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THE SPECIFICS OF OPERATING MINOR DEPOSITS (as given by the examples of gas condensate deposits of the Northern Caucasus)

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One of the most important directions in upgrading well productivity in the process of mining hydrocarbons consists in fighting with salt formation and salt deposition. Solving that problem becomes especially actual when operating deposits that are in their final stage of exploitation in complex mining and geological conditions accompanied by deposition of salts in the well foot area of oil bed and their sedimentation on the sub-surface and surface equipment. It provokes a drop in well productivity and results in off-schedule repair works.

Specifics are considered of exploiting minor gas condensate deposits of the Northern Caucasus that are operated under complicated mining and geological conditions of anomalously high bed pressures, high temperatures, strong depressions on the beds and inflow of mineralized water from water saturated seams.

Processes are studied of salt deposition from heavy hydrocarbons in the well foot and the bed area surrounding it.

Water sample analyses data from different wells have demonstrated that the main salts carrier is the associated water, and the principal sedimenting agents are corrosion products, as confirmed by the results of microscopic studies.

The dynamics is presented of salt deposition in the “well foot – wellhead – separator” system retrieved from the results of studies of reaction products in the well foot zone of oil bed.

It is demonstrated that the efficiency of struggling with salt deposition in the course of mining hydrocarbons depends on comprehensive approach to the problem, the principal thrust lying with prevention of such deposition.

Possible ways are considered to prevent precipitation of ferric compounds in the course of operating gas condensate wells, a way is suggested to intensify gas inflow.

Key words**:** minor gas-condensate oil deposits, salt formation, salt deposition, acidic components, associated water, products of corrosion.

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Increasing the level of extraction of gas, gas condensate and oil from earth entrails is one of the most important tasks in the area of rational exploiting of minor deposits of hydrocarbons. Developing minor deposits of the Northern Caucasus has its own particularities related to the specific conditions of operating wells and geological and mining conditions at the developed site. One of the problems is salt formation and deposition in the course of operating gas condensate wells.

The formation of sediments occurring in operational gas condensate wells of minor deposits, and in the course of transporting bed fluids to the surface complicates their production and builds up its costs considerably. Pipe internal cross-section decreases, pressure losses increase, temperature regime is violated, putting instruments and sensors through the pipe becomes impossible. The problem of salt formation and deposition in mining equipment is common for many minor deposits, especially those in their final operational stage.

Domestic and foreign experience in operating oil and gas deposits indicates that salt deposition occurs at every stage of mining, transporting and processing hydrocarbon fluids [6-8, 13, 19, 21].

The global practice claims that forecasting and preventing salt formation to be preferable to fighting salt deposits after they have formed already. Consider this problem using the example of one of the minor deposits of the north Caucasus, specifically the Koshekhablsky gas condensate field (GCF).

The possible cause for a depletion in productivity of operational wells of the Koshekhablsky GCF is the formation of sediments in both the surface and sub-surface production equipment, and possibly at well feet of the wells and in sub-well feet zones [5, 7, 11, 14-16].

Consider the principal factors that define physico-chemical processes of salt deposition.

- *Complex geological and production conditions of fluid bed stratification, specifically*: anomalously high bed pressures; high temperature; large depressions on the bed; squeezing of mineralized water from water saturated seams into the sub-well foot zone of the bed.

With violation of thermodynamic equilibrium at well foot and in the well foot surrounding zone of the bed salts and heavy hydrocarbons precipitate from the bed.

- *Presence of acidic components in the gas: hydrogen sulfide* (up to 2.0% of volume); carbon dioxide (up to 6.0% of volume).

High solubility of “acidic” components in condensate water (pH = 5.1-5.9) produces the conditions for electrochemical hydrogen sulfide and carbonic acid corrosion. Joint presence of hydrogen sulfide and carbon dioxide results in a synergic effect increasing their combined corrosion activity by a factor of about 4. The product of hydrogen sulfide corrosion is ferric sulfide precipitating into a deposit; carbonic acid corrosion produces soluble ferrum hydrocarbonate which then transforms into non-soluble ferrum carbonate.

- *Presence of heavy gas condensates in well production*: density of 0.84-0.85 g/cm^3; contain resins and paraffins.

Oil resins are high molecular substances of dark brown color colloidally dispersed in hydrocarbons. In the course of refining they do not proceed to distillates but remain in the non-refinable residual. Such a residual reaches more than 4% after the Koshekhablsky gas condensate is distilled.

Paraffins dissolve well in hydrocarbons at temperatures exceeding 40°C. Paraffins’ melting temperatures depend on their molecular weight and vary from 18°C (low molecular components) to 137°C (high molecular components). Deposited paraffins present a mixture of several hydrocarbons, so they do not have a clearly defined melting temperature. Clear crystallization of paraffins is noted in distillates free of resin substances that prevent such crystallization.

In the course of fluids rising via the tubing phase transformations of gas condensate take place, resins and paraffins precipitate and deposit on tube walls.

- *Waters extracted together with hydrocarbons contain ions that provoke sedimentation*, and in case of violation of thermodynamic equilibrium (a drop of pressure, temperature, substance incompatibility) they supersaturate and form insoluble compounds. Practically, the salts all belong to the 6-component system: $CaCl_2$, $MgCl_2$, Na_2SO_4 – well dissolved in water; $CaCO_3$, $CaSO_4{\cdot}2H_2O$, $CaSO_4$, $BaSO_4$ – poorly dissolved formations.
- *Mutual incompatibility of corrosion inhibitors and their incompatibility with associated waters.*

Tables 1-3 present the composition of gas in the extracted water and characteristics of gas condensate. Consider the change in composition of the components of gas flow using the example of a single well.

Table 1

Gas composition from well A of a gas condensate field in the Northern Caucasus (perforation interval 511-5,064 m)

Parameter	Operating year			
	1st	2nd	3rd	4th
Sampling conditions:				
P_{sep}, kgf/cm^2	19.6	22.6	23.4	29.07
t_{sep}, °C	16	7	9	14
Gas composition, % volume:				
Hydrogen	0.00	0.00	0.00	0.00
Methane	90.63	90.45	89.77	90.16
Ethane	2.01	1.89	2.28	2.26
Propane	0.42	0.34	0.37	0.42
i-Butane	0.08	0.27	0.08	0.08
n-Butane	0.06	0.07	0.07	0.07
i-Pentane	0.03	0.03	0.03	0.03
n-Pentane	0.01	0.01	0.02	0.01
$\sum iC_6$	2.31	2.32	2.31	2.305
nC_6	0.01	0.00	0.01	0.005
Heptane	0.00	0.00	0.00	0.00
Nitrogen + rare elements	0.19	0.20	0.20	0.21
Carbon dioxide	6.47	6.64	7.08	6.70
Helium	0.00	0.00	0.00	0.00
Hydrogen sulfide	0.08	0.08	0.08	0.05
Relative density by picnometer	0.639	0.643	0.640	0.634

Table 2

Gas condensate parameters, operational wells A (nominator) and B (denominator)
Gas condensate field, Northern Caucasus

Sampling conditions	Operating year				
	1st	2nd	3rd	4th	5th
Density, kg/m^3	0.842/0.8388	0.8285/0.8385	0.8378/0.8351	0.8375/0.8402	0.8381/0.8420
Temperature of, °C:					
boiling start	100/95	85/100	100/99	94/102	110/99
fraction flashing-off:					
10%	117/115	106/118	113/120	114/130	125/121
30%	135/137	125/141	133/150	141/155	151/147
50%	170/175	153/182	156/188	165/179	180/198
70%	223/239	218/238	213/236	248/245	241/256
90%	313/299	292/302	286/308	332/345	340/347
Output, %	95.0/98.0	96.0/98.0	98.0/98.0	96.0/94.0	93.0/93.0
Residual, %	4.0/1.0	3.0/1.0	1.0/1.0	3.0/5.0	6.0/6.0
Paraffins:					
Content, % by mass	Not found				2.8/3.1
t_{melt}, °C					45.0/44.0

Comment: 1. Perforation interval, well A: 5,111-5,064 m, well B: 4,992-5,015 m. 2. Gas condensate losses constitute 1%.

Table 3

Water composition for gas condensate field, Northern Caucasus

Sample number	$\frac{pH}{d_4^{20}}$	Mass concentration, mg/dm^3; mg eq/dm^3; %-eq.							Aggressive components content, mg/dm^3
		$Na^+ + K^+$	Ca^{2+}	Mg^{2+}	Cl^-	SO_4^{2-}	HCO_3^-	Σ ions	
1	$\frac{4.2}{1.001}$	639 27.80 27.05	160 8.00 7.79	Not found	141 3.48 3.39	2.299 47.90 46.61	Absent	3,675 102.76 100.00	$H_2S + HS^-$ – 30.0; CO_{2aggr} – 160.6; Fe^{2+} – 435
2	$\frac{5.1}{0.999}$	377 16.39 38.67	64 3.20 7.55	20 1.60 3.78	699 19.72 46.53	13 0.27 0.64	73 1.20 2.83	1,246 42.38 100.00	$H_2S + HS^-$ – 3.54; CO_{2aggr} – 52.80; Fe^{2+} – 103
3	$\frac{5.3}{0.998}$	127 5.54 29.03	56 2.80 14.68	15 1.20 6.29	300 8.47 44.39	13 0.27 1.42	49 0.80 4.19	560 19.08 100.00	$H_2S + HS^-$ – 59.87; CO_{2aggr}– 140.80 mg/dm^3; Fe^{2+} – 28 mg/dm^3
4	$\frac{6.0}{0.998}$	11 0.47 24.23	10 0.50 25.77	Not found	Not found	13 0.27 13.92	43 0.70 36.08	77 1.94 100.00	$H_2S + HS^-$ – not found; CO_{2aggr}– 44.0; Fe^{2+} – not found
5	$\frac{7.9}{1.001}$	580 25.23 36.64	128 6.40 9.29	34 2.80 4.07	Not found	1,076 22.43 32.57	732 12.00 17.43	2,550 68.86 100.00	H_2S+HS^- – 73.95; CO_{2aggr}– 16.0; Fe^{2+} – not found

Comment NH^4 ion not detected, the ion CO_3^{2-} – is absent; d_4^{20} – oil products relative density at 20°C vs. water density at 4°C.

Methane content has dropped in the gas (Table 1), heavy isomers have been identified (ΣiC_6 2.31%), such as *n*-hexane, heptane which were not present in the gas before. Similar changes were noted for the other wells too.

Gas condensate also demonstrates a tendency for heavier components. According to results of analyses of gas condensate (Table 2) 90% fraction is distilled at the temperature of 340°C (in the previous years it was $t < 300$°C), paraffin content is 2,8%, their melting temperature being 45°C; the residual has increased to 6% after distilling gas condensate.

When that condensate is used as the foundation to prepare corrosion inhibitor it undergoes second distillation. One should also keep in mind that having reached ground surface, gas condensate loses its light fractions, oxidizes, gets enriched with resins, etc.

One of the providers of salt deposition is associated water. Since developing the Oxford bed of Koshekhablsky deposits occurs without injecting (off-contour) waters, the water coming up together with gas ("associated water") is a mixture of condensate and water "squeezed" out of non-collector seams due to high depressions. When thermodynamic equilibrium is perturbed, salt forming ions proceed to supersaturation and sediment. Such water contains corrosion aggressive components as well.

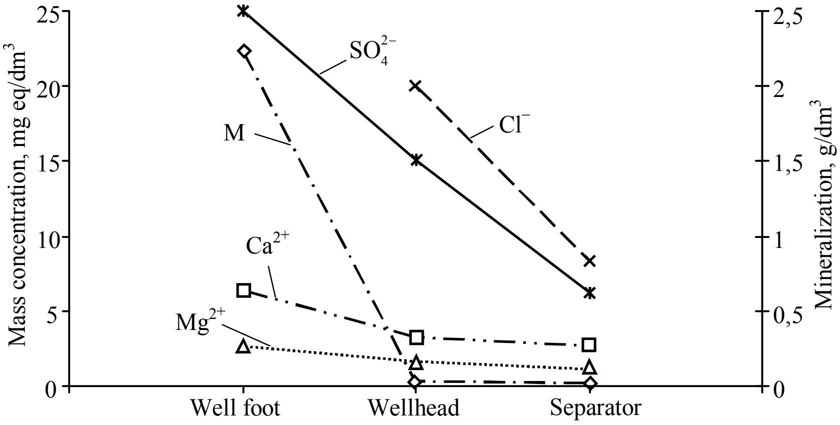

Fig. 1. The dynamics of concentration changes for deposition forming ions in the "well foot – wellhead – separator" system

Within all the years of exploitation the analyses were run of associated water sampled during the studies of gas dynamics. These were taken from the individual sampling separator used to monitor watering of the field. Condensation waters may hardly reflect any changes of such indicators since their composition depends on the amount of moisture precipitated in the separator (Table 3). However the acidity of these waters (pH = 4.2-6.1) testifies to their high corrosion activity.

The results of analyses of water samples taken at different levels of the well (Table 3, samples 1-3) show that their composition differs from point to point. Samples hat are most informative are those taken at the wellhead and at the intake of production testing separator.

The upper part of the sample is brown gas condensate of 0.8420 g/cm^3 density, its 90% fraction distilled at $t = 347$°C (the figure from previous years was $t = 302$-308°C), while the distillation residual has grown from 1 to 6% (see Table 2).

The lower layer of the sample is light brown turbid water of 2.6 g/dm^3 mineralization featuring higher concentrations of calcium, sulfates, hydro-carbonates, hydrogen sulfide (up to 74 mg/dm^3), no ferrum detected (Table 3, sample 5). Possibly, this is the only information on well foot water. Using it one may trace the dynamics of changes in concentration of salt forming ions at different points of the well (see the Figure).

The forecast of forming salt deposits is presented using the example of associated water from the well of Koshekhablsky GCF (Table 3, sample 2). Water sampled at the wellhead has pH = 5.1 and contains aggressive components ($CO_{2\,\text{aggr}}$: 53 mg/dm^3, $H_2S + HS^{-}$ 3.5 mg/dm^3).

The forecast of calcium carbonates deposition was dome digitally using the technique by Stiff and Davies [10]. According to the results obtained the index of saturation, IS = –2.5, the index of stability, ISt = 10.1, is assessed as very aggressive, capable of dissolving $CaCO_3$.

The process of gypsum formation in water systems is controlled by the presence of Ca^{2+}, SO_4^{2-} and other ions and depends on saturation deficit of the solutions of $CaSO_4$, retrieved from computational formulas and nomograms [10]. Saturation deficit reached 21,516 mg/dm^3. Therefore the forecast does not envisage any formation of calcium carbonate and sulfate in the system considered.

Theoretically, the probability of salts deposition in the depth is due to higher content of deposition forming ions under the harsher local conditions (pH, high content of aggressive and salt forming components). The principal deposition forming substances are corrosion products, as demonstrated by the results of microscopic studies of sediments from the wells (Table 4) [1, 17].

During the interaction of hydrogen sulfide that is in its dissociated state, with pipe metal, metal is eroded at the anode, iron transferring into its ion state. The cathode process is accompanied by the hydrogen driven pole depolarization, its results consisting in the appearance of hydrogen first in its atomic, and then its molecular form, which produces corrosion fracturing of metal. To describe the process of hydrogen sulfide corrosion the following equation is used

$$Fe^0 + H_2S \rightarrow FeS\downarrow + H_2\uparrow,$$

the forming ferric sulfide sedimenting.

Table 4

Results of microscopic studies of well depositions

Sample number	Macroscopic description of the sample	pH / d_4^{20}	Macrocomponent composition of water phase, mg/dm^3							Aggressive components in the pulp, mg/dm^3		
			Cl^-	HCO_3^-	SO_4^{2-}	Ca^{2+}	Mg^{2+}	NH_4^+	Σ ions	H_2S+HS^-	Fe^{3+}	Fe^{2+}
2	Water, black suspended matter on its surface ~40%	$\frac{4.6}{1.058}$	1.251	20	36.704	521	97	1.558	63.329	5.525	4.259	18.919
3	Water, black suspended matter on its surface ~50%	$\frac{4.8}{1.060}$	1.876	31	16.336	689	214	645	19.791	4.420	1.117	21.782
4	Water, sediment ~10%	$\frac{4.4}{1.055}$	2.988	12	13.661	681	97	580	18.019	1.190	1.117	16.197
5	Water, oily black suspended matter on its surface	$\frac{4.0}{1.048}$	6.323	Absent	29.709	481	97	625	37.235	1.400	3.630	21.782

Comment. Sample 1 is the sediment resulting from processing the tubes with sulphamine acid, a gray-green paste with high content of paraffins. The organic component: sediment in the spirit-benzene extract (1:1) is presented by paraffins; the content of organics in chloroform is 3.2%; after extracting the organics by hexane the residual is presented by iron hat manifests magnetic properties (~100% of that residual is attracted by magnet).

During carbonic acid corrosion, water soluble ferric hydrocarbonate is formed:

$$Fe + 2H_2CO_3 \rightarrow Fe(HCO_3)_2 + H_2\uparrow.$$

Tracing water concentration of Fe^{2+} and HCO_3^- one may assess carbonic acid corrosion. The final product of that reaction is insoluble ferric carbonate. Also resins and paraffins get deposited on tubing walls.

As indicated above, water from the wellhead (see Table 3, sample 2) contains aggressive components (Fe^{2+} – 103 mg/dm^3) and ferric sulfide in the layer of condensate.

Water from the preliminary individual separator sampled during the same day (Table 3, sample a 3) differs strongly from that taken at the wellhead: in contrast to depleted mineralization (by approximately the factor of 2.3) the content of aggressive components grew: CO_{2aggr} – 141 mg/dm^3, $H_2S + HS^-$ – 60 mg/dm^3, Fe^{2+} – 28 mg/dm^3; no ferric sulfide was detected in the layer of condensate.

A strong drop of pressure (34 kgf/cm^2 at the wellhead, and 30 kgf/cm^2 at the separator intake) plus water composition suggest that deposits are formed in the plume and the environment changes. Surface corrosion indentions may work to form stagnant corrosive medium; due to autocatalytic process it acidifies and the corrosion processes intensify [12, 23].

When moisture condenses together with hydrocarbons on metal surface и a two-phase system of "electrolyte – hydrocarbon" forms [9], in which the process of corrosion in the presence of hydrogen sulfide acquires certain specific character: ferric sulfide forms and stimulates corrosion even further.

In combination with the iron of the tube ferric sulfide forms a galvanic element in which the tube is the anode disintegrating quite fast. An important role is played by the phenomena of selective moistening: a thin layer of water is formed in the zone of hydrocarbons which stimulates faster penetration of H_2S reaching the anode (iron of the tubing). Conditions are formed for fast accumulation of corrosion products. in our opinion these phenomena are also typical for the plumes [24].

The sample taken from the well (sampling point at separator intake) yielded acidic water (pH = 4.2) with high sulphate content (2,299 mg/dm^3), divalent iron (435 mg/dm^3) and aggressive components. Such a combination is possible when oxygen is present and sulfides oxidize transforming into sulfate salts. Due to processes of sulfate reduction the latter form CO_2 and H_2S again. A chain reaction develops hat consists of processes renewing and corrosion damages.

Microscopic studies of deposit dissolving in the above-ground and well production equipment have demonstrated that after hot water treatment these are presented by transparent colorless prismatic crystals of 0.05 mm size and a refraction index of 1.59. Possibly, this is a technogenic mass of sulphate - phosphate salts of calcium (anhydrite, gypsum, phosphates).

The principal drawback of polyphosphates as salt deposition inhibitors is their low thermal stability. At $T > 50°C$ they hydrolize and transform into orthophosphates which form poorly soluble sediments with ions of calcium [22]. Chemical and microscopic techniques were used to identify phosphates in the liquid phase and precipitate in the form of calcium salts.

Table 5

Composition of deposits from well tubing of Koshekhablsky GCF

Parameter	Sample number		
	1	2	3
Humidity, %	13.48	1.00	20.82
pH	7.7	4.8	7.4
Water extract composition reduced to dry residual, %			
HCO_3^-	0.1	0.01	0.07
Ca^{2+}	0.03	0.18	0.05
Mg^{2+}	Not found	Not found	Not found
Cl^-	0.01	0.02	0.03
SO_4^{2-}	0.02	2.04	0.06
NH_4^{2-}	0.007	0.03	0.013
Fe^{2+}	Not found	1.19	Not found
Σ salts	0.16	3.47	0.21
H_2O insoluble residual, microscopic description	Super-fine particles of black-magnetic iron (0.005-0.01 mm)	Tobacco-grey mixture aggregates, 5% of magnetic iron, fine isometric non-identifiable double-refracting particles (0.005 mm)	Tobacco-grey mixture aggregates, 10% of magnetic iron, fine isometric non-identifiable double-refracting particles (0.005 mm)
Organic component, %			
Chloroform Bitumoid Analysis	0.01	0.005	0.02
Resin Bitumoid Analysis	0.0025	0.0013	0.0025
Calcareousness, %	16.3	34.2	28.0
Water insoluble precipitate, composition, %			
$H_2S + HS$	1.04	0.07	0.30
Fe^{3+}	15.56	29.92	17.45
Fe^{2+}	38.30	26.43	31.03
Σ Fe	53.86	56.35	48.48
HCI (1:1) insoluble residual, %	66.44	63.99	74.39

Positive results in dissolving secondary precipitates were obtained using alkali solutions (NaOH, 2-5%). Precipitates are mainly presented by carbonates and ferric sulfides (Table 5).

Therefore studies of secondary precipitates have established the following:

1. The principal precipitate forming substances for the operating wells of Koshekhablsky GCF are corrosion products: ferric sulfides and carbonates, magnetic iron. Their content exceeds 80%. the components present include chlorides, sulfates, organic components (resins, paraffins).
2. When treating well tubing with sulphamine acid salt deposits are removed in the form of paste (paraffins, magnetic iron, ferric sulfide, etc.) and liquid (chlorates, carbonates). In the absence of thorough washout of corrosion products paraffin globules and secondary sediments set on the walls of well tubing that serve as crystallization centers for new formations [2, 4].
3. Using the ATMP or aminotris (methylenephosphonic acid as salt deposition inhibitor at high temperatures ($T > 50°C$) results in hydrolysis of the inhibitor to orthophosphates and forming of water-insoluble sulphate-phosphate calcium salts. This fact is confirmed by the results of chemical and microscopic studies.
4. Salt deposits are also formed in plumes.
5. When treating wells to remove salt deposits, their washout with technical water to remove reaction products was insufficient.

A series of experiments was undertaken with variable mass of precipitates (1-10 g). Satisfactory results on precipitate solubility (up to 40%) at corrosion rate of 40-47 g/(m^2·hr) were obtained for the "precipitate – reagent" ratio of 1:10. Free acidity was then from 36 to 80 mg-eq/100 cm^3 of reagent.

Note that the composition of precipitate studied underwent considerable changes with time: sulfides oxidized to sulphates. When running first experiments hydrogen sulfide was actively released and corrosion in the samples was of groove shape while in the latter tests the odor of hydrogen sulfide was hardly felt, which does not reflect the actual state of precipitate in the well.

Salt deposits in the tubing and well pipelines of operational wells of the Koshekhablsky GCF are presented by organic compounds (paraffins, resins), chlorides, carbonates, sulphates of sodium, calcium, magnesium that reach 10-15% of the deposit. The principal part of precipitate (> 80%) consists of corrosion products: ferric sulfides and carbonates, magnetic iron. Study results revealed the following:

- Going by the chemical composition of well foot fluid one may suggest that gypsum organic sediments, carbonates and chlorides are mainly present in the well foot zones of the wells with he open well foot. When treating such wells one should envisage using alkali, among other things.
- Using sulphamine acid (SAA) and aminotris(methylenephosphonic acid) (ATMP) to remove salt deposits from the wells of Koshekhablsky GCF is not recommended due to high concentrations of sulphates, sulphites, ammonia, calcium, chlorides, etc. in liquid phase, which in case in insufficient washout of wells from reaction products stimulate fast accumulation of precipitates.
- The process of dissolving general precipitate and iron in it with non-inhibited muriatic acid (5 to 20%) was practically independent of acid concentration.
- Adding the "Dodigen" inhibitor to reagent slows down both corrosion rate and precipitate dissolving.
- Adding organic (acetic, formic) acids to reagent is hardly effective, it neither slows corrosion down nor improves dissolving of deposits.

Positive results were obtained using the reagent that consisted of 5% solution of HCI with 1% solution of urotropine added as inhibitor. The rate of corrosion of samples was 40-50 g/(m^2·hr), 40-69% of precipitate dissolving. Free acidity of he reagent in dependence of the amount of precipitate was 13-33 g/dm^3 for the initial free acidity of 41 g/dm^3.

Because of the presence of large amounts of corrosion products and high corrosion rates one has to pay special attention to the following points during washout of wells to remove salt deposits:

- – inhibitor compatibility with evacuated water;
- – continuous feed of inhibitor to the well foot;
- – monitoring of the inhibitor evacuation;
- – installation of control corrosion samples at wellheads;
- – systematic monitoring of the liquid phase of fluid through the "wellhead – entry into the group installation (pipeline end) – individual separator" chain including identification of the medium acidity and aggressive components and ferrum in it and study of precipitates;
- – the analysis of gas condensate (density, composition by fractions, paraffins content and melting temperature) [4].

- In dependence of the results terms of gaging the tubing should be corrected (to define the depth of salt deposits) and, respectively, of well washout to remove salt deposits. Pipeline cleaning should be preceded by washout of the tubing [3, 20].
- To intensify fluid inflow from high temperature wells with abnormally high reservoir pressure, low permeability of the carbonate collector and aggressive components present (hydrogen sulfide and carbon dioxide) in the extracted fluid calls for a particularly serious approach to and comprehensive analysis of selection, composition and application of the reagent solution.

The studies have demonstrated that in order to prevent deposition of ferric compounds as precipitate various complex-forming substances and complexing agents are used [5, 18], while the solution of hydrochloric acid fits best the wells of Koshekhablsky field to intensify gas inflow. Ferrum ions stabilizer should be added to it with the account of well foot precipitates, plus an effective corrosion inhibitor. The optimum concentration of hydrochloric acid is defined from the results of corrosion rate tests of corrosion inhibitors in acid solution at gas bed temperature. 12 and 15% solutions of hydrochloric acid are chosen as basic ones.

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