ORIGINAL

PHASE BEHAVIOUR ASPECTS OF RESERVOIR OPTIMIZATION

By

F. Brent Thomas, Hycal Energy Research Laboratories Ltd.
Zhou Xue Long, Hycal Energy Research Laboratories Ltd.
D. Brant Bennion, Hycal Energy Research Laboratories Ltd.
Douglas W. Bennion, Hycal Energy Research Laboratories Ltd.

Introduction

Any oil or gas recovery process involves a combination of phase behaviour and fluid flow characteristics. Many times the day to day field operations tend to mask the importance of these phenomena and often global indicators (production rates, compositions, and pressures) are interpreted and responded to without accounting for phase behaviour influences.

This paper discusses four areas where phase behaviour can and should be used to investigate reservoirs in order to define operating strategies which will optimize performance. The four areas are:

1. How to obtain representative reservoir fluids in order to assess optimization strategies.
2. What influence can judicious choice and orientation of separator conditions have on oil yield.
3. Insights gained by phase behaviour analysis pertaining to mature miscible flood strategies.
4. Phase behaviour measurements for solid precipitation mitigation.

These four themes will now be discussed sequentially detailing the procedures and technologies that have been developed and are in daily use by the authors.

Representative Reservoir Fluids

To assess most operating strategies, representative reservoir fluids need to be used in the evaluation. Whether core flood experiments or detailed fluid phase behaviour are contemplated, much of the quality of the results depends on the reservoir fluid used.

Initially a comment should be made regarding the type of sampling which should be performed. Should bottomhole samples (BHS) be requested or are surface separator samples equally valid? Since bottomhole samples are more expensive, if good quality surface samples are possible then they would be recommended from an economic perspective. However, for some cases, only bottomhole samples will suffice. Those cases are fairly restricted, but if the oil has a high pour point temperature (greater than surface temperature) then bottomhole samples would be recommended. In addition if solids precipitate, as in asphaltene precipitation, then bottomhole sampling may be the only way to keep the whole oil in a homogeneous phase. If the solid phase is allowed to separate in the well bore then the PVT properties of the reservoir fluid may be significantly altered (one would usually expect an upgrading effect as the heavier compounds leave the liquid phase), where P_{sat}, GOR and transport properties will be affected.

Similarly gas condensate systems sometimes exhibit extreme sensitivity with respect to pressure and temperature conditions and it is difficult to get representative liquid and gas samples unless one has access to a large separator, where large fluid volumes have been averaged, and where stable flow rates are observed. Sometimes BHS are subject to these sensitivities and their results need to be quantified and closely scrutinized. Depending upon the BHS tool used and the condition of the reservoir fluid, BHS can be difficult to capture and high failure rates have been observed (from our experience as many as half the BHS taken on some projects have been observed to be unrepresentative of the reservoir fluid - on one project 3 out of 6 samples showed inconsistent GOR's and saturation pressures). For gas condensate systems there is no guarantee that a BHS will be superior to surface samples and therefore all results need to be closely examined.

In light of the previous discussion it must be recognized that one must always be vigilant in performing quality control of whatever sampling program has been implemented, whether surface or BHS. One technique which can be effectively used to obtain representative fluids for use in laboratory studies will now be discussed. With the exception of high pourpoint oils and those showing solids precipitation effects, surface samples almost always lead to representative recombined oil samples if the following steps are used:

1. Perform GOR Versus Flowrate Sensitivity Test

Perform a GOR versus flowrate sensitivity test to determine if one is observing coning or gas liberation effects. Figure 1 shows the standard relationship which one might expect for such a well. For the best opportunity to obtain representative samples, the surface separator should be operated at a condition below the threshold ΔP or flowrate. If operated above, then the likelihood of having excess gas (over and above the solution GOR) along with a leaner gas phase is much increased.

2. Use Equation of State Modeling

Use an Equation of State (EOS) or correlation to check the adequacy of the gas phase sampled. Even if the separator has been stabilized, many times the sampled gas phase may have the wrong composition, particularly for depleted oil reservoirs, where the current reservoir pressure is below the original bubblepoint and where the liquid is saturated. In these situations what can be done if the gas phase is inconsistent with the sampled oil phase and how can you discern if the sampled gas is inadequate? This will be shown by way of example.

The situation is shown in Figure 2 wherein the reservoir was initially undersaturated and during primary depletion a secondary gas cap had formed. From early in the reservoir's life, a reservoir fluid composition was known and the EOS model was tuned to match the bubblepoint pressure of 15680 kPag (2300 psig) at 75°C (167°F). Figure 3 shows the flow chart used to estimate the separator gas that would be expected and Table 1 shows the comparison. Based on the separator gas compositions, there is a significant amount of excess methane in the sampled gas which is probably the result of gas cap gas or free gas entrainment into the separator. Using the separator gas resulted in a saturation pressure much higher than the maximum reservoir pressure for the appropriate GOR. In order to reduce the P_{sat} to an acceptable level the GOR had to be decreased by 20% thus altering the transport properties and compositions of the oil.

3. Blend Optimal Separator Gas

In order to obtain the correct recombined oil, the procedure outlined in Figure 4 was followed. In this manner a separator gas composition was calculated that would be blended to combine with separator oil to obtain the original reservoir fluid composition. Blending the gas as predicted by the EOS following the schematic of Figure 4 resulted in a comparison of original reservoir fluids (original versus recombined) as shown in Table 2. To obtain the current in situ liquid phase the recombined oil of Table 2 can be depressurized to reservoir conditions and one has a representative oil phase for use in whatever testing is desired. If the separator gases and oils had been recombined as received, one would have obtained a low GOR oil with a higher viscosity for the same saturation pressure, due to the presence of gas cap or free gas in the separator gas.

The main advantage of using these techniques over the BHS is the cost. For very small volumes this procedure may only be 10 to 15% less expensive than the BHS. For reservoir volumes over 6 litres, such as would be required for displacement test, for example, this procedure results in savings of over 50% compared to BHS. In most cases, when a reservoir is sampled below the bubblepoint the oil is in equilibrium with a gas different than the initial oil was in equilibrium with. Consequently bottom hole samples may not give representative results.

Shrinkage Minimization

An obvious method of increasing revenues is to maximize the sales liquid volumes for each unit volume produced from the reservoir. Oftimes the conditions which the produced hydrocarbons are subjected to between the wellhead and the stock tank, particularly for mature hydrocarbon miscible floods exhibiting solvent breakthrough and high-GOR oils, can result in liquid shrinkage of up to 10 volume %. If this shrinkage could be reduced by only 2.5 to 3 volume % then for some operations significant increases in cashflow could result. An example will be provided later in this paper based on measured shrinkage changes. In order to determine the optimal sequence of processing conditions one must be able to measure small volumetric changes. Standard laboratory equipment is inadequate to accurately measure the subtle volumetric changes which occur when production stream unit operations are modified. Usually laboratory techniques include the use of a "Ruska" or a "Jerguson" cell which have calibration constants from 3.3 to 10 cm^3/cm; that is for every cm travelled the associated volume is 10 cm^3. Common visual pressure vessels have a maximum internal volume of 100 cm^3 and to allow for pressure manipulation and adequate expansion, less than 50 cm^3 is usually used. Therefore, if one can read interfaces accurately to ±0.5 mm one may still have a ±1 cc or about 2 volume % error. Oftimes curved interfaces make the volumetric measurements even less accurate and therefore systematic error dominates the standard analytical techniques and masks the subtleties of process conditions and their impact on shrinkage.

To respond to this deficiency, Hycal has designed a set of equipment which is accurate to ±0.40 volume % and has tested it on effluent from a mature miscible flood. Figure 5 presents a standard process stream including inlet surge vessel, free water knockout (FWKO), treater and gas boot. Conditions were altered and shrinkage dependencies determined. Table 3 presents some comparisons of volumes and conditions for this oil system. Implementing a chiller at the free water knockout appears to provide significant shrinkage improvement. A multicontacting procedure provides a better final stock tank oil API gravity than the initial orientation but not as good as with the FWKO chiller. Different gas phase components are responsible for these influences and gas volumes evolved show some of these changes. A few tests can be done like this and then a volume-modified EOS tuned to fit these data. The EOS can then be used to screen many other scenarios and final optimal process orientation can be quantified and confirmed with additional experimentation. Table 3 presents an example of the increased revenues due to implementation of such a separator optimization scheme. Based on the parameters measured here in the increased revenues of a field producing 1000 m^3/day of reservoir fluid would be in excess of $1.69 million per year. With these revenues being lost and never able to recover (since once produced they are gone) they constitute a direct lack of efficiency of turning production into cashflow. There may be many reservoirs in Canada wherein the same production rates could result in millions of dollars per annum of increased revenue for an extremely small investment by comparison. Screening oils for this potential is recommended.

Mature Miscible Floods

Conventional P-x diagrams have been used for many years to infer the miscible response of the reservoir fluid of interest with an injection gas. Figure 6 presents such a response for a light oil. At reservoir pressure the oil/solvent mixture exhibited a GOR of 500 m^3/m^3 while the reservoir fluid had a GOR of approximately 350 m^3/m^3. Many more tests were performed on this fluid and the miscible design was implemented in the field in 1989. Now more than three years later one of the wells is producing at a GOR of close to 900 m^3/m^3. The questions to answer are: "Does this respond to a single or two-phase system downhole?" and "What would be the influence of starting to drop the pressure by decreasing the voidage replacement ratio and recovering some of the solvent which had been injected?".

There are many parameters which impact the response to such questions but based on phase behaviour considerations alone valuable insight can be gained. To determine whether the system is single or two-phase downhole some experimentation was performed wherein multicontacting in a manner consistent with the mechanism was done (forward contacting in this case). Just from the conventional P-x diagram (Figure 6) one would conclude that a GOR of 900 m^3/m^3 would indicate a two-phase system. However, does this result really represent downhole conditions? It must be remembered that the P-x response in Figure 6 results from forcing all the gas into solution by increasing the pressure. However, in the field the pressure will never rise above the reservoir pressure (injection pressure) and therefore much of the data obtained from conventional P-x diagram data lies in unphysical pressure space and hence all the transport properties measured at those pressures will never be obtained. More appropriately, multicontacting operations performed at reservoir pressure provide a much better indication of compositions and transport properties. The procedure employed was therefore to contact the solvent and oil in a manner consistent with the mechanism and then to analyze the change in composition of the leading edge gas phase. Once asymptoted, this upper phase was then used to contact the reservoir fluid and the P-x response measured. Figure 8 shows these results compared to the conventional P-x response. The cricondenbar is much lower than that of the conventional P-x diagram and confirms that the MMP (due to multicontact miscibility - from the development of a zero IFT zone) is below 25 MPa. More important in answering the question regarding the status of the fluid downhole (one or two phases) however is the fact that the reservoir pressure is 28 MPa and the GOR of 988 m^3/m^3 has been observed to have a Psat of 25 MPa. Therefore it is possible to have GORs higher than those produced in the field and still have single phase operation despite the fact that the conventional P-x diagram indicates that two phases should result. It must be observed that these high GORs correspond to dewpoint systems which for this light oil are very extensive (critical point below 50% solvent on P-x diagram) and are efficient in contacting the reservoir fluid. The high GOR-producing regions may correspond to two possible scenarios:

1. The leading edge of the displacement after which the transition zone and then injection gas will breakthrough.
2. A bypassing gas which is vaporizing a sufficient amount of oil and creating a very rich gas (200 bbl/MMSCF) from a dry injection gas.

From phase behaviour alone one knows that the fluids produced from the separator can exist as a single phase downhole with either of the above scenarios being possible. Figure 9 shows the ternary diagram representation of the compositions. This diagram confirms that downhole compositions can be produced in the laboratory at reservoir pressures which can not be done with only P-x diagram procedures.

The second question concerned the effect of decreasing pressure on the miscible displacement. Some of the influences which need to be considered in order to answer this are: solubility, condensation of intermediate compounds and extraction of heavier intermediates. Figure 7 showed a P-x response where the intersection of the bubblepoint curve with the reservoir pressure defines the solubility limit. Once the solubility limit is reached any further gas injection will result in an exchange of components and continuing GOR changes at reservoir pressure but condensation of intermediates (C_5^+) into the oil may occur while the liquid gives up light intermediates (C_2 - C_4). This mechanism is responsible for the development of miscibility as is shown by the decrease in IFT as a function of contact number (Figure 10). Figure 11 also shows the increasing content of the C_2 to C_4 fraction in the upper phase as is consistent with a forward contacting system. What happens when the pressure is decreased even if only by 100 psi? Figure 12 shows that much of the gas evolved is methane which would tend to dilute the solvent which has been developed. Depending upon the amount of oil left in the reservoir compared to the solvent injected this effect can be significant. Figure 13 shows the change in IFT which could result if significant oil remains which has been either bypassed or yet to be recovered. The IFT may increase drastically due to dilution of the miscible slug by premature depressurization even though this represents only a 100 psi reduction. The larger the pressure decrease the more the dilution and the more deleterious the effect.

Rules of thumb which arise from this analysis are:

1. Before depressurizing the mature miscible flood in order to recover expensive solvent, calculate what ratio of oil to solvent is in place.
2. Determine what the impact of IFT will be due to dilution of the solvent with evolving gas.
3. If you do not have obvious solvent breakthrough, do not consider depressurization even if the current operating pressure is considerably above the MMP - the components transferred to effect the development of miscibility will not be the same ones that will evolve when the pressure is reduced.

Solids Precipitation

Solid precipitation, including compounds ranging from waxes to asphaltenes, are a problem in many reservoirs world wide. The impact of solid precipitation is seen in both in situ permeability reduction, such as in Figure 14 as well as in plugging tubing strings and requiring frequent workovers. Indeed some production well precipitation is so serious that the wells may be shut in 10 to 20% of the time. What are some techniques which can be used to reduce this problem? Moreover, what are the available laboratory techniques which can be used to asses potential problems and remedies?

On method to mitigate in situ solid precipitation due to the injection of hydrocarbon gases or CO_2 is to asses what gases will result in the most serious asphalt precipitation. This can be evaluated in a laboratory by using an apparatus such as that shown in Figure 15. The equipment represents a common design with the exception of the laser cell and source. The injection gas and oil are mixed in the visual cell at increasing gas mole ratios. At each ratio the fluid is observed and then laser light is transmitted through the fluid. Since the gases added are more optically transparent than the oil, the transmission through the fluid increases with mole fraction of gas added. Once the solids begin to flocculate and precipitate some of the light is reflected providing a decrease in transmission. Thus the incipient precipitation point is determined. Figure 16 presents an example of this. Using this technique precipitation dependence on gas composition can be assessed. Figure 17 presents data that were generated for one oil system. With these data optimization can be performed to select the best precipitation criteria along with the recovery considerations.

Another recent development concerns the incorporation of chemicals, designed to defer incipient precipitation conditions, in the solvent injected. A company, who wishes their product and their name to remain confidential at this time, contracted the authors to assess the influence of an additive on precipitation limits. A high pressure titration was performed with injection gas and the incipient precipitation limit ascertained. An equilibrium amount of the additive was then included in the injection gas and a titration performed. Figure 18 shows that the precipitation point was delayed by about 10 to 15 mole %. What influence does that have if precipitation will occur anyway? The plot at the bottom of Figure 18 shows the pressure response. Since the reservoir pressure is higher than the saturation pressure at x_1, sufficient gas solubility will occur to precipitate solids. However by a delay of 10 to 15% (x_2 - x_1) the pressure response is sufficient so that the saturation pressure at x_2 is higher than $P_{reservoir}$; thus the reservoir pressure is insufficient to solubilize sufficient gas to precipitate. After that, depending upon the compositions of the oil and gas this may totally negate solid precipitation or at least reduce the problem. The same procedure was also used to determine if xylene would have a similar influence. It did not thus alluding to two possible mechanisms: one (the xylene) depending upon solubility of the solid in the additive and the other (additive) depending upon the synergism that the additive produces with the crude oil and not upon the solubility of asphalt in the additive itself. These parameters were scoped out for use in the injection gas.

Production well applications have yet to be evaluated but these are in progress at time of writing. The production well situation is different and is described in Figure 19. In this case the solids form in the production well and are usually dominated by temperature and pressure decreases as the oil rises towards the surface. Temperature is usually the stronger driving force. The same laser equipment has been used to perform high pressure cloud point determination. Cloud points are detected by monitoring transmission through the oil phase while the temperature is decreased by a cold glycol circulation jacket. A thermocouple monitors instantaneous liquid temperature and the transmission voltage is plotted versus temperature. There is an initial gradual slope associated with increasing optical density as temperature is lowered. Once the cloud point is achieved then there is a rapid decrease in voltage from the photodiode. The equipment has been tested with fluids of known cloud point and the laser-measured ones are usually 0.5 to 1.0°C higher due to the more sensitive nature of the detection system. Figure 20 shows how the cloud point may change in the presence of the additive, these being performed at time of writing. If the cloud point suppression (ΔT) is greater than $T_{reservoir}$ - $T_{surface}$ then the precipitation problems can be deferred until surface at which point the solids can be treated on a continuous basis avoiding costly downtime.

Preliminary experimentation has shown that the equipment is able to measure these parameters at pressures up to 4500 psig. The possible chemicals are presently being evaluated.

Overview

1. Procedures were shown for obtaining representative recombined oils. In most cases these techniques provide equally as representative reservoir fluids as any other method.

2. Detailed separator design has been shown to result in significant increased revenue for very little capital investment.

3. Analysis of phase behaviour associated with a mature miscible flood has shown that one needs to be extremely careful in decreasing operating pressure even though the pressure may be above the MMP. Dependence of specific parameters on pressure has been shown.

4. Novel techniques have been shown for assessing asphalt precipitation problems. Equipment has been developed for determining most parameters associated with both in situ and production well precipitation problems. Proprietary organic chemical has been shown to have some merit for delaying asphalt precipitation.

TABLE 1
COMPARE SEPARATOR GAS WITH THE EOS-GENERATED SEPARATOR GAS

Comparison of Separator Gases		
Component	**EOS**	**Sampled**
N_2	0.0059	0.0146
CO_2	0.0512	0.0446
H_2S	0.0064	--
C_1	0.6387	0.7309
C_2	0.1362	0.0986
C_3	0.0907	0.0641
C_4	0.0554	0.0392
C_5	0.0155	0.0090
C_6	--	--

TABLE 2

Comparison of Recombined Oils			
Component	**Using Synthetic Separator Gas**	**Original Recombined Oil**	**Using Sampled Separator Gas**
N_2	0.0044	0.0032	0.0089
CO_2	0.0275	0.0289	0.0219
H_2S	0.0039	0.0038	0.0009
C_1	0.3522	0.3500	0.3643
C_2	0.0747	0.0780	0.0699
C_3	0.0622	0.0576	0.0456
$i\text{-}C_4$	0.0175	0.0142	0.0103
$n\text{-}C_4$	0.0348	0.0295	0.0204
$i\text{-}C_5$	0.0112	0.0134	0.0076
$n\text{-}C_5$	0.0124	0.0137	0.0095
C_6^+	0.3992	0.4077	0.4407
GOR (m^3/m^3)	82.5	82.0	68.0

TABLE 3
SHRINKAGE OPTIMIZATION REVENUES BASED ON 1000 m^3/day OF RESERVOIR FLUID

	Initial Design	**Optimized**
STO Density (kg/m^3)	830	823
Overall Shrinkage (%)	8.3	4.8

Benefits:

1. Due to density reduction \$0.15/(kg/m^3) over 825 per m^3 savings of \$0.75/m^3 of oil which equates to \$237,750/year.

2. Due to shrinkage reduction (8.3 - 4.8)/100 x 1000 m^3/day equates to 35 m^3 oil per day based on \$18/bbl this results in revenues of \$1.45 million/year.

FIGURE 1
GOR vs FLOWRATE (delta P) FOR GAS CONING OR GAS LIBERATION WELL

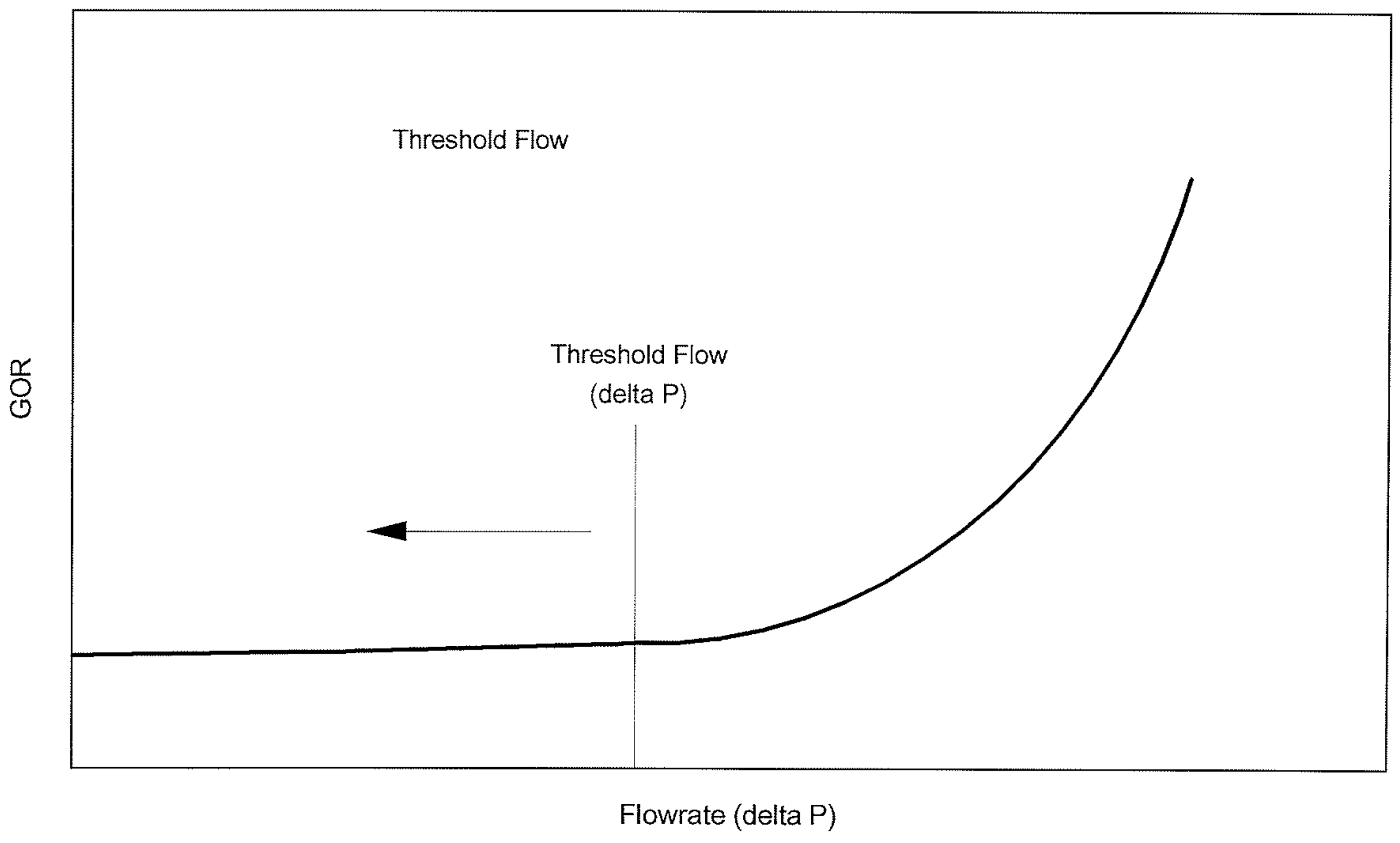

FIGURE 2

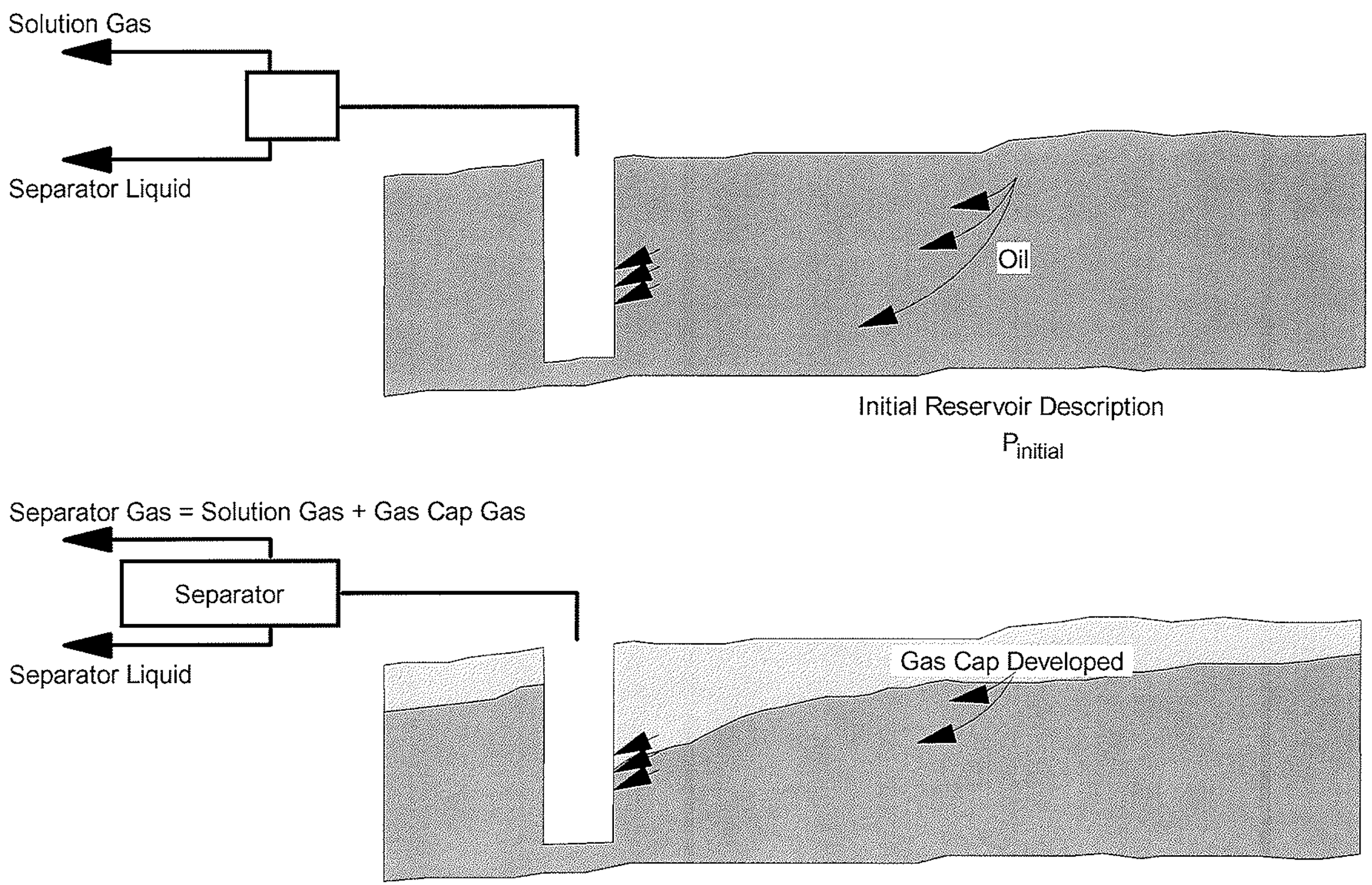
Solution Gas
Separator Liquid
Oil
Initial Reservoir Description
$P_{initial}$
Separator Gas = Solution Gas + Gas Cap Gas
Separator
Separator Liquid
Gas Cap Developed

FIGURE 3
PERFORM EOS SCREENING CALCULATIONS

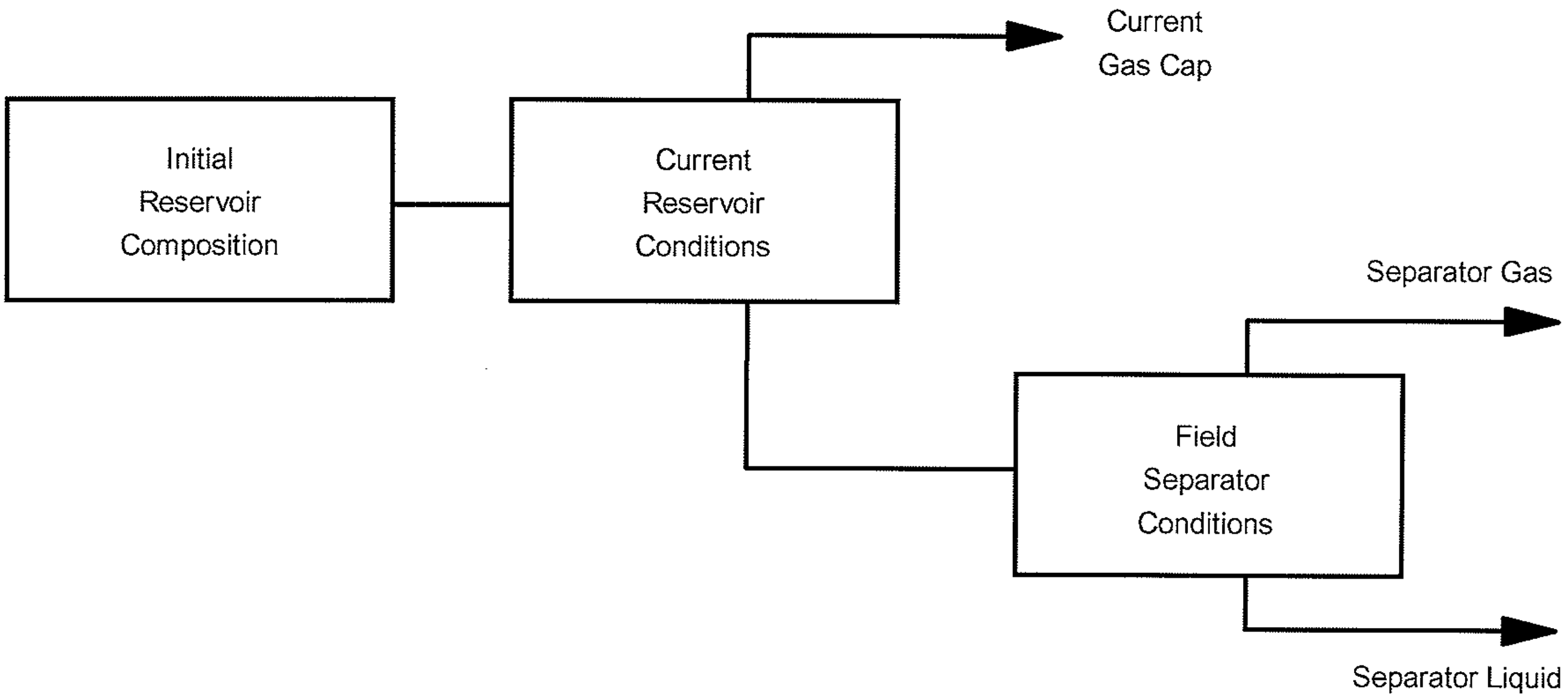

FIGURE 4
BLEND OPTIMAL SEPARATOR GAS TO ACCOMPANY SEPARATOR LIQUID

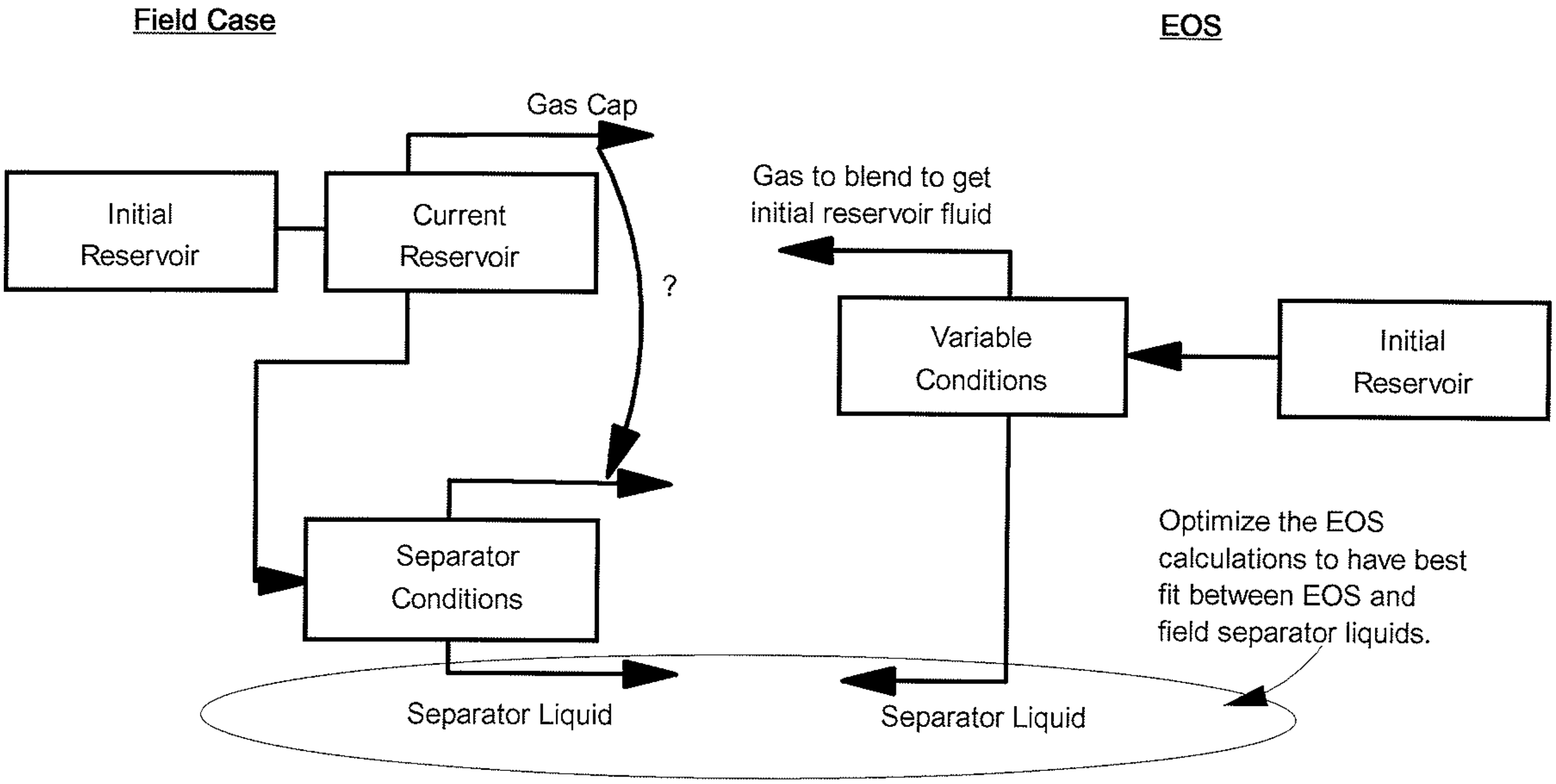

FIGURE 5
TYPICAL SURFACE PROCESSING OPERATIONS

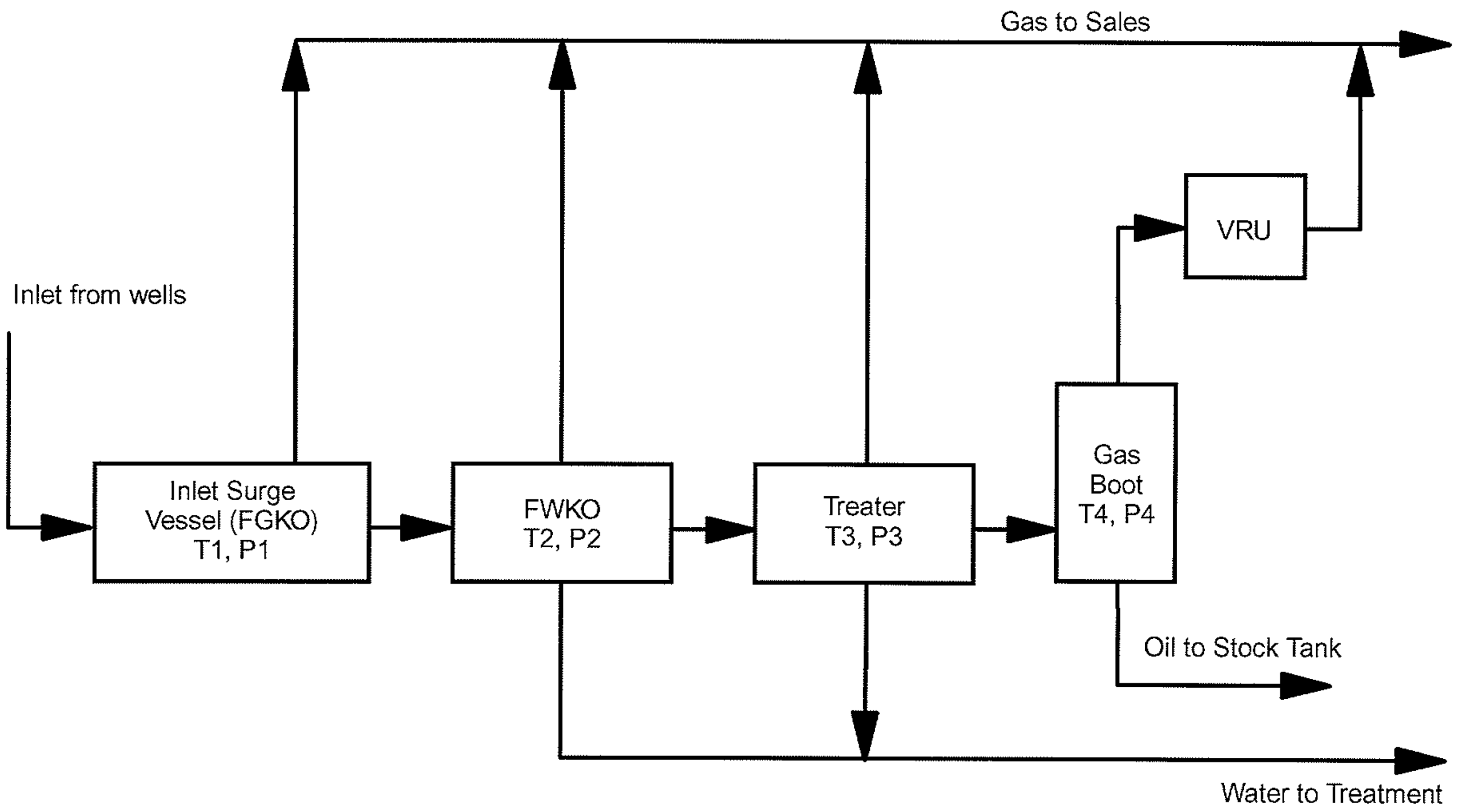

FIGURE 6
CONVENTIONAL P-x DIAGRAM

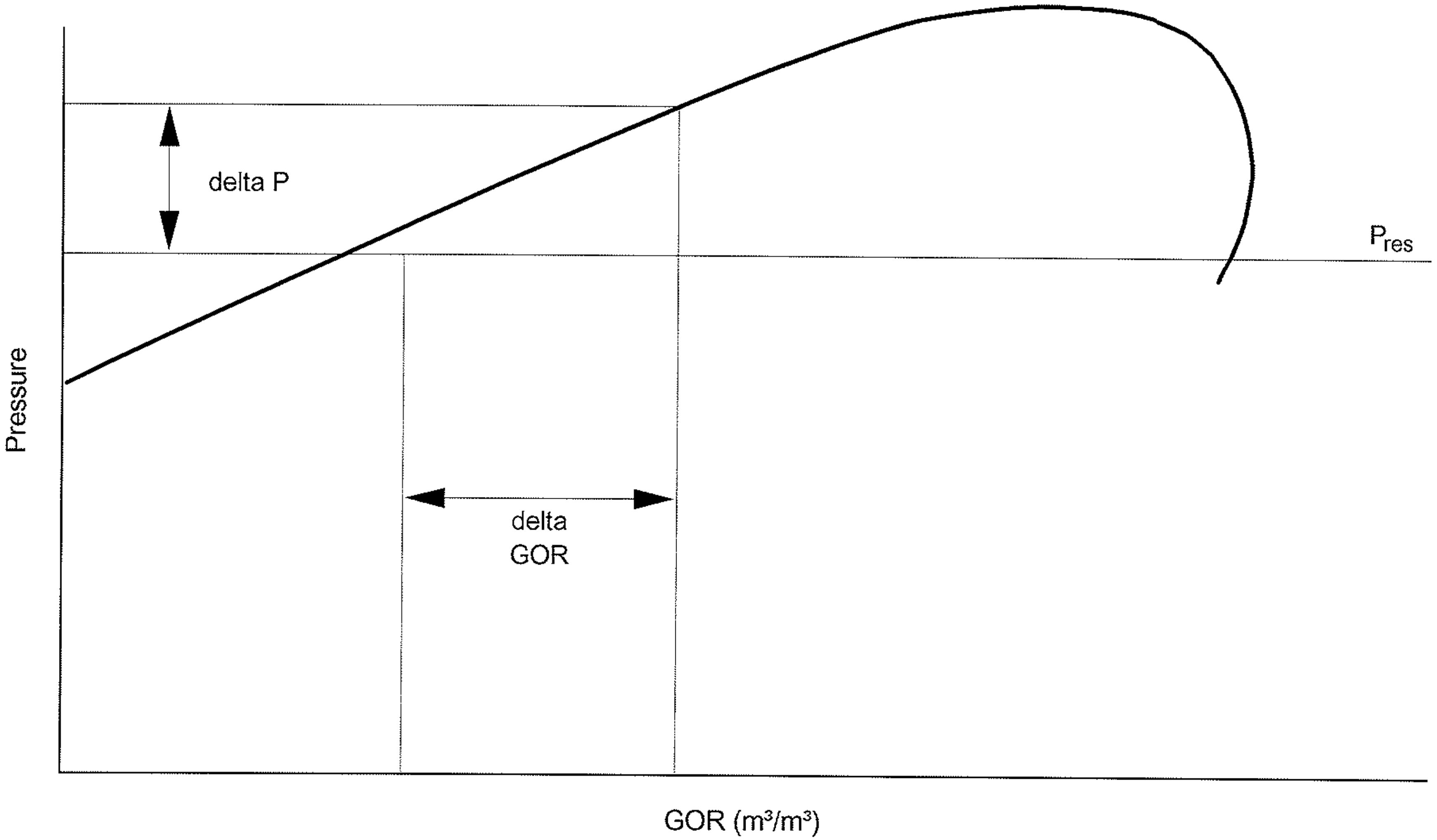

FIGURE 7

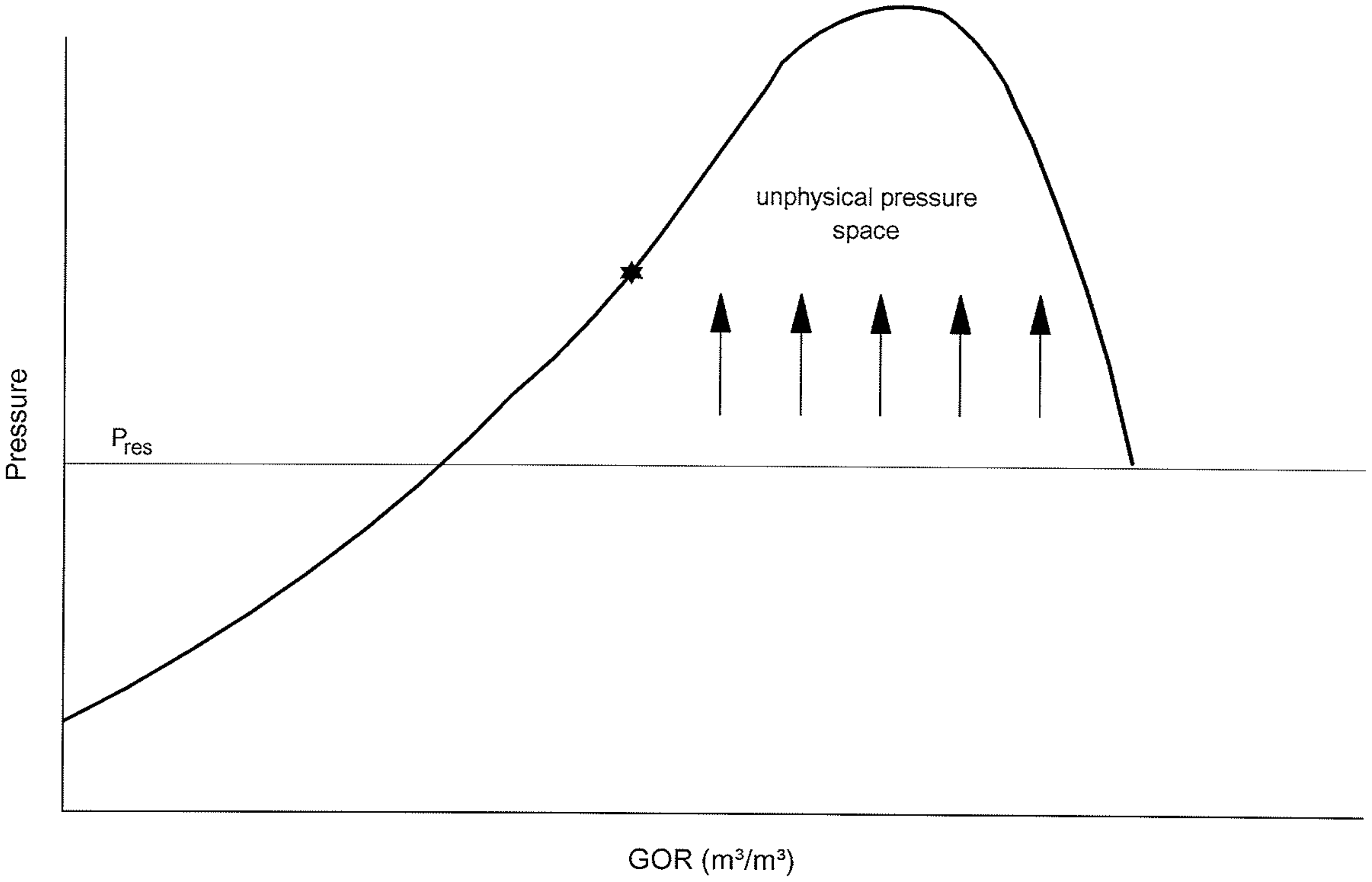

FIGURE 8

CONVENTIONAL & MULTICONTACT P-x RESPONSE

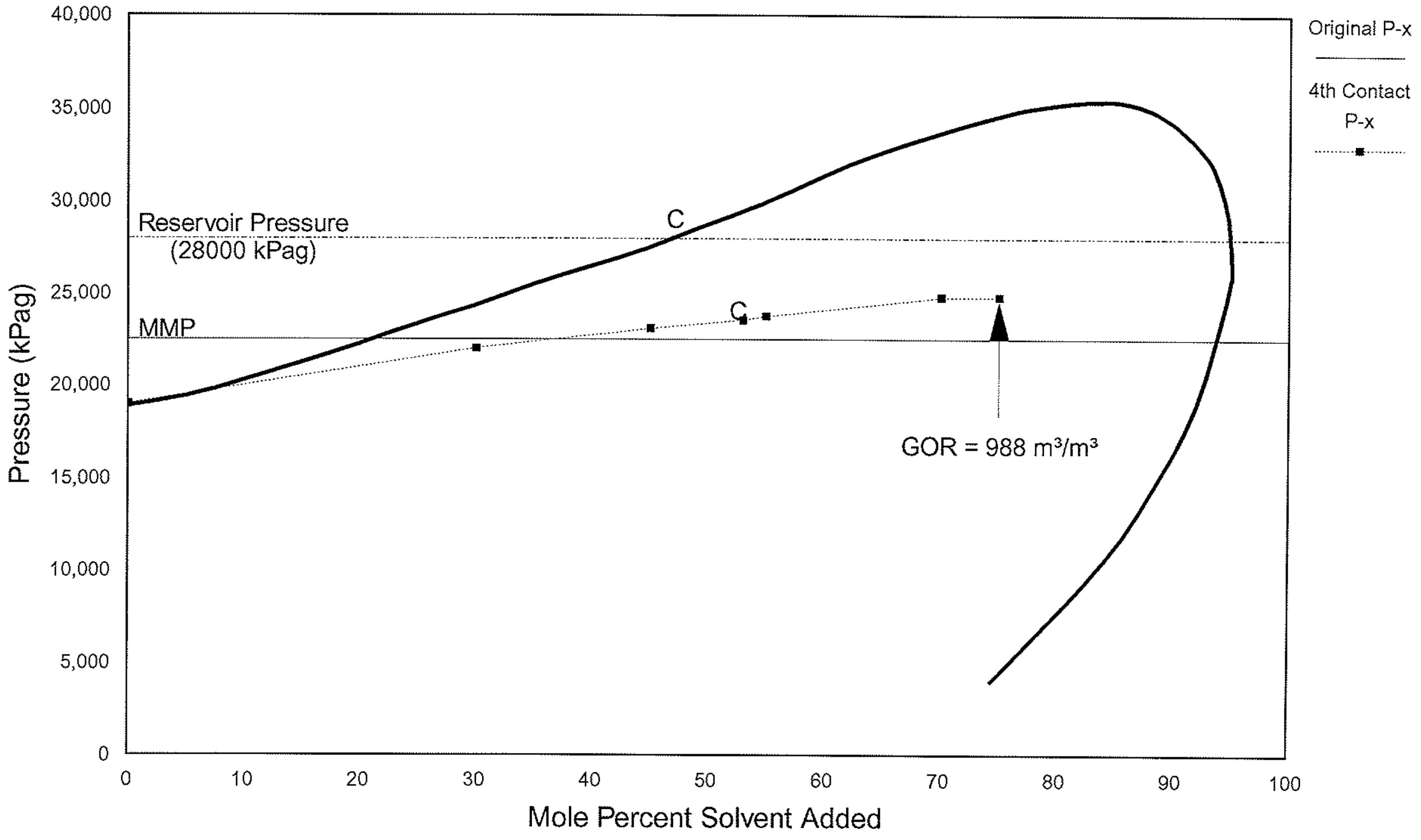

FIGURE 9

TERNARY DIAGRAM REPRESENTATION OF THE COMPOSITIONS

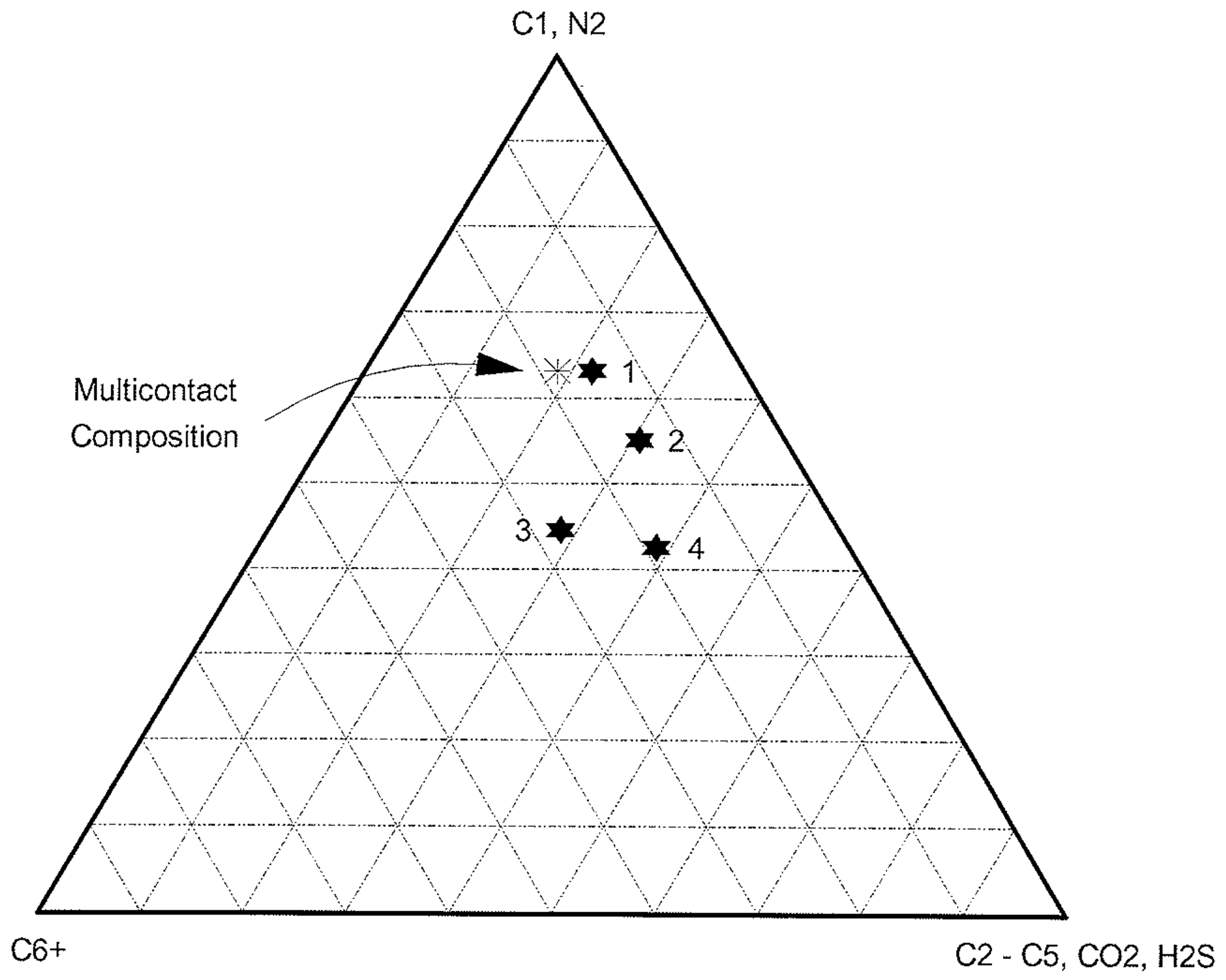

FIGURE 10

INTERFACIAL TENSION CALCULATION

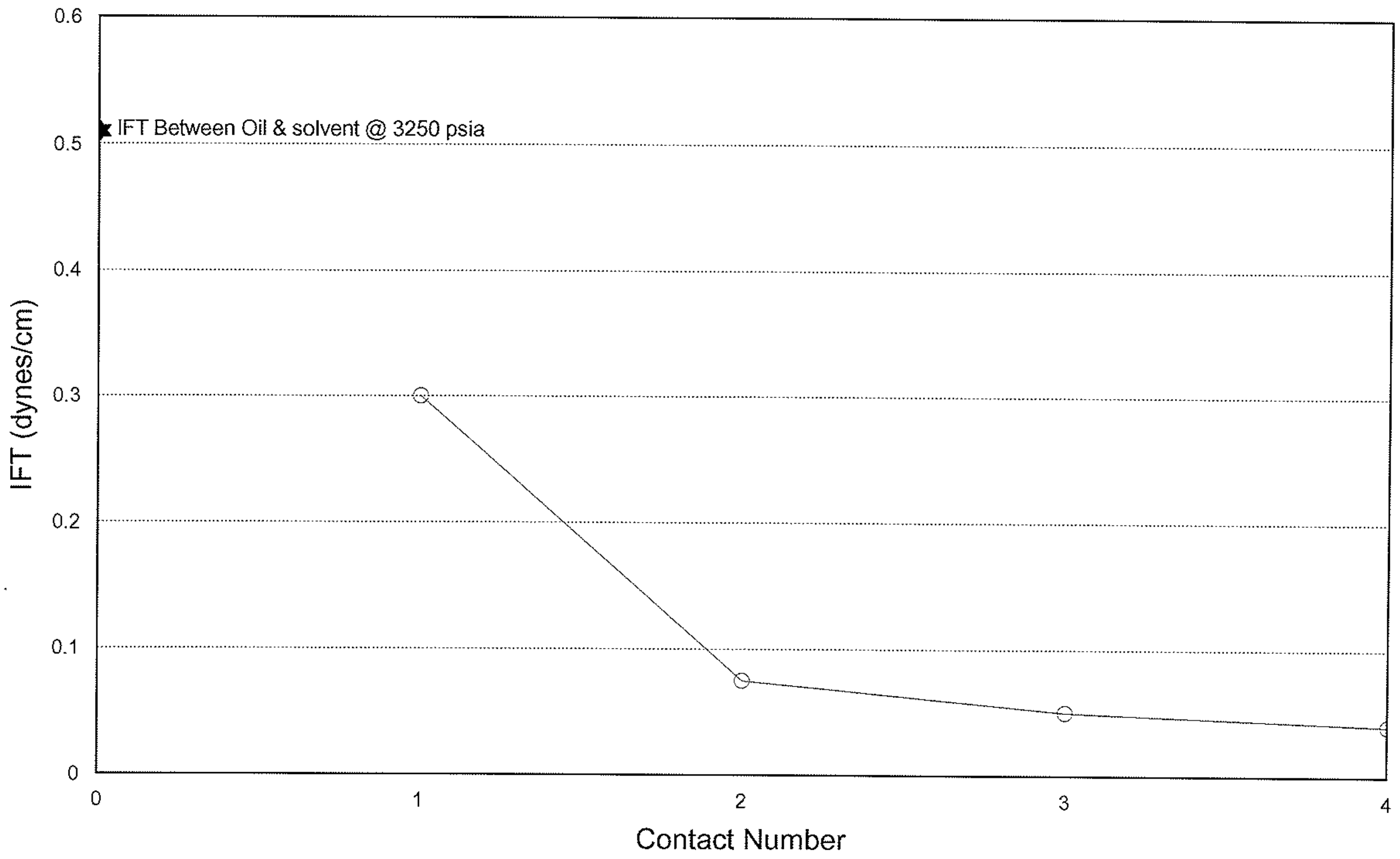

FIGURE 11
UPPER PHASE COMPOSITION

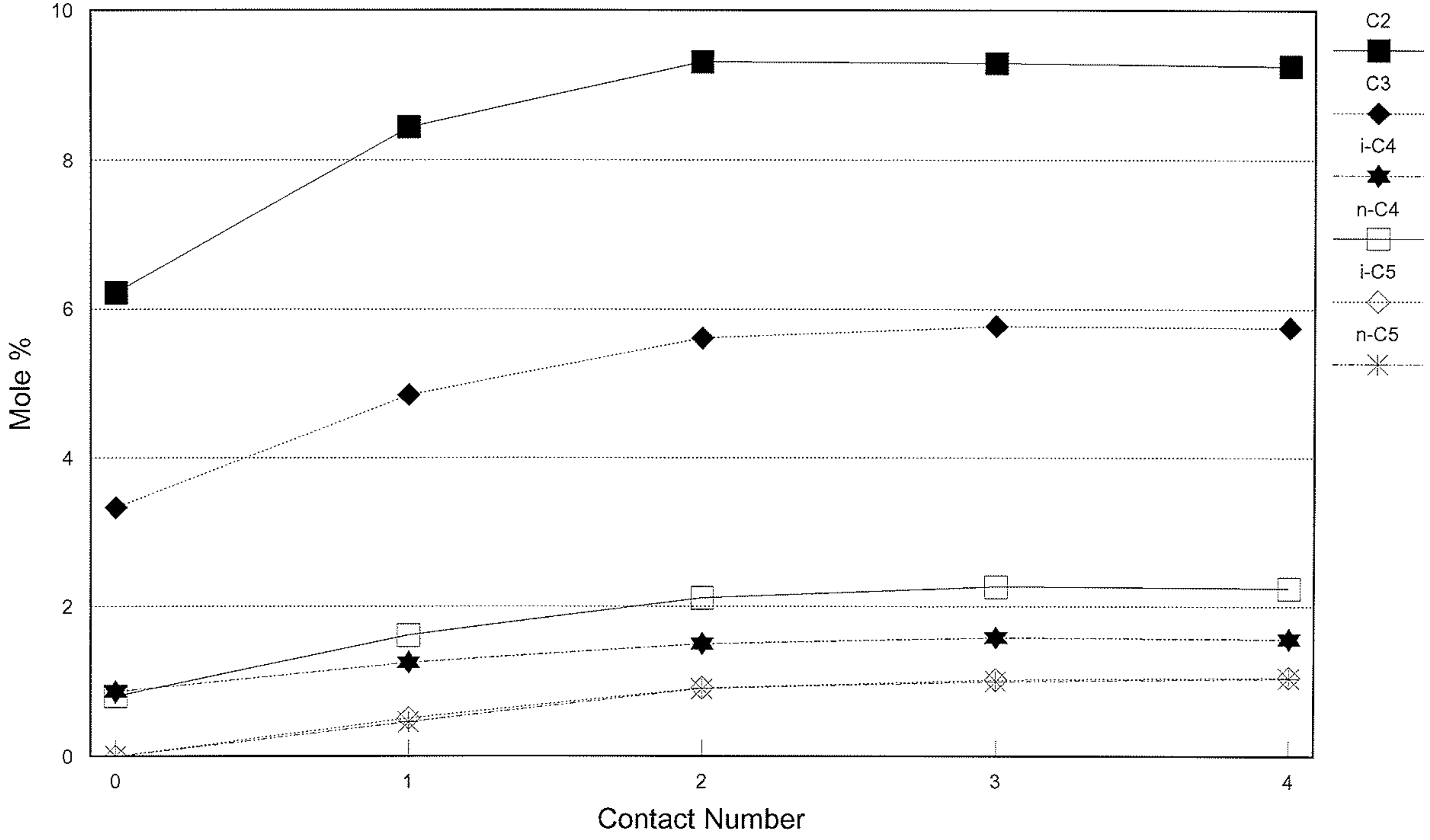

FIGURE 12
EFFECT OF DEPRESSURIZATION
MICROFLASH VAPOUR PHASE COMPOSITION

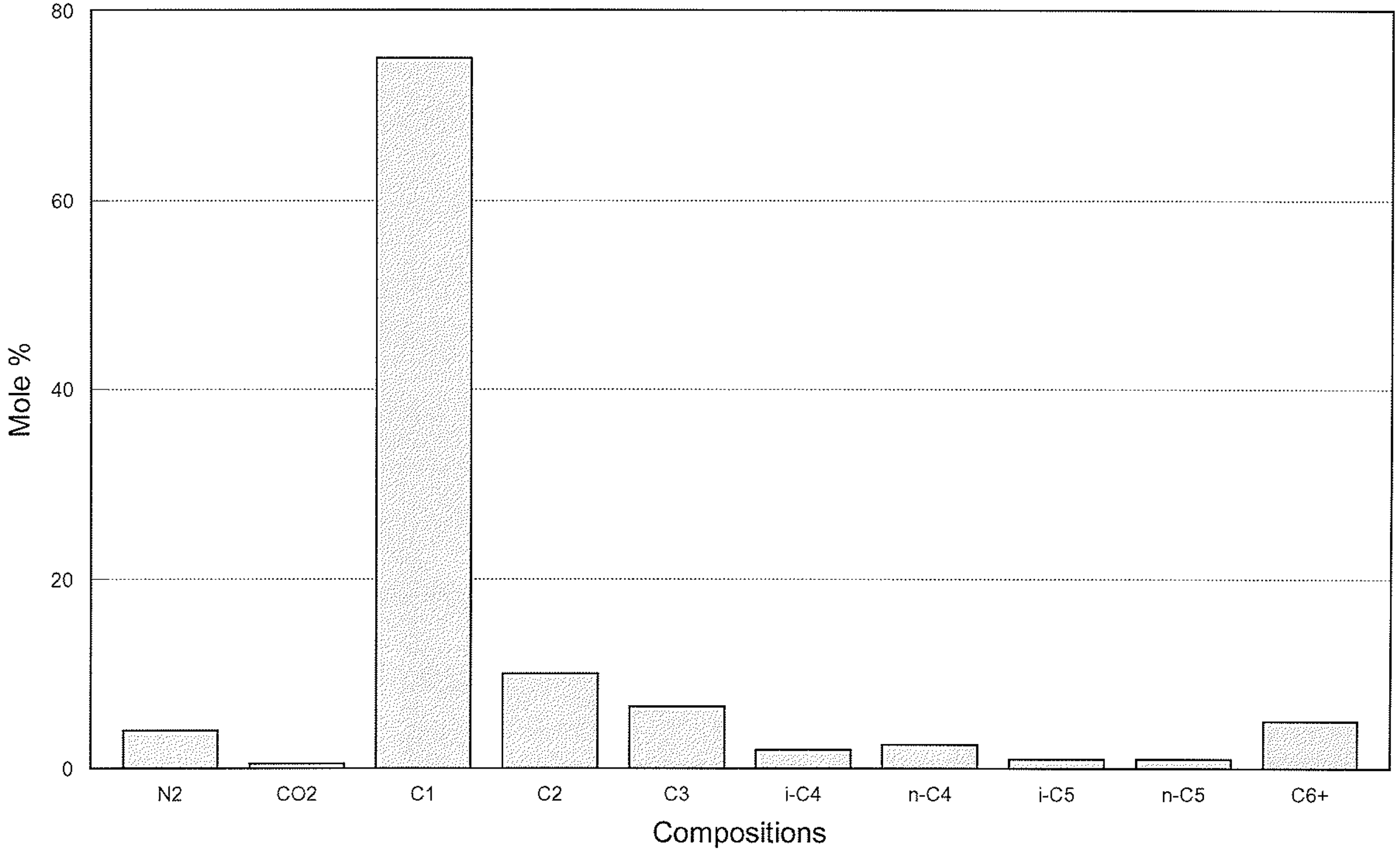

FIGURE 13
INTERFACIAL TENSION CALCULATION

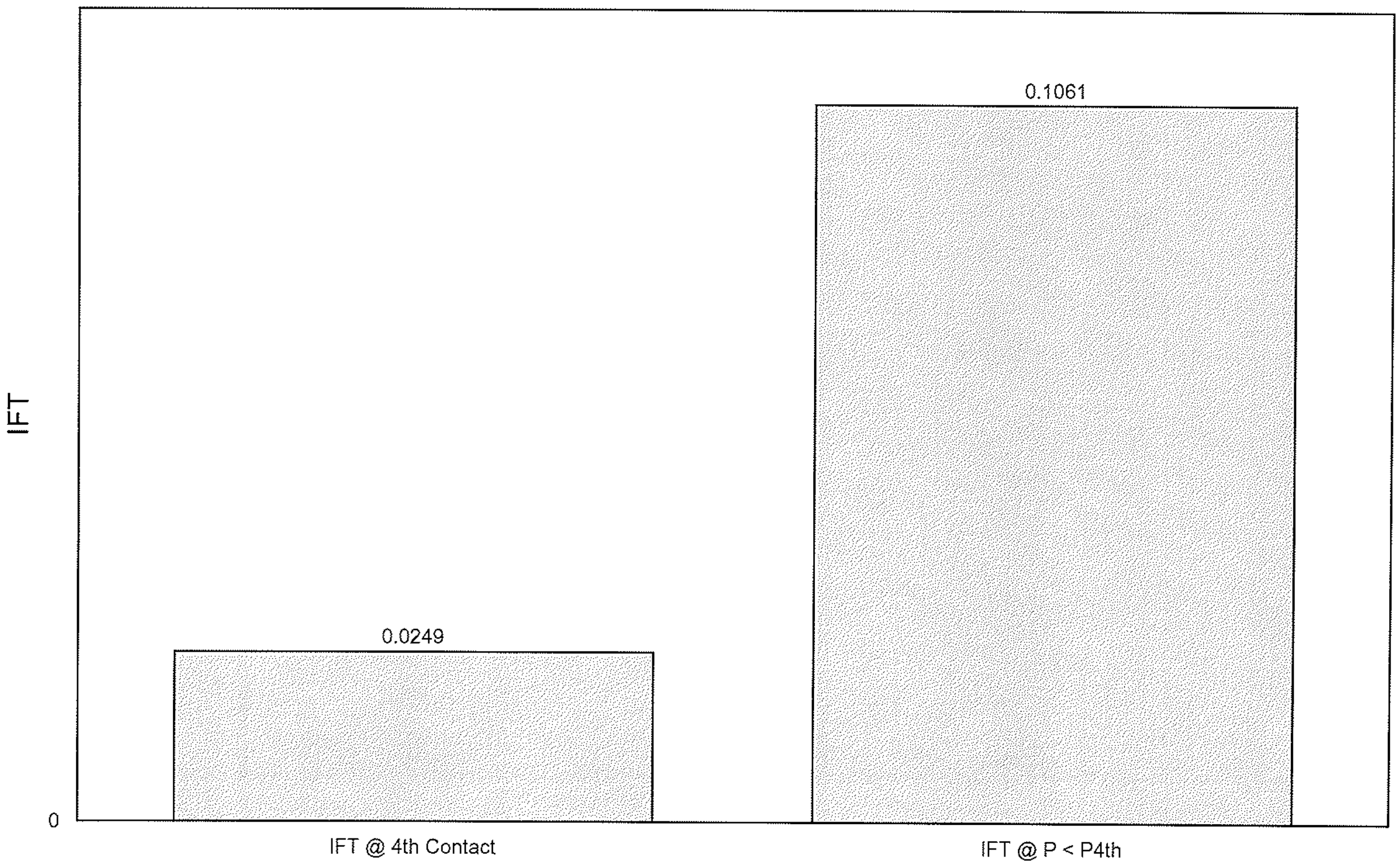

FIGURE 14

PERMEABILITY REDUCTION DUE TO IN SITU SOLIDS PRECIPITATION

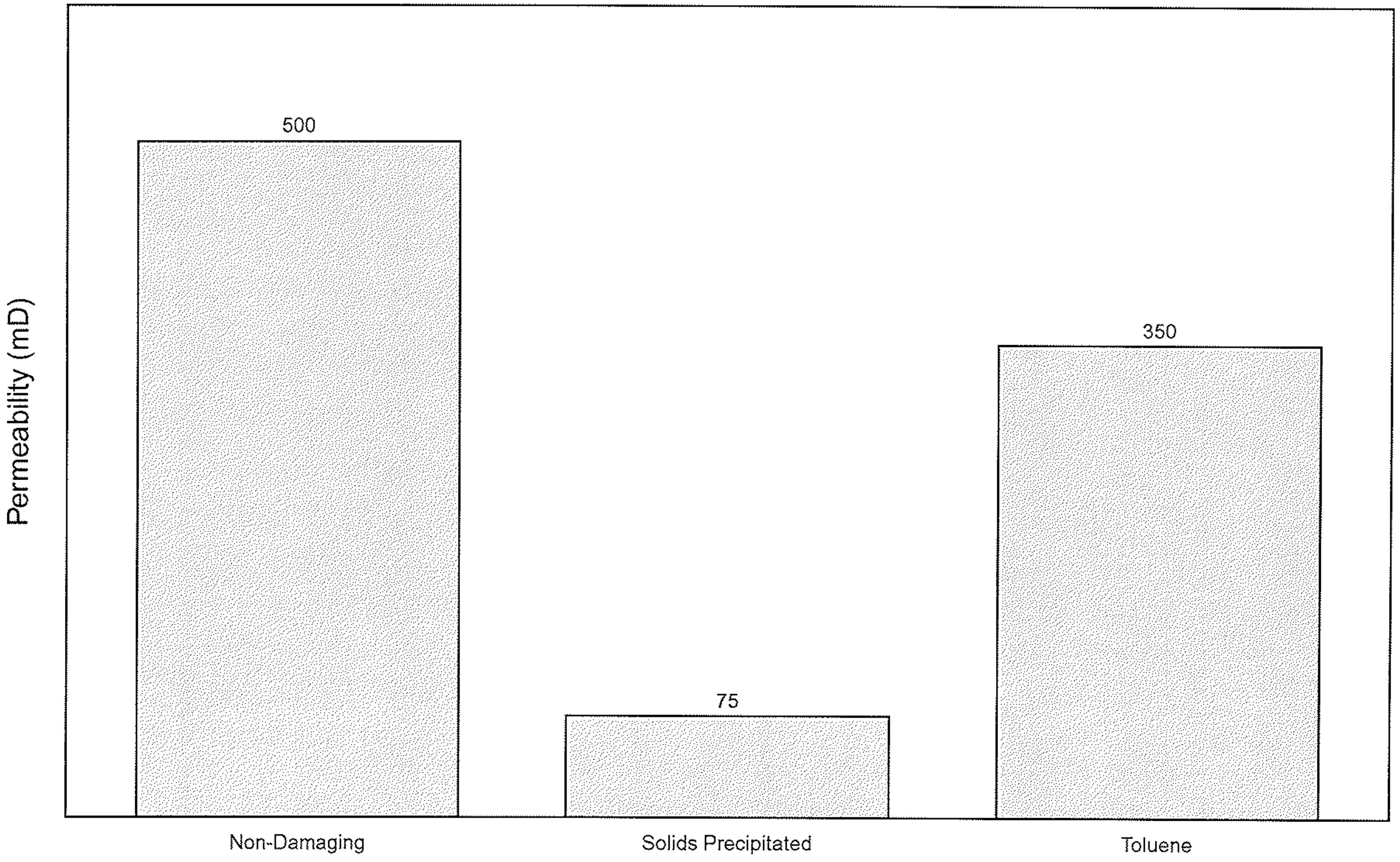

FIGURE 15
LASER CELL CONFIGURATION

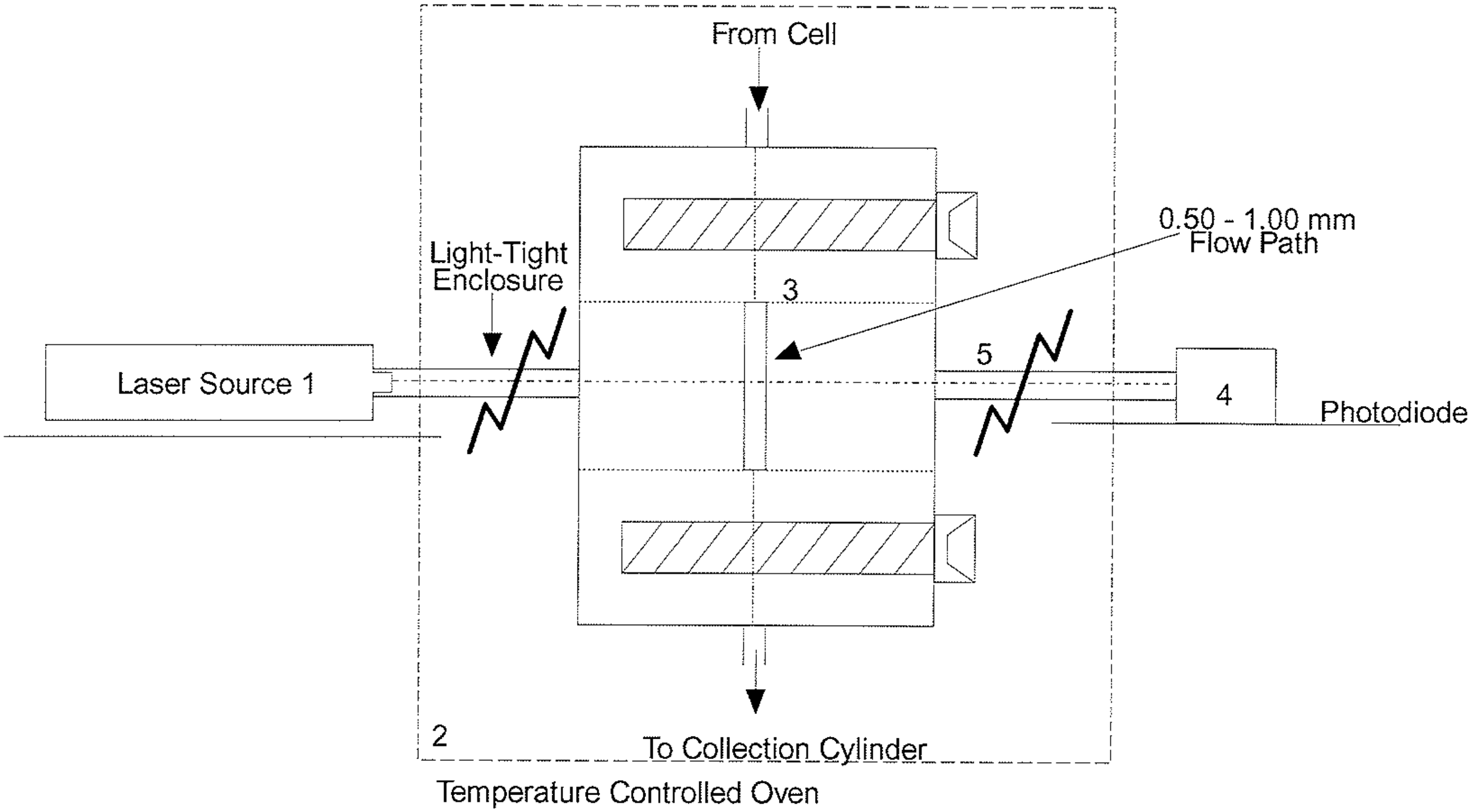

FIGURE 16

DETERMINATION OF INCIPIENT PRECIPITATION CONDITIONS

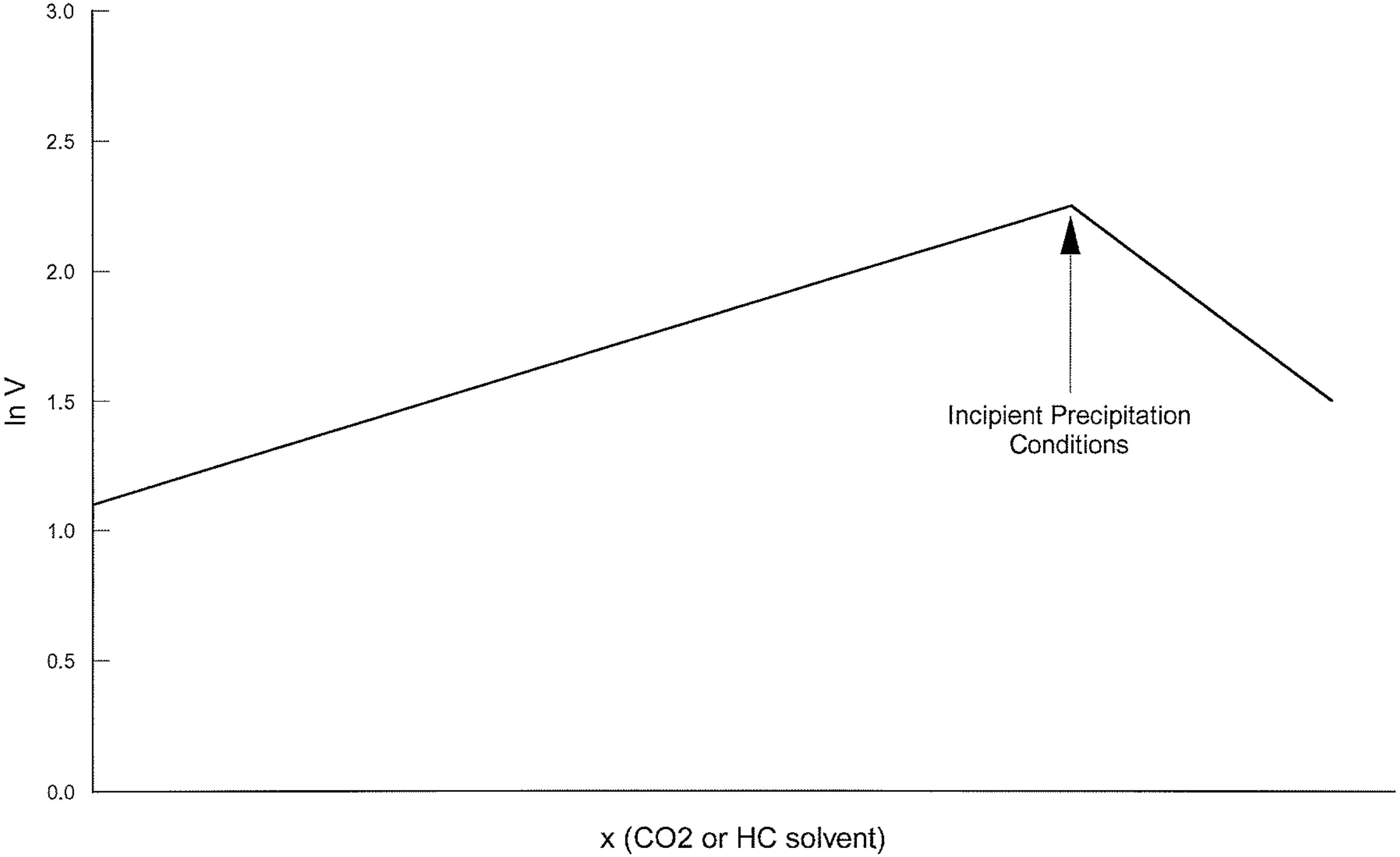

FIGURE 17

EFFECT OF COMPOSITION ON INCIPIENT PRECIPITATION

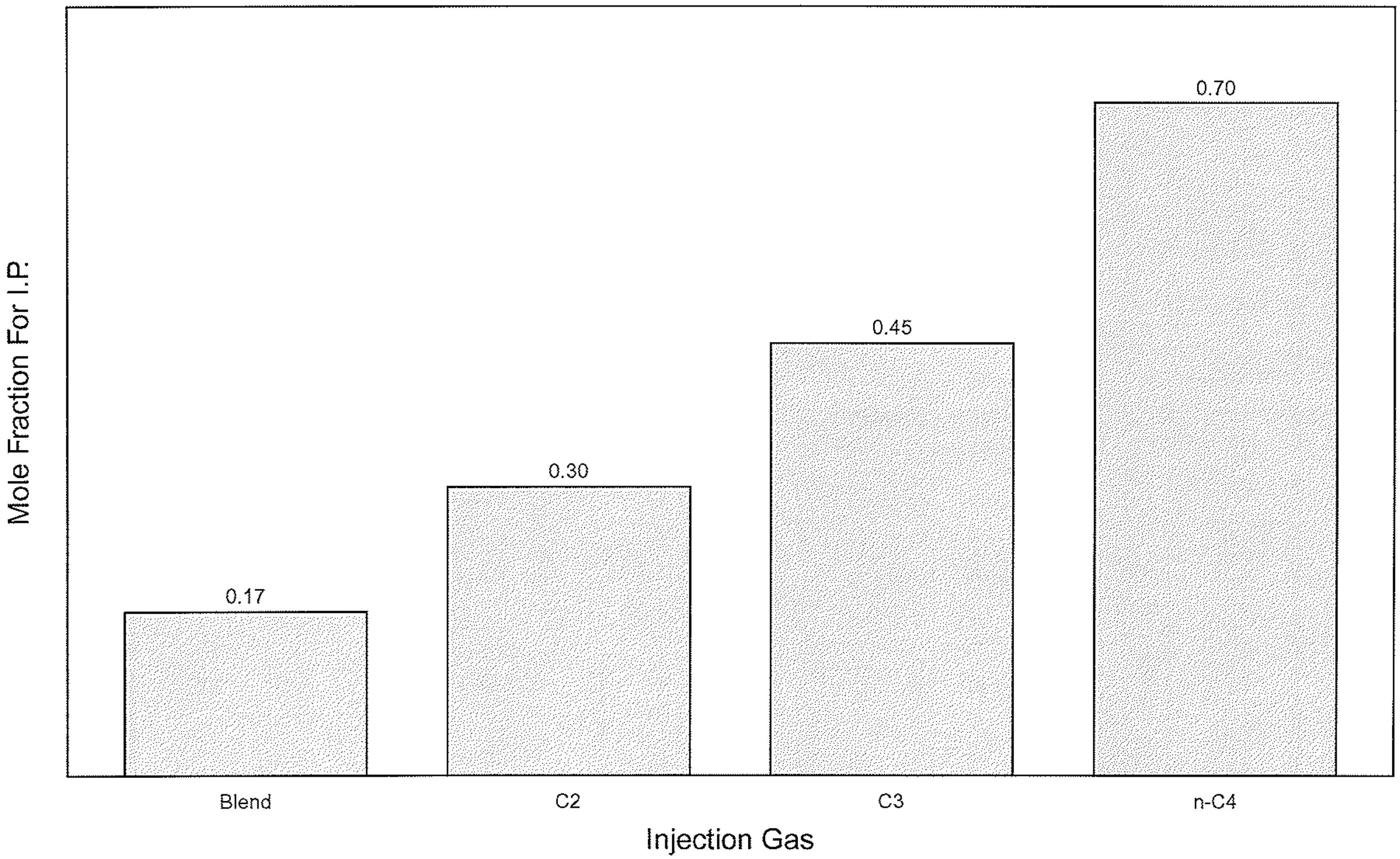

FIGURE 18

PRECIPITATION DEPENDENCY IN THE PRESENCE OF ADDITIVE

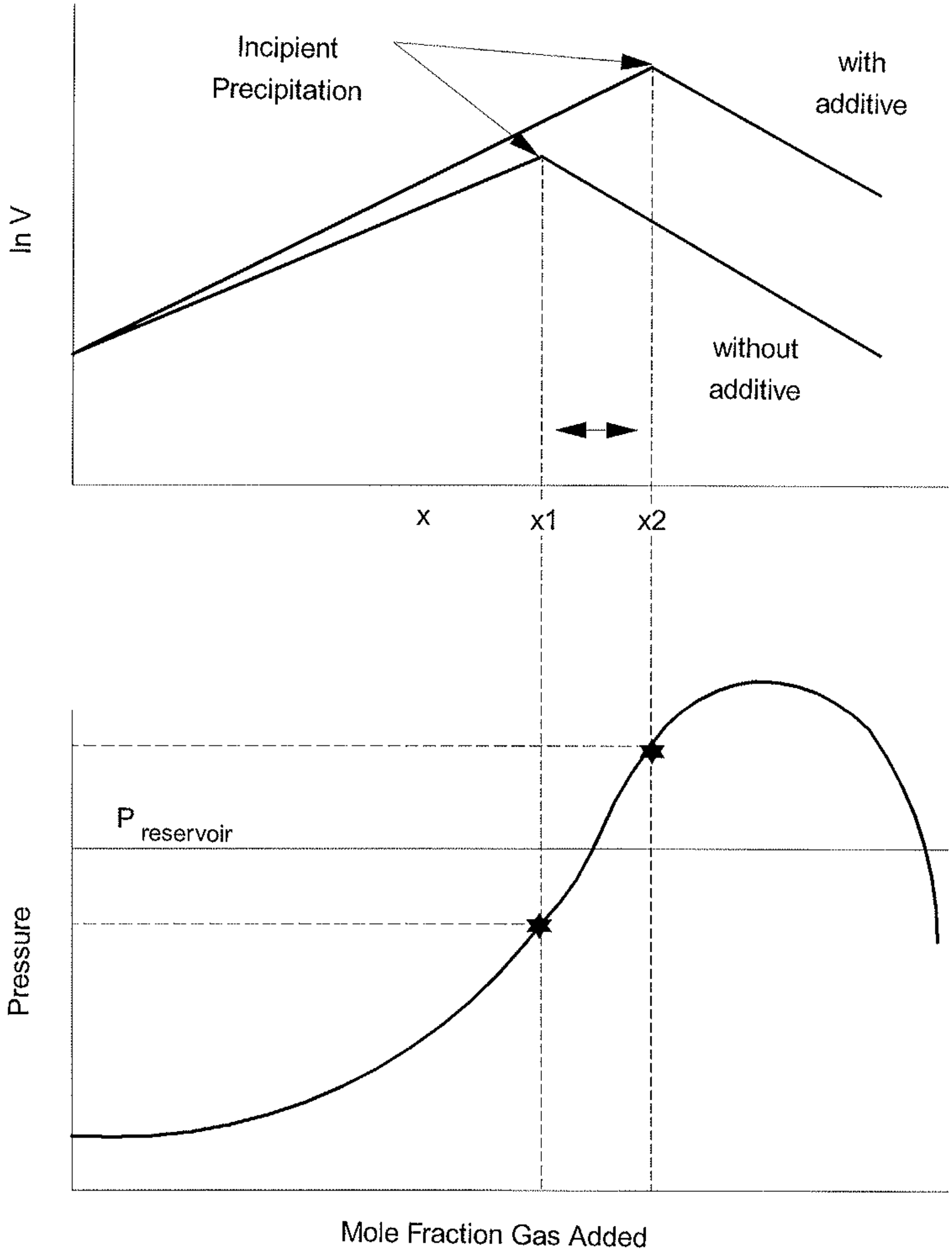

FIGURE 19
PRODUCTION WELL PRECIPITATION

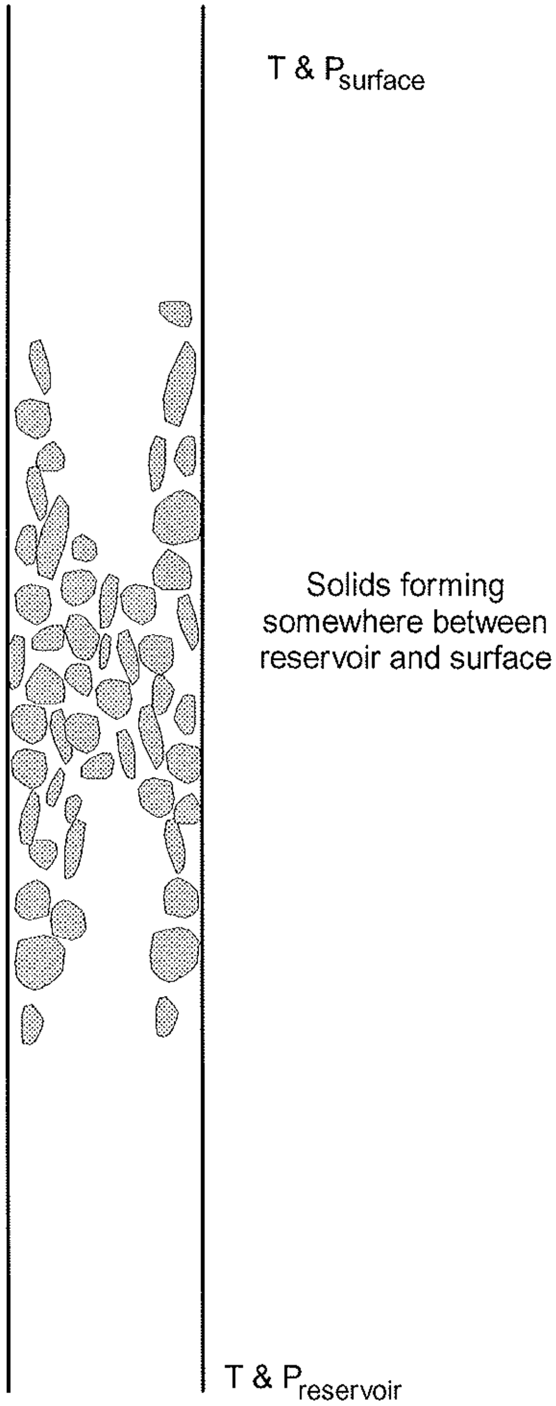

FIGURE 20

CLOUD POINT SUPPRESSION