severance tax adjustment with respect to such barrel provided by section 4996(c).

"(b) NET INCOME LIMITATION ON WINDFALL PROFIT.—

"(1) IN GENERAL.—The windfall profit on any barrel of crude oil shall not exceed 90 percent of the net income attributable to such barrel.

"(2) DETERMINATION OF NET INCOME.—For purposes of paragraph (1), the net income attributable to a barrel shall be determined by dividing—

"(A) the taxable income from the property for the taxable year attributable to taxable crude oil, by

"(B) the number of barrels of taxable crude oil from such property taken into account for such taxable year.

"(3) TAXABLE INCOME FROM THE PROPERTY.—For purposes of paragraph (2)—

"(A) IN GENERAL.—Except as otherwise provided in this paragraph, the taxable income from the property shall be determined under section 613(a). 26

"(B) CERTAIN DEDUCTIONS NOT ALLOWED.—No deduction shall be allowed for—

"(i) depletion,

"(ii) the tax imposed by section 4986,

"(iii) section 263(c) costs, or 26

"(iv) qualified tertiary injectant expenses to which an election under subparagraph (E) applies.

"(C) TAXABLE INCOME REDUCED BY COST DEPLETION.—Taxable income shall be reduced by the cost depletion which would have been allowable for the taxable year with respect to the property if—

"(i) all—

"(I) section 263(c) costs, and

"(II) qualified tertiary injectant expenses to which an election under subparagraph (E) applies,

incurred by the taxpayer had been capitalized and taken into account in computing cost depletion, and

"(ii) cost depletion had been used by the taxpayer with respect to such property for all taxable periods.

"(D) SECTION 263(c) COSTS.—For purposes of this paradeducted as expenses for purposes of this title (other than this paragraph). Such term shall not include costs incurred in drilling a nonproductive well.

"(E) ELECTION TO CAPITALIZE QUALIFIED TERTIARY INJECTANT EXPENSES.—

"(i) IN GENERAL.—Any taxpayer may elect, with respect to any property, to capitalize qualified tertiary injectant expenses for purposes of this paragraph. Any such election shall apply to all qualified tertiary injectant expenses allocable to the property for which the election is made, and may be revoked only with the consent of the Secretary. Any such election shall be made at such time and in such manner as the Secretary shall by regulations prescribe.

Post, p. 286.

"(ii) QUALIFIED TERTIARY INJECTANT EXPENSES.—The term 'qualified tertiary injectant expenses' means any expense allowable as a deduction under section 193.

"(4) SPECIAL RULE FOR APPLYING PARAGRAPH (3)(C) TO CERTAIN TRANSFERS OF PROVEN OIL OR GAS PROPERTIES.—

"(A) IN GENERAL.—In the case of any proven oil or gas property transfer which (but for this subparagraph), would result in an increase in the amount determined under paragraph (3)(C) with respect to the transferee, paragraph (3)(C) shall be applied with respect to the transferee by taking into account only those amounts which would have been allowable with respect to the transferor under paragraph (3)(C) and those costs incurred during periods after such transfer.

"(B) PROVEN OIL OR GAS PROPERTY TRANSFER.—For purposes of subparagraph (A), the term 'proven oil or gas property transfer' means any transfer (including the subleasing of a lease or the creation of a production payment which gives the transferee an economic interest in the property) after 1978 of an interest (including an interest in a partnership or trust) in any proven oil or gas property (within the meaning of section 613A(c)(9)(A)).

26 USC 613A.

"(5) SPECIAL RULE WHERE THERE IS PRODUCTION PAYMENT.—For purposes of paragraph (2), if any portion of the taxable crude oil removed from the property is applied in discharge of a production payment, the gross income from such portion shall be included in the gross income from the property of both the person holding such production payment and the person holding the interest from which such production payment was created.

"(c) REMOVAL PRICE.—For purposes of this chapter—

"(1) IN GENERAL.—Except as otherwise provided in this subsection, the term 'removal price' means the amount for which the barrel is sold.

26 USC 103.

26 USC 613.

"(2) SALES BETWEEN RELATED PERSONS.—In the case of a sale between related persons (within the meaning of section 103(b)(6)(C)), the removal price shall not be less than the constructive sales price for purposes of determining gross income from the property under section 613.

"(3) OIL REMOVED FROM PREMISES BEFORE SALE.—If crude oil is removed from the premises before it is sold, the removal price shall be the constructive sales price for purposes of determining gross income from the property under section 613.

"(4) REFINING BEGUN ON PREMISES.—If the manufacture or conversion of crude oil into refined products begins before such oil is removed from the premises—

"(A) such oil shall be treated as removed on the day such manufacture or conversion begins, and

"(B) the removal price shall be the constructive sales price for purposes of determining gross income from the property under section 613.

"(5) MEANING OF TERMS.—The terms 'premises' and 'refined product' have the same meaning as when used for purposes of determining gross income from the property under section 613.

"SEC. 4989. ADJUSTED BASE PRICE.

"(a) ADJUSTED BASE PRICE DEFINED.—For purposes of this chapter, the term 'adjusted base price' means the base price for the barrel of crude oil plus an amount equal to—

"(1) such base price, multiplied by

"(2) the inflation adjustment for the calendar quarter in which the crude oil is removed from the premises.

The amount determined under the preceding sentence shall be rounded to the nearest cent.

"(b) INFLATION ADJUSTMENT.—

"(1) IN GENERAL.—For purposes of subsection (a), the inflation adjustment for any calendar quarter is the percentage by which—

"(A) the implicit price deflator for the gross national product for the second preceding calendar quarter, exceeds

"(B) such deflator for the calendar quarter ending June 30, 1979.

"(2) ADDITIONAL ADJUSTMENT FOR TIER 3 OIL.—The adjusted base price for tier 3 oil shall be determined by substituting for the implicit price deflator referred to in paragraph (1)(A) an amount equal to such deflator multiplied by 1.005 to the nth power where 'n' equals the number of calendar quarters beginning after September 1979 and before the calendar quarter in which the oil is removed from the premises.

"(3) FIRST REVISION OF PRICE DEFLATOR USED.—For purposes of paragraphs (1) and (2), the first revision of the price deflator shall be used.

"(c) BASE PRICE FOR TIER 1 OIL.—For purposes of this chapter, the base price for tier 1 oil is—

"(1) the ceiling price which would have applied to such oil under the March 1979 energy regulations if it had been produced and sold in May 1979 as upper tier oil, reduced by

"(2) 21 cents.

"(d) BASE PRICES FOR TIER 2 OIL AND TIER 3 OIL.—For purposes of this chapter—

"(1) GENERAL RULE.—Except as provided in paragraph (2), the base prices for tier 2 oil and tier 3 oil shall be prices determined pursuant to the method prescribed by the Secretary by regulations. Any method so prescribed shall be designed so as to yield, with respect to oil of any grade, quality, and field, a base price which approximates the price at which such oil would have sold in December 1979 if—

"(A) all domestic crude oil were uncontrolled, and

"(B) the average removal price for all domestic crude oil (other than Sadlerochit oil) were—

"(i) $15.20 a barrel for purposes of determining base prices for tier 2 oil, and

"(ii) $16.55 a barrel for purposes of determining base prices for tier 3 oil.

"(2) INTERIM RULE.—For months beginning before October 1980 (or such earlier date as may be provided in regulations taking effect before such earlier date), the base prices for tier 2 oil and tier 3 oil, respectively, shall be the product of—

"(A)(i) the highest posted price for December 31, 1979, for uncontrolled crude oil of the same grade, quality, and field, or

"(ii) if there is no posted price described in clause (i), the highest posted price for such date for uncontrolled crude oil at the nearest domestic field for which prices for oil of the same grade and quality were posted for such date, multiplied by

"(B) a fraction the denominator of which is $35, and the numerator of which is—

"(i) $15.20 for purposes of determining base prices for tier 2 oil, and

"(ii) $16.55 for purposes of determining base prices for tier 3 oil.

For purposes of the preceding sentence, no price which was posted after January 14, 1980, shall be taken into account.

"(3) MINIMUM INTERIM BASE PRICE.—The base price determined under paragraph (2) for tier 2 oil or tier 3 oil shall not be less than the sum of—

"(A) the ceiling price which would have applied to such oil under the March 1979 energy regulations if it had been produced and sold in May 1979 as upper tier oil, plus

"(B)(i) $1 in the case of tier 2 oil, or

"(ii) $2 in the case of tier 3 oil.

26 USC 4990.

"SEC. 4990. PHASEOUT OF TAX.

"(a) PHASEOUT.—Notwithstanding any other provision of this chapter, the tax imposed by this chapter with respect to any crude oil removed from the premises during any month during the phaseout period shall not exceed—

"(1) the amount of tax which would have been imposed by this chapter with respect to such crude oil but for this subsection, multiplied by

"(2) the phaseout percentage for such month.

"(b) TERMINATION OF TAX.—Notwithstanding any other provision of this chapter, no tax shall be imposed by this chapter with respect to any crude oil removed from the premises after the phaseout period.

"(c) DEFINITIONS.—For purposes of this section—

"(1) PHASEOUT PERIOD.—The term 'phaseout period' means the 33-month period beginning with the month following the target month.

"(2) PHASEOUT PERCENTAGE.—The phaseout percentage for any month is 100 percent reduced by 3 percentage points for each month after the target month and before the month following the month for which the phaseout percentage is being determined.

"(3) TARGET MONTH.—The term 'target month' means the later of—

"(A) December 1987, or

"(B) the first month for which the Secretary publishes an estimate under subsection (d)(2).

In no event shall the target month be later than December 1990.

"(d) DETERMINATION OF AGGREGATE NET WINDFALL REVENUE.—

"(1) ESTIMATE BY THE SECRETARY.—For each month after 1986, the Secretary shall make an estimate of the aggregate net windfall revenue as of the close of such month. Any such estimate shall be made during the preceding month and shall be made on the basis of the best available data as of the date of making such estimate.

"(2) PUBLICATION.—If the Secretary estimates under paragraph (1) that the aggregate net windfall revenue as of the close of any month will exceed $227,300,000,000, the Secretary shall (not later than the last day of the preceding month) publish notice in the Federal Register that he has made such an estimate for such month. Pu... Fe... Re...

"(3) AGGREGATE NET WINDFALL REVENUE DEFINED.—For purposes of this subsection, the term 'aggregate net windfall revenue' means the amount which the Secretary estimates to be the excess of—

"(A) the gross revenues from the tax imposed by section 4986 during the period beginning on March 1, 1980, and ending on the last day of the month for which the estimate is being made, over

"(B) the sum of—

"(i) the refunds of and other adjustments to such tax for such period, plus

"(ii) the decrease in the income taxes imposed by chapter 1 resulting from the tax imposed by section 4986.

For purposes of subparagraph (A), there shall not be taken into account any revenue attributable to an economic interest in crude oil held by the United States.

"Subchapter B—Categories of Oil

"SEC. 4991. TAXABLE CRUDE OIL; CATEGORIES OF OIL. 26...

"(a) TAXABLE CRUDE OIL.—For purposes of this chapter, the term 'taxable crude oil' means all domestic crude oil other than exempt oil.

"(b) EXEMPT OIL.—For purposes of this chapter, the term 'exempt oil' means—

"(1) any crude oil from a qualified governmental interest or a qualified charitable interest,

"(2) any exempt Indian oil,

"(3) any exempt Alaskan oil, and

"(4) any exempt front-end oil.

"(c) TIER 1 OIL.—For purposes of this chapter, the term 'tier 1 oil' means any taxable crude oil other than—

"(1) tier 2 oil, and

"(2) tier 3 oil.

"(d) TIER 2 OIL.—For purposes of this chapter—

"(1) IN GENERAL.—Except as provided in paragraph (2), the term 'tier 2 oil' means—

"(A) any oil which is from a stripper well property within the meaning of the June 1979 energy regulations, and

"(B) any oil from an economic interest in a National Petroleum Reserve held by the United States.

"(2) EXCLUSION OF CERTAIN OIL.—The term 'tier 2 oil' does not include tier 3 oil.

"(c) TIER 3 OIL.—For purposes of this chapter—

"(1) IN GENERAL.—The term 'tier 3 oil' means—

"(A) newly discovered oil,

"(B) heavy oil, and

"(C) incremental tertiary oil.

"(2) NEWLY DISCOVERED OIL.—The term 'newly discovered oil' has the meaning given to such term by the June 1979 energy regulations.

"(3) HEAVY OIL.—The term 'heavy oil' means all crude oil which is produced from a property if crude oil produced and sold from such property during—

"(A) the last month before July 1979 in which crude oil was produced and sold from such property, or

"(B) the taxable period,

had a weighted average gravity of 16 degrees API or less (corrected to 60 degrees Fahrenheit).

"(4) INCREMENTAL TERTIARY OIL.—

"For definition of incremental tertiary oil, see section 4993.

26 USC 4992.

"SEC. 4992. INDEPENDENT PRODUCER OIL.

"(a) GENERAL RULE.—For purposes of this chapter, the term 'independent producer oil' means that portion of an independent producer's qualified production for the quarter which does not exceed such person's independent producer amount for such quarter.

"(b) INDEPENDENT PRODUCER DEFINED.—For purposes of this section—

26 USC 613A.

"(1) IN GENERAL.—The term 'independent producer' means, with respect to any quarter, any person other than a person to whom subsection (c) of section 613A does not apply by reason of paragraph (2) (relating to certain retailers) or paragraph (4) (relating to certain refiners) of section 613A(d).

"(2) RULES FOR APPLYING PARAGRAPHS (2) AND (4) OF SECTION 613A(d).—For purposes of paragraph (1), paragraphs (2) and (4) of section 613A(d) shall be applied—

"(A) by substituting 'quarter' for 'taxable year' each place it appears in such paragraphs, and

"(B) by substituting '$1,250,000' for '$5,000,000' in paragraph (2) of section 613A(d).

"(c) INDEPENDENT PRODUCER AMOUNT.—For purposes of this section—

"(1) IN GENERAL.—A person's independent producer amount for any quarter is the product of—

"(A) 1,000 barrels, multiplied by

"(B) the number of days in such quarter (31 in the case of the first quarter of 1980).

"(2) PRODUCTION EXCEEDS AMOUNT.—If a person's qualified production for any quarter exceeds such person's independent producer amount for such quarter, the independent producer amount shall be allocated—

"(A) between tiers 1 and 2 in proportion to such person's production for such quarter of domestic crude oil in each such tier, and

"(B) within any tier, on the basis of the removal prices fo such person's domestic crude oil in such tier removed durin such quarter, beginning with the highest of such prices

"(d) QUALIFIED PRODUCTION OF OIL DEFINED.—For purposes of thi section—

"(1) IN GENERAL.—An independent producer's qualified pro duction of oil for any quarter is the number of barrels of taxabl crude oil—

"(A) of which such person is the producer,

"(B) which is removed during such quarter,

"(C) which is tier 1 oil or tier 2 oil, and

"(D) which is attributable to the independent producer' working interest in a property.

"(2) WORKING INTEREST DEFINED.—

"(A) IN GENERAL.—The term 'working interest' means a operating mineral interest (within the meaning of sectio 614(d))—

"(i) which was in existence as such an interest o January 1, 1980, or

"(ii) which is attributable to a qualified overridin royalty interest.

"(B) QUALIFIED OVERRIDING ROYALTY INTEREST.—For pu poses of subparagraph (A)(ii), the term 'qualified overridin royalty interest' means an overriding royalty interest i existence as such an interest on January 1, 1980, but only on February 20, 1980, there was in existence a bindin contract under which such interest was to be converted in an operating mineral interest (within the meaning of sectio 614(d)).

"(3) PRODUCTION FROM TRANSFERRED PROPERTY.—

"(A) IN GENERAL.—Except as otherwise provided in th paragraph, in the case of a transfer on or after January 1980, of an interest in any property, the qualified productio of the transferee shall not include any production attribu ble to such interest.

"(B) SMALL PRODUCER TRANSFER EXEMPTION.—

"(i) IN GENERAL.—Subparagraph (A) shall not apply any transfer of an interest in property if the transfer establishes (in such manner as may be prescribed by t Secretary by regulations) that at no time after Dece ber 31, 1979, has the property been held by a person w was a disqualified transferor for any quarter endi after September 30, 1979, and ending before the da such person transferred the interest.

"(ii) DISQUALIFIED TRANSFEROR.—The term 'disqua fied transferor' means, with respect to any quarter, a person who—

"(I) had qualified production for such quar which exceeded such person's independent p ducer amount for such quarter, or

"(II) was not an independent producer for su quarter.

"(iii) SPECIAL RULES.—For purposes of this pa graph—

"(I) PROPERTY HELD BY PARTNERSHIPS.—Prope held by a partnership at any time shall be treate owned proportionately by the partners of such p nership at such time.

"(II) PROPERTY HELD BY TRUST OR ESTATE.—Property held by any trust or estate shall be treated as owned both by such trust or estate and proportionately by its beneficiaries.

"(III) CONSTRUCTIVE APPLICATION.—This chapter shall be treated as having been in effect for periods after September 30, 1979, for purposes of making any determination under subclause (I) or (II) of clause (ii).

"(C) OTHER EXCEPTIONS.—Subparagraph (A) shall not apply in the case of—

26 USC 613A "(i) a transfer of property at death,

"(ii) a change of beneficiaries of a trust which qualifies under clause (iii) of section 613A(c)(9)(B) (determined without regard to the exception at the end of such clause), and

"(iii) any transfer so long as the transferor and transferee are required by subsection (e) to share the 1,000 barrel amount contained in subsection (c)(1)(A).

The preceding sentence shall apply in the case of any property only if the production from the property was qualified production for the transferor.

"(D) TRANSFERS INCLUDE SUBLEASES, ETC.—For purposes of this paragraph—

"(i) a sublease shall be treated as a transfer, and

"(ii) an interest in a partnership or trust shall be treated as an interest in property held by the partnership or trust.

"(e) ALLOCATION WITHIN RELATED GROUP.—

"(1) IN GENERAL.—In the case of persons who are members of the same related group at any time during any quarter, the 1,000 barrel amount contained in subsection (c)(1)(A) for days during such quarter shall be reduced for each such person by allocating such amount among all such persons in proportion to their respective qualified production for such quarter.

"(2) RELATED GROUP.—For purposes of this subsection, persons shall be treated as members of a related group if they are described in any of the following clauses:

"(A) a family,

"(B) a controlled group of corporations,

"(C) a group of entities under common control, or

"(D) if 50 percent or more of the beneficial interest in 1 or more corporations, trusts, or estates is owned by the same family, all such entities and such family.

"(3) DEFINITIONS AND SPECIAL RULES.—For purposes of this subsection—

"(A) CONTROLLED GROUP OF CORPORATIONS.—The term 'controlled group of corporations' has the meaning given such term by section 613A(c)(8)(D)(i).

"(B) GROUP OF ENTITIES UNDER COMMON CONTROL.—The term 'group of entities under common control' means any group of corporations, trusts, or estates which (as determined under regulations prescribed by the Secretary) are under common control. Such regulations shall be based on principles similar to the principles which apply under subparagraph (A).

"(C) FAMILY.—The term 'family' means an individual and the spouse and minor children of such individual.

"(D) CONSTRUCTIVE OWNERSHIP.—For purposes of paragraph (2)(D), an interest owned by or for a corporation, partnership, trust, or estate shall be considered as owned directly by the entity and proportionately by its shareholders, partners, or beneficiaries, as the case may be.

"(E) MEMBERS OF MORE THAN 1 RELATED GROUP.—If a person is a member of more than 1 related group during any quarter, the determination of such person's allocation under paragraph (1) shall be made by reference to the related group which results in the smallest allocation for such person.

"SEC. 4993. INCREMENTAL TERTIARY OIL.

"(a) IN GENERAL.—For purposes of this chapter, the term 'incremental tertiary oil' means the excess of—

"(1) the amount of crude oil which is removed from a property during any month and which is produced on or after the project beginning date and during the period for which a qualified tertiary recovery project is in effect on the property, over

"(2) the base level for such property for such month.

"(b) DETERMINATION OF AMOUNT.—For purposes of this section—

"(1) BASE LEVEL.—The base level for any property for any month is the average monthly amount (determined under rules similar to rules used in determining the base production control level under the June 1979 energy regulations) of crude oil removed from such property during the 6-month period ending March 31, 1979, reduced (but not below zero) by the sum of—

"(A) 1 percent of such amount for each month which begins after 1978 and before the first month beginning after the project beginning date, and

"(B) 2½ percent of such amount for each month which begins after the project beginning date (or after 1978 if the project beginning date is before 1979) and before the month for which the base level is being determined.

"(2) MINIMUM AMOUNT IN CASE OF PROJECTS CERTIFIED BY DOE.—In the case of a project described in subsection (c)(1)(A), for the period during which the project is in effect, the amount of the incremental tertiary oil shall not be less than the incremental production determined under the June 1979 energy regulations.

"(3) ALLOCATION RULES.—The determination of which barrels of crude oil removed during any month are incremental tertiary oil shall be made—

"(A) first by allocating the amount of incremental tertiary oil between—

"(i) oil which (but for this subsection) would be tier 1 oil, and

"(ii) oil which (but for this subsection) would be tier 2 oil,

in proportion to the respective amounts of each such oil removed from the property during such month, and

"(B) then by taking into account barrels of crude oil so removed in the order of their respective removal prices, beginning with the highest of such prices.

"(c) QUALIFIED TERTIARY RECOVERY PROJECT.—For purposes of this section—

"(1) IN GENERAL.—The term 'qualified tertiary recovery project' means—

"(A) a qualified tertiary enhanced recovery project with respect to which a certification as such has been approved and is in effect under the June 1979 energy regulations, or

"(B) any project for enhancing recovery of crude oil which meets the requirements of paragraph (2).

"(2) REQUIREMENTS.—A project meets the requirements of this paragraph if—

"(A) the project involves the application (in accordance with sound engineering principles) of 1 or more tertiary recovery methods which can reasonably be expected to result in more than an insignificant increase in the amount of crude oil which will ultimately be recovered,

"(B) the project beginning date is after May 1979,

"(C) the portion of the property to be affected by the project is adequately delineated,

"(D) the operator submits (at such time and in such manner as the Secretary may by regulations prescribe) to the Secretary—

"(i) a certification from a petroleum engineer that the project meets the requirements of subparagraphs (A), (B), and (C), or

"(ii) a certification that a jurisdictional agency (within the meaning of subsection (d)(5)) has approved the project as meeting the requirements of subparagraphs (A), (B), and (C), and that such approval is still in effect, and

"(E) the operator submits (at such time and such manner as the Secretary may by regulations prescribe) to the Secretary a certification from a petroleum engineer that the project continues to meet the requirements of subparagraphs (A), (B), and (C).

"(d) DEFINITIONS AND SPECIAL RULES.—For purposes of this section—

"(1) TERTIARY RECOVERY METHOD.—The term 'tertiary recovery method' means—

10 CFR 212.78. "(A) any method which is described in subparagraphs (1) through (9) of section 212.78(c) of the June 1979 energy regulations, or

"(B) any other method to provide tertiary enhanced recovery which is approved by the Secretary for purposes of this chapter.

"(2) PROJECT BEGINNING DATE.—The term 'project beginning date' means the later of—

"(A) the date on which the injection of liquids, gases, or other matter begins, or

"(B) the date on which—

"(i) in the case of a project described in subsection (c)(1)(A), the project is certified as a qualified tertiary enhanced recovery project under the June 1979 energy regulations, or

"(ii) in the case of a project described in subsection (c)(1)(B), a petroleum engineer certifies, or a jurisdictional agency approves, the project as meeting the requirements of subparagraphs (A), (B), and (C) of subsection (c)(2).

"(3) PROJECT ONLY AFFECTS PORTION OF PROPERTY.—If a qualified tertiary recovery project can reasonably be expected to increase the ultimate recovery of crude oil from only a portion of a property, such portion shall be treated as a separate property.

"(4) SIGNIFICANT EXPANSION TREATED AS SEPARATE PROJECT.—A significant expansion of any project shall be treated as a separate project.

"(5) JURISDICTIONAL AGENCY.—The term 'jurisdictional agency' means—

"(A) in the case of an application involving a tertiary recovery project on lands not under Federal jurisdiction—

"(i) the appropriate State agency in the State in which such lands are located which is designated by the Governor of such State in a written notification submitted to the Secretary as the agency which will approve projects under this subsection, or

"(ii) if the Governor of such State does not submit such written notification within 180 days after the date of the enactment of the Crude Oil Windfall Profit Tax Act of 1980, the United States Geological Survey (until such time as the Governor submits such notification), or

"(B) in the case of an application involving a tertiary recovery project on lands under Federal jurisdiction, the United States Geological Survey.

"(6) BASIS OF REVIEW OF CERTAIN QUALIFIED TERTIARY RECOVERY PROJECTS.—In the case of any project which is approved under subsection (c)(2)(D)(ii) and for which a certification is submitted to the Secretary, the project shall be considered as meeting the requirements of subparagraphs (A), (B), and (C) of subsection (c)(2) unless the Secretary determines that—

"(A) the approval of the jurisdictional agency was not supported by substantial evidence on the record upon which such approval was based, or

"(B) additional evidence not contained in the record upon which such approval was based demonstrates that such project does not meet the requirements of subparagraph (A), (B), or (C) of subsection (c)(2).

If the Secretary makes a determination described in subparagraph (A) or (B) of the preceding sentence, the determination of whether the project meets the requirements of subparagraphs (A), (B), and (C) of subsection (c)(2) shall be made without regard to the preceding sentence.

"(7) RULINGS RELATING TO CERTAIN QUALIFIED TERTIARY RECOVERY PROJECTS.—In the case of any tertiary recovery project for which a certification is submitted to the Secretary under subsection (c)(2)(D)(ii), a taxpayer may request a ruling from the Secretary with respect to whether such project is a qualified tertiary recovery project. The Secretary shall issue such ruling within 180 days of the date after he receives the request and such information as may be necessary to make a determination.

"SEC. 4994. DEFINITIONS AND SPECIAL RULES RELATING TO EXEMPTIONS.

"(a) QUALIFIED GOVERNMENTAL INTEREST.—For purposes of section 4991(b)—

"(1) IN GENERAL.—The term 'qualified governmental interest' means an economic interest in crude oil if—

"(A) such interest is held by a State or political subdivision thereof or by an agency or instrumentality of a State or political subdivision thereof, and

"(B) under the applicable State or local law, all of the net income received pursuant to such interest is dedicated to a public purpose.

"(2) NET INCOME.—For purposes of this paragraph, the term 'net income' means gross income reduced by production costs, and severance taxes of general application, allocable to the interest.

"(3) AMOUNTS PLACED IN CERTAIN PERMANENT FUNDS TREATED AS DEDICATED TO PUBLIC PURPOSE.—The requirements of paragraph (1)(B) shall be treated as met with respect to any net income which, under the applicable State or local law, is placed in a permanent fund the earnings on which are dedicated to a public purpose.

"(b) QUALIFIED CHARITABLE INTEREST.—For purposes of section 4991(b)—

"(1) IN GENERAL.—The term 'qualified charitable interest' means an economic interest in crude oil if—

"(A) such interest is—

26 USC 170. "(i) held by an organization described in clause (ii), (iii), or (iv) of section 170(b)(1)(A) which is also described in section 170(c)(2), or

"(ii) held—

"(I) by an organization described in clause (i) of section 170(b)(1)(A) which is also described in section 170(c)(2), and

"(II) for the benefit of an organization described in clause (i) of this subparagraph, and

"(B) such interest was held by the organization described in clause (i) or subclause (I) of clause (ii) of subparagraph (A) on January 21, 1980, and at all times thereafter before the last day of the taxable period.

"(2) SPECIAL RULE.—For purposes of paragraph (1)(A)(ii), an interest shall be treated as held for the benefit of an organization described in paragraph (1)(A)(i) only if all the proceeds from such interest were dedicated on January 21, 1980, and at all times thereafter before the last day of the taxable period, to the organization described in paragraph (1)(A)(i).

"(c) FRONT-END TERTIARY OIL.—

"(1) EXEMPTION FOR TERTIARY PROJECTS OF INDEPENDENTS.—For purposes of this chapter, the term 'exempt front-end oil' means any domestic crude oil—

"(A) which is removed from the premises before October 1, 1981, and

"(B) which is treated as front-end oil by reason of a front-end tertiary project on one or more properties each of which is a qualified property.

"(2) REFUNDS FOR TERTIARY PROJECTS OF INTEGRATED PRODUCERS.—

"(A) IN GENERAL.—In the case of any front-end tertiary project which does not meet the requirements of paragraph (1)(B), the excess of—

"(i) the allowed expenses of the taxpayer with respect to such project, over

"(ii) the tertiary incentive revenue,

shall be treated as a payment by the taxpayer with respect to the tax imposed by this chapter made on September 30, 1981.

"(B) LIMITATION BASED ON AMOUNT OF TAX.—The amount of the payment determined under subparagraph (A) with

respect to any producer shall not exceed the aggregate tax imposed by section 4986 with respect to front-end oil of that producer removed after February 1980 and before October 1981.

"(C) TERTIARY INCENTIVE REVENUE.—For purposes of this paragraph, the term 'tertiary incentive revenue' has the meaning given such term by the front-end tertiary provisions of the energy regulations.

"(3) DEFINITION OF ALLOWED EXPENSES; PREPAID EXPENSES NOT TAKEN INTO ACCOUNT.—For purposes of this subsection (including the application of the front-end tertiary provisions for purposes of this subsection)—

"(A) ALLOWED EXPENSES.—Except as provided in subparagraph (B), allowed expenses shall be determined under the front-end tertiary provisions of the energy regulations.

"(B) PREPAID EXPENSES NOT TAKEN INTO ACCOUNT.—The term 'allowed expenses' shall not include any amount attributable to periods after September 30, 1981.

"(C) PERIOD TO WHICH ITEM IS ATTRIBUTABLE.—For purposes of subparagraph (B)—

"(i) any injectant and any fuel shall be treated as attributable to periods before October 1, 1981, if the injectant is injected, or the fuel is used, before October 1, 1981, and

"(ii) any other item shall be treated as attributable to periods before October 1, 1981, only to the extent that under chapter 1 deductions for such item (including depreciation in respect of such item) are properly allocable to periods before October 1, 1981.

For purposes of the preceding sentence, an act shall be treated as taken before a date if it would have been taken before such date but for an act of God, a severe mechanical breakdown, or an injunction.

"(4) DEFINITIONS AND SPECIAL RULES.—For purposes of this subsection—

"(A) FRONT-END TERTIARY PROVISIONS.—The term 'front-end tertiary provisions' means—

"(i) the provisions of section 212.78 of the energy regulations which exempt crude oil from ceiling price limitations to provide financing for tertiary projects (as such provisions took effect on October 1, 1979), and

"(ii) any modification of such provisions, but only to the extent that such modification is for purposes of coordinating such provisions with the tax imposed by this chapter.

"(B) FRONT-END OIL.—The term 'front-end oil' means any domestic crude oil which is not subject to a first sale ceiling price under the energy regulations solely by reason of the front-end tertiary provisions of such regulations.

"(C) QUALIFIED PROPERTY.—The term 'qualified property' means any property if, on January 1, 1980, 50 percent or more of the operating mineral interest in such property is held by persons who were independent producers (within the meaning of section 4992(b)) for the last quarter of 1979.

"(D) FRONT-END TERTIARY PROJECT.—The term 'front-end tertiary project' means any project which qualifies under the front-end tertiary provisions of the energy regulations.

Dockets Nos. 38-81 and 39-81 are tentatively set for December 2, and December 15, 1981. Application for hearing must be filed at least 22 days in advance of hearing date.

DOCKET: EXAMINER HEARING - THURSDAY - NOVEMBER 19, 1981

9 A.M. - OIL CONSERVATION DIVISION CONFERENCE ROOM
STATE LAND OFFICE BUILDING, SANTA FE, NEW MEXICO

The following cases will be heard before Richard L. Stamets, Examiner, or Daniel S. Nutter, Alternate Examiner:

ALLOWABLE: (1) Consideration of the allowable production of gas for December, 1981, from fifteen prorated pools in Lea, Eddy and Chaves Counties, New Mexico.

(2) Consideration of the allowable production of gas for December, 1981, from four prorated pools in San Juan, Rio Arriba, and Sandoval Counties, New Mexico.

CASE 7410: Application of B.O.A. Oil & Gas Company for two unorthodox oil well locations, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks approval for the unorthodox location of a well to be drilled 2035 feet from the South line and 2455 feet from the East line and one to be drilled 2455 feet fron the North line and 1944 feet from the East line, both in Section 31, Township 31 North, Range 15 West, Verde-Gallup Oil Pool, the NW/4 SE/4 and SW/4 NE/4, respectively, of said Section 31 to be dedicated to said wells.

CASE 7356: (Continued from October 21, 1981, Examiner Hearing)

Application of S & I Oil Company for compulsory pooling, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the W/2 SW/4 of Section 12, Township 29 North, Range 15 West, Cha Cha-Gallup Oil Pool, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7411: Application of Viking Petroleum, Inc., for an unorthodox gas well location, Chaves County, New Mexico. Applicant, in the above-styled cause, seeks approval for the unorthodox location of a well to be drilled 330 feet from the North and East lines of Section 12, Township 11 South, Range 27 East, the NE/4 of said Section 12 to be dedicated to the well. (This case will be dismissed).

CASE 7412: Application of Gulf Oil Corporation for salt water disposal, Lea County, New Mexico. Applicant, in the above-styled cause, seeks authority to dispose of produced salt water into the Lower Yates, Queen, San Andres and Delaware formations in the open hole interval from 4375 feet to 7452 feet in its Lea "ZD" State Well No. 1 located in Unit M of Section 30, Township 13 South, Range 35 East, Air-Strip Field.

CASE 7413: Application of Gulf Oil Corporation for Directional Drilling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks authority to directionally drill its Arnott Ramsey Well No. 12, the surface location of which is 500 feet from the South line and 1400 feet from the East line of Section 32, Township 25 South, Range 37 East, to a bottomhole location within 150 feet of a point 500 feet from the South line and 800 feet from the East line of Section 32, Township 25 South, Range 37 East, Langlie Mattix Pool, the SE/4 SE/4 of said Section 32 to be dedicated to the well.

CASE 7414: Application of Gulf Oil Corporation for downhole commingling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for the downhole commingling of the Drinkard and Wantz-Granite Wash production in the wellbore of its Hugh Well No. 10, located in Unit C of Section 14, Township 22 South, Range 37 East.

CASE 7415: Application of Gulf Oil Corporation for downhole commingling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for the downhole commingling of the Tubb and Drinkard production in the wellbore of its T. R. Andrews Well No. 3, located in Unit J of Section 32, Township 22 South, Range 38 East.

CASE 7379: (Continued from October 21, 1981, Examiner Hearing)

Application of JEH Resources, Inc., for vertical pool extension and special GOR limit, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks the vertical extension of the Cave-Grayburg Pool to include the San Andres Formation, and the establishment of a special gas-oil ratio limit for said pool to 6000 to one or, in the alternative, the abolishment of the gas-oil ratio limit in said pool, all to be effective October 1, 1981.

CASE 7407: (Continued from November 4, 1981, Examiner Hearing)

Application of Mesa Petroleum Company for compulsory pooling, Chaves County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Abo formation underlying the NE/4 of Section 23, Township 5 South, Range 24 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7416: Application of El Paso Natural Gas Company for pool creation and redelineation, Lea County, New Mexico. Applicant, in the above-styled cause, seeks to contract the horizontal limits of the Jalmat Gas Pool by deleting therefrom all lands in Township 26 South, Range 37 East. Applicant also proposes to contract the horizontal limits of the Rhodes Yates - Seven Rivers Oil Pool by deleting therefrom all of the gas productive lands in the North end thereof and to create the Rhodes Yates-Seven Rivers Gas Pool comprising all such deleted lands. Applicant further proposes the deletion of certain oil productive lands from said Rhodes oil pool and the extension of the Scarborough Pool to include said lands. Applicant further proposes to contract the horizontal boundaries of the Rhodes Gas Storage Unit to delete certain lands and wells not participating in the Rhodes Gas Storage Project and to withdraw without restriction all gas remaining in the newly created Rhodes Gas Pool.

CASE 7417: (This case will be dismissed.)

Application of Northwest Pipeline Corporation for 13 non-standard gas proration units, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks approval for 13 non-standard Pictured Cliffs gas proration units ranging in size from 142.39 acres to 176.77 acres and each comprised of various contiguous lots or tracts in Sections 4,5,6,7, and 18 of Township 31 North, Range 7 West. Said proration units result from corrections in the survey lines on the North and West sides of Township 31 North, Range 7 West and overlap seven non-standard Mesaverde proration units previously approved by Order No. R-1066.

CASE 7418: Application of Morris R. Antweil for special pool rules, Lea County, New Mexico. Applicant, in the above-styled cause, seeks the promulgation of special pool rules for the West Nadine-Drinkard Pool including a special gas-oil ratio of 6,000 to one.

CASE 7419: Application of Morris R. Antweil for special pool rules, Lea County, New Mexico. Applicant, in the above-styled cause, seeks the promulgation of special pool rules for the West Nadine-Blinebry pool including a special gas-oil ratio of 4,000 to one.

CASE 7420: Application of Southland Royalty Company for two unorthodox oil well locations, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for the unorthodox location of two previously drilled wells, the first being 760 feet from the South line and 660 feet from the East line of Section 5 the other being 660 feet from the North and West lines of Section 9, both in Township 19 South, Range 35 East, both to be plugged back to the Scharb-Bone Springs Pool, the S/2 SE/4 of Section 5 and the N/2 NW/4 of Section 9, respectively, to be dedicated to the wells.

CASE 7421: Application of Doyle Hartman for compulsory pooling, unorthodox well location and non-standard spacing unit, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Eumont Gas Pool underlying a 120-acre non-standard spacing unit consisting of the S/2 SW/4 and the NW/4 SW/4 of Section 3, Township 20 South, Range 37 East, to be dedicated to a well to be drilled at an unorthodox location 2,310 feet from the South line and 330 feet from the West line of Section 3. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well and a charge for risk involved in drilling said well.

CASE 7415: Application of Gulf Oil Corporation for downhole commingling, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for the downhole commingling of the Tubb and Drinkard production in the wellbore of its T. R. Andrews Well No. 3, located in Unit J of Section 32, Township 22 South, Range 38 East.

CASE 7379: (Continued from October 21, 1981, Examiner Hearing)

Application of JEM Resources, Inc., for vertical pool extension and special GOR limit, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks the vertical extension of the Cave-Grayburg Pool to include the San Andres Formation, and the establishment of a special gas-oil ratio limit for said pool to 6000 to one or, in the alternative, the abolishment of the gas-oil ratio limit in said pool, all to be effective October 1, 1981.

CASE 7407: (Continued from November 4, 1981, Examiner Hearing)

Application of Mesa Petroleum Company for compulsory pooling, Chaves County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Abo formation underlying the NE/4 of Section 23, Township 5 South, Range 24 East, to be dedicated to a well to be drilled at a standard location thereon. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7416: Application of El Paso Natural Gas Company for pool creation and redelineation, Lea County, New Mexico. Applicant, in the above-styled cause, seeks to contract the horizontal limits of the Jalmat Gas Pool by deleting therefrom all lands in Township 26 South, Range 37 East. Applicant also proposes to contract the horizontal limits of the Rhodes Yates - Seven Rivers Oil Pool by deleting therefrom all of the gas productive lands in the North end thereof and to create the Rhodes Yates-Seven Rivers Gas Pool comprising all such deleted lands. Applicant further proposes the deletion of certain oil productive lands from said Rhodes oil pool and the extension of the Scarborough Pool to include said lands. Applicant further proposes to contract the horizontal boundaries of the Rhodes Gas Storage Unit to delete certain lands and wells not participating in the Rhodes Gas Storage Project and to withdraw without restriction all gas remaining in the newly created Rhodes Gas Pool.

CASE 7417: (This case will be dismissed.)

Application of Northwest Pipeline Corporation for 13 non-standard gas proration units, San Juan County, New Mexico. Applicant, in the above-styled cause, seeks approval for 13 non-standard Pictured Cliffs gas proration units ranging in size from 142.39 acres to 176.77 acres and each comprised of various contiguous lots or tracts in Sections 4,5,6,7, and 18 of Township 31 North, Range 7 West. Said proration units result from corrections in the survey lines on the North and West sides of Township 31 North, Range 7 West and overlap seven non-standard Mesaverde proration units previously approved by Order No. R-1066.

CASE 7418: Application of Morris R. Antweil for special pool rules, Lea County, New Mexico. Applicant, in the above-styled cause, seeks the promulgation of special pool rules for the West Nadine-Drinkard Pool including a special gas-oil ratio of 6,000 to one.

CASE 7419: Application of Morris R. Antweil for special pool rules, Lea County, New Mexico. Applicant, in the above-styled cause, seeks the promulgation of special pool rules for the West Nadine-Blinebry pool including a special gas-oil ratio of 4,000 to one.

CASE 7420: Application of Southland Royalty Company for two unorthodox oil well locations, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for the unorthodox location of two previously drilled wells, the first being 760 feet from the South line and 660 feet from the East line of Section 5 the other being 660 feet from the North and West lines of Section 9, both in Township 19 South, Range 35 East, both to be plugged back to the Scharb-Bone Springs Pool, the S/2 SE/4 of Section 5 and the N/2 NW/4 of Section 9, respectively, to be dedicated to the wells.

CASE 7421: Application of Doyle Hartman for compulsory pooling, unorthodox well location and non-standard spacing unit, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests in the Eumont Gas Pool underlying a 120-acre non-standard spacing unit consisting of the S/2 SW/4 and the NW/4 SW/4 of Section 3, Township 20 South, Range 37 East, to be dedicated to a well to be drilled at an unorthodox location 2,310 feet from the South line and 330 feet from the West line of Section 3. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well and a charge for risk involved in drilling said well.

CASE 7422: Application of Conoco, Inc. for dual completion and an unorthodox location, Lea County, New Mexico. Applicant, in the above-styled cause, seeks approval for the dual completion of its Southeast Monument Unit Well No. 121, to produce oil from the Skaggs Grayburg and an undesignated Paddock pool through parallel strings of tubing. Applicant further seeks approval of the unorthodox location of said well 1310 feet from the North line and 1330 feet from the West line of Section 19, Township 20 South, Range 38 East, the NE/4 NW/4 of said Section 19 to be dedicated to the well.

CASE 7423: Application of Conoco, Inc., for a waterflood project, Lea County, New Mexico. Applicant, in the above-styled cause, seeks authority for three companies to institute a cooperative waterflood project in the Blinebry oil and gas pool by the injection of water into the Blinebry formation through 13 injection wells located on leases operated by Conoco, Shell Oil Company, and Southland Royalty Company, in Sections 33 and 34, Township 20 South, Range 38 East, and Sections 2 and 3, Township 21 South, Range 37 East.

CASE 7424: Application of Rice Engineering and Operating, Inc., for salt water disposal, Lea County, New Mexico. Applicant, in the above-styled cause, seeks authority to dispose of produced salt water into the Lower San Andres formation in the perforated interval from 4300 feet to 4852 feet in its Eunice-Monument Eumont SWD "G" Well No. 8, located in Unit G of Section 8, Township 20 South, Range 37 East.

CASE 7425: Application of H. L. Brown, Jr. for compulsory pooling and an unorthodox location, Lea County, New Mexico. Applicant, in the above-styled cause, seeks an order pooling all mineral interests from the top of the San Andres formation to the base of the Pennsylvanian formation underlying the S/2 of Section 36, Township 16 South, Range 37 East, to be dedicated to a well to be drilled at an unorthodox location 554 feet from the South and West lines of said Section 26, provided that in the event the subject well encounters production in the Casey-Strawn Pool and/or the West Knowles-Drinkard Pool, the lands pooled would be the W/2 SW/4 of said Section 26. Also to be considered will be the cost of drilling and completing said well and the allocation of the cost thereof as well as actual operating costs and charges for supervision, designation of applicant as operator of the well, and a charge for risk involved in drilling said well.

CASE 7426: Application of Phillips Petroleum Company for Amendment of Division Order No. R-5897 and certification of a tertiary recovery project, Lea County, New Mexico. Applicant, in the above-styled cause, seeks the Amendment of Division Order No. R-5897, to include the injection of carbon dioxide in the previously authorized pressure maintenance project in the East Vacuum Grayburg-San Andres Unit, for conversion of existing injectors to water/carbon dioxide injection, and for certification to the Secretary of the IRS that the East Vacuum Grayburg-San Andres Unit Project is a qualified tertiary oil recovery project.

CASE 7427: Application of Belco Petroleum Corporation for a special allowable, Eddy County, New Mexico. Applicant, in the above-styled cause, seeks an adjustment to the manner in which allowables are calculated for wells in the South Carlsbad-Morrow Gas Pool in order to grant relief to the overproduced status of its Douglas Com. Well No. 1 located in Unit H of Section 7, Township 22 South, Range 27 East, said well being subject to shut-in being more than six times its allowable overproduced. In the alternative, applicant seeks to make up the over-production at a rate less than complete shut-in by curtailing production from the well to 80 percent of its top allowable until it is back in balance.

CASE 7428: In the matter of the hearing called by the Oil Conservation Division on its own motion for an order creating; and extending certain pools in Chaves, Eddy, Lea, and Roosevelt Counties, New Mexico.

(a) CREATE a new pool in Lea County, New Mexico, classified as a gas pool for Wolfcamp production and designated as the North Antelope Ridge-Wolfcamp Gas Pool. The discovery well is J. C. Williamson Triple A Federal Well No. 1 located in Unit F of Section 10, Township 23 South, Range 34 East, NMPM. Said pool would comprise:

TOWNSHIP 23 SOUTH, RANGE 34 EAST, NMPM
Section 10: N/2 and N/2 SW/4

(b) CREATE a new pool in Lea County, New Mexico, classified as an oil pool for Wolfcamp production and designated as the Diamondtail-Wolfcamp Pool. The discovery well is the Superior Oil Company Triste Draw Federal Well No. 1 located in Unit J of Section 14, Township 23 South, Range 32 East, NMPM. Said pool would comprise:

TOWNSHIP 23 SOUTH, RANGE 32 EAST, NMPM
Section 14: SE/4

(c) CREATE a new pool in Lea County, New Mexico, classified as an oil pool for Bone Spring production and designated as the North Grama Ridge-Bone Spring Pool. The discovery well is the Hunt Oil Company State 4 Well No. 1 located in Unit T of Section 4, Township 21 South, Range 34 East, NMPM. Said pool would comprise:

TOWNSHIP 21 SOUTH, RANGE 34 EAST, NMPM
Section 4: SW/4

(d) CREATE a new pool in Lea County, New Mexico, classified as an oil pool for Wolfcamp production and designated as the Grassland-Wolfcamp Pool. The discovery well is C. F. Qualia State 23 Well No. 1 located in Unit K of Section 23, Township 15 South, Range 34 East, NMPM. Said pool would comprise:

TOWNSHIP 15 SOUTH, RANGE 34 EAST, NMPM
Section 23: SW/4

(e) CREATE a new pool in Lea County, New Mexico, classified as an oil pool for Bone Spring production and designated as the North Lusk-Bone Spring Pool. The discovery well is Petroleum Development Corporation Shelly Federal Com. Well No. 1 located in Unit H of Section 5, Township 19 South, Range 32 East, NMPM. Said pool would comprise:

TOWNSHIP 19 SOUTH, RANGE 32 EAST, NMPM
Section 5: NE/4

(f) CREATE a new pool in Eddy County, New Mexico, classified as a gas pool for Atoka production and designated as the McMillan-Atoka Gas Pool. The discovery well is Southland Royalty Company Pecos River 21 Federal Com Well No. 1 located in Unit K of Section 21, Township 19 South, Range 27 East, NMPM. Said pool would comprise:

TOWNSHIP 19 SOUTH, RANGE 27 EAST, NMPM
Section 21: S/2

(g) CREATE a new pool in Eddy County, New Mexico, classified as a gas pool for Morrow production and designated as the Springs-Morrow Gas Pool. The discovery well is Jake L. Hamon State 33 Com Well No. 1 located in Unit I of Section 33, Township 20 South, Range 26 East, NMPM. Said pool would comprise:

TOWNSHIP 20 SOUTH, RANGE 26 EAST, NMPM
Section 32: E/2
Section 33: All

(h) EXTEND the Antelope Ridge-Morrow Gas Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 23 SOUTH, RANGE 34 EAST, NMPM
Section 11: All
Section 15: N/2

(i) EXTEND the Baldridge Canyon-Morrow Gas Pool in Eddy County, New Mexico, to include therein:

TOWNSHIP 24 SOUTH, RANGE 24 EAST, NMPM
Section 14: N/2

(j) EXTEND the Bear Draw-Queen-Grayburg-San Andres Pool in Eddy County, New Mexico, to include therein:

TOWNSHIP 16 SOUTH, RANGE 29 EAST, NMPM
Section 28: N/2 SE/4

(k) EXTEND the Bluitt-Wolfcamp Gas Pool in Roosevelt County, New Mexico, to include therein:

TOWNSHIP 8 SOUTH RANGE 37 EAST, NMPM
Section 10: SE/4

(l) EXTEND the Buffalo Valley-Pennsylvanian Gas Pool in Chaves County, New Mexico, to include therein:

TOWNSHIP 15 SOUTH, RANGE 27 EAST, NMPM
Section 4: All

(m) EXTEND the Bunker Hill-Penrose Pool in Eddy County, New Mexico, to include therein:

TOWNSHIP 16 SOUTH, RANGE 31 EAST, NMPM
Section 13: SE/4 SW/4

(n) EXTEND the Burton Flat-Morrow Gas Pool in Eddy County, New Mexico, to include therein:

TOWNSHIP 20 SOUTH, RANGE 27 EAST, NMPM
Section 35: W/2

(O) EXTEND the Eagle Creek-Strawn Gas Pool in Eddy County,New Mexico, to include therein:

TOWNSHIP 17 SOUTH, RANGE 25 EAST, NMPM
Section 27: N/2

TOWNSHIP 18 SOUTH, RANGE 25 EAST, NMPM
Section 1: All

(p) EXTEND the Golden Lane-Morrow Gas Pool in Eddy County, New Mexico, to include therein:

TOWNSHIP 21 SOUTH, RANGE 29 EAST, NMPM
Section 8: S/2

(q) EXTEND the Kennedy Farms-Upper Pennsylvanian Gas Pool in Eddy County, New Mexico to include therein:

TOWNSHIP 17 SOUTH, RANGE 26 EAST, NMPM
Section 34: N/2
Section 35: N/2

(r) EXTEND the North Mason-Delaware Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 26 SOUTH, RANGE 32 EAST, NMPM
Section 8: S/2 S/2

(s) EXTEND the West Osudo-Morrow Gas Pool in Lea County,New Mexico, to include therein:

TOWNSHIP 20 SOUTH, RANGE 35 EAST, NMPM
Section 35: N/2

(t) EXTEND the West Parkway-Morrow Gas Pool in Eddy County, New Mexico, to include therein:

TOWNSHIP 19 SOUTH, RANGE 29 EAST, NMPM
Section 29: W/2

(u) EXTEND the Peterson-Mississippian Pool in Roosevelt County, New Mexico, to include therein:

TOWNSHIP 4 SOUTH, RANGE 33 EAST, NMPM
Section 29: NE/4

(v) EXTEND the POW-Morrow Gas Pool in Eddy County, New Mexico, to include therein:

TOWNSHIP 17 SOUTH, RANGE 26 EAST, NMPM
Section 4: S/2

(w) EXTEND the Saunders-Permo Upper Pennsylvanian Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 14 SOUTH, RANGE 33 EAST, NMPM
Section 32: NE/4

(x) EXTEND the Scharb-Bone Spring Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 19 SOUTH, RANGE 35 EAST, NMPM
Section 8: NE/4

(y) EXTEND the East Siete-San Andres Pool in Chaves County, New Mexico, to include therein:

TOWNSHIP 8 SOUTH, RANGE 31 EAST, NMPM
Section 10: NE/4

(z) EXTEND the Teague-Abo Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 23 SOUTH, RANGE 37 EAST, NMPM
Section 27: NW/4

(aa) EXTEND the Tom-Tom-San Andres Pool in Chaves County, New Mexico, to include therein:

TOWNSHIP 7 SOUTH, RANGE 31 EAST, NMPM
Section 28: SE/4

(bb) EXTEND the North Turkey Track-Morrow Gas Pool in Eddy County, New Mexico to include therein:

TOWNSHIP 18 SOUTH, RANGE 29 EAST, NMPM
Section 21: All

(cc) EXTEND the North Young-Bone Spring Pool in Lea County, New Mexico, to include therein:

TOWNSHIP 18 SOUTH, RANGE 32 EAST, NMPM
Section 9: NE/4

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
DIVISION FOR THE PURPOSE OF
CONSIDERING:

Case No. 7426
Order No.

APPLICATION OF PHILLIPS PETROLEUM
COMPANY FOR AMENDMENT OF DIVISION
ORDER NO. R-5897 AND APPROVAL OF A
QUALIFIED TERTIARY OIL RECOVERY
PROJECT UNDER THE CRUDE OIL WINDFALL
PROFITS TAX ACT OF 1980, LEA COUNTY
NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 9:00 a.m., on November 19, 1981, at Santa Fe, New Mexico, before Examiner Richard L. Stamets.

NOW, on this ____ day of ______________, 1981, the Division Director, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Division has jurisdiction of this cause and the subject matter thereof.

(2) That the applicant, Phillips Petroleum Company, seeks the Amendment of Division Order No. R-5897, to include the injection of carbon dioxide in ~~the~~ its previously authorized pressure maintenance project in the East Vacuum Grayburg-San Andres Unit, for conversion of existing injectors to water/carbon dioxide injection, and for the approval of a portion of the East Vacuum Grayburg-San Andres Unit as a Qualified Tertiary Oil Recovery Project under the Crude Oil Windfall Profits Tax Act of 1980.

(3) That said secondary recovery project lies within the Vacuum Grayburg-San Andres Pool, Lea County, New Mexico.

(4) That said pool was discovered May 5, 1924, by Socony Vacuum Oil Company, experienced substantial development thereafter with waterflooding being initiated in ~~one~~ a project during 1958.

(5) That the Phillips Petroleum Company East Vacuum Unit Pressure Maintenance Project consisting of approximately 7025 acres was approved by said Division Order R-5897 on January 16, 1979, and water injection was commenced within said project during December, 1979.

(6) That the applicant now seeks approval for the injection of carbon dioxide ~~gas~~ and water into 45 project wells and the designation of a qualifying tertiary recovery project area within said pressure maintenance project.

(7) That the proposed Qualifying Tertiary Project Area (QTP Area) lies wholly within said East Vacuum Unit Pressure

Maintenance Project and consists of the following described acreage:

<u>Township 17 South, Range 35 East, NMPM</u>
Section 26: W/2; NE/4; W/2 SE/4; NE/4 SE/4
Section 27: all
Section 28: all
Section 29: all
Section 31: N/2 SE/4; and SE/4 SE/4
Section 32: all
Section 33: all
Section 34: N/2; SW/4; and NW/4 SE/4
Section 35: N/2 NW/4

<u>Township 18 South, Range 35 East, NMPM</u>
Section 4: N/2 NW/4; and NW/4 NE/4
Section 5: N/2; and NW/4 SW/4

containing 4997 acres more or less.

(8) That the QTP Area ~~project area~~ is adequately delineated and that the entire ~~project~~ area will be ~~adequated~~ affected.

(9) The the New Mexico Oil Conservation Division has been designated by the Governor of the State of New Meixco as the appropriate agency to approve Qualified Tertiary Recovery Projects in New Mexico for purposes of the Crude Oil Windfall Profits Tax Act of 1980.

(10) That the tertiary oil recovery method used in the Phillips OTP Area ~~Project~~ is a carbon dioxide miscible displacement method which is a recognized tertiary oil recovery method described in Section 212.78(c) of the Department of Energy Regulations in effect in June, 1979.

(11) That the Tertiary Recovery method includes overinjection of voidage with water at maximum rates to achieve a miscibility pressure in the formation~~, which tests indicate will be 1369 psia~~.

(12) That slim tube tests have determined such miscibility pressure to be approximately 1369 psia

(~~11~~ 13) That overinjection began on February 1, 1981, and carbon dioxide injection will begin after miscibility pressure has been achieved.

(~~12~~ 14) That under the tertiary recovery method to be used, it is anticipated that the injected carbon dioxide, measured at reservoir temperature and pressure will be more than 10% of the reservoir pore volume being served by the injection wells.

(~~13~~ 15) That because of the geological and reservoir characteristics of the affected ~~Vacuum San Andres~~ reservoir, the QTP Area is well suited for miscible fluid displacement by carbon dioxide as an enhanced recovery process.

(~~14~~ 16) That the estimated primary production from the East Vacuum Unit Pressure Maintenance Project Area is 72 million barrels and that water flooding secondary recovery operations will recover an additional 38 million barrels.

(~~15~~ 17) That an estimated twenty-six million (26,000,000) barrels of additional oil (which is 10% of the original-oil-in-place within the project area) will be recovered as a result of the tertiary recovery operations, which is more than an insignificant increase in the amount of crude oil which will ultimately be recovered.

(~~16~~ 18) That the QTP Area tertiary recovery operations beginning date is after May, 1979.

(~~17~~ 19) That the QTP Area tertiary recovery operations beginning date (i.e., the date on which the injection of liquids, gases or other matter begins) was February 1, 1981.

(~~18~~ 19) That the proposed tertiary recovery operations within said QTP Area meet all requirements of Section 4993 of the Internal Revenue Code.

(~~19~~ 20) That the Phillips ~~Project~~ QTP Area project is designated in accordance with sound engineering principles.

(~~20~~ 21) That the approval of this application will prevent waste, protect correlative rights and promote conservation.

IT IS THEREFORE ORDERED:

(1) That effective December 1, 1981, the Qualifying Tertiary Recovery Project Area, described in Finding No. (7) of this Order, of the Phillips Petroleum Company ~~West~~ East Vacuum Unit Pressure Maintenance Project, Vacuum Grayburg-San Andres Pool, Lea County, New Mexico, is hereby approved as a Qualified Tertiary Recovery Project under the Crude Oil Windfall Profits Tax Act of 1980.

(2) That the applicant, Phillips Petroleum Company, is hereby authorized to inject water and carbon dioxide ~~gas~~ into the 45 wells listed on Exhibit "A" attached to this Order.

(3) That Order R-5897 is hereby amended to authorize injection of carbon dixode up to ~~a~~ an average maximum bottom hole pressure of 3150 psi.

(4) That jurisdiction of this case is retained for the entry of such further orders as the Division may deem necessary.

Done at Santa Fe, New Mexico, on the day and year hereinabove designated.

State of New Mexico
Oil Conservation Division
Joe D. Ramey, Director

Tom Kellahin

RECEIVED
DEC 4 1980
HOUSTON LAW

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

OIL AND GAS DOCKET
NO. 3-75,823

IN RE: CONSERVATION AND PREVENTION OF WASTE OF CRUDE PETROLEUM AND NATURAL GAS IN THE STATE OF TEXAS

NOTED
DEC 8 1980
BURTON BRANSTETTER

APPLICATION OF GULF OIL CORPORATION FOR A CERTIFICATION AS APPROVED QUALIFIED TERTIARY OIL RECOVERY PROJECT UNDER THE CRUDE OIL WINDFALL PROFITS TAX FOR THE KURTEN (WOODBINE) FIELD, BRAZOS COUNTY, TEXAS

OPINION AND ORDER

This is Gulf Oil Corporation's application for certification of the Kurten (Woodbine) Field enhanced recovery unit as a qualified tertiary oil recovery project under the Crude Oil Windfall Profits Tax (26 U.S.C. 4993). The Railroad Commission of Texas has been designated by Governor William Clements, Jr. as the proper agency to make these certifications.

The Kurten (Woodbine) Field was discovered in 1976 and developed with 131 wells on 160 acre units. The Woodbine is encountered at approximately 8100 feet. The pilot Jones Enhanced Recovery Unit proposed by Gulf contains 672 acres and has four existing producing wells. Gulf proposes to drill four new injection wells and one new producing well, number 6, on this unit. (Tr 15) The development pattern will be an assymetrical forty acre five-spot pattern. Gulf will drill its number 5 well to the Wilcox at 4000 feet as a water supply well.

The estimated primary production from this unit is one million barrels of oil or 11 percent of the oil in place. (Tr 14 and Tr 29). Gulf investigated waterflooding (Tr 19-22) as well as several methods of tertiary recovery for this field (Tr 14). Since the permeability of this Woodbine reservoir was low, 2 millidarcies, (Tr 25) the only feasible method of recovery was the CO_2 miscible displacement method. Tests show that miscibility could be obtained at a pressure of between 3000 and 3500 psi. It is estimated that this miscible displacement method will increase ultimate recovery by 1.2 million barrels of oil over the period from September, 1981 through September, 1986.

The Gulf plan calls for all new wells to be drilled and completed by April, 1981. At that point Gulf will repressure the reservoir by injecting approximately 400 barrels of water per day in each injection well for three months (Tr 16). In July, 1981, 40 tons per day per well of CO_2 will be injected for about nine months. Thereafter, Gulf will inject alternate slugs of CO_2 and water for three month periods until about 1986.

The result of this proposed tertiary oil recovery project will be to increase recovery from this field from 1 to 2.2 million barrels of oil. This is a 120 percent increase in ultimate recovery.

FINDINGS OF FACT

Based on the record evidence, the Commission makes the following findings of fact:

1. The Kurten (Woodbine) Field is located in Brazos County, Texas;

2. The Gulf Jones Enhanced Recovery Unit in the Kurten (Woodbine) Field consists of 672 acres;

3. The Gulf unit is in the later stages of primary depletion;

4. Gulf plans to go directly from primary to tertiary oil recovery because:
   (a) Secondary recovery by gas injection would eliminate CO_2 miscible flooding due to large remaining gas saturations which would cause CO_2 channelling and reduce sweep efficiency;
   (b) Comparisons with other Woodbine waterflood projects located near the Kurten (Woodbine) Field indicate waterflood recovery would be low;
   (c) Waterflooding is not a necessary prerequisite for CO_2 miscible flooding;
   (d) Tertiary recovery projects generally have a higher probability for success if initiated early in a reservoir's life;
   (e) Tertiary recovery would be reduced by a lengthy waterflood program;

5. The tertiary oil recovery method Gulf plans to use in the Kurten (Woodbine) Field is a CO_2 miscible displacement method;

6. The CO_2 miscible displacement method is a recognized tertiary oil recovery method described in Section 212.78(c) of the Department of Energy Regulations in effect on June 1, 1979;

7. The estimated primary production from the Gulf unit is one million barrels of oil or 11 percent of the oil in place;

8. The estimated total production after the tertiary oil recovery project is 2.2 million barrels of oil or 25 percent of the oil in place;

9. The increase in recovery is estimated to be 1.2 million barrels or 120 percent of primary recovery. This is more than an insignificant amount of oil recovery;

10. The Gulf plan calls for the drilling of four new injection wells, one new producing well and one new water supply well.

11. In April, 1981, Gulf will inject approximately 400 barrels of water per day into each injection well for approximately three months to repressure the reservoir to a miscible pressure of between 3000 and 3500 psi.

12. After the reservoir is repressured (July, 1981), Gulf will inject 40 tons of CO_2 per day per injection well for nine months. Thereafter, Gulf will alternate three month injections of CO_2 and water until 1986;

13. The project beginning date will be after May, 1979;

14. The Railroad Commission of Texas has been duly designated by the Governor of Texas as the jurisdictional agency authorized under state law to qualify tertiary recovery projects for purposes of the Crude Oil Windfall Profits Tax of 1980.

CONCLUSIONS OF LAW

1. The project proposed by Gulf involves a miscible fluid displacement process, which is one of the tertiary oil recovery methods described in Section 212.78(c) of the Energy Regulations of the D.O.E. in effect on 6-1-79.

2. The project proposed by Gulf will result in a more than insignificant amount of additional oil recovery from the Jones Enhanced Recovery Unit.

3. The project proposed by Gulf will begin after May, 1979.

4. The project proposed by Gulf will affect all of the 672 acre unit and such unit is adequately delineated.

5. The Railroad Commission of Texas has been designated as the appropriate agency to certify qualified tertiary oil recovery projects pursuant to Section 4993(d)(5)(A)(i) of the Internal Revenue Code.

6. The project meets, and the Commission approves the project as meeting, the requirements of subparagraphs (A), (B) and (C) of Section 4993 (C)(2) of the Code.

IT IS THEREFORE ORDERED BY THE RAILROAD COMMISSION OF TEXAS THAT the CO_2 miscible gas displacement by Gulf in its Jones Enhanced Recovery Unit in the Kurten (Woodbine) Field is hereby certified as a qualified tertiary oil recovery project under Section 4993 of the Internal Revenue Code.

Done this the 1st day of December, 1980.

RAILROAD COMMISSION OF TEXAS

John Poerner

CHAIRMAN

James E. (Jim) Nugent

COMMISSIONER

Mack Wallace

COMMISSIONER

ATTEST:

Elizabeth Mavrogoulis

SECRETARY

BRS:djl

KELLAHIN and KELLAHIN
Attorneys at Law
500 Don Gaspar Avenue
Post Office Box 1769
Santa Fe, New Mexico 87501

Jason Kellahin
W. Thomas Kellahin
Karen Aubrey

Telephone 982-4285
Area Code 505

October 19, 1981

Mr. Joe D. Ramey
Oil Conservation Division
P.O. Box 2088
Santa Fe, New Mexico 87501

Case 7426

RE: Phillips Petroleum Company

Dear Joe:

Please find enclosed our application on behalf of Phillips Petroleum Company for the addition of carbon dioxide as an injection substance in the Phillips Pressure Maintenance Project in the East Vacuum Grayburg-San Andres Unit area, Lea County, New Mexico.

This pressure maintenance project was originally approved on January 26, 1979, in Case 6367 by Order R-5897. I believe that case file reflects the Division has copies of all the documents now required by the new Rule 701. Please advise me if you desire us to obtain any other data.

In addition, the application requests approval of the Oil Conservation Division that the subject project is a qualified tertiary oil recovery project under Section 4993 of the Interval Revenue Code.

The Code allows an operator to either obtain approval of the New Mexico Oil Conservation Division as the jurisdictional agency or in the alternative to have a certification from a petroleum engineer. However, in the case of certification by a petroleum engineer the IRS need not issue a ruling. Conversely when approval is obtained from the jurisdictional agency, the IRS must issue a ruling within 180 days of the date he receives the request. Because of the tremendous amount of money to be expended on this project, Phillips is unwilling to rely simply upon a certification by a petroleum engineer and respectfully requests your consideration of this case.

For your information, I have enclosed a copy of the Crude Oil Windfall Tax Act of 1980, and a copy of a recent Texas Railroad Commission Order on this matter, and a copy of a recent article in Oil & Gas Journal on the subject.

We desire a hearing on November 19, 1981, the next available Examiner docket.

Please call me if you have any questions.

Very truly yours,

W. Thomas Kellahin

WTK:jm
cc: Mr. Bill Berry, Phillips Petroleum

STATE OF NEW MEXICO

DEPARTMENT OF ENERGY AND MINERALS

OIL CONSERVATION DIVISION

IN THE MATTER OF THE APPLICATION OF PHILLIPS PETROLEUM COMPANY FOR AMENDMENT TO ORDER R-5897 TO INCLUDE THE INJECTION OF CARBON DIOXIDE, FOR CONVERSION OF EXISTING INJECTORS TO WATER AND CO_2 INJECTION, AND FOR APPROVAL OF THE EAST VACUUM GRAYBURG SAN ANDRES UNIT PROJECT AS A QUALIFIED TERTIARY OIL RECOVERY PROJECT PURSUANT TO THE CRUDE OIL WINDFALL PROFITS TAX ACT.

Case 7426

A P P L I C A T I O N

COMES NOW PHILLIPS PETROLEUM COMPANY, by and through its attorneys, Kellahin & Kellahin, and applies to the New Mexico Oil Conservation Division for an Amendment to Order R-5897 to include the injection of Carbon Dioxide, for conversion of existing injectors to water-CO_2 injection, and for approval of the East Vacuum Grayburg San Andres Unit Project as a qualified tertiary oil recovery project pursuant to the Crude Oil Windfall Profits Tax Act (26 U.S.C. 4993), and in support thereof would show:

1. Applicant is the operator of the East Vacuum Grayburg San Andres Unit Pressure Maintenance Project as approved by the New Mexico Oil Conservation Division in Order R-5897 entered January 16, 1979 and Order R-5871 entered November 27, 1978.

2. In accordance with Division Order R-6702 (Rule 701), applicant has completed and attached Form C-108 for the purpose of amending Order R-5897 (Pressure Maintenance Project) to allow for the injection of carbon dioxide as more fully described therein.

3. That the East Vacuum Grayburg San Andres Unit qualifies as a tertiary oil recovery project pursuant to the Crude Oil Windfall Profits Tax Act of 1980 because:

(a) The Governor of the State of New Mexico has submitted written notification to the Secretary of the Internal Revenue Service that the New Mexico Oil Conservation Division is the jurisdictional agency in a case of an application involving a tertiary recovery project pursuant to 26 USC 4993.

(b) That the Phillips Project, a part of the East Vacuum Grayburg San Andres Unit consisting of approximately 5000 acres more or less, of State lands, located in Lea County, New Mexico and operated as a unit approved by the New Mexico Oil Conservation Division pursuant to Order R-5971 is adequately delineated , all as shown on Exhibit (1) hereto.

(c) That the Vacuum Field was discovered May 5, 1929, by Socony Vacuum Oil Company. Development began in 1939. The first waterflood project in the field began in 1958 by Mobil. The latest flood in the field is the subject East Vacuum Grayburg San Andres Unit operated by Phillips effective December 1, 1978.

(d) That said unit is in the later stages of primary depletion.

(e) That the tertiary recovery project beginning date is after May, 1979.

(f) That carbon dioxide miscible displacement method is a recognized tertiary oil recovery method described in Section 212.78(c) of the Department of Energy Regulations in effect on June 1, 1971.

(g) That the Phillips Unit in the Vacuum San Andres reservoir for the miscible displacement by carbon dioxide injection is well suited as an enhanced recovery process because of the low permeability of the pay and high formation water salinity.

(h) That the estimated increase in primary production from the Phillips Project as a result of pressure maintenance with use of carbon dioxide is 26 million barrels of oil or 10 percent of the original oil in place.

(i) After the reservoir is repressured to approximately 1400 psig by approximately early 1984, Phillips will begin full scale injection of CO_2 into the 45 wells shown as water-alternate-gas (WAG) injectors, Exhibit 1, after the reservoir is repressured to 1400 psig. Injection should be an average of 40 MMSCFPD into half of the total WAG injectors at any given time. The injection period will be for six months, with rotation to the other half of the injectors every six months. The WAG ratio would then be near 5:4 (reservoir barrels water per reservoir barrel gas).

(j) That the project will affect all of the approximately 5000 acre area shown on Exhibit (1) and more fully described as follows:

Township 17 South Range 35 East, NMPM
Section 26: all
Section 27: all
Section 28: all
Section 29: all
Section 31: N/2SE/4 and SE/4SE/4
Section 32: all
Section 33: all
Section 34: N/2; SW/4 and NW/4SE/4

Township 18 South, Range 35 East, NMPM
Section 4: N/2NW/4 and NW/4NE/4
Section 5: N/2 and NW/4SW/4

(k) That completion of pressure maintenance by waterflooding alone is not a necessary prerequisite for carbon dioxide miscible flooding.

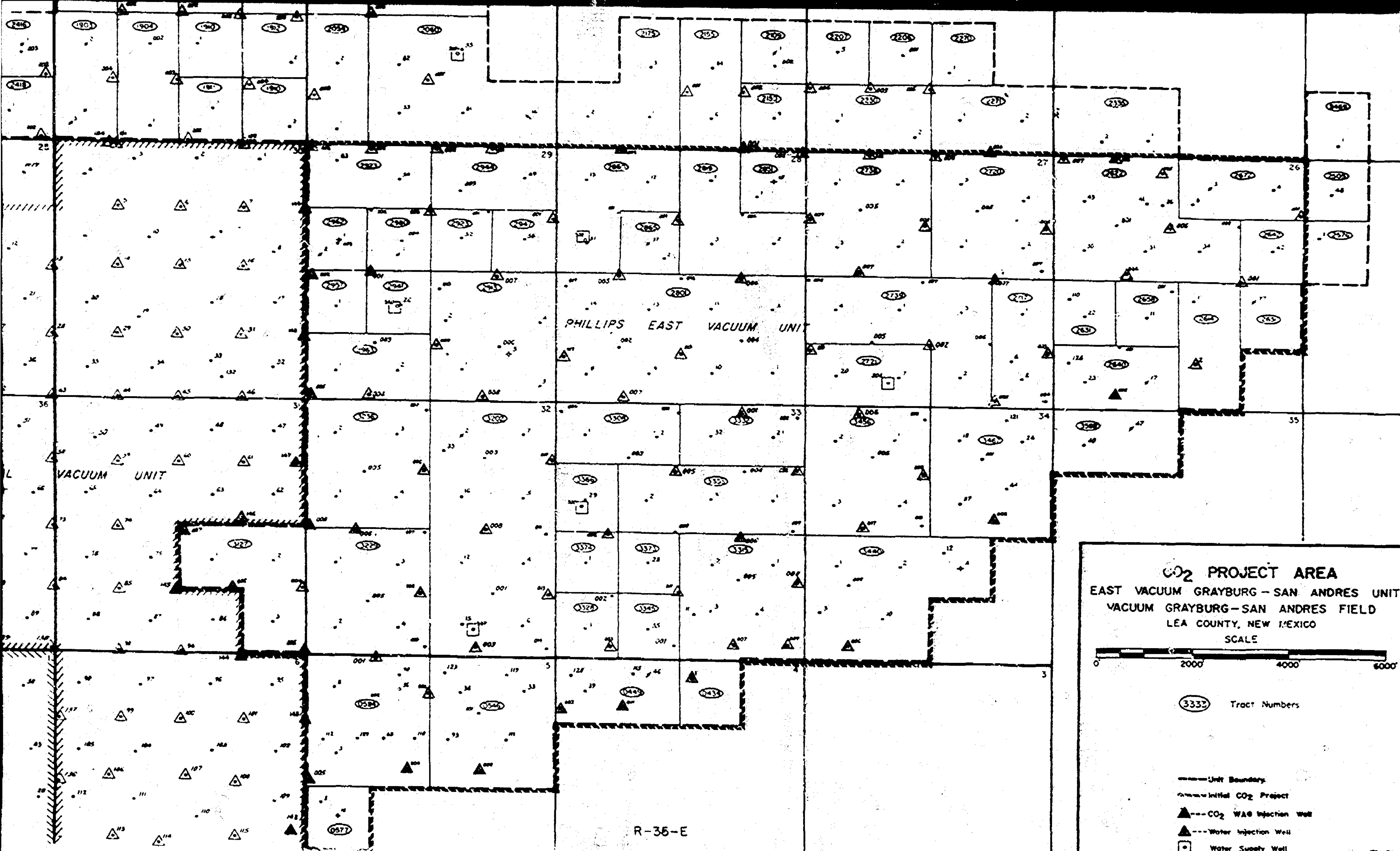
(l) That tertiary recovery projects generally have a higher probability for success if initiated early in a reservoir life.

(m) The project requires that the wells currently used for water injection be converted to water-carbon dioxide injectors.

KELLAHIN & KELLAHIN

By W. Thomas Kellahin

W. Thomas Kellahin
P.O. Box 1769
Santa Fe, New Mexico 87501
(505) 982-4285



PHILLIPS EAST VACUUM UNIT
VACUUM UNIT
R-35-E
CO2 PROJECT AREA
EAST VACUUM GRAYBURG - SAN ANDRES UNIT
VACUUM GRAYBURG - SAN ANDRES FIELD
LEA COUNTY, NEW MEXICO
SCALE
0 2000' 4000' 6000'
3333 Tract Numbers
Unit Boundary
Initial CO2 Project
CO2 WAG Injection Well
Water Injection Well
Water Supply Well

FIG. 1

ENERGY AND MINERALS DEPARTMENT

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87501

Revised 7-1-81

APPLICATION FOR AUTHORIZATION TO INJECT

I. Purpose: /_/ Secondary Recovery /X/ Pressure Maintenance /_/ Disposal /_/ Storage
Application qualifies for administrative approval? /_/ yes /X/ no

II. Operator: Phillips Petroleum Company

Address: Box 1967, Houston, Texas 77001

Contact party: W. B. "Bill" Berry Phone: (713) 669-2104

III. Well data: Complete the data required on the reverse side of this form for each well proposed for injection. Additional sheets may be attached if necessary.

IV. Is this an expansion of an existing project? /X/ yes /_/ no
If yes, give the Division order number authorizing the project R-5897.

V. Attach a map that identifies all wells and leases within two miles of any proposed injection well with a one-half mile radius circle drawn around each proposed injection well. This circle identifies the well's area of review.

VI. Attach a tabulation of data on all wells of public record within the area of review which penetrate the proposed injection zone. Such data shall include a description of each well's type, construction, date drilled, location, depth, record of completion, and a schematic of any plugged well illustrating all plugging detail.

VII. Attach data on the proposed operation, including:

1. Proposed average and maximum daily rate and volume of fluids to be injected;
2. Whether the system is open or closed;
3. Proposed average and maximum injection pressure;
4. Sources and an appropriate analysis of injection fluid and compatibility with the receiving formation if other than reinjected produced water; and
5. If injection is for disposal purposes into a zone not productive of oil or gas at or within one mile of the proposed well, attach a chemical analysis of the disposal zone formation water (may be measured or inferred from existing literature, studies, nearby wells, etc.).

VIII. Attach appropriate geological data on the injection zone including appropriate lithologic detail, geological name, thickness, and depth. Give the geologic name, and depth to bottom of all underground sources of drinking water (aquifers containing waters with total dissolved solids concentrations of 10,000 mg/l or less) overlying the proposed injection zone as well as any such source known to be immediately underlying the injection interval.

IX. Describe the proposed stimulation program, if any.

X. Attach appropriate logging and test data on the well. (If well logs have been filed with the Division they need not be resubmitted.)

XI. Attach a chemical analysis of fresh water from two or more fresh water wells (if available and producing) within one mile of any injection or disposal well showing location of wells and dates samples were taken.

XII. Applicants for disposal wells must make an affirmative statement that they have examined available geologic and engineering data and find no evidence of open faults or any other hydrologic connection between the disposal zone and any underground source of drinking water.

XIII. Applicants must complete the "Proof of Notice" section on the reverse side of this form.

XIV. Certification

I hereby certify that the information submitted with this application is true and correct to the best of my knowledge and belief.

Name: W. Thomas Kellahin Title Attorney

Signature: W. T. Kellahin Date: October 20, 1981

* If the information required under Sections VI, VIII, X, and XI above has been previously submitted, it need not be duplicated and resubmitted. Please show the date and circumstance of the earlier submittal. Submitted Oct 25, 1978, Hearing Case 6367 (R-5897)

DISTRIBUTION: Original and one copy to Santa Fe with one copy to the appropriate Division District office.

XIII. WELL DATA

A. The following well data must be submitted for each injection well covered by this application. The data must be both in tabular and schematic form and shall include:

(1) Lease name; Well No.; location by Section, Township, and Range; and footage location within the section.

(2) Each casing string used with its size, setting depth, sacks of cement used, hole size, top of cement, and how such top was determined.

(3) A description of the tubing to be used including its size, lining material, and setting depth.

(4) The name, model, and setting depth of the packer used or a description of any other seal system or assembly used.

Division District offices have supplies of Well Data Sheets which may be used or which may be used as models for this purpose. Applicants for several identical wells may submit a "typical data sheet" rather than submitting the data for each well.

B. The following must be submitted for each injection well covered by this application. All items must be addressed for the initial well. Responses for additional wells need be shown only when different. Information shown on schematics need not be repeated.

(1) The name of the injection formation and, if applicable, the field or pool name.

(2) The injection interval and whether it is perforated or open-hole.

(3) State if the well was drilled for injection or, if not, the original purpose of the well.

(4) Give the depths of any other perforated intervals and detail on the sacks of cement or bridge plugs used to seal off such perforations.

(5) Give the depth to and name of the next higher and next lower oil or gas zone in the area of the well, if any.

XIV. PROOF OF NOTICE

All applicants must furnish proof that a copy of the application has been furnished, by certified or registered mail, to the owner of the surface of the land on which the well is to be located and to each leasehold operator within one-half mile of the well location.

Where an application is subject to administrative approval, a proof of publication must be submitted. Such proof shall consist of a copy of the legal advertisement which was published in the county in which the well is located. The contents of such advertisement must include:

(1) The name, address, phone number, and contact party for the applicant;

(2) the intended purpose of the injection well; with the exact location of single wells or the section, township, and range location of multiple wells;

(3) the formation name and depth with expected maximum injection rates and pressures; and

(4) a notation that interested parties must file objections or requests for hearing with the Oil Conservation Division, P. O. Box 2088, Santa Fe, New Mexico 87501 within 15 days.

NO ACTION WILL BE TAKEN ON THE APPLICATION UNTIL PROPER PROOF OF NOTICE HAS BEEN SUBMITTED.

NOTICE: Surface owners or offset operators must file any objections or requests for hearing of administrative applications within 15 days from the date this application was mailed to them.

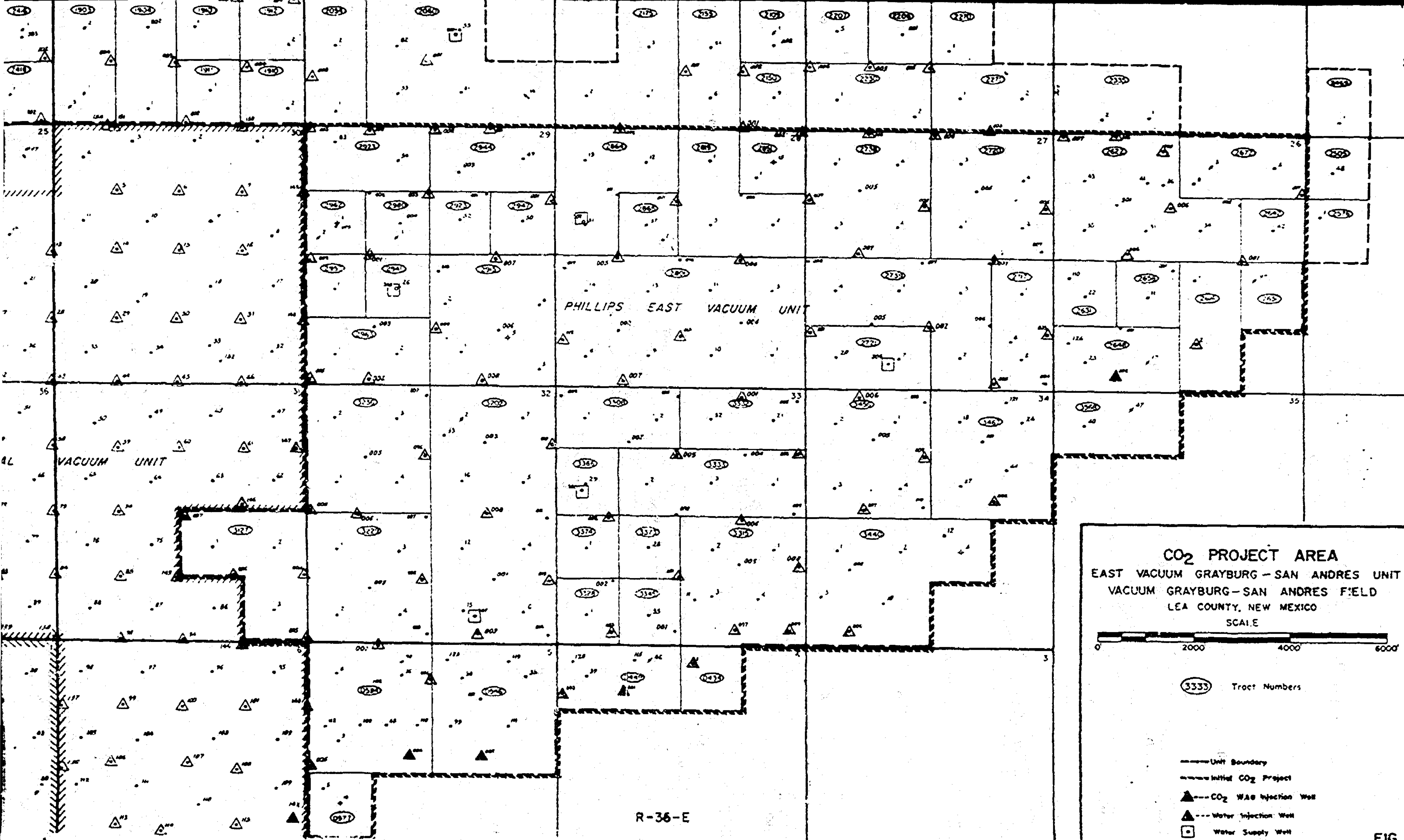

PHILLIPS EAST VACUUM UNIT
VACUUM UNIT
R-36-E
CO2 PROJECT AREA
EAST VACUUM GRAYBURG – SAN ANDRES UNIT
VACUUM GRAYBURG – SAN ANDRES FIELD
LEA COUNTY, NEW MEXICO
SCALE
0
2000
4000
6000'
3333 Tract Numbers
Unit Boundary
Initial CO2 Project
CO2 WAG Injection Well
Water Injection Well
Water Supply Well

FIG.1

Qualifying tertiary recovery projects under the WPT act

R. Sullivan
Railroad Commission of Texas
Austin, Tex.

One area of the Crude Oil Windfall Profits Tax Act of 1980, Qualified Tertiary Oil Recovery Projects, will be discussed here. The Tax Act provides the lowest *tax rate of 30% on* [illegible].

Discussion of the incremental tertiary portion of the Tax Act (26 USC 4993) will be followed by different ways of qualifying a project, the Railroad Commission's experience in handling these projects, and some recommendations and a checklist for preparing cases.

Qualified projects. Certification as a qualified tertiary oil recovery project under the Windfall Profits Tax Act entitles an operator to the lowest permissible tax rate of 30%.

The 30% rate applies to the incremental oil production attributable to the tertiary oil recovery project. The certification also accelerates the base level decline, thus freeing up more oil faster for the lower tax treatment.

Incremental tertiary oil is the amount of oil produced in excess of the base level production. The base level production is defined as the average monthly production removed from the property for the six month period prior to March 31, 1979 (October 1, 1978 through March 31, 1979), reduced by 1% for each month after 1978 up to the date the project begins.

After the project beginning date, the base level decreases by 2½% per month.

The accompanying graph shows the tax calculation for a project with a base level production of 900 bo/d and a project beginning date of January 1, 1983. The incremental oil production is allocated pro rata between the tier 1 (70% tax rate) and tier 2 (60% tax rate) oil production from the project.

In order to be certified the tertiary project must be one of the ten projects listed in the June 1979 Department of Energy, Energy Regulations, 10 CFR 212.78(c). The June 1979 Energy Regulations list the following projects as qualifying:

1. Miscible fluid displacement
2. Steam drive injection
3. Microemulsion flooding
4. In situ combustion
5. Polymer augmented waterflooding
6. Cyclic steam injection
7. Alkaline flooding
8. *Carbonate waterflooding*
9. Immiscible carbon dioxide displacement
10. Any other method approved by the Secretary of IRS

The Energy Regulations in effect in June 1979 were amended by DOE on October 1, 1979. The Windfall Profits Tax Act, however, ties tertiary projects to the June 1979 regulations.

There is considerable doubt as to whether the June 1979 or October 1979 regulations will be followed. Generally, the October 1979 regulations are more detailed than the June 1979 regulations. The accompanying inset box gives a side by side comparison of the two sets of Energy Regulations.

One important note is that the October regulations change "immiscible carbon dioxide displacement" to "immiscible gas displacement." This could be important if IRS feels constrained to follow the June 1979 Energy Regulations exclusively.

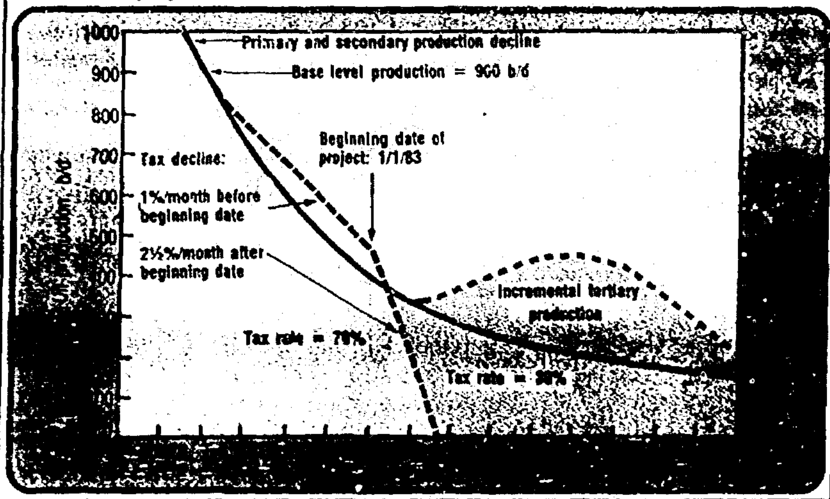
The tenth method listed leaves *some flexibility* in the system for new types of projects. This will require an operator to request from the Secretary of the Internal Revenue Service a "revenue ruling" that the new project qualifies as an enhanced oil recovery technique.

In addition to fitting within one of the categories listed above, several other items have to be proved. First, the process must be applied in accordance with "sound engineering" principles and must "be expected to result in more than an insignificant increase in the amount of crude oil which will ultimately be recovered" (26 U.S.C. 4993).

Whether a project is expected to recover more than an insignificant amount of crude oil is a facts-and-circumstances determination made in each case.

One very important point is that, even though it does not say so anywhere in the statute, the IRS expects an explanation anytime an operator goes directly from primary production to a tertiary project.

Tertiary project tax calculation



An operator is expected to show that the "more than insignificant" amount of production attributable to the tertiary project would occur over a secondary process. Therefore an operator should compare expected tertiary recovery with expected recovery from primary and secondary means. The fact that a field is not amenable to secondary methods or that secondary methods would destroy the potential use of tertiary methods would seem to be satisfactory reasons for going directly from primary to tertiary production.

The Commission has heard two cases where the project goes directly from primary to tertiary. These are Gulf's application in the Kurten (Woodbine) Field and Coastal Oil and Gas' application in the Panhandle (Red Cave) Field. The two cases are cited later in this article.

Second, the project beginning date must be after May 1979. The project beginning date is defined as the later of the date on which tertiary injection begins or the date the project is certified.

The project can be certified by DOE as a qualified tertiary enhanced recovery project under DOE regulations for front-end costs or can be self-certified by a petroleum engineer or certified by the jurisdictional agency under 4993(c)(2)(D) of the Windfall Profits Tax Act for the lower tax rate. The Railroad Commission has been designated as the Texas jurisdictional agency.

Third, the property affected by the project must be clearly delineated. If a pilot project or only a portion of a field is involved in the certification, the operator must show the area th[illegible] project will affect. Only productio[illegible] from the wells affected will qualify fo[illegible] the lower tax.

When a whole field is to be cert[illegible]fied, injection wells should b[illegible] planned so that there is no questi[illegible] that the whole field will be affected[illegible]

Finally, the Tax Act treats a signifi[illegible]cant expansion of an existing projec[illegible] as a separate project. (See ARCO'[illegible] application in the Block 31 (Devon[illegible]ian) Field, Crane County, Tex., cite[illegible] below.)

The question of what is a significan[illegible] expansion is again a facts-and-cir[illegible]cumstances determination made i[illegible] each case. Operators are required t[illegible] file periodic certifications that the pro[illegible]ject still continues to qualify. Th[illegible] requirements for this filing have no[illegible] yet been published.

[illegible] tertiary enhanced oil rec[illegible]o[illegible]

1. [illegible] ent, i.e., an oil displacement [illegible] in which gas or alcohol is injected [illegible] reservoir at pressure levels such [illegible] gas or alcohol and reservoir oil [illegible] process may include the [illegible] subsequent injection of [illegible] may be natural gas [illegible] liquefied petroleum gas [illegible] carbon dioxide [illegible] cycling, i.e., gas injection into gas condensate reservoirs, is not a miscible fluid displacement technique nor a tertiary enhanced recovery technique within the meaning of this section.

2. Steam Drive Injection, i.e., the continuous injection of steam into one set of wells (injection wells) or other injection source to effect oil displacement toward and production from a second set of wells (production wells).

3. Microemulsion, or micellar/emulsion flooding, i.e., an augmented water-flooding technique in which a surfactant system is injected in order to enhance oil displacement toward producing wells. A surfactant system normally includes a surfactant, hydrocarbons, cosurfactant, an electrolyte and water, and polymers for mobility control.

4. In Situ Combustion, i.e., combustion of oil in the reservoir sustained by continuous air injection, to displace unburned oil toward producing wells.

5. Polymer-Augmented Waterflooding, i.e., augmented [illegible]y[illegible] [illegible]al and w[illegible]

6. Cyclic [illegible]at[illegible]ing injection of [illegible] with condensed [illegible]ls.

7. [illegible] an augmented [illegible] the water is made [illegible] the addi[illegible]

8. Carbon Dioxide Augmented Waterflooding, i.e., injection of carbonated water or water and carbon dioxide to increase waterflood efficiency.

9. Immiscible Carbon Dioxide Displacement, i.e., injection of carbon dioxide into an oil reservoir to effect oil displacement under conditions in which miscibility with reservoir oil is not obtained.

10. Not defined.

Amended regulations effective October 1, 1979

1. Miscible Fluid Displacement means an oil displacement process in which fluid is injected into an oil reservoir at pressure levels such tha[illegible] the injected fluid and [illegible] oil [illegible] miscible. The process may [illegible] alterna[illegible]ing, or [illegible] injecte[illegible] fluid measured [illegible] and pres[illegible]sure must, with reasonable expectations, be mor[illegible] than 10 percent [illegible] volum[illegible] being [illegible]ells. G[illegible]

This filing is to insure that the operator receives the tax benefit only while the project is ongoing.

There are two ways to certify a project under the Tax Act. The first is to have a petroleum engineer certify the project and the second is to have the jurisdictional agency make the certification. There are advantages to each method but the author believes jurisdictional agency certification to be superior for the reasons discussed below.

When the jurisdictional agency certifies a project, it is presumed valid [26 USC 4993(d)(6)]. This presumption does not extend to petroleum engineer certified projects. The jurisdictional agency determination can only be overturned if there is not substantial evidence on the record to support the certification or if additional evidence not in the record shows that the project does not qualify.

The final advantage to the jurisdictional agency certification is that an operator can submit the certification with the evidence submitted to the agency to the Secretary of IRS and request a ruling that the project qualifies. The Secretary of IRS has 180 days to rule on the request.

Once approved by the Secretary of IRS, possible liability for back taxes from a future audit is cut off. Of course, if the project should cease to qualify at a future point, the Secretary's approval will also cease.

Texas certifications. The Railroad Commission of Texas has heard several different types of tertiary certification cases to date. Table 1 is a list of the cases and type of tertiary process involved.

Preparing cases. [illegible] preparing cases for presentation before the jurisdictional agency, an operator should come fully prepared. The operator should review the statute and make sure that he has covered all the applicable points.

Finally, an operator should be sure the proposed project uses a method that is described in both the Department of Energy, Energy Regulations in effect in June 1979 and the Energy Regulations of October 1, 1979.

With the potential tax liability that could be involved, an operator should fully comply with all aspects of the tax and regulations.

The following is a checklist of the minimum filing requirements for applications to the Railroad Commission for certification of tertiary recovery projects pursuant to the Windfall Prof-

cycling, i.e., gas injection into gas condensate reservoirs, is not a miscible fluid displacement technique nor a tertiary/enhanced recovery technique.

2. Conve[illegible] Drive Injection means the conti[illegible] at least 50% quality steam [illegible] into one set of wells (injection [illegible] displacements toward and pro[illegible] second set of wells (production wel[illegible] may include the prior, concu[illegible] quent injection of wate[illegible] fluids into any portion[illegible] recovery and confo[illegible]

3. Mic[illegible] micellar/emulsion) Flooding means [illegible] waterflooding technique in [illegible] system is injected in order [illegible] toward producing [illegible] system normally includes a [illegible] cosurfactant, an electrolyte [illegible] polymers for mobility contro[illegible] size of the micellar slu[illegible] polymers and other no[illegible] must be more than 3[illegible] active surfactan[illegible] concen[illegible] volum[illegible]

4. [illegible] combustion of oil in [illegible] injec[illegible] producing [illegible] combustion must be intended to continue until at least 15 percent of the reservoir volume being served by the injection well or wells has been burned. The process may include the concurrent, alternating, or subsequent injection of water.

5. Polymer augmented [illegible] means augmented waterflooding in which polymers are injected with the water to improve [illegible] and vertical sweep efficiency.

6. Cyclic Steam Injection means the alternating injection of at least 50% quality steam (surface conditions) and production of oil with condensed steam from the same well or wells.

7. Alkaline (or caustic) Flooding means an augmented waterflooding technique in which the water is made chemically basic as a result of the addition of alkali metals. The concentration and size of the alkaline slug must be at least 500 ppm-PV for the alkaline concentration multiplied by the pore volume of the alkaline slug.

8. Not defined.

9. Immiscible Gas Displacement means injection of non-hydrocarbon gas into an oil reservoir to effect oil displacement under conditions in which miscibility with reservoir oil is not obtained. The process may include the concurrent, alternating [illegible] injection [illegible] injected fluid measured at reservoir temp[illegible] and pressure must, with reasonable expectation, be more than 10 percent of the reservoir pore volume being served by the injection well or wells.

10. Enhanced Heavy Oil Recovery Technique means any technique for the recovery of crude oil with a gravity less than 16° API.

Table 1

Texas certification cases

Docket no.	Date heard	Applicant	Field and county	Type of project
[illegible]	[illegible]	[illegible]	[illegible]	Miscible gas [illegible]
8-76,022	12-8-80	American Petrofina	[illegible] Southeast Unit, Mitchell County	Polymer augmented waterflood
10-76,032	12-9-80	Coastal Oil & Gas	Panhandle (Red Cave) Field, Potter County	Miscible gas/alkaline flood
[illegible]	12-17-80	[illegible]	[illegible] Gray County	Polymer augmented waterflood
8-76,155	1-13-81	Southland Royalty	McElroy Field, Upton and Crane Counties	

[illegible] yet certified [illegible] under staff review or [illegible]

The author...

Sullivan

Brian R. Sullivan is a legal examiner for the Railroad Commission of Texas. Previously, he was a law clerk with the Austin, Tex., law firm of Scott, Douglass & Keeton. He graduated from the University of Texas law school in May 1979 and also received a BS degree (with honors) in petroleum engineering from the University of Texas in 1976. Sullivan is a past SPE-AIME student chapter president and a student member of the American Bar Association's Natural Resources Law Section. Sullivan has worked as a petroleum engineer for Amoco Production Co. in Corpus Christi, Tex., and for Max F. Powell, Consulting Petroleum Engineer, in Austin.

it Tax Act.

1. A clear description of the property or portion of property which will be affected by the tertiary recovery program.

2. The beginning date of the project (date injection will commence).

3. A description of the type of tertiary recovery method to be used: (a) It must be one of ten methods listed in the Federal Energy Regulations of June 1979 or a type which is approved by the Secretary of the Treasury. (For a description of the methods, see 10 CFR 212.78); (b) A description of any secondary or tertiary project used on the property in the past; and (c) The history and projection of the tertiary process—pilot flood history, past development, planned development.

4. An estimate of the recoverable reserves: (a) without the tertiary project; and (b) with the tertiary project.

5. The production history of the property: (a) Past production; (b) Future production projected without the tertiary project and with the tertiary project.

6. Characteristics of the formation field, including: (a) name of the field; (b) depth; (c) lithology; (d) thickness; (e) porosity; (f) permeability; (g) reservoir pressure history; and (h) any other relevant geological data.

7. A description of how these geological and engineering factors were taken into account in developing the program.

Recommendations. It is recommended that all operators obtain a jurisdictional agency certification of their projects. The jurisdictional agency certification carries a presumption of validity that petroleum engineer certifications do not carry.

After jurisdictional agency certification an operator should request a ruling from IRS that the project qualifies. This insures that an operator will not be liable for back taxes from a future audit.

Acknowledgements. The following people have contributed their ideas, help, editing, and criticisms to this article, for which I am grateful: Deena Lyssy, Susan Kovar, Mike McElroy, John Camp, Sandy Buch, Woody Ervin, and Kenny Helgren. •

Equilibrium

R. N. Maddox
J. H. Erbar
Oklahoma State University
Stillwater, Okla.

Prediction methods for thermodynamic properties may be classified as either single or split equations of state.[1] The single equation of state uses the same equation to predict properties of both the vapor and the liquid phase.

The Soave Redlich Kwong[2] (SRK), Peng Robinson[3] (PR), and Benedict Webb Rubin[4, 5] (BWR) are single equations of state. The Chao Seader[6] (CS) is an example of a split equation of state which uses different equations to represent the vapor and liquid phases.

The equations for the SRK are shown in Table 1, those for the CS are shown in Table 2. The relative merits and demerits of each type of equation of state have been summarized by Erbar[1] and are presented in Table 3.

While the split equation of state offers a number of advantages, it tends to suffer from two serious, if not fatal, weaknesses in the hydrocarbon-phase-equilibrium area. The first of these is illustrated in Fig. 1. Peaks or spikes are found in the bubble point curve on the (PT) pressure-temperature diagram at higher pressures on the liquid side of the envelope.

Fig. 2 demonstrates a second kind of behavior. Once again, the two separate equations of state do not come to a common point. As a matter of fact, they may never intersect when an attempt is made to calculate the bubble point-dew point envelope for the mixture.

There are a number of calculational problems that can arise when computer programmed equations of state are used for hydrocarbon phase behavior calculations. Some of the more frequently occuring will be discussed, together with their causes and cures.

All K values equal to 1. A notorious failure with K-value-prediction methods based on a single equation of state is when all K values equal 1. The first time it occurs the engineer/user is usually sent into a state of consternation.

However, in most cases the cause of the problem is quite simple; an

HERBIE
DIANE

STATE OF NEW MEXICO

ENERGY AND MINERALS DEPARTMENT

OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
DIVISION FOR THE PURPOSE OF
CONSIDERING:

CASE NO. 7426
Order No. R-6856

APPLICATION OF PHILLIPS PETROLEUM
COMPANY FOR AMENDMENT OF DIVISION ORDER
NO. R-5897 AND APPROVAL OF A QUALIFIED
TERTIARY OIL RECOVERY PROJECT UNDER THE
CRUDE OIL WINDFALL PROFITS TAX ACT OF
1980, LEA COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 9:00 a.m. on November 19, 1981, at Santa Fe, New Mexico, before Examiner Richard L. Stamets.

NOW, on this ________ day of December, 1981, the Division Director, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the

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NOW, on this ________ day of December, 1981, the Division Director, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the premises,

FINDS:

(1) That due public notice having been given as required by law, the Division has jurisdiction of this cause and the subject matter thereof.

(2) That the applicant, Phillips Petroleum Company, seeks the Amendment of Division Order No. R-5897, to include the injection of carbon dioxide in its previously authorized pressure maintenance project in the East Vacuum Grayburg-San Andres Unit, for conversion of existing injectors to water/carbon dioxide injection, and for the approval of a portion of the East Vacuum Grayburg-San Andres Unit as a Qualified Tertiary Oil Recovery Project under the Crude Oil Windfall Profits Tax Act of 1980.

(3) That said ~~secondary recovery~~ pressure maintenance project lies within the Vacuum Grayburg-San Andres Pool, Lea County, New Mexico.

(4) That said pool was discovered May 5, 1924, by Socony Vacuum Oil Company, experienced substantial development thereafter with waterflooding being initiated in a project during 1958.

(5) That the Phillips Petroleum Company East Vacuum Unit Pressure Maintenance Project consisting of approximately 7025 acres was approved by said Division Order No. R-5897 on January 16, 1979, and water injection was commenced within said project

during December, 1979.

(6) That the applicant now seeks approval for the injection of carbon dioxide and water into 45 project wells and the designation of a qualifying tertiary recovery project area within said pressure maintenance project.

(7) That the proposed Qualifying Tertiary Project Area (QTP Area) lies wholly within said East Vacuum Unit Pressure Maintenance Project and consists of the following described acreage:

TOWNSHIP 17 SOUTH, RANGE 35 EAST, NMPM

Section 26:	W/2; NE/4; W/2 SE/4; and NE/4 SE/4
Section 27:	All
Section 28:	All
Section 29:	All
Section 31:	N/2 SE/4 and SE/4 SE/4
Section 32:	All
Section 33:	All
Section 34:	N/2; SW/4; and NW/4 SE/4
Section 35:	N/2 NW/4

TOWNSHIP 18 SOUTH, RANGE 35 EAST, NMPM

Section 4:	N/2 NW/4 and NW/4 NE/4
Section 5:	N/2 and NW/4 SW/4

containing 4997 acres more or less.

(8) That the QTP Area is adequately delineated and that the entire area will be affected.

(9) That the New Mexico Oil Conservation Division has been designated by the Governor of the State of New Mexico as the appropriate agency to approve Qualified Tertiary Recovery Projects in New Mexico for purposes of the Crude Oil Windfall Profits Tax Act of 1980.

(10) That the tertiary oil recovery method used in the Phillips QTP Area is a carbon dioxide miscible displacement method which is a recognized tertiary oil recovery method described in Section 212.78(c) of the Department of Energy Regulations in effect in June, 1979.

(11) That the Tertiary Recovery method includes overinjection of voidage with water at maximum rates to achieve a miscibility pressure in the formation.

(12) That slim-tube tests have determined such miscibility pressure to be approximately 1369 psia.

(13) That overinjection began on February 1, 1981, and carbon dioxide injection will begin after miscibility pressure has been achieved.

(14) That under the tertiary recovery method to be used, it is anticipated that the volume of injected carbon dioxide measured at reservoir temperature and pressure will be more than 10 percent of the reservoir pore volume being served by the injection wells.

(15) That because of the geological and reservoir characteristics of the effected reservoir, the QTP Area is well suited for miscible fluid displacement by carbon dioxide as an enhanced recovery process.

(16) That the estimated primary production from the East Vacuum Unit Pressure Maintenance Project Area is 72 million

barrels and that water flooding secondary recovery operations will recover an additional 38 million barrels.

(17) That an estimated ~~twenty-six~~ 26 million ~~(26,000,000)~~ barrels of additional oil (which is 10 percent of the original oil in place within the project area) will be recovered as a result of the tertiary recovery operations, which is more than an insignificant increase in the amount of crude oil which will ultimately be recovered.

(18) That the QTP Area tertiary recovery operations beginning date is after May, 1979.

(19) That the QTP Area tertiary recovery operations beginning date (i.e., the date on which the injection of liquids, gases or other matter begins) was February 1, 1981.

(20) That the proposed tertiary recovery operations within said QTP Area meet all requirements of Section 4993 of the Internal Revenue Code.

(21) That the Phillips QTP Area project is designated in accordance with sound engineering principles.

(22) That the approval of this application will prevent waste, protect correlative rights and promote conservation.

IT IS THEREFORE ORDERED:

(1) That effective December 1, 1981, the Qualifying

Tertiary Recovery Project Area, described in Finding No. (7) of this Order, of the Phillips Petroleum Company East Vacuum Unit Pressure Maintenance Project, Vacuum Grayburg-San Andres Pool, Lea County, New Mexico, is hereby approved as a Qualified Tertiary Recovery Project under the Crude Oil Windfall Profits Tax Act of 1980.

(2) That the applicant, Phillips Petroleum Company, is hereby authorized to inject water and carbon dioxide into the 45 wells listed on Exhibit "A" attached to this Order.

(3) That Order No. R-5897 is hereby amended to authorize injection of carbon dioxide up to an average maximum bottom hole pressure of 3150 psi.

(4) That jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

JOE D. RAMEY,
Director

S E A L

CASE 7426
ORDER R-

EXHIBIT A

Approved Water-Alternate-Carbon Dioxide Injectors

Tract 2622 - Well 004
Well 006

Tract 2717 - Well 003
Well 005
Well 007

Tract 2720 - Well 006

Tract 2721 - Well 001
Well 002

Tract 2738 - Well 007
Well 008
Well 009

Tract 2801 - Well 005
Well 006
Well 007
Well 012
Well 015

Tract 2865 - Well 001

Tract 2913 - Well 007
Well 008
Well 009

Tract 2941 - Well 001

Tract 2947 - Well 001

Tract 2963 - Well 004

Tract 2980 - Well 003

Tract 3127 - Well 004

Tract 3202 - Well 008
Well 009
Well 010
Well 013

Tract 3229 - Well 006
Well 008

Tract 3236 - Well 006

Tract 3315 - Well 006
Well 008

Tract 3328 - Well 003

Tract 3332 - Well 001

Tract 3333 - Well 005
Well 006

Tract 3373 - Well 001

Tract 3374 - Well 002

Well 006
Tract 3456 - Well 007
Well 009

Tract 0524 - Well 001
Well 006