Reservoir Fluid Sampling and Analysis for Unconventional Reservoirs

Presented to the Dallas SPEE Chapter
May 9, 2013 by By Toddy Guidry,
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RESERVOIR OPTIMIZATION

Overview

- Intro to PVT: Why? When? What?
  - Reservoir Engineering 101
- Sample Sources
  - Brief overview of Surface vs Subsurface
  - pros/cons for each
  - Detailed look at FT tool sampling
- Blueprint for Fluids Program
  - Phase Behavior basics
  - Production Trends
  - PVT, Flow Assurance
  - Experimental theories, Mathematics
- Value of Fluids Testing

The Big Picture: Optimize Recovery?

- **Predict reservoir drive mechanism**
  - **Depletion, expansion, aquifer support**
- **Determine reservoir geophysical properties**
- **Determine rock properties**
  - **Porosity, perm/relative perms, wetting characteristics, capillary pressures**
- **Determine fluid properties**
  - **Viscosity, compressibility, gas solubility, density, shrinkage, flow assurance, chemistry, retrograde behavior**

Why Collect Reservoir Fluid Samples ?

Formation fluid samples are needed for a variety of reasons. Fluid samples are evaluated in the lab to establish their physical and chemical properties, such as hydrocarbon type and the pressure, volume, temperature (PVT) behavior of the reserves in place. These properties help form the foundation for planning efficient field development. The investment in facilities and processing depends on the amount, types and flow characteristics of fluids in the reservoir.
How large are the reservoirs and what will be the recovery?
What kind of crude will be produced?
Does the crude contain 'unwanted' compounds that can inhibit production?
Who gets what, i.e. allocation?

<u>Bottomline: phase behavior, crude quality/price, flow assurances</u>

When?

- Exploration and Appraisal
  - design facilities
  - tune models
  - appraisal well counts
- Development
  - confirmation studies
  - developmental well counts
  - allocation
- Production and Abandonment
  - infill programs
  - facility upgrades
  - EOR
  - allocation

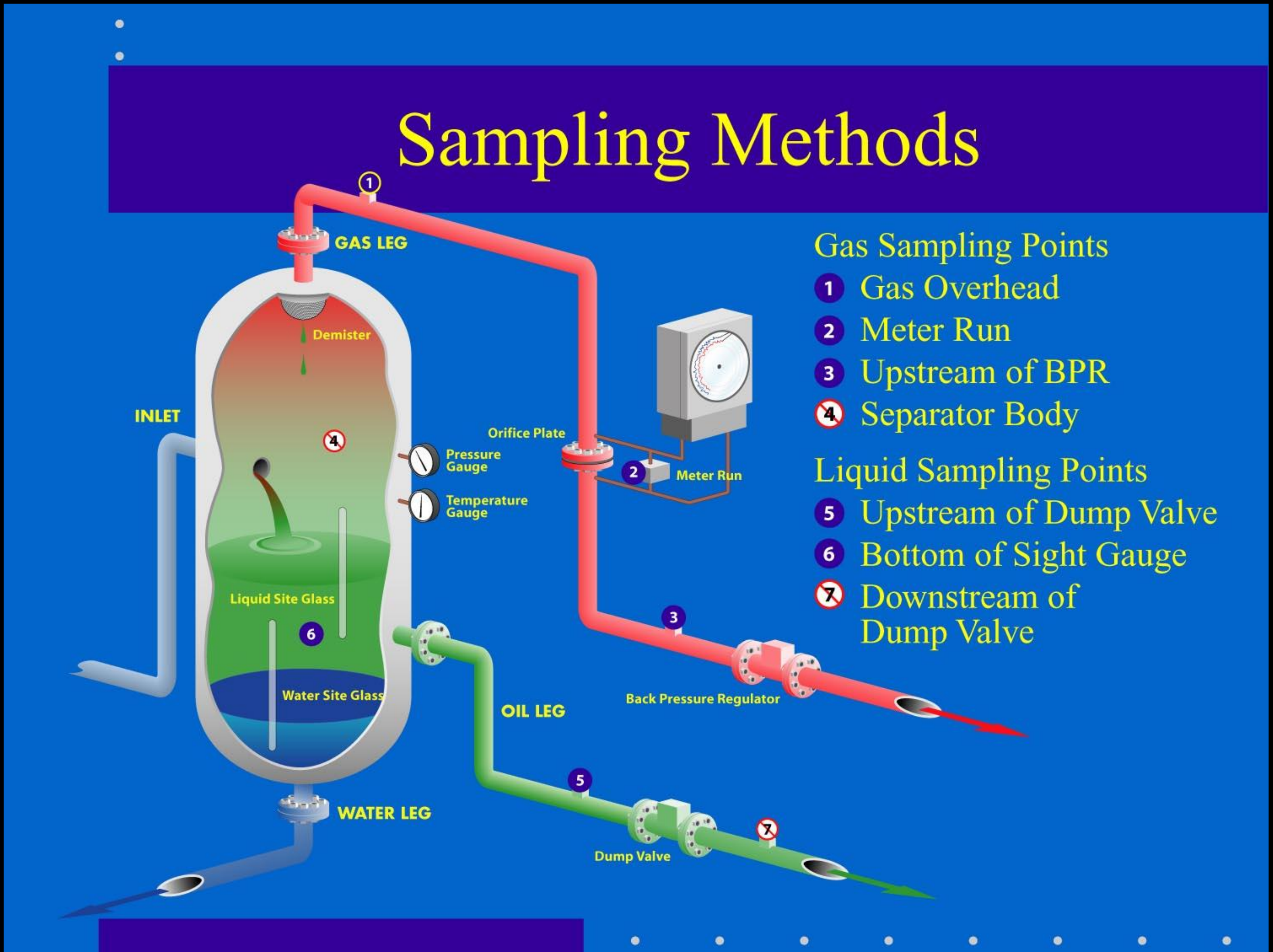
What?

- Phase behavior
- Saturation pressure
- Gas solubility
- Volume of oil at surface per equivalent barrel in reservoir
- Fluid Density
- Fluid viscosity
- Surface recoveries/ratios
- Fluid compressibility
- Compositional analyses
- Atmospheric liquid analyses
- Crude ‘quality’
- Flow Assurance properties

First Things First: Let's get some samples!

- **Surface Separator:**
  - **Large volumes of reservoir fluid are produced**
  - **Flow rate stability can be monitored, no sense of 'urgency'**
  - **Multiple sample sets can be collected**
  - **Drawdown is the enemy, GOR key**
    - **Unconventional concerns**
- **Surface Wellhead**
  - **Likely multi-phase**
- **Subsurface (Standard Downhole Samples):**
  - **Ideal when GOR not available or not accurate**
  - **Recommended for solids analyses**

Surface Separator Sampling



Separator Sampling

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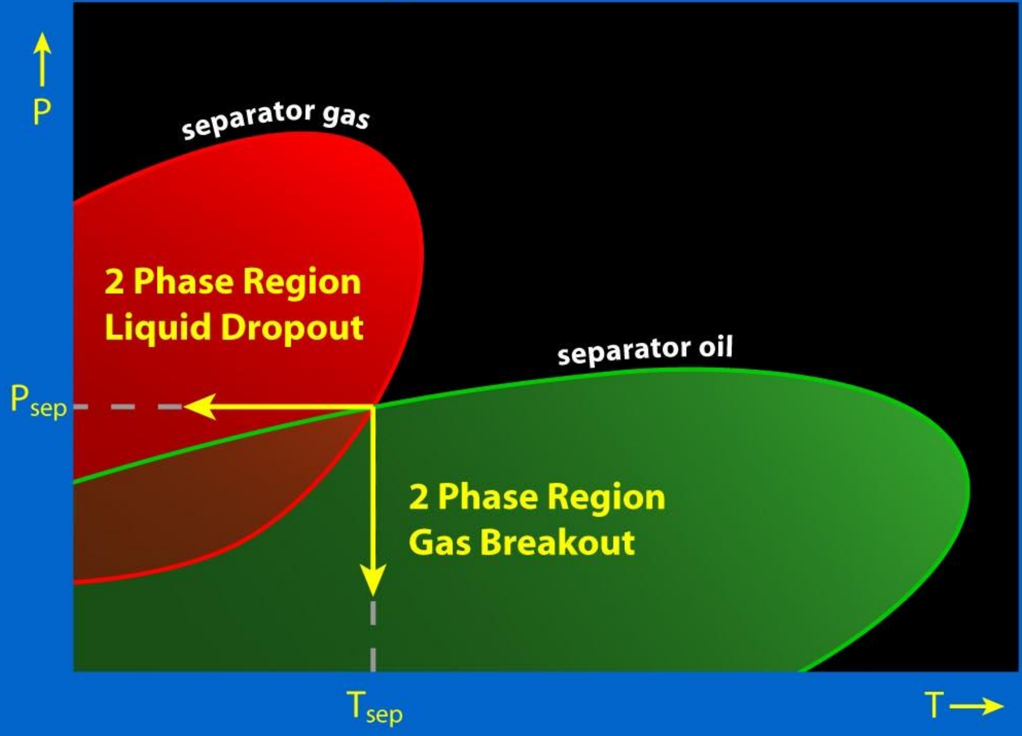
Separator = Mini Reservoir

Sampling Methods

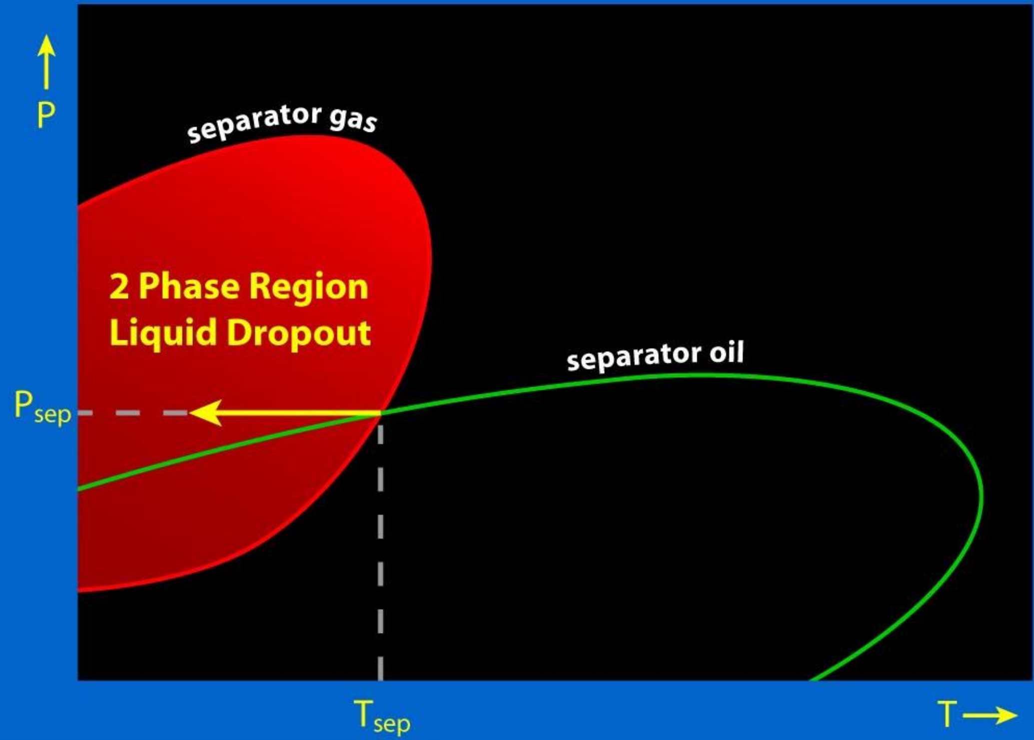
Phase Behaviour Relationship Between Sep. Gas and Oil



Sample Altering?

Sampling Methods

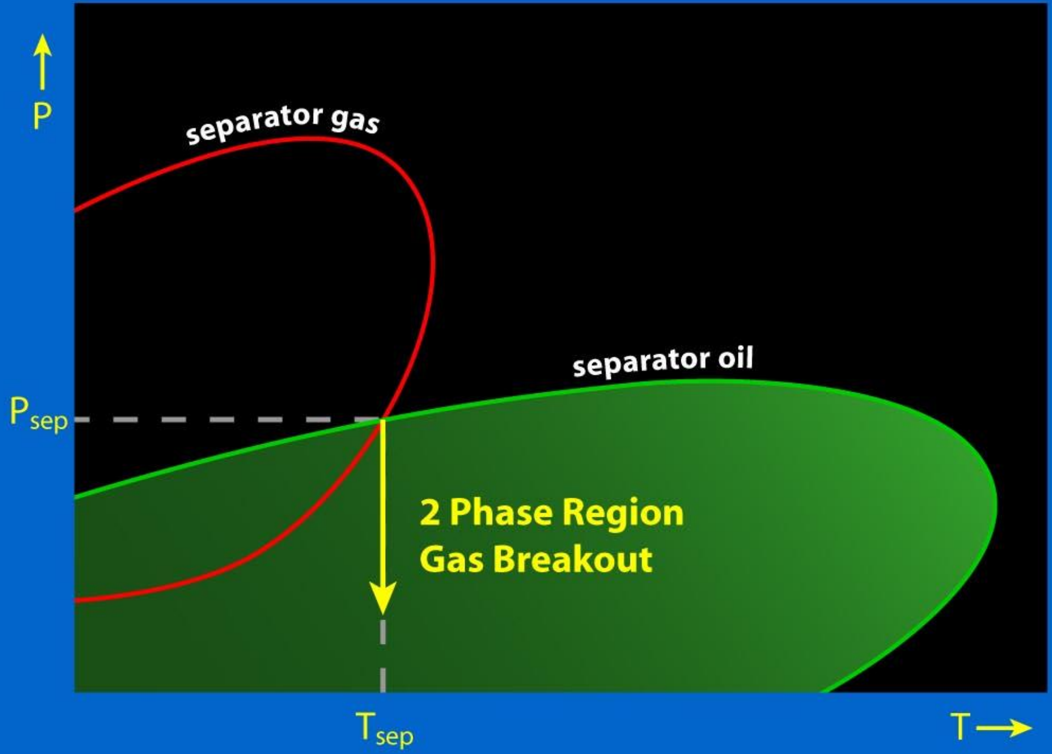
Temperature Drop – Liquid Dropout



Sample Altering

Sampling Methods

Pressure Drop – Gas Breakout



Evaluation of Samples

- **Separator Liquid**
  - **bubble point determination at separator temp**
  - **Methane content vs pressure**
  - **Flash test, ie GOR, composition**
  - **K-P “Hoffman” plot**
- **Separator Gas**
  - **Opening pressure**
  - **Oxygen/nitrogen content**
- **GOR?**
  - **Extrapolate to time=0 or initial yield?**
- **Wellhead**
  - **Single phase?**
- **Subsurface: transfer, flash test, bubble point**

Wireline Formation Test Tools
‘Big’ Chambers vs ‘Small’ Chambers

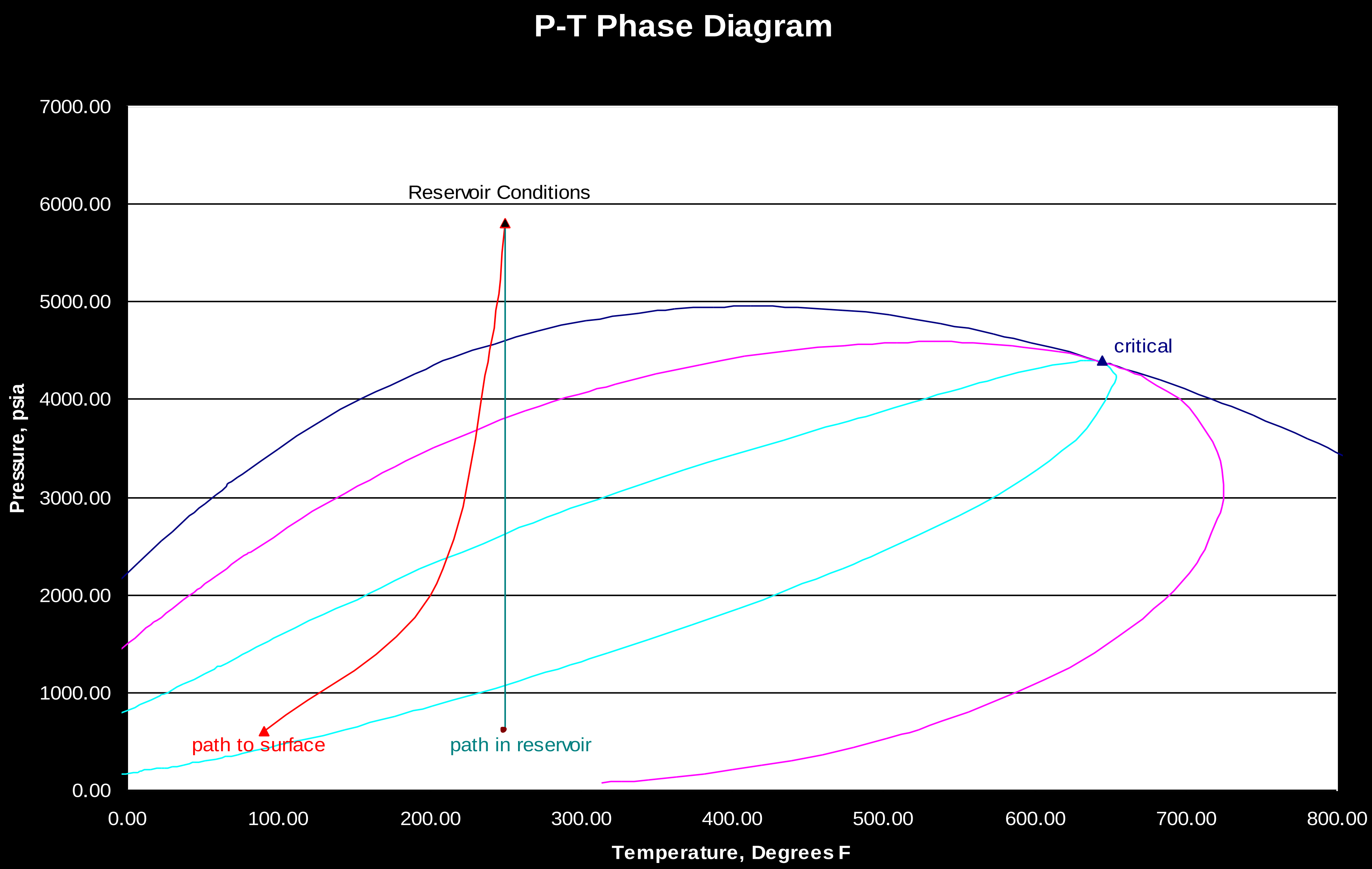
- **‘Big’ Chambers**
  - **1 gallon, 2 ¾ gallon**
  - **Non-DOT**
  - **Onsite evaluations**
  - **Onsite transfers**
  - **Minimal restoration**
  - **Time is money$$$**

- **‘Small’ Chambers**
  - **400-1000 cc**
  - **DOT approved, mobile**
  - **onsite/lab evaluations**
  - **Unlimited restoration**
  - **Analysis preference**

Answer 3 Questions:

- **What is the fluid behavior in the range of expected operating pressures and temperatures**
- **What is the market price of the discovered hydrocarbons and how can they be accommodated in export systems, ie, sample quality**
- **Does the fluid have the potential for hydrate, wax or asphaltene precipitation, ie, flow assurance**

Reservoir Fluid Behavior



Black Oil Reservoirs

- **Behavior**
  - **Heavy oil = lean gas**
  - **Viscosity discrepancy**
  - **Simple black oil models**
- **Production Trends**
  - **Consistent above bubble point**
  - **Preferential gas flow, GORs increase**
  - **Pressure trends**
- **Lab/operational issues**
  - **Emulsions, temp control, GC errors, hi viscosity errors**
  - **Well conditioning, slugging, metering**
  - **hi viscosity, hi impurities, par/asph, gas lift**
  - **Sampling inconsistent**

Gas-Condensate Behavior

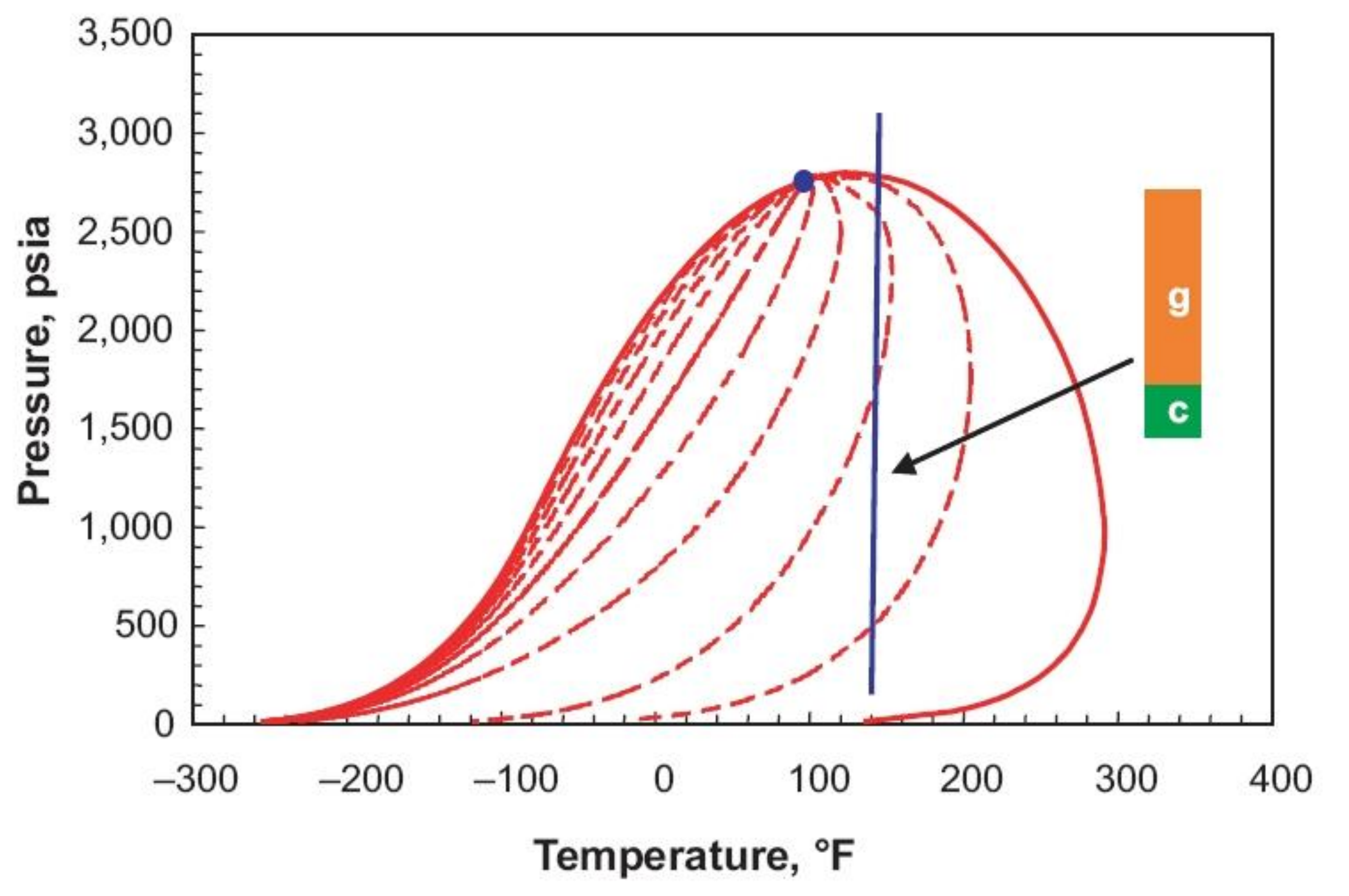
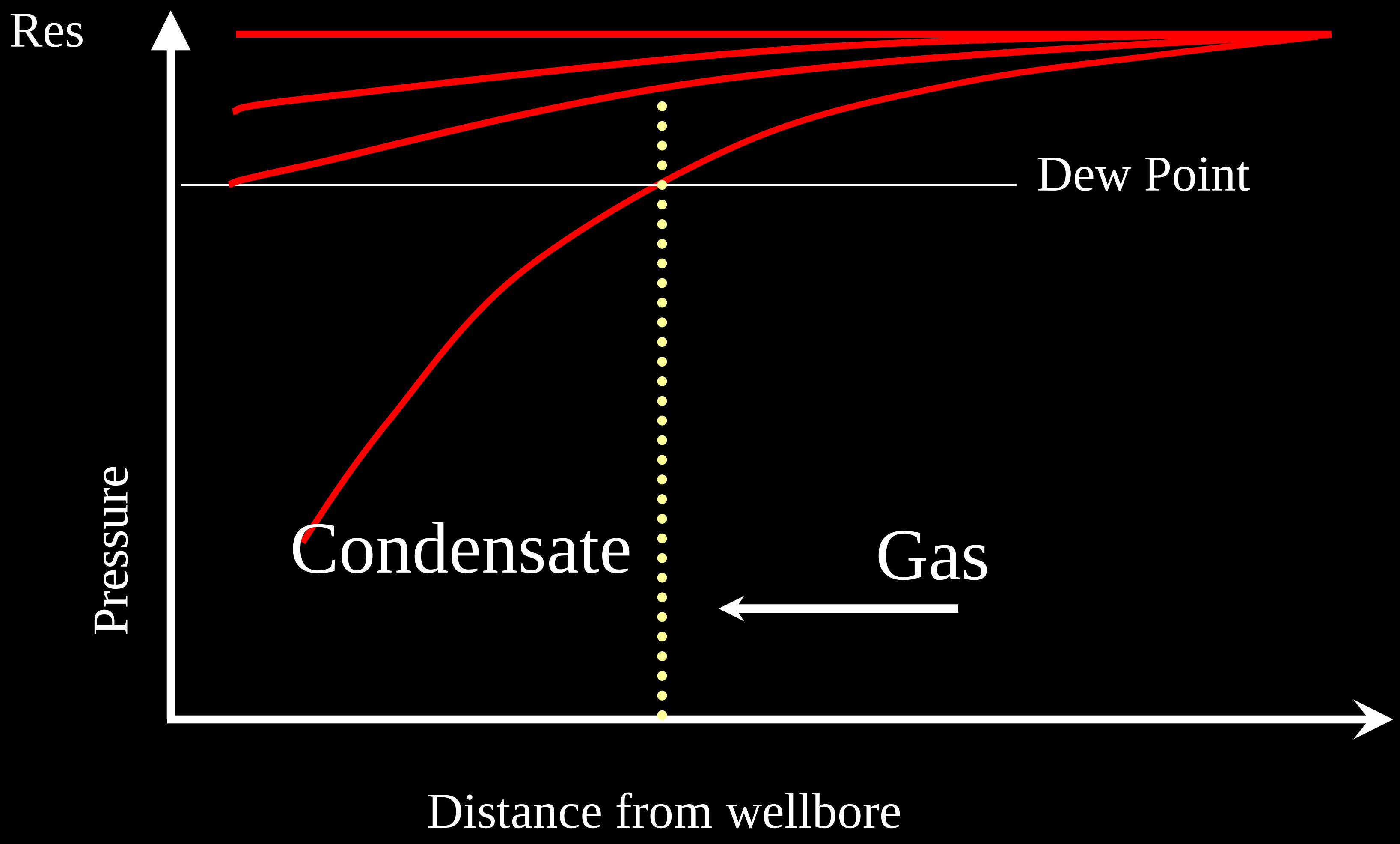


Fig. 1—Phase diagram of gas-condensate system: g=gas and c=condensate.

So…what the hell is happening?

- Flowing bottomhole pressure drops below dew point in near-wellbore area
  - Condensation begins
- Drawdown extends radially through reservoir
  - Condensate banking leaches out into reservoir
  - High condensate saturation reduces perm of gas
  - High perm vs low perm reservoirs?

Condensate ‘Banking’



But ..Eventually..

"During early production, a ring of condensate rapidly formed around the wellbore when near-wellbore pressures decreased below dew point. The saturation of this condensate ring was considerably higher than measured from PVT studies due to relative permeability effects. This high condensate saturation reduced the effective permeability to gas, thereby reducing gas productivity."

" After pressure throughout the reservoir decreased below the dew point, condensate formed throughout the reservoir, thus the gas flowing into the ring became leaner causing the condensate ring to decrease. This increased the effective permeability of the gas. This caused the gas productivity to increase as was observed in the field."

SPE 59773 'Investigation of Well Productivity in G-C Reservoirs'

Banking vs Time

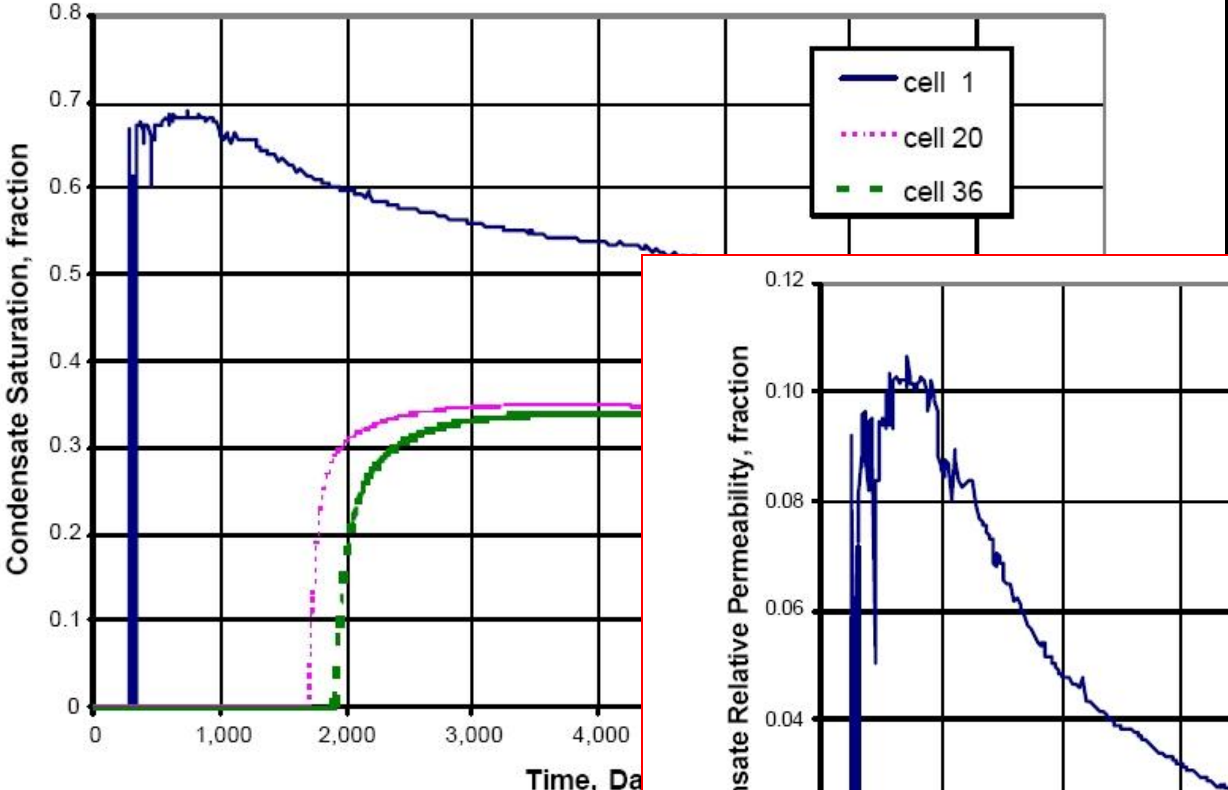


Fig. 6 - Reservoir condensate satura

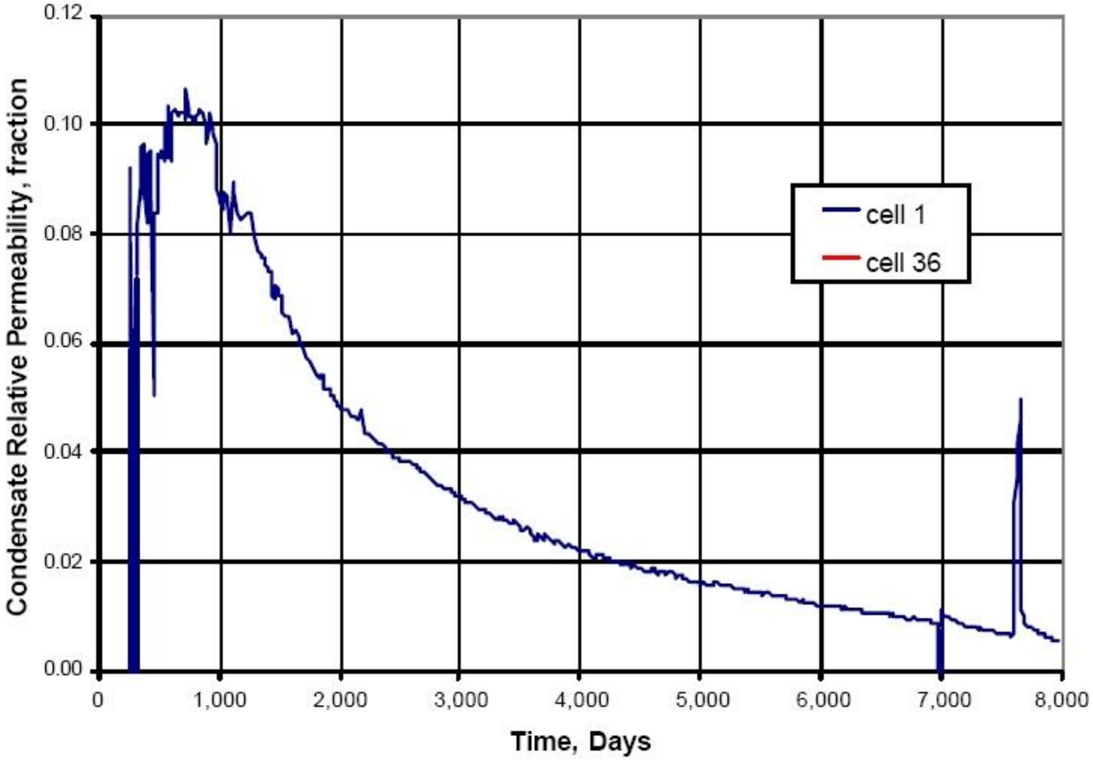


Fig. 7 - Reservoir condensate relative permeability

Gas Relative Perm Changes?

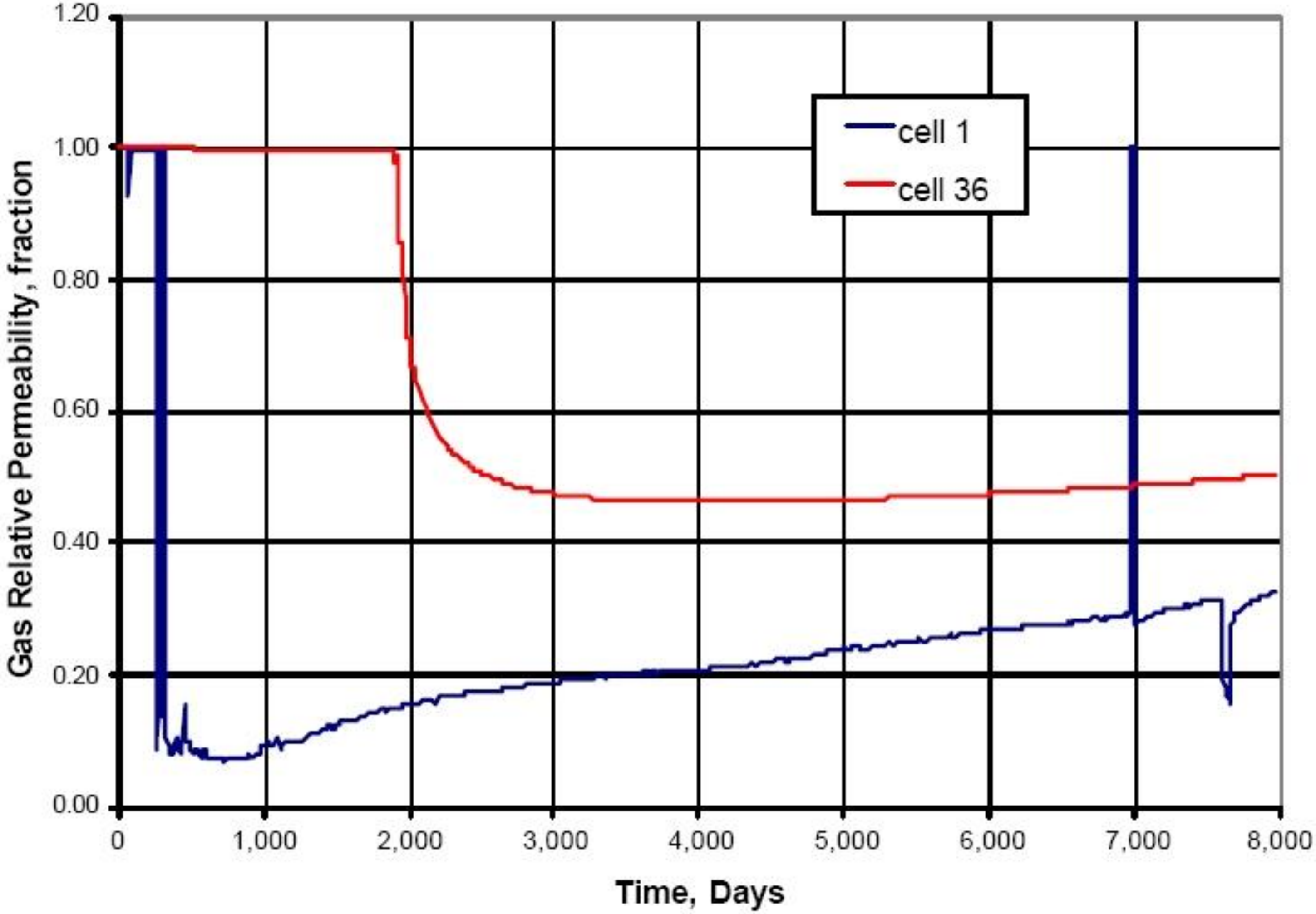


Fig. 8 - Reservoir gas relative permeability

Gas-Condensate Production Trends

- **Pressure Trends:**
  - **No discontinuity**
- **Gas Production**
  - **Pressure driven**
  - **Decrease due to condensation & condensate induced reduction in perm**
  - **Eventual increase due to increased gas perm**
- **Pressure Trends:**
  - **no discontinuity**
- **Liquid (ie condensate) Production:**
  - **> Psat = consistent**
  - **< Psat = decline**
  - **∴ Yields decline**

Summary: What can go wrong with my models?

- **Improper well conditioning**
  - **sample too late in life, significant drawdown**
  - **Productivity testing vs. PVT testing**
- **Sample quality**
  - **‘unsteady state’ sampling, gas carryover**
- **Inaccurate PVT analysis**
  - **Lean gases, small retrograde liquid volumes**
- **Gas reservoir testing procedures**
  - **Drawdown is the enemy**
  - **Tapered strings? Non-Darcy flow?**
  - **Unrepresentative gas production**

Near-Critical Fluids: Volatile Oils, 'Rich' Gases

- Light oil, heavy gas
- Full range of components
  - Solution gas and oil comps similar
- Hea
  - bution
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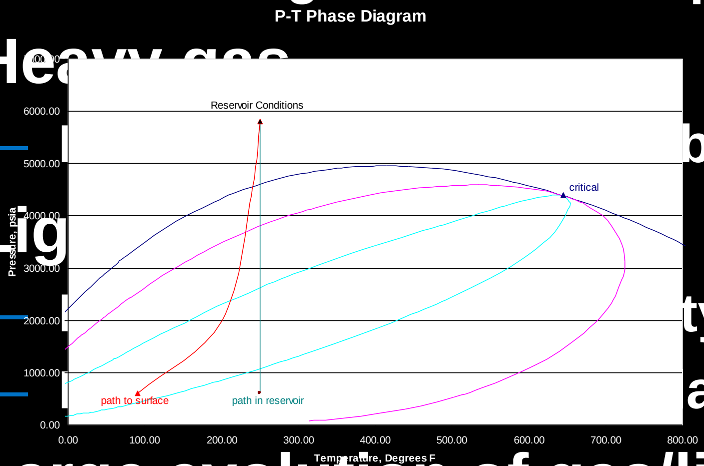

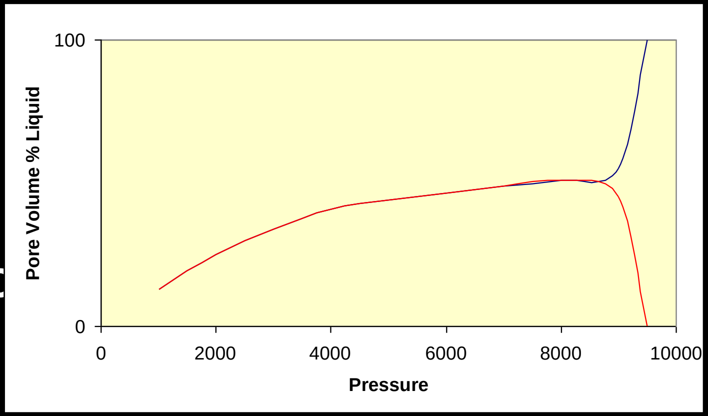

- Large evolution of gas/liquid upon pressure drop
- Handled by compositional model, accounting for both phases, compositional gradients

Near Critical Production

- **Composition: heavies, lights and mid-range**
- **Light liquid –heavy gas**
- **Large initial shrinkage and gas liberation**
- **Gas/liquid comps similar**
  - **Gas volumes increase SLIGHTLY**
  - **'oil' volumes decrease SLIGHTLY**
- **Volatile Oils:**
  - **gas/oil viscosity increases, less preferential flow**
  - **Separator liquid = 1 part oil + 3 parts condensate**

PVT Experiments:
Simulation of Reservoir Depletion

- **Black Oils:**
  - Differential liberation, viscosity, separator flash tests
  - Black oil behavior
  - models
- **Gas-Condensates:**
  - Constant volume depletion
  - Gas-condensate behavior
- **Near-Critical, Volatile Oils**
  - CVD study, viscosity
  - Oil properties, gas-phase properties
  - Volatile oil behavior, models

‘Meat and Potatoes’ of a Black Oil PVT Study

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Differential Liberation at 158 °F

Oil Properties

Pressure (psia)		Oil Density (g/cm^3)	Oil Compress. (V/V/psi) x 10^6	Oil Viscosity (cP)	Liberated GOR, R_l (scf/bbl)	Solution GOR, R_{sd} (scf/bbl)	Oil FVF, B_{od} (vol/resid. vol)	Solution GOR, R_s (scf/bbl)	Sep. Adj. FVF, B_o (vol/ST vol)
10,000		0.790	5.63	2.289	0	723	1.306	679	1.282
9338	**Reservoir**	**0.787**	**5.88**	**2.158**	**0**	**723**	**1.311**	**679**	**1.287**
9000		0.786	6.02	2.106	0	723	1.314	679	1.290
8000		0.781	6.46	1.944	0	723	1.322	679	1.298
7000		0.775	6.97	1.800	0	723	1.332	679	1.307
6000		0.769	7.56	1.694	0	723	1.342	679	1.317
5000		0.763	8.26	1.579	0	723	1.353	679	1.328
4120	**Saturation**	**0.757**	**9.28**	**1.498**	**0**	**723**	**1.364**	**679**	**1.339**
3250		0.774	5.84	1.797	140	583	1.303	548	1.283
2400		0.791	5.50	2.227	277	446	1.249	419	1.233
1500		0.812	5.25	2.936	422	301	1.191	283	1.180
750		0.831	5.04	3.904	545	178	1.141	168	1.134
150		0.850	4.84	5.562	659	64	1.088	60	1.085
15		0.866		6.322	723	0	1.044	0	1.044
15	at 60 °F	0.899	**API = 25.7**				1.000		

Vapor Properties

Pressure (psia)	Gas Density (g/cm^3)	Gas Z Factor (vol/vol at std)	Incr. Gas Gravity (Air = 1.00)	Cum. Gas Gravity (Air = 1.00)	Gas FVF, B_g (res bbl /mmscf)	Gas FVF, B_g (res cu ft / scf)	Total FVF, B_t (vol/resid. vol)	Calc. Gas Viscosity (cP)
3250	0.179	0.901	0.708	0.708	882	0.0050	1.426	0.022
2400	0.129	0.890	0.681	0.695	1179	0.0066	1.575	0.018
1500	0.077	0.906	0.664	0.684	1921	0.0108	2.001	0.015
750	0.038	0.933	0.681	0.684	3956	0.0222	3.294	0.013
150	0.009	0.985	0.876	0.717	20882	0.1172	14.851	0.012
15.025	0.002	1.000	1.607	0.795	212088	1.1908	154.308	0.009

Notes:

- Compressibility is calculated using the indicated and previous pressur
- The Separator Adjusted GOR and FVF represent the differentially liberated oil produced through the surface separators (see MSF)
- Sep. Adjusted Data using Muhammad A. Al-Marhoun method
- Gas MW = Vapor Gravity x Molecular Weight Air
- Standard Condition: 15.025 psia at 60 °F
- Atmospheric Step completed at Reservoir Temperature
- B_o = Oil Volume at P,T / Stock Tank Volume at 60 °F
- B_{od} = Oil Volume at P,T / Residual Oil Volume at 60 °F
- R_s = Gas Volume at Standard Conditions / Stock Tank Volume
- $B_t = B_o + [(\text{Total Liberated Vapor}, R_l) \times B_g] \times 10^{-6}$
- R_l is cumulative liberated gas / Residual Oil Volume
- Vapor Viscosity calculated with Lee-Gonzales Correlation
- Oil Viscosity measured using electro magnetic viscometer

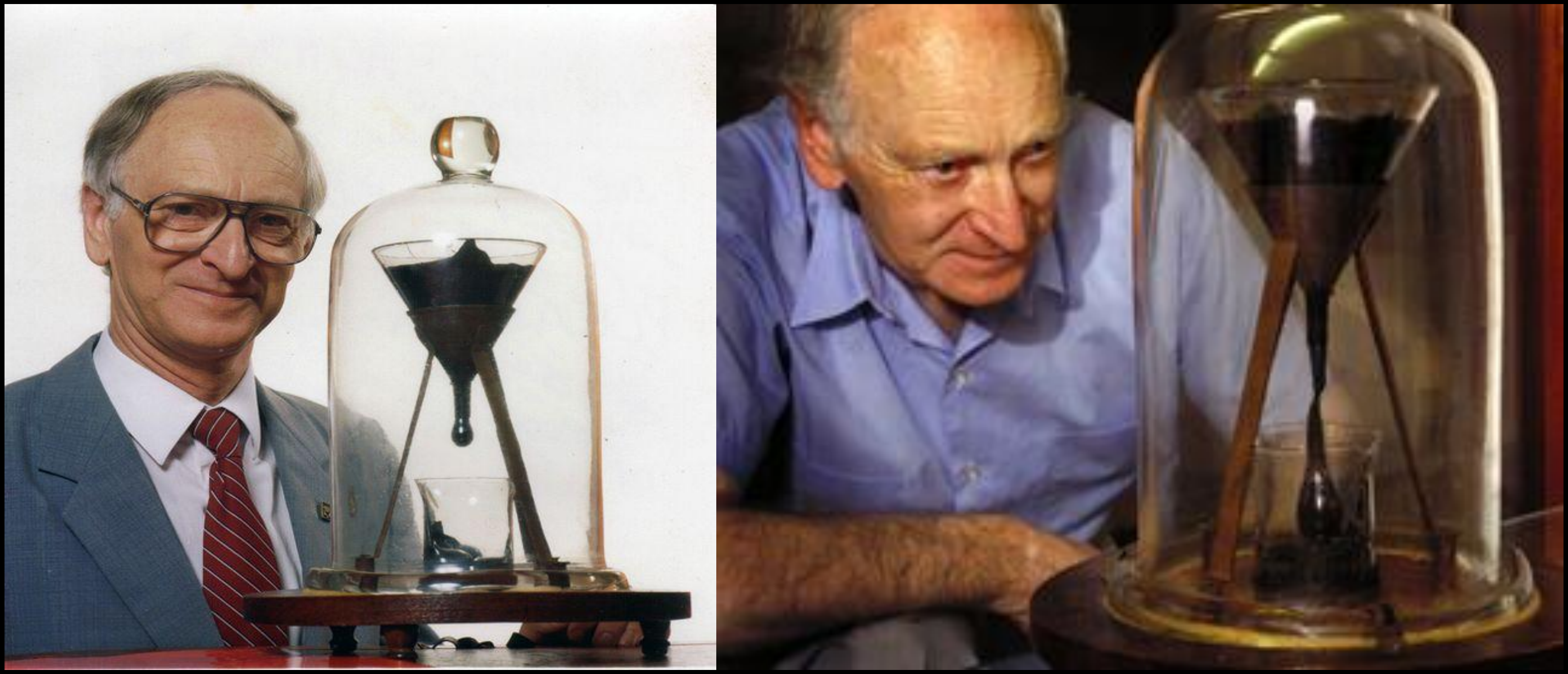
So..how good is that oil study?

Flash Comparison

Experimental Procedure	GOR (SCF/STB)	FVF (P_{sat} bbl/STB)	Gas Gravity	API at 60 °F
Reservoir Oil Single-Stage Flash	816	1.339	0.672	21.9
Differential Liberation @ Res. Temperature	795	1.329	0.652	22.1
Multi-Stage Separator Test	771	1.311	0.623	23.1

What is the longest continuously running science experiment in the world?

Pitch Drop Experiment, started 1927 by Dr Thomas Parnell



Viscosity = 100-300 billion centipoise

Simulation of Reservoir Depletion

- **Black Oils:**
  - **Differential liberation, viscosity**
  - **Black oil behavior**
  - **models**
- **Gas-Condensates:**
  - **Constant volume depletion**
  - **Gas-condensate behavior**
- **Near-Critical, Volatile Oils**
  - **CVD study, viscosity**
  - **Oil properties, gas-phase properties**
  - **Volatile oil behavior, models**

How Good is that Gas study?

Constant Volume Depletion Fluid Compositions

Component	Saturation Pressure *(mole %)*	6000 psia *(mole %)*	5000 psia *(mole %)*	4000 psia *(mole %)*	3000 psia *(mole %)*	2000 psia *(mole %)*	Liquid at 2000 psia *(mole %)*
Nitrogen	0.197	0.236	0.228	0.209	0.184	0.166	0.350
Carbon Dioxide	0.211	0.225	0.233	0.229	0.220	0.215	0.138
Hydrogen Sulfide	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Methane	90.098	91.929	92.532	93.057	93.382	93.624	39.429
Ethane	2.596	2.662	2.676	2.630	2.615	2.543	2.943
Propane	1.566	1.580	1.588	1.528	1.529	1.459	3.241
Iso-Butane	0.391	0.377	0.366	0.353	0.345	0.356	1.177
N-Butane	0.567	0.540	0.505	0.485	0.475	0.476	2.086
Iso-Pentane	0.257	0.242	0.215	0.194	0.175	0.178	1.407
N-Pentane	0.254	0.222	0.196	0.170	0.155	0.158	1.661
Hexanes	0.423	0.330	0.282	0.241	0.207	0.184	3.936
Heptanes	0.523	0.381	0.335	0.292	0.255	0.235	4.806
Octanes	0.583	0.368	0.312	0.268	0.236	0.216	6.070
Nonanes	0.467	0.268	0.213	0.174	0.142	0.120	5.686
Decanes +	1.867	0.640	0.320	0.170	0.080	0.070	27.068
Totals	100.00	100.00	100.00	100.00	100.00	100.00	100.00
C10+ MW	194.4	178.2	169.0	161.0	155.6	150.9	197.0
Mole Weight	22.69	19.79	19.02	18.57	18.28	18.17	87.73
Gravity (Air = 1.0)	0.783	0.683	0.657	0.641	0.631	0.627	-
Z Factor (@ P & T)	1.211	1.061	0.983	0.936	0.926	0.936	-

Gas Depletion Study

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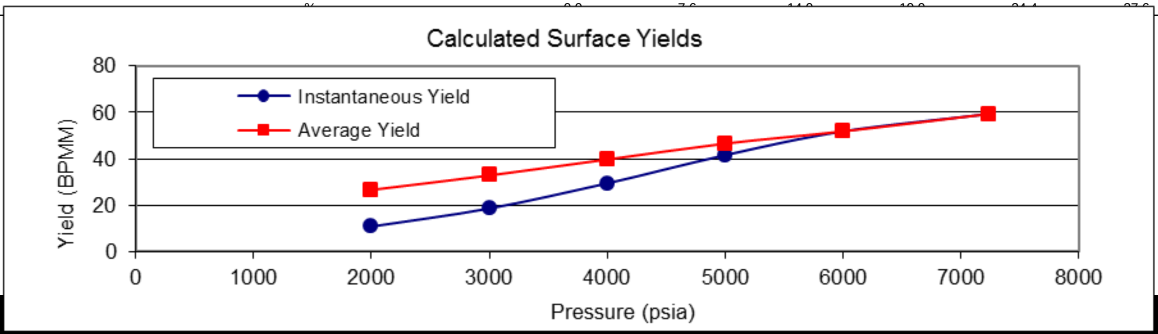
Calculated Surface Gas and Liquid Recovery

Experimental and Equation of State Predictions

		Initial	Pressure (psia) 7232	6000	5000	4000	3000	2000
Moles in PVT Cell			0.769	0.703	0.633	0.544	0.436	0.307
Fraction Vapor Liberated / Step			0	0.066	0.070	0.090	0.107	0.130
EOS Predicted Liquid Fractions								
1st Stage: 1015 psia, 96°F	(mole fraction)		0.061	0.056	0.048	0.036	0.024	0.015
2nd Stage: 515 psia, 72°F	(mole fraction)		0.861	0.858	0.856	0.854	0.852	0.851
3rd Stage: 105 psia, 104°F	(mole fraction)		0.829	0.826	0.825	0.823	0.823	0.822
Stock Tank, 15 psia, 60°F	(mole fraction)		0.950	0.949	0.948	0.948	0.947	0.946
Predicted Liquid Molar Volume	(cc/mole)		184.0	175.9	167.2	158.4	150.9	145.3

Calculated Surface Recovery

Initial Reservoir Fluid in Place	mscf	1000	1000					
Vapor Produced / Step	mscf		0.0	86.1	90.4	116.6	139.4	168.8
Cumulative Vapor Produced	mscf		0.0	86.1	176.5	293.1	432.5	601.3
Predicted Surface Liquids	stb		0.0	4.3	3.6	3.4	2.6	1.8
Cumulative Surface Liquids	stb		0.0	4.3	7.9	11.3	13.9	15.7
Predicted Surface Vapor	mscf		0.0	82.8	87.5	113.8	137.2	167.2
Cumulative Surface Gas	mscf		0.0	82.8	170.4	284.1	421.3	588.5
Instantaneous Yield	stb/mmscf		59.3	51.9	41.6	29.5	18.6	10.9
Average Yield	stb/mmscf		59.3	51.9	46.6	39.7	32.9	26.6
Instantaneous GCR	scf/stb		16859	19282	24033	33906	53634	91744
Average GCR	scf/stb		16859	19282	21462	25159	30417	37546
Gas Recovery Factor	%		0.0	8.3	17.0	28.4	42.1	58.8
Liquid Recovery Factor	%		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]



Notes:

Simulation of Reservoir Depletion

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Enhanced Oil Recovery

- Miscible Displacement Studies
- Multi-Contact Studies
- Solubility / Swelling Studies
- Gas Injection Revaporization

Enhanced oil recovery studies are used to define volumetric and compositional changes in a reservoir fluid during secondary and tertiary recovery processes. The data is most often used to define the operating parameters and track fluid changes during an enhanced oil recovery project.

Mathematics and Evolution…

- **Models, EOS, Simulators**
  - **reservoir dynamics, phase behavior**
- **Measured data used as input to ‘tune’ models**
  - **chemical properties altered to ‘force’ predictions to match behavior**
- **Multiple scenario, feasibility studies**
  - **tuned models used to explore other possible environments**

PVT lab

Answer 3 Questions:

- **What is the fluid behavior in the range of expected operating pressures and temperatures**
- **What is the market price of the discovered hydrocarbons and how can they be accommodated in export systems, ie, sample quality**
- **Does the fluid have the potential for hydrate, wax or asphaltene precipitation**

Reservoir Fluid Composition

- Flash of reservoir fluid to 0 psig
- GC analysis of flash/separator products
  - C10+, C20+, C30+, C50+ analyses
  - Internal standard method, distillation method
- Mathematical recombination of flash/separator products to measured GOR from flash (or meter)

Dead Oil (Stock Tank) Analyses
‘Pipeline Package’

- Paraffin, Asphaltene, Sulfur Weight %
- Pour Point, Cloud Point
- SARA analysis
- Viscosity (multi-temp)
- Acid Number, Vapor Pressure, BSW
- Fingerprint Analysis, Geochemical Analysis
- Solids Screening

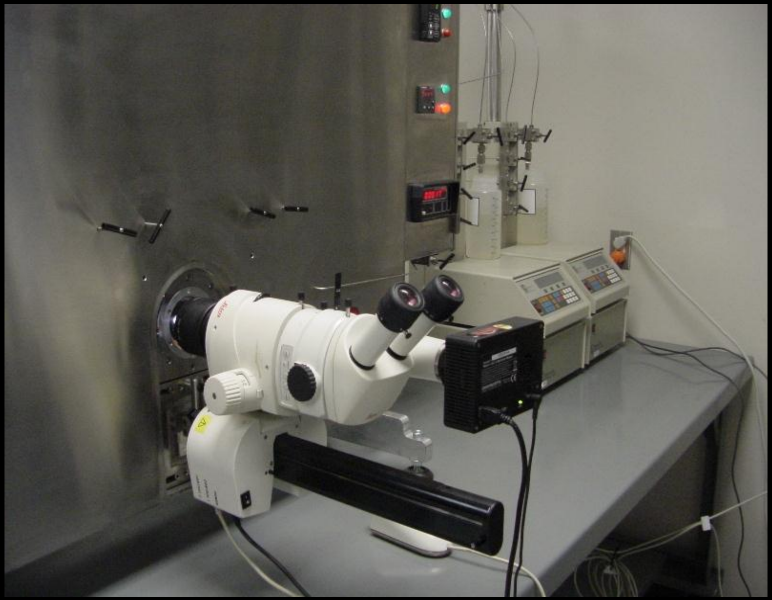
Paraffins/Waxes

- **Long straight hydrocarbon chain molecule (Normal Paraffin)**
- **With decrease in temperature Wax molecules begin to crystallize (Freeze)**
- **The onset of Wax Crystals is referred to as Cloud Point**
- **Reversible behavior**
- ***<u>Problem Avoidance:</u> Sample handling at temperatures > 130°F, production heaters***

Asphaltenes

- **Defined as pentane or heptane insoluble**
- **Heaviest and largest molecules in the hydrocarbon mixture (ex: $C_{79}H_{92}N_2S_2O$, MWT > 750)**
- **Characteristic black color**
- **Become unstable with significant changes in density, usually due to changes in pressure,temperature**
- **Can be stabilized by similar typed 'resins'**
- **Problems can also occur due to commingling**
- ***<u>Problem Avoidance:</u>* *Pressure maintenance in reservoir, chemical treatments. Pressure/density maintenance during sample handling. Avoid volume changes.***

Pressurized Fluid Imaging (PFI) System



Blueprint for Fluids Program

- **Proper sampling**
- **Chemistry**
- **Physical properties**
  - **fluid flow assurance, viscosity etc, dead oil analyses**
- **Reservoir depletion simulation**
  - **CME, Diff Lib, CVD**
- **Surface recovery simulation**
  - **separator tests**
- **Mathematics**

Thanks for not falling asleep!
Questions?

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