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ASX ANNOUNCEMENT

20 January 2015

INDEPENDENT TECHNICAL REPORT

Attached to this announcement is the independent technical report prepared by MHA Petroleum Consultants LLC as at 30 September 2014, and which is referred to in the notice of special general meeting dated 20 January 2015.

A copy of the report can also be obtained from www.feore.com.

- END -

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Resource Evaluation of the Marleysu East Yizbaskent, Yizbaskent-Arash and Susamur Blocks in Kyrgyzstan

Prepared for

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Clarendon House, 2 Church Street
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September 30, 2014

MHA Petroleum Consultants LLC

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As part of the proposed transaction contemplated by FeOre Limited (FEO) involving a potential investment in PEL LLC (PEI) and at the request of FEO, MHA Petroleum Consultants (MHA) has performed an evaluation and assessment of the Contingent and Potential Resources on permits of which PEI has a contractual interest in, namely: Marleysu East Yizbaskent Oilfield, Yizbaskent-Arash Exploration Target Area and the Susamur Exploration Area in Kyrgyzstan. (Figure 1) The evaluation was based on technical data supplied by PEI in the way of historical well completion reports, historical evaluations, well logs and seismic data and an "Integrated Exploration and Development Research Approach Study" contracted for PEI by the Shandong Haikuo TianChang Petroleum Technology Development Co. Ltd.

MHA has prepared a resource estimate, on a 100% working interest basis only, using the information available and based on the analysis methodology described in this report. PEI has represented to MHA that the licenses described in this report are currently valid and PEI is the operator of all further well operations for new wells on these licenses. PEI has brought to MHA's attention and MHA has taken into account that all wells under production at the time of PEI's signing of the license are solely 100% working interest to the Government of Kyrgyzstan, even if they are geographically within a PEI license boundary.

Resource Estimates

The resource estimates presented in this report have been prepared for publication in Australia under the Australian Stock Exchange (ASX) reporting rules using an evaluation approach for conventional resources which is consistent with Society of Petroleum Engineers Petroleum Resources Management System (SPE PRMS) 2007 and the SPE 2011 PRMS guidelines (attached). PEI has indicated to MHA that it intends to develop the Marleysu East Yizbaskent Oilfield through a series of horizontal stimulated wells which at the time of this report PEI has yet to attempt, nor has PEI presented cost and economic data that could be verified. For the purposes of this report, MHA has assigned volumes of recoverable oil and gas in areas where there has been historical production to Contingent Resources, pending demonstration of commercial economics, and volumes of recoverable oil and gas in areas outside of historical production to Prospective Resources. Prospective Resources are defined as per the PRMS which state:

> "Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub- classified based on project maturity."

Prospective Resources under this classification are as yet undiscovered and as such carry significant exploration risk. All Contingent and Prospective Resources volumes presented in this report are unrisked. The resource estimates do not relate to unconventional petroleum resources. Petroleum reserves were not assigned to any of the licenses.

A summary of those estimates is shown in the tables below.

Table 1: Contingent Resource Estimates in tonnes (Gross 100% ownership basis)

	Original Oil-in Place (tonnes)			Remaining Contingent Resources (tonnes)		
License	Low Case	Best Case	High Case	Low Case	Best Case	High Case
Marleysu East Yizbaskent	10,612,720	13,354,467	16,596,083	376,533	1,023,486	1,954,516

Table 2: Contingent Resource Estimates in barrels (Gross 100% ownership basis)

	Original Oil-in Place (barrels)			Remaining Contingent Resources (barrels)		
License	Low Case	Best Case	High Case	Low Case	Best Case	High Case
Marleysu East Yizbaskent	77,472,856	97,487,609	121,151,406	2,748,691	7,471,448	14,267,967

1C denotes low estimate scenario of Contingent Resources
2C denotes best estimate scenario of Contingent Resources
3C denotes high estimate scenario of Contingent Resources

Table 3: Prospective Resource Estimates in tonnes (Gross 100% ownership basis)

	Original Oil-in Place (tonnes)			Remaining Prospective Resources (tonnes)		
License	Low Case	Best Case	High Case	Low Case	Best Case	High Case
III Marleysu East Yizbaskent downdip	1,238,629	1,524,910	1,839,376	118,259	190,974	289,823
Yizbaskent-Arash License Total	8,233,828	13,281,675	20,719,585	1,088,161	1,979,499	3,620,804
Susamur License Total	23,552,501	62,154,067	123,959,269	484,644	2,289,991	7,575,461

Table 4: Prospective Resource Estimates in barrels (Gross 100% ownership basis)

	Original Oil-in Place (barrels)			Remaining Prospective Resources (barrels)		
License	Low Case	Best Case	High Case	Low Case	Best Case	High Case
III Marleysu East Yizbaskent downdip	9,041,992	11,131,843	13,427,445	863,291	1,394,110	2,115,708
Yizbaskent-Arash License Total	60,106,943	96,956,224	151,252,973	7,943,574	14,450,346	26,431,869
Susamur License Total	160,658,683	424,512,281	846,641,808	3,310,119	15,640,641	51,740,400

"The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons."

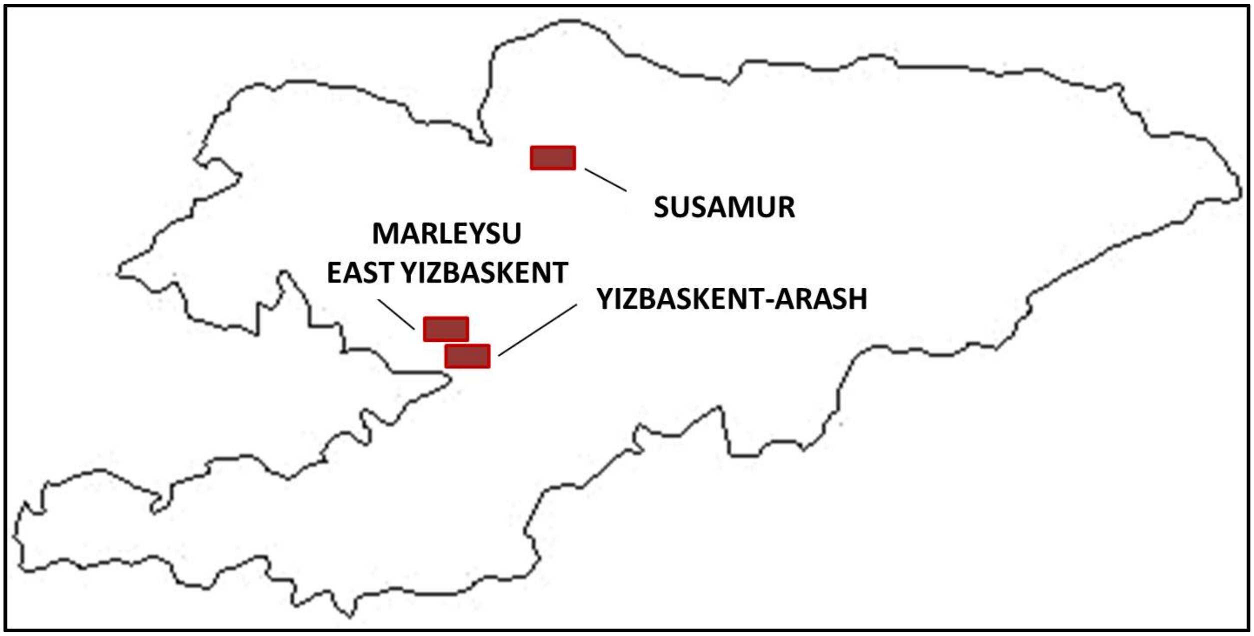


Figure 1: Location of the three PEI permits within Kyrgyzstan

Development Permit Marleysu East Yizbaskent Oilfield

Development Interest: PEI LLC (PEI) PSC with Kyrgyzneftegaz (KNG)
New Production Well: KNG 40% \ PEI 60%
Rejuvenate a non-production well or abandoned well: KNG 35% \ PEI 65%
Enhancement of an existing Production well: KNG 60% \ PEI 40%
Exploration well: KNG 30% \ PEI 70%
New wells in high volume output block: KNG 20% for year 1, 55% thereafter \ PEI 80% for year 1 and 45% thereafter

Area: 33.8 Square Kilometers

Grant of Exploration Permit: Expires 11 December 2019

Term: Mandatory Work Program specified for 3 years

Work Program

Type	Reservoir	2014	2015	2016
Production well	III-XIX	Provide 2 rigs and drill 4 wells	Drill 12 wells	Drill 12 wells
Workover	III-XIX	Provide 2 workover rigs: 10 workovers	1 rig and 15 workovers	1 rig and 15 workovers
Enhancement			3 hydraulic fracturing wells	3 hydraulic fracturing wells

Exploration Permit Yizbaskent-Arash

Development Interest: PEI LLC (PEI) PSC with Kyrgyzneftegaz (KNG)
New Production Well: KNG 40% \ PEI 60%
Rejuvenate a non-production well or abandoned well: KNG 35% \ PEI 65%
Enhancement of an existing Production well: KNG 60% \ PEI 40%
Exploration well: KNG 30% \ PEI 70%
New wells in high volume output block: KNG 20% for year 1, 55% thereafter \ PEI 80% for year 1 and 45% thereafter

Area: 171 Square Kilometers

Grant of Exploration Permit: Expires 31 December 2016

Term: Mandatory Work Program specified for 3 years

Work Program

Type	Reservoir	2014	2015	2016
Exploration well	III-XIX	Exploration every year	Exploration every year	Exploration every year

Exploration Permit Susamur

Development Interest: PEI LLC (PEI) PSC with Kyrgyzneftegaz (KNG)
Exploration well: KNG 30% \ PEI 70%
New wells in high volume output block: KNG 20% for year 1, 55% thereafter \ PEI 80% for year 1 and 45% thereafter

Area: 334 Square Kilometers

Grant of Exploration Permit: Expires 31 December 2016

Term: Mandatory Work Program specified for 3 years

Work Program

Type	Reservoir	2014	2015	2016
Exploration well	As of yet unknown	Exploration every year	Exploration every year	Exploration every year

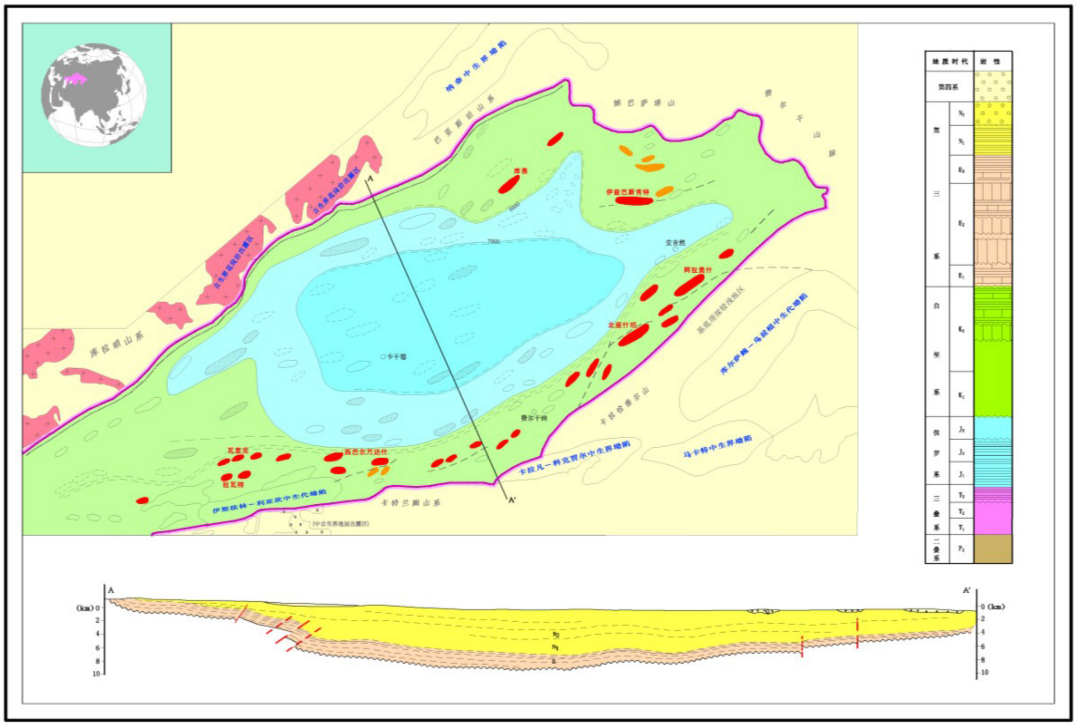


Figure 2: Fergana Basin, the location of the Marleysu East Yizbaskent Oilfield Development Lease and the Yizbaskent-Arash Exploration Lease

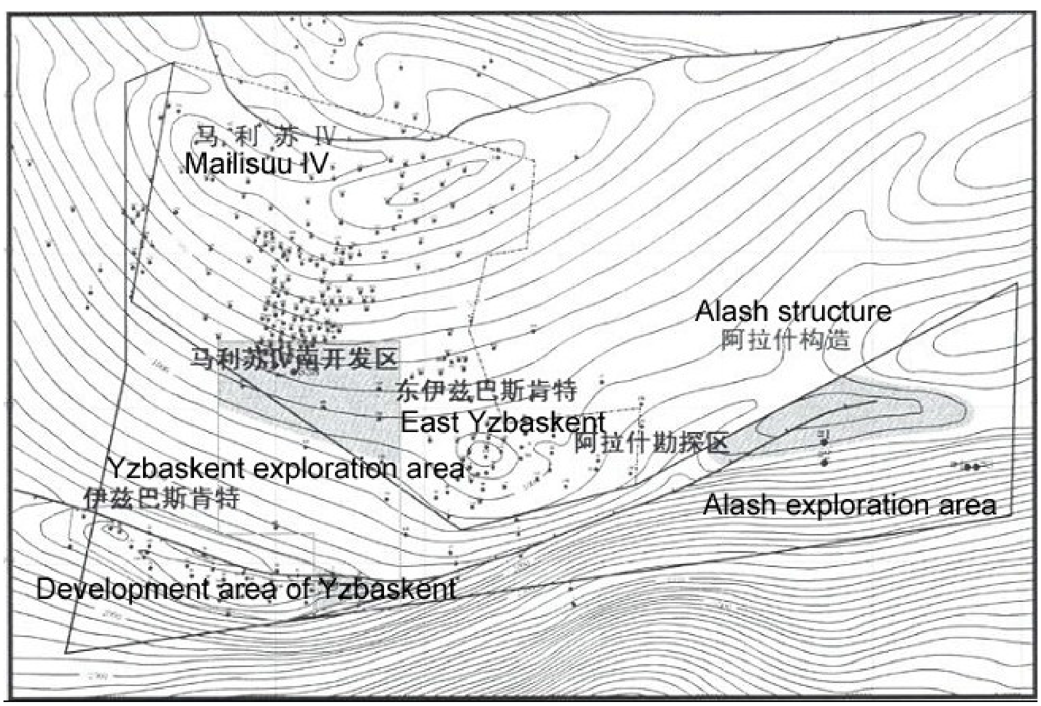


Figure 3: Marleysu East Yizbaskent Development License and the East Yizbaskent-Arash Exploration area with the generalized geologic structure map as provided by Shandong HTPTD.

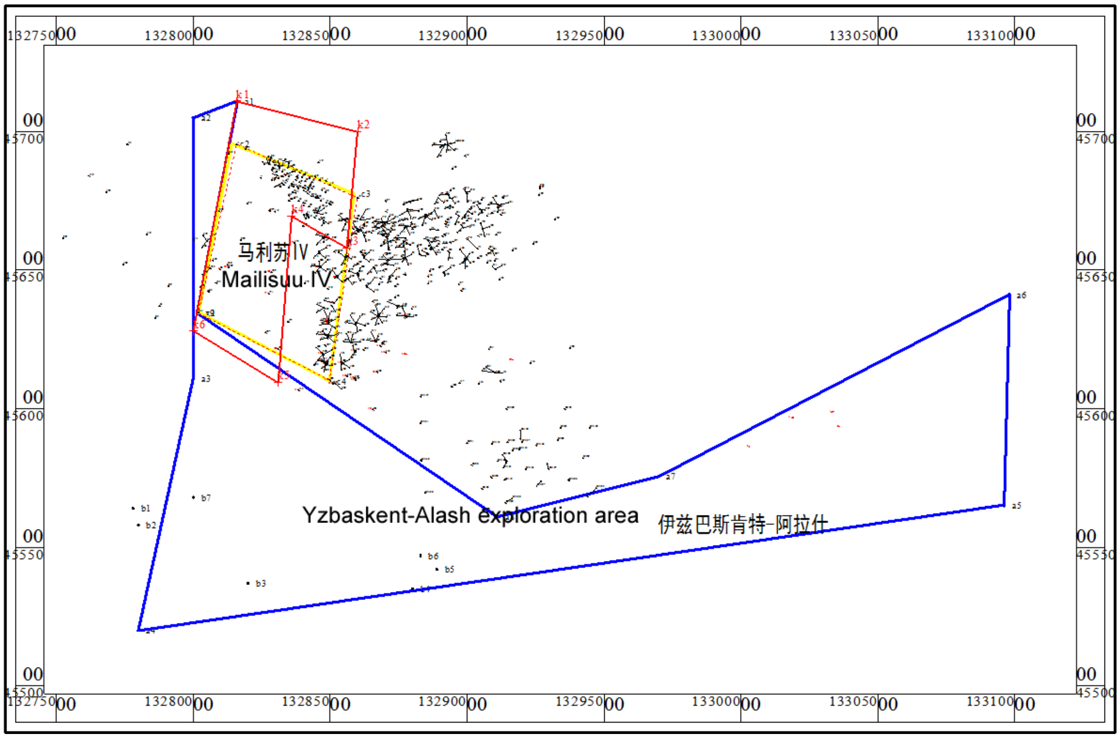


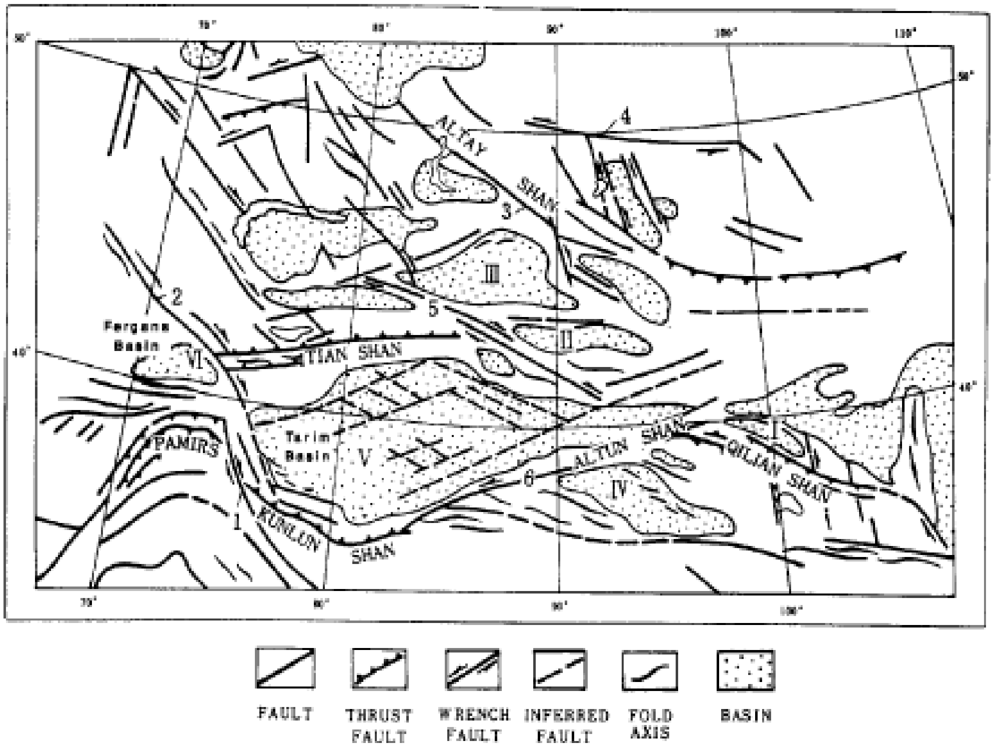
Figure 4: PEI Data Set for the Marleysu East Yizbaskent Development and the Yizbaskent-Arash Exploration Licenses

Introduction

Regional Geology

The Fergana Basin sits astride the borders of Uzbekistan, Tadzhikistan and Kyrgyzstan and is approximately 300 kilometers long with a maximum extent of about 120 kilometers. It is an intermountain basin with over 55 discovered oil and gas fields in compressional traps generally along the southern margin in primarily Tertiary aged reservoirs. (Figure 5) Exploration and oil discovery began as early as 1900, although bitumen deposits were known at least as early Marco Polo's journey through the "Silk Road". There are over 30 defined pay zones in the Fergana basin, all within the Paleozoic and Cenozoic section. They are designated Zone I through XXXII in order of increasing depth (DOE/EIA-0575(94)).

There have been three primary stages of tectonic development; An early Miogeoclinal stage of primarily clastic deposition from the Cambrian until the Permian then the second stage, a Platform Stage following the Hercynican Orogeny from the Late Permian until the Alpine Orogeny in the late Oligocene and the last stage, a Final Orogenic Stage where the Fergana Basin is one of several "West China" Tertiary Basins formed during the Alpine Orogeny.



Sketch map of Xiyu tectonic domain, northwest part of China and adjacent regions. Basins: (I) Jiuquan, (II) Turpan, (III) Junggar, (IV) Quidam, (V) Tarim, and (VI) Fergana. Faults: (1) Karakorum, (2) Talaso-Fergana, (3) Ertix, (4) Changaja, (5) Boro-horo, and (6) Altun Shan.

Figure 5: Xiyu tectonic domain, northwest part of China and adjacent regions.

Stratigraphy

According to Beznosov, 1987, the Lower Jurassic are the oldest known rocks of the sedimentary fill of the Fergana Basin however there are suggestions that Triassic and Permian sediments may exist in the center of the basin as there are descriptions of slightly metamorphosed sediments of that age in the mountains surrounding the basin. The Lower Jurassic is comprised of conglomerates, sandstones and occasional coal beds. The Middle Jurassic consists of sandstone, siltstone, claystones and thin coals. Thicknesses range from 100 to 300m. The Upper Jurassic is a sequence of redbeds; conglomerates and sandstones with red claystones that alternate with a total thickness of up to 400m. There are several known pay zones in the Jurassic labeled XXIII to XXIX from top to bottom.

The Lower Cretaceous sediments are well developed in the eastern and southeastern section of the Fergana Basin and maintain the continental clastic deposition patterns that were developed in the Upper Jurassic (Khodzhayev and others, 1973). The Muyan Formation of Neocomian-Aptian age has twelve pay zones (XI-XXII), all are sandstones that typically shale out towards the center of the basin. The total thickness of the Muyan Formation is highly variable (5-300m) as it thins along the basin margin.

The Albian section is comprised of the Lyakan formation (30-80m) and the Kyzyl-Pilyal Formation (5-400m). The Lyakan is a gray to pink limestone and is designated pay zone XVIIIg. The Kyzyl-Pilyal Formation is a bedded red sandstone and variegated claystone with lenses of gypsum and palygorskite indicating periods of arid climate and high salinity. It contains pay zones XVIIIa, XVIIIb, and XVIIIv.

The Cenomanian is primarily a thick (480m) sandstone unit in the eastern Fergana Basin. Known as the Kalachin Formation there are no known pay zones perhaps due to no internal seals. Above the Kalachin lies the Turonian Ustricha Formation, a carbonate unit known for its mollusk shells. The thickness is fairly consistent 30-40m and pay zones XVI and XVII are in this formation. The Late Cretaceous Turonian-Senonia Yalovach Formation (15-66m) consists of variegated sandstones, red and green claystones and argillaceous sandstones and contains pay zone XVa. The uppermost Cretaceous unit is the Senonian Pestrotsvet marl. It can be a well formed limestone and contain pay zones XI-XV. Thickness can range from 15m at the edge of the basin to over 250m in the center of the basin.

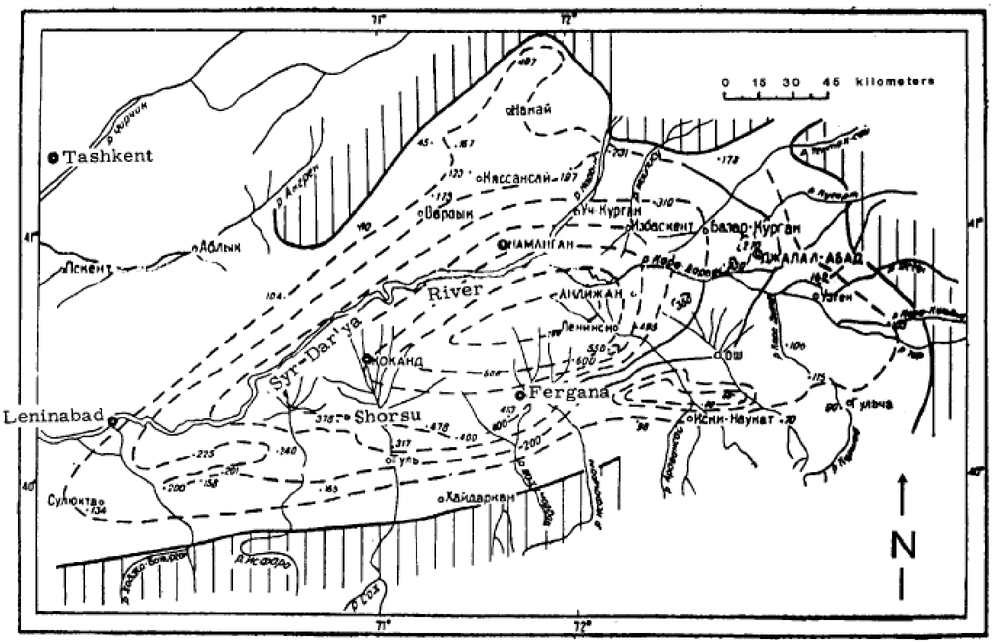
The Tertiary Cretaceous boundary is marked by a continuous white gypsum bed called the Goznau Formation (Paleocene) which ranges in thickness from 2m in the west to over 100m in the east of the Fergana Basin. It has been designated pay zone X. Above it lays the Bukhara Formation limestone beds, two additional pay zones; VIII and IX. The Eocene is called the Susak Formation which have a wide range of thickness from 10m in the west to almost 100m in the east. The Susak Formation is primarily interbedded sandstone and claystones that grade upwards into a limy dolomite. There are no know productive reservoirs in the Susak unit.

Pay Zone VII is the middle Eocene Alay Formation which is a carbonate bed that can vary from10-160m in thickness. It is generally bioclastic in nature and often fractured. It is bounded by claystone beds. The Upper Eocene contains the Turkestan Beds (50m), the Rishtan Beds (40m), and the Isafara Beds (30m). In general this is a gradational sequence from limestones and sandstones (Pay Zones VI, and V) upward to a gray dolomite (50m) that exists only in the eastern Fergana Basin (Pay Zone V). This dolomite is also a bioclastic carbonate that is heavily fractured. The Isafara beds are dominantly gray-green claystones. These grade into the lower Oligocene Khanabad Formation, a 30-40m green clay with no reservoir beds. After this time there is no evidence of any marine deposition in the Fergana Basin (Nalivkin, 1973).

The Middle Oligocene contains the primary productive zone of the Fergana Basin, the Sumsar Formation and Pay Zone III. This is primarily continental sandstone that thickens to the west and splits into and upper and lower pay zone with the upper zone designated as Pay Zone II. Neogene orogenic events associated with the Alpine Orogeny created boundary high elevations on all sides of the Fergana Basin and shed debris into the basin to create what is known as the Cenozoic Molasse. Two stages are described (Khodzayev, et al, 1973) the Massaget and the Baktria stage. The Massaget is lower Neogene “brick-red” and “pale-pink” sandstones, siltstones and conglomerates more than 4,000m thick. The Baktria stage overlays the Massaget and is mostly claystones with conglomeratic fans around the edge of the basin. It too can reach 4,000m in thickness in the center of the basin. Quaternary lacustrine and fluvial sediments are present in the center of the basin where they can reach a thickness of 500m.

The primary reservoir system of the PEI lease in the Marleysu area is the Paleocene-Eocene-Oligocene System that was deposited during the Platform Stage. The region that is now part of the Fergana Basin was part of the Tethys Sea. The total thickness of the Paleogene can range from less than 100m to greater than 700m in the basin center. (Figure 6)

Figure 18. Thickness in Meters of Paleogene (Paleocene-Eocene-Oligocene) Marine Sediments in the Fergana Basin



Note: Thicknesses represented by dashed isopachous contour lines show maximum 700 meters (2,297 feet) near basin's center. Minimum thickness contoured is 100 meters (328 feet), near the basin's edge. Contour interval is 100 meters.
Source: Slightly modified from Ryshkov (1959).

Figure 6: Paleogene Marine Sediment thickness in the Fergana Basin.

The Marleysu East Yizbaskent Oilfield was discovered in what is now Kyrgyzstan in the eastern most extent of the Fergana Basin in 1948. Production has been established in the greater field from fourteen separate reservoirs, including several Cretaceous and Jurassic formations. In the area of the PEI license there are 138 drilled wells and most of the production is from three reservoirs: the Oligocene Layer III low permeable siltstone and Layers V and VII, both Eocene fractured limestones. The stratigraphic section is represented by the type log (well #60). (Figure 7) The display is the common curves available: two resistivity curves and a Spontaneous Potential (SP) curve.

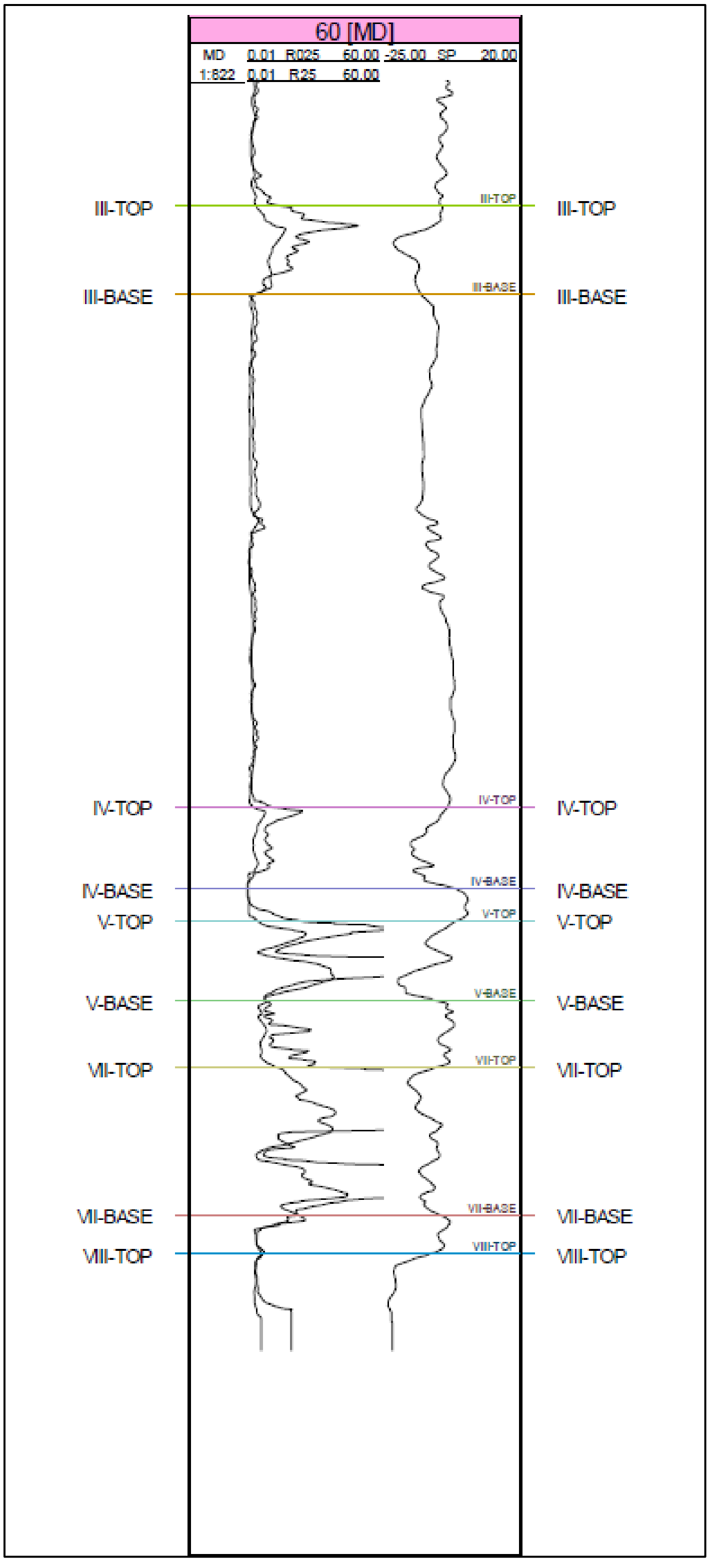


Figure 7: Diagram of the Productive Reservoirs and Log Markers of the Marleysu East Yizbaskent Oilfield

Hydrocarbon Potential

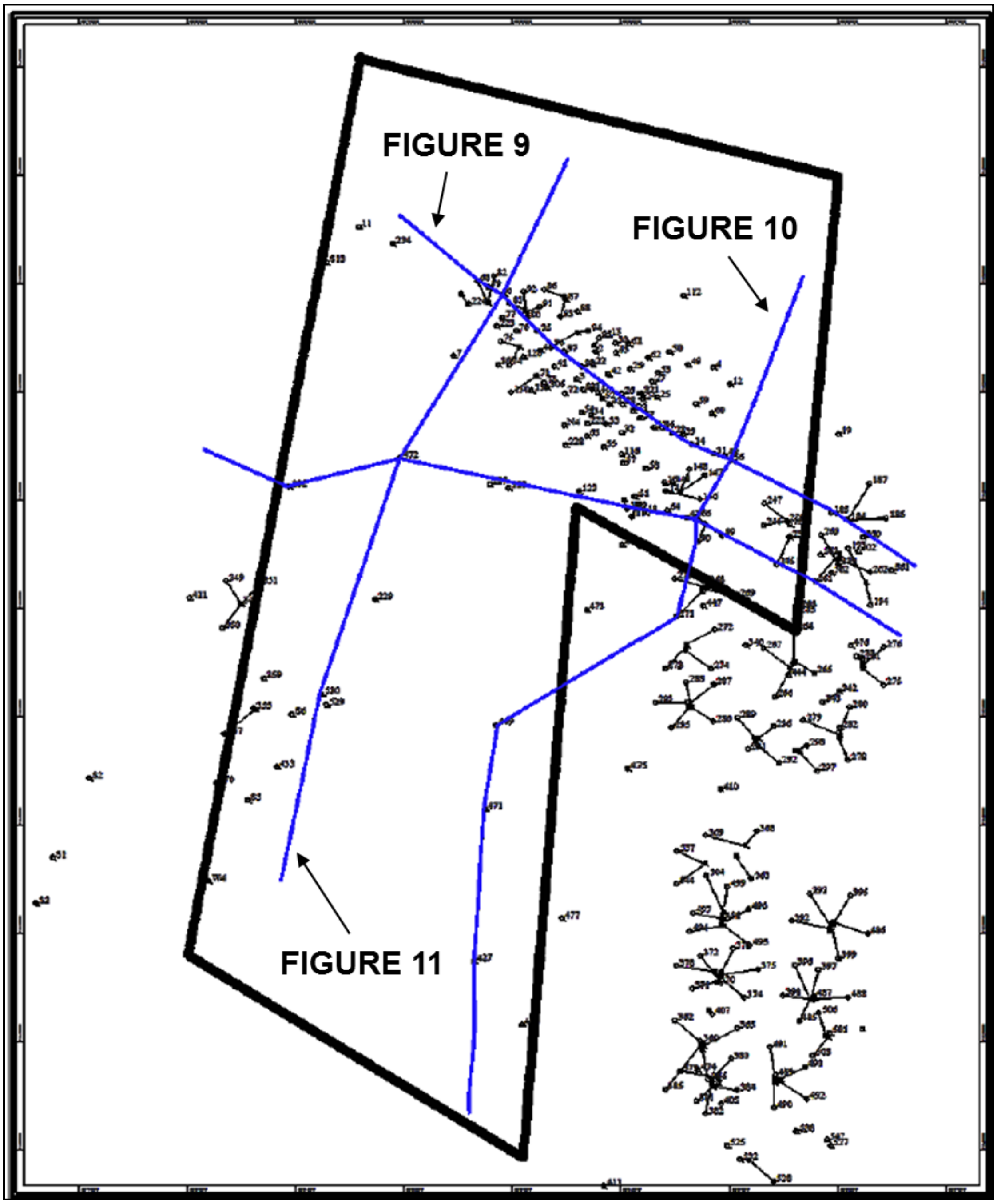


Figure 8: Marleysu East Yizbaskent Oilfield well locations, and cross-section references.

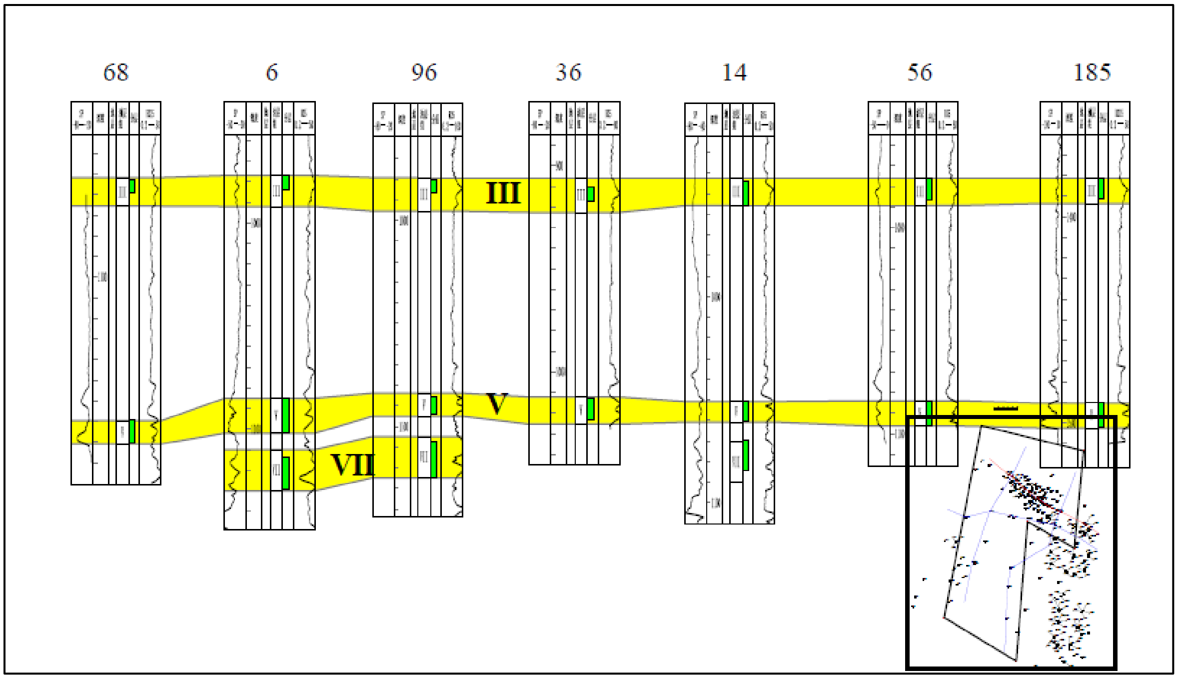


Figure 9: West to East Stratigraphic Cross-Section (Flattened on the top of Zone III) showing the reservoirs Zone III, V and VII.

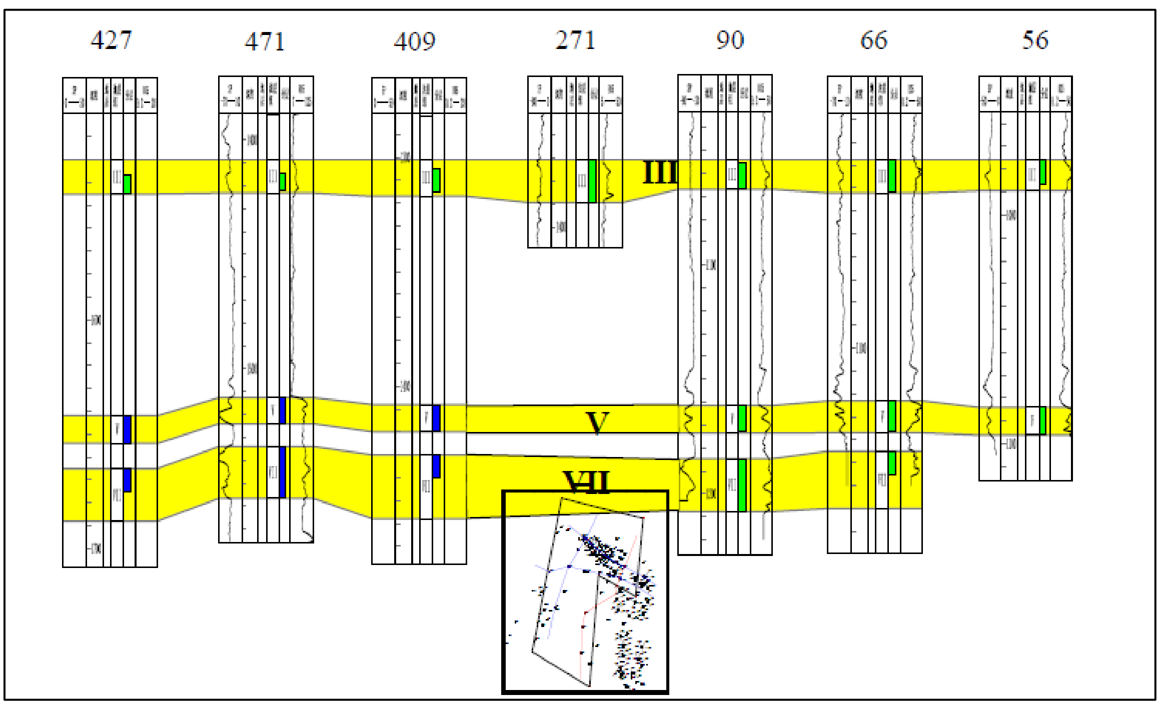


Figure 10: South to North Stratigraphic Cross-Section (Flattened on the top of Zone III) showing the reservoirs Zone III, V and VII. Green indicates oil zones, Blue indicates water zones.

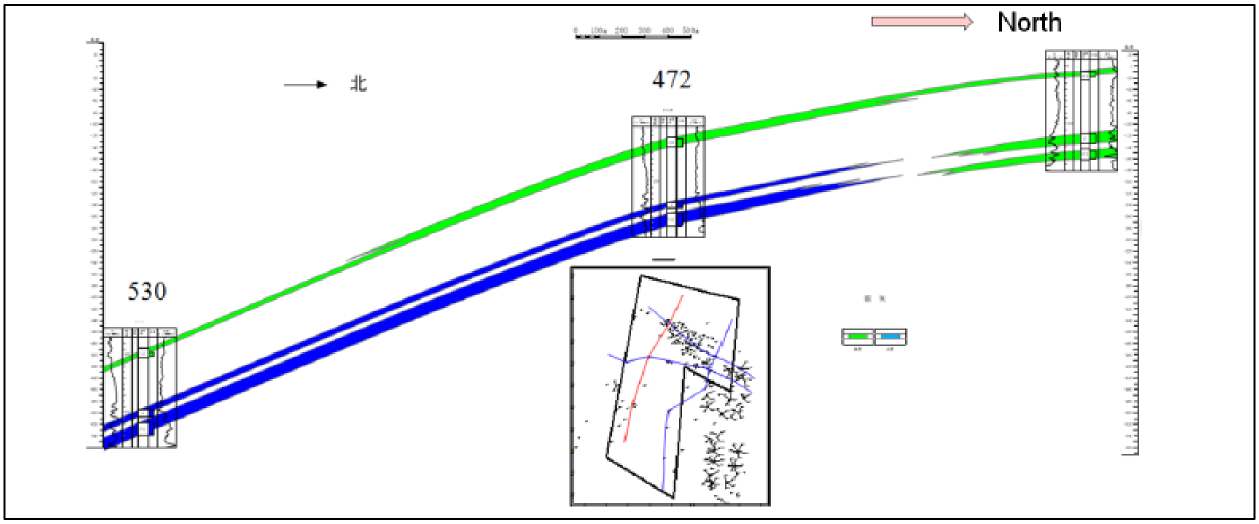


Figure 11: South to North Structural Cross-Section showing the reservoirs Zone III, V and VII. Green indicates oil zones, Blue indicates water zones.

Methodology

MHA built an IHS Petra Project to interpret the well and map data. The dataset that MHA used was data provided by PEI. The dataset consisted of well completion reports, well logs (LAS files, PDF files, TIFF images), Excel files of complied well tops, petrologic and petrophysical analyses, various reports on the geology of the Fergana Basin. The quality of the data as conveyed to MHA by PEI as to well data, production data, and reservoir and fluid properties has been provided by Kyrgyzneftegaz (The National Oil & Gas Company), and has not been verified by PEI nor by MHA.

Using the available SP and Resistivity curves MHA calculated net pays for 67 wells in Zones III, V and VII and mapped out the structure and net pay for each horizon. (Figures 12-17) MHA was also provided the historical production of the Marleysu East Yizbaskent field within the PEI lease through December 2013 and MHA has estimated the total production of the Marleysu East Yizbaskent field within the PEI lease through September 30, 2014. MHA has been informed that all wells that were under production at the time of PEI's signing of the license are solely 100% working interest to the Government of Kyrgyzstan, even if they are geographically within a PEI license boundary. Based on the provided data, MHA is aware of five wells that are still currently classified as active: two wells in Layer III, two wells in Layer V, and one well in Layer VII. As PEI is currently not allowed to drill within the same Spacing Unit as the currently producing wells, MHA has estimated potential future recoverable volumes of these producing wells, and has factored this into the resource estimates provided in this report.

Using available data, MHA has estimated the net pay and a range of reservoir properties for Layer III, Layer V, and Layer VII, and used these properties to estimate oil-in-place volumes.

MHA then applied a range of recovery factors to the oil-in-place volumes, and subtracted the historical cumulative production by seam, as well as the estimated future recoveries by the currently producing wells, to determine the remaining potential resources available to PEI within this area. As PEI has indicated that the forward plan of development will be through horizontal wells, which PEI has yet to attempt, and there are yet to be established firm economics on the execution and performance of horizontal wells, MHA has classified the resources within the previously developed area as Contingent and Prospective Resources. MHA anticipates as PEI demonstrates horizontal drilling costs and flow rates at commercial thresholds, it will be possible to evaluate at that time the migration of Contingent Resources into Reserves.

MHA has not stated net resources in this report as the PEI/KNG interest split is on a per well basis depending on the type and status of the well. Thus the volumes in this report are reported by the lease and net volumes attributable to any single future well are not reported.

Areas of any PEI license where there is inadequate drilling or production to support Contingent Resources are classified as Prospective Resources, if a case can be supported for a trap in one or more reservoirs. MHA has classified the prospects on the Yizbaskent-Arash Exploration license and the Susamur Exploration license as Prospective Resources. There are two prospects on the Yizbaskent-Arash Exploration license; an eastern four-way dip closure on the south side of a major reverse fault (Figure 20) and a western dip closure on the north side of the reverse fault (Figure 21). Both prospects are defined by well control as seismic data is either poor (see Figures 22-23) or lacking and thus MHA has taken a probabilistic approach to the resource volumes by estimating the minimum, most likely and maximum reservoir parameters and using a Monte Carlo simulation to calculate a Low Case, Best Case and High Case OOIP and recoverable volume of oil and gas. In addition, there is an area, labeled District 4, which lies to the west of the Marleysu-IV Development License that is on structure and within the area that MHA calculates net pay for in Zone III. MHA has assigned Prospective Resources to this area as well.

The Susamur Exploration license in the Susamur Basin is purely an exploration play with no exploration wells yet drilled in the basin. There is a historical seismic survey that has delineated several prospects, and on the basis of reports from this survey and PEI's work, MHA has assigned Prospective Resources to this license with the acknowledgement that the exploration risk remains very high until further delineation work is carried out. PEI has commissioned a study by Shandong HaiKuoTianChang Petroleum Technology Development Co., Ltd. Of the China University of Petroleum (East China) which compared the geology of the Susamur Basin to the Ili and the Dzungaria Basins of Xinjiang. As the Susamur belongs to the same micro-tectonic plate within the collision zone of the Asian and Siberian plates and the overall sedimentology and tectonics have been described as similar the use of the Ili and Dzungaria Basins as analogs is an acceptable technique. MHA has used the Shandong deterministic evaluation as a base case and run a Monte Carlo probabilistic evaluation of the prospects in the Susamur License to create a Low Case, Best Case and High Case Potential Resource evaluation.

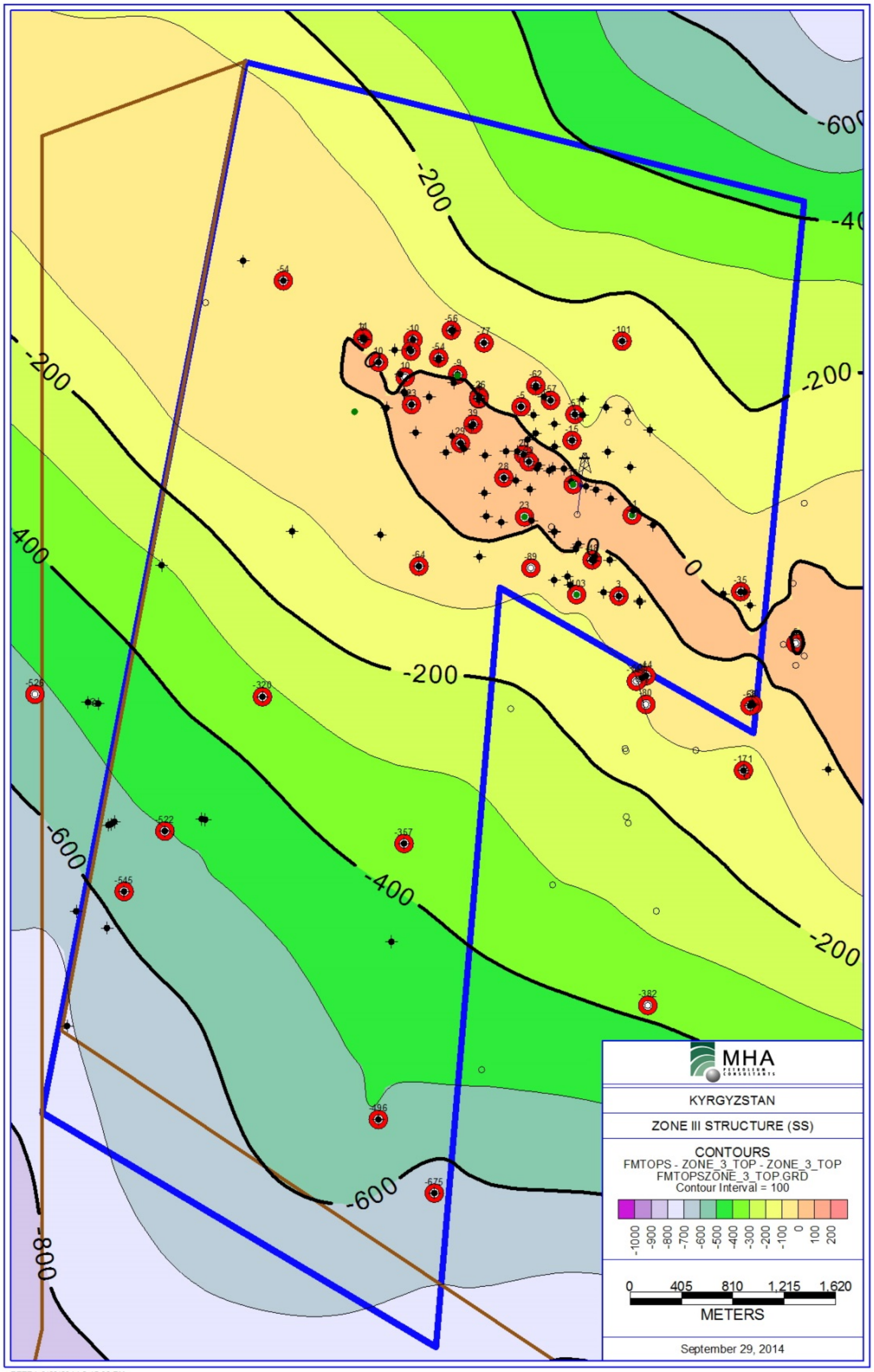


Figure 12: MHA interpretation of the Structural top of the Layer III. (Posted values of SSTVD of Layer III)

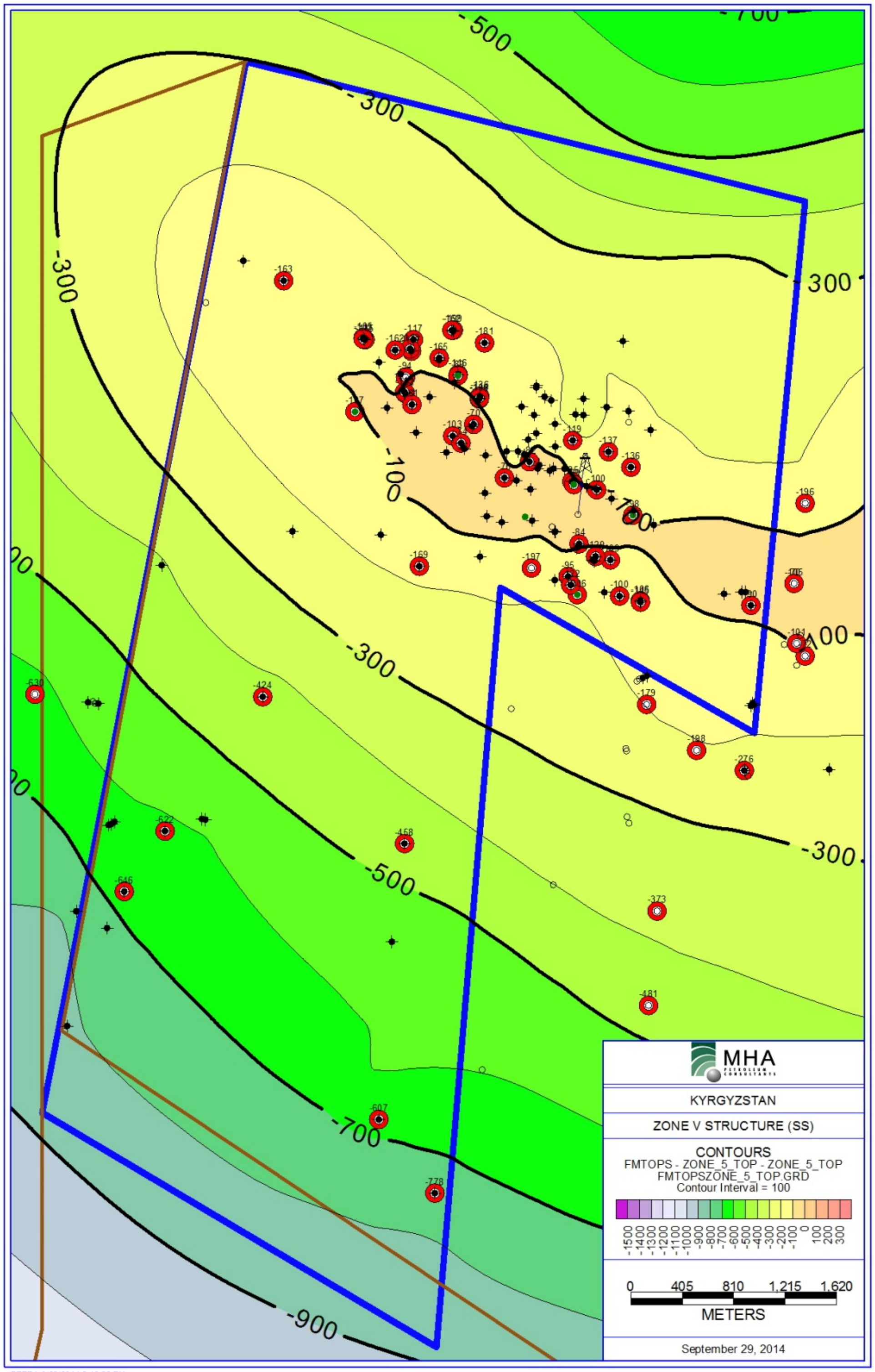


Figure 13: MHA interpretation of the Structural top of the Layer V. (Posted values of SSTVD of Layer V)

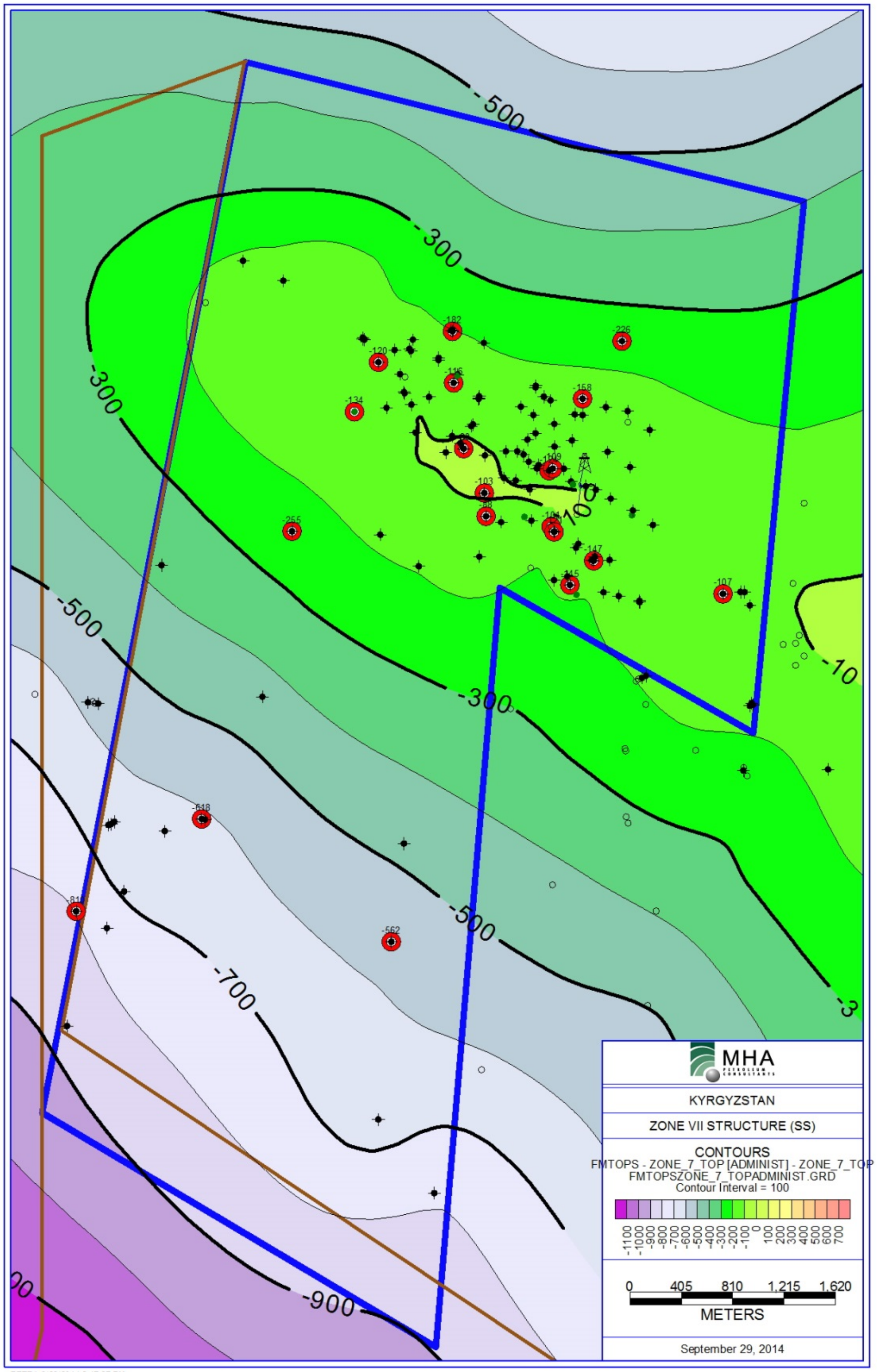


Figure 14: MHA interpretation of the Structural top of the Layer VII. (Posted values of SSTVD of Layer VII)

Mailisuu IV– East Yzbaskent Oilfield						
Position	Layer No.	Average burial depth m	Effective thickness	Lithology	Porosity	Permeability
Paleogene system	III	1350	5.4	Limy siltstone	15.1	54-120
	V	1445	9.1	Limestone	8.4-12.6	16-69
	VII	1460	8.4	Bioclast limestone	9.9	36-40

(Resources: geological data of Mailisuu – East Yzbaskent)

Figure 15: Lithology, Permeability and Porosity summary of the major reservoirs within the Marleysu East Yizbaskent Oilfield (Shandong)

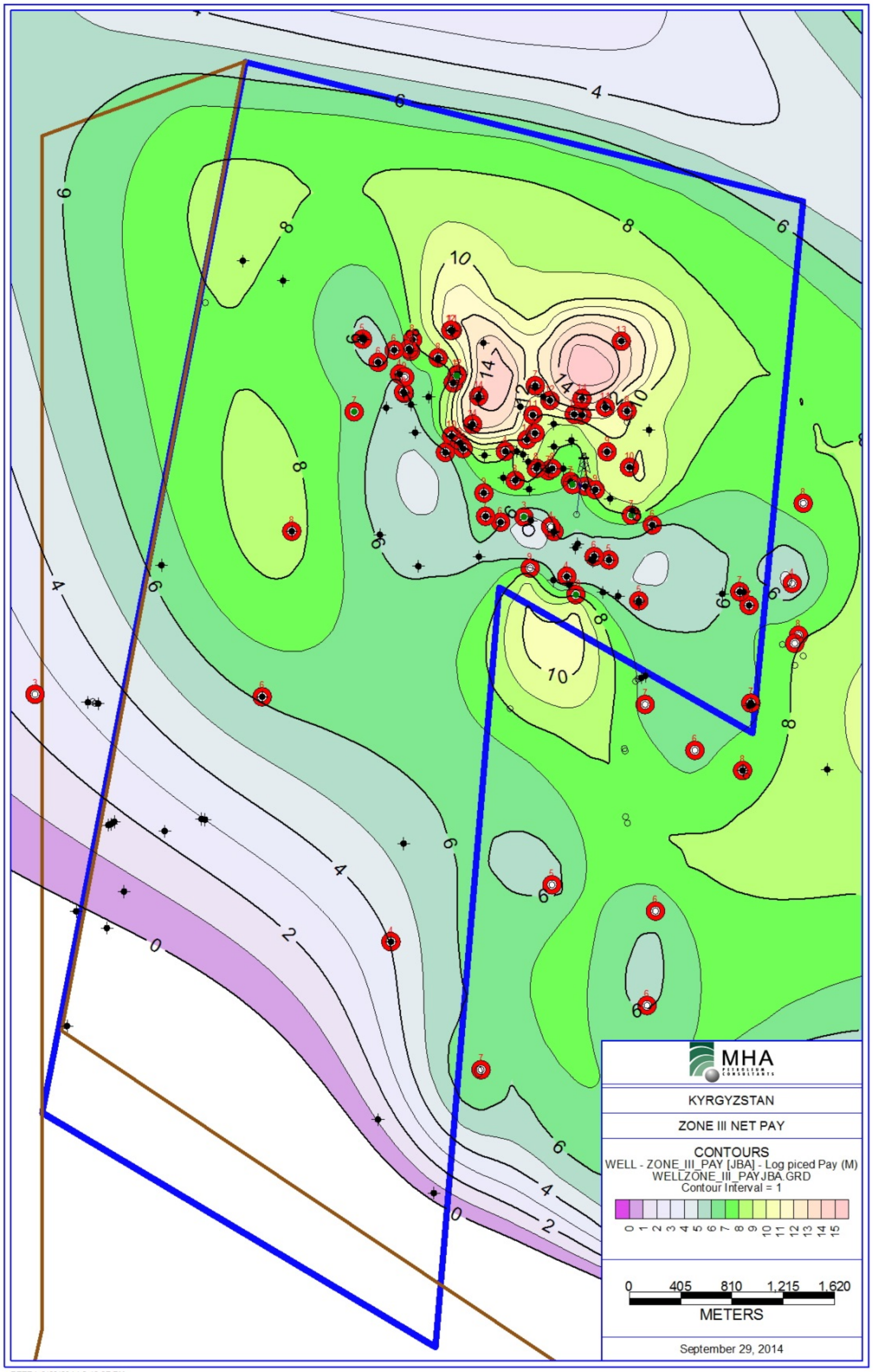


Figure 16: MHA interpretation of the Net Pay of Layer III. (Posted values of SSTVD of Layer III in black and Net Pay of Layer III in red.)

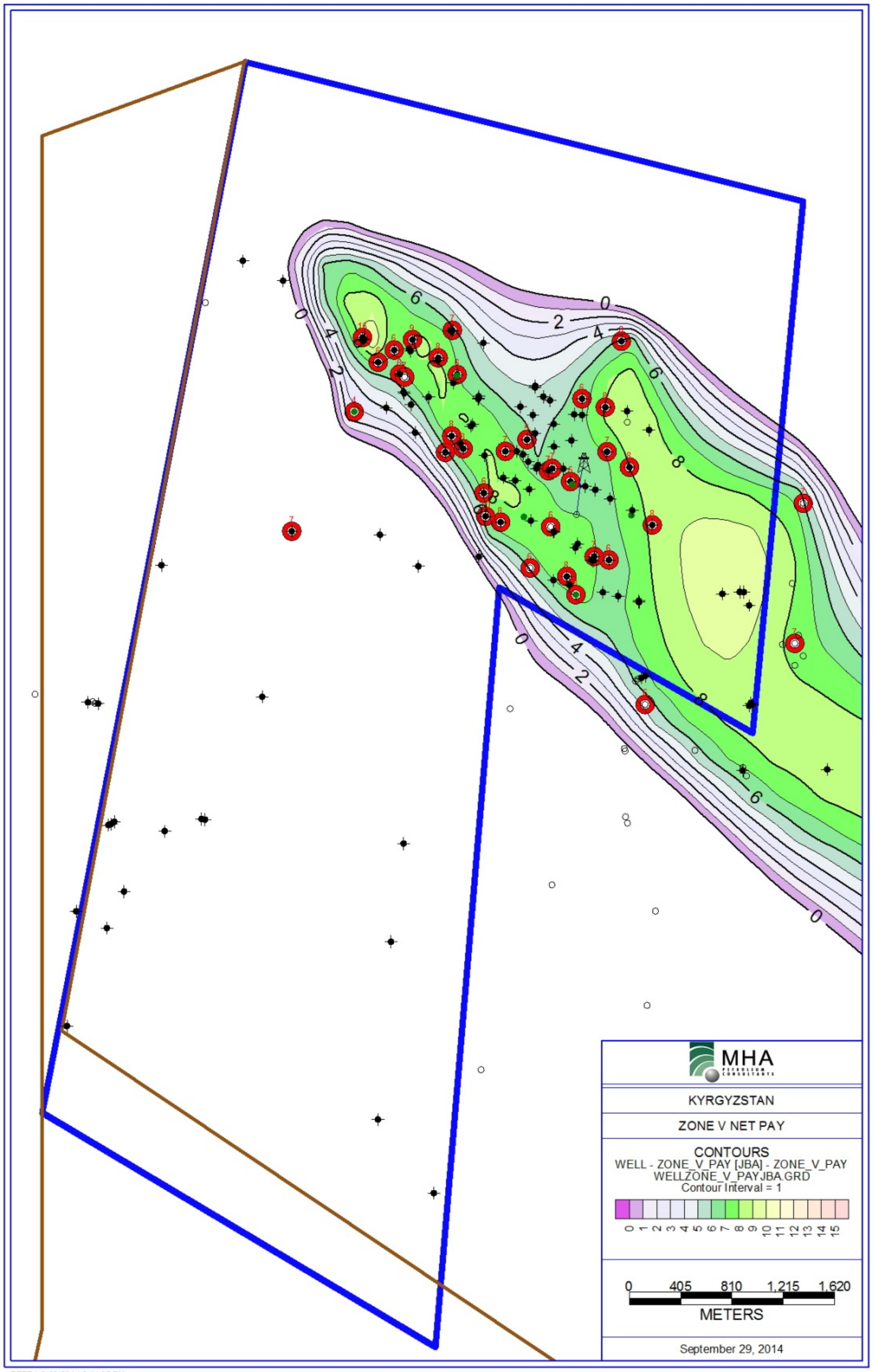


Figure 17: MHA interpretation of the Net Pay of Layer V. (Posted values of SSTVD of Layer V in black and Net Pay of Layer V in red.)

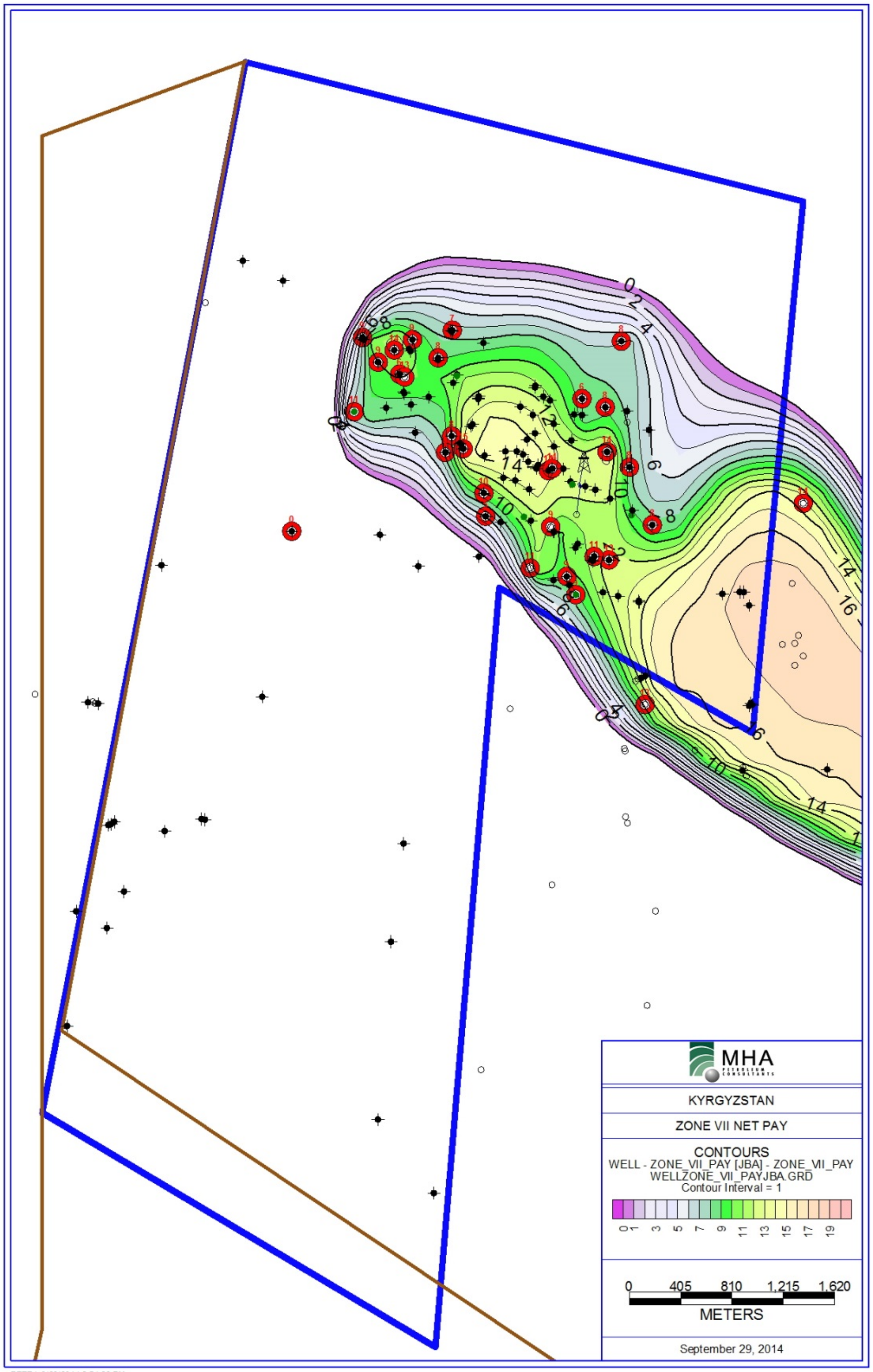


Figure 18: MHA interpretation of the Net Pay of Layer VII. (Posted values of SSTVD of Layer III in black and Net Pay of Layer VII in red.)

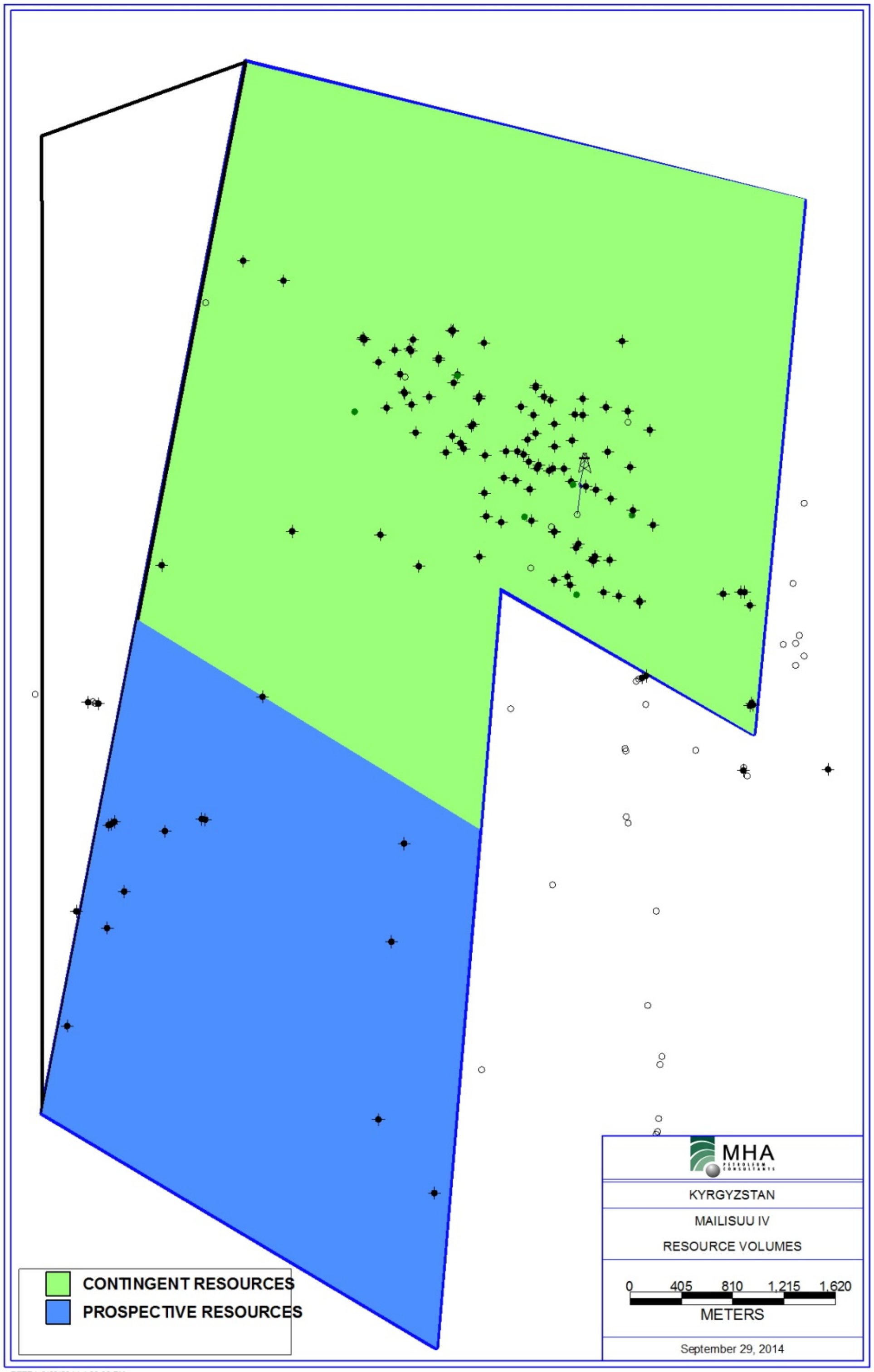


Figure 19: Contingent and Prospective Resource areas for Marleysu East Yizbaskent Block

Table 5: Marleysu East Yizbaskent Contingent Resource Estimates by Layer in tonnes (Gross 100% ownership basis)

	Original Oil-in Place (tonnes)			Remaining Contingent Resources (tonnes)		
Layer	Low Case	Best Case	High Case	Low Case	Best Case	High Case
III	6,161,888	7,554,072	9,184,220	178,814	536,398	1,046,173
IV	1,781,697	2,397,252	3,116,430	38,278	162,301	345,028
V	2,669,135	3,403,143	4,295,433	159,441	324,787	563,315
Marleysu East Yizbaskent	**10,612,720**	**13,354,467**	**16,596,083**	**376,533**	**1,023,486**	**1,954,516**

Table 6: Marleysu East Yizbaskent Contingent Resource Estimates by Layer in barrels (Gross 100% ownership basis)

	Original Oil-in Place (barrels)			Remaining Contingent Resources (barrels)		
Layer	Low Case	Best Case	High Case	Low Case	Best Case	High Case
III	44,981,782	55,144,726	67,044,806	1,305,342	3,915,705	7,637,063
IV	13,006,388	17,499,940	22,749,939	279,429	1,184,797	2,518,704
V	19,484,686	24,842,944	31,356,661	1,163,919	2,370,945	4,112,200
Marleysu East Yizbaskent	**77,472,856**	**97,487,609**	**121,151,406**	**2,748,691**	**7,471,448**	**14,267,967**

Table 7: Marleysu East Yizbaskent Prospective Resource Estimates by Layer in tonnes (Gross 100% ownership basis)

	Original Oil-in Place (tonnes)			Remaining Prospective Resources (tonnes)		
Reservoirs	Low Case	Best Case	High Case	Low Case	Best Case	High Case
III Marleysu East Yizbaskent downdip	**1,238,629**	**1,524,910**	**1,839,376**	**118,259**	**190,974**	**289,823**

Table 8: Marleysu East Yizbaskent Prospective Resource Estimates by Layer in barrels (Gross 100% ownership basis)

	Original Oil-in Place (barrels)			Remaining Prospective Resources (barrels)		
Reservoirs	Low Case	Best Case	High Case	Low Case	Best Case	High Case
III Marleysu East Yizbaskent downdip	**9,041,992**	**11,131,843**	**13,427,445**	**863,291**	**1,394,110**	**2,115,708**

These Resource Estimates account for recovery factor, historical cumulative production, and future estimated production from currently active wells.

"The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a

risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons."

1C denotes low estimate scenario of Contingent Resources
2C denotes best estimate scenario of Contingent Resources
3C denotes high estimate scenario of Contingent Resources

Yizbaskent-Arash Exploration License

PEI subdivides the Yizbaskent-Arash Exploration license into four districts. District 1 to the east has one prospect with a target in Zone V. District 2 in the center has no exploration prospects at the current time. District 3 to the south of the development license has one prospect with a target in Zone III. District 4 to the west of the development license is considered as prospective for Zone III as it lays too far to the west of the existing production to have high confidence that this area will be easily developable. (Figures 19-20)

PEI has acquired four seismic lines in the exploration block to assist in its assessment. (Figure 21) The four highlighted lines in yellow are the lines that PEI has purchased and reprocessed to attempt to improve the imaging of the seismic data. The easternmost north south line is shown in the image below, after reprocessing. The interpreted horizon is thought to be close to Zone V.

The reprocessing of the seismic data primarily has been to gain the data and there does not appear to be any advanced modern statics correction or processing. Resolution of reflectors at the target (Zone V and deeper) horizons is highly interpretable. (Figure 22)

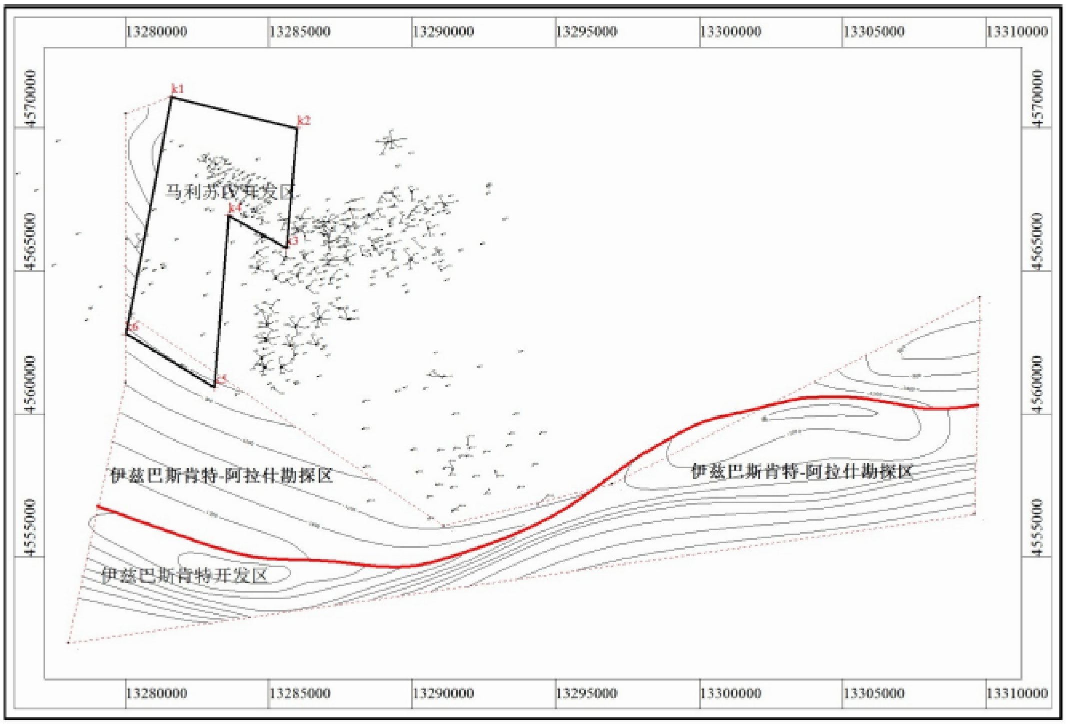


Fig. 4-1-1 Mining rights of Yzbaskent-- Alash exploration area

Figure 20: Yizbaskent-Arash exploration area (Shandong)

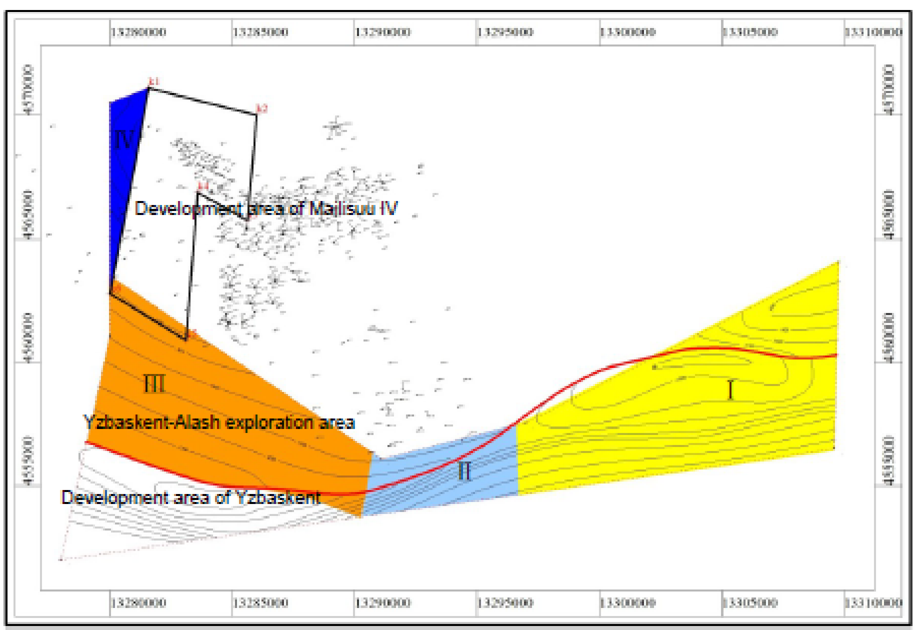


Figure 21: Districts within Yizbaskent-Arash exploration area (Shandong)

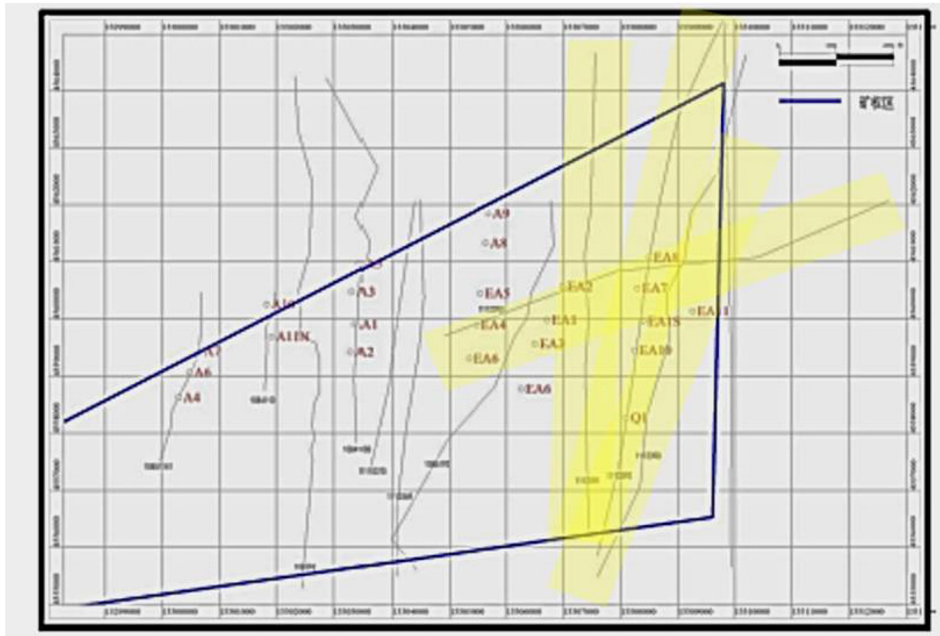


Fig. 4-1-3 The 2D seismic distribution graph of east Yzbaskent- Alash exploration area

Figure 22: Map of seismic lines. PEI purchased and reprocessed seismic lines highlighted in yellow.

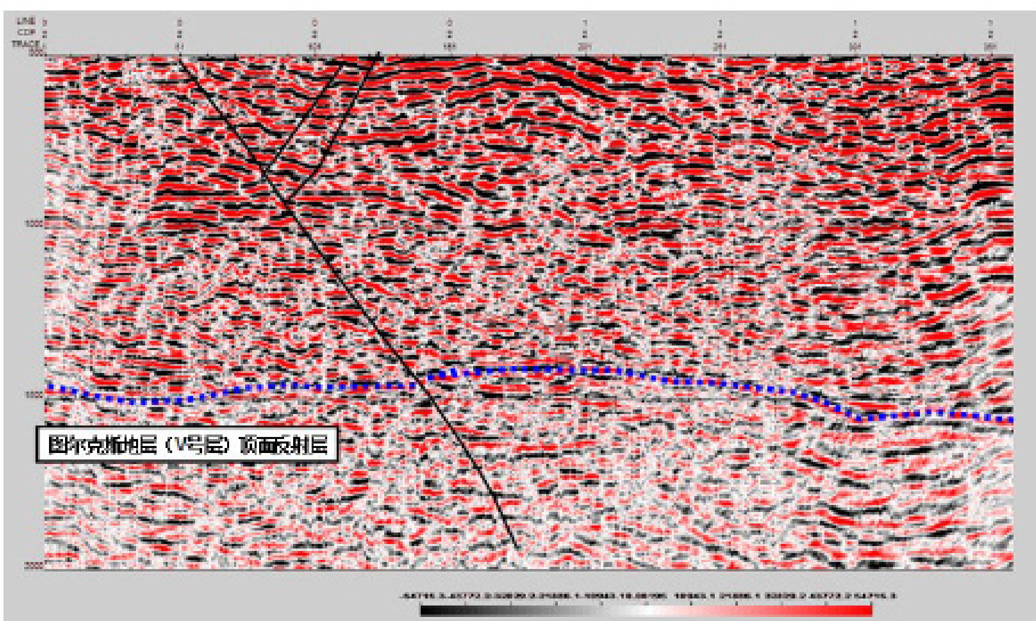


Fig. 4-2-3 The seismic cross-section after gained (line 1112390)

Figure 23: Example of seismic cross-section (Shandong)

There is one prospect in the eastern area of the license in the area called “District 1” which is a four way compressional fold on the hanging wall side of the reverse fault. The prospect is set up by the discovery of oil pay in zone V in the A1 well (Figures 23-26) which is about 40m off the crest of the structure. All other flanking wells are water bearing in all zones. This leaves a small, 1.2 to maximum 4.5km^2 closure at the crest of the structure that can contain oil in zone V. (Figure 26) There have been several tests in the Paleozoic that on production have tested 1m^3/d or less but at this time MHA has not seen sufficient evidence to warrant the delineation of a drillable prospect for the Paleozoic.

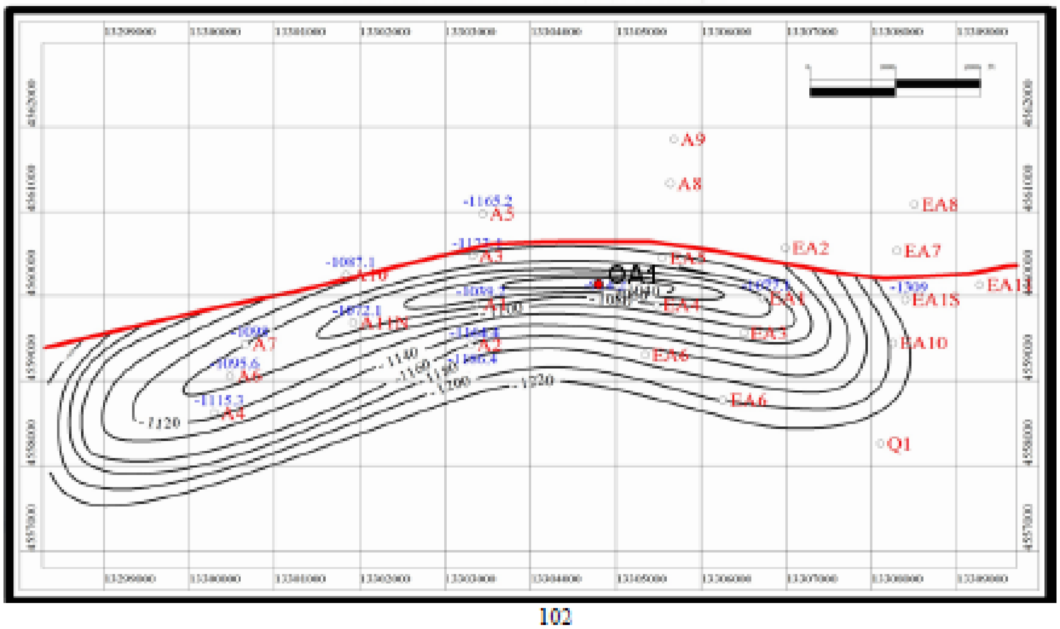


Figure 24: Structure of Layer V in the Arash exploration area (Shandong)

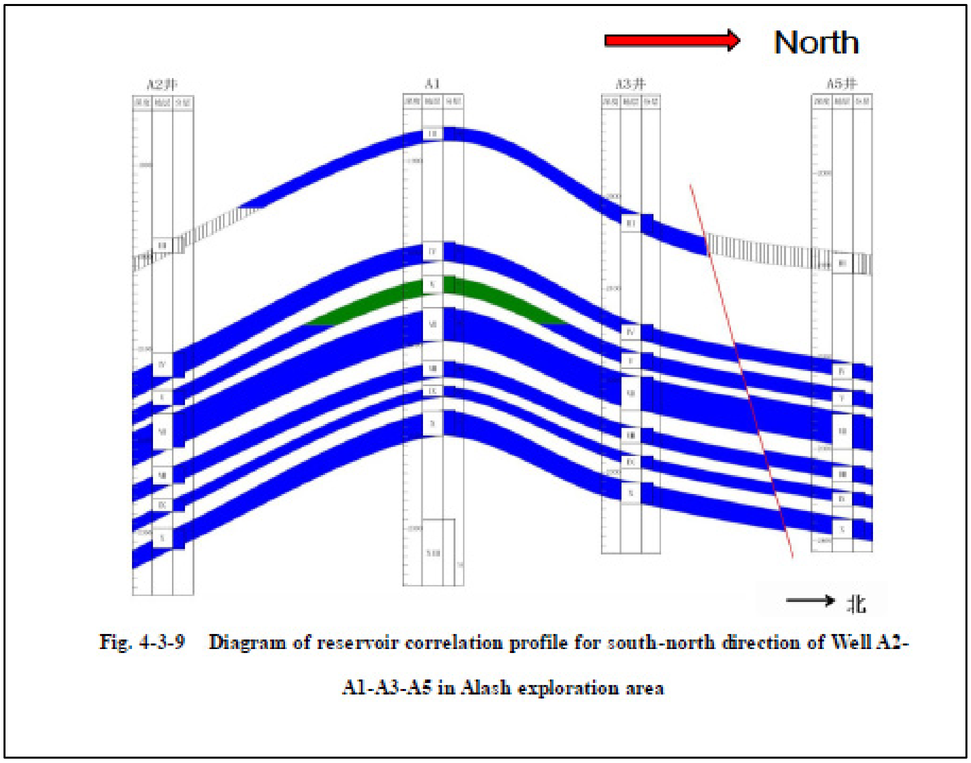


Figure 25: South to North Cross-section over the District 1 Zone V prospect (Shandong)

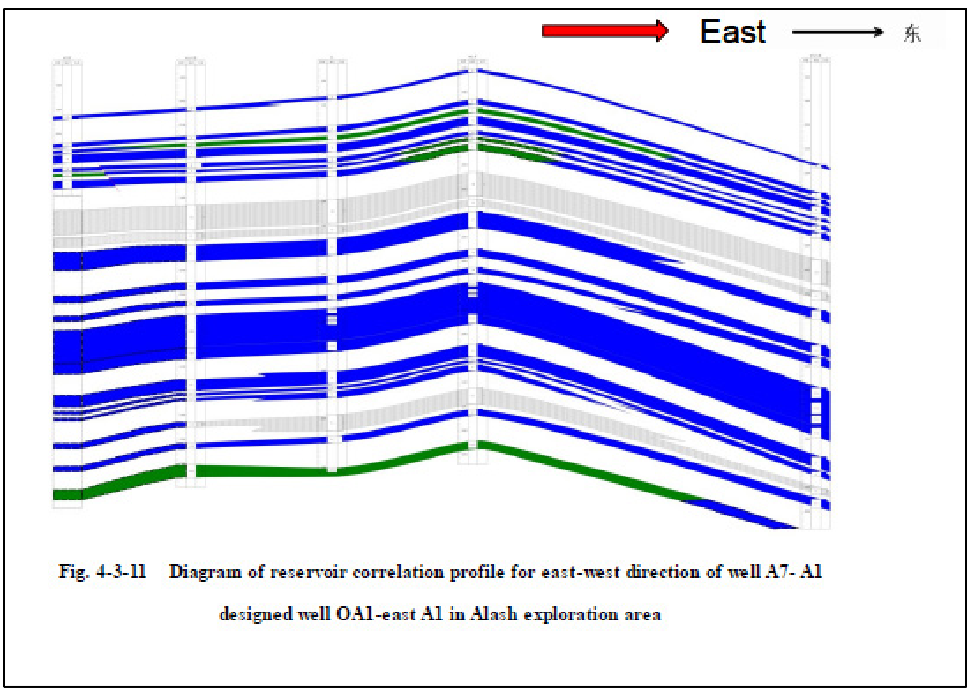


Figure 26: West to East Cross-section over the District 1-Zone 5 prospect (Shandong)

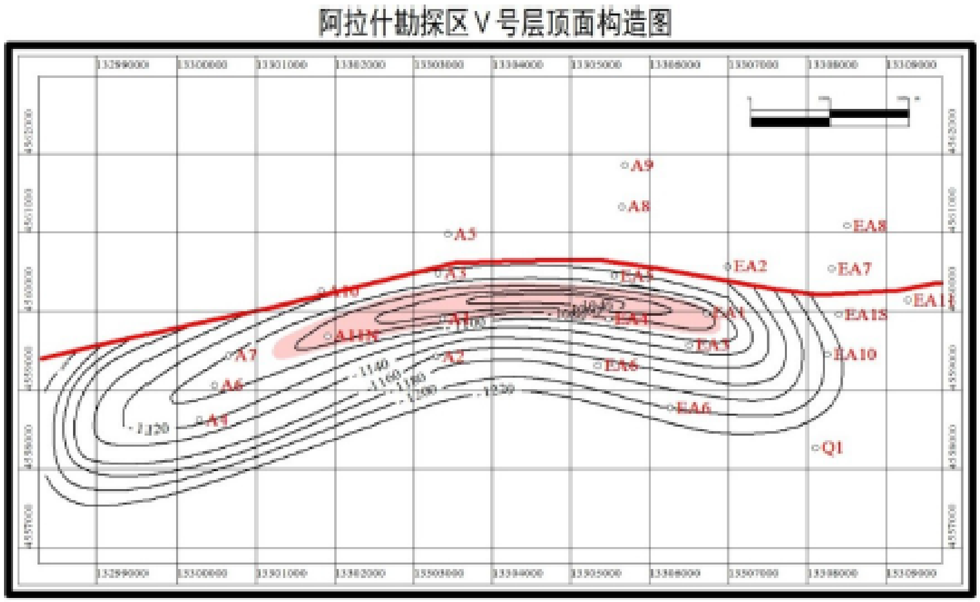


Fig. 4-5-3 The oil-bearing area chart of the layer V of District 1 in Yzbaskent—Alash exploration area

Figure 27: The most likely (2.5km^2) extent of the District 1 Layer V Prospect (Yizbaskent-Arash)

The second prospect is a monoclinal updip fault trap in Zone III set up by an oil zone logged in well M413 at the edge of the lease and M408 to the north outside of the lease. Oil is expected as far down as -1,100m, the anticipated O/W contact in the Marleysu East Yizbaskent Field development lease. (Figure 27)

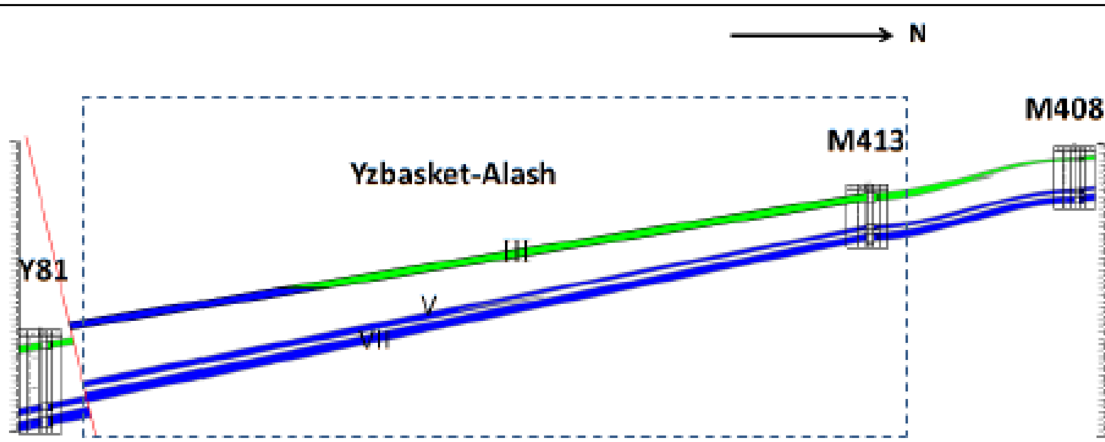


Fig. 4-5-4 The sectional View of District 3 Reservoirs in Yzbaskent—Alash exploration area

Figure 28: Sectional view of District 3 Reservoirs in Yizbaskent –Arash exploration area (Shandong)

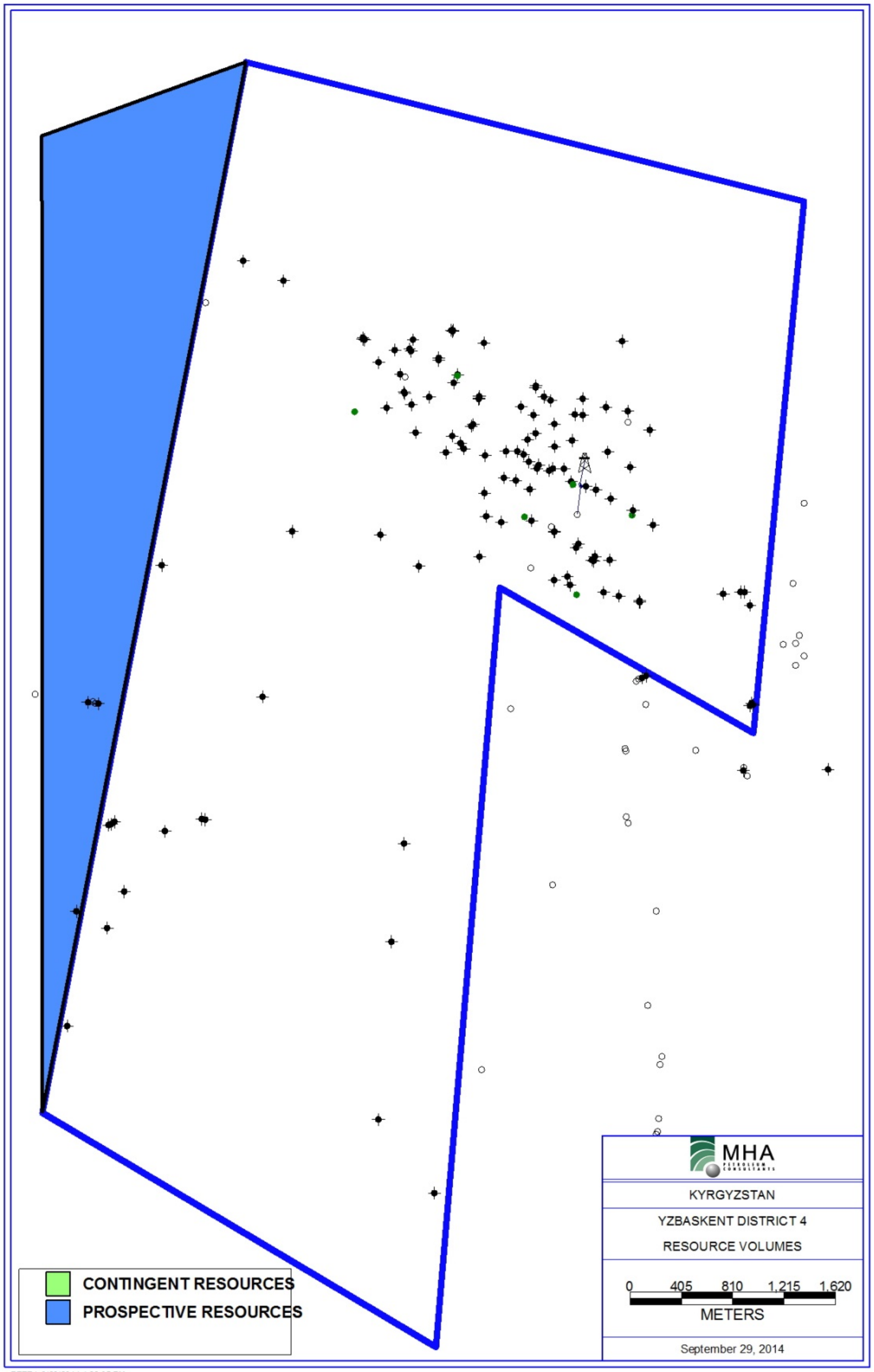


Figure 29: Yizbaskent-Arash District 4 Prospective Resource Area

Prospective Resources

Table 9: Yizbaskent-Arash Prospective Resources in tonnes (Gross 100% ownership basis)

		Original Oil-in Place (tonnes)			Prospective Resources (tonnes)		
License	**Area/Reservoir**	**Low Case**	**Best Case**	**High Case**	**Low Case**	**Best Case**	**High Case**
Yizbaskent-Arash	District 1 Zone V	704,903	1,183,236	1,892,274	94,758	178,425	333,525
Yizbaskent-Arash	District 3 Zone III	6,289,414	10,574,740	16,978,041	823,074	1,559,742	2,940,293
Yizbaskent-Arash	District 4 Zone III	1,239,511	1,523,698	1,849,271	170,329	241,333	346,986
Yizbaskent-Arash License Total		**8,233,828**	**13,281,675**	**20,719,585**	**1,088,161**	**1,979,499**	**3,620,804**

Table 10: Yizbaskent-Arash Prospective Resources in barrels (Gross 100% ownership basis)

		Original Oil-in Place (barrels)			Prospective Resources (barrels)		
License	**Area/Reservoir**	**Low Case**	**Best Case**	**High Case**	**Low Case**	**Best Case**	**High Case**
Yizbaskent-Arash	District 1 Zone V	5,145,789	8,637,625	13,813,598	691,735	1,302,500	2,434,733
Yizbaskent-Arash	District 3 Zone III	45,912,723	77,195,604	123,939,697	6,008,437	11,386,115	21,464,139
Yizbaskent-Arash	District 4 Zone III	9,048,430	11,122,995	13,499,678	1,243,402	1,761,731	2,532,998
Yizbaskent-Arash License Total		**60,106,943**	**96,956,224**	**151,252,973**	**7,943,574**	**14,450,346**	**26,431,869**

The evaluation of the Susamur License is limited by an extreme lack of tangible data: no known well penetrations, no detailed geologic map, no basin level gravity or magnetic survey. (Figure 29) What is known is that the Susamur Basin is thought to have a similar stratigraphic and tectonic history as the Ili Basin and Dzungaria Basin; two adjacent basins to the northeast within the Kazakhstan microplate (Shandong Report). Thus the more detailed information on the Ili, Junggar and Dzungaria Basins can be used to create a framework for the Susamur Basin. Further, there is a vintage 2D seismic survey that was acquired by the Soviets that spans most of the Susamur Basin. (Figure 30) The data has not been made available to PEI but one map of the structural interpretation by the Soviets has been made available and it shows a large faulted anticline running north-east to south-west down the center of the basin.

Background Geology

Three primary reservoir intervals are expected in the Susamur Basin; a Lower Carboniferous carbonate and mudstone unit (R3), an Upper Carboniferous volcanoclastic tuff unit interbedded with siltstones and marlstones (R2) and an overlying Permian clastic sequence (R1). (Figure 31)

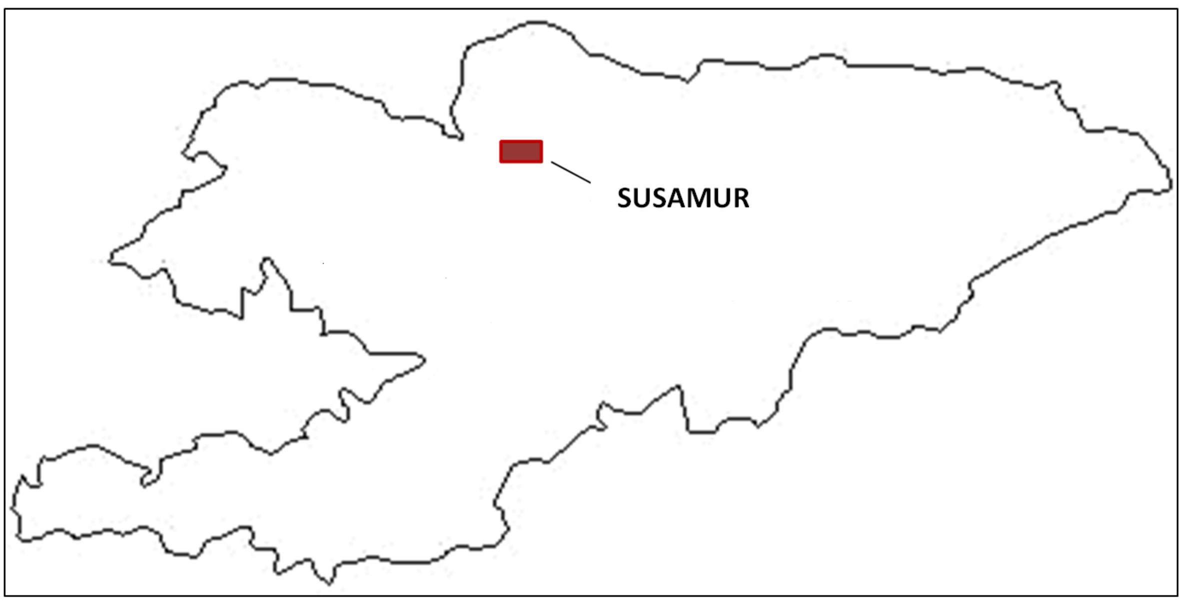


Figure 30: Position of Susamur Basin (Shandong)

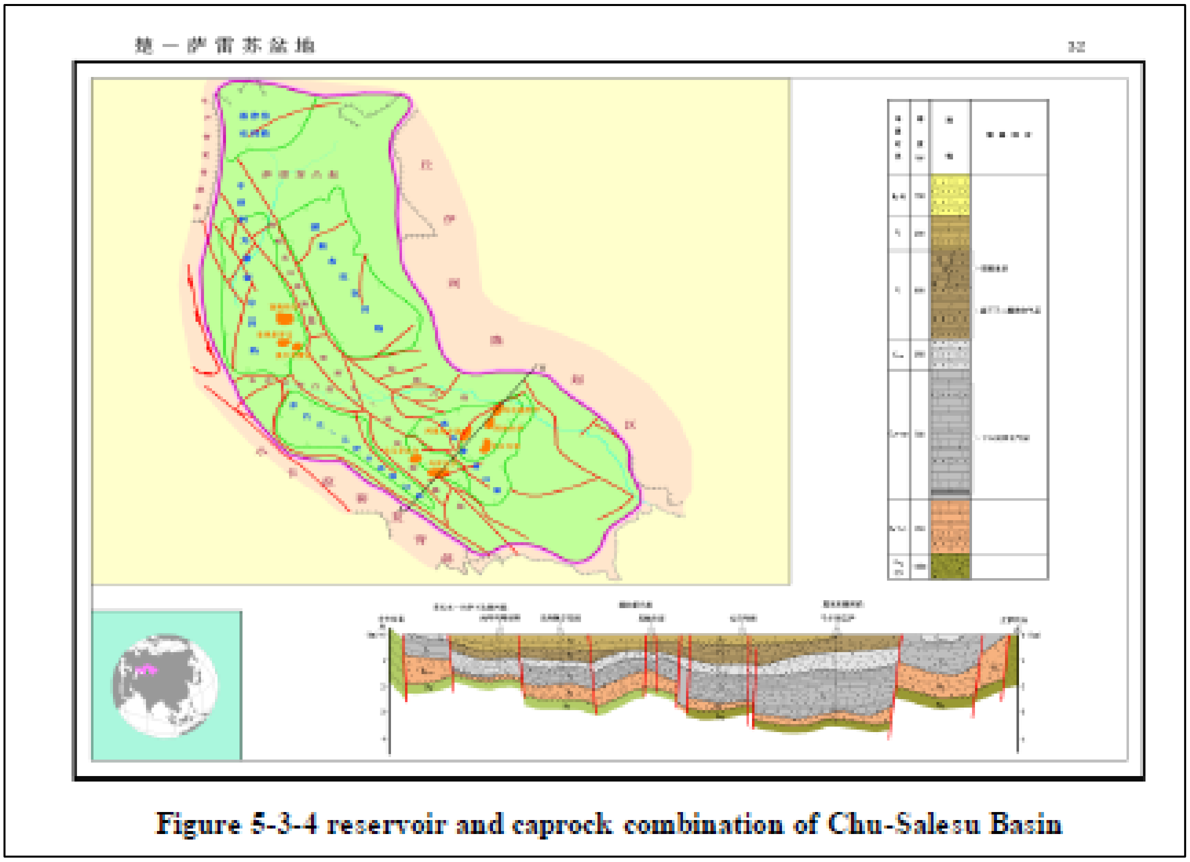


Figure 31: Reservoir and caprock combination of Chu-Salesu Basin (Shandong)

Several orogonies have metamorphosed and eroded all to nearly all pre-Carboniferous strata thus the thick, up to 1,200m, Lower Carboniferous is the earliest potential reservoir package. (Figure 32) Most of the oil source material in the adjacent Chu-Sarysu Basin is in Lower Carboniferous mudstones and shales. These organic rich rocks are reported to be sapropelic and although there is not a definitive test are expected to be of Type II affinity. Maturity is unknown but it has been reported to reach Ro of .3 and .4% in the T4 well in the Chu- Sarysu Basin. This would indicate that source rocks, if present in the Susamur Basin, should be mature at the expected depths. The Lower Carboniferous reservoirs are expected to be thick limestones with possibly interbeded thin marine sandstones.

The Upper Carboniferous (300-1,000m) is a volcanoclastic unit if the Susamur Basin is similar to the other basins to the northeast and northwest. Reservoirs are expected to be fractured tuffs, volcanic sills and poor quality clastic rocks.

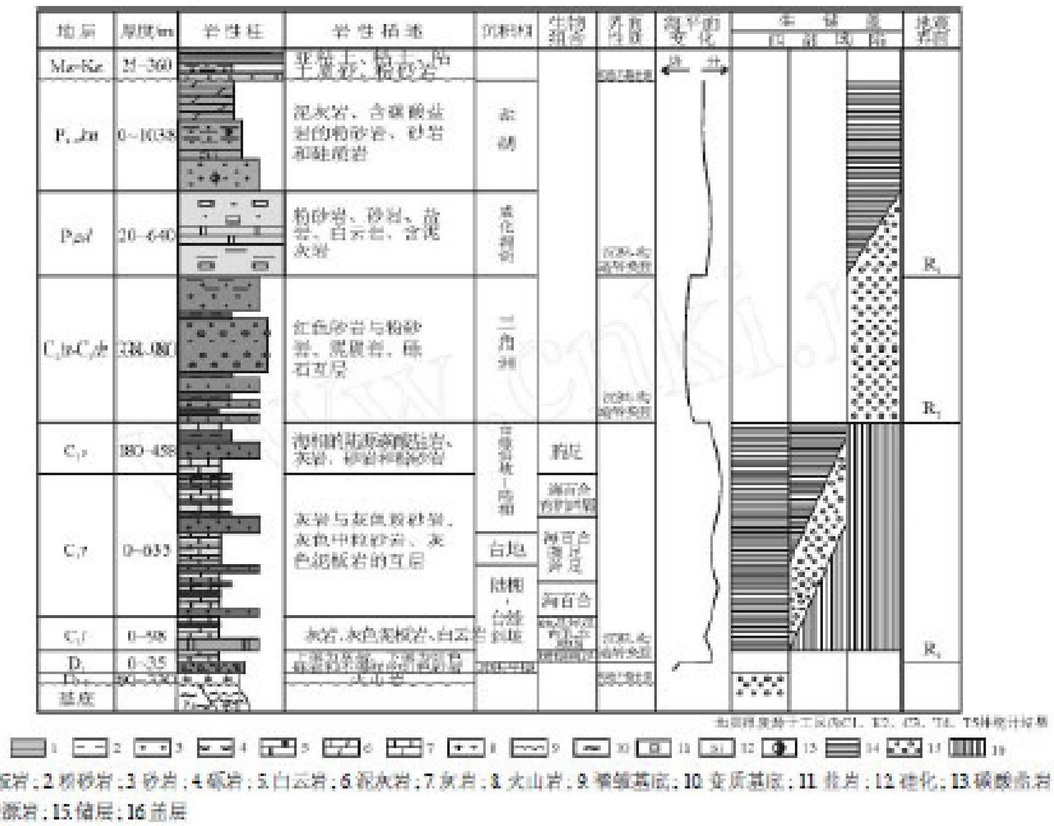


Fig 2 Sedimentary-tectonic evolution and source-reservoir-seal associations in the Zhezkazgan region
1 = mud slate; 2 = siltstone; 3 = sandstone; 4 = conglomerate; 5 = dolostone; 6 = marl; 7 = limestone; 8 = volcanic rocks; 9 = folded basement; 10 = metamorphic basement; 11 = salt rock; 12 = silicification; 13 = carbonate rock; 14 = source rock; 15 = reservoir rock; 16 = seal rock

Figure 32: Sedimentary-evolution and source-reservoir-seal associations of Susamur Basin (Shandong)

The Permian system is a continental system with some evaporates and it has a very high hydrocarbon charge risk as the Lower Carboniferous oil must migrate through the volcanic section and the evaporitic section before encountering the Permian reservoirs. Fault migration may assist the migration effort. The Permian is highly variable (20-1,600m in thickness) but if present could be excellent reservoirs.

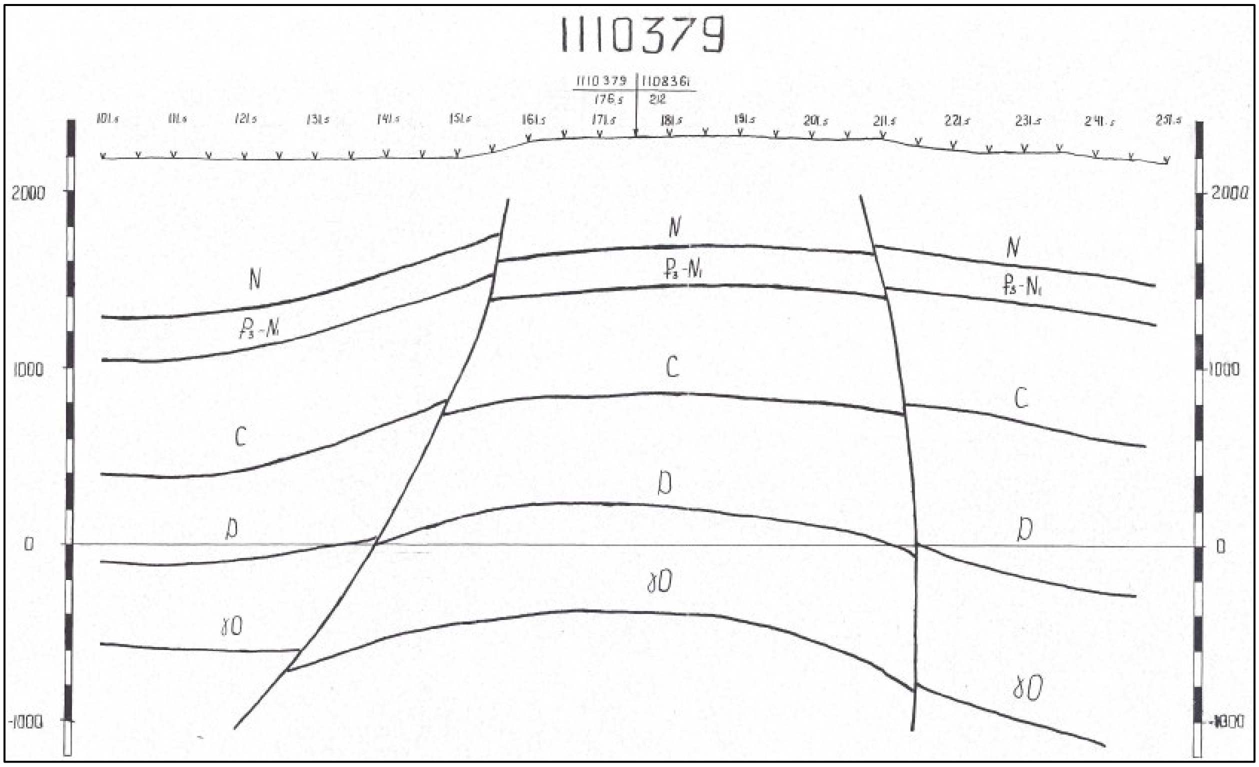


Figure 33: North-South geologic section map of Susamur Basin (Shandong)

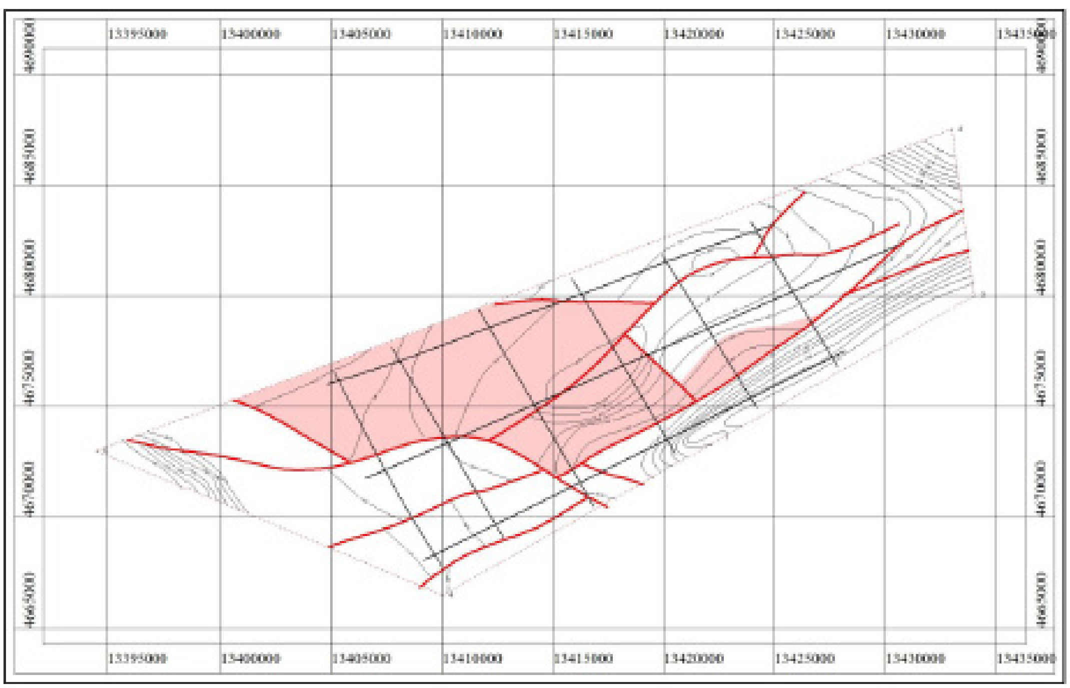


Figure 34: The constructional map of Paleozoic in Summary exploration area (Shandong)

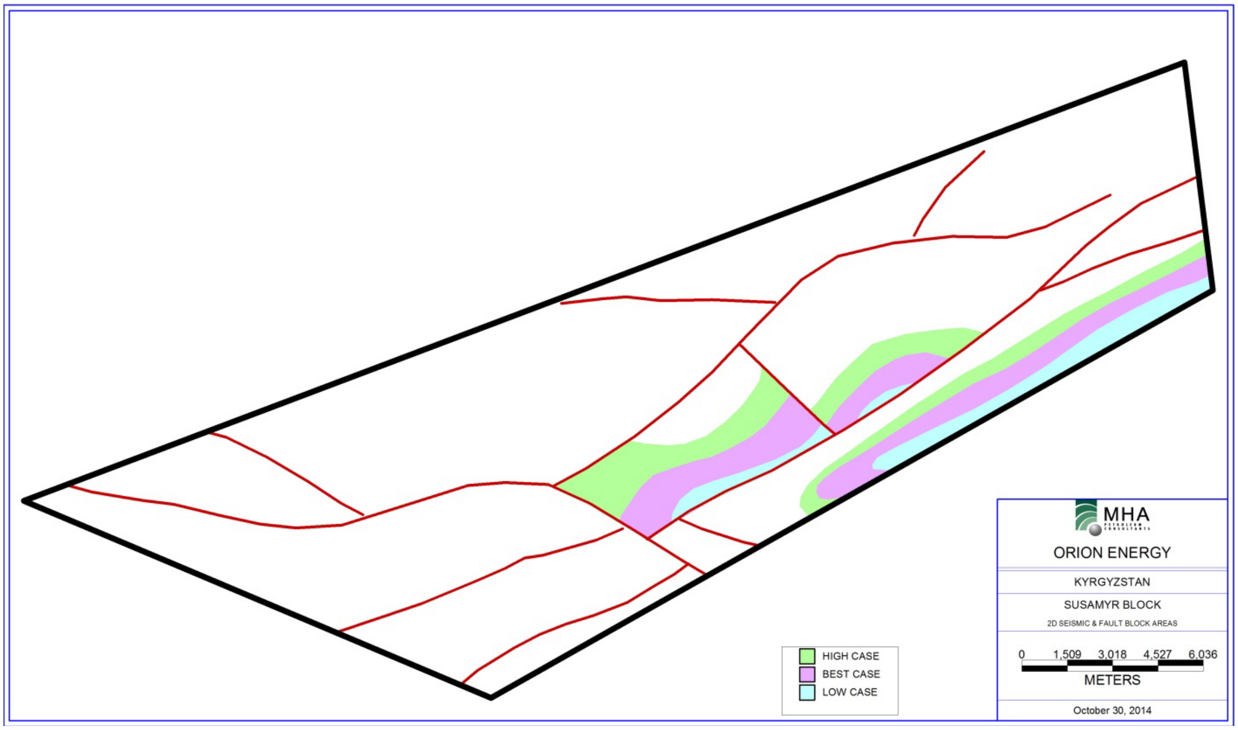


Figure 35: Diagram of MHA's interpretation of the fault blocks over the basin center doubly plunging anticline.

Figure 34 is the Soviet era seismic interpretation map of the Susamur Basin, a structural contour map at the top of the Carboniferous. Shandong highlighted three faultblocks (red) of primary interest. It is MHA's interpretation that there are five fault blocks that lay over the crest of a basin center doubly plunging anticline that form the most likely prospect (Figure 35). MHA has run a probabilistic range of original oil in place (OOIP) and Potential Resources (PR) for the three primary reservoirs (R1, R2, R3) in each of the 5 fault blocks and summed the results. The results are shown in Tables 11-12 below.

Table 11: Sumasur Prospective Resource Estimates in tonnes (Gross 100% ownership basis)

		Original Oil-in Place (tonnes)			Prospective Resources (tonnes)		
Fault Block	**Reservoirs**	**Low Case**	**Best Case**	**High Case**	**Low Case**	**Best Case**	**High Case**
Fault Block 1	R1, R2, R3	11,154,555	22,955,003	44,531,465	61,309	306,643	1,080,103
Fault Block 2	R1, R2, R3	6,183,973	13,644,016	29,309,383	165,823	767,831	2,638,014
Fault Block 3	R1, R2, R3	6,183,973	25,555,049	50,118,421	257,513	1,215,517	3,857,344
Susamur License Total		**23,522,501**	**62,154,067**	**123,959,269**	**484,644**	**2,289,991**	**7,575,461**

Table 12: Sumasur Prospective Resource Estimates in barrels (Gross 100% ownership basis)

		Original Oil-in Place (barrels)			Prospective Resources (barrels)		
Fault Block	**Reservoirs**	**Low Case**	**Best Case**	**High Case**	**Low Case**	**Best Case**	**High Case**
Fault Block 1	R1, R2, R3	76,185,609	156,782,669	304,149,904	418,739	2,094,374	7,377,103
Fault Block 2	R1, R2, R3	42,236,537	93,188,628	200,183,086	1,132,569	5,244,286	18,017,639
Fault Block 3	R1, R2, R3	42,236,537	174,540,984	342,308,818	1,758,811	8,301,980	26,345,658
Susamur License Total		**160,658,683**	**424,512,281**	**846,641,808**	**3,310,119**	**15,640,641**	**51,740,400**

Statement of Risk

The accuracy of resource evaluations is always subject to uncertainty. The magnitude of this uncertainty is generally proportional to the quantity and quality of data available for analysis. As a prospect, project, or well matures and new information becomes available revisions may be required which may either increase or decrease the previous estimates. By definition, a Play is a Proven Hydrocarbon System that is defined by known limits to the generative source rock area and to the limits of the known reservoirs and traps. Contingent Resources are volumes to be potentially recoverable from known accumulations, but not yet mature enough for commercial development, and thereby have their own degree of geologic and commercial risk. Prospective Resources are undiscovered prospects that each has their own degree of geologic and commercial risk. It is MHA's opinion that the estimated resources and other information as specified in this report are reasonable, and have been prepared in accordance with generally accepted petroleum engineering and geological evaluation principles. Further pre-drill evaluation of the prospects is warranted, particularly as regards to additional seismic data. As there are no reserves evaluated for this report there are no estimates of economic valuation.

Neither MHA, nor any of our employees have any interest in the subject properties and neither the employment to do this work, nor the compensation, is contingent on our estimates of the resources for the properties in this report. No MHA employee or contractor has visited the PEI's field facilities discussed in this report as this report is concerned with subsurface volumes only and uses data that was supplied by PEI. MHA has not verified the accuracy of the information provided to it during the course of this investigation. However, we have aimed to satisfy ourselves that all of the information provided has been prepared in accordance with proper industry standards and best practice, and is based on data that MHA considers to be of acceptable quality and reliability

This report was prepared for the exclusive use of FEO and will not be released by MHA to any other parties without FEO's written permission. MHA did not conduct a site visit to the licenses or any of the field offices, other than the PEI dataroom in Beijing, China. The data and work papers used in this preparation of this report are available for examination by authorized parties in our offices.

Thank you for this opportunity to be of service to FEO. If you have any questions or wish to discuss any aspect of the report further please feel free to contact me.

Kindest regards,

Jeffrey B. Aldrich
Vice President

Timothy L. Hower
Chief Executive Officer

Qualifications

Jeffrey B. Aldrich is a Certified Petroleum Geologist, #3791, by the American Association of Petroleum Geologists (AAPG) and is an active member of the AAPG and the Society of Petroleum Engineers (SPE). He has over thirty years as a practicing petroleum geologist\geophysicist and over twenty years of experience in oil and gas reserve evaluations. He holds a Bachelor's of Science degree in Geology from Vanderbilt University and a Master's of Science degree in Geology from Texas A&M University.

Timothy L. Hower is the Chief Executive Officer, and a full-time employee of MHA, and is a qualified person as defined under the ASX Listing Rule 5.42. He is a Registered Professional Engineer, a member of the SPE, and holds Bachelor's of Science and Master's of Science degrees in Petroleum Engineering from Penn State University. Mr. Hower has over thirty years of experience as a practicing reservoir engineer working on reserves and resource evaluations. This resource evaluation was prepared under Mr. Hower's direct control and supervision in accordance with the SPE Petroleum Resource Management System guidelines.

MHA Petroleum Consultants LLC is a leading independent petroleum engineering and independent certification firm based in Denver, Colorado which has experience working in most of the significant petroleum provinces throughout the world. MHA has completed reserve and resource assessments for numerous clients in Australia and internationally including Shell, Petrochina, Conoco Phillips, Santos, Woodside Petroleum, and Sunbird Energy.

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Appendix 1: Petroleum Resources Management System

The following is a summary of the 2011 ***"Guidelines for Application of the Petroleum Resources Management System"*** sponsored by the Society of Petroleum Engineers (SPE); the American Association of Petroleum Geologists (AAPG); the World Petroleum Council (WPC); the Society of Petroleum Evaluation Engineers (SPEE) and the Society of Exploration Geophysicists (SEG). A copy of the complete document can be downloaded from the SPE website (spe.org).

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

This document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 “Guidelines for the Evaluation of Petroleum Reserves and Resources”; the latter document remains a valuable source of more detailed background information, and specific chapters are referenced herein. Appendix A is a consolidated glossary of terms used in resources evaluations and replaces those published in 2005.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

This SPE/WPC/AAPG/SPEE Petroleum Resources Management System document, including its Appendix, may be referred to by the abbreviated term “SPE-PRMS” with the caveat that the full title, including clear recognition of the co-sponsoring organizations, has been initially stated.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project’s economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term “resources” as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth’s crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered “conventional” or “unconventional.”

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

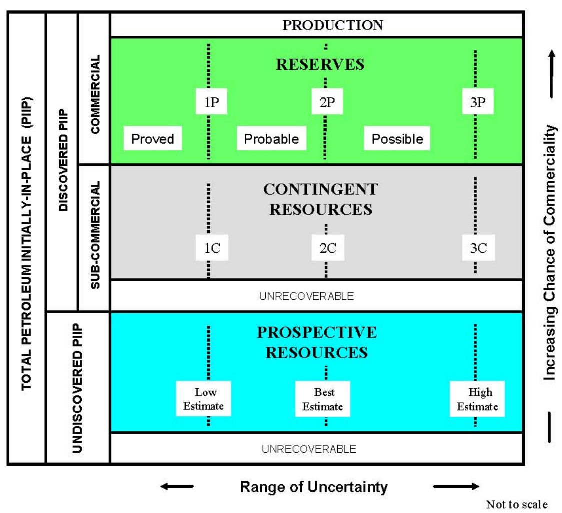

Figure 1-1: Resources Classification Framework.

The “Range of Uncertainty” reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the “Chance of Commerciality, that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to “total resources”).

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

In specialized areas, such as basin potential studies, alternative terminology has been used; the total resources may be referred to as Total Resource Base or Hydrocarbon Endowment. Total recoverable or EUR may be termed Basin Potential. The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." When such terms are used, it is important that each classification component of the summation also be provided. Moreover, these quantities should not be aggregated without due consideration of the varying degrees of technical and commercial risk involved with their classification.

1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

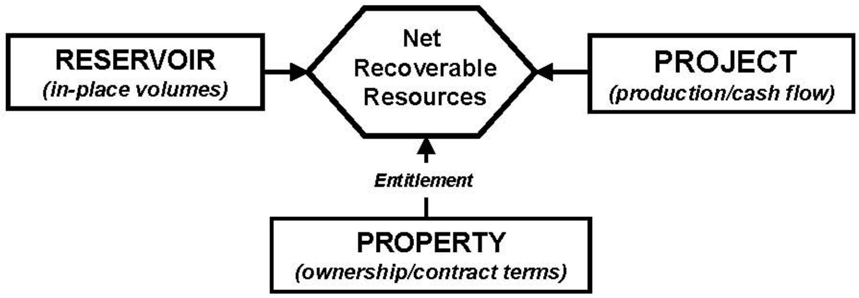

Figure 1-2: Resources Evaluation Data Sources.

The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.

- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.
- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see Commercial Evaluations, section 3.1). "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification system as shown in Figure 1-1. These guidelines reference this classification system and support an evaluation in which projects are "classified" based on their chance of commerciality (the vertical axis) and estimates of recoverable and marketable quantities associated with each project are "categorized" to reflect uncertainty (the horizontal axis). The actual workflow of classification vs. categorization varies with individual projects and is often an iterative analysis process leading to a final report. "Report," as used herein, refers to the presentation of evaluation results within the business entity conducting the assessment and should not be construed as replacing guidelines for public disclosures under guidelines established by regulatory and/or other government agencies.

Additional background information on resources classification issues can be found in Chapter 2 of the 2001 SPE/WPC/AAPG publication: "Guidelines for the Evaluation of Petroleum Reserves and Resources," hereafter referred to as the "2001 Supplemental Guidelines."

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria:
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available:
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.1.3 Project Status and Commercial Risk

Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized by standard project maturity level descriptions (qualitative) and/or by their associated chance of reaching producing status (quantitative).

As a project moves to a higher level of maturity, there will be an increasing chance that the accumulation will be commercially developed. For Contingent and Prospective Resources, this can further be expressed as a quantitative chance estimate that incorporates two key underlying risk components:

- The chance that the potential accumulation will result in the discovery of petroleum. This is referred to as the "chance of discovery."
- Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development."

Thus, for an undiscovered accumulation, the "chance of commerciality" is the product of these two risk components. For a discovered accumulation where the "chance of discovery" is 100%, the "chance of commerciality" becomes equivalent to the "chance of development."

2.1.3.1 Project Maturity Sub-Classes

As illustrated in Figure 2-1, development projects (and their associated recoverable quantities) may be sub-classified according to project maturity levels and the associated actions (business decisions) required to move a project toward commercial production.

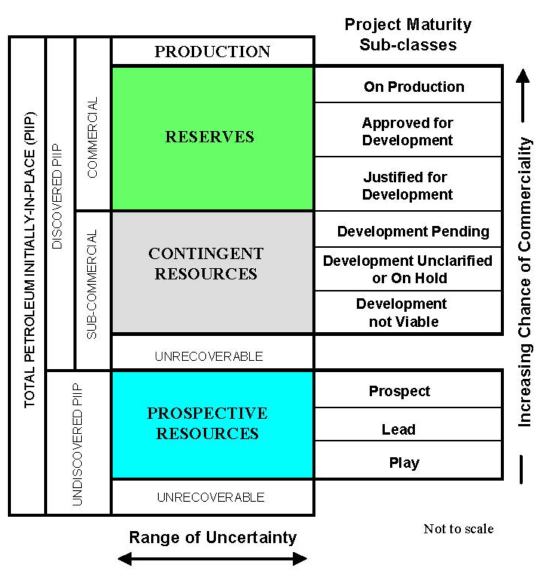

Figure 2-1: Sub-classes based on Project Maturity.

Project Maturity terminology and definitions have been modified from the example provided in the 2001 Supplemental Guidelines, Chapter 2. Detailed definitions and guidelines for each Project Maturity sub-class are provided in Table I. This approach supports managing portfolios of opportunities at various stages of exploration and development and may be supplemented by associated quantitative estimates of chance of commerciality. The boundaries between different levels of project maturity may be referred to as “decision gates.”

Decisions within the Reserves class are based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. For Contingent Resources, supporting analysis should focus on gathering data and performing analyses to clarify and then mitigate those key conditions, or contingencies, that prevent commercial development.

For Prospective Resources, these potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under appropriate development projects. The decision at each phase is to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity where a decision can be made to proceed with exploration drilling.

Evaluators may adopt alternative sub-classes and project maturity modifiers, but the concept of increasing chance of commerciality should be a key enabler in applying the overall classification system and supporting portfolio management.

2.1.3.2 Reserves Status

Once projects satisfy commercial risk criteria, the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan (detailed definitions and guidelines are provided in Table 2):

- Developed Reserves are expected quantities to be recovered from existing wells and facilities.
    - Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.
    - Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.
- Undeveloped Reserves are quantities expected to be recovered through future investments.

Where Reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Determination of Commerciality, section 2.1.2) is justified, a reasonable time frame is generally considered to be less than 5 years.

Development and production status are of significant importance for project management. While Reserves Status has traditionally only been applied to Proved Reserves, the same concept of Developed and Undeveloped Status based on the funding and operational status of wells and producing facilities within the development project are applicable throughout the full range of Reserves uncertainty categories (Proved, Probable and Possible).

Quantities may be subdivided by Reserves Status independent of sub-classification by Project Maturity. If applied in combination, Developed and/or Undeveloped Reserves quantities may be identified separately within each Reserves sub-class (On Production, Approved for Development, and Justified for Development).

2.1.3.3 Economic Status

Projects may be further characterized by their Economic Status. All projects classified as Reserves must be economic under defined conditions (see Commercial Evaluations, section 3.1). Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- Marginal Contingent Resources are those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.

- Sub-Marginal Contingent Resources are those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonably forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.

Where evaluations are incomplete such that it is premature to clearly define ultimate chance of commerciality, it is acceptable to note that project economic status is "undetermined." Additional economic status modifiers may be applied to further characterize recoverable quantities; for example, non-sales (lease fuel, flare, and losses) may be separately identified and documented in addition to sales quantities for both production and recoverable resource estimates (see also Reference Point, section 3.2.1). Those discovered in-place volumes for which a feasible development project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Economic Status may be identified independently of, or applied in combination with, Project Maturity sub-classification to more completely describe the project and its associated resources.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods. (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1 P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1 C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Table III presents category definitions and provides guidelines designed to promote consistency in resource assessments. The following summarizes the definitions for each Reserves category in terms of both the deterministic incremental approach and scenario approach and also provides the probability criteria if probabilistic methods are applied.

- Proved Reserves are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

- Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

- Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the “best estimate” is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see “2001 Supplemental Guidelines,” Chapter 2.5).

2.3 Incremental Projects

The initial resource assessment is based on application of a defined initial development project. Incremental projects are designed to increase recovery efficiency and/or to accelerate production through making changes to wells or facilities, infill drilling, or improved recovery. Such projects should be classified according to the same criteria as initial projects. Related incremental quantities are similarly categorized on certainty of recovery. The projected increased recovery can be included in estimated Reserves if the degree of commitment is such that the project will be developed and placed on production within a reasonable timeframe.

Circumstances where development will be significantly delayed should be clearly documented. If there is significant project risk, forecast incremental recoveries may be similarly categorized but should be classified as Contingent Resources (see Determination of Commerciality, section 2.1.2).

2.3.1 Workovers, Treatments, and Changes of Equipment

Incremental recovery associated with future workover, treatment (including hydraulic fracturing), re-treatment, changes of equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed or Undeveloped Reserves depending on the magnitude of associated costs required (see Reserves Status, section 2.1.3.2).

2.3.2 Compression

Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in Reserves estimates. If the eventual installation of compression was planned and approved as part of the original development plan, incremental recovery is included in Undeveloped Reserves. However, if the cost to implement compression is not significant (relative to the cost of a new well), the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

2.3.3 Infill Drilling

Technical and commercial analyses may support drilling additional producing wells to reduce the spacing beyond that utilized within the initial development plan, subject to government regulations (if such approvals are required). Infill drilling may have the combined effect of increasing recovery efficiency and accelerating production. Only the incremental recovery can be considered as additional Reserves; this additional recovery may need to be reallocated to individual wells with different interest ownerships.

2.3.4 Improved Recovery

Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir performance. It includes waterflooding, secondary or tertiary recovery processes, and any other means of supplementing natural reservoir recovery processes.

Improved recovery projects must meet the same Reserves commerciality criteria as primary recovery projects. There should be an expectation that the project will be economic and that the entity has committed to implement the project in a reasonable time frame (generally within 5 years; further delays should be clearly justified).

The judgment on commerciality is based on pilot testing within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the analysis on which the project is based.

These incremental recoveries in commercial projects are categorized into Proved, Probable, and Possible Reserves based on certainty derived from engineering analysis and analogous applications in similar reservoirs.

2.4 Unconventional Resources

Two types of petroleum resources have been defined that may require different approaches for their evaluations:

- Conventional resources exist in discrete petroleum accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water. The petroleum is recovered through wellbores and typically requires minimal processing prior to sale.
- Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrates, natural bitumen, and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders).

For these petroleum accumulations that are not significantly affected by hydrodynamic influences, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum may not be possible. Thus, there typically is a need for increased sampling density to define uncertainty of in-place volumes, variations in quality of reservoir and hydrocarbons, and their detailed spatial distribution to support detailed design of specialized mining or in-situ extraction programs.

It is intended that the resources definitions, together with the classification system, will be appropriate for all types of petroleum accumulations regardless of their in-place characteristics, extraction method applied, or degree of processing required.

Similar to improved recovery projects applied to conventional reservoirs, successful pilots or operating projects in the subject reservoir or successful projects in analogous reservoirs may be required to establish a distribution of recovery efficiencies for non-conventional accumulations. Such pilot projects may evaluate both extraction efficiency and the efficiency of unconventional processing facilities to derive sales products prior to custody transfer.

3.0 Evaluation and Reporting Guidelines

The following guidelines are provided to promote consistency in project evaluations and reporting. "Reporting" refers to the presentation of evaluation results within the business entity conducting the evaluation and should not be construed as replacing guidelines for subsequent public disclosures under guidelines established by regulatory and/or other government agencies, or any current or future associated accounting standards.

3.1 Commercial Evaluations

Investment decisions are based on the entity's view of future commercial conditions that may impact the development feasibility (commitment to develop) and production/cash flow schedule of oil and gas projects. Commercial conditions include, but are not limited to, assumptions of financial conditions (costs, prices, fiscal terms, taxes), marketing, legal, environmental, social, and governmental factors. Project value may be assessed in several ways (e.g., historical costs, comparative market values); the guidelines herein apply only to evaluations based on cash flow analysis. Moreover, modifying factors such contractual or political risks that may additionally influence investment decisions are not addressed. (Additional detail on commercial issues can be found in the "2001 Supplemental Guidelines," Chapter 4.)

3.1.1 Cash-Flow-Based Resources Evaluations

Resources evaluations are based on estimates of future production and the associated cash flow schedules for each development project. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project.