PRESSURE DISTRIBUTION ANALYSIS IN HORIZONTAL WELLS

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Two problems shall be concurrently solved to evaluate pressure distribution in a horizontal well including as follows:

1. Define influx/flow pattern from the reservoir to the wellbore.
2. Define flow pattern in the horizontal wellbore.

Concurrent solution of both problems requires application of numerical integration and iterative approximation methods.

The following input data will be required:

Fluid Properties.

1. Formation Temperature, K.
2. Dead (degassed) Oil Density at standard conditions (at 20 C), kg/m3.
3. Liberated Gas Density at standard conditions, kg/m3.
4. Oil Formation Volume Factor, m3/m3.
5. Formation Water Density at standard conditions (at 20 C), kg/m3.
6. Bubble point pressure, atm.
7. GOR at standard conditions, m3/m3.
8. Dead Oil Viscosity at standard conditions (at t=20 C), mPA*s.

Well Data.

1. Liquid Rate at standard conditions, m3/day.
2. Watercut at standard conditions, %.
3. Bottomhole Pressure, atm.
4. Horizontal Section ID, mm.
5. Formation Pressure, atm.
6. Horizontal Section Length, m.

Additional Data.

1. Horizontal Section Irregularity, m.

Horizontal section shall be broken into n-number of 10m sections, dL=10m, n=Lhorizontal/dL.

Fluid flow to the wellbore can be derived from the following equation:

$$Q_{тек} = K_{прод}(P_{пл} - P_{заб})$$

Where $Q_{тек}$ - current liquid rate, m^3/day; $K_{прод}$ - productivity index, m^3/(day*mPA); $P_{пл}$ - current formation pressure in the near wellbore area, МПа; $P_{заб}$ - downhole pressure, mPA.

I. METHODOLOGY

1. Define productivity factor ($Q_{тек}$) from equation (1.1) for the given current liquid rate $P_{пл}$, formation pressure $P_{заб}$ and downhole pressure $K_{ïðîä}$.

$$K_{ïðîä} = \frac{Q_{òåê}}{P_{ïë} - P_{çàá}} \tag{I.1}$$

2. First approximation of the productivity factor ($K_{ïðîä\ 0}$) shall be calculated for the 1 m of the horizontal section.

$$K_{ïðîä\ 0} = \frac{K_{ïðîä}}{L_{ãîð}} \tag{I.2}$$

3. Identify well section i for investigation. Define pressure p_i and rate Q_i for the well section i. In section No. 1 (i=1) the pressure p_1 will equal downhole pressure and rate Q_1 will be equal to the total well rate at p_1, and $T_{ïë}$.

4. Define liquid flow rate for the section of interest.

$$q_i = K_{ïðîä\ 0} \cdot (P_{ïë} - ð_i) \cdot dL \tag{I.3}$$

5. Define flow rate for the next horizontal section (i+1).. The flow rate in the next horizontal section will be equal to the total rate minus liquid volume in the section i: $Q_{i+1} = Q_i - q_i$.

6. Calculate friction losses for section i - $\left(\frac{dP}{dH}\right)_{òð\,(i)}$ based on the known p_i and Q_i values, where $\left(\frac{dP}{dH}\right)_{òð\,(i)}$ - friction loss gradient, PA/m.

7. Define pressure value at the beginning of the next horizontal section i+1.

$$p_{i+1} = p_i - \left(\frac{dP}{dH}\right)_{òð\,(i)} \tag{I.4}$$

8. Repeat steps 3-7 until i equals n, therefore, the end section of the horizontal wellbore is reached.

9. Compare the cumulative flow rate for the entire horizontal section $\sum_{1}^{n} q_i$ and total well rate Q_1, and match the adopted value of the productivity index for 1 m of the horizontal section $K_{ïðîä\ 0}$. Repeat steps 3-8.

$K_{ïðîä\ 0}$ shall be matched until $\sum_{1}^{n} q_i$ equals Q_1 (the difference of 2% from Q_1 value shall be considered acceptable)..

II. KEY RELATIONSHIPS APPLICABLE FOR CALCULATION

For the purposes of this analysis the following input data shall be obtained:
$Q_{ж\ ст}$ ($Q_{нд}$) - Liquid rate at standard conditions (dead oil rate), m^3/day; $B_{в\ ст}$ - watercut at standard conditions; $T_{пл}$ - formation temperature, K; $d_{внут.Э/К}$ - production casing ID (for horizontal section), m; $\rho_{нд}$ - dead oil density at standard conditions, kg/m^3; $\mu_{нд}$ - dynamic viscosity of dead oil, mPA*s; $P_{нас}$ - bubble point pressure at formation temperature, mPA; G_0 - gas content of formation oil (GOR), m^3/m^3; $\rho_{го}$ - density of gas released from oil at flash liberation test at normal conditions, kg/m^3; $\rho_{в\ ст}$ - water density at standard conditions, kg/m^3.

For the purposes of pressure distribution analysis it will be necessary to apply the following equation to adjust GOR to normal conditions:

$$\Gamma_0 = G_0 \frac{T_0}{T_{ст}}, \tag{II.1}$$

where Γ_0 - GOR at normal conditions, m^3/m^3; G_0 - GOR at standard conditions, m^3/m^3.

The following equation apply to derive the bulk well rate

$$q_{ж} = Q_{ж\,ст}(1 - B_{в\,ст})\overline{\rho}_{нд} + Q_{ж\,ст} B_{в\,ст} \overline{\rho}_{в\,ст}, \tag{II.2}$$

where $q_{ж}$ - bulk well rate, t/day; $\overline{\rho}_{нд} = \frac{\rho_{нд}}{1000}$; $\overline{\rho}_{в\,ст} = \frac{\rho_{в\,ст}}{1000}$.

Calculation of the gas super-compressibility factor for the associated dissolved gases.

Specific density of gas at specific PVT conditions (P_i, T_i) [5] shall be defined from the following equation:

$$\overline{\rho}_{г}(P_i, T_i) = 2(\overline{\rho}_{г} - 0{,}5)(e^{-\alpha P} - 0{,}5) + 0{,}5, \tag{II.3}$$

$$\overline{\rho}_г = \frac{\rho_{го}}{\rho_{воз}},$$

$$\alpha = A + BP,$$

$$A = 0{,}0964e^{-0{,}0127t},$$

$$B = -0{,}0044e^{-0{,}02t}$$

where $\overline{\rho}_г$ - specific density of gas (to air) released from oil during flash liberation test at normal conditions; $\rho_{го}$ - density of gas released from oil during flash liberation test at normal conditions, kg/m^3; $\rho_{воз}$ - density of air, kg/m^3 (at normal conditions it equals 1,293); $\overline{\rho}_a$ - specific density of nitrogen to air ($\overline{\rho}_a = 0{,}97$); t - temperature, degr. C.

To define gas supercompressibility factor at specific PVT conditions (P_i, T_i) [5] the following equation apply:

$$z = \alpha_1 + \beta_1(z_1 - 0{,}5), \tag{II.4}$$

$$\alpha_1 = 0{,}9573e^{-0{,}0433P},$$

$$\beta_1 = 0{,}2582P^{0{,}5},$$

$$z_1 = A_1t^2 + B_1t + C_1,$$

$$A_1 = -\left(10\overline{\rho}_г(P_i,T_i) + 0{,}5\right)10^{-6},$$

$$B_1 = \left(5\overline{\rho}_г(P_i,T_i) - 0{,}2\right)10^{-3},$$

$$C_1 = -0{,}8\overline{\rho}_г(P_i,T_i) + 1{,}18$$

Density of gas released from oil during flash liberation test $\rho_{гi}$ *shall be calculated form the following equation:*

$$\rho_{гi} = a[\overline{\rho}_г - 0{,}0036(1+R_i)(105{,}7 + U\ R_i)]\rho_{воз}, \tag{II.5}$$

where a, U - coefficients derived from the following equations:

$$a = 1 + 0{,}0054(t - 20), \tag{II.6}$$

$$U = \overline{\rho}_{нд}\Gamma_{0м} - 186, \tag{II.7}$$

where $\overline{\rho}_{нд} = \frac{\rho_{нд}}{1000}$, $\Gamma_{0м} = \frac{\Gamma_0}{\overline{\rho}_{нд}}$, $\Gamma_{0м}$ - GOR, m^3/t, $\rho_{воз}$ - air density at normal conditions ($\rho_{воз} = 1{,}293$ kg/m^3).

$$R_i = \frac{1 + \lg P_i}{1 + \lg P_{нас}} - 1, \quad P_{нас} \geq P_i \geq 0{,}1. \tag{II.8}$$

Density of gas released from oil at predefined P and T will be calculated from the following equation:

$$\rho_г(P,T) = \frac{\rho_{гi} P T_0}{z(P,T) P_0 T}, \qquad \text{(II.9)}$$

where $z(P,T)$ - supercompressibility factor for the flash test gas for specified P and T; $T_0 = 273\,K$, $P_0 = 0{,}1\,МПа$ mpa.

Specific volume of gas released from oil at predefined P *and* T, *m^3/t, shall be calculated as follows:*

$$G_{0мi} = Г_{0м} R_i m [D\ (1 + R_i) - 1], \qquad \text{(II.10)}$$

$$m = 1 + 0{,}029(T_i - 293)(\overline{\rho}_{нд}\,\overline{\rho}_г - 0{,}7966), \qquad \text{(II.11)}$$

$$D\ = 4{,}06(\overline{\rho}_{нд}\,\overline{\rho}_г - 1{,}045). \qquad \text{(II.12)}$$

Calculation of density of gas remained in solution $\rho_{г.р.i}$.

To define specific volume of dissolved gas the following equation applies:

$$G_{р.м\,i} = Г_{0м} m - G_{0мi}. \qquad \text{(II.13)}$$

Density of dissolved gas shall be calculated from the following equation:

$$\rho_{г.р.i} = \frac{Г_{0м}}{G_{р.м\,i}} \left(am\overline{\rho}_г - \overline{\rho}_{гi} \frac{G_{0мi}}{Г_{0м}} \right) \rho_{воз}, \qquad \text{(II.14)}$$

where $\overline{\rho}_{гi} = \frac{\rho_{гi}}{\rho_{воз}}$ - specific density of liberated gas.

Oil Volume Factor Calculation $b_{нi}$

$$b_{нi} = 1 + 1{,}0733 \cdot 10^{-3} \rho_{нд} G_{р.м\,i} \frac{\lambda}{m} + \alpha_н (t - 20) - 6{,}5 \cdot 10^{-4} P_i, \qquad \text{(II.15)}$$

$$\lambda = 10^{-3} \left(4{,}3 - 3{,}54 \cdot 10^{-3} \rho_{нд} + 1{,}0337 \frac{\overline{\rho}_{г.рi}}{a} + 5{,}581 \cdot 10^{-6} \rho_{нд} \left(1 - 1{,}61 \cdot 10^{-6} \rho_{нд} G_{р.м\,i}\right) G_{р.м\,i} \right), \qquad \text{(II.16)}$$

$$\alpha_н = 10^{-3}(3{,}083 - 2{,}638 \cdot 10^{-3} \rho_{нд}), \qquad \text{(II.17)}$$

where P_i - pressure, MPA.

Gas Saturated Oil Density Calculation $\rho_{нi}$

The technique used for calculation of gas-saturated oil density ($\rho_{нi}$) is based on the relationships between densities of saturated oil and dead oil and density of gas liberated during flash test and formation volume factor. The key equation used for calculation of saturated oil density is:

$$\rho_{н\,i} = \frac{\rho_{нд}}{b_{н\,i}}\left(1 + 1{,}293 \cdot 10^{-3}\,\frac{\overline{\rho}_{г.р\,i} G_{р.м\,i}}{ma}\right), \tag{II.18}$$

where $\overline{\rho}_{г.р\,i} = \frac{\rho_{г.р\,i}}{\rho_{воз}}$ - specific gravity of liberated gas, kg/m^3; $b_{н\,i}$ - oil formation volume factor at predefined P and T; $\rho_{нд}$ - specific gravity of dead oil, kg/m^3.

Fluid Flow Rate Calculation

Gas rate at the pump intake with assumed pressure of $P_{пр.нас} = P_{нач}$ and design temperature $T_{пр.нас}$ is calculated on the basis of the number of input parameters.

Water content at standard conditions (watercut of the liquid) is:

$$B_{в\,ст} = \frac{Q_{в\,ст}}{Q_{в\,ст} + Q_{н\,ст}} = \frac{Q_{ж\,ст} - Q_{н\,ст}}{Q_{ж\,ст}}, \tag{II.19}$$

where $Q_{в\,ст}$, $Q_{н\,ст}$, $Q_{ж\,ст}$ - water, oil and liquid rates (respectively) at standard conditions, m^3/day;

Water rate $Q_в$ and oil rate $Q_н$ at predefined P and T:

$$Q_в = Q_{ж\,ст} b_в B_{в\,ст},\ (b_в = 1), \tag{II.20}$$

$$Q_н = Q_{ж\,ст} b_{н\,i}(1 - B_{в\,ст}), \tag{II.21}$$

where $b_в, b_н$ - water and oil formation volume factors at predefined P and T;

Volumetric water content B at predefined P and T

$$B = \frac{B_{в\,ст} b_в}{B_{в\,ст} b_в + (1 - B_{в\,ст}) b_{н\,i}}; \tag{II.22}$$

Volumetric parameters of the fluid flow (gas + liquid) $Q_{ж\,пр.нас}$ and $Q_{г\,пр.нас}$ at pump intake shall be calculated using the following equations:

$$Q_{ж\,i} = Q_{ж\,ст}(1 - B_i) b_{н\,i} + Q_{ж\,ст} B_i, \tag{II.23}$$

$$Q_{г\,i} = G_{0м\,i}(1 - B_i)\overline{\rho}_{н\,i} Q_{ж\,ст} z_i \frac{P_0 T_i}{P_i T_0}, \tag{II.24}$$

where $\overline{\rho}_{н\,i} = \frac{\rho_{н\,i}}{1000}$.

Fluid (gas + liquid) density

$$\rho_{см} = \rho_ж (1 - \varphi_г) + \rho_г \varphi_г, \tag{II.25}$$

where $\rho_ж, \rho_г$ - density of liquid phase and gas phase (respectively) at specific PVT conditions for the predefined section of the flow, kg/m^3; $\varphi_г$ - true gas content in the fluid flow (gas volume in the fluid) to be calculated from the following analytical equation:

$$\varphi_г = \frac{\beta_г w_{см}}{w_{ги}} = \beta_г (C_1 + C_2 Fr_{см}^{-0,5}), \qquad (II.27)$$

where $\beta_г$ - volumetric gas content in the fluid to be derived from the following equation:

$$\beta_г = \frac{Q_г}{Q_ж + Q_г}, \qquad (II.28)$$

$Q_г, Q_ж$ - volumetric gas rate and liquid rate (respectively) at specific PVT conditions (to be derived from the following equations (II.23) and (II.24)), m^3/s; $w_{ги}, w_{см}$ - average true velocity of gas phase and average standard fluid velocity (respectively), m/s; C_1, C_2 - dimensionless correlation coefficients, accounting for hydrodynamic parameters of the flow and physical properties of various phases; $Fr_{см}$ - Froude Factor (function of fluid velocity $w_{см}$):

$$Fr_{см} = \frac{w_{см}^2}{g d_{вн}}. \qquad (II.29)$$

$$w_{см} = \frac{4(Q_ж + Q_г)}{\pi d_{вн}^2}, \qquad (II.30)$$

$d_{вн}$ - ID of tubing string (production casing ID), where fluid flow (gas + liquid) occurs, m.

Correlation coefficients can be derived from the following relationships:

$$C_1 = \frac{2,2361 e^{0,049 \bar{\mu}_ж}}{1 + 1,1002 e^{0,049 \bar{\mu}_ж}} - 0,5447 \bar{\mu}_ж^{-0,6} (d_{вн} - 0,015), \qquad (II.31)$$

$$C_2 = \frac{1 + 0,1082 e^{0,049 \bar{\mu}_ж}}{1 + 1,1002 e^{0,049 \bar{\mu}_ж}} - \left(6,707 - 0,168(\bar{\mu}_ж - 1)\right)\left(d_{вн} - 0,015\right), \qquad (II.32)$$

where $\bar{\mu}_ж$ - specific viscosity of liquid calculated as the ratio of viscosity of liquid in the hoist at known PVT conditions (mPA s) and viscosity of water at standard conditions ($\mu_{в\,ст} = 1 мПа \cdot с$).

$$\bar{\mu}_ж = \frac{\mu_ж}{\mu_{в\,ст}}. \qquad (II.33)$$

The relationship (II.31) is true for the following tubing IDs and specific liquid viscosities:

$$\begin{aligned} d_{вн} &= 0,0381\, м, \quad 1 < \bar{\mu}_ж \le 1500 \\ d_{вн} &= 0,0508\, м, \quad 1 < \bar{\mu}_ж \le 750 \\ d_{вн} &= 0,0635\, м, \quad 1 < \bar{\mu}_ж \le 450 \\ d_{вн} &= 0,0762\, м, \quad 1 < \bar{\mu}_ж \le 300 \end{aligned} \qquad (II.34)$$

The equation (II.32) is true for the following range of values $1 < \bar{\mu}_ж \le 40$. If $\bar{\mu}_ж > 40$, the correlation coefficient will be:

$$C_2 = \frac{1 + 0,1082 e^{0,049 \bar{\mu}_ж}}{1 + 1,1002 e^{0,049 \bar{\mu}_ж}}. \qquad (II.35)$$

Friction loss gradient

$$\left(\frac{dP}{dH}\right)_{тр} = \frac{\lambda_{тр} w_{см}^2 \rho_{см}}{2d_{вн}}, \tag{II.36}$$

where λ - hydraulic resistivity coefficient for liquid phase flowing with the velocity of the fluid. It is function of Reynolds number for the liquid phase:

$$\mathrm{Re}_{ж} = \frac{w_{см} d_{вн} \rho_{ж}}{\mu_{ж}} \tag{II.37}$$

For this case the following equation shall apply:

$$\lambda_{тр} = 0{,}067\left(\frac{158}{\mathrm{Re}_{ж}} + 2\frac{\in}{d_{вн}}\right)^{0,2}, \tag{II.14}$$

where $\in$ - absolute roughness of the internal surface of the pipe (for the pipes specifically designed for the Oil&Gas Industry, the pipes shall be scale, paraffin and tar free, $\in = 1{,}4 \cdot 10^{-5} м$), m.

It shall be noted that the relationships (II.31), (II.32), and (II.35) can be used for the hoists with ID of $0{,}015м \le d_{вн} \le 0{,}0762м$. If the hoist ID is $d_{вн} > 0{,}0762м$, it is assumed that the true and volumetric gas contents are equal, $\varphi_{г} = \beta_{г}$.

Gas phase density at specific PVT conditions shall be derived from the following equations: (II.5)-(II.9).

Structure and type of the fluid (water + oil) shall be defined to measure density and viscosity of the liquid phase.

The following fluid properties shall be measured to define structure and type of the fluid (water and oil mixture):

Normalized velocity (m/s) of the water/oil mixture for the selected section of the pipe:

$$w_{см\,пр} = \frac{Q_{в} + Q_{н}}{F}, \tag{II.15}$$

where F - area of the cross-section, m^2.

Flow structure definition

There are two types of fluid structure (water and oil mixture): droplet type and emulsion type. These two types have different critical fluid velocity characteristics $w_{см\,кр}$ (m/s):

$$w_{см\,кр} = 0{,}487\sqrt{gD_m}, \tag{II.16}$$

where D_m - tubing ID (production casing ID), m.

If

$$w_{см\,пр} < w_{см\,кр}, \tag{II.17}$$

than the fluid is of the droplet type. This type of fluid has an internal dispersed phase (in the form of 0.5-2cm droplets) distributed in the external continuous phase.

If

$$w_{см\,пр} > w_{см\,кр}, \tag{II.18}$$

than the fluid is of the emulsion type. This type of fluid has an internal dispersed phase in the form of spherical drops with diameter of $10^{-3} – 10^{-5}$ cm.

Definition of the fluid (water and oil mixture) type

The droplet structure fluid can be characterized by the volumetric water content:

if $B \le 0{,}5$, than the fluid will be of the water-in-oil type with water on the inside and oil - on the outside;

if $B > 0{,}5$, than the fluid will be of the oil-in-water type with discrete oil phase on the inside and water - on the outside;

For the emulsion flow type in addition to B value it is necessary to define critical velocity of the emulsion $w_{э\,кр}$. The critical velocity of the emulsion will be:

$$w_{э\,кр} = 0{,}064 \cdot 56^{B} \sqrt{gD_m}\ . \tag{II.19}$$

For water in oil emulsions - $B \le 0{,}5$ and $w_{см\,пр} > w_{э\,кр}$. For oil in water emulsions - $B \le 0{,}5$ and $w_{см\,пр} < w_{э\,кр}$ or $B > 0{,}5$.

Density Calculation

Droplet structure

Define surface tension on the water phase boundary:

$$\sigma_{нв} = \sigma_{вг} - \sigma_{нг}, \tag{II.20}$$

where $\sigma_{нг}, \sigma_{вг}$ - surface tension at the oil-gas interface and water-gas interface, mN/m.

Surface tension $\sigma_{вг}$ can be defined from the following equation:

$$\sigma_{вг} = \frac{1000}{10^{1{,}19+0{,}01P_i}}, \tag{II.21}$$

where P_i - pressure, MPA.

Surface tension $\sigma_{нг}$ can be defined from the following equation:

$$\sigma_{нг} = \frac{1000}{10^{1{,}58+0{,}05P_i}} - 72 \cdot 10^{-3}(T - 305). \tag{II.22}$$

The true phase volume in the flow shall be calculated.

For water in oil flow the true volume fraction of water is:

$$\varphi_{в} = \frac{w_{в\,пр}}{w_{см\,пр} - \left(0{,}425 - \dfrac{0{,}827 w_{см\,пр}}{\sqrt{gD_m}}\right)\left(4\sigma_{нв} g \dfrac{(\rho_{в} - \rho_{н\,i})}{\rho_{н\,i}^{2}}\right)^{0{,}25}}, \tag{II.23}$$

$$w_{в\,пр} = \frac{Q_{в}}{F}, \tag{II.24}$$

where $w_{в\,пр}$ - standard velocity of water, m/s; $\rho_в, \rho_н$ - water and oil density (respectively) at predefined P and T, kg/m^3.

The true volume fraction of external phase (oil) will be:

$$\varphi_н = 1 - \varphi_в. \qquad \text{(II.25)}$$

For the water in oil flow the true volume fraction of oil will be:

$$\varphi_н = \frac{w_{н\,пр}}{w_{см\,пр} + \left(0{,}54(1{,}01 + B^{0{,}152}) - \frac{w_{см\,пр}}{\sqrt{gD_m}}\right)\left(4\sigma_{нв} g \frac{(\rho_в - \rho_{н\,i})}{\rho_в^2}\right)^{0{,}25}}, \qquad \text{(II.26)}$$

$$w_{н\,пр} = \frac{Q_н}{F}, \qquad \text{(II.27)}$$

where $w_{н\,пр}$ - standard velocity of oil, m/s.

The true volume of external phase (water) will be:

$$\varphi_в = 1 - \varphi_н. \qquad \text{(II.28)}$$

Density of the fluid (water + oil) $\rho_{вн}$ is:

$$\rho_{вн} = \rho_в \varphi_в + \rho_н \varphi_н. \qquad \text{(II.29)}$$

Dynamic viscosity of the water-oil mixture with droplet type structure shall be equal to the dynamic viscosity of the external phase:

For water-in-oil fluid - $\mu_{вн} = \mu_н$,

For oil-in-water fluid - $\mu_{вн} = \mu_в$,

where $\mu_н, \mu_в$ - oil and water viscosity (respectively) at predefined *P* and *T*, mPA *s*.

Emulsion type structure

To define the structure of the emulsion it is necessary to calculate the true volumetric fractions of the emulsion phases. For the purposes of calculation the movement of phases in respect to each other is not accounted for due to the high phase dispersion in emulsions and the true volumetric fractions of phases are assumed to be equal to the phase volumes.

$$\left.\begin{aligned}\varphi_в &= B,\\ \varphi_н &= \beta_н = 1 - B.\end{aligned}\right\} \qquad \text{(II.30)}$$

Define the density of the oil-water emulsion. The density of the oil-water emulsion is:

$$\rho_{вн} = \rho_в(1 - B) + \rho_н B. \qquad \text{(II.31)}$$

Define apparent viscosity of the oil-water emulsion $\eta_э$ for water in oil emulsion. The apparent viscosity of the oil-in-water emulsion is:

$$\eta_э = \frac{D(1 + 2{,}9B)}{1 - B}, \qquad \text{(II.32)}$$

where D - coefficients derived from the following equation:

(when $A \le 1 \quad D = \mu_н$), (II.33)

(when $A > 1 \quad D = A\mu_н$),

(II.34)

A is the parameter accounting for shear rate impact on the viscosity.

$$A = \frac{1 + 20B^2}{w_{сд}^{0,48B}}, \quad \text{(II.35)}$$

$w_{сд}$ - shear rate of the oil-water emulsion at the predefined *P* and *T*, *l/s*:

$$w_{сд} = \frac{8w_{э\,пр}}{D_г}, \quad \text{(II.36)}$$

where $w_{э\,пр}$ - normalized emulsion shear rate which is derived from the equation (III.15), m/*s*; $D_г$ - hydraulic diameter of the flow channel, m.

The apparent viscosity for the oil-in-water emulsion is:

$$\eta_э = \mu_в 10^{3,2(1-B)}. \quad \text{(II.37)}$$

Oil Viscosity Calculation

Dead Oil Viscosity Calculation..

Very often there is no sufficient information about some oil properties, for example, oil viscosity $\mu_н$. Oil viscosity at 20°C and atmospheric pressure can be calculated using the Dunuyshkin equation:

$$\bar{\mu}_{н20} = \left(\frac{0,658\bar{\rho}_{нд}^2}{0,886 - \bar{\rho}_{нд}^2} \right)^2 \quad \text{(when } 0,845 < \bar{\rho}_{нд} < 0,924\text{)},$$

$$\bar{\mu}_{н20} = \left(\frac{0,456\bar{\rho}_{нд}^2}{0,833 - \bar{\rho}_{нд}^2} \right)^2 \quad \text{(when } 0,78 < \bar{\rho}_{нд} \le 0,845\text{)}, \quad \text{(II.38)}$$

where $\bar{\mu}_{н20}$ - specific dynamic viscosity (for water) of dead oil at 20 °C and atmospheric pressure.

Dead Oil Viscosity Calculation at any temperature.

Dead oil viscosity and temperature relationship can be plotted using Dunyushkin equation:

$$\mu_{нt} = \frac{1}{c}(c\bar{\mu}_{нt1})^a, \quad \text{(II.39)}$$

where $\mu_{нt}$ - specific dynamic viscosity (in water) of dead oil at predefined temperature *t*; $\bar{\mu}_{нt1}$ - specific dynamic viscosity (to water) of dead oil at the known temperature *t1*; *a* – coefficient, derived from the following equation:

$$a = \frac{1}{1 + b(t - t_1)\lg(c\overline{\mu}_{нt1})}, \quad \text{(II.40)}$$

b, c – coefficients expressed as the function of dead oil viscosity and calculated from the following relationships:

(when $\overline{\mu}_н \geq 1000, \quad b = 2{,}52 \cdot 10^{-3}$ 1/°C, $c = 10$), (II.41)

(when $10 \leq \overline{\mu}_н \leq 1000, \quad b = 1{,}44 \cdot 10^{-3}$ 1/°C, $c = 100$),

(II.42)

(when $\overline{\mu}_н < 10, \quad b = 0{,}76 \cdot 10^{-3}$ 1/°C, $c = 1000$), (II.43)

Calculation of Gas Saturated Oil Viscosity at formation temperature.

Saturated oil viscosity at formation temperature as function of gas content and dead oil viscosity at formation temperature and atmospheric pressure can be derived from the following equation:

$$\overline{\mu}_{нг} = A\overline{\mu}_{нt}^{B}, \quad \text{(II.44)}$$

where $\overline{\mu}_{нг}$ - specific viscosity of saturated oil at temperature *t* and bubble point pressure; $\overline{\mu}_{нt}$ - specific viscosity of dead oil at temperature *t* and atmospheric pressure; *A, B* – correlation coefficients as function of the volume of gas dissolved in oil:

$$A = \exp[-87{,}24 \cdot 10^{-4} Г^* + 12{,}9 \cdot 10^{-6} (Г^*)^2],$$

$$B = \exp[-47{,}11 \cdot 10^{-4} Г^* + 8{,}3 \cdot 10^{-6} (Г^*)^2], \quad \text{(II.45)}$$

$Г^*$ - gas saturation of oil (gas volume is calculated at 15°C and atmospheric pressure), m³/m³

$$Г^* = 0{,}983(1 + 5\alpha_н)Г_0, \quad \text{(II.46)}$$

$Г_0$ - gas saturation of the fluid (volume of gas is calculated at 20°C and atmospheric pressure) m³/m³, $\alpha_н$ - coefficient of thermal expansion of oil which is derived from the following equation:

$$\alpha_н = 10^{-3} \begin{cases} 2{,}638(1{,}169 - \overline{\rho}_{нд}) & \text{при} \quad 0{,}78 \leq \overline{\rho}_{нд} \leq 0{,}86 \\ 1{,}975(1{,}272 - \overline{\rho}_{нд}) & \text{при} \quad 0{,}86 < \overline{\rho}_{нд} \leq 0{,}96 \end{cases}; \quad \text{(II.47)}$$

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