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Predictions of Oil or Gas Potential by Near-Surface Geochemistry[1]

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ABSTRACT

Recent advances in surface geochemical prospecting have enabled age-old seep-detection technology to be used to determine the gas versus oil character of a potential fairway. Extensive field work has demonstrated that the chemical compositions of near-surface hydrocarbon soil gases, measured by flame ionization gas chromatography, are largely determined by the hydrocarbons in nearby underlying reservoirs. By using compositions and ratios of the light hydrocarbons, methane, ethane, propane, and butane, one may predict whether oil or gas is more likely to be discovered in the prospect area. Near-surface hydrocarbons are best represented by normalized histograms of composition data. These histograms are strongly correlative with those of reservoir gas and with compositions of gas from shows recorded in downhole mud logging. This correspondence with the actual formation gases suggests that the upward migration of reservoired light hydrocarbons into near-surface soils represents a viable mechanism, allowing surface geochemical exploration to be utilized for regional hydrocarbon evaluations.

Geochemical profiles over known production areas are shown for the Sacramento and San Joaquin basins in California and for the Utah-Wyoming Overthrust belt. Geochemical predictions were documented by subsequent drilling near the Pineview field in Utah. The data imply that the Pineview field should extend westward into an area containing a dry hole. In addition, a new gas discovery—on the intersection of a Landsat lineament and a large methane anomaly—was made 6.5 km (4 mi) northeast of the Pineview field by Amoco in 1981.

Most of the geochemical examples reported show direct anomalies over known fields. However, seeps can be laterally displaced in certain geologic settings. In addition, geochemical investigations indicate that seep magnitudes depend on tectonic activity to aid gas migration along faults and fractures, which appear to provide the major migration pathways. This fault association suggests that diffusion is of secondary importance.

Geochemical prospecting must be used with caution, and only in conjunction with geologic and geophysical tools, because the location and shape of many geochemical anomalies are governed more by the local tectonic structure of the region than by the position and shape of the actual deposit. Regional groundwater flow is less significant. Thus, geochemical prospecting, when used alone, cannot predict whether a particular soil-gas anomaly is associated with a commercial deposit. It can only be used to verify the presence of petroleum hydrocarbons and to predict whether gas or oil is likely to occur in a potential structure. Geochemical prospecting yields excellent regional evaluations of hydrocarbon potential.

INTRODUCTION

There is no older technology for finding petroleum than the use of near-surface seeps. Although the relationship between near-surface seeps (both macro- and micro-) and buried deposits is sometimes difficult to establish, Link (1952) clearly showed that macroseeps have a definite regional association with productive areas. In the early days of the industry, Thompson (1933) said that, "With the exception of some of the oil fields of the Eastern, Mid-Continental, and Rocky Mountain States of the U.S.A., practically all the great oil fields of the world were marked by oil and gas issues near the crest of anticlines or the apices of domes." DeGolyer (1940) reported that oil and gas seeps have resulted in the discovery of more oil and gas fields than has any other single method. According to Dickey and Hunt (1972), visible seeps are most common around the margins of petroliferous basins where the oil-bearing sediments crop out. Seeps commonly occur at the outcrop of a permeable rock unit that constituted an oil reservoir until the overlying impermeable stratum was breached by erosion or broken by tectonic activity. Wells drilled near seeps often discover reservoirs in deeper zones, either directly beneath the seep or downdip within the same stratigraphic interval. This is because seeps and their associated hydrocarbon reservoirs tend to develop in migration fairways, thus forming similar reservoirs in the same general area and stratigraphic interval. According to Pyre (1977), Gulf entered Kuwait and Italy on the basis of the presence of seeps. In the Burgan field of Kuwait and in Ragusa field of Sicily, the seepage was directly over the fields.

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This paper represents the contributions of numerous Gulf Oil Corp. personnel in the use of seeps in rational exploration programs. Credit for the original ideas must be given to A. J. Teplitz and J. K. Rogers, who attempted to use seep compositions as early as 1932. They achieved limited success with the technology available. Gulf's analytical capabilities were developed mainly by R. J. Mousseau, with assistance from J. G. McKelvey, J. C. Williams, R. T. Rupert, and T. C. Ashbaugh. The technique used to measure hydrocarbon gases in waters was developed by T. J. Weismann and T. C. Ashbaugh. Geologic mapping was provided by R. A. Hodgson, B. H. Mecham, and Ravi Venkateswaren. Early drafts of the manuscript were read by T. J. Weismann, R. J. Pirkle, M. D. Matthews, and W. C. Sidle, who provided numerous suggestions and valuable insights. Finally, special thanks go to Debbie Cushman, Vince Flotta, and Kathy Logan for drafting the figures.

The centennial issue of the *Oil and Gas Journal* (January 28, 1979) stated, "Drilling on oil seeps and trends is as good a way of prospecting today as it was then and down the years more oil has probably been found by the use of these simple principles than from all the new techniques of geology and geophysics combined." No reflection on the technical merits of the latest methods is implied.

Present-day exploration for oil and gas requires a coordinated effort based on all useful techniques of geophysics, geology, and geochemistry. Surface hydrocarbon prospecting is truly a direct detection technique in that it senses migrating hydrocarbon gases associated with prospective oil or gas pools. A seep not only proves the existence of a source, but it also implies that migration has occurred as recently as the age of the youngest sediments (Bernard, 1980). However, geochemical anomalies must be used with great caution because the shape and location of a surface geochemical anomaly are governed more by the local tectonic structure of the region than by the position and shape of the actual deposit. In addition, geochemical investigations have shown that the magnitude of seep anomalies depends on the tectonic activity and its influence on gas migration to the surface.

Extensive field work at Gulf Research and Development Co. (GR&DC) has demonstrated that the chemical compositions of near-surface hydrocarbon soil gases are largely determined by the hydrocarbons in nearby underlying reservoirs. That is, soil-gas signatures typical of oil seeps occur over oil fields, whereas seeps of slightly lighter or gassier composition occur over gas fields. Present geochemical methods cannot predict whether an anomaly is associated with a commercial deposit, because commercial is an economic definition. Geochemical prospecting can, however, be used to verify the presence of petroleum hydrocarbons and to predict whether oil or gas is likely to occur in a potential structure. Economics, on the other hand, must be determined by the drill and by conventional geophysical and geological mapping to estimate the dimensions of a potential trap.

The oil industry is entering an exploration phase in which stratigraphic traps will probably dominate. Today, both geologic and geophysical exploration are undergoing extensive refinement to develop techniques aimed at finding these stratigraphic, or nonstructural, accumulations. This paper points out some recent developments in surface geochemical prospecting that have given this age-old technology a new lift as it takes its proper place in exploration.

FREE OR ADSORBED GASES?

The idea of the soil-gas survey appears to have been reported at about the same time by Laubmeyer (1933) in Germany and Sokolov (1933) in the USSR. Sokolov (1933, 1971) showed experimentally that subsoil air over petroleum accumulations contains more abundant hydrocarbon gases than does subsoil air far from any oil or gas pool (Kartsev et al, 1959; Sokolov and Cheremisinov, 1971). Gulf's interest began in 1932 with a research project by Teplitz and Rodgers (1935) that involved the vacuum desorption of ethane from soil samples. The first literature on petroleum geochemical prospecting in the United States was published by Rosaire (1938, 1940). This was soon followed by publications by Horvitz (1939, 1969), Pirson (1960), Ransone (1947), and many others. Much positive evidence has appeared in the literature concerning geochemical case histories; an excellent summary was given by Davidson (1963). Scientists from the USSR have probably contributed more to the literature of soil-gas prospecting than any other group, and have reported extraordinary success (70%) in locating new oil and gas deposits by this method (Sokolov, 1971). For a more detailed and excellent summary of geochemical surface prospecting up to 1971, the reader is referred to McCrossan et al (1971).

The first geochemical surveys used the free gases (subsoil air) taken from a depth of 2 to 3 m (6.5 to 10 ft) (Kartsev et al, 1959; Sokolov, 1971; Sokolov et al, 1971). Later, hydrocarbons were removed from soil and rock samples by heating the sample in a partial vacuum at temperatures below 100°C (212°F). Early experiments suggested that only the loosely held hydrocarbons, representing a small part of the total amount present, were released by heat and vacuum. This led to an acid extraction procedure that has received considerable attention in the United States (Horvitz, 1939). Most of the work in the United States and Canada (Debnam, 1969) has been of this type, because it was anticipated that analysis for the adsorbed and occluded hydrocarbons would yield greater values than would analysis of interstitial air collected in situ. A second reason for using the soil-extraction technique was that samples could be collected in practically every area of the world, under widely varying conditions. For example, soil and sediment samples can be readily collected from water-covered areas, whereas soil air cannot be measured under water, or even in wet soils. However, hydrocarbons dissolved in ground water can be measured by well-established techniques (McAuliffe, 1966, 1971). Experience in handling groundwater samples has led GR&DC to develop techniques that permit hydrocarbon anomalies derived from both soil air and ground water to be used jointly in interpretation.

The early focus on desorption techniques was advocated primarily as a matter of convenience because soil cores were much easier to handle than soil gas. This was particularly true before the introduction of the portable gas chromatograph. Failure to recognize that the composition of soil gas was similar to the underlying reservoirs may be attributable to this emphasis on adsorbed gases rather than on free gases. This is particularly interesting because Sanderson (1940) pointed out the problem at the very outset and suggested that a return to the older method of using free soil gases might be simpler and more useful. Whether composition can be predicted from adsorbed-hydrocarbon data was not established during our study.

Early development of gas surveys was hindered also by lack of sufficiently precise and rapid analytical methods. Over the past 15 to 20 years, the gas chromatograph (for separating hydrocarbon compounds), coupled with the hydrogen-flame ionization detector (for measuring levels of these compounds in parts per billion) has been developed. Interest in surface geochemical prospecting at GR&DC was renewed in 1970 following development of a portable and sensitive gas chromatograph.

METHOD OF SOIL-GAS ANALYSIS

A diagrammatic representation of the GR&DC soil-gas sampling procedure is shown in Figure 1. Soil-gas measurements are made in a shallow hole, at least 4 m (13 ft) deep, which is generally auger drilled with a 8.9-cm (3½ in.) diameter auger. A packing device that also serves as a soil-gas probe is placed in the hole and inflated to isolate the bottom of the hole from the atmosphere. Soil gases are then pumped into a dual gas chromatograph for determination of light hydrocarbons, helium, and hydrogen.

Hydrocarbons are measured by a flame ionization detector (FID) coupled to a 1-m (3.3-ft) alumina column; helium and hydrogen are measured by a thermal conductivity detector coupled to a 3-m (9.85-ft) molecular sieve column. Both chromatographs contain a short precolumn and 10-port valve to aid selectivity, thus speeding up response time by keeping undesirable components out of the analytical columns, and to allow back flushing of the precolumn during analysis. Using these techniques, a sample can be analyzed every 7 minutes. Sensitivity for hydrocarbons is approximately 10 ppb; sensitivity for helium and hydrogen is near 5 ppm. Carbon dioxide is analyzed continuously by infrared techniques, with a sensitivity of 0.02%.

Soil gases are collected in an evacuated cylinder that can be returned to the laboratory for additional gas analyses (Fig. 1). This is currently used for mass spectrometer and carbon-isotope analysis of the soil gases. Occasionally hydrogen sulfide and radon are added to the list of gases measured.

Analysis of hydrocarbons is generally limited to methane, ethane, ethylene, propane, propylene, isobutane, and n-butane. Hydrocarbons heavier than n-butane are not typically measured, because of their extended elution times. Sample gas chromatograms for hydrocarbons are illustrated in Figure 2. The top-left chromatogram represents a typical background site in the San Joaquin basin in California; the top-right chromatogram represents a sample directly over the Lost Hills oil field.

RATIONALE FOR NONHYDROCARBON GAS MEASUREMENTS

Large helium anomalies are generally correlated with deep basement faults and are commonly a tectonic indica-

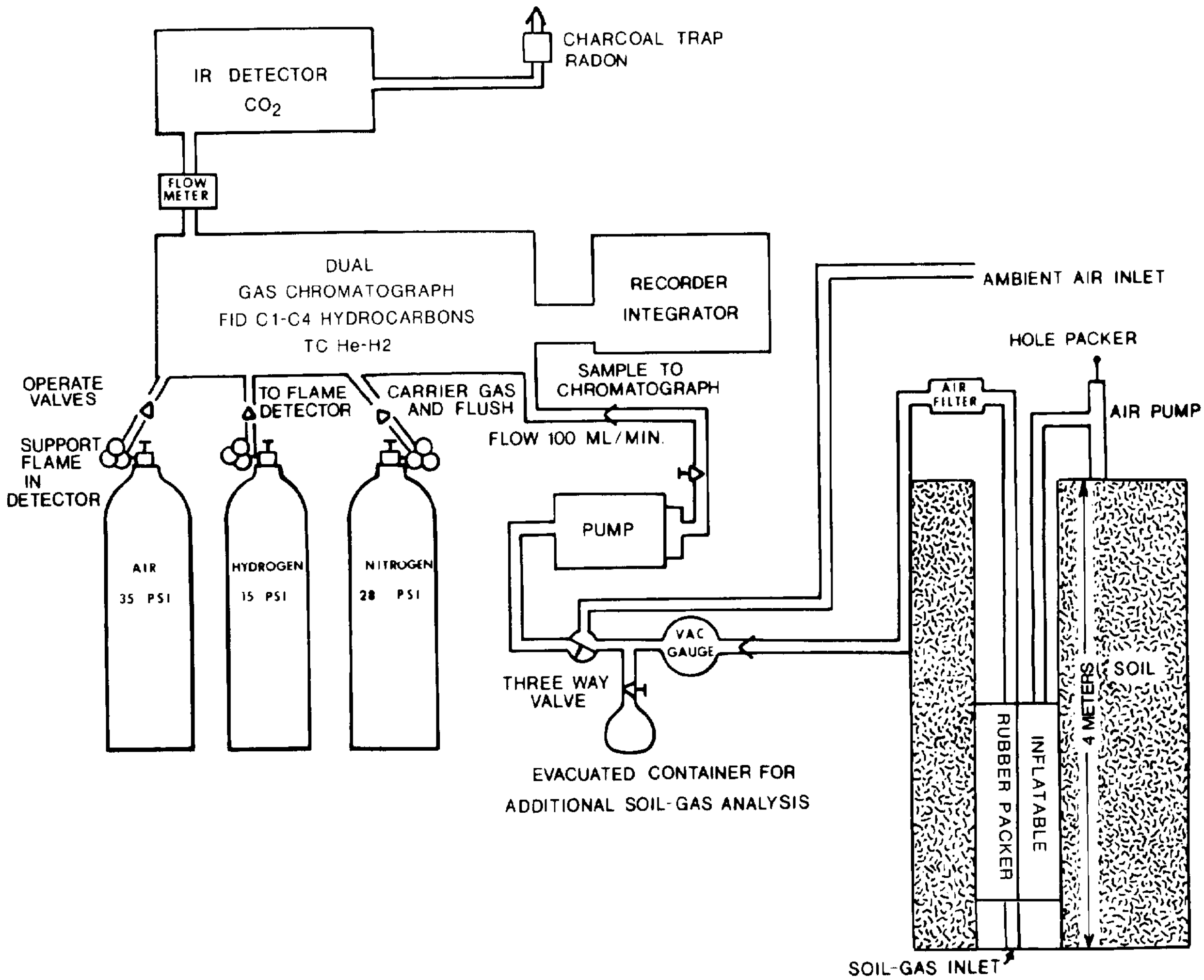

FIG. 1—Diagram showing procedure for soil-gas sampling and analysis.

tor. Helium anomalies are also associated with oil and gas fields, uranium deposits, and geothermal fields; therefore, considerable judgment is required to interpret helium data. Hydrogen has been documented as a petroleum indicator by Nechayeva (1968), who studied many

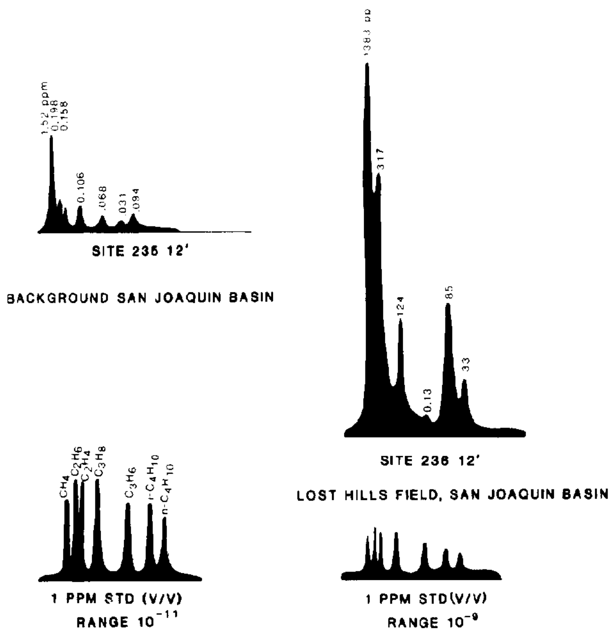

FIG. 2—Comparison of standard chromatograms [all components at 1 ppm (v/v)] with typical soil-gas chromatograms, San Joaquin basin. Output from log scale on integrator.

reservoirs in western Siberia. He noted that oil fields are distinguished by many more hydrogen occurrences, in all stratigraphic reservoir intervals studied, than are found in gas and gas-condensate fields. Hydrogen was observed in 18% of all gas fields, 27% of all gas-condensate fields, and 46% of all oil fields. Moreover, peak percentages of hydrogen in reservoir gases were 0.9% for western and northern gas fields, 6% for eastern gas-condensate fields, and 11.2% for oil fields.

Carbon dioxide measurements may prove useful to distinguish between reservoirs because the amount of carbon dioxide in known reservoirs varies appreciably. In addition, carbon dioxide can be formed by microbes in the near-surface oxidizing environment. The complexity of sources for these gases requires considerable knowledge of the geologic environment for proper interpretation.

FIELD EVIDENCE

Field observations are divided into two parts in this paper. The first part outlines the data base and demonstrates that near-surface soil gases have chemical compositions which are strongly correlative with those found in reservoir gas and in gas shows encountered while drilling wells. The second part consists of geochemical profiles that illustrate the strong relationship between fault and fracture systems and the larger seeps.

A map of major basins in the United States (Fig. 3) illustrates the regional coverage of the geochemical data base gathered from 1972 to the present; dots represent basins in which geochemical surveys have been conducted. The cur-

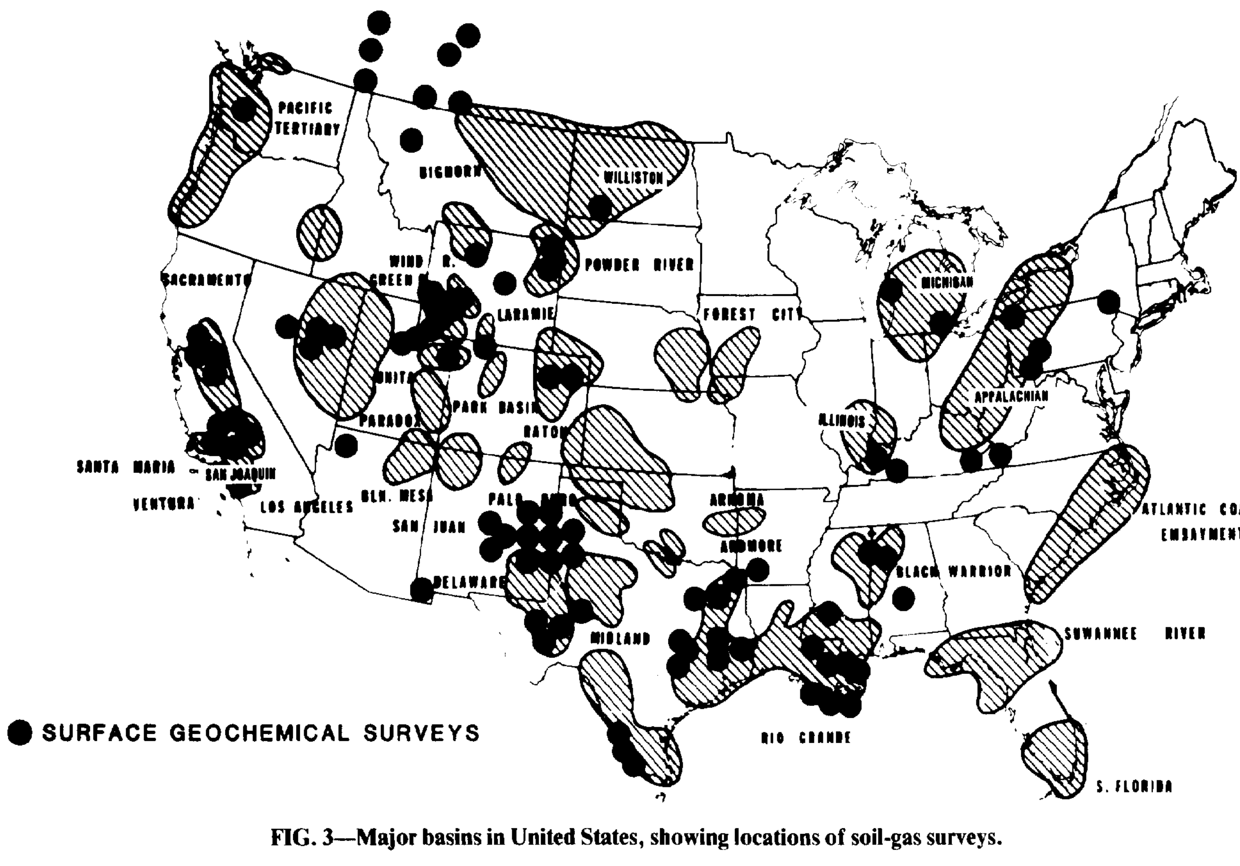

FIG. 3—Major basins in United States, showing locations of soil-gas surveys.

rent data base contains more than 21,000 measurements, covering approximately 16,000 line km (10,000 line mi) of geochemical data. Examples chosen are from the Sacramento and San Joaquin basins of California and the Pineview and Ryckman Creek areas of the Utah-Wyoming Overthrust belt.

Soil-Gas Composition

An empirically determined range of the soil-gas data is shown in Table 1. A small selection of surveys from the GR&DC data base is shown in Table 2. The geochemical distinction between gas- and oil-type basins was first noted from surveys in the Sacramento and San Joaquin basins in California. Surveys were conducted in 1972, 1974, and 1975 in these two basins, with excellent repeatability (Table 2). Surveys conducted in southwest Texas in 1975 supported the differences noted in California and implied that this technique might have wide application. Additional data on the oil versus gas predictions were obtained in 1976 when numerous surveys were run in all three types of productive areas—gas, gas-condensate, and oil.

Soil-gas data from the Sacramento dry-gas, Alberta gas-condensate, and Permian basin oil areas are used to establish statistically valid populations that demonstrate a close association with reservoir gases and gas shows in drilling fluids.

Table 1. Empirically Determined Composition Range for Soil-Gas Hydrocarbons over Different Reservoir Types

	$C_1/\Sigma C_n$	C_1/C_2	$(C_3/C_1) \times 1{,}000$
Dry gas	100-95	100-20	2-20
Gas condensate or oil and gas	95-75	20-10	20-60
Oil	5-50	10-4	60-500

Reservoir-Gas Analysis

Some typical percentages of methane and relative amounts of ethane through butanes in different types of deposits are given in Table 3. These data, taken from Katz and Williams (1952), show clearly that methane decreases in the trend from a dry-gas deposit to a typical low-pressure undersaturated oil deposit containing only dissolved gas but no gas cap.

A better demonstration of this relationship comes from the study by Nikonov (1971), who compiled gas-analysis data from 3,500 different reservoired deposits in the United States, Europe, and USSR, and grouped them into the populations shown in Figure 4. Gases from basins containing only dry gas (designated NG) contain less than 5% heavy homologs, whereas gases dissolved in oil pools (designated P) contain an average of 12.5 to 15% heavy homologs. The heavy homologs (Fig. 4) include ethane, propane, butane, and pentane. Although pentane is not included in this soil-gas study, similar histograms can be constructed from soil-gas data that use only methane through butanes.

Comparison of Soil Gases and Reservoir Hydrocarbons

Three of the near-surface data sets from Table 2 are particularly useful for this comparison because the soil-gas measurements were made in basins that contained only one type of production. They are the dry-gas Sacramento basin (more than 450 sites), the gas-condensate in the Alberta foothills (more than 650 sites), and oil in the Per-

Table 2. Average Compositions and Ratios of Light Hydrocarbons from Selected Soil-Gas Surveys

	Date	$C_1/\Sigma C_n$ (%)	C_1/C_2	$(C_3/C_1) \times 1{,}000$
Sacramento basin, dry gas	1972	95	55	6
	1974	95	49	8
	1975	94	55	11
San Joaquin basin, oil and gas	1972	82	8	46
	1974	84	7	61
	1975	82	8	56
Gas-condensate surveys				
Southwest Texas	1975	89	12	33
Western Overthrust	1976	90	11	30
Alberta foothills	1978	88	12	30
Oil surveys				
Uvalde, Texas	1975	77	5	77
Permian basin	1976	75	5	64
Utah Overthrust				
Pineview	1976	77	5	83
Appalachian folded belt				
Rosehill	1978	73	4	141
Uinta basin				
Duchesne	1976	68	4	171

mian basin (more than 450 sites). These three areas are unusual because they mainly produce only dry gas, gas-condensate, and oil with no gas cap, respectively. Figure 5, 6, and 7 give data on methane content (% C_1), the methane/ethane ratio (C_1/C_2), and the propane/methane ratio (C_3/C_1) × 1,000 from these three soil-gas populations. These figures clearly demonstrate that the chemical compositions of the soil gases from these three different areas form separate populations that appear to reflect the differences which exist in the subsurface reservoirs in these three basins. This correlation is particularly striking when compared with the Nikonov (1971) data, shown in Figure 4.

The use of hydrocarbon compositions in soil-gas prospecting requires enough data to allow statistically valid and separate populations to be defined, so that a particular geochemical anomaly can be related to a geologic or geophysical objective or province. A percentage composition based on only two or three sites having 85 or 95% methane is not sufficient to define a population. As shown by the Nikonov diagram (Fig. 4), considerable overlap exists among the intermediate gas-condensate and oil and gas-type deposits. In basins having mixed production, prediction of a reservoir gas to oil ratio, GOR, is clearly impossible.

The seep compositions may not match those in any of the underlying reservoirs where the seeps contain gases from more than one reservoir. Mixing of a shallow oil and a deep gas will generally yield an oily but intermediate-type composition. Without some knowledge of the reservoir possibilities, this type of signature cannot be recognized; however, the intermediate nature of the seep will indicate some liquid potential at depth. Thus, dry-gas basins can be distinguished from basins that have at least some liquid oil or condensate potential. As suggested by Bernard (1980), the presence of fairly large ethane-propane-butane anomalies strongly suggests of oil-related sources.

Gas Analysis from Mud Logging

Pixler (1969) found that the gases observed during drilling could distinguish the type of production associated with the hydrocarbon show. Pixler's data (Fig. 8) were obtained by monitoring the C_1 to C_5 hydrocarbons collected by steam-still reflux gas sampling during routine mud logging. Individual ratios of the C_2 to C_5 light hydrocarbons with respect to methane provided discrete distributions that reflect the true natural variations of formation hydrocarbons from oil and gas deposits. Ratios below approximately 2, or above 200, indicated to Pixler that the deposits were noncommercial. The upper range for these ratios for dry-gas deposits has been enlarged by Verbanac et al (1982), who studied more than 250 wells from 10 oil and gas fields. Their data suggest the following upper limits for dry-gas reservoir ratios: $C_1/C_2 < 350$, $C_1/C_3 < 900$, $C_1/C_4 < 1{,}500$, $C_1/C_5 < 4{,}500$. These gas-deposit ratios clearly overlap the biogenic range. Another empirical rule suggested by Pixler is that the slope of the lines defined by these ratios must increase to the right; if

Table 3. Compositions of Typical C_1 to C_4 Reservoir Hydrocarbons*

Reservoir Hydrocarbon	Dry Gas	High-Pressure Gas	High-Pressure Oil	Low-Pressure Oil
Methane	0.91	0.81	0.77	0.37
Ethane	0.05	0.07	0.08	0.21
Propane	0.03	0.07	0.08	0.21
Butanes	0.01	0.05	0.07	0.21

*In mole fractions. After Katz and Williams (1952).

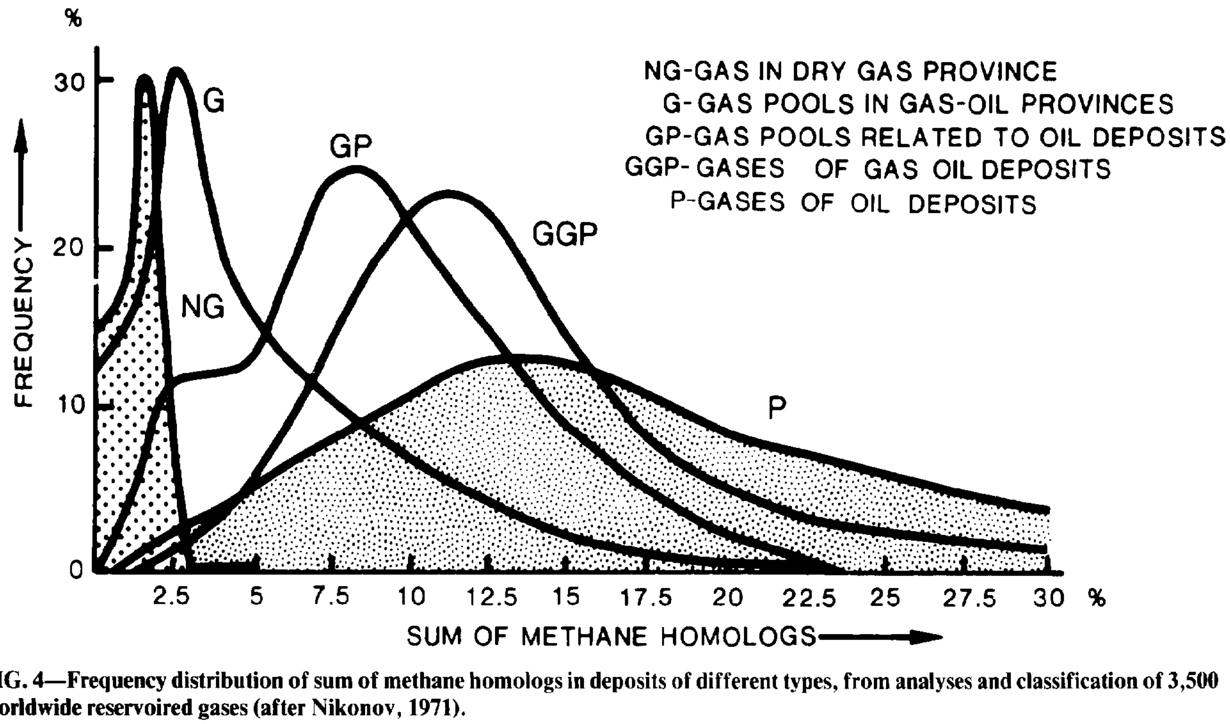

FIG. 4—Frequency distribution of sum of methane homologs in deposits of different types, from analyses and classification of 3,500 worldwide reservoired gases (after Nikonov, 1971).

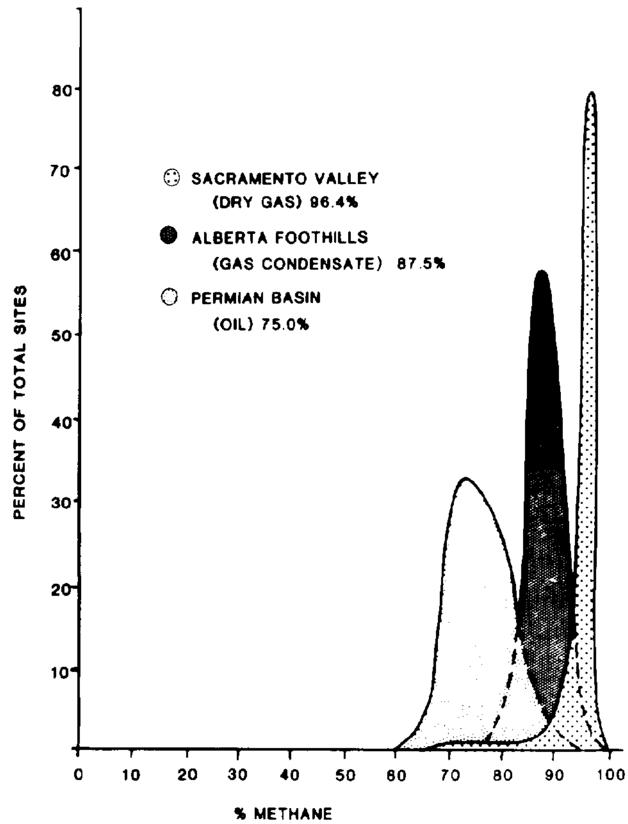

FIG. 5—Typical soil-gas histograms for percentage of methane over dry-gas, condensate, and oil-producing basins surveyed.

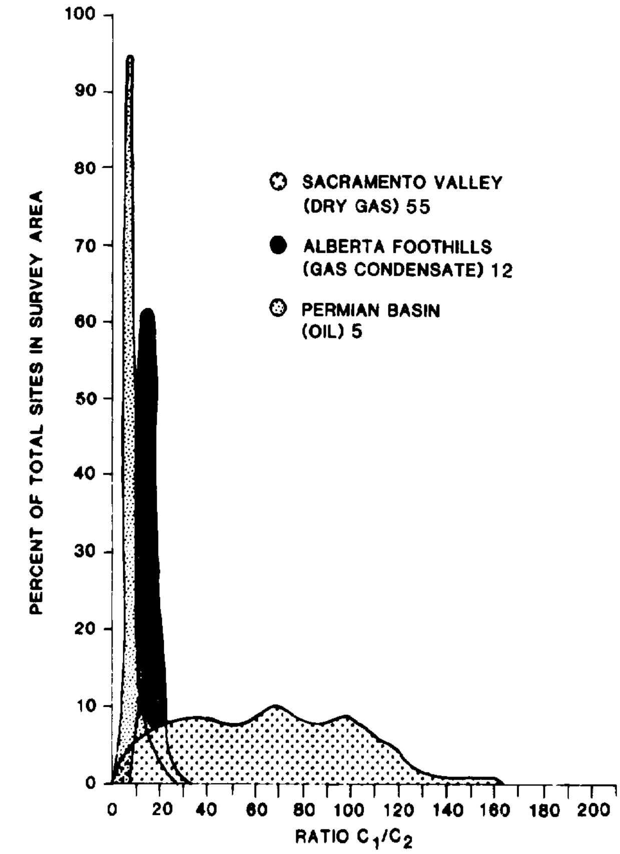

FIG. 6—Typical soil-gas histograms for methane/ethane ratio (C_1/C_2) over dry-gas, condensate, and oil-producing basins surveyed.

they do not, the reservoir will be water-wet and therefore nonproductive. Verbanac et al (1982) suggested that a negative slope connecting individual ratios may result from subsurface reservoir zones of limited permeability.

Our data for shallow soil gas are plotted on a Pixler-type diagram in Figure 9. Direct comparison of these two independent data sets is very striking and supports the concept of migration of reservoired hydrocarbons to the surface.

The use of chemical compositions and component ratios often reveals other types of deposits. Biogenic gases and gases from coal deposits typically have ratios of methane to ethane that exceed 10^3 or 10^4 (Janezic, 1979; Coleman, 1976; Bernard, 1980). However, Oremland (1981) reported small quantities of biogenic C_2 to C_4 hydrocarbons from marine muds where the lowest C_1/C_2 ratio was 149:1. Although the heavier components may be present in very minute amounts in coal or biogenic gas, the ratio of these components with respect to methane is very small. Thus, petroleum-type gases can generally be distinguished clearly from typical coal or biogenic deposits, even though the latter may contain low but measurable amounts of the heavier gases, ethane and propane. Measurement of the stable carbon isotopes of methane can provide additional resolution of biogenic methane versus thermal methane.

Amounts of migrated gases almost always decrease in the following order: methane > ethane > propane > butane. Thus, in a Pixler-type diagram, soil-gas data, like reservoir data, generally plot as line segments of positive slope for the soil gases to represent a typical migrated seep

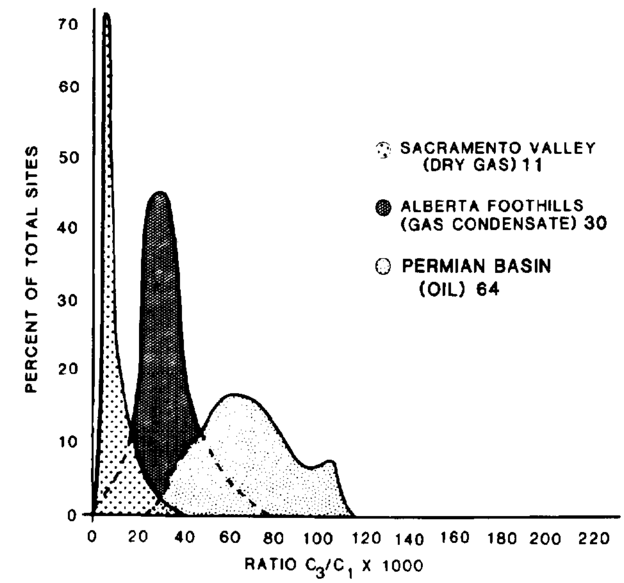

FIG. 7—Typical soil-gas histograms for propane/methane ratio—(C_3/C_1) × 1,000—over dry-gas, condensate, and oil-producing basins surveyed.

gas. Exceptions to this order have been noted where surface source rocks were drilled, which thus far have yielded ratios with lighter gases depleted in relation to heavier gases. According to Leythaeuser (1980), this would be

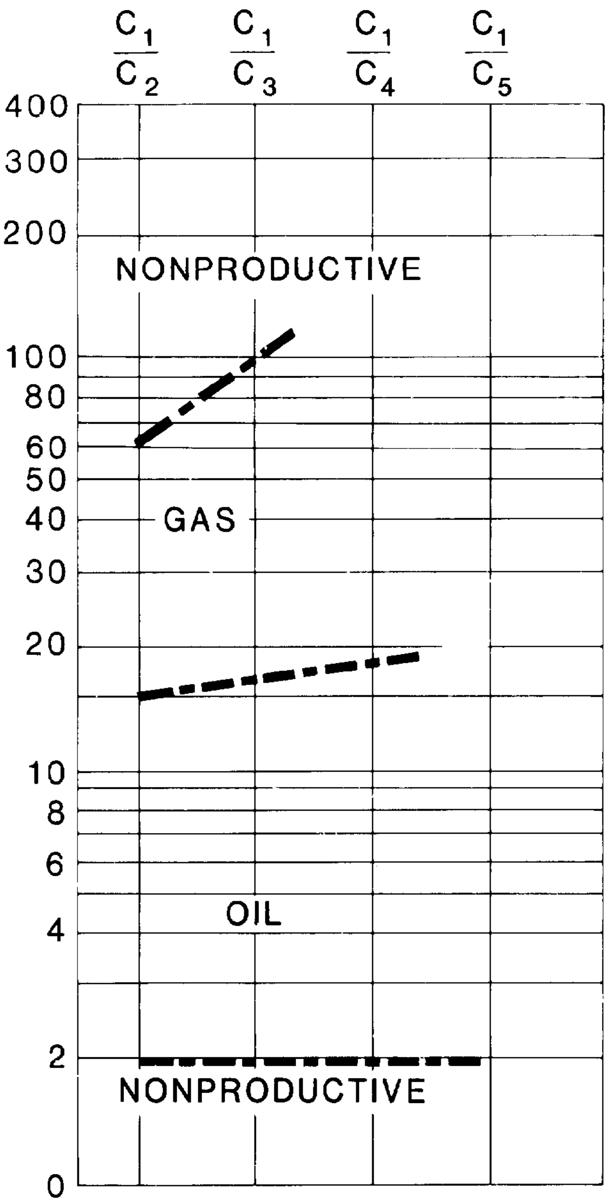

FIG. 8—Gas ratios determined from well logging (after Pixler, 1969).

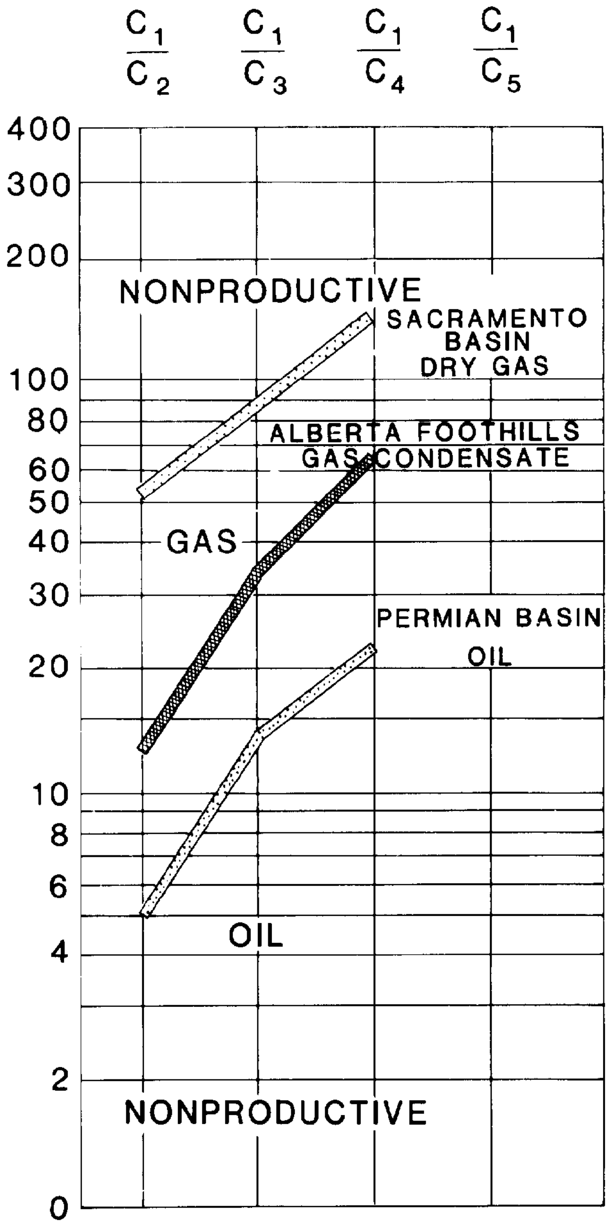

FIG. 9—Soil-gas ratio data plotted on Pixler diagram.

expected if gases in the boundary layer very near the surface followed a diffusion model. Thus, compositional changes related to diffusion might be expected at or very near a boundary layer where the hydrocarbon gas concentration approaches zero. This behavior has been observed when comparing soil-gas probe data measured at very shallow depths (0.3 to 0.6 m, 1 to 2 ft) with their associated data from 4 m (13 ft). The probe data are always "oilier," indicating preferential loss of methane and implying diffusion from the 4-m (13 ft) level to the surface. If diffusion was the dominant migration mechanism, a chromatographic effect would be expected for gas that migrated through the earth. The fact that the compositions of the soil-gas data from 4 m (13 ft) so obviously reflect the underlying reservoirs implies that the major migration to the near-surface must be by faults and fractures rather than by diffusion. The following examples demonstrate a clear relationship between faults and surface-gas magnitudes. Lack of a chromatographic effect implies that the seepage must be continuous geologically. However, this does not rule out intermittent seepage on a historical basis.

At least two other papers cite chemical compositions of migrated hydrocarbons to predict the type of source deposit (gas, gas-condensate, or oil). Sokolov and Cheremisinov (1971) reported that the ratio of methane to total heavier gaseous hydrocarbons can be used as a criterion for hydrocarbon prospecting. The maximum ratio is 150 to 200 and corresponds to gas pools formed by distant lateral migration and to gases from mud volcanos. Lower ratios correspond to oil fields with associated gas. They

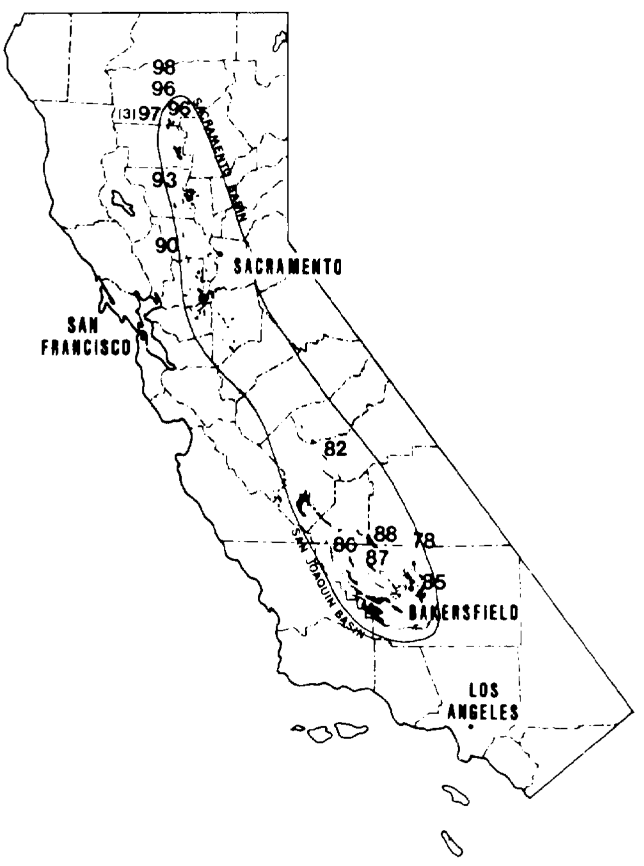

FIG. 10—Percentage of soil-gas methane in California basins.

further stated that, "In those areas where the vertical migration does not substantially effect the formation of gas pools, this criterion can be used to predict oil and gas-condensate accumulation with probability equal to one."

Panchenko and Bogdanov (1974) found that comparative analysis of water-dissolved gases in the pre-Caucasus can be used to predict oil, gas-condensate, or gas deposits. This prediction is based on methane and its homologs. The highest (30 to 50%) concentration of methane homologs is characteristic of oil deposits and the lowest (as much as 5%) is characteristic of gas. Gas-condensate fields show intermediate values.

Prediction of the type of subsurface deposit by use of near-surface soil-gas compositions represents an important accomplishment and offers strong evidence for the viability of soil-gas prospecting. This compositional relationship supports the genetic association between soil-gas hydrocarbons and reservoirs.

GEOCHEMICAL ANOMALIES ASSOCIATED WITH PRODUCTION

California Region

In addition to the compositional differences (Table 2) between the two California basins (Sacramento, 95% CH_4; San Joaquin, 82% CH_4), the data imply that a soil-gas grid would have defined local differences regionally. The percent-methane compositions in Table 2, taken from surveys conducted in California in 1972, 1974, and 1975, are plotted in Figure 10. Note the decrease from 98% in the north to 90% in the south part of the Sacramento basin.

Pleasant Creek Gas Storage Area

The first example focuses on the survey represented by the 90% methane value posted west of Sacramento (Fig. 10). Plotted at the top of the geochemical profile (Fig. 11) over the Pleasant Creek gas-storage area is methane, ethane, propane, and hydrogen. The reservoir is a shallow stratigraphic trap, truncated at the top of the Cretaceous section at a depth of 760 m (2,500 ft) (Hunter, 1955). The reservoir was filled to capacity with a pressure of 10,343 kPa (1,500 psi) when the traverse was run. Because the area initially contained only fairly dry gas, the filling of an abandoned gas sand with typical pipeline gas cannot be expected to change appreciably the composition of surface soil gases. However, the storage gas should keep the migration avenues charged. The geochemical data are repeatable (Table 4), and similar repeatability was observed on all of the posted soil-gas surveys conducted from 1972 to 1975. For example, the percent-methane values posted on the California map (Fig. 10) were all determined at least two or three times, and found to be repeatable over this 3-year period. Compositional data have remained repeatable throughout our experience with soil-gas surveys.

Table 4. Repeatability of Soil-Gas Surveys near Pleasant Creek Area, California

Date	$C_1/\Sigma C_n$	C_1/C_2	$(C_3/C_1) \times 1{,}000$
May 1975	90	20	19
July 1975	89	18	24
July 1976	89	16	20

Lost Hills Field

A geochemical traverse (Fig. 12) was made in 1975 across the San Joaquin basin. This traverse extends approximately 40 km (25 mi) off each side of the Lost Hills oil field, from near Paso Robles in the west to Famosa in the east-central part of the basin. The lower profile shows methane and propane, which are the main oil indicators; as shown by the scale, methane exceeds propane. The top profile is a plot of hydrogen and helium. This field illustrates many of the associations found to be useful in soil-gas prospecting, using these four gases.

The most obvious feature is the large hydrocarbon and hydrogen anomaly directly over the Lost Hills oil field. The large-magnitude chromatogram in Figure 2 represents the hydrocarbon concentration over the top of the field. The methane value of 1,383 ppm on this large-scale anomaly is truncated at 22 ppm (Fig. 12) because the values off the field are much lower. Background appears to be less than 1.5 ppm, and thus the soil-gas values show a very large anomaly over the Lost Hills field. Also, some inter-

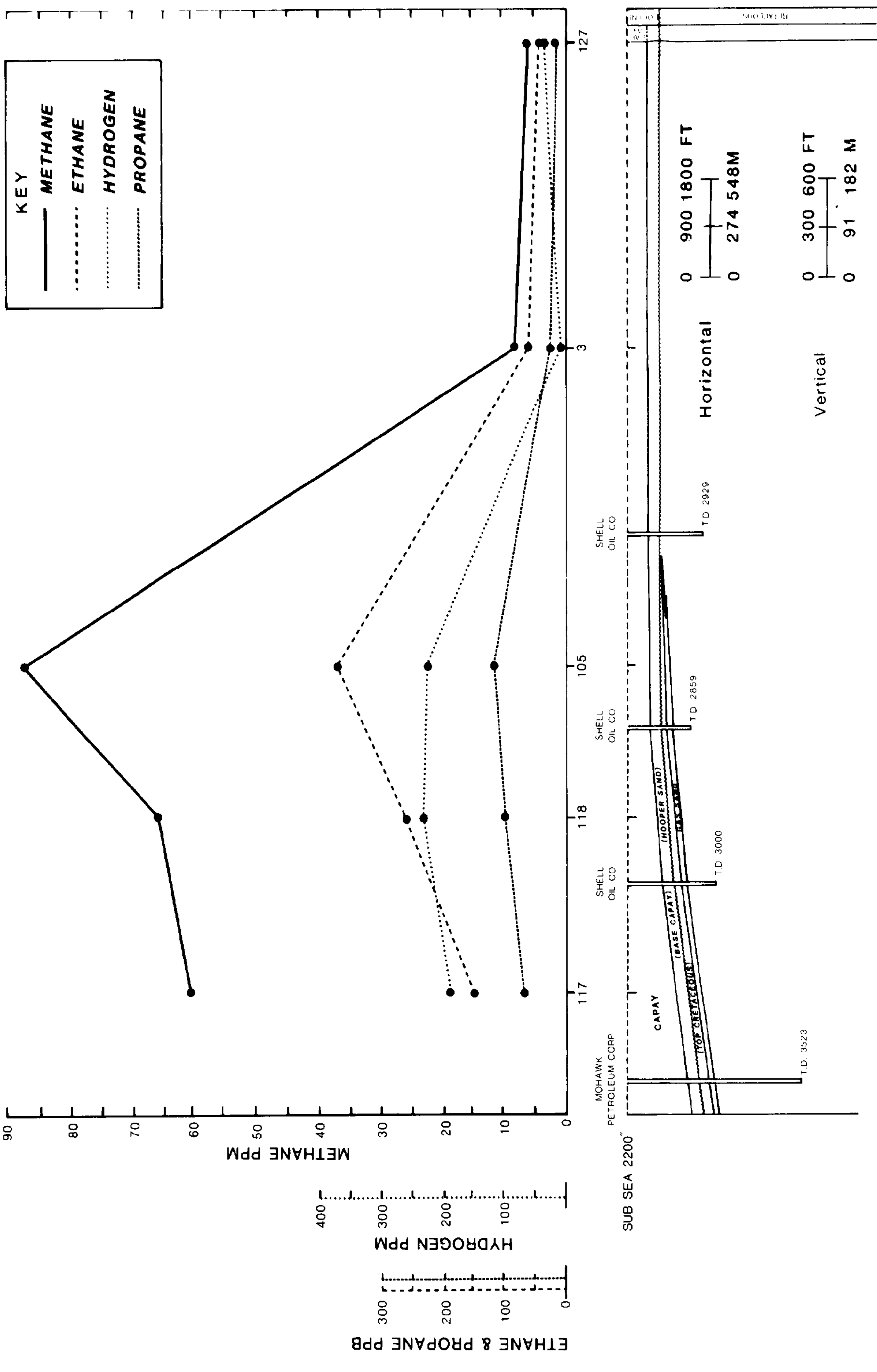

FIG. 11—North-south soil-gas profile of Pleasant Creek gas-storage area, Sacramento Valley, California.

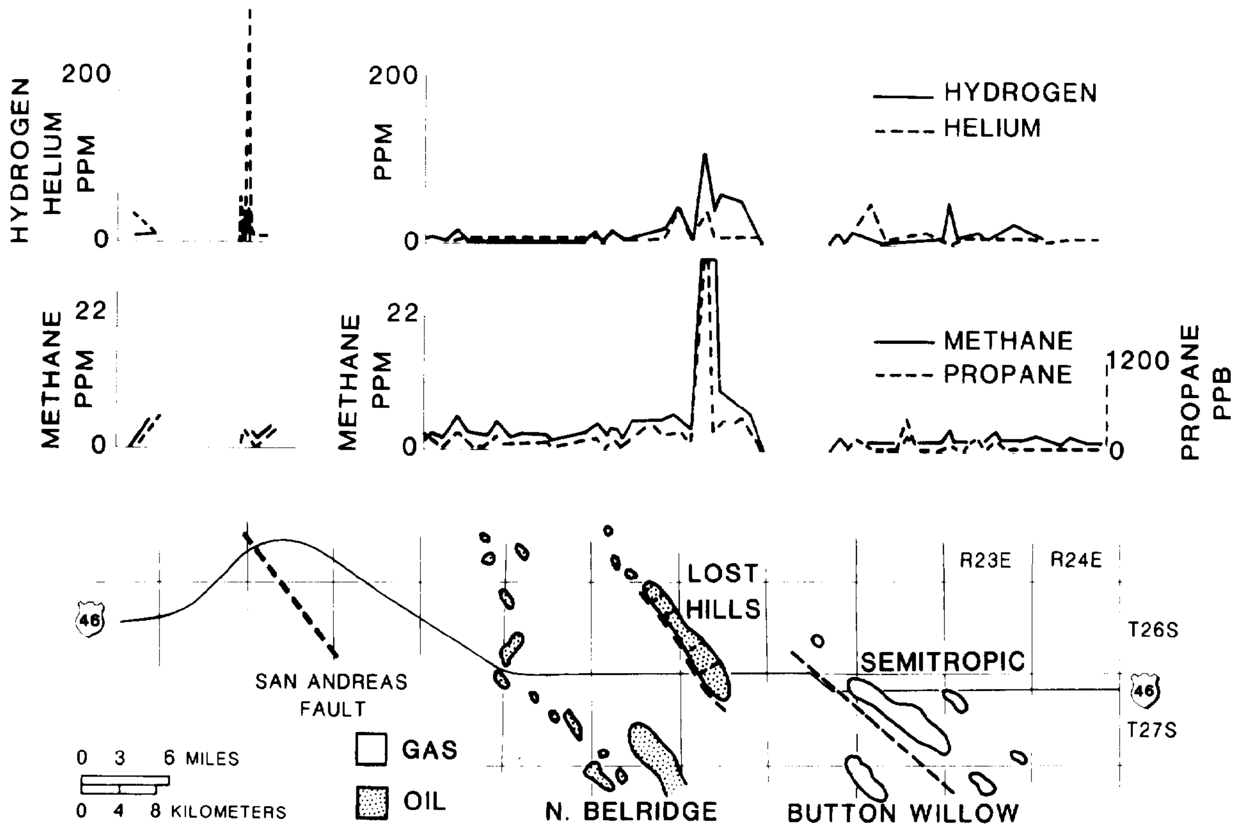

FIG. 12—Soil-gas survey in San Joaquin basin, California.

esting and untested anomalies lie off the edges of the field. These range upward to about 5 or 6 ppm methane on the west side and 6 to 10 ppm on the east side. The Lost Hills field is an anticlinal structure with very shallow production, ranging between 60 m (200 ft) and about 300 m (1,000 ft) (McCabe, 1924; Ayars, 1939; Scouler, 1952). The Semitropic field to the east produces from the San Joaquin Formation, which pinches out on both the eastern and the western edges of the Lost Hills field (Kaplow, 1938). Thus, one explanation of these edge anomalies may be that they are direct expressions of stratigraphic traps in the San Joaquin Formation. The western anomaly at Lost Hills might also be related to the deep fault along the western edge of the field (Fig. 15) (Follansbee, 1943).

The data are also significant regionally. Very low magnitudes of all gases are found on the east side of the basin (Fig. 12). This is particularly significant because the eastern part of the traverse crosses the basin in an area that has poor hydrocarbon potential, compared with the west side. Most of the major fields lie along the western edge of the basin in the area of the traverse (Fig. 10). Data from the eastern part of the line average approximately 88% methane; the western part averages about 80% methane. The eastern part of the line crosses the trend of several gas fields, such as Buttonwillow and Semitropic (Fig. 12); Trico gas field lies just off the map, north of these gas fields. Thus, the soil gases outline a district in the central part of the San Joaquin basin, where the fields contain almost exclusively gas. An earlier survey near Semitropic gas field, in 1972, found 87% methane, in excellent agreement with the data observed 3 years later. Thus, soil-gas prospecting appears to define local variations in productive potential within the San Joaquin basin.

San Andreas Fault

Helium and hydrogen are shown on the uppermost profile in Figure 14. Hydrogen appears to be related directly to the hydrocarbon anomalies, and thus appears to be a petroleum predictor. Our studies have confirmed that helium is a deep-fault, or tectonic indicator, commonly independent of oil and gas. Along this 80-km (50-mi) line, helium anomalies are associated with the western flank of the Lost Hills field and possibly with the cross faults. The helium anomalies are not random, but are highly localized and appear to be concentrated near basement faults (Figs. 12, 13). Helium and hydrogen have been reported in association with faults elsewhere (Eremeev et al, 1973; Ovchinnikov et al, 1972). To prove that helium is a tectonic indicator, this survey was extended to the vicinity of Paso Robles in order to cross the San Andreas fault (Fig. 14). Helium values as high as 430 ppm were observed over this deep fault. At adjacent sites they range from 40 to 98 ppm within 20 to 40 m (65 to 130 ft) of the mapped fault. A similar signature (not shown) was obtained on Gold Hill, which is about 8 km (5mi) north of the first crossing. This second traverse was adjacent to a tiltmeter, and confirms the association of helium with the fault. Hydrogen and

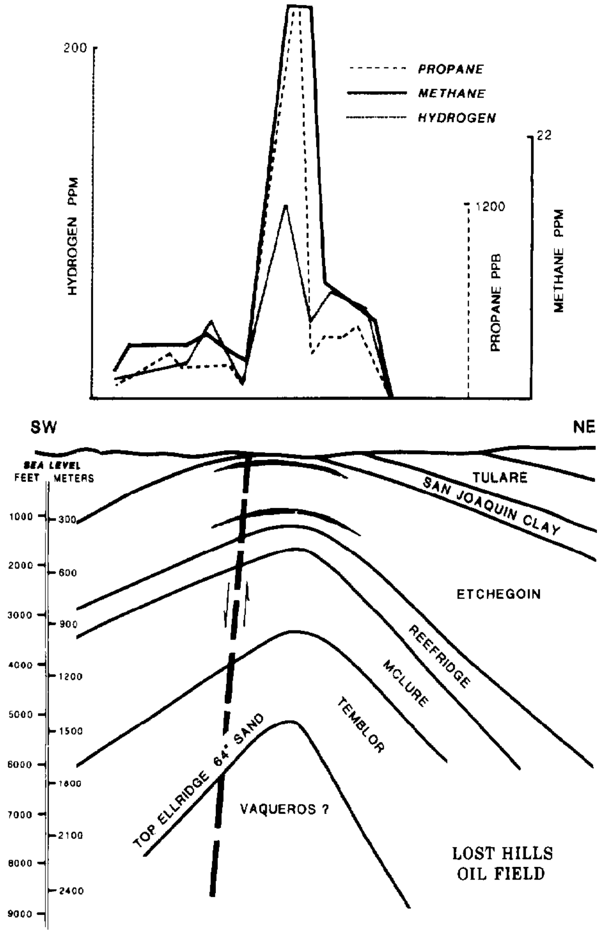

FIG. 13—Idealized cross section illustrating proposed deep fault adjacent to Lost Hills field, San Joaquin basin, California (after Follansbee, 1943).

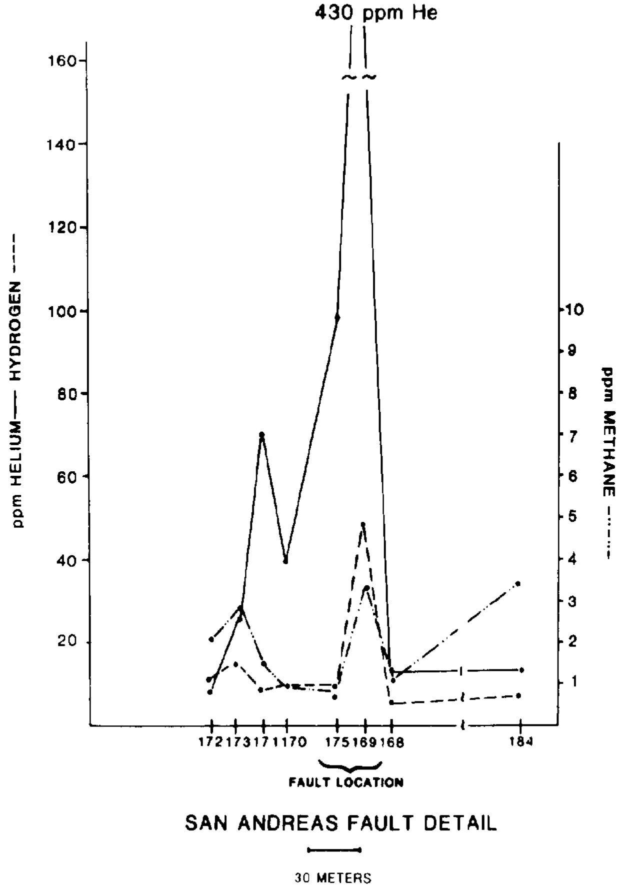

FIG. 14—Helium-hydrogen association with San Andreas fault.

methane also are associated with this basement fault, as expected (Fig. 14). However, heavier hydrocarbons are not associated with San Andreas fault seepage in this area.

Some explanation of these helium magnitudes is needed because most of the published near-surface surveys (Roberts, 1981; Reimer et al, 1979) reported helium anomalies of only a few parts per million relative to ambient air (5.24 ppm v/v). Our data suggest that these very low values are due to the effects of atmospheric exchange at the very shallow depths they sampled (less than 1 m, 3.3 ft). Deeper sampling generally produces larger anomalies, in our experience. Sampling in the deepest available boreholes has also been stressed by Sokolov et al (1959).

The main point of the previous two examples is to show that both structural and stratigraphic traps produce positive or direct surface anomalies, given positive gas and oil pressure within the traps.

Utah-Wyoming Overthrust Belt

The following examples are from Pineview field, Utah, and Ryckman Creek field, Wyoming, both in the Utah-Wyoming Overthrust belt (Fig. 15). Surveys in this highly faulted area show an absolutely clear association of geochemical anomalies with fault zones. Moreover, many of the major faults can be mapped at the surface, permitting verification of the physical relations between the faults and the anomalies.

Pineview Field

A profile of the geochemical data plotted approximately to scale over a cross section taken from a Veezay study (1976) is shown in Figure 16. The hydrocarbons show a clear association with faults mapped by Conner and Colvin (1977). Sites 26 and 27 are near a fault that passes directly through the field (see Fig. 17). Sites 31 to 33 are located where the sole fault of the Tunp thrust crosses the traverse. As indicated geochemically, and demonstrated by drilling, this fault appears to mark the eastern limit of the field as presently known. There is a large anomaly at site 22 (Fig. 16), west of any known commercial production at the time this survey was conducted. This anomaly is isolated by a normal fault just west of the first well drilled, which was a dry hole with noncommercial oil shows. The well has since been reported to produce 400 bbl/day (57 tons/day) of oil (R. D. Matthews, personal commun., 1977). A relative low exists over this fault at sites 23 and 24. At these sites the fault cannot be precisely located directly over the field, owing to the Tertiary cover. However, faults can be mapped accurately on the western part

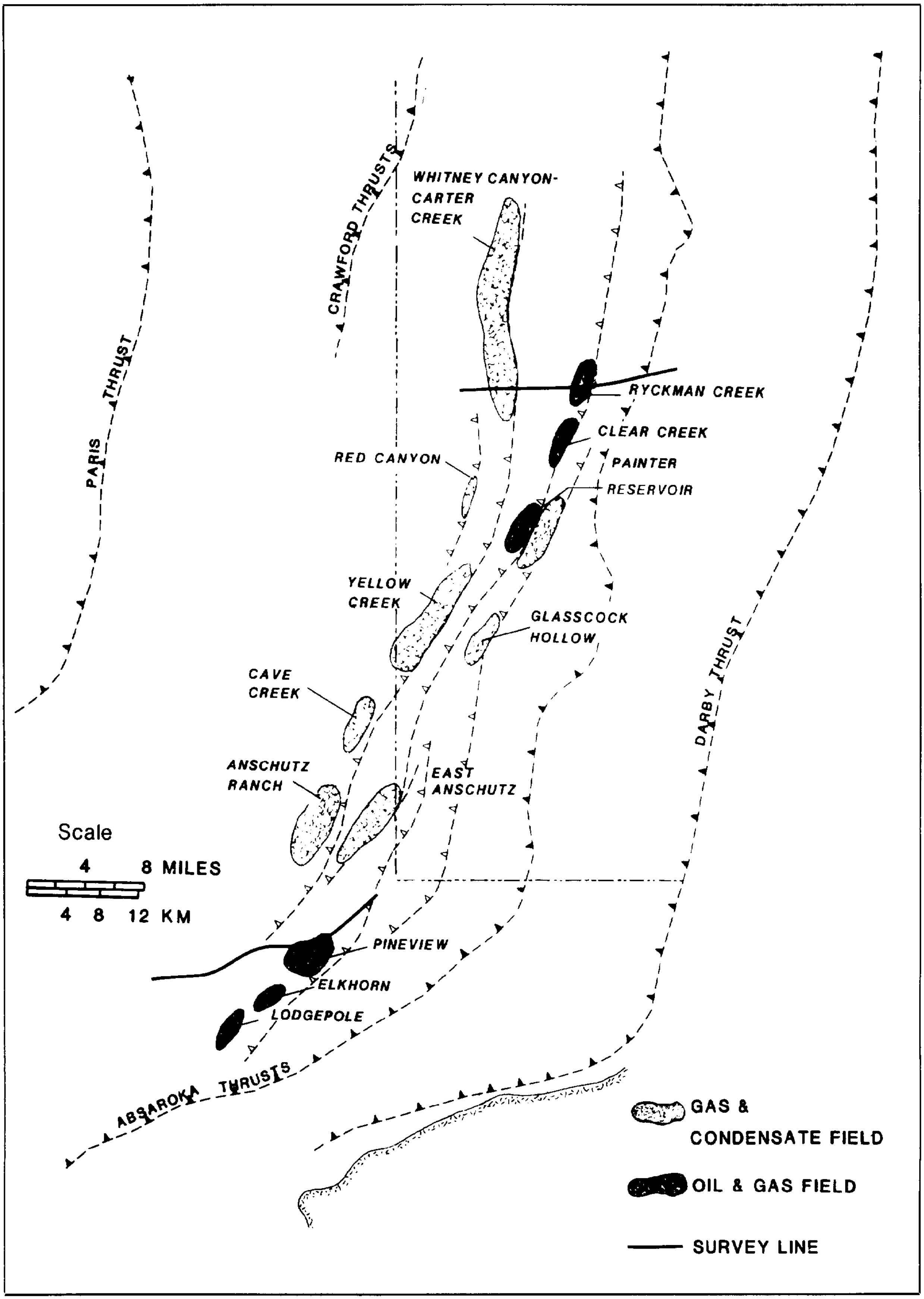

FIG. 15—Location map of geochemical surveys in Utah-Wyoming Overthrust belt.

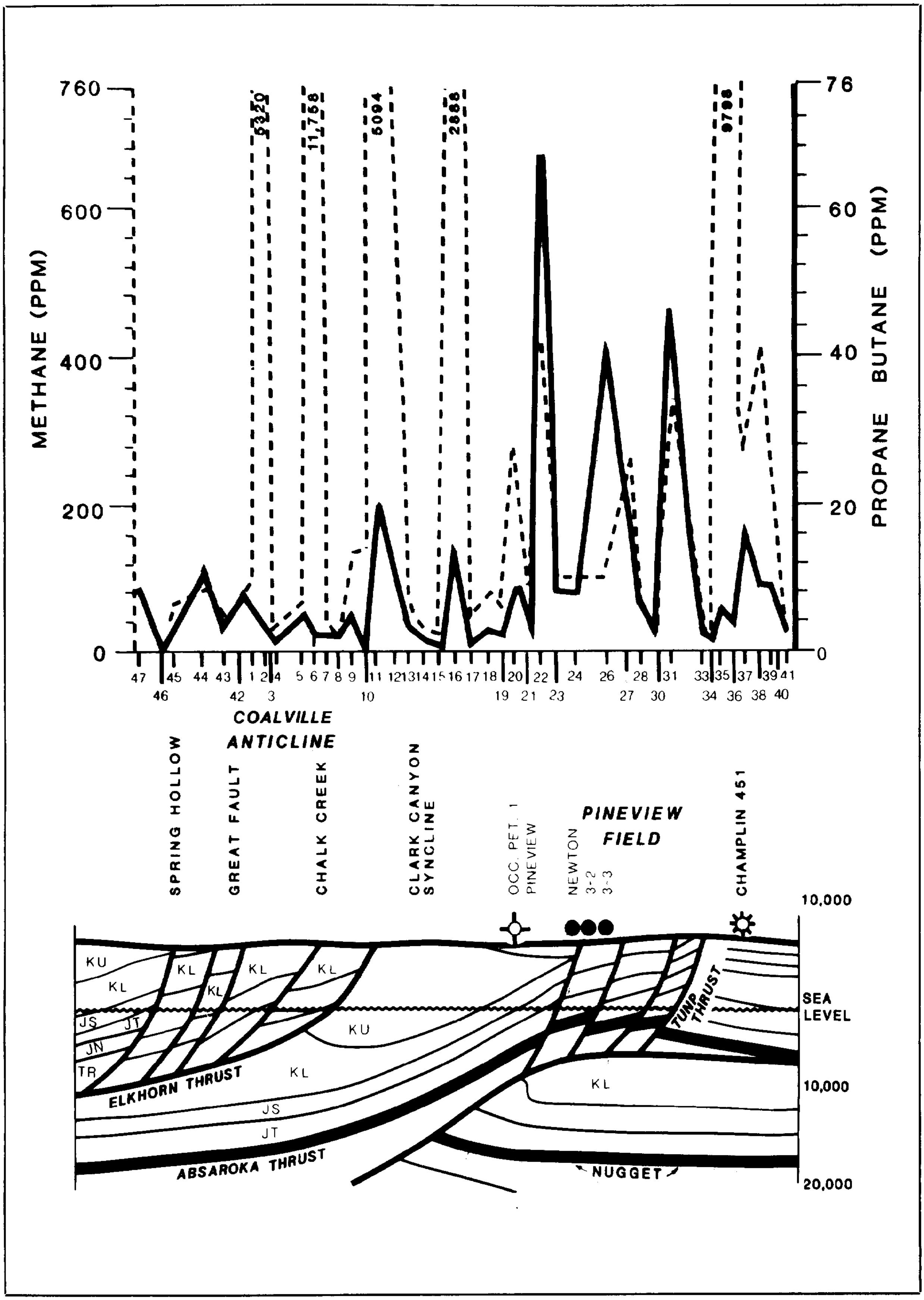

FIG. 16—Soil-gas survey of Pineview field, Utah.

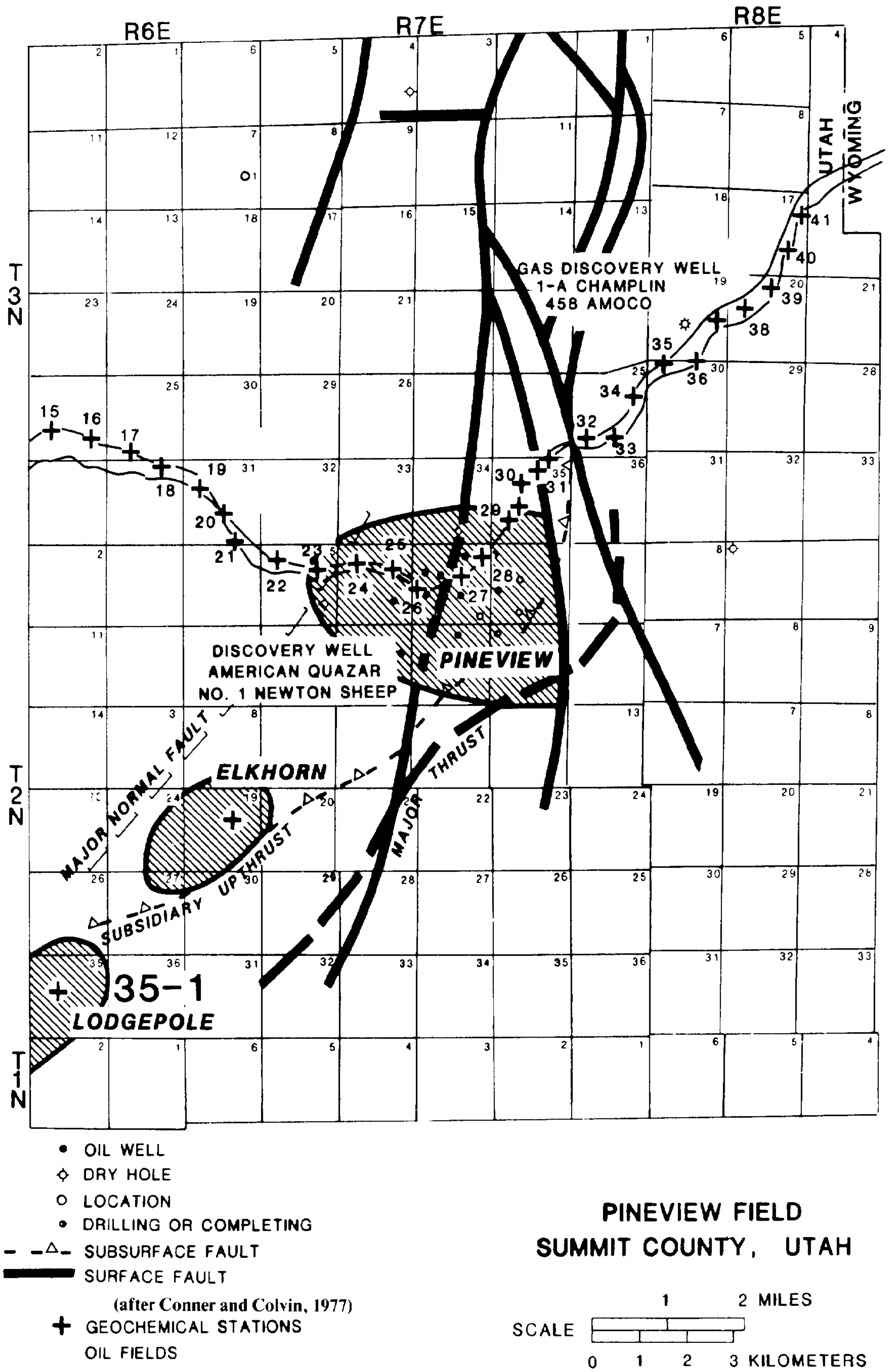

FIG. 17—Soil-gas survey sites at Pineview field, Utah (after Conner and Colvin, 1977).

of the traverse where the Cretaceous section crops out (Hale, 1963). The most striking feature over the Coalville anticline is the very high magnitude methane anomalies with very low-magnitude heavier hydrocarbons (Fig. 16). After this geochemical traverse was conducted, two deep wells were drilled on the Coalville anticline, both with negative results (Rountree, 1977). Large methane anomalies are found at sites 2, 6, 11, and 16. The close relationship between the strong anomalies and the major faults is illustrated in Figure 18. Obviously, the main leakage of these gases is directly over the thrust faults, suggesting that the faults provide fracture permeability to depth.

Very low propane and butane values are found over the Coalville anticline, and very high values are found over the Pineview anticline (Fig. 16). The geochemical anomalies imply that the most prospective zone for oil production is between the Tunp and Chalk Creek faults. Thus, one could infer that the productive area extends westward toward the Chalk Creek thrust. Two additional fields have been discovered southwest of Pineview since this geochemical survey was run. Well 35-1 (Figure 21) was originally considered a gas well, which tested 1.1 MMcf/day (31,000 m^3/day) from the Dakota formation underlying the upper thrust (Gregg, 1976). The gas did not last, and the well was subsequently plugged back to the Nugget, and produced 135 bbl/day (19 tons/day) of oil on pump. A second well confirmed an oil discovery that resulted in the Lodgepole field.

In addition to the possibilities of deep gas production, shown by the 35-1 discovery well, a further complication exists over the Coalville anticline because a shallow gas-storage sandstone reservoir lies between sites 2 and 6. The first major methane anomaly occurs right on the Great fault which provides closure on the west side of this gas-storage area. Thus, some of the methane leakage might be related to this sandstone. The east side of the gas-storage area is truncated by a thrust fault. However, the methane anomalies at sites 11 and 16 do not appear to be associated with the gas-storage area, and therefore the possibility of an independent, deeper gas source must be considered.

The potential for deeper gas was confirmed in 1981 on the east side of the Pineview field, by the A-1 Champlin-458 Amoco-B. This well (Figs. 16, 17) flowed gas at 1.5 MMcf/day (42,450 m^3/day) and 189 bbl/day of water on a production test of the Watton Canyon zone of the Twin Creek Jurassic sandstone through perforations at 3,770 to 3,795 m (12,366 to 12,450 ft). This gas discovery is located at the intersection of a Landsat lineament and a large methane anomaly (9,798 ppm, nearly 1%). The soil-gas signature indicated gas potential at sites 35, 36, and 37 along the geochemical traverse. The Landsat lineament intersecting site 36 was first identified in the field by a low swale about 30 m (100 ft) across and a couple of meters below the adjacent topography. The feature was identified by R. A. Hodgson (personal commun.) as a soil and vegetation-moisture anomaly; the greatly increased moisture along the zone was quite apparent in the field. This lineament marks a very minor fault or fracture zone that would be expected to provide a preferential channel for the migration of ground water and ascending gases.

An example of shallow probe measurements along the Pineview traverse is shown in Table 5. These probe data were collected in 1979, 3 years after the initial Pineview survey. This traverse was chosen for the shallow probe test because we assumed that the large-magnitude seeps at the 4-m (13 ft) depth would generally overwhelm any near-surface effects of lithology and barometric pumping. This assumption appears to be valid for such a disturbed area. A diffusion-related composition change was observed, as predicted. The composition probably means very little for the low-magnitude nonsourced sites. However, the large-magnitude sourced sites have clearly kept their identity; sites 2 and 6 are gassy, whereas site 26 is oilier. Comparison of these data with the normal composition at 4 m (13 ft) indicates a preferential decrease in methane as the soil-gas observations approach the surface.

Although the faults obviously provide the major avenues of leakage, the chemical composition of the gas signatures associated with each of these faults is different. The only faults having oily anomalies occur in areas where known oil production is either directly below or downdip. Only gassy anomalies occur over the Coalville anticline; thus, a striking difference in seep compositions is shown for the Coalville and Pineview anticlines.

Ryckman Creek Field

A second example is provided by the Ryckman Creek traverse. An idealized subsurface cross section of the Ryckman Creek field, from Powers (1977), is shown in Figure 19; a geologic cross section paralleling the geochemical traverse is shown in Figure 20. A fairly thick Tertiary section, perhaps 900 to 1,220 m (3,000 to 4,000 ft), is associated with the thrust faults that reach upward to essentially the bottom edge of the Tertiary (Figs. 19, 20).

The hydrocarbon seeps occur directly over the subcrop of the thrust faults, and thus gases would appear to migrate along the thrust plane and then vertically through the Tertiary section (Fig. 20). The compositions of these three seeps are similar, indicating a gas to gas-condensate-type deposit. Within the Ryckman Creek discovery, about 150 m (500 ft) of closure is reported, which contains gas, condensate, and oil. Thus, one finds a gas-condensate signature directly over the top of this field, which suggests vertical migration from the gas cap. The compositional signature changes dramatically to the east of the Ryckman Creek field. Much larger propane plus butane anomalies occur out in front and updip from the field. This oily zone occurs also in an area of Cretaceous subcrop that may be an oil source (P. Swetland, personal commun., 1977). The oily signature could be indicative of the source material in either a near-surface Cretaceous formation or a mature Cretaceous source in the footwall of the main thrust. In addition, this oily signature might have resulted from the updip migration of gases from the oil reservoir at depth.

An important observation made from empirical geochemical data is: the deeper the basin and the longer the apparent migration paths, the smaller will be the soil-gas anomalies. Thus, large-magnitude seeps, as observed at Pineview, generally imply very active tectonics or a source or trap quite close to the surface. Migration through the Tertiary cover over the Ryckman Creek field may partly account for the reduced magnitudes, compared with Pineview. A longer, less well-defined migration pathway is suggested as the cause for the anomalies becoming more diffuse with increased migration distance.

DISCUSSION

Our examples were chosen to illustrate the geochemical signatures found over various types of hydrocarbon reservoirs and fault zones, particularly deep-seated fault zones that extend near or to the surface. Hydrocarbon seeps are not observed over all faults; one example is the San Andreas fault in the Cholame Valley. However, there is no doubt that faults provide the most permeable avenues for hydrocarbon migration, and they must be considered whenever one makes a geochemical interpretation. Both magnitudes and compositions of seep gases are important; for example, there are no oily seeps over the Coalville anti-

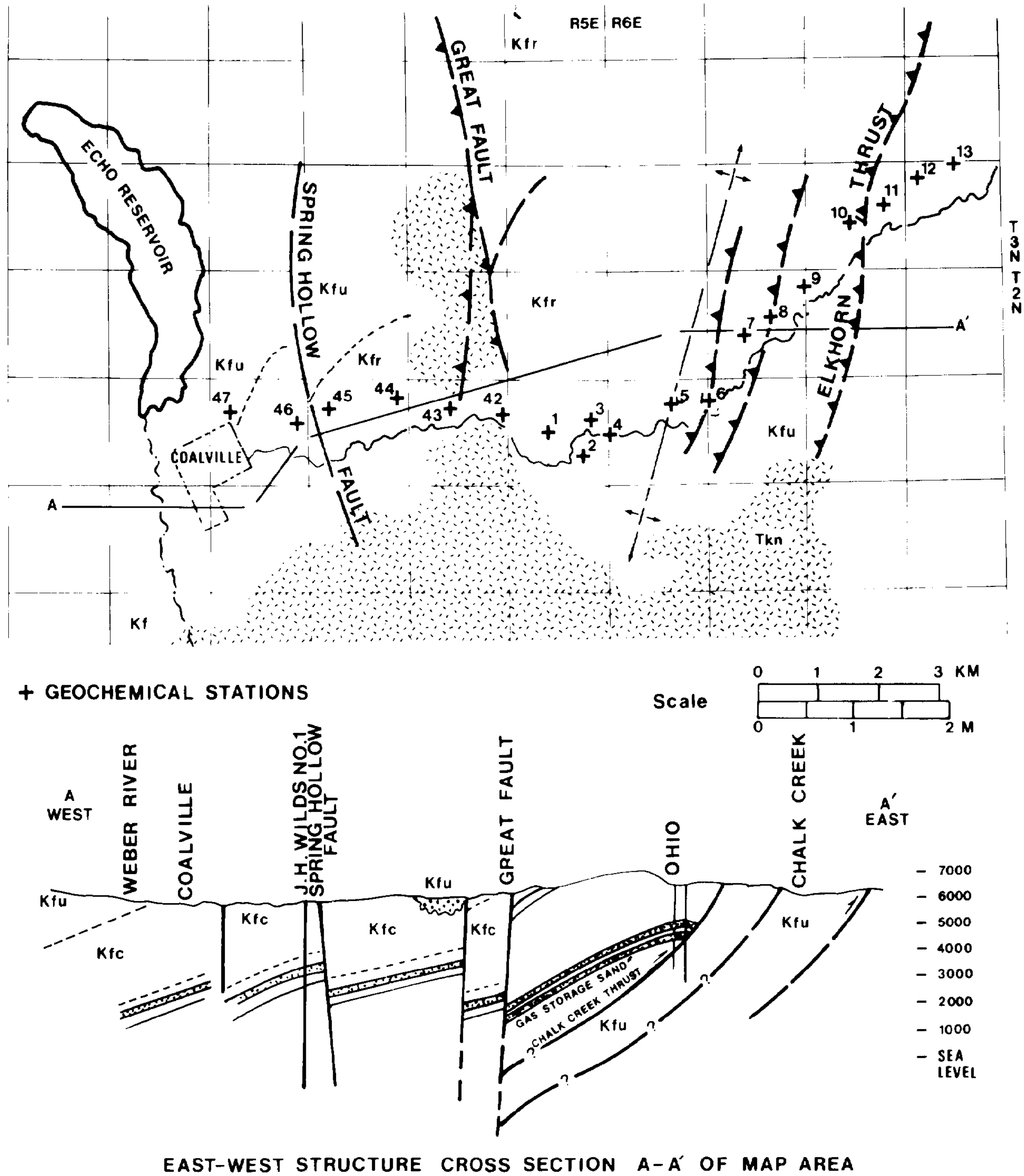

FIG. 18—Surface geology and cross section of Coalville anticline, Utah (after Hale, 1963).

cline, which is adjacent to the Pineview oil field. Thus, even though large-magnitude seeps are found on all the faults on the Pineview traverse, which crosses both a productive and nonproductive anticline, oil seeps clearly predict where oil production is located.

The Pineview survey proves also that faults can serve both as a leak and as a seal. Faults tapping the Pineview field might be compared to a critical orifice that acts as a partial seal, allowing hydrocarbons to build up behind the fault zones but also allowing some leakage. The exceedingly large hydrocarbon seeps that must have existed for a very long time over the Pineview field imply a fair loss of hydrocarbons from the reservoir. Perhaps these seeps even imply that primary migration is still going on, from the Cretaceous sediments beneath the Pineview field.

All of the examples in this report are considered to be direct or positive geochemical anomalies, and not negative-type halo anomalies. For example, the Lost Hills oil field in California is a structural trap that has direct anomalies. Our experience has generally shown that the surface anomalies formed by free soil gases are direct. They are direct because they occur over the fault and fracture systems, and one has to relate the surface anomalies to the deposits through these systems. If the faults and fractures lie on the edges of the deposit, the anomalies may appear to be halos. In the salt dome deposits of the Gulf Coast, where radial fractures and large hydrocarbon accumulations exist on the periphery of the salt domes, one might expect to observe soil-gas anomalies around the edges of the salt domes. This would lead to the conclusion that halos exist, when, in fact, the soil-gas signature was a direct anomaly. Negative, or halo-type, anomalies seem to occur also over stratigraphic traps that are undersaturated with gas. Thus, the very low gas pressure in the trap causes subsurface methane to migrate into the trap, rather than out of it, creating a "shadow" (lower magnitudes) at the surface because the upward migration of light hydrocarbon gases is interrupted. The Yellowhouse Creek oil field in the Permian basin (Fig. 21) is an example of a field with such a halo-type feature. Additional research must be con-

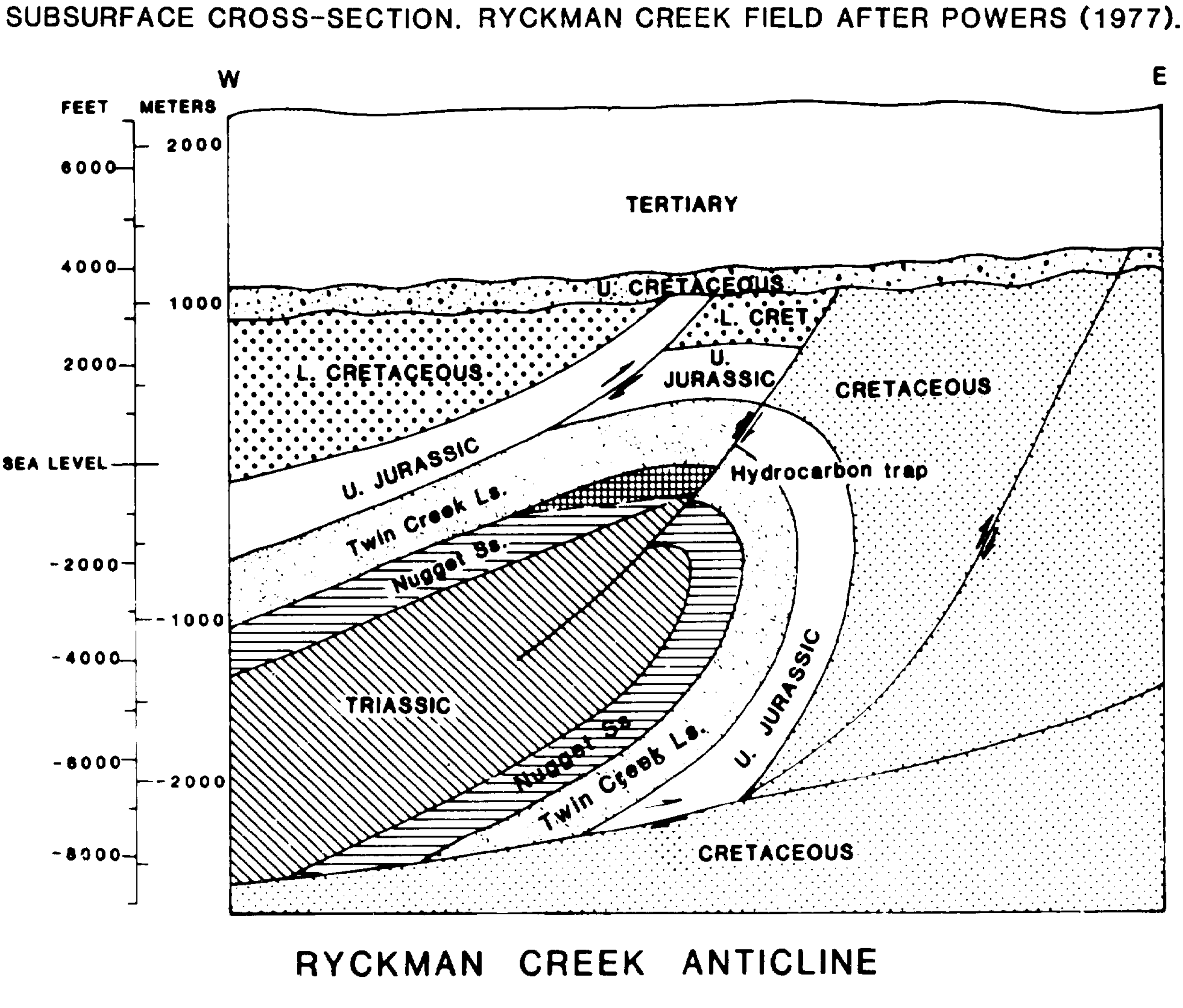

FIG. 19—Cross section of Ryckman Creek field, Wyoming (after Powers, 1977). Producing part of Nugget Sandstone is cross-hatched.

ducted on halo-type anomalies to prove that they are not due to methodology or to some geologic feature interposed between the deposit and the surface.

CONCLUSION

We have demonstrated that a well-ordered chemical relationship among light hydrocarbon gases in near-surface soils and gases exists as noted by Nikonov (1971) in reservoirs and by Pixler (1969) in gas shows from drilling wells. The correlations are certainly encouraging and imply that subsurface hydrocarbons do migrate to the surface. These conclusions were drawn initially from data observed in California basins, then supported by southwest Texas surveys, and later supported by observations in several major western basins. These same conclusions could have been drawn from data observed in eastern basins, such as the Appalachian and Michigan basins.

This established compositional relationship proves that the method directly detects subsurface hydrocarbons. Regardless of commercial considerations, a soil-gas seep leaves no doubt that hydrocarbons have been generated within the basin.

Current knowledge of surface geochemistry suggests that it provides an excellent tool for regional evaluations. This is especially true in relatively unexplored basins where additional accumulations, or any accumulations, are unknown. The prediction of oil versus gas production has obvious economic importance.

Another objective of this paper is to illustrate the relationship between hydrocarbon migration paths and local soil-gas anomalies. Pineview is an excellent example of where surface geochemical exploration might have pioneered discovery of the field, and did in fact predict both the westward extension of the field and the gas potential outside the field limits. One of these gas anomalies was confirmed by a wildcat well in 1981. One certainly could have predicted the right place to drill, even if drilled directly on the soil-gas anomalies, without due regard for downdip projections.

The question of lateral versus vertical migration is very important to the interpretation of geochemical data. Our present knowledge indicates that both occur. The extent of either depends on the geometry of the sediments and the tectonics. Our empirical data indicate that in most places there is enough vertical permeability for a seep to exist directly over a deposit. However, some lateral migration (particularly near the surface) generally occurs, so that the shape and location of the surface anomaly will not exactly match that of the prospective reservoir.

Surface geochemical anomalies are nothing more than microlevel oil and gas seeps. Link (1952) stated, "A look at the exploration history of the important oil areas of the world proves conclusively that oil and gas seeps gave the first clues to most oil-producing regions. Many great oil fields are the direct results of seepage drilling." More recently, Dickey and Hunt (1972) noted, "It is probable that more oil fields have been discovered by drilling on or

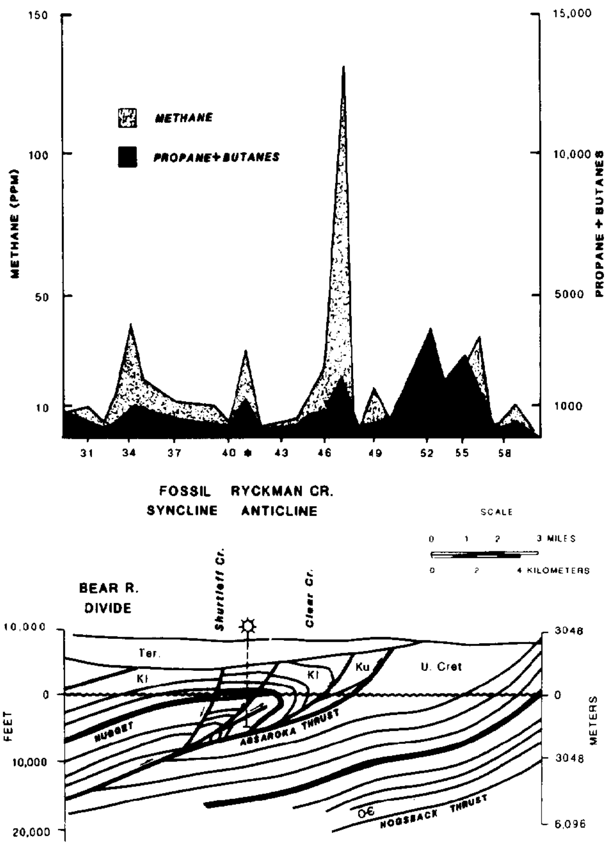

FIG. 20—Geology and soil-gas correlations over Ryckman field, Wyoming. Heavy lines are thrust faults which reach essentially to base of Tertiary.

Table 5. Soil-Gas Data from Shallow Holes in Background and Anomalous Locations in Pineview Area, Utah*

Site	Methane	Ethane	Propane	Isobutane	N-Butane	Ethylene	Propylene
			Background "Low" Sites				
P-8	2.450	0.101	0.048	0.000	0.052	0.061	0.081
P-14	1.896	0.033	0.015	0.004	0.007	0.012	0.008
P-18	2.715	0.105	0.043	0.000	0.028	0.045	0.051
			Anomalous "High" Sites				
P-2	15.682	1.265	0.527	0.245	0.399	0.401	0.234
P-6	10.456	0.821	0.397	0.139	0.226	0.326	0.210
P-26	3.882	0.636	0.296	0.115	0.224	0.114	0.074

*Holes were 0.3 m (1 ft) deep. All values are in ppm (v/v).

near seeps than any other prospecting method." Development of this technology to date has proved the usefulness of surface geochemistry for regional basin evaluation. Local evaluations may be difficult because the migration path must be established to determine whether a surface seep has originated from a particular subsurface trap. Evaluation of a particular seep requires a great deal of cooperation among geochemists, geologists, and geophysicists to obtain the amount and type of information needed for a correct interpretation.

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SOIL-GAS PROFILE OVER YELLOWHOUSE CREEK OIL FIELD

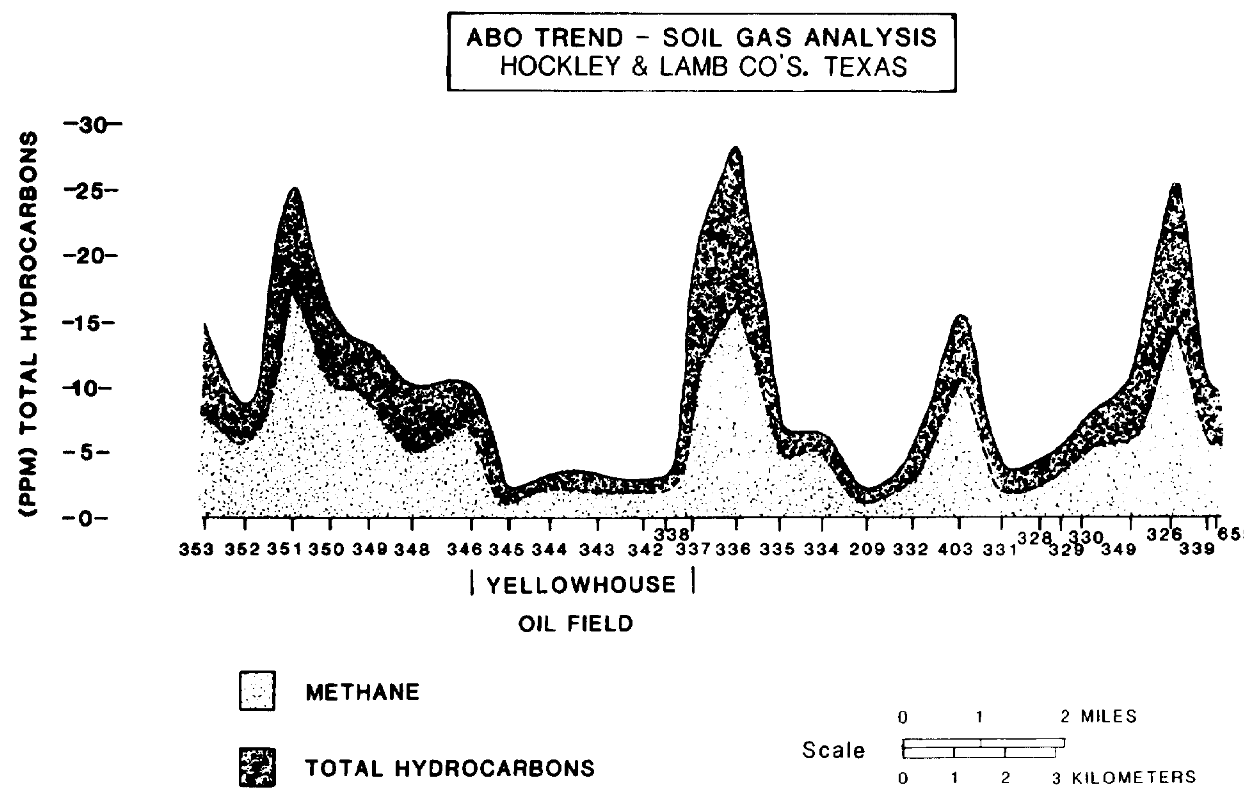

FIG. 21—Soil-gas profile of Yellowhouse Creek oil field, southwest Texas.

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