

An Overview of Challenges and Errors in Sampling and Recombination of Gas Condensate Fluids

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ABSTRACT

A proper understanding of reservoir fluid phase behavior is the first crucial step in the development and production of an oil/gas field. This paper addresses the challenges and errors associated with the fluid sampling that may arise before, during and after the sampling operation. For this aim, DST and PVT data of exploration and production wells of a supergiant offshore gas condensate reservoir were analyzed. It was found that well conditioning and flow stability are essential before sampling. The main sources of error during the sampling include separator instability, lack of vapor-liquid equilibrium, volume ratio of separator outlets, and the presence of contaminants. Analysis of separator outlet streams further indicated deviation from equilibrium for some wells, which can have direct impact on dew-point pressure and condensate gas ratio (CGR) prediction of well stream. Improper fluid handling, oil and gas leakage, and the presence of corrosive compounds can severely affect the quality of the recombined fluid.

1. Introduction

A successful experimental reservoir fluid analysis requires a proper fluid sampling, which provides correct and reliable pressure, volume, temperature (PVT) information that can be used as a basis for material balance and integrated reservoir management [1]. It is well established that to maintain the equilibrium conditions in the reservoir conditions the best time for sampling is after exploration and before any production from the reservoir [2, 3]. The reservoir fluid has been in equilibrium for geological time, and any change in reservoir conditions that results from production needs a long time to attain a new equilibrium condition. The PVT analysis is routinely conducted for engineering calculations, understanding fluid components for the proper economical status of reservoir, and the analysis of special components such as carbon dioxide, sulfur components, mercury, and helium. Also, results of the reservoir fluid analysis are used to predict flowing capacity in well tubing, flow lines and transmission pipelines, changes in viscosity due to precipitation of solids like wax, asphaltene and hydrate, and flow assurance [4]. Also, future field development, drilling and production plans are based on the analysis of representative fluid samples [5]. All these support the need for the proper sampling of representative fluids from producing zone of reservoir. On the other hand, improper fluid sampling can lead to a waste of time and cost, yet putting the field development plan into risk. It is worth noting that well preparation is a crucial step prior to sampling, followed by fluid recombination, a key step in preparing representative fluid. The recombination involves mixing gas and liquid samples collected from the separator in a preset proportion so that the recombined fluid behaves like the reservoir fluid. In this study, details of well preparation are discussed, followed by determining criteria for standard fluid recombination. Also, potential errors associated with each process are addressed. Analysis and discussion are made using 57 set of DST and PVT data and reports available for one of the world largest offshore gas condensate reservoirs located in Persian Gulf. Table 1 gives sampling depth, pressure and temperature in this reservoir. Average composition (Ave.) and standard deviation (STD) of CH₄, C₁₂₊, and dew point pressure (P^{sat}) of the separator samples are given in Table 2. According to this Table, deviation in CH₄ composition is negligible, while C₁₂₊ and P^{sat} of samples show considerable deviations throughout the reservoir. More details on PVT data and fluid phase behaviour of the reservoir under study are given elsewhere [6, 7].

Table 1: Minimum and maximum depth, pressure, and temperature of separator samples

Depth (ft)		Pressure (psia)		Temperature (°F)	
Min.	Max.	Min.	Max.	Min.	Max.
8920	11269.5	5376	4170.4	188	222

Table 2: Average composition (Ave.) and standard deviation (STD) of CH₄, C₁₂₊, and dew point pressure of separator samples

CH ₄ (mole %)		C ₁₂₊ (mole %)		Dew Point (psia)	
Ave.	STD	Ave.	STD	Ave.	STD
82.60	0.92	0.55	0.17	4780.11	349.90

2. Well Conditioning

Well conditioning implies removing the fluid remained in borehole and replacing the reservoir fluid. When reservoir pressure falls below the initial saturation pressure, the properties of reservoir fluid change considerably. The change in fluid properties due to pressure drop becomes more pronounced in the borehole. As pressure drop increases, changes in fluid properties extend farther in the reservoir, depending on production time and the value of bottom hole pressure drops below reservoir pressure [3]. The flow rate during well conditioning should be low enough to minimize the drawdown pressure by using the lowest possible choke size [8]. On the other side, the flowing velocity should be higher than the critical velocity to prevent the liquid holdup in well [9, 10].

According to steady-state flow theory, the static experimental analysis of fluid samples can simulate the dynamic behavior of reservoir fluids when samples are collected at steady-state conditions [3, 11, 12]. The steady-state sampling requires that parameters such as wellhead and separator temperature and pressure, solids flow rate, flow rates of separator gas and separator liquid, and gas-oil ratio be at stable conditions [9]. Figure 1 shows the fluctuation of these parameters in a well being condition for sampling (sample number: **W-1**).

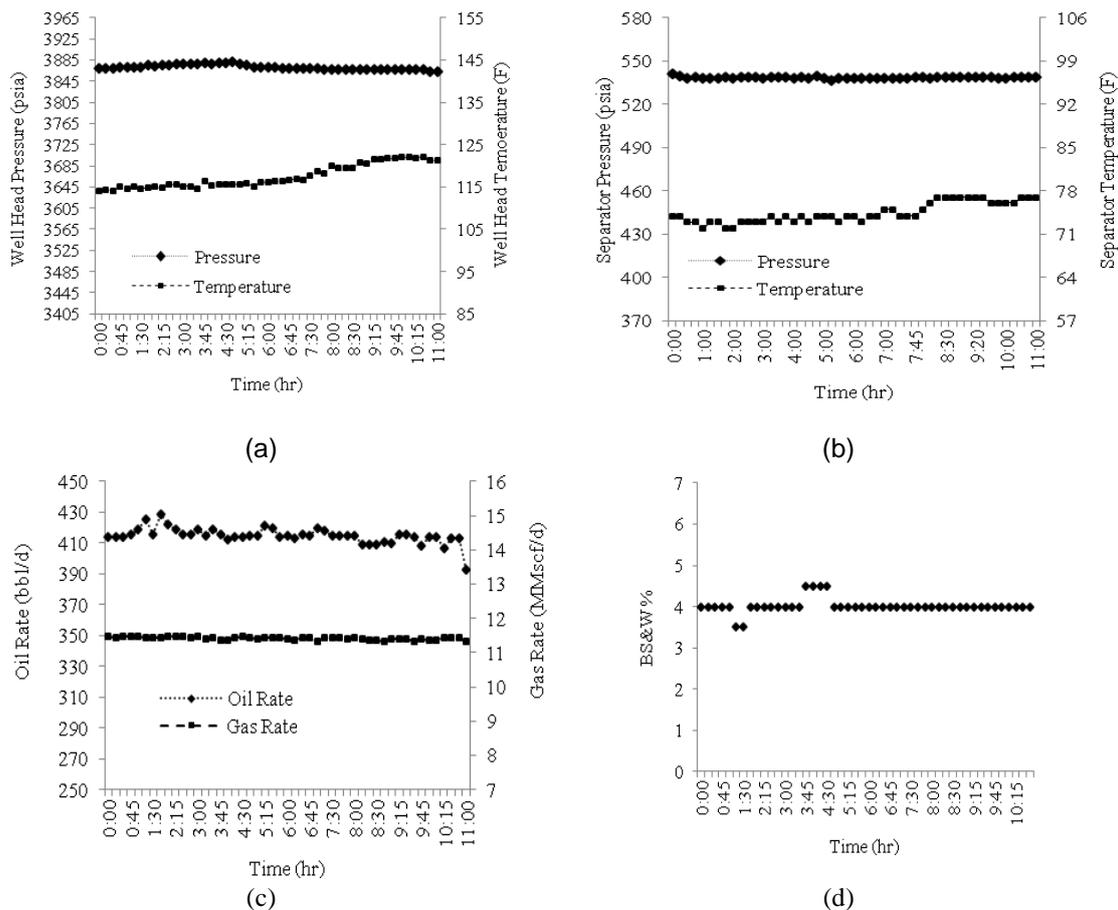


Figure 1: Variation of key parameters with respect to time for a conditioned well (sample number: **W-1**): (a) well head pressure and temperature, (b) separator pressure and temperature, (c) separator oil and gas rates, (d) basic sediment and water

The acceptable range of fluctuations for each property is discussed in references [6, 13] and is also shown in Table 3. It is suggested that well is shut-in at least 24 hours prior to sampling [3]. Normally, the well is prepared by gradual decreasing the flow rate to make sure that the well is clean enough and collect samples at the smallest lift flow rate. In the case of the saturated gas condensate reservoirs, taking too long time may result in the accumulation of the condensate. In this case, it is suggested to collect the samples right after the well stability [14].

Table 3: Acceptable range of fluctuations of well head pressure, separator pressure, oil rate, and BS&W

Well head pressure (psia)	Separator pressure (psia)	Oil rate (bbl/day)	BS&W (%)
± 20	± 15	± 10	Max. 5%

Figure 2 shows variations in wellhead pressure and temperature for sample **W-2** (2-a) and separator oil and gas rates for sample **W-3** (2-b). These figures are examples of data that do not fall within the acceptable range, implying that the well and separator have not reached the stability conditions. As a result, the collected samples cannot represent the reservoir fluid.

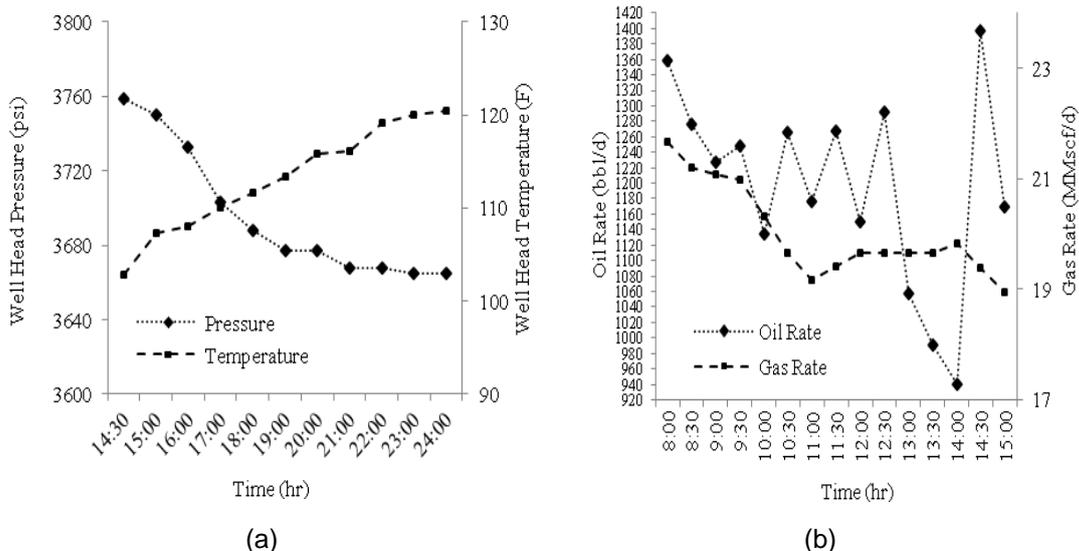


Figure 2: Fluctuation of parameters for unsatisfied condition of representative fluid sampling: (a) well head pressure and temperature (sample number: **W-2**), (b) separator oil and gas rates (sample number: **W-3**)

3. Sampling

Generally, there are three types of fluid sampling applied in upstream oil and gas operations, i.e. surface, sub-surface and well head sampling. Surface sampling is conducted in a surface separator and is normally applied extensively in many hydrocarbon reservoirs, including gas condensate, saturated oil, high-viscosity oils and foamy oils. There are three techniques for surface sampling, known as standard, isokinetic and mini-laboratory (Thorton)

sampling [15]. For gas-condensate samples, the standard technique is recommended. However, if the gas is suspected to have liquid carry over, the isokinetic technique is preferred [16, 17]. The Thorton sampling is a small portable laboratory used for sampling from gas condensate wells. However, this technique is more expensive than the separator sampling [15]. Overall, surface sampling is relatively simple and cheap compared to the subsurface and Thorton sampling. In this technique, well production is not interrupted and fluid storage does not occur in the well. Also, it can be applied for the cases where water is present in the tubing. In addition, the collected well fluid does not need to be in single phase in the wellbore. Moreover, separator fluid sampling may be performed repeatedly in high volumes to study such phenomena as asphaltene deposition, wax formation, emulsions, hydrates and corrosion.

In subsurface sampling, the sampling device is moved via the wellhead down to sampling point. The well fluid is collected in sampling device as a result of the high pressure gradient, and moved up by pulling the device out of the well. The collected sample is then pressurized to become single phase and transferred to laboratory in special vessels. The subsurface sampling can be performed right after drilling and well preparation. It is worth noting that the fluid should be at single phase in this technique to make sure that all components have been collected properly [18]. In this technique, the separator and measuring devices for fluid flow are not required. Also, human errors associated with the recombination are eliminated, as there is no need to recombine the collected fluids. In addition, collected samples have less volume compared to surface sampling; consequently, fluid handling to laboratory is easier. The wellhead sampling is not as common as the surface and sub-surface sampling. However, it has valuable potentials to replace the other techniques. If the well fluid is single phase at wellhead temperature and pressure, wellhead sampling can be conducted as a reliable technique with more simplicity. This technique can be applied to undersaturated oil and dry gas samples [19].

4. Challenges of fluid sampling and recombination

The main objective of fluid recombination is to obtain original composition of reservoir fluid. In this operation, the separator gas and liquid effluents are mixed with reservoir gas oil ratio (GOR) proportion. It is crucial that the recombined streams must be at equilibrium during the sampling [13]. Thermodynamic equilibrium is a key factor for a successful sampling. Figure 3 shows phase diagram for separator gas (a), separator oil (b) and recombined fluid (c) [20]. According to this figure, the separator gas and liquid should be collected at saturation conditions, i.e. their dew and bubble pressures. In addition, they should be single phase during transfer into the sampling vessels. For separator gas, this means that the sample temperature should not be lower than the separator temperature (line 1 on figure 3-a) or throttled before entering the sampling vessel, as simultaneous pressure and temperature drop changes the fluid conditions in the two-phase region (line 2 on Figure 3-a). Similarly, the separator liquid should be collected at equilibrium conditions with neither a drop in pressure (line 2 on figure 3-b) nor an increase in temperature (line 1 on Figure 3-b).

Figure 4 compares the separator conditions, sample number: **W-4**, with ideal thermodynamic conditions that occur at the intersection between the two curves. The mismatch between the two points indicates deviation from the equilibrium conditions, which is about 120 (psia) for this case.

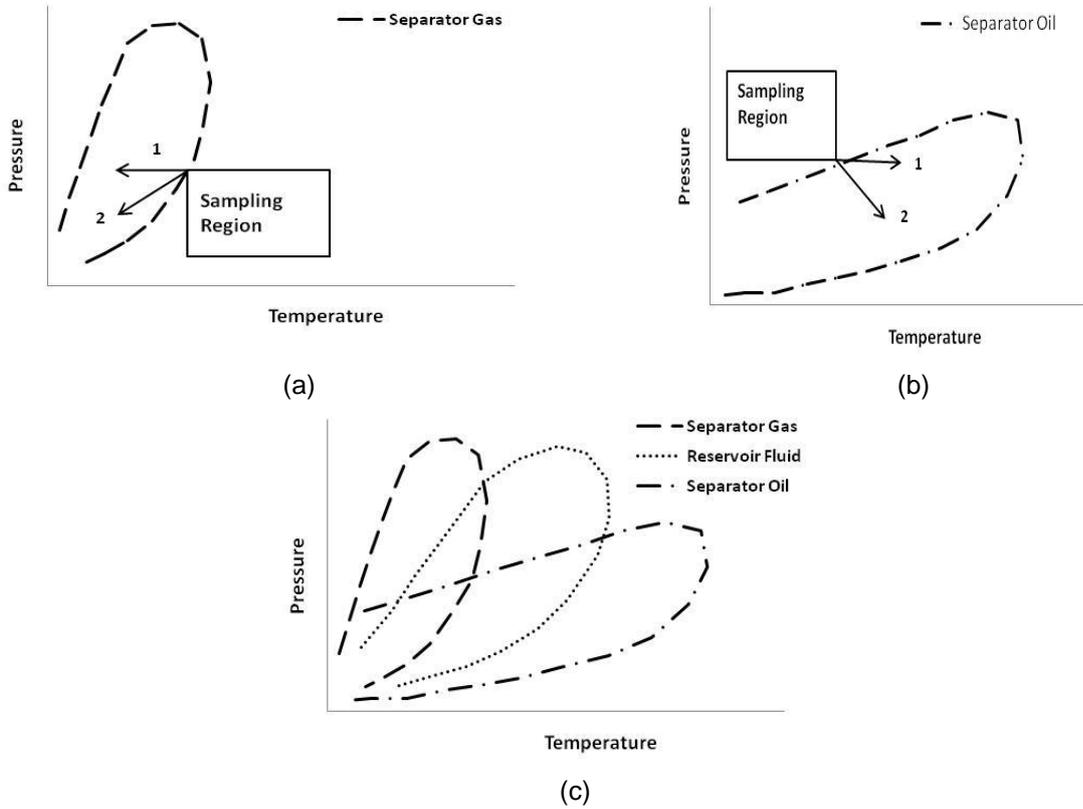


Figure 3. Phase diagram of gas (a), oil (b) and representative reservoir fluid (c) [20]

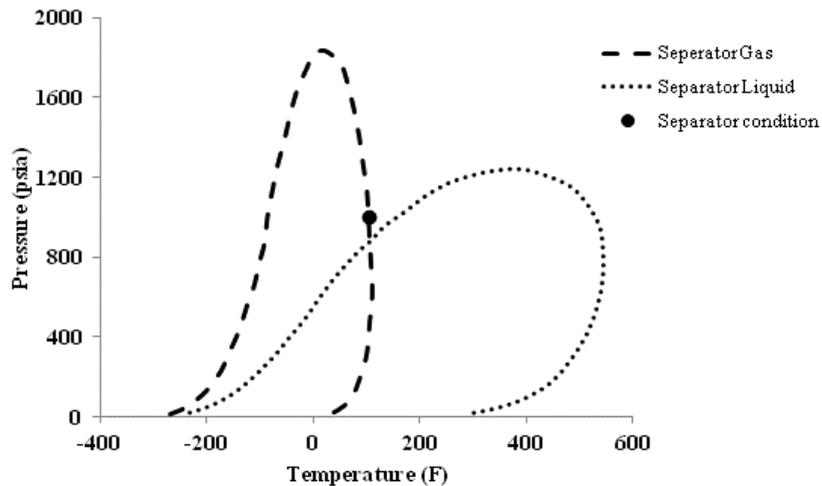


Figure 4: Phase diagram of separator gas and oil (sadle number: **W-4**) in non-equilibrium condition

The original composition of reservoir fluid is readily determined in dry and wet gas reservoirs through recombination. For gas condensate reservoirs, this technique is applicable only when the reservoir pressure is above the original dew point pressure. When the reservoir pressure falls below the dew point during the production, recombining separator streams does not result in original reservoir fluid and produces large errors when conducted at these pressures. In 1994, two techniques were proposed by Reffstrup and Olsen [21] and Fevang et al. [18] to determine the original fluid composition for a depleted reservoir. Reffstrup and Olsen [21] described the producing fluid by using an equation of state and added incremental volumes of produced condensate to enrich the gas stream until the original dew point pressure was reached. The second technique proposed by Fevang et al. [18] applies to gas condensate reservoirs with initial oil rim when both oil and gas zones are produced simultaneously. This technique involves the following steps:

- Recombining producing gas and condensate to reach well head producing composition;
- Converting the recombined fluid to prevailing reservoir temperature and pressure;
- Producing all liquid condensate that is formed in this process;
- Producing part of the equilibrium gas;
- Gradual injecting equilibrium condensate into equilibrium gas until dew point pressure of recombined fluid approaches that of the original fluid.

This technique is an experimental procedure and has no theoretical background. Moreover, this technique has not been tested in field conditions.

The collection of samples that do not represent reservoir fluid can lead to analyses which affect all the subsequent engineering calculations. As mentioned before, one of the main challenges in fluid sampling from gas condensate reservoirs is well and separator stability prior to the sampling. Also, there may be challenges during fluid sampling, e.g. a) when separator temperature is lower than the surrounding, b) producing fluid contains CO₂ and/or H₂S, and c) reservoir fluid contains considerable amounts of paraffins (wax) and asphaltene. When separator temperature falls below the surrounding, the temperature of sampling vessel should be lowered down to separator temperature, otherwise entering liquid flashes and part of vessel is occupied by the flashed vapor. This leads to a decrease in volume of the collected fluid. Similar problem may occur when insufficient liquid sample is collected.

The presence of CO₂ and/or H₂S in reservoir fluid can lead to corrosion in sampling vessel, especially when water is present. In this case, corrosion resistant vessels should be used for sampling to make sure that fluid composition remains unchanged while delivering samples to laboratory. Also, deposition of solid compounds from collected fluids may interfere with sampling and affect the quality and composition of the collected samples. Paraffinic and asphaltic oil samples may deposit in reservoir, wellbore, separator and sampling vessels. Generally, paraffins deposit upon cooling and degassing. Similarly,

asphaltic oil samples deposit upon cooling and in contact with light hydrocarbons. Therefore, pressure and temperature drop should be minimized to prevent the fluid loss in these systems [2].

Another challenging issue refers to the sampling point. For surface sampling, it is conducted at points with minimum pressure drop to avoid the sampling and measurement errors. On the other hand, subsurface samples are normally collected from the lowest well depth for safety reason and to assure that its static pressure is higher or equal than the fluid saturation pressure [22]. Presence of water in collected samples is considered as contamination that should be minimized. Foaming is another challenge that may interfere with fluid sampling in certain reservoirs that produces stable foam. In these cases, liquid carry over may appear with separator gas [23]. In addition, such contaminants as injecting chemicals and drilling mud fluids may downgrade the quality of the collected samples.

Figure 5 illustrates changes in dew point pressure with gas oil ratio (GOR) for a gas condensate sample [24]. This is another challenging issue in recombining oil and gas streams extracted from the gas condensate separator. According to this Figure, two recombined samples with different compositions and GOR can result in the same P^{sat} (points a and b on Figure 5). Yet the true P^{sat} of reservoir fluid (point c) may be much higher than that measured for the recombined fluid. In other words, relying on GOR may not lead to a representative recombined fluid.

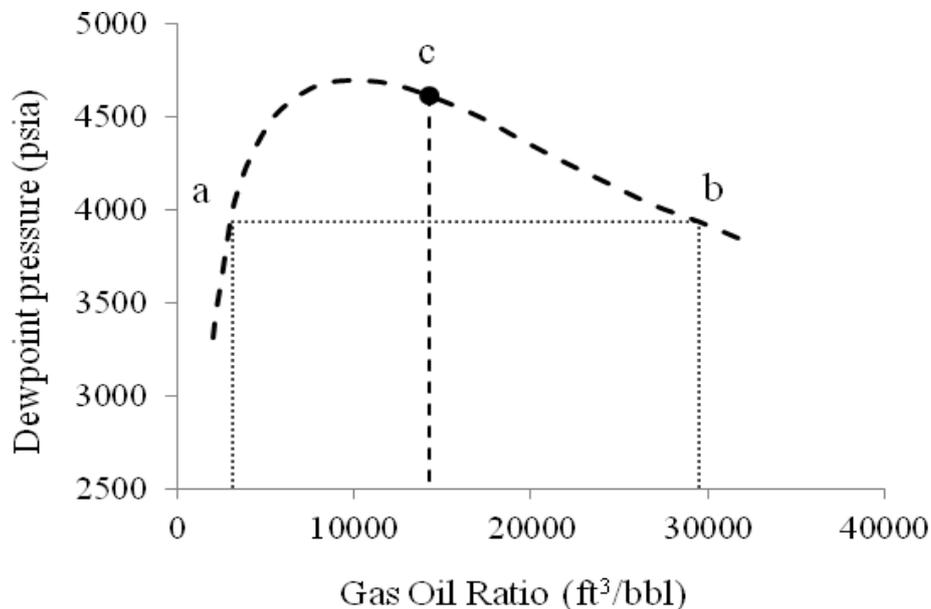


Figure 5: Variation of dew-point pressure of gas condensate with GOR [24]

Another challenging issue in gas condensate sampling is the non-uniform behaviour of GOR versus the flow rate. At low rates, the gas stream cannot carry the liquid condensate produced in the wellbore; consequently, it results in

an increase in GOR of the producing stream. On the other side, by increasing the flow rate, condensate banking and GOR decreases. At very high flow rates, condensate drop-out in the reservoir results in the increase in producing GOR. Therefore, there is an optimum flow rate region where GOR remains unchanged [22].

There are many factors that can adversely affect the quality of the separator recombined fluid. The key factors address the compositional analysis of separator gas and liquid streams and proper selection of GOR for mixing streams to simulate the reservoir fluid [23]. The latter is of special importance for gas condensate systems. In cases with low separator oil volume, GOR is largely affected by a loss in liquid volume, which itself causes considerable deviation from the representative reservoir fluid properties [25].

Formation of condensate bank around the wellbore is another critical factor that may cause major variations in GOR and PVT properties of the recombined fluid. In early production, reservoir pressure is higher than dew point of original fluid, and pressure drop causes liquid drop-out in the area near the wellbore [3, 26]. The resulting liquid phase does not flow until its saturation reaches a critical value, which eventually starts flowing as the second phase alongside gas flow. At steady state, condensate saturation in two-phase region decreases in such a way that volume of condensate flowing towards wellbore equals condensate drop-out in reservoir. As a result, the saturation is stabilized in the area near wellbore and composition of stream that enters the condensate rim is equal to the composition of mixture flowing towards wellbore. Moreover, producing GOR is constant at this stage and recombining the separator streams can represent the reservoir fluid. Many studies have shown that the steady conditions do not occur. In addition, flowing pressure and pressure gradient in reservoir near wellbore decrease with time, and the size of the condensate rim increases gradually [3, 9, 27]. Therefore, preparing a representative fluid is much more difficult in gas condensate reservoir compared to the crude oil systems.

5. Sources of error in fluid sampling and recombination

Overall, errors associated with sampling and recombination of reservoir fluids may be categorized as instrumental, human, contamination and transfer errors. Instrumental errors include liquid and gas flow measuring devices, e.g. orifice meters, which are supposed to be properly calibrated prior to the sampling. Any error in GOR measurement may interfere with laboratory analyses. For example, improper selection of orifice size in gas flow meter can cause 50% error in bubble pressure of the recombined sample. Such a large error suggests the importance of using calibrated measuring devices in measuring surface flow rates [2]. Other sources of instrumental errors refer to mechanical factors such as wax and hydrate deposit on orifice meter plate. On the other hand, the sources of error for in-situ measurement of specific gravity and compressibility factor are not as important, because these properties are

measured carefully in the laboratory. However, it is important to know the calibration conditions and correction factors for gas flow rate.

Another source of error addresses those related to human activities, which may happen both during field sampling and laboratory testing, causing all collected samples to be studied in unrealistic conditions no matter how good quality they have. Errors in recording temperature, pressure, flow rate, sampling depth, etc. are examples of human error. In practice, sampling depth should be away from gas-oil, gas-water, and oil-water contact to prevent coning while the well is undergoing sampling.

The contamination of collected samples is another source of error. For example, acidizing can reduce condensate bank near the wellbore; however, this process can release CO₂, H₂S, and metal ions that can contaminate fluid samples collected afterwards. Moreover, use of oil-based drilling mud is another source of contamination in near-wellbore samples [22]. In addition, injection of the anti-hydrate compounds like methanol or glycol contaminates the collected fluids. In practice, methanol injection should be stopped before sampling for at least five times of separator residence time [14]. The specifications of two contaminated samples with air and two uncontaminated ones with mud and free water have been shown in Tables 4 and 5, respectively.

Table 4: Two contaminated samples

Sample Number	Hydrocarbon sample volume (cc)	Air Content (mole%)
W-5	20000	0.54
W-6	20000	0.10

Table 5: Two uncontaminated samples

Sample Number	Opening pressure (psia)	Free water drained (cc)	Volume of mud (cc)
W-7	495	Nil	Nil
W-8	497	Nil	Nil

The last source of error in fluid sampling and recombination addresses those related to movement and transfer of collected samples from field to laboratory. In many cases, collected samples are regarded as dangerous chemicals that should be moved with special care. Disregarding the local and international considerations and regulations may have consequences such as financial penalties and stopping samples. Sampling cylinders should be kept away from smoke, fire, operating engines and match. All electrical devices can cause explosion. In the presence of H₂S, special corrosion resistant cylinders must be used. Also, the cylinders must be checked for leakage. To minimize the risk of any accident, high-pressure cylinders should be placed in special containers before transferring to laboratory [19].

6. Conclusion

In this work, PVT and DST data of a supergiant offshore gas condensate well were analyzed to address the challenges and errors associated with sampling and recombination of the samples in laboratory. Results showed that well preparation is the key, yet the most challenging step in obtaining representative reservoir fluid. The well should be stabilized in a step-by-step flow reduction to ensure the reservoir fluid contaminated with drilling fluid is removed from well. After that, the flow rate is gradually reduced to prevent the formation of condensate banking in the reservoir region around the well bore. It is expected that the offshore wells are not fully stabilized prior to sampling due to field and equipment restrictions. Therefore, maximum considerations should be acknowledged for all factors that contribute to well stability. Besides, surface separators are found as the most convenient and cheapest techniques for sampling, provided the reservoir pressure remains above the dew point pressure. However, this technique may suffer from serious errors addressed by deviation from equilibrium conditions. Analysis of available data revealed that separator sampling was not conducted at equilibrium conditions for some wells. This can result in failure in preparing the representative reservoir fluid. Therefore, it is essential to know and carefully follow all sampling regulations and procedures before the sampling.

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بررسی چالش‌ها و خطاهای فرایند نمونه‌گیری و ترکیب مجدد سیالات گاز میعانی

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چکیده

درک مناسب رفتار فازی سیال مخزن اولین مرحله توسعه و بهره‌برداری از یک میدان نفتی/گازی می‌باشد. در این مطالعه چالش‌ها و خطاهایی که ممکن است است قبل، حین و بعد از عملیات نمونه‌گیری ایجاد شود مورد بررسی قرار گرفت. داده‌های ساق مته حفاری و فشار-حجم-دمای چاه‌های اکتشافی و تولیدی یکی از مخازن فوق‌عظیم گاز میعانی مورد تحلیل قرار گرفت. مشخص گردید که تثبیت چاه و پایداری جریان قبل از نمونه‌گیری الزامی است. منابع اصلی خطا در حین نمونه‌گیری شامل ناپایداری تفکیک‌کننده، فقدان تعادل مایع-بخار، نسبت حجمی جریان‌های خروجی تفکیک‌کننده و حضور آلاینده‌ها می‌باشند. آنالیز جریان‌های خروجی تفکیک‌کننده برخی از چاه‌ها انحراف از حالت تعادل را نشان داد، که این مهم می‌تواند به طور مستقیم بر روی فشار نقطه شبنم و پیش‌بینی نسبت میعانات به گاز تأثیر داشته باشد. انتقال نامناسب سیال، نشسته نفت و گاز، و حضور ترکیبات خورنده به شدت می‌تواند بر کیفیت سیال ترکیب مجدد اثرگذار باشد.