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Identification of Cross-Formation Flow in Multireservoir Systems Using Isotopic Techniques (Phase I)

Final Report

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IDENTIFICATION OF CROSS-FORMATIONAL FLOW IN MULTIRESERVOIR SYSTEMS USING ISOTOPIC TECHNIQUES (PHASE I)

By Michael Szpakiewicz

ABSTRACT

This study, consisting of two phases, was designed to add quantitative and sometimes unique solutions to the problem of undesirable hydraulic communication which results in active fluid flow between productive horizons. The interformational communication is conventionally identified in the subsurface by expensive and time-consuming engineering methods and by analysis of anomalous well production. Transfer of novel geochemical methods, based on effective, economic, and environmentally acceptable isotopic techniques for identification of leaking hydrocarbon reservoirs, is a major objective of this study.

Phase 1 of the project revealed that interformational hydrodynamic communication is a common and well documented phenomenon worldwide. The effectiveness of a continuous trap's seal depends on an equilibrium between the capillary forces holding formation water in pore spaces of the seal and the buoyancy forces of the oil and gas column in a system. Therefore, some seals may leak selectively at changing pressure and temperature conditions with respect to different fluid phases (oil, gas, and water). A break in continuity of confining layers, which may be of depositional, erosional, tectonic, or physical nature, will promote relatively fast interreservoir migration of fluids. Leakage of hydrocarbons between horizons through geologic discontinuities may negatively affect all production stages. It may intensify, though, in reservoirs subjected to high pressures during implementation of secondary and tertiary processes of recovery. Such fluid flow should result in identifiable chemical, isotopic, and often thermal anomalies in the area of an open flow path. Carbon-13/12, oxygen-18/16, and protium to deuterium ratios in hydrocarbon and water molecules are best suited for identification of cross-flow. Some other isotopes such as sulfur-34, strontium-87, chlorine-36, and chlorine-37 supplement an array of natural isotopes suitable for solving natural and man-induced fluid communication problems. Relative differences in isotopic ratios between pairs of fluid samples can best be applied in decameter, hectometer, and kilometer scales.

Quantitative hydrodynamic reservoir modeling based on geochemical/isotopic and other evidence of fluid migration in a system require, however, more systematic methodological study. Such a methodological study, involving interdisciplinary effort and based on specific field results,

is being recommended as Phase 2 of this project in addition to a field demonstration of the method in a selected oil/gas reservoir where geochemical and production anomalies have been documented.

EXECUTIVE SUMMARY

The objective of this project is to substantiate fluid migration patterns into, within, and out of a reservoir by adapting natural isotopic geochemical techniques to the requirements of quantitative hydrodynamic reservoir modeling.

Phase 1 of the project, which is reported here, was initiated in mid-August of 1990. The study, consisting of two phases, was designed to add quantitative and sometimes unique solutions to the problem of undesirable hydraulic intercommunication conventionally detected by analysis of anomalous well production and costly pressure buildup tests, interference tests, and tracer tests.

The emphasis during Phase 1 of this project has been on (1) a review of reported evidence of dynamic conditions and cross-flow in multireservoir systems, (2) identification of the best approaches and the stable and radioactive environmental isotopes which are best suited for studying the cross-flow phenomena, (3) a review of successful field applications of geochemical isotopic techniques to identify cross-formational flow, (4) preselection of candidate hydrocarbon (HC) reservoirs in the U.S. for a field demonstration of the isotopic method, and (5) identification of major field-specific aspects of conjectural cross-formational fluid migration and mixing in candidate oil and gas fields preselected for a demonstration of the method proposed for Phase 2 of this study.

According to the working hypothesis adopted in this project, the formation fluids which are compartmentalized in isolated and often overpressured hydraulic systems should possess generally similar chemical and isotopic characteristics within an individual system. Differences in fluid origin and specific isotopic fractionation processes should lead to a distinct isotopic composition in isolated systems.

A break in continuity of confining layers, which may be of depositional, erosional, tectonic, or physical nature, will promote interreservoir migration of fluids. Such fluid flow should result in chemical, isotopic, and often thermal anomalies in the area of an open flow path.

In the case of exceptionally active subsurface drainage of fluids along, for example, an open fault zone, hydraulic fracturing zone, breccia pipe, or an unconformity, a deep water discharge

(DWD) will cause effective mixing and geochemical homogenization of formation fluids along a flow path. Several cases of DWD's in oil fields have been reviewed. Geochemical methods including isotopic techniques add a quantitative aspect to some of the reviewed cases where hydrodynamic conditions are well documented.

The isotopic techniques find numerous applications in hydrogeological studies for hydrodynamic modeling and documenting inter-aquifer migration (leakage) of ground water . Transfer of this novel, safe, and economic technology to the petroleum industry, including small independent oil companies, is a major objective of this study which will provide an opportunity of its immidiate use for solving vital problems of active fluid flow between oil and gas reservoirs subjected to expensive processes of improved hydrocarbon recovery.

The most promising stable and radio-isotope candidates, naturally occurring in reservoir fluids have been preliminarily screened, based on previous study[1] and the current review of literature which targeted geochemical methodology for identification of fluid communication between oil and gas reservoirs. The deuterium (D), oxygen-18, and carbon-13 distribution in liquid and gaseous hydrocarbons and in molecules of the associated formation waters appear to be the most applicable and the best quantitative indicators of reservoir intercommunication. Some other environmental isotopes are also considered for solving specific problems.

The stable isotope composition of reservoir gases is particularly indicative for cross-formational flow because mobility of gases through imperfect reservoir seals is greater than that of liquids. A number of earlier studies indicated that isotopic composition of formation methane alone may not be fully diagnostic for identification of gas sources and hydrodynamic communication between horizons. Examination of carbon-13/12 and hydrogen-2/1 ratios in the HC fractions in methane, ethane, propane, and butane is therefore being primarily considered. Carbon-13, oxygen-18, deuterium, sulfur-34, and some other stable isotope ratios such as strontium-87, nitrogen-15, chlorine-37, and probably boron-11 in undissociated non-hydrocarbon formation gases (CO_2, H_2S, N_2, etc.) and in cations, anions, and undissociated species dissolved in formation water supplement an array of natural isotopes and fluid species usable for solving natural and man-induced fluid communication problems. Certain radioactive isotopes, naturally occurring in formation or injection fluids, such as tritium, carbon-14, and chlorine-36, may be particularly helpful in identification of surface fluids introduced by man to a reservoir system.

To substantiate a need for adapting geochemical methods for identification of cross-formational flow in hydrocarbon reservoirs, several field cases reported in the literature were reviewed to demonstrate commonality of such phenomena in the subsurface. Interreservoir

migration and mixing of formation fluids in the area of discontinuity or breakage normally have been caused by deep fluid discharge through open faults and fracture systems, erosional cuttings through confining layers, or a rupture of a confining layer due to natural or man-made buildup of formation pressure in hydrodynamically closed systems.

Numerous previously reviewed applications of isotopic techniques in hydrogeology and those recently reported in the petroleum literature for this project indicate that examination of relative isotopic differences between fluid samples can best be applied for identification of cross-formational flow in larger scales. Decameter and hectometer scales find best application in the interwell area (horizontally) and interreservoir area (vertically). Hectometer and kilometer scales are best applied to fieldwide and interfield interpretations of fluid movement.

A broad-scale study of fluid intercommunication may be considered in Phase II for major oil-bearing horizons in the Powder River Basin in Wyoming and Montana: Fall River-Lakota, Muddy, Frontier, Shannon, Sussex and Teapot formations. Tectonic discontinuities and large breccia pipes may provide conduits for extensive fluid exchange between these HC productive horizons in the Powder River Basin.[2] Several geochemical anomalies have been recorded in the general area. Their origin and magnitude, however, were neither specified nor quantified, and their influence on oil production remains unclear. Isotopic techniques seem to be well suited for this purpose. Such a study may be suggested as an expanded version of the proposed Phase II of the project, and it would encompass a number of prolific reservoirs in the region including Naval Petroleum Reserve No. 3 - Teapot Dome oil field of nationwide strategic importance.

Field application of the stable isotope techniques for solving specific reservoir problems in the deca- and hectometer scales is recommended for Patrick Draw, Teapot Dome NPR No.3, and Big Muddy oil and gas fields in Wyoming, and Elk Hills NPR No.1 and Buena Vista NPR No.2 fields in California, where complications in inter-reservoir fluid flow and a strong possibility of vertical cross-formational flow have been indicated by geological and production data.

Final selection of one or two of these reservoirs for field demonstration of application of the environmental isotope techniques for identification of cross-formational fluid flow, as well as reservoir-specific design of sampling methods and patterns tailored to specific production problems and geological conditions of the selected field, will be performed in suggested Phase II of the project.

INTRODUCTION

Most of the reviewed practical applications of natural stable isotopes come from hydrogeological studies of multilayered aquifer systems. This study has been designed to fill an existing niche in petroleum applications by transferring technological advances from the succesful hydrogeological field studies. Merging of the two applied disciplines, both of which deal with withdrawal of subsurface fluids, manifests naturally in case of water encroachment to oil or gas reservoirs. Too often productivity declines dramatically because of water breakthough. In such cases, the aim of a new development strategy is to recognize and control the aquifer. Hydrogeochemical methods developed for oil-associated brines, where application of isotopic techniques is almost routine, become handy for solving practical problems of hydraulic intercommunication between hydrocarbon reservoirs.

The stable isotope geochemical technique has not been directly applied so far for identification of cross-flow at advanced stages of reservoir development except for underground storage of hydrocarbon reserves. Isotopic tracer analyses in oil reservoirs have mostly involved radioactive slugs of tritium, carbon-14, iodide-125 and sometimes cobalt-57, 58 and 60. Safety aspects and methodological difficulties (cobalt-58 for example is very short lived) restrain companies from using radioactive tracers.

Evidence of gas escape from a reservoir indicates high risk for fluid breakthrough at microfractures, fault planes, or other passages which may open wider with high, induced reservoir pressures. The interformational leakage may cause economic failure of an enhanced oil recovery (EOR) project by ineffective injection of stimulation fluids or may eliminate a leaky formation as a target for storage of hydrocarbon reserves. If vertical conduits or semiconduits exist within an EOR pattern, the productivity may be severely impaired by undesirable escape of injected gases and chemicals and formation fluids to the under- or overlying formations. The problem may become even more sensitive (environmentally and economically) in case of underground storage of liquid hazardous wastes.

Effective tracing of fluid flow barriers and conduits between productive horizons or reservoirs is vital at any stage of field development. Prediction and control of fluid migration paths, however, are particularly critical at the stage of EOR because high injection pressures may be applied and expensive chemicals or processes may be used for mobilization of residual oil.

In characterization of reservoir flow, fluid heterogeneities are usually less adequately addressed than the heterogeneity of the reservoir rock system. In most cases, the emphasis is on

properties of reservoir container rather than reservoir content and its mobility. In such a system where fluid heterogeneities are poorly recognized, the reservoir characterization is incomplete, and the fluid flow cannot be effectively predicted. Observations on hydrocarbon migration phenomena in sedimentary basins debated at the Second French Petroleum Institute (IFP) Research Conference led to the conclusion that the number of available well documented case histories, based on proper geological and geochemical information, is very low, and more examples are definitely needed.[3] Evidence of current migration of fluids between oil reservoirs is scarce primarily because of yet less common use of geochemical tools in their characteristics. Interference with process of production and difficulties in obtaining representative, uncontaminated samples of formation fluids from individual productive horizons probably are additional factors.

Several active and dominantly ascending systems of fluid migration from a source rock to pools in a shallow hydrogeological system (or to the surface) have been documented worldwide. Specific mechanisms, pathways, and velocities of fluid flow between individual productive horizons in a system, however, have been discussed in only a few cases.

Integrity of confining layers is crucial for keeping formation fluids confined and injected fluids under control. Seal efficiency governs hydrostatic (confined) and hydrodynamic (leaking) conditions in subsurface. Seals separate hydrostatic regimes (fluid compartments) in the subsurface. They isolate individual oil and gas horizons, confined (artesian) aquifers, and formations used for underground storage of excess natural gas and crude oil (strategic reserves) and for injection of hazardous chemical and radioactive wastes from the biosphere and from each other. The seals also work selectively on different fluid phases (oil, gas, and water molecules) and at changing pressure and temperature conditions in a system.

Lithostratigraphic, tectonic, and geochemical seals, such as shale layers, annealed faults, fractures, bedding planes and tightly cemented intervals due to matrix diagenesis, or man-made seals such as plugged and abandoned wells may leak. Leaking seals may cause serious economic, environmental, and health hazards.

Conventional methods of identification of the confining layers' integrity such as pressure buildup tests, interference tests, tracer tests, and analysis of anomalous well production are expensive and time-consuming. Geochemical analysis of the system, however, can provide early warning and unique information regarding location and characteristics of fluid leakage after first wells have been drilled in the area and the formation fluids sampled at different stratigraphic levels.

The isotopic techniques involving distribution of naturally occurring stable and radioactive isotopes in a subsurface system, primarily the isotopic ratios of hydrogen ($^{1}H/^{2}D$ and T), oxygen ($^{18}O/^{16}O$), carbon ($^{13}C/^{12}C$, and ^{14}C), sulfur ($^{34}S/^{32}S$), chlorine ($^{37}Cl/^{35}Cl$, and ^{36}Cl), and strontium ($^{87}Sr/^{86}Sr$), are still by far underutilized in the petroleum industry and in petroleum-related environmental applications. However, isotopic geochemistry recently began finding practical applications in characterization of hydrocarbon reservoirs. Major oil companies have become more interested in utilizing the environmental isotopes as an important tool for the assessment of oil and gas mobility between pressure compartments and individual productive horizons and calculation of fluid proportions in mixing systems, fluid correlations between source rock and reservoirs, and for identify of actual sources of hydrocarbons contaminating soil, groundwater, and surface waters.

Recently reported applications of stable carbon-13 isotopic composition of wet gas components (mostly propane, iso-butane, and n-butane) by Exxon Production Research Company, Esso Resources Canada, Exxon Company USA, Esso Norge a.s, Statoil, and Norsk Hydro for correlation of reservoir gases in their North American (Canada and USA) and Norwegian (North Sea) fields[4-5] as well as the isotopic study performed by Chevron, Amoco, and other majors[6-7] indicate strong industry activity in utilization the emerging geochemical techniques. Powley[6] conducted numerous special studies for Amoco including research on hydrodynamics of some giant oil fields. Below shallower hydrodynamic zones, he documented a number of deep-seated oil-bearing fluid compartments usually under anomalous pressures. A special study using isotopes to identify potential crossflow between fluid compartments through leaking seals has been initiated on fluid samples from Amoco reservoirs by the University of Arizona.[6]

In most reviewed cases, however, the emphasis is still on the genetic aspects of reservoir fluids and their source rock-reservoir correlation rather than on the identification of current active flow paths in interconnected systems by correlating one reservoir gas or oil with another.

There is high potential and a need for transferring the novel technology to independent oil producers because isotopic analyses are very indicative and relatively inexpensive. In simple cases, their relatively straightforward interpretation may significantly help solve flow problems in stimulated reservoirs and comply with increasing environmental restrictions. Identification of financial losses due to ineffective injection as well as severe penalties in case of fluids breakthrough to potable aquifers or to the surface could be minimized if natural or man-made pathways such as leaking faults and abandoned wells were identified before initiating an injection procedure.

Indications of Dynamic Conditions and Cross-flow in Multireservoir Systems– Structural, Lithostratigraphic, and Erosional Conduits

Structural and stratigraphic interrelationships promoting interreservoir fluid migration in several major oil and gas reservoirs worldwide has been investigated. The reviewed cases of cross-formational fluid migration highlight the importance of fluid leakage for hydrodynamic characterization of reservoirs. Stratigraphic and structural framework has been reviewed from this point of view for such typical super-giant fields as Urengoy (USSR), Ghawar (Saudi Arabia), Samotlor (USSR), Handil (Indonesia), Prudhoe Bay (U.S.), Lake Maracaibo (Venezuela), Brent (North Sea), Gaschsaran (Iran) and some domestic multireservoir fields (West Ranch and Northmarkham-North Bay City, TX; Big Muddy, Teapot Dome, Patrick Draw, and Elk Basin, WY; Elk Hills and Buena Vista, CA.). In many reviewed cases, the structural features controlled vertically stacked multireservoir systems.

Indonesian Handil, East Kalimantan multireservoir oil field produces from a transversely faulted anticline with some 150 independent reservoirs between depths of 1,500 ft and 9,500 ft.[8] The general arrangement of productive horizons in Handil field is illustrated in figure 1. Figure 2 provides a closeup of the complex organization of productive deltaic sandbodies between R9 and R10 coal markers within a main-interval in figure 1 and erosional channels cutting through some of them. The incisions provide excellent hydraulic communication paths for formation fluids at a vertical scale of tens of meters. The major fault cutting through the entire field is considered a seal at the present. However, the oils found in the various reservoirs of Handil field have about the same composition and must have been generated from the same type of organic matter.[8] Its maturation is too low in the formation surrounding the reservoirs to allow these formations to be the source rock of the hydrocarbons. Indeed, the source rock is located deeper,[9] and the upward migration of Handil oil is probably still taking place.[8] It can be concluded at this point that Handil oil field is under active dynamic conditions and that its multireservoir characteristics are due to the leakage of hydrocarbons upward from one reservoir to another. However, the time, rate, and conduits of that leakage cannot be estimated without hydrochemical, isotopic, and mass balance analyses.

In case of exceptionally active subsurface drainage of fluids along, for example, an open fault zone, hydraulic fracturing, breccia pipe, or unconformity, a deep water discharge (DWD) may cause further pressure drop below the hydrostatic level ("underpressured" reservoir). Roberts[10] provides well documented examples of DWD's from Athabasca, Orinoco, Middle East, and Gulf Coast oil reservoirs. The DWD concept of hydrocarbon accumulation has been derived from

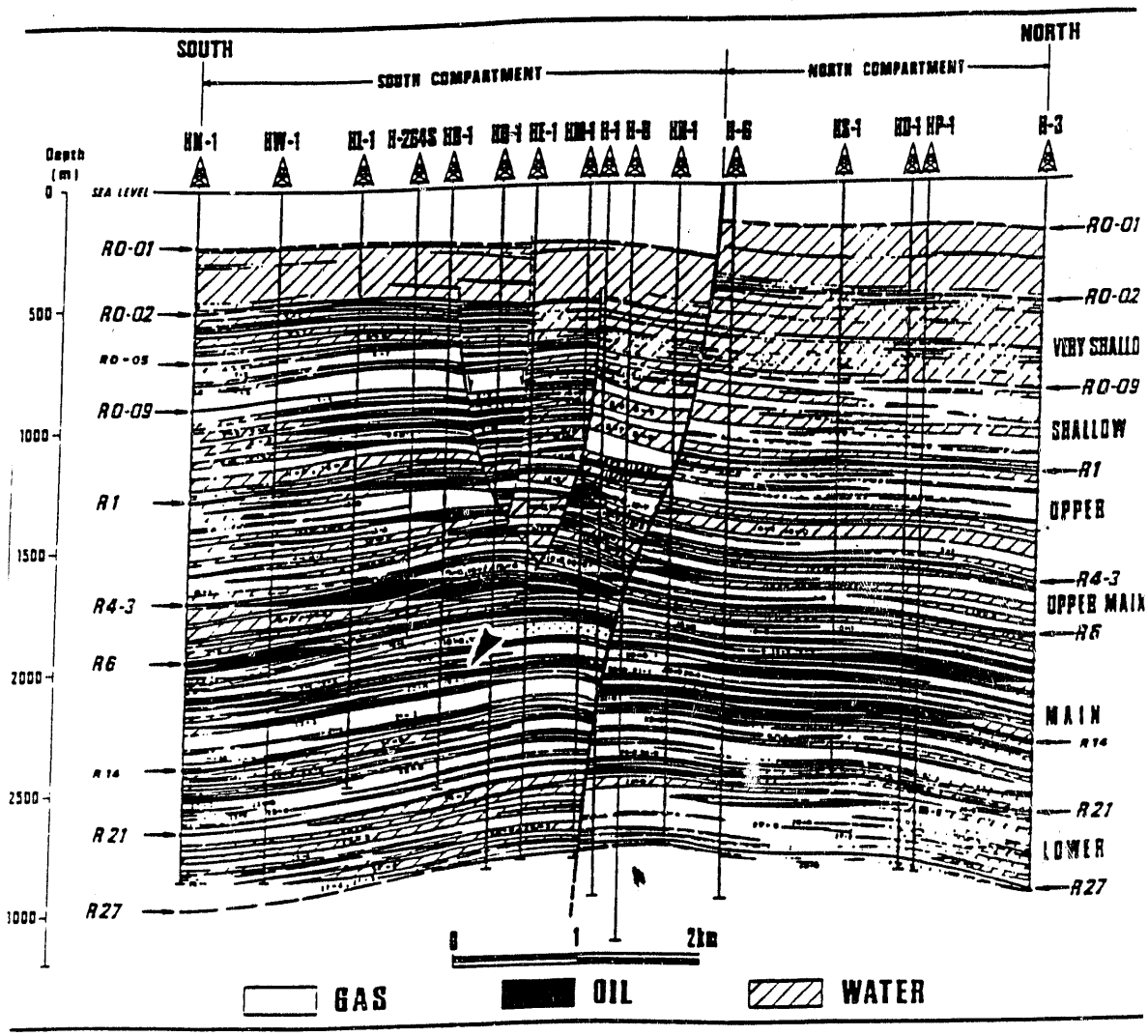

FIGURE 1. - Schematic north to south cross section of Handil field Indonesia indicating the multiple reservoirs and the distribution of the hydrocarbons. Note position of the 19-7 reservoir reached at depth of 1,970 m and located between R9 and R10 marker (arrow). The arrangement of sandstone bodies in the 19-7 reservoir is shown in fig. 2. (After Verdier et al.[8]).

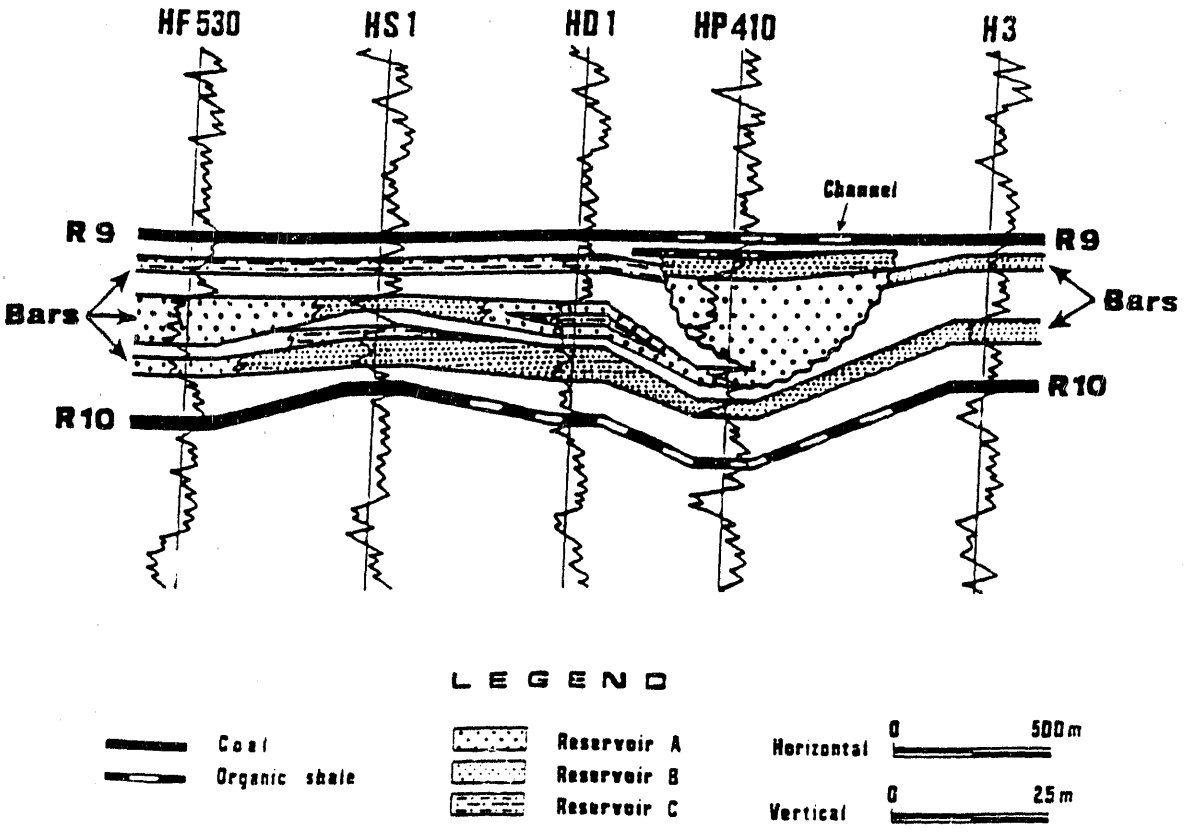

FIGURE 2. - Complex organization of sandstone bodies within 19-7 reservoir, Handil field, Indonesia. Erosional feature (the upper channel) links the oil-bearing strata into one hydrodynamic system. There are no fluid incompatibilities or discrepancies in the pressure measurements between A, B, and C subreservoirs. Position of the 19-7 reservoir in the Handil multiple reservoir system is shown in fig. 1. (After Verdier et al.[8])

frequently observed oil and gas seepages carried by the ascending brine toward surface. Active oil seepage at Mene Grande ("Great Seepage") east of Lake Maracaibo, Venezuela provides a spectacular example of the DWD process.[11] The Mene Grande overlies Boliver Coastal field, the largest oil accumulation in the new world which occurs under complex structural and stratigraphic conditions.[12]

One of the more active Iranian anticlinal seepages of water, hydrocarbons, and deadly hydrogen sulfide lies over the large, shallow, oil productive Masjed E. Suleyman anticline.[10] Miocene Asmari dolomite of the Gachsaran, Iranian giant oil field crops out 9 miles east of the productive anticline and about 1,640 ft higher. The pressures in the anticline, however, are not artesian. "Apparently, the artesian head is relieved by DWD via cross-formational flow along the lateral flow path and especially at the crest of the anticline where the cover is thin and weak".[10]

Tilted fault blocks bounded by major normal faults of more than 6,500 ft throw have been documented in the Viking Graben reservoir system, North Sea. Where the fault system is considered poorly permeable or impervious, the severely overpressured Jurassic reservoir leaks.[13] Gas escape from the reservoir is much more rapid than water at the same pressure gradient resulting in a very rapid depletion of the gas accumulation and a resultant drop in reservoir pressure. Pressure distribution across the Smorbukk gas condensate and oil fields, illustrated in figure 3, explains a reason for the actual position of productive and nonproductive wells in the area. The cap rock damage by the sudden leakage phenomena, which was documented by numerous examples worldwide,[14] leaves open conduits for further fluid migration. Isotopic analyses of the formation fluids within, beneath and above an alleged cap rock should leave little doubts about its integrity.

Natural seeps provide unspecified volume of hydrocarbons to the biosphere onshore and offshore. Approximately 0.25 million metric tons of oil per year, constituting about 8% of the oil input into the sea, is derived from natural seeps, the rest being anthropogenic.[16] A submarine seep in the Santa Barbara Channel, California is the only known offshore natural sea bottom discharge of hydrocarbons producing oil and gas of a modest economic value.[16]

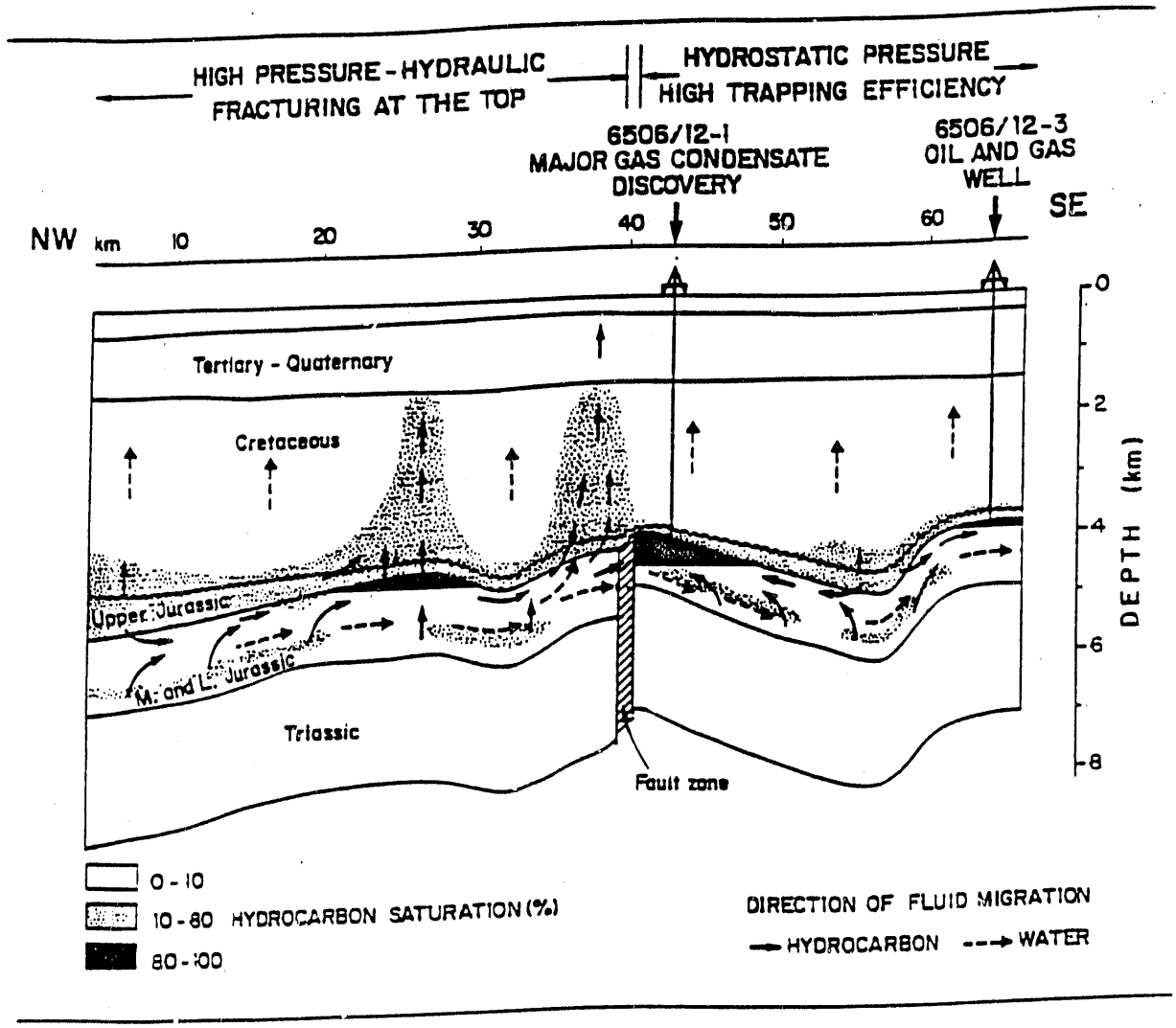

FIGURE 3. - Migration model on cross section through Smorbukk hydrocarbon field, Maltenbanken, Viking graben, North Sea. Southeast part of the section is oil and gas productive because greater pressure in Cretaceous shales than in reservoir makes these shales a very efficient cap rock. Isotopic composition of fluids is predicted to be distinctly different in vertical profile. Northwest, reservoirs are highly overpressured and leak to the overlying strata through ruptured cap rock. There is no economic hydrocarbon accumulations north and west of sealed fault zone. Isotopic composition of fluids is predicted to be near uniform in vertical profile due to leakage. (Modified from Ungerer et al.[13])

Six giant near-surface, oil-impregnated rock deposits in Utah are estimated to contain as much as 29 billion barrels of petroleum.[16] Asphalt seeps actively discharging fresh tar from numerous exposures of the Permian White Rim Sandstone (SE Utah) were described by Baars and Seager in 1970.[17] The influence of local geologic structures on fluid migration paths and distribution of oil-impregnated sandstone units in these examples is not well documented. Asphalt is apparently seeping from fractures and bedding planes. Continuous flow obviously indicates dynamic communication with either an oil reservoir and/or a source rock.

The spectacular examples of interformational leakage and in some cases a contemporary active fluid flow, which finds obvious manifestation at the surface, would be an excellent field laboratory for testing applicability of isotopic techniques to identification of flow paths and actual source of seeping fluids. Isotopic data, however, are not available from those locations.

A significant pressure drop in a producing hydrocarbon reservoir causes similar effects as a natural deep water discharge, i.e., a mobilization of fluids in the entire interconnected system. Monitored subtle changes in isotopic composition of the produced fluids would indicate initiation of fluid withdrawal from remote sections of the reservoir or even from another reservoir providing that the distribution of the original isotopic fingerprint of the system were recorded. Engineering measures can be undertaken to prevent an undesirable influx of foreign fluids, for example, water encroachment from adjacent aquifers, or an escape of injected fluids such as surfactants or polymers to the biosphere.

Pressure Ruptures

Interreservoir communication releases fluid pressure built up by petrostatic pressure or expansion of fluids, and the "leaky" reservoirs may gradually become part of an open hydrodynamic system under predominantly normal pressures. Hydrostatic pressure favors high trapping efficiency while highly overpressured systems may become susceptible to hydraulic fracturing at the top causing severe leakage of formation fluids.

Hydrocarbon leakage through ruptured overburden clearly indicates a necessity of quantification at the advanced stages of reservoir development. In some cases, the actual vertical distribution of hydrocarbons has been explained by their migration through ruptures in confining layers toward carrier horizons of lower pressure potential. If the generative potential of a source rock vastly exceeds the storage capacity of the traps in the area, as is the case in the Haltenbanken provinces of the North Sea,[18] the generated liquids and gases must break toward carrier horizons of lower pressure potential or even to the surface. The constant flow keeps conduits open or rupture will reoccur in geochemically healed areas if thermodynamic conditions in the system

favored mineral scale precipitation. Natural gas has great tendency to migrate vertically because it has a lower specific gravity than oil and water. The migration will generally result in a spatial separation of oil and gas.

One of the first published papers to propose a mechanism for escape of fluids through natural ruptures appears to have been that of A.N. Snarsky.[19-20] Later, Dickey[21] recognized the possibility that highly pressured interstatial waters "May burst the rock, and the water can therefore move out through fissures which it forms itself." Hedberg[14] provides historical review of fluid escape mechanisms resulting in migration of fluids out of the pressured system through microfracture network. When fracturing occurs, vertical discharge is favored, while the lateral direction is preferentially followed in the case of slightly overpressured zones, where the contrast in permeabilities is the dominant parameter for fluid flow direction.[22]

A modern example of monitoring methane plumes which escape to the water surface of the Gulf of Mexico above a section containing overpressured shales as a result of gas leakage through the confinement to the overlying sections was shown on marine echograms by Hedberg.[14] An extensive, presently active fluid flow has been documented in the Eugene Island area, offshore Louisiana by computation of the heat flow distribution at the seafloor.[23] The fluid flow velocities of several meters per year were required to account for the magnitudes of some of the high heat flow anomalies in the area. These very high fluid flow velocities can be maintained only with the episodic bursts of fluids through very high permeability pathways along faults.[16] Seepage of gaseous and liquid petroleum in the Northern Gulf of Mexico has only recently been extensively documented in the offshore regions. The fluids seeping at the seafloor were unambiguosly matched chemically and isotopically with the petroleum reservoired at depths of about 6,000 to 9,000 ft.[24]

The paper by Chiarelli and Rouchet [25] reveals the frequency of migration phenomena through cap rock and their role in the spatial distribution of hydrocarbons. Due to extensive migration certain hydrocarbon resources probably can be classified in economic terms as renewable ones if naturally driven supply rate keeps pace with fluid leakage.

Seismic sections, such as those running across Gullfaks field, North Sea[26] reveal strong faulting of the pre-Cretaceous formations and seismic evidence for gas escape structures in the Tertiary-Quaternary system. Disturbed reflectors overflying Gullfaks field were observed on the seismogram which indicated a mechanism such as natural hydrofracturing for gas escape. This may explain why the fields shallower than Brent field do not have a gas cap. Seismic reflection profiles across mud or shale diapirs in petroliferous areas of the Gulf of Mexico have been

demonstrated by Hedberg.[14] Some fluid escape forms in the area may extend vertically for thousands of feet and laterally for tens of thousand feet (compare figs. 6, 7, 8, 10, 11, and 12 in Hedberg[14]). An actual dynamic flow, however, cannot be demonstrated by seismic tool. A spatial homogenization of isotopic composition of methane molecules in a vertical profile would indicate active flow through randomly distributed leakage spots such as gas escape structures (mud diapirs) or through reactivated faults. A linear homogenization in the vicinity of distinctive linear features would indicate a gas leakage through conductive faults.

Rock vibrations associated with earthquakes (which occur in most hydrocarbon productive areas of the continental U.S.) may be responsible for rapid (jet-like) fluid relocation through reactivated conduits such as previously unconductive (sealed) faults, fractures, or joints. The hydrodynamic pulses also may negatively affect the confinement of unfractured lithostratigraphic seals in hydrocarbon reservoirs. Sudden increase in pressure transmitted from vibrating rocks to formation fluids, when summed up with the buoyancy forces of oil and gas, may overcome the capillary forces holding water in pore or microfracture spaces of the seal and cause an extensive interformational leakage. In tectonically active regions such spurts of fluids through less tight sections of reservoir seal may homogenize them chemically and isotopically. There is a possibility that similar effects may occur during engineering pressurization of artifically fractured reservoirs .

General Methodological Approach and Selection of Most Promising Natural Isotopes for Cross-Flow Study

Based on international standards, the isotope ratios are given in δ (delta) values as shown below for carbon in ‰ (per mil) units.

$$\delta^{13}C‰ = \frac{{}^{13}C^{12}C\ \text{sample} - {}^{13}C^{12}C\text{standard}}{{}^{13}C/12_{\text{standard}}} \times 1000\ (‰)$$

The sample stable carbon δ values are given a negative notation related to the Peedee belemnite (PDB) if the $^{13}C/^{12}C$ ratio is lower (isotopically lighter) than the belemnite standard value (arbitrarily given a 0 ‰ value) and positive if the $^{13}C/^{12}C$ ratio is greater (isotopically heavier) than the standard value. By this criterion, the $^{13}C/^{12}C$ of most crude oil samples fall in a $\delta^{13}C$ range of -18 and -34 ‰ according to Stahl[27] and -21 to -32 ‰ according to Fritz and Fontes.[28] Methane (CH_4) from non-marine deposits has a spread in $\delta^{13}C/^{12}C$ values, about -20 to -30 ‰ and from marine environment from -30 ‰ (overcooked source rock) to -50‰ (low mature). Biogenic methane is very light; i.e. depleted in $^{13}C/^{12}C$ by fractionation, from -55 to -100 ‰.[25] Alekseyev [29] in his analysis of reservoirs across the USSR defined three ranges of

$\delta^{13}C$, associated with the means by which gases formed: biogenic zone, -55 to -95 ‰; transition zone, -55 to -65 ‰; and thermogenic zone, -36 to -58 ‰. Shoell[30] indicated three major genetic groups of methane and their corresponding distinct stable isotopic fingerprint of carbon-13; (1) the biogenic methane generated in immature regime $\delta^{13}C(CH_4)$ = -80 to -60 ‰; (2) the thermogenic methane generated in mature regime $\delta^{13}C(CH_4)$ = -55 to -40 ‰; and (3) the thermogenic methane generated in over-mature regime $\delta^{13}C(CH_4)$ = -40 to -20 ‰

Normally, $\delta^{13}C$ can be measured with a precision of about 0.2‰ and δD with a precision of about 2.0‰; therefore a subtle difference in the isotopic composition of a pair of fluids representing productive horizons can be detected. Covariation in the stable carbon-13 and deuterium composition of methane-ethane pairs can be used for differentiation of gases of mixed (non-cogenetic) origin.[31-32]

The isotopic fingerprint can be utilized for identification of (1) a presence or absence of interformational communication and active cross-flow; (2) an origin of migrating gas along vertically oriented conduits such as strikeslip faults, microfractures induced by overpressure ruptures, breccia pipes, halokinetic fracturing and faulting, etc.; (3) a probable source of the migrating gas; (4) a probable rate of migration which should be high if no significant mixing and chemical or isotopic modification is observed; and (5) a mixing ratio of not co-genetic gases in case of slow rate of migration or diffusion trough semipermeable overburden.

In depleted reservoirs, water from another formation or horizons may invade through the original vertical open conduits to equalize the hydrostatic pressure. Such open conduits may also provide pathways for escaping the EOR injection fluids or hazardous wastes.

Certain early indicators of fluid leakage may require in-depth study before implementation of an EOR process in an area. The leakage may manifest itself through oil and gas pockets in drilling mud above the target HC reservoir; methane bubble plumes; dry exhalations of methane and other gases above an HC pool; methane-rich mineral springs; oil seeps; and soil-gas anomalies. Most of these symptoms can be observed at the surface but only before depletion of reservoir pressure. Few methods can actually provide evidence of fluid migration in subsurface. Recent advances in applied petroleum isotopic geochemistry[30] provide a powerful tool which begins finding its practical application in the petroleum industry.

Numerous reported cases of leakage between two aquifers identified on the bases of studying the relationship of stable isotope ratios were reviewed.[1] The relationship between stable isotope

contents of fluids sampled from two interconnected reservoirs or aquifers normally defines straight lines of mixing between the representative points of the two end members.

Each drop of chemically pure water is a mixture of 6 isotopes of oxygen and hydrogen ($^{3,2,1}H_2$ $^{18,17,16}O$). In fact, dissolved substances increase the actual number of isotopes available for investigation in oil-associated formation waters. In two- or three- phase systems (oil, gas, and formation water), the number of combinations increases greatly because the isotope ratios can be examined in different chemical components of each phase. This fact provides opportunity for more reliable identification of fluid mixing and their migration paths within and between horizons in natural and man-induced hydrodynamic systems.

In general, oxygen and hydrogen isotopic composition of oil field brines collected at different locations of a number of U.S. sedimentary basins varies in a broad range between the basins and within individual basin [33-34] (table 1). These wide ranges of isotopic data indicate that reported isotopic compositions represent different dynamic regimes. Fractionation processes may result, for example, from isotopic exchange between oil-associated brine and reservoir rock which promotes a unique composition in different reservoirs of the same basin. It is more probable, however, that isotopic differentiation within individual basins mostly results from different origin and mixing of reservoir fluids rather than the rock-brine isotopic interaction because rocks normally do not contain hydrogen for exchange (except hydrous minerals and hydroxides).

TABLE 1. - Isotopic composition of oil field brines from the North American basins (modified from Montgomery and Perry, 1982)

Basin samples	$\delta^{18}O/^{16}O$ ‰	$\delta D/H$ ‰	Number of samples
Illinois	-10 to +4.5	-85 to +8	35
Michigan	-13.5 to +4.5	-110 to -25	24
Gulf Coast	+2.5 to +9.0	-13 to +18	10
Alberta	-12.5 to +3.0	-120 to -50	8

According to the working hypothesis adopted in this project, the formation fluids which are compartmentalized in isolated and often overpressured hydraulic systems should possess generally similar chemical and isotopic characteristics within a comparted system. The differences in fluid origin and specific isotope fractionation processes should lead to a distinct isotopic composition in such systems. Calcite is probably the dominant solid phase in oxygen isotope exchange because it is widely distributed and rather rapidly dissolved.[33] A subtle difference in isotopic composition between two samples taken from different depths but closely similar geographic position can be caused by fractionation processes such as ultrafiltration through semipermeable shale membranes. The sign of the difference in a pair of samples indicates the direction of cross-formational flow in that local area. Based on that principle, a downward movement of formation water was postulated on the Gulf Coast, in the Michigan Basin, and on the north flank of the Illinois Basin, but upward in the deeper part of the Illinois Basin.[35] Upward and out of the basin movement of fluids was indicated in the Alberta Basin by isotopic composition of lateral pairs of samples. Recharge from the west into the Alberta Basin appeared to be blocked by a fault zone. In many cases, however, no measurable lateral effect was observed.[35] Stronger vertical than lateral isotopic fractionation effect in tectonically undisturbed areas may have resulted from dominantly stratiform arrangement of most clastic reservoirs. Accumulating evidence indicates that deep saline groundwaters have migrated for long distances across the North American midcontinent with suggested flow rates of about 33 ft/yr redistributing hydrocarbons, forming metallic ores, and diagenetically altering sediments.[36] Isotopic fractionation of formation waters during subsurface migration due to geochemical processes such as precipitation or recrystallization has been extensively studied. Tracing the migration of hydrocarbons and methane by their isotopic composition is based on the assumption that the composition is related to hydrocarbon origin and that no appreciable isotope fractionation has occurred during migration.[32,37-38]

A break in continuity of a confining layer, which may be of depositional, erosional, tectonic, or physical nature (ruptures), will promote interreservoir migration of fluids. Such flow should manifest itself in chemical and isotopic anomalies in the area of an open flow path. The absolute values may not give usable results; however, relative differences expressed as percentages of variations and calculated as suggested by Vuataz et al.[39] may reveal small positive or negative variations indicating crossformational fluid movement.

Mobility of gases in a three-phase reservoir system is greater than that of oil and associated formation water. Therefore, the natural and man-induced paths for fluids in the subsurface can be best identified by monitoring changes in chemical and isotopic composition of hydrocarbon and non-hydrocarbon gases. In some cases, the isotopic techniques are the only available technique

capable to distinguish between chemically identical molecules of C_1,C_{1+}, CO_2, H_2S, or N_2 from different sources.

Evidence of methane plumes near the surface (in water wells, surface waters, and soils) calls for application of quantitative tools suited for identification of gas origin and reconstruction of its migration paths. Isotopic fingerprints of molecule components, such as carbon-13 and deuterium in methane or sulfur-34 and deuterium in hydrogen sulfide, are diagnostic in distinguishing a reservoir gas from genetically different shallow occurrences. Relative changes in isotopic composition enable quantitative estimation of proportions of mixing fluids.

It is believed that colloidal-size gas bubbles are readily displaced upward by the surrounding water at rates up to several millimeters per second and thus can relatively quickly ascend hundreds or even thousands of feet.[40] Natural gas ascending primarily through networks of joints and bedding planes[41] can rapidly develop soil hydrocarbon anomalies over repressurized or newly filled gas storage reservoirs which rapidly disappear after the reservoir is depleted.[42-43] Price[44] developed the concept of vertical ascension of ultra-small (colloidal size) gas bubbles through a network of interconnected, groundwater-filled microfractures. Hydrocarbons with carbon number greater than C_{5+} may not be present in significant amounts in soil gases because those hydrocarbons are liquid at near-surface temperatures and pressures and do not have the required buoyancy to migrate to the surface by the microseepage mechanism.[44] In such a case, the chemical composition of near surface gases may mimic shallow biogenic gas and only the isotopic composition (ratios of $^{13}C/^{12}C$ and $D/^{1}H$) may reveal their actual source and mixing proportions with shallow biogenic gas. Chemical and isotopic composition of associated non-hydrocarbon gases such as CO_2 or H_2S may be of valuable assistance in geochemical modeling of such a system.

Recommendations for analytical reliability of different laboratories specializing in stable isotope ratio analyses (SIRA) and natural radioactive isotopes have been sought. Laboratories specializing in isotope analyses were preselected based on recommendations of their clients. Three of the laboratories (Krueger Enterprises, Inc. - Geochron. Laboratories, ChemPet Research Corporation, and Global Geochemistry Corporation) were contacted for comparison of offered services, detection limits, analytical accuracy, sampling requirements, and price schedules. This information is crucial for realistic planning of suggested Phase II of the SGP43 project.

Successful Applications of Isotopic Techniques for Solving Leakage Problem: Selected Examples From Aquifers

A number of cases exemplifying the application of isotopic techniques in hydrogeology were previously reviewed.[1] A study by Wallick et al.[45] was based on oxygen-18, deuterium, tritium, and sulfur-34 isotopes and brought specific and practically important answers to the hydrochemical and hydrodynamic problems involved in accessement of the environmental impacts of oil sand mining in Alberta, Canada. Relationships between stable isotopes of oxygen and deuterium and between deuterium and chloride clearly indicated effective isolation of two aquifers of concern in the mining area. Normally, the relationship between stable isotope content of water sampled from two interconnected aquifers defined straight line of mixing between the representative points of the two end members.

The case of the South Australian aquifers reported by Ramamurthy and Holmes[46] provides good insight into the capability of isotopic methods. Subsurface seepage between two aquifers was identified and quantified in that study by the hydrochemical and environmental isotopic techniques. The investigated area is characterized by two aquifers: the upper, unconfined aquifer of highly saline water and a lower, confined aquifer of comparatively low salinites, which is tapped for irrigation. Part of the lower aquifer is showing trends of increasing salinity in recent years presumably as a consequence of induced vertical seepage from the unconfined aquifer. Recharge to the aquifers from two rivers has been observed to occur across an inferred fault zone. Horizontal seepage and recharge from a fresh water lake was inferred by flow net analysis based on potentiometric heads and pumping tests. Results of numerical modeling, however, based on these data did not match the observed configuration of poteniometric contours.

Additional study involved hydrochemistry and environmental isotopes such as the uranium series, deuterium, and tritium. The two aquifers could not be distinguished on the basis of their hydrochemical nature. The isotopic composition, however, confirmed their hydrodynamic inter-communication. Fairly uniform deuterium content (δD = -21.4 to -29.1 ‰) excluded significant recharge (leakage) of water to the aquifers from isotopically heavy Lake Alexandrina (δD = -39 ‰) except one well where the evident leakage of the lake water only to the upper unconfined aquifer was revealed (δD = -10.2 ‰). The lower, confined aquifer, however, remained unaffected (δD =- 24.9 ‰). This implies that there is no hydraulic connection between the two aquifers in the area of that particular well and as a consequence there is no vertical seepage. In this case study, the stable isotope data added quantitative aspect to the hydrodynamic modeling of the aquifer system.

Selected Examples From Hydrocarbon Reservoirs

According to Hirner[47] a recent study in Germany, concerning the distribution of stable isotopes and trace elements, helped enormously to improve previous hypotheses on the origin and hydraulic connections between different groups of oils in the German Molasse sediments. Triassic oils are isotopically lighter than those in the Jurrasic and Tertiary sediments. All the oil groups are clearly separated because of their distinct stable carbon isotope composition.

Alekseyev[29] in his analysis of reservoirs across the USSR defined three ranges of $\delta^{13}C$, associated with the means by which gases formed: biogenic zone, -55 to -95; transition zone; -55 to -65; and thermogenic zone, -36 to -58. Isotopic composition of gases in the transition range strongly indicates mixing of gases from different genetic sources. The 10 largest gas fields in the world produce from Neocomian and Cenomanian complexes of the West Siberian basin east of the Ural Mountains. Isotopic and other geochemical indicators suggest that hydrocarbons in Neocomian reservoirs were generated by thermal maturation of organic matter, while methane in the Cenomanian section appears to be a combination of thermogenic and biogenic gas.[48] Urengoy field (the largest gas field in the world with reserves estimated at 286 tcf) contains 12 geochemically isolated gas and condensate reservoirs in the Neocomian section. The overlying Cenomanian section, (containing 218 tcf of reserves), is hydrodynamically connected across the length of the field, in part by channel sands. Yamburg field, (the second largest field in the world with 170 tcf in gas reserves), is a single, massive, hydrodynamically connected reservoir.[48]

Prosolov et al.[49] provided stable isotope data for about 40 gas fields of West Siberia including such super-giants like Urengoy and Yamburg gas fields. They documented two isotopically distinctive groups of natural gases; those in the Upper Cretaceous and those in the Lower Cretaceous, which appear to have formed in two separate gas kitchens. They are not in vertical hydrodynamic contact because the carbon of the methane of the Upper Cretaceous Cenomanian gas is isotopically light: the average value of $\delta^{13}C$ being -45 and -50 ‰. Most pools have values between -45 and -50 ‰. The methane of the Lower Cretaceous Neocomian gas is heavier at -39.7 ± 4.6‰.

Distribution of isotopic ratios of carbon in gases from the Lower and Upper Cretaceous reservoirs indicates horizontal hydraulic communication between some of the reservoirs. For example the Upper Cretaceous horizons of the Urengoy, Zapolyar, Medvezh, and Sever (North) Urengoy are characterized by similar isotopic composition ($\delta^{13}C$ = -47.5 to -50 ‰) and seem to be

horizontally in hydraulic contact. The gas in adjacent Urengoy field is significantly lighter and indicates impairment of horizontal hydraulic communication with other gas reservoirs in the region.

An interesting application of isotopic data to identification of gas leakage from underground storage reservoirs in Illinois was provided by Coleman et al.[43] Their data suggest that in areas where bacteriogenic methane occurs in the near-surface aquifers, isotopic analysis of methane can be used to distinguish this gas from gas that has leaked from underground reservoirs and/or from distributory pipelines. Bacteriogenic methane has $\delta^{13}C$ value in the range of -64 to -90 ‰, whereas the pipeline and reservoir gases have had values in range of -40 to -46 ‰. The underground storage of pipeline gas was attempted in the Middle Ordovician St. Peter formation in three storage areas at depths of about 2,000 ft. The integrity of the confining layer had been in question, and the system was sampled for chemical and isotopic analysis (table 2). Isotopically light biogenic methane has been naturally generated near surface in glacial drift deposits in the area, and the gas commonly appeared in the shallow aquifers tapped by numerous water wells. The injected pipeline gas had $\delta^{13}C$ values in the range of -40 to -46 ‰. A distribution of isotopic composition of methane in samples collected from the aquifers and from gas storage reservoirs in the three underground storage locations clearly indicates (1) no crossformational gas leakage in the first area (Fig. 4); (2) the obvious leakage of the stored gas upward to the shallow aquifer in the second area (Fig. 5), with the highest concentration of leaking gas located directly over the injection area; and (3) a partial leakage, estimated for 15 to 65 % of the injected gas in the aquifer gas in the third area (Fig. 6).

The isotopic data cast new light on safety and economics of the project, and the storage of natural gas in the St. Peter formation was discontinued. The gas was withdrawn from units overlying the Galesville Sandstone and safely reinjected into the deeper and non-leaking Mt. Simon formation.

Based on the chemical data alone (table 2) it would normally be concluded that the gas in the water wells is of bacteriogenic origin and is unrelated to the storage reservoir, because the heavier hydrocarbons were obviously removed as the gas migrated upward

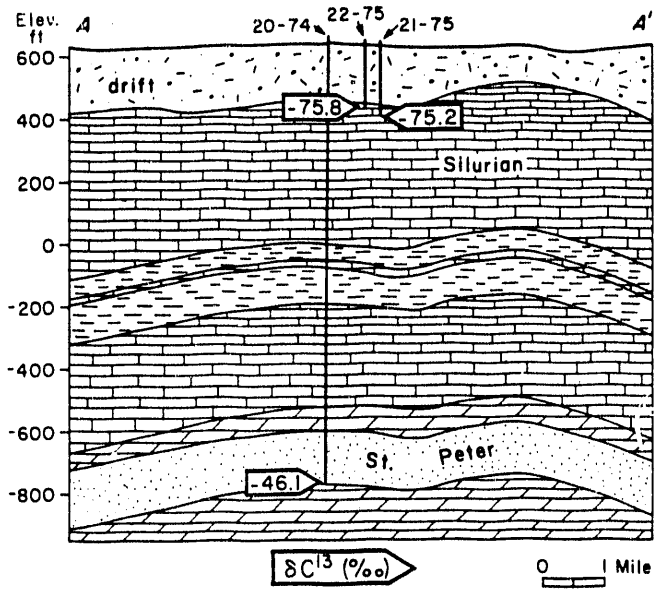

FIGURE 4. - Isotopic composition of methane in samples from Crescent City Project area, Illinois. St. Peter sandstone is well confined in this area and no gas leakage to shallow aquifers is indicated by isotopic data. The gas recovered from water wells is isotopically light and indicates its local biogenic origin (after Coleman et al.[43]).

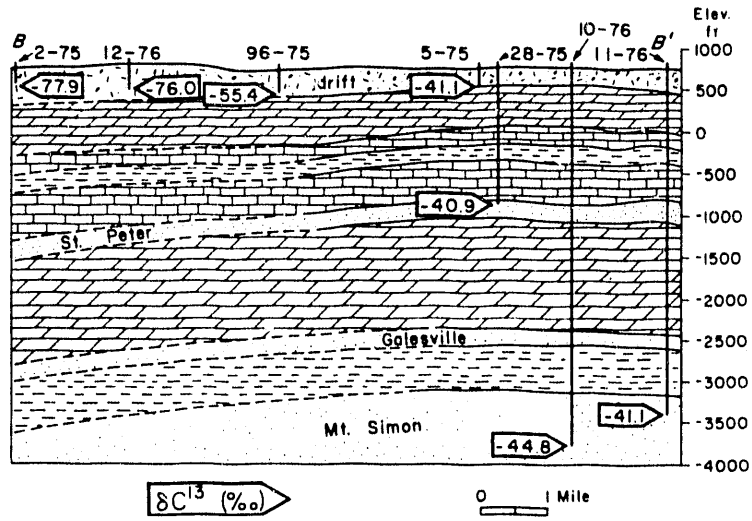

FIGURE 5. Isotopic composition of samples from near the Manlove Project, IL. Shallow water well No. 5-75 contains gas which has identical isotopic composition as that injected to the deep St. Peter sandstone. Gas in well No. 96-75 is probably a mixture of the injected and biogenic gas. Gas in wells No. 2-75 and 12-76 is of shallow biogenic origin (after (Coleman et al.[43]).

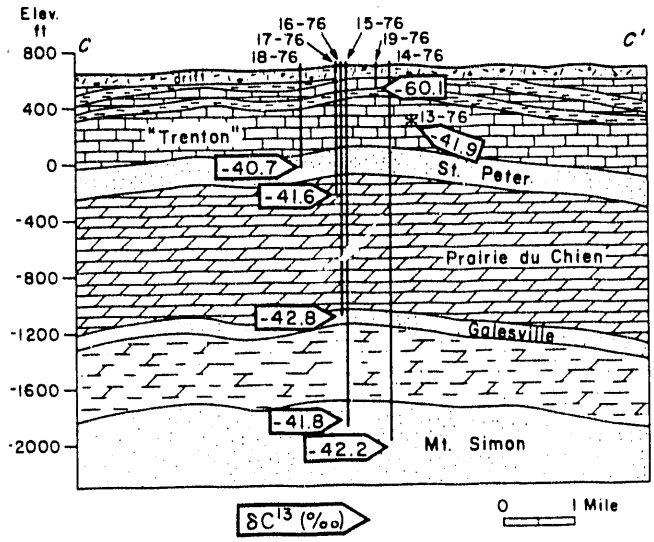

FIGURE 6. - Isotopic composition of samples from the Herscher Project, IL. Gas in water well No. 19-76 contains between 15 and 65% of leakage gas from the Gallesville sandstone (after Coleman et al.[43]).

from the St. Peter Sandstone to the surface.[43] Possible mechanism for such a removal of certain fractions from ascending fluids was discussed earlier in this text after Price.[44]

The isotopic analyses of natural gases in Po Basin, Northern Italy provided evidence for hydraulic isolation and different source of gas in three gas fields located less than 4 miles apart.[50] Collecchio field produces isotopically light bacterial gas ($\delta^{13}C$ = 76.3 ‰) from depth of 560 ft, whereas a dry thermogenic gas is being produced in Vigatto field ($\delta^{23}C$ = -42.3 ‰) from depth of 1,942 ft and in Medesano field ($\delta^{13}C$ = -44.1 ‰) from depth of only 460 ft. Chemically the Medesano gas resembles almost exactly the shallow gas from the adjacent Collecchiano field, and one would clearly assume a bacterial origin for both gases. The authors[50] relate the vertical migration of thermogenic Medesano gas from greater depth to strong faulting in the area close to the Apennine overthrust frontier. The tectonic related migration paths must remain open for active flow to keep the shallow gas isotopically heavy.

The modern isotopic pore fluid composition of a number of the North Sea Brent reservoirs in the Bergen High area is incompatible with diagenetic models based on flushing of the Brent aquifer by hot saline water expelled during compaction.[51] Produced formation waters largely composed of entrapped meteoric water are less saline than sea water (about 10 g/L Cl^-) and have negative

oxygen and hydrogen isotope composition: $\delta^{18}O$ = -1.5 to -2.3; δD = -32 to -33. Significant hydrocarbon and compaction fluid may have initially bypassed Brent traps along faults with ineffective seals that later evolved into effective seals with continued Tertiary burial.[52]

Quantitative hydrodynamic reservoir modeling based on geochemical/isotopic and other evidence of fluid migration in a system require, however, more systematic methodological study. Such a methodological study, involving interdisciplinary effort and based on specific field results, is being proposed for Phase II of this project in addition to the field demonstration of the method in a selected oil/gas reservoir.

TABLE 2. - Chemical and isotopic composition of pipeline gas injected into St. Peter, Galesville, and Mt. Simon sandstones in Illinois and the composition of methane from shallow aquifers. Chemical composition is not necessarily diagnostic in distinguishing between gases from different sources, while the isotopic composition clearly identifies the pipeline and biogenic gases as well as their mixtures due to leakage (after Coleman et al. 1977 [43]).

Sample number	Type of well	Depth in feet	Material	CH_2 (%)	C_2H_6 (%)	C_3H_8 (%)	C_4H_{10} (%)	$\Sigma C_{n>3}$ (%)	δC^{13} (‰)
Crescent City Reservoir Area									
21-75	water	225	Silurian ls	100	nd	nd	nd	nd	-75.2
22-75	water	193	Silurian ls	100	nd	nd	nd	nd	-75.8
20-74	gas	1,399	St. Peter SS	94.7	2.6	0.4	0.1	2.2	-46.1
Manlove Reservoir Area									
2-75	water	162	glacial drift	100	nd	nd	nd	nd	-77.9
12-76	water	284	glacial drift	100	nd	nd	nd	nd	-76.0
96.75	water	286	glacial drift	100	nd	nd	nd	nd	-55.4
5-75	water	205	glacial drift	100	nd	nd	nd	nd	-41.1
28-75	gas	1,554	St. Peter SS	94.9	3.9	0.9	0.3	nd	-40.9
10-76	gas	(2)	Mt. Simon SS	95.1	2.2	0.4	0.2	2.1	-44.8
11-76	gas	4,142	Mt. Simon SS	94.1	2.9	0.5	0.2	2.3	-41.1
Herscher Reservoir Area									
19-76	water	112	Ft. Atkinson (Divine) LS	99.2	0.7	0.1	nd	nd	-60.1
18-76	gas	705	St. Peter SS	94.4	2.9	0.5	0.2	2.1	-40.7
17-76	gas	905	Prairie du Chien Group	95.2	2.6	0.4	0.1	1.7	-41.6
16-76	gas	1,774	Galesville SS	93.2	2.5	0.4	0.1	3.8	-42.8
15-76	gas	2,568	Mt. Simon SS	94.2	2.8	0.5	0.2	2.3	-41.8
14-76	gas	2,665	Mt. Simon SS	92.8	3.3	0.5	0.2	3.2	-42.2
13-76	gas	(3)	Galena (Trenton) Group	94.1	32.0	0.5	0.2	2.2	-41.9

nd = not detected

Candidate Reservoirs for Field Demonstration of the Isotopic Method

Powder River Basin Oil Prolific System, Wyoming

A broad-scale study of fluid intercommunication may be considered for major oil-bearing horizons in the Powder River Basin in Wyoming and Montana; namely, the Fall River-Lakota, Muddy, Frontier, Shannon, Sussex and Teapot formations. Tectonic discontinuities and large breccia pipes may provide conduits for extensive fluid exchange between these HC productive horizons in the Powder River Basin.[2] Several geochemical anomalies have been recorded in the general area. Their origin and magnitude, however, were neither specified nor quantified, and their influence on oil production remains unknown. Isotopic techniques seem to be well suited for this purpose. Such a study may be suggested as an expanded version of the proposed Phase II of the project, and it would encompass a number of prolific reservoirs in the region including Teapot Dome Naval Petroleum Reserve No.3 (NPR-3) oil field of national strategic importance.

Field application of the stable isotope techniques for solving specific reservoir problems in the deca- and hectometer scales is primarily being considered for Patrick Draw, Teapot Dome NPR -3, and Big Muddy oil and gas fields in Wyoming, and Elk Hills NPR-1 and Buena Vista NPR -2 fields in California.

Patrick Draw Field

A possibility of horizontal compartmentalization and vertical leakage of fluids through open conduits in the multireservoir system of the Upper Almond formation in Patrick Draw field is strongly indicated by anomalous pattern of an original distribution of fluids revealed in the course of this study and NIPER'S base program (BE1 Project) by the analysis of the initial production (IP) data and by geochemical information.[53-54]

One powerful tool that can provide valuable data to substantiate the hypothesis of vertical cross-formational flow is isotopic analysis. Geochemical isotopic analysis of carbon-13 and deuterium in the hydrocarbon gas produced from different horizons (UA-8, UA-6, UA-5, and Fox Hills) and in different areas of Patrick Draw field could cast new light on the connectivity of the system and help to design a more effective method of stimulated oil production. Most wells produce from individual horizons, and the gas samples for stable isotopes can probably be collected at selected wellheads. A reconnaissance of Patrick Draw field in Sweetwater County, Wyoming (Oct. 1990) provided an opportunity to estimate field conditions for sampling of reservoir fluids at the wellheads if such a study would be considered feasible for the Almond

formation in Patrick Draw field. A good opportunity now exists for sampling the formation fluids. A new gas well was completed in early October, 1990 (in Sec. 34-T19N-R99W). The UA-5 interval was perforated at 4,180 to 4,200 ft in this well. Other new wells are planned to define better the gas cap in the UA-5 horizon. Several wells produce natural gas from the UA-8 sandstone which normally lies about 70 ft beneath the UA-5 and UA-6 horizons in Patrick Draw. The UA-8 sandstone thickens eastward to an approximately 200-ft sequence of gas-producing barrier island facies (predominantly foreshore facies) at depths of 10,000 to 12,000 ft in Table Rock field. Local high gas production (9,500 Mcf from well 1 in Sec. 8 - and 2,264 Mcf from well 1 in Sec. 5 T19N-R98W) from the Fox Hills formation, which lies 800 to 1,200 ft above the Almond formation, may suggest that gas migrated through the Lewis Shale formation to overlying horizons. There are no other known hydrocarbon accumulations above the Almond formation in the Patrick Draw area; however, a distinct soil gas anomaly has been reported above Patrick Draw field.[55]

Certain kinds of EOR operation may not be appropriate in this system if hydrodynamic communication exists between the Upper Almond productive horizons and possibly between other formations. The communication may take place laterally and vertically through continued permeable media (sandstone bodies), bedding planes, fault planes, fractures, or their combination. A CO_2-EOR project is being considered the Union Pacific Resources Co. in Patrick Draw field.

According to a recent regional study performed by Amoco in the Greater Green River Basin,[7] geochemical and other data such as oxygen isotopes, total dissolved solids, water resistivity, and pressure-depth profiles for the general area of the Red Desert and Washakie Basins (where Patrick Draw field is located) suggest that at depths of 9,000 to 12,000 ft the Upper Almond and the Main Almond are two distinctly separate reservoirs (Fig.7). Their results, presented on the plot of $\delta^{18}O(H_2O)$ vs. total dissolved solids (TDS) of the associated formation waters, however, also indicate (although not interpreted that way by the authors) a possibility of local mixing of formation fluids between the Lower ("Main") and Upper Almond reservoirs. Supplemental isotopic investigation would be recommended in the area where oxygen isotope signature of water samples from both horizons is close to -6 ‰ (Fig.7). The regional hydrodynamic pattern may not be valid in field-wide and interwell scales.

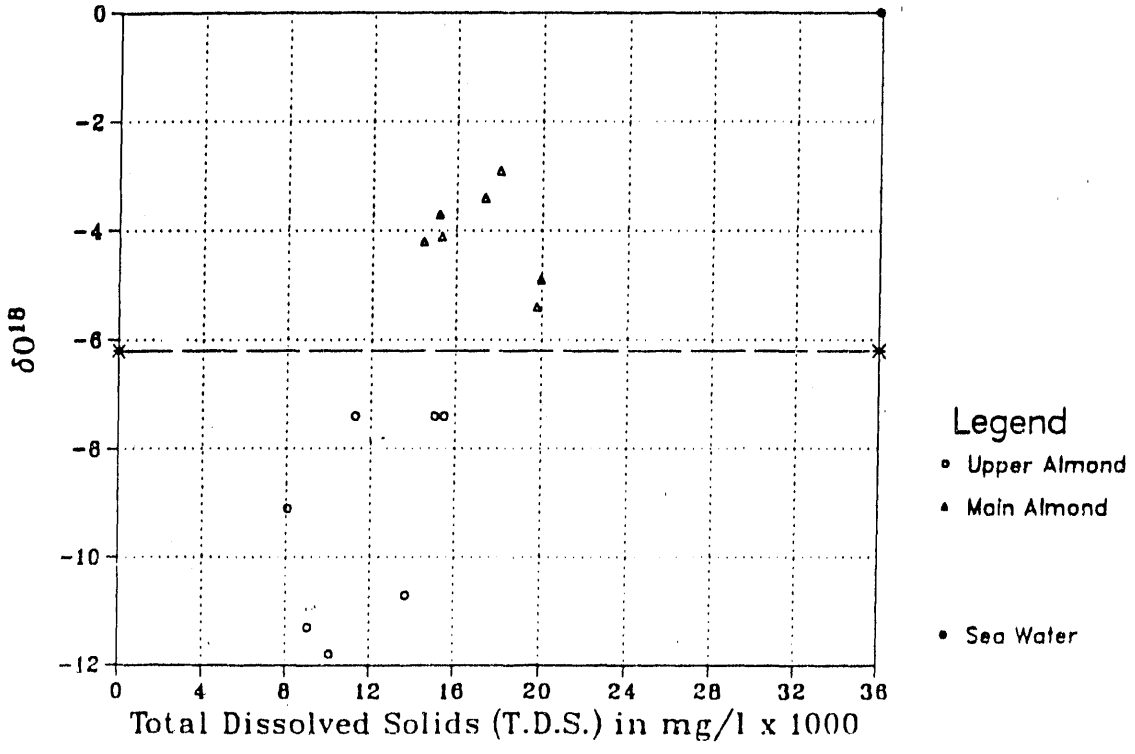

FIGURE 7. - Plot of $\delta^{18}O$ (H_0O) vs. TDS showing general distinction between comtemporary formation waters in dominantly marine Upper Almond (isotopically lighter) and dominantly continental Main Almond (isotopically heavier) which clearly suggest hydraulic separation of the two reservoirs. Samples closest to the isotopic "division line" (-6‰), however, may indicate a tendency for local leakage between the Main and Upper Almond. Formation water salinity and isotopic composition in both horizons clearly indicate a significant admixture of a non-marine component (modified from Meshri and Walker[7]).

Studies of geochemical anomalies in the Patrick Draw field area which manifest by much lower than expected water mineralizations (TDS) and compositional heterogeneity at depths below 4,000 ft,[54] and which expand downdip to at least 12,000 ft at Table Rock and other reservoirs,[7,54] should throw new light on the hydrodynamics of the region. More specific isotopic investigation of hydraulic interconnections between different horizons of the Upper Almond formation and the adjacent hydrocarbon-bearing formations in Patrick Draw field is of vital importance before selection and implementation of an EOR process at depth of nearly 5,000 ft and in a few square miles of the Monell Unit .

Further study is needed to substantiate the available regional observations and the field-specific geologic and geochemical data with engineering data in Patrick Draw field (current BE1 project) to design a fluid sampling program in different productive horizons located several hundred feet apart for examination of their stable isotope and chemical composition (suggested Phase 2 of the SGP project). Isotopic techniques supported by conventional geochemical data (which also need to be acquired) seem to be well suited for this purpose and should work well for EOR by defining the migration paths and the origin of gaseous hydrocarbons in Patrick Draw / Table Rock oil and gas system.

Teapot Dome Field: NPR-3

The tectonically shattered Shannon formation producing oil at Teapot Dome (WY) oil field, Naval Petroleum Reserve No. 3, may pose some problems for the DOE-sponsored steamflood expansion project which started there in October 1985.[56] Previous waterflooding in the upper Shannon probably failed because of communication between upper and lower sandstone branches.[57] Water breakthrough at producers occurred early in the steamflood pilot's life because of the fractured nature of the reservoir. Despite the inefficiencies caused by the formation's fractures and other heterogeneities, the north pattern flood has remained economic. The south pattern, however, produced only an unsatisfactory 20,000 bbl of incremental oil from steaming.[56,58,59] The potential for interformational cross-flow in decameter, hectometer, and possibly even larger scales is very high in the Teapot Dome NPR-3 because of strong tectonization of this general area of Salt Creek anticline. Geochemical evidence for fluid cross-flow between the upper and lower Shannon sandstones through nearly 30-ft-thick fractured marine shales can be observed in Shannon outcrops on the western side of the Salt Creek anticline about 5 miles northwest of Teapot Dome field.[60]

Evidence for cross-formational flow commonly is observed by field geologists in studied outcrops and reservoir cores. Fractures healed by precipitate which is "foreign" to the formation in which it occurs, (calcite fill in fractured clastic sequences or crystalline quartz in fractured or vugged carbonates), provide clear evidence that fluids oversaturated with respect to these minerals migrated into the formation after the rock was solidified, faulted, and fractured.

Examination of Shannon formation outcrops surrounding the Salt Creek anticline near Teapot Dome oil field (NPR No. 3) provides geochemical evidence that the formation was exposed sometime in its postdepositional history to hydrodynamic contact with fluids from at least three different external sources. Fractures cutting the Shannon's best productive High Energy Ridge

Margin facies (HERM) are filled with gypsum on the western side of the anticline, with calcite on the northeastern side, and with silica on the southeastern side.[60] Very little is known about diagenetic cement in Teapot Dome reservoir cores. The Shannon formation contains no sedimentary evaporites such as anhydrite or carbonate, and silica normally precipitates from ascending hot deep-seated solutions. Relative time and probably origin of the precipitates can be estimated by stable isotopic techniques, e.g., considering ^{34}S and ^{18}O in $CaSO_4$; ^{13}C and ^{18}O in $CaCO_3$; and ^{18}O in SiO_2. Such an approach might substantiate diagenetic models and help to explain the secondary permeability distribution; however, it would probably not generate the principal answer required by geo-engineering, i.e., whether there is a potential for occurrence of cross-formational fluid migration at a time of hydrocarbon production or fluid injection into the reservoir. Isotopic composition of reservoir fluids migrating through the system is a primary target for identification of a current potential for cross-formational flow. The superiority of studying isotopic composition of fluids is in their potential to indicate the pathways for migration.

Teapot Dome field, NPR-3 may be considered as one of the promising candidates for the proposed geochemical/isotopic modeling of interformational flow in multireservoir systems.

Elk Hills Field, NPR-1 and Buena Vista NPR-2, CA

Reservoir data reviewed by NIPER in 1985 clearly indicated an importance of structural features on reservoir hydrodynamics and on distribution of hydrocarbons in the Elk Hills and Buena Vista multireservoir system. Production in Elk Hills is from two large en-echelon anticlines forming structural dome 17 miles long, 7 miles wide, and with closure of 450 ft. The western anticline is a relatively simple fold with no faults. The eastern anticline is cut by numerous normal faults. Four of the faults reach the surface. The hydraulic role of the faults is still unclear. The general problem of oil migration on the south flank of the Elk Hills Naval Petroleum Reserve No.1 was extensively debated in the late 1950s between the Department of the Navy, the Elk Hills District in Bakersfield, Calif., and the Bureau of Mines Petroleum Experiment Station in Bartlesville, Okla. (now NIPER). There was a strong indication that the edge water of the SS-1 sand of the Shallow Oil Zone might be in hydraulic communication with neighboring oilfields such as Railroad Gap, Asphalto, Buena Vista, and North Coles Levee. The Buena Vista oil fields (NPR-2), which are located 3 miles to the South, produce oil from the same SS-1 sand. Both fields are connected by a common aquifer. The aquifer pressure has been maintained since 1958 by water injection on the south flank of the field, although migration paths of fluids in the system remain unknown. The source of dry gas in the shallow Pliocene sand zones is also unspecified. Chemical composition indicates a different source and origin than that of the deeper gas. A detailed

geochemical analysis of the Elk Hills fluid system has never been completed, and there is need for identification of inter- and cross-formational flowpaths. Isotopic techniques are well suited for this purpose and may add much to the understanding of hydrodynamics of this economically and strategically important but geologically and structurally extremely complicated system.

Big Muddy Field

Production in Big Muddy field is primarily from the Second Wall Creek sandstone member of the Upper Cretaceous Frontier formation. There are three Wall Creek sandstones in the field. The upper and lower sandstones are unproductive and are separated from the middle Second Wall Creek sandstone by 20 and 30 ft, respectively. The reservoir characteristics for the Second Wall Creek sand and the DOE-sponsored EOR performance in Big Muddy field were reported.[62]

In Big Muddy field, an extensive leak between the Dakota and the oil-productive Second Wall Creek formations was previously indicated by chemical, geochemical, and radioactive tracer methods.[62] Tracer surveys and temperature logs indicated that injected fluids were migrating up-section, possibly along the annulus of old abandoned wells or within the prevailing fracture system. There also is an indication that the Second Wall Creek Sandstone may be in hydraulic communication with the Niobrara, Shannon, and other formations located nearly 2,000 ft apart. Fault interpretation in Big Muddy field was a controversial issue, and many of the original faults were omitted from EOR structure maps. Several arguments support the concept for highly tectonic reservoir, however, including the proximity to highly faulted reservoirs near the Laramie Uplift and the complexity of photo lineaments observed on Landsat imagery throughout the region.[61] Application of the stable isotope technique is recommended for identification of hydrodynamic intercommunication in Big Muddy field.

CONCLUSIONS

1. Effective, economic, and environmentally acceptable geochemical techniques for identification of active fluid flow through "vents" in confining layers of hydrocarbon reservoirs are being sought to improve the design of recovery operations and control of the injected fluids.

2. Partial hydrodynamic communication between productive horizons is a common and well documented phenomenon worldwide. It is conventionally identified in subsurface by expensive and time-consuming engineering methods. Occurrences of oil, gas, and brine seeping to the surface from reservoirs of great depths are also common. They usually document large scale fluid migration often through many thousand feet thick overburden.

3. Leakage of hydrocarbons between horizons through geologic discontinuities may negatively affect all production stages. It may intensify, though, in reservoirs subjected to high pressures during implementation of secondary and tertiary processes of recovery or subsurface storage of strategic hydrocarbon (HC) reserves.

4. It is concluded, based on the feasibility study and on the limited number of field applications reported by major U.S. and foreign oil companies (some of them being published after initiation of this project), that comparative analysis of the isotopic composition of reservoir fluids (hydrocarbons, formation water, and non-hydrocarbon gases) in multireservoir systems provides unique answers regarding hydrodynamics and sealing properties of the system. The emerging technique has been proved so far in a number of cases where identification of inter-formational cross-flow would be difficult and expensive by using conventional methods.

5. Potential is very high for the broad application by U.S. and state governments, and major oil companies of the innovative, reliable, safe, and economic technology utilizing a distribution of natural isotopes in formation fluids to identify a cross-formational flow (leakage) between hydrocarbon-bearing reservoirs.

6. The potential is highest for assuring compliance of drilling, injection, and abandonment practices with EPA requirements regarding hydraulic isolation of reservoirs from aquifers.

7. Isotopic evidence of cross-flow from oil reservoirs subjected to EOR processes is very scarce, primarily because of infrequent use of geochemical tools by producers for reservoir characterization. Difficulty in obtaining representative and uncontaminated samples of formatiom fluids from individual horizons is probably an additional factor.

8. Inter-reservoir migration and mixing of formation fluids in the areas of proven discontinuity or breakage are normally caused by deep fluid discharge through open faults and fracture systems, paleo-erosional surfaces cutting down through confining layers, or a rupture of confining layer due to natural or man-made build up of formation pressure in hydrodynamically closed systems, and substantial drilling and completion practices.

9. The stable isotopic compositions of reservoir gases in a stratigraphic profile is particularly indicative for cross-formational flow because mobility of gases through imperfect reservoir seals is greater than that of liquids.

10. The isotopic techniques involving distribution of naturally ocurring stable and radioactive isotopes in the system, primarily the ratios of hydrogen ($^{1}H/^{2}D$), oxygen ($^{18}O/^{16}O$), carbon ($^{13}C/^{12}C$), sulfur ($^{34}S/^{32}S$), chlorine ($^{37}Cl/^{35}Cl$), and strontium ($^{87}Sr/^{86}Sr$) are most prospective for identification of fluid cross-flow. Natural radioactive tritium (T), ^{14}C, and ^{36}Cl may serve as indicators of admixture of man-induced waters to the reservoir fluid system.

11. Comparing the isotopic composition of fluid sample pairs, taken from different productive horizons and from different parts of a reservoir, is indicative for seal efficiency (tightness or leakage of confining layers) in a stratigraphic section.

12. Relative differences in isotopic ratios between pairs of fluid samples can best be applied for identification of cross-formational flow in larger scales. Decameter and hectometer scales find best application in the interwell area (horizontally) and inter-reservoir area (vertically). Hectometer and kilometer scales are best applied to fieldwide and interfield hydrodynamic interpretations.

13. According to the working hypothesis adopted in this project, the formation fluids which are compartmentalized in isolated and often overpressured hydraulic systems should possess generally similar chemical and isotopic characteristics within individual systems. Differences in fluid origin and specific isotope fractionation processes should lead to a distinct isotopic composition between isolated hydrogic systems.

14. A break in continuity of confining layers, (which may be of depositional, erosional, tectonic, or physical nature), will promote inter-reservoir migration of fluids. Such fluid flow should result in detectable chemical and isotopic admixture anomalies in the area of an open flow path.

RECOMMENDATIONS

1. Identification of cross-formational flow using recent advances in geochemical and isotopic technologies substantially upgrades the quality of reservoir characterization. It is recommended in Phase II of this project to utilize isotopic correlation of formation fluids from multireservoir systems to further quantify hydrodynamic reservoir characteristics for enhancement of oil production.

2. A broad-scale study may be considered for major oil-bearing horizons in the oil prolific Powder River Basin, in Wyoming and Montana, namely, the Fall River-Lakota, Muddy, Frontier, Shannon, Sussex and Teapot formations where geologic and engineering sparce baseline data indicate cross-formational flow resulting in geochemical and production anomalies.

3. Field application of the stable isotope techniques for solving specific reservoir problems in the deca- and hectometer scales is being recommended for Patrick Draw, Teapot Dome NPR No. 3, and Big Muddy oil and gas fields in Wyoming, and Elk Hills NPR No. 1 and Buena Vista NPR No. 2 fields in California where geochemical and/or production anomalies were recorded.

4. Quantitative hydrodynamic reservoir modeling based on geochemical/isotopic and other evidence of fluid migration in a system require additional methodological study. Such a methodological study, involving interdisciplinary effort and based on specific field results, is being recommended as Phase II of this project in addition to a field demonstration of the method in a selected oil/gas reservoir.

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