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## **Integrated PVT Modeling for Gas Condensate Systems**

P.M.W. Cornelisse, Shell

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### **Abstract**

On the basis of PVT data from 10 well/reservoirs, fluid models were developed for subsurface and surface requirements. The present paper described a methodology that can be used to maximize consistency between the data used for subsurface as well as surface network modeling. The models were developed to honor all of the experimental data, even though in some cases inconsistencies between the different experimental data sets were found. The workflow is not preliminary aimed at the best match between model and experiment of a single sample but getting the most representative model for the reservoir fluid based on all knowledge. The basis of the model is a PR78 with constant Peneloux volume shift.

The paper describes the workflow for low CGR gas condensate systems from low permeability formations and focuses on three different steps tackling the impact of sampling and experimental issues. It is shown that for this example system many bottom hole samples, both open and cased hole samples, have some external contamination in the C34-C36 range that artificially increases the dew point and liquid drop out at pressures above 2500 psia, while having little to no effect on the overall CGR. Some separator sample sets seem to be depleted in the C5-C10 range compared to all bottom hole samples. It is likely that incomplete equilibration in the separator in combination with some water washing is the reason for this behavior. This observation is supported by the fact that this issue becomes more pronounced for leaner fluids. The issue has a quite strong effect on the CGR (~30%). So the most representative compositions were obtained from cased hole and open hole fluids, corrected for contamination and draw down effects.

In the modeling part of the workflow several steps can be identified: 1) Generation of a 1<sup>st</sup> model used for QC of data and definition of the parameter ranges (22 comp), 2) Create a model as above but doing a compositional correction for contamination or other compositional irregularities like H<sub>2</sub>S content, specific contaminants, effects of depletion/enrichment due to 2 phase sampling (22 comp), 3) Create a unified model (32 comp). The model is derived from model 2 but includes BTEX and is mapped onto a single ABC set of pseudo components that are the same for all reservoirs/wells. 4) As 3, but with S-components included. 5) Create the compositional 10 component lumped reservoir model (6 light end + 4 C<sub>7+</sub> components).

The models generated show good agreement to the data and are believed to be the most realistic estimate of the fluid behavior of the reservoir fluids. On top of that we can swap from one model to another using a simple lumping/delumping scheme.

## Introduction

As part of the work processes of dealing with fluids samples, generating PVT data and performing QC, several PVT models were generated for fluid samples from the exploration and first appraisal well. Later other parts of the field were appraised, with strongly different compositions. As a result the question arose whether it is possible to describe all those fluids with the same models, and if so could we use that characterization to model the surface processing steps at least to some degree without having to go to a completely new fluid model with pseudo components and interaction parameters. Several approaches in the open literature are available but none did exactly meet the needs we had in mind for this project. As far as lumping/delumping procedures are concerned, the method as presented by Leibovici [2, 4, and 5] seems most suitable.

The present paper describes the selection and further rationalization of the use of several fluid models, and puts them on a unified characterized basis. The unification in this context refers to the idea that a single set of pseudo components is used to describe all reservoir fluids, so that at any later stage the fluids can be mixed without increasing the number of components.

The procedure used in this study is to generate models for two to three reservoirs indicated as A, B and C as penetrated by 3 wells (well 1, 2, 3) and a sidetrack (well 2ST1). The reservoirs A and B as penetrated in well 1 were very similar suggesting possibly a connected system, but the same reservoirs penetrated in well 2 indicated a lower CGR although being deeper. This might suggest a non-connected system or an effect of TSR. Something similar is the case for the reservoir C. No (complete) reservoir hydrocarbon fluid samples were extracted in the well 2 reservoir C, neither down hole nor at surface. Only a gas sample obtained during the well test was available (no separator liquid could be sampled). That gas composition indicated a very similar composition between well 1 and 2, and as such suggests connectivity, in absence of strong Thermal Sulphate Reduction (TSR) effects. The well 3 seems to penetrate the reservoirs with quite different compositions.

The paper is organized as follows:

1. Sampling: How are open hole, cased hole and surface samples acquired and what are the specific issues
2. QA/QC: The various aspects of QA/QC like contamination, and how certain components are added/removed from the samples depending on the way the sample was collected: CGR, H<sub>2</sub>S, C3-C7 and aromatics, COS & mercaptans
3. Modeling: Typical aspects for gas condensate systems. What it means to go to a unified model and explaining the pros and cons to have a consistent description between subsurface and surface. Application to sour gas condensate system using HFPT model type set-up.

All fluid descriptions in this report are based on PR78 with a constant Peneloux volume shift.

## Sampling and how it affects sample compositions

The way samples are collected determines to a large extent how compositions can get affected. The specific aspects of the different sample collection methods and their impact on fluid compositions are indicated below.

### Open hole sampling

The main feature of the open hole sampling is that it only targets a single zone. This will give us an idea about the properties local fluid as well as rock properties. The main issues with obtaining open hole samples are the fact that we have an invaded zone where mud filtrate resides and thus needs to be cleaned out before a sample is collected. In a carbonate system drilled with WBM that is often easier said than done, especially for water samples. However, also hydrocarbons can be affected by the WBM system. The formation permeability ranges between 0.1 – 10 mD, but at some locations had fractures as well, where

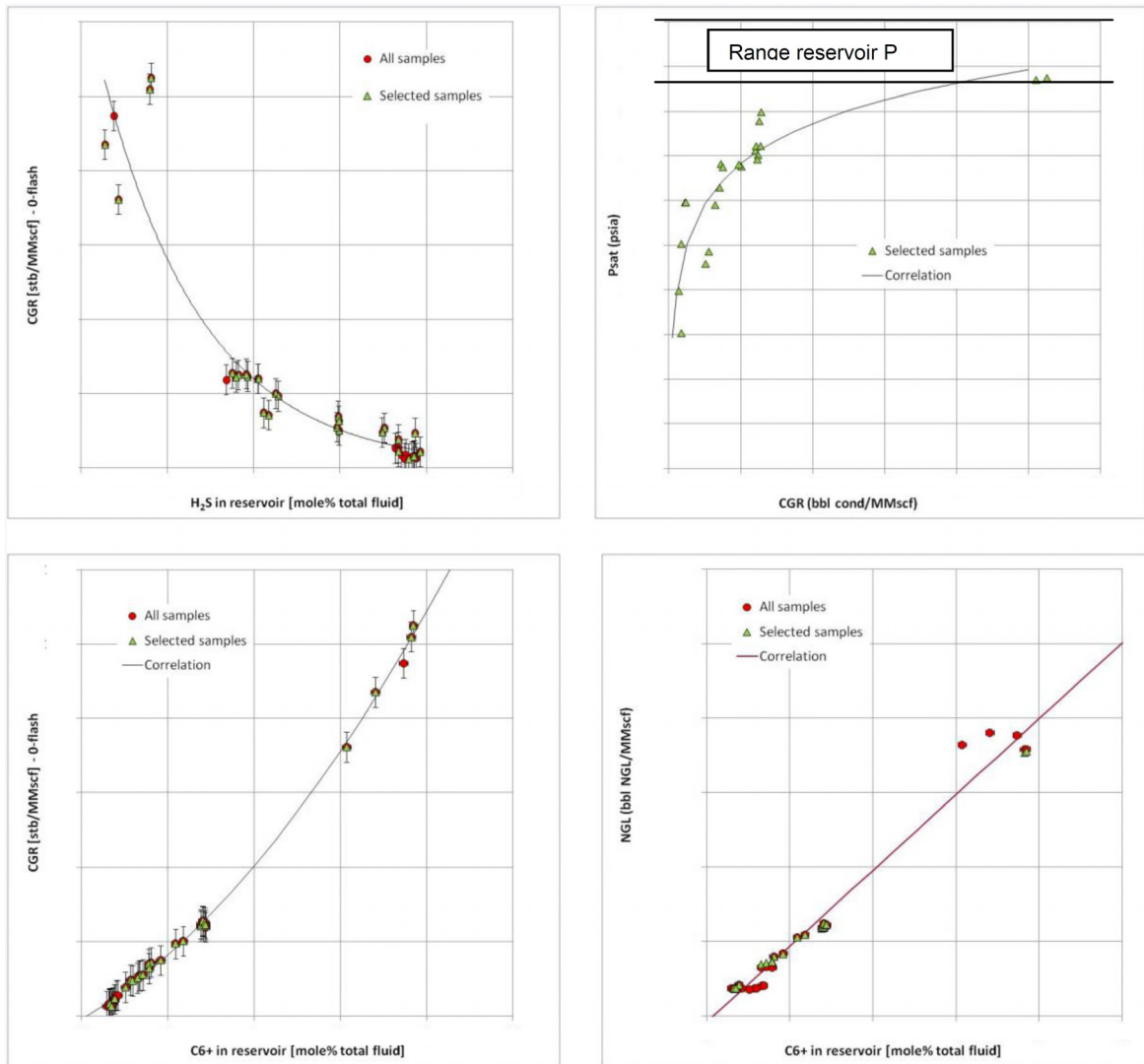
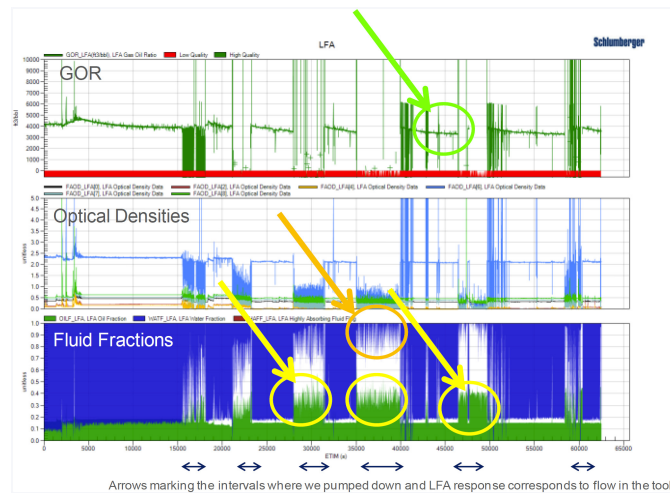


Figure 1—Indication of key properties for the fluids encountered. Saturation pressures are approaching reservoir pressure (4800-5700 psia) when CGR goes up. The CGR and H<sub>2</sub>S are somehow connected through TSR.

some near wellbore fractures were the result of drilling the well. A well test would not see those but for an open hole sampling job they could be important.

Another issue that is important is the drawdown during sampling. Since it is often attempted to avoid areas with fractures because it could be difficult to straddle those, the sampling is done from the matrix where perms are low. As a result the drawdown could be high leading to sampling pressures below dew point of the gas. In the present example cases most fluids are not that close that saturation in the reservoir but some of them are within about 1000 psi, so could well be drawn below P<sub>dew</sub> when being sampled. Note that roughly as indicated in Figure 1, the P<sub>dew</sub> correlates with CGR, but it is clearly stated here that not the CGR but the detailed compositional variation is the determining factor for the actual value of the dew point pressure. However, since the fluids are all the result of a similar formation process, a CGR correlation like shown in Figure 1 could sometimes arise.

Contamination and drawdown are somehow related but are unfortunately not influenced by the same parameters in the same way. Cleaning out the invaded zone requires large volume flow, while that immediately leads to large drawdown. So in order to achieve both one needs to play with surface area for flow (packer selection), optimization of flow rates (Larger rates could be applied earlier in the process when only filtrate is flowing), and time on station.



**Figure 2—LFA (Live Fluid Analyzer) output for a gas station in WBM indicating three phase flow. GOR is not close to the actual GOR and is only used as a relative measure of clean fluid.**

The selection of packers is not always simple since larger packer surface area in the form of straddle packers have a large surface area but it always very difficult to clean out the area between the packers. In the present case the gasses are known to contain  $H_2S$  and since we are interested in the  $H_2S$  content exposure to more WBM filtrate (possibly containing some scavenger fines) is not recommended. So in this case we selected single probes with a large flow area, which have the additional advantage that they can be set quicker and as such reset more often as well without losing too much time. Other packers that combine features of both types of systems like the (sour service) Saturn 3D of Schlumberger were not available at the time of these wells.

Picking the place proper place for setting the probe is also a way to limit the contact with the filtrate from the mud. For example, setting the probe just below a tight zone makes that gravity works in your advantage in this case of a gas sampling job. Having mentioned that open hole sampling only targets a single point/zone, it should be mentioned that for carbonate environments the single zone could be larger especially with fractures in the system.

So with all precautions taken samples will be acquired that are of the best possible quality. However still there are instances where the samples get in contact with the filtrate even till the last moment before making it into the bottle. The reason is that there are often slugs that remain in dead volumes of the tool. This is important to realize when interpreting the compositional data. A lot of the history of the samples is available via down hole fluid analyzers. An example is given in Figure 2. There are many parameters to look at but in the context here the fact that at almost the entire period there is some water visible, as well as a hydrocarbon liquid phase. So despite all efforts to get a 100% clean sample we should record those observations as they are important for the sample QC later.

As a result of this multiphase flow the impact on the fluid samples could appear in many different ways. A short list is shown here. All are compositional and effects could:

- I. Loose/gain components due to:
  - a. flash
  - b. stripping
  - c. water washing (intermediates, aromatics)
  - d. chemical conversion (note also due to p,T only ! e.g. S-components, scale),
  - e. oversaturation (scale, asphaltene, wax)
  - f. contaminants
  - g. Reactive and more polar components like  $H_2S$ ,  $CO_2$  and Hg.

- II. Losses/gains depend on mud composition and sampling. Note scavengers or muds that bring contaminants with them like some barites.

Further on [Figure 2](#), it is important to note that the tool was configured such that the pump direction could be switched when filling bottles, this in order to take advantage of gravity in the gas situation. It was also noted that the GOR as indicated was not close to the actual GOR of the fluid and was only used as a relative measure, similar to the optical densities shown. The CFA output was recoding data when pumping in the upward direction. As such at all times there is information about what fluid (and solid) phases are present in the tool.

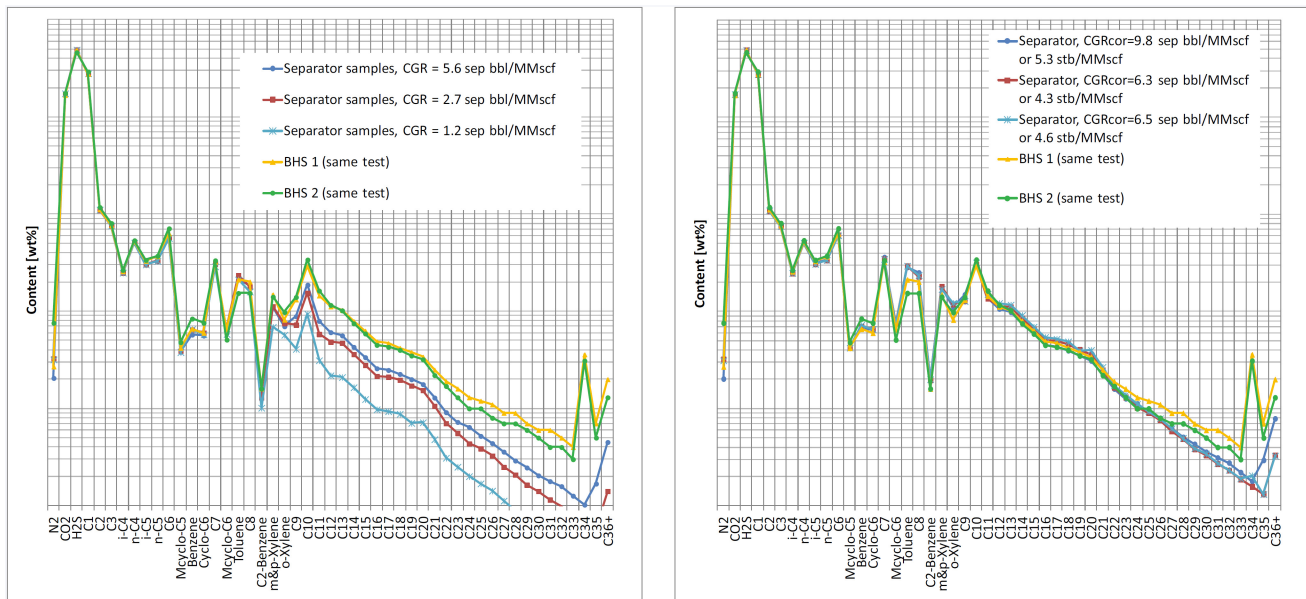
Note that it is not simply always the case that a gas will lose something when brought below dew point. As we discussed above, depending on the tool configuration, and actual flow regimes in the tool (multi-phase flow around T-splits is notoriously difficult to predict) and the situation before entering the tool could both enrich and deplete the gas. Since we are dealing here with a WBM case, the contamination by mud components is small but not completely absent.

### **Cased hole sampling (well test: BHS & Surface)**

The 3 wells also were tested at which moment samples were collected. One set was obtained via down hole sampling on a slick line tool, while the second set are the more conventional surface separator samples. Since the samples were collected in a well test all samples are the results of an averaged composition over a certain depth interval without any open hole data it is not possible to find out if differences in composition are the result of a sampling issue or a situation where several different sections with different compositions are contributing. Therefore it is good to use both open-hole as well as cased hole data together to come to an understanding of the correct reservoir composition. Since the samples from a well test are obtained from a flowing well, possibly over a longer time it is tempting to believe that these samples are always more representative than any of the open-hole samples. To a certain extent that is true especially with the BHS, but there are some aspects that we should not forget.

The issues that could actually affect the compositions of samples obtained during a well test are very similar to those affecting the open hole samples. Again the drawdown could be large and as a result also there the gas condensate could have gone below dew point. Depending on where liquid drop-out happens, the BHS and also separator samples could be affected. Besides that, also new contamination sources could manifest itself in the form of completion, perf, cementing and residual drilling fluids. On top of that there are the production chemicals that are sometimes added during the test (EG, MeOH, CI, PPD, etc). For separator samples the measurements of the GOR is an important parameter to come to an accurate reservoir fluid composition. Although it is in principle possible to measure an accurate GOR, for lean gasses (say  $CGR < 10$  stb/MMScf) it becomes difficult to get a reliable condensate rate, especially when the condensed water, will be hard to separate from the condensate. Another factor is that some components are reactive and equilibria could change as a result of changing  $p$  and  $T$ . This is relevant when looking at S-components. The last aspect we want to mention here is that one should be careful with surface samples when looking at solids like wax, scale (and less relevant in the present case, asphaltenes), etc. When the fluids loose solids deeper in the well it is very hard to notice that at surface. This is obviously less of an issue for the cased hole BHS, for which  $p, T$  of collection is often closer to the  $p, T$  of the reservoir.

In the following figures several examples are presented of issues with down hole sampling as well as surface sampling that are affecting the fluid compositions. The first example shows a set of samples that were collected from the leanest part of the reservoir A in well 2 during the well test. The samples are both surface separator pair samples as well as BHS. It is clear that the 2 BHS are very consistent but that the recombined separator samples are not. It appeared however that the condensate is so lean the separator does not work very efficiently and depending on the various times of sampling the fluid rates recorded



**Figure 3—Compositions from well 2, formation A. Samples collected during well test from separator and slick line. Left uncorrected, right corrected. Note that all separator samples after correction have a CGR around 5 stb/MMscf for the separator train. The first set (blue line), was collected during flow period with lower T and slightly higher P, compared to the other 2 sets, so the fact that the CGR is slightly higher is normal.**

were actually not representative for what actually came out of the well (as indicated by the BHS) since a lot of liquid was missed in the form of carry over and emulsions. That latter aspect also made it difficult to read independent water rates, and the applied split between water and condensate was not very well known. The CGR and WGR were in the same range in this test. This high water/condensate ration also appeared in water washing effects of the condensate.

On comment should be made about the CGRs mentioned in [figure 3](#). The numbers quoted are sep bbls, and not stb. This introduced a bit more scatter due to the variation in p,T in the separator as well. As a result it is possible that 2 fluids result in a very similar reservoir composition, although having a different CGR in terms of sep bbls. Further optimizing the CGRs of the well test made that all the fluids in [Figure 3](#) easily overlap. Note that one sample set was collected for a flow periods with a lower temperature compared to the other two sets. So the fact that that CGR is slightly higher is in line with this. As a general statement it can be mentioned that it is often better to compare only single stage flashes or even composition fractions (C5+ or C7+ etc) when we compare samples obtained by different methods. That way we treat the wetness of the sample as a true fluid property and not as something that depends on operational conditions.

On comment should be made on the large peak in the C34 range. It was found out that this was also a contaminant, which was later confirmed to originate from the seals in the bottles, a so called plasticizer. The differences in the C22 range between BHS and surface samples are not simply a matter of collecting free liquids (which is what this looks like, see next section), because the sample as collected has a dew point quite well below reservoir pressure-draw down. However it is likely liquid that dropped out or was stripped out earlier and made it gradually into the gas flow. The fact that it reduces over time (samples collected 30 min after one another) points into that direction.

Another illustration of issues encountered when a fluid flashes during sampling is shown in [Figure 4](#). The first example is a fluid that flashed during sampling in an open hole situation, while the second is an example of a fluid with a very high CGR that is collected during a well test where condensate drop-out/banking played a role.

In the first figure ([Figure 4](#) left) it is clear that during the sampling the open hole sampling the fluid went below dew point and some free liquids were formed. The variation of the composition was also

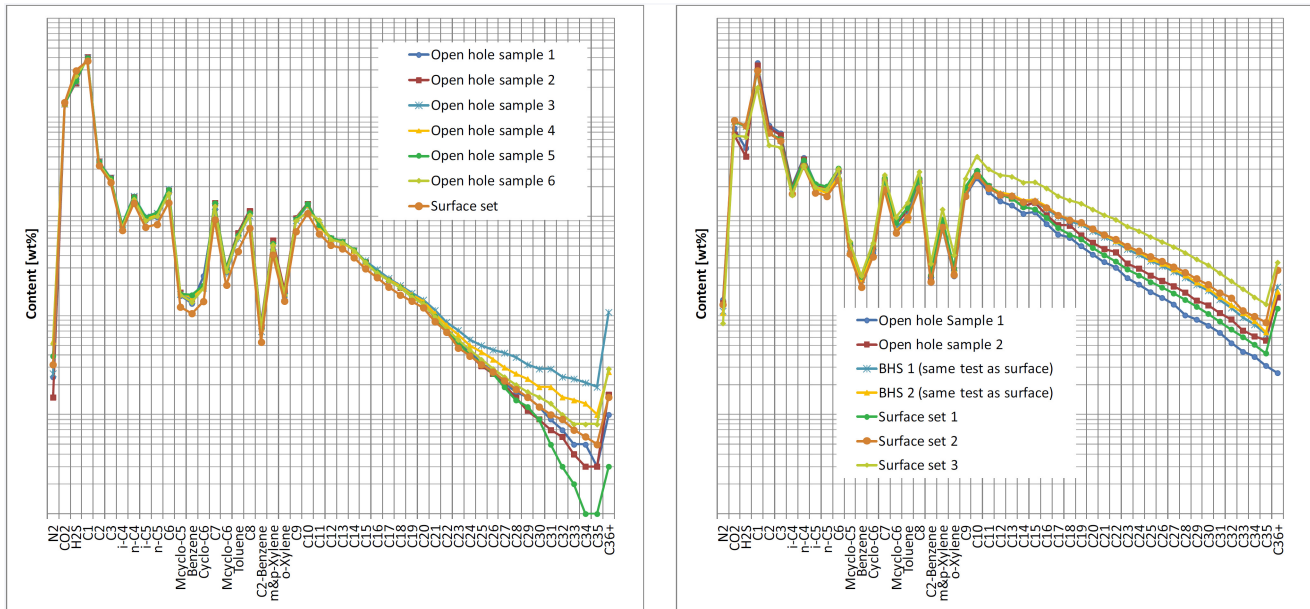


Figure 4—Compositions from well 1, formation C (left): Samples collected during open hole sampling show clear signs of liquid drop out as well as enrichment. In same plot one surface sample set collected during well test from same interval. Also shown (right) are samples from well 3 Formation C: Samples from the open hole sampling show strong losses of fluids, while the surface samples show a range, while the BHS during the well test plot in the middle but still show losses.

confirmed by the measured dew points for these samples. What is also clear is that not only components are lost, but that some fluids got actually enriched with a fluid that dropped out for other samples of the same set. So apparently sometimes also the free liquid made it into the bottles. In those cases it is valuable to have also DST samples that were obtained with a much lower drawdown. So in that way the true reservoir composition was easy to find.

In the plot on the right the situation is more complex. The CGR of this fluid is over 100 stb/MMscf and the reservoir pressure is very close to dew point. In combination with the fact that the rock here is the tightest in that particular area made that the drawdown during the open hole sampling, but also during the testing was quite high. The latter is partly due to condensate banking effects, resulting the well to produce variably high and low CGR fluids ranging between 50 to over 200 stb/MMscf. At the same time we see that the open hole samples were most likely depleted as was confirmed from measured dew points. It appeared that doing the total mass balance over the entire well test leading to a CGR around 125 stb/MMscf (via separator) gave a handle on what the true reservoir fluid composition would be. At the same time this numbers corresponded quite well with the BHS (compare 2 BHS and surface set 2). Still one can see that in the higher end still some components could be missing, however the concentration of those is small and will not have a strong effect in the CGR. However on the dew point there still remains some uncertainty.

One other sampling effect needs to be discussed which is the scavenging effect on  $H_2S$ . Since the fluids have  $H_2S$  in very high concentrations (tens of percents) the scavenging effects we are talking about here must be quite severe to be noticed. The tools were all prepared in order to avoid scavenging on the metal surfaces, using coating on bottles and the parts that come into contact with the fluids. However the WBM system used in this well is due to its design to scavenge  $H_2S$  for safety reasons not the best environment to sample a sample for a representative  $H_2S$  content. The fact that sometimes a little bit of WBM filtrate makes it into the bottle is already sufficient to affect the  $H_2S$  content. It was also noted that in these instances also the COS and R-SH and other heavier S components increased. Suggesting that the free water (filtrate) phase enhances certain chemical conversions to occur. This effect is very similar for surface samples that were sampled in situations of high water cut (high condensed water volume compared

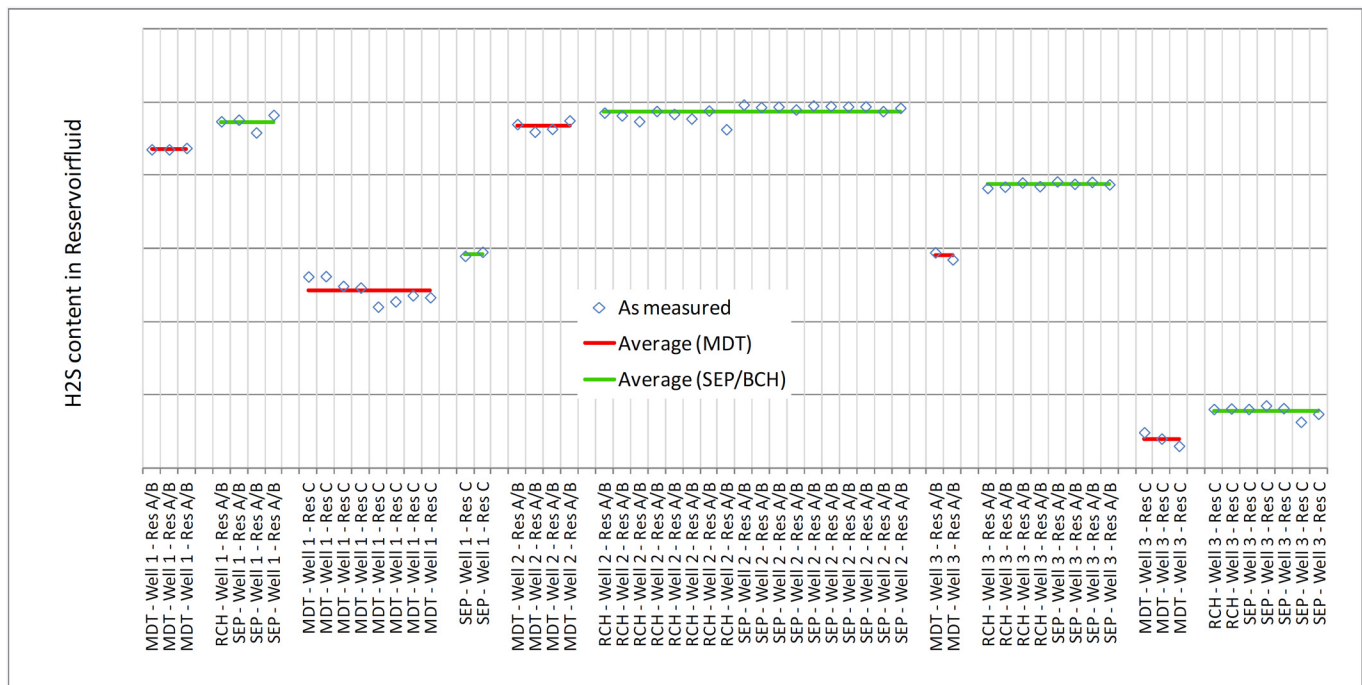


Figure 5—Effect of sampling methods on the measured H<sub>2</sub>S content in the reservoir fluids. MDT samples consistently are below the values for separator (SEP) or bottom-cased hole (RCH) samples.

to the condensate volume). So apparently it is also the presence of a free water phase in itself that causes this.

From the above it is clear that the various sampling techniques will have different effects on the samples. From assessing all a clear understanding arises about what the true composition of the various reservoirs is. However the best PVT sample might not necessarily also be the one with the most representative H<sub>2</sub>S content. Therefore an approach was followed to select the best PVT samples first from which the phase boundaries and other volumetric behavior can successfully be obtained. If necessary in a second review was done to correct the composition for small effects like C34 contamination, flash effects and H<sub>2</sub>S content. As such the reservoir composition could be derived from a number of samples instead of one. In this way we are able to get a more representative fluid model. The adjustments have different impact on the fluid models. The C34 contaminants do not affect the CGR much, but have a considerable impact on the dew point of the leaner fluids (couple of 100 psi), while the surface recombination ratio, or the measurement error of the CGR in the lab has a direct impact on the CGR, but does not affect the dew point much. The other S-components like R-SH and COS do not impact the phase behavior at all but variation in those components have huge cost implications for surface design.

## Modeling multi fluid systems

The aim in the fluid modeling approach is to obtain a model that will use the same set of (underlying) pseudo components for each of the individual reservoirs as well as compartments penetrated by the different wells. At the same time the model should be the basis for both the subsurface modeling as well as the surface modeling. That does not necessary mean it should be identical but it should at least be convertible consistently.

The reservoir engineers will either use black oil simulation or a full compositional model using around 12 components. Since the approach will be such that the basis of the unified model will contain more components than that, lumping and delumping schemes will be required. The approach chosen for doing



this are as described by Leibovici [4, 5]. The method is completely analytical and has shown to produce the most consistent results.

For the modeling de PR78 EOS was used with a Peneloux volume correction to have a better match for the densities. The procedure followed was to use 3 sets of pseudo components only differing on all properties but not in boiling point. The range of the Mw, Peneloux factor, accentric factor critical parameters is defined such that it covers the extremes required to cover the pseudo components of the individual fluid. Step by step the procedure is as follows.

- Fit the experimental data using the compositions as provide in the respective report (in wt%). For this step the  $k_{ij}$  between methane and the pseudos was fixed at 0.03, which is a reasonable value for gas condensate systems. In this step the light ends till C6 are fully specified while the C7+ is split in 6 pseudo components for which  $T_c$ ,  $P_c$ ,  $\omega$ , and  $c$  (the Peneloux correction) are obtained in this fit.
- Make the corrections for the C34 contaminant, flash issues as reflected in the tail and  $H_2S$ ,
- Define 3 sets of 6 pseudo components (the A, B and C set) that can cover the range/variation seen in the individual fits. The initial set of 6 as well as the A, B, C set are aligned on  $T_b$  but differ in the other properties.
- Map the pseudo onto the A, B and C sets using the Leibovici schemes.
- Create a 10 component reservoir model for compositional simulation if needed. This will give us also a lumping / delumping matrix for each of the fluids. It is assumed that the effect of the change of composition within one lumped group will not vary too much so that the matrices can be kept constant over time. Since even the differences between the various fluids are not too big within a lumped group we believe that assumption is defendable.

The BTEX and other S-components are added as an after processing step. For the S-components the concentrations are very small, so can be added without model adjustments. The heavy S-component, being the model component introduced for the unidentified S components is just added as a fraction of the C16 pseudo. For oils (so not part of this study) where the amount of heavy-S could be quite large we have opted for a tracer type of description, so that the overall PVT behavior is not affected, why still being able to capture its behavior and quantify amount at every stream.

The BTEX components are bit more difficult since every fluid has a different amount of these components and taking them out of a certain pseudo (So C7, C8, C9 and C10) and correcting its residual properties would make that pseudo component a fluid specific component losing the integrated characterization of the A, B and C sets. However it was noted that for the fluids studied here the BTEX content normalized per carbon number group was quite similar within certain groups of fluids, which is often the case, so it was decided to use BTEX free components in the A, B and C sets that are corrected for the effect using that similarity. So for example a Benzene/C7 ratio was set at a certain value for the A-set, at a slightly different value for the B-set and again at a different value for the C-set. The values of these ratios are covering the range that we have seen for the fluids studied here. The properties of the BTEX free component properties are again calculated using the Leibovici schemes.

An illustration of how a fitted composition is mapped onto the grid is show in [Figure 6](#) for  $P_c$  and  $T_c$ . Similar figures arise for the other pseudo properties. In this approach the  $k_{ij}$ -s were chosen to be the same for all sets, but that could be relaxed if needed.

The model was developed for a straight depletion. As such the main simulation work will be done using a black oil model. The process of delumping that is adopted for such a situation that the fluids as produced from the each reservoir, flow into the well, at which moment the individual flows will be unpacked into the full ABC type model. Based on the above structure this is possible for both the black oil as well as the compositional model. This full slate can then be handed to the surface teams or network modeling for simulations of the surface facilities. This is done using a simple delumping matrix in case to the

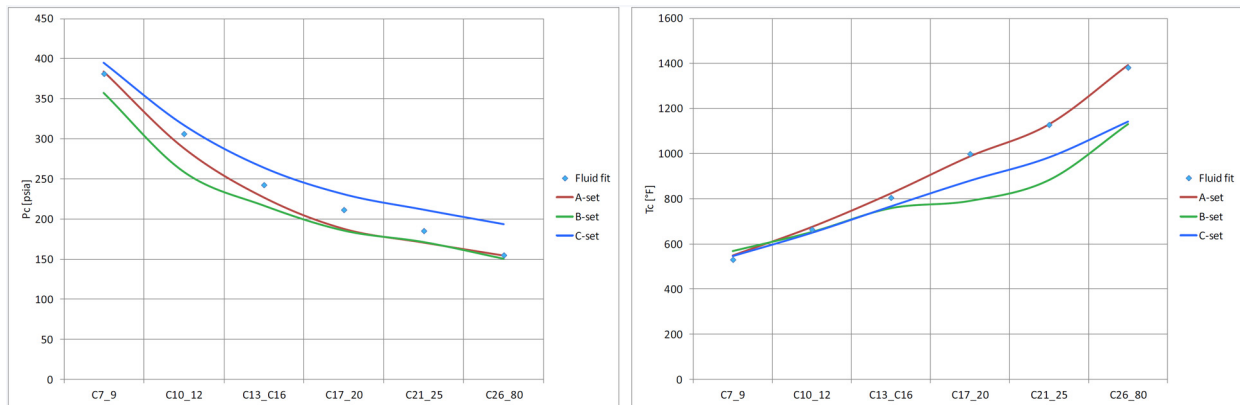


Figure 6—Illustration of mapping the critical pressure and temperature (Before adding BTEX) the ABC grid.

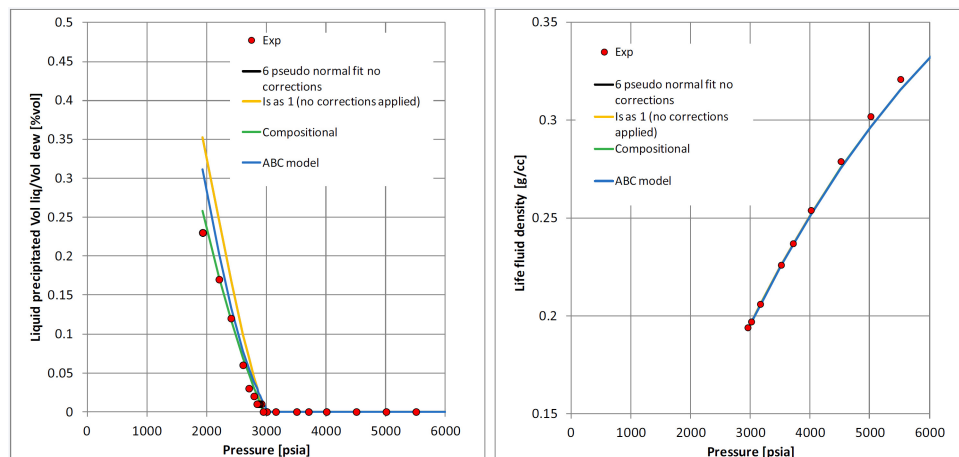


Figure 7—CCE experiments on a cased hole bottom hole sample, compared to 4 model versions. 1-black line, full mode fitted to experimental data, 2-yellow line, same as 1, but with corrections made to the composition removing possible contaminants, flash effects etc, so not matching data (for this samples no correction needed to be made so yellow=black), 3-blue line, ABC model, model described by yellow line mapped onto the ABC grid, 4-green line, Compositional model (limited number of pseudo components).

compositional model, or using the stored fluid compositions belonging to the black oil gas and liquid streams as is available within Shell's MORES simulator that was used.

## Results

The PVT simulation results for the various models are illustrated in Figures 7 and 8 using the CCE test as an example. The first is a very lean fluid (3 stb/scf from stock tank flash) and the second a richer fluid (100 stb/scf from stock tank flash). The experimental drop-out data for the leaner fluid should be used with some care since the experimental error on these low numbers is quite large.

When looking at the modeling results Figure 7 show that the black and yellow lines overlay, since no compositional corrections were made to take out contaminants, or to correct for flash effects during sampling. The green and blue curves indicate the compositional model and the ABC model. As one can see these models start to deviate somewhat below the saturation pressure due to flashing of the samples, at which point the lumping is not exact anymore.

Figure 9 shows a case of a situation where corrections were made to the fluid composition to correct for contamination and flash effects as illustrated in the first section of this paper. The yellow line is now no longer coinciding with the black line but with the green one. This is mainly due to changing the composition in the C20+ range to correct for contaminants and flash effects. The corrected composition is more representative for the reservoir composition, but will no longer describe the experimental data. As

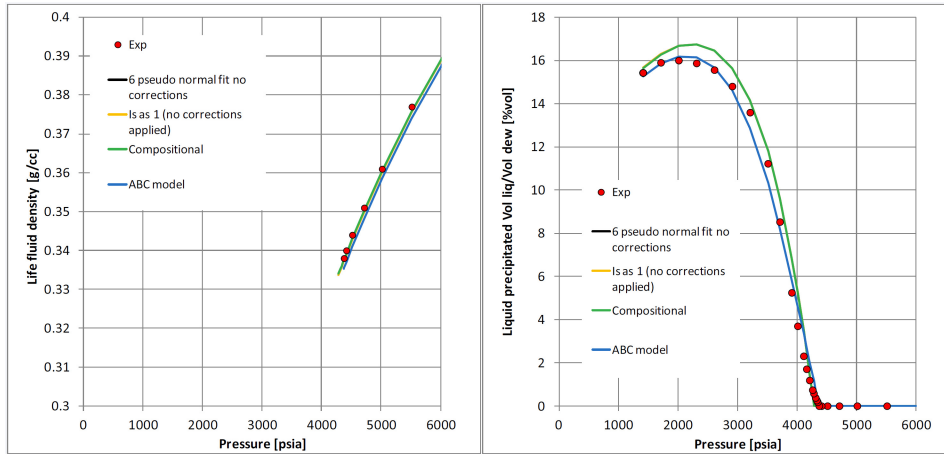


Figure 8—CCE experiments on an cased hole bottom hole sample, compared to 4 model versions. 1-black line, full mode fitted to experimental data, 2-yellow line, same as 1, but with corrections made to the composition removing possible contaminants, flash effects etc, so not matching data (for this samples no correction needed to be made so yellow=black), 3-blue line, ABC model, model described by yellow line mapped onto the ABC grid, 4-green line, Compositional model (limited number of pseudo components).

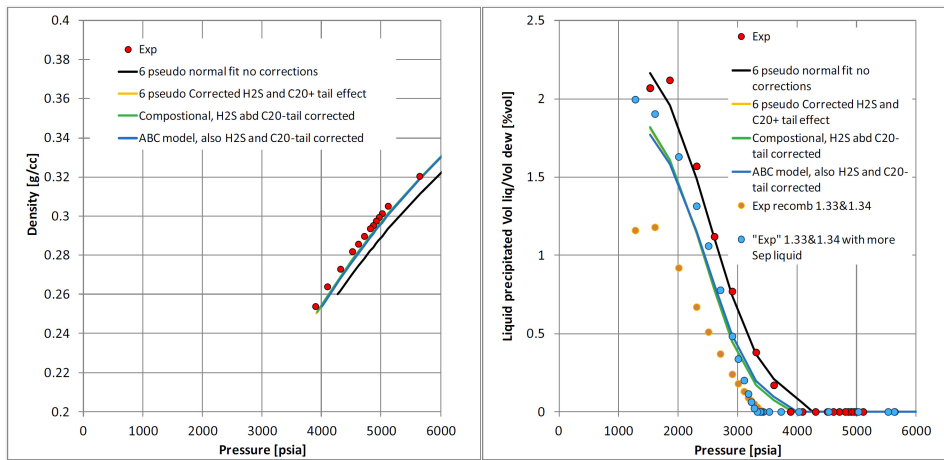


Figure 9—CCE experiments on an MDT down hole sample, compared to 4 model versions. 1-black line, full mode fitted to experimental data, 2-yellow line, same as 1, but with corrections made to the composition removing possible contaminants, flash effects etc, so not matching data, 3-ABC model, model described by yellow line mapped onto the ABC grid, 4-Compositional model (limited number of pseudo components). Yellow and blue circles is data on a recombined fluid for 2 different recombination ratios (Blue is matching CGR of MDT sample, see similarity around max liquid drop-out but difference around dew point).

one can see, the separator recombined data (Yellow and Blue circles) was already quite different from the MDT data (red circles).

### Conclusions

In the paper a modeling approach is demonstrated that will make it possible to have a consistent delumping of fluid streams from each reservoir for surface modeling applications. It was illustrated to do this for both black oil as well as compositional models that use a limited slate (up to 10 components). At the same time the approach chosen makes it possible to add new fluids later, without making it necessary to redo the entire modeling for all other fluids as well.

The approach that was chosen is to define 3 groups of pseudo components labeled A, B and C-set, and map the individual fluids onto those grids. The model can then also be lumped into a 10 component compositional model. Delumping can be done at a reservoir/well level at the moment the fluids enter the well, giving a complete fluid definition for the surface applications. All models show a fairly good consistency, well within experimental/sampling uncertainty.

More specifically some things are worth noting here at the end relating to the sampling effects also discussed here.

- Low CGR fluids often have different ways that could be affected by sampling, keep this in mind when fitting. Neither BH nor surface samples are the silver bullet.
- Liquid drop out curves often tabulated with high precision, but often very inaccurate.
- WBM and seals can also contaminate condensate.
- MDT samples with WBM often H<sub>2</sub>S too low, even in coated bottles.
- Most difficult is to get an idea what was lost from a sample not what contaminated it
- Taking some time to align PVT models in an early phase makes life easier for later when an integrated model needs to be created.

## References

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