

Compositional Simulation of Gas Condensate Wells from Tintea – ASTRA Field

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Abstract: The main aim of this article is to simulate the performance of gas condensate wells utilizing a compositional model. The compositional simulation model is done for available data of three drilled wells A, B, and C of this field. P-T diagrams of wells A, B, and C of various critical pressures and temperatures, and various cricondentherm, and cricondenbar are constructed. Results show that composition significantly varies as a function of fluid phase behavior and producing sequence; condensate recovery can be improved with proper producing strategy, and productivity loss can be reduced by changing the producing sequence. Additionally, well A yields the liquid phase (gasoline with condensation traces) due to the present of C7 + C8 components in the mixture starting with the exit of the gases from the choke and up to the separator. However, wells B and C do not yield the liquid phase along the entire tubing path traveled by the extracted gases from the producing zone to the heater of the wells B and C.

Keywords: Compositional simulation, thermodynamic properties, gas condensate, P-T diagram

1. Introduction

Gas reservoirs are classified into dry gas, wet gas, and gas condensate reservoir depending on the gas composition along with temperature and pressure at which the accumulation exists [1-4]. Gas condensate reservoirs are considered one of the important sources of hydrocarbon reserves. The term "retrograde" means that liquid phase condenses in the reservoir as pressure reduces below dewpoint at constant temperature. The retrograde condensation region is formed only at temperatures between the critical point and cricondentherm on the phase diagram of the gas condensate reservoirs. This liquid phase has usually zero or very low mobility except near well. Producing both gas and condensate liquid at surface is occurred in gas condensate reservoirs [1-5]. These kinds of reservoirs have the following properties [1-4]: gas/liquid ratios of approximately 3-150 MCF/STB (Millions Cubic Foot/ Stock Tank Barrel), or condensate surface yields ranging from 7 to 333 STB/MMCF, stock tank liquid gravity of 40 – 60 API, liquid color of lightly colored, brown, orange, greenish or water white.

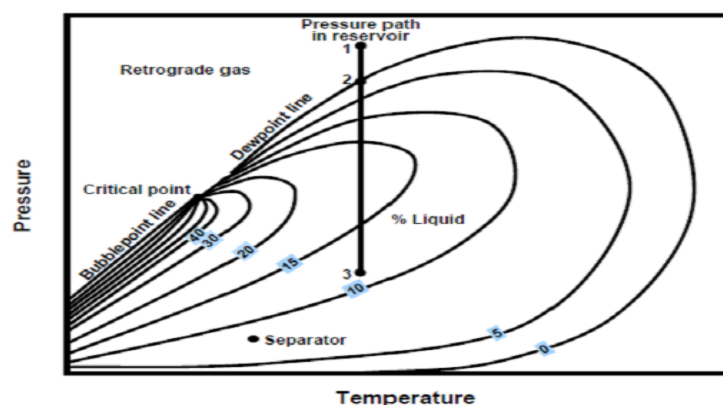


Figure 1. Phase diagram of a typical retrograde gas condensate [3]

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The phase diagram of a gas condensate system has a critical temperature lower than the reservoir temperature and a cricondentherm point greater than the reservoir temperature (Fig.1). The gas condensate reservoir is initially gas at the reservoir condition, point 1, and as the reservoir pressure declines below the dewpoint, point 2, liquid condenses from gas and forms a “ring” or “bank” around the producing well in the near-well region [5].

Flow regions are classified into three main regions while the condensate reservoir fluids are flowing towards a producing well, during depletion as follows [6].

- Near well region 1. An inner near-well region where the reservoir pressure declines further below the dewpoint pressure, the critical condensate saturation is surpassed, and part of the condensate buildup becomes mobile. The mobility of the gas phase is greatly impaired due to the existence of the liquid phase.

- Condensate buildup region 2. A region where the reservoir pressure drops below the dew point, and the condensate drops out in the reservoir. However, the accumulated condensate saturation is not high enough for the liquid phase to flow. Therefore, in this region, the flowing phase still contains only the single gas phase, and the flowing gas becomes leaner as the heavier component drops into the reservoir.

- Single-phase gas region 3. A region that is far away from the well and has the reservoir pressure higher than the dew point, and hence only contains single phase gas.

A significant part of the income of a field may come from the surface condensate (Liquid) production. The additional economic value of produced condensate liquid, along with gas production, makes the condensate recovery a key consideration in the gas condensate reservoirs' development. Consequently, the demand for a compositional simulation for the gas condensate reservoirs and their drilled wells became extensively beneficial. Black-oil models are often used to simulate gas condensate wells. However, this study simulates the gas condensate well with a compositional simulation model, and a pseudoization procedure that diminishes the multicomponent condensate fluid to a pseudo-component. The pseudoization permits a simpler, less expensive use of the compositional simulation.

This paper work is focused on the composition variation aspects of gas condensate flow. The objective of this article is to study how the compositions alteration of heavy components of a gas condensate system effects on the producing wells during depletion, and how the rate of the composition variation influences the fluid thermodynamic properties and, hence, defining the dynamic phase diagram of the fluid in the reservoir. This work is essential to investigate ways to optimize wells productivity by controlling the liquid composition that drops out near wells and optimizing the producing pressure strategy in order to avoid a lighter liquid to be condensed in the reservoir and loss productivity.

In order to implement the compositional simulation of gas condensate wells; equation of state, equilibrium flash calculations, flow behavior of gas condensate systems, gas condensate flow modeling, thermodynamic properties, and wells pressure distribution calculations should be introduced and discussed.

2. Materials and methods

Equation of State (EOS). The chronological order of EOS, which is used for simulating laboratory PVT data, is:

1. van der Waals
2. Redlich-Kwong
3. Soave-Redlich-Kwong EOS and its modification
4. Pen-Robinson EOS and its modification

The most suitable one will be selected during performing study. Details of the preceded EOS are presented by several reservoir engineering textbooks [1-4,12].

Equilibrium flash calculations. The importance of flash calculations appears in compositional

simulation of a gas condensate reservoir in order to estimate percentages of liquid and vapor with changing temperature and pressure. Flash calculations are presented by several articles and handbooks. Therefore, in order to review the flash calculation, details calculations presented by Lyons [1], Tarek [2], McCain [3], Smith [4], Tiab et al. [7], and Ikoku [12] are taken into account. Consider 1 mole of a fluid composition $Z_1, Z_2, Z_3, Z_4, \dots, Z_n$ which divides at some pressure and temperature (P, T) into L moles of liquid of composition $x_1, x_2, x_3, x_4, \dots, x_n$ and V moles of vapor composition $y_1, y_2, y_3, \dots, y_n$. Then,

$$L + V = 1 \quad (1)$$

$$L \cdot x_i + V \cdot y_i = Z_i \quad (2)$$

$$\sum_{i=1}^n x_i = \sum_{i=1}^n y_i = \sum_{i=1}^n Z_i = 1 \quad (3)$$

By definition, the K -value of the i^{th} component is expressed as:

$$K_i = \frac{y_i}{x_i} \quad (4)$$

And as a result, the expressions of x_i and y_i are as follows:

$$x_i = \frac{Z_i}{1 + V \cdot (K_i + 1)} \quad (5)$$

$$y_i = \frac{K_i \cdot Z_i}{1 + V \cdot (K_i + 1)} \quad (6)$$

Generally, the total mole composition (Z_i) and either the pressure or the temperature and the vapor mole fraction ($V=0$) at the bubble point or $V=1$ at the dewpoint are known. At the thermodynamic equilibrium, fugacities of the component in the liquid and vapor phase must be equal: $f^L = f^V$ which can be used to solve the n K -values.

Flow behavior of gas condensate systems. In order to analyze the flow behavior of a gas condensate system, it is important to recognize the difference between the values of static and flowing properties. The static values represents in situ fluid properties determined at a certain reservoir location at a given time, while the flowing values represents the properties of the flowing fluids [5, 8-11]. In reservoir simulations, static values indicate the property values of a given grid block and time. However, the taken samples at the wellhead flowing phase are represented the laboratory experiments and field sampling cases. Therefore, the compositions of the wellhead samples are not the same as the total compositions in the reservoir or reservoir simulations static values, although they may point out the changes of flow property variations in the reservoir [5, 8-11]. In order to perform flow behavior of gas condensate system, the fluid is examined primarily using:

- Constant Composition (Mass) Expansion (CCE/CME), also called flash vaporization to obtain the dewpoint and Constant Volume Depletion (CVD) to simulate reservoir production behavior.
- Differential Condensation (DC) to investigate the composition variation at the wellhead.
- Flow regions identification

Details of flow behavior of gas condensate system, CEE, DVD, DC, and flow regions are presented by [1-5]

Gas condensate flow modeling. The behavior of compositional variation in the reservoir and wells were studied through experimental, theoretical and numerical simulation research. The general mathematical models of theoretical compositional variation to describe dynamic condensate problems in both 1D linear flow and 3D radial flow in the porous media are deduced from the following general equation for multi-components, multiphase convection as follows [5,8-11]:

$$x_i = \frac{\partial z_i}{\partial z_i} = A_i \cdot \frac{\partial p}{\partial t} + B_i \cdot \left(\frac{\partial p}{\partial t} \right)^2, \quad i = 1, n_c \quad (7)$$



$$\text{where } A_i = \left(\frac{m_i}{m} - z_i \right)^2 \frac{\delta \ln G}{\partial p}, B_i = \frac{m_i}{\phi G} \frac{\partial}{\partial p} \ln \left(\frac{m_i}{m} \right), m_i = \sum_{j=1}^n x_{ij} \rho_j \frac{k k_{rj}}{\mu_j}, G_i = \sum_{j=1}^n x_{ij} \rho_j S_j, i = 1, n_c$$

Where ϕ is the porosity of the porous media, k and k_r are referring to the permeability and the relative permeability for the porous media, S_j is saturation of phase j , ρ_j is the molar density of phase j , x_{ij} is the mole fraction of component i in phase j , G_i is an overall molar density of component i , and m_i an overall mobility of component i weighted with component molar density. Both A_i and B_i are functions of relative permeability, viscosity, pressure and PVT properties. During the production from gas condensate reservoirs, the reservoir pressure and the fluid composition are changing with time and distance as shown in equation 7. For a constant bottom well flowing pressure ($\partial p / \partial t = 0$), the only pressure gradient is utilized to determine the compositional change rate. Furthermore, for low k , the pressure gradient is typically great around the wellbore, and hence the fluid composition significantly varies around the wellbore as well. On the other hand, the pressure gradient is usually small away from borehole and fluid composition is basically determined by solving the time derivative of pressure ($\partial p / \partial t \neq 0$). The theoretical models can be used to isolate and investigate certain parameters which influence the compositional variation of the heavy components with time in the near-well region during depletion. The effects of relative permeability, fluid type and pressure on condensate banking are discussed by Chunmei [5].

Pressure distribution in gas condensate wells. It is important to determine the pressure distribution in gas condensate wells in order to predict and identify when and where liquid condensate will form. There are several methods which can be used to estimate fluids pressure in wells depending on certain assumptions. These methods are divided into single phase static conditions' methods, single phase flowing conditions' methods, and two-phase flowing conditions' methods. For one phase methods, the assumptions taken into consideration are [12-13]:

- Steady-state flow
- Single-phase flow, although it may be used for condensate flow if proper adjustments are made in the flow rate, gas gravity, and compressibility factor
- Change in kinetic energy is small and may be neglected
- Constant temperature for particular average values
- Constant gas deviation factor for particular average values
- Constant friction factor over the length of the conduit

Single phase static conditions' methods. The static pressure estimation from surface measurements only includes calculating the additional pressure exerted by the weight of the static fluid column. The methods used for pressure determination are [12-13]:

1. Average temperature and deviation factor method

$$p_{ws} = p_{ts} \cdot e^{0.01875 \cdot \gamma_g \cdot \frac{H}{\bar{C} \cdot \bar{T}}} \quad (8)$$

2. Sukkar and Cornell method

$$\int_{p_{pr1}}^{p_{pr2}} \frac{C}{p_{pr}} dp_{pr} = \frac{0.01875 \cdot \gamma_g \cdot H}{\bar{T}} \quad (9)$$

3. Cullender and Smith method

$$p_{ws} = p_{ts} + \frac{112.5 \cdot \gamma_g \cdot C}{I_{ts} + 4 \cdot I_{ms} + I_{ws}} \quad (10)$$

where:

$$I_s = \int \frac{C \cdot T}{P} \quad , \text{ and } I_{ts} \text{ is evaluated at well depth } (H)=0, I_{ms} \text{ at } H/2, I_{ws} \text{ at } H, \text{ and } I = 1000 \frac{C \cdot T}{P} \text{ (t=}$$

tubing head, m=mid of tubing, w=wellbore, and s=static)

P_{ws} = Static bottom-hole pressure, psia

P_{ts} = Static wellhead pressure, psia

γ_g = Gas specific gravity (air=1)

H = Well depth from surface, ft

$\bar{T}$ = Average temperature, °R (usually arithmetic mean of bottom and wellhead temperatures)

$\bar{C}$ = Compressibility factor at arithmetic mean temperature and arithmetic mean pressure.

P_{pr1} = Pseudo-reduced wellhead pressure

P_{pr2} = Pseudo-reduced bottom-hole pressure

C = Compressibility factor at particular pressure and temperature

Single phase flowing conditions' methods. The flowing bottom-hole pressure of a gas well is the sum of the flowing wellhead pressure, the pressure exerted by the weight of the gas column, the kinetic energy change, and the energy losses resulting from friction [12]. Flowing methods for calculating flowing pressure are [12-13]:

1. Average temperature and deviation factor method

$$P_{wf}^2 = P_{tf}^2 \cdot e^5 + \frac{25 \cdot \gamma_g \cdot \bar{T} \cdot \bar{C} \cdot f \cdot L \cdot (e^5 - 1) \cdot q^2}{s \cdot D^5} \quad (11)$$

$$\text{where } s = \frac{2 \cdot \gamma_g \cdot H}{53.34 \cdot T \cdot C}$$

2. Sukkar and Cornell method

$$\frac{\gamma_g \cdot L \cos \theta}{53.34 \cdot \bar{T}} = \int_{(P_{tf})^r}^{(P_{wf})^r} I(p_r) \cdot dp_r = \int_{(P_{tf})^r}^{(P_{wf})^r} \frac{\frac{C}{p_r}}{1 + B \left(\frac{C}{p_r} \right)} \cdot dp_r \quad (12)$$

$$\text{where Log average temperature } (\bar{T}) = \frac{T_{res} - T_{surf}}{\ln \frac{T_{res}}{T_{surf}}}, \quad B = \frac{667 \cdot f \cdot q^2 \cdot \bar{T}^2}{D^5 \cdot P_{pc}^2 \cos(\theta)}$$

3. Cullender and Smith method

$$37.5 \cdot \gamma_g \cdot C = \frac{P_{wf} - P_{tf}}{3} (I_{tf} + 4 \cdot I_{mf} + I_{wf}) \quad (13)$$

$$\text{where } I = \frac{\frac{p}{C \cdot T}}{\frac{2.6665 \cdot \left(\frac{f}{4} \right) \cdot q^2}{D^5} + \frac{1}{1000} \cdot \frac{C}{L} \cdot \left(\frac{p}{C \cdot T} \right)^2}$$

T_{surf} = Surface temperature at well head, °F

T_{res} = Reservoir temperature at perforations, °F

P_{wf} = Flowing bottom hole pressure, psia

P_{tf} = Flowing wellhead pressure, psia

$\bar{T}$ = Arithmetic average of bottom hole and wellhead temperatures, °R

f = Moody friction factor at arithmetic average temperatures and pressures

L = Length of flow tubing, ft

q = Gas flow rate, MMcfd at 14.65 psia and 60°F

D = Flow tubing diameter, in

θ = Flow tubing inclination, degrees

P_{pr} = Reduced pressure of gas, psia

P_{pc} = Critical pressure of gas, Psia

Two phase flowing conditions' methods. The preceded equations in the previous methods are strictly accurate for single phase of a dry gas well flow. Several gas wells produce condensates and water. In these cases, some liquid will be moving with gas in the well. Consequently, gas-liquid flow appears in wells. The best correlations for two-phase flow are those of Hagedorn and Brown, Duns and Ros, Orkiszewski, Beggs and Brill, and Govier and Aziz [1].

Thermodynamic properties of gas condensate well. Calculation of thermodynamic properties from pressure, volume, temperature and specific heat data is considered as a vital issue in the compositional simulation of gas condensate fluid flow. These properties involve superficial tension, thermal conductivity, Joule Thomson coefficient, isochoric specific heat, isobaric specific heat, Gibbs energy, entropy change, and enthalpy change. Additionally; the fluid properties such as molar volume, molar mass, dynamic viscosity, compressibility factor, specific density, fluid impurities, gas to liquid (G/L) ratio, separated volume, and separated mole are included during thermodynamic properties determination. Formulas of thermodynamic properties are presented by Ikoku [12] and Katz [15]

Compositional simulation modelling. Figure 2 shows a flow diagram of the compositional simulation model procedures for gas condensate wells.

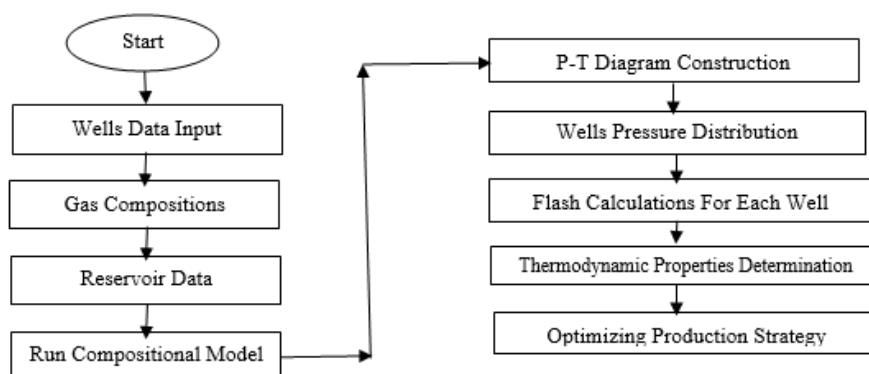


Figure 2. Flow diagram of the gas condensate well model

Table 1. Wells data and reservoir measured parameters

Parameters	Well A	Well B	Well C
Depth, m	3610	3904	4202
Perforation interval, m	3578-3568	3536-3522	4082-4076
Diameter of the production casing, cm	13.97+11.43	13.97+11.43	13.97 + 11.43
Depth of production tubing, m	3555	3510	4171
The diameter of production tubing, cm	7.3025	$d_1=7.3025$ from 0 to 2003 $d_2=6.0325$ from 2003 to 3510	$d_1=7.3025$ from 0 to 1362 $d_2=6.0325$ from 1362 to 4056
Reservoir pressure (static), bar	29	41	85
The pressure at the eruption head, bar	10	27	58
Column pressure, bar	21	0	63
Christmas tree outlet pressure, bar	8.8	8.8	10.8
Reservoir temperature, (degrees Celsius) °C	117	115.7	132
Flow rate, m ³ /day	8000	31000	33000
Salt water flow rate, L/day	230	410	1730
Condensate flow rate, L/day	250	700	4400
Distance between choke & Christmas tree, m	50	38	42
Choke diameter, mm	10	10	7
Pipe diameter between choke & Christmas tree, in	7.3025	7.3025	7.3025
Pipe length between choke & heater, m	900	38	52
Pipe diameter between choke & heater, cm	10.16	--	--
Inlet temperature in the heater, °C	2	7	14
Outlet temperature from the heater, °C	15	10	45
Pipe distance from the heater to the separator, m	30	30	1100
Diameter of pipeline between heater and separator, cm	4	4	7.3
Initial reservoir pressure, bar	336	336	329
Current reservoir pressure, bar	29	41	85
Reservoir temperature, °C	98	98	95
Relative density of gases at 0 °C	0.60856	0.672737	0.6497
Gasoline content, g/m ³	116.774	21.215	91.526
Final distillation point, °C	218.9	227.9	227.9
Density of the petroleum product at 20 °C, kg/m ³	799.4	735.5	735.5

Table 2. Gas composition (%molar) of wells a, b, and c from gas chromatography analysis from separator

Well No.	C ₁	C ₂	C ₃	i-C ₄	n-C ₄	i-C ₅	n-C ₅	C ₆	C ₇	C ₈	N ₂	CO ₂	Ar	O ₂
A	85.6149	6.0595	2.1860	0.5659	0.8535	0.3803	0.3091	0.3735	0.1621	0.0160	3.1284	0.3143	0.0147	0.0218
B	75.8178	1.7514	0.4695	0.1366	0.1150	0.0771	0.0311	0.0502	0.00355	0.0155	16.8931	0.2468	-	4.3604
C	86.8281	5.9232	2.0588	0.4818	0.6982	0.2531	0.1818	0.1594	0.0591	0.0072	3.2766	0.0178	0.0152	0.0397

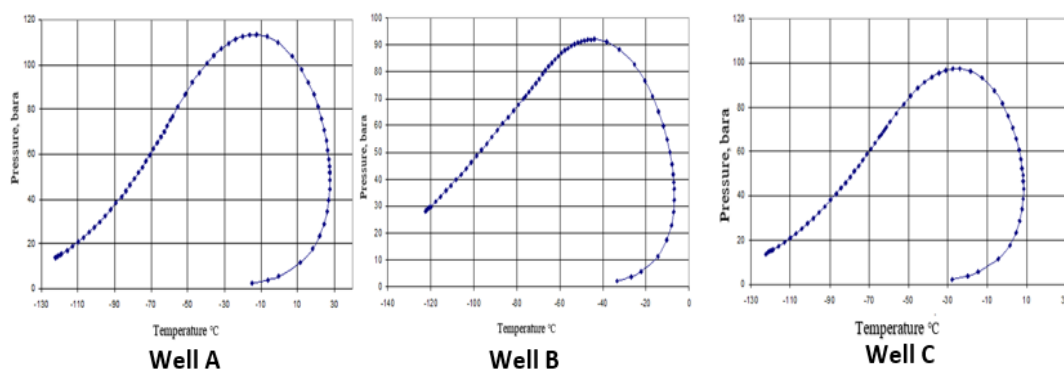


Figure 3. P-T phase diagram for wells A, B, and C

Table 3. Critical pressure and temperature, cricondentherm, and cricondenbar for wells A, B, and C

Calculated Parameters		Well A	Well B	Well C
Critical parameters	Critical pressure ,bar	77.0871	69.9552	73.4647
	Critical temperature, °C	-58.3434	-76.8675	-59.2618
Cricondentherm parameters	Cricondentherm pressure, bar	48.5323	32.4023	43.0044
	Cricondentherm temperature, °C	27.5326	-6.7994	8.4658
Cricondenbar parameters	Cricondenbar pressure, bar	113.5032	91.932	97.4285
	Cricondenbar temperature, °C	-12.4071	-44.1548	-24.0201

3. Results and discussions

Tintea – ASTRA Field Data

Tintea – ASTRA field is an onshore gas condensate reservoir field, with a gas processing plant located in Ploiesti, Romania. Data of three drilled wells A, B, and C in this reservoir are available. Reservoir measured parameters, wells dimensions, and wells production data are shown in Table 1. The gas composition measured of wells A, B, and C is shown in Table 2.

Results Analysis

A Compositional simulation of Tintea – ASTRA field was implemented based on limited data available. It has produced P-T diagrams for wells A, B, and C (Figure 3). From P-T diagrams of wells A, B, and C; critical pressure and temperature, cricondentherm, and cricondenbar are extracted as shown in Table 3. The P-T diagrams established on the basis of the data in Tables 1 and 2. With the help of these diagrams, it can be determined the areas in which the analyzed hydrocarbon system is presented in a gaseous, liquid or two phase state. In addition to P-T diagrams, the pressure distribution of wells is determined as shown in Figures 4 through 6. Moreover, the flash calculations are performed at selected points from producing zone to separator in order to check the conditions of the liquid phase, as well as its composition (Tables 4 through 6). The values of the selected points are determined and verified from pressure distribution calculations (Figures. 4 through 6). The formation of the liquid phase along the column of the production pipes, the Christmas tree, the surface pipes network or separator does not create problems in the operation of the rich gas wells, however, if it is formed

around wellbore; it will cause a condensate banking or condensate blocking phenomena. The thermodynamic properties of gas condensate are also estimated for both liquid and gas phases (Tables 7 through 12).

By interpreting the results of well A, the calculations resulted in the values of the critical parameters: the critical pressure (P_{cr}) = 77.0871 bar and the critical temperature (T_{cr}) = -58.3434 °C for well A. From the same diagram, the coordinates of the cricondenterm parameters: P_{ctm} = 48.5323 bar and (T_{ctm}) = 27.5326 °C, and the cricondenbar parameters: P_{cbr} = 113.5032 bar and T_{cbr} = -12.4071 °C. In order to identify the appearance of the liquid phase in well A, the values of the gas parameters and its thermodynamic properties are calculated and checked under various conditions and various locations (i.e. various pressures and temperatures according to different locations). These conditions and locations are normal conditions ($P_o=0$ bar, $T_o=0$ °C), standard conditions ($P_s=1$ bare, $T_s=15.5$ °C), reservoir conditions ($P_z=29$ bar, $T_z=98$ °C), the level of perforations ($P_{perf}=13.4$ bar, $T_{perf}=98$ °C), well head ($P_{CE}=10$ bar, $T_{CE}=10.51$ °C), the entrance and the exist of choke ($P_{id}= 9.5$ bar, $T_{id}= 9.7$ °C, $P_{ed}=8.89$ bar, $T_{ed}=7.35$ °C), and the entrance of gas heaters ($P_{ical}=8.86$ bar, $T_{ical}=2.7$ °C). Moreover, Table 8.3 presents the composition of the vapor and liquid phases which is obtained from the flash calculations at such previous pressure and temperature conditions at the respective places. The condensation conditions are occurred starting from the exit from the choke nozzle to the separator, locations at which the composition of the phases is presented. That means, starting with the exit gases from the choke and up to the separator, the liquid phase (gasoline with condensation traces) due to the presence of C7 + C8 components in the mixture will yield (Tables 4, 7 through 8). To describe the pressure variation in the reservoir-well system and along the extraction pipe column, one phase correlations are used to develop a depth-pressure plot (Fig. 4). However, once the condensate is starting to yield in the well, two phase flow correlations will be utilized to construct the pressure gradient of the system. In the case of well A, the curves were constructed. These curves allow the verification of the measured values of the reservoir pressure and of the pressure of the well head and, at the same time, the determination of the dynamic pressure near the perforations, and at the extraction pipes. The conclusion to be drawn from the interpretation of above results is that from the gas outlet from the choke nozzle to the separator, the liquid phase represented by the gasoline with traces of condensate due to the C7 + C8 components present in the mixture.

However; based on interpretation of wells B and C results, the liquid phase does not appear along the entire tubing path traveled by the extracted gases from the producing zone to the heater of the wells B and C (Tables 5 through 6 and 9 through 12). The P-T diagrams, which are established on the basis of the data in Tables 1 and 2, are shown in Figure 3 and allow the determination of the areas in which the analyzed hydrocarbon system is in the gaseous, liquid or two phase regions. Furthermore, the determined values of the critical parameters and the coordinates of the parameters cricondenterm and cricondenbar for well B are P_{cr} = 69.9552 bar, T_{cr} = -76.8675 °C, P_{ctm} = 32.4023 bar and T_{ctm} = -6.7994 °C, P_{cbr} = 91.932 bar, and T_{cbr} = -44.1548 °C respectively. Also, for well C, these parameters are P_{cr} = 73.4647 bar, T_{cr} = -59.2618 °C, p_{ctm} = 43.0044 bar, T_{ctm} = 8.4658 °C, P_{cbr} = 97.4285 bar and T_{cbr} = -24.0201 °C respectively as well. The flash calculations, gas parameters and its thermodynamic properties are computed in order to investigate the occurrence of the liquid phase for wells B and C at the same locations and conditions that are checked in well A, as presented in Tables 5 through 6 and Tables 9 through 12. It was found that the only composition of the vapor phase is appeared, while the liquid phase does not form for the required pressure and temperature conditions. Therefore, the pressure variation plots were constructed based on single phase flow equations in the formation-well system as shown in Figures 5 and 6 for well B and C respectively.

Finally, there are many fields all over the world which are suffering from the condensate blockage problem. This is because they have a reservoir pressure lower than the dewpoint pressure due to gas production with time. Based data analyses presented in the resulted Figures and Tables at Țintea – ASTRA, it does not directly extract the liquid phase mainly represented by gasoline or condensate. The occurrence of the liquid phase in the reservoir, which would lead to the blocking by contamination

of the production zone around the wellbore and consequently to the reduction of the gas mobility, will not yield. However, well A is a rich gas well with condensate formation after choke and it is predicted to yield the condensate after a certain period of time in production tubing or around it. Therefore, based on well (A) P-T and pressure variation plots, the pressure, at which the condensate will form, can be estimated, and then the condensate blockage will be avoided by changing the production rate or using gas recycling.

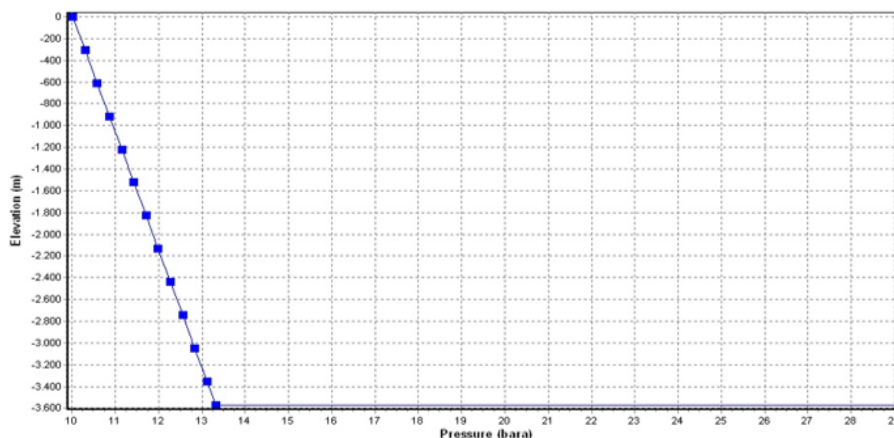


Figure 4. Variation of pressure in the reservoir and in the production pipes for well A

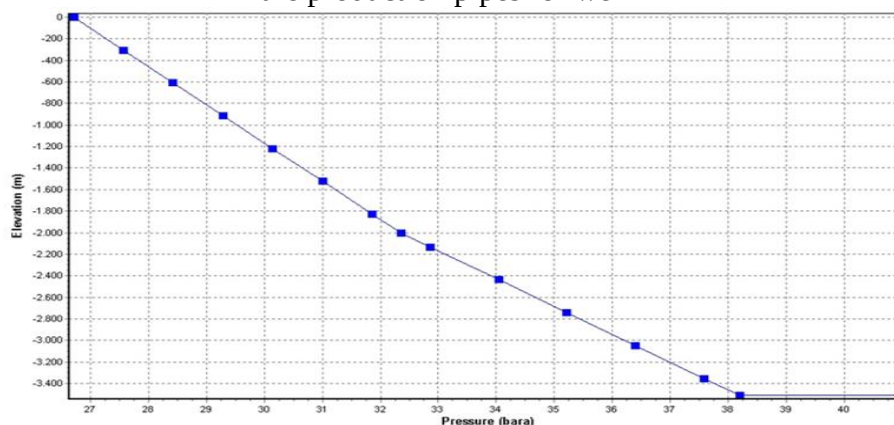


Figure 5. Variation of pressure in the reservoir and in the production pipes for well B

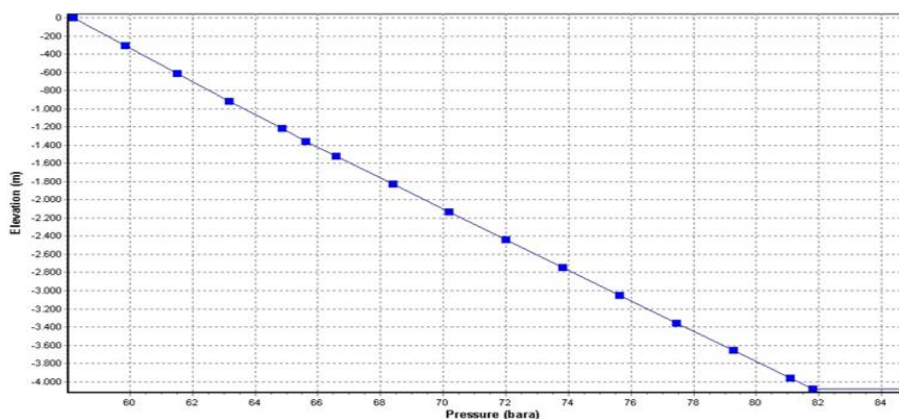


Figure 6. Variation of pressure in the reservoir and in the production pipes for well C

Table 4. Flash calculations for well A

Components	$P_0=1 \text{ bar}; T_0=0^\circ\text{C}$		$P_{ed}=8.89 \text{ bar}; T_{ed}=7.35^\circ\text{C}$		$P_{ical}=8.86 \text{ bar}; T_{ical}=2.7^\circ\text{C}$	
	Steam	Liquid	Steam	Liquid	Steam	Liquid
C_1	85.6149	0	85.6153	4.3226	85.7369	4.5159
C_2	6.0813	0	6.0813	2.1212	6.087	2.3158
C_3	2.2007	0	2.2007	2.9667	2.199	3.3464
i- C_4	0.5659	0	0.5659	2.1754	0.563	2.4988
n- C_4	0.8535	0	0.8535	4.8567	0.8463	5.6168
i- C_5	0.3803	0	0.3803	5.7666	0.3708	6.7134
n- C_5	0.3091	0	0.3091	6.4269	0.2983	7.4769
C_6	0.3735	0	0.3734	27.395	0.3289	30.0176
C_7	0.1621	0	0.1619	35.7974	0.114	32.1047
C_8	0.016	0	0.016	8.0761	0.0081	5.2936
N_2	3.1284	0	3.1284	0.0444	3.133	0.0449
CO_2	0.3143	0	0.3143	0.0511	0.3147	0.055

Table 5. Flash calculations for well B

Components	$P_0=1 \text{ bar}; T_0=0^\circ\text{C}$		$P_{ed}=8.8 \text{ bar}; T_{ed}=7.46^\circ\text{C}$		$P_{ical}=8.5 \text{ bar}; T_{ical}=7^\circ\text{C}$	
	Steam	Liquid	Steam	Liquid	Steam	Liquid
C_1	75.8179	0	75.8179	0	75.8179	0
C_2	6.1118	0	6.1118	0	6.1118	0
C_3	0.4695	0	0.4695	0	0.4695	0
i- C_4	0.1366	0	0.1366	0	0.1366	0
n- C_4	0.115	0	0.115	0	0.115	0
i- C_5	0.0771	0	0.0771	0	0.0771	0
n- C_5	0.0311	0	0.0311	0	0.0311	0
C_6	0.0502	0	0.0502	0	0.0502	0
C_7	0.0355	0	0.0355	0	0.0355	0
C_8	0.0155	0	0.0155	0	0.0155	0
N_2	16.893	0	16.893	0	16.893	0
CO_2	0.2468	0	0.2468	0	0.2468	0

Table 6. Flash calculations for well C

Components	$P_0=1 \text{ bar}; T_0=0^\circ\text{C}$		$P_{ed}=57.5 \text{ bar}; T_{ed}=19.75^\circ\text{C}$		$P_{ical}=10.8 \text{ bar}; T_{ical}=2.24^\circ\text{C}$	
	Steam	Liquid	Steam	Liquid	Steam	Liquid
C_1	86.8281	0	86.8281	0	86.8281	0
C_2	5.9629	0	5.9629	0	5.9629	0
C_3	2.074	0	2.074	0	2.074	0
i- C_4	0.4818	0	0.4818	0	0.4818	0
n- C_4	0.6982	0	0.6982	0	0.6982	0
i- C_5	0.2531	0	0.2531	0	0.2531	0
n- C_5	0.1818	0	0.1818	0	0.1818	0
C_6	0.1594	0	0.1594	0	0.1594	0
C_7	0.0591	0	0.0591	0	0.0591	0
C_8	0.0072	0	0.0072	0	0.0072	0
N_2	3.2766	0	3.2766	0	3.2766	0
CO_2	0.0178	0	0.0178	0	0.0178	0

Table 7. Thermodynamic properties calculation for well A

Calculated parameters	$P_0=1 \text{ bar}; T_0=0^\circ\text{C}$		$P_{st}=1 \text{ bar}; T_{st}=15.5^\circ\text{C}$		$P_z=29 \text{ bar}; T_z=98^\circ\text{C}$		$P_{perf}=13.4 \text{ bar}; T_{perf}=98^\circ\text{C}$	
	Steam	Liquid	Steam	Liquid	Steam	Liquid	Steam	Liquid
Mole separated, %	100.0000	0.0	100.0000	0.0	100.0000	0.0	100.0000	0.0
Volume of separate, %	100.0000	0.0	100.0000	0.0	100.0000	0.0	100.0000	0.0
G/L Ratio, m^3/m^3	0.0000	-	0.0000	-	0.0000	-	0.0000	-
Impurities, %	0.0000	-	0.0000	-	0.0000	-	0.0000	-
Specific density	0.8554	0.0	0.8093	0.0	18.9068	0.0	8.5622	0.0
C - factor	0.9961	0.0	0.9967	0.0	0.9622	0.0	0.9817	0.0
Dynamic viscosity, cp	0.0103	0.0	0.0109	0.0	0.0140	0.0	0.0137	0.0
Molar mass, kg/kmol	19.3579	0.0	19.3579	0.0	19.3579	0.0	19.3579	0.0
Molar volume, m^3/mol	0.0226	0.0	0.0239	0.0	0.0010	0.0	0.0023	0.0
Enthalpy, J/g	-50793.0	0.0	-20.2754	0.0	134.6768	0.0	146.7769	0.0
Entropy, J/g/K	-175.850	0.0	-0.0671	0.0	0.2538	0.0	0.3172	0.0
Gibbs energy, J/g	-2800.30	0.0	-0.9182	0.0	40.4951	0.0	29.0433	0.0



Isobaric specific heat, J/g/K	1934.300	0.0	1.9903	0.0	2.2726	0.0	2.2798	0.0
isochoric Specific heat, J/g/K	1505.1000	0.0	1.5612	0.0	1.8731	0.0	1.8638	0.0
Joule Thomson coefficient, J/g/K	0.000	0.0	0.0000	0.0	0.0000	0.0	0.0000	0.0
Thermal conductivity, W/m/K	0.0349	0.0	0.0350	0.0	0.0350	0.0	0.0350	0.0
Superficial tension, N/m	0.0000	0.0	0.0000	0.0	0.0000	0.0	0.0000	0.0

Table 8. Thermodynamic properties calculation for well A, cont

Calculated Parameters	P _{CE} =10 bar; T _{CE} =10.51°C		P _{id} =9.5 bar; T _{id} = 9.7 °C		P _{ed} = 8.89 bar; T _{ed} = 7.35 °C		P _{ical} = 8.86 bar; T _{ical} = 2.7 °C	
	Steam	Liquid	Steam	Liquid	Steam	Liquid	Steam	Liquid
Mole separated,%	100.0000	0.0	100.0000	0.0	99.9995	0.0005	99.8498	0.1502
Volume of separate,%	100.0000	0.0	100.0000	0.0	99.99999	0.00001	99.9928	0.0072
G/L Ratio, m ³ /m ³	0.0000	-	0.0000	-	1999999	-	131855.46	-
Impurities,%	0.0000	-	0.0000	-	0.0000	-	0.0000	-
Specific density	8.5039	0.0	8.0899	0.0	7.6234	667.8309	7.7001	666.6736
C-factor	0.9652	0.0	0.9666	0.0	0.9679	0.0466	0.9666	0.0461
Dynamic viscosity, cp	0.0109	0.0	0.0108	0.0	0.0108	0.3965	0.0106	0.3939
Molar mass, kg/kmol	19.3579	0.0	19.3579	0.0	19.3575	81.5782	19.2673	79.5884
Molar volume, m ³ /mol	0.0023	0.0	0.0024	0.0	0.0025	0.0001	0.0025	0.0001
Enthalpy, J/g	-41.5231	0.0	-42.5394	0.0	-46.5330	-282.451	-55.9580	-292.110
Entropy, J/g/K	-0.2470	0.0	-0.2487	0.0	-0.2604	-0.6059	-0.2947	-0.6447
Gibbs energy, J/g	28.5433	0.0	27.8043	0.0	26.4998	-112.489	25.3235	-114.273
Isobaric specific heat, J/g/K	1.9771	0.0	1.9740	0.0	1.9656	1.5587	1.9541	1.5996
Isochoric Specific heat, J/g/K	1.5512	0.0	1.5479	0.0	1.5389	1.5200	1.5247	1.5602
Joule Thomson coefficient, g/K	0.0000	0.0	0.0000	0.0	0.0000	0.0000	0.0000	0.0000
Thermal conductivity, W/m/K	0.0350	0.0	0.0350	0.0	0.0350	0.1000	0.0350	0.1000
Superficial tension, N/m	0.0000	0.0	0.0000	0.0	0.0000	0.0188	0.0000	0.0189

Table 9. Thermodynamic properties calculation for well B

Calculated Parameters	P _o =1 bar; T _o = 0 °C		P _{st} =1 bar; T _{st} = 15.5 °C		P _z = 41 bar; T _z = 98 °C		P _{perf} = 38.2 bar; T _{perf} =98 °C	
	Steam	Liquid	Steam	Liquid	Steam	Liquid	Steam	Liquid
Mole separated, %	100.0000	0.0	100.0000	0.0	100.0000	0.0	100.0000	0.0
Volume of separate, %	100.0000	0.0	100.0000	0.0	100.0000	0.0	100.0000	0.0
G/L Ratio, m ³ /m ³	0.0000	-	0.0000	-	0.0000	-	0.0000	-
Impurities,%	0.0000	-	0.0000	-	0.0000	-	0.0000	-
Specific density	0.8552	0.0	0.8089	0.0	26.6104	0.0	24.7446	0.0
C-factor	0.9971	0.0	0.9976	0.0	0.9669	0.0	0.9688	0.0
Dynamic viscosity, cp	0.0112	0.0	0.0118	0.0	0.0152	0.0	0.0152	0.0
Molar mass, kg/kmol	19.3663	0.0	19.3663	0.0	19.3663	0.0	19.3663	0.0
Molar volume, m ³ /mol	0.0226	0.0	0.0239	0.0	0.0007	0.0	0.0008	0.0



Enthalpy, J/g	-46.6629	0.0	-18.4818	0.0	119.3983	0.0	120.9549	0.0
Entropy, J/g/K	-0.1616	0.0	-0.0613	0.0	0.1897	0.0	0.1965	0.0
Gibbs energy, J/g	-2.5137	0.0	-0.7859	0.0	49.0093	0.0	48.0320	0.0
Isobaric specific heat, J/g/K	1.7912	0.0	1.8339	0.0	2.0362	0.0	2.0380	0.0
Isochoric specific heat, J/g/K	1.3624	0.0	1.4053	0.0	1.6518	0.0	1.6505	0.0
Joule Thomson coefficient, J/g/K	0.0000	0.0	0.0000	0.0	0.0000	0.0	0.0000	0.0
Thermal conductivity, W/m/K	0.0350	0.0	0.0350	0.0	0.0350	0.0	0.0350	0.0
Superficial tension, N/m	0.0000	0.0	0.0000	0.0	0.0000	0.0	0.0000	0.0

Table 10. Thermodynamic properties calculation for well B, cont

Calculated Parameters	P _{CE} =27 bar T _{CE} =15°C		P _{id} =26.9 bar T _{id} = 14.7 °C		P _{ed} = 8.8 bar T _{ed} = 7.46 °C		P _{ical} = 8.5 bar T _{ical} =7 °C	
	steam	Liquid	steam	Liquid	steam	Liquid	steam	Liquid
Mole separated, %	100.0000	0.0	100.0000	0.0	100.0000	0.0	100.0000	0.0
Volume of separate, %	100.0000	0.0	100.0000	0.0	100.0000	0.0	100.0000	0.0
G/L Ratio, m ³ /m ³	0.0000	-	0.0000	-	0.0000	-	0.0000	-
Impurities, %	0.0000	-	0.0000	-	0.0000	-	0.0000	-
Specific density	23.2701	0.0	23.2083	0.0	7.4756	0.0	7.2278	0.0
C - factor	0.9379	0.0	0.9379	0.0	0.9771	0.0	0.9778	0.0
Dynamic viscosity cp	0.0123	0.0	0.0123	0.0	0.0117	0.0	0.0116	0.0
Molar mass, kg/kmol	19.3663	0.0	19.3663	0.0	19.3663	0.0	19.3663	0.0
Molar volume, m ³ /mol	0.0008	0.0	0.0008	0.0	0.0026	0.0	0.0027	0.0
Enthalpy, J/g	-43.9468	0.0	-44.4499	0.0	-40.8532	0.0	-41.4132	0.0
Entropy, J/g/K	-0.2927	0.0	-0.2943	0.0	-0.2435	0.0	-0.2441	0.0
Gibbs energy, J/g	40.3899	0.0	40.2739	0.0	27.4890	0.0	26.9707	0.0
Isobaric specific heat, J/g/K	1.8312	0.0	1.8305	0.0	1.8126	0.0	1.8113	0.0
Isochoric Specific heat, J/g/K	1.4225	0.0	1.4216	0.0	1.3887	0.0	1.3873	0.0
Joule Thomson coefficient, J/g/K	0.0000	0.0	0.0000	0.0	0.0000	0.0	0.0000	0.0
Thermal conductivity, W/m/K	0.0350	0.0	0.0350	0.0	0.0350	0.0	0.0350	0.0
Superficial tension, N/m	0.0000	0.0	0.0000	0.0	0.0000	0.0	0.0000	0.0

Table 11. Thermodynamic properties calculation for well C

Calculated Parameters	P _o =1 bar; T _o = 0 °C		P _{st} =1 bar; T _{st} = 15.5 °C		P _z = 85 bar; T _z = 95 °C		P _{perf} = 81.7 bar; T _{perf} =95 °C	
	Steam	Liquid	Steam	Liquid	Steam	Liquid	Steam	Liquid
Mole separated, %	100.0000	0.0	100.0000	0.0	100.0000	0.0	100.0000	0.0
Volume of separate, %	100.0000	0.0	100.0000	0.0	100.0000	0.0	100.0000	0.0
G/L Ratio, m ³ /m ³	0.0000	-	0.0000	-	0.0000	-	0.0000	-
Impurities, %	0.0000	-	0.0000	-	0.0000	-	0.0000	-
Specific density	0.8292	0.0	0.7841	0.0	57.0654	0.0	54.7181	0.0
C - factor	0.9963	0.0	0.9969	0.0	0.9129	0.0	0.81	0.0
Dynamic viscosity, cp	0.0104	0.0	0.0109	0.0	0.0152	0.0	0.0151	0.0
Molar mass,	18.7611	0.0	18.7611	0.0	18.7611	0.0	18.7611	0.0



kg/kmol								
Molar volume, m ³ /mol	0.0226	0.0	0.0239	0.0	0.0003	0.0	0.0003	0.0
Enthalpy, J/g	-51.4278	0.0	-20.4854	0.0	88.9416	0.0	91.1774	0.0
Entropy, J/g/K	-0.1779	0.0	-0.0678	0.0	0.0953	0.0	0.1019	0.0
Gibbs energy, J/g	-2.8218	0.0	-0.9162	0.0	53.8627	0.0	53.6462	0.0
Isobaric specific heat, J/g/K	1.9608	0.0	2.0163	0.0	2.2544	0.0	2.2564	0.0
Isochoric Specific heat, J/g/K	1.5178	0.0	1.5736	0.0	1.9055	0.0	1.9036	0.0
Joule Thomson coefficient, J/g/K	0.0000	0.0	0.0000	0.0	0.0000	0.0	0.0000	0.0
Thermal conductivity, W/m/K	0.0350	0.0	0.035	0.0	0.0350	0.0	0.035	0.0
Superficial tension, N/m	0.0000	0.0	0.0000	0.0	0.0000	0.0	0.0000	0.0

Table 12. Thermodynamic properties calculation for well C, cont

Calculated parameters	P _{CE} =58 bar T _{CE} =20,1°C		P _{id} =57.5 bar T _{id} = 19.75 °C		P _{ed} = 10.8 bar T _{ed} = 2.24 °C	
	Steam	Liquid	Steam	Liquid	Steam	Liquid
Mole separated, %	100.0000	0.0	100.0000	0.0	100.0000	0.0
Volume of separate, %	100.0000	0.0	100.0000	0.0	100.0000	0.0
G/L Ratio, m ³ /m ³	0.0000	-	0.0000	-	0.0000	-
Impurities, %	0.0000	-	0.0000	-	0.0000	-
Specific density	53.0429	0.0	23.2083	0.0	7.4756	0.0
C - factor	0.8414	0.0	0.9379	0.0	0.9771	0.0
Dynamic viscosity, cp	0.0126	0.0	0.0123	0.0	0.0117	0.0
Molar mass, kg/kmol	18.7611	0.0	19.3663	0.0	19.3663	0.0
Molar volume, m ³ /mol	0.0004	0.0	0.0008	0.0	0.0026	0.0
Enthalpy, J/g	-80,1735	0.0	-44,4499	0.0	-40,8532	0.0
Entropy, J/g/K	-0,4144	0.0	-0,2943	0.0	-0,2435	0.0
Gibbs energy, J/g	41,3632	0.0	40,2739	0.0	27,4890	0.0
Isobaric specific heat, J/g/K	2,0412	0.0	1,8305	0.0	1,8126	0.0
Isochoric specific heat, J/g/K	1,6409	0.0	1,4216	0.0	1,3887	0.0

4. Conclusions

Based on the results and analysis, the following conclusions are extracted:

- Compositional simulation of gas condensate flow is considered as an important study for future operations of Țintea – ASTRA field.
- The pressure of condensate blockage can be predicted and avoided for Țintea – ASTRA wells.
- When and where the condensate liquid phase is obviously determined and anticipated
- Productivity loss is absolutely avoided, and profit maximization is achieved.
- In order to prevent formation of condensate liquid, it is recommended to use water injection, dry miscible gas recycling, and phase equilibrium method

Nomenclatures

P_o= Pressure at normal conditions for natural gas (P=1 bar, T= 0°C)

T_o= Temperature at normal conditions for natural gas (P=0 bar, T= 0°C)

P_{st}= Standard pressure for natural gas in imperial system, bar (P=1 bar)

T_{st}= Standard temperature for natural gas in imperial system, °C (T= 15.5°C)

P_z= Reservoir pressure, bar

T_z= Reservoir temperature, °C

P_{perf}= Perforation pressure, bar

T_{perf}= Temperature at perforation, °C



P_{ce} = Christmas tree pressure, bar
 T_{ce} = Christmas tree temperature, °C
 P_{id} = Inlet choke pressure, bar
 T_{id} = Inlet choke temperature, °C
 P_{ed} = Outlet choke pressure, bar
 T_{ed} = Outlet choke temperature, °C
 P_{ical} = Inlet heater pressure, bar
 T_{ical} = Inlet heater temperature, °C
Absolute Psi (P_{sia}) = Gauge Psi (P_{sig}) + 14.65

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Manuscript received: 11.10.2019

