A TECHNICAL SURVEY OF IMMISCIBLE GAS

INJECTION PROJECTS

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# A TECHNICAL SURVEY OF IMMISCIBLE GAS INJECTION PROJECTS

by

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REPORT

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## ABSTRACT

Reservoir, fluid, and oil recovery data were gathered for ongoing and completed projects which implemented immiscible gas injection as an enhanced oil recovery process. A data base consisting of information from 24 immiscible gas injection projects was compiled. Selected fluid, reservoir, and oil recovery parameters were analyzed using frequency plots and statistical analysis techniques in an effort to determine if correlation could be found between oil recovery and reservoir and fluid parameters.

Because of the small amount of oil recovery information available, it was not possible to explore whether or not there was correlation between oil recovery and reservoir and fluid parameters. In spite of this, the study did generate some significant results. Several of these results are: the reservoir oil targeted for immiscible gas flooding tended to be a high gravity ($\geq 35^{\circ}$ API), low viscosity ($\leq 0.5$ cp) crude, most of the producing formations were deep (>7000 feet), high temperature (>150$^{\circ}$F), high pressure (>3000 psi) reservoirs, and permeabilities of the producing formations tended to be low (<40 md).

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# CHAPTER I

# INTRODUCTION

## OVERVIEW OF GAS INJECTION RECOVERY MECHANISMS

When gas is injected into a reservoir for the purpose of displacing reservoir fluids, recovery takes place by one of three processes. The simplest process is first-contact miscible displacement, which occurs when the injected gas is completely miscible with the displaced fluid upon first contact. Because high pressures are generally required to achieve first-contact miscibility, this type of recovery is not common.

The second type of recovery mechanism is developed, or repeated contact, miscibility. There are two types of developed miscibility; condensing, or enriched, gas drive and vaporizing gas drive. In each case miscibility is developed over a period of time by repeated contact between the injected gas and the reservoir fluid.

The third process is immiscible displacement. Immiscible displacement occurs when the injected gas is not, nor becomes, miscible with the reservoir fluid and there is interfacial tension between two distinct phases.

### First-Contact Miscible Displacement

Miscibility occurs when two phases mix in all proportions immediately upon contact without an interface being formed between the phases.[1] In theory, if a gas is injected into a reservoir and is completely miscible with the reservoir fluids, the capillary and interfacial forces will disappear and 100 per cent of the contacted oil will be displaced.[2] First- contact miscibility is not very often achieved in gas flooding because of the high pressures required to make the injected gas miscible with reservoir fluids.

The ternary diagram in Figure 1.1 shows the relationship between an injection gas and reservoir oil in a first-contact miscible displacement. At given values of pressure and temperature all points located within the envelope will exist as a gas-liquid, or two-phase, system and all points located outside the envelope will be in a single (gas or liquid) phase state.[2]

In order for a first-contact miscible displacement to occur, a straight line drawn from the injection gas composition to the plotted oil composition must not intersect the two-phase envelope. The displacement would be a single-phase process with the formation of a gas-oil mixing zone which would be completely miscible with the reservoir oil at its leading edge and completely miscible with the injected gas at its trailing edge.

**SCHEMATIC OF MISCIBLE DISPLACEMENT**

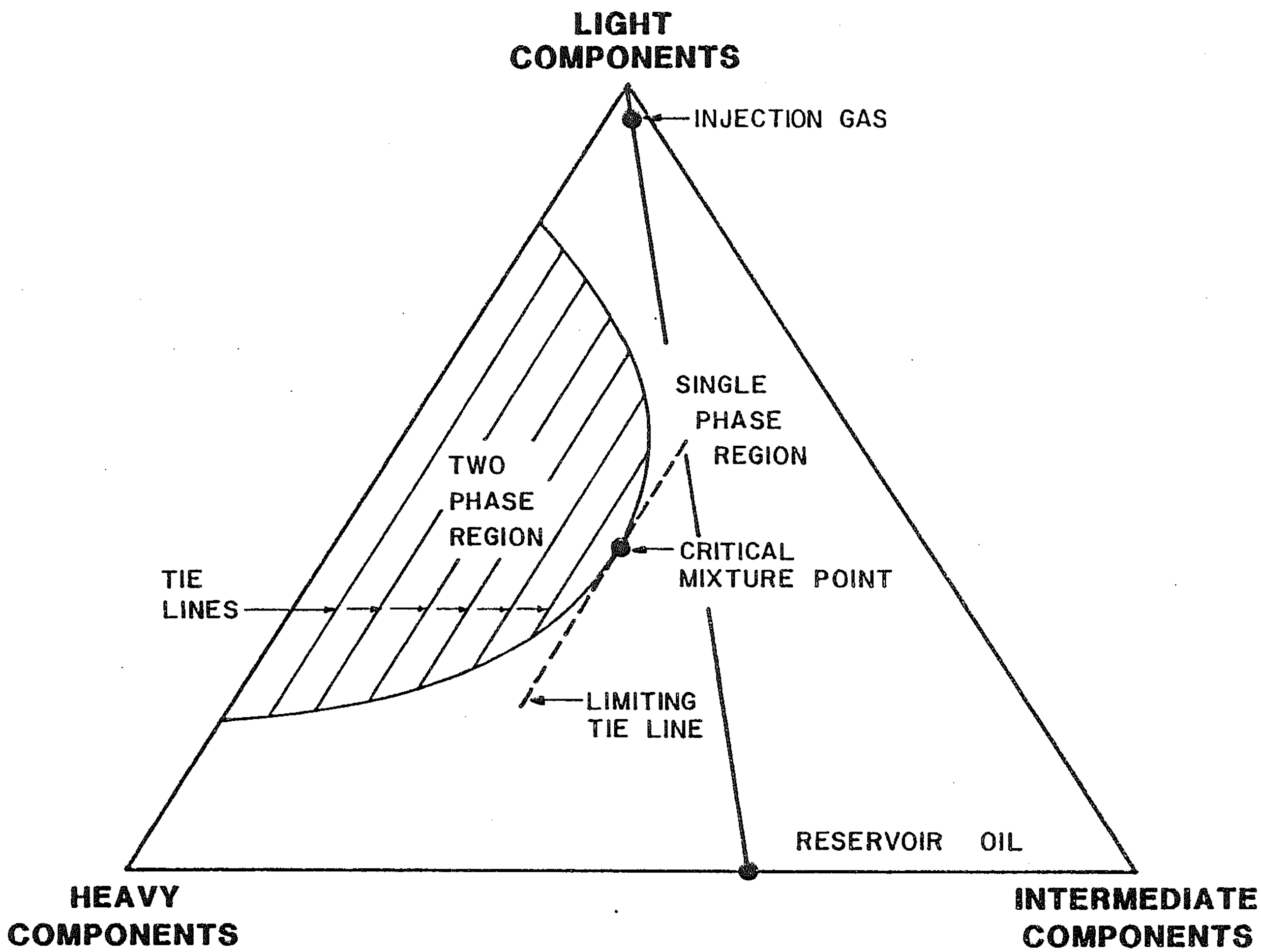


FIGURE 1.1

A reduction in pressure would increase the size of the two-phase envelope, which would narrow the range of reservoir oil compositions that could be miscibly (first-contact) displaced by the given injection gas. Conversely, an increase in pressure would shrink the envelope, enabling the injected gas to miscibly displace a wider range of reservoir oil compositions. The pressure required for a first-contact miscible displacement varies according to the reservoir temperature and the compositions of the injection gas and the reservoir oil.

## Developed Miscible Displacement

Developed miscibility occurs when a gas is injected into the reservoir which is not miscible with the reservoir fluid but which develops a zone of miscibility between the oil and the injected gas through mass transfer brought about by repeated contacts between the two phases.[3] There are two basic variations of this process, the vaporizing (high pressure) gas drive and the condensing (enriched) gas drive.[2,4]

### Vaporizing Gas Drive

The vaporizing gas process entails injection of a lean, or dry, gas into a reservoir which contains oil that is rich in intermediate ($C_2$-$C_6$) components.

Historically, natural gas (primarily methane, $C_1$) has been used as the injection gas in this process, but nitrogen, flue gas and carbon dioxide can also be used. The pressures and temperatures for which miscibility will occur will vary according to which gas is used.

Upon injection the gas front contacts the oil and the intermediate components are evaporated out of the oil into the gas. As the displacement front repeatedly contacts the oil, the gas is further enriched with intermediate components from the oil until it becomes miscible with the reservoir oil. A buffer zone is then formed which is miscible both with the trailing edge of the oil bank and with the leading edge of the gas front. Figure 1.2 depicts the vaporizing gas drive process.[5]

The ternary diagram in Figure 1.3 illustrates the process of developed miscibility which is achieved by multiple contacts between nitrogen and the reservoir oil.[6]

The injection gas in Figure 1.3 is pure nitrogen contacting crude oil composed of 50% intermediates and 50% heavy components. The oil and $N_2$ reach equilibrium and the mixture composition $M_1$ is located in the two-phase region of the phase envelope. The mixture $M_1$ separates into a gas phase $G_1$ and a liquid phase $L_1$. The gas, $G_1$ is more mobile than the liquid, $L_1$, and moves ahead to contact fresh oil. The crude and gas $G_1$ will mix and reach equilibrium. The equilibrium point of the second mixture is on the tie line at $M_2$ and is composed of the gas $G_2$ and liquid $L_2$.[5,6]

Gas $G_1$ has approximately 35% intermediate hydrocarbons, gas $G_2$ has approximately 40%, and gas $G_3$ approximately 50%. The leading edge of the gas continues to be enriched upon each contact with the oil as the oil contacted is stripped of intermediate components. This process

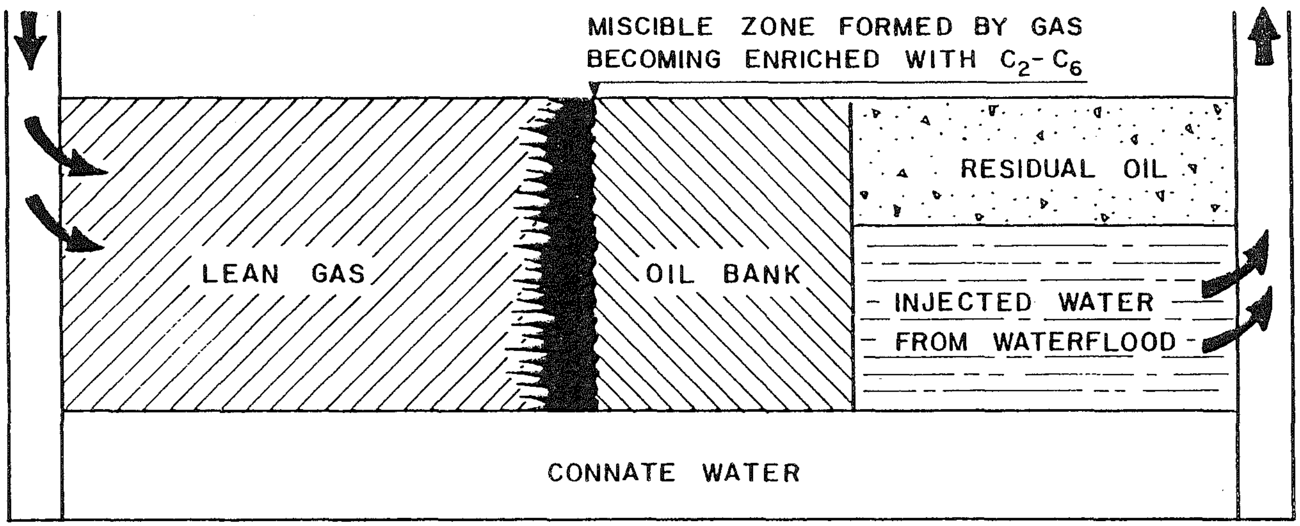


FIGURE 1.2

Schematic of The Vaporizing
Gas Drive Process (from van Poollen, 1980)[5]

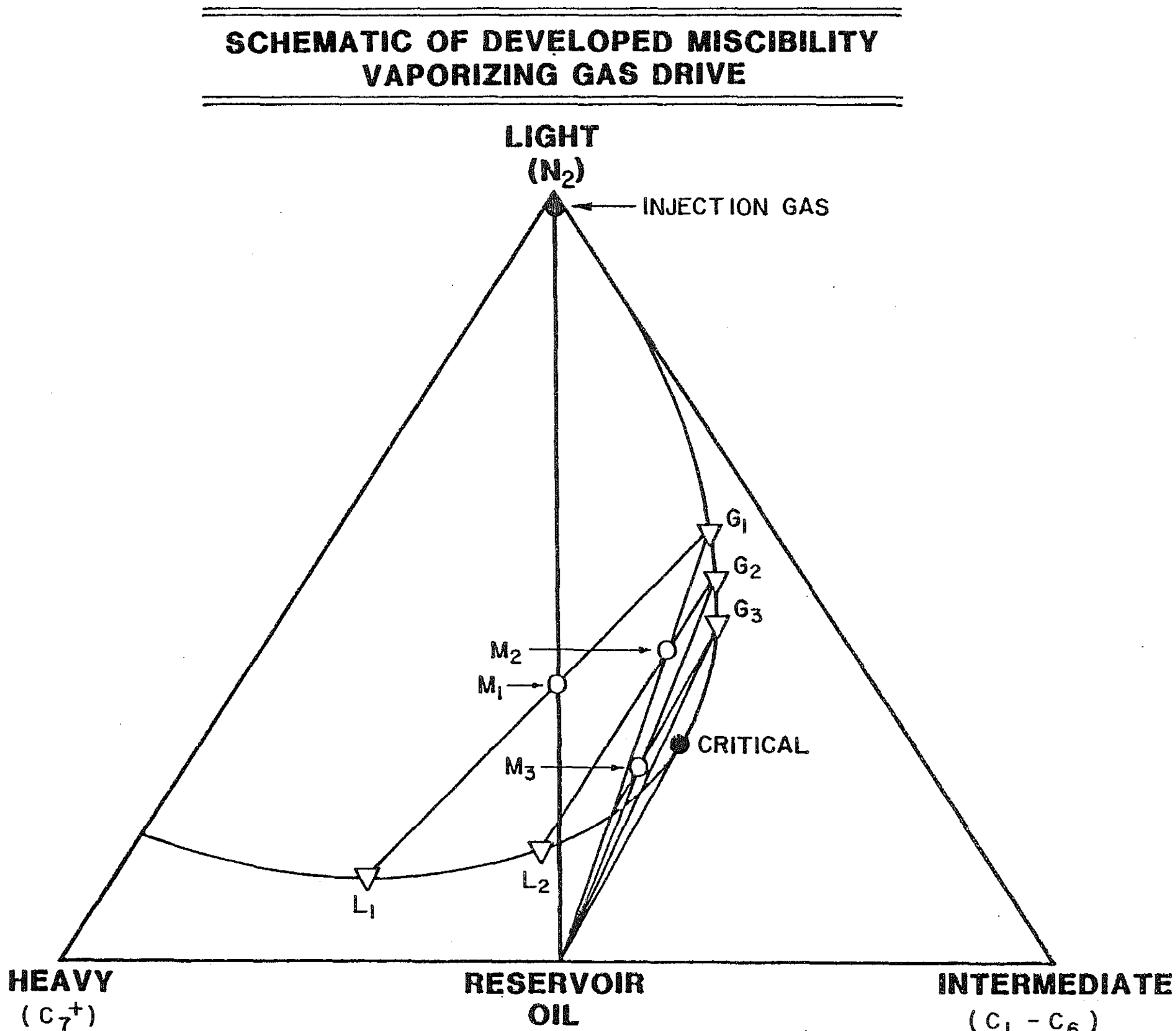


FIGURE 1.3 (from Rushing et al., 1976)[6]

continues until the leading edge of the gas front becomes miscible with the reservoir oil. In theory, oil displacement at the leading edge of the miscible zone then approaches 100%.[1,2,5,6] It should be noted that, in order for the injected gas and reservoir oil to develop miscibility using the vaporizing gas drive process, the reservoir fluid composition must plot on the intermediate component side of a line drawn tangent to the two-phase envelope and through the critical mixture point. If this condition is not met, the gas cannot become enriched enough to develop miscibility with the reservoir oil.[4,5]

Two criteria must be satisfied in order to be successful in using the vaporizing gas drive process; first, the oil to be displaced must be undersaturated and rich in intermediate ($C_2$ - $C_6$) components, and second, the reservoir pressure must be high. This would exclude the application of this process to reservoirs that contain heavy oils and those at shallow depths. In general, the vaporizing gas drive process is applicable when the oil gravity exceeds $40^{o}$ API and when the reservoir depth is greater than 5000 feet.[4,5]

### Condensing Gas Drive

The primary difference between the condensing and the vaporizing gas drive processes is that in the former, the intermediate components ($C_2$ - $C_6$) are supplied by the gas, and in the latter, those components are supplied by the reservoir oil.

In the condensing gas drive process an enriched gas (containing intermediates) is injected into the reservoir and contacts reservoir oil.

Upon contact the intermediate components from the gas condense into the oil. As the injected gas repeatedly contacts the oil, condensation continues until a miscible zone is formed between the oil and the gas, as shown in Figure 1.4[5]. The miscibility in the buffer zone between the oil and the gas develops at the tail of the gas-oil mixing zone instead of at the leading edge of the gas front, as in the vaporizing gas drive process. Because enriched gas is expensive, usually only a slug of enriched gas will be injected and dry (lean) gas will then be utilized to push the slug through the reservoir.[2,5,7,8]

Figure 1.5 illustrates the condensing gas drive process with the use of a ternary diagram.[4] An enriched gas, point G, is injected into a reservoir with reservoir fluid composition represented by point O. In this case the reservoir fluid is located inside the two-phase envelope and has a liquid phase composition of $L_1$ and a gas phase of composition $G_1$. As the enriched gas is initially injected, it will tend to displace the gas phase, $G_1$, and mix with the liquid phase of the oil, $L_1$; the composition of this mixture is represented by $M_2$. The mixture $M_2$ consists of two phases, $L_2$ (liquid) and $G_2$ (gas). Additional injection of enriched gas will displace the gas, $G_2$, and will mix with the liquid, $L_2$.

The composition of the new mixture will be point $M_3$ which will separate into a liquid phase, $L_3$, and a gas phase, $G_3$. Continuing the gas injection will result in the displacing of the gas phase, $G_3$, and mixing with the liquid phase, $L_3$, to form the mixture $M_4$. This process continues until the enriched oil becomes completely miscible with the injected gas.

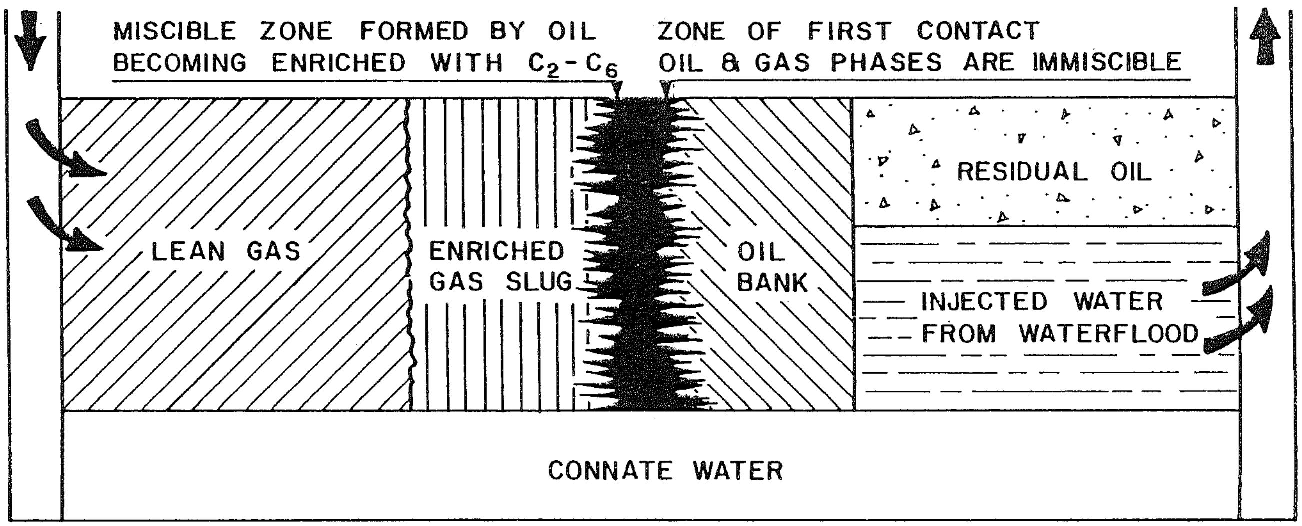


FIGURE 1.4

Schematic of The Condensing
Gas Drive Process (from van Poollen, 1980)[5]

## SCHEMATIC OF DEVELOPED MISCIBILITY CONDENSING GAS DRIVE

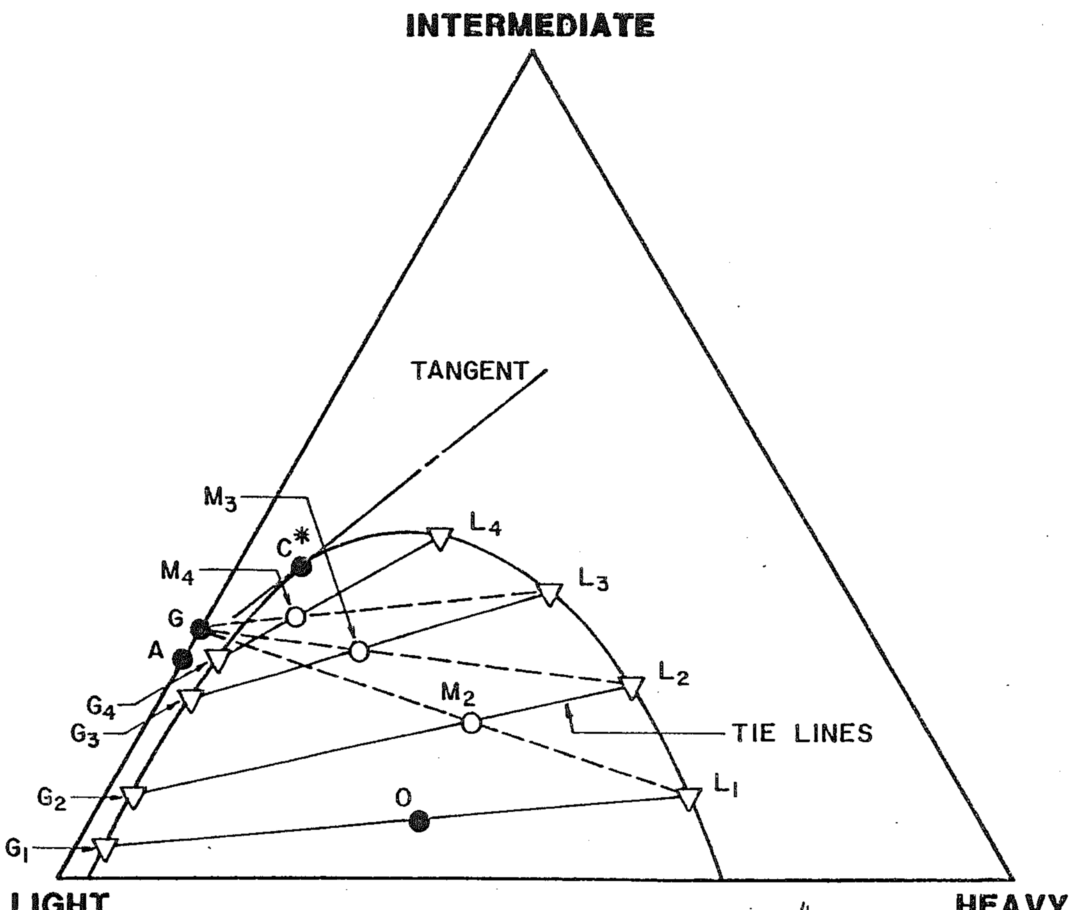


FIGURE 1.5 (from Sandrea et al., 1974)[4]

For the conditions represented in Figure 1.5, the composition of the enriched injection gas, in order to give a miscible displacement, must plot above the limiting tie line, which is drawn through the critical mixture point $C^*$, and tangent to the two-phase envelope. Point A represents the composition of the leanest injection gas that will develop a miscible displacement for the given pressure and temperature.[2,4]

The condensing gas drive process works best with low gravity oils (> $20^{\circ}$ API) which can be either saturated or undersaturated. The process does not require high pressures (> 1000 psia) which would make it applicable to shallow reservoirs.[4,9]

Immiscible Displacement

Miscible displacement of oil by gas injection is a much more efficient recovery process than is immiscible displacement, but in many instances, usually due to economic considerations, it is not possible to achieve a miscible displacement. Inadequate pressure is a common reason why miscibility is not obtained in a gas flood.

Even though a displacement process is immiscible, it is tending towards miscibility and some of the advantages of a miscible displacement process are found, though not to as great a degree as in a miscible displacement. These advantages are swelling of the oil, reduction of oil viscosity, and reduction of capillary and interfacial forces, all of which improve oil recovery.[8,10]

When two fluids are immiscible, interfacial tensions exist between the phases which prevent mixing and a distinct interface separates the fluids. The ternary diagram in Figure 1.6 illustrates the limitations in an immiscible displacement process.[7]

In this case, the injection gas and the reservoir oil are in single-phase regions, but both are on the two-phase side of the critical tie line. Upon injection the gas will contact the oil and an initial mixture, $M_1$, will result which is composed of a gas phase, $G_1$, and a liquid phase, $L_1$. As before, the gas $G_1$ will flow forward to contact the new oil and the mixture $M_2$ will form, and so on. As in the vaporizing gas drive process, the gas is being enriched with intermediates at the leading edge (forward contacts) of the gas-oil mixing zone, but in this case the enrichment process is limited. The gas cannot be enriched any further than the composition given by the tie line which when extended passes through the reservoir oil (forward contact limiting tie line in Figure 1.6). At the leading edge (forward contacts) of the gas-oil mixing zone the mixture displacing the reservoir oil will have the composition of the mixture on this limiting tie line. This displacement is an immiscible displacement since the displacing mixture ($M_3$, $M_4$, etc.) is located in the two-phase region of the phase envelope.

Returning to the initial contact, the injected gas contacts the reservoir oil and the liquid $L_1$ mixes with the gas to form the mixture $M_{-1}$ which is composed of a gas phase, $G_{-1}$, and a liquid phase, $L_{-1}$. The gas phases $G_{-1}$, $G_{-2}$, and so on, are losing their intermediate components at the trailing edge (reverse contacts) of the gas-oil mixing zone as in the condensing gas drive process. This condensing process also has a limit. The condensing process is limited by the tie line which, when

SCHEMATIC OF IMMISCIBLE DISPLACEMENT

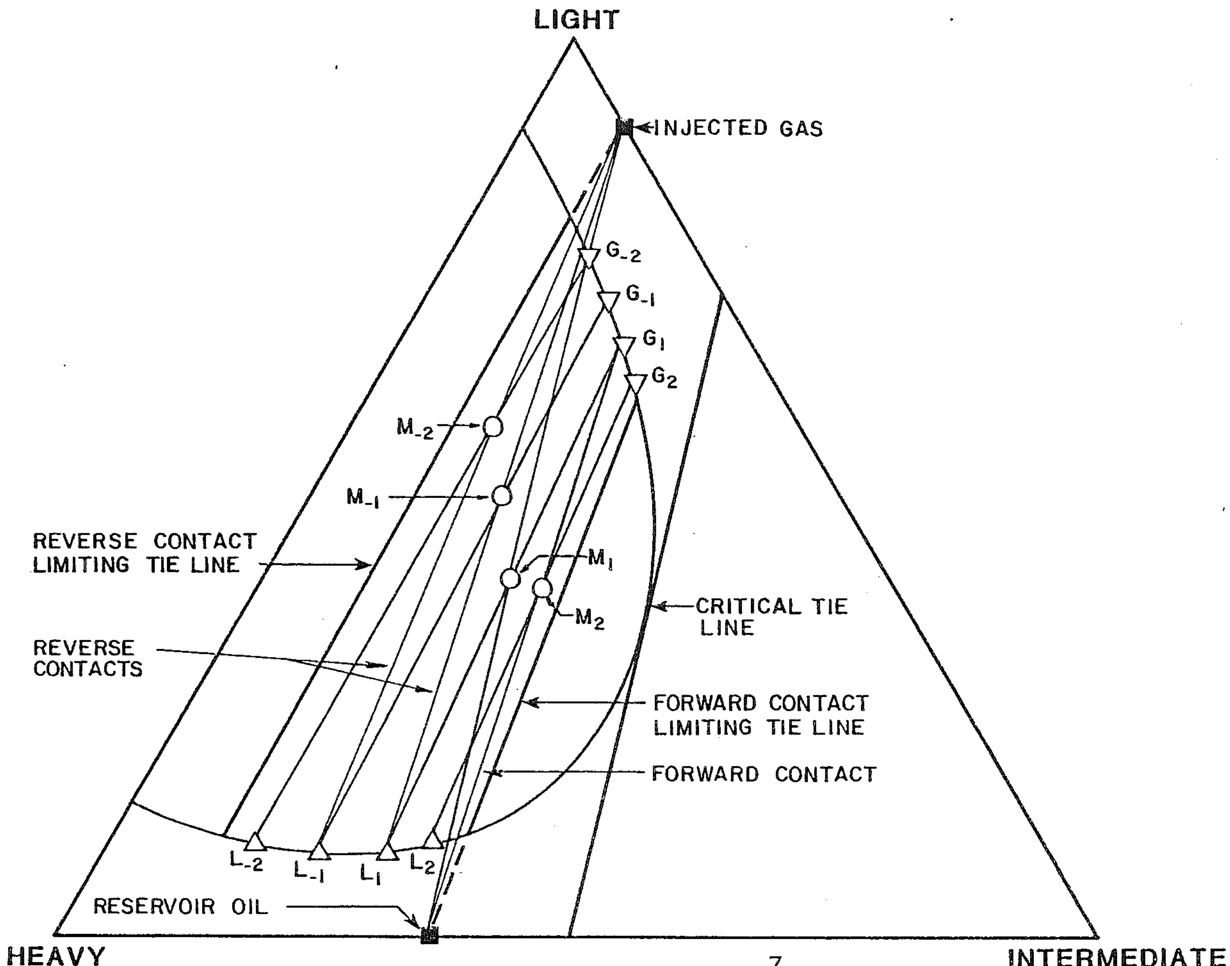


FIGURE 1.6 (from Lake et al.)[7]

extended, passes through the injection gas composition (reverse contact limiting tie line in Figure 1.6). The displacement is immiscible at the reverse contacts of the gas-oil mixture since a single phase gas is displacing a two-phase mixture ($M_{-1}$, $M_{-2}$, etc.). The displacement process is completely immiscible, then, since the displacement process is immiscible at the forward contacts of the gas-oil mixing zone as well as at the reverse contacts.[7]

## GASES USED IN IMMISCIBLE DISPLACEMENT

The gases which are most frequently used for displacing oil immiscibly are flue gas, nitrogen, air, methane, and $CO_2$. Each gas has properties and characteristics that determine the reservoir fluid compositions it will most efficiently displace.

Flue gas, nitrogen, and air are also known as inert gas, inert gas being a gas that is either pure nitrogen or a gaseous mixture that is predominantly nitrogen.[5]

The composition of flue gas varies depending on its source, but generally it is made up of 10-15% $CO_2$, 80-85% nitrogen, and the remainder is small amounts of impurities, such as CO. Flue gas is also referred to as exhaust gas; the terminology used is based on the source of the gas. When the gas is produced by the burning of natural gas or other fossil fuels, the gas generated is known as flue gas. When the gas is obtained from the exhaust of internal combustion engines, it is referred to as exhaust gas.[11]

Flue gas requires relatively higher pressures than $CO_2$ or natural gas to become miscible with reservoir oil; the miscibility pressure depends on the composition of the oil and the flue gas. In general, flue gas gives the best results when applied to reservoirs containing low API gravity oils. This is due to the viscosity reducing effects of the $CO_2$ (10-15% of flue gas is $CO_2$) as it dissolves in the heavy oil.[11]

Air is made up of approximately 79% $N_2$ and 21% $O_2$ and is the cheapest and most easily obtainable gas available for immiscible injection. In spite of this, air is not often used because of the problems associated with its use. Many of these problems are due to the oxygen in the air and its reactive nature. These problems include corrosion, emulsion formation, spontaneous ignition of the oil near injection wells, and explosive mixture formation.[5]

Nitrogen requires very high pressures to achieve miscibility with reservoir oil, generally pressures must exceed 4000-5000 psi. The success of a nitrogen injection project depends on the API gravity of the oil (which is generally related to the reservoir depth, pressure, and temperature); the higher the API gravity, the lower the miscibility pressure will be. Oil gravities should be $35^{\circ}$API and greater before using nitrogen as an injection gas; nitrogen requires that an oil have light ends and intermediate components in order to become miscible with the reservoir oil. The more solution gas dissolved in the oil (this infers both high reservoir pressures and a high API gravity oil) the more easily miscibility between the injected nitrogen and the reservoir oil will be achieved.[11]

Nitrogen also has the advantage of being relatively inexpensive to obtain and to transport. Pure nitrogen is readily available using the cryogenic air separation process.[5]

Carbon dioxide is generally not miscible with most reservoir oils, but miscibility can be developed through multiple contacts of the $CO_2$ with the oil. Oils with medium to high API gravities are best suited to miscible $CO_2$ flooding. The pressure required for first-contact miscibility with $CO_2$ (>4000 psi) is substantially lower than the first contact miscibility pressure needed for nitrogen flooding (>6000 psi). Multiple contact miscibility with $CO_2$ flooding can be achieved with pressures as low as 1200 psi. Again, the pressure needed to develop multiple contact miscibility with nitrogen flooding is significantly greater (>4000 psi) than that required for $CO_2$.[8,11]

Carbon dioxide can also be used to displace heavy (low API gravity) oils and, even though the displacement process will be immiscible, some of the same effects present in a miscible displacement will contribute to oil recovery. Carbon dioxide is relatively soluble in reservoir oils, though nitrogen is not. Because of this, $CO_2$ injection will result in swelling of the crude oil and a reduction in oil viscosity, even when used to displace heavy oils. Low interfacial tensions can also develop in an immiscible $CO_2$ displacement due to vaporization and solubility effects.[8]

As shown previously in the discussion of the vaporizing, or high pressure, gas drive process, methane can be used to miscibly displace oil at high pressures or can develop miscibility at lower pressures; in each case the reservoir oil must contain an adequate amount of intermediate components or the process will be immiscible.

Methane injection increases oil recovery by inducing the same effects as $CO_2$ injection, oil swelling, reduction of oil viscosity, and reduction of interfacial forces, although $CO_2$ is more effective in swelling the reservoir oil than is methane.[8]

## COMPARISON OF GAS INJECTION TYPES

Nitrogen and immiscible $CO_2$ flooding are the most frequently used types of immiscible gas injection and, depending on the reservoir conditions and other factors, one may be more suitable than the other. The primary differences between nitrogen and carbon dioxide are their viscosity, miscibility, gravity, and volumetric characteristics. The properties of flue gas fall between those of nitrogen and carbon dioxide, depending on its composition. The following comparisons illustrate the major differences between nitrogen, flue gas, and carbon dioxide.

1. At average reservoir pressures and temperatures the compressibility factor of nitrogen is three times that of carbon dioxide.
2. Nitrogen is a non-toxic and inert (not reactive) gas. $CO_2$ is not inert and is corrosive in the presence of water. Flue gas is usually more corrosive than $CO_2$ due to the water vapor, $CO_2$, and nitrous oxides present in flue gas.
3. The best prospects for high pressure nitrogen displacement are reservoir fluids with a gravity of $35^{o}$

and greater. Low API gravity oils are not good prospects for nitrogen displacement.

4. $CO_2$ is soluble in reservoir fluids, whereas nitrogen is less soluble in most oils.

5. Nitrogen and $CO_2$ are both miscible with reservoir oil to some degree depending on the oil composition and reservoir pressure. Given a specific oil composition and reservoir condition, nitrogen requires pressures >6000 psi to establish first contact miscibility with oil whereas $CO_2$ requires pressures >4000 psi for first contact miscible displacement.

6. Nitrogen does not reduce oil viscosity nearly as much as does $CO_2$. $CO_2$ can also reduce the viscosity of low gravity (<$25^o$ API) oils.

7. $CO_2$ is soluble in reservoir fluids and will increase oil volume by 10 to 40 percent; nitrogen is relatively insoluble in oil and does not increase oil volume. Flue gas is also soluble in reservoir fluids.

8. $CO_2$ is more dense than nitrogen, which is generally less dense than gas-cap gas.

9. Flue gas and nitrogen are much easier to obtain than $CO_2$. Nitrogen can be generated from cryogenic air separation plants and can be produced from plants burning fossil fuels or from chemical industries.

10. Less nitrogen than $CO_2$ is needed to pressurize a given

reservoir; the amount of flue gas needed falls between $CO_2$ and $N_2$.

11. The cost of $CO_2$ is approximately \$1.00 to \$1.25/mcf; flue gas costs \$0.55 to \$0.85/mcf and nitrogen costs are \$0.40 to \$0.60/mcf.
12. Cryogenic air separation plants are more reliable and cheaper to operate than flue gas plants.
13. Flue gas requires treatment before injection, the extent of the treatment depending on the source of the flue gas.
14. Relatively less energy is needed to compress flue gas or $CO_2$ than is required for the compression of $N_2$.[11]

## PURPOSE OF STUDY

The use of immiscible gas flooding as an enhanced oil recovery process is not a common practice, although it is being implemented more frequently than in the past; in 1971 there were no active immiscible gas flooding projects in the United States but ten projects were in progress in 1982. The application of immiscible gas injection to potential recovery projects is being considered more often due to improved economic and technical feasibility of the process.

In order to more completely evaluate the applicability of the immiscible gas injection process to a prospective project, actual field results from both active and completed projects are needed. By obtaining this information, comparisons can be made between original projected results and the results that were actually achieved. These comparisons will make it possible to predict more accurately the results of future projects and to better judge the applicability of the immiscible gas injection process to a particular field.

This study was conducted with the purpose of achieving these objectives. The following procedure was used to obtain the results of this study:

1. Develop a data base that both qualitatively and quantitatively describes completed and current immiscible gas injection projects.
2. Conduct a statistical analysis of selected reservoir and fluid parameters and oil recovery information to evaluate project data.
3. Evaluate data to determine if there is correlation between oil recovery and fluid and reservoir parameters.

## CHAPTER II

## DATA BASE

### DESCRIPTION OF DATA SOURCES

Several main sources of information were used to compile the data which make up the data base used for this study. As a result of searching these various publications and data bases, 24 immiscible gas injection projects, both on-going and completed, were located.

The search for relevant data was begun by conducting a literature survey from the Applied Science & Technology Index for the years 1954-1982, inclusive. The AS&T Index is an annual publication which gives a bibliographical listing of science and technical articles that are published each year and lists these articles according to subject. The AS&T Index was very valuable in locating articles in industry publications. Most of the articles were found in the Journal of Petroleum Technology, Society of Petroleum Engineers Transactions, World Oil, Drill Bit, and Petroleum Engineer International.

Other information found in the literature search that contributed to the data base was located in two Department of Energy publications. These publications were "State-of-the-art Review of Nitrogen and Flue Gas Flooding in Enhanced Oil Recovery" (DOE/MC/08333-2) and "Target Reservoirs for $CO_2$ Miscible Flooding-Final Report" (DOE/MC/08341-17).[11,12]

A computer search was also conducted of the literature data base of the University of Tulsa. No additional articles were located as a result of this effort.

Two enhanced oil recovery data bases were searched for immiscible gas injection project data. The first of these was the Enhanced Recovery Projects File of the University of Oklahoma at Norman. This data base is one of many which make up the Petroleum Data System (PDS). Information in the Enhanced Recovery Projects File consists of data from secondary and enhanced recovery projects in Texas, Kansas, Louisiana and Illinois.[13]

The second data base used was the Department of Energy's (DOE) Enhanced Oil Recovery Database which was compiled as part of a research program at the Bartlesville Energy Technology Center (BETC). This data base contains information on active EOR projects which were submitted under the Incentives Program and data collected under contract to BETC to identify potential EOR projects.[14] This data base supplied information on the majority of the projects used in the study.

Both of the above-mentioned data bases contained information on project location, operator and lease name, reservoir and fluid parameters (viscosity, porosity, permeability, lithology, etc.), and recovery. Also included are information regarding type of gas injected, size of the project (acres and number of wells), and production data.

The last major source of data was provided by a publication entitled A Survey of Secondary and Enhanced Recovery Operations in Texas to 1980 (Bulletin 80)[15], published by the Railroad Commission of Texas at Austin in 1980. The Railroad Commission also provided another data source in Form QB-82 (Questionnaire for Fluid Injection into a Productive Reservoir) which was obtained from the Railroad Commission's Austin Office for recent projects that were not included in the 1980 publication.[16]

Table 2.1 lists the major data sources and indicates the number of projects for which each source supplied information. In some cases more than one information source was used to obtain data for a project, which explains the reason for the total number of projects represented in Table 2.1 being greater than the number of projects in the database used for the study.

TABLE 2.1

Major Data Sources and Number of Projects For Which Each Supplied Data

| DATA SOURCE | NUMBER OF PROJECTS |
|---|---|
| Literature Survey | 12 |
| Enhanced Oil Recovery Database<br>Department of Energy | 13 |
| Enhanced Recovery Projects File<br>University of Oklahoma at Norman | 2 |
| Railroad Commission of Texas | 7 |

DISCUSSION OF RELEVANT RESERVOIR, FLUID, AND OIL RECOVERY PARAMETERS

The database for the immiscible gas injection projects consists of a tabulation of 45 different parameters, as depicted in Tables 2.3 through 2.11. In order to further evaluate the gas injection projects, 17 relevant reservoir, fluid, and oil recovery parameters were chosen from among the set of 45 parameters and are listed in Table 2.2. The units and definitions of database parameters that are not self-explanatory are given in the Nomenclature.

A number of the parameters listed in Table 2.2 have been cited in the literature as screening factors for other types of EOR processes such as LPG injection, enriched gas flooding, miscible $CO_2$ injection, microemulsion flooding, and polymer flooding.[9,17] The screening factors are useful in determining whether or not a project is suitable for a particular type of recovery process. Although these screening factors were not used in reference to the type of EOR process addressed in this study, it is assumed that some of the same parameters (those denoted by * in Table 2.2) would also be useful in screening potential immiscible gas injection projects. Other parameters included in Table 2.2 are those that are generally used to describe any reservoir and are necessary to give a more detailed description of and to better analyze each project.

TABLE 2.2

Relevant Reservoir, Fluid, and Oil Recovery Parameters

| RESERVOIR PARAMETERS | FLUID PARAMETERS | OIL RECOVERY PARAMETERS |
|---|---|---|
| *Net Pay | *Oil Gravity | Original Oil in Place |
| *Permeability | | Estimated Oil Recovery-Previous Production-Primary |
| *Depth of Reservoir | Original Water Saturation | |
| Gross Pay | Original Oil Saturation | Estimated Oil Recovery-Previous Production-Secondary |
| Project Area | *Oil Viscosity | |
| Number of Injection Wells | | |
| Original Reservoir Pressure | | |
| *Porosity | | |
| Number of Producing Wells | | |
| *Reservoir Temperature | | |

*denotes screening factors used for other enhanced oil recovery methods such as LPG injection, miscible $CO_2$ injection, micellar flooding, and polymer flooding.

## DESCRIPTION OF DATA BASE

The types of gases considered in this study as those that would immiscibly displace reservoir fluids are nitrogen, flue gas, methane, and carbon dioxide. The projects used were those in which the injected gas actually displaced reservoir fluids; gas injection projects that were implemented for pressure maintenance purposes or those in which the injected gas was used to chase or push another displacing agent through the reservoir were not included.

Although air injection is known to immiscibly displace oil, no air injection projects were used in this study because the information obtained regarding this type of injection was negligible.

Flue gas, nitrogen, and methane are frequently referred to in the literature and in practice as miscible recovery processes. These types of gas flooding can be miscible if injection or reservoir pressures are sufficient, but because of the high pressures needed for the injected gas to obtain miscibility with reservoir fluids, in the majority of cases these types of gas injection are actually immiscible processes. For the purposes of this study then, all injection projects using nitrogen, flue gas, or methane as a displacing agent were assumed to be immiscible displacement processes, whether or not they were identified as such. It is recognized that many carbon dioxide gas flooding operations are miscible displacement processes due to the more favorable properties of carbon dioxide. For this reason, only those $CO_2$ projects that were reported as immiscible displacement processes were included in this study.

The data base used in this study consists of 24 gas injection projects: five flue gas, five methane, nine nitrogen, and five carbon dioxide injection projects. The project locations are illustrated in Figure 2.1. Although many of the database parameters are defined in the Nomenclature, it is necessary to explain some parameters in more detail.

For some projects the reservoir temperature (RESVR TEMP) was not available. In these cases, since reservoir depth information was available for all projects, the reservoir temperature was calculated from the following equation:

$$T_f = (G_t \times D_f/100) + T_{mst} \qquad (2.1)$$

where

$T_f$ = reservoir temperature, $^oF$

$D_f$ = reservoir depth, ft

$G_t$ = temperature gradient, $^oF/100$ ft

$T_{mst}$ = annual mean surface temperature, $^oF$

The temperature gradients and the annual mean surface temperatures were obtained from Frick.[18]

The parameter FW/PILOT designates whether a project was field wide (FW) or a pilot project (PILOT). The Saratoga, North Cowden, and Huntington Beach projects are pilots. The North Cowden project was described by the operator as being a pilot project, and the Huntington Beach and Saratoga projects were judged to be pilot projects because the project areas were small as was the number of the injection and production wells. Because there were few pilot projects, these projects were not analyzed as a separate group, but their data were not included

## LOCATION OF IMMISCIBLE GAS INJECTION PROJECTS

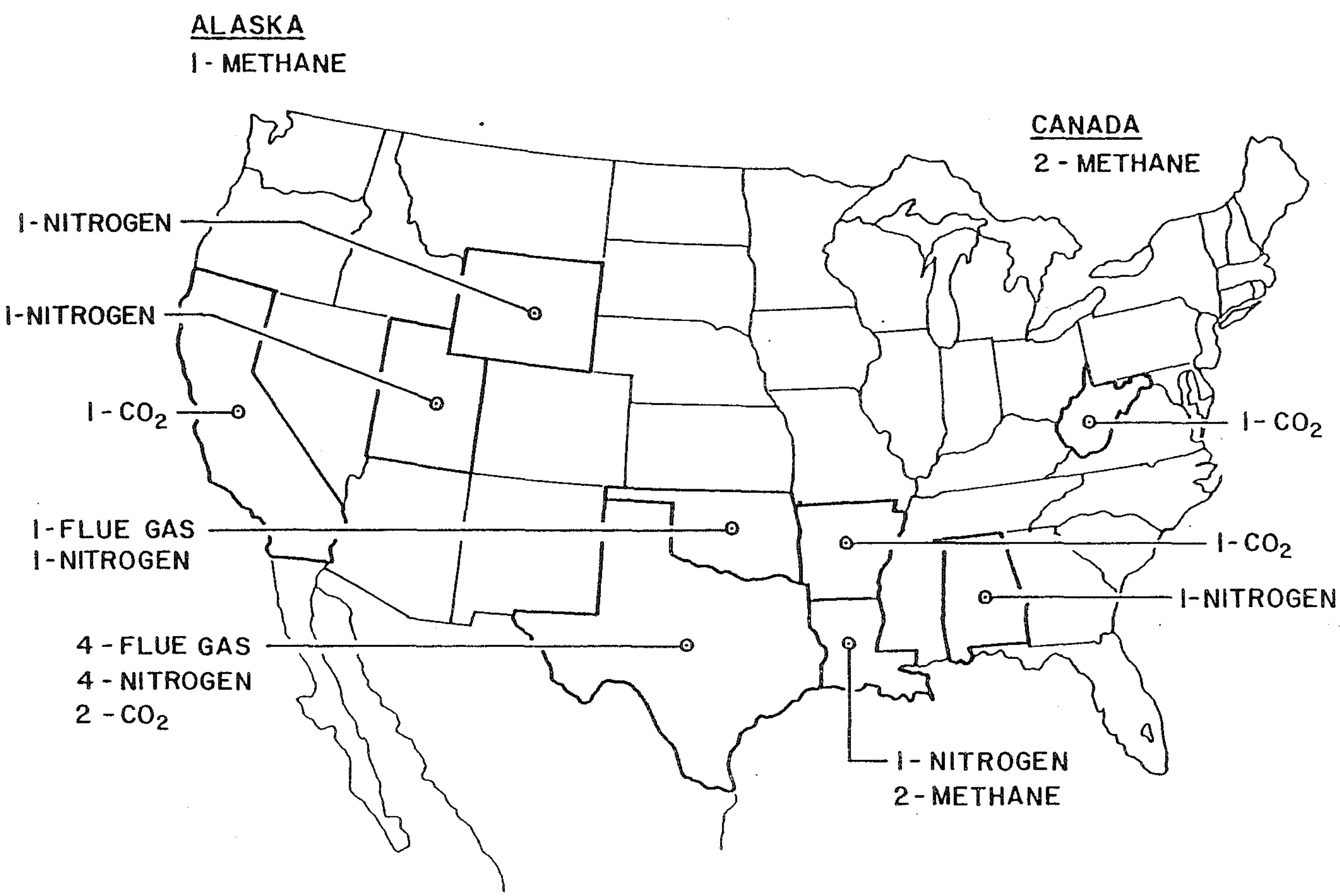


FIGURE 2.1

when the parameter being analyzed was affected by project size (project area, original oil in place, and number of injection and production wells). Pilot project data were included in the analysis of parameters which were not affected by project size (oil viscosity, net pay, permeability, porosity, etc.).

The FIELD and PROJECT parameters serve to identify the gas injection projects. The PROJECT parameter was included for cases where a second identifier such as a unit, lease, or project name was given.

Two projects, the Fordoche and Hawkins fields, were each written up in the literature as a single project. In each project, however, the producing formation contained two zones which were being flooded in the gas injection project. In both projects the two zones being flooded had different reservoir and fluid parameters (project area, and number of injection and production wells were the same). Because the reservoir and fluid parameters were different, both projects were divided into two projects; in other words each zone being flooded was considered as a separate project. The Fordoche project was divided into the Fordoche, 8-A and the Fordoche, 12-A while the Hawkins project was separated into the Hawkins, Lewisville and the Hawkins, Dexter projects.

The parameters PROJ RECOVERY, SECRECV, and TERRECV are projected estimates (determined by the project operator) of oil recovery due to gas injection; PROJ RECOVERY has units of millions of stock tank barrels and SECRECV and TERRECV have units of per cent of original oil in place. The parameter CURRENT OIL RECOVERY describes the amount of oil that has been recovered at the time the data were reported and which can be attributed to gas injection.

AMOUNT GAS INJ describes the amount of gas that had been injected into the reservoir at the time the data were reported. The phrase "at the time data were reported" has been used in reference to several of the database parameters and requires further explanation. As was mentioned previously, the data used in this study were gathered from several different sources. There was no common time reference as to at what point in the gas injection projects the data were reported; the project phases at which data were reported varied from initiation of the project to completion. Because of this it was not possible to include some time-dependent parameters (oil saturation, reservoir pressure, etc.) in the data analysis that otherwise would have been included; however, these parameters were used in the database to better describe the projects.

Frequently instances occurred where there were more than one source of data for a project and the data were conflicting. In those cases the most recent data were used unless they were obviously incorrect.

TABLE 2.3: DATABASE PARAMETERS

| NUM | PROJECT | FIELD | STATE | COUNTY | REGDIST |
|---|---|---|---|---|---|
| 1 | - | HAWKINS | TEXAS | WOOD | TRRC6 |
| 2 | - | HAWKINS | TEXAS | WOOD | TRRC6 |
| 3 | - | BLOCK 31 | TEXAS | CRANE | TRRC8 |
| 4 | - | SARATOGA | TEXAS | HARDIN | TRRC3 |
| 5 | - | EAST BINGER | OKLAHOMA | CADDO | - |
| 6 | - | SWANSON RIVER | ALASKA | - | - |
| 7 | - | CAROLINE CARDIUM E | CANADA | ALBERTA | - |
| 8 | - | FORDOCHE,8-A | LOUISIANA | PT. COUPEE | - |
| 9 | - | FORDOCHE,12-A | LOUISIANA | PT. COUPEE | - |
| 10 | NISKU POOL A | BRAZEAU RIVER | CANADA | ALBERTA | - |
| 11 | EMBAR LEASE | ANDECTOR | TEXAS | ECTOR | TRRC8 |
| 12 | - | JAY LITTLE | ALABAMA | ESCOMBIA | - |
| 13 | ATKINS LEASE | STONEBLUFF | OKLAHOMA | WAGONER | - |
| 14 | - | LISBON | UTAH | SAN JUAN | - |
| 15 | - | PAINTER | WYOMING | UNITA | - |
| 16 | UNIT 38,39,43,44 | LAKE BARRE | LOUISIANA | TERREBONNE | - |
| 17 | DELAWARE UNIT | TWOFREDS | TEXAS | LOVING | TRRC8 |
| 18 | E. VEALMOOR UNIT | EAST VEALMOOR | TEXAS | HOWARD | TRRC8 |
| 19 | S. RATLIFF LEASE | NORTH HEADLEE | TEXAS | ECTOR | TRRC8 |
| 20 | MEAKIN SAND UNIT | LICK CREEK | ARKANSAS | BRADLEY | - |
| 21 | N. BOLSA STRIP | HUNTINGTON BEACH | CALIFORNIA | ORANGE | L. A. |
| 22 | 12 ACRE PILOT | NORTH COWDEN | TEXAS | ECTOR | TRRC8 |
| 23 | - | HILLY UPLAND | W. VA. | LEWIS | - |
| 24 | HAYNES LEASE | COMITAS | TEXAS | ZAPATA | TRRC4 |

TABLE 2.4: DATABASE PARAMETERS

| NUM | REGION | OPERATOR | FW/PILOT | YR BEGIN | YR END | DOE |
|---|---|---|---|---|---|---|
| 1 | MID CONTINENT | EXXON | FW | 4/1977 | - | - |
| 2 | MID CONTINENT | EXXON | FW | 4/1977 | - | - |
| 3 | WEST TEXAS | ARCO | FW | 3/1966 | - | - |
| 4 | GULF COAST | GENERAL CRUDE OIL CO | PILOT | 4/1973 | 1974 | - |
| 5 | MID CONTINENT | PHILLIPS | FW | 9/1977 | 9/1992 | $ |
| 6 | ALASKA | CHEVRON USA | FW | 6/1966 | - | - |
| 7 | FOREIGN | PACIFIC PET. LTD. | FW | 8/1978 | - | - |
| 8 | GULF COAST | SUN OIL | FW | 1971 | - | - |
| 9 | GULF COAST | SUN OIL | FW | 1971 | - | - |
| 10 | FOREIGN | - | - | - | - | - |
| 11 | WEST TEXAS | PHILLIPS | FW | 11/1981 | 1988 | - |
| 12 | - | EXXON | FW | 1981 | 1995 | $ |
| 13 | MID CONTINENT | GULF | FW | 8/1981 | 7/1996 | $ |
| 14 | ROCKY MOUNTAIN | UNION OIL OF CA | FW | 12/1981 | 12/1986 | $ |
| 15 | ROCKY MOUNTAIN | CHEVRON USA | FW | 6/1980 | 6/2039 | $ |
| 16 | GULF COAST | TEXACO | FW | 8/1978 | - | $ |
| 17 | WEST TEXAS | HNG FOSSIL FUELS CO | FW | 10/1980 | - | - |
| 18 | WEST TEXAS | GETTY OIL | FW | 12/1981 | 1/1997 | $ |
| 19 | WEST TEXAS | MOBIL OIL | FW | 6/1981 | 6/1985 | $ |
| 20 | MID CONTINENT | PHILLIPS | FW | 1976 | 12/1990 | $ |
| 21 | WEST COAST | AMINOIL USA | PILOT | 12/1980 | 12/1981 | $ |
| 22 | WEST COAST | AMOCO | PILOT | 1979 | - | - |
| 23 | APPALACHIA | ALLEGHANY | FW | 1976 | - | - |
| 24 | GULF COAST | THRASH OIL & GAS | FW | 6/1980 | 8/1980 | $ |

TABLE 2.5: DATABASE PARAMETERS

| NUM | TYPE OF GAS INJ | PROD FORMATION | ZONE | AGE | OTHER COMMENTS |
|---|---|---|---|---|---|
| 1 | FLUE GAS | WOODBINE | LEWISVILLE | CRETACEOUS | FAULTED |
| 2 | FLUE GAS | WOODBINE | DEXTER | CRETACEOUS | FAULTED |
| 3 | FLUE GAS | DEVONIAN | - | - | - |
| 4 | FLUE GAS | MIOCENE | D | - | - |
| 5 | FLUE GAS | MARCHAND | - | - | CONSOLIDATED |
| 6 | METHANE | KENAI | HEMLOCK | JURASSIC | FAULTED |
| 7 | METHANE | CARDIUM | - | - | - |
| 8 | METHANE | WILCOX | 8-A | - | - |
| 9 | METHANE | WILCOX | 12-A | - | - |
| 10 | METHANE | NISKU | POOL A | DEVONIAN | - |
| 11 | NITROGEN | ELLENBURGER | - | - | - |
| 12 | NITROGEN | SMACKOVER | - | - | CONSOLIDATED |
| 13 | NITROGEN | - | - | - | CONSOLIDATED |
| 14 | NITROGEN | MCCRACKEN | SERIES 341 | DEVONIAN | CONSOLIDATED |
| 15 | NITROGEN | PAINTER | - | - | CONSOLIDATED |
| 16 | NITROGEN | R-1 SAND | SEGMENT G | MIOCENE | - |
| 17 | NITROGEN | DELAWARE | - | PERMIAN | - |
| 18 | NITROGEN | CANYON REEF | SERIES 310 | PERMIAN | CONSOLIDATED |
| 19 | NITROGEN | 39971500 | 340 | DEVONIAN | CONSOLIDATED |
| 20 | IMMIS. CO2 | MEAKIN | 212 | CRETACEOUS | CONSOLIDATED |
| 21 | IMMIS. CO2 | JONES | - | - | - |
| 22 | IMMIS. CO2 | GRAYBURG | A 11 | PERMIAN | - |
| 23 | IMMIS. CO2 | BASAL GREBRIAR | BIG INJUN | MISSISSIPPIAN | - |
| 24 | IMMIS. CO2 | MIRANDO SAND | - | - | CONSOLIDATED |

TABLE 2.6: DATABASE PARAMETERS

| NUM | LITHOLOGY | ENVIRONMENT | DEP UNIT | DEPTH (FT) | RESVR TEMP (DEGREES F) |
|---|---|---|---|---|---|
| 1 | SANDSTONE | - | - | 4400 | 168 |
| 2 | SANDSTONE | - | - | 4531 | 168 |
| 3 | LIMESTONE | - | - | 8500 | 140 |
| 4 | SANDSTONE | - | - | 810 | 86 |
| 5 | SANDSTONE | - | - | 10003 | 190 |
| 6 | SANDSTONE | MARINE | - | 10377 | 180 |
| 7 | CHERT,SANDSTONE | - | - | 8134 | 173 |
| 8 | SANDSTONE | MARINE | DELTA | 13180 | 267 |
| 9 | SANDSTONE | MARINE | DELTA | 13650 | 274 |
| 10 | DOLOMITE | MARINE | REEF | 10214 | 217 |
| 11 | DOLOMITE | - | - | 8480 | 159 |
| 12 | SANDSTONE,CARBONATE | - | - | 15552 | 285 |
| 13 | - | - | - | 1100 | 85 |
| 14 | CARBONATE | - | - | 9000 | 140 |
| 15 | SANDSTONE | AEOLIAN | - | 10800 | 174 |
| 16 | SANDSTONE | - | - | 17500 | 291 |
| 17 | SANDSTONE | - | - | 4820 | 104 |
| 18 | CARBONATE,LIMESTONE | MARINE | REEF | 7350 | 155 |
| 19 | CARBONATE | - | - | 12250 | 190 |
| 20 | SANDSTONE | - | - | 2500 | 118 |
| 21 | SANDSTONE | - | - | 2900 | 130 |
| 22 | SANDSTONE,DOLOMITE | - | - | 4300 | 196 |
| 23 | LIMESTONE | - | - | 1800 | 77 |
| 24 | SANDSTONE | - | - | 1050 | 80 |

TABLE 2.7: DATABASE PARAMETERS

| NUM | PROJECT AREA (ACRES) | PATTERN TYPE | ACRES/PATTERN | NO. INJECTORS | NO. PRODUCERS |
|---|---|---|---|---|---|
| 1 | 10590 | - | - | 38 | 351 |
| 2 | 10590 | - | - | 38 | 351 |
| 3 | 7200 | 9-SPOT,5-SPOT | 320,40 | 7 | 61 |
| 4 | 6 | SINGLE WELL | 6 | 1 | 1 |
| 5 | 12960 | LINE DRIVE | - | 16 | 68 |
| 6 | - | - | - | 12 | 54 |
| 7 | - | - | - | 6 | 28 |
| 8 | 6119 | - | 160 | 5 | 18 |
| 9 | 6119 | - | 160 | 5 | 18 |
| 10 | - | - | - | - | - |
| 11 | 775 | - | - | 1 | 17 |
| 12 | 14415 | STAGGERED LINE DRIVE | 640 | 35 | 76 |
| 13 | 674 | MULTIPLE-IRREGULAR | - | 26 | 45 |
| 14 | 5120 | CRESTAL INJECTION | - | 4 | 12 |
| 15 | 1655 | CRESTAL INJECTION | - | 8 | 28 |
| 16 | 600 | SINGLE INJECTOR | 600 | 1 | 2 |
| 17 | 4546 | MODIFIED 5-SPOT | - | 8 | 42 |
| 18 | 3353 | CRESTAL INJECTION | - | 1 | 44 |
| 19 | 800 | CRESTAL INJECTION | - | 2 | 8 |
| 20 | 900 | MODIFIED 9-SPOT | 87.5 | 16 | 38 |
| 21 | 13 | - | 3 | 2 | 5 |
| 22 | 1 | 5-SPOT | 1 | 1 | 4 |
| 23 | 200 | - | - | 1 | 6 |
| 24 | 975 | PERIPHERAL LINE DRIVE | - | 14 | 39 |

TABLE 2.8: DATABASE PARAMETERS

| NUM | NET PAY (FT) | GROSS PAY (FT) | NET PAY/GROSS PAY | PERMEABILITY (MD) | POROSITY (%) |
|---|---|---|---|---|---|
| 1 | 187.5 | - | - | 1194 | 24.6 |
| 2 | 275 | - | - | 3396 | 27.9 |
| 3 | 103 | 1000 | 0.103 | 1 | 15 |
| 4 | 30 | - | - | 536 | 34 |
| 5 | 27 | 27 | 1.0 | 0.20 | 7.5 |
| 6 | 250 | 400 | 0.63 | 97 | 21 |
| 7 | 3 | - | - | 30 | 11.3 |
| 8 | 25 | - | - | 8.6 | 20 |
| 9 | 34 | - | - | 4.6 | 19 |
| 10 | 256 | - | - | 400 | 10 |
| 11 | 221 | 1053 | 0.21 | 2000 | 3.8 |
| 12 | 95 | 350 | 0.27 | 35.4 | 14 |
| 13 | - | - | - | - | - |
| 14 | 300 | 400 | 0.75 | 550 | 5.5 |
| 15 | 330 | 433 | 0.76 | 7.1 | 11.7 |
| 16 | 57 | 130 | 0.44 | 95 | 16.1 |
| 17 | 16 | 25 | 0.64 | 33 | 20.3 |
| 18 | 107 | 167 | 0.64 | 38 | 9.5 |
| 19 | 76 | 180 | 0.42 | 0.3 | 5 |
| 20 | 8.6 | 10 | 0.86 | 1203 | 33 |
| 21 | 300 | 450 | 0.67 | 575 | 24 |
| 22 | - | - | - | 6 | 9.1 |
| 23 | 12 | - | - | 4 | 14 |
| 24 | 7 | 7 | 1.0 | - | 28 |

TABLE 2.9: DATABASE PARAMETERS

| NUM | ORIG WATER SAT (%) | ORIG OIL IN PLACE (MM STB) | ORIG OIL SAT (%) | API GRAVITY | OIL VISCOSITY (CP) |
|---|---|---|---|---|---|
| 1 | 25 | - | - | 24.2 | 3.7 |
| 2 | 9.6 | - | - | 24.2 | 3.7 |
| 3 | 35 | 312 | - | 46 | 0.3 |
| 4 | - | 169 | - | 17.1 | - |
| 5 | 25 | 80 | 75 | 46 | 0.3 |
| 6 | - | 435 | 60 | 49 | 1.1 |
| 7 | - | 23.2 | - | - | - |
| 8 | 47 | - | - | 44 | 0.13 |
| 9 | 58 | - | - | 45 | 0.13 |
| 10 | 10 | 33.3 | - | - | - |
| 11 | - | 16.2 | - | 44 | - |
| 12 | 12.7 | 728.3 | 87.3 | 51 | 0.18 |
| 13 | 25 | - | 75 | 38 | - |
| 14 | 29 | 86.6 | 71 | 60 | 0.5 |
| 15 | 20 | 376.7 | 80 | 46 | 0.2 |
| 16 | 24.7 | 28.1 | 43 | 35.2 | 0.35 |
| 17 | 43.5 | 54.9 | - | 36 | 1.47 |
| 18 | 16.5 | 125.4 | 83.7 | 43 | 0.85 |
| 19 | 35 | 4.3 | 65 | 47 | 0.13 |
| 20 | 32 | 23.4 | 68 | 17 | 160 |
| 21 | 22 | 5.15 | 78 | 18 | 175 |
| 22 | - | - | 67 | 35 | 1.4 |
| 23 | 25 | - | 73 | 42 | 1.75 |
| 24 | 35 | 8.7 | 65 | 29 | 40 |

TABLE 2.10: DATABASE PARAMETERS

| NUM | ORIG RESVR PRESS (PSIG) | PRESENT RESVR PRESS (PSIG) | AMOUNT GAS INJ (BCF) | PREVIOUS PROD | WETTABILITY |
|---|---|---|---|---|---|
| 1 | 1710 | - | 33 | PRIMARY | - |
| 2 | 1985 | 1477 | - | - | - |
| 3 | 4145 | 3671 | 234 | PRIMARY | - |
| 4 | 284 | 284 | 0.015 | PRIMARY | - |
| 5 | - | 4290 | 125 | PRIMARY | OIL WET |
| 6 | 5580 | - | - | - | - |
| 7 | 4188 | 3290 | 1.39 | PRIMARY | - |
| 8 | 10598 | 6500 | 26.1 | PRIMARY | - |
| 9 | 10800 | 6300 | 44.2 | PRIMARY | - |
| 10 | 6674 | - | - | - | - |
| 11 | 3485 | 1695 | 0.032 | PRIMARY | - |
| 12 | - | 5750 | 368 | WATERFLOOD | OIL & WATER WET |
| 13 | - | - | 5.5 | - | - |
| 14 | - | 2490 | 11.3 | - | - |
| 15 | 4161 | 4046 | 680 | PRIMARY | WATER WET |
| 16 | 9535 | 4200 | 1.4 | NATURAL GAS INJ | WATER WET |
| 17 | 2385 | 2285 | 0.001 | WATERFLOOD | - |
| 18 | 3362 | 2049 | 0.045 | WATERFLOOD | WATER WET |
| 19 | - | 3300 | 4.5 | - | WATER WET |
| 20 | 1200 | [illegible] | 4.75 | PRIMARY | WATER WET |
| 21 | - | 1100 | 0.52 | - | WATER WET |
| 22 | - | - | - | PRIMARY | - |
| 23 | 700 | [illegible] | - | PRIMARY | - |
| 24 | - | [illegible] | - | - | WATER WET |

TABLE 2.11: DATABASE PARAMETERS

| NUM | CURRENT OIL RECOVERY (MM STB) | PROJ RECOVERY (MM STB) | SECRECV (% OIIP) | TERRECV (% OIIP) | REF |
|---|---|---|---|---|---|
| 1 | - | - | - | - | 19,20 |
| 2 | - | - | - | - | 19,20 |
| 3 | - | 123.0 | 39.4 | - | 16,21,22 |
| 4 | 0.001 | - | - | - | 23 |
| 5 | 12.34 | - | - | - | 19,24 |
| 6 | - | - | - | - | 5,25 |
| 7 | - | 4.99 | 21.5 | - | 26 |
| 8 | - | - | - | - | 27,28 |
| 9 | - | - | - | - | 27,28 |
| 10 | - | - | - | - | 29 |
| 11 | - | 0.974 | 6.0 | - | 19,30 |
| 12 | - | - | - | - | 19,24,31 |
| 13 | - | - | - | - | 24 |
| 14 | - | - | - | - | 24 |
| 15 | - | 68.0 | 40.0 | - | 19,24,32 |
| 16 | - | 5.3 | - | 18.9 | 24,33 |
| 17 | - | 5.0 | - | 9.1 | 12,16 |
| 18 | - | 12.5 | - | 9.97 | 16,24 |
| 19 | - | - | - | - | 15,24 |
| 20 | - | 31.5 | 12.8 | - | 12,24 |
| 21 | - | - | - | - | 19,24 |
| 22 | - | - | - | - | 15,24 |
| 23 | - | - | - | - | 24 |
| 24 | - | - | - | - | 24 |

# CHAPTER III

# PRESENTATION OF RESULTS

## PARAMETER STATISTICS

A subset of 17 parameters was chosen for statistical analysis from the 45-parameter data base. The 17 parameters analyzed were determined to be relevant for reasons discussed in Chapter II and are listed in Table 2.2. As part of the data analysis, the data from 16 of the 17 parameters were incorporated into frequency plots, Figures 3.2 - 3.17. Ideally other parameters such as oil saturation at start of project, percent of original oil in place at start of project, barrels of oil recovered per MCF of injected gas, barrels of oil actually recovered due to gas injection at project completion, etc. could be included in the data analysis, but the data available were not complete or extensive. Also only three of the projects, two of which were pilots, had been concluded at the time of this study.

Table 3.1 presents the seven statistics for each of the parameters in Table 2.2. These seven statistics are number of projects, minimum, maximum, mean, median, mode, and standard deviation. The first four statistics need not be defined but a short explanation will be given for each of the last three.

The median, like the mean, is a measure of central tendency and is defined as the value positioned in the middle of a data sample when the data are arranged in increasing order. If the data sample size, n, is odd the median of the sample is the middle term in the data arrangement. If the sample size, n, is an even number the median will be average of the two middle terms in the array.[34,35,36]

For example, the data for the parameter SECRECV (projected oil recovery for projects whose previous production was primary, in terms of percent of original oil in place) consists of five values; arranged in order of increasing value these are: 6.0, 12.8, 21.5, 39.4, and 40. Because the number of terms is odd, the median will be the middle term, 21.5. If the value of 40 were not in the sample, there would be an even number of terms and the median would be the average of the two middle terms, 12.8 and 21.5.

An important property of the median is its insensitivity to extreme values; the mean does not have this characteristic. In the above example if the value of 40.0 were replaced with a value of 95.0, the median would still be 21.5. This property of the median makes it useful in describing central tendency.[35]

The mode is also a measure of central tendency and is defined as the value which occurs most frequently for a given parameter. Much of the data analyzed in this study were bimodal. The symbol -0 in Table 3.1 indicates that the data were bimodal.

The standard deviation is a measure of variability or dispersion and gives a quantitative idea of how the data in a sample deviate from the mean of that sample. The standard deviation is calculated according to equation 3.1[34,35,36]

$$s = \sqrt{\left[\sum_{i=1}^{N} (x_i - \bar{x})^2\right] / (N - 1)} \tag{3.1}$$

where

$s$ = standard deviation

$\overline{x}$ = mean of the sample

$N$ = number of values in the data sample

$x_i$ = individual terms in the data sample; $x_1, x_2 \ldots x_N$

Before discussing the results of the statistical analysis and frequency plots, several general statistical compilations will be presented to more completely analyze the data.

## GENERAL STATISTICAL COMPILATIONS

Table 3.2 is a comparison of the lithologies found in the producing formations of the database projects. The lithology types are classified as sandstone, carbonate, or sandstone and carbonate. Lithology data were available for 23 of the 24 projects and include both fieldwide and pilot projects. The results show that in the majority of the projects (57%) gas was injected into a formation made up of sandstone. 26% of the projects had a producing formation of carbonate lithology and in 17% of the projects the lithology consisted of a combination of both sandstone and carbonate.

The map shown in Figure 2.1 depicts the geographical location of the various immiscible gas injection projects. It is from this map that the data in Tables 3.3A and 3.3B were compiled.

Table 3.3A lists the number of projects in each state or country and the percentage of the total number of projects which that number represents. Texas has the greatest number of projects, ten, which represents 42% of the total number of projects in the study. Louisiana

TABLE 3.1

STATISTICAL ANALYSIS OF DATA

| PARAMETER | NO. PROJECTS | MIN | MAX | MEAN | MEDIAN | STD. DEV. | MODE |
|---|---|---|---|---|---|---|---|
| POROSITY (%) | 23 | 3.80 | 34.0 | 16.71 | 15.00 | 8.85 | 14.00 |
| NET PAY (FT) | 22 | 3.00 | 330.0 | 123.64 | 85.50 | 116.35 | 300.00 |
| PERMEABILITY (MD) | 18 | .20 | 575.0 | 134.51 | 31.50 | 213.94 | -0 |
| API GRAVITY | 22 | 17.00 | 60.0 | 37.21 | 41.00 | 12.11 | 45.00 |
| DEPTH OF RESERVOIR (FT) | 24 | 810.00 | 17500.0 | 7633.25 | 8307.00 | 4828.76 | -0 |
| GROSS PAY (FT) | 14 | 7.00 | 1053.0 | 330.86 | 265.00 | 338.26 | 400.00 |
| OIL VISCOSITY (CP) | 16 | .13 | 3.7 | 1.01 | .43 | 1.18 | -0 |
| PROJECT AREA (ACRES) | 18 | 200.00 | 14415.0 | 4866.17 | 3950.00 | 4635.28 | -0 |
| NO. INJECTORS | 20 | 1.00 | 38.0 | 12.20 | 7.50 | 12.46 | 1.00 |
| NO. PRODUCERS | 18 | 2.00 | 76.0 | 33.56 | 33.00 | 21.98 | -0 |
| ORIG OIL IN PLACE (MMSTB) | 14 | 4.33 | 435.0 | 99.94 | 44.10 | 127.38 | -0 |
| ORIG OIL SAT (%) | 13 | 60.00 | 87.5 | 73.09 | 75.00 | 8.02 | 75.00 |
| ORIG RESVR PRESS (PSIG) | 16 | 284.00 | 10800.0 | 4424.50 | 3815.00 | 3389.98 | -0 |
| ORIG WATER SAT (%) | 19 | 9.60 | 58.0 | 27.26 | 25.00 | 12.65 | 25.00 |
| RESVR TEMP (DEGREES F) | 24 | 77.00 | 291.0 | 164.46 | 163.50 | 65.21 | -0 |
| SECRECV (% OIIP) | 5 | 6.00 | 40.0 | 23.54 | 21.50 | 15.40 | -0 |
| TERRECV (% OIIP) | 3 | 9.10 | 18.9 | 12.66 | 9.97 | 5.42 | -0 |

TABLE 3.2

Comparison of Sandstone and Carbonate Lithologies

in Project Producing Formations

| | Sandstone Lithology | Carbonate Lithology | Sandstone & Carbonate Lithology |
|---|---|---|---|
| Number of Projects with Data Available | 13 | 6 | 4 |
| % of Total Projects with Data Available | 57 | 26 | 17 |

has the second greatest number of projects with three (13% of the total projects), and Canada and Oklahoma follow with two projects apiece. One project is located in each of the remaining states listed.

The purpose of Table 3.3B is to list the four project types, the state or country which has the largest number of each project type, the number of times that project type occurs in the state/country, and what percentage that number is of the total number of the project type. In three of the four project types (flue gas, nitrogen, and immiscible carbon dioxide) Texas is the state where those project types are conducted most frequently. Two methane projects are found in Louisiana and two are located in Canada. 80% of the flue gas projects, 44% of the nitrogen projects, and 40% of the immiscible carbon dioxide projects are located in Texas.

The third general statistical compilation is a comparison of the number of projects conducted by major oil companies and those conducted by independent oil companies. Table 3.4 shows the comparison by project type. It is clear from examination of Table 3.4 that the major oil companies operate the majority (78%) of the projects surveyed in this study.

TABLE 3.3A

A Listing of Projects by State/Country

| State/Country | Number of Projects | % of Total Number of Projects |
|---|---|---|
| California | 1 | 4 |
| Wyoming | 1 | 4 |
| Alaska | 1 | 4 |
| Utah | 1 | 4 |
| Oklahoma | 2 | 8 |
| Arkansas | 1 | 4 |
| Texas | 10 | 42 |
| Louisiana | 3 | 13 |
| Alabama | 1 | 4 |
| W. Virginia | 1 | 4 |
| Canada | 2 | 8 |

TABLE 3.3B

Listing of State/Country with Largest Number of Each Project Type

| Project Type | State/Country with Largest Number of | Number of Project Type in State/Country | % of Total Project Type |
|---|---|---|---|
| Flue Gas | Texas | 4 | 80 |
| Methane | Canada & Louisiana | 2 (each) | 40 (each) |
| Nitrogen | Texas | 4 | 44 |
| Immiscible Carbon Dioxide | Texas | 2 | 40 |

TABLE 3.4
Comparison of the Number of Projects Operated by Major and Independent Oil Companies

| PROJECT TYPE | Number of Project Type For Which Data Are Available | Operator-Major Oil Co.* | | Operator-Independent Oil Co.* | |
|---|---|---|---|---|---|
| | | Number of Project Type | % of Total Project Type | Number of Project Type | % of Total Project Type |
| Flue Gas | 5 | 4 | 80 | 1 | 20 |
| Methane | 4 | 3 | 75 | 1 | 25 |
| Nitrogen | 9 | 8 | 89 | 1 | 11 |
| Immiscible Carbon Dioxide | 5 | 3 | 60 | 2 | 40 |
| TOTAL | 23 | 18 | 78 | 5 | 22 |

*Classification obtained from the 1982 USA Oil Industry Directory[37]

TABLE 3.5

Comparison of the Production Methods
Used Prior to Immiscible Gas Injection

| PROJECT TYPE | Number of Project Type for Which Data Are Available | Previous Production-Primary | Previous Production-Secondary |
|---|---|---|---|
| FLUE GAS | 4 | 4 | 0 |
| METHANE | 3 | 3 | 0 |
| NITROGEN | 6 | 2 | 4 |
| IMMISCIBLE CARBON DIOXIDE | 3 | 3 | 0 |
| TOTAL | 16 | 12 | 4 |

The last general statistical compilation is a comparison of the type of production, primary or secondary, that was used prior to start-up of immiscible gas injection. Table 3.5 shows the results of the comparison. Of the 16 projects for which data were available, the previous production for 12 of those projects was primary production. Waterflooding was the production method used in three of the four projects which implemented secondary production prior to immiscible gas injection; natural gas injection was the other secondary production method used.

## DATA ANALYSIS

### Explanation of Data Manipulation

A presentation of the results of statistically analyzing the 18 parameters listed in Table 2.2 is shown in Table 3.1. In calculating these results and plotting the frequency diagrams several data manipulations were made that require explanation.

The parameters PERMEABILITY, OIL VISCOSITY, and NO. PRODUCERS (number of production wells) each had some extreme values that were disregarded in the statistical calculations because inclusion of these values distorted the results and misrepresented what the majority of the data would show.

Values greater than 1000 md were not included in calculations for the PERMEABILITY parameter. This resulted in leaving out four values: 1194, 1200, 2000, and 3396 md. Three values of OIL VISCOSITY (40, 160, and 175 cp) were disregarded. Originally only the values 160 and 175 cp were not included but the results were still badly distorted; therefore the value of 40 cp was also removed. For the parameter, NO. PRODUCERS, two values were left out, 351 and 351 wells. These two values are the same because the projects were the Hawkins, Dexter and the Hawkins, Lewisville. It was explained previously that the Hawkins was one of two projects (Fordoche is the second) where two zones in the same formation were gas flooded simultaneously. Although most of the reservoir and fluid parameters for the zones are different, some parameters (NO. PRODUCERS, NO. INJECTORS, and PROJECT AREA) are the same. In the cases where these projects (Hawkins, Lewisville & Dexter, or Fordoche, 8-A & 12-A) did have the same values for a given parameter, they were not considered in determination of the mode for that parameter.

Since there were only three projects of the 24 surveyed that were identified as pilot projects, a separate analysis of pilot and fieldwide projects was not conducted. However, in the analysis of several parameters the inclusion of data from the pilot projects would distort the results obtained. Therefore, for those parameters affected by project size (ORIG OIL IN PLACE, NO. PRODUCERS, NO. INJECTORS, and PROJECT AREA), data from the pilot projects were not included.

## Frequency Diagrams

To better illustrate the frequency distribution of the data analyzed in Table 3.1, frequency plots were made for 17 of the 18 parameters listed. (A plot of the parameter SECRECV was not made because of too little data.) In order to transform the data for each parameter into a frequency plot, the data were grouped into class intervals. By grouping the data into class intervals, four types of graphical illustrations can be developed:[17,35] histograms, frequency polygons, frequency curves and modified frequency polygons. The modified frequency polygon was used to illustrate the data of the parameters shown in Table 3.1. Examples of these graphical illustrations are shown in Figure 3.1[17]. In plotting data using the modified frequency format, the frequency for each class interval x is plotted at the upper limit of the class interval, instead of the midpoint, and the curve is drawn to connect these points.

There is no general method that can be applied to all data in determining the number of class intervals to be used for a frequency polygon. Many times the choice of the number of class intervals to be used must be made using one's judgment and consideration of the amount, range, and occurrence of the data. However, it is generally agreed that most data can be adequately represented using from seven to fifteen class intervals.[17,35] Most of the frequency plots shown in Figures 3.2 - 3.17 make use of 11 class intervals, although several (NET PAY, OIL GRAVITY, PROJECT AREA AND NO. INJECTORS) use only six.

To illustrate how the frequency plots should be interpreted, the plot of ORIGINAL OIL SATURATION (Figure 3.13) will be explained. Each plot is designed to show the frequency with which each type of

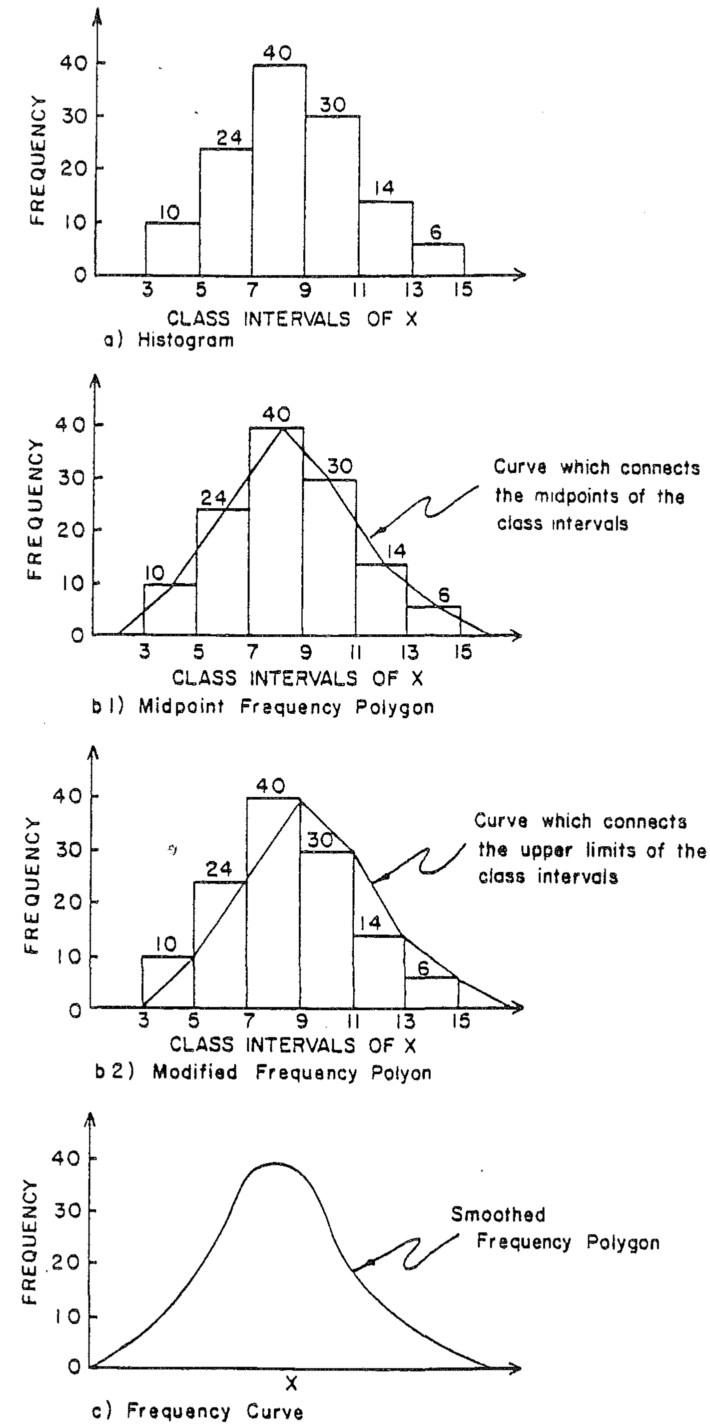


FIGURE 3.1

Graphical Presentations of Frequency Data (from Manning, 1983)[17] project occurs and the frequency with which all the projects together occur for a given class interval. Each symbol represents a particular type of gas injection, as shown by the legend. The projects are plotted cumulatively so that the curve drawn represents the frequency that all project types occur for a given class interval.

Figure 3.13 shows that there is one methane project that occurs in the oil saturation interval $50\% < x \leq 60\%$. For the class interval $60\% < x \leq 70\%$ there is one nitrogen project and three (4-1) immiscible carbon dioxide projects; a total of four gas injection projects fall within this interval. Similarly, for the interval $70\% < x \leq 80\%$, there are one flue gas project, three (4-1) nitrogen projects, and two (6-4) immiscible carbon dioxide projects, for a total of six projects in the interval. In the interval $80\% < x \leq 90\%$ two nitrogen projects occur; there are no projects with an original oil saturation greater than 90%.

## DISCUSSION OF RESULTS

One of the most important objectives of this study, to determine the amount of oil recovered as a result of immiscible gas injection, was unfortunately very difficult to achieve. Because of the lack of available data the only recovery parameter that could be analyzed was the projected amount of oil recovery due to gas injection, in terms of per cent of original oil in place. Data for this recovery parameter had to be divided into projects that were produced by primary production prior to gas injection, SECRECV, and those that were produced by secondary recovery prior to gas injection, TERRECV. The result was that a small amount of data, 8 projects, was made even smaller when previous production was taken into account; SECRECV data were available for five projects and TERRECV data available for three. In spite of the small amount of data available for these two parameters, they were included in the statistical analysis. In both cases the mean and median values are in fairly close agreement, but because each parameter has at least one extreme (high) value as compared to the other data, the median is probably the best estimate of oil recovery for both SECRECV and TERRECV. When reviewing these results note that the data for these parameters were projected, and not actual oil recovery; optimistic estimates of oil recovery would give erroneous statistical results. Of the two oil recovery parameters, only the data of the parameter TERRECV were illustrated with a frequency plot; there were not sufficient data to plot SECRECV.

After examining the results of the statistical analysis, the frequency plots, and the data listing for each of the parameters analyzed, it was found that the results were inconclusive for some of the parameters. No general trends could be discerned after studying the data and results for the following parameters: porosity, net pay, gross pay, project area, number of injection wells , number of production wells, and original oil in place.

Study of the permeability frequency plot, Figure 3.4, shows there are several extreme values of permeability, which result in a high mean value (as compared to the median), but also shows that the majority of the data fall at or below 60 md. Inspection of the data base reveals that 12 of the total 18 projects have permeabilities less than 40 md.

Since the parameters oil gravity and oil viscosity are related, the results for the two parameters will be discussed at the same time. The mean and median for oil gravity are $37.2^{o}$API and $41^{o}$ API, respectively, and agree fairly closely. The frequency plot for oil gravity shows that half of the 22 projects have gravities between $36^{o}$API and $48^{o}$API; 16 of the projects have oil gravities $\geq 35^{o}$API. The median value for oil viscosity is 0.43 cp and the mean is 1.01 cp. These two values do not agree well; several high values of viscosity distort the mean value. The frequency diagram for oil viscosity indicates that 9 of the 16 projects have viscosities $\leq 0.50$ cp.

The results for the parameters reservoir temperature, original reservoir pressure, and depth of reservoir denote that the majority of the projects have deep, high-pressure, high-temperature reservoirs. Mean and median values of original reservoir pressure are 4424 psi and 3815 psi, respectively; 10 of the 16 projects have original pressures > 3000 psi. 14 of 24 projects have a reservoir depth > 7000 feet, with the median value being 8307 feet. The median value for reservoir temperature is $163.5^{o}$F and 14 of 24 projects have temperatures which exceed $150^{o}$F.

It was also found that the project reservoirs tended to have a high original oil saturation and a low original water saturation. The median value for original oil saturation is 75%, with all of the projects falling within the range of 60% to 90%. Water saturation has a median value of 25%; 12 of the 19 projects have an original water saturation of 25% or less.

One final determination is that the ratio of net pay to gross pay thickness is fairly low. Examination of the data base, Table 2.8, indicates that 11 of the 14 projects have a net pay-to-gross pay ratio of less than 0.80.

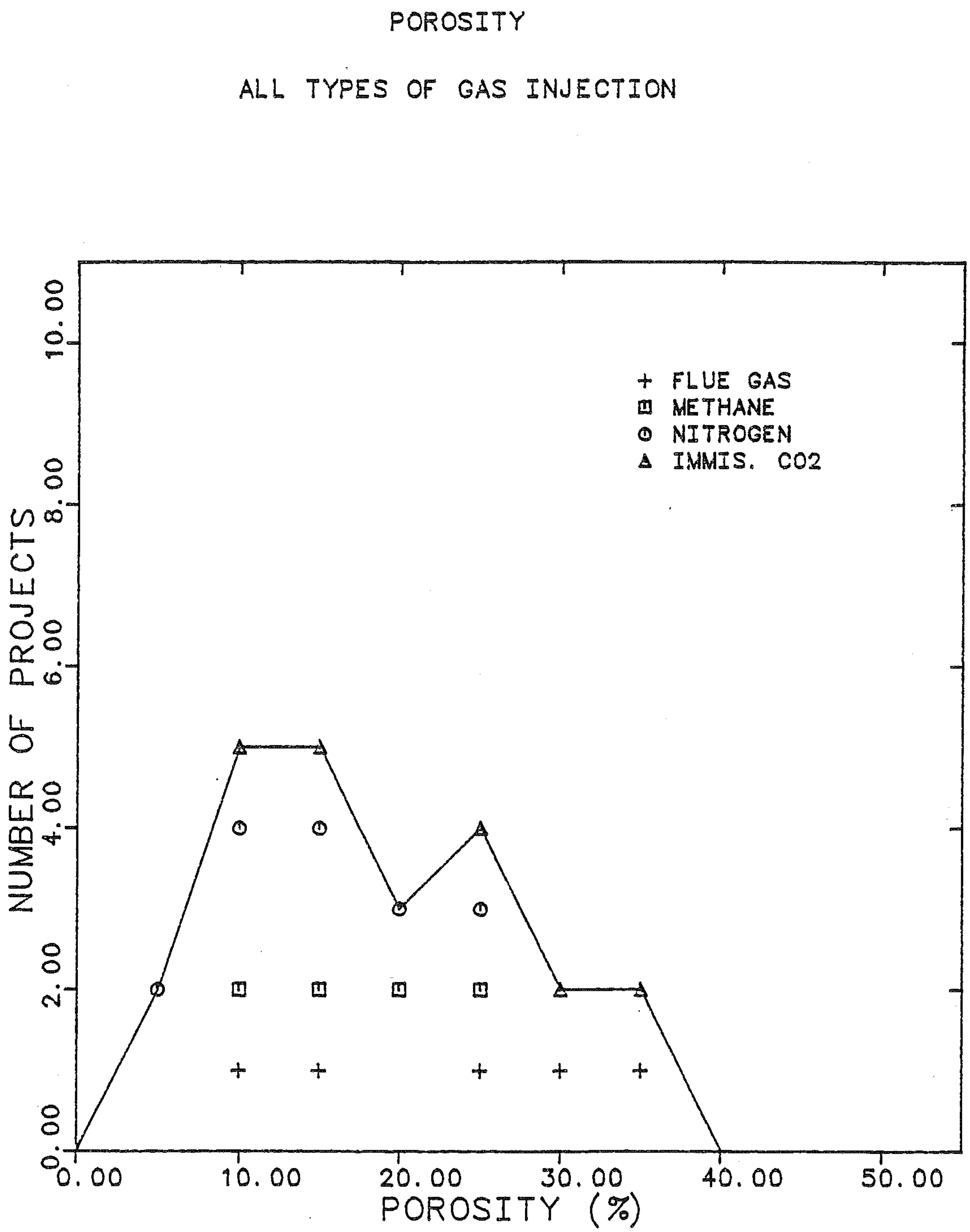
POROSITY
ALL TYPES OF GAS INJECTION
FLUE GAS
METHANE
NITROGEN
IMMIS. CO2
NUMBER OF PROJECTS
0.00
2.00
4.00
6.00
8.00
10.00
0.00
10.00
20.00
30.00
40.00
50.00
POROSITY (%)

FIGURE 3.2

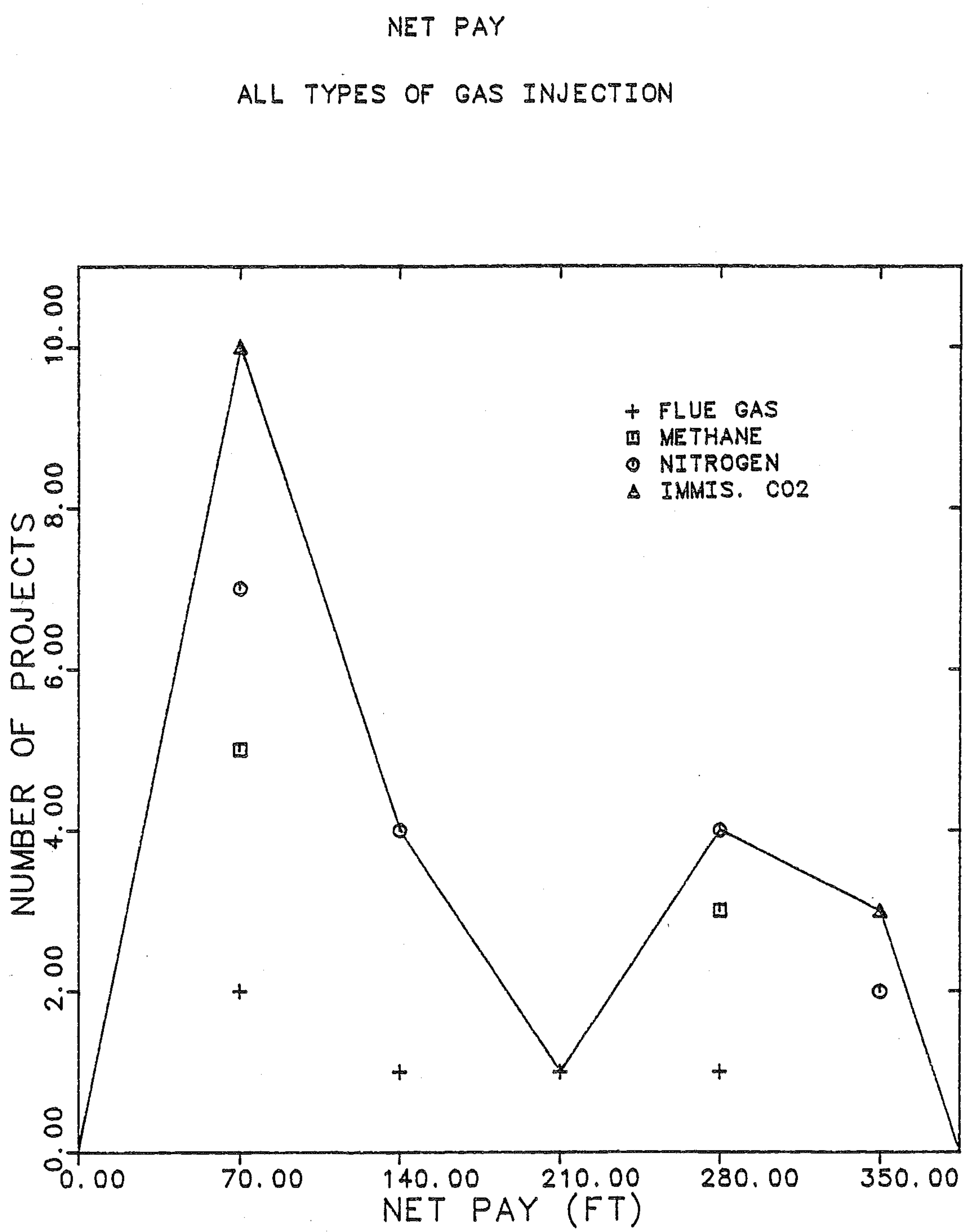
NET PAY
ALL TYPES OF GAS INJECTION
FLUE GAS
METHANE
NITROGEN
IMMIS. CO2
NUMBER OF PROJECTS
0.00
2.00
4.00
6.00
8.00
10.00
0.00
70.00
140.00
210.00
280.00
350.00
NET PAY (FT)

FIGURE 3.3

PERMEABILITY

ALL TYPES OF GAS INJECTION

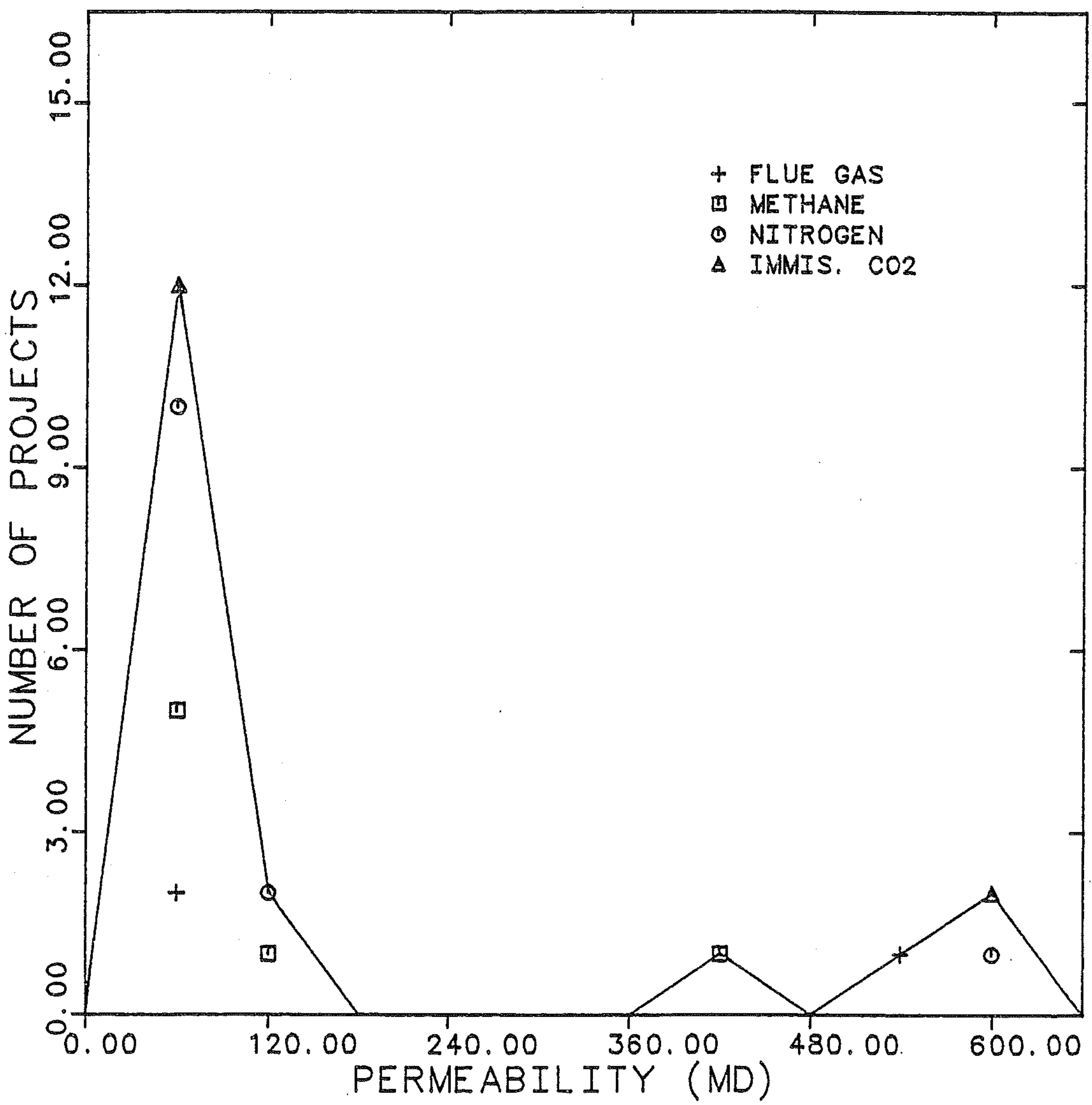


FIGURE 3.4

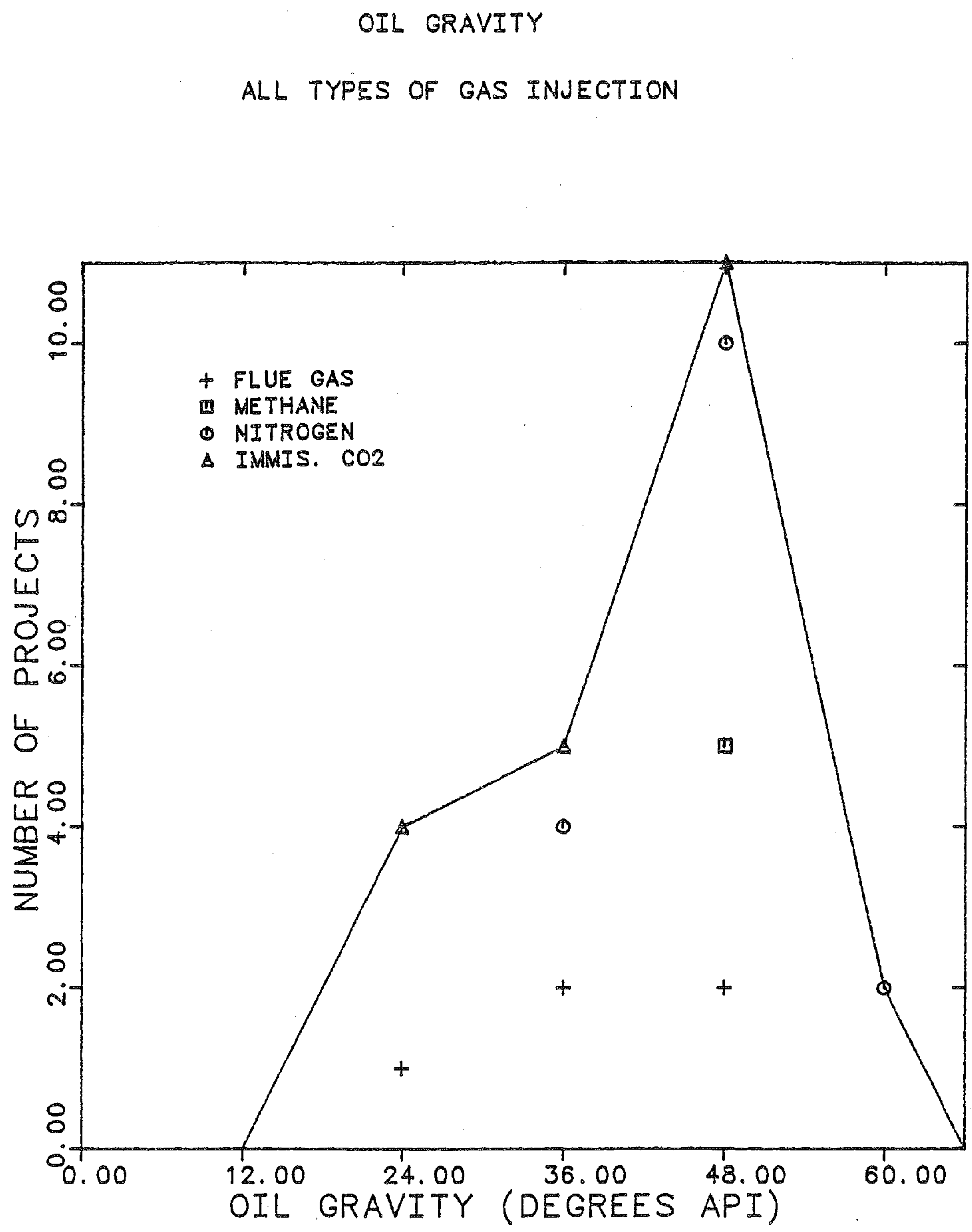
OIL GRAVITY
ALL TYPES OF GAS INJECTION
+ FLUE GAS
METHANE
NITROGEN
IMMIS. CO2
NUMBER OF PROJECTS
0.00
2.00
4.00
6.00
8.00
10.00
0.00
12.00
24.00
36.00
48.00
60.00
OIL GRAVITY (DEGREES API)

FIGURE 3.5

DEPTH OF RESERVOIR

ALL TYPES OF GAS INJECTION

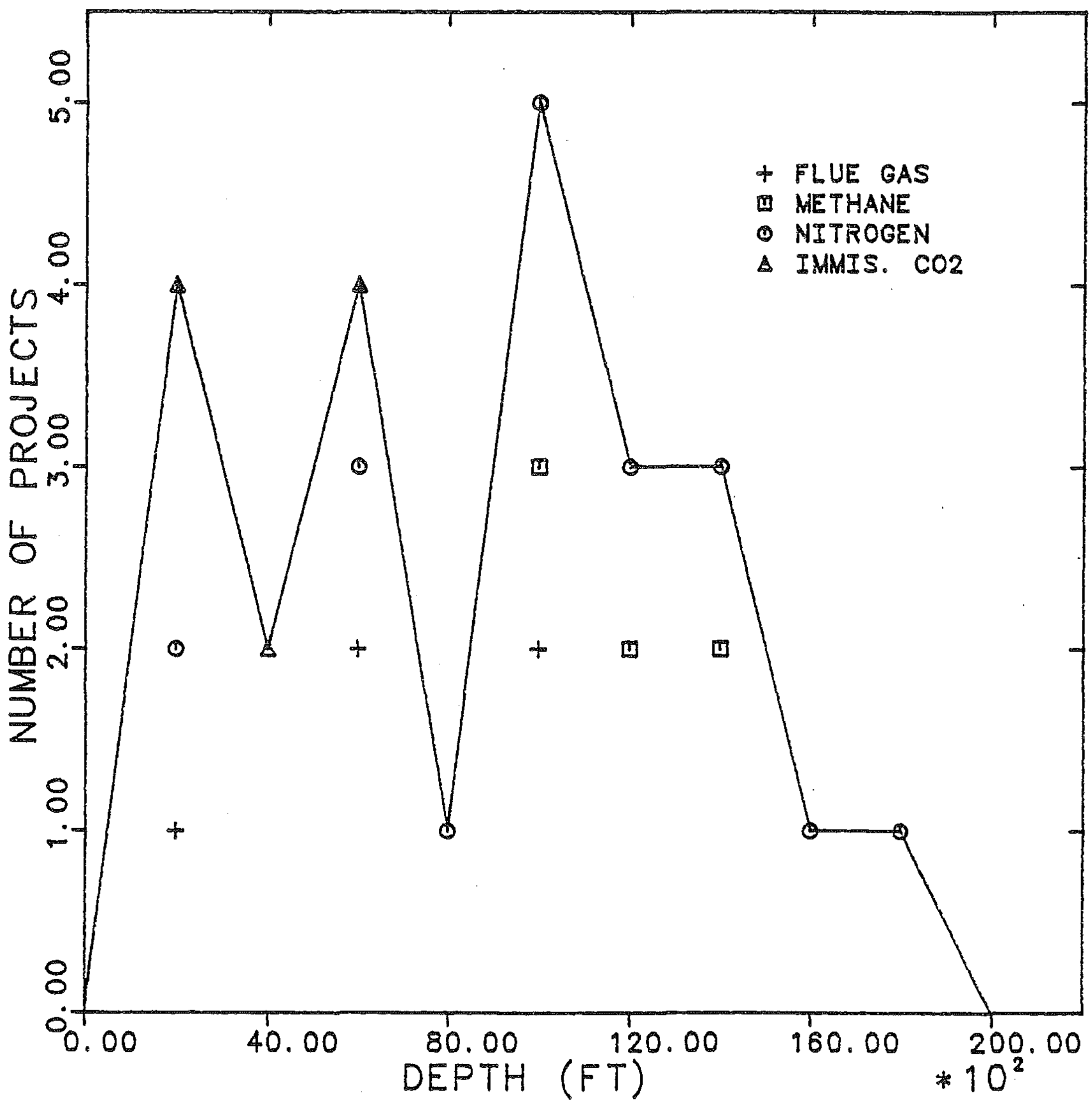


FIGURE 3.6

GROSS PAY

ALL TYPES OF GAS INJECTION

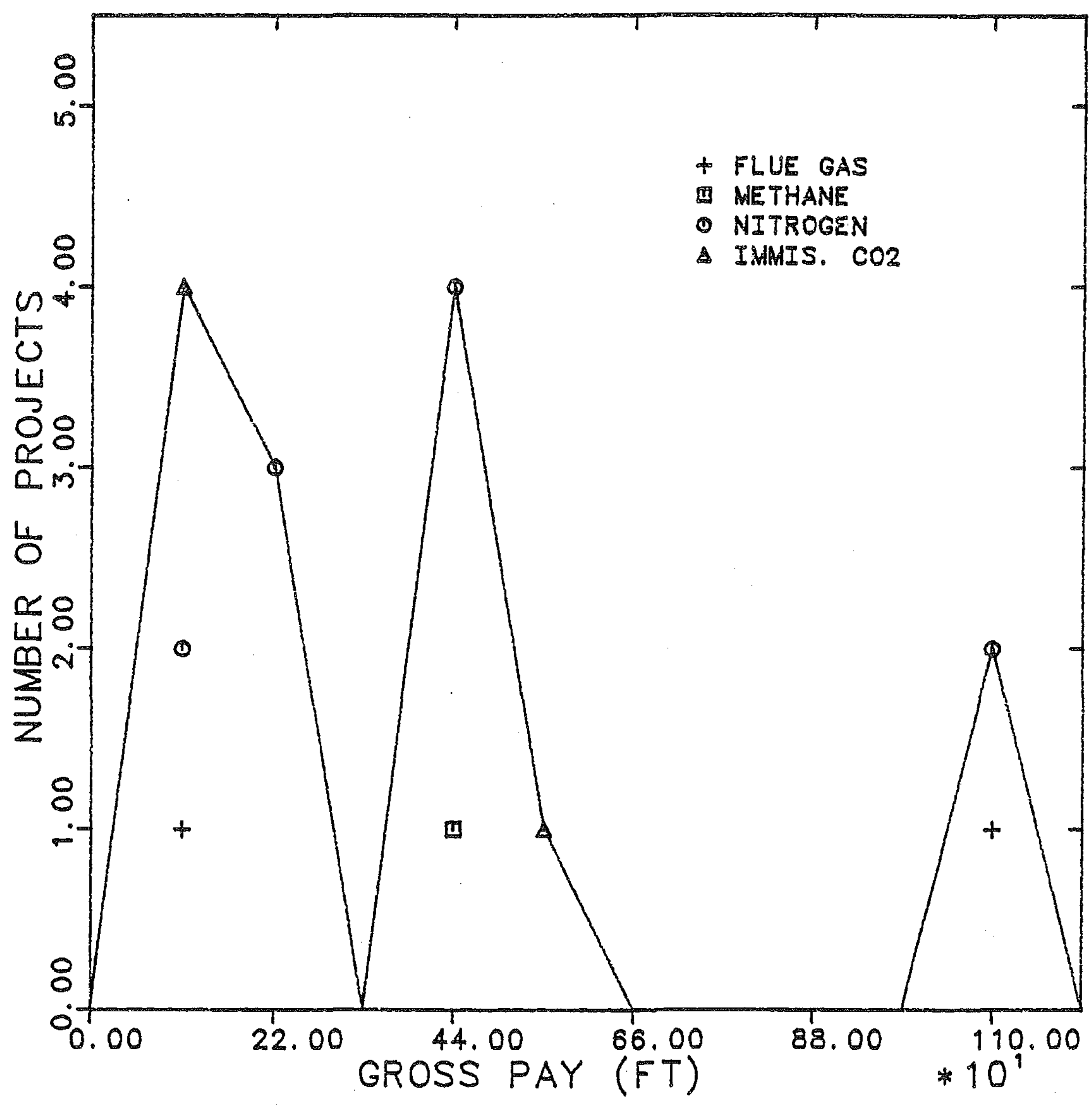


FIGURE 3.7

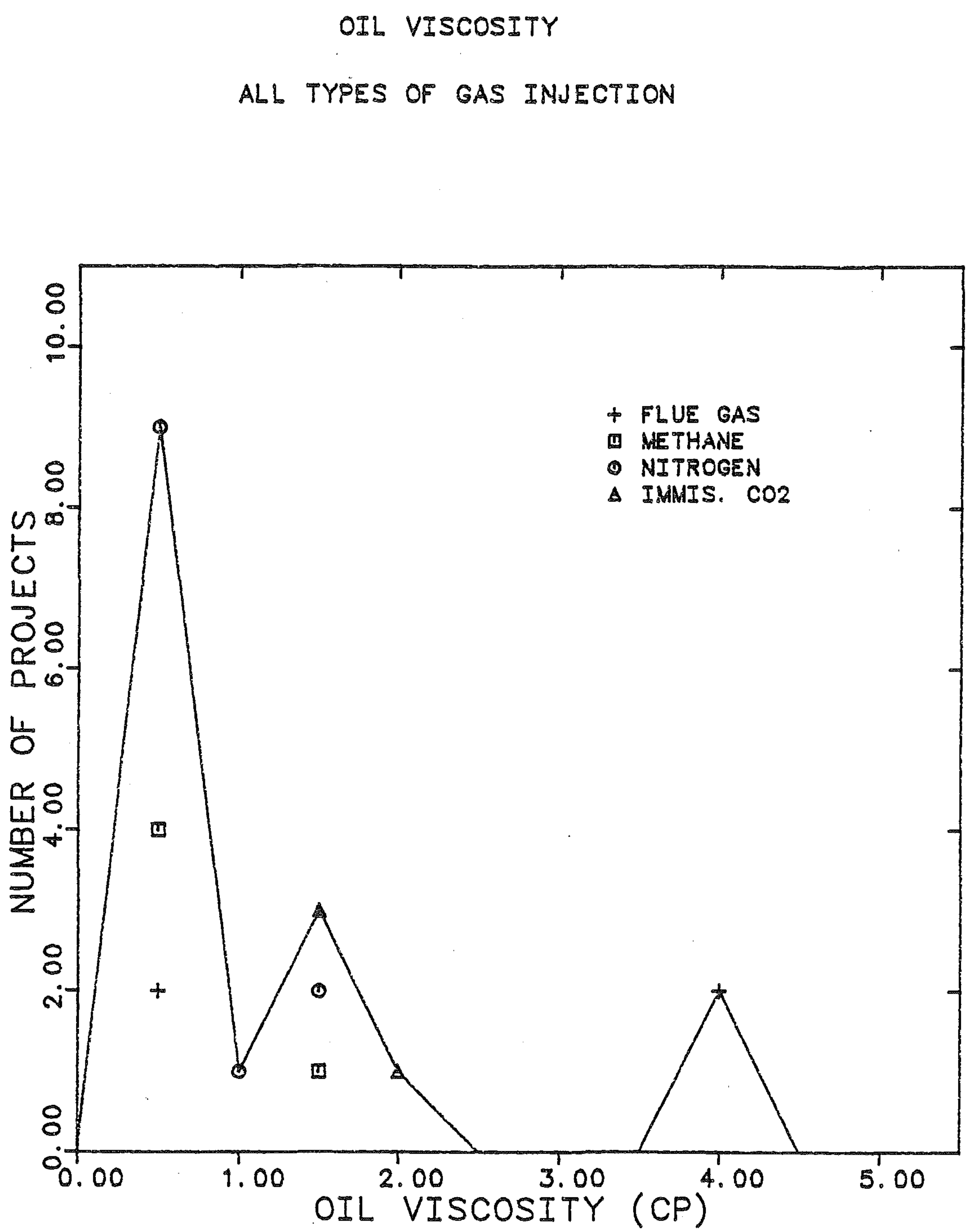
OIL VISCOSITY
ALL TYPES OF GAS INJECTION
+ FLUE GAS
METHANE
NITROGEN
IMMIS. CO2
NUMBER OF PROJECTS
0.00
2.00
4.00
6.00
8.00
10.00
0.00
1.00
2.00
3.00
4.00
5.00
OIL VISCOSITY (CP)

FIGURE 3.8

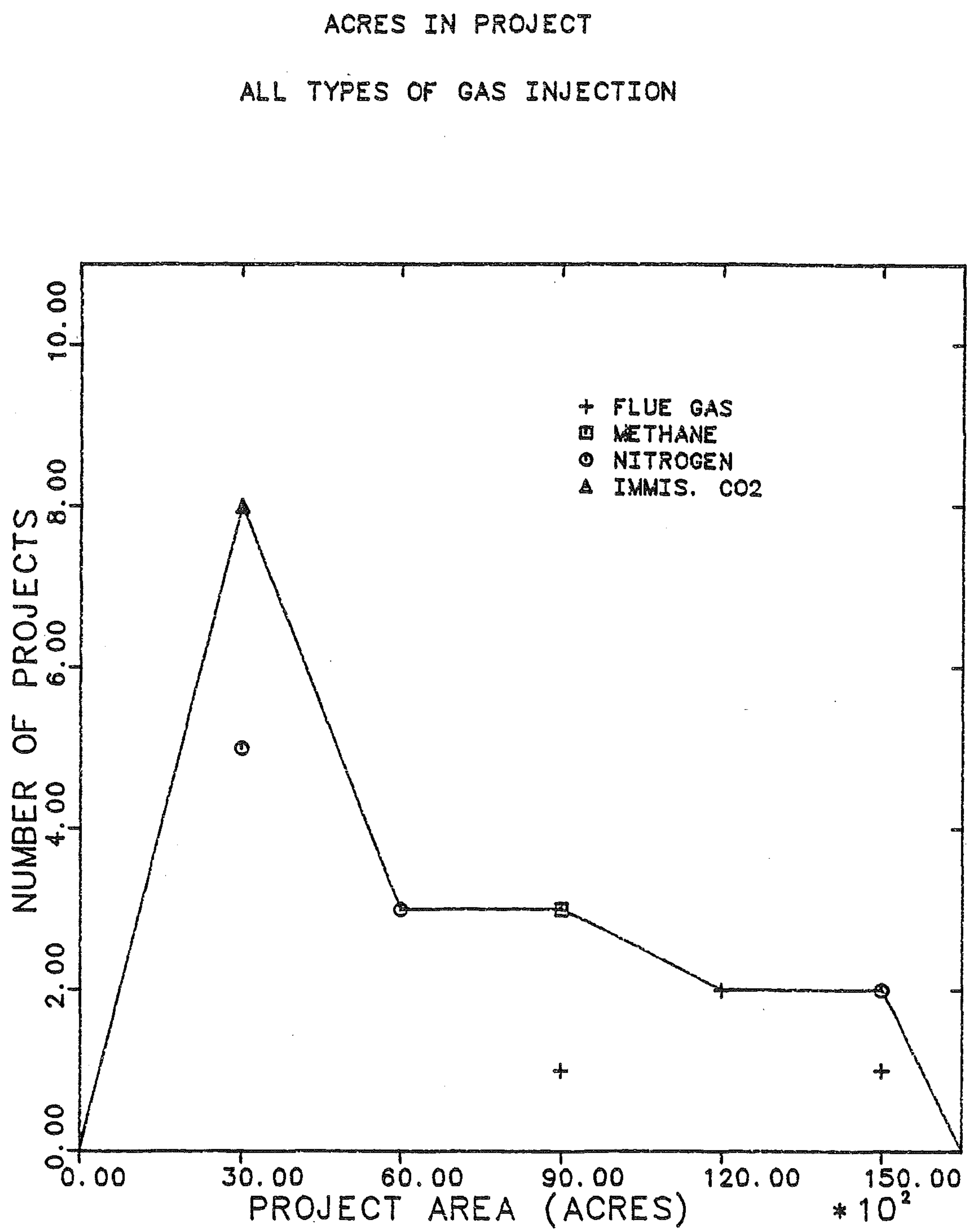
ACRES IN PROJECT
ALL TYPES OF GAS INJECTION
NUMBER OF PROJECTS
0.00
2.00
4.00
6.00
8.00
10.00
+ FLUE GAS
METHANE
NITROGEN
IMMIS. CO2
0.00
30.00
60.00
90.00
120.00
150.00
PROJECT AREA (ACRES)
$*10^2$

FIGURE 3.9

INJECTION WELLS IN PROJECT

ALL TYPES OF GAS INJECTION

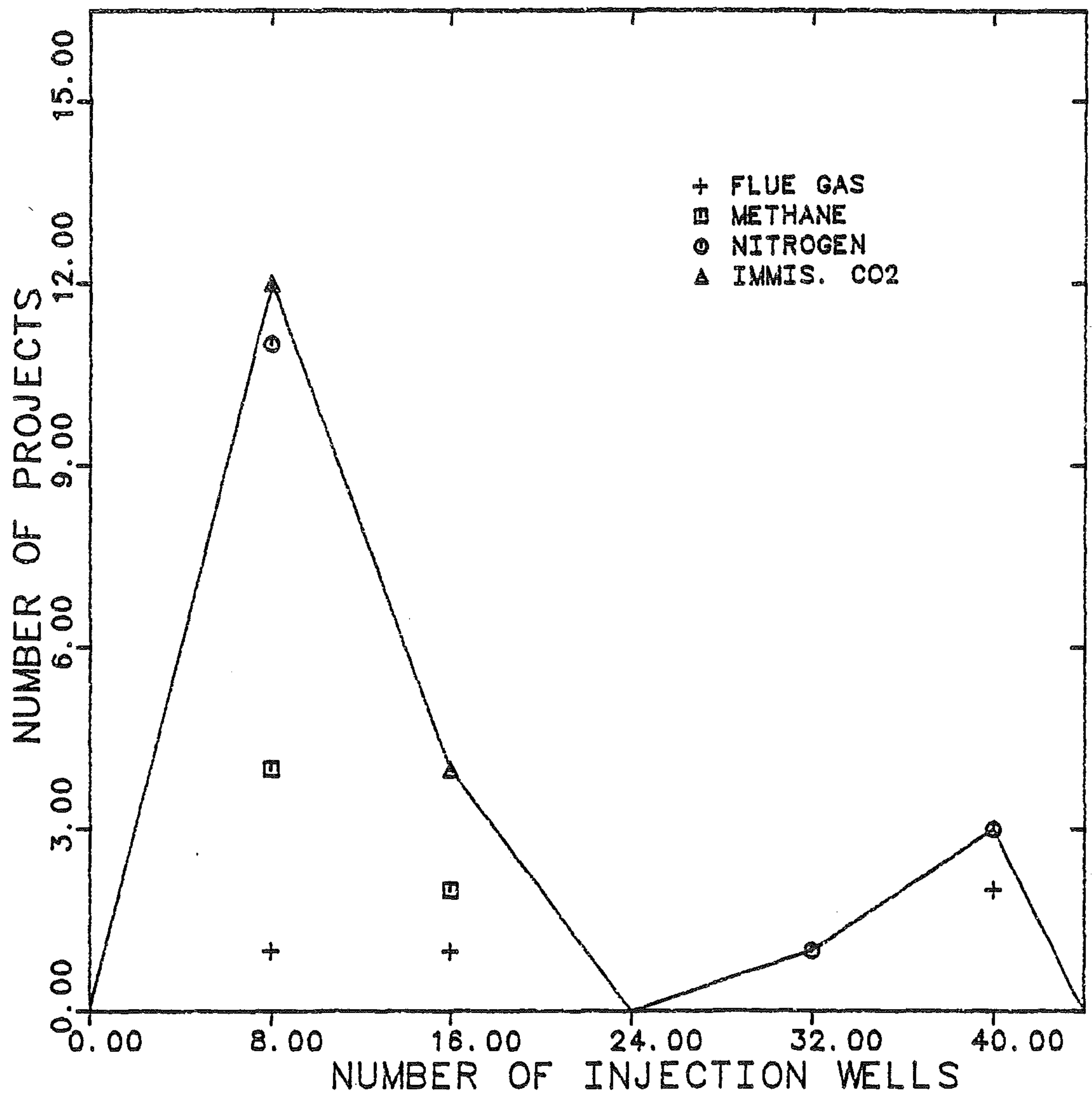


FIGURE 3.10

PRODUCING WELLS IN PROJECT

ALL TYPES OF GAS INJECTION

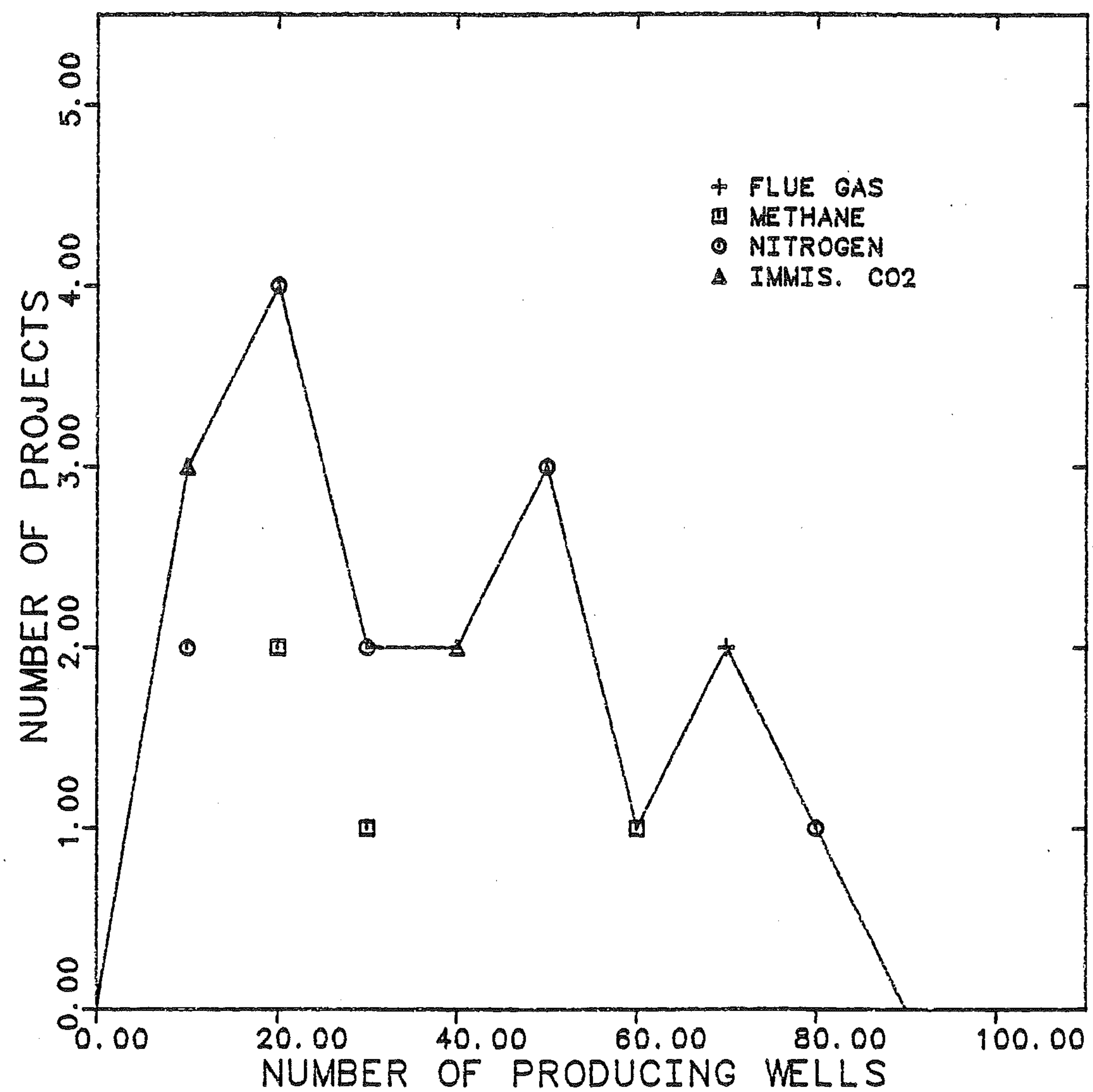


FIGURE 3.11

ORIGINAL OIL IN PLACE

ALL TYPES OF GAS INJECTION

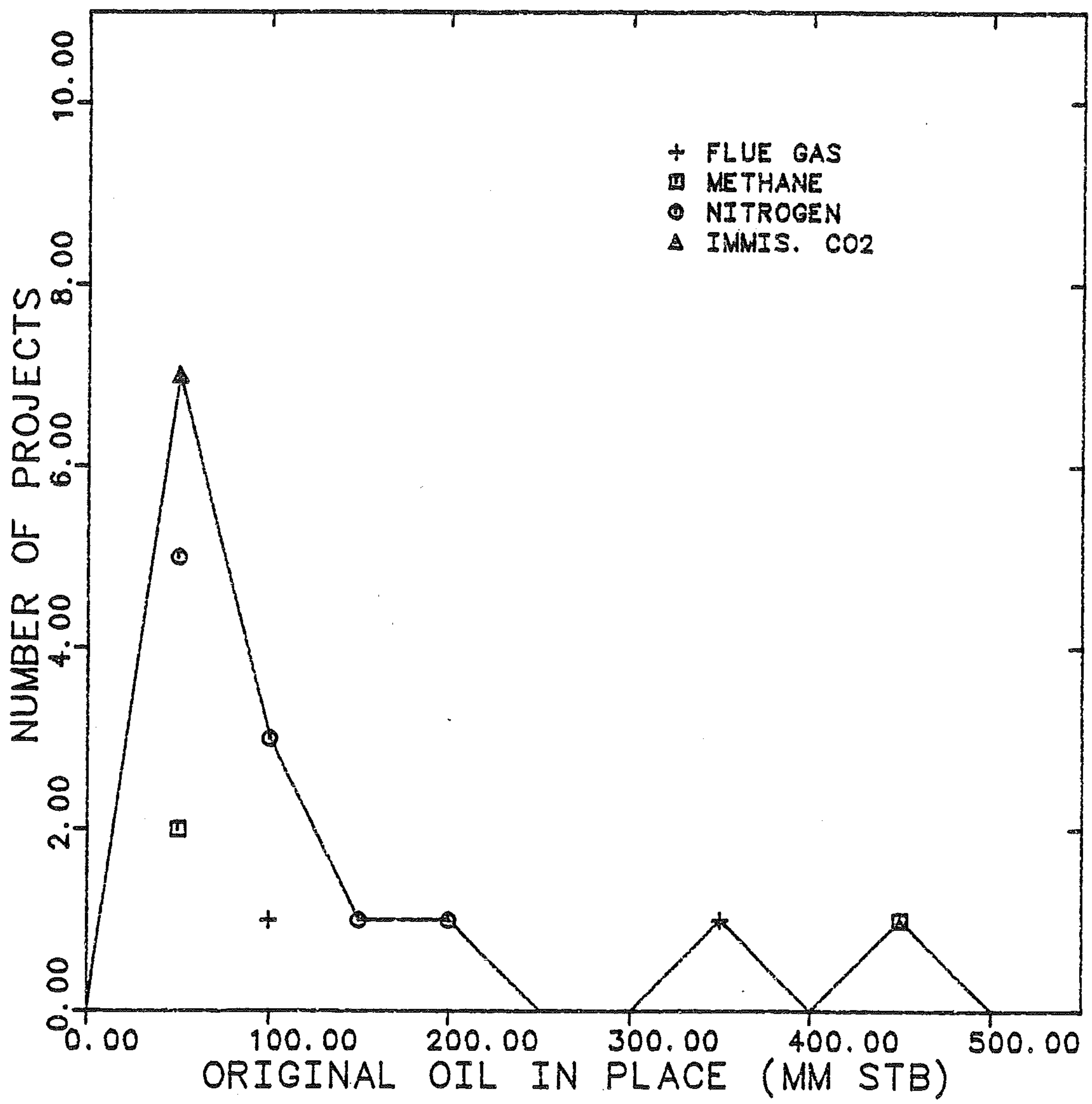


FIGURE 3.12

ORIGINAL OIL SATURATION

ALL TYPES OF GAS INJECTION

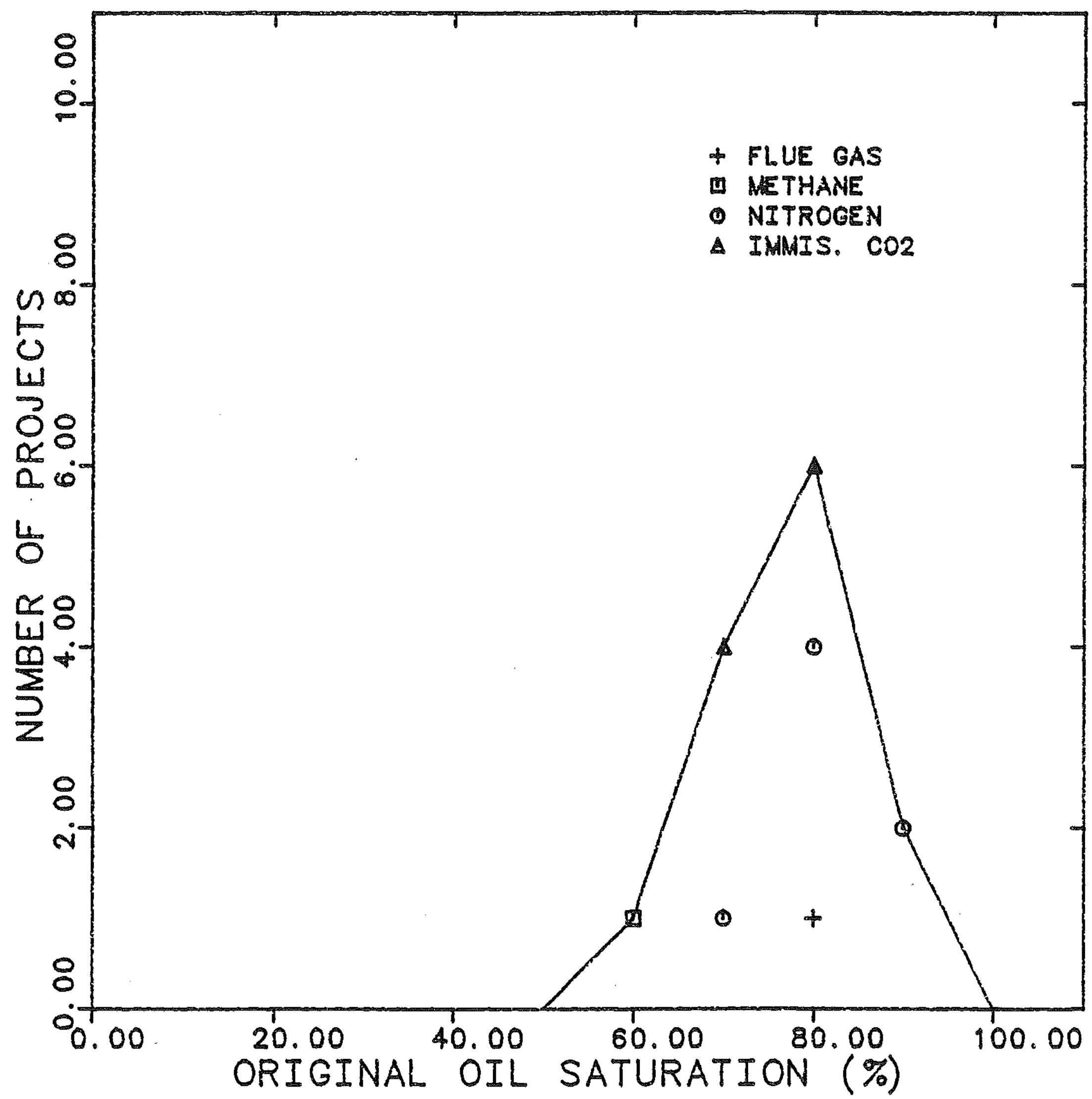


FIGURE 3.13

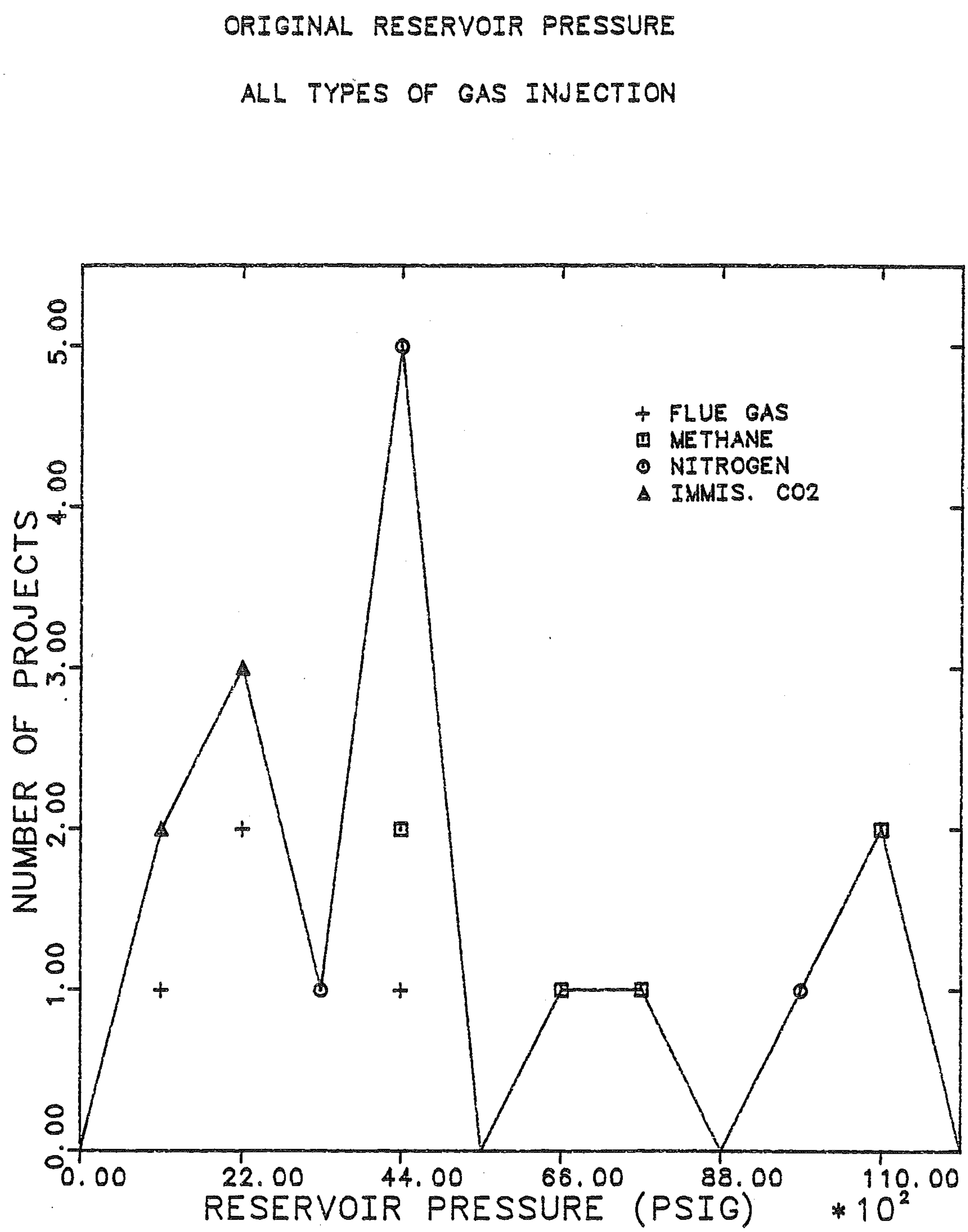
ORIGINAL RESERVOIR PRESSURE
ALL TYPES OF GAS INJECTION
NUMBER OF PROJECTS
0.00
1.00
2.00
3.00
4.00
5.00
+ FLUE GAS
METHANE
NITROGEN
IMMIS. CO2
0.00
22.00
44.00
66.00
88.00
110.00
RESERVOIR PRESSURE (PSIG) *10²

FIGURE 3.14

ORIGINAL WATER SATURATION

ALL TYPES OF GAS INJECTION

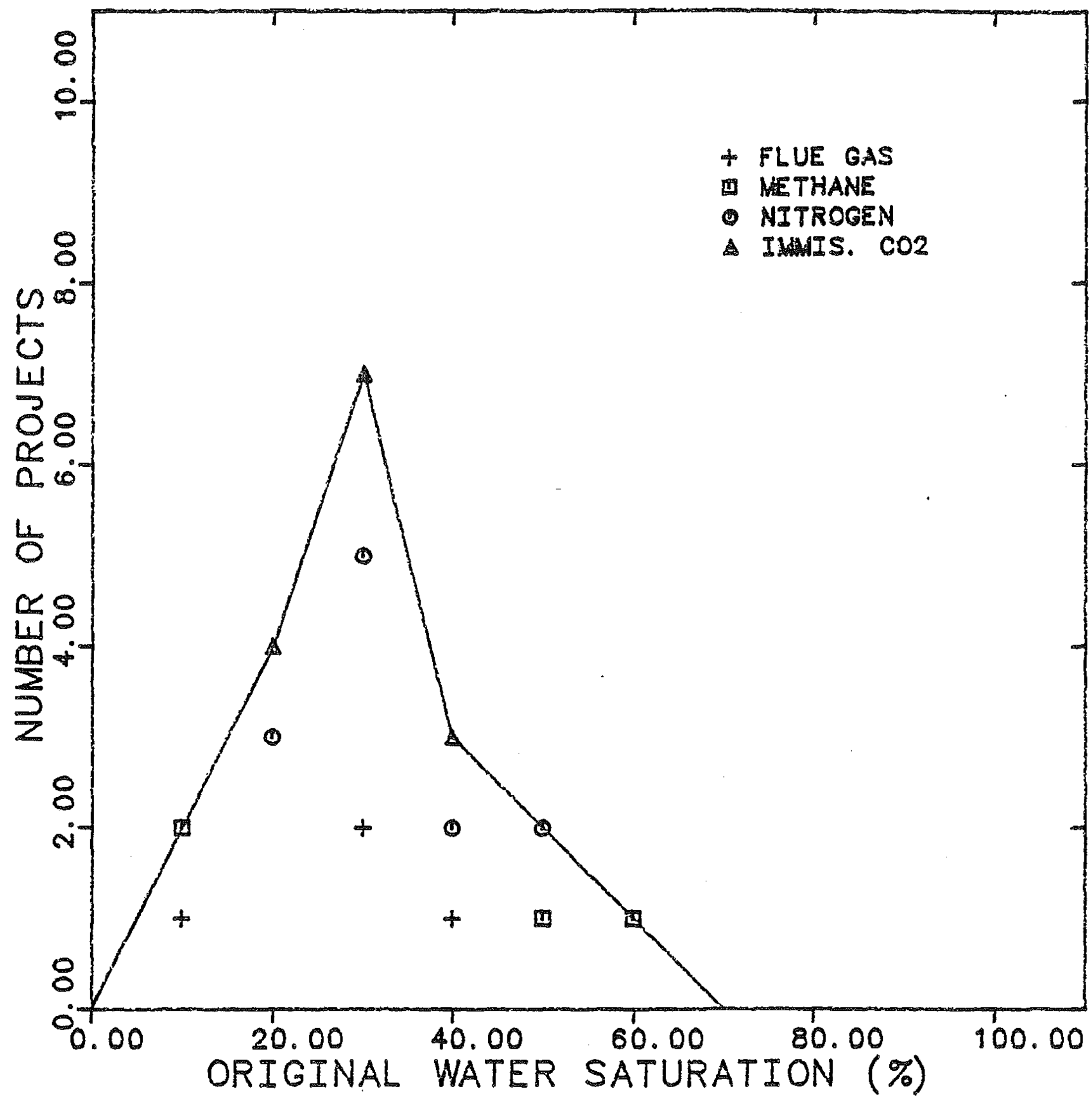


FIGURE 3.15

RESERVOIR TEMPERATURE

ALL TYPES OF GAS INJECTION

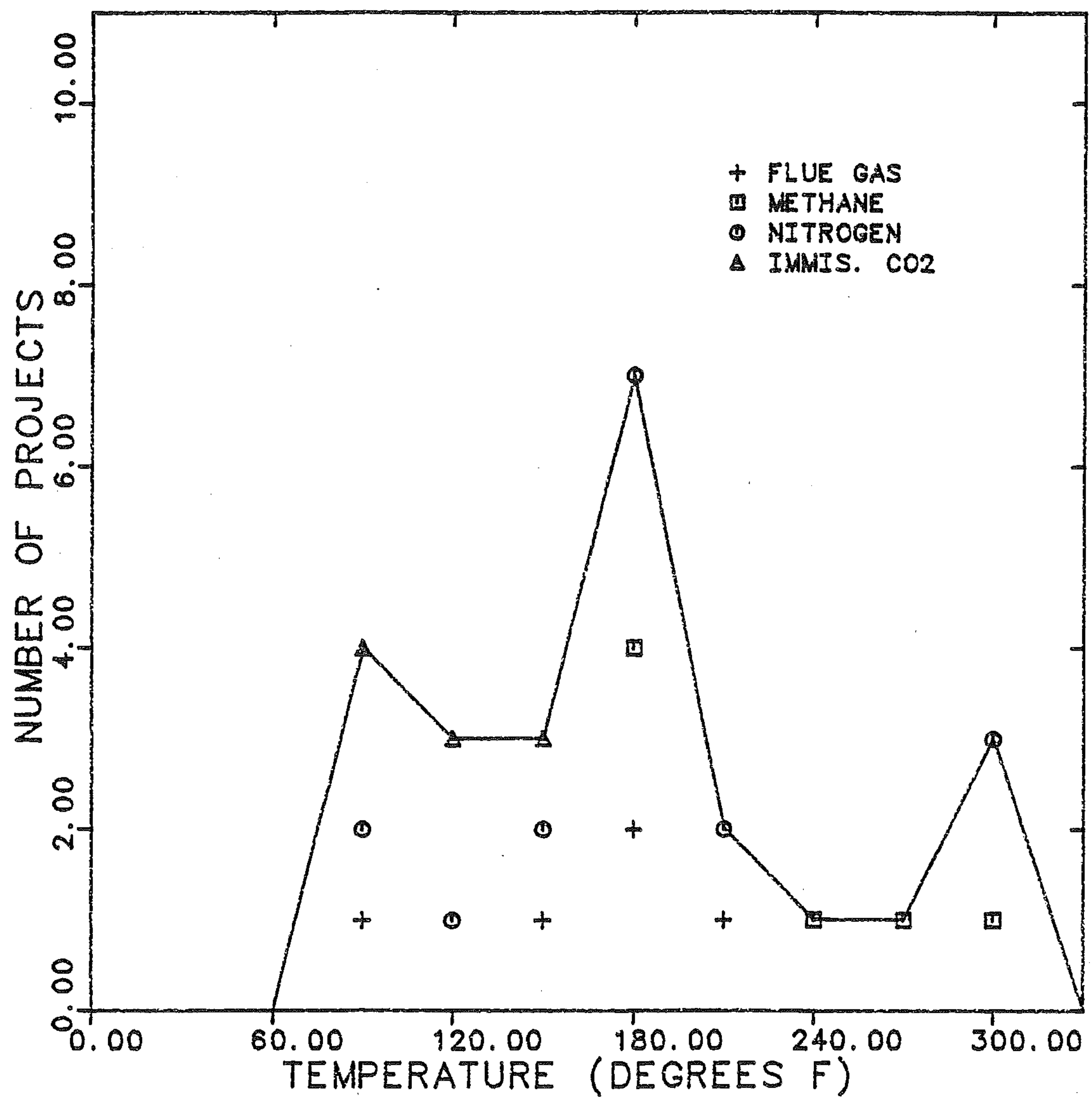


FIGURE 3.16

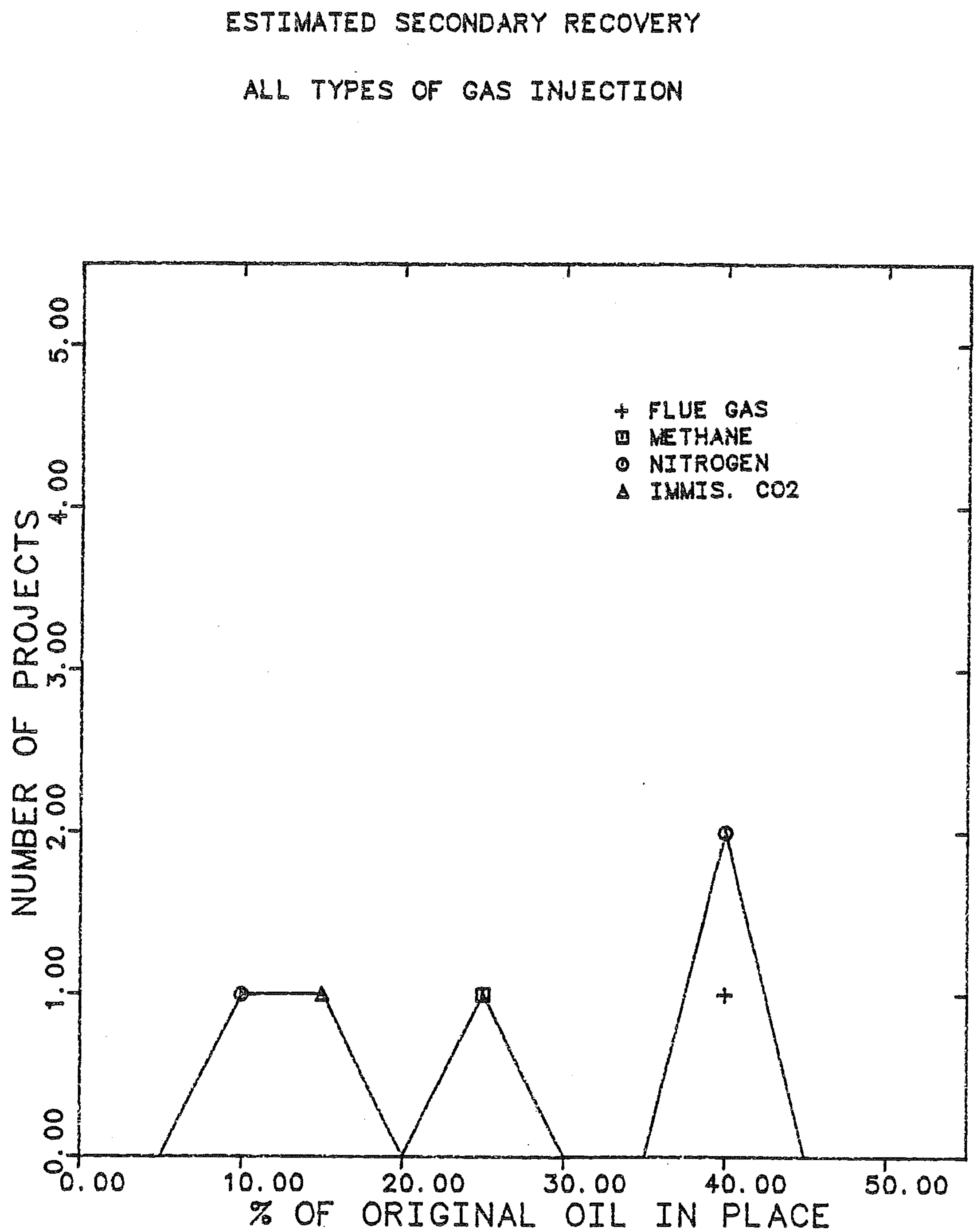
ESTIMATED SECONDARY RECOVERY
ALL TYPES OF GAS INJECTION
FLUE GAS
METHANE
NITROGEN
IMMIS. CO2
NUMBER OF PROJECTS
0.00
1.00
2.00
3.00
4.00
5.00
0.00
10.00
20.00
30.00
40.00
50.00
% OF ORIGINAL OIL IN PLACE

FIGURE 3.17

CHAPTER IV

# CONCLUSIONS

This study of immiscible gas injection projects details four types of gas injection: flue gas, methane, nitrogen, and carbon dioxide. A database consisting of 24 completed and current projects was compiled; the 24 projects are made up of five projects each of flue gas, methane, and immiscible carbon dioxide injection and nine nitrogen injection projects. A statistical analysis was performed on selected reservoir, fluid and oil recovery parameters and frequency diagrams were composed to facilitate data analysis. As a result of this study, the following conclusions were made:

1. Immiscible gas injection is not yet widely used as an enhanced recovery process. Therefore, data for these types of gas injection were scarce -- oil recovery information was especially difficult to find.
2. The major oil companies, rather than independent oil companies, conducted most (78%) of the immiscible gas flooding projects.
3. A majority of the projects for which information was available, 75%, were produced by primary production prior to immiscible gas injection.
4. A comparison of the types of lithologies (sandstone,

carbonate, or sandstone and carbonate) which make up the project producing formations shows that 57% of the projects are produced from sandstone formations. An additional 17% of the project formations consisted of both sandstone and carbonate lithologies.

5. Of all the states/countries where the projects were located, the vast majority, 42%, were found in Texas. The only foreign country represented was Canada with 8% of the total projects.

6. Although there were four high values of permeability, the general trend was low (< 40 md) permeability producing formations.

7. Oil recovered from the project producing formations tended to be a high gravity ($\geq$ 35°API), low viscosity ($\leq$0.50 cp) crude.

8. The majority of the producing formations were deep (>7000 feet), high temperature (> 150°F), high pressure (>3000 psi) reservoirs.

9. Producing formations that were gas flooded generally had a high original oil saturation and a low original (connate) water saturation ($\leq$ 25%).

10. The net pay thickness-to-gross pay thickness ratio was low. 79% of the projects had a net pay-to-gross pay ratio of less than 0.8.

11. A small amount of oil recovery data was available for

statistical analysis. Projected oil recovery due to gas injection for projects that had been produced using primary production prior to gas injection was estimated at 21.5% of the original oil in place. Projects that were produced by secondary production prior to gas injection could recover approximately 10% of the the original oil in place. Only a small amount of confidence should be placed in these estimates as oil recovery was projected, not actual, production and the number of projects for which projected oil recovery information was available was limited.

# CHAPTER V

## RECOMMENDATIONS FOR FURTHER STUDY

1. Since the largest drawback in this study was the lack of data, it is suggested that after a period of time (to allow for the initiation of additional immiscible gas injection projects) another effort be conducted to gather data and enlarge the data base used in this work. To ensure that the supplemental data are complete and accurate it would be best to contact the project operators and request specific information; this is the most time-consuming method of obtaining data but also gives the best results.

2. A special effort should be made to acquire information on actual oil recovery. Data regarding the following parameters would be valuable in determining the recovery that could be expected from immiscible gas injection: oil saturation at project completion, amount of oil remaining in the reservoir at project initiation, actual oil recovered (at project completion) due to gas injection, total amount of gas injected throughout project life, amount of oil recovered per unit of injected gas, and residual oil saturation.

3. The expanded data base should be analyzed in more detail. In addition to the frequency plots and statistics applied in this study, it would be useful to employ linear regression techniques (assuming there are sufficient data) to determine if there is correlation between oil recovery and selected fluid and reservoir parameters.

NOMENCLATURE

| | |
|---|---|
| ACRES/PATTERN | Number of acres per well pattern |
| AGE | Period (Mesozoic or Paleozoic rocks) or epoch (Cenozoic rocks) in which PROD FORMATION originated |
| AMOUNT GAS INJ | Amount of immiscible gas injected into project PROD FORMATION at time data were reported (BCF) |
| API GRAVITY | Stock tank oil gravity ($^{o}$API at 60$^{o}$F) |
| CURRENT OIL RECOVERY | Amount of incremental oil recovered due to gas injection at time data was reported (MM STB) |
| DEPTH | Average subsurface depth to top of PROD FORMATION (feet) |
| DEP UNIT | Type of formation deposit (reef, delta, bar, etc.) |
| DOE | $ indicates cost of project was shared by Department of Energy; - indicates information is not known (Table 2.4) |
| ENVIRONMENT | Depositional environment of PROD FORMATION (marine, aeolian, fluvial, etc.) |
| FIELD | Name of oil field in which immiscible gas injection was used |

| | |
|---|---|
| FW/PILOT | Indicates if project is field wide (FW) or pilot project (PILOT) |
| GROSS PAY | Average gross pay thickness found in project PROD FORMATION (feet) |
| L.A. | Los Angeles |
| NET PAY | Average effective pay thickness found in project PROD FORMATION (feet) |
| NET PAY/GROSS PAY | Net pay-to-gross pay thickness ratio (dimensionless) |
| NO. INJECTORS | Number of injection wells in project |
| NO. PRODUCERS | Number of producing wells in project |
| NO. PROJECTS | Number of projects for which parameter data were available |
| NUM | Number assigned to each project for identification purposes |
| OIL VISCOSITY | Average viscosity of oil at reservoir conditions (cp) |
| ORIG OIL IN PLACE | Original oil in place in project PROD FORMATION at discovery (MM STB) |
| ORIG OIL SAT | Average oil saturation in project PROD FORMATION at discovery (%) |
| ORIG RESVR PRESS | Reservoir pressure in project PROD FORMATION at discovery (psig) |
| ORIG WATER SAT | Average water saturation in PROD FORMATION at discovery (%) |

| | |
|---|---|
| PATTERN TYPE | Type of well pattern used in project (9-spot, 5-spot, etc.) |
| PERMEABILITY | Average permeability in project PROD FORMATION (md) |
| POROSITY | Average porosity in project PROD FORMATION (%) |
| PRESENT RESVR PRESS | Average reservoir pressure at time data was reported (psig) |
| PREVIOUS PROD | Method of production used prior to initiation of immiscible gas injection |
| PROD FORMATION | Name of geologic formation from which project is producing |
| PROJECT | Unit, lease, or project name that identifies the gas injection project |
| PROJECT AREA | Surface area overlying project PROD FORMATION (acres) |
| PROJ RECOVERY | Estimated amount of oil that will be recovered due to gas injection (MM STB) |
| REF | Bibliographical reference for individual project |
| REGDIST | Regulatory or conservation districts within a state |
| REGION | Large geographical area of the United states (Gulf Coast, Rocky Mountain, West Texas, Appalachia, Mid Continent, West |

| | |
|---|---|
| | Coast or Foreign) |
| RESVR TEMP | Temperature of PROD FORMATION ($^{o}F$) |
| SECRECV | Estimated amount of incremental oil recoverable due to gas injection; project previously produced by primary production (% OIIP) |
| STD.DEV. | Standard deviation |
| TERRECV | Estimated amount of incremental oil recoverable due to gas injection; project previously produced by secondary recovery method (% OIIP) |
| TYPE OF GAS INJ | Type of gas used as injectant for the project |
| WETTABILITY | Fluid that preferentially wets reservoir rock (water wet, oil wet) |
| YR BEGIN | Month and year when immiscible gas injection began |
| YR-END | Month and year in which gas injection ended or estimation of when injection will end |
| ZONE | Local name for horizon or zone into which gas is injected |

APPENDIX

```
PROGRAM PLOT1(INPUT,OUTPUT,PLOTR,TAPE6=INPUT,TAPE10=OUTPUT)

COMMON/TITL/NTITLE,ITITL(5,5)
COMMON/AXLABL/XLABEL(3),YLABEL(3),NXCHAR,NYCHAR,LABSID
COMMON/LINMOD/LINMOD(10)
COMMON/FXDSCL/XFSTV,YFSTV,XDELV,YDELV,IXAXFX,IYAXFY
COMMON/SYMBZT/ISYMZT(10)
COMMON/LEGEND/LEGEND,FACTL,YLEGND(3,10)

DIMENSION NPTS(10),X(30,10),Y(30,10),LINTYP(10)

LOGICAL LABSID
LOGICAL LEGEND

NMAX2=30
XMIN=0.
YMIN=0.
NXCHAR=30
NYCHAR=30
IPLT=2
FACTL=0.9

READ DATA FROM FILE

FIRST LINE OF DATA FILE IS FILE DESCRIPTION

READ(6,10)
FORMAT(1H0)

READ IN PLOT TITLE

NTITLE=3
DO 20 J=1,NTITLE
READ(6,30) (ITITL(I,J),I=1,5)
FORMAT(6A10)
CONTINUE

READ IN AXIS LABELS

READ(6,40) (XLABEL(I),I=1,3)
READ(6,40) (YLABEL(I),I=1,3)
FORMAT(3A10)

READ(6,*)XMAX,YMAX,NVECT
IVECT=NVECT-1

DO 60 J=1,IVECT
LEGEND=.TRUE.
READ(6,*)NUMPT
NPTS(J)=NUMPT
LINMOD(J)=3
LINTYP(J)=-1

READ IN X AXIS VALUES
READ(6,*) (X(I,J),I=1,NUMPT)

READ IN Y AXIS VALUES
READ(6,*) (Y(I,J),I=1,NUMPT)

READ IN LEGEND
I=1
```

```
      READ(6,85) YLEGND(I,J)
85    FORMAT(A10)
60    CONTINUE

C     READ IN  VALUES FOR LAST VECTOR
C     READ  NUMBER OF POINTS IN LAST VECTOR

      READ(6,*)NUMPT
      J=NVECT
      NPTS(J)=NUMPT

C     READ IN X AXIS VALUES FOR LAST VECTOR

      READ(6,*)  (X(I,J),I=1,NUMPT)

C     READ IN Y AXIS VALUES FOR LAST  VECTOR

      READ(6,*)  (Y(I,J),I=1,NUMPT)

      LINTYP(J)=0
      LINMOD(J)=2


C     CALL PLOT ROUTINE

      CALL PLOTS(0,0,5LPLOTR)
      XFSTV=0.0
      YFSTV=0.0
      IXAXFX=2
      IYAXFY=2
      XDELV=(XMAX-XMIN)/5.5
      YDELV=(YMAX-YMIN)/5.5

      CALL PLOTZ2(X,Y,IPLT,NVECT,NPTS,NMAX2,LINTYP)
      CALL PLOT(2.0,2.0,999)

      STOP
      END
```

```
      PROGRAM STAT(INPUT,OUTPUT,TAPE 6=INPUT,TAPE10)
C     PROGRAM TO CALCULATE AND PRINT THE FOLLOWING VALUES FOR
C     VARIOUS PARAMETERS:  NUMBER OF PROJECTS, MINIMUM, MAXIMUM,
C     MEDIAN, MODE, MEAN, AND STANDARD DEVIATION

C     LOAD THIS PROGRAM WITH DATA FILE 'TSTAT' TO OBTAIN TABLE OUTPUT
      REAL MIN,MAX,MED,MOD,MEAN
      DIMENSION X(30,30),PAR(90),N(30),MIN(30),MAX(30)
      DIMENSION MED(30),MOD(30),STD(30),MEAN(30)
      DIMENSION SUM(30),ADD(30),DUM(30)

      WRITE(10,8)
8     FORMAT('1')
      WRITE(10,7)
7     FORMAT(T59,'TABLE 3.5',/)
      WRITE(10,15)
15    FORMAT(T50,'STATISTICAL ANALYSIS OF DATA',/)
      WRITE(10,20)
20    FORMAT(T3,122('-'),/)

      WRITE(10,40)
40    FORMAT(T5,'PARAMETER',T30,'NO. PROJECTS',T48,'MIN',T60,
     *'MAX',T72,'MEAN',T84,'MEDIAN',T97,'STD. DEV.',T113,
     *'MODE',/)

      WRITE(10,20)

C     READ IN DATA
      K=17
      DO 100,J=1,K
      READ(6,50)
50    FORMAT(1H0)
      READ(6,60)PAR(J),PAR(J+20),PAR(J+40)
60    FORMAT(3A10)
      READ(6,*)N(J),MED(J),MOD(J)
      L=N(J)
      READ(6,*) (X(J,I),I=1,L)
      MIN(J)=X(J,1)
      MAX(J)=X(J,L)

C     CALCULATE MEAN

      SUM(J)=0.
      DO 70,I=1,L
      SUM(J)=SUM(J) + X(J,I)
70    CONTINUE

      MEAN(J)=SUM(J)/L

C     CALCULATE STANDARD DEVIATION

      ADD(J)=0.
      DO 80,I=1,L
      DUM(J)=(X(J,I)-MEAN(J))**2
      ADD(J)=ADD(J) + DUM(J)
80    CONTINUE

      STD(J)=(ADD(J)/(L-1.))**0.5

100   CONTINUE
```

```
C     PRINT OUT DATA

      M=17
      DO 110,J=1,M
      WRITE(10,120)PAR(J),PAR(J+20),PAR(J+40),N(J),MIN(J),MAX(J),
     *MEAN(J),MED(J),STD(J),MCO(J)
120   FORMAT(T5,A10,A10,A10,T30,I5,T45,F7.2,T57,F7.1,T69,F8.2,T81,
     *F9.2,T93,F10.2,T108,F9.2,/)

110   CONTINUE

      WRITE(10,20)

      STCP
      END
```

```
      PROGRAM TABLE1(INPUT,OUTPUT,TAPE6=INPUT,TAPE10)
C     PROGRAM TO PRINT THE FOLLOWING PARAMETERS FOR
C     EACH OF 24 PROJECTS:  PROJECT,FIELD,STATE,COUNTY,
C     AND REGDIST
C     LOAD THIS PROGRAM WITH DATA FILE 'T1'
      DIMENSION PROJ(2),FIELD(2)

      WRITE(10,8)
8     FORMAT('1')
      WRITE(10,20)
20    FORMAT(T3,122('-'),/)
      WRITE(10,30)
30    FORMAT(T46,'TABLE 2.3:  DATABASE PARAMETERS',/)
      WRITE(10,20)
      WRITE(10,40)
40    FORMAT(T7,'NUM',T25,'PROJECT',T57,'FIELD',
     +T80,'STATE',T98,'COUNTY',T115,'REGDIST',/)
      WRITE(10,20)

C     READ IN DATA AND INITIATE LOOP

      READ(6,50)
50    FORMAT(1HC)

      DO 90,J=1,24
      READ(6,60)NUM,PROJ,FIELD,STATE,COUNTY,REGDIST
60    FORMAT(A5,2A10,2A10,A10,A10,A6)
      WRITE(10,70)NUM,PROJ,FIELD,STATE,COUNTY,REGDIST
70    FORMAT(T7,A5,T25,2A10,T57,2A10,T80,A10,
     +T98,A10,T115,A6,/)

90    CONTINUE
      WRITE(10,20)

      STOP
      END
```

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