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Accurate Insitu Compositions in Petroleum Reservoirs

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Abstract

This paper describes experimental procedures for determining accurate estimates of original insitu reservoir oil and gas compositions. The proposed *equilibrium contact mixing* (ECM) method can use samples which are clearly *not* representative of insitu fluids (e.g. due to near-wellbore multiphase behavior, reservoir depletion, or separator sampling problems). ECM procedures are recommended for saturated, undersaturated, and depleted reservoirs.

Examples are given for reservoir fluids ranging from very lean-gas/black-oil systems to highly volatile gas/oil systems. Furthermore, it is shown that the proposed ECM method can be used to obtain depth-weighted average insitu compositions in reservoirs with gravity-induced vertical compositional gradients.[1]

The Peng-Robinson (PR) and Soave-Redlich-Kwong (SRK) equations of state (EOS) are used in calculations, with extensive characterization of the C_{7+} fractions. Static PVT experiments and radial 1D/2D compositional simulations of typical fluid-sampling conditions are used to verify the proposed methods.

Partly due to the success of the ECM method, the traditional definition of a "representative" sample is reconsidered, and a more general definition is recommended. The general definition ("*reservoir-representative*") is any sample produced from a reservoir, where the measured composition and PVT properties are of good quality. The traditional definition ("*insitu representative*") is a special case where the sample represents an insitu reservoir composition at a specific depth (or an average composition for a depth interval).

Separator sampling of gas condensate and volatile oil reservoirs is widely used. We present an analysis of traditional separator sampling methods, potential errors in separator sampling, and a critical evaluation of the "isokinetic" sampling method. Isokinetic sampling is currently used to sample separator gas streams when separator liquid "carryover" is suspected. Problems with the isokinetic method are discussed, and we suggest field and laboratory measurements which are needed to confirm the validity of isokinetic sampling.

Introduction

Historically, the only acceptable method for determining initial reservoir compositions has been to *directly* obtain bottomhole or recombined separator samples which truly represent insitu compositions. Sampling procedures have been developed to assist in obtaining insitu-representative samples, but for reservoirs that are initially saturated or only slightly undersaturated, it may be impossible to obtain such samples. When flowing bottomhole pressure drops below the reservoir fluid's saturation pressure, multiphase behavior near the wellbore may result in mixtures flowing into the wellbore which are clearly *not* insitu representative.

When reliable insitu-representative samples can not (or have not) been obtained early in the life of a reservoir, considerable uncertainty in initial hydrocarbons (oil and gas) in place may exist. One consequence is that process facilities may need to be overdesigned to account for these uncertainties. Accurate insitu-representative samples are particularly important for gas condensate reservoirs where significant income may come from processed LPGs, NGLs, and stabilized condensate.

Obtaining accurate insitu *oil* composition early in the life of a reservoir is not usually a problem, even when flowing bottomhole pressure drops below the original bubblepoint. Separator samples can be recombined in a ratio (not necessarily the same as measured during sampling) that yields a

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References and illustrations at end of paper bubblepoint pressure equal to the reservoir pressure at the gas-oil contact (GOC). This approach generally works well, mainly .because separator gas and separator oil compositions are relatively insensitive to multiphase effects near the wellbore.

A problem in many older oil reservoirs is that samples were not collected initially (e.g. many West Texas CO_2 candidate reservoirs). No generally-accepted procedure has been published for determining the initial oil compositions in depleted reservoirs. Usually the only alternative is to recombine currently-producing separator oil and separator gas samples in a ratio that yields the initial reservoir bubblepoint pressure.

Already in the late 1930s, special sampling methods had been designed for obtaining accurate samples from gas condensate wells.[2-4] Based on "isokinetic" sampling of wellstream mixtures at the wellhead, extensive compositional and PVT data were measured onsite during production tests. These methods were still used in the mid-1950s (and probably later).[5]

During the past thirty years, commercial service companies have used standard separator sampling techniques, collecting separator oil and separator gas samples directly from a standard test or production separator. Separator sampling is still the industry standard for gas condensates, but it is also used for sampling oil wells (as a supplement to bottomhole samples, and when larger samples are needed for special PVT analyses).

More recently, several oil companies (and subsequently service companies) have again started using techniques similar to the isokinetic wellstream sampling methods developed in the late 1930s. Unfortunately, information and test results from these newer methods have not yet been published. The lack of open verification of the newer testing methods has caused concern in the industry. There is also a general skepticism about whether the significant additional costs of these methods is commensurate with the results obtained.

Two recent publications address the problem of obtaining accurate insitu-representative samples of saturated gas condensates.[6,7] McCain and Alexander[6] use compositional reservoir simulation to study the problem. They conclude that accurate insitu-representative samples of saturated gas condensates *can be* obtained at an early stage of depletion when sampling at low rates (with minimum drawdown), even when bottomhole flowing pressure is below the original dewpoint. However, they also indicate that production rates must be "stabilized," where stabilization can require from several days (for moderate-permeability reservoirs) to several months (for low-permeability reservoirs).

McCain and Alexander study the effect of producing from several commingled layers with contrasting permeabilities ($k_{max}/k_{min} \simeq 100$, where the layers are communicating). Results indicate that it is more difficult to obtain accurate insitu-representative samples in a layered system. The authors recommend that samples be collected as early as possible in layered systems, and with rates as low as possible.

Several other observations were made by McCain and Alexander: (1) shutting in a well prior to low-rate sampling is not recommended, (2) at high gas rates the producing GOR may appear constant without the wellstream being representative of the original reservoir fluid, and (3) a wellstream dewpoint compared with average reservoir (or bottomhole flowing pressure) is not a reliable means for determining if a sample is insitu representative.

The last observation was also made by Standing[8] in 1951. Standing warned that the dewpoint pressure of a gas condensate sample can be lower, equal to, or higher than the original dewpoint without the sample being representative of the original reservoir fluid. The reason is that dewpoint pressure is not a monotonic function of the recombination GOR (a maximum in the dewpoint-GOR is often observed, see Standing's Fig. 40).

Reffstrup and Olsen[7] study the problem of obtaining insitu-representative samples from low-permeability, saturated gas-condensate reservoirs. Black-oil *radial* well simulations and static PVT calculations based on a detailed EOS characterization are used in this study. The authors show that for an *idealized single-rate testing sequence*, the produced wellstream will always have a lower dewpoint than the original dewpoint. Initially the wellstream dewpoint will be about equal to the flowing bottomhole pressure, but gradually the wellstream dewpoint becomes more representative of the reservoir gas at average reservoir pressure (i.e. outer-boundary pressure).

The procedure recommended by Reffstrup and Olsen for obtaining original reservoir composition is to first characterize the produced wellstream mixture using an EOS. Using the EOS characterization, calculate the incipient oil composition at the wellstream's dewpoint (the sampled mixture is assumed to have a dewpoint lower than the original dewpoint). A new mixture is created by adding incipient oil to the sampled wellstream until the dewpoint equals the initial reservoir pressure (i.e. the original dewpoint). The authors note that several "contacts" may be required in this procedure. The resulting mixture with dewpoint equal to initial reservoir pressure is shown to yield a good approximation of the original reservoir gas.

Representative Samples

The concept of a "representative" sample has traditionally meant a sample that represents the "original" reservoir fluid. This definition may be misleading for the following reasons:

1. Even if a sample is obtained, representative of an original insitu fluid, this sample may only be representative of a specific depth or depth interval of the reservoir. A uniform fluid composition does not always exist throughout a reservoir because of compositional variations; vertical variations due to gravity and thermal effects, and other variations between fault blocks and non-communicating layers.
2. It may be impossible to obtain a truly representative sample of insitu fluids because of near-wellbore multiphase behavior in saturated, slightly undersaturated, and low-permeability reservoirs.

3. Samples which are not representative of insitu fluids can be used to "create" near-exact representations of original insitu fluids (as shown in this paper).
4. Accurate PVT data and compositions of samples that are *not* representative of insitu fluids are still useful in developing an EOS fluid characterization (as useful as samples that are representative of insitu fluids).

Based on these observations, we introduce a more general definition of a representative sample: *a "reservoir-representative" sample is any sample produced from a reservoir*. As a special case, *an "insitu-representative" sample represents the volume-weighted average of original fluid(s) in the depth interval drained by a well during sampling.*

Reservoir-representative samples are readily obtained, and in many cases they can be used to create accurate estimates of insitu-representative fluids. Direct sampling of insitu-representative fluids, on the other hand, may be difficult or impossible.

Two important points should be made about the application of representative samples:

1. Accurate insitu-representative samples are used to determine the initial hydrocarbons (oil and gas) in place. Insitu-representative samples may vary as a function of depth, from one fault block to another, and between non-communicating layers. All insitu-representative samples are needed in the difficult task of defining hydrocarbons in place.
2. All reservoir-representative samples having reliable PVT data and accurately-determined compositions should be used *simultaneously* in developing an EOS fluid characterization. The resulting characterization, with a *single* set of EOS parameters, can be used to consistently describe the phase and volumetric behavior of *all* fluids within the reservoir.

Unfortunately, the "mapping" of original insitu compositions for a reservoir may not be possible until several wells have been drilled and production data become available. On the other hand, an EOS fluid characterization can be developed as soon as one reservoir-representative sample is available. This characterization can be used for preliminary calculations based on simplified assumptions about the original hydrocarbons in place.

As additional representative samples and PVT data become available, the EOS characterization can be modified as necessary to match both the old and the new PVT data. If additional insitu-representative samples become available, new estimates can also be made of the original hydrocarbons in place.

Equilibrium Contact Mixing (ECM)

Laboratory methods have been developed to obtain accurate samples of original insitu fluids in saturated reservoirs. The methods are based on mixing a reservoir oil sample and a reservoir gas sample together at a specified reservoir condition, bringing the system to equilibrium through one or more contacts ("equilibrium contact method"). Neither reservoir sample used in the mixing procedure needs to be representative of an insitu fluid.

Description of the ECM Methods

Collecting and Preparing Reservoir Samples

Samples of the reservoir oil and reservoir gas are first made up in the laboratory. Separator samples should always be used for the reservoir gas, and usually for the reservoir oil. Bottomhole samples *can* be used for the reservoir oil when available (and considered "reliable"), though separator samples are preferred if available.

The reservoir gas is made by recombining separator samples to yield the *actual* test wellstream (i.e. using *measured* separator GORs in the recombination, corrected if necessary for liquid carryover, etc.). The separator samples from the gas zone should *not* be recombined specifically to obtain a dewpoint equal to the initial pressure at the GOC.

When using separator samples to recombine a reservoir oil, the actual test GOR should be used to make the recombination, taking into account any valid corrections to the recombination GOR (oil meter corrections, gas rate corrections, etc.).

An *initial* recombined oil sample should have a bubblepoint close to the original reservoir pressure. A recombined oil bubblepoint much less than the original reservoir pressure might indicate compositional grading with depth. A recombined oil bubblepoint much greater than the original reservoir pressure might indicate gas coning during sampling. In both cases, the proposed ECM procedures require that test GOR be used for recombination of the reservoir oil sample to obtain a true sample of the produced wellstream.

Initially Saturated Gas/Oil Reservoirs (ECM1)

The containers with reservoir gas and reservoir oil samples should be brought to single-phase conditions. The two samples are transferred to a PVT cell in a ratio that results in an oil volume fraction of 50% or greater at equilibrium. Slightly more accurate equilibrium compositions are obtained using higher oil fractions, but with the disadvantage that smaller reservoir gas samples are available for subsequent studies (e.g. constant volume depletion).

The PVT cell is brought to initial reservoir conditions at the gas-oil contact and mixed thoroughly to establish equilibrium. The resulting equilibrium oil and equilibrium gas should provide excellent estimates of the original insitu fluids at the GOC. Each phase is removed to separate containers for further analysis. Compositions and PVT data are measured for each sample separately. This procedure represents the equilibrium contact mixing method ECM1.

The ECM1 method can also be used for an initial oil well test with gas coning. The separator samples are recombined at the producing GOR measured at the time of sampling. The mixture is brought to initial conditions at the GOC and mixed thoroughly to establish equilibrium. The resulting equilibrium oil and equilibrium gas should provide excellent estimates of the original insitu fluids at the GOC.

For systems with gravity-induced compositional gradients having a saturated GOC, the ECM1 method (applied at initial GOC conditions) does *not* provide estimates of equilibrium composition *at* the GOC. Instead, the method provides a depth-averaged estimate of the insitu oil between the GOC and oil-sampling depth, and a depth-averaged estimate of the insitu gas between the GOC and the gas- sampling depth.

Depleted Solution Gas Drive Oil Reservoirs (ECM2)

A second ECM method (ECM2) can be applied to oil reservoirs currently being depleted by solution gas drive (producing GOR must be greater than the solution GOR at current average reservoir pressure). The method provides an estimate of original insitu oil composition, when this composition was not obtained initially. The method works for initially saturated and undersaturated oil reservoirs.

The produced wellstream sample is prepared by recombining separator samples using the test GOR. The recombined mixture is brought to equilibrium at the current average reservoir pressure and temperature. All of the equilibrium gas is removed at constant pressure to another container. The equilibrium oil remains in the PVT cell.

The equilibrium gas is injected incrementally back into the PVT cell containing equilibrium oil. After each injection, the bubblepoint is measured. When the bubblepoint reaches the original reservoir bubblepoint, this mixture can be considered a very good approximation of the original reservoir oil. As shown in the examples below, the resulting composition is better than simply recombining separator gas and separator oil samples in a ratio that yields the original bubblepoint pressure (particularly for intermediate components C_2-C_6, but also for C_1 and C_{7+}).

Undersaturated Produced Oil Sample

Accurate estimates of original oil composition can usually be obtained if the produced reservoir oil sample is undersaturated relative to the current average reservoir pressure. This might occur during the period of critical gas saturation buildup, or in a partially depleted solution gas drive reservoir that has subsequently undergone water flooding.

During the period when reservoir pressure first drops below the original bubblepoint and a critical gas saturation is building up, the produced wellstream may be undersaturated relative to the current reservoir pressure (ECM1 and ECM2 methods will not work). Recombining separator samples at a GOR that yields the original bubblepoint pressure has been found to give accurate estimates of the original reservoir oil.

Many oil reservoirs have been repressurized by water flooding after previously having undergone depletion by solution gas drive (e.g. many West Texas CO_2-flood reservoirs). The only *practical* laboratory method we have found successful for creating an approximation of the original reservoir oil is recombination of currently producing separator samples to the original bubblepoint pressure.

The recombination method of depleted oil samples works well in the two examples presented below, but we are unsure how accurate the method will work in other reservoirs. For example, a reservoir where separator gas composition has changed significantly during depletion, the separator recombination method may not work well.

Depleted/Saturated Gas Condensate Reservoirs

An estimate of the original gas composition of an initially saturated gas zone (with underlying oil) can be achieved in a depleted reservoir. Separator samples must be collected from both the gas zone and the oil zone. First an ECM2 procedure is performed on the reservoir oil to create an estimate of the original reservoir oil. The resulting ECM2 oil sample is mixed with the reservoir gas sample using the ECM1 procedure. The final mixture is brought to equilibrium at the original GOC conditions, with the equilibrium gas providing an accurate estimate of the original reservoir gas.

Depleted/Undersaturated Gas Condensate Reservoirs

A reliable ECM method has not yet been developed for estimating the original reservoir gas composition in a depleted gas condensate reservoir that was initially undersaturated (i.e. where an original reservoir oil sample is not available). One approach, a modification of the ECM2 method, has been tested. Reasonable results were obtained for a gas condensate with liquid yield of about 45 STB/MMscf, but we are not finished testing the method for other systems.

Verification of Equilibrium Contact Method

The proposed ECM methods have been tested for a wide range of gas/oil reservoir systems:

BO	black oil / very lean condensate
SVO	slightly volatile oil / lean condensate
MGC	medium gas condensate / somewhat volatile oil
VO	volatile oil / rich condensate
NCO	near-critical oil / gas

Each fluid system was described using a cubic equation of state (Peng-Robinson, PR, or Soave-Redlich-Kwong, SRK) and a detailed C_{7+} characterization tuned to match experimental PVT data. All fluid systems except MGC are taken from Whitson and Belery[1].

The ECM laboratory procedures are tested and verified in the results presented below. Static PVT experiments were first simulated to verify the potential of the ECM approach. Thereafter a series of detailed compositional simulations were made to study realistic testing and sampling procedures. A radial grid was used in the simulations, with an innermost block radius of 1.2 ft, and 14 logarithmically-spaced grids out to a total radius of 2000 ft. Most simulations used 10 layers with a total thickness of 200 ft.

Static PVT Cell Simulations

MGC fluids were used in the static PVT cell simulations. The MGC system has a saturation condition of 4808 psia at 259°F. The saturated reservoir gas has a solution OGR of 43.5

STB/MMscf (GOR of 23 Mscf/STB) and the saturated reservoir oil has a solution GOR of 855 scf/STB.

The original reservoir gas and reservoir oil were separately subjected to constant composition expansions (CCE). At each stage in the CCE experiment, equilibrium gas and oil compositions were calculated. These are shown as dash-dot lines in **Fig. 1** for methane and C_{7+}. To test the ECM procedure at a given stage of depletion, the equilibrium gas from the reservoir gas CCE was mixed with equilibrium oil from the reservoir oil CCE at initial saturation conditions of 4808 psia and 259°F. Equilibrium compositions at these conditions should approximate the original reservoir oil and gas.

The amount of each phase being mixed was chosen so that the final equilibrium volumes were 50% (though results are not really sensitive to this ratio). **Fig. 1** shows results of the ECM1 method as short dashed lines.

If *original reservoir oil* is mixed with equilibrium gas from the reservoir gas CCE experiment, somewhat better estimates of the original reservoir gas are obtained (see **Figs. 1a-1b**), particularly far into depletion. This result is the basis for proposing the combined ECM2/ECM1 approach for depleted (initially saturated) gas condensate reservoirs.

Initial Test Simulations

The MGC system was again used to test the proposed ECM methods, this time based on reservoir simulations of actual testing and sampling conditions. First we give a summary of the simulation tests used to obtain "initial" samples (prior to the start of depletion).

Description of Well Tests and Sampling

Low-Drawdown Gas Test (DST 1). This gas test produces at a relatively low drawdown for 2.5 days. **Fig. 2** show the production characteristics during the test. The producing GOR decreases gradually during the test, only about 1 to 1.5% higher than the insitu GOR. Dewpoint of the produced wellstream is essentially constant about 200 psi below the insitu dewpoint of 4808 psia. Flowing BHP drops to about 4300 psia at 1 day when Sample 1 is taken.

The original reservoir gas composition is shown in **Table 1** (column A). This composition can be compared with Sample 1 (column B), which is too lean. The difference in compositions is not significant except for the heaviest components.

When separator gas and oil representing Sample 1 are recombined at a GOR to obtain the correct dewpoint pressure (4808 psia), a much poorer (too rich) wellstream results (column C). The economic consequences of using this overly-rich wellstream is obvious. In fact, the error in using the dewpoint-corrected composition is much greater than using Sample 1 *with a dewpoint underpredicted by 200 psi*.

High/Low-Rate Gas Test (DST 2). This gas test produces at about 50 MMscf/D for two days, followed by a rate reduction to 1 MMscf/D for two days (see **Fig. 3**). Flowing BHP drops to 2000 psia during the high-rate period, then increases to about 4700 psia during the low-rate period. GOR decreases gradually from about 26 to 24 Mscf/STB during the high-rate period, then drops sharply to about 12 Mscf/STB when rate is reduced, increasing rapidly towards 21 Mscf/STB during the two-day low-rate period (initial solution GOR is 23 Mscf/STB). Produced wellstream dewpoint is slightly increasing during the high-rate period, about 500 psi lower than the insitu dewpoint of 4808 psia. Following the rate reduction the produced wellstream dewpoint increases almost 1200 psi (900 psi above the insitu dewpoint), then decreases sharply towards the insitu dewpoint during the two-day low-rate period.

Sample 1 is taken at 1 day during the high-rate period, Sample 2 is taken at 2.06 days (1.5 hours after the rate reduction), and Sample 3 is taken at 2.5 days. The compositions of Samples 1-3 are given in **Table 3** (columns B, D, and F).

Fig. 6 shows the complicated relationship between produced wellstream dewpoint and GOR during both rates in DST 2. During the high-rate period the wellstream dewpoint-GOR trend appears to extrapolate to the insitu dewpoint/GOR. However, already at 1.5 days the GOR and dewpoint have become essentially constant.

When separator samples representing Sample 1 are recombined at varying ratios, the trend in dewpoint-GOR is given by the lower dashed line. A mixture with GOR of about 15.3 Mscf/STB (column C, **Table 3**) yields the insitu dewpoint of 4808 psia. This mixture obviously does not represent the insitu reservoir gas GOR of 23 Mscf/STB. Clearly the danger of recombining separator samples to match the (assumed) insitu dewpoint is obvious from this example (and DST 1 results).

The upper part of **Fig. 6** shows the wellstream dewpoint-GOR trend during the low-rate period. Even though the dewpoint approaches the insitu dewpoint, the producing GOR is still lower than the insitu value.

When separator samples for Sample 2 are recombined at varying ratios, the trend in dewpoint-GOR is somewhat similar to the produced wellstream trend. The recombination mixture yielding the insitu dewpoint has a GOR of 21.6 Mscf/STB (column E, **Table 3**), somewhat lower than the insitu value of 23 Mscf/STB.

High-Drawdown Oil Well Test (DST 3). This oil test produces with a relatively high drawdown for 2.5 days (see **Fig. 4**). The producing GOR increases gradually from 770 to 815 scf/STB (insitu solution GOR is 855 scf/STB). The wellstream bubblepoint increases accordingly, from about 4530 to 4640 psia, compared with insitu bubblepoint of 4808 psia. (Bubblepoint is a simple *monotonic* function of GOR, in contrast to the complicated relationship between dewpoint and GOR.) Flowing BHP drops more than 2600 psi during the test.

Sample 1 is taken after 12 hours of production. The composition of Sample 1 is given in **Table 4** (column B). When separator samples representing Sample 1 are recombined to the insitu bubblepoint, the resulting mixture (column C) has a composition very close to the original reservoir oil.

Oil Well Test with Gas Coning (DST 4). This test produces from the oil zone 20 ft below the GOC. Gas coning occurs shortly after production begins, as seen in **Fig. 4**. Sample 1 is collected after 1 day with a producing GOR of 950 scf/STB, and Sample 2 is collected at the end of the test (2.5 days) with a producing GOR of 1370 scf/STB. Wellstream bubblepoint increases almost linearly during the test, reaching 6600 psia at the end of the test.

In general, samples collected during an oil test with gas coning are considered "unrepresentative." Therefore, separator samples from such a test would not usually be recombined in the laboratory (e.g. to match an assumed insitu bubblepoint). If done, the resulting oil composition would be too light compared with the original reservoir oil (see column B, **Table 6**).

Standard ECM1 Application (DSTs 1 & 3)

Gas Sample 1 collected during DST 1 (low drawdown) was mixed with oil Sample 1 collected during DST 3 (high drawdown) using the standard ECM1 method. The resulting equilibrium compositions at the original GOC conditions (4808 psia and 259°F) are shown in **Tables 1 and 2** [columns labelled ECM(a)]. Resulting equilibrium gas and oil compositions are practically identical to the original reservoir fluids.

An ECM1 procedure was also conducted using the same gas Sample 1 from DST 1, but mixed with the bubblepoint-adjusted Sample 1 from DST 3. Even though this reservoir oil is closer to the original reservoir oil, ECM1 results are slightly poorer [compare columns ECM(a) and ECM(b) in **Tables 1 and 2**].

Application of ECM1 to High/Low-Rate Gas Test (DSTs 2 & 3)

The ECM1 method was applied (separately) using reservoir oil Sample 1 from DST 3 with the three reservoir gas samples collected during DST 2. The method was also applied using oil Sample 1 from DST 3 and dewpoint-corrected Sample 2 from DST 2.

Results are shown in **Tables 3 and 4**. In *all* cases the resulting equilibrium oil and gas compositions from the ECM1 method are very close to the original reservoir fluids, and they are superior to the sampled compositions.

The real improvement using the ECM1 method is obtaining a *consistently accurate* estimate of original gas composition. For example, dewpoint-adjusted gas compositions can (and usually are) erroneous (as shown in DST 1 Sample 1 and DST 2 Sample 1). By chance, a dewpoint-adjusted gas composition can be reasonably accurate, as is the case for Samples 2 and 3 in DST 2. However, the estimate of original reservoir gas composition based on the ECM1 method is consistently accurate, almost independent of the reservoir samples used in the ECM1 procedure.

This observation is also seen when comparing the solution OGR (r_s) versus pressure for the different reservoir gases (**Fig. 7**). All reservoir gas compositions determined using the ECM1 method overlay the r_s curve of the original reservoir gas. Dewpoint-adjusted samples do not, even though they appear to have a reasonable initial composition (e.g. Sample 2, DST 2).

Interestingly, all reservoir oil samples have essentially the same PVT properties, as seen in **Fig. 8**. The original Sample 1 from DST 3 has a bubblepoint some 500 psi too low, but the PVT properties (R_s and B_o) fall on the same saturated curve as the original oil.

Effect of Mixing Volumes on ECM1 Results

A study has been made of the effect that oil volume ratio has on equilibrium compositions using oil Sample 1 (DST 3) and gas Sample 1 (DST 2). Results are shown in **Fig. 9**. It is clear that an acceptable oil volume ratio is 0.5 or greater. In our examples we use (conservatively) a volume ratio of 0.5 for all ECM calculations. A higher ratio would have given even better results. For ECM applications with coning samples (as shown below), the producing GOR at the time of sampling automatically determines the oil volume ratio.

Application of ECM1 to Gas Coning During an Oil Test (DST 4)

Sample 1 (DST 4) was brought to conditions at the GOC using the ECM1 procedure. Resulting equilibrium compositions are shown in **Tables 5 and 6**. Sample 2 (DST 4) was also brought to conditions at the GOC using the ECM1 procedure, with resulting equilibrium compositions shown in **Tables 5 and 6**. For both samples the resulting ECM1 estimates of initial reservoir compositions are nearly exact.

Based on these results, it is clear that samples collected during an initial oil test with gas coning can provide a unique opportunity to obtain *very* accurate samples of the original saturated oil and gas. The main reason for better accuracy with this method is that the produced reservoir gas has a minimum "loss" of condensed retrograde liquid as it flows to the wellbore. The reservoir gas is flowing through the oil zone to reach the wellbore - i.e. through pores that already have a high oil saturation. This ensures immediate and complete mobility of any liquid condensed from the reservoir gas on its path to the wellbore.

In fact, we *recommend* designing oil well tests *with gas coning*, specifically to obtain the most accurate samples of original reservoir fluids. (As a bonus, coning tests give valuable reservoir information about vertical communication). Another advantage of sampling during a test with coning is that separator liquid carryover will not be a problem, as it might be if the gas zone is tested separately. And finally, the drawdown can practically be as large as desired (or necessary to induce coning). The quality of results using coning samples evaluated with the ECM1 method do not depend on the level of drawdown.

To ensure a reasonable oil ratio (V_o/V_t>0.5), the samples should be collected before reaching a maximum GOR_{max} which be estimated from the relation

$$V_o/V_t = V_o/(V_o+V_g) = \frac{B_{ob}(R_{sb}(p_b),T,\gamma_o,\gamma_g)}{B_{tb}(GOR_{max},p_b,T,\gamma_o,\gamma_g)} > 0.5 \qquad (1)$$

p_b is the bubblepoint pressure (i.e. reservoir pressure at the GOC), T is reservoir temperature, γ_o is the STO specific gravity, and γ_g is the surface gas specific gravity. B_{ob} is the oil FVF at p_b, R_{sb} is the solution GOR at p_b, and B_{tb} is the total FVF evaluated at p_b, where all three properties can be estimated from correlations.[9,10]

Depletion Simulations

Application of ECM2 to Depleted MGC Reservoir (Oil Zone)

Fig. 10 shows the production performance from the oil zone in the MGC reservoir during five years of solution gas drive depletion where reservoir pressure drops about 1800 psi to 3000 psia. GOR increases from 855 to 2000 scf/STB, and the wellstream saturation pressure increases to nearly 10,000 psia (becoming a dewpoint between 7000 and 8000 psia).

Sample 1 was taken after 180 days of production when producing GOR had decreased to 750 scf/STB with a wellstream bubblepoint of 4330 psia. Recombining separator samples from Sample 1 at a ratio that results in the original bubblepoint provides a composition that closely resembles the original reservoir oil (column B of **Table 7**).

Sample 2 was collected at 1800 days when reservoir pressure was 3065 psia and producing GOR was 1975 scf/STB. Several approaches were tried for reestablishing an accurate estimate of the original oil using Sample 2. The first method recombined separator samples to obtain the original bubblepoint pressure. Results are reasonably accurate, as shown in column C of **Table 7**.

The second approach was the ECM1 procedure using the produced wellstream directly. Sample 2 was brought to conditions at the original GOC, with the resulting equilibrium oil composition shown in column D of **Table 7**. Results are poor.

The recommended method (ECM2) brings the produced wellstream (Sample 2) to the reservoir pressure at the time of sampling. Equilibrium gas is removed to a second container. This gas is then reinjected incrementally to the equilibrium oil until the original bubblepoint is reached. Results from this method are very accurate, as shown in column E of **Table 7**.

Finally we evaluate the possibility of reconstructing the original oil composition when only a depleted reservoir oil sample is available. For example, if the reservoir is water flooded after five years of depletion, then samples collected later in the water flood would consist only of reservoir oil. This reservoir oil was saturated at the end of depletion, but it would be undersaturated at the time of sampling (relative to the current reservoir pressure).

We have found that the best experimental method for creating an approximate sample of the original reservoir oil is simply to recombine the current separator samples in a ratio that gives the original bubblepoint. In this example, separator samples of the reservoir oil at the end of depletion (1800 days) were recombined to obtain the original bubblepoint. The resulting composition is shown in column F of **Table 7**.

Application of ECM1 to Depleted MGC Reservoir (Gas Zone)

Fig. 11 shows the depletion performance of the gas zone in the MGC reservoir for a five-year period. Two samples are taken at about the same reservoir pressure as Sample 2 in the oil zone depletion study (the gas zone and oil zone depletion simulations were run independently). Sample 1 was taken at the plateau production rate of 50 MMscf/D (column B **Table 8**), and Sample 2 was taken during a short rate reduction to 0.5 MMscf/D (column C **Table 8**). From Sample 1 to Sample 2 the producing GOR dropped from 33.2 to 29.5 Mscf/STB (OGR increased from 30 to 34 STB/MMscf), with dewpoint increasing from 3206 to 3446 psia (average reservoir pressure was 3254 psia at the time of sampling).

The ECM1 method was used to obtain an estimate of the original reservoir gas. The ECM2-created oil from the oil zone was mixed with Sample 1 from the gas zone at original GOC conditions. The resulting equilibrium gas composition is shown in **Table 8** (column D). An additional ECM1 contact was made with the same two reservoir samples using a higher oil volume ratio (90% instead of 50%). A noticeable improvement in the estimated original gas composition is observed, as shown in **Table 8** (column E).

The ECM1 procedure was also done using the ECM2-created oil from the oil zone and Sample 2 from the gas zone. These results are also in **Table 8** (column F). Results from both ECM1 procedures are accurate.

We also tried a procedure similar to the ECM2 method for Sample 2 from the gas zone, as this sample had a dewpoint higher than the current reservoir pressure. Sample 2 was brought to current reservoir pressure. All of the equilibrium oil was removed, and some of the equilibrium gas. The equilibrium oil was reinjected incrementally to the remaining equilibrium gas until the original dewpoint was reached. The resulting composition is shown in **Table 8** (column G).

This modified ECM2 procedure gives only approximate estimates of original reservoir gas, and the method is only recommended for depleted gas condensates when a reservoir oil sample is unavailable. Using a bottomhole sampler, it may be possible to obtain larger quantities of free reservoir oil during rate reduction or shutin in depleted condensate wells. Such BH samples would probably make a modified ECM2 method more accurate, and easier to implement in the laboratory.

Application of ECM2 to Depleted VO Reservoir (Oil Zone)

A second example testing the ECM2 method for depleted reservoir oil is presented for a more volatile system. **Fig. 12** shows the production performance of a volatile oil during five years of depletion from an initial undersaturated pressure of 7000 psia to less than 3000 psia. Producing GOR increases from 2000 scf/STB to almost 20,000 scf/STB. Bubblepoint pressure of the produced wellstream varies from an initial value of 5850 psia to a maximum of nearly 8000 psia reached after 2.5 years.

Sample 1 was taken at 720 days when reservoir pressure had declined to about 4200 psia with a producing GOR of 5700 scf/STB. Separator samples were recombined in a ratio to give a bubblepoint of the original oil (5850 psia). The resulting composition is very poor (much too light), as shown in **Table 9** (column B).

Sample 1 was brought to original reservoir conditions using the ECM1 method. The resulting equilibrium oil is again very poor (much too heavy), as shown in **Table 9** (column C).

Sample 1 was then brought to current reservoir pressure using the recommended ECM2 method. Equilibrium gas was removed, and then reinjected to the equilibrium oil until the original bubblepoint was reached. The resulting composition is quite accurate, as shown in **Table 9** (column D).

Having only a sample of the reservoir oil at 720 days and using the separator samples corresponding to this sample, a recombination is made to reach the original bubblepoint pressure. The resulting reservoir oil composition from this procedure (recommended when previously-depleted, currently-undersaturated oils are sampled) is shown in **Table 9** (column E). The oil is heavier than the original reservoir oil as seen in **Fig. 13**.

The separator recombination approach is acceptable for some previously-depleted, currently-undersaturated oils, but this example shows that the accuracy deteriorates for more volatile systems (compared with the MGC results). We also fear that the method may be inadequate for reservoirs that have reached far into depletion before being repressurized.

Application of ECM1 to Systems with Compositional Gradient

A valid question regarding the utility of the proposed ECM methods is whether they provide useful information for reservoir systems that exhibit compositional variation with depth. This problem has been studied for several reservoirs exhibiting compositional variation due to isothermal gravity/chemical equilibrium. All systems considered have a saturated gas-oil contact.

The short dashed lines in **Figs. 14-16** represent the actual compositional variation with depth calculated using the isothermal gravity/chemical equilibrium assumption.

Based on insitu, depth-specific compositions taken at equal distances above and below the GOC, the ECM1 procedure has been tested for three reservoir systems with greatly differing compositional gradients. The solid circles (connected by medium-dashed lines) represent the equilibrium compositions at GOC conditions resulting from the ECM1 procedure. These compositions clearly do not represent the true equilibrium compositions at the GOC.

Instead, we found for these three reservoir systems that ECM1-determined compositions give a good estimate of the depth-weighted average composition from the GOC to the points of sampling. The integrated depth-averaged compositions are shown as solid lines in **Figs. 14-16**). The ECM1-determined compositions give surprisingly accurate estimates for the depth-weighted average in the oil zone. Results in the gas zone are somewhat less accurate, but they should still be useful.

Further studies are needed to verify that ECM1-determined compositions in systems with compositional gradients *consistently* yield reasonable depth-weighted averages from the GOC to the point of sampling. For example, (1) when the reservoir gas and oil samples are not collected at equal depths away from the GOC, and (2) when reservoir samples already represent average compositions over a limited depth interval.

Separator Sampling

Traditional Sampling

Traditional separator samples are used for compositional analysis and PVT studies of gas condensate and oil reservoirs. Separator samples are also collected for gas injection studies requiring large sample volumes, and for special studies involving analysis of asphaltene precipitation, wax point, emulsions, hydrates, and corrosion.

Accuracy of separator gas and oil rates is typically 5% or better. Samples are collected simultaneously at the primary separator, using 20 l containers for the separator gas and 500 to 1000 ml containers for the separator oil. The gas sampling probe points downstream to ensure that only separator gas enters the sampler (*not* including liquid droplets that may be dispersed in the gas stream leaving the separator). A standard gas sample should therefore represent the actual separator gas composition when carryover exists.

Liquid Carryover in the Gas Well Stream

Gas condensates producing through a standard horizontal test separator may have some liquid leaving the separator as small droplets in the gas stream. Liquid "carryover" is most severe at high gas rates because the settling time is reduced, and coalescence processes in the separator are less efficient. Generally speaking, carryover is more important for leaner gas condensates because the total liquid "lost" due to carryover can be large relative to the total liquid content of the produced wellstream.

If carryover goes uncorrected in the recombination process, the result will be a wellstream composition that is always too lean. Carryover is identical to an erroneously-measured low oil rate. In fact, correction for carryover requires only a simple adjustment to the recombination GOR, as shown below.

We define carryover (δ) on a molar basis, $\delta=\Delta n_o/n_o$, where Δn_o is the moles of separator oil carried out of the separator in the gas stream, and n_o is the total moles of separator oil. The wellstream composition $\mathbf{z}$ entering the separator is given by $\mathbf{z}=\beta\mathbf{y}+(1-\beta)\mathbf{x}$, where β is the mole fraction of separator gas in the total wellstream, $\beta=n_g/(n_g+n_o)$, $\mathbf{y}$ is the composition of separator gas (obtained from a standard gas separator sample), and $\mathbf{x}$ is the composition of the separator oil. β is calculated from

$$\beta = \frac{\beta_{test} - \delta}{1 - \delta}$$

$$\beta_{test} = [1 + \frac{2130\rho_{osp}}{M_{osp}(R_{sp})_{test}}]^{-1} \qquad (2)$$

where $(R_{sp})_{test}$ is the measured (erroneous) test GOR in scf/sep.bbl, ρ_{osp} is the separator oil density in lb/ft^3, and M_{osp} is the separator oil molecular weight. The separator GOR R_{sp} corrected for carryover is then given by

$$R_{sp} = (R_{sp})_{test} \frac{\beta_{test}^{-1} - 1}{\beta^{-1} - 1} \qquad (3)$$

Effect of Carryover on ECM Procedure

Very Lean Gas (BO)

Fig. 17 shows production characteristics of a very lean saturated gas during a 2.5 day test. Producing GOR varies from 500 to 550 Mscf/STB during the test, compared with the insitu GOR of 445 Mscf/STB. The pressure drawdown is large (almost 2000 psi). Wellstream dewpoint remains constant at about 1600 psia which is substantially lower than the insitu dewpoint of 2275 psia. Sample 1 was taken after 12 hours of production.

The reservoir gas is underlain by an oil zone containing a low-GOR black oil. A very accurate sample of the original reservoir oil is obtained by recombining separator samples from an oil well test to the original bubblepoint.

The composition of Sample 1 is shown in **Table 10** (column B). This sample, when passed through a separator operating at 105°F and 375 psia produces the separator gas shown in **Table 10** (column C). Neither composition is accurate when compared with the original gas composition. The inaccuracies of these samples may be particularly important in the design of seabed transportation requirements (e.g. pigging requirements of the pipeline).

Sample 1 was mixed with the original reservoir oil using the ECM1 procedure. The resulting estimate of original reservoir gas is practically exact, as shown in **Table 10** (column D).

The separator gas from Sample 1, assuming 100% liquid carryover without correction, was mixed with the original reservoir oil using the ECM1 procedure. Again, the resulting estimate of original reservoir gas is almost exact as shown in **Table 10** (column E).

Medium Gas Condensate

A more extreme test of the effect that uncorrected carryover has on ECM results is given using the MGC gas which has a liquid yield of about 45 STB/MMscf. The high-drawdown (high-rate) DST 2 Sample 1 gas is used, where 20% carryover is assumed. **Table 11** gives the actual composition of Sample 1 (DST 2) in column B, together with the wellstream composition that would be incorrectly determined with 20% carryover (column C).

ECM1 results using gas Sample 1 (DST 2) and oil sample 1 (DST 3) with an oil volume ratio of 70% are shown in **Table 11** [column ECM(a)]. Results are excellent when compared with the original gas composition.

ECM1 results using uncorrected Sample 1 (DST 2) with 20% carryover and oil sample 1 (DST 3) with an oil volume ratio of 70% are also shown in **Table 11** [column ECM(b)]. Again, the results are excellent (only slightly different than using the correct Sample 1).

Table 12 gives the ECM1 oil compositions with and without correction for carryover. Results are excellent, with only a slight deterioration when carryover is not corrected.

In summary it appears that the ECM method is not dependent on reservoir gas samples being corrected for carryover. Given that larger carryover occurs only for lean condensates, and smaller carryover is expected for rich condensates, we conclude that the ECM method can be used with confidence even when uncorrected carryover exists. Obviously, however, we recommend that recombined gas samples be corrected if carryover has been quantified.

Isokinetic Sampling

In 1941, Buckley and Lightfoot[2] describe "isokinetic" wellstream sampling equipment and a miniature separator design used to make detailed compositional and PVT measurements on a gas condensate producing from a formation at 10,000 ft with reservoir pressure of 5055 psia and reservoir temperature of 178°F. Average liquid yield was about OGR=16 STB/MMscf, with a condensate gravity of 48 to 50°API.

One year later Flaitz and Parks give a detailed description of similar isokinetic sampling equipment for gas condensate wells. A wellhead mixture is sampled with a small-diameter (1/16 to 3/32 in) probe located in the center of the production tubing near the wellhead. The sample mixture enters the probe at a velocity equal to the average wellstream velocity. This "isokinetic" sampling rate ensures that the entrained liquid drops (assumed to be homogeneously distributed throughout the entire cross section of the tubing) enters the sample probe undisturbed. A miniature multistage separator with pressure and temperature control is used to analyze produced wellstream samples.

The Flaitz-Parks paper presents *detailed* comparisons of wellstream isokinetic samples with vertical separator (2.5 by 11 ft) samples for twelve condensate systems (oil-gas ratios ranging from 10 to 100 STB/MMscf). Recombined wellstream compositions are also compared for the two sampling methods. Results are quite impressive, though a clear increase in error was found with increasing OGR.

Perhaps the most impressive results were an extensive 18-month testing procedure where multi-well, rate-averaged isokinetic wellstream liquid yields were compared with actual liquid yields from a Gulf Coast recycling plant facility. Maximum deviation in liquid yields during the 18 months was 7%, and the average deviation was only 1%.

The Flaitz and Parks paper gives some theoretical analysis of the isokinetic wellstream procedure. Furthermore, several special field tests were conducted to study the effect of flow rate and probe diameter on sampling efficiency.

In 1953, Hoffman, et al.[5] used similar isokinetic wellstream equipment to conduct a study on reservoir compositions and equilibrium ratios of a saturated gas/oil system. To our knowledge, this paper is the most recent application of isokinetic wellstream sampling.

During the past 5 to 10 years, several oil companies and, subsequently, service companies have introduced isokinetic sampling technology for *separator gas streams* (not wellstream). The justification for isokinetic separator gas sampling has been to quantify liquid carryover in high-rate gas condensates. There does not appear to be other reasons for using isokinetic separator gas sampling, so the method is not a replacement for standard separator sampling.

In fact, standard separator samples must *also* be collected (and analyzed) to quantify carryover using the isokinetic method. This is at least the case using the "SAD" minimization method. This method calculates the carryover that minimizes the sum of absolute differences (SAD) between all components, $SAD=\sum_i |u_i^*-u_i|$, where u_i is the measured overall composition of the isokinetic sample and u_i^* is the calculated overall composition of a mixture with β moles of separator gas y_i and $\delta(1-\beta)$ moles of separator oil x_i, or $u_i^*=[\beta y_i+\delta(1-\beta)x_i]/[\beta+\delta(1-\beta)]$.

A fundamental problem with the SAD approach is that the overall composition of the isokinetic sample must be determined. This may be difficult. Current laboratory procedures heat the isokinetic gas container to about 100°C (at constant volume) before transferring the sample to a gas chromatograph. The assumption is that liquid carryover is *completely* revaporized during the heating process. Our experience is that this probably never occurs.

Fig. 18 shows the carryover liquid volume (as a percent of the sample container volume) for isokinetic gas samples from a lean gas condensate with an OGR of 18 STB/MMscf. The reservoir gas was passed through a separator operating at 105°F and 375 psia.

For varying amounts of carryover from 10 to 40%, isokinetic samples were created. The liquid volume of each isokinetic sample is plotted versus pressure in **Fig. 18**. The closed circles represent the condition after heating to 212°F at constant volume (note that pressure increases to about 500 psia for all samples). The numbers in parentheses (below the carryover values) are liquid volume percents at original separator conditions.

From **Fig. 18** it is obvious that the heating process does not revaporize liquid carryover for this relatively light condensate. In fact, elevated pressures greater than 2000 psia are required to completely revaporize the liquid at 212°F.

So, what is the error in carryover that would be calculated by using the equilibrium gas in an isokinetic sample container after heating (when only part of the liquid is vaporized)? This gas is what would be analyzed in the laboratory and defined as u_i in the SAD process of determining the carryover value. The SAD graphical minimum in **Fig. 19** gives a carryover value of 33% (instead of the correct value of 40%). Also note that the SAD function is not as well behaved; a better function for determining carryover by minimization would be the sum of squares (SSQ) function, also shown in **Fig. 19**.

In summary we can conclude that a simple heating procedure should not be used for trying to bring an isokinetic sample to single phase conditions.

The best method (most accurate and simplest procedure) for determining carryover from an isokinetic separator gas sample would be to measure, *onsite*, the physical volume of liquid carryover in the isokinetic container *at separator conditions*. Given the liquid carryover volume, test GOR can be corrected immediately without any compositional analysis. A simple onsite method for measuring liquid carryover volume needs to be developed.

However, we feel strongly that the best solution to the carryover problem is to produce gas wells at lower rates during sampling, thereby minimizing carryover. And finally, if an ECM method can be used, the effect of carryover is minimal.

Conclusions

1. A laboratory procedure (ECM1) is recommended for making up accurate samples of *original insitu* reservoir gas and reservoir oil in saturated reservoirs.
2. The traditional application of the ECM1 procedure uses separate reservoir oil and reservoir gas samples. A novel application of the ECM1 procedure uses separator samples collected during gas coning in an oil well test. Both applications yield very accurate results.
3. Because of the high accuracy obtained with the ECM procedures, lengthy stabilization periods are no longer needed to ensure that produced wellstreams are representative of insitu fluids. Consequently, time and expenses can be saved during testing (particularly for gas condensates).
4. The ECM1 procedure can be applied to reservoirs with vertical compositional gradients and a saturated GOC. The resulting ECM1 samples provide reasonable estimates of depth-averaged compositions.
5. For oil reservoirs depleting by solution gas drive, a slightly modified ECM procedure (ECM2) is proposed for obtaining accurate insitu-representative samples of the original reservoir oil. The method requires a current wellstream sample from the oil zone and an estimate of the original oil bubblepoint (the oil can be initially saturated *or* undersaturated).
6. For a depleted gas condensate *initially saturated with an underlying oil*, accurate insitu-representative samples of the original reservoir gas can be obtained using the ECM1 procedure. A currently-producing gas wellstream is mixed with a reservoir oil sample made up using the ECM2 procedure.
7. For oil reservoirs previously depleted by solution gas drive but currently undersaturated (e.g. following water flooding), reasonably accurate insitu composition of the original reservoir oil can be obtained by recombining currently producing separator samples in a ratio to obtain the original oil bubblepoint.
8. Results of the ECM1 procedure are only slightly affected by errors in recombination separator GOR (e.g. due to liquid carryover).

Nomenclature

B_{ob}	Oil FVF at bubblepoint, RB/STB
B_{tb}	Total gas-plus-oil FVF at bubblepoint, RB/STB
GOR	Producing GOR, scf/STB
M_{osp}	Separator oil molecular weight
n_g	Moles of separator gas
n_o	Moles of separator oil
Δn_o	Moles of liquid (oil) carryover
p_b	Bubblepoint pressure, psia
R_{sb}	Solution GOR at bubblepoint, scf/STB
R_{sp}	Separator GOR, scf/separator bbl
T	Reservoir temperature, °F or °R
u	Measured isokinetic sample overall molar composition
u^*	Calculated isokinetic sample overall molar composition
V_g	Reservoir gas volume, ft^3
V_o	Reservoir oil volume, ft^3
V_t	Total gas-plus-oil reservoir volume, ft^3
x	Separator oil molar composition
y	Separator gas molar composition
z	Wellstream molar composition

Greek

β	Gas mole fraction
γ_g	Average surface gas specific gravity, air=1
γ_o	STO specific gravity, water=1
δ	Molar liquid carryover
ρ_{osp}	Separator oil density, lb/ft^3

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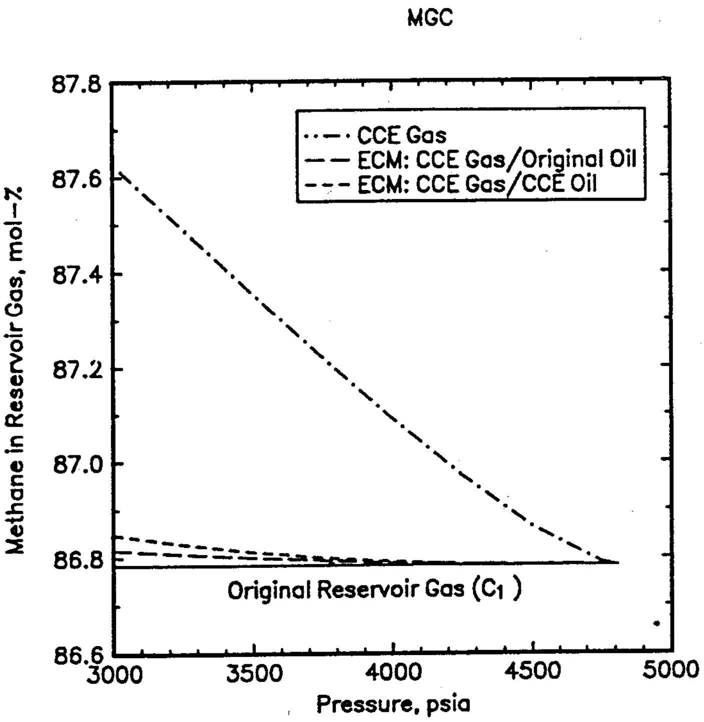

Fig. 1a ECM1 results for static PVT cell simulations using MGC reservoir. Methane molar composition in reservoir gas.

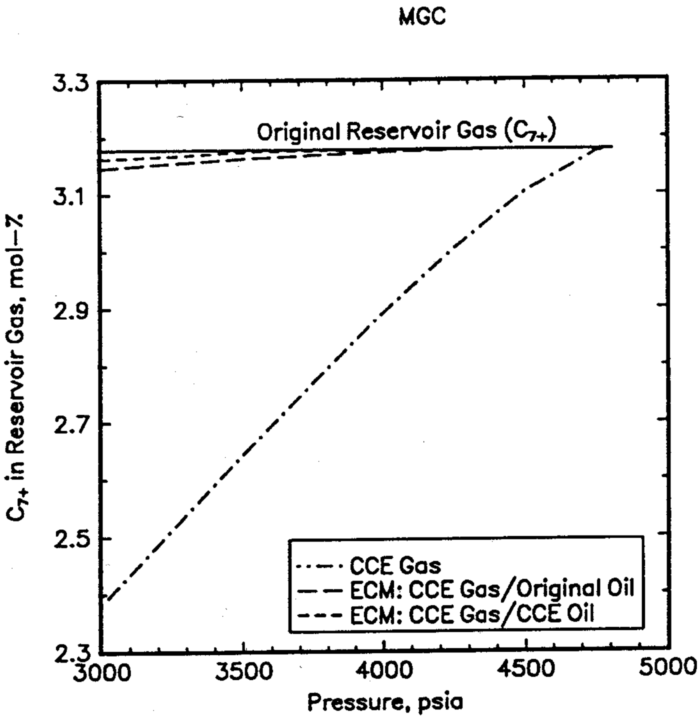

Fig. 1b ECM1 results for static PVT cell simulations using MGC reservoir. C_{7+} molar composition in reservoir gas.

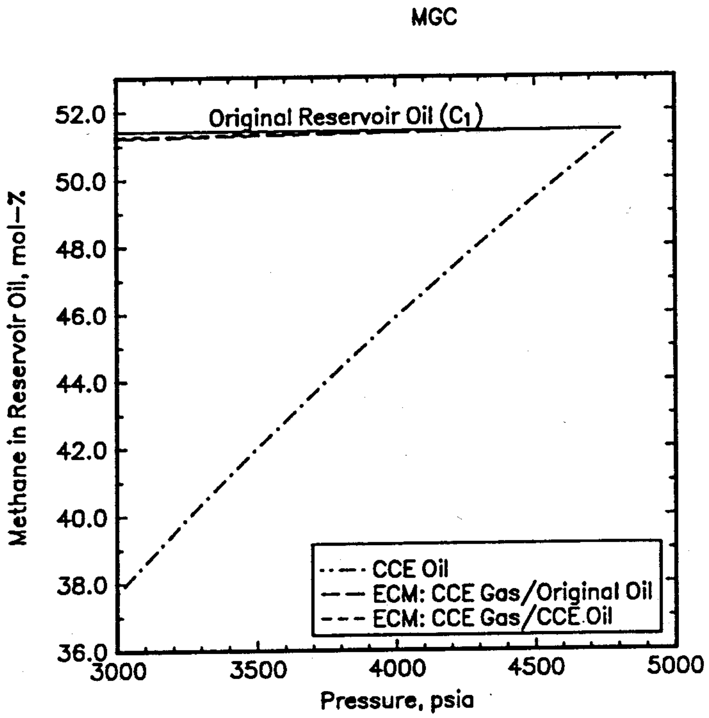

Fig. 1c ECM1 results for static PVT cell simulations using MGC reservoir. Methane molar composition in reservoir oil.

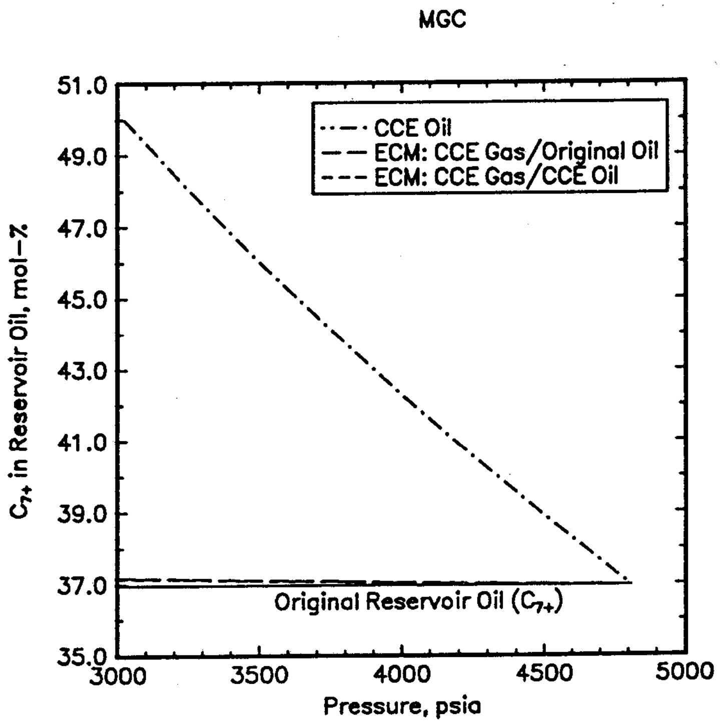

Fig. 1d ECM1 results for static PVT cell simulations using MGC reservoir. C_{7+} molar composition in reservoir oil.

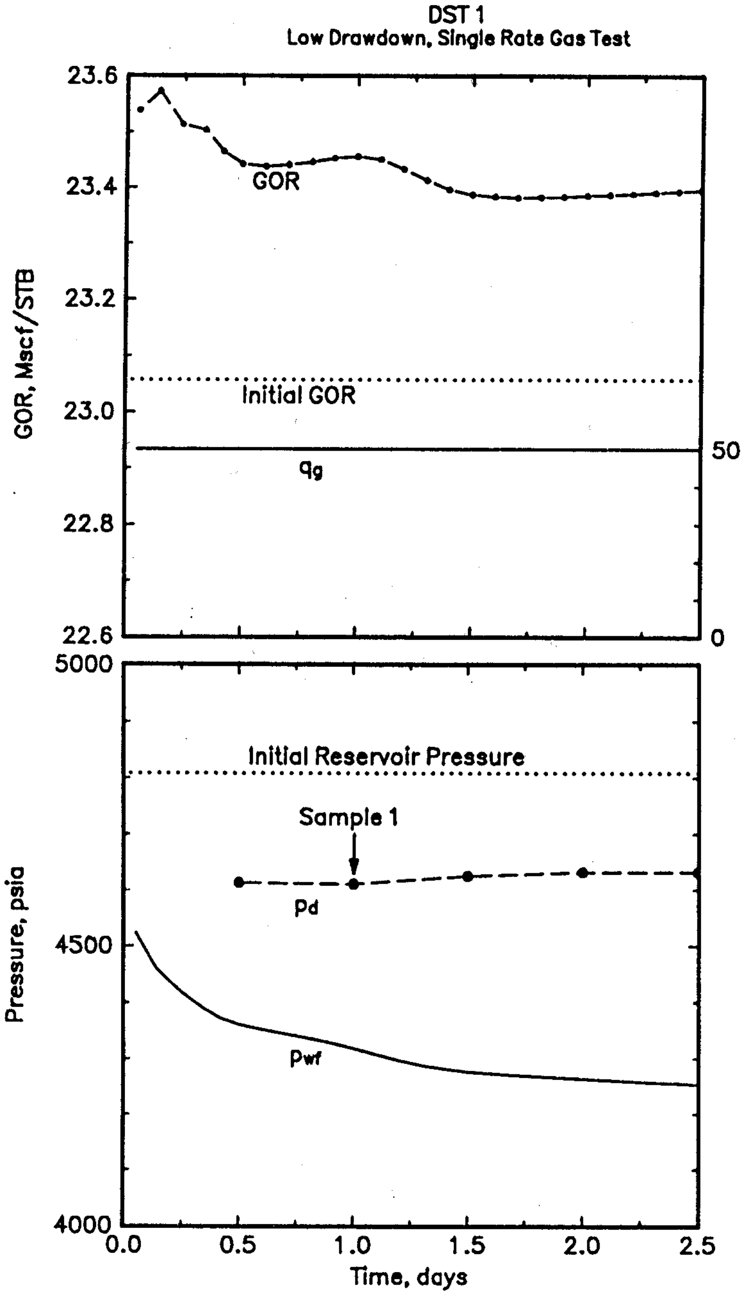

Fig. 2 Production performance during low-drawdown gas test DST 1, initially saturated MGC reservoir.

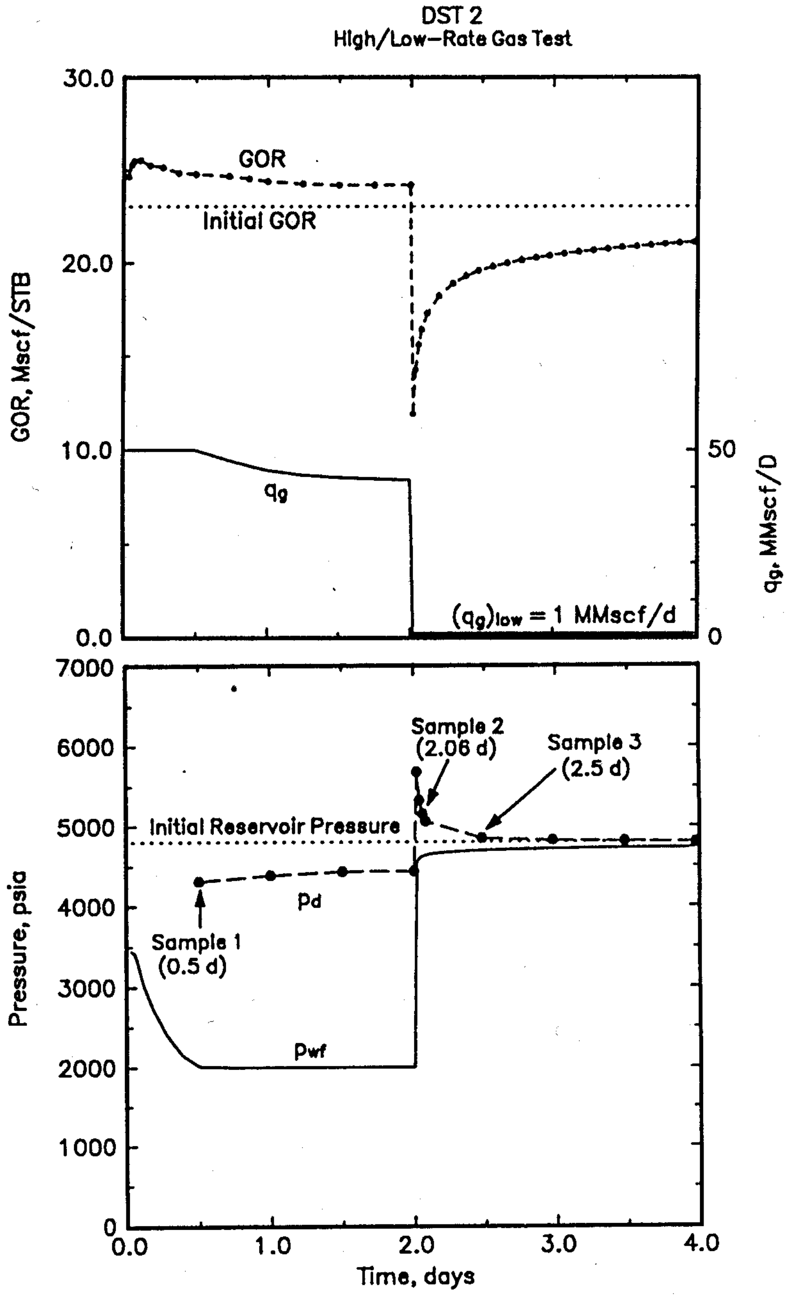

Fig. 3 Production performance during high/low-rate gas test DST 2, initially saturated MGC reservoir.

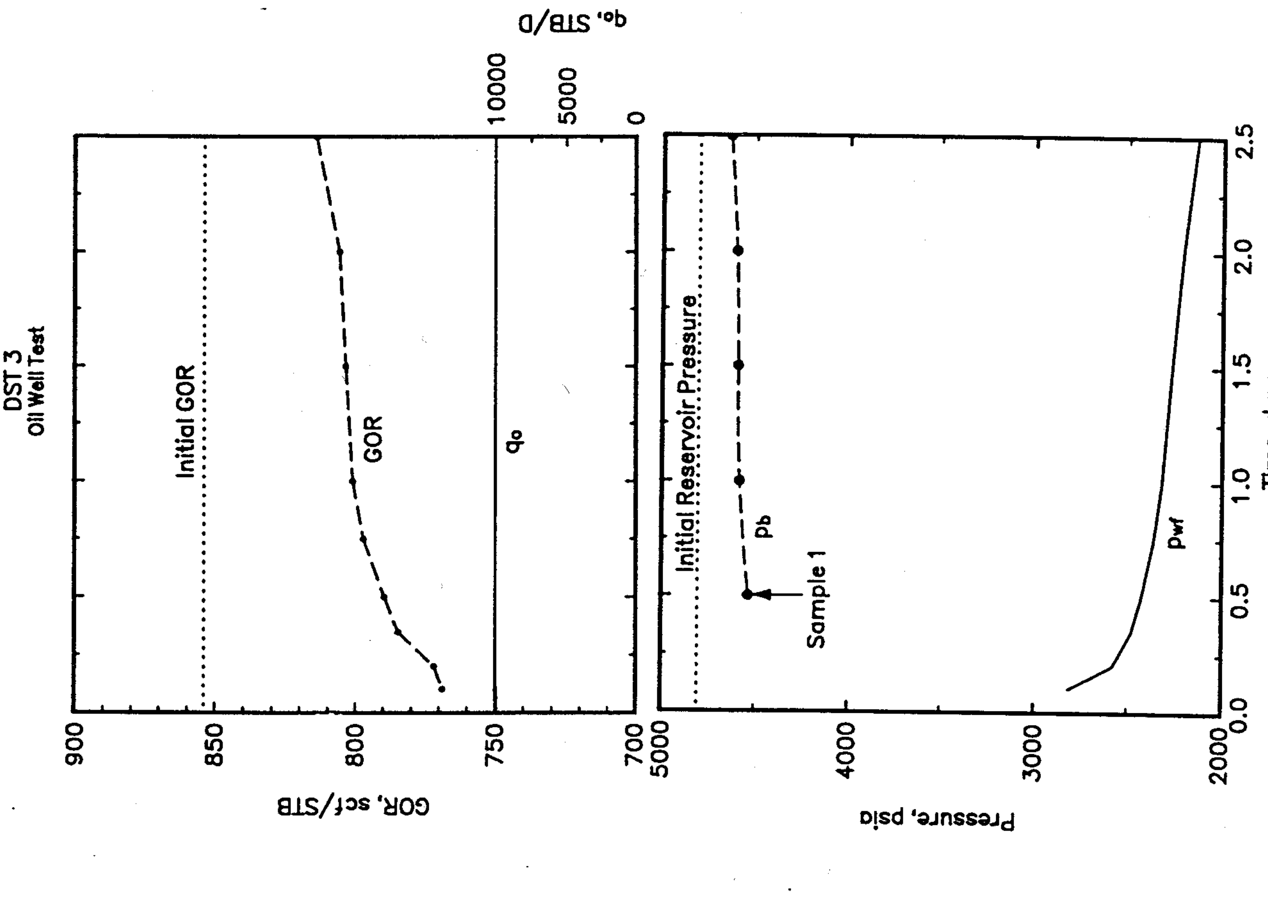

Fig. 4 Production performance during high-drawdown oil test DST 3, initially saturated MGC reservoir.

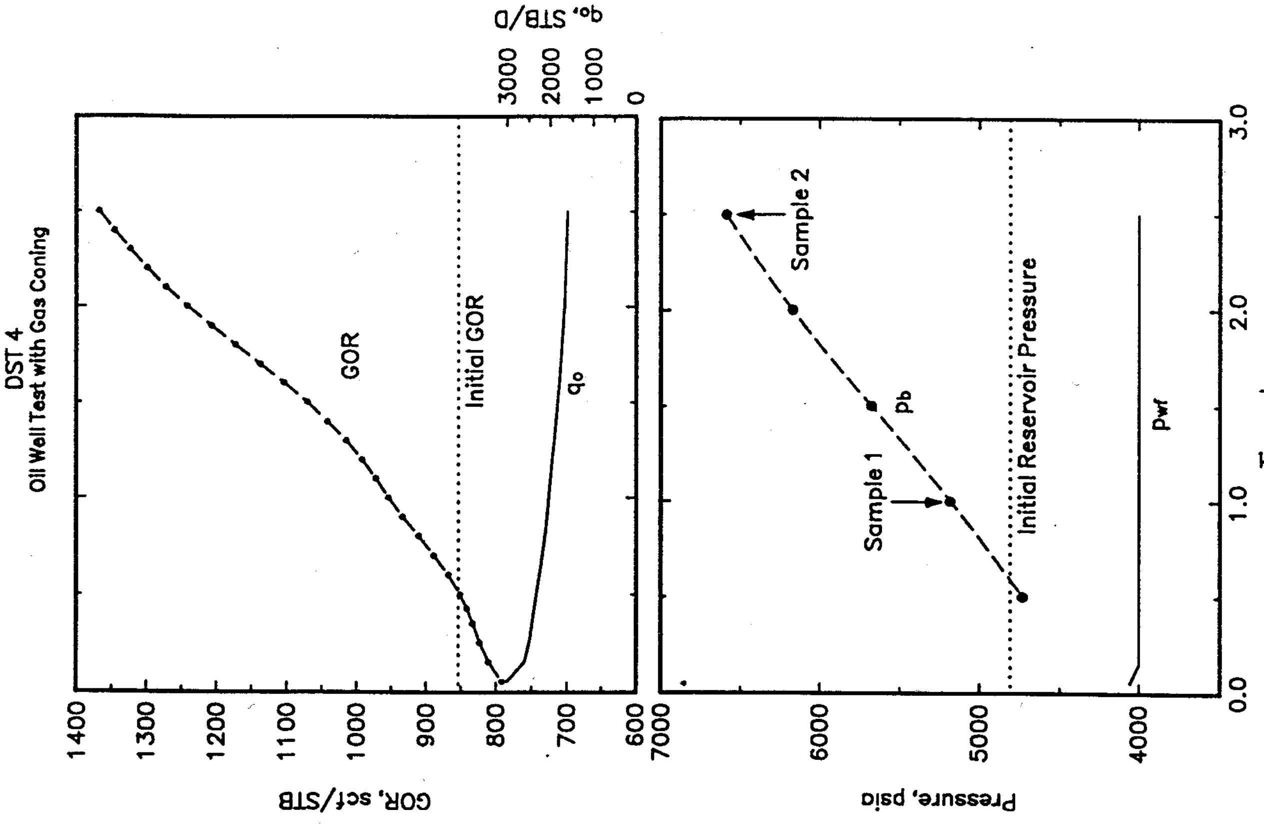

Fig. 5 Production performance during gas coning in oil test DST 4, initially saturated MGC reservoir.

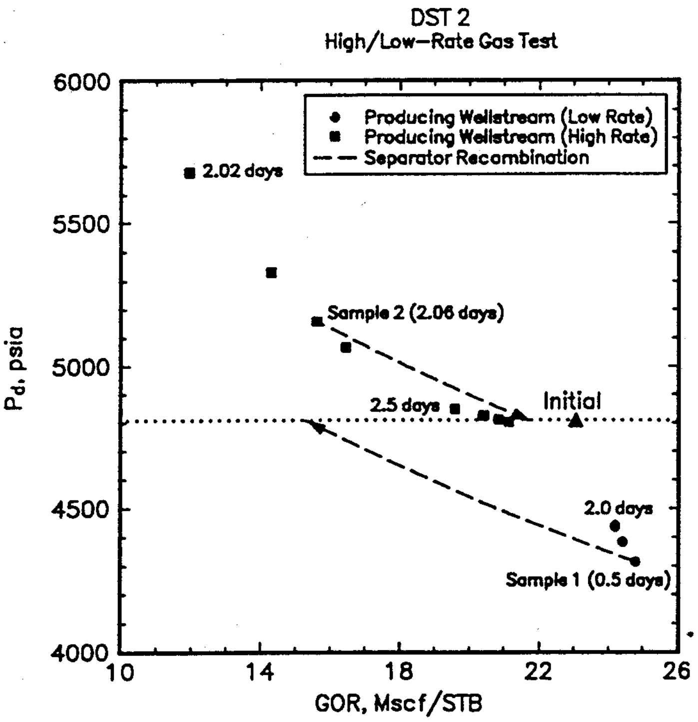

Fig. 6 Produced wellstream dewpoint vs. GOR behavior during high- and low-rates in gas test DST 2, initially saturated MGC reservoir.

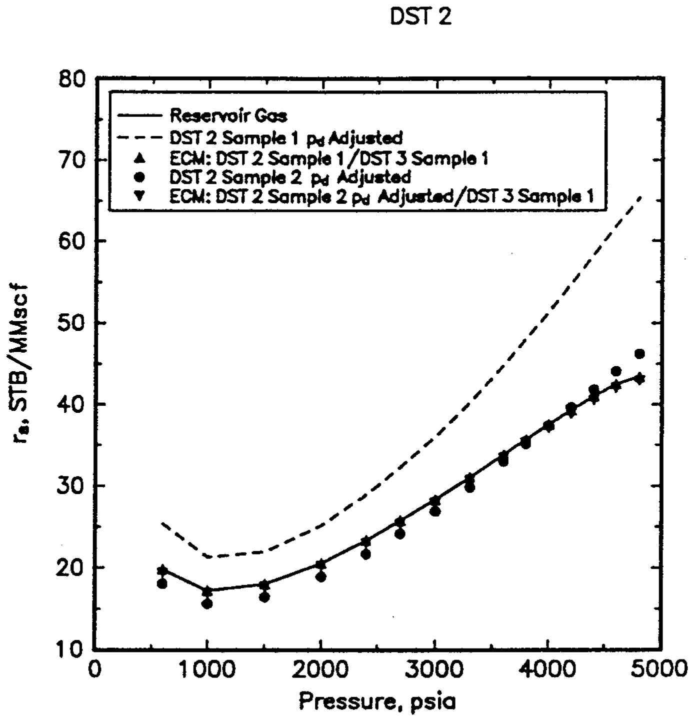

Fig. 7 Solution OGR of MGC insitu reservoir gas and various laboratory-prepared samples approximating the original reservoir gas.

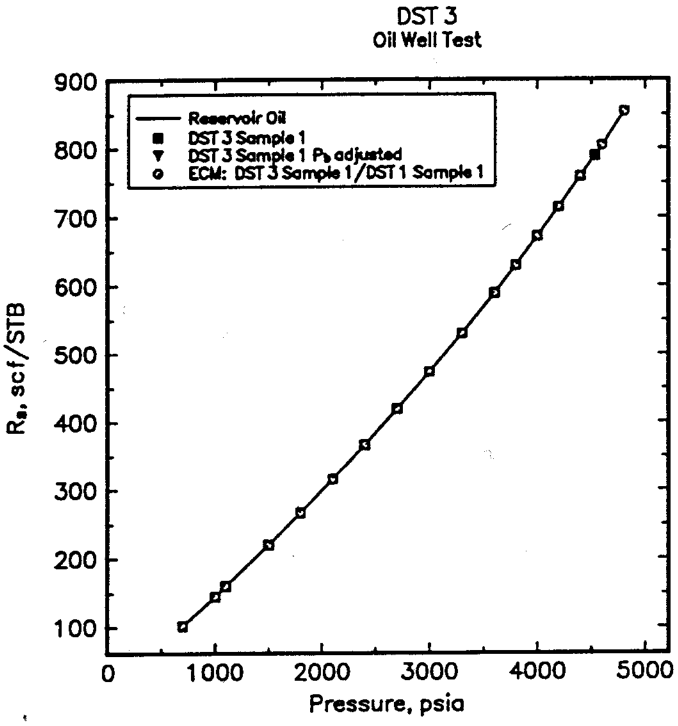

Fig. 8 Solution GOR of MGC insitu reservoir oil and various laboratory-prepared samples approximating the original reservoir oil.

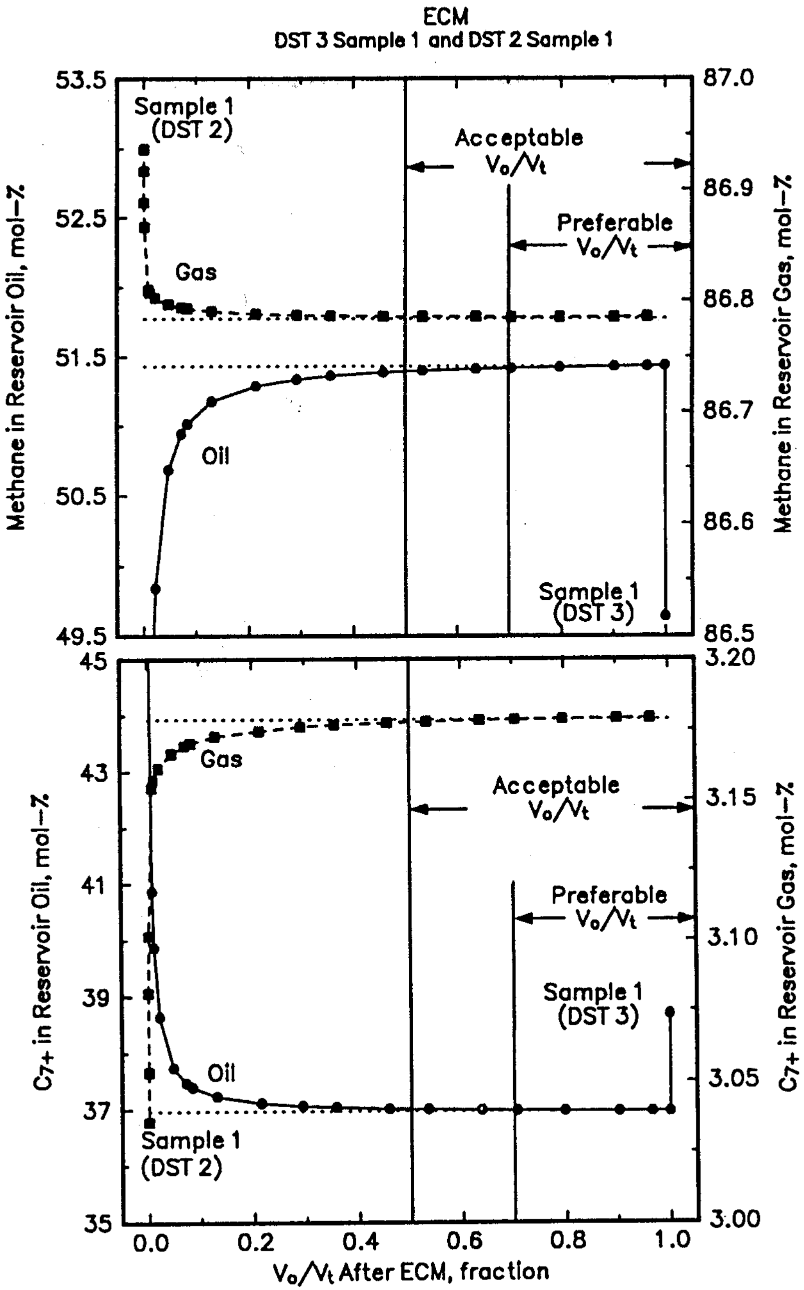

Fig. 9 Effect of oil volume ratio V_o/V_t on ECM1 results (methane and C_{7+} molar compositions) for MGC reservoir oil and gas. DST 2 Sample 1 and DST 3 Sample 1.

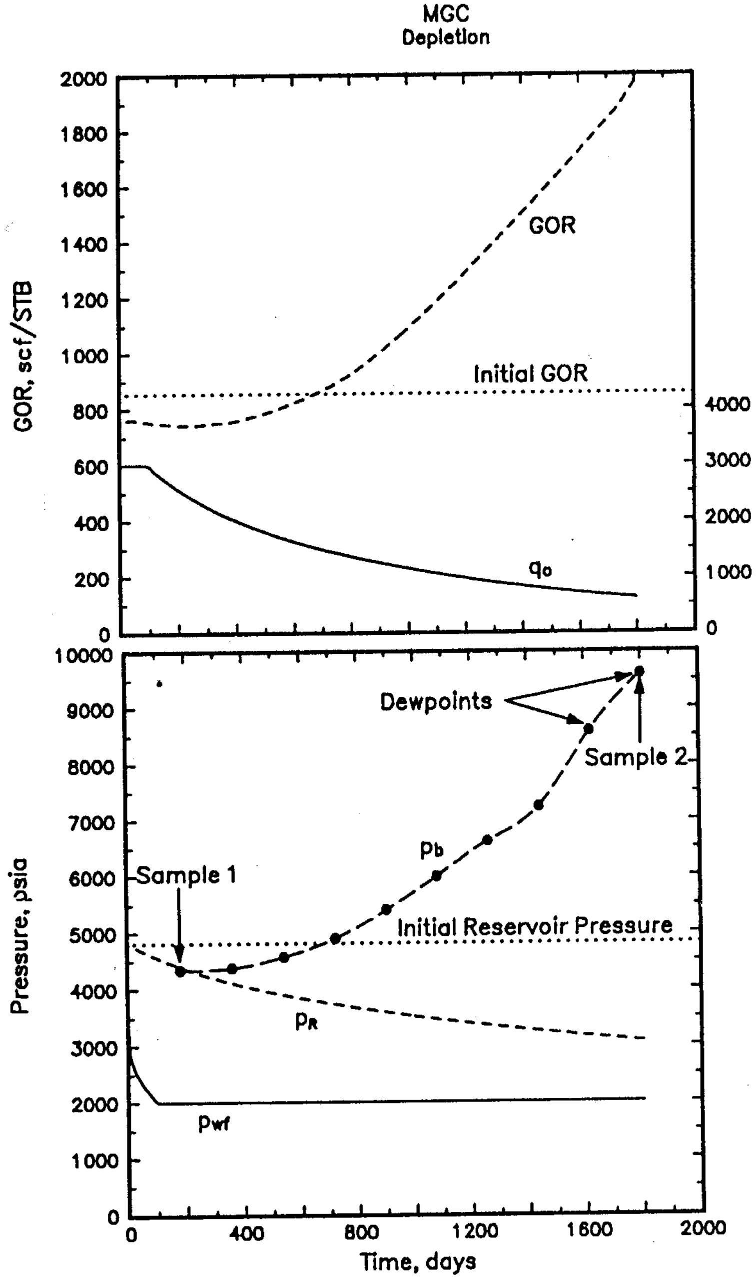

Fig. 10 Production performance during depletion of oil zone in initially-saturated MGC reservoir.

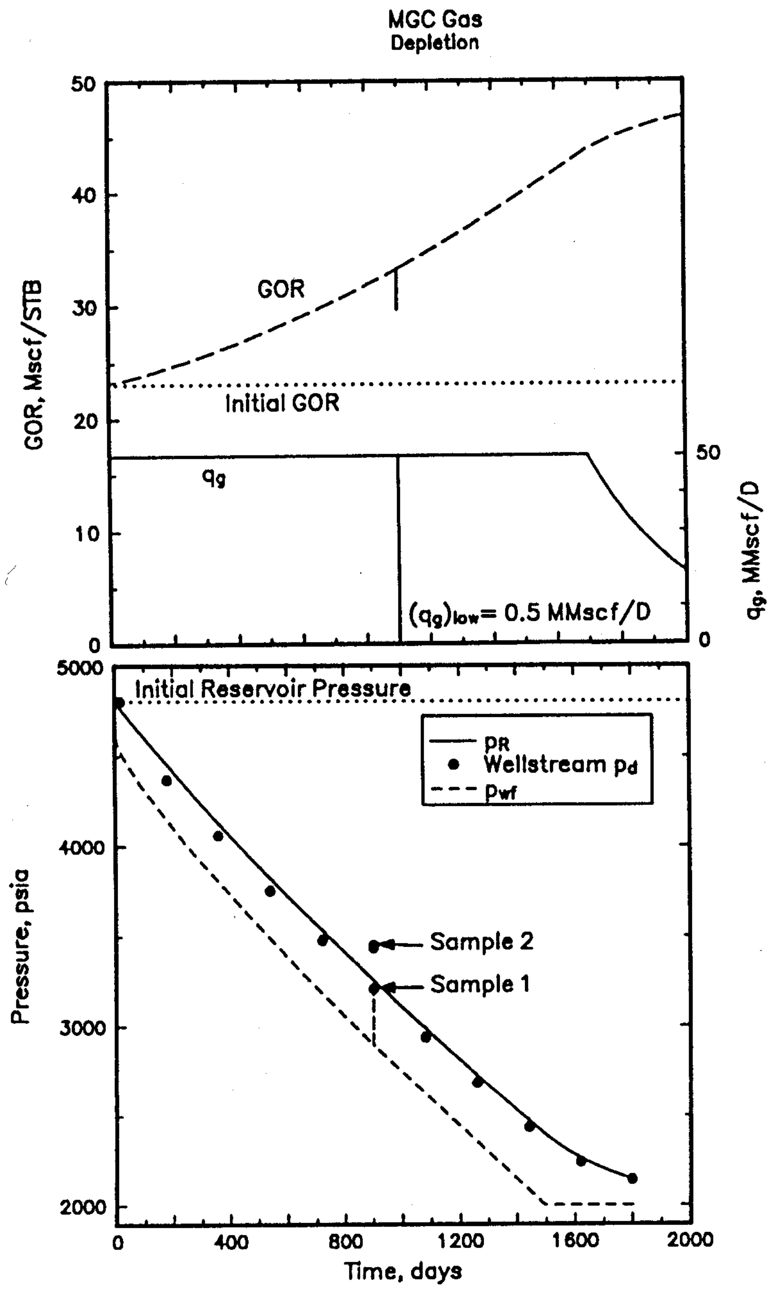

Fig. 11 Production performance during depletion of gas zone in initially-saturated MGC reservoir.

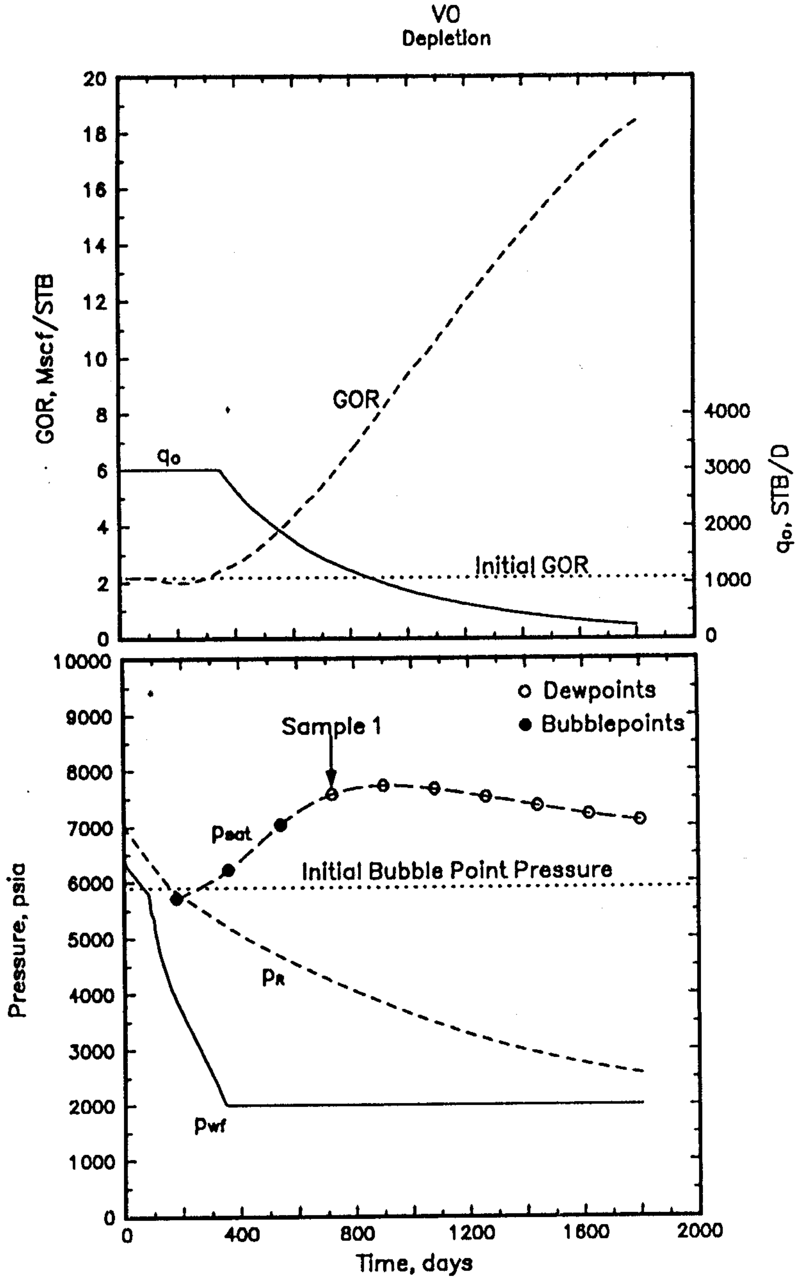

Fig. 12 Production performance during depletion of oil zone in initially-undersaturated VO reservoir.

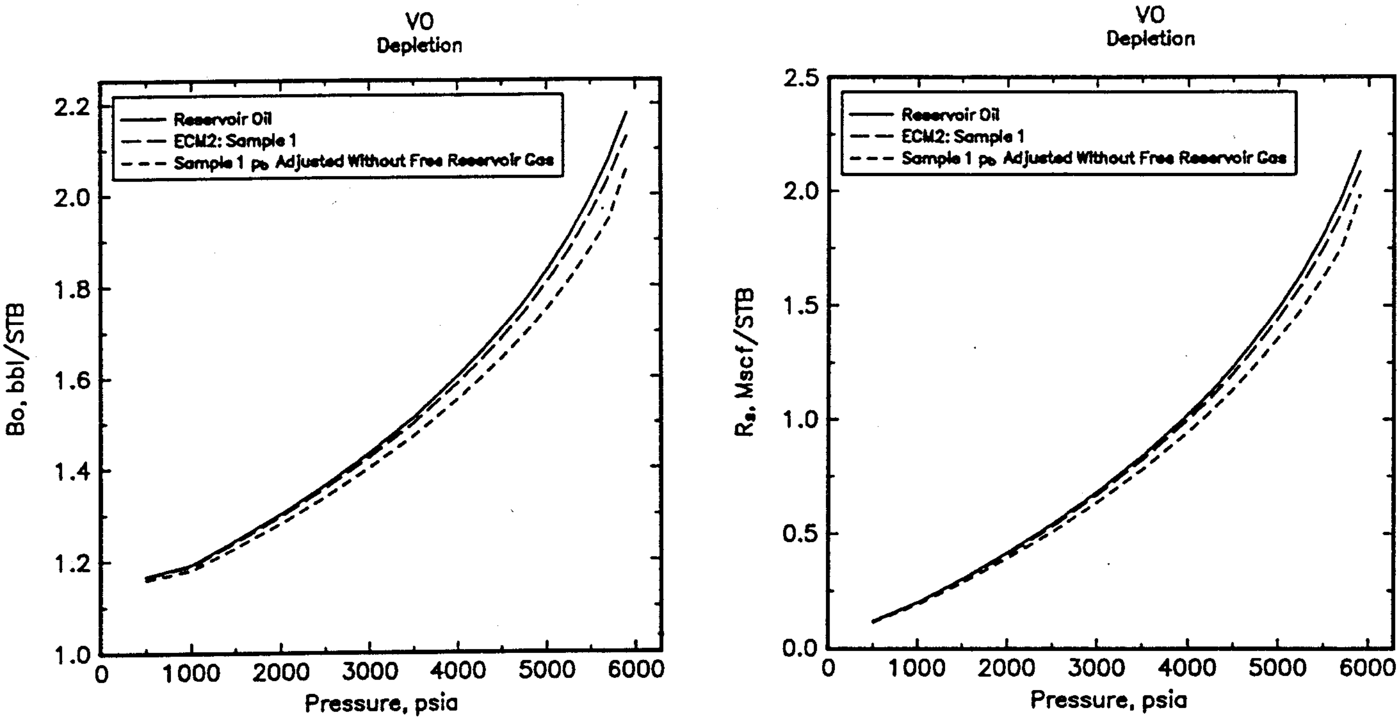

Fig. 13 Solution GOR and oil FVF of VO insitu reservoir oil and various laboratory-prepared samples approximating the original reservoir oil.

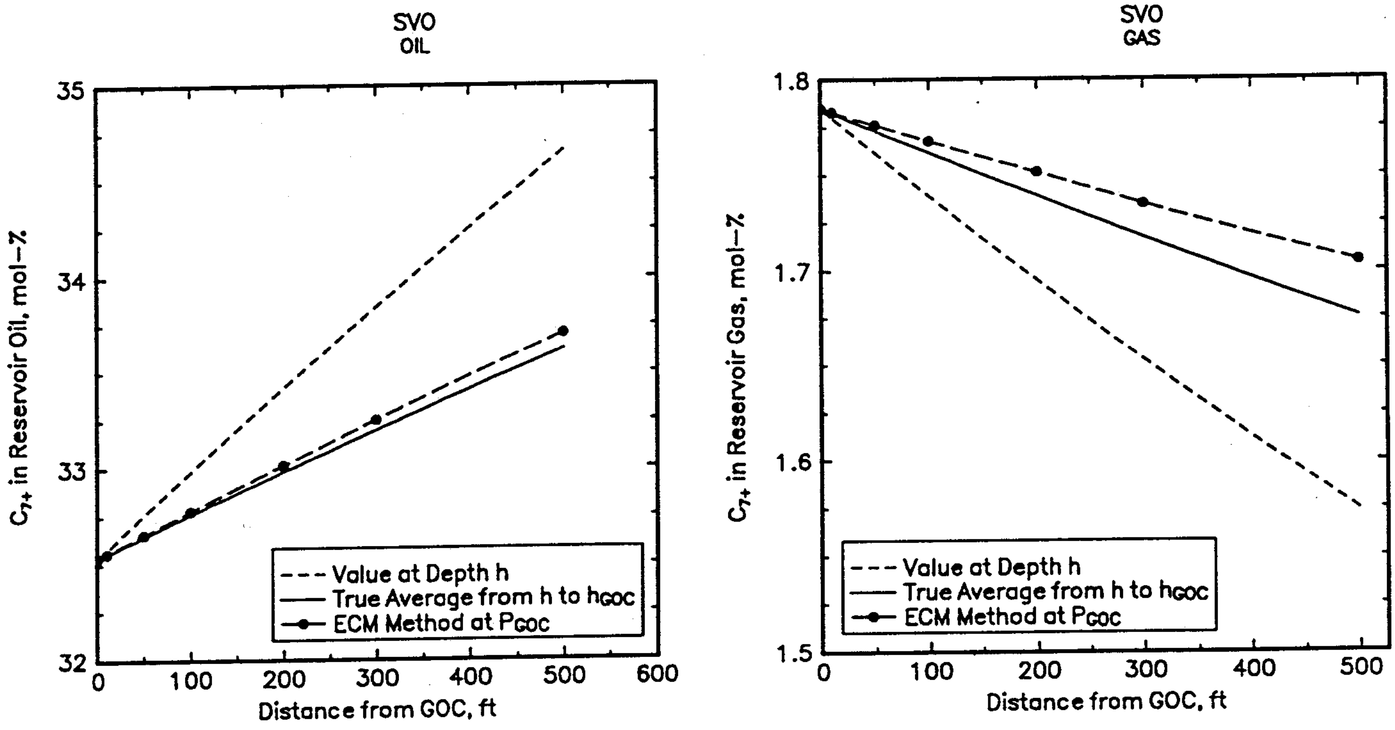

Fig. 14 ECM1 calculations (C_{7+} compositions) for SVO reservoir with vertical compositional gradient.

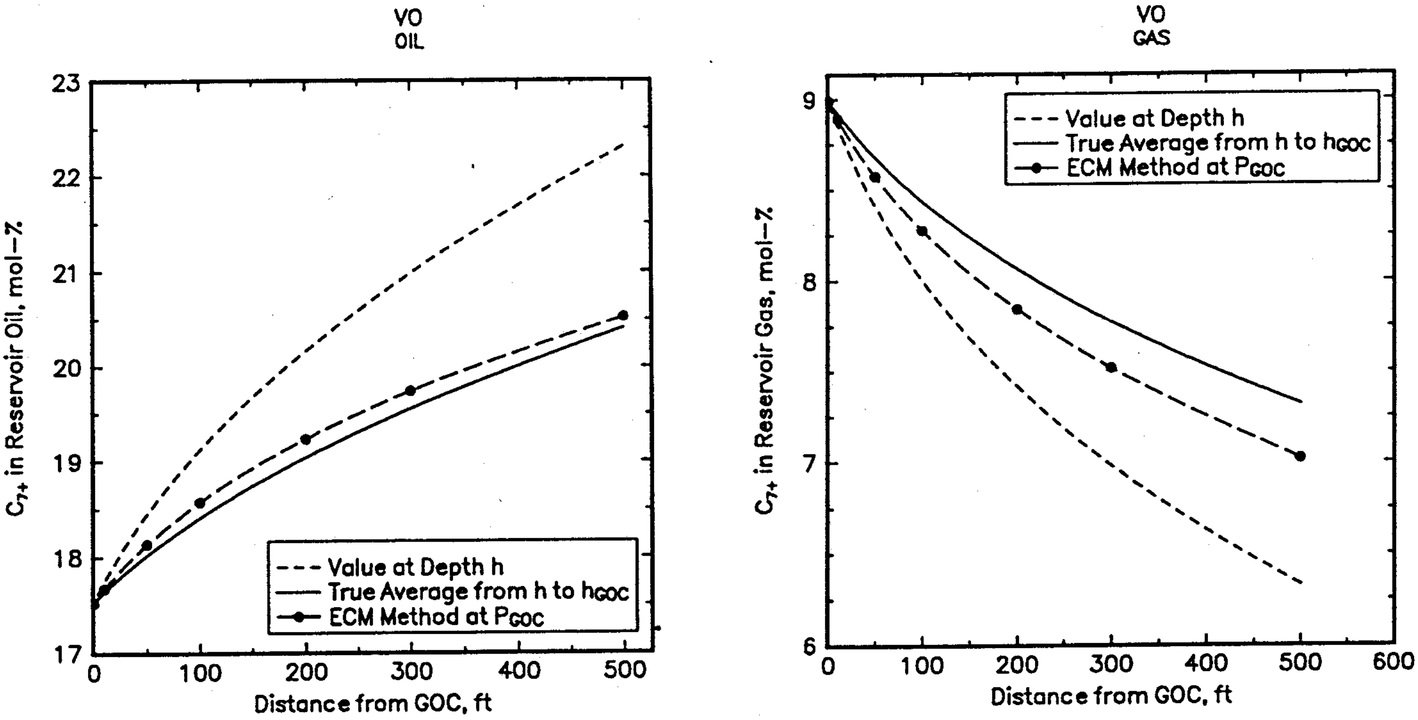

Fig. 15 ECM1 calculations (C_{7+} compositions) for the VO reservoir with vertical compositional gradient.

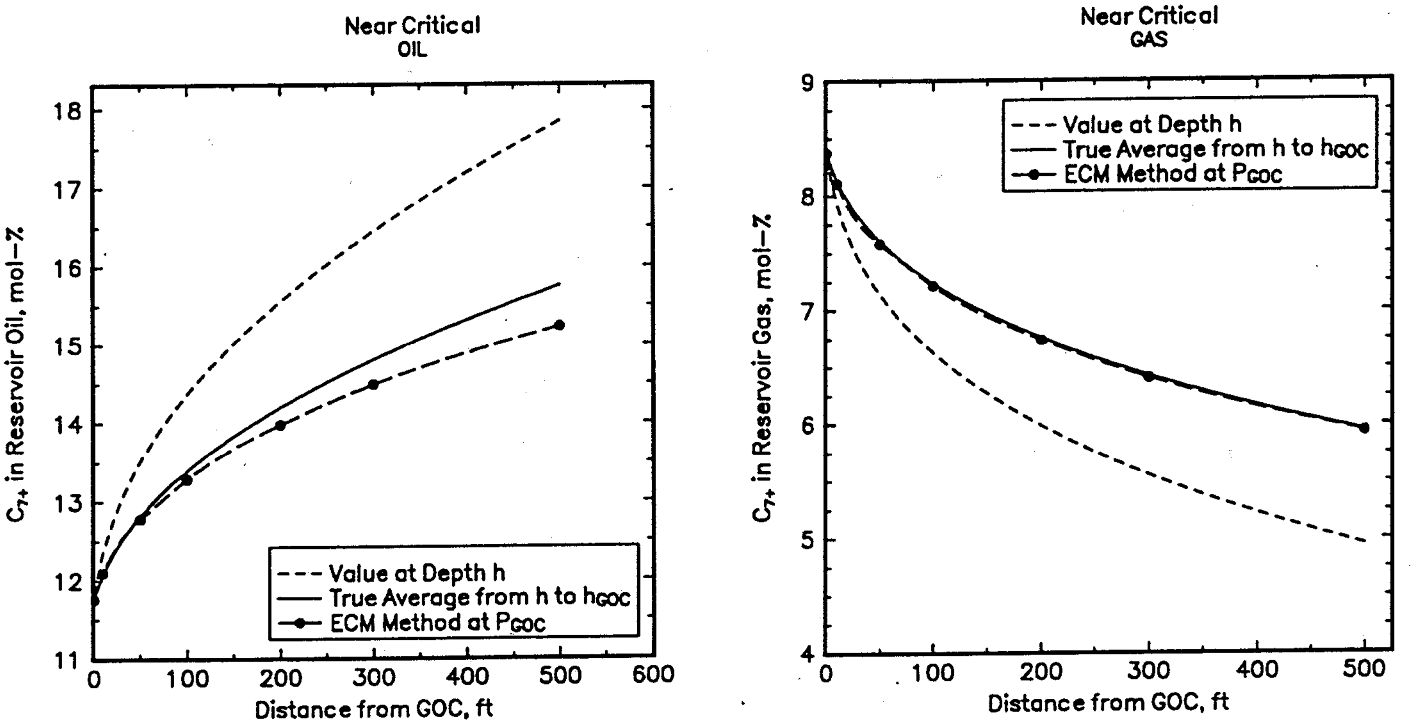

Fig. 16 ECM1 calculations (C_{7+} compositions) for the NCO reservoir with vertical compositional gradient.

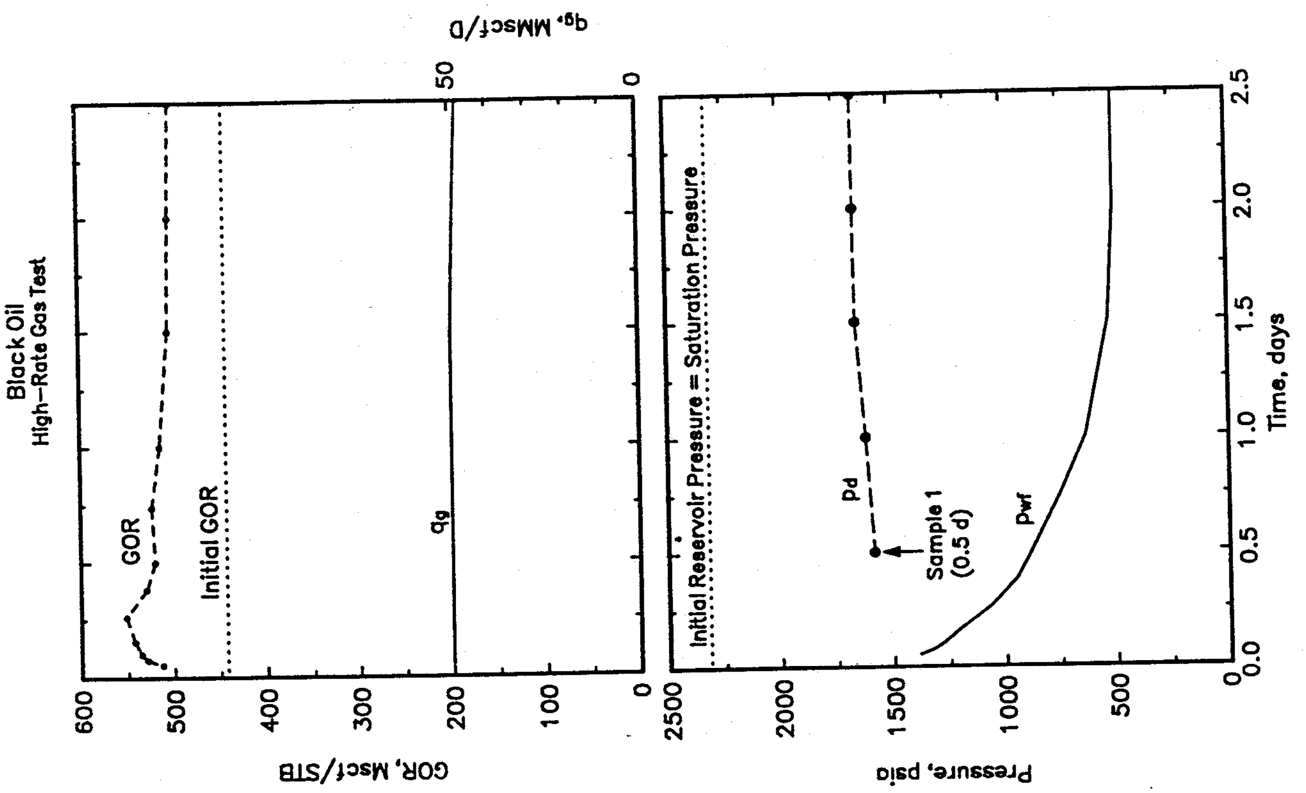

Fig. 17 Production performance during high-rate gas test, initially saturated BO reservoir.

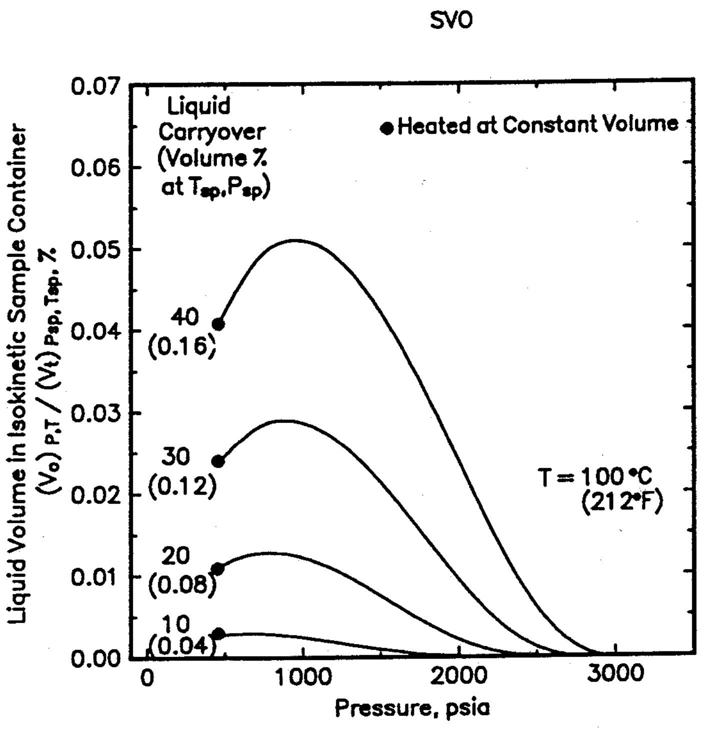

Fig. 18 Partial revaporization of isokinetic samples taken from separator gas stream of SVO insitu reservoir gas sample. Heated to 212°F.

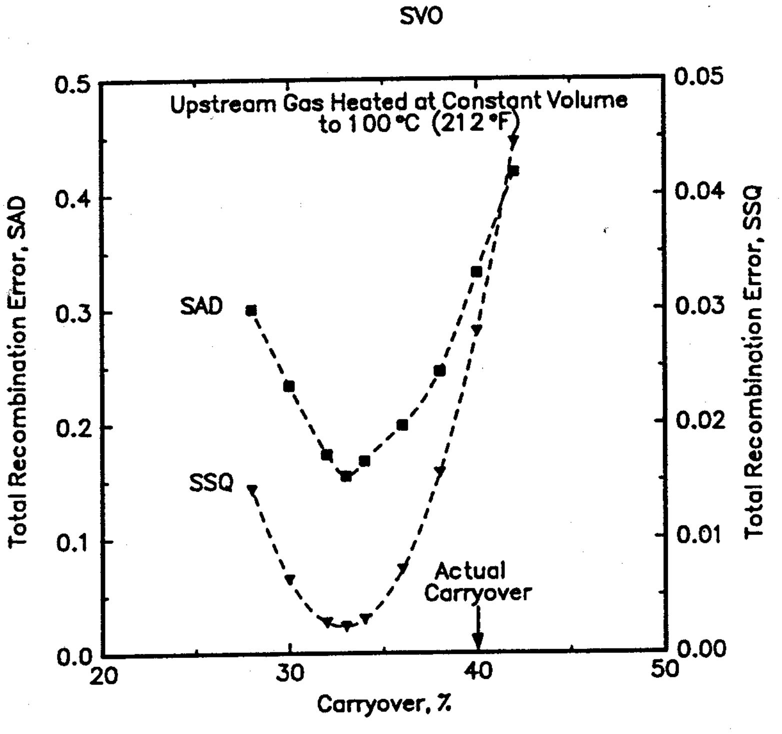

Fig. 19 Effect of incorrect sample taken from isokinetic container after heating (liquid carryover only partially revaporized).

TABLE 1

	Molar Composition of Reservoir Gas (DST 1 / DST 3 Initial Tests)				
	A	B	C	ECM(a)	ECM(b)
N2	0.755	0.756	0.750	0.756	0.750
CO2	3.615	3.615	3.592	3.614	3.634
C1	86.784	86.819	86.150	86.784	86.772
C2	2.578	2.578	2.568	2.578	2.595
C3	1.156	1.155	1.161	1.156	1.158
IC4	0.359	0.359	0.365	0.359	0.358
C4	0.565	0.565	0.579	0.565	0.563
IC5	0.293	0.293	0.309	0.294	0.292
C5	0.271	0.271	0.289	0.271	0.270
C6	0.444	0.443	0.496	0.444	0.441
C7+	3.178	3.146	3.742	3.179	3.168
C10+	1.336	1.311	1.583	1.336	1.334
C15+	0.330	0.315	0.381	0.330	0.330
C36+	0.013	0.011	0.013	0.013	0.013

A Original Reservoir Gas
B DST 1 Sample 1
C DST 1 Sample 1 Dewpoint Adjusted
ECM1 using DST 1 Sample 1 Gas with Oils:
(a) DST 3 Sample 1
(b) DST 3 Sample 1 Bubblepoint Adjusted

TABLE 2

	Molar Composition of Reservoir Oil (DST 1 / DST 3 Initial Tests)				
	A	B	C	ECM(a)	ECM(b)
N2	0.33	0.309	0.321	0.330	0.327
CO2	2.950	2.915	2.990	2.949	2.965
C1	51.430	49.637	51.377	51.425	51.385
C2	2.650	2.653	2.689	2.649	2.667
C3	1.570	1.591	1.577	1.570	1.573
IC4	0.580	0.591	0.578	0.580	0.579
C4	1.010	1.033	1.004	1.010	1.007
IC5	0.630	0.647	0.624	0.630	0.626
C5	0.620	0.638	0.614	0.620	0.616
C6	1.270	1.312	1.258	1.270	1.262
C7+	36.960	38.675	36.970	36.966	36.992
C10+	27.810	29.152	27.862	27.814	27.872
C15+	16.850	17.685	16.903	16.851	16.908
C36+	3.032	3.184	3.044	3.033	3.045

A Original Reservoir Oil
B DST 3 Sample 1
C DST 3 Sample 1 Bubblepoint Adjusted
ECM1 using DST 1 Sample 1 Gas with Oils:
(a) DST 3 Sample 1
(b) DST 3 Sample 1 Bubblepoint Adjusted

TABLE 3

	Molar Compositions of Reservoir Gas (DST 2 / DST 3 Initial Tests)									
	A	B	C	D	E	F	ECM(a)	ECM(b)	ECM(c)	ECM(d)
N2	0.755	0.757	0.740	0.745	0.756	0.750	0.755	0.759	0.758	0.756
CO2	3.615	3.618	3.555	3.562	3.605	3.600	3.615	3.593	3.609	3.610
C1	86.784	86.937	85.137	85.520	86.750	86.307	86.786	86.705	86.852	86.755
C2	2.578	2.578	2.550	2.557	2.576	2.576	2.578	2.562	2.575	2.575
C3	1.156	1.154	1.168	1.164	1.154	1.161	1.156	1.152	1.154	1.156
IC4	0.359	0.358	0.375	0.368	0.356	0.363	0.359	0.360	0.357	0.360
C4	0.565	0.563	0.602	0.584	0.558	0.573	0.565	0.567	0.561	0.566
IC5	0.293	0.292	0.336	0.311	0.283	0.300	0.293	0.296	0.288	0.294
C5	0.271	0.270	0.319	0.290	0.259	0.278	0.271	0.274	0.266	0.272
C6	0.444	0.440	0.583	0.496	0.409	0.461	0.444	0.453	0.431	0.447
C7+	3.178	3.036	4.635	4.402	3.294	3.631	3.177	3.277	3.149	3.210
C10+	1.336	1.228	1.942	2.118	1.552	1.640	1.335	1.380	1.341	1.351
C15+	0.330	0.270	0.428	0.559	0.409	0.430	0.330	0.334	0.330	0.332
C36+	0.013	0.006	0.010	0.013	0.010	0.010	0.013	0.013	0.013	0.013

A Original Reservoir Gas
B DST 2 Sample 1
C DST 2 Sample 1 Dewpoint Adjusted
D DST 2 Sample 2
E DST 2 Sample 2 Dewpoint Adjusted
F DST 2 Sample 3
ECM1 using DST 3 Sample 1 Oil with following Gases:
(a) DST 2 Sample 1
(b) DST 2 Sample 2
(c) DST 2 Sample 2 Dewpoint Ajusted
(d) DST 2 Sample 3

TABLE 4

	Molar Composition of Reservoir Oil (DST 2 / DST 3 Initial Tests)					
	A	B	ECM(a)	ECM(b)	ECM(c)	ECM(d)
N2	0.330	0.309	0.330	0.335	0.331	0.331
CO2	2.950	2.915	2.948	2.941	2.946	2.949
C1	51.430	49.637	51.391	51.809	51.475	51.564
C2	2.650	2.653	2.649	2.635	2.649	2.648
C3	1.570	1.591	1.570	1.562	1.569	1.569
IC4	0.580	0.591	0.580	0.579	0.578	0.580
C4	1.010	1.033	1.010	1.008	1.004	1.010
IC5	0.630	0.647	0.630	0.632	0.621	0.631
C5	0.620	0.638	0.620	0.623	0.609	0.621
C6	1.270	1.312	1.270	1.284	1.237	1.273
C7+	36.960	38.675	37.001	36.591	36.983	36.825
C10+	27.810	29.152	27.846	27.310	27.957	27.642
C15+	16.850	17.685	16.879	16.197	16.870	16.629
C36+	3.032	3.184	3.043	2.854	3.012	2.962
	A Original Reservoir Oil **B DST 3 Sample 1** **ECM1 using DST 3 Sample 1 Oil with Gases:** **(a) DST 2 Sample 1** **(b) DST 2 Sample 2** **(c) DST 2 Sample 2 Dewpoint Ajusted** **(d) DST 2 Sample 3**					

TABLE 5

	Molar Compositions of Reservoir Gas (DST 4 Initial Test with Coning)		
	A	ECM(a)	ECM(b)
N2	0.755	0.755	0.755
CO2	3.615	3.615	3.615
C1	86.784	86.784	86.784
C2	2.578	2.578	2.578
C3	1.156	1.156	1.156
iC4	0.359	0.359	0.359
C4	0.565	0.565	0.565
iC5	0.293	0.293	0.293
C5	0.271	0.271	0.271
C6	0.444	0.444	0.444
C7+	3.178	3.178	3.178
C10+	1.336	1.336	1.336
C15+	0.330	0.330	0.330
C36+	0.013	0.013	0.013
V_d/V_p %		95	78
	A Original Reservoir Gas **ECM1 using Produced Wellstream** **(a) DST 4 Sample 1 (1.0 day)** **(b) DST 4 Sample 2 (2.5 days)**		

TABLE 6

	Molar Composition of Reservoir Oil (DST 4 Initial Test with Coning)		
	A	ECM(a)	ECM(b)
N2	0.330	0.330	0.330
CO2	2.950	2.950	2.950
C1	51.430	51.429	51.428
C2	2.650	2.650	2.650
C3	1.570	1.570	1.570
iC4	0.580	0.580	0.580
C4	1.010	1.010	1.010
iC5	0.630	0.630	0.630
C5	0.620	0.620	0.620
C6	1.270	1.270	1.270
C7+	36.960	36.961	36.962
C10+	27.810	27.811	27.812
C15+	16.850	16.850	16.852
C36+	3.032	3.032	3.033
V_d/V_p %		95	78
	A Original Reservoir Oil **ECM1 using Produced Wellstream** **(a) DST 4 Sample 1 (1.0 day)** **(b) DST 4 Sample 2 (2.5 days)**		

TABLE 7

	Molar Composition of Reservoir Oil (MGC Depletion)					
	A	B	C	D	E	F
N2	0.330	0.315	0.369	0.307	0.329	0.272
CO2	2.950	3.017	2.759	3.066	2.958	3.205
C1	51.430	51.348	51.861	51.092	51.411	51.166
C2	2.650	2.716	2.416	2.750	2.659	2.896
C3	1.570	1.581	1.529	1.602	1.574	1.596
IC4	0.580	0.576	0.609	0.581	0.581	0.562
C4	1.010	1.000	1.085	1.009	1.011	0.970
IC5	0.630	0.620	0.706	0.620	0.630	0.596
C5	0.620	0.610	0.698	0.608	0.619	0.586
C6	1.270	1.250	1.422	1.231	1.267	1.207
C7+	36.960	36.968	36.547	37.134	36.960	36.946
C10+	27.810	27.887	26.952	28.182	27.826	28.007
C15+	16.850	16.928	16.141	17.288	16.872	17.049
C36+	3.032	3.049	2.894	3.142	3.037	3.073

A Original Reservoir Oil
B Sample 1 Bubblepoint Adjusted
C Sample 2 Bubblepoint Adjusted
D ECM1: Sample 2
E ECM2: Sample 2
F Undersaturated Sample Bubblepoint Adjusted

TABLE 8

	Molar Gas Composition (MGC Depletion)						
	A	B	C	D	E	F	G
N2	0.755	0.764	0.766	0.754	0.753	0.758	0.754
CO2	3.615	3.632	3.610	3.622	3.624	3.611	3.588
C1	86.784	87.529	87.325	86.805	86.775	86.805	86.342
C2	2.578	2.579	2.561	2.584	2.586	2.574	2.561
C3	1.156	1.147	1.141	1.158	1.159	1.154	1.154
IC4	0.359	0.354	0.354	0.359	0.360	0.359	0.361
C4	0.565	0.554	0.556	0.565	0.566	0.564	0.570
IC5	0.293	0.284	0.288	0.293	0.293	0.293	0.299
C5	0.271	0.262	0.266	0.270	0.271	0.271	0.278
C6	0.444	0.420	0.433	0.441	0.443	0.444	0.464
C7+	3.178	2.474	2.701	3.148	3.171	3.168	3.630
C10+	1.336	0.835	0.964	1.321	1.333	1.328	1.620
C15+	0.330	0.110	0.139	0.328	0.330	0.328	0.407
C36+	0.013	0.001	0.001	0.013	0.013	0.013	0.008

A Original Reservoir Gas
B Sample 1
C Sample 2
D ECM1: Sample 1 Gas/ECM2 Sample 2 Oil (V_o/V_g)= 0.5
E ECM1: Sample 1 Gas/ECM2 Sample 2 Oil (V_o/V_g)= 0.9
F ECM1: Sample 2 Gas/ECM2 Sample 2 Oil (V_o/V_g)= 0.5
G ECM2 (modified): Sample 2 Gas without reservoir oil

TABLE 9

	Molar Composition of Reservoir Oil (VO Depletion)				
	A	B	C	D	E
CO2	0.956	0.949	0.948	0.954	1.006
N2	0.231	0.261	0.204	0.228	0.194
C1	62.537	65.098	59.669	62.155	61.801
C2	7.933	7.815	7.677	7.913	8.309
C3	4.202	4.159	4.129	4.201	4.249
IC4	0.923	0.957	0.911	0.923	0.878
C4	2.101	2.214	2.086	2.103	1.968
IC5	0.762	0.850	0.759	0.763	0.685
C5	1.134	1.280	1.130	1.136	1.012
C6	1.694	1.931	1.690	1.696	1.510
F1	5.071	5.475	5.072	5.076	4.661
F2	5.242	4.600	5.255	5.252	5.246
F3	4.054	2.665	4.502	4.162	4.545
F4	2.194	1.217	3.866	2.380	2.721
F5	0.967	0.529	2.103	1.057	1.213
C7+	17.528	14.485	20.798	17.928	18.387

A Original Reservoir Oil
B Sample 1 Bubblepoint Adjustment
C ECM1 Sample 1
D ECM2 Sample 2
E Undersaturated Oil Bubblepoint Adjustment

TABLE 10

	Reservoir Gas Composition (BO Very Lean Gas Carryover)				
	A	B	C	D	E
N2	1.58246	1.58289	1.58583	1.58243	1.58173
CO2	0.59625	0.59634	0.59725	0.59626	0.59644
C1	92.69770	92.71723	92.87722	92.69767	92.69748
C2	3.66008	3.66010	3.66376	3.66014	3.66227
C3	0.38920	0.38907	0.38875	0.38921	0.38948
IC4	0.34046	0.34021	0.33887	0.34046	0.34061
C4	0.08571	0.08562	0.08508	0.08571	0.08574
IC5	0.11749	0.11726	0.11535	0.11748	0.11743
C5	0.02319	0.02314	0.02264	0.02319	0.02318
C6	0.12099	0.12042	0.11333	0.12098	0.12069
C7+	0.38652	0.36771	0.21192	0.38645	0.38496
F3+	0.13494	0.12021	0.03073	0.13490	0.13452
F8+	0.00008	0.00000	0.00000	0.00008	0.00008

A Original Reservoir Gas
B Gas Sample 1
C Separator Gas from Sample 1
D ECM1: Sample 1 / Original Reservoir Oil
E ECM1: Separator Gas from Sample 1 / Original Reservoir Oil

TABLE 11

	Reservoir Gas Composition (MGC DST 2 Carryover / DST 3)				
	A	B	C	ECM(a)	ECM(b)
N2	0.755	0.757	0.763	0.756	0.755
CO2	3.615	3.618	3.639	3.614	3.618
C1	86.784	86.937	87.551	86.785	86.825
C2	2.578	2.578	2.587	2.578	2.581
C3	1.156	1.154	1.149	1.156	1.156
IC4	0.359	0.358	0.352	0.359	0.358
C4	0.565	0.563	0.550	0.565	0.563
IC5	0.293	0.292	0.277	0.293	0.291
C5	0.271	0.270	0.253	0.271	0.269
C6	0.444	0.440	0.391	0.444	0.437
C7+	3.178	3.036	2.489	3.178	3.145
C10+	1.336	1.228	0.984	1.336	1.327
C15+	0.330	0.270	0.215	0.330	0.329
C36+	0.013	0.006	0.005	0.013	0.013

A Original Reservoir Gas
B DST 2 Sample 1
C DST 2 Sample 1 with 20 % Carryover
ECM1 (V_o/V_t=0.7) using DST 3 Sample 1 Oil with Gases:
(a) DST 2 Sample 1
(b) DST 2 Sample 1 with 20% Carryover

TABLE 12

	Reservoir Oil Composition (MGC DST 2 Carryover / DST 3)		
	A	ECM(a)	ECM(b)
N2	0.330	0.330	0.329
CO2	2.950	2.949	2.951
C1	51.430	51.415	51.347
C2	2.650	2.649	2.653
C3	1.570	1.570	1.572
IC4	0.580	0.580	0.580
C4	1.010	1.010	1.008
IC5	0.630	0.630	0.627
C5	0.620	0.620	0.616
C6	1.270	1.270	1.255
C7+	36.960	36.977	37.063
C10+	27.810	27.823	27.988
C15+	16.850	16.860	17.018
C36+	3.032	3.036	3.070

A Original Reservoir Oil
ECM1 (V_o/V_t=0.7) using DST 3 Sample 1 Oil with Gases:
(a) DST 2 Sample 1
(b) DST 2 Sample 1 with 20% Carryover