Estimation of Uncertainles in Gas-Condensate Systems Reserves by Monte Carlo Simulation

Jakub Siemek *and* ***Stanislaw Nagy***[1]

Abstract

In the paper, an impact of improper condensate sampling on calculation of gas and condensate reserves of gas-condensate system is presented. The paper discusses probabilistic methods in reserves estimation (proven, possible, probable). The Peng-Robinson equation of state (EOS) has been used to calculations of phase properties. Sensitivity of CGR during recombination of stream process on liquid and gas reserves has been shown. The large error in estimation of condensate reserve has been obtained. The impact of CGR error on the vapor phase reserve is small.

Key words*: uncertainty gas condensate reserves, Monte Carlo porous medium sampling recombination*

Introduction

There are several definitions of reserves (fig.1) in the gas/condensate/oil systems (Herrell&Gardner, 2003). Under the SPE/WPC/AAPG definitions, reserve estimations may be prepared using either deterministic or probabilistic methods. With the deterministic method, single values for each parameter have to be used in the calculation of reserves. With the probabilistic method, the full range of possible values is described for each parameter. A mathematical technique such as Monte Carlo Simulation (Newendorp, 1975, Davidson&Cooper, 1979, Rubinstein, 1981, Iman et al. 1980, Smith & Buckee 1985) may be used to perform a large number of random, repetitive calculations to generate a range of possible outcomes for the reserves and their associated probability of occurrence.

Classic volumetric reserve calculation method

The most classic attitude in estimation of reserves of gas, oils and gas-condensate systems is presented in Arps (1956) Craft& Hawkins (1959). This approach is rather deterministic with use of single – average parameter estimation (Arps, 1956, Craft& Hawkins, 1959, Siemek et al., 1987) or based upon numerical integration of geologic properties maps (Zawisza &Nagy1996). The two main equations for volumetric reserve estimation are following:

$$N = V_{HC} \cdot NTG \cdot \phi(1 - S_w) / OFVF \quad (1)$$

$$G = V_{HC} \cdot NTG \cdot \phi \cdot (1 - S_w) / B_g \quad (2)$$

where V_{HC} - reservoir volume with hydrocarbon saturation (above OWC or GWC – where exist only gas),

ϕ - effective porosity fraction,

ϕ S_w -water saturation fraction,

ϕ NTG – Net to Gross coefficient,

ϕ OFVF and Bg- Formation Volume Factor for oil and for gas.

Probabilistic Methods Applied to the Gas-Condensate and Volatile Oils Fields

To compute volumetric estimation of reserve by means probabilistic tools following equation may be used.

$$N = \int_D I_R(x,y,z)\phi((x,y,z)NTG(x,y,z)(1 - S_w(x,y,z)) / FVF(x,y,z)dxdydz \quad (3)$$

[1] *Jakub Siemek, Stanislaw Nagy*, AGH Univ. of Science and Technology, Faculty of Drilling and Oil-Gas, Al. Mickiewicza 30, 30-059 Kraków, Poland, Tel.: +48.12.6172227, Fax: +48.12.6172219, siemek@agh.edu.pl, nagy@agh.edu.pl

where D- domain covering the reservoir,
I_R(x,y,z) =1 inside reservoir,
and I_R(x,y,z) =0 outside reservoir,
NTG (x,y,z)- net to gross ratio,
φ (x,y,z) – porosity,
Sw (x,y,z)- water saturation,
FVF (x,y,z) –formation volume factor.

Using Monte Carlo simulation of gas and condensate reserves, it is possible to construct probability density function (e.g. fig.2), which may be useful to fix proven (P90), possible (P50) and probable (P10) type of reserves. The MC simulation is done usually using 1000-3000 random sampling or Latin Cube procedures (Garb 1988, Iman et al. 1980).

Sensitivity Analysis.

There are several uncertain factors related to definitions of reserves in the gas/condensate/oil systems. Caldwell & Heater (2001) and Bu &Damsleth (1996) claim that 75% of uncertainty of reserves is linked to structural, geological properties (fault description, tops on seismic velocity etc) and only 25% to the petrophysical properties. Some of possible errors in volumetric reserve calculation are presented in the table 1 - based on DeSorcy (1980), Smith&Buckee(1985), Bu&Damsleth (1996) papers. In the table it is not taken into consideration grading compositional effect or non-representative sampling of hydrocarbon fluid or compositional grading (CG). In grading case the uncertainty of FVF may rise up to 50% (Siemek&Nagy 2004).

Reserve Volume

Estimation. After (1956) recommendation, reserve volume may be evaluated by planimetering or numerical integrating (Simpson, trapezoidal, pyramidal), horizontal and vertical slices. The descriptions of real porous model systems are much more complicated. The layer is usually non-horizontal (slope) with anisotropy and heterogeneity; discontinuity may change shape of reservoir. The properties of rock may spatially vary: vertically or laterally. Assuming uncertainty in the structure and volume of reservoir, minimum three scenarios have to be prepared: pessimistic (minimum value, most likely and optimistic (highest value). These values may be used later in the Monte Carlo simulation of reserves

Sensitivity to Porosity and to Effective Pay Thickness (Net to Gross).

The parameters like porosity and effective pay thickness depend on type of geological heterogeneity of rocks. There are three different types of heterogeneity in sandstones (different depositional units in the same reservoir, lateral & multiple reservoirs apparently “blanket” sands, shale “breaks” of indeterminate aerial extends) and two types in carbonate reservoirs (lateral discontinuities in pay zones, very erratic – sometimes vugular – porosity).

Sensitivity to Water Saturation.

The water saturation is usually computed from well logs using some of simply formulas (Archie, Humble, etc.). Based on the computed data, it is possible to determine characteristics of distribution (vertical/lateral) or estimate triangular distribution with minimal, most likely and maximum water saturation.

Tab. 1. Possible uncertainties of field variables used in reserve and risk analysis

	Source of Estimate	Approx. range of accuracy (%)		
		DeSorcy (1979)	Smith&Buckee (1985)	Bu& Damsleth (1996)
Area	Drill holes	±10-20	±10	
	Geoph.data	±10-20	±15	
	Reg. Geol.	±50-80	±50	
Pay thickness	Cores	± 5-10	±8	
	Logs	±10-20	±30	
	Reg. Geol.	±40-60	±50	
Porosity	Cores	± 5-10		
	Logs	±10-20	±15	±5
	Prod. Data	±10-20	±8	
	Drilling Cuttings	±20-40		
	Correlation	±30-50	±50	
Water Saturation	Cap. Press.	± 5-15		
	Oil Cores	± 5-15	±20	
	Sat. logs	±10-25	±8	±20
	Correlation	±25-30	±50	
FVF	PVT	± 5-10	±10	±2
	Correlation	±10-30	±20	

Tab. 2. The summary of geological date and PVT data used in sensitivity

	Min.	Most likely	Max.
Volume [10^8 m^3]	**1.800**	**2.00**	**2.200**
NTG [-]	**0.810**	**0.90**	**0.990**
PHI [-]	**0.135**	**0.15**	**0.165**
SW [-]	**0.270**	**0.30**	**0.330**
OilFVF[m^3/m^3]	**11.35**	**18.98**	**25.26**
GasFVF[m^3/m^3]	**0.0057**	**0.0058**	**0.0060**

Tab. 3. Prototype of gas-condensate system (Walsh &Raghavan, 1994)

Component	Mole fraction [-]
Nitrogen (N2)	0.0223
Methane (C1)	0.6568
Carbon Dioxide (CO2)	0.0045
Ethane (C2)	0.1170
Propane (C3)	0.0587
Iso-Butane (iC4)	0.0127
Normal Butane (nC4)	0.0168
Iso-Pentane (iC5)	0.0071
Normal Pentane (nC5)	0.0071
Hexane (C6)	0.0098
C_{7+}	0.0872

Tab. 4. Comparison of reserve using Monte Carlo simulation based upon crisp and triangular distribution of FVF for condensate and gas phases

Type of reserve	Condensate reserves [10^6 Sm^3]		Gas reserves [10^9 Sm^3]	
	Triangular	**Crisp**	**Triangular**	**Crisp**
P90	8.33	9.085	29.73	29.74
P50	9.94	9.932	32.28	32.51
P10	17.7	12.15	39.15	39.77

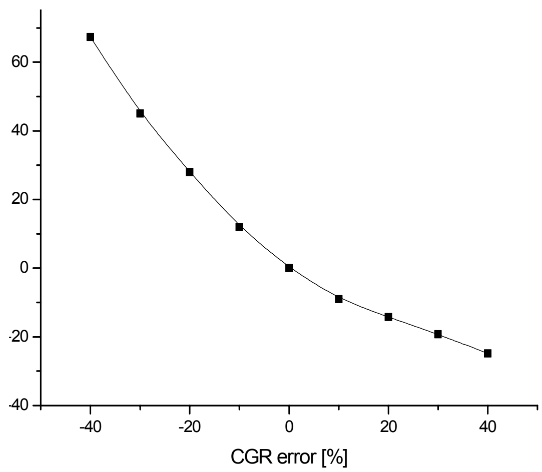

Fig. 1. Sensitivity of condensate reserves error for over- and underestimation of CGR

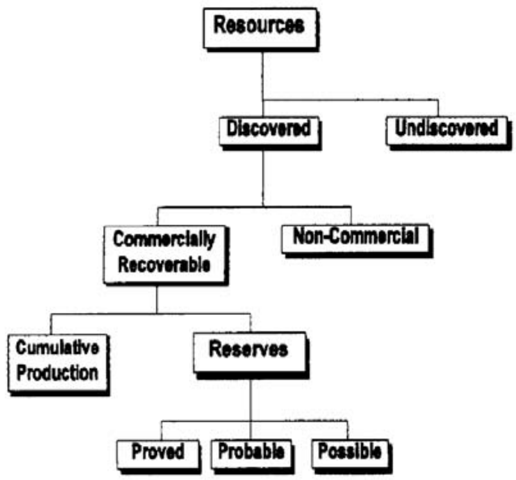

Fig. 2. Resource classification tree (Cronquist, 1991).

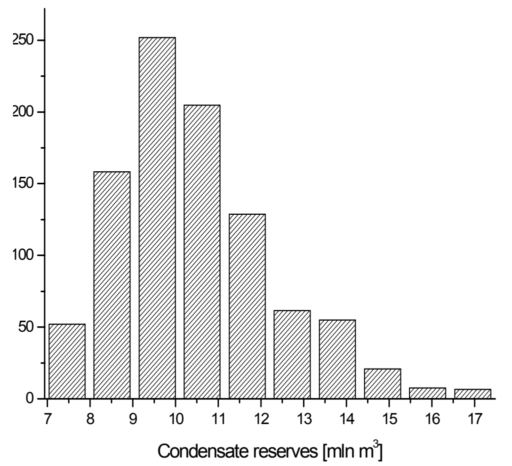

Fig. 3. Probability density function of condensate reserves

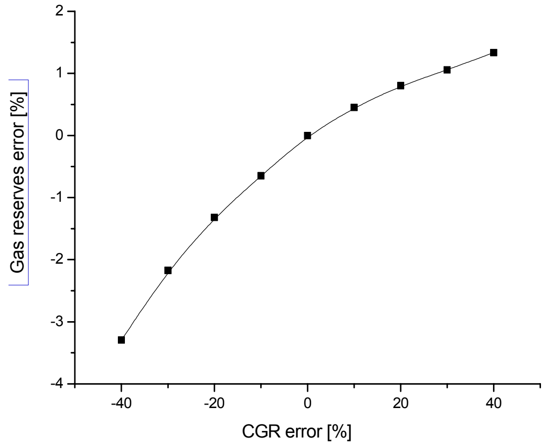

Fig. 4. Sensitivity of gas reserves error for over- and underestimation of CGR

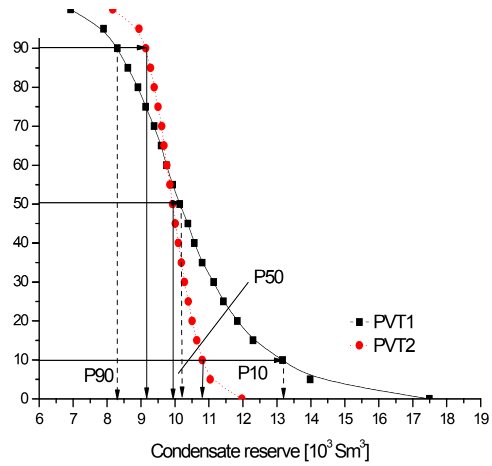

Fig. 5. Estimation of P90,
P50 & P10 type of condensate reserves:
PTV1 – with high uncertainties in CGR
PVT2- true recombination sampling

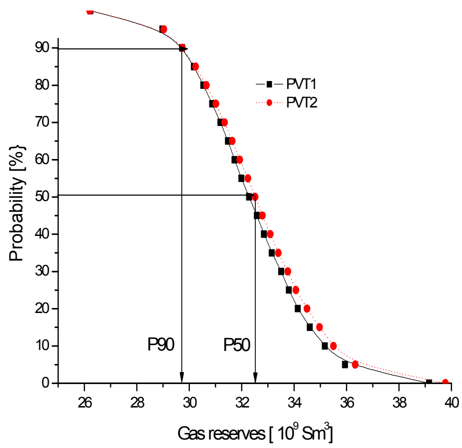

Fig. 6. Estimation of P90,
P50 & P10 type of gas reserves:
PTV1 – with high uncertainties in estimation of CGR;
PVT2- true recombination sampling

The correct estimation of Water-Hydrocarbon Contact may be sometimes difficult to achieve. The fixing Gas-Water-Contact GWC or Oil-Water-Contact (OWC) may be erroneous, sometimes the border is fixed at 80% water saturation, in other case limit of 75% or 85% may be correct. This is correlated directly to the Gross Volume uncertainties.

Sensitivity to FVF.

The following phenomena may be important for evaluation of sensitivity of Formation Volume Fluid (FVF): improper well conditioning, sample contamination, inadequate or poor PVT analysis, inappropriate fluid model. In case of improper sampling of gas condensate system (e.g. with non stable CGR) the PVT properties may mask current estimation of HCIIP. The errors of estimation may reach up to +/-50% or more. The influence of incorrect well conditioning (e.g. inappropriate CGR) is given in the fig. 2 and 3, the impact of false CGR on gas phase properties is small (below 4% in presented case, fig. 4), but is extremely high in case of condensate yield +70% and -20% (fig.3).

Examples

Based upon triangular presented in the table 2 MC simulation has been performed. Triangular distribution favor the estimated maximum point taken from the model parameter prefers any random pseudo-generated value from the variable range. The Latin Hypercubic sampling (LHC) has been chosen, because LHC method reduces the number of samples and variance(Rubinstein, 1981, Iman et al. 1980). One run in full triangular distribution of all parameters (PVT1) and one additional simulation run for crisp PVT data (PVT2) for each phase has been performed. The preparation of gas and condensate phases has been done using flash procedure described in Nagy (1996, 2002) using Peng-Robinson equation of state (EOS) type (Tsai&Chen,1998, Nagy 2002) (is standard conditions). Data of gas-condensate systems composition are presented in the tab. 2 (from Walsh&Raghavan 1994). The two calculations of reserves has been presented (fig. 5-6) for both condensate and gas phase. It is evident based on observation of fig. 5, that introducing possible inaccuracies into the Oil Formation Volume Factor based upon earlier estimation of improper CGR estimation (±40%) causes movement of "true" probability cumulative curve and its "scouring". The comparison of proven and possible and probable reserves for condensate and gas phase is given in the table 4. The movement of P90 reserves is 8.3%. The effect is negligible for gas phase – as is presented in the fig. 6 and tab. 4. The maximum error of calculation is below 0.3% (!). The errors for P10 for condensate phase are -45% and for gas phase 1.6%.

Conclusions

1. Evaluation of uncertainties in the estimation of geological reserves based upon Monte Carlo method is important in cases where full compositional simulation (FCS) or material balance with constant volume depletion (MBE CVD) is not performed.
2. Impact of improper estimation of PVT data (well conditioning, sample contamination, inadequate or poor PVT analysis, and inappropriate fluid model) on GIIP/OIIP may be significant. Other uncertainties in estimation of hydrocarbon liquid reserves using reservoir simulation may be caused by: data inaccuracies; data coverage; data smoothing/interpolating; numerical solution limits. The effect of improper CGR

estimation may be of range of 10% in case of P90 reserve and may expand up to -45% for P10 reserve for condensate phase.

3. The sensitivity to the FVF of gas-condensate system for gas phase is negligible and could be omitted.

References

[1] Arps J.: Estimation of Primary Oil and Gas Reserves*, Trans. AIME, 207, p.182-91, 1956.*

[2] Bu, T., Damsleth, E.: SPE Formation Evaluation*, Sep, p. 194-200, 1996.*

[3] Caldwell, R.H., Heater, D.I.*:* SPE 68592*, 2001.*

[4] Craft, B., C., Hawkins, M., F.: Applied Petroleum Reservoir Engineering*, Prentice-Hall, Inc.., 1959*

[5] Cronquist, Ch.: JPT*, Oct. p.1258-1264, 1991.*

[6] Davidson, L., B., Cooper, D., O.: JPT*, Sep, 1979.*

[7] De Sorcy, G.I.: Proc. of the 10^{th} WPC*, Vol. 2, pp.269-277, 1980.*

[8] Garb, F., A.: JPT*, June, p. 765-778, 1988.*

[9] Herrell, D., R.,. Gardner, T.,L.: SPE 84145*, 2003.*

[10] Iman, R., L,. et al.: Latin Hypercubic Sampling*, Sandia Laboratory Report SAND 79-1473, 1980.*

[11] Nagy, S.: Archives of Mining Sciences*, Vol. 41, No.3, p. 275-290 (in Polish), 1996.*

[12] Nagy, S.: Archives of Mining and Sciences*, Vol. 47, No.2, p.205-253, 2002.*

[13] Newendorp, P., D.: Decision Analysis for Petroleum Exploration*, Petr. Publ. Co, Tulsa, 1975.*

[14] Rubinstein, R., Y.: Simulation and the Monte Carlo Method*., New York: John Wiley & Sons, 1981.*

[15] Siemek, J., Nagy, S.: Uncertainty in Geologic Reserve Estimation of Compositional Grading Gas-Condensate Systems*, ENERGEX 2004, Lisbon, 2-6 May, 2004.*

[16] Siemek, J., Jucha, S., Olajossy, A., Rybicki, C., Zawisza, L.: Paper Gas/Sem/12/R/22*, Seminar UN. Nations, Economy Commission for Europe, held at Warsaw (Poland), 25-30 May, 1987.*

[17] Smith, P., J., Buckee, J.,W.: SPE 13776, *1985*

[18] Tsai, J.,Ch., Y., P., Chen: Fluid Phase Equilibria*, Vol. 145, p. 193-215, 1998.*

[19] Walsh, M., P., Raghawan, R.,: SPE 27684, *1994.*

[20] Zawisza, L., Nagy, S.: Errors in gas-condensate reservoirs*, Proc. of EMW conference, AGH UST Krakow, 1996.*