Sampling Gas-Condensate Wells

W.D. McCain Jr.,* SPE, and **R.A. Alexander,** SPE, Cawley, Gillespie & Assocs. Inc.

SPE 19729

Summary. The industry has a procedure for stabilizing and sampling retrograde-gas (gas-condensate) wells; however, no investigation of the quality of the samples resulting from this procedure has been published. During sampling, bottomhole flowing pressure (BHFP) typically is less than the dewpoint pressure of the original reservoir gas. This causes condensate liquid to build up in the reservoir around the wellbore. This paper presents the results of a study of the sampling procedure and of the buildup and stability of the condensate ring around the wellbore. A procedure designed to give the best chance of obtaining a representative sample is presented.

Introduction

A gas sample from a retrograde-gas (gas-condensate) reservoir almost always is obtained by sampling the gas and liquid from the separator and recombining the samples at the producing gas/liquid ratio.[1-3] It is important that the wellhead pressure and the gas and liquid production rates be stable before and during sampling. Also, the gas production rate during this time must be large enough to remove all liquid continuously from the production string.

During sampling, it is likely that the BHFP will be less than the dewpoint pressure of the original reservoir gas. If so, there will be a pressure gradient in the reservoir near the well where pressure is less than dewpoint pressure.

How can a recombined surface sample representative of the original reservoir gas be obtained under these conditions? This paper answers that question. Sampling problems, such as human error, measurement bias, and incorrect laboratory recombination, are not considered here. Rather, this paper addresses the conditions necessary for the production stream to be of the correct composition so that obtaining a good sample is possible.

Radial compositional simulation was used to examine the pressure and saturation distributions in the reservoir, the producing GOR, and the composition of the total production stream at the surface during sampling. ("GOR" is used in this paper because of its common usage in the petroleum industry; the liquid is actually condensate.) The equation of state (EOS) was tuned with laboratory data.

Three retrograde gases (gas condensates) with different compositions were used in the study. The richest gas caused the largest buildup of condensate around the wellbore. The conclusions of this study are independent of gas composition, however, so the results presented are based on only one of these gases.

Several different sets of relative permeability data were used. All were for water-wet systems. The positions of the endpoints and shapes of the relative permeability curves affected the quantity of condensate around the wellbore but did not affect the conclusions of this study. Thus, the results reported here are based on one set of relative permeability data.

Several combinations of initial reservoir pressure and dewpoint pressure of original reservoir gas were examined. Only the worst case of initial reservoir pressure slightly greater (15 psi) than dewpoint pressure is presented.

Simulation Procedure

The Soave-Redlich-Kwong (SRK) EOS was used in the compositional simulation.[4] Compositional analyses through C_{30} were available for all gases used. Components between C_7 and C_{30} were grouped into four pseudocomponents, iso- and n-butanes and pentanes were combined, and the small amounts of nonhydrocarbon components were combined with the appropriate hydrocarbons. This resulted in a 10-component mixture.

The EOS was tuned to constant-composition-expansion and constant-volume-depletion data. The Ω_a and Ω_b of methane and the four heavy pseudocomponents and the binary interaction coefficients between methane and each of the four heavy pseudocomponents were adjusted in the manner suggested by Coats and Smart.[5]

*Now at S.A. Holditch & Assocs. Inc.

Agreement between the results of the tuned EOS and the laboratory data was excellent, the reservoir conditions during simulation were well within the limits of the data used in tuning, and reservoir conditions were well removed from the critical point of the mixture. Thus, the characterization of the reservoir fluid was adequate for the purpose of this study.

Dewpoint pressure of the original reservoir gas was 5,170 psia, and the initial reservoir pressure at the top of the reservoir was 5,185 psia.

The endpoint of the three-phase relative permeability to liquid condensate occurred at a condensate saturation of 8.5% and a gas saturation of 75.0%. Irreducible water saturation was 16.5%.

The reservoir discussed in this paper was a radial 160 acres made up of five layers of various thicknesses. Vertical and horizontal permeabilities were equal. The permeability-thickness product was high, about 700 md-ft. Sensitivity runs indicated, however, that when the gas production rate was normalized to percent of capacity, the value of the permeability-thickness product was immaterial to the conclusions of the study.

The grid pattern was radial 5 layers by 12 segments. The solution was implicit with D4 Gaussian elimination.

The results presented in this paper are for a well perforated across the entire interval. Wells with partial completions acted like layered reservoirs and should be considered as such for the purposes of planning a fluid sampling program.

Results

Fig. 1 shows the total producing GOR (separator plus stock-tank gas) and quantity of heptanes plus in the recombined surface samples for a well producing at a constant rate of about 15% of capacity. Although the production rate is low and constant, a sample representative of the original reservoir gas can be obtained only during the first 30 days of production. After 30 days, the loss of condensate from the gas in the reservoir results in a decrease of surface liquid. This causes the producing GOR to increase from the initial value of 6,633 scf/STB and the quantity of heptanes plus in the recombined surface samples to begin a steady decline away from the value of 7.04% in the original gas.

The composition of heptanes plus is selected as the criterion of a good sample for two reasons. First, heptanes plus is the component most affected by loss of condensate in the reservoir. Second, the composition and properties of heptanes plus strongly affect the properties of the recombined surface sample.

At 330 days, the gas production rate was reduced to 5% of capacity in an attempt to get a good sample. This caused an instantaneous change in producing GOR. However, GOR did not stabilize; rather, it continued to increase steadily. The quantity of heptanes plus in the recombined samples did not recover to the correct value. Obviously, the cutback did not result in a good sample.

Once the opportunity of obtaining a good sample is lost, reducing the rate or even shutting in will not improve the chance of getting a good sample (as shown later). This shows that sampling must take place early in the production of a well. The remainder of this paper focuses on the early production period.

Condensate Ring. Fig. 2 shows the buildup of the condensate ring around the wellbore as pressure falls below the dewpoint. The condensate saturation near the wellbore quickly builds to a stable level

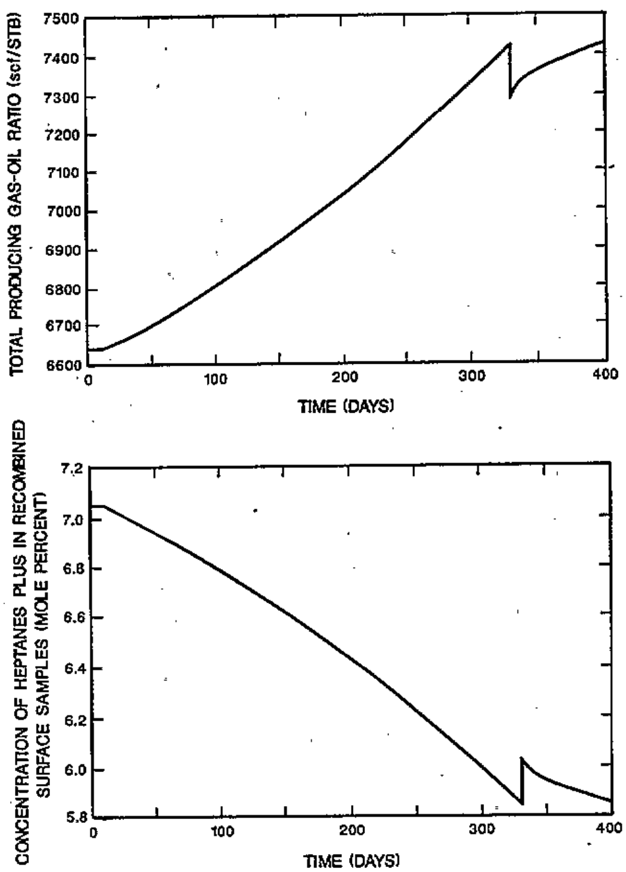

Fig. 1—Simulation results. Well in center of layered 160-acre retrograde-gas reservoir produced at 15% of capacity with rate reduction to 5% of capacity at Day 330.

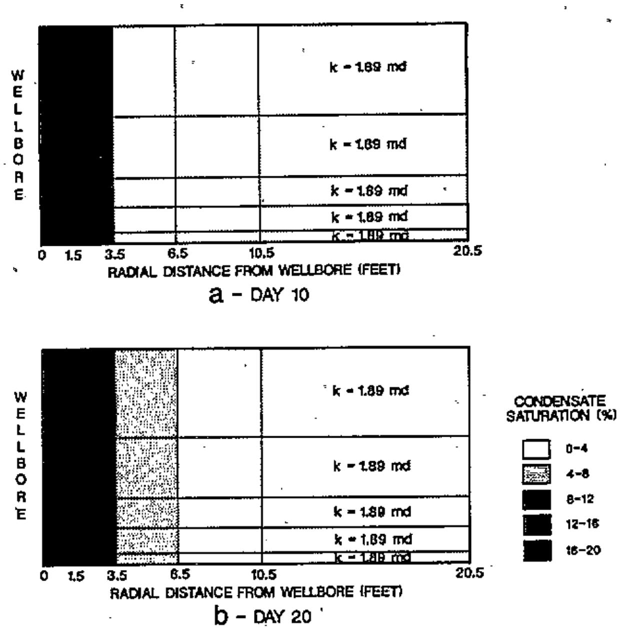

Fig. 2—Simulation results. Condensate saturation distribution in retrograde-gas reservoir near the wellbore during production. Homogeneous reservoir.

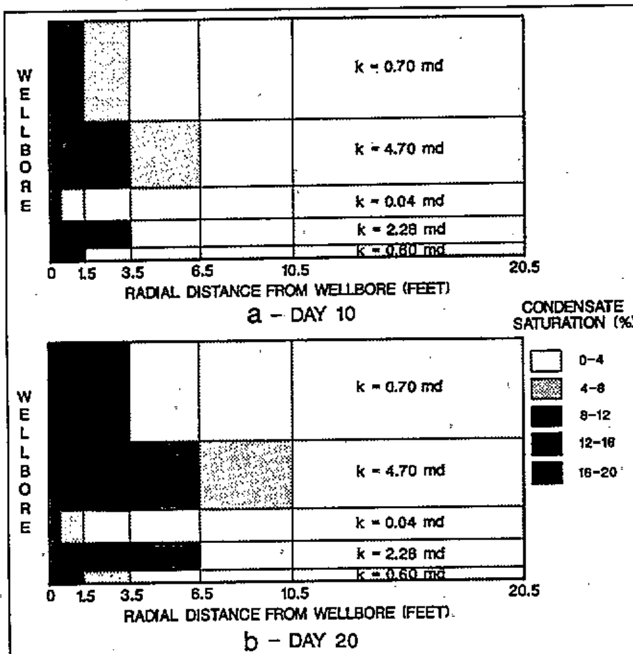

Fig. 3—Simulation results. Condensate saturation distribution in retrograde-gas reservoir near the wellbore during production. Layered reservoir.

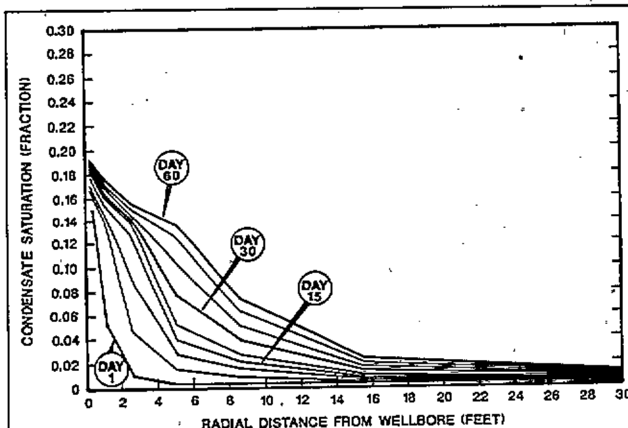

Fig. 4—Simulation results. Condensate saturation profile in retrograde-gas reservoir during production of gas at 25% of capacity showing buildup of condensate ring. Homogeneous reservoir.

(in this case, just more than 16%) and remains virtually constant. A comparison of Figs. 2a and 2b shows that continued production causes the ring to grow into the reservoir.

The maximum condensate saturation near the wellbore is much greater than the equilibrium saturation indicated in the laboratory PVT study (in this case, <1% at the existing pressure). The quantity of condensate in the ring around the wellbore depends on three factors: the pressure, the quantity of gas passing through the ring, and the relative permeability to the liquid condensate.

At early producing times, most of the reservoir has pressure slightly above the dewpoint pressure of the original gas. Rich gas with original composition flows into the lower-pressure zone around the wellbore. This gas releases condensate around the wellbore and then flows into the well. Initially this condensate will not flow, so the quantity of condensate builds as additional gas flows through the zone around the wellbore. This creates a ring of condensate saturation.

The saturation of condensate in this ring very quickly increases to the point at which its relative permeability allows it to flow. Two-

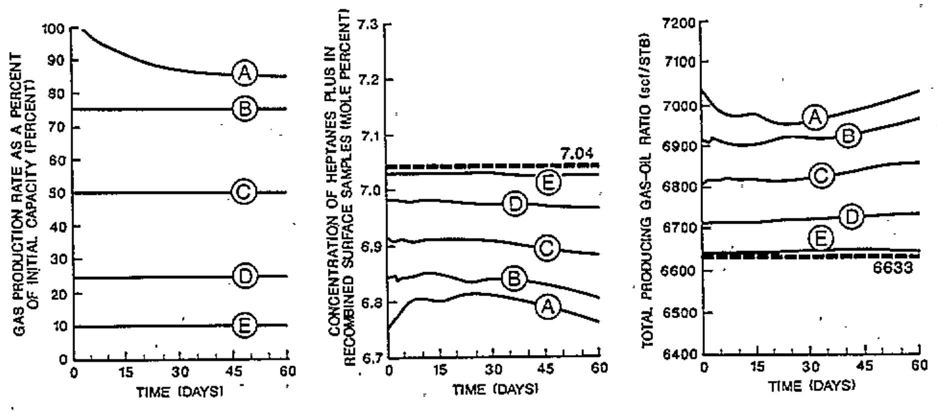

Fig. 5—Simulation results. Well in center of homogeneous 160-acre retrograde-gas reservoir producing at various gas rates. Letters indicate corresponding production rates, heptanes plus in samples, and GOR.

phase flow occurs from the ring into the well. The condensate saturation adjusts so that the volume of condensate flowing into the well equals the volume of liquid condensed from the flowing gas. When this occurs, the saturation near the wellbore tends to stabilize.

A near-steady-state situation exists in which the mass of gas flowing from the reservoir into the ring equals the mass of gas plus liquid condensate flowing into the well. The composition of the gas/condensate mixture flowing into the well is equal to the composition of the gas entering the ring. Thus, the producing GOR will be constant and a recombined separator sample will have the composition of the original reservoir gas.

This situation is not exactly steady-state because BHFP and the pressure gradient around the well both decrease with time. Thus, the ring slowly increases in size (Fig. 2b).

At higher gas production rates, more gas passes through the ring, causing more liquid to condense in the ring. This requires a higher liquid saturation for the relative permeability to the condensate to be large enough for the ring to stabilize. For instance, the gas and relative permeability combination used to generate Fig. 2 requires a stabilized liquid saturation of more than 25% when gas production is near capacity. The stabilized liquid saturation is only 16% when gas production rate is 25% of capacity.

Fig. 2 illustrates the saturation profile in a homogeneous reservoir. A more realistic case is shown in the layered reservoir of **Fig. 3**. The process is identical; the condensate builds more quickly in the more permeable layers, however, because more gas is flowing through them. The overall permeability-thickness products and gas production rates are identical in Figs. 2 and 3. Further discussion will deal with the homogeneous reservoir. Note, however, that layered reservoirs must be sampled sooner and at lower gas production rates because of the more rapid growth of the condensate ring in the zones with higher permeabilities.

The buildup of the condensate ring is illustrated in **Fig. 4** for a well producing at a constant rate of 25% of capacity. The change in size of the ring appears dramatic because of the scale of the graph. However, most of the nearly 1,500 ft of radial distance from the wellbore has pressure slightly greater than dewpoint and no condensate saturation. BHFP is about 100 psi below the dewpoint pressure of the reservoir gas on Day 1 and is almost 200 psi below dewpoint on Day 60.

Note that the liquid saturation near the wellbore stabilizes at about 15% on Day 1 and then slowly increases as the BHFP slowly decreases. The ring slowly increases in size as production proceeds. The ring is never exactly stable, and the amount of liquid condensate flowing into the wellbore is always slightly less than for the case of complete stability. Thus, the composition of the production stream will be slightly deficient in the heavier components.

At higher production rates, the growth in ring size is more rapid and the production stream is more deficient in condensate. **Fig. 5** shows the relationship of sample quality to production rate. Again, sample quality is represented by the mole fraction of heptanes plus in the recombined samples.

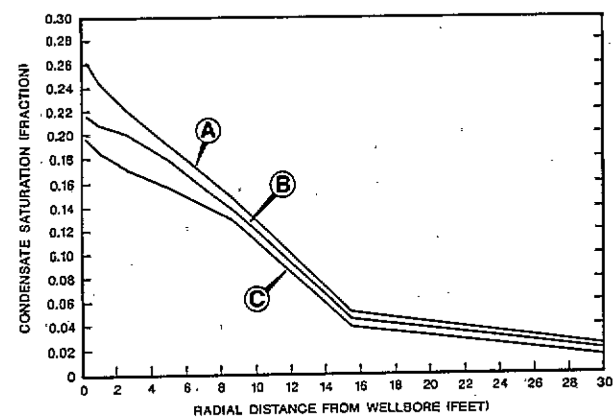

Fig. 6—Simulation results. Condensate saturation profile in retrograde-gas reservoir produced at capacity for 3 days and then produced at 20% of capacity: A = profile after 3 days; B = profile 1 hour after rate reduction; C = profile 1 day after rate reduction.

All samples in Fig. 5 have heptanes-plus compositions reasonably close to that of the original reservoir gas. Thus, it is possible to get a good sample when BHFP is below the dewpoint pressure of the reservoir gas. However, lower production rates result in better quality samples.

The GOR is virtually constant in every case. This indicates that a lined-out GOR is not necessarily equal to a good or perfect sample.

Rate Reduction Before Sampling. A common practice is to reduce gas production rate before sampling. Then an attempt is made to stabilize the gas and condensate rates from the separator before samples are taken. **Fig. 6** illustrates what happens in the reservoir during this procedure. In this instance, the well is produced at capacity for 3 days and then the rate is reduced to 20% of capacity.

Line A in Fig. 6 shows the saturation profile of the ring of condensate after 3 days of production at capacity. Line B shows the shape of the ring 1 hour after production rate is reduced to 20% of capacity.

When production rate is reduced, the pressure around the well increases. This causes some of the condensate to revaporize, greatly enriching the gas flowing into the well. Also, some liquid is dumped into the well because liquid saturation must adjust to the reduced rate of condensation from gas flowing into the ring. Both of these effects cause a large increase in the heavy components of the production stream.

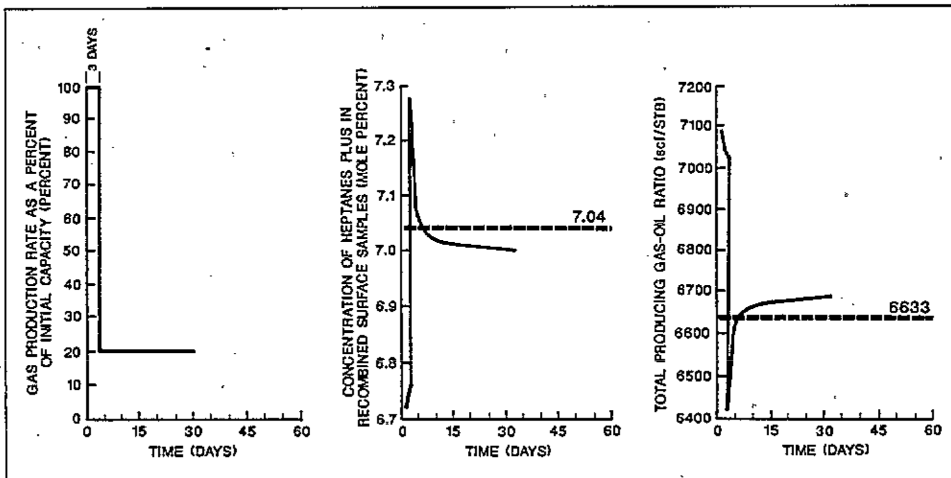

Fig. 7—Simulation results. Well in center of homogeneous 160-acre retrograde-gas reservoir produced at capacity for 3 days followed by rate reduction to 20% of capacity.

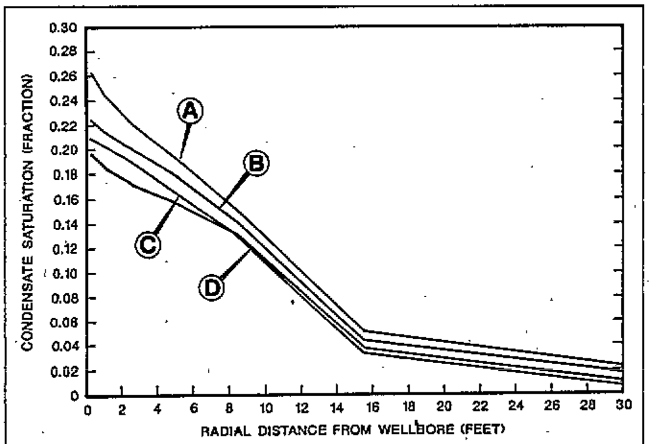

Fig. 8—Simulation results. Condensate saturation profiles in retrograde-gas reservoir produced at capacity for 3 days, shut in for 10 days, and then produced at 20% of capacity: A = profile after 3 days; B = profile 1 hour after shut-in; C = profile 10 days after shut-in; D = profile 1 day after restart of production.

Line C in Fig. 6 shows the ring 1 day after the rate reduction. Liquid saturation has decreased to stabilize at a value to accommodate the lower condensate rate. More liquid has flowed into the well than has been dropped by the gas flowing through the ring.

Fig. 7 shows the effect of this reduction in gas production rate on both the producing GOR and the heptanes-plus composition of the recombined surface samples. The partial collapse of the condensate ring causes an immediate increase in the quantity of condensate at the surface. This decreases the GOR and causes a large increase in heptanes plus in the surface samples. As the condensate ring adjusts to the new production rate, GOR and the quantities of heptanes plus in the samples approach the values for that rate.

Fig. 7 illustrates that a rate reduction followed by a line-out period before sampling could improve the sample quality. However, this technique presents two problems. First, the normal variation in GOR could obscure the onset of line out and cause sampling during the spike in heptanes-plus concentration. Second, it takes a long time for a tight reservoir to line out, so long that the chance of obtaining a good sample could be lost in the attempt to stabilize the separator rates.

If sampling occurs during the spike of heptanes-plus composition, the recombined sample will have too much of the heavier components. This excess of heavier components will cause the laboratory-measured dewpoint pressure to be in error. The measured dewpoint pressure will be low if the actual reservoir gas is very rich; it will be high if the actual reservoir gas is lean. Thus, the difference between the dewpoint pressures of the bad sample and the reservoir gas is variable and unpredictable.

A criterion often used to evaluate the quality of a recombined sample of retrograde gas is that the dewpoint pressure should be lower than the reservoir pressure and/or BHFP. If the surface samples are taken soon after a rate reduction (or shut-in), this criterion could be met by a sample with excessive heptanes-plus composition.

The effects of 3 days of capacity production followed by a rate change illustrated here are not unique. Any reduction from any previous production rate will cause the disruption in producing GOR

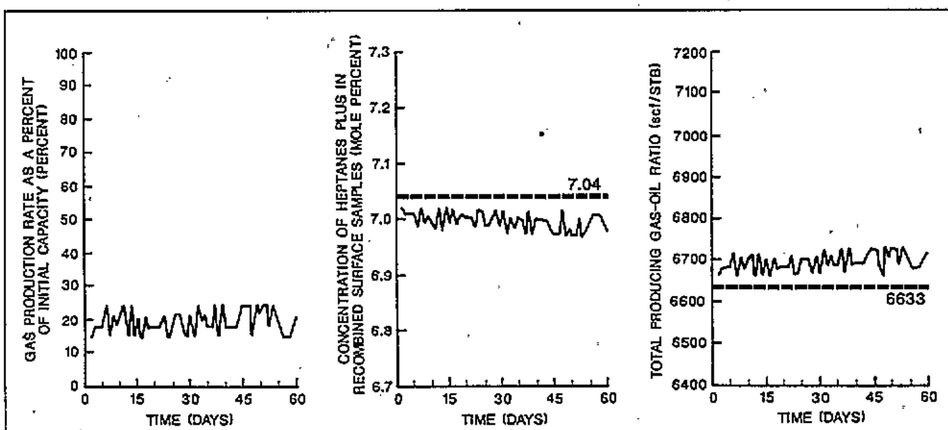

Fig. 9—Simulation results. Well in center of homogeneous 160-acre retrograde-gas reservoir produced at randomly varying gas rates from 15% to 25% of capacity.

Authors

Alexander

McCain

Now at S.A. Holditch & Assocs. Inc. in College Station, TX, **William D. McCain Jr.** was professor and head of the Dept. of Petroleum Engineering at *Mississippi* State U. He also worked for Esso Research Laboratories in Louisiana and taught petroleum engineering at Texas A&M U. He holds a BS degree from Mississippi State U. and MS and PhD degrees from Georgia Tech. McCain is an SPE short course instructor and *ex-officio* member of the Engineering Registration Committee. He was a member of the 1986–89 Career Guidance, 1967–71 Education and Accreditation, and the 1972–75 *Textbook committees.* **Richard Alexander** is a partner at Cawley, Gillespie & Assocs. Inc. His areas of expertise include reservoir simulation, field studies, numerical models, and litigation and regulatory support. He has served as a technical hearings examiner for the *Texas Railroad Commission.* He is a member of the Editorial Review Committee for the *SPE Computer Applications Newsletter.* Alexander holds BS and MS degrees in petroleum engineering from U. of Texas.

and the spike in heptanes plus in the recombined samples. The effects are not as great for rate changes of lower magnitudes.

Shut-In Before Sampling. Wells sometimes are shut in for a period before they are put on production at a low rate for sampling. **Fig. 8** shows the results of shutting in the well for 10 days after 3 days of capacity production. Line A in Fig. 8 is the same as Line A in Fig. 6. Lines B and C are for 1 hour and 10 days after shut-in, respectively.

The differences in condensate saturation of Line A and Lines B and C are caused by the revaporization of condensate as pressure increases. Line D is the saturation profile 1 day after the well was returned to production at 20% capacity. Note the similarity of Line D in Fig. 8 and Line C in Fig. 6.

The partially collapsed ring and enriched gas remain in place during shut-in. The enriched gas and liquid condensate are dumped into the wellbore when production begins again. The resulting situation at the surface is virtually identical to that of Fig. 7.

The length of shut-in period does not affect the sampling outcome. The enriched gas and condensate remain around the wellbore, ready to be dumped whenever production begins.

Production Rate Before Sampling. The production rate need not remain exactly constant during the period before sampling as long as the change in rate is not excessive. **Fig. 9** shows the results of random changes in gas production rate. The ring changes but does not collapse and adjusts quickly to each new rate. The heptanes plus in the recombined surface samples and the producing GOR do not deviate greatly from the correct values. At this point, the rate could be lined out at some production rate near average, the separator rates stabilized, and a good sample obtained.

Recommended Sampling Procedures

The sampling procedure that will result in the best possible chance of getting a recombined surface sample representative of the original reservoir gas is as follows.

1. Bring the well on initial production at the lowest production rate consistent with removing liquids from the production string.
2. Maintain that rate reasonably constant until the well cleans up.
3. Then stabilize separator gas and condensate rates and sample.

This procedure is especially important if the reservoir is tight.

If the reservoir has good permeability and if the production rate has been high, a rate reduction before stabilization for sampling probably will improve the chances of obtaining a good sample. The gas and condensate rates from the separator, however, should be observed over a period of days, not hours, before sampling to ensure that the heptanes-plus spike has subsided.

In either case, sampling should be done very early in the production of the well. Once the pressure in the bulk of the reservoir becomes less than the dewpoint pressure of the gas, no sampling procedure will result in a good sample.

Conclusions

1. It is possible to get a representative (if not perfect) recombined surface sample of a retrograde-gas reservoir when the BHFP is less than the dewpoint pressure of the reservoir gas if the sample is taken early in the life of the well and at low production rate.
2. Production rate reduction before stabilizing separator rates for sampling will cause the sample composition to be more nearly correct; however, extreme care must be taken to ensure that the well is stabilized before sampling. Stabilization requires days for reservoirs with good permeability and months for low-permeability reservoirs.
3. Samples must be obtained in the first month or so of production. When the pressure in the bulk of the reservoir falls below the dewpoint pressure of the original gas, no sampling technique will result in a representative sample.
4. Gas production rate before the separator is stabilized for sampling does not have to be constant as long as the rate changes are moderate.
5. Reservoirs with extreme vertical heterogeneity must be sampled as soon as possible and with production rates as low as possible.
6. Shutting in a gas well for a period before sampling will not improve sample quality.
7. At high production rates, the producing GOR could appear to be stabilized (constant) when the composition of the production stream is not representative of the original reservoir gas.
8. The fact that the dewpoint pressure of a sample is less than reservoir BHFP is not sufficient proof that a good sample was obtained.

Nomenclature

Ω_a, Ω_b = constants in the SRK EOS

Acknowledgments

Many people made this study possible. James Fortner and Frank Vrla of Core Laboratories provided the laboratory PVT studies, and Don Parker and George Zeito of Integrated Technologies assisted with the reservoir simulation. Phil Moses, retired from Core Laboratories, provided a great amount of advice and insight into sampling procedures. We are grateful to Cawley, Gillespie and Assocs. Inc. for assistance and permission to publish this paper.

References

1. Reudelhuber, F.O.: "Separator Sampling of Gas-Condensate Reservoirs," *Oil & Gas J.* (June 21, 1954) 138–40.
2. *RP 44, Recommended Practice for Sampling Petroleum Reservoir Fluids,* API, Dallas (1966) 5.
3. Moses, P.L.: "Engineering Applications of Phase Behavior of Crude Oil and Condensate Systems," *JPT* (July 1986) 715–23.
4. Soave, G.: "Equilibrium Constants From a Modified Redlich-Kwong Equation of State," *Chem. Eng. Sci.* (1972) 27, No. 6, 1197–203.
5. Coats, K.H. and Smart, G.T.: "Application of a Regression-Based EOS PVT Program to Laboratory Data," *SPERE* (May 1986) 277–99.

SI Metric Conversion Factors

acres	× 4.046 873	E−01	=	ha
ft	× 3.048*	E−01	=	m
md	× 9.869 233	E−04	=	μm^2
psi	× 6.894 757	E+00	=	kPa
scf/STB	× 1.781 073	E−01	=	std m^3/stock-tank m^3

*Conversion factor is exact.

SPERE

Original SPE manuscript received for review Oct. 9, 1989. Revised manuscript received May 3, 1990. Paper accepted for publication Sept. 16, 1991. Paper (SPE 19729) first presented at the 1989 SPE Annual Technical Conference and Exhibition held in San Antonio, Oct. 8–11.

NOMENCLATURE

Ωa, Ωb = Constants in the SRK EOS

ACKNOWLEDGEMENTS

The following people made this study possible. James Fortner and Frank Vrla of Core Laboratories provided the laboratory PVT studies and Don Parker and George Zeito of Integrated Technologies gave assistance with the reservoir simulation. Phil Moses, retired from Core Laboratories, provided a great amount of advice and insight into sampling procedures. The authors are grateful to Cawley, Gillespie and Associates, Inc. for assistance and permission to publish.

REFERENCES

1. Reudelhuber, F.O.: "Separator Sampling of Gas-Condensate Reservoirs," OGJ (June 21, 1954) 138-140.

2. API Recommended Practice For Sampling Petroleum Reservoir Fluids, RP 44, American Petroleum Institute, Dallas (1966) 5.

3. Moses, P.L.: "Engineering Applications of Phase Behavior of Crude Oil and Condensate Systems," JPT (July 1986) 715-723.

4. Soave, G.: "Equilibrium Constants from A Modified Redlich-Kwong Equation of State,: Chem. Eng. Sci. (1972) 27, No. 6, 1197-1203.

5. Coats, K.H. and Smart, G.T.: "Application of A Regression- Based EOS PVT Program to Laboratory Data," SPERE (May 1986) 277-299.

SI METRIC CONVERSION FACTORS

bbl	x 1.589 873	E-01 =	m^3
cu ft	x 2.831 685	E-02 =	m^3
ft	x 3.048*	E-01 =	m
md	x 9.869 233	E-04 =	μm^2
psi	x 6.894 757	E+00 =	kPa
scf/STB	x 1.781 073	E-01 =	std m^3/stock-tank m^3

* Conversion factor is exact.

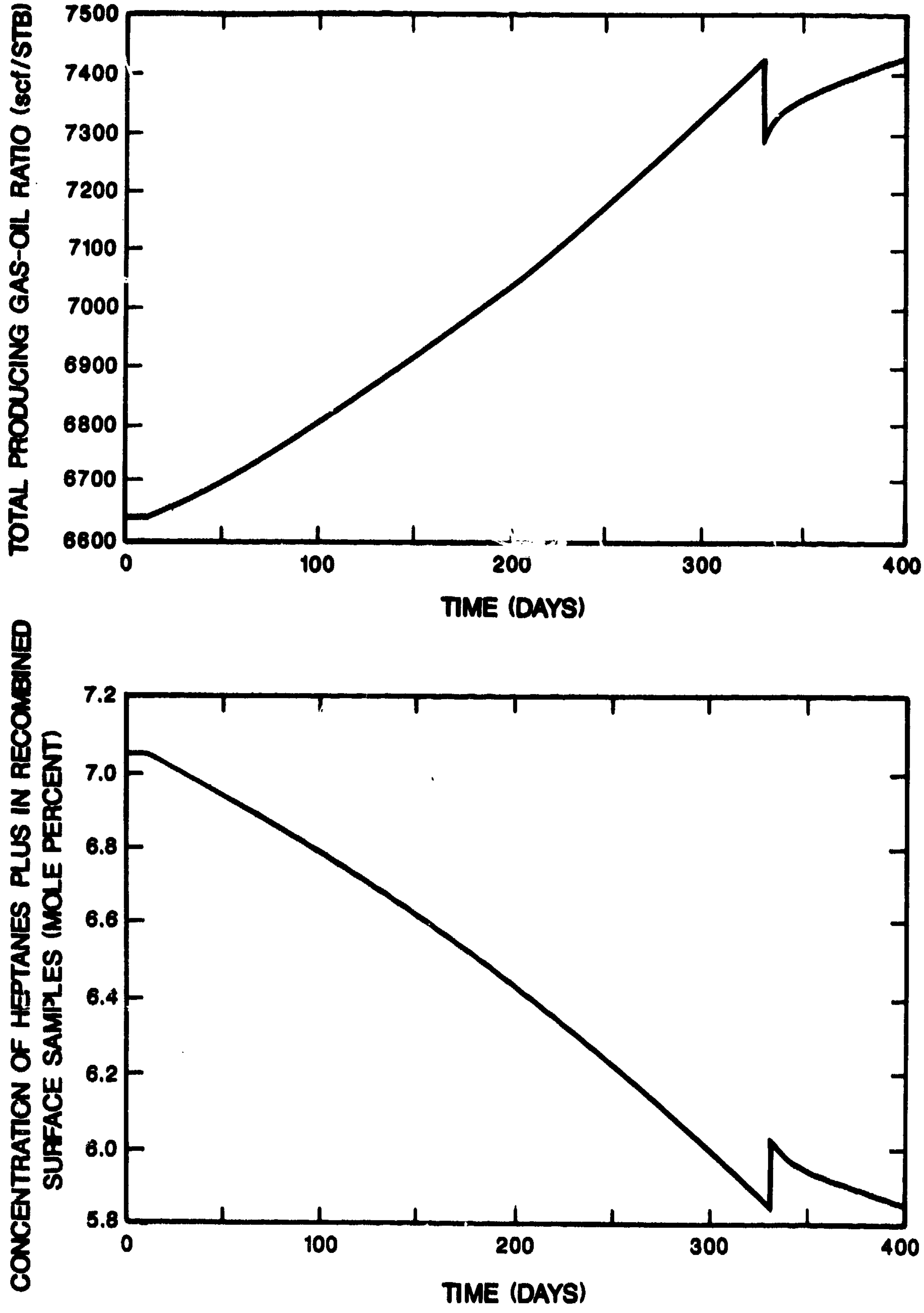

Figure 1. Simulation results. Well in center of layered 160 acre retrograde gas reservoir produced at 15 percent of capacity with rate reduction to five percent of capacity at day 330.

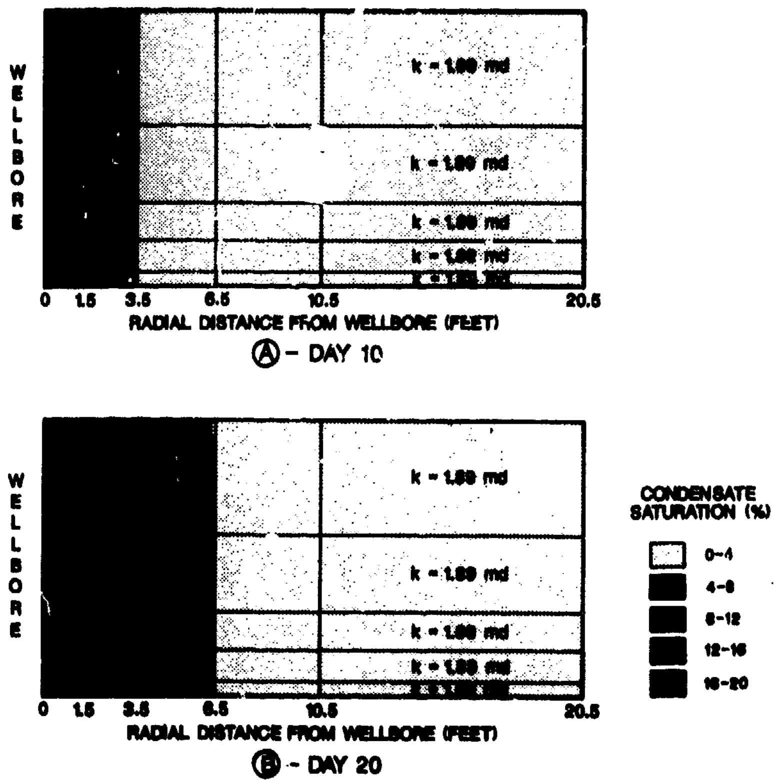

Figure 2. Simulation results. Condensate saturation distribution in retrograde gas reservoir near the wellbore during production. Homogeneous reservoir.

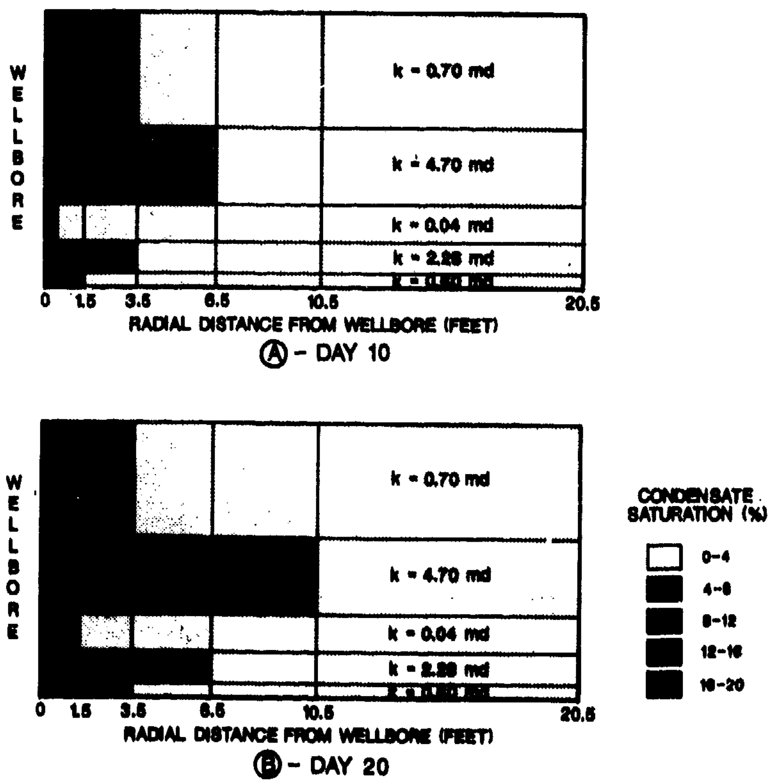

Figure 3. Simulation results. Condensate saturation distribution in retrograde gas reservoir near the wellbore during production. Layered reservoir.

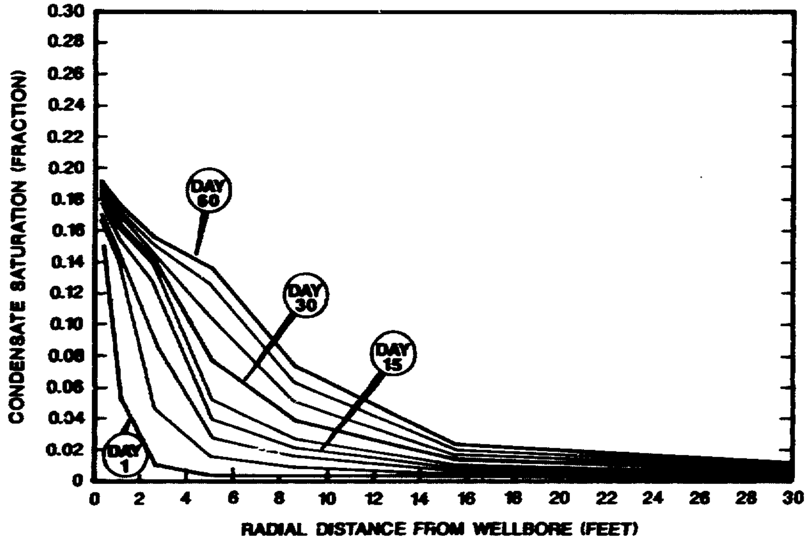

Figure 4. Simulation results. Condensate saturation profiles in retrograde gas reservoir during production of gas at 25 percent of capacity showing buildup of condensate ring. Homogeneous reservoir.

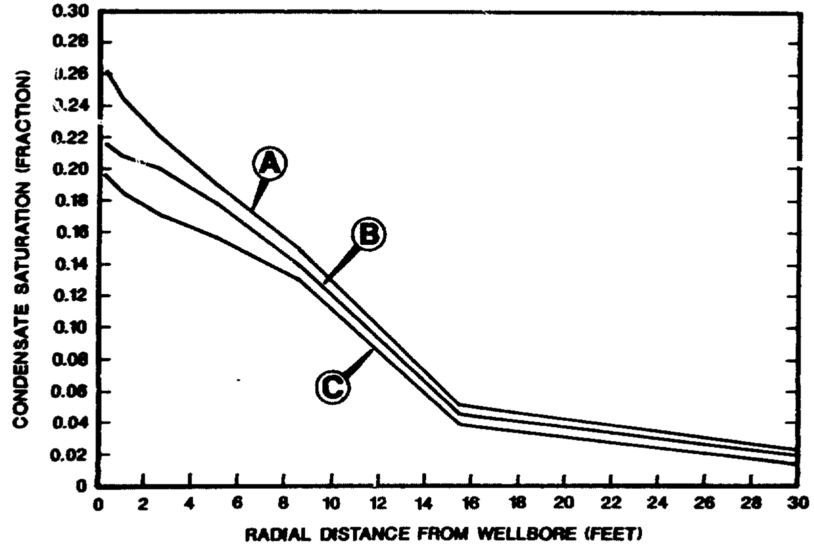

Figure 6. Simulation results. Condensate saturation profiles in retrograde gas reservoir produced at capacity for three days and then produced at 20 percent of capacity. A: profile after three days. B: profile one hour after rate reduction. C: profile one day after rate reduction.

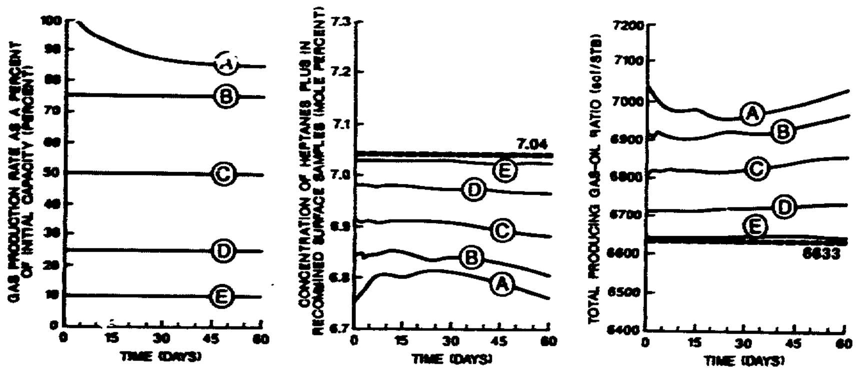

Figure 5. Simulation results. Well in center of homogeneous 160 acre retrograde gas reservoir producing at various gas rates. Letters indicate corresponding production rates, heptanes plus in samples, and gas-oil ratios.

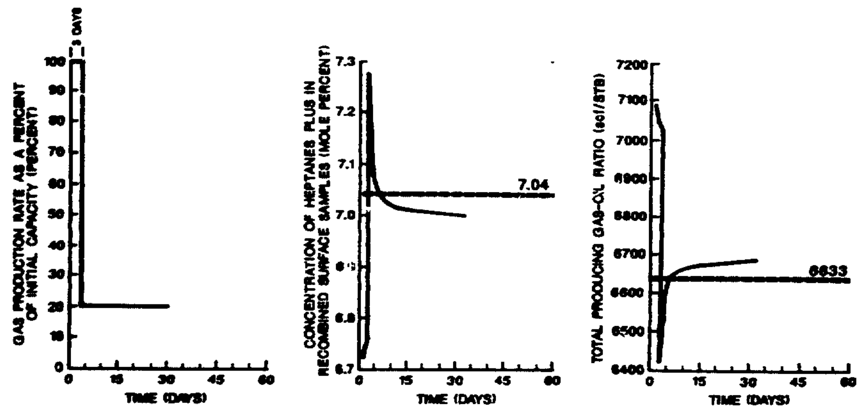

Figure 7. Simulation results. Well in center of homogeneous 160 acre retrograde gas reservoir produced at capacity for three days followed by rate reduction to 20 percent of capacity.

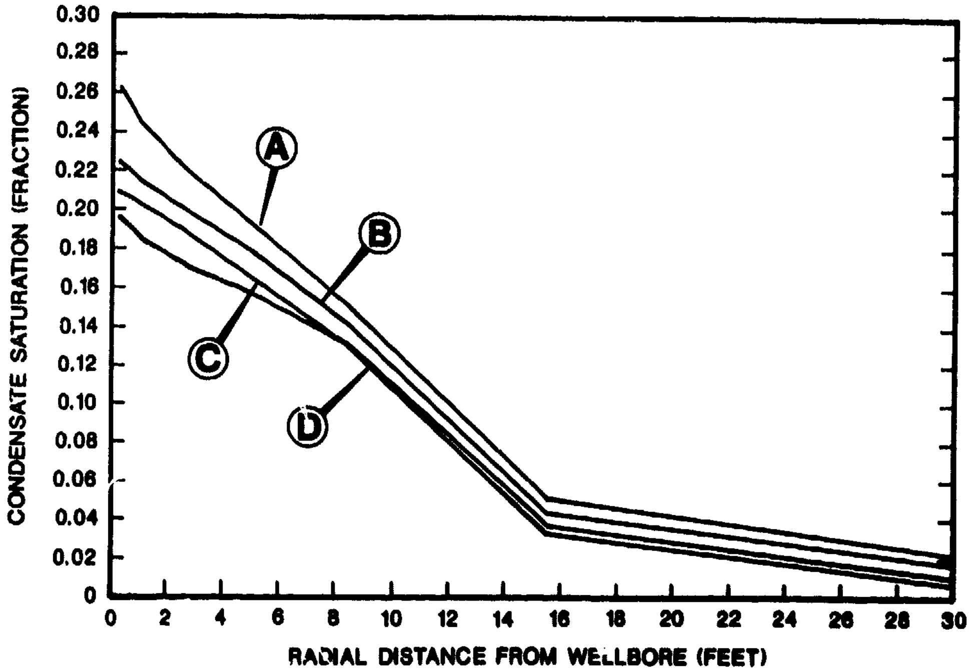

Figure 8. Simulation results. Condensate saturation profiles in retrograde gas reservoir produced at capacity for three days, shut-in for ten days, and then produced at 20 percent of capacity. A: profile after three days. B: profile one hour after shut-in. C: profile ten days after shut-in. D: profile one day after restart of production.

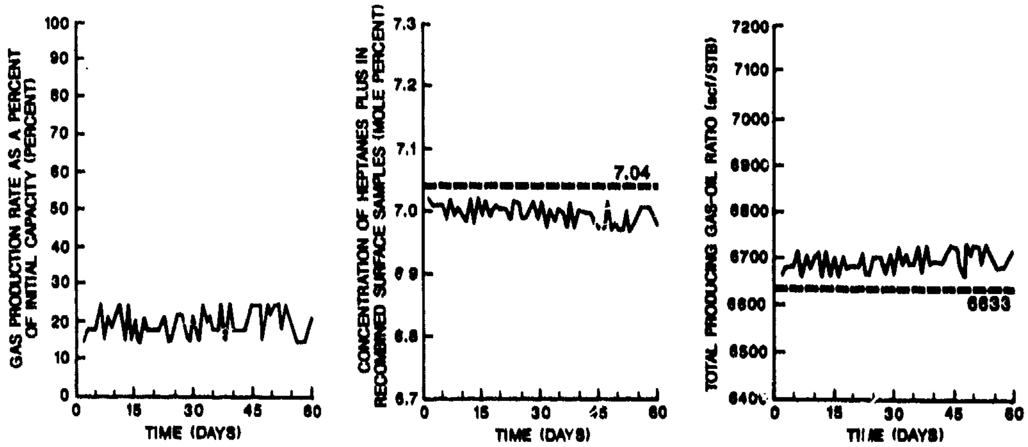

Figure 9. Simulation results. Well in center of homogeneous 160 acre retrograde gas reservoir produced at randomly varying gas rates from 15 to 25 percent of capacity.