THE USE OF TRACERS IN DIAGNOSING INTERWELL RESERVOIR HETEROGENEITIES: FIELD RESULTS*

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INTRODUCTION

In fluid-injection projects, the channeling or bypassing of injected fluids through fractures and high-permeability stringers results in poor reservoir sweep efficiency and low oil recovery. When the injected fluid is water, channeling problems have a less servere impact on the flood economics because water is relatively inexpensive, and it can be recovered and recycled through the reservoir to recover additional oil. However, many of the improved oil-recovery processes employ expensive fluids such as surfactants, micellar fluids, and solvents, which must produce oil during a single pass of a relatively small volume through the reservoir. Therefore, it is important to identify and correct any serious reservoir heterogeneities which would lead to channeling and to the inefficient use of the expensive improved recovery fluids. Some knowledge of the near wellbore reservoir heterogeneities can be derived from well logs and core permeability data. Pressure transient and pressure pulse tests are useful in detecting interwell fractures and in determining interwell communication. Other information is sometimes available from prior waterflood performance. A supportive method of determining reservoir interwell anatomy and reservoir performance in an improved recovery process is the tracing of interwell flow of injected water during an initial waterflood.

During the past several years, the results of approximately 20 tracer programs that have been conducted in reservoirs undergoing waterfloods, gas drives, and alternate water-solvent injection have become available to the author. These tracer programs have provided the proving ground and the opportunity for screening the performance of numerous water and gas tracer materials and for arriving at a suite of "preferred" tracers for waterfloods and gas drives.

This paper discusses the use of chemical and radioactive tracers to identify sweep problems in a tertiary miscible pilot area in West Texas, two potential micellar pilot areas in Wyoming, a Wyoming waterflood, and a hydrocarbon miscible project in Alberta, Canada.

DISCUSSION

Information Obtainable from Interwell Tracing

The specific information obtainable from tracing the interwell flow of injected fluids through a subterranean formation and the way this information is derived from the tracer data are discussed below. This type of information is the objective of every oilfield tracing program and is useful in the design, control, and interpretation of subsequent tertiary oil recovery processes applied in such programs.

1. Volumetric Sweep
   The volume of fluid injected at an injection well *to breakthrough* of the traced fluid at an offset producer is indicative of the volumetric sweep efficiency between that pair of wells. Very small injected volumes to breakthrough (relative to the interwell pore volume) indicate the existence of an interwell open fracture or a very thin high permeability stringer and give an idea of the volume of that channel. Knowledge of the channel volume is important to the sizing of a remedial treatment.

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2. Identification of Offending Injectors
Problem injection wells can be identified by associating the breakthrough of a specific tracer to the point at which it was injected. It is at this well that a remedial treatment to seal a channel would normally be applied.
3. Directional Flow Trends
When fluids are injected in a regular pattern (five-spot, nine-spot, line drive, etc.) with the fluids injected at each well tagged with a different tracer, any directional flow trends will be obvious from the repeated early tracer breakthrough at producers located in a preferential direction from the injectors. Where directional flow trends are prevalent, the interwell sweep efficiency can often be improved by altering the injection pattern, by altering the injection and withdrawal rates at selected wells, or by altering both.
4. Delineation of Flow Barriers
Faults with large displacement along the fault plane and permeability pinchouts can represent barriers to the flow of fluids perpendicular to their axes. Normally, such barriers are detected by bottom-hole pressure build-up surveys run in wells located in the vicinity. However, the course of these barriers can be further delineated from the response or lack of response of producing wells to traced water injection at an array of wells surrounding the producer.
5. Relative Velocities of Injected Fluids
When different fluids are injected simultaneously, alternately, or sequentially in the same well, each fluid being tagged with a different non-adsorbing tracer, the relative velocities of these fluids can be measured from the individual tracer arrival times at offset producers. For example, assume that traced solvent and traced water were being injected alternately in the same well. The early arrival of one of the traced fluids at the producing well would indicate that the early arriving fluid had contacted less of the reservoir than the late arriving fluid. This phenomenon would indicate the need to alter one of the fluid injection cycles to achieve more uniform sweep of the reservoir. Similarly, in a micellar flood where a water preflush, micellar fluid, polymer, and chase water are injected sequentially, the overrunning or fingering of one injected fluid through another would indicate the need for better fluid-mobility control to achieve more uniform sweep by the various injected fluids.
6. Evaluation of Sweep Improvement Treatments
Remedial treatments to correct sweep problems can be evaluated by comparison of the before- and after-treatment interwell volumetric sweep as determined by tracing.

"Preferred" Water and Gas Tracers

The "preferred" water and gas tracers listed in table 1 were screened from a larger list of potential tracer materials, based on satisfactory performance in field fluid-tracing programs. Many of these tracer materials have been used by other operators in the industry [1,2,3,4,5] with varied reported success.

These tracer materials may be classified as follows.

1. Radioisotopes: Tritium as a gas, or in combination with water or other hydrocarbon gases, may be used for tracing. In any form, tritium emits 100 percent beta radiation at relatively low energies. Tritium is probably the *best performing* and *most widely used* single tracer in the industry. It is easily detectable in low concentrations during its 12.4-year half-life, is relatively inexpensive, requires very thin shielding to contain its low energy radiation, and thus presents no practical health hazard. Beta emissions from tritium are not detectable by a gamma-ray logging tool; therefore, the presence of tritium does not interfere with well-logging operations. The handling and injection of radio-active materials must be done by an organization licensed by the National Regulatory Commission (NRC—formerly the Atomic Energy Commission).

   Krypton^{85} is an inert gas having a half-life of about 10.7 years. Krypton^{85} radiation is 99.5 percent beta, although some gamma emission occurs. Logging tools pick up the gamma radiation when krypton^{85} is present in large quantities. Being inert, krypton has low adsorption on reservoir rock and does not enter into the animal biological processes. This material has a density about 5 times that of methane and should be injected in a carrier gas like argon.

Promethium[147] injected in a sequestering agent did not perform satisfactorily in two field projects not discussed in this paper.

2. Salts with detectable cations or anions: Field experience has indicated that cations, whether radioactive or nonradioactive, do not propagate through reservoir rock as readily as does the anion portion of a salt. The ammonium, potassium, or sodium forms of the salts are normally used because of their high solubility in water. Background concentrations of iodide and bromide are often found in oilfield brines, and use of these elements as tracers should be avoided if the background concentrations exceed about 20 ppm.
3. Fluorescent dyes: Two potentially useful soluble dyes are marketed as uranine and rhodamine-b. Under ultraviolet light, these dyes can be detected in concentrations down to parts per billion. However, these dyes are highly adsorbed on reservoir rock, and certain ions in reservoir waters tend to quench their fluorescence. They are not recommended as tracers when expected residence time for them in the reservoir exceeds about 5 days. Dyes are most useful in identifying interwell fractures when residence times are short and losses due to adsorption are minimal.
4. Water-soluble alcohols: The lower alcohols, methyl, ethyl, and isopropyl, are preferentially water soluble, can be transported in water solution, and are detectable chromatographically in low concentrations. Isopropyl alcohol appears to be unaffected, but aerobic bacteria will biodegrade both methyl and ethyl alcohols. Special well treatments may be required to overcome this degradation.[5] An oxygen scavenger or bactericide is usually injected (in concentrations of about 50 ppm) with these tracers. Further, approximately the same bactericide concentration should be added to produced water samples to prevent alcohol degradation during storage or during transit to an analytical laboratory.

Major Considerations in the Field Tracer Programs

The choice of tracers in the reported field-tracing programs was based on the level of background concentrations of the trace materials in the reservoir fluids, on their compatibility with the fluid to be traced, on their performance in past field tests, and on cost considerations.

The quantity of tracer material which was injected depended upon the reservoir volume to be traced and, therefore, upon the well spacing, average pay thickness, porosity, and fluid saturations. The loss of chemical tracer due to adsorption on a reservoir rock surface is not known for the chemical salts listed in Table 1. For this reason, the amount of chemical tracer injected was normally overdesigned to compensate for possible adsorption loss and to gain sensitivity in the analysis of produced samples. The objectives in each tracer-program design were to achieve in the produced fluids (1) a chemical tracer concentration which was well above its minimum detectable limit for a sustained period, and (2) a safe upper level of radioactive-tracer concentration. The tracer concentration should represent no hazard to operations personnel even if earlier-than-expected breakthrough of the traced fluids occurred. A modified version[6] of the Brigham-Smith model[7] for predicting tracer flow in a five-spot well pattern provided the guidelines for achieving the desired level of tracer concentrations in the produced fluids. This mathematical model assumes zero adsorption of the tracer used, but accounts for the many tracer dilution effects. The equation used for predicting both water and gas tracer flow is presented in the appendix.

All radioactive tracers were injected by properly licensed commercial organizations. The chemical tracers were mixed and injected by normal oilfield pumping equipment or pump trucks. All tracers were injected as "spikes" usually requiring from 1 hour to 1 day for injection at any one well.

Tracers should not be injected until the pattern area has been pressured-up with the injected fluid. If the traced injection fluid is spent in collapsing a gas phase or otherwise pressuring-up the reservoir, the volume injected to tracer breakthrough (which is indicative of the volumetric sweep to breakthrough) may be significantly larger than that determined after the pattern area has been pressured.

In multi-tracer programs, the tracers injected should be arranged so that adjacent wells do not receive the same tracer.

Where practical, all producing wells in the immediate traced area were sampled on a regular schedule. The sampling frequency depended on the interwell distances, injection rates, and breakthrough expectancy. The first sample from each producing well was usually taken within four to seven days after tracer injection to avoid missing a severe channeling problem like an interwell fracture. In the South Swan Hills Unit tracer program (to be discussed), the large number of producing wells (more than 200) and the high wellhead pressures made it impractical to sample every well on a regular basis or to collect wellhead samples.

For most of the field tracing programs, analysis of the radioactive gas samples and the chemical tracers was done in-house, while a commercial analytical company provided the tritiated water analyses.

FIELD RESULTS

Five field tracer programs are used to illustrate information which has been obtained and ways this information has been used.

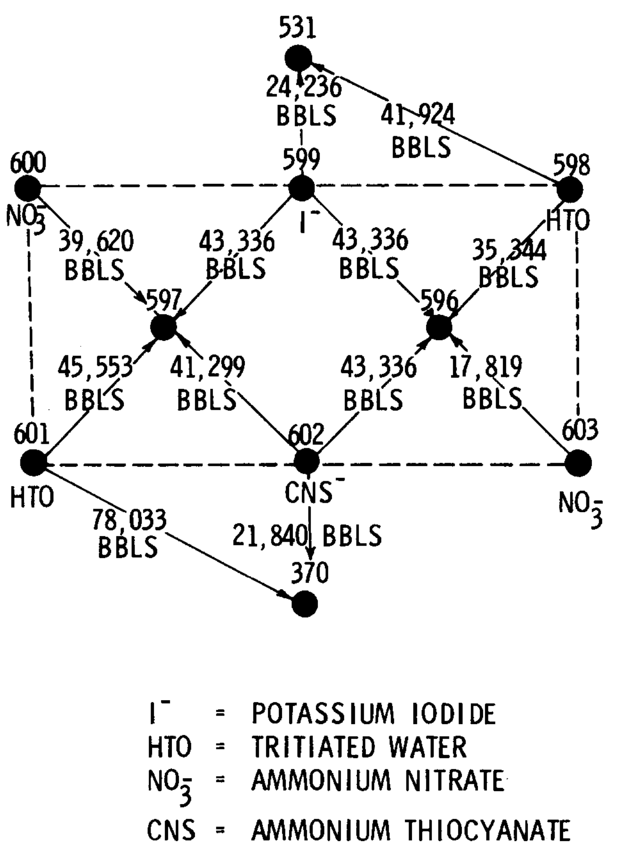


FIG. 1—TERTIARY PILOT AREA, LEVELLAND UNIT.

1. *Levelland Unit Tertiary Miscible Pilot:* This West Texas pilot area is developed on two adjacent five-spot flood patterns with six injectors, two center producers, and two flanking producers as shown in Figure 1. The pilot area comprises approximately 12 acres. During the the waterflood of this area, four tracers were employed: 6 curies of tritiated water (HTO) per well at Wells 598 and 601, 10,000 pounds of ammonium nitrate (NO_3^-) per well at Wells 600 and 603, 1400 pounds of potassium iodide (I^-) at Well 599, and 2400 pounds of ammonium thiocyanate (CNS^-) at Well 602. Figure 1 shows the volume of water injected at each well from the date of tracer injection to the breakthrough of the tracer at the near offset producers. Assuming that one-fourth the volume of water injected at each well during this time actually invaded the pattern area, a volumetric sweep to tracer breakthrough ranging from 20 to 25 percent of the absolute pore volume was calculated for all quadrants in the two pattern areas with the exception of that quadrant served by injection Well 603, where a 10 percent pore volume volumetric sweep was achieved. The low volumetric sweep efficiency achieved between Wells 603 and 596 indicates a possible reservoir problem in this interwell area, one that may require some remedial treatment prior to initiating a tertiary oil recovery operation.

A reservoir simulator was used to match waterflood performance in this pilot area. The actual tritiated water breakthrough times at the center producers (Wells 596 and 597) and the reservoir stratification in the tracer prediction model[5] were used to project the after-breakthrough performance of the tritiated water tracer at Wells 596 and 597. A comparison of the calculated and actual performance of this tracer at these wells is shown in Figures 2 and 3. The secondary peaks in tracer concentrations shown in these tracer elution curves indicate traced water breakthrough from zones having successively lower fluid transmissibility. This match between predicted and actual arrival times of the peak tracer concentrations at these wells and the fact that the predicted peak concentrations were not exceeded gives confidence

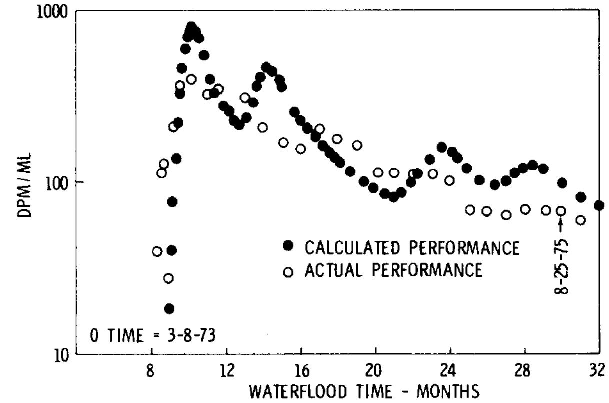


FIG. 2—COMPARISON OF CALCULATED AND ACTUAL TRACER PERFORMANCE - LU WELL 596.

in the tracer prediction model for providing guidelines for attaining safe radiation limits at the producing wells in other tracing programs.

Following waterflood depletion in the Levelland pilot, a miscible flood will be conducted with carbon dioxide as the injected gas. The suite of gas tracers listed in table 1 will be used to trace the injected gas.

2. *Potential Micellar Pilot Area, Salt Creek Field, Wyoming*: Figure 4 is a map of a 3-acre five-spot pattern developed in the Second Wall Creek Formation, Salt Creek Field, Wyoming, which was evaluated as a potential micellar pilot area. This 3-acre test area is defined by injection Wells 41, 42, 43, and 44 and the center producer, Well 9. To help confine the oil movement to the three-acre pilot area, water was also injected at Wells 6, 37, 15, and 18 which define a 12-acre test area encompassing the smaller pilot. All water injected into the test area was traced by use of the waterflood tracers indicated in Figure 4. Sufficient water was injected to pressure the area prior to injection of the tracers. The traced waterflood evaluation of this test area lasted for 7 months. If one-fourth of the water injected at Wells 41, 42, 43, and 44 during that period were assumed to have invaded the 3-acre pilot area, then approximately 90 percent of the aqueous pore volume of the pattern should have been displaced. However, based on the same assumptions, an overall injection-withdrawal ratio of 2.23 was calculated for this area, indicating that more than 50 percent of the assumed amount of injected water had been lost outside the pattern area or to zones other than the Second Wall Creek Formation.

In Figure 4, arrows are drawn from the injection wells to the producing wells at which traced injection water was detected. The figure shows that only the tritiated water tracer injected at Well 41 arrived at the center producer, Well 9. Further, less than 2 percent of the injected tritiated water was recovered at Well 9. The meager response at Well 9 from injector 41 and the complete lack of response to the other

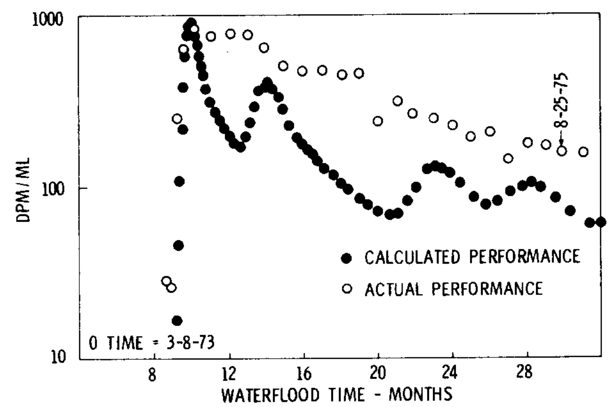


FIG. 3—COMPARISON OF CALCULATED AND ACTUAL TRACER PERFORMANCE - LU WELL 597.

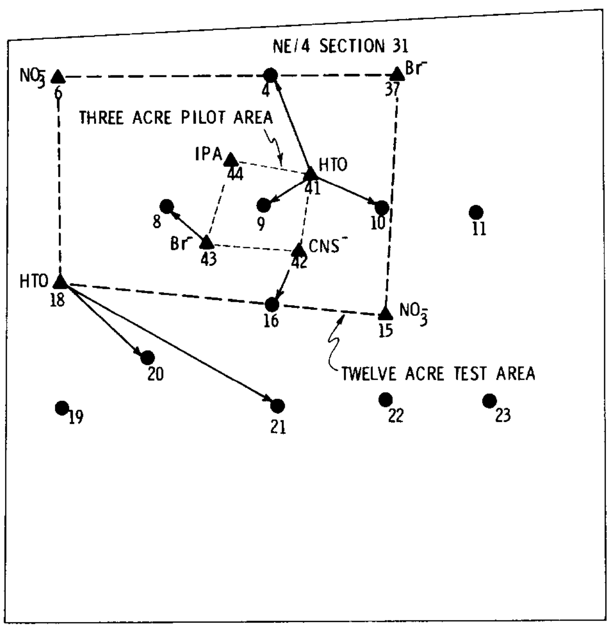


FIG. 4—MICELLAR PILOT AREA, SECOND WALL CREEK FORMATION, SALT CREEK FIELD, WYOMING.

three injectors indicates that Well 9 was in poor communication with these injectors. These results also support the contention that much of the injection water flowed outside the pattern area. The conclusion was drawn that the capability of a micellar flood in this area to move and recover oil could not be evaluated unless the interwell communication were improved and the loss of injected fluids outside the pattern area were corrected.

A recent high volume acid stimulation of Well 9 has been successful in removing a large "skin" effect and approximately doubling the producing rate of this well. Following the stimulation of Well 9, a second tracing program is being considered to re-evaluate the interwell communication in this area.

A second area (an 18-acre tract) in the Salt Creek Field, shown in Figure 5, was also evaluated as a potential site for micellar flooding. Two traced waterfloods were conducted in this tract under different conditions. The four injection wells were traced by use of some of the water tracing materials listed in Table 1. During the initial tracing program, all water was injected at pressures exceeding the formation parting pressure. Tracer breakthrough occurred within 4 days between two sets of wells (38 and 3, 39 and 13),

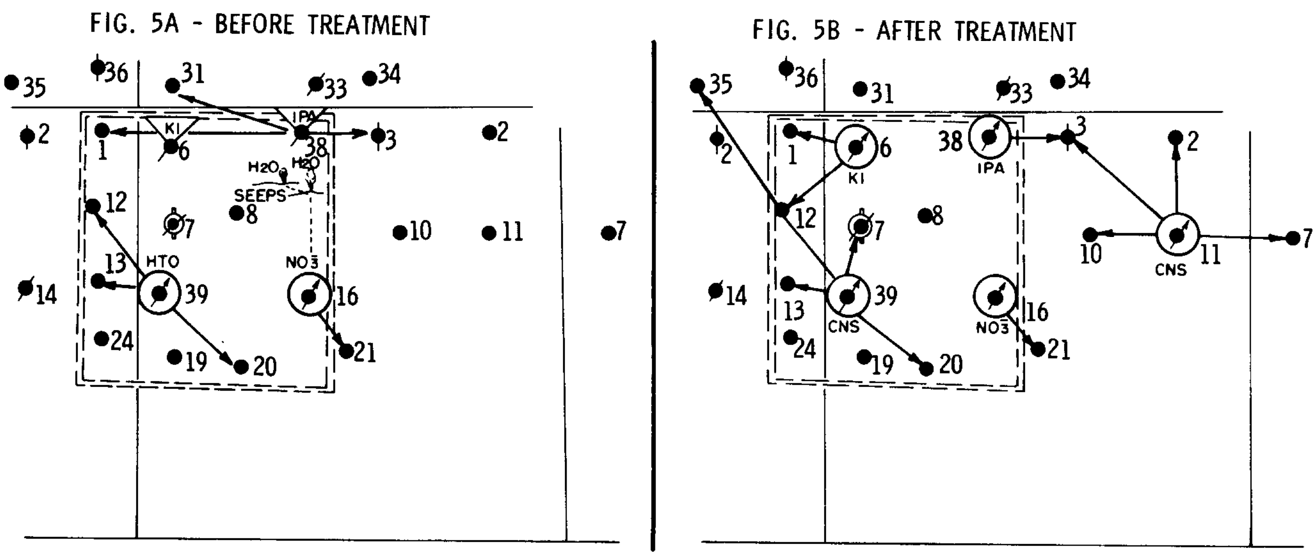
TABLE 1—PREFERRED TRACER MATERIALS

A. WATER TRACERS

1. TRITIATED WATER
2. AMMONIUM THIOCYANATE
3. AMMONIUM NITRATE
4. SODIUM OR POTASSIUM BROMIDE
5. SODIUM OR POTASSIUM IODIDE
6. SODIUM CHLORIDE
7. FLUORESCENT DYES
8. WATER SOLUBLE ALCOHOLS

B. GAS TRACERS

1. TRITIUM (H^3)
2. TRITIATED METHANE (H^3CH_3)
3. TRITIATED ETHANE (H^3CH_2-CH_3)
4. KRYPTON-85 (Kr^{85})

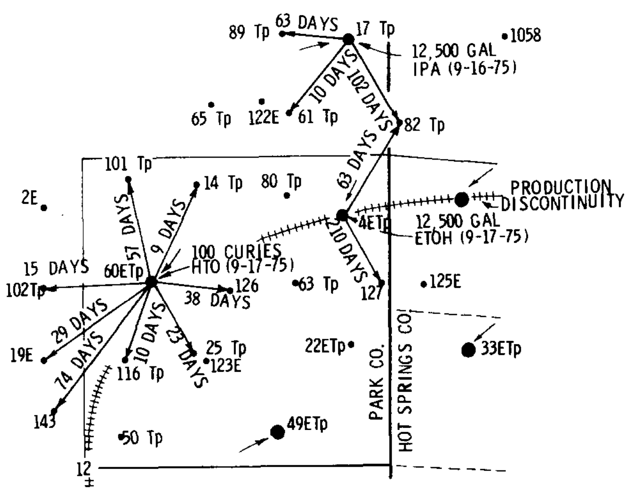


KI --- POTASSIUM IODIDE
HTO --- TRITIATED WATER
IPA --- ISOPROPYL ALCOHOL
NO_3^- --- AMMONIUM NITRATE
CNS^- --- AMMONIUM THIOCYANATE

FIG. 5—PROPOSED MICELLAR PILOT AREA, SALT CREEK FIELD, WYOMING.

indicating that fractures were present in the interwell area. The fracture orientation resulted in the loss of injected water outside the pattern area. Water from two surface seeps in the interwell area contained traced injection water, and injection Well 16 was identified by the tracer as having no cement bond behind the casing. No traced injection water was detected at the center producer, Well 8.

After the reducing of injection pressure below formation parting pressure and squeeze-cementing behind the casing at two wells, a second tracer program was initiated to reevaluate the area (see Fig. 5B). Again, early tracer breakthrough occurred between Wells 38 and 3 and Wells 39 and 13, indicating that the fractures had not healed with lowering of the injection pressure. The behind-casing cement squeezes were successful in drying up the surface seeps (originating at Well 16) and in reducing the vertical loss of injection water at Well 6. An unsuccessful attempt was made to seal the interwell fracture between Wells 39 and 13 with 23 tons of fly ash. A dye injected subsequent to the fly-ash treatment arrived at the offset producer (Well 13) two days after injection, indicating that no seal of the interwell fracture had been achieved. Further, the dye was detected at a producing well 3/4 a mile away and outside the pattern area, verifying the continued loss of injected fluid outside the test tract.



6—LITTLE BUFFALO BASIN, NORTH END WATERFLOOD.

Additional sweep improvement treatments are now being considered.

3. *Little Buffalo Basin, Wyoming Waterflood:* Figure 6 is a map of the area in which a traced waterflood was conducted to determine preferential flow trends, to delineate flow barriers, and to determine if water injected into the Tensleep Formation (Tp) was being lost to the overlying Embar (E) Formation. As indicated in figure 6, 100 curies of tritiated water tracer was injected at Well 60 ETp, 12,500 gal of ethyl alcohol tracer (containing 50 ppm bactericide) was injected at Well 4 ETp, and 12,500 gal of isopropyl alcohol tracer was injected at Well 17 Tp. Production response to earlier fluid injection had indicated that a possible produ- tion discontinuity in the area as shown in Figure 6. The arrows in Figure 6 indicate the producing wells at which traced injection water had been detected, with the required to breakthrough of the tracer given in days.

   The very earliest tracer breakthrough times around each injection well defined a preferential flow trend in the northeast-southwest direction. The breakthrough of tritiated water tracer at Wells 116 Tp, 25 Tp, and 126, as well as the breakthrough of the ethyl alcohol tracer at Well 127, discredited the presence of the production discontinuity line as shown in Figure 6. The early and multiple breakthrough of tritiated water (injected at Well 60 ETp) at producing wells located radially around Well 60 ETp indicated that the Tensleep Formation around this injector was highly fractured. Although tracer breakthrough occurred earlier than expected at each of these wells, the highest tritium concentration detected at any well was 350 picocuries/ml at Well 14 Tp. Water injected into the Tensleep Formation found its way into the Embar Formation at Wells 19 E and 60 ETp. Well 60 ETp is a dually completed injector-producer. No degradation problems associated with the use of the ethyl alcohol tracer were observed. The peak concentration of ethyl alcohol produced at Well 82 Tp was 130 ppm.

4. *South Swan Hills Unit Hydrocarbon Miscible Flood, Alberta, Canada*[8]: The South Swan

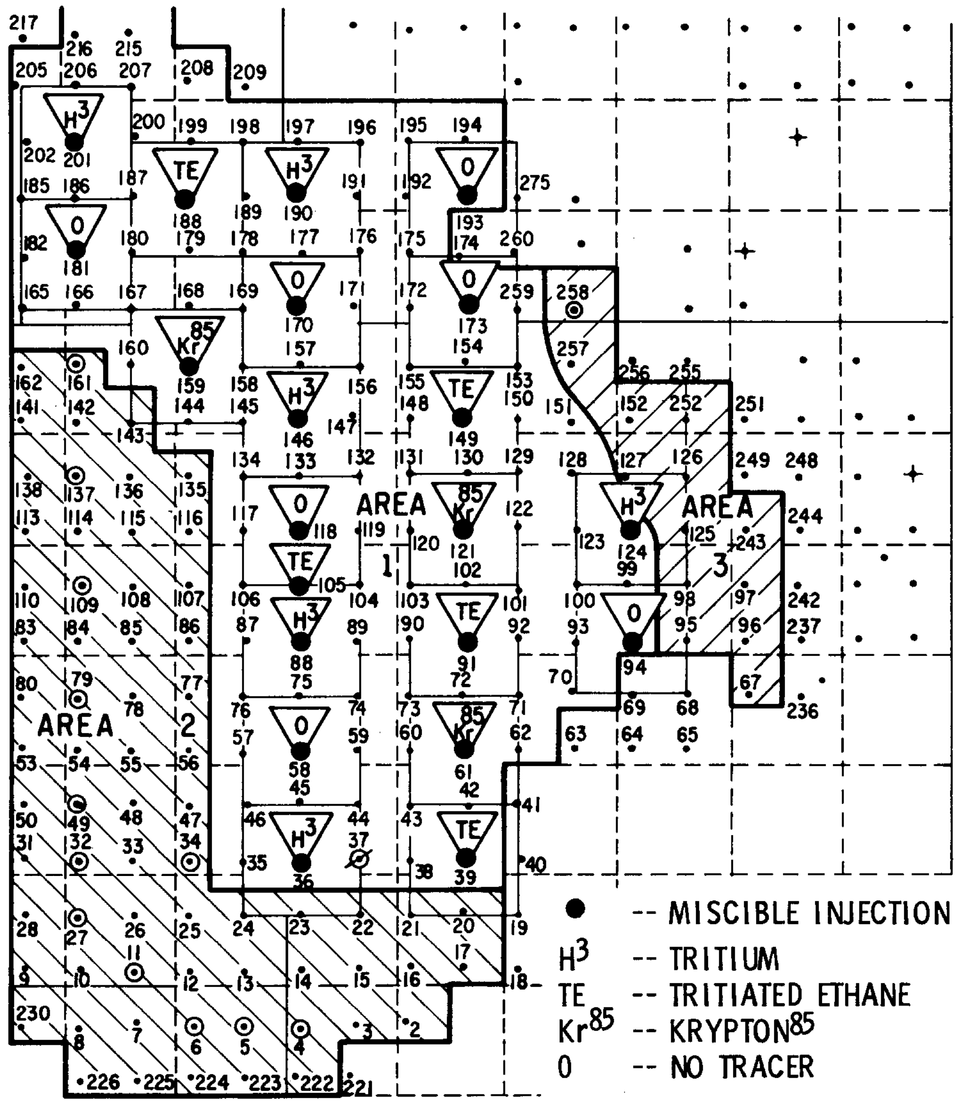


FIG. 7—SOUTH SWAN HILLS UNIT SOLVENT TRACING

Hills Unit was developed on 160-acre well spacing. It comprises 221 wells, 21 of which are injectors, and produces from the Beaverhill Lake Formation. In July 1973, a miscible flood operation was initiated in which enriched gas was injected alternately with water on 30-day cycles. Early injected solvent and water cycles were traced by use of selected tracers from the "preferred" listing in Table 1. The deployment of these tracers during the early solvent and water cycles is shown in Figures 7 and 8. Details of the tracer-program design and tracer-injection amounts are discussed in SPE 5125. A tritium-krypton analyzer having a sensitivity of 10 picocuries per liter was installed in the South Swan Hills Unit to provide on site analytical service for the radioactive gas samples. A commercial analytical organization provided the analytical service for the radioactive and chemical water tracer samples. With the exception of three wells which were used as produced water disposal wells and the injectors 181, 201, and 206, the miscible flood unit had no prior waterflood history.

Figure 9 is a map of the northwest quarter of the unit where several areas of poor sweep efficiency have been identified by the early breakthrough of solvent and water tracers through zones of high permeability near the top of the pay. The prime problem areas where remedial action has been taken to reduce cycling of the solvent are identified in figure 9 by highlighting of the offending injection well number. Injection Wells 159 and 170 have been dually completed to permit better distribution of the injected fluids. A 9000-barrel barrel lignosulfonate treatment[9] was performed at injection Well 201, and a 13,500 barrel lignosulfate treatment was performed at Well 146. These treatments were designed to reduce but not eliminate flow in selected zones. Selected producing wells have been choked back to reduce solvent cycling. All remedial action taken is now being evaluated.

The solvent and water tracers used in this program have all performed satisfactorily; that is, the radioactivity levels in the produced fluids have created no hazards to operations

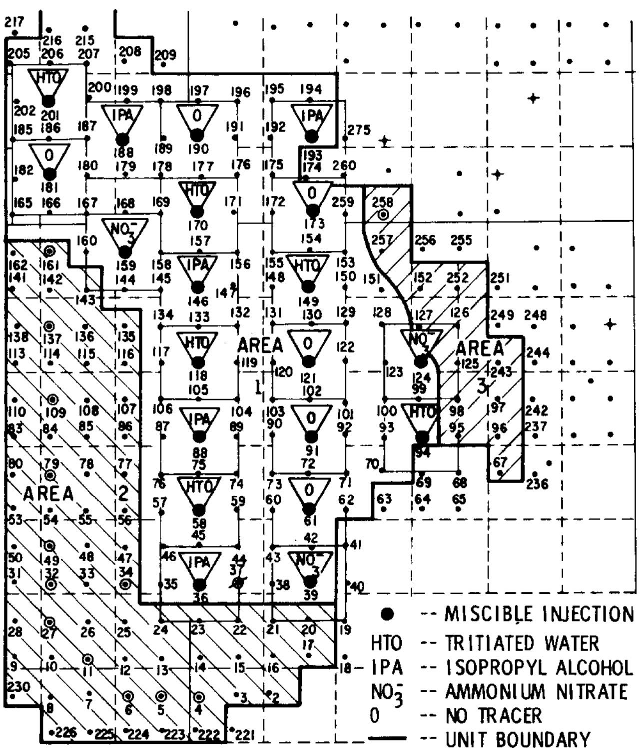


FIG. 8—SOUTH SWAN HILLS UNIT WATER TRACING

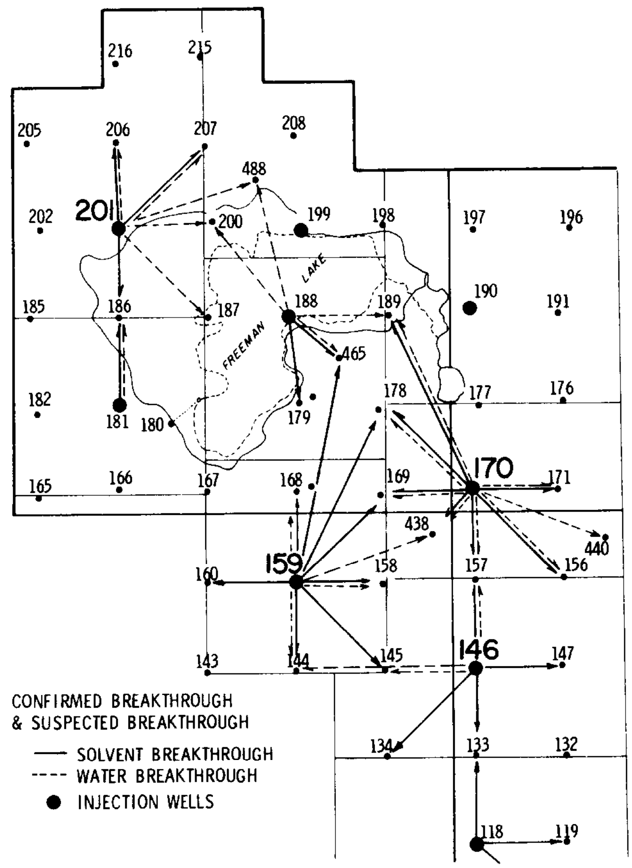


FIG. 9—TRACER BREAKTHROUGH, SOUTH SWAN, HILLS UNIT.

personnel, and the chemical-tracer concentrations in the produced fluids have been sufficiently high to give good analysis resolution.

CONCLUSIONS

Conclusions which may be drawn from experimental data are as follows.

1. A suite of gas and water tracers is proved for tracing interwell fluid flow.
2. The usefulness of a tracer prediction model in providing guidelines for tracer program designs is validated.
3. Tracing the interwell flow of injected fluids in potential tertiary pilot areas and in large field floods can identify reservoir heterogeneities responsible for poor sweep efficiency and can provide information useful in the design, control, and interpretation of subsequent tertiary oil recovery processes in these reservoirs.

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APPENDIX

Tracer Performance Prediction Method

The model which was developed to predict produced tracer concentrations was based on the waterflood tracer model proposed by Brigham and Smith[7]. The reservoir is assumed to be a layer-cake with radially uniform properties (porosity, permeability, etc.) for each layer. Volumetric behavior is assumed; *i.e.*, for each barrel of fluid injected, one barrel of fluid (at bottom-hole conditions) is produced. The displaced and displacing fluids are assumed to have the same mobility. This assumption is thought to be valid for the situation in which rich gas is injected simultaneously or alternately with water.

Pattern (areal sweep) effects are accounted for by the inclusion of the ideal five-spot production curve, in the manner described by Brigham.[7]

The major modification of the Brigham-Smith model was the inclusion of dilution effects by co-produced gas and by expansion from bottom-hole to surface conditions. The resulting equation which is derived in reference[6] is:

$$C_s = \frac{\Sigma\, k_i h_i C_i}{\left(\dfrac{GOR}{RVF + WOR}\right)(n\Sigma k_i h_i - \Sigma k_i h_i f_i) + E\Sigma k_i h_i f_i} \qquad (1)$$

where C_i is the concentration of produced tracer at bottom-hole conditions and C_s is the concentration of tracer at the surface. The summations are over all layers (i).

This form of the equation clearly indicates the effect of dilution from co-produced gas (GOR) and expansion (E) from bottom-hole to surface conditions. The same equation (1) can be used to model the dilution of waterflood tracer if GOR is replaced by WOR and expansion E is approximately unity.