Integrated approach to gas accumulation identification in Field M

K Malyshevskaya\textsuperscript{1,2}, V Rukavishnikov\textsuperscript{1} B Belozerov\textsuperscript{2} and A Podnebesnikh\textsuperscript{2}

\textsuperscript{1}Tomsk Polytechnic University, Tomsk, Russia
\textsuperscript{2}LLC Gazpromneft Science and Technology Center, Saint Petersburg, Russia

E-mail: rukavishnikovvs@hw.tpu.ru

Abstract. The given paper describes how the integration of different methods, such as core data, well logs, production logging, seismic data and well test analysis, was used to solve the problem of determining gas accumulation boundaries in sediment complex PK1-3 of Field M. This paper is devoted to the block with wells 2, 36, 49, 85, 127, 148 of the field, since it is characterized by high uncertainty, sc. recently drilled wells 1V, 2V and 120 have produced oil, although according to the present-day geological concept they were considered to be gas saturated in the intervals investigated with production logging. Besides, well 127 that was presumably oil saturated has produced gas.

By accounting mismatching production data and the geological concept, the authors have supposed that PK1-3 gas accumulation is characterized by a more complex structure than it was supposed by the predecessors and it is represented by reservoir compartmentalization and high heterogeneity. Therefore, the main goal of the work was to revise the distribution of gas saturated reservoir within the PK1-3 sediment complex. To achieve this goal, the authors have set the following tasks: to revise the geological correlation and gas oil contact; to carry out fault interpretation by means of seismic and well test data; to determine areal facies distribution on the basis of integrated core, perform a log motifs and seismic facies analysis. Thus, the estimation of the gas saturated reservoir portion was implemented in two stages: defining the boundary of gas accumulation in depth on the basis of well logs, production data and fault interpretation; reservoir distribution determination on the basis of the seismic facies analysis within the derived gas accumulation boundary.

1. Introduction
Field M is located in the south-east of the Gydan Peninsula, Tazovskiy Region of the Yamalo-Nenets Autonomous District of the Tyumen province (figure 1). According to the regional tectonics, it is limited to the Srednemessoaykhskiy arch that represents part of the regional megalithic banks system with sublatitudinal extension. This field is located on the eastern local lifted block of the Srednemessoyakskiy arch.

On the basis of its hydrocarbon potential, Field M is related to the Messovskiy petroleum region of the Gydan petroleum area. According to the present-day geological concept, most reserves are concentrated in the PK1-3 sediment complex being part of the Pokurskaya formation (Cenomanian age) overlain by the regional shaly seal of the Kuznetsovskaya formation (Turonian age). The top of the Pokurskaya formation is a regional lithostratigraphic marker and corresponds to regional seismic key reflector G.
In general, the PK1-3 sediment complex is comprised of grey siltstones and sandstones generated in the alluvial and lacustrine depositional environment and according to the present-day geological concept it is represented by a massive gas and oil reservoir divided into separate blocks by faults. According to [1], the eastern local arch was formed as a structural trap predominantly at the end of the Cretaceous period and at the beginning of the Paleogene period and later it was filled in with hydrocarbons. Most field reserves are concentrated in the block under study within wells 2, 36, 49, 85, 127, 148.

The direct development of the field will start in 2016. Nowadays, 27 exploration wells have been drilled with two water supply wells and two pilot bores 33PL and 13PL among them in Field M. Three horizontal wells have been drilled from pilot wells and the whole area of Field M is covered by 2D and 3D seismic surveys (figure 2).

Figure 1. Field location

Figure 2. Field M exploration maturity

2. Depositional environment
As for the present-day depositional environment, according to [18], PK1-3 is represented by a subaerial delta plain with three predominant facies: the first one is a floodplain facies comprising fine-grained rocks with rootlets, coal laminae and bioturbation deposited in low energy conditions; the second is floodplain facies deposited in high energy conditions and represented by distinct thin-bedded very fine to fine-grained sandstone with bioturbation and rootlets at the top. These facies are interpreted as the distinct distal parts of sheet flood area. The last facies is distributary channels.
consisting of sheet flood sandstones located near the channels and delta channels themselves. The sheet flood sandstones are represented by sandstones with rare current ripples and vegetation and the delta channels comprise massive to cross laminated fine to medium sandstones. The reservoir facies are delta channels and sheet flood sandstones, floodplain facies are a non-reservoir. The conceptual scheme of the depositional environment is illustrated in figure 3.

It should be noted that from the date when this depositional environment concept was worked out, a significant part of the wells were drilled, therefore, the facies distribution in the recently drilled wells was determined on the basis of matching the derived lithofacies and electrical log motifs (SP, GR) in the wells with and without cores.

Figure 3 Initial conceptual depositional environment for C interval [16]

3. Geological correlation
Since the recently drilled wells were not used in the present-day geological correlation, well correlation was revised to account data on new wells. According to the well correlation, investigated sediment complex PK1-3 can be divided into three intervals: A, B and C, while interval A can be subdivided into two zones: A1 and A2. Zone A1 includes the interbedding of all three facies and is characterized by shaly floodplain facies at the base. The thickness of A1 varies from 9.8 to 23.5 m and its petrophysical characteristics are the following: effective thickness ($H_{eff}$) is 8.8 m, porosity ($\phi$) is 27.6%, permeability ($k$) is 72.2 mD and hydrocarbon saturation ($Shc$) is equal to 59.2%. As for A2, its top is clearly picked as the bottom of the shaly layer in the lower part of A1. A2 is characterized by the predominance of the channel and proximal part of the delta facies, therefore, it has better reservoir properties than A1 and is regarded as a good reservoir. The thickness of this interval lies within the range of 18.8-44.3m and it has the following petrophysical properties: $H_{eff}$=19.5 m, $\phi$=29.7%, $k$=274.1mD and $Shc$=58.7%. Zone B is a non-reservoir unit, since it is represented by shaly rocks that can be obtained over the whole investigated area. The genesis of this shale interval (marine or continental) is undefined because of the absence of palynological studies. Perhaps this interval was formed during short-time transgression. The thickness of interval B varies from 1.5 to 7.3 m. Interval C is represented by predominantly thick channel facies and is characterized by the best reservoir properties: $H_{eff}$=35.9 m, $\phi$=33.2%, $k$=771.6 mD. However, hydrocarbons occur predominantly in interval A (and $Shc$ in interval C=42.3%).

4. Gas oil (water) contact
Gas oil (water) contact was determined on the basis of measurements acquired from resistivity, neutron and density logs and production data. An interval was considered to be gas saturated if it was characterized by different indicators of resistivity tools with different lengths, where the highest value corresponded to the longest tool. Another “fingerprint” of a gas saturated reservoir was small values of density logs and a relatively high value of neutron logs.

Thus, two levels of GOC were determined: the first GOC level is 784 m on average ($\pm$4m) in the block limited by wells 85, 49, 58 and the second level is 776 m in the block of well 127. The separate
gas accumulation with GOC level being equal to 811 m was defined in interval C of the block of well 127.

Different GOC levels in the above-mentioned blocks were presumed to be caused by reservoir compartmentalization due to faults, therefore, the next stage was the determination of impermeable faults from seismic and well test data.

5. Fault interpretation from seismic and well test data

Direct fault tracking was implemented by analyzing the vertical sections of the origin amplitude cube and horizontal slices of such attributes as “Variance” and “Ant tracking”. Besides, the directions of faults were determined with the help of the “Dip angle” attribute derived along the PK1-3 top time surface map (figure 4).

The attributes show that the area under study is characterized by the abundance of tectonic disruptions, and despite a rather high quantity of faults tracked during (orange color) and before (red color) this work, the full interpretation of all faults in the given area requires a great amount of time. Therefore, fault detection was concentrated on the area next to well 127 and 1V due to the high uncertainty in the geological concept connected with them.

Figure 4. Attributes used in fault interpretation with overlapped fault lines (a) Ant tracking (718 ms); (b) variance horizontal slice (718 ms); (c) dip angle extracted from the PK1-3 top time surface overlapped variance horizontal slice (718 ms)
In general, all the derived faults (by predecessors and directly in this work) are represented by sub-vertical disruptions, the combination of which generates the system of normal and reverse faults. In seismic sections, faults were determined by the vertical displacement of seismic events in the vertical direction and sharp amplitude alteration on both sides of the fault plane. Most derived faults are characterized by an increasing amplitude displacement magnitude up to the section. The maximum magnitude of amplitude displacement at the level of the PK1-3 top is equal to 100 m. It should be noted that the abundance of tectonic disruptions affects the wave pattern and, consequently, the interpretation results in all.

Fault transmissibility was estimated on the basis of well test data and conducted in horizontal wells 11G, 13G, 15G (pad 1), 31G, 33G (pad 2) and vertical well 120. It should be noted that the well test data analysis in this study was carried out only on the basis of the log-log plots represented in reports describing well test interpretation [15, 21, 22, 23, 24, 29], because raw data was not available. Since both pads are situated in proximity of the previously extracted faults (figure 5), the foremost well test results of these wells were considered.

![Figure 5. Location of horizontal wells with wells test data used for fault transmissibility analysis](image)

It should be noted that wells in one pad were operating and shut in practically at the same time that resulted in their interference with each other. Thus, the pad 2 drainage area of each well is far smaller than the distance to the fault (from the top of the perforation interval) and more than half of the distance between them (150 m), therefore, the effect from the sealing fault could be masked provided the build-up was long enough to reach LTR. As for the first pad, well 11G has unrepresentative data because of the small drawdown duration and as the remaining wells directly intersect extracted faults Nos. 2, 3 and 4. Analyzing the interference of the wells observed in pressure measurements shows that it is most probable that the presence of faults № 1, 3 and 4 was masked, since the distance from the top of the perforation interval to these faults is less than half of the distance between them (i.e. this fault is permeable at the interval of less than 150 m). As for fault No. 2, it is close to the completion interval.
top in well 13 G and it is most likely that this fault is permeable, otherwise, it would have been reflected on the log-log plot by a specific ½ slope.

Taking the aforesaid into consideration, it can be concluded that fault No.1 derived next to wells 85 and 1V is permeable and does not act as a barrier to flow, while the fault systems to the north from well 148 is considered to be impermeable because of the absence of well test data to verify this supposition.

6. Integration of results
Gas accumulation boundaries were determined on the basis of well logging data and fault interpretation. According to the interpretation of these data, two separate gas accumulations can be singled out in interval A due to the fault compartmentalization of well 127 and 1V. The first gas accumulation is at the level of 784 m on average (±4 m). Another gas accumulation is limited by the faults tracked around well 127; the depth level of this accumulation is 776 m (figure 6).

A separate gas accumulation was determined in interval C in the block of well 127. The depth level of this accumulation is 811 m and it is isolated from overlain interval A by the impermeable shale of interval B. Besides, the block with oil producing well 1V is also isolated.

---

**Figure 6.** Gas accumulation boundaries in interval A (on the left) and interval C (on the right) determined on the basis of well logs, production data and fault interpretation results

8. Seismic facies analysis
A seismic facies analysis was carried out to determine a gas saturated reservoir within gas accumulation boundaries previously defined by well logs and fault interpretation. As for this study, seismic facies were calculated by classifying the waveform in the original amplitude data, since this technique is supposed to be the most effective one [19, 20].

The possibility to calculate seismic facies within intervals A, B and C was estimated on the basis of the time thickness of a particular interval and correspondence of its depth thickness to the vertical seismic resolution (Table 1). Time thickness was considered to be sufficient for the seismic facies calculation if it covered more than 1.5 cycles of a seismic event (~30ms) for the more accurate
estimation of the waveform. Depth thickness was compared with the vertical resolution to evaluate the ability of seismic data to detect facies distribution features.

According to Table 1, the seismic facies calculation is more valid for the whole interval A, since the separate computation of seismic facies within interval A1 is supposed to be inaccurate due to its small time thickness. When it comes to interval B, its time and depth thickness are too small to be reliably reflected on seismic data.

| Zone | Time thickness | Depth thickness | Vertical resolution | Seismic facies calculation |
|------|---------------|----------------|---------------------|--------------------------|
| A1   | 19 ms         | 22 m           | 22.4 m              | +                        |
| A2   | 29 ms         | 17.5 m         | 24.8 m              | +                        |
| B    | 4.7 ms        | 6.3 m          |                     | +                        |
| C    | 38 ms         | 44.7 m         | 24.4 m              | +                        |

Table 1. Possibility of calculating seismic facies within intervals A, B, C

9. Seismic facies analysis within interval A

The optimal number of classes (model traces) for calculating seismic facies within this interval was determined on the basis of the correlation function (the degree of similarity of different model traces i, j as the function of the difference (i-j)), correlation maps and matching core and well logging data. This correlation function had to be represented by a straight line implying a correlation coefficient diminishing with the increase (i-j) and, consequently, accurate extraction of model traces (classes). As for the correlation maps, they had to be represented by the predominant value equal to ±70 %.

The minimum number of classes was set to be 3, since there are three facies as follows from the core data. The maximum number of classes was 15 and further it was chosen for a direct seismic facies calculation (figure 7).

Figure 7. Optimal number of classes for seismic facies calculation within interval A (a) and interval C (b)
The result of the seismic facies analysis is given in figure 8. According to the core data, all wells may be combined into the following groups on the basis of predominant facies:

- Delta channel facies: wells 58, 85, 57
- Proximal part of the delta plain (sheet flood sands): 127, 49, 42
- Alternation of delta and channel facies: 2, 148, 2V, 121, 120, 1V

The seismic facies for interval A clearly reveals the anomalies of purple-dark blue colors elongated in the north-east to the south-west direction. These anomalies presumably follow the paleochannel direction (highlighted by white stippled arrows), since they correspond to wells 85 and 58 with the predomination of channel facies. As for the wells characterized by the predomination of the proximal part of the delta plain facies, they are marked blue. Most wells with the alternation of all facies (148, 2V, 1V) do not correspond to one color that is presumably caused by the fact that such a frequent alternation of thin facies is out of seismic vertical resolution. It should be noted that the poor matching of the seismic facies in vicinity of wells 2, 120, 121 (with alternation of facies) and 57 (channel facies) is most likely caused by their location close to the large faults characterized by a collapsed wave pattern around them and, this in turn, affects seismic facies calculation. This supposition can be proved by correlation maps (figure 7) that illustrate a lower correlation coefficient along faults.

In order to make the seismic facies derived comparable with the facies observed in the core data, they were combined in three groups corresponding to the delta channels (1-3 classes of the dark blue color in figure 9), sheet flood sands (4-7 classes) and delta facies (8-15 classes).

The final gas saturated reservoir distribution was determined by extracting only reservoir facies, i.e. delta channels and sheet flood sandstones, within the gas accumulation boundary previously derived with well logs data and fault interpretation.

**Figure 8.** Seismic facies map, electrical log motifs and core facies for interval A.
10. Seismic facies analysis within interval C

The minimum number of classes for calculating seismic facies within this interval was set to 3 and the maximum number was set to 15. The optimal number of model traces for computing seismic facies within interval C is 9 (figure 9).

On the basis of the core data, the following well groups in compliance with the predominant facies may be discriminated:

- Wells with the predominance of delta channel facies: 57, 49, 127, 121
- Wells with the predominance of sheet flood sandstone facies: 120, 85
- Wells with the equal portion of delta channel facies and sheet flood sandstones facies: 2, 42.1V, 2V, 148

Figure 10 shows a seismic facies map calculated for interval C with the direction of paleochannels highlighted with white stippled arrows. By matching the seismic facies and core data, one can assume that the paleochannels corresponds to the purple-dark blue classes (1, 2) and consequently they were elongated from the north-west to the south-east along the direction of the wells with delta channels and combination of delta channels and sheet flood sandstones facies.

Another notation is contradiction in wells 2, 57, 120 and 121. Wells 2, 57, 121 do not correspond to the purple-dark blue color, unlike the remaining wells with delta channels and delta channels/sheet flood sandstones, while well 120 lies in the purple area, but is characterized by the predominance of sheet flood sandstones. Like in interval A, the aforesaid may be explained by the proximity of these wells to large faults.

The similarly with the interval A gas saturated reservoir distribution was defined by eliminating non-reservoir floodplain facies and putting them on the gas accumulation boundary determined in the previous section (figure 11).
11. Comparison with the present-day geological concept

According to the present-day geological concept, PK1-3 is represented by a massive homogeneous accumulation formed as a result of tectonic activity. In compliance with the described study in this paper, the sediment complex under consideration is characterized by high reservoir heterogeneity both in the vertical direction due to shale impermeable barriers to flow and the areal direction due to facies variation.
The present-day concept states a single gas-oil contact within the investigated block, while according to the concept developed in this paper, there are two separate blocks of a gas saturated reservoir in interval A, one of which is at the depth of 784 m and is limited by wells 85, 49, 58 and the second one is a block formed due to faults compartmentalizing, well 127. In addition, a single gas accumulation was determined in interval C of the block with well 127 at the depth of 811 m.

The alteration of the present-day geological concept may lead to changes in the development strategy. A more detailed discussion of this aspect will be given further.

12. Influence on development strategy
Since oil production in Field M is of prime importance, this article concentrates on the influence of geological concept alteration on the development strategy in terms of oil production efficiency. As direct field development has been only recommended currently, the development strategy arises from the geological features of present-day concept and PVT properties of fluids, i.e. a homogeneous reservoir with a single GOC and WOC in the block under study, small net pay thickness, three mobile fluids (gas, oil and water) and highly viscous oil (103.9 cPZ).

A well pattern is given in figure 12 and is represented by a line drive system with horizontal producers and deviated injectors to extract oil from small net pay thickness. As for the position of wells, they are supposed to be drilled within oil saturated thickness for 2 meters along the regional stress direction. Polymer injection is recommended to enhance oil mobility.

In general, the changes in the gas saturated reservoir portion represented by the concept in this paper will lead to the alteration of the oil saturated reservoir portion. The occurrence of different blocks implies their separate development. As for the waterflooding pattern, in case of a highly heterogeneous reservoir, the most common spot patterns used in practice to increase the probability of drilling a reservoir zone are 5, 7 or 9.

![Figure 12. Recommended development strategy [7]](image)

References
[1] Agalakov S E, Baburin A N, Besperlova S N, Bochkarev V S and Korovina I O 2007 *Geological Composition Features and Oil and Gas Bearing Capacity of Srednemessoyakhskiy Arch* Nedra-Consult SibNATS

[2] Ampilov Y P 2008 *From Seismic Interpretation to Modeling and Estimation of Oil and Gas Fields* Spektr, Moscow
[3] Boganik G N and Gurvich Y Y 2006 Seismic Survey. College Textbook Tver’

[4] Brown A R 1999 Interpretation of Three-Dimensional Seismic Data Published jointly by the American Association of Petroleum Geologists and the Society of Exploration Geophysicists, Tulsa, Oklahoma, USA

[5] Chopra Satinder and Marfurt Kurt J 1985 Seismic Attributes Mapping of Structure and Stratigraphy

[6] Desbrandes R 1985 Encyclopedia of Well Logging Imprimerie Nouvelle

[7] Fedorov M V, Podnebesnykh A V and Klimov M Y 2013 Techno-Economic Justification of Obtained Oil Recovery Factor and Condensate Recovery Factor for Field M Report Gazpromneft NTC Tyumen’

[8] Fedynsky V V, Ivanov L I, Polshkov M K, Puzyrev N N, Rapoport M B, Timoshin Y V and Mihalysev A V 1979 Application of a Combination of Geophysical Methods of Direct Detection of Oil and Gas Deposits World Petroleum Cong.

[9] Gogonenkov G N and Timurziev A I 2010 Strike-Slip Faults in the West Siberian Basin: Implications for Petroleum Exploration and Development Geology and Geophysics 3

[10] Heriot Watt University 2005 Reservoir Geophysics Manual

[11] Horne R N 2000 Modern Well Test Analysis Petroway Inc.

[12] Kasatkin V E 2012 Hydrocarbon In Place Estimation and Techno-Economic Justification of Obtained Oil Recovery Factor and Condensate Recovery Factor for Field M Report Gazpromneft NTC Tyumen

[13] Levitskaya T V 2012 MDT Interpretation Results Acquired in Water Supply Well 1V of M Field Gazpromneft NTC

[14] Levitskaya T V 2012 MDT Interpretation Results Acquired in Water Supply Well 2V of M Field Gazpromneft NTC

[15] Levitskaya T V, Mazhar V A 2013 Well Test Interpretation Results Acquired in Well 15G of Field M Gazpromneft NTC

[16] Lopatin A, Latypov E, Baraboshkin E, Petrov E, Aleshina O, Topunova G, Shakirova Y, Shevyakov V and Grobushkina O 2012 Kinematic and Dynamic Interpretation of 3D Cubes. Structural Interpretation of Horizons and Tectonic Model. Detailed Interpretation for PK1-3 FM. Detailed Interpretation within Cube 4 for MKH8-9, BU6_1-2, BU8 Halliburton Consulting and Project Management report, Moscow

[17] Lopatin A, Latypov E, Gavrilov S, Grobushkina O, Bardina N, Kasiyanov A, Shevyakov V, Kosenkova O and Shakhovalova E 2012 Structural Model Building. Building digital 3D Geological Model of Reservoir Within PK1-3 FM (Including all Accumulations), MKH8-9, BU6_1-2, BU8 (Including Accumulations within Cube 4) Halliburton Consulting and Project Management Report, Moscow

[18] Lopatin A, Latypov E, Tikpeny A, Russel K, Petrov E, Grobushkina O, Shevyakov V, Zavadskaya N Report 2012 “Lithofacies Model of Sediment Complex PK1-3 of Messoyakhskoe Field” Halliburton Consulting and Project Management Moscow

[19] Malyarova T N “Seismic Facies Analysis as Universal Method of Reservoir Composition Interpretation” Paradigm

[20] Malyarova T N and Ivanova N A 2006 Modern Methods of Seismic Facies Analysis Demonstrated on Case Studies VIII International Research and Practical Conf. “Geomodel-2006”

[21] Maslak S G 2013 Well Test Interpretation Results Acquired in Well 11G of Field M Gazpromneft NTC

[22] Mazhar V A, Levitskaya T V and Maslak S G 2013 Well Test Interpretation Results Acquired in Well 13G of Field M Gazpromneft NTC

[23] Mazhar V A, Levitskaya T V and Maslak S G 2013 Well Test Interpretation Results Acquired in Well 31G of Field M Gazpromneft NTC
[24] Mazhar V A and Maslak S G 2013 Well Test Interpretation Results Acquired in Well 33G of Field M Gazpromneft NTC
[25] Merkulov V P 2006 Reservoir Properties Evaluation and Express Analysis of Wireline Logs Tomsk
[26] Muromtsev V S 1984 Electrometrical Geology of Sand Bodies in Lithological Traps of Oil and Gas Moscow: Nedra
[27] Popova O I, Zinatulin M M and Konyaev D N Report 2010 Building Seismic Models for Reservoir Sediment Complexes of Field M on the Basis of Integrated Analysis of Well and Seismic Surveys by Means of Specific 3D Processing and Interpretation for Geological Exploration Optimization and Subsequent Development Slafneft-NPC, Tver’
[28] Reading H G et al. 1978 Sedimentary Environments and Facies Published by Blackwell Scientific Publications Oxford
[29] Ridel A A 2013 Well Test Interpretation Results Acquired in Well 120 of Field M Gazpromneft NTC
[30] Rovnin L I, Nesterov I I, Salmanov F K and Ervae Y G 1975 Laws Governing Oil and Gas Accumulations in Western Siberia World Petroleum Cong.
[31] Serra O 1985 Sedimentary Environments from Wireline Logs Schlumberger Houston
[32] Schlumberger Petrel 2011.1 Manual
[33] Sulimov D, Ezerskiy D, Philimonov A, Cyclakov A, and Egorov S 2013 Report. Interpretation of open Hole Well Logs Acquired in Well 121R of Field M Schlumberger
[34] Sulimov D, Ezerskiy D, Cyclakov A, Malinin Y and Egorov S Report 2013 Interpretation of Open-Hole Well Logs Acquired in Well 120 of Field M Schlumberger