PECOS SLOPE ABO GAS FIELD
COMPLETION PRACTICES AND RESERVE ESTIMATES

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ABSTRACT

Yates Petroleum has developed successful drilling and completion practices through experience with 250 wells in the Pecos Slope Abo gas field. Several methods have been used for estimating ultimate reserves from the wells in this low permeability reservoir. The most promising is a drawdown analysis that matches computerized type curves with data on daily flow rates and tubing pressure.

INTRODUCTION

The Pecos Slope Abo gas field was discovered in June of 1977 when Yates Petroleum re-entered the Honolulu McConkey #1 in Section 10-9S-26E of Chaves County, New Mexico. By the end of 1979, only one well had been connected to a pipeline. Twenty more wells began production in 1980. Development began in earnest after May of 1981 when the Abo formation was designated as a tight gas formation under Section 107 TF of the Natural Gas Policy Act. This designation covered 1.54 million acres in Chaves and DeBaca counties (Figure 1). By the start of December of 1982, 384 wells were producing an average of 115 MMcf/D or about 298 Mcf/D per well. The two principal operators are Yates Petroleum with 163 producing wells and Mesa Petroleum with 128.

In May of 1982, Yates and ANR Production applied for tight sand designation for 5.1 million additional acres to the west and north of the approved tight gas area. About 25 wildcats have been drilled in this extension area (Figure 1) and several wells have been completed as small producers. This application was approved by the New Mexico Oil Conservation Division in December, 1982, and forwarded to the Federal Energy Regulatory Commission for final consideration.

The Abo sandstone is a siltstone consisting of quartz, feldspar and mica, cemented with calcite and clays. The reservoir rock is known informally as a "red bed" section. These silty sandstones were probably deposited by a river system flowing generally from the northwest to the southeast during Permian Time. Productive zones in the main portion of the field occur at depths between about 3500 and 5000 feet. Permeability estimates in the producing zones normally average between 0.03 and 0.05 md. The reservoirs are underpressured with average bottom-hole pressure of 1125 psig. Table 1 shows the composition of the sweet gas produced. The wells now produce into a pipeline pressure of 200 psia. The purchaser has contracted to reduce the pipeline pressure further to 150 psia in the future.

The purpose of the paper is to describe how Yates Petroleum drills and completes a well in the Pecos Slope Abo field and then estimates reserves.

DRILLING PRACTICES

Total depth of a typical well in the developed portion of the field is 4200 ft. Two or three strings of casing are required depending on the severity of lost circulation problems in the basal San Andres. The well is spudded with fresh water gel, and surface casing is set at the top of the Slaughter zone at 800 to 900 ft. The New Mexico Oil Conservation Division requires that cement be circulated behind this string of casing to protect the fresh water. Normally, 40.5#, 10 3/4" J-55 is used but 8 5/8" casing can be substituted if there is no chance of problems further down-hole.

Lost circulation occurs most frequently at 1300 to 1500 ft in the San Andres. When circulation is lost, the hole is swept at least twice with a slug of a commercial lost-circulation material (LCM). If the problem is not cured, the hole is drilled without circulation to the top of the Glorietta at about 1500 ft. In two cases, wells were lost when cavings buried the drill pipe at about 1400 ft. This should not happen if the hole is swept in a timely fashion. Intermediate 8 5/8" casing is set at about 1500 ft and cemented to surface. There is no need for intermediate casing if circulation can be maintained through the San Andres.

Ten pound brine is used to drill below 1500 ft because of the presence of a salt section. At $3 per barrel, brine is too expensive to use in the upper part of the hole where lost circulation is common. At the top of the Abo near 3500 ft, salt gel and starch are added to give mud with 32 to 35 vis in order to remove cuttings. Occasionally, circulation is lost into one of the potential producing zones in the Abo. Circulation can be regained by sweeping the hole with a pill of lost-circulation material. At total depth, the mud is raised to 50 vis and the hole is circulated bottoms up over about 4 hours. The normal logging suite consists of a CNL-FDC[R] followed by a DLL-Rxo[R] combination. Figure 2 shows the productive Abo section of the porosity log for a representative producing well.

The outside of the 4 1/2" production casing is "rough coated" through the Abo interval in order to promote good bonding of cement to casing. The casing is cemented with about 350 sacks preceded by a small (250 gallon) mud sweep. Top of cement is usually 500 ft above the top of the Abo. In addition, the governmental agencies require cement from the top of the Glorietta to the surface. If there is no intermediate casing, Yates runs cement through a 1 in. string outside the production casing from about 1500 ft to surface.

Yates drilled several wells with an air rig in one area of the field where there were severe lost-circulation problems in the San Andres. The compressed air lifted the cuttings without breaking down the formation, and the air rig outperformed a conventional rig in the problem area. However, in more typical areas the air rig was more costly to operate overall. It drilled a well in 5 days rather than 9, but extra cementing and compression costs outran the time savings.

Over the past year, experience and improved operations have combined with an increased supply of drilling rigs to lower the cost of drilling and completing an Abo well. Total costs have dropped to near $250,000 from around $350,000 for a well with no special problems.

COMPLETION PRACTICES

Yates Petroleum Corporation's completion activities in the Pecos Slope Abo gas field began with re-entry of the Honolulu Oil Corporation's plugged and abandoned McConkey well No. 1 in Section 10-9S-26E. After unsuccesful completion attempts in deeper formations the Abo interval (4764' to 4782') was perforated on June 27, 1977 with 22 0.34" holes. The zone had a natural flow rate of 540 Mcf/D. Initial treatment consisted of 2500 gallons of 15% acid with nitrogen to aid in clean up. The well was then fractured treated with 15,600 gallons of gelled KCl water with 15,000 pounds of 20-40 sand and 2500 pounds of 100 mesh sand. Carbon dioxide was used to aid in treatment clean up. This frac was pumped down 2 3/8" tubing at an average pressure of 4000 psig. The average pump rate was 12 barrels per minute. The well was tested after frac on September 6, 1977 with a stabilized flow rate of 2550 Mcf/D.

The McConkey well No. 1 set a trend for Yates Petroleum Corporation's early Pecos Slope Abo completions. Basic features of this completion approach include:

1. Only one zone was completed and produced at a time.

2. All wells were treated down tubing.

3. A well was tested before treatment and after each state of treatment.

4. Nitrogen was used in the acid breakdown and carbon dioxide was used in the frac fluid to aid in cleanup.

5. Gelled 2% KCl water was used as a fracturing fluid.

6. Sand concentrations averaged approximately 2 lb/gal.

Of these features only the fracturing fluid and low sand concentrations are retained in present day completions. All others have changed.

The first completion procedure to change was the extensive amount of testing during various stages of completion. Much of the testing was intended to support the application for a tight reservoir designation. This involved obtaining a natural flow rate as well as flow rates after each stage of treatment. Average natural flow rate was 70 Mcf/D with most wells making no gas before stimulation. Bottom hole pressure build-up tests were also run during completion operations on some of the earlier wells. Much of this data gathering was discontinued once the tight gas reservoir determination had been approved.

The decision to stop treating each Abo pay section individually represented a very significant change in Yates Petroleum's completion procedures. If all Abo zones could be effectively treated at one time, much time and expense could be saved by eliminating the need for subsequent recompletion and additional costly stimulations. A limited entry technique was adopted to accomplish multiple zone completions. All zones were perforated at one time. The number and size of the perforations used plus the frac rate were changed to distribute the treatment to all zones. After perforating, each individual zone was then straddled with a packer and retreivable bridge plug and acidized separately to insure good break down. Nitrogen was dispensed with in acid treatments inasmuch as flow tests after acid were no longer required and cleanup did not have to be carried to the point of obtaining an after-acid flow rate. After acidizing, the packer and retreivable bridge plug were removed from the well and tubing was run back in open ended. The fracture treatment was pumped down both tubing and annulus to get the higher frac rates of 30 to 60 barrels per minute required for limited entry. After cleanup, wells were left to produce through tubing without a packer. Radioactive and temperature surveys were run to determine frac distribution in order to judge how effectively all zones were treated. Although not always conclusive, these surveys indicated effective treatment of the desired zones and helped to develop confidence in this completion technique. Figure 2 contains a tracer survey showing the distribution of radioactive frac sand. However, most confidence in the technique's application to Pecos Slope Abo wells has been gained through good completion tests and good sustained production rates.

Recent changes have served to cut costs slightly. The wells are now fraced down casing instead of the tubing and tubing-casing annulus. This cuts down on friction losses a little thereby saving on horsepower requirements. Also, use of carbon dioxide has been eliminated since the well is not equiped to produce imm-ediately after treatment. In this completion method, tubing and packer are run in the well after frac and the well is swabbed-in. Our experience shows that an average well can be swabbed-in in about two days at a lower cost than when the carbon dioxide was used for cleanup while fracing down tubing and annulus. Another reason for omitting CO_2 from the fracture treatment is that the wells now produce high-BTU gas as soon as they go on line. The purchaser pays for the gas on the basis of an analysis taken early in the well's life. When CO_2 was used, there was often 5% residual CO_2 in the first gas sold. The CO_2 disappears within two weeks but the purchaser continues to pay for low-BTU gas for several months until the gas is re-analysed.

The poresent completion approach includes these basic features:

1. All Abo zones are completed and produced at one time.
2. The zones are acidized individually down tubing but fractured all at the same time down casing.
3. The well is tested only after it has been fractured.
4. No nitrogen or carbon dioxide is used in treating most wells. Occasionally CO_2 is added to help the poorest wells cleanup.
5. Gelled 2% KCl water is used as the fracturing fluid (20 lb of gel per 1000 gal).
6. About 2 lb/gal of 20-40 mesh sand serves as propant.

Fracture treatments have ranged from 20,000 to 80,000 gallons of gelled water. The average treatment is sized on the basis of about 1500 gallons per ft of pay and contains about 40,000 gallons. The injection rate approximates 1.5 BPM per ft of pay and has ranged as high as 95 BPM down 4 1/2" casing. For limited entry, the number of perforations is 0.5 to 0.7 per ft of pay and 0.45" holes are normally used. Surface injection pressures during fracture treatment are limited to 3500 psig and average about 2500 psig.

Table 2 shows the effects of the various parts of the treatment on the flow rate. On the average, a well that initially produces 500 Mcf/D into the pipeline tested 1450 Mcf/D after fracture. This well would make 100 Mcf/D after the acid treatment and nothing naturally. The other columns in Table 2 show similar sets of numbers for a poorer well and a better well.

RESERVE ESTIMATES

Reserve estimates are difficult in the Pecos Slope Abo field. The reservoir consists of low-permeability channel sands with irregular shapes. Production decline curves are controlled as much by the line pressure as by the well's performance. Thus, volumetric calculations and extrapolations from decline curves give questionable results at best. Shut-in bottom-hole pressures (BHP) require long times to reach the radial-flow regime where the Horner [1] analysis becomes valid. Bottom-hole pressures simply do not stabilize within a shut-in time that can be justified economically. Yates has run one 7-day pressure buildup. It was at the Duncan LH No. 1 well in December of 1981 after the well had produced for about one year. The BHP was still increasing 1 to 2 percent per day at the end of the test and the gas flow regime that controls the pressure at the wellbore was linear rather than radial.

Yates has used two main types of analysis in estimating reserves. The first is a modification of the classical P/Z curve and the second is a draw-down test conducted throughout the producing life of the well.

By convention, shut-in bottom-hole pressure (SIBHP) tests are limited to 72 hours in order to minimize the loss of production. The first analysis method uses a purely empirical procedure to estimate a stabilized SIBHP from the BHP (P") measured after a shut-in time of 72 hours. Four assumptions were made:

1. The stabilized SIBHP is a function of only P" and the well's productivity.

2. Higher productivity wells reach a stabilized SIBHP sooner than lower productivity wells.

3. A reasonable measure of a well's productivity is its maximum sustained producing rate, Q_{MAX}. In practice, this parameter is simply the maximum daily rate for any month in the well's history.

4. This type of relation can be calibrated via data from three carefully chosen wells where decline curves and pressure buildups gave consistent estimates of original reserves.

The resulting estimate for stabilized SIBHP is

$$P' = P'' \left[1.15 - 0.09\, Q_{MAX}\right] \cdot \left[1 + 0.1(4-0.00357P'')^{0.25}\right] \quad \ldots\ldots (1)$$

Here $Q_{MAX} < 1.7$ MMcf/D and $P'' < 1050$ psi. The idea behind Equation 1 is simply to make a reasonable extrapolation from P" to a stabilized SIBHP. The success of the method depends critically on the accuracy of the reserve estimates for the three calibration wells (Godfrey MP No. 1, McClellan MB No. 1 and McConkey HX No. 1).

Figure 3 shows three P/Z estimates derived from BHP for the Godfrey MP No. 1. As expected, the estimates of original reserves increase with production when the 72 hour SIBHP is used. Both the Horner extrapolation and the results from Equation 1 give P/Z values that lie close to a straight line. The correction due to Equation 1 is more pronounced for wells of lower productivity than Godfrey MP No. 1. The long dashed line in Figure 3 is the P/Z curve associated with the pressure draw-down analysis (PDDA) for this well. All three estimates from SIBHP are quite low compared with the results of the PDDA.

The second method (PDDA) is based on the fact that the behavior of a gas well can be analyzed as an extended variable rate draw-down test.[2-4] The measured data are tubing head pressure and production rate provided daily by the pumper. The tubing pressure is used to estimate BHP from which a "normalized" pseudopotential is calculated (Appendix A). Time is corrected for the effects of the variable production rate. The exact form of this correction depends on the type of flow that dominates the pressure behavior at the subject well. The change in pseudopotential divided by the production rate for each day is plotted versus the corrected time on a log-log graph. Most of the points cluster tightly along a smooth curve when the correct flow regime is used. A type curve [5] is matched to these points; and initial gas in place, transmissibility and fracture half length are estimated from the match point. An interactive desktop computer is used to store the data, make the calculations, plot the data, generate the type curves and print a summary report.

It was hoped originally that this method could serve as a reservoir limit test.[3] However, pseudo steady state flow has been observed in only the smallest reservoirs. Most of the Abo reservoirs are still exhibiting transient flow behavior. This implies that the calculated gas in place is a minimum estimate.

Figure 4 shows the PDDA for the Godfrey MP No. 1 which has been producing for over two years. Gas in place is estimated as 2.6 Bcf and total recoverable reserves down to 100 psi reservoir pressure are 2.4 Bcf. Figure 5 shows the PDDA for the Smernoff NL No. 1 whose reserves are more typical of the average Abo well. This well has also been producing for more than two years, but at lower rates. Gas in place is estimated as 397 MMcf by PDDA and 264 MMcf by Equation 1. The scatter in the data is more severe for low rate wells because it is more difficult to estimate daily producing rates and because low rate wells are more affected by operational problems like compressor breakdowns and small amounts of water production. These PDDA calculations give an average permeability of about 0.05 md and average fracture half length of approximately 900 ft.

Reserve estimates for the 59 Yates Abo wells producing on January 1, 1982 are summarized in Table 3. These estimates were made in the fall of 1982. The first two rows illustrate that reserves based on 72 hour SIBHP taken early in the life of the well are ultra conservative. The estimate of 325 MMcf per well from Equation 1 is probably also conservative in view of the PDDA results. The pressure draw-down analysis says that average reserves are at least 556 MMcf per well. It is possible that a portion of this gas lies within the drainage radius of a recently drilled offset well since 556 MMcf per well corresponds to a drainage area of 150 to 200 acres.

As more offset wells are drilled on 160-acre spacing units, more instances of pseudo steady state flow should be observed in the PDDA.

CONCLUSION

Yates Petroleum has learned to complete Pecos Slope Abo wells successfully by fracturing down casing at high rates through a limited number of perforations. Estimates of the average original reserves per well by several methods seem to indicate 400 to 500 MMcf per well as the most probable range. Further experience with a computerized method of pressure draw-down analysis offers potential to improve the reserve estimates for individual wells in the field.

c = total compressibility

c_f = formation compressibility

c_g = gas compressibility

c_o = oil compressibility

c_w = water compressibility

G = gas in place

h = average reservoir thickness

k = permeability

p = bottom hole pressure at time, t

ΔP_D = dimensionless pressure drop

P' = extrapolated pressure from Equation 1, psia

P'' = bottom hole pressure at the end of a 72 hours build-up test, psia

P^* = Horner extrapolated pressure, psia

Q_j = Q_{sc} during j'th real time interval
Q_{MAX} = maximum sustained producing rate, MMcf/D
Q_{sc} = flow rate at surface conditions
S_g = gas saturation
S_o = oil saturation
S_w = water saturation
t = pressure and variable rate corrected time
t_{corr} = variable rate corrected time
t_{DX_f} = dimensionless time
t_j = end of j'th real time interval
x_D = dimensionless distance along the fracture
x_e = reservoir half-width
x_f = fracture half-length
x_w = distance from the center of the fracture to the edge of the reservoir
y_e = reservoir half-length
y_w = distance from fracture to the end of the reservoir
z = real gas deviation factor
B_g = gas reservoir volume factor
μ = gas viscosity
ϕ = average reservoir porosity
$\Delta\psi n$ = "normalized" pseudo-potential drop

Any rationalized system of units may be used with the equations in the appendix.

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APPENDIX A

Production Draw Down Analysis (PDDA) uses type curve matching techniques to analyze production data as if it were an extended variable rate draw down test. Type curve matching requires two log-log plots with matching grid sizes.[3] The first is a data plot which is the potential drop versus time. The second is the type curve which is the dimensionless pressure drop versus dimensionless time. The potential drop and the dimensionless pressure drop differ from each other by a constant factor. The time and the dimensionless time differ from each other by another constant factor. The points on the data plot lie along a smooth curve which is identical to the type curve except that it is displayed vertically and horizontally from it.

The potential drop that we have chosen to plot is a "normalized" pseudo-potential drop divided by flow rate at surface conditions:

$$\frac{\Delta\psi n}{Q_{sc}} = \frac{\mu_i z_i}{k_i p_i^2 Q_{sc}} \int_{p}^{p_i} \frac{kpdp}{\mu z} \quad \ldots\ldots \text{(A-1)}$$

which has the dimensions of reciprocal rate.

Time must be corrected for rate and pressure changes before it is plotted. Variable rate can be approximated by step rate changes. Q_j is constant over the real time interval from t_{j-1} to t_j. The proper variable rate time correction depends upon which type of flow dominates pressure behavior in the reservoir at the well.[6]

For pseudo steady state flow:

$$t_{corr} = \frac{1}{Q_N} \sum_{j=1}^{N} (t_N - t_{j-1})\,(Q_j - Q_{j-1}) \quad \ldots\ldots \text{(A-2)}$$

For radial flow:

$$t_{corr} = \prod_{j=1}^{N} (t_N - t_{j-1})^{(Q_j - Q_{j-1})/Q_N} \quad \ldots\ldots \text{(A-3)}$$

For linear flow:

$$t_{corr} = \left[\frac{1}{Q_N} \sum_{j=1}^{N} (Q_j - Q_{j-1}) \sqrt{t_N - t_{j-1}}\right]^2 \quad \ldots\ldots \text{(A-4)}$$

For bi-linear flow[6]:

$$t_{corr} = \left[\frac{1}{Q_N} \sum_{j=1}^{N} (Q_j - Q_{j-1}) \sqrt[4]{t_N - t_{j-1}}\right]^4 \quad \ldots\ldots \text{(A-5)}$$

The variable rate corrected time is then corrected for changing pressure

$$t = \frac{1}{2}\left[1 + \frac{k\phi_i\mu_i c_i}{k_i\phi\mu c}\right] t_{corr} \quad \ldots\ldots\ldots \text{(A-6)}$$

The type curves that we have chosen to match are log-log plots of the dimensionless pressure drop versus the dimensionless time for a vertically fractured rectangular reservoir.(5)

$$\Delta P_D(t_{Dx_f}) = 2\pi \int_0^{t_{Dx_f}} \left[1 + 2\sum_{n=1}^{\infty} \exp\left(-\left(\frac{n\pi}{2}\frac{x_f}{x_e}\right)^2 t_{Dx_f}\right) \cdot \right.$$

$$\left. \frac{\sin\left(\frac{n\pi}{2}\frac{x_f}{x_e}\right)}{\frac{n\pi}{2}\frac{x_f}{x_e}} \cos\left(\frac{n\pi}{2}\left(\frac{x_w}{x_e} + \frac{x_D x_f}{x_e}\right)\right)\right] \cdot \left[1 + 2\sum_{n=1}^{\infty} \exp\left(\left(\frac{n\pi}{2} \cdot \frac{x_f}{x_e}\frac{x_e}{y_e}\right)^2 t_{Dx_f}\right.\right.$$

$$\left.\left. \cos^2\left(\frac{n\pi}{2} \cdot \frac{y_w}{y_e}\right)\right)\right] \left(\frac{x_f}{2x_e}\right)^2 \frac{x_e}{y_e}\, d(t_{Dx_f}) \quad \ldots\ldots\ldots \text{(A-7)}$$

Every point on the data curve is related to every matching point on the type curve by these equations:

$$t_{Dx_f} = \frac{k_i t}{\phi_i \mu_i c_i x_f^2} \quad \ldots\ldots\ldots\ldots\ldots\ldots \text{(A-8)}$$

$$\frac{\Delta\psi n}{Q_{sc}} = \frac{1}{2\pi p_i} \frac{B_{gi}}{k_i h/\mu_i} \Delta P_D \quad \ldots\ldots\ldots\ldots\ldots \text{(A-9)}$$

Any point can be selected as the match point and can be used to estimate the transmissibility:

$$\frac{k_i h}{\mu_i} = \frac{B_{gi}}{2\pi P_i} \left.\frac{\Delta P_D}{\Delta\psi n/Q_{sc}}\right|_{mp} \quad \ldots\ldots\ldots\ldots\ldots \text{(A-10)}$$

Initial gas in place:

$$\left[1 + \frac{s_w c_w + s_o c_o + c_f}{s_g c_g}\right] G_i = \frac{B_{gi} \; 4x_e y_e}{2\pi c_{gi} x_f^2} \cdot \left.\frac{\Delta P_D}{\Delta\psi n/Q_{sc}}\right|_{mp} \left.\frac{t}{t_{Dx_f}}\right|_{mp} \quad \ldots . \text{(A-11)}$$

and the fracture half-length:

$$s_{gi}\phi_i h \left[1 + \frac{s_w c_w + s_o c_o + c_f}{s_g c_g}\right]_i x_f^2 = \frac{B_{gi}}{2\pi P_i c_{gi}} \left.\frac{\Delta P_D}{\Delta\psi n/Q_{sc}}\right|_{mp} \left.\frac{t}{t_{Dx_f}}\right|_{mp} \quad \ldots \text{(A-12)}$$

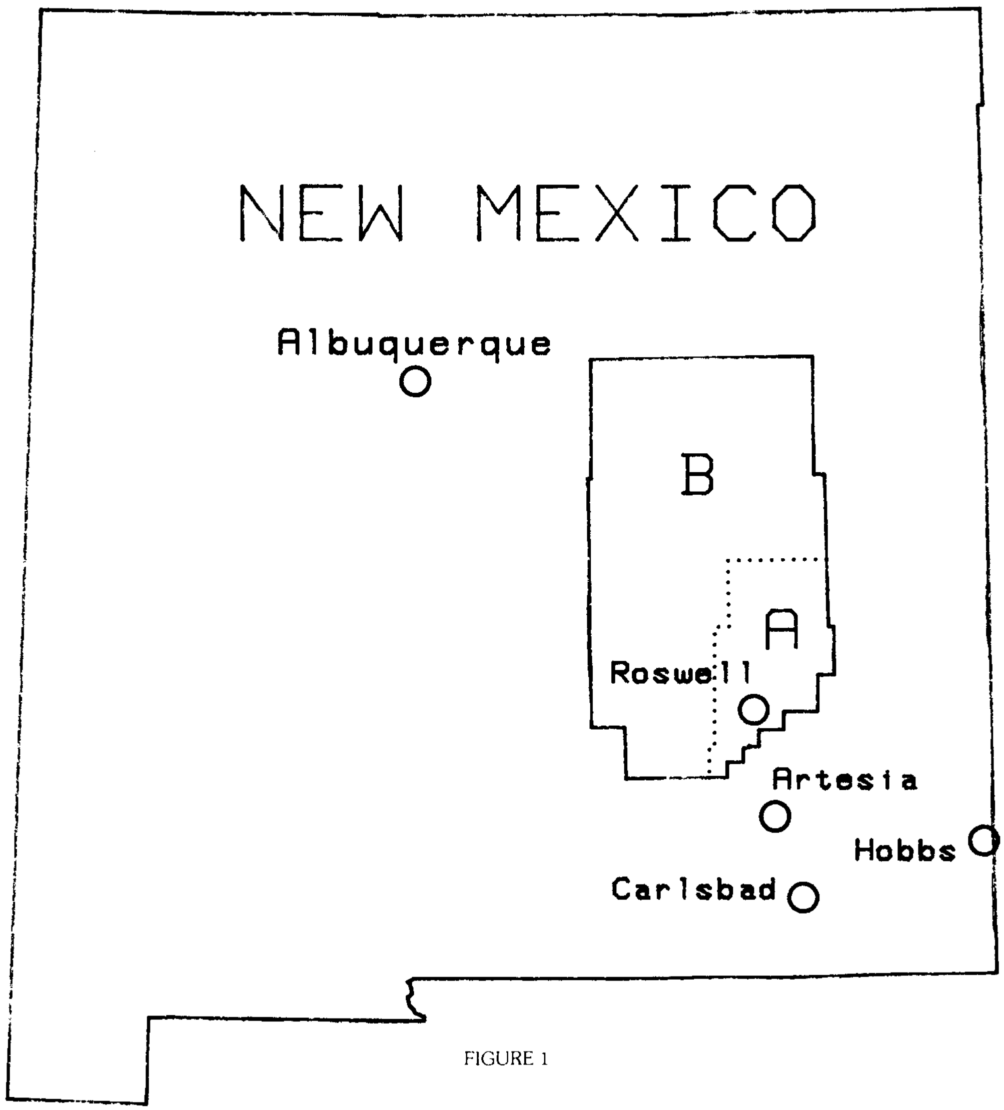
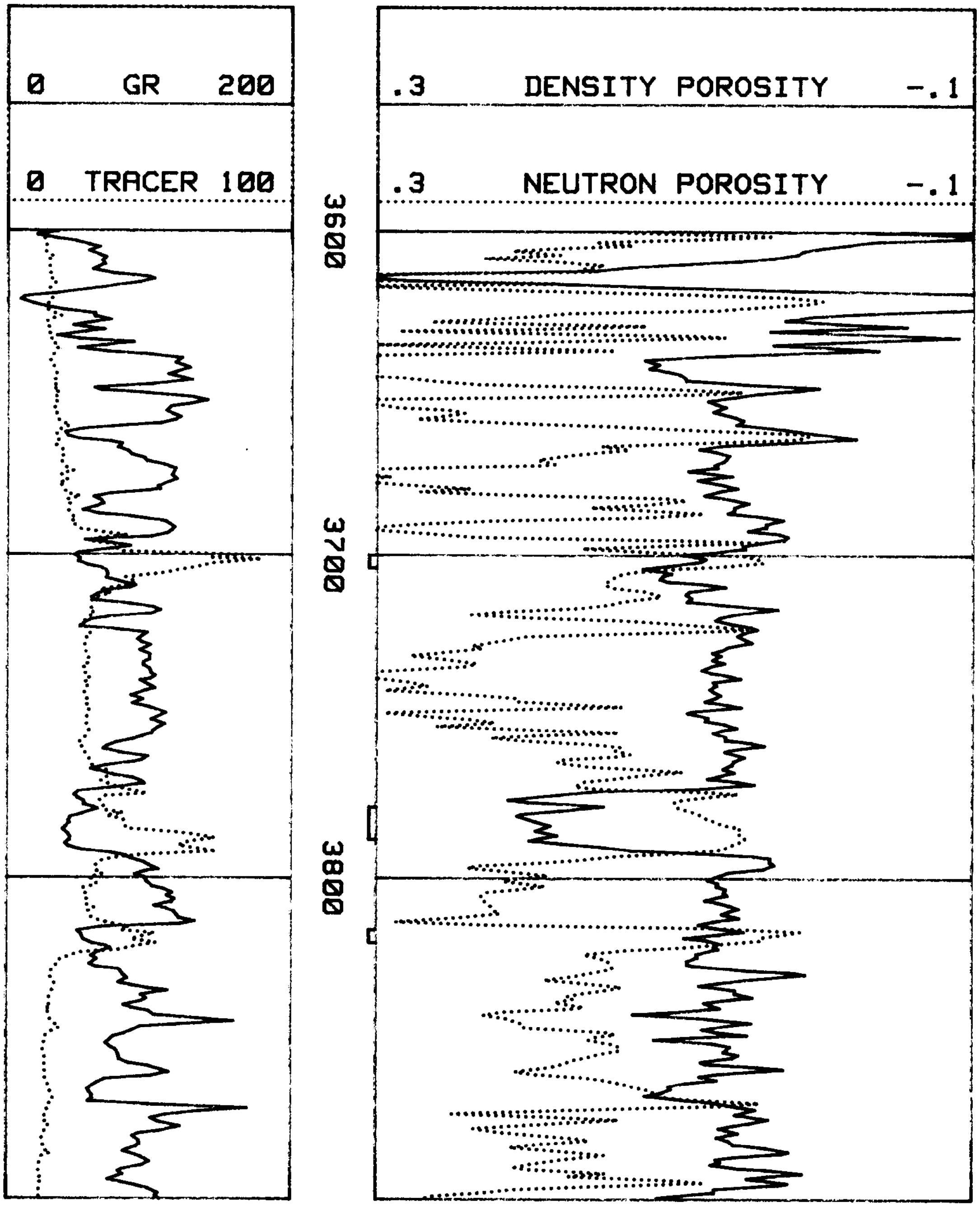


FIGURE 1



0 GR 200
0 TRACER 100
.3 DENSITY POROSITY -.1
.3 NEUTRON POROSITY -.1
3600
3700
3800

FIGURE 2

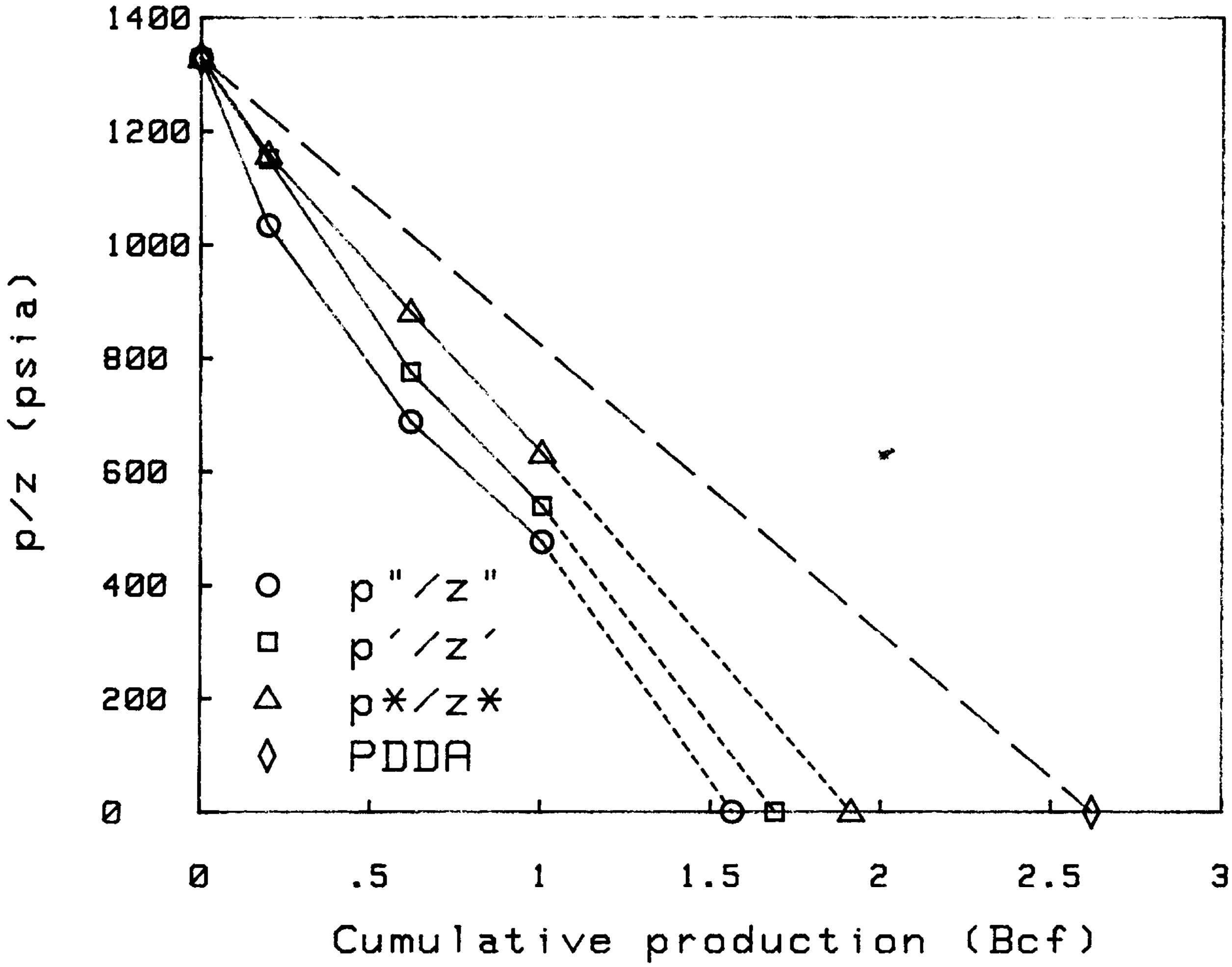

1400
1200
1000
800
600
400
200
0
p/z (psia)
0
.5
1
1.5
2
2.5
3
Cumulative production (Bcf)
p"/z"
p′/z′
p*/z*
PDDA

FIGURE 3

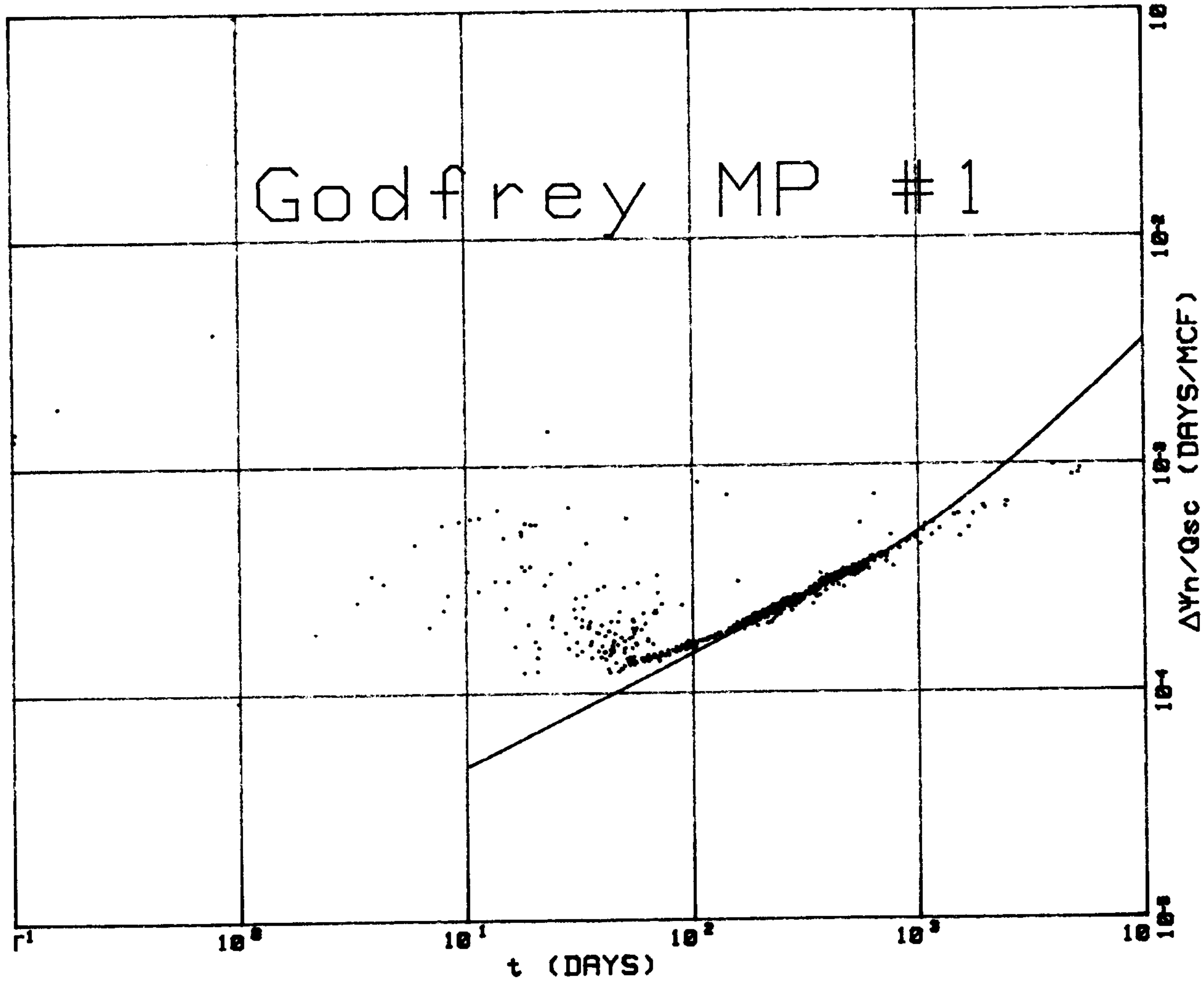

Godfrey MP #1
t (DAYS)
ΔΨn/Qsc (DAYS/MCF)
10⁰
10¹
10²
10³
10⁻²
10⁻³
10⁻⁴
10⁻⁵

FIGURE 4

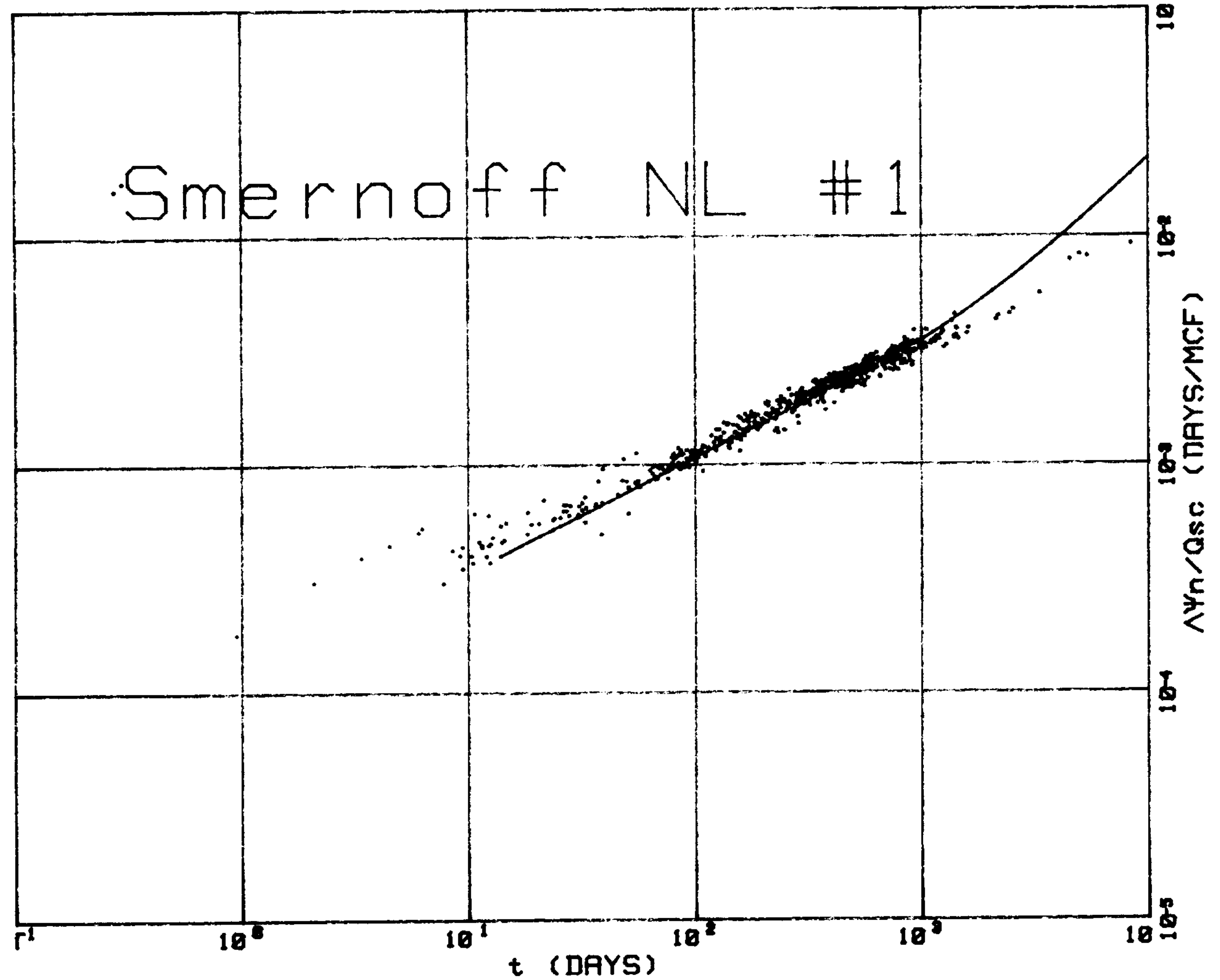

Smernoff NL #1
10
10-2
10-3
10-4
10-5
ΔΨn/Qsc (DAYS/MCF)
10-1
10 0
10 1
10 2
10 3
10 4
t (DAYS)

FIGURE 5

TABLE 1
ANALYSIS OF GAS FROM PECOS SLOPE ABO FIELD
GODFREY MP #1
AUGUST 26, 1982

Component	Mole Fraction
Nitrogen	0.0522
Carbon Dioxide	0.0003
Methane	0.8657
Ethane	0.0479
Propane	0.0180
Isobutane	0.0031
N-Butane	0.0065
Isopentane	0.0020
N-Pentane	0.0021
Hexanes	0.0015
$Heptanes^{+}$	0.0007

Specific Gravity = 0.645

Heating Value = 1050 Btu

TABLE 2
EFFECT OF TREATMENTS ON FLOW RATES (Mcf/D)

Rate on Line	100	500	1000
After Frac	420	1450	2500
After Acid	2	100	600
Natural	TSTM	TSTM	40

TABLE 3
ESTIMATES OF AVERAGE ORIGINAL RESERVES FOR YATES WELLS

Analysis Method	Original Reserves per Well MMcf
Actual 72-hour BHP (1981)	183
Actual 72-hour BHP (1982)	286
Estimated pressure from Equation 1	325
Pressure from Horner Extrapolation	397
Pressure Draw Down Analysis	556