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Tight gas development in the Mezardere Formation, Thrace Basin Turkey

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ABSTRACT

More than 600 m of Lower Oligocene and Upper Eocene marine sedimentary rocks contain tight gas resources in the Thrace Basin of Turkey. Positive hydraulic fracture stimulation results, along with the presence of many untested, off-structure stratigraphic traps, indicate there is a large potential for future tight gas development in the basin.

Extracting value from these complex set of reservoirs needs the use of state of the art technologies. Many companies have recognized that this theme requires the Asset Team project management methodology wherein geologists, geophysicists, engineers, log analysts, and other professionals come together to combine their skills and insight to better understand, measure and predict reservoir properties in low-permeability reservoirs and to use that information in resource evaluation, reservoir characterization and management.

This manuscript describes how such a multidisciplinary asset team approach was used to determine the petrography, reservoir and petrophysical properties of the tight gas reservoirs in the Thrace Basin Turkey. Geological details and detailed core studies were integrated into petrophysical analyses, along with mud logs to identify the unconventional pay zones for executing hydraulic fracture stimulation in the area. As a result, stimulations were designed to avoid frequent interlaced water-bearing sand stringers and resulted in numerous successful recompletions of the existing wells, drilling of vertical and horizontal wells with increasing recoverable reserve by over 40 Billion Standard Cubic Feet (BCF) in proved reserves during a 2 year project.

1. Introduction

Unconventional resources have been an increasingly important role in the Oil & Gas industry., Applying recent engineering techniques with integrated geological studies where the hydrocarbon resources are located, significantly increased proven reserves in the world. Although it has been widely recognized that the completion technologies and proven detailed assessment of the size and recoverability of each resource drive developing of unconventional plays, the project feasibility is based on the wells' initial production rates and short term recovery (Aybar et al., 2015). In contrast to the global industry concerns on developing unconventional resources based on market conditions, relying almost entirely on imports to meet domestic gas demand and relatively high gas prices in Turkey, made unconventional plays attractive for development in the Thrace Basin.

The Tertiary Thrace Basin is the most productive gas province in Turkey. Exploration in the basin started in the early 1960s with more than 600 wells being drilled as of year-end 2014. More than 15 natural gas fields varying in size, between 50 and 200 Billion Standard Cubic Feet (BCF) in Expected Ultimate Recovery (EUR), have been discovered. Although gas is the dominant hydrocarbon phase, oil is produced on the flanks of the basin in the Devecatagi and Kuzey Osmancik oil fields which have produced around 2 million barrels of oil (MMBO) mostly from the Sogucak limestone formation. In the offshore portion of the Thrace Basin, Kuzey Marmara field having 190 BCF Original Gas In Place (OGIP) has been discovered in the conventional hydrocarbon bearing Sogucak reefal limestone formation.

In this study, reservoir and geomechanical models were built using a combination of open hole well logs, seismic and core data. These models provided a way to predict the existence of "as yet undeveloped" new drilling locations or behind pipe intervals in

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existing wells that could be stimulated. The application of hydraulic fracturing stimulations on the tight gas targets identified by these studies were successful and economic production rates with resulting rapid cost recovery were achieved. In the Thrace Basin, three different horizons were determined to contain unconventional resource potential, including the Upper Mezardere Siltstone, Teslimkoy sandstone, and Upper Kesan sandstone.

Since the project was initiated, 55 single stage re-entry frac and an additional 22 vertical wells plug and perforation multi stage frac operations were performed. Additionally, 6 new horizontal wells were drilled and stimulated successfully. As a result of this achievement, recoverable reserves within the study area were increased by over 40 BCF in proved reserve category from YE 2012 to YE 2014 in addition to conventional reservoirs having produced over 400 BCF of natural gas production in the entire Thrace Basin.

2. Geological summary and depositional environmental

The Thrace Basin located in northwest Turkey is of Tertiary age and covers an area of more than 15,000 square kilometers. It is filled with Eocene to Pliocene (predominately marine) sediments. The basin is bound to the north by the Istranca Massif, to the west by the Rhodope Massif, the Sakarya paleo-continent to the south and the Marmara Sea to the southeast.

The gross sedimentary sequence of the Thrace Basin reflects transgression in the Eocene and then progressive regression of the marine depositional environment from the Early Oligocene. Deep marine clastics grade to shallow marine clastics and carbonates, then ultimately to deltaic and continental deposits that are mostly siliciclastic and volcanoclastic sediments up to 9000 m (29,500 ft) thick in the central part of the basin (Kopp et al., 1969; Turgut et al., 1983, 1991; Siyako, 2006).

The evolution of the Thrace Basin started after the collision of the Sakarya Continent with the Rhodope–Pontide Fragment in Late Cretaceous–Paleocene, this enabled initiation of transtensional stress which was responsible for the creation of necessary accommodation space for deposition of the initial Thrace sediments (Siyako and Huvaz, 2007). By the Early-Middle Eocene, normal basement faults had opened the basin and a transgressive marine encroachment resulting in the Middle Eocene sequence being deposited over the basement rocks. The fault controlled transgression reached its maximum extent in the Early Oligocene. Deep troughs were filled with deep water sediments and carbonate buildups developed on the northern shelf and other paleo-high areas. A period of volcanism in the Late Eocene-Early Oligocene resulted in tuff beds, which became interbedded with clastic sediments of the Hamitabat, Ceylan, and Mezardere Formations and was followed by a regressive cycle of the Osmancik, Danismen Formation in the Middle Oligocene-Early Miocene. Late Miocene-Pliocene tectonism and fault reactivation resulted in uplift and erosion of the northern and southern basin margins. Pliocene, non-marine sediments of the Ergene Group were subsequently deposited, completing the sequence (Fig. 2).

The Thrace Fault System (TFS), comprises a series of wrenched and reactivated northwest trending faults along the northern margin of the basin. Structural aspects of the Thrace basin are controlled by two NW–SE strike-slip faults in the north and WSW-ENE North Anatolian faults (NAF) in the south. Strike slip motion developed in the Late Miocene to earliest Pliocene along the TFS sets up the complex present day structuring of the northern basin margin.

The Eocene structures, which contain the Hamitabat gas field and Devecatagi oil field, trend in a WNW-ESE direction. However, Miocene structures containing the Tekirdag, Osmanli, Karacali, Umurca, Gocerler and Adatepe Fields are oriented in a NW-SE direction and are controlled by strike-slip fault zones with normal and reverse fault separations that can be mapped via cross-sections created utilizing interpreted seismic and subsurface data (Fig. 1A).

3. Tight gas reservoirs in Thrace Basin

Generally, the term “Tight Gas Reservoirs” is used in the industry to describe reservoirs having less than 0.1 millidarcy permeability and porosity ranges from 5% to 15% (e.g. Law and Curtis, 2002). Unlike the tight gas concept in the industry, reservoirs having less than 1.6 md permeability will not flow gas at commercial rates using conventional technologies in the Thrace Basin and require additional investments (i.e. hydraulic fracturing) to make completions commercially viable.

Historically, there were many stacked tight sandstone/siltstone reservoirs in the Mezardere Formation which were perforated and tested with minimal gas flow noted because of low permeability.

4. Tekirdag Field development

The study area is located in the southern portion of the Thrace Basin of northwestern Turkey. Like most of the folds in the Thrace Basin, the structures in the south were formed during Late Oligocene to Early Miocene time by collisional compression of the basin. High angle reverse faults with 25–100 m displacement are common in the study area and create folding and traps for Oligocene age clastic horizons in both conventional and unconventional type reservoirs.

The Tekirdag structure is the major gas field in the study area. Since 2003, 134 commercial gas producers out of 164 wells were drilled and total conventional cumulative gas production of 0.1 TCF was produced from 300 m to 700 m subsea depth in Danismen and Osmancik formations.

Although, many reservoir levels having hydrocarbon indications in Mezardere formation had been tested in the pilot area, they were temporarily abandoned as “uneconomic tight gas intervals” due to the lack of natural flow after perforations. Since well control and archived data are an essential starting point for the project in order to determine reservoir description and lithological (sand, shale, clay content, mineralogy, etc.) characterization in addition to such key reservoir controls such as porosity, permeability and water saturation which could be calculated from existing open hole logs and core data. BTD and DTD fields of the Tekirdag Field were targeted for the initial unconventional tests by engineers and geologists (Fig. 1B).

The main tight gas sandstone reservoirs occur in the lower part of the Mezardere Formation, with the formation itself being the source rock for hydrocarbon charging of the Danismen and Osmancik Formations. The Mezardere Formation is largely a prodeltaic facies in gradual transitional with the Kesan and Ceylan Formations and the overlying Osmancik Formation (Siyako, 2005; Moslow et al., 2014) (Fig. 2). The Mezardere lithology mainly consists of interbedded greenish to gray shales, siltstones marlstones, tuffites and fine grained sandstones indicating less tectonic activity and shallow to moderate deep marine depositional environment.

Although shales are the dominant lithology at the top of the Mezardere formation, the lithology becomes sandier through the lower parts where it can be observed that pore pressure gradient and mineralogy do not vary significantly. The sandiest part is referred to as the “Teslimkoy” Member of the Mezardere Formation and is mostly shallow marine to marginal marine, fine grained, subrounded with 8–12% porosity.

The Eocene-Early Oligocene aged Yenimuhacir Group (Mezardere Fm., Osmancik Fm., Danismen Fm.) outcrops in the southwestern part of the basin. The outcrops provide an opportunity to

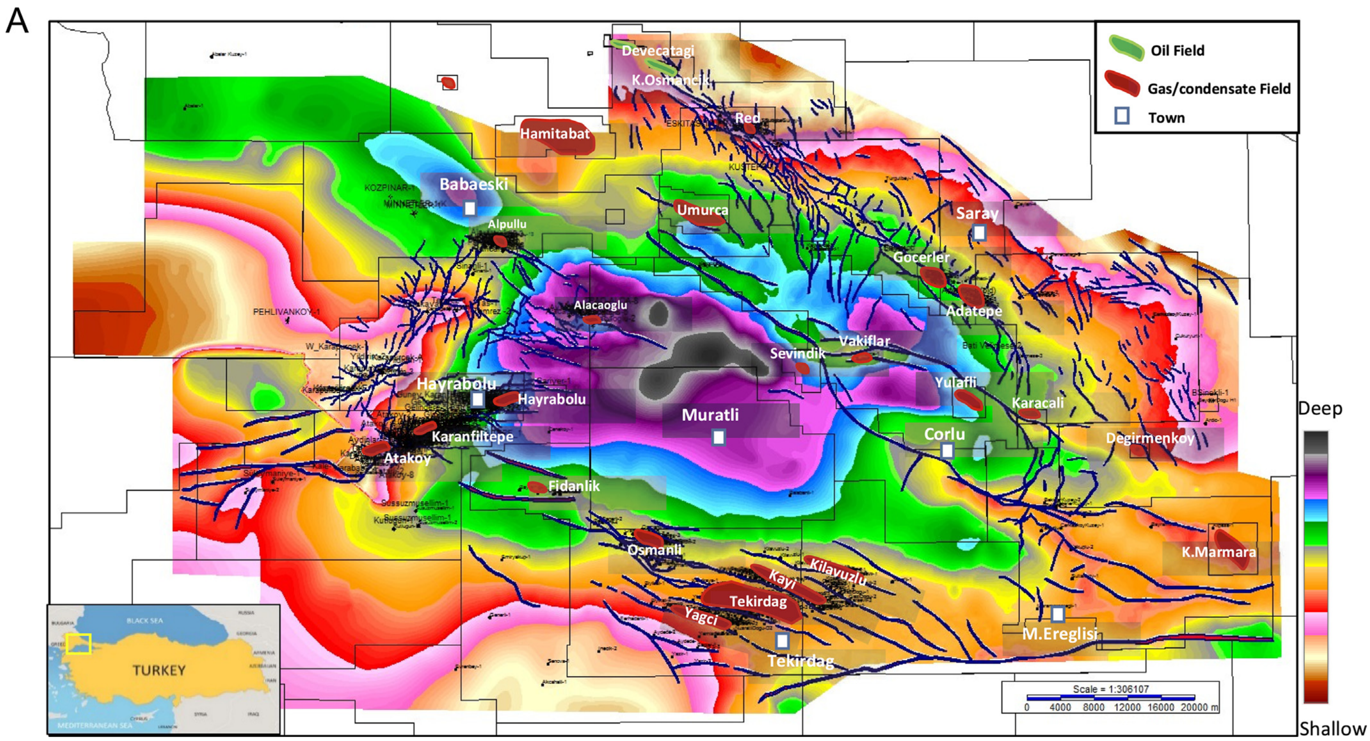

Fig. 1A. Location and structural map of Mezardere Formation showing oil and gas fields in the Thrace Basin. Tertiary sequence of mostly siliciclastic and volcanoclastic sediments is up to 9000 m thick in the central part of the basin.

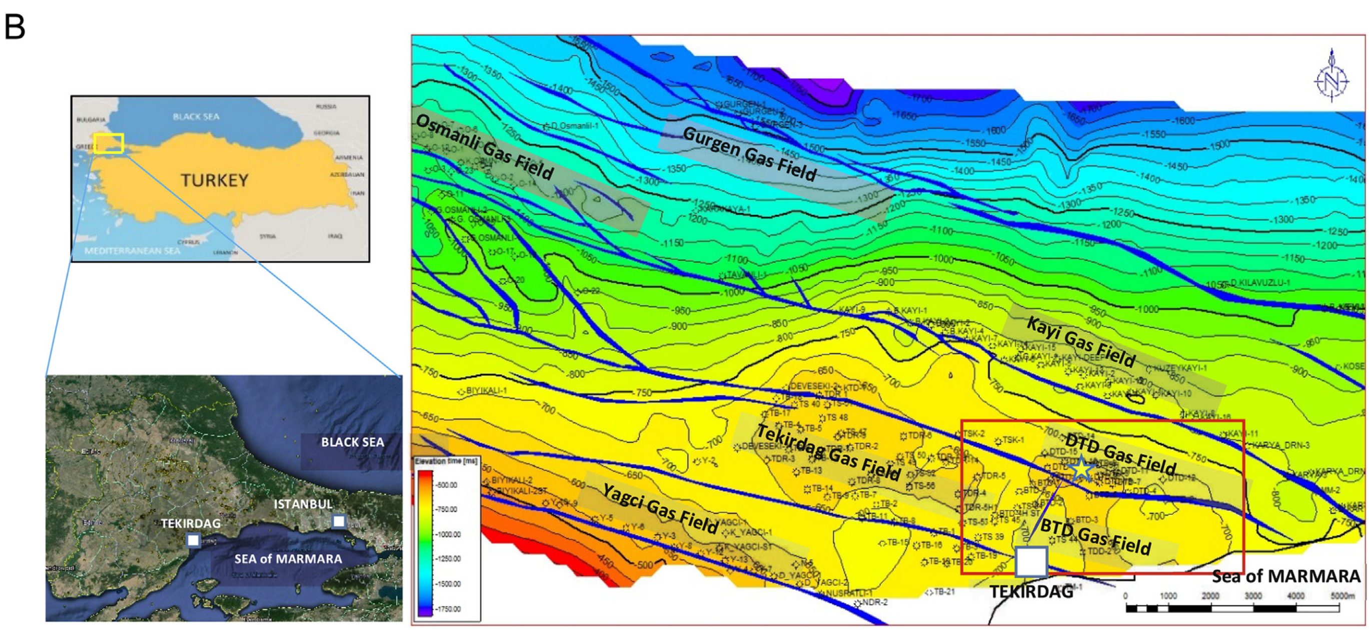

Fig. 1B. Structural map of Mezardere Formation showing gas fields in Tekirdag Region - South Thrace Basin. Study area (DTD-BTD Gas Field) is shown by polygon with solid red line. Baglik-1 well location is shown by yellow star. The cored interval within Baglik-1 well represents the general tight gas sand reservoir characteristics of the Teslimkoy Member. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

understand the stratigraphic and reservoir properties of the sandier tight part of Mezardere Formation (Fig. 3).

In the study area, the Teslimkoy member is highly variable in thickness based on the drilled well data in the southern portion of the Thrace Basin. Although the Teslimkoy Member pinches out to the east of the field, the silty Upper Mezardere section (encountered and completed as a secondary objective) has a larger areal extension compared to Teslimkoy sands (Fig. 4).

5. Petrography and reservoir properties

The first objective of the study was to develop an accurate understanding of the geological and petrophysical parameters necessary to identify potentially productive tight gas sands within

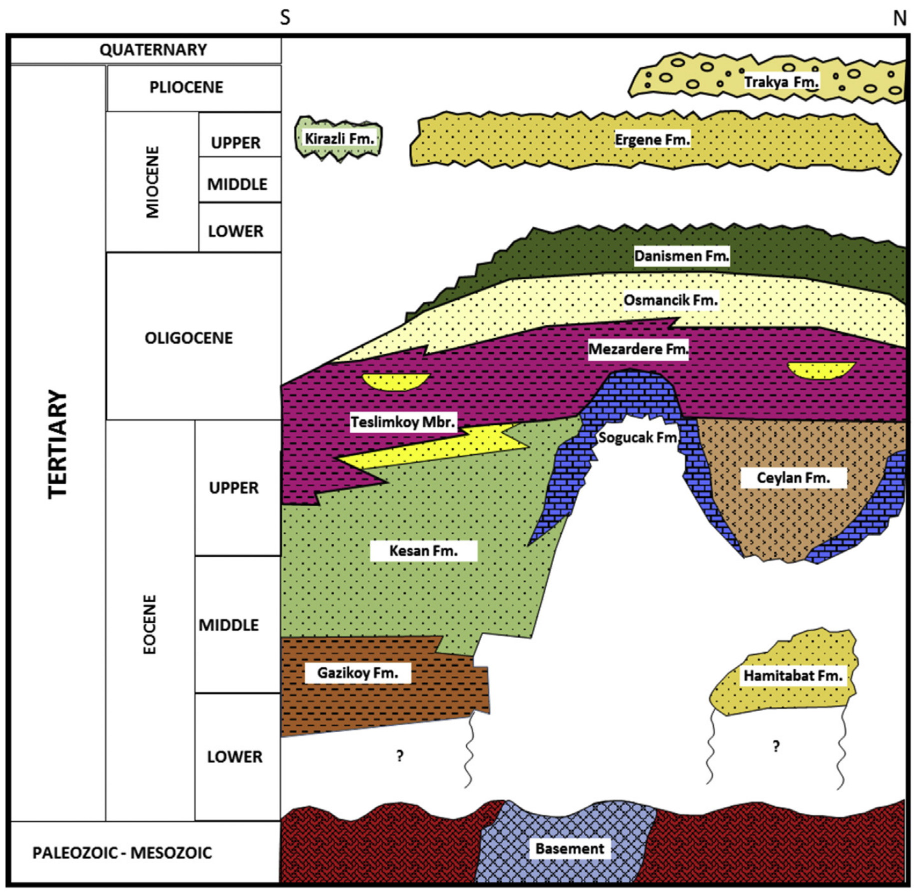

Fig. 2. Generalized Stratigraphic column of Thrace Basin. Middle to Upper Eocene Kesan Group in the southern Thrace Basin is often referred to as the Ceylan Formation in the northern Thrace Basin (modified from Siyako, 2005).

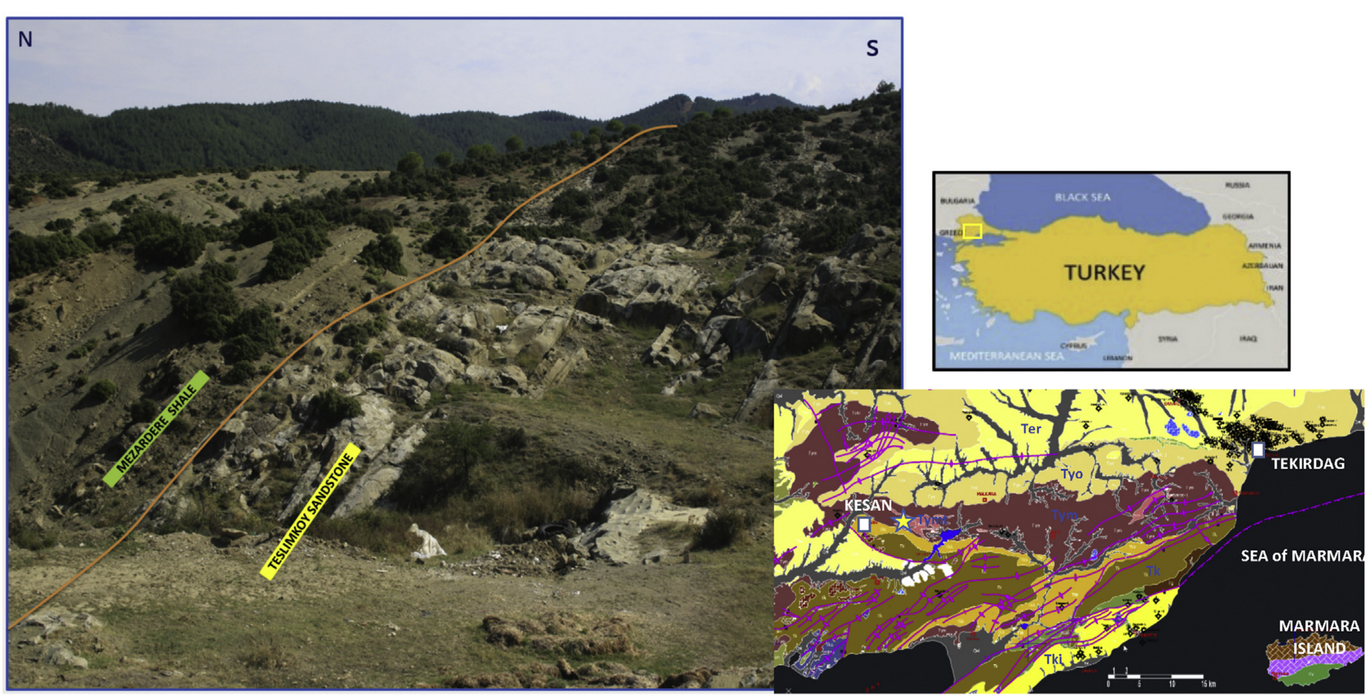

Fig. 3. Teslimkoy Formation outcrops in Yenimuhacir village located 6 km east of Kesan and 78 km southwest of Tekirdag. Sands are mostly shallow marine to marginal marine deposits and fine grained, sub-rounded to sub-angular and moderately to well sorted with intergranular and grain moldic porosity 8–12%. Outcrop location was shown as a yellow star on surface geology map showing exposed formations at the surface and folding with faults (Tk: Kesan Fm, Tymt: Teslimkoy Fm, Tym: Mezardere Fm, Tyo: Osmancik Fm, Ter: Ergene Fm, Tki: Kirazli Fm). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

the target sequences. The structures within the study area were initially mapped in light of known depositional sequence stratigraphy using 3D seismic data, existing well logs and production data. Structure maps of the reservoir levels in the study area show that hydrocarbon bearing zones are typically located proximate to NW–SE trending fault assisted 4 way closures (Fig. 5).

Conventional logging tools are used to reveal porous and potentially permeable areas zones in a given section. Water saturation evaluations using resistivity values and porosity were found to be challenging in shaley/silty areas which were believed to contain tight gas potential. Because of the proximity of many high water saturation zones to zones believed to be gas bearing, it was impractical to expect that all such sand bodies could be eliminated from being stimulated by fracs migrating out of target zones. In the Mezardere and Kesan Formations, more than 20 thin potential layers (with over 6% effective porosity cut off) are often encountered which may variously contain dry gas and mobile water. These zones were initially identified in wells drilled by less dense KCL polymer muds, which allowed for the direct detection of gas bearing zones by wellsite geologists aided by mud logs (gas chromatographs, cutting inspection, etc.), and Geolograph parameters (WOB, ROP, etc.).

An example mud log response is shown in Fig. 6 for the Upper Mezardere siltstone reservoir. In this case, there is no significant reservoir and hydrocarbon indication on wireline logs for the siltstone section in Upper Mezardere Formation but the mudlog's ROP, lithology analysis and total gas curves exhibit the presence of hydrocarbons – often referred to as "a show". The interval featured in the composite log below is from a well 4 km NW of the Tekirdag Field and after performing a single stage hydraulic frac stimulation on the interval, the production rate after 30 days of production was 1.2 MMCFD.

Water saturation occupies pore space and thereby shrinks potential gas reserves. The presence of water in the pore throats also has a negative effect on the effective permeability to gas resulting in a reduction of the ability of gas to flow through the rock, often

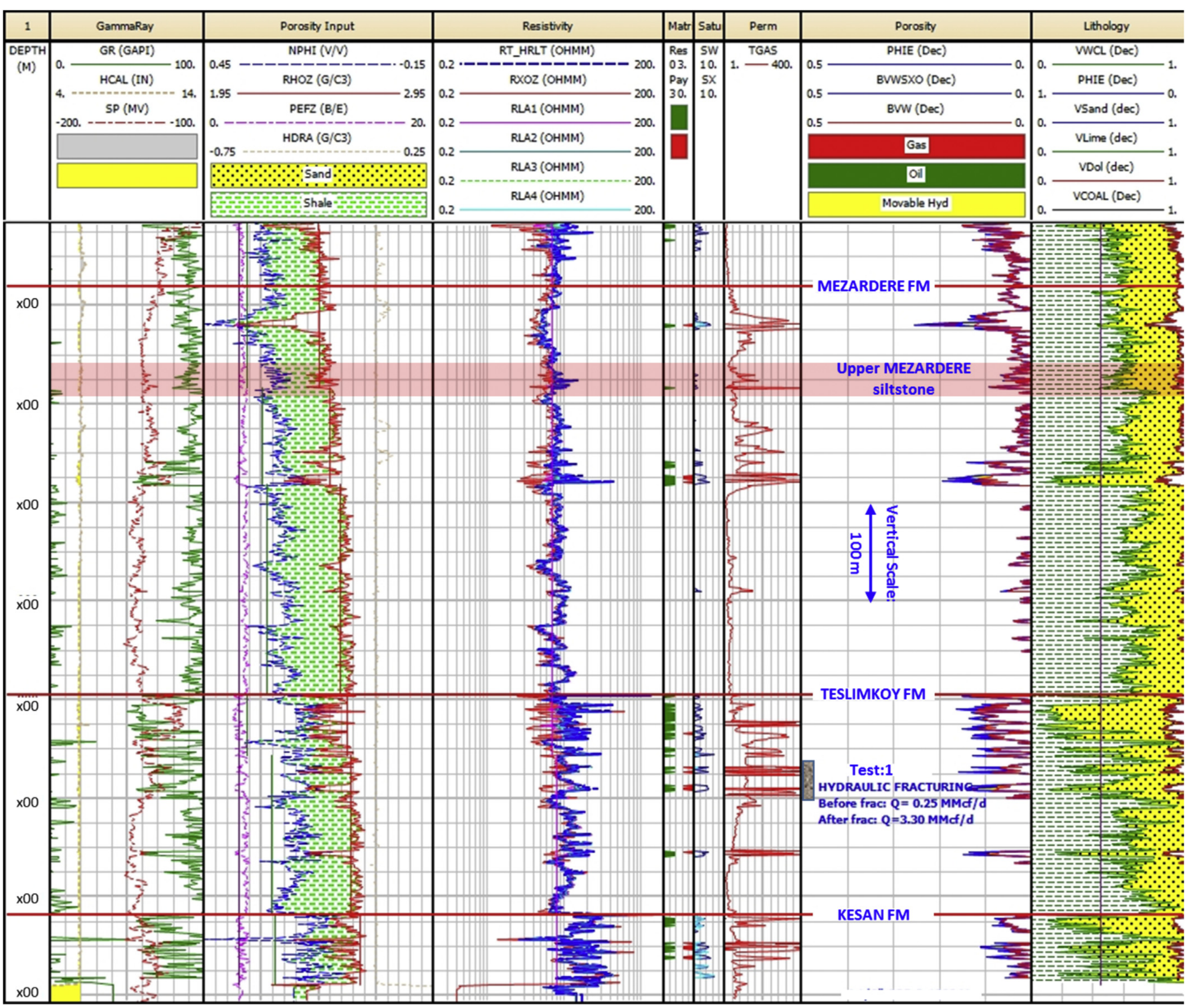

Fig. 4. Sample composite log showing the open hole log responses and formation tops of the tight gas target zones in the study area. Teslimkoy Member which is 200 m in thickness is located below 400 m of shaley part of Mezardere Formation. Silty part of upper Mezardere Formation varies from 17 m to 22 m in thickness and has better correlation with offset wells in the study area.

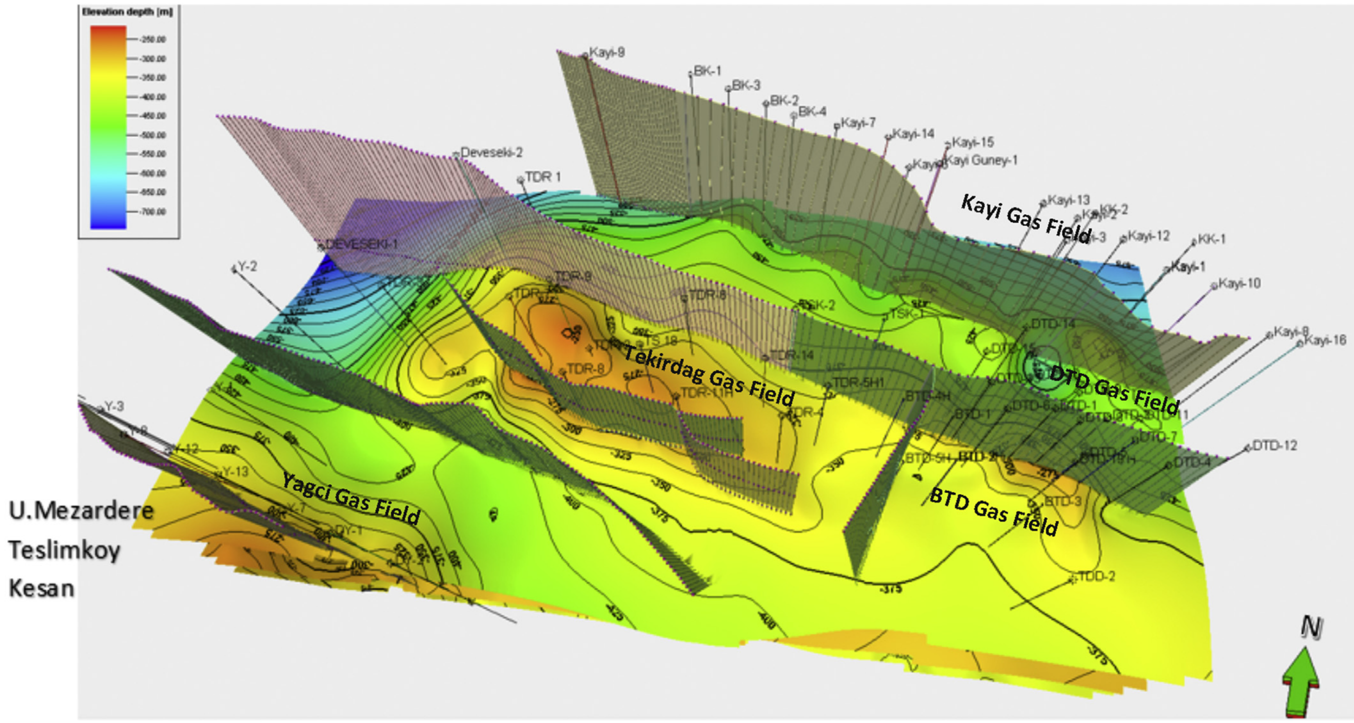

Fig. 5. Structural map of the study area shows that hydrocarbon bearing zones are NW–SE trending and fault assisted 4 way closures. 3 interpreted reservoir levels (Upper Mezardere, Teslimkoy and Kesan) have similar structural trend and parallel closure geometry. Faults have high dip angle (>75°) with 100–25 m displacement and generally trend to NW.

resulting in gas flow rates which are below the economic limit for successful production. Once potential gas bearing zones were identified, water saturation studies (Sw) were conducted to identify practical cutoff values of key input variables used in various shaley sand saturation equations.

Once the initial water saturation is more accurately determined for all layers, stimulation design can be made to avoid completions which could communicate with high water saturation zones. Helping mitigate the situation, however, is that often, the low absolute permeability in tight gas reservoirs will not permit significant water production rates by way of the inherent low permeability of the zones.

Sw calculations were initially made using deep (true) resistivity values obtained from logs by employing a model relating to porosity, connate-water resistivity, and rock properties. Table 1 represents the water resistivity (Rw) values used in the tight gas evaluations.

In studying of tight reservoirs, very small excursions utilizing gamma ray (GR) and spontaneous potential (SP) log curves may be meaningful. Non-reservoir and reservoir lithologies are easily distinguished from one another utilizing GR and SP logs in combination with various density, neutron and sonic porosity tools. SP responses develop as a result of a streaming potential which develops when mud hydrostatic pressure is greater than that in the formation causing mud filtrate with a different salinity than the formation water to invade the formation. Depending on whether or not the mud filtrate salinity is greater or less than that in the formation will dictate the direction of the deflection from values measured in the bounding shales above and below the permeable sand (the latter is used to create the Shale Base Line or "SBL" from which the deviation caused by the SP can be quantified). The amplitude of the deflection from that in the boundaries can, in a known water bearing sand, be used to calculate an apparent water resistivity or "Rwa". The presence of hydrocarbons has an insulating effect within the pores, forcing the electricity to travel a more circuitous route from one node detector on the logging tool to the other, resulting in a suppression of the spontaneous potential response amplitude.

KCL-Polymer muds have been used for drilling operations in the basin since the 1980's to help improve wellbore stability by inhibiting reactive or water sensitive clays exposed by the drill bit. The system is non-dispersed and has multiple inhibition mechanisms. The potassium ions, encapsulation polymers, low fluid loss agents and glycol combine to provide a suitably inhibitive environment that minimizes the hydration of reactive clays in shale formations. The cation exchange of the potassium with ions on active sites on the water sensitive formation clays is the key mechanism which reduces the swelling tendency of those clays.

Research (by Gucuyener and Celik, 2013) indicated the amount of KCL actually needed in completion fluids to inhibit activation of most of the clays encountered in drilling the subject targets in the Thrace Basin is in the 1–4% range by weight (35,000–50,000 ppm salinity). The use of KCL additives further ties up water molecules contributing to shale and hydrate inhibition.

For drilled wells using mud saltier than formation water, the SP curve deflects to the right of the SBL. Again, because of the nature of the mechanism by which the streaming potential is created, the detection of any such potential implies some difference in resistivity of mud filtrate into formation saturated with formation brine of different salinity. Such invasion implies permeability, hence the SP log is useful to assist in the qualitative detection of permeable beds within the body of the formation. As mentioned before, The SP is a deflection from the SBL in a water bearing zone is useful for verification of formation water resistivity (Rwa), as well as determining the volume or thickness ratio of permeable zones to that of the overall host formation thickness (often called the "Net

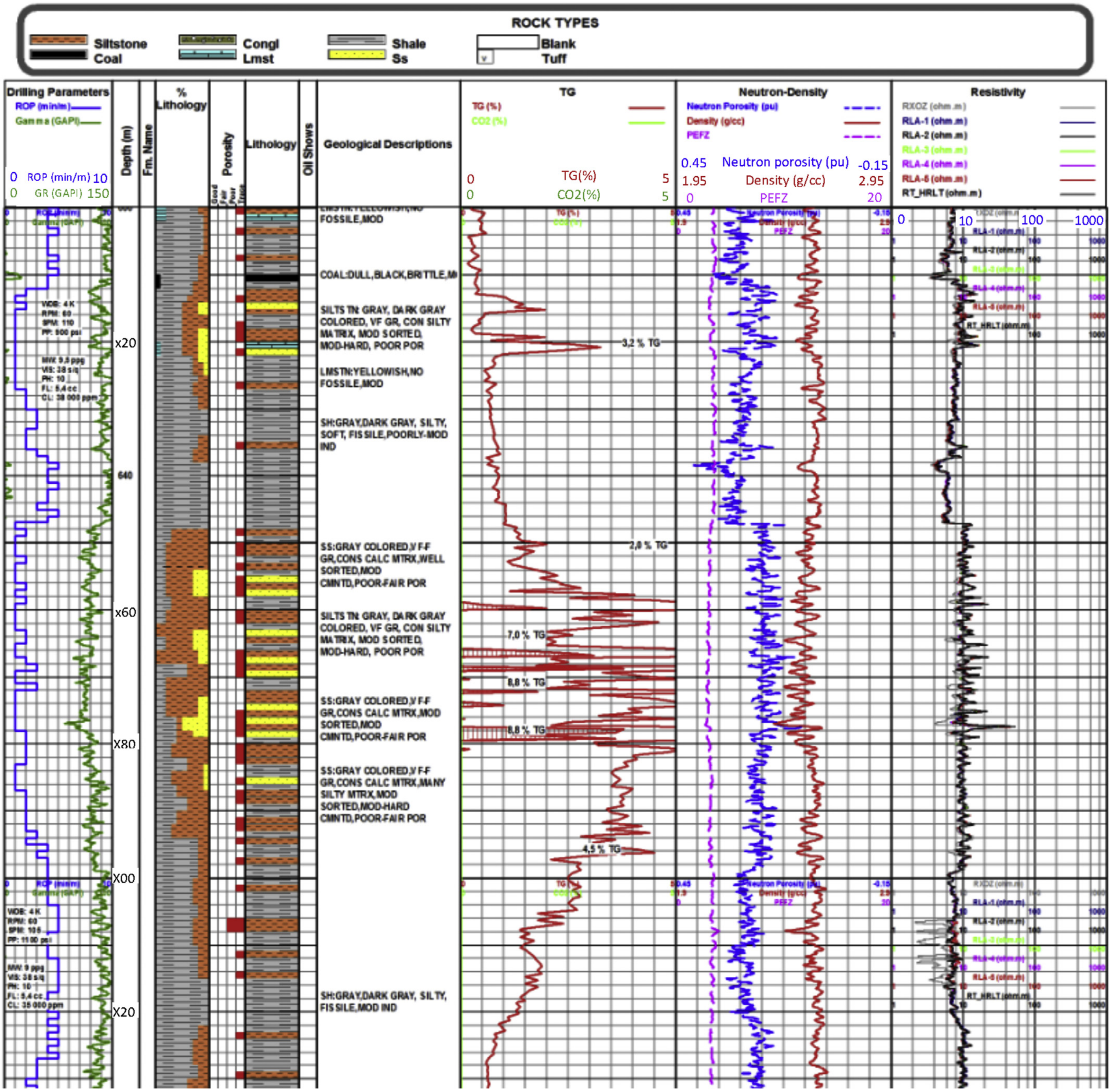

Fig. 6. Sample composite logs for upper Mezardere siltstone reservoirs displaying ROP, lithology, gas measurement (only total gas), cutting descriptions, drilling/mud parameters with existing open hole wireline logs (GR, density, PEF, porosity, and resistivity). During drilling at near-balanced condition, an increase in ROP was accompanied by increasing siltstone, sand content and a gas show which reached to 8.8% of total formation gas.

−to-Gross" ratio).

The implication of the presence of hydrocarbons by the suppression of the SP curve below what would have been normally expected given the relative salinity ratios of mud filtrate to formation water is another beneficial use of the SP log response. Comparison of SP responses in a correlated sand across a structure may reveal the Gas-Water-Contact (GWC) or transition zone wherein the "HC" suppression disappears down dip. Below the GWC, the SP deflection becomes the maximum possible. Given knowledge of the maximum expected deflection along with a prior knowledge of Rw, Rmf (resistivity of the mud filtrate) at formation temperature, the likely the presence of a water-saturated zone can be verified. As a result of a number of other unknown variables affecting the development of the SP response, this is only a qualitative approach useful to detect wet vs. gas bearing intervals. An example log response is shown in Fig. 7. In this case, it can be seen that the SP changes within the same zone. The GR readings decrease toward the bottom of the sand where cleaner sand was detected and recorded on the mud-log, however there are no corresponding changes noted in measured resistivity values. Many factors affect the SP and it is difficult to identify dry gas bearing layers directly using this method alone, but this often is useful to

Table 1
Formation water resistivities (Rw) for tight sandstone reservoirs in Thrace Basin.

Formation	Water resistivities (Rw)
Shallower	Rw = 0.70 @ 75 deg F (8000 ppm NaCl)
Teslimkoy	Rw = 0.41 @ 75 deg F (14,000 ppm NaCl)
Kesan	Rw = 0.38 @ 75 deg F (15,400 ppm NaCl)

detect thin potential gas bearing zones near the top of the layer with water present in the bottom.

In developing the tight gas concept for the basin, core studies were conducted on full diameter and plug cores taken from newly drilled wells which penetrated both conventional and unconventional targets. Two full diameter cores and a set of sidewall cores were collected from the Upper Mezardare, Teslimkoy and Kesan formations in a one deep well. Relatively complete core studies were performed including the measurement of rock and reservoir data using X-ray diffraction (XRD) to determine lithology (including clay types) and geomechanical testing to determine various properties such as bulk modulus, Poison's ratio, compressibility, etc.

The petrographic analyses of Teslimkoy Formation included point count analysis performed on seven thin sections from full diameter cores are shown in Fig. 8. The mineralogy of the Teslimkoy Formation samples identifies the sandstones as moderately and well sorted feldspathic litharenite.

The XRD data for the reservoir cores are presented in Tables 2 and 3. Measured mean grain size varies from 0.125 mm to 0.195 mm (mid-medium sand). Average mean grain size for eight analyzed samples is 0.164 mm (lower - mid fine sand). Coarse silt size to lower very fine sand size clasts represent the smallest measured grains. Maximum measured grain size ranges from upper fine sand to upper medium sand.

Non-clay minerals form 90.9%–94.5% of the eight Teslimkoy

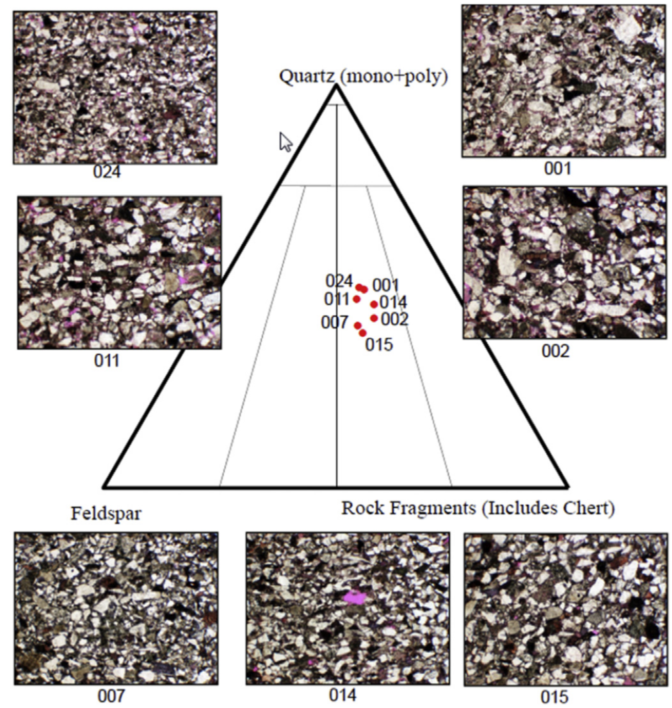

Fig. 8. Ternary classification (Q, F, R) diagram, for Teslimkoy Formation, full diameter core in Baglik-1 well. Point counting identified Teslimkoy sandstones as feldspathic litharenites.

Formation samples analyzed. Bulk XRD results indicate quartz is the principal mineral in all samples, forming 52.2%–72.9% of the bulk fractions. Petrographic analyses show quartz occurs as

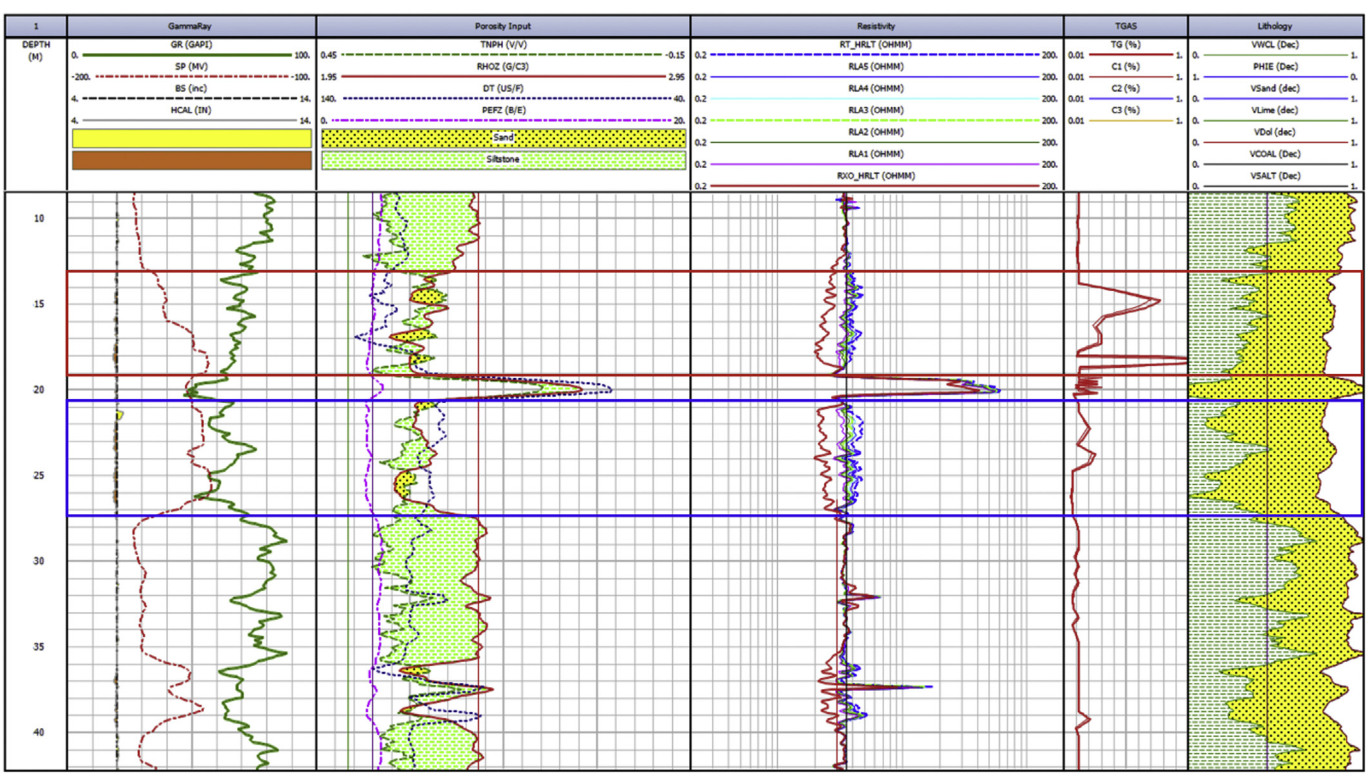

Fig. 7. Sample log characteristic for Teslimkoy zone having "tight gas" potential.

Table 2
Bulk fraction X-ray diffraction data for full diameter core sample from Teslimkoy tight sandstone reservoir, Baglik-1 well in DTD Field. Table includes weight percentage mineralogy.

Formation	Depth (m)	Qtz	KFd	Plag	Cal	Ank	Pyr	Sid	Kaol	Ill	Chl	M-L	Smec	Total clay
Teslimkoy	898.36	60.3	4.0	13.7	12.5	1.0	0.8	–	0.3	2.7	4.7	–	present	7.7
Teslimkoy	898.51	58.2	7.8	9.7	15.7	–	–	0.4	0.8	2.6	4.8	–	present	8.2
Teslimkoy	900.16	53.8	4.3	12.8	20.0	–	–	–	1.0	2.7	5.4	–	present	9.1
Teslimkoy	900.65	72.9	1.7	7.0	12.8	–	0.3	–	0.7	1.3	3.3	–	present	5.3
Teslimkoy	901.14	57.5	5.9	9.1	17.6	0.6	0.2	–	1.0	3.1	5.0	–	present	9.1
Teslimkoy	901.40	52.2	3.7	7.4	29.4	1.0	0.8	–	0.7	1.7	3.1	–	present	5.5
Teslimkoy	914.25	67.0	3.4	8.3	12.0	0.4	0.7	0.6	0.6	2.4	4.6	–	present	7.6
Teslimkoy	914.68	67.2	6.3	8.3	8.2	0.7	0.6	0.7	0.6	2.8	4.6	–	present	8.0

Qtz - Quartz - SiO_2, KFd - Potassium Feldspar $KAlSi_3O_8$, Plag - Sodium Feldspar - $NaAlSi_3O_8$, Cal - Calcite - $CaCO_3$, Ank - Ankerite - Ca $(Fe^{+2}, Mg)(CO_3)_2$, Pyr - Pyrite - FeS_2, Sid - Siderite - $FeCO_3$, Kaol - Kaolinite - $Al_2Si_2O_5(OH)_4$, Ill - Illite - $(K_1H_3O)Al_2Si_3AlO_{10}(OH)_2$, Chl - Chlorite - $(Mg,Al)_6(Si,Al)_4O_{10}(OH)_8$, M-L - Mixed Layer, Smec - Smectite - $Ca_{0.2}(Al,Mg)_2Si_4O_{10}(OH)_2 \cdot xH_2O$, Total Clay - Kaol + Ill + Chr + M-L + Smec.

Table 3
Less than 2 μm glycolated clay fraction X-ray diffraction data for full diameter core sample from Teslimkoy tight sandstone reservoir, Baglik-1 well in DTD Field. Chlorite is the most common clay detected in all samples. The presence of minor expandable smectite clays indicates at least minor sensitivity to fresh water with respect to clay swelling in Teslimkoy Formation.

Formation	Depth [m]	Total clay in bulk sample	Total smectite in bulk sample	Kaolinite	Illite	Chlorite	Mixed layer	Smectite
Teslimkoy	898.36	7.7	0.84	2.5	20.9	65.7	–	10.9
Teslimkoy	898.51	8.2	0.78	5.0	17.6	67.9	–	9.5
Teslimkoy	900.16	9.1	0.40	4.1	24.8	66.7	–	4.4
Teslimkoy	900.65	5.3	0.39	4.8	22.2	65.7	–	7.3
Teslimkoy	901.14	9.1	0.65	5.7	28.1	59.1	–	7.1
Teslimkoy	901.40	5.5	0.64	4.7	23.0	60.7	–	11.6
Teslimkoy	914.25	7.6	0.61	4.5	28.5	59.0	–	8.0
Teslimkoy	914.68	8.0	0.70	5.7	27.2	58.4	–	8.7

common monocrystalline quartz, moderate to common volumes of polycrystalline quartz and lesser volumes of chert, quartz cement and quartz contained within rock fragments. Feldspar forms 8.7%–12.3% of the samples with an average value of 10.4%. Polycrystalline quartz occurs in moderate volumes, forming 2.3%–8.7% of the samples.

Total clay minerals comprise 5.3%–9.1% of the bulk fractions of the analyzed samples. Chlorite is the most common clay detected in all samples, forming 3.1%–5.4% of the bulk fractions. Illite comprises 1.3%–3.1% of the bulk fractions. Kaolinite occurs in lesser volumes forming 0.3%–1.0% of the bulk fractions. The presence of smectite is indicated in all samples (<1%) but there have been no significant formation damage problems by swelling clays during treatment operations in the Teslimkoy Formation.

In the seven Teslimkoy Formation samples selected for petrographic analysis, core analysis porosity varied from 4.3% in the (compacted and moderately calcite and ferroan calcite cemented) lowermost fine grained sample to 13.6% in the (moderately compacted, low moderate calcite and ferroan calcite cemented) lower - mid fine grained sample. The average total porosity for the seven sample suite was 8.5%.

Fig. 9 shows the ternary Sandstone Porosity Classification Diagram for the Teslimkoy core taken from the Baglik-1 well indicating that the majority of the observed thin section porosity is "microporosity" with a minor component of "intergranular" and "grain moldic" porosity.

In addition, micro-porosity related to authigenic clays such as kaolinite and illite/smectite with large surface area supports high irreducible water saturation. Cementation by authigenic clays, quartz-overgrowths and calcite have an important role in porosity reduction and limitation of pore connections (Ilkhchi et al., 2014). The difference between total porosity and effective porosity represents the microporosity component. The presence of moderate volumes of calcite and ferroan calcite and minor volumes of dolomite and ferroan dolomite cement can significantly lower effective porosity.

Core derived overburden porosity and air permeability measured at ambient temperature and three incrementally increasing hydrostatic pressures (800/1200/1700 psi) from Baglik-1

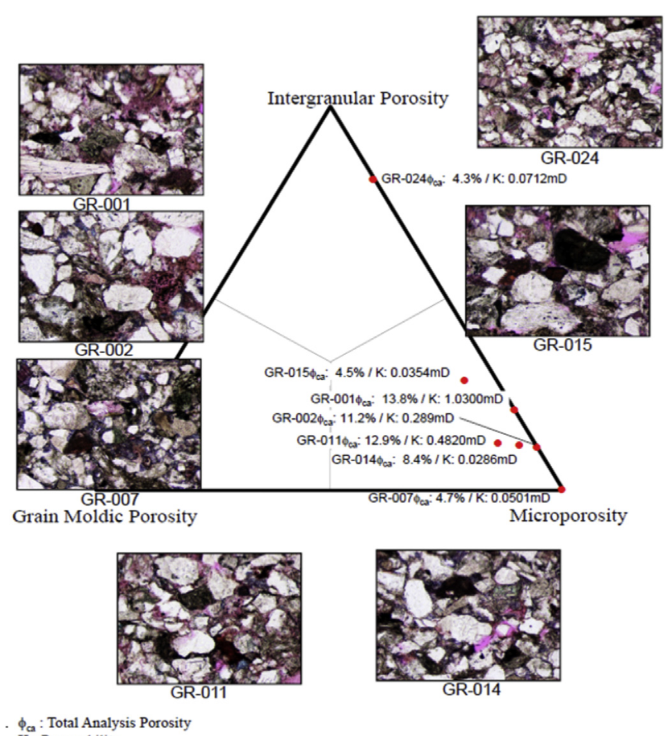

Fig. 9. Porosity sandstone classification diagram for the Teslimkoy core in Baglik-1 showing that the majority of observed thin section porosity is microporosity.

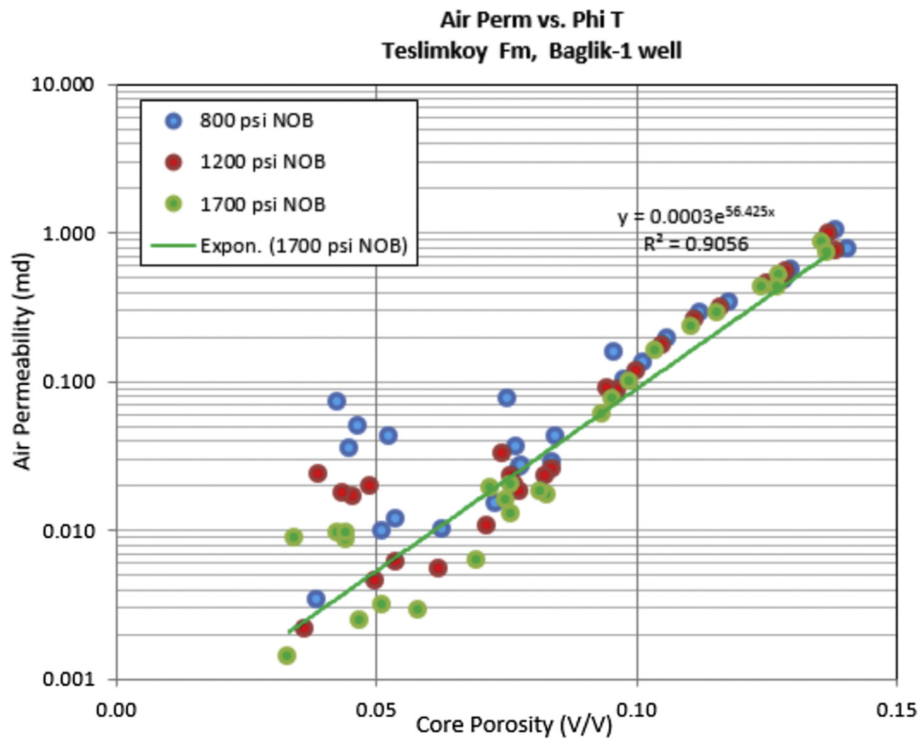

Fig. 10. Core porosity vs. air permeability for three incrementally increasing hydrostatic pressures (800/1200/1700 psi) from plug core samples in the depth interval of 898–915 m. Individual samples are color coded to show the porosity vs permeability measurements at net over burden pressures (NOB).

core plug samples are shown in Fig. 10. The overburden porosity and air permeability of the samples at 1700 psi net confining pressure range from 3.3% to 13.7% and 1.40×10^{-3} md to 0.858 md, respectively. It should be noted that the influence of increasing net overburden stress exhibits an increasingly negative impact on resulting permeability beginning at porosity values below about 7% (v/v) or less.

The data illustrates how the values of porosity changed in Teslimkoy cores when they were tested both at low net stress and at simulated NOB. Notice that the measurements of porosity are one to two porosity units less when measured under net overburden pressure rather than when measured under minimal stress.

Special core measurements were performed to obtain parameters for log formation evaluation including the determination of "m" (the cementation exponent), and "n" (the saturation exponent) for fluid saturation determinations and integrated with early log based calculations. Once obtained, the water saturations in the same wells from which the cores were obtained were computed using the Modified Simandoux Shaly Sand Model (Simandoux, P, 1963) using neutron-density cross-plot techniques to determine the porosity to be used as input into the equation (including corrections for shale and gas effects). Table 4 shows electric properties analysis.

The Teslimkoy cementation exponent (m) of 1.63 was initially found to be too optimistic from cross-plot of formation volume factor vs. core porosity. With over-burden and non-reservoir porosity samples removed, the new adjusted value of m was determined to be 1.77. The saturation exponent (n) was also adjusted to reflect the reservoir quality rock by removing outlier data and exponents re-averaged. For simplicity, in all of the shaly-sand models, the cementation constant "a", was assumed to be 1.0 but if another iteration indicated that an acceptable match was not forthcoming, the value can be better refined using a more in-depth Rw analysis.

In the end, it was determined that a calculated water saturation greater than 60% would identify non-hydrocarbon bearing reservoir rocks. Once applied, all such zones were eliminated from further consideration for completion and would often affect the design of adjacent zone completions.

Table 4
Electrical properties analysis for Teslimoy and Kesan Formations.

Formation	Initial trial	Final correction
Teslimkoy	a = 1.0; m = 1.63; n = 1.96	a = 1.0; m = 1.77; n = 1.75
Kesan	a = 1.0; m = 1.83; n = 1.78	a = 1.0; m = 1.83; n = 1.65

6. Results

Three different consistent layers: The Upper Mezardere Siltstone, Teslimkoy and Upper Kesan sandstones have been developed as productive tight gas formations in Thrace Basin after significant geological and engineering studies. Based on several well completions in these tight gas reservoirs, Teslimkoy Formation was identified as the most prospective of the three reservoir levels in terms of economic gas production rates and rate of return after stimulation within the study area.

Analyzed Teslimkoy Formation samples identify the sandstones as moderately and well sorted feldspathic litharenite. Bulk XRD results indicate quartz is the principal mineral in all samples (52.2%–72.9%) and clay minerals comprise 5.3%–9.1% of the bulk fractions of the analyzed samples. The presence of smectite is indicated in all samples (<1%) but there are no significant formation damage problems with swelling clays during treatment operations in Teslimkoy Formation.

The overburden porosity and air permeability of the samples (at 1700 psi net confining pressure) range from 3.3% to 13.7% and 1.40×10^{-3} md to 0.858 md, respectively. The presence of calcite and ferroan calcite and minor volumes of dolomite and ferroan dolomite cement in Teslimkoy sandstone reservoirs can significantly lower effective porosity.

By core data results and final correctioned water saturation cutoff value of 60% is used to determine free gas productive zones for all stimulation design in the study area. If gas zones were shown to be sufficiently distant from adjoining water bearing zones, these zones were fracture stimulated.

The water saturation and (cross plot) porosity values were used to establish parameters for volumetric OGIP and subsequent reserves calculations.

More than 600 m of marine sediments have tight gas potential in the depth range of 600–1200 m in south Thrace Basin. Several untested off structure and stratigraphic traps which are especially marine channel deposits having stacked sandstone reservoir levels varying from 5 m to 20 m in thickness in Mezardere formation increase the current estimated of unconventional gas reserves (tight sand and siltstone).

Sandstone reservoirs having less than 1.6 md permeability will not flow commercial gas in Thrace Basin, but Upper Mezardere siltstone as well as the Teslimkoy & Upper Kesan tight sandstones have been successfully developed in the southern part of basin resulting in 40 BCF increase in proved reserve category from YE 2012 to YE 2014.

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Nomenclature

BCF	Billion Cubic Feet
EUR	Estimated Ultimate Recovery
GR	Gamma Ray
GWC	Gas Water Contact
JV	Joint Venture
KCL	Potassium Chloride
MMBO	Million Barrels of Oil
NAF	North Anatolian Faults
NOB	Net Over Burden
OGIP	Original Gas In Place
RMF	Resistivity of Mud Filtrate
ROP	Rate of Penetration
RTA	Rate Transient Analysis
SBL	Shale Base Line
SCAL	Special Core Analysis
SP	Spontaneous Potential
TCF	Trillion Cubic Feet
TFS	Thrace Fault System
XRD	X-Ray Powder Diffraction

Appendix A. Supplementary data

Supplementary data related to this article can be found at http://dx.doi.org/10.1016/j.jngse.2016.05.049.

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