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Simulation-Based Optimization for Multistage Crude Oil Production Units: Economic Evaluation and Decision-Making Process

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ABSTRACT

The optimization of the operating pressure of the separators in the multi-stage crude oil production units has an undeniable effect on the quantity and quality of oil production. In this regard, the present study exploited a simulation-based approach to optimize a multi-stage crude oil production unit by determining the optimal separator pressure and number which maximizes the oil production rate, and operational flexibility while minimizing fixed and operating costs, and power consumption of the compressors. The decision-making process was performed for two cases in the national Iranian south oil company. The number of separation stages and their different arrangements were considered the desired goals. According to the results, for the first case, maximum oil production can be achieved using these two-phase separators and one degasser tank, while the cold stripping method was recommended for the second case. Furthermore, economic evaluations were conducted by calculating the fixed initial investment and the total operating costs. The simulation results predicted the pressure of the production well in 2030 as 8.27 MPa. For the reservoir pressure of 7.58 MPa, the fixed project costs will be reduced by $11965307, while the oil production will decrease by about 20 barrels per day. It will result in a $58.4 million reduction in revenue over the next twenty years. Therefore, the optimal pressure of the reservoir was assumed to be about 6.89 MPa.

Introduction

High pressure at the bottom of the production well can result in the dissolution of a huge quantity of gases in the crude oil. These dissolved gases tend to leave the crude oil at low pressures (i.e. upon bringing the crude oil to the surface) [1]. The dissolved gases (in the gas phase) can be separated from the crude oil (in the liquid phase) by a separator [2]. A separator is a pressure vessel capable of separating the oil/gas well fluids into gaseous and liquid components. The process of crude oil production involves two or more consecutive separators (multi-stage) that operate at lower pressures to maximize the gas/liquid separation [3, 4]. The number of stages in the multi-stage crude oil production depends on API-gravity oils, gas/oil ratios (GORs), and flowing pressures [5]. Theoretically, more stages of consecutive separation will lead to more recovered liquid offering higher commercial value. In practice, however, the

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real number of separations is often limited by the available space and operational cost [6]. The single-stage separation system is used in the primary oil preparation plants. Such systems are fair and reasonable for oils with low water and gas content (less than 1/3 of the total mixture). Two-stage separation systems are recommended in the cases where the total water and gas content is significantly higher or equal to the oil content [7]. Among the various arrangement, the four-stage separation process has been often considered the most optimal choice [8]. In comparison with three-stage separation, the four-stage arrangement offers 2–12% higher liquid recoveries which can sometimes rise to 25% higher recoveries. Despite the higher recovery rates of the processes with more separation stages, such units are limited due to the capital investment and operating costs associated with higher numbers of separators [9]. The operating pressure plays a crucial role in separator performance as it can determine the amount of liquid production. In practice, this pressure is controlled with a backpressure valve through which the separated gas flows to the gas pipeline [10].

Although the temperature is a major factor in the quantity of recovered liquid along with the pressure, it is a function of the ambient temperature, and the separators usually operate at temperatures almost the same as the surface temperature. Therefore, pressure is typically the key factor in optimization studies. The high separator pressure will maintain a huge quantity of light components in the liquid phase. These components (along with other valuable components) will be then transformed into the gas phase at the stock tank [11, 12]. On the contrary, too low pressures will lead to the separation of a large number of light components from the liquid phase, while they can attract large amounts of intermediates and heavier components [13]. Therefore, it is essential to optimize the operating separator pressures in winter and summer to maximize the recovered liquid [2]. Furthermore, the operating pressure of the separator has another undeniable impact on the process of the separated streams. The successful delivery of oil to the next processing stage requires minimum pressure.

Moreover, high pressure will deliver the gas stream for sales at higher output pressure. Hence, maintaining a high-pressure condition will decline the compressor power in the gas pumping process [14]. The optimum operating pressure is a pressure that compromises the two extreme conditions (high-pressure and low-pressure operations) to maximize the oil production rate [15].

Theoretically, the equilibrium flash calculations can be used to estimate the quantities of the recovered gas and liquid based on the equation of states, which provides the optimal pressure corresponding to each separator [16]. The performance of a separation process can be evaluated by reasonable mathematical-based methods and algorithms [17-19]. The process of crude oil production is influenced by numerous obstacles; Moreover, its inherent complex internal interactions are another challenge in finding effective approaches considering quantitatively and qualitatively [9, 20]. Despite the development of various correlation methods for estimation of the optimized pressure, the desired technique has not been accessed yet due to the complexity of phase behavior calculations and costly methods [21-23]. In this context, in this work, the process simulation was evaluated as a prominent procedure to optimize the separator pressure for maximizing the liquid recovery while reducing the fixed and operating costs, as well as the energy consumption.

The most accurate correlation method for the optimization of the middle-stage separator pressure is applying vapor/liquid equilibrium thermodynamics to model the behavior of crude oil through the separation process. This defines the middle-stage pressure, which maximizes oil accumulation in the stock tank. The value of the pressures of the stages was determined by using flash calculations. In this calculation, the properties of the corresponding fluid are a key point, and it changes through separation stages. The equation of states can predict the properties of the fluid at any pressure and composition. These equations are then used in the flash calculation to achieve the desired data. Hence, by employing an optimization-based method, the maximum oil production can be traced while flash calculations are conducted in a process simulator with a different set of pressures. In this study, certain production and compression units were modeled for a multi-stage separation unit using a process simulator. To predict the phase behavior and properties of the fluid at different pressures, the Peng-Robinson equation of state was used in the optimization process.

The first step is defining the fluid composition and fraction optimization. Afterward, the initial pressure values of all the separators are calculated by the constant-ratio method. Then, the optimization process is conducted for the first separator by considering the defined constraints. After the convergence of the pressure of the first separator, the second separator is optimized, and the same procedure is repeated for the other separators. By reaching the final separator, the whole procedure is repeated for all the separators again until full convergence is achieved. It should be noted that in optimizing the pressure of each separator, the pressure is set at the optimized pressure values of the separators, which are optimized before the current one.

The number of stages in a multi-stage conventional separation process is a function of the American petroleum institute (API) gravity of the oil, gas-oil ratio (GOR), and the wellhead flowing pressure. The separator pressure can be optimized by calculating the API gravity and GOR in the manner outlined above at different assumed pressures. The optimum pressure corresponds to a maximum in the API gravity and a minimum in GOR. To this end, two different cases were selected: a crude oil production unit with four separation stages (Case#1) and a gas condensate production unit with three separation stages (Case#2). These cases have been planned by the national Iranian south oil company to prevent associated gas flaring. By this project commissioning, the existing cases will be extended, and the following units/pipeline will be added:

• Sweetening of 17000 standard barrels per day of sour crude oil.
• Gas compression & injection unit.

The gas released from Case#1 will be compressed in different stages after gathering, which will be finally injected into well #7. The maximum required injection rate is 27000 MMSCFD.

Problem Statement

The national Iranian south oil company intends to prevent the burning of the associated gases by injecting them from the Case#1 plant. In this regard, it has been decided to collect the gases from the Case#1 oil production unit (Case#1 and Case#2 plants) to increase the pressure for the injection operation by adding a gas collection and injection unit. Currently, there is a pipeline between well No. 5 (Case#1) and the injection of well No. 7 whose fluid, in the new design, should be sent to the Case#1 compression unit due to the reduction in pressure of well No. 5; in this way, after the separation of the condensates, the pressure of exhaust gases will be increased up to injection pressure.

The main objectives of this work are:

- The maximum rate of oil production (barrel per day)
- Maximum operational flexibility
- Minimizing the fixed and operating costs
- Minimizing the power consumption of compressors

The objective function ($f(x)$) for separator pressure optimization can be formulated as follows:

$$f(x) = \begin{cases} Maximize \begin{cases} Stock\ tank\ oil\ gravity\ (API) \\ Liquid\ volume\ in\ the\ stock\ tank\ (V_{OST}) \end{cases} \\ Minimize \begin{cases} Total\ gas - \ oil\ ratio\ (GOR) \\ Oil\ formation\ volume\ factor\ (B_0) \end{cases} \end{cases}$$

The terms of the stated objective function are equivalent, e.g., if stock tank oil API gravity is maximized, then the oil formation volume factor and gas-oil ratio are minimized.
The constraints of the optimization problem can be expressed as:

$$P_1 < P_{allowable} \tag{1}$$

The first-stage pressure must not exceed the maximum allowable designed pressure:

$$P_1 . P_2 . \dots P_{N-1} \ < P_N \tag{2}$$

The subscripts i, 1, 2, 3, …, and N represent stage numbers. The pressure of a separator before the stock tank must not be below the stock tank pressure, which equals atmospheric pressure approximately:

$$P_{i+1} > P_i \tag{3}$$

The pressure of a separator cannot exceed the pressure of the previous separator.

The value of the objective function (API, GOR, B_o, and V_{OST}) with assigned feasible pressure to each separator is obtained. To calculate the objective function of each solution in the population, HYSYS software was used to perform flash calculations for each separator. After that, the outputs of HYSYS software were analyzed to calculate the objective function.

Another suggested calculation method for optimizing the surface separation operations focuses on the maximum production of the liquid and minimum gas recompression costs associated with the selection of a low middle-stage operating pressure. This method is based on the minimization of required compressor horsepower. When produced, the gas must be compressed to pipeline pressures; minimizing compressor horsepower may yield the most economical. However, experience shows that horsepower optimization may not be as simple as maximizing stock-tank oil recovery, and it has very little effect on oil production and API gravity.

Methodology

The main objective of this work is to optimize the number of separation stages depending on the type of the applied sweetening method. Two crude oil production units were considered: (i) Case#1, and (ii) Case#2. In Case#1 unit, a four-stage separation (two-phase separator) was used, while for Case#2, the two-phase and three-phase separators were not efficient due to the presence of hydrogen sulfide (Table. A.1). Therefore, two different methods can be used for Case#2: hot stripping and cold stripping. Given the higher investment and operation costs of the hot stripping, cold stripping was selected for Case#2. A comprehensive strategy based on HYSYS software was applied to simulate the crude oil separation. The separation stages can be optimized by determining the optimum pressure for middle separators. Accordingly, vapor-liquid equilibrium calculations should be used. The optimum pressure value of each stage corresponds to the minimum liquid yield (by minimizing the gas-oil-ratio (GOR) and the formation volume factor) of the minimum quality (by maximizing stock-tank API gravity)[6].

In HYSYS, the Peng–Robinson package is inclusive and enhanced binary parameters for all library pairs of hydrocarbon–hydrocarbon and for most hydrocarbon–non-hydrocarbon binaries. In this work, the Peng–Robison equation of state was chosen because the equation solves most single-phase, two-phase, and three-phase systems more efficiently and reliably. The enhancements made in the Peng–Robinson model ensure its accuracy for various systems over conditions of a wide range. HYSYS automatically generates the interaction parameters of hydrocarbon–hydrocarbon bond for hydrocarbon pseudo-components. Here the theoretical approach is used. It is stated as van der Waals equations, and the Peng–Robinson equations are solved until the fugacity parameter was distinguished to be the phases of hydrocarbon fluid mixtures. However, the thermodynamic property method was implemented in HYSYS to calculate the fugacity coefficient and convergence criteria.

The computational steps of the separator calculation are described as follows:

Step 1: Given the composition of the feed stream to the first separator and the operating conditions of the separator (i.e. separator pressure and temperature) calculate the equilibrium ratios of the hydrocarbon mixture by a pre-tuned EOS. In this work, the Peng-Robinson EOS was used.

Step 2: Assuming a total of F moles of the feed entering the first separator and using the above-calculated equilibrium ratios, perform flash calculations to obtain the compositions and quantities (in moles) of the gas and the liquid leaving the first separator.

Step 3: Using the composition of the liquid leaving the first separator as the feed for the second separator, calculate the equilibrium ratios of the hydrocarbon mixture at the prevailing pressure and temperature of the separator.

Step 4: Based on 1 mole of the feed, perform a flash calculation to determine the compositions and quantities of the gas and liquid leaving the second separation stage.

Step 5: The previously outlined procedure is repeated for each separation stage, including the stock tank stage, and the calculated moles and compositions are recorded.

Step 6: Determine the volume of stock tank oil occupied by moles of liquid.

Step 7: Calculate the specific gravity and the API gravity of the stock tank oil.

Step 8: Calculate the total GOR.

The separator pressure can be optimized by calculating the API gravity and GOR in the manner outlined above at different assumed pressures. The optimum pressure corresponds to a maximum in the API gravity and a minimum in GOR.

The phase behavior model can be employed to calculate the API gravity and the formation volume factor (B0). The GOR was also calculated using the following equation [16]:

$$GOR = \frac{Total\ Volume\ of\ Gas\ Produced\ (in\ standard\ cubic\ feet)}{Total\ Volume\ of\ Liquid\ Produced\ (in\ stock{-}tank\ barrels)} = \frac{(V_g)_{SC}}{(V_o)_{ST}/5.615} \tag{4}$$

where

$$(V_0)_{ST} = \frac{n_{ST}(Z_0)_{ST}RT_{ST}}{P_{ST}} \tag{5}$$

$$(V_g)_{SC} = 379.4\frac{SCF}{Ibmol}(n_g)_{TOTAL} = 379.4(1-n_{ST})_{[basis:1\ Ibmol\ of\ feed]} \tag{6}$$

therefore

$$GOR = \frac{5.615}{379.4}R\ (\frac{n_{ST}}{1-n_{ST}})(\frac{T_{ST}}{P_{ST}})(Z_0)_{SC_{[SCF/STB]}} \tag{7}$$

As one of the well-known equations of states, the Peng-Robinson equation was applied to model the process. The isothermal flash calculations were also used to estimate the composition in the gas and liquid phases for each of the separation stages as follows:

$$K_i(P\&T\&z_i) = \frac{x_i}{y_i} \tag{8}$$

where the K_i is the equilibrium ratio of component i.

The mole fraction computations were performed for each stream using the following equations:

$$z_i = f_g(K_i x_i) + (1 - f_g)x_i \tag{9}$$
$$x_i = z_i/(f_g(K_i - 1) + 1) \tag{10}$$
$$y_i = z_i K_i/(f_g(K_i - 1) + 1) \tag{11}$$

where $f_g = n_V/n$, $f_l = n_L/n$, $z_i = n_i/n$, $y_i = n_{gi}/n$, $x_i = n_{Li}/n$ and $n = n_L + n_g$.

By calculation ofn_{gi}, n_{Li} and y_i, the GOR and API Gravity can be calculated for each separator. Hence, the optimum pressure can be obtained for a multi-stage separation process.

The compressor power requirement is an essential key in designing a multi-stage crude oil production unit. Accordingly, the power consumption calculations were performed using the following equations:

$$\frac{Power}{Stage} = \frac{m^{\cdot}(h_2 - h_1)}{Efficiency} \tag{12}$$

where $m^{\cdot}$ represents the mass flow rate, while h_1 and h_2 are the specific enthalpies at suction and discharge of compressor, respectively. The power requirement for an isentropic process is calculated using the following equation:

$$\frac{Power}{Stage} = \frac{k}{k-1}\frac{T_1 Z_a}{\eta} q \frac{P_s}{T_s}\left[\left(\frac{P_2}{P_1}\right)^{\frac{K-1}{K}}\right] \tag{13}$$

The power requirement for an isentropic process can be obtained using the following equation:

$$Power = \frac{k}{k-1} T_1 Z_a m^{\cdot} R\left[\left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}} - 1\right] \tag{14}$$

Accordingly, the power requirement for a polytropic process is calculated using the following equation:

$$\frac{Power}{Stage} = \frac{n}{n-1}\frac{T_1 Z_a}{\eta_p} q \frac{P_s}{T_s}\left[\left(\frac{P_2}{P_1}\right)^{\frac{n-1}{n}} - 1\right] \tag{15}$$

As mentioned above, a very important economic option for the reduction in operating cost is the minimizing of compressor power consumption over the years. Thus, calculations of power demand were performed using Eq. 16. This equation helps to estimate total compressors' horsepower to optimize a multi-stage separation facility.

$$H_{Pg} = \frac{q_1 P_1}{229 E_P}\left(\frac{Z_1 + Z_2}{2Z_1}\right)\left(\frac{r^R P - 1}{R_p}\right) \tag{16}$$

where H_{Pg} is compressor demand (hp), while P_1, P_2, and T_1 represent the compressor suction pressure (Pa), discharge pressure (Pa), and compressor temperature (K), respectively. Z_1 and Z_2 represent compressibility factors at the inlet and outlet, respectively.

The cost-saving through the minimization of compressor demand can be calculated for a projection of one year as against the original plant:

$$Annual\ Energy\ Cost\ (\$) = H_{Pg}\ x\ EE_{cu}\ x\ t \quad (17)$$

where EE_{cu} shows the electrical energy cost per unit (\$/W.s), while t indicates the compressor operating time (s).

Assumption

- The oil production rate of Case#1 in the early years of the project is 15,000 BPD (regardless of the returned condensate from the gas compression section).
- The oil production rate of Case#2 in the early years of the project is 2,000 BPD (regardless of the returned condensate from the gas compression section).
- The injection gas flow rate to Case#1 in the early years of the project is 27 MMSCFD.
- Due to the pressure of the Case#1 wells, 15% of the wells can flow to a maximum pressure of 0.36 MPa.
- The desalination unit is situated after the degassing tank.
- The multi-phase separator of well # 5 is located in the gas collection and injection unit of Case#1.
- Regarding the infeasibility of using a pump to transfer oil to the degassing tank, the minimum pressure of the separation stage before the degassing tank is 0.14 MPa.
- The degassing tank operates at the pressure of 0.10 MPa, as the final separation stage.

The first separator of both Case#1 and Case#2 operates at the highest possible pressure to achieve maximum oil recovery at the lowest compressor unit work.

Results and Discussion

After selecting the sweetening method, the determination of the number of separation stages is the desired goal. First, the sweetening of the crude oil related to each plant was investigated, then the mixture of the crude oils from both plants was studied. To compare the results, 277.8 mol/s of the Case#1 crude oil (inlet to plant, dry), and 55.6 mol/s of the Case#2 crude oil (inlet to plant, dry) at a constant level, were considered as the basis of the calculations. These values were selected based on the approximated oil production of Case#1 Plant and Case#2 Plant (15000 and 2000 barrels per day, respectively) (Table. A.2).

Case #1 crude Oil Production Plant

The schematic of Case#1 crude oil production plant using four separation stages is depicted in Fig. 1.

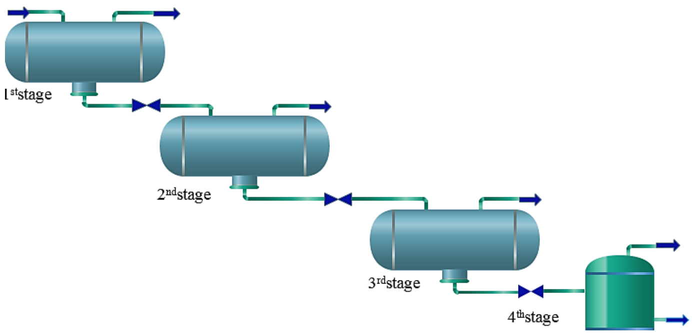

Fig. 1. The schematic of Case#1 crude oil production plant using four separation stages

The pressure of the separations stages was 0.82 MPa, X, 0.14 MPa, and 0.007 MPa corresponding to the 1st, 2nd, 3rd, and 4th stages, respectively. To determine the optimum pressure of the four separation stages, the pressure of the third stage was set at 0.14 MPa and 0.18 MPa, and the effect of the pressure of 2nd separation stage on the oil production rate was investigated (Fig. A.1 and A2). As can be seen, an increase in pressure of the second stage enhanced oil production. But since the second stage pressure can have the maximum pressure of 0.36 MPa to pass 15% of the wells in the Case#1 zone, this pressure was considered the optimum pressure.

A reduction in the pressure of the third separation stage increased oil production. However, as the minimum pressure of the third stage can be 0.14 MPa, this pressure was considered the optimal pressure of the third stage. If the pressure of the second stage separation is equal to the maximum allowable level, i.e. 0.36 MPa, the oil production rate will be per the values listed in Table 1. As can be seen, the maximum oil production rate can be recorded at the minimum pressure of the 3rd stage.

Table 1. The oil production rate

The pressure of separation stages (MPa)				**Oil production rate (standard barrel per day)**
1st	**2nd**	**3rd**	**4th**	
0.83	0.36	0.14	0.007	15032
0.83	0.36	0.18	0.007	15021

Fig. 2 shows the effect of second stage pressure on the oil production rate, while the third stage pressure is set to 0.14 MPa (the minimum allowable pressure for the 3rd stage). The daily oil production rate will reach 15032 barrels if the pressure of the second stage is set to 0.36 MPa. Notably, from the operational point of view, as there is no path to deliver crude oil from low-pressure wells to the third stage of separation, such action requires adding headers from the low-pressure wells to the third stage of separation. If the header-collecting wells are connected to the third stage separator, it is possible to increase the second stage separator pressure.

Fig. 3 illustrates the transfer of 15% of Case#1 crude oil to the third stage separator with a pressure of 0.14 MPa at a variable second stage separator. It can be seen that the oil production rate was lower than when 15% of the wells were sent to the second separation stage. In the case of using four-stage separation, the optimum condition was achieved at pressures of 0.83 MPa, 0.36 MPa, 0.14 MPa, and 0.007 MPa corresponding to the 1st, 2nd, 3rd, and 4th separation stages, respectively. Under this condition, 15% of Case#1 wells' crude oil is sent to the second separation stage.

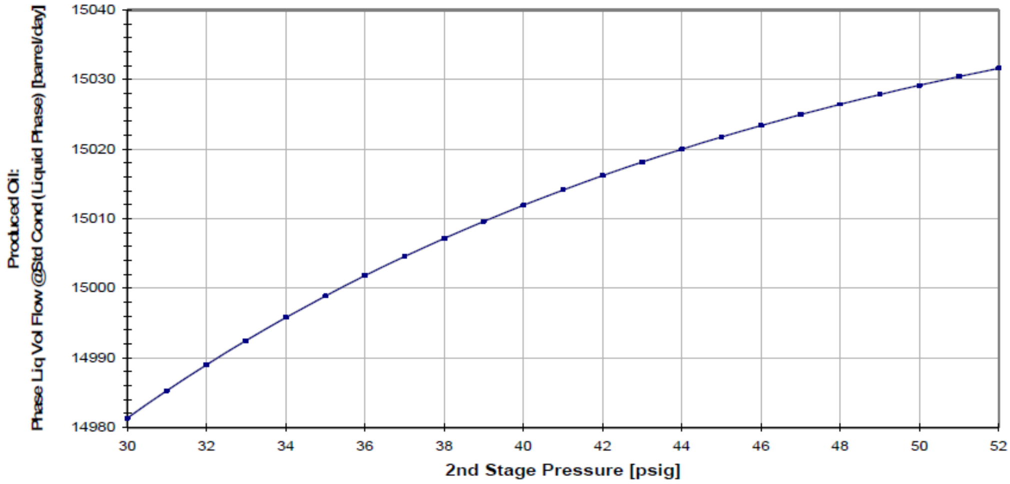

Fig. 2. The effect of 2nd stage separator pressure variation on the oil production rate, assuming the 3rd stage separator pressure be 0.14 MPa

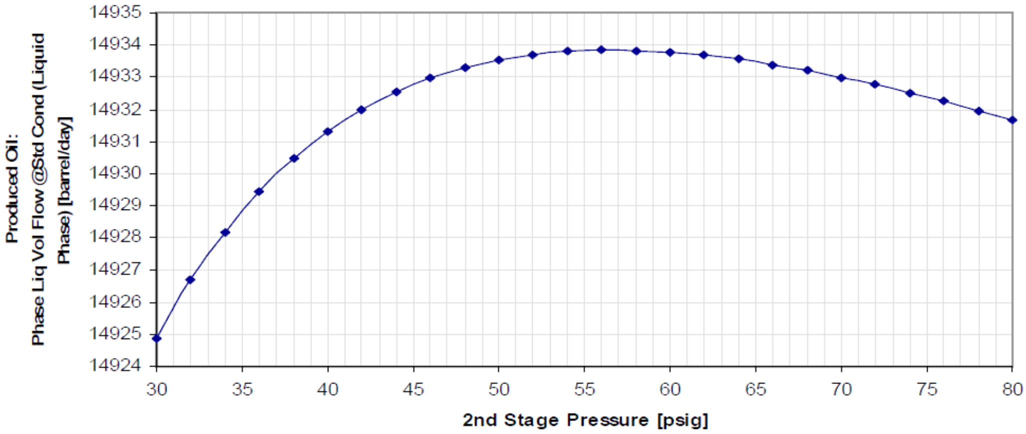

Fig. 3. The effect of 2nd stage separator pressure variation on the oil production rate, based on the transfer of 15% of Case#1 crude oil to the third stage separator with a pressure of 0.14 MPa

To investigate the feasibility of using separators of Case#1 unit, for the Case#2 crude oil processing, three separation stages of the Case#1 crude oil were studied (removing a separator from the Case#1 service to be used in Case#2 oil processing). The pressure of the 1st, 2nd, and 3rd stages was 0.83 MPa, X, and 0.007 MPa, respectively (Fig. A.3).

For calculating the optimum pressure of mid-stage separation, the pressures of the first separation stage and the storage tank were set at 0.83 MPa (the maximum possible pressure), and 0.007 MPa, respectively, and the effect of the mid-stage separation pressure was assessed on the oil production rate.

According to Fig. A.4, the optimum pressure of the 2nd stage was 0.17 MPa which can result in the maximum oil production rate. However, the 2nd stage pressure was assumed to be 0.36 MPa to equalize the pressure of this stage with the first stage of Case#2 oil and reduce the compressor work (see Fig. A.5). At the second stage pressure of 0.36 MPa, the daily oil production rate will be 14970 barrels. It is worth noting that by elevating the 2nd stage pressure from 0.30 MPa to 0.36 MPa, the oil production rate will be decreased by only two barrels per day (Fig. A.4), while the work of compressors will be declined by 9000 W (Fig. A.5).

The Influence of Gas Collection Scenario (Case#1 Production unit) on Compressor Power

Gases collection was separately investigated for the three-stage and four-stage processes. The following assumptions were considered:

- The pressure drop of air coolers, inter-stage piping, and inter-stage separators was considered as 0.05 MPa.
- According to the standards, the maximum compressor outlet temperature should be less than 423.15 K. In the actual simulation, however, it is better to limit this temperature to 403.15 K to consider a safety margin.
- The pressure drop caused by the control valve and piping in the path of the separator outlet gases to the compressor was considered to be 10% of the operating pressure of the separator.
- Because the gas injection compressors are less sensitive to the gas collection method from the operating unit, their power was not compared here.

Collection of Gases from Four Stages of Separation

In this case, there are three different scenarios considered. In the first scenario, the first stage of compression involves increasing the pressure of the degasser tank gases (4th stage of separation) up to the outlet pressure of the third stage separator (Fig. 4). The second stage of compression involves receiving the gases of the first stage of compression and raising its pressure to the pressure of the 2nd stage separator (Fig. 4); while the third stage encompasses receiving the second stage gases of the compression and enhancing its pressure to the pressure of the 1st stage separator (Fig. 4).

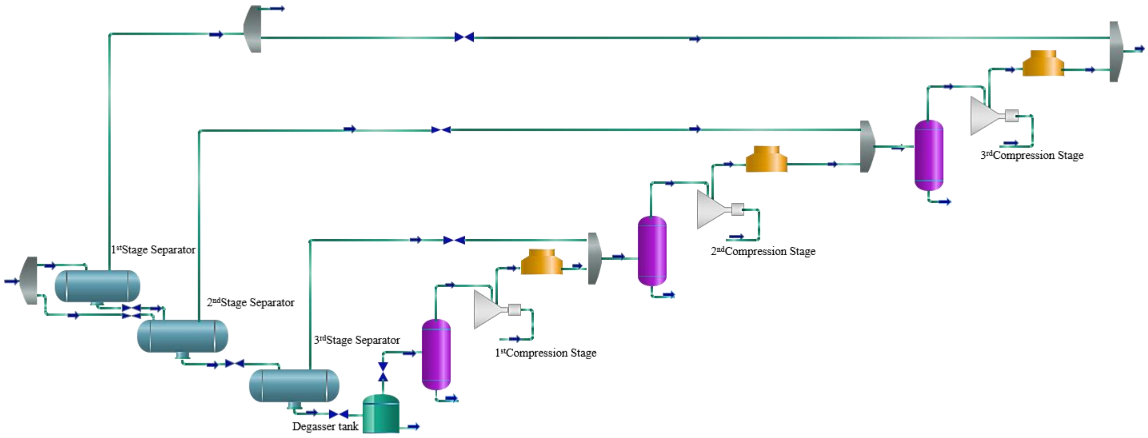

Fig. 4. The schematic of crude oil production plant: The first scenario

The second scenario includes the following steps: The first compression stage involves increasing the pressure of the degasser tank gases (4th stage of separation) to the outlet pressure of the third stage separating gases (Fig. A.6). The pressure of the outlet gases from the 2nd stage separator is reduced to the output pressure of the first compression stage to be mixed with the outlet gases of this stage (Fig. A.6).

In the third scenario, the first compression stage involves reducing the pressure of the outlet gases from the third stage to the pressure of the degasser tank (4th stage of separation). Then the pressure of these gases from the first stage of the compression is elevated to the pressure of the 2nd stage separator (Fig. A.7). The second compression stage involves receiving the first stage gases of the compression and increasing its pressure to that of the first stage separator (Fig. A.7).

The results of the different gas collection scenarios are presented in Table 2. As can be seen, the second scenario is not suitable due to its compressors' higher power consumption as well as the enhanced heat load of the air coolers. The second scenario also increased operating costs. The first and third scenarios are close together in terms of the power consumption of compressors as well as the thermal load of air coolers. Given that the first scenario requires an additional compression stage (hence requiring more equipment), the third scenario was selected as the optimal one.

Table 2. The results of the different gas collection scenarios

Scenario No.	Number of compression stages	Total power consumption of compressors (W)	Output temperature of the compression stages (ºC)		The total heat load of air cooling (W)
First	3	136000	First Stage	78	131000
			Second Stage	91.5	
			Third Stage	91.3	
Second	2	219000	First Stage	78.3	215000
			Second Stage	130	
Third	2	138000	First Stage	108	132000
			Second Stage	91.4	

Collection of Gases from Three Stages of Separation

The first compression stage involves increasing the pressure of the degasser tank gases (3rd stage of separation) to the outlet pressure of the 2nd stage separator gases (Fig. 5). The second compression stage also includes receiving the gases from the first compression stage and increasing its pressure to the 1st stage separator (Fig. 5). The obtained results are presented in Table 3.

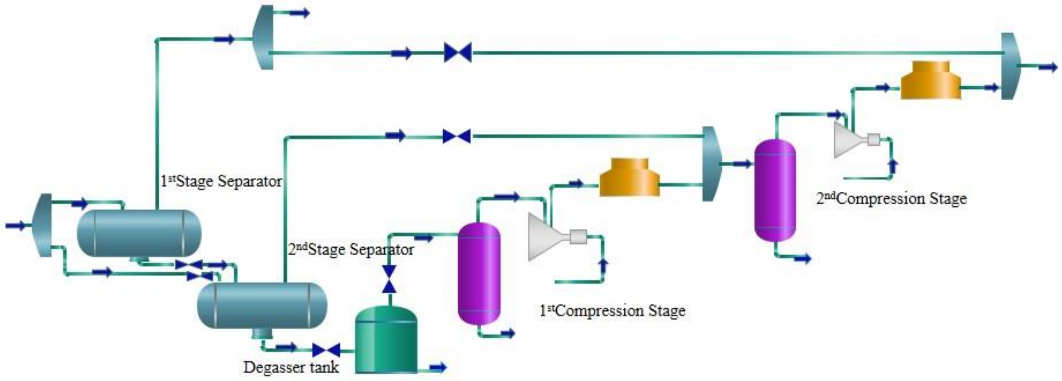

Fig. 5. The schematic of crude oil production plant: Collection of gases from three stages of separation

Table 3. The results of the collection of gases from three stages of separation

Number of compression stages	Total power consumption of compressors (W)	Output temperature of the compression stages (K)		The total heat load of air cooling (W)
2	148000	First Stage	377.15	151000
		Second Stage	363.15	

To increase the pressure of the gases resulting from the three separation stages, a compression stage was also examined. According to Fig. A.8, the pressure of the second separation stage is reduced to the pressure of the third separation stage. The pressure of the total gases resulting from the second and third stages increases to 0.83 MPa. The obtained results are presented in Table 4.

Table 4. The results for crude oil production plant: a collection of gases from three stages of separation

Number of compression stages	Total power consumption of compressors (W)	Output temperature of the compression stages (K)	The total heat load of air cooling (W)
1	314000	432.15	152000

Based on the results, two compression stages are recommended as one compression stage is not appropriate due to the high power consumption and output temperature of the compressor. In the case of using four separation stages for Case#1 plus three compression stages to increase the pressure of gases, the daily oil production rate will be 15032 barrels at the compressor power consumption of 138 kW.

In the case of using three separation stages for Case#1 oil plant plus two compression stages, the daily oil production rate will be 14970 barrels at the compressor power consumption of 148 kW.

The oil production difference between these two methods is about 63 barrels per day. As expected, the oil production rate from the four separation stages is greater than that of the three separation stages. In this case, the power consumption of the compressors also declined. As the application of four separation stages at the Case#1 plant causes no additional cost, four separation stages along with three compression stages are recommended.

Case#2 Crude Oil Production Plant

Case#2 inlet crude oil flow must first enter a two- or three-phase separator to convert the unstable flow into a stable one. This separator removes possible slugs (Surge & Slug) in addition to the separation process. For three-stage separation, the pressure of the 1^{st}, 2^{nd}, and 3^{rd} stages was 0.36 MPa, X, and 0.007 MPa, respectively (Fig. A.9). The oil production rate or the oil recovery rate exhibits an enhancement upon elevating the pressure of the second stage (stripping column) (Fig. A.10).

For the oil to flow from the first separation stage to the stripping column, the maximum pressure of the column should be 0.21 MPa. Therefore, the pressure of the stripping column is considered 0.14 MPa:

- Selecting pressure of 0.14 MPa for the third stage of Case#1 crude oil separation and coordinating the inlet pressure to the compressors of the gas collection and injection unit.
- There is a slight difference between the oil productions at the column pressure of 0.21 MPa compared to the condition where the column pressure is set at 0.14 MPa (~3 barrels per day).
- Reduction in the design pressure of the stripping column.
- Reducing the amount of gas needed for the crude oil sweetening causes a decline in the power consumption of the compressors in the gas collection and injection unit (Fig. A.11).

As mentioned in the assumptions, the pressure of the first separation stage is assumed at its maximum possible value (0.36 MPa). For the total pressure below 0.45 MPa, there is no requirement for the international standard of NACE MR0175/ISO 15156. Therefore, to change Case#2 crude oil separator pressure from the mentioned standard range, the maximum pressure of this separator will be considered as 0.34 MPa. In this case, the rate of crude oil production will be 2080 barrels per day, while the power consumption of the compressors will be 147 kW.

Case#1 and Case#2 Oil Processing in a Mixed-State

In this method, Case#1 crude oil first enters the first Case#1 separator, which operates at a pressure of 0.83 MPa (Fig. 6). The separated oil will enter the first Case#2 separator operating at 0.36 MPa. This pressure also allows for receiving oil from low-pressure Case#1 wells. The oil produced in this separator (0.36 MPa) will be sent to the stripping column, whose minimum operating pressure is 0.14 MPa.

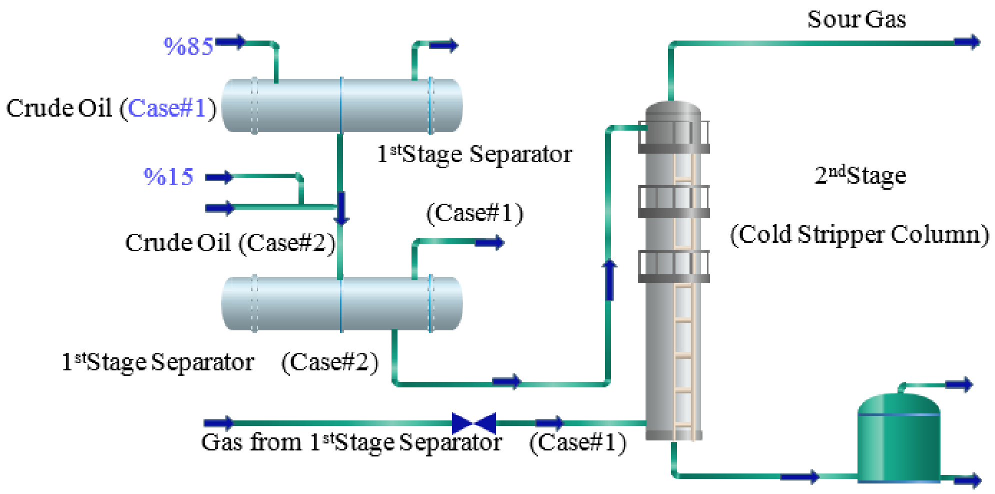

Fig. 6. The schematic of a crude oil production plant for case#1 and case#2 in a mixed-state

As discussed earlier, the maximum stripping column pressure can be set to 0.21 MPa with no need for a pump to transfer fluid from the separator at a pressure of 0.36 MPa (Fig. A.12).

The disadvantages of this method are:

- The maximum oil production of this method (175 barrels per day) is lower than the individual separation processing.
- Due to the transfer of all crude oils to the stripping column, the column diameter should be substantially enlarged from 0.7 m to 1.4 m, which will augment the column cost as well as its installation costs.
- Due to a decrease in oil production and an increment in the exhaust gas, the compressor's power consumption will grow to 116 kW.

The summary of the results is provided in Table 5.

Table 5. The summary results of oil production rates in different conditions

Case#1 Plant Oil Production					
The pressure of 1st stage separator (MPa)	The pressure of 2nd stage separator (MPa)	The pressure of 3rd stage separator (MPa)	The pressure of 4th stage separator (MPa)	Oil production rate (standard barrel per day)	The total power required by compressors to increase the exhaust gas pressure from 0.007 MPa to 0.83 MPa (kW)
0.83	0.36	0.17	0.007	15021	141
0.83	0.36	0.14	0.007	15032	139
0.83	0.36	0.007	---	14970	148
Case#2 Plant Oil Production					
The pressure of 1st stage separator (MPa)	The pressure of the 2nd stage separator (MPa)	The pressure of 3rd stage separator (MPa)	Oil production rate (standard barrel per day)		The total power required by compressors to increase the exhaust gas pressure from 0.007 MPa to 0.36 MPa (kW)
0.36	0.14	0.007	2081		142
0.36	0.21	0.007	2085		154
0.34	0.14	0.007	2080		147
Total Oil Production					
Total crude oil production based on optimal selection methods in standard conditions (barrels per day)					17112
The total power required by compressors to increase the exhaust gas pressure from 0.007 MPa to 0.83 MPa (kW)					286000
Mixed-State Oil Production					
The pressure of 1st stage separator (MPa)	The pressure of the 2nd stage separator (MPa)	The pressure of 3rd stage separator (MPa)	The pressure of the 4th stage separator (MPa)	Oil production rate (standard barrel per day)	The total power required by compressors to increase the exhaust gas pressure from 0.007 MPa to 0.83 MPa (kW)
0.83	0.36	0.14	0.007	16937	402

According to the reports provided by the National Iranian South Oil Company, the pressure of Well No. 5 (Case#1) in 2011 was about 13.8 MPa (at maximum value), while its pressure will reach about 8.27 MPa (at minimum value) by 2030. The fluid of this well enters a three-phase separator located at Case#1 gas collecting and injection unit after passing through the choke valve and the multi-phase pipeline. Due to the reduction in the well pressure during different years and the dependence of the end stages of gas collection and injection unit on the gas pressure received from the well, the lowest well pressure is considered as the basis of design to equalize the pressure in the gas collection and injection unit during different years. This approach will also offer optimally minimum operating pressure for the pipelines. Overall, the maximum pressure of the separator can be 8.27 MPa. However, due to the following items, this pressure will be less than 8.27 MPa with a maximum value of about 6.89 MPa:

- Feasibility of fluid flow from Well # 5 to the separator in the ending years of production.
- Pressure drop along the pipeline route (Well # 5 is located at a 55000 m distance from Case#1 Unit).
- The pressure drop of the choke valve and wellhead installations.

- Considering the safe distance from the estimated well pressure in the ending years.
- A possible pressure drop in the installations of the gas collection and injection unit.

According to the above and also for the maximum possible use of well pressure to minimize the work of the final stage of the compressors of the gas collection and injection unit, the relative pressure between 6.89 MPa and 7.58 MPa was investigated.

Economic Evaluation

To maximize the possible use of Well # 5 pressure for minimizing the work of the final stage of the gas compressor, the separator pressure was examined in the range of 6.89 MPa-7.58 MPa (Table. 6). According to the above table, at the reservoir pressure of 7.58 MPa, the fixed project costs (kW of compressor consumption and initial investment) will be reduced by $11965307. On the other hand, the production will be decreased by ~20 barrels per day, giving rise to a $ 58.4 million reduction in revenue over the next twenty years. Therefore, the optimal pressure table of the reservoir should be about 6.89 MPa.

The economic evaluations, including labor-related costs and equipment depreciation, were present in Table 7, as follows. Furthermore, total fixed costs related to equipment, piping, civil, instrumentation, electrical, insulation, and paint were added. The total operational costs, including maintenance and Labor-related costs, were also added.

Table 6. The summary results of initial investment and economic evaluation

Determination of Initial Investment

Reservoir pressure (MPa)	[(e)] The compressor of the first injection stage			[(e)] The compressor of the second injection stage			[(e)] The Air cooler of the first injection stage		[(e)] The Air cooler of the second injection stage		Reservoir	Fixed Initial Investment ($)
	Fixed cost per compressor ($)	Fixed cost ($)	Motor size (kW)	Fixed cost per compressor ($)	Fixed cost ($)	Motor size (kW)	Fixed cost ($)	Motor Fan (kW)	Fixed cost ($)	Motor Fan (kW)	Fixed cost ($)	
7.58	427000	1281000	400	610800	1832400	670	95200	3	116900	4.44	29071	3354571
6.89	366101	10983303	375	672563	2017689	800	95200	3	116900	4.44	28786	3356878

Economic Evaluation

Reservoir pressure (MPa)	The total operating costs	The total cost of consumed electricity [(b, c, f)]	Total costs	Oil production rate (BPD)	[(d)] Oil production rate ($)
7.58	3354571	19965000	23319571	17920	5232640000
6.89	3356878	31928000	35284878	17940	5238480000

[a] During 20 years of oil production.
[b] The cost of consuming electricity is $ 0.053 per kWh.
[C] The inflation rate of 0.05 is considered to calculate the cost of electricity.
[d] The price of crude oil is considered $ 40 per barrel.
[e] The interest rate is considered 0.14.
[f] The value of each dollar is considered to be 12280 Rials (Iran).

Table. 7. Economic evaluations including labor-related costs and equipment depreciation

Total cost estimation		Third and fourth stages of the compression unit		The second stage of the compression unit		The first stage of the compression unit	
		Screw compressor with the electrical motor driver		Reciprocating compressor with the electrical motor driver		Reciprocating compressor with the electrical motor driver	
Compression station arrangement		1+1	2+1	1+1	2+1	1+1	2+1
Outlet /Inlet Operation Pressure (Psig)		0.9/42.9		40/107.3		100/395	
kW consumed per compressor		49.69	24.8	210.4	105.3	815.2	407.6
Estimated engine size per compressor		75	37	280	132	1120	530
The volume rate of gas flow per row (MMSCFD)		0.84	0.42	5.59	2.79	13.88	6.94
Total fixed costs ($)	Equipment	345666	269893	467469	376931	643384	485034
	Piping	23632	18198	32001	25344	31099	26498
	Civil	11855	11855	11855	11855	17909	17597
	Instrumentation	18928	16118	21108	19577	22022	19628
	Electrical	2045	1882	2450	2139	2894	2399
	Insulation	6796	6130	1946	1650	8283	7114
	Paint	886	706	2698	2020	1207	966
Total fixed costs per compressor row		409808	324782	539527	439516	726798	559236
Total fixed costs for all rows		819616	974346	1079054	1318548	1453596	1677708
Operational Costs		109054	132190	150120	184634	202564	237472
Total operational costs ($)	Maintenance costs ($)	1353794	1353794	1353794	1353794	1358922	1358922
	Labor-related cost ($)	699800	617400	2613000	2463000	10450000	9891000
	Electrical ($)	2162648	2103384	4116914	4001428	12011486	11487394
Total costs ($)		2982264	3077730	5195968	5319976	13465082	13165102

Conclusion

A simulation-based approach was applied to optimize a multi-stage crude oil production unit, including Case#1 and Case#2 plants in the national Iranian south oil company. The number of separation stages and their different arrangements were studied as the desired goals to maximize the oil production rate and reduce the fixed and operating costs and energy consumption. The following results can be mentioned:

- For oil production from Case#1 unit, three two-phase separators and a degasser tank were used at the respective pressures of 0.83 MPa, 0.36 MPa, 0.14 Mpa, and 0.007 MPa.
- The cold stripping method was recommended for the crude oil sweetening in Case#2.
- For oil production from Case#2 unit, the three-stage separation was utilized, including a three-phase separator, a stripping column, and a degasser tank at the respective pressures of 0.34 MPa, 0.14 MPa, and 0.007 MPa.
- The reservoir separator pressure was selected to be 6.89 MPa which is equal to the output pressure of the first stage of the injection compressor.

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Appendices

Table A. 1. The specifications of Case#1 and Case#2 Plants.

Plant	Number of separation stages	The max. amount of H_2S in the production oil (ppmw)
Case#1	4	6
Case#2	3	498
Case#1 and Case#2 oil processing in a mixed-state	4	147

Table A.2. (Basis: inlet feed in summer condition)

Plant	Total inlet crude oil flow rate (kgmol/hr)	Crude oil flow rate (standard Barrels Per Day)	Gas flow rate (MMCFD)
Case#1	1000	15618	10.81
Case#2	200	2110	2.75

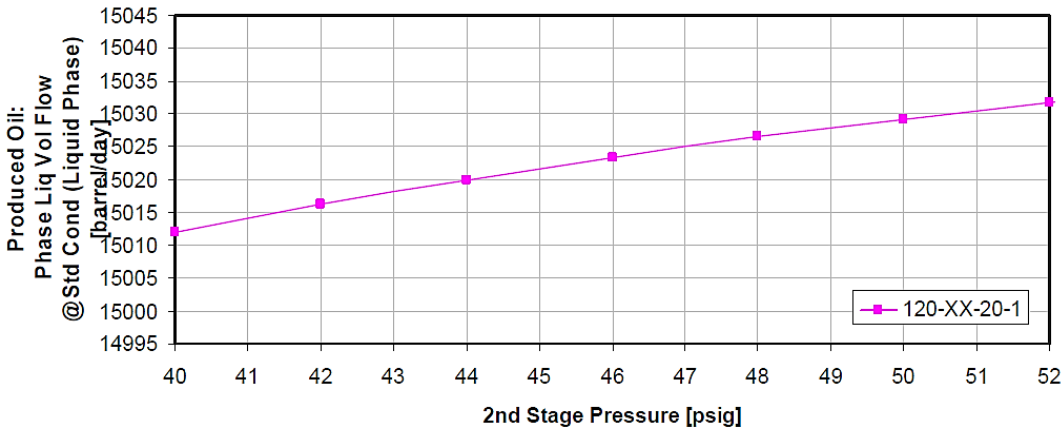

Fig. A.1. Changes in the Case#1 oil production rate versus 2nd stage separator pressure, assuming the 3rd stage separator pressure be 0.14 MPa

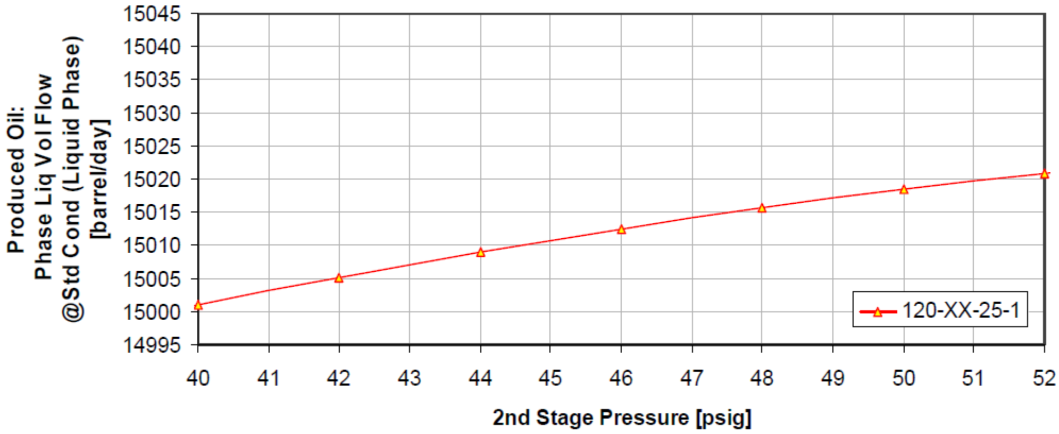

Fig. A.2. Changes in the Case#1 oil production rate versus 2nd stage separator pressure, assuming the 3rd stage separator pressure be 0.18 MPa

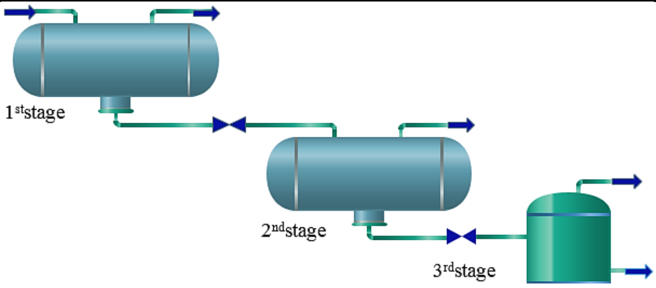

Fig. A.3. The schematic of Case#1 crude oil production plant using three separation stages

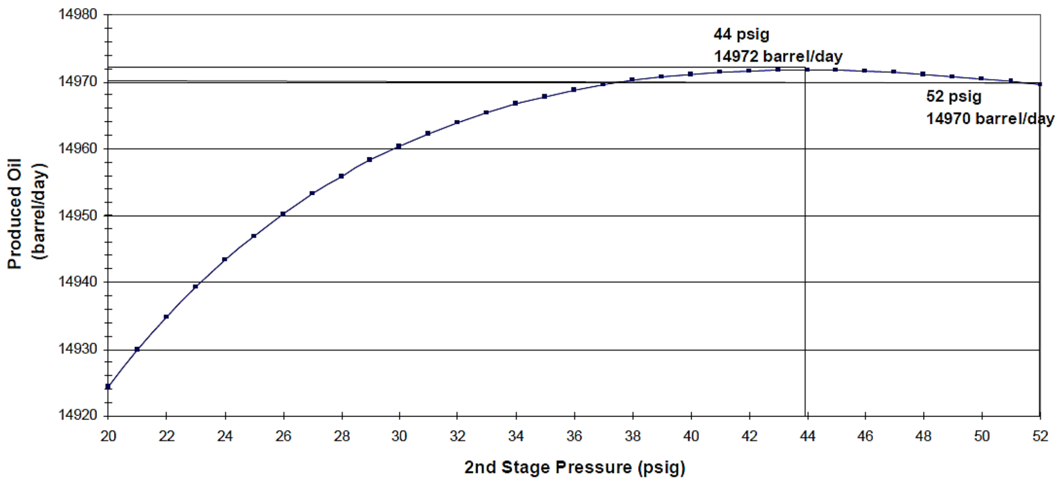

Fig. A.4. Effect of 2nd stage separator pressure variation on the oil production rate

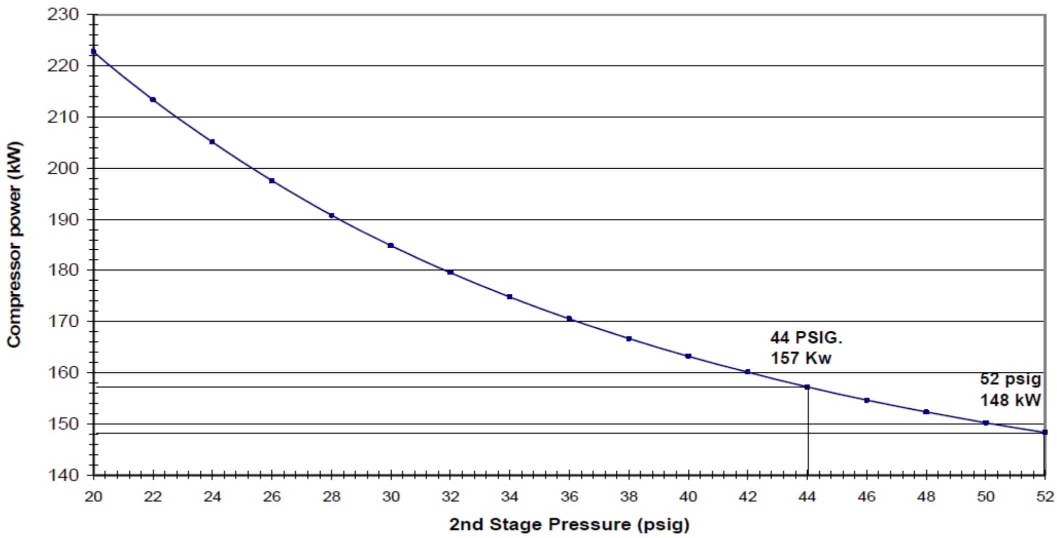

Fig. A.5. Effect of 2nd stage separator pressure variation on the compressors work

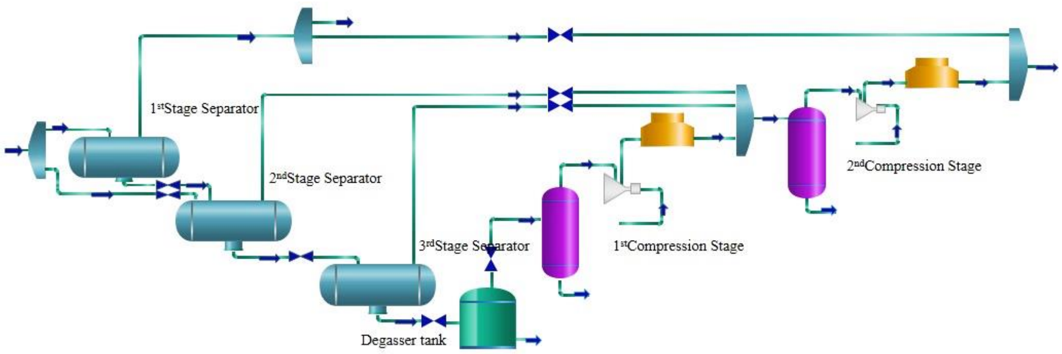

Fig. A.6. Schematic of crude oil production plant: The second method

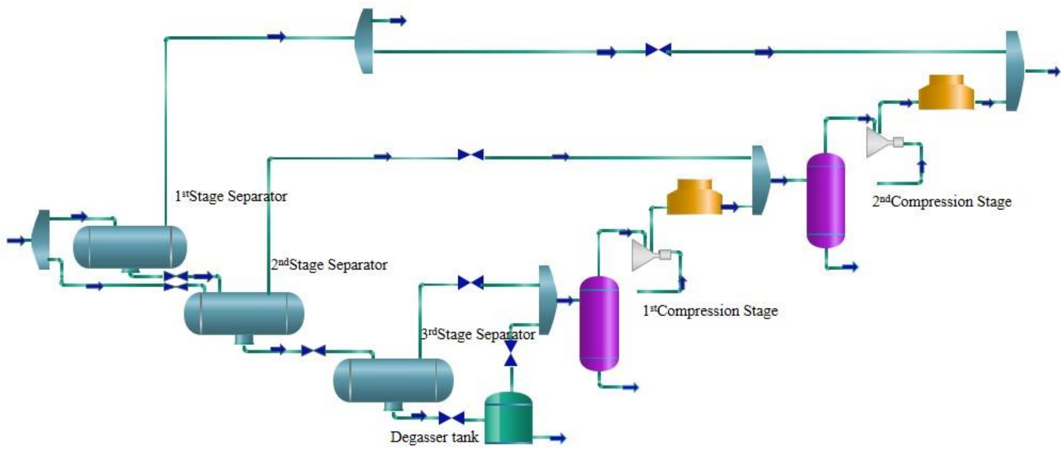

Fig. A.7. Schematic of crude oil production plant: The third method

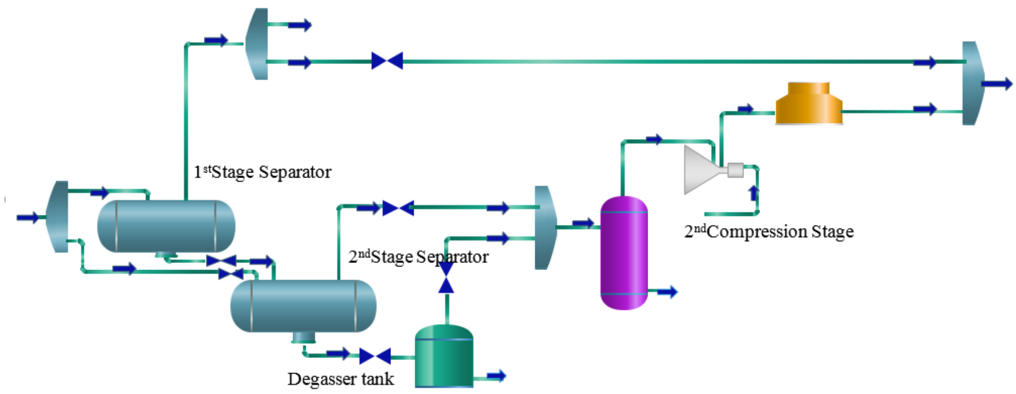

Fig. A.8. Schematic of crude oil production plant: an alternative for collection of gases from three stages of separation

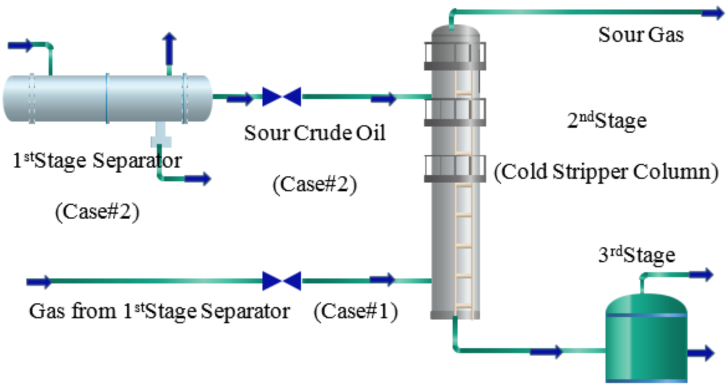

Fig. A.9. Schematic of crude oil production plant for case#2: Three separation stages

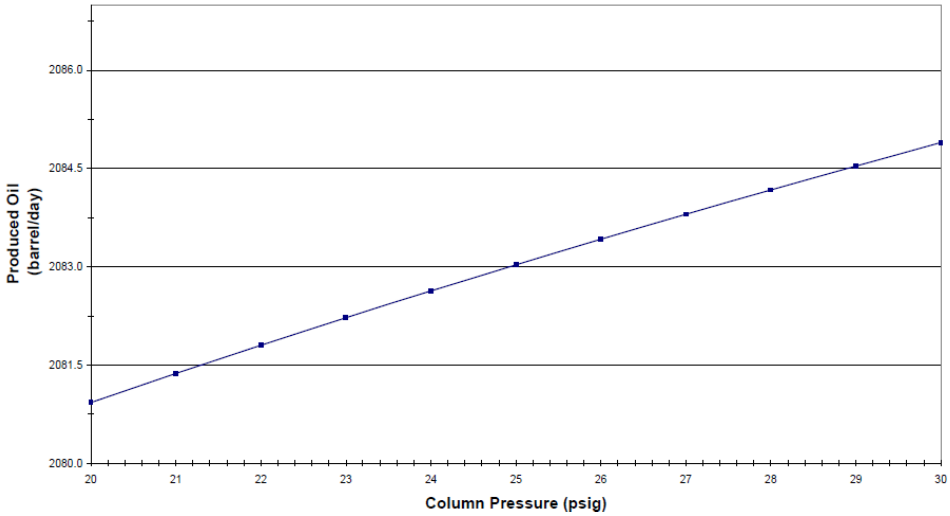

Fig. A.10. Effect of the column pressure variation on the oil production rate

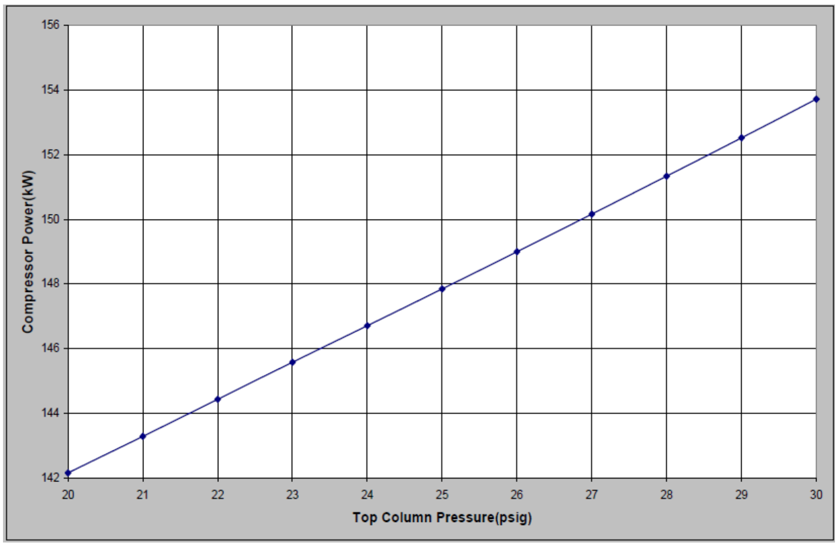

Fig. A.11. Compressor power vs. top column pressure variation

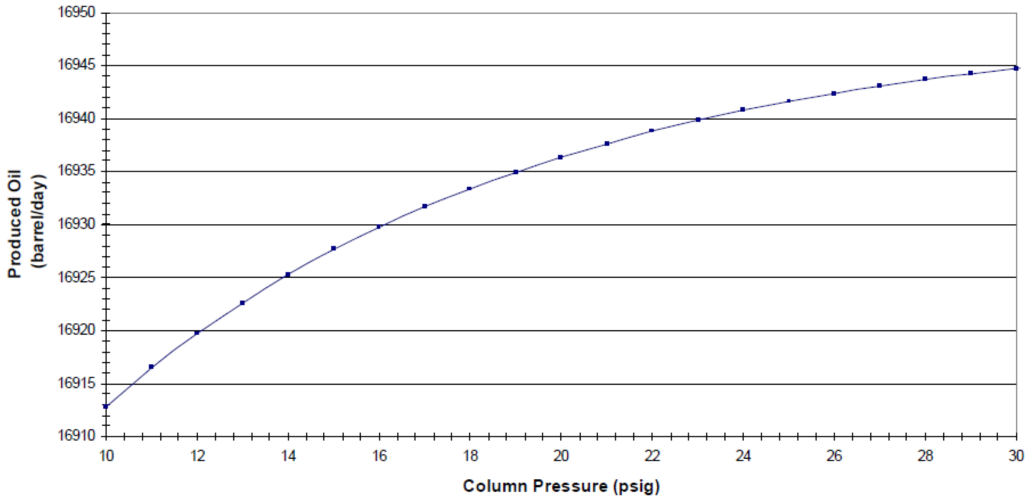

Fig. A.12. Effect of the stripping column pressure variation on the oil production rate