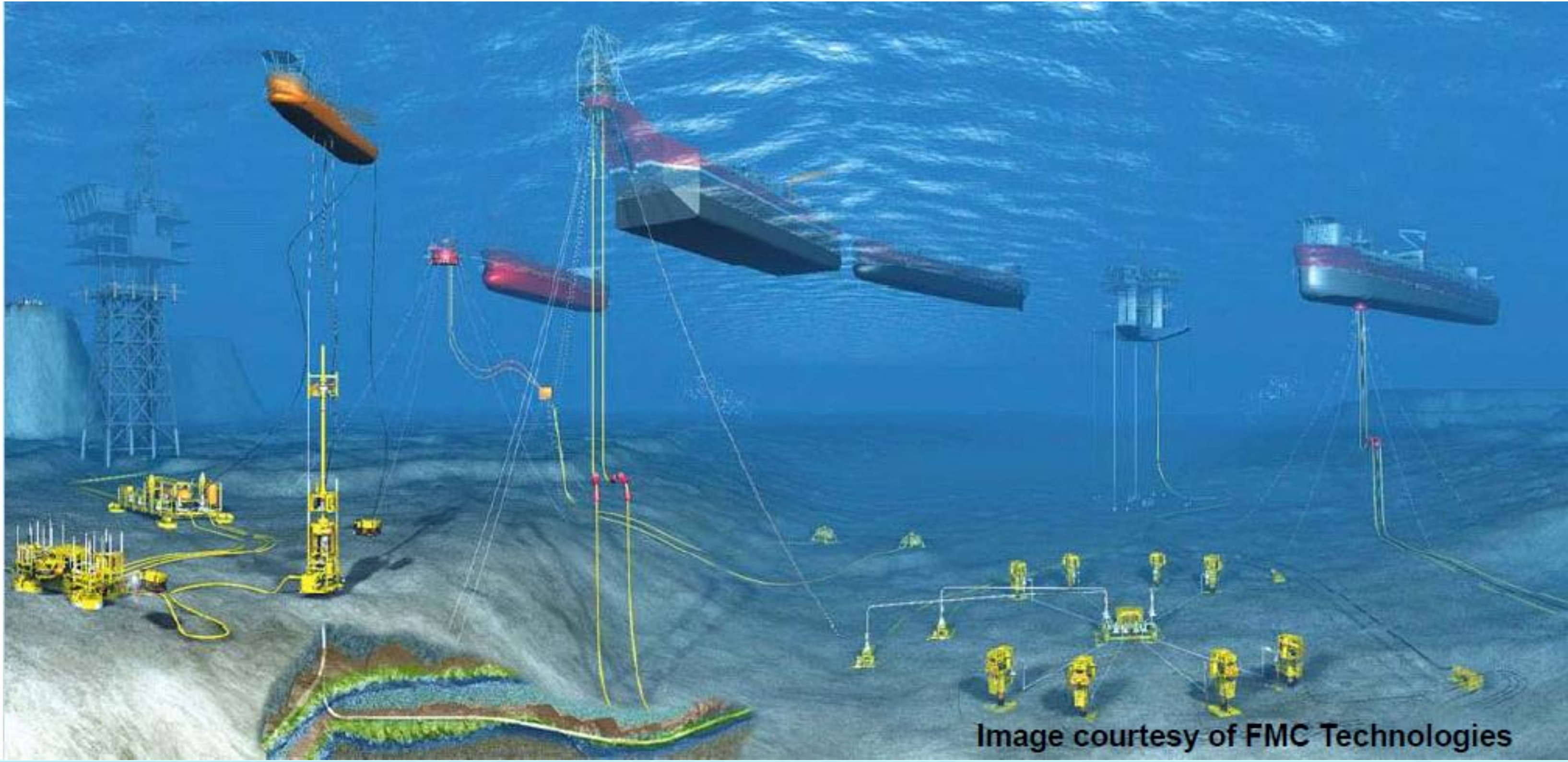


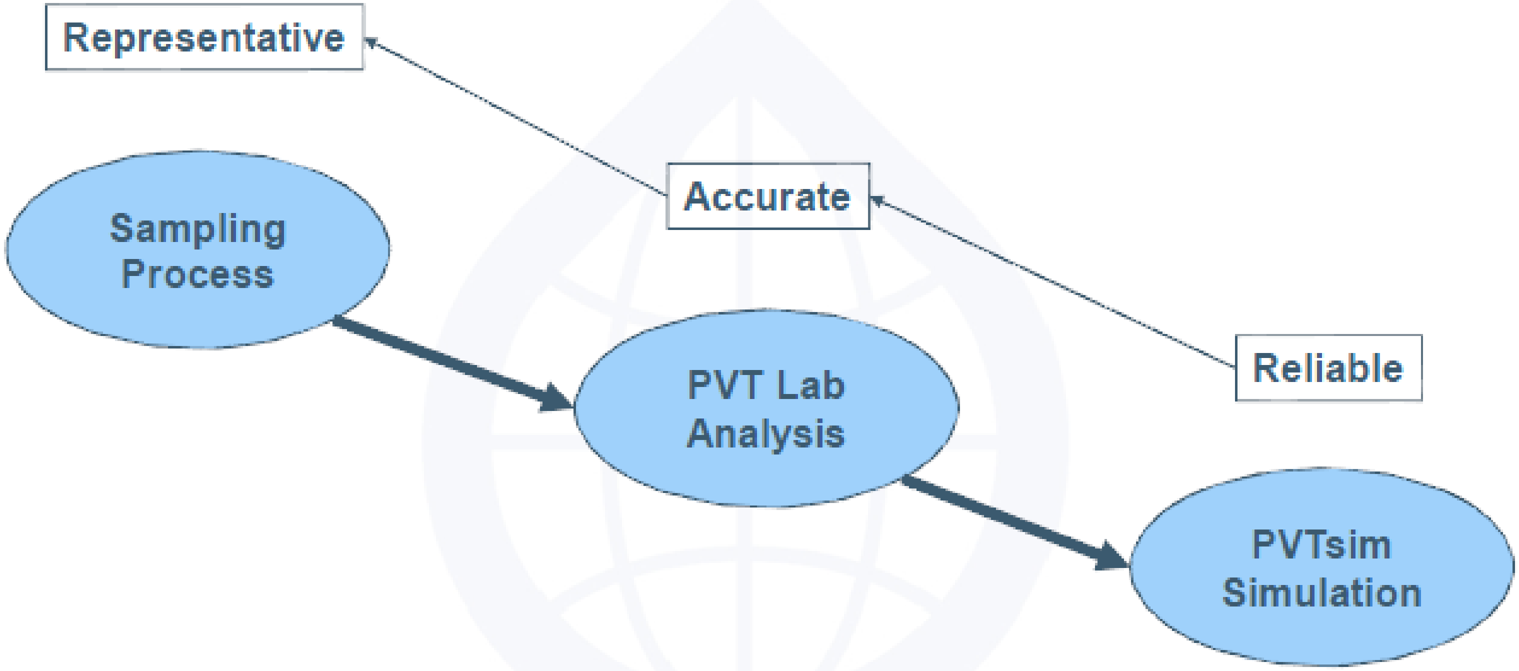
Image courtesy of FMC Technologies

해저 공학

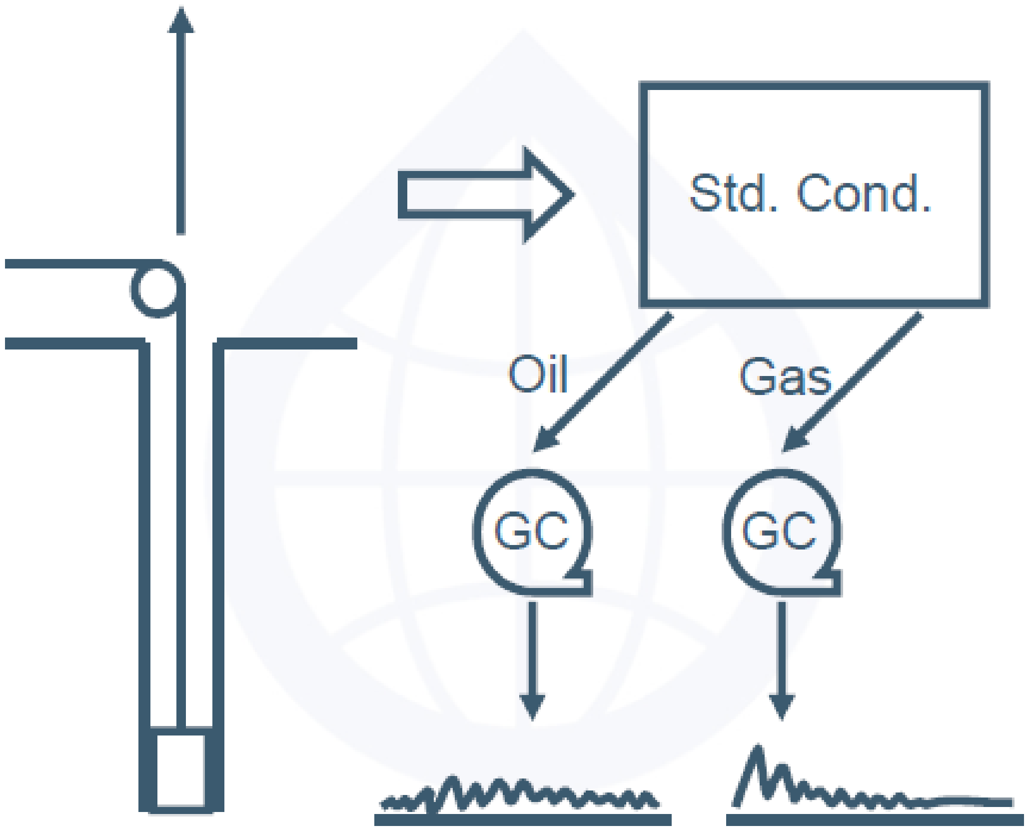
서유택

Fluid characterization

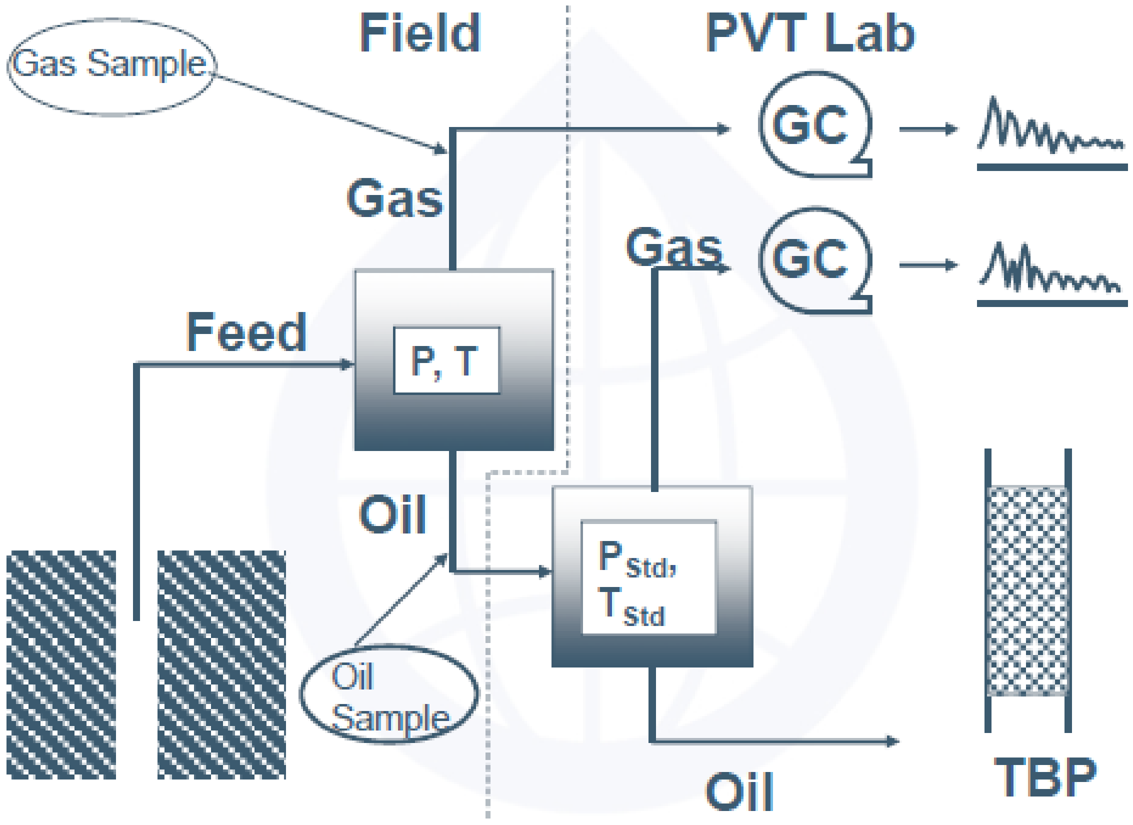
Fluid characterization



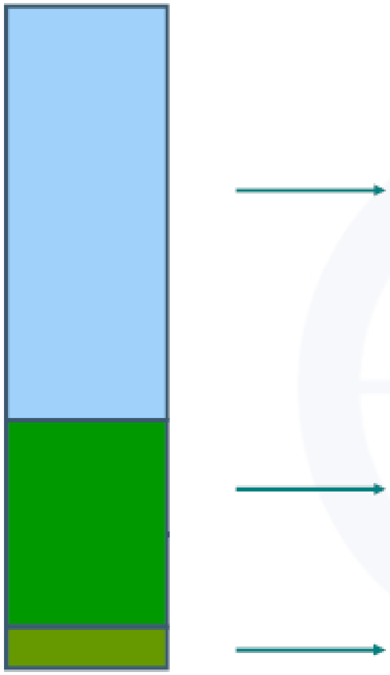
Bottom hole sampling



DST Separator analysis



Constituents of reservoir fluids

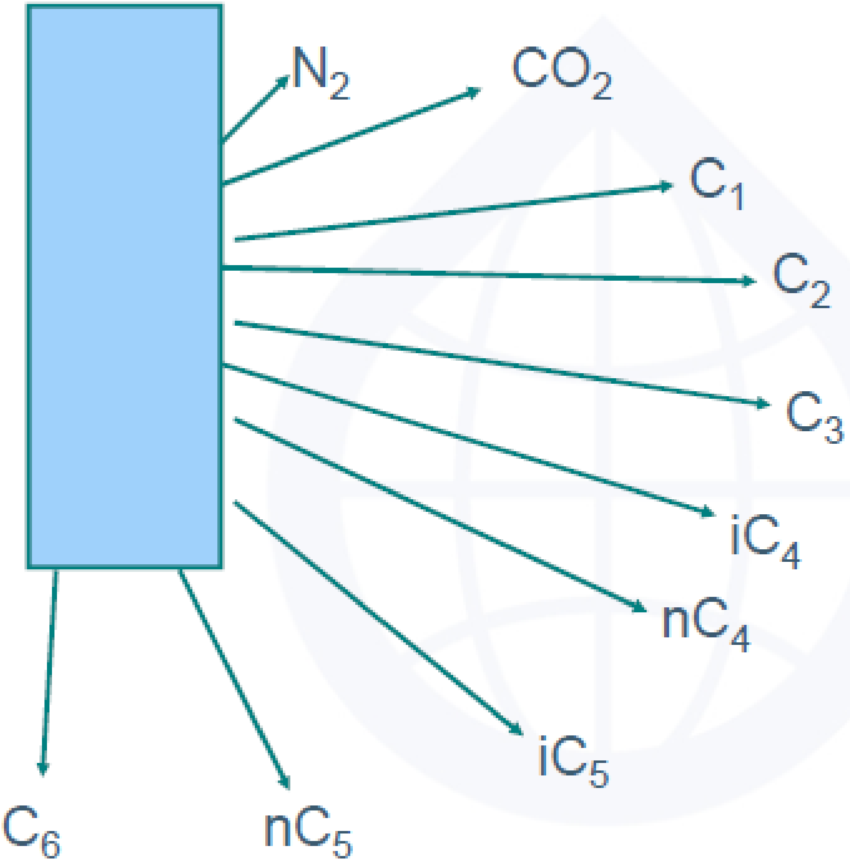


Defined components

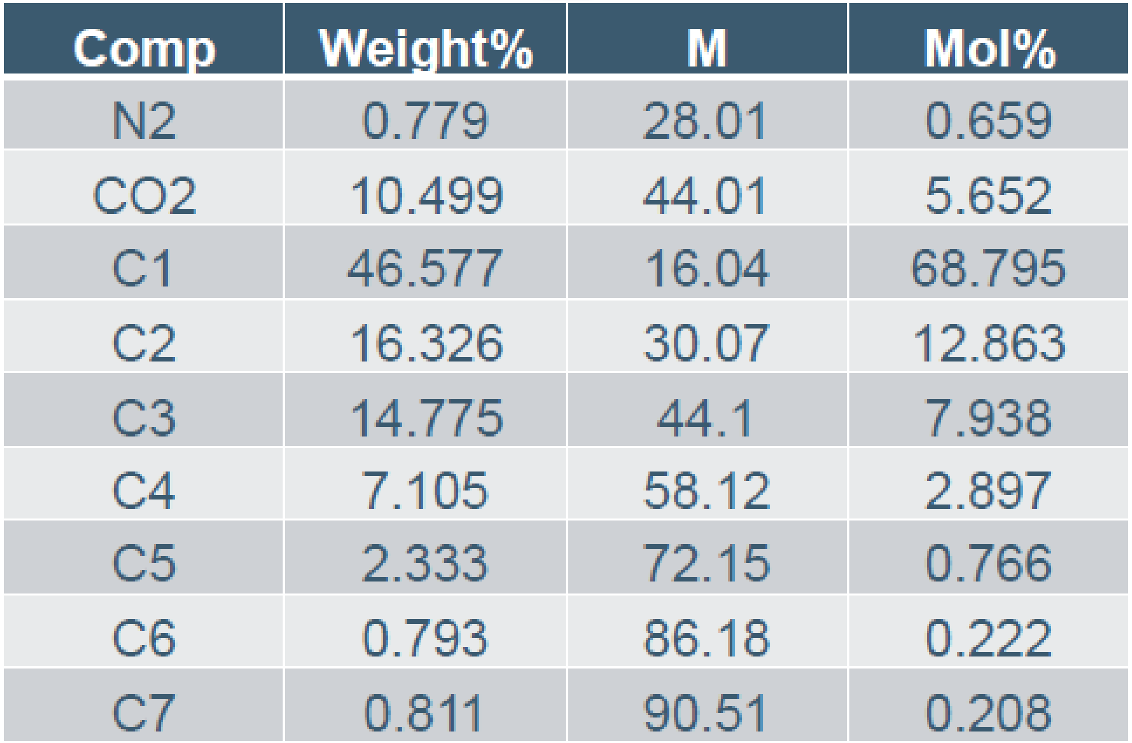
TBP fractions

TBP residue

Defined components

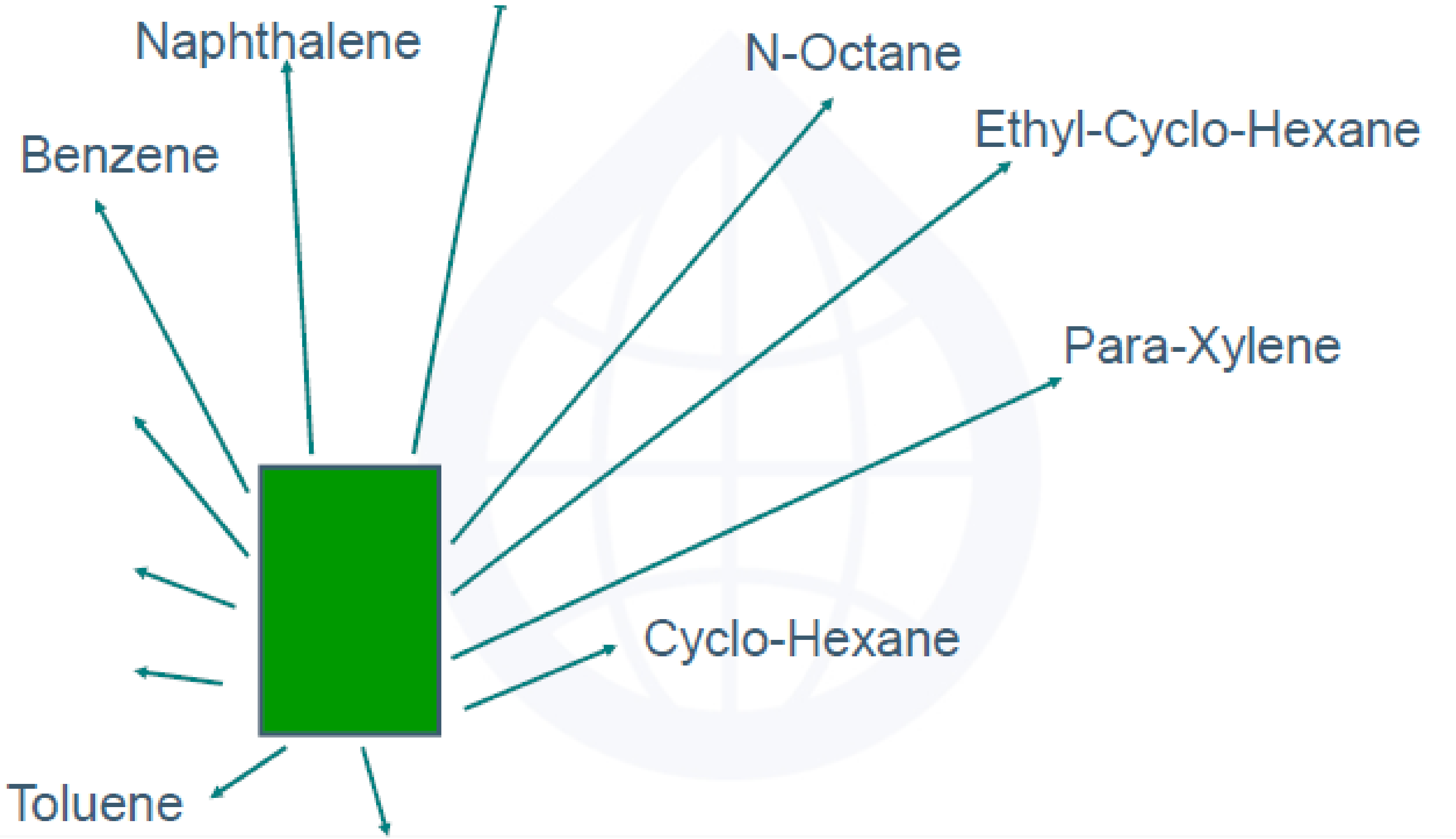


GC analysis - Gas



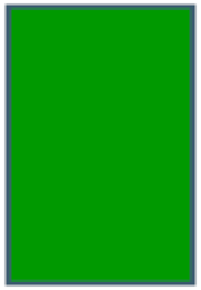
Comp	Weight%	M	Mol%
N2	0.779	28.01	0.659
CO2	10.499	44.01	5.652
C1	46.577	16.04	68.795
C2	16.326	30.07	12.863
C3	14.775	44.1	7.938
C4	7.105	58.12	2.897
C5	2.333	72.15	0.766
C6	0.793	86.18	0.222
C7	0.811	90.51	0.208

C7+ components



Boling point (carbon number) fractions

C_7 contains all components boiling between T_b of nC_{6+} (+0.5 °C) and nC_7 (+0.5 °C), e.g. Benzene and Cyclo-Hexane

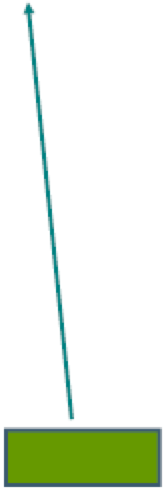


C_8 contains all components boiling between T_b of nC_7 (+0.5 °C), and nC_8 (+0.5 °C), e.g. Toluene and Methyl-Cyclo-Hexane

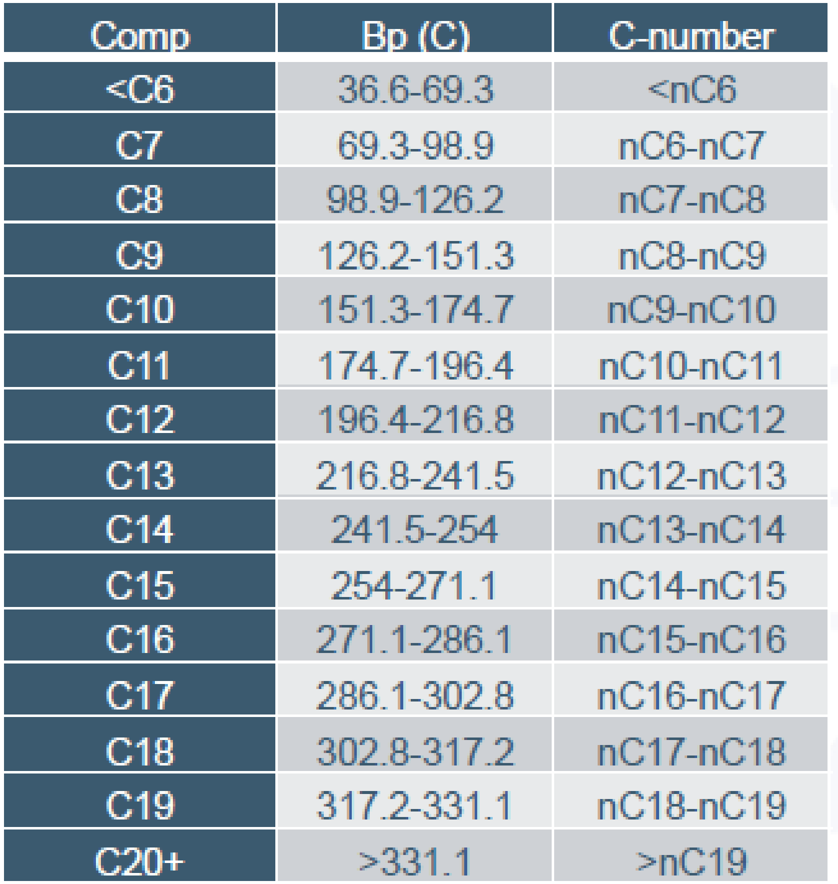
etc.

Residue

C_{n+} contains all components with a higher boiling point than nC_{n-1}. Residue may contain thousands of different components

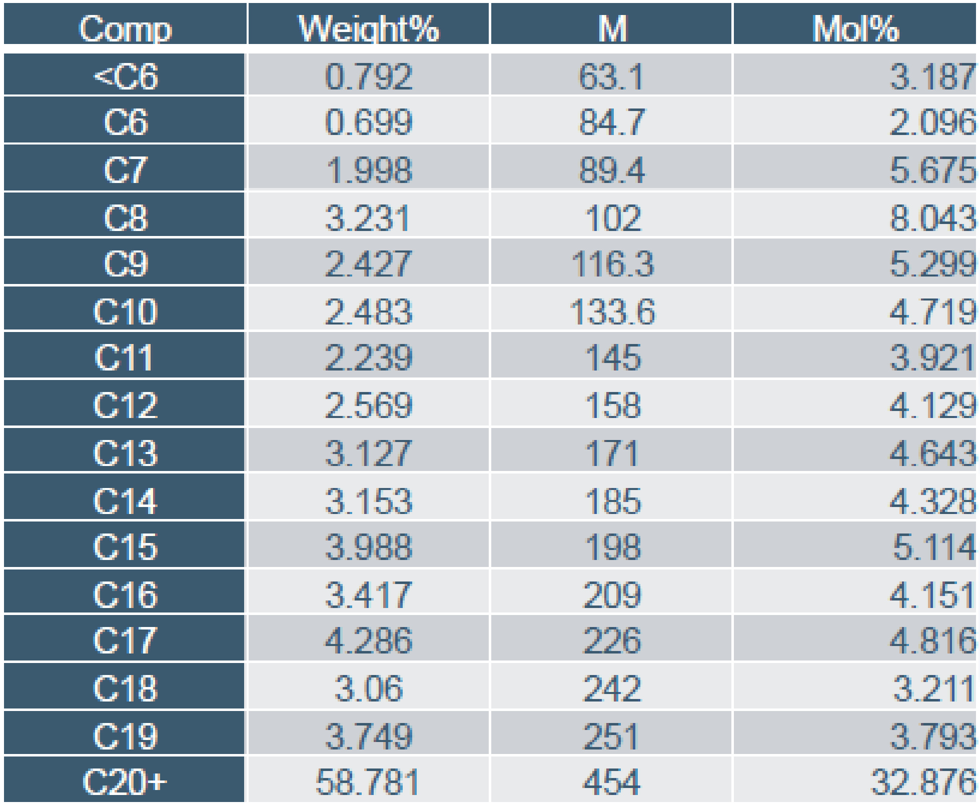


TBP Cuts



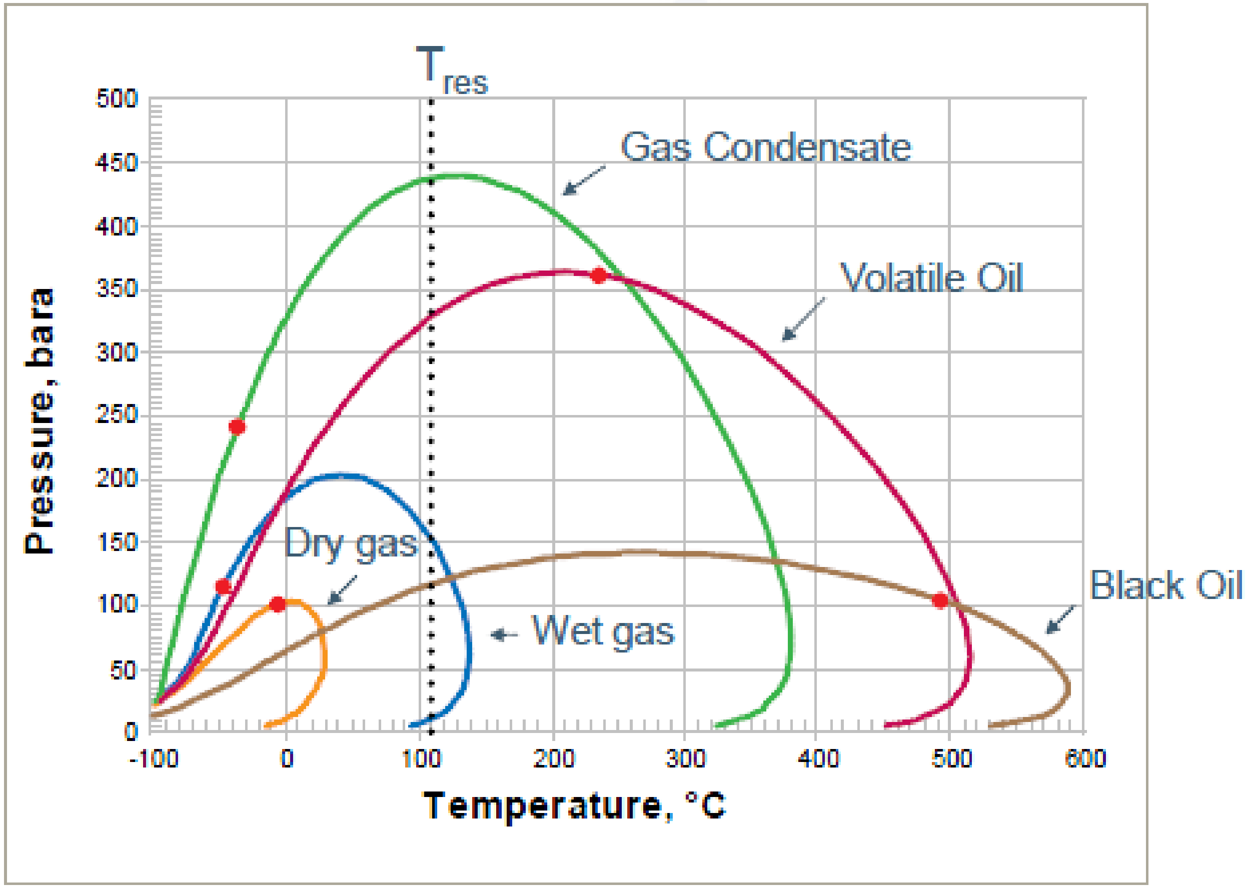
Comp	Bp (C)	C-number
<C6	36.6-69.3	<nC6
C7	69.3-98.9	nC6-nC7
C8	98.9-126.2	nC7-nC8
C9	126.2-151.3	nC8-nC9
C10	151.3-174.7	nC9-nC10
C11	174.7-196.4	nC10-nC11
C12	196.4-216.8	nC11-nC12
C13	216.8-241.5	nC12-nC13
C14	241.5-254	nC13-nC14
C15	254-271.1	nC14-nC15
C16	271.1-286.1	nC15-nC16
C17	286.1-302.8	nC16-nC17
C18	302.8-317.2	nC17-nC18
C19	317.2-331.1	nC18-nC19
C20+	>331.1	>nC19

TBP analysis



Comp	Weight%	M	Mol%
<C6	0.792	63.1	3.187
C6	0.699	84.7	2.096
C7	1.998	89.4	5.675
C8	3.231	102	8.043
C9	2.427	116.3	5.299
C10	2.483	133.6	4.719
C11	2.239	145	3.921
C12	2.569	158	4.129
C13	3.127	171	4.643
C14	3.153	185	4.328
C15	3.988	198	5.114
C16	3.417	209	4.151
C17	4.286	226	4.816
C18	3.06	242	3.211
C19	3.749	251	3.793
C20+	58.781	454	32.876

Phase envelops



Experiments depends on fluid types

- Black Oil: Constant Mass Expansion (CME / CCE / PV), Differential Liberation (DV / DL), Separator Test, Viscosity

- Volatile Oil: CME (with liquid shrinkage), Constant Volume Depletion (CVD), Separator Test, Viscosity

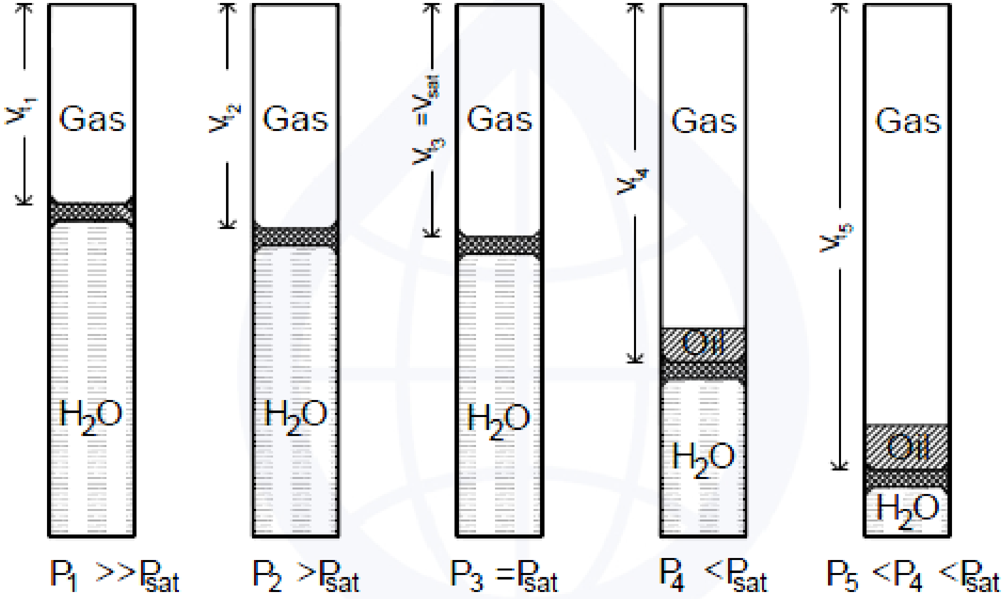
- Gas Condensate: CME Dew-point, CVD, Gas Viscosity

- Wet Gas: CME Dew-point

- Dry Gas: CME-Z

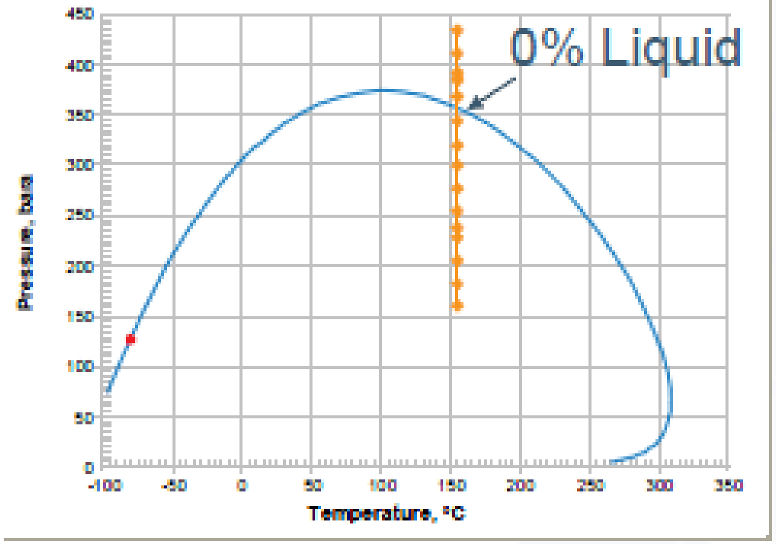
Constant Mass Expansion

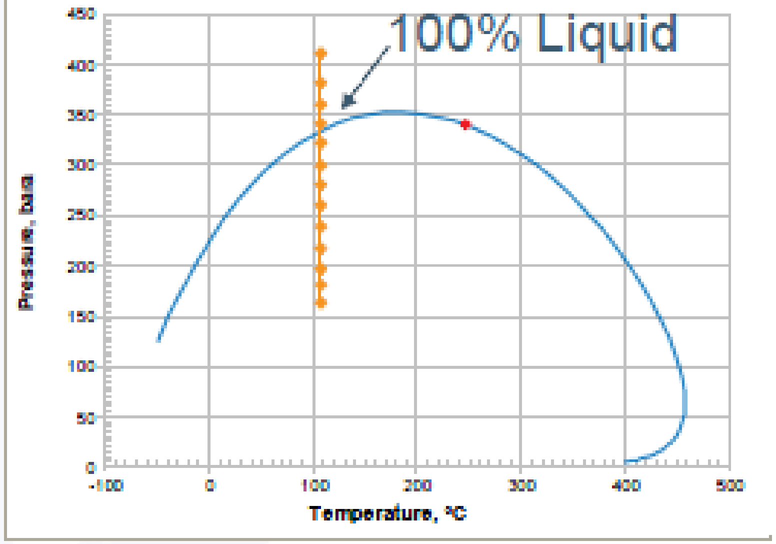
- Carried out in almost all PVT studies irrespective of fluid type
- Performed to determine relation of Pressure and Volume at Reservoir Temperature
- Also be referred to as: PV or CCE (Constant Composition Experiments).



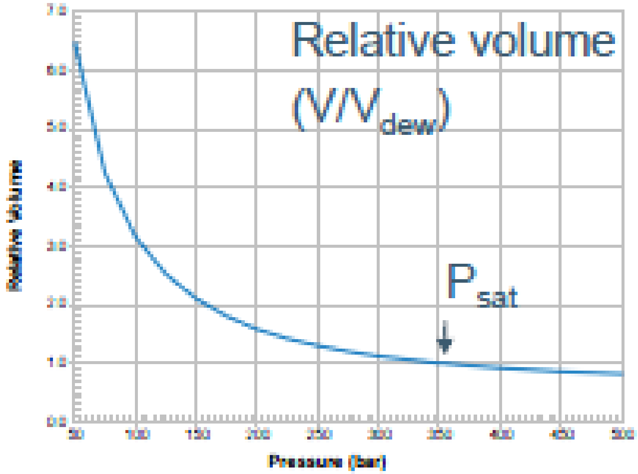
All Fluid Types

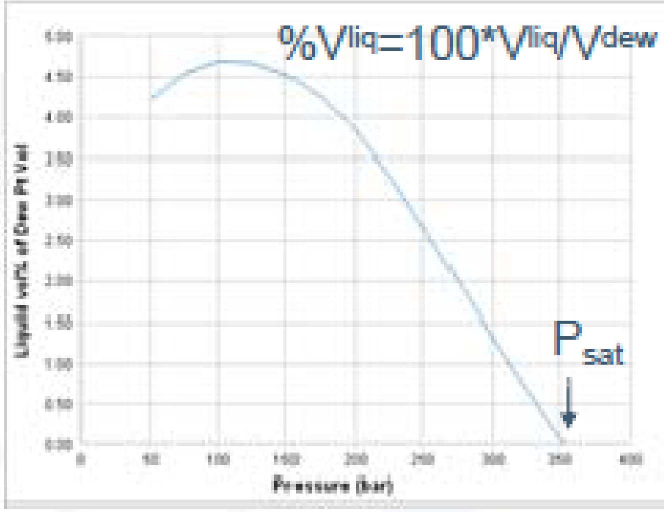
CME in phase diagram

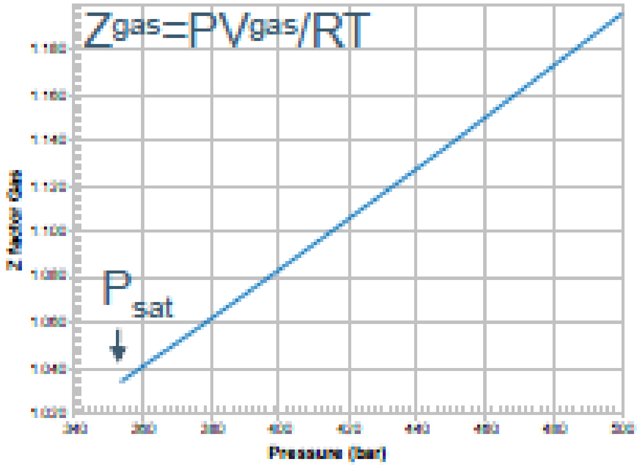

CME gas condensate


CME oil mixture

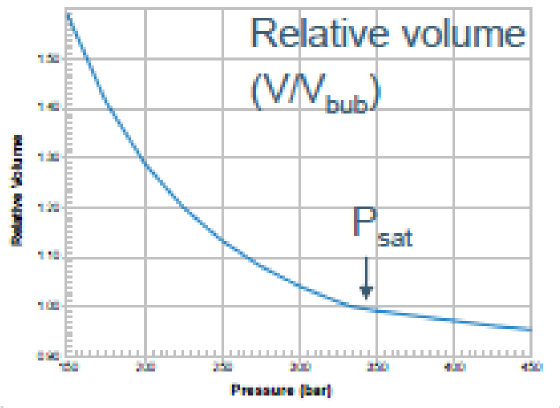
CME results – gas condensate

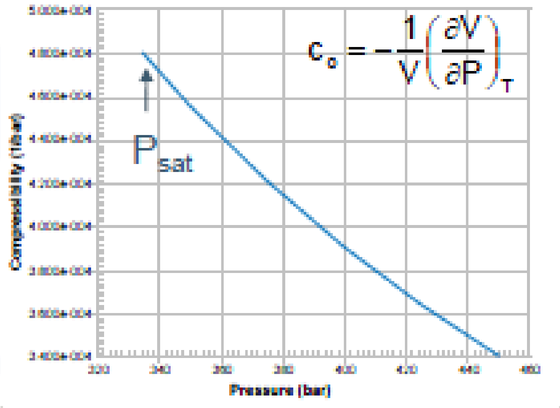




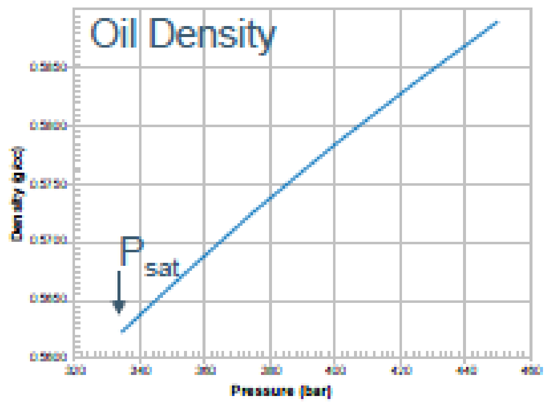


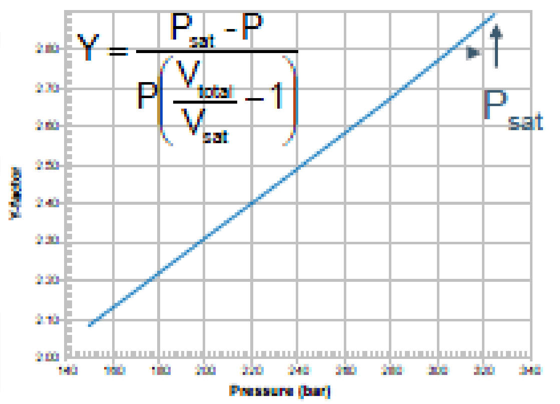
CME results – oil mixture





$$c_o = -\frac{1}{V}\left(\frac{\partial V}{\partial P}\right)_T$$

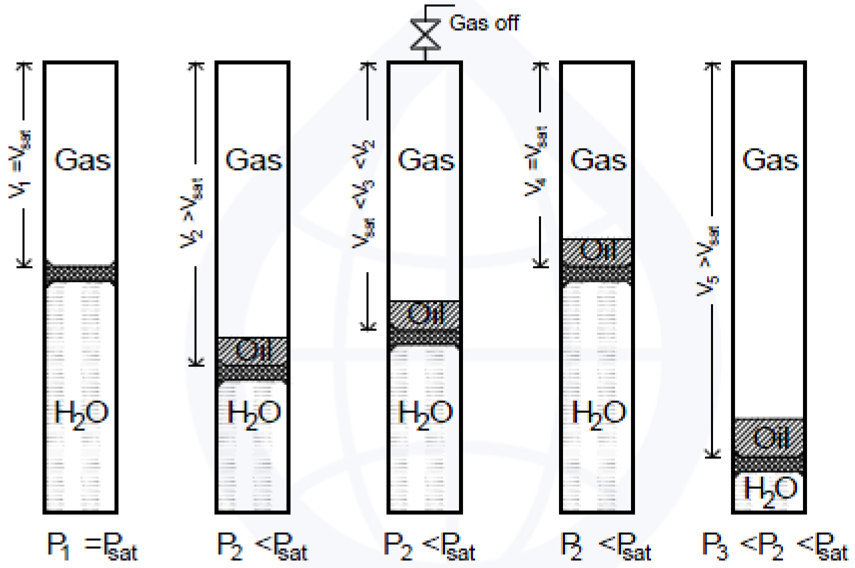




$$Y = \frac{P_{sat} - P}{P\left(\frac{V_{total}}{V_{sat}} - 1\right)}$$

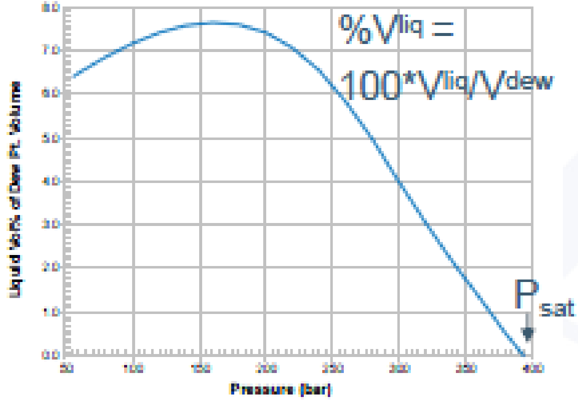
Constant Volume Depletion

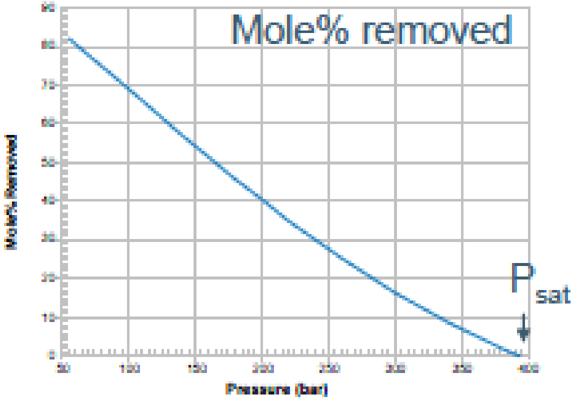
- Carried out on either gas condensates or volatile oils at Reservoir Temperature to simulate the volumetric and compositional changes in the reservoir during production (depletion)
- Carried out in 6 - 8 stages depending on the fluid type.

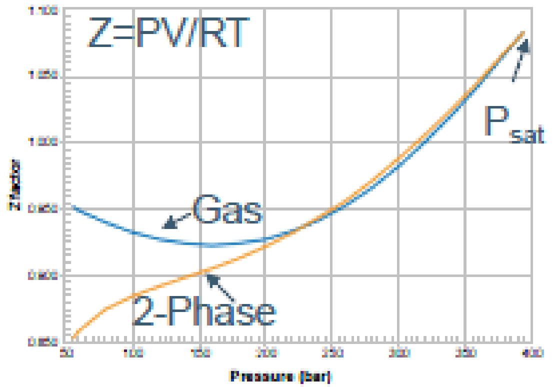


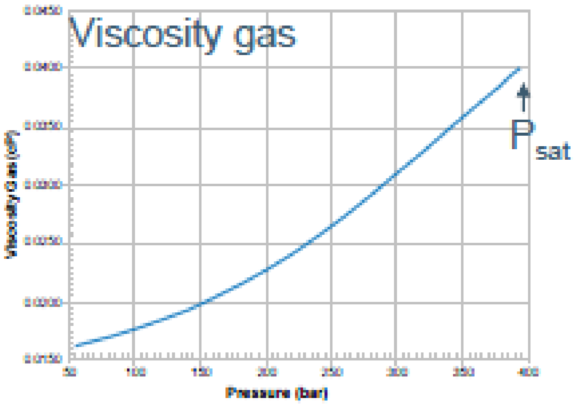
Gas condensates and volatile oils

CVD results


%Vliq =
100*Vliq/Vdew
Psat
Liquid Vol% of Dew Pt. Volume
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
50
100
150
200
250
300
350
400
Pressure (bar)

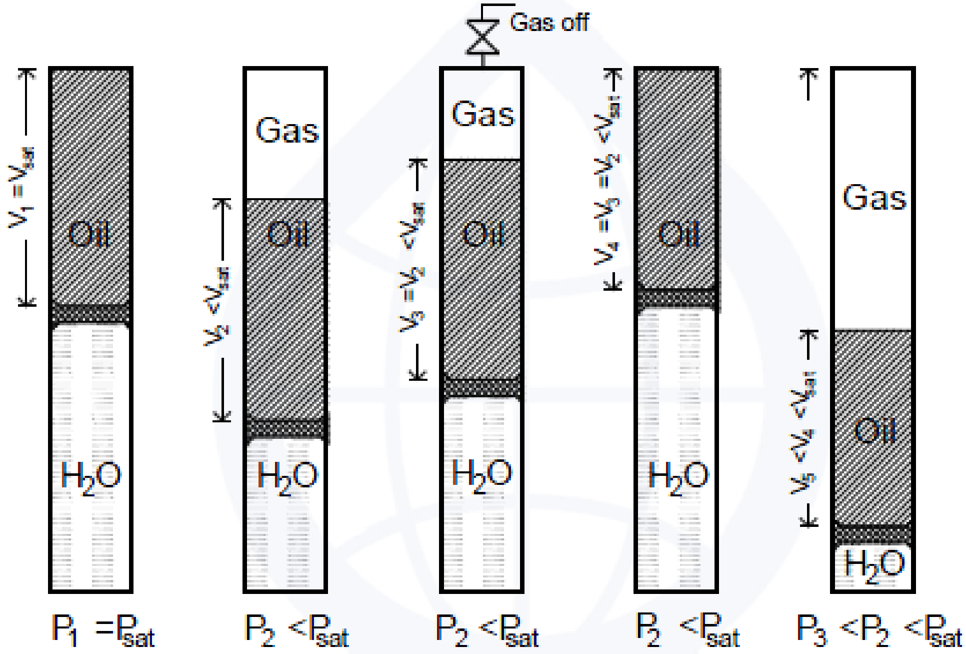

Mole% removed
Psat
Mole% Removed
90
80
70
60
50
40
30
20
10
0
50
100
150
200
250
300
350
400
Pressure (bar)


Z=PV/RT
Gas
2-Phase
Psat
Z factor
1.100
1.050
1.000
0.950
0.900
0.850
50
100
150
200
250
300
350
400
Pressure (bar)

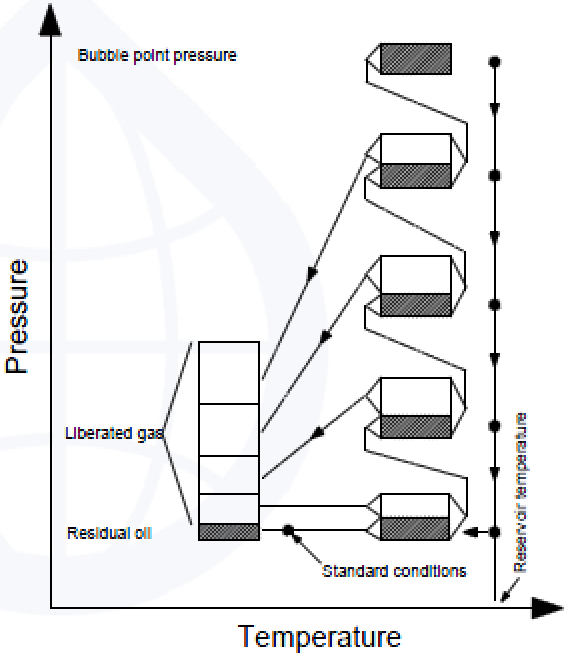

Viscosity gas
Psat
Viscosity Gas (cP)
0.0450
0.0400
0.0350
0.0300
0.0250
0.0200
0.0150
50
100
150
200
250
300
350
400
Pressure (bar)

Differential liberation

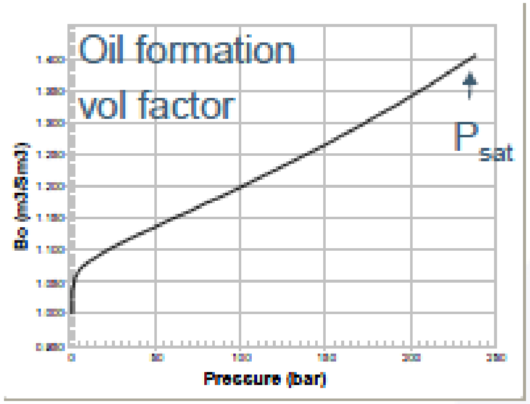
- Carried out on Black Oils at Reservoir Temperature to simulate the volumetric and compositional changes in the reservoir during production

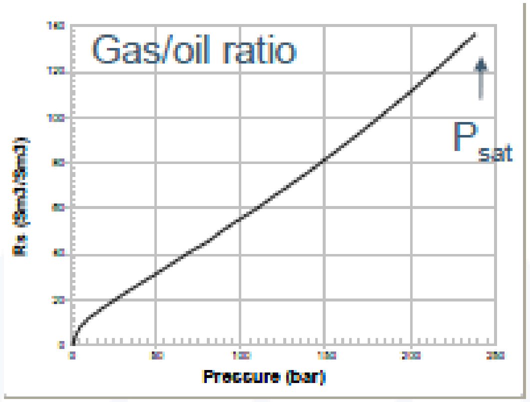


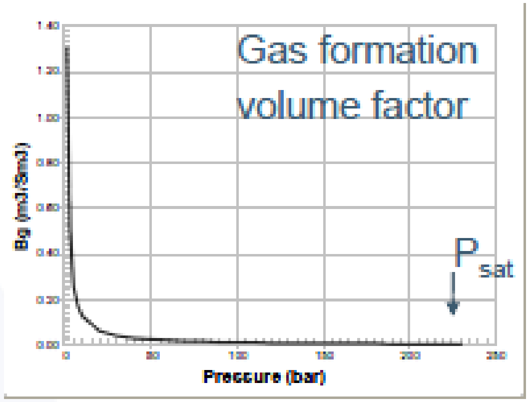
Oil mixtures

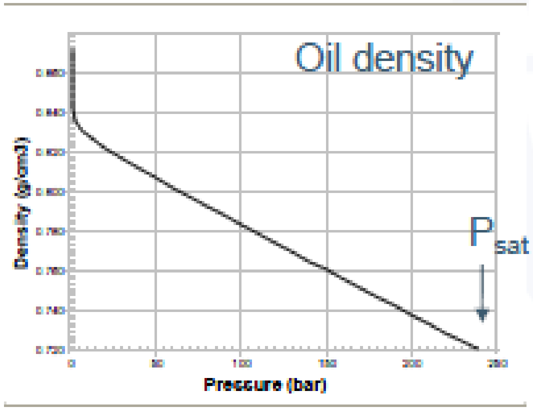


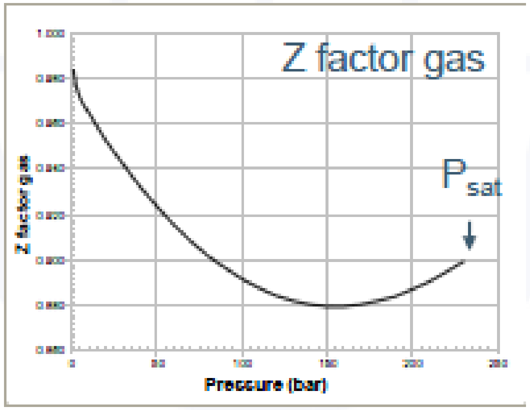
DL results

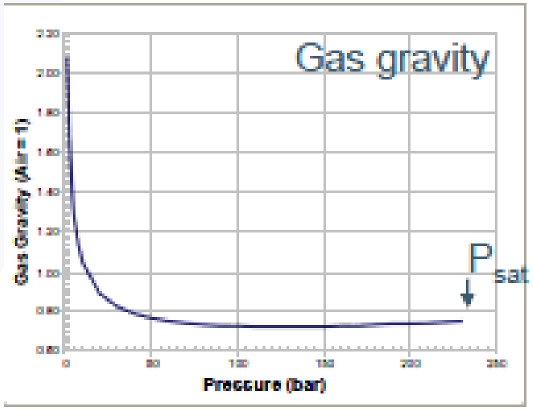

Oil formation vol factor
P$_{sat}$
Bo (m3/Sm3)
0
50
100
150
200
250
Pressure (bar)


Gas/oil ratio
P$_{sat}$
Rs (Sm3/Sm3)
0
20
40
60
80
100
120
140
0
50
100
150
200
250
Pressure (bar)


Gas formation volume factor
P$_{sat}$
Bg (m3/Sm3)
0
50
100
150
200
250
Pressure (bar)

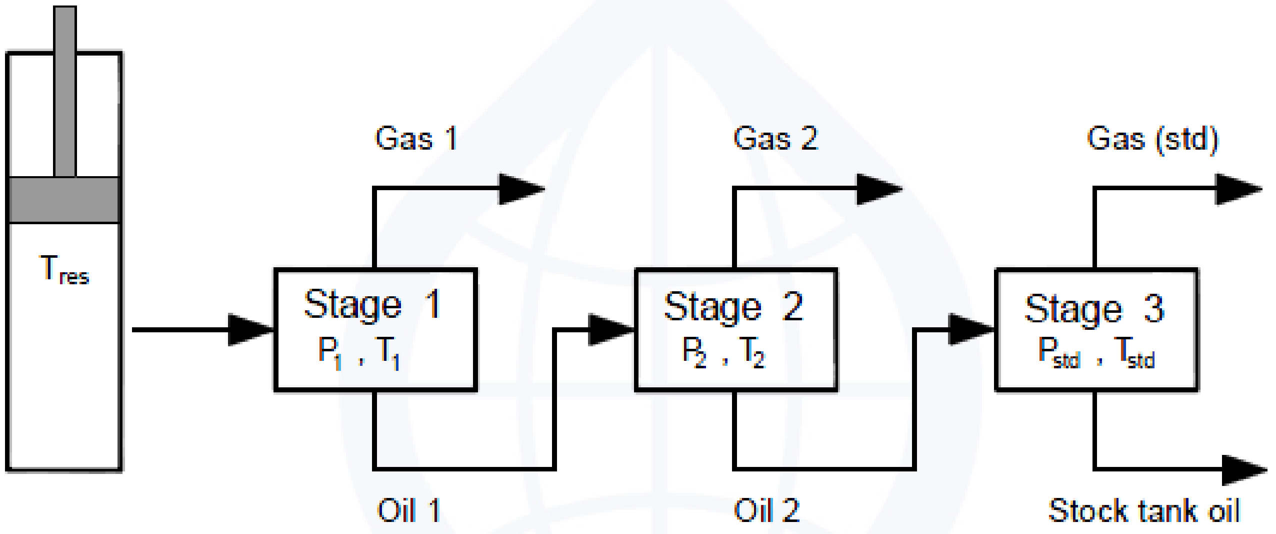

Oil density
P$_{sat}$
Density (g/cm3)
0
50
100
150
200
250
Pressure (bar)


Z factor gas
P$_{sat}$
Z factor gas
0
50
100
150
200
250
Pressure (bar)


Gas gravity
P$_{sat}$
Gas Gravity (Air=1)
0
50
100
150
200
250
Pressure (bar)

Separator test

- Separator Tests are mostly carried out on oils to simulate the volumetric and compositional changes when the reservoir flows through production separators.

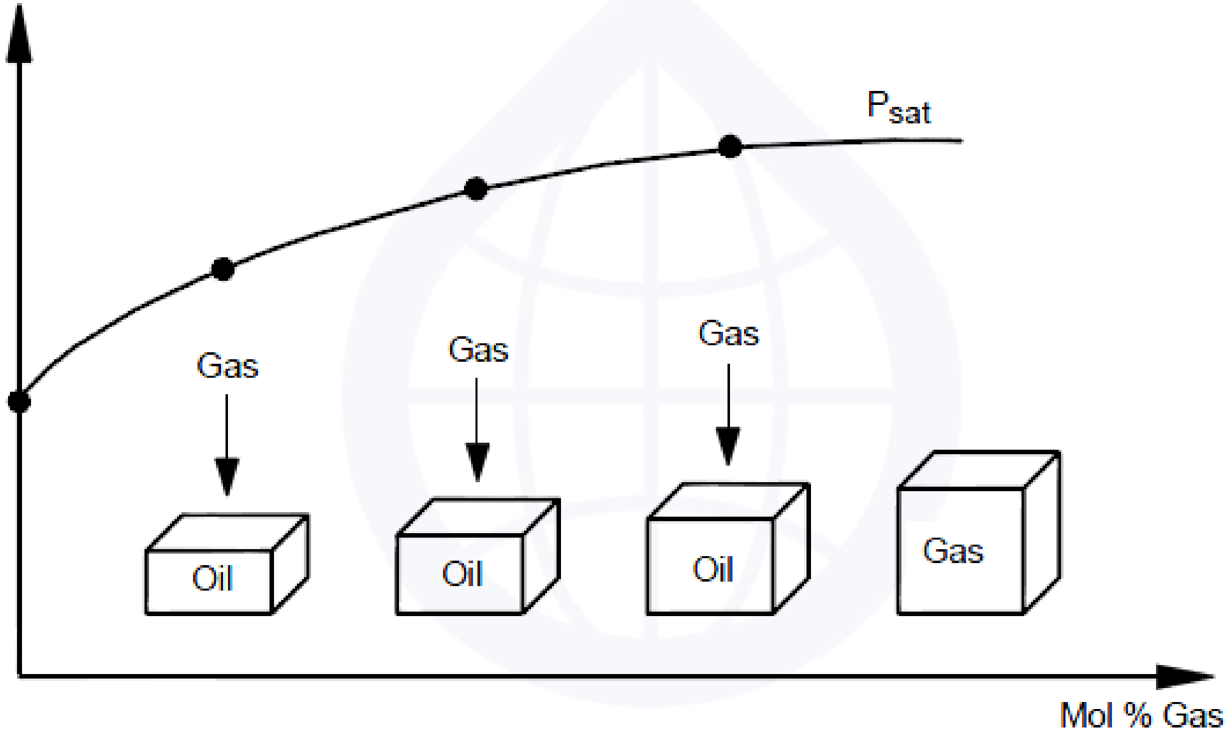


Separator test is similar to depletion tests except that here the temperature is also changed.

Separator test results

- Gas/oil volumetric ratio – GOR
- Oil density
- Gas gravity
- Oil formation volume factor - FVF

Swelling test



Swelling test results

- Mole% of gas added
- Saturation point
- Swollen volume
- Density
- Viscosity of the swollen oil mixtures

Temperature covered by PVT data

- Reservoir Temperature
    - CME
    - CVD
    - Differential liberation
    - Viscosity
- Temperatures < Reservoir temperature
    - Separator

- Only Separator data can be used to validate fluid description for Pipeline and Process conditions

Case study: Well B – DST 2 sample

Well	B
Production test	DST 2
Flow period	Flow period 1
Top perforation (m)	2900
Bottom perforation (m)	3000
Mid perforation (m)	2995
Formation	Formation 1
Date	July 2007
Available PVT data	Composition up to C36+ CCE.CVD at 290F
CGR (stb/MMscf)	55
Separator P (psi)	500
Separator T (F)	80
Dew point pressure (psi)	4600
Temperature (F)	290

PVT test

- CCE and CVD
: Vapor Z factor, liquid saturation, vapor density, vapor viscosity

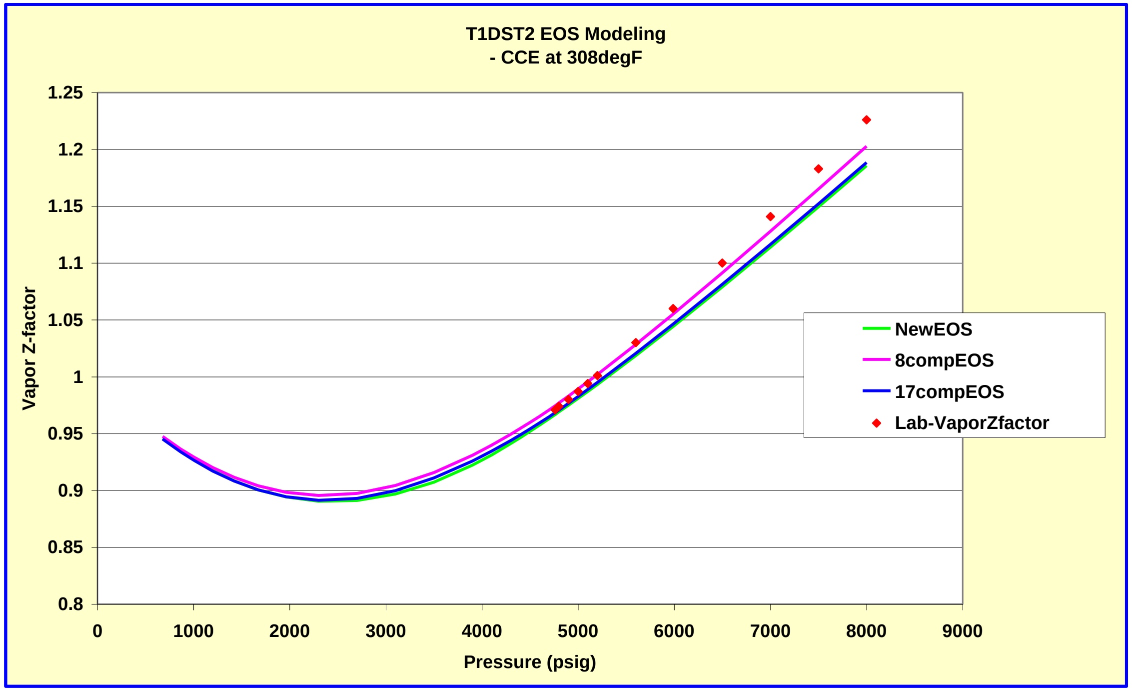
- 40 components can be used for EOS model as reported by the lab data, but it was not practical to be used for characterization in terms of the required CPU time.

EOS development

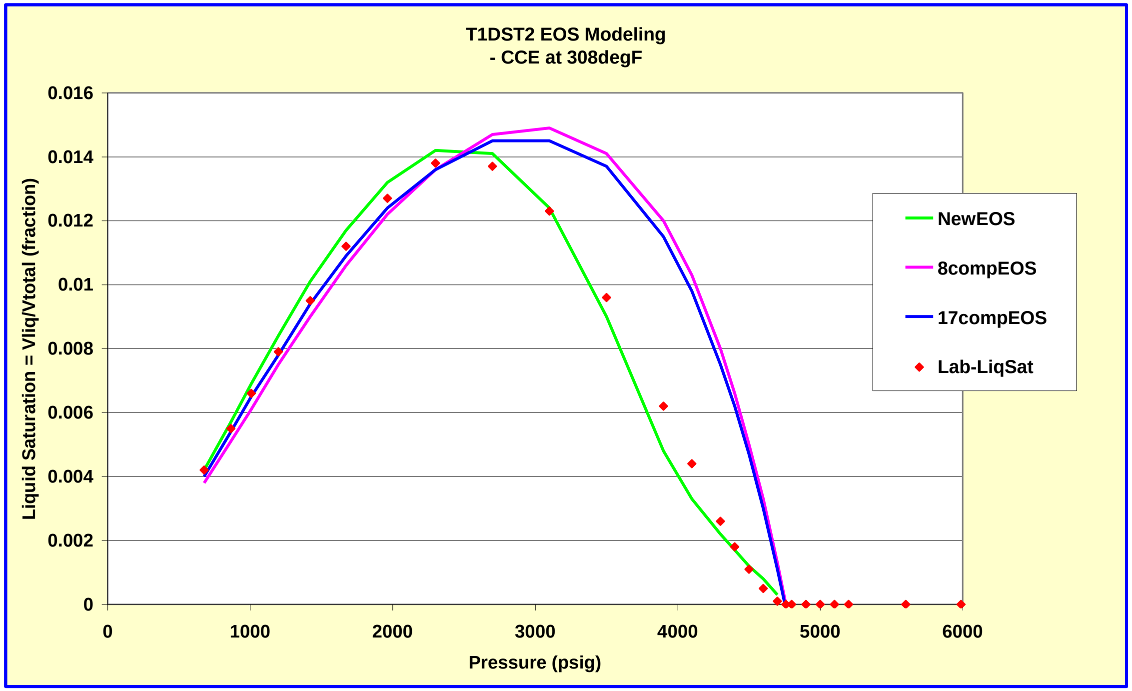
Name	8comp EOS	17comp EOS	New EOS
EOS	PR	PR	PR
Number of Components	8	17	21
Components	CO2, C1N2, C2, C3, C4, C5+, C12+, C18+	CO2, N2, C1, C2, C3, iC4, nC4, iC5, nC5, C6, C7, C8, C9, C10, C11, C12+, C19+	CO2, N2, C1, C2, C3, iC4, nC4, iC5, nC5, C6, C7, C8, C9, C10, C11, C12, C13, C14, C15+, C20+, C36+
Composition	B-DST2 composition	B-DST2 composition	B-DST2 composition
Matching data	CCE, CVD, CGR at DST	CCE, CVD, CGR at DST	CCE, CVD
Regression parameters	OmegaA, OmegaB, Acentric Factor, Volume shift parameter of C1N2, C5+, C12+, C18+.	OmegaA, OmegaB, Acentric Factor	Tc, Pc, Acentric Factor of above C6.
Others	For reservoir evaluation.	For facility design.	Updated after 3 years

Comparison of EOS and Lab. data

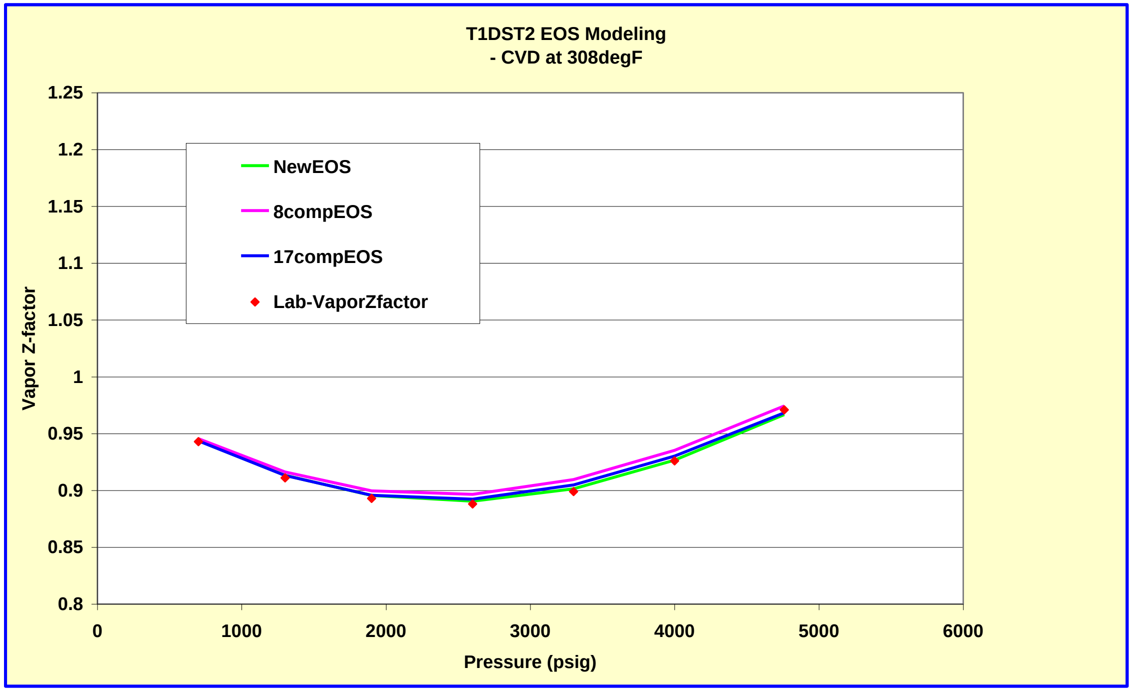
- CCE – vapor z-factor at 308 ^oF



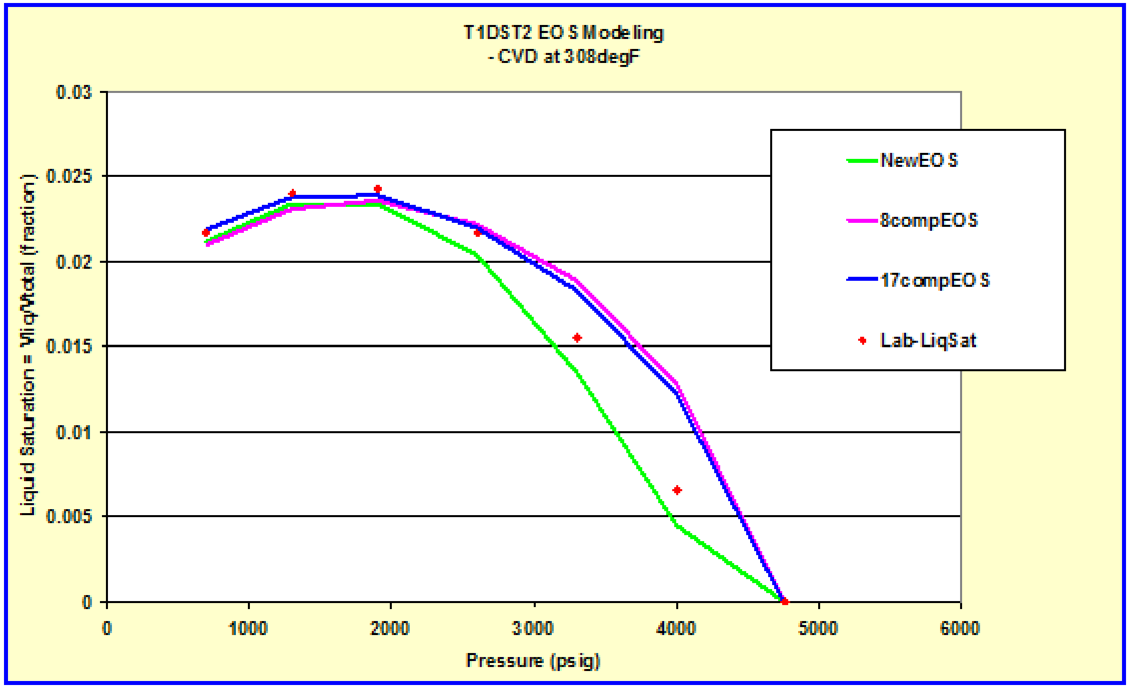
- CCE, liquid saturation at 308 ^{o}F



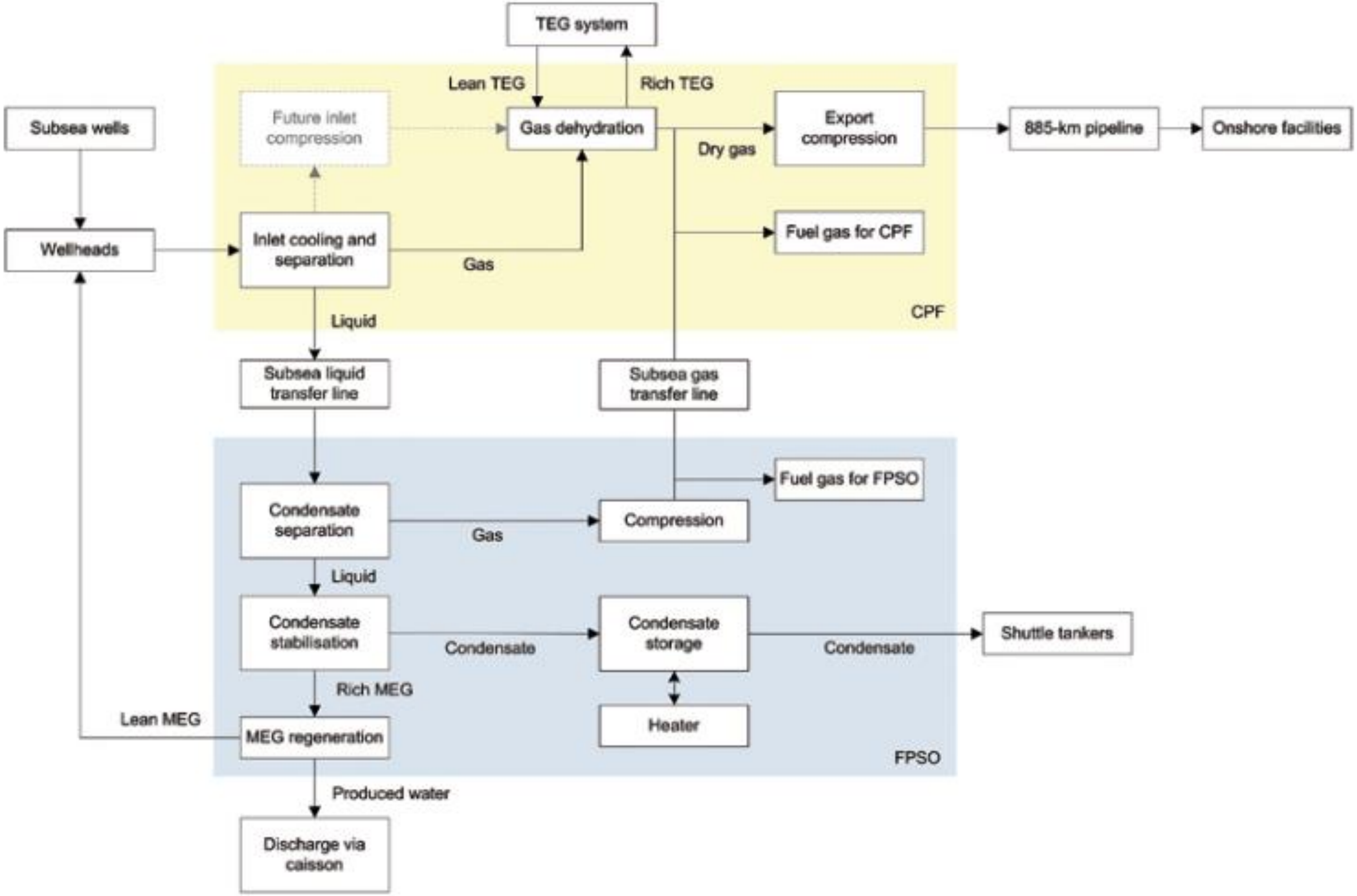
- CVD, vapor z-factor at 308 ^{o}F



- CVD, liquid saturation at 308 °F

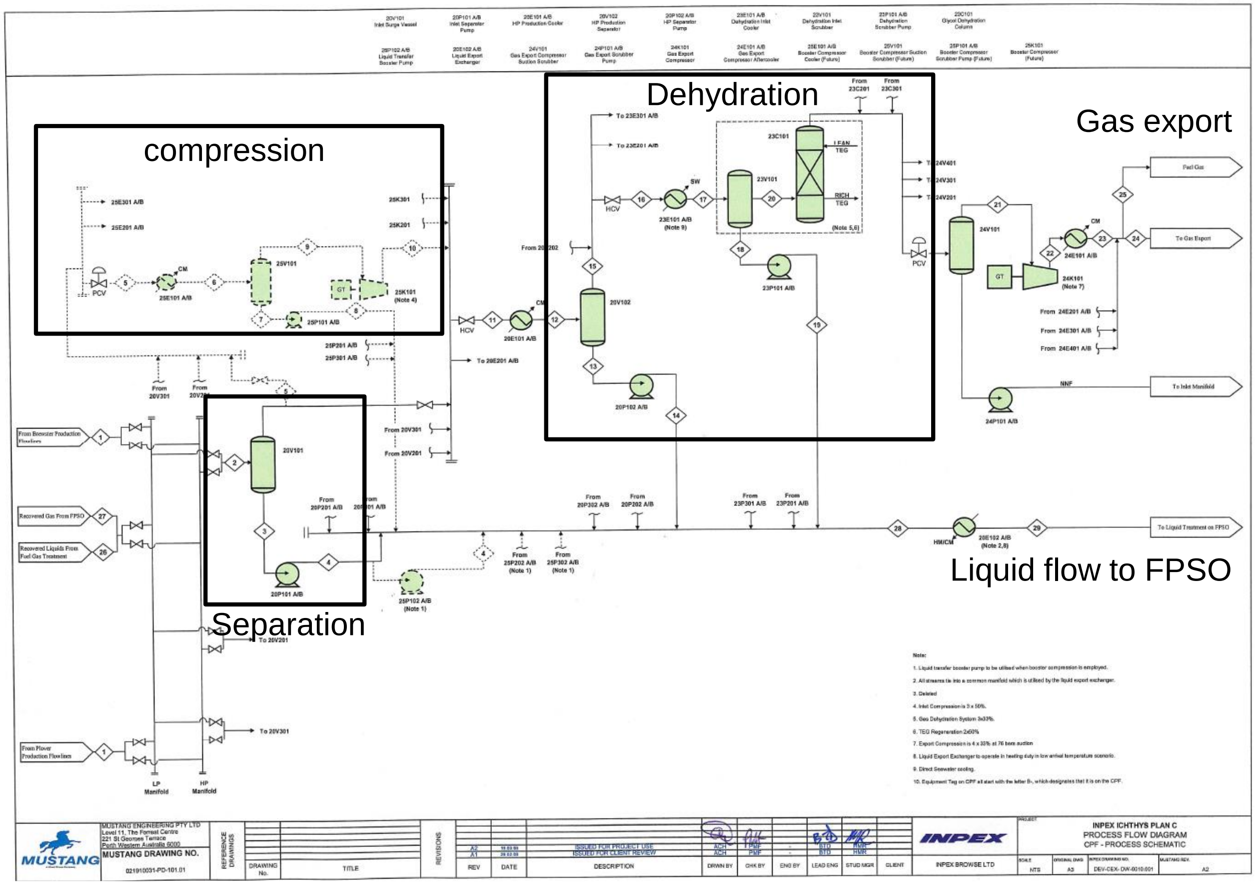


Offshore process flow diagram

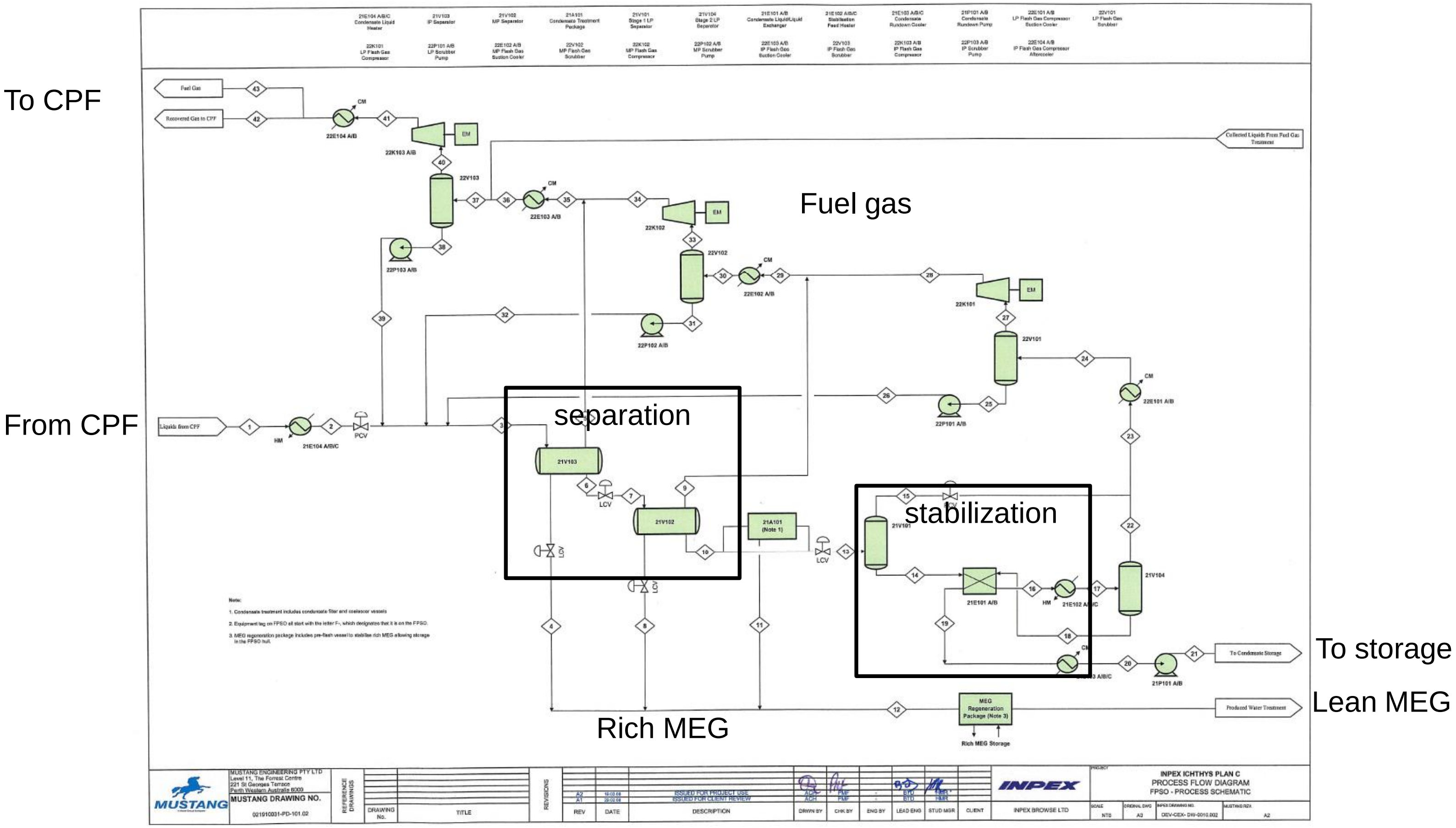


Process simulation

- Offshore facility – CPF (natural gas export)



- Offshore facility – FPSO (condensate export)

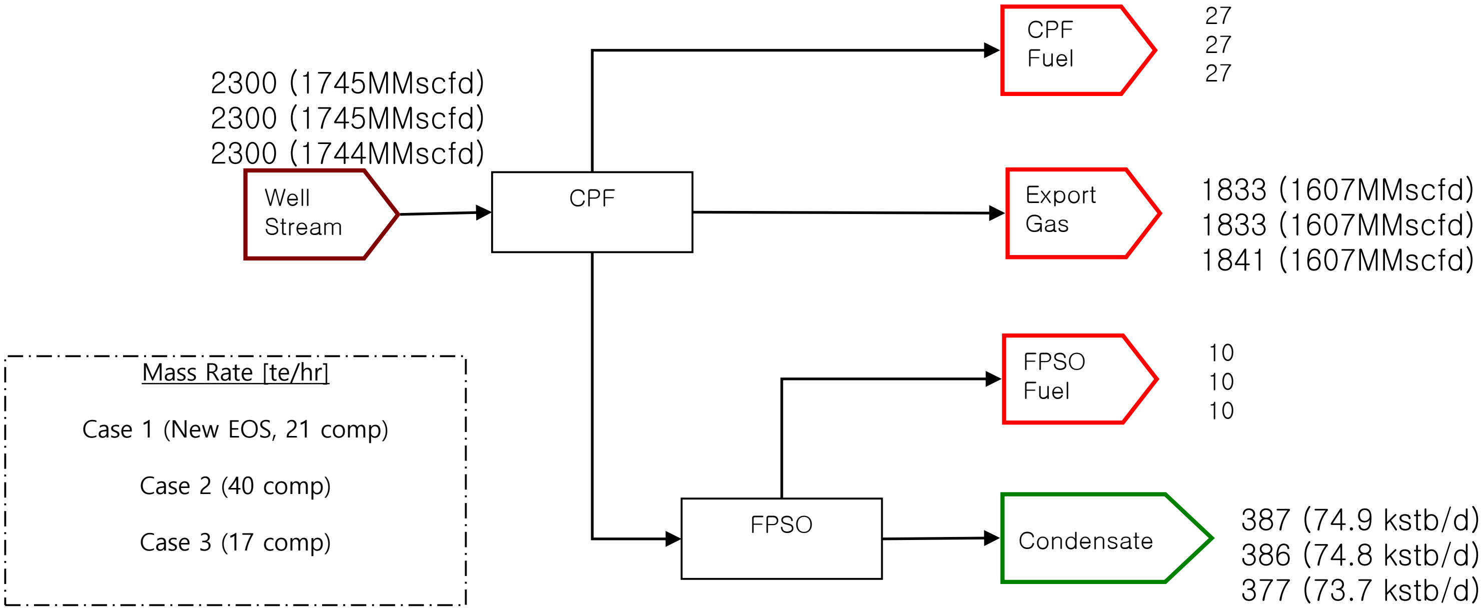


- Product comparison

: New EOS yield less GEP export gas due to fewer heavy components than 17comp EOS model

: Condensate rate for new EOS model is 3wt% larger

Offshore Process Block Diagram



2300 (1745MMscfd)
2300 (1745MMscfd)
2300 (1744MMscfd)

Well Stream

CPF

CPF Fuel

27
27
27

Export Gas

1833 (1607MMscfd)
1833 (1607MMscfd)
1841 (1607MMscfd)

FPSO

FPSO Fuel

10
10
10

Condensate

387 (74.9 kstb/d)
386 (74.8 kstb/d)
377 (73.7 kstb/d)

Mass Rate [te/hr]

Case 1 (New EOS, 21 comp)

Case 2 (40 comp)

Case 3 (17 comp)

Thermodynamic analysis

Ideal gases

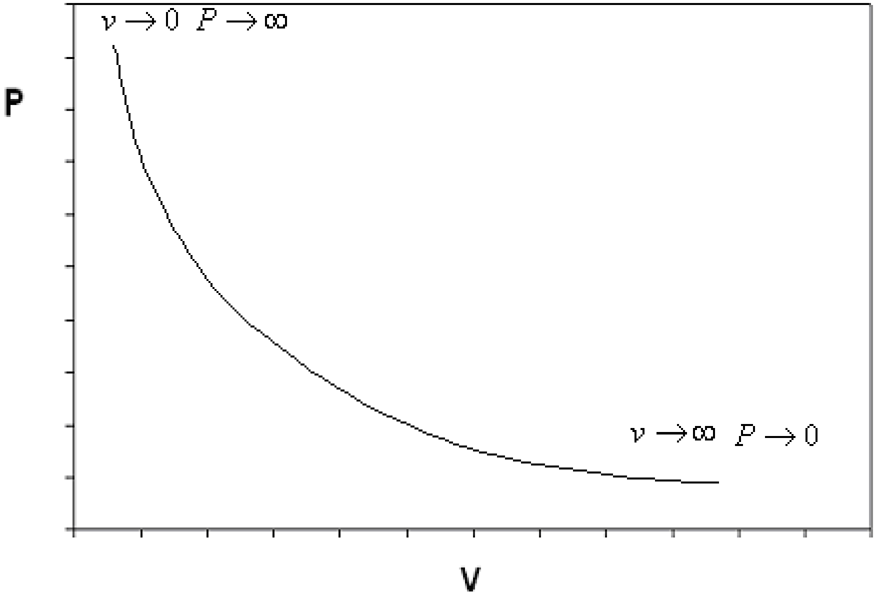
- An ideal gas is an *imaginary* gas that satisfies the following conditions

  : Negligible interactions between the molecules,

  : Its molecules occupy no volume (negligible molecular volume),

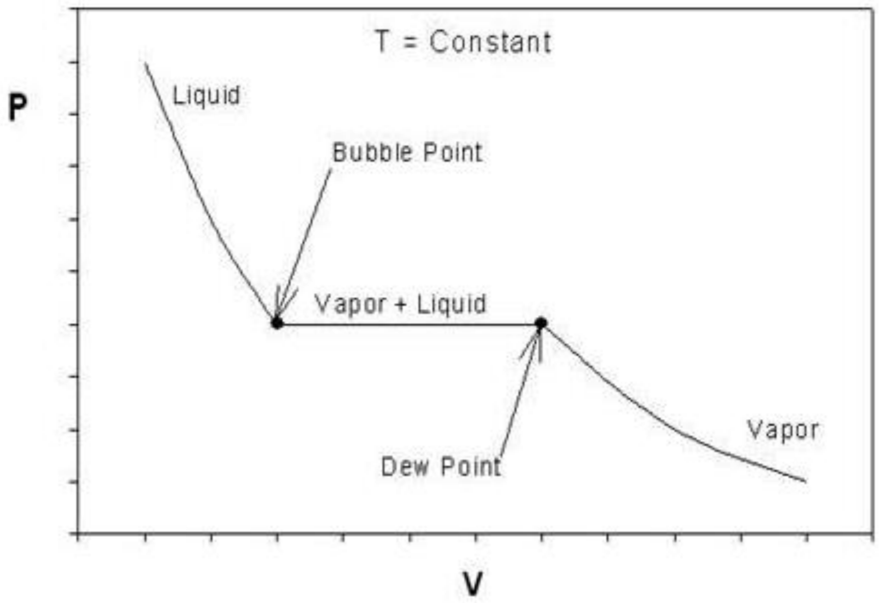
  : Collisions between molecules are perfectly elastic (no energy is lost after colliding)

- If we construct the P-v diagram for an ideal gas at a given temperature, we end up with the isotherm shown as follows,



Real gases

- Typical P-V behavior of a pure substance.



- For a real substance, as pressure increases, there **must** be a point of discontinuity that represents the phase change.
- *Ideal gas will not condense, no matter what pressure it is subjected to, regardless of the temperature of the system*. In other words, we cannot hope to reproduce the above P-v behavior using the ideal equation since no discontinuity is to be found

Cubic EOS

- If we multiply the EOS by V^2 and expand the factorized product by applying the distributive law,

$$\left(P + \frac{a}{V^2}\right)(V - b) = RT \quad \longrightarrow \quad V^3 - \left(b + \frac{RT}{P}\right)V^2 + \left(\frac{a}{P}\right)V - \frac{ab}{P} = 0$$

- This is a third order polynomial in V i.e. it is cubic in molar volume.
- Thus van der Waals EOS is referred to as *cubic* because it is a polynomial of order 3 in molar volume. In general, any equation of state that is cubic in volume and explicit in pressure is regarded as a *cubic equation of state.*
- All the transformations and modifications that it has undergone during the more than one hundred years since its publication are also *cubic EOS* including RK, SRK, and PR.

van der Waals EOS (1873)

- Capable of handling the transition from vapor to liquid

$$P = \frac{RT}{(V-b)} - \frac{a}{V^2} \rightarrow \left(P + \frac{a}{V^2}\right)(V-b) = RT$$

$$a = \frac{27}{64}\frac{R^2 T_c^2}{P_c}, \; b = \frac{1}{8}\frac{RT_c}{P_c}, \; then\, V_c = \frac{3}{8}\frac{RT_c}{P_c}$$

Modern cubic EOS

- SRK (1972)

$$P = \frac{RT}{(V-b)} - \frac{\alpha\ a}{V(V+b)} \rightarrow \left(P + \frac{\alpha\ a}{V(V+b)}\right)\left(V-b\right) = RT$$

$$a = 0.42748\frac{R^2T_c^2}{P_c},\ b = 0.08664\frac{RT_c}{P_c}$$

$$\alpha = \left(1+m\left(1-T_R^{1/2}\right)\right)^2, m = 0.48508 + 1.55171\cdot\varpi - 0.1561\cdot\varpi^2$$

- PR (1976)

$$P = \frac{RT}{(V-b)} - \frac{\alpha\ a}{V(V+b)+b(V-b)} \rightarrow \left(P + \frac{\alpha\ a}{V(V+b)+b(V-b)}\right)(V-b) = RT$$

$$a = 0.45724\frac{R^2T_c^2}{P_c},\ b = 0.07780\frac{RT_c}{P_c}$$

$$\alpha = \left(1+m\left(1-T_R^{1/2}\right)\right)^2, m = 0.37464 + 1.5422\cdot\varpi - 0.26992\cdot\varpi^2$$

Comparison of SRK and PR EOS

- RK EOS

- Generally good for gas phase properties, but poor for liquid phase properties

- Better when used in conjunction with a correlation for liquid phase behavior.

- SRK and PR EOS

- Serve similar functions as RK EOS but require more parameters

- PR obtains better liquid densities than SRK

- Overall, PR does a better job, slightly, for gas and condensate then SRK. However for polar systems, SRK always makes a better prediction, but in the petroleum industry, we do not usually deal with those.

- Peng and Robinson (Uni. Of Calgary) was trying to develop an EOS specifically focused on natural gas systems. PR EOS shows a slightly better behavior at the critical point. This slightly better performance around critical conditions makes the PR EOS somewhat better suited to gas condensate systems.

Z_c to compare EOS performance

- Critical compressibility factor, z at (T_c, P_c)
- Experimental values

CO_2	0.2744
CH_4	0.2862
C_2H_6	0.2793
nC_5	0.2693
nC_6	0.2659

- The experimental values of z_c are normally substance dependent, but close enough among themselves.
- All cubic EOS predict a unique and universal value of z at the critical point regardless of the substance due to the corresponding sate principle.

Ideal EOS	1.000
van der Waals EOS	0.375
RK EOS	0.333
SRK EOS	0.333
PR EOS	**0.301**

Pros and Cons

- Advantages of using cubic EOS
  - Simplicity of application
  - Only a few parameters need to be determined
  - Low computational requirement, in the early stages of computers

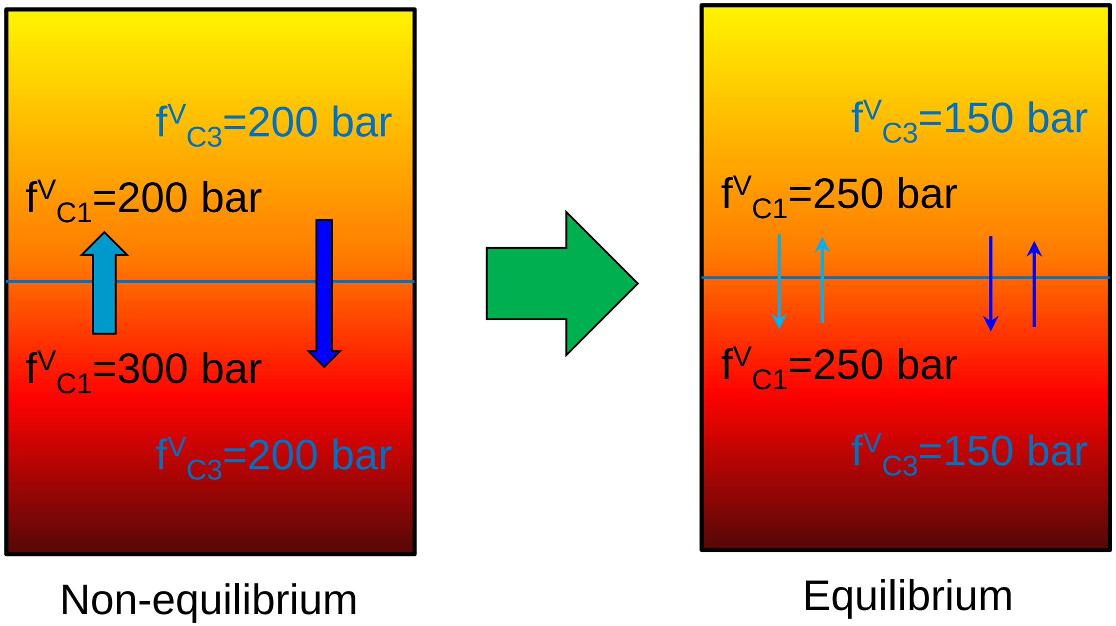
- Disadvantages
  - Limited accuracy that they can provide, particularly for complex systems
  - Empirical adjustments through the use of the binary interaction parameters is essential as well as the use of mixing rule

Vapor – Liquid Equilibrium (VLE)

- List of petroleum production systems that involve VLE
- Separators
- Reservoir
- Pipelines
- Wellbore
- LNG Processing
- NGL Processing
- Storage
- Oil and LNG Tankers
- Vapor/liquid equilibrium pertains to all aspects of petroleum production with which we are concerned
- Depends on the production conditions, phase changes would affect the design and operation of each production system. Ex)retrograde condensation, bubble/dew point, phases fraction

Phase equilibrium

- At equilibrium all components will have the same fugacity (f_i) in all phases.
- Fugacity may be understood as effective partial pressures taking into account non-ideal interactions with other molecules



Fluid modeling

- Parameters for EOS modeling of reservoir fluids

- Temperature range
- Pressure range
- Composition
- Experimental data (density, viscosity, composition, phase behavior)
- Critical and other properties of components
  - Tc, Pc, *Acentric factor*
  - *Molecular weight*
  - *Ideal gas heat capacities*
  - *Liquid density*
  - *Normal boiling point*
- Binary interaction parameters (k_{ij})

- The EOS models calculate (for a given composition, T & P):

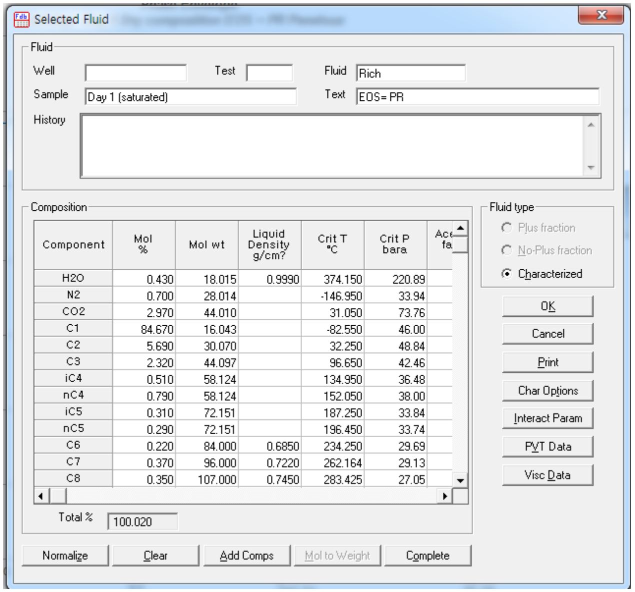
- Density
- Phase behavior
- Enthalpy & entropy

- They do not calculate (done with other correlations)

- Viscosity
- Thermal conductivity
- Interfacial tension

- Aqueous and polar components require special calculations

Simulation Example – PVTSim



Selected Fluid

Fluid

Well:

Test:

Fluid: Rich

Sample: Day 1 (saturated)

Text: EOS= PR

History:

Composition

Component	Mol %	Mol wt	Liquid Density g/cm?	Crit T °C	Crit P bara	Ace fa
H2O	0.430	18.015	0.9990	374.150	220.89	
N2	0.700	28.014		-146.950	33.94	
CO2	2.970	44.010		31.050	73.76	
C1	84.670	16.043		-82.550	46.00	
C2	5.690	30.070		32.250	48.84	
C3	2.320	44.097		96.650	42.46	
iC4	0.510	58.124		134.950	36.48	
nC4	0.790	58.124		152.050	38.00	
iC5	0.310	72.151		187.250	33.84	
nC5	0.290	72.151		196.450	33.74	
C6	0.220	84.000	0.6850	234.250	29.69	
C7	0.370	96.000	0.7220	262.164	29.13	
C8	0.350	107.000	0.7450	283.425	27.05	

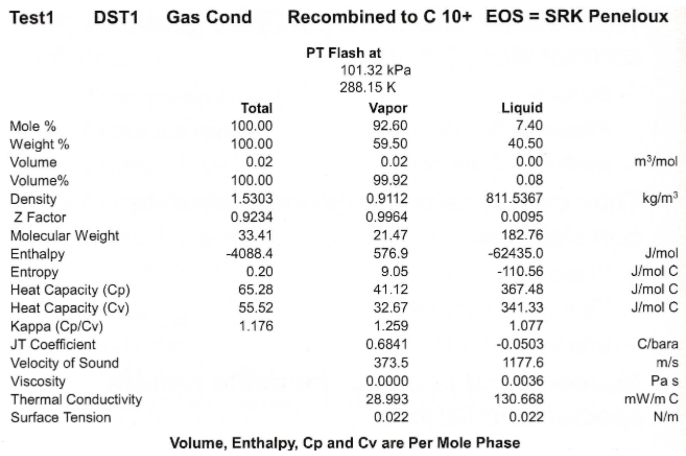
Total %: 100.020

Fluid type

○ Plus fraction

○ No-Plus fraction

● Characterized

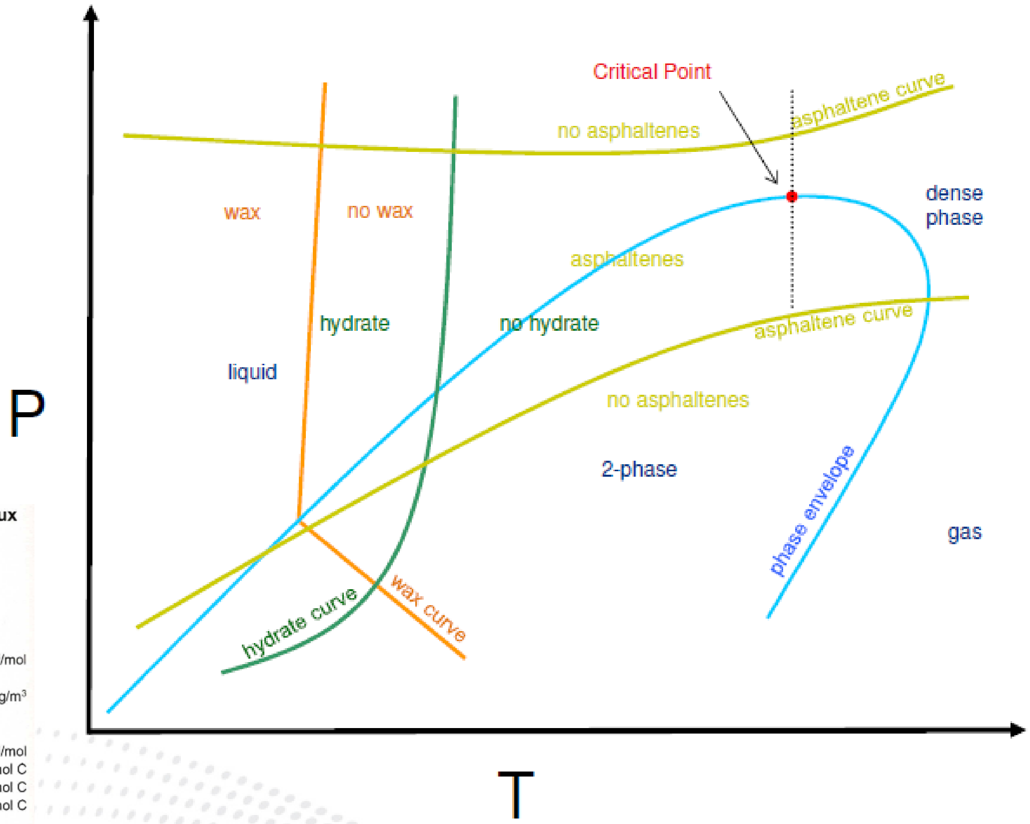


Test1 DST1 Gas Cond Recombined to C 10+ EOS = SRK Peneloux

PT Flash at
101.32 kPa
288.15 K

	Total	Vapor	Liquid	
Mole %	100.00	92.60	7.40	
Weight %	100.00	59.50	40.50	
Volume	0.02	0.02	0.00	m³/mol
Volume%	100.00	99.92	0.08	
Density	1.5303	0.9112	811.5367	kg/m³
Z Factor	0.9234	0.9964	0.0095	
Molecular Weight	33.41	21.47	182.76	
Enthalpy	-4088.4	576.9	-62435.0	J/mol
Entropy	0.20	9.05	-110.56	J/mol C
Heat Capacity (Cp)	65.28	41.12	367.48	J/mol C
Heat Capacity (Cv)	55.52	32.67	341.33	J/mol C
Kappa (Cp/Cv)	1.176	1.259	1.077	
JT Coefficient		0.6841	-0.0503	C/bara
Velocity of Sound		373.5	1177.6	m/s
Viscosity		0.0000	0.0036	Pa s
Thermal Conductivity		28.993	130.668	mW/m C
Surface Tension		0.022	0.022	N/m

Volume, Enthalpy, Cp and Cv are Per Mole Phase



Which EOS to use?

- SRK or PR(78) company standard?
  - Choose that one
  - PR densities better than SRK if no volume correction
- Peneloux volume correction
  - Always to be used when density counts
  - SRK and PR equally good with volume correction
- Peneloux(T)

$$c = c + c'\,(T - 288.15\ K)$$

  - Recommended for heavy oils (improves shrinkage factor from reservoir to surface conditions)

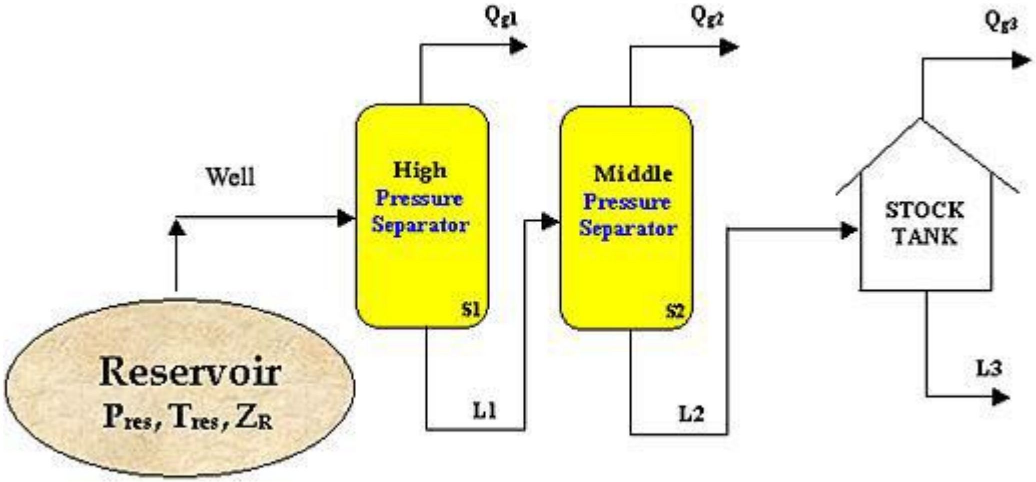
Design and Optimization of Separators

- Once oil and gas are brought to the surface, our main goal becomes that of transportation of the oil and gas from the wellhead to the refinery (for final processing) *in the best possible form.*
- All equipment and processes required to accomplish this are found at the *surface production facility*. Hence, all surface production starts right at the wellhead.
- Starting at the wellhead, the complex mixture of produced fluids makes its way from the production tubing into the flow line. Normally, many wells are drilled to effectively produce the hydrocarbons contained in the field. From each of these wells emerge one or more flow lines depending on how many layers are being produced simultaneously.

- The gathered fluids must be processed to enhance their value.
- First of all, fluids must be separated into their main phase components;namely, oil, water, and natural gas.
- The *separation system* performs this function. For this, the system is usually made up of a free water knock-out (FWKO), flow line heater, and oil-gas (two-phase) separators.
- The physical separation of these three phases is carried out in several steps. Water is separated first from the hydrocarbon mixture (by means of the FWKO), and then the hydrocarbon mixture is separated into two hydrocarbon phases (gas and oil/condensate).

- A successful hydrocarbon separation maximizes production of condensate or oil, and enhances its properties. In field applications, this is accomplished by means of *stage separation*.
- Stage separation of oil and gas is carried out with a series of separators operating at consecutively reduced pressures. Liquid is discharged from a higher-pressure separator into the next-lower-pressure separator.
- The purpose of stage separation is to obtain maximum recovery of liquid hydrocarbons from the fluids coming from the wellheads and to provide maximum stabilization of both the liquid and gas effluents.

Three stage separators



- Under the assumption of equilibrium conditions, and knowing the composition of the fluid stream coming into the separator and the working pressure and temperature conditions, we could apply our current knowledge of VLE equilibrium (flash calculations) and calculate the vapor and liquid fractions at each stage.

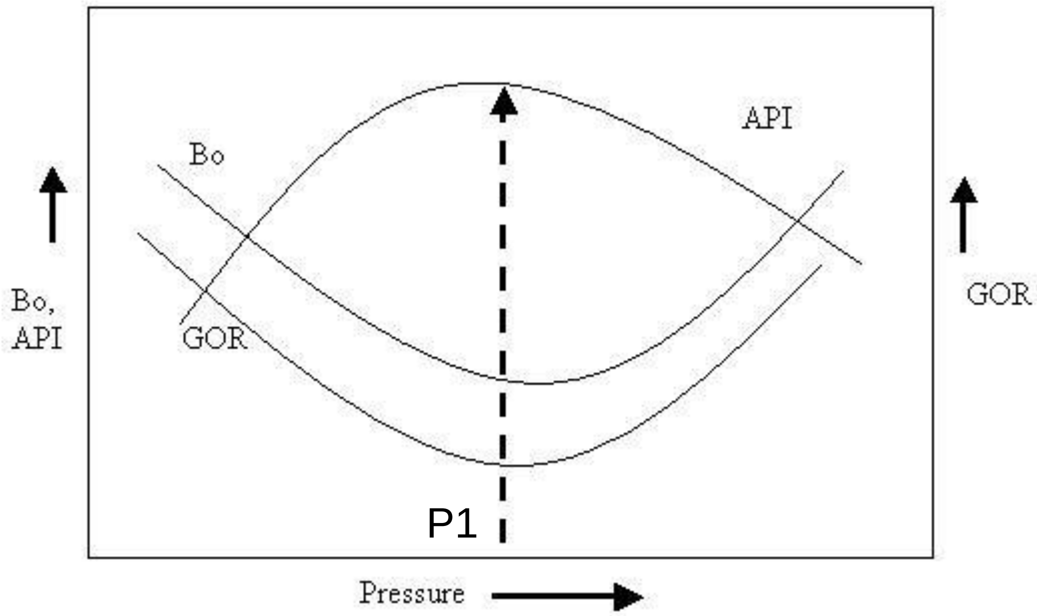
- However, if we are looking at designing and optimizing the separation facility, we would like to know the optimal conditions of pressure and temperature under which we would get the most economical profit from the operation.
- In this context, we have to keep in mind that stage separation aims at reducing the pressure of the produced fluid in sequential steps so that better and more stock-tank oil/condensate recovery will result.
- Separator calculations are basically performed to determine:
  - Optimum separation conditions: separator P and T
  - Compositions of the separated gas and oil phases
  - Oil formation volume factor
  - Producing Gas-Oil ratio
  - API gravity of the stock tank oil

- In case of three-stage separation, temperature conditions in the surface separation facility are very much determined by the atmospheric condition and incoming stream temperatures.
- As for pressures, the very first separator pressure is controlled by the gathering lines coming from well heads, thus there is not much room for playing with pressure in the first separator. The same arguments are valid for the last stage of separation (stock tank), which usually operates at atmospheric conditions.
- Therefore, we are only left with the *middle separator* for optimization.
- What we can do, using our phase behavior knowledge, is to find this optimum middle stage pressure applying our understanding of VLE equilibrium.

What we need to achieve

- Here is a typical effect of playing with the middle separator pressure on the quality and quantity of produced oil/condensate at the stock tank.
- Quality and quantity are measured in terms of properties, such as API and B_o, and the overall GOR at the separation facility.
- The optimum value of pressure for the middle stage is the one that produces the maximum liquid yield (by minimizing GOR and B_o) of a maximum quality (by maximizing stock-tank API gravity).
- The smaller the value of GOR and B_o, the larger the liquid yield. The higher the API gravity of the stock-tank fluid, the more profitable its commercialization.

- From this figure, we see that P1 is found at neither extreme (low/high) values of middle stage pressure. There is, in fact, an optimal value for middle stage pressure.



Natural Gas Pipeline Modeling

- Once natural gas is produced and processed, few to several hundred kilometers may lie in between it and its final consumers.
- A cost-effective means of transport is essential to bridge the gap between the producer and consumer. In the technological area, one of the challenges pertains to the capacity of the industry to ensure continuous delivery of natural gas while its demand is steadily increasing.
- Thus, it is no wonder that pipelines have become the most popular means of transporting natural gas from the wellhead to processing — and from there to the final consumer — since it better guarantees continuous delivery and assures lower maintenance costs.

- The major variables that affect the design of gas pipelines are

  : the projected volumes that will be transported,

  : the required delivery pressure (subject to the requirements of the facilities at the consumer end),

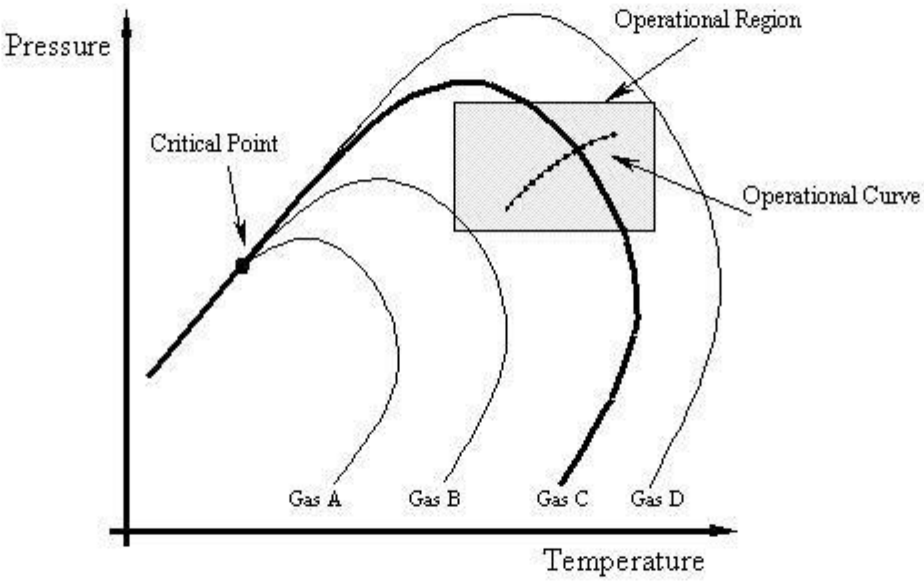
  : the estimated losses due to friction,

  : the elevation changes imposed by the terrain topography.

- Overcoming such losses will likely require higher pressure than the one available when the gas is being produced. Thus, forcing a given gas rate to pass through a pipeline will inevitably require the use of compressor stations.

- Once a pipeline is deployed, it has a more or less a fixed operational region. An upper and lower set of operational conditions allowable within the pipeline (in terms of pressure and temperature) will exist.
- On the one hand, the upper allowable condition will be set by the pipe strength, pipe material, diameter, and thickness. These will determine the maximum pressure that the pipe can endure without failure (i.e., maximum operating pressure).
- On the other hand, maximum pressure and temperature of the compressor station discharge (which feeds the inlet of the pipe) will also contribute to set this upper level. It is clear that the conditions at the discharge of the compressor station cannot go beyond the maximum operating pressure of the pipe — otherwise the pipe will fail.
- The minimum or lower pressure and temperature condition of the operational region will be assigned by an agreement with the end consumer.

- The foregoing description of the operational region is shown schematically as the shaded area in this figure.



- In natural gas flow, pressure and temperature changes (P-T trace) may cause formation of a liquid phase owing to partial condensation of the gaseous medium.

- This figure shows four typical phase envelopes for natural gases, which differ in the extent of their heavy components.
- For a given composition, the prevailing pressure and temperature conditions will determine if the fluid state is all liquid (single-phase), all gas (single-phase) or gas-liquid (two-phase).
- Each envelope represents a thermodynamic boundary separating the two-phase conditions (inside the envelope) from the single-phase region (outside).
- Each envelope is made of two curves: the dew point curve (right arm, where the transition from two-phase to single-gas occurs) and the bubble point curve (left arm, where the transition from single-liquid to two-phase occurs). Both arms meet at the critical point.

- The wetness of the gas is an important concept that helps to explain the different features in the figure.
- This concept pertains to the amount of heavy hydrocarbons (high molecular weight) that are present in the gas composition.
- In the figure the driest gas — i.e., the least wet — can be recognized as that whose left and right arms are the closest to each other, having the smallest two-phase region (gas A).
- In this figure, it can be seen that the right arm is extremely susceptible to the presence of heavies in the natural gas composition. Depending on the gas composition, the pipeline operational region can be either completely free of liquid (gas A, the driest) or partially submerged in the two-phase region (gas B, C). If the gas is wet enough, the pipeline will be entirely subjected to two-phase conditions (gas D, the wettest).

- In the figure, a pipeline handling a dry gas (gas A) will be operating a single-phase mode from its inlet through its outlet. For this case, any of the popular single-phase gas equations can be used for design purposes and to help to predict the actual operational curve (P-T trace).
- If a richer gas comes into the system (gas C), it will show a single-phase condition at the inlet, but after a certain distance the pressure and temperature conditions will be within the two-phase region.
- The case might also be that the system is transporting a wetter gas (gas D), in which case it would encounter two-phase conditions both at the inlet and at the outlet of the pipe.

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Thank you