Groundwater compatibility with formation water and pay zone rocks in Pervomaysk oil-gas-condensate field to maintain formation pressure

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Abstract. The paper describes the research results in determining the compatibility of groundwater from Aptain-Albian-Cenomanian aquifer with formation water and pay zone rocks in U_1 layer sediments, Pervomaysk oil field.

1. Introduction
Pervomaysk oil field is located within two territorial areas of the Russian Federation: southern area (the largest) in Kargasoksk region, Tomsk Oblast and northern area (the smallest) in Surgut region, Khanty-Mansi Autonomous District – Ugri. This oil field was discovered in 1969 as a result of drilled-in Upper Jurassic formation (well № 260) and further developed in 1981. Commercially, oil-bearing field is attributed to terrigenous Upper Jurassic sediments, Vasugan suite (U_1 layer embracing sandstones with interbedded aleurites and clays) [1].

Currently, Pervomaysk oil field is in the III development stage, which, in most cases, is usually marked by the production decline under conditions of water cutting. Since 1982 formation pressure maintenance (FPM) system by injecting groundwater from Aptain-Albian-Cenomanian aquifer has been applied in the southern oil field area, and in 1990- in the northern area [2, 3]. This aquifer, upper level of lower West Siberian artesian basin hydrostratigraphic unit, embraces significant groundwater supplies within the Western Siberian territory which are applied in FPM.

According to existing regulatory documents water used in FPM systems should be assessed to determine its compatibility to formation water and reservoir rocks. In this case, the authors have applied the numerical physic-chemical modeling based on software system HydroGeo [4, 5]. This software system is used to solve a wide spectrum of problems [6].

2. Modeling design
To model geochemical terrigenous processes applicable to "water-rock" system in U_1 layer the following method was used.

Modeling hydrogeochemical processes included (1) base particles - "independent" components: H^+, Na^+, K^+, Ca^{2+}, Mg^{2+}, NH_4^+, Fe^{2+}, Sr^{2+}, Al^{3+}, OH^-, Cl^-, HCO_3^-, SO_4^{2-}, H_2O, SiO_2; (2) dependent components and associates: $(CO_3)^{2-}$, H_2CO_3, CO_2, NH_4HCO_3, $(NH_4)_2CO_3$, NH_4Cl, NH_3, NH_4OH, $NaHCO_3$, $(NaCO_3)^-$, $(NaSO_4)^-$, $NaCl$, $Mg(HCO_3)_2$, $(MgHCO_3)^+$, $MgCO_3$, $MgSO_4$, $MgCl^+$, $MgCl_2$,

$(HSi_2O_6)^{3-}$, $KHCO_3$, KCl, $(CaHCO_3)^+$, $Ca(HCO_3)_2$, $CaCO_3$, $CaSO_4$, $CaCl^+$, $CaCl_2$, $(SrHCO_3)^+$, $SrCO_3$, $SrCl^+$, $SrCl_2$, $(FeHCO_3)^+$, $FeCO_3$, $FeCl^{+,}$ and (3) minerals (which could be dependent components): SiO_2 -calcedony, SiO_2 _ quartz, $Al(OH)_3$ _ hydrargillite, $Al_2Si_2O_5(OH)_4$ -kaolinite, $Al_2Si_4O_{10}(OH)_2$ _,, montmorillonite, $Al_4Si_4O_{10}(OH)_8$ – chlorite (Al), $NaAlSi_3O_8$– albite, $KAlSi_3O_8$ -feldspar (K), $CaAl_2Si_2O_8$ _ anorthite, $MgAl_2SiO_6$ – monocline pyroxene, $CaCO_3$ -calcite, $FeCO_3$ _ siderite, $(Fe^{2+})(OH)_2$ _ amakinite, $CaSO_4$ _ anhydrite, $CaSO_4(H_2O)_2$ – gypsum [7]. The first (independent components) and third (minerals) series were determined by the water analysis of investigated components, mineral composition identification of formation rocks and expected composition of secondary solid phase. Applying Pitzer model in calculating solution particle activity coefficient the required ionic associate composition was determined by a series of preliminary calculations including their maximum number. Furthermore, those associates that were of insignificant concentrations were excluded. Analogous selection was applied relevant to the minerals.

The calculations were performed relevant to two different conditions: (1) at standard conditions (22°C and 0.1 MPa), approximate to reproduced storage conditions and laboratory sampling, and (2) at formation (reservoir) conditions embracing thermodynamic conditions of Vasugan suite sediments (U_1 layer -90.7°C and 25.8 MPa), where groundwater injection into Pokurskoe suite sediments was planned.

The first stage included importing initial lab analysis data of formation water from Vasugan suite sediments (U_1 layer), Pervomaysk oil field into the software system HydroGeo (Table 1). This included the recalculations for solution electroneutrality reduction at standard conditions: t=22°C, P=0.1 MPa (electroneutrality reduction was performed to Cl ion). Then, the water composition in Pervomaysk oil field was reduced to thermodynamic formation conditions (90.7°C and 25.8 MPa) involving CO_2 invasion, which, in its turn, changed the acid-alkali properties of the solution itself (Table 1) and being normalized to the conventional reservoir formation condition – equilibrium via selecting standard Gibbs free energy values relevant to the equilibrium of both flowing solution composition and rocks [8].

Table 1. Groundwater composition changes in Vasugan suite (U_1 layer), Pervomaysk oil field during modeling preparation.

Compo-nent	Ca^{2+}	Mg^{2+}	Na^+	K^+	Fe^{2+}	Al^{3+}	HCO_3	Cl^-	$(SO_4)^{2-}$	SiO_2	$(CO_3)^{2-}$	CO_2	pH	M (gr/lit)	Density(kg/m^3)	Ionic strength (kg/m^3)	T° (C)	P (MPa)
Initial electro-neutrality	1160.8	300.1	12961.9	12.8	54.5	$5.0E^{-05}$	319.8	23427.0	0.05	$3.0E^{-06}$	2.1	5.5	7.0	41.2	1027.7	0.7	22.0	0.1
Balanced to CO_2 in layer	1169.4	317.2	13166.1	11.9	52.7	$5.0E^{-05}$	0.0	23999.2	0.04	$3.3E^{-05}$	0.0	6.5	3.1	40.2	1000.7	0.8	90.7	25.8

Reference rock composition was based on the lithologic description data of U_1 layer: quartz- 48%, calcite-10.5%, albite and K-feldsdpar- 10%, respectively, anorthite- 9%, kaolinite and monocline pyroxene- 6% respectively, siderite- 0.3%, chlorite- 0.2%. In addition, the following accessory mineral impurities were included: hydrargillite, montmorillonite, dolomite, anhydrite and gypsum as expected from the overall lithological observation. Total porosity is 16.5%.

The second modeling stage involved preparing groundwater within Aptain-Albian-Cenomanian sediments after the same pattern as for formation water.

The changes, conditioned by possible technogenic alterations of the solution composition itself, occurring throughout the groundwater flow path within Aptain-Albian-Cenomanian sediments from water production wellhead to water injection well bottom hole are associated with thermodynamic condition shifting. Due to the lack of information on injected water flow rate and discharge, the calculations for pipelines and field equipment are performed excluding the residence time. In this case, these results are not actual but only maximum possible salt precipitation (Figure 1).
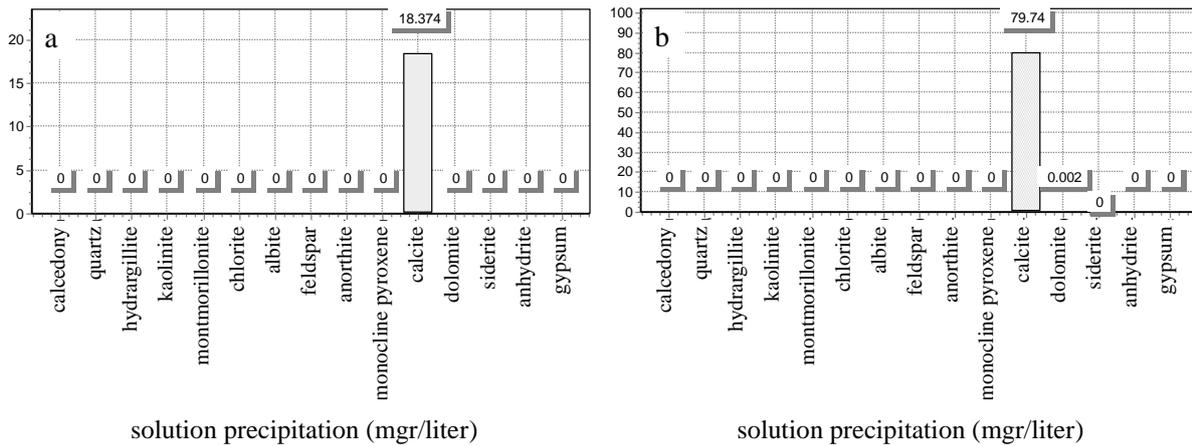
Figure 1. Possible salification; (a) in gathering facilities and processing systems for groundwater within Aptain-Albian-Cenomanian sediments under standard thermodynamic conditions; (b) in wellbore during groundwater injection into pay zone

The changes in solution composition are depicted in Table 2. Modeling data of possible chemical processes, occurring during technogenic mineral formation, in both subsurface equipment and injected wellbores indicate insignificant solution composition changes even if the following fact is regarded, i.e. calcite precipitation of 18.4 mgr. in one litre in subsurface equipment and 79.7mgr. - in injection wells. Moreover, gradual accumulation of carbonates in subsurface equipment and water injection well bottomhole could result in certain production decline.

Table 2. Groundwater composition changes within Aptain-Albian-Cenomanian sediments, Pervomaysk oil field during modeling preparation.

Component mg/dm³	Ca^{2+}	Mg^{2+}	Na^+	K^+	Fe^{2+}	Al^{3+}	HCO_3	Cl^-	$(SO_4)^{2-}$	SiO_2	$(CO_3)^{2-}$	CO_2	pH	M (gr/lit)	Density(kg/m³)	Ionic strength (kg/m³)	T° (C)	P (MPa)
Initial electro-neutrality	549.7	89.6	6674.8	80.5	1.60	4,0E-06	109.2	11639.2	0.83	1,2E-06	1.3	0.5	7.6	19.9	1012.8	0.4	22.0	0.1

Settling simulation and behavior in subsurface equipment	543.4	89.6	6675.7	80.5	1.61	1,3E-09	101.1	11639,1	0.83	1,8E-06	0.5	1.0	7.2	19.8	1012.2	0.4	22.0	0.1
At bottomhole (reduction to formation conditions)	528.1	84.5	6794.9	78.8	1.65	3.2E-10	8.9	11870.1	0.86	2.2E-04	0.2	0.6	6.5	19.8	987.7	0.4	90.7	25.8

The third modeling stage involves the injection of groundwater from Aptain-Albian-Cenomanian sediments directly into formation water of Vasugan suite sediments, Pervomaysk oil field to maintain formation pressure. Geochemically, the behavior of injected water within pay zones is rather complex. This is the result of injected water and formation water being mixed and / or this combination of waters within the reservoir could possibly react with rock minerals and gas phase which is dissolved in residual oil. The mixture of formation (A) and injected (B) waters in the ratio of 0.8:0.2 – 0.0: 1.0 (i.e. from 80:20 to 0:100 %), simulates the increase of injected water from Aptain-Albian-Cenomanian sediments into the formation water from 20% to complete reservoir filling. Progressively towards the injection well, this mixture is reduced in equilibrium to formation rocks in every modeling stage. The calculations of the interaction within water-rock system are performed without reference to time, i.e. to complete equilibrium (Table 3). To determine the solution composition   of specified mixed waters the Mixture/Evaporation model was applied; and to calculate the interaction of obtained mixture with formation rocks the Solution/Precipitation model was used (based on Hydrogeochemistry of software system HydroGeo).

Table 3. Solution composition at the final modeling stage, mgr/litre (pay zone after the interaction with rocks).

Component	U_1 layer	A:B=0.8:0.2	A:B=0.6:0.4	A:B=0.4:0.6	A:B=0.2:0.8	A:B=0.0:1.0	Aptain-Albian-Cenomanian
Ca^{2+}	1169.38	941.08	784.47	628.78	499.51	455.55	528.05
Mg^{2+}	317.18	259.57	218.56	175.16	131.92	90.22	94.52
Na^+	13166.10	11792.40	10538.50	9279.58	8019.41	6720.32	6794.90
K^+	11.88	27.47	38.92	49.95	63.67	76.92	78.81
Fe^{2+}	52.69	19.80	5.77	2.24	0.16	0.59	1.65
Al^{3+}	5.00E-05	8.06E-05	3.25E-06	4.74E-04	2.41E-05	2.45E-06	3.18E-10
$(HCO_3)^-$	0.04	0.00	0.00	0.00	0.00	0.00	8.90
Cl^-	23999.20	21303.40	18931.10	16554.20	14172.10	11707.60	11870.10
$(SO_4)^{2-}$	0,04	0.04	0.03	0.03	0.04	0.03	0.86
SiO_2	3.33E-05	3.99E-12	2.11E-05	1.78E-05	1.92E-05	1.81E-05	0.00
$(CO_3)^{2-}$	5.36E-07	7.84E-12	7.60E-12	7.28E-12	7.25E-12	5.54E-12	0.16
H_2CO_3	427.14	0.12	0.23	0.39	0.46	0.05	36.60
CO_2	6.50	0.00	0.00	0.01	0.01	0.00	0.55
pH	3.05	2.45	2.33	2.24	2.25	2.71	6.50
M(gr/litre)	40.20	35.19	31.20	27.21	23.26	19.27	19.76
Density.(kg/m^3)	1000.68	997.92	995.29	992.65	990.04	987.45	987.68
Ionic strength (mole/litre)	0.76	0.66	0.59	0.51	0.43	0.36	0.36

3. Results of modeling

Technogenic geochemical changes of the water and rock compositions, based on modeling data, provide evidence of the fact that secondary mineral formation processes predominate over formation rock solution processes (in 1 liter of solution the amount of newly-formed minerals is 120-380 mgr

more than amount of dissolved minerals). This, in its turn, indicates the possible decrease of the reservoir properties and injection well rate.

Basically, technogenic reservoir changes are associated not only with the dissolution of feldspar, chlorite, kaolinite and quartz but also the formation of secondary sulphates, clay (montmorillonite) and carbonates (calcite and siderite) (Figure 2). Every washout cycle initiates comparatively insignificant rock composition changes and frequent washout could result in a rather significant alteration of the mineral composition and porosity [9], while the latter gradually decreases causing relevant changes of the reservoir properties.
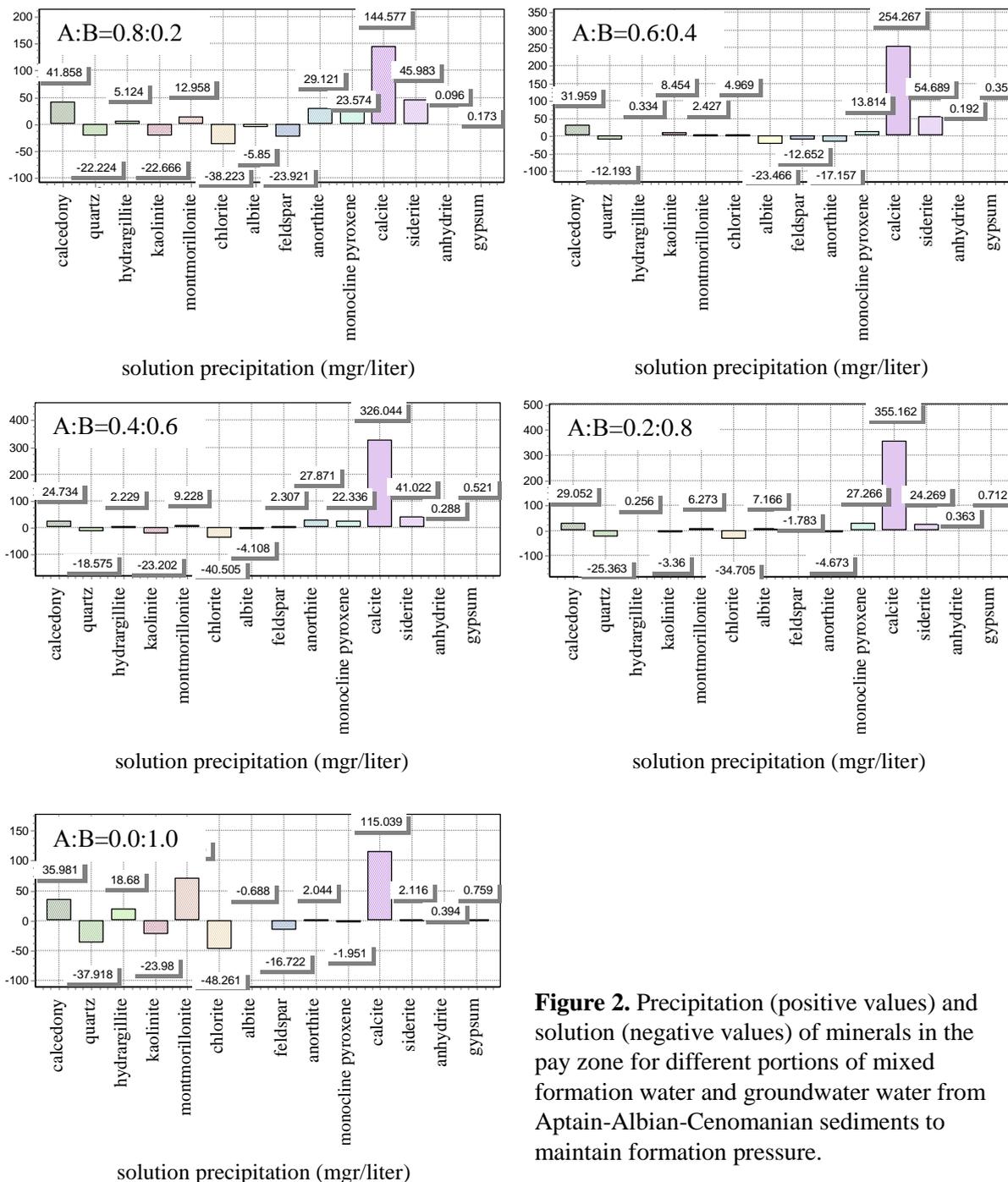
Figure 2. Precipitation (positive values) and solution (negative values) of minerals in the pay zone for different portions of mixed formation water and groundwater water from Aptain-Albian-Cenomanian sediments to maintain formation pressure.

4. Conclusion

Modeling data results of Aptain-Albian-Cenomanian water injection into pay zone (U_1 layer) indicate a relatively good compatibility of above-mentioned waters. It should be noted that the quantitative composition changes of solutions and rocks are the possible maximum changes which actually could be lower (if considering interaction time in the water-rock system).

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