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Determination of the Optimum Scheme for the Development of the Tolumskoye Field using CO_2 Injection

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Определение оптимальной схемы обустройства Толумского месторождения с использованием закачки CO_2

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The main goal of modern field development is the most complete recovery of the recoverable share of reserves with maximum economic efficiency. The growth in the share of unconventional reserves, associated with the depletion and watering of most of the mature fields, leads to the need to use complex methods of oil recovery. The most important component of the process is definitely computer modeling of development conditions, which requires adaptation of the model to the historical data array and the possibility of invariant calculations in order to determine the most effective development methods. Due to the high cost of implementing modern approaches to increase the oil recovery factor under conditions of a degraded structure of residual oil reserves, conditioned input data and dependencies are required to improve the accuracy of modeling.
The results of updating the hydrodynamic model according to laboratory studies of the enhanced oil recovery technology at the Tolumskoye field by injection of associated petroleum gas with a high content of CO_2, the source of which was the Semividovskaya group of fields, were presented, as well as various schemes for the implementation of the injection of associated petroleum gas with the determination of the most cost-effective implementation option.

Ключевые слова:
моделирование, адаптация, закачка газа, утилизация попутного нефтяного газа, дополнительная добыча нефти, схемы обустройства, экономическая целесообразность

Основной целью современной разработки месторождений является наиболее полное получение извлекаемой доли запасов с максимальной экономической эффективностью. Рост доли трудноизвлекаемых запасов, связанный с истощением и обводнением большей части зрелых месторождений, приводит к необходимости применения сложных методов нефтеотдачи пластов. Важнейшей составляющей процесса определенно является компьютерное моделирование условий разработки, требующее адаптации модели на исторический массив данных и возможность проведения инвариантных расчетов с целью определения наиболее эффективных методов разработки. В связи с высокой стоимостью реализации современных подходов по увеличению коэффициента извлечения нефти в условиях ухудшенной структуры остаточных запасов нефти необходимы кондиционные входные данные и зависимости для повышения точности моделирования [7].
Представлены результаты актуализации гидродинамической модели по данным лабораторных исследований технологии повышения нефтеотдачи Толумского месторождения путем закачки попутного нефтяного газа с высоким содержанием CO_2, источником которого служит Семивидовская группа месторождений, а также рассмотрены различные схемы реализации закачки попутного нефтяного газа с определением наиболее экономически эффективного варианта реализации.

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Introduction

Enhanced oil recovery technologies based on the injection of various gases into the reservoir have been successfully used abroad, especially in the USA, since the mid-20th century [1–10]. Carbon dioxide has received the greatest use as an agent for influencing deposits, since it is able to dissolve in oil in large quantities under in-situ conditions, and also has a convenient phase behavior from a technological point of view. However, in Russia the technology of CO_2 injection for the purpose of enhancing oil recovery has not become widespread due to the small number of natural CO_2 sources near the developed fields. However, recently, due to the relevance of decarbonization, oil companies are paying more and more attention to the development of technologies providing man-made greenhouse gases utilization [11, 12].

The production of associated petroleum gas in Russia is constantly increasing which is connected with the new field commencement [13]. According to data [14] in 2015 Russia produced 78.6 billion m^3 of associated petroleum gas (APG), about 10 billion m^3 was flared; it is comparable with the annual gas consumption in some European countries [15]. APG flaring including at power generation facilities causes significant emissions of carbon dioxide and other greenhouse gases which negatively affects the environmental situation. The introduction of a trans boundary tax on greenhouse gas emissions, together with state penalties for the flaring of associated gas, will become an additional burden on oil producing companies [16, 17]. Thus, an important task is to find the most optimal variant for APG utilization, which, on the one hand, would reduce the burden on the environment, and, on the other hand, reduce the financial costs of petroleum and mining engineers.

There are various options for reducing the APG emission and its utilization products, such as injection into reservoirs, recycling into gas processing plants, use for field needs, electricity generation, processing into chemical products and motor fuels in small-sized installations [18, 19]. Considering the APG content of the Semividovskaya group of fields where the main component is carbon dioxide (share 55–75 %), as well as the geographical location of gas separation facilities and potential facilities for its injection into the reservoir, the most appropriate way for APG utilization is its injection into the wells in the Tolumskoye field in order to increase oil recovery.

The most large-scale project for the implementation of water-alternation gas (WAG) in Russia is an industrial experiment at the Samotlor field [20]. During the period from the 1980s to the 1990s a classic version of the water injection was used at the field involving sequential APG and water slug injection. Due to the need to reduce high capital costs while implementing alternating injection in 2006–2008. An injection variant of a finely dispersed water-gas mixture (FWGM) created by special ejection-dispersing devices was tested. The effect of FWGM injection continued until 2011. In total, about 24.2 thousand tons of oil were additionally produced which amounted to 11.2 % of oil production at the pilot site.

A scheme for injecting WGM into a reservoir with APG utilization is considered in work [21], using the example of the Sredne-Khulymskoye field development project (RITEK JSC). Proposed technical solution is based on the use of equipment mastered in serial production. The developed technological scheme made it possible not only increasing the oil recovery factor and utilizing associated gas, but also flexibly responding to changes in the water/gas ratio in the WGM injected into the reservoir.

There are also examples of the greenhouse gases usage (in particular CO_2) to enhance oil recovery and make possible gas utilization during cyclic gas injection into a production well (Huff'n'Puff) [22–24].

Table 1

Experimental sites at the Eastern deposit
of the Tolumskoye field

Section	Injection well	Observation production well
1	1576	3942, 3944, 3945, 3991, 1582L
2A	3954	3955, 3948, 1506Б, 3947, 3995, 1508
2B	3995	3947, 1692, 1694, 1508
3	3969	3996, 1528, 1590, 3968, 1537

While implementing this technology, the gas agent is injected into the reservoir with cycles, each of which consists of three stages:

1) gas injection to the required pressure; 2) closing the well to dissolve the injected gas in the reservoir oil; 3) selection of oil and gas.

Cyclic gas injection can be used in both light [25–27] and high-viscosity oil fields [28–30]. Moreover, in light oil fields greater efficiency is achieved while reaching the minimum miscibility pressure at the gas injection stage [31].

In Russia, the first [32] successful pilot production (PP) on cyclic CO_2 injection in order to increase oil recovery was carried out at RITEK JSC at the Maryinskoye high-viscosity oil field in the Samara region [33]. According to the results of pilot work, CO_2 injection made it possible to increase oil production and put previously idle wells into operation. Analysis of the experimental results showed that the effect was due to a decrease in oil viscosity and its swelling appeared because of the CO_2 dissolution.

Previously, the authors published the results of laboratory studies [8] to determine the minimum miscibility pressure of APG with CO_2 and in-situ oil in the Tolumskoye field, as well as a review of potential areas for the APG injection implementation with a high CO_2 content and filtration experiments on core reservoir models to assess changes in the displacement coefficient at different gas pumping options [9]. This article presents brief results connected with the adaptation of the geological-hydrodynamic model, invariant results of model calculations and also discusses schemes for implementing the APG injection with a high CO_2 content and the process equipment selection.

Updating the hydrodynamic model

Computer Modeling Group (CMG) is a Canadian company that is a pioneer in the field of reservoir simulating hard-to-recover hydrocarbon reserves.

CMG GEM is a simulator that allows you to model the bland compositions of gas condensates, volatile oil, as well as processes that involve complex mixtures (gas injection, including CO_2, water-gas repression, etc.) Unlike simulators using only a black model for simulating oil, CMG GEM allows you to accurately model structurally complex and changing fluid combinations, taking into account the calculation of phase equilibrium constants [34].

To create the model in CMG GEM software, the original model in Tempest software was used [35]. The fluid model was separately created in CMG Winprop.

Table 1 shows injection and reacting production wells in the concerned areas.

Methods for updating a hydrodynamic model in terms of initial input data are described in many scientific works and literature [5, 36, 37, 38]. In the initial Tolumskoye field model, the following data were updated based on laboratory research data:

– PVT properties and dependencies including determination of gas content, saturation pressure, viscosity and density;

– MMP (minimum miscibility pressure);

– Coefficients of oil displacement by water, APG model for different permeability zones;

– Relative phase permeabilities at different APG concentrations.

Table 2 shows a comparison of actual experimental data and calculated data in a hydrodynamic model (HDM) (refined model).

Approaches to updating the HDM:

• injection volumes of wells located on the field boundary are adjusted according to pressure and the water flow into the nearest wells, thus taking into account the water flow beyond the boundaries of the cut-out area. Sector edge wells were modeled by “cutting back” production or injection to obtain actual reservoir pressure. “Cutbacks” of common boundary wells for two HDM were taken into account, that is, if in one HDM 70 % of the well production was included in the history, for the second GDM it was, respectively, considered 30 %;

• a limit was set on the maximum injection pressure selected by modeling the reservoir pressure according to the isobar map;

• relative phase permeabilities were built taking into account the permeability distribution.

Adaptation results

While reproducing the development history (adapting the hydrodynamic model), the input well data for specific dates were set using data from the original hydrodynamic model [39] as well as flow rate and pressure measurements from the production data system, the source of which is field data [40].

In the changed model, oil production and bottom-hole pressures, for which discrepancies between actual and calculated values are possible, were adapted. Responsive (target) wells in selected areas of the pilot project were adapted to accumulated oil production indicators within 5 %. A comparison of calculated and actual cumulative production was made for all wells; an example of well 1540 is shown in Fig. 1.

Adaptation by reservoir pressure: in constructing isobar maps in the injection wells areas only reservoir average pressures were used (Fig. 2).

Multivariate calculations

Within the framework of compositional hydrodynamic modeling, calculations of various options for gas/water-gas impact were carried out at four sections of the pilot project. Calculations for associated gas injection with carbon dioxide and water were carried out at the fields.

Granted the continued wells operation outside the sector, including injection ones, a restriction is set on the historical minimum bottom-hole pressure at production wells.

Based on the results of invariant calculations, the following options are proposed for further consideration:

– the basic version providing the field development under current conditions, was selected as the compared option;

– in variant 2 water injection in well 3954 is replaced by APG injection with CO_2 with an injectability of 64 thousand m^3/day;

– in variant 3 calculation with stopping production for 2.5 months to increase reservoir pressure to the MMP level, with injection of APG with CO_2 at a rate of 64 thousand m^3/day into well 3995 and a limitation on the minimum bottom-hole pressure at all production wells of 14 MPa was carried.

– in variant 4 calculation with stopping production for 2.5 months to increase reservoir pressure and with APG injection at a rate of 64 thousand m^3/day into well 3995 and a limitation on the minimum bottom-hole pressure at all production wells of 12 Mpa was carried, an increase in the injection volume by 8 % was taked.

Table 2

Comparison of calculated parameters in the hydrodynamic model with actual ones

Parameter	HDM, calculation	Experiments, fact	Mismatch, %
Oil density in situ kg/m^3	807	827	–2.42
Oil density at surface., kg/m^3	878	865	1.50
Oil viscosity in situ., cP	2.3	2.23	3.14
Oil viscosity in situ with APG (28,8 %), cP	1.7	1.75	–2.86
Bubble point pressure, MPa	8	8	0.00
Volume coefficient, fr.unit	1.185	1.185	0.00
MMP, MPa	14.2	14.8	–4.05
$K_{выт.}$ In terms of penetration	According to experiments		

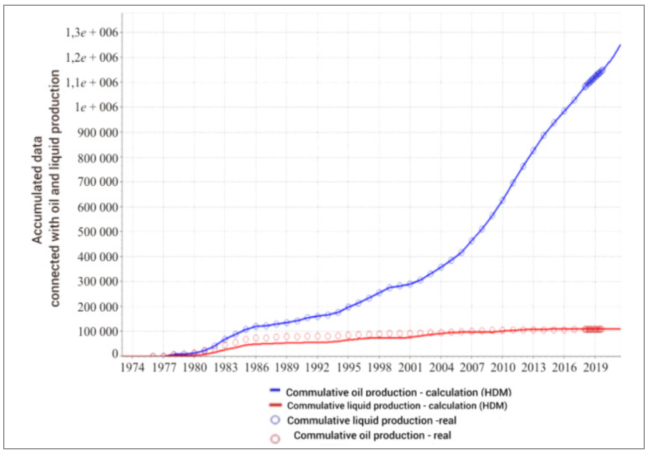

Fig. 1. Matching calculating and real cumulating well production 1540

– in variant 5 calculation with stopping production for one month to increase reservoir pressure and injection of APG with CO_2 at a rate of 64 thousand m^3/day into well 3995, with Huff-n-puff at wells 1508, 1583, 1584 (two days of injection APG with CO_2 having roductivity of 48 thousand m^3/day and three months of production, which is eight cycles in general) and a minimum limit bottomhole pressure at all production wells to 10.5 MPa was carried, an increase in injection volume by 35 % was taken.

– in variant 6 calculation with stopping production for one month to increase reservoir pressure and injection of APG with CO_2 at a rate of 64 thousand m^3/day into wells 3995 and 3954, Huff-n-puff at wells 1583, 1584 (two days of APG injection with CO_2 productivity of 48 thousand m^3/day and three months of production which is eight cycles in general) and a restriction on the minimum bottom-hole pressure at all production wells equal to 10.5 MPa was carried, an increase in injection volume by 8% was taken.

Table 3 shows summary results on the total oil production of all wells in the short term (four years) and in the long term (nine years). The best variant is number 6.

Variant 6 allows you to involve the section of wells with the largest area. Huff-n-puff at wells 1583, 1584 increases efficiency due to targeted impact in the area where reservoir pressure decreases. Subsequently, the calculations were supplemented with options 6.1 and 6.2, taking into account the changed order of introducing blocks for APG injection with CO_2, alternating pressure every 1.5 g.

Description of schemes used for the experimental sites development for the implementation of CO_2 injection technology (APG) at the selected Tolumskoye field area

The main initial data for substantiating design decisions for the developing experimental sites for the APG injection with CO_2 at the Tolumskoye field site are presented in table 4.

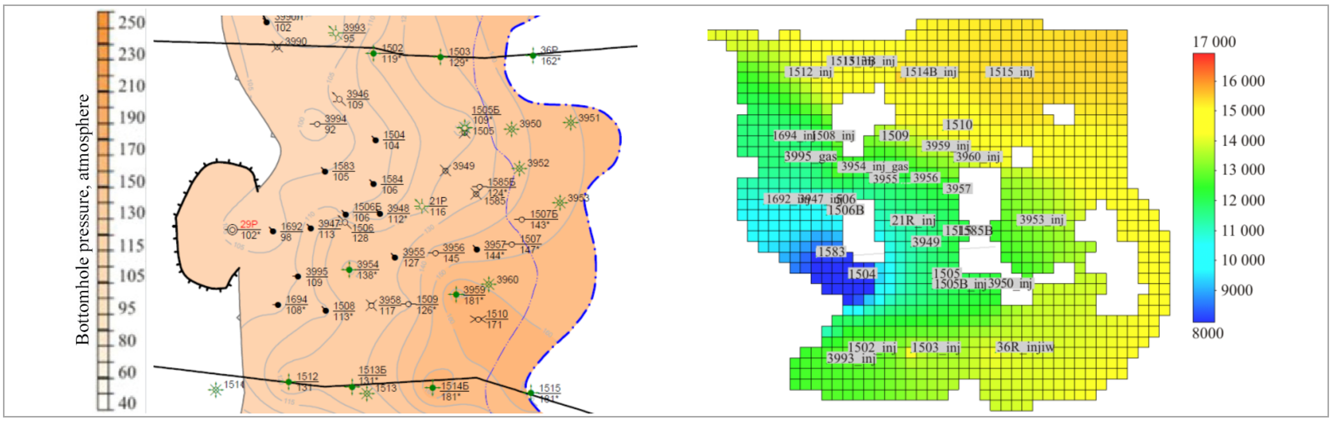

Fig. 2. Formation pressure adaptation

Table 3

Summary results of hydradynamical calculations in additional oil production during 9-year realization of APG with CO_2

Variant 1	Variant 2	Variant 3	Variant 4	Variant 5	Variant 6
Cumulating oil production, thou. m^3					
1584.20	1617.38	1587.34	1630.83	1672.03	1684.85
Additional oil production concerning variant 1, thous.m^3					
	33.18	3.14	46.63	87.83	100.65
Oil production during 9 years, thou. m^3					
113.94	147.12	117.08	160.57	201.77	214.59
Additional oil production concerning variant 1, % in a period					
	29.12	2.75	40.92	77.09	88.33

Table 4

Development parameters in pilot work fields on variants 2, 4, 6, 6.1, 6.2

№ п/п	Parameter names	Units	Variant					
			basic	2	4	6	6.1	6.2
1	Maximum oil production (year)	thou.t.	187.4 (2029)	190.0 (2029)	193.6 (2029)	197.5 (2029)	206.8 (2029)	205.1 (2029)
2	Maximum liquid production (year)	thou.t.	6595.7 (2022)	6595.7 (2022)	6595.7 (2022)	6595.7 (2022)	6595.7 (2022)	6595.7 (2022)
3	Maximum gas production (year)	mil.m^3	90.7 (2021)	90.7 (2021)	90.7 (2021)	90.7 (2021)	90.7 (2021)	90.7 (2021)
	Including inrushing gas	mil. m^3	–	14.0 (2031)	16.8 (2031)	49.9 (2031)	69.7 (2029)	63.5 (2029)
4	Maximum water injection (year)	thou. m^3	5911.3 (2022)	5911.3 (2022)	5911.3 (2022)	5911.3 (2022)	5911.3 (2022)	5911.3 (2022)
5	Maximum gas injection (year)	mil m^3	–	23.4 (2025–2033)	23.4 (2025–2033)	52.3 (2030–2031)	102.9 (2028)	99.0 (2028)
6	Switching wells over year-round injection CO_2 (APG)	pcs.	–	4 (one for each 2,5 gr. on the field)	4 (one for each 2,5 gr. on the field)	7 (one for each 2,5 gr. on the field)	7 (one for each 2,5 gr. on the field)	7 (one for each 2,5 gr. on the field)
7	Switching wells over Huff-n-Puff	pcs.	–	–	–	57	57	57

It should be noted that the life cycle of the equipment considered in the article is intended for high corrosive activity conditions.

Variants 2 and 4 include only year-round CO_2 injection (APG) from the preliminary water discharge installation of booster pumping station No. 4 (BPS-4 UPSV) of the East Tolumskoye field with phased implementation in the following experimental sites:

– block 2 (stage I) – injection from 01.2025 to 07.2027 along the designed high-pressure gas pipelines (HG) with a length of 4 km through well 3995;

– block 3 – east (stage II) injections from 07.2027 to 12.2029 along the HG 3.5 km through well 3996;

– block 4 – east (stage III) injections from 01.2030 to 07.2032 along the HG 3.5 km through well 3976;

– block 4 – west (stage IV) injections from 07.2032 to 12.2034 along the HG 5.5 km through well 1553.

Variants 6, 6.1 and 6.2 include both year-round APG injection with CO_2 and cyclic injection (Huff-n-Puff) from preliminary water removal unit in Tolumskoye field BPPS-4 with phased implementation in the following experimental sites.

In block 2 (stage I) injection is carried out through designed low-pressure gas pipelines (LG) with a length of 4 km to a gas distribution point (GDP) for year-round injection into wells 3954, 3995 and cyclic injection into 16 wells (Huff-n-puff) within the time frame for options 6, 6.1 from 01.2029 to 07.2031; according to version 6.2 (Huff-n-puff mode) from 01.2029 to 07.2031

In block 3 – east (phase II) – injection is carried out along the 3.5 km LG at the hydraulic fracturing station for year-round injection into wells 3969, 3996 and cyclic injection into 13 wells (Huff-n-puff) within the time frame for option 6 from 07.2031 to 12.2033; according to option 6.1 from 07.2030 to 12.2032; according to option 6.2 (Huff-n-puff) from 07.2030 to 12.2032

In block 4 – east (stage III) – injection is carried out along an oil pipeline of 3.5 km to hydraulic fracturing for year-round injection into wells 1568, 3976 and cyclic injection into 19 wells (Huff-n-puff) within the time frame for option 6: from 01.2026 to 07.2028; according to option 6.1 from 01.2024 to 07.2026; according to option 6.2 (Huff-n-puff) from 01.2024 to 07.2025.

In block 4 – west (stage IV) – injection is carried out along 5.5 km LG for hydraulic fracturing for year-round injection into wells 1184R, 1553 and cyclic injection into nine wells (Huff-n-puff) within the time frame for option 6 from 07.2032 to 12.2034; according to option 6.1 from 07.2029 to 12.2031; according to option 6.2 (Huff-n-puff) from 07.2029 to 12.2031.

In a year-round mode the APG injection with CO_2 is planned to be carried into each gas injection well in a volume of 64 thousand m^3/day, in a cyclic Huff-n-puff mode it will be 48 thousand m^3/day. The gas injection pressure at the well bottom is assumed to be 12.2–13.5 MPa.

Basic technological solutions and basic diagrams arrangement of experimental sites. Technological equipment selection

The gas-liquid mixture of the East Tolumskoye, North Semividovskoye and West Semividovskoye fields under wellhead pressure through separate oil-gathering pipelines enters the inlet manifold of preliminary water removal unit in Tolumskoye field BPPS-4 and is then sent to oil and gas separators where the I separation stage was carried. The separated emulsion is supplied to oil settling tanks, where preliminary oil dehydration occurs. At the preliminary water removal unit in BPPS-4, to improve the settling process, a demulsifier is supplied to the inlet manifold of the BPPS using chemical injection units (CIU) dosing pumps.

Oil from settling tanks enters buffer separators, where complete oil degassing occurs. From the buffer tank oil is sent to the external pumping station and after operational accounting is transported for preparation to marketable condition to the oil processing and pumping shop (OPPS). The treated oil is sold into the main oil pipelines of Transneft-Siberia JSC.

Associated petroleum gas released in oil and gas separators is sent to, firstly, an water-oil emulsion heating unit (WOEHU), located at the site preliminary water removal unit in Tolumskoye field BPPS-4; secondly, to gas engine generator plant "Vostochno-Tolumskaya" (GEGP); thirdly, to boiler room of the rotational camp (r/c) "East Tolum".

Produced water from the settling tanks enters treatment vertical steel tanks (VST), from where it is pumped to the modular cluster pumping station MCPS-8 of the Tolumskoye field reservoir-pressure maintenance system (Fig. 3).

Variants 2, 4 of APG injection with CO_2 (centralized compression, Fig. 4, a) provide the transportation of associated petroleum gas from the booster compressor station (BCS) preliminary water removal unit in Tolumskoye field BPPS-4 through a system of high-pressure gas pipelines to well pads No. 45, 47, 52, 49 with subsequent injection into injection wells No. 3995, 3996, 3976, 1553, respectively.

A year-round regime of APG injection with CO_2 is planned for 2.5 years at each well pad according to the order of commissioning of the experimental sites.

Gas is pumped into injection wells from the booster compressor station through high-pressure manifolds (P_{op} = 21 MPa) through a high pressure gas pipeline system P_{op} = 15 MPa Ø114 × 16 mm with a total length of 11.5 km.

Variants 2, 4 of CO_2 injection (centralized compression) include the following construction stages:

1st construction stage:

– BCS at preliminary water removal unit in BPPS-4 with maximum injection of associated petroleum gas Q_g = = 64 thou m^3/day;

– high pressure gas supply pipeline P_{op} = 15 MPa from the booster compressor station (preliminary water removal unit in BPPS-4) to the gas injection well of cluster No. 45 Ø114 × 16 mm and a total length of 7.1 km;

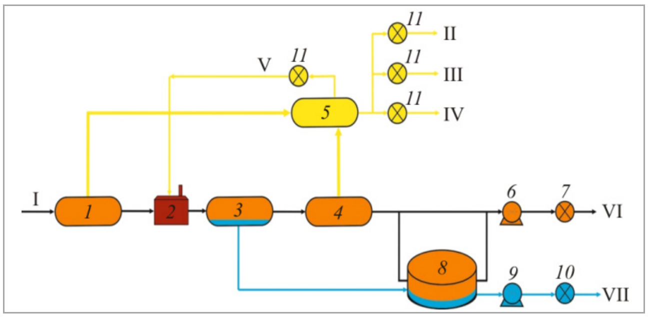

Fig. 3. Schematic flow diagram of preliminary water removal unit in Tolumskoye field BPPS-4: *1* – first stage separator; *2* – WOEHU; *3* – settling tank; *4* – stage II separator; *5* – gas separator; *6* – oil pump; *7* – operational oil metering unit; *8* – cleaning tank; *9* – pump for supplying water to the MCPS; *10* – operational water metering unit; *11* – operational gas metering unit; I – wells oil; II – gas to the flare; III – gas to the boiler room; IV – gas at the gas power plant; V – gas at WOEHU; VI – oil at the central processing plant; VII – water at MCPS

– injection wellhead equipment No. 3995 with gas reduction unit (GRU) and horizontal flare unit (HFU for emergency gas release);

2nd construction stage:

– high pressure gas supply pipeline P_{op} = 15 MPa from the insertion pad point No. 45 to the gas injection pad well No. 47 Ø114 × 16 mm and length of3.2 km;

– equipment at the injection wellhead No. 3996 GRU and HFU;

3rd construction stage:

– high pressure gas supply pipeline P_{op} = 15 MPa from the booster compressor station (preliminary water removal unit in BPPS-4) to the gas injection pad well No. 52 Ø114 × 16 mm and a length of 4.7 km;

– equipment at the injection wellhead No. 3976 GRU and HFU;

4th stage of construction:

– high pressure gas supply pipeline P_{op} = 15 MPa from the insertion pad point of No. 47 to the gas injection pad well No. 49 Ø114 × 16 mm and a length of 2.8 km;

– equipment at the injection wellhead No. 1553 GRU and HFU.

Compressor equipment for implementing the technology of APG injection with CO_2

It is recommended to use a modular compressor station (P_{in} = 0.5 MPa, P_{out} = 15 MPa) as a booster compressor station for pumping APG with CO2. To take gas to the booster compressor station, it is planned to insert into the gas outlet pipeline the gas separators (first separation stage) from preliminary water removal unit in Tolumskoye field BPPS-4. The operating pressure of 0.3...0.6 MPa in the gas supply system to the booster compressor station is maintained by control valves installed in front of the booster compressor station inlet filter-separators. The operation of the booster compressor station is ensured by gas piston drives; it is recommended to use gas from the Tolumskoye field with a minimum CO_2 content as the fuel gas for the booster compressor drives (for stable operation of the compressors).

Four-stage piston compressors with adjustable capacity ensure gas injection at the required flow rate throughout the entire period of saturation of the pore space of the formation with gas.

Variants 6, 6.1, 6.2 of APG injection with CO_2 (distributed compression, Fig. 4, b) provide the transportation of associated petroleum gas from the low-pressure compressor station (LPCS) from preliminary water removal unit in Tolumskoye field BPPS-4 to mobile booster compressor stations (MBCS) of well pads No. 45, 47, 52, 49 with

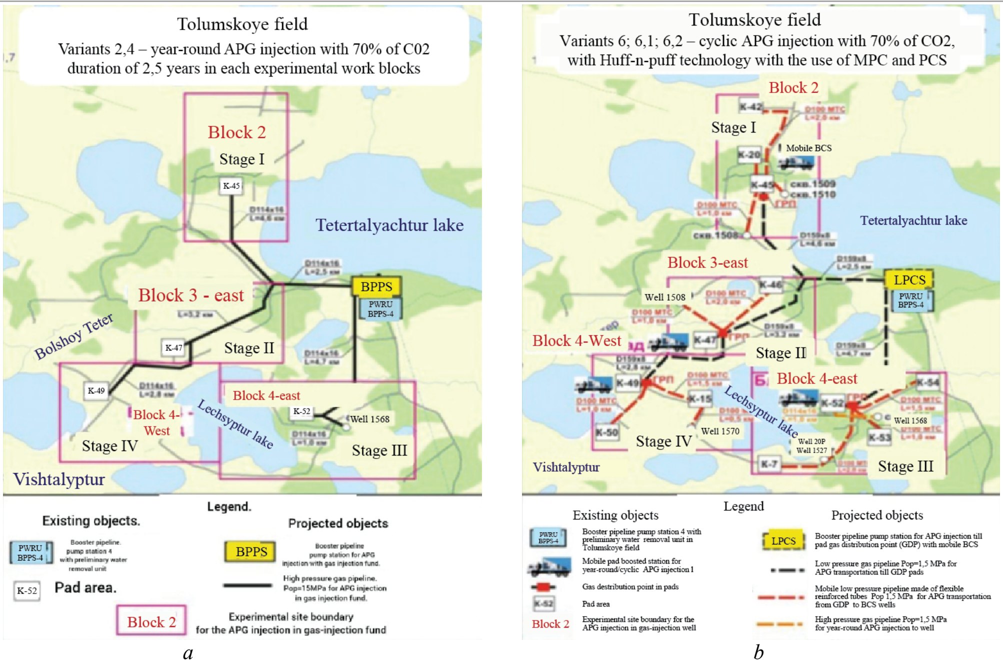

Fig. 4. Variants 2, 4 (*a*); 6, 6.1, 6.2 (*b*) of APG injection with CO_2 for the pilot work in Tolumskoye field

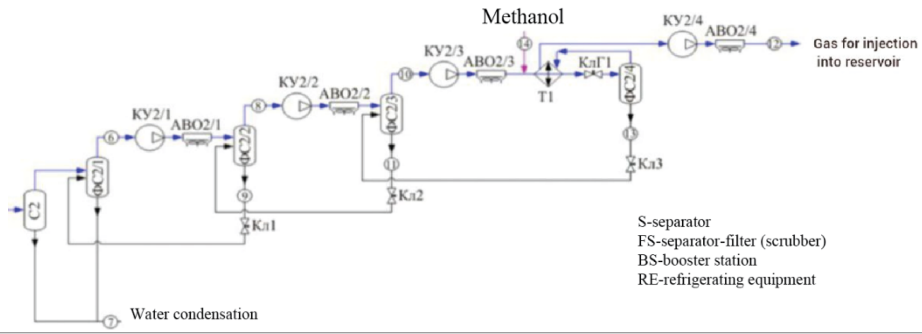

Fig. 5. Principle technological scheme boosting compressor station

subsequent injection into injection wells No. 3994 and 3995, 3969 and 3996, 1568 and 3976, 1553, respectively, as well as into the oil production fund using Huff-n-puff technology.

Associated petroleum gas under a pressure of 1.5 MPa from the LPSC (preliminary water removal unit in BPPS-4) is transported through a system of low-pressure gas pipelines to the MBCS (based on four-stage piston compressors). Low pressure gas pipelines are equipped with gas distribution points (GDP) at the MBCS connection points at well pads No. 45, 47, 52, 49.

Variants 6, 6.1 and 6.2 of APG injection with CO_2 differ in the order of experimental sites entry and, accordingly, the number of MBCS for year-round and cyclic (Huff-n-puff) gas injection (Table 5).

Variants 6, 6.1, 6.2 of APG injection with CO_2 (distributed compression) include the following construction stages:

• 1st construction stage:

– low pressure compressor station at preliminary water removal unit in BPPS-4 with maximum gas supply to MBCS-1, 2 Q_g = 176 thou m^3/day;

– low pressure gas supply pipeline P_{op} = 1.5 MPa from LPCS (preliminary water removal unit in BPPS-4) to MBCS-1 Ø159 × 8 mm and length of 7.1 km;

– mobile booster compressor station MBCS-1 at well pad No. 45 with maximum gas injection Q_g = 128 thou m^3/day (year-round injection);

– mobile booster compressor station MBCS-2 (Huff-n-puff) at well pad No. 45 with maximum gas injection Q_g = 48 thou m^3/day (cyclic injection);

– mobile pipeline system (MPS) of low pressure P_{op} = = 1.5 MPa from pad GDP No. 45 to MDKS-2 Ø125/100 mm and a maximum length of 3 km;

– equipment at the injection wellheads No. 3954, 3995 GRU and HFU (for emergency gas discharge);

• 2nd construction stage:

– 2nd low pressure compressor station at preliminary water removal unit in BPPS-4 with maximum gas supply to MBCS-1, 2 Q_g = 176 thou m^3/day (for options 6.1, 6.2 with simultaneous year-round injection into the reservoir in two experimental sites);

– low pressure gas supply pipeline P_{op} = 1.5 MPa from pad No. 45 to pad No. 47 Ø159 × 8 mm and length of 3.2 km;

– 2nd mobile booster compressor station MBCS-1 at well pad No. 47 with maximum gas injection Q_g = 128 thou m^3/day (for options 6.1, 6.2 with simultaneous year-round injection into the reservoir in two experimental sites);

– 2nd mobile booster compressor station MBCS-2 (Huff-n-puff) at well pad No. 47 with maximum gas injection Q_g = 48 thou m^3/day. (for option 6.1 with simultaneous cyclic injection into the reservoir in two experimental sites);

– equipment at the injection wellheads No. 3969, 3996 GRU and HFU;

• 3rd construction stage:

– low pressure gas supply pipeline P^{op} = 1.5 MPa from LPCS (preliminary water removal unit in BPPS-4) to pad No. 52 Ø159 × 8 mm and length of 4.7 km;

– equipment at the injection wellhead No. 1568, 3976 GRU and HFU;

Table 5

MBCS transportation graph for APG injection with CO_2 in variants

Year	Injection season	Injection variant CO_2 (APG)							
		Modul 2		Modul 3-east		Modul 4-east		Modul 4-west	
		Cicle	Year	Cicle	Year	Cicle	Year	Cicle	Year
Variant 6									
2025	Winter	1	1						
	Summer	1	1						
2026	Winter	1	1						
	Summer	1	1						
2027	Winter	1	1						
	Summer			1	1				
2028	Winter			1	1				
	Summer			1	1				
2029	Winter			1	1				
	Summer			1	1				
2030	Winter					1	1		
	Summer					1	1		
2031	Winter					1	1		
	Summer					1	1		
2032	Winter					1	1		
	Summer							1	1
2033	Winter							1	1
	Summer							1	1
2034	Winter							1	1
	Summer							1	1
Variant 6.1									
2025	Winter	1	1						
	Summer	1	1						
2026	Winter	1	1						
	Summer	1	1	2	2				
2027	Winter	1	1	2	2				
	Summer			2	2				
2028	Winter			2	2	1	1		
	Summer			2	2	1	1		
2029	Winter					1	1		
	Summer					1	1	2	2
2030	Winter					1	1	2	2
	Summer							2	2
2031	Winter							2	2
	Summer							2	2
Variant 6.2									
2025	Winter	1	1						
	Summer	1	1						
2026	Winter	1	1						
	Summer		1	1	2				
2027	Winter		1	1	2				
	Summer			1	2				
2028	Winter				2	1	1		
	Summer				2	1	1		
2029	Winter					1	1		
	Summer						1	1	2
2030	Winter						1	1	2
	Summer							1	2
2031	Winter							1	2
	Summer							1	2
Fund Huff-n-puff	Year-rounsd	16 wells	2 wells	13 wells	2 wells	19 wells	2 wells	9 wells	1 wells

N o t e : 1 – one mobile compressor station with mobile pipeline system for Huff-n-puff;
1 – one mobile compressor station for year-round APG injection ;
2 – two mobile compressor stations with mobile pipeline system for Huff-n-puff;
2 – two mobile compressor stations for year-round APG injection.

a *b*

Fig. 6. Mobile technical stations : *a* – external view of mobile technical station and connections in portable pipeline; *b* – station assembling with the connection with existing infrastructure

• 4th construction stage:

– low pressure gas supply pipeline P_{op} = 1.5 MPa to pad No. 49 Ø159×8 mm and length of 2.8 km;

– equipment at the injection wellheads No. 1553 GRU and HFU.

Associated petroleum gas from the LPCS is transported to the MBCS, according to the equipment composition similar to the description of the BCS (preliminary water removal unit in BPPS-4) for options 2, 4 of APG injection with CO_2 (centralized compression). MBCS-1 for year-round APG injection with CO_2 into the reservoir includes four piston compressors (two working + two reserve), MBCS-2 (Huff-n-puff) for cyclic APG injection with CO_2 into the reservoir – two compressors (one working + one reserve).

For cyclic APG injection with CO_2 into the reservoir (Huff-n-puff), it is planned to move MBCS-2 from one production well to another within the experimental site, and therefore stationary gas pipelines for transporting APG from LPCS (preliminary water removal unit in BPPS-4) to MBCS are equipped with GDP for connecting MBCS-2 using MPS [41] from flat-folded hoses (Fig. 6). MPS includes a hose line BALTICFLEX 100-20-3000 Ø100 mm with a total length of 3 km (P_{op} = 2.0 MPa), a specialized container 20' Open Top (1CC) with an awning, pre-treatment for installing TN-4 tightening device modules and an operator's balcony, tightening device TN-4 for DN 100. The tightening device TN-4 is a special module equipped with an autonomous engine and a hydraulic drive to rollers, which allow you to carefully wind up the pipeline remove the remaining pumped liquid from it and deliver it to an open container in a flat-folded form. To connect flat-folded hoses (mobile pipelines), quick-release connecting fittings of the portable pipeline type are used, consisting of portable pipeline hose tips, portable pipeline connecting locks, self-sealing collars and transitions for connection to existing pipeline networks.

The most capital-intensive variants are 6.1 and 6.2 due to the need of doubling the compressor capacity for simultaneous APG injection at two blocks; the least expensive variants are 2 and 4 with centralized APG injection from one compressor station.

A mobile technical station made of flat-folded hoses (with a working pressure from 0.5 to 4.0 MPa) requires the creation of a backwater at the preliminary water removal unit in BPPS-4 up to P_{op} = 1.5÷2.0 MPa for its normal operation.

Cost-effectiveness assessment application of APG injection technology with CO_2 at the Tolumskoye field

All technical and economic calculations are carried out in the format of investment project certificate (IPC) [42] using the company's unified scenario conditions (USC).

For the economic variants assessment the main performance indicators were used: the accumulated net income of the subsoil user - net cash flow and discounted cash flow - net discounted flow under scenario conditions taking into account inflation.

The system of evaluation indicators includes investments, operating expenses, taxes and payments allocated to the budgetary and extra-budgetary funds of the Russian Federation. The volume of additionally produced oil is considered as a marketable product.

Within the framework of the IPC model, the tax base, frequency, procedure for calculating taxes and tax payment rates are adopted in accordance with the current taxation procedure and considering changes made to the tax legislation of the Russian Federation relating to the activities of the oil and gas industry.

The Tolumskoye field is located within the boundaries of the Tolumskoye license area with the AIT taxation system

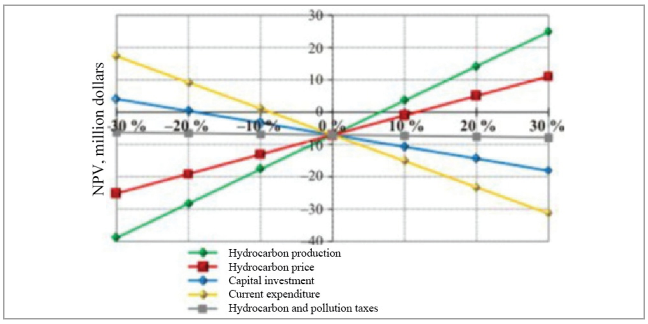

Fig. 7. Sensitivity NPV analysis on changing main initial index due to variant 4

(additional income tax) sp. 3 p. 1 art. 333.45 of the Tax Code of the Russian Federation [43].

Based on forecast technological data on the dynamics of oil and liquid production, water injection, and the existing stock of production and injection wells, a technical and economic assessing the effectiveness of using APG injection technology with CO_2 was carried out according to methodological recommendations [44]. Calculations were performed using the basic option and additional options with regulation of injection volumes. All considered options, except the basic one, considering the discount rate of 15%, are negative under the current taxation system due to high capital investments. NPV (net present value) varies in the range from –7 to –81 million dollars.

While the discount rate decreases to 12.2 %, variants 2 and 4 enter the positive zone (+8.8 and +$9.7 million respectively). The most cost-effective variant is number 4. However, it should be noted that the effectiveness of the project should be assessed taking into account the imposition of a future carbon tax [45].

Project efficiency sensitivity (Fig. 7) to changes in key factors (volume of hydrocarbon production, price of hydrocarbons, capital investments, current costs) was analyzed.

A sensitivity analysis with a discount rate of 15 % showed that development becomes profitable in the event of an increase in oil production by 6.6 %, an increase in the selling price of oil by 11.7 %, a decrease in operating costs by 8.7 %, or a reduction in capital investments by 19 %. A change in other factors within 30 % does not affect the conclusions about the project.

Conclusion

The completed set of calculations for hydrodynamic modeling and implementation variants for APG injection with CO_2 and analysis of possible development schemes allow us to draw the following conclusions:

All considered variants assume an increase in production relative to the base option from 2.7 to 88.3 %.

The best (recommended) variant for additional oil production in the short term (four years) and in the long term (nine years) is to stop production for one month with the APG injection with CO_2 at a rate of 64 thou m^3/day into wells 3995 and 3954, from Huff-n-puff to wells 1583, 1584 with a limitation on the minimum bottom-hole pressure at all production wells to 10.5 MPa, an increase in the volume of water injection by 8 %. Additional production from all wells over nine years is 101 thou m^3 (87 thousand tons) relative to the base case.

Gas injection allows you to reduce the average water cut compared to the base case (water).

The most capital-intensive variants are 6.1 and 6.2 due to the need to double compressor capacity for simultaneous APG injection with CO_2 to two blocks; the least expensive are variants 2 and 4 with centralized APG injection with CO_2 from one compressor station.

All necessary equipment was selected for the duration of the project, taking into account the results of experiments on the corrosive environment effects.

The most optimal is variant 4 with a final NPV of –$7 million at a discount rate of 15 % and +$9.7 million at a discount rate of 12.2 %. The sensitivity analysis performed at a discount rate of 15 % showed that development becomes profitable in the event of an increase in oil production by 6.6 %, an increase in the selling oil price by 11.7 %, a decrease in operating costs by 8.7 %, or a reduction in capital investments by 19 %. A change in other factors within 30% does not affect the conclusions about the project.

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