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Compositional Simulation and Performance Analysis of the Prudhoe Bay Miscible Gas Project

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ABSTRACT

Compositional analysis of produced fluids from enriched-hydrocarbon miscible floods to evaluate EOR performance is significantly more complex than that of CO_2 floods.[1] This is particularly true at Prudhoe Bay, where a number of sources of free gas exist in the reservoir, the solvent composition is not radically different than the solution gas composition, and active primary and secondary oil recovery masks tertiary oil production. A methodology was developed to effectively utilize 12-component Prudhoe Bay reservoir simulation results by reducing the molar production data into three pseudocomponent streams. These pseudo-components were used in the interpretation of separator gas samples to provide insight into actual EOR performance by quantifying solvent breakthrough and production rates. Field examples of various reservoir mechanisms affecting the efficiency of Prudhoe Bay EOR are examined.

INTRODUCTION

The Prudhoe Bay Miscible Gas Project (PBMGP) is the world's largest miscible gas flood, with a solvent injection rate of roughly 400 Mmscf/D at an average water-alternating-gas (WAG) ratio of 2:1. Although the Prudhoe Bay field has been featured in numerous papers, only a few have dealt with EOR operations at Prudhoe.[2, 3, 4] Prudhoe Bay EOR began in late-1982 with the 11-pattern Flow Station 3 Injection Project (FS-3 IP) which was located at Drill Site 13 within the Eastern Peripheral Wedge Zone (EPWZ). EOR operations were expanded in 1987 and now consist of 67 patterns in four separate areas of the field, as shown in Fig. 1. Reservoir properties and anticipated EOR performance in these areas were described by Dawson, et al., and will not be repeated here.[5] Instead, this paper will focus on the compositional aspects of monitoring and evaluating the enriched-gas miscible flood.

The first part of the paper briefly examines the development of the equation-of-state (EOS) characterization of the Prudhoe Bay oil/solvent system, the results of PBMGP studies made with a compositional reservoir simulator, and the methodology used to group hydrocarbon production from the simulations into three pseudocomponent streams. The second part of the paper describes the separator flash routine and allocation program which uses these pseudocomponent streams to interpret compositional data obtained from separator gas samples. This program was utilized to monitor EOR performance for individual wells, selected areas of the field, and the PBMGP as a whole. Specific examples of a number of reservoir mechanisms affecting the efficiency of the miscible flood are cited. Finally, results for the entire PBMGP are compared with predictions made by pattern scale-up forecasting programs to verify their predictive ability.

References and illustrations at end of paper.

MISCIBLE DISPLACEMENT STUDIES

In order to undertake meaningful compositional studies of the PBMGP, it was first necessary to understand the relevant miscible displacement mechanisms and to develop an accurate EOS description of the Prudhoe Bay oil/solvent system. This was done with an extensive series of slimtube, coreflood, multiple contact, and near-critical swell experiments. Two distinct fluid characterizations are used in PBMGP evaluations. Both characterizations are based upon the Peng-Robinson equation of state and incorporate the volumetric shift parameter developed by Jhaveri and Youngren.[6] A 12-component EOS characterization was specifically calibrated to the near-critical range found in the PBMGP oil/solvent system and was used in all reservoir, coreflood, and slimtube simulation studies. These studies utilized ARCO's General Purpose Reservoir Simulator (GPRS). A 19-component characterization with a more detailed breakdown of solvent-range components was used in all flash calculations to interpret the compositional data obtained from separator gas samples. The pseudocomponents used in these characterizations are listed in Table 1.

During a detailed analysis of the laboratory experiments, it was determined that the classical industry understanding of the condensing-gas drive mechanism[7] did not apply to either the PBMGP or the FS-3 IP. Rather, miscibility was developed by the condensing/vaporizing mechanism, in which light intermediate components from the solvent condensed into the liquid phase and middle intermediate components from the oil vaporized into the gas phase.[8] Fig. 2 shows slimtube recoveries from some of the PBMGP experiments. It should be noted that none of the displacements shown were calculated to be "thermodynamically miscible" in the classical sense of forming a single hydrocarbon phase. Displacement with the PBMGP solvent is "effectively miscible", with a lean gas bank leading the near-critical displacement front and a zone of very heavy oil at low saturations remaining behind the front. The size of the lean gas bank in the experiments was a function of how close the solvent was to the MMP, which was defined by the breakover point in the slimtube recovery plot. This highly efficient condensing/vaporizing displacement mechanism typically yielded residual oil saturations of 2 to 6% in both the slimtube and coreflood experiments.[8, 9] The tertiary displacement process during a simultaneous WAG coreflood is illustrated in the pseudoternary diagram of Fig. 3 and in the saturation profile of Fig. 4. It is important to note that numerical dispersion in the simulator can significantly affect these results and should be considered when evaluating either pseudoternary diagrams or saturation profiles.

The PBMGP solvent was designed to maximize EOR for the limited volume of enriching fluids available from the Prudhoe Bay Central Gas Facility (CGF). Average compositions of the PBMGP solvent and the FS-3 IP solvent (which was injected in 11 EPWZ patterns from 1983 through 1986) are shown in Table 2. The CGF solvent has a calculated MMP which is about 400 psi (2800 kPa) lower than the average reservoir pressure. The lower MMP is necessary because reservoir pressure has been declining at about 30 psi/year (210 kPa/year). This lower MMP provides a safety factor to insure that effective miscibility is maintained despite the declining reservoir pressure and the potential dilution of the solvent by evolved solution gas. The PBMGP will not attain "thermodynamic miscibility", however. If the CGF solvent had been enriched sufficiently to suppress the development of the lean gas bank, as suggested in a recent paper,[10] solvent availability would have been considerably reduced with a commensurate loss in EOR reserves.

RESERVOIR STUDIES

A large number of 2-D reservoir simulations were made with GPRS to evaluate the effects of solvent slug size, WAG ratio, and reservoir description on PBMGP EOR. This effort was similar in many respects to the studies reported by Dawson, et al.,[5] but had the advantage of providing compositional information as well as oil and water production. Waterflood and WAG flood production rates for a typical case are shown in Fig. 5. Fig. 6 shows the C_1, C_3, and C_{8-10} production for the WAG flood case. This plot shows the production of a lean gas bank ahead of the EOR oil bank, with the C_1/C_3 ratio gradually decreasing as injected solvent is produced. This behavior is very similar to that seen in the 1-D simulation studies of tertiary WAG displacement of saturated oil. However, there are some important differences between the 1-D and 2-D results. The solution gas evolved from the oil because of declining reservoir pressure elevates the GORs and prevents the C_1/C_3 ratio from reaching the same value as that of the injected solvent. In addition, the tertiary oil itself has a higher C_1/C_3 ratio than the MI and will alter the overall C_1/C_3 ratio when it is produced.

The 12-component hydrocarbon production stream from these simulations can be accurately represented by three pseudocomponents: live oil at the appropriate reservoir pressure, returned miscible injectant (RMI), and a lean gas stream, which consists of both "EOR offgas" and evolved solution gas. RMI composition is assumed to be identical to injected solvent. The lean gas was calculated by a component material balance and has a composition which is essentially identical to the equilibrium gas which currently exists throughout Prudhoe Bay because of the declining reservoir pressure (see Table 2). Fig. 7 shows the pseudocomponent production for the example 2-D WAG simulation.

Relationships based on this pseudocomponent representation were developed from the 2-D GPRS studies to generate recovery curves for EOR oil, lean gas, and RMI production volumes and rates for the various reservoir "type" patterns evaluated. These curves were adjusted for anticipated reservoir heterogeneities such as faults, thief zones, etc., which would reduce vertical and areal sweep efficiencies and increase RMI. The adjusted curves were input into ARCO's multi-pattern scale-up tool, the ADDER, which allocates solvent and water injection rates to each of the many injector-producer segments in the waterflood areas. The ADDER is ARCO's primary tool to provide regional and full-field waterflood, EOR, and RMI forecasts for Prudhoe Bay. Comparisons between ADDER predictions of RMI and actual field RMI should provide insight into the validity of the ADDER EOR forecasts as well as our solvent availability forecasts, which are strongly influenced by recycled MI.

RETURNED MI ANALYSIS PROGRAMS

Programs were developed using the pseudocomponent methodology described above to compute the RMI rate for all PBMGP separator gas samples having corresponding well test data. These results were then combined with the Prudhoe Bay production database to allocate RMI to each producer on a monthly basis. The computation process involved the following three steps:

1. Creating a gas sample compositional database;

2. Calculating RMI for each separator gas sample using a separator flash program based on the 19-component Peng-Robinson EOS fluid characterization; and

3. Allocating RMI on a monthly basis to individual wells, and adding monthly allocated RMI from individual wells to generate RMI for selected areas of the field and the entire PBMGP.

The gas sample compositional database was constructed to consolidate and enable mass processing of all separator gas sample analyses from the PBMGP. The database contains sample identification data, sample temperature and pressure, gas composition, and well production and artificial-lift gas rates measured at the time of sampling. The database contains 1,255 separator and 239 artificial-lift gas samples from 236 different wells. The data covers a time span from January, 1982, to March, 1990, and includes all available data from both the ARCO and BP Operating Areas.

Separator Flash Programs

The separator analysis program (RMICALC) calculates RMI for each complete separator gas sample stored in the database. The program retrieves artificial-lift gas rate and composition, separator gas composition, separator temperature and pressure, and well test data from the database. This data, along with solvent composition, reservoir oil composition, and historical reservoir pressure, is supplied to an EOS separator flash subroutine (SEPFLASH). SEPFLASH first corrects the orifice meter calibration factors for the test separator gas composition since these factors can vary significantly with changing gas compositions. It then uses successive substitution flashes to compute the relative amounts of RMI, lean gas, and live reservoir oil that would need to enter the wellbore to match separator oil rate, separator gas rate, and separator gas C_1/C_3 ratio to within 0.01%.

The discriminator used within SEPFLASH to differentiate between RMI and lean gas is the C_1/C_3 mole fraction ratio. This ratio was found to be the most sensitive discriminator because of the large difference in C_1/C_3 ratio between RMI and lean gas. As shown in Table 2, typical C_1/C_3 ratios for RMI and lean gas are 1.6 and 31.0, respectively. Other discriminators such as C_2 and CO_2 content, were not as definitive. A plot of C_1, C_3 and CO_2 mole fractions from the EPWZ is shown in Fig. 8. We have found that CO_2 is a poor discriminator because it appears to be affected by geochemical reactions and does not correlate well with changes in the other component mole fractions. The low C_3 readings (mole fractions of less than 2.5%) prior to 1986 were caused by high separator pressures which kept additional C_3 in the oil phase.

A comprehensive error analysis was developed and included in SEPFLASH to provide a way to discard data that would provide meaningless results and to put confidence limits on computed RMI. Inputs to the error analysis (e.g. the accuracy of the separator oil rate) are currently assumed, and we plan to further investigate these inputs.

RMI Allocation Programs

Since gas samples were collected in the field at different times, calculated RMI rates from individual wells were also at different times. For this reason, RMI rates from individual wells could not be directly combined to obtain RMI rates for selected areas of the field or the entire field. A methodology was developed to allow the estimation of RMI rates for each well on a uniform-time basis so RMI rates from individual wells could be combined. Two programs were written to utilize the separator flash calculation results and the Prudhoe Bay production database to generate monthly allocated RMI (RMIA) production.

Program RMIMTH linearly interpolates between values calculated from each gas sample to obtain a monthly interpolated value for each well. For calculating RMIA, interpolating directly between RMI rates was not the best approach. For example, if interpolated values between two RMI rate points showed RMI production when the well was actually shut-in, the results would obviously be erroneous. Well productivity can also change radically between gas samples due to changes in choke setting, artificial-lift gas rate, or well workovers. Clearly, the assumption that monthly RMI or gas production rate from a well varies linearly with time is not a good one. For these reasons, the concentration or fraction of RMI in the "excess" gas stream (%RMI) was chosen as the interpolation variable. "Excess" gas is defined as all gas production from the well that is neither solution gas associated with the oil production nor artificial-lift gas. By interpolating between %RMI data points, an assumption is made that RMI concentration varies linearly with time between sample points. This assumption is reasonable, since %RMI is strongly influenced by reservoir mechanisms. These mechanisms will not fluctuate as rapidly as the produced gas rate, which is controlled by wellbore conditions and facilities constraints as well.

Program RMIALLOC combines interpolated results from RMIMTH with the Prudhoe Bay production database to calculate RMIA for each well. This is accomplished by multiplying the interpolated monthly %RMI by the allocated monthly "excess" gas from the production database. Because "excess" gas production reflects variable well productivity and well shut-ins, these factors are also accounted for in the resulting RMIA. The program then adds individual well RMIA values to obtain RMIA for selected areas of the field and the entire PBMGP.

An example plot containing both RMI computed by RMICALC from individual gas samples and RMIA from RMIALLOC for well DS 13-29 is shown in Fig. 9. Note that the %RMI values upon which this plot is based had no statistical significance until a gas sample was taken in late-1988 when the well was producing about 500 Mscf/D (14,150 m^3/d) of "excess" gas. In general, unless the "excess" gas rate is at least 10% of the total separator gas rate, the sample will not yield a statistically meaningful value for %RMI. Fig. 9 also demonstrates the need to gather gas samples on a frequent basis.

The curves in Fig. 9 are defined as follows:

1. RMIA: Monthly allocated RMI;
2. RMIAHI: Upper confidence limit of RMIA;
3. RMIALO: Lower confidence limit of RMIA;
4. EGAS: Monthly allocated excess gas; and
5. RMISMPL: RMI as determined directly from a separator gas sample and the corresponding well rates.

RMISMPL data points often do not fall directly on top of the RMIA curve. This occurs because RMISMPL is computed from "daily" well rates while RMIA is computed from "monthly allocated" well rates. Well rates measured on a given day can be significantly different than the allocated well rate for a given month due to number of days on production, artificial-lift gas rate, and a myriad of other factors.

PBMGP SURVEILLANCE DATA

Field data analyzed with the above programs has provided important insights into the performance of the PBMGP. It is now possible to quantify solvent breakthrough in producing wells using a consistent and rigorous methodology. Poorly performing EOR patterns can now be identified easily, and MI breakthrough mechanisms are better understood. In addition, since the majority of the RMI will be captured at the Central Gas Facility for reinjection, our confidence in making MI availability forecasts has significantly improved.

Returned MI Breakthrough Mechanisms

A well-by-well review of the RMI data has identified four MI breakthrough mechanisms in the PBMGP:

1. Normal pattern performance as predicted by GPRS simulations, where the well produces a significant volume of EOR offgas, which is gradually replaced by RMI (see Fig. 7). Numerous examples of this behavior have been observed in the field, especially in the more mature FS-3 IP area (see Fig. 9). However, many of the wells in the upstructure waterflood areas also produce lean gas from the gas cap, so it is difficult to quantify the volume of lean gas due to solvent injection. Downstructure wells such as 13-29 have no other source of lean gas;

2. Thief-dominated performance, where a relatively thin, continuous interval of high-permeability sand connects the injector and producer, leading to rapid MI breakthrough. EPWZ well 13-02A, shown in Fig. 10, is an example of this breakthrough mechanism. The offset WAG injector is a cored well with a high-permeability interval just below the unconformity at the top of the Sadlerochit. History-match studies confirmed the presence of this thief zone. A number of wells in the EPWZ and Flow Station 2 areas appear to have problems with thief zones;

3. Fault-dominated performance, where a highly conductive fault connects the injector and producer, leading to rapid MI breakthrough. EPWZ well 12-09, shown in Fig. 11, is an excellent example of severe breakthrough which appears to be caused by faulting. The offset WAG injector 13-21 shows virtually all injected fluid entering a thin interval in the middle of the pay zone, despite attempts to plug the interval. The core taken on well 12-09 had a thin high-permeability interval at the top of the Sadlerochit sand, but there was no anomaly in the interval of apparent solvent breakthrough. Only a few wells in the PBMGP have exhibited fault-dominated behavior; and

4. Flux across pattern boundaries, where MI breakthrough is rapid in the "downstream" producers. Northwest Fault Block (NWFB) well M-24, shown in Fig. 12, is an example of this MI breakthrough mechanism. Solvent injection into offset well M-28 is followed in about 2 months by high GORs in M-24, with 30-90% of the "excess" gas being RMI. This well also showed early breakthrough in the 1986 NWFB waterflood tracer program.[11] Significant flux affecting MI breakthrough currently appears to be confined to several NWFB patterns. This problem appears to be exacerbated by faulting in the area.

Regional and Full-Field RMI

The RMI predicted with a full-field ADDER pattern scale-up program is used in generating MI availability forecasts. Regional ADDER programs are also used to predict oil and water production for the waterflood/EOR areas of the field. By using the RMI programs to calculate RMIA for selected regions or the entire field, confidence in MI availability forecasts and our understanding of the effectiveness of the EOR project can be improved. Historical RMIA for each area has been calculated and is in good agreement with the full-field ADDER RMI forecast, as shown in Fig. 13. This plot also shows that solvent retention in the reservoir has been good. As of April, 1990, cumulative solvent injection was 386 Bscf (1.09 $\times 10^{10}$ m^3) while cumulative solvent production was only 33 Bscf (9.3 $\times 10^9$ m^3).

Relative comparisons of the EOR process efficiency were made for the four main EOR areas. These comparisons are made in a plot of cumulative RMI vs. cumulative solvent injection shown in Fig. 14. The RMI is currently dominated by a handful of problem wells in each area. Thief zones, conductive faults, and major flux across pattern boundaries are potential contributors to early RMI production, lower sweep efficiencies, and reduced EOR. As the PBMGP matures, it will be possible to draw inferences about EOR efficiency in each area from these plots. Areas where more solvent is retained in the reservoir relative to the amount of solvent injected should provide higher EOR efficiency than areas where substantial RMI is produced earlier.

CONCLUSIONS

1. The existance of a lean gas bank ahead of the miscible front has been confirmed by both laboratory and field data.

2. The PBMGP produces a lean gas bank by displacing the evolved solution gas which exists everywhere in the reservoir. This evolved gas is due to the declining reservoir pressure. The PBMGP will also generate a lean gas bank ahead of the displacement front because the PBMGP is an "effectively miscible" displacement and is not "thermodynamically miscible".

3. The appropriate analytical tools and methodology have been developed to allow a meaningful quantitative analysis of separator gas samples taken from PBMGP producers. If separator gas samples are taken on a sufficiently frequent basis, these calculations will give an accurate estimate of the actual RMI over time.

4. At Prudhoe Bay, the C_1/C_3 ratio is the best discriminator between RMI and other produced gases.

5. A comprehensive error analysis is necessary to eliminate meaningless data and provides confidence limits on computed RMI. If the excess gas is less than about 10% of the total gas stream, the %RMI calculation is not meaningful.

6. Programs were developed to utilize the %RMI calculations and the production database to calculate monthly allocated RMI for individual producers. This has allowed the following tasks to be performed:
   a. Quantify MI breakthrough in PBMGP producers using a consistent and rigorous methodology;
   b. Identify and improve our understanding of MI breakthrough mechanisms;
   c. Improve MI availability forecasts;
   d. Better understand the effectiveness of the PBMGP EOR process; and
   e. Flag poorly performing EOR patterns to help recommend appropriate changes to operating strategies.

7. As of April, 1990, cumulative solvent injection at Prudhoe Bay was 386 Bscf (1.09 $\times 10^{10}$ m^3) while cumulative solvent production was only 33 Bscf (9.3 $\times 10^9$ m^3). RMI production to date has been dominated by a small number of problem wells. The early MI breakthrough in these wells is apparently due to thief zones, conductive faults, or major flux across pattern boundaries.

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The techniques and conclusions presented in this paper are those of ARCO Alaska, Inc., and may not reflect those of the other Working Interest Owners at Prudhoe Bay.

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Table 1 - Pseudocomponents used in PBMGP fluid characterizations

19-Component System		12-Component System	
Component	Molecular Weight	Component	Molecular Weight
CO2	44.0	CO2	44.0
N2	28.0	C1	16.0
C1	16.0	C2	40.1
C2	30.1	C3	44.1
C3	44.1	C4	58.1
I-C4	58.1	C5	72.2
N-C4	58.1	C6+	94.2
I-C5	72.2	C8+	116.0
N-C5	72.2	C11+	169.5
C6	85.2	C15+	232.6
C7	92.0	C20+	328.0
C8	104.2	C30+	628.0
C9	120.7		
C10	134.0		
C11-13	158.3		
C14-19	214.4		
C20-26	300.9		
C27-35	403.1		
C36+	668.3		

Table 2 - Typical PBMGP and FS-3 IP gas compositions

Component	Average FS-3 IP MI	Average CGF MI	Live Oil Solution Gas	Typical Lean Gas
CO2	0.1380	0.2115	0.1179	0.0939
N2	0.0007	0.0000	0.0033	0.0083
C1	0.3719	0.3344	0.6692	0.7927
C2	0.1292	0.1978	0.0883	0.0538
C3	0.1381	0.2152	0.0584	0.0256
I-C4	0.0260	0.0179	0.0092	0.0035
N-C4	0.0690	0.0225	0.0247	0.0087
I-C5	0.0198	0.0006	0.0068	0.0027
N-C5	0.0261	0.0000	0.0089	0.0036
C6+	0.0813	0.0000	0.0133	0.0072
C1/C3 Ratio	2.69	1.55	11.46	30.96

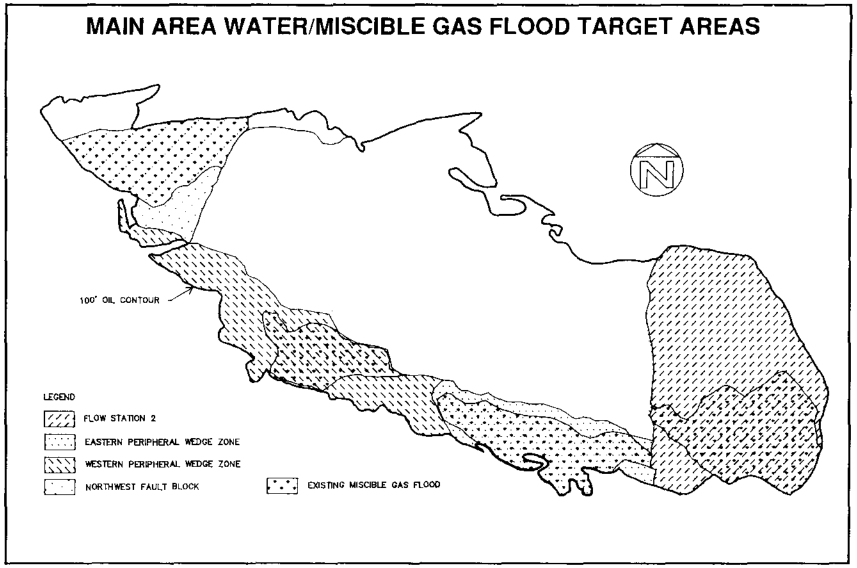

Fig. 1—Prudhoe Bay Unit map showing the four waterflood/EOR areas.

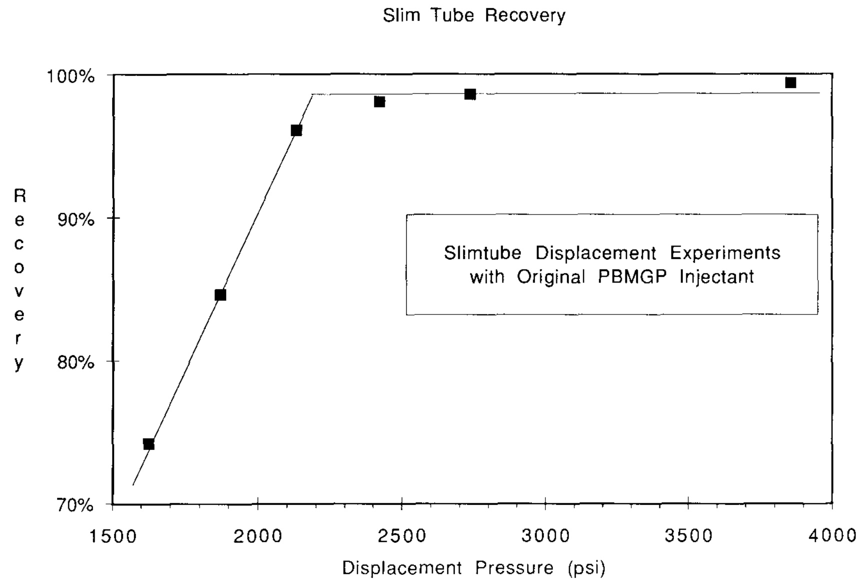

Fig. 2—Slimtube recovery vs. displacement pressure.

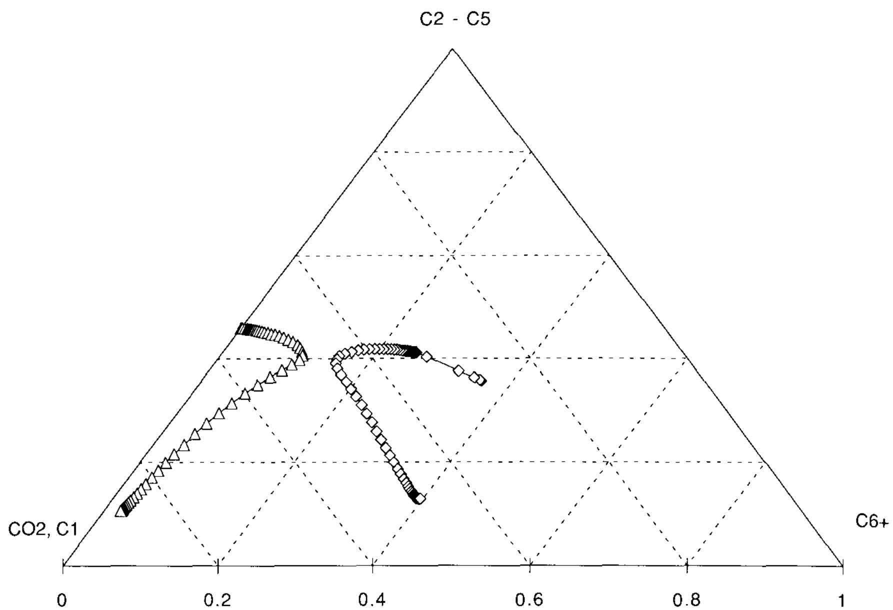

Fig. 3—Pseudoternary diagram for a typical 1-D WAG simulation.

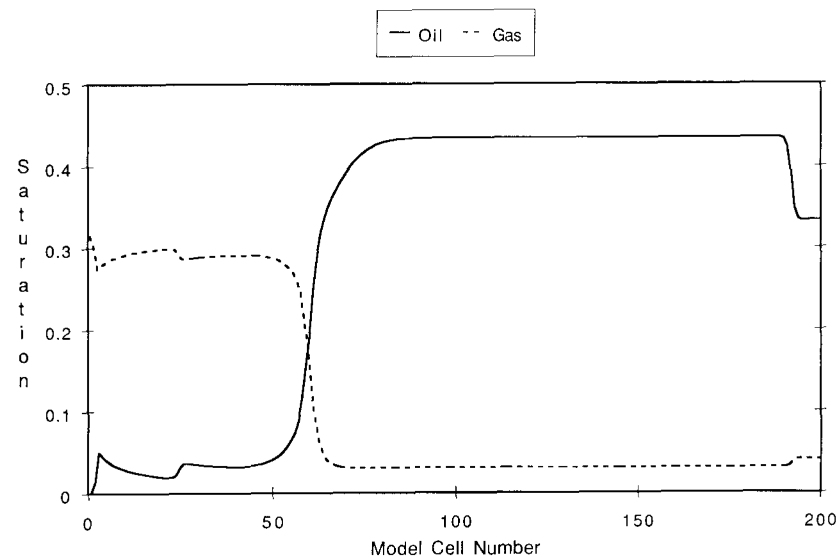

Fig. 4—Saturation profile for a typical 1-D WAG simulation.

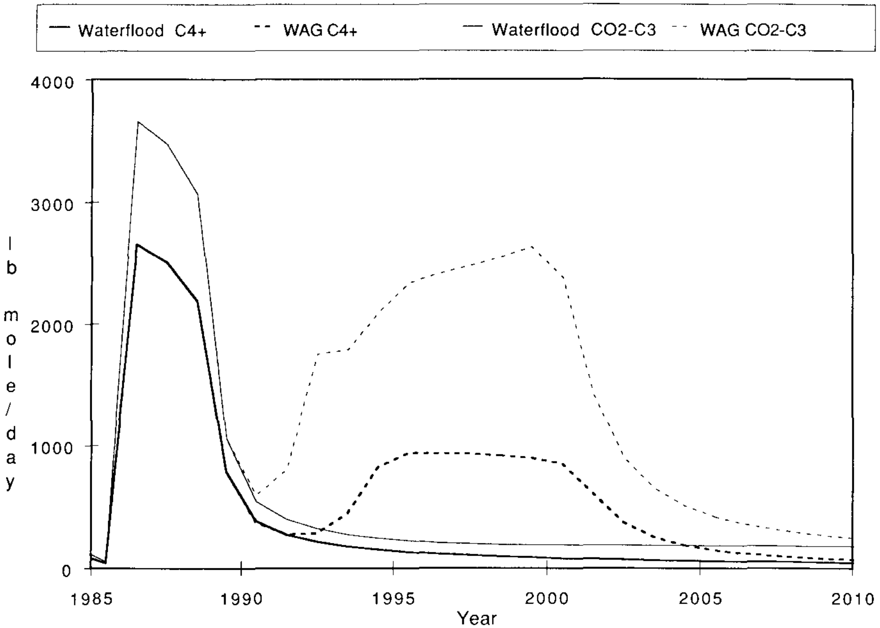

Fig. 5—Oil and gas production rates for a typical EPWZ waterflood and WAG simulation.

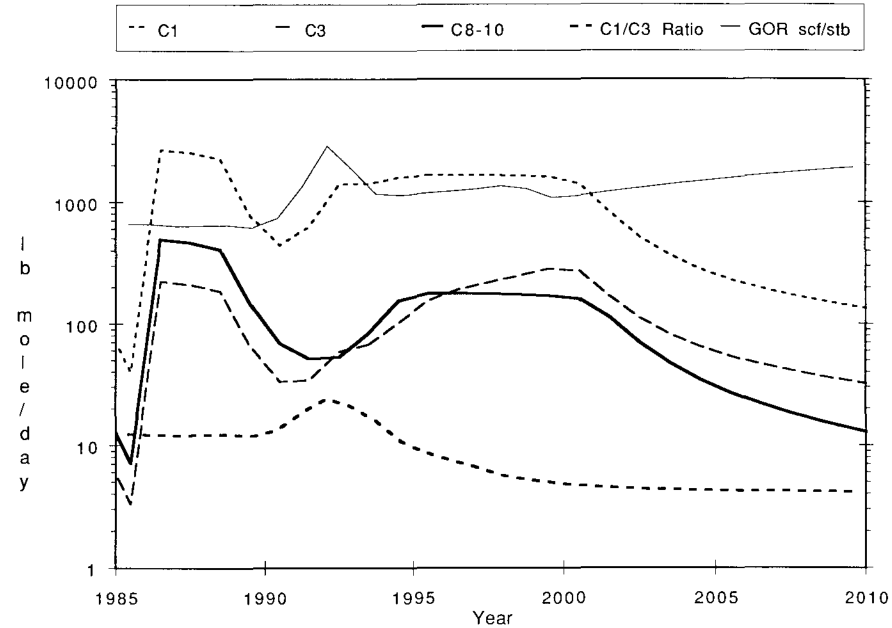

Fig. 6—C_1, C_3, and C_{8-10} production rates, GOR, and C_1/C_3 ratio for the EPWZ WAG simulation.

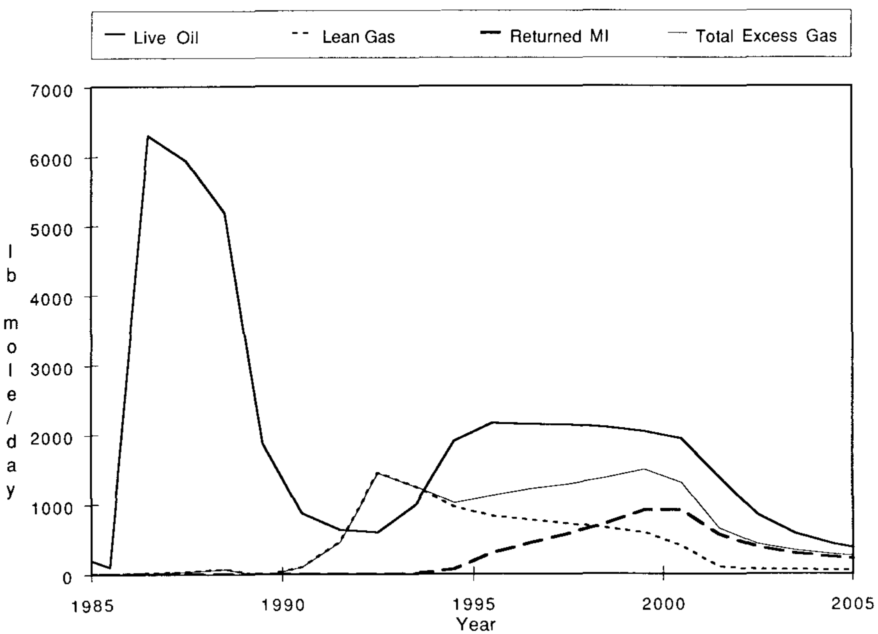

Fig. 7—Live oil, RMI, and lean gas pseudocomponent rates for the EPWZ WAG simulation.

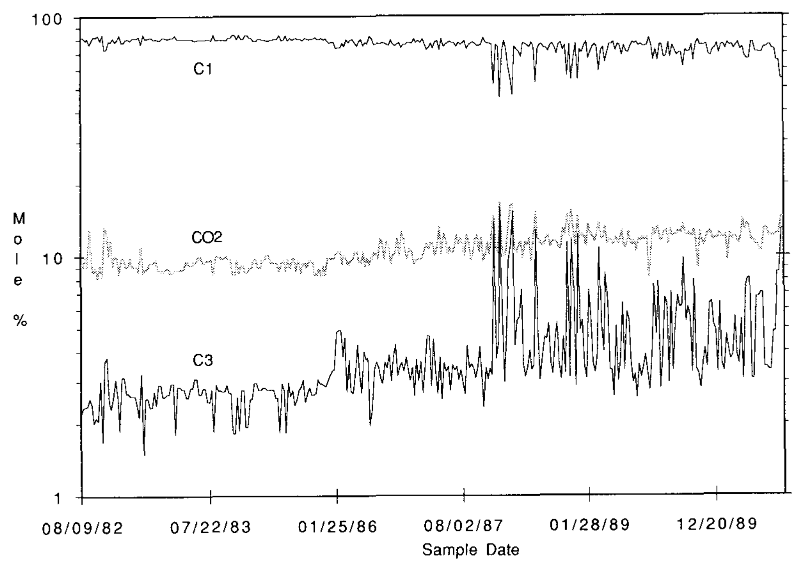

Fig. 8—EPWZ separator gas sample compositions vs. time.

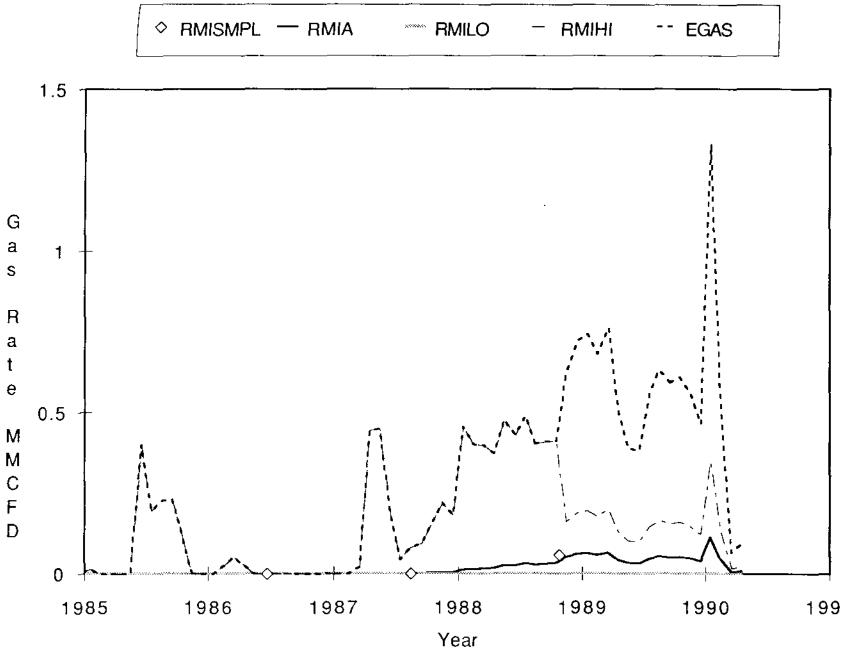

Fig. 9—Well 13-29 RMI and excess gas rates with RMI confidence limits.

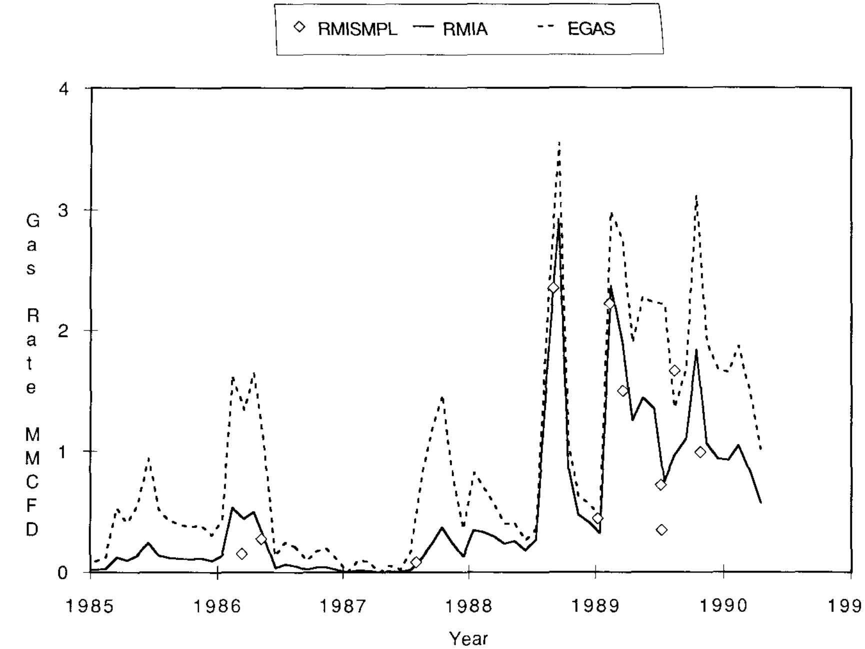

Fig. 10—Well 13-02A RMI and excess gas rates.

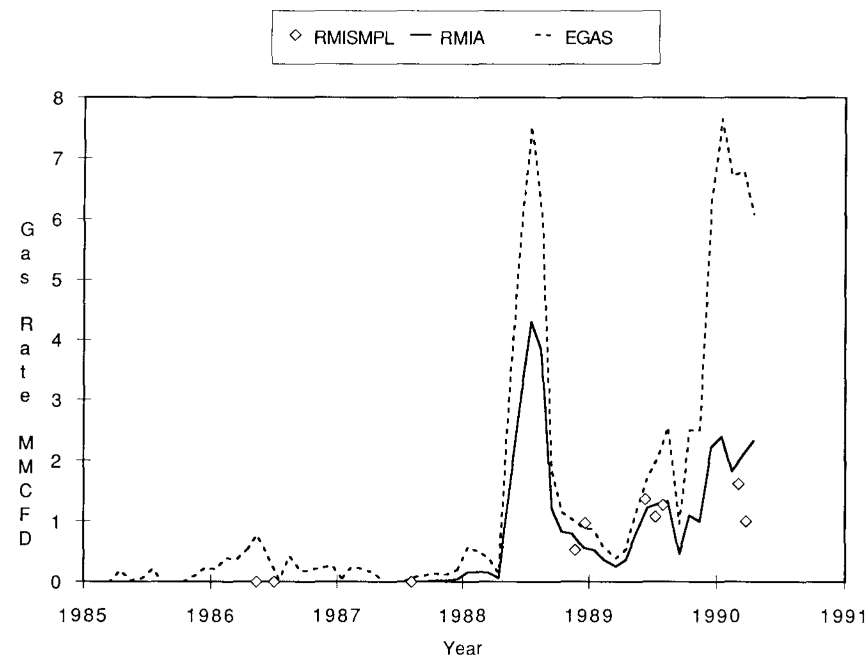

Fig. 11—Well 12-09 RMI and excess gas rates.

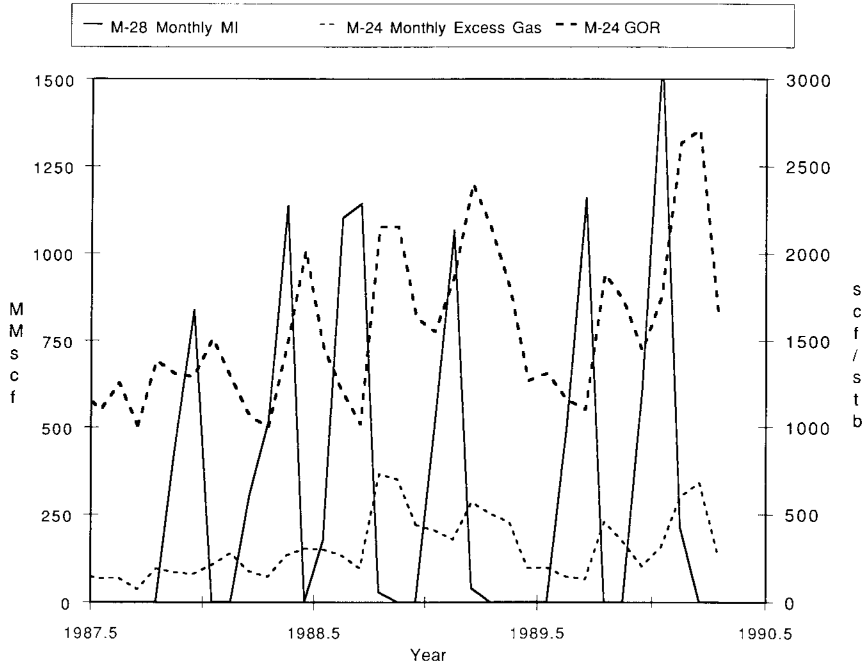

Fig. 12—Comparison of Well M-28 MI rates with M-24 excess gas rates and GOR trends.

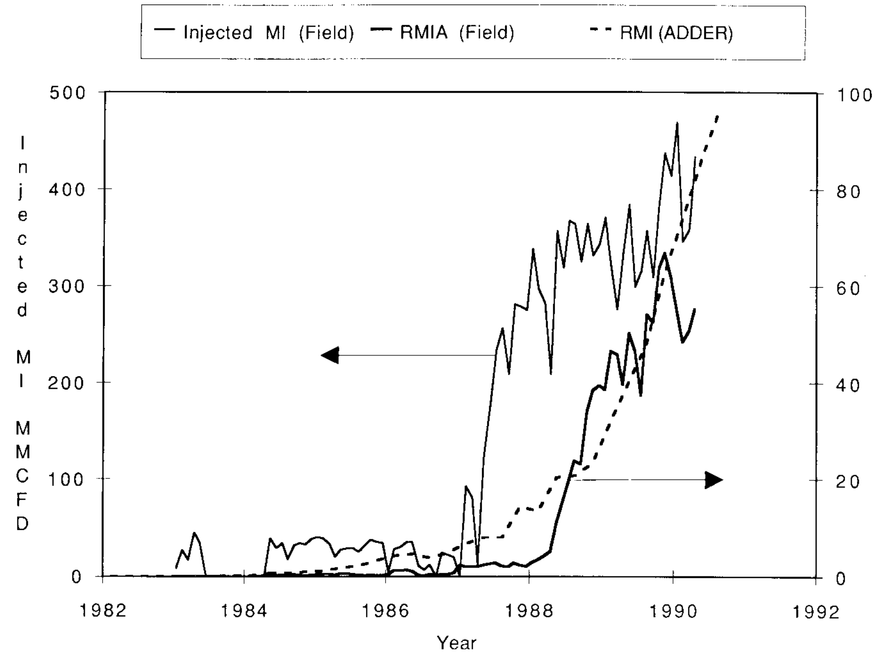

Fig. 13—Comparison of actual PBMGP RMI with ADDER RMI and injected MI.

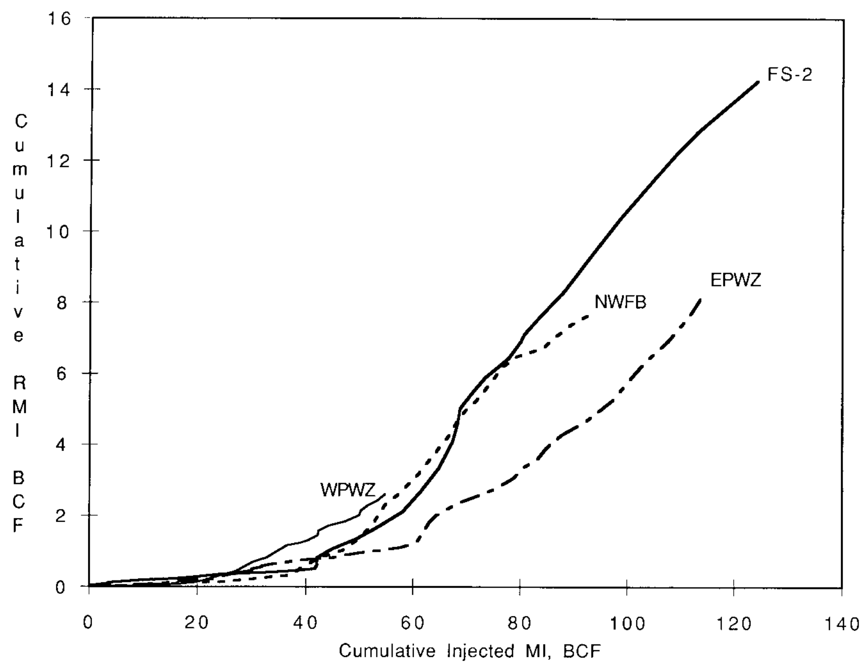

Fig. 14—Cumulative RMI vs. injected MI for each ADDER area.

PROCEEDINGS

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Σ Reservoir Engineering

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