New Method To Estimate Surface-Separator Optimum Operating Pressures

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Summary

The significance of setting optimal surface separation pressures cannot be overemphasized in surface-separation design for the purpose of maximizing the surface liquid production from the wellstream feed. Usually, classical pressure-volume-temperature (PVT) analysis of reservoir fluids provides one or several separator tests through which the optimum separator pressures are estimated. In case separator tests are not available, or the limited numbers of separator tests are not adequate to determine the optimum separator pressures, empirical correlations are applied to estimate the optimum separator pressures. The empirical correlations, however, have several disadvantages that limit their practical applications.

In this study, we approached the problem with a rigorous method with a theoretical basis. According to the gas/liquid equilibrium calculation, the optimum separator pressures were determined. Comparisons of our results with experimental data indicated that the proposed method can simulate the separator tests very well. Because the method has a theoretical basis and does not require existing two-stage or multiple-stage separator-test data as in the application of empirical correlations, it potentially has wide applications in practice for a variety of conditions and yields a more optimal separation scheme than the empirical correlations. Furthermore, the method is independent of reservoir fluid. In the event that separator tests are available from fluid analysis, our method can be used as a quality-control tool. Because the setting for optimal separation pressures vary as the composition of the wellstream changes during the field life, our method provides a quick and low-computational-cost approach to estimate optimum separator pressures corresponding to different compositions.

Introduction

Oil and gas production usually requires surface separation before they are transported to market. The pressure vessel used for separating well fluids produced from oil and gas wells into vapor and liquid components is called a separator. The vessel is engineered to separate production fluids into their constituent components of oil, gas, and water. These separating vessels are normally used on a producing lease or platform near the wellhead, manifold, or tank battery to separate the wellstream into gas, which goes to a gas pipeline; oil, which flows to a stock tank; and water, which is discharged to a water treatment facility. Separators work on the principle that the three streams (vapor-phase, liquid-oil, and liquid-water) have different densities, which allow them to stratify when moving slowly with gas on top, water on the bottom, and oil in the middle. A simplified diagram of such a vessel is illustrated in Fig. 1. Any solids such as sands will also settle in the bottom of the separator. There are several types of separators. In this paper, we discuss oil and gas separators.

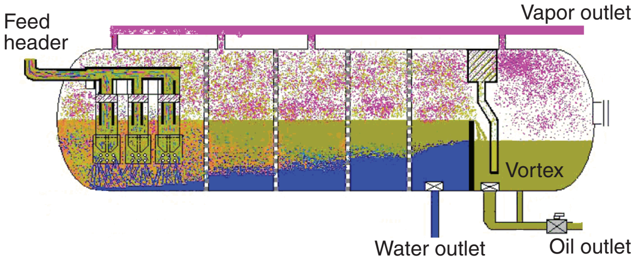

Fig. 1—Diagram of three-phase separator in the oil and gas separation process.

The surface separation system is a combination of separator/separators and the stock tank. Different numbers of stages are applied for different reservoir fluids. For the same fluid stream, more liquid yield is usually preferred because of its higher commercial value. Theoretically, the more stages of consecutive separation exist, the higher the liquid production. However, in practice, the real number of separations is often limited by available space and operational cost. The simplest system is two-stage separation consisting of one separator and one stock tank. It is most applicable for low-API-gravity oils, low gas/oil ratios (GORs), and low flowing pressures. More complicated systems contain several separators and stock tanks operated in series at successively lower pressures to maximize the liquid yield. The three-stage separation is used for intermediate gravity oils, intermediate to high GOR, and intermediate wellhead flowing pressures. The four-stage separation is designed for high-API-gravity oils, high GOR, and high flowing pressures. Four-stage separation is also used where high-pressure gas is needed for market or for pressure maintenance. The pressure of the separator is controlled with a backpressure valve through which the separated gas flows to the gas pipeline. The temperatures of the separator and the the stock tank are determined by the temperature of the feed and ambience. Vaporization and expansion also affect the vessel temperature. Separator temperature can be adjusted by cooling and heating. The fact that the percentage of liquid recovery from surface separation is controlled by separator pressures and temperatures and stock-tank pressure and temperature for given wellstream composition is well known. There are optimum operating conditions for a certain system to separate a specific wellstream. During the production, there is a small room for the temperature adjustment. The pressure window of the primary separator is also narrow because it should be lower than the flowing tubing pressure (FTP) but higher than sale gas pipeline pressures because of the fact that if primary separator pressure is lower than gas pipeline pressure, recompression will be required, thus leading to high operating costs. Therefore, the opti-

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mization of surface separation is realized through the adjustments of separator pressures, assuming the stock tank is connected to the atmosphere. Usually, reservoir fluid studies provide one or several separator tests through which the optimum separator pressures are estimated to recover maximum liquid hydrocarbons. In case separator tests are not available, or a limited number of separator tests cannot determine the optimum separator pressures, empirical correlations are applied to estimate the optimum separator pressures. The empirical correlations are limited to specific types of reservoir fluids and are only as good as the lab data upon which they are based.

To overcome the shortfalls of empirical correlations and the limited numbers of separator tests owing to the time and cost, we approached the problem with a rigorous method with a theoretical basis. The gas/liquid equilibria at separators and stock tanks under different conditions are calculated using the Peng-Robinson equation of state (EOS) (1976). With this EOS, the gas/liquid equilibria at any condition can be evaluated. Our unique method gives a way to obtain optimum separator pressures that result in a minimum of total GOR, a minimum in oil formation volume factor B_o), and a maximum in stock-tank oil API gravity.

Literature Review

Although the separation of produced fluids simultaneously occurred with the production of oil, study of the optimization of surface separation became popular in the early 1950s. Many studies were conducted to develop different approaches to optimize the surface separation.

Whinery and Campbell (1958) developed a correlation to calculate the optimum second-stage pressure in a three-stage separation system. The inputs required for the calculation are primary pressure; stock-tank pressure; and the mole fractions of methane, ethane, and propane. This correlation does not need flash calculations. The advantages of this method are quick and simple and do not require the full-spectrum composition of reservoir fluid. The disadvantages are that the accuracy and reliability of the calculations cannot be guaranteed because temperatures of the separator and stock tank and compositions of butane and heavier components are not included in the correlation. Chilingarian and Beeson (1969) proposed a method to determine the optimum separator pressure for the two-stage separation provided that the stock tank is connected to the atmosphere. In their method, GORs obtained from different separators are plotted against separator pressure, and then the optimum pressure is the pressure that produces minimum GOR. For multistage separation higher than two-stage, Chilingarian and Beeson resorted to the Whinery-Campbell correlation. The Natco Company (1972) used a constant pressure ratio between two successive pressures as the optimum pressure for separating stages. It is fast but inaccurate. Bahadori et al (2008) presented a methodology for optimizing separator pressures in the crude-oil production unit. It can be used to estimate the optimum pressures of separators in different stages of separation. The disadvantage of this method is that it requires tremendous numbers of trial-separator pressures and still may not be able to obtain exact optimum pressures. Al-Jawad and Hassan (2010a, b) developed a group of correlations for optimum separator pressure for volatile oils using the results of the computer model. These correlations are based on data from over 6,000 computer model runs with various independent variables. The variables are temperatures of stages, mole fractions of some components ($C1\%+H_2S\%+CO_2\%+N_2\%$) of the feed stream, and optimum separator pressures that present before the required separator. Again, Al-Jawad–Hassan correlations are empirical correlations and do not take the full composition of the wellstream into account. They cannot be extrapolated beyond the database upon which they are based. Their applications in reservoirs other than volatile oil are yet to be proved. This literature review indicates that a rigorous and efficient method to obtain optimum separator pressures is needed.

Methodology

Before implementation of the method, an EOS describing the phase behavior of the fluid should be tuned using experimental data such as differential liberation, constant composition expansion, and live-oil viscosity measurement. The proposed method uses EOS as an engine to compute the fluid properties such as B_o and GOR.

In the optimization of surface separation, we make the following assumptions:

1. The temperature of separators and the stock tank are constant.
2. The stock-tank pressure is atmospheric pressure (14.7 psia).
3. The adjustable variables are separator pressures.
4. The compositions of fluid stream are constant.
5. Separators work efficiently and phase equilibrium is achieved during the separation process.

In this study, we consider an n-stage separation system with n–1 separators and a stock tank. The wellstream pressure is FTP, pwh, and the stock-tank pressure is atmospheric pressure, patm. Our objective is to obtain optimum separator pressures that produce the maximum amount of stock-tank liquid. The calculation procedure follows:

1. Calculate the average pressure ratio using Eq. 1:

$$\text{Ratio}_p = \left(\frac{p_{wh}}{p_{\text{atm}}}\right)^{\frac{1}{n}} . \quad (1)$$

2. Calculate gas/liquid equilibrium using EOS at conditions of

$$\text{primary separator pressure} = \frac{p_{wh}}{\text{Ratio}_p} \quad (2)$$

secondary separator pressure

$$= \frac{\text{primary separator pressure}}{\text{Ratio}_p} \quad (3)$$

third separator pressure

$$= \frac{\text{second separator pressure}}{\text{Ratio}_p} \quad (4)$$

$(n–1)^{\text{th}}$ separator pressure

$$= \frac{(\text{n-2})^{\text{th}} \ \text{separator pressure}}{\text{Ratio}_p} \quad (5)$$

$$\text{stock-tank pressure} = p_{\text{atm}} \quad (6)$$

3. Change the primary separator pressure while keeping other separator pressures constant; calculate gas/liquid equilibrium using EOS at different primary separator pressures.

4. Collect the total GOR, stock-tank oil API gravities, and B_o at different primary separator pressures calculated in Steps 2 and 3. The primary separator pressure that gives minimum total GOR is the initial optimum pressure for the primary separator.

5. Change the second separator pressure while keeping other separators pressures constant; at this stage, the primary separator pressure is the initial optimum pressure obtained in Step 4, and the third through $(n–1)^{\text{th}}$ separators pressures are those calculated in Step 2; calculate total GOR, stock-tank oil API gravities, and B_o.

6. Determine the initial optimum pressure for the second separator using the GOR, stock-tank oil API gravities, and B_o calculated in Step 5.

7. Change the third separator pressure while keeping other separators pressures constant; at this stage, the primary and second separators pressures are the initial optimum pressure obtained in Steps 4 and 6, and the fourth through $(n–1)^{\text{th}}$ separators pressures

TABLE 1—COMPOSITION OF A WELL STREAM THROUGH A TWO-STAGE SEPARATION

Component	Mole Fraction
Hydrogen sulfide	0
Carbon dioxide	0
Nitrogen	0
Methane	0.0385
Ethane	0.0391
Propane	0.0516
i-Butane	0.0145
n-Butane	0.0575
i-Pentane	0.0231
n-Pentane	0.0346
Hexane	0.0491
Heptanes plus	0.692
Properties of heptanes plus	
Specific gravity	0.8576
Molecular weight	227 lb/lb-mole

are those calculated in Step 2; calculate total GOR, stock-tank oil API gravities, and B_o.

8. Determine the initial optimum pressure for the third separator using the total GOR, stock-tank oil API gravities, and B_o calculated in Step 7.

9. Similar steps are used to obtain initial optimum pressures for the fourth through $(n–1)^{\text{th}}$ separators.

10. After obtaining initial optimum pressures for all separators, repeat Steps 3 through 9 to obtain new optimum pressures for all separators.

11. Repeat the iteration until the all optimum separator pressures converge. The converged pressures are the optimum pressures that produce a maximum amount of stock-tank liquid.

12. For practical cases, the primary separator pressure should be near the FTP and higher than gas pipeline pressure; if the optimum primary separator pressure obtained in Step 11 is outside of the range between FTP and sale gas pipeline pressure, then the operating primary separator pressure is set between FTP and the gas pipeline pressure, and the optimization is only applied to nonprimary separators.

13. Calculate the average pressure ratio using Eq. 7:

$$\text{Ratio}_p = \left(\frac{p_{SP1}}{p_{\text{atm}}}\right)^{\frac{1}{n-1}} . \qquad (7)$$

14. Repeat Steps 2 through 11 to obtain optimum operating pressures for nonprimary separators.

Case Study

Three cases, one for two-stage, one for three-stage, and one for four-stage separation, are used to illustrate the applications of our method in optimizing sequential-stage separation pressures of multistage separation systems.

Two-Stage Separation. A reservoir fluid study of a black-oil sample was conducted. The separator test was a two-stage separation. The temperatures of the separator and the stock tank were 110°F and 105°F, respectively. During optimization the temperatures are kept constant. **Table 1** shows the composition of the wellstream that was fed into the separator. **Table 2** shows the total GOR, B_o, and stock-tank oil API gravity as a function of separator and stock-tank pressures and temperatures.

The separator test at the conditions of separator pressure of 79.7 psia and temperature of 110°F, and a stock-tank pressure of 14.7 psia and temperature of 105°F gives a total GOR of 103 scf/STB, a B_o of 1.105 rb/STB, and a stock-tank oil gravity of 38.5 °API, which agree with the theoretical calculation of a total GOR of 101.9 scf/STB, a B_o of 1.1075 rb/STB, and a stock-tank oil gravity of 38.6767 °API, as shown in Table 2. The small differences between the calculated and laboratory GOR, B_o, and stock-

TABLE 2—RESERVOIR FLUID SATURATION PRESSURE AND TEMPERATURE, SEPARATOR AND STOCK-TANK PRESSURES AND TEMPERATURES, AND TOTAL GOR, B_o, AND STOCK-TANK OIL API GRAVITY THROUGH A TWO-STAGE SEPARATION

Flowing Tubing Pressure (psia)	Reservoir *T* (°F)	Separator *P* (psia)	Separator *T* (°F)	Stock-Tank *P* (psia)	Stock-Tank *T* (°F)	Total GOR (scf/STB)	B_o (rb/STB)	Stock-Tank Oil Gravity (°API)
230	140	24.7	110	14.7	105	103.1	1.1080	38.6499
230	140	29.7	110	14.7	105	97.5	1.1042	38.8247
230	140	34.7	110	14.7	105	96.7	1.1033	38.8635
230	140	39.7	110	14.7	105	96.0	1.1029	38.8826
230	140	44.7	110	14.7	105	96.0	1.1030	38.8812
230	140	49.7	110	14.7	105	96.3	1.1032	38.8685
230	140	54.7	110	14.7	105	97.6	1.1043	38.8214
230	140	64.7	110	14.7	105	100.0	1.1061	38.7397
230	140	74.7	110	14.7	105	101.3	1.1070	38.7011
230	140	84.7	110	14.7	105	102.5	1.1081	38.6525
230	140	94.7	110	14.7	105	103.7	1.1091	38.6063
230	140	104.7	110	14.7	105	104.9	1.1101	38.5632
230	140	114.7	110	14.7	105	105.9	1.1110	38.5234
230	140	124.7	110	14.7	105	106.9	1.1118	38.4876
230	140	134.7	110	14.7	105	107.8	1.1125	38.4552
230	140	154.7	110	14.7	105	110.3	1.1145	38.3669
230	140	174.7	110	14.7	105	111.6	1.1156	38.3192
230	140	194.7	110	14.7	105	112.5	1.1164	38.2870
230	140	79.7	110	14.7	105	101.9	1.1075	38.6767

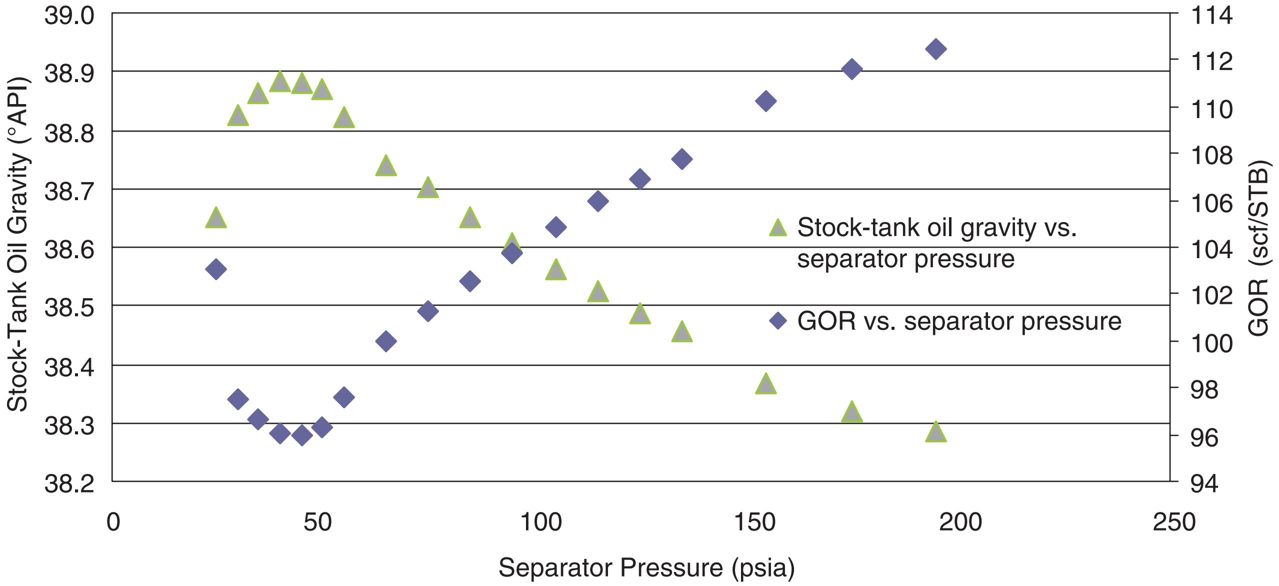

Fig. 2—Plots of total GOR and stock-tank oil API gravity vs. separator pressure.

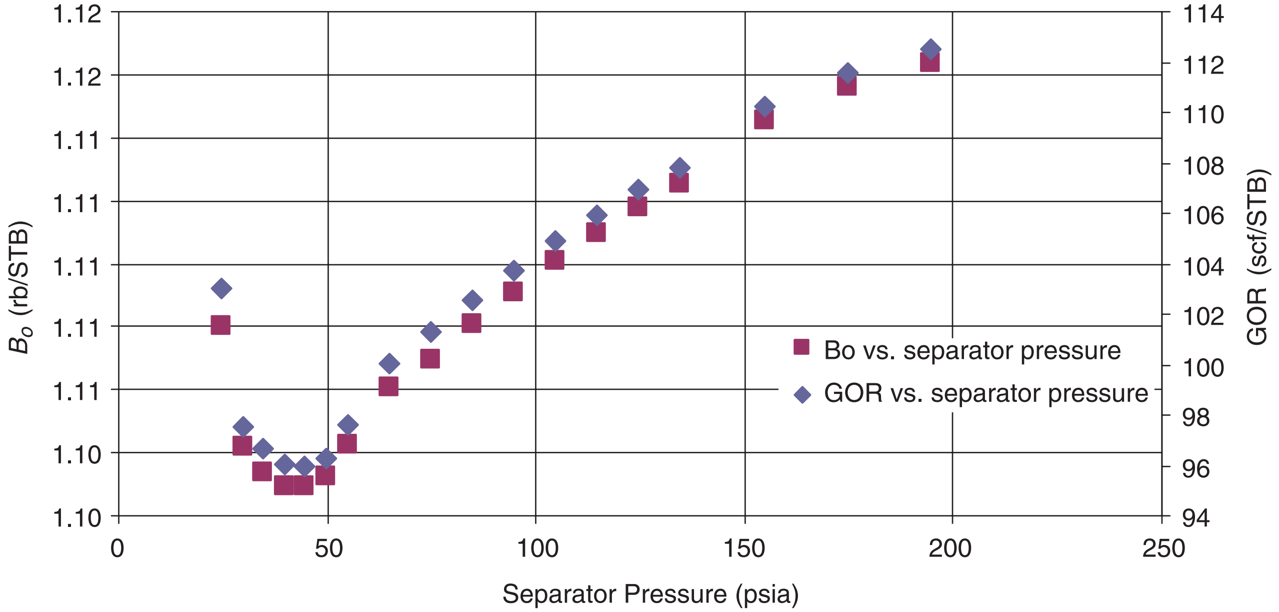

Fig. 3—Plots of total GOR and B_o vs. separator pressure.

TABLE 3—COMPARISONS OF GOR, B_o, AND STOCK-TANK OIL GRAVITY FROM DIFFERENT METHODS IN TWO-STAGE SEPARATION

	This Study	Natco Company Method (constant pressure ratio)	Bahadori's Method
Optimum separator pressure (psia)	39.7	58.1	54.7
GOR (scf/STB)	96.0	98.1	97.6
B_o (rb/STB)	1.1029	1.1047	1.1043
Stock-tank oil gravity (°API)	38.8826	38.8017	38.8214
Percent increase in stock tank barrels (%) This study compares with Natco Company method	0.16321	–	–
Percent increase in stock tank barrels (%) This study compares with Bahadori's method	0.12694	–	–

TABLE 4—COMPOSITION OF A WELL STREAM THROUGH A THREE-STAGE SEPARATION

Component	Mole Fraction
Hydrogen sulfide	0.0914
Carbon dioxide	0.0891
Nitrogen	0.0025
Methane	0.2515
Ethane	0.0817
Propane	0.0574
i-Butane	0.0114
n-Butane	0.0403
i-Pentane	0.0134
n-Pentane	0.0194
Hexane	0.024
Heptanes plus	0.3179
Properties of heptanes plus	
Specific gravity	0.8525
Molecular weight	219 lb/lb-mole

tank oil gravity mean that the EOS had been tuned finely and can be used for calculations of gas/liquid equilibria. The optimum separator pressure of two-stage separation, which is 39.7 psia, can be obtained by the aforementioned procedure. Table and plots of total GOR, B_o, and stock-tank oil API gravity vs. separator pressure indicate the optimum separator pressure of 39.7 psia as shown in **Figs. 2 and 3** and Table 2. Comparisons of GOR, B_o, and stock-tank oil gravity from our method with those from other methods are shown in **Table 3.** These indicate that our method gives the lowest GOR and B_o and the highest stock-tank oil gravity, which are the objectives of separation optimization.

Three-Stage Separation. Composition of a volatile oil sample was analyzed, and a three-stage separation test was performed assuming FTP was equal to saturation pressure. Temperatures of the primary separator, the secondary separator, and the stock tank are 160, 148, and 140°F, respectively. During optimization the temperatures are kept constant. **Table 4** shows the composition of the wellstream that was fed into the separator.

A separator test at the conditions of a primary separator pressure of 264.7 psia and a temperature of 160°F, a secondary pressure of 64.7 psia and temperature of 148°F, and a stock-tank pressure of 14.7 psia and a temperature of 140°F gives a total GOR of 986 scf/STB, a B_o of 1.604 rb/STB, and a stock-tank oil gravity of 38.0 °API, which agree with the theoretical calculation of a total GOR of 951 scf/STB, a B_o of 1.553 rb/STB, and a stock-tank oil gravity of 37.64 °API. The small differences between the calculated and laboratory GOR, B_o, and stock-tank oil gravity mean that EOS had been tuned and can be used for calculations of gas/liquid equilibria.

With the tuned EOS, the optimum separator pressures can be obtained by following the aforementioned procedure. Table 5 shows the constant pressure ratio and several trials that led to the optimum separator pressure. It should be noted that after six trials, the pressures converge to the optimum separator pressures. Table 5 also shows the total GOR, B_o, and stock-tank oil API gravity as functions of separators and stock-tank pressures and temperatures at different trials in the calculation procedure. The percent increases in the stock-tank barrel are also shown in Table 5. The calculation procedure gives an optimum primary separator pressure of 294.7 psia and a secondary separator pressure of 49.7 psia that result in a total GOR of 948 scf/STB, a B_o of 1.551 rb/STB, and a stock-tank oil gravity of 37.7 °API illustrated in Table 5, which agree with the optimum separator pressures obtained from plots in **Figs. 4 through 6.** Comparisons of GOR, B_o, and stock-tank oil gravity from our method with those from other methods are shown in **Table 6.** These indicate that our method gives the lowest GOR and B_o and the highest stock-tank oil gravity for three-stage separation.

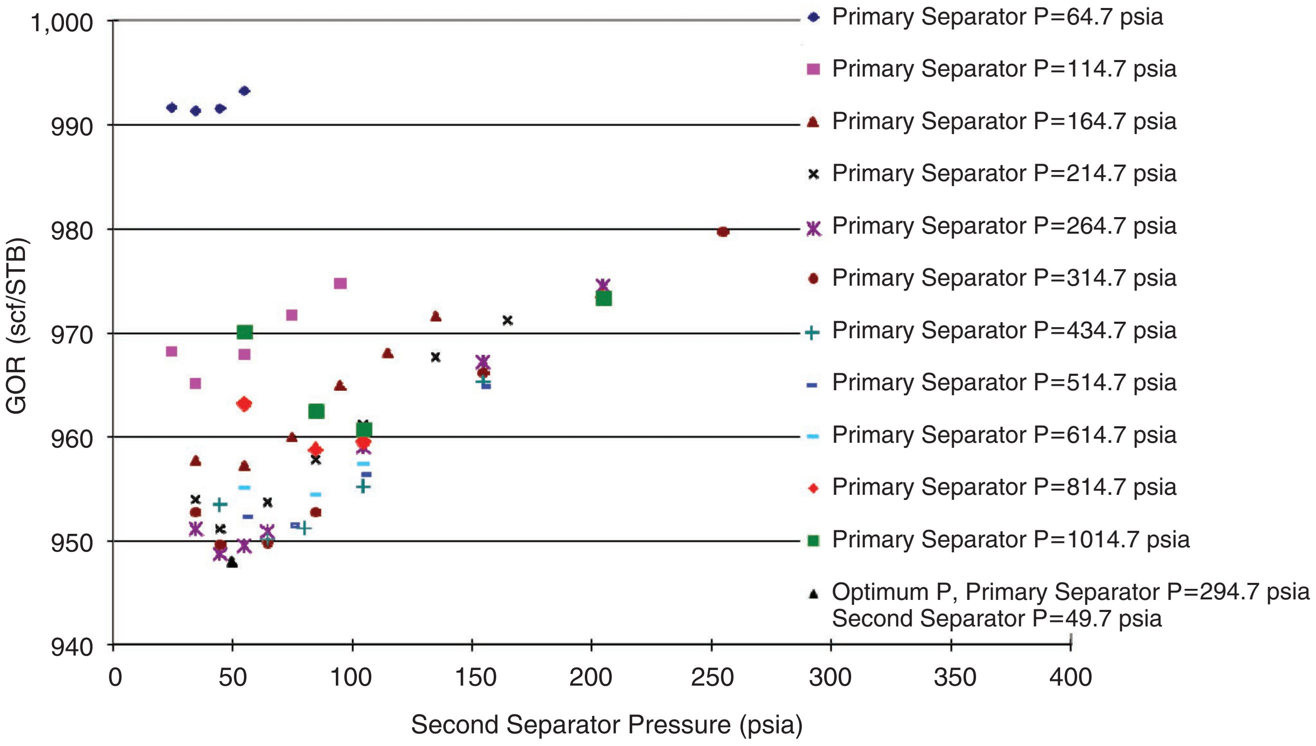

Fig. 4—Plots of total GOR vs. separator pressures.

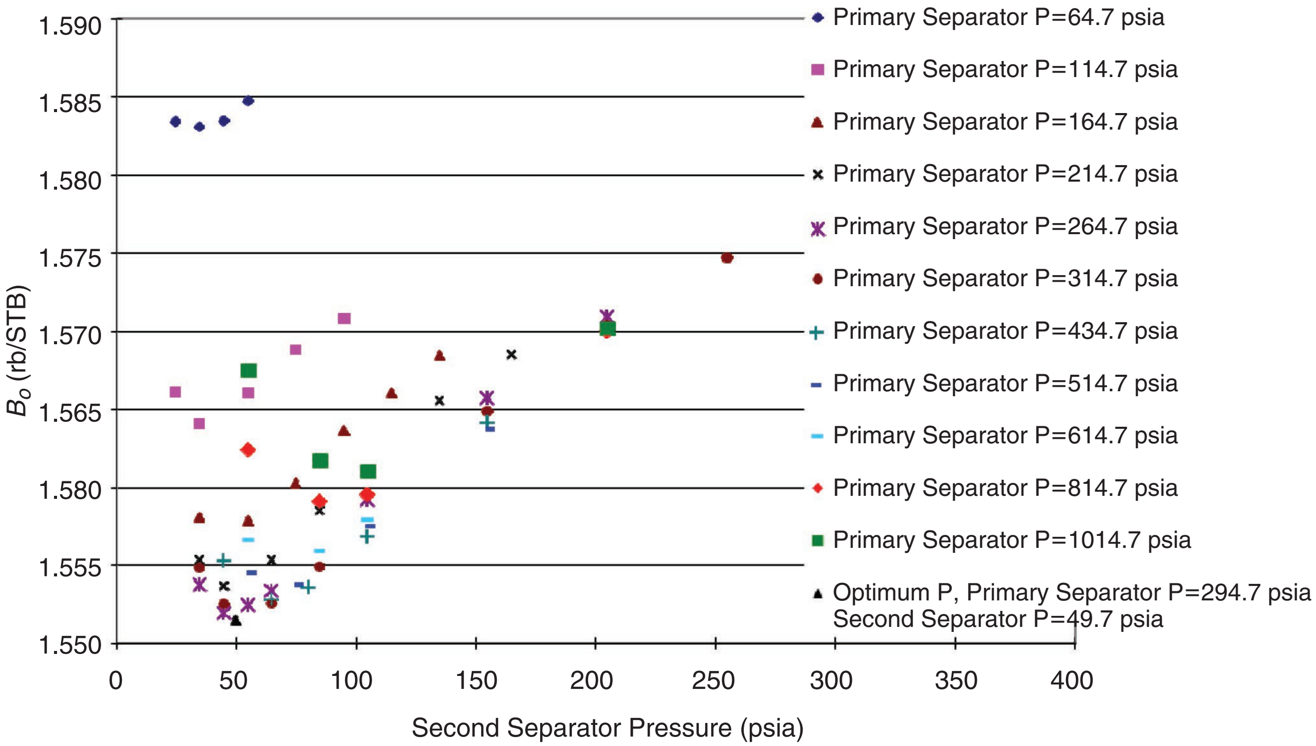

Fig. 5—Plots of B_o vs. separator pressures.

Four-Stage Separation. Composition of an oil sample was analyzed, and a four-stage separation test was performed assuming that FTP was equal to saturation pressure. Temperatures of the primary separator, secondary separator, third separator, and the stock tank are 120, 120, 110, and 60°F, respectively. During optimization the temperatures are kept constant. **Table 7** shows the composition of the wellstream that was fed into the separator.

In this four-stage separation, the wellstream flows at conditions of FTP of 4,383 psia and a temperature of 149°F. Separator tests at the conditions of the primary separator pressure of 1,850 psia

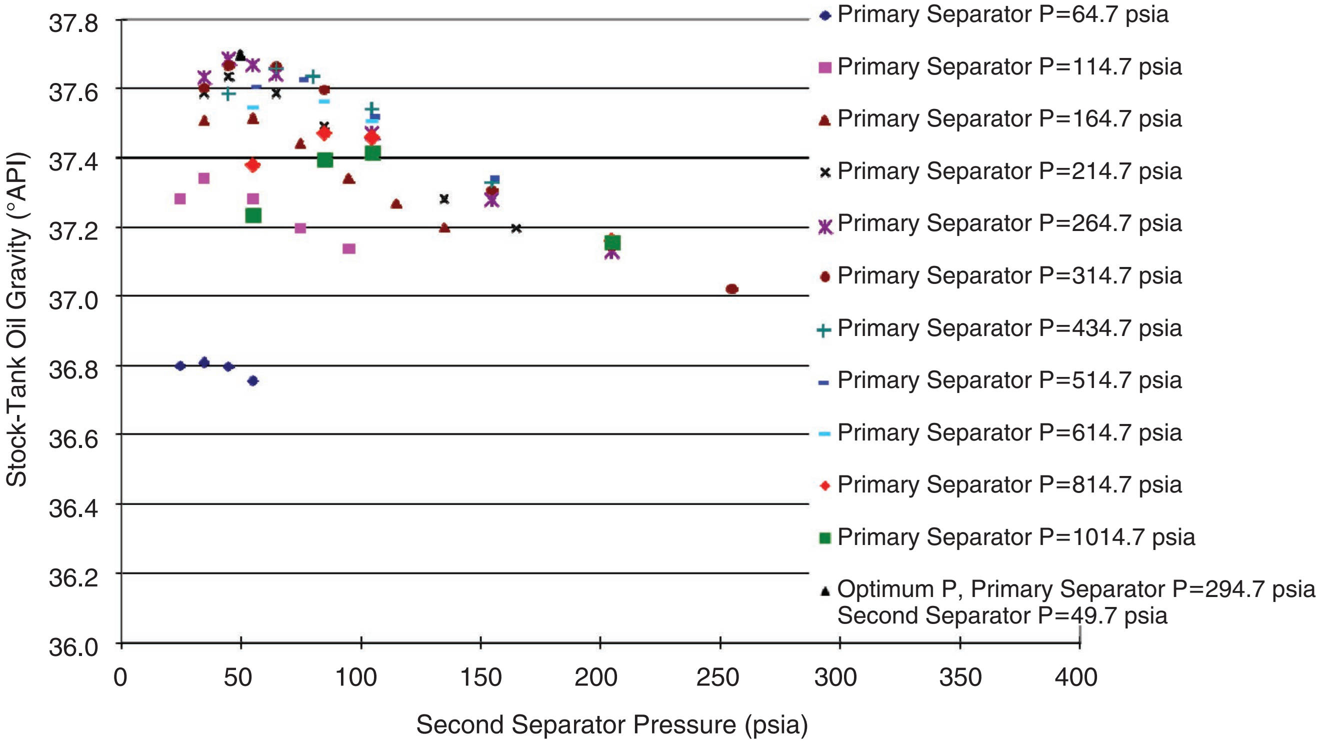

Fig. 6—Plots of stock-tank oil API gravity vs. separator pressures

TABLE 6—COMPARISONS OF GOR, B_o, AND STOCK-TANK OIL GRAVITY FROM DIFFERENT METHODS IN THREE-STAGE SEPARATION

	This Study	Natco Company Method (constant pressure ratio)	Bahadori's Method
Optimum primary separator pressure (psia)	294.7	434.3	314.7
Optimum secondary separator pressure (psia)	49.7	79.9	44.7
GOR (scf/STB)	948.011	941.892	950.233
B_o (rb/STB)	1.5510	1.5541	1.5532
Stock-tank oil gravity (°API)	37.705	37.617	37.665
Percent increase in stock tank barrels (%) This study compares with Natco Company method	0.1999	–	–
Percent increase in stock tank barrels (%) This study compares with Bahadori's method	0.1418	–	–

TABLE 7—COMPOSITION OF A WELL STREAM THROUGH A FOUR-STAGE SEPARATION

Component	Mole Fraction
Hydrogen sulfide	0
Carbon dioxide	0.0010
Nitrogen	0.0031
Methane	0.5633
Ethane	0.0313
Propane	0.0320
i-Butane	0.0076
n-Butane	0.0182
i-Pentane	0.0085
n-Pentane	0.0077
Hexane	0.0161
Heptanes plus	0.3112
Properties of heptanes plus	
Specific gravity	0.796
Molecular weight	213 lb/lb-mole

and temperature of 120°F, the second separator pressure of 750 psia and temperature of 120°F, the third separator pressure of 250 psia and temperature of 110°F, and the stock-tank pressure of 15 psia and temperature of 60°F give a total GOR of 926 scf/STB, a B_o of 1.448 rb/STB, and a stock-tank oil gravity of 47.0 °API, which agree with the theoretical calculation of a total GOR of 912 scf/STB, a B_o of 1.446 rb/STB, and a stock-tank oil gravity of 48.7 °API. The small differences between the calculated and laboratory GOR, B_o, and stock-tank oil gravity mean that EOS had been tuned and can be used for calculations of gas/liquid equilibria.

With the tuned EOS, the optimum separator pressures can be obtained by following the aforementioned procedure. **Table 8** shows the constant pressure ratio and several trials that led to the optimum separator pressure. It should be noted that after nine trials, the pressures converge to the optimum separator pressures. Table 8 also shows the total GOR, B_o, and stock-tank oil API gravity as functions of the separator and stock-tank pressures and temperatures at different trials in the calculation procedure. The percent increases in the stock-tank barrel are also shown in Table 8. The calculation procedure gives an optimum primary separator pressure of 999.7 psia, a second separator pressure of 299.7 psia, and a third separator pressure of 89.7 psia that result in a total GOR of 899.64 scf/STB, a B_o of 1.4391 rb/STB, and a stock-tank oil gravity of 48.996 °API, illustrated in Table 8, which agree with the optimum separator pressures obtained from **Tables 9 through 11.** Comparisons of GOR, B_o, and stock-tank oil gravity from our method with those from other methods are shown in **Table 12.** These indicate that our method gives the lowest GOR and B_o and the highest stock-tank oil gravity for four-stage separation.

Comparing the results from three cases, we observed that as the number of separation stages increases, the effect of change in separator pressures on the total GOR, B_o, and stock-tank oil API gravity decreases. Therefore, separator pressure has the highest effect on total GOR, B_o, and stock-tank oil API gravity in two-stage separation. Studies of three multistage separation cases illustrated that our method gives better results than existing methods. Our method is also crucial because of the fact that the number of separator tests in reservoir fluid studies is usually limited by cost and time, so that most reservoir fluid studies have less than five separator tests. With some studies only having one separator test, under such conditions it is difficult to estimate optimum separator pressure.

Conclusions

We have presented a method to estimate optimum separator pressures, using EOS to calculate the gas and liquid composition in separators and the stock tank. The optimum separator pressures result in a minimum of total GOR, a minimum in Bo, and a maximum in stock-tank oil API gravity.

Although case studies indicate that our method gives better results than does merely assuming a constant ratio between stages, the improvements are not significant given the uncertainties in fluid samples, as well as the changes in wellhead flowing pressures and fluid properties over time. Potentially either method has as much likelihood as being "optimum" over any finite period of time in the life of a field.

Optimum separator pressures should be determined considering oil recovery and equipment design constraints. It is important to choose the right initial separator pressure; to take into account pressure ratings of pipe, valves and fittings, and sales gas pressure; to select the correct number of stages; and to balance the cost and the complexity of adding each successive stage with diminishing returns in terms of liquid recovery and gravity. However, it is possible once the number of stages and their approximate pressures are chosen for initial design to consider minor modifications of operating pressures during the field life using our procedure as fluid properties become better defined and change with time.

As the number of separation stages increases, the effect of the change in separator pressures on the total GOR, Bo, and stock-tank oil API gravity decreases. Therefore, separator pressure has the highest effect on the performance of two-stage separation.

The proposed method can be applied to separator-test design if the reservoir fluid composition is available for PVT analysis. In cases where separator tests are not available, the proposed method can be used as a guiding tool for selecting the optimum separator pressures provided that the composition of the wellstream is known.

TABLE 8—CALCULATED TOTAL GOR, B_o, AND STOCK-TANK OIL GRAVITY IN DIFFERENT TRIALS USING AFOREMENTIONED CALCULATION PROCEDURE FOR FOUR-STAGE SEPARATION

	Constant Pressure Ratio	First Trial	Second Trial	Third Trial	Fourth Trial	Fifth Trial	Sixth Trial	Seventh Trial	Eighth Trial	Ninth Trial	Tenth Trial
Optimum primary separator pressure (psia)	1054.8	839.7	839.7	839.7	974.7	974.7	974.7	999.7	999.7	999.7	999.7
Optimum secondary separator pressure (psia)	253.8	253.8	224.7	224.7	224.7	289.7	289.7	289.7	294.7	299.7	299.7
Optimum third separator pressure (psia)	61.1	61.1	61.6	74.5	74.5	74.5	89.7	98.7	89.7	89.7	89.7
GOR (scf/STB)	913.544	902.750	901.959	901.656	901.302	901.024	900.717	099.421	899.850	899.640	899.640
B_o (rb/STB)	1.4475	1.4453	1.4438	1.4421	1.4411	1.4403	1.4400	1.4396	1.4393	1.4391	1.4391
Stock-tank oil gravity (°API)	48.698	48.853	48.903	48.921	48.932	48.945	48.969	48.979	48.988	48.996	48.996
Percent increase in stock tank barrels* (%)	0	0.1522	0.2563	0.3745	0.4441	0.4999	0.5208	0.5488	0.5697	0.5837	0.5837

* Comparing with constant pressure ratio method

Optimal separator setting is a dynamic process, and it should be changed according to input composition. When the wellstream composition changes with the producing time, the proposed method can be used to estimate the new optimum-separator pressures to update separating conditions.

Nomenclature

B_o = oil formation volume factor, rb/STB
GOR = gas/oil ratio, scf/STB
p = pressure, psia
p_{atm} = atmospheric pressure, psia
p_{sat} = saturation pressure of well stream fed into primary separator, psia
p_{SP1} = primary separator pressure, psia
p_{wh} = flowing tubing pressure, psia
Ratio_p = averaged pressure ratio
$SP1$ = primary separator
$SP2$ = second separator
$SP3$ = third separator
T = temperature, °F

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TABLE 9—TOTAL GOR (scf/STB) OF RESERVOIR OIL THROUGH A FOUR-STAGE SEPARATION

SP1 = 800 psia

SP3 Pressure	SP2 Pressure			
	150	210	250	300
20	922.68	924.83	828.53	931.65
50	904.21	902.63	904.45	905.17
80	903.61	900.85	900.95	900.88
110	905.37	902.35	902.11	901.72
140	907.86	905.48	904.53	904.15

SP1 = 900 psia

SP3 Pressure	SP2 Pressure			
	170	230	280	330
30	912.09	913.57	916.20	918.92
50	904.05	903.62	904.86	905.81
80	903.41	901.26	900.61	901.69
110	905.00	902.63	901.79	901.37
160	909.83	906.73	905.77	905.23

SP1 = 1000 psia

SP3 Pressure	SP2 Pressure			
	180	250	300	350
40	907.36	904.74	909.01	910.95
60	903.67	902.28	902.78	903.80
90	903.82	900.75	**899.64**	900.15
120	905.55	903.27	902.54	901.64
170	908.87	907.71	906.33	905.69

SP1 = 1100 psia

SP3 Pressure	SP2 Pressure			
	200	265	300	350
40	907.93	908.55	909.60	911.41
65	903.38	901.78	902.04	902.79
90	903.73	901.68	804.09	903.69
130	907.66	904.61	904.09	903.69
180	911.03	907.93	907.24	906.66

SP1 = 1200 psia

SP3 Pressure	SP2 Pressure			
	210	280	350	450
40	909.07	909.54	911.69	915.81
65	903.99	902.45	903.13	905.33
100	904.42	902.16	901.65	902.24
150	903.9	906.34	905.00	904.50
200	912.03	909.80	908.28	904.34

SP1 = 1300 psia

SP3 Pressure	SP2 Pressure			
	240	300	400	500
40	909.55	910.60	914.27	917.95
65	903.78	903.13	904.60	906.76
100	903.86	902.49	902.17	903.06
150	908.25	906.50	904.86	904.86
230	912.72	911.83	910.16	909.47

SP1 = 1500 psia

SP3 Pressure	SP2 Pressure			
	300	325	500	700
40	911.83	912.15	918.08	925.45
70	904.36	904.25	906.08	910.71
150	907.51	906.96	905.48	906.77
250	914.17	913.56	911.14	910.97
290	1012.51	915.72	913.56	913.14

SP1 = 1700 psia

SP3 Pressure	SP2 Pressure			
	300	350	500	700
40	913.28	914.28	919.09	925.94
70	905.87	905.56	906.98	911.23
150	908.91	907.68	906.18	907.26
250	915.42	913.65	911.63	911.40
290	916.54	915.92	914.08	913.37

SP1 = 1900 psia

SP3 Pressure	SP2 Pressure			
	350	380	600	1000
40	915.53	916.23	922.82	935.65
75	906.33	906.19	908.61	917.19
150	908.97	908.30	906.76	910.07
250	914.81	914.19	912.01	912.95
340	919.54	919.30	917.03	916.97

SP1 = 2100 psia

SP3 Pressure	SP2 Pressure			
	350	400	800	1100
40	916.63	917.67	930.03	939.00
75	907.67	907.35	913.26	919.86
150	910.16	908.97	908.48	911.47
250	916.02	914.81	912.04	913.00
340	920.60	919.70	916.98	917.47

SP1 = 2300 psia

SP3 Pressure	SP2 Pressure			
	400	430	800	1200
40	918.55	919.22	930.30	941.87
80	907.93	907.80	912.45	920.61
150	909.73	909.18	909.29	913.00
250	915.49	914.79	912.45	913.72
390	922.58	922.41	920.04	920.09

TABLE 10— B_o (rb/STB) OF RESERVOIR OIL THROUGH A FOUR-STAGE SEPARATION

SP1 = 800 psia					SP1 = 900 psia				
	SP2 Pressure					SP2 Pressure			
SP3 Pressure	150	210	250	300	SP3 Pressure	170	230	280	330
20	1.4527	1.4545	1.4565	1.4586	30	1.4463	1.4472	1.4489	1.4506
50	1.4414	1.4407	1.4416	1.4422	50	1.4414	1.4412	1.4419	1.4425
80	1.4412	1.4397	1.4395	1.4396	80	1.4411	1.4398	1.4394	1.4399
110	1.4424	1.4407	1.4402	1.4401	110	1.4421	1.4406	1.4401	1.4398
140	1.4438	1.4423	1.4416	1.4413	160	1.449	1.4429	1.4424	1.4420

SP1 = 1000 psia					SP1 = 1100 psia				
	SP2 Pressure					SP2 Pressure			
SP3 Pressure	180	250	300	350	SP3 Pressure	200	265	300	350
40	1.4434	1.4437	1.4445	1.4458	40	1.4438	1.4442	1.4449	1.4460
60	1.4413	1.4403	1.4406	1.4413	65	1.4411	1.4401	1.4403	1.4407
90	1.4414	1.4397	**1.4391**	1.4394	90	1.4414	1.4401	1.4398	1.4399
120	1.4425	1.4410	1.4406	1.4400	130	1.4435	1.4416	1.4412	1.4410
170	1.4445	1.4437	1.4428	1.4424	180	1.4457	1.4438	1.4433	1.4430

SP1 = 1200 psia					SP1 = 1300 psia				
	SP2 Pressure					SP2 Pressure			
SP3 Pressure	210	280	350	450	SP3 Pressure	240	300	400	500
40	1.4445	1.4449	1.4462	1.4489	40	1.4449	1.4455	1.4479	1.4502
65	1.4415	1.4405	1.4410	1.4423	65	1.4414	1.4410	1.4419	1.4432
100	1.4418	1.4404	1.4400	1.4404	100	1.4415	1.4406	1.4404	1.4409
150	1.4444	1.4427	1.4419	1.4416	150	1.4439	1.4428	1.4418	1.4418
200	1.4464	1.4450	1.4440	1.4435	230	1.4468	1.4463	1.4453	1.4448

SP1 = 1500 psia					SP1 = 1700 psia				
	SP2 Pressure					SP2 Pressure			
SP3 Pressure	300	325	500	700	SP3 Pressure	300	350	500	700
40	1.4463	1.4466	1.4504	1.4551	40	1.4473	1.4479	1.4510	1.4555
70	1.4418	1.4417	1.4429	1.4458	70	1.4427	1.4425	1.4435	1.4462
150	1.4435	1.4432	1.4422	1.4430	150	1.4444	1.4436	1.4427	1.4433
250	1.4487	1.4474	1.4459	1.4458	250	1.4486	1.4475	1.4463	1.4461
290	1.5134	1.4488	1.4475	1.4472	290	1.4494	1.4490	1.4478	1.4474

SP1 = 1900 psia					SP1 = 2100 psia				
	SP2 Pressure					SP2 Pressure			
SP3 Pressure	350	380	600	1000	SP3 Pressure	350	400	800	1100
40	1.4487	1.4492	1.4535	1.4618	40	1.4495	1.4501	1.4582	1.4640
75	1.4431	1.4430	1.4445	1.4500	75	1.4439	1.4437	1.4475	1.4517
150	1.4445	1.4441	1.4431	1.4452	150	1.4452	1.4445	1.4442	1.4461
250	1.4483	1.4479	1.4465	1.4471	250	1.4452	1.4445	1.4442	1.4461
340	1.4513	1.4512	1.4498	1.4497	340	1.4520	1.4514	1.4497	1.4501

SP1 = 2300 psia				
	SP2 Pressure			
SP3 Pressure	400	430	800	1200
40	1.4507	1.4511	1.4583	1.4659
80	1.4441	1.4440	1.4470	1.4523
150	1.4450	1.4447	1.4447	1.4471
250	1.4488	1.4483	1.4469	1.4477
390	1.4533	1.4532	1.4517	1.4518

TABLE 11—STOCK-TANK OIL API GRAVITY OF RESERVOIR OIL THROUGH A FOUR-STAGE SEPARATION

SP1 = 800 psia

	SP2 Pressure			
SP3 Pressure	150	210	250	300
20	48.522	48.468	48.400	48.335
50	48.917	48.939	48.908	48.889
80	48.923	48.973	48.980	48.978
110	48.880	48.938	48.953	48.946
140	48.831	48.878	48.902	48.912

SP1 = 900 psia

	SP2 Pressure			
SP3 Pressure	170	230	280	330
30	48.747	48.717	48.659	48.601
50	48.916	48.925	48.897	48.877
80	48.925	48.971	48.985	48.967
110	48.889	48.940	48.958	48.967
160	48.791	48.857	48.876	48.888

SP1 = 1000 psia

	SP2 Pressure			
SP3 Pressure	180	250	300	350
40	48.847	48.839	48.810	48.769
60	48.922	48.954	48.943	48.920
90	48.916	48.973	48.996	48.986
120	48.877	48.925	48.941	48.960
170	48.805	48.831	48.861	48.874

SP1 = 1100 psia

	SP2 Pressure			
SP3 Pressure	200	265	300	350
40	48.835	48.822	48.799	48.760
65	48.929	48.963	48.957	48.941
90	48.919	48.963	48.970	48.969
130	48.842	48.907	48.918	48.926
180	48.764	48.829	48.844	48.856

SP1 = 1200 psia

	SP2 Pressure			
SP3 Pressure	210	280	350	450
40	48.811	48.801	48.755	48.667
65	48.916	48.949	48.934	48.887
100	48.904	48.952	48.963	48.950
150	48.812	48.867	48.986	48.907
200	48.742	48.788	48.820	48.840

SP1 = 1300 psia

	SP2 Pressure			
SP3 Pressure	240	300	400	500
40	48.802	48.779	48.701	48.623
65	48.921	48.935	48.903	48.857
100	48.916	48.946	48.953	48.933
150	48.828	48.864	48.900	48.900
230	48.726	48.743	48.778	48.793

SP1 = 1500 psia

	SP2 Pressure			
SP3 Pressure	300	325	500	700
40	48.75	48.75	48.62	48.47
70	48.91	48.91	48.87	48.77
150	48.84	48.86	48.89	48.86
250	48.69	48.71	48.76	48.76
290	48.84	48.66	48.70	48.71

SP1 = 1700 psia

	SP2 Pressure			
SP3 Pressure	300	350	500	700
40	48.72	48.70	48.60	48.46
70	48.88	48.89	48.85	48.76
150	48.82	48.84	48.87	48.85
250	48.67	48.71	48.75	48.75
290	48.65	48.66	48.70	48.71

SP1 = 1900 psia

	SP2 Pressure			
SP3 Pressure	350	380	600	1000
40	48.63	48.66	48.53	48.26
75	48.87	48.87	48.82	48.64
150	48.82	48.83	48.86	48.79
250	48.68	48.70	48.74	48.72
340	48.58	48.59	48.63	48.63

SP1 = 2100 psia

	SP2 Pressure			
SP3 Pressure	350	400	800	1100
40	48.66	48.63	48.38	48.20
75	48.84	48.85	48.72	48.59
150	48.79	48.82	48.83	48.77
250	48.66	48.69	48.74	48.72
340	48.56	48.58	48.64	48.63

SP1 = 2300 psia

	SP2 Pressure			
SP3 Pressure	400	430	800	1200
40	48.62	48.60	48.37	48.14
80	48.84	48.84	48.74	48.57
150	48.80	48.82	48.81	48.73
250	48.67	48.69	48.74	48.71
390	48.52	48.52	48.57	48.57

TABLE 12—COMPARISONS OF GOR, B_o, AND STOCK-TANK OIL GRAVITY FROM DIFFERENT METHODS IN FOUR-STAGE SEPARATION

	This Study	Natco Company Method (constant pressure ratio)	Bahadori's Method
Optimum primary separator pressure (psia)	999.7	1054.8	1500
Optimum secondary separator pressure (psia)	299,7	253.8	500
Optimum third separator pressure (psia)	89.7	61.1	100
GOF (scf/STB)	899.640	913.544	905.812
B_o (rb/STB)	1.4391	1.4475	1.4425
Stock-tank oil gravity (°API)	48.996	48.698	48.878
Percent increase in stock tank barrels (%) This study compares with Natco Company method	0.5837	–	–
Percent increase in stock tank barrels (%) This study compares with Bahadori's method	0.2363	–	–

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