Panterra Group

Gas and Condensate Reserve Estimate in Accordance with SPE-PRMS, Vostochno-Makarovskoye and Dobrinskoye Fields, Volgograd Region

Prepared for: LLC Gaznefteservis

Compiled by: LLC Panterra Group

Date: February 7, 2020

Attn.: Management
LLC Gazneftеservis
ul. Kiseleva 65, Saratov
February 7, 2020

Dear Sirs,

This report was prepared by LLC "Panterra Group" (hereinafter referred to as the "Panterra"), as of December 31, 2019.

Panterra is an independent qualified evaluator (QE) responsible for this report. Production of this report was supervised by Mr. Vadim Vasiliev who meets the requirements for the independent QE (see Appendix 1).

Panterra estimated net oil and gas reserves and future net revenues, as of December 31, 2019, attributed to the interests of LLC "Gazneftеservis" (GNS) in the Vostochno-Makarovskoye and Dobrinskoye fields located in the Volgograd region, Russian Federation.

The reserves and resources reported herein were estimated in accordance with the standards of Petroleum Resources Management System (PRMS), which was prepared by Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE). This document (PRMS) was prepared with participation of the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), the Society of Petroleum Evaluation Engineers (SPEE), the Society of Exploration Geophysicists (SEG), the Society of Petrophysicists and Well Log Analysts (SPWLA), the European Association of Geoscientists and Engineers (EAGE). It was approved by the SPE Board of Directors in June 2018. Definitions from the SPE-PRMS are included in Appendix 2 to this report.

Data and information used by QE for preparation of this report were provided by GNS to QE and were not independently verified by QE, as it was beyond the scope of our assignment. This report uses specific values, tables and discussions provided by GNS, which were not independently verified by QE.

Estimates herein, excluding parameters provided by other sources, reflect our competent opinions and depend on initial uncertainties related to interpretation of geological, geophysical and engineering information. These uncertainties include, but not limited to the following: 1) use of data on analogs and indirect data, and 2) use of professional conclusions. State policy and market conditions different from that were employed for this study can result in change of 1) total oil, condensate or gas production volumes, 2) actual rates, 3) sale prices, or 4) operating and capital expenses, in comparison with that were provided in this report. Minor precision inconsistencies may exist in the report due to truncation or rounding of intermediate and aggregated values.

С уважением,

Юдин Михаил
Заместитель генерального директора
по геологии ООО «Пантерра Групп»

Very truly yours,
Mikhail Yudin
Deputy Director General of Geology
LLC "Panterra Group"

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1. EXECUTIVE SUMMARY

Reserve estimate results, as of December 31, 2019, are shown below:

Table 1.1 – Reserve Summary

RESERVE CATEGORY	NET RESERVES				
	CONDENSATE		GAS		LPG
	Mbbl	Mt	MMcf	MMm^3	Mt
Proved developed producing	1,467	168	10,756	305	24
Total proved	1,467	168	10,756	305	24
Total probable	1,467	168	10,756	305	24

Table 1.2 – Reserves Summary by Field

RESERVE CATEGORY	NET RESERVES				
	CONDENSATE		ГАЗ		LPG
	Mbbl	Mt	MMcf	MMm^3	Mt
CATEGORY: TOTAL PROVED RESERVES					
DOBRINSKOYE	81	9	1,589	45	4
VOSTOCHNO-MAKAROVSKOYE	1,387	159	9,167	260	20
Total	1,467	168	10,756	305	24
CATEGORY: TOTAL PROVED PLUS PROBABLE					
DOBRINSKOYE	81	9	1,589	45	4
VOSTOCHNO-MAKAROVSKOYE	1,387	159	9,167	260	20
Total	1,467	168	10,756	305	24
CATEGORY: TOTAL POSSIBLE RESERVES					
Total	0	0	0	0	0

Recoverable reserve and resource estimates are based on the data and information provided to Panterra by GNS. Estimates can be changed when additional information is received, and also depend on uncertainties related to the application of solution factors. Maximum production volumes can significantly differ from the estimates presented in this report.

We relied on the information on ownership in the license areas provided by GNS, and accepted it as represented, as verification of such data and information was beyond the scope of this assignment.

The estimated proved developed producing reserves can be produced from existing wellbores operating as of the date of estimate in the report, i.e. as of December 31, 2019. Reserves for these wells were estimated by production decline extrapolation to economic limits (minimum allowable rate). Estimate of decline curves used geological and simulation models generated by Schlumberger.

Possible reserves were not estimated, as GNS does not have assets with such category.

Reserves estimates from volumetric calculations and from analogies are often less certain than reserve estimates based on well performance obtained over a period during which a substantial portion of the reserves was produced. Reserves were forecasted over the future field life of 3 years, no provision was made for expiration of production or exploration licenses.

2. GENERAL

The results presented in this Qualified Evaluator (QE)'s report are derived from the application of engineering and geological data provided to Panterra by GNS and, in some cases, of analog field data and public sources of information. Panterra did not independently gather any information other than that provided by GNS and other information from public domains. These data and information were accepted by Panterra as represented, as verification of such data and information was beyond the scope of this assignment. The fundamental data provided to Panterra included data acquired in drilling of wells (logs, cores, tests and fluid samples); production rate measurements and actual production histories; pressure measurements; and seismic data. Analysis of available data resulted in various conclusions on deposits with regards to the geological model, physical sizes and recovery process. Our reserve estimates were made with the use of deterministic method.

In general, infrastructure facilities look well maintained, without visible evidence of spills or other damage to the environment. The required guidelines for spill reduction, communication system and safety guidelines seem to be available.

Infrastructure facilities include various equipment for storage, treatment and metering, as well as appropriate office buildings. The description of facilities of each field is presented in the section "Field Infrastructure and Hydrocarbon Production".

3. REGION REVIEW

The territory of the Russian Federation can be divided into several basins. Three most important basins in reserves include West-Siberian, Volgo-Urals and Timan-Pechora. GNS license areas are located in the Volga-Urals oil and gas basin.

Volga-Urals along with Western Siberia are the largest oil and gas basins of Russia.

Volga-Urals was the largest region in production through late 1970s, then Western Siberia became the first. Today this region is second in production, accounting for about 22% of the total Russian production. The giant Romashkinskoye field (discovered in 1948) is the largest in the region.

Europe and Russia are interdependent on export of Russian energy products. Almost 30% of European oil import and over 30% of natural gas are accounted for Russian supplies. According to the Russian Federation Ministry of Energy, oil and gas yield about 8% of the gross domestic product of Russia. Below is the map showing major producing areas.

- GNS assets

The Volgo-Urals oil and gas basin is confined to the eastern part of the East-European platform and Pre-Urals foredeep; limited in the north and in the east by Timan and Urals, in the south borders the Pre-Caspian syneclise, and in the west – the Voronezhsky arch and Tokmovsko-Syselskaya arch system. The platform basement is Pre-Cambrian, heterogenic. In the eastern part of the platform the thickness of the Riphean-Vendian and Paleozoic mantle (with minor occurrence of the Mesozoic) is 9 to 12 km. Sedimentary interval is represented with continental, litoral-marine and marine (clastic and carbonate) formations of the Riphean-Vendian, Devonian, Carboniferous and Permian age. A number of major arches (Tatarsky, Permsko-Bashkirsky, Zhigulyovsko-Orenburgsky, etc.), depressions, swells and troughs are identified, which are complicated with over 2 thousand local uplifts, ranging from 1 x 2 to 10 x 50 km in size and from 10 to 100 m and more in amplitude. Commercial oil and gas discoveries

were made in the Devonian, Carboniferous and Permian, and oil shows were identified in the Riphean-Vendian rocks. Productive horizons were identified at the depth ranging from 0.5 to 5 km and more. Deposits are mainly sheet four-way closure, lithologically truncated sheet four-way closure, massive, and, in a small number, are faulted. Well rates at normal hydrostatic pressures are medium (up to 100-200 t/day) and low. As a rule, deposits are developed with formation pressure maintenance.

The generalized stratigraphic column of the Volgo-Urals basin is shown in Table 3.1.

Table 3.1 - Generalized stratigraphic column, Volgo-Urals basin

SYSTEM	EPOCH	STAGE	HORIZON	FIELD	LITHOLOGY
CRETACEOUS	Upper				
	Lower	Albian			Shaley sandstone
		Aptian			Sandstone
JURASSIC	Upper				Calcareous shale
	Middle				Shale
	Lower				Sandey shale
TRIASSIC	Upper				N/A
	Middle		Indersky		Limestone
	Lower				Limestone/Shale
PERMIAN	Upper	Tatarian			Calcareous shale
		Kazanian			Limestone
		Ufimian	Sheshminsky		Limestone
	Lower	Artinskian			Limestone
		Sakmarian			Limestone
		Asselian			Limestone
CARBONIFEROUS	Upper	Orenburgian			Limestone
		Gzelian			Limestone
		Kasimovian			Limestone
	Middle	Moscovian	Myachkovsky		Limestone
			Podolsky		Limestone
			Kashirsky		Sandstone
					Limestone
		Bashkirian			Limestone
	Lower	Serpukhovian	Protvinsky		Limestone
			Aleksinsky		Limestone/Sandstone
			Tulsky		Sandstone
			Bobrikovsky	Vostochno-Makarovskoye	Sandstone
			Radayevsky		Shaley limestone
		Tournaisian			Limestone
DEVONIAN	Upper	Famennian	Zavolzhsky		Limestone
			Lebedyano-Dankovsky		Limestone
			Zadonsko-Yeletsky		Dolomite

SYSTEM	EPOCH	STAGE	HORIZON	FIELD	LITHOLOGY
		Frasnian	Евланско-левинский	Vostochno-Makarovskoye Dobrinskoye	Dolomite
			Voronensky		Limestone
			Buregsky		Limestone
			Mendimsko-Semiluksky		Limestone
			Domanikovsky		Shaley limestone
			Sargayevsky		Limestone
			Kynovsky		Sandstone
			Pashyisky		Sandstone

4. REGULATORY PROVISIONS

Regulations of Russian Petroleum Industry

Legislative and regulatory framework for the Russian petroleum industry is based (in each case, as amended from time to time) on the Constitution of the Russian Federation, the Civil Code and the Law of the Russian Federation "On the Subsoil", dated February 21, 1992 (the "Subsoil Law"), Federal Law No. 147-FZ on Natural Monopolies, dated August 17, 1995 (the "Law on Monopolies"), Federal Law No. 187-FZ, dated November 30, 1995 "On the Continental Shelf of the Russian Federation", dated November 30, 1995 (the "Continental Shelf Law") and Federal Law No. 225-FZ "On Production Sharing Agreements", dated December 30, 1995 (the "PSA Law").

The principal Russian federal authorities regulating the Russian petroleum industry include the Russian Federation Government, the Ministry of Natural Resources and Ecology, the Federal Agency for Subsoil Use, the Federal Service for Ecological, Technological and Nuclear Supervision, the Ministry of Energy, and the Federal Tariff Service. The Ministry of Natural Resources and Ecology and other agencies under its auspices, including the Federal Agency for Subsoil Use, the Federal Service for Supervision of Use of Natural Resources, and the Federal Service for Ecological, Technological and Nuclear Supervision implement and monitor subsoil legislation and are responsible for granting, monitoring and terminating subsoil licenses. The Ministry of Energy and the Federal Tariff Service regulate and oversee the oil transportation, among other things.

Subsoil Licensing

Rights to explore and produce oil and gas are granted under mineral licenses issued by the Federal Agency for Subsoil Use (Rosnedra). Three relevant categories of subsoil license are as follows:

1. Licenses for the exploration and assessment
2. Licenses for the production of natural resources

3. Combined licenses for the exploration, assessment and production of natural resources.

The maximum term of an exploration license is five years (or 10 years for offshore exploration), whereas a production license may be issued for the useful life of the mineral reserves field, calculated on the basis of an exploration and production feasibility study that ensures the rational use and protection of the subsoil. The Subsoil Law also provides that the license to use a field may be extended by the relevant authorities at the request of the license holder, if an extension is necessary to finish production in the field, provided that the license holder has not violated the terms of its license. To date, the major Russian oil companies have not experienced significant problems with the extension of their licenses.

Production licenses and combined exploration and production licenses are granted following a tender or auction conducted by the Federal Agency for Subsoil Use. In a tender process, the winner is a bidder who submits the most technically competent, financially attractive, and environmentally sound proposal that meets published tender terms and conditions. In an auction process, the bidder who submits the highest price wins. Production licenses may also be issued, without holding an auction or tender, to holders of exploration licenses who discover mineral resource deposits through exploration operations conducted at their own expense. Offshore licenses may be granted without a tender or auction in certain cases.

Licenses may be transferred only in certain limited circumstances under the Subsoil Law, including the reorganization or merger of the license holder, or in the event that an initial license holder transfers its licenses to its subsidiary, its parent company, or a "sister" company, provided that certain conditions established by the Subsoil Law are met. The transfer of licenses for federal plots deemed to be of strategical significance to entities under non-Russian participants is generally prohibited.

A license holder has the right to develop and sell oil produced from the license area that it owns. The Russian Federation, however, retains ownership of all subsoil resources at all times, and the license holder has rights to the crude oil only when produced, provided that such right is envisaged with relevant licenses. Licenses generally require the license holder to make various commitments, including the following:

1. Extracting any agreed target amount of reserves annually
2. Conducting agreed drilling and other exploration and development activities
3. Protecting the environment in the fields
4. Providing geological information and data to the relevant authorities
5. Submitting formal progress reports to regional authorities on a regular basis
6. Paying the mineral extraction tax when due

The Federal Service for Supervision and Use of Natural Resources and its regional divisions monitor license holders' compliance with the terms of their licenses and subsoil legislation. A license holder can be fined for failing to comply with the terms of its licenses, and a license can be revoked, suspended, or limited in certain circumstances, including the following:

1. Breach or violation by the license holder of material terms and conditions of the license
2. Repeated violation of the subsoil regulations by license holder
3. Failure by the license holder to commence operations or to produce the required volumes as specified in its license
4. An emergency situation
5. A direct threat to the life or health of people working or residing in the area affected by the operations under the license
6. Liquidation of the license holder, or
7. Failure to submit reporting data in accordance with applicable law

In addition, under the Subsoil Law, a license is automatically terminated in certain cases stipulated in the license, or in the event of a transfer of the license in breach of the procedure set out in the Subsoil Law.

Upon the expiry of a license or termination of the subsoil use, all infrastructure facilities in the relevant license area, including underground infrastructure facilities, must be removed or properly abandoned. All site facilities, including oil wells, must be maintained so that they are safe for the surrounding population, the environment, buildings, and other infrastructure facilities. Abandonment procedures must also ensure the conservation of the relevant oil fields, mining facilities and wells.

Land Use Permits and Plot Allotments

In addition to a subsoil license, surface rights to the license area are required. Subsoil licenses do not grant any surface rights, which must be obtained separately from subsoil licenses. Most land in the Russian Federation is owned by federal, regional, or municipal authorities that can sell, lease or grant other rights for the use of the land to third parties through public auctions or tenders, or private negotiations.

Surface rights are typically granted for specified areas upon the submission of standard reports, technical studies, pre-feasibility studies, budgets, or environment impact statements. Documents that grant surface rights generally require that the holder make land payment and return the land plot to the condition sufficient for future use, at the license holder's expense, upon the expiry of the permit.

Subsoil Use Payments

Effective January 1, 2002, the previous system of subsoil use payments was modified by merging royalties, excise taxes, and mineral replacement fee into a single tax called the mineral extraction tax. In addition, subsoil users are required to make or pay the following:

1. One-time payments in the circumstances specified in the license
2. Regular payments for subsoil use, such as rental payments for the right to conduct prospecting/appraising and exploration operations
3. Payments to the state for geological subsoil information
4. Fees for the right to participate in tenders and auctions
5. Fees for the issuance of license

The rates for such payments are generally set forth in the relevant license by the federal authorities within a range of minimum and maximum rates established by the Subsoil Law.

Environmental Requirements

Russian environmental law establishes a "pay-to-pollute" regime administered by the Federal Service for Ecological, Technological, and Nuclear Supervision and local authorities. Fees are assessed both for pollution within the agreed-on emissions and effluents limits, and for pollution in excess of these limits. There are additional fines for certain other breaches of environmental regulations and documents. Under the environmental protection law, compensation must be paid to the budget for all environmental losses caused by pollution. The prosecutor's office or other authorized governmental bodies may bring proceedings, if there is a dispute over losses caused by breaches of environmental laws and regulations; there is no right to seek damages for such losses in civil law. Courts may impose clean-up obligations subject to the agreement between the parties in lieu of or in addition to imposed fines.

Exploration licenses and production licenses generally require license holders to agree to certain environmental commitments. Although such commitments may be stringent in a particular license, the penalties for failing to comply with clean-up requirements are generally low. Subsoil users are also subject to obligations concerning the decommissioning of operational facilities and the soil recultivation or groundwater purification at their facilities when they cease operations.

GNS Licenses

GNS has provided information regarding each licenses it holds. Panterra has not independently verified the data on the licenses. Our reserve estimates are not limited by the license expiration date, because GNS expects its licenses to be updated before their expiration. Information on license's expiration dates is summarized below:

Table 4.1 – Summary of License Expiration Dates

FIELD	PRODUCT TYPE	LICENSE NO. AND TYPE	ISSUE DATE	LICENSE EXPIRATION DATE
Dobrinskoye	gas, condensate	ВЛГ 01998 НЭ	July 2012	January 2026
Vostochno-Makarovskoye	gas, condensate	ВЛГ 01323 НЭ	June 2006	June 2026

5. OVERVIEW OF ASSETS

Vostochno-Makarovskoye and Dobrinskoye Fields

Administratively, the Vostochno-Makarovskoye and Dobrinskoye fields are located within the Zhirnovsky district, Volgograd region, near the northeastern boundary with the Saratov region.

In accordance with the geological oil and gas zonation the Vostochno-Makarovsky and Dobrinsky license areas are related to the Lower-Volga oil and gas region (OGR). The Vostochno-Makarovskoye field was discovered in 1989 as a part of the single Makarovskoye field. The Dobrinskoye field was discovered in 1987 in prospecting Well No. 22, which was drilled in the crest of a reef uplift. Geologically, the structure include the Paleozoic, Mesozoic and Cenozoic. Commercial presence of gas is confined to the Bobrikovsky sandstones and reefogenic Upper Frasnian, Yevlanovsky-Livensky age.

The field is located within the Aleshnikovskaya prospect of the Dobrinsko-Ilovlinskaya reef system. The geological structure of the Vostochno-Makarovskoye uplift was mapped on nine reflectors. In 2007 and 2016 3D seismic acquisition was performed in the license area.

In that year only 2D seismic acquisition was performed in the Dobrinskoye field. The survey resulted in structure building on five reflectors.

In 2019 Schlumberger performed the work "Updating Geological Structure and Optimization of Development, Vostochno-Makarovskoye Field", which included seismic data interpretation, log data analysis, special core analyses, building a geological and simulation model of the field. The work resulted in an update of field reserves and justification of hydrocarbon production forecast.

The field well count includes:

- Vostochno-Makarovskoye - 6 wells
- Dobrinskoye – 2 wells

By reservoir type, the Yevlanovsky-Livensky gas/condensate deposit of the Vostochno-Makarovskoye field is massive, with aquifer. The deposit height to the lowest known gas is 187.3 m. The Yevlanovsky-Livensky deposit is 3.9 x 1.7 km in size. Reservoir rock is composed of dense, hard and vuggy dolomites.

The Yevlanovsky-Livensky horizon is penetrated in all wells. To the southwest of the crestal part of the uplift the reefogenic productive interval is replaced with denser, tight carbonates. The gross thickness of the Yevlanovsky-Livensky horizon ranges from 28.4 m to 312.9 m, averaging 156.6 m. The gas net pay thickness ranges from 5.4 m to 167.5 m. The average gas net pay thickness is 72 m. Attachment 3 shows the structure map and the gas isopach map of the Yevlanovsky-Livensky deposit.

The Yevlanovsky-Livensky interval was tested in all wells drilled at the Vostochno-Makarovskoye field. Well test data allowed for adequate update of the deposit geometry, establish GWC, and study the fluid properties.

DST data on Well No. 42 at the interval of 2,824-2,849 m (-2,533.1-2,558.0 m subsea) proved the reservoir was wet. By log data confirmed by test data, Well No. 62 had no reservoir encountered. Test data on Wells Nos. 30 Dobrinskaya, and 1, 2, 4 Vostochno-Makarovskoye, proved the presence of gas-bearing reservoir rocks. The location of GWC is established at -2,465.3 m subsea by log data on Well No. 4 Vostochno-Makarovskoye. By IL, LL and LLS (large sonde) data resistivity is lower at this depth. The employed GWC is confirmed by test data on Well No. 4.

By reservoir type, the deposit of the Bobrikovsky sandstones, Vostochno-Makarovskoye field, is sheet, four-way closure, with aquifer. The Bobrikovsky deposit is 1.4 km x 1.6 km in size.

Productivity of the Bobrikovsky horizon is confined to clastic reservoir rocks (sandstone and siltstone). Two reservoirs are identified in the horizon. The net pay thickness of the upper I reservoir ranges from 3 m to 3.7 m. The I reservoir is continuous and occurs in all wells. Core analysis data proved that I reservoir sandstones are of the best reservoir properties. The lower II reservoir is composed of sandstone of, seemingly, bar type. The net pay thickness of the II reservoir ranges from 28.3 m to 37.5 m, with the gas net pay thickness of 8.7 m. Attachment 3 shows the structure map and the gas isopach map of the Bobrikovsky deposit. DST was performed in the Bobrikovsky horizon of all the wells, except for Well No. 62 Dobrinskaya. GWC is employed at -1,627.2 m subsea, i.e. at the base of reservoir rock identified in Well No. 42.

The commercial presence of gas proved by test data on Well No. 22 at the Dobrinskoye field is related to the Yevlanovsky-Livensky. In productive Well No. 26 the gas net pay thickness is up to 57.9 m, whereas in Well No. 22 – 34.4 m; in other wells of the field the reservoir is wet. The gross thickness of the Yevlanovsky-Livensky within the field is 42.2 m, with the net pay thickness of reservoir rocks of 31.8 m. The average gas net pay thickness of the deposit is 31.6 m.

By log data on the wells, reservoir rocks of reef type have sufficient homogeneity, without tight streaks. Stratification and continuity ratios (analog to net-to gross ratio for carbonate reservoir rocks) are assumed to be 1.

The gas-water contact was determined by both test, and log data. First, with formation tester Well No. 22 tested 20 Mm^3/day of gas at the drawdown of 5.7 MPa from the interval of 2,613 – 2,630 m (- 2,387.9 – 2,404.9 m subsea), and then 211 m^3/day of formation water at the drawdown of 8.9 MPa from the interval of 2,629 – 2,640 m (– 2,403.9 – 2,414.8 m subsea). In cased hole the well tested 113 Mm^3/day of gas and 63 m^3/day of condensate through an 8-mm choke from the interval of 2,595 – 2,615 m (-2,369.7 - 2,391.9 m subsea). By log data on

Well No. 22 the gas-water contact was established at 2,624 m (-2,404 m subsea). Well No. 26 tested (in open hole) 90 Mm^3/day of gas and 40 m^3/day of condensate through a 7-mm choke from the interval of 2,580 – 2,610 m (-2,337.7 to 2,367.7 m subsea).

The deposit is massive, four-way closure, with the gas area of 2.22 km^2 and the height of 58 m.

Proved reserves were estimated for these fields.

Additionally, LPG (liquefied petroleum gas) reserves were estimated. LPG is produced at the LPG plant, with technical characteristics and construction timeline shown in Section 6, and the production cost - in Section 7.

Justification of Recoverable Reserves

Reservoir type of the Vostochno-Makarovskoye and Dobrinskoye fields is carbonate, porous-fractured-vuggy. Main gas reserves are held in porous matrix (60 % to 90% by various estimates). Fractured component serves as a transport environment and contains lower gas reserves (10% - 40%).

Runs of the dual-porosity (matrix-fracture) models of the Dobrinskoye field showed that breakthrough of bottom water in the fracturing system results in premature watering-out of wells, with even lift of GWC throughout the deposit area (Fig. 5.1). As a result, main gas reserves are stranded in porous blocks of the flooded part of the gas deposit. Due to capillary imbibition, some gas from porous blocks enters fractures and may float up to the top of deposit, replenishing free gas reserves. Sigma parameter and fracture capacity were determined by history match and simulation of well watering out using a 3D simulation model.

In December 2018, side-track No. 26 BS2 was drilled from Well No. 26 to the crestal part of the deposit at the Dobrinskoye field. To date, the well produces at high gas rate (100 - 300 Mm^3/day) and high operating wellhead pressure (16 - 17 MPa). There is no significant volume of formation water in well production. Condensate/gas ratio is 150 - 400 g/m^3. Higher condensate/gas ratio can result from gas coning from GOC at high gas rates. GOC is below lower perforations (Fig. 5.2).

Similar to the Dobrinskoye field, in 2019 oil and formation water cuts sharply increased in well production of the Vostochno-Makarovskoye field. Gas rates decreased to 30 - 100 Mm^3/day at operating wellhead pressure of 12 - 14 MPa, while condensate/gas ratio increased to 400 – 3,500 g/m^3 (Fig. 5.3). This data proves the rising gas/fluid contact to the crestal part of the deposit. Further estimates was based on reserve estimates performed by Schlumberger.

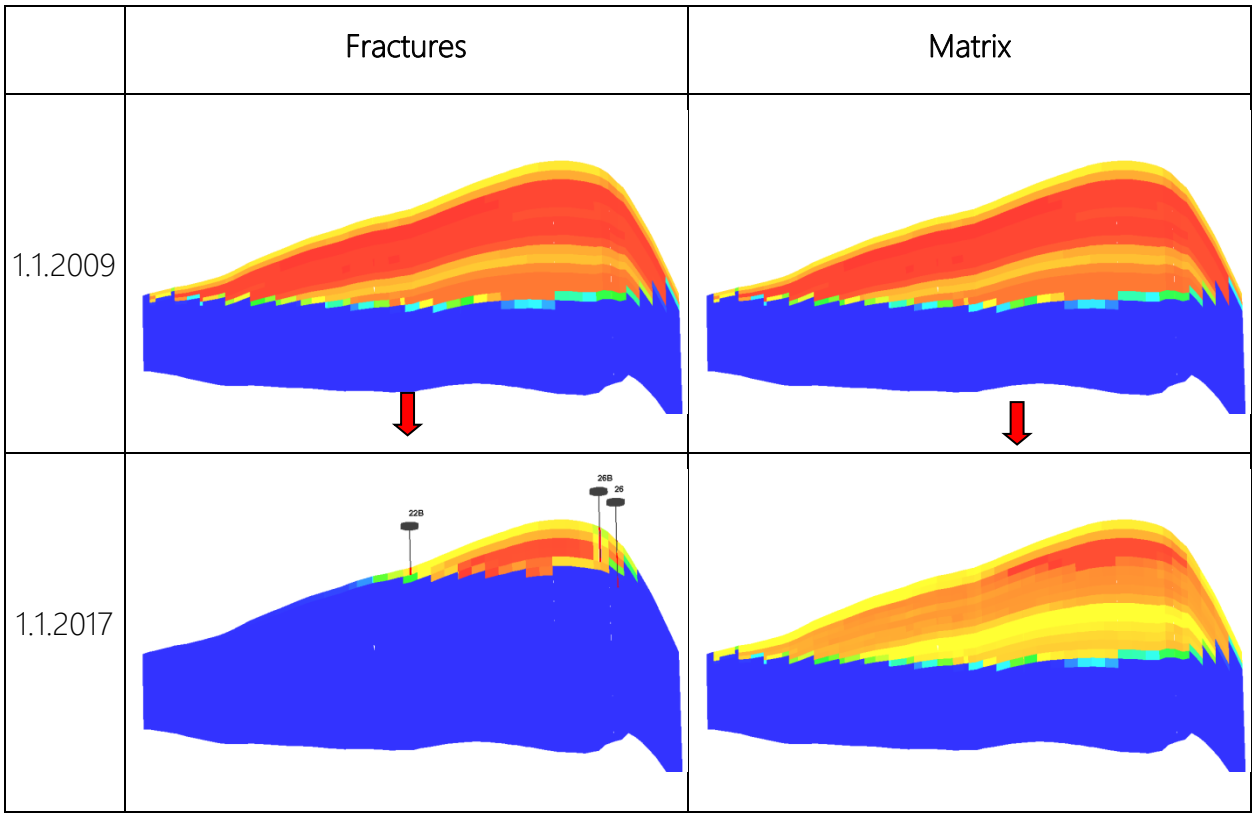


Fig. 5.1 – Dobrinskoye field. Gas saturation before inception (2009), and as of 01.01.2017. Matrix and fractures, history-matched model, D_3ev-lv reservoir

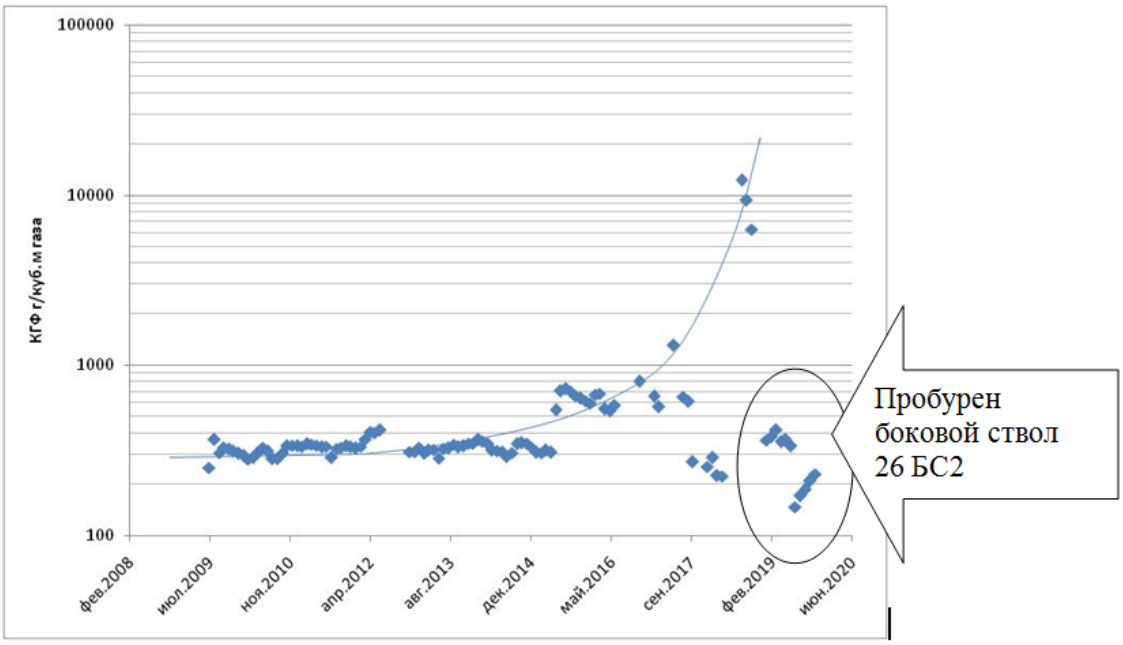


Fig. 5.2 – Condensate/Gas Ratio History by Well, Dobrinskoye Field

(side-track No. 26 BS2 is drilled).

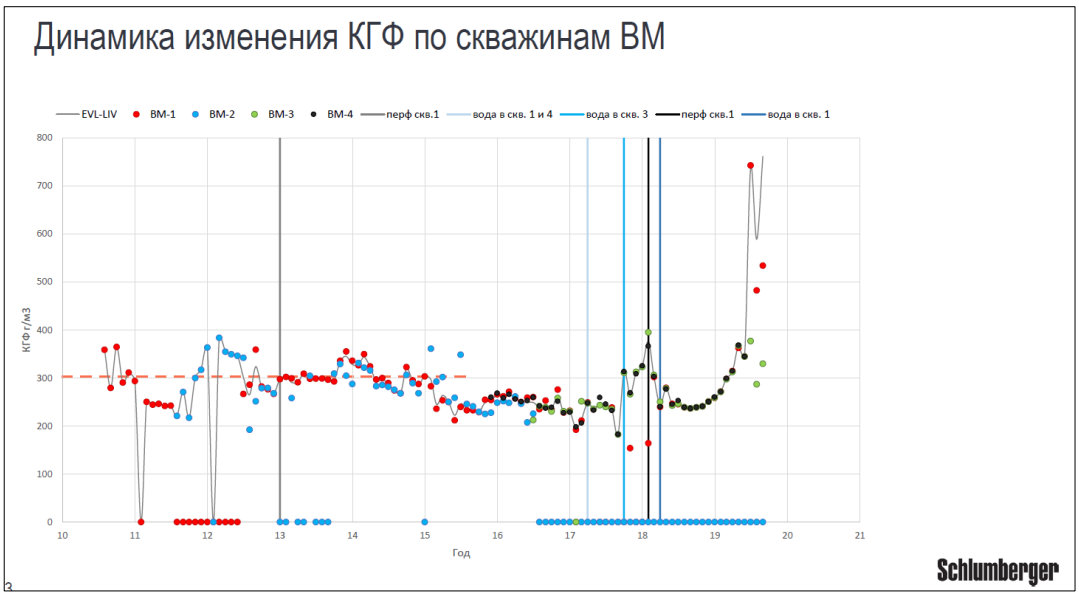


Fig. 5.3 – Condensate/Gas Ratio History by Well, Vostochno-Makarovskoye Field.

For building the 3D geological model of the Vostochno-Makarovskoye field Schlumberger used log data analyses and open hole log data analysis report for Well No. VM-3_2 of 08/27/2015 – 09/30/2015, core description, as well as seismic data attribute analysis. The discrete fracture network (DFN) method was selected for building the fracturing model.

DFN allows for creating relatively natural structure of fracture geometry. The DFN model depicts fractures and faults as a set of flat surfaces with adjustable parameters in three dimensions. Each surface has individual parameters of extension, openness and permeability. Using stochastic method, this model generates the size, spatial location, intensity and orientation of these surfaces. This allows for the use of several DFN implementations in uncertainty analysis. The fracturing modeling results in property cubes describing heterogeneity, anisotropy and coherence of the modeled reservoir by fracturing parameters.

Unfortunately, FMI reservoir microimager data only on one well does not allow for representation of fracturing distribution throughout the field, and the available volume of digital images and core description do not allow for update their spatial distribution.

However, survey results answer a number of significant questions, allowing for building a working concept before obtaining new data.

The resultant 3D geological model was used in building the 3D dual environment simulation model. Gas and condensate reserves were estimated using the 3D simulation model.

Fig. 5.4 shows the saturation distribution for the gas/condensate deposit of the Vostochno-Makarovskoye field, as well as GOC and WOC as of 09/01/2019. The model was history-matched. Adaptation parameters were permeability, wet horizon parameters, GOC, allocation of reserves between matrix and fractures, stranded gas.

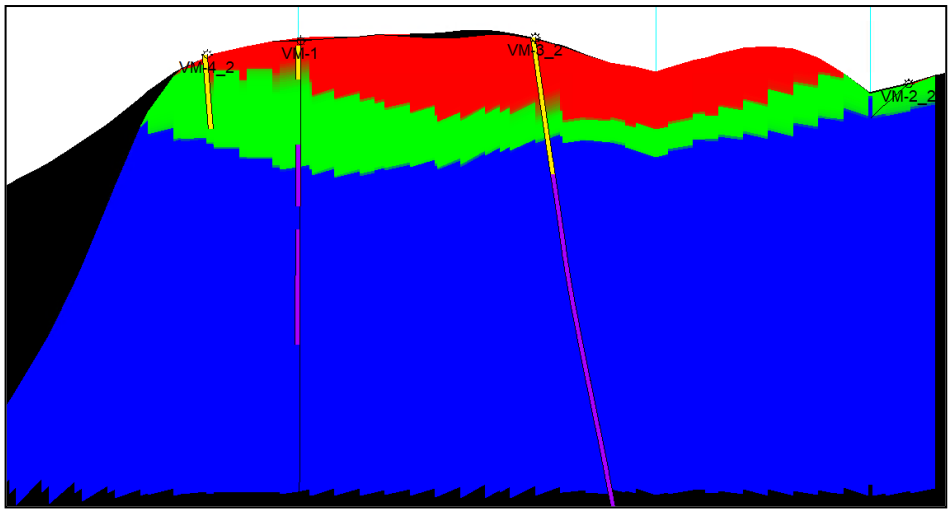


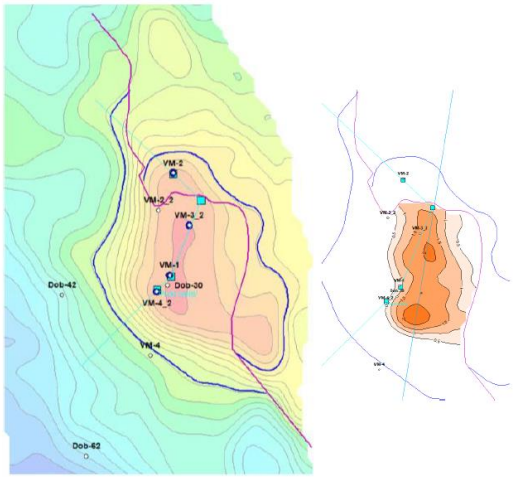
Fig. 5.4 – Fracturing Saturation, as of 09/01/2019

(Schlumberger, 2019).

The following original and remaining hydrocarbons in-place were estimated in the area of modeled WOC (Table 5.1).

Table 5.1 – Reserve Distribution in Region

	Запасы газа, млрд. м3		Запасы нефти, тыс. м3	
	Матрица	Трещины	Матрица	Трещины
Начальные	1.51	0.9	286	151
Остаточные	0.227	0.09	-	174



Schlumberger

	Gas volumes, Blnm3		Oil volumes, Mm3	
	Matrix	Fracture	Matrix	Fracture
Original in-place volumes	1.51	0.9	286	151
In-place volumes	0.227	0.09	--	174

Reserves estimate for the Vostochno-Makarovskoye field is based on the history-matched 3D simulation model. The estimated scenario provides for gas production through casing side at 300 Mm^3/day, accelerated formation water recovery from the initial WOC in active wells (Nos. 1, 3, 4), and drilling of Wells Nos. 5 and 6.

The selected optimum scenario is the scenario with maximum gas production of 300 Mm^3/day. By Schlumberger estimates, in such case the main remaining gas reserves of the Vostochno-Makarovskoye field will be produced in 2020 and 2021. In the third year (2022) gas production will sharply drop. The total gas production over three years will be 253.3 MMm^3 (Table 5.2).

Table 5.2 – Gas and Condensate Production, Gas Deposit, Yevlanovsky-Livensky Horizon, Vostochno-Makarovskoye Field

Years	Vostochno-Makarovskoye (Yevlano-Livensky gas deposit)	
	Gas production, MMm^3/year	Liquid hydrocarbon production, Mt
2020	108.6	54.2
2021	109.5	86.3
2022	17.4	15.6
TOTAL	235.3	156.1

Gas production from the Bobrikovsky gas/condensate deposit, Vostochno-Makarovskoye field, in Well No. 30 is estimated at 10 MMm^3/year. The total gas production over three years will be 30 MMm^3.

For the Yevlanovsky-Livensky gas deposit of the Dobrinskoye field gas production is estimated at the level of year of 2019, with reduction of gas production in 2020 - 2022. The total gas production over three years will amount to 46.0 MMm^3 (Table 5.3). The number of active wells is 1.

Table 5.3 – Gas and Condensate Production History, Yevlanovsky-Livensky Horizon, Dobrinskoye Field

Years	Dobrinskoye field (Yevlanovsk-Livensky gas deposit)	
	Gas production, MMm^3/year	Liquid hydrocarbon production, Mt
2020	16.9	3.4
2021	15.1	3.0
2022	14.0	2.8
TOTAL	46.0	9.2

6. FIELD INFRASTRUCTURE AND HYDROCARBON PRODUCTION

Hydrocarbon Production and Transportation to CGTF

Development Well Count, Vostochno-Makarovskoye Gas/Condensate Field:

Wells Nos. 1, 3 and ***4*** are producing from the Yevlanovsky-Livensky deposit.

Well No. 30 is producing from the Bobrikovsky deposit.

Well No. 2, drilled and completed to the Yevlanovsky-Livensky deposit, was converted to a monitor well.

Well Count, Dobrinskoye Gas/Condensate Field:

Total development well count includes 1 well:

Well No. 26 is producing from the Yevlanovsky-Livensky deposit.

The license area also has three exploratory wells (Nos. 13, 12, 21 Dobrinskoye) plugged and abandoned after drilling due to geological reasons, as well as Well No. 23 restored by LLC "GNS" from abandonment after drilling due to geological reasons and Well No. 22 which was in the development well count.

Well No. 23 is now disposal for separated and sewage water injection into the Myachkovsky-Podolsky carbonates.

On 06/04/2016 ***Well No. 22*** was converted to disposal.

Hydrocarbon Production and Transportation

Now hydrocarbons at the Vostochno-Makarovskoye gas/condensate field are produced from four producers (Nos. 1, 3, 4, and 30), which optimum productivity is as follows:

- Well No. 1: 76 Mm^3/day of gas through a 10-mm choke;
- Well No. 3: 144 Mm^3/day of gas through a 10-mm choke;
- Well No. 4: 25 Mm^3/day of gas through a 10-mm choke.

Gas/condensate system produced from the wells of the Vostochno-Makarovskoye field is moved to the Complex Gas Treatment Facilities (CGTF) site of the Dobrinskoye gas/condensate field through a 5.8-km main gas gathering line. At CGTF the system is separated into gas and liquid components. Gas component is treated to the required specifications and sold to the gas transportation system of LLC "Gazpromtransgaz-Volgograd".

Liquid phase is stabilized and trucked from the CGTF site.

Hydrocarbons from the Dobrinskoye gas/condensate field are produced from one producer (No. 26). Gas/condensate system from the well through a separate flow line is moved for further treatment to the CGTF site of the Dobrinskoye gas/condensate field.

In November 2019 the daily production from the two fields, using the existing hydrocarbon treatment and purification technology, was as follows:

- 400 Mm^3 of gas

- 229 t of condensate

The CGTF process infrastructure throughput is enough for handling such volumes of hydrocarbons.

Infrastructure for Hydrocarbon Treatment

Dobrinskoye Field

The Complex Gas Treatment Facilities (CGTF) of the Dobrinskoye gas/condensate field is designed to produce the following:

- Sales gas in accordance with the requirements of the STO Gazprom 089-2010 "Combustible Natural Gases Supplied and Transported Through Main Pipelines" industry state standard. It is moved through a pipeline to the branch gas pipeline to Zhirnovsk and then to the OJSC "Gazprom" transportation system;

- Stable condensate in accordance with the requirements of the GOST P 54389-2011 "Stable Gas Condensate" industry state standard;

- Process gases (propane and butane mixture) in accordance with the requirements of the GOST P 52087-2003 "Hydrocarbon Liquefied Fuel Gases" industry state standard.

Year of CGTF commissioning: 2009.

Year of refurbishment start: 2013.

Year of refurbishment end: 2018.

Infrastructure History, Dobrinskoye Gas/Condensate Field:

1. Infrastructure construction at the Dobrinskoye gas/condensate field was performed in accordance with the design "Infrastructure Construction, Dobrinskoye Gas/Condensate Field". The design was compiled by LLC "Volgogradnefteproekt" in 2008, with the Saratov Affiliate of the "Glavgosekspertiza of Russia" Federal State-Funded Institution issuing an approval No. 0480-08/SGE-0089/02.

The design also included the final design concept for line section and custody sales point "Gas Pipeline, Dobrinskoye Field to Branch Pipeline to Zhirnovsk" compiled by LLC "Gaznadzor", Volgograd Gas Technical Center.

2. In 2012 "Retrofitting and Upgrading of Sulfur Recovery Unit, CGTF, Dobrinskoye Gas/Condensate Field" was compiled which allowed for integration of the desulfurization unit into the existing process. The documentation was compiled by LLC "VolgaTEKinzhiniring" and was approved after industrial safety peer review (Reg. No. 39-PD-00575-2012).

3. Over the period of 2013 – February 2018 a staged refurbishment, retrofitting and upgrading was performed at CGTF of the Dobrinskoye gas/condensate field. Engineering work was performed by LLC "VolgaTEKinzhiniring". The staged refurbishment at CGTF of the Dobrinskoye gas/condensate field, as well as hook-up of the pipeline from the Vostochno-Makarovskoye gas/condensate field resulted in the increase in crude gas production rate from 250 Mm^3/day to 1,050 Mm^3/day, and in unstable condensate production rate from 81 m^3/day to 481 m^3/day. The design documentation "Refurbishment of CGTF, Dobrinskoye Gas/Condensate Field" was approved by "Glavgosekspertiza of Russia" Federal State-Funded Institution (No. 961-13/GGE-8757/02) and permit for construction No. VLG-3000066-UVS/S). The design documentation was compiled with consideration of the work performed under the documentation "Retrofitting and Upgrading of CGTF, Dobrinskoye Gas/Condensate Field (Sulfur Recovery Unit, Condensate Stabilization Unit, Low-Temperature Separator)". The documentation passed the industrial safety peer review (Reg. No. 39-PD-00575-2012).

4. In 2013, to improve CGTF performance safety, the documentation "Retrofitting and Upgrading of MGS Blocks and Absorbers with Inhibitor Proportioning at CGTF, Dobrinskoye Gas/Condensate Field" was compiled by LLC "VolgaTEKinzhiniring" and passed the industrial safety peer review (Reg. No. 39-PD-12042-2013).

5. In 2016 the work under "Retrofitting and Upgrading of Stable Condensate Depot at CGTF, Dobrinskoye Gas/Condensate Field" was performed, under which a 2,000-m^3 vertical tank was added. A total volume of stable condensate depot storage after retrofitting and upgrading is 2,290 m^3. The design documentation passed the industrial safety peer review (No. 39-TP-14948-2016).

6. In 2018, to improve gas treatment and maximize condensate separation, as well as to refurbish the Condensate Stabilization Unit, the documentation "Retrofitting and Upgrading of Low-Temperature Separator (Block 1) with Condensate and Process Gas Stabilization at CGTF, Dobrinskoye Gas/Condensate Field" was compiled. The documentation for retrofitting and upgrading passed the industrial safety peer review (Reg. No. 39-TP-15558-2018).

7. In 2018, to improve gas desulfurization process, the documentation "Retrofitting and Upgrading of Sulfur Recovery Unit with Use of Natural Gas Desulfurization Technology by Hydrogen Sulfide Liquid-Phase Oxidation with Iron Chelates at CGTF, Dobrinskoye Gas/Condensate Field" was compiled (Fig. 6.1).

Fig. 6.1 - Complex Gas Treatment Facilities (CGTF), Dobrinskoye Gas/Condensate Field.

Process Description

Natural gas treatment, stable condensate and process gas recovery processes at CGTF, Dobrinskoye gas/condensate field, include the following three stages:

– production and transportation of gas/condensate system from field Wells No. 26, Dobrinskoye gas/condensate field, and Nos. 1, 3, 4 and 30D, Vostochno-Makarovskoye gas/condensate field

– entry of reservoir gas from Well No. 26 at the input unit of the Dobrinskoye gas/condensate field
– entry of reservoir gas from Wells Nos. 1, 3, 4 and 30D at the input unit of the Vostochno-Makarovskoye gas/condensate field
– condensate and water separation from natural gas from the wells of the Vostochno-Makarovskoye and Dobrinskoye gas/condensate fields at S-3 and S-4 separators
– desulfurization of natural gas from the wells of the Vostochno-Makarovskoye and Dobrinskoye gas/condensate fields at the high-pressure sulfur recovery unit, including A-3 and A-4 absorbers;
– desulfurization of gas liberated from RZh-1 tank and K-1 column downstream the condensate stabilization unit at low-pressure sulfur recovery unit, including A-1 and A-2 absorbers
– ejection of low-pressure gases from gas condensate stabilization
– low-temperature gas separator (LTS)
– gas condensate stabilization
– storage and loading of condensate to the consumer
– process gas recovery (gas fractionation)
– storage and loading of process gas to the consumer
– combined gas metering at custody metering unit
– absorbent solution mixing
– absorbent solution gas liberation and recovery
– temporary storage of absorbent solution (in warm period)
– sulfur by-product recovery

Besides, the unit includes auxiliary systems and modules supporting main stages:

– fuel gas treatment system (gas for own needs)
– high-pressure and low-pressure flare systems, a horizontal flare unit (flare system)
– methanol system and methanol and chemical proportioning modules
– high- and low-pressure drainage systems
– nitrogen ramp and inert gas supply system to the customer
– nitrogen station and receiver
– steam and heat supply system

Gas Treatment Train Downstream Wells, Dobrinskoye and Vostochno-Makarovskoye Gas/Condensate Fields

At the input unit from the Vostochno-Makarovskoye gas/condensate field and at the module input unit of the Dobrinskoye gas/condensate field the pressure of gas/condensate system feeding the unit through intrafield pipelines from gathering units is reduced (choked) to 9.0 MPa with manually-driven pressure reducers. Combined gas/condensate system is fed to S-3 and S-4 input separators, where gas/condensate system is separated into two phases: natural gas and hydrocarbon liquids, water (methanol water).

Hydrocarbon liquids from S-3 and S-4 separators are fed to condensate stabilization equipment at the LTS site (item 1.25, Plant Layout).

Separation gas is fed to the high-pressure sulfur recovery site (item 1.24, Plant Layout), sequentially entering A-3 and A-4 absorbers where sour components (H2S and mercaptans) are separated. Maximum throughput of the sulfur recovery unit is 960 Mm^3/day (40 Mm^3/h) of gas.

Gas purification in the A-3 absorber is performed by means of liquid-phase hydrogen sulfur oxidation to elemental sulfur with ferric chelate sequestering.

Natural gas purified in the absorbers from the sulfur recovery site is fed to the ejection process and then to LTS process to ensure the required dew point of water and hydrocarbons.

Process Gas Train

Process gases are recovered by means of gas liquids fractionation. Downstream gas stream cooling in T-3 (ejection process) and T-4 (LTS process) heat exchangers liquids are mixed and fed to the input of K-2 flash gas column to separate methane and ethane. Gas from the top of K-2 flash gas column is cooled in T-4 gas/liquid heat exchange and is fed to S-7 low-temperature separator. Heat supply to the lower section of K-2 flash gas column is made by means of I-2 evaporator, which is designed for condensate vapors generation and equipped with a coil for steam input from the boiler room. Downstream K-2 flash gas column liquids are cooled in AVO-1 air cooler unit to the temperature of 40 °C and is fed to the input of K-3 flash gas column to produce propane/butane fractions and stable condensate. Gas from the upper section of K-3 flash gas column is cooled in AVO-4/1 and AVO-4/2 air cooler units for total condensation of propane/butane system.

Process Gas Storage and Loading Train

Propane/butane system downstream AVO-4/1 and AVO-4/2 air cooler units is collected in E-5/1 and E-5/2 reflux accumulators. Propane/butane system is feed to K-3 column reflux by means of N-3 and N-4 pumps. Stable condensate from K-3 flash gas column is cooled in AVO-3 air cooler unit and is fed to the existing E-3/1, E-3/2, E-3/3 tanks (item 1.30, Plant Layout).

In the process of accumulation of unevaporated liquid residuum in E-5/1 and E-5/2 tanks liquids is moved by means of KM-1 and KM-2 compressors to a tank truck for further utilization.

Condensate Stabilization Train

Hydrocarbon liquids from S-3 and S-4 input separators is fed to the LTS site for condensate stabilization (item 1.25, Plant Layout).

In RZh-1 liquids separator hydrocarbon liquids are separated into gas, condensate and water/methanol system. Condensate from RZh-1 liquids separator is fed to K-1 condensate

stabilization column to strip propane/butane fractions from stable condensate. Heat supply to the lower section of K-1 condensate stabilization column is made by means of I-2 evaporator, which is designed for condensate vapors generation and equipped with a coil for steam input from the boiler room. Gas stream from the upper section of K-1 condensate stabilization column is fed to low-pressure gas sulfur recovery unit (item 1.23, Plant Layout). Stable condensate stream downstream K-1 column is cooled in AVO-2/1 and AVO-2/2 air cooler units to the temperature of 30 - 40 °C.

Gases of condensate stabilization from RZh-1 liquids separator and the upper section of K-1 column are fed into A-2 absorber of the low-pressure gas sulfur recovery unit (item 1.23, Plant Layout). Gas purification in the A-2 absorber is performed by means of liquid-phase hydrogen sulfur oxidation to elemental sulfur with ferric chelate sequestering.

Purified gas stream from A-2 absorber is fed to the ejection process and then to LTS process (item 1.25, Plant Layout).

Condensate Storage and Loading Train

Stable condensate cooled in AVO-2/1 and AVO-2/2 air cooler units is fed to the existing condensate service tanks site (item 1.30, Plant Layout), including 200-m^3 tanks (E-3/1, E-3/2, E-3/3). Stable condensate is also stored in RVSP-1 2000-m^3 tank (item 1.35, Plant Layout). Sable condensate is fed to RVSP-1 tank with pumps of the process pumping station (item 1.10, Plant Layout) from E-3/1, E-3/2, E-3/3 condensate service tanks.

Stable hydrocarbon condensate from E-3/1, E-3/2, E-3/3 service tanks and RVSP-1 tank is loaded into tank trucks at the existing condensate truck loading terminals Nos. 1 and 2 (items 1.14a and b, Plant Layout).

Absorbent Recovery, Activation and Temporary Storage Train

Spent water-based solution of ferric chelate sequestering agent with elemental sulfur is fed to KSU-1 and KSU-2 terminal separation units from the lower section of A-1 and A-2 absorbers of the low-pressure gas sulfur recovery site (item 1.23, Plant Layout) and A-3 and A-4 absorbers of the high-pressure gas sulfur recovery site (item 1.24, Plant Layout).

In KSU-1 and KSU-2 terminal separation units gas is separated from spent water-based solution of ferric chelate sequestering agent to the low-pressure flare stack. Degassed solution is fed to R-1 (R-2) atmospheric regenerating units. Compressed air is envisaged to be fed from V-1/1 and V-1/2 air blowers into the lower section of R-1 (R-2) atmospheric regenerating units through the air distributor. In the process of air lifting through a bed of spent water-based solution of ferric chelate sequestering agent recovery occurs, namely, ferrous complexonate is oxidized into ferric complexonate with air oxygen. Lean water-based solution of ferric chelate sequestering agent is fed o the VS-1 sulfur by-product recovery unit for elemental sulfur recovery, and then – to B-1 circulating drum. From B-1 drum solution is moved with NP-1 and NP-2 feed pumps to the input of N-7/1, N-7/2, N-7/3, N-7/4, N-6/1, and N-6/2 pumps.

R-3 (E-1/1), R-4 (E-1/2), E-1/3 and E-1/4 tanks (item 1.9, Plant Layout) are designed for activation and temporary storage of water-based solution of ferric chelate sequestering agent. R-3 (E-1/1), R-4 (E-1/2), E-1/3, and E-1/4 tanks are envisaged to operate only in warm season.

The purpose of the activation process is oxidation of ferrous complexonate to ferric complexonate with air oxygen. Fresh nonactivated water-based solution of ferric chelate sequestering agent is fed to P-3 (E-1/1), P-4 (E-1/2), E-1/3, E-1/4 from KSU-1. Solution is activated in R-3 and R-4 (E-1/1 and E-1/2) tanks when compressed process air is fed to the turbo-expanders from V-2/1 and V-2/2 blowers.

Retrofitting of LTS Unit, CGTF, Dobrinskoye Field. Turbo-Expander Unit Integration into LTS Process

1. Making changes in the layout configuration and train fixing methods
2. Change of K-22 line tap-in point downstream K-104 compressor to K-2 column to ensure more correct temperature mode of LTS unit.
3. Added automatic condensate discharge from the separator of the compressor unit.

The specified changes provide for convenience and simplicity of operation of the equipment to be installed and do not violate specified regulations and requirements of industrial safety.

The key technical solutions presented in the earlier compiled specified documentation for retrofitting remain intact (Fig. 6.2).

Fig. 6.2 - Complex Gas Treatment Facilities (CGTF), Dobrinskoye and Vostochno-Makarovskoye Gas/Condensate Fields.

The purposes of this work are as follows:

1. Deeper gas treatment by means of cooling below minus 80 °C in the turbo-expander unit (TDU).
2. Higher energy saving of LTS cycle by means of the use of kinetic energy of gas for TDU operation with the use of said energy for further gas compression to parameters required by the customer.
3. Higher liquids yield by means of additional gas cooling for loading to the customer.

To implement the specified objectives, this documentation envisages integration of the turbo-expander unit into the LTS cycle.

7. VALUATION

In this report revenues were estimated using initial data on prices and expenses provided by GNS. The cost estimates shown in the report were performed in US dollars (US$) at the 2019 average exchange rate of the Central Bank of the Russian Federation in the amount of 61.91 Rubles per US$. In this report values of proved reserves were based on future production forecasts and revenues prepared for the subject fields without risked re-estimates of probable reserves.

Prices - GNS provided with gas, condensate, LPG prices shown in Table 7.1. Prices were held constant for the life of fields.

Revenue. Gross future revenue is the revenue related to production and sale of estimated total reserves at sales price.

Cash flow. Cash flow was estimated by deduction of estimated operating expenses, capital investments and abandonment costs, mineral extraction taxes and other taxes, as well as profit tax from gross revenues.

GNS cash flow. GNS cash flow was determined as GNS ownership interest in cash flow after deduction of the interest of other owners.

GNS present worth. The Customer's present worth is determined as cash flow discounted at arbitrary rate over the period of expected sale. In this report the GNS present worth at the discount rate of 10% is shown in details. Present worth at the discount rates of 0 to 100% is shown as a profile.

Operating expense and capital investments. Operating and capital expenses and cost forecasts as of December 31, 2019, were provided by the Customer and used for the estimate of future costs required for field development (Table 7.1). Future expenses were used without price escalation due to inflation.

Operating expenses. Operating expenses include fixed and variable components which are forecasted so as to provide for production and its sale from the fields evaluated and are

based on actual historical expenses in the region and forecasted expenses provided by GNS. Compared to the operating expenses forecasted for analogous objects located near the subject fields, forecasted operating expenses of GNS seem to be justified for the expected operation conditions.

Capital investments. Capital investments for side-tracking, infrastructure and other programs required for development of the evaluated fields were based on the actual historical costs in the region and forecasted costs provided by GNS. Compared to capital investments forecasted for analogous objects located near the subject fields, the capital investment forecast seem to be justified for the expected operation conditions.

Depreciation. *Future* capital investments were depreciated over 5 years. Depreciation was applied to the first year of incurred costs. Capital investments were considered evenly allocated over a year.

Taxes

For the purposes of this analysis it was assumed that the tax laws effective as of December 31 continues to be effective over the period of estimate. The description of the principle taxes is shown below.

Mineral extraction tax

Gas condensate. The base rate is 42 Rubles per tonne of gas condensate production. This rate is multiplied by the base value of a unit of conditional fuel (Eut), by the factor characterizing the degree of complexity of combustible natural gas and/or gas condensate production from a hydrocarbon deposit (Ks), and by the adjustment factor (Kkm). The product is totaled with the value of the coefficient (Kkan)*0.75. Resulted rate is deducted with NGL incentive (156 Rubles per tonne in 2020 and 183 Rubles per tonne since 2021).

Gas. The base rate is 35 Rubles per 1,000 cubic meters of combustible natural gas production. The specified tax rate is multiplied by the base value of a unit of conditional fuel (Eut), and by the factor characterizing the degree of complexity of combustible natural gas and/or gas condensate production from a hydrocarbon deposit (Ks). The product is totaled with the value of the parameter characterizing combustible natural gas transportation expenses (Tg).

Value added tax

VAT is estimated at the rate of 18 per cent of the sales price of hydrocarbons sold in the domestic market.

Property tax

Property tax is estimated annually at the rate of 2.2 per cent of the remaining balance of field facilities.

Deductions to extra-budgetary funds

The base for the assessment of insurance payments is determined as a sum of payments and other fees estimated by insurance contribution payers over the estimate period in favor of natural persons on all grounds. The total rate of insurance since 2019 is 30% of the payroll fund.

Profit tax

Profit tax is estimated at the rate of 20% of taxable revenue. The taxable revenue is estimated by deduction of operating expenses, depreciation allowances of taxes from the future gross revenue.

Summary and conclusions

Estimates of GNS cash flow and present worth related to proved reserves attributed to GNS at the Dobrinskoye and Vostochno-Makarovskoye fields, as of December 31, 2019, with the price and expenses assumptions mentioned above, are shown below in thousand US dollars (MUS$). Values were estimated in US dollars at the exchange rate of 61.91 Rubles per US$, as of December 31, 2019. Detailed calculations are shown in Tables 7.2-7.5.

	Cash flow (MUS$)	Present worth at 10% disc.rate (MUS$)
Total proved reserves	29,995.9	25,507.5

CONCLUSIONS

Estimated reserves are shown in 1. Brief Review with additional details in attachments.

Table 7.1 ECONOMIC PARAMETERS as of December 31, 2019 GNS assets		
Exchange rate, Rubles/US$	61.91	
Gas sales allocation		
Export market, %	0.00	
Domestic market, %	100.00	
Condensate sales allocation		
Export market, %	32.00	
Domestic market, %	68.00	
LPG sales allocation		
Export market, %	0.00	
Domestic market, %	100.00	
Condensate Price, 2020	Rubles/tonne	US$/tonne
Contract Price	29,046.38	469.17
Less		
Commissions and dues		
Export tariff	4,757.07	76.84
Intermediate price	24,289.31	392.33
Transportation	3,700.00	59.76
Net domestic condensate price	20,589.31	332.57
Condensate Price, 2021	Rubles/tonne	US$/tonne
Contract Price	29,046.38	469.17
Less		
Commissions and dues		
Export tariff	3566.02	57.60
Intermediate price	25480.36	411.57
Transportation	3700.00	59.76
Net domestic condensate price	21780.36	351.81
Condensate Price, 2022	Rubles/tonne	US$/tonne
Contract Price	29,046.38	469.17
Less		
Commissions and dues		
Export tariff	2,374.97	38.36
Intermediate price	26,671.41	430.81
Transportation	3,700.00	59.76
Net domestic condensate price	22,971.41	371.05

Table 7.1 continued

Domestic LPG price	Rubles/tonne	US$/tonne
Contract Price	23,796.00	378.07
Less		
VAT	3,966.00	63.01
Intermediate price	19,830.00	315.06
Transportation	0.00	0.00
Net domestic gas price	19,830.00	315.06
Domestic gas price	Rubles/Mm^3	US$/Mm^3
Contract price	5,422.80	86.16
Less		
VAT	903.80	14.36
Intermediate price	4,519.00	71.80
Transportation	0.00	0.00
Net domestic gas price	4,519.00	71.80
Operating expenses		
- Fixed	MRubles/well/mo	MUS$/well/mo
	2,820.35	45.56
- Variable	Rubles/tonne of condensate	US$/boc
	1,802.17	29.11
- Variable	Rubles/tonne of LPG	US$/ tonne of LPG
	2,326.41	37.58
- Variable	Rubles/Mm^3	US$/Mm^3
	1,191.80	19.25
Development costs, MUS$/well	MRubles/well	MUS$/well
- Drilling and completion of deviated well	40000.00	635.52
- Drilling and completion of horizontal well	-	-
- Side-tracking		
Dobrinskoye field	-	-
Vostochno-Makarovskoye field	-	-
Future capital for infrastructure	MRubles	MUS$
Dobrinskoye field	-	-
Vostochno-Makarovskoye field	20,000.00	317.75

Table 7.2 - TOTAL PROVED RESERVES AND CASH FLOW FORECASTS (except for VAT)

As of December 31, 2019

Vostochno-Makarovskoye field

Date	Reserves			Future Gross Revenues	Operating Expenses	Capital Investments	MET and Other Taxes	Profit tax	GNS Net Interest (2020-2022)	
	Condensate	Sales Gas	LPG						Net Cash Flow	Present worth at 10% discount rate
	Mbbl	MMcf	Mtonnes	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$
CF, as of 12/31/2019										
2020	481.3	4,094.8	9.0	29,641.2	6,409.0	1,615.2	9,675.3	1824.7	10,116.9	9,197.2
2021	762.1	4,126.6	9.0	42,058.0	7,360.7	0.0	16,877.4	2,677.3	15,142.6	12,514.5
2022	143.5	946	2.1	8,714.0	3,270.4	0.0	3,547.3	0.0	1,896.2	1,424.6
Total	**1,386.9**	**9,167.4**	**20.1**	**80,413.2**	**17,040.2**	**1,615.2**	**30,100.1**	**4,501.9**	**27,155.7**	**23,136.4**

PRESENT WORTH PROFILE (2020-2022)

Discount Rate	Present Worth of Future Net Revenues	Discount Rate	Present Worth of Future Net Revenues	Discount Rate	Present Worth of Future Net Revenues
0%	27,155.7	25%	18,755.7	60%	12,701.1
5%	25,008	30%	17,605.5	70%	11,576.7
10%	23,136.4	35%	16,573.4	80%	10,619.3
15%	21,494.1	40%	15,643.2	90%	9,795.78
20%	20,043.8	50%	14,036.5	100%	9,081.14

Table 7.3 - TOTAL PROVED RESERVES AND CASH FLOW FORECASTS (except for VAT)

As of December 31, 2019

Dobrinskoye field

Date	Reserves			Future Gross Revenues	Operating Expenses	Capital Investments	MET and Other Taxes	Profit tax	GNS Net Interest (2020-2022)	
	Condensate	Sales Gas	LPG						Net Cash Flow	Present Worth at 10% discount rate
	Mbbl	MMcf	Mtonnes	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$
CF, as of 12/31/2019										
2020	29.6	582.5	1.3	2,744.9	1,019.2	0.0	669.1	0.0	1,056.5	960.4
2021	26.4	522.4	1.1	2,495.1	966.6	0.0	627.9	0.0	900.6	744.3
2022	24.5	483.6	1.1	2,391.3	939.0	0.0	605.0	0.0	847.2	636.5
Total	80.5	1,588.5	3.5	7,631.2	2,924.9	0.0	1,902.0	0.0	2,804.4	2,341.3

PRESENT WORTH PROFILE (2020-2022)

Discount Rate	Present Worth of Future Net Revenues	Discount Rate	Present Worth of Future Net Revenues	Discount Rate	Present Worth of Future Net Revenues
0%	2,804.4	25%	1,855.39	60%	1,218.96
5%	2,554.96	30%	1,731.24	70%	1,105.55
10%	2,341.32	35%	1,621.12	80%	1,010.19
15%	2,156.77	40%	1,522.9	90%	929.054
20%	1,996.15	50%	1,355.64	100%	859.309

Table 7.4 - TOTAL PROVED RESERVES AND CASH FLOW FORECASTS (except for VAT)

as of December 31, 2019

Total GNS

Date	Reserves			Future Gross Revenues	Operating Expenses	Capital Investments	MET and Other Taxes	Profit tax	GNS Net Interest (2020-2022)	
	Condensate	Sales Gas	LPG						Net Cash Flow	Present Worth at 10% discount rate
	Mbbl	MMcf	Mtonnes	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$	MUS$
CF, as of 12/31/2019										
2020	510.8	4,677.3	10.3	32,386.1	7,428.2	1,615.2	10,344.5	1,822.4	11,175.7	10,159.8
2021	788.6	4,649.0	10.1	44,553.1	8,327.3	0.0	17,505.2	2,643.8	16,076.7	13,286.5
2022	168	1,429.7	3.2	11,105.3	4,209.5	0.0	4,152.4	0.0	2,743.4	2,061.2
Total	1,467.4	10,755.9	23.6	88,044.4	19,965.0	1,615.2	32,002.1	4,466.2	29,995.9	25,507.5

PRESENT WORTH PROFILE (2020-2022)

Discount Rate	Present Worth of Future Net Revenues	Discount Rate	Present Worth of Future Net Revenues	Discount Rate	Present Worth of Future Net Revenues
0%	29,995.9	25%	20,634.3	60%	13,934.6
5%	27,595.5	30%	19,358.3	70%	12,695.2
10%	25,507.5	35%	18,214.6	80%	11,641.1
15%	23,678.2	40%	17,184.9	90%	10,735.3
20%	22,065.1	50%	15,408.6	100%	9,949.97

Table 7.5

By 2019 Panterra report As of December 31, 2019	Condensate		Gas		LPG	Total
	Mbbls	Mtonnes	MMcf	MMm^3	Mt	MMboe
Proved reserves	1,467	168	10,756	305	24	3.537
Proved+Probable reserves	1,467	168	10,756	305	24	3.537

Conversion factors

Sales gas	1 scf = 0.006 boe	1 scf = 0.0283 m^3
Condensate	1 barrel = 1 boe	1 barrel = 1 tonne / (ρ_{cond} * 0.158983)
LPG	1 tonne = 11.735 boe	1000 m^3 = 0.0985 tonnes

LPG volumes were calculated by produced gas composition analyses. Considering that mole fraction of propane and butane in dry gas is 0.06831 and content of these components is 98.4 g/m^3, to convert to barrel of oil equivalent, density, conversion factors of 1 barrel =158.983 liters, 1 cubic meter =1,000 liters and the standard formula for calculation of mass as a product of density and volume were used.

ADDENDUM 1

QUALIFICATIONS AND BASIS OF JUDGEMENT

LLC "Panterra Group" Company renders services and expertise to dozens of clients in a spectrum of activities for petroleum industry. The firm has a team of highly qualified professionals and a staff to perform reserve estimates within and outside Russia. Company's specialists performed over 50 asset evaluations and reserve estimates, which are accepted by producers, independent operators, banks and other financial institutions, state and national regulatory agencies, trusts, courts, arbitrates and investors as a basis for reserves disclosure and making decisions on such issues as project financing, unification, stock revaluation, acquisitions, asset divestiture, public offering of shares or debt securities, development programs, enhanced recovery projects, infrastructure obligations, settlement by negotiations, cooperative agreements, leasing and auctions.

Engineering work for this report was supervised by Mr. Vadim Vasiliev, a SPE member, who has a professional qualification with more than 19 years of relevant experience in the estimate, assessment and evaluation of oil and gas reserves.

Competence of key specialists of oil and gas asset evaluation group is shown in table below.

INDEPENDENCE

LLC "Panterra Group" is an independent oil and gas consulting firm. No director, officer, or key employee of Panterra Group has any financial ownership in LLC "Gaznefteservis", or any affiliate of the Company. Our compensation for the required investigations and preparation of this report is not contingent on the results obtained and reported, and we have not performed other work that would affect our objectivity.

Key Specialist Competence

ALEKSANDR PLAKHOV Director General, Panterra Group	Geophysicist, expert in geophysical methods of oil and gas field prospecting and exploration. 14-years work experience. Extensive experience in application of seismics for prospecting, exploration and development of oil and gas fields, development of methods of comprehensive interpretation of geological and geophysical data for building detailed field models, expert review of geological and technical part of assets of a number of licensed areas for petroleum, investment companies and banks of RF. Arrangement and performance of office seismic studies for seismic and geological and evaluation projects. Author of 3 scientific publications. Member of international associations: EAGE, SEG.
MIKHAIL YUDIN Deputy Director General of Geology, Panterra Group , M.s	19-years experience in oil and gas geology for prospecting and exploration of oil and gas fields, reserve and resource evaluation, geology of natural reservoirs and 3D geological modeling, expert review of geological and technical part of assets of a number of licensed areas for petroleum, investment companies and banks of RF. Evaluated over 50 target zones. Author of 10 scientific and technical publications. Member of professional association: EAGE.
SERGEI GRANDBERG Chief Economist, PhD	Economist, specialist in investment evaluation of oil and gas fields. 19-years work experience. Extensive experience in evaluation of investment project efficiency. Creation, support and modification of financial models of projects, identification of asset cost. Interaction with evaluation companies (participation in due diligence projects in asset sale). Compilation of analytic document, strategy and long-term plans of company, expert review of part of assets of a number of license areas for petroleum, investment companies and banks of RF. Performed evaluation for over 40 target zones, including fields of GAZPROM and LUKOIL. Author of 5 scientific publications. Member of professional associations: EUESU, SCR economic expert.
IGOR ZAITSEV Gas Field Expert, PhD	Reservoir engineer, specialist in designing of gas/condensate field development. 40-years work experience. Project manager of 27 projects for development of gas/condensate and oil/gas/condensate fields of Russia and CIS. Experience in expert review of technical and technological part of assets of a number of licensed areas for petroleum, investment companies and banks of RF. 10-years experience in expertise of technical projects for gas/condensate field development in CCFD Rosnedra. Author of 20 scientific publications. Member of professional association: EUESU, SCR economic expert.

ADDENDUM 2

Definitions and Guidelines for Petroleum Resources

Recoverable Resources and Reserves Classes and Sub-Classes

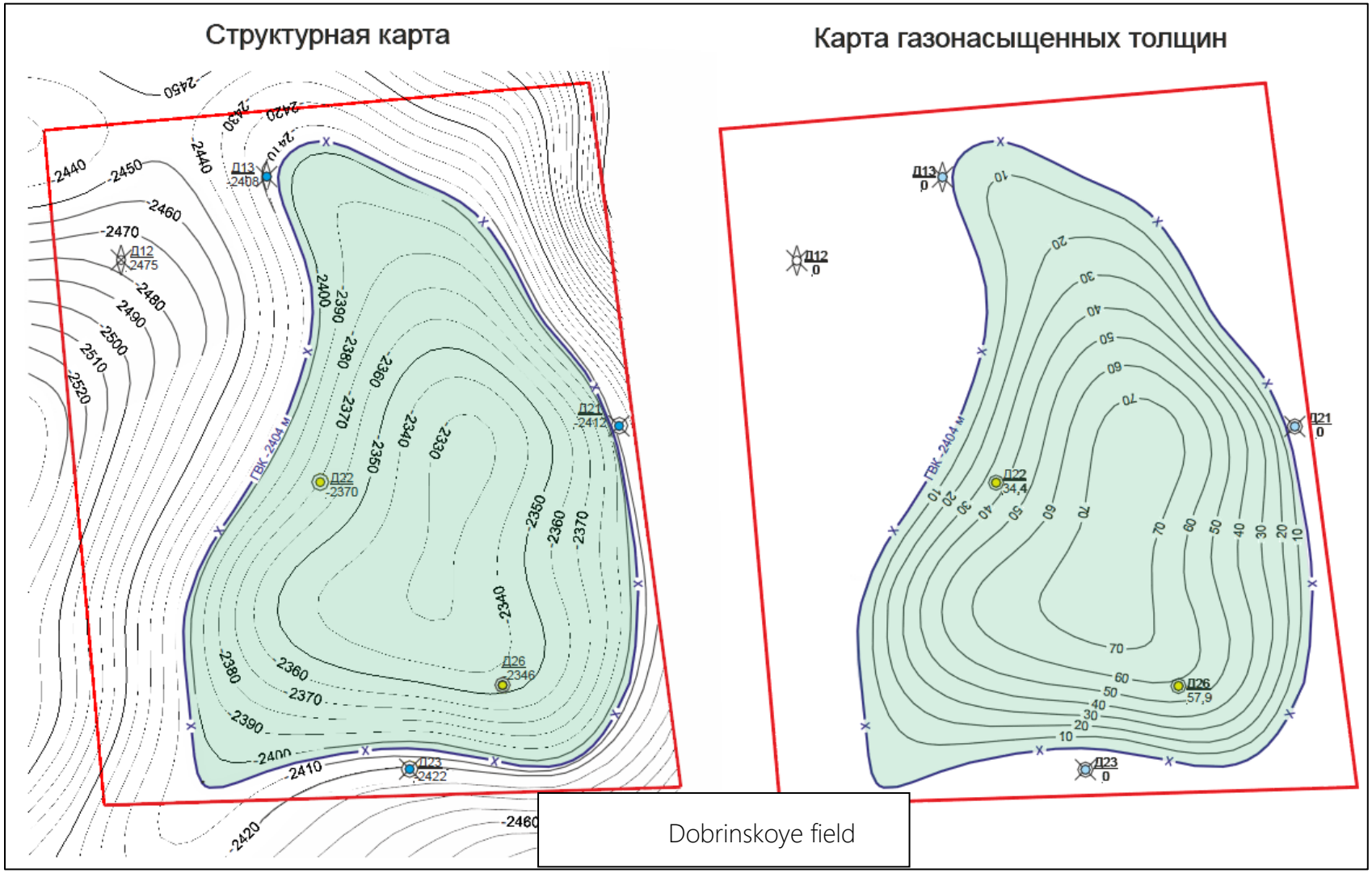
Status	Definition	Methodological instructions
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production with low expenditure for unloading of these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.
Proved Reserves	Those quantities of petroleum that, 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	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 (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the

Status	Definition	Methodological instructions
	conditions, operating methods, and government regulations.	reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates 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. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

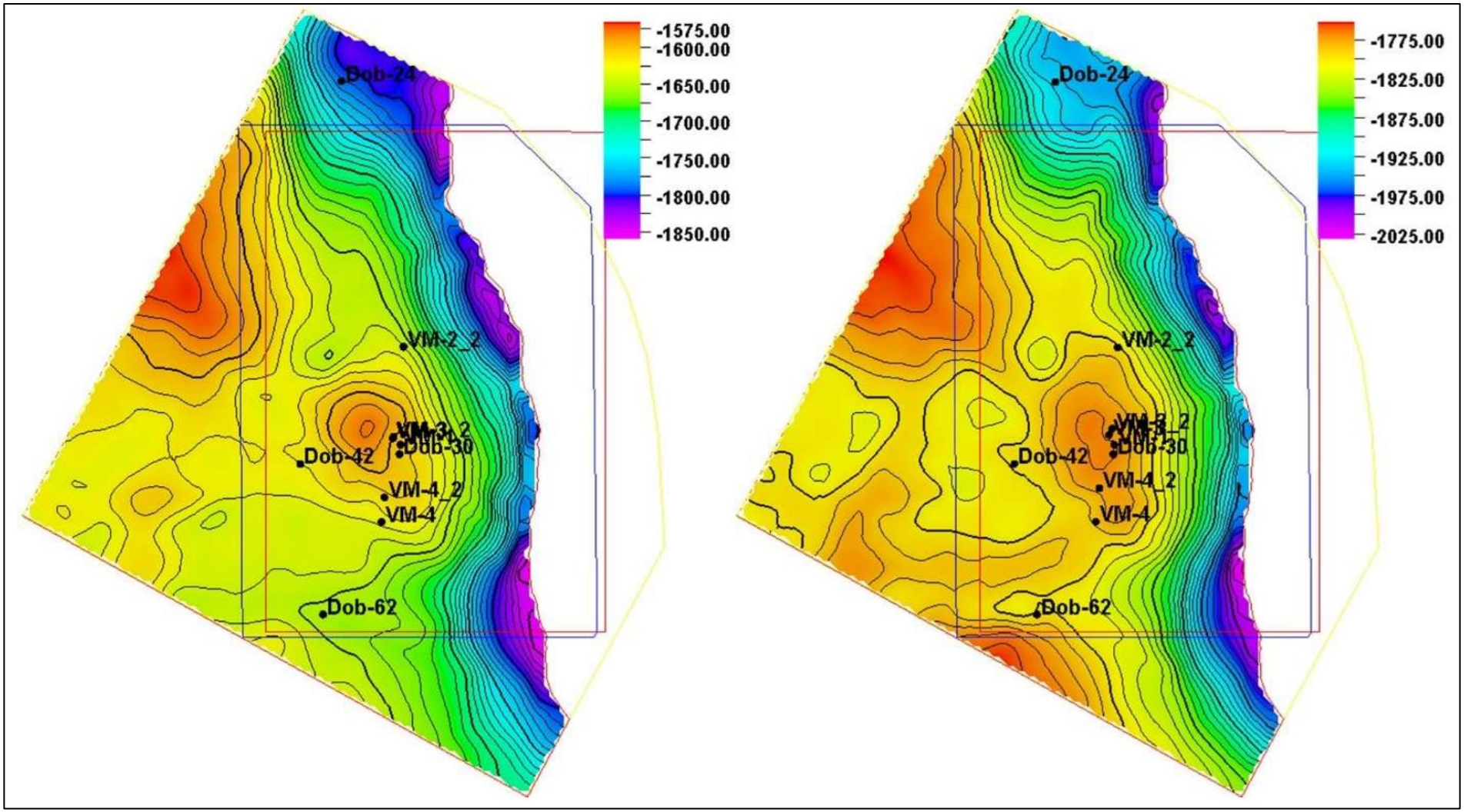
Status	Definition	Methodological instructions
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/ or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or

Status	Definition	Methodological instructions
		negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations

ATTACHMENT 1. D3ev-lv, Yevlanovsky-Livensky Horizon, Dobrinskoye Field. Structure map and isopach map

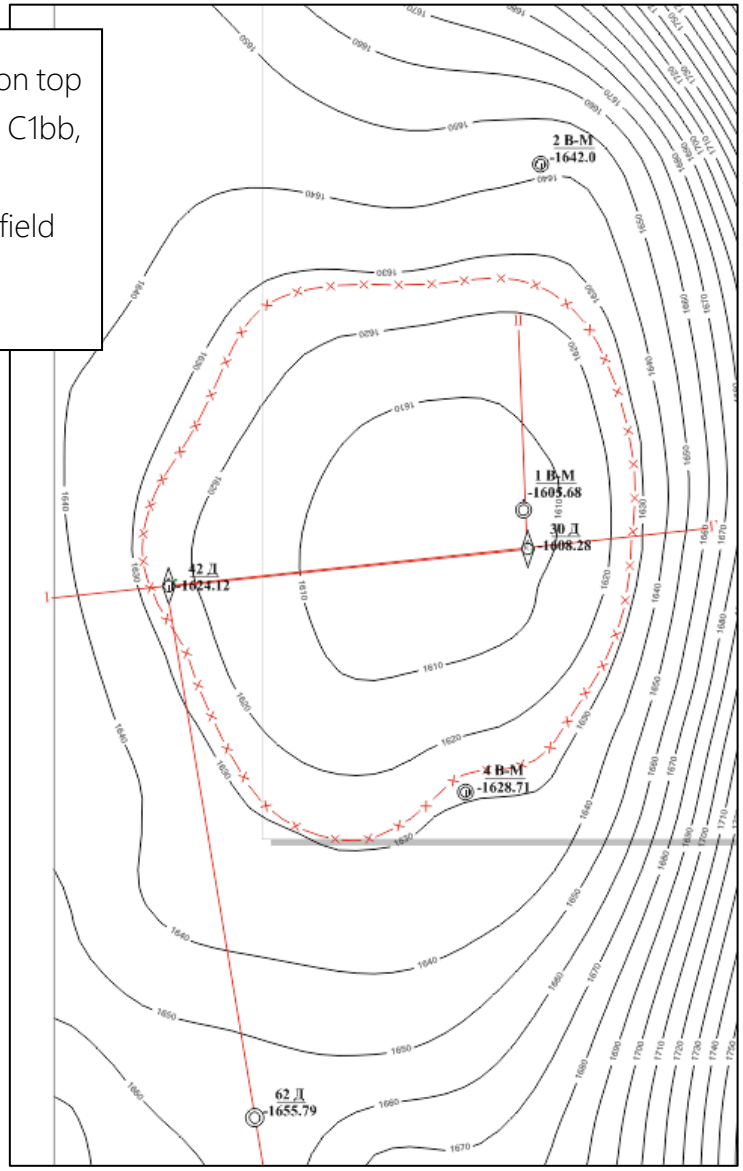


Attachment 2. Structure Map on C1bb and D3zv Reflectors, Dobrinskoye Field (Schlumberger, 2019)

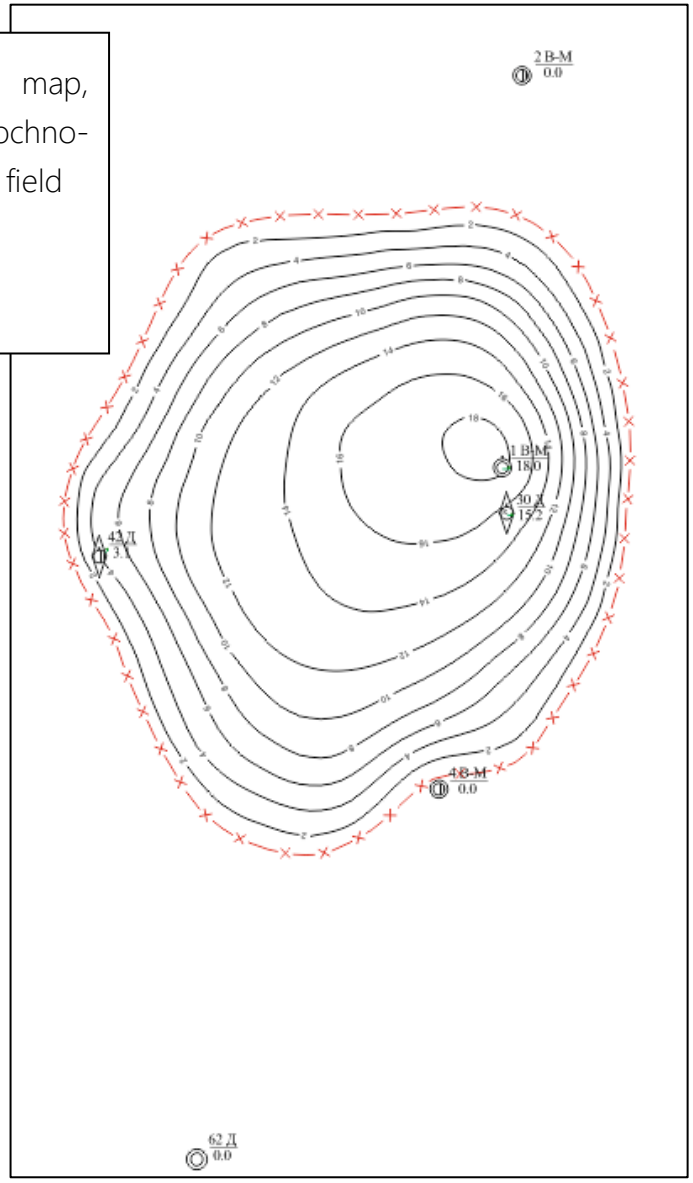


Attachment 3. C1bb Deposit, Vostochno-Makarovskoye Field.

Structure map on top of sand, C1bb, Vostochno-Makarovskoye field

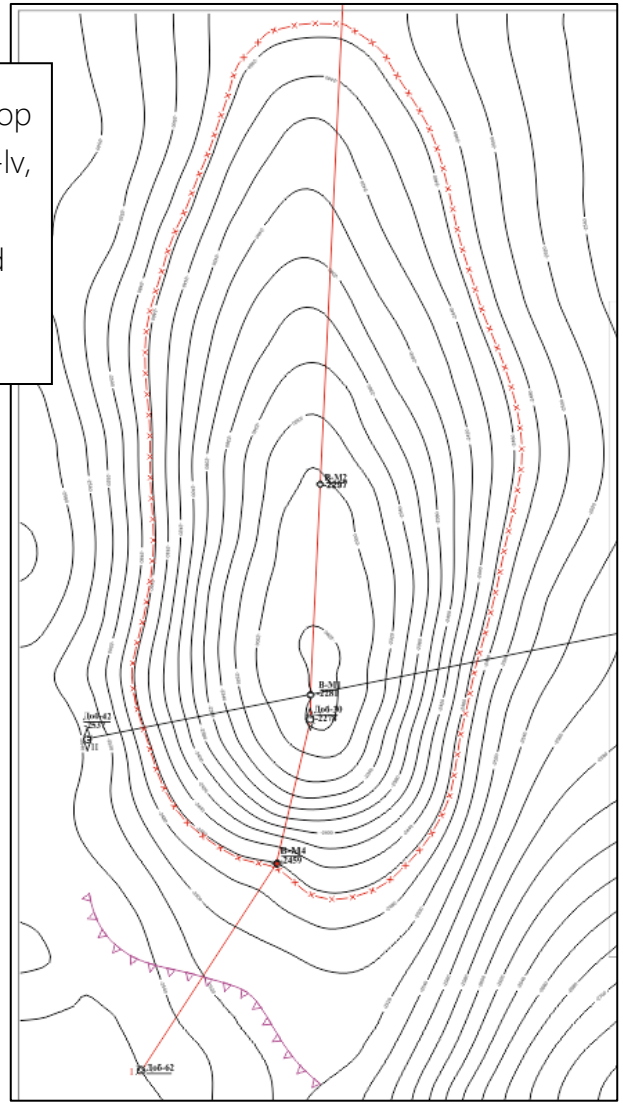


Gas isopach map, C1bb, Vostochno-Makarovskoye field

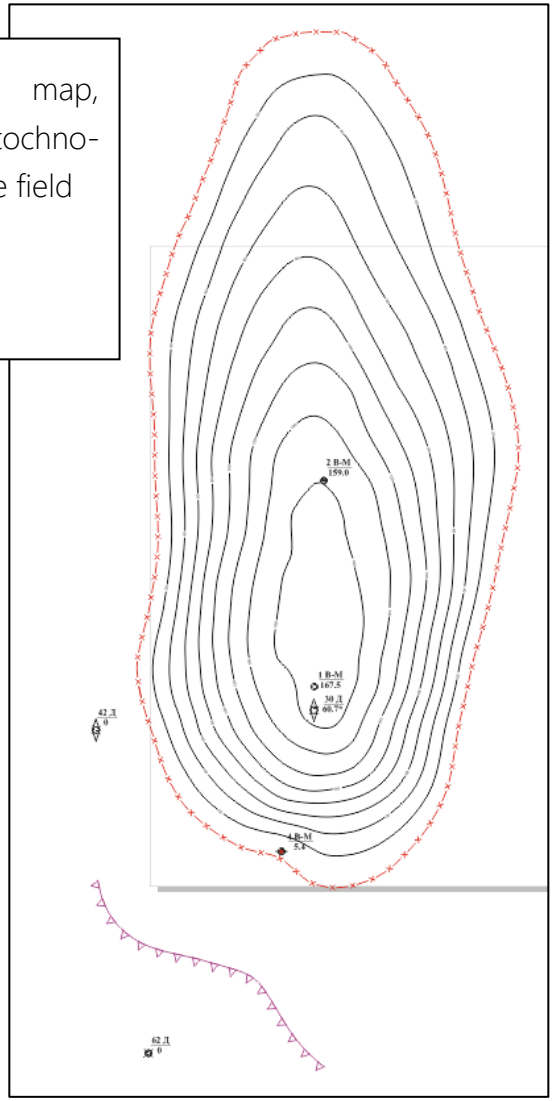


Attachment 4. B3ev-lv Deposit, Vostochno-Makarovskoye Field.

Structure map on top of sand, D3ev-lv, Vostochno-Makarovskoye field



Gas isopach map, D3ev-lv, Vostochno-Makarovskoye field



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