Chemical Flooding the Lansing-Kansas City Formation in Kansas*

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Abstract

The Tertiary Oil Recovery Program at the University of Kansas in cooperation with the Research Partnership to Secure Energy for America (US DOE funded) and industry partners are presently designing a chemical flood for implementation in the Trembley Oilfield, Reno County, KS. The purpose of the project is to test and demonstrate the performance of chemical flooding. An overview of chemical flooding will be presented that will include the basics of the oil-recovery process and considerations for where it might be applied. A summary of the field project and the progress to-date will be reported. The chemical flood design covers laboratory testing to formulate a chemical system that achieves desired performance for the Trembley reservoir (oil, water and rock) and evaluation of the reservoir to design the field implementation. Results of both the laboratory work and the field evaluation will be presented. The Trembley Oilfield produces from a thin bed of oolitic grainstone in the Pennsylvanian Lansing-Kansas City (LKC) interval. Oil production was initially by fluid expansion and like many LKC fields, it has been successfully waterflooded. The Trembley has favorable characteristics to be chemical flooded and good performance should lend promise to the application of chemical flooding of other LKC reservoirs.

References Cited

Chatzis, I., and N.R. Morrow, 1984, Correlation of capillary number relationships for sandstone: SPE Journal, v. 24/5, p. 555-562.

Huh, C., 1979, Interfacial tensions and solubilizing ability of a microemulsion phase that coexists with oil and brine: J. Colloid Interface Science, v. 71, p. 408-426.

AAPG Mid-Continent Section Meeting

Chemical Flooding the Lansing-Kansas City Formation in Kansas

KU TORP
Tertiary Oil Recovery Program

Mark Ballard, Petroleum Engineer

Our Partners

Funding

RPSEA
Research Partnership to Secure Energy for America

Field Partner

BEREXCO

KU TORP
Tertiary Oil Recovery Program

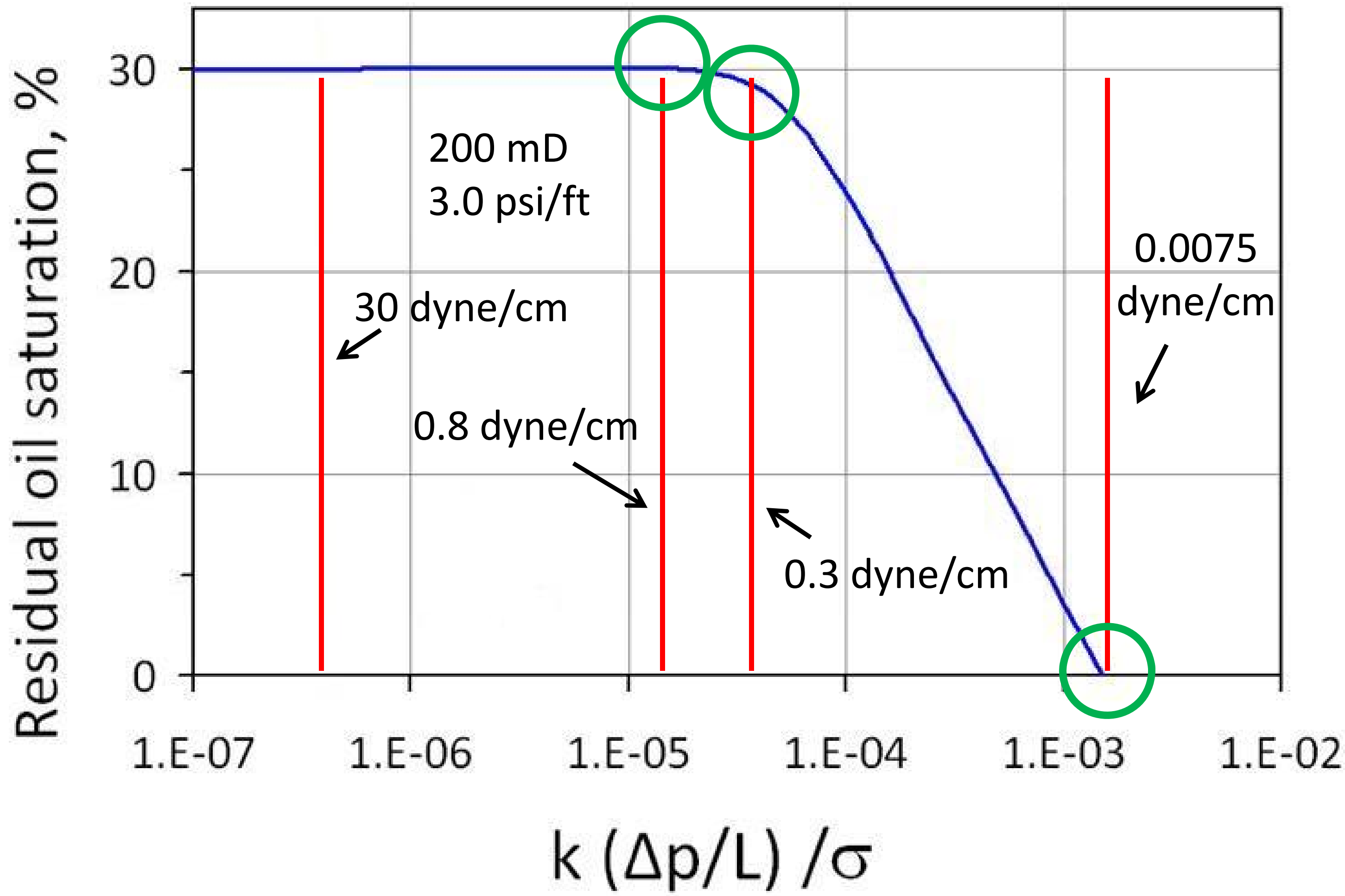
Surfactant and Formulation

HUNTSMAN
Enriching lives through innovation

Polymer and field equipment

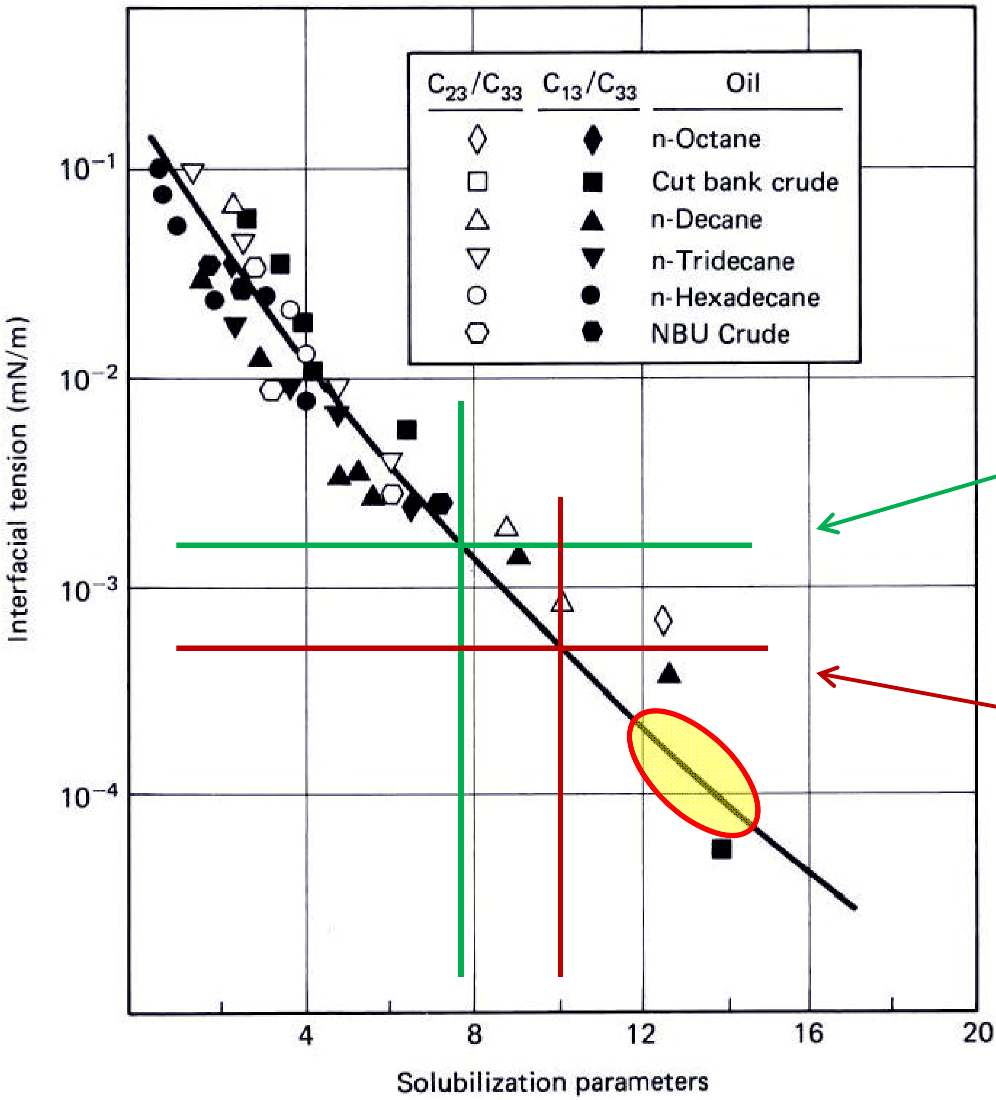
SNF FLOERGER

Capillary Number



Chatzis & Morrow *SPEJ*, Oct. 1984

Solubilization Ratio => IFT



$$IFT = \frac{Salinity}{Solubilization^2}$$

IFT = 0.0075

Solubilization Ratio > 10

Chun Huh, 1979

What does it take?

- Field (target) selection
- Chemical system
- Field implementation

Reservoir Selection

- Field (target) selection
  - Connected Flow Units
  - Volumetric Sweep

Reservoir Selection

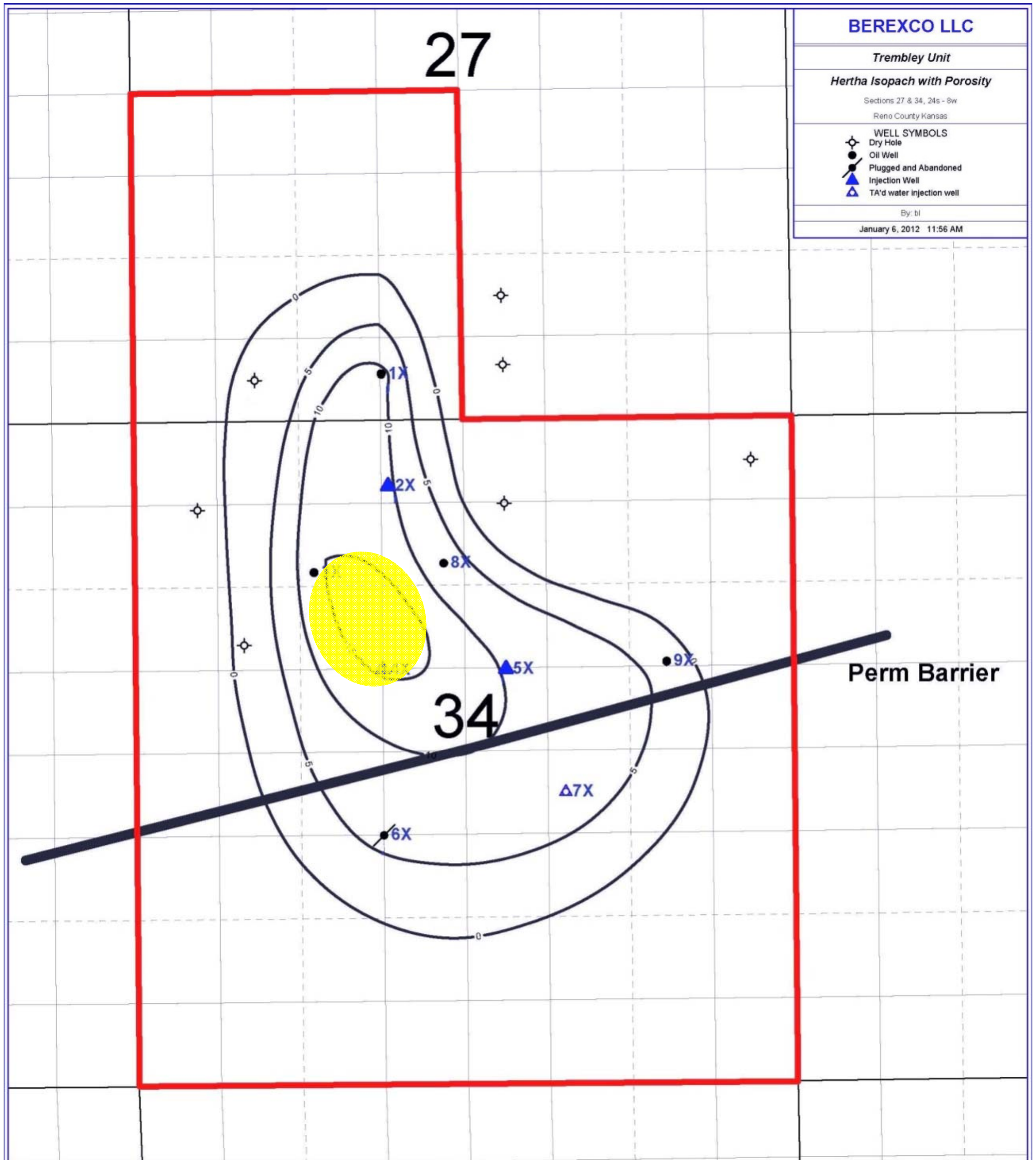
Responsive waterflood

Floodable

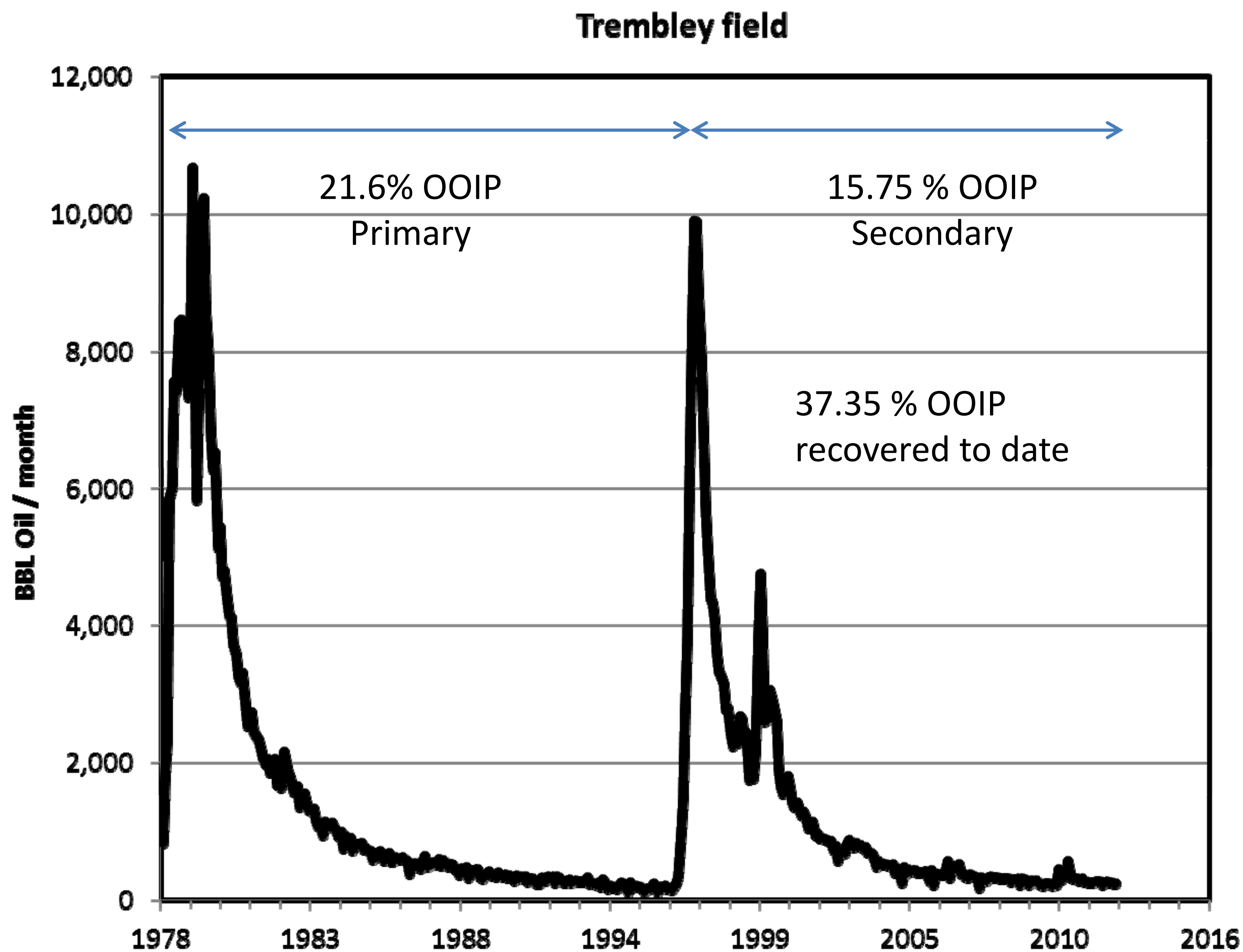
Significant reservoir sweep

More reservoir data

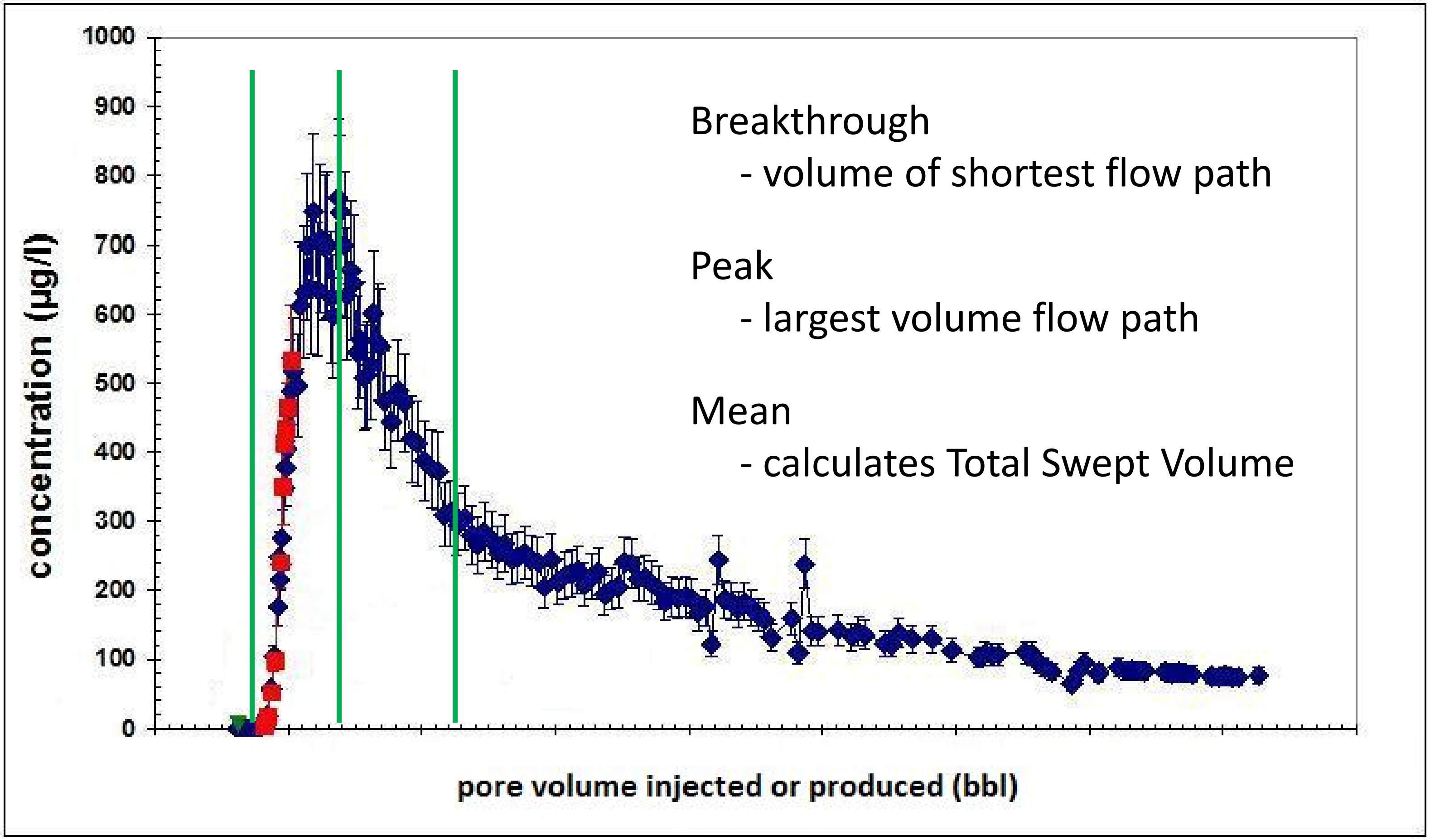
Available surface facilities



BEREXCO LLC
Trembley Unit
Hertha Isopach with Porosity
Sections 27 & 34, 24s - 8w
Reno County Kansas
WELL SYMBOLS
Dry Hole
Oil Well
Plugged and Abandoned
Injection Well
TA'd water injection well
By: bl
January 6, 2012 11:56 AM
27
34
1X
2X
8X
5X
9X
7X
6X
Perm Barrier


Trembley field
12,000
10,000
8,000
6,000
4,000
2,000
0
BBL Oil / month
1978
1983
1988
1994
1999
2005
2010
2016
21.6% OOIP
Primary
15.75 % OOIP
Secondary
37.35 % OOIP
recovered to date

Tracers – connected flow units



Chemical System - Formulation

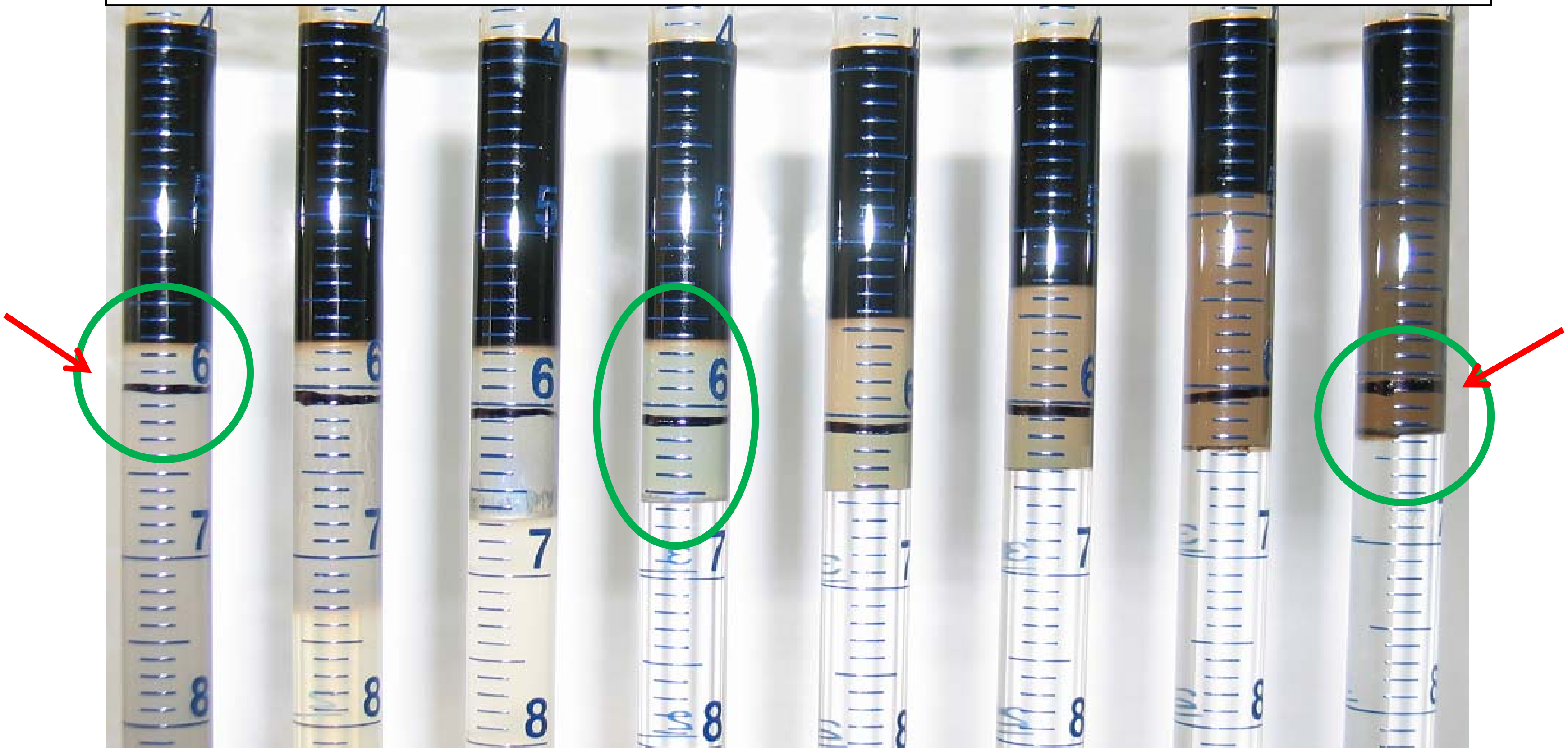
- Several variables
  - **Solubilization** (IFT)
  - Salinity
  - WOR
  - Aqueous Phase Stability (APSL)
  - **Adsorption**

Chemicals

- **Surfactants** - mobilize trapped oil
- Solvents - enhance solubility
- Sacrificial agents - reduce adsorption
- Salts - affects behavior
- **Polymer** - min. mixing /max. sweep
- Water

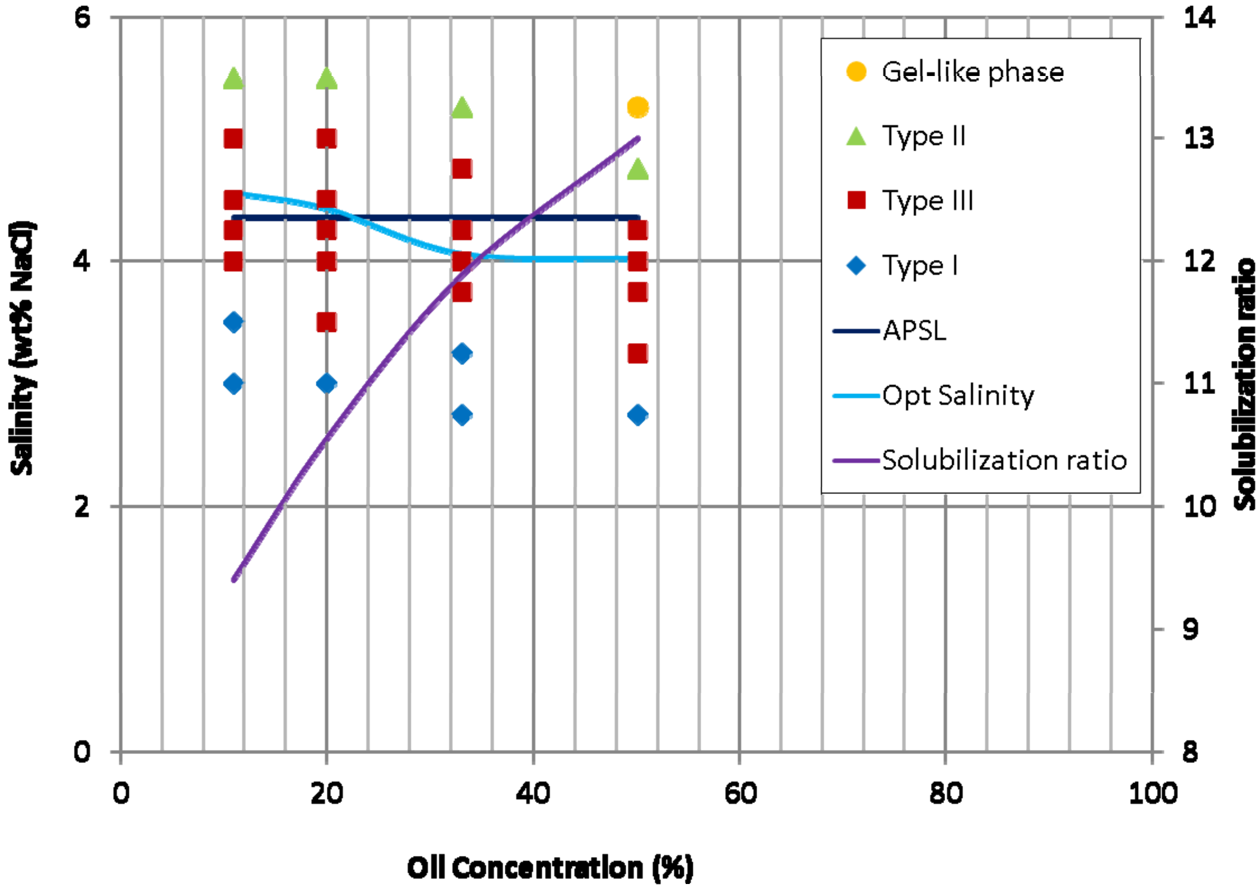
NaCl conc (%)

3.25 3.50 3.75 4.00 4.25 4.50 4.75 5.00

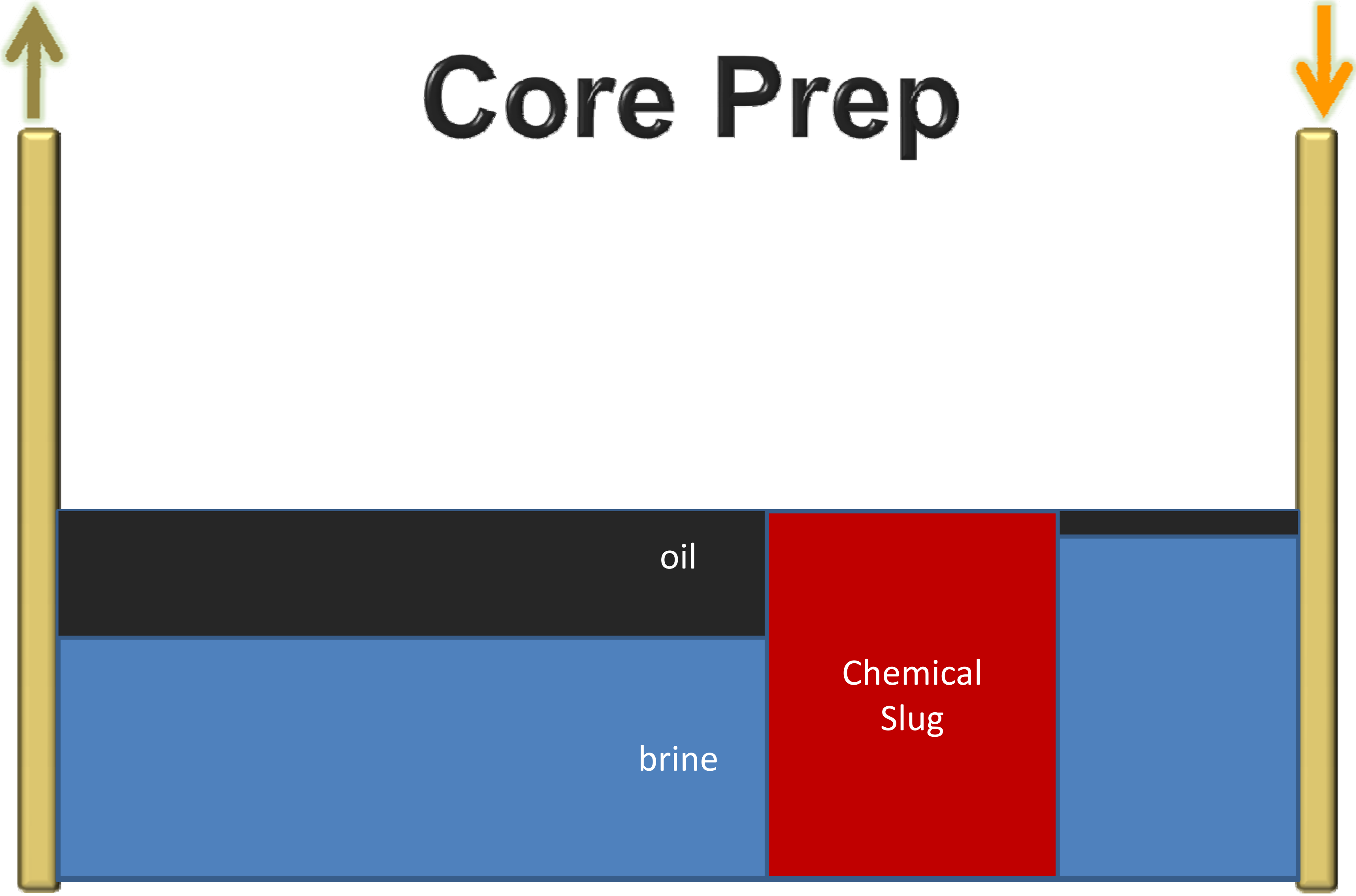


0.5% XOF-100S 2.0% $NaCO_3$
0.1% XOF-600S 0.2% SNF 3330S

Activity Diagram

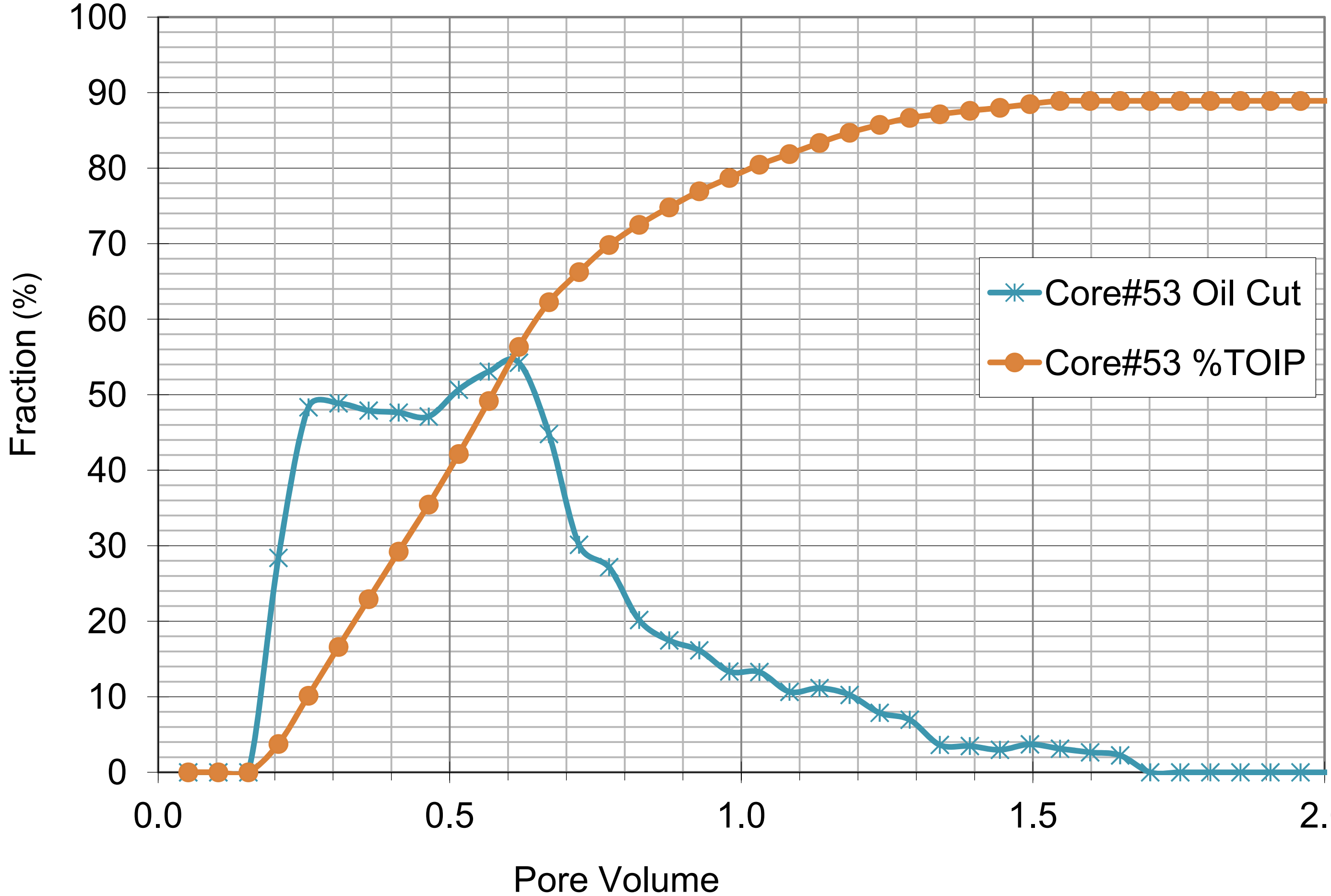


Core Prep



Core 53

(Berea) (includes alkali)



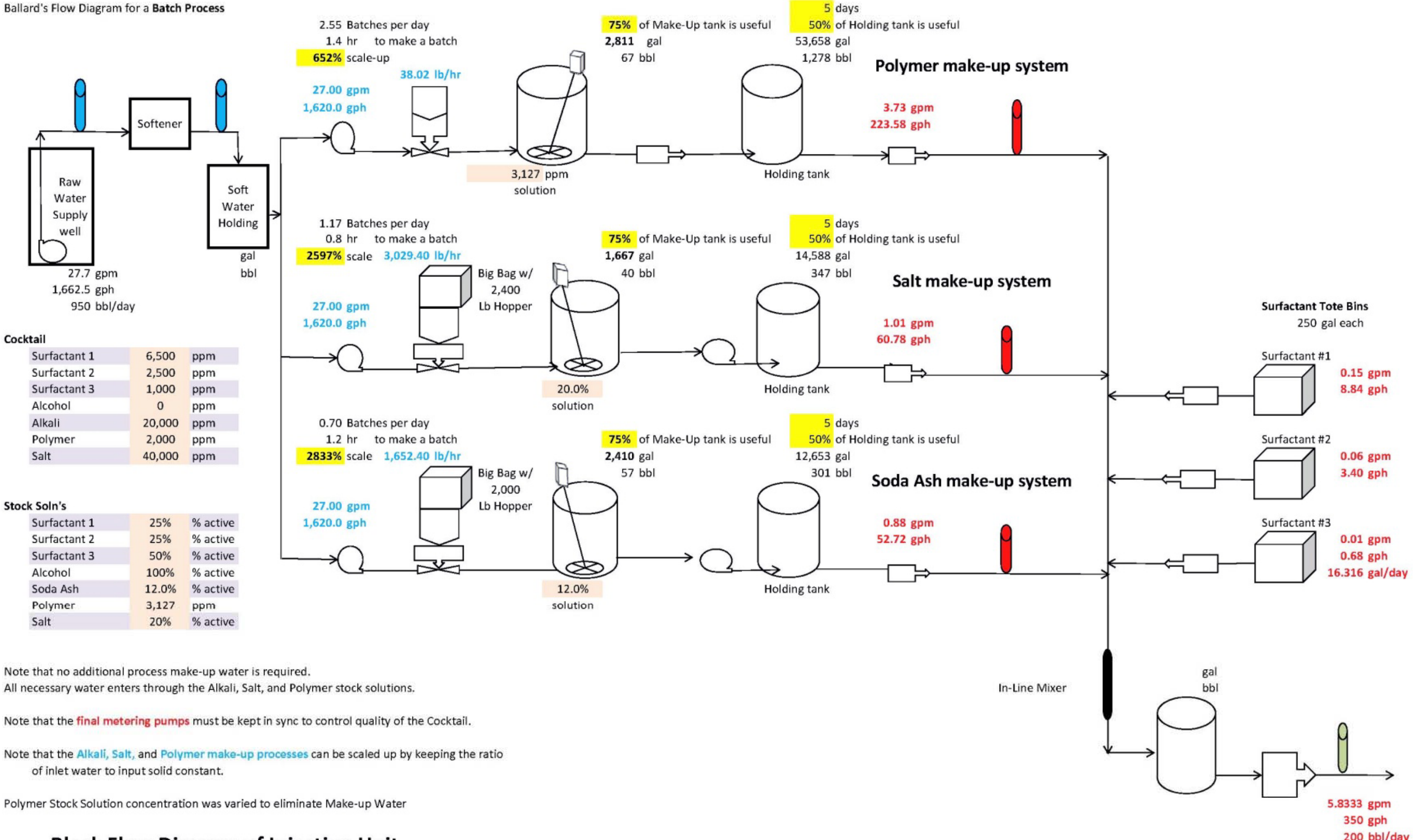
100R10, A10, P20, L42-20

What does it take?

- Field (target) selection
- Chemical system
- Field implementation
  - Injectivity
    - Well workovers
  - Chemical Slug make-up
    - Quality control !!!
  - Production well testing
    - Slug transit & breakthrough

Injection Plant

Ballard's Flow Diagram for a **Batch Process**



Cocktail

Surfactant 1	6,500	ppm
Surfactant 2	2,500	ppm
Surfactant 3	1,000	ppm
Alcohol	0	ppm
Alkali	20,000	ppm
Polymer	2,000	ppm
Salt	40,000	ppm

Stock Soln's

Surfactant 1	25%	% active
Surfactant 2	25%	% active
Surfactant 3	50%	% active
Alcohol	100%	% active
Soda Ash	12.0%	% active
Polymer	3,127	ppm
Salt	20%	% active

Note that no additional process make-up water is required.
All necessary water enters through the Alkali, Salt, and Polymer stock solutions.

Note that the final metering pumps must be kept in sync to control quality of the Cocktail.

Note that the Alkali, Salt, and Polymer make-up processes can be scaled up by keeping the ratio of inlet water to input solid constant.

Polymer Stock Solution concentration was varied to eliminate Make-up Water

Block Flow Diagram of Injection Unit

Injection Plant

Instructions: Yellow boxes require data entry

(1) Enter injection rates
(2) Enter wellhead or pump outlet maximum pressure
(3) Enter the minimum polymer maturation time
(4) Enter the ASP formula
(5) Enter data for the state of the delivered chemicals
(6) Check the Stock Solutions for accuracy
(7) Enter the actual size of the Polymer Maturation Tank

(1) Injection Rate	200	**bbl/day**
(2) Max Pressure	1,200	**psi**
(3) Min. polymer maturation time	60	**min**

Notes:
The Cocktail density is IMPORTANT. Many subsequent calculations are based upon it.
Most calculations are based upon the "Consumption, lb/day"
Densities of constituents delivered as liquid are also important to get the Cocktail right
Densities of Stock Solutions are important to get the Cocktail right

1.0 wt% = 10,000 ppm

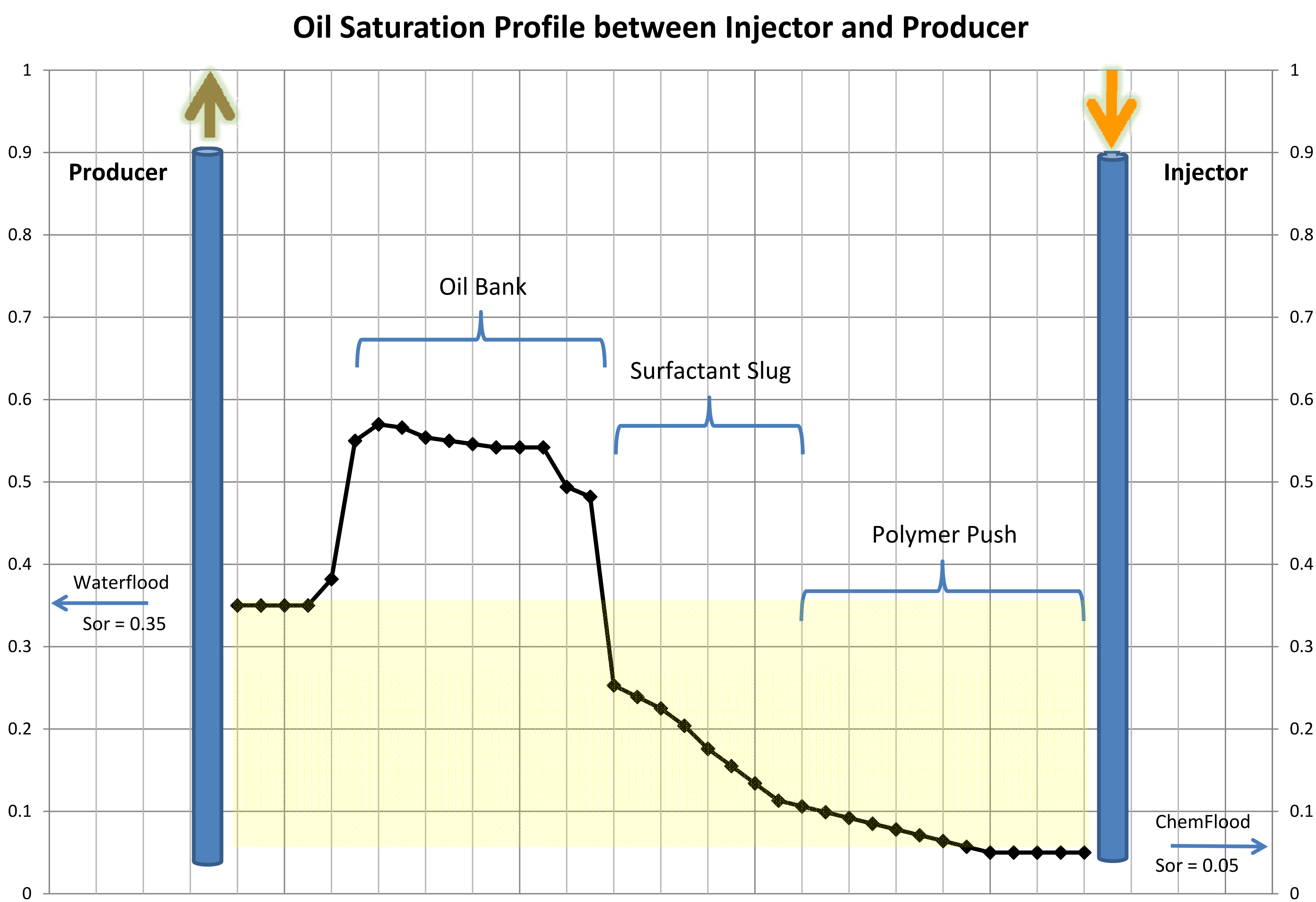
(4) ASP Formula		
Surfactant 1	6,500	ppm
Surfactant 2	2,500	ppm
Surfactant 3	1,000	ppm
Alcohol	0	ppm
Alkali	20,000	ppm
Polymer	2,000	ppm
Salt	40,000	ppm

(5) Chemical Delivered State					Density	
Phase/Form	Activity	Size		Type		
Liquid	25%	250	gal	tote	8.58	lbs / gal
Liquid	25%	250	gal	tote	8.58	lbs / gal
Liquid	50%	250	gal	tote	8.58	lbs / gal
Liquid	100%	250	gal	tote	6.75	lbs / gal
Powder	100%	2,000	lb	super-sack	60.00	lb / ft^3
Powder	100%	55	lb	sack	49.92	lb / ft^3
Powder	100%	2,400	lb	super-sack	79.00	lb / ft^3

(6) Stock Solutions:			Density	
Surfactant 1	25%	% active	8.58	lbs / gal
Surfactant 2	25%	% active	8.58	lbs / gal
Surfactant 3	50%	% active	8.58	lbs / gal
Alcohol	100%	% active	6.75	lbs / gal
Soda Ash	12.0%	% active	9.22	lbs / gal
Polymer	3127.5	ppm	8.34	lbs / gal
Salt	20%	% active	9.60	lbs / gal
Cocktail			8.333	lbs / gal

	Stock Solution **Metering Pumps** gal/min	gal/hr	gal/day	bbl/day	Consumption (as delivered) lb/hr	lb/day	lb/mo	sack/tote per mo	gal/day	gal/mo
Metering Pumps										
Surfactant 1 (stock soln)	0.15	8.84	212.1	5.05	75.83	1,820	55,508	25.9	212.1	6,469
Surfactant 2 (stock soln)	0.06	3.40	81.6	1.94	29.17	700	21,349	10.0	81.6	2,488
Surfactant 3 (stock soln)	0.01	0.68	16.3	0.39	5.83	140	4,270	2.0	16.3	498
Alcohol	0.00	0.00	0.0	0.00	0.00	0	0	0.0	0.0	0
Alkali (stock solution)	0.88	52.72	1,265	30.13	58.33	1,400	42,698	21.3		
Polymer (stock soln)	3.73	223.58	5,366	127.76	5.83	140	4,270	77.6		
Salt (stock solution)	1.01	60.78	1,458.8	34.73	116.66	2,800	85,397	35.6		
Dilution Water Rate	0.00	0.00	0.00	0.00						
Main injection pump	5.83333	350	8400	200						

	Polymer Maturation tank gal	bbl	ft^3	Main Inj Pump HP	kW
Main injection pump				4.10	3.05
Polymer Maturation Tank					
Minimum Maturation Tank Working Volume	223.58	5.32	29.89		
Recommended Total Tank Volume	279.47	6.65	37.36		
(7) Actual Tank size specified	279.47	6.65	37.36		
Actual polymer maturation time	75.00 **minutes**				
	1.25 hours				



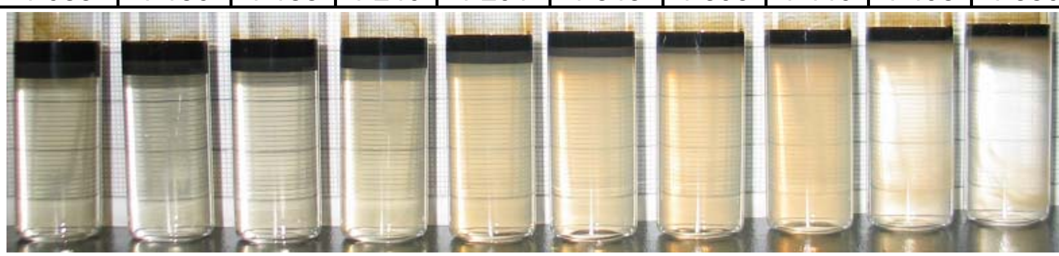
Oil Saturation Profile between Injector and Producer
Producer
Injector
Oil Bank
Surfactant Slug
Polymer Push
Waterflood
Sor = 0.35
ChemFlood
Sor = 0.05
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0

Core 53 effluent collection vials

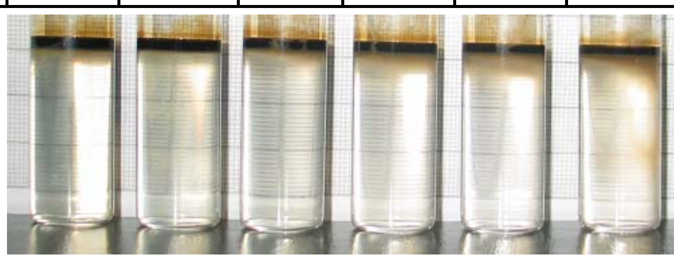
PV	0.052	0.103	0.155	0.207	0.258	0.310	0.362	0.413	0.465	0.517

PV	0.568	0.620	0.672	0.723	0.775	0.827	0.878	0.930	0.981	1.033

PV	1.085	1.136	1.188	1.240	1.291	1.343	1.395	1.446	1.498	1.550



PV	1.601	1.653	1.705	1.756	1.808	1.860				



Concluding Remarks

- Great performance in the lab
- Translating performance to field is challenging
- Advantages for success
  - good waterflood performance
  - inter-well tracer study
  - core material
  - good field data
- **Successful demonstration in the Trembley**

Thank You

Funding

RPSEA
Research Partnership to Secure Energy for America

Field Partner

BEREXCO

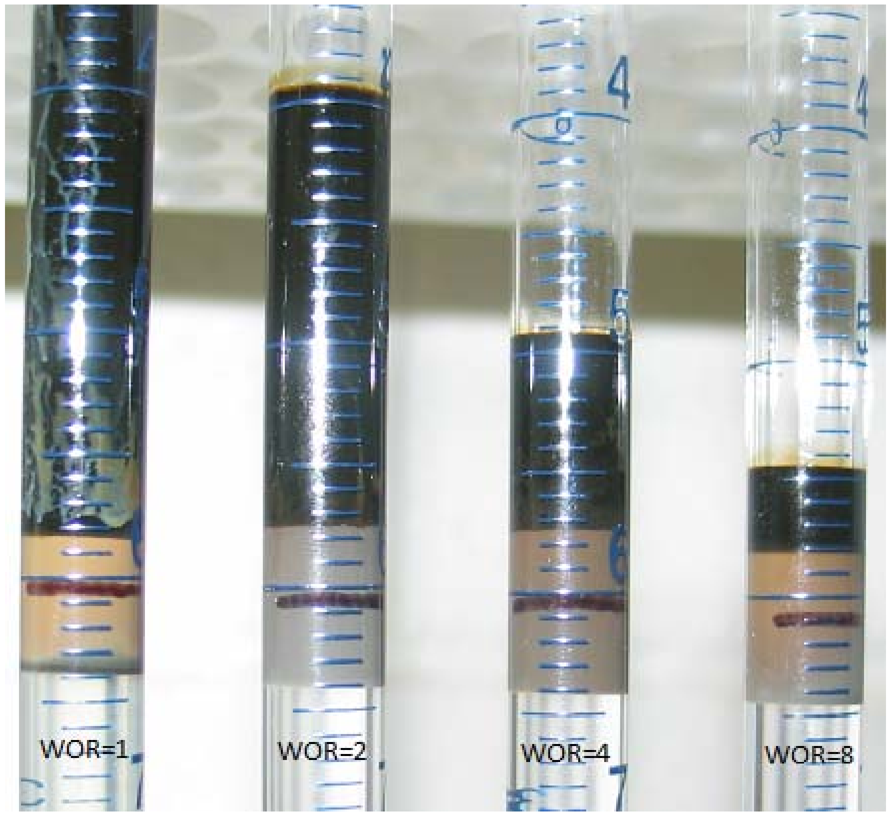
KU TORP
Tertiary Oil Recovery Program

Surfactant and Formulation

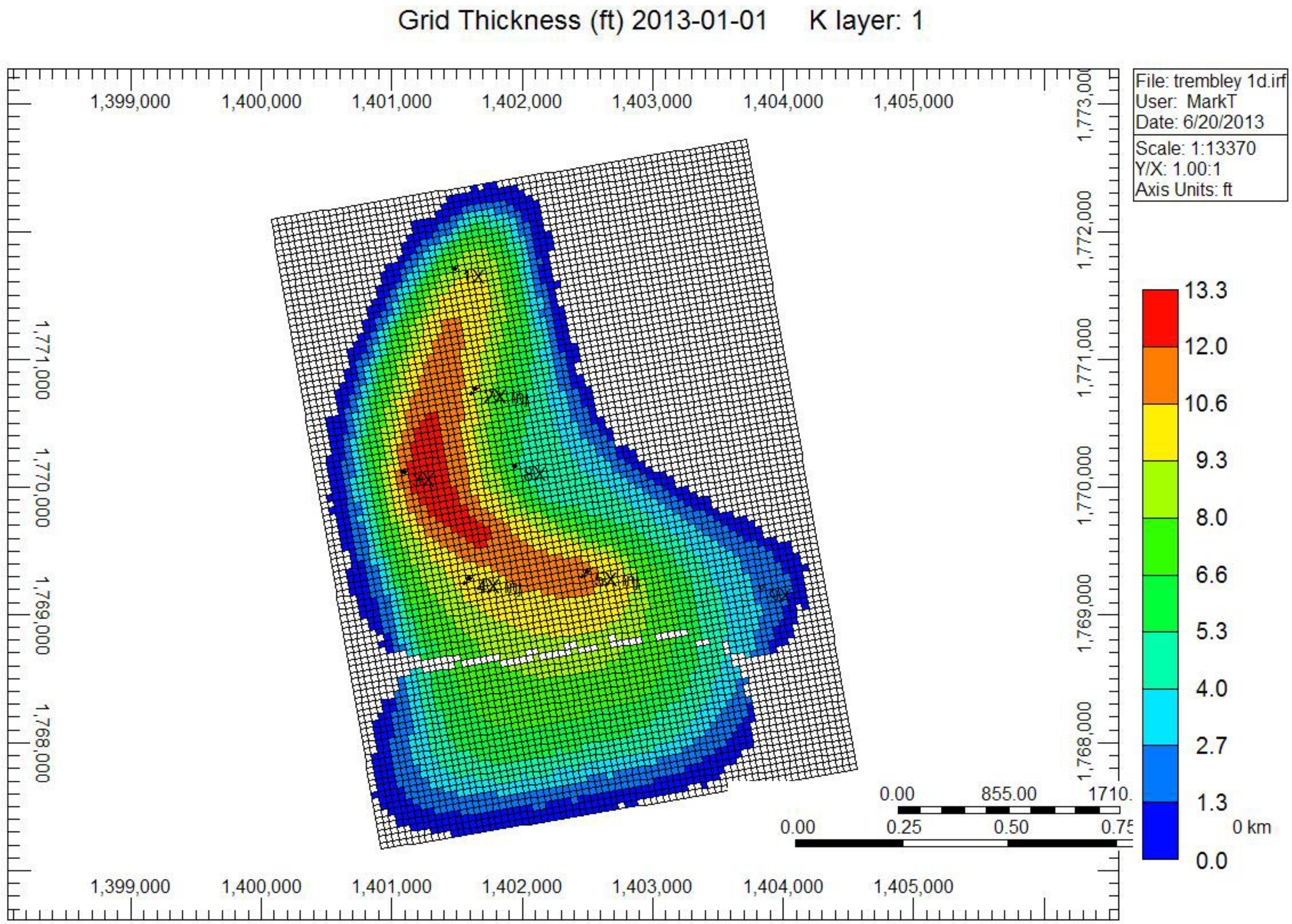
HUNTSMAN
Enriching lives through innovation

Polymer and field equipment

SNF FLOERGER

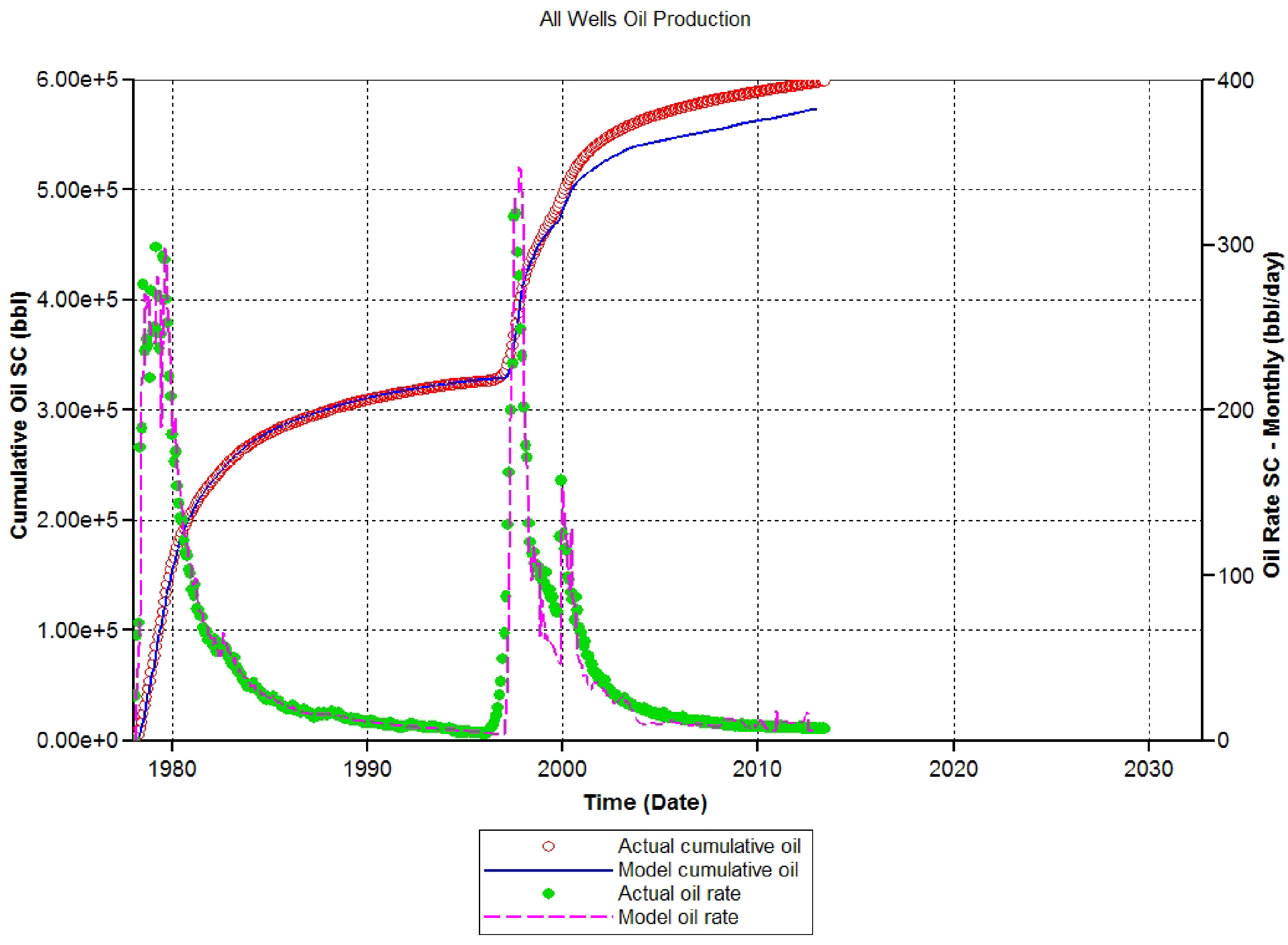

WOR=1
WOR=2
WOR=4
WOR=8

Simulation



Grid Thickness (ft) 2013-01-01 K layer: 1
1,399,000
1,400,000
1,401,000
1,402,000
1,403,000
1,404,000
1,405,000
1,773,000
1,772,000
1,771,000
1,770,000
1,769,000
1,768,000
File: trembley 1d.irf
User: MarkT
Date: 6/20/2013
Scale: 1:13370
Y/X: 1.00:1
Axis Units: ft
13.3
12.0
10.6
9.3
8.0
6.6
5.3
4.0
2.7
1.3
0.0
0.00
855.00
1710.
0.25
0.50
0.75
0 km

Simulation



All Wells Oil Production
6.00e+5
5.00e+5
4.00e+5
3.00e+5
2.00e+5
1.00e+5
0.00e+0
Cumulative Oil SC (bbl)
400
300
200
100
0
Oil Rate SC - Monthly (bbl/day)
1980
1990
2000
2010
2020
2030
Time (Date)
Actual cumulative oil
Model cumulative oil
Actual oil rate
Model oil rate