P204 TENGUIZ OIL FIELD — RECOVERY PREDICTION BY EXPANSION ABOVE THE BUBBLEPOINT

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Abstract

The Giant Tengiz oil field in Kazakhstan was discovered in 1981 and put into development in 1991. The primary drive mechanism is of rock compaction and fluid expansion is above the bubblepoint. Due to anomal high initial reservoir pressure and large difference between initial reservoir pressure and saturation pressure, a record-high oil recovery is expected. For recovery prediction instead of some average values of compressibility oil c_o , water c_w and pore volume of reservoir rocks c_p , their non-linear functions of pressure and depth were suggested to be used which significantly improves recovery prediction. It is proposed to use a concept of differential and integral compressibility and parameter h^2/k by values of which double porosity reservoir matrix blocks can be divided into drainable and non-drainable. At fields of Tengiz type range of matrix permeability determination in reservoir conditions should be expanded to minimum 10^{-20} m² (0.00001 md).

Introduction

Tengiz oil field in Kazakhstan is located at the distance of 15 km from the Caspian Sea coast in its north-eastern part. Oil field, well-known due to its giant sizes and unique complex geological and physical conditions of oil occurrence, was discovered in 1981 and put into development in 1991. This discovery presents a particular interest due to the field being a super overpressured and undersaturated super high oil recovery by expansion above the bubblepoint is expected. Tengiz oil field is appeared to be atoll-like massive type reservoir trapezoidal in its cross section, composed of Middle-Lower Carboniferous carbonate rocks. Depth of the highest point reservoir top is about 3800 m, original OWC (as of 01.01.92) was not penetrated, lower pool boundary was taken preliminarily at the depth of 5400 m, plan size of reservoir is 18 to 25 km, the oil column is 1600 m. Reservoir is supposed to be the double porosity type. Carbonates are presented for the most part by organic and organic-and-fragmental limestones, reservoir void space is formed by thin primary pores, secondary leaching pores, cavities and numerous fractures. Rock porosity lies between 1 to 24% and permeability - from 0 to $300 \cdot 10^{-15}$ m², the best by reservoir properties formation intervals are characterized by average porosity and permeability values not exceeding 11% and $20 \cdot 10^{-15}$ m², respectively. At the depth of 4600 m (middle of oil column) initial reservoir pressure is found to be abnormally high, equal to 83.63 MPa, saturation pressure is low, equal to 25.56 MPa, formation temperature is 120.8°C. Oil is volatile, reservoir oil viscosity is 0.18 mPa.s, volume factor is 1.92, gas saturation is 462 m³/m³, reservoir oil density is 626.2 kg/m³, stock-tank oil density is 805.1 kg/m³, dissolved gas contains 19.2% of hydrogen sulphide. During primary oil estimate of reserves¹ the net pay thickness was assumed equal to gross one. It was supposed, that due to widely developed fracturing, massive reservoir body will be 100% drainable at primary drive of active depletion of oil, water and rock compression energy. Matrix permeability was considered as minor characteristics, and reservoir rock was divided into three different types with account of porosity only (Table 1). Primary predicted recovery² was calculated by method of material balance for undersaturated oils using average values of compressibility of oil c_o , water c_w and pore volume c_p without account of fractures compressibility c_f . For Tengiz field results of these calculations are appeared as a rough estimation. The purpose of this study was to get more adequate description of dynamics and ultimate results of compression energy depletion with account of the fact, that in reality compressibilities c_o , c_p and c_f were proved to be non-linearly and strongly dependent on pressure p and depth. With depths, changing from 3800m to 5400 m initial reservoir pressure increases from 78.69 to 88.52 MPa, reservoir temperature - from 102.4 to 139.2°C, overburden pressure - from 85.89 to 125.44 MPa, initial effective stress - from 7.2 to 36.92 MPa, reservoir oil density at depth-independent stock-tank one decreases from

631.8 to 620.8 kg/m³ (Table 2). Overburden pressure and initial effective stress are calculated by actual data on cap rocks density, 2304 kg/m³ and reservoir rock density, 2520 kg/m³.

Table 1

Reservoir rock type number	Description of rock type	Porosity limits, %	Average porosity, %		Oil saturation, %		Permeability, 10 ⁻¹⁵ m ²	Fraction of oil reserves
			matrix	fracture	matrix	fracture		
I	fractured	<3	1.8	0.35	100	85	6	1.2
II	fractured - porous	3 - 7	4.97	0.5 ^x	77	85 ^x	9	32.7
III	fractured - porous	>7	10.20	0.5 ^x	93.3	85 ^x	20	66.1
Total reservoir			6.26	-	82.4	-	12	100

*) accepted approximately in current study

Table 2³

Depth, m	Initial reservoir pressure, MPa	Overburden pressure, MPa	Initial effective stress, MPa	Reservoir temperature, °C	Gas saturation pressure, MPa	Initial reservoir oil density, kg/m ³
3800	78.69	85.89	7.20	102.4	25.04	631.8
4600	83.63	105.67	22.04	120.8	26.56	624.9
5000	88.52	125.44	36.92	139.2	28.08	620.8

Experimental data on compressibility and other parameters of reservoir oil for the whole pressure interval $p_i - p_*$ (as of 01.01.91) were available in exploratory well 43, and present study was based on them.

Differential and integral compressibility

While describing behaviour of oil, rock and water elastic properties vs pressure change the concept of differential and integral compressibility was considered useful.

Differential compressibility of oil was determined from the following relation:

$$c_o^* = -\frac{1}{V} \left(\frac{\partial V}{\partial p} \right)_T \quad (1)$$

which can be approximated for finite pressure change by using the well-known equation:

$$c_o^* = (V_1 - V_2) / V_a (p_2 - p_1) \quad (2)$$

in which at conditions (1) and (2) $p_2 > p_1$, and $V_1 > V_2$ and $V_a = (V_1 + V_2) / 2$ Integral compressibility is determined by the relation

$$c_o = (V - V_i) / V_i (p_i - p) \quad (3)$$

Coefficient c_o^* is the instantaneous or point oil compressibility under pressure p , coefficient c_o - average or integral oil compressibility within the range of pressure change from p_i to p . Results of experimental studies of oil subsurface sample from well 43 are given in Fig. 1 in the form of curvilinear dependence of $c_o^* = f(p)$ and $c_o = f(p)$. Values c_o^* and c_o are equal at the beginning of integration, while p is decreasing, difference $(c_o^* - c_o)$ increases, reaching maximum with $p = p_*$. In case of pressure decreasing from p_i to p_* , c_o^* increases 4 times and c_o - nearly 2 times. Analysis of compressibility of Tengiz oil and highly gas saturated oils from a number of other fields of Russia as well as reference hydrocarbons (n-heptane and n-dodecane) showed⁴ that dependence of $c_o^* = f(p)$ and $c_o = f(p)$ in logarithmic coordinates is governed by linear law (Fig. 2). Change of compressibility differential coefficient c_o^* vs pressure p at different temperatures (depths) is approximated by empirical equation

$$c_o^* = m / p^n \quad (4)$$

where exponent $n=1.18$, and coefficient m changes from 0.294 for depth of 3800 m to 0.363 for depth of 5400 m.

Integration of equation (4) gives relationship for determination of integral compressibility coefficient c_o :

$$c_o = 5.555m(p_i^{-0.18} - p^{-0.18})(p_i - p)^{-1} \quad (5)$$

Results of reservoir rocks compressibility determination by different laboratories^{5,8} do not correlate sufficiently well, probably due to difference of applied experimental methods and approaches. Present study is based on relationship of pore volume differential compressibility c_p^* vs effective stress during hydrostatic stress of core samples⁵:

$$c_p^* = \phi^{-1}(1.5 \cdot 10^{-5} + 1530 \cdot 10^{-5} \cdot \sigma^{-1.8}) \quad (6)$$

Model of uniaxial reservoir strain ε_z in the absence of lateral strain $\varepsilon_x = \varepsilon_y = 0$ more likely conforms to reservoir conditions. Sandstone studies⁶ showed, that with hydrostatic stress and uniaxial strain mode pore volume change is governed by the same power law except for coefficient F_σ :

$$\Delta V_p(\sigma) = A(\sigma^n - \sigma_i^n) \quad (7)$$

$$\Delta V_p(\sigma_z) = F_\sigma A(\sigma^n - \sigma_i^n) \quad (8)$$

For carbonate reservoir such investigations were carried out with three core samples of Korolev field⁷ which is satellite of Tengiz field. Carbonates behaviour is governed by the same dependences which were obtained for consolidated sandstones. Pore volume change vs effective stress relationship with one of studied samples is shown in Fig. 3. Coefficient F_σ by three analysis is 0.70. After its entering to the equation (6) and integration we obtained equation for determination of pore volume integral compressibility in reservoir conditions:

$$c_p = \phi^{-1}[1.05 \cdot 10^{-5} - 1339 \cdot 10^{-5}(\sigma_i^{-0.8} - \sigma^{-0.8}) \cdot (\sigma_i - \sigma)^{-1}] \quad (9)$$

To estimate fracturing in expansion drive, differential fracture compressibility as a function of effective compression stress experimentally obtained⁹ was used.

$$c_f^* = \frac{1}{\sigma \cdot \ln \sigma / \sigma_h} \quad (10)$$

Correspondingly, integral fracture compressibility was calculated by the following relation:

$$c_f = \frac{\sigma / \sigma_i}{(\sigma - \sigma_i) \ln \sigma / \sigma_h} \quad (11)$$

For water, experimentally obtained dependence of differential compressibility¹¹ on different factors was used:

$$1/c_w^* = m_1 + p + m_2 c + m_3 T + m_4 \quad (12)$$

where: $m_1 = 7.033$; $m_2 = 0.373$; $m_3 = 7.821$; $m_4 = 2780$

Correspondingly, integral water compressibility can be determined from the equation:

$$c_w = \frac{1}{m_1(p_i - p)} \ln \frac{m_1 p + m_3}{m_1 p_i + m_3} \quad (13)$$

where; $m_3 = m_2 C + m_3 T + m_4$

From a.m. equations it can be seen that all compressibility factors in more or less extent depend on pressure, and all of them are non-linear. When reservoir pressure decreases, c_o and c_w increase, and c_p and c_f , on the contrary, decrease. As a parameter summarizing oil, water, pore and fracture deformations it's accepted integral total compressibility c_t equal to cumulative volume of fluid outflow from reservoir bulk volume unit per unit of reservoir pressure drop $\Delta p = p_i - p$. Product of $c_t \Delta p$ equal to potential elastic storage of reservoir bulk volume unit for given p . For reservoir with double porosity, integral total compressibility can be determined from the relation:

$$c_t = c_o \phi_m (1 - S_{wm}) + c_w \phi_m S_{wm} + \phi_m c_p + c_o \phi_f (1 - S_{wf}) + c_w \phi_f S_{wf} + \phi_f c_f \quad (14)$$

Results of the calculations and discussion

Results of calculations of total compressibility for III - type reservoir rocks are shown in Fig. 4. Kind of relationship $c_t = f(p)$ varies from evenly increasing curvilinear function at the depth of 5400m to parabolic one at the depth of 3800 m. For reservoir rocks with porosity higher than 7% response to the start of oil production in the lower part of reservoir begins from minimum $c_t = 28.0 \cdot 10^{-5} \text{ MPa}^{-1}$ followed by its growth to $c_t = 42.1 \cdot 10^{-5} \text{ MPa}^{-1}$ at $p = p_s$, whereas in the upper underloaded reservoir layer depletion begins with maximum $c_t = 68.0 \cdot 10^{-5} \text{ MPa}^{-1}$ followed by reducing to minimum $c_t = 37.7 \cdot 10^{-5} \text{ MPa}^{-1}$ at $p = 47.5 \text{ MPa}$ and then again by growth to $c_t = 42.8 \cdot 10^{-5} \text{ MPa}^{-1}$ at $p = p_s$.

In spite of depletion different laws, complete potential of elastic storage (c_t at $p = p_s$) for 3800m and 5400m depths coincides. For II and especially for I rock types potential difference is more significant. In particular, for I rock type elastic storage potential at 3800m depth equals to $10.8 \cdot 10^{-5} \text{ MPa}^{-1}$, at depth of 5400m - $6.6 \cdot 10^{-5} \text{ MPa}^{-1}$. Elastic storage potential decreases with rock reservoir properties deterioration. If mean potential of elastic storage for III rock type is accepted as 100%, then for II type it equals to 54.5% and for I type - 20.3% (Table 3). Contribution of various reservoir compression energy sources for various types of rocks is different. Mean complete potential of elastic storage for III rock type is caused by oil compressibility, equal to 80%, for II type - to 63% and I type - only to 13%

Table 3

Reservoir rock types	Average complete potential of elastic storage (c_t at $p = p_s$)		Contribution in elastic storage potential, %			
	10^{-5} MPa^{-1}	%	c_o	c_w	c_p	c_f
III	42.4	100	80	<1	8	11
II	23.1	54.5	63	2	15	20
I	8.6	20.3	13	10	37	40

Share of residual water compressibility in reservoir elastic storage potential for III rock type is less than 1%, for II type is 2% and only for I type it increases to 10%. In spite of small volume, due to high compressibility, fractures may be of great importance in generation of elastic storage potential. For all three rock types share of fractures is more than share of pore volume. Fracture compressibility in conjunction with pore compressibility is dominating for I rock type.

Drainable and undrainable matrix blocks

To estimate in what extent reservoir elastic storage potential, determined by equation (14), can be actually realized, reliable information about matrix permeability is first priority. However, analysis of core from this non-standard formation with exclusively low permeability was carried out per standards and methods obtained in studying normal highly permeable reservoirs. Most of laboratories analysing Tengiz oil field cores, including⁸, used standard devices not allowing to measure permeability less than 10^{-17} m^2 . Therefore, in data bank on core physical properties of reservoir for many specimens of II and III reservoir types permeability is designated as " $<10^{-17} \text{ m}^2$ " or "impermeable" mark. In 1991 we have conducted control repeated estimations of core samples with "impermeable" mark, received from other laboratories. As an example, Fig. 5 shows measured results for such specimen which is of III reservoir type by porosity. The usage of devices with higher sensitivity the sample is found to be permeable. In hydrostatic stress under 1.0 MPa its gas permeability as a function of average sample pressure decreases from $24 \cdot 10^{-20} \text{ m}^2$ to $4.2 \cdot 10^{-20} \text{ m}^2$ (slippage correction for helium 0.774 MPa). Effective permeability of specimen at reservoir conditions will be obviously less and may amount to not more than 10^{-21} m^2 .

Permeability-effective stress relation, $k = f(\sigma)$, remains poorly studied for Tengiz field conditions. Fig. 6 shows measurement data for specimen 92-2704 similarly from collection with "impermeable" mark of 8.1% porosity. Permeability was determined under 5 different effective stresses. As σ increases from 5 to 50 MPa, permeability decreases from $41.4 \cdot 10^{-19} \text{ m}^2$ to $1.3 \cdot 10^{-19} \text{ m}^2$. Matrix permeability presented by this specimen in reservoir conditions can not exceed 10^{-21} m^2 . Results of control tests give the reason to suppose that some differences of carbonate rocks classified as II and III reservoir types by porosity, can have permeability in reservoir conditions up to 10^{-22} m^2 . Release of elastic energy from matrix block

with such ultralow permeability under pressure decrease in fracture system will be sluggish, and quantitative value of this process is of practical interest.

Reservoir with double porosity is schematized either as cubes or strata model. Release of matrix single block elastic storage after reservoir pressure decrease in fractures is a non-stationary process. For its analytical description exponential approximation function of inflow from single block $q(t)$ can be used.

$$q(t) = \eta \cdot \alpha \cdot e^{-\eta \alpha t} \quad (15)$$

where parameter " α " characterizing block geometry can be determined from relation¹¹:

$$\alpha = 60 / h_b^2 \text{ (cubes)}, \alpha = 15 / h_b^2 \text{ (strata)}$$

The equation (15) is corresponded to a unit-step pressure change of the surface of the blocks. By means of integrating equations (15) find function of cumulative up inflow from block $Q(t)$:

$$Q(t) = 1 - e^{-\eta \alpha t} \quad (16)$$

For quantitative estimation of the process introduce the concept of elastic storage semi-depletion periods $t_{0.5}$ by analogy with known concept of semi-decay period in nuclear physics which is the time when elastic storage for set pressure drop halves in comparison with initial one and determined from relation:

$$t_{0.5} = \ln 2 / \eta \alpha \quad (17)$$

For double-porosity reservoir $t_{0.5}$ is directly proportional to block thickness squared and inversely proportional to matrix permeability. Specifically, for strata model of rock type III at $c_f = 23 \cdot 10^{-11} \text{ Pa}^{-1}$.

$$t_{0.5} = 2.13 \cdot 10^{-15} h_b^2 / k \quad (18)$$

In accordance with results of calculations (table 4) blocks with $h^2/k \geq 10^{23}$ are evidently not drainable and they should be excluded from net volume of reservoir.

Table 4

Block thickness, $h_b, \text{ m}$	Matrix block permeability, $K, \text{ m}^2$	Parameter h_b^2	Elastic storage semi-depletion period, $t_{0.5}$	
		K	seconds	years
1	10^{-20}	10^{20}	$2.13 \cdot 10^5$	0.007
1	10^{-22}	10^{22}	$2.13 \cdot 10^7$	0.675
10	10^{-20}	10^{21}	$2.13 \cdot 10^6$	0.068
10	10^{-22}	10^{23}	$2.13 \cdot 10^8$	6.75
100	10^{-18}	10^{22}	$2.13 \cdot 10^7$	0.675
100	10^{-20}	10^{24}	$2.13 \cdot 10^9$	67.5

More definite division of matrix blocks on drainable and undrainable is difficult because of a lack in the first place of core permeability survey in the region of $K < 10^{-15} \text{ m}^2$. At fields of Tengiz type range of matrix permeability determination in reservoir conditions should be expanded to minimum 10^{-20} m^2 (0.00001 md).

Conclusion

1. For high oil column fields containing volatile oil and having large difference between initial reservoir pressure and saturation pressure, instead of some commonly used average parameters of fluid and rock compressibility, their non-linear functions of pressure and depth should be used that significantly improves recovery prediction by expansion drive above the bubble point.
2. It is suggested to use concept of fluids and rock differential and integral compressibility in description and estimation of strain processes in fluid-rock system.
3. Elastic drive being the most active in natural oil recovery mechanism for dense carbonate reservoirs can not ensure 100% drain of reservoir volume and full realization of complete elastic storage potential.
4. It is suggested to use geometric-filtration parameter h^2/k , by values of which double porosity reservoir matrix block can be divided into drainable and non-drainable.
5. At fields of Tengiz type range of matrix permeability determination in reservoir conditions should be expanded to minimum 10^{-20} m^2 (0.00001 md).

Nomenclature

A	= coefficient of fit in Equation (6) and (7)
C	= salinity, g/l
c^*	= differential compressibility, MPa ⁻¹
c	= integral compressibility, MPa ⁻¹
f	= function
F_σ	= hydrostatic to uniaxial correction factor
h	= thickness, m
k	= permeability, m ²
m	= constant
n	= exponent
p	= pressure, MPa
p_s	= bubblepoint pressure, MPa
$\bar{p}$	= average pressure, MPa

S	= saturation
T	= temperature, °C
t	= time, s
$t_{0.5}$	= semi-period of depletion
V	= volume, m ³
α	= geometrical parameter of matrix blocks
η	= diffusivity, m ² /s
σ	= effective stress, MPa
σ_h	= apparent healing stress, MPa
ε	= strain
ϕ	= porosity
$q(t)$	= function outflow, m ³ /s
$Q(t)$	= function cumulative outflow, m ³

Subscripts

b	= matrix block
f	= fracture
i	= initial
m	= matrix
o	= oil

p	= pore
t	= total
w	= water
x, y	= lateral or horizontal coordinate
z	= axial or vertical coordinate

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Fig1. Differential and integral oil compressibility for Tengiz field vs reservoir pressure at T=123 °C

Fig.2 Differential oil compressibility for Tengiz field vs reservoir pressure

Fig3. Pore volume change vs effective stress for Korolev oil field, well 13, core sample depth 5032 m, $\Phi=10.6\%$ $K=0.65 \cdot 10^{-15} \text{ m}^2$

Fig4. Integral total compressibility vs reservoir pressure for III type reservoir rocks of Tengiz oil fields at depths of 3800 m and 5400 m

Fig.5 Gas measured permeability K_g vs reciprocal of mean pressure P for core sample AZ - 779 of Tengiz oil field

Fig6. Permeability vs effective stress for sample N 92-2704 of Tengiz oil fields