Manzano Oil Corporation

P.O. Box 2107
Roswell, New Mexico 88202-2107
(505) 623-1996
FAX (505) 625-2620

July 13, 1993

Case 10796

State of New Mexico
Energy, Minerals and Natural Resources Department
Oil Conservation Commission
Post Office Box 2088-87504
Santa Fe, New Mexico 87504

RECEIVED
JUL 14 1993

Attn: Mr. William J. Lemay, Director

Re: Emergency Order
Manzano Oil Corporation's
Neuhaus "14" Federal #2
660'FNL & 1650'FEL
Section 14, T20S, R35E
Lea County, New Mexico

Dear Mr. Lemay:

Manzano Oil Corporation is currently attempting a completion in the Wolfcamp in the Neuhaus "14" Federal #2. The top of the Wolfcamp pay is 11,354' or -7676' subsea. Total net pay is 120'. A total of 50' will be perforated throughout the total net pay interval.

A drill stem test in this Wolfcamp interval resulted in gas to surface at 2000 MCFGPD on a 3/8" choke with surface pressure of 650 psi. Static bottom hole pressure on both the initial and final shut in pressures was 2128 psi.

The Manzano Neuhaus "14" Federal #2 is the direct south offset to the Marathon Oil Jordan "B" #1, 660'FSL & 1650'FEL of Section 11, T20S, R35E. The Jordan "B" #1 was completed in the Wolfcamp with 38' of perforated interval over a gross net pay of 60'. IPCAOF was 9108 MCFGPD with a GOR of 9900. The extrapolated bottom hole pressure was 3460 psi.

The Jordan "B" #1 began production in February 1992. Cumulative production as of May 1, 1993 is 2,180,628 MCFG, 228,053 barrels of condensate and 65,822 barrels of water. The average daily rate has been 5161 MCFGPD + 539 BCPD + 158 BWPD.

The top of the Wolfcamp pay in the Manzano Neuhaus "14" Federal #2 is 61' higher subsea from the Marathon Jordan "B" #1 and has twice the net pay, 120' versus 60'. The reservoir pressure on the Neuhaus line has been reduced some 1332 psi by production from the Marathon Jordan "B" #1.

State of New Mexico
Energy, Minerals and Natural Resources Department
Oil Conservation Commission
July 13, 1993
Page Two

Not true

Since both wells are equal distance from the lease line, it is obvious that the Neuhaus is being drained by production from the Jordan and correlative rights are not being protected. Therefore, Manzano Oil Corporation requests an emergency order allowing the Neuhaus "14" Federal #2 to produce at one and one-half (1-1/2) the life time average daily rate of the Marathon Jordan "B" #1 until such time after a hearing to determine ratable take from each well to protect correlative rights.

Manzano requests that if there is any penalty applied to the Neuhaus production, that adjustments be applied after the hearing date which is scheduled for August 12, 1993.

Sincerely,

Kenneth Barbe, Jr.

KB:ar

4 Point
Deliverability
Pipeline Pressure

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR

ANITA LOCKWOOD
CABINET SECRETARY

July 21, 1993

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87504
(505) 827-5800

Manzano Oil Corporation
P. O. Box 2107
Roswell, New Mexico 88202-2107

Case 10796

Attention: Kenneth Barbe, Jr.

Re: Manzano Oil Corporation
Newham "14" Federal No. 2
660' FNL and 1650' FEL
Section 14, T20S, R35E
Lea County, New Mexico

Gentlemen:

Your request to produce the subject well is approved as a testing allowable. You can produce the well to gather data for your hearing scheduled for August 12, 1993 but not beyond that date until an order has been issued in the case. Be advised that the gas produced as a testing allowable may have to be made up as a result of the hearing order.

The testing allowable will be 882 Mcf/D which is 1/3 of the calculated Absolute Open Flow of 2647 Mcf/D. This gas must be produced to a pipeline and cannot be vented.

Prior to producing the well you must submit a new C-102 showing the dedicated acreage and producing formation and obtain an approved C-104 from the OCD Hobbs district office.

At the conclusion of the testing period, you must submit a report to my attention, detailing the gas produced during this testing period.

Sincerely,

William J. LeMay
Director

cc: Robert Unger, Marathon

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR

ANITA LOCKWOOD
CABINET SECRETARY

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87504
(505) 827-5800

August 13, 1993

Manzano Oil Corporation
P. O. Box 2107
Roswell, New Mexico 88202-2107

Attention: Kenneth Barbe, Jr.

Re: Manzano Oil Corporation
Newham "14" Federal No. 2
660' FNL and 1650' FEL
Section 14, T20S, R35E
Lea County, New Mexico

Gentlemen:

Your request to produce the subject well has been approved as a testing allowable by correspondence dated July 21, 1993. You were allowed to produce the well to gather data for your hearing originally scheduled for August 12, 1993 but rescheduled for August 19, 1993. You were advised that the gas produced as a testing allowable may have to be made up as a result of the hearing order.

The testing allowable was 882 Mcf/D which was 1/3 of the calculated Absolute Open Flow of 2647 Mcf/D. This gas was to be produced into a pipeline and not vented. At the time you submitted your original CAOF you indicated that there was a problem with this measurement because of fluid in the hole. We are is receipt of your new test indicating a CAOF of 35,240 MCFGPD. Effective today you may produce up to 1/3 of this amount being 11,740 MCFGPD for testing purposes only. All other provisions of my July 21, 1993 letter to you remain in effect.

Sincerely,

William J. LeMay, Director

WJL/sl

cc: Robert Unger, Marathon

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Roswell District Office
1717 West Second Street
Roswell, New Mexico 88201-2019

IN REPLY REFER TO:

3100.2 (065)

AUG 17 1993

Director, Oil Conservation Division
New Mexico Energy, Minerals and Natural Resources Department
P. O. Box 2088
State Land Office Building
Santa Fe, New Mexico 87504

Dear Sir:

This letter provides comments from the Bureau of Land Management (BLM) regarding the disposition of case number 10796, which is scheduled for hearing on Thursday, August 19, 1993. This hearing concerns application by Manzano Oil Corporation for an unorthodox gas well location in section 14, T. 20 S., R. 35 E., Lea County, New Mexico. The affected well is on federal oil and gas lease NM-16835.

Manzano has recently completed the Neuhaus Federal "14" No. 2 well at 660'/FNL and 1650'/FEL within section 14. It is completed in the Wolfcamp formation, with perforations from 11,354 - 11,485 feet. It is currently producing at an allowable rate of 1/3 of the tested Absolute Open Flow. Manzano have determined that this Wolfcamp reservoir is limited in extent, and occurs within the NE/4 of section 14 and the SE/4 of section 11. Our geologic staff has examined maps prepared by Manzano that will be presented at the hearing and find that they are valid interpretations of the data presented. Most of the reservoir volume is mapped in section 14. Based on the maps presented, it appears that these two wells will fully develop the reservoir.

According to Manzano, the operators of the Jordan "B" No. 1 well at 660'/FSL and 1980'/FEL, section 11, plan to protest Manzano's application for unorthodox location and will seek to decrease the authorized allowable production. The Jordan "B" No. 1 is also producing from the Wolfcamp through perforations at 11,426 - 11,478; the net pay in the Jordan "B: No. 1 well is correlative with the net pay in the Neuhaus Federal "14" No. 2 well, but is considerably thinner. Manzano has shown us pressure transient data, radial flow data, and drainage encroachment maps based on greater than four per cent porosity which indicate that physical drainage of gas from Manzano's Federal lease has been occurring, and will continue to occur if the authorized allowable production is reduced.

The Federal Government, as lessor, has the responsibility of protecting the Public's royalty interests. We urge the Oil Conservation Division to allocate allowable production between these wells through some allocation schedule, cooperative plan, agreement, or designated allowable per well that will reflect actual reservoir parameters, including the estimated volume of the reservoir in place on each lease.

Should you wish to discuss this further, please contact Jim Pettengill at (505) 627-0272.

Sincerely,

for Leslie M. Cone
District Manager

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR

ANITA LOCKWOOD
CABINET SECRETARY

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87504
(505) 827-5800

August 20, 1993

Manzano Oil Corporation
c/o Campbell, Carr, Berge
& Sheridan, P.A.
P.O. Box 2208
Santa Fe, New Mexico 87504-2208

Attention: Mr. William F. Carr

Re: Neuhaus Federal Well No. 2
Section 14, T-20S, R-35E, NMPM

Dear Mr. Carr:

Please be advised that under the terms and conditions contained within my letter to Manzano Oil Corporation dated August 13, 1993, and, as directed by the Division Examiner at the conclusion of the hearing in Case No. 10796, the Neuhaus Federal Well No. 2 shall be <u>shut-in</u> until further notice of the Division, or until an order is issued approving the unorthodox well location.

Sincerely,

William J. LeMay, Director

WJL/dc

cc: Marathon Oil Co.
c/o W. Thomas Kellahin

Manzano Oil Corporation

P.O. Box 2107
Roswell, New Mexico 88202-2107
(505) 623-1996
FAX (505) 625-2620

August 20, 1993

State of New Mexico
Oil Conservation Division
P.O. Box 2088
Santa Fe, New Mexico 87504

Attn: Mr. Bill LeMay

Re: Neuhaus "14" Federal #2
Lea County, NM

Dear Mr. LeMay:

Enclosed is a detailed report of gas produced on the above referenced well as requested in your letter of July 21, 1993 and subsequent letter of August 13, 1993, whereby you stated that we submit a report to your attention detailing the gas produced during our testing period, which ended August 19, 1993, as stated in your letter.

With regards to condensate production, Manzano was also in compliance with the condensate allowable as authorized by Jerry Sexton on July 20, 1993 (see attached authorization). If you would like a detailed report of the condensate production, please do not hesitate to contact us.

If you have any questions or need anything further, please do not hesitate to give me a call. Thank you for your continued cooperation in this matter.

Sincerely,

Ken Barbe

Kenneth Barbe, Jr.

Production Test Data
Neuhaus "14" Federal #2
Section 14, T20S, R35E
Lea County, New Mexico

Date	Gas Prod MCF	Cum Gas Prod MCF	Cum Allowable 882 MCFPD	Cum Allowable 11,740 MCFPD
Open 8:00 p.m. 7/24/93				
1993 July 25	3,178	3,178	882	
26	3,240	6,418	1,764	
27	3,178	9,596	2,646	
28	3,104	12,700	3,528	
29	3,120	15,820	4,410	
30	3,135	18,955	5,292	
31	3,193	22,148	6,174	
Aug 1	3,227	25,375	7,056	
2	3,272	28,647	7,938	
3	3,306	31,953	8,820	
4	1,815	33,768	9,702	
~~5~~	~~SI~~	~~33,768~~	~~10,584~~	
6	2,885	36,653	11,466	
7	3,984	40,637	12,348	
8	3,988	44,625	13,230	
9	3,931	48,556	14,112	
10	3,955	52,511	14,994	
11	4,021	56,532	15,876	
12	4,084	60,616	16,758	
13	4,134	64,750		28,498
14	4,202	68,952		40,238
15	4,263	73,215		51,978
16	4,321	77,536		63,718
17	4,384	81,920		75,458
18	4,665	86,585		87,198
19	4,896	91,481		98,938

JB

OIL CONSERVATION DIVISION

Hobbs, New Mexico 88240

DISTRICT OFFICE

July Thru
December, 1993
NO. 1052L

SUPPLEMENT TO THE OIL PRORATION SCHEDULE

DATE: 07/20/93

PURPOSE: CONDENSATE ALLOWABLE

Effective 07/14/93, a condensate allowable of 6000 barrels per month is hereby assigned to the

MANZANO OIL CORP.,

NEUHAUS "14" FEDERAL, 2 - B, 14-20-35,

LEA UNDESIGNATED;WOLFCAMP (GAS) Pool.

July Total	6000 Barrels
August Total	6000 Barrels
September Total	6000 Barrels

OIL CONSERVATION DIVISION

Jerry Sexton

DISTRICT SUPERVISOR

JS:nm

MANZANO OIL CORP.

KSV

GPM

DISTRIBUTION: WHITE-OPERATOR,GREEN-TRANSPORTER,CANARY-OCC SANTA FE,PINK-OFFICE COPY,GOLDENROD-EXTRA COPY

DIVISION

'93 AUG 9 23

Manzano Oil Corporation

P.O. Box 2107
Roswell, New Mexico 88202-2107
(505) 623-1996
FAX (505) 625-2620

August 24, 1993

State of New Mexico
Oil Conservation Division
P.O. Box 2088
Santa Fe, New Mexico 87504

Attn: Mr. David Catanach

Re: Condensate Production
Neuhaus "14" Federal #2
Lea County, New Mexico

Dear Mr. Catanach:

Pursuant to your request directed to Mr. Bill Carr regarding the condensate production from the Neuhaus "14" Federal #2, I have enclosed a detailed report of the production as was approved by the OCD. Manzano was originally granted a condensate allowable of 6,000 barrels for the months of July, August and September, respectively. After our corrected four point test was submitted, Manzano was granted a testing allowable of up to 11,740 MCFPD, which is reflected from August 13th to August 19th. On August 19th, the hearing date, the well was shut-in as was requested by Mr. LeMay's original letter in which an allowable was granted until the hearing date.

If you have any questions, please do not hesitate to call. Thank you for your prompt attention to this matter.

Sincerely,

Kenneth Barbe, Jr.

KB:ar

cc: Bill Carr

Production Test Data
Neuhaus "14" Federal #2
Section 14, T20S, R35E
Lea County, New Mexico

Date	BCPD	Cum Condensate Bbls	Cum Condensate Allowable @ 6000 B/M	
Open 8:00 p.m. 7/24/93				
1993 July 25	563	563		
26	556	1,119		
27	597	1,716		
28	553	2,269		
29	528	2,797		
30	596	3,393		
31	656	4,049	6,000	
Aug 1	542	4,591		
2	619	5,210		
3	539	5,749		
4	412	6,161		
5	SI	6,161		
6	520	6,681		
7	687	7,368		
8	680	8,048		
9	701	8,749		
10	728	9,477		
11	643	10,120		
12	579	10,699	12,000	
13	538	11,237		Gas Allowable
14	682	11,919		Increased to
15	633	12,552		11,740 MCFPD
16	570	13,122		
17	693	13,815		
18	677	14,492		
19	660	15,152		

Manzano Oil Corporation

P.O. Box 2107
Roswell, New Mexico 88202-2107
(505) 623-1996
FAX# (505)-625-2620

TO: David Catanach / NMOCD

FROM: [illegible]

DATE: 8/24/93

NUMBER OF PAGES (including this cover sheet) 3

MESSAGE:

527-5741

Manzano Oil Corporation

P.O. Box 2107
Roswell, New Mexico 88202-2107
(505) 623-1996
FAX (505) 625-2620

August 24, 1993

State of New Mexico
Oil Conservation Division
P.O. Box 2088
Santa Fe, New Mexico 87504

Attn: Mr. David Catanach

Re: Condensate Production
Neuhaus "14" Federal #2
Lea County, New Mexico

Dear Mr. Catanach:

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If you have any questions, please do not hesitate to call. Thank

Sincerely,

Kenneth Barbe, Jr.

KB:ar

cc: Bill Carr

Production Test Data
Neuhaus "14" Federal #2
Section 14, T20S, R35E
Lea County, New Mexico

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15	633	12,552		11,740 MCFPD
16	570	13,122		
17	693	13,815		
18	677	14,492		
19	660	15,152		

CAMPBELL, CARR, BERGE
& SHERIDAN, P.A.
LAWYERS

MICHAEL B. CAMPBELL
WILLIAM F. CARR
BRADFORD C. BERGE
MARK F. SHERIDAN
WILLIAM P. SLATTERY

PATRICIA A. MATTHEWS
MICHAEL H. FELDEWERT
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SANTA FE, NEW MEXICO 87504-2208
TELEPHONE: (505) 988-4421
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September 7, 1993

HAND-DELIVERED

RECEIVED
SEP 7 1993
OIL CONSERVATION

Mr. David R. Catanach
Hearing Examiner
Oil Conservation Division
New Mexico Department of Energy,
Minerals and Natural Resources
State Land Office Building
Santa Fe, New Mexico 87503

Re: Case No 10796: Application of Manzano Oil Corporation for an Unorthodox Gas Well Location, Lea County, New Mexico

Dear Mr. Catanach:

Pursuant to your request of August 19, 1993, I am enclosing for your consideration the proposed Order of Manzano Oil Corporation in the above-referenced case.

If you need anything further from Manzano to proceed with your consideration of this application, please advise.

Very truly yours,

William F. Carr

WILLIAM F. CARR
WFC:mlh
Enclosure
cc: Mr. Ken Barbe (w/enclosure)
W. Thomas Kellahin, Esq. (w/enclosure)

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

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

Case No. 10796
Order No. R-______

APPLICATION OF MANZANO OIL CORPORATION FOR AN UNORTHODOX GAS WELL LOCATION, LEA COUNTY, NEW MEXICO.

MANZANO OIL CORPORATION'S PROPOSED
ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 1:00 p.m. on August 19, 1993, at Santa Fe, New Mexico, before Examiner David R. Catanach.

NOW, on this _____ day of September, 1993, the Division Director, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the premises,

FINDS THAT:

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

(2) The applicant, Manzano Oil Corporation ("Manzano") seeks approval of an unorthodox gas well location 660 feet from the North line and 1650 feet from the East line (Unit B) of Section 14, Township 20 South, Range 35 East, NMPM, Lea County, New Mexico for its Neuhaus Federal Well No. 2 which has been drilled and completed in the Wolfcamp formation, Lea-Wolfcamp Pool. The E/2 of said Section 14 is dedicated to the well forming a standard 320-acre gas spacing and proration unit.

(3) At the time of the hearing, Marathon Oil Company ("Marathon"), a direct offset operator to the north of the subject acreage and operator of the standard 320-acre gas spacing and proration unit comprising the S/2 of Section 11, Township 20 South, Range 35 East, Lea-Wolfcamp Pool, appeared at these proceedings in objection to this application and tendered witnesses and offered evidence in support of its protest. The S/2 of said Section 11 is currently dedicated to Marathon's Jordan "B" Well No. 1 located 660 feet from the South line and 1980 feet from the East line of Section 11.

(4) Geological evidence presented by both parties indicates that the Lea-Wolfcamp Pool is a reservoir of limited extent which could be drained by either the Manzano Neuhaus Well or the Marathon Jordan "B" No. 1 Well. There are no other producing wells in this pool.

(5) The Marathon Jordan "B" No. 1 Well was drilled in 1984 and completed in the Morrow formation as a commercial producer. In 1991 the well was abandoned in the Morrow, plugged back and completed in the Wolfcamp formation, Lea-Wolfcamp Pool. It first produced from the Wolfcamp formation in January, 1992. The Marathon well produces at a rate of approximately 4000 mcf per day and through May, 1993 had cumulative gas production of more than 2.1 BCF and 221,500 barrels of condensate.

(6) The Manzano Neuhaus Federal No. 2 Well was originally proposed and permitted as an oil test at a standard oil well location for the Strawn formation. This area contains multiple zones with potential for commercial hydrocarbon production and the Wolfcamp production was a factor in selecting this location.

(7) The Manzano and Marathon wells are each set back 660 feet from the common spacing unit boundary between the wells. However, the Manzano well is at an unorthodox location under Division rules because it was unable to reach a voluntary agreement with the owner of the NW/4 of Section 14 for development of this acreage with the N/2 unit and, instead an E/2 spacing unit was dedicated to the well.

(8) The Manzano well was spud on June 3, 1992. After drilling into the Wolfcamp formation, a drill stem test was run which showed an excellent reservoir that had been partially drained. The well was drilled an additional 169 feet and then drilling ceased and the well was completed in the Wolfcamp formation because (a) drainage was occurring in the Wolfcamp (initial reservoir pressure of approximately 3600 pounds had declined to an initial pressure of 2,129 pounds in the Manzano well); (b) the wellbore was overbalanced by 3,300 pounds; (c) the reservoir had high permeability and had already undergone significant skin damage; (d) the well was taking fluid; and (e) continued drilling could cause extensive damage to the Wolfcamp reservoir.

(9) Manzano sought and was given permission by the Division Director to produce a temporary testing allowable pending a hearing to obtain approval of the well's location. Manzano was required to provide daily production data to the Division at the end of the temporary testing allowable period. This period ended on August 16, 1993 and the required data was provided to the Division on August 20 and 24, 1993.

(10) Both Manzano and Marathon presented geologic and engineering evidence in this case.

(11) The geologic evidence presented by Manzano shows:

(a) the Wolfcamp formation in the Lea-Wolfcamp Pool is a carbonate buildup like the Osudo-Wolfcamp-Southwest Pool to the South which is a small localized pod feature which flanks off quickly;

(b) the Middle Wolfcamp pay interval thickens substantially from 63 feet in the Marathon well to 131 feet in the Manzano well. (Manzano Exhibit 2, Tr. p. 13).; and

(c) There is more than twice the pay zone in the Manzano well than in the Marathon well. [(a) clean dolomite porosity greater than 4%: 115 feet v. 39 feet. (Manzano Exhibits 2, 3 and 4, Tr. at 14, 18); (b) net porosity greater than 4%: 119 feet v. 62 feet. (Manzano Exhibits 2 and 5, Tr. at 15, 19); (c) net porosity feet in each well (no cut off): 11.6 feet v. 5.3 feet. (Manzano Exhibits 2 and 6, Tr. at 15, 20); and (d) net hydrocarbon feet in each well: 10.3 feet v. 4.6 feet. (Manzano Exhibits 2 and 7, Tr. at 15, 21)].

(12) The geologic evidence presented by Marathon shows:

(a) the Wolfcamp formation in the Lea-Wolfcamp Pool is a debris flow deposit;

(b) that this formation extends to the north and includes the Jordan "B" No. 2 Well: an abandoned well in the Middle Wolfcamp located in Unit G of Section 11;

(c) there are 39 feet of clean porosity greater than 4% in the Marathon well and 90 feet in the Manzano well. (Marathon dropped 10 feet of pay within the main body of the pay interval and cut the lower 15 feet of clean dolomite porosity in the Manzano well even though the porosity logs show greater than 4% porosity and the resistivity log shows a profile which is indicative of reservoir quality rock in this section). (Marathon Exhibit 6, L. Gholston, Tr. at 91, 102-103).; and

(d) a thickening of the pay to the east of the Marathon well in the SE/4 of Section 11 based on broad contour spacing on the Marathon acreage, tight contour spacing on the Manzano acreage and no control points to support this interpretation. (Marathon Exhibit 6).

(13) The engineering data presented by Manzano shows:

(a) there are approximately 9,942 net acre feet in this reservoir (Manzano Exhibit 10, D. Brown, Tr. at 53) which confirms the geologic interpretation of 10,070 acre feet. (Manzano Exhibit 12).

(b) the Manzano well would have to produce at a rate almost twice that of the Marathon well to prevent net drainage from the Manzano tract to the Marathon well. (Manzano Exhibit 11, Radial Flow Equation for Compressible Flow, Tr. at 46-47).;

(c) only 21% of the total reservoir acre feet are under the Marathon tract. If the wells produced at equal rates, 2,882 acre feet would be drained from the Manzano tract by the Marathon well and from this point forward, Marathon will produce 50% of the remaining recoverable reserves and 68% of the total recoverable reserves with only 21% of the total acre feet. (Manzano Exhibit 12, Drainage Encroachment Map, Tr. at 57-58).; and

(d) the drainage area from the Marathon well would extend 105 feet across the common lease line between the Manzano and Marathon wells if they produce at equal rates. (Manzano Exhibit 13, Calculated Drainage Area Boundary, Tr. at 60).

(14) Marathon's engineering witness contended the Manzano well has more than twice the deliverability of the Marathon well although data in the records of the Division filed by Marathon show the Marathon well has produced at an average maximum rate of 6,000 mcf per day, a rate comparable to that of the Manzano well and furthermore show Marathon is changing the tubing size in the well to increase its deliverability. Marathon then recommended that the Manzano well be penalized and permitted to produce at a rate equal to only 20% of its deliverability. (See, testimony of R. Tracy, Tr. at 124-125, Marathon Exhibits 9 through 16).

(15) Although there is general disagreement between the two parties regarding the exact shape and thickness of the overall reservoir characteristics, the evidence presented in this case by Manzano and Marathon is generally in agreement that:

(a) the Wolfcamp formation in the Lea-Wolfcamp Pool is a small localized geologic feature with the productive reservoir limited to the SE/4 of Section 11 and the NE/4 of Section 14, Township 20 South, Range 35 East. (Manzano Exhibits 4 through 7; Marathon Exhibit 6).;

(b) the Manzano and Marathon wells are equal distance from the common spacing unit boundary between their spacing units;

(c) the Manzano well is 60 feet structurally high to the Marathon well on the top of the Middle Wolfcamp pay interval;

(d) the Middle Wolfcamp pay interval is more than twice as thick in the Manzano well as in the Marathon well; and

(e) there is more than twice as much pay in the Manzano well as in the Marathon well.

(16) The evidence presented by both Manzano and Marathon is in agreement that if the Manzano well was at a standard location 1980 feet from the North line of Section 14 it would either be outside the reservoir or could not efficiently drain the reserves under the NE/4 of Section 14. (See, Testimony of M. Brown, Tr. at 40; Testimony of L. Gholston, Tr. at 100).

(17) The unorthodox well location of the Manzano Neuhaus Federal Well No. 2 is not only at a better geologic position than the nearest standard well location in the Lea-Wolfcamp Pool, it is necessary if Manzano is to be afforded the opportunity to produce its just and equitable share of the reserves underlying the NE/4 of Section 14 and therefore this well location should be approved.

(18) Whenever an unorthodox location is approved, the Division may take such action as will offset any advantage which the person securing the exception may obtain over other producers by reason of the unorthodox location. (See, Oil Conservation Division Rule 104G).

(19) Since the Manzano well is no closer than the Marathon well to the common boundary between the subject spacing units, since it would be at a standard set back from this boundary if a N/2 spacing unit could have been dedicated to the well, and since there is no drainage from the Marathon tract by the Manzano well, no advantage is gained on Marathon by reason of this unorthodox location.

(20) the Middle Wolfcamp formation in the Manzano Neuhaus Federal Well No. 2 is more than twice as thick and of better quality than this formation in the Marathon Jordan "B" No. 1 Well.

(21) The evidence demonstrates that drainage is occurring from underneath the Manzano acreage thereby making the Manzano well necessary to offset the drainage being caused by the Marathon well within the limited confines of this reservoir.

(22) A penalty in this instance is not required since the unorthodox location will not cause drainage of production from the Marathon acreage but will instead serve to capture production now being drained from the Manzano acreage by the Marathon Jordan "B" No. 1 Well and, furthermore, even without a penalty on the Manzano well, reserves will continue to be drained from the Manzano tract by the Marathon well.

IT IS THEREFORE ORDERED THAT:

(1) The application of Manzano Oil Corporation for an unorthodox gas well location 660 feet from the North line and 1650 feet from the East line (Unit B) of Section 14, Township 20 South, Range 35 East, NMPM, Lea County, New Mexico is hereby approved for its Neuhaus Federal Well No. 2 which has been drilled and completed in the Wolfcamp formation, Lea-Wolfcamp Pool.

(2) The E/2 of said Section 14 shall be dedicated to the above-described well forming a standard 320-acre gas spacing and proration unit.

(3) No limitation or penalty on any gas production from the Middle Wolfcamp formation by this well shall be imposed.

(4) Jurisdiction is hereby 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

WILLIAM J. LeMAY
Director

S E A L

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W. THOMAS KELLAHIN*

*NEW MEXICO BOARD OF LEGAL SPECIALIZATION
RECOGNIZED SPECIALIST IN THE AREA OF
NATURAL RESOURCES-OIL AND GAS LAW

JASON KELLAHIN (RETIRED 1991)

TELEPHONE (505) 982-4285
TELEFAX (505) 982-2047

September 9, 1993

HAND DELIVERED

David R. Catanach
Oil Conservation Division
310 Old Santa Fe Trail
Santa Fe, New Mexico 87501

Re: NMOCD Case 10796
Application of Manzano Oil
Corporation for an Unorthodox Gas Well
Location, Lea County, New Mexico

Dear Mr. Catanach:

On behalf of Marathon Oil Company, please find enclosed our proposed order for entry in this case which if adopted by the Division would impose an 80% penalty on the Manzano well. A copy of our proposed order has also been placed on the enclosed floppy disk using a Wordperfect program.

In addition, at the hearing held on August 19, 1993, you requested Marathon to submit its calculations of the affect of each of the various penalties discussed at the hearing. In response, I am enclosing a copy of Mr. Craig Kent's letter to me dated August 30, 1993 including all of his attachments to that letter.

Finally, there is some uncertainty of the pool designation for the pool. Our draft order and the docket refers to this as the Osudo-Wolfcamp Pool, while it may in fact be the Lea-Wolfcamp Pool.

Please let me know if you need anything further.

Very truly yours,

W. Thomas Kellahin

cc: William F. Carr, Esq.
cc: Jerry Sexton-OCD
cc: Dow Campbell, Esq (Marathon)

Mid-Continent Region
Production United States

Marathon Oil Company

P.O. Box 552
Midland, TX 79702-0552
Telephone 915/682-1626

August 30, 1993

Mr. W. T. Kellahin
Kellahin and Kellahin
El Patio - 117 N. Guadalupe
Santa Fe, New Mexico 87504-2265

Dear Mr. Kellahin,

Attached is the information requested by the hearing examiner from Marathon Oil Company regarding NMOCD Case No. 10976.

In reference to Marathon's exhibit number 6 , the net isopach map, the total volume of the pool was 6,328 acre-feet with 3,776 acre-feet in the South half of Section 6 and 2,331 acre-feet in the East half of Section 14. Attachment 1 is an illustration of Marathon's allowable calculation using acre-feet rather than surface acres. As you can see, the use of acre-feet in the calculation changes the allowable from 20% of deliverability to 21%.

Attachments 2 and 3 are PVT analyses performed on recombined fluid samples from the Jordan 'B' No. 1. Attachment 2 contains analyses performed by Core Laboratories in April, 1992 and again in June, 1992. The purpose of the tests were to determine the original state of the reservoir fluid and to confirm the dew point pressure measured on the first sample. As you will notice, the dew point pressure measured on both samples is greater than the reservoir pressure at the time the samples were taken. The cause of this anomaly is due to the fact that the reservoir had dropped below the dewpoint prior to testing and that free condensate was being produced. The additional condensate in the sample meant that the pressure of the sample had to be increased to a point above the then current reservoir pressure to cause all of the liquid to vaporize into the gas phase. Attachment 4 is a paper by Philip Moses of Core Laboratories which describes this phenomenon. Attachment 3 contains an analysis of the June, 1992 sample performed by Marathon. The purpose of the analysis was to confirm the dewpoint pressure reported by Core Laboratories and to determine the PVT properties of the reservoir fluid.

Attachments 5 and 6 are information regarding the reservoir pressure for the Jordan 'B' No. 2. Attachment 5 is a copy of the C-122 submitted by TXO on the initial completion of the Jordan 'B' No. 2 and supporting pressure data. As shown, the original reservoir pressure was 4,698 psig. Attachment 6 is a report from a static fluid level shot on the well in May, 1992. A fluid level was detected 2,941 feet from surface which corresponds to a bottom hole pressure of 3,867 psia using a liquid gradient of 0.455 psi/ft. This data was used to support out geologic model of the pool.

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Attachment 7 contains information regarding recoveries for the Marathon Jordan 'B' No. 1 and the Manzano Neuhaus 14 Federal No. 2 at various allowables for the Manzano well. Figure 1 summarizes the recovery for each well at the various allowables and computes a relative share which represents the recovery of the Neuhaus No.2 compared to the Jordan 'B' No.1. You will notice that two scenarios are presented in Figure 1, one which represents the recovery for the wells if the existing 2-3/8" tubing in the Jordan 'B' No. 1 is left in place and a second which represents the recovery for the wells if 3-1/2" tubing is installed. It is Marathon's intention to install 3-1/2" tubing in the Jordan 'B' No.1 in the near future.

The method used to determine the recoveries of the wells utilizes material balance in the form of a P/Z plot and NODAL analysis. With the additional pressure data presented by Manzano at the hearing, it was necessary to modify Marathon's P/Z plot which was presented at that time. As shown on Figures 2 and 3, a revised OGIP of 6,381 MMCF was calculated which back calculates to a reservoir volume of 6,824 acre-feet. Using this data the following procedure was used to calculate recovery for the wells as shown on Figures 4-15:

1. Based on actual daily production data from the Jordan 'B' No. 1 and estimated production from the Neuhaus 14 Federal No. 2 (3.5 MMCFD average from the date the well was connected to sales) the reservoir pressure on August 20 was estimated from the P/Z plot.

2. A series of decreasing reservoir pressures in 100 psi increments from 1957 psia was listed.

3. The corresponding Z factor for each pressure was entered into the table and the value of P/Z was calculated.

4. Using the P/Z plot the cumulative gas production at each value of P/Z was calculated.

5. The incremental gas production for each pressure step was then calculated.

6. For each reservoir pressure, a production rate was calculated for each well. Marathon's in-house NODAL analysis program was used to calculate the rates. Rates from the Jordan 'B' No. 1 were calculated using a Darcy flow model based on data from pressure buildup testing for the flow through the reservoir and Gray's correlation for flow through the tubing. Rates from the Neuhaus 14 Federal No. 2 were calculated using the back pressure equation and data from Manzano's August 3 Four-point test for flow through the reservoir and Gray's correlation for flow through the tubing. Both wells were assumed to produce with a flowing wellhead pressure of 250 psia initially. When the analysis indicated the well would no longer flow at those conditions it was assumed that 1-1/2" coiled tubing would be installed in the well and that flowing tubing pressure would be reduced to 150 psia.

7. The rates for the two wells were added to determine the total production rate from the reservoir.

8. The average rate for each pressure step was calculated and divided into the incremental gas production for the pressure step to determine the length of time for the pressure step.

9. Using a starting point of August 20, the incremental time for each pressure step was added to determine the date at which each pressure would occur.

10. The average rates for each well for each pressure step for each well were calculated and multiplied by the length of each pressure step and added to determine the total recovery for each well.

11. In the cases where the Neuhaus 14 Federal No. 2 was restricted, the well was allowed to produce at the designated fraction of its calculated deliverability against line pressure. The deliverability was recalculated approximately in August of each year and a new allowable was applied. If the calculated allowable was less than 500 mcfd the well was allowed to produce at full deliverability.

Figures 4 through 15 illustrate the calculations for each allowable scenario and the recovery information is summarized on Figure 1.

Should you have any questions, please contact me at (915) 682-1626, extension 8282.

Sincerely,

Craig T. Kent

Craig T. Kent

xc: D. L. Campbell, w/Attachments
D. R. Petro, w/o Attachments
T. N. Tipton, w/o Attachments
R. W. Tracy, w/o Attachments

CTK097.sk

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

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

CASE NO. 10796
Order No. R-

APPLICATION OF MANZANO OIL CORPORATION FOR AN UNORTHODOX GAS WELL LOCATION, LEA COUNTRY, NEW MEXICO.

MARATHON OIL COMPANY'S PROPOSED ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 8:15 a.m. on August 12, 1993, and was continued to 1:00 p.m. on August 19, 1993 at Santa Fe, New Mexico, before Examiner David R. Catanach.

NOW, on this ___day of September, 1993, the Division Director, having considered the testimony, the record and the recommendations of the Examiner, and being fully advised in the premises,

FINDS THAT:

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

(2) The applicant, Manzano Oil Company ("Manzano"), seeks approval of an unorthodox gas well location for its Neuhaus Federal Well No 2 which has been drilled at an unorthodox gas well location 660 feet from the North and 1650 feet from the East line (Unit B) of Section 14, T20S, R35E, NMPM, Lea County, New Mexico with an E/2 dedication for production from the Wolfcamp formation in the Osudo-Wolfcamp Gas Pool.

(3) Marathon Oil Company ("Marathon"), operator of the Jordan "B" No 1 Well located 660 feet from the South line and 1980 feet from the East line of Section 11, T20S, R35E, NMPM, Lea County, New Mexico with a S/2 dedication, which is currently producing from the Wolfcamp formation in the Osudo-Wolfcamp Gas Pool, appeared at the hearing in opposition to the application.

(4) In December, 1991 Marathon's Jordan "B" No. 1 Well was recompleted as a Wolfcamp gas producer and as of August 19, 1993 had the capacity to produce 3,900 MCFPD.

(5) On January 21, 1993, Manzano filed an application for permit to drill its Sims State Well No.1 660 feet from the South and West lines of Section 12, T20S, R35E, NMPM, Lea County New Mexico as a Strawn oil well on 40-acre statewide oil spacing to be drilled to a total depth of 12,100 feet.

(6) However, instead of drilling its Sims State Well No.1 to its proposed target in the Strawn, when the well reached the Wolfcamp formation at 11,532 feet (some 600

feet above the Strawn formation) it was determined that the Wolfcamp was not productive, and Manzano abandoned this well.

(7) The Sims State Well No.1 would have been the direct eastern offset to the Marathon Jordan B Well No 1.

(8) The closest established Strawn oil pool is some 7 miles to the west of this area while the nearest established Wolfcamp gas production is that operated by Marathon in the next section to the west.

(9) Having failed to obtain commercial Wolfcamp production in the Sims State Well No 1, Manzano then filed on April 20, 1993 an application for permit to drill its Neuhaus "14" Federal Well No 2 in the section immediately to the south of the Marathon Jordan "B" No 1 well.

(10) Again, rather than file for an unorthodox Wolfcamp gas well location, Manzano applied for a standard Strawn oil well location for its Neuhaus "14" Federal Well No 2 in Unit B of Section 14 to be drilled to a total depth of 12,400 feet.

(11) And again, rather than drill to the permitted depth in the Strawn oil pool, when Manzano reached the Wolfcamp gas formation, it discovered it had encountered gas production correlative to that being produced by Marathon and elected to complete the subject well in the Wolfcamp.

(12) Manzano's Neuhaus "14" Federal Well No. 2 was completed at an unorthodox well location some two-third's closer to Marathon's spacing unit than permitted by Division rules.

(13) While Manzano recognized it would have to notify Marathon and obtain the Division's approval to produce the Wolfcamp formation after a hearing, Manzano sought an exparte emergency order from the Division's Director to allow the illegal well to produce.

(14) On July 21, 1993, the Division Director granted Manzano's request for a temporary testing allowable which authorized Manzano to produce the subject well at a rate of 882 MCF/D until August 12, 1993, the date of the hearing in this matter.

(15) At the hearing, Manzano testified that it had violated the Director's order letter of July 21, 1993 and had been producing the well at average rates in excess of 3,300 MCFPD.

(16) Thereafter, Manzano again sought and obtained an exparte order from the Division Director without notice either to Marathon or the Division Examiner, seeking this time to obtain a testing allowable based upon a new 4-point test which indicated the well's CAOF of 35,240 MCFGPD. On August 13, 1993, the Division Director issued an exparte order grating this request and approving production from August 13, 1993 to August 19, 1993 at a maximum daily rate of 11,740 MCFGPD.

(17) Manzano testified at the hearing that its well had been produced as high as 5,000 MCFPD and Marathon calculates this well to have a maximum capacity of 6,889 MCFPD. Thus the new testing allowable authorized by the Division Director did not in any way restrict the well's capacity to produce even though it was 1,320 feet closer to the Marathon spacing unit than allowed by Division rules.

(18) Marathon provided expert engineering data which was uncontested by Manzano, that the new four-point test used by the Director to approve the testing allowable was absolutely unreliable and inaccurate. In addition, the 4 points at which pressure data was taken for the four-point test failed to comply with the testing procedures set forth in the Division's 4-point well testing manual because they were taken too close to each other.

(19) Based upon the foregoing, the Division issued a notice to Manzano dated August 19, 1993 directing that the illegal well be shut-in immediately and stay shut-in pending an order to be entered in this case.

(20) Manzano has failed to provide any evidence establishing that the testing allowables resulted in any necessary test data.

(21) The geologic interpretation of this Wolfcamp reservoir presented by Manzano contends that:

a) Manzano's Neuhaus well was located near the highest (-7609 feet) and near the thickest point (119 net feet) in this limited Wolfcamp reservoir;

b) Marathon's Jordan "B" Well No. 1 was located at the northwest edge of this limited reservoir with 39 feet of net pay and at -7630 feet on the structure;

c) Marathon's Jordan "B" No. 1 well was <u>NOT</u> in the same reservoir with the Marathon's Jordan "B" No. 2 Well to the north;

d) the size, shape and orientation of this Wolfcamp reservoir was such that Manzano's E/2 spacing unit had 7600 acre-feet and 140 productive acres, while

e) Marathon's Jordan "B" No 1 well's spacing unit in the S/2 has only 2333 acre-feet and 58 productive acres.

(22) In opposition, Marathon presented a substantially different geologic interpretation of this reservoir contending that:

a) Manzano's Neuhaus well was located near the highest (-7513 feet) and near the thickest point (90 net feet) in this limited Wolfcamp reservoir;

b) Marathon's Jordan "B" Well No 1. was located to the north and west of the point of greatest reservoir thickness but well within this limited reservoir with 39 feet of net pay and at -7536 feet on structure.

c) Marathon's Jordan "B" Well No 2 IS in the same reservoir as the Marathon's Jordan "B" Well No 1 to the south, and

(d) the reservoir extends farther north than mapped by Manzano with the point of greatest reservoir thickness shared between the two spacing units.

(23) Marathon's engineer concluded that:

a) the size, shape and orientation of this Wolfcamp reservoir was such that Manzano's E/2 of Section 14 spacing unit has 2,331 acre-feet and 72 net productive acres, while

b) Marathon's Jordan "B" No 1 well's spacing unit in the S/2 of Section 11 has 3,776 acre-feet and 123 net productive acres; and

c) the pool originally contained 6.4 BCF of gas with a total original reservoir volume of 6,250 acre-feet (later recalculated to 6,328 acre-feet) and now has 3.2 BCF of gas remaining to be produced.

(24) The inclusion or exclusion of the Marathon's Jordan "B" Well No 2 from this Wolfcamp reservoir is the point of greatest dispute between the parties and affects one of the factors to be used in calculating a penalty for the Manzano well.

(25) By excluding Marathon's Jordan "B" Well No 2, Manzano's geologic interpretation allowed it to shift the entire reservoir farther south and more directly located over its spacing unit and still be consistent with their calculation of reservoir volume.

(26) By including Marathon's Jordan "B" Well No 2 in this same reservoir, Marathon's geologic interpretation locates the entire reservoir farther north and more directly located over its spacing unit and still provides a reservoir size which is consistent with their calculation of reservoir volume.

(27) Manzano's engineering evidence sought to validate the Manzano geology based upon Manzano's conclusion that the Jordan "B" Well No 2 was not in the same reservoir as the Jordan "B" Well No 1.

(28) Marathon's engineering witness provided uncontested evidence that the Jordan "B" Well No 2 was completed in 1985 with an initial pressure of 4700 psi; that when the Jordan "B" Well No. 1 was completed in 1991 its initial pressure was 3800 psi; that the Jordan "B" Well No 2 was the only well in the area which could have drained the reservoir and caused the pressure depletion measured in the Jordan "B" Well No 1; therefore these two wells are in fact in pressure communication and must be in the same reservoir.

(29) Manzano's engineering witness had estimated the reservoir volume to be 9,942 acre feet based upon P/Z analysis using a Z factor for a dry gas reservoir.

(30) Marathon's engineering witness used the correct Z factor for a gas-condensate reservoir and calculated the same reservoir to have a volume of 6,250 acre feet based upon P/Z analysis.

(31) Marathon's engineering witness provided uncontroverted testimony that this was a gas-condensate reservoir and established that Manzano had used the wrong Z factor for its acre-feet calculation. Thus, while Manzano by co-incidence arrived at an accurate material balance calculation of original gas in place its volumetric calculation is in error because it used a Z factor for a dry gas reservoir.

(32) The Division finds that Marathon's understanding and interpretation is based upon more reliable data, (including PVT analysis), more accurately interprets the reservoir and correctly calculates the acre-feet underlying each spacing unit.

(33) Regardless of the geologic interpretation, both Manzano and Marathon are in agreement that Manzano could not have located a well capable of commercial production at a standard well location in its spacing unit.

(34) As a result of drilling at an unorthodox well location, Manzano has the opportunity to produce more than its fair share of the recoverable gas remaining in the reservoir and has violated Marathon's correlative rights. The unfair advantage Manzano has obtained over Marathon can be minimized by imposing a production limitation.

(35) Marathon provided various possible penalty calculations to be imposed upon the Manzano well, the most appropriate being a deliverability adjusted penalty based upon the average of two factors: (1) deviation from a standard well location in the north/south direction; and (2) productive acreage underlying the E/2 of Section 14 relative to productive acreage underlying the S/2 of Section 11, and then reduced by a deliverability ratio of 2.3, all as shown as follows:

Factor 1 = 660 feet/1980 feet = 0.33333
Factor 2 = 72/123 = 0.58536

Average of Factors 1 & 2 /2 = 0.45935
and reduced by a deliverability adjustment of 2.3 which results in
A 20 PERCENT ALLOWABLE FACTOR (0.19963)

(36) Without a deliverability adjustment, if Manzano is allowed to produce 46% of its calculated maximum capacity of 6,889 MCFPD or a maximum allowable rate of 3,169 MCFPD, then its well will recover 89% of its relative share compared to the Marathon well.

(37) Because there is a direct relationship between net pay and deliverability, a deliverability adjustment of 2.3 was calculated based upon the respective net pays of the Marathon and Manzano wells.

(38) The adoption of a 2.3 deliverability adjustment factor in the penalty will reduce Manzano's relative share over the Marathon well from 89 percent to 42 percent and is necessary to protect Marathon's correlative rights.

(39) A production allowable of 20% of its capacity into the pipeline (penalty of 80%) still allows the Manzano well a maximum producing rate of 1,378 MCFPD.

(40) Marathon testified that it is physically impossible for Manzano's well with 2-7/8 inch tubing and with a reservoir pressure of 2128 psig to flow at a rate of 35,240 MCFPD. Therefore, a production allowable factor applied against the well's CAOF is meaningless in this case and therefore such a factor should be applied to the Manzano's ability to produce on a sustained basis under actual operating conditions into the pipeline.

(41) Approval of the unorthodox well location for production from the Wolfcamp formation in the Osudo-Wolfcamp Gas Pool, subject to a producing allowable factor of 20 percent, will afford the applicant the opportunity to recover its just and equitable share of the remaining gas in the pool underling the E/2 of Section 14, will protect Marathon's correlative rights and will otherwise prevent waste.

IT IS THEREFORE ORDERED THAT:

(1) The applicant, Manzano Oil Corporation, is hereby authorized to produce its Neuhaus "14" Federal No 2 Well at an unorthodox gas well location 660 feet from the North line and 1650 feet from the East line (Unit B) of Section 14, T20S, R35E, NMPM, Lea County, New Mexico, in the Wolfcamp formation of the Osudo-Wolfcamp Gas Pool.

(2) The E/2 of Section 14 shall be dedicated to the subject well forming a standard 320-acre gas spacing and proration unit for said pool.

(3) The Neuhaus "14" Federal Well No 2 is hereby assigned a production limitation factor of 20 percent (80% penalty) to be applied against its current deliverability which has been calculated to be 6,889 MCFPD and which results in a maximum daily allowable of 1,378 MCFPD.

(4) This production limitation factor shall be applied against the well's ability to produce into the existing pipeline as determined by deliverability tests conducted on the well on an annual basis. The current deliverability has been calculated to be 6,889 MCFPD which shall be used as the well's deliverability until the next deliverability test which shall be conducted in August, 1994 and then every August thereafter. The well shall be allowed to produce at its penalized rate or 500 MCFPD which ever is greater.

(5) The penalized allowable set forth above shall be applied to the subject well from the date of first production. In the event the well has been overproduced its production limitation factor allowable on a monthly basis (30 days being a month) then and in that event, the well shall be shut-in until that over production has been made up with a portion of the next month's production allowable.

(6) Manzano shall provide the Division with accurate daily production volumes of gas, oil and water from date of initial production through August 19, 1993.

(7) 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

WILLIAM J. LEMAY
Director

SEAL

PRESSURE AND PRODUCTION DATA

CUMULATIVE GAS PROD. MMCF	PRESSURE PSIA	Z	P/Z PSIA	OGIP MMCF
0	3,800	0.6759	5,622	
320	3,600	0.6586	5,314	5,841
2,577	2,128	0.6586	3,346	6,381

FIGURE 2

P/Z (PSI)

6000
5000
4000
3000
2000
1000
0

JORDAN 'B' No.1

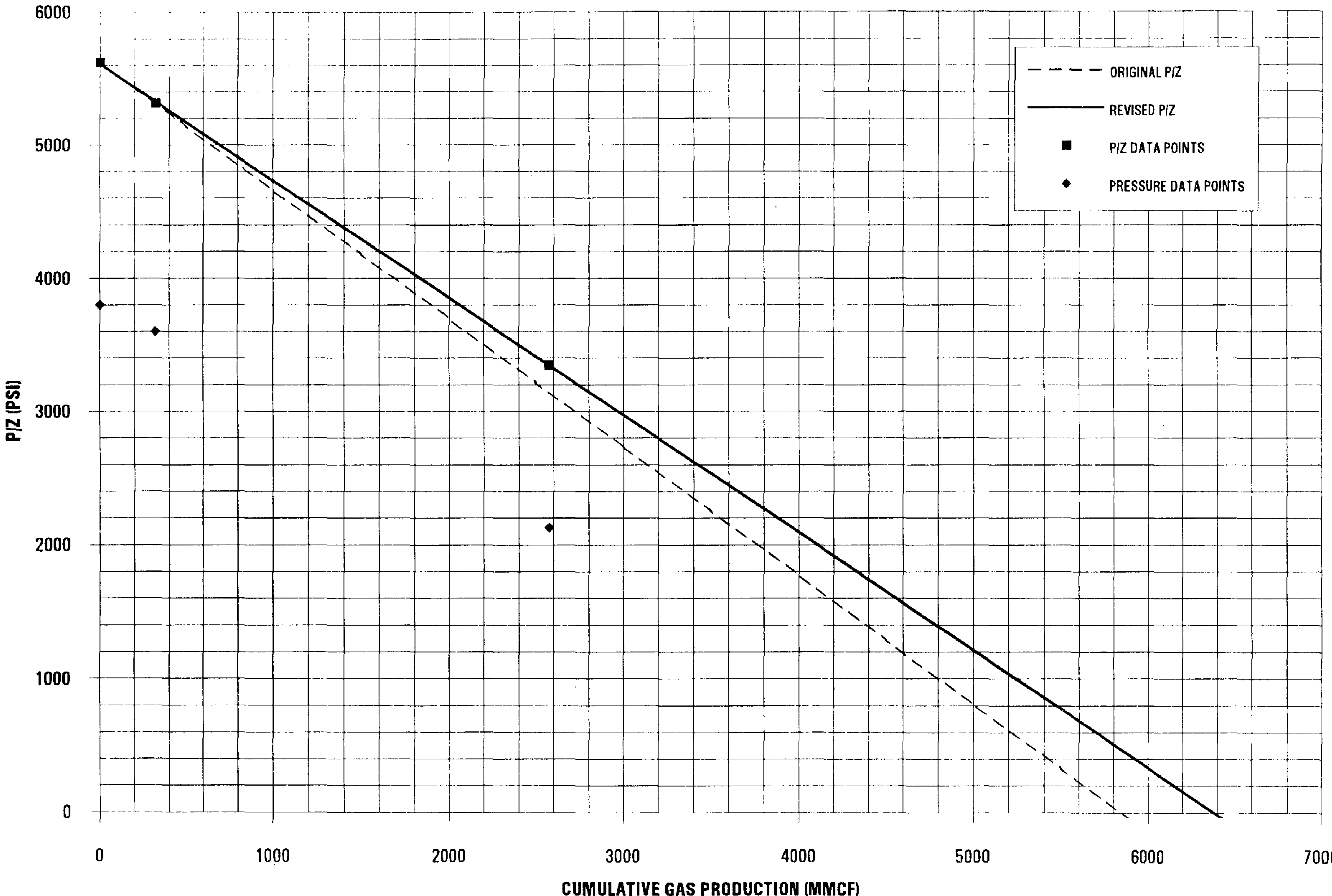

FIGURE 3

ATTACHMENT 7

NEUHAUS 14 FED. No. 2 ALLOWABLE		PER WELL RECOVERY AT VARIOUS ALLOWABLES (MCF)					
		JORDAN 'B' No. 1 2-3/8" TUBING			JORDAN 'B' No. 1 3-1/2" TUBING		
%	MCFD	JORDAN 'B' No. 1	NEUHAUS 14 FED. No. 2	RELATIVE SHARE	JORDAN 'B' No. 1	NEUHAUS 14 FED. No. 2	RELATIVE SHARE
100%	6,889	1,227,521	1,979,298	161%	1,433,657	1,773,161	124%
58%	3,996	1,374,563	1,832,255	133%	1,579,310	1,627,508	103%
46%	3,169	1,497,182	1,709,637	114%	1,696,898	1,509,921	89%
33%	2,273	1,780,502	1,426,316	80%	1,942,707	1,264,111	65%
25%	1,722	1,949,487	1,257,331	64%	2,113,302	1,093,516	52%
20%	1,378	2,103,383	1,103,435	52%	2,262,468	944,350	42%

FIGURE 1

			JORDAN 'B' No. 1 2-3/8" TUBING				NO PENALTY ON NEUHAUS 14 FEDERAL No. 2							
PRESSURE	Z	P/Z	CUM. GAS	DELTA CUM. GAS	JORDAN RATE	NEUHAUS RATE	TOTAL RATE	AVERAGE RATE	DELTA TIME	DATE	JORDAN AVG RATE	NEUHAUS AVG RATE	JORDAN CUM. GAS	NEUHAUS CUM. GAS
PSIA		PSIA	MMCF	MMCF	MCFD	MCFD	MCFD	MCFD	DAYS		MCFD	MCFD	MCF	MCF
2128	0.6359	3346	2,575.156							7/4/93				
2000	0.6389	3130	2,820.960	245.804										
1957	0.6339	3087	2,870.212	49.252	3,950	6,889	10,839			8/20/93			200,556	94,500
1900	0.6447	2947	3,029.669	208.710	3,802	6,641	10,443	10,641	20	9/8/93	3,876	6,765	276,579	227,187
1800	0.6506	2767	3,234.632	204.963	3,550	6,231	9,781	10,112	20	9/28/93	3,676	6,436	351,089	357,640
1700	0.6564	2590	3,435.947	201.316	3,299	5,823	9,122	9,452	21	10/20/93	3,425	6,027	424,030	486,014
1600	0.6623	2416	3,633.713	197.765	3,040	5,415	8,455	8,789	23	11/11/93	3,170	5,619	495,352	612,457
1500	0.6683	2244	3,828.827	195.115	2,782	5,006	7,788	8,122	24	12/5/93	2,911	5,211	565,288	737,636
1400	0.6759	2071	4,025.853	197.025	2,525	4,594	7,119	7,454	26	1/1/94	2,654	4,800	635,430	864,519
1300	0.6835	1902	4,218.496	192.644	2,258	4,176	6,434	6,777	28	1/29/94	2,392	4,385	703,416	989,177
1200	0.7018	1710	4,437.005	218.509	1,995	3,753	5,748	6,091	36	3/6/94	2,127	3,965	779,702	1,131,399
1100	0.7267	1514	4,660.087	223.082	1,727	3,320	5,047	5,398	41	4/16/94	1,861	3,537	856,618	1,277,565
1000	0.7515	1331	4,868.416	208.329	1,461	2,876	4,337	4,692	44	5/31/94	1,594	3,098	927,393	1,415,119
900	0.7764	1159	5,063.409	194.993	1,180	2,412	3,592	3,965	49	7/19/94	1,321	2,644	992,342	1,545,163
800	0.8012	998	5,246.306	182.897	871	1,913	2,784	3,188	57	9/14/94	1,026	2,163	1,051,175	1,669,227
700	0.8261	847	5,418.200	171.893	422	1,290	1,712	2,248	76	11/30/94	647	1,602	1,100,610	1,791,686
600	0.8509	705	5,580.053	161.854	316	308	624	1,168	139	4/17/95	369	799	1,151,744	1,902,406
500	0.8758	571	5,732.722	152.668	160	175	335	480	318	3/1/96	238	242	1,227,521	1,979,298

FIGURE 4

			JORDAN 'B' No. 1 3-1/2" TUBING				NO PENALTY ON NEUHAUS 14 FEDERAL No. 2							
PRESSURE	Z	P/Z	CUM. GAS	DELTA	JORDAN	NEUHAUS	TOTAL	AVERAGE	DELTA	DATE	JORDAN	NEUHAUS	JORDAN	NEUHAUS
				CUM. GAS	RATE	RATE	RATE	RATE	TIME		AVG RATE	AVG RATE	CUM. GAS	CUM. GAS
PSIA		PSIA	MMCF	MMCF	MCFD	MCFD	MCFD	MCFD	DAYS		MCFD	MCFD	MCF	MCF
2128	0.6359	3346	2,575.156							7/4/93				
2000	0.6389	3130	2,820.960	245.804										
1957	0.6339	3087	2,870.212	49.252	5,671	6,889	12,560			8/20/93			200,556	94,500
1900	0.6447	2947	3,029.669	208.710	5,444	6,641	12,085	12,323	17	9/5/93	5,558	6,765	294,685	209,081
1800	0.6506	2767	3,234.632	204.963	5,047	6,231	11,278	11,682	18	9/23/93	5,246	6,436	386,722	322,006
1700	0.6564	2590	3,435.947	201.316	4,648	5,823	10,471	10,875	19	10/11/93	4,848	6,027	476,462	433,582
1600	0.6623	2416	3,633.713	197.765	4,247	5,415	9,662	10,067	20	10/31/93	4,448	5,619	563,837	543,972
1500	0.6683	2244	3,828.827	195.115	3,855	5,006	8,861	9,262	21	11/21/93	4,051	5,211	649,181	653,743
1400	0.6759	2071	4,025.853	197.025	3,454	4,594	8,048	8,455	23	12/15/93	3,655	4,800	734,346	765,603
1300	0.6835	1902	4,218.496	192.644	3,052	4,176	7,228	7,638	25	1/9/94	3,253	4,385	816,392	876,201
1200	0.7018	1710	4,437.005	218.509	2,647	3,753	6,400	6,814	32	2/10/94	2,850	3,965	907,769	1,003,333
1100	0.7267	1514	4,660.087	223.082	2,235	3,320	5,555	5,978	37	3/19/94	2,441	3,537	998,868	1,135,316
1000	0.7515	1331	4,868.416	208.329	1,808	2,876	4,684	5,120	41	4/29/94	2,022	3,098	1,081,129	1,261,383
900	0.7764	1159	5,063.409	194.993	1,317	2,412	3,729	4,207	46	6/14/94	1,563	2,644	1,153,559	1,383,946
800	0.8012	998	5,246.306	182.897	1,205	1,913	3,118	3,424	53	8/7/94	1,261	2,163	1,220,927	1,499,476
700	0.8261	847	5,418.200	171.893	878	1,290	2,168	2,643	65	10/11/94	1,042	1,602	1,288,663	1,603,633
600	0.8509	705	5,580.053	161.854	316	308	624	1,396	116	2/4/95	597	799	1,357,880	1,696,270
500	0.8758	571	5,732.722	152.668	160	175	335	480	318	12/19/95	238	242	1,433,657	1,773,161

FIGURE 5

			JORDAN 'B' No. 1 2-3/8" TUBING				20% ALLOWABLE ON NEUHAUS 14 FEDERAL No. 2							
PRESSURE	Z	P/Z	CUM. GAS	DELTA CUM. GAS	JORDAN RATE	NEUHAUS RATE	TOTAL RATE	AVERAGE RATE	DELTA TIME	DATE	JORDAN AVG RATE	NEUHAUS AVG RATE	JORDAN CUM. GAS	NEUHAUS CUM. GAS
PSIA		PSIA	MMCF	MMCF	MCFD	MCFD	MCFD	MCFD	DAYS		MCFD	MCFD	MCF	MCF
2128	0.6359	3346	2,575.156							7/4/93				
2000	0.6389	3130	2,820.960	245.804										
1957	0.6339	3087	2,870.212	49.252	3,950	1,378	5,328			8/20/93			200,556	94,500
1900	0.6447	2947	3,029.669	208.710	3,802	1,378	5,180	5,254	40	9/28/93	3,876	1,378	354,526	149,240
1800	0.6506	2767	3,234.632	204.963	3,550	1,378	4,928	5,054	41	11/8/93	3,676	1,378	503,604	205,124
1700	0.6564	2590	3,435.947	201.316	3,299	1,378	4,677	4,803	42	12/20/93	3,425	1,378	647,156	262,888
1600	0.6623	2416	3,633.713	197.765	3,040	1,378	4,418	4,548	43	2/1/94	3,170	1,378	784,993	322,816
1500	0.6683	2244	3,828.827	195.115	2,782	1,378	4,160	4,289	45	3/19/94	2,911	1,378	917,420	385,503
1400	0.6759	2071	4,025.853	197.025	2,525	1,378	3,903	4,032	49	5/7/94	2,654	1,378	1,047,101	452,848
1300	0.6835	1902	4,218.496	192.644	2,258	1,378	3,636	3,770	51	6/27/94	2,392	1,378	1,169,320	523,272
1200	0.7018	1710	4,437.005	218.509	1,995	751	2,746	3,191	68	9/3/94	2,127	1,064	1,314,945	596,156
1100	0.7267	1514	4,660.087	223.082	1,727	751	2,478	2,612	85	11/28/94	1,861	751	1,473,899	660,284
1000	0.7515	1331	4,868.416	208.329	1,461	751	2,212	2,345	89	2/24/95	1,594	751	1,615,509	727,003
900	0.7764	1159	5,063.409	194.993	1,180	751	1,931	2,072	94	5/30/95	1,321	751	1,739,810	797,696
800	0.8012	998	5,246.306	182.897	871	500	1,371	1,651	111	9/17/95	1,026	626	1,853,414	866,988
700	0.8261	847	5,418.200	171.893	422	500	922	1,147	150	2/14/96	647	500	1,950,343	941,953
600	0.8509	705	5,580.053	161.854	316	308	624	773	209	9/11/96	369	404	2,027,606	1,026,544
500	0.8758	571	5,732.722	152.668	160	175	335	480	318	7/26/97	238	242	2,103,383	1,103,435

FIGURE 6

			JORDAN 'B' No. 1 3-1/2" TUBING				20% ALLOWABLE ON NEUHAUS 14 FEDERAL No. 2							
PRESSURE	Z	P/Z	CUM. GAS	DELTA CUM. GAS	JORDAN RATE	NEUHAUS RATE	TOTAL RATE	AVERAGE RATE	DELTA TIME	DATE	JORDAN AVG RATE	NEUHAUS AVG RATE	JORDAN CUM. GAS	NEUHAUS CUM. GAS
PSIA		PSIA	MMCF	MMCF	MCFD	MCFD	MCFD	MCFD	DAYS		MCFD	MCFD	MCF	MCF
2128	0.6359	3346	2,575.156							7/4/93				
2000	0.6389	3130	2,820.960	245.804										
1957	0.6339	3087	2,870.212	49.252	5,671	1,378	7,049			8/20/93			200,556	94,500
1900	0.6447	2947	3,029.669	208.710	5,444	1,378	6,822	6,936	30	9/19/93	5,558	1,378	367,798	135,968
1800	0.6506	2767	3,234.632	204.963	5,047	1,378	6,425	6,624	31	10/20/93	5,246	1,378	530,118	178,610
1700	0.6564	2590	3,435.947	201.316	4,648	1,378	6,026	6,226	32	11/21/93	4,848	1,378	686,873	223,171
1600	0.6623	2416	3,633.713	197.765	4,247	1,378	5,625	5,826	34	12/25/93	4,448	1,378	837,858	269,951
1500	0.6683	2244	3,828.827	195.115	3,855	1,378	5,233	5,429	36	1/30/94	4,051	1,378	983,448	319,476
1400	0.6759	2071	4,025.853	197.025	3,454	1,378	4,832	5,033	39	3/10/94	3,655	1,378	1,126,524	373,425
1300	0.6835	1902	4,218.496	192.644	3,052	1,378	4,430	4,631	42	4/21/94	3,253	1,378	1,261,844	430,748
1200	0.7018	1710	4,437.005	218.509	2,647	1,378	4,025	4,228	52	6/11/94	2,850	1,378	1,409,128	501,974
1100	0.7267	1514	4,660.087	223.082	2,235	664	2,899	3,462	64	8/15/94	2,441	1,021	1,566,419	567,764
1000	0.7515	1331	4,868.416	208.329	1,808	664	2,472	2,686	78	10/31/94	2,022	664	1,723,238	619,274
900	0.7764	1159	5,063.409	194.993	1,317	664	1,981	2,227	88	1/27/95	1,563	664	1,860,079	677,426
800	0.8012	998	5,246.306	182.897	1,205	664	1,869	1,925	95	5/2/95	1,261	664	1,979,889	740,514
700	0.8261	847	5,418.200	171.893	878	500	1,378	1,624	106	8/16/95	1,042	582	2,090,161	802,135
600	0.8509	705	5,580.053	161.854	316	308	624	1,001	162	1/24/96	597	404	2,186,691	867,459
500	0.8758	571	5,732.722	152.668	160	175	335	480	318	12/8/96	238	242	2,262,468	944,350

FIGURE 7

			JORDAN 'B' No. 1 2-3/8" TUBING				25% ALLOWABLE ON NEUHAUS 14 FEDERAL No. 2							
PRESSURE	Z	P/Z	CUM. GAS	DELTA	JORDAN	NEUHAUS	TOTAL	AVERAGE	DELTA	DATE	JORDAN	NEUHAUS	JORDAN	NEUHAUS
				CUM. GAS	RATE	RATE	RATE	RATE	TIME		AVG RATE	AVG RATE	CUM. GAS	CUM. GAS
PSIA		PSIA	MMCF	MMCF	MCFD	MCFD	MCFD	MCFD	DAYS		MCFD	MCFD	MCF	MCF
2128	0.6359	3346	2,575.156							7/4/93				
2000	0.6389	3130	2,820.960	245.804										
1957	0.6339	3087	2,870.212	49.252	3,950	1,722	5,672			8/20/93			200,556	94,500
1900	0.6447	2947	3,029.669	208.710	3,802	1,722	5,524	5,598	37	9/26/93	3,876	1,722	345,064	158,701
1800	0.6506	2767	3,234.632	204.963	3,550	1,722	5,272	5,398	38	11/3/93	3,676	1,722	484,643	224,086
1700	0.6564	2590	3,435.947	201.316	3,299	1,722	5,021	5,147	39	12/12/93	3,425	1,722	618,599	291,445
1600	0.6623	2416	3,633.713	197.765	3,040	1,722	4,762	4,892	40	1/21/94	3,170	1,722	746,743	361,066
1500	0.6683	2244	3,828.827	195.115	2,782	1,722	4,504	4,633	42	3/4/94	2,911	1,722	869,337	433,587
1400	0.6759	2071	4,025.853	197.025	2,525	1,722	4,247	4,376	45	4/18/94	2,654	1,722	988,822	511,127
1300	0.6835	1902	4,218.496	192.644	2,258	1,722	3,980	4,114	47	6/4/94	2,392	1,722	1,100,821	591,772
1200	0.7018	1710	4,437.005	218.509	1,995	1,722	3,717	3,849	57	7/31/94	2,127	1,722	1,221,558	689,543
1100	0.7267	1514	4,660.087	223.082	1,727	830	2,557	3,137	71	10/10/94	1,861	1,276	1,353,900	780,283
1000	0.7515	1331	4,868.416	208.329	1,461	830	2,291	2,424	86	1/4/95	1,594	830	1,490,895	851,617
900	0.7764	1159	5,063.409	194.993	1,180	830	2,010	2,151	91	4/5/95	1,321	830	1,610,629	926,876
800	0.8012	998	5,246.306	182.897	871	830	1,701	1,856	99	7/12/95	1,026	830	1,711,713	1,008,689
700	0.8261	847	5,418.200	171.893	422	500	922	1,312	131	11/20/95	647	665	1,796,448	1,095,848
600	0.8509	705	5,580.053	161.854	316	308	624	773	209	6/17/96	369	404	1,873,710	1,180,439
500	0.8758	571	5,732.722	152.668	160	175	335	480	318	5/1/97	238	242	1,949,487	1,257,331

FIGURE 8

			JORDAN 'B' No. 1 3-1/2" TUBING				25% ALLOWABLE ON NEUHAUS 14 FEDERAL No. 2							
PRESSURE	Z	P/Z	CUM. GAS	DELTA CUM. GAS	JORDAN RATE	NEUHAUS RATE	TOTAL RATE	AVERAGE RATE	DELTA TIME	DATE	JORDAN AVG RATE	NEUHAUS AVG RATE	JORDAN CUM. GAS	NEUHAUS CUM. GAS
PSIA		PSIA	MMCF	MMCF	MCFD	MCFD	MCFD	MCFD	DAYS		MCFD	MCFD	MCF	MCF
2128	0.6359	3346	2,575.156							7/4/93				
2000	0.6389	3130	2,820.960	245.804										
1957	0.6339	3087	2,870.212	49.252	5,671	1,722	7,393			8/20/93			200,556	94,500
1900	0.6447	2947	3,029.669	208.710	5,444	1,722	7,166	7,280	29	9/17/93	5,558	1,722	359,894	143,871
1800	0.6506	2767	3,234.632	204.963	5,047	1,722	6,769	6,968	29	10/17/93	5,246	1,722	514,201	194,527
1700	0.6564	2590	3,435.947	201.316	4,648	1,722	6,370	6,570	31	11/16/93	4,848	1,722	662,748	247,296
1600	0.6623	2416	3,633.713	197.765	4,247	1,722	5,969	6,170	32	12/18/93	4,448	1,722	805,314	302,495
1500	0.6683	2244	3,828.827	195.115	3,855	1,722	5,577	5,773	34	1/21/94	4,051	1,722	942,229	360,695
1400	0.6759	2071	4,025.853	197.025	3,454	1,722	5,176	5,377	37	2/27/94	3,655	1,722	1,076,150	423,799
1300	0.6835	1902	4,218.496	192.644	3,052	1,722	4,774	4,975	39	4/6/94	3,253	1,722	1,202,114	490,479
1200	0.7018	1710	4,437.005	218.509	2,647	1,722	4,369	4,572	48	5/24/94	2,850	1,722	1,338,314	572,787
1100	0.7267	1514	4,660.087	223.082	2,235	1,722	3,957	4,163	54	7/17/94	2,441	1,722	1,469,120	665,064
1000	0.7515	1331	4,868.416	208.329	1,808	720	2,528	3,242	64	9/19/94	2,022	1,221	1,599,005	743,507
900	0.7764	1159	5,063.409	194.993	1,317	720	2,037	2,282	85	12/14/94	1,563	720	1,732,496	805,009
800	0.8012	998	5,246.306	182.897	1,205	720	1,925	1,981	92	3/16/95	1,261	720	1,848,919	871,484
700	0.8261	847	5,418.200	171.893	878	720	1,598	1,762	98	6/21/95	1,042	720	1,950,552	941,744
600	0.8509	705	5,580.053	161.854	316	308	624	1,111	146	11/14/95	597	514	2,037,525	1,016,625
500	0.8758	571	5,732.722	152.668	160	175	335	480	318	9/28/96	238	242	2,113,302	1,093,516

FIGURE 9

			JORDAN 'B' No. 1 2-3/8" TUBING				33% ALLOWABLE ON NEUHAUS 14 FEDERAL No. 2							
PRESSURE	Z	P/Z	CUM. GAS	DELTA CUM. GAS	JORDAN RATE	NEUHAUS RATE	TOTAL RATE	AVERAGE RATE	DELTA TIME	DATE	JORDAN AVG RATE	NEUHAUS AVG RATE	JORDAN CUM. GAS	NEUHAUS CUM. GAS
PSIA		PSIA	MMCF	MMCF	MCFD	MCFD	MCFD	MCFD	DAYS		MCFD	MCFD	MCF	MCF
2128	0.6359	3346	2,575.156							7/4/93				
2000	0.6389	3130	2,820.960	245.804										
1957	0.6339	3087	2,870.212	49.252	3,950	2,273	6,223			8/20/93			200,556	94,500
1900	0.6447	2947	3,029.669	208.710	3,802	2,273	6,075	6,149	34	9/22/93	3,876	2,273	332,115	171,650
1800	0.6506	2767	3,234.632	204.963	3,550	2,273	5,823	5,949	34	10/27/93	3,676	2,273	458,766	249,963
1700	0.6564	2590	3,435.947	201.316	3,299	2,273	5,572	5,698	35	12/1/93	3,425	2,273	579,767	330,277
1600	0.6623	2416	3,633.713	197.765	3,040	2,273	5,313	5,443	36	1/7/94	3,170	2,273	694,938	412,871
1500	0.6683	2244	3,828.827	195.115	2,782	2,273	5,055	5,184	38	2/13/94	2,911	2,273	804,502	498,422
1400	0.6759	2071	4,025.853	197.025	2,525	2,273	4,798	4,927	40	3/25/94	2,654	2,273	910,623	589,326
1300	0.6835	1902	4,218.496	192.644	2,258	2,273	4,531	4,665	41	5/5/94	2,392	2,273	1,009,392	683,201
1200	0.7018	1710	4,437.005	218.509	1,995	2,273	4,268	4,400	50	6/24/94	2,127	2,273	1,115,008	796,093
1100	0.7267	1514	4,660.087	223.082	1,727	1,096	2,823	3,545	63	8/26/94	1,861	1,684	1,232,108	902,075
1000	0.7515	1331	4,868.416	208.329	1,461	1,096	2,557	2,690	77	11/12/94	1,594	1,096	1,355,566	986,946
900	0.7764	1159	5,063.409	194.993	1,180	1,096	2,276	2,417	81	1/31/95	1,321	1,096	1,462,120	1,075,385
800	0.8012	998	5,246.306	182.897	871	1,096	1,967	2,122	86	4/27/95	1,026	1,096	1,550,530	1,169,873
700	0.8261	847	5,418.200	171.893	422	500	922	1,445	119	8/24/95	647	798	1,627,462	1,264,834
600	0.8509	705	5,580.053	161.854	316	308	624	773	209	3/21/96	369	404	1,704,725	1,349,425
500	0.8758	571	5,732.722	152.668	160	175	335	480	318	2/2/97	238	242	1,780,502	1,426,316

FIGURE 10

			JORDAN 'B' No. 1 3-1/2" TUBING				33% ALLOWABLE ON NEUHAUS 14 FEDERAL No. 2							
PRESSURE	Z	P/Z	CUM. GAS	DELTA	JORDAN	NEUHAUS	TOTAL	AVERAGE	DELTA	DATE	JORDAN	NEUHAUS	JORDAN	NEUHAUS
				CUM. GAS	RATE	RATE	RATE	RATE	TIME		AVG RATE	AVG RATE	CUM. GAS	CUM. GAS
PSIA		PSIA	MMCF	MMCF	MCFD	MCFD	MCFD	MCFD	DAYS		MCFD	MCFD	MCF	MCF
2128	0.6359	3346	2,575.156							7/4/93				
2000	0.6389	3130	2,820.960	245.804										
1957	0.6339	3087	2,870.212	49.252	5,671	2,273	7,944			8/20/93			200,556	94,500
1900	0.6447	2947	3,029.669	208.710	5,444	2,273	7,717	7,831	27	9/15/93	5,558	2,273	348,682	155,083
1800	0.6506	2767	3,234.632	204.963	5,047	2,273	7,320	7,519	27	10/12/93	5,246	2,273	491,680	217,048
1700	0.6564	2590	3,435.947	201.316	4,648	2,273	6,921	7,121	28	11/10/93	4,848	2,273	628,732	281,312
1600	0.6623	2416	3,633.713	197.765	4,247	2,273	6,520	6,721	29	12/9/93	4,448	2,273	759,609	348,199
1500	0.6683	2244	3,828.827	195.115	3,855	2,273	6,128	6,324	31	1/9/94	4,051	2,273	884,595	418,328
1400	0.6759	2071	4,025.853	197.025	3,454	2,273	5,727	5,928	33	2/11/94	3,655	2,273	1,006,068	493,881
1300	0.6835	1902	4,218.496	192.644	3,052	2,273	5,325	5,526	35	3/18/94	3,253	2,273	1,119,472	573,121
1200	0.7018	1710	4,437.005	218.509	2,647	2,273	4,920	5,123	43	4/30/94	2,850	2,273	1,241,022	670,079
1100	0.7267	1514	4,660.087	223.082	2,235	2,273	4,508	4,714	47	6/16/94	2,441	2,273	1,356,538	777,645
1000	0.7515	1331	4,868.416	208.329	1,808	949	2,757	3,633	57	8/12/94	2,022	1,611	1,472,473	870,040
900	0.7764	1159	5,063.409	194.993	1,317	949	2,266	2,512	78	10/29/94	1,563	949	1,593,783	943,722
800	0.8012	998	5,246.306	182.897	1,205	949	2,154	2,210	83	1/20/95	1,261	949	1,698,142	1,022,260
700	0.8261	847	5,418.200	171.893	878	949	1,827	1,991	86	4/16/95	1,042	949	1,788,083	1,104,213
600	0.8509	705	5,580.053	161.854	316	308	624	1,226	132	8/26/95	597	629	1,866,930	1,187,220
500	0.8758	571	5,732.722	152.668	160	175	335	480	318	7/10/96	238	242	1,942,707	1,264,111

FIGURE 11

			JORDAN 'B' No. 1 2-3/8" TUBING				46% ALLOWABLE ON NEUHAUS 14 FEDERAL No. 2							
PRESSURE	Z	P/Z	CUM. GAS	DELTA CUM. GAS	JORDAN RATE	NEUHAUS RATE	TOTAL RATE	AVERAGE RATE	DELTA TIME	DATE	JORDAN AVG RATE	NEUHAUS AVG RATE	JORDAN CUM. GAS	NEUHAUS CUM. GAS
PSIA		PSIA	MMCF	MMCF	MCFD	MCFD	MCFD	MCFD	DAYS		MCFD	MCFD	MCF	MCF
2128	0.6359	3346	2,575.156							7/4/93				
2000	0.6389	3130	2,820.960	245.804										
1957	0.6339	3087	2,870.212	49.252	3,950	3,169	7,119			8/20/93			200,556	94,500
1900	0.6447	2947	3,029.669	208.710	3,802	3,169	6,971	7,045	30	9/18/93	3,876	3,169	315,383	188,382
1800	0.6506	2767	3,234.632	204.963	3,550	3,169	6,719	6,845	30	10/18/93	3,676	3,169	425,455	283,273
1700	0.6564	2590	3,435.947	201.316	3,299	3,169	6,468	6,594	31	11/18/93	3,425	3,169	530,014	380,030
1600	0.6623	2416	3,633.713	197.765	3,040	3,169	6,209	6,339	31	12/19/93	3,170	3,169	628,904	478,905
1500	0.6683	2244	3,828.827	195.115	2,782	3,169	5,951	6,080	32	1/20/94	2,911	3,169	722,322	580,602
1400	0.6759	2071	4,025.853	197.025	2,525	3,169	5,694	5,823	34	2/23/94	2,654	3,169	812,112	687,837
1300	0.6835	1902	4,218.496	192.644	2,258	3,169	5,427	5,561	35	3/29/94	2,392	3,169	894,966	797,627
1200	0.7018	1710	4,437.005	218.509	1,995	3,169	5,164	5,296	41	5/10/94	2,127	3,169	982,712	928,389
1100	0.7267	1514	4,660.087	223.082	1,727	3,169	4,896	5,030	44	6/23/94	1,861	3,169	1,065,248	1,068,936
1000	0.7515	1331	4,868.416	208.329	1,461	2,876	4,337	4,617	45	8/7/94	1,594	3,023	1,137,180	1,205,332
900	0.7764	1159	5,063.409	194.993	1,180	1,110	2,290	3,313	59	10/5/94	1,321	1,993	1,214,895	1,322,611
800	0.8012	998	5,246.306	182.897	871	1,110	1,981	2,135	86	12/30/94	1,026	1,110	1,302,735	1,417,668
700	0.8261	847	5,418.200	171.893	422	1,110	1,532	1,757	98	4/6/95	647	1,110	1,366,002	1,526,294
600	0.8509	705	5,580.053	161.854	316	308	624	1,078	150	9/4/95	369	709	1,421,405	1,632,745
500	0.8758	571	5,732.722	152.668	160	175	335	480	318	7/18/96	238	242	1,497,182	1,709,637

FIGURE 12

			JORDAN 'B' No. 1 3-1/2" TUBING				46% ALLOWABLE ON NEUHAUS 14 FEDERAL No. 2							
PRESSURE	Z	P/Z	CUM. GAS	DELTA	JORDAN	NEUHAUS	TOTAL	AVERAGE	DELTA	DATE	JORDAN	NEUHAUS	JORDAN	NEUHAUS
				CUM. GAS	RATE	RATE	RATE	RATE	TIME		AVG RATE	AVG RATE	CUM. GAS	CUM. GAS
PSIA		PSIA	MMCF	MMCF	MCFD	MCFD	MCFD	MCFD	DAYS		MCFD	MCFD	MCF	MCF
2128	0.6359	3346	2,575.156							7/4/93				
2000	0.6389	3130	2,820.960	245.804										
1957	0.6339	3087	2,870.212	49.252	5,671	3,169	8,840			8/20/93			200,556	94,500
1900	0.6447	2947	3,029.669	208.710	5,444	3,169	8,613	8,727	24	9/12/93	5,558	3,169	333,473	170,292
1800	0.6506	2767	3,234.632	204.963	5,047	3,169	8,216	8,415	24	10/7/93	5,246	3,169	461,245	247,484
1700	0.6564	2590	3,435.947	201.316	4,648	3,169	7,817	8,017	25	11/1/93	4,848	3,169	582,978	327,066
1600	0.6623	2416	3,633.713	197.765	4,247	3,169	7,416	7,617	26	11/27/93	4,448	3,169	698,459	409,350
1500	0.6683	2244	3,828.827	195.115	3,855	3,169	7,024	7,220	27	12/24/93	4,051	3,169	807,934	494,989
1400	0.6759	2071	4,025.853	197.025	3,454	3,169	6,623	6,824	29	1/22/94	3,655	3,169	913,456	586,493
1300	0.6835	1902	4,218.496	192.644	3,052	3,169	6,221	6,422	30	2/21/94	3,253	3,169	1,011,038	681,555
1200	0.7018	1710	4,437.005	218.509	2,647	3,169	5,816	6,019	36	3/29/94	2,850	3,169	1,114,492	796,609
1100	0.7267	1514	4,660.087	223.082	2,235	3,169	5,404	5,610	40	5/8/94	2,441	3,169	1,211,559	922,625
1000	0.7515	1331	4,868.416	208.329	1,808	2,876	4,684	5,044	41	6/18/94	2,022	3,023	1,295,052	1,047,461
900	0.7764	1159	5,063.409	194.993	1,317	2,412	3,729	4,207	46	8/3/94	1,563	2,644	1,367,481	1,170,024
800	0.8012	998	5,246.306	182.897	1,205	880	2,085	2,907	63	10/5/94	1,261	1,646	1,446,819	1,273,584
700	0.8261	847	5,418.200	171.893	878	880	1,758	1,921	89	1/3/95	1,042	880	1,539,990	1,352,306
600	0.8509	705	5,580.053	161.854	316	308	624	1,191	136	5/19/95	597	594	1,621,121	1,433,029
500	0.8758	571	5,732.722	152.668	160	175	335	480	318	4/1/96	238	242	1,696,898	1,509,921

FIGURE 13

			JORDAN 'B' No. 1 2-3/8" TUBING				58% ALLOWABLE ON NEUHAUS 14 FEDERAL No. 2							
PRESSURE	Z	P/Z	CUM. GAS	DELTA CUM. GAS	JORDAN RATE	NEUHAUS RATE	TOTAL RATE	AVERAGE RATE	DELTA TIME	DATE	JORDAN AVG RATE	NEUHAUS AVG RATE	JORDAN CUM. GAS	NEUHAUS CUM. GAS
PSIA		PSIA	MMCF	MMCF	MCFD	MCFD	MCFD	MCFD	DAYS		MCFD	MCFD	MCF	MCF
2128	0.6359	3346	2,575.156							7/4/93				
2000	0.6389	3130	2,820.960	245.804										
1957	0.6339	3087	2,870.212	49.252	3,950	3,996	7,946			8/20/93			200,556	94,500
1900	0.6447	2947	3,029.669	208.710	3,802	3,996	7,798	7,872	27	9/15/93	3,876	3,996	303,320	200,446
1800	0.6506	2767	3,234.632	204.963	3,550	3,996	7,546	7,672	27	10/12/93	3,676	3,996	401,527	307,201
1700	0.6564	2590	3,435.947	201.316	3,299	3,996	7,295	7,421	27	11/8/93	3,425	3,996	494,432	415,611
1600	0.6623	2416	3,633.713	197.765	3,040	3,996	7,036	7,166	28	12/5/93	3,170	3,996	581,909	525,900
1500	0.6683	2244	3,828.827	195.115	2,782	3,996	6,778	6,907	28	1/3/94	2,911	3,996	664,142	638,782
1400	0.6759	2071	4,025.853	197.025	2,525	3,996	6,521	6,650	30	2/1/94	2,654	3,996	742,765	757,184
1300	0.6835	1902	4,218.496	192.644	2,258	3,996	6,254	6,388	30	3/3/94	2,392	3,996	814,892	877,701
1200	0.7018	1710	4,437.005	218.509	1,995	3,753	5,748	6,001	36	4/9/94	2,127	3,875	892,322	1,018,780
1100	0.7267	1514	4,660.087	223.082	1,727	3,320	5,047	5,398	41	5/20/94	1,861	3,537	969,238	1,164,945
1000	0.7515	1331	4,868.416	208.329	1,461	2,876	4,337	4,692	44	7/4/94	1,594	3,098	1,040,013	1,302,499
900	0.7764	1159	5,063.409	194.993	1,180	1,399	2,579	3,458	56	8/29/94	1,321	2,137	1,114,475	1,423,030
800	0.8012	998	5,246.306	182.897	871	1,399	2,270	2,424	75	11/12/94	1,026	1,399	1,191,837	1,528,566
700	0.8261	847	5,418.200	171.893	422	1,290	1,712	1,991	86	2/7/95	647	1,345	1,247,652	1,644,644
600	0.8509	705	5,580.053	161.854	316	308	624	1,168	139	6/25/95	369	799	1,298,786	1,755,364
500	0.8758	571	5,732.722	152.668	160	175	335	480	318	5/9/96	238	242	1,374,563	1,832,255

FIGURE 14

			JORDAN 'B' No. 1 3-1/2" TUBING				58% ALLOWABLE ON NEUHAUS 14 FEDERAL No. 2							
PRESSURE	Z	P/Z	CUM. GAS	DELTA CUM. GAS	JORDAN RATE	NEUHAUS RATE	TOTAL RATE	AVERAGE RATE	DELTA TIME	DATE	JORDAN AVG RATE	NEUHAUS AVG RATE	JORDAN CUM. GAS	NEUHAUS CUM. GAS
PSIA		PSIA	MMCF	MMCF	MCFD	MCFD	MCFD	MCFD	DAYS		MCFD	MCFD	MCF	MCF
2128	0.6359	3346	2,575.156							7/4/93				
2000	0.6389	3130	2,820.960	245.804										
1957	0.6339	3087	2,870.212	49.252	5,671	3,996	9,667			8/20/93			200,556	94,500
1900	0.6447	2947	3,029.669	208.710	5,444	3,996	9,440	9,554	22	9/10/93	5,558	3,996	321,967	181,798
1800	0.6506	2767	3,234.632	204.963	5,047	3,996	9,043	9,242	22	10/3/93	5,246	3,996	438,305	270,424
1700	0.6564	2590	3,435.947	201.316	4,648	3,996	8,644	8,844	23	10/25/93	4,848	3,996	548,654	361,389
1600	0.6623	2416	3,633.713	197.765	4,247	3,996	8,243	8,444	23	11/18/93	4,448	3,996	652,824	454,984
1500	0.6683	2244	3,828.827	195.115	3,855	3,996	7,851	8,047	24	12/12/93	4,051	3,996	751,049	551,875
1400	0.6759	2071	4,025.853	197.025	3,454	3,996	7,450	7,651	26	1/7/94	3,655	3,996	845,164	654,785
1300	0.6835	1902	4,218.496	192.644	3,052	3,996	7,048	7,249	27	2/2/94	3,253	3,996	931,613	760,980
1200	0.7018	1710	4,437.005	218.509	2,647	3,753	6,400	6,724	32	3/7/94	2,850	3,875	1,024,213	886,888
1100	0.7267	1514	4,660.087	223.082	2,235	3,320	5,555	5,978	37	4/13/94	2,441	3,537	1,115,312	1,018,872
1000	0.7515	1331	4,868.416	208.329	1,808	2,876	4,684	5,120	41	5/24/94	2,022	3,098	1,197,573	1,144,939
900	0.7764	1159	5,063.409	194.993	1,317	2,412	3,729	4,207	46	7/9/94	1,563	2,644	1,270,003	1,267,502
800	0.8012	998	5,246.306	182.897	1,205	1,110	2,315	3,022	61	9/8/94	1,261	1,761	1,346,327	1,374,076
700	0.8261	847	5,418.200	171.893	878	1,110	1,988	2,151	80	11/27/94	1,042	1,110	1,429,546	1,462,750
600	0.8509	705	5,580.053	161.854	316	308	624	1,306	124	3/31/95	597	709	1,503,533	1,550,617
500	0.8758	571	5,732.722	152.668	160	175	335	480	318	2/12/96	238	242	1,579,310	1,627,508

FIGURE 15

ALLOWBLE CALCULATION

MANZANO OIL COMPANY

NEUHAUS 14 FEDERAL No. 2

ATTACHMENT 1

$$\text{ALLOWABLE} = \frac{\dfrac{\text{ACTUAL STANDOFF}}{\text{LEGAL STANDOFF}} + \dfrac{\text{MANZANO RESERVOIR VOLUME}}{\text{MARATHON RESERVOIR VOLUME}}}{2} * \frac{\text{MARATHON NET PAY}}{\text{MANZANO NET PAY}}$$

$$\text{ALLOWABLE} = \frac{\dfrac{660'}{1{,}980'} + \dfrac{2{,}331 \text{ ACRE-FEET}}{3{,}776 \text{ ACRE-FEET}}}{2} * \frac{39'}{90'}$$

$$\boxed{\textit{ALLOWABLE} = \quad \textit{21\%}}$$

ATTACHMENT 2

Reservoir Fluid Study
for

MARATHON OIL COMPANY

Jordan 'B' #1
OSUDO
Lea County, New Mexico

RFLM 92037
12-Aug-92

A product of
Core Laboratories
a division of Western Atlas International, Inc.

Western Atlas International
A Litton Dresser Company

CORE LABORATORIES

12 August 1992

Marathon Oil Company
125 Missouri Ave
Midland, Texas 79701

Attention: Mr. Shawn Posey

Subject:	Reservoir Fluid Study
Well:	Jordan 'B' #1
File:	RFLM 92037

Gentlemen :

Samples of separator liquid and vapor were collected from the subject well on 16 April 1992 and submitted to our Midland laboratory facilities for use in a condensate reservoir fluid study. A second sampling was performed on 17 June 1992.

It was requested by a Marathon representive not to continue the testing. The following report is the compositional and recombination results.

Should any questions arise or if we may be of further service in anyway, please do not hesitate to contact us.

Sincerely,

Tom Coleman

Thomas R. Coleman
Supervisor
Reservoir Fluid Laboratory-Midland

LABORATORY PROCEDURES

RFLM 92037
12 August 1992

Duplicate samples of separator gas and separator liquid were received in our laboratory on 16 April 1992. As a quality check, the opening pressures of the separator gas cylinders were determined. In addition, the room temperature bubblepoint pressure of the separator liquid samples was measured. This information, summarized on page three of the report, indicated that the samples received in the laboratory closely represented reported field separator conditions.

The composition of the separator gas was determined using temperature programmed extended gas chromatography. The composition, together with the calculated properties of the separator gas, is presented on page four. The composition of the separator liquid was measured to an eicosanes plus fraction using the flash/chromatographic technique. This resulted in the composition listed on page five.

The reported gas production rate was corrected with the factors shown on page two. A shrinkage test was performed to determine the first stage liquid rate. Using the corrected gas/liquid ratio in conjunction with the compositions of the separator products, the reservoir fluid composition was calculated. This composition is presented on page six. The separator gas and separator liquid were physically recombined to the gas/liquid ratio and the resulting fluid was used to complete the remaining testing program.

A portion of the reservoir fluid was charged to a high pressure visual cell and thermally expanded to the reported reservoir temperature of 152 °F. After establishing thermal equilibrium, the fluid sample was subjected to a constant composition expansion. During the expansion, a dewpoint pressure was observed to occur at 5649 psig.

To ensure that the mix was made correctly a spike/flash routine was performed on the mix in order to compare its composition with the composition (page 6) used in the recombination of separator products. The results listed on page 7 show a good comparison between the two compositions.

A second set of samples were taken on 17 June 1992 in order to determine if the first set of samples were of good quality. Composition of the separator gas and liquid was determined and showed a good comparison to the first set of samples. These compositons are listed on pages 8 and 9.

Comparison of the reported reservoir pressure of approximately 3800 psig to the observed dewpoint of 5649 psig indicates either the reservoir fluid is saturated or the producing interval has a thin layer in which a light gravity oil is being produced with the gas.

General Well Information

(Section 1)

RFLM 92037
12-Aug-92

MARATHON OIL COMPANY
Jordan 'B' #1
RFLM 92037

General Well Information

Company	**MARATHON OIL COMPANY**
Well Name	**Jordan 'B' #1**
API Well Number	
File Number	**RFLM 92037**
Date Sample Collected	**16-Apr-92**
Sample Type	**Separator**
Geographical Location	**Lea County, New Mexico**
Field	**OSUDO**

Well Description

Formation	**Wolfcamp**	
Pool (or Zone)	*	
Date Completed	*	
Elevation	**11322**	ft
Producing Interval	**11426-11478**	ft
Total Depth	**11617**	ft
Tubing Size	**2 3/8**	in
Tubing Depth	**11314**	ft
Casing Size	*	in
Casing Depth	*	ft

Pressure Survey Data

Data from Original Discovery Well

Date	*	
Reservoir Pressure	**3800**	psig

Data at Sample Collection

Date	**16-Apr-92**	
Reservoir Pressure	*	psig
Reservoir Temperature	**152**	°F
Pressure Tool	*	
Flowing Bottom-Hole Pressure	*	psig
Flowing Tubing Pressure	**1575**	psig

* Data not forwarded to Core Laboratories.

MARATHON OIL COMPANY
Jordan 'B' #1
RFLM 92037

Production Data

Data from Original discovery Well

Location	*	
Date	*	
Oil Gravity @ STP	*	°API
Separator Pressure	*	psig
Separator Temperature	*	°F
Production Rates		
Gas	*	Mscf/D
Liquid	*	STbbl/D
Gas/Liquid Ratio	*	scf/bbl

Separator Conditions

Primary Separator Pressure	**480**	psig
Primary Separator Temperature	**78**	°F
Secondary Separator Pressure	**88**	psig
Secondary Separator Temperature	**78**	°F
Primary Separator Gas Production Rate	**5440**	Mscf/D

Gas Factors -

Field Values:		
Pressure Base	**15.025**	psia
Temperature Base	**60**	°F
Compressibility Factor (Fpv)	*	
Gas Gravity Factor (Fg)	**1.1893**	
Laboratory Values:		
Pressure Base	**14.65**	psia
Temperature Base	**60**	°F
Compressibility Factor (Fpv)	**1.0513**	
Gas Gravity Factor (Fg)	**1.1986**	

Primary Separator Liquid Rate	*	bbl/D	at	°F
Secondary Separator Liquid Rate	*	bbl/D	at	°F
Separator Gas / Separator Liquid Ratio	*	scf/bbl		
Separator Gas / Stock Tank Liquid Ratio	**8774**	scf/bbl		
Stock Tank Liquid / Separator Gas Ratio	*	bbl/Mscf		
Separator Liquid / Stock Tank Liquid Ratio	*	bbl/bbl	at	°F

* Data not forwarded to Core Laboratories.

Preliminary Quality Checks

(Section 2)

RFLM 92037
12-Aug-92

PRELIMINARY QUALITY CHECKS PERFORMED ON SAMPLES
RECEIVED IN LABORATORY

Separator Gas					
Cylinder Number	Sampling Conditions		Laboratory Opening Conditions		
	psig	°F	psig	°F	Liquid Recovered (cc)
K18299	480	78	440	70	0
*K24464	480	78	450	70	0

Separator Liquid					
Cylinder Number	Sampling Conditions		Laboratory Bubblepoint		Water Recovered (cc)
	psig	°F	psig	°F	
95	480	78	450	65	0
*139	480	78	450	67	1
6	480	78	445	67	0

* Used for recombination

Wellstream Composition

(Section 3)

RFLM 92037
12-Aug-92

MARATHON OIL COMPANY

Jordan 'B' #1

RFLM 92037

SEPARATOR GAS COMPOSITION

IN WELLSTREAM RECOMBINATION

Component	Mol %	GPM	MW
Hydrogen Sulfide	0.00		34.080
Carbon Dioxide	0.32		44.010
Nitrogen	1.25		28.013
Methane	81.00		16.043
Ethane	10.72		30.070
Propane	4.30		44.097
i-Butane	0.57		58.123
n-Butane	1.13		58.123
i-Pentane	0.23		72.150
n-Pentane	0.24		72.150
Hexanes	0.14		86.177
Heptanes	0.07		100.200
Octanes	0.02		114.230
Nonanes	0.01		128.270
Totals	100.00	0.000	

Gas Cylinder Number

K18299:1

Sampling Conditions

Separator Pressure, psig 480
Separator Temperature, °F 78

Field Data

Pressure Base, psig 15.025
Temperature Base, °F 60

Fg factor 1.1987
Fpv factor 1.0079

Field measured gas flow rate in Mscf/D
at 15.025 psia and 60 °F 5440

Laboratory Data

Pressure Base, psig 15.025
Temperature Base, °F 60

Fg factor 1.1987
Fpv factor 1.0079

Lab corrected gas flow rate in Mscf/D
at 15.025 psia and 60 °F 5,290.0

Total Gas Properties

Calculated separator gas gravity
(air=1.000) 0.696

Gross heating value in Btu/scf
at 15.025 psia and 60 °F 1194

Calculated Z (deviation) factor
at sampling conditions 0.945

MARATHON OIL COMPANY

Jordan 'B' #1

RFLM 92037

SEPARATOR LIQUID COMPOSITION
IN WELLSTREAM RECOMBINATION

Component	Mol %	Weight %	Plus Fractions	
			Density gm/cc at 60 °F	Molecular Weight
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.10	0.05		
Nitrogen	0.05	0.02		
Methane	12.77	2.20		
Ethane	8.07	2.61		
Propane	9.34	4.43		
i-Butane	3.25	2.03		
n-Butane	7.11	4.45		
i-Pentane	3.62	2.81		
n-Pentane	4.64	3.60		
Hexanes	6.55	6.07		
Heptanes	9.23	9.95		
Octanes	10.45	12.84		
Nonanes	6.22	8.58		
Decanes	4.26	6.52		
Undecanes	2.93	4.92		
Dodecanes	1.99	3.64		
Tridecanes	1.81	3.59		
Tetradecanes	1.37	2.92		
Pentadecanes	1.12	2.56		
Hexadecanes	0.79	1.92		
Heptadecanes	0.66	1.71		
Octadecanes	0.59	1.61		
Nonadecanes	0.49	1.41		
Eicosanes plus	2.59	9.56	0.9963	343.
Totals	100.00	100.00		

Liquid Cylinder Number

QC139:1

Sampling Conditions

Separator Pressure, psig 480

Separator Temperature, °F 78

Stock Tank Flow Rate

(at 60 °F)

756.1 bbl/D

Separator Flow Rate

(at sampling conditions)

930.1 bbl/D

Total Liquid Properties

(at sampling conditions)

Sample Density, gm/cc 0.6732

Sample Molecular Weight .... 93.

MARATHON OIL COMPANY

Jordan 'B' #1

RFLM 92037

RESERVOIR FLUID COMPOSITION
FROM RECOMBINED WELLSTREAM

Component	Mol %	GPM	Plus Fractions Density gm/cc at 60 °F	Plus Fractions Molecular Weight
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.29			
Nitrogen	1.11			
Methane	72.83			
Ethane	10.40	2.860		
Propane	4.90	1.182		
i-Butane	0.89	0.186		
n-Butane	1.85	0.355		
i-Pentane	0.64	0.084		
n-Pentane	0.77	0.087		
Hexanes	0.91	0.054		
Heptanes	1.17	0.031		
Octanes	1.27			
Nonanes	0.75			
Decanes	0.51			
Undecanes	0.35			
Dodecanes	0.24			
Tridecanes	0.22			
Tetradecanes	0.16			
Pentadecanes	0.13			
Hexadecanes	0.09			
Heptadecanes	0.08			
Octadecanes	0.07			
Nonadecanes	0.06			
Eicosanes plus	0.31		0.9963	343.
Totals	100.00	4.839		

Sampling Conditions

Separator Pressure, psig 480

Separator Temperature, °F 78

Field measured
Separator Gas / Stock Tank Liquid ratio
at sampling conditions
6.9965 Mscf/bbl

Lab corrected
Separator Gas / Separator Liquid ratio
at sampling conditions
6.9363 Mscf/bbl

Marathon Oil

Jordan 'B' #1

RFL 92037

Composition of Mix #1 From Spike Flash

(From Flash / Chromatographic Technique)

Component.	Mol %	Wt %	Density (gm/cc)	GPM	Vol %
Hydrogen Sulfide	0.00				
Carbon Dioxide	0.29	0.44	0.8172		0.23
Nitrogen	1.09	1.07	0.8086		0.55
Methane	73.17	41.14	0.2997		57.24
Ethane	10.35	10.90	0.3558	2.753	12.78
Propane	5.00	7.72	0.5065	1.370	6.36
iso-Butane	0.86	1.76	0.5623	0.280	1.30
n-Butane	2.00	4.06	0.5834	0.627	2.90
iso-Pentane	0.69	1.74	0.6241	0.251	1.16
n-Pentane	0.85	2.15	0.6305	0.306	1.42
Hexanes	0.92	2.79	0.6630	0.376	1.75
Heptanes	0.93	3.27	0.6875	0.427	1.98
Octanes	0.83	3.34	0.7063	0.423	1.97
Nonanes	0.63	2.82	0.7212	0.353	1.63
Decanes	0.50	2.47	0.7335		1.40
Undecanes	0.37	2.02	0.7442		1.13
Dodecanes	0.26	1.56	0.7520		0.87
Tridecanes	0.25	1.58	0.7600		0.87
Tetradecanes	0.18	1.25	0.7663		0.68
Pentadecanes	0.15	1.12	0.7723		0.61
Hexadecanes	0.11	0.82	0.7758		0.44
Heptadecanes	0.09	0.73	0.7803		0.39
Octadecanes	0.08	0.68	0.7853		0.36
Nonadecanes	0.07	0.60	0.7893		0.32
Eicosanes plus	0.33	3.97	0.9939		1.66
Totals	100.00	100.00		7.166	100.00

Sample Characteristics

Total Sample Molecular Weight 28.6

Theoretical Sample Density at 14.65 psia and 60 °F in gm/scc 0.4170

Gas Mol Fraction 0.9596

Liquid Mol Fraction 0.0404

Properties of Heavy Fractions

Plus Fraction	Mol %	Wt %	Density (gm/cc)	°API	MW
Hexanes Plus	5.70	29.02	0.7531	56.4	146
Heptanes Plus	4.78	26.23	0.7642	53.7	157
Decanes Plus	2.39	16.80	0.8026	44.8	202
Undecanes Plus	1.89	14.33	0.8159	41.9	218
Dodecanes Plus	1.52	12.31	0.8290	39.2	233
Pentadecanes Plus	0.83	7.92	0.8737	30.5	275
Eicosanes Plus	0.33	3.97	0.9939	10.9	341

Marathon Oil

Jordan 'B' #1

RFL 92037

Composition of Separator Gas-Second Sampling

(From Chromatographic Technique)

Component	Mol %	GPM	MW	Liq Dens (gm/cc)
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.31		44.010	.8172
Nitrogen	1.28		28.013	.8086
Methane	81.39		16.043	.2997
Ethane	10.72	2.924	30.070	.3558
Propane	4.35	1.223	44.097	.5065
iso-Butane	0.50	.167	58.123	.5623
n-Butane	1.14	.367	58.123	.5834
iso-Pentane	0.10	.037	72.150	.6241
n-Pentane	0.11	.041	72.150	.6305
Hexanes	0.04	.017	86.177	.6630
Heptanes	0.05	.024	100.20	.6875
Octanes	0.01	.005	114.23	.7063
Nonanes	Nil			
Decanes	0.00			
Undecanes	0.00			
Totals	100.00	4.805		

Sampling Conditions

490 psig
86 °F

Sample Characteristics

This is Core Lab sample number 210

Critical Pressure (psia) 663.5
Critical Temperature (°R) 384.4

Average Molecular Weight 19.90

Calculated Gas Gravity (air = 1.000) 0.687

Gas Gravity
Factor, Fg 1.2066
Super Compressibility Factor, Fpv
at sampling conditions 1.0451
Gas Z-Factor
at sampling conditions * 0.916

at 15.025 psia and 60 °F

Gross Heating Value
(BTU/scf dry gas) 1198

Properties of Plus Fractions

Component	Mol %	MW	Liq Dens (gm/cc)	API Gravity
Heptanes plus	0.06	102.5	0.691	50.5

* From: Standing, M.B., "Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems", SPE (Dallas),1977, 8th Edition, Appendix II.

Marathon Oil Company

Jordan 'B' #1

RFL 92037

Composition of Separator Liquid-Second Sampling

(From Flash / Chromatographic Technique)

Component	Mol %	Wt %	Density (gm/cc)	GPM	Vol %
Hydrogen Sulfide	0.00				
Carbon Dioxide	0.11	0.05	0.8172		0.04
Nitrogen	0.05	0.02	0.8086		0.01
Methane	12.01	2.12	0.2997		4.69
Ethane	7.62	2.52	0.3558	2.079	4.69
Propane	8.74	4.23	0.5065	2.456	5.54
iso-Butane	2.50	1.60	0.5623	0.834	1.88
n-Butane	6.55	4.18	0.5834	2.106	4.75
iso-Pentane	4.72	3.74	0.6241	1.762	3.98
n-Pentane	4.13	3.28	0.6305	1.526	3.45
Hexanes	7.65	7.24	0.6630	3.210	7.25
Heptanes	10.42	11.47	0.6875	4.902	11.06
Octanes	11.59	14.55	0.7063	6.051	13.68
Nonanes	6.78	9.55	0.7212		8.78
Decanes	4.56	7.14	0.7335		6.45
Undecanes	3.05	5.24	0.7442		4.67
Dodecanes	2.02	3.77	0.7520		3.32
Tridecanes	1.79	3.62	0.7600		3.16
Tetradecanes	1.31	2.85	0.7663		2.47
Pentadecanes	1.04	2.43	0.7723		2.09
Hexadecanes	0.71	1.72	0.7758		1.47
Heptadecanes	0.57	1.48	0.7803		1.26
Octadecanes	0.48	1.33	0.7853		1.12
Nonadecanes	0.38	1.10	0.7893		0.93
Eicosanes plus	1.22	4.77	0.9713		3.26
Totals	100.00	100.00		24.926	100.00

Sample Characteristics

Total Sample Molecular Weight 91.0

Theoretical Sample Density at 15.025 psia and 60 °F in gm/scc 0.6633

Gas Mol Fraction 0.4207

Liquid Mol Fraction 0.5793

Properties of Heavy Fractions

Plus Fraction	Mol %	Wt %	Density (gm/cc)	°API	MW
Hexanes Plus	53.57	78.26	0.7316	61.9	133
Heptanes Plus	45.92	71.02	0.7394	59.9	141
Decanes Plus	17.13	35.45	0.7786	50.2	188
Undecanes Plus	12.57	28.31	0.7909	47.4	205
Dodecanes Plus	9.52	23.07	0.8023	44.9	221
Pentadecanes Plus	4.40	12.83	0.8408	36.8	266
Eicosanes Plus	1.22	4.77	0.9713	14.2	357

Osudo Reservoir Fluid Study
Jordan B No. 1 Well

by

G.M. Ginley

Work done by: D.L. Burnham

G.M. Ginley

Marathon Oil Company

Petroleum Technology Center

Project 22 97 016

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Reservoir Fluid Study
Jordan "B" No. 1 Well
Osudo Reservoir
Lea County, New Mexico

A reservoir fluid study was performed on first stage separator gas and liquid samples taken from the Jordan "B" No. 1 well. This report contains the following results:

(1) Summary of sampling conditions.

(2) Compositional analysis of the first stage separator gas and first stage separator liquid.

(3) Discussion of field separator scheme and procedure used to calculate the first stage gas oil ratio.

(4) Recombination of separator fluids.

(5) Data obtained from a constant composition expansion (CCE) study of the recombined fluid.

(6) Data obtained from a constant volume depletion (CVD) study of the recombined fluid.

(7) Comparison between Core Laboratory data and PTC data.

Sampling Conditions

Separator gas and liquid samples were obtained from the subject well on June 17, 1992 by a representative of Core Laboratories. Reported field and sampling data are given in Table 1. This data is directly from S. M. Posey, Midland or from the Core Laboratory sampling documentation. Samples were received at PTC on June 25, 1992.

Analysis of Fluid Compositions

The compositions of the separator fluids were analyzed using gas chromatography. The molecular weights of components C_6 - C_{14} are the values reported by Katz and Firoozabadi[1] for general petroleum fractions. The molecular weight of the C_{15+} fraction is calculated using a three step procedure. First, the separator liquid is flashed to atmospheric conditions. Then we measure the molecular weight, specific gravity, and composition of the resulting liquid. The C_{15+} molecular weight is then calculated using the fluid composition and overall molecular weight. The specific gravity for each carbon number fraction is calculated using a constant Watson K factor of 11.920 for each frac-

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[1] Katz, D. L. and Firoozabadi, A., "Predicting Phase Behavior of Condensate/Crude-Oil Systems Using Methane Interaction Coefficients", J. Pet. Tech., November 1978, pp. 1649-1655.

tion. The value of the Watson K factor is picked so that the calculated specific gravity of the stabilized liquid matches the measured value. Table 2 shows the composition of the separator gas. The separator liquid composition is given through C_{15+} in Table 3.

Calculation of First Stage Separator Gas Oil Ratio

Field measurements of the primary separator gas and liquid rates were not available. Instead measurements were obtained for the stock tank oil rate, combined gas rate from the three separators, and gas rate from the stock tank. A schematic diagram of the separator scheme is given in Figure 1. We flashed a sample of separator liquid to the low pressure separator conditions and then flashed the resulting liquid to stock tank conditions. Information obtained from the flash was combined with density and measured fluid compositions to obtain an actual primary gas oil ratio of 9217 scf primary separator gas/bbl primary separator liquid. Table 4 gives a summary of the data used to calculate the actual GOR. In performing these calculaitons, it was assumed that all of the fluid flowed through the 2 stage high pressure separator. S. M. Posey of Midland informed us that approximate 90% of the flow does go through this separator.

Second stage separator liquid was flashed to 12 psia and 90°F. Table 5 gives the properties of the resulting gas and liquid. The GOR reported in Table 5 varies from the field stock tank GOR. The actual field ratio was used in calculating the primary separator flow rates.

Recombination of First Stage Separator Fluids

The separator gas and liquid were recombined with a target GOR of 9217 scf sep gas/bbl sep liquid. The actual GOR of the recombined fluid used by our lab in the phase behavior experiments were 9179 scf sep gas/bbl sep liquid. Table 6 contains the calculated composition of the recombined fluid used in the phase behavior experiments. Molecular weights and specific gravities of the plus fractions and the overall fluid are given in Table 7.

Constant Composition Expansion

The recombined fluid was charged to the PVT cell at reservoir temperature (152°F) and 8428 psia. A constant composition expansion test was performed on the fluid. A visual dew point pressure of 7213 psia was observed. This was the first point at which the fluid remained "cloudy" after equilibration. At 6562 psia we first observed liquid droplets. The first measurable amount of liquid occurred at 5713 psia.

Pressure-Volume relations of the reservoir fluid obtained during the CCE are presented in Table 8. Figures 2 and 3 present the relative volume and compressibility of the fluid as a function of pressure. Figure 4 shows the liquid dropout curve. The liquid volume in this graph is expressed as a percent of the total volume at the current cell pressure. This fluid system exhibits a very long tail on the liquid dropout curve. There is a 1500 psi difference between the visual dew point pressure and the pressure at which we obtained a measurable amount of liquid. We chose to begin the constant volume depletion study at 5713 psia. Thus, the relative volume data in Table 8 are reported relative to the volume at 5713 psia. You can easily recalculate the volumes relative to the total volume at the visual dew point of 7213 psia if necessary. The data presented in Figure 4 are shown as a percent of the total volume at the stated pressure.

Constant Volume Depletion

After completion of the CCE, the fluid was repressurized to 5713 psia. The cell volume was increased until a pressure of 3912 psia was obtained. The fluids were equilibrated and volume measurements were obtained. Then enough gas was removed while maintaining 3912 psia pressure in the cell to return to the original volume at the dew point pressure (5713 psia). This procedure was repeated at 2514, 2012, 1013 and 512 psia. The weight of gas removed was recorded for each depletion step. The composition of the gas obtained at each pressure was measured by gas chromatography. Table 9 gives the measured gas compositions and calculated molecular weights, densities, and compressibility factors. Also stated in Table 9 is the cumulative production as a percent of the initial moles present. Table 10 gives the measured liquid volumes for the depletion steps as percent of the saturation volume. Figure 5 compares the liquid volumes present during the constant composition expansion and the constant volume depletion. The liquid volumes in this figure are expressed as a percent of the saturation volume.

Comparison of PTC Data with Core Laboratory Data

At the start of our reservoir fluid study, there was some concern expressed about the dew point pressure of approximately 5600 psia obtained by Core Laboratories. Several possible sources of error were considered and Core Laboratories took a second set of samples and repeated the compositional analyses of the separator fluids. We obtained samples from the second sampling period. I had several discussions with T. Coleman and F. Vrla of Core Laboratories concerning GOR calculations and fluid compositions. The GOR calculated by Core Laboratories is consistent with the value we obtained from our measurements. The measured liquid composition is also comparable to our measured composition. Core Laboratories reported a dew point pressure of 5600 psia. This value was obtained with the first set of separator samples. This dew point value is consistent with the 5713 psia pressure at which we observed the first measurable amount of liquid. Core Laboratories did not measure the liquid dropout curve so it is impossible to compare the two studies any further.

Table 1
Field Data for Reservoir Fluid Study

Well Record

Well	Jordan "B" No. 1	
Field	Osudo	
County	Lea	
State	New Mexico	

Well Characteristics

Formation	Wolfcamp	
Elevation	11,322	ft
Total Depth	11,617	ft
Producing Interval	11,426-11,478	ft
Tubing Size	2 3/8" OD, 1.995" ID	
Tubing Depth	11,314	ft
Reservoir Temperature	153	°F
Reservoir Pressure	3500	psig
Water Cut	19	%
Tubing Pressure (flowing)	1340	psig
Reservoir Pressure (flowing)	3200	psig

Sampling Conditions

Well Testing Company	Core Laboratories	
Date Sampled	6/17/92	
2 stage Primary Separator Temperature	86	°F
2 stage Primary Separator Pressure	490	psig
3 stage Primary Separator Temperature	80	°F
3 stage Primary Separator Pressure	400	psig
Low Pressure Separator Temperature	76	°F
Low Pressure Separator Pressure	150	psig
Gas Meter Temperature	68	°F
Gas Meter Pressure	95	psig
Metered Gas Rate	6022	Mscf/day
(Total of primary and secondary separator gases)		
Stock Tank Temperature	90	°F
Stock Tank Oil Rate	534	STB/day
Stock Tank Water Rate	136	bbl/day
Stock Tank Gas Rate	175	Mscf/day
Standard Pressure	15.025	psia
Standard Temperature	60	°F

Table 2
Separator Gas Composition

Component	Mass Percent	Mole Percent	Molecular Weight
Nitrogen	1.573	1.133	
Carbon Dioxide	0.664	0.304	
Methane	64.422	81.171	
Ethane	15.703	10.517	
Propane	9.438	4.315	
iso-Butane	1.642	0.570	
n-Butane	3.388	1.176	
iso-Pentane	0.943	0.263	
n-Pentane	0.981	0.274	
Hexanes	0.655	0.157	84.00
Heptanes	0.423	0.089	96.00
Octanes	0.160	0.030	107.00
Nonanes	0.008	0.001	121.00
Total	100.00	100.00	

Molecular Weight	20.160
Gas Gravity	0.6959

Table 3
Separator Liquid Composition

Component	Mass Percent	Mole Percent	Molecular Weight	Specific Gravity
Nitrogen	0.00	0.00		
Carbon Dioxide	0.00	0.00		
Methane	2.19	13.35		
Ethane	1.97	6.38		
Propane	3.40	7.50		
iso-Butane	1.41	2.36		
n-Butane	4.02	6.75		
iso-Pentane	2.68	3.61		
n-Pentane	3.56	4.80		
Hexanes	6.31	7.32	84.00	0.7102
Heptanes	10.24	10.39	96.00	0.7293
Octanes	13.05	11.88	107.00	0.7455
Nonanes	8.44	6.79	121.00	0.7614
Decanes	6.80	4.95	134.00	0.7756
Undecanes	5.03	3.33	147.00	0.7880
Dodecanes	4.14	2.51	161.00	0.7998
Tridecanes	4.43	2.47	175.00	0.8102
Tetradecanes	3.33	1.71	190.00	0.8204
C15+	18.99	3.89	475.00	0.8522
Total	100.00	100.00		
C6+	80.77	55.24	142.4	0.7710
C7+	74.45	47.92	151.4	0.7710
C12+	30.89	10.57	284.6	0.8358
C15+	18.99	3.89	475.0	0.8522

Molecular Weight	97.41
Specific Gravity	0.7016

Table 4
GOR Determination

Reservoir	Osudo	
Well	Jordan "B" No. 1	
Primary Separator pressure	505	psia
Primary Separator Temperature	86	°F
Pressure Base	15.025	psia
Temperature Base	60	°F
Primary Separator Gas		
Flow Rate (calculated)	5908	Mscf/day
Lab Gas Compressibility Factor (z)	1.1050	
Lab Gas Gravity	0.8598	
Molecular Weight	24.910	g/mol
Density	0.0311	g/cm^3
Density at standard conditions (ideal gas)	0.0671	lb/scf
Secondary Separator Gas		
Lab Gas Compressibility Factor (z)	0.9560	
Flow Rate (measured from two stage flash)	114	Mscf/day
Primary Separator Liquid		
Flow Rate (calculated)	641.0	sep bbl/day
Density	44.88	lb/ft^3
Shrinkage Factor	0.8331	STB/bbl
(S. T. Liquid Volume @ 60 °F/Prim Sep Liq Volume @ 86 °F)		
Gas Oil Ratio using calculated flow rates	9217	scf prim sep gas/bbl prim sep liq
Gas Oil Ratio (g gas/g liquid)	2.453	g gas/g liquid
Gas Oil Ratio of PTC Recombined Fluid	7429	scf prim sep gas/bbl prim sep liq
	1.977	g gas/g liquid

Table 5
Second Stage Separator Liquid
Flashed to 12 psia and 90 °F

Gas Liquid Ratio	=	269	scf/STB
Gravity of S.T. Liquid	=	64.4	°API @ 60°F

Stock Tank Gas Composition

Component	Mass Percent	Mole Percent	Molecular Weight
Nitrogen	0.000	0.000	
Carbon Dioxide	0.686	0.388	
Methane	40.324	62.778	
Ethane	24.868	20.580	
Propane	18.089	10.217	
iso-Butane	2.976	1.276	
n-Butane	6.175	2.648	
iso-Pentane	1.649	0.569	
n-Pentane	1.712	0.591	
C6+	3.521	0.953	92
Total	100.00	100.00	

Molecular Weight	24.91
Gas Gravity	0.8598

Table 6
Recombined Fluid Composition

Component	Separator Gas Mass Percent	Separator Liquid Mass Percent	Recombined Mass Percent	Recombined Mole Percent
Nitrogen	1.57		1.04	1.03
Carbon Dioxide	0.66		0.44	0.28
Methane	64.42	2.19	43.52	74.75
Ethane	15.70	1.97	11.09	10.13
Propane	9.44	3.40	7.41	4.62
iso-Butane	1.64	1.41	1.56	0.74
n-Butane	3.39	4.02	3.60	1.70
iso-Pentane	0.94	2.68	1.52	0.58
n-Pentane	0.98	3.56	1.85	0.70
Hexanes	0.65	6.31	2.56	0.84
Heptanes	0.42	10.24	3.72	1.06
Octanes	0.16	13.05	4.49	1.15
Nonanes	0.01	8.44	2.84	0.64
Decanes		6.80	2.28	0.47
Undecanes		5.03	1.69	0.32
Dodecanes		4.14	1.39	0.24
Tridecanes		4.43	1.49	0.23
Tetradecanes		3.33	1.12	0.16
C15+		18.99	6.38	0.37
Total	100.00	100.00	100.00	100.00
C6+			27.96	5.49
C7+			25.40	4.65
C12+			10.38	1.00
C15+			6.38	0.37

Table 7
Properties of Recombined Fluid

	Molecular Weight	Specific Gravity
C6+	140.0	0.7802
C7+	150.1	0.7873
C12+	284.6	0.8357
C15+	475.0	0.8522
Total Fluid	27.48	

Table 8
Pressure-Volume Relations at 152°F
Constant Composition Expansion

	Pressure (psia)	Relative Volume(1)	Deviation Factor Z	Liquid Volume Percent(2)
	8428	0.8603	1.0603	
	8212	0.8636	1.0372	
	8020	0.8742	1.0254	
	7813	0.8829	1.0088	
	7612	0.8885	0.9891	
	7414	0.8968	0.9723	
	7213	0.9081	0.9579	Trace
	7012	0.9170	0.9404	Trace
	6812	0.9373	0.9337	Trace
	6562	0.9469	0.9087	Trace
	6464	0.9545	0.9023	Trace
	6362	0.9585	0.8918	Trace
	6212	0.9645	0.8762	Trace
	6012	0.9768	0.8588	Trace
	5813	0.9877	0.8397	Trace
dew point	5713	1.0000	0.8355	0.01
	5613	0.9954	0.8170	0.12
	5512	1.0036	0.8090	0.09
	5412	1.0166	0.8046	0.21
	5313	1.0322	0.8020	0.30
	5212	1.0355	0.7893	0.42
	5011	1.0481	0.7681	0.65
	4813	1.0730	0.7552	1.06
	4613	1.0962	0.7395	1.44
	4362	1.1297	0.7207	1.99
	3912	1.1915	0.6816	3.42
	3415	1.3073	0.6529	5.08
	2912	1.4871	0.6333	7.04
	2513	1.7094	0.6282	7.37
	2012	2.1690	0.6382	6.85
	1512	3.0181	0.6674	4.87
	1262	3.7192	0.6864	3.83

(1) Relative Volume(Bt): V/Vsat is the total volume of fluid(oil and gas) at the indicated pressure per volume of saturated oil at the dew point pressure.

(2) Liquid Volume Percent is calculated as a percent of total volume at 152 °F and the indicated pressure.

Table 9
Constant Volume Depletion Study at 152 °F
Compositions of Produced Wellstreams - Mole Percent

Pressure (psia)	**3912**	**2514**	**2012**	**1013**	**512**
Component					
Nitrogen	1.166	1.095	1.155	1.113	1.156
Carbon Dioxide	0.198	0.170	0.135	0.125	0.128
Methane	76.914	79.413	80.015	79.882	77.834
Ethane	10.638	10.419	10.383	10.636	11.317
Propane	5.180	4.907	4.616	4.733	5.584
iso-Butane	0.793	0.683	0.654	0.651	0.779
n-Butane	1.819	1.480	1.407	1.398	1.685
iso-Pentane	0.594	0.421	0.393	0.368	0.441
n-Pentane	0.735	0.480	0.443	0.412	0.482
Hexanes	0.779	0.405	0.347	0.388	0.341
Heptanes-Plus	1.184	0.527	0.453	0.293	0.253
Total	100.000	100.000	100.000	100.000	100.000
Hexanes-Plus	1.963	0.932	0.800	0.682	0.595
Heptanes-Plus	1.184	0.527	0.453	0.293	0.253
Molecular Weight:					
Total	22.5	21.2	20.9	20.8	21.3
Hexanes-Plus	94	94	94	90	90
Heptanes-Plus	101	101	101	99	97
Compressibility Factor(z)	0.8387	0.7884	0.8004	0.8770	0.9315
Density (g/cm3)	0.2559	0.1645	0.1280	0.0586	0.0286
Cumulative moles produced (percentage of initial)	16.948	37.547	47.025	68.432	78.493

Table 10
Liquid Dropout
Constant Volume Depletion at 152 °F

Pressure (psia)	Liquid Volume Percent
3912	5.00
2514	11.16
2012	11.45
1013	10.01
512	8.74

Figure 1

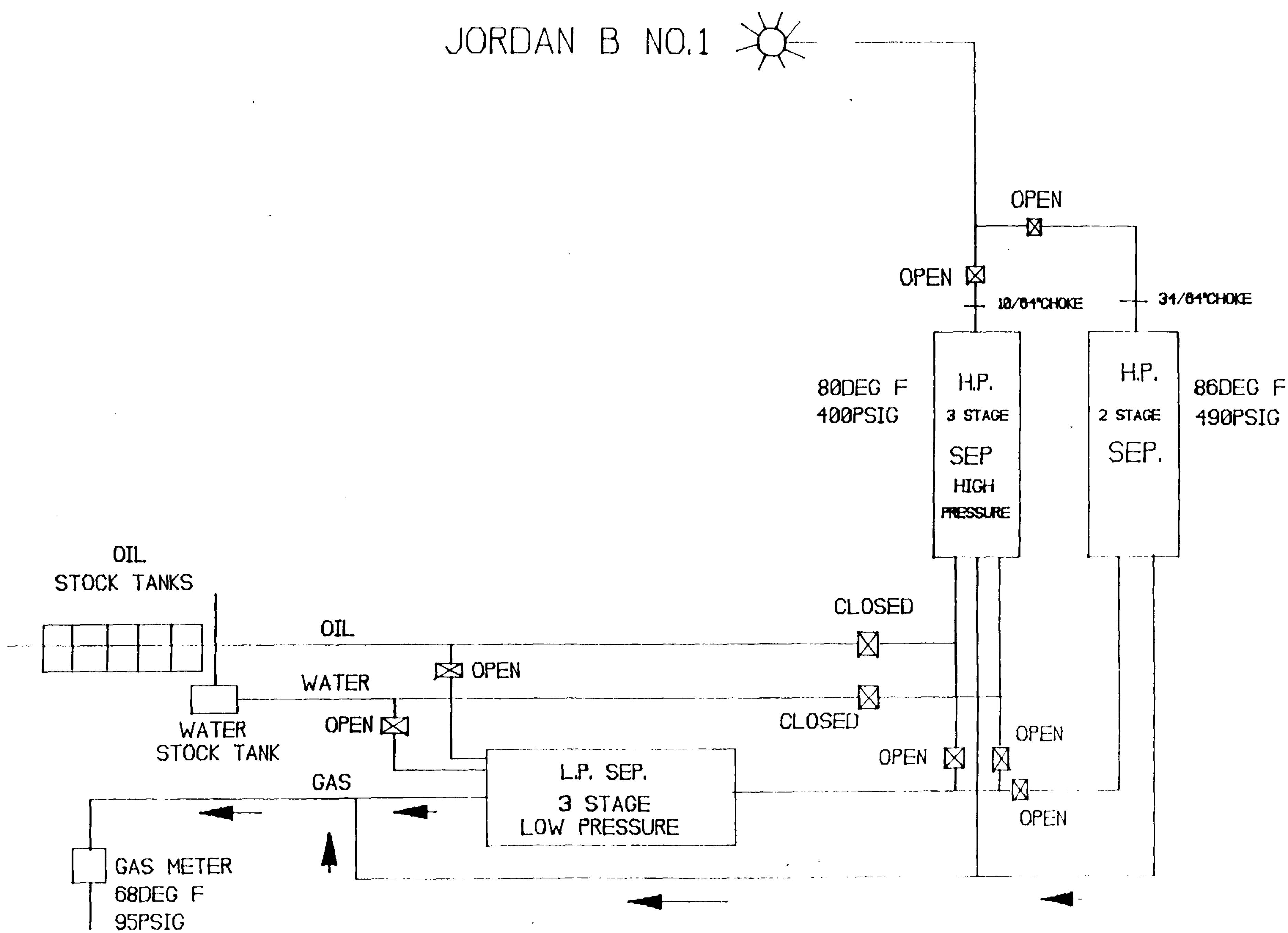

JORDAN B NO.1
OPEN
OPEN
10/64"CHOKE
34/64"CHOKE
80DEG F
400PSIG
H.P.
3 STAGE
SEP
HIGH
PRESSURE
H.P.
2 STAGE
SEP.
86DEG F
490PSIG
OIL
STOCK TANKS
OIL
CLOSED
OPEN
WATER
CLOSED
WATER
STOCK TANK
OPEN
OPEN
OPEN
OPEN
GAS
L.P. SEP.
3 STAGE
LOW PRESSURE
GAS METER
68DEG F
95PSIG

Figure 2

Relative Volume

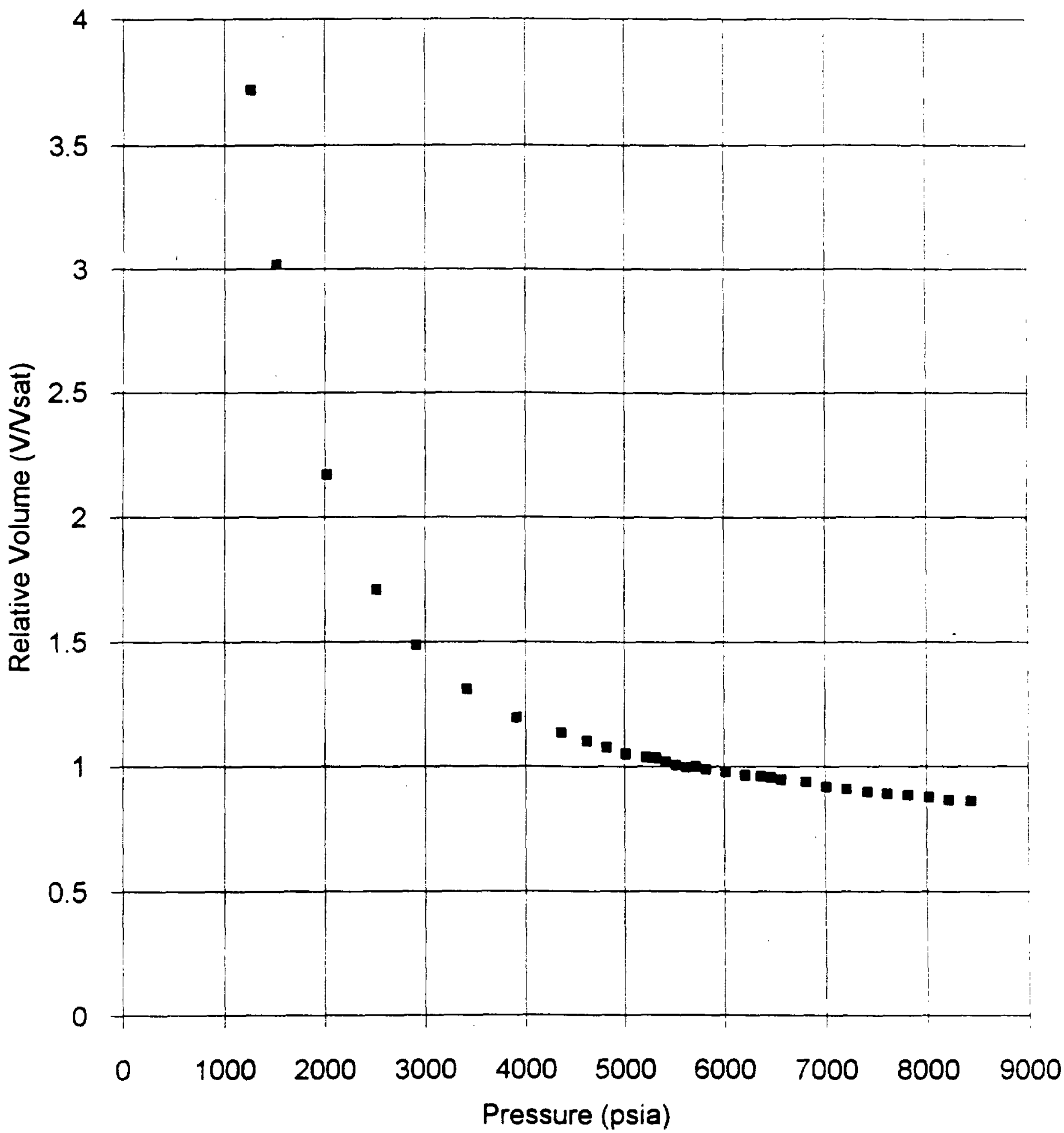


Figure 3

Compressibility Factor (z)

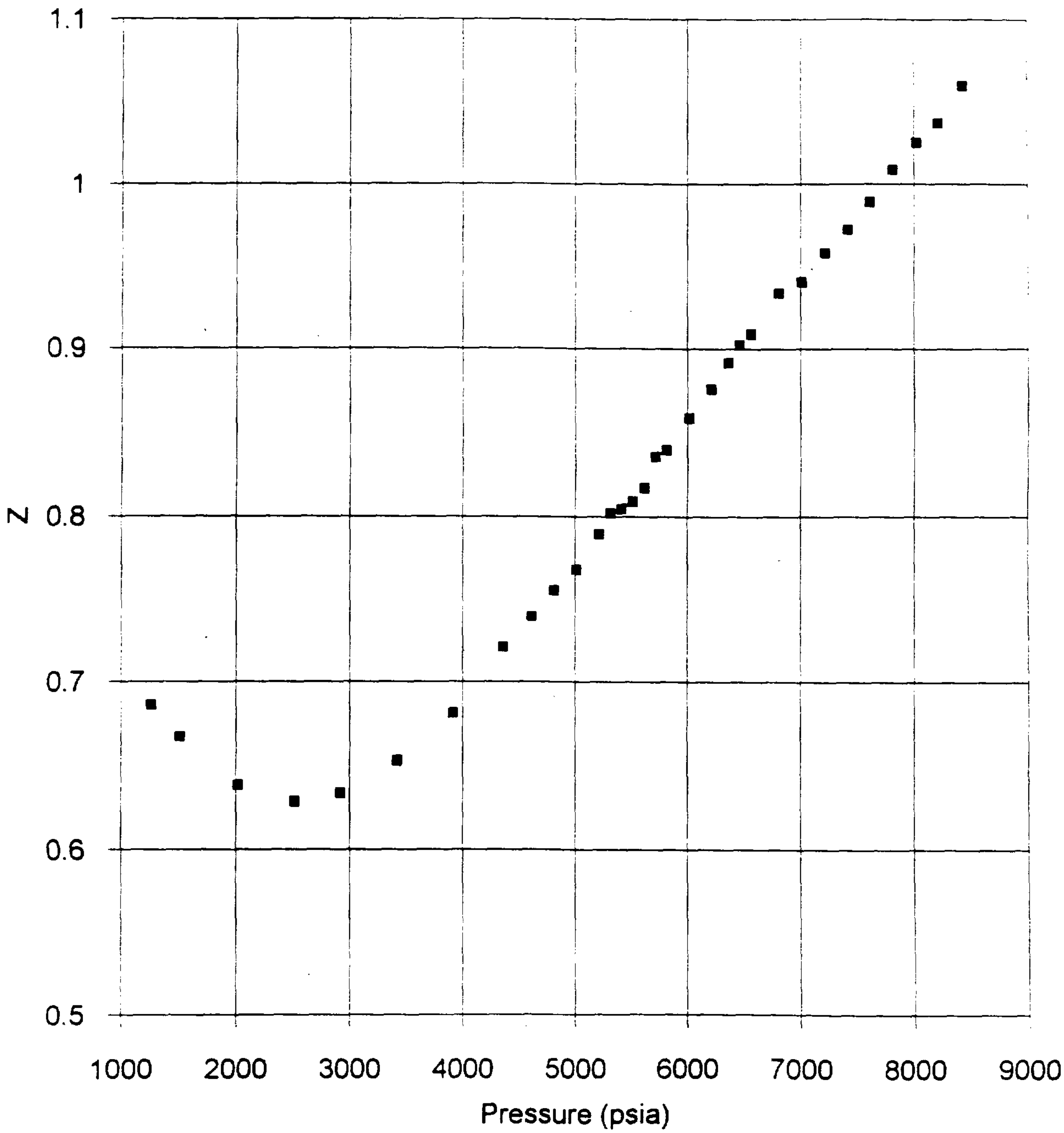


Figure 4

Liquid Dropout Curve
Constant Composition Expansion

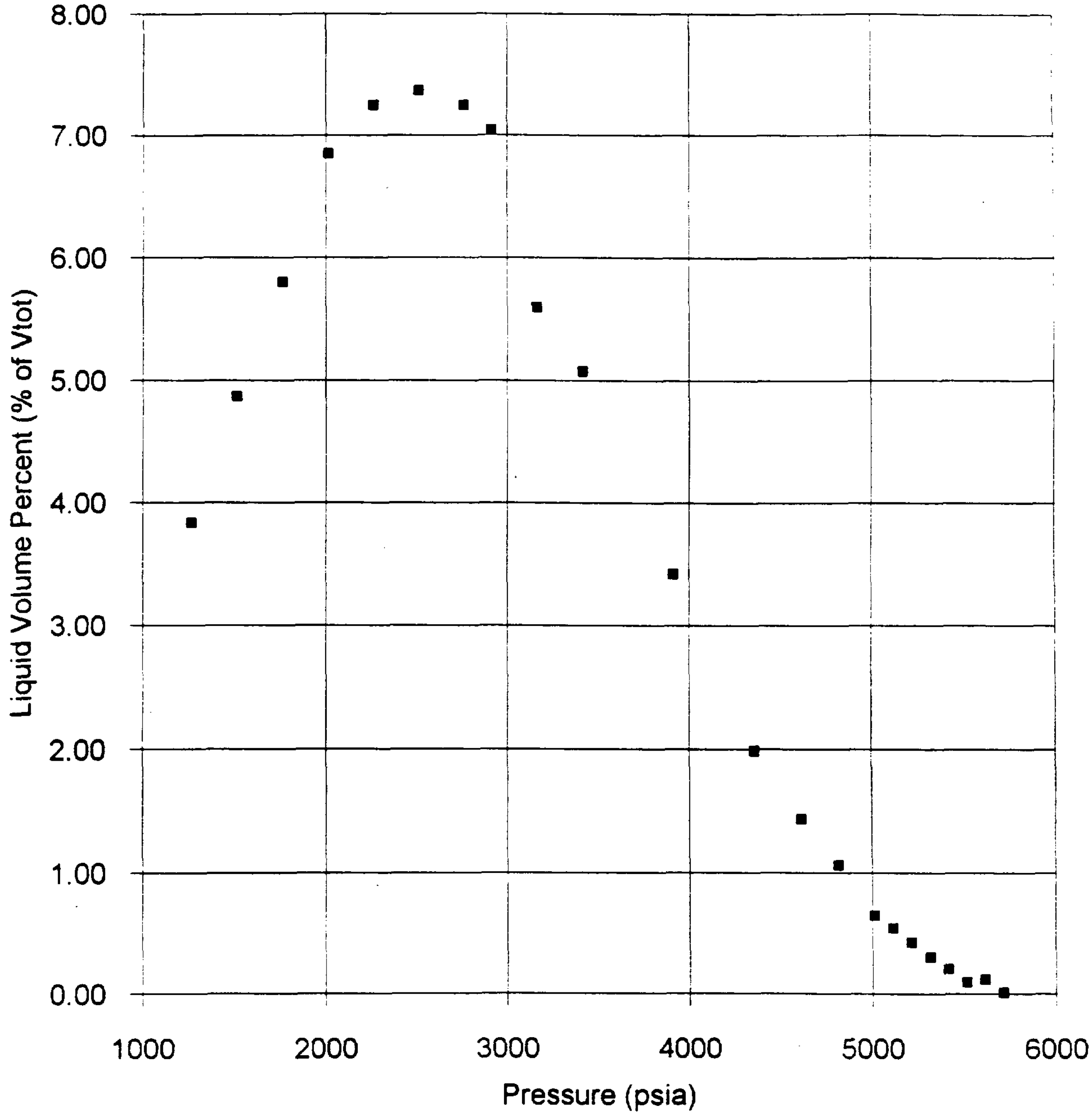
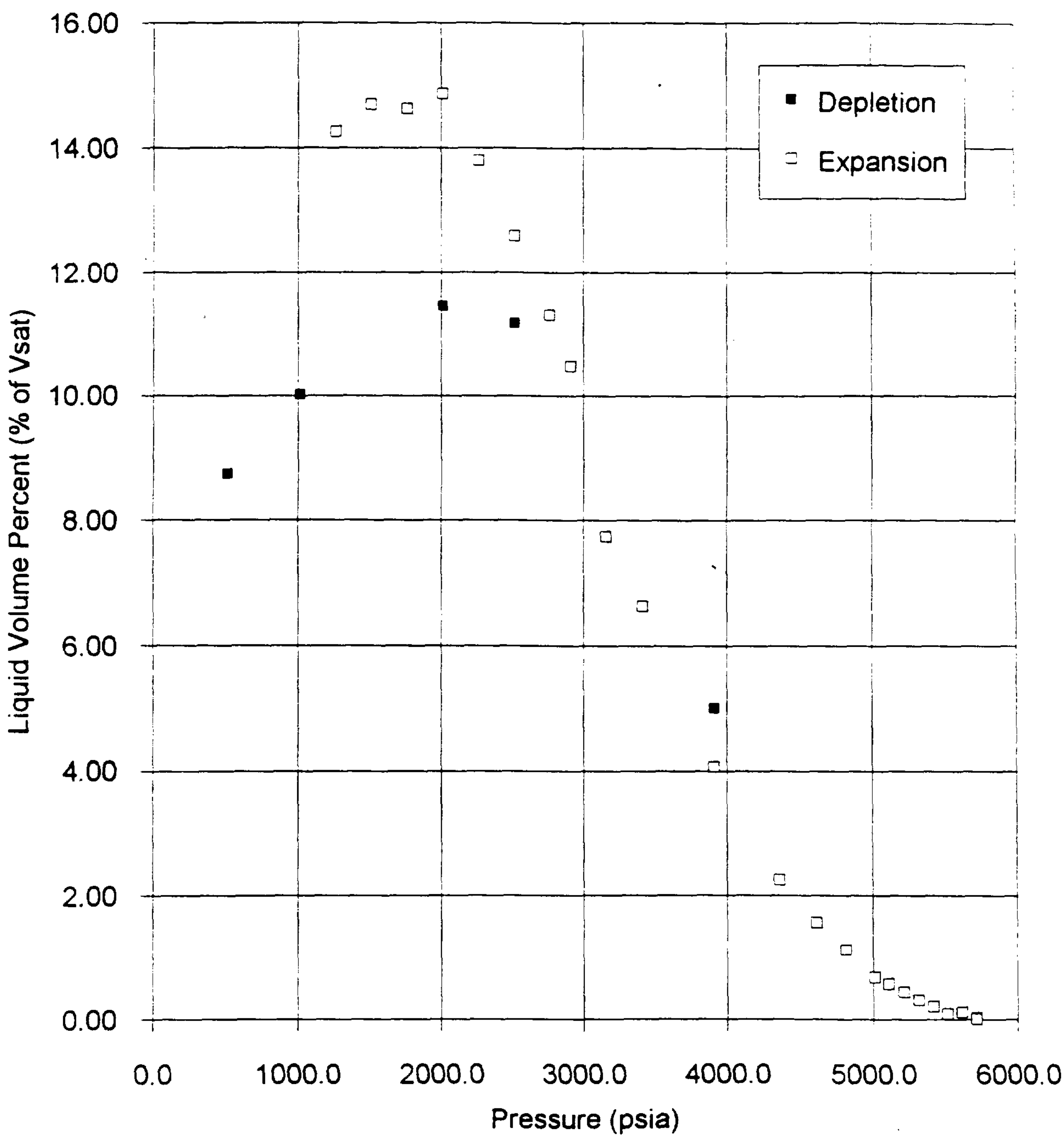


Figure 5

Liquid Dropout Curves



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ATTACHMENT 4

With more than 36 years of petroleum industry experience in mud logging, core analysis, and phase-behavior studies, **Phillip L. Moses**, reservoir fluid analysis manager at Core Laboratories Inc. in Dallas, develops new equipment and techniques for gas/liquid analyses and phase-relationship studies at elevated pressures and temperatures. He has directed phase-behavior studies from reservoirs in the U.S., Canada, South America, and Indonesia. A graduate of Texas A&M U. with a BS degree in physics, he has completed basic and advanced petroleum reservoir engineering courses at Texas A&M U. Moses has written several technical papers and has given phase-behavior lectures to numerous groups. He was a 1967–68 SPE Admissions Committee chairman.

Engineering Applications of Phase Behavior of Crude Oil and Condensate Systems

Phillip L. Moses, SPE, Core Laboratories, Inc.

Summary. Fluid samples must be taken early in the life of a reservoir to obtain samples truly representative of the reservoir fluid. They should be taken only after a carefully planned well conditioning and testing program. When the PVT data obtained from these samples are used, care should be taken to adjust FVF's and gas/oil ratios (GOR's) for surface separator conditions.

Introduction

The proper development, engineering, and production of an oil or gas reservoir requires a considerable amount of planning. At the same time that plans are formulated to develop the field, plans should also be made for a data-gathering program to facilitate reservoir engineering months and even years into the future. This data-gathering plan should include a sufficient number and variety of electric logs and cores on key wells to describe the reservoir adequately. Electric logs and core analyses evaluate the reservoir rock. If reservoir engineering calculations are to be made to optimize production from a reservoir, including EOR, then the properties of the reservoir fluids must also be known. The properties of the reservoir water fall within narrow ranges and are seldom studied at reservoir pressures and temperatures. The properties of the reservoir water determined are normally confined to chemical analysis and possibly compatibility tests in cases of injection projects. This paper is concerned primarily with the study of the hydrocarbon fluids contained in a reservoir.

Coring and logging programs should continue throughout the development of a reservoir. The data obtained from the last well drilled are as valuable as the data obtained from the first well. This is usually not the case for reservoir fluids. Samples representative of the original reservoir can be obtained only when the reservoir pressure is equal to or higher than the original bubblepoint or dewpoint. Methods are available for extrapolating fluid data obtained after some pressure decline. Remember, however, that extrapolation is an educated man's word for guessing. Plans for obtaining reservoir fluid samples and analyses should be made early in the life of a reservoir. Reservoir fluid samples should be taken before significant reservoir pressure decline has been experienced.

Oil Reservoirs

Oil reservoirs can be divided into two categories: ordinary oil reservoirs and near-critical reservoirs. The ordinary oil reservoirs are sometimes called black-oil reservoirs. This misnomer does not reflect the color of the reservoir fluids. It is meant only to distinguish them from near-critical oil reservoir fluids. The near-critical fluids will be discussed in subsequent paragraphs.

Ordinary oils are characterized by GOR's up to approximately 2,000 ft^3/bbl [360 m^3/m^3], oil gravities up to 45°API [0.8 g/cm^3], and FVF's of less than 2 bbl/bbl [2 m^3/m^3]. Remember that there is no sharp dividing line between an ordinary and a near-critical oil. Such factors as composition and reservoir temperature greatly influence the behavior of the reservoir fluid. It is often impossible to determine whether a fluid should be studied as a near-critical oil or as an ordinary oil until it is actually in the laboratory being observed.

We have two methods for sampling ordinary or noncritical oils: surface sampling and subsurface sampling. These methods were discussed by Reudelhuber[1-3] and are not covered in detail in this paper, but it should suffice to say that wells should be carefully conditioned before sampling. If wells are not conditioned properly and the samples are not representative of the reservoir fluid, then the resulting fluid study may yield invalid data. In subsurface sampling, well conditioning usually consists of a period of reduced flow followed by shut-in. In separator sampling, it is imperative that the well be stabilized, then tested for a sufficiently long period to determine the GOR accurately.

The reservoir fluid study on a noncritical oil should consist of five tests.

Pressure/Volume Relations. This is a constant-composition expansion of the reservoir fluid at the reservoir temperature during which the bubblepoint is measured. Above the bubblepoint, the compressibility of the single-phase fluid is measured. Below the bubblepoint, the two-phase volume is measured as a function of pressure.

Differential Vaporization. This test measures the amount of gas in solution as a function of pressure and the resultant shrinkage of the oil as this gas is released from solution. Also measured are the properties of the evolved gas, including the specific gravity and deviation factor. The density of the oil phase is also measured as a function of pressure.

Viscosity. Viscosity, which is resistance to flow, should be measured as a function of pressure at reservoir temperature.

These three tests are all conducted at reservoir temperature, and the results describe the behavior of the reservoir fluid as it exists in the reservoir.

Separator Tests. One or more separator tests should be measured to determine the behavior of the reservoir fluid as it passes up the tubing, through the separator or separators, and finally into the stock tank. The FVF, B_o, and gas in solution, R_s, are measured during these tests. It is usually recommended that four of these tests be used to determine the optimum separator pressure, which is usually considered the separator pressure that results in the minimum FVF. At the same pressure, the stock-tank-oil gravity will be a maximum and the total evolved gas—i.e., the separator gas and the stock-tank gas—will be at a minimum. For most midcontinent crudes, this optimum separator pressure usually occurs in a range from about 90 to 120 psi [621 to 827 kPa]. Obviously, some field producing conditions do not allow the operation of the separator at optimum pressure. If the gas-gathering line in the field is at 1,000 psig [6895 kPa], the first-stage separator must be operated at this pressure or higher. Therefore, a second separator must be placed in the flow stream to achieve a near-optimum FVF. The optimum second-stage separator pressure may also be determined by the PVT laboratory either experimentally or through equilibrium ratio calculations with the reservoir fluid composition and computers.

As reservoir pressure is depleted and gas is evolved from solution within the reservoir, the FVF of the reservoir oil gradually becomes smaller. Ideally, the FVF of the reservoir oil should be measured as a function of reservoir pressure by placing a large sample of oil in a PVT cell and pressure-depleting by differential liberation at the reservoir temperature. At each of several pressure levels during this differential depletion, samples are removed and passed through a separator or separators at surface conditions, and the FVF and gas in solution are measured. Sufficient pressure levels should be studied to obtain the data to plot a curve of FVF and gas in solution as a function of reservoir pressure. This method, described by Dodson *et al.*,[4] is an excellent way to study noncritical oils and should be considered the preferred method. Unfortunately, most reservoir fluid studies contain only the separator data on the reservoir oil at its original bubblepoint. The reservoir fluid report does not contain a curve of FVF as a function of reservoir pressure, but only the FVF's at the bubblepoint. The FVF curve and gas-in-solution curve must be constructed with a correlation first described by Amyx *et al.*,[5] and later by Dake.[6] This correlation, the adjustment of the differential data to flash conditions, works reasonably well in most instances and is far superior to making no correction at all. Again, Dodson's method is superior.

It is my observation that 70 to 80% of reservoir engineers do not understand the conversion of differential data to flash data; consequently, the relative-oil-volume curve from the differential liberation is used instead of the flash-formation-factor curve. This can lead to errors of 10 to 20% or more in calculation of oil in place (OIP) and recoverable oil. An explanation of the conversion from differential to flash is presented in the Appendix.

Composition of the Reservoir Fluid. Most of the parameters measured in a reservoir fluid study can be calculated with some degree of accuracy from the composition. It is the most complete description of reservoir fluid that can be made. In the past, reservoir fluid compositions were usually measured to include separation of the components methane through hexane, with the heptanes and heavier components grouped as a single component reported with the average molecular weight and density. With the development of more sophisticated equations of state to calculate fluid properties, it was learned that a more complete description of the heavy components was necessary. It is now recommended that compositional analyses of the reservoir fluid include a separation of components through C_{10} as a minimum. The more sophisticated research laboratories now use equations of state that require compositions through C_{30} or higher.

Near-Critical Oils

Near-critical oils have often been referred to as volatile oils. Volatile oil is not an apt description because virtually all reservoir fluids are volatile. What is really meant is that the reservoir fluid exhibits the properties of an oil existing in the reservoir at a temperature near its critical temperature. These properties include a high shrinkage immediately below the bubblepoint. In extreme cases, this shrinkage can be as much as 45%

of the hydrocarbon pore space within 10 psi [69 kPa] below the bubblepoint. GOR's are usually 2,000 to 3,000 ft^3/bbl [360 to 540 m^3/m^3], and the oil gravity is usually 40°API [0.83 g/cm^3] or higher. Near-critical oils have FVF's of 2 or higher. The compositions of near-critical oils are usually characterized by 12.5 to 20 mol% heptanes plus, 35% or more of methane through hexanes, and the remainder ethane.

Near-critical oils were first discussed in the literature by Reudelhuber and Hinds[7] and by Jacoby and Berry.[8] Near-critical oils must be studied differently in the laboratory and by the reservoir engineer to arrive at an accurate prediction of reservoir performance. To understand this, it is necessary to consider that near-critical oils are borderline to very rich gas condensates on a phase diagram.

There is a fairly sharp dividing line between oils and condensates from a compositional standpoint. Reservoir fluids that contain heptanes and are heavier in concentrations of more than 12.5 mol% are almost always in the liquid phase in the reservoir. Those with less than 12.5 mol% are almost always in the gas phase in the reservoir. Oils have been observed with heptanes and heavier concentrations as low as 10% and condensates as high as 15.5%. These cases are rare, however, and usually have very high tank liquid gravities.

As mentioned, a near-critical oil undergoes a very high shrinkage as the pressure falls below the bubblepoint. This high shrinkage creates a high gas saturation in the pore space. Because of the gas/oil relative-permeability characteristics of most reservoir rocks, free gas achieves high mobility almost immediately below the bubblepoint. It is fortunate that this free gas is a rich gas condensate. Conventional volumetric material-balance techniques on ordinary oils make no provisions for treating this mobile gas as a retrograde condensate. Instead, the calculation procedures bring this free gas flowing in the reservoir to the surface as free gas and add it to the solution gas.

A properly performed reservoir fluid study on a near-critical oil furnishes the data that will enable the reservoir engineer to perform a compositional material balance. In this manner, he can account for production of retrograde condensate, as well as oil, from the reservoir. Reudelhuber and Hinds[7] reported that for the reservoir they studied, a compositional material-balance calculation procedure would predict a liquid recovery from the reservoir approximately four times higher than conventional volumetric material balance would. Jacoby and Berry[8] reported an approximately 2.5-fold increase for the reservoir they studied. Jacoby and Berry's study was done on a reservoir in north Louisiana that was discovered in late 1953. By conventional material-balance techniques, Jacoby and Berry predicted that 880,000 bbl [140×10^3 m^3] oil would be produced from the reservoir. By compositional material-balance techniques, they predicted that 2.2 million bbl [350×10^3 m^3] would be produced. By 1965 the field had been depleted, and Cordell and Ebert[9] presented a case history. Actual recovery from the reservoir was 2.4 million bbl [382×10^3 m^3]. The excellent agreement between the actual performance and the predicted performance confirms the theory behind the compositional material-balance approach.

Retrograde Gas-Condensate Reservoirs

A retrograde gas-condensate reservoir fluid is a hydrocarbon system that is totally gas in the reservoir. Upon pressure reduction, liquid condenses from the gas to form a free liquid phase in the reservoir. Retrograde condensate reservoirs are characterized by gas/liquid ratios of approximately 3,000 to 150,000 ft^3/bbl [540 to 27×10^3 m^3]. Liquid gravities usually range from about 40 to 60°API [0.83 to 0.74 g/cm^3], although condensate gravities as low as 29°API [0.88 g/cm^3] have been reported.[10] Color alone is not a good indicator of whether a particular hydrocarbon liquid is condensate or oil. The 29°API [0.88-g/cm^3] condensate was black. High-gravity condensates and oils can be water-white. We normally do not expect to see retrograde behavior at reservoir pressures below about 2,500 psi [17.2 MPa]. At these relatively low pressures, the condensate is usually very light in color and high in gravity. The lower gravities and darker colors observed in condensates are indicators of heavy hydrocarbons. High pressure is required to vaporize heavy hydrocarbons; consequently, a reservoir producing a dark condensate should be expected to have a high dewpoint.

Gas-condensate reservoirs are almost always sampled at the separator and recombined in the producing gas/liquid ratio. Oil wells are conditioned for subsurface sampling by a reduction in the flow rate for a period of time and then shut-in until static pressure has been achieved. If we were to attempt to condition a gas-condensate well in the same manner, we would find that the liquid condensate in the tubing would coalesce and fall to the bottom of the tubing when the well was shut in. A subsurface sample would then retrieve a sample of this liquid. The liquid would exhibit a bubblepoint rather than a retrograde dewpoint. The composition of the liquid would be totally different from the composition of the reservoir fluid.

To obtain samples for reservoir fluid analysis from a gas-condensate well, the well should ideally be produced at a rate equal to or slightly above the minimum stable rate. If, however, a well has been producing at a stable rate for some time and the rate is not excessive, then it is usually better to test at this rate than to adjust the rate to the minimum stable rate. The most important factor in a flow test is stabilization. This includes stable wellhead pressure, stable gas production, and stable liquid production. For a well producing with a subsurface flowing pressure below the dewpoint, the liquid saturations and compositions in the drainage area must also be stabilized. Once stabilization has been achieved, as a barrel of liquid condenses from the reservoir fluid in the vicinity of the wellbore, then another barrel of liquid must enter the wellbore. In this manner, the saturations and compositions in the vicinity of the

TABLE 1—DEPLETION STUDY AT 256°F.

Hydrocarbon Analyses of Produced Well Stream, Mol%

Component	Reservoir Pressure (psig) 6,010	5,000	4,000	3,000	2,100	1,200	700	700*
Carbon dioxide	0.01	0.01	0.01	0.01	0.01	0.01	0.01	Trace
Nitrogen	0.11	0.12	0.12	0.13	0.13	0.12	0.11	0.01
Methane	68.93	70.69	73.60	76.60	77.77	77.04	75.13	11.95
Ethane	8.63	8.67	8.72	8.82	8.96	9.37	9.82	4.10
Propane	5.34	5.26	5.20	5.16	5.16	5.44	5.90	4.80
iso-Butane	1.15	1.10	1.05	1.01	1.01	1.10	1.26	1.57
n-Butane	2.33	2.21	2.09	1.99	1.98	2.15	2.45	3.75
iso-Pentane	0.93	0.86	0.78	0.73	0.72	0.77	0.87	2.15
n-Pentane	0.85	0.76	0.70	0.65	0.63	0.68	0.78	2.15
Hexanes	1.73	1.48	1.25	1.08	1.01	1.07	1.25	6.50
Heptanes plus	9.99	8.84	6.48	3.82	2.62	2.25	2.42	63.02
	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molecular weight of heptanes plus	158	146	134	123	115	110	109	174
Density of heptanes plus	0.827	0.817	0.805	0.794	0.784	0.779	0.778	0.837
Deviation factor								
Equilibrium gas	1.140	1.015	0.897	0.853	0.865	0.902	0.938	
Two-phase	1.140	1.016	0.921	0.851	0.799	0.722	0.612	
Well stream produced								
Cumulative percent of initial	0.000	6.624	17.478	32.927	49.901	68.146	77.902	

*Composition of equilibrium liquid phase.

wellbore do not change. If the flowing rate is changed, 3 months may be required to restabilize the well. Once the well is stable, the gas and liquid production rates should be measured for 48 hours or more before sampling.

As is the case with oil reservoirs, gas-condensate reservoirs should be sampled early in their life, before significant pressure loss has occurred. Once reservoir pressure has declined below the original dewpoint, it is no longer possible to get samples that represent the original reservoir fluid. When the reservoir pressure falls below the retrograde dewpoint, liquid condensate forms from the reservoir fluid. Initially, there is no permeability to this liquid phase, and only the remaining reservoir gas flows to the wellbore. If we sample the well stream under these conditions by taking samples of separator gas and liquid and recombining them in the produced gas/liquid ratio, the dewpoint of the mixture should be expected to be the current reservoir pressure.

As reservoir pressure continues to fall, more and more retrograde liquid condenses in the formation; at some saturation point, this liquid will begin to flow and enter the wellbore. If the well is tested and sampled under these conditions, the resultant fluid after recombination would yield a dewpoint higher than the current reservoir pressure and could conceivably be higher than the original reservoir pressure. When the recombined reservoir fluid is examined at the current reservoir pressure, some free liquid will be found in the PVT cell. The amount of gas in the cell relative to the amount of liquid is usually interpreted as a measurement of the mobility ratio in the reservoir at the drainage boundary.

A reservoir fluid study on a condensate reservoir should include the composition of the separator gas, separator liquid, and recombined reservoir fluid. In the past, these compositions were carried only through hexanes, with heptanes plus lumped together as one fraction. I recommend that these compositions be carried through decanes as a minimum, with the undecanes and heavier lumped together as a single fraction, to facilitate compositional modeling of gas-condensate reservoirs. As indicated earlier, some of the more sophisticated major producing companies now request analyses to C_{30} and higher.

The reservoir fluid study should include a measurement of the retrograde dewpoint, the fluid compressibility above the dewpoint, and the gas and liquid volumes below the dewpoint during a constant-composition expansion.

Finally, the fluid study should consist of a simulated depletion. This depletion generally consists of a series of expansions and constant-pressure displacements of the reservoir fluid such that the volume of the cell remains constant at the termination of each displacement. This procedure is referred to as a constant-volume depletion. The reservoir gas produced during each constant-pressure displacement is charged to analytical equipment, and the composition and volume are determined. The deviation factor of the gas produced, the two-phase deviation factor of the hydrocarbons remaining in the cell, and the volume of liquid remaining in the cell should be measured at each of the depletion pressures. The two-phase deviation factor is not understood well by most reservoir engineers. The most popular form of material balance on a condensate reservoir is the *P/Z*-vs.-cumulative-production curve. The deviation factor used should be the deviation factor of all of the hydrocarbons remaining in the reservoir. This includes the

TABLE 2—CALCULATED RECOVERY DURING DEPLETION

Calculated Cumulative Recovery During Depletion

Cumulative Recovery per MMscf of Original Fluid	Initial in Place	Reservoir Pressure (psig) 6,010	5,000	4,000	3,000	2,100	1,200	700
Well Stream, Mscf	1,000	0	66.24	174.78	329.27	499.01	681.46	779.02
Normal Temperature Separation*								
Stock-tank liquid, bbl	181.74	0	10.08	21.83	31.89	39.76	47.36	51.91
Primary-separator gas, Mscf	777.15	0	53.18	145.16	283.78	440.02	608.25	696.75
Second-stage gas, Mscf	38.52	0	2.26	5.17	8.03	10.51	13.21	14.99
Stock-tank gas, Mscf	38.45	0	2.29	5.38	8.73	11.85	15.51	18.05
Total "Plant Products" in Primary Separator Gas, gal								
Ethane	1,841	0	126	344	674	1,050	1,474	1,709
Propane	835	0	58	163	331	526	749	873
Butanes (total)	368	0	26	73	155	256	374	441
Pentanes plus	179	0	12	35	73	122	177	206
Total "Plant Products" in Second-Stage Gas, gal								
Ethane	204	0	12	27	42	55	70	80
Propane	121	0	7	17	27	36	47	54
Butanes (total)	53	0	3	8	13	17	23	27
Pentanes plus	23	0	1	3	5	7	10	11
Total "Plant Products" in Well Stream, gal								
Ethane	2,295	0	153	404	767	1,171	1,626	1,880
Propane	1,461	0	95	250	468	707	979	1,137
Butanes (total)	1,104	0	70	178	325	486	674	789
Pentanes plus	7,352	0	408	890	1,322	1,680	2,037	2,249

Calculated Instantaneous Recovery During Depletion

	Reservoir Pressure (psig) 6,010	5,000	4,000	3,000	2,100	1,200	700
Normal Temperature Separation*							
Stock-tank liquid gravity, °API at 60°F	49.3	51.7	55.4	60.4	64.6	67.5	68.6
Separator gas/well-stream ratio, Mscf/MMscf							
Primary-separator gas only	777.15	802.85	847.45	897.28	920.44	922.04	907.14
Primary- and second-stage separator gases	815.67	837.04	874.26	915.77	935.04	936.84	925.38
Separator-gas/stock-tank-liquid ratio, scf/STB							
Primary-separator gas only	4,276	5,277	7,828	13,774	19,863	22,121	19,475
Primary- and second-stage separator gases	4,488	5,502	8,076	14,058	20,178	22,476	19,867
GPM from Smooth Well-Stream Compositions							
Ethane plus	12.212	10.953	9.175	7.509	6.851	6.970	7.574
Propane plus	9.917	8.648	6.856	5.164	4.469	4.479	4.963
Butanes plus	8.456	7.209	5.434	3.752	3.057	2.990	3.349
Pentanes plus	7.352	6.158	4.437	2.800	2.108	1.959	2.171

*Primary separator at 450 psig and 75°F; second-stage separator at 100 psig and 75°F; stock tank at 75°F

remaining gas phase and the retrograde liquid. The two-phase deviation factor furnishes this information. On lean gas-condensate reservoirs, use of the wrong deviation factor will not result in serious error, but use of the wrong deviation factor on a rich-condensate reservoir will cause serious errors and will generally lead to an understatement of reserves. Table 1 illustrates data typically measured during a depletion study.

The data measured during the depletion study are then used for a recovery calculation for a unit volume reservoir. The results of these calculations are illustrated in Table 2. The unit volume chosen was 1 MMcf [28×10^3 m^3] original reservoir fluid at the dewpoint pressure. Col. 1 in Table 2 illustrates the amount of stock-tank liquid, primary-separator gas, second-stage separator gas, stock-tank gas, etc., in place in this unit volume reservoir. The amount of stock-tank liquid in 1 MMcf [28×10^3 m^3] reservoir fluid depends on the temperature and pressure of the separators at the surface. At this point, the reservoir fluid study can be tailored to a specific field condition by making the recovery calculations at the separator conditions used in the field. Because the data reported in Table 2 are the results of computer calculations, a variety of separator conditions can be investigated with a relatively small additional investment in computer time. Note that in Col. 1 of the example, 181.74 bbl [29 m^3] of stock-tank liquid were initially in place in the unit volume reservoir. By the time the reservoir pressure had been depleted to 700 psig [4.8 MPa] (Col. 8), only 51.91 bbl [8.3 m^3] had been produced. The difference between the initial in place and that produced at 700 psi [4.8 MPa] is 129.83 bbl [20.6 m^3]. This amount remains in the reservoir at this pressure as retrograde loss or unproduced at this pressure. Similar figures are available for the primary-separator gas, second-stage gas, etc. (For a more detailed explanation of these recovery calculations, refer to Ref. 11.) The recovery calculations of the gas-condensate reservoir are made with the assumption that the retrograde liquid does not achieve mobility in the reservoir, which allows for a finite solution of a recovery calculation as opposed to the trial-and-error solution required for an oil reservoir where two phases flow. This assumption appears to be a good one for most gas-condensate reservoirs. Only the very rich gas-condensate reservoirs ever achieve sufficient liquid saturation to achieve liquid mobility in significant amounts. In cases where liquid mobility is significant, a compositional material-balance approach is required to predict reservoir performance.

Conclusions

The two basic methods of collecting reservoir fluid samples are subsurface and surface or separator samples. In either case, the reservoir must be sampled before a significant loss in pressure has been experienced, and great care must be taken in preparing a well for sampling. Both must be adhered to if representative samples are to be obtained.

The studies performed in the laboratory must recognize the character of the oil. For the laboratory personnel or the reservoir engineer to treat a near-critical oil as an ordinary oil would grossly understate the producing potential of the field.

The reservoir engineer must make proper adjustments in fluid data to account for the differences in the flash and differential processes.

Nomenclature

B_o = barrels of bubblepoint oil required to yield 1 STB [0.16 stock-tank m^3] oil at 60°F [16°C], bbl/bbl [m^3/m^3]

B_{od} = barrels of oil at some reservoir pressure other than the bubblepoint pressure required to yield 1 bbl [0.16 m^3] residual oil at 60°F [16°C] when differentially liberated to atmospheric pressure, bbl/bbl [m^3/m^3]

B_{odb} = barrels of bubblepoint oil required to yield 1 bbl [0.16 m^3] residual oil at 60°F [16°C] when differentially liberated to atmospheric pressure, bbl/bbl [m^3/m^3]

B_{of} = barrels of oil at some reservoir pressure other than the bubblepoint pressure required to yield 1 STB [0.16 m^3] at 60°F [16°C] when flashed through the separator to stock-tank conditions, bbl/bbl [m^3/m^3]

B_{ofb} = barrels of bubblepoint oil required to yield 1 STB [0.16 m^3] at 60°F [16°C] when flashed through the separator to stock-tank conditions, bbl/bbl [m^3/m^3]

R_{sd} = cubic feet of gas in solution at any pressure less than the bubblepoint in 1 bbl [0.16 m^3] residual oil when measured by differential liberation, ft^3/bbl [m^3/m^3]

R_{sdb} = cubic feet of gas in solution at the bubblepoint in 1 bbl [0.16 m^3] residual oil when measured by differential liberation at reservoir temperature, ft^3/bbl [m^3/m^3]

R_{sf} = cubic feet of separator and stock-tank gas in solution at any pressure less than the bubblepoint in 1 STB [0.16 m^3], ft^3/bbl [m^3/m^3]

R_{sfb} = cubic feet of separator and stock-tank gas in solution at the bubblepoint in 1 STB [0.16 m^3], ft^3/bbl [m^3/m^3]

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Appendix—Toward a Better Understanding of the Differential Flash Process

Reservoir depletion and production consist of two separate processes or a combination of them: differential liberation of gas and flash liberation of gas. The differential liberation is defined as a process whereby gas is removed from oil as it is released from solution. By contrast, in a flash liberation of gas, all of the gas remains in contact with all of the oil until equilibrium between the two phases is attained.

Most people believe that the differential liberation process more nearly represents the process that occurs in an oil reservoir. Actually, the reservoir process is a combination of differential and flash. Immediately below the bubblepoint, while there is little or no permeability to a gas phase, the process is

TABLE A-1—DIFFERENTIAL VAPORIZATION AT 220°F

Pressure (psig)	Solution GOR,* R_{sd}	Relative Oil Volume, B_{od}**
2,620	854	1.600
2,350	763	1.554
2,100	684	1.515
1,850	612	1.479
1,600	544	1.445
1,350	479	1.412
1,100	416	1.382
850	354	1.351
600	292	1.320
350	223	1.283
159	157	1.244
0	0	1.075
	at 60°F =	1.000

*Cubic feet of gas at 14.65 psia and 60°F per barrel of residual oil at 60°F

**Barrels of oil at indicated pressure and temperature per barrel of residual oil at 60°F

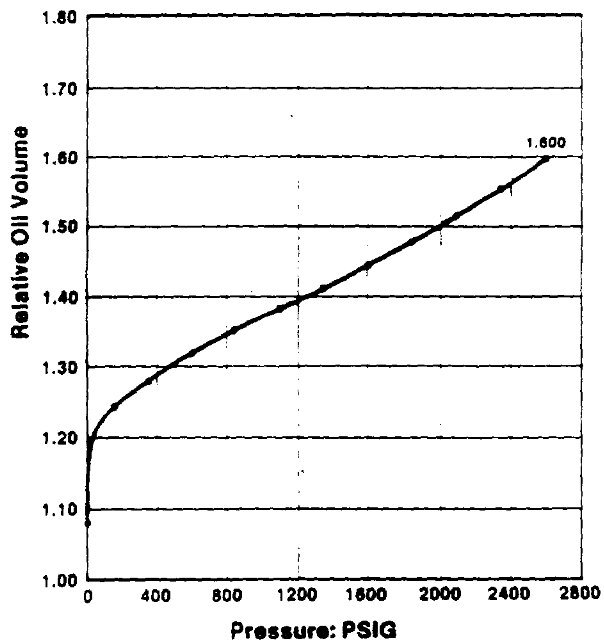


Fig. A-1—Relative oil volume vs. pressure.

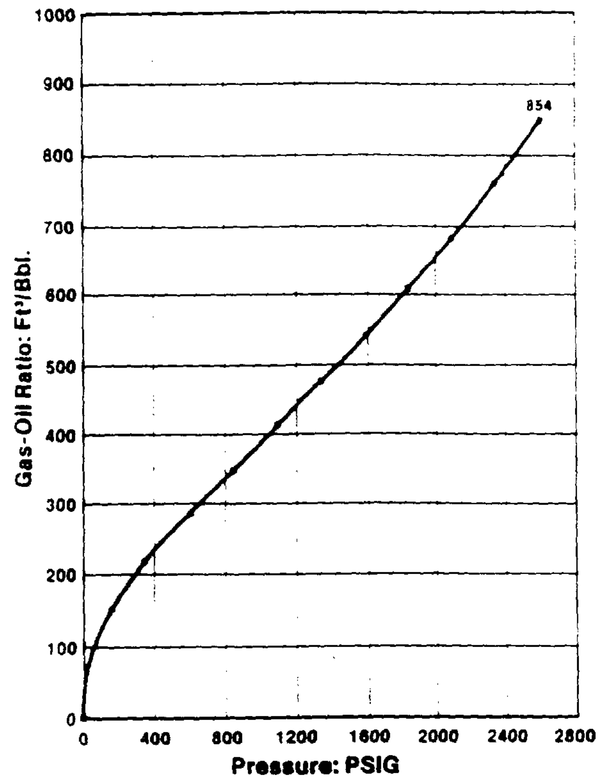


Fig. A-2—Adjustment of gas-in-solution curve to separator conditions.

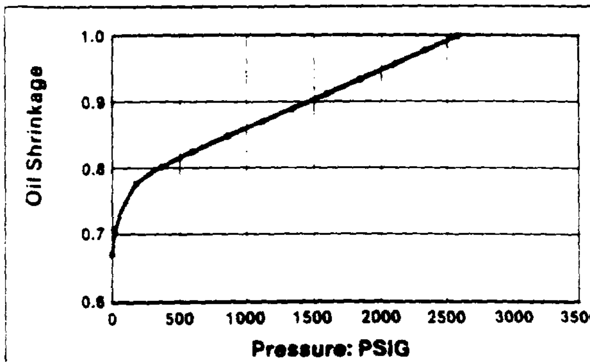


Fig. A-3—Oil-shrinkage curve.

primarily a flash process. As the reservoir gas saturation reaches the critical saturation, gas begins to flow and is removed from the reservoir oil. This is a differential liberation of gas. Much of the gas, however, remains in the reservoir with the oil as pressure in the reservoir falls. This is a flash liberation of gas. So the reservoir process begins as a flash process and soon becomes a combination flash and differential process. As pressure continues to decline, more and more gas flows, bringing the process closer to a differential process. Once oil and gas enter the tubing, they flow together until they reach the separator. In the separator they are brought to equilibrium, and the gas and oil are separated. This is a flash separation.

The reservoir process is simulated in the laboratory by a differential liberation. The test is sometimes referred to as a differential vaporization. The flash liberation is simulated in the laboratory with separator tests. It takes a marriage of the differential vaporization and separator tests to prepare the reservoir fluid data for engineering calculations.

In the laboratory, the differential liberation consists of a series—usually 10 to 15—of flash liberations. An infinite series of flash liberations is the equivalent of a true differential liberation. At each pressure level, gas is evolved and measured. The volume of oil remaining is also measured at each depletion pressure. This process is continued to atmospheric pressure. The oil remaining at atmospheric pressure is measured and converted to a volume at 60°F [16°C]. This final volume is referred to as the residual oil. The volume of oil at each of the higher pressures is divided by the volume of residual oil at 60°F [16°C].

TABLE A-2—SEPARATOR TESTS

Separator Pressure (psig)	Temperature (°F)	GOR, R_{sfb}*	Stock-Tank Oil Gravity (°API at 60°F)	FVF, B_{ofb}**
50	75	737		
to 0	75	41	40.5	1.481
		778		
100	75	676		
to 0	75	92	40.7	1.474
		768		
200	75	602		
to 0	75	178	40.4	1.483
		780		
300	75	549		
to 0	75	246	40.1	1.495
		795		

*GOR in cubic feet of gas at 14.65 psia and 60°F per barrel of stock-tank oil at 60°F

**FVF is barrels of saturated oil at 2,620 psig and 220°F per barrel of stock-tank oil at 60°F

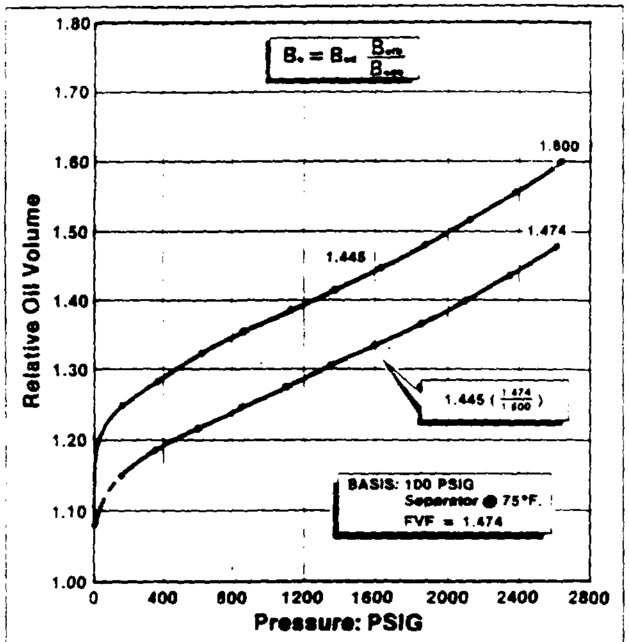


Fig. A-4—Adjustment of oil-relative-volume curve to separator conditions.

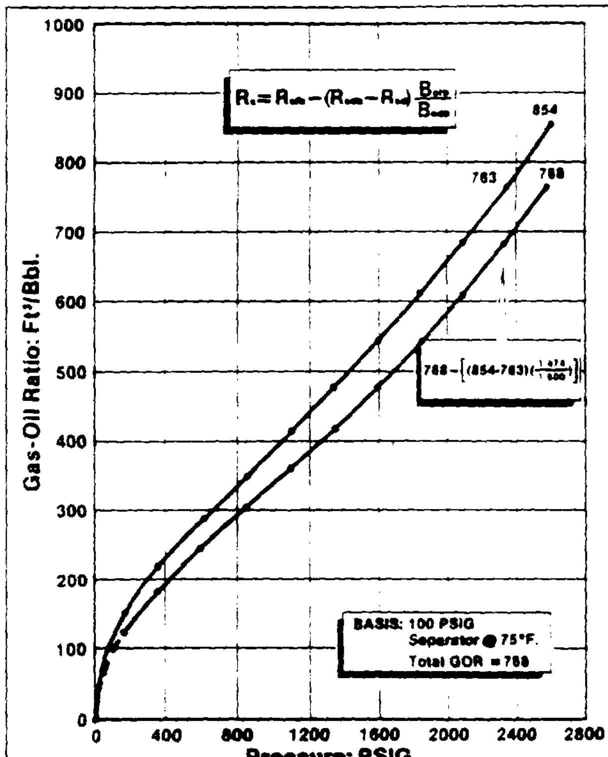


Fig. A-5—Adjustment of gas-in-solution curve to separator conditions.

Table A-1 and Fig. A-1 illustrate these data. The volumes of gas evolved are also divided by the residual oil volume to calculate the solution GOR data in Table A-1 and Fig. A-2. These data are reported in this form by long-standing, but unfortunate, convention. The residual oil in the reservoir is never at 60°F [16°C] but always at reservoir temperature. Reporting these data relative to the residual oil at 60°F [16°C] gives the relative-oil-volume curve the appearance of an FVF curve, leading to its misuse in reservoir calculations. A better method of reporting these data is in the form of a shrinkage curve. We may convert the relative-oil-volume data in Fig. A-1 and Table A-1 to a shrinkage curve by dividing each relative oil volume factor, B_{od}, by the relative oil volume factor at the bubblepoint, B_{odb}.

The shrinkage curve now has a value of 1 at the bubblepoint and a value of less than 1 at subsequent pressures below the bubblepoint, as in Fig. A-3. As pressure is reduced and gas is liberated, the oil shrinks. The shrinkage curve describes the volume of this original barrel of oil in the reservoir as pressure declines. It does not relate to a stock-tank barrel or surface barrel.

We now know the behavior of the oil in the reservoir as pressure declines. We must have a way of bringing this oil to the surface through separators and into a stock tank. This process is a flash process. Most reservoir fluid studies include one or more separator tests to simulate this flash process. Table A-2 is a typical example of a set of separator tests. During this test, the FVF is measured. The FVF is the volume of oil and dissolved gas entering a wellbore at reservoir pressure and temperature divided by the resulting stock-tank oil volume after it passes through a separator.

The FVF is B_o; because separators result in a flash separation, we should add a subscript, B_{of}. In most fluid studies, these separator tests are measured only on the original oil at the bubblepoint. The FVF at the bubblepoint is B_{ofb}. To make solution-gas-drive or other material-balance calculations, we need values of B_{of} at lower reservoir pressures. From a technical standpoint, the ideal method for obtaining these data is to place a large sample of reservoir oil in a cell, heat it to reservoir temperature, and pressure-deplete it with a differential process to simulate reservoir depletion. At some pressure a few hundred psi below the bubblepoint, a portion of the oil is removed from the cell and pumped through a separator to obtain the flash FVF, B_{of}, at the lower reservoir pressure. This should be repeated at several progressively lower reservoir pressures until a complete curve of B_{of} vs. reservoir pressure has been obtained. These data are occasionally measured in this manner in the laboratory; this method, which is the best for obtaining data, is sometimes called the Dodson method.[4] The process is time-consuming and consequently adds to the cost of a study. Most studies include only values of B_{ofb}, the FVF at the bubblepoint. The values of B_{of} at lower pressures must be obtained by other means. A method has been proposed for accomplishing this mathematically.[5,6] In essence, the method calls for multiplying the flash FVF at the bubblepoint, B_{ofb}, by the shrinkage factors at various reservoir pressures obtained earlier. The shrinkage factor was calculated by dividing the relative oil volume factors, B_{od}, by the relative oil volume factor at the bubblepoint, B_{odb}. If we combine both calculations, we can start with the differential-relative-volume curve and adjust it to separator or flash conditions by

$$B_o = B_{od}\frac{B_{ofb}}{B_{odb}} \quad \text{(A-1)}$$

This calculation is illustrated in Fig. A-4.

To perform material-balance calculations, we must also have the separator and stock-tank gas in solution as a function of reservoir pressure. These values are expressed as standard cubic feet per barrel and usually are designated R_{sf}. The separator tests give us this value at the bubblepoint, R_{sfb}. As pressure declines in the reservoir, gas is evolved from solution. The amount of gas remaining in solution in the oil is then somewhat less. The differential vaporization tells us how much gas was evolved from the oil in the reservoir: $(R_{sdb}-R_{sd})$, where R_{sdb} is the amount of gas in solution at the bubblepoint as measured by differential vaporization at the reservoir temperature and R_{sd} is the gas in solution at subsequent pressures.

The units of R_{sdb} and R_{sd} are standard cubic feet per barrel of residual oil. Because we must have the gas in solution in terms of standard cubic feet per barrel of stock-tank oil, this term must be converted to a stock-tank basis. If we divide $(R_{sdb}-R_{sd})$ by B_{odb}, we have the gas evolved in terms of standard cubic feet per barrel of bubblepoint oil. If we then multiply by B_{ofb}, we will have the gas evolved in terms of standard cubic feet per barrel of stock-tank oil. This expression now is $(R_{sdb}-R_{sd})(B_{ofb}/B_{odb})$. The gas remaining in solution then is $R_s = R_{sfb} - (R_{sdb}-R_{sd})(B_{ofb}/B_{odb})$ standard cubic feet per stock-tank barrel. For every pressure studied during the differential liberation, R_s may be calculated from this equation. This calculation is illustrated in Fig. A-5.

It is a fairly common practice to use differential vaporization data for material-balance calculations. Values of B_{od} and R_{sd} are almost always higher than the corresponding values from separator tests; consequently, calculations of OIP and recoverable oil will usually be lower than is correct. The differential vaporization data should be converted to separator flash conditions before use in calculations. The methods presented in this paper are approximations. For more accurate data, consider the method proposed by Dodson *et al.*[4]

SI Metric Conversion Factors

°API	141.5/(131.5+°API)		=	g/cm^3
bbl	× 1.589 873	E−01	=	m^3
ft^3	× 2.831 685	E−02	=	m^3
ft^3/bbl	× 1.801 175	E−01	=	m^3/m^3
°F	(°F−32)/1.8		=	°C
gal	× 3.785 412	E−03	=	m^3
psi	× 6.894 757	E+00	=	kPa

JPT

This paper is SPE 15836. Distinguished Author Series articles are general, descriptive presentations that summarize the state of the art in an area of technology by describing recent developments for readers who are not specialists in the topics discussed. Written by individuals recognized as experts in the areas, these articles provide key references to more definitive work and present specific details only to illustrate the technology. Purpose: To inform the general readership of recent advances in various areas of petroleum engineering. A softbound anthology, *SPE Distinguished Author Series: Dec. 1981–Dec. 1983*, is available from SPE's Book Order Dept.

S.P.G.

MARATHON OIL COMPANY
HOBBS, NEW MEXICO OPERATIONS

*168+ HOUR SHUT IN SONIC FLUID LEVEL REPORT

Date: 5/1/92

Field: Osudo / North Wolfcamp   Well: Jordan "B" # 2

Fluid Level Data

Fluid Above Pump: 8448 Ft.   Casing Pressure: 0 PSIG

Fluid Level Depth: 2941 Ft.   Fluid Level Depth: 94 Jts.

Well Test Data   Date: *12/8/91 = latest available test

Produced: 0 bo + 150 bw = 150 bbls. total
Oper. @ Unknown 0 " Gross SPM With an: 1.25 " Pump

Avail. gross pump displ. = 0 Bbls. per day
Pumping speed req. to prod. test volume = ERR Strokes per min.

Tubing Record Data   Date: 5/5/90

Size: 2-7/8"

Pump Depth: 11389 Ft.   Pump Depth: 364 Jts.

Perfs: 11440'- 50' w/ Perforated tbg. nipple f/ 11487' - 11491'.

Tubing anchor @ 11392 Ft.   364 Joints from surface

Ave. Joint Length: 31.29 Ft.

Tested By: Greenough

Remarks: C640-285-120 Lufkin w/ sub = 0#, 8478 ROA 4 hole cranks & OARO masters w/ OAS auxiliaries. Operating in the # 3 (") stroke hole w/ an 8.5 x 10 Ajax.

* Well has been shut in since 12/91.

ANALYZING WELL PERFORMANCE(1.2)
ACOUSTIC BHP SOFTWARE BY ECHOMETER

Jordanb2	WELL NAME
05-01-1992	DATE
11445	FORMATION DEPTH(FT)
11389	PUMP DEPTH(FT)
31.29	JOINT LENGTH(FT)
.8	GAS GRAVITY(SG)
	N2%
	CO2
	H2S%
42	OIL GRAVITY(API)
1.05	WATER GRAVITY(SG)
90	SURFACE TEMP(F)
170	BOTTOMHOLE TEMP(F)
0	BOPD
150	BWPD
---PRODUCING	CONDITION---
15	CASING(PSIG)
364	# JOINTS
0	dP
10	dT
---STATIC CONDITION---	
0	CASING(PSIG)
94	# JOINTS

PRODUCING BHP

PBHP= 50(PSIA)
100% LIQUID IN COLUMN
LIQUID AT 11390 (FT)

STATIC BHP

SBHP= 3867(PSIA)
OIL AT 2941 (FT)
H2O AT 2941 (FT)

VOGEL'S IPR CURVE

100% EFFICIENCY
0.0 MAX OIL RATE
150.4 MAX LIQ RATE

ATTACHMENT 5

NEW MEXICO OIL CONSERVATION COMMSSION
MULTIPOINT AND ONE POINT BACK PRESSURE TEST FOR GAS WELL

Form C-122
Revised 9-1-65

Type Test: [X] Initial [ ] Annual [ ] Special		Test Date	
Company: TXO PRODUCTION CO.	Connection: TO AIR		
Pool: OSUDO WEST	Formation: WOLFCAMP		Unit

Completion Date	Total Depth	Plug Back TD	Elevation	Farm or Lease Name
6-24-85	12,884	11950		Jordan "B"

Csg. Size	Wt.	d	Set At	Perforations:	Well No.
5½"	17#	4.892	12884	From 11440 To 11445	2

Tbg. Size	Wt.	d	Set At	Perforations:	Unit	Sec.	Twp.	Rge.
2 7/8"	6.4#	2.441	11289	From OPEN ENDED	G	11	20S	35E

Type Well – Single – Bradenhead – G.G. or G.O. Multiple	Packer Set At	County
SINGLE	11289	LEA

Producing Thru	Reservoir Temp. °F	Mean Annual Temp. °F	Baro. Press. – P_a	State
Tubing	187° @ 11442'	60°	13.2	N.M.

L	H	Gg	% CO_2	% N_2	% H_2S	Prover	Meter Run	Taps
1.1442	11442	.7582	1.507	.797			4.026	Flange

	FLOW DATA						TUBING DATA		CASING DATA		
NO.	Prover Line Size	x	Orifice Size	Press. p.s.i.g.	Diff. h_w	Temp. °F	Press. p.s.i.g.	Temp. °F	Press. p.s.i.g.	Temp. °F	Duration of Flow
SI									PKR	CHOKE	72 Hrs.
1.	4.026	x	2.000	41	4	70°	2380	75°		6½/64	1 Hr.
2.	4.026	x	2.000	41	6¼	70°	2310	75		8/64	1 Hr.
3.	4.026	x	2.000	40	25	70	2090	75		16/64	1 Hr.
4.	4.026	x	2.000	42	41	70	1950	75		11 3/4	1 Hr.
5.											

RATE OF FLOW CALCULATIONS

NO.	Coefficient (24 Hour)	$\sqrt{h_w P_m}$	Pressure P_m	Flow Temp. Factor F_t	Gravity Factor F_g	Super Compress. Factor, F_{pv}	Rate of Flow Q, Mcfd
1	19.81	14.72	54.2	.9905	1.149	NIL	331.8
2	19.81	18.41	54.2	.9905	1.149	NIL	415.1
3	19.81	36.47	54.2	.9905	1.149	NIL	822.2
4	19.81	47.57	54.2	.9905	1.149	NIL	1072.5
5							

NO.	P_r	Temp. °R	T_r	Z
1	.08	530	1.31	NIL
2	.08	530	1.31	NIL
3	.08	530	1.31	NIL
4	.08	530	1.31	NIL
5				

Gas Liquid Hydrocarbon Ratio 6.875 Mcf/bbl.
A.P.I. Gravity of Liquid Hydrocarbons 53.7 @ 60° Deg.
Specific Gravity Separator Gas .7582 XXXXXXXXX
Specific Gravity Flowing Fluid XXXXX
Critical Pressure 674 P.S.I.A. ______ P.S.I.A.
Critical Temperature 405 R ______ R

P_c 4698 P_c^2 22071.2

NO	P_t^2	P_w	P_w^2	$P_c^2 - P_w^2$
1		4483	20097.3	1973.9
2		4350	18922.5	3148.7
3		3997	15976	6095.2
4		3357	12652.3	9418.9
5				

(1) $\frac{P_c^2}{P_c^2 - P_w^2}$ = 22071.2

(2) $\left[\frac{P_c^2}{P_c^2 - P_w^2}\right]^n$ = 9418.9

AOF = Q $\left[\frac{P_c^2}{P_c^2 - P_w^2}\right]^n$ = 2513.8

Absolute Open Flow 2514 Mcfd @ 15.025 Angle of Slope θ 45° Slope, n 1.000

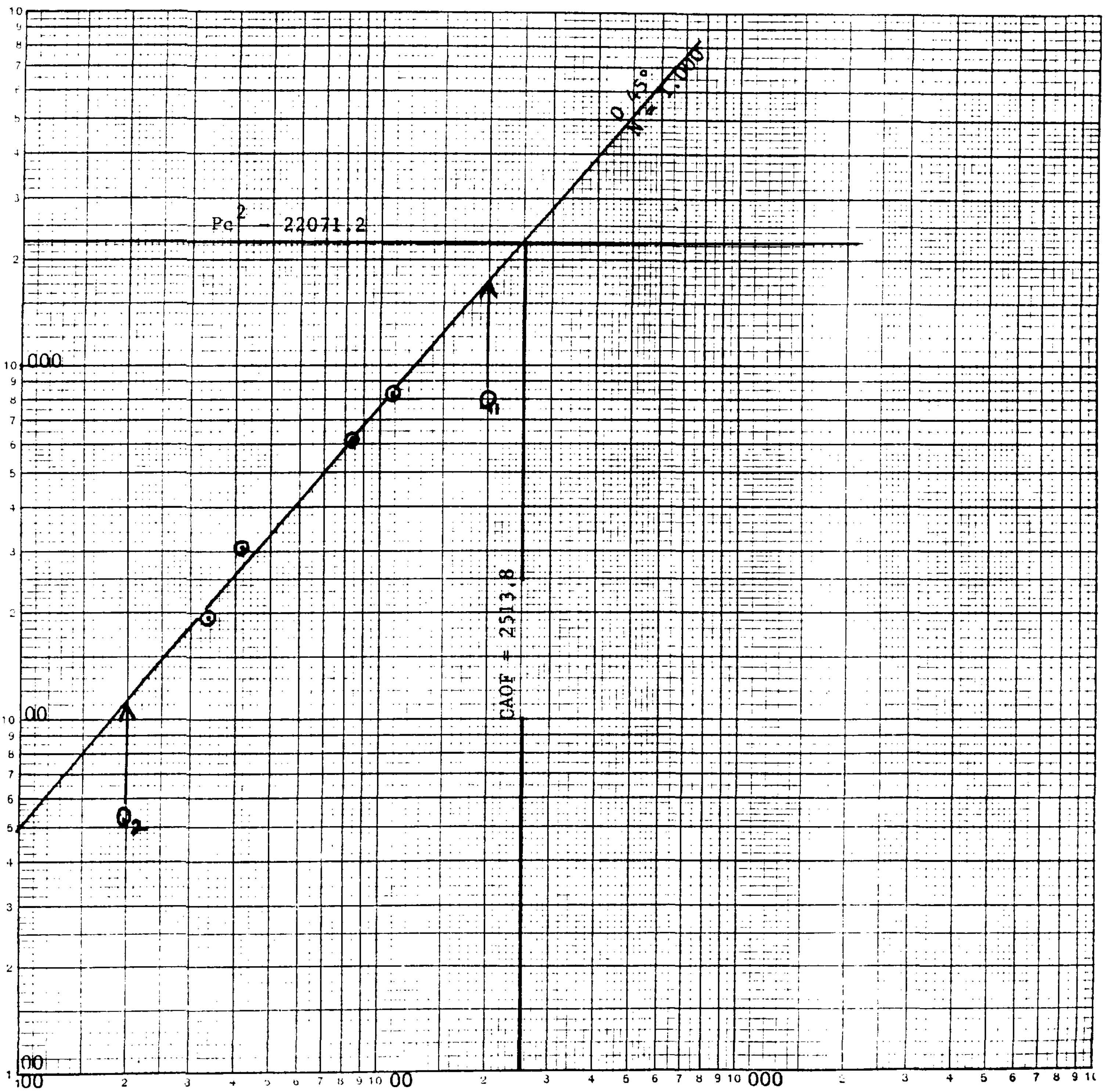
Remarks: calculated from known Bottom Hole Pressures taken with a Kuster Gauge
Well made 16 Bbls. of condensate during test.

Approved By Commission:	Conducted By:	Calculated By:	Checked By:
	R.W.	J.D.	J.D.

TXO PRODUCTION CO. JORDAN "B" NO. 2 JULY 8, 1985

Q1 = 2000 = Log - 3.3010300
Q2 = 200 = Log - 2.3010300
1.000000

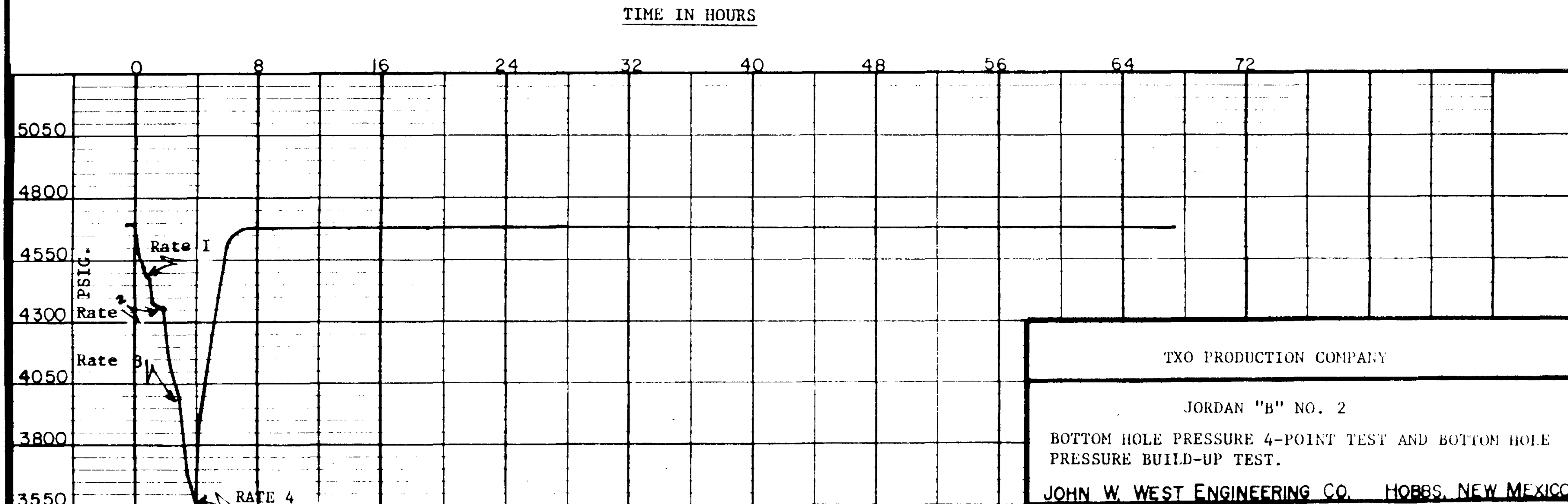
$$CAOF = 1072.5 \left(\frac{22071.2}{9418.9}\right)^{1.000} = 2513.8$$



Q = Mcf/Day

TEST DATE:	JULY 8 to 11, 1985
TEST DEPTH:	11442 FEET
ELEMENT NO:	34911
RANGE:	0-6000 PSI
CLOCK NO:	20439
RANGE:	0-72 Hours

NOTE: See tabulation of times and pressures on attached sheet.



TXO PRODUCTION COMPANY

JORDAN "B" NO. 2

BOTTOM HOLE PRESSURE 4-POINT TEST AND BOTTOM HOLE PRESSURE BUILD-UP TEST.

JOHN W. WEST ENGINEERING CO. HOBBS, NEW MEXICO

Date: 7-12-85 Drawn by bsm Scale as shown

'XO PRODUCTION COMPANY
:ORDAN "B" NO. 2
;OTTOM HOLE PRESSURE 4-POINT TEST AND
;OTTOM HOLE PRESSURE BUILD-UP TEST.
'ABULATION OF TIMES AND PRESSURES.

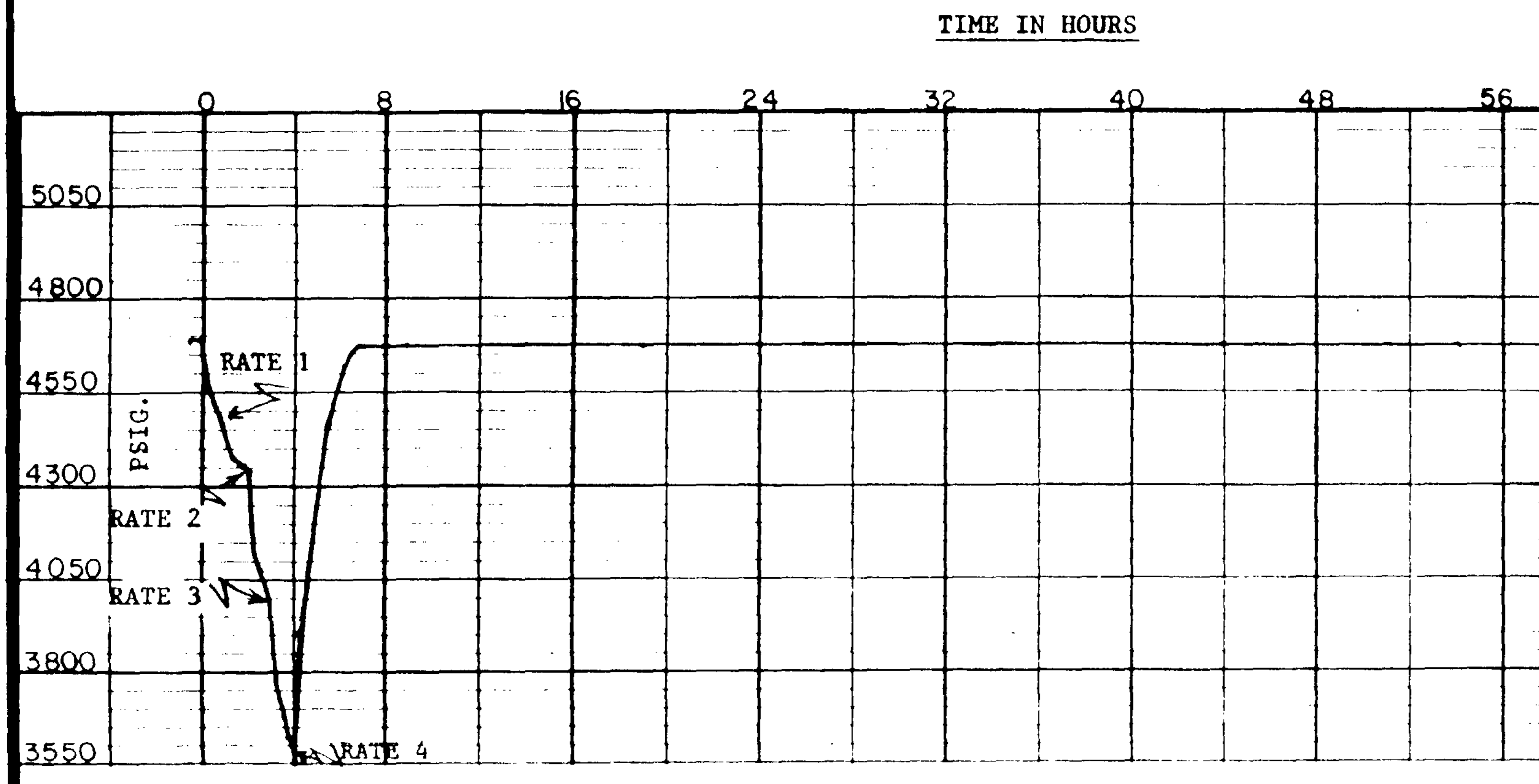
TEST CONDUCTED BY:
JOHN WEST ENGINEERING CO.

'EST DATE: JULY 8-11, 1985
:EST DEPTH: 11,442 FEET
:LEMENT NO: 34911 (0-6000 psi)

ATE	TIME	CUM HRS./MIN.		PSIG @ 11,442 FEET
-8-85	2:00 P.M.			4698 gauge reached 11,442'
	2:30 P.M.	00 Hrs.	00 Min.	4698 Begin 4-Point Test.
	2:45 P.M.	00	15	4571
	3:00 P.M.	00	30	4526
	3:15 P.M.	00	45	4495
	3:30 P.M.	01	00	4483 End Rate I
	3:45 P.M.	01	15	4381
	4:00 P.M.	01	30	4369
	4:15 P.M.	01	45	4359
	4:30 P.M.	02	00	4350 End Rate II
	4:45 P.M.	02	15	4133
	5:00 P.M.	02	30	4079
	5:15 P.M.	02	45	4045
	5:30 P.M.	03	00	3997 End Rate III
	5:45 P.M.	03	15	3786
	6:00 P.M.	03	30	3681
	6:15 P.M.	03	45	3633
	6:30 P.M.	04	00	3557 End Rate IV
'-8-85	6:30 P.M.	00 Hrs.	00 Min.	3557 Shut-In, Begin Build-Up
	6:45 P.M.	00	15	3913
	7:00 P.M.	00	30	3982
	7:15 P.M.	00	45	4021
	7:30 P.M.	01	00	4287
	8:00 P.M.	01	30	4462
	8:30 P.M.	02	00	4631
	9:00 P.M.	02	30	4659
	9:30 P.M.	03	00	4671
	10:30 P.M.	04	00	4677
'-8-85	11:30 P.M.	05	00	4677
'-9-85	4:30 A.M.	10	00	4680
	9:30 A.M.	15	00	4683
7-9-85	2:30 P.M.	20	00	4683
7-10-85	12:30 A.M.	30	00	4683
	10:30 A.M.	40	00	4683
7-10-85	8:30 P.M.	50	00	4683
7-11-85	6:30 A.M.	60	00	4683
7-11-85	10:00 A.M.	63	30	4683 Gauge off bottom, end of tes

TEST DATE:	JULY 8 to 11, 1985
TEST DEPTH:	11,442 FEET
ELEMENT NO:	53217
RANGE:	0-7100 PSI
CLOCK NO:	E-794
RANGE:	0-72 Hours

NOTE: See tabulation of times and pressures on attached sheet.



TXO PRODUCTION COMPANY

JORDAN "B" NO. 2

BOTTOM HOLE PRESSURE 4-POINT TEST AND BOTTOM HOLE PRESSURE BUILD-UP TEST.

JOHN W. WEST ENGINEERING CO. HOBBS, NEW MEXICO

Date: 7-12-85 | Drawn by: bsm | Scale: as shown

TXO PRODUCTION COMAPNY
JORDAN "B" NO. 2
BOTTOM HOLE PRESSURE 4-POINT TEST AND
BOTTOM HOLE PRESSURE BUILD-UP TEST.
TABULATION OF TIMES AND PRESSURES.

TEST CONDUCTED BY:
JOHN WEST ENGINEERING COMPANY

TEST DATE: JULY 8 to 11, 1985
TEST DEPTH: 11,442 FEET
ELEMENT NO: 53217 (0-7100 PSI)
OPERATOR: R.W.

DATE	TIME	CUM HRS./MIN.		PSIG @ 11,442 FEET
7-8-85	2:00 P.M.			4691 gauge reached 11,442 Feet
	2:30 P.M.	00 Hrs.	00 Min.	4691 Shut-In, Begin Build-Up
	2:45 P.M.	00	15	4566
	3:00 P.M.	00	30	4520
	3:15 P.M.	00	45	4491
	3:30 P.M.	01	00	4477 End Rate I
	3:45 P.M.	01	15	4376
	4:00 P.M.	01	30	4365
	4:15 P.M.	01	45	4354
	4:30 P.M.	02	00	4344 End Rate II
	4:45 P.M.	02	15	4129
	5:00 P.M.	02	30	4075
	5:15 P.M.	02	45	4039
	5:30 P.M.	03	00	3991 End Rate III
	5:45 P.M.	03	15	3780
	6:00 P.M.	03	30	3676
	6:15 P.M.	03	45	3626
	6:30 P.M.	04	00	3551 End Rate IV
	6:30 P.M.	00 Hrs.	00 Min.	3551 Shut-In, Begin Build-Up
	6:45 P.M.	00	15	3909
	7:00 P.M.	00	30	3976
	7:15 P.M.	00	45	4014
	7:30 P.M.	01	00	4283
	8:00 P.M.	01	30	4455
	8:30 P.M.	02	00	4627
	9:00 P.M.	02	30	4656
	9:30 P.M.	03	00	4666
	10:30 P.M.	04	00	4666
7-8-85	11:30 P.M.	05	00	4666
7-9-85	4:30 A.M.	10	00	4674
	9:30 A.M.	15	00	4677
7-9-85	2:30 P.M.	20	00	4677
7-10-85	12:30 A.M.	30	00	4677
	10:30 A.M.	40	00	4677
7-10-85	8:30 P.M.	50	00	4677
7-11-85	6:30 A.M.	60	00	4677
7-11-85	10:00 A.M.	63	30	4677 Gauge off bottom, end of test

NEW-TEX
LAB
PHONE 505/393-3561 • P. O. BOX 1161 • 611 W. SNYDER • HOBBS, NEW MEXICO 88240

ANALYSIS CERTIFICATE

:LIENT:	JOHN WEST ENGINEERING	ANALYSIS NUMBER:	7527
;DDRESS:	412 N DAL PASO	DATE OF RUN:	7 9 85
:ITY, STATE:	HOBBS NM 88240	DATE SECURED:	7 8 85

;AMPLE IDENT: TXO PRODUCING COMPANY - JORDAN B-42
;AMPLING PRESS: SAMPLING TEMP:70 DEG F

?EMARKS: TRAP PRESSURE 42 #

********* GAS ANALYSIS *********

	MOLE PERCENT	GAL/ MCF
;ITROGEN	0.797	
:ARBON DIOXIDE	1.507	
!ETHANE	74.728	
:THANE	12.805	3.415
'ROPANE	6.312	1.733
SO-BUTANE	0.912	0.298
!ORMAL BUTANE	1.839	0.578
SO-PENTANE	0.384	0.141
!ORMAL PENTANE	0.388	0.140
!EXANES	0.328	0.135
'OTAL	100.000	6.440

'ROPANE GPM:	1.73	BUTANES GPM:	0.88
:THANE GPM:	3.41	PENTANES PLUS GPM:	0.42

;PECIFIC GRAV (CALC): 0.7582
!OLE WEIGHT: 21.96

!HV-BTU/CU FT	PRESSURE (PSIA)	WET	DRY
	14.696	1254	1277
	14.650	1251	1273
	14.730	1257	1280
	14.735	1258	1280

D Deane Simpson

DEANE SIMPSON

STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

BRUCE KING
GOVERNOR

ANITA LOCKWOOD
CABINET SECRETARY

POST OFFICE BOX 2088
STATE LAND OFFICE BUILDING
SANTA FE, NEW MEXICO 87504
(505) 827-5800

September 21, 1993

RE: CASE NO. 10796
Order No. R-9974

Mr. William F. Carr
Campbell, Carr, Berge, and Sheridan
Attorneys at Law
Post Office Box 2208
Santa Fe, New Mexico 87504-2208

Dear Mr. Carr:

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

Sincerely,

Florene

Florene Davidson
OC Staff Specialist

Copy of order also sent to:

Hobbs OCD__x______
Artesia OCD_x______
Aztec OCD________
Thomas Kellahin