Workover Effects on Surface Facilities

- Facility Design
- Impact of completions, workovers and stimulations on facility operations
- Facility problems and solutions

Problem Components and Properties

- Low pH – range from 7 to 0
- Polymer waste
- Bacterial mass
- Salts
- Saturated solutions
- Corrosion by-products
- Undissolved and poorly wetted fines
- Incompatible waters
- Paraffin and asphaltenes

Polymer as it is mixed – in what form does it return?

Polymer causes:

Oil carry over in the dumped water,

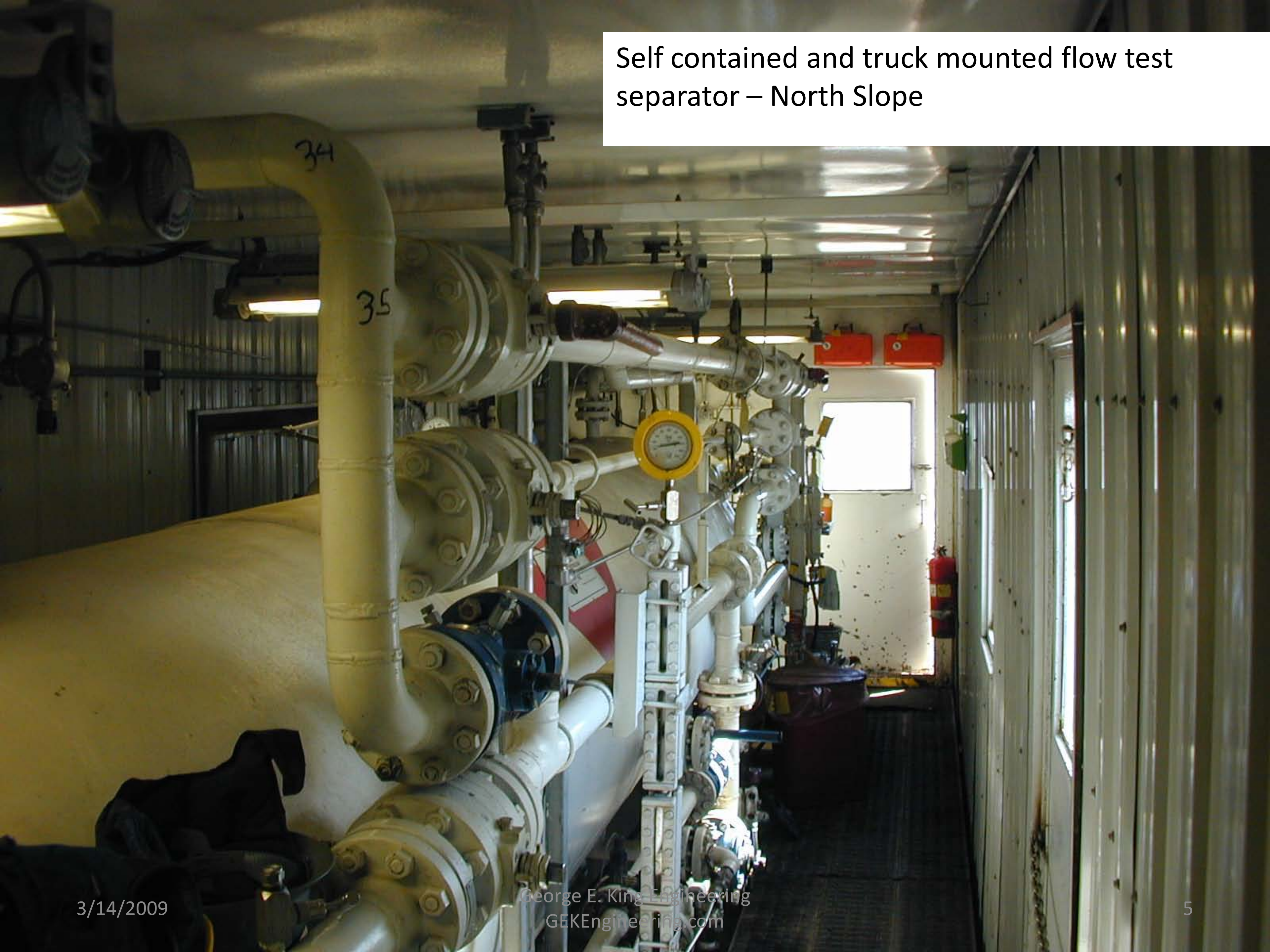
Slow emulsion breaks, stabilize emulsions

Carries large amounts of fines.

Spent Completion/Stimulation Fluid Density

- Frac flowback 8.5 lb/gal
- 10% HCl 9 lb/gal
- 15% HCl 10 lb/gal
- 28% HCl 11 lb/gal

Self contained and truck mounted flow test separator – North Slope



Causes of Treating Upsets

- Change in pH of in-coming fluid
- Increased flow overwhelming separators
- Formation solids
- Paraffin and asphaltenes
- Completion fluids and additives
- Corrosion solids (soluble iron maximums)
- Polymers, acids, caustics, etc.

Predict and Prevent Upsets.

- Isolate workover fluid returns
- Monitor well flowback
  - pH
  - Ions
  - Fluid Volumes
  - Have treating chemical on site

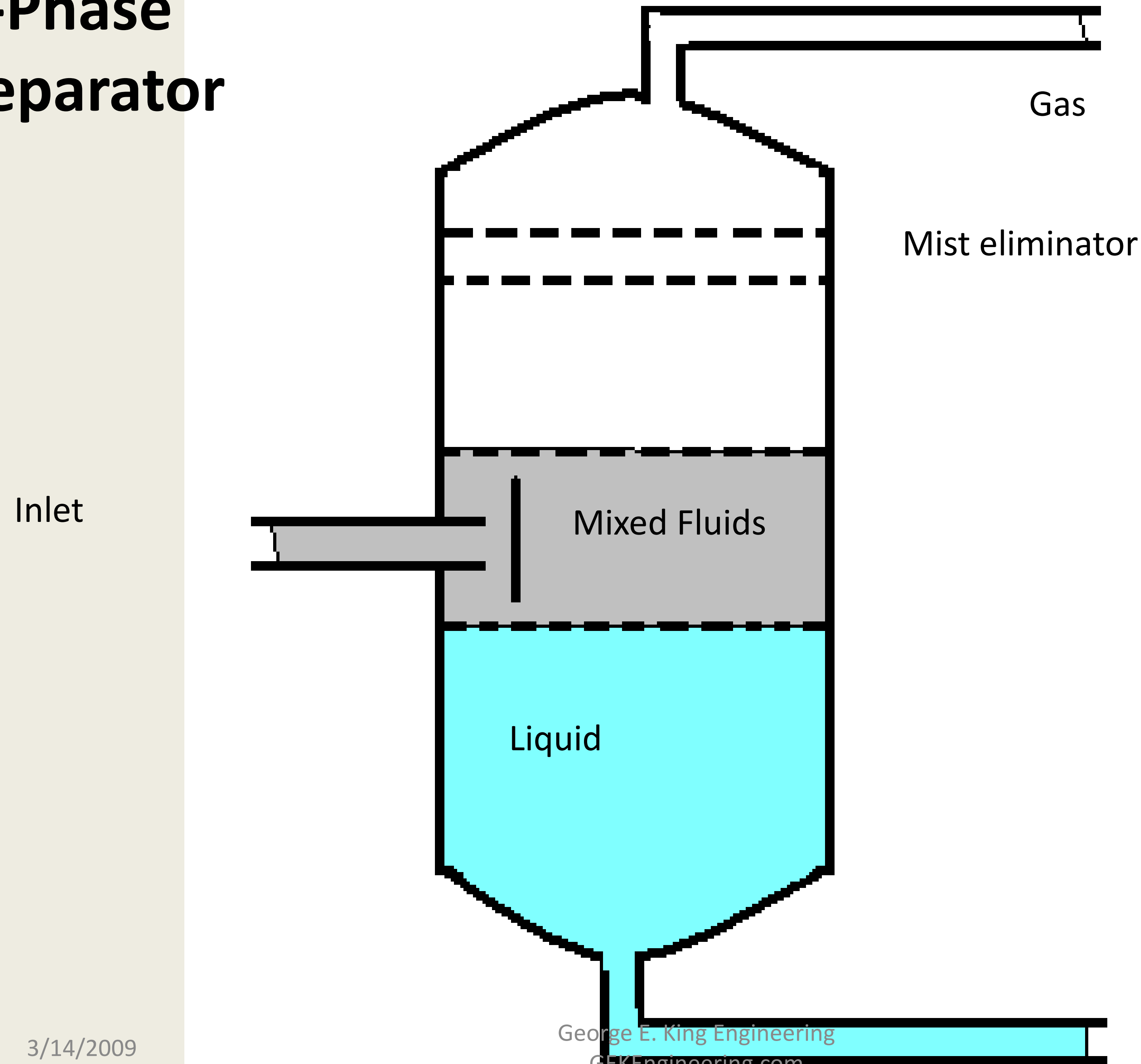
Basic Separation, 2 and 3 Phase

- 2 phase
  - Usually separates gas from liquid
  - Components: mist eliminator, inlet diverter, liquid level control and liquid dump valve.
- 3 Phase
  - Separate gas from liquids
  - Separate water from oil
- Separator efficiency depends heavily on residence time.

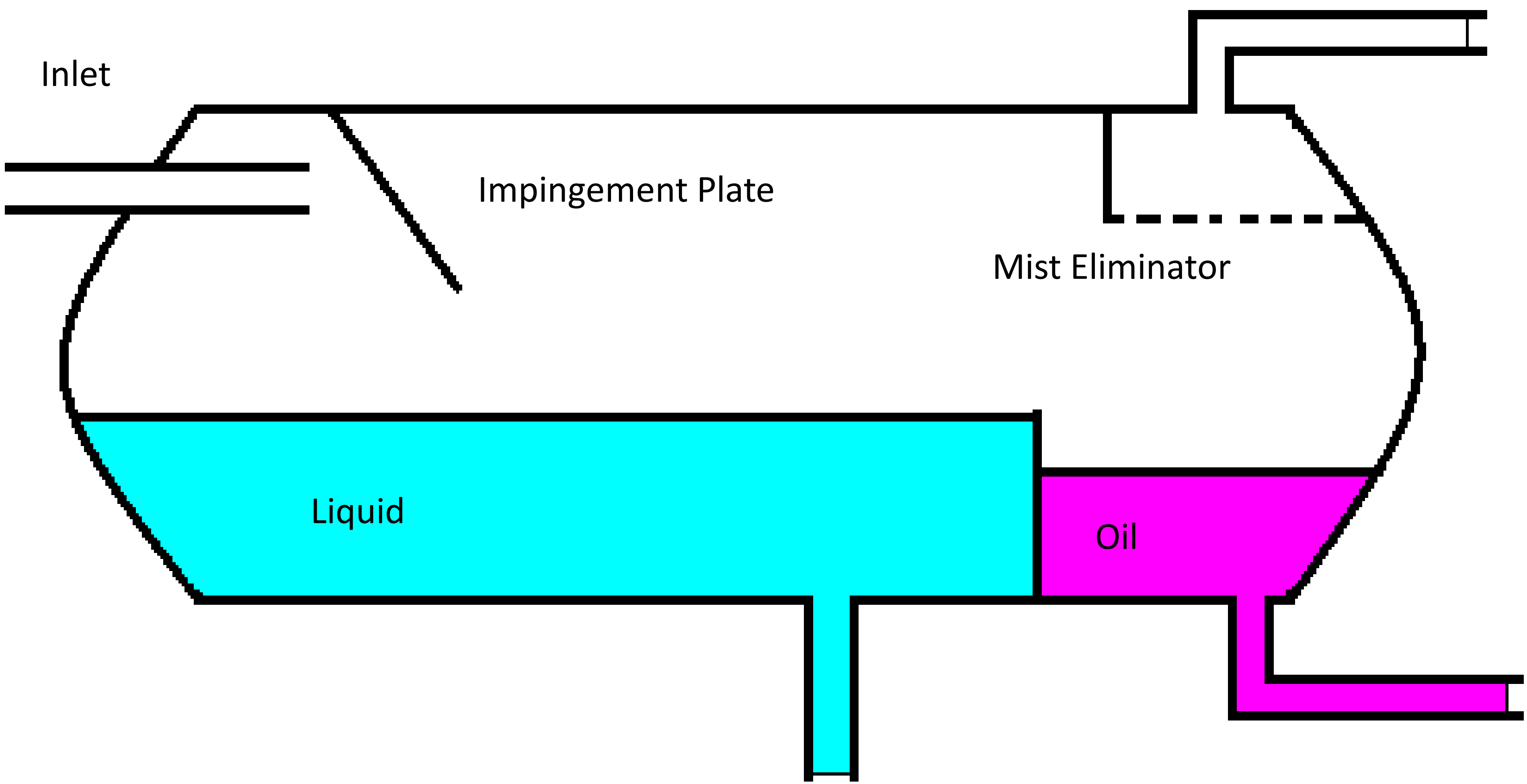
Well backflow after a nitrified acid stimulation – note multi component nature (gas, spend acid, oil, solids, corrosion products, etc.)

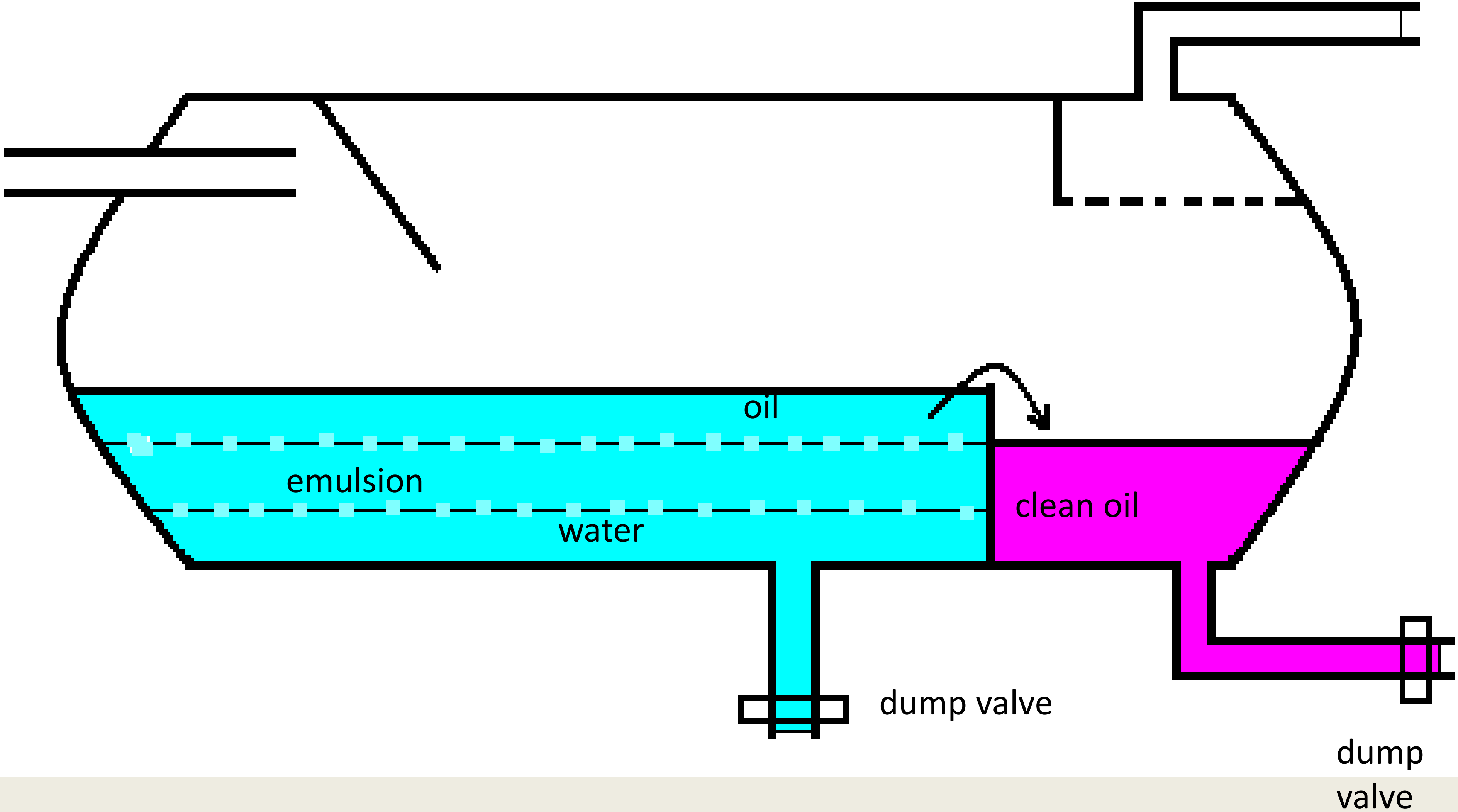
– flowback pit; cira 1960's. – using specialized flowback tanks today.

2-Phase Separator



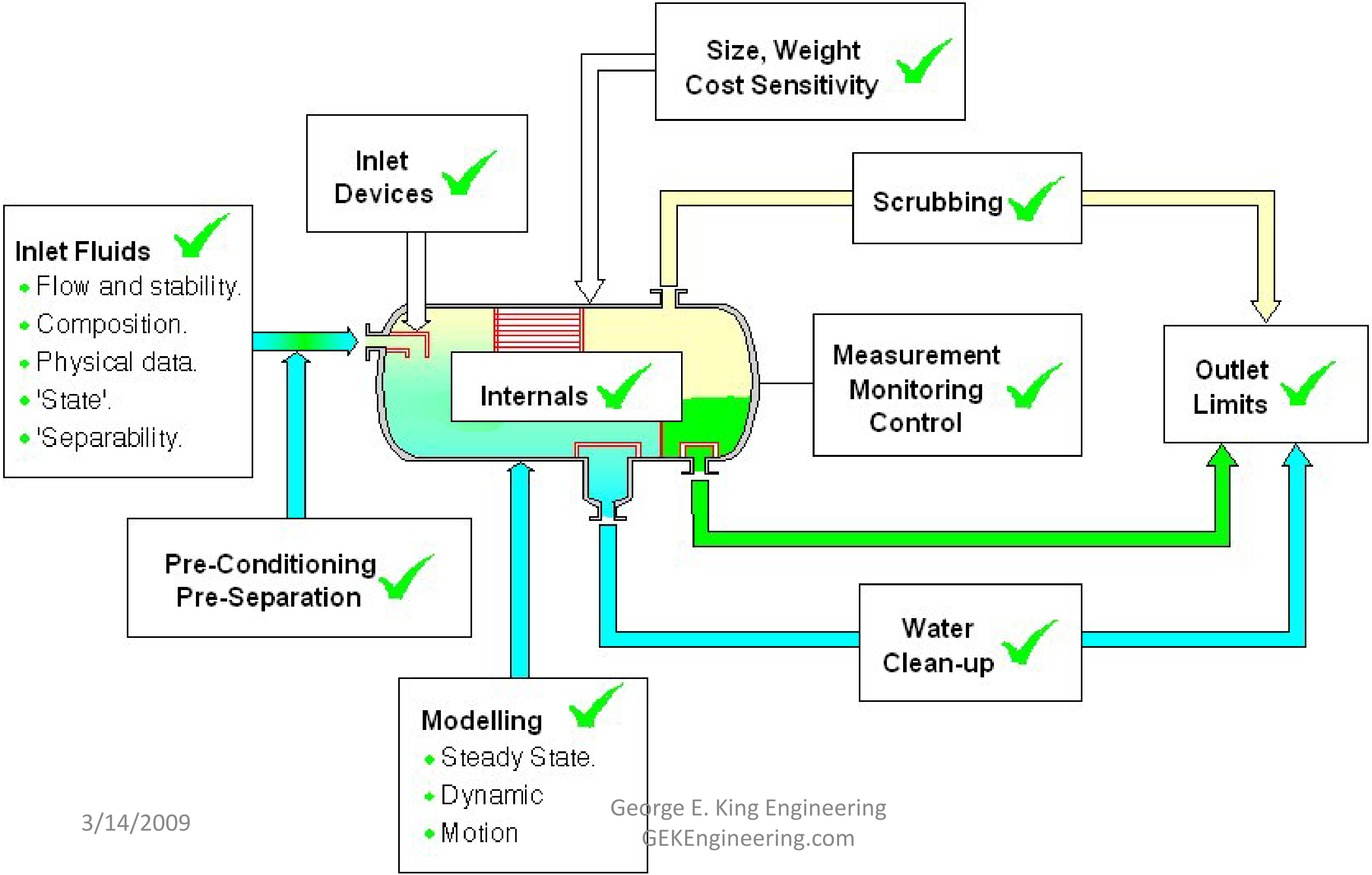
3-Phase Horizontal Separator





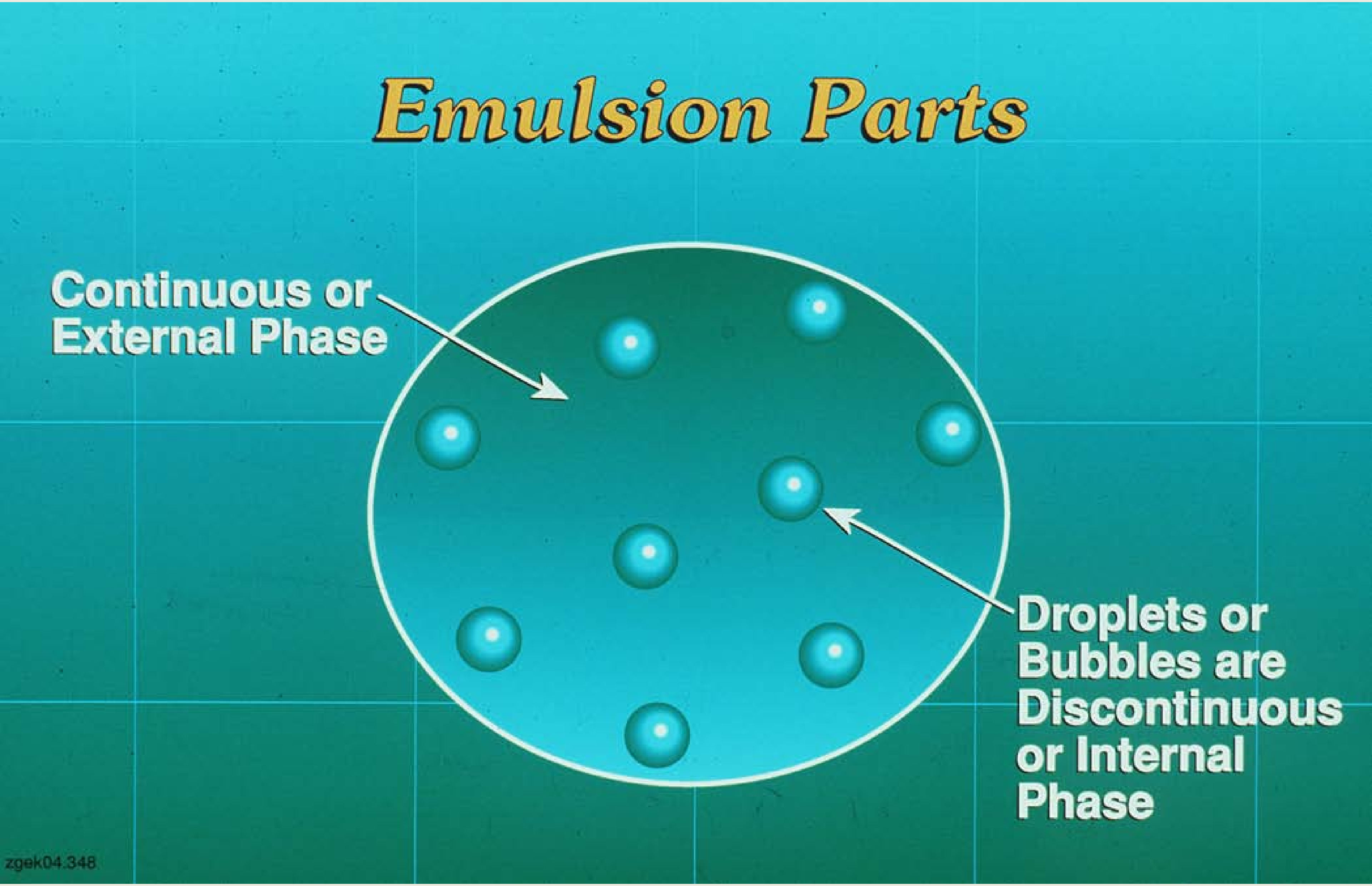
The liquid section is the active separation layer and the site of chemical action.

Component Considerations for Three Phase Separation



General Separator Behavior

Separator Type	High Gas Capacity	High Liquid Capacity	High GOR	Low GOR	Slugging Service	Resist Plugging	Foam	Oil-water Separation
Horiontal	2	1	2	1	1		2	1
vertical	2	2	1	2	2		3	2
1= well suited								
2= fairly suited								
3 = poorly suited								


Emulsion Parts
Continuous or External Phase
Droplets or Bubbles are Discontinuous or Internal Phase
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Energy Sources

- lift system
- gas breakout
- shear at any point in the well
- choke
- gas expansion

Stabilizers

- surfactant (film stiffeners)
- solids (silt, rust, wax, scale, cuttings)
- emulsion or component viscosity (prevents particle or droplet contact)

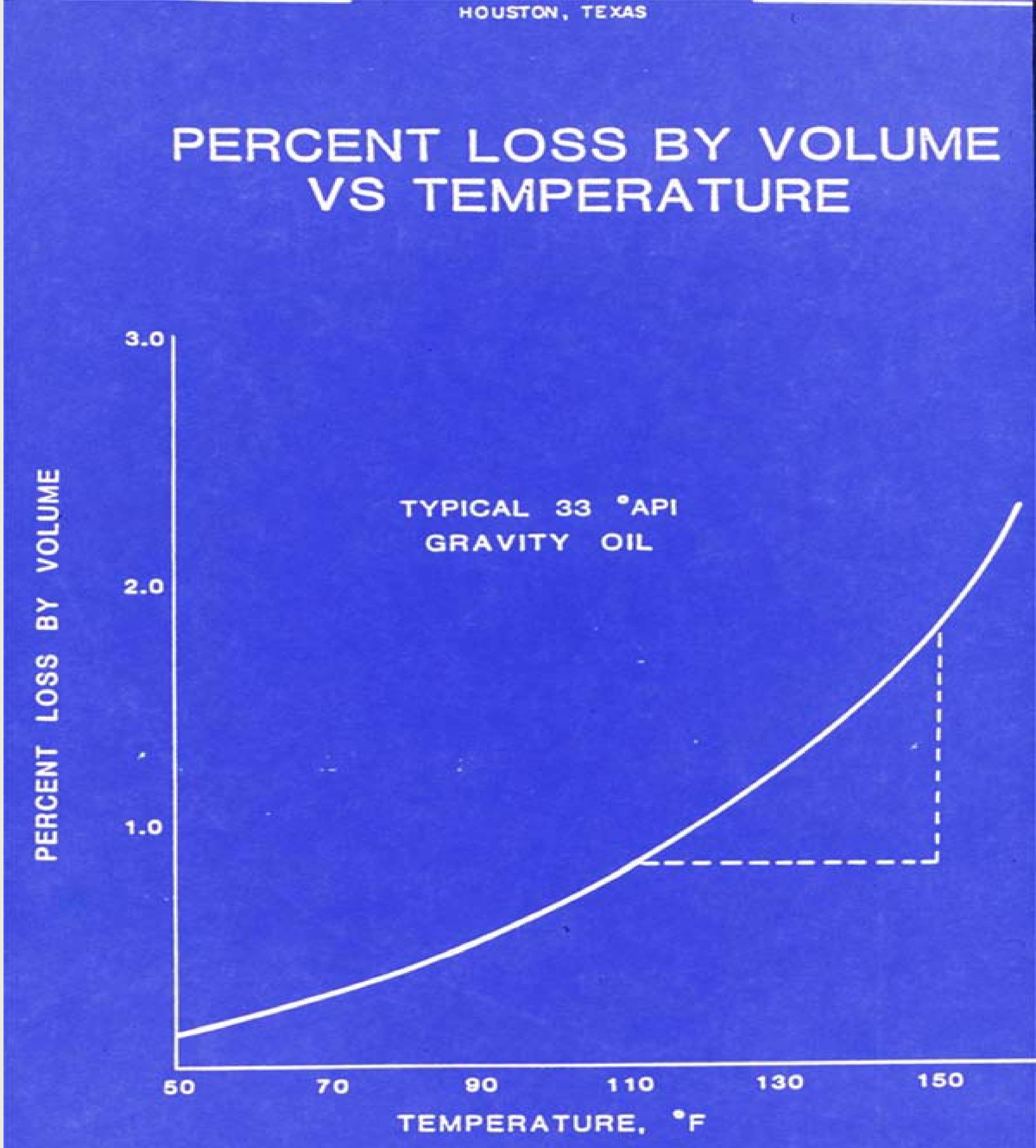
Types of Emulsions

- oil-in-water
- water-in-oil
- gas-in-water (foams and froths)
- solids-in-liquids (muds, etc.)

Cold Treating

- Minimize loss of light ends by heating
- Reduction of Operating Costs
- Chemicals added to promote separation
  - Demulsifiers
  - Wetting Agents
  - Polymers

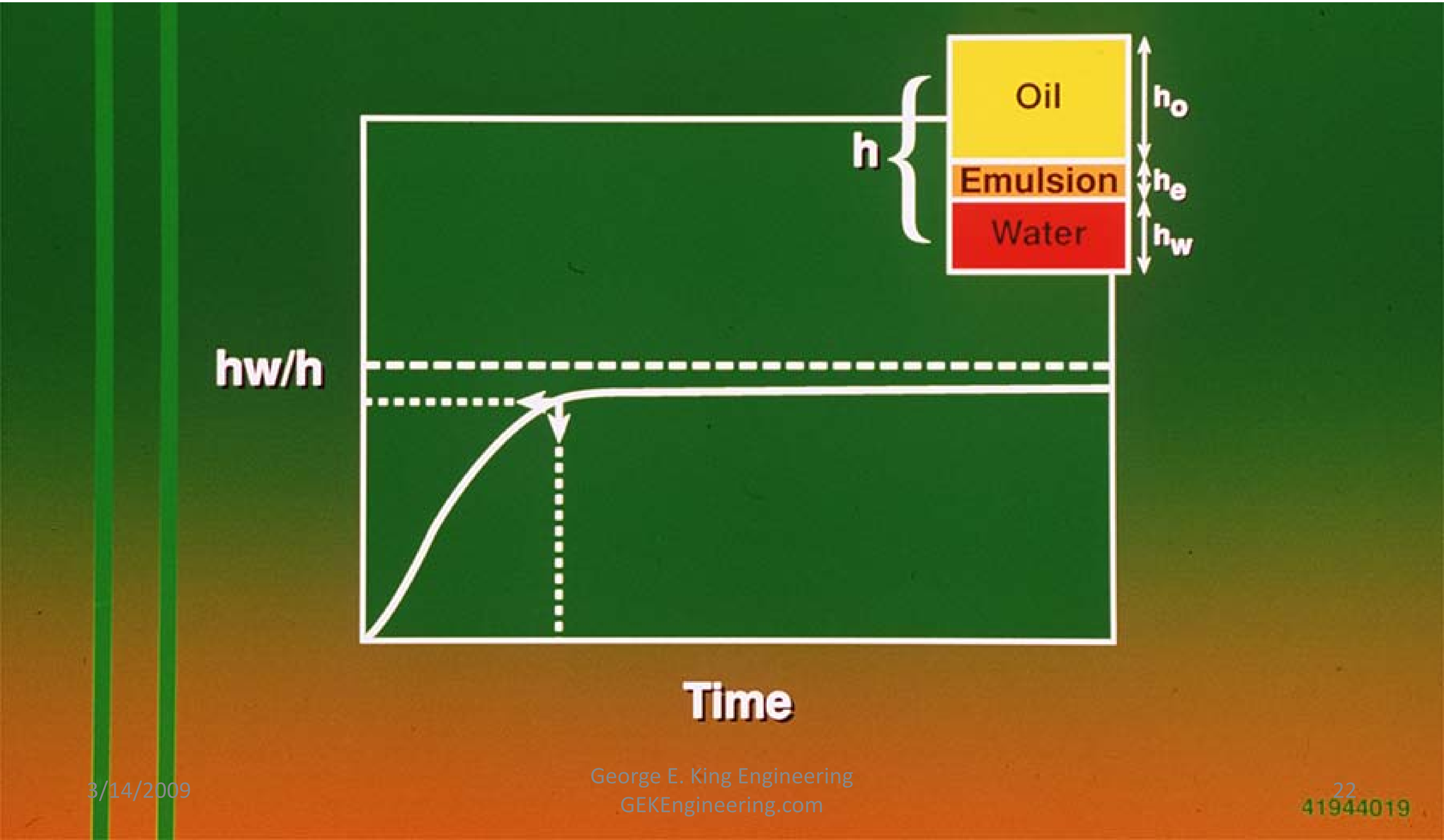
Cold treating is favored to prevent loss of value in the oil by the removal of light ends during the heating process.



Demulsifiers

- Disrupts stability films at oil/water interface
- Promote coalescence of water drops
- Control emulsion pad growth – separator worry – upset critical
- Improve oil quality
- Improve brine quality

Fluid separation is usually a function of treating time in the separator and management of the emulsion pad thickness at the interface. Surfactants concentrate at interfaces and the chemicals used for separation must be effective at quickly breaking down the emulsion pad.

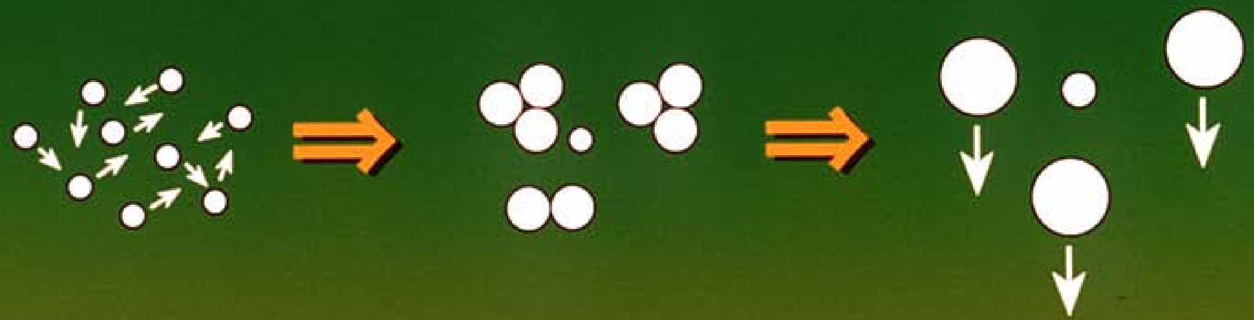


Separated Fluid Qualities

- Gas – may have specs on gas, H_2S, CO_2
- Oil – only trace water allowed, may also have specs on solids, gas, H_2S, CO_2, etc.
- Water – upper limits on oil specified, even when it is re-injected.

Coalescence

≡ The joining of droplets to make larger drops



Larger drops separate faster

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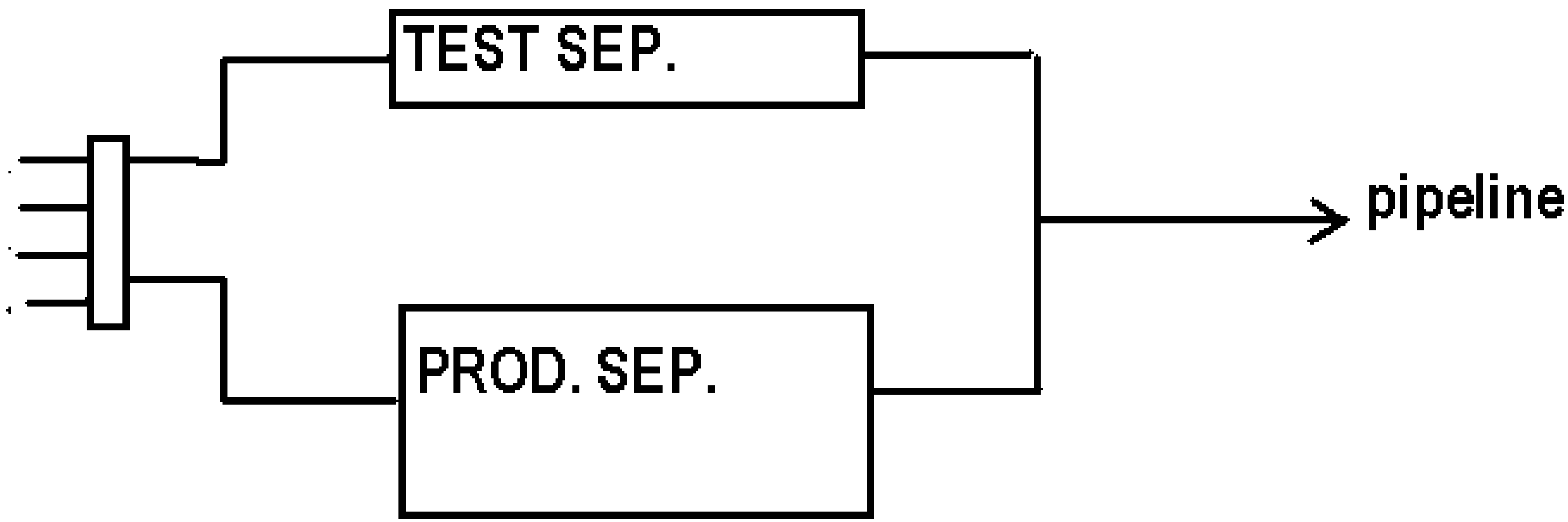
Other Chemicals

- Wetting Agents
  - De-oil solids
  - Minimize effect of solids on emulsion stability
  - Improve brine quality
  - Continuous feed
- Polymers
  - Control growth of emulsion pad
  - Improve brine quality
  - Feed as needed

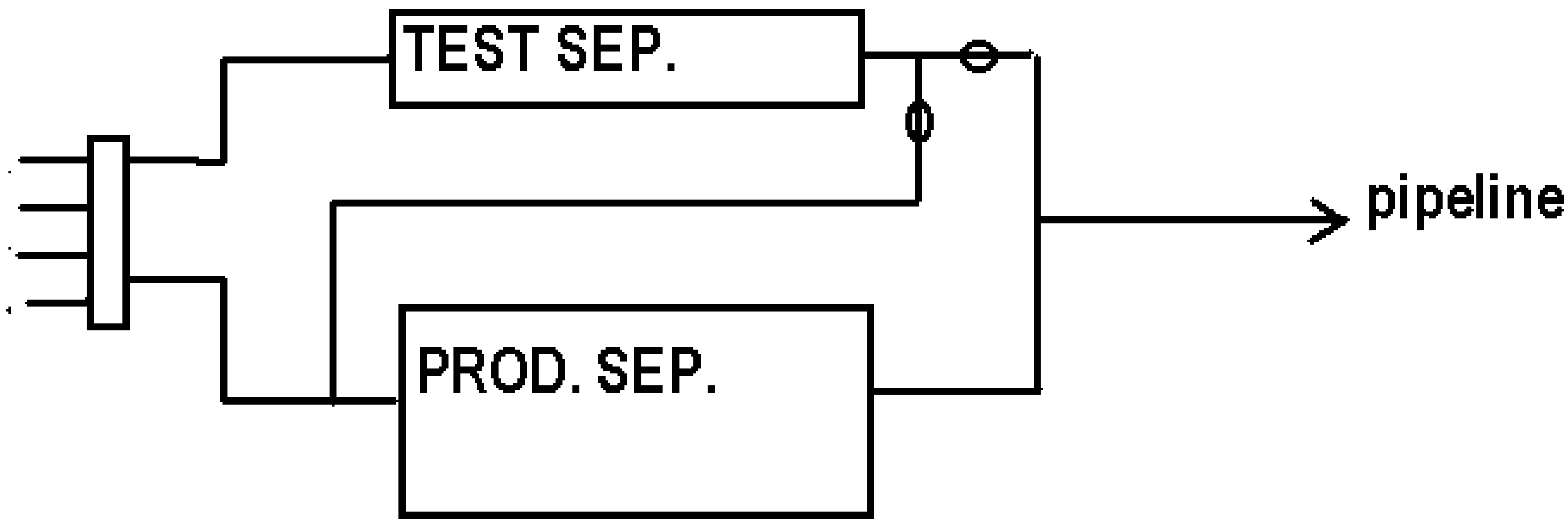
Separation Problems With Workover Fluids

- Brines - more easily emulsified - increase/change demulsifiers
- Solids - from acid jobs - emulsion stabilizers - wetting agents?
- Low pH - corrosion and surfactant action modification - neutralization?
- Emulsions - put surfactants in early?

Typical production and test separator layout.
One problem is that you can't test lowest possible limits of treating chemical addition without risking routing upset to sales line.



Adding a few valves and a line from the test separator outlet to the production separator inlet will allow letting the test separator go to failure on a chemical limit test without risking an upset in the sales line.



Avoiding Treater Upsets – a few suggestions

- Pretest fluids – use field samples wherever possible. Use all the additives in the test fluids. Test under reservoir conditions.
- Expect emulsions – sludges, foams, froths – know how to break and how long to treat. What causes them? How to break? What chemicals to have on location?
- Identify the signs of when the job has flowed back and will cause no more problems.
- Have a Q/C program to make sure you know what goes down hole.