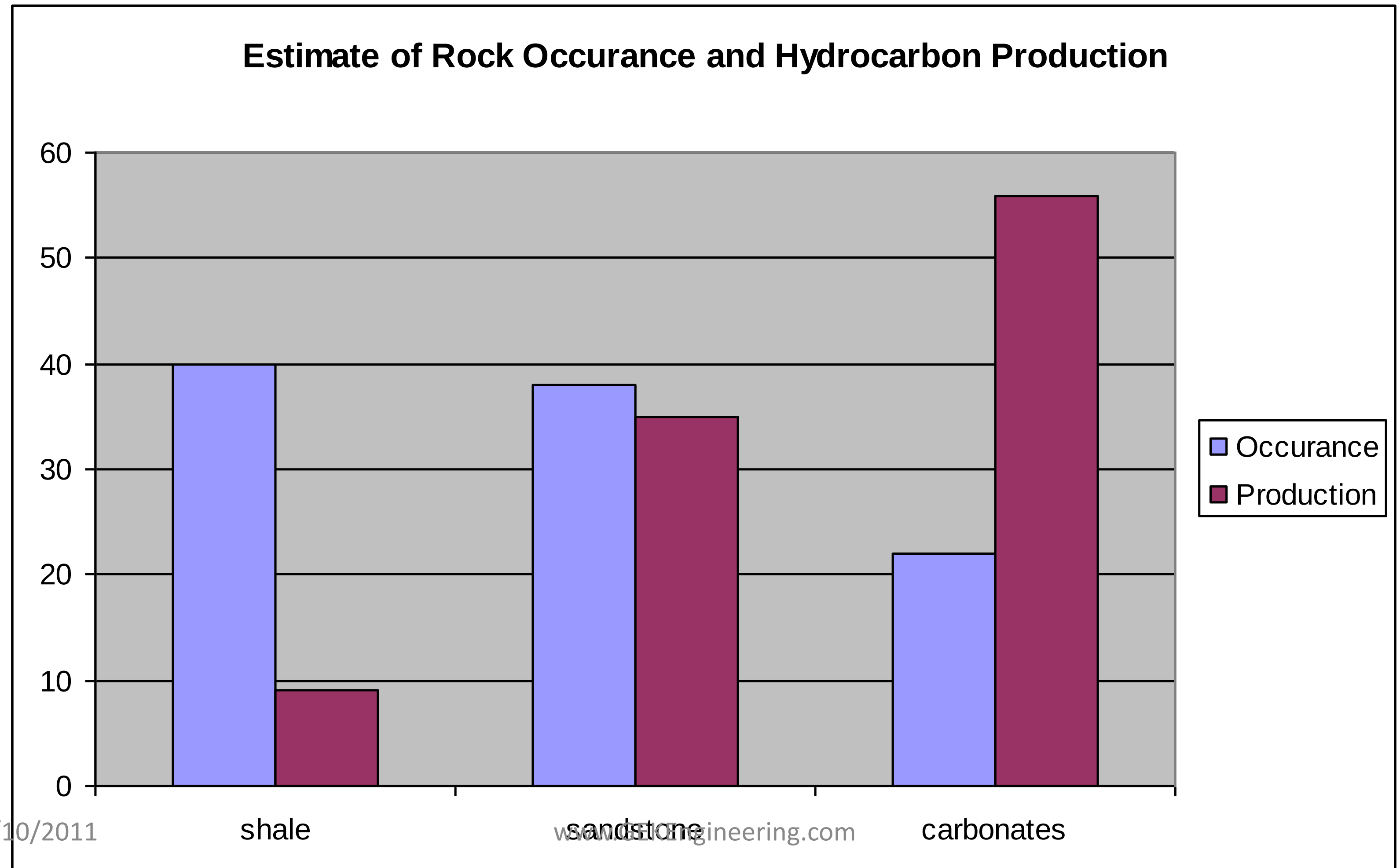
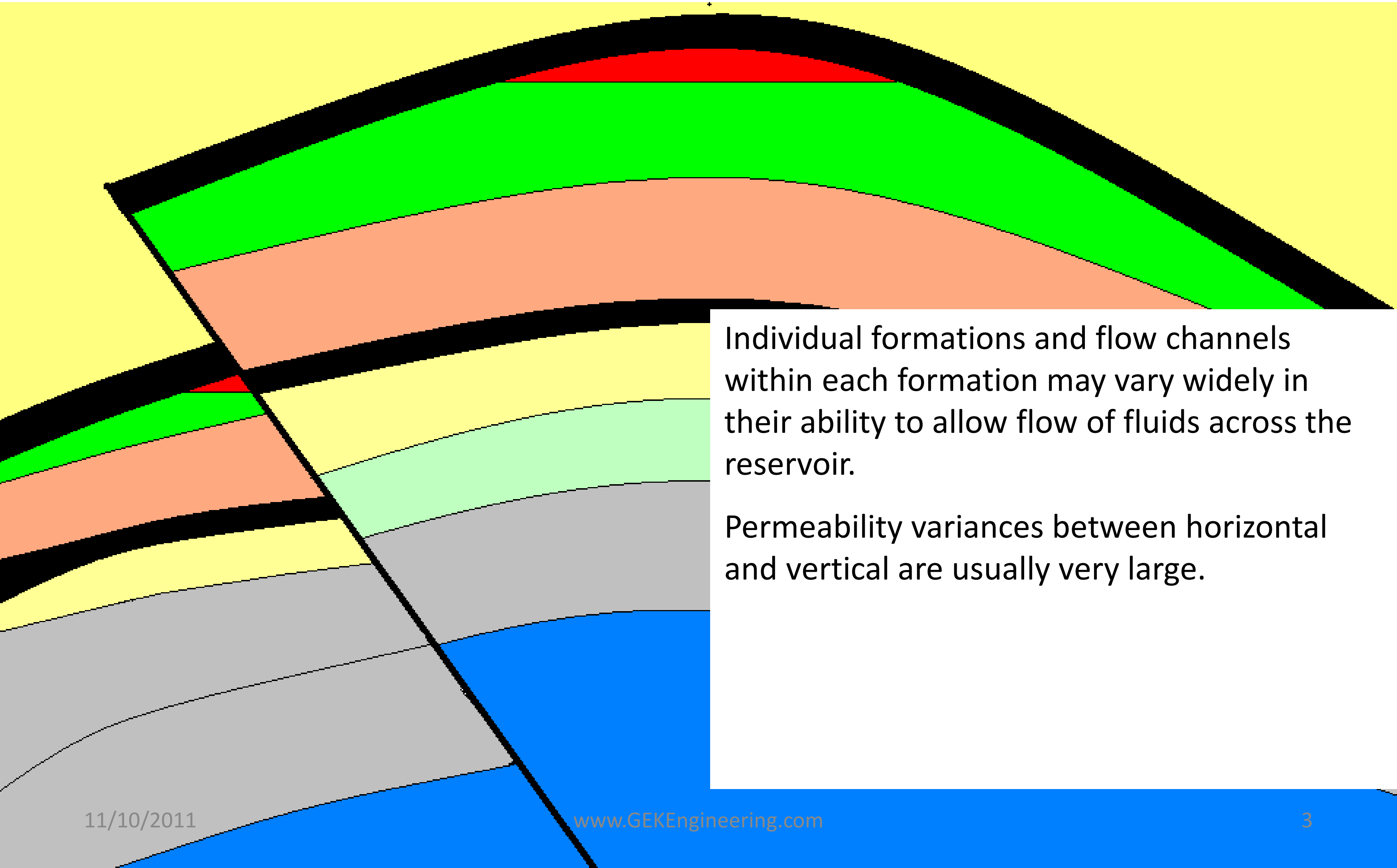
From the Reservoir Limit to Pipeline Flow: How Hydrocarbon Reserves are Produced

Rock Occurance and Production

Although carbonates are a smaller volume of rock present, they dominate oil production totals (Mid East fields). Why?



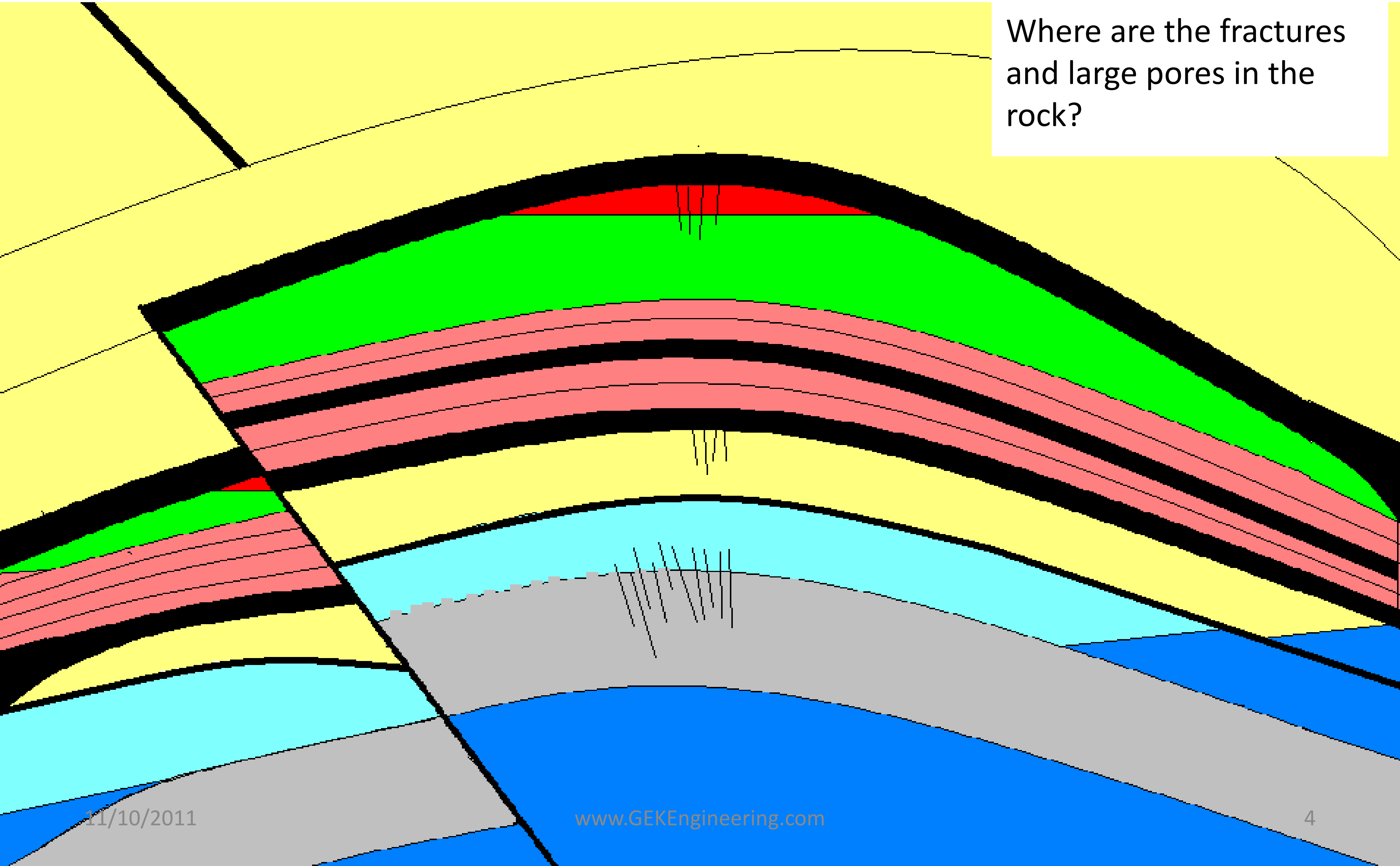
What routes are open to flow?



Individual formations and flow channels within each formation may vary widely in their ability to allow flow of fluids across the reservoir.

Permeability variances between horizontal and vertical are usually very large.

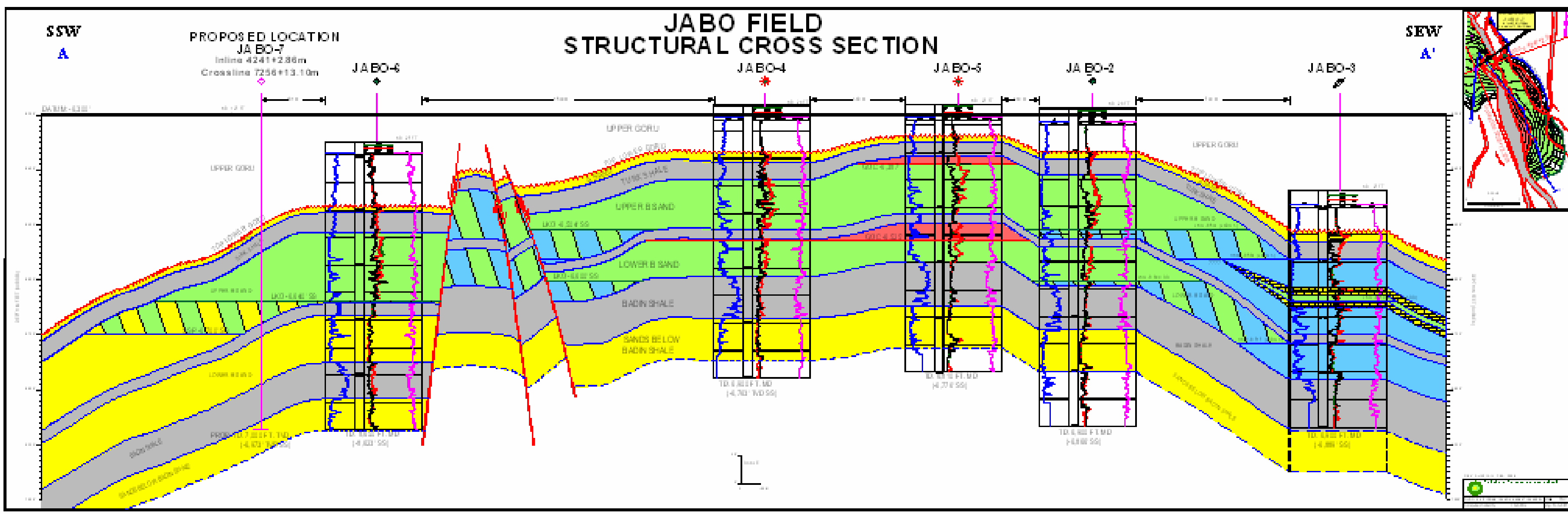
What is the accuracy of the Information?



Where are the fractures and large pores in the rock?

A cross section of a reservoir

This type of illustration helps to understand reservoir complexity, compartments, potential pays and water sources. Permeabilities in these pays are reported at 1 to 9 Darcies.

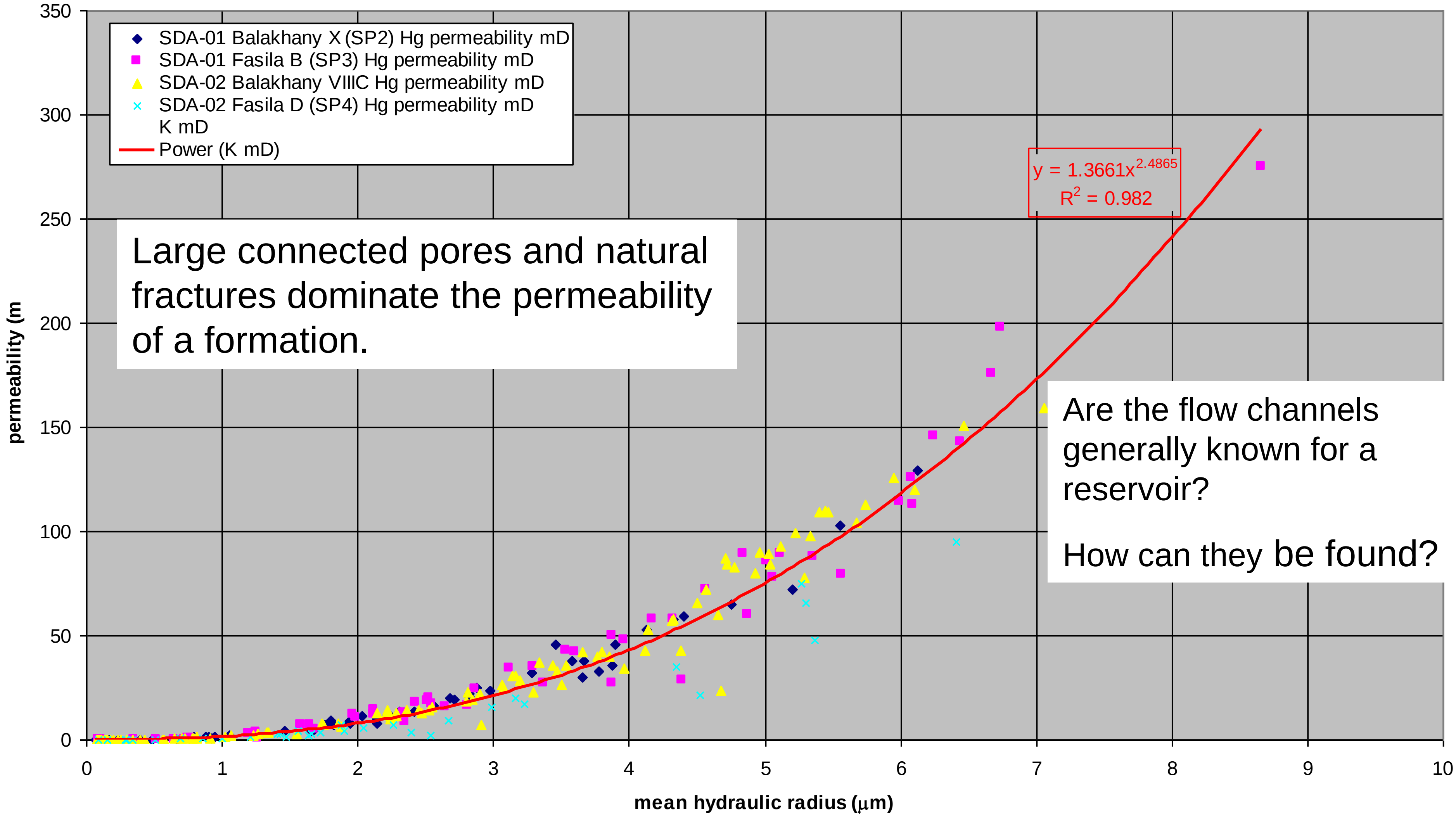


Source – Karamat Ali, BP Pakistan

Segments

- Rock properties and reservoir character, quality,
- Reservoir fluid qualities – how they change during movement and over time with depletion.
- Reservoir flow paths and compartments impact on fluid flow
- The effects of pressure drop and back pressure on fluid flow in the reservoir
- Well Placement and Impact of Wellbore-to-Reservoir contact
- Fluid behavior in approach and entry to the wellbore
- Lift type and optimization of flow from bottom hole through the tubing
- Operations effect on the flow rate –
  - Choke settings
  - Restrictions
  - Separator operations
  - Pipeline
  - Start-ups, operations, shut-downs, stabilizing actions

Pore Size vs. Permeability



Large connected pores and natural fractures dominate the permeability of a formation.

Are the flow channels generally known for a reservoir?

How can they be found?

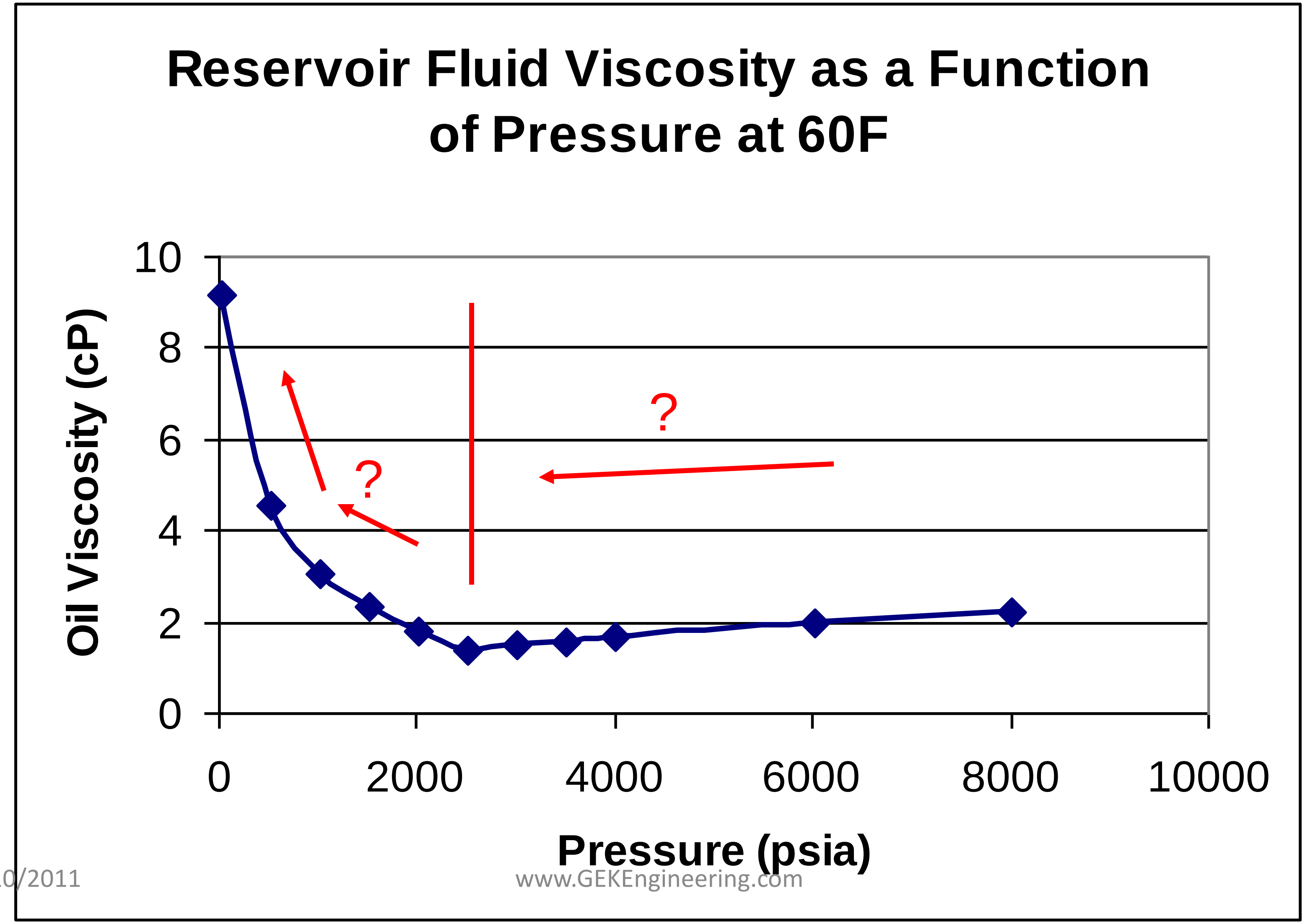
Reservoir Fluids – What a PE needs to understand.

- What phases are present?
- Where are they?
- Do the fluid compositions or quantities change? How?
- How do fluids and fluid changes affect permeability?

PVT Properties (Pressure Volume Temperature)

- Oil Formation Volume Factor – how many reservoir barrels it takes to equal a stock tank barrel after the oil volume shrinks during production due to loss of associated gas.
- Bubble Point Pressure – the pressure at which free gas is seen in a reservoir with no gas cap.
- GOR – gas to oil ratio of produced oil.
- API Gravity (density): API° = [(141.5/SG)-131.5]
- Dynamic Viscosity – the viscosity at reservoir conditions (temperare and associated gas decrease viscosity making the viscosity in the reservoir lower than the viscosity at surface).

What happens to the oil viscosity during production? Why?



Oil Types

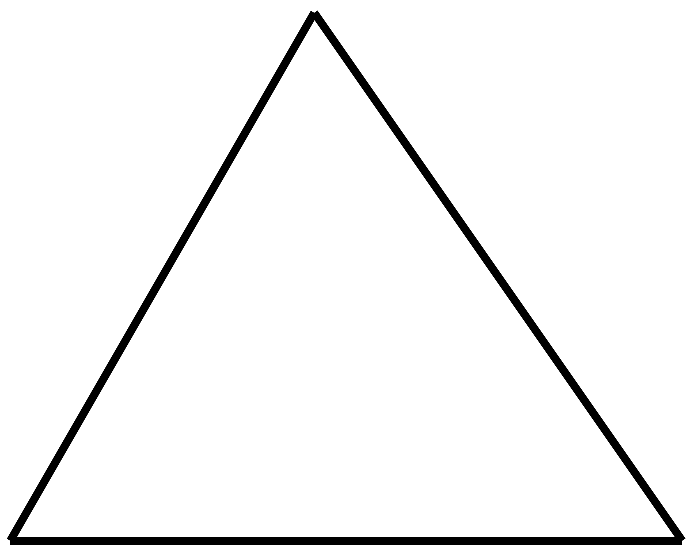
- Paraffin Base
  - Straight chain hydrocarbons. Natural gas condensates, waxes, lube oils.
- Naphthene Base Oils
  - Ring or cyclic structure, but single bonds.
  - Usual API gravities below 25º API. Dominates the longer chain, heavier weight oils.
- Olefinic Series – double bonds in a straight carbon chain.
- Aromatic Series – double bonds in a ring

Saturated Hydrocarbons

Unsaturated Hydrocarbons

Oil Types

Paraffin – or linear carbon chain



Aromatic – or cyclic structure carbon chain

Asphaltene (Naphthene) – normally cyclic groups with Nitrogen and Sulfur components (Heavy)

Hydrocarbon Liquids

- Crude Oils
- Condensates (API 40 and above)
- NGL – natural gas liquids
- LPG – Liquified Petroleum Gas
- LNG – Liquified Natural Gas

Range of compositions from C2 to C6+

Reservoir Brines

- A vast array of water based fluids from fresh water with very low resistivity to super saturated salt water.
- Tracking the composition of waters and the changes with time can be beneficial to determine the source of water production and leaks.
- Tracking the composition of flow back after a workover or a stimulation that uses an injected brine can signal when the job has cleaned up.

Water Analysis Over Time

Deep Water GOM

Date	NaCl	Cl	Na	Ca	Mg	pH	HCO3	Ba	SO4	Fe	Sr	TDS
12/23/04	112,000	67,961		4,400	680	6.80	230	110	45			
01/13/05	104,000	63,107	34,000	3,300	600	8.50	230	100	61	1.3	130	
02/11/05	101,000	61,286	32,000	3,000	560	7.46	450	99	20	1.3	130	
03/24/05	97,000	58,859	31,000	2,800	550	7.84	166	90	37	0	120	102,000
04/28/05		60,400	31,700	2,680	650	7.90	195	94	10	5.8	127	96,400
05/19/05		59,320	28,100	2,164	612	7.85	225	82	7	1	117	91,140
07/21/05		68,075	36,210	3,441	759	7.68	137	109	4	1	147	109,700
08/11/05		68,075	32,440	2,800	766	7.84	220	99	11	1	132	105,000
11/10/05		58,065	29,000	2,400	470	7.97	176	81	15	1	110	90,508
11/17/05		58,064	29,000	2,400	480	6.35	219	85	0	14	120	90,574
12/29/05		58,064	29,000	2,300	490	7.39	195	75	0	2.3	110	90,440
01/05/06		60,066	32,000	2,600	510	7.87	214	89	0	1	120	95,832
01/19/06		61,067		2,700	520	7.41	195	93	1	0	130	95,909

Brine Reactivity Factors

1. Ion type (usually cations) in fluids moving through the matrix pores (some impact on fluids in fractures but to a lesser extent)
2. Size of the cations
3. Charge on the cation
4. Effective salt concentration – higher salt concentrations are usually more effective in controlling mineral concentrations. Due to cation exchange, salt concentration is lost from the brine with rock contact.
5. pH – low pH fluids have generally less effect on clays than high pH fluids.
6. Clay location – detridal clays (in the matrix body) are usually less reactive than authogenic (in the pore throat forms).
7. Clay type – Smectite typically has a high reactivity while kaolinite and chlorite usually have low reactivities.
8. Clay form – some clays like illite may have forms like the "hairy or spider web" deposits that can be more reactive due to higher surface areas.
9. Coatings on clays such as heavy oil fractions can prevent many reactions unless removed by soaps or solvents.
10. Time in contact.

Reactivity of Clays

Mineral	Typical Area (M^2/g)	Cation Exchange Capacity Range (Meq/100 g)
Sand (up to 60 microns)	0.000015	0.6
Kaolinite	22	3 - 15
Chlorite	60	10 - 40
Illite	113	10 - 40
Smectite	82	80 - 150

Size ranges for clays depend on deposit configuration.
CEC's affected by coatings and configurations.

Load Water Recovery

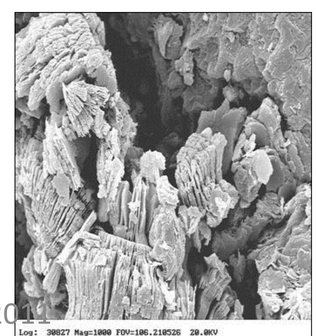
- Range – 5% to 60%+ : the amount of load fluid recovery depends on the formation properties, the fluids properties, the pressure and the time span between pumping and flow back.
- Assists – some surfactants (not all), alcohol, nitrogen gas.
- Detriments – high vertical permeability, high interfacial & surface tension, long shut-in times, low energy, small pore throats….

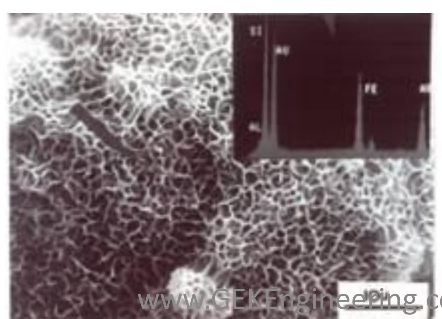
Scale Deposition Causes

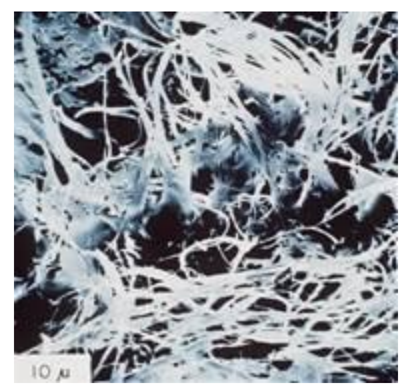
- Change in flow conditions make the scale minerals super-saturated and an upset causes precipitation
  - Temperature change
  - Pressure change
  - Outgassing of CO_2
  - Change in pH
  - Evaporation of water
- Mixing incompatible waters
- Contact with existing scale – scale crystal growth from ions in the water.

Rock Structure

- Lithology or mineralogy – describes the solid or matrix portion of the rock, generally the primary mineralogy, e.g., sandstone, limestone, etc.
- Mineralogy analysis often describes the chemical composition of the components of the rock: sand (SiO_2), limestone ($CaCO_3$), dolomite ($CaMgCO_3$), anhydrite ($CaSO_4$), clays, etc.
- SEM (Scanning Electron Microscope) analysis shows the shape and form of the minerals.



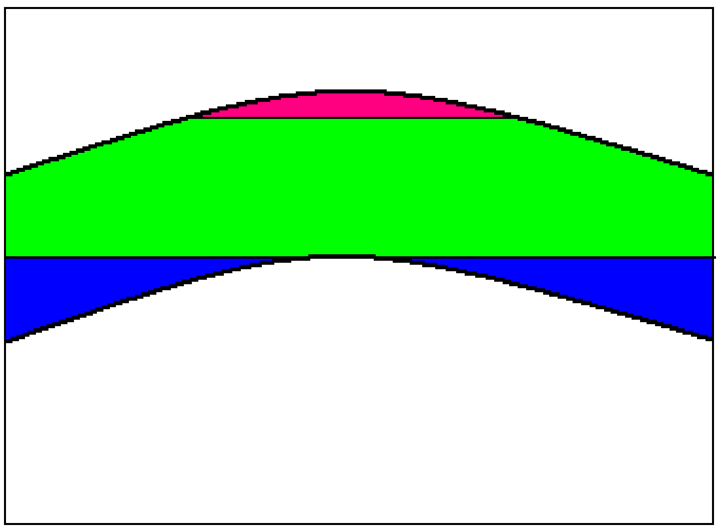




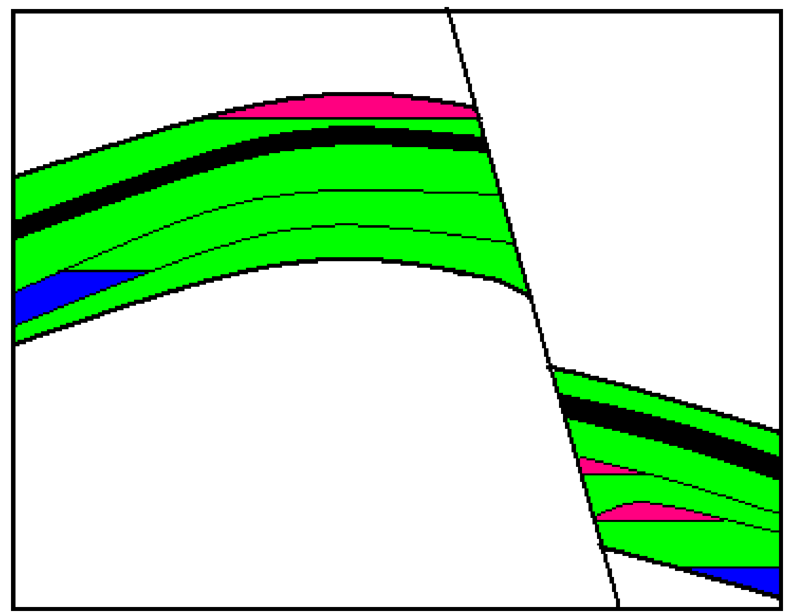
Evaluation of Damage and Barriers

- Production Logs
  - Fluid type and entry or exit at specific intervals,
  - Mechanical condition of parts of the well or equipment,
  - Fluid movement (and holdup) along the wellbore.
- Production History
  - Rates and types of fluids, decline %, water increase, etc.
  - Sudden changes, flood arrivals, workover tracking.
- Deliverability Tests
  - Isochronal, flow-after-flow, four point tests – describe the flow from the formation.
- Buildup & Draw-down Tests – Pressure Transient Analysis (PTA)
  - Investigates damage extent and depth (?), drainage radius, boundaries, etc. Requires some critical assumptions.

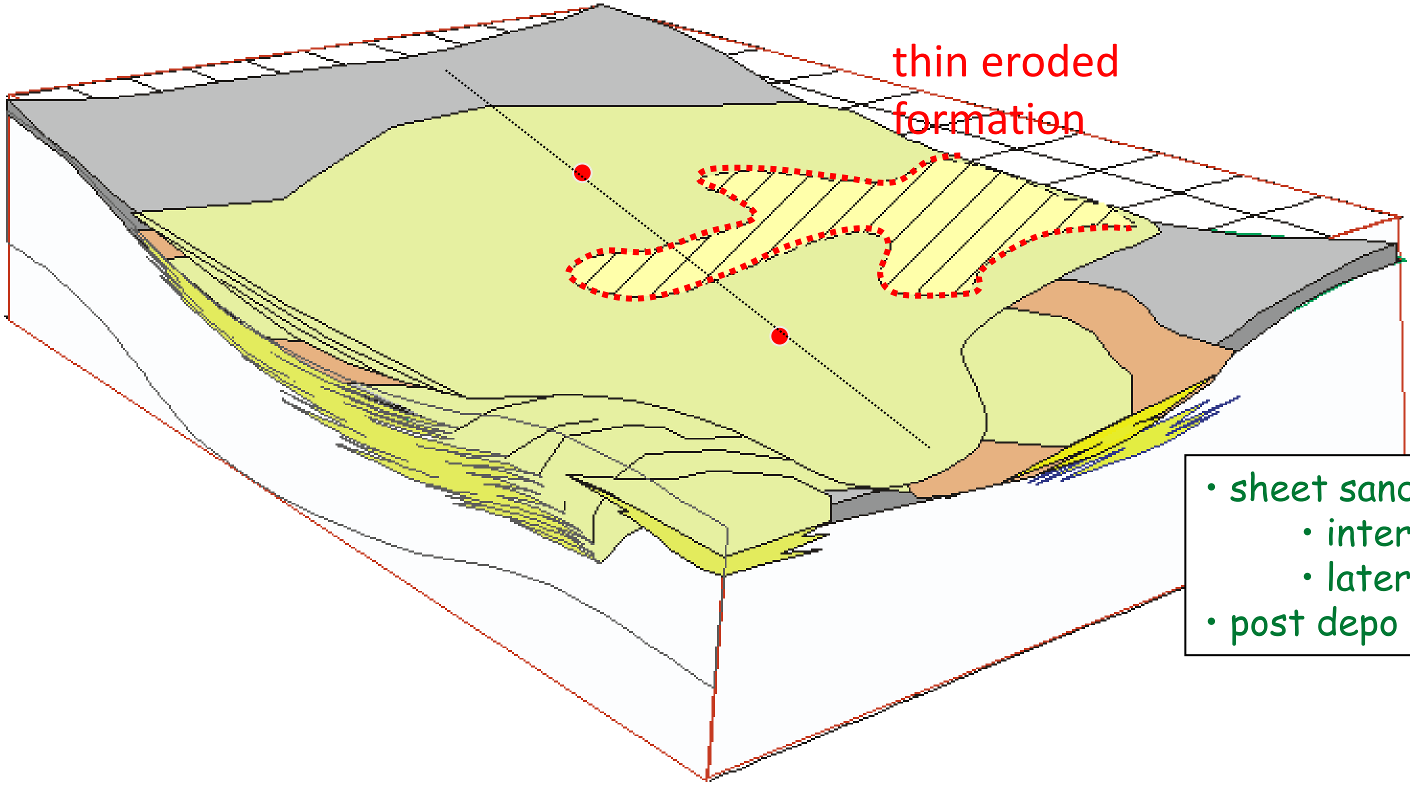
Complexity in the Reservoir



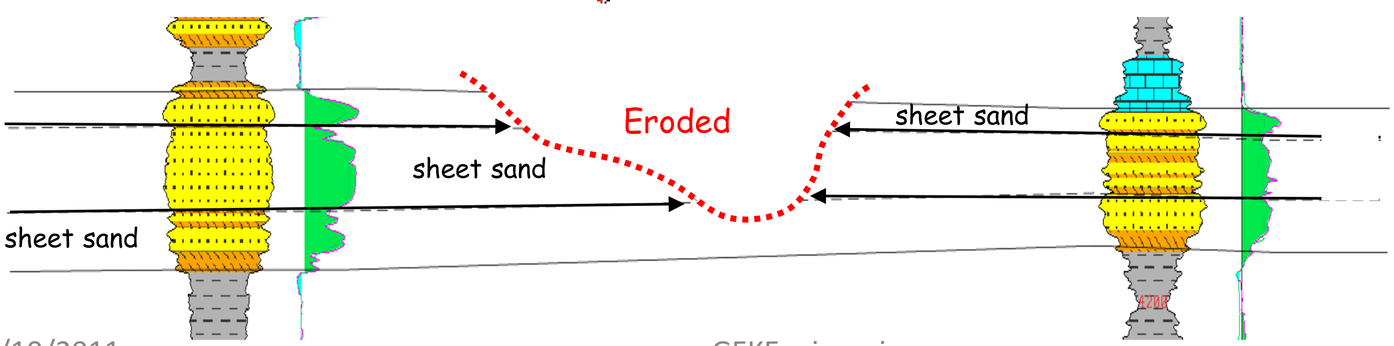
Simple Reservoir ? Only in a text book.



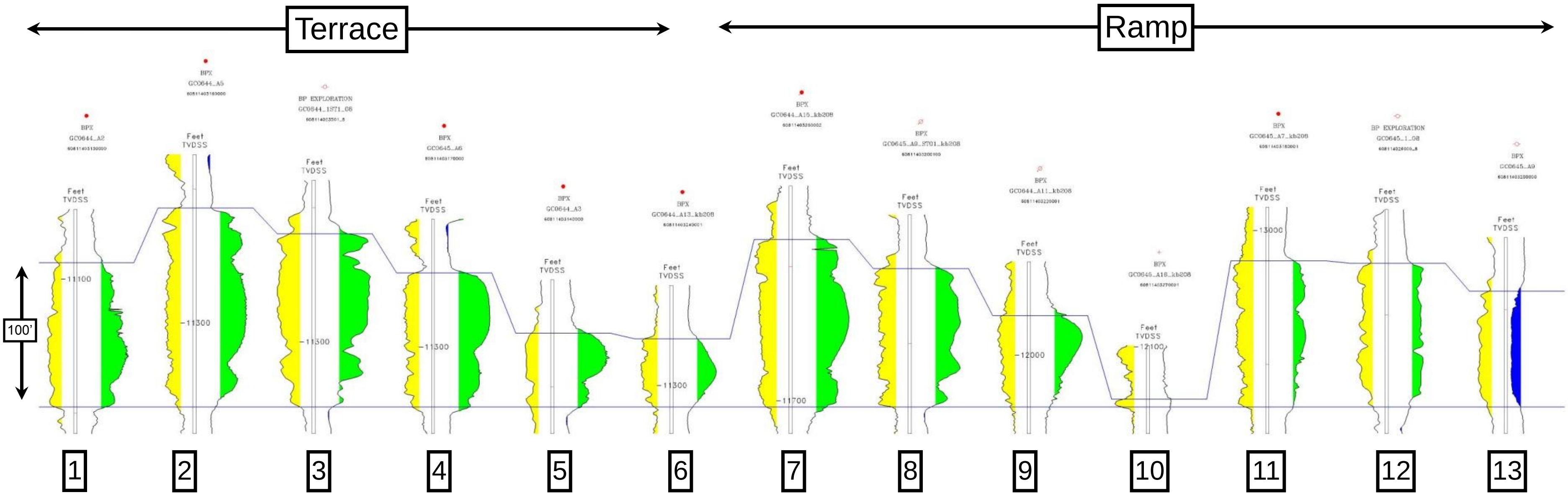
How can this reservoir be produced? What type of completions and what flexibility are needed to effectively deplete the reserves.



- sheet sandstones
    - internally homogenous
    - laterally/vertically connected
- post depo erosion



Pay Quality

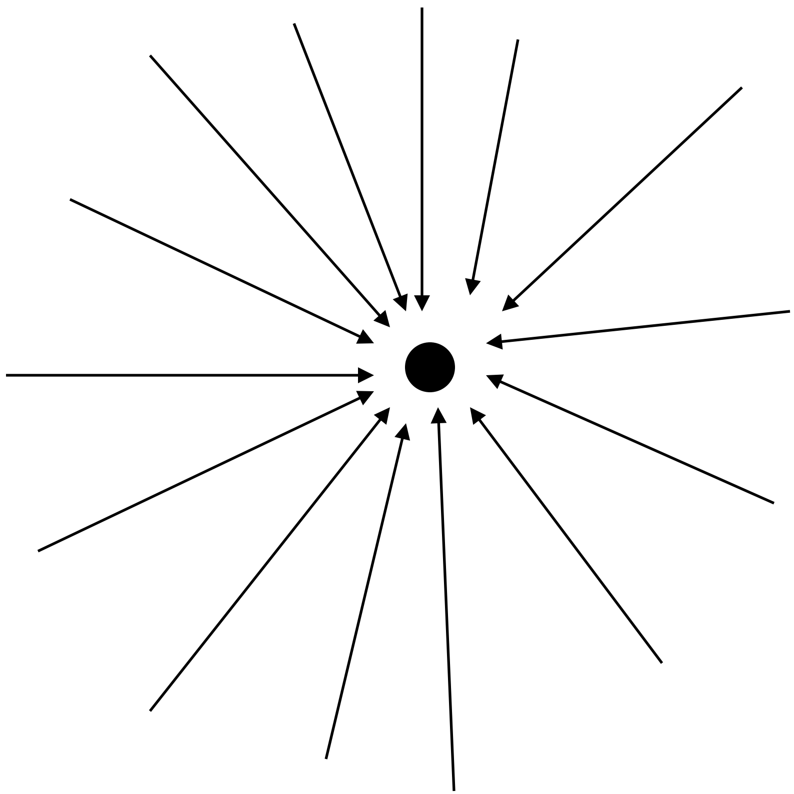


The XX is a clean and very fine grain bedded to amalgamated sand. Where present, thin shale occurs as interbeds capping turbidite bed complexes. XX architecture ranges from channelforms and parallel lobes to shingled complexes. Erosion has removed much of the XX on the ramp causing moderate to significant baffling which limits the effectiveness of the waterflood.

Attribute	Range	Average
Gross h (TVT feet)	3-82’	47’
Net Pay (TVT feet)	3-77’	43’
Net-to-Gross	.88-.99	.91
Porosity	.25-.31	.29
Sw	.10-.30	.18

Inflow – What is the flowpath from near wellbore into the reservoir

Convergent Flow – less and less pore space as fluids near the wellbore – higher friction, higher turbulence.



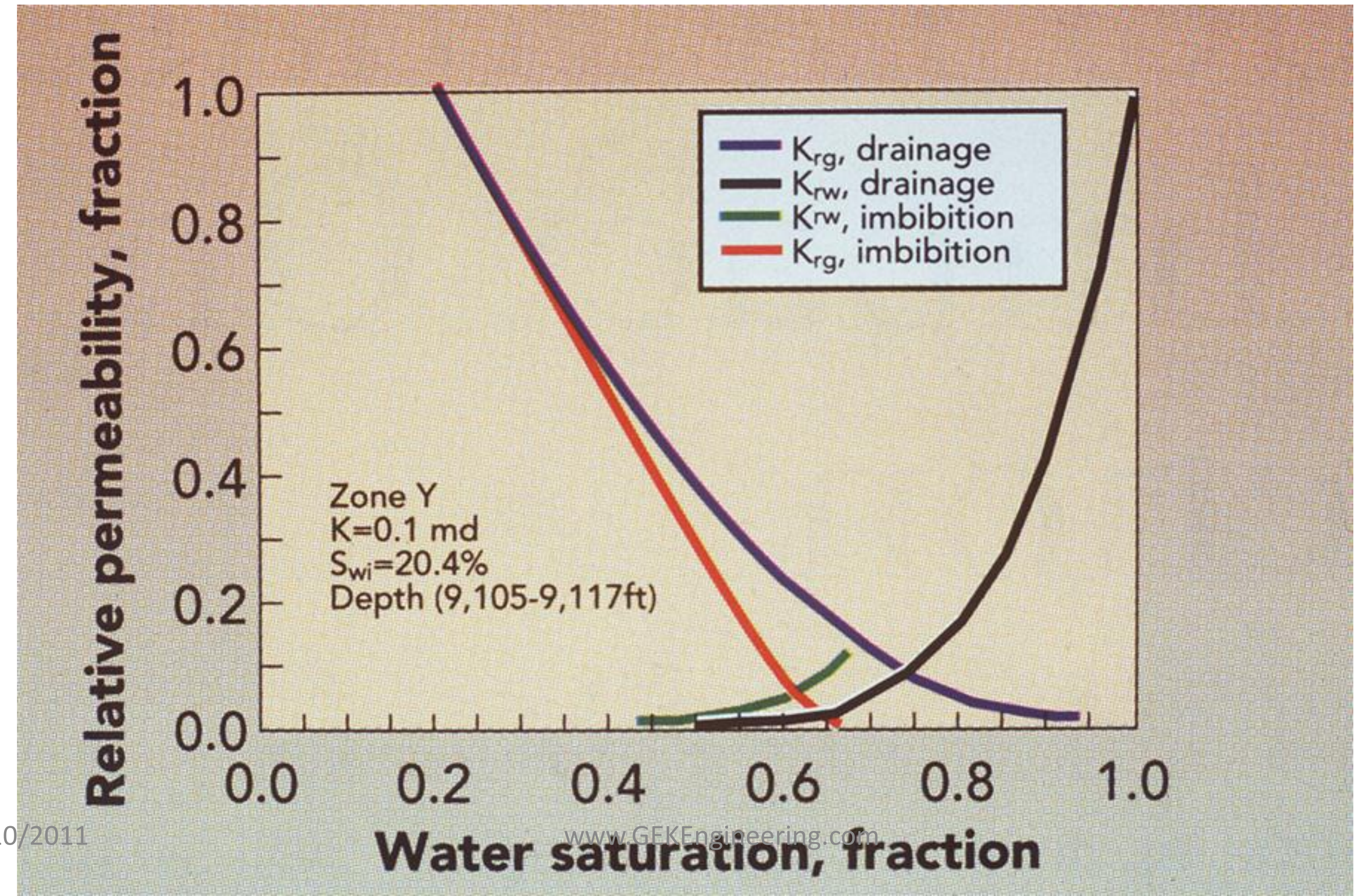
Even with a fracture, flow towards a single point becomes restrictive as the inflow point is neared.

Permeability

- Permeability, k, is the ability of the rock to transmit fluids.
- Permeability is controlled by the size of the connecting passages between the pores.
- Secondary porosity, particularly natural fractures and solution vugs dominate permeability – often are 100x the matrix permeability.
- Permeability is NOT a constant – it changes with stress, fluid saturation, produced fluid deposition, stimulations, damage from fluids, etc.

Relative Permeability

Note that the permeability to the starting fluid decreases with invasion of a second phase, and that permeability to the invading phase gradually increases with saturation of that phase.



Permeability Measurements

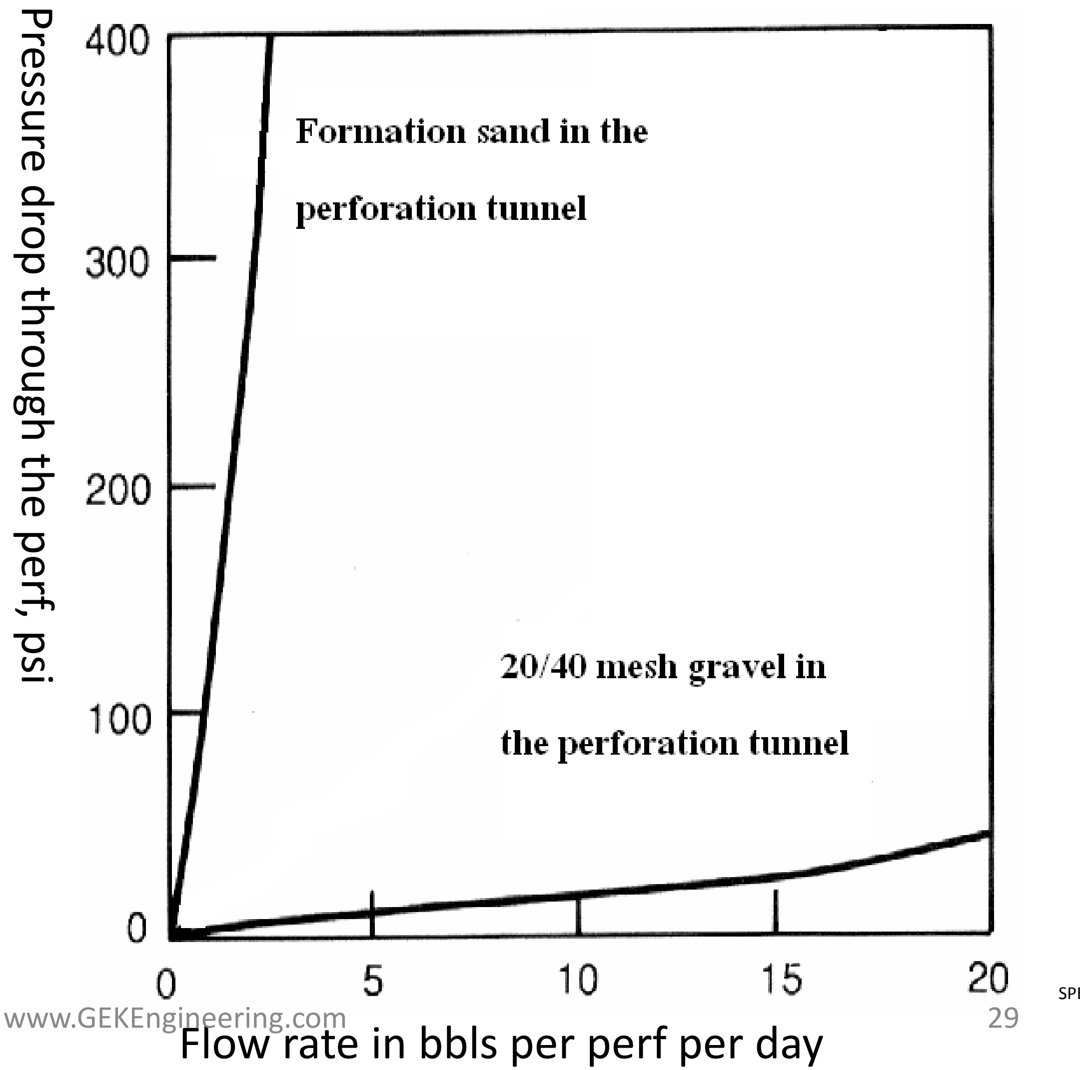
- Absolute Permeability – the ability of a rock to transmit a single fluid when it is saturated with that fluid.
- Effective Permeability – the ability of the rock to transmit one fluid in the presence of another when the two fluids are immiscible.
- Relative permeability – the ratio between effective permeability to a specific fluid at partial saturation and the absolute permeability.

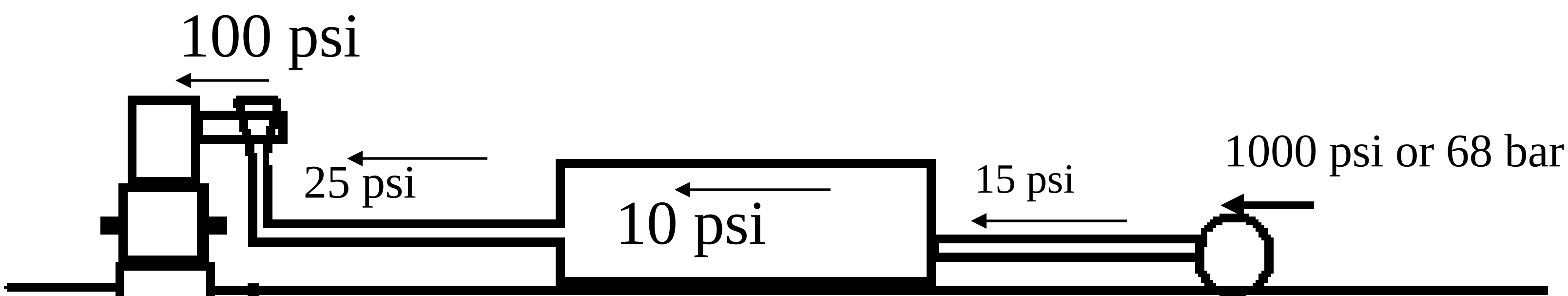
Source – AAPG Basic Well Log Analysis, Asquith. G., Krygowski, S.

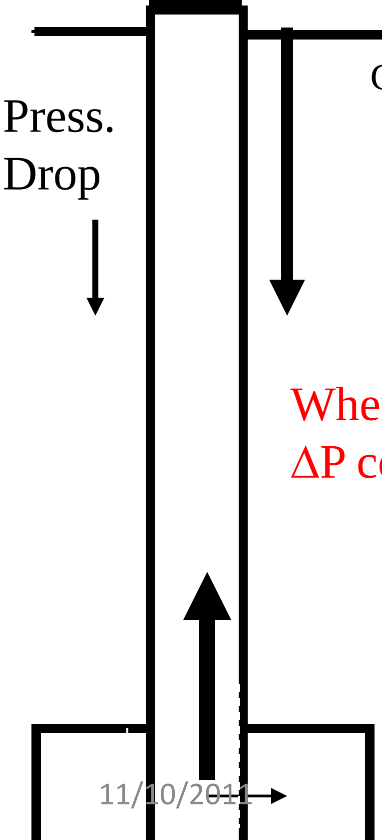
What is the pressure drop in the Perforation Tunnel

The perforations open a very small area in the casing.

If that area is filled with sand, the pressure drop increases significantly.







Column Densities:

Gas = 1.9 lb/gal = 0.1 psi/ft = 1900 psi in a 10,000 ft well
Dead oil = 7 lb/gal = 0.364 psi/ft = 3640 psi in a 10,000 ft well
Fresh water = 8.33 lb/gal = 0.433 psi/ft = 4330 psi in a 10,000 ft well
Salt water = 10 lb/gal = 0.52 psi/ft = 5200 psi in a 10,000 ft well
Gas cut flowing oil = 5 lb/gal = 0.26 psi/ft = 2600 psi in a 10,000 ft well

Where does the pressure drop or ΔP come from?

4600 psi reservoir pressure
-2600 psi flowing gradient for oil
- 150 psi press drop
- 100 psi through the choke
- 25 psi through the flow line
- 10 psi through the separator
- 15 psi through downstream flow line
-1000 psi sales line entry pressure

ΔP = 700 psi drawdown pressure

10,000 ft or 3050 m

4600 psi or 313 bar

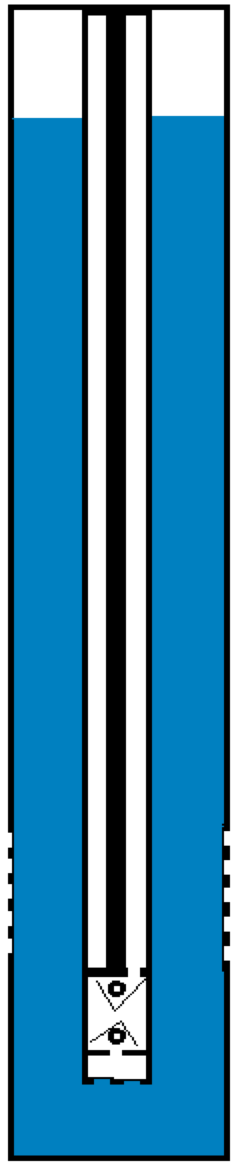
Liquid Height Over The Pump – Does it matter?

More fluid height over the pump?

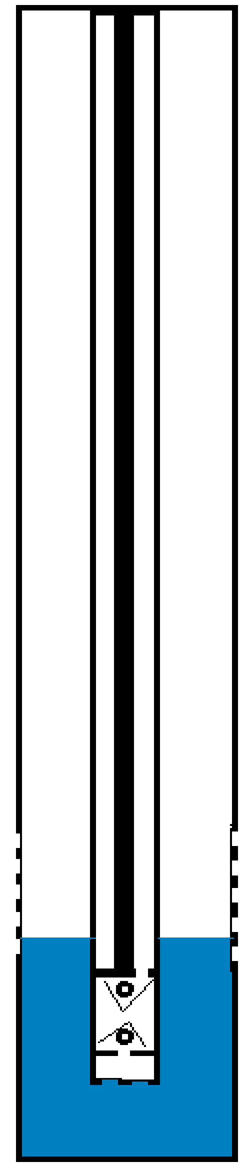
Holds more back pressure.

Restricts the inflow?

May keep gas collapsed!



The ideal fluid height over the pump depends on fluid and wellbore characteristics.



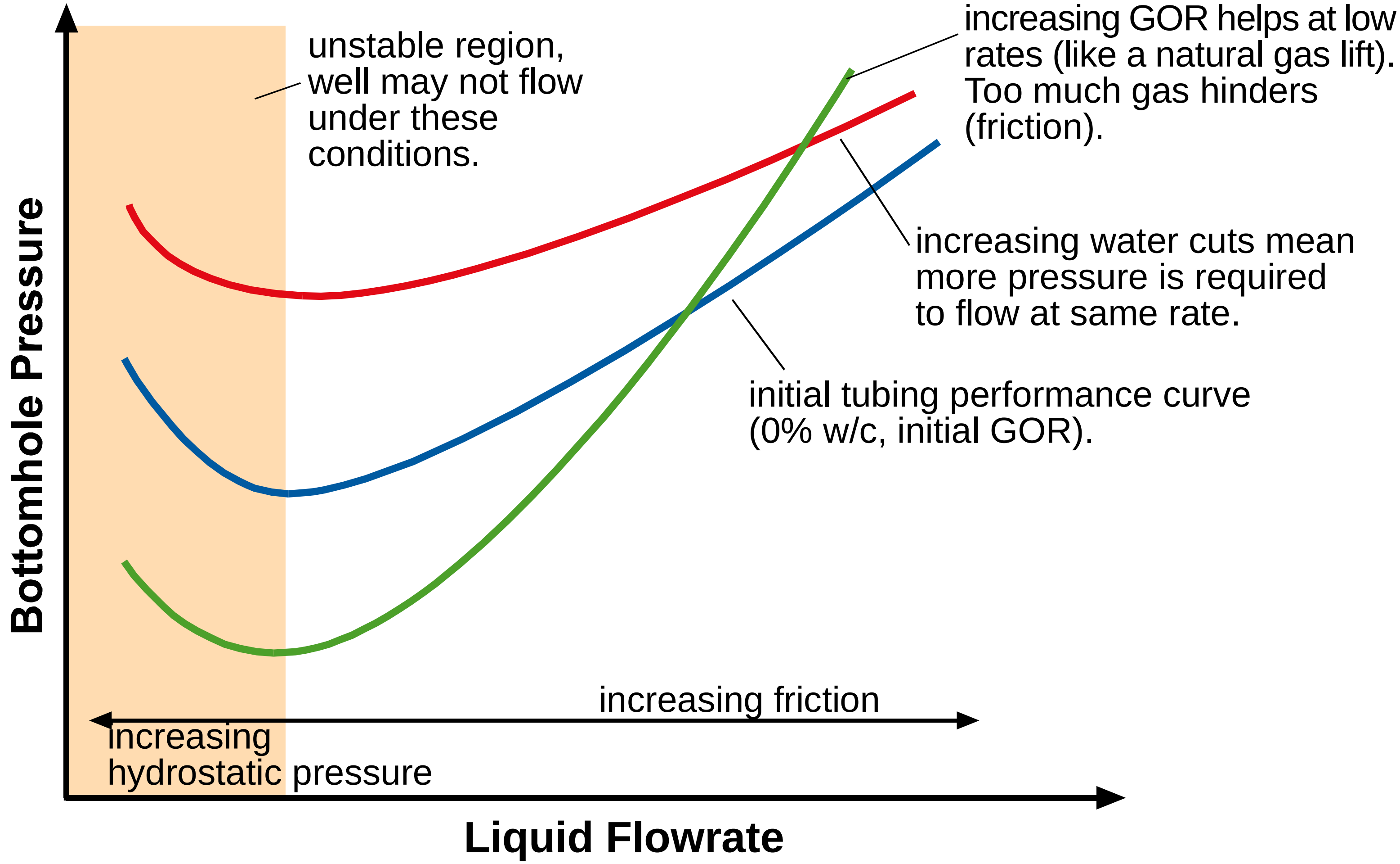
Less fluid over the pump?

Lower BHFP.

At higher gas content, pump may become gas locked.

Too little fluid increases the potential for pump-off.

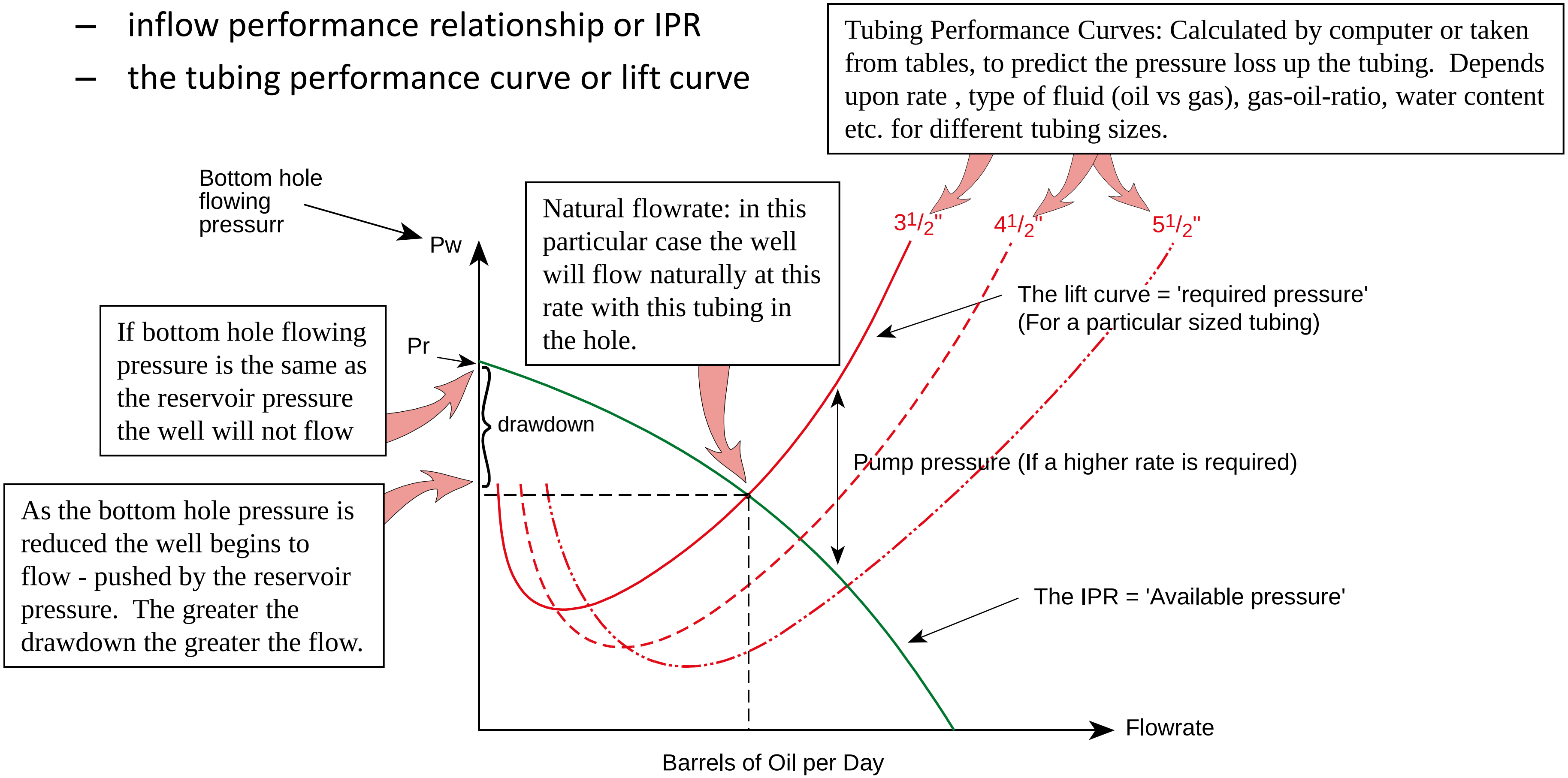
Completions - Tubing Performance



TUBING PERFORMANCE RELATIONSHIP

How Wells Produce -
Production Rate and Tubing Sizing

- The pressure drops are plotted against flowrate to give
  - inflow performance relationship or IPR
  - the tubing performance curve or lift curve



Inflow Performance Relationship (IPR) and tubing Performance Curves

Expansion of gas occurs as the gas rises from the bottom of the well. The expanding gas can entrain and carry liquid with it if the flow rate reaches critical velocity (the velocity necessary to lift liquid).

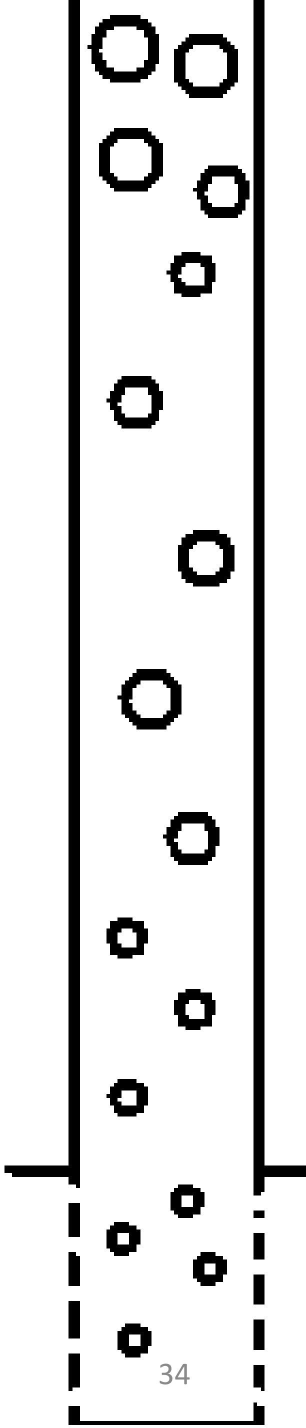
Remember – the volume of the gas bubble (and indirectly the velocity of the upward flowing fluid) is controlled by the pressure around it. This pressure is provided by the formation pore pressure and controlled by the choke and other back pressure resistances.

2500 ft

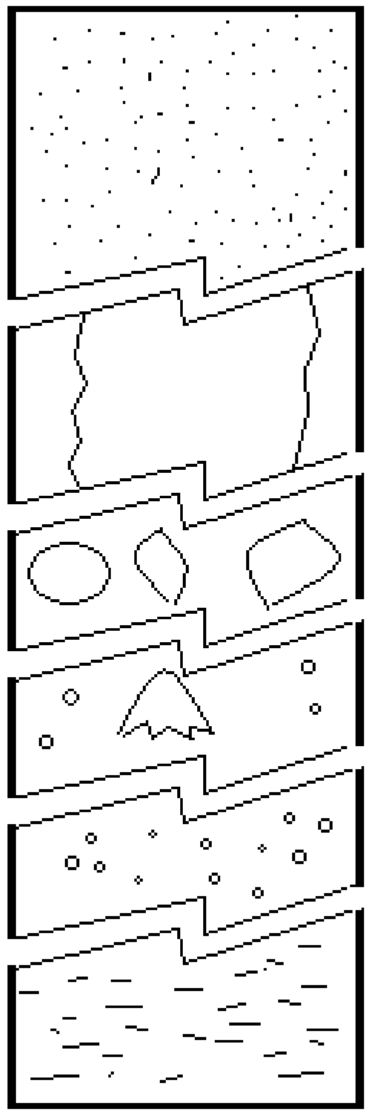
1075 psi

5,000 ft

2150 psi



Depth and Pressure



Mist Flow – external phase is gas with a small amount of liquid

Channel or annular flow

Slug or churn flow

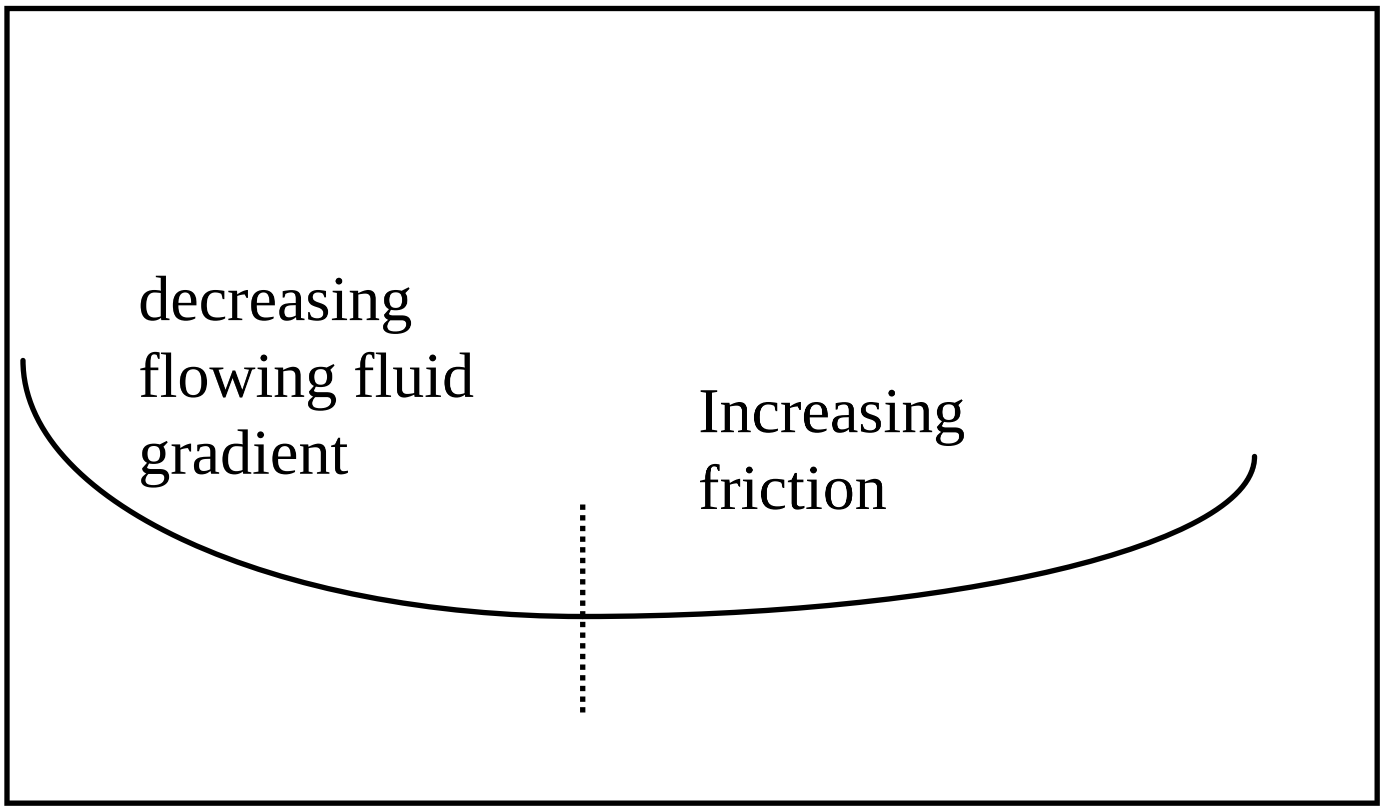
Piston flow

Bubble flow

Single phase liquid flow

– As gas is added, the FBHP decreases due to gas cut liquid. When too much gas is added, the friction from the flowing volume increases.

FBHP



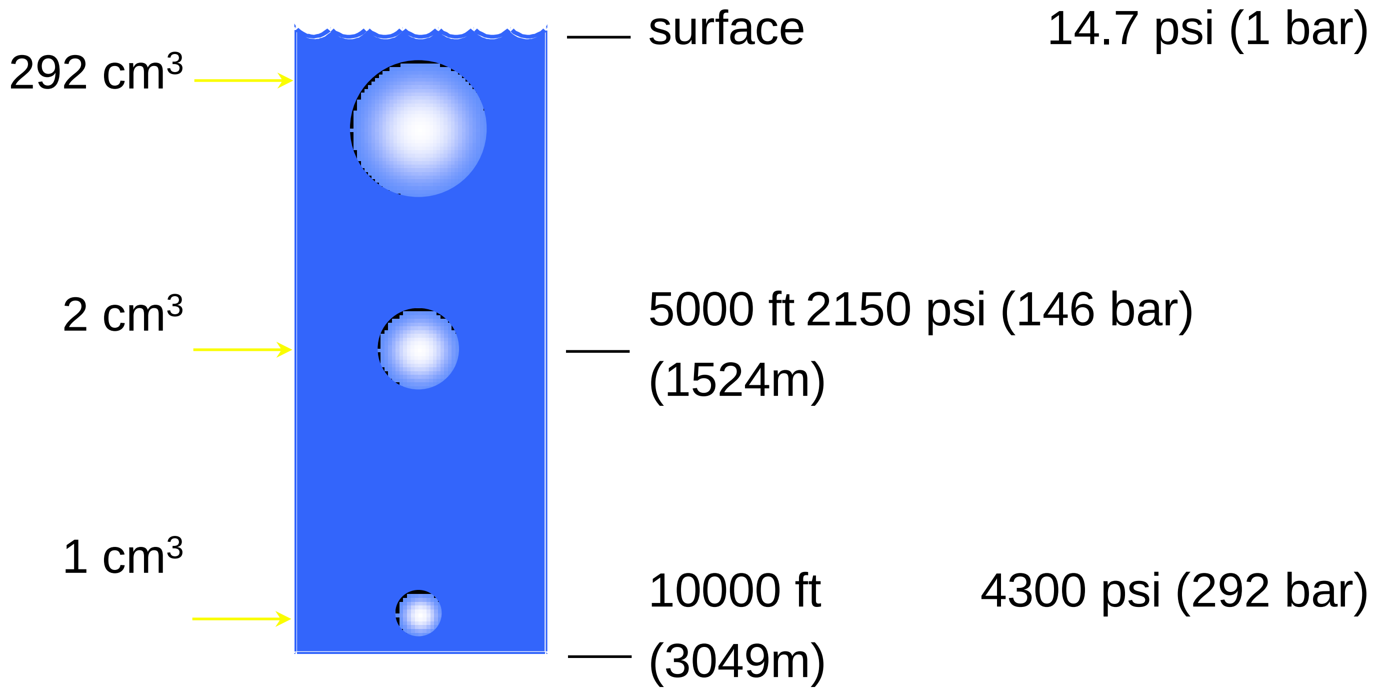
Increasing Gas Injection or GLR

Variable Chokes - good for bringing wells on gradually and optimizing natural gas lift flow in some cases.

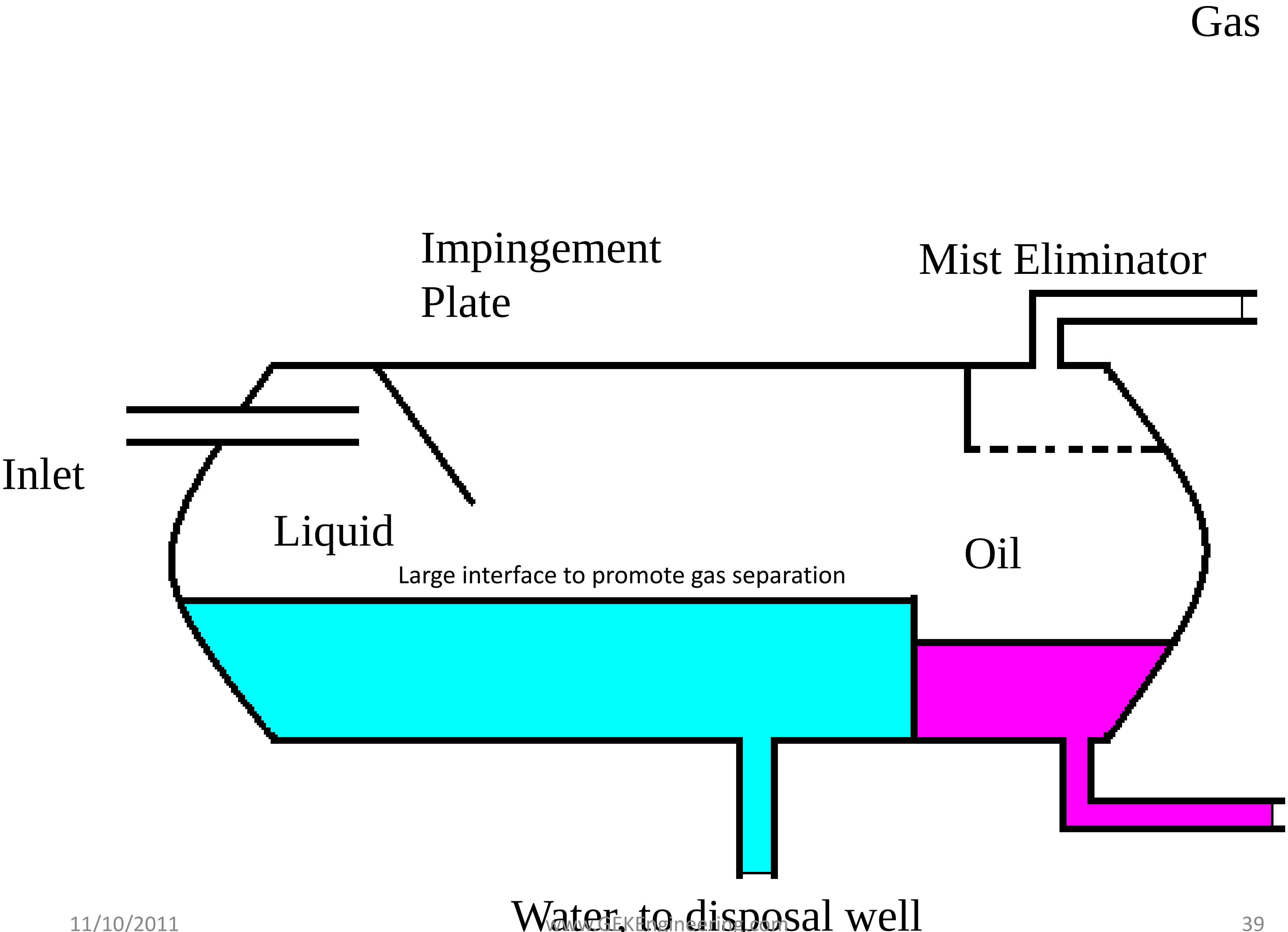
Prone to washouts from high velocity, particles, droplets.

Solutions - hardened chokes (carbide components), chokes in series, dual chokes on the well head.

Size of a Bubble Rising in a Liquid Column



What will the expansion of the bubbles produce at surface?
Energy and friction.


Gas
Impingement
Plate
Mist Eliminator
Inlet
Liquid
Large interface to promote gas separation
Oil
Water, to disposal well

Conclusions

- The Flow System – from reservoir to pipeline
  - Every pressure drop lowers production
  - Pressure drops:
    - Converging flow
    - Damaged permeability or natural fractures
    - Low flow capacity fractures
    - Perforations that are partly plugged
    - Liquid in the wellbore
    - Choke backpressures
    - Friction in tubulars
    - Facility backpressures