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Geologic Challenges of Exploration – Onshore China[1]

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ABSTRACT

There are more than 20 major sedimentary basins onshore China. Significant hydrocarbon production is currently limited to only a few of these basins including the Songliao, Bohaiwan, and Junggar basins. Exploration results in some of the other interior basins has been disappointing, while in others activities have been limited as a result of their remoteness.

Much of the resources within the producing basins were derived from lacustrine systems and often found in nonmarine sandstones. The oils found are often waxy and reservoir properties poor, with limited vertical and lateral continuity. Consequently, although field sizes may be large, flow-rates from individual wells may be limited and a large number of wells are required to capture the reserves. For example, the Daqing field (Songliao basin) had initial reserves of more than 8 billion barrels of oil and is producing ~1 million bbl/day, but contains more than 10,000 wells. Similarly, typical flow-rates from vertical wells in the Shengli petroleum province (Bohaiwan basin) are less than 700 bbl/day. Recent horizontal wells in the Shengli field have shown significant improvements in production rates, with individual wells achieving rates in excess of 5000 bbl/day.

An examination of the less explored basins suggests that many of the key components of petroleum systems are present. For example, in the Tarim basin multiple marine and lacustrine source rocks have been identified, as have been both clastic and carbonate reservoirs ranging in age from Cambro-Ordovician through Paleogene. Active seeps have also been observed within the basin and more than 240 structural targets identified, with over 140 having surface expression. The primary

exploration challenges in many of these basins appear to be associated with relative timing, preservation of hydrocarbon accumulations, and communication between the generative basin and the trap.

INTRODUCTION

Nearly 45% of the onshore surface area of the People's Republic of China is covered by unmetamorphosed sedimentary rock (Li Desheng, 1985). Much of this sediment is contained within 20 or so major and moderate sized basins (Figure 1), with more than 600 sedimentary basins having been identified (Tian Zaiyi, 1990). Sediment thickness in these basins can often exceed 10 km (Li Desheng, 1985).

From a historical perspective there is substantial evidence to suggest that these basins hold considerable exploration potential. Active oil seepage has been known for at least 4000 years (Hu Boliang, 1992). The magnitude of some of these seeps can be quite significant, with individual asphalt-covered areas in the Junggar basin exceeding 1000 km^2 (Taner, 1988). In fact, the village of Karamay in the Junggar basin has its name derived from the "black hill" associated with an asphalt deposit that has been mined for centuries (Taner et al., 1988).

In addition to oil, the presence of natural gas has also been well documented for many centuries. For example, natural gas has been produced for commercial purposes from brine wells in the Sichuan basin for almost 1000 years (Vogel, 1993).

Today, significant oil production onshore is limited to three basins – Songliao, Bohaiwan, and Junggar. The major field in the Songliao basin is Daqing. The Daqing Field complex currently has daily oil production of ~1.1 million bbl. The complex, which was discovered in 1959, will ultimately produce more than 8 billion barrels of oil (Meyerhoff and Willums, 1981). Within the Bohaiwan basin the major hydrocarbon production is from the Shengli Field complex, which was discovered in 1960. Daily production from Shengli currently approaches that of Daqing. Meyerhoff and Willums (1981) estimate that the Shengli complex has reserves of ~5 billion barrels. Within the Junggar basin it is the giant Karamay Field complex, discovered in 1957, which currently dominates the basin's production. Although initial production was limited, partially as a result of oil quality, the discovery of a deep light oil pool has resulted in an increase in the field's production level. Production of ~200,000 bbl/day is now targeted for the Karamay Field complex for 2000.

Other basins have either limited production or have had significant shows. For example, in the Tarim basin three discoveries are worth highlighting (Hu Bliang, 1992; and Li Desheng, 1995). The Ke #1 well located along the southwest margin of the basin had reported initial flow rates of 10,000 bbl/day and 9.5 mmcf/day from Lower Miocene sands. The Shacan (or Shashen) #2 well which penetrated Ordovician dolomites had initial flow rates of greater than 7000 bbl/day and more than 70 mmcf/day. And, also from Lower Ordovician dolomites the Tazhong #1 well located in the central portion of the basin had tested oil flows of over 4000 bbl/day.

Although circumstantial evidence suggests the possibility of significant hydrocarbon potential, the magnitude of the resources for individual basins and consequently the country as a whole is poorly known. Hsu (1994) suggested that the Tarim basin could have generated more than 350 billion barrels of oil. Li Desheng (1996) suggests that China's (both onshore and offshore) in-place oil exceeds 500 billion barrels and that ~1160 TCF of natural gas are present. But these estimates must be viewed with some degree of caution, they appear to be based largely on hydrocarbon source rock potential (i.e., source rock richness and volume) rather than a more complete integrated assessment. The USGS estimates known reserves at ~52.6 billion barrels of oil and natural gas liquids and ~57.7 TCF of natural gas. But even these estimates must be viewed with some degree of caution as a result of the wide-range of published reserve estimates for individual fields. For example, published reserve estimates for the Karamay Field (Junggar basin) differ by more than an order of magnitude, ranging from 219 million to more than 9 billion barrels (Carroll et al., 1992). In part, this uncertainty exists because of the limited amount of data available, the vintage of the data, and the manner in the data are interpreted.

Regardless of the uncertainty in reserve estimates, oil and gas are present. However, the mere presence of oil and gas does not insure that it will be commercial. Whether an accumulation is commercial is dependent on such factors as the volume of hydrocarbons present, rates of production, reservoir continuity, target depth, proximity to market, cost of infrastructure, and the value of a barrel of crude oil.

A review of exploration results in China reveals that several exploration challenges exist before commercial accumulations can be established beyond the known producing basins. These challenges include establishing the potential for initial hydrocarbon charge, the preservation of hydrocarbon accumulations, the quality of potential reservoirs, and the effectiveness of communication between source and reservoir/trap.

If one accepts the axiom that "oil and gas is where you find it" a re-examination of onshore China does appear warranted. It is the focus of this paper to examine aspects of hydrocarbon charge and reservoir quality and their possible implications on future exploration within the Tarim and Junggar basins (Figures 2 and 3). These two basins were selected because of their size and reported hydrocarbon reserve potential. Others have discussed the presence and abundance of potential structural traps in these basins as well as their different tectonic histories. For example, Xie Hong (1993) have noted that over 200 potential structural traps have been identified in Tarim basin, with more than half of these being identifiable through surface mapping.

HYDROCARBON CHARGE

Hydrocarbon charge is dependent on the quality and quantity of organic matter present, the extent of organic diagenesis, the relative timing of hydrocarbon generation compared to the timing of trap development, the efficiency of migration, and the preservation of the hydrocarbon accumulation.

Source Rock Potential

The hydrocarbon source rock potential of a sedimentary sequence is dependent on three factors: the level of organic enrichment; the hydrocarbon generation potential; and the type of organic matter present. The criteria used to establish the presence or absence of an oil or gas source rock system (i.e., source rock thresholds) differ as a result of their different expulsion mechanisms. Oil-prone hydrocarbon source rocks require that the source rock's pore network become saturated for expulsion to occur. In contrast, primary migration in gas-prone systems is largely driven by diffusion. Diffusion does not require that the pore system become saturated with gas only that a concentration gradient be present. Thus, lower threshold criteria with respect to organic enrichment and generation potential exist for gas-prone versus oil-prone source rocks.

Statistical studies have suggested that potential and/or effective oil source rocks contain above-average concentrations of organic carbon (i.e., > 1.0%) and have above-average total pyrolytic yields (S_1+S_2 > 2.5 mg HC/g rock; Bissada, 1982). These statistically derived values also provide the necessary free hydrocarbon content (~850 ppm; Momper, 1978) at the top of the “oil-window” for pore network saturation to take place and for oil expulsion to proceed. Good oil-prone source rocks typically display hydrogen index values greater than ~400 mg HC/g TOC. Most, if not all, of the source rocks for major petroleum systems display characteristics significantly better than the threshold requirements (i.e., TOC > 2.0%; S_1+S_2 > 6.0 mg HC/g rock; hydrogen indices > 400 mg HC/g rock).

The threshold criteria for gas-prone source rock systems are not as stringent and also appear to be less well defined. Although it has been suggested that as little as 0.1% TOC may be necessary for gas generation (Clayton, 1992), it is more likely that the source rock threshold value approaches 0.5% TOC (Rice and Claypool, 1981). The gas source threshold values are probably site specific because the volumes of gas necessary for an accumulation to be economic vary so widely.

It should be noted that an oil-prone rock would within the main phase of hydrocarbon generation produce both oil and gas. Similarly, a gas-prone rock may generate and expel minor amounts of liquids. The classification used here is based on whether significant amounts of liquid hydrocarbons could reasonably be expected. The relative yield of the two hydrocarbon phases is partially controlled by the abundance of organically bound hydrogen. In reality kerogen composition can be viewed as a continuum. Oil yields increase with increasing H/C ratios (hydrogen index values) and decreasing O/C ratios (oxygen index values).

Kerogen characterization can be accomplished through several different chemical and physical means. Most commonly organic matter characterization is accomplished through the use of the “Rock-Eval” data, i.e., the relationship between the hydrogen and oxygen indices as presented on a modified van Krevelen-type diagram.

Within the Tarim basin three possible source rock intervals have often been cited - the Cambro-Ordovician, Permo-Carboniferous, and the Upper Triassic to Middle Jurassic (Junhong Chen et al., 1996). It has also been proposed that Late Cretaceous-Paleogene shales may also be a possible source (Ulmishek, 1984). Graham et al. (1990) suggest from their limited outcrop sampling that much of the source rock potential is actually limited to the Ordovician marine shales and the Upper Triassic-Middle Jurassic lacustrine and paludal sequences.

There is, however, only limited source rock data available from the Tarim basin to support these speculations. For example, Yang Bin (1991) reports that the Cambrian gray-black limestones recovered from the Kunan #1 well had organic carbon contents that ranged from only 0.55 to 0.92 wt.%. Yang Bin further reported that outcropping Ordovician limestones and claystones also typically contained less than 1.0 wt.%, with the exception of only two samples that contained 1.17 and 1.19 wt.%. These generally low levels of organic enrichment most probably reflect both an advanced levels of thermal maturity (discussed below) and the nature of the facies examined (i.e., platformal vs. basinal). At more advanced levels of thermal maturity similar to that observed within the Lower Paleozoic sequence in the Tarim basin organic carbon content could be reduced by more than 50% (Daley and Edman, 1987). Hsu (1994) suggested that the sampled facies represent shallow water deposits rather than the more basinal facies where higher levels of organic enrichment are to be expected. In fact, Hsu suggests that a thick Lower Paleozoic euxinic basinal sequence underlies nearly half of the basin at depths that cannot be reached by drilling. This basinal facies outcrops along the northeast rim of the basin where a sequence of black shales and cherts are present.

The presence of organic-rich Lower Paleozoic sediments is, however, supported by the reported maximum organic carbon value of 5.22 wt.% for the Cambro-Ordovician sequence (Hu Jianyi et al., 1997). Hanson (1998), citing unpublished data, noted that organic carbon contents of the Cambro-Ordovician sequence display maximum values of between 4 and 6 wt.%. Hanson notes, however, that much of the thick (>5 km) basinal shales, including laminated intervals, commonly contain less than 0.2 wt.% organic carbon and prefers an alternative depositional model for the organic-rich intervals. Hanson suggests that the organic-rich sediments where deposited within an oxygen minimum along the shelf edge or slope.

The difference between these two proposed source rock depositional models for the Lower Paleozoic of the Tarim basin is more than of academic importance. The two models would result in dramatically different source rock distributions and volumes. The Hsu model would provide a much wider distribution of possible source rocks than the Hanson model. It would also provide for a much greater source rock volume. The

Hanson model would suggest a distribution that largely rings the basin margin and paleohighs. Not only does the Hanson model constrain the volume of source rock but it also restricts its geographic distribution.

Graham et al. (1990) report a maximum organic carbon and total hydrocarbon generation potential of 2.75 wt.% and 4.68 mg HC/g rock, respectively, for the Saergan Formation (Middle Ordovician; Figure 4). The significance of their data is that they indicate that limited number of Lower Paleozoic samples studied are gas-prone, with a maximum hydrogen index of 168 mg HC/g TOC (Figure 5). A further examination of this dataset suggests that reported geochemical attributes do not appear representative of the original rock character and that surface weathering may have also reduced both the quality (i.e., organic carbon and generation potential) and quantity of organic matter (i.e., hydrogen index).

As with the Lower Paleozoic series, the amount of geochemical data available for the Permo-Carboniferous in the Tarim basin is limited. The Permo-Carboniferous within the basin evolved from a marginal sea dominated by platform carbonates that may reach 2 km in thickness (Li Desheng et al., 1996) to near-shore clastics and finally to a non-marine series. And, although the Permo-Carboniferous has been cited as a potential source these depositional settings are not considered very favorable for source rock development. Limited source rock potential does, however, appear present within the sequence. Li Desheng et al. (1996) cite a maximum organic carbon content of 11.15 wt.% for this interval. Graham et al.'s (1990) dataset suggests that the any source rock potential for this interval is limited to “coaly” intervals within the Kalundaer Formation (Lower Permian). Although organic-rich (maximum reported TOC of 34.38

wt.%; Figure 4) and capable of generating significant quantities of hydrocarbons (maximum reported S_1+S_2 of 26.58 mg HC/g rock; Figure 4) the studied samples are gas-prone (hydrogen indices less than 150 mg HC/g TOC; Figure 5). Such rocks would not be capable of contributing significantly to the oil resource base. Furthermore, the distribution and volumetric significance of this facies is poorly understood. It has, however, also been speculated that a Late Permian lacustrine facies exists in the subsurface and that these rocks could display geochemical attributes similar to organic-rich Permian lacustrine strata present in the Junggar and Turpan basins (see discussion below).

The third interval cited as a source in the Tarim basin is within the Upper Triassic – Middle Jurassic. Organic matter within this interval is largely concentrated in a suite of coals and carbonaceous shales. Graham et al. (1990) and Hendrix et al. (1995) have summarized the geochemical characteristics of these sediments. These authors report that the organic carbon contents of these sediments ranges upward to ~96 wt.% (Figure 4). and that the maximum measured hydrocarbon generation potential is 296 mg HC/g rock. These rocks are predominantly gas-prone, containing type III organic matter (Figure 5). The hydrogen indices are typically less than 250 mg HC/g TOC. It is interesting to note, however, that the pyrolysis gas-chromatography results suggest that these coals could generate higher molecular hydrocarbons (Hendrix et al., 1995). Pyrolytic generation of higher molecular weight compounds from coals does not, however, equate to an ability to expel these compounds in nature. Katz et al. (1991) note that these higher molecular weight hydrocarbons would be retained within the coal until cracked and would be released as gas. A possible exception to the above discussion is a single coal sample from the Kezileinuer Formation (Middle Jurassic) where Graham et al. (1990) reports a hydrogen index of 424 mg HC/g TOC. This sample displays a type II affinity and could, at the appropriate levels of thermal maturity both generate and expel liquid hydrocarbons.

In addition to these coaly gas-prone facies, a Jurassic lacustrine facies has also been identified in the Tarim basin (Hendrix et al., 1995; and Ritts, 1998). These largely oil-prone sediments average between 3 and 5 wt.% TOC, with maximum levels of organic enrichment approaching 9 wt.%.

The Late Cretaceous-Paleogene interval, although cited as a source, appears to be organic-poor, with TOC levels less than 1.0 wt.% (Ulmishek, 1984). The available data, therefore, do not support the suggestion that this stratigraphic interval is a possible source.

Within the Junggar basin the Permian sequence is thought to be the principal oil source rock. Ulmishek (1984) and Clayton et al. (1997) do raise the possibility that additional effective source rocks maybe present in the Junggar basin and that some of these sources may be of only local importance or effectiveness. They suggest that these secondary source rocks may be present in the Jurassic and Tertiary sequences.

The Permian lacustrine sequence in the Junggar basin ranks among the thickest and richest hydrocarbon source rock sequences (Carroll, 1998). Within a gross lacustrine sequence of approximately 2000 meters, Carroll et al. (1992) calculated for an 800 meter net source rock interval an average organic carbon content and residual generation potential (S_2) for the Lucaogou Formation of 4.1 wt.% and 26.2 mg HC/g rock, respectively. Carroll et al. (1992) report a maximum organic carbon content exceeding 22 wt.% and a maximum generation potential approaching 200 mg HC/g rock (Figure 6). Hydrogen indices for the Lucaogou Formation typically exceed 600 mg HC/g TOC, consistent with that a type I kerogen (Figure 7).

The complete Permian lacustrine sequence records an overall evolution from a shallow evaporative lake to a deep freshwater lacustrine system associated with fluvial systems (Carroll, 1998). He further suggested that the organic-rich laminated sequence of the Lucaogou Formation developed largely as a result of salinity induced stratification and that inorganic sedimentation rate may have been the primary control on organic carbon content. Carroll (1998) suggests that the inverse relationship between the hydrogen index and stable carbon isotope composition is supporting evidence for limited productivity within the lake basin. The underlying Jingjingzigou Formation, which was deposited under shallow lake conditions, displays as a result of reduced preservation potential significantly lower levels of organic enrichment (commonly less than 0.5 wt.%) and lower hydrogen indices. Samples from the overlying Hongyanchi Formation often contain more than 1.0 wt.% TOC (Figure 6) the organic matter is hydrogen depleted (hydrogen indices typically less than 150 mg HC/g TOC; Figure 7) as a result of the relative abundance of vitrinite and inertinite.

The possible Jurassic source sequence in the Junggar basin is associated with the basin's coal measures (Hendrix et al., 1995). Within the Junggar basin Jurassic coals average 67.6 wt.% TOC and have and total hydrocarbon generation potential of 116.9 mg HC/g rock (Figure 6). Both of these averages are higher than observed in their stratigraphic equivalents in the Tarim basin. The coals also display a slighter average higher hydrogen index (161 vs. 127 mg HC/g TOC; Figure 7). These differences are not, however, sufficient to suggest that the Junggar basin coals are more oil-prone (i.e., the represent an important potential gas source).

An areally and volumetrically limited Jurassic lacustrine facies most probably also exists in the Jurassic sequence of the Junggar basin (Hendrix, 1992). Some oil generating potential may be associated with these lacustrine strata.

No source rock data are available to support the inferred Tertiary source within the Junggar basin.

Thermal Maturity

Thermal maturity provides an estimate as to the extent of organic diagenesis, which relates to the extent of hydrocarbon generation and their preservation. One of the most common measures of thermal maturity is vitrinite reflectance. Other thermal maturity measures are often reported as vitrinite reflectance equivalent values. True vitrinite is limited to the post-Silurian portion of the stratigraphic record. Thermal maturity levels can also be estimated through the use of numeric models.

Junhong Chen et al. (1996) report thermal maturity levels for the Ordovician section in the Tarim basin equivalent to a vitrinite reflectance greater than 1.17%. Guo Jian Hua and Zhu Yangming (1995) reported for that the Cambro-Ordovician sequence in the Kunan #1 well has achieved thermal maturity levels ranging between 1.74 and 2.04%. Hanson (1998) also reports similar maturity levels for the Cambro-Ordovician sequence. (These vitrinite reflectance values are estimated from bitumen reflectances.) Such elevated levels of thermal maturity suggest that Ordovician sequence is largely over-mature and that the Lower Paleozoic sediments are no longer capable of generating liquid hydrocarbons. These levels of thermal maturity are, however, consistent with the preservation of light oils and condensates. Hanson (1998) does, however, question whether the correlation between vitrinite and bitumen reflectivity is valid. He suggests that the biomarker content of some Cambrian rocks imply a lower level of thermal maturity. It is possible, however, that these slightly elevated biomarker contents may be the result of contamination by migrated hydrocarbons.

Junhong Chen et al. (1996) suggest that the Permo-Carboniferous sequence in the Tarim basin displays a thermal maturity equivalent to a vitrinite reflectance between 0.6 and 1.1%. The Triassic/Jurassic is immature except in the northern portion of the Tarim basin, where Hendrix et al. (1995) report vitrinite reflectance values which may exceed 1.7%. They suggest that these more elevated thermal maturity levels in the northern portion of the basin are the result of tectonic overburden caused by the stacking of thrust sheets.

King et al. (1994) examined the level of thermal maturity along the margins of the Junggar basin. They concluded that the basin has been relatively cool since the Permian. Heat flow levels appear to have been slightly above average during the mid-Permian and have been cooling since to their present values, which are below the global average. Available data suggest that the level of thermal maturity of the Permian sequence is highly variable ranging from immature to over-mature. For example, the Permian interval in the Caican #4 has a vitrinite reflectance between 0.79 and 1.07% (Figure 8). While in the Aican #1 well the vitrinite reflectance of the Permian interval ranges from 0.91 to 2.02% (Figure 9). Carroll et al. (1992) report that at their two sampled outcrop localities – Urumqi and Tianchi – in the southern Junggar basin display vitrinite reflectances between 0.73 and 0.88%. The observed levels of thermal maturity at the two outcrop locations suggest that there has been a significant amount of unroofing, possibly on the order of 5 kilometers.

Hendrix et al. (1995) report that the Jurassic coals along the southern margin of the Junggar basin are largely immature (R_o ranges between 0.45 and 0.71%).

Using the data reported by King et al. (1994) the top of the main stage of oil generation and release is located at about 3 km, with the base of the “oil-window” at about 4300 meters. A review of available isopach data (Ulmishek, 1984) suggests that the Permian source rock is over-mature in about half of the basin (Figure 10). At these more advanced levels of thermal maturity prospectivity is largely dependent on the timing of hydrocarbon generation and the preservation of the trap. These data also imply that although the Permian lacustrine sequence was initially oil-prone, large volumes of gas may be expected from this sequence.

Timing of Generation

Although thermal maturity can be measured the timing of hydrocarbon generation can only be approximated through the use of thermal maturation models, which integrate the effects of time and temperature on the conversion of kerogen to oil.

Hsu (1994) suggest that within the Tarim basin the Cambro-Ordovician source in basinal positions generated and expelled hydrocarbons during the Late Paleozoic and Early Mesozoic and that generation was complete when buried by 5 kilometers of sediment. Modeling results obtained in the vicinity of the Shacan #2 well indicate that initial generation from the Ordovician sequence would have began during the early Carboniferous (Yang Bin, 1991). Generation was terminated and the trapped oil was uplifted during the Hercynian Orogeny, which permitted biodegradation to proceed.

Subsidence was again initiated during the Mesozoic. During this subsidence phase a second phase of generation was initiated. Xiao Xianming et al. (1996) also concluded that multiple generation events occurred in the central portion of the Tarim basin in the vicinity of the Tazhong uplift. They conclude that the later phases of generation are of greater importance than the earlier phases of generation even though the magnitude of generation during these later episodes was significantly. In part, this greater relative importance is a result of the breaching of earlier traps.

In the Junggar basin King et al. (1994) and Zhaohui Tang et al. (1997) suggest that the main stage of oil generation in the more basinal positions began early in the Triassic. These simulations also suggest that in these basinal sequences oil generation would have been completed prior to the close of the Jurassic (Figure 11). Lawrence (1990) further concluded that by Cretaceous times these initially oil-prone rocks would be generating sufficient gas to displace much of the oil that had been available to Permo-Triassic reservoirs. These models also indicate that the Jurassic sources would begin contributing hydrocarbons during the Tertiary.

On the Junggar basin margins the generation history is much more complex. There are segments of the margin where hydrocarbon generation appears to be actively occurring. Elsewhere, the current level of thermal maturity appears to have been "frozen" as a result of the numerous uplift and erosional events that occurred throughout the Mesozoic and Tertiary, including a major unconformity at the base of the Tertiary. Post-uplift subsidence and re-burial has not commonly been sufficient for the maturation/generation process to be reinitiated. As noted above, as much as 5^+ kilometers of overburden may have been removed. If the heat flow and/or geothermal gradients did not change significantly at least this amount of reburial would be required for significant amounts of hydrocarbons to be generated. Carroll et al. (1992) further suggest that as a result of the structural history of the southern margin hydrocarbon generation preceded the creation of potential traps formed by Neogene thrusting.

Oil and Gas Geochemistry

As in the Tarim basin there is only limited source rock data. This lack of data results from the few wells present in frontier situations, the position of wells outside the limits of the generative basin, and the often disassociated nature of the source-reservoir couplet. In these cases a significant amount of information can be obtained from the geochemical character of oils and gas present.

Among the oils for which detailed geochemical data are available are the Shacan #2 located in the northern portion of the Tarim basin. This well, which produced from between 5363 and 5391 m from karstified Ordovician dolomites has been genetically linked to the Cambro-Ordovician sequence (Yang Bin, 1991). There are several positive lines of evidence supporting this correlation. Gas chromatography reveals the oils' low pristane/phytane ratio (0.85 to 0.88) and the limited concentration of *n*-alkanes with greater than 20 carbons. Gas chromatography-mass spectrometry reveals sterane distributions dominated by C_{29} steranes (31%, 21%, and 48% for C_{27}, C_{28}, and C_{29} steranes respectively), and the presence of C_{30} steranes. The oils also contain very limited quantities of trace metals (vanadium and nickel content is 2.29 ppm and 0.46 ppm, respectively). The oils also display light carbon isotopic compositions ($\delta^{13}C$ –33.43 to –32.78 ‰). Negative evidence, which eliminated other possible source rock candidates including the non-marine Upper Triassic-Mid-Lower Jurassic and the marine

Carboniferous-Lower Permian intervals, include the absence of β-carotane, differences in sterane distributions, and the pristane/phytane ratios.

Detailed geochemical data are also available for oils and gases from the Kekya Field situated in the southwestern portion of the Tarim basin. This field, largely a gas field, produces some light oil and condensate (API gravity ranges from 39 to 66^{o}) from Oligo-Miocene sandstones from between 3000 and 6450 meters. The geochemical characteristics of these oils suggest that they were derived from a Permo-Carboniferous marine shale with a mixed marine and terrestrial source. As with the Shacan oil the proposed correlation is based on both positive and negative lines of evidence. The supporting data for this assessment are the pristane/phytane ratios which are greater than 1.5 and the saturate fraction stable carbon isotope values that are all heavier (i.e., more positive) than –30 ‰. These values along with the regular sterane distribution are more consistent with the Permo-Carboniferous marine sequence than with any of the other possible source rock sequences suggested for the basin. The stratigraphic relationship between the inferred source and the reservoir suggest that vertical hydrocarbon migration has played some role.

Maowen Li et al (1999) have further suggested that based on stable carbon isotope data the gases and liquid hydrocarbons have been derived from different source rock intervals. Although Maowen Li et al. suggest that the gases were derived from a Permo-Carboniferous coal bearing sequence, the data presented is also consistent with a derivation from a more mature marine source rock system. The light hydrocarbon stable carbon isotope data are consistent with a source rock vitrinite reflectance greater than 1.6%. This suggests the possibility that the light hydrocarbons were derived from the Cambro-Ordovician sequence. Additional data are required to differentiate between the two possible origins.

Maowen Li et al. (1999) present data from the Qunkuqiake Field also in the southwest and report that it is derived from a different source than the Kekeya Field (i.e., Cambro-Ordovician rather than Permo-Carboniferous). It is, therefore, more similar to the Tazhong complex in the central portion of the basin.

Hanson (1998) after examining twenty-three oils from the Tarim basin concluded that at least seven different oil families are present in the Tarim basin. He concluded, however, that these different oils were most probably derived from only two stratigraphic intervals, the Middle to Upper Ordovician and the Lower to Middle Jurassic. The differences in oil chemistry reflect facies variations within these stratigraphic intervals.

Data from some of the oils from the Tarim basin suggests a high level of thermal maturity, with thermal maturity levels equivalent to vitrinite reflectance values greater than 1.1% (Junhong Chen et al., 1996). The highest inferred levels of thermal maturity are associated with the northern and central portions of the Tarim basin. Condensates from the Tazhong structure have a vitrinite reflectance equivalence of ~1.9%. These levels of thermal maturity are consistent with a derivation from the Cambro-Ordovician sequence. Slightly lower levels of thermal maturity for the oils in the Kekya Field from the southwestern portion of the basin is consistent with the proposed Permo-Carboniferous source for the field (Maowen Li et al., 1999). The possibility of multiple episodes of hydrocarbon charging events within the Tarim basin raises questions whether a single maturity parameter can effectively represent an oil's thermal maturity

Zhao Hong et al. (1995), i.e., any estimated thermal maturity based on geochemical attributes may actually represent an “average” of the different charging episodes.

It is also interesting to note that the Shacan oil that contains a full suite of *n*-alkanes also contains a suite of 25-norhopanes (Yang Bin, 1991). 25-norhopanes are often associated with severe biodegradation. The presence of both *n*-alkanes and the 25-norhopane series may also be used as evidence of multiple episodes of hydrocarbon generation and migration.

Clayton et al. (1997) report geochemical data on oils from nine fields from the Junggar basin. They suggest that at least five genetic oil types are present, representing a wide-range of source rock depositional settings. The Karamay oil type is the dominant oil type within the basin. It includes in addition to oils from the Karamay Field oils from Baikouquan, Fencheng, Xiazijie, Chepaizi, and Hongshanzui Fields. Although Hsu (1994) suggested a Lower Paleozoic marine source for at least some of the oils in the Karamay Field, Clayton et al (1997) present data that indicate a marginal, possibly saline, Permian lacustrine source. In part, this assessment is based on the relative abundance of β-carotane (β-carotane/nC_{30} greater than 1 and often exceeding 5), stable carbon isotope composition (saturate and aromatic hydrocarbons range from –30.9 to –28.4 and –29.0 to –27.9‰, respectively), normal sterane distribution ($C_{29} > C_{28} \geq C_{27}$), relative abundance of gammacerane (gammacerane indices typically greater than 30), and the *n*-alkane distribution. The *n*-alkane distribution includes an abundance of higher molecular weight (nC_{20+}) components. Lower Paleozoic marine oils lack β-carotane, are isotopically lighter, and are depleted in the longer chain *n*-alkanes.

It should be noted, however, that the distribution of *n*-alkanes within this group does display some important differences.

Clayton et al. place the Mahu Field oils in a separate group and infer a more basinal, possibly a fresher water, lacustrine source for these oils than for the Karamay-type oils. This assessment is based on the lower relative abundance of β-carotane (β-carotane/nC_{30} < 1), a more depleted carbon isotopic composition (saturate and aromatic carbon isotope values range from –31.35 to –31.04‰ and –29.58 to –29.07‰, respectively), lower gammacerane indices (less than 30), and their different normal sterane distributions ($C_{29} \geq C_{28} \geq C_{27}$).

The Jimusar Field represents the third group of oils. Clayton et al. suggest that this group of oils was also derived from the Permian lacustrine sequence, specifically the Lacaogou Formation. It is principally differentiated from the group 1 oils by its isotopic composition. These oils are isotopically lighter. And, although Clayton et al. noted that the observed isotopic variation is inconsistent with a common origin with the basin's other lacustrine oils, other lacustrine oils have been shown to display even greater isotopic variability (Katz and Mertani, 1989). Clayton et al. have also suggested based on the low abundance of *n*-alkanes that the Jimusar oils are less mature than the other oils studied from the basin. It is this author's opinion that the lower relative abundance of saturated hydrocarbons and the low *n*-alkane abundance is more probably a result of biodegradation. Clayton et al. concluded, in part, that these oils were not biodegraded because of the absence of demethylated hopanes. The absence of demethylated hopanes in an oil should not be equated to a lack of biodegradation (Peters and Moldowan, 1993).

The Qigu and Dushanzi oils are different from each other and the other oils studied by Clayton et al (1997). The Qigu oil displays the highest pristane/phytane ratio and the greatest relative abundance of C_{29} steranes. These characteristics are indicative of a source rich in terrestrial organic matter and would be consistent with derivation from the Jurassic coal measures. The Dushanzi oil is the isotopically heaviest oil studied by Clayton et al. ($\delta^{13}C$ of the saturated and aromatic hydrocarbon fractions are –27.63 and –25.19, respectively). This oil also has the highest relative abundance of C_{27} steranes. It is speculated that this oil was derived from an undefined Tertiary source rock.

It is interesting to note, however, that although Clayton et al. (1997) have proposed that much of the Junggar basin's oils can be correlated to the lacustrine Permian sequence their sterane distributions are markedly different than that presented by Carroll (1998) for the extracts from the three Permian lacustrine units. These differences could reflect either a different source than proposed or alternatively differences in analytical methods and the manner in which the sterane abundances are calculated. The available does not permit a full examination of this observation.

RESERVOIR POTENTIAL

Within China potential reservoirs have been identified throughout the stratigraphic column as well as within altered "basement". The presence of potential reservoir rocks does not appear to be as much of a problem as producibility, reservoir continuity, and heterogeneity. For example, within the Daqing Field as many as 24 separate producing zones may be present. The typical well, however, produces on the average only ~320 bbl/day (Meyerhoff and Willums, 1981), because of both reservoir and crude oil properties. In order to compensate for these low production rates large numbers of wells are often required. In the Daqing complex more than 10,000 wells have been drilled and more than 3000 are actively producing.

In the Tarim basin potential reservoirs have been identified in the Ordovician, Carboniferous, Triassic, Paleogene and Neogene sequences, with many of these reservoir targets being located at depths greater than 5000 meters. The Lower Paleozoic reservoirs are marine carbonates. The remaining reservoirs are sandstones. The Carboniferous sandstones are marine and the Mesozoic and Tertiary reservoirs are non-marine. Little detailed information is publicly available on these different reservoir rocks.

In the Shacan #2 well (Yakla Field) karstified carbonates flowed with initial oil production exceeding 7000 bbl oil and 70 mmcf gas per day. The Yingmai #1 well tested at 1300 bbl oil per day from a 23 meter interval also from a karstified Ordovician dolomite (Chai Guilin et al., 1992). Fractured Ordovician limestones in the Lunnan Field (Lunnan #8) displayed high initial flow rates, 5000 bbl of oil and 6.6 mmcf of gas per day, as well (Chai Guilin et al., 1992), with other wells within the field having daily oil flow rates between 177 and 3150 bbl/day. The heterogeneity of these Ordovician reservoirs appears typical and can be even more dramatic as in the Tazhong uplift. The Tazhong #1 well flow at ~4000 bbl/day while the Tazhong #3 well tested dry in the same interval (Li Desheng et al., 1996). No mention is made of production from preserved primary porosity.

Carboniferous, marine quartz sandstones penetrated in Tazhong structure (Tarim basin) displayed porosity and permeability values of 15.6 to 21.3%, and 171 to 407 md., respectively (Li Desheng et al., 1996). Carboniferous sands appear to be on the order of 5 to 10 m thick on the Tazhong uplift and may exceed 250 meters in the northern portion of the basin (Donghetang Field). These sands produce at rates as high as 1850 bbl/day/well.

Non-marine Triassic sandstones have displayed initial flow rates exceeding 3600 bbl/day in the Lunnan Field, with similar flow rates being obtained in the Tazhong #4 and #10 wells (Li Desheng et al., 1996). Individual Triassic sands may achieve a gross thickness of up to ~50 meters.

Eocene sandstones in the northern portion of the basin have also produced hydrocarbons. These sands have flowed over 1200 bbl/day of condensate (Li Desheng et al., 1996) in the Yaha Field. In the Yimali Field this basal Eocene sandstone achieve thicknesses of between 30 and 40 meters.

The Kekya Field in the southwestern portion of the basin produces largely from a series of Oligocene and Miocene sandstones. The fifteen Oligo-Miocene sandstones from display effective porosities between 13.3 and 15.9% and permeabilities of 11.2 to 90.6 md. (Hu Boliang, 1992). The thickest individual pay section is slightly less than 100 meters. Most sands are, however, less than 50 meters.

Reservoir rocks within the Junggar basin are present largely in the Permian, Triassic, and Jurassic lacustrine, fluvial and alluvial fan deposits. Minor production has also been established in the Lower Cretaceous, Oligocene, and Miocene sandstones.

Zhaohui Tang et al. (1997) suggest that the Permian, Triassic, and Jurassic sandstones are characterized by volcanic litharenites (Figure 12). Diagenetic studies by Zhaohui Tang et al. suggest that calcite cementation, authigenic clay and zeolite formation have substantially reduced porosity. Secondary porosity development varies considerably within these sandstones. Fluvial sandstones tend to display the highest average porosity and permeability values as a result of the retention of primary porosity through the formation of early clay coatings that prevent compaction.

The most important field within the basin is Karamay. Much of the field's production comes from alluvial fans. As would be expected in an alluvial fan complex these reservoirs are poorly sorted (Chang Chiyi, 1981). Individual layers display highly variable reservoir properties. Taner et al. (1988) report permeability values for the alluvial fan sequences ranging upward to 323 md. and porosities as high as 39%. The field also produces from nearshore lacustrine deposits. Permeability in these fine- to medium-grained sandstones is significantly better ranging between 1704 and 6783 md. Porosity values in these sandstones may reach 35%. Producing intervals within the Karamay Field approach 50 meters (Maowen Li et al., 1999). Production rates from individual wells were generally low until the discovery of the lighter less degraded deeper pool as a result of the biodegraded nature of the crude in the shallower pay-zones. API gravities in the biodegraded pools can be as low as about 10°. Wells in the shallow pay zones also experienced rapid decline, where the average well was producing only 14 bbl/day. It is also interesting to note that the best producing wells from the Karamay Field are located close to fault zones, especially those intersecting faults (Taner et al., 1988).

The now abandoned Dushanzi Field produced from the younger reservoirs noted above. Each of these sandstones ranged in thickness from 3 to 9 meters. Effective porosity levels were between 12 and 18% (Taner et al., 1988). Individual wells have initial flow rates up to 511 bbl/day but rapidly declined to a few tens of barrels per day.

EXPLORATION IMPLICATIONS

An effective petroleum system requires the presence of a source, seal, reservoir, trap, and the necessary overburden for hydrocarbon generation to proceed. In addition to the simple presence of these components they must share a favorable temporal and geographic relationship. In this study, structure and seal have largely been assumed. The available data do, however, place some significant limitations on the remaining exploration potential of the two basins.

Within the Tarim basin the distribution and volume of the organic-rich Ordovician facies is clearly problematic. Although the Ordovician sequence represents a significant rock volume, possibly as much as 2 x 10^6 km^3 (Hsu, 1994), the available sampling suggests that the actual volume of effective source is much more limited and that where present currently displays only limited source rock potential. Sufficient geochemical differences are present in the oil to suggest that even those oils derived from a single stratigraphic level display facies differences suggesting that the effective source basins for each accumulation is restricted. In the most optimistic case, even if this source were universally present, it would be largely over-mature. Generation appears to have begun relatively early in the basin’s history prior to the formation of many of the basin’s current structural targets. Although multiple episodes of hydrocarbon generation appear to have occurred the last episode, considered to be the most important relative to current traps, appears to have been the volumetrically least significant.

Hydrocarbons preserved in the basin would also reflect this advanced level of maturity (i.e., light oil, condensate, and large volumes of gas). The advanced level of thermal maturity would also open up the possibility of displacement of liquid hydrocarbons from early preserved traps through the late introduction of gas.

Secondary source rocks in the Tarim basin are largely gas-prone, although some lacustrine oil source rock potential is believed to exist. The data suggest, however, that with the exception of the northern portion of the basin (i.e., the Kuche depression) much of these younger sources would be thermally immature and these rocks would not significantly contribute to the resource-base.

The best producing reservoirs in the Tarim basin appear to be within the karstified Ordovician carbonate sequence. Prediction of these reservoirs will require a detailed understanding of their uplift and erosion history. Clearly this history is complex with nearby wells from the same field having dramatically different production rates and reservoir properties. Some of the sandstones display only modest porosity and permeability values, making them better gas reservoirs than oil reservoirs. The younger Tarim basin sandstone reservoirs can have significant production rates, but because of their non-marine character display limited lateral and vertical continuity resulting in reservoir compartmentalization.

In the Junggar basin a different story has evolved. The primary source rock is a lacustrine Permian shale. Although the properties of this rock have been well documented, its detailed distribution does remain somewhat problematic. This source rock sequence displays a wide-range of thermal maturity levels. However, more than half of the basin's area appears to have matured beyond the main stage of oil generation. In fact, a large portion of the basin has achieved levels of thermal maturity that would be consistent with gas generation.

In the central portion of the basin it appears that the main stage of generation would have been completed prior to the Cretaceous. On the basin margins the generation history in the Junggar basin is much more complex as a result of thrusting, uplift, and erosion. It appears, however, that along the margins generation still appears to have occurred prior to the development of the most recent traps. The currently observed levels of thermal maturity were probably "frozen" in place as a result of the significant amount of erosion that has occurred. The potential for preserving some of the accumulations that may have been generated is reduced because of the potential for breaching of the earlier traps by thrusting.

Reservoir potential in the Junggar basin also appears to be somewhat limited. The mineralogic immaturity of the sandstones tends to result in a reduction in both porosity and permeability. In the near-shore lacustrine sandstones, where both porosity and permeability tend to be higher, lateral and vertical reservoir continuity appears to remain a potential problem. Problems with potential reservoirs are further complicated by their typically very rapid drop off in production from their initial flow rates.

It, therefore, appears that the exploration potential of these basin's, which have been cited as among those with the greatest exploration potential onshore China, is significantly less than previously suggested. Although sweet spots do exist several components of their respective petroleum systems appear to be limited and cannot be easily extrapolated beyond known limits.

SUMMARY AND CONCLUSIONS

Available geochemical data, both rock and oil data, suggest the presence of multiple source rock horizons within each basin. Included in the suite of source rock candidates is the Permian lacustrine Lucaoguou Formation of the Junggar basin, which ranks among the richest and thickest. These data further suggest that there are significant facies variations within the different source intervals. These facies differences amplify the problems associated with establishing the distribution and volume of each of the source intervals. This is particularly true for the Cambro-Ordovician source sequence in the Tarim basin.

Even if the sources are widely distributed thermal maturity data indicate that much of the source sequences in both the Tarim and Junggar basins are currently over-mature and hydrocarbon generation has often preceded the development of the trap. The advanced level of thermal maturity suggests that there is also a potential for gas displacement of any liquid hydrocarbons that may have been retained by traps during these basins multiple tectonic episodes. Further complicating the hydrocarbon charge story is the potential for multiple episodes of hydrocarbon generation. Typically the latest episodes would be most significant, unfortunately the generation potential remaining after the earlier episodes reduces the volume of hydrocarbons that could be generated.

In both of the basins examined reservoir heterogeneity and the lack of reservoir continuity place great limitations on the exploration potential of on-shore China. These problems exist in both the Ordovician carbonate reservoirs of the Tarim basin and for the Permian through Jurassic non-marine sandstones of the Junggar basin. Production rates from individual wells within a single field can vary from less than 200 to over 5000 bbl/day. Many of the wells also appear to experience a very rapid decline in production.

Based on these observations it appears that the overall exploration potential of these regions is limited and that many of the previous estimates as to the region's potential are inflated. Clearly the discoveries suggest that hydrocarbon potential does exist within both of these basins and the sweet spots may exist, however, the exploration challenges and risks appear to out-weigh the potential rewards. This is particularly the case when the remoteness of the basins and the lack of a local market are considered.

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Figure 12. Classification of Permo-Triassic sandstones of the Junggar basin (modified from Zhaohui Tang et al., 1997).

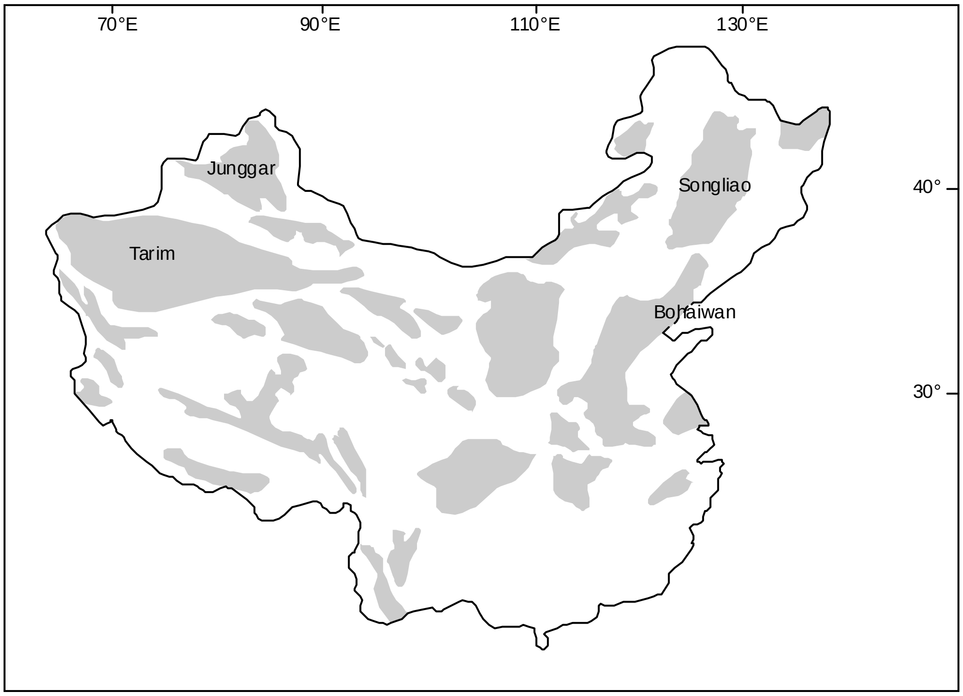


Figure 1. Distribution of major and moderate-sized sedimentary basins.

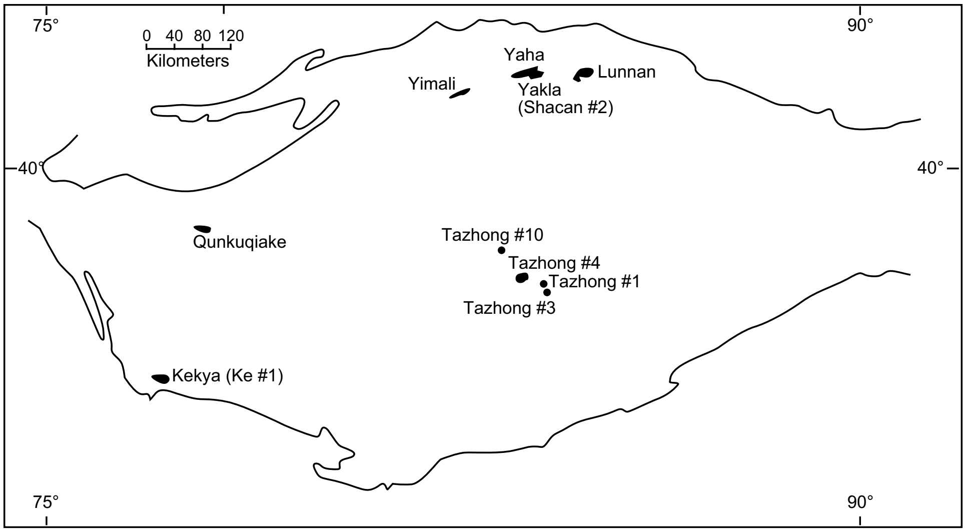


Figure 2. Index map for the Tarim basin.

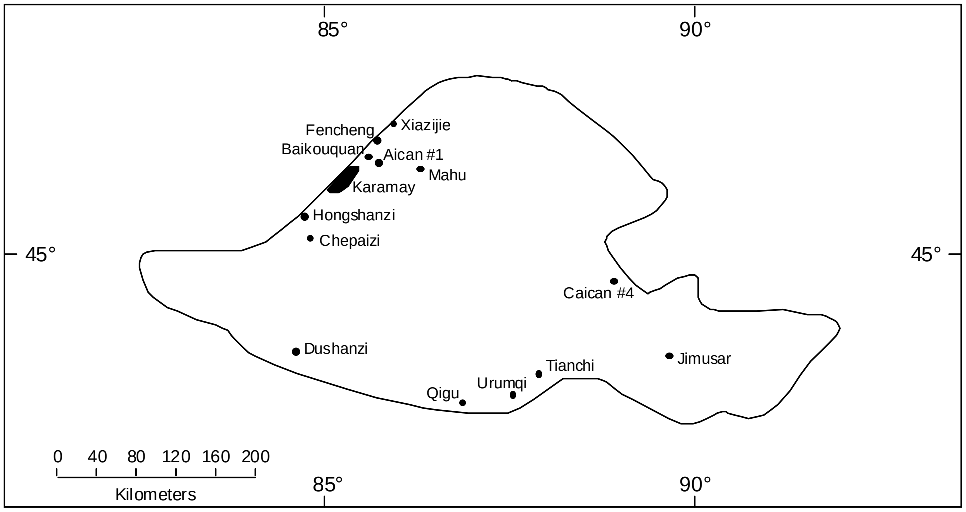


Figure 3. Index map for the Junggar basin.

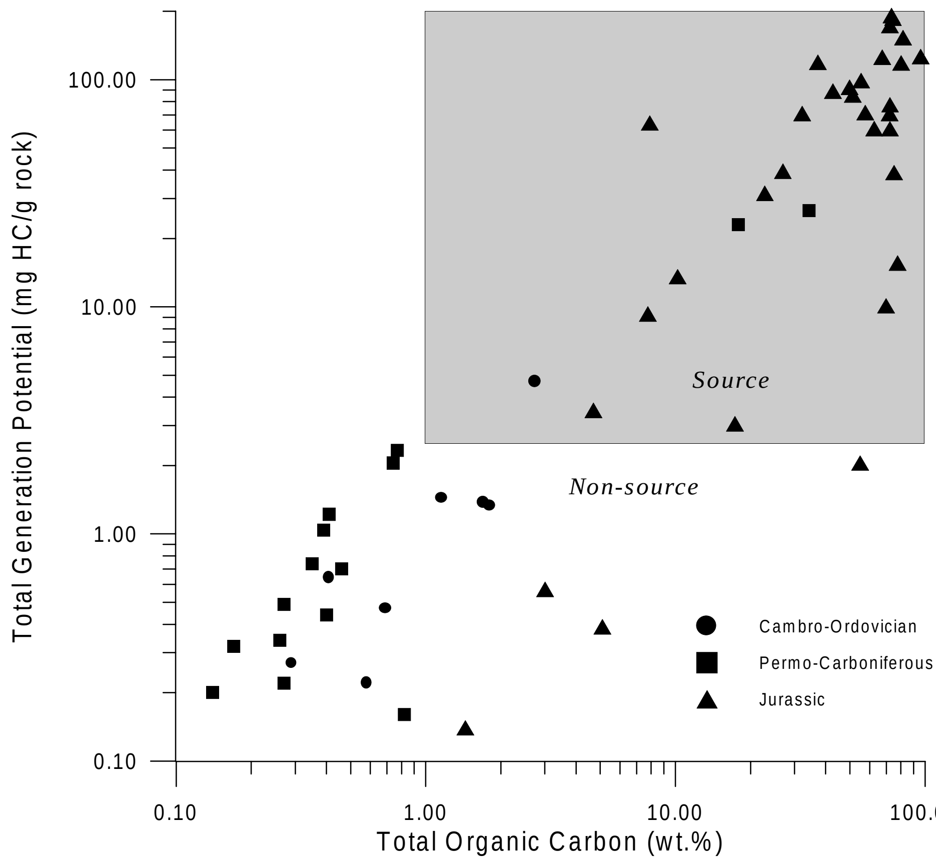


Figure 4. Generation potential vs. organic carbon content for possible source rocks within the Tarim basin. Data sources include Graham et al. (1990) and Hendrix et al. (1995).

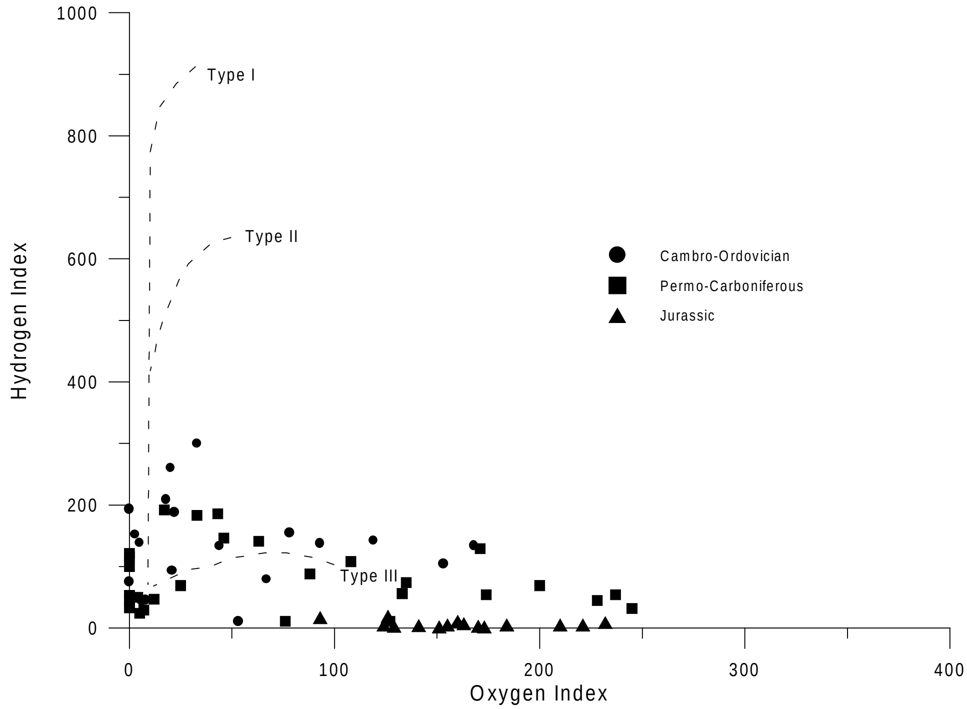


Figure 5. Modified van Krevelen-type diagram for possible source rocks with the Tarim basin. Data sources include Graham et al. (1990) and Hendrix et al. (1995).

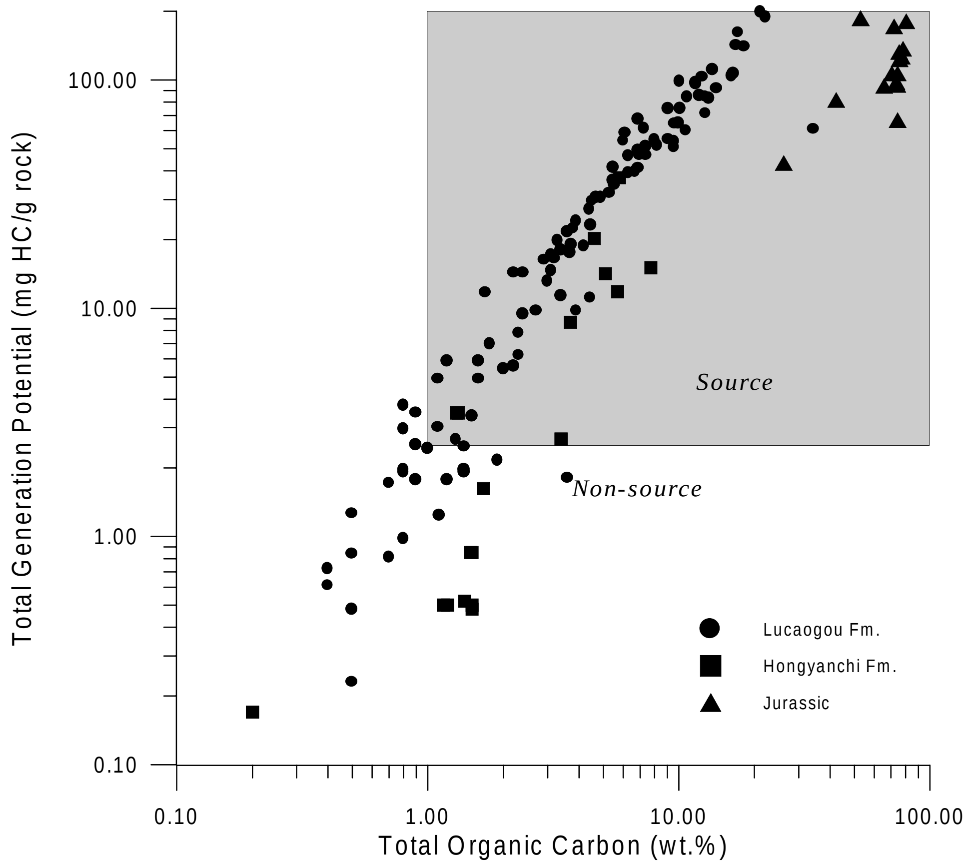


Figure 6. Generation potential vs. organic carbon content for possible source rocks within the Junggar basin. Data sources include Graham et al. (1990), Carroll et al. (1992) and Hendrix et al. (1995).

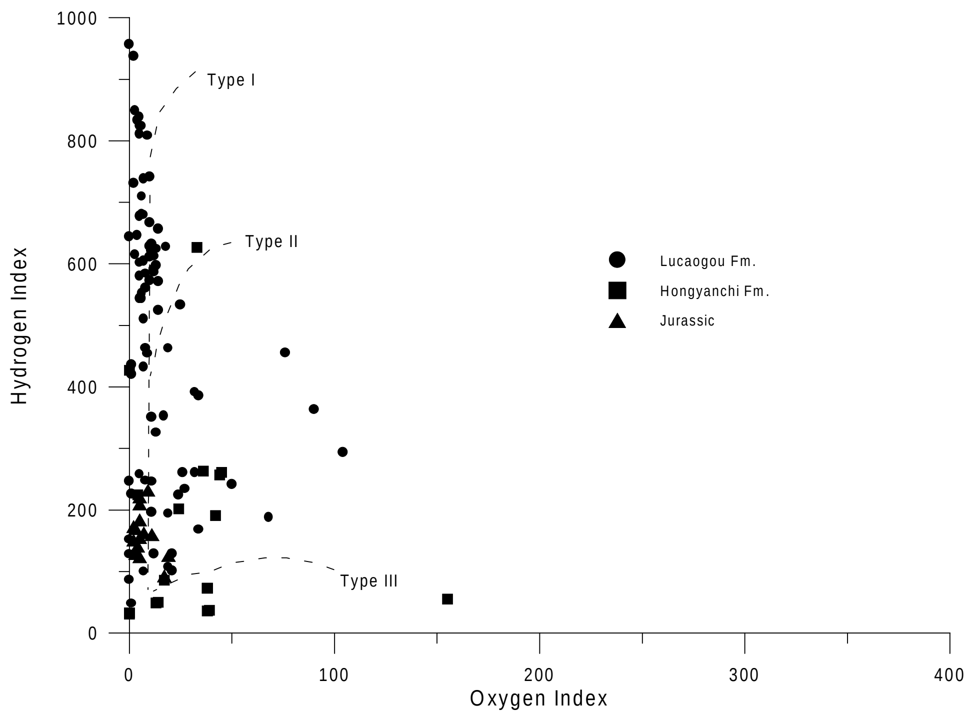


Figure 7. Modified van Krevelen-type diagram for possible source rocks with the Junggar basin. Data sources include Graham et al. (1990), Carroll et al. (1992) and Hendrix et al. (1995).

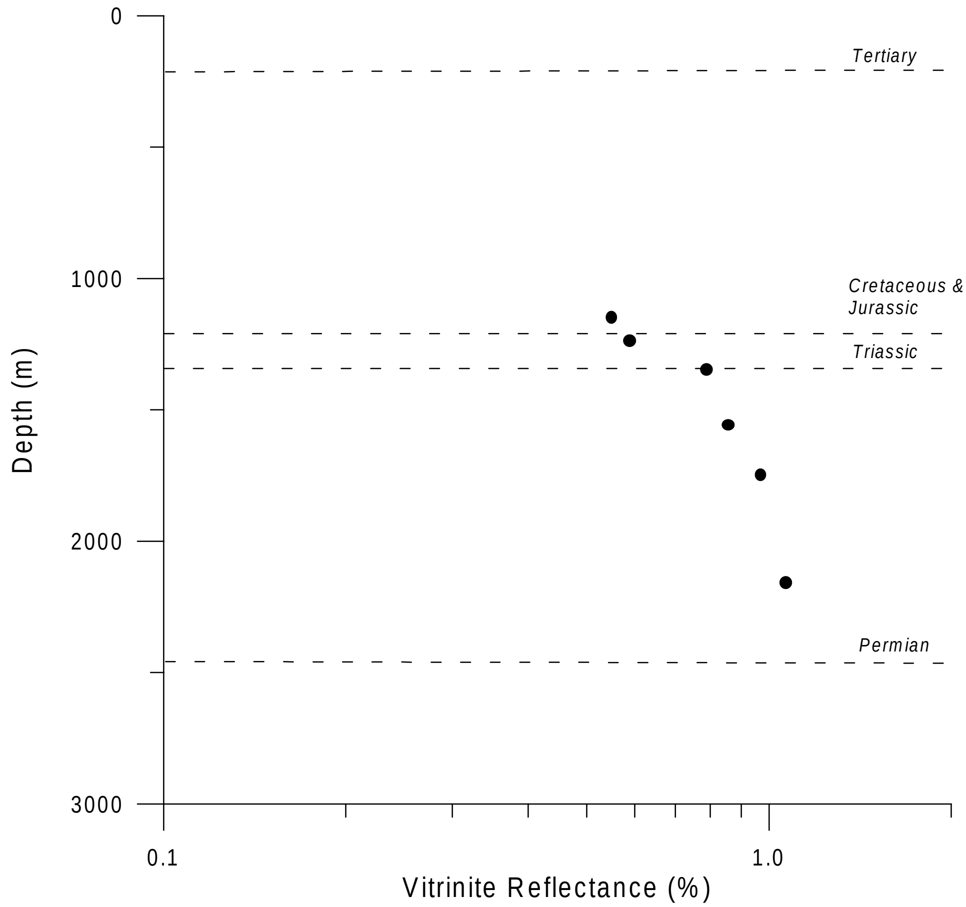


Figure 8. Vitrinite reflectance profile for the Caican #4 well, Junggar basin (data reported by King et al., 1994).

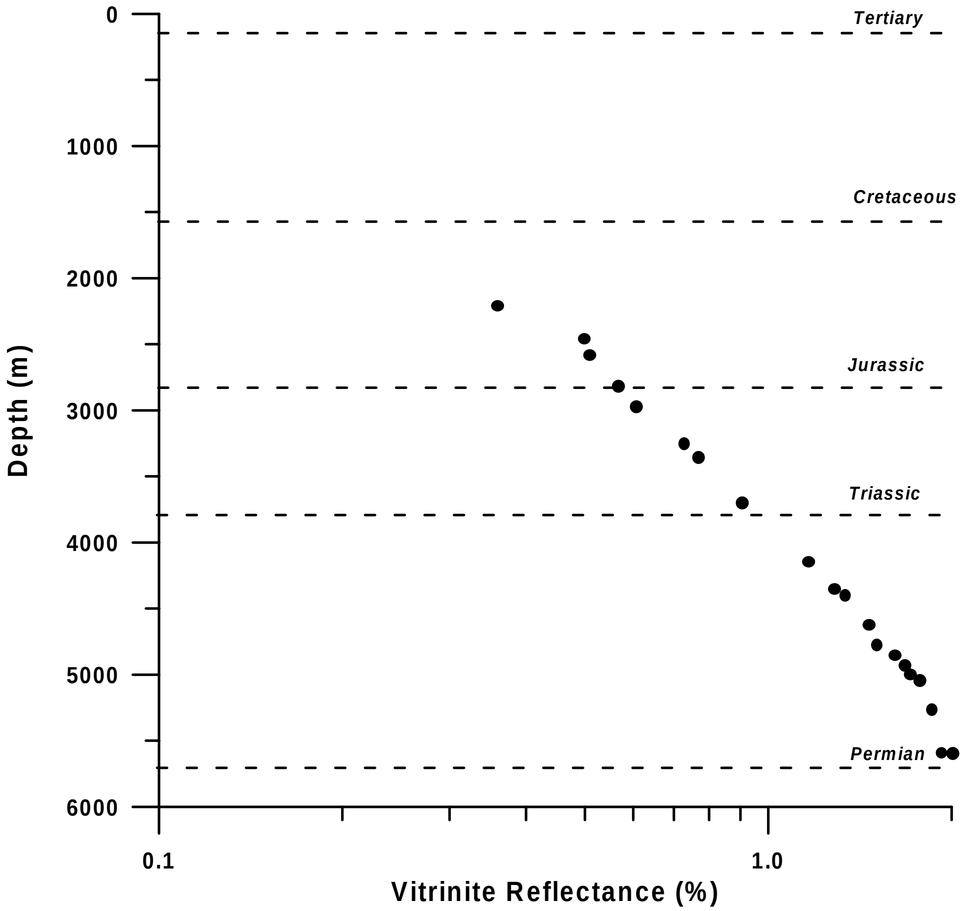


Figure 9. Vitrinite reflectance profile the Aican #1 well, Junggar basin (data reported by King et al., 1994).

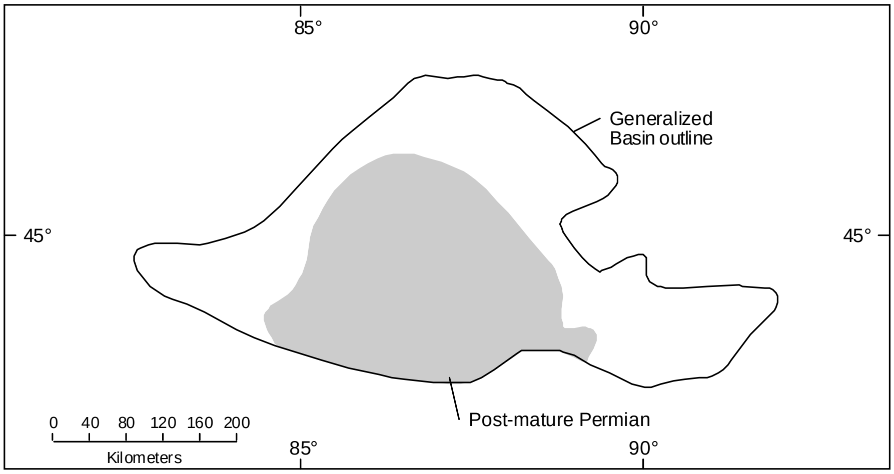
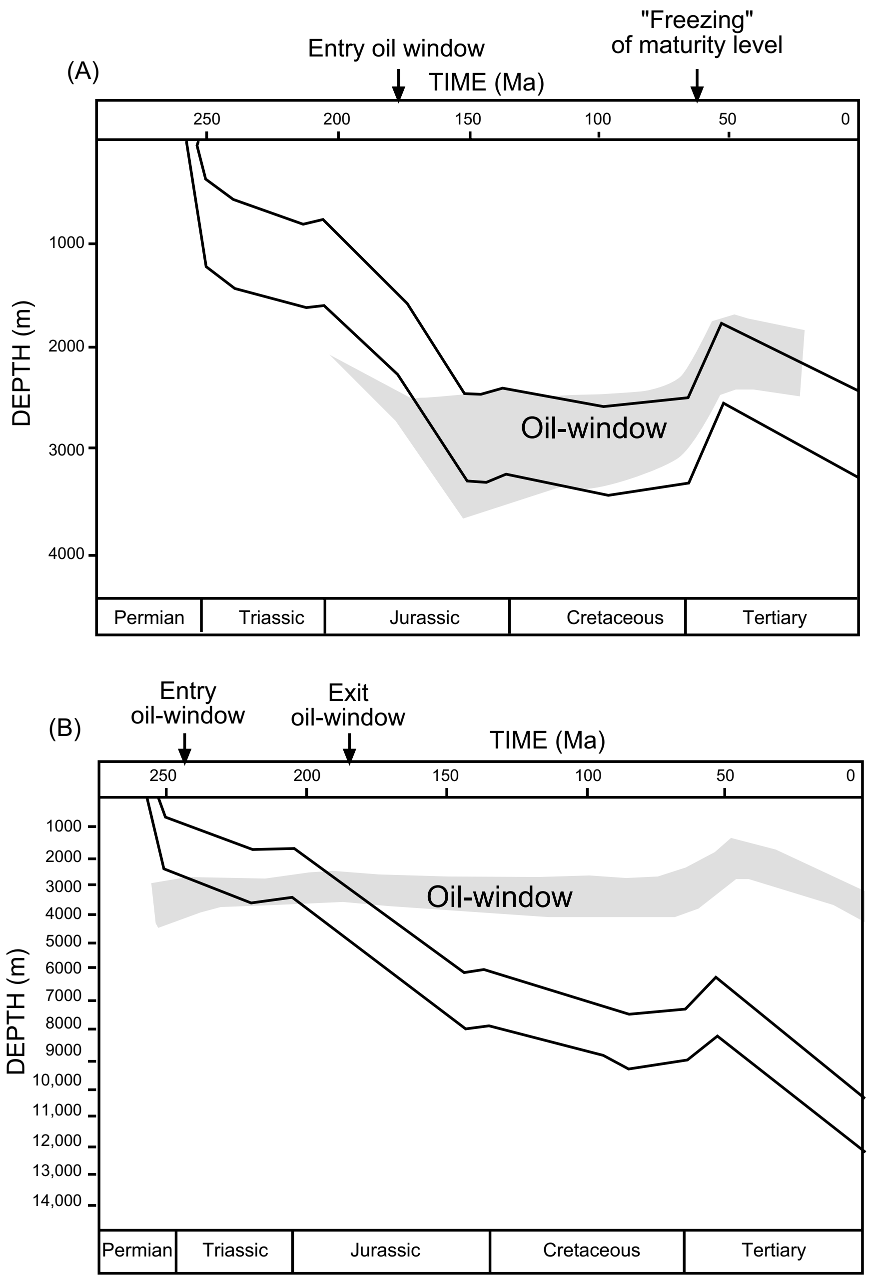


Figure 10. Generalized areal distribution of post-mature Permian rocks in the Tarim basin based on the isopach data presented by Ulmishek (1984).



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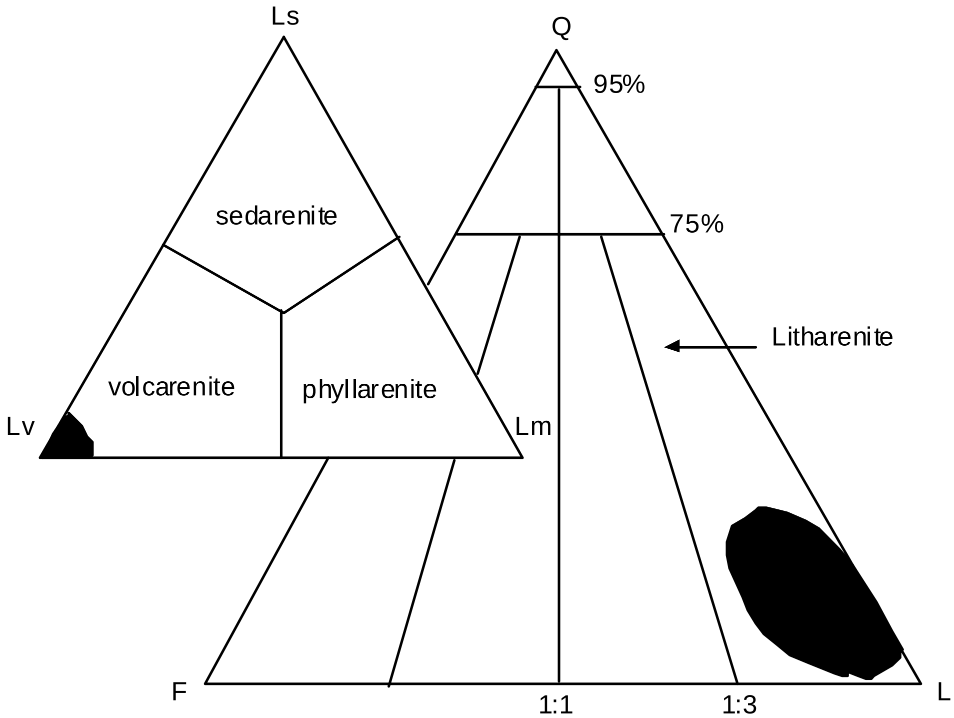

Figure 12. Classification of Permo-Triassic sandstones of the Junggar basin (modified from Zhaohui Tang et al., 1997).