Independent Statistics & Analysis
U.S. Energy Information Administration

# Technically Recoverable Shale Oil and Shale Gas Resources:

## Kazakhstan

September 2015

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

# Contents

# Executive Summary

## Introduction

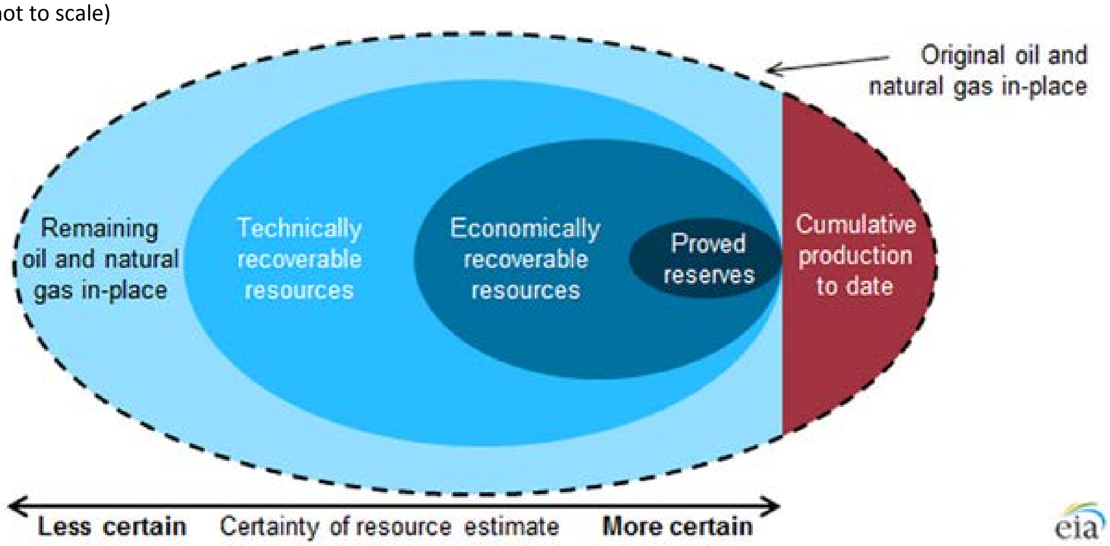
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically recoverable oil and natural gas resources. This chapter is a supplement to the 2013 EIA world shale report Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States.

## Resource categories

When considering the market implications of abundant shale resources, it is important to distinguish between a technically recoverable resource, which is the focus of this supplement as in the 2013 report, and an economically recoverable resource. Technically recoverable resources represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Economically recoverable resources are resources that can be profitably produced under current market conditions. The economic recoverability of oil and gas resources depends on three factors: the costs of drilling and completing wells, the amount of oil or natural gas produced from an average well over its lifetime, and the prices received for oil and gas production. Recent experience with shale gas and tight oil in the United States and other countries suggests that economic recoverability can be significantly influenced by above-the-ground factors as well as by geology. Key positive above-the-ground advantages in the United States and Canada that may not apply in other locations include private ownership of subsurface rights that provide a strong incentive for development; availability of many independent operators and supporting contractors with critical expertise and suitable drilling rigs and, preexisting gathering and pipeline infrastructure; and the availability of water resources for use in hydraulic fracturing. See Figure 1.

**Figure 1. Stylized representation of oil and natural gas resource categorizations**

(not to scale)




Source: U.S. Energy Information Administration
Note: Resource categories are not drawn to scale relative to the actual size of each resource category. The graphic shown above is applicable only to oil and natural gas resources.

Crude oil and natural gas resources are the estimated oil and natural gas volumes that might be produced at some time in the future. The volumes of oil and natural gas that ultimately will be produced cannot be known ahead of time. Resource estimates change as extraction technologies improve, as markets evolve, and as oil and natural gas are produced. Consequently, the oil and gas industry, researchers, and government agencies spend considerable time and effort defining and quantifying oil and natural gas resources.

For many purposes, oil and natural gas resources are usefully classified into four categories:

- Remaining oil and gas in-place (original oil and gas in-place minus cumulative production at a specific date)
- Technically recoverable resources
- Economically recoverable resources
- Proved reserves

The oil and natural gas volumes reported for each resource category are estimates based on a combination of facts and assumptions regarding the geophysical characteristics of the rocks, the fluids trapped within those rocks, the capability of extraction technologies, and the prices received and costs paid to produce oil and natural gas. The uncertainty in estimated volumes declines across the resource categories (see figure above) based on the relative mix of facts and assumptions used to create these resource estimates. Oil and gas in-place estimates are based on fewer facts and more assumptions, while proved reserves are based mostly on facts and fewer assumptions.

**Remaining oil and natural gas in-place (original oil and gas in-place minus cumulative production)**. The volume of oil and natural gas within a formation before the start of production is the original oil and gas in-place. As oil and natural gas are produced, the volumes that remain trapped within the rocks are the remaining oil and gas in-place, which has the largest volume and is the most uncertain of the four resource categories.

**Technically recoverable resources.** The next largest volume resource category is technically recoverable resources, which includes all the oil and gas that can be produced based on current technology, industry practice, and geologic knowledge. As technology develops, as industry practices improve, and as the understanding of the geology increases, the estimated volumes of technically recoverable resources also expand.

The geophysical characteristics of the rock (e.g., resistance to fluid flow) and the physical properties of the hydrocarbons (e.g., viscosity) prevent oil and gas extraction technology from producing 100% of the original oil and gas in-place.

**Economically recoverable resources.** The portion of technically recoverable resources that can be profitably produced is called economically recoverable oil and gas resources. The volume of economically recoverable resources is determined by both oil and natural gas prices and by the capital and operating costs that would be incurred during production. As oil and gas prices increase or decrease, the volume of the economically recoverable resources increases or decreases, respectively. Similarly, increasing or decreasing capital and operating costs result in economically recoverable resource volumes shrinking or growing.

U.S. government agencies, including EIA, report estimates of technically recoverable resources (rather than economically recoverable resources) because any particular estimate of economically recoverable resources is tied to a specific set of prices and costs. This makes it difficult to compare estimates made by other parties using different price and cost assumptions. Also, because prices and costs can change over relatively short periods, an estimate of economically recoverable resources that is based on the prevailing prices and costs at a particular time can quickly become obsolete.

**Proved reserves.** The most certain oil and gas resource category, but with the smallest volume, is proved oil and gas reserves. Proved reserves are volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves generally increase when new production wells are drilled and decrease when existing wells are produced. Like economically recoverable resources, proved reserves shrink or grow as prices and costs change. The U.S. Securities and Exchange Commission regulates the reporting of company financial assets, including those proved oil and gas reserve assets reported by public oil and gas companies.

Each year EIA updates its report of proved U.S. oil and natural gas reserves and its estimates of unproved technically recoverable resources for shale gas, tight gas, and tight oil resources. These reserve and resource estimates are used in developing EIA's Annual Energy Outlook projections for oil and natural gas production.

- Proved oil and gas reserves are reported in EIA's U.S. Crude Oil and Natural Gas Proved Reserves.
- Unproved technically recoverable oil and gas resource estimates are reported in EIA's Assumptions report of the Annual Energy Outlook. Unproved technically recoverable oil and gas resources equal total technically recoverable resources minus the proved oil and gas reserves.

Over time, oil and natural gas resource volumes are reclassified, going from one resource category into another category, as production technology develops and markets evolve.

Additional information regarding oil and natural gas resource categorization is available from the Society of Petroleum Engineers and the United Nations.

## Methodology

The shale formations assessed in this supplement as in the previous report were selected for a combination of factors that included the availability of data, country-level natural gas import dependence, observed large shale formations, and observations of activities by companies and governments directed at shale resource development. Shale formations were excluded from the analysis if one of the following conditions is true: (1) the geophysical characteristics of the shale formation are unknown; (2) the average total carbon content is less than 2 percent; (3) the vertical depth is less than 1,000 meters (3,300 feet) or greater than 5,000 meters (16,500 feet), or (4) relatively large undeveloped oil or natural gas resources.

The consultant relied on publicly available data from technical literature and studies on each of the selected international shale gas formations to first provide an estimate of the "risked oil and natural gas in-place," and then to estimate the unproved technically recoverable oil and natural gas resource for that shale formation. This methodology is intended to make the best use of sometimes scant data in order to perform initial assessments of this type.

The risked oil and natural gas in-place estimates are derived by first estimating the volume of in-place resources for a prospective formation within a basin, and then factoring in the formation's success factor and recovery factor. The success factor represents the probability that a portion of the formation is expected to have attractive oil and natural gas flow rates. The recovery factor takes into consideration the capability of current technology to produce oil and natural gas from formations with similar geophysical characteristics. Foreign shale oil recovery rates are developed by matching a shale formation's geophysical characteristics to U.S. shale oil analogs. The resulting estimate is referred to as both the risked oil and natural gas in-place and the technically recoverable resource. The specific tasks carried out to implement the assessment include:

1. Conduct a preliminary review of the basin and select the shale formations to be assessed.
2. Determine the areal extent of the shale formations within the basin and estimate its overall thickness, in addition to other parameters.
3. Determine the prospective area deemed likely to be suitable for development based on depth, rock quality, and application of expert judgment.
4. Estimate the natural gas in-place as a combination of *free gas*[1] and *adsorbed gas*[2] that is contained within the prospective area. Estimate the oil in-place based on pore space oil volumes.
5. Establish and apply a composite success factor made up of two parts. The first part is a formation success probability factor that takes into account the results from current shale oil and shale gas activity as an indicator of how much is known or unknown about the shale formation. The second part is a prospective area success factor that takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the prospective area from development.
6. For shale oil, identify those U.S. shales that best match the geophysical characteristics of the foreign shale oil formation to estimate the oil in-place recovery factor.[3] For shale gas, determine the recovery factor based on geologic complexity, pore size, formation pressure, and clay content, the latter of which determines a formation's ability to be hydraulically fractured. The gas phase of each formation includes dry natural gas, associated natural gas, or wet natural gas. Therefore, estimates of shale gas resources in this report implicitly include the light wet hydrocarbons that are typically coproduced with natural gas.
7. Technically recoverable resources[4] represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Technically recoverable resources are determined by multiplying the risked in-place oil or natural gas by a recovery factor.

Based on U.S. shale production experience, the recovery factors used in this supplement as in the previous report for shale gas generally ranged from 20 percent to 30 percent, with values as low as 15 percent and as high as 35 percent being applied in exceptional cases. Because of oil's viscosity and capillary forces, oil does not flow through rock fractures as easily as natural gas. Consequently, the recovery factors for shale oil are typically lower than they are for shale gas, ranging from 3 percent to 7 percent of the oil in-place with exceptional cases being as high as 10 percent or as low as 1 percent. The consultant selected the recovery factor based on U.S. shale production recovery rates, given a range of factors including mineralogy, geologic complexity, and a number of other factors that affect the response of the geologic formation to the application of best practice shale gas recovery technology. Because most shale oil and shale gas wells are only a few years old, there is still considerable uncertainty as to the expected life of U.S. shale wells and their ultimate recovery. The recovery rates used in this analysis are based on an extrapolation of shale well production over 30 years. Because a shale's geophysical characteristics vary significantly throughout the formation and analog matching is never exact, a shale formation's resource potential cannot be fully determined until extensive well production tests are conducted across the formation.

---

[1] Free gas is natural gas that is trapped in the pore spaces of the shale. Free gas can be the dominant source of natural gas for the deeper shales.

[2] Adsorbed gas is natural gas that adheres to the surface of the shale, primarily the organic matter of the shale, due to the forces of the chemical bonds in both the substrate and the natural gas that cause them to attract. Adsorbed gas can be the dominant source of natural gas for the shallower and higher organically rich shales.

[3] The recovery factor pertains to percent of the original oil or natural gas in-place that is produced over the life of a production well.

[4] Referred to as risked recoverable resources in the consultant report.

## Key exclusions

In addition to the key distinction between technically recoverable resources and economically recoverable resources that has been already discussed at some length, there are a number of additional factors outside of the scope of this report that must be considered in using its findings as a basis for projections of future production. In addition, several other exclusions were made for this supplement as in the previous report to simplify how the assessments were made and to keep the work to a level consistent with the available funding.

Some of the key exclusions for this supplement as in the previous report include:

1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas resources that may exist within these countries were also excluded from the assessment.
3. **Assessed formations without a resource estimate**, which resulted when data were judged to be inadequate to provide a useful estimate. Including additional shale formations would likely increase the estimated resource.
4. **Countries outside the scope of the report**, the inclusion of which would likely add to estimated resources in shale formations. It is acknowledged that potentially productive shales exist in most of the countries in the Middle East and the Caspian region, including those holding substantial non-shale oil and natural gas resources.
5. **Offshore portions of assessed shale oil** and shale gas formations were excluded, as were shale oil and shale gas formations situated entirely offshore.

# KAZAKHSTAN

## SUMMARY

Kazakhstan contains a series of major hydrocarbon basins, including North Caspian, Middle Caspian/South Mangyshlak, South Turgay, North Ustyurt and Chu-Sarysu, as shown in Figure 1. These basins enclose a series of world class oil and gas fields such as Tengiz, Karachaganak and Kashagan and numerous smaller fields. The conventional reservoirs in these basins have been sourced from an extensive stack of Devonian, Carboniferous, Triassic and Jurassic shale source rocks. However, significant portions of these source rocks, particularly of Devonian age, exceed the 5,000 meter (16,400 ft) depth cut-off established for this study. Thus, the resources in these deep shales while important, are not included in this assessment.

Figure 1. Kazakhstan Sedimentary Basins


Source: ARI, 2014.

Our assessment indicates that the shales and other organic-rich source rocks of Kazakhstan hold 221 billion barrels of risked, shale oil/condensate in-place, with 10.6 billion barrels as the risked, technically recoverable shale oil resource. In addition, we estimate that Kazakhstan contains 253 Tcf of dry, wet and associated shale gas in-place, with 27 Tcf as the risked, technically recoverable shale gas resource. Breakdowns for Kazakhstan shale oil reservoir properties and resources are presented in Tables 1 and 2.

Table 1. Shale Oil Reservoir Properties and Resources, Kazakhstan

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | North Caspian (212,000 $mi^2$) | | | | | Mangyshlak (30,000 $mi^2$) | South Turgay (60,000 $mi^2$) | |
| | | | North Basin Margin | | | | SE Basin Margin | | | |
| | Shale Formation | | Tournaisian, Radaevskiy-Kosvinkskiy | | L. Serpukhovian, Vereiskiy, Gzelian-Kasimovian | | Visean | Karadzhatyk | Karagansay | Abaleen |
| | Geologic Age | | L. Carboniferous | | M. - U. Carboniferous | | L. Carboniferous | L. Triassic | M. Jurassic | L. Jurassic |
| | Depositional Environment | | Marine | | Marine | | Marine | Marine | Lacustrine | Lacustrine |
| Physical Extent | Prospective Area ($mi^2$) | | 20 | 240 | 1,500 | 520 | 9,710 | 2,460 | 2,280 | 1,140 |
| | Thickness (ft) | Organically Rich | 450 | 417 | 294 | 294 | 1,640 | 1,640 | 600 | 1,300 |
| | | Net | 225 | 208 | 147 | 147 | 328 | 328 | 300 | 390 |
| | Depth (ft) | Interval | 14,500 - 16,400 | 15,000 - 16,400 | 8,200 - 16,400 | 12,500 - 16,000 | 4,500 - 16,400 | 6,600 - 16,400 | 8,000 - 12,000 | 11,000 - 16,400 |
| | | Average | 15,500 | 16,333 | 12,613 | 14,181 | 11,000 | 11,000 | 10,000 | 13,000 |
| Reservoir Properties | Reservoir Pressure | | Highly Overpress. | Highly Overpress. | Highly Overpress. | Highly Overpress. | Normal | Normal | Normal | Normal |
| | Average TOC (wt. %) | | 2.1% | 2.2% | 2.1% | 2.0% | 2.0% | 3.0% | 3.0% | 3.0% |
| | Thermal Maturity (% Ro) | | 0.85% | 1.15% | 0.85% | 1.15% | 0.80% | 0.85% | 0.80% | 0.90% |
| | Clay Content | | Medium | Medium | Medium | Medium | Medium | Medium | Medium | Medium |
| Resource | Oil Phase | | Oil | Condensate | Oil | Condensate | Oil | Oil | Oil | Oil |
| | OIP Concentration (MMbbl/$mi^2$) | | 20.8 | 6.1 | 13.7 | 4.7 | 40.3 | 39.3 | 38.1 | 42.9 |
| | Risked OIP (B bbl) | | 0.3 | 1.0 | 13.3 | 1.6 | 125.3 | 38.6 | 26.1 | 14.7 |
| | Risked Recoverable (B bbl) | | 0.01 | 0.05 | 0.67 | 0.08 | 6.26 | 1.93 | 1.04 | 0.59 |

Source: ARI, 2014.

Table 2. Shale Gas Reservoir Properties and Resources, Kazakhstan

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Basic Data | Basin/Gross Area | | North Caspian (212,000 $mi^2$) | | | | | | | Mangyshlak (30,000 $mi^2$) | South Turgay (60,000 $mi^2$) | |
| | | | North Basin Margin | | | | | | SE Basin Margin | | | |
| | Shale Formation | | Tournaisian, Radaevskiy-Kosvinkskiy | | | L. Serpukhovian, Vereiskiy, Gzelian-Kasimovian | | | Visean | Karadzhatyk | Karagansay | Abaleen |
| | Geologic Age | | L. Carboniferous | | | M. - U. Carboniferous | | | L. Carboniferous | L. Triassic | M. Jurassic | L. Jurassic |
| | Depositional Environment | | Marine | | | Marine | | | Marine | Marine | Lacustrine | Lacustrine |
| Physical Extent | Prospective Area ($mi^2$) | | 20 | 240 | 100 | 1,500 | 520 | 360 | 9,710 | 2,460 | 2,280 | 1,140 |
| | Thickness (ft) | Organically Rich | 450 | 417 | 400 | 294 | 294 | 292 | 1,640 | 1,640 | 600 | 1,300 |
| | | Net | 225 | 208 | 200 | 147 | 147 | 146 | 328 | 328 | 300 | 390 |
| | Depth (ft) | Interval | 14,500 - 16,400 | 15,000 - 16,400 | 15,000 - 16,400 | 8,200 - 16,400 | 12,500 - 16,000 | 14,400 - 16,400 | 4,500 - 16,400 | 6,600 - 16,400 | 8,000 - 12,000 | 11,000 - 16,400 |
| | | Average | 15,500 | 16,333 | 16,400 | 12,613 | 14,181 | 15,350 | 11,000 | 11,000 | 10,000 | 13,000 |
| Reservoir Properties | Reservoir Pressure | | Highly Overpress. | Highly Overpress. | Highly Overpress. | Highly Overpress. | Highly Overpress. | Highly Overpress. | Normal | Normal | Normal | Normal |
| | Average TOC (wt. %) | | 2.1% | 2.2% | 2.2% | 2.1% | 2.0% | 2.0% | 2.0% | 3.0% | 3.0% | 3.0% |
| | Thermal Maturity (% Ro) | | 0.85% | 1.15% | 1.45% | 0.85% | 1.15% | 1.45% | 0.80% | 0.85% | 0.80% | 0.90% |
| | Clay Content | | Medium | Medium | Medium | Medium | Medium | Medium | Medium | Medium | Medium | Medium |
| Resource | Gas Phase | | Assoc. Gas | Wet Gas | Dry Gas | Assoc. Gas | Wet Gas | Dry Gas | Assoc. Gas | Assoc. Gas | Assoc. Gas | Assoc. Gas |
| | GIP Concentration (Bcf/$mi^2$) | | 41.6 | 33.7 | 127.9 | 27.0 | 23.3 | 90.2 | 37.4 | 31.7 | 29.0 | 48.1 |
| | Risked GIP (Tcf) | | 0.5 | 5.3 | 8.3 | 26.3 | 7.9 | 21.1 | 116.3 | 31.2 | 19.9 | 16.5 |
| | Risked Recoverable (Tcf) | | 0.1 | 0.5 | 1.7 | 2.6 | 0.8 | 4.2 | 11.6 | 3.1 | 1.6 | 1.3 |

Source: ARI, 2014.

## INTRODUCTION

Kazakhstan covers a vast land area in central Asia. Its borders are with China on the east, Russia on the north, Uzbekistan and Kyrgyzstan on the south, and the Caspian Sea on the west. Kazakhstan is one of the world's major oil producers, providing over 1.5 million barrels per day of production. The bulk of Kazakhstan's oil production, which has remained relatively flat since 2010, is exported. Kazakhstan's annual natural gas production has been increasing steadily over the past decade up to 1.4 Tcf today, most of which (over 70%) is re-injected into oil fields to enhance oil production.

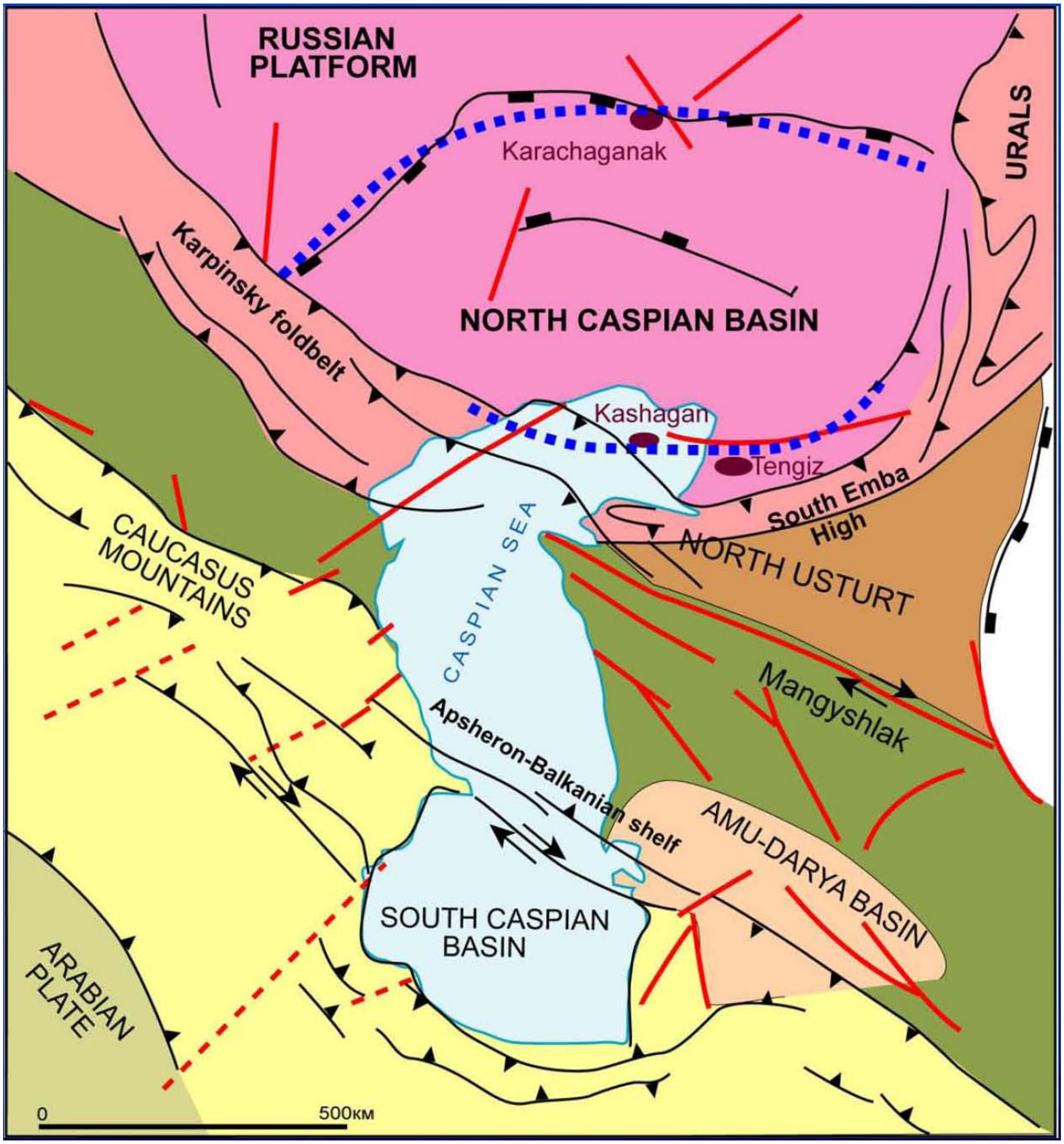
Kazakhstan's petroleum basins, located in the western portion of the country, have undergone a complex tectonic and depositional history resulting in a series of major features, presented in Figure 2. One of the notable features is the Kungurian (Lower Permian) salt formation that separates the strata in the North Caspian Basin into sub-salt and suprasalt intervals. Another main feature, the Central Mangyshlak rift, represented by compressed inverted and deformed structure, separates the North Ustyurt and Middle Caspian/South Mangyshlak basins. Finally, the regional Karatau Fault controls the major grabens in the South Turgay Basin.

This shale gas and oil resource assessment addresses three of Kazakhstan most prospective sedimentary basins:

- The North Caspian Basin
- The Middle Caspian/South Mangyshlak Basin, and
- The South Turgay Basin

This study also examined the source rocks and shale formations of the North Ustyurt Basin in western Kazakhstan and the Chu-Sarysu Basin in south-central Kazakhstan. However, the study has not identified sufficient publically available geologic and reservoir data for supporting a quantitative resource assessment for these two basins.

Figure 2. Major Structural Features of Western Kazakhstan Sedimentary Basins




Source: Kuandykov et al., 2010.

# 1. NORTH CASPIAN BASIN

## 1.1 Introduction and Geologic Setting

The North Caspian Basin (also called the Pre-caspian or Pricaspian Basin) is a large, complex regional structure located in western Kazakhstan and southern Russia, with about 80% of its area located in Kazakhstan, as Figure 3 shows.

The basin covers an overall area of about 212,000 $mi^2$ (550,000 $km^2$). However, the primary source rocks (shales) underlying the major portion of the basin,are buried below 16,400 feet (5,000 m), the depth cut-off established for this resource assessment, as illustrated in Figure 4. As such, this resource study addresses the shallower portion of shale source rocks along the northern, eastern, and southern rims of the North Caspian Basin.

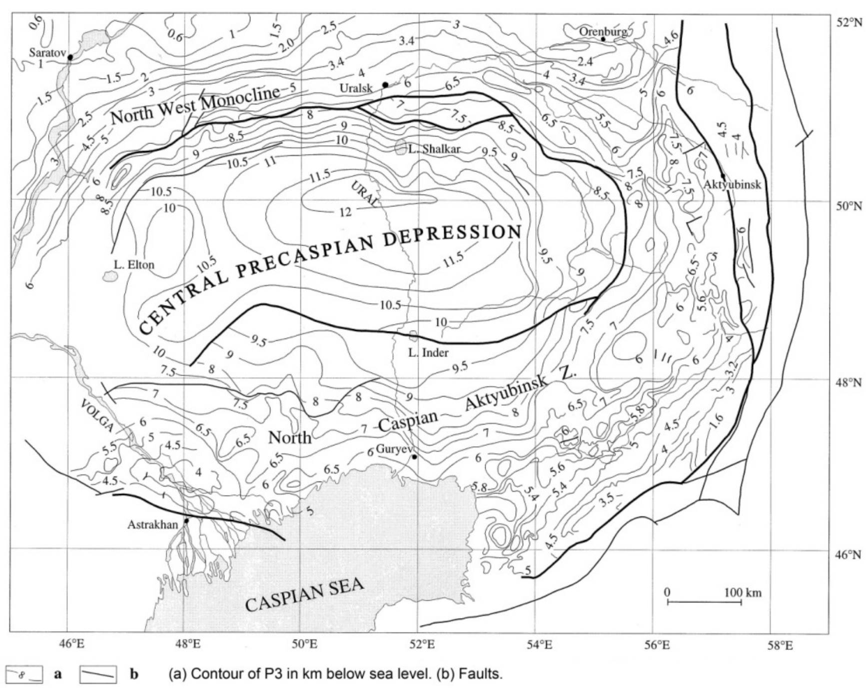
The North Caspian Basin is bounded on the north by the Russian Platform, on the east by the Ural Mountains, on the southeast by the Northern Ustyurt Block, on the southwest by the Karpinski inverted rift, and on the west by the Kazakhstan and Russia border. The study excluded the offshore portion of the basin in the Caspian Sea.

The North Caspian Basin contains more than 20,000 m of sedimentary fill, including a rich sequence of shale source rocks. Given its size and petroleum potential, "it is considered to be one of the most important sedimentary basins of the world" (Brunet et al., 1998). Figure 5 presents a synthetic stratigraphic column (based on seismic velocities) for the North Caspian Basin.

Figures 6 and 7 show a west-to-east cross-section from the center of the North Caspian Basin to the east basin margin and a south-to-north cross-section through the entire North Caspian Basin, respectively. These cross-sections illustrate: (1) the great depth of the sediments in the center of the basin; (2) the extensive salt deposition throughout this basin; and (3) the shallowing basin margins, on the north, as well as the east and south, evaluated by this shale resource assessment.

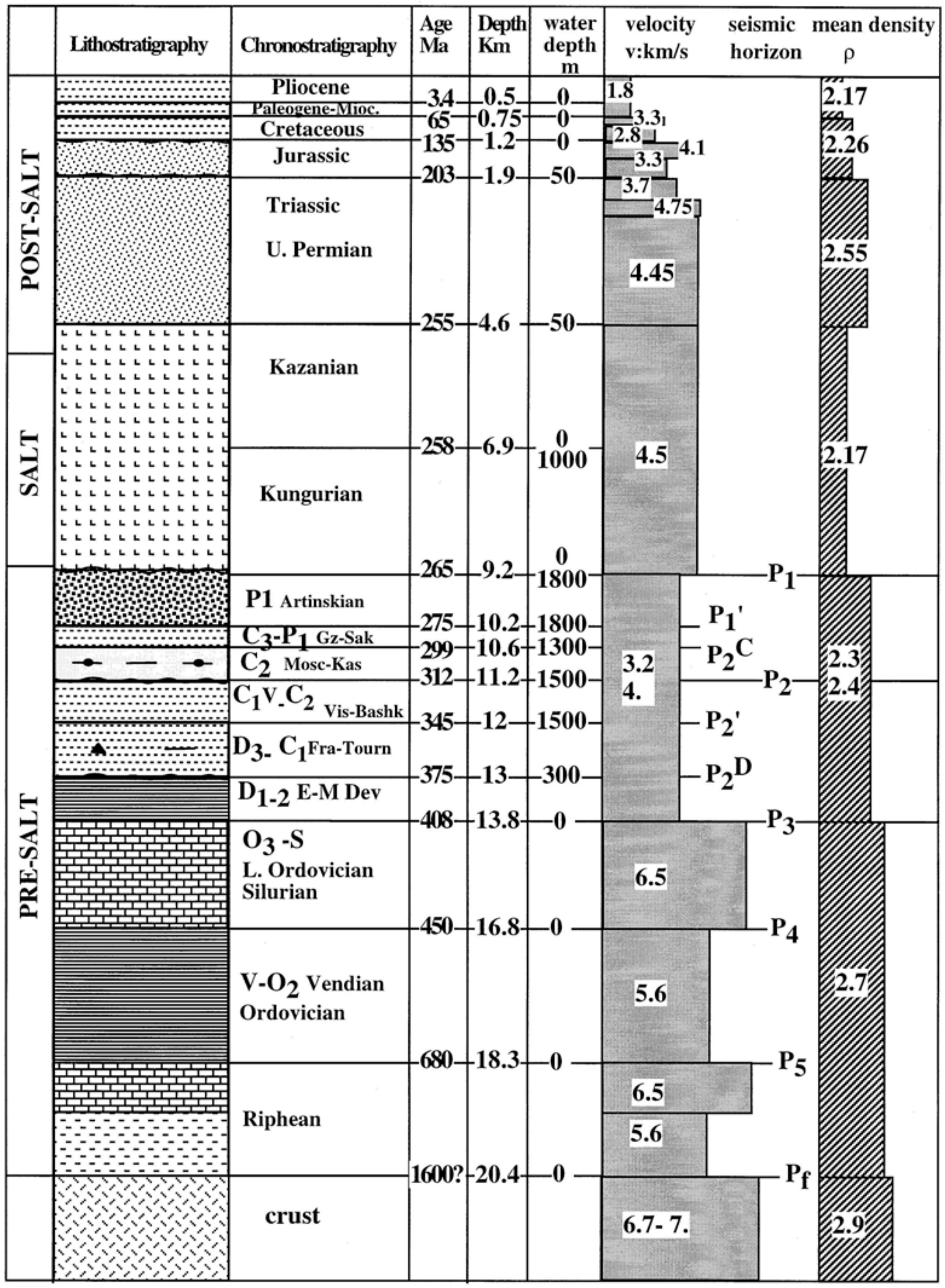
Figure 3. Cross-Section Location Map, the North Caspian Basin


Figure 4. Depth Map of the Base of Devonian Interval, the North Caspian Basin



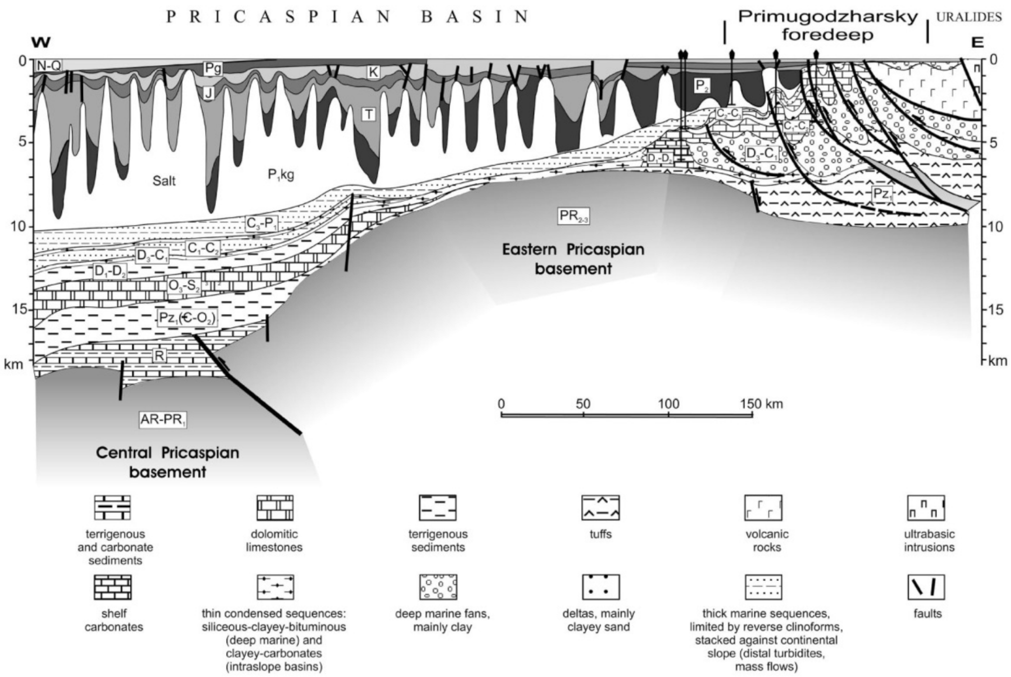

Source: Brunet et al., 1998.

Figure 5. Synthetic Stratigraphic Column for the North Caspian Basin



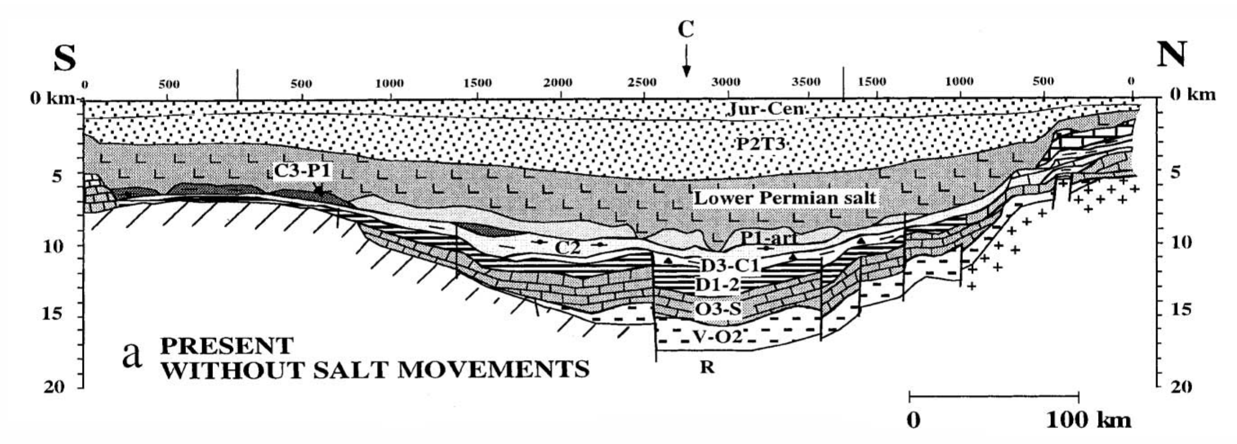

Source: Brunet et al., 1998.

Figure 6. West-to-East Cross-Section, the North Caspian Basin




Source: Volozh et al., 2003.

Figure 7. South-to-North Cross-Section, the North Caspian Basin

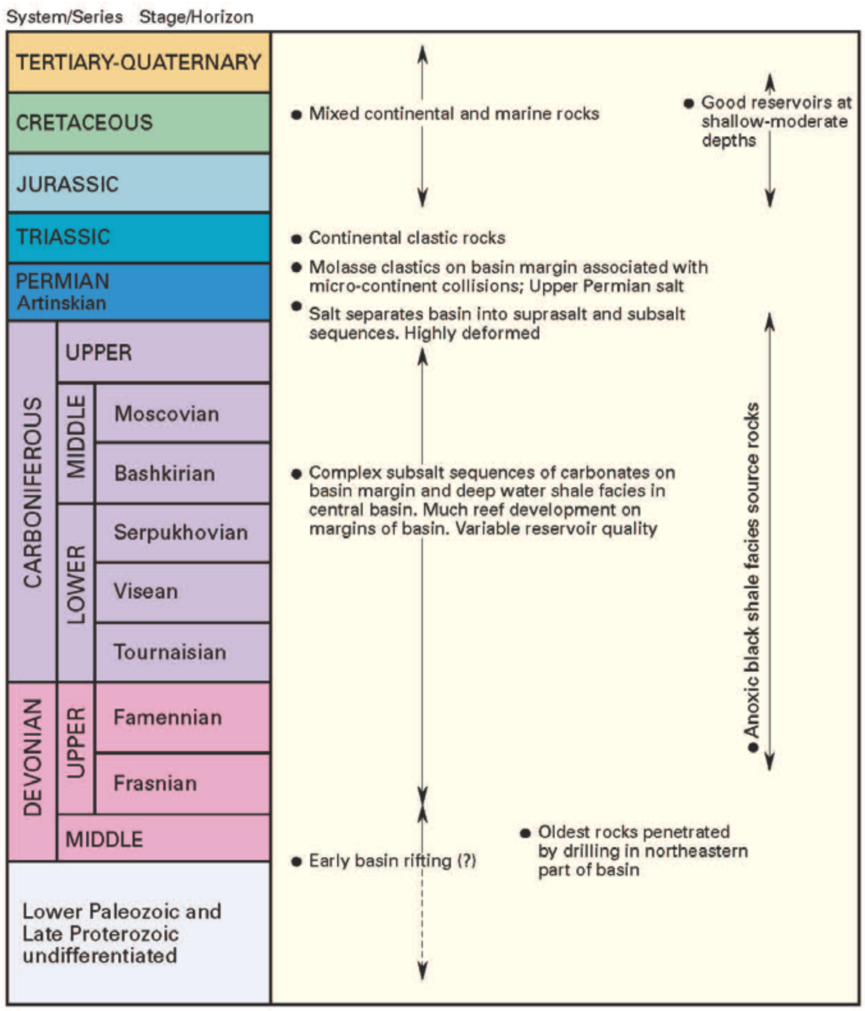



Source: Brunet et al., 1998.

The North Caspian Basin contains the thick Kungurian (Lower Permian) salt formation that has been deformed into domes and intervening depressions (See Figure 6), which divides the sediments into subsalt and suprasalt intervals. The subsalt sequence consists of alternating carbonate formations, clastic wedges, and deep-water anoxic black shales. The suprasalt sequence is composed primarily of clastic rocks several thousand feet thick in the depression areas between the salt domes, as shown by the regional cross-section from the deep center of the basin to its shallower northern and eastern margins (See Figure 7).

Figure 8 presents an overview of the major geologic events and list of primary source and reservoir rocks of the North Caspian Basin. The figure identifies the deep-water, anoxic Upper Devonian and Carboniferous black shales that serve as the principle source rocks in this basin.

Figure 8. Major Geologic Events and Primary Source and Reservoir Rocks of the North Caspian Basin




Source: Dyman et al., 2001.

Because of the size and complexity of the North Caspian basin, we have partitioned the onshore Kazakhstan portion of this basin into two resource assessment areas as follows: the North Basin Margin and South-East Basin Margin.

## 1.A NORTH BASIN MARGIN

### 1.A.1 Introduction and Geologic Setting

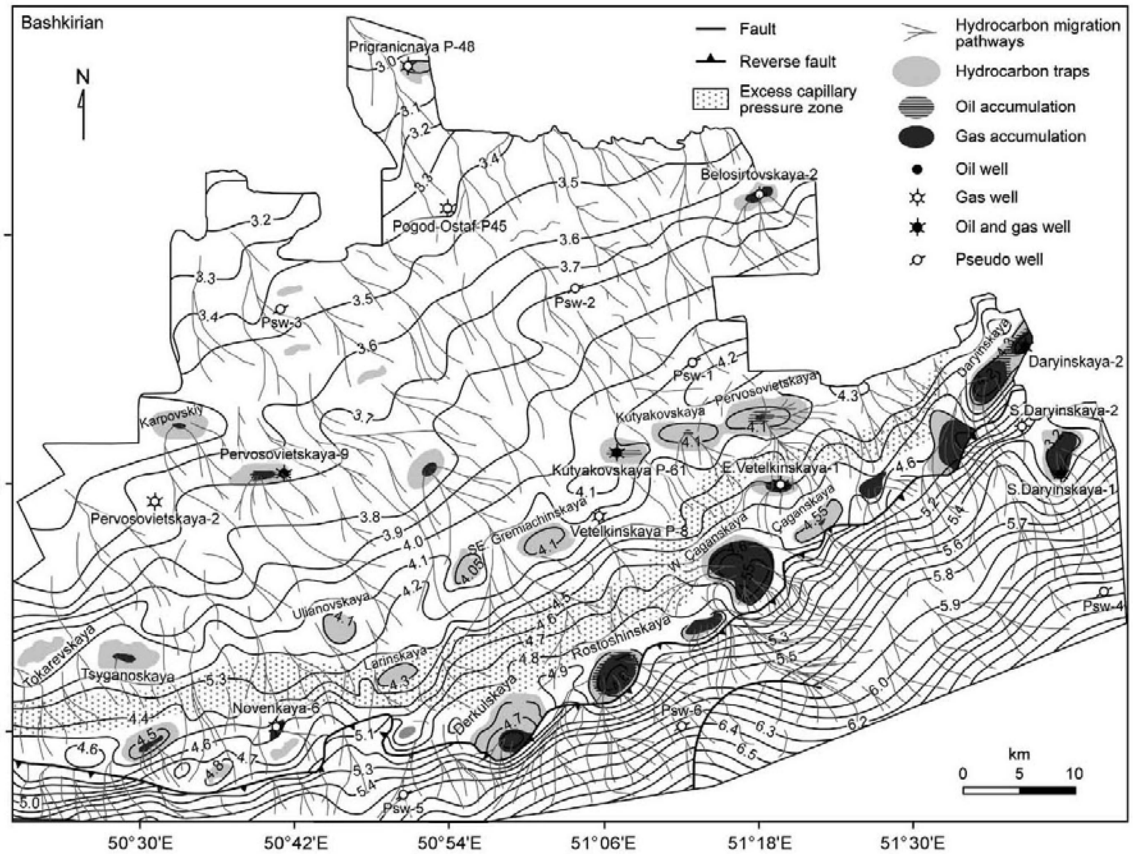
The North Basin Margin contains the giant subsalt Lower Permian Karachaganak gas condensate and oil field containing a hydrocarbon column of about 5,300 ft (1,600 m), one of the thickest in the world (Ulmishek, 2001). Additional smaller oil fields exist on the northern margin of the basin.

The North Basin Margin contains a thick package of Devonian and Carboniferous organic-rich, marine shale source rocks. Five of these shale source rocks were evaluated in this study.

- The Devonian source rocks in this area are buried deeper than the 16,400 feet (5,000 m) cut-off used by the study and thus are not included in the resource assessment.
- The deepest shale source rock evaluated is the Lower Carboniferous Tournaisian formation. This formation also exceeds the depth criterion as it dips to the south in the central part of the basin.
- The four other shale source rocks evaluated are the Lower Carboniferous Radaevskiy-Kosvinskiy (Moscovian),Lower Serpukhovian, the Middle Carboniferous Vereiskiy, and the Upper Carboniferous Gzelian-Kasimovian formations.

Figure 9 presents a structural map of the top of the Middle Carboniferous interval in the North Caspian Basin Margin, as it dips toward the south and southeast.

Figure 9. Depth Map of the Carboniferous Interval, the North Caspian Basin




Source: Huvaz et al., 2007.

## 1.A.2 Reservoir Properties (Prospective Area)

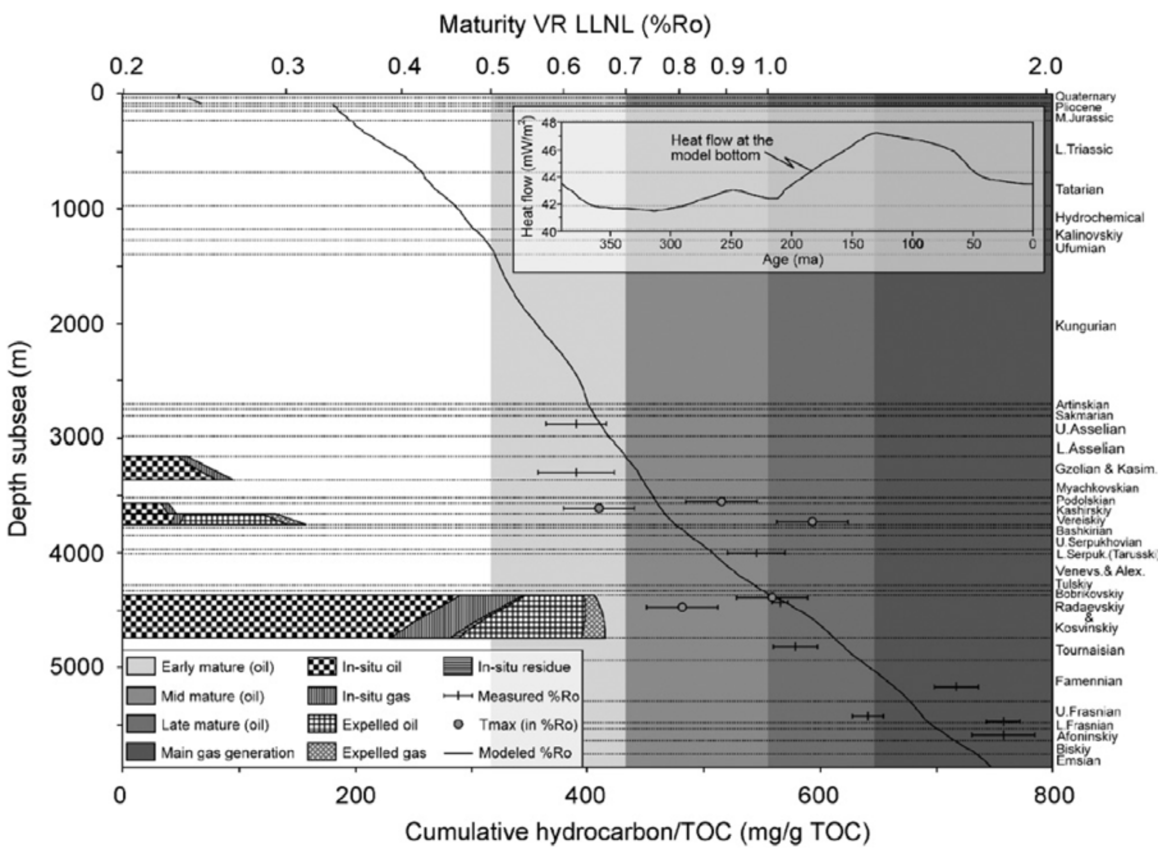
The reservoir properties for the prospective areas of the organic-rich shales in the North Basin Margin of the North Caspian Basin are based on a combination of well data and previous detailed geochemistry and source rock research results (Huvaz et al., 2007). This study performed evaluation of the deep marine Devonian and Carboniferous black shales utilizing basin modeling combined with rigorous compilation of geological, geophysical, and geochemical data. Particular emphasis was placed on evaluating the sub-salt source rocks of the North Basin Margin with reported TOC values of up to 10% (Maximov and Ilinskaya, 1989.)

The hydrocarbons in the sub-salt reservoirs have medium to high oil gravities of 38$^{o}$ to 67$^{o}$ API. The sub-salt reservoirs including the shale source rocks are highly over-pressured, with reservoir pressure approaching two times hydrostatic pressure.

A portion of the geological and reservoir data assembled for the North Basin Margin of the North Caspian Basin, particularly information on TOC, have been obtained from well observations in the major Karachaganak Field, located due east of the study area.

The study identified a series of potential deep water organic-rich shales of Devonian and Carboniferous age. Four of the potential Devonian source rocks, while organically rich and thick, are buried below the depth cut-off of 5,000 m. This study assessed five of the Carboniferous shale source rocks with maturity values of 0.7 to 1.3% Ro, which places the bulk of these source rocks in the oil window, as shown in Figure 10. These five formations, including Tournaisian, Radaevskiy-Kosvinskiy, Lower Serpukhovian, Vereiskiy, and Gzelian-Kasimovian shales are described below.

Figure 10. Calibrated Present Day Maturity Profile Against the Thermal Indicators from the Belosirtovskaya-2 Well




Source: Huvaz et al., 2007.

Tournaisian. The Tournaisian formation is one of the major source rocks in the North Caspian Basin, with high maturation and rich, Type II TOC. The Belosirtovskaya-2 well encountered the top of the Tournaisian interval at a depth of 15,600 ft (4,734 m). The observed thickness of the formation was established as of 630 ft (192 m) with 34% shale content. The Tournaisian formation contains dry gas, wet gas/condensate, and oil along the northern portion of the study area, with TOC values of over 2%. The Tournaisian interval dips below 16,400 ft (5,000 m) in the southern portion of the North Basin Margin. We estimate a small (10 $mi^2$) area prospective for oil, a 200 $mi^2$ area prospective for wet gas/condensate, and a 100 $mi^2$ area prospective for dry gas, as shown in Figure 11.

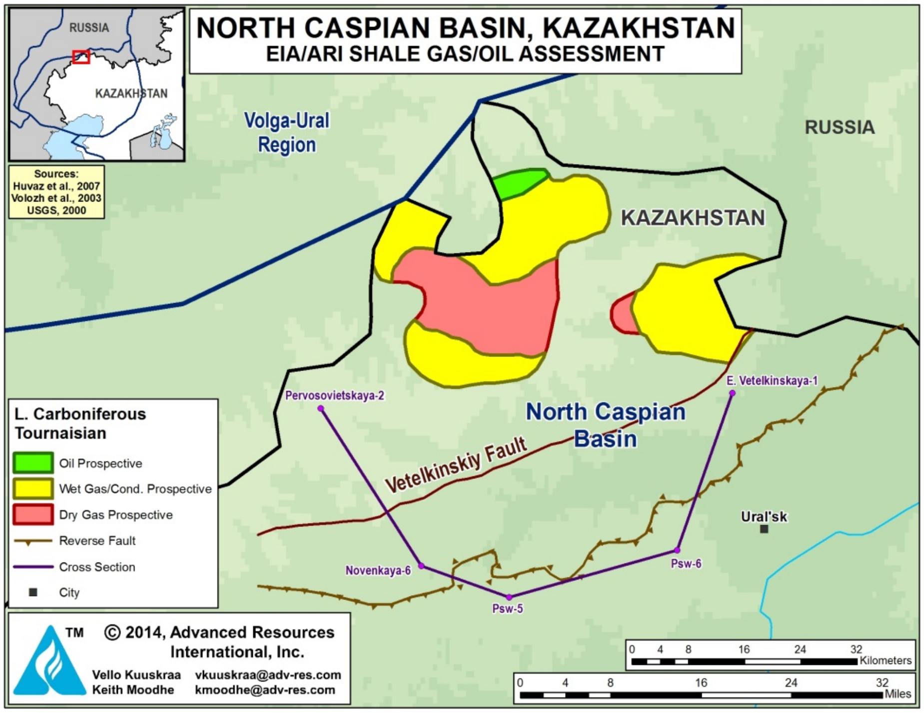
Radaevskiy-Kosvinskiy (R-K). The R-K source rock liesat a depth of less than 16,400 ft (5,000 m) and covers a small area (50 $mi^2$) in the northeastern portion of the basin, as Figure 12 illustrates. The formation contains a mix of Type II and Type III kerogen in equal proportions. The Belosirtovskaya-2 well encountered the top of the R-K interval at a depth of 14,400 ft. (4,354 m), with measured thickness of 1,250 ft (380 m) and 60% of shale content. The R-K prospective area contains oil and wet gas/condensate.

Lower Serpukhovian. The Lower Serpukhovian (the upper unit of the Lower Carboniferous) source rock spreads widely in the North Basin Margin. Only a modest portion of this interval along the southern margin of the North Basin Margin, dips below 16,400 ft (5,000 m), as presented in Figure 13. As such, the Lower Serpukhovian formation encompasses a 300 $mi^2$ area prospective for dry gas, 460 $mi^2$ area prospective for wet gas/condensate, and 1,120 $mi^2$ area prospective for oil. The formation contains rich Type II/III organic matter with TOC of 2 to 3%. The Serpukhovian formation is primarily in the oil window and enters the wet associated gas/condensate and dry gas window in the center of the study area.

Vereiskiy. The Middle Carboniferous (Moscovian) Vereiskiy formation is one of the most important source rocks in the Northern Caspian Basin. However, it is sparsely distributed in the study area, with mostly Type III kerogen and low TOC values, as Figure 14 shows. The Vereiskiy shale source rock has a small (60 $mi^2$) area prospective for dry gas, a small (60 $mi^2$) area prospective for wet gas/condensate, and a larger (120 $mi^2$) area prospective for oil.

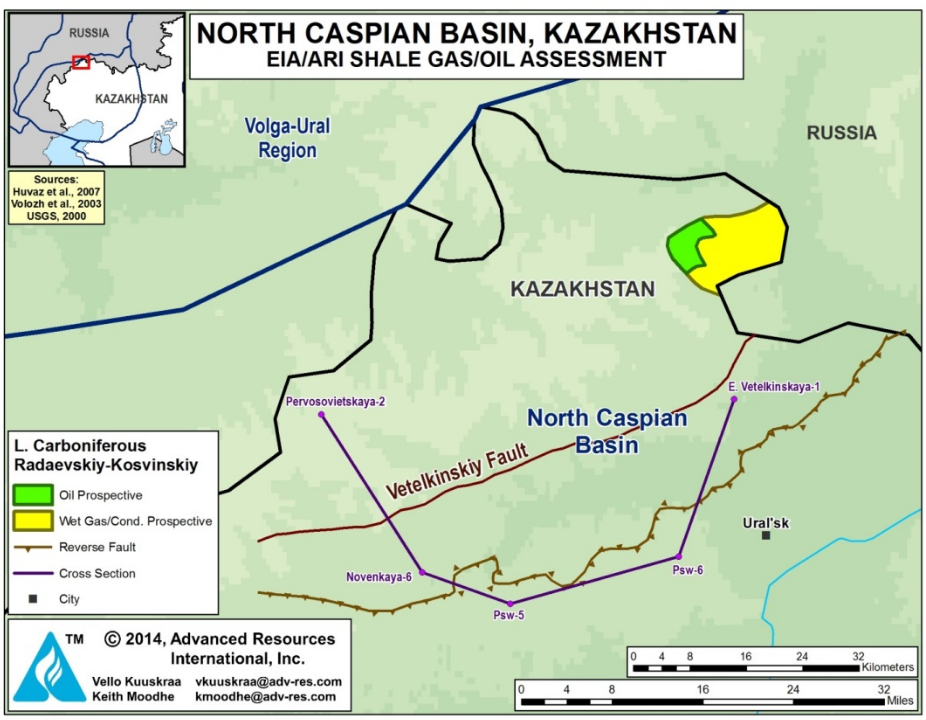
Gzelian-Kasimovian (G-K). The Upper Carboniferous G-K formation with moderately rich (2 to 3%) Type II TOC is sufficiently mature for oil only in a modest (260 $mi^2$) portion of the study area, as shown in Figure 15.

Figure 11. Map of the Prospective Tournaisian Shale Extent in the North Caspian Basin



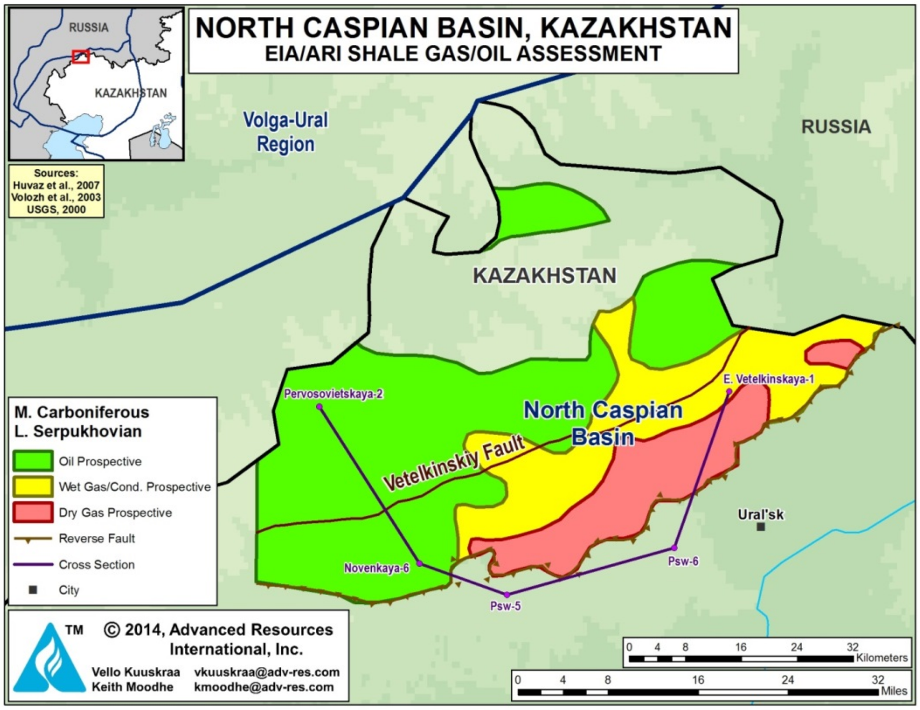

Source: Modified from Huvaz et al., 2007.

Figure 12. Map of the Prospective Radaevskiy-Kosvinskiy Shale Extent in the North Caspian Basin



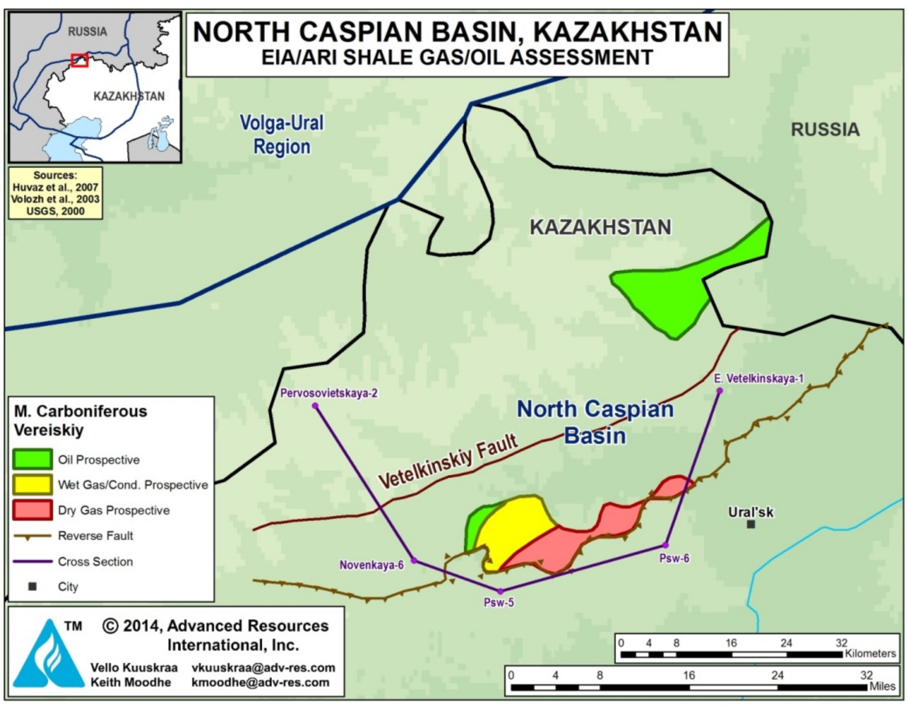

Source: Modified from Huvaz et al., 2007.

Figure 13. Map of the Prospective Lower Serpukhovian Shale Extent in the North Caspian Basin



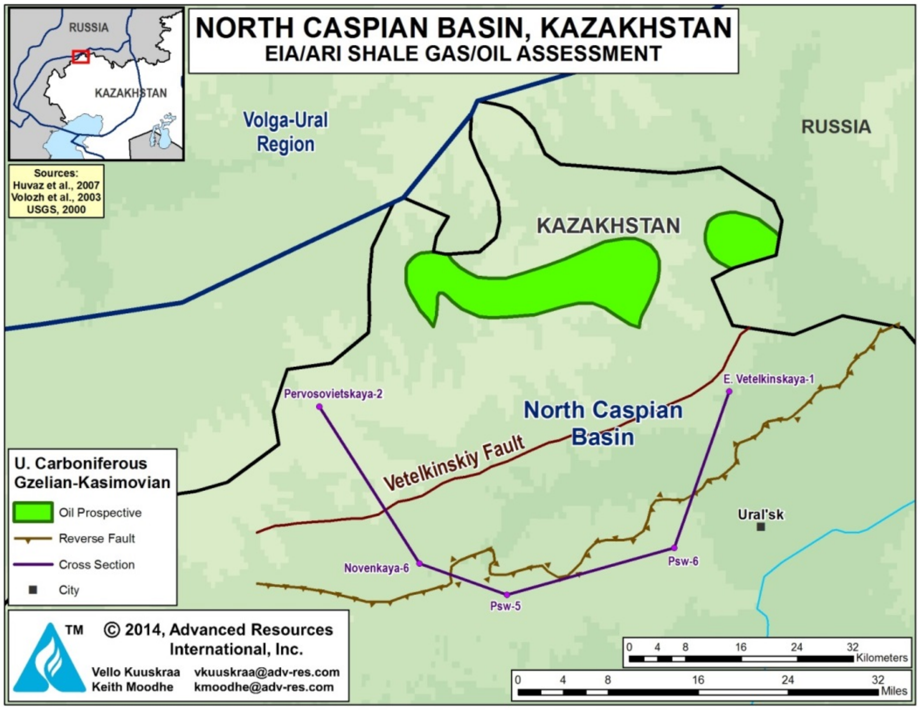

Source: Modified from Huvaz et al., 2007.

Figure 14. Map of the Prospective Vereiskiy Shale Extent in the North Caspian Basin




Source: Modified from Huvaz et al., 2007.

Figure 15. Map of the Prospective Gzelian-Kasimovian Shale Extent in the North Caspian Basin




Source: Modified from Huvaz et al., 2007.

### 1.A.3 Resource Assessment

For the North Caspian Basin resource assessment, we combined the two Lower Carboniferous shale intervals (Tournaisian and Radaevskiy-Kosvinskiy) and the three Middle/Upper Carboniferous shale intervals (L. Serpukhovian, Vereiskiy and Gzelian-Kasimovian).

Lower Carboniferous. The prospective footprint of the Lower Carboniferous shale (at a depth less than 5,000 m) covers an area of 360 $mi^2$. Within this area, 20 $mi^2$ is prospective for oil and associated gas, 240 $mi^2$ is prospective for wet gas/condensate, and 100 $mi^2$ is prospective for dry gas (See Table 1).

The oil/condensate prospective areas holds a risked resource in-place estimated at 1.2 billion barrels and a risked, technically recoverable shale oil/condensate resource of 0.06 billion barrels. The dry, wet and associated gas prospective areas hold a risked resource in-place of 14 Tcf and a risked, technically recoverable shale gas resource of 2.2 Tcf.

Middle-Upper Carboniferous. The prospective footprint of the Middle/Upper Carboniferous shale (at a depth less than 5,000 m) covers an area of 2,380 $mi^2$. Within this area, 360 $mi^2$ is prospective for dry gas, 520 $mi^2$ is prospective for wet gas/condensate, and 1,500 $mi^2$ is prospective for oil and associated gas (See Table 2).

The oil and condensate areas hold a risked resource in-place of 15 billion barrels and a risked, technically recoverable shale oil/ condensate resource of 0.7 billion barrels. The dry, wet and associated gas prospective areas holds a risked resource in-place of 55 Tcf and a risked, technically recoverable shale gas resource of 8 Tcf.

# 1.B EAST-SOUTHEAST BASIN MARGIN

## 1.B.1 Introduction and Geologic Setting

The shale resource assessment is performed for a 10,000 $mi^2$ area of the Southeast Basin Margin of the North Caspian Basin, as shown in Figure 16. The assessment area is bounded by the basin margin on the southeast and the 5,000 m (16,400 ft) depth limit (for the Middle Carboniferous) on the northwest.

The principal source rocks in this assessment area are of Early Carboniferous (Visean) and Early Permian (Sakmarian and Asselian) age, as shown on the stratigraphic column (Figure 17) for this portion of the North Caspian Basin.

The publically available information on the distribution, richness and maturity of these source rocks is limited. However, according to previous research there is numerous evidence of the presence of prospective shale source rocks in this area.

- The Biikzhal deep well located basin-ward from the Southeast Basin Margin identified Middle Carboniferous black shales with a TOC of 6.1% (Arabadzhi et al., 1993).
- Middle Carboniferous black shales on the east basin margin had TOC values up to 7.8% (Dalyan, 1996).
- Collection of source rock core samples from the eastern portion of the basin revealed high TOC content in the Early- to Mid-Visean, Late Carboniferous and Early Permian intervals (Yensepbayev et al., 2010).

The shales primarily contain Type II kerogen and become increasingly thick toward the basin center. The maturity of these source rocks corresponds to the early oil generation window. The Early Permian source rocks in this area enter the oil window from 6,000 to 13,200 ft (2,000 to 4,000 m). The Carboniferous rocks in this area enter the oil window at a depth of 10,500 to 13,200 ft (3,200 to 4,000 m) (Yensepbayev et al., 2010).

In addition, previous investigators suggest that the Upper Devonian-Lower Carboniferous Izembet Formation in the southeast margin of the basin contains significant petroleum source rocks with the measured TOC values averaging less than 1% (Tverdova et al., 1992).

Figure 16. Prospect Map of the South-East Basin Margin, the North Caspian Basin

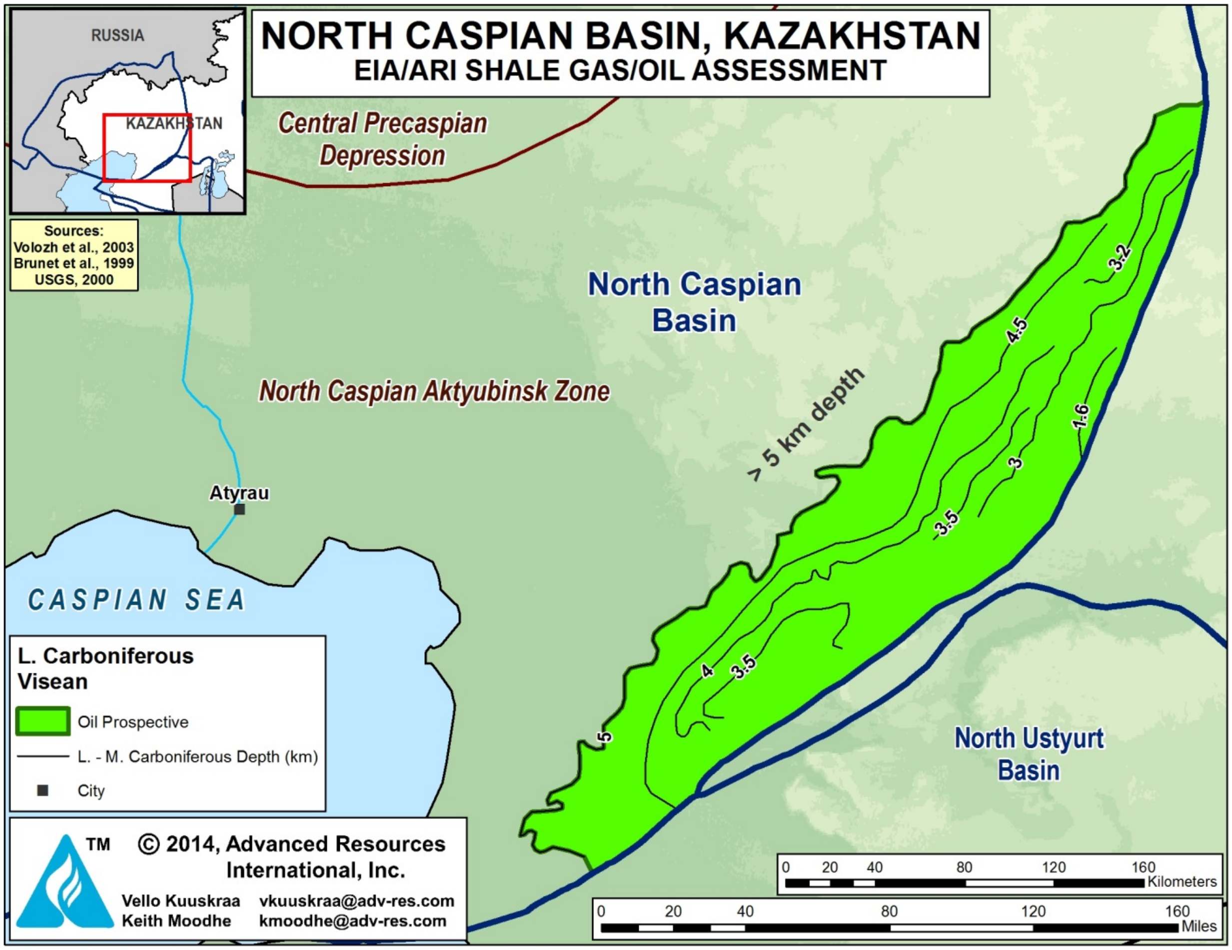
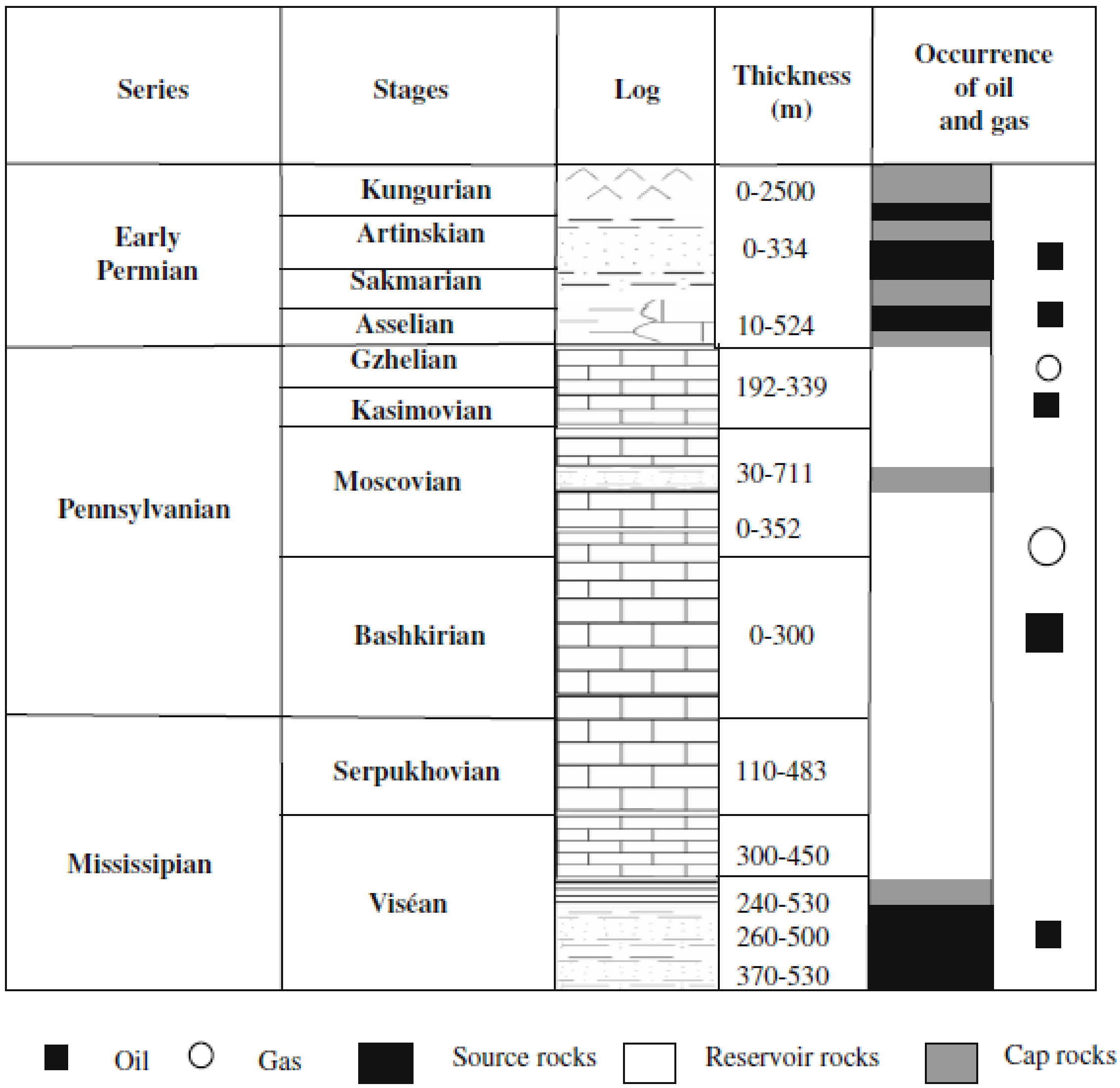


Figure 17. Stratigraphic Column for the South-East Basin Margin, the North Caspian Basin




Source: Yensepbayev et al., 2010.

### 1.B.2 Reservoir Properties (Prospective Area)

The depth of the reservoirs in the larger prospective area, as shown on Figure 16, ranges from 4,500 to 16,400 ft. Based on thermal maturity, we have included only the deeper portion of this larger prospective area in our resource assessment. The gross interval of the organically-rich section, while poorly defined, is extensive and has an estimated thickness of 1,640 ft. We used a conservative 20% net to gross ratio to establish 328 ft of net pay thickness.

We estimate an average TOC of 2% for the organically-rich portion of the net pay and a thermal maturity of 0.8%, placing the source rocks in the early oil generation window.

The subsurface geothermal gradient in this portion of the basin is low, averaging about $1^{o}$F/100 ft. We assume this basin area is normally pressured.

### 1.B.3 Resource Assessment

The prospective footprint for oil and associated gas resources in the South-East Basin Margin of the North Caspian Basin covers an area of 9,710 $mi^2$ (See Figure 16). Within the prospective area, the resource concentrations are 40 million barrels/$mi^2$ for oil and 37 Bcf/$mi^2$ for associated gas.

The oil/associated gas prospective area holds risked resources in-place of 125 billion barrels of oil and 116 Tcf of associated gas. The risked, technically recoverable resources are estimated at 6.3 billion barrels of shale oil and 12 Tcf of associated shale gas.

# 2. MIDDLE CASPIAN/SOUTH MANGYSHLAK BASIN

## 2.1 Introduction and Geologic Setting

The eastern portion of the Middle Caspian Basin contains the South Mangyshlak Basin that covers about 30,000 $mi^2$ with about 14,000 $mi^2$ onshore. The Kazakhstan portion of the South Mangyshlak Basin is bordered on the north by the Mangyshlak foldbelt that separates it from the North Ustyurt Basin. The basin is bounded on the west by the Caspian Sea, on the east by the Uzbekistan border, and on the on the south by the Karabogaz regional basement high and the Turkmenistan border, as presented in Figure 18.

Figure 18. Structure Map of the Basement, Middle Caspian Region, Mangyshlak Basin, Kazakhstan




Advanced Resources International, Inc.

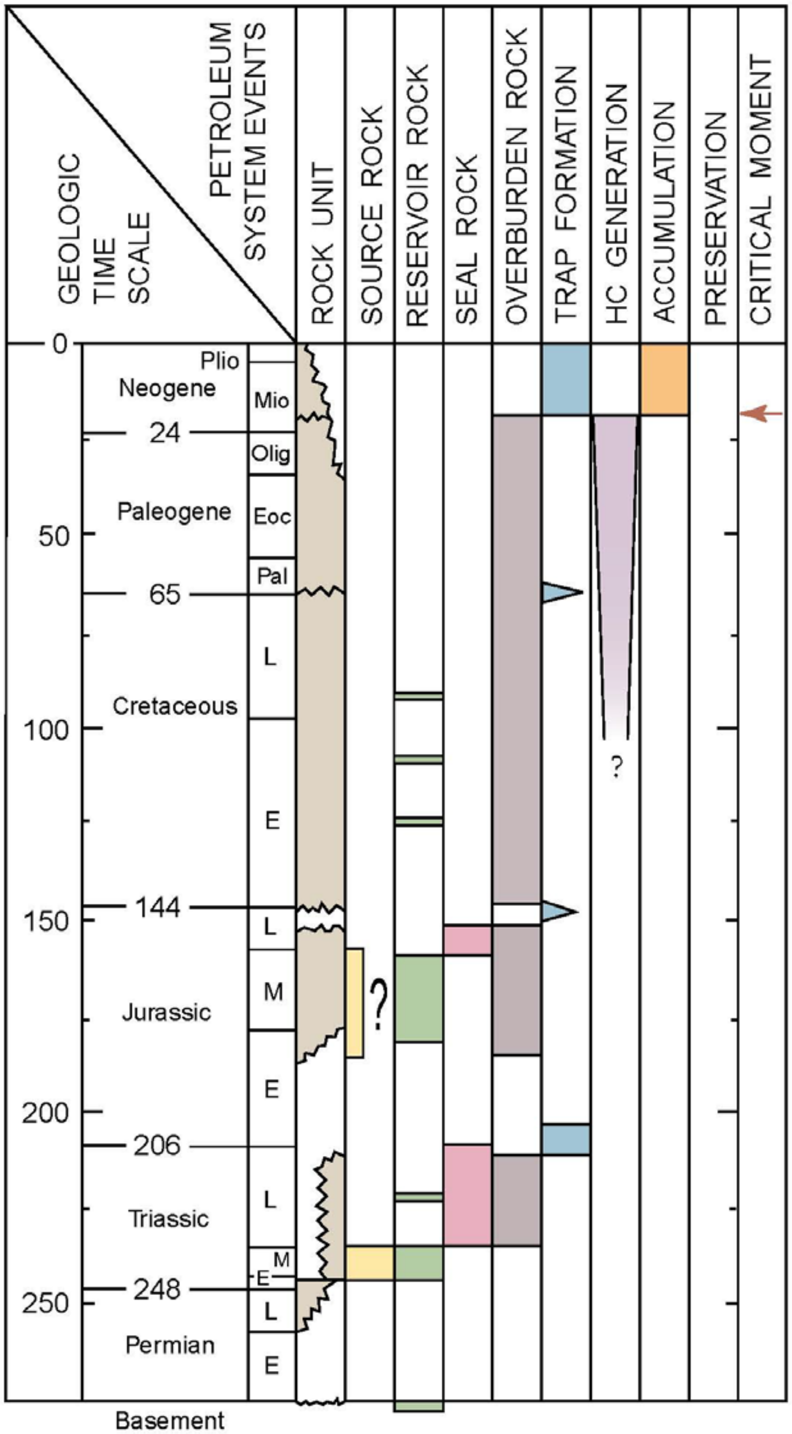
The South Mangyshlak Basin contains a series of oil and gas fields located primarily of i Middle Jurassic age, including the giant Uzen and Zhetybay fields. Subsequent exploration has discovered a number of additional medium and small oil and gas fields in Triassic rocks. The Triassic formations in the Mangyshlak Basin are highly deformed. The collision of the Mangyshlak and Ustyurt plates resulted in tangential compression and led to the formation of a series of linear mega-anticlines and mega-synclines.

Though the source rocks in the South Mangyshlak Basin have not been fully geochemically studied, the prevailing view is that the majority of the hydrocarbons in this basin were generated from Triassic source rocks (Timurziev, 1986). The stratigraphic column of the South Mangyshlak Basin (Figure 19) shows that age of the shale source rocks ranges from Early to possibly Middle Triassic. The main areas of source rocks in the basin, and thus the prospective areas defined by this study, are located in the Bekebashkuduk Anticline and Zhetybay Step in the northeast portion of the basin and the onshore portion of the Peschanomys Uplift in the western portion of the basin, Figure 20.

Two north-to-south cross-sections through the middle of the Mangyshlak Basin (cross-sections I and II, presented in Figures 21 and 22) demonstrate the presence of Lower Triassic ($Tr_i$) sediments in the uplifted structures, including the Bekebashkuduk Anticline, Zhetybay Step, and Peschanomys Uplift. In these three prospective areas the Lower Triassic sediments are thick and fit well within the depth window established for the study.

No oil and gas has been found in the depressions of the South Mangyshlak Basin, most likely because of the absence of Triassic source rocks (Ulmishek, 2001).

Figure 19. South Mangyshlak Stratigraphic Column




Source: Ulmishek, 2001.

Figure 20. Prospective Areas of the Mangyshlak Basin, Kazakhstan

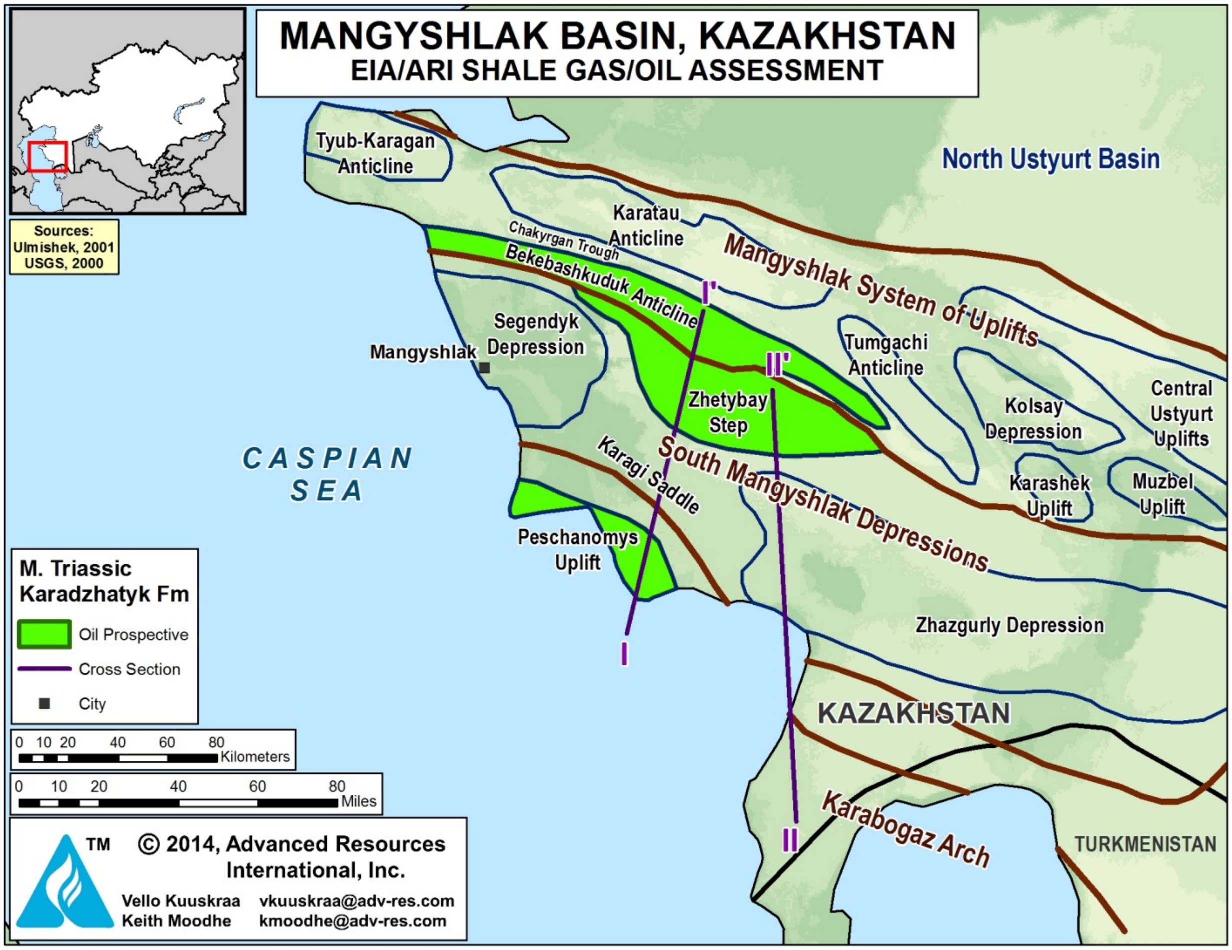
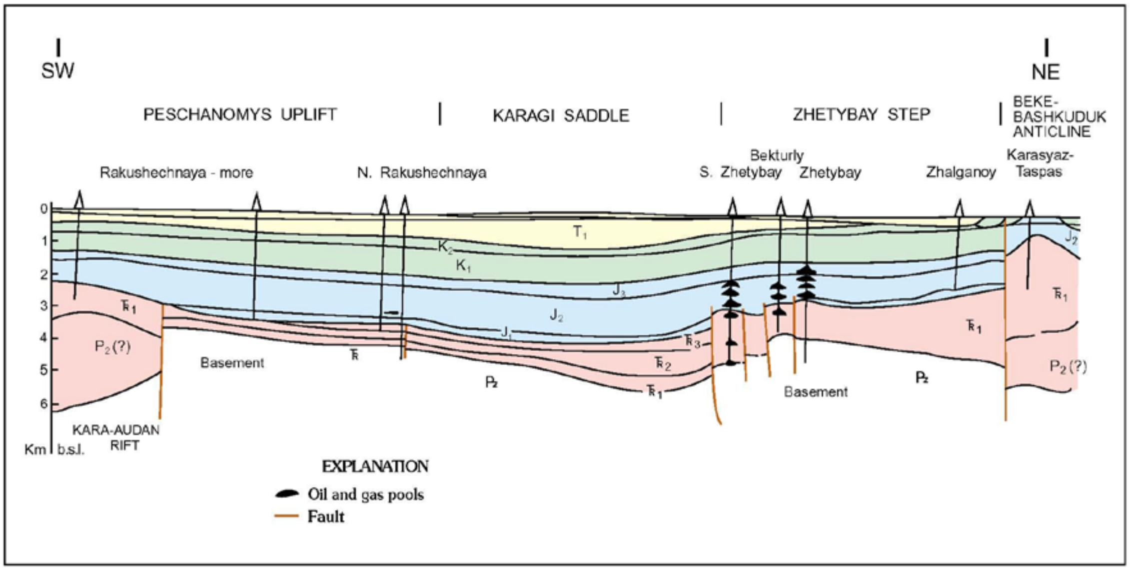
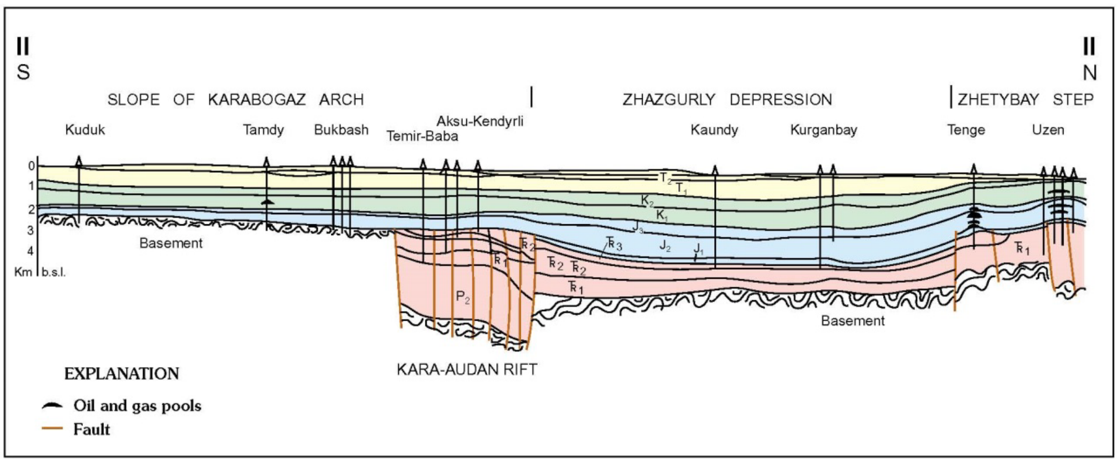


Figure 21. Cross-Section I-I' Through the Southern Part of the Mangyshlak Basin




Modified from (Orudzheva et al.,1985). Location shown in Figure 19. Pz, Paleozoic; P, Permian; TR, Triassic, J, Jurassic; K, Cretaceous, T, Tertiary. Subscripts 1, 2 and 3 denote lower, middle and upper respectively.
Source: Ulmishek, 2001.

Figure 22. Cross-Section II-II' Through the Southern Part of the Mangyshlak Basin




Modified from (Orudzheva et al., 1985). Location shown in Figure 19. Pz, Paleozoic; P, Permian; TR, Triassic, J, Jurassic; K, Cretaceous, T, Tertiary. Subscripts 1, 2 and 3 denote lower, middle and upper respectively.
Source: Ulmishek, 2001.


Advanced Resources International, Inc.

## 2.2 Reservoir Properties (Prospective Area)

According to the publically available data, the Lower Triassic Section composed of alternating shales, carbonates, and clastics, is about 2,500 ft (750 m) thick in the Zhetybay Step and 800 to 1,000 ft (250-300 m) thick in the Peschanomys Uplift (Ulmishek, 2001). We assume a gross thickness of 1,640 ft with a net to gross thickness of 20% for the organic-rich shales in the Lower Triassic section. The measured TOC contents of the shales reach 9.8% with typical TOC values ranging from 1 to 4%. (Shablinskaya et al., 1990).

The organic matter is dominated by Type II kerogen. The depth of the shale source rocks in the three prospective areas ranges from 6,600 to 16,400 ft (2,000 to 5,000 m), with the deepest Triassic shales present in the Zhetybay Step. The observed geothermal gradient is about 2.7$^{o}$F/100 ft (40$^{o}$C/km).

## 2.3 Resource Assessment

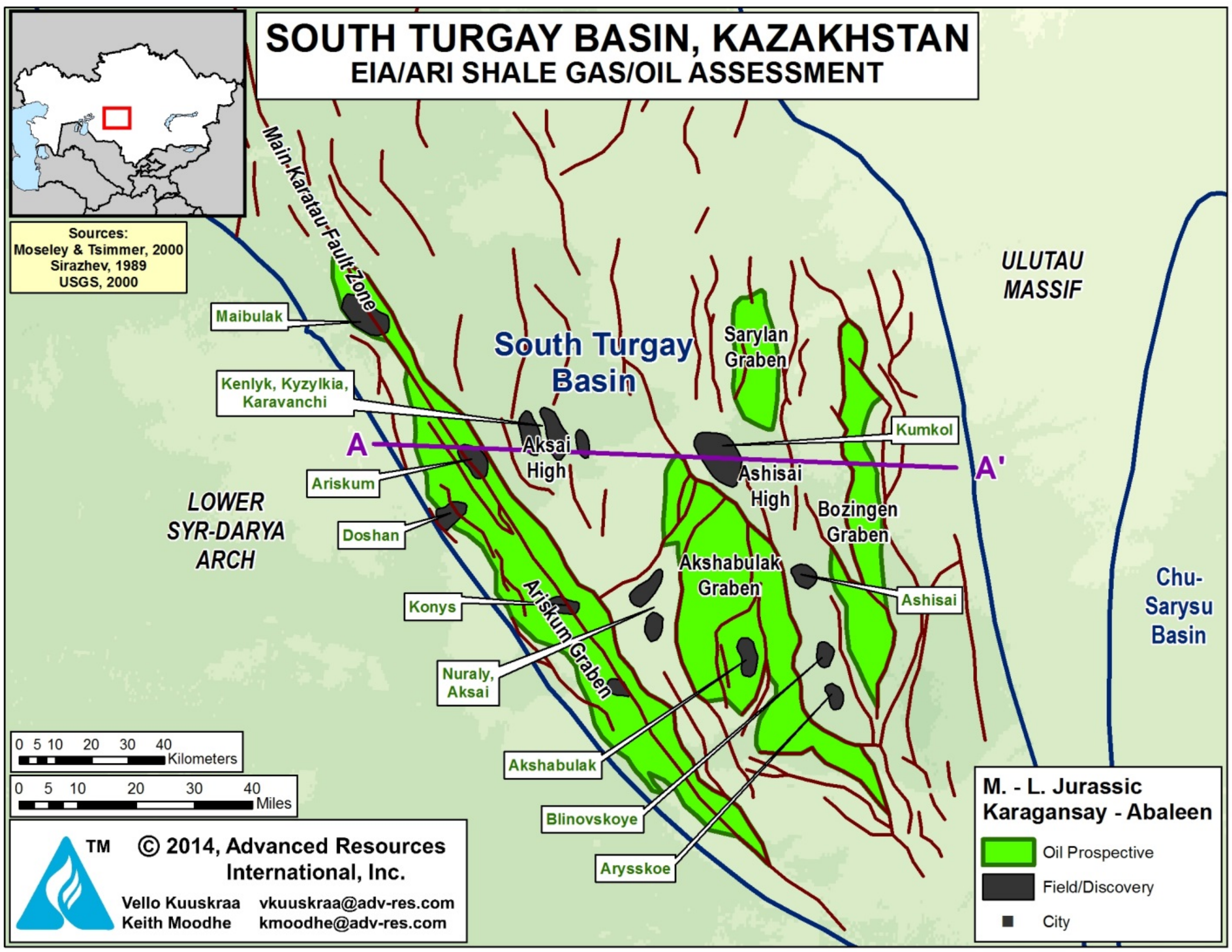
The 2,460 mi$^2$ prospective area for oil and associated gas in the South Mangyshlak Basin contains resource concentrations of 39 million barrels/mi$^2$ for oil and 32 Bcf/mi$^2$ for associated gas. The risked oil in-place is estimated at 39 billion barrels with a risked, technically recoverable resource of 1.9 billion barrels. The risked associated gas in-place is estimated at 31 Tcf, with a risked, technically recoverable resource of 3 Tcf.

# 3. SOUTH TURGAY BASIN

## 3.1 Introduction and Geologic Setting

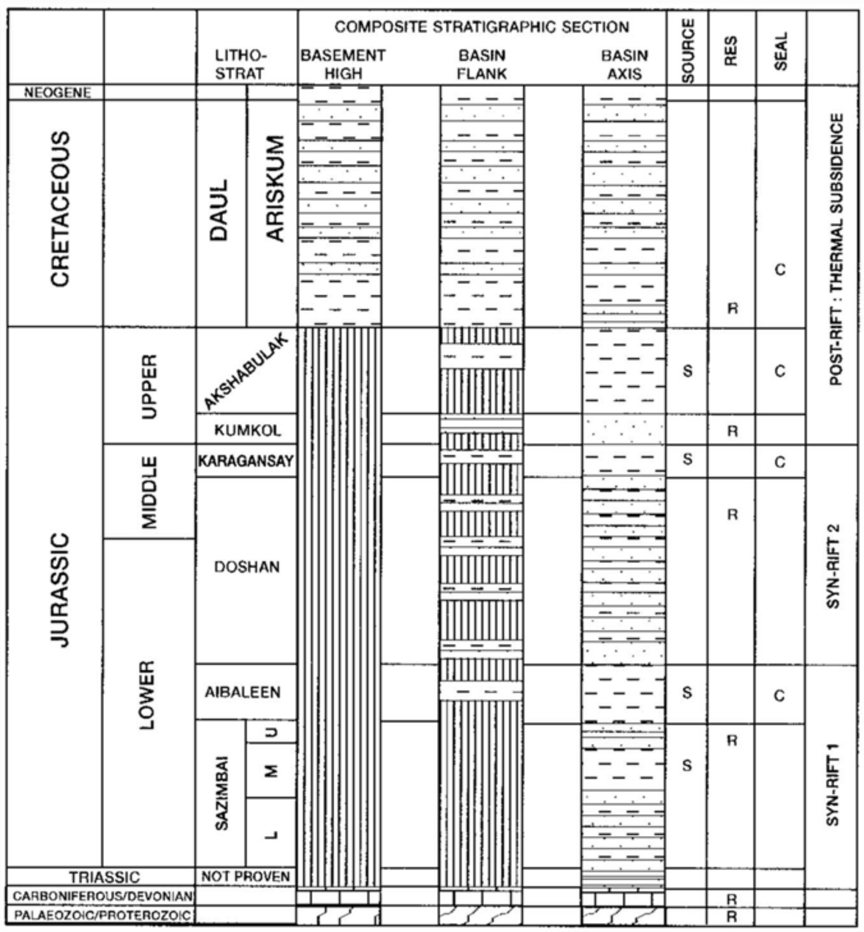
The South Turgay Basin located in central Kazakhstan covers an area of about 60,000 mi$^2$ (160,000 km$^2$; Effimoff, 2000). This triangular shaped basin is bounded in the southwest by the Lower Syr-Darya Arch, on the north by the Minbulak Saddle, and on the west by the Ulutau Massif, Figure 23. The strike-slip Main Karatau Fault (MKF) runs along the southwestern border of the basin, influencing many of the geological features in this basin. The basin contains the large Kumkol oil field estimated to hold a billion barrels of oil equivalent of reserves as well as a number of smaller oil pools.

Figure 23. Prospective Areas of the South Turgay Basin, Kazakhstan



The South Turgay Basin is an intracontinental rift basin containing Lower Jurassic to Lower Cretaceous lacustrine sediments overlying Pre-Cambrian metamorphics and Paleozoic rocks. The primary source rocks in this basin include Lower Jurassic Sazimbai and Aibaleen shales, as well as the Middle Jurassic Karagansay Shale and the Upper Jurassic Akshabulak Shale, as Figure 24 shows.

Figure 24. Stratigraphic Section of the Turgay Basin

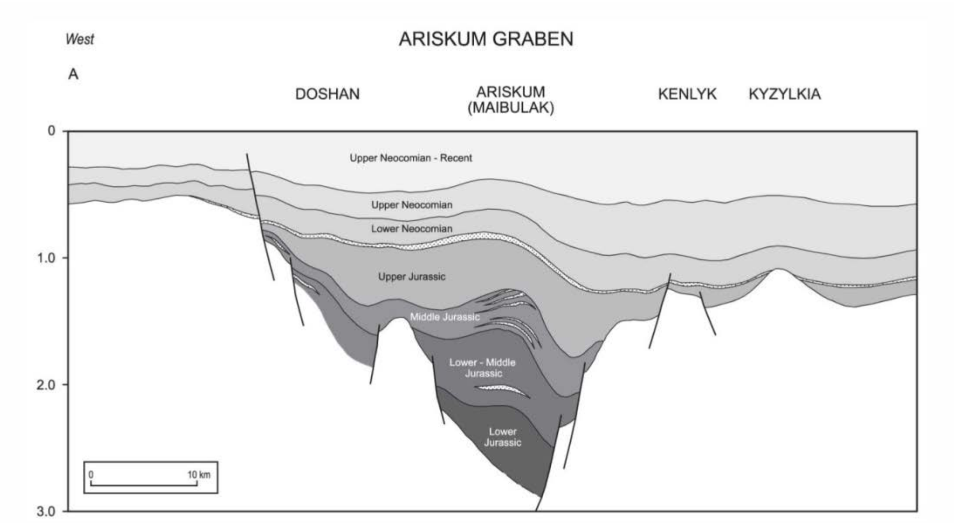



S, source; R, reservoir; C, seal.

Source: Mosley and Tsimmer, 1998.

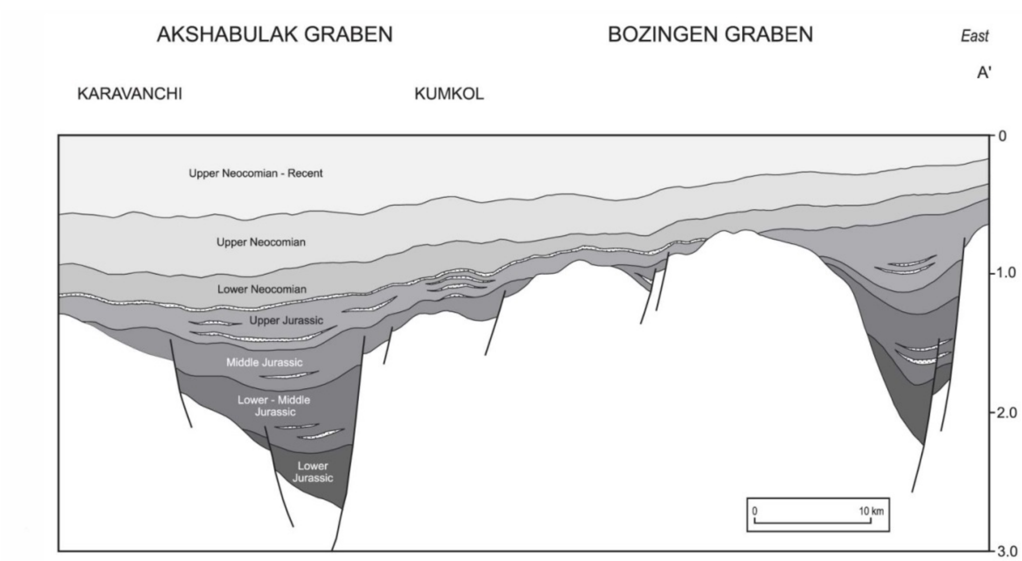
The Turgay basin encompasses four graben systems, including Ariskum, Akshabulak, Sarylan and Bozingen grabens. These graben structures are separated by basement highs and contain up to 16,400 feet (5,000 m) of primarily continental sediments. Figures 25A and 25B demonstrate cross-section views for the Ariskum, Akshabulak, and Bozingen grabens, including the deep Jurassic sediments at the base of the graben.

Figure 25A. Cross-Section through the Ariskum Graben




Source: Mosley and Tsimmer, 1998.

Figure 25B. Cross-Section through the Akshabulak and Bozingen Grabens




Source: Mosley and Tsimmer, 1998.

## 3.2 Reservoir Properties (Prospective Area)

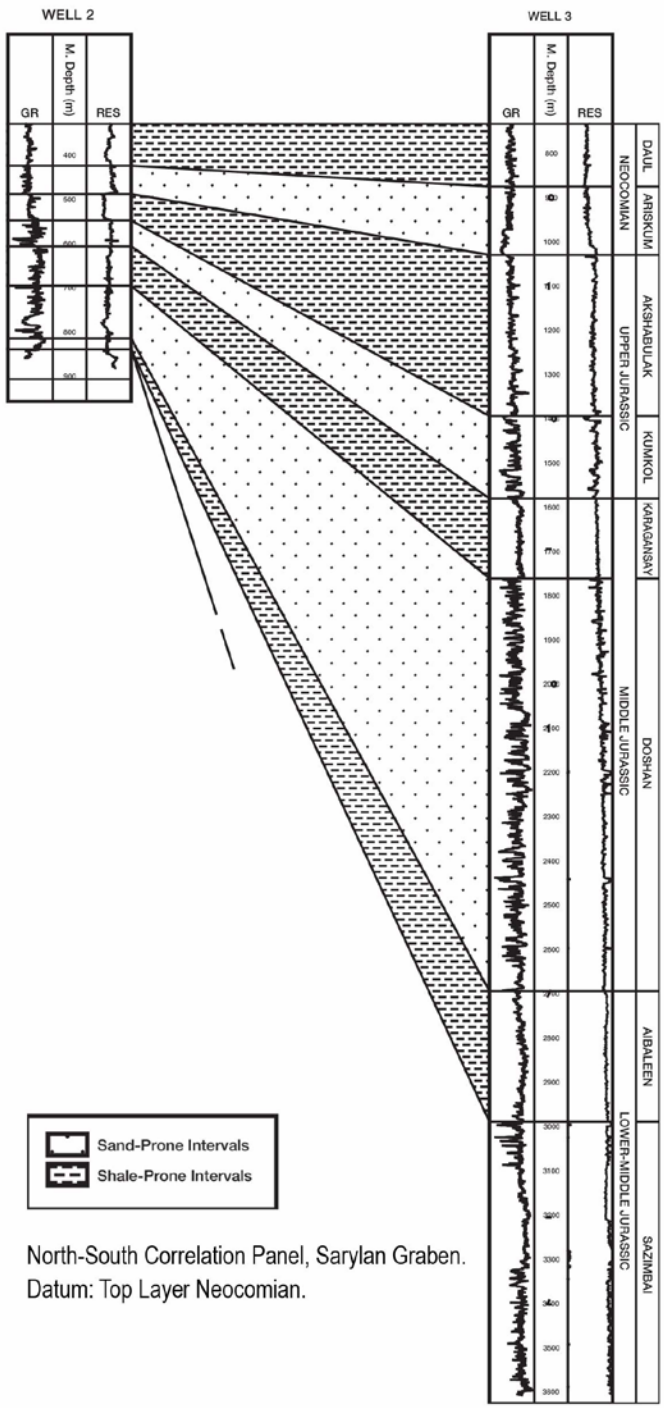
According to the scarce, limited open source data the Lower and Middle Jurassic (Aibaleen and Karagansay) lacustrine shales are the principal source rocks in the South Turgay Basin. These shales are considered to contain "high quality algal-rich kerogen in the graben centers" with high TOC. The kerogen is primarily Type I-II.

Basin modeling suggests that the Lower and Middle Jurassic shales enter the main oil generation below 7,300 to 10,000 ft (2,200 to 3,000 m). With a vitrinite reflectance gradient of 0.05% Ro per 1,000 ft, the Lower Jurassic shales enter the wet gas window at the base of the grabens. The shallower Upper Jurassic Akshabulak shale is immature even in the deeper graben areas.

While the Middle Jurassic Karagansay Shale lies at depth of 5,600 ft (1,700 m), the Lower Jurassic Aibaleen Shale is buried at depth about 9,200 ft (2,800 m) in the Sarylan Graben. Figure 26 presents a regional structure map of the top of Pre-Mesozoic (Neocomian) interval. The Aibaleen shale encompasses a thick 1,320 ft (400 m) interval. Based on limited gamma-ray log data, we estimate a net-to-gross ratio of 50% for the Karagansay and 30% for the Aibaleen.

The geothermal gradient in the basin ranges from 1.9 to 2.2$^{o}$F/100 ft (3.5-4.0$^{o}$C/100m). The produced oil is light (35 to 40$^{o}$ API) and sweet but has a high (10 to 15%) paraffin content.

Figure 26. North-South Correlation Panel, the Sarylan Graben.




Source: Mosley and Tsimmer, 1998.

## 3.3 Resource Assessment

The prospective areas of the organic-rich shales are limited to the graben-syncline of the Turgay Basin.

Karagansay Shale. The Middle Jurassic Karagansay Shale enters the top of the oil window of 8,200 ft (2,500 m) in deeper portions of the graben and thus is limited in its areal extent. Within the 2,280-$mi^2$ prospective area in the four grabens, the Karagansay has a resource concentration of 38 million barrels/$mi^2$ for oil as well as 29 Bcf/$mi^2$ of associated gas. The risked resource in-place for the oil prospective areas of the Karagansay is estimated at 27 billion barrels. With moderately favorable reservoir properties, but likely of high clay content, we estimate a risked, technically recoverable resource of 1.0 billion barrels for oil.

The Karagansay Shale contains associated gas, estimated at 20 Tcf of risked gas in-place including 2 Tcf estimated as the technically recoverable resource.

Aibaleen Shale. The Lower Jurassic Aibaleen is in the oil window in each of the four grabens. Within the 1,140-$mi^2$ prospective area, the Aibaleen has a resource concentration of 43 million barrels/$mi^2$ for oil plus 48 Bcf/$mi^2$ of associated gas. The risked resource in-place for the oil prospective area of the Aibaleen is estimated at 15 billion barrels. With moderately favorable reservoir properties but potential for higher clay content, we estimate a risked, technically recoverable resource of 0.6 billion barrels for oil.

The Aibaleen Shale also contains associated gas, estimated at 17 Tcf of risked gas in-place, with 1 Tcf estimated as the technically recoverable resource.

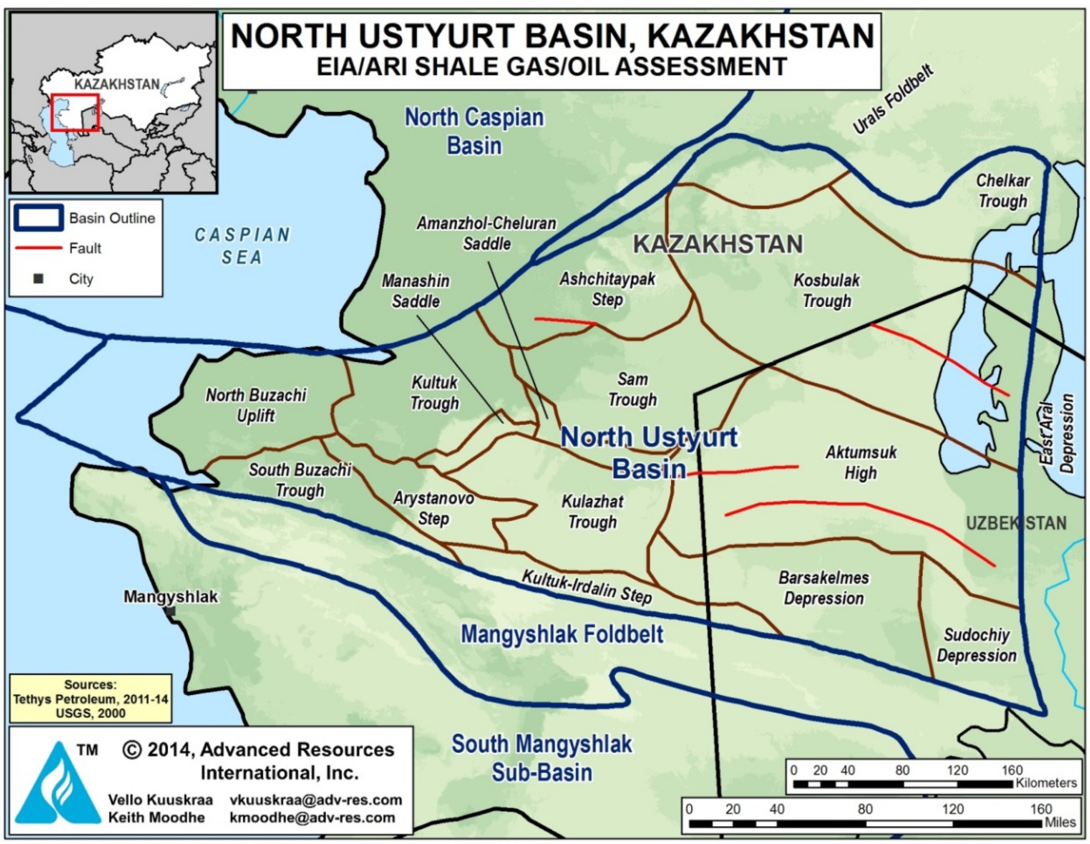
# 4. NORTH USTYURT BASIN

## 4.1 Introduction and Geologic Setting

The North Ustyurt Basin covers an area of about 56,000 mi$^2$ (145,000 km$^2$) with about 80% of this area located in Kazakhstan, as Figure 27 demonstrates. A series of shallow, heavy oil Jurassic and Cretaceous-age fields have been discovered along the western edge of the basin, including the large Karazhanbas Field, which holds about 500 million barrels of recoverable reserves.

The oil source rocks in this basin are not well documented. The discovered oil in the western part of this basin may have migrated from the Devonian and Permian organic-rich shales of the North Caspian Basin (Effimoff, 2000). Due to limited publically available data, the study does not provide a quantitative shale resource assessment for the North Ustyurt Basin.

Figure 27. Schematic Tectonic Map of the North Ustyurt Basin



# 5. CHU-SARYSU BASIN

## 5.1 Introduction and Geologic Setting

Known mostly for uranium and other mineral resources, the large Chu-Sarysu Basin also contains Middle Carboniferous (Visean) and Early Permian (subsalt) modest size oil and gas fields in its southern part, as shown in Figure 28.

The principle source rocks are Lower Carboniferous (Tournaisian) marine black shale and high organic-content Permian bituminous marls, as Figure 29 displays. The southwest-to-northeast schematic cross-section through the Chu-Sarysu Basin is presented in Figure 30. Paleozoic shales and locally hydrocarbon bearing sandstones and limestones comprise the sedimentary sequence of the Chu-Sarysu Basin. Due to limited publically available data the study does not provide a quantitative shale resource assessment for the Chu-Sarysu Basin.

Figure 28. Schematic Tectonic Map of the Chu-Sarysu Basin

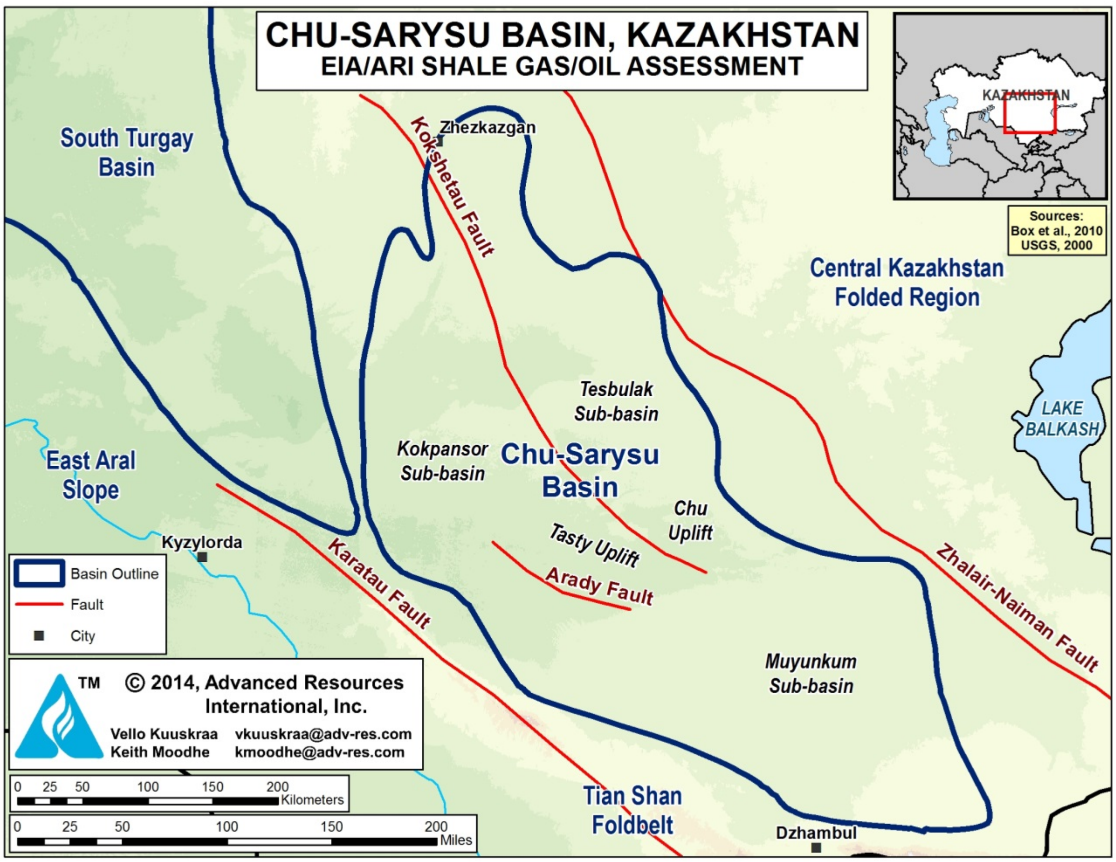
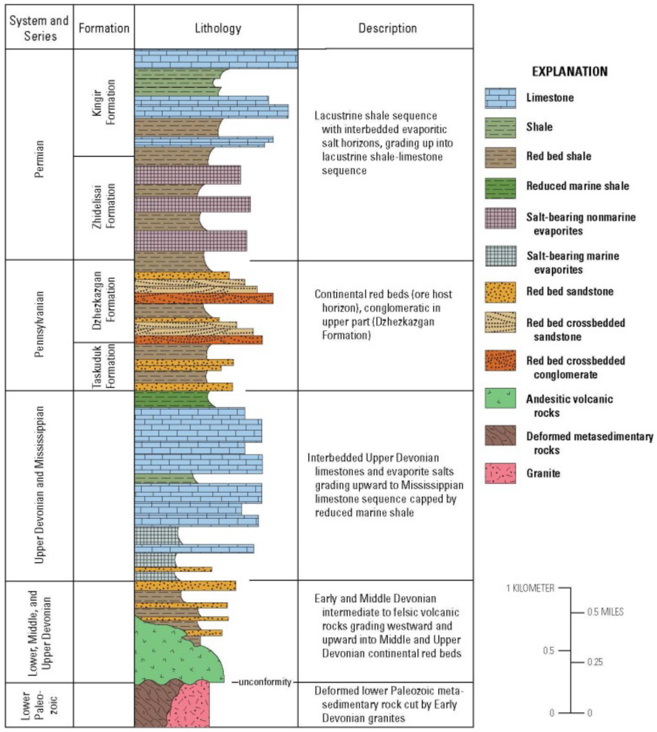
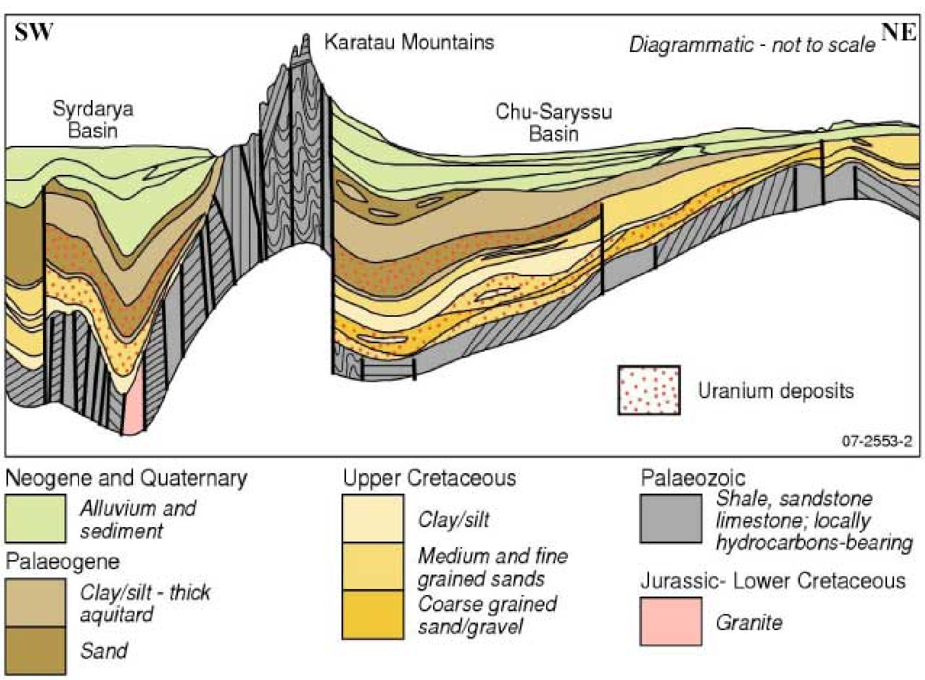


Figure 29. Generalized Paleozoic Stratigraphic Column of the Chu-Sarysu Basin, Central Kazakhstan




Source: Box et al., 2010.

Figure 30. Schematic SW-to-NE Cross-Section with Host Sequences through the Chu-Sarysu Basin, Central Kazakhstan




Source: Jaireth et al., 2008.

## REFERENCES


Akhmetshina, L.Z., Bulekbaev, Z.E., Gibshman, N.V., 1993. Devonian of the Eastern Flank of the Precaspian Syneclise (in Russian). Otechestvennaya Geol. 2, 42–48.

Arabadzhi, M.S., Bezborodov, R.S., Bukharov, A.V., and others, 1993. Prediction of Petroleum Potential of the Southeastern North Caspian Basin (Prognoz neftegazonosnosti yugo-vostoka Prikaspiyskoy sineklizy): Moscow, Nedra, 160 p.

Box, S.E. et al., 2010. Sandstone Copper Assessment of the Chu-Sarysu Basin, Central Kazakhstan, Global Mineral Resource Assessment, Scientific Investigations Report 2010–5090–E, U.S. Department of the Interior, U.S. Geological Survey.

Brunet, M.F. et al., 1999. The Geodynamic Evolution of the Precaspian Basin (Kazakhstan) Along a North–South Section, Elsevier Tectonophysics 313 (1999) 85–106.

Dalyan, I.B., 1996. Tectonics of Subsalt Rocks of the Eastern Margin of the North Caspian Basin in Connection with Petroleum Potential: Geologiya Nefti i Gaza, no. 6, p. 8–17.

Dyman, T.S. et al., 2001. Geology and Natural Gas Potential of Deep Sedimentary Basins in the Former Soviet Union, Geologic Studies of Deep Natural Gas Resources, Chapter C, U.S. Department of the Interior, U.S. Geological Survey.

Effimoff, I., 2000. Future Hydrocarbon Potential of Kazakhstan, AAPG, presented at the 2nd Wallace E Pratt Conference, Petroleum Provinces of the 21st Century, San Diego, CA, January 12-15.

Huvaz, O. et al., 2007. Petroleum Systems and Hydrocarbon Potential Analysis of the Northwestern Uralsk Basin, NW Kazakhstan by Utilizing 3D Basin Modeling Methods, Elsevier, Marine and Petroleum Geology 24 (2007) 247–275.

Jaireth, S., McKay, A., and Lambert, I., 2008. Sandstone Uranium Deposits Associated with Hydrocarbon-Bearing Basins: Implications for Uranium Exploration in Australia, Australian Government, Geoscience Australia.

Kuandykov, B.M. et al., 2010. Specifics of Geological Development of Caspian Block Structure, abstract from an oral presentation at AAPG European Region Annual Conference, Kiev, Ukraine, October 17-19, 2010, Search and Discovery Article #10309 (2011).

Maximov, S.P. and Ilinskaya, V.V., 1989. Physicochemical Characteristics and Hydrocarbon Composition of Oils and Condensates of the Soviet Union. Nedra Publication House, Moscow, 296pp (in Russian).

Mosley, B.A., and Tsimmer, V.A., 1998. Evolution and Hydrocarbon Habitat of the South Turgay Basin, Kazakhstan, presented at the EAGE Conference, Leipzig, June 1998. Petroleum Geoscience, Vol. 6 2000, p.125-136.

Orudzheva, D.S., Popkov, V.I., and Rabinovich, A.A., 1985. New Data on the Geology and Petroleum Potential of Pre-Jurassic Rocks of South Mangyshlak: Geologiya Nefti I Gaza, no. 7, p. 17–22.

Shablinskaya, N.V., Budanov, G.F., and Lazarev, V.S., 1990, Promezhutochnye kompleksy platformennykh oblastey SSSR i ikh neftegazonosnost (Intermediate Complexes of the Platform Regions of the USSR and Their Petroleum Potential): Leningrad, Nedra, 180 p.

Sirazhev, N. Zh., 1989. “Geologic History and Oil and Gas Potential of the South Turgay Syneclise”, International Geology Review, 31:11, 1173-1178, DOI: 10.1080/00206818909465969.

Tverdova, R.A., Bulekbaev, Z.E., and Dalyan, I.B., 1992, Geochemical characteristics and petroleum potential of Lower Carboniferous clastic rocks of the eastern North Caspian basin: Otechestvennaya Geologiya, no. 10, p. 3–9.

Ulmishek , G.F., 2001. Petroleum Geology and Resources of the North Caspian Basin, Kazakhstan and Russia, U.S. Geological Survey Bulletin 2201-B, U.S. Department of the Interior. U.S. Geological Survey.

Volozh, Y. et al. 2003. Salt Structures and Hydrocarbons of the Pricaspian Basin, AAPG Bulletin, v. 87, no. 2 (February 2003), pp. 313–334.

Yensepbayev, T. et al., 2010. Geochemical Characterization of Source Rocks and Oils from the Eastern Part of the Precaspian and Pre-Uralian Basins (Kazakhstan): Palaeoenvironmental and Palaeothermal Interpretation, Elsevier, Organic Geochemistry 41 (2010) 242–262.