ГЕОЛОГИЯ И НЕФТЕГАЗОВОЕ ДЕЛО
(НА АНГЛИЙСКОМ ЯЗЫКЕ)

THE MODERN TOTAL SYSTEM APPLICATION FOR TOPOGRAPHY SURVEY AREA CONSTRUCTION OF OIL AND GAS PIPELINES

Y.F. Denisov
Scientific advisor senior teacher O.V. Rozhkova
Tomsk polythechnic university, Tomsk, Russia

Designing, structure and operation of oil and gas pipelines demands precise engineering-geodesic maintenance, the quality of which depends on application of scientific-technological progress achievements. The modern surveying instrument is a product of high technology integration, which includes the latest achievements in electronic engineering, optic and laser technology, precision mechanics and other sciences.

The electronic total system increases productivity of survey area by maximum automation of the process. The use of the total system eliminates all intermediate manual operations typical for conventional micrometer theodolites (such as 2T2 and 2T5K). Thus, errors and miscalculations are possible when an inexperienced operator fulfills taken reports. It increases measurement speed except for subjective error of the look-out. However, angular measurement errors by the total system reaches 1 sec, and linear – 1 mm + 1 pmm, where device computer memory allows information recording in more than 3000 points of a surveyed area, ensuring core budget up to 4 MB. The total system ensures distance measurements up to 5 km. The capability of the total systems have servomechanism – computerized prompt on a prism and some devices excluding deflector application.

The modern total system is applied on the base of Sokkia Set 510 № 023539 on Taishet – Scovorodino (1130 – 1196 km) pipeline in the Eastern Siberia – Pacific Ocean.

Selection of the total system is determined by:

Split-hair accuracy of measurements (5 sec horizontal and vertical angles and ± (2 mm + 2 mm/km) linear measurements)

Distance measurement range (up to 2400 meters with a deflector, and without – up to 100 meters)

Temperature resistance range (from -20^0 up to $+50^0$)

Internal memory up to 1000 points.

In each survey point the following operations are carried out:

Total system is established and centered above a point

Device is turned into run position

Reference vertical (zenith) and horizontal direction

Necessary data is put into tachymeter memory:

- at an altitude of a taken point (HO). The tachymeter processes this information immediately and determines true altitudes of bearing points H, by default – excesses h;
- according to reference direction (A) azimuth, the tachymeter determines position bearing point angle direction and, by default – on the right course to superjacent horizontal angles β;
- coordinates of a taken point ($_{xo,yo,}$) allow the tachymeter to plot position bearing points X, Y, by default – increase of coordinates from a reference direction ΔX, ΔY;
- coefficient, taken where temperature and atmospheric pressure are taken into account;
- device and a deflector altitude differences (i-1);
- scheduled – altitude binding all epines of a designed line plumps by geodesic satellite receivers: Topcon Javad Legasy.

Scheduled – altitude determination of points when obtaining the fixed solution accumulation results 20-40 minutes with an interval record of 4 sec. Received outcomes were treated with the program Ashtech Solutions 2.60 in coordinates СК – 42. Transition parameters from system WGS-84 to СК-42 are realized in program Ashtech Solutions 2.60. From available points of GGS base stations, from which binding datum marks and taking points were executed, were determined. Main theodolite and tachymetry courses fixed on satellite system GPS of temporary datum marks and timbered points are built on the pipeline route. Then, topographical plans of a designed pipeline route are constituted by the atomized method (the computer program «CREDO») in the basic computer. Outcomes of final camera machining of materials are submitted in «AutoCad 2002» and 0.5 m on 11 and 9 are introduced on the draughting machine with a scale 1:2000 in contour interval horizons of 1.0 m and 1:5000. Then, in the basic computer the digital model of the surveyed area is created with allowance for all measurement discrepancies and topographical plan printed on the draughting machine.

The advantages of the total system used for field measurements, excluding subjective error of the look-out, are obvious. The system reduces the survey time by maximum automatization of the process.

The advantages of new technologies are underestimated in oil and gas industry and are considered to be “wasteful mechanisms”. Financing many activities, especially building, general economic problems and relatively high consumer price for electronic tachymeters (from 10 up to 25-35,000 $) do not allow many organizations to involve this modern digital technology in field work. Nevertheless, in case of substantial Russian market development in the sphere of services including geodesy, cartography and geoinformatics, the company applying most incentive and efficient technologies can considerably influence the companies working on low technologies.

In the near future, equipment costs will decrease on the world market, and built-in software prices and their appendices will increase. Service cost and duplicate parts will also decrease owing to devices reliability activity increase and their operation life prolongation.

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OIL AND GAS RECOVERY FORECASTING IN RUSSIA IN XXI CENTURY

A.A. Karas
Scientific advisor senior teacher R.N. Abramova
Tomsk Polytechnic University, Tomsk, Russia

Bases of the forecast levels of oil and gas recovery for the first 25-30 years XXI century and the forecast of extraction and development of a raw-material base of hydrocarbons for the subsequent period are various. At the initial stage extraction will be conducted from deposits already in development with various degree of clarity of stocks, deposits that are open, but are not developed and also deposits which will be opened and developed during the initial stage.

The long-term proved forecast of production levels of initial energy and structures of fuel and energy balance is extremely important for maintenance of the country power safety. Forecasting calculations have been determined and divided into four groups of deposits: developed, prepared for development, being explored and predicted.

It is necessary to say that it is possible to predict extraction levels only in developed deposits. The forecast extraction levels of deposits prepared for development can be executed in analogy to develop and are less reliable. The forecast level of extraction of explored and predicted deposits is even less certain.

There are there variants of oil recovery forecast in Russia: 1) optimistic; 2) acceptable; 3) pessimistic. In all three variants oil recovery tendencies are approximately identical. At first, oil recovery level will increase to maximum because of “old” oilfields in Northern Caucasus and European part of Russia, as well as, new oilfields in Western and Eastern Siberia, the Far East and Sakhalin shelf.

After 2020-2025 recovery rate will begin to fall, because of resource ripeness and share of difficult access resource and will be about 180-200 million ton. Probably, rate of oil recovery will sink in series.

The forecast levels of oil& gas recovery for the first 25-30 years of the XXI century (initial stage) and the forecast of extraction and development of new hydrocarbon fields fro the following years are various. At the initial stage, extraction will be conducted from deposits already under development; deposits, which have been discovered but not, developed; and also deposits which will be discovered and developed during the initial stage.

Forecasts for the thirty-year period are based on discovered and developed reserves. At the next stage (2031-2100) the non-developed reserves will be considered. The forecast is based on the quantitative resource estimation results.

In XXI century Russia will also have a powerful raw-material base of natural gas. The current estimated reserves of gas for 01.01.2000 are 46,9 trillion m^3. Average clarity of reserves –20 %. The total amount of the current developed reserves is more than 29 trillion m^3, including:

About 4 trillion m^3 –on maintained deposits;
17,2 trillion m^3 – on the deposits prepared for development;
0,4 trillion m^3 –on the inhibited deposits;
7,6 trillion m^3 – on exploring deposits.

In XXI century gas will be the main energy source because oil recovery will decrease. The predictable levels of gas extraction in the XXI century can be seen in view of the following basic division of gas streams into “western” (internal consumption and export to Europe) and “eastern” (mainly export to the countries of Asia-Pacific region). In the XXI century gas recovery level will be high, but will fall because of low-pressure gas increase with sour components and helium. Here it must be stated that the main gas areas are Jamal, Nadim, Gidan, the northern seas, Western and Eastern Siberia.

The condition of petroleum and gas reserves in Russia allows predicting the function of the petroleum and gas industry during the XXI century. Thus, maxi8mum level of oil recovery is expected in 2020, and gas- in 2030. Comparing the forecasts of level dynamics of oil& gas recovery during the XXI century in Russia and in the world, it is necessary to note that in most cases, the expected decrease of oil recovery will be from 2000-2015; and gas-to 2030 which is based mainly on the given data in Russia. In the second half of the XXI century it is necessary to search for new energy sources.

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METHODS OF OIL RECOVERY MAINTENANCE

N. Khryapinskaya
Scientific advisor senior teacher T.F. Dolgaya
Tomsk Polytechnic University, Tomsk, Russia

Nowadays, despite technology advances in primary and secondary production, a lot of reservoir original oil-in-place remains untapped after the above-mentioned phases of production cycle. That's why the problem of improved oil recovery is very important and simply necessary for further oil development.

The purpose of Improved Oil Recovery (IOR) is improvement of recovery rates of oil fields and oil recovery found in pores between rock particles. IOR is the application of any process or technology that enhances the displacement of oil from the reservoir. The methods of Oil Recovery Maintenance (or simply, IOR methods) cover all approaches to improve hydrocarbon recovery/ IOR method refers to any recovery method other than primary and the conventional secondary recovery methods through "flooding"(water or fire) or through injecting steam or gas such as nitrogen or carbon dioxide.

Oil methods include all methods that use external sources of energy and\or materials to recover oil that cannot be produced economically by conventional means. They can be classified by the method of achieving the necessary effect. The following is the most commonly used type of classification and it is divided into five groups: 1) physical-chemical; 2) thermal; 3) mechanical; 4) gas; 5) others.

Physical-chemical methods are processes that use special chemicals in water to push oil out of the formation. They are divided into:

Surfactant flooding (also known as micellar-polymer flooding) – the injection of surfactants to reduce interfacial tension between the oil and water phases, thus allowing the recovery of oil trapped in smaller pores;

Polymer flooding- the method in which water-soluble polymers are added to the injection water to increase its viscosity relative to that of the oil it is displacing;

Alkaline flooding- the injection of chemicals such as sodium hydroxide, sodium silicate or sodium carbonate. These chemicals react with organic petroleum acids in certain crudes to create surfactants in situ. They also react with reservoir rocks to change wettability;

Acidizing – the simplest form of chemical stimulation, a 90% acid-in-oil emulsion or other artificially treated acid solvent, containing sand, is forced into the fractures if the reservoir rock or its cement is acid-soluble.

Thermal processes: the reservoir temperature is increased to reduce oil viscosity, thus improving the oil mobility ratio/ This category include:

Steam injection and flooding is the method where steam enters into the reservoir and heats up the oil-bearing formation, the reservoir fluids, some of the adjacent cap and base rock, reducing their viscosity;

In-situ combustion – the injection of air or oxygen into the formation and use a controlled underground fire to burn a portion of the in-place crude. Heat and pressure move oil toward production wells.

Mechanical method – a hydraulic fracturing. It is the creation of cracks on the production formation with the help of fluid injection under high pressure and their strengthening with proppant. It is one of the most efficient processes for low-permeable and pollutes reservoirs.

4. **Gas methods** which use gases such as natural gas, nitrogen or carbon dioxide that expand in a reservoir to push additional oil to a production wellbore, or other gases that dissolve in the oil to lower its viscosity and improve its flow rate. The technique that is attracting the new market interest is carbon dioxide (CO_2) injection. Carbon dioxide flooding is carried out by injecting large quantities of CO_2 (15 % or more) into the reservoir. It is highly soluble but not fully miscible with oil. Its solution causes the oil to expand and lowers its viscosity, driving it through the reservoir and extracting the light-intermediate components from the oil. Even if complete miscibility is not achieved, it will function as a solution gas drive. Nitrogen and flue gas flooding are also used. These are oil recovery methods, which use these inexpensive non-hydrocarbon gases to displace oil in systems, which may be either miscible or immiscible depending on the pressure and oil composition.

Other methods: microbial; wave; electromagnetic; nuclear explosion. These methods are not still widespread, however, they are only being studied.

Basic knowledge of these IOR methods and their applications are needed for sound reservoir management.

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TECHNOLOGY OF THE OIL PIPELINE DAMAGED SECTION REPLACEMENT

A.V. Konev
Scientific advisor senior teacher O.V. Rozhkova
Tomsk Polytechnic University, Tomsk, Russia

This paper discusses the methods of pipeline replacement with swapping oil stoppage (blocking the damaged site by gate valve) and without stoppage (with lining bypass line).

Pipeline damaged section repair is carried out by replacing it, if the following types of damage are revealed:

50 mm long and longer cracks in a welded seam or pipe basic metal;

Breakage of a ring (assembly) seam;

Breakage of a longitudinal (factory) seam and pipe metal;

Dents with a depth exceeding 3,5 % of pipe diameter;

Scratches with a depth more than 30 % of wall thickness and with a length up to 50 mm and more.

Depending on the applied technology of conducted repair works, pipe section replacement can be carried out by means of oil stoppage during pipeline transportation, thus the damaged section is completely or partially emptied and a loop (bypass) line is laid, which stops oil transport only for the period of its installation and connection.

The technology of damaged section replacement with oil transportation stoppage is widely applied in repairing domestic pipelines. According to this technology, when oil transportation is stopped, the revealed damaged section is blocked from the line with two linear latches. In case of pipeline failures, the telemechanization system and pump units are automatically switched off; the damaged section is localized with linear latches.

With the brigade arrival, the first measures are to restrict oil spreading area, preventing oil from flowing into fire-hazardous places and ponds, and also providing population safety.

Communication is established with a dispatcher on duty, pipeline section is prepared for opening; capacity for oil gathering is also prepared. The order of work organization for pipeline damaged section replacement without a bypass line is the following:

Failure location is defined;

Section is opened with simultaneous flowing oil pumped out;

Window in the pipeline is cut out by means of nonfire method and oil is pumped out of the pipe;

Pipeline internal section is blocked and defective section is cut out;

New coil is marked;

New coil is centered and welded;

Welded seams are tested;

Repaired section is isolated and backfilled.

The essence of damaged section replacement with a bypass line method is in the fact that pipeline damaged section is blocked; a bypass line is cut in and laid for oil transport reconstruction. Repair works based on pipeline damaged section replacement are carried out according to the usual scheme, which promotes erection-welding works quality improvement.

The scheme of repair works based on pipe defective section with bypass line application is shown on Fig. 2. Simultaneously with the beginning of repair works on pipeline section opening and flowing oil gathering and pumping out, shut-off dampers are installed for damaged section separation from trunk pipeline on both sides of removed pipeline section (without emptying it).

These works include two essential operations: making holes in pipeline and installation of shut-off dampers through them. For this purpose two nipples or sectional T-joints are welded to pipeline at the point of shut-off damper installation. In a flange of a T-joint there are special grooves for shut-off damper installation after repair works are completed. Nipples are connected with special stop valves, to which apertures cutting mechanism is attached. The design of the mechanism allows cutting out apertures in the pipeline, which is under the pressure of transported oil.

After apertures cutting mechanism is dismantled, armature is closed; and shut-off damper installation device replaces this mechanism. The shut-off damper is a ribbed cone mounted on rods. Pipeline shut-off damper cone bottom is directed to high-pressure liquid in order to provide neoprene seal film adherence to pipeline walls.

Shut-off damper design allows keeping liquid working pressure in the pipeline. Apertures are drilled with a cylindrical tubular mill with a face working pert. A mill is placed precisely along the axis of a prospective aperture, and a frame is fixed on a flange.

The mill spindle is supplied with a special device, which holds the cut out piece of metal and allows removing it. Mill rotary movement and its submission are provided by framework built – in pneumatic actuator or hydrodrive. After cutting out apertures in the pipeline and drilling device dismantling, stop valve is connected with bypass pipeline, through which oil is transported. The damaged section is cut out and replaced by a new one. After these operations having been performed, overlapping devices are dismantled, nipples are plugged with special segmented stoppers; stop valve on a bypass line is blocked, and the stream of oil is transported by trunk pipeline. Damaged section replacement includes such activities as pipeline defective section cutting out and new coil welding. These works should be carried out in accordance with certain requirements. The length of the cut out pipeline defective section should be not less than 100 mm longer than the defect itself from both sides.

Pipeline defective section replacement method should be chosen depending on specific conditions, presence of corresponding means and applied technology DRW*. The following methods can be used:

Cold cutting (with the help of special machines for explosive cutting pipes).

Gas cutting (cutting by flame from combustion of a propane-oxygen mixture).

Cutting with explosion energy application.

When cutting method has been chosen, it is necessary to keep in mind the following factors:

Cold cutting requires the maintenance of engine by reducing free rotation around the pipeline, i.e. corresponding preparation of a foundation ditch, and also working body cooling by a lubricating-cooling liquid for fire safety assurance.

Gas cutting is possible only in case when all fire-preventative measures for fire works in explosive conditions are taken (i.e. the pipeline should be emptied and luted).

Pipeline defective section cutting out with the help of explosion energy is carried out on filled by transported oil or emptied pipelines according to operating instructions.

Pipeline ends preparation for installation and welding is necessary for correct welded seam formation and the inserted section sizes conformity with the sizes of the cut out pipeline section. For this purpose, it is recommended to apply special adaptations for sectoring which allow transferring the sizes of an inserted section to the pipeline end or, vice-versa, the sizes of the pipeline cut off according to the sizes of the new inserted section, taking into consideration, the gaps and rims dulling. Due to this, high quality and speed of installation works are provided.

The minimal coil length for pipes in diameter up to 530 mm should be not less than 0.5 m; foe pipes in diameter of 530 mm and more should be equal with diameter of the pipeline, and thickness of a welded in pipe wall should be equal with thickness of a trunk pipeline wall. The coil should be made of molded pipes. Pressure of molding should correspond 0.95 a_m (a_m – pipe metal yield point), and time period from the moment of molding to repairs should not exceed half a year.

DRW* - damage recovery work.

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THE PRINCIPLES OF OIL AND GAS FIELD DISTRIBUTION IN TOMSK REGION

E.O. Konovalova
Scientific advisor senior teacher T.F. Dolgaya
Tomsk Polytechnic University, Tomsk, Russia

More than 120 oil and gas fields in Tomsk region are in the western part. The biggest ones are accumulated in Kaymysovskaya and Nijnevartovskaya suites. East direction fields are small and medium in size and hydrocarbon reserves.

The first favorable condition for generation, accumulation and conservation of oil and gas deposits is the presence of reservoirs and cap rocks. The main caprock for the Upper Jurassic deposits is Bazhenovskaya series presented by dense mudstones that block the fluid migration and, at the same time, contain organic matter. So, Bazhenovskaya series is oil producing. The series tapers out to the West-Siberian plain boundaries (i.e. east Tomsk region). Thus, in the eastern region part, there is no regional cap rock for Upper Jurassic deposits [2]

Vasyuganskaya quartz sandstones series in coastal environment is a reservoir within Tomsk region. Vasyuganskaya series is situated in the west of the region where all the fields are situated. In the direction from west to east it can be seen that sandstone bed U_1 of Vasyuganskaya series changes to clay-sandstone of Naunakaya series. This is caused by the changes of coastal environment in the west to continental one in the east. Further, eastwards, Naunakaya series is replaces by clay deposits of Tyajinskaya series. This explains that in the east part of Tomsk region there are no reservoirs and regional caprocks for deposit formations.

Looking at the map of oil and gas field distribution in Tomsk region by fluid type, the following relationship can be noted: in the west oil fields predominate (Kaymysovskaya and Nijnevartovskaya suites, Aleksandrovskaya and Sredne-Vasyganskaya mega suites, Koltogorskaya mega and Nyurolskaya depression); further in the east-oil-gas fields (east slope of Sredne-Vasyganskaya mega suite) and in the central part of the region – gas and gas-condensate fields (Parabelskaya mega suite).

The western part of Tomsk region (east slope and the central arch part of Kaymysovskaya suite) is bedded hypsometrically lower than Sredne-Vasyganskaya mega suite taken as a whole. Hypsometric bottom marks of Bazhenovskaya series in the Kaymysovskaya suite are 2600-2700m, in the Sredne-Vasyganskaya mega suite – 2300-2400m, and in the Parabelskaya mega suite- 2100-2200m.

A deposit consists of gas, oil and water. Gas is lighter than oil (by density) and accumulates in the upper part of the deposit, so it will be the first to migrate in the upper dome. The oil migrating from below squeezes out all gas in the trap lying hypsometrically higher, so the first trap is filled by oil. When the first trap is filled by oil to the limit, it (oil) starts moving higherand in the next trap it pushes out some gas up again and mixes with the residuary gas forming oil-gas deposits. Free gas that has moved to the higher strata forms gas deposits. This process goes on according to the principle of differentiated hydrocarbon in the traps.

During the last few years scientists who studied Tomsk region deposits, supposed that the presence of oil and gas accumulations are on the right-bank of the Ob-river. Drilling of a few parametric wells up to the basement was planned which indicated the possibility of even finding reservoirs (oil and gas saturated rocks) and caprocks in Paleozoic and probably Mesozoic deposits. Geologists from our University and Tomsk Research Institute of Oil are studying core samples from the well Vostok-3.

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EFFICIENCY EVALUATION OF NON-UNIFORM UPGRIDDING METHOD BASED ON STREAMLINES APPROACH: FIELD EXAMPLE

S. Kh. Kurelenkov
Scientific adviser director I. N. Koshovkin
Tomsk Polytechnic University, Tomsk, Russia

Introduction. Fine-scale geological models are often at a resolution of about 1 m vertically and 50 to 100 m areally, resulting in reservoir models on the order of 10^6 – 10^7 grid cells. Current computing power limits from simulating such detailed reservoir models on practical time scales. Most of simulation grids are one order lower in magnitude (about 10^5 – 10^6 grid cells). Thus, a special translation of the fine-scale models to a coarser is required. This technique is currently referred to as Upscaling [2]. Properties, such as porosity and water saturation, are easy to upscale – they may be averaged arithmetically (water saturation – pore volume weighted). The most challenging problem is upscaling of permeability.

There are two main groups of permeability upscaling methods: one-phase techniques, which are based on the determination of effective absolute permeability, without changing rock relative permeabilities, and two-phase (pseudoization) techniques, which are based on the determination of modified (pseudo) relative permeabilities [4, 5].

One-phase upscaling comprises two processes: upgridding, whereby the fine grid is optimally coarsened in such a way as to preserve the characteristics of the fine grid, and upscaling itself, whereby the properties for the new coarse-scale model are computed [2].

In this work we have compared several upgridding techniques in combination with upscaling methods currently included in commercially available software with the new Streamlines-based upgridding method. The main idea of this technique is briefly discussed. In the context of the project it was realized (coded). The comparative analysis was done on the field example via the application of concerned techniques for the "K" field (Western Siberia) which is highly heterogeneous. The comparison was based on the methodology of the 10th SPE Comparative Solution Project [3].

Upgridding method based on streamlines approach. The main idea of the technique is that the coarsening of fine-scale model is made by grouping geological layers with equal sweep efficiency or swept volume. The swept volume for the layer can be defined as the sum of pore volumes (of cells) which were swept by injection wells to the current moment of time. Thus, the flow simulations should be carried out on the geocellular model for application of this upgridding method [1, 6].

As it was mentioned, current computing power limits from simulating detailed reservoir models on practical time scales, thus it was proposed to use the 3D streamline simulator instead of finite-differences one. Streamline simulators, e.g. FrontSim (Shlumberger), 3DSL (StreamSim), have higher speed of the calculations, thus they are well suited for large scale flow simulations. Another reason of using streamline simulator is that it is well suited for calculating the volumetric sweep based on time of flight connectivity [1, 6].

The swept volume simply represents the reservoir volume that correspond to a time of flight less than or equal to the given time of interest. For the gridblock model the swept volume can be defined as the sum of pore volumes of cells which time of flight is less than or equal to the time of interest [1],

$$V_{swept}(t) = \sum_{i,j,k} \phi_{ijk} V_{ijk} \theta(t - \tau_{ijk}), \tag{1}$$

where V_{ijk}, ϕ_{ijk} ,τ_{ijk} are the volume, porosity and time of flight of gridblock *(i, j, k)* correspondingly; *t* is the time of interest.

The swept volume can be determined by equation (1) for each geological layer. According to the method, geological layers with "equal" sweep efficiencies are grouped into coarse-scale ones. In this work we choose the *variation* (as for Variation-based upgridding [9]) as the measure of homogenization which is simply equal to difference of sweep efficiencies between 2 neighbor layers. Pair of layers having less variation is grouped together into a coarse one.

Field description. The considered "K" field is a large oil reservoir of Jurassic age located in Western Siberia. The reservoir structure is a complex of local elongated folds subdivided by numerous narrow troughs. The fault distribution was considered negligible (no faults were seen by 3D seismic survey) [8].

Hydrocarbon reserves of the oilfield are associated with the formation of Upper-Jurassic period which comprises of Vasuganskaya, Georgievskaya and Bagenovskaya formations. Bagenovskaya formation is the source rock and the seal (caprock) for the reservoir which contains bituminous mudstones. The bottom of Bagenovskaya formation is Georgievskaya formation which consists of shale. It is the top of Vasuganskaya formation which contains all hydrocarbon reserves. The Nizhnevasuganskaya formation is mainly represented by shale while the Verchnevasuganskaya formation contains sandstones. It comprises of three major flow units J_1^2, J_1^3 and J_1^4 [8].

The J_1^3 layer is the most productive one and considered to be the main object for development. The reservoir is highly heterogeneous in vertical and horizontal direction. Gross thickness varies from 4,7 to 20,2 meters. Net reservoir thickness ranges from 3,8 to 19,1 meters. The average porosity is 0,16. Reservoir rocks were deposited in a sand-rich deltaic environment and are composed of sandstones with permeability varying from 0,01 to 500 md [8].

Geological and Simulation models description. In the context of the project the new geocellular model (finer in vertical direction) of the "K" field was constructed. Both existing and new geomodels were constructed by the same methodology based the Hydraulic Flow Unit (HFU) concept [8]. The areal cell size of both models is 100 m. The only difference between the structure of models is in the vertical cell size which is equal to 1 m for a new model (instead of 1.3 m) which results in 97×84×26 (211848) cells.

To make the comparison of upgridding techniques the grids which are constructed by them must be comparable, i.e. have equal number of layers (and cells). The existing simulation model of "K" field consists of 10 layers, thus to have a chance to compare it with the new models this number of layers were chosen (scale up factor is equal to 2,6). Dimensions of the new simulation models coincide with ones of existing simulation model and equals to 97×84×10 (81480) cells. Four different coarse grids were constructed and examined in the context of the analysis:

1. Uniform grid (layers have equal average thickness).
2. Non-uniform grid constructed by Variation-based upgridding [9].
3. Non-uniform grid constructed by Flow-based Upgridding [9].
4. Non-uniform grid constructed by Streamlines-based upgridding.

First 3 methods are included in commercially available software. The Streamlines-based upgridding algorithm is not currently included in any commercially available software. In the context of the project it was realized via internal programming language of the upgridding software.

Four different one-phase upscaling methods of two groups, Algebraic Averaging and Boundary Conditions, were applied on each constructed grid. As a result we have 16 simulation models which would be used in comparative analysis. The following upscaling techniques were used:

1. Simple upscaling (Algebraic Averaging): horizontal permeability (in X and Y directions) was upscaled using Arithmetic Averaging, and vertical permeability (in Z direction) was upscaled using Harmonic Averaging.
2. No Flow Boundary Conditions (all directions) [9].
3. Linear Flow Boundary Conditions (all directions) [9].
4. Adjoint method (all directions) [9].

Comparative analysis. The comparison was done in two stages. Firstly, the analysis was held in each upgridding group to distinguish the best fit upscaling method for the group. After that, the comparison was carried out for upgridding techniques where each class of upgridding was used with its best upscaling method.

The comparison of one-phase upscaling and upgridding techniques was based on the methodology which had been used for analysis of upscaling algorithms (one-phase and two-phase) in the 10th SPE Comparative Solution Project [3]. The main idea of one-phase upscaling methods analysis is to carry out simulations on the geocellular and upscaled models with the same conditions and using rock relative permeabilities. After the simulations is held, the estimation of field performance parameters (rates, cumulative parameters and etc.) deviation of coarse-scale models from the fine-scale one is held. The best method (model) is that which has the least deviation. In contrast to the 10th SPE Comparative Solution Project [3], it was suggested to use mathematical expressions as the measure of deviation.

Another performance characteristic of models simulated via streamline simulator is the distribution of streamlines, i.e. streamline maps. The numerical parameter, namely reservoir swept pore volume [9] is directly connected with the streamline distribution was used for models comparison. The analysis of deviations is held by comparing next quantities:

1. Standard deviation between multidimensional quantities (consists of oil, water production and injection rates);
2. Relative deviation of cumulative performance parameters;
3. Standard deviation between average reservoir pressures;
4. Standard deviation between swept pore volumes of the reservoir.

The comparative analysis have shown that the simulation model constructed via concerned upgridding method (Streamlines-based) has the less than or equal values of deviations than that constructed by the Flow-based technique [7]. This coarse model was chosen as the simulation model of the reservoir.

Conclusion. The comparative analysis shown that non-uniform upgridding techniques account for vertical heterogeneity than uniform one and that new Streamlines-based method is effective in application for the field of Western Siberia. The chosen model is more adequate to real reservoir which is proved by that fact that history matching process was done in a short time by a little change in relative permeabilities (in contrast to previous simulation model).

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EVALUATION OF FILTRATION ANISOTROPY INFLUENCE ON DEVELOPMENT OF A COMPLEX FIELD

P.V. Molodykh
Scientific advisor Associate Professor, PhD Vitaly P. Merkulov
Tomsk polytechnic university, Tomsk, Russia

Introduction. There are many complex reservoirs with heterogeneous and anisotropic distribution of formation filtration properties to be studied nowadays. The magnitude and orientation of horizontal permeability anisotropy may significantly influence on anisotropic reservoir development strategy and its economic outcome. Such strategy may include the change of water flooding patterns resulting in sweep efficiency difference and better reservoir performance [1].

Natural fractures and depositional features that result in preferential grain orientation are considered to be the main sources of horizontal permeability anisotropy. This fact may significantly change reservoir performance in terms of time of water breakthrough [2].

Orientation and magnitude are the main permeability anisotropy parameters. Anisotropy magnitude may be estimated by core permeability measurements, while anisotropy azimuth orientation may be investigated from lithological study of preferential quartz grain orientation. Besides, permeability maps and depositional environment may be used to confirm obtained results.

Current problem was studied on the base of Z-K field data (Western Siberia). Analysis of core permeability measurements, lithological research and petrophysical logging were available sources of information for particular part of the field. Obtained results confirmed the presence of horizontal permeability anisotropy and allowed estimating its orientation and magnitude. However, these parameters varied with depth combining “complex” anisotropy. This resulted in the use of special technique of anisotropy consideration in simulation model when each layer has its own anisotropy parameters.

Field description and input data. The main productive formation of Field Z-K, J_3^1, is related to Jurassic deposits formed in shallow marine and coastal sedimentary environment [3]. Typical facies of J_3^1 are deltaic deposits. Thickness map of field Z-K J_3^1 reservoir is presented in fig. 1.

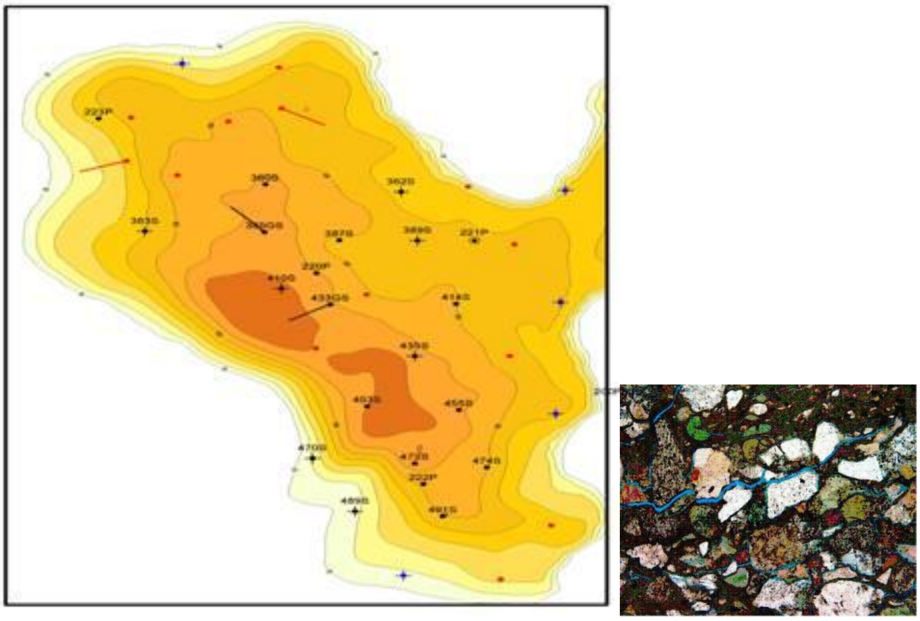

Fig. 1. Thickness map of Z-K field with an object of research

The object of research was chosen as the part of J_3^1 reservoir nearby the well *222R.*

In order to study horizontal permeability anisotropy on Z-K oilfield, lithological analysis results implemented on well №222R (J_3^1 reservoir), were used. The objective of lithological analysis is to estimate quantitatively the preferential quartz grain orientation in sandstone samples. According to microscopic research of sandstones taken from depth *2739,6 m*, well *222R*, piece *146* matrix is packed mostly in North-East (South-West) direction (fig. 2).

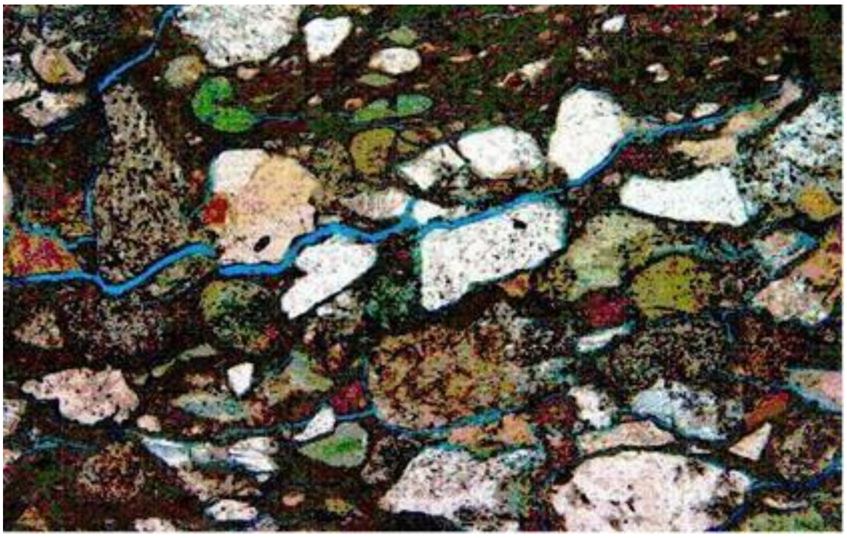

Fig. 2. Sandstone texture with preferential orientation of quartz grains.
Core sample collection from well 222R. Optical microscope

Analysis of several horizontal microstructure sections showed that preferential orientation of quartz grains in samples is not uniform and may be characterized by “spiral” distribution of orientation with depth. However, the main part of quartz grains is directed at North-East.

Research procedure. Research procedure of horizontal permeability distribution investigation may include the following stages.

1. Lithological analysis (determination of horizontal permeability azimuth orientation)

Since permeability anisotropy may be described by ellipse, the distribution of quartz grain orientation was also approximated with ellipse in polar coordinates

2. Permeability measurements on core samples (determination of horizontal permeability magnitude)

Core samples from available collection of oriented core were sawed in two mutually orthogonal directions – preferential quartz grain orientation direction and perpendicular horizontal direction. These directions were assumed as maximum and minimum permeability directions. The results of core samples’ measurements of are presented in table 1.

Table 1

Permeability measurements on core sample

Well	Sample	Depth	Permeability	Orientation
222R	144a	2735,6	29,4	NW
	144b		25,6	NE
222R	145a	2736,6	30,4	W
	145b		18,7	N
222R	146a	2739,6	59,1	NE
	146b		32,4	NW
222R	147a	2740,6	62,1	NE
	147b		43,2	NW
222R	149a	2741,6	18,6	NE
	149b		13,5	NW
222R	151a	2743,9	20,5	NE
	151b		13,2	NW
222R	152a	2744,5	7,5	NE
	152b		13,7	NW
222R	154a	2747	4,2	NE
	154b		3,8	NW
222R	155a	2748	2,2	NE
	155b		2,1	NW

Histogram of K_{HMAX}/K_{HMIN} values’ distribution is presented in fig. 3.

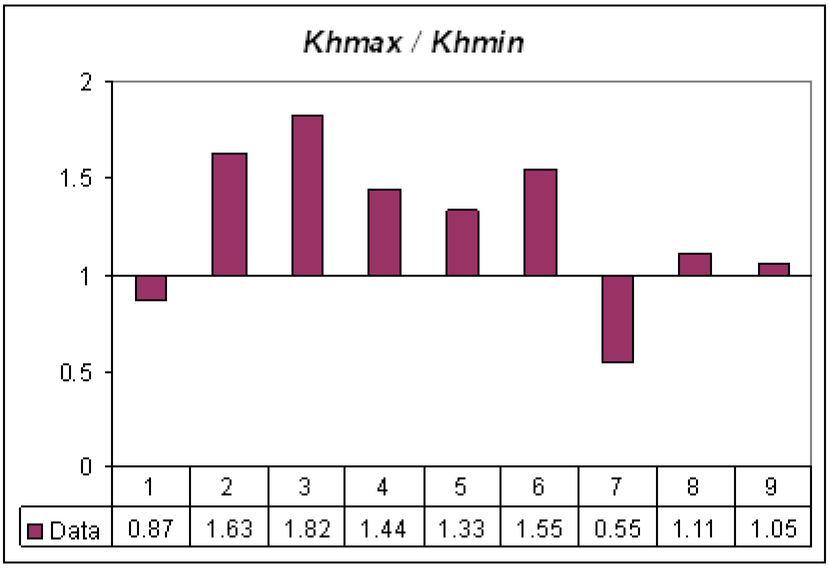

Fig. 3. Histogram of K_{Hmax}/K_{Hmin} values' distribution measured from oriented core samples

Thus, obtained results from lithological analysis and permeability measurements conform the presence of horizontal permeability anisotropy in the region of well № 222R. Anisotropy magnitude (K_{HMAX}/K_{HMIN} ratio) which is oriented mostly in North-East direction resulted in the value of 1,27.

3. Comparison of results with permeability maps and geological data

The significance of obtained results' comparison with permeability maps is in confirmation of the following assumption: permeability anisotropy is apparent at micro level (quartz grain orientation), medium level (permeability maps) and macro level (depositional environment).

According to geological description of Z-K field, deltaic deposits together with mostly North-Western direction of reservoir thickness increase should indicate the presence of horizontal permeability anisotropy in North-Western direction. According to sedimentological map (fig. 4), horizontal permeability anisotropy should be mainly oriented in the North-Eastern direction (macro level). Lithological research on quartz grain orientation confirmed this geological assumption (micro level) [4].

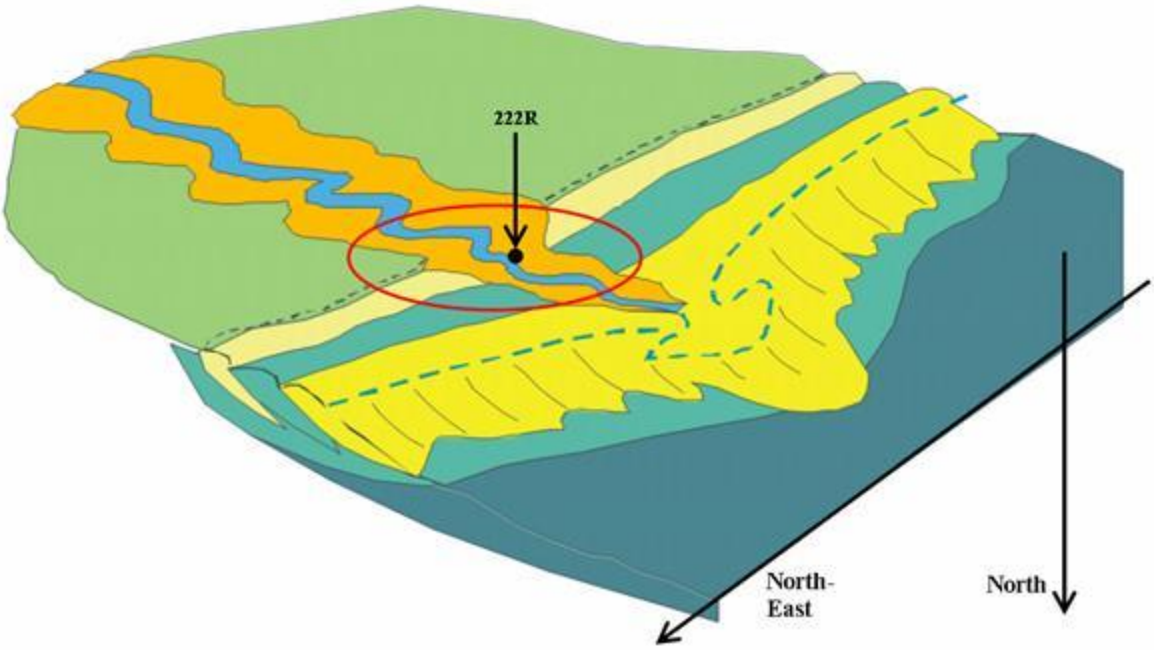

Fig. 4. Well 222R location on sedimentological model (by Belozerov V.B.)

In order to prove assumption on medium level (permeability maps), it was necessary to divide formation into several thickness intervals and construct several permeability maps (fig. 5) (6th depth interval - well 222R, depth 2740).

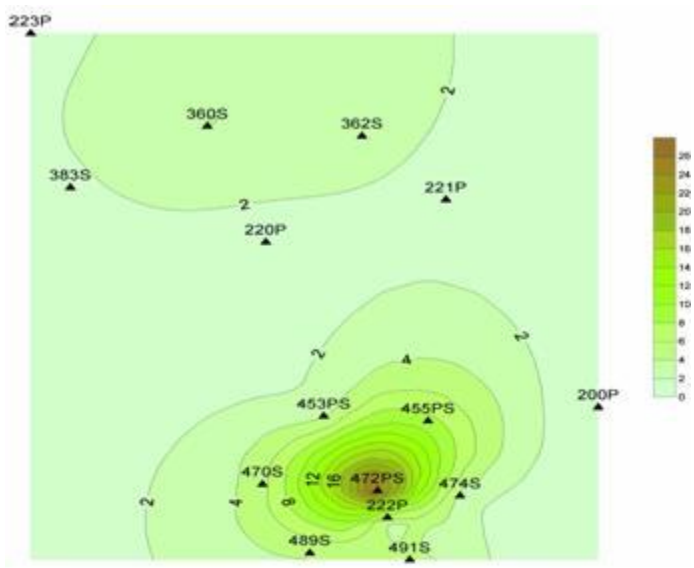

Fig. 5. Permeability map on 6th depth interval (well 222R – 2740 m)

Preferential orientation of equal permeability contours on the map coincides with preferential orientation of quartz grains and conforms geological analysis described before. The applicability of the theory was demonstrated on simulation model.

Construction of simulation model. The next step of research should have include the following steps.

1. Permeability tensor components' variation

For permeability tensor modification in the model, the following formula was used [5]:

$$K = \begin{bmatrix} K_a \cos^2\Theta + K_H \sin^2\Theta & (K_a - K_H)\sin\Theta\cos\Theta \\ (K_a - K_H)\sin\Theta\cos\Theta & K_a \sin^2\Theta + K_H \cos^2\Theta \end{bmatrix}, \quad (4)$$

where K_A and K_b – maximum and minimum permeability respectively (K_{HMAX}, K_{HMIN}); Θ – orientation angle of permeability anisotropy (π/2 – Ψ, where Ψ is azimuth). It is assumed that K_{Hmax} / K_{Hmin} ratio is varying with anisotropy, hence effective permeability should be kept constant. Thus, for a certain permeability anisotropy magnitude and orientation, K_{XX}, K_{XY}, K_{YY} were calculated (table 2).

Table 2

Permeability tensor components

	1,27 (K_{Hmax} / K_{hmin})		
Depth, m	permx	permy	permxy
2735,6	0,96	1,04	0,06
2736,6	1,27	0,78	0,00
2739,6	1,12	0,98	-0,30
2740,6	1,11	0,92	-0,15
2741,6	0,90	1,12	-0,12
2743,9	0,91	1,14	-0,19
2744,5	1,33	0,76	-0,10
2747	0,98	1,03	-0,04
2748	1,00	1,00	-0,02

The distinctive feature of permeability tensor components' calculation here is that anisotropy magnitude and orientation values are taken from lithological analysis of quartz grains, i.e. permeability tensor is calculated according to the depth of core sampling. This is a very bold assumption, but reservoir simulation results are considered to be more accurate.

2. Simulation procedure

In order to avoid massive data recalculation, simulation model with historical data (2001 – 2005) and certain average anisotropy orientation (65°) and magnitude (1,27) values was constructed. This model was assumed to be the base variant for simulation with the purpose to analyse the relative changes in field oil production that may arise with permeability anisotropy occurrence.

According to geological data, this reservoir should have one dominating anisotropy orientation. However, according to petrophysical analysis and preferable quartz grains' orientation, permeability anisotropy on Z-K field is characterized by various azimuth and magnitude values. This fact was considered in the models.

There were 2 models to be simulated in order to evaluate the influence of heterogeneous anisotropy on simulation and hence reservoir development:

Prognosis on 2005 – 2015 years with anisotropy of standard type infill drilling

Prognosis on 2005 – 2015 years with anisotropy of complex type infill drilling.

3. Simulaiton results

The differences in calculations between proposed technique and conventional one (*Delta* column, table 3) may be explained by an assumption that permeability anisotropy has greater influence on development of fields with lower well spacing.

Table 3

Oil production and main economic parameters

	Model 1	Model 2	Δ
Start of analysis	2005	2005	
Duration, years	10	10	
Oil production total, 10^3 ton	3303,87	3294,2	9,67
Revenue, 10^6 \$	578,84	577,14	1,7
Capex, 10^6 \$	34,4	34,4	0
Opex, 10^6 \$	159,3	159,09	0,21
Taxes, 10^6 \$	284,99	284,22	0,77
NPV, 10^6 \$	237,37	236,45	0,92
NPV (0,10), 10^6 \$	172,14	171,58	0,56

Infill drilling accelerates oil production at the same time leading to earlier water breakthrough. In the presence of permeability anisotropy this process is being accelerated if producer and injector are visually located parallel to the line of horizontal permeability anisotropy azimuth. However, according to present grid it is impossible to make such confident conclusion, because of relatively low horizontal permeability magnitude 1,27.

Nevertheless, the difference of 8,97 × 10^3 ton allows expecting greater difference on models with larger permeability anisotropy magnitude in contrast to current field with permeability only up to 30-50 mD.

New technique of anisotropy estimation results in later water breakthrough as shown in fig. 6.

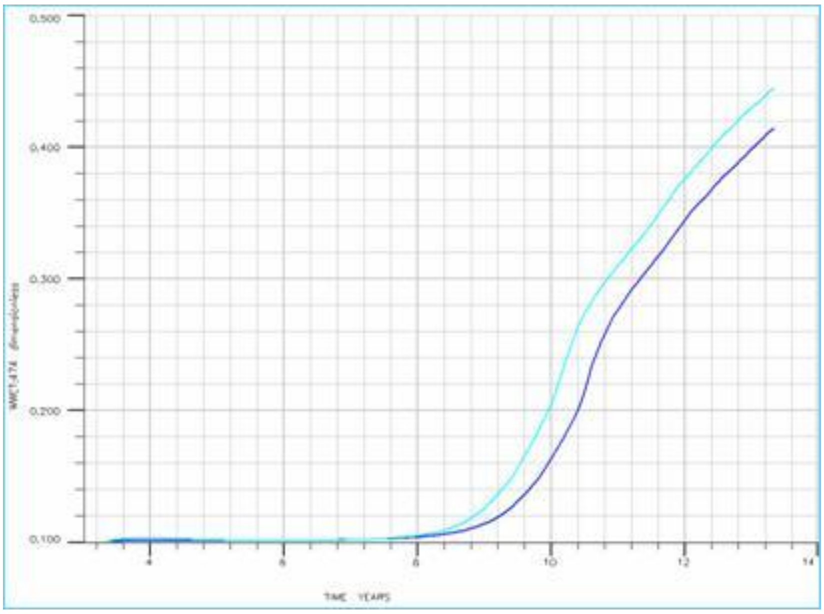

Fig. 6. Well 474 water cut

This may be explained by the fact that anisotropy orientation and magnitude in reservoir is not homogeneous unlike "standard" type of horizontal permeability anisotropy. In is necessary to note that simulation was made on bounded limited model during only 10 years just to show the difference in models. Besides, an object of research does not have large horizontal permeability anisotropy magnitude.

Conclusion. Horizontal permeability anisotropy influences on fluid flow performance leading to early water breakthrough and possible changes in reservoir development plan. Proposed technique of horizontal permeability magnitude and orientation determination together with well test results may serve as a very reliable source of information about the presence of investigated property (fig. 7). In spite of absence of significantly different results between two types of permeability anisotropy simulation in the model, it is possible to consider different permeability anisotropy orientations in reservoir as a very interesting result specific to Z-K oilfield: permeability anisotropy is present but does not influence significantly on production due to compensating magnitudes and orientations.

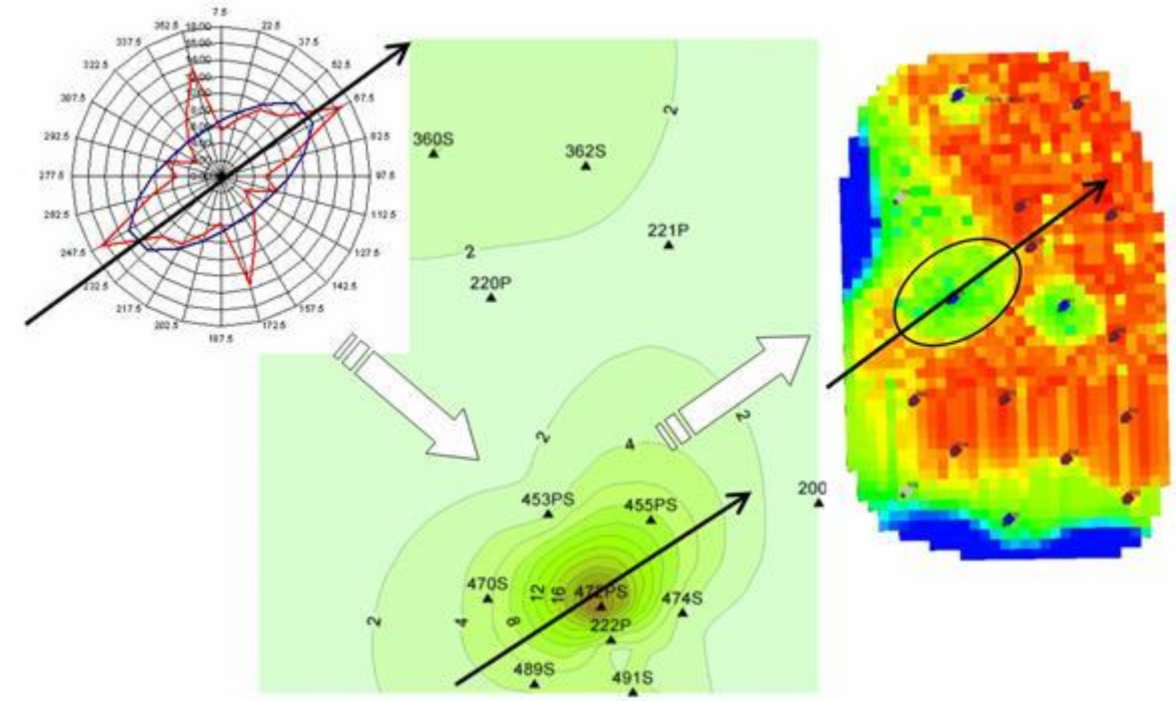

Fig. 7. Comparison of displacement front with permeability anisotropy azimuth according to permeability maps and lithological analysis

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IS RUSSIA PREPARED FOR OIL DRILLING IN THE ARTIC SHELF

I.M. Mukhametdinov
Scientific advisor senior teacher R.N. Abramova
Tomsk polytechnic university, Tomsk, Russia

The basic potential stocks of hydrocarbons raw material on our planet are concentrated on the continental shelf. The Russian shelf contains 1/3 of all Russian potential resources of gas and an essential part of oil and condensate resources. Thus, more than 85 % of resources of the Russian shelf belong to the Arctic areas. Among the Arctic seas the major value have Barentsevo, Pechorskoe and Karskoe seas, which contain more than 4\5 of all oil and gas resources in the Russian Arctic Shelf. Thus, it is possible to draw the conclusion that development of the Russian Arctic shelf is rather perspective, as it can stabilize the Russian economy and increase the country's potential.

This fact becomes increasingly important when the gradual depletion of the resources of Western Siberia and European is taking place. In its turn, the development of oil and gas deposits involves a correct investment policy, directed toward the creation of suitable conditions to attract foreign investments. Present global tendencies show that the process of oil and gas production is moving from land to sea. Russia is behind in this shift: only 3% of Russian oil is drilled offshore. The Arctic shelf is full of hydrocarbon. Fifteen oilfields and gasfields had, by the end of 2002, been discovered in the Barentsevo, Pechorskoe and Karskoe seas and in the Ob Bay. There are three unique oilfields- nine large-scale, two average and one small field.

The main priorities of oil and gas companies in the future will be 2 huge deposits: Shtokmanovskoe and Prirazlomnoye (table 1, 2).

Table 1

Shtokmanovskoe gas-condensate field

Discovered	1988
Project gas production capacity	67.5bil km^3 \ year
Project gas condensate production capacity	350.000 tonnes\year
Distance from the shore	655 km north-west of Murmansk, 290km to the west from Novaya Zemlya Island

Sea depth	280-380m
Required investments	$ 12-20 billion
Production license holders	JSC “Sevmorneftegaz”

Table 2

Prirazlomnoye oil and gas field

Discovered	1989
Amount of oil producing	83.2 ml. tonnes
Distance from the shore	60km
Project oil production capacity	6.59 ml.tonnes\year
Required investments	$15.1 million
Gross revenue	$20 billion
Production license holders	JSC “Sevmorneftegaz”

The above-mentioned facts show that the development of these deposits demands

A huge investment value is important to create the suitable conditions to attract foreign investment. However, the history of Russian offshore projects is short. Russia started its first experience in constructing drilling platforms in the temperate Caspian Sea where an international oil consortium is now at work. The second was in Sakhalin with its obviously more severe climate. Five production projects, belonging to different companies, are working or are planning to work here. In 1996, two large consortiums signed contracts to explore oil and gas off the northeast coat of the island- Sakhalin-I and Sakhalin – II. These two consortiums are estimated to spend a combined $21 billion US dollars on these two projects.

The above-mentioned facts show that additional research of both the Shtokmanovskoe and Prirazlomnoye fields is necessary. However, according to the plans of oil producing companies, oil production in the Prirazlomnoye oilfield will start only at the end of 2006.

The main shortcomings of these current projects are:

- There are no approved technologies in Russia for operation in Arctic offshore conditions;
- There no special tankers in Russia;
- High threat to the environment;
- The development of Russian Arctic shelf demands huge investments.

All these facts show that Russia is not ready to develop Arctic offshore oil fields- and not only because of insufficient research of the regions in question. In our country there is neither the technology nor the equipment required for this purpose. Besides, Arctic offshore production will require (and already requires) large investments for scientific research of offshore geology. That’s why the main ways of solving these present problems are: first – to invite specialists to the Arctic who have technologies, for example, the Norwegians, and to work according to their standards. The second is to develop its own technologies, but in that case, the cost of project and terms of its realization increase several times.

Thus, it is necessary to say that the development of fuel and energy potential; of the Russian continental shelf is supposed to stabilize oil and gas extraction. It can compensate the decrease of extraction predicted by some experts because of the depletion of Arctic deposits in 2010-2020. But, on the other hand, the development of Arctic deposits demands new technologies and enormous investment values. That’s why the question “Will Russia continue the development of Arctic shelf?” stays unanswerable.

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RADIAL TEMPERATURE GRADIENT ESTIMATION DURING FLUID FLOW IN THE WELL

A.V. Parshin, O.B. Khamitov
Scientific advisor Associate professor A.Sh. Ramazanov
Bashkir state university, Ufa, Russia

In the case of heat exchange during fluid flow along the well either heating or cooling of wellbore boundary layers is observed. Thereby at the beginning of the tube central part of the fluid retains the temperature, which is equal to the entry temperature and doesn't participate in the heat exchange. The temperature varies only in the wellbore boundary layers. Thus, at the surface of the tube in its initial part thermal boundary layer forms and the thickness of this layer expand as the distance from the entry increases. In a spaced position these thermal boundary layers close up and further the whole fluid takes part in the heat exchange. Dimensionless profile of the temperature for slightly compressible fluid $y = (t - t_{st})/(t_0 - t_{st})$ remains constant along the length of tube.

Relevance of this work is explained by the fact that during temperature survey measurement of the temperature is carried out in the well itself. Present methods of measurements and interpretation of temperature logs neglect the radial temperature gradient. It's valid for high-flow-rate wells, but if it is valid or not for low-flow-rate wells is worth to discuss.

The well is a vertical round tube, which contacts with surrounding rocks. Initial temperature distribution is geothermal. Fluid flows downward. Flow rate, temperature of wellbore environment and initial inflow temperature are known. This problem is solved with the following assumptions: temperature distribution is steady, fluid is incompressible and its properties do not depend on temperature, no heat sources, vertical thermal conductivity is neglected due to convective heat flow. It's important that on the wellbore wall temperature is maintained equal to the initial geothermal distribution.

Equation of energy in the steady-state case has the following form:

$$w_x \frac{\partial T}{\partial x} = a \frac{1}{r} \frac{\partial}{\partial r} r \frac{\partial T}{\partial r}, \ 0<r<R;\ x>0 \qquad (1)$$

$$T\big|_{x=0} = T_1; \qquad T\big|_{r=R} = T_0 + Gx.$$

Here $w_x(r) = 2\overline{w}(1 - \frac{r^2}{R^2})$ — velocity distribution of the flow along radius of tube, $\overline{w} = \frac{Q}{\pi R^2}$ — caverage velocity, a – thermal diffusivity, G – geothermal gradient, Q – flow rate.

In order to find the solution of this problem we introduce dimensionless temperature and pass on the dimensionless variables. At first we obtain solution for constant temperature on wellbore wall. It's a known solution of Nussels problem. And then using Duamel integral we find solution for transient temperature on wellbore wall.

On the base of the solution calculations of temperature change with depth have been performed in the event of hot water (fig. 1) and cold water (fig. 2) injection into the wellbore.

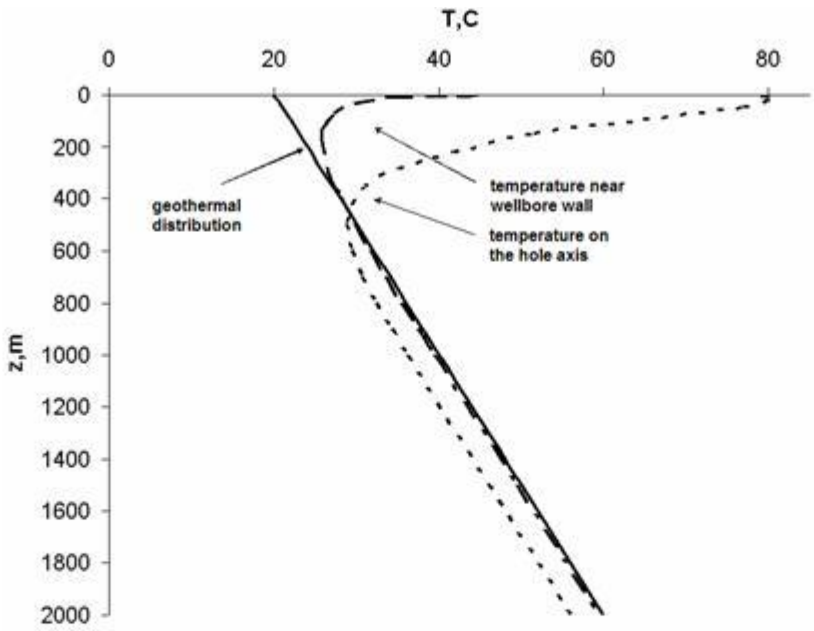

Fig. 1. Temperature distribution along wellbore for the case of hot water injection

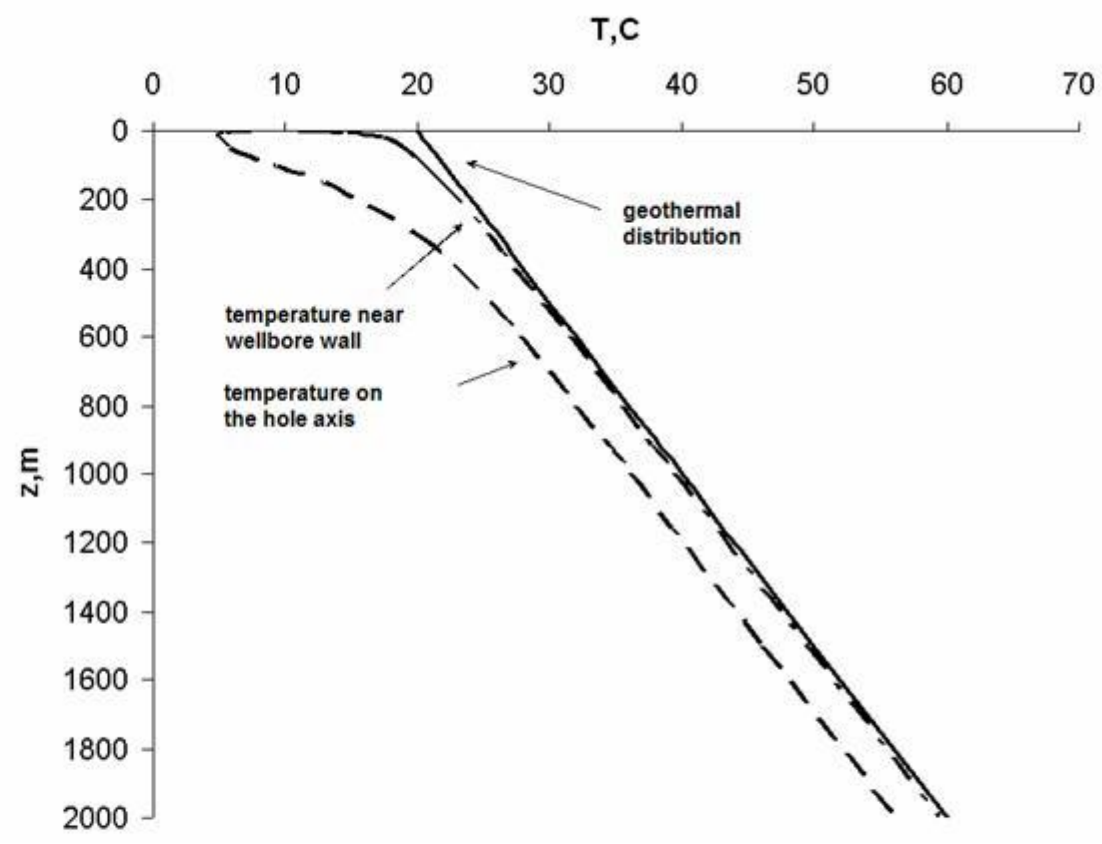

Fig. 2. Temperature distribution along wellbore for the case of cold water injection

It can be seen from both figures that below a certain depth temperature difference between hole axis and wall cease to change. This fact allows obtaining exact solution of the problem (1), which yields the expression for estimation of maximum temperature difference between hole axis and near wellbore wall:

$$\Delta T = \frac{3}{8\pi}\frac{QG}{a}. \qquad (2)$$

Maximum temperature difference in the case of laminar flow cannot exceed 5K for water and 10K for oil.

Analysis of the solution and graphs obtained has shown:

1. The value of radial temperature gradient depends on well radius, flow rate, thermal diffusivity and geothermal gradient.
2. Below a certain depth radial temperature gradient cease to depend on depth.
3. The solution of the problem in the case of steady-state laminar fluid flow shows temperature difference between hole axis and wellbore wall. It is necessary to be taken into account during measurements.

In the case of turbulent flow the intensity of heat exchange has to increase substantially due to mixing of the fluid that can lead to the decline of radial temperature gradient.

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CORROSION AND METHODS OF PIPELINE CORROSION PREVENTION

A.V. Pruss
Scientific advisor senior teacher R.N. Abramova
Tomsk polytechnic university, Tomsk, Russia

New technologies don’t eliminate the problem of trunk pipeline corrosion protection, which is still urgent in Russia. Analyzing experimental information in table 1 it can be seen that the increase in the number of trunk pipeline breakdowns for the last years.

Table 1

Increase number of breakdowns for the last years

Year	Number of breakdowns
2000	693
2001	697
2002	847
2003	925

Firstly, built-up coating compositions are based on bituminous and asphalt-resinous mastics. This type of built-up coating id divided into normal and intensive. The normal type is usually used, but in zones of increased corrosion danger, intensive type is also applied. Such zones are salted ground of any area, marshy, boggy, transitions through railway and highways, sites of wandering currents, sources of direct current, territory of pump stations, crossings with various pipelines, etc. The structure of this type of coating – bituminous insulating coating can be seen in table 2.

Table 2

Bituminous insulating coating

Type	Construction and material	General thickness, mm.
Normal	Primer, mastic (2mm), reinforcing covering (1 layer), mastic (2mm), protective covering	4.0
Intensive	Primer, mastic (3mm), reinforcing covering (1 layer), mastic (3mm), reinforcing covering (1 layer), protective covering	6.0

In addition to built-up coating, polymeric coating is used. They are based on extrusion polyolefin, polyurethane resin, heat-shrinkage material, polymeric or bituminous polymeric protective covering. The design of bitumen make their application long-termed. The layer is a covering of bitumen solution on gasoline. It fills in all micro-roughness on a metal surface. The first coating serves as a more full contact, and consequently, the best adhesion between the surfaces of metal and basic insulation layer – bitumen mastic. There are three industrial types of protective coatings: one-layer, two-layer and three-layer.

To sum up, trunk pipelines have 200000km length in Russia. That is why industrial protective coatings are used for trunk pipeline construction. They have replaced built-up coating, polymeric coating, heat-shrinkage coating which are used only for pipeline repairs.

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FIELD PIPELINES CORROSION MONITORING

M.V. Rozhkova

Scientific advisor senior teacher O.V. Rozhkova

Tomsk polytechnic university, Tomsk, Russia

Corrosion monitoring includes estimation of current corrosion condition, its forecasting, anticorrosion measures efficiency and choice of protective means.

Corrosion condition estimation and reasons for Tomskneft Company pipelines breakdown analysis have revealed that within the period from 1998 to 2005 amount of metal corrosion has increased from 55% up to 95%. Corrosion has lead to an increased number of field pipeline breakdowns.

To forecast corrosion condition the following methods are used: massometric (gravimetric) method, profilometry (caliper measurement), electrical resistivity method, linear polarization method, diffusive-mobile hydrogen measuring method, potential measurement, FSM method, CEION method.

Such methods as AC resistance, surface thin-layer activation, electrochemical noise measuring, and radioisotope method are being developed. These methods are not provided with industrial equipment, and they have not come into wide application. The given methods are applied by using the following devices: Monicor –1, Monicor –2, CORRDATA, Corrater 9000, Corrater 9030, manufactured deep corrosion detectors.

Data gathering is based on Monicor-zond device, which provides gauges input into pipeline system. A set of anticorrosion measures received by Monicor-2-based monitoring is carried out in the following way: the data given by the gauges is transformed as dependence of speed on time. Corrosion is often monitored by using corrosion witness samples, which are placed in pipeline system.

Field pipeline breakdowns analysis shows that one of their basic reasons is corrosion wear of pipeline bottom forming internal surface, which is classified as grooved corrosion type. In order to increase pipeline operation term, a damaged section is turned relatively to its longitudinal axis at some angle and then patched. Field pipeline corrosion protection methods have been developed on the basis of carried out monitoring. These methods are: technological method, electrochemical method and insulation, applying insulation materials.

Corrosion monitoring is the only method to determine corrosion processes and their rates in pipelines.

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SECONDARY SALT FORMATION MODELING IN MYLGINO AREA

A.K. Sarlybaeva

Scientific advisor senior teacher O.V. Rozhkova

Tomsk Polytechnic University, Tomsk, Russia

The Tomsk region is extremely rich in renewable, safe, cheap and stable hydrothermal resources of groundwater, which is concentrated at shallow depths (1-4 km). This fact, therefore, makes the Tomsk region the most perspective in terms of development of this extremely valuable natural resource.

Power generation, heating system and hot water supply of towns and villages, all-year-round heated greenhouses, thermal showers and swimming pools, sanatorium hydropathical establishments and industrial bottling of medical waters, thermal water pumping into oil reservoirs to increase reservoir recovery – this is a list of the promising and highly effective use of ground thermal water in the Tomsk region.

Towns where petroleum production and oil fields are situated, within or nearby huge industrial heat efflux and medical water carry-over is accomplished draw special attention. The advantages of thermal water accumulation are: 1) its broad areal extent, 2) significant supplies and 3) accessibility to different types of consumers. High salinity, gas saturation and common thermal water hardness are considered to be drawbacks, indicating difficulties for thermal water output in producing well with the help of pumps. The problem was to predict the quantity and intervals between mineral fallouts during the process of thermal water output in Mylgino area. Mylgino oil-gas condensate field is situated in Kargasok district, Tomsk region, and has the name of the period, being part of the southeast Srednevasugansk mega swell. Strata, caprock, lithologically screened oil accumulation is monitored by a gas-water contact at 2005 m. According to its supplies these fields are considered to be major ones. The above-mentioned problem was solved on the example of the Jurassic horizon, Kolumzinskaya series with the help of physico-chemical modeling, according to HydroGeo computer program.

The modeling consisted of two stages. The first stage consisted of initial data input, recalculation of the data under RT standard conditions (conditions of analysis), transition to in-place conditions, reconstruction of water analysis inner equilibrium, solution and gas and rock of this layer balancing.

Then, at the second stage, the estimation of rock secondary mineral water solubility was carried out under the condition P CO_2 = const. This condition corresponds to the hypothesis of initial equilibrium of the layer water-carbonates system. This confirms the maximum possible deposit of different minerals from water when transferring such a solution back to surface conditions reflecting its production.

Phased quantity (in milligrams per liter) and quality estimation of scale (accumulation of salts) in production well bore was carried out taking into account supposition that thermal water is produced during a long-time period and under sufficient discharge, so the well and adjoining rocks are heated to initial temperature of produced thermal water (86^0 C). This condition allows conducting modeling at a constant temperature and under alternating pressure.

The results of the second stage of modeling are: carbonates fall-out dynamics depends on depth (milligram per liter). The carbonate fall-out begins at a depth of 255,1 m and ends at a depth of 51 m. Altogether, scale interval (accumulation of salts) is 204,1 m. Negative values signify that solution to the carbonate minerals is unsaturated, respectively, and dissolves them as the pressure changes upward. Altogether, 0.32 mg of carbonates per 1 liter of solution will deposit in the form of salt on the production well walls.

Analysis of carbonate fall-out diagram allows concluding where it would be better to install a pump, while scale dynamics (accumulation of salts) in production well bore can be easily traced. Thus, it is necessary to install pump at a depth below 256 m.

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FOUR-STAGE MUD SEPARATION SYSTEM

A.Y. Shirokov
Scientific advisor senior teacher O.V. Rozhkova
Tomsk Polytechnic University, Tomsk, Russia

Drilling site location is often limited in area selection application. Consequently, alternatives for pit location, which is used for rock cuttings storage, are minimized. The pit is sometimes constructed under unfavorable hydrogeological conditions. Thus, groundwater pollution risk increases.

One of the basic regulations of the low-waste well construction technology is to separate waste solution treatment and their utilization at the early stage of formation. Nevertheless, the basic principle of this technology is drilling mud cleaning.

Drilling mud coming out of the well can be recycled but must be separated from rock cuttings.

Till recently, a three-stage mud separation system has been widely used for this purpose. However, a four-stage mud separation system has lately come into wide application.

The first separation stage takes place in the shale shaker. The shale shaker consists of two main parts: mobile and fixed. Separation is carried out by drilling mud screening through expanded lath. Vibration motion is transferred to expanded lath with the help of two vibratory drives. The main factors determining separation efficiency and shaker carrying capacity are mesh size and expanded lath area. With the help of shale shaker, it is possible to separate rock cutting particles more than 74 mcm in size. Separated drilling mud flows down to the mud tank, from which it is then delivered into the sand separator with the help of a sludge pump. The sludge pump may be of two types: horizontal and vertical. The horizontal pump is connected with the mud tank outlet, whereas the vertical pump is plunged into the mud tank. The pump is driven by means of electric motor.

The main operating part of the sand separator is hydrocyclone with external diameter more than 150 mm. Drilling mud is supplied through inlet nozzle in hydrocyclone shell tangent to interior surface. Under the influence of internal forces, rock cuttings particles are cast away to hydrocyclone wall and move to sand nozzle. Drilling mud is concentrated in sinuous stream moving bottom-up. Rock cuttings move top-down in outward sinuous stream to nozzle tip. With the help of a sand separator, it is possible to separate rock cuttings particles 44-74 mcm in size. Separated drilling mud flows from hydrocyclones through flow-off fitting and outlet into drainage tank and further through pipes into the circulation system.

Then drilling mud is delivered into hydrocyclone silt master unit. The main operating part of the silt master unit is the hydrocyclone with external diameter less than 100 mm. Its operation principle is the same as that of the sand separator, but due to smaller diameter, fine-grained rock cuttings 10-25 mcm in size can be separated. Separated drilling mud is delivered through outlet to the last separation stage.

The main feature of four-stage drilling mud separation system is the centrifuge. The special feature of the centrifuge is a built-in drum screw conveyor used for continuous cutting removal. Drilling fluid is supplied through filter in the direction of spreader and through charging opening to the interior revolving rotor. Under the influence of centrifugal force solid phase particles 2-10 mcm in size precipitate at the rotor inner surface, and later, they are removed from screw conveyor. Clean drilling mud streams down through rotor wall orifices to mud tank. Rotor is driven by means of electric motor with the help of texrope drive.

The process of drilling mud separation results in rock cuttings and water. The rock cuttings are put into settling pit or mounted into cone-shaped bunker and later utilized. The water after treating and testing is recycled for drilling mud and oil well cement preparation, for boiler house needs or as displacement fluid.

The four-stage drilling mud separation system allows to:

Cut down chemical cost.

Drilling cutting amount decrease and expenses cut down for their utilization.

Drill without mud pit.

Lessen drilling fluid negative effect on productive horizon.

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ASSOCIATED GAS: PROCESSING INSTEAD FLARING

M.E. Tsoy
Scientific advisor senior teacher R.N. Abramova
Tomsk polytechnic university, Tomsk, Russia

The natural gas used by consumers is composed almost entirely of methane. Raw natural gas comes from three types of wells: oil wells, gas wells and condensate wells. Natural gas that comes from oil wells is typical termed "associated gas (AG)". This gas can exist separately from oil in the formation (free gas) or be dissolved in crude oil (dissolved gas). Natural gas from gas and condensate wells, in which there is little or no crude oil, is termed " non-associated gas". Whatever the source of natural gas, once separated from crude oil (if present), it commonly exists in mixtures with other hydrocarbons, principally ethane, butane and pentane. In addition, raw natural gas contains water vapor, hydrogen sulfide, carbon dioxide, helium, nitrogen and other compounds. Especially, AG contains such impurities, which cannot be handled easily and moreover, cannot be given for consumption as it is recovered during oil production process.

The annual volume of associated gas being flared and vented is about 110 billion cubic meters (bcm), enough fuel to provide the combined annual natural gas consumption of Germany and France. Flaring in Africa (37 bcm in 2000) could produce 200 Terwatt hours (TWh) of electricity which is about 50 % of the current power consumption of the African continent and more than twice the level of power consumption in sub-Saharan Africa (excluding the Republic of South Africa).

It is widely acknowledged that flaring and venting of associated gas contributes significantly to greenhouse (GHG) emissions and has negative impacts on the environment. Russia has the 3rd place in the world flared AG volume with its 13.5 bcm and 12 % of total in 2005.

Major causes of AG underutilization are a high prime cost, a legislative gap, an unsuitable pricing mechanism, an undeveloped domestic market and undeveloped infrastructure or hard access to it. With the growing share of natural gas in global energy consumption and moreover, the growing pressure from environmentalists, there is increasingly higher interest in AG utilization issues. Many countries have committed for reducing gas flaring and toward this direction too many gas companies already are studying or have even invested in projects that process AG in order to reduce the gas flaring.

Technically, there are several options for AG handling or utilization. Alternatives include: preparing AG as fuel in various forms and export via pipelines; gas re-injection; electricity generation in site needs or for transmissions; processing, such as LNG or CNG and export via tankers; conversion to petrochemical industry feedstock; conversion to products (for example, methanol) for further transport; processing GTL or GTS.

Preparing AG as fuel means separating (purification) all of the various hydrocarbons and fluids from pure natural gas to produce what is known as "pipeline quality" dry natural gas before its transport. The actual practice of processing AG to pipeline dry gas quality levels involves 4 main processes: oil and condensate removal, water removal, separation of NGL (Natural gas liquids), sulfur and carbon dioxide removal.

Gas-to-liquids technology (GTL) is primarily the formation of liquid hydrocarbons, dimethyl ether or methanol from natural gas. This new technology being developed specifically for offshore gas production, converts gas to hydrates to make transportation to market easier, where it is re-gasified at receiving terminal. GTL technology provides a wide range of end product advantages over their conventional petroleum alternatives, such as clean diesel and jet fuel, middle distillates, lubricants, olefins and methanol.

Liquefied Natural Gas (LNG) is cooling gas to its boiling point to condensate into liquid form. This technology is useful mostly for transport. Support from gas sources can enable the plant to run at a steady production. But the plant requirement to process AG is more expensive. The principle challenge is really scale and supply continuity.

For gas injection option two alternatives exist. They are the injection into a producing oil reservoir to increase oil recovery with the expectation that once the oil is depleted, the recoverable gas will be produced and marketed; and the injection into a non-producing oil reservoir with the expectation that prior to lease or field abandonment, the injected gas will be produced and marketed.

The option of electricity generation with gas as fuel is an efficient technology, especially for Russia. Electric power can be used mostly in site needs. But also, it can be transmitted. Electricity generation is a very perspective option, especially in case of remoteness of an oil field and undeveloped infrastructure. Nowadays, there are already a broad variety of electricity plants.

Thus, there is a wide range of efficient and perspective alternatives over gas flaring. Involving these technologies in domestic or in world markets could provide a benefit for oil and gas industry.

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