IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG)
e-ISSN: 2321–0990, p-ISSN: 2321–0982.Volume 6, Issue 4 Ver. II (Jul. – Aug. 2018), PP 62-104
www.iosrjournals.org

High Accuracy Estimation with Computer-Aided Hydrochemical Methods of Oil and Gas Deposits in Wildcat Sedimentary Basins

Adil Özdemir[1], S. Orkun Turgay[2] and Alperen Şahinoğlu[3]
[1] *Adil Özdemir Consulting, Ankara, Turkey (adilozdemir2000@yahoo.com)*
[2]*İskenderun Technical University, Petroleum and Natural Engineering Department, Hatay, Turkey*
[3]*İstanbul Rumeli University, Graduate School of Natural and Applied Science, İstanbul, Turkey*
Corresponding Author: Adil Özdemir

Abstract:*In the wildcat sedimentary basin which will be explorated oil and gas, to increase the possibility discovery of find of commercial oil and gas must be benefit from approximately 90 years of experience in petroleum hydrogeology. These methods provide considerable simplicity especially in geological and geophysical surveys on illuminating subsurface geology. The HYDROPET is a new computer software was developed by authors to contribute to oil and gas exploration, especially in geologically complex and wildcat sedimentary basins. The program is developed with chemical and isotopic classification, analysis and interpretation methods proposed by a large number of different researchers based on water chemistry analysis data.This study includes test results in known oil and gas production fields that composed of different and complex geological structures.Results of the program and the data of the known oil and gas production fields are same. Program allows basin/field-scale interpretation based on water chemistry data show that especially in geologically complex and wildcatsedimentarybasins, location of oil and gas deposits and properties of petroleum geology and subsurface geology can be estimated with high accuracy.*

Keywords: *Oil and gas exploration, oilfield waters, formation waters, hydrochemistry, HydroPet software*

Date of Submission: 25-07-2018 Date of acceptance: 08-08-2018

I. Introduction

The rocks are tilted and bending by the plate tectonic forces and gravity. As a result of these geological events, many petroleum trap and cover rock types occurred. Understanding the formations of these trap types helps to identify potential reservoirs of oil and gas. The main purpose of oil and gas exploration is to estimating these hidden oil and gas reservoirs in complex terrain conditions. So, the information be obtained by drilling is be critical. Because drilling provides direct information on oil and gas traps. But, the drilling data only provide information on the geological features of the locality where it is made.

Oil and gas traps can be determined by conventional geophysical methods (especially seismic). But, no information can be obtained about whether there is oil or gas in the field or basin where it is applied. Also, application of conventional methods such as drilling and seismic survey are difficult and expensive, especially in the case of complex geological and topographical distressed terrain conditions. In this case, geochemical exploration methods are the most effective ways to increase oil and gas exploration efficiency and reduce exploration costs. Because, the components that are determined by geochemical methods are only found together with hydrocarbon accumulations, or are derived from them. Therefore, data which are obtained from geochemical exploration studies are evidence of the presence of oil and gas in basins and traps. Anomaly maps (target areas for geophysical measurements and/or drilling) with these data obtained from geochemical exploration methods emerge. To prepare these maps, are a result of oil and gas exploration in wildcat sedimentary basins and the experiences in the sector since today.

Investigation into the groundwater setting is an important issue in petroleum potential assessment in various regions at different stages of exploration (Kurchiko and Plavnik, 2009). In a wildcat sedimentary basin, ateam engaged in oil and gas exploration should focus on areas that is permeable unit which is under the non-permeable geological strata keeps oil and gas. Because, connate waters are more important than other water types for oil and gas exploration. In oil and gas exploration, thousands of water samples and geological structures of oil and gas fields studied by many researchers (e.g. Sulin, 1946; Chebotarev, 1955; Schoeller, 1955; Vel'kov, 1960; Bojarski, 1970; Schoeneich, 1971 and Wei et al., 1996) for the useage of water geochemistry have been examined, different classification methods have been developed. All of these researchers focused on the determination of with the water geochemistry data and the presence of oil and gas in basins and estimating the location of hydrocarbons reservoirs in the basin.The authors compared the methods suggested by these researchers with data from oil and gas production fields around the world. Comparing with results have been determined to be directly compatible with the results of known oil and gas fields. During these studies, the conclusion that the manual feasibility of the calculations in the proposed numerical classification methods in these methods is impractical (maybe because of the difficulty of working with so many numerical methods, the usage of the methods is limited). To develop a computer program that useful results and includes isotopic methods as a whole with these chemical classification methods seen in the tests made by the authors are intended. The HYDROPET is a new computer program developed by authors to contribute to oil and gas exploration, especially in geologically complex and wildcat sedimentary basin. Software is developed with chemical and isotopic classification, analysis and interpretation methods proposed by a large number of different researchers based on water chemistry analysis data.

Image. 1. Main screen view of Hydropet program

In this study, the authors aimed to share with the sector stakeholders the experience gained up to now in the field of oil and gas exploration during the preparation and development stages by the hydrogeochemical methods of HYDROPET program.

II. Hydrochemical Exploration for Minimizing Oil and Gas Exploration Risk and Cost

Sustainability of oil exploration and production projects is possible by first evaluating the availability, quantity and economic potential of oil, which primarily fills the reservoir rock pores with water. Therefore, after the formation of oil and migration, starting with the water, which is the first fluid inlet to the pores of the reservoir rock, and their association with the millions of years, it is obligatory to determine the basic qualities of the water in order to understand the existence of hydrocarbons. Water, the first agent to fill the voids of the rock during sedimentation, reflects other physicochemical properties, primarily salinity of the sedimentary environment (Çoban, 2017). Assuming that oil and gas originated from dispersed organic matter, the accumulation into pools is possible only by migration through waterfilled porous rocks. Fundamentally there are two possibilities: (a) accumulation in a stagnant water system, that means under hydrostatic conditions (b) accumulation along with mobile water, that means under hydrodynamic conditions. Oil and gas, which originated from dispersed organic matter, must be transported to the traps under normal geological conditions with the helps of water. Assuming that the accumulation in a stagnant system is theoretically possible, it is certain that water currents of a hydrodynamic system would be much more effective if the release of the dissolved matter is kept (Meinhold, 1972).

Gas, oil and water is collocating in subsurface. Because of the density of petroleum is less than the density of salt water, the petroleum layer on the oil traps is above the layer where the salt water is. In oil traps (usually called anticlines), water beneath the petroleum is salty water and represents the sea water (fossil marine water) at the time of the oil formation. In the operated oil wells, when the oil in the petroleum strata decreases, the following salt water invades oil deposits. So, after a while, the oil starts to withdraw from the wastewater with very little oil and salt water, and when the bed "economy" loses its condition, it is deactivated in terms of well production (Fig. 1).

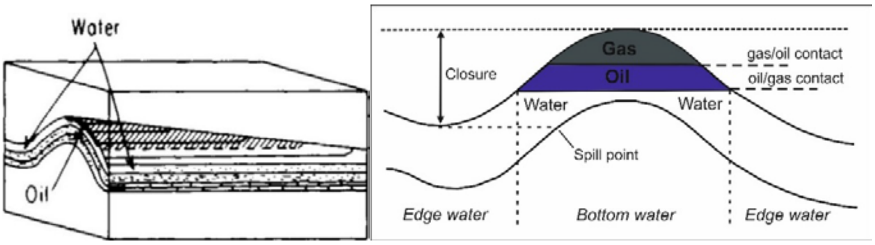


Fig. 1. Relationship between oil, gas and water in an anticline trap

Formation water is a constant companion of petroleum shows and deposits,thus providing useful related information (Mazor, 2004):

- Identification of formation waters that are possibly associated with nearbypetroleum deposits: Formation waters that are associated with petroleum differ from regular formation waters by their detectable concentrations of petroleum compounds. This provides a tool for petroleum exploration. The potential of this method is high as formationwaters are encountered along all deep drilling operations. Highconcentrations of petroleum compounds raise the prospect of finding associated petroleum deposits.

- Understanding and mapping the structure of individual petroleum fields: Oil and gas fields are heterogeneous, composed of separated petroleum-containing rock-compartments interwoven with only water-containingcompartments. The detailed structure of every field can be mapped bythe properties of the water as well as the petroleum occurrences. Information of this kind is essential in placing central production plants and siting of new wells.

The fact that companies do not use thousands of water analyzes and well test results in the determination of new search areas and investment decisions is not the only way to determine the location of wells on the basis of physicochemical and hydrodynamic data, but instead of a few seconds difference in seismic sections alone. This demonstrates the necessity of petroleum hydrogeology assessments to be used in combination with the structure of well sites in a rational way, when close to each other and taking into account the results of most unsuccessful wells. The solution of this fundamental defect in oil exploration is possible by the identify new exploration areas and the well oppenings or by evaluating water physicochemical, salinity and hydrodynamic data together with structural data. Authors should underscore to the fact that this development will enable the development of the sector's upper arm activities on a successful and economic basis, by exploring the oil exploration and production based on scientific data and oil and gas discovery with a high probability of exploration (Çoban, 2017).

Pirson (1942) determined the success ratios for the followingexploration methods: random drilling, 5.8%; geology, 8.2%; geophysics,14.9%; and geochemistry, 57.8%. Basically, the separation of the geochemical anomalies from background is very important in order to interpret the hydrocarbon accumulations zones.The active neotectonic (dynamically "excited", "unbalanced") geologically complex basins of the Alpine mobile belts, the implementation of the standard exploration strategy and techniques rooted in the half-century-oldexploration empirics within relatively simple, tectonically "quiescent" platform regions with the dominating old foursome of "source rocks/traps/reservoir rocks/seals" turns out to be costly and often unsuccessful. A most telling example is the South-Caspian Basin (SCB). There is largest western transnational companies and consortia, working under the PSA arrangements from 1995 through 2008, drilled 28 exploratory wells,up to 7,301 m deep (almost 24,000 feet). The wells were spudded on thestructures deemed highly potential and preliminarily subjected to high-resolution 3D seismic surveys. The effort cost about $1 billion and did not result in a single commercial discovery. Geologically complex oil and gas basins within the Alpine mobile belts in most cases have an exceedingly great number of distinctive features (Rachinsky and Kerimov, 2015).

The close association of hydrocarbon accumulations with subsurface waters has led to the use of properties of these waters as a secondary exploration tool. Both chemical and physical characteristics of subsurface waters have been utilized in the exploration for petroleum. The movement of subsurface waters are made a significant contribution to the accumulation of petroleum. In addition to dissolved organic and inorganic constituents, hydrodynamic movement, oxidation-reduction potentials, and water classification systems have been advocated for use in petroleum exploration (Ostroff, 1975). Identification of water category encountered or expected in an accumulation is very important. It affects the field development strategy, well pattern, production techniques, reservoir management, drilling, and workover operations. These issues are solved taking into account hydrogeologic conditions not just in a single accumulation but in the entire field. Most important is information about changing hydrogeologic environment in that field. Information about the pre-development hydrogeologic (hydrodynamic and hydrochemical) environment is crucial. Hydrogeologic studies during the petroleum exploration are also very important and data for solving the mentioned problems should be collected during this stage. Significant issues during the exploration stage are: (1) Identification of independent hydrogeologic systems in the basin being studied; (2) hydrodynamic drives occurring in each one; (3) their hydrodynamic and geochemical evolution; (4) the identification of hydrodynamic and geochemical anomalies as indicators of cross-flows between various horizons; (5) the distribution of the normalized pressure within the identified hydrogeologic stages, in the section and laterally; (6) the identification of locations for possible hydrocarbon traps and patterns in their distribution; and (7) analyzing the concepts of hydrocarbon migration in the basin and the formation and destruction of hydrocarbon accumulations (Chilingar et al., 2005).

The purpose of hydrogeochemical exploration methods is to find direct and indirect markers of oil and gas deposits where commercial discovery can be made in areas where hydrocarbon potential is unknown or little known, and to estimate the oil and gas presence a general or specific scale in the region and the most promising regions on a general or specific scale. These investigations are particularly more important in areas where the geological structure is not well known, particularly with the information on the presence or absence of oil and gas in the basin. Because, hydrogeochemical investigations also show geological structure. The examination of structural conditions from hydrogeochemical indicators will naturally facilitate the exploration of oil and gas. Today, hydrogeochemical investigations are carried out primarily in areas where many cold-and-hot springs are present. But, the oil and gas potentials were continued in uninvestigated regions in detail. These hydrogeochemical data are very valuable in areas where there are many natural spring waters and shallow and deep wells drilled for different purposes. Also the composition of groundwater is known by the analysis results and geological structure is relatively well known. Because, hydrogeochemical investigation is based on the interpretation of data which are obtained from existing analysis of water already existing for different purposes and new analyzes to be made if necessary. Hydrogeochemical maps are prepared from these water analysis data and maps predicting the oil and gas potential of the region are evaluated. Later, regions where commercial oil and gas exploration are estimated are classified (Figs, 2 and 3).

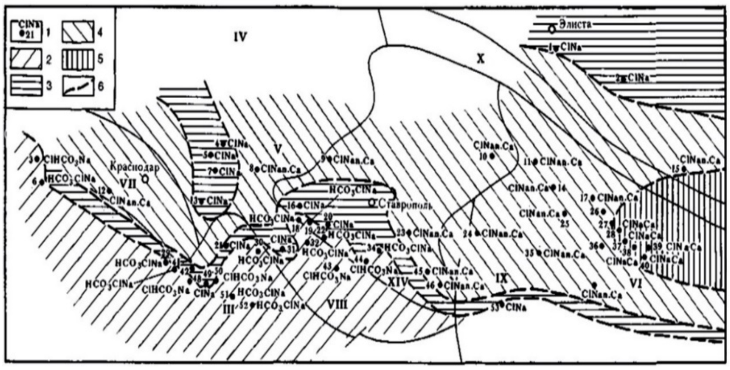


Fig. 2. A hydrogeochemical map: 1. No. of water point and chemical composition formula by thecomponent precedence; zones of water distribution with composition: 2. HCO_3-Cl-Na,Cl-HCO_3. Na; 3. Cl-Na; 4. Cl-Na-Ca; 5. Cl-Na-Ca; 6. Zone boundary (Tikhomirov, 2016)

Fig 3. Map for predicting petroleum from the composition of water. The numbers indicate the importance of the regions (Kartsev et.al, 1954)

The main criterion used is the degree of stagnancy of the water. One should however, keep in mind that the prediction of commercial value of individual oil and gas bearing zones on the basis of hydrochemical indicators alone is not sufficient because the reservoir properties of the rocks are not taken into account. The investigations of Sukharev (1948) shows in some cases it is possible not only to predict oil and its commercial value but also to predict the nature of the deposits in a given zone (Kartsev et al., 1954). Even though it is not possible to precisely estimate the economics of a groundwater based approach in petroleum exploration, a cost-saving of up to 50% in regional surveys on continental areas may be expected and there is a strong case for a field-test of the concepts (Toth, 1987).

III. Definition, Classification and Evolution of Oilfield Waters

Many chemical classifications have been proposed or discussed by Roger (1917), Tolstikhin (1932), Piper (1944), De Sitter (1947), Durov (1948), Sulin (1946), Vassoyevich (1954), Chebotarev (1955), Schoeller (1955), Rainwater and White (1958), Chave (1960), Eremenko (1960), Hounslow (1995) and Rosental (1997), to mention just a few investigators. The water classifications have been reviewed in Chilingar (1957, 1958), Chilingar and Degens (1964), Samedov and Buryakovsky (1966), Collins (1975), Lawrence and Cornfordt (1995), Boschetti (2011), Boschetti et al. (2014) ve Engle et al. (2016).

Waters can be classified in a number of ways. Most commonly they are grouped according to the following criteria (Roger, 1917): (1) water origin - meteoritic, connate, or juvenile waters, (2) water chemistry, e.g., bicarbonate, sulfate, or chloride waters, and (3) total water salinity, i.e., fresh water, saline water, or brine water.

Meteoric water; White (1957) defined it as water that was recently involved in atmosphere circulation and further that “the age of meteoric groundwater is slight when compared with the age of the enclosing rocks and is not more than a small part of a geologic period.”

Sea water; The composition of sea water may vary somewhat, but in general will have a composition relative to the following (in mg/l): chloride - 19,375, bromide - 67, sulfate - 2,712, potassium - 387, sodium - 10,760, magnesium - 1,294, calcium - 413, and strontium - 8 (Collins, 1975).

Interstitial water; Interstitial water is the water contained in the small pores of spaces between the minute grains or units of rock. Interstitial waters are: (1) syngenetic (formed at the same time as the enclosing rocks); or (2) epigenetic (originated by subsequent infiltration into rocks) (Collins, 1975).

Connate water; The term connate implies born, produced, or originated together. Therefore, connate water probably should be considered to be an interstitial water of syngenetic origin. White (1957) called connate water of this definition a fossil water, i.e., water that has been out of contact with the atmosphere for at least a large part of a geologic period. As White (1957) pointed out the implication that connate waters are only those “born with” the enclosing rocks is an undesirable restriction.

Diagenetic water; Diagenetic waters have changed chemically and physically, both before, during, and after sediment consolidation. Some of the reactions that occur in or to diagenetic waters include bacterial, ion exchange, replacement (dolomitization), infiltration by permeability, and membrane filtration (Collins, 1975).

Juvenile water; Water is existed in primary magma or derived from primary magma is juvenile (White, 1957).

“Formation water” is a term for water, saline or otherwise, present within the pore spaces of a sedimentary rock, and can include locally recharged waters of meteoric origin as well as that originally present when the sediment was deposited. Pore waters are ubiquitous in sediments and sedimentary rocks and exhibit significant variation in composition (Houston, 2007). Formation waters in sedimentary basins are dominantly of local meteoric or marine connate origin. However, bittern (residual) water, geologically old meteoric water, and especially waters of mixed origin are important components in many sedimentary basins (Table1; Kharaka ve Hanor, 2007).

Table 1. A synthesis of nomenclature describing geofluids (Lawrence and Cornfordt, 1995)

<table>
<tr><th>Adopted grouping</th><th>Subgroup</th><th>Sub-subgroups</th><th colspan="2">Other groupings</th><th>Comments</th></tr>
<tr><td rowspan="5">Internal fluids</td><td rowspan="2">Formation water</td><td>Pore water</td><td>Interstitial water</td><td rowspan="2">Oil field brines, connate waters</td><td rowspan="2">Trapped during sedimentation e.g. from clay dehydration</td></tr>
<tr><td>Diagenetic water</td><td rowspan="2">Products of diagenesis</td></tr>
<tr><td rowspan="3">Hydrocarbons</td><td>Gas</td><td>Petroleum</td><td>Both bio- or thermogenic methane recognized</td></tr>
<tr><td>Oil</td><td colspan="2"></td><td>Thermally degrades to solid bitumen and gas</td></tr>
<tr><td>‘Solid’ bitumens</td><td></td><td>‘Plastic solids’</td><td></td></tr>
</table>

	'Fluid' rocks				Once fluid/plastic flow e.g. Salt or shale behaving as fluid
	Anthropogenic	Surface water			e.g. Drinking water, effluent
External fluids	Meteoric or artesian water	Precipitation			Contains dissolved air and bacteria
		Tectonically 'uplifted' water		Hydrothermal	Pore water
	Metamorphic				Lakes etc.
		Water			From dehydration reactions e.g. H_2, CH_2, CO_2, H_2S (dissolved)
		Gases			
	Mantle	Water	Primordial		Often chemically reactive
		Methane			Never known to be commercial

If a fluid is defined as 'that which flows', then heat and energy might appear in this table. Connate water is defined as 'water that has not been exposed to the atmosphere since "deposition"'. Pore water is sometimes called 'interstitial water', which can include diagenetic contributions.

Produced water; Any water produced from a hydrocarbon well, including flowback water, formation water, injected fluids, water condensing from the gas phase, and mixtures (also referred to as co-produced water) (Engle et al., 2014).

Flowback water; During the development of unconventional resources such as shale gas or tight oil, a fracturing fluid and a proppants are injected into the reservoir under high pressure in order to create fractures to increase rock porosity and permeability. Flowback water consists primarily of the injected water and is generated in the first few days to weeks following hydraulic fracturing (Engle et al., 2014).

Deformation is an important part of the dynamic evolution of basins. High deviatoric stress causes faulting and fracturing which usually reflect the fundamental mechanisms of basin formation e.g. (normal faults in rift basins, reverse or thrust hilts in foreland basins, strike-slip faults in 'pull-apart' basins). Faults can operate as both fluid pathways and flow barriers and in this way can contribute to complex 3-D pathways for fluids of different origins in evolving sedimentary basins (Figs., 4,5 and 6; Lawrence and Cornfordt, 1995; Knipe, 1993).

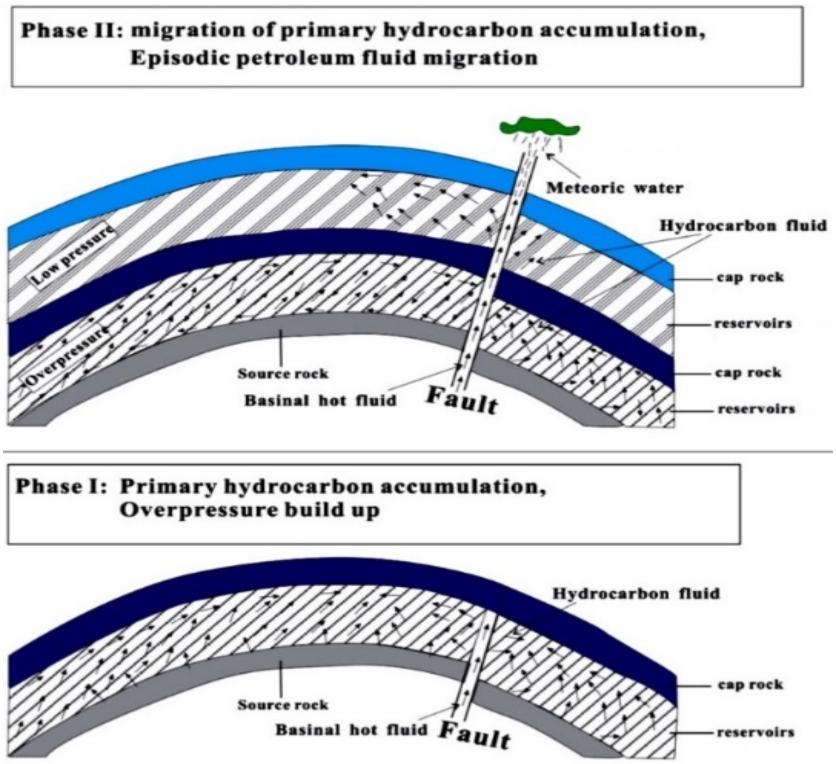


Fig. 4. Schematic model for episodic fluid migration in the fault-zone area (Jin et al., 2008)

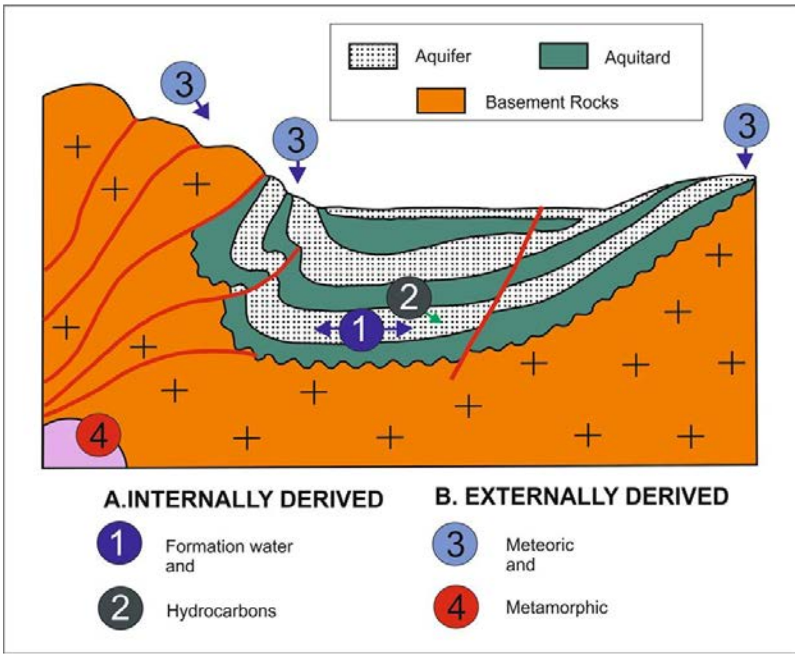


Fig.5. Fluids internal to basins (A) comprise formation waters (1) initially trapped during sedimentation augmented by water generated during diagenetic and low-grade metamorphic dehydration reactions, together with hydrocarbons (2) generated from organic-rich petroleum source rocks. Externally derived fluids (B) comprise meteoric waters (3) derived from precipitation in areas of topographic elevation, and metamorphic fluids (4) emanating from metamorphic dewatering in zones below and external to the basin. (Note magmatic fluids associated with volcanic activity are included in this category for convenience) (Lawrence and Cornfordt, 1995).

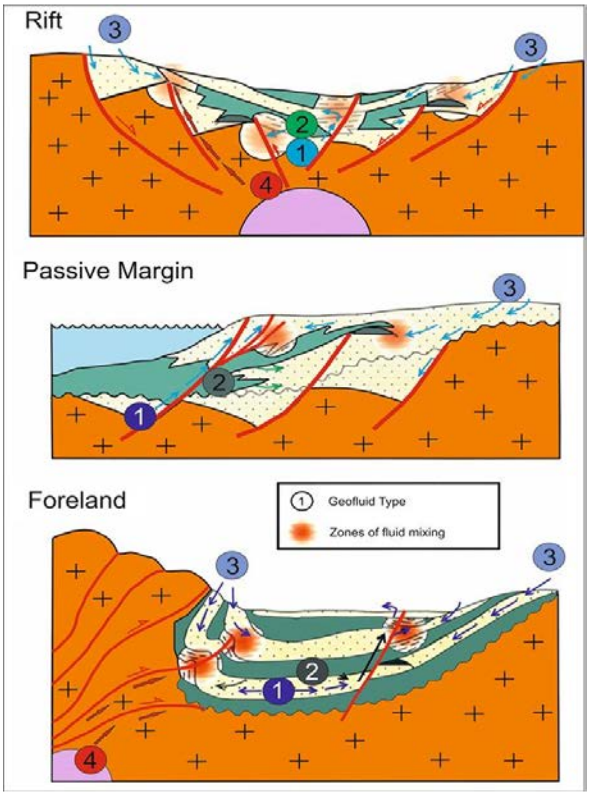


Fig. 6. The effectiveness of the various geofluid flow regimes are characteristic of different basin types and settings. Flow regimes and the potential for fluid mixing will evolve with basins as depicted by a plate tectonic (Wilson cycle) evolutionary path from intracontinental rifting through passive margin and ultimate continental collision with foreland basin development (Lawrence and Cornfordt, 1995, see Figure 5).

Since all natural waters are mixtures, it is impossible to classify them rigorously, and any system of classification is a matter of convenience rather of fixed principles. For practical convenience is evident that oilfield waters should be classified as far as possible according to their position in relation to the oil. As waters near the oil measureable difference in composition from those nearer the surface a classification based directly on the chemical character of the waters and indirectly on their position in relation to the oil may be made. This classification may be summarized as follows (Fig. 7; Roggers, 1917):
Group 1. Normal, strongly sulfate water (typically of meteoric origin).
Group 2. Modified, less strongly sulfate water (may be either meteoric or connate but is commonly a mixture in which meteoric water predominates).
Group 3. Altered, practically sulfate-free water (meteoric and connate waters and mixtures of the two).
- Reversed (carbonate water, originally meteoric).
- Mixed (chloride-carbonate water).
- Brine (chloride water, originally connate).

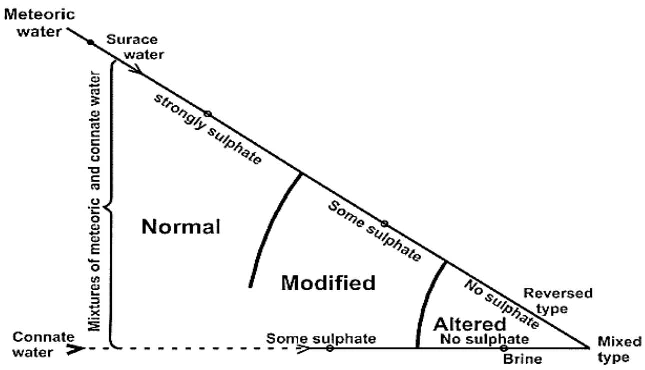


Fig. 7. Diagram illustrating relation of oilfield waters of the meteoric and connate types, and their alteration as the oil zone is approached (Rogers, 1917)

However, there are also basins where fresh waters are associated with the pools. Two cases can observed (Coustau, 1977) :(1) The waters may be meteoric waters which may have invaded the reservoir after the oil migrated into the trap; however, the interstitial water associated with the oil in the predominantly oil-saturated column, is probably salty; one must take into account this phenomenon when water saturation and reserves are considered. An example is the Douleb oilfield in Tunisia. An analysis of the water samples obtained above and below the oil-water contact is shown in Table 2.

Table2. Comparison of water analyses **-** Douleb oilfield, Tunisia (values expressed in mg/liter) **(**Coustau, 1977)

Property	**Water associated with oil**	**Water below the oil-water contact**
Na (mg/l)	14,283	2626
K (mg/l)	331	80
Ca (mg/l)	1536	493
Mg (mg/l)	417	87
HCO_3 (mg/l)	595	842
SO_4 (mg/l)	2276	1980
Cl (mg/l)	23,315	3189
Total solids (mg/l)	42,753	9297

IV. Hydrochemical Classification and Interpretation Methods in HYDROPET Program

Sulin (1946) classification

Sulin's characteristic of formation waters is based on the genetic principle (Table 3).

Table 3. Sulin's classification (Yang, 2017)

Equivalent Proportion	**Parameter for judgment**	**Water type**	**Environment**
$Na^+ / Cl^- > 1$	$Na^+ - Cl^- / SO_4^{-2} < 1$	$NaSO_4$ type	Continental washing (land-surface water)
	$Na^+ - Cl^- / SO_4^{-2} > 1$	$NaHCO_3$ type	Continental deposit (water in oil-and gasfields)
$Na^+ / Cl^- < 1$	$Na^+ - Cl^- / Mg^+ < 1$	$MgCl_2$ type	Marine deposit (water in oil-and gasfields)
	$Na^+ - Cl^- / Mg^+ > 1$	$CaCl_2$ type	Deep closed construction (gasfield water)

(1) Sulfate-sodium (Na_2SO_4) type: It represents an environment of continental washing. Generally speaking, this type reflects a weak enclosed conditionon which the oil and gas could not be gathered or stored easily. Most of theland-surface waters belongs to this type.
(2) Bicarbonate-sodium ($NaHCO_3$) type: It represents an environment of continental deposit. This type is widely distributed in oil fields and can beutilized as a sign of a good oil-and gas bearings.
(3) Chloride-magnesium ($MgCl_2$) type: It represents an environment of marine deposit. This type usually exists in oil-and gasfields.
(4) Chloride-calcium ($CaCl_2$) type: It represents an environment of deepenclosed construction. This type reflects a good enclosed condition onwhich the oil and gas can be gathered and stored easily. This is also a sign of an oil- and gas bearing.

The first two types are characteristic of meteoric and/or artesian waters, the third of marine environments and evaporite sequences, and the fourth of deep stagnant conditions. In the Soviet Union, Sulin's system of water characterization is used as a tool in hydrochemical systems of exploration for oil and gas formations (Kartsev et al, 1954). Sulin (1946) is a Russian hydrogeologist and his suggested classification is widely used in the oil industry in the United States. The Sulin diagram shows that oil interpretation of groundwater by examining the anions and cations of oil can be used as very good markers in determining hydrocarbon accumulations. Researchers have been underestimating that oilfield waters are mostly chloride-calcium and bicarbonate-sodium type water (Çoban, 2017). Knowledge of the type and class plus what Sulin describes as the significant indicators (direct and indirect) appears useful in hydrocarbon exploration studies (Collins, 1975).

Schoeller (1955) classification

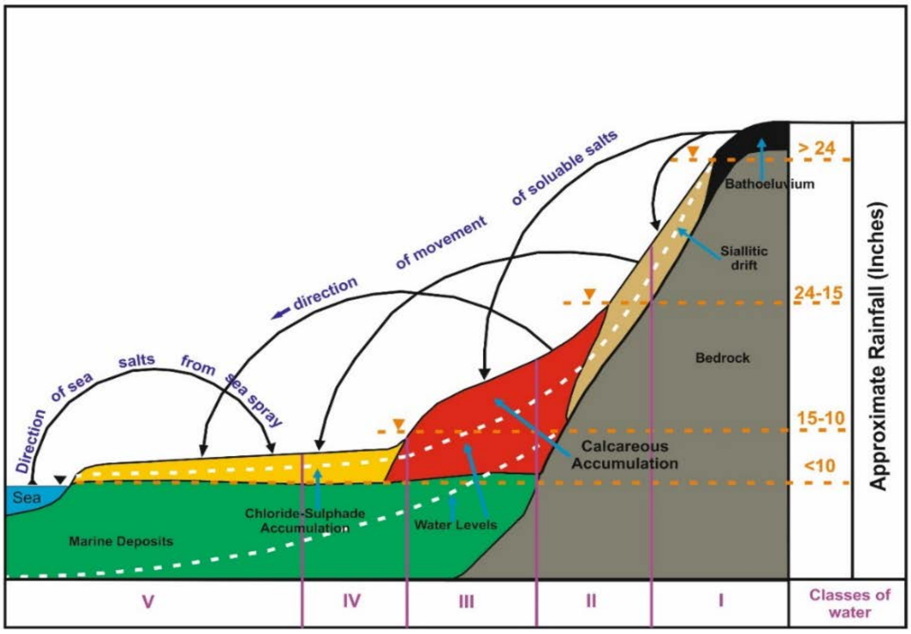
Schoeller's study of petroleum reservoir waters indicated that a positive IBE is more frequent asthe Cl- increases. A negative IBE is more frequent as the C1 decreases, and a negative value is predominant in low and normal chloride waters associated with petroleum. In fact, this characteristic appears specific for petroleum reservoir waters since in other subsurface waters a positive index occurs as frequently as a negative index (Table 4). Ancient sea water (connate water) deposited with the sediments usually have IBE >0.129 and a Cl/Na >1.17. Meteoric waters in sedimentary marine rockshave IBE <0.129 and Cl/Na <1.17. Petroleum reservoir waters with an IBE greater than sea water 0.129 also main characteristics Cl/Na >1.17, Cl/Ca >26.8, Cl/Mg >5.13, Mg/Ca >5.24. Petroleum-reservoir waters containing infiltrating meteoric water mixed with ancient sea water have an IBE less than sea water, 0.129, and the characteristics Cl/Na <1.17, the ratio Mg/Ca increases and approaches but never equals 5.24 (Çoban, 2017; Collins, 1975).

Table 4. IBE value calculation (Çoban, 2017; Collins, 1975)

Cl > Na	IBE = (Cl - Na + K) / Cl
Na > Cl	IBE = (Cl - Na + K) / SO_4 + HCO_3 + CO_3)

Chebotarev (1955) classification

Chebotarev, classified waters on the basis of dissolved bicarbonate, sulfate, and chloride, and he does not consider the acid waters or those that contain free sulfuric or hydrochloric acid. His fundamental assumption is that the anions are independent variables while the cations are dependent.According to Chebotarev's classification hydrodynamical and hydrostatical conditions are most important to accumulation of hydrocarbons at reservoir in this situation and its motion status is hydrodynamical conditions. Chebotarev also given geological structure and relative depth for related sample for related water/hydrocarbon reservoir (Fig. 8). Chebotarevapplied his classification to 917 subsurface waters in oilfields in the world. The classification indicated that 73.7% of the waters were of the chloride genetic type, 23.0% of the bicarbonate type, and 3.3% of the sulfate types are associated with oil and gas bearings.



Major group of water	Genetic types of water		Reacting value in per cent						Products derived from weathering of :
			$HCO_3 + CO_3$	Cl	SO_4	$Cl + SO_4$	$HCO_3 + Cl$	$HCO_3 + SO_4$	
Bicarbonate	I	Bicarbonat (Alkaline)	>40	-	-	<10		-	Igneous/metamorphic rocks
	II	Bicarbonate-chloride (Alkaline-saline)	30-40	-	-	10-20		-	Igneous/metamorphic derived silicates and calcareous accumulations
	III	Chloride-bicarbonate (Saline-Alkaline)	15-30	-	-	20-35		-	Calcareous accumulations
Sulphate	IV	Sulphate-chloride (Saline) Sulphate (Saline)	5-15 -	<25 -	>25 >40	- -	<10	-	Alluvium/gypsum
Chloride	III	Chloride-bicarbonate (Saline-alkaline)	15-30	>20	-	-	-	-	Calcareous accumulations
	IV	Sulphate-chloride (Saline)	5-15	>20	-	-	-	<25	Alluvium and gypsum
	V	Chloride (Saline)	<5	>40	-	-	-	<10	Marina sediments

Hydrodynamic zones		Geochemistry of water				Geological environment		
Recharge-discharge cycle	Water-exchange	Classes	Hydrochemicalfacies	Salinity (‰)	Common terms for water	Structures	Relation to water	Depth (m)
Zone of recharge	Active exchange	I, II (sometimes III)	Low salinefacies	0 - 2	Fresh	Different	Intensive flush	Usually less than 150 m
			Transitional (typical) facies	2 - 9	Brackish	Deep portions of structures with peculiar geochemical environment	Delayed flush	Sometimes 1550 - 2100 m
			High salinefacies	9 - 35	Saline		Hampered flush	
Zone of pressure	Delayed exchange	III ve IV	Low salinefacies	0 - 0.2	Fresh	Different	Inadequate flush	Usually less than 300 m
			Transitional (typical) facies	0.2 - 1.1	Brackish	Deeper portions of structures, folded zones		Sometimes 900 - 1200 m
			High salinefacies	1.1 - 3.8	Saline		Circulation anddrainage limited	
Zone of accumulation	Stagnant conditions	V	Low salinefacies	0 - 0.25	Fresh and Saline	Different	Salt accumulation prevails upon leaching	Different
			Transitional (typical) facies	0.25 - 0.7	Saline and brine	Deeper portions of structures, highly folded zones		Sometimes 2400 - 3900 m
			High salinefacies	0.7 - 1.9	Brines		Water exchange manifests on geological scale time	

Fig. 8. Chebotarev's classification

Wei et al. (1996) classification

Wei et al (1996) classification shows trap and faulting conditions using water ions (Na/Ca-Na/Cl) (Table 5). Theclassification is based on Sulin's water types.

Table 5. Wei et al. (1996) classification

Oil/gas reservoir classification		**Non-destructive (I)**	**Weakly destructive (II)**		**Strongly destructive (III)**	
			Slightly weakly destructive (II_1)	**Unevenly destructive (II_2)**	**Oil bed-exposed type (III_1)**	**Tectonically destructive type (III_2)**
Hydrogeological parameters of oilfield	Na/Cl	<0.85	> 1.00	> 1.00	> 1.00	0.85-1.00
	(SO_4 x 100) / Cl	0.02-2.00	0.00-2.25	0.20-20.00	> 3.5	0.00-3.50
	Na/Ca	2.50-10.00	8-12	10-50	30-175	15-55
	Water Type	$CaCl_2$	$NaHCO_3$	$NaHCO_3$	$NaHCO_3$	$CaCl_2$ dominantly
Petroleum geological characteristics	Degree of trap destruction	Not destroyed	Local faults interlinked with formation water at shallow depth	Faults relatively developed, locally interlinked with the Earth's surface	Exposed-on-the surface oil beds suffering denudation	Strong tectonic uplifting, faults leading to the surface
	Activity of oilfield water	Oilfield water tending to be stagnant	$NaHCO_3$-type water present locally, surface water permeating locally	Surface water permeating through faults	Leached by rain water, surface water permeating	Oilfield water relatively strongly active, surface water permeating
	Other aspects	Complete cover strata	Incompletely closed cover strata	Oil and gas lost in small amounts, partly migrating to other location	No cover strata, oil and gas lost in large amounts	Incomplete cover strata, oil and gas lost in large amounts

Other Classifications and Approaches

Bojarski (1970) observed a large variation in the chemical composition in the chloride-calcium type of water and subdivided this type (Table 6). Bojarski considers a zone of this typeto be one of the most likely areas where hydrocarbons are accumulated.Additional characteristics of water associated with hydrocarbon accumulations are as follows: (1) iodine >1 mg/l; (2) bromide > 300 mg/l; (3) Cl/Br < 350; and (4) (SO_4 xl00)/Cl < 1 (Collins, 1975).

Table 6. Bojarski's classification (Collins, 1975)

Water class	**Su type**	**Na/Cl ratio (epm)**	**Properties**
1	$CaCl_2$	> 0.85	zone of little prospect for the preservation of hydrocarbon deposits
2	$CaCl_2$	0.85 - 0.75	poor zone for hydrocarbon preservation
3	$CaCl_2$	0.75 - 0.65	fairly favorable environment for the preservation of hydrocarbons
4	$CaCl_2$	0.65 - 0.50	good zone for the preservation of hydrocarbons
5	$CaCl_2$	< 0.50	Presence of ancient residual sea water

Schoeneich (1971) found that in Poland the waters associated with hydrocarbon bearing reservoirs show the following characteristics (Coustau, 1977) : I > 10 mg/l; C1/Br < 120; SO_4 < 0.7 g/l; SO_4/HCO_3 < 2.

Vel'kov (1960) findings in Russia, subsurface waters of the Saratov area was established that SO_4/HCO_3 was less than 3 in waters in contact with the oil or located near an oil pool. This ratio was greater than 3 in waters of non-productive horizons or far from an oil pool.

Roshental (1997), Ca-chloride waters, are defined as thosein which Q = Ca/(SO_4 + HCO_3), Na/Cl < 0.80, Mg/Ca < 0.5 and Cl/Br $\leq$ 286

Buljan (1962 and 1963), every natural water, including contact waters (oilfield brines), can be characterized by two important properties, namely: 1. The balance of sulphate (B.S) which equals the loss of sulphate during the diagenesis of water. 2. The index of aeration (I.A) which indicates the degree of aeration of the water. The B.S and I.A are calculated from hydrochemical data of natural waters (formation waters, oilfield brines, sulphurous springs, …etc.) that are associated with these deposits. For hydrocarbon deposits, B.S values were negative and ranged from few to several thousands, while I.A values were positive and ranged from zero to 10 for excellent prospects to 100 or to 1000 for less important prospects. For natural sulphur deposits, both the B.S and I.A values were positive and ranged from few hundreds to thousands. These two indices have numerical values which can be calculated for every water from the results of a routine chemical analysis (Jamil, 2004):

$B.S = (SO_4)_{sample} - (SO_4)_t$

$I.A = [(SO_4)_{sample} / (SO_4)_t] \times 100$

$(SO_4)_t = 0.1394 \times (Cl)_{sample}$

From these two equations it is evident that for sea water: B.S = zero and I.A = 100.

The authors of this article found that at least 1 mg/l lithium and at least 3 mg/l boron ions were in the waters associated with oil and gas production fields (unpublished data).

Isotopic Classifications and Interpretations

Wang et al. (2016) studied links of helium type to mantle species (using R/Ra ratio) (Fig. 9). Herndon (2011) examined the R/Ra ratios of some oil-and gasfields in rift valleys such as Deccan and Siberian traps in India to determine the origin of helium. According to Herndon, during the formation and continuation of rift basins, basaltic explosions occur. High $^3He/^4He$ ratios indicate that source of the heat in the process causing this explosion is Earth's core (Herndon, 2011). Today, it is known that Siberian basin contains some of the world's largest oil, gas and coal reserves. Herndon (2016) examined the helium ratios of oil and gas, both of which are biogenic in the reservoirs, as well as the presence of abiotic methane and hydrocarbons leaking from the mantle in these traps. It also with scientific rationales explains that it is the reasons to doubt the relationship between decompression-driven rift basin formation and mantle methane availability.

Classification of Waples (1985) contains C13 isotope and compares it different intervals to determine carbon type like inorganic or organic carbon and detect organic matter type (Fig., 10 and 11). Reich et al. (2013) classified source of iodine according to $^{129}I/I$ ratio (Fig. 12). Clark (2015) describes derived rock types specified by strontium isotope (Fig. 13) and also using with Oxygen-18 and deuterium isotopes to detect brine type (basin or shield) (Fig. 14).

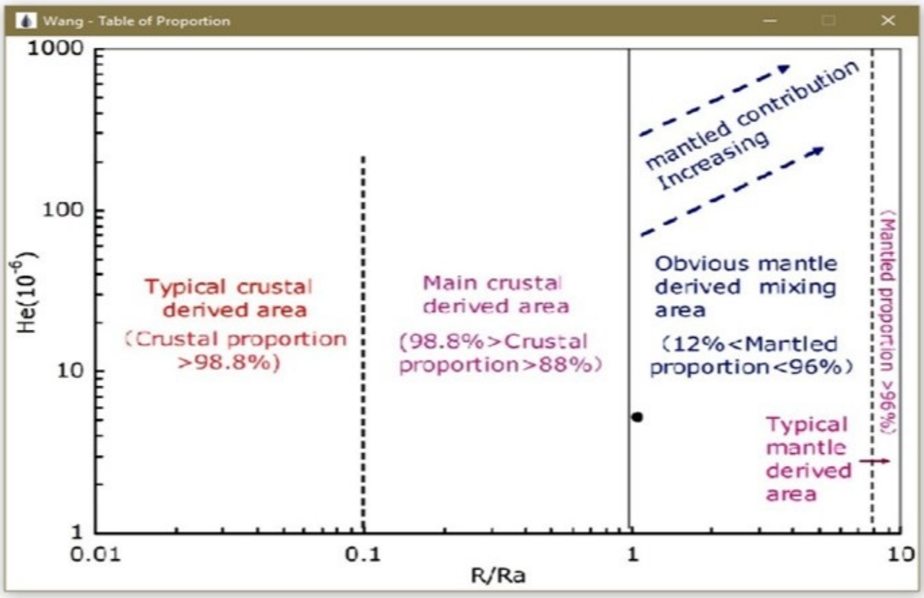


Fig. 9. Helium origin graphy (Wang et al., 2016)

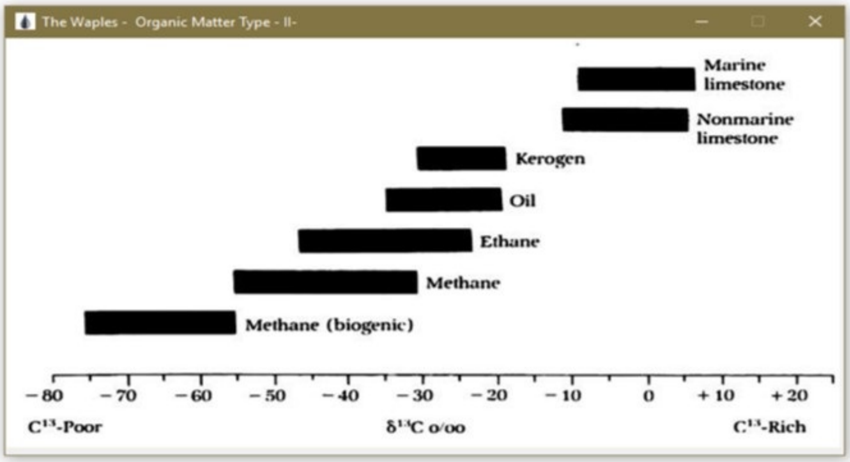


Fig. 10. Isotopic interpretation of organic matter type (Waples, 1985)

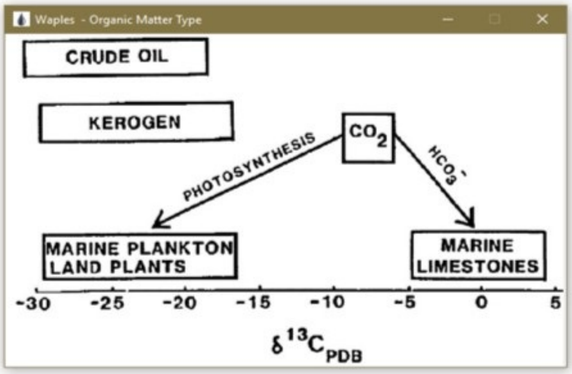


Fig. 11. Organic matter origin according to Waples (1985) carbon isotope classification

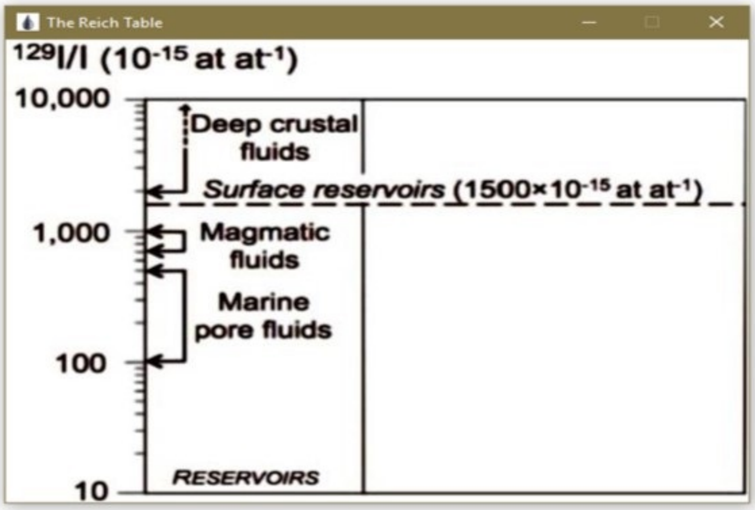


Fig. 12. Source of iodine (Reich et al., 2013)

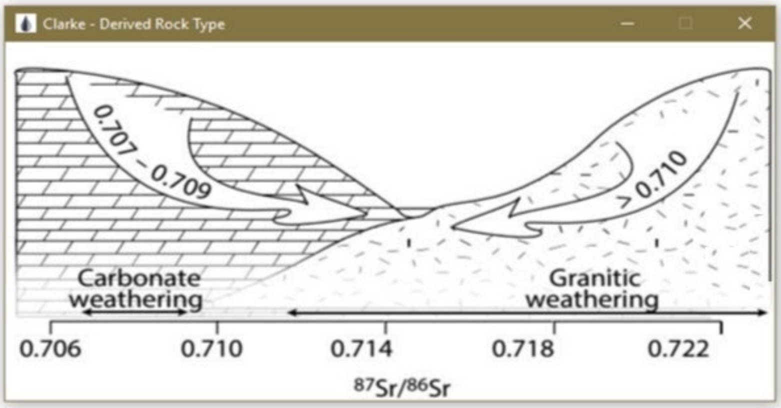


Fig. 13. Derived rock type (Clark, 2015)

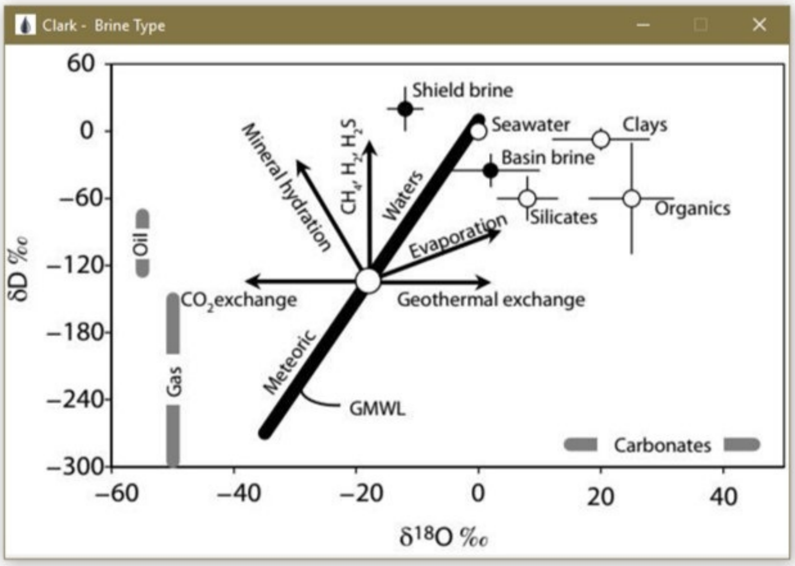


Fig. 14. Brine type (basin or shield brine) detection of Clarke's isotope classification (Clark, 2015)

As a strongly biophilic element, iodine is commonly found heavily enriched in fluids associated with hydrocarbons, such as oil field brines (Moran et al., 1995) or coal-bed methane reservoirs (Snyder et al., 2003). Accordingly, the iodine isotope has been used recently for the determination of source formations of hydrocarbons in a variety of settings (e.g. Fehn et al., 1990; Birkle, 2006). Formation water age may be determine with follow formula (Fehn et al., 2007) or Fig.15 using $^{129}I/I$ isotope.

$T = \ln\left(^{129}I/I_{measured}/^{129}I/I_{cosmogenic(marine)}\right)/(-ʎ_{129})$

T = Age (Ma)

$^{129}I/II_{cosmogenic(marine)} = 1500 \times 10^{-15}$

$ʎ_{129}$ = decay constant= 4.41×10^{-8} year

Half-life of iodine, $T_{1/2}$= 17 Ma

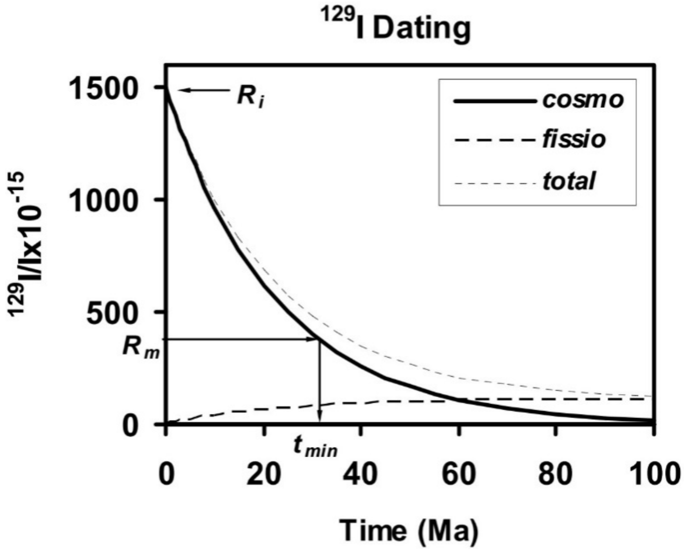


Fig. 15. Iodine dating: Systematics of the decrease of cosmogenic and build-up offissiogenic $^{129}I/I$ ratios. The cosmogenic (marine) $^{129}I/I$ ratio decays from the input ratioR_i = 1500x10^{-15}. Arrows indicate the determination of t_{min} from the measured ratio R_m using the decay curve of cosmogenic $^{129}I/I$ (Fehn et al., 2007).

V. Comparison of HYDROPET Program Classifications with Data of Known Oil and Gas Fields

5.1. Method and Data

HYDROPET was tested on more than 80,000 onshore and offshore oil and gas production fields and basins formation waters that are carefully selected from the published global literature regarding different geological environments during the preparation and development processes (Table 7). Within the scope of this article, in order to submit the oil and gas production fields / basins data of the classification methods in the program and the comparison results, 3 samples as Jujo-Tecominoacán oil field (Gulf of Mexico), West Qaidam basin (China) and Adiyaman oilfields (Southeast Anatolian basin, Turkey) for which both the geological structure and production data (depth and production amount of formation water etc.) and the results of both chemical and isotopic analysis results are issued, are selected.

The Jujo-Tecominoacán oil reservoir (Gulf of Mexico), based on geological-tectonic features, the oilfield is divided into theTecominoacán production zone in the northern section and Jujo towards the south (Fig. 16). Major reservoir column is formed by meso- and microcrystalline dolomite, packstone and anhydrite, followed by mudstones and micro-crystalline dolomite. As the reservoirs strongly deformed by tectonic activities (Birkle et al., 2009a). Chemical and isotopic analysis results of waters from the Jujo and Tecominoacán fields at Table 8 is given.

The Western Qaidam Basin (China) is a large intermontane basin at the northeastern corner of the Tibetan plateau. Within the basin, a series of NWW trending anticlines were developed by deep fault controls and extrusions from the surrounding mountains (Fig. 17).The oilfield brines produced in Tertiary sedimentary strata and modern salt lake brines should be no relation to ancient sedimentary seawater based on the geological setting. Through recent geological research and surveys in western Qaidam Basin, rich and unique oilfield brine resources (formationwaters in the reservoirs of Paleocene-Oligocene strata) were found in many tectonically controlled units (anticlines) (Tan et al., 2011). Chemical and isotopic analysis results of waters from the western Qaidam Basin at Table 9 is given.

Table 7. Locations of oilfield water chemical analyses data that testing of HYDROPET program

Locations	**References**
USGS Produced Waters Geochemical Database, USA	Blondes et al. (2016)
California - Los Angeles, USA	Jensen (1934); Rachinsky and Kerimov (2015)
Gulf of Mexico, USA-Mexico	Land and Macpherson (1992); Franks and Uchytil (2016); Birkle et al. (2009); Birkle et al. (2002); Birkle and Angulo (2005)
Illions Basin, USA	Stueber et al. (1993); Stueber and Walter (1991); Demir and Seyler (1999)
Kansas, U.S.A	Cihaudhuri et al. (1987)
Southwestern Louisiana, USA	Dickey et al. (1972)
Central Mississippi, USA	Carpenter et al. (1974); Kharaka et al. (1987)
New Mexico, USA	Barnaby et al. (2004)
Pennsylvania, USA	Dresel and Rose (2010); Rowan et al. (2015)
Permian Basin, USA	Engle et al. (2016)
Texas, USA	Fisher and Kreitler (1987); Macpherson (1992)
Eastern Ohio, USA	Breen and Masters (1985)
Indiana, USA	Risch and Silcox (2016)
Paradox Basin Region, USA	Hanshaw and Hill (1969)
Viennese Basin, Austria	Rachinsky and Kerimov (2015)
South Caspian Basin, Azerbaijan	Rachinsky and Kerimov (2015); Mazzini et al. (2009); Planke et al. (2003); Lavrushina et al. (2015); Chilingar (1958)
Qaidam Basin, China	Tan et al. (2011); Qishun et al. (2010);
Tarim Basin, China	Chunfang et al. (2006)
Yinggehai Basin, China	Jiang et al. (2015)
Sichuan Basin, China	Xun et al. (1997)
Daqang, Gudao-Shengli, Shengli, Renqie fields,China	Yang (2017)
Mahakam Basin, Indonesia	Bazin et al. (1997)
Paris Basin, France	Fontes (1993)
Krishna Godavari Basin, India	Murthy et al. (2011)
North Sea	Bazin et al. (1997); Smalley et al. (1995)
East Midlands, United Kingdom	Downing and Howitt (1968)
Iraq	Jamil (2004); Al-Marsoumi and Abdul-Wahab (2005); EIzarka and Ahmed (1983); Quadir (2008)
Zagros Foredeep, Iran	Rachinsky and Kerimov (2015); Bagheri et al. (2014a,b,c); Miri and Moghadasi (2012); Mirnejad et al. (2011); Rafighdoust et al. (2015)
Israel	Chan et al. (2002); Bentor (1969)
Padan Depression, Italy	Rachinsky and Kerimov (2015)
Japan	Sudo (1967)
East Java, Indonesia	Purwaningsih and Notosiswoyo (2013)
Alberta, Canada	Hitchton et al (1971)
Canadian Shield	Frape et al. (1984)
Southwestern Ontario, Eastern Michigan Basin, Canada	Weaver et al. (1995)
South-Central Saskatchewan/Williston Basin, Canada	Bernatsky (1998); Toop and Toth (1995)
Irrawaddy-Andaman Basin, Myammar	Rachinsky and Kerimov (2015)
Norwegian shelf-offshore	Egeberg and Aagaard (1989); Bjorlykke et al. (1995)
Poland	Uliasz-Misiak (2016); Schoeller (1962)
Romania	Schoeller (1962)
Indol-Kuban Foredeep, Russia	Rachinsky and Kerimov (2015)
West Siberia, Russia	Kurchikov and Plavnik (2009); Novikov and Shvartsev (2009); Novikov (2012); Kokh and Novikov (2014); Novikov (2013b)
Siberian Platform, Russia	Shouakar-Stash et al. (2007)
Terk-Caspian Foredeep, Russia	Rachinsky and Kerimov (2015)
Yamal Peninsula, Russia	Novikov (2013a)
Southern Sudan	Rueskamp (2014)
Saudi Arabia	Birkle (2016a), Birkle (2016b); Birkle et al. (2013)
Gulf of Suez	Israr et al. (1971)
Trinidad	Dia et al. (1999)
Southern Tunisia	Morad et al. (1994); Coustau (1977)
Southern Turkey	Celik and Sarı (2002); Hoshan et al. (2008); Çelik et al. (1998); Uğur and Örgün (1996)
Thrace Basin, Turkey	Ozgun et al. (2012); Cakmakcı et al (2008); Okandan et al. (1994)
Cheleken Peninsula**,** Western Turkmenistan	Oppo et al. (2014); Oppo and Capozzi (2015)
Carpathian Foredeep, Ukrania	Rachinsky and Kerimov (2015)
Oman	Sakroon (2008)
Maracaibo Basin, Venezuela	Boschetti et al. (2016); Rachinsky and Kerimov (2015)
South Vietnam Shelf	Kireeva (2010)
General reference	Mazor (2004)

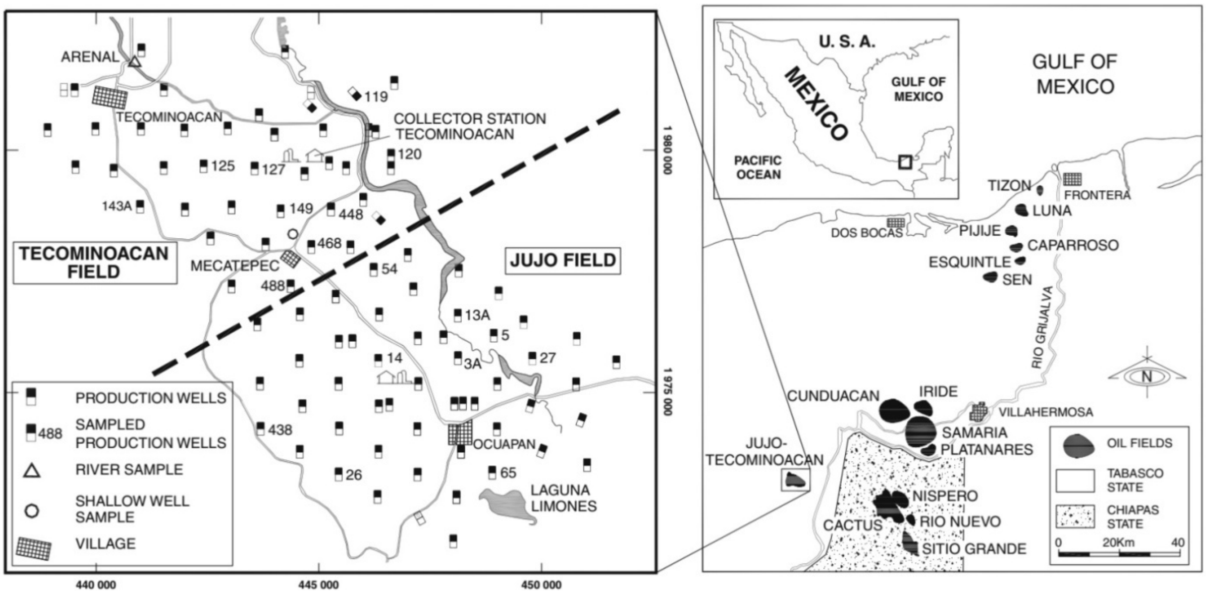


Fig. 16. Location of production wells and sample sites in the Jujo-Tecominoacán oil field **(**Birkle et al., 2009a)

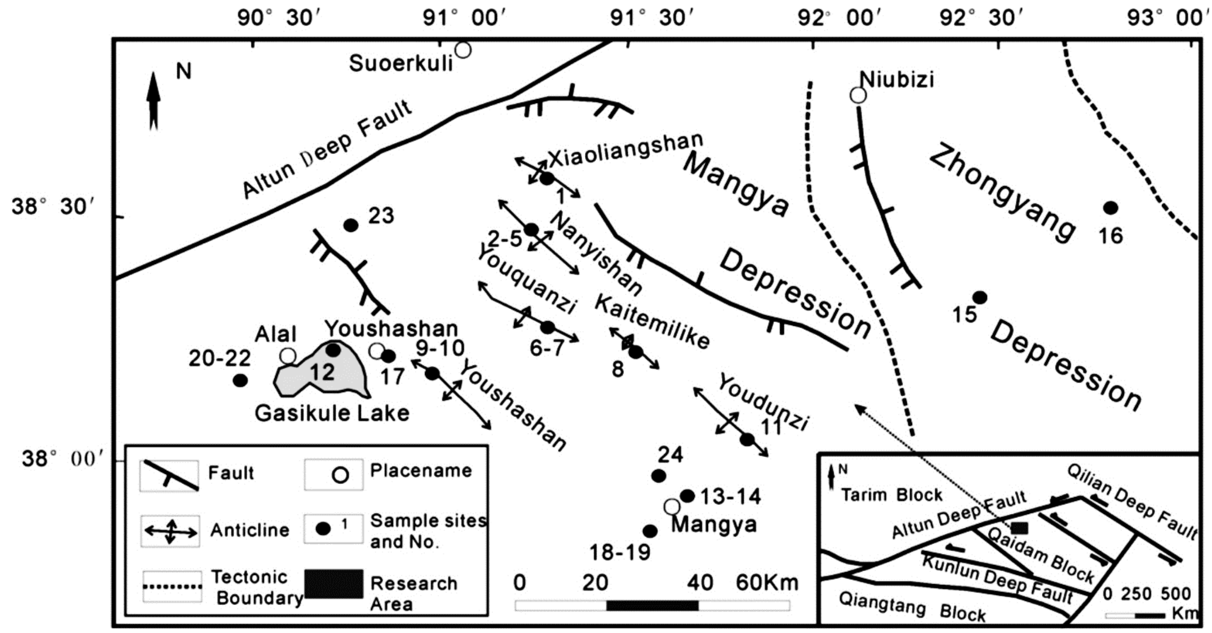


Fig 17. Location of the western Qaidam basin and distribution of its main anticlines, oilfield bines and sample sites (Tan et al., 2011).

Adıyaman oilfields (Southern Turkey) is located on the marginal folded belt placed on the northern margin of the shelf-platform of the Arabian-African plate. Çelik and Sarı (2002) focusses on the chemical evolution of fresh and saline groundwaters in the calcareous rocks of the Adıyaman oilfields (Fig. 18). Purpose of this study is to classify waters by different methods and examine their origin. Meteoric effect was determined in the water produced from a well in the Karababa C Formation. In another study (Çelik et al., 1998), it was stated that the formation waters of Adıyaman region may have been trapped in old marine deposits and got mixed with meteoric groundwater. Chemical and isotopic analysis results of waters from the Adıyaman oilfields at Table 10 is given.

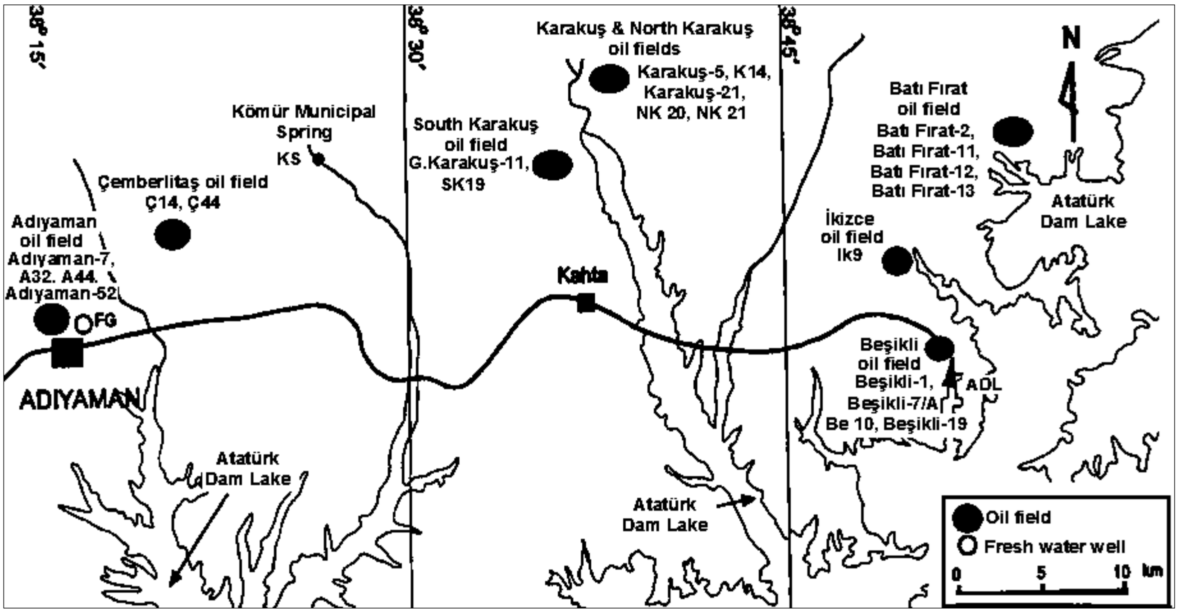


Fig. 18. Location map of water samples and Adıyaman oilfields (modified from Çelik and Sarı, 2002)

Table 8. Chemical and isotopic analysis results of waters from the Jujo and Tecominoacán fields **(**Birkle et al., 2009a,b)

Sample	Interval depth (m)	Water type	Na (mg/l)	Ca (mg/l)	Mg (mg/l)	K (mg/l)	Cl (mg/l)	SO_4 (mg/l)	HCO_3 (mg/l)	I (mg/l)	Br (mg/l)	Li (mg/l)	B (mg/l)	^{18}O (‰)	D (‰)	$^{87}Sr/^{86}Sr$
J-3A	5675-5705	Ca-Na-Cl	62400	52200	2900	9580	218000	<60.0	169	35.5	2970	158	155	-1.4	-14	0.70893
J-5	6040	Ca-Na-Cl	50300	45400	2130	7880	183000	<60.0	399	27.5	2950	124	133	1.3	-13	0.70908
J-13A	5655-5673	Ca-Na-Cl	61700	45200	2780	8690	195000	<60.0	169	18.8	2760	124	143	4	-13	0.70878
J-14D	5760-5783	Ca-Na-Cl	45700	47000	2570	8300	189000	<60.0	217	22.2	2620	149	139	0.8	-9	0.70926
J-26	5455-5490 5505-5530	NaCl	2900	138	6.00	48	6180	136	193	4.18	32.3	1.00	105	9.3	1	0.70791
J-27	5237	Ca-Na-Cl	42700	39400	1980	6840	151000	150	332	17.9	1740	88.3	116	4.7	-12	0.70898
J-54	5637-5675 5737-5780 5810-5890	Ca-Na-Cl	52700	52600	2860	9420	195000	<60.0	169	24.8	2620	175	157	4	-13	0.70927
J-65	5575-5595	Ca-Na-Cl	16500	44200	3370	5460	154000	<60.0	242	7.60	1940	74.2	172	7.1	-8	0.70854
J-438	5935	Ca-Na-Cl	3760	1900	466	827	11300	357	1370	8.56	40.9	3.30	26.7	8.7	-11	0.70868
T-119	5445-5475	Ca-Na-Cl	26300	35500	2910	5800	129000	138	201	13.0	1695	73.3	132	8.5	-7	0.70879
T-120	5517-5526 5533-5542 5562-5573	Ca-Na-Cl	35400	46200	3810	8040	166000	65.6	181	18.1	2240	117	174	5.5	-13	0.70889
T-125	5900, 6010 6090-6114	Ca-Na-Cl	30500	43100	2780	6900	153000	88.9	290	14.3	2300	88.9	156	7.9	-12	0.70896
T-127	5375-5390 5425-5435	Ca-Na-Cl	38800	53000	3240	8940	181000	<60.0	205	16.5	2760	126	187	5.8	-11	0.70875
T-143A	6160	Na-Cl	6470	927	60.0	604	13400	689	785	8.70	109	4.20	80.1	10.2	-10	0.70832
T-149	5600	Na-Cl	3330	462	19.0	91	6720	694	271	5.46	36.5	1.40	37.4	3.1	-7	0.70825
T-448	5405-5435	Ca-Na-Cl	47100	50000	2970	8870	192000	<60.0	157	21.9	3130	160	147	4.3	-11	0.70923
T-468	5565-5580 5608-5628	Ca-Na-Cl	22800	32000	2050	5190	116000	161	205	11.7	1650	67.4	127	10	-11	0.70883
T-488	5860	Ca-Na-Cl	60600	55700	2420	10,200	248000	<60.0	447	28.7	3670	205	139	4.3	-13	0.70944
Arenal river	-	Na-Ca-HCO_3	17.8	44.5	7.28	4.59	7.55	5.28	164	0.02	0.05	0.01	0.04	-3.8	-21	0.70738
Mecatepec well	-	Na-HCO_3-Ca	11.4	23.9	1.92	4.87	5.24	0.49	67.6	0.01	0.05	0.02	0.05	-4.6	-25	0.70868

Table 9. Chemical and isotopic analysis results of waters in the western Qaidam Basin (Tan et al., 2011)

Sample site	Sample type	Na (mg/l)	Ca (mg/l)	Mg (mg/l)	K (mg/l)	Cl (mg/l)	SO_4 (mg/l)	HCO_3 (mg/l)	Br (mg/l)	Li (mg/l)	B (mg/l)	^{18}O (‰)	D (‰)	$^{87}Sr/^{86}Sr$	$^3He/^4He$ (Ra)
1	Oilfield brine	55780	1580	330	840	89010	2050	5	54.8	36	84.4	7.1	-50	0.711413	
2	Oilfield brine	17290	117910	7780	43040	296960	30	5	537	1890	3978	15.89	-27.8	0.711229	0.747
3	Oilfield brine	44590	69100	5050	35750	237860	160	290	281	983	3332.3	13.88	-28.1	0.71121	0.735
4	Oilfield brine	32300	15530	1320	5350	85710	290	100	38.2	182.63	2699.83	-1.35	-34.7	0.711184	
5	Oilfield brine	28420	7220	840	2230	60620	430	230	43.68	81.2	2396.79	-2.47	-30.9	0.711163	
6	Oilfield brine	94410	13580	2060	780	176150	190	5	80.9	91.6	182.3	7.19	-38.4	0.711621	
7	Oilfield brine	96670	13510	2130	600	179590	150	5	79.1	89.9	227.7	7.07	-46	0.711779	
8	Oilfield brine	59650	2620	1610	240	98740	3590	220	102.1	33.8	133.7	9.52	-36.1	0.711666	
9	Oilfield brine	68050	6510	1300	300	120040	570	70	98	2.1	250.6	0.47	-41.6	0.711937	
10	Oilfield brine	27620	1550	450	410	46380	550	380	30.9	6.2	218.6	0.62	-44.6	0.711819	
11	Oilfield brine	115680	4450	1790	1840	191790	1560	310	79.3	13	394.4	6.2	-47	0.711699	
12	Salt lake brine	56650	80	46650	6840	177730	69250	1500	53.3	45.3	185.4	1.98	-11.3	0.711745	
13	Salt lake brine	111080	550	7970	3760	187310	15100	750	21.3	24.5	205	13.99	9.1	0.712295	
14	Salt lake brine	111110	610	7830	3790	187150	15020	720	20.1	23.9	206.5	14.21	6.2	0.712396	
15	Intercrystalline brine	112390	6740	2250	2070	192530	1310	250	105	14.7	614.9	10.86	-30.9	0.711566	
16	Intercrystalline brine	108360	410	13910	12360	175020	60200	180	17	6	63	8.62	-42.6	0.71178	
17	Spring water	40	32	9	2	40	52	121				-6.07	-53.5		
18	Groundwater	100	25	12	19	120	91	115		0.016		-8.46	-46.6		
19	Groundwater	340	77	36	24	422	399	130		0.054		-7.2	-44.4		
20	Groundwater	140	41	39	4	114	118	362		0.034		-8	-58		
21	Groundwater	140	37	43	4	119	129	350		0.031		-7.9	-46.8		
22	Groundwater	220	35	12	5	124	167	343		0.033		-7.78	-59.6		

Table 10. Chemical and isotopic analysis results of waters in the Adıyaman oilfields (Data: Çelik and, 2002; Hoşhan et al., 2008; Gümüş and Altan, 1995; G.D.P.A**)**

Sample	Well depth (m)	Coordinates		Sample type	Na (mg/l)	Ca (mg/l)	Mg (mg/l)	K (mg/l)	Cl (mg/l)	SO_4 (mg/l)	HCO_3 (mg/l)	I (mg/l)	Br (mg/l)	Li (mg/l)	B (mg/l)	^{18}O (‰)	D (‰)
		Latitude	Longitude														
ADL	0	37.726759°	38.852188°	Fresh water	17	38.4	13.6	2.5	19	20.7	122						
KS	-	37.864999°	38.430443°	Fresh water	0.9	70.4	9.48	0.3	6	5	166						
FG	-	37.782149°	38.258539°	Fresh water	2.9	44	10.02	0.2	11	<0.2	128						
Adıyaman 7	1064	37.790552°	38.225824°	Formation water	4505	613.5	122.4	70.4	8250	100	342.8						
A 32	1636	37.795476°	38.224795°	Formation water	1000	620	104.5	70	8000	183.4	271		38.8			-9.41	-61.7
A 44	1582	37.791387°	38.210278°	Formation water	298	72	19.4	10.3	480	17.1	244	0.75		<0.1	0.56	-7.8	-62.68
Adıyaman 52	1668	37.793034°	38.219426°	Formation water	6257.5	930.8	180.8	76.9	11835	300	249.9						
Batı Fırat 2	1522	37.871381°	38.929165°	Formation water	8762.5	992.9	156.4	415.5	15234	800	714.2						
Batı Fırat 11	958	37.869999°	38.924436°	Formation water	7482.5	830.2	131.2	363.5	12690	850	856.9						
Batı Fırat 12	949	37.867775°	38.927497°	Formation water	7135	946.2	139.2	378	12348	850	999.8						
Batı Fırat 13	1856	37.864160°	38.926386°	Formation water	12022.5	1130	181.2	353.5	20915	950	642.7						
Beşikli 1	1625	37.757494°	38.861941°	Formation water	12240	1844	362.6	399	23189	800	342.8						
Beşikli 7/A	1795	37.751386°	38.849443°	Formation water	7202.5	1199	230.1	261.2	13500	700	285.6						
Be 10	1944	37.756941°	38.851941°	Formation water	5875	968	140.9	215	9713	1061	188	2.48		2.3	19.71	-7.53	-61.21
Beşikli 19	1684	37.755550°	38.872491°	Formation water	10810	1700	346.6	501	21000	800	357						
Ç 14	3225	37.816662°	38.347777°	Formation water	2925	552	48.6	150	6000	488	293		25.2			-8.24	-73.05
Ç 44	3055	37.813610°	38.351655°	Formation water	2500	520	63.2	100	5024	655	655	120	19.6	12	1.97	-8.49	-42.80
G.Karakuş 11	1734	37.819442°	38.601101°	Formation water	7717.5	944.9	147.1	235.7	13692	850	385.6	3.66	54.8	34.02	5.1	-5.99	-44.23
SK 19	2445	37.824992°	38.628047°	Formation water	5960	840	85.1	285	11500	708	359		65.3			-6.39	-49.59
Karakuş 5	2359	37.845828°	38.591935°	Formation water	7185	880.1	128.8	250.2	12463	700	314.2						
K 14	2610	37.856386°	38.593047°	Formation water	6375	700	48.6	270	10527	744	202	7.10		6.8	39.40	-7.51	-76.94
Karakuş 21	1621	37.849998°	38.588331°	Formation water	7565	892.7	119.9	247	13279	700	428.5						
NK 20	2577	37.876665°	38.619714°	Formation water	7900	1120	60.8	360	15500	733	276		77.5			-4.64	-42.74
NK 21	2596	37.876665°	38.619714°	Formation water	7600	1160	133.7	335	14500	706	493		77.3			-4.66	-48.54
Ik 9	2254	37.786383°	38.841388°	Formation water	5188	740	133.7	288	8422	982	370	1.20		5.5	21.69		

5.2. Discussion

Water type and origin

In order to assess type and origin of the water samples, Sulin (1946), Chebotarev (1955), Wei et al. (1996) and Rosental (1997) classifications are selected. Selected oilfield water observed as chlorite type water according to the software classifications. Other water types are Na_2SO_4, $NaHCO_3$ and $MgCl_2$ type waters according to the Sulin classification. As an example, examined results of fields are compatible with the results of the classifications included in the program. However, the definitions used for the same type of water are different from each other in the 4 classes selected for the identification of the type and origin of the water samples. Usage of hydrochemical facies for the identification of the water type of the samples studied in petroleum hydrogeology studies and the identifications of Sulin (1946) classification within definition of water origin that is determined by Na/Cl (%meq) ratio and recommended by Roger (1917) (connate or meteoric-origin water) eliminates this difference (Tables 11, 12 and 13).

Table 11. Types and origins of waters in Jujo ve Tecominoacán oilfield (Gulf of Mexico)

Sample	Sample type	Water type	Sulin (1946)	Chebotarev (1955)	Wei et al. (1996)	Rosental (1997)	Water origin
J-3A, J-13A	Reservoir water	Na-Ca-Cl	$CaCl_2$	Chloride	$CaCl_2$	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
J-5, J-14D, J-27, J-54, J-65, J-438, T-119, T-120, T-125, T-127, T-448, T-468, T-488	Reservoir water	Ca-Na-Cl	$CaCl_2$	Chloride	$CaCl_2$	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
J-26	Reservoir water	Na-Cl	$CaCl_2$	Chloride	$CaCl_2$ dominantly	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
T-143A, T-149	Reservoir water	Na-Cl	$CaCl_2$	Chloride	$CaCl_2$ dominantly	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
Arenal river	Surface water	Na-Ca-HCO_3	$NaHCO_3$	Bicarbonate	n/a	Ca-Chloride (Mg/Ca <0.5)	Meteoric water (Sulin Na/Cl > 1)
Mecatepec well	Groundwater	Na-HCO_3-Ca	$NaHCO_3$	Bicarbonate	n/a	Ca-Chloride (Q > 1)	Meteoric water (Sulin Na/Cl > 1)

Table 12. Types and origins of waters in western Qaidam basin (China)

Sample	Sample type	Water type	Sulin (1946)	Chebotarev (1955)	Wei et al. (1996)	Rosental (1997)	Water origin
1, 8, 9, 10, 11	Oilfield brine	Na-Cl	$CaCl_2$	Chloride	$CaCl_2$ dominantly	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
2	Oilfield brine	Ca-Cl	$CaCl_2$	Chloride	$CaCl_2$	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
3	Oilfield brine	Ca-Na-Cl	$CaCl_2$	Chloride	$CaCl_2$	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
4, 5	Oilfield brine	Na-Ca-Cl	$CaCl_2$	Chloride	$CaCl_2$	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
6, 7	Oilfield brine	Na-Cl	$CaCl_2$	Chloride	$CaCl_2$	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
12	Salt lake brine	Mg-Na-Cl-SO_4	$MgCl_2$	n/a	$CaCl_2$	Ca-Chloride (Na/Cl <0.80)	Connate water (Sulin Na/Cl < 1)
13, 14	Salt lake brine	Na-Cl	$MgCl_2$	Chloride	$CaCl_2$ dominantly	n/a	Connate water (Sulin Na/Cl < 1)
15	Intercrystalline brine	Na-Cl	$CaCl_2$	Chloride	$CaCl_2$ dominantly	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
16	Intercrystalline brine	Na-Cl-SO_4	$MgCl_2$	n/a	n/a	n/a	Connate water (Sulin Na/Cl < 1)
17	Spring water	Na-Ca-HCO_3-Cl-SO_4	$NaSO_4$	Chloride-Bicarbonate	n/a	Ca-Chloride (Mg/Ca <0.5)	Meteoric water (Sulin Na/Cl > 1)
18	Groundwater	Na-Cl-SO_4-HCO_3	$MgCl_2$	n/a	n/a	n/a	Connate water (Sulin Na/Cl < 1)
19	Groundwater	Na-Cl-SO_4	$MgCl_2$	n/a	n/a	n/a	Connate water (Sulin Na/Cl < 1)
20, 21	Groundwater	Na-Mg-HCO_3-Cl-SO_4	$NaHCO_3$	Chloride-Bicarbonate	n/a	n/a	Meteoric water (Sulin Na/Cl > 1)
22	Groundwater	Na-HCO_3-Cl-SO_4	$NaHCO_3$	Chloride-Bicarbonate	n/a	n/a	Meteoric water (Sulin Na/Cl > 1)

Table 13. Types and origins of waters in Adıyaman oilfields (Turkey)

Sample	Sample type	Water type	Sulin (1946)	Chebotarev (1955)	Wei et al. (1996)	Rosental (1997)	Water origin
ADL	Fresh water	Ca-Mg-Na-HCO_3	Na_2SO_4	Bicarbonate-Chloride	n/a	n/a	Meteoric water (Sulin Na/Cl > 1)
KS	Fresh water	Ca-Mg-HCO_3	$MgCl_2$	Bicarbonate	$CaCl_2$	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
FG	Fresh water	Ca-Mg-HCO_3	$MgCl_2$	Bicarbonate	$CaCl_2$	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
Adıyaman 7, Batı Fırat 2, Batı Fırat 11, Batı Fırat 12, Batı Fırat 13	Formation water	Na-CI	$CaCl_2$	Chloride	$CaCl_2$ dominantly	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
A 32, Adıyaman 52, Beşikli 1, Beşikli 7/A, Beşikli 19, Batı Fırat 13, Be 10, Ç 14, Ç 44, G.Karakuş 11, SK 19, Karakuş 5, K 14, Karakuş 21, NK 20, NK 21, Ik 9	Formation water	Na-CI	$CaCl_2$	Chloride	$CaCl_2$	Ca-Chloride (Q > 1)	Connate water (Sulin Na/Cl < 1)
A 44	Formation water	NaCI-HCO_3	$MgCl_2$	n/a	$CaCl_2$ dominantly	Ca-Chloride (Mg/Ca <0.5)	Connate water (Sulin Na/Cl < 1)

Chebotarev (1955) and Clark (2015) classifications are chosen for the assessment of the geological environment where the water samples are derived. Jujo and Tecominoacán reservoir water classified as "Derived from weathering of marine sediments" according to Chebotarev classification and as "Derived from carbonate weathering" according to the Clark classification. The major reservoir column is formed by meso- and microcrystalline dolomite, packstone and anhydrite, followed by mudstones and micro-crystalline dolomite (Birkle et al, 2009a). Thus, the classification of the geological environment where the water is derived for Jujo and Tecominoacán reservoir waters is compatible with the data known (Table 14).

West Qaidam basin water classified as "Derived from weathering of marine sediments" according to Chebotarev classification and as "Derived from granitic weathering" according to the Clark classification. Also, according to the Wang et al. (2016) classification, helium in the water is classified as "Main crustal derived (98.8% > crustal proportion > 88%)". The formation of West Qaidam basin waters as a mixture of different fluids (predominantly magmatic fluids and formation waters) (Tan et al., 2011) describes the different results in the Chebotarev and Clark classifications (Table 15). In case such different results are observed in Cheboratev and

Clark classifications, as detailed in Lawrence and Cornfordt (1995), the consequence that fluids are derived from different sources in the sedimentary basin mix with each other and the oilfield water is a mixture of these fluids, is obtained.

Adıyaman oilfield waters is classified as "Derived from weathering of marine sediments" according to the Chebotarev classification. In Adıyaman oil fields, reservoir rocks and other rocks are composed of limestone, dolomites and other marine sediments (Çelik and Sarı, 2002). Thus, the classification of the geological environment that is performed for the water where the water is derived is compatible with the data known (Table 16).

Table 14. Derived rock types of waters in Jujo ve Tecominoacán oilfield (Gulf of Mexico)

Sample	**Sample type**	**Water type**	**Chebotarev (1955)**		**Clark (2015)**
J-3A, J-13A	Reservoir water	Na-Ca-Cl	Chloride	Derived from weathering of marine sediments	Derived from carbonate weathering
J-5, J-14D, J-27, J-54, J-65, J-438, T-119, T-120, T-125, T-127, T-448, T-468, T-488	Reservoir water	Ca-Na-Cl	Chloride	Derived from weathering of marine sediments	Derived from carbonate weathering
J-26, T-143A, T-149	Reservoir water	NaCl	Chloride	Derived from weathering of marine sediments	Derived from carbonate weathering
Arenal river	Surface water	Na-Ca-HCO_3	Bicarbonate	Derived from weathering of Igneous/metamorphic rocks	Derived from carbonate weathering
Mecatepec well	Groundwater	Na-HCO_3-Ca	Bicarbonate	Derived from weathering of Igneous/metamorphic rocks	Derived from carbonate weathering

Table 15. Derived rock types of waters in western Qaidam basin (China)

Sample	**Sample type**	**Water type**	**Chebotarev (1955)**		**Clark (2015)**	**Sample**
1, 6, 7, 8, 9, 10, 11	Oilfield brine	Na-Cl	Chloride	Derived from weathering of marine sediments	Derived from granitic weathering	
2	Oilfield brine	Ca-Cl	Chloride	Derived from weathering of marine sediments	Derived from granitic weathering	Main crustal derived (98.8% > crustal proportion > 88%)
3	Oilfield brine	Ca-Na-Cl	Chloride	Derived from weathering of marine sediments	Derived from granitic weathering	Main crustal derived (98.8% > crustal proportion > 88%)
4	Oilfield brine	Na-Ca-Cl	Chloride	Derived from weathering of marine sediments	Derived from granitic weathering	
5	Oilfield brine	Na-Ca-Cl	Chloride	Derived from weathering of marine sediments	Derived from granitic weathering	
12	Salt lake brine	Mg-Na-Cl-SO_4	n/a	n/a	Derived from granitic weathering	
13, 14	Salt lake brine	Na-Cl	Chloride	Derived from weathering of marine sediments	Derived from granitic weathering	
15	Intercrystalline brine	Na-Cl	Chloride	Derived from weathering of marine sediments	Derived from granitic weathering	
16	Intercrystalline brine	Na-Cl-SO_4	n/a	n/a	Derived from granitic weathering	
17	Spring water	Na-Ca-HCO_3-Cl-SO_4	Chloride-Bicarbonate	Derived from weathering of calcareous accumulations		
18	Groundwater	Na-Cl-SO_4-HCO_3	n/a	n/a		
19	Groundwater	Na-Cl-SO_4	n/a	n/a		
20, 21	Groundwater	Na-Mg-HCO_3-Cl-SO_4	Chloride-Bicarbonate	Derived from weathering of calcareous accumulations		
22	Groundwater	Na-HCO_3-Cl-SO_4	Chloride-Bicarbonate	Derived from weathering of calcareous accumulations		

Table 16. Derived rock types of waters in Adıyaman oilfields (Turkey)

Sample	**Sample type**	**Water type**	**Chebotarev (1955)**	
ADL	Fresh water	Ca-Mg-Na-HCO_3	Bicarbonate-Chloride	Igneous/metamorphic derived silicates and calcareous accumulations
KS	Fresh water	Ca-Mg-HCO_3	Bicarbonate	Igneous/metamorphic derived silicates and calcareous accumulations
FG	Fresh water	Ca-Mg-HCO_3	Bicarbonate	Igneous/metamorphic derived silicates and calcareous accumulations
A 44	Formation water	Na-CI-HCO_3	n/a	n/a
Other water samples	Formation water	Na-CI	Chloride	Marine sediments

Association with Oil and Gas Deposits

In order to assess the association of the water samples and an oil and gas deposit; the classifications taking the Sulin (1946), Schoeller (1955), Bojarski (1970), Vel'kov (1960), Schoneich (1971), Buljan (1962, 1963), Li and B ratios as a basis are selected. The field samples selected are classified as "Water associated with hydrocarbon accumulations" according to the software classifications. Results of the classifications specified in the program, the results of the fields examined as a sample are compatible.

Iodine analysis result is present for all the Jujo and Tecominoacán reservoir water and a part of Adıyaman oilfield waters. In case the iodine analysis results of the investigated basin water samples are available, the Bojarski (1970) classification should be the preferred method since it specifies the waters associated with hydrocarbon accumulations that are directly based on iodine content. The results of the studies examined as an example verify this opinion (Table 17, all the Jujo and Tecominoacán reservoir waters and Table 19, Be 10, Ç14, Ç44, K14, Ik 9 samples having the results of Adıyaman oilfields iodine analysis). In case of iodine analysis results of the investigated basin water samples are not present, the Br/Cl <350 approach proposed by Borjarski (1970) becomes prominent. In all Jujo and Tecominoacán field reservoir samples and A32, Ç14, Ç44, G.Karakuş 11, SK 19, NK 20 and NK 21 samples having Br data of Adıyaman oilfields; Br/Cl is < 350 (Tables 17 and 19).

West Qaidam basin, there is no iodine data for the basin water and Br/Cl is > 350 (Table 9). However, there are connate-origin waters (Sulin Na/Cl<1) in the basin (Table 12). Therefore necessary to question that whether these connate-origin waters are associated to oil and gas deposits or not. The West Qaidam basin oilfield waters consist of a mixture of different fluids (mainly magmatic fluids and formation waters) (Tan et al., 2011) and the boron ratio is very high (Table 9). It seems appropriate to use the Li ≥ 1 and B ≥ 3 approaches proposed by the authors in order to determine the waters associated with oil and gas deposits in such basins where the connate waters and the magmatic contribution to the B ratio in the formation waters (due to magmatic contribution) are high. (All the West Qaidam basin oilfield waters, All Jujo and Tecominoacán reservoir waters, Be10, Ç44, G.Karakuş 11, K14 and Ik 9 samples of Adıyaman oilfields having Li and B analysis results) and the equation (SO_4 x 100)/Cl < 1 that is recommended by Bojarski (1970) (Most of the West Qaidam basin oilfield brines, all the Jujo and Tecominoacán reservoir waters excluding 4 samples) (Tables 17, 18 and 19).

It is observed that Buljan (1962, 1963) classification is found to be very compatible with the data on all the fields sampled (Tables 17, 18 and 19). Jamil (2004) has tested this classification on oilfield waters in Iraq and has achieved similar results with this study regarding the applicability of classification.

Table 17. Relation to oil and gas deposit of waters in Jujo ve Tecominoacán oilfield (Gulf of Mexico)

Sample	**Water origin**	**Sulin (1946)**	**Schoeller (1955)**	**Bojarski (1970)**	**Vel'kov (1960)**	**Schoeneich (1971)**	**Buljan (1962, 1963)**	**Li ≥ 1 and B ≥ 3**
J-3A, J-5, J-13A, J-14D, J-27, J-54, J-65, T-119, T-120, T-125, T-127, T-448, T-468	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (I > 1 mg/l)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (Cl/Br < 120)	Excellent prospect (BS: negative, IA: < 10)	Water associated with hydrocarbon accumulation
J-26	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (I > 1 mg/l)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (SO_4/HCO_3< 2)	Good prospect (BS: negative, IA: 10-100)	Water associated with hydrocarbon accumulation
J-438, T-143A, T-149	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (I > 1 mg/l)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (SO_4/HCO_3< 2)	Good prospect (BS: negative, IA: 10-100)	Water associated with hydrocarbon accumulation
T-488	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (I > 1 mg/l)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (I > 10 mg/l)	Excellent prospect (BS: negative, IA: < 10)	Water associated with hydrocarbon accumulation
Arenal river	Meteoric water (Sulin Na/Cl > 1)	A sign of a good oil and gas bearing ($NaHCO_3$)	Meteoric water (IBE: negative)	Water associated with hydrocarbon accumulation (Cl/Br < 350)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (SO_4/HCO_3 < 2)	Native sulphur deposit (BS: positive, IA: 100-1000)	n/a
Mecatepec well	Meteoric water (Sulin Na/Cl > 1)	A sign of a good oil and gas bearing ($NaHCO_3$)	Meteoric water (IBE: negative)	Water associated with hydrocarbon accumulation (Cl/Br < 350)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (Cl/Br < 120)	Good prospect (BS: negative, IA: 10-100)	n/a

Table 18. Relation to oil and gas deposit of waters in western Qaidam basin (China)

Sample	**Water origin**	**Sulin (1946)**	**Schoeller (1955)**	**Bojarski (1970)**	**Vel'kov (1960)**	**Schoeneich (1971)**	**Buljan (1962, 1963)**	**Li ≥ 1 and B ≥ 3**
1	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (Cl/Mg > 5.13)	n/a	n/a	n/a	Good prospect (BS: negative, IA: 10-100)	Water associated with hydrocarbon accumulation
2	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (SO_4 x 100/Cl < 1)	n/a	n/a	Excellent prospect (BS: negative, IA: < 10)	Water associated with hydrocarbon accumulation
3, 5	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (SO_4 x 100/Cl < 1)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoirs (SO_4/HCO_3 < 2)	Excellent prospect (BS: negative, IA: < 10)	Water associated with hydrocarbon accumulation
4	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (SO_4 x 100/Cl < 1)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	n/a	Excellent prospect (BS: negative, IA: < 10)	Water associated with hydrocarbon accumulation
6, 7, 9	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas	Water associated with petroleum	Water associated with	n/a	n/a	Excellent prospect	Water associated with

		bearing ($CaCl_2$)	(IBE > 0.129)	hydrocarbon accumulation (SO_4 x 100/Cl < 1)			(BS: negative, IA: < 10)	hydrocarbon accumulation
8	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (Cl/Mg > 5.13)	n/a	n/a	n/a	Good prospect (BS: negative, IA: 10-100)	Water associated with hydrocarbon accumulation
10	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (Cl/Mg > 5.13)	Water associated with hydrocarbon accumulation (SO_4 x 100/Cl < 1)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoirs (SO_4/HCO_3 < 2)	Excellent prospect (BS: negative, IA: < 10)	Water associated with hydrocarbon accumulation
11	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (Cl/Mg > 5.13)	Water associated with hydrocarbon accumulation (SO_4 x 100/Cl < 1)	n/a	n/a	Excellent prospect (BS: negative, IA: < 10)	Water associated with hydrocarbon accumulation
12	Connate water (Sulin Na/Cl < 1)	Exist in the interior of the oil and gas fields ($MgCl_2$)	Water associated with petroleum (IBE > 0.129)	n/a	n/a	n/a	Native sulphur deposit (BS: positive, IA: 100-1000)	Water associated with hydrocarbon accumulation
13, 14	Connate water (Sulin Na/Cl < 1)	Exist in the interior of the oil and gas fields ($MgCl_2$)	Water associated with petroleum (Cl/Mg > 5.13)	n/a	n/a	n/a	Good prospect (BS: negative, IA: 10-100)	Water associated with hydrocarbon accumulation
15	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (Cl/Mg > 5.13)	Water associated with hydrocarbon accumulation (SO_4 x 100/Cl < 1)	n/a	n/a	Excellent prospect (BS: negative, IA: < 10)	Water associated with hydrocarbon accumulation
16	Connate water (Sulin Na/Cl < 1)	Exist in the interior of the oil and gas fields ($MgCl_2$)	Water associated with petroleum (Mg/Ca > 5.24)	n/a	n/a	n/a	Native sulphur deposit (BS: positive, IA: >1000)	Water associated with hydrocarbon accumulation
17	Meteoric water (Sulin Na/Cl > 1)	Reflect a weak enclosed conditionon which the oil and gas could not be gathered or stored easily (Na_2SO_4)	Meteoric water (IBE: negative)	n/a	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoirs (SO_4/HCO_3 < 2)	Native sulphur deposit (BS: positive, IA: 10-100)	No data
18	Connate water (Sulin Na/Cl < 1)	Exist in the interior of the oil and gas fields ($MgCl_2$)	Meteoric water (IBE: negative)	n/a	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoirs (SO_4/HCO_3 < 2)	Native sulphur deposit (BS: positive, IA: 10-100)	No data
19	Connate water (Sulin Na/Cl < 1)	Exist in the interior of the oil and	Meteoric water (IBE: negative)	n/a	n/a	n/a	Native sulphur deposit	No data

		gas fields ($MgCl_2$)					(BS: positive, IA: 10-100)	
20, 21, 22	Meteoric water (Sulin Na/Cl > 1)	A sign of a good oil and gas bearing ($NaHCO_3$)	Meteoric water (IBE: negative)	n/a	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoirs (SO_4/HCO_3 < 2)	Native sulphur deposit (BS: positive, IA: 100-1000)	No data

Table 19. Relation to oil and gas deposit of waters in Adıyaman oil fields (Turkey)

Sample	**Water origin**	**Sulin (1946)**	**Schoeller (1955)**	**Bojarski (1970)**	**Vel'kov (1960)**	**Schoeneich (1971)**	**Buljan (1962, 1963)**	**Li ≥ 1 and B ≥ 3**
ADL	Meteoric water (Sulin Na/Cl > 1)	Reflect a weak enclosed conditionon which the oil and gas could not be gathered or stored easily (Na_2SO_4)	Meteoric water (IBE: negative)	n/a	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (SO_4/HCO_3 < 2)	Native sulphur deposit (BS: positive, IA: 10-100	No data
KS	Connate water (Sulin Na/Cl < 1)	Exist in the interior of the oil and gas fields ($MgCl_2$)	Water associated with petroleum (IBE > 0.129)	n/a	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (SO_4/HCO_3 < 2)	Native sulphur deposit (BS: positive, IA: < 10)	No data
FG	Connate water (Sulin Na/Cl < 1)	Exist in the interior of the oil and gas fields ($MgCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (100 x SO_4/Cl < 1)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (SO_4/HCO_3 < 2)	Excellent prospect (BS: negative, IA: < 10)	No data
Adıyaman 7	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (100 x SO_4/Cl < 1)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (SO_4/HCO_3 < 2)	Excellent prospect (BS: negative, IA: < 10)	No data
A 32, SK 19, NK 21	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (Cl/Br < 350)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (SO_4/HCO_3 < 2)	Good prospect (BS: negative, IA: 10-100)	No data
A 44	Connate water (Sulin Na/Cl < 1)	Exist in the interior of the oil and gas fields ($MgCl_2$)	Water associated with petroleum (Cl/Mg > 5.13)	n/a	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (SO_4/HCO_3 < 2)	Good prospect (BS: negative, IA: 10-100)	No data
Adıyaman 52	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	(4), good zone for the preservation of hydrocarbons	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (SO_4/HCO_3 < 2)	Good prospect (BS: negative, IA: 10-100)	No data
Batı Fırat 2, Batı Fırat 11, Batı	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum	n/a	Water in contact withthe oil or located near	Water associated with hydrocarbon	Good prospect (BS: negative,	No data

Fırat 12, Batı Fırat 13			(Cl/Mg > 5.13)		an oil pool (SO_4/HCO_3< 3)	bearing reservoir (SO_4/HCO_3 < 2)	IA: 10-100)	
Beşikli 1, Beşikli 7/A, Beşikli 19	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	(4), good zone for the preservation of hydrocarbons	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	n/a	Good prospect (BS: negative, IA: 10-100)	Water associated with hydrocarbon accumulation (Beşikli 7), No data of other samples
Be 10, K 14	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (Cl/Mg > 5.13)	Water associated with hydrocarbon accumulation (I > 1 mg/l)	n/a	n/a	Good prospect (BS: negative, IA: 10-100)	Water associated with hydrocarbon accumulation
Ç 14	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (I > 1 mg/l)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (SO_4/HCO_3 < 2)	Good prospect (BS: negative, IA: 10-100)	No data
Ç 44	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (I > 1 mg/l)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (I > 10 mg/l)	Good prospect (BS: negative, IA: 10-100)	n/a
G.Karakuş 11	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (Cl/Br < 350)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	n/a	Good prospect (BS: negative, IA: 10-100)	Water associated with hydrocarbon accumulation
Karakuş 5	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (Cl/Mg > 5.13)	(4), good zone for the preservation of hydrocarbons	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	n/a	Good prospect (BS: negative, IA: 10-100)	No data
Karakuş 21	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (Cl/Mg > 5.13)	(4), good zone for the preservation of hydrocarbons	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	Water associated with hydrocarbon bearing reservoir (SO_4/HCO_3 < 2)	Good prospect (BS: negative, IA: 10-100)	No data
NK 20	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (IBE > 0.129)	Water associated with hydrocarbon accumulation (Cl/Br < 350)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	n/a	Good prospect (BS: negative, IA: 10-100)	No data
Ik 9	Connate water (Sulin Na/Cl < 1)	A sign offine oil and gas bearing ($CaCl_2$)	Water associated with petroleum (Cl/Mg > 5.13)	Water associated with hydrocarbon accumulation (I > 1 mg/l)	Water in contact withthe oil or located near an oil pool (SO_4/HCO_3< 3)	n/a	Good prospect (BS: negative, IA: 10-100)	Water associated with hydrocarbon accumulations

Petroleum and Subsurface Geology

Chebotarev (1955), Bojarski (1970) and Wei et al. (1996) classifications are selected in order to perform the assessments regarding the petroleum and subsurface geology characteristics of the basin where the water samples belong.

Meteoric-origin waters in selected areas (Sulin Na/Cl > 1); examples of Jujo and Tecominoacán samples Arenal and Mecatepec wells (Table 20); samples no. 17, 20, 21, 22, 23 of West Qaidam basin (Table 21); ADL, KS and FG samples of Adıyaman oilfields (Table 22) were found in the hydrodynamic zone (recharge zone) according to the Chebotarev classification and the connate-origin water of all the fields take place in hydrostatic zone (Sulin Na/Cl < 1). Only sample no. A44 of Adıyaman oilfields takes plane in the pressure zone (transition zone) (Table 22). In the study of Çelik and Sarı (2002), A44 sample is defined as "brackish water" as different from other water types (Fig. 19) and its hydrochemical facies is NaCI-HCO_3 (Table 16) and according to the Sulin classification, only A44 sample, $MgCl_2$, among the connate-origin water is identified as (Exist in the interior of the oil and gas field) (Table 19). Here, it can be seen that the water in the pressure zones (transition zone) is brackish-type water. Boschetti (2011) and Boschetti et al. (2014) have examined the characteristics of the water in pressure zones in their study in detail. According to these results, the consequence that the hydrodynamic and hydrostatic zones of the Chebotarev classification are quite successful, is obtained.

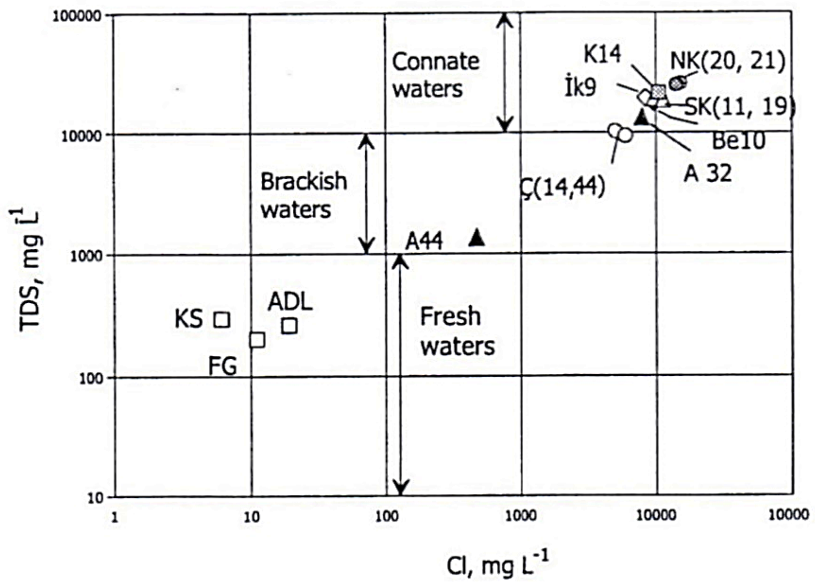


Fig. 19. Chloride concentrations versus TDS in Adıyaman region waters (Çelik and Sarı, 2002)

According to Bojarski (1970) classification, all the Jujo and Tecominoacán field reservoir waters (Table 20), samples no. 2, 3, 4, 5 of West Qaidam basin (Table 21), samples no. A32 and Ç14 of Adıyaman oilfields (Table 22) are classified as "(5), Presence of ancient residual sea water". Samples no. 6, 7, 8, 9, 10 and 11 of West Qaidam basin (Table 21), other formation water samples excluding A32 and Ç14 of Adıyaman oil fields (Table 22) "(4), Good zone for the preservation of hydrocarbons". Sample no. 1 of West Qaidam basin is identified as "(1), Zone of little prospect for the preservation of hydrocarbon deposits" (Table 21). As a result of the Wei et al. (1996) classification; the same sample (sample no. 1 of West Qaidam basin) is identified as "(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts" (Table 21). Sample no. 1 of West Qaidam basin is taken from the Xiaoliangshan anticlinal. Xiaoliangshan anticlinal is located in a more active tectonic zone when compared to other anticlinals (Figs, 17 and 22). This situation explains the reason of different identifications performed for the same sample in the classification.

According to the classification of Wei et al. (1996), Jujo and Tecominoacán field reservoir water samples (excluding J-26, T143A, T149) are identified as "(I), Trap is not destroyed, oilfield water tending to be stagnant, complete cover strata" (Table 20); J-26, T143A, T149 samples are identified as "(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts" (Table 20). J-26 sample is a faulty area near a salt diapir and where the contours are compressed topographically. Also, the fact that J-26 well is one of the first wells coming from Jujo-Tecominoacán reservoirs in 1993 confirms the classification made for the J-26 production well (Fig. 18, Birkle et al., 2009b). The presence of T143A sample on a fault and in an oil-water contact and the presence of T149 sample on a fault, and the presence of topographical contours in a compressed area confirm the accuracy of the classification (Figs, 16 and 20). Also, between 1993 and 2001, the water movement/fluid migration from the west side of Jujo and Tecominoacán sites reservoir that is an anticlinal-type reservoir, towards the center and then to the east side (especially from T-143A and T-149 wells in 1999) verifies the classification made for T-143A and T-149 wells (Fig. 21; Birkle et al., 2009b). The fact that the classifications of petroleum and subsurface geology for the J-26 and T-143A and T-149 wells are in accordance with the sample field data is an indicator for that the classification made by Wei et al. (1996) is quite efficient.

Table 20. Petroleum and subsurface geology of Jujo-Tecominoacán field

Sample	**Sample type**	**Water origin**	**Bojarski (1970)**	**Chebotarev (1955)**	**Wei ve diğ. (1996)**
J-3A, J-5, J-13A, J-14D, J-27, J-54, J-65, J-438, T-119, T-120, T-125, T-127, T-448, T-468, T-488	Reservoir water	Connate water (Sulin Na/Cl < 1)	(5), Presence of ancient residual sea water	(V), Zone of accumulation, stagnant conditions, deeper portions of structures, highly folded zones, water exchange manifests on geological scale time, sometimes 2400 - 3900 m	(I), Trap is not destroyed, oilfield water tending to be stagnant, complete cover strata
J-26	Reservoir water	Connate water (Sulin Na/Cl < 1)	(5), Presence of ancient residual sea water	(V), Zone of accumulation, stagnant conditions, deeper portions of structures, highly folded zones, water exchange manifests on geological scale time, sometimes 2400 - 3900 m	(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts
T-143A	Reservoir water	Connate water (Sulin Na/Cl < 1)	(5), Presence of ancient residual sea water	(V), Zone of accumulation, stagnant conditions, deeper portions of structures, highly folded zones, salt accumulation prevails upon leaching, sometimes 2400 - 3900 m	(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts
T-149	Reservoir water	Connate water (Sulin Na/Cl < 1)	(5), Presence of ancient residual sea water	(V), Zone of accumulation, stagnant conditions, different, salt accumulation prevails upon leaching, different	(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts
Arenal river	Surface water	Meteoric water (Sulin Na/Cl > 1)	n/a	(I), Zone of recharge, active exchange, different, intensive flush, usually less than 150 m	n/a
Mecatepec well	Groundwater	Meteoric water (Sulin Na/Cl > 1)	n/a	(I), Zone of recharge, active exchange, different, intensive flush, usually less than 150 m	n/a

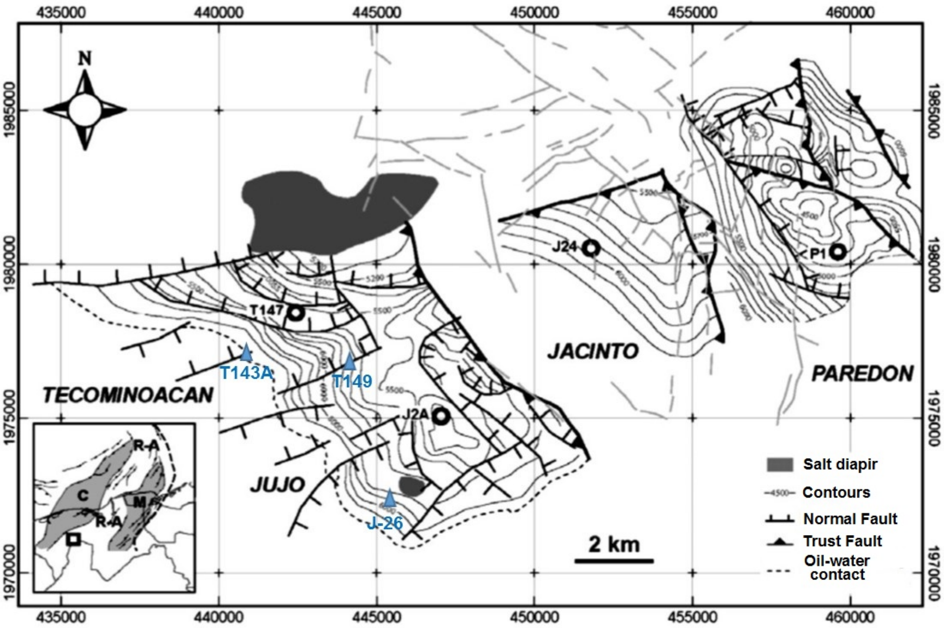


Fig. 20. Tectonic map of Jujo-Tecominoacán field (modified from Bourdet, 2008)

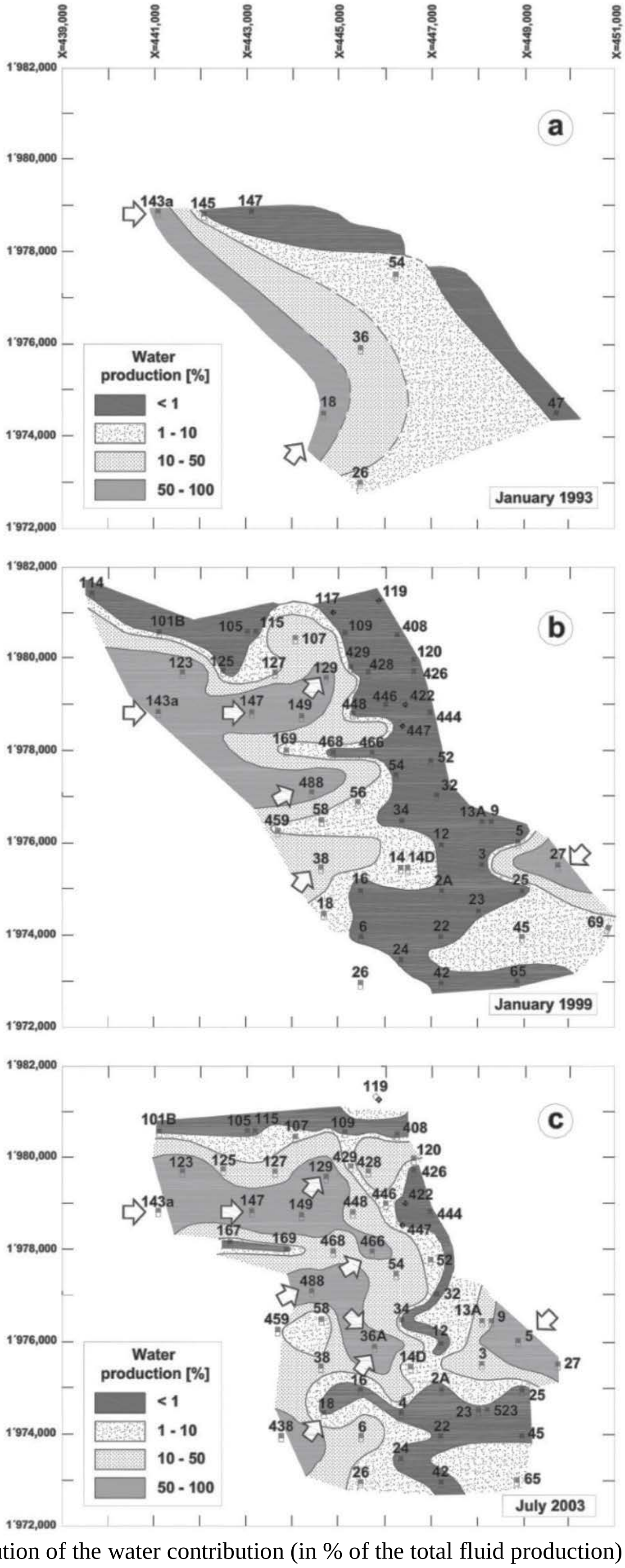


Fig. 21. Lateral distribution of the water contribution (in % of the total fluid production) in production wells of the Jujo-Tecominoacán field from 1993 to 2003 (Birkle et al., 2009b)

According to the classification of Wei et al. (1996), samples no. 2, 3, 4, 5, 6 and 7 of West Qaidam basin oilfield brines are identified as "(I), Trap is not destroyed, oilfield water tending to be stagnant, complete cover strata" (Table 20); samples no. 8, 9, 10, are identified as "(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts" (Table 20). Sample no. 12 of the salt lake brines is identified as "(I), Trap is not destroyed, oilfield water tending to be stagnant, complete cover strata" (Table 20); samples no. 13 and 14 are identified as "(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts" (Table 20). Samples no. 15 and 16 that are the inter crystalline brines are identified as "(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts" (Table 20).

The thick-sequence of primary petroleum source rocks of the Qaidam basin was deposited in the major rifted depression and the restricted drainage graben ofthe rifted protobasin. During the tectonic inversion megastage they were subject to deep burial and prolonged heating. A major and a minor oil-generating basin have developed. The tectonic inversion processes produced several structural features that may contain potential hydrocarbon reservoirs and traps (Xia et al., 2001). Petroleum reservoirs in the basin take place in the area called as the oil hill and its immediate vicinity (Fig. 22). According to the classification of Wei et al. (1996), the samples of West Qaidam basin that are classified as "(I), Trap is not destroyed, oilfield water tending to be stagnant, complete cover strata" are the samples taken from this oil hill and its immediate vicinity (Fig. 17 and Table 20). The petroleum reservoirs in Qaidam basin are located in the northwest and northeast parts of basin. The samples identified as "(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts" (Table 20) take place in the south and southwest parts of the basin and they are the samples taken from the most tectonic and sediment areas of the basin (oil-generating depressions) (Figs. 17 and 22). Therefore, the classifications and the sample field data are totally compatible.

Table 21. Petroleum and subsurface geology of western Qaidam basin

Sample	Sample type	Water origin	Bojarski (1970)	Chebotarev (1955)	Wei ve diğ. (1996)
1	Oilfield brine	Connate water (Sulin Na/Cl < 1)	(1), Zone of little prospect for the preservation of hydrocarbon deposits	(V), Zone of accumulation, stagnant conditions, deeper portions of structures, highly folded zones, water exchange manifests on geological scale time, sometimes 2400 - 3900 m	(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts
2, 3, 4, 5	Oilfield brine	Connate water (Sulin Na/Cl < 1)	(5), Presence of ancient residual sea water	(V), Zone of accumulation, stagnant conditions, deeper portions of structures, highly folded zones, water exchange manifests on geological scale time, sometimes 2400 - 3900 m	(I), Trap is not destroyed, oilfield water tending to be stagnant, complete cover strata
6, 7	Oilfield brine	Connate water (Sulin Na/Cl < 1)	(4), Good zone for the preservation of hydrocarbons	(V), Zone of accumulation, stagnant conditions, deeper portions of structures, highly folded zones, water exchange manifests on geological scale time, sometimes 2400 - 3900 m	(I), Trap is not destroyed, oilfield water tending to be stagnant, complete cover strata
8, 9, 10, 11	Oilfield brine	Connate water (Sulin Na/Cl < 1)	(4), Good zone for the preservation of hydrocarbons	(V), Zone of accumulation, stagnant conditions, deeper portions of structures, highly folded zones, water exchange manifests on geological scale time, sometimes 2400 - 3900 m	(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts
12	Salt lake brine	Connate water (Sulin Na/Cl < 1)	n/a	n/a	(I), Trap is not destroyed, oilfield water tending to be stagnant, complete cover strata
13, 14	Salt lake brine	Connate water (Sulin Na/Cl < 1)	n/a	(V), Zone of accumulation, stagnant conditions, deeper portions of structures, highly folded zones, water exchange manifests on geological scale time, sometimes 2400 - 3900 m	(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts
15	Intercrystalline brine	Connate water	(4), Good zone for the	(V), Zone of accumulation, stagnant conditions, deeper portions of structures, highly	(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active,

		(Sulin Na/Cl < 1)	preservation of hydrocarbons	folded zones, water exchange manifests on geological scale time, sometimes 2400 - 3900 m	surface water permeating, incomplete cover strata, oil and gas lost in large amounts
16	Intercrystalline brine	Connate water (Sulin Na/Cl < 1)	n/a	n/a	(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts
17	Spring water	Meteoric water (Sulin Na/Cl > 1)	n/a	(I), Zone of recharge, active exchange, different, intensive flush, usually less than 150 m	n/a
18, 19	Groundwater	Connate water (Sulin Na/Cl < 1)	n/a	n/a	n/a
20, 21, 22	Groundwater	Meteoric water (Sulin Na/Cl > 1)	n/a	(I), Zone of recharge, active exchange, different, intensive flush, usually less than 150 m	n/a

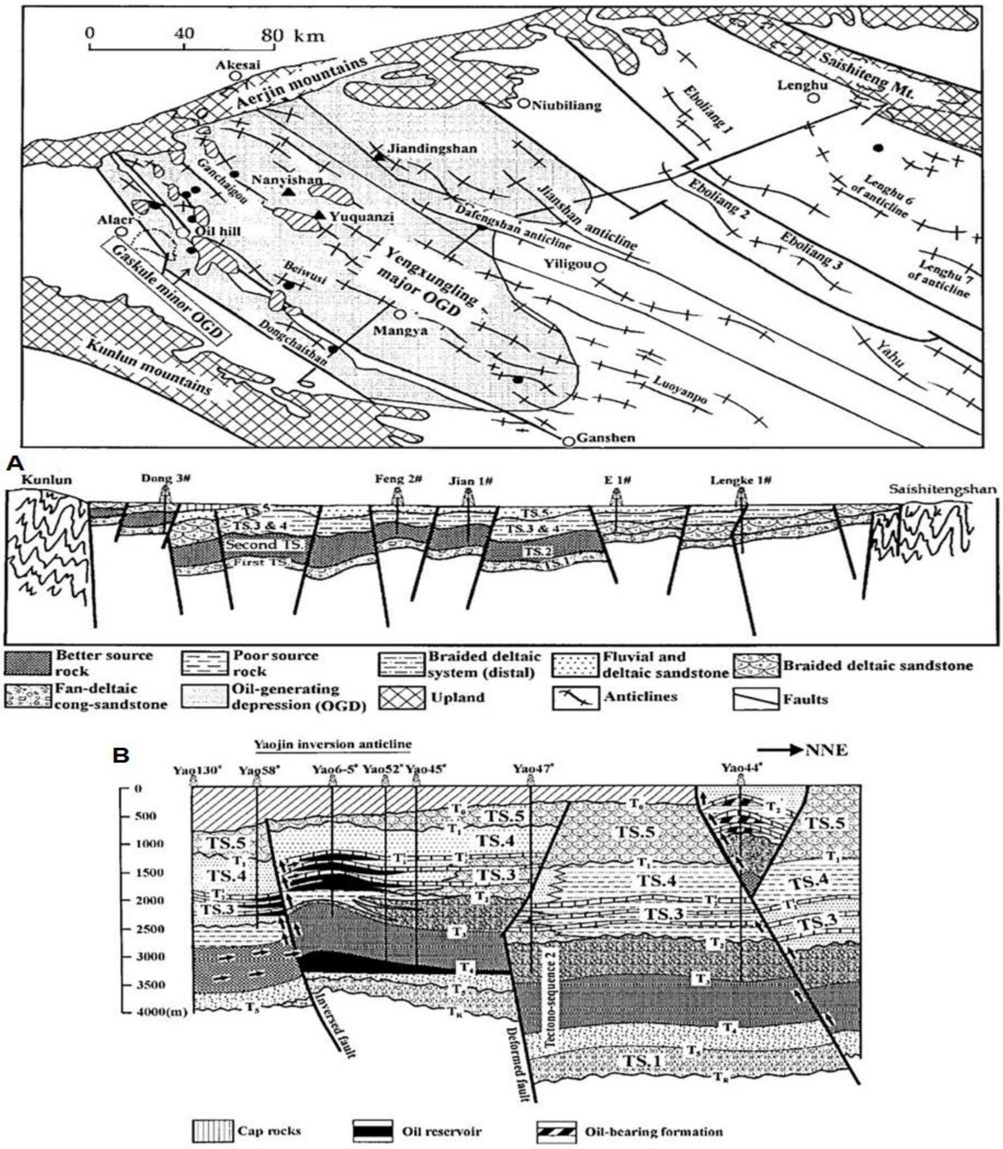


Fig. 22. A: Distribution map of oil-generating depression and anticline in western Qaidam basin, B: (B) Yaojin-Youshashan (oil hill) cross section, showing the reversed structures formed by basin tectonic inversion processes (from Xia et al., 2001)

Only 4 of 22 samples taken from Adıyaman oilfields (A32, Adıyaman 52, Beşikli 1, Beşikli 7A and Beşikli 19 samples) are identified as "(I), Trap is not destroyed, oilfield water tending to be stagnant, complete cover strata". Other samples are defined as "(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts" (Table 22). In most of the wells at Adıyaman oilfields, CO_2 and O_2 concentration are high and water production is about 90% as an average (Hoşhan et al., 2008; Çelik and Sarı, 2002; Table 23). This data indicates that there is a significant uplift in the region and the oil is located in local and very limited traps. Hence, it verifies the accuracy of the classification made.

Table 22. Petroleum and subsurface geology of Adıyaman oil fields

Sample	**Sample type**	**Water origin**	**Bojarski (1970)**	**Chebotarev (1955)**	**Wei ve diğ. (1996)**
ADL	Fresh water	Meteoric water (Sulin Na/Cl > 1)	n/a	(I), Zone of recharge, active exchange,different, intensive flush, usually less than 150 m	n/a
KS, FG	Fresh water	Connate water (Sulin Na/Cl < 1)	n/a	(I), Zone of recharge, active exchange,different, intensive flush, usually less than 150 m	n/a
Adıyaman 7, Batı Fırat 2, Batı Fırat 11, Batı Fırat 12, Batı Fırat 13, Be 10, Ç 44, G.Karakuş 11, SK 19, Karakuş 5, K 14, Karakuş 21, NK 20, NK 21, Ik 9	Formation water	Connate water (Sulin Na/Cl < 1)	(4), Good zone for the preservation of hydrocarbons	(V), Zone of accumulation, stagnant conditions, deeper portions of structures, highly folded zones, water exchange manifests on geological scale time, sometimes 2400 - 3900 m	(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts
A 32	Formation water	Connate water (Sulin Na/Cl < 1)	(5), Presence of ancient residual sea water	(V), Zone of accumulation, stagnant conditions, deeper portions of structures, highly folded zones, water exchange manifests on geological scale time, sometimes 2400 - 3900 m	(I), Trap is not destroyed, oilfield water tending to be stagnant, complete cover strata
A 44	Formation water	Connate water (Sulin Na/Cl < 1)	n/a	(IV), Zone of pressure, delayed exchange, deeper portions of structures, folded zones, circulation and drainage limited, 900 - 1200 m	(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts
Adıyaman 52, Beşikli 1, Beşikli 7/A, Beşikli 19	Formation water	Connate water (Sulin Na/Cl < 1)	(4), Good zone for the preservation of hydrocarbons	(V), Zone of accumulation, stagnant conditions, deeper portions of structures, highly folded zones, water exchange manifests on geological scale time, sometimes 2400 - 3900 m	(I), Trap is not destroyed, oilfield water tending to be stagnant, complete cover strata
Ç 14	Formation water	Connate water (Sulin Na/Cl < 1)	(5), Presence of ancient residual sea water	(V), Zone of accumulation, stagnant conditions, deeper portions of structures, highly folded zones, water exchange manifests on geological scale time, sometimes 2400 - 3900 m	(III_2), Strong tectonic uplifting, faults leading to the surface, oilfield water relatively strongly active, surface water permeating, incomplete cover strata, oil and gas lost in large amounts

Table 23. Oil and water productions and API gravity of wells in the Adıyaman oil fields (Data: Hoşhan et al., 2008; Çelik and Sarı, 2002; PDGA, 2008; DPT, 2001)

Well Name	Gravity (API)	Sulphur ratio (%)	Water production (barrel/day)	Oil production (barrel/day)	Water ratio (%)	Fluid level (m)	Well depth (m)	Oil Production Screen level (m)	Oil production formation
Adıyaman-7	26.7	1.5	202	12	94	432	1064		Karababa + Karaboğaz
A32 (Adıyaman-32)					94	949	1636	1628-1636	
A44 (Adıyaman-44)					93	338		1679-1685	
Adıyaman-52			130	18	86	1569	1582		
Batı Fırat-2	35.2	1.1	360	22	94	1034	1522		Karababa + Derdere
Batı Fırat-6			90	23	74	1800	1800		
Batı Fırat-9			22	7	70	1817	1817		
Batı Fırat -11			411	21	95	206	958		
Batı Fırat-12			480	96	80	329	949		
Batı Fırat-13			100	16	84	1184	1856		
Ç14 (Çemberlitaş-14)	31	0.7		50 (well average)	94	394		2957-2975	Karababa C
Ç44 (Çemberlitaş-44)					97	835		3017-3025	Derdere
Karakuş-5	30		1218	37	97	1598	2359		Karaboğaz + Karababa + Derdere + Sabunsuyu
Karakuş-7			400	160	60	1391	1778		
Karakuş-12			4374	87	98	554	1779		
Karakuş-13			352	253	28	1739	2196		
K14 (Karakuş-14)					98	695		2547-2554	
Karakuş-21			260	13	95	902	1621		
Beşikli-1	25.6	2.4	300	60	80	1353	1625		Karaboğaz + Karababa
Beşikli-2			225	86	62	1166	1838		
Beşikli-7/A			134	27	80	1062	1795		
Beşikli -9			305	73	76	1306	1761		
Be 10 (Beşikli-10)					80	893		1893-1905	Karaboğaz
								1925-1934	Karababa C
Beşikli -19			255	10	96	949	1684		
G.Karakuş-11	26.5		163	26	84	1391	1734	2536-2549	Karaboğaz
								2557-2575	Karababa C
								2598-2628	Karababa B
SK-19 (G.Karakuş-19)					92	1320		2410-2435	Derdere
NK20 (Kuzey Karakuş-20)	29	0.8			94	587		2576-2595	Derdere
								2607-2639	Derdere
NK21 (Kuzey Karakuş-21)					94	658		2520-2535	Sayındere
								2590-2615	Karababa B + Karababa C
Ik-9 (İkizce-9)	26.4	2.2		50 (well average)	98	37		2249-2255	Derdere

In the 4 classifications selected for the identification of types and origins of the water samples (Sulin, 1946; Chebotarev 1955; Wei et al., 1996 and Rosental, 1997), the identifications used for the same types of water are different from each other. The use of the hydrochemical facies for the identification of the water type of the samples studied in petroleum hydrogeology studies and the identifications of Sulin (1946) classification within definition of water origin that is determined by Na/Cl (%meq) ratio and recommended by Roger (1917) (connate or meteoric-origin water) eliminates this difference.

In order to perform the assessments regarding the geological environment where the water samples are derived; Cheboratev and Clark classifications are used. In Cheboratev and Clark classifications, in case different results are obtained for the same water sample, as detailed in Lawrence and Cornfordt (1995), the consequence that fluids are derived from different sources in the sedimentary basin mix with each other and the oilfield water is a mixture of these fluids, is obtained.

In order to assess the relation of water samples and an oil and gas deposit; the results of (1946), Schoeller (1955), Bojarski (1970), Vel'kov (1960), Schoneich (1971), Buljan (1962, 1963), Li and B classifications that take Li and B ratios as a basis are compatible with the results of fields examined as a sample.

In case the iodine analysis results of investigated basin water samples are available, the Bojarski (1970) classification preferred method since it specifies the waters associated with hydrocarbon deposits are directly based on iodine content. In case of iodine analysis results of the investigated basin water samples are not present, the Br/Cl < 350 approach proposed by Borjarski (1970) becomes prominent.

In order to determine that the B ratio in the connate water that is developed by the mixture of different fluids (primarily magmatic fluids and formation waters) (due to magmatic contribution) is high, there is no iodine data and to determine the water related to oil and gas deposis in the basins with Br/Cl > 350; it is suitable to use the Li ≥ 1 and B ≥ 3 approach that is recommended by the authors together with the (SO_4 x 100)/Cl < 1 equation that is recommended by Bojarski (1970).

It is observed that Buljan (1962, 1963) classification is found to be quite compatible with the data on all the fields sampled (Tables 17, 18 and 19). Jamil (2004) has tested this classification on oilfield waters in Iraq and has achieved similar results with this study regarding applicability of classification.

It is found that Chebotarev (1955) and Bojarski (1970) classifications are quite successful in the determination of hydrodynamic and hydrostatic zones. Compliance of the petroleum and subsurface geology classifications in Wei et al. (1996) classification with the field data tested is an indicator that the classification made by Wei et al. (1996) is quite efficient. The proposed systematic study method for predicting the location, petroleum and subsurface geological properties of oil and gas deposits in a wildcat sedimentarybasin with high accuracy using hydrogeochemical methods is given in Fig. 23.

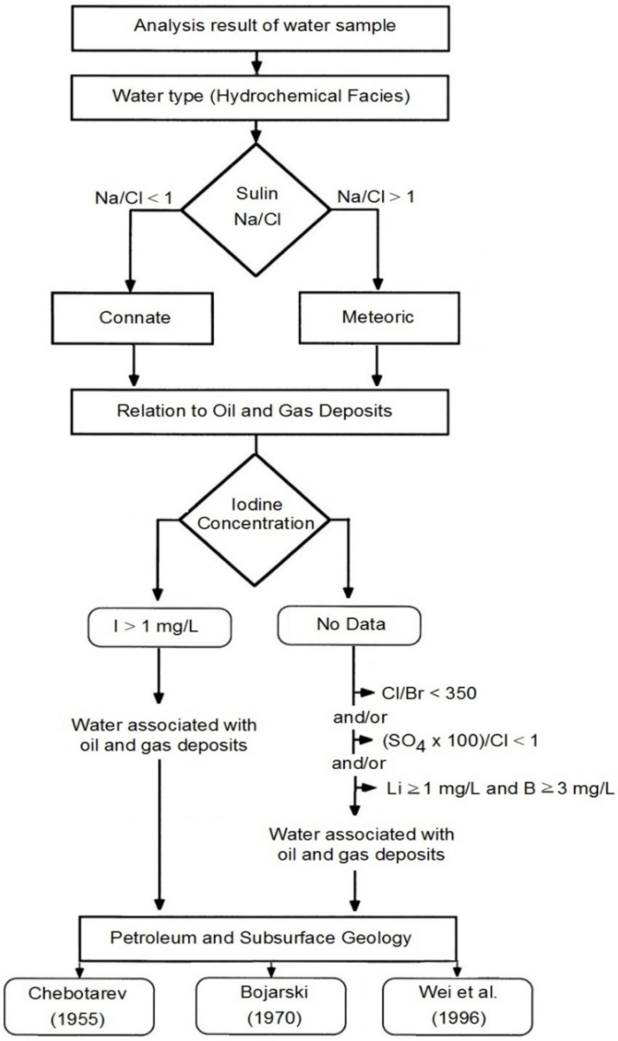


Fig. 23. Systematic work flow chartproposed forhigh-accuracy estimation with hydrochemical methods of oil and gas deposits in a wildcat sedimentarybasin

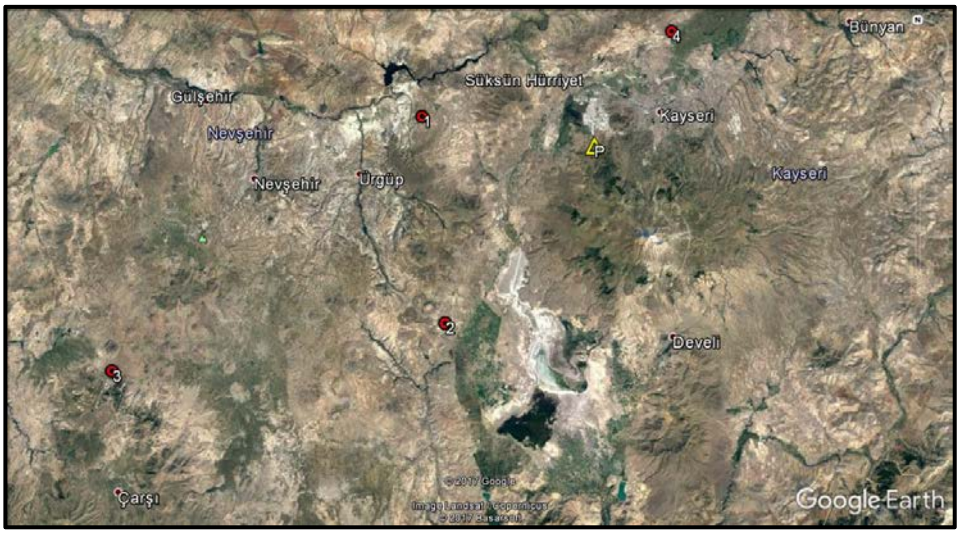
The iodine in waters is an important and well-known indicator of oil and gas. In most natural waters, the content of iodine is negligible. In fresh surface waters and fresh groundwaters, the iodine content is from 10^{-5} to 10^{-3} mg/l, in sea water about 5 x 10^{-2}mg/l, in underground saline waters 10^{-1} to 1 mg/l (Kartsev et al., 1954). Characteristics of water associated with hydrocarbon accumulations are iodide > 1 mg/l (Çoban, 2017; Collins, 1975; Borjarski, 1970 and many others). Portable iodine checkers are capable of measuring the amount of iodine in the water up to 12.5 mg/l are developed and they are available on the market (Fig. 24). These portable iodine checkers can be used for obtaining a preliminary idea regarding the field being studied and to select samples that will be sent to the analysis of the samples for the water resources (springs and wells) in investigation.

Fig. 24. Portable iodine checker

In order to test the applicability of the systematic method shown in Figure 23, assessments on the current analysis results of the cold and hot water resources in Central Anatolian region (Turkey) where no detailed oil and gas exploration is done and there is no production fields but the presence of oil seep as specified in Erentöz and Ternek (1959) are performed. As a result of the assessments made, water samples are taken from the specified water resources in order to perform iodine analysis. In 4 of these water samples that are analyzed; the presence of more than 1 mg/l is determined (Table 24 and Map 1).

Table 24. Iodine analysis results of water samples in Center Anatolia region (Turkey)

Sample No	Sample Name	Location	Coordinates		Iodine (mg/l)
			Latitute	Longitute	
1	Karakaya mineral water	Ürgüp / Nevşehir	38.717228°	35.032163°	4.18
2	Yeşilhisar mineral water	Yeşilhisar / Kayseri	38.412021°	35.074547°	3.55
3	Narlıgöl Thermal bath water	Merkez / Niğde	38.344714°	34.461820°	2.75
4	Yazır cold spring	Kocasinan / Kayseri	38.844077°	35.511399°	2.31



Map 1. Locations of water samples in Center Anatolia (Turkey), (yellow triangle : oil seep)

VI. Conclusions

In this article, it is aimed to give an idea about how the hydrogeochemistry data could affect the success of oil and gas exploration projects in a basin or field-scale. Hydrogeochemistry data (chemical data of cold and hot water springs and wells) is a powerful tool to minimize the risk of hydrocarbon exploration in wildcat sedimentary basins. In this study; it is exemplified how the hydrogeochemistry data can guide the regional and local studies, and how the exploration teams can be supported regarding the minimization of the risk of drilling to be performed in known and future hydrocarbon basins. As an example, the results of the fields examined (including the Central Anatolian region sample) are completely compatible with the results of the classifications included in the program. It is clear that the results of analysis of water samples obtained from hydrogeochemical exploration studies in any wildcat sedimentary basin will provide crucial data regarding the petroleum and subsurface geology characteristics of petroleum and gas deposits in case they are interpreted by experienced engineers. It can also predicted that the classification methods of oilfield waters in the program will provide important contributions to the evaluation of petroleum and subsurface geology assessments to be made in the production phase and in the determination of the development direction of the field.

References

[1]. Al-Marsoumi, H.A. and Abdul-Vahab, D.S., 2005. Hydrochemistry of Yamama reservoir formation water-West Qurna oil field-Southern Iraq. Basrah Journal of Scienec C., 23(1), 10-20

[2]. Amiri, M. and Moghadasi, J., 2012. The prediction of calcium carbonate and calciumsulfate scale formation in Iranian oilfields atdifferent mixing ratios of injection waterwith formation water. Petroleum Science and Technology, 30, 223-236

[3]. Bagheri, R., Nadri, A., Raeisi, E., Eggenkamp, H.G.M., Kazemi, G.A. and Montaseri, A., 2014a. Hydrochemical and isotopic (δ18O, δ2H, 87Sr/86Sr, δ37Cl and δ81Br)evidence for the origin of saline formation water in a gas reservoir. Chemical Geology 384, 62-75

[4]. Bagheri, R., Nadri, A., Raeisi, E., Shariati, A., Mirbagheri, M. and Bahadori, F., 2014b. Chemical evolution of a gas-capped deep aquifer,southwest of Iran. Environmental Earth Sciences, 71, 7, 3171-3180

[5]. Bagheri, R., Nadri, A., Raeisi, E., Eggenkamp, H.G.M., Kazemi, G.A. and Montaseri, A., 2014c. Origin of brine in the Kangan gasfield: isotopicand hydrogeochemical approaches. Environmental Earth Sciences, 71, 7, 3171-3180

[6]. Barnaby, R.J., Oetting, G.C. and Gao, G., 2004. Strontium isotopic signaturesof oil-field waters: Applicationsfor reservoir characterization. AAPG Bulletin, 88(12), 1677-1704

[7]. Bazin, B., Brosse, I. and Sommer, F., 1997a. Chemistry of oil-field brines in relation todiagenesis of reservoirs I. Use of mineral stabilityfields to reconstruct in situ water composition.Example of the Mahakam basin. Marine and Petroleum Geology, 14(5), 481-495

[8]. Bazin, B., Brosse, I. and Sommer, F., 1997b. Chemistry of oil-field brines in relation todiagenesis of reservoirs-2. Reconstruction ofpalaeo-water composition for modelling illitediagenesis in the Greater Alwyn area (North Sea). Marine and Petroleum Geology, 14(5), 497-511

[9]. Bentor, Y.K., 1969. On the evolution of subsurface brines in Israel. Chemical Geology. 4, 83-110

[10]. Bernatsky, R., 1998. Hydrogeochemistry of formation waters in Southern Saskatchewan. University of Regina, MSc. Thesis, 206 p.

[11]. Birkle, P., 2006. Application of $^{129}I/^{127}I$ to define the source of hydrocarbons of the Pol-Chuc, Abkatún and Taratunich-Batab oil reservoirs, Bay of Campeche, southern Mexico. Journal of Geochemical Exploration, 89,15-18

[12]. Birkle, P., García, B.M. and Padrón, C.M.M., 2009a. Origin and evolution of formation water at the Jujo-Tecominoacán oil reservoir,Gulf of Mexico. Part 1: Chemical evolution and water-rock interaction, Applied Geochemistry, 24, 543-554

[13]. Birkle, P., García, B.M. and Padrón, C.M.M., 2009b. O Origin and evolution of formation water at the Jujo–Tecominoacán oil reservoir,Gulf of Mexico. Part 2: Isotopic and field-production evidence for fluid connectivity, 24, 555-573

[14]. Birkle, P., Aragon, J.J.P., Portugal, E.and Aguilar, J.L.F., 2002. Evolution and origin of deepreservoir water at theActivo Luna oil field,Gulf of Mexico, Mexico. AAPG Bulletin, 86(3), 457-484

[15]. Birkle, P., 2016a. Geochemical fingerprinting of hydraulic fracturing fluidsfrom Qusaiba Hot Shale and formation water fromPaleozoic petroleum systems, Saudi Arabia. Geodluids, doi: 10.1111/gfl.12176

[16]. Birkle, P., 2016b. Recovery rates of fracturingfluids and provenance ofproduced water from hydraulicfracturing of Silurian Qusaibahot shale, northern SaudiArabia, with implications onfracture network. AAPG Bulletin, 100(6), 917-941

[17]. Birkle, P., Jenden, P.D. and Al-Dubaisi, J.M., 2013. Origin of formation water from the Unayzah and Khuffpetroleum reservoirs, Saudi Arabia. Procedia Earth and Planetary Science, 7, 77-80

[18]. Birkle, P. and Angulo, M., 2005. Conceptual hydrochemical model of late Pleistoceneaquifers at the Samario-Sitio Grande petroleumreservoir, Gulf of Mexico, Mexico. Applied Geochemistry, 20, 1077-1098

[19]. Bjorlykke, K., Aagaard, P., Egeberg, P.K. and Simmons, S.P., 1995. Geochemical constraints from formation water analyses fromthe North Sea and the Gulf Coast Basins on quartz, feldsparand illite precipitation in reservoir rocks. Cubitt, J.M. and England, W.A. (eds), The Geochemistry of Reservoirs,Geological Society Special Publication No. 86, pp. 33-50.

[20]. Blondes, M.S., Gans, K.D., Rowan, E.L., Thordsen, J.J., Reidy, M.E., Engle, M.A., Kharaka, Y.K. and Thomas, B., 2016. U.S. Geological Survey National Produced Waters Geochemical Database, Version 2.2. http://eerscmap.usgs.gov/pwapp/

[21]. Bojarski, L., 1970. Die Anwendung der hydrochemischen Klassifikation bei Sucharbeiten auf Erdol. 2. Angew. Geol., 16:123-125

[22]. Boschetti, T., 2011. Application of brine differentiation and Langelier-Ludwig plotsto fresh-to-brine waters from sedimentary basins: diagnostic potentials andlimits. J. Geochem. Explor. 108, 126-130

[23]. Boschetti, T., Angulo, B., Cabrera, F., Vásquez, J. and Montero, R.L., 2016. Hydrogeochemical characterization of oilfield waters from southeast MaracaiboBasin (Venezuela): diagenetic effects on chemical and isotopic composition. Marine and Petroleum Geology, 73, 228-248

[24]. Boschetti, T., Toscani, L. and Marian, E.S., 2014. Boron isotope geochemistry of Na-bicarbonate, Na-chloride,and Ca-chloride waters from the Northern ApennineForedeep basin: other pieces of the sedimentary basinpuzzle. Geofluids, 15, 546-562

[25]. Bourdet, J., 2008. Diagenetical and filling history of Mesozoic carbonate petroleum reservoirs of the Mexican Southeast Basin, Mexico. UHP, Nancy I, PhD Thesis, 358 p.

[26]. Breen, K.J. and Masters, R.W., 1985. Chemical and Isotopic Characteristics of Brines From ThreeOil- and Gas-Producing Sandstones in Eastern Ohio, With Applications to The Geochemical Tracing of Brine Sources. U.S. Geological Survey. Water-InvestigationsReport. 84-4314, 58 p.

[27]. Buljan, M., 1962. Nova geochemijska metoda za razlikovanje prirodnihvoda. Croat.Chem. Acta, 23, Zagreb, pp.12-23 (in Jamil, A.K., 2004. Hydrogeochemical indices for the prospecting of hydrocarbon and native sulphur deposits. Iraqi Jour. of Earth Sci., 4 (2), 1-10)

[28]. Buljan, M., 1963. An aspect of geochemical significance of sea water among the naturalwaters. Rapp. Et Proc,-Verb. Des reunions de la Commis. Hnt. Expl. Sci. MerMediterrane, XVII (3), Paris (in Jamil, A.K., 2004. Hydrogeochemical indices for the prospecting of hydrocarbon and native sulphur deposits. Iraqi Jour. of Earth Sci., 4 (2), 1-10)
[29]. Cakmakcı, M., Kayaalp, N. and Koyuncu, I., 2008. Desalination of produced water from oil productionfields by membrane processes. Desalination, 222, 176-186
[30]. Carpenter, B.A., Michael, T.L. and Edwarde, P.E., 1974. Preliminary report on the origin and chemical evolution of lead-and zinc-rich oil field brines in central Mississippi, Economic Geology, 69, 1191-1206
[31]. Celik, M. and Sarı, A., 2002. Geochemistry of formation waters from upper cretaceous calcareous rocks of Southeast Turkey. Journal Geological Society of India. 59, 419-430
[32]. Celik, M., Sarı, A., Bahtiyar, I. and Afşin, M., 1998. Origin of formation waters in Adıyaman oil fields. 12th International Petroleum Congress and Exhibition of Turkey, pp. 149-159
[33]. Chan, L., Starinsky, A. and Katz, A., 2002. The behavior of lithium and its isotopes in oilfield brines: Evidence from theHeletz-Kokhav field, Israel. Geochimica et Cosmochimica Acta, 66, 4, 615-623
[34]. Chave, K. E., 1960. Evidence on history of seawater from chemistry of deeper subsurface waters of ancient basins. Bull. Am. Assoc. Petrol. Geol., 44, 357-370.
[35]. Chebotarev, I.I., 1955. Metamorphism of natural waters in the crust of weathering, 1-3. Geochim. Cosmochim. Acta, 8: 22-48, 137-170, 198-212
[36]. Chilingar, G.V., Buryakovsky, L.A., Eremenko, N.A. and Gorfunkel, M.V., 2005. Geology and Geochemistry of Oil and Gas. Elsevier BV, 370 p.
[37]. Chilingar, G.V., 1957. Soviet methods of reporting and displaying results of chemical analyses of natural waters and methods of recognizing oil-field waters. Trans. Am. Geophys. Union, 38(2): 219-221
[38]. Chilingar, G.V., 1958. Chemical composition of oil-field waters from Apsheron Peninsula, Azerbaijan S.S.R.: A summary. Geochim. Cosmochim. Acta, 14: 168-172
[39]. Chilingar, G. V. and Degens, E. T., 1964. Notes on chemistry of oil-field waters. Bol. Asoc. Mexicana Geol. Petrol., 15 (7-8): 177-193
[40]. Cihaudhuri, S., Broedel, V. and Clauer, N., 1987. Strontium isotopic evolution of oil-field waters from carbonate reservoirrocks in Bindley field, Central Kansas, U.S.A. Geochimica et Cosmochimica Acta. 51, 45-53
[41]. Chilingar, G.V., 1958. Chemical composition of oil-field waters from Apsheron Peninsula, Azerbaijan S.S.R.: A summary. Geochim. Cosmochim. Acta, 14: 168-172.
[42]. Chunfang, C., Licai, P. Bowen, M. and Yingkai, X., 2006. B, Sr, O and H isotopic compositions of formation watersfrom the Bachu Bulge in the Tarim basin. Acta Geologica Sinica, 80(4), 550-556
[43]. Clark, I., 2015. GroundwaterGeochemistryand Isotopes. Taylor & Francis Group, LLC., 421 p.
[44]. Collins, A.G, 1975. Geochemistry of Oilfield Waters. Developments in Petroleum Science, 1, Elsevier Scientific Publishing Company, Amsterdam, 496 p.
[45]. Coustau, H., 1977. Formation waters and hydrodynamics. Journal of Geochemical Exploration, 7, 213-241
[46]. Çoban, M.K., 2017. Petrol Hidrojeolojisi (İkinci Baskı). Poyraz Ofset. 533 s. (Petroleum Hydrogeology, Second Edition, 533 p., in Turkish)
[47]. De Sitter, L.U., 1947. Diagenesis of oil-field brines. Bull. Am. Assoc. Petrol. Geol., 31: 2030-2040
[48]. Demir, I. and Seyler, B., 1999. Chemical composition and geologic history ofsaline waters in Aux Vases and CypressFormations, Illinois Basin. Aquatic Geochemistry, 5, 281-311
[49]. Dia, A.N., Castrec-Rouelle, M., Boulegue, J. and Comeau, P., 1999. Trinidad mud volcanoes: Where do the expelled fluids come from ? . Geochimica et Cosmochimica Acta. 63(7/8), 1023-1038
[50]. Dickey, P.A., Collins, A.G. and Fajardo M.I., 1972. Chemical composition of deep formation waters in Southwestern Louisiana. AAPG Bulletin, 56(8), 1530-1570
[51]. Downing, R.A. and Howitt, F., 1968. Saline ground-waters in theCarboniferous rocks of theEnglish East Midlands inrelation to the geology. Q. J. Eng. Geol. 1, 1969, 241-269
[52]. DPT, 2001. Petrol ve Doğalgaz Sektör Raporu, 130 s. ((Planning Organization of Turkey, Report of Oil and Natural Gas Sector, 130 p.)
[53]. Dresel, P. E. and Rose, A.W., 2010. Chemistry and origin of oiland gas well brines in western Pennsylvania: Pennsylvania Geological Survey, 4th ser.,Open-File Report OFOG 10-01.0, 48 p.
[54]. Durov, S.A., 1948. Classification of natural waters and graphical presentation of their composition. Trans. USSR Acad. Sci., 59 (1), 87-90
[55]. Egeberg, P.K. and Aagaard, P., 1989. Origin and evolution of formation waters from oil fields on the Norwegian shelf. Applied Geochemistry, 4, 131-142
[56]. EIzarka, M.H. and Ahmed, W.A.M., 1983. Formational water characteristicsas an indicator for the process of oilmigration and accumulatıon at theAin Zalah field, Northern Iraq. Journal of Petroleum Geology, 6(2), 165-178142
[57]. Engle, M.A., Reyes, F.R., Varonka, M.S., Orem, W.H., Ma, L., Ianno, A.J., Schell, T.M., Xu, P. and Carroll, K.C., 2016. Geochemistry of formation waters from the Wolfcamp and "Cline"shales: Insights into brine origin, reservoir connectivity, and fluid flow inthe Permian Basin, USA. Chemical Geology, 425, 76-92
[58]. Engle, M.A., Cozzarelli, I.M. and Smith, B.D., 2014. USGS Investigations of Water Produced During Hydrocarbon Reservoir Development: U.S. Geological Survey Fact Sheet 2014-3104, 4 p., https://dx.doi.org/10.3133/fs20143104
[59]. Eremenko, N. A. (Ed.), 1960. Geology of Petroleum, I - Principles of Geology and Petroleum. Gostoptekhizdat, Moscow, 592 p.
[60]. Erentöz, C. ve Ternek, Z., 1959. Türkiye sedimantasyon havzalarındapetrol imkânları. MTA Dergisi, 53, 21-36 (English version : Oil possibilities in the sedimentary basins of Turkey, Bull. Min. Res. Exp., 2-38)
[61]. Fehn, U., U. Snyder, G.T. and Muramatsu, Y., 2007. Iodine as a tracer of organic material: ^{129}I results from gas hydrate systems and fore arc fluids. Journal of Geochemical Exploration. Volume 95, Issues 1-3, October-December 2007, Pages 66-80
[62]. Fehn, U., Tullai-Fitzpatrick, S., Teng, R.T.D., Gove, H.E.,Kubik, P.W., Sharma, P. and Elmore, D., 1990. Dating of oil field brines using ^{129}I. Nuclear Instruments and Methods in Physics Research B52, 446-450
[63]. Fisher, R.S. and Kreitler, C.W., 1987. Geochemistry and hydrodynamics of deep-basin brines,Palo Duro Basin, Texas, U.S.A. Applied Geochemistry, 2, 459-76
[64]. Fontes, J.C. and Matray, J.M., Geochemistry and origin of formation brines from theParis Basin, France: 2. Saline solutions associated with oil fields. Chemical Geology, 109, 177-200
[65]. Franks, S.G. and Uchytil, S.J., 2016. Geochemistry of formationwaters from the subsalt TubularBells Field, offshore Gulf ofMexico: Implications for fluidmovement and reservoircontinuity, AAPG Bulletin, 100(6), 943-967

[66]. Frape, S.K., Fritz, p. and Mcnutt, R.H., 1984. Water-rock interaction and chemistry of groundwaters from the Canadian Shield. Geochimica et Cosmochimica Acta. 48, 1617-1627
[67]. Gümüş, Ö. and Altan, Y., 1995. Gümüş, Ö. ve Altan, Y., 1995. Petrolün Tarihçesi ve Türkiye'de Açılan Petrol Kuyuları. Petrol İşleri Genel Müdürlüğü Yayını, 78 s. (History of Petroleum and Oil Wells Drilled in Turkey. General Directorate of Petroleum Affairs of Turkey, 178 p., Turkish - English)
[68]. Hanshaw, B.B. and Hill, G.A., 1969. Geochemistry and hydrodynamics of the Paradox basin region,Utah, Colorado and New Mexico., Chemical Geology, 4, 263-294 Herndon, J.M., 2016. New concept on the origin of petroleum and natural gas deposits. J. Petrol. Explor. Prod. doi:10.1007/s13202-016-0271-5
[69]. Herndon, J.M., 2011. Geodynamic basis of heat transport in the Earth. Curr. Sci. 101(11), 1440-1450
[70]. Hitchon, B. and Billings, G.K. and Klovan, J.E., 1971. Geochemistry and origin of formation waters in the western Canadasedimentary basin-III. Factors controlling chemical composition. Geochimica et Cosmochimica Acta. 35, 567-598
[71]. Hoşhan, P., Çelik, S. and Çanga, B., 2008. Inspection and control of corrosion problemsfor production oil wells tubing and rod in Adıyaman oil fields. International Corrosion Symposium, October 22-25, 2008, Izmir, Turkey, pp. 13-20
[72]. Hounslow, A.W. 1995. Water Quality Data: Analysis and Interpretation, CRC Lewis Publishers, 416 p.
[73]. Houston, S.J., 2007. Formation waters in petroleum reservoirs;their controls and applications. The University of Leeds, School of Earth and Environment, PhD Thesis, 240 p.
[74]. Issar, A., Rosenthal, O.E., Eckstein, O.Y. and Bogoch, R., 1971. Formation waters, hot springs and mineralizationphenomena along the eastern shore of the Gulf of Suez. Bulletin of the International Association of Scientific Hydrology.Bulletin, 16(3), 25-44
[75]. Jamil, A.K., 2004. Hydrogeochemical indices for the prospecting of hydrocarbon and native sulphur deposits. Iraqi Jour. of Earth Sci., 4(2), 1-10
[76]. Jensen, J., 1934. California oilfield waters. In Problems of Petroleum Geology, AAPG, 953-985
[77]. Jiang, T., Xie, X., Chen, H., Wang, Z., Li, X., 2015. Geochemistry of pore water and associated diageneticreactions in the diapiric area of Yinggehai basin,Northwestern South China Sea. Journal of Earth Science, 26(3) 306-316, DOI: 10.1007/s12583-015-0526-y
[78]. Jin, Z., Cao, J., Hu, W., Zhang, Y., Yao, S., Wang, X., Zhang, Y., Tang, Y. and Shi, X., 2008. Episodic petroleum fluid migration in fault zones of the northwestern Junggar Basin (northwest China): Evidence from hydrocarbon-bearing zoned calcite cement. AAPG Bulletin, 92, 9, 1225-1243
[79]. Kartsev, A. A., Tabasaranskii, S. A., Subbota, M. I. and Mogilevsky, G. A., 1954. Geochemical methods of prospecting and exploration for petroleum and natural gas (P. A. Witherspoon and W. D, Romey, eds., English translation) : Berkeley, Univ. Calif. Press, 1959, 238 p.
[80]. Kharaka, Y.K., Maest, A.S., Carothers, W.W., Law, L.M., Lamothe, P.J. and Fries, T.L., 1987. Geochemistry of metal-rich brines from central Mississippi SaltDome basin, U.S.A., Applied Geochemistry, 2, 543-561
[81]. Kharaka, Y.K., and Hanor, J.S., 2007. Deep fluids in the continents: I. Sedimentary basins. Treatise on Geochemistry, Volume 5, 1-48
[82]. Kireeva, T.A., 2010. Genesis of the Underground Water from the White Tiger Deposit, South Vietnam Shelf, in Relation to Its Petroleum Resource Potential. Moscow University Geology Bulletin, 65(4), 244-249
[83]. Knipe, R.J., 1993. The influence of fault zone processes and diagenesis on fluid flow. In: Diagenesis and Basin Development (Ed. by E. D. Horbury and A. G. Robinson), Amer. Ass. Petrol. Geol. Studies in Geology, 36, 135-154
[84]. Kokh, A.A. and Novikov, D.A., 2014. Hydrodynamic conditions and vertical hydrogeochemical zonalityof groundwater in the western Khatanga artesian basin. Water Resources, 41(4), 396-405
[85]. Kurchikov, A.R. and Plavnik, A.G., 2009. Clustering of groundwater chemistry data with implicationsfor reservoir appraisal in West Siberia. Russian Geology and Geophysics 50, 943-949
[86]. Land, S.L. and Macpherson, G.L., 1992. Origin of saline formation waters, Cenozoic section, Gulf of Mexico sedimentary basin, AAPG Bulletin, 76(9), 1344-362
[87]. Lavrushina, V.Y., Guliev, I.S., Kikvadze, O.E. Aliev, A.A., Pokrovskya, B.G. and Polyak, B.G., 2015. Waters from mud volcanoes of Azerbaijan:Isotopic-geochemical properties and generation environments. Lithology and Mineral Resources, 50, 1, 1-25
[88]. Lawrence, S.R. and Cornfordt, C., 1995. Basin geofluids. Basin Research, 7, 1-7
[89]. Macpherson, G.L., 1992. Regional variations in formation water chemistry: major and minor elements, Frio formation fluids, Texas. AAPG Bulletin, 76(5), 740-757
[90]. Mazor, E., 2004. Global WaterDynamics (Shallow and Deep Groundwater,Petroleum Hydrology,Hydrothermal Fluids, and landscaping). Marcel Dekker, Inc., 393 p.
[91]. Mazzini, A., Svensen, H., Planke, S., Guliyev, I., Akhmanov, G.G., Fallik, T. and Banks, D., 2009. When mud volcanoes sleep: Insight from seep geochemistryat the Dashgil mud volcano, Azerbaijan. Marine and Petroleum Geology, 26(9), 1704-1715
[92]. Meinhold, R., 1972. Hydrodynamic control of oil and gas accumulation as indicated by geothermal, geochemical and hydrological distribution patterns, Trans. 8th World Petrol.Cong., 2, 55-66
[93]. Mirnejad, H., Sisakht, V., Mohammadzadeh, H., Amini, A.H., Rostron, B.R. and G. Haghparast, G., 2011.Major, minor element chemistry and oxygen and hydrogen isotopiccompositions of Marun oil-field brines, SW Iran: Source historyand economic potential. Geological Journal, 46, 1-9
[94]. Morad, S., Ismail, H.N.B., De Ros, L.F., Al-Aasms, I.S. andSerrhini, N.E., 1994. Diagenesis and formation water chemistry of Triassic reservoir sandstones fromsouthern Tunisia. Sedimentology, 41, 1253-1272
[95]. Moran, J.E., Fehn, U., and Hanor, J.S., 1995. Determination of source ages and migration of brines from the U.S. Gulf Coast basin using 129 I. Geochim. Cosmochim. Acta 59, 5055-5069.
[96]. Murthy, M.V.K., Padhy, P.K. and Prasad, D.N., 2011. Mesozoic hydrogeologic systemsand hydrocarbon habitat,Mandapeta-Endamuru area,Krishna Godavari Basin, India, AAPG Bulletin, 95(1), 147-167
[97]. Novikov, D.A. and Shvartsev, S.L., 2009. Hydrogeological conditions of the Pre-Yenisei petroleum subprovince. Russian Geology and Geophysics, 50, 873-883
[98]. Novikov, D.A., 2012. Hydrogeology of oil-and-gasbearing deposits of the Severnyi arch (Northern areas of the West Siberian Megabasin (WSMB). Oil and Gas Business, 4, 521-535
[99]. Novikov, D.A., 2013a. Hydrogeochemical features of petroleum-bearing deposits of the Yamal Peninsula.Oil and Gas Business, 1, 114-143
[100]. Novikov, D.A., 2013b. Hydrogeology of the western part of the Yenisei-Khatanga regional trough.Neftegazovaya Geologiya, Teoriya I Praktika, 8(1), www.ngtp.ru/rub/4/2_2013.eng.pdf
[101]. Okandan, E., Mehmetoğlu, T., Doyuran, V., Demiral, B., Parlaktuna, M., Gümrah, F., Kuru, E., Behlülgil, K., Karacan, Ö. and Karaaslan, U., 1994. Effect on Environment of Petroleum Exploration and Production Activities. The Scientific and Technical Research Council of Turkey, Project No.YBAG-0057, 92 p. (Unpublished, in Turkish)

[102]. Oppo, D., Capozzi, R., Nigarov, A. and Esenov, P., 2014. Mud volcanism and fluidgeochemistry in the Cheleken Peninsula, western Turkmenistan, Marine and Petroleum Geology, 57, 122-134
[103]. Oppo, D. and Capozzi, R., 2015. Spatial association of mud volcano and sandstoneintrusions, Boyadag anticline, westernTurkmenistan. Basin Research, 1-13, doi: 10.1111/bre.12136
[104]. Ostroff, A.G., 1975. Subsurface water: Tool for petroleum exploration. Society of Petroleum Engineers Journal. 50-64
[105]. Ozgun, H.,Ersahin, M.E.,Erdem, S.,Atay, B.,Sayili, S., Eren, E., Hoshan, P., Atay, D., Altinbas, M.,Kinaci, C. andKoyuncu, I., 2013. Comparative evaluation for characterization ofproduced water generated from oil, gas, andoil-gas production fields. Clean - Soil, Air, Water, 41(12), 1175-1182
[106]. Palmer, C., 1924. California oilfield waters. Economic Geology, 19. 623-635
[107]. Piper, A.M., 1944. A graphic procedure in the geochemical interpretation of water analyses. AmericanGeophysical Union Transactions, 25, 914-923.
[108]. Pirson, S.J., 1942. Theoretical and economic significance of geodynamic prospecting. World Petrol., 13, 38-42
[109]. Planke, S.,Svensen, H.,Hovland, M.,Banks, D.A. and Jamtveit, B., 2003. Mud and fluid migration in active mud volcanoes in Azerbaijan. Geo-Mar. Lett. 23, 258-268
[110]. Purwaningsih, E. and Notosiswoyo, S., 2013. Hydrochemical study of groundwater in Sidoarjo mud volcanoarea, East Java Indonesia. Procedia Earth and Planetary Science, 6, 234-241
[111]. Rachinsky, M.Z. and Kerimov, V.Y., 2015. Fluid Dynamics of Oil and Gas Reservoirs. Scrivener Publishing LLC - John Wiley and Sons, Inc., 613 p.
[112]. Rainwater, F. H. and White, W. F., 1958. The solusphere - its inference and study. Geochim. Cosmochim. Acta, 14: 244-249
[113]. Reich, M., Snyder, G.T., Álvarez, F., Pérez, A., Palacios, C., Vargas, G.,Cameron, E.M., Muramatsu, Y. and Fehn, U., 2013. Using iodine isotopes to constraın supergene fluid sources in arid regions:Insights from the Chuquicamata Oxide Blanket. Economic Geology, 108, 163-171
[114]. Risch, M.R. and Silcox, C.A., 2016. Groundwater Quality from PrivateDomestic Water-Supply Wells in theVicinity of Petroleum Production inSouthwestern Indiana. U.S. Geological Survey. Open-File Report 2016-1081, 29 p.
[115]. Rogers, S.G., 1917. Chemical relations of the oil-field waters in San Joaquin Valley, California. United States Geological Survey. 119 p.
[116]. Rosenthal, E., 1997. Thermomineral waters ofCa-chloride composition: review ofdiagnostics and of brine evolution. Environmental Geology, 32 (4), 245-250
[117]. Rowan, E.L., Engle, M.A., Kraemer, T.F., Schroeder, K.T., Hammack, R.W. and Doughten, M.W., 2015. Geochemical and isotopicevolution of water producedfrom Middle DevonianMarcellus shale gas wells,Appalachian basin,Pennsylvania. AAPG Bulletin, 99(2), 181-206
[118]. Rueskamp, H., Ariki, J., Stieglitz, K. and Treskatis, C., 2014. Effect of oil exploration and production on the salinity of a marginally permeable aquifer system in the Thar Jath-, Mala- and Unity Oilfields, Southern Sudan. Zbl. Geol. Paläont. Teil I, 1, 95-115
[119]. Qishun, F., Haizhou, M.A., Zhongping, L., Hongbing, T. and Tingwei, l., 2010. Origin and evolution of oilfield brines from Tertiary strata in western Qaidam Basin: Constraintsfrom 87Sr/86Sr, δD, δ18O, δ34S and water chemistry. Chin. J. Geochem., 29, 446-454
[120]. Quadir, M.F., 2008. Formation Evaluation of Upper Qamchuqua Reservoir, Khabbaz Oil Field, Kirkük Area, Northeastern Iraq, University of Sulaimani, PhD. Thesis, 168 p.
[121]. Sakroon, S.A., 2008. Effect of oilfeld brine on groundwater quality inMarmul area, Sultanate of Oman. United Arab Emirates University, MSc. Thesis, 146 p.
[122]. Samedov, F. I. and Buryakovsky, L. A., 1956. Chemical composition and origin of formation waters of the Neftyanyye Kamni field. Trans. Azerbaijan Acad. Sci., 12(11), 841-848
[123]. Schoeller, H., 1955. Geochemie des eaux souterraines. Rev. Znst. Fr. Pet., 10:181-213,219-246, 507-552
[124]. Schoeller, H.J., 1962. Les Eaux Souterraines: Hydrologie Dynamique et Chimique : Recherche, Exploitation et Evaluation des Ressources. 642 p.
[125]. Schoeneich, K., 1971. Indices of oil bearing deposits as based on the formation waters of Poland. Nafta (Pol.), 27, 154-157.
[126]. Shouakar-Stash, O., Alexeev, S.V., Frape, S.K., Alexeeva, L.P. and Drimmie, R.J., 2007. Geochemistry and stable isotopic signatures, includingchlorine and bromine isotopes, of the deep groundwaters ofthe Siberian Platform, Russia. Applied Geochemistry, 22, 589-605
[127]. Smalley, E.C., Dodd, T.A., Stockden, I.L., Raheim, A. and Mearns, E.W., 1995. Compositional heterogeneities in oilfield formation waters:identifying them, using them. Cubitt, J.M. & England, W.A. (eds), 1995, The Geochemistry of Reservoirs,Geological Society Special Publication No.86, 59-69
[128]. Stueber, A.M., Walter, L.M., Huston, T.J. and Pushkar, P., 1993. Formation waters from Mississippian-Pennsylvanian reservoirs, Illinois basin, USA:Chemical and isotopic constraints on evolution and migration. Geochimica et Cosmochimica Acta. 57, 163-784
[129]. Stueber, A.M. and Walter, L.M., 1991. Origin and chemical evolution of formation waters from Silurian-Devonian stratain the Illinois basin, USA. Geochimica et Cosmochimica Acta. 55, 309-325
[130]. Sudo, Y., 1967. Geochemical study of brine from oil and gas fields in Japan. Journal of The Japanese Association of Petroleum Technologists. 32, 5, 286-296
[131]. Sukharev, G.M., 1948. Hydrogeological conditions of formation of oil and gasdeposits in Tersk-Dagestan oil province. Groz. obi. izd-vo (in Kartsev, A. A., Tabasaranskii, S. A., Subbota, M. I. and Mogilevsky, G. A., 1954. Geochemical methods of prospecting and exploration for petroleum and natural gas (P. A. Witherspoon and W. D, Romey, eds., English translation) : Berkeley, Univ. Calif. Press, 1959, 238 p.
[132]. Sulin, V.A., 1946. Waters of Petroleum Formations in the System of Nature Waters. Gostoptekhizdat, Moscow, 96 p. (in Russian)
[133]. Snyder, G.T., Riese, W.C., Franks, S., Fehn, U., Pelzmann, W.L., Gorody, A.W. and Moran, J.E., 2003: Origin and history of waters associated with coal-bed methane: 129I, 36Cl, and stable isotope results from the Fruitland Formation, CO and NM. Geochim. Cosmochim. Acta, 67, 4529-4544
[134]. Tan, H., Rao, W., Ma, H., Chen, J. and Li, T., 2011. Hydrogen, oxygen, helium and strontium isotopic constraints on the formationof oilfield waters in the western Qaidam Basin, China. Journal of Asian Earth Sciences, 40, 651-660
[135]. Tikhomirov, V.V., 2016. HydrogeochemistryFundamentals andAdvancesVolume 1: GroundwaterComposition and Chemistry. Scrivener Publishing LLC., 309 p.
[136]. Tolstikhin, N. I., 1932. Toward question of graphical representation of analysis of waters. In: V. Golubyatnikov (Editor), Sampling of Mineral Deposits. Gosgeolizdat, Moscow-Leningrad, pp. 1-8.
[137]. Toop, D.C. and Toth, J., 1995. Hydrogeochemical characterization offormation waters using ionic ratios,South-Central Saskatchewan. Seventh International Williston Basin Symposium, 313-319

[138]. Tooth, J., 1987. Petroleum hydrogeology: a potential application of groundwater science. Journal of Geological Survey of India, 29(1), 172-179

[139]. Vassoyevich, N. B. (Ed.), 1954. Companion of Field Petroleum Geologist, Part II. Gostoptekhizdat, Leningrad, 564 p.

[140]. Vel'kov, A.M., 1960. Hydrochemical indicators of gas-oil productivity. Petroleum Geology: A digest of Russian literature on Petroleum Geology, 4, 9B, 539-541

[141]. Uğur, Z. and Örgün, Y., 1996. The hydrogeochemistry of oilfield waters in Adiyaman Region. 11th Petroleum Congress of Turkey, Ankara, 182-189

[142]. Uliasz-Misiak, B., 2016. Water accompanying hydrocarbon deposits as a potentialsource of iodine, lithium and strontium. Gospodarka Surowcami Mineralnymi - Mineral Resources Management 32(2), 31-44

[143]. Wang, X., Chen, J., Li, Z., Li, J., Wang, D., Wang, Y., Yang, C. and Cui, H., 2016. Rare gases geochemical characteristics and gas source correlation for Dabei gas field in Kuche depression, Tarim Basin. Energy Exploration & Exploitation, 34(1), 113-128

[144]. Waples, D.W., 1985.Geochemistryin PetroleumExploration. D. Reidel Publishing Company. International Human Resources Development Corporation. 232 p.

[145]. Weaver, T.R., Frape, S. K. andCherry, J.A., 1995. Recent cross-formational fluid flow and mixing in the shallowMichigan Basin. GSA Bulletin, 107(6), 697-707

[146]. Wei, L., Limin, L. and Xiaohong, C., 1996. Geochemical characteristics of oilfield waters fromthe Turpan Depression, Xinjiang and theirpetroleum geological significance. Chinese Journal of Geochemistry, 15(4), 374-382

[147]. Xia, W., Zhang, N., Yuan, X.,Fan, L. and Zhang, B., 2001. Cenozoic Qaidam basin,China: A stronger tectonicinversed, extensionalrifted basin. AAPG Bulletin, 85(4), 715-736

[148]. Xun, Z., Cijun, L., Xiumin, J., Qiang, D. and Lihomg, T., 1997. Origin of subsurface brines in the Sichuan basin, Groundwater, 35(1), 53-58

[149]. White, D.E., 1957. Magmatic, connate and metamorphic waters. Geol. Soc. Amer. Bull., 68, 1659-1682

[150]. Yang, S., 2017. Fundamentalsof Petrophysics. Springer-Verlag GmbH, 502 p.

[151]. Younger, P.L., 2007. Groundwater in the Environment: An Introduction. Blackwell Publishing Ltd., 318 p.

Adil Özdemir " High Accuracy Estimation with Computer-Aided Hydrochemical Methods of Oil and Gas Deposits in Wildcat Sedimentary Basins. "IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG) 6.4 (2018): 62-104.