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Abstract

Black oil tables used in reservoir simulation and/or RTA/PTA history matching exercises are generated based on a fixed surface process (number of separator stages, p_{sep} , T_{sep}). However, even though the number of separator stages remain fixed, the separator pressure and temperature vary over time. This variation of separator conditions over time leads to an inconsistency between the rates used in history matching (assumes constant separator conditions) and the actual measured rates (changing separator conditions in the field).

This paper provides a method to adjust all measured rates to a fixed surface process to ensure consistency between the black oil tables and rates used in history matching, and it also investigates for what fluid systems this normalization procedure is important. First, daily wellstream compositions are predicted based on a common equation of state (EOS) model, welltest and production data (separator oil and gas compositions, GOR, stock tank liquid API). Thereafter, these wellstreams are run through a fixed surface process, with the same separator pressure and temperature used to generate the black oil tables utilized in the reservoir modeling.

Several practical observations are made. CGR normalization is in general not important for black- and volatile oil systems. However, it may be very important for near-critical fluids and gas condensate systems. The obvious application of the proposed normalization scheme is to calculate a set of consistent oil and gas rates for every well that can be used for history-matching purposes. Additionally, as black oil PVT properties are a function of the separator process, it is recommended to define a common surface process for an entire field or basin to ensure consistent apple-to-apple comparison between wells.

Technical contributions include a qualitative framework of when CGR normalization is important and when it is not. The paper also proposes a simple solution to a widely known, but under-addressed and overlooked problem, not earlier presented in the open literature.

Introduction

This paper is motivated by the following practical observations made while working with a wide range of companies in the petroleum industry:

- Surface rates are dependent on the separation process (#stages, pressure and temperature) used to process the fluids from the reservoir to sales point.
- Reservoir simulators, RTA/PTA tools, well performance and nodal analysis tools use surface rates (processed through a fixed separation train) for internal calculations and reporting. That is why they require the definition of a *fixed* surface process within the modeling tool.
- In real life, even though the number of separator stages typically remain fixed over time, the separator pressure and temperature can and will vary, as opposed to the *fixed* surface process defined in the modeling tools.
- The variation of separator conditions over time leads to an inconsistency between the rates used in history matching (assumes constant separator conditions) and the actual measured rates (changing separator conditions in the field).

In this paper, we provide a comprehensive overview and best practices related to handling of changing separator conditions with time. Summarized, we will attempt to present and discuss

- 1. what condensate-gas ratio (CGR) normalization is
- 2. a rigorous and consistent method to convert daily rates into a common¹ surface process
- 3. under what circumstances appropriate CGR normalization is important and why

Even though condensate-gas ratio (CGR) and gas-oil ratio (GOR) are two ratios describing the same thing (CGR = 1/GOR), we will use CGR consistently throughout the paper. We could have used both terms interchangeably but will use CGR as surface process normalization ("CGR normalization") is more important for reservoir gases than reservoir oils – in which it is more common to talk about CGRs.

CGR Normalization – What is it?

Surface volumes are "Path Dependent". The relationship between reservoir volumes and surface volumes (B_o, R_s | b_{gd}, r_s) is "path dependent". For instance, for any given petroleum fluid, a *three-stage* separator process yields more surface liquid than a *single-stage* separator process, as exemplified in **Fig. 1**. In other words, how much of the reservoir fluid that translates into surface oil ($V_{\bar{o}}$) and surface gas ($V_{\bar{g}}$) is related to the *compositional path* the components are subject to from reservoir to sales. For petroleum engineering purposes, this "path" is generally determined by the surface process, i.e. typically i) number of surface separator stages and ii) pressure and temperature of each stage.

Equilibrium ratios. For a given temperature, pressure and composition, the "*K* values" dictate the relative amount that partitions into equilibrium gas and equilibrium oil at each separation stage. Equilibrium ratios define the ratio of equilibrium gas composition y_i to the equilibrium liquid composition x_i ($K_i \equiv y_i/x_i$). **Fig. 2** shows an example of the classical log-log plot of K-values vs. pressure at a given temperature (T= 100 F in this case). For reservoir fluids, *K* values typically reach a minimum at pressures >1000 psia and converge to 1 at the so-called convergence pressure (p_k). At pressures <1000 psia, the K values are more or less independent of the convergence pressure, i.e. they are independent of the composition. It is the variation of *K* values with pressure, temperature and composition that makes the surface volumes "path dependent".



Fig. 1. A three-stage separator process yields more surface liquid (higher CGR) than a single-stage separator process for any fluid

Fig. 2. Example of how K-values, y_i/x_i , (equilibrium ratios) change as a function of pressure for a given wellstream composition (z_i) and reservoir temperature (in this case = 100 F).

Black Oil PVT. Most reservoir engineering analysis in the petroleum industry is performed utilizing black oil tables. Important for this discussion, is that the volumetric black oil properties (B_o , $R_s | b_{gd}$, r_s) are dependent on the surface process (#stages, p_{sep} , T_{sep}). *Traditional* black oil tables (B_o , R_s , $\mu_o | b_{gw}$, μ_g) assume that all gas produced from the reservoir is "dry", which is a decent assumption for fluid systems with an in-situ solution GOR (R_{si}) less than 1000 scf/STB. *Modified* black oil tables (B_o , R_s , $\mu_o | b_{gd}$, r_s , μ_o) on the other hand, account for the condensate (oil) that is in solution with the reservoir gas. This becomes especially important for volatile oils, near critical fluids and gas condensates. In general, a black oil table is a two-component (oil and gas) PVT model, where three properties are defined for each component:

- Composition (R_s | r_s) *surface process dependent*
- Formation volume factor (B_o | B_{gd}) surface process dependent
- Viscosity $(\mu_0 | \mu_g)$ surface process independent

In addition, surface oil and surface gas densities are assumed constant, e.g. that

- $\gamma_{\bar{o}o} = \gamma_{\bar{o}g} \neq f(R_s, r_s)$
- $\overline{\gamma_{\bar{g}o}} = \overline{\gamma_{\bar{g}g}} \neq f(R_s, r_s)$

In practice, this means the surface oil produced from the reservoir oil $(V_{\overline{0}0})$, and the surface condensate (oil) produced from the reservoir gas $(V_{\overline{0}g})$ are assumed to have the same surface density $(\gamma_{\overline{0}0} = \gamma_{\overline{0}g})$. Similarly, the surface gas produced from the reservoir oil $(V_{\overline{g}0})$ and the surface gas produced from the reservoir gas $(V_{\overline{g}g})$ are assumed to have the same surface density $(\overline{\gamma_{\overline{g}0}} = \overline{\gamma_{\overline{g}g}})$.

Compositional vs. Black-Oil Models. As laid out in detail by Fevang et al. (2000), a black-oil model is always adequate for simulating *depletion performance* of petroleum reservoirs if (i) solution GOR (R_s) and solution CGR (r_s) are initialized properly and (ii) the PVT data are generated properly. For *gas injection*, a black-oil model should only be used in (i) oil reservoirs when there is minimal vaporization and (ii) lean to medium-rich gas condensate reservoirs undergoing cycling above the dewpoint. Hence, as black oil tables are adequate for most reservoir engineering purposes, most reservoir modeling is conducted with black oil tables.

Condensate Gas Ratio (CGR) Normalization. Black oil tables are generated assuming a fixed surface process, but in reality, separator conditions change through time. Hence, there is a risk for inconsistencies between the rates used in history matching (*assumes constant separator conditions*) and the actual measured rates (*changing separator conditions in the field*). If surface process separator conditions are changing significantly over time, a "correction" to a set of constant separator conditions *might* be needed for

- Consistent well-to-well performance comparison
- Consistent usage of black oil tables in history matching (using RTA/PTA or res. simulation)
- Consistent analysis of CGR performance over time

The correction is referred to as CGR normalization, as we "normalize" for changing separator conditions (remove the effect of changing separator conditions). The objective of this paper is to provide a qualitative framework of when CGR normalization is important and how to do this when it is found to be important.

CGR Normalization – Procedure

CGR normalization usually consists of two steps: (1) estimate the flowing wellstream composition based on the measured data and (2) re-process the estimated wellstream composition using a common surface process for all wells. Generally, CGR normalization requires (1) a properly tuned EOS model that matches relevant fluid properties of a specific reservoir or basin, (2) measured CGR, (3) measured separator conditions (pressure and temperature) and (4) a reasonable estimate of the flowing wellstream composition.

Wellstream Composition Estimation. There are a range of methods available to estimate daily wellstream compositions. What method to use depends primarily on the amount of production data available on a given day, as presented in **Table 1**. Carlsen et al. (2020) summarize the differences between these methods in detail and the accuracy associated with each method. All methods exactly match the measured test CGR. However, if the "produced fluid properties" (CGR, liquid API, compositions) change rapidly, the methododology picked can have a large impact on the estimation of the wellstream composition. This will also influence the normalized rates (obtained after re-processing the estimated composition in the common surface process).

Data available	Recommended Method	Regression variable(s)
CGR	Hoda and Whitson (2013)	Fg
CGR, γ_{API} and γ_g	Hoda et al. (2017)	F_g and MW_{C7+}
CGR, γ_{API} and separator gas composition (y _i)	Whitson and Sunjerga (2012)	Fg, MW _{C7+} and seed feed C ₆₋ molar fractions
CGR, separator oil and gas compositions (y _i and x _i)	Carlsen et al. (2020)	Fg and MW _{C7+}

Table 1. Recommended wellstream composition estimation methods based on the available data.

In short, the different methodologies can be summarized as follows:

• Hoda and Whitson (2013) proposed a method to convert well test measured rates into molar rates. The method requires (1) an EOS model, (2) the measured test gas and oil rates, (3) the measured (*p*, *T*) conditions of the test separator and (4) a reasonable estimate of the composition (the *seed feed*). The proposed method does not require iterations and matches exactly the measured CGR.

- Hoda et al. (2017) improved the method by matching the measured liquid API and gas specific gravity using the Hoffman correlation and the gamma model.
- Whitson and Sunjerga (2012) proposed an alternative iterative method that relies on finding a wellstream composition that when input in an EOS model, exactly reproduces the welltest data (i.e separator-gas compositions, separator CGR, and stock-tank liquid API).
- Carlsen et. al (2020) suggest a recombination procedure when separator oil and gas compositions are measured until C₇₊. First, the C₇₊ is split with a field-wide gamma model (Whitson 1983), where the shape (η) and bound (β) remains fixed for all samples found in a field, while the average C₇₊ molecular weight varies from sample to sample (MW_{C7+})

Re-processing Using a *Common* **Surface Process.** The estimated wellstream composition is then reprocessed using a *common* surface process for all wells, which is the same surface process defined in all the modeling tools (e.g. reservoir simulation, nodal analysis, pipe flow). The *common* surface process can be (1) a multi-stage flash process, (2) a K-value based surface process modeling the actual process plant (e.g. where K-values are obtained from a converged process simulation) or (3) a full process modeled in a process simulation application (e.g. HYSYS/UNISIM). The normalized CGR is then computed using the total gas and total oil coming out of this *common* surface process.

Using a full process model for re-processing the wellstream compositions allows more than two final plant products. Hoffmann et al. (2017) used a full process simulation for re-processing wellstream compositions of gas condensates wells. The contribution of individual wells to three final plant products (sales gas, LPG and stabilized oil) were calculated based on the process simulation.



CGR Normalization – What is Important and Why?

Fig. 3. Single-well CGRs are typically measured using a test separator in which the oil and gas rates are measured at separator conditions (p_{sep}, T_{sep}) .

Fig. 4. Field example of separator pressure and temperature change with time. Notice how the separator pressure decreases until it ~stabilizes, and how temperature changes with the seasons.

Measurement of CGR in the Field. Single-well CGR is measured using a test separator, in which the oil (condensate) and gas rates are measured at separator conditions (p_{sep} , T_{sep}) as illustrated in **Fig. 3**. It is often not practically possible to test the individual well rates through the entire multi-stage process because the feed to the multistage process is a commingled feed from multiple wells. Hence, to obtain stock-tank rates (and CGRs), the separator oil is sent for laboratory analysis in which the shrinkage and flash factor (separator oil solution GOR) are reported. With the availability of this data, the following pitfalls are commonly observed:

- 1. Separator rates are used *directly* in engineering analysis without accounting for shrinkage or additional gas released of separator oil i.e. separator CGR (sep.bbl/MMscf) is used instead of total CGR (STB/MMscf).
- 2. Separator conditions are changing significantly, such that the "fixed surface process" assumption (#stages, p_{sep}, T_{sep}) used in modeling tools is not valid, or particularly good.

The goal of this section is to develop a *rule of thumb* of when this is important, and when it is less important, to consider CGR normalization.

1. Separator rates are used directly in engineering analysis without accounting for shrinkage of separator oil – i.e. separator CGR (sep.bbl/MMscf) are used instead of total CGR (STB/MMscf). Petroleum engineering tools (reservoir simulation, RTA/PTA, well performance) use total CGR (not separator CGR) defined trough a fixed surface process as either input and/or output. Leveraging separator rates instead of stock tank rates yields consistently higher oil rates and consistently lower gas rates (higher CGR). For instance, if a shrinkage factor of 0.8 STB/sep.bbl is ignored, a 25% higher oil volume is incorrectly assigned to that well.

To further illustrate this point, and quantify the magnitude of the error, **Fig. 5** shows an example of (a) shrinkage factor (SF) and (b) flash factor (FF) for a variety of fluid systems² ranging from very lean gas condensates (1 STB/MMscf) to black oils (>1000 STB/MMscf) at different separator conditions. Low shrinkage factors and high flash factors indicate a large difference between separator CGR (at separator conditions) and total CGR (at stock tank). The figures indicate that the difference between separator CGR (at separator CGR (at separator conditions) and total CGR (at stock tank) are larger for (1) fluids with lower CGRs and (2) higher separator pressures (and temperatures, as shown in further detail in **Appendix A**).



Fig. 5. Effect of the change in 1^{st} stage separator pressure ($T_{sep} = 100$ F) on shrinkage factors (SF) and flash factors (FF) for different fluid systems.

2. Separator conditions are changing significantly, such that the "fixed surface process" assumption (#stages, p_{sep} , T_{sep}) used in modeling tools is not valid, or particularly good. Here, the separator CGR has been correctly converted for shrinkage and flash factor (gas released from the separator oil), i.e. GOR_{tot} = GOR_{sep}/SF + FF. However, the separator conditions (p_{sep} , T_{sep}) have not been corrected for. Remember that petroleum engineering tools (reservoir simulation, RTA/PTA, well performance) leverage total CGR defined trough a fixed surface process. A "fixed" surface process means that:

 $^{^{2}}$ The different fluid systems are created by recombining the same surface oil and surface gas at different solution CGRs. The solution CGR (r_{s}) is based on a single-stage flash process to stock tank conditions. Details are provided in Appendix A.

- Process units from wellhead to sales (e.g. number of sepearator stages) remain unchanged through the lifetime of the well. This is in general true, but some field examples exist in which separators, heater treaters and other processing units have been added or removed with time. For the sake of this discussion, it is assumed to be constant.
- Operating conditions (pressure and temperature) of each unit operation in the process are kept *constant* throughout the lifetime of the well. This is obviously a simplification. Specially important is how the temperature and pressure of the first-stage separator change with time; which sometimes can be significant. In this discussion, changing operating conditions is something we will look closer at.

To understand how *changing* separator conditions can impact the producing CGR over time, a wide range of wellstream compositions were analyzed and processed through a set of different separator conditions (p_{sep} , T_{sep}). The separator temperature range analyzed was 50 to 150 F, while the separator pressure range was 50 to 1000 psia; typical separator operating conditions. To quantify how sensitive the total CGR³ is to different separator conditions, the relative difference, δ , between the maximum (CGR_{max}) and minimum total CGR (CGR_{min}) was calculated for a range of different compositions, i.e. $\delta = CGR_{max}/CGR_{min}$.

For instance, if δ is 2, the maximum total CGR is twice as large as the minimum total CGR for a given wellstream composition. In practice, this means that there can be a difference of up to 200% (!) between the measured and normalized CGR – i.e. CGR normalization is very important. If δ is 1 (or very close to 1), on the other hand, the difference between CGRs (normalized vs measured) is less important (for the range of P_{sep}, T_{sep} studied).

Fig. 6 presents the sensitivity (δ) to changing separator conditions versus solution CGR. Each point on the figure represents one fluid composition, and as seen, changes in separator conditions can have a significant effect on the reported CGR – specially for leaner gas condensate systems, i.e. <100 STB/MMscf. Further details of how the CGR changes with the variation in first stage p_{sep}, T_{sep} are presented in **Appendix B**.



Fig. 6. CGR sensitivity ("path sensitivity") to changes in separator conditions (p_{sep} & T_{sep}) for different fluid systems.

³ Total CGR: cumulative CGR after being processed to stock tank conditions, units: STB/MMscf



Examples **Example 1: Reservoir Simulation.**

Fig. 7. Phase envelope (p-T diagrams) for the different fluid systems referenced in this paper.



To understand the importance of CGR normalization in reservoir simulation, a 3D compositional reservoir simulation model identical to what was presented by Carlsen et al. (2019) was leveraged. The key model parameters are given in **Table 4**. The models were run on a BHP profile that mimics the "typical" BHP behavior seen in tight unconventionals: rapid decline from initial reservoir pressure (7500 psia) until some minimum, constant, bottomhole pressure (500 psia). The four different in-situ reservoir fluid systems presented in Table 5 were studied; black oil, volatile oil, near-critical oil and gas condensate. The associated phase envelopes are presented in Fig. 7. It is important to understand the relative importance of different fluid systems as most unconventional basins, e.g. Permian, Eagle Ford, and Montney, span a wide range of fluids. The common EOS model presented in **Table 3** was used in the analysis. Hence, the only difference between each of the different runs were the in-situ reservoir fluid composition (z_{Ri}) , which allows for consistent apples-to-apples comparison.

The simulated daily wellstream compositions were used to study producing CGRs over time and its sensitivities to, i) different in-situ fluid systems, and ii) changing separator conditions as illustrated in Fig. 8. For simplicity we considered a two-stage process, in which the first-stage separator conditions were allowed to change, while the second stage was always fixed at stock-tank conditions (1 atm and 60 °F).





Fig. 9a. Comparison of "normalized" (fixed separator conditions) and measured (changing separator conditions) for a in-situ volatile oil (VO) system and a in-situ near-critical volatile oil (NCVO) system.

Fig. 9b. Comparison of "normalized" (fixed separator conditions) and measured (changing separator conditions) for a in-situ gas condensate (GC) system and a in-situ black oil (BO) system.

Fig. 9 shows the impact of CGR normalization on the producing CGR for the different in-situ fluid systems presented in Fig. 7. The impact on low GOR fluids, e.g. volatile oil and black oil, is minimal. However, the simulated results emphasize the importance of CGR normalization for gas condensates and near critical fluids. For instance, for the gas condensate system, on day 70, *measured* CGR is 24 STB/MMscf, while the *normalized* CGR is 17 STB/MMscf – a difference of more than 40%!

Example 2: Gas Condensate Diagnostic Plot.

In gas condensate fields (wells), the CGR versus pressure curve obtained from a CVD test of the insitu reservoir fluid composition⁴ will give a very good estimate of the actual CGR performance of the well: *CGR vs average reservoir pressure* in conventionals and *CGR vs bottomhole pressure* in unconventionals. An example is shown in **Fig. 10** in which the results of a reservoir simulation with a lean gas condensate (initial CGR = 50 STB/MMscf) are presented. This reservoir simulation is using the same model assumptions and parameters as Example 1.



Fig. 10a. GC Diagnostic Plot - Comparison of "normalized" (fixed separator conditions) and measured (changing separator conditions) CGR for a lean gas condensate system, plotted together with the CGR of the CVD gases.

Fig. 10b. Relative difference of measured vs normalized CGR for a lean gas condensate system as shown in the GC Diagnostic Plot.

The simulated daily wellstream compositions were processed through a separation process in which the separator conditions were changing daily, as illustrated in Fig. 8. For simplicity we considered a two-stage process, in which the first-stage separator conditions were allowed to change, while the second stage was always fixed at stock-tank conditions (1 atm and 60 °F). The wellstreams were also processed through a common set of separator conditions to obtain the normalized CGRs. Both the "normalized" and "measured" CGRs are plotted with the CGR of the released gases from a CVD test of the insitu fluid.

The gas condensate diagnostic plot can be used to forecast a field's or well's CGR over time. Using the measured data without normalization can lead to large errors in the forecasting of CGR, especially later in time when the well's CGR is at its lowest, with errors of up to 50% as shown in Fig. 10b. Also, in this example, the observed discrepancy between the "measured CGR" and "CVD CGR" could incorrectly suggest that the reservoir condensate is mobile ($k_{ro} \neq 0$). This is a good reminder of when not doing CGR normalization can lead to incorrect interpretations of fundamental reservoir behavior.

⁴ For unconventional wells, this is essentially a comparison of the i) producing CGR versus bottomhole pressure and and the solution CGR (r_s) curve from a properly generated black oil table for that well.

Example 3: Decreasing CGRs above Saturation Pressure in "Shales".

Decreasing CGRs are observed while flowing bottomhole pressures are above the saturation pressure in several unconventional basins throughout North America such as Eagle Ford and Duvernay. Different reservoir related explanations have been proposed, among which the most popular are:

- Fluid heterogeneity (Whitson et al. 2018)
- Gas adsorption (Walker et al. 2017)
- Pore confinement effects (Devegowda et al. 2012; Jin et al. 2016)

Even though there are several working reservoir related theories, there seem to be a lack of consensus in the industry on the primary drivers behind this characteristic. General agreement, however, seems to be established around it being more prominent for leaner fluids (lower CGRs) than richer fluids (higher CGRs). Other than that, there seem to be several ways to mimick this behavior physically and with simulation, which leaves this to be a somewhat non-unique exercise without large amounts of high-quality lab and field data supporting either theory. What further complicates this exercise, is that operational effects can have a significant impact on producing CGRs – even if the producing wellstream composition is constant⁵– such as,

- Separator gas blowby (gas "carryover")
- Different early time (handle lots of water) and late time surface process (handle less water)
- Significant changes in separator conditions $(T_{sep} \text{ and } p_{sep})$ as discussed throughout this paper

Fig. 11 shows CGR normalization applied to a well in the Eagle Ford producing from a *lean* gas condensate fluid system. Separator pressures are decreasing from 1000 psia to 250 psia in ~1000 days, as seen in Fig. 11a. If the changing separator conditions are not accounted for, it looks like the CGR decreases significantly from day 1. However, after applying CGR normalization, much of the relative decrease in CGR is reduced, as seen in Fig. 11b. This is a good example of when CGR normalization has a large impact in general, which is expected as the separator conditions are changing significantly, and the fluid system is relatively lean.

Fig. 12 shows similar analysis for a *rich* gas condensate fluid system. Here, the relative change due to CGR normalization are less prominent, which is expected, as both the fluid system is richer, and the separator conditions are changing less compared to the lean gas condensate case.



Fig. 11a. Separator temperature and pressure for a *lean* gas condensate well in the Eagle Ford.



⁵ Producing compositions are constant while flowing BHPs are above the saturation pressure of the reservoir fluid ($p_{wf} > p_{sat}$)



Summary

Several practical observations are made:

- 1. CGR normalization is in general not important for black- and volatile oil systems. However, it may be very important for near-critical fluids and gas condensate systems.
- 2. CGR normalization is especially important when i) both "produced fluid properties" (GOR, liquid API) and ii) separator conditions change significantly over time.
- 3. The proposed normalization scheme can be used to calculate a set of consistent oil and gas rates for every well that can be used for CGR performance analysis and history-matching purposes.
- 4. Additionally, as surface volumes are a function of the separator process, it is recommended to define a common surface process for an entire field or basin to ensure consistent apple-to-apple comparison between wells. This common surface process would be used whenever any surface rates are reported for any work (e.g. well tests, PVT experiments, reservoir simulation) related to the field.

Nomenclature

\mathbf{B}_{gd}	= "dry" gas formation volume factor (FVF), res.bbl/STB = $(p_{sc}TZ)/(T_{sc}p)$
\mathbf{B}_{gw}	= "wet" gas formation volume factor (FVF), res.bbl/STB = ($p_{sc}TZ$)/($T_{sc}p$) 1/ $F_{\bar{g}g}$
Bo	= oil formation volume factor (FVF), res.bbl/STB
$\mathbf{B}_{o,sep}$	= oil formation volume factor (FVF) of separator oil, sep.bbl/STB
F_{g}	= molar gas fraction = $(z_i-x_i)/(y_i-x_i)$, fraction
FF	= flash factor, scf/STB – the solution GOR (R_s) of the separator oil
K_i	= "K-values" / equilibrium ratios = y_i/x_i , fraction
p_{avg}	= average reservoir pressure, psia
p_b	= bubblepoint pressure, psia
p_d	= dewpoint pressure, psia
p_i	= initial reservoir pressure, psia
p_k	= convergence pressure, psia
p_{sat}	= saturation pressure, psia

p_{wf}	= flowing bottomhole pressure, psia
S_{gc}	= critical gas saturation
SF	= shrinkage factor, STB/sep.bbl – the inverse of separator formation volume factor ($B_{o,sep}$)
R _{si}	= initial solution GOR, scf/STB
R_s	= solution GOR, scf/STB
R_p	= producing GOR, scf/STB
T_{res}	= reservoir temperature, °F
Vo	= reservoir oil volume, reservoir bbl
V_g	= reservoir gas volume, reservoir cf (or bbl)
$V_{\bar{o}o}$	= surface oil volume originating from reservoir oil, STB
$V_{ar{g}o}$	= surface gas volume originating from reservoir oil, scf
$V_{ar{g}g}$	= surface gas volume originating from reservoir gas, scf
$V_{\bar{o}g}$	= surface oil (condensate) volume originating from reservoir gas, STB
X_i	= separator oil composition, mol%
<i>Yi</i>	= separator gas composition, mol%
Zi	= wellstream composition, mol%
Zsi	= "seed feed" composition – estimate of actual wellstream composition, mol%
ZRi	= in-situ reservoir composition, mol%
α	= shape, a parameter in the gamma model
γαρι	= stock-tank liquid API
γ_g	= gas specific gravity
γ_{g+}	$= \gamma_{g+}$ is the specific gravity of the additional gas realsed from the first stage separator
η	= bound, a parameter in the gamma model
μ_g	= gas viscosity, cp
μ_o	= oil viscosity, cp

Acknowledgements

We would like to thank Innovation Norway and the Norwegian Research Council for continuing support of our technology development related to compositional analysis.

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Appendix A – Shrinkage Factors and Flash Factors

Component	Liquid	Vapor				
H2S	0.00	0.00				
N2	0.00	0.83				
CO2	0.00	0.05				
C1	0.47	84.34				
C2	0.38	9.55				
C3	0.31	2.03				
I-C4	0.47	1.18				
N-C4	0.38	0.65				
I-C5	0.51	0.32				
N-C5	0.27	0.12				
C6	2.45	0.39				
C7	7.36	0.37				
C8	7.84	0.12				
C9	6.41	0.03				
C10	5.58	0.01				
C11	4.96	0.00				
C12	4.45	0.00				
C13	4.03	0.00				
C14	3.67	0.00				
C15	3.35	0.00				
C16	3.07	0.00				
C17	2.82	0.00				
C18	2.60	0.00				
C19	2.40	0.00				
C20	2.22	0.00				
C21	2.05	0.00				
C22	1.90	0.00				
C23	1.77	0.00				
C24	1.64	0.00				
C25	1.53	0.00				
C26p	25.12	0.00				
Total	100	100				
MW	224.0	19.81				
Z-factor	0.011	0.997				
Density (g/cc)	0.829	0.001				





Fig. 13a. Shrinkage Factors (SF) vs. solution CGR for p_{sep} (T_{sep} =100 F)



Fig. 13b. Flash Factors (FF) vs. solution CGR for different psep (Tsep=100 F)



Fig. 13c. Shrinkage Factors (SF) vs. solution CGR for different T_{sep} (P_{sep} =100 psia)





Appendix B – CGR versus different Separator Conditions and Fluid Types



Separator Pressure. Effect of the first stage separator pressure on the change in separator CGR

Fig. 14. Effect of the change in separator pressure (1st stage) on the measured CGR for different fluid systems (a-d). First stage separator temperature is kept constant at 100 F for all these cases.



Separator Temperature. Effect of the first stage separator temperature on the change in separator CGR

Fig. 15. Effect of the change in separator temperature (1st stage) on the measured CGR for different fluid systems (a-d). First stage separator pressure is kept constant at 300 psia for all these cases.

Appendix C – Number of Separation Stages

Fig. 16 exemplifies the effect of the number of separation stages on the CGR. For a given fluid the three different bars represent three different separation processes which have been defined using the conditions show in **Table 3**. As seen, the biggest difference in CGR is observed when going from a 1-stage to a 2-stage separation process.

1	-stage Proces	S	2	-stage Proces	S	3-stage Process						
Stage	Pressure (psia)	Temperature (F)	Stage	Pressure (psia)	Temperature (F)	Stage	Pressure (psia)	Temperature (F)				
1	14.7	60	1	300	100	1	300	100				
			2	14.7	60	2	150	80				
						3	14.7	60				









(b) Rich Gas Condensate Fluids



(c) Volatile Oil Fluids

(d) Black Oil Fluids

Fig. 16. Effect of the number of separator stages on the measured CGR for different fluid systems (a-d). Separator conditions are the same for all cases, as shown in Table 3.

Appendix D – Tables for Reservoir Model and EOS Fluid Characterization

Variable	Unit	Value
Reservoir pressure, p _R	psia	7500
Minimum flowing bottomhole pressure, p _{wf}	psia	500
Reservoir temperature, Tr	F	250
Fracture half length, x _f	ft	325
Frac-to-Frac distance	ft	50
Thickness, h	ft	150
Matrix permeability	nd	200
Porosity, φ	-	0.03
Initial water saturation, S _{wi}	-	0
Residual oil saturation in gas-oil system, S_{org}	-	0.4
Critical gas saturation, S _{gc}	-	0.1
Corey oil exponent, n _o	-	2
Corey gas exponent, n _g	-	2
krg at maximum S _g	-	0.7
kro at maximum S_o	-	1
Fracture permeability	md	12005
Rock pore volume compressibility, c _f	1/psi	4E-06
Separator pressure (stage#1)	psia	300
Separator temperature (stage#1)	F	100
Separator pressure (stage#2)	psia	14.7
Separator temperature (stage#2)	F	60
Number of grid cells per fracture	#	24000

Table 4. Reservoir simulation model assumptions

Component	Near-Critical Gas Condensate	Near-Critical Volatile Oil	Volatile Oil	Black Oil
H2S	0.00	0.00	0.00	0.00
N2	0.31	0.56	0.21	0.34
CO2	2.37	1.30	0.93	0.02
C1	73.19	69.44	58.77	34.62
C2	7.80	7.88	7.57	4.11
C3	3.55	4.26	4.09	1.01
I-C4	0.71	0.89	0.91	0.76
N-C4	1.45	2.14	2.09	0.49
I-C5	0.64	0.90	0.77	0.43
N-C5	0.68	1.13	1.15	0.21
C6	1.09	1.46	1.75	1.61
C7	1.13	1.07	2.19	4.51
C8	1.12	1.09	2.25	4.70
C9	0.85	0.86	1.78	3.81
C10	0.70	0.73	1.52	3.31
C11	0.58	0.63	1.32	2.94
C12	0.49	0.55	1.16	2.64
C13	0.42	0.49	1.03	2.39
C14	0.36	0.43	0.92	2.17
C15	0.31	0.38	0.82	1.99
C16	0.27	0.34	0.74	1.82
C17	0.23	0.31	0.67	1.67
C18	0.20	0.28	0.60	1.54
C19	0.18	0.25	0.55	1.42
C20	0.16	0.22	0.49	1.31
C21	0.14	0.20	0.45	1.22
C22	0.12	0.18	0.41	1.13
C23	0.10	0.17	0.37	1.05
C24	0.09	0.15	0.34	0.97
C25	0.08	0.14	0.31	0.91
C26+	0.68	1.58	3.83	14.89
Total	100	100	100	100
		Properties		
p _{sat} , psia	6086	6044	4542	1985
GOR, scf/STB	5714	3938	1589	326
OGR, STB/MMscf	175	254	629	3067
Yарi	49.0	47.0	44.4	39.3
0	8.2	10.0	21.8	56.4

Table 5. Different fluid systems analyzed in this paper

Table 6b. BIPS of the "generic" SRK EOS model used for example simulations in this paper. Values not presented in this table are 0.

		Comp	H2S	N2	CO2	Ω
lien Zn	IMW	H2S	0			
		N2	0	0		
0.283		C02	0	0	0	
0.274		<u>c</u> 1	0.08	0.02	0.12	0
0.286		C2	0.07	0.06	0.12	0
0.279		ទួ	0.07	0.08	0.12	0
0.276		I-C4	0.06	0.08	0.12	0
0.282		N-C4	0.06	0.08	0.12	0
0.274		-05	90.0	0 08	0 12	o
0.272		Z-07	90.08	0 08	0 12	D
0.200	0 37	C	50.0	0 08	0 12	D
0.264	90.1	C7	0.03	0.08	0.1	0.0149
0.260	103.9	C8	0.03	0.08	0.1	0.0173
0.256	117.5	63	0.03	0.08	0.1	0.0197
0.248	144.0	C10	0.03	0.08	0.1	0.0219
0.245	157.2	C11	0.03	0.08	0.1	0.024
0.242	170.3	C12	0.03	0.08	0.1	0.026
0.239	183.3	C13	0.03	0.08	0.1	0.0278
0.236	196.2	C14	0.03	0.08	0.1	0.0295
0.233	209.0	C15	0.03	0.08	0.1	0.0311
0.200	22/ 3	C16	0.03	0.08	0.1	0.0325
0.224	246.8	C17	0.03	0.08	0.1	0.0339
0.222	259.2	C18	0.03	0.08	0.1	0.0352
0.219	271.5	C19	0.03	0.08	0.1	0.0364
0.216	283.7	C20	0.03	0.08	0.1	0.0374
0.214	295.8	C21	0.03	0.08	0.1	0.0385
0.212	307.8				<u> </u>	
0.209	319.7	C22	0.03	0.08	0.1	0.0394
0.199	331.5	C23	0.03	0.08	0.1	0.0403
		C24	0.03	0.08	0.1	0.0411
		C25	0.03	0.08	0.1	0.0419
		C26p	0.03	0.08	0.1	0.045

Table 6a. Component properties of the "generic" Soave-Redlich-Kwong (SRK) equation of state (EOS) model used for example simulations in this paper.

-																															
C26p	C25	C24	C23	C22	C21	C20	C19	C18	C17	C16	C15	C14	C13	C12	C11	C10	C9	C8	C7	C6	N-C5	I-C5	N-C4	I-C4	ដ	C2	C1	CO2	N2	H2S	Component
381.5	325.4	313.5	301.6	289.6	277.4	265.1	252.8	240.3	227.7	215.1	202.3	189.4	176.5	163.4	150.3	137.1	123.8	110.4	96.7	83.6	72.2	72.2	58.1	58.1	44.1	30.1	16.0	44.0	28.0	34.1	Mol Wt
1571.8	1504.3	1488.5	1471.9	1454.4	1436.1	1416.7	1396.2	1374.4	1351.2	1326.5	1300.0	1271.6	1240.9	1207.6	1171.4	1131.7	1087.9	1038.7	983.9	8.126	845.5	828.7	765.2	734.1	665.7	549.6	343.0	547.4	227.2	672.1	Tc (R)
141.9	163.0	168.4	174.3	180.8	187.9	195.7	204.3	213.8	224.3	236.0	249.1	263.8	280.3	299.0	320.3	344.6	372.5	404.8	439.7	475.0	488.8	490.4	550.6	527.9	616.1	706.6	667.0	1069.5	492.8	1300.0	Pc (psia)
0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	Crit Z
0.3663	0.3457	0.3402	0.3342	0.3277	0.3206	0.3129	0.3045	0.2953	0.2854	0.2746	0.2630	0.2505	0.2370	0.2227	0.2074	0.1913	0.1744	0.1568	0.1452	0.1343	0.1195	0.0977	0.1103	0.1095	0.0908	0.0589	-0.0025	0.2175	-0.0009	0.1015	Vol Tran
1.0943	0.9498	0.9183	0.8863	0.8536	0.8203	0.7863	0.7516	0.7163	0.6803	0.6436	0.6062	0.5681	0.5293	0.4898	0.4496	0.4088	0.3675	0.3256	0.2859	0.2507	0.2520	0.2290	0.2000	0.1860	0.1520	0.0990	0.0110	0.2250	0.0370	0.0900	AF
0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	0.42748	A
0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	0.08664	в
1293.9	1212.1	1193.1	1173.3	1152.6	1130.9	1108.1	1084.2	1059.1	1032.6	1004.7	975.3	944.1	911.0	875.9	838.5	798.5	755.8	709.5	660.5	608.7	557.0	542.4	491.1	471.1	416.2	332.7	201.6	333.3	139.4	382.4	Tb (R)
0.199	0.209	0.212	0.214	0.216	0.219	0.222	0.224	0.227	0.230	0.233	0.236	0.239	0.242	0.245	0.248	0.252	0.256	0.260	0.264	0.269	0.268	0.272	0.274	0.282	0.276	0.279	0.286	0.274	0.292	0.283	Visc Zc
331.5	319.7	307.8	295.8	283.7	271.5	259.2	246.8	234.3	221.7	209.0	196.2	183.3	170.3	157.2	144.0	130.8	117.5	103.9	90.1	76.9											LMW