Reservoir Fluid Properties Required for Low-Permeability Oil Reservoir Analysis*

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Abstract

Quantifying fluid flow through porous media requires accurate fluid property estimates. This is especially important for low-permeability oil reservoirs which will produce gas, oil, and water in time-dependent proportions due to hydraulic fracture stimulation and production pressures below oil bubble-point pressure. Gas and oil properties are required to properly quantify flowing properties, such as the effective permeability to each phase, to determine the oil and gas volumes in-place, to predict future production rates and recovery, and to evaluate open-hole log data.

Reservoir fluid systems are classified based upon the phase behavior relative to the critical point of a multicomponent hydrocarbon mixture. The fluid- system phase behavior PVT (pressure-volume-temperature) analysis depends on the fluid type. Representative fluid samples are required for the analysis. These samples are best acquired by recombining separator oil and gas samples collected under relatively stable production conditions very early in the life of a reservoir. The samples are recombined at the separator gas-oil rate ratio to serve as the reservoir fluid sample.

Oil production behavior is strongly dependent upon the oil gravity and the original solution gas-oil ratio. The differences in behavior for three actual Permian oil reservoirs are demonstrated with reservoir simulation models. An example PVT analysis of one of the fluid systems is discussed.

References Cited

Alharthy, N.S., T.N. Nguyen, T.W. Teklu, H. Kazemi, and R.M. Graves, 2013, Multiphase compositional modeling in small-scale pores of unconventional shale reservoirs: SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, 30 September–2 October 2013. SPE 166306.

Whitson, C.H., and M.R. Brule, 2000, Phase Behavior: SPE Monograph Series, v. 20, p. 6, 9, 15.

RESERVOIR FLUID PROPERTIES REQUIRED FOR LOW- PERMEABILITY OIL RESERVOIR ANALYSIS

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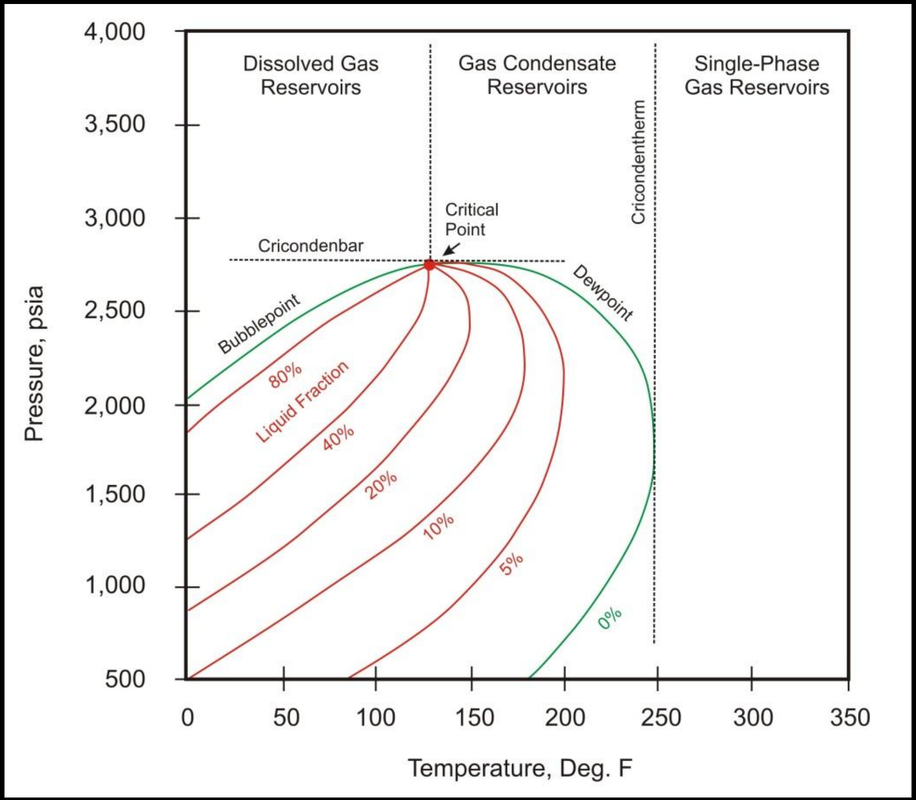
Nov. 4, 2013



Reservoir Fluid Property Importance

- Fluid flow through porous media requires accurate fluid phase behavior data
- Especially important under multiphase flow conditions
- Fluid-in-place volumes
- Future production and recovery forecasts
- Reservoir flow properties (permeability to fluids, etc.)

Properties for In-Place and Recovery Estimates

- Phase pressure and temperature boundaries
- Density & formation volume factor
- Vapor & liquid solubility
- Compressibility
- Viscosity

Outline

- Classification of reservoir fluid systems
- Basic phase behavior concepts
- Fluid sampling and rate measurement
- Effect of solution gas-oil ratio upon well performance
- PVT study black oil properties
- Possible modifications for tight oil reservoirs

Classification of Reservoir Fluid Systems

- Reservoir Fluid Types
  1. Dry Gas
  2. Wet Gas
  3. Gas Condensate
  4. Volatile Oil
  5. Black Oil
- Classification based upon:
  - Reservoir temperature relative to the critical point and cricondentherm
  - Properties at the 1st stage separator temperature and pressure relative to the fluid phase diagram

Single Molecular Species p-T Diagram

Reference:
Whitson & Brule
Phase Behavior
SPE Monograph
Series Vol. 20
p. 9

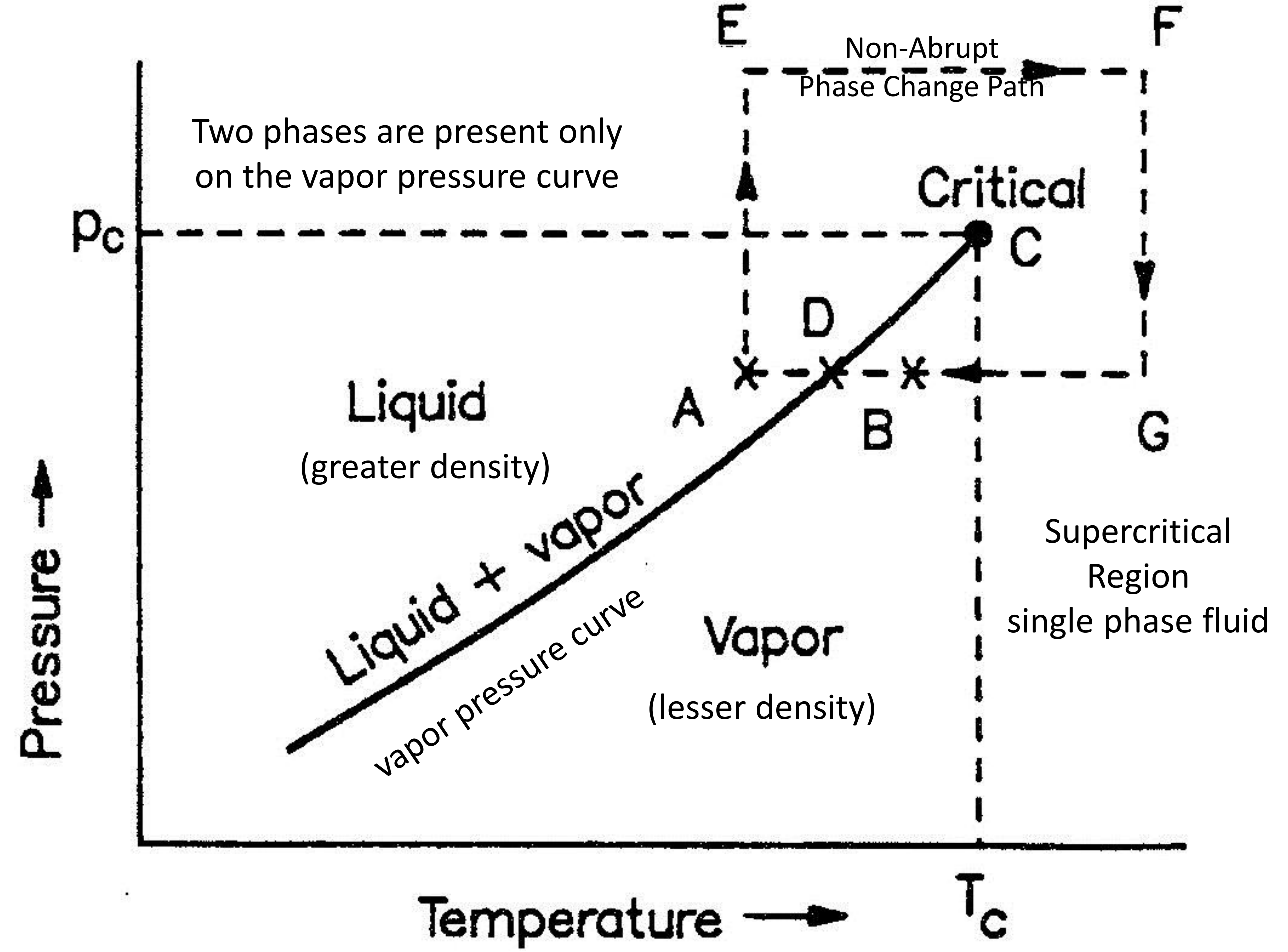
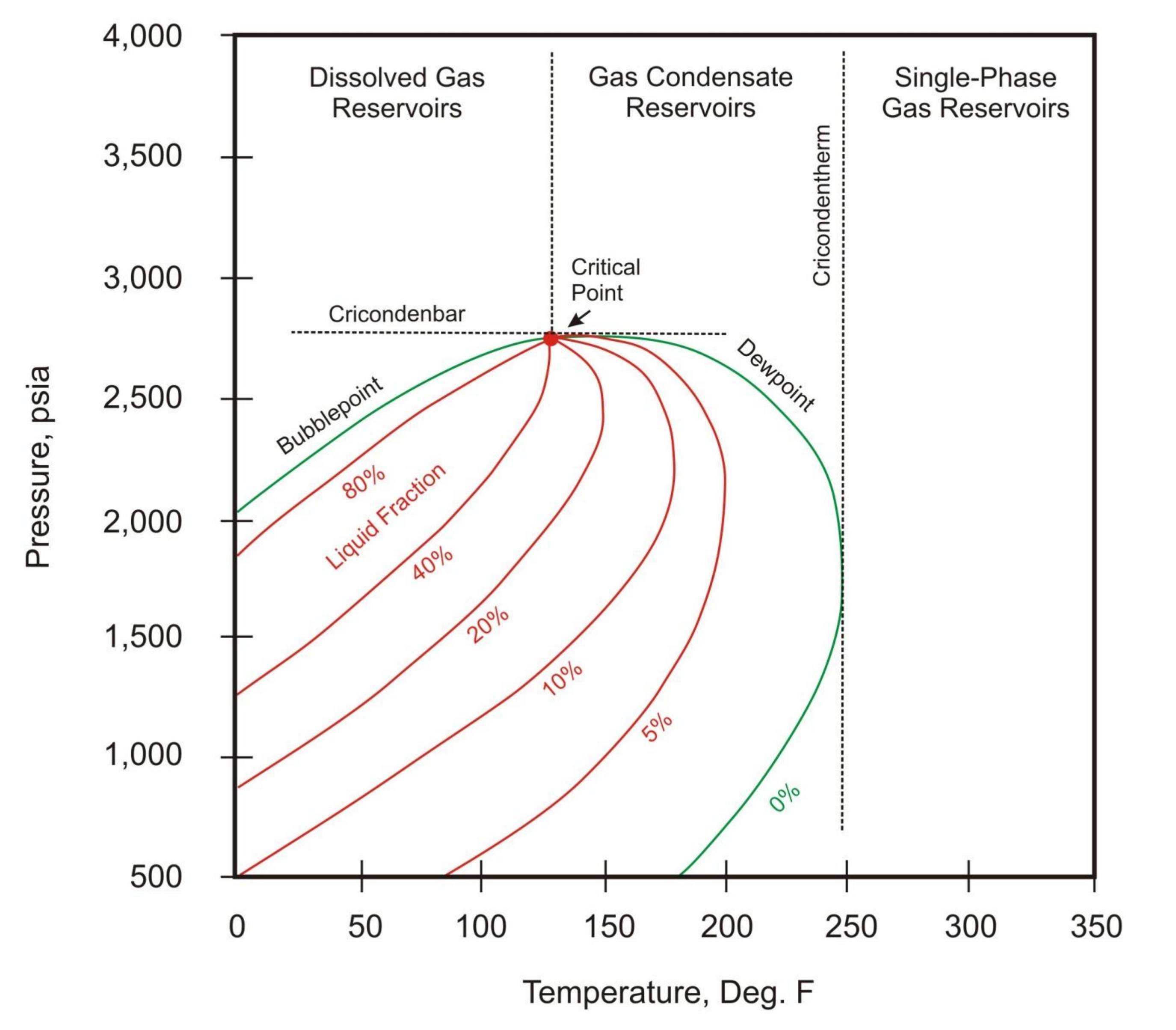


Fig. 2.4—*p-T* diagram for a single component in the region of vapor/liquid behavior near the critical point (p_c = critical pressure and T_c = critical temperature).

Multicomponent p-T Phase Diagram



Reference:
Whitson & Brule
Phase Behavior
SPE Monograph
Series Vol. 20
p. 15

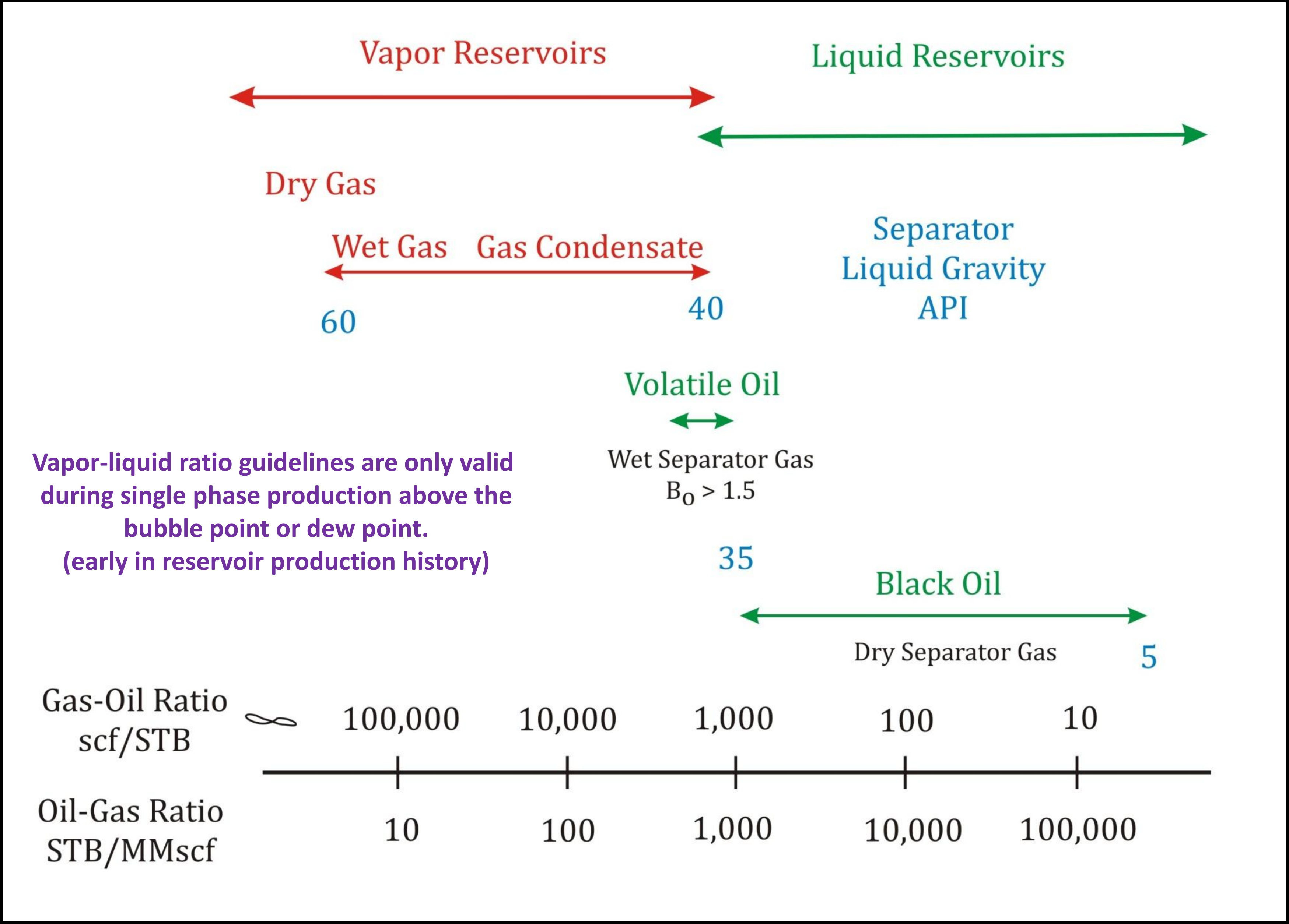
Example Reservoir Fluid Compositions

Reference:
Whitson & Brule
Phase Behavior
SPE Monograph
Series Vol. 20
p. 6

TABLE 2.1—COMPOSITION AND PROPERTIES OF SEVERAL RESERVOIR FLUIDS

Component	Dry Gas	Wet Gas	Gas Condensate	Near-Critical Oil	Volatile Oil	Black Oil
Composition (mol%)						
CO_2	0.10	1.41	2.37	1.30	0.93	0.02
N_2	2.07	0.25	0.31	0.56	0.21	0.34
C_1	86.12	92.46	73.19	69.44	58.77	34.62
C_2	5.91	3.18	7.80	7.88	7.57	4.11
C_3	3.58	1.01	3.55	4.26	4.09	1.01
i-C_4	1.72	0.28	0.71	0.89	0.91	0.76
n-C_4		0.24	1.45	2.14	2.09	0.49
i-C_5	0.50	0.13	0.64	0.90	0.77	0.43
n-C_5		0.08	0.68	1.13	1.15	0.21
$C_{6(s)}$		0.14	1.09	1.46	1.75	1.61
C_{7+}		0.82	8.21	10.04	21.76	56.40
Properties						
$M_{C_{7+}}$		130	184	219	228	274
$\gamma_{C_{7+}}$		0.763	0.816	0.839	0.858	0.920
K_{wC_7}		12.00	11.95	11.98	11.83	11.47
GOR, scf/STB	∞	105,000	5,450	3,650	1,490	300
OGR, STB/MMscf	0	10	180	275		
γ_{API}		57	49	45	38	24
γ_g		0.61	0.70	0.71	0.70	0.63
p_{sat}, psia		3,430	6.560	7,015	5,420	2,810
B_{sat}, ft^3/scf or bbl/STB		0.0051	0.0039	2.78	1.73	1.16
ρ_{sat}, lbm/ft^3		9.61	26.7	30.7	38.2	51.4

Reservoir Fluid Classification

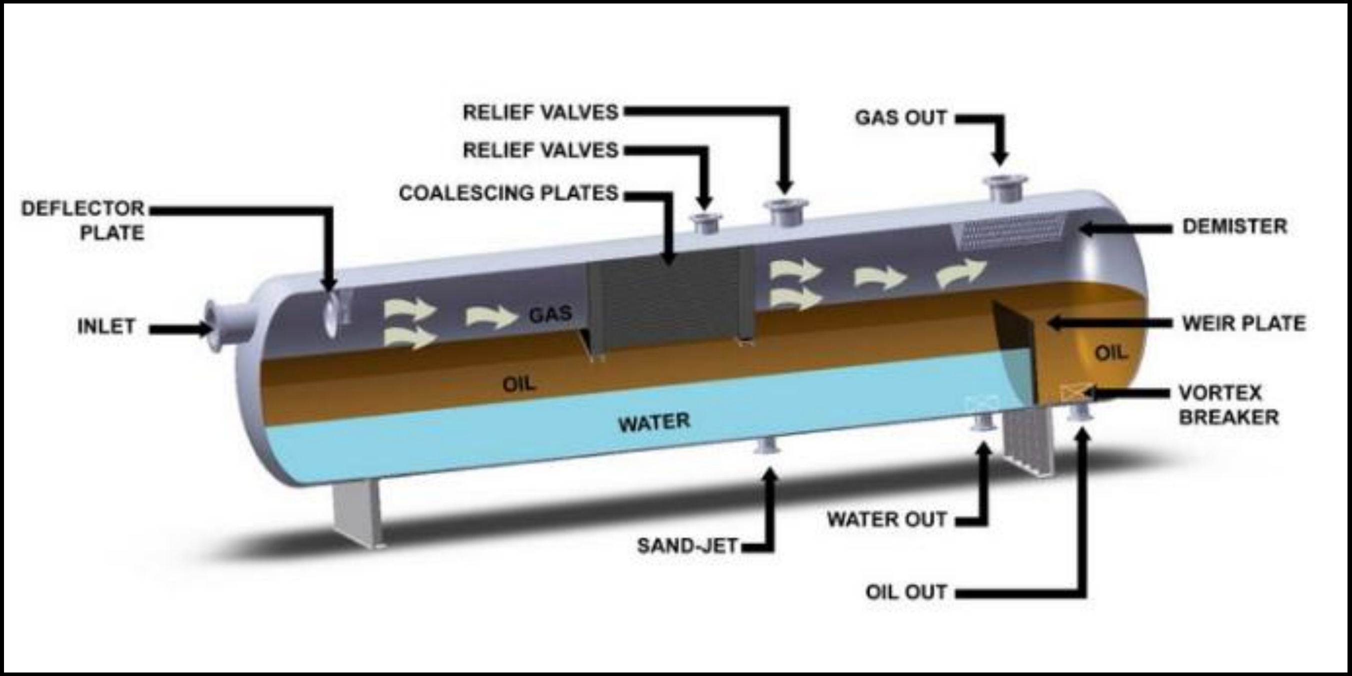


PVT Studies Require Reservoir Fluid Samples

PVT: Pressure-Volume-Temperature

- Recombined Separator Oil & Gas Samples
  - Accurate gas, oil, and water flow rates required
  - Gas-oil ratio must be relatively stable
  - Gas & oil samples are recombined by the PVT lab
- Downhole Samplers
  - *Should not be used for low-perm reservoirs*
  - Reliable only for single phase flow above bubble point or dew point pressure
  - Compromised by water production

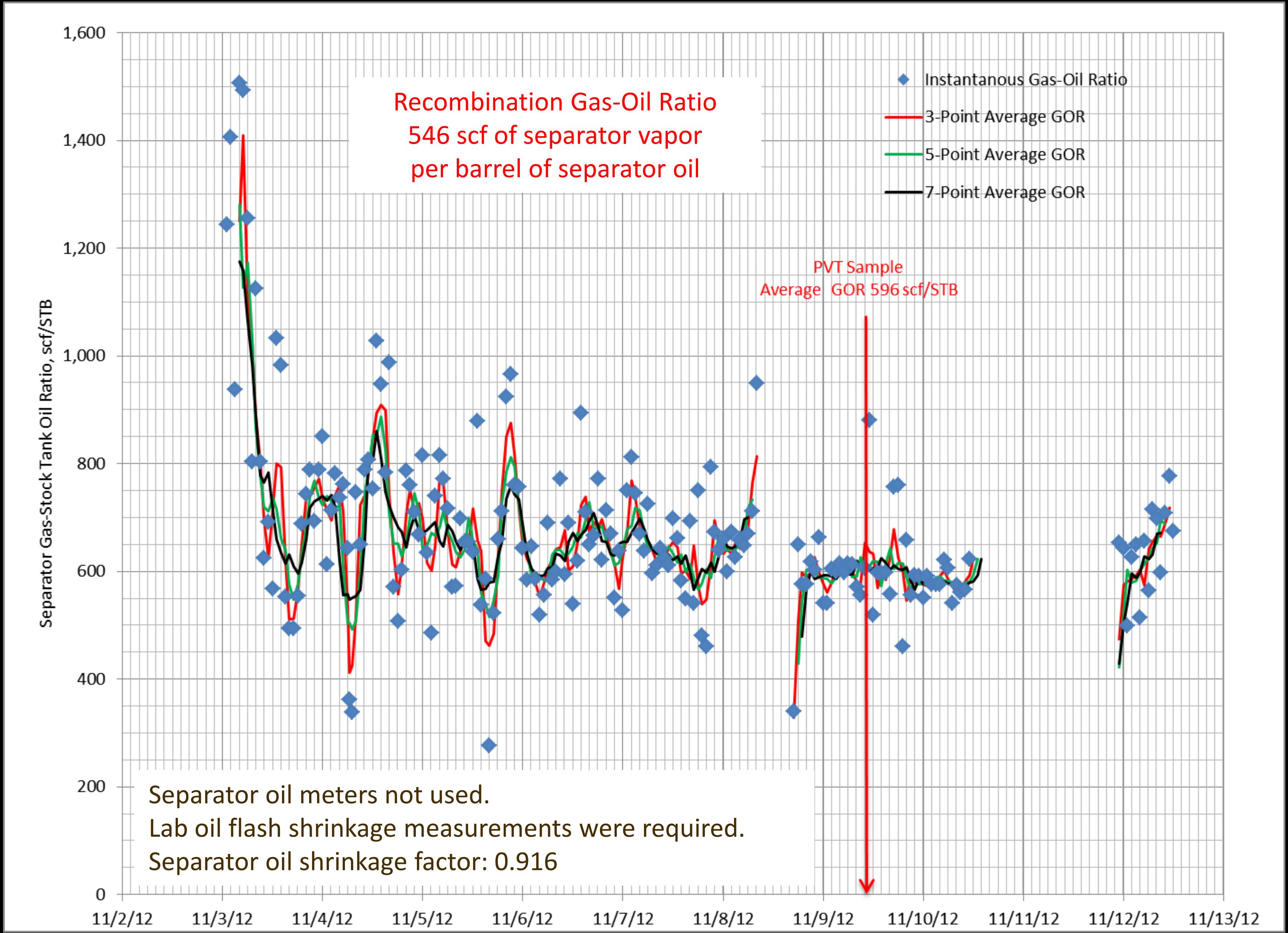
Single-Stage Three-Phase Gas-Oil-Water Separator

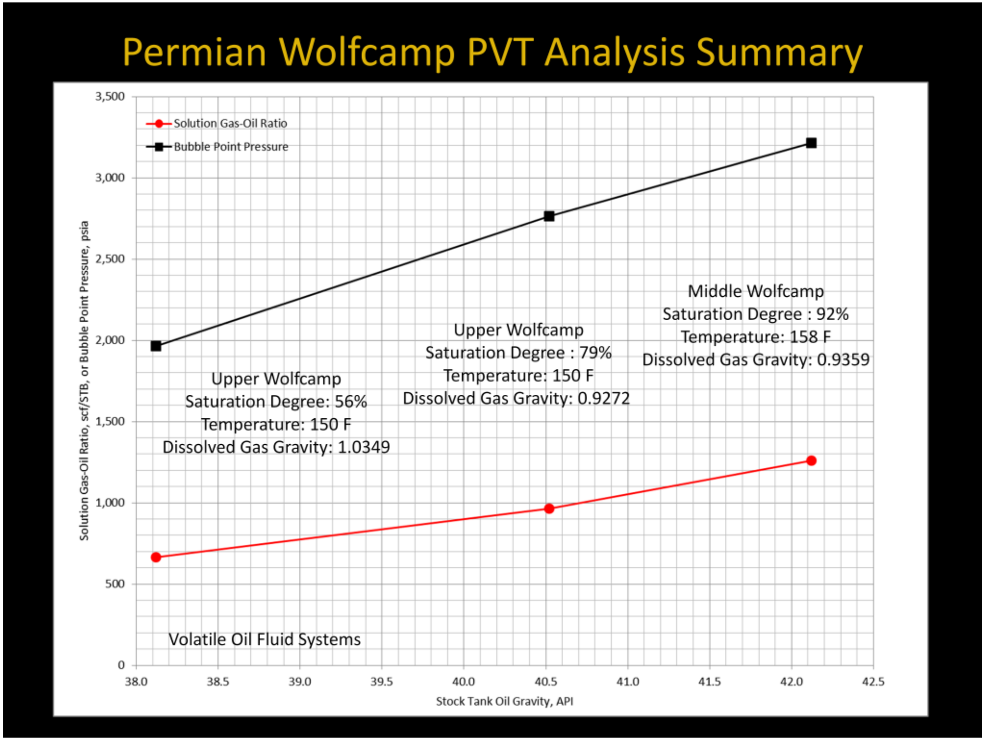


Gas rates are commonly measured with gas orifice meters

Oil and water rates are commonly measured with turbine flow meters and stock tank straps (liquid level in the tank)

Permian Tight Oil Well GOR During Sampling



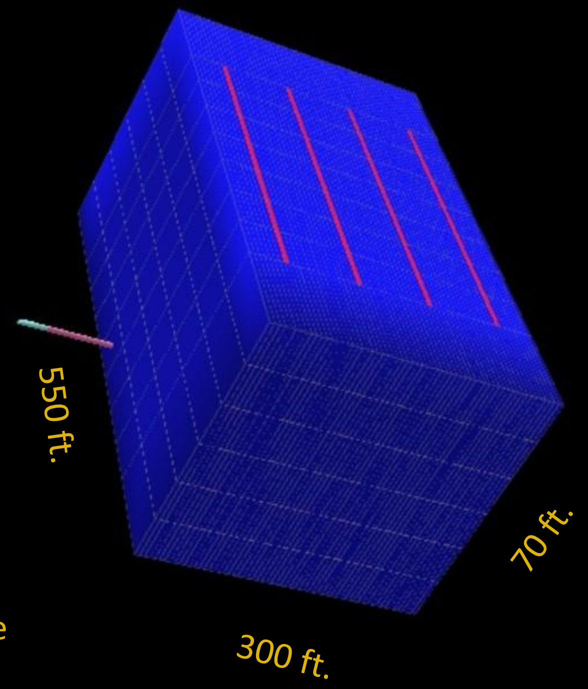


Presenter's notes:Three Wolfcamp PVT studies have been completed on recombined separator gas and oil samples. There has been a minor variation in oil gravity with a substantial variation in solution gas-oil ratios which affects reservoir fluid properties, in particular the bubble point pressure.

The reservoir fluid classification is volatile oil based upon the oil gravity and gas-oil ranges.

In each case, the reservoirs are under-saturated with bubble point pressures less than the initial reservoir pressure. The degree of saturation (bubble point pressure / reservoir pressure) increases with the increase in oil gravity and solution gas-oil ratio for these three samples.

Simulation of One Stage of a Tight Oil Frac

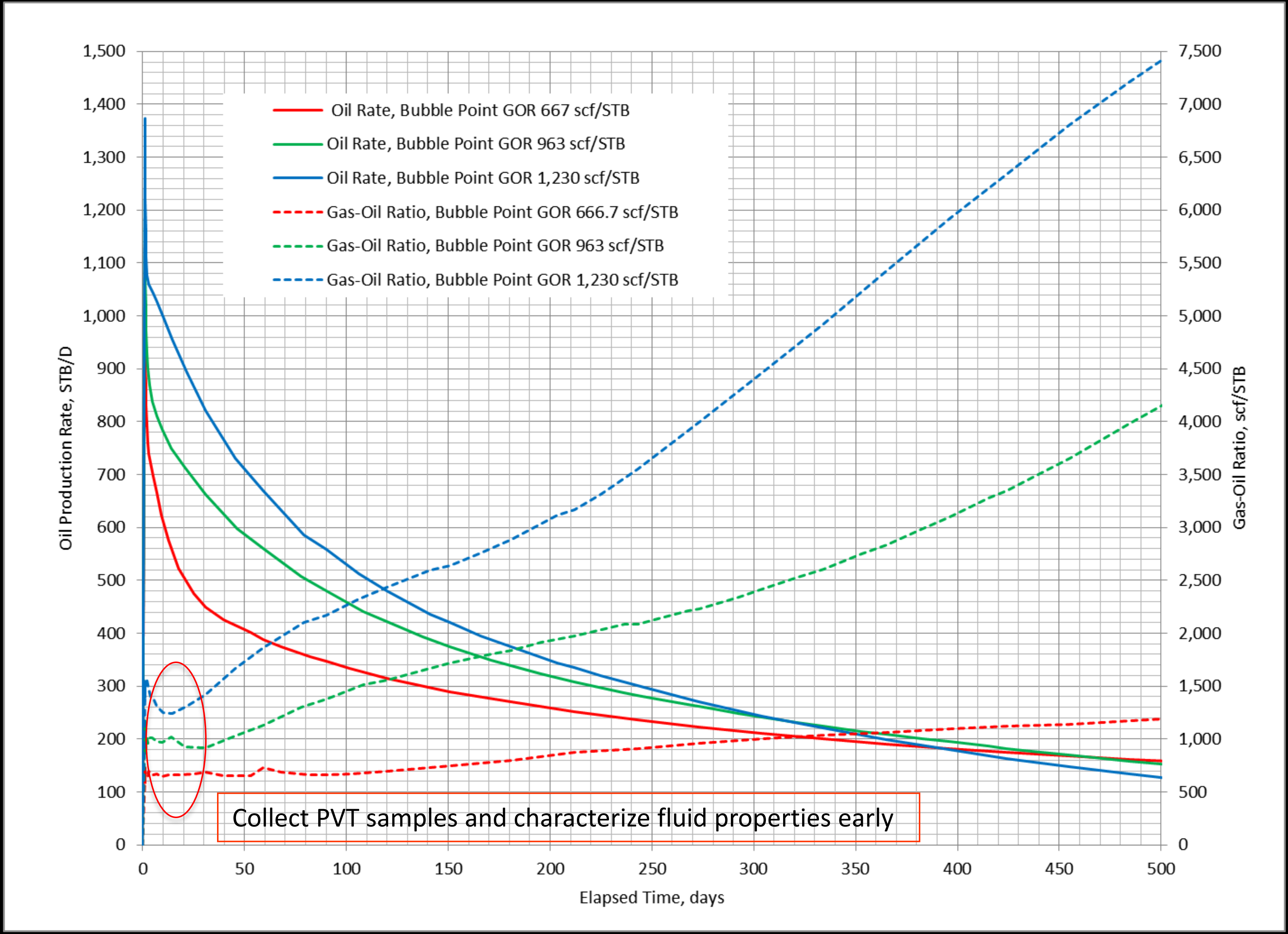


Stage Drainage Area
3.8 acres

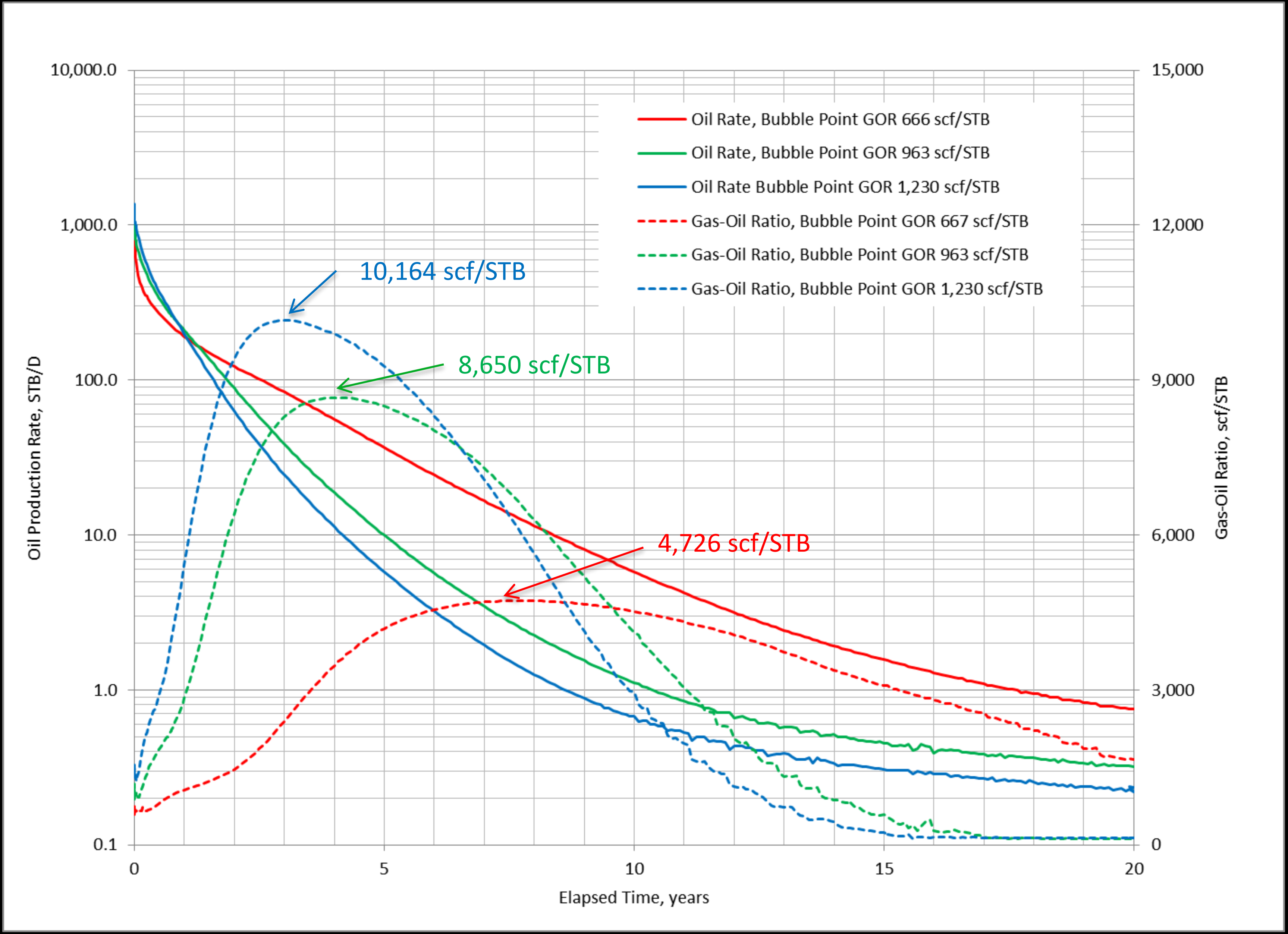
23 Total Stages
4 perf clusters & induced fracs per stage
Induced frac length 350 feet

Matrix permeability to oil: 0.001 md
Matrix block spacing: 10 feet
Induced frac perm: 4 md
Induced frac cond. 20 md-ft

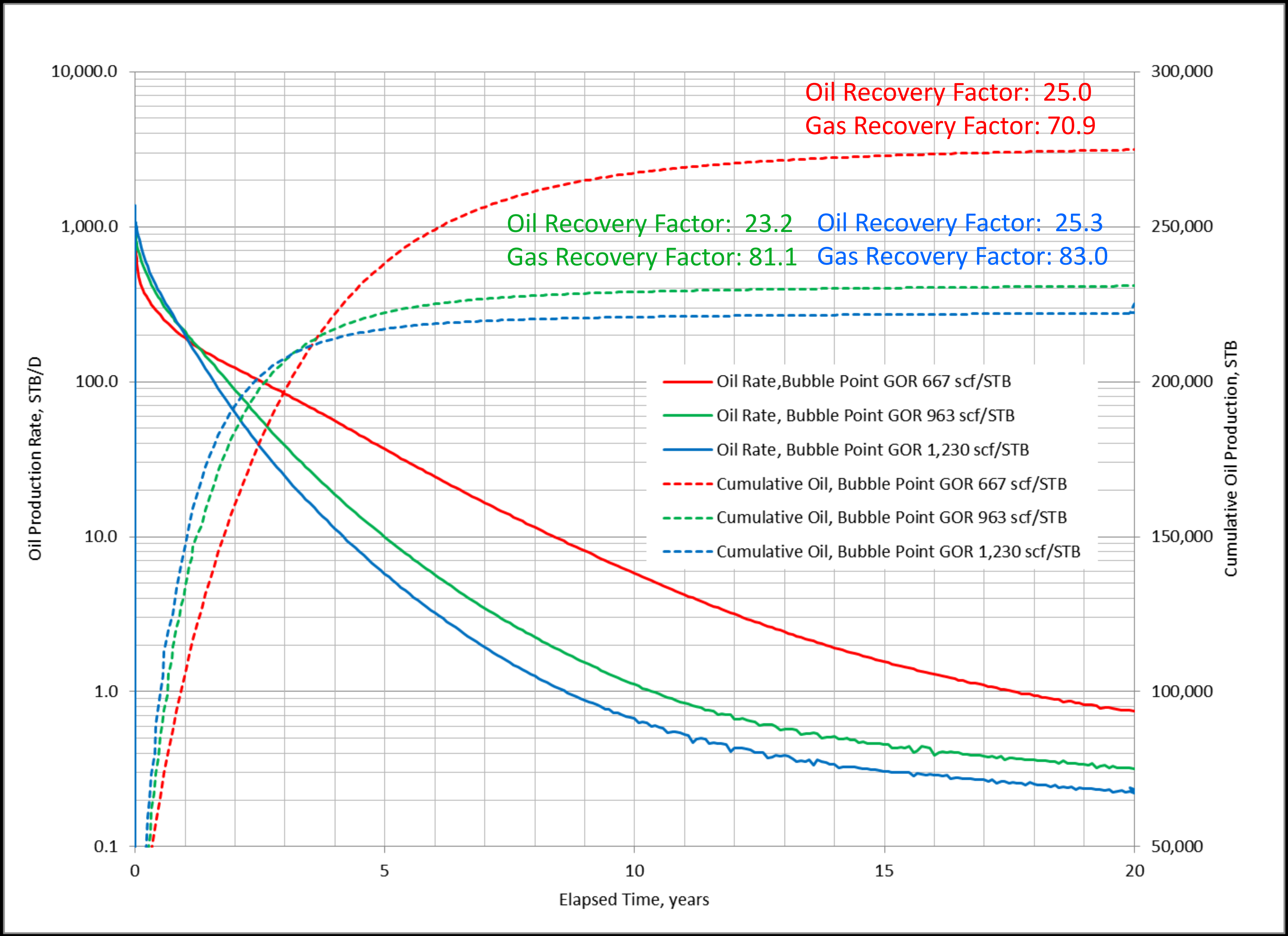
Early Time Oil Rate and Produced GOR



Long Term Oil Rate and Produced GOR



Oil Rate and Recovery vs. Initial GOR



Permian Wolfcamp PVT Study Oil Properties

Pressure	Liquid Density	Oil Formation Volume Factor (1)	Solution Gas-Oil Ratio (2)	Oil Compressibility	Oil Viscosity	Incremental Gas Gravity (3)	Cumulative Gas Gravity (4)	Gas z Factor	Gas Formation Volume Factor (5)	Gas Expansion Factor (6)	Calculated Gas Viscosity	Oil-Gas Viscosity Ratio
psia	g/cm3	reservoir volume / stock tank volume	scf/STB	1/psi	cp	relative to air	relative to air	-	volume / standard volume	standard volume / volume	cp	-
6,015	0.7385	1.3151	666.6		0.708							
5,515	0.7351	1.3212	666.6	9.45E-06	0.689							
5,015	0.7316	1.3276	666.6	9.87E-06	0.675							
4,515	0.7279	1.3343	666.6	1.04E-05	0.662							
4,015	0.7240	1.3414	666.6	1.10E-05	0.650							
3,450	0.7194	1.3500	666.6	1.18E-05	0.637							
3,015	0.7156	1.3572	666.6	1.27E-05	0.627							
2,515	0.7109	1.3662	666.6	1.39E-05	0.619							
2,315	0.7089	1.3700	666.6	1.44E-05	0.616							
1,965	0.7052	1.3773	666.6	1.58E-05	0.614							
1,615	0.7136	1.3291	536.6		0.685	0.8035	0.8035	0.820	0.0088	113.901	0.0167	41.02
1,315	0.7218	1.2907	440.4		0.774	0.8053	0.8043	0.838	0.0110	90.751	0.0156	49.62
1,015	0.7304	1.2535	349.8		0.883	0.8131	0.8068	0.860	0.0147	68.255	0.0145	60.90
715	0.7401	1.2129	253.2		1.023	0.8486	0.8166	0.885	0.0214	46.723	0.0136	75.22
415	0.7519	1.1659	149.5		1.174	0.9296	0.8393	0.917	0.0382	26.173	0.0128	91.72
115	0.7750	1.0799	0.0		1.460	1.2011	0.9213	0.964	0.1449	6.899	0.0119	122.69
15	0.8068	0.9768	0.0		2.074	1.5634	1.0349	0.998	1.1505	0.869	0.0113	183.54

green	properties at approximate reservoir pressure
red	saturation pressure at 150 Deg. F.
1	barrels of oil at indicated pressure and 150 Deg. F. per barrel of stock tank oil at standard conditions
2	volume of gas at standard conditions in solution per barrel of stock tank oil at standard conditions
3	gravity of gas released by pressure decrease from previous pressure level
4	gas gravity of all gas released by pressure decrease from saturation pressure
5	volume of gas at 150 Deg. F. and indicated pressure divided by volume of gas at standard conditions
6	volume of gas at standard conditions divided by volume of gas at indicated pressure and 150 Deg. F.

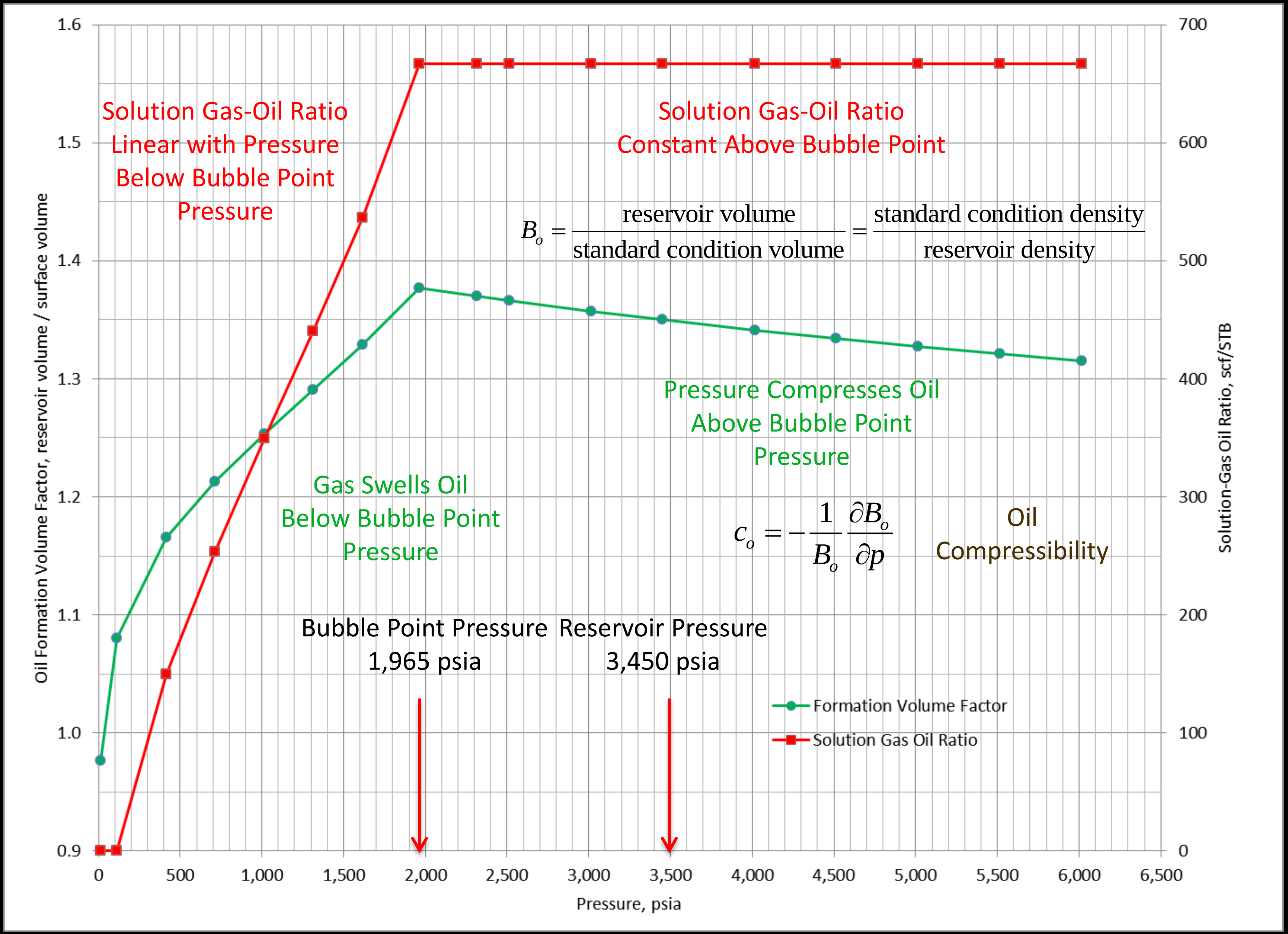
standard conditions: 60 Deg. F. and 14.7 psia

separator conditions: 97 Deg. F and 134 psia

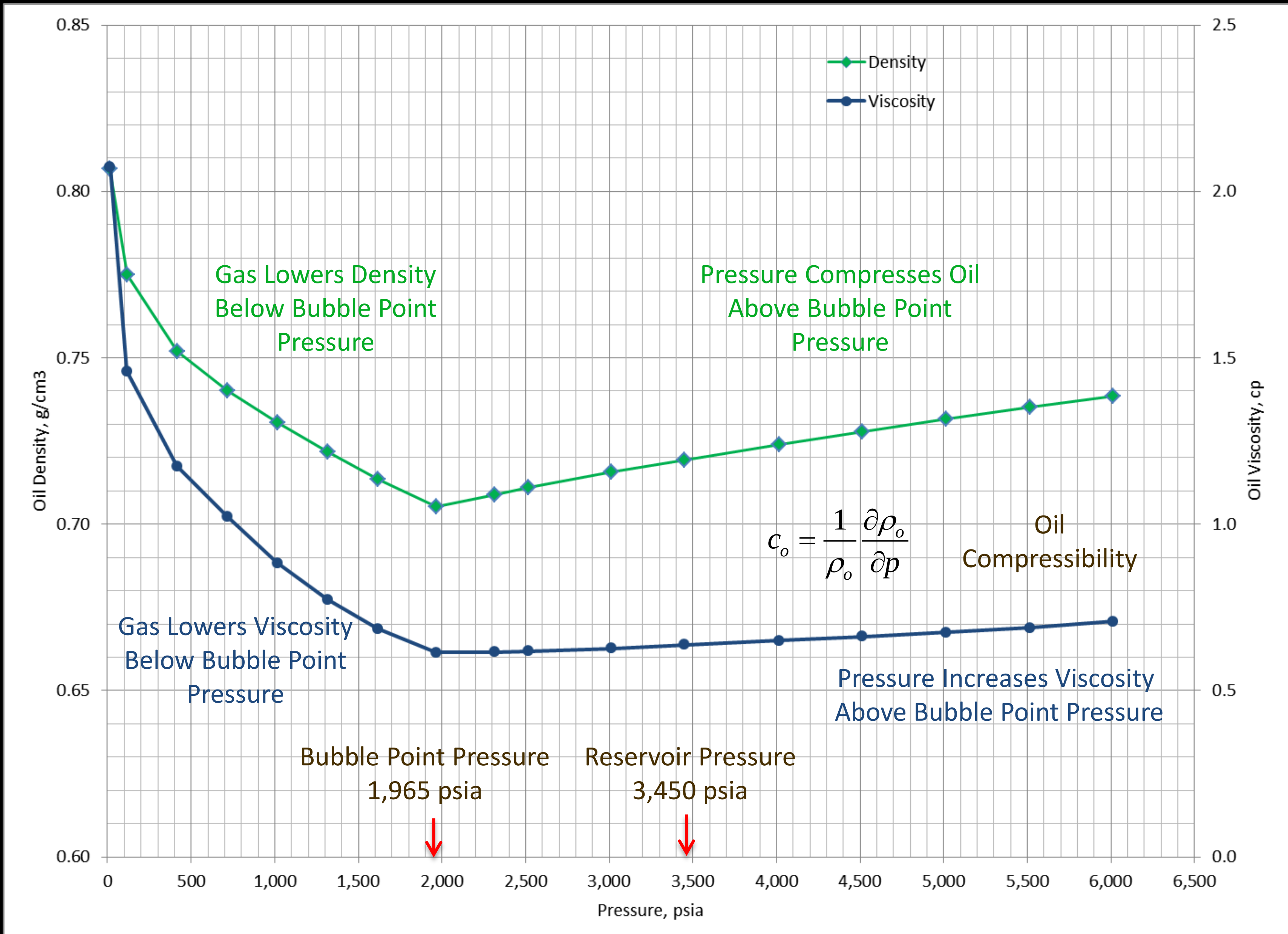
oil gravity: 38.12 Deg. API at 14.7 psia and 60 Deg. F

separator gas gravity: 0.799 relative to air

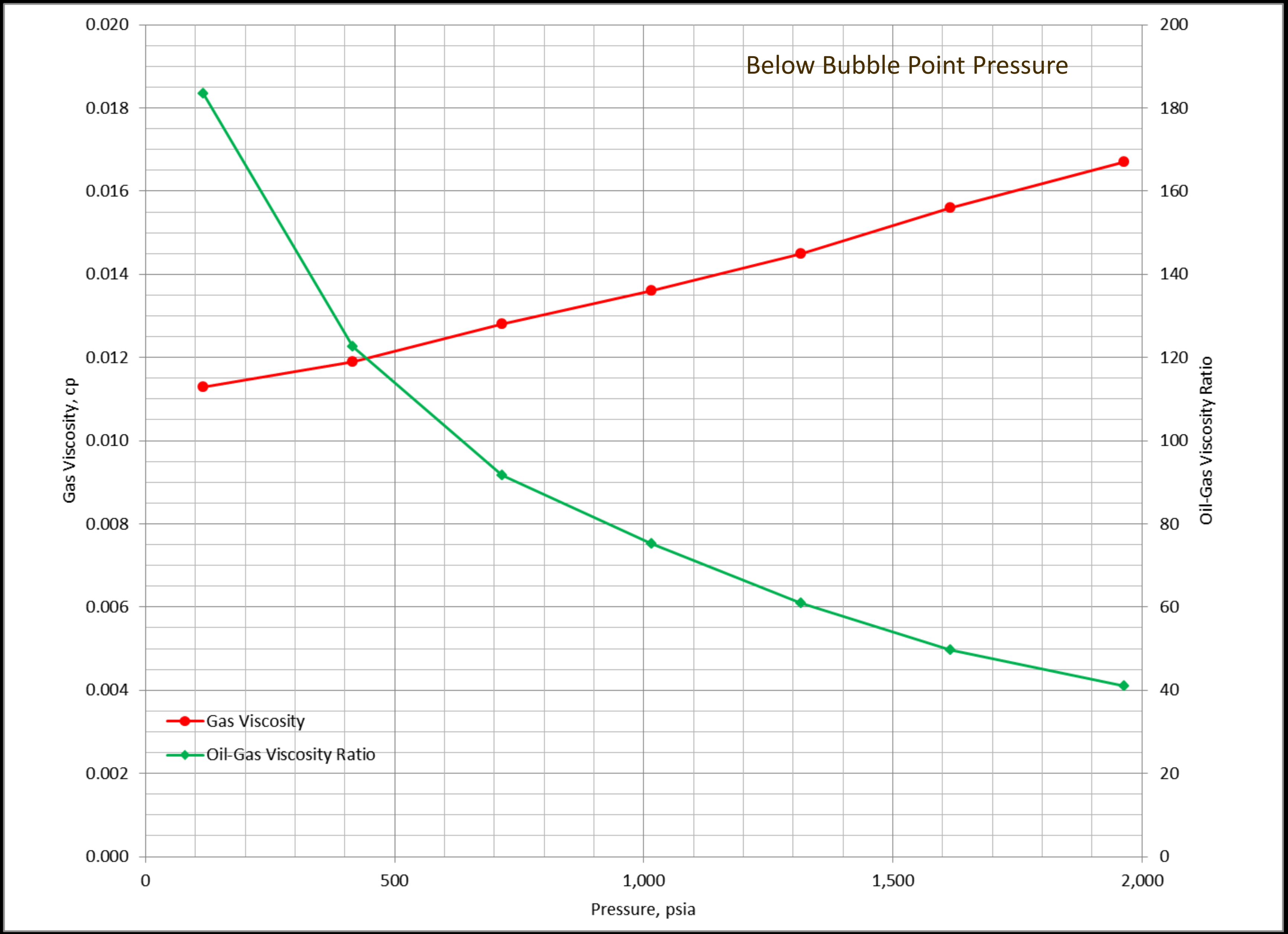
Oil Formation Vol. Factor and Solution Gas



Oil Density and Viscosity



Gas Viscosity vs. Oil Viscosity



Phase Behavior in Small Pore Spaces

- Pore sizes smaller than 100 nm can cause bubble-point pressure suppression and dew-point pressure suppression or elevation
- Deviations from measured PVT data become greater as pore size decreases
- Pore size distribution becomes important
- Mathematically accounted for by:
  - including capillary pressure in equation of state computations, i.e., vapor and liquid pressures differ by capillary pressure (function of pore radius, interfacial tension, and wetting angle)
  - shifting critical pressure and temperature conditions

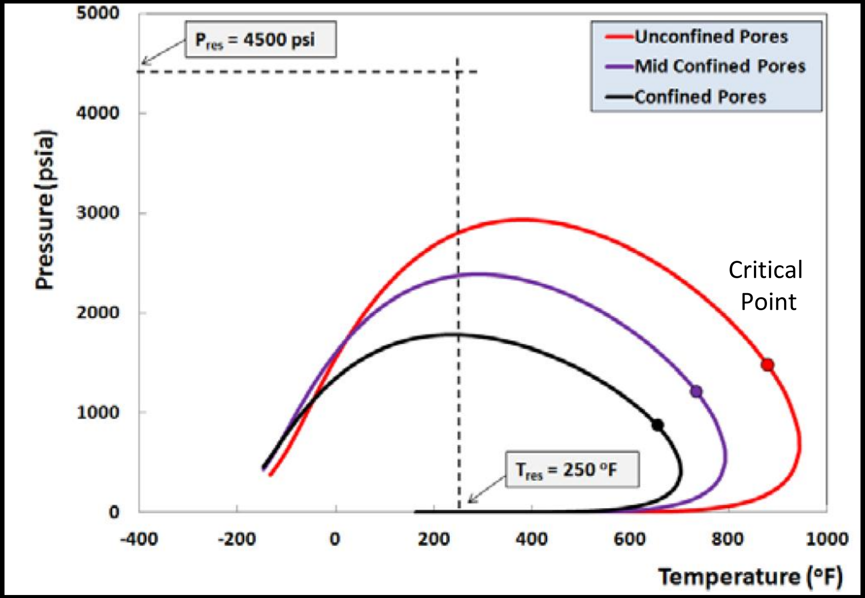
Pore Size Ranges Published in SPE 166306

- Macropores (unconfined) 80-87% of pore space
  - Average radius > 100 nm
- Mesopores (mid confined) 10-15% of pore space
  - Average radius about 25 nm
- Nanopores (confined) 3-5% of pore space
  - Average radius 2-3 nm

Black Oil System Unconfined Properties

Bubble Point Pressure:	2,260 psia
Bubble Point Gas-Oil Ratio:	500 scf/STB
Stock Tank Oil Gravity:	37.7 API

Phase Envelope for Each Pore Size Class



SPE 166306 Simulated Production