

ENHANCED OIL RECOVERY BY GAS INJECTION: PROPOSED SCREENING CRITERIA

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ABSTRACT

As production from oil-bearing reservoirs matures, the need for enhanced oil recovery becomes increasingly important. In many of these reservoirs, waterfloods have been implemented and are presently approaching their economic limit in terms of producing water-oil ratio. One of the most important processes for revitalization of mature reservoirs is EOR by gas injection.

Over the last 20 years, the authors have seen significant change in the approach to gas injection design and thus in the 1990's the oil industry has a greater understanding of gas EOR than ever before. This knowledge notwithstanding, many times operating companies fail to understand some of the complexities associated with appropriate gas injection design and consequently target reservoirs for gas EOR which may have characteristics which would preclude the reservoir from such EOR applications.

This paper summarizes approximately two years work performed wherein effects of interfacial tension, viscosity ratio, gravity and wettability, all in the context of the microscale pore size distribution, have been evaluated. In particular, four reservoirs, wherein specific laboratory measurements including coreflood testing have been

performed, are analyzed. Some counterintuitive responses are then described on the basis of these parameters. Finally, screening criteria for gas EOR projects has been proposed. Three reservoirs which have been evaluated on a field scale are then ranked according to the screening criteria proposed herein. The approach used appears to confirm the response observed in the field thus lending credence to the gas EOR screening criteria developed in this paper.

The objective of the screening criteria developed from this work is to allow an operating company to rank candidate gas injection EOR reservoirs according to that which has the most promise to that which has the least promise. In this manner, limited resources can be focused on that reservoir or reservoirs which are most likely to result in the best performance, thus stabilizing the reserves base for the corporation and allowing for more optimal corporate performance in the future.

Displacement Paradigms

In analyzing corefloods over the past fifteen years, the simple paradigm which has exhibited repeated efficacy is that which is described in the literature. Dullien¹ described the features of importance in multiphase flow in porous media. Whereas many practitioners of reservoir engineering have

tended to employ global observations to infer small-scale response, Chatsis², Diaz³, Kwiecien et al⁴, Kantzas et al⁵ and Ionnadis et al^{6,7,8} have focused on pore level to describe macro-scale performance. A host of other researchers has also contributed to the body of insightful literature which helps us to comprehend why porous media systems behave as they do. The domain of flow in porous media inheres of such challenging subjects that recently the pundits of the fractal domain have directed much attention to the treatment of the problems which were reserved, in previous decades, for the more pragmatic reservoir engineers. Feder, Mandelbrot and a host of others have begun to see flow in porous media as a pons asinorum to which fractal mathematics may hold an insightful eye.

In studying the literature and in performing mundane experimentation into coreflooding, the academics and engineers appear to conflate pertaining to the concepts that govern flow in porous media. How they treat the concepts differs but not the concepts themselves. The paradigm used to understand flow in porous media appears to be the same, independent of whether we sit with the researchers or the practitioners. It has been the experience of the authors however that communication between the two groups may tend to be restricted and therefore a summary of the concepts will be provided herein.

Interfacial Tension Effects

The first of these is the capillary pressure effect which is described by the following relation

$$P_{cap} \propto \frac{\sigma}{D} \quad (1)$$

To displace oil from a pore the applied pressure drop must be at least as large as the capillary pressure influence. Only if the applied differential pressure is large enough will the injected fluid access the oil contained in the pore associated with the pore throat of diameter D . As shown in Equation 1, as the interfacial tension (IFT) decreases the capillary force decreases and as the pore throat diameter decreases the capillary force increases.

The influence of Equation 1 is often used as a simplistic way of describing why gas injection schemes, if properly designed, can recover more oil than waterflood. Figure 1 shows a schematic representation of a pore size distribution. According to the applied differential pressure and the IFT between the water and the oil, Equation 1 states that porous features of diameter $D_{w/o}$ will be accessed. Porous features tighter than $D_{w/o}$ will not be. If Figure 1 portrays pore volume versus diameter and if accessibility equates to displacement then all oil contained in porous features greater

than $D_{w/o}$ will be produced. From this model therefore, if the gas/oil IFT were lower than the water/oil IFT the gas should then access porous features of a smaller diameter than did the water thus recovering more oil. As with most physical processes they are much more complex than depicted here and consequently instead of providing a succinct model by which to understand injection schemes, Equation 1 only provides the relationship between three parameters which must be considered in understanding and thereafter designing gas injection strategies - the three parameters are IFT, pore size distribution and applied pressure or flowrate. Other parameters which cause a deviation from accessibility/displacement proportionality are many. Mobility effects will be discussed first.

Mobility Effects

Another parameter, putatively recognized as being of extreme importance, is mobility.^{9,10,11} The common fractional flow equation (data) describes the flow of oil and displacing fluid as

$$f_d = \frac{1}{1 + \frac{1}{M}} \quad (2)$$

where

$$M \equiv \frac{\mu_o}{\mu_d} \frac{k_{rd}}{k_{ro}} \quad (3)$$

$$M \propto \frac{\mu_o}{\mu_d} \quad (4)$$

Since k_{rd} and k_{ro} are functions of IFT and μ it is preferable to use a proportionality as Collins¹² showed that if dispersion is neglected, the length of a "viscous finger" is

$$\log(L) \propto \frac{\mu_o}{\mu_d} \quad (5)$$

Superimposed over this finger growth expression is a statement by Feder "the fluid flow problem is controlled by the microscopic length scale in all spatial directions" and therefore Equation 5 may occur but is influenced by the pore size distribution of the porous media. An example of how the pore size distribution can influence flow is obvious from a simple thought experiment. If it is assumed that pore throats appear as bundles of tubes, then the surface area to

volume of a tube is equal to $4/D$. If the pore throats deviate from cylindrical then the following proportionality may result

$$\frac{\text{Surface Area}}{\text{Volume}} \propto \frac{1}{D} \quad (6)$$

Oil reservoirs are replete with interfacial effects due to intermolecular forces¹³ and there is attraction between fluid and rock. The forces of attraction will therefore differ between pore throats of differing diameters - this results in different fluid drag as a function of pore throat size, drag being less in porous features where the surface area to volume ratio is lower. Thus fingering may result from an adverse viscosity ratio but may also result from a porous media induced path of least resistance being established.

Therefore, a departure from microscale flow consistency (accessibility not being equal to recovery) is caused by at least two parameters: viscosity ratio and paths of least resistance associated with the inherent properties of the porous media. These two are included in the authors' usage of the term "Mobility Effects". Another parameter of major influence is gravity of which a short discussion ensues.

Gravity Effects

It is recognized that gravity plays an important role in all reservoirs and the thicker the reservoir, the more dominant the gravity influence. Asgarpour¹⁴ summarizes some vertical flood results and Kantzas et al^{15,16} provide insight into both low and high IFT vertical gasfloods. Stability analysis indicates that the main benefit of a vertically oriented gasflood is that the buoyancy effect compensates for the adverse viscosity ratios. The critical rate for stability, according to Stalkup,¹⁷ applied to a vertical system is

$$V_{vg} = \frac{V\mu}{k_o\Delta\rho g} \quad (7)$$

Fayers and Zhou¹⁸ indicate that displacements at an IFT of 0.10 dynes/cm, in a vertical homogeneous sandpack column, performed worse than displacements at an IFT of 38 dynes/cm but which were at a value of V_{vg} lower than 1. It would be expected that more dispersed pore size distributions would even show a greater proclivity to be influenced by the mobility/gravity compromise and less dependent upon IFT. Thus the importance of knowing whether a reservoir will be more strongly influenced by IFT or mobility/gravity. Indeed Hicks and Deans¹⁹ have indicated that "the displacement front, as expected, is found to be a strong function of the permeability distribution ... for the core".

One point which has received short shrift in the technical

literature is whether the rates of oil recovery can be maintained sufficiently high at higher levels of gas/oil IFT. The benefit of low IFT is to access pores of a smaller diameter. The argument in favour of higher IFT systems has been that the greater density difference between oil and lean gas may compensate for the accompanying higher IFT compared to enriched gas injection. Indeed, if the system is dominated by adverse mobility so that the paths followed by the high and low IFT gases are the same, then the benefit of low IFT is negligible. This would represent a significant deviation between accessibility (defined by Equation 1) and sweep (those pores from which oil is actually recovered), whereas for the higher IFT gas there will usually be greater convergence between accessibility and sweep. It will be apparent to the reader therefore that the injection of high or low IFT gas into a reservoir must therefore be made on the basis of whether the IFT/mobility/gravity compromise favours adherence to accessibility expectations (IFT dominance) or paths of least resistance (mobility, gravity).

A corollary of the foregoing paragraph is that if the lower IFT gas displaces oil in a manner consistent with the IFT conditions, then the system is linear and S_{or_g} will be proportional to the IFT level. The aficionados of high IFT gasfloods tend to emphasize the stability of lean gas stating that "the immiscible displacements resemble miscible displacements at viscosity ratios at least two orders of magnitude less, and therefore they can be considered as considerably more stable".²⁰ This conclusion was based on Shaw experimentation which has no porous media. The low IFT systems have an implicit stabilizing influence in porous media due to the greater accessibility which can equate to effectively larger cross sectional areas for flow. Therefore, although the $\Delta\rho$ may favour high IFT lean gas systems, the high IFT may result in only a fraction of the pore size distribution being accessed (Figure 1). The effective swept area on the microscale is smaller and therefore the interstitial velocities with the high IFT gas will be higher. Thus although the $\Delta\rho$ produces less stability in the rich, low IFT gas injections, the IFT may result in greater cross-sectional areas for flow which decreases interstitial velocity. In any case, it is obvious the role that gravity can play in vertical gasfloods. For horizontal gas injection, the scales are tipped in favour of enriched gas.

Stalkup¹⁷ shows the four regimes pertaining to levels of the viscous to gravity ratio in Equation 7. In horizontal gas injection the viscous to gravity ratio must exceed a certain value in order to reduce the serious effects of gravity override. In this case, the lower the gas-oil density difference the better and viscous fingering will result which, compared to override, is beneficial. The optimal injection rate recommended however lies between the transition from gravity override at the low end to the damaging deviation

between accessibility and displacement at the high end. Although the horizontal gasfloods technically favour low IFT gas conceptually, again if the porous media are diverse, showing broad pore size distributions, vuggy nature and/or fractures, the difference between high and low IFT gas will be less (Stern²¹). In this case, mobility control strategies can be implemented (WAG, foam, water/gas co-injection) to improve convergence between accessibility and displacement.

Wettability

Much has been written on the influence of wettability on gas injection schemes. Stern²¹ describes the influence of wettability on by-passing indicating that wettability can predispose a core to having solvent follow a path of least resistance through large or small pores stating that it is likely to occur in mixed- and water-wet rock. Rao²² provided a succinct summary of some of the influence that wettability can have on gasflood potential.

By means of summary, the influence of water-wetness can be good and bad. In Figure 2, the assumption is made that the water is "attracted" to the portion of the rock where the surface area to volume ratio is maximized. In such a case, if the smallest pore throats are occupied by water then an IFT below $\sigma_{g/o}$ would be unnecessary - all the oil is contained in pores greater than D_1 and therefore access into porous features smaller than D_1 is overkill. Contrasting this with a reservoir which exhibits significant oil saturation in the smaller pores, the level of IFT for an oil-wet core will be required to be lower for the same degree of accessibility. Therefore water-wet may relax the demands on IFT and therefore allow for a cheaper injectant without negatively influencing the accessibility. Commentary on solvent enrichment will be provided later on in this work.

Water blocking is more severe in water-wet media^{23,24,25} since the presence of water reduces contact between oil and solvent. If gas injection is implemented without water injection then this effect is negligible, but if a tertiary scheme is implemented then water blocking in water-wet reservoirs can be serious. With oil-wet media the IFT requirement might be more severe (and the gas more costly) but waterflood may induce little water blocking and thus overall the tertiary process may be more economic compared to gas injection in water-wet media, depending upon levels of oil recovery on waterflood, gas enrichment required and other reservoir parameters.

With these four parameters it can sometimes be an exercise in logic to understand the optimal strategies for EOR. A number of corefloods will now be discussed and the relative merits of each discussed. Some counter intuitive responses are also observed and explained in the context of these corefloods and the four influences described above.

Coreflood Results

Reservoir 1

The first reservoir studied was a sandstone reservoir consisting of a number of different flow units. The most permeable exhibited an air permeability of 500 mD whereas the least permeable was in the 10 mD range. The porosities correlated at 23 and 18% respectively. The most dominant (thickness and therefore net pay) had a porosity and permeability of 19% and 45 mD respectively, somewhere in the mid range.

The focus for this work was on evaluating tertiary versus secondary gas injection. LPG was available and therefore the low IFT option was the most likely EOR candidate since the reservoir was relatively thin. The results were as follows:

Test #	Rock Perm (mD)	Process	Oil Rec From Waterflood	Oil Rec After Gas Inj	Total Rec	Orientation (Hor/Vert)
1	10	3°WAG(.3,.3)x2	52	29	81	H
2	500	3°WAG(.3,.3)x2	45	51	96	H
3	45	2°Cont.Gas	N/A	90	92	H
4	45	3°Cont.Gas	58	30	88	H
5	45	3°WAG(.2,.2)x3	53	37	90	H
6	45	3°WAG(.2,.2)x3	57	35	92	H
7	45	3°Cont.Gas	60	40	100	V
8	10	3°WAG(.1,.3)x3	50	34	84	H

In performing these corefloods, the following interpretation can be made. The comparative evaluation will include commentary on the four parameters discussed in the previous section.

In order to compare the influence of IFT, the nature of the rock must be examined. Figure 3 shows the pore size distribution based on image analysis. The areas of the porous features of the rock are determined and based on the independent features they are grouped into a number of "bins" of discrete size ranges. In Figure 3 the number of pores in these distinct area groups is shown. Typically the smaller pores are the most plentiful as is shown here. The assumptions to translate these numbers of porous features into pore volume were:

- 1) The porous features were assumed to be circular and therefore they would correspond to spheres.
- 2) The porous features correspond to all the pore volume of the porous media.

According to these assumptions, the pore volume distribution is shown in Figure 3, both in terms of the density of each size range and the cumulative pore volume. This shows the bulk of the pore volume is found at the larger size range; the numbers of small pores was large but the associated volume was small due to the equivalent spherical

assumption being a function of porous feature diameter to the third power. A total of 126963 separate features were counted as part of this analysis. The same definitions apply to the image analysis results in Figures 4 and 5.

Comparing the corefloods there are many differences. The IFT of the gas was measured to be 0.6 dynes/cm using a technique similar to that developed by Rotenberg et al.²⁶ The viscosity ratio (oil/gas) was about 40. The waterflood recoveries were 52 and 45% with the higher permeability core resulting in lower recovery for the first two tests. Wettability results indicated a USBM index near zero corresponding to neutral-wet with minimal spontaneous imbibition of either phase. Since the lower permeability rock resulted in more oil recovery, it is thought that there is better microscale sweep in the low permeability rock than in the high permeability sample. The 500 mD rock may exhibit a broader range of accessible pores to the water. If there is little imbibition of water and the oil is displaced from the largest pores to the smallest then the lower limit would correspond to about 70 μm . If this governs the diameter to which this can be swept then it should result in accessibility into 90% of the pores in the 500 mD rock. Therefore, since the recovery is lower for the 500 mD rock, this indicates that the water was "routed" through larger porous features and the smaller pores, although potentially accessed, were by-passed. This effect appears to be corroborated by the 45 mD waterflood results which rock has a slightly larger distribution of pores than the 10 mD core but has quite a narrow distribution and thus less tendency to have microscale by-passing.

The same trends are then exhibited during the gasflood. If the system is not dominated by mobility effects, then one should observe a significant influence of IFT on recovery or, conversely, appreciable changes in performance with changes in the pore size distribution. At 0.6 dynes/cm recoveries in 220 mesh slim tubes were in excess of 95% OOIP and about 80% of the porous features in such a slim tube are between 75 and 100 μm . Once access is achieved into 50 μm pores then virtually all the oil can be recovered. Figure 6 presents a standard pore size distribution of a 220 mesh crushed quartz sandpack slim tube. The pore size distribution is also much more narrow than that found in the reservoir. The examination of the gasflood response shows that the 0.6 dynes/cm was apparently inadequate for the 10 mD rock. However, comparison of test #1 and test #8 shows that the WAG ratio has an appreciable influence. The tertiary WAG with 2 cycles of 0.3 PV gas and 0.3 PV water resulted in an incremental 29% OOIP being recovered. The WAG implementation of 3 cycles of 0.1 gas and 0.3 water for 3 cycles resulted in 34% of OOIP as an incremental recovery to the WAG. This was a surprising result in that 34% of OOIP was recovered which was even larger than the 30%

HCPV injected. Moreover this indicates that mobility control was very important and that a higher water ratio recovered more oil than when more gas was injected. Gas was a necessary condition for incremental recovery but in light of this result, the optimal slug size and WAG ratio would be a very important set of variables to optimize. It would be anticipated that this effect would even be more pronounced in a broader distribution of porous features. This dependence on WAG ratio was not investigated with the 500 mD rock shown in Figure 4.

Other testing was performed (not reported herein) with a carbonate that exhibited a more diverse pore size distribution than shown here. In this case changing the water to gas co-injection ratio from 1:1 to 5:1 only decreased the oil recovery, for the same total injection volume, from 95% to 91%. Again the more dispersed pore size distribution makes the system more sensitive to the "time spent" controlling mobility of the injected gas as opposed to injecting the gas.

Comparing corefloods 1 and 2 shows the difference of 0.6 dynes/cm IFT for the 10 mD and 500 mD cores. The IFT is inadequate for the 10 mD rock whereas for the 500 mD core it is adequate, i.e. accessibility seems to converge with recovery. In comparing the levels of recovery for the 45 mD core, corefloods 4 and 7 show the change between horizontal and vertical orientation. In light of the virtually 100% recovery in the vertical orientation, this indicates a 12% increase over the tertiary continuous gas implementation in a horizontal orientation. The response in the vertical attests to the adequacy of 0.6 dynes/cm from an accessibility perspective whereas the significantly lower recovery in the horizontal flood, is probably due to some deviation from IFT domination (mobility). The frontal advance rate used in all of these floods was about 1.7 feet/day.

The effect of water blocking appears to be minimal when comparing the secondary and tertiary continuous gasfloods: secondary was 92% whereas the tertiary was 88%. Both tertiary WAGs done on this 45 mD core resulted in higher recovery than the continuous 3^o gas injection due to some element of mobility control (which was the insight gained above when comparing the tertiary continuous gas in the horizontal and vertical modes).

The comparative evaluation of this set of corefloods is relatively straight forward to do in the context of the four parameters previously described: IFT, mobility, gravity and wettability. Implicit in the evaluation of these parameters is the relative pore size distribution.

Reservoir 2

The purpose of the work performed on this reservoir was to evaluate the relative merits of low IFT gas versus high IFT lean gas in a vertical tertiary scheme - the reservoir has been

on waterflood for the last thirty years. It is a calcareous sandstone.

The gas available was a 75 mole % methane gas cap gas. Enrichment was to occur with LPG consisting of propane and normal butane. The design of the desired enrichment included slim tube testing, rising bubble test (RBA) and explicit IFT measurements. The level of IFT achieved with the enriched gas was 0.2 dynes/cm. The oil/gas viscosity ratio was in the range of 50. Coreflood results, from full diameter core, were:

Test #	Process Used (vertical)	Oil Recovery On Waterflood (%)	Oil Recovery On Gasflood (%)	Total Recovery (%)
1	3° Cont Lean Gas	50	11	61
2	3° Cont Lean Gas	35	20	55
3	3° Enriched Gas	52	38	90

The first coreflood was performed using brine injection from the bottom up and gas from the top down. The rates of injection corresponded to a frontal velocity of 0.37 feet per day. This rate was still about ten times higher than the rate calculated by the Dietz equation (0.027 feet/day)

$$V_{crit} = \frac{0.0439 (\rho_{oil} - \rho_{gas})}{\left(\frac{\mu_{oil}}{K_{oil}} - \frac{\mu_{gas}}{K_{gas}} \right)} \quad (8)$$

but with the large pore volume of the core the Dietz-calculated critical flowrate would require about 40 weeks per gasflood and therefore the rate was increased. By experience at least for comparing low and high IFT response, 10 times the Dietz-rate has always provided a rate which is acceptable from a time perspective and yet low enough to provide significant difference between EOR laboratory strategies. This then provides insight into the approach to exploitation approaches in the field.

The first test included a waterflood and resulted in about 50% oil recovery. The field recovery is in this same range. The reservoir about 1000 feet in thickness and the reservoir oil viscosity was 1.0 cP at reservoir conditions of 95°C and 17.3 MPa (2500 psi). The stock tank oil had an API gravity of 40 degrees. Once the waterflood was completed the gas injection was begun. Incremental oil recovery was 11%. According to the previous paradigms the oil recovery would be achieved by the gas/oil IFT being lower than the water/oil IFT. Figure 7a shows this schematically. This is consistent with expectation.

The didactic nature of this testing inheres in the comparison with test #2. In test #2 the waterflood was abbreviated to consist of only 2/3 of the breakthrough water volume. This was done to evaluate the influence of leaving a "pad" of oil at the top. Although the incremental volume recovered during the gasflood was significantly higher than during the first test, the overall recovery was lower. This appears to be in error and in fact only allows for two explanations.

The first explanation could be according to Figure 7b where the crosshatched section corresponds to oil recovery by imbibition. The diameter corresponding to σ_{wo} demarcates the features accessed by the water and from which oil is produced by drainage. The only way therefore that the results shown in tests 1 and 2 could be consistent would be if the oil due to recovery by imbibition was greater than the incremental recovered by gas. That is in the top third (oil pad), if secondary gas recovery was the only mechanism then oil recovered might be represented by area B+C. Whereas in the tertiary zone the recovery would be A+B+C. If the superposition of the mechanisms is linear or could be assumed to be linear then the following would have to hold:

$$0.67(0.62) + 0.33(Rec_{gas}) = 0.55 \quad (9)$$

Therefore the recovery due to gas would only be 0.41, less than the waterflood recovery efficiency. The only way this could be so is if the imbibition volume is substantial so that recoveries A+C are greater than B+C or in other words A = 20%, B = 11% and C = 30%. The authors have not investigated this previously since all intuition would usually suggest that water blocking would make the tertiary scheme less efficient than secondary gas. With high waterflood recoveries however this scenario could result just from capillary pressure considerations.

A second alternative is of course that the gas is much less stable and that the instability was compounded by the presence of an oil pad at the injection end. This could be the case if the gas/water IFT were to be sufficiently high compared to the gas/oil IFT to more than compensate for the porous features which have been accessed by water and those which have not been. That is, if the gas/water IFT is ten times greater than the gas/oil then for the same accessibility tendency the gas is equally as likely to access the pores which are ten times smaller than those accessed by the water. If there is an oil pad at the top however this benefit is not realized. The larger pores may contain a segment of oil which vitiates this threshold pressure-based flow improvement and therefore gas preferentially flows into the larger pores, and the gas, oil and water subsequently moves downward and once breakthrough occurs the recovery of oil is much less

than was expected. It is thought that although this effect may be less likely in the field, there may be reason for closely evaluating secondary and tertiary gas. The idea that water blocking will always make tertiary implementation worse than secondary gasfloods appears to be invalid. The more heterogeneous the porous media, the more likely that secondary gas will perform less efficiently than tertiary. Moreover the extrapolation of this logic would indicate that higher water-gas ratios, in such processes as WAG and co-injection, will be more efficient in rock with greater heterogeneity.

The influence of IFT in this case was obvious where even though the density difference between the oil and gas is much less in the low IFT scenario ($\Delta\rho$ was 371 kg/m³ for the enriched gas and $\Delta\rho$ was 497 kg/m³ for the gas cap gas) the greater accessibility translated to significantly greater oil recovery. This indicates that although the flowrate was about ten times the critical rate the response was still very sensitive to the IFT level. The decision as to whether the low IFT gas will be implemented becomes an economic decision as is always the case. Technically, the superiority of the enriched gas is obvious but the cost is significantly higher per unit volume injected. Figure 8 presents a plot of purchase cost, at reservoir conditions, per m³ of injected solvent. It is apparent that as the C₂₊ MW increases the solvent cost increases quickly. This shows therefore, that not only does C₂₊ MW and mole % play a role but the level of IFT required is an important consideration for economic reasons as well. Figure 8 shows that for an IFT of 0.097 dynes/cm the cost per m³ goes from about 27 \$/m³ for a C₂₊ MW of 36 (at reservoir conditions which for the case of Figure 8 were at 26.2 MPa and 97°C) up to about 45 \$/m³ for a C₂₊ MW of 43.5. The difference between the low and high MW C₂₊ (other than the cost) appears to impact the stability of the gas particularly in situations where gravity override can contribute.²⁷ The sensitivity of cost to the level of IFT is equally as important; at a C₂₊ MW of 36.5 for an IFT of 0.097 dynes/cm the cost would be about 50 \$/m³ whereas at an IFT of 0.3 dynes/cm the cost would be about 20 \$/m³. The cost per m³ of solvent at 0.3 dynes/cm is significantly less than at 0.097 dynes/cm. Figure 9 shows these relationships as a function of different C₂₊ MW. The costs used in this analysis were 1.80 \$/MSCF for dry gas, 2.79 \$/MSCF for LPG (32 \$/m³ equivalent liquid) and 8.18 \$/MSCF for propane (78.80 \$/m³ equivalent liquid C₃). The dry gas and LPG are shown in Table 1. Thus the decision of what IFT to use is an extremely important one economically and should be evaluated accurately. Novosad et al^{28,29} have proposed techniques with which to design gas injection strategies as have Orr et al,³⁰ Christiansen et al,³¹ Poettmann et al,³² Rutherford³³ and Thomas et al.^{34,35}

The difference between the low IFT gas (0.2 dynes/cm)

and the lean gas (3.7 dynes/cm) was that the low IFT gas accessed much more of the oil than the high IFT gas. Hagoort³⁶ suggests that very high recovery levels can be observed with immiscible gas injection. The evidence provided here suggests that there will be however significantly different levels of recovery based on IFT. Indeed the low IFT gas should be much less stable than the high IFT gas (due to gravity influence) and therefore the difference must be due to accessibility criteria. It may be that "immiscible" gravity-assisted gas injection may recover as much oil due to film flow and drainage but if the level of IFT influences accessibility then it can also influence the area available for film flow and therefore the rate of drainage. As with all recovery processes the rate of recovery is critical in terms of net present value (NPV) of any property. Much of the reservoir acquisition activity occurring today is based on the rate at which oil will be recovered and therefore although, in the limit, the S_o, to a lean gas might converge to that level of a low IFT gas, the economic rate of recovery will be more acceptable from the low IFT gas than with the high IFT gas, at least for this example.

Reservoir 3

Randall²⁷ summarized thirty years of horizontal hydrocarbon solvent flood performance in Alberta and indicated that, on average, the waterflood recovery factors were 41% with the tertiary hydrocarbon injection increasing total oil recovery to about 51%. He indicated that, although the same IFT can be achieved with ethane-rich systems, the higher MW solvents (at least on a C₂₊ MW basis) perform better. This has been observed in laboratory studies performed by the authors. The general results of a series of five corefloods were as follows:

Test #	Tpc (K)	C ₂₊ MW	Total Recovery (%)	PV Injected For 90% of Ultimate Recovery
1	280	30.9	83	1.1
2	286	45.3	91	0.7
3	283	30.9	87	0.8
4	263	45.3	90	0.7
5	268	31.0	87	0.7

The gases used conformed to a plot like Figure 8. The last two tests correspond to higher IFT but in light of the performance of the fourth test it appears that the IFT is low enough to satisfy the accessibility criterion. Although the recoveries are higher, with the higher MW injection fluids, the amount of gas injected by the time 90% of the oil has been recovered is also lower - that is the oil appears to be able to be recovered faster. Moreover, of note are tests #1,

#3, #4 and #5 where the pseudocritical temperature of test #5 is up to 20K less but it recovers more oil than the other three. In this case, the IFT would be higher in test #4 than in the other tests (1, 3 & 5) but it is still low enough to establish accessibility. The influence of the higher MW compound appears to have achieved more efficient displacement than the ethane rich solvents. The results of Randall²⁷ corroborate this. Reasons for this have been proposed.³⁵ Figure 8 describes the IFT contours with changing C_{2+} MW and at the higher MW C_{2+} , even though the solvent has more C_1 , the density is still higher. Along the IFT contour, the gas at a C_{2+} MW of 35, to have the same density as at a C_{2+} MW of 43, requires a 200 psi increase. Therefore to achieve the same stability with respect to gravity override with a 35 C_{2+} MW fluid that would be present with a 43 C_{2+} MW fluid the operating pressure would have to be 200 psi higher - gravity not IFT.

The corefloods however would have very little, if any tendency for gravity override and therefore it is thought that the improved stability of the higher C_{2+} MW injection gas would be due to its solubility in the oil. Although the solubility of the higher MW C_{2+} components would "leave behind" methane, this separation would have much more influence on the liquid phase viscosity than on the gas phase viscosity. Thus a more stable displacement. Moreover as the C_{2+} MW increases, the mechanism may change from forward to reverse contacts which would affect the mixing zone length (L_{MZ}) and could contribute to the results shown in the corefloods (L_{MZ} is longer for forward contact mechanisms compared to reverse contact systems or even combined systems).

Reservoir 4

This reservoir exhibited a very broad pore size distribution consonant with a vuggy carbonate rock type. Some of the cores analyzed showed pores ranging over five orders of magnitude with bimodal distributions (Figure 10). The oil found in the structure is about 40°API and is a high H_2S system (in excess of 30 mole %). The reservoir has some potential for vertical stabilization but would be classically categorized as having a horizontal orientation. The reservoir was evaluated for immiscible gas injection in the secondary and tertiary modes. The results were as follows:

Test #	Waterflood % Recovery	Gasflood % Recovery	Vertical Operation
1	33	0	Tertiary
2	N/A	34	Secondary

These floods were done in a vertically stabilized manner at a frontal velocity of 0.11 feet/day which was about 2.5 times

higher than the critical velocity as calculated from the Dietz equation. The water/oil IFT was about 19 dynes/cm and the lean gas/oil IFT was about 4 dynes/cm. This shows a very striking trend - regardless of which fluid was used the recovery was about equal. It appeared that the larger porous features were accessed and resulted in oil recovery whereas in all likelihood the smaller pores were by-passed. A factor of two fold decrease in IFT resulted in no incremental oil recovery. The commentary which accompanies this reservoir result is comparable to that of reservoir 2. The recovery response can be easily described in light of the compromise reached between IFT, viscosity, surface area to volume influences and all in the context of the porous media. It is obvious in test #1 that the gas/oil IFT condition was not conducive to incremental oil recovery - the threshold pressure was not sufficiently lower in the smaller oil-filled pores, compared to the larger water-filled pores, to result in good incremental oil recovery. Therefore although the spreading coefficient for his system was positive (greater than 25 dynes/cm), incremental oil recovery due to gravity drainage did not occur. Film flow of oil might have begun but it was so slow that no oil was observed during weeks of gas injection. It may be argued that had the critical rate been imposed, vastly superior results would have occurred. This may be so but the authors have never observed extreme sensitivity to rates that have been this close to the critical rate - within about a factor of 3 higher than Dietz velocity.

Summary

The four reservoirs reviewed herein exhibited characteristics which encompass many gas injection scenarios: immiscible (high IFT usually > 3 dynes/cm) and "miscible" (IFT in the range <0.5 dynes/cm) (miscible is in quotations since miscible is defined as zero IFT whereas practitioners have called floods miscible if they involve enrichment or manipulation of pressure to achieve lower IFT, vertical and horizontal, sandstone and carbonate which in this paper have been discussed mainly with respect to homogeneous versus heterogeneous on the microscale. As well, secondary and tertiary modes have been compared. Although the macroscale analysis has been blatantly excluded from the evaluation, it must be emphasized that reservoirs exhibiting characteristics contributing to heterogeneity and complexity (fractures, faults, barriers, high permeability streaks, etc.) will usually be more challenging to exploit by gas injection. Restricting attention to the results summarized in this paper only the following deductions are made:

1. Just as the macroscale geology is the most important screening criterion for overall reservoir quality, the microscale geology is the foremost determinant in the design of EOR strategies.
2. Each flow unit has an optimal level of interfacial tension

at which the displacing fluid should be designed. What is appropriate for one flow unit may not be appropriate for another in the same reservoir. The apposite design therefore needs to assess the oil target location [which flow unit(s)] and the cost of achieving an adequate level of IFT in the several flow units.

3. Although the correct level of IFT is a necessary condition for optimal exploitation, the balance between IFT, gravity, mobility and microscale core properties is the element of gas injection design which must be properly evaluated. The data provided in this paper have shown how the recovery response, regardless of how counter-intuitive the performance, can be understood once all relevant parameters are properly considered.
4. Lean gas and rich gas (high and low IFT) injection schemes have been compared in secondary and tertiary modes. From this data set the low IFT gas showed a response significantly better than the high IFT fluids. It may be that the high IFT gas may ultimately drain the porous media to the same S_o , but if so the time required would be much longer than with the low IFT gas. If the oil drains through the films present in the high IFT case, whereas the low IFT actually displaces the oil, then this may describe why the high IFT test would require much longer to perform. Although the gravimetric influence is better in the lean gas system it was insufficient to compensate for significantly reduced accessibility and coincident decrease in recovery (and possibly surface area available for film flow).
5. Even when comparing low IFT gas designs it appears that the compositional nature of the injectant can influence the rate and stability of displacement even though the IFT is comparable. The higher MW of C_{2+} components the better the performance. The field cases summarized herein showed that propane-rich gases have performed better than ethane-rich solvents.
6. One example has been provided where a five fold reduction in IFT, from water/oil to gas/oil resulted in negligible incremental oil recovery in a tertiary mode and almost the same recovery with secondary gas as for secondary water despite the IFT being almost five times lower for the gas/oil system as for the water/oil system. In such a case, the path of least resistance followed appears to be invariant with IFT. In such cases significantly enhanced oil recovery will probably only be possible if profile modification strategies are implemented. In reservoirs like this, mobility control will be critical whereas IFT would be of concern only once the mobility is controlled.

These points can be schematically assembled into the

screening criteria according to Figure 11. It is hoped that this approach to screening criteria will be helpful to those evaluating mature fields for gas injection potential.

To attempt to create the screening criteria provided in Figure 11 there are many parameters which must be introduced. The authors recognize that there are only a finite number of characteristics which have been included in the proposed scheme. Nevertheless, this is intended to provide a reasonable procedure by which corporate priorities can be associated with individual production units. Due to the multivariable nature of gas injection candidates the following commentary attempts to elucidate the prioritization scheme displayed in Figure 11.

Reserves, Gas Availability, Process and Gas Consumption

All reservoir engineers have an idea of what target is available for EOR in each reservoir. Knowing the residual oil or the OOIP for a newly discovered well the total possible revenue can be approximated. Assuming the historical recoveries reported by Asgarpour,¹⁴ Randall²⁷ and Fayers and Zhou,¹⁸ (incremental oil recovery in vertical mode of 15 to 40%, incremental oil recovery after waterflood of 5 to 15% in horizontal mode, 4000 scf/bbl of incremental oil) an approximate value can be associated with the reservoir. Note that the gas consumption number of 4 MSCF/bbl is based on lean gas. Enriched hydrocarbon floods should be much lower (~2 MSCF/bbl). Moreover, the equipment to implement gas injection will require upfront capital cost and therefore the pool has to be of such a size to justify the expenditure. It is proposed that with these conservative numbers along with those of Figure 9 (2 to 3 \$CDN/MSCF) an idea of margin can be developed. Since this is a pivotal item, if the reservoir is large enough so that capital cost is small compared to expected oil recovery and if the cost per barrel is not greatly in excess of 10 to 11 \$CDN/bbl then, with present oil prices, the property may hold promise (~20 US\$/bbl).

The priorities assigned to this initial stage of evaluation are somewhat arbitrary and each corporation will have their own. Nevertheless, it is proposed that:

Margin (Mr) (\$CDN/m ³)	Rank
>70	30
50 < Mr < 70	15
<50	5

Macroscale Evaluation

Once the initial screen has been performed and the

property is deemed worthwhile for EOR scrutiny then the next stage is evaluated, the macroscale features. It is proposed that a hierarchy of characteristics be included in the following manner:

Orientation	Large Reserves	Small Reserves
Vertical	15	10
Horizontal	5	0

An added complexity, as was emphasized throughout the data reported herein, is the presence of macroscale heterogeneities such as faults, fractures, high permeability streaks and barriers. These can ultimately greatly reduce sweep efficiency and therefore should detract from the ranking. Again the value to use would be arbitrary but horizontal barriers for vertical systems may seriously degrade the potential of a vertical implementation. In this case it is proposed that zero be added. For high permeability streaks, depending upon the nature, the severity and the extent, a rank of zero may be applied or some higher number. One may be able to infer from waterflood performance this contribution. It is proposed that these macroscale characteristics range from 0 to 10. Natural fractures may not present a significant deleterious effect (Tan and Firoozabadi^{37,38}). Absence of these factors should result in a rank of 10 being added to the macroscale evaluation shown above.

Reservoir Fluid Properties

Most of the reservoirs reported herein have contained oil with viscosities in the 0.5 to 1.5 cP range. Since the finger growth is exponential with viscosity ratio, the oil viscosity can be a significant disadvantage. Because oils with viscosities less than 0.5 cP have shown significant response to gas EOR, it is proposed that:

μ Oil @ T & P	Rank
< 0.5 cP	15
> 1.0 cP	5

This again is arbitrary but it does provide a means of associating a rank to the viscosity ratio, although arbitrary. Field scale gas injection schemes have worked well in this range (<0.5 cP) whereas the authors' database is less extensive for oils with live oil viscosities greater than 0.5 cP. Again, this only serves to offer some input into prioritizing EOR candidates. Of course the viscosity ratio is also greatly aided and abetted by the microscale geology provided in the next section.

Solids precipitation problems can also be very serious.

Those which occur in the wellbore can be treated fairly easily in many cases³⁹ whereas if precipitation occurs in the rock then permeability reduction can ensue which can be more difficult to resolve. Core tests can be readily done to see if permeability reduction is expected.

Solids	Rank
None	10
Wellbore only	5
In-situ	0

The presence of a gas cap can also adversely affect the performance of a gas injection scheme but it is much more pronounced for a horizontal operation than for a vertical flood. The impact that a gas cap will have is a function of the reservoir fluid properties, the orientation, core properties, the gas cap extent and gas availability.

Gas Cap	Rank
Gas cap	0
No gas cap	10

Microscale Geology

It is obvious from the data provided herein that the pore size distribution greatly impacts the performance of the gas injection schemes.

Permeability is not a good criterion to use since if there are large porous features which are connected then the bulk of the flow will occur through them. Thus with diverse pore sizes resulting in microscale by-passing tendencies, the high permeability will not indicate potential for EOR but may in fact reduce the efficiency of the EOR implementation. Therefore, in the authors opinion, on the basis of the work done herein and the existing literature, rocks exhibiting narrow pore size distributions (microscale homogeneity) show the most promise. Therefore, it is proposed:

Microscale Homogeneous	15
Multiple Homogeneous Flow Units	10
Broad Pore Size Distribution	5
Vuggy, Bi-Modal Pore Size	0

Necessary Condition IFT

The design of gas is closely coupled to the porous media and all the attendant conditions. With the costs approximated by Figure 9, the sensitivity of cost on IFT is apparent. For most reservoirs observed, a gas/oil IFT of less than 0.2 dynes/cm has usually been adequate. This however is a

function of wettability and the pore size distribution as described. For enriched gas, the IFT can always be adjusted by increasing the LPG content and/or the C_{2+} MW. It therefore becomes a question of whether the enrichment required is affordable or not. It is proposed, in light of this, that:

IFT Achieved For Accessibility	Rank
Yes	15
Water/Oil IFT	0

By way of description, if the gas/oil IFT is designed low enough to access all pore throats, then a rank of 15 is attached. Note this does not mean zero IFT since for water-wet systems the IFT should be designed to access the diameter corresponding to water-filled features, nothing smaller. The water/oil IFT is ranked at zero since it is the base level. Most immiscible gasfloods have IFT in the 3 to 6 dynes/cm range whereas water/oil is usually in the 12 to 18 dynes/cm range. The interpolation should then be:

$$\log_{10}(0.1) = -1$$

$$\log_{10}(\text{IFT}_{w/o}) \approx 1$$

Consequently

$$\text{IFT}_{g/o} = 3 \quad \log_{10}(3) = 0.48$$

and the ranking would be 3.9 as an example. For horizontal floods this is much more important than for vertical floods and therefore for vertical floods it is proposed that 10 be added to this ranking; if horizontal orientation nothing will be added. In this manner a vertical flood at 3 dynes/cm will appear close to the same, in terms of priority, as a horizontal flood at 0.6 dynes/cm. This depends on the other parameters detailed above but does reflect the general experience of the authors.

Balance Between IFT, Mobility, Gravity, Wettability, Secondary, Tertiary

This section describes, for the most part, the testing that has been detailed in the main body of this paper. Although all the different parameters can be determined independently, in order to obtain an initial view of this balance coreflood responses are extremely important. To comment on the effects of mobility versus IFT domination, certain core orientations can be utilized (i.e. horizontal versus vertical as in the case of Reservoir 1, tests 4 and 7). As well, all other parameters can be held constant and the IFT level can be altered. This allows for insight into the IFT/mobility compromise. Secondary and tertiary operation can also easily be scoped along with WAG, co-injection or continuous gas as has been shown herein. Water shielding versus imbibition

benefit is readily scoped as well. It is proposed that the following ranking be used:

IFT Domination	20
Mobility Dominated (WAG or co-injection when water works well)	10
Mobility Dominated (water results are poor)	5
Gravity Override Dominated	0

The reason for this ranking is that if the system is dominated by IFT then the IFT changes from being a necessary condition to a sufficient condition - recovery approaches accessibility. In such a case the design becomes easier and risk is lower. Mobility dominated reservoirs have an element of risk associated since they are inherently unstable unless steps prove efficacious in controlling the gas. This higher risk is why the rank is downgraded from 20 to 10. If water works well in controlling the gas displacement however, the system can be very effective and water is inexpensive. If the system is mobility dominated (which includes viscosity effects and path of least resistance concerns), and if water does not enhance the control, then more risky implementations may be required (profile modifiers such as foams polymers, bacterial slimes, etc.). This type has therefore been downgraded to 5 in the ranking.

The gravity override factor has been given a zero ranking only to indicate the potential problem. If the viscous to gravity ratio can be increased sufficiently to resolve an initial gravity override problem then this can be upgraded. However to do so the engineer will need to consider the terms in Equation 7 and determine if their manipulation is possible. If not then gravity override can be a serious limitation and would significantly downgrade the reservoir rank.

None of the remaining three have been commented on in the ranking since the results of the simulator are closely connected to the data sets used, the geological model and the engineer. However, the simulation results will often persuade a corporation to perform a pilot or will at least provide one more layer of risk analysis on which to make the final decision of field trial or not.

To summarize this set of screening criteria, it is emphasized that many complexities have surely been oversimplified if not disregarded altogether. All this set of criteria should be used for is to quickly rank candidate reservoirs for gas EOR potential and should be viewed as a first pass.

Three reservoirs will now be ranked as examples of how

to use the screening approach. The criteria are:

Parameter	Rank
Reserves Evaluation	
Margin (Mr) > 70 \$CDN/m ³	30
50 < Mr < 70 \$CDN/m ³	15
50 \$CDN/m ³	5
Macroscale (Reserves)	Large Small
Vertical	15 10
Horizontal	5 0
Heterogeneities	
None	10
Present	0
Fluid Properties	
Oil Viscosity	5 - 15
Solids precipitation	
None	10
Production Wells	5
Core plugging	0
Presence of gas cap	0
Absence of gas cap	10
Microscale Geology	
Homogeneous	15
Multiple homogeneous flow units	10
Broad pore size distribution	5
Vuggy, bi-modal pore size	0
Necessary Condition IFT	0 - 15
Vertical	10
Horizontal	0
Balance of IFT, Mobility Gravity, Wettability, Secondary, Tertiary	
IFT dominant	20
WAG for mobility	10
Profile mod for mobility	5
Gravity override	0

Using this ranking approach the maximum value is 150. The absolute value is immaterial since the evaluations performed are on a comparative basis to other reservoirs involved in the examination. Thus these proposed screening criteria allow for the ranking of candidate reservoirs for gas EOR as opposed to associating an absolute value of how good a reservoir really is. This approach will identify to an operator, of all possible reservoirs, which might be the best gas EOR candidate. However, since the authors have not a sufficient database of application, one can not conclude that a value beneath 60 for example means that there is no economic potential for gas EOR. All it does is identify the reservoir with the best gas EOR potential from a list of candidates. An example of the use of this criteria follows. Assume we have three reservoirs and want to rank them in order to focus limited resources on the development of the best one. Here are the specifics. Note that it has been assumed in this example that 0.1 dynes/cm is the best IFT

level to maximize accessibility. This will vary from reservoir to reservoir and therefore the contribution of IFT to the ranking should be 15 if that optimal IFT is achieved. That is the key. The means for interpolating between water-oil and optimal gas-oil IFT should be derived in the context of the pore size distribution as well. To keep it simple for this example the log₁₀-based interpolation was used.

Reservoir 1 - Characteristics

- 25 - 40 MMbbls oil
- horizontal, homogeneous sand, only one flow unit, thin 6 to 10 feet
- 50°API, 0.10 cP oil viscosity
- gas available from re-injection and pipelines
- low Sw_c, oil-wet

Some laboratory work was then performed to evaluate the pore size distribution and interfacial tension. The balance between the pertinent factors which comment on the coupling between IFT, mobility, secondary and tertiary operation etc. were not done due to corporate budget restrictions.

The rank for this reservoir would be (assuming 50 to 70 \$CDN/m³ in terms of the initial reserves evaluation):

Reservoir 1	Rank
Margin	15
Macroscale	
- reserves	0
- no heterogeneities	10
Fluid Properties	
- viscosity	15
- no solids	10
- no gas cap	10
Microscale geology	
- 1 homogeneous flow unit	15
IFT	
- <0.1 dynes/cm	15
- horizontal	0
Balance	
- assumed IFT domination	20
	110

This reservoir has been under gasflood for about seven years and is an economically viable "miscible" flood. There have been some surprises with respect to premature breakthrough which may have been presaged had the core work been performed which evaluates this specific question.

Nevertheless with 110/150 points, this reservoir scored highly.

Reservoir 2 - Characteristics

- > 200 MMbbls oil
- vertical, zones of vuggy carbonate (20% of oil), total reservoir >100 metres
- 40°API, 0.5 cP oil viscosity
- gas readily available
- solid precipitation (asphaltenes)

Reservoir 2	Rank
Margin	15
Macroscale	
- reserves	15
- heterogeneities (20% of pay vuggy)	7
Fluid Properties	
- viscosity	15
- solids (wellbores)	5
- gas cap present	0
Microscale geology	
- broad pore size distribution	5
IFT	
- < 0.1 dynes/cm	15
- vertical	10
Balance	
- assumed IFT dominated	20
	107

This flood has been operating for many years at a flow rate below the critical value. To date about 80% of OOIP has been recovered and is a technical and economic success.

Reservoir 3 - Characteristics

- > 50 MMbbls oil
- horizontal, vuggy
- 35°API, $\mu > 0.5$ cP
- gas readily available

Reservoir 3	Rank
Margin	15
Macroscale	
- reserves	5
- heterogeneities (some)	5
Fluid Properties	
- oil viscosity ($\mu > 0.5$ cP)	10
- solids	5
- no gas cap	10
Microscale Geology	
- bi-modal pore size distribution	0
IFT	
- about 0.5 dynes/cm	9.8
Balance	
- mobility dominated (poor water results)	5
	~65

This reservoir was never developed since laboratory waterflood recovery was poor (<20%) and gasflood was also poor. The only pores swept were the large vuggy pores of the rock and all the smaller porous features containing the oil were by-passed. Using lab-generated relative permeability curves, the field simulation also indicated inadequate economics to justify development. The operator therefore chose not to continue with the project even though there is significant oil still in place.

From using this set of screening criteria, the reservoirs ranked 1, 2 and 3. Both reservoirs 1 and 2 have proven to be technical and economic field successes and so the ranking should be high. Reservoir 3 had significant limitations and the ranking indicated that if a company had these three candidate reservoirs, that reservoirs 2 and 1 would receive attention significantly before reservoir 3. Reservoir 2 may be ranked higher than reservoir 1 because of its size and vertical nature once the economics are performed accounting for the size and associated economy of scale.

The authors hope that this approach to gas EOR screening will help operators to prioritize their candidate EOR reservoirs in a manner such that optimal benefit can be realized.

Nomenclature

ρ	density
D	diameter
f	fractional flow
g	gravity
σ	interfacial tension
Mr	margin
M	mobility ratio
k	permeability
P	pressure
\propto	proportionality
v	velocity
μ	viscosity

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TABLE 1
BASIS FOR GAS AND LPG CALCULATIONS

Component	Dry Gas	LPG
N ₂	0.000	0.000
CO ₂	0.028	0.021
C ₁	0.935	0.008
C ₂	0.037	0.646
C ₃	0.000	0.224
i-C ₄	0.000	0.033
n-C ₄	0.000	0.034
i-C ₅	0.000	0.011
n-C ₅	0.000	0.012
C ₆	0.000	0.011
	1.000	1.000
MW	17.3	36.9
T _{pc} * (K)	198.0	332.3
P _{pc} (psia)	680.6	675.4

FIGURE 1
SCHEMATIC OF A PORE SIZE DISTRIBUTION

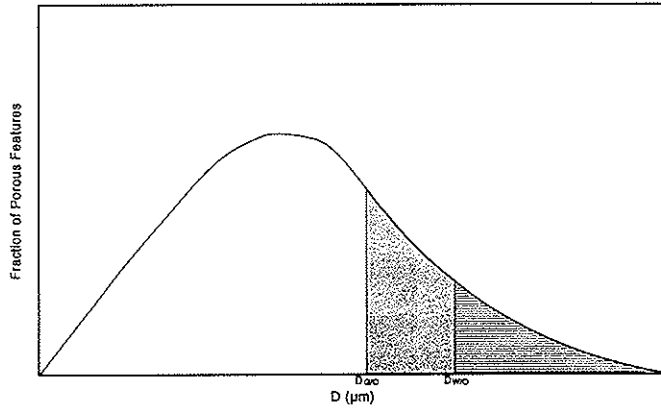


FIGURE 2
EFFECT OF WETTABILITY SCHEMATIC

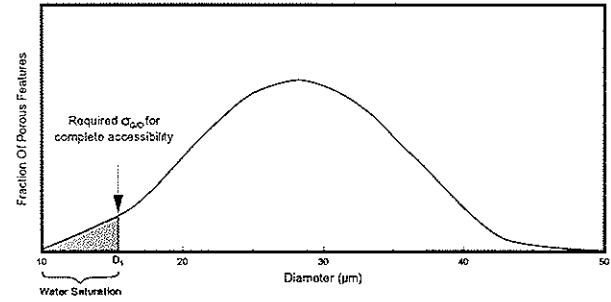


FIGURE 3
FLOW UNIT 1 - 10 mD
APPARENT PORE VOLUME DISTRIBUTION

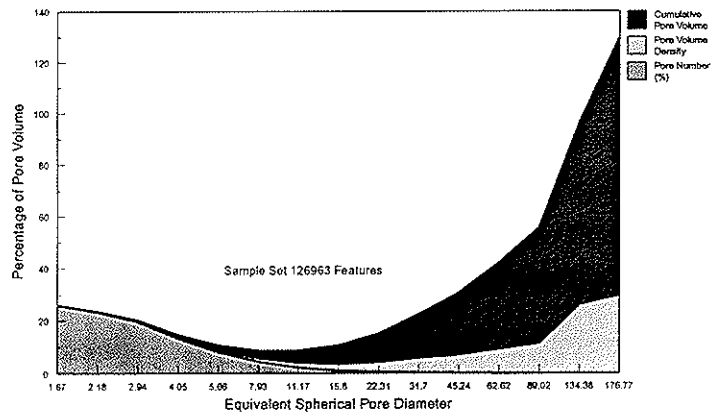


FIGURE 4
FLOW UNIT 2 - 500 mD
PORE VOLUME DISTRIBUTION

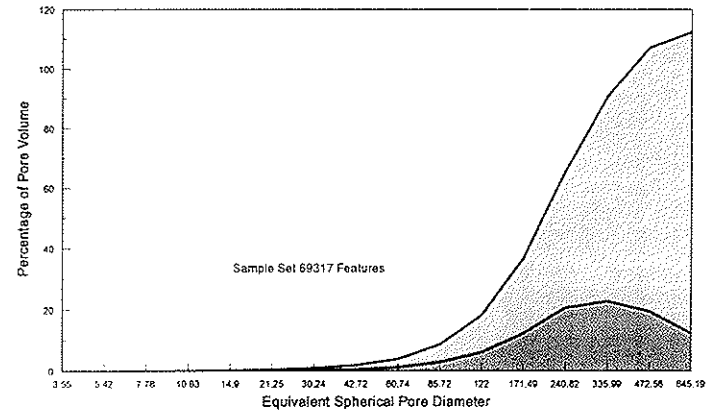


FIGURE 5
FLOW UNIT 3 - 45 mD
PORE VOLUME DISTRIBUTION

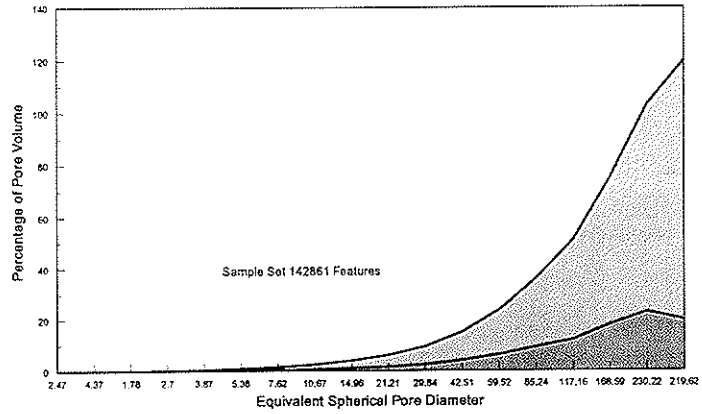


FIGURE 6
PORE SIZE DISTRIBUTION OF 220 MESH SAND PACK

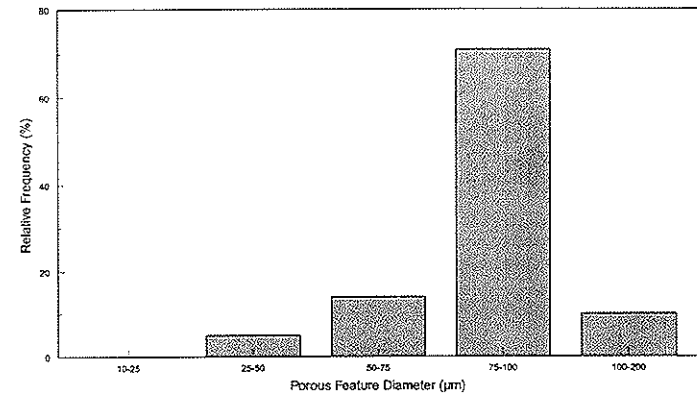


FIGURE 7
DESCRIPTION OF COREFLOOD RESPONSES
IN THE CONTEXT OF THE MICROSCALE FACTORS

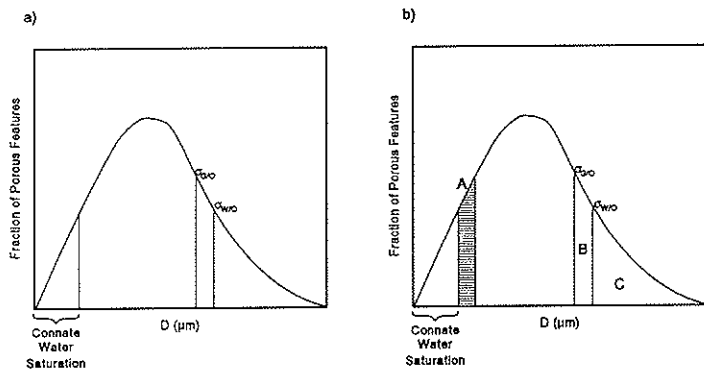


FIGURE 8
C2+ MOLE FRACTION & COST vs C2+ MOLECULAR WEIGHT

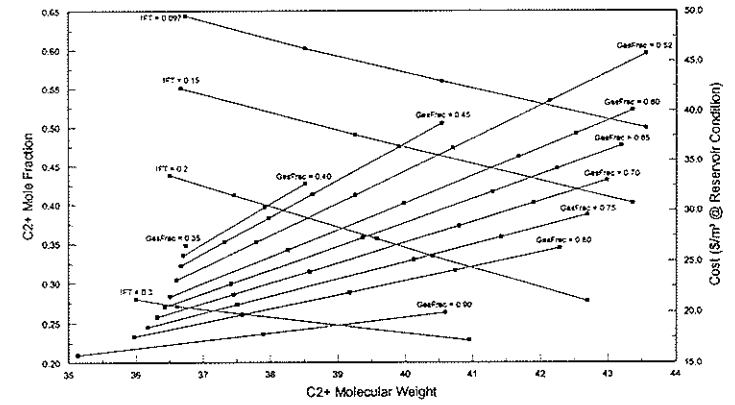


FIGURE 9
IFT vs COST OF SOLVENT

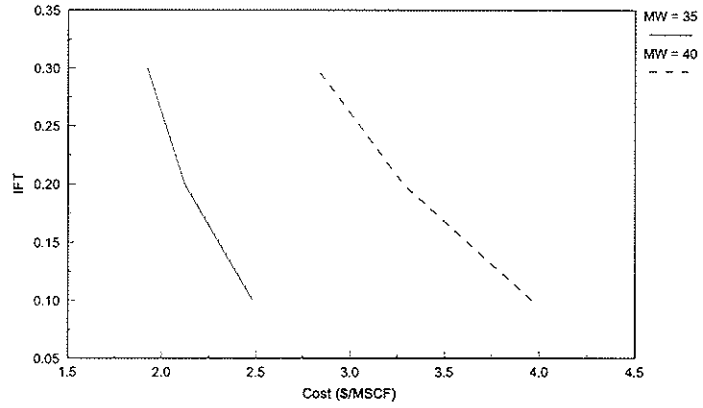


FIGURE 10
PORE THROAT SIZE DISTRIBUTIONS
(MERCURY CAP PRESSURE)

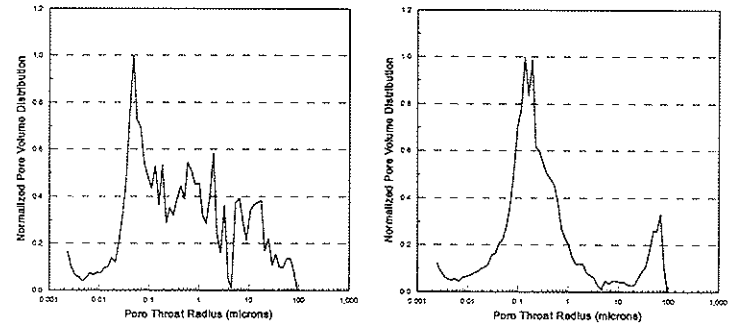


FIGURE 11
PROPOSED GAS INJECTION SCREENING CRITERIA

