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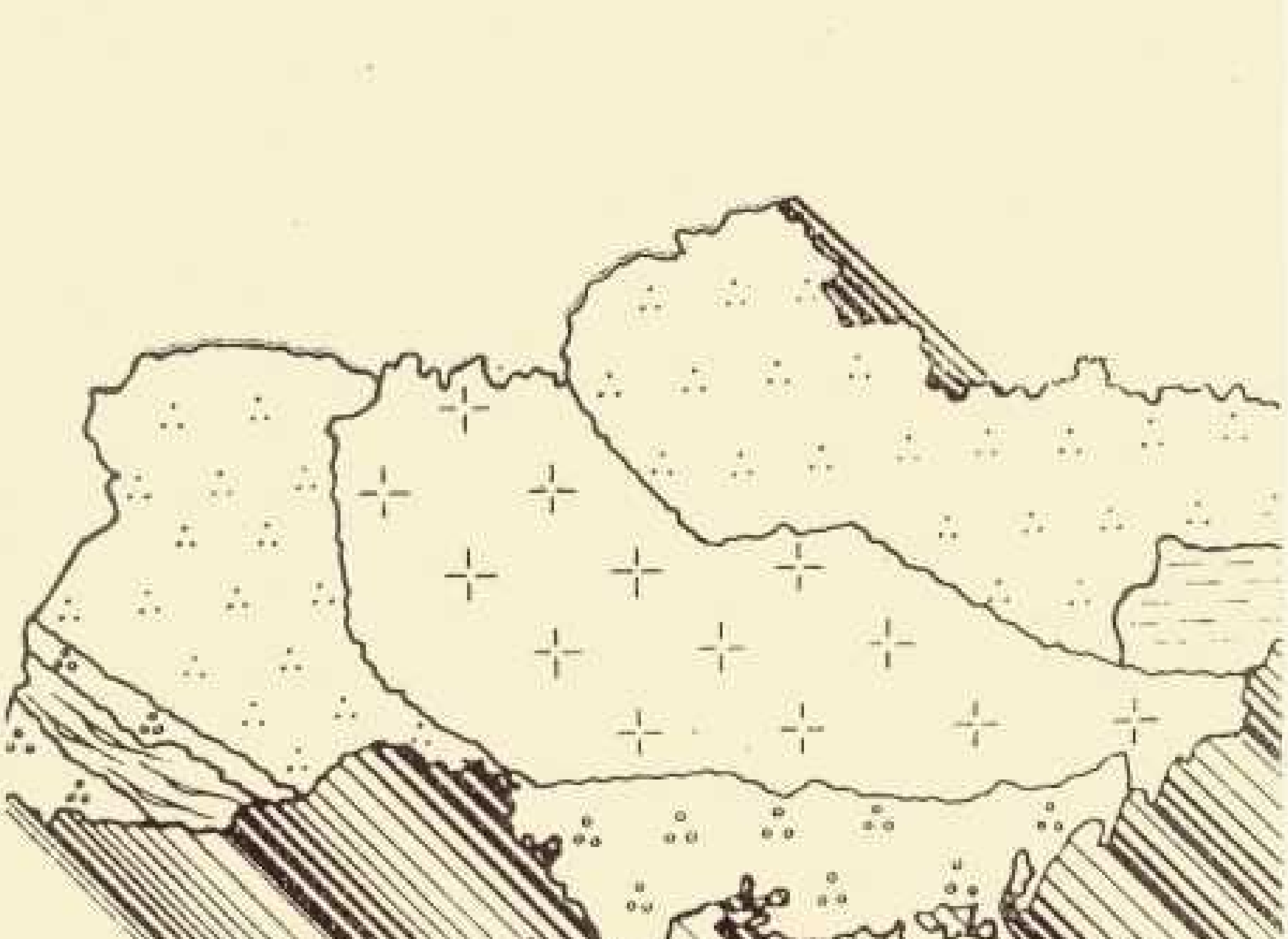
ДОКЛАДЫ МЕЖДУНАРОДНОГО СЕМИНАРА ООН "НЕФТЯНАЯ ГЕОЛОГИЯ И ГЕОХИМИЯ"

НЕФТЬ. ГАЗ. УГОЛЬ

ЛИТОЛОГИЯ. ГЕОХИМИЯ



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HEAT FLOW MEASUREMENTS IN EARLY EXPLORATION STRATEGY

УДК 553.98:(550.36)

ТЕРМИЧЕСКАЯ СЪЕМКА В НЕФТЕГАЗОПОИСКОВОЙ СТРАТЕГИИ

Глобальное изучение тепловых потоков, идущих из земных недр, и обобщение данных о геотермических градиентах подтверждают гипотезу о том, что осадочные бассейны и месторождения нефти и газа, где наблюдается усиленный восходящий вертикальный природный тепломассоперенос, могут быть как зонами наибольшей концентрации запасов нефти и газа, так и местами их наибольшей добычи. Использование термической съемки в неглубоких (1—10 м) горных выработках для картирования этих зон и мест на суше и в море гораздо эффективнее, чем обычная термометрия глубоких скважин. Результаты такой съемки позволяют значительно оптимизировать также количественные определения нефтегазогенерирующего потенциала осадочных пород, что особенно важно при поисках нефти и газа в слабо изученных, отдаленных или трудно доступных регионах.

Еще в 1972 г. Х. Д. Клемме обратил внимание на связь между высокими геотермическими градиентами и высокими уровнями теплового потока из внутренней части Земли с мировым размещением гигантских месторождений нефти и газа. Яркими примерами являются Лос-Анджелесский (США), Венский и Аравийско-Иранский бассейны, колоссальная площадь Советского Союза (особенно Бакинский район), дельта р. Миссисипи и три индонезийских нефтедобывающих области-бассейна. Однако эта связь не является однообразной, поскольку даже в сильно прогретых бассейнах тепловое поле напоминает «мозаику» из горячих и холодных участков, о чем свидетельствуют данные многих исследователей, в том числе советских — В. И. Артеменко, Ю. А. Балакирова, В. М. Березкина, В. Ф. Борзасекова, Н. Г. Волкова, Г. Д. Гинзбурга, М. А. Киричека, А. А. Кунарева, Ю. П. Маловицкого, В. Г. Осадчего, В. П. Палненко, И. Л. Соколовского, Л. И. Хребтова.

Изучать тепловое поле с помощью термометрии глубоких скважин дороже, дольше, сложнее и менее эффективно, чем неглубоким (1—10 м) термозондированием, использующим колодцы, шурфы, картировочное бурение, скважины для сейсмовзрывов, так как упомянутое зондирование позволяет создать наиболее густую и представительную сеть точек замера температуры с расстоянием между ними менее 1 км. Это особенно важно для слабо изученных и трудно доступных районов суши и шельфа, для которых необходимо обеспечить компьютерно-статистический анализ материалов и надежно определить характер вариаций теплового поля при сравнении с другими хорошо прогретыми площадями, характеризующимися богатой нефтегазоносностью недр.

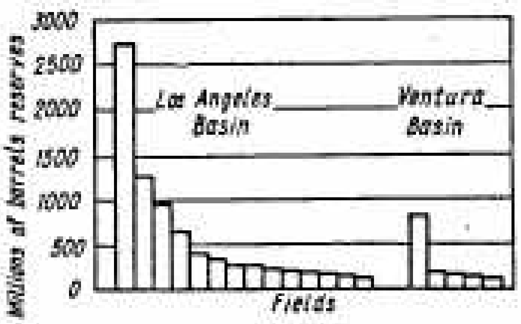
Исследование приповерхностных температур дает еще одно преимущество. Согласно физике тепломассопереноса, тепловой поток, начинающийся на глубине, равной нескольким километрам, и идущий вверх со скоростью около 1 см/год, может заметно изменить геотерму, поскольку происходит усиление теплового сигнала на меньших глубинах. В результате этого максимальный геотермоградиент наблюдается у земной поверхности, а не в стволе глубокой скважины. Таким образом, такое усиление теплового сигнала позволяет лучше и надежнее выявлять пути вертикальной восходящей миграции нефти и газа по замерам именно близповерхностных температур и более успешно указывать участки не только с высокой нефтегазоносностью, но и с более высокой дебитностью скважин и более высоким коэффициентом нефтеотдачи. Данная методика термокартирования использована Г. Зелинским и его коллегами при изучении теплового поля и нефтегазоносности недр Магелланова бассейна Огненной Земли (1983 г.) и Западного пояса надвигов (Скалистые горы, США), пересекающего нефтегазовые месторождения Уинти-Каньон и Рыкмен-Крик в штате Уайоминг (1985 г.).

В. А. Краюшкин

In March of 1972, a conference entitled, «Petroleum and Global Tectonics» was held at Princeton University. At that conference, H. D. Klemme (1975) pointed to a relationship between high geothermal gradients and high heat flow (the flux of heat from Earth's interior) and the worldwide location of giant oil and gas fields. Among Klemme's data (Fig. 1), the contrast in oil production between the Los Angeles and Ventura basins of California was noted with significantly higher geothermal gradients (Fig. 2) observed in the more productive Los Angeles basin. Similar findings were reported for the Vienna basin in Europe, three Indonesian oil-producing basins, a vast area of the Soviet Union and in detail for the Baku area, the Mississippi delta, and the petroliferous Arabian/Iranian basin.

In Fig. 3, all of the examples combined indicate greater hydrocarbon recovery in basins with higher geothermal gradients. This is obvious by comparison of type 1 interior basins with predominately higher heat flow type 6 and 7 intermontane basins. One high geothermal gradient type 2 basin is estimated to have more than twice the hydrocarbon recovery of 12 low to normal type 2 basins. The two high recovery delta areas are classified geothermally normal; however, higher temperatures are observed in the overpressured production zones. From the examples, it might be inferred that higher regional geothermal gradients may enhance oil generation and accumulation. Of course, temperature can be a double-edged sword in that too much can destroy hydrocarbons; however, some favorable overriding mechanism must prevail in order to explain Klemme's relationship.

One explanation put forth by H. D. Klemme was that higher geothermal gradients would favor oil and gas generation at shallower depths, where less compaction and more sediment porosity would favor hydrocarbon accumulation. Regardless of the exact mechanism, it seems from



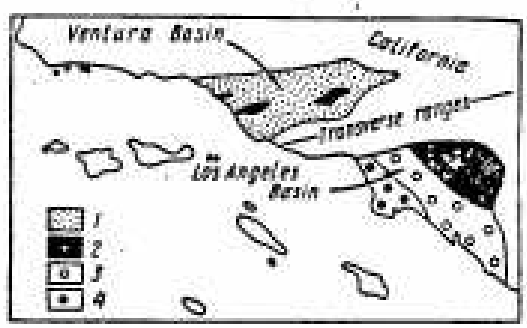


Fig. 1. The comparison of oil reserves

Fig. 2. Distribution of temperature zones in sedimentary basins, California
1 — 1.4°F/100' or less; 2 — 1.4°F to 2.0°F/100'; 3 — 2.0°F to 2.7°F/100'; 4 — 2.7°F or over

Fig. 3 that exploring for oil and gas in regions of higher geothermal gradient and heat flow should result in improved success. However, in his final remarks regarding the Arabian Gulf, H. D. Klemme noted the following, «... as the central Iranian massif or nuclear area is approached, low gradients with local 'hot spots' are present. Prolific production in the Arabian/Iranian basin is associated with relatively high gradients; however, just as much or more production is associated with low gradients.» He concluded that, «... temperature does not appear to be the principal factor in the world's greatest producing area».

H. D. Klemme characterized the geothermal gradient field in this part of the Middle East as containing a mixture of high values (as for the super giant Ghawar field, Saudi Arabia) interspersed with normal and low values, exhibiting a high degree of variability over relatively small lateral distances. Note that in addition to the higher geothermal

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gradients found in the Los Angeles basin compared with the Ventura basin (Fig. 2) there is also more lateral variability in the gradients.

The general observation that thermal data from areas of high heat flow and high geothermal gradient exhibit higher variability or scatter is well documented. Fig. 4 (above), for example, is a plot of heat flow versus seafloor age for the northwest Atlantic Ocean (Embley et al.,

Crustal types		Basin type	Geothermal gradient / (number of basins used)	Recovery / bbls.(or gas equivalent) per cu. mi. of total basin sediment
Crustal types	Craton	1. Interior	4 low	18,000
		2. Intracontinental composite	1 high 12 low to normal (25 unknown *)	(200,000) 83,000
		3. Rift	5 high (3 unknown *)	120,000
	Intermediate	4. Extracontinental downwarp	7 normal to high with „hot spots" (15 unknown *)	280,000
		5. Pull-apart	(All unknown *)	?
		6.+7. Intermontane strike and transverse	6 high 3 normal to high (15 unknown *)	420,000 (240,000)
		Delta	2 normal (above over pressured zone)	200,000

Fig. 3. The relationship between the basin type, geothermal gradient and petroleum recovery

* Unknown — no data on geothermal gradient. In bracks — estimated recovery

1983). The solid curve is the theoretical conductive heat flow which exhibits higher values at younger ages when the rocks of which the seafloor is comprised are closer to their initially near-molten temperatures. (The symbols plotted in Fig. 4, above, are the mean heat flow values measured in the age range indicated by the horizontal bars.) The range or scatter of observed heat flow values for each age group is indicated by a vertical bar. Note the tendency for higher observed values at younger seafloor age; however, individual values and even means can often fall much below the theoretical conductive curve. Equally important is the tendency for a large range or scatter of observed values within the younger, higher heat flow provinces. Thus, the degree of scatter in heat flow (or geothermal gradient) can also be diagnostic of a high heat flow province. The ubiquity of the phenomena just described can be seen in Fig. 4 (below) which shows a compilation of heat flow data from Europe (Chapman et al., 1979). Hence the example of the Arabian Gulf (discussed earlier) may not be contradictory to Klemme's thesis.

The underlying cause of the scatter in marine heat flow values near mid-ocean ridge crests has been the object of much investigation and it is now widely accepted that hydrothermal circulation in the oceanic crust (Langseth, 1980) is responsible. Moving water can effectively redistribute heat by convection and transport that heat directly to the overlying seawater, thereby escaping detection by the heat flow measurements. While the circulation itself has the ability to create local highs and lows in the heat flow if subsurface waters and viable pathways are available for movement, convection is more likely to occur in high heat flow provinces. Therein lies an alternate explanation for Klemme's global correlation of high heat flow and hydrocarbon production. The possibility that fluid circulation, an apparent manifestation of high heat flow areas, contributes to the global correlation received reinforcement by P. T. Fowler (1980) who described the effect of moving groundwater on the distribution of hydrocarbons in a sedimentary basin. Emphasis was placed on the role of water in mobilizing hydrocarbons, which would otherwise remain disbursed throughout a basin, and focusing them into discrete commercial accumulations. The moving waters would produce large lateral variations in temperature which could be used in P. T. Fowler's own words for, «telling live basins from dead ones».

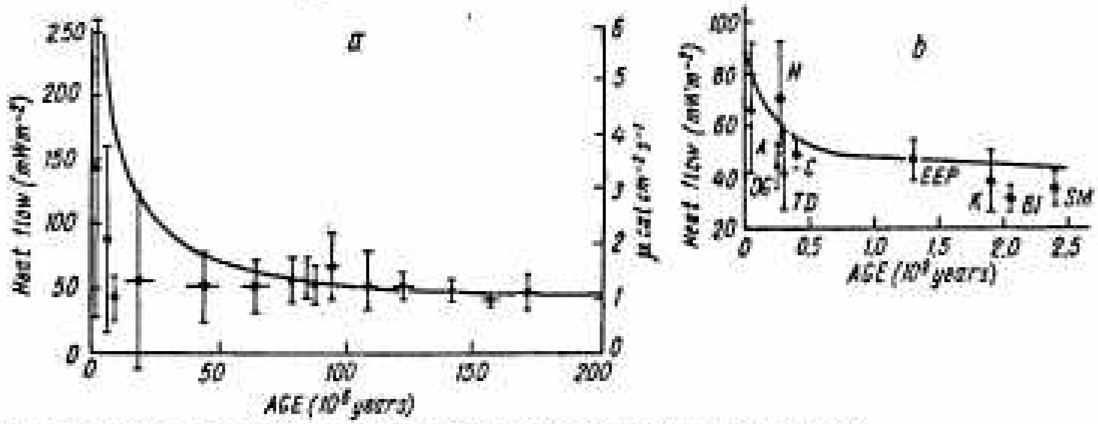

Fig. 4. Features of heat flow in North-West Atlantic (*a*) and Europe (*b*)
SM — Saamian; *BI* — Belmorian; *K* — Karelian; *EEP* — East European Platform; *C* — Caledonian; *TD* — Tersk depression; *H* — Hercynian; *OG* — Oslo graben; *A* — Alpine

P. T. Fowler's rendition of the hydrothermal effect upon hydrocarbons within a producing basin, in terms of scale, forms a bridge between the global association pointed to by H. D. Klemme (1975) and the individual hydrocarbon-bearing trap. It stands to reason that given Fowler's theory, the second essential ingredient for hydrocarbon accumulation is the existence of hydrocarbon traps along the flow path. A likely example of this (Beck, 1929; van Orstrand, 1934) is the Salt Creek field in the Powder River basin, Wyoming, an anticlinal structure with associated near vertical faults. The presence of surface hydrocarbon seeps (Mallory, 1949) over the structure serves both as evidence for vertical fluid migration and for the fact that the trap does not form a perfect seal. A dynamic fluid system is, furthermore, required to explain the coinciding positive thermal anomaly indicated by an upward bow in the 80 °F isothermal surface. This physical example strongly suggests the possibility of using surface thermal measurements to study vertical migration which, according to J. M. Hunt (1980), is particularly important for interpreting surface geochemical anomalies which are used as both regional and local indicators of subsurface petroleum accumulations.

The association of temperature anomalies with hydrocarbon fields has for some time become subject matter for Soviet textbooks and monographs (Borzasekev, 1969; Balakirov, 1970; Ginsburg, 1973; Volkov et al., 1981; Eremin, 1982). N. G. Volkov et al. (1981) for example references ten fields, located in the Ukraine, representing oil, gas and mixed production all from Upper Paleozoic structure of varying dimension and at depths greater than 2,000 m. The temperatures measured at 14 m depth show varying amounts of agreement with production. In somewhat more detail, A. I. Khrebtov (1960) published results of an areal study of hydrocarbon entrapment on the flank of a positive structure with a clearly associated temperature pattern present in measurements made 250—270 m above the structure.

The foregoing examples mainly involve structural traps. While examples of structure related thermal anomalies appear more numerous, V. M. Berezkin et al. (1978) reference a well defined thermal anomaly at 100 m depth associated with an oil bearing stratigraphic trap with production at 1000—1200 m.

Using drill-stem test temperature data, H. J. Meyer and H. W. McGee (1985) studied 22 oil and gas fields from six states in the Rocky Mountain region of the U. S. Of the 22 fields studied, 15 had well-defined thermal gradient anomalies which coincided areally with productive zones. Included were 3 gas fields and 12 oil fields, 9 structural traps and 6 stratigraphic traps. Of the remaining 7 fields, 5 were possible hot spots and one was inconclusive, all resulting from insufficient rather than negative data. The authors suggested the most likely explanation in terms of vertical fluid migration. Furthermore, they showed that had it been possible to map zones of the highest quartile geothermal gradient (or heat flow) prior to drilling, initial producer to dry hole ratios would have doubled simply by selectively drilling these areas. Such deep borehole measurements are often useful in understanding the processes at work in developed areas. From the logistic and economic standpoint, however, they are not a viable tool for frontier exploration.

An example of a temperature anomaly detected at 1.2 m depth in the floor of the Caspian Sea, Baku area, USSR (Artemenko and Malovitskiy, 1977). Oil and gas production occurs at about 5,000 m and is associated with a faulted anticlinal structure similar to that of the Salt Creek field. A study by V. G. Osadchiy et al. (1978) with shallower (500 m) production depths, resulted in a 1 °C temperature anomaly measured at 1.5 m depth. It was correlated with a near-surface geochemical anomaly, (reduction number) which relates to hydrocarbon gases in the surface soils. V. I. Artemenko and Y. P. Malovitskiy (1977) and V. G. Osadchiy et al. (1978) both report 0.5—1.0 °C temperature anomalies at 1.2—1.5 m depth over hydrocarbon bearing structures. The increase in local heat flow required to cause such an anomaly can be estimated at eight-fold, assuming a sediment thermal conductivity of 0.002 cal/°C·cm·s. The existence of such an anomaly related to deep structure implies upward convective heat transport by fluid flow. As for the Salt Creek example, a totally conductive explanation, given the absence of shallow magma, can be categorically ruled out.

Another example of «shallow probe» measurement illustrates the variation in relative heat flow values (made to 3 m depth) over two hydrocarbon producing fields in Tierra del Fuego, Argentina. The high in relative heat flow coincides with positive basement structure where the highest density of basement faulting is observed (Zielinski and Bruchhausen, 1983). As for V. I. Artemenko and Y. P. Malovitskiy (1977) and V. G. Osadchiy et al. (1978) temperatures at 1.2 m were génerally found to be 0.5—1.0 °C higher over the field. The measured heat flow anomaly of nearly ten-fold must again be explained by vertical fluid migration. The most plausible source depth for fluid upwelling in this area is 1.5 km, which requires a flow rate of 5 cm/yr upward along basement faults to produce the observed heat flow anomaly. For the Magellan basin as a whole, based on deep well thermal measurements, the identical flow rate of 5 cm/yr was calculated for flow from deeper in the basin into the hydrocarbon province. Burial history estimates of hydrocarbon generation (Waples, 1980) supported more than 100 km of lateral hydrocarbon migration in the Magellan basin. This migration was further required to be at a rate sufficiently close to the flow velocity derived from the thermal models to rule out hydrocarbon transport by aqueous soluability (Zielinski and Bruchhausen, 1983).

It was subsequently learned that geochemical analysis of oils from the Magellan basin reservoirs by Deminex (Federal Republic of Germany) supports the long range migration called for by G. W. Zielinski and P. M. Bruchhausen (1983) (G. J. Schrayer, personal communication). Despite the limited number of measurements presented in G. W. Zielinski and P. M. Bruchhausen (1983), the study serves to illustrate the usefulness of shallow land-based heat flow measurements in frontier areas. In addition, it emphasizes the ability of such studies to impact problems in petroleum geochemistry.

A second and larger suite of relative heat flow measurements was obtained by G. W. Zielinski et al. (1985) across a segment of the Western Over-thrust Belt, traversing the Whitney Canyon and Ryckman Creek fields. These measurements, made in seismic shot holes up to 100 ft deep, were indicative of the applicability of the techniques to environments with much higher topographic relief and more varied lithology and groundcover than in G. W. Zielinski and P. M. Bruchhausen (1983). Opportunity to remeasure stations in different seasons, furthermore, confirmed the repeatability of the measurements. Comparing the variation of these measurements with the heat flow across the Galapagos Spreading Center, an established marine hydrothermal area (Williams et al., 1974), led G. W. Zielinski et al. (1985) to postulate transport of heat by moving groundwater. Comparing the heat flow trend with the subsurface geologic structure revealed that two relative heat flow highs could be correlated with major faulting associated with the two hydrocarbon producing structures. As in the Salt Creek example, the faults could be channeling hydrocarbons into associated structural traps. Thus, the recurrent relation between hydrocarbons, heat flow and groundwater movement, is again preserved.

DISCUSSION AND CONCLUSIONS

A wide variety of thermal data support the hypothesis that areas of hydrothermal circulation, an apparently ubiquitous feature of zones of higher heat flow, tend to be more favorable locations for the generation, migration and accumulation of hydrocarbons. The relationship appears to hold on a regional scale as well as for individual hydrocarbon producing fields. Such areas can be defined thermally by high variability or scatter in individual heat flow values with, to a greater or lesser degree, elevated mean values. The implication of this result with respect to the common practice of using relatively sparse deep-well thermal data for burial history/source rock maturation calculations and applying those results to broad basin areas is that large errors are likely.

The published data results suggest that a more viable approach for frontier areas, both onshore and offshore, is to perform higher density shallow-probe heat flow measurements at a measurement site spacing of greater than 1 km, in order to characterize statistically the heat flow variability over an area and in comparison with other areas. Subsequent detailed investigations, at site spacings of less than 1 km as suggested by the more regional data, should be aimed at targeting areas for verification by seismic methods.

Physical insight into the applicability of near-surface heat flow measurements for detecting vertical migration can be gained from the following theoretical example (Fig. 5). In the simplest case of direct vertical fluid migration from depth to the surface the normal geotherm (solid line) bows upward (dashed curve) the amount depending upon the flow velocity (Bredehoeft and Papadopulos, 1965).

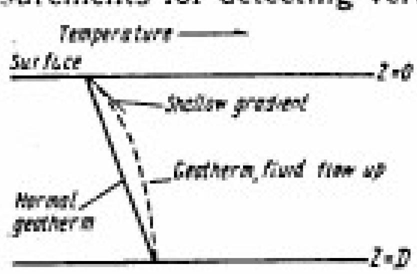

Fig. 5. Dependance of heat flow on depth

For flows originating from several kilometers depth, velocities on the order of 1 cm/yr can alter the geotherm by adetectable amount. For such conditions the shallow thermal gradient (dT/dZ) measured by a shallow probe would correspond to the tangent to the curve (Fig. 5) at the surface. Note that this is a maximum value at the surface, whereas the gradient resulting from a single BHT measurement at depth $Z=D$ (the «normal geotherm») would be much less. Hence, there is an amplification of the heat flow signal at shallow depth. This amplification can result in the ability to map vertical migration using shallow-probe heat flow measurements to an extent not possible with conventional deep well measurements.

Recently, increased interest has been given surface geochemical surveys which infer source type (oil/gas) and maturation from the ratios of light (C1-C4) hydrocarbons in soils and in shallow marine sediments. Such measurements can be performed in «shallow-probe-fashion» on land, in seismic shotholes and via marine core-sampling in offshore areas. The aforementioned ability of the shallow heat flow measurement to detect vertical migration and the operational and logistical similarities between shallow heat flow and geochemical data acquisition strongly suggests that these data should be collected jointly and interpreted in an integrated fashion.

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