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A Unified Approach for Quality Control of Drilled Stem Test (DST) and PVT Data

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Abstract: Finding a representative fluid in a hydrocarbon reservoir is crucial for integrated reservoir management. In this study, a systematic approach for screening and selecting consistent fluid samples in a reservoir was developed. The model integrated quality control (QC) of well conditioning before sampling, QC of PVT data, thermodynamic modeling and compositional gradient within a reservoir. Well and separator conditioning were examined as essential steps before sampling at equilibrium conditions. Sampling criteria were deduced according to available data, sampling standards, and tolerance of field measurement devices. Then, PVT data of consistent fluid samples were carefully screened for efficient phase behavior studies. This model suggests that thermodynamic modeling and equation of state (EOS) tuning be performed on screened fluids using only consistent experimental data. The proposed model was implemented on PVT samples of a supergiant gas condensate reservoir in the Middle East. Results show that only 10% of collected samples are at equilibrium, good candidates for PVT studies. Also, ±0.1% change in composition of C_{12+} causes ±300 psia change in dew-point pressure, revealing no substantial difference between validated samples for the reservoir under study, and one representative fluid suffices throughout the reservoir.

Keywords: Gas Condensate, Sampling, Well Conditioning, EOS Tuning, Compositional Gradient

1. Introduction

The major worldwide resources of natural gas distribution and global regulations for lowering greenhouse gases have led many countries to shift towards natural gas consumption. According to the published data, global gas reserves have increased from 142 TCM (Trillion Cubic Meters) to 196 TCM between 1995-2011 ("World oil gas review 2012", 2012). The gas condensate reservoirs, intermediate between gas and volatile oil reservoirs, make up the majority of reserves in the world (McCain Jr W.D. , 1990).

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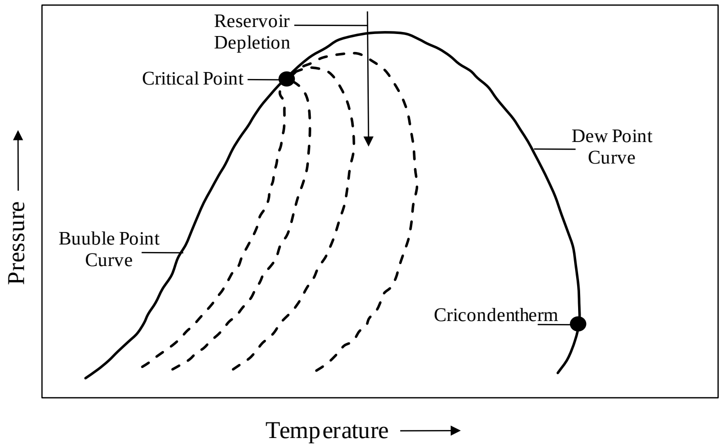


Figure 1. Typical phase plot of a gas condensate fluid

Figure 1 shows a typical phase plot of gas condensate fluids, which has a complex thermodynamic phase behavior. The reservoir temperature is between critical point and cricondentherm, and retrograde condensation of intermediate and heavy hydrocarbon components causes gradual dropping out of condensate liquids in the reservoir, especially near the well bore (Tarek H. Ahmed, 1989).

Optimum development and integrated management of a gas condensate reservoir for maximum gas and condensate recovery, as well as prediction of well productivity require a careful understanding of fluid characterization (Nagarajan, Honarpour, & Sampath, 2007). Due to complexities in its phase and flowing behavior, fluid sampling of gas condensate reservoirs must be conducted thoroughly, followed by rigorous and detailed experiments (K.S. Pedersen, Thomassen, & Fredenslund, 1989). Careful fluid sampling with ensured well conditions is vital for correct PVT analysis, fluid composition, economic evaluation of reservoir, acid gas, i.e. H_2S and CO_2, content and corrosive properties of reservoir fluid, flowing potential of fluid in tubing and pipeline, flow assurance, precipitation of solid, e.g. hydrate, wax and asphaltene, components, and preventing two-phase flow and productivity loss in reservoir and well (Bon, Sarma, & Rodrigues, 2007). Therefore, it is essential to collect fluid samples carefully under controlled and equilibrium conditions and through a standard procedure, so that they represent the fluid of producing zone in the reservoir. On the other side, improper fluid sampling and analysis can influence all subsequent engineering calculations and reservoir development strategies (Williams, 1994). The best sampling time is right after drilling appraisal wells, where the whole reservoir fluid has been in equilibrium during the geological time (El-Banbi & McCain, 2001). In surface sampling, gas and liquid samples are collected from surface separators and mixed in such a proportion that phase behavior of the recombined fluid matches that of reservoir fluid. Also, quality control (QC) of collected data must be performed before, during and after sampling. Improper QC or any error in recorded data can be misleading in the next steps of fluid modeling, fluid properties measurement, and construction of thermodynamic model for representative reservoir fluid. Williams (Williams, 1994) listed these errors in two major categories, i.e. error sources due to the nature of gas condensate and error sources due to human operations. A poor sample may be obtained due to improper sampling conditions, human errors during sampling, impurities in sampling bottles, and leakage during transfer to laboratory. Such errors may be reflected as wide variations in thermodynamic properties of samples, which introduces trouble for final decision on selecting the representative fluid sample (Moffatt & Williams, 1998). Therefore, it is important to conduct fluid sampling and recombination using standard protocols to minimize errors and uncertainties.

In this work, a conceptual protocol is developed which integrates QC of well conditioning before sampling, QC of DST and PVT measurements on collected gas and liquid samples, thermodynamic modeling and compositional gradient within a reservoir to select the representative reservoir fluid. The proposed protocol considers QC criteria for well conditioning, as well as consistency checking and QC of PVT experiments before thorough EOS tuning and compositional gradient studies. In the next sections, a brief review of available data for more than 70 fluid samples collected from a supergiant gas condensate reservoir is presented first. Next, proposed protocol is described in detail. The protocol is then tested on the collected fluid samples to select the representative reservoir fluid and compositional gradient in the reservoir. Concluding remarks are presented afterwards.

2. Available Data

A set of drill stem test (DST) and PVT test data were collected from different multilayer wells of a supergiant gas condensate reservoir in time interval of 1992-2013 and from depths of 8600-10400 ft. This collection is containing dynamic data such as well head pressure and temperature, separator pressure and temperature, separator oil and gas rates, and basic sediment and water (BS&W) with respect to time. Moreover, static data including constant volume depletion (CVD) and constant composition expansion (CCE) tests are available in the collected data.

Figure 2 shows distribution of P^{dew} of fluid samples. According to this figure, reported P^{dew} varied between 3800 psia and 5300 psia. Similar variations were observed in other experimental results, including composition of plus fraction, volume of liquid drop out, and condensate to gas ratio (CGR), as shown in figure 3. The corresponding data are shown in appendix A. Therefore, screening of fluid samples and experiments must be done using QC criteria to identify the suitable sample(s) for further PVT studies.

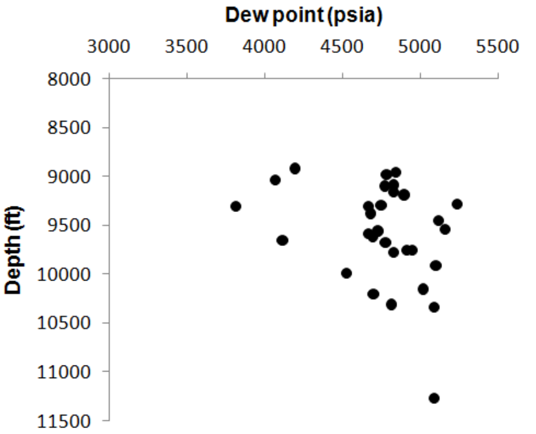
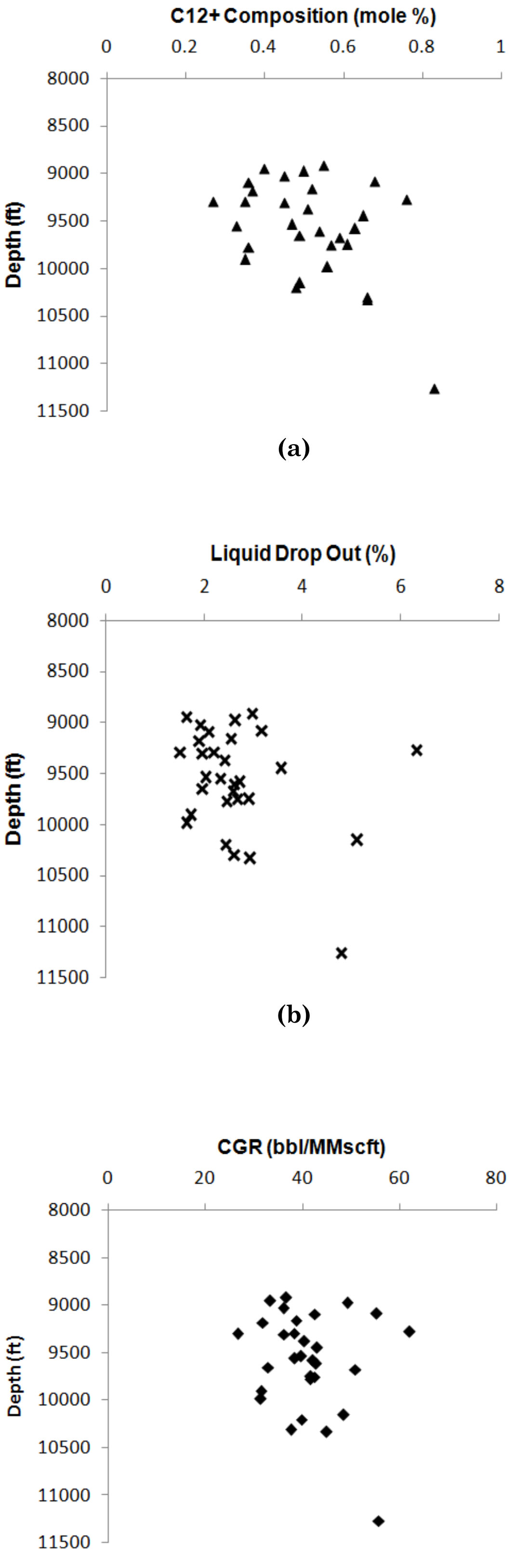


Figure 2. Distribution of dew point pressure (P^{dew}) of fluid samples



(a)

(b)

(c)

Figure 3: Distribution of fluid properties: Composition of plus fraction; b) Volume of liquid drop out; c) Condensate to gas ratio (CGR)

2.1. QC of Well Conditioning

The well needs to be conditioned before any fluid sampling (American Petroleum Institute, 2003). Sampling is made when the well is stabilized with sufficient fluid velocity to prevent liquid loading in the well (Olmos Torres, 2010). Also, fluid production should be low, so that drawdown pressure remains at minimum (Moffatt & Williams, 1998; Witt, Crombie, & Vaziri, 1999). The stabilized flow is maintained when such parameters as well head pressure and temperature, separator pressure and temperature, flow rate of water, basic sediment and water (BS&W) content, oil flow rate, gas flow rate, and CGR fluctuate within a certain range (McCain & Alexander, 1992). As explained in previous section, the acceptable range of fluctuation for each parameter was obtained by careful review of measuring instruments' precision and tolerance, as well as stabilized flow and statistical analysis on DST data of separator samples, including mean, variance and standard deviation. The results are summarized in table 1. The relative allowable tolerance (column 2) is given as well as absolute allowable tolerance (column 3). The stabilized well flow is met when all parameters fall within either relative or absolute tolerance. Figure 4 shows the trends of these parameters for a typical sample. As fluctuations of all parameters fall within the aforementioned limits, the well is prepared and ready for sampling.

Table 1. Relative and absolute allowance for stabilized well flow

Parameter	Relative Allowable Tolerance	Absolute Allowable Tolerance
Wellhead pressure	±1%	±20 (psia)
Wellhead temperature	±3%	±5 (˚F)
Separator pressure	±3%	±15 (psia)
Separator temperature	±5%	±5 (˚F)
Oil flow rate	±2.5%	±10 (bbl/d)
Gas flow rate	±5%	±1 (MMscf/d)
CGR	±2.5%	±1 (bbl/MMscf)
BS & W	--	+5%

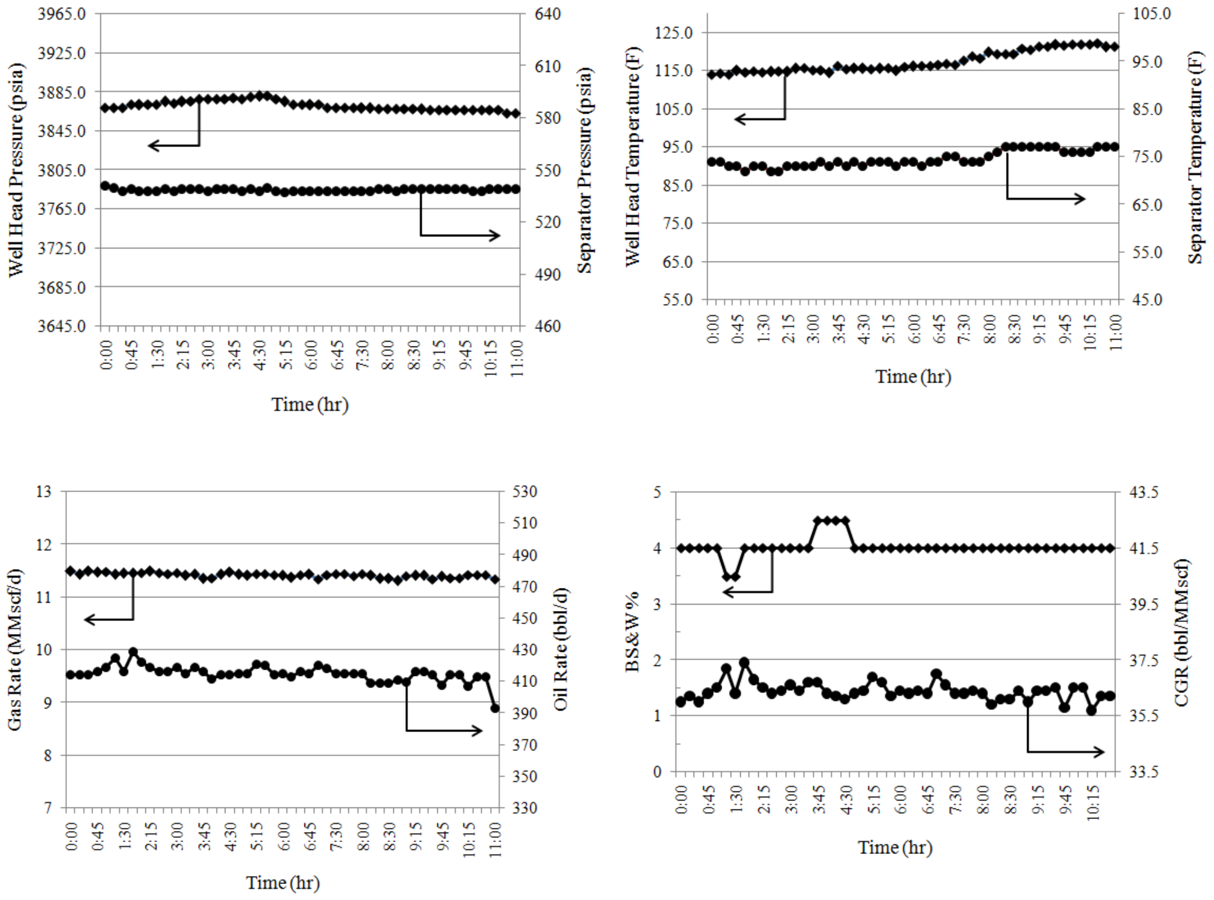


Figure 4. Trends of operating parameters for a sample with stabilized well flow

Figure 5 shows flow chart of well conditioning criteria with QC of all parameters reported in a DST test. According to this flow chart, each parameter is examined carefully to explore its fluctuation. In addition, it is important to ensure that no solid (wax, hydrate) has been formed (K. S. Pedersen & Christensen, 2007). Furthermore, as mentioned before, flowing velocity must be higher than minimum loading velocity to prevent any liquid loading in the well.

2.2. QC of PVT Data

When the collected samples pass the well conditioning screening criteria in the first stage, the quality of measured PVT data must be checked. PVT experiments are normally performed on recombined samples. Figure 6 shows a schematic of fluid recombination.

When more than one gas and liquid samples are collected from separator, the first step in QC of PVT data is selecting preferred gas and liquid samples to recombine. The gas sample with minimum air content and minimum difference between bottle opening pressure and separator pressure is preferred. Also, the oil sample is selected by comparing its bubble point pressure and bottle opening pressure with separator pressure (K. S. Pedersen & Christensen, 2007). In the next step, equilibrium conditions of oil and gas samples must be checked. The Hoffman-Standing plot is a useful tool for checking equilibrium conditions of selected gas and liquid samples (T.H. Ahmed, 2007).

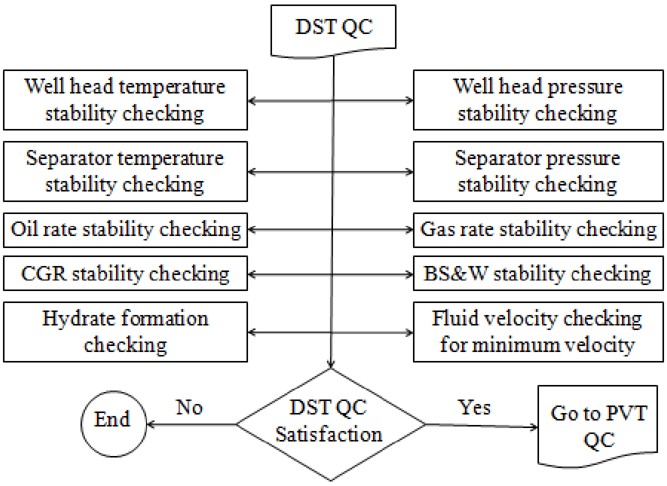


Figure 5. Flow chart of well preparation and QC of DST data

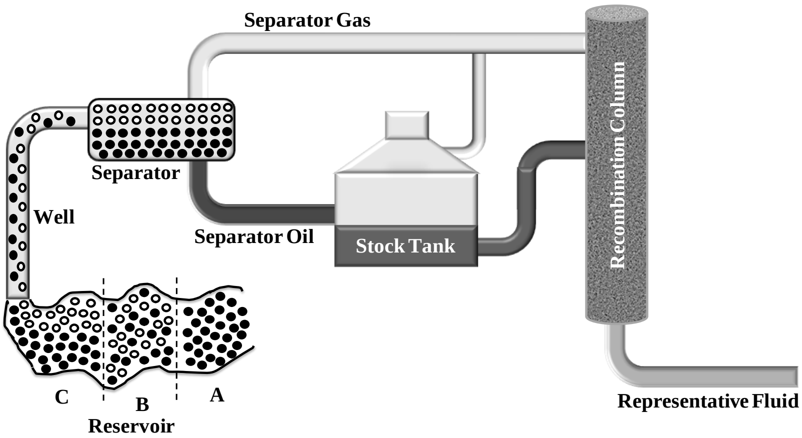


Figure 6. Schematic of recombination process.

The equilibrium constant, K_i, of each component is calculated from oil and gas compositions:

$$K_i = y_i/x_i \quad (1)$$

x_i and y_i are compositions of component i in the liquid and vapor phase, respectively. The Hoffman characterization coefficient, F_i, is calculated by equation (2):

$$F_i = b_i\left(\frac{1}{T_{b_i}} - \frac{1}{T_{sp}}\right) \quad (2)$$

T_{bi} is normal boiling point of component i and T_{sp} is separator temperature. b_i is a constant of component i, calculated as follows:

$$b_i = \frac{log\left(\frac{P_{c_i}}{P_{sc}}\right)}{{}^{1}/_{T_{b_i}} - {}^{1}/_{T_{c_i}}} \quad (3)$$

T_{ci}, P_{ci} and P_{sc} are critical temperature and pressure of component i and separator pressure, respectively. For a typical fluid sample of reservoir under study with separator composition given in table 2, the Hoffman plot is shown in figure 7. The $R^2>0.9$ indicates that separator oil and gas samples are in equilibrium.

The second step in QC of PVT data involves separator gas oil ratio, R_{sp}, which may be subject to error due to errors in oil and/or gas flow rates, presence of gas bubble in the oil flow line or presence of oil mist in the gas flow line (Moffatt & Williams, 1998). The procedure for correcting R_{sp} in the case of condensate flow in gas line is described in Appendix B. Also, R_{sp} must be corrected for laboratory conditions, shown by equation (4) before recombining gas and oil samples (Eyton, 1987):

$$(R_{sp})_{lab} = (R_{sp})_{field} \frac{\sqrt{(Z_g)_{field}(\gamma_g)_{field}}}{\sqrt{(Z_g)_{lab}(\gamma_g)_{lab}}} \frac{(\rho_{sc})_{field}}{(\rho_{sc})_{lab}} \quad (4)$$

In order to verify the validity of recombined fluid, separator material balance must be checked by equation (5):

$$\frac{y_i}{z_i} = -\frac{(1-\beta)}{\beta}\frac{x_i}{z_i} + \frac{1}{\beta} \quad (5)$$

x_i, y_i, and z_i are composition of component i in the separator liquid, separator gas and recombined (reservoir) fluid, respectively, and β is the gas molar ratio to total moles of liquid and gas. A plot of y_i/z_i versus x_i/z_i for each component would give a line with slope of $-\frac{(1-\beta)}{\beta}$ at equilibrium conditions. Figure 8 shows results of separator material balance for data of table 2. A linear trend ($R^2\approx1$) indicates that separator material balance is verified.

Table 2. Composition of separator gas, separator liquid and recombined fluid compositions (T^{sep} = 537 R, P^{sep} = 525 psia)

Component	Separator Liquid (mol%)	Separator Gas (mol%)	Reservoir Fluid (mol%)
N_2	0.2	4.05	3.92
CO_2	0.71	2.17	2.12
H_2S	0.53	0.75	0.74
CH_4	13	84.84	82.37
C_2H_6	3.81	5.08	5.04
C_3H_8	4.25	1.75	1.84
iC_4H_{10}	1.81	0.34	0.39
nC_4H_{10}	4.19	0.53	0.66
iC_5H_{12}	3.25	0.18	0.29
nC_5H_{12}	3.45	0.15	0.26
C_6	6.88	0.1	0.33
C_{7+}	57.92	0.06	2.04

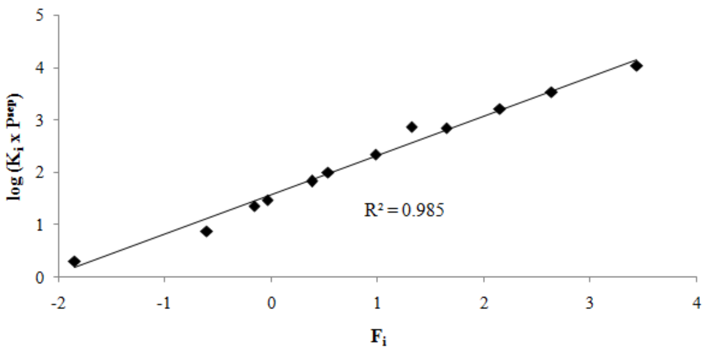


Figure 7. Hoffman-Standing plot for separator sample of table 2

The third step in QC of PVT data involves the evaluation of CVD experimental data through material balance calculations (C. H. Whitson & Torp, 1981). Generally, material balance calculations are more valid for rich gas condensate than lean condensate samples (Danesh, 1998). The material balance may be performed in both forward and backward approaches. However, checking material balance would not be sufficient for validity of PVT experiments. Rather, plots of trends in such parameters as gas and liquid densities, compositions, and Hoffman plot at successive depletion pressures can be useful for validation of CVD experiments (C.H. Whitson & Brule, 2000). Figure 9 shows a flow chart for complete QC of PVT data. According to this flow chart, the validity of selected oil and gas samples for recombination is checked first. Then, thermodynamic equilibrium conditions of selected samples are verified. In the third step, R_s is corrected in case of oil carry over in the gas stream. After that, the material balance of selected oil and gas phases for recombination is checked. Finally, the validity of CVD experiments is investigated. For gas condensate samples, the last stage usually results in negative composition for one or more components. In this case, the reported CVD compositions should not be used for regression and tuning of equation of states (EOS).

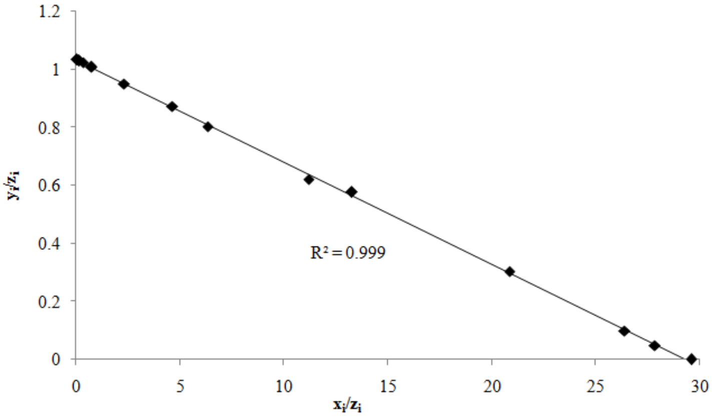


Figure 8. Separator material balance for data of table 2

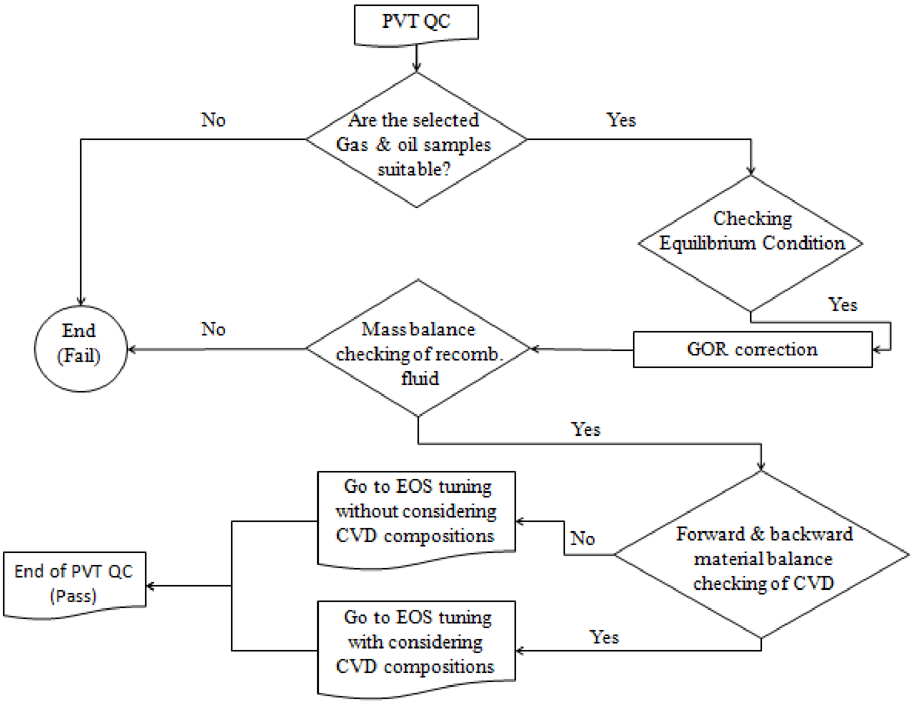


Figure 9. Flowchart for complete QC of PVT data.

2.3. Representative Fluid Determination

If all previous steps including well conditioning, sampling and PVT experiment are successful, it may be possible to determine representative fluid sample(s). However, if the samples show considerable areal and /or vertical compositional gradient in the reservoir, more than one PVT region may be selected rather than a single representative fluid. In the case of the reservoir under study, it was found that gradient for methane is 0.004 mol%/m, which is insignificant compared to compositional gradient in other gas condensate reservoirs (Danesh, 1998; K. S. Pedersen & Lindeloff, 2003). Therefore, it may be possible to determine a representative reservoir fluid sample among valid samples. Table 3 summarizes seven screened fluid samples after comprehensive quality control of DST and PVT data. According to this table, average P^{dew} for seven samples was found 4726 psia with standard deviation of ±123 psia. Further investigation of data shows that P^{dew} of fluid of well W1 is close to average P^{dew} for all samples. However, PVT modeling of W1 fluid using Peng Robinson EOS (Peng & Robinson, 1976) with Twu (Twu, 1984) and Lee-Kesler (Kesler & Lee, 1976) correlations for critical properties and acentric factor of plus fraction, respectively, revealed that only ±0.1mol% change in the composition of plus fraction results in P^{dew} of as much as ±300 psia, which is much larger than the calculated standard deviation of P^{dew} for these samples. As discussed in the previous section, such an error in composition of plus fraction is expectable, as many gas condensate analyses show errors in composition due to partial liquid drop-out in the capillary tube of gas chromatograph (Moffatt & Williams, 1998; Stephen, Bergman, Dodd, & Kriel, 2008). Therefore, the observed variation in P^{dew} of selected fluid samples does not necessarily imply that there is significant difference between them. In other words, all seven samples are essentially the same with little changes in composition and fluid properties. As the fluids samples of table 3 are distributed throughout the reservoir both areal and vertical, it may be concluded that there is practically one fluid throughout this supergiant reservoir.

The methodology described in the previous sections can be integrated in a conceptual, strategic model for determining representative fluid(s) in a reservoir, as shown in figure 10. This model integrates systematic and step-by-step QC of DST data and PVT data according to figures 4 and 9, respectively, compositional gradient, representative fluid for each region in the reservoir (in the case of compositional gradient) or for the whole reservoir (in the case of no compositional gradient) and thermodynamic modeling of reservoir fluid(s). According to this model, thermodynamic modeling is performed on only the equilibrium fluid samples. Also, EOS tuning is carried out using experimental data collected under thermodynamic equilibrium with approved material balance, rather than a blind regression on all samples using any uncertain experimental data which result in a tuned EOS whatsoever. Such a careful data analysis before EOS tuning reduces the uncertainties in EOS parameters and increases robustness of tuned EOS in reservoir studies and recovery predictions.

Table 3. Screened fluid samples after comprehensive QC

S/N	Well ID	Reservoir Temperature (°F)	Reservoir Pressure (psia)	Dew Point Pressure (psia)	Methane (mole%)	Plus-Fraction (C12+) (mole%)	Depth (m)
1	W1	211	5240	4748	82.37	0.60	2807
2	W2	205	5165	4665	83.14	0.69	2941
3	W3	218	4994	4682	83.06	0.51	2858
4	W3	218	5094	4695	83.09	0.62	2931
5	W3	218	5104	4950	82.79	0.57	2974
6	W4	218	5214	4815	82.67	0.66	3142
7	W4	218	5000	4525	83.31	0.56	3045
Average of Dew Point Pressure (psia)				4726			
Variance of Dew Point Pressure (psia)				±123			

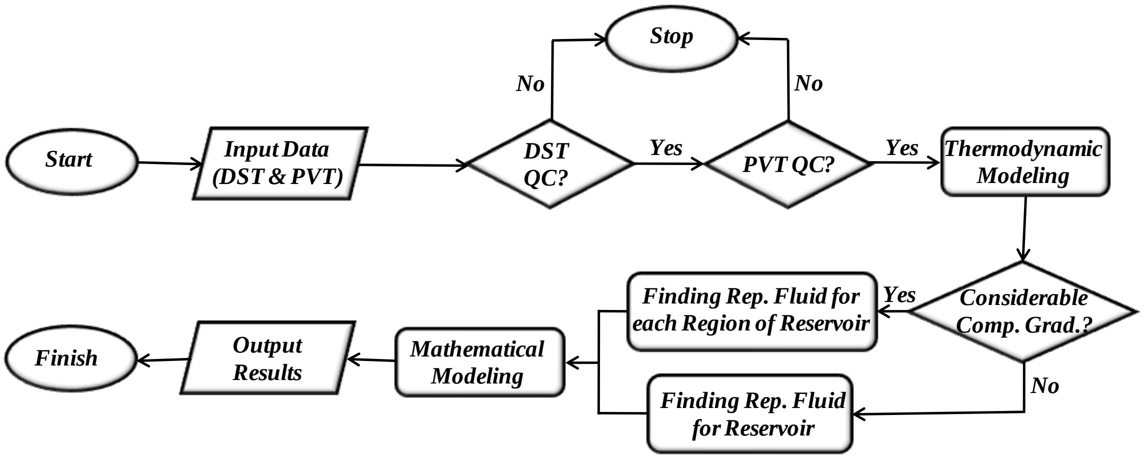


Figure 10. Conceptual, strategic model for determining representative fluid(s) in a reservoir

3. Conclusion

In this work, an integrated conceptual model was proposed for determining representative fluid(s) in a reservoir. This model integrates systematic QC of DST and PVT data with, followed by thermodynamic modeling of reservoir fluid(s), compositional gradient and determining representative fluid for each region in the reservoir (in the case of compositional gradient) or for the whole reservoir (in the case of slight compositional gradient). Thermodynamic modeling is performed on only equilibrium fluid samples, and unnecessary calculation on suspicious data is avoided. In this way, this model prevents blind EOS tuning on all fluids using all experimental data, and limits calculations to thermodynamically consistent experimental data with approved material balance. In the case of negative composition for one or more components in the reported CVD compositions, the whole experiment should be excluded from tuning of equation of states (EOS). Application of this methodology on the gas condensate reservoir under study showed that only less than 10% of reported experiments passed all criteria of DST QC successfully. Also, small changes in the composition of plus fraction of lean gas condensates which result in sharp variations of saturation pressure and PVT behavior should be considered in determining the representative fluid and PVT regions. For the reservoir under study, 0.1mol% change in the composition of plus fraction results in P^{dew} of as much as ±300 psia. So, there is no substantial difference between validated fluid samples, and one fluid can be used as representative for the whole reservoir.

Nomenclature:

b_i	Constant related to component i in Hoffman plot
CGR	Condensate gas oil ratio (bbl/MMscf)
CVD	Constant volume depletion
F_i	Hoffman characterization coefficient
F_{gsp}	Mole fraction of producing gas, separator outlet
K_i	K-Value, yi/xi
n_g	Molar gas flow rate
n_o	Molar oil flow rate
n	Total molar gas flow rate
n_o^*	Net molar oil rate
Δn_o	- Carried over oil flow rate
P_{ci}	Critical pressure of component i
P_{sc}	Standard Critical pressure
R_{sp}	Separator oil-gas ratio
T_{bi}	Normal boiling point of component i
T_{ci}	Critical temperature of component i
T_{sp}	Separator temperature
xi	Liquid mole fraction of component i, separator outlet
yi	Gas mole fraction of component i, separator outlet
zi	Component I mole fraction, inlet to separator
Z_g	Gas compressibility factor

Greek Letters

β	gas molar ratio to total moles of liquid and gas
δ_{osp}	Fraction of oil in the gas
ρ_{sc}:	Density at standard condition

Appendix A:

Available data for figures 2 & 3

ID	Depth (ft)	Dew Point (psia)	C12+*	LDOˣ (%)	CGR♦	ID	Depth (ft)	Dew Point (psia)	C12+	LDO (%)	CGR
S1	9540.5	5159.0	0.5	2.0	39.8	S16	10335.0	5090.0	0.7	2.9	45.0
S2	8954.5	4845.0	0.4	1.6	33.4	S17	9449.0	5115.0	0.7	3.6	43.1
S3	9678.5	4775.0	0.6	2.6	50.9	S18	11269.5	5091.0	0.8	4.8	55.8
S4	9088.0	4830.0	0.7	3.2	55.3	S19	9585.0	4665.0	0.6	2.7	42.1
S5	9186.0	4895.0	0.4	1.9	31.9	S20	9908.0	5100.0	0.4	1.7	31.5
S6	8981.0	4782.0	0.5	2.6	49.2	S21	10154.0	5020.0	0.5	5.1	48.4
S7	10206.7	4698.7	0.5	2.4	39.9	S22	9757.0	4950.0	0.6	2.7	42.5
S8	9558.5	4726.7	0.3	2.3	38.4	S23	9616.0	4695.0	0.5	2.6	42.7
S9	9302.0	4665.7	0.3	1.5	26.7	S24	9378.0	4682.0	0.5	2.4	40.5
S10	9780.5	4829.7	0.4	2.5	41.6	S25	8920.0	4195.0	0.6	3.0	36.7
S11	9297.5	4748.0	0.4	2.2	38.3	S26	9657.0	4115.0	0.5	2.0	32.9
S12	9096.5	4771.7	0.4	2.1	42.6	S27	9308.0	3815.0	0.5	2.0	36.2
S13	9279.5	5236.1	0.8	6.3	62.1	S28	9033.5	4071.0	0.5	1.9	36.1
S14	9752.0	4912.7	0.6	2.9	41.7	S29	10308.0	4815.0	0.7	2.6	37.7
S15	9161.5	4829.7	0.5	2.6	38.8	S30	9989.0	4525.0	0.6	1.7	31.4

* C12+: mole % , ˣ LDO: Liquid Drop Out , ♦ CGR: bbl/MMscf

Appendix B:

Procedure for correcting Rsp in the case of condensate flow in gas line (C. H. Whitson, 1998).

Figure B-1 shows schematic of an isokinetic separator. When liquid is carried over in the gas line, total molar gas flow rate is the sum of gas, n_g, and carried over oil, Δn_o, flow rates. Also, the net molar oil rate, n_o^*, is oil rate, n_o, minus carried over oil, Δn_o:

$$n_o^* = n_o - \Delta n_o \qquad \text{(B-1)}$$

Total mole balance is written as:

$$n = n_g + (n_o^* + \Delta n_o) \qquad \text{(B-2)}$$

Component mole balance is written as:

$$\begin{aligned} z_i.n &= y_i.n_g + x_i.n_o && \text{(B-3)} \\ &= y_i.n_g + x_i.(n_o^* + \Delta n_o) && \text{(B-4)} \\ &= y_i.n_g + x_i.n_o^* + x_i.\Delta n_o && \text{(B-5)} \\ &= y_i^*.\left(n_g + \Delta n_o\right) + x_i.n_o^* && \text{(B-6)} \end{aligned}$$

z_i, x_i, and y_i are compositions of feed, liquid and vapor outlet of separator at equilibrium, respectively. y_i^* is the composition of vapor with oil carried over. Fraction of oil in the gas is defined as:

$$\delta_{osp} = \frac{\Delta n_o}{n_o} \qquad \text{(B-7)}$$

If oil is produced by gas stream, the mole fraction of producing gas, $(F_{gsp})_{test}$, must be corrected:

$$(F_{gsp})_{corr} = \frac{n_g}{n_g + n_o} = \frac{n_g}{n} \qquad \text{(B-8)}$$

$$= \frac{(F_{gsp})_{test} - \delta_{osp}}{1 - \delta_{osp}} \qquad \text{(B-9)}$$

Also, the measured gas-oil ratio, $(R_{sp})_{test}$, is corrected to obtain the separator gas-oil ratio:

$$(R_{sp})_{corr} = (R_{sp})_{test} \frac{1/(F_{gsp})_{test} - 1}{1/(F_{gsp})_{corr} - 1} \qquad \text{(B-10)}$$

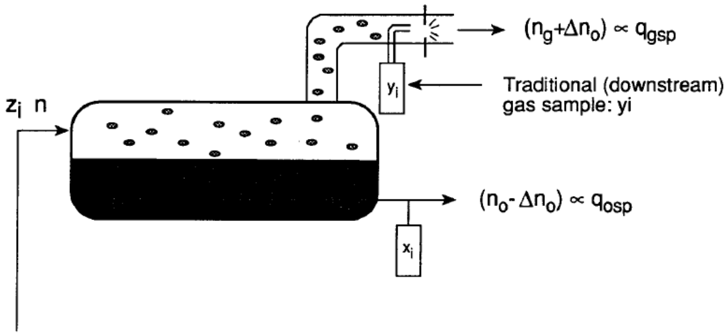


Figure B-1. Schematic of an isokinetic separator

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