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CHEMICAL PROPERTIES OF RESERVOIRS, OIL AND GAS OF KASHAGAN FIELD, SOUTHERN PART OF PRE-CASPIAN DEPRESSION, KAZAKHSTAN

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ABSTRACT

Kashagan field is one of the largest oil fields discovered in the last 30 years. It is a large, isolated carbonate bank, one of the biggest buildups in an archipelago that characterized the Pre-Caspian Basin from the Devonian to the Carboniferous and that now hosts large hydrocarbon reserves. Three new wells were drilled in East Kashagan (KE-4, KE-6, KE-A-01), another three are being drilled (KE-A-02, KE-A-03, KE-5-01) and reservoir properties[1].

Key words: Oil, Gas, Chemical properties, Kashagan field, Kazakhstan.

INTRODUCTION

Kashagan field is situated in the southern part of Pre-Caspian depression in the Southern flung of Astrakhan-Aktyubinsk elevation system of basal complex and associated with Tengiz-Kashagan interbasin carbonate platform (Fig. 1). The platform is composed of separate carbonate early Carboniferous blocks resting on the common Devonian (late Fransian-Fammenian) carbonate base. Four of them are: Kashagan, Kashagan South-West, Aktote and Kairan are located on the Caspian shelf and Karaton, Tengiz and Korolev on the coastal line of the eastern Caspian. Depositions of Devonian through to Elephantine inclusive were penetrated in Kashagan. The maximum section penetrated during drilling was 5172 m in KE-1. Pre-salt and post-salt units separated by thick Kungurian of Lower Permian salt-bearing section were identified in the well log. The pre-Caspian basin has been formed from Paleozoic to Cenozoic time and the Kashagan field is situated in the southern part of

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Pre-Caspian depression in the Southern flung of Astrakhan-Aktyubinsk elevation system of basal complex and associated with Tengiz-Kashagan interbasin carbonate platform[1].

Fig. 1: Map of the area

Chemical properties of fluid in reservoir

During the studies of Kashagan field (after the completion of KEPDS) a series of test was carried out based on the data from KE-6 and KE-A-01. The results of these analyses allowed updating physical and chemical properties of the fluids. For further study more drilling data, sample collection and analyses of the fluid from new wells, especially in the western area, are required for the objective evaluation of oil and gas properties and the update of the fluid model.

Oil properties in reservoir conditions

The analyses of the fluid samples in reservoir conditions were carried out according to the internal methodology of Pencor, Petrotech, Oil phase, EXPRO, TOTAL FINA ELF, DBR based on the recommendations of SPE and API, as well as OST 39112-80. It should be noted, that the bulk of the analyses of the fluid in reservoir conditions was conducted by EXPRO and Pencor. As per the analysis results oil saturation pressure at reservoir conditions in the investigated part of the field is 26.06-29.10 MPa. Oil has a high compressibility factor ranging from 25.3E-4 to 38.8E-41/MPa. The initial reservoir pressure (Pres init) exceeds the saturation pressure (Ps) by 50 MPa which ensures long-lasting stable production of the field.

Oil specific gravity at initial PVT conditions varies within 574-619 kg/m^3, and viscosity is 0.1-0.37 мPa.s. Similar to the gas condensate systems to achieve a correct match of the gas phase from the reservoir oil gaseous HC and non-HC components (He, H_2, H_2S, CO_2, N_2, C_1-C_4) were identified and re-calculated by 100%[2].

Table 1 shows gas composition by components. Analysis of the distribution of the physico-chemical properties across the field by depth shows that there is no significant difference in the fluid and no clear variation trend of properties or composition of the fluid under the conditions of the massive deep reservoir. This phenomenon is accounted for by relatively light composition of oils which are characterized by minimum content of resin, asphaltenes and high yield of light components with low boiling temperature determining relatively low density of oils. Thus the increase of the temperature with depth to some degree hampers the gravitational effect by means of component concentration levelling in the process of thermal molecular agitation. In addition, multidirectional effect of temperature and pressure in a thick reservoir is compensated to a certain degree and this determines a relatively constant density, viscosity and reservoir oil FVF values across the section of the field.

Thus, with the present knowledge of the fluid oil system of Kashagan, there is no need in differentiated approach to the reservoir fluid evaluation parameters. Consequently, the averaging of reservoir and separator oil values across the entire oil bearing reservoir with future adaptation of the PVT model to the results of laboratory four stage separation tests, CCE and gas injection into oil is an option under consideration. The parameters of reservoir oil are different despite similar separator oil density. According to the KW-1 sample analysis there is a trend of gas content increase which leads to the FVF rise and variation of other reservoir oil parameters in the western part of the field (Table 2). Reservoir and separator oil parameters were defined by means of the phase equilibrium calculations using the programme “Total Best”. This programme based on the input PVT conditions, composition and properties of reservoir fluid pseudo-components enables to calculate all interrelated oil parameters in reservoir conditions with depth and also allows modeling variation of properties and phasing composition in various types of separation (flash, multi-state separation, and CCE, CVD and gas injection)[2].

The world’s practice of study of deep reservoir volatile oils shows that the separation test provides the most reliable data on evaluation parameters because flash test and differential evaporation overestimate the values of density, gas content and FVF. The current report uses four stage separation results as evaluation parameters because that is the separation scheme used on the field.

- Stage I (P = 9.60 MPa, t = 70°C)
- Stage II (P = 3.00 MPa, t = 60.0°C)
- Stage III (P = 0.85 MPa, t = 52.0°C)
- Stage IV (P = 0.1 MPa, t = 15.6°C)

Three samples from KE-5, KE-6 (DST-1) and KE-6 (DST-2) analyzed under the above separation conditions in EXPRO were used as actual data. Therefore, the current EOS8 (2004) model could be used to evaluate the parameters and forecast the evolution of properties. EOS8 (2004) calculation results for the weighted average depth – 4300 m at the initial reservoir pressure 77.72 MPa and reservoir temperature 100°C produced the following evaluation parameters for the entire field after conversion to the standard temperature of 20°C[3].

- FVF – 2.173
- Separator oil density – 799.2 kg/m^3
- GOR – 642.6 m^3/t

Deviation from the test data are within the range of 0.3 – 1.6 % (Table 2).

Oil and gas composition and properties in stock tank conditions

Oil class

Based on the sulphur content (0.68 – 0.90 mass %) Kashagan oil belongs to Class II and is considered to be sour. The average concentration of sulphur is 0.77 mass %.

Oil type

1. Density at 20°C. The crude oil density varies from 796.8 to 812.4 kg/m^3. As per the average density, it is classed as extra light, type 0.
2. Fractional yield. Volume fractional recovery at the temperature up to 200°C varies from 23.0 to 47.75 vol. %, averaging to – 38.1 vol. %, up to 300°C – 57-69.16 vol. %, averaging to – 67.5 vol. %. According to the fractional yield Kashagan oil is classed as type 0.
3. Paraffin content. Paraffin mass fraction varies from 1.75 to 4.60 mass %, averaging to 3.04 mass % and does not exceed the established limit (under 6%).

Oil group

1. Water. Water mass fraction varies from 0.01 to 0.2%, averaging to 0.1% which does not exceed the established limit (under 1%). By water content Kashagan oil belongs to Group I[3].
2. Chlorine salts. Chlorine concentration varies from 8 to 163.7 mg/dm^3, averaging to 42.91 mg/dm^3, which is within the set limit (fewer than 900 mg/dm^3).

According to sulphur content Kashagan oil belongs to Class II with the concentration in the range of 0.68 – 0.90 mass% and is sour. The average sulphur content – 0.77 %. H_2S content varies between 7.75% and 30% averaging to 17.5 %, the content of mercaptan in fractions 640 g/m^3. By density Kashagan oil is Type 0 (under 812.4 kg/m^3) and is classed as extra light. By chlorine content Kashagan oil belongs to Group I (under 100 mg/L). Average chlorine content – 42.91 mg/L. Average vapour pressure of Kashagan oil is 346 mm mercury column which lies within the required level (< 500 mm mercury column). According to the regulations, it is paraffinic oil with paraffin content 1.75 – 4.6 %. Mass fractional yield of light ends during distillation at fewer than 300^{o}C is 57 – 69.16 mass %.

3. No solids.

In accordance with the requirements of the state standard the Kashagan oil:

(i) For sale to consumers in Kazakhstan, is characterized by the following mean values: mass percentage of sulphur: 0.77 % (Class 2); density at 20^{o}C: 804.4 mg/dm^3; concentration of chlorous salts 42.91 mg/dm^3; mass percentage of water: 0.1 % (Group 1) and, where hydrogen sulphide is present in 17.5 %, it is designated as 2.0.1.1 GOST R 51858-2002.

(ii) For export sale, it is characterized by the following mean values: mass percentage of sulphur: 0.77 % (Class 2); density at 20^{o}C: 804.4 mg/dm^3; volumetric percentage of the fractions up to 200^{o}C: 38.1 %, up to 300^{o}C: 67.5 %, mass percentage of wax: 3.04 % (Type 0e), concentration of chlorous salts 42.91 mg/dm^3; mass percentage of water: 0.1 % (Group 1) and, where hydrogen sulphide is present in 17.5 %, it is designated as 2.0e.1.1 GOST R 51858-2002.

Shell and Expro labs conducted special tests on determination of asphaltene content in wellhead and bottomhole samples. Results of the tests show that in the eastern part of the Kashagan field the asphaltene content varies from 0.03 to 1.03 mass % and from 0.41 to 0.61 % mass % in pentane and from 0.11 to 0.15 mass % in heptanes; in the western part of the field (KW-1 well) concentration of asphaltenes is < 0.05 mass %. On the whole, the analyzed Kashagan dead oils are characterized as light, low viscous, sulphurous, paraffinic, and low resinous, with high mercaptan concentration.

Average weighted gas composition evolved from the reservoir oil under 4-state separation test (Table 1) is characterized by high hydrogen sulphide concentration from 17.7 to 18.1 mol. % and methane from 58.66 to 58.83 mol. % and is wet, highly sulphurous, carbon oxide, low nitrogen. Mean molar concentration of the gas components is as follows: hydrogen sulphide, 17.81%; carbon dioxide, 5.08%; nitrogen, 1.01%; methane, 58.77%; ethane, 9.01%; propane, 4.54 %; butane, 2.29 %; C5$^+$, 4.23 %. Concentration of C5$^+$ in the gas dissolved in oil is 60 g/m^3. Gas density at 20ºC is 0.807 kg/m^3, relative density 0.6699, molar mass, 19.26 g/mol. By technical classification, the gas is flammable and characterized by highest heating capacity at the level of 37731 and 41468 kJ/m^3, respectively.

Table 1: Gas composition by components, average weighted composition and properties of the evolved gas phase during all stages of the separation test

Well	**KE-5**	**KE-6**	**KE-6**	**Mean value**	**EOS-2004-E by separation test No. 1**	**Experimental deviation, %**
Age	C1t (II)	C1V2	C2b			
Test	DST # 1	DST # 1	DST # 2			
Sample type	BH	WH	WH			
Sampling date	12-16.11.02	27.11.03	18.04.03			
Cylinder	PT-20K029	PT-12K02	PT-12K09			
Sample number	1.73	1.11	2.10			
Mid interval TVDSS	-4491	-4168	-4034			
Component	**Mol.%**	**Mol.%**	**Mol.%**	**Mol.%**	**Mol.%**	**Mol.%**
N_2	1.02	0.96	1.04	1.01	1.15	0.14
CO_2	5.06	5.09	5.09	5.08	5.10	0.02
H_2S	17.69	18.09	17.65	17.81	18.18	0.37
C1	58.83	58.66	58.81	58.77	58.73	0.04
C2	9.10	8.98	8.96	9.01	8.89	0.12
C3	4.69	4.43	4.49	4.54	4.12	0.42
i-C4	0.76	0.76	0.77	0.76	0.83	0.06
n- C4	1.52	1.53	1.53	1.53	1.86	0.33
i- C5	0.45	0.47	0.47	0.46	0.14	0.33
n- C5	0.40	0.42	0.42	0.41	0.14	0.27

Cont…

Component		**Mol.%**	**Mol.%**	**Mol.%**	**Mol.%**	**Mol.%**	**Mol.%**
Pseudo C6		0.30	0.35	0.36	0.34	0.22	0.12
Pseudo C7		0.13	0.17	0.19	0.16	0.29	0.13
Pseudo C8		0.04	0.06	0.09	0.06	0.28	0.22
Pseudo C9		0.01	0.02	0.03	0.02	0.02	0.00
Pseudo C10		0.00	0.00	0.02	0.01	0.02	0.01
Pseudo C11		0.00	0.00	0.01	0.00	0.01	0.01
Pseudo C12$^+$		0.00	0.00	0.06	0.02	0.03	0.01
Total		**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**%**
Gas density	(Air- 1.000)	0.8775	0.8817	0.8865	0.8819	0.8623	2.7
20^{o}C	kg/m^3	1.0571	1.0621	1.0679	1.0624	1.0387	2.7
Mole mass 4	g/mol	25.16	25.29	25.43	25.29	25.32	0.4
Heat value							
Max	kJ/m^3	41388	41418	41597	41468	41167	1.0
Min	kJ/m^3	37655	37686	37851	37731	37454	1.0
Pentane + at 20^{o}C							
Mole mass	g/mol	77.3	78.3	79.5	82.79	96.5	-21.4
Density	kg/m^3	652.4	658.7	672.3	662.1	668.5	0.6
Content	g/m^3	42.5	48.5	54.8	51.3	46.1	16.0

Amine corrosion

Amine is used to remove H_2S and CO_2 from hydrocarbon gas. Amine solutions are generally referred to as fresh, lean or rich, denoting zero, low or high concentrations of absorbed acid gas in solution. In the absence of amine breakdown product (heat stable salts), lean amine solutions are not corrosive to carbon steel, at flow velocities below 2 m/s and at temperatures below ~90^{o}C. However the flow velocity for rich amine solutions should be restricted to 1 m/s to avoid high corrosion rates. Above 90^{o}C, corrosion depends on amine (type and concentration) and acid gas H_2S and CO_2 partial pressure.

Alkaline corrosion

Sodium hydroxide solutions can cause alkaline stress corrosion cracking of carbon steel, depending on their concentration and temperature. Seawater corrosion (Offshore facilities only). Sea water intake will be present on Block D only[4].

Table 2: Kashagan reservoir oil parameters based on separation test results

		Test				Model (8 component)				Test	Model (8 component)			
Well		KE-5	KE-6	KE-6		Meat based on test	EOS-2004-E based on separation test No. 1		Experimental deviation, %	KW-1	(EOS-2005W based on separation test No. 2	Experimental deviation, %	EOS-2005- based on separation test No. 1	
Age(Unit)		II	C1V2	C2b						C2b				
Test type and No.		DST#1	DST#1	DST#2						DST#1				
TVDSS depth		-4491	-4168	-4034						-4382				
Sample type		BH	WH	WH						BH				
Sample No.		1.73	1.11	2.10						1.05				
By		Expro	Expro	Expro						Expro				
Report No.		4014	4147	4148						3590				
Parameters	**Unit**													
Standard temp.	^{o}C	15.6°C				20°C	15.6°C	20°C		15.6°C			15.6°C	20°C
FVF		2.23	2.20	2.204	2.211	2.208	2.176	2.173	1.6	2.542*	2.51*	1.3	2.444	2.440
GOR	m^3/m^3	516.0	510.0	505.0	510.3	517.3	506.7	513.6	0.7	615.0	615.4	0.1	618.1	626.5
	m^3/t					644.8	633.0	642.6	0.3					787.6
Separator oil density	kg/m^3	801.7	805.0	804.0	803.6	802.3	800.5	799.2	0.4	815.7	798.5	2.1	796.8	795.5

It will be made up of the following components: sea water charge pump, service water feed pump and sea water lines. Water/foam fire fighting system is made up of the following main components: firewater pumps, jockey pumps, fire water piping, foam skid and firefighting network underground piping. Corrosion concerns are related to oxygen corrosion, galvanic effects, MIC, localized corrosion (pitting and crevice), chlorides stress corrosion cracking. Estimated corrosion rate, with reference to carbon steel, is in the order of 0.2-0.5 mm/y. The inner side of the caissons and the outer side of the pumps column shall be protected with coating and cathodic protection with sacrificial aluminum anodes located on the pump column. The outer side of the caisson shall be protected with coating and cathodic protection with sacrificial aluminum alloy anodes. Galvanic corrosion between superduplex and coppernickel pipe shall be avoided by use of electrical insulation kit or lined spool. All equipments of the sea water system are either superduplex SS type 2507, Nickel-Aluminum Bronze ASTM B148 or Monel 400. The piping is specified as Cupronickel 91/10.

Hydrogenation section

Tail gas consisting mainly of nitrogen and water with small amounts of H_2S, SO_2, CO, CO_2, H_2 and fuel gas enters the Reducing Gas Generator at 175°C. This is well above the aqueous dew-point and permits the use of CS + 3 mm CA, because dry gas is not corrosive. The Reducing Gas Generator's firing chamber and stack are refractory lined carbon steel, to resist high combustion temperatures generated at the burner. Carbon steel is selected for the line from the reducing gas generator to the Hydrogenation Reactor, because the partial pressure of H_2S is too low to cause severe corrosion, even at 330°C. An exothermic reaction occurs in the Hydrogenation Reactor. The shell therefore is lined with refractory in order to handle, with certainty, occasional temperature excursions, of up to 530°C maximum, from the normal operating temperature of about 400°C.

Metal temperatures of the Reactor Effluent Cooler are less than 300°C, below which sulfidation is insignificant, the metal temperatures are also above the aqueous dew-point of the gas (~80°C). LTCS is suitable for these components and for the inlet line into the Contact Condenser.

Gas cooling section

The Tail Gas from the Reactor Effluent Cooler of the Sulfur Recovery Unit contains approximately 1.5 mole % H_2S, 1.9 mole % CO_2 and also 36 mole % H_2O vapor. However, the operating temperature is sufficiently above the water dew-point to guard against the risk of corrosion. LTCS with a 3 mm corrosion allowance is therefore specified for the line to the Contact Condenser. The hot gas entering the Contact Condenser is rapidly cooled (quenched) by the counterstream of water which is dosed with caustic to control the pH to 6 to 7.

Experience has shown that corrosion in the Contact Condenser can occur at hot spots near the inlet, and also in the cooler upper section, due to desorption of wet acid gas from the water. LTCS with 6 mm corrosion allowance is therefore specified for the column. The Tail Gas Contact Condenser has been classed as wet H_2S service because the H_2S partial pressure in the top of the vessel is 0.025 bara and conditions are wet, and for this reason, the shell must be stress relieved.

Absorber

The offgas from the contact condenser contains 88% nitrogen with small amounts of H_2S and CO_2 (2.3 mole % and 2.8 mole %, respectively). This gas is fed to the DEA absorber, in which most of the H_2S and CO_2 are absorbed by the amine solution to form "rich amine". At 52°C the H_2S mitigates LTCS corrosion in amine solutions containing CO_2. In view of these mildly corrosive conditions, the absorber shell is LTCS 3 mm CA, but post weld heat treated as a precaution against alkaline stress corrosion cracking by the amine solution. It is also necessary to PWHT lean and rich amine pipework welds.

There is very little H_2S (0.0165% or 165 ppm) in the overhead line from the absorber. However, the partial pressure of CO_2 is low at 0.023 bara. At 40°C LTCS is corroded only at 0.1 mm/y, a low rate.

Thermal oxidizer

The treated effluent gas from the Absorber is incinerated in the thermal oxidizer to destroy combustible constituents and convert residual H_2S to SO_2 before being vented to atmosphere. The firebox of the thermal oxidizer, the stack and interconnecting piping are refractory lined carbon steel to resist the high temperature of 650°C. The thermal oxidizer super-heater is required to operate at 725°C maximum. To resist oxidation and provide adequate service life (100,000 hours) at this tube metal temperature, the heat exchange tubes should be specified in 304 H stainless steel (ASTM A213 S30409) with corrosion allowance of 1.5 mm.

CONCLUSION

The Kashagan oil field is one of the largest oil fields discovered in the last 30 years. The field of 820 km^2 belongs to Atyrau region and is situated in the Northeast sector of the Kazakhstan part of the Caspian Sea. The well first to discover oil in Kashagan was KE-1, which produced commercial oil flow from the pre-salt carbonate deposits during the well test. Kashagan is Kazakhstan's largest offshore hydrocarbon field with a potential of 38 billion barrels of oil. Average weighted gas composition evolved from the reservoir oil under 4-state separation test is characterized by high hydrogen sulphide concentration from 17.7 to 18.1 mol. % and methane from 58.66 to 58.83 mol. %, and is wet, highly sulphurous, carbon oxide, low nitrogen. Mean molar concentration of the gas components is as follows: hydrogen sulphide, 17.81%; carbon dioxide, 5.08%; nitrogen, 1.01%; methane, 58.77%; ethane, 9.01%; propane, 4.54%; butane, 2.29%; $C5^+$, 4.23%. Concentration of $C5^+$ in the gas dissolved in oil is 60 g/m^3. Gas density at 20^oC is 0.807 kg/m^3, relative density 0.6699, molar mass, 19.26 g/mol. By technical classification, the gas is flammable and characterized by highest heating capacity at the level of 37731 and 41468 kJ/m^3, respectively.

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