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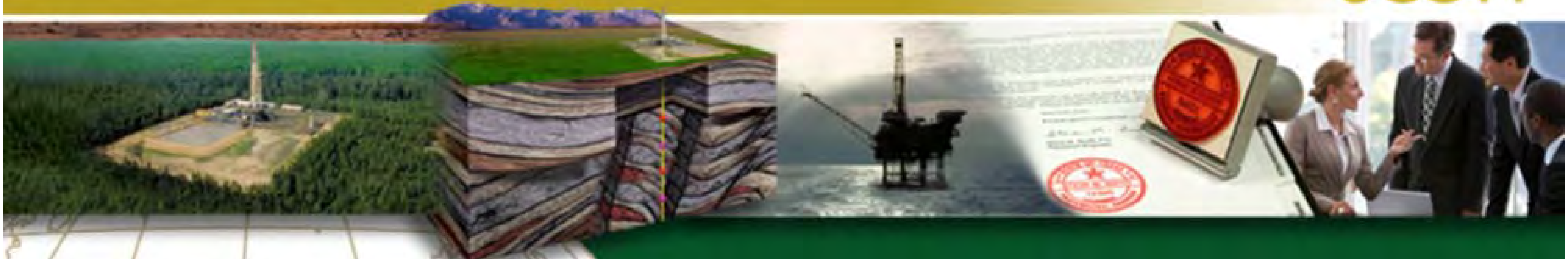


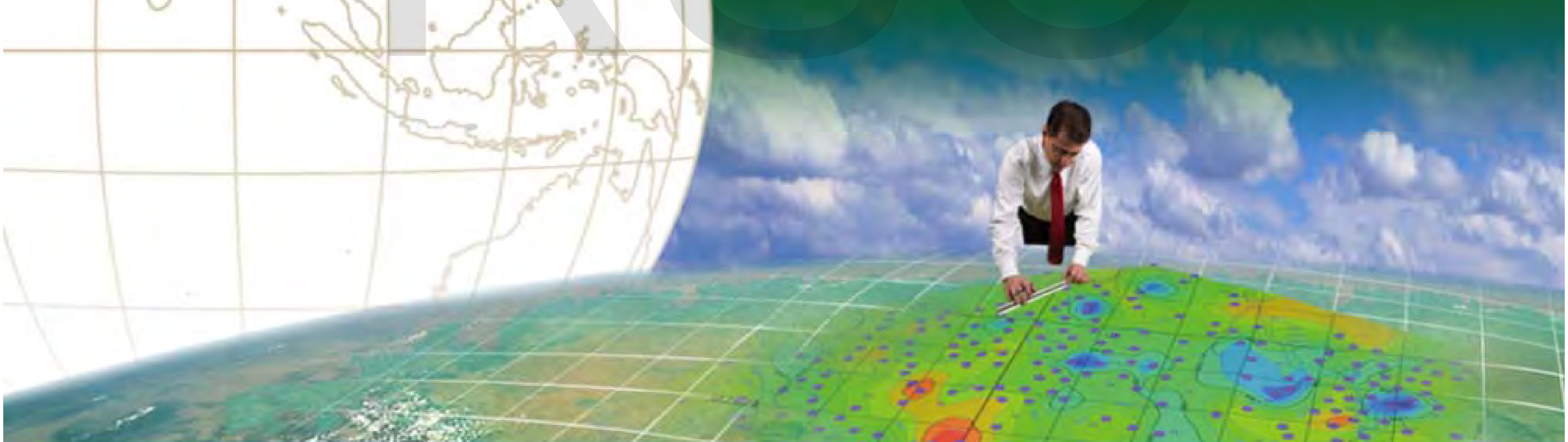
Ryder Scott Company

Reservoir Evaluations in the Eagle Ford Shale

SPEE – Central Texas Chapter

SPE – Austin Chapter

November 3, 2015

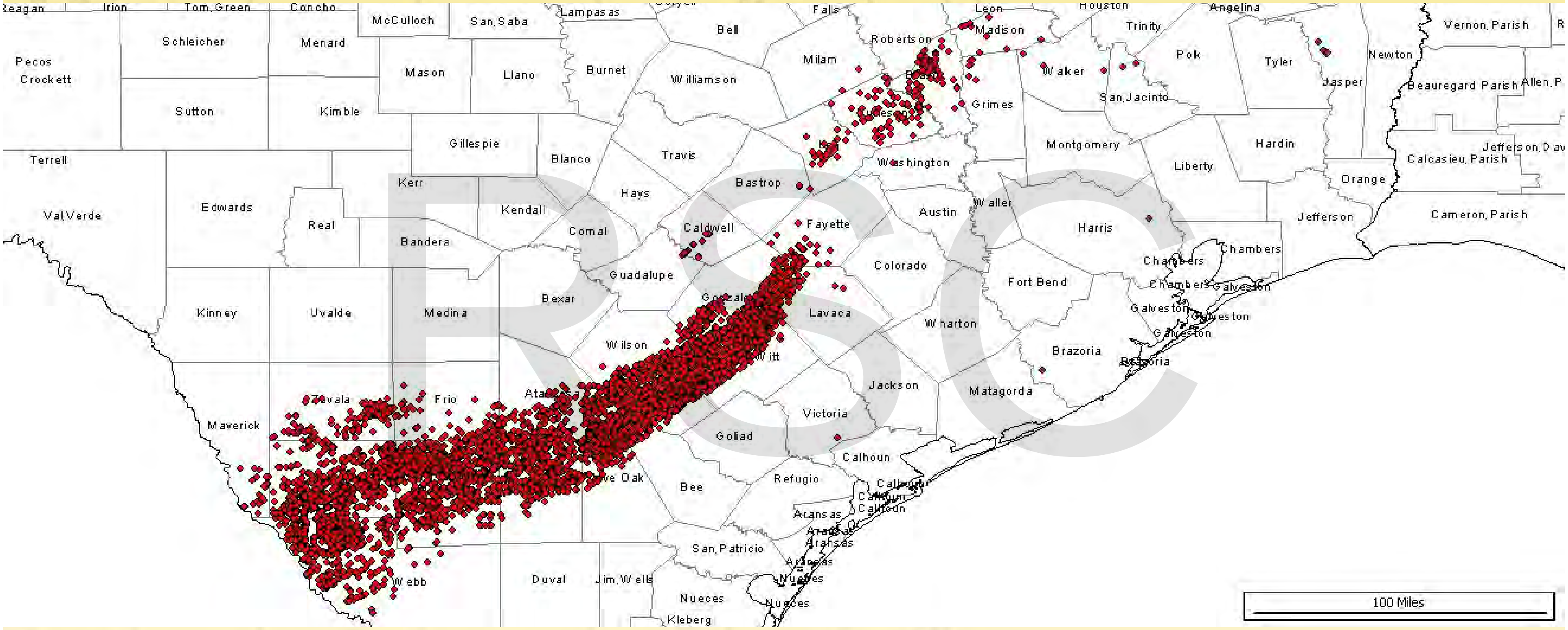


Agenda

- Overview
- Geology and Petrophysics
- Completions
- Performance
- Economic Parameters
- Reserve Considerations

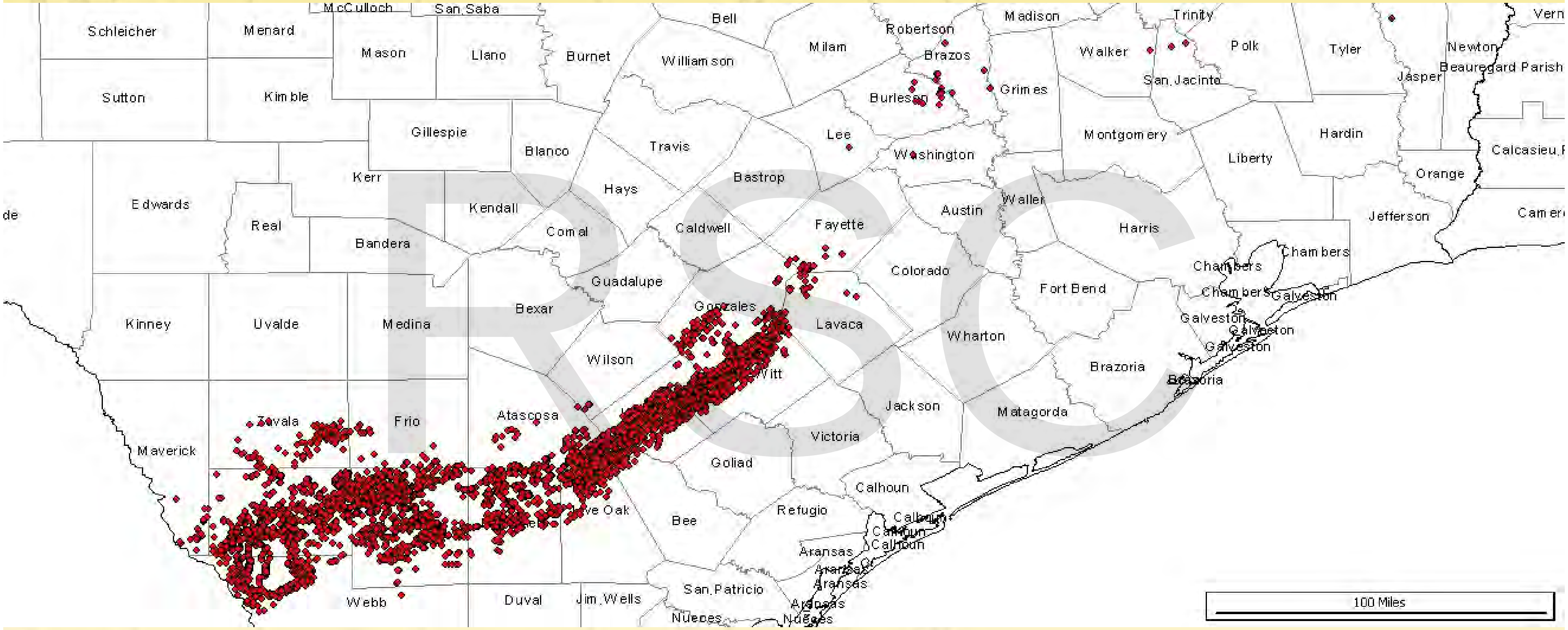
Active Producing Wells

Approximately 14,300 wells



Client Producing Wells

Approximately 9100 wells



Top Producing Counties

Texas operators as of June have completed 11,542 wells, down from 15,828 wells recorded during the first half of 2014.

Here are the state's top crude oil producers for June, in barrels:

1. Karnes (Eagle Ford) – 6,797,988
2. DeWitt (Eagle Ford) – 4,691,734
3. La Salle (Eagle Ford) – 4,620,430
4. Gonzales (Eagle Ford) – 3,156,164
5. Upton (Permian Basin) – 3,093,674
6. Andrews (Permian Basin) – 3,078,394
7. Midland (Permian Basin) – 3,052,231
8. Martin (Permian Basin) – 3,046,948
9. McMullen (Eagle Ford) – 2,922,426
10. Reeves (Permian Basin) – 2,527,124

Here are Texas' top natural gas producers for June, by MCF:

1. Webb (Eagle Ford) – 58,555,033
2. Tarrant (Barnett) – 51,523,950
3. Panola (Haynesville Shale) – 27,740,460
4. Dimmit (Eagle Ford) – 23,321,147
5. Johnson (Barnett) – 23,049,439
6. DeWitt (Eagle Ford) – 20,807,735
7. Wise (Barnett) – 19,422,338
8. Karnes (Eagle Ford) – 18,571,638
9. Denton (Barnett) – 16,919,808
10. La Salle (Eagle Ford) – 15,879,814

Source: Houston Chronicle – Eagle Ford Shale tops list of top crude, gas producers – Jennifer Hiller

Geology

- Structure
- Log Response
- Hydrocarbon Pay Maps

Eagle Ford Shale

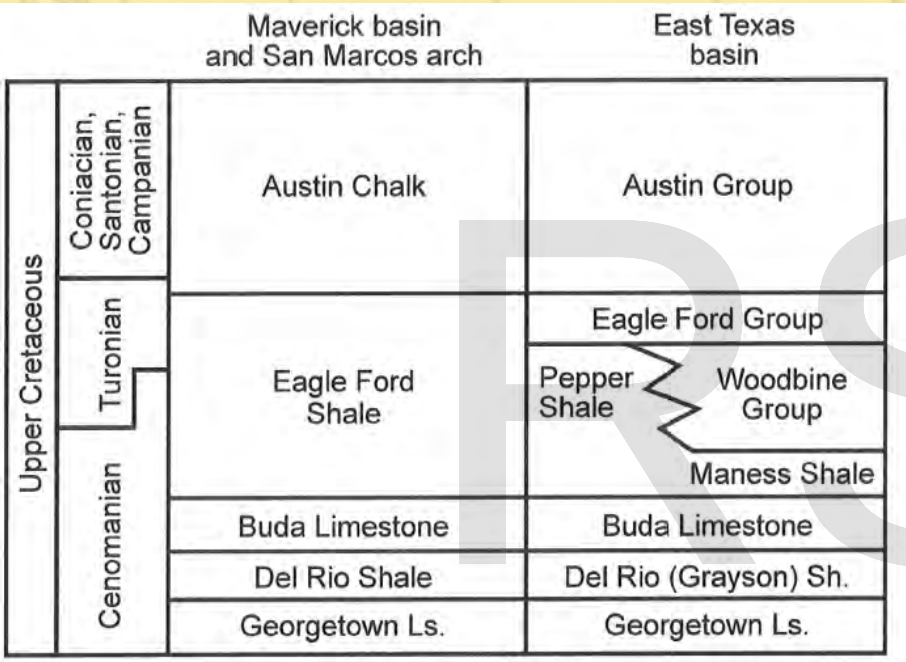
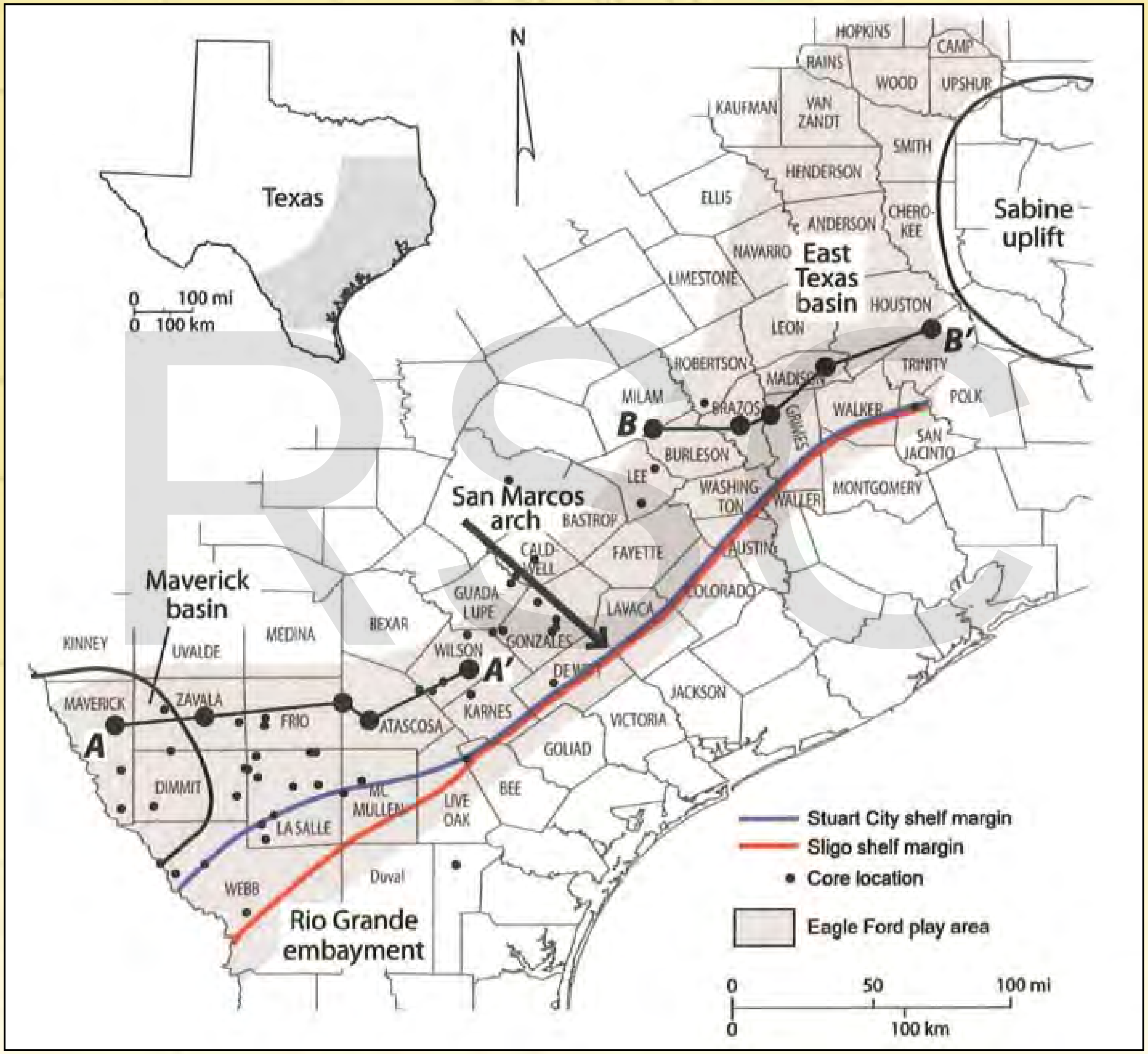


Figure 1. Conventional lithostratigraphy of Eagle Ford Shale play area (modified after Childs et al., 1988).

- Composed of Cretaceous aged sediments filling basins formed during the Laramide Orogeny.
- Depositional environment was low energy with a stable water column. High organic content of 3-5% was preserved due to anoxic conditions.
- Thermal degradation of the organics into hydrocarbon chains forced water out of the shale. These hydrocarbons eventually saturated the shale and seeped out, forming accumulations in overlying formations such as the Austin Chalk.
- The low permeability of the shale has allowed significant amounts of hydrocarbons to remain trapped in-situ.

Eagle Ford Shale



Hentz & Ruppel

Eagle Ford Shale

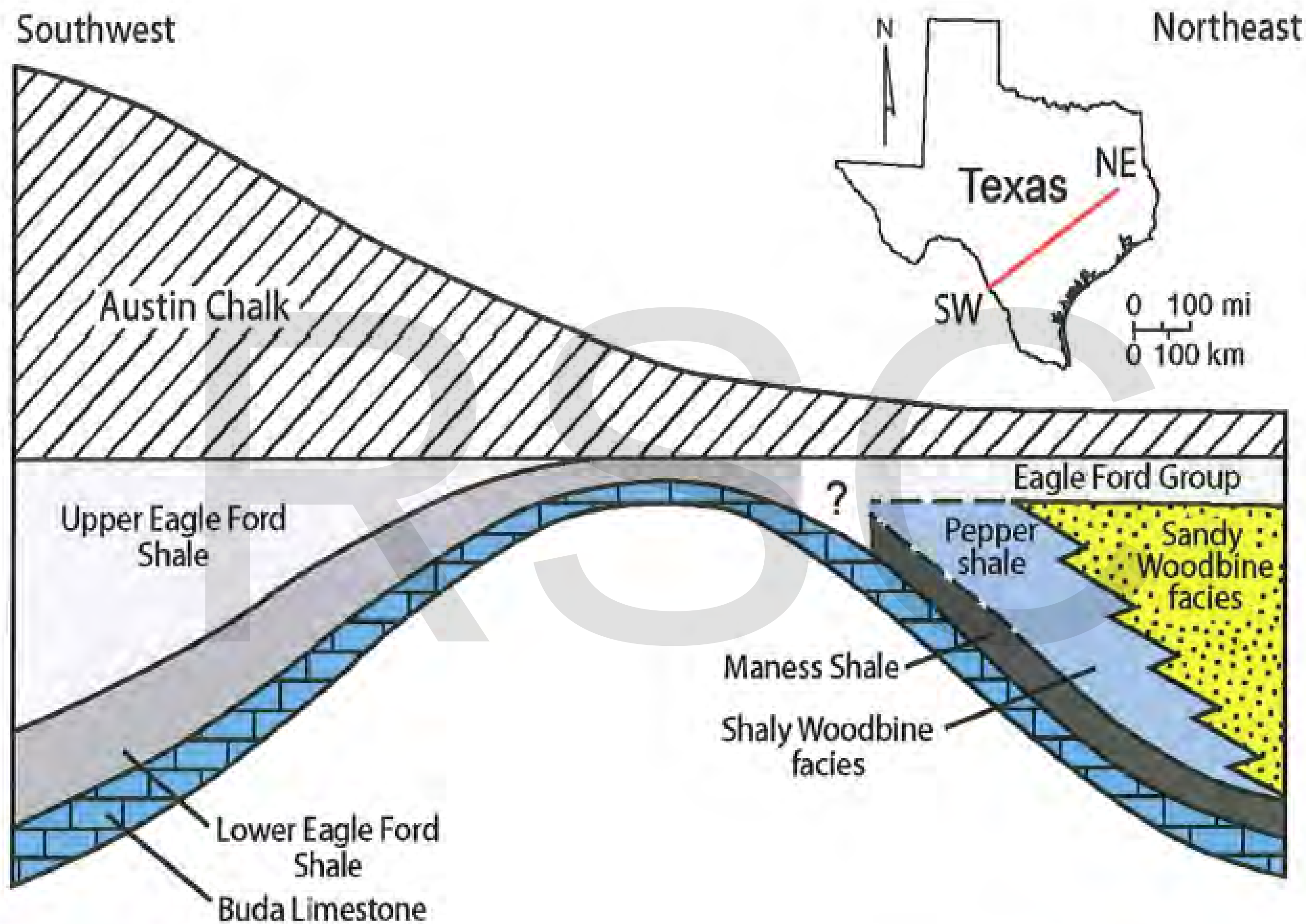


Figure 9. Southwest-northeast schematic strike cross section illustrating regional lithostratigraphic relationships across the Eagle Ford play area.

Hentz & Ruppel

Lower Eagle Ford Thickness

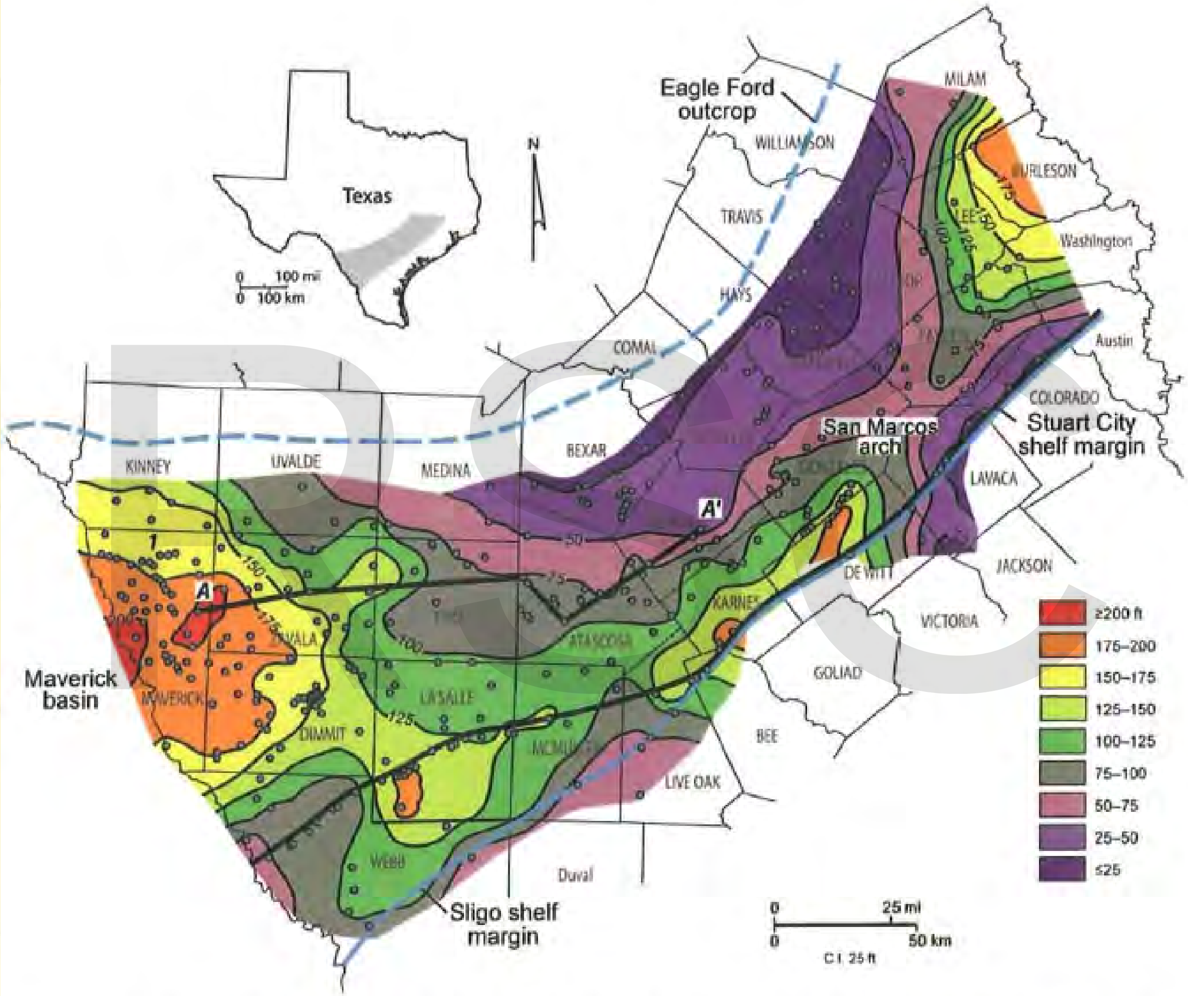


Figure 6. Isopach map of the lower Eagle Ford Shale. Cross section A-A' is shown in Figure 5. Note that areas of greatest thickness are the Maverick Basin and immediately northeast of the San Marcos Arch.

Hentz & Ruppel

Upper Eagle Ford Thickness

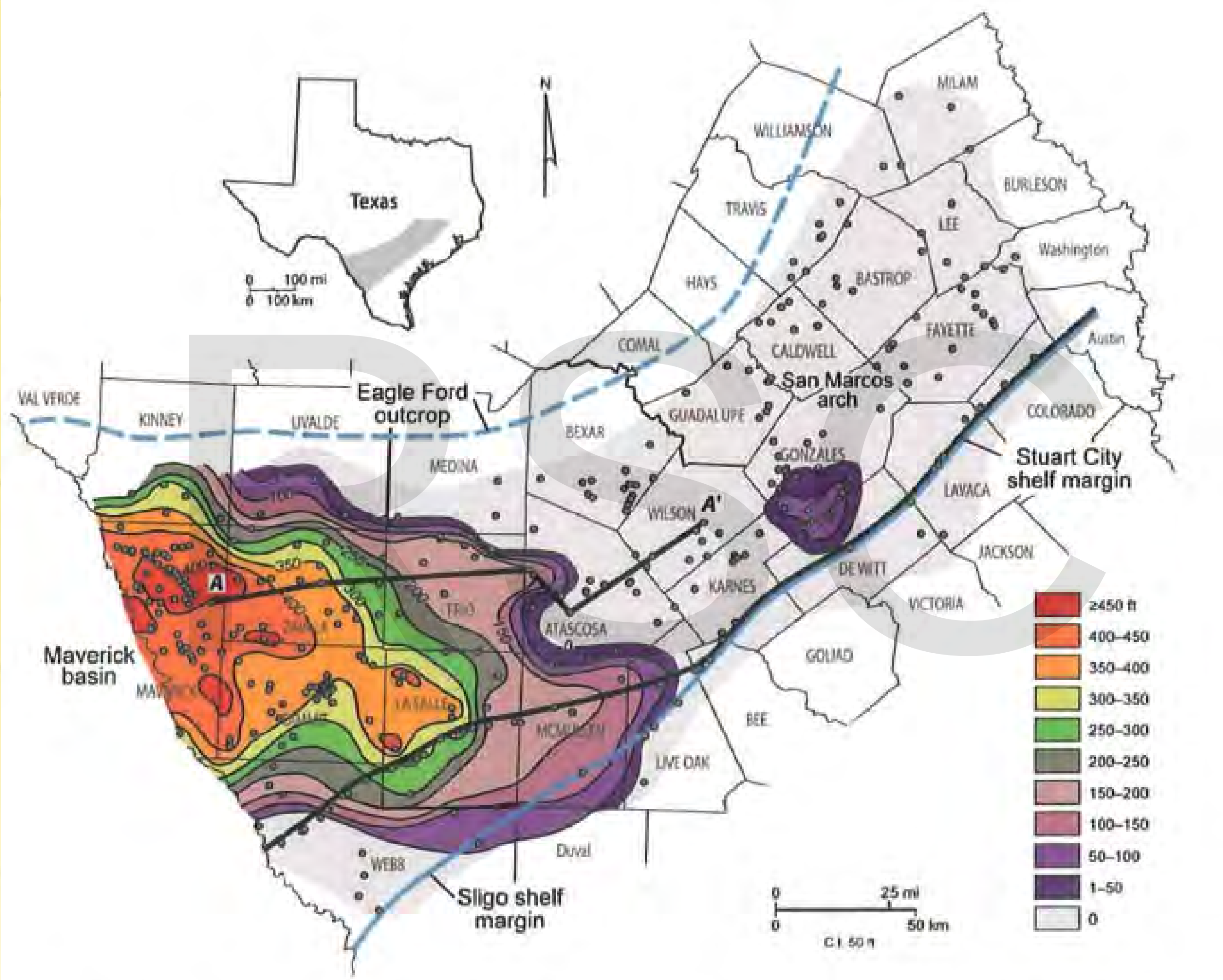
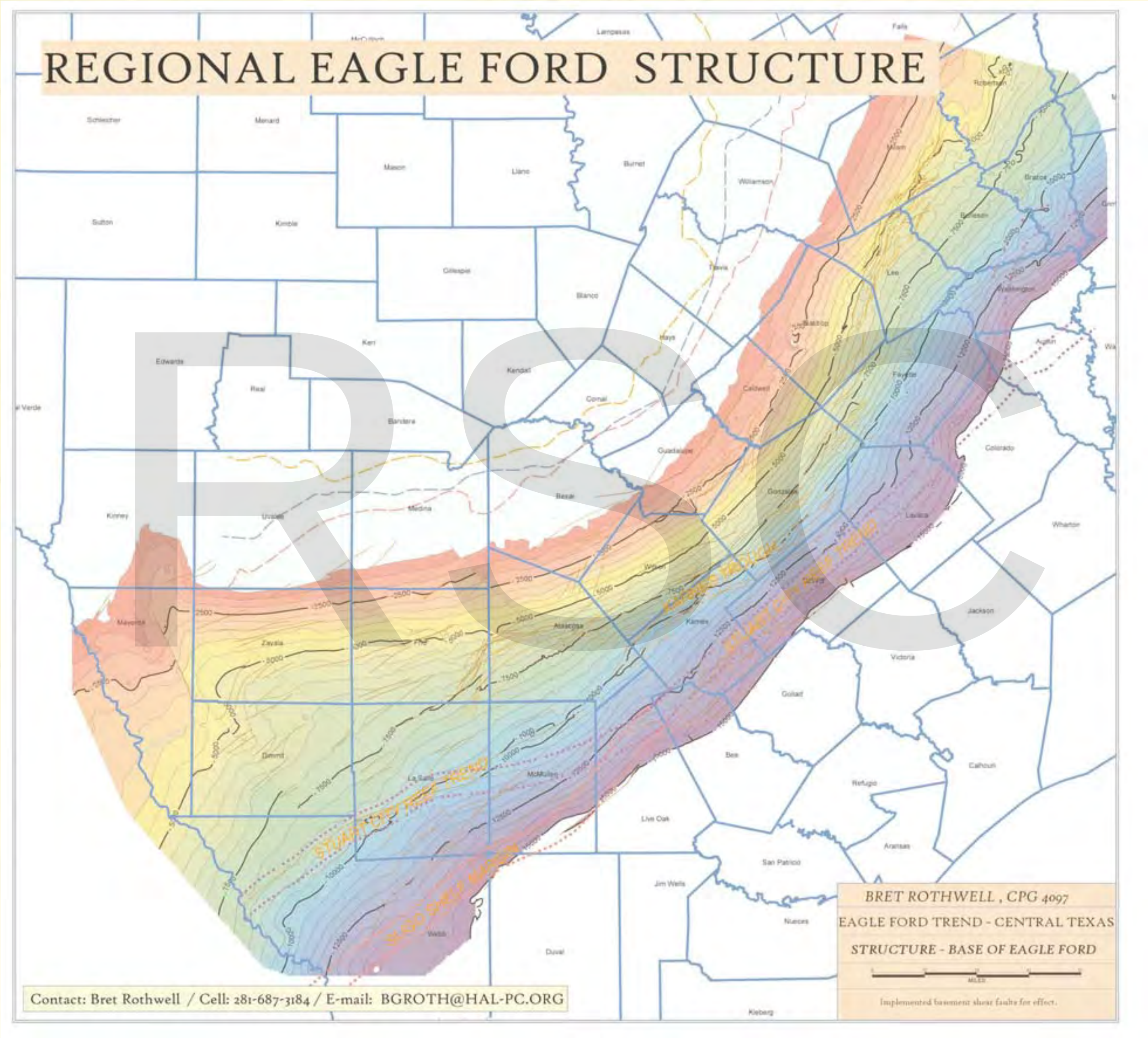


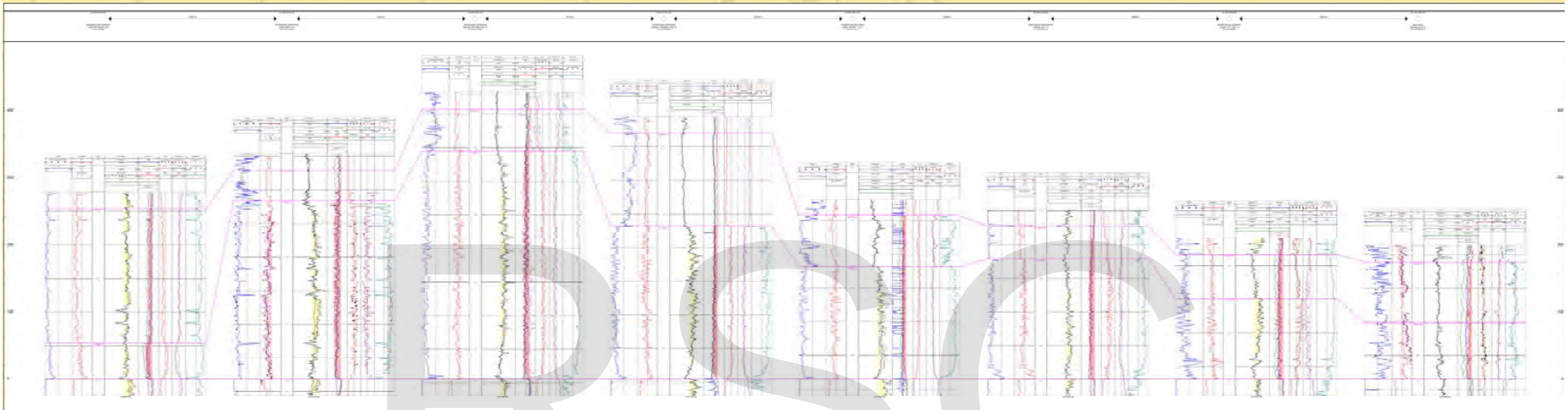
Figure 7. Isopach map of the upper Eagle Ford Shale. Cross section A-A' is shown in Figure 5.

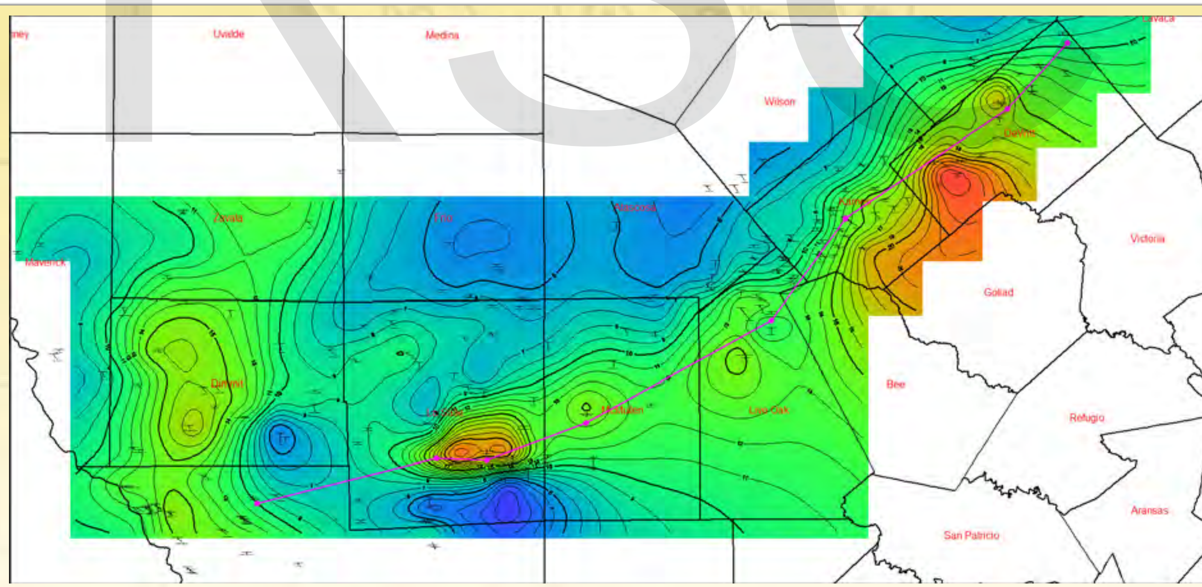
Hentz & Ruppel

Structure Map

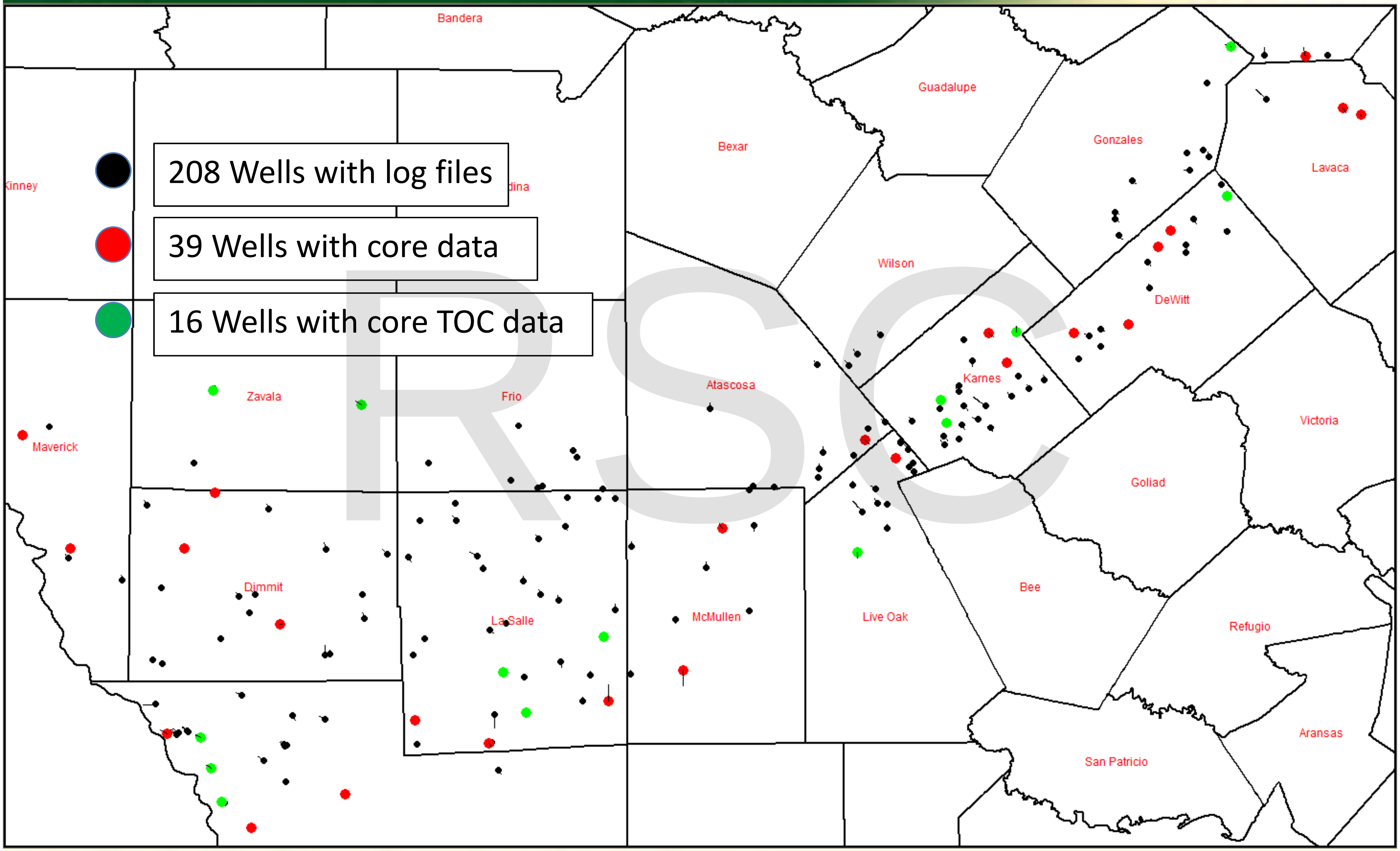


Cross Section





Geology: Wells with Core TOC



$$TOC_{wt/wt} = (Vol_{ker} * Rho_{ker}) / (RHOB * K)$$

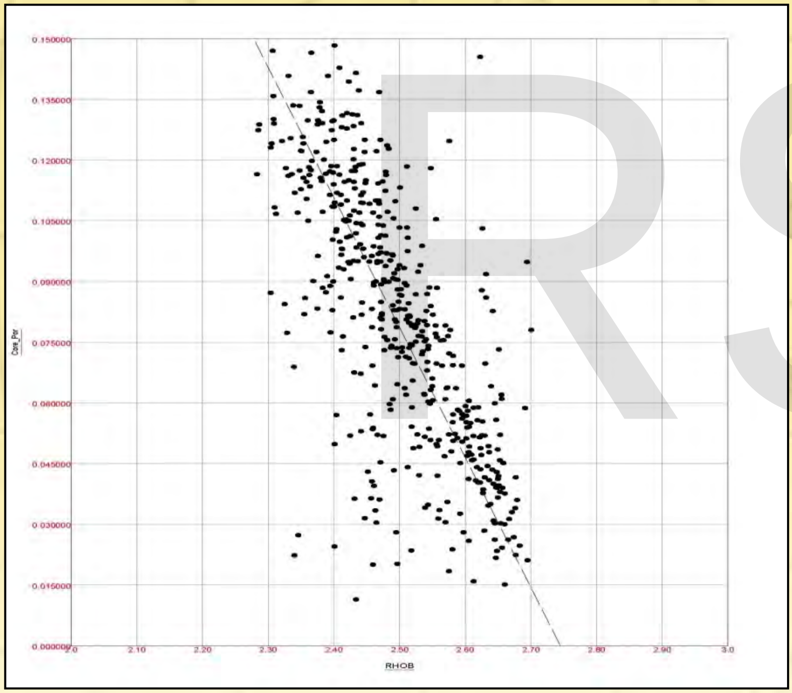
K = Kerogen Conversion Factor (1.2)

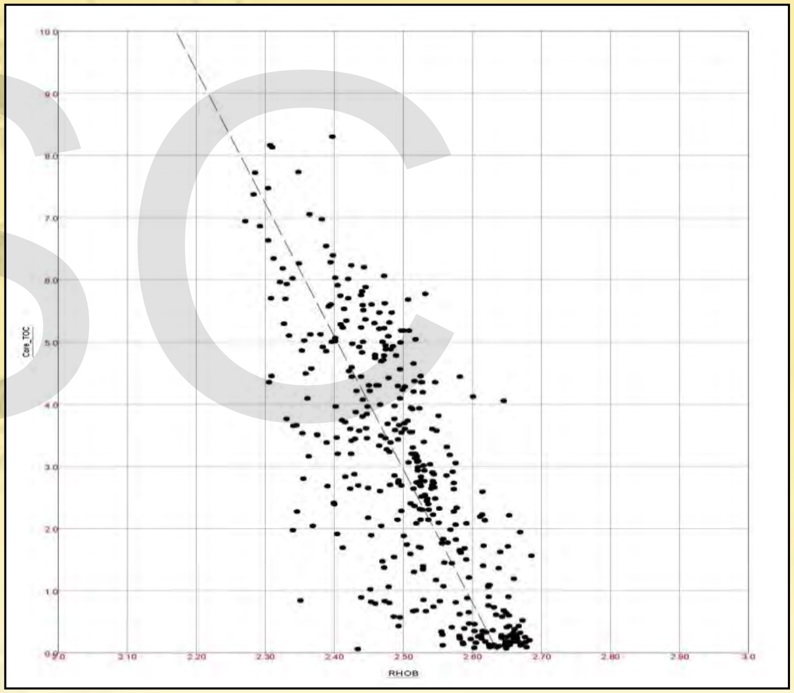
Rho_{ker} ranges 0.9 (immature) to 1.4(very mature) g/cc

Crain suggests default value of 1.26 g/cc

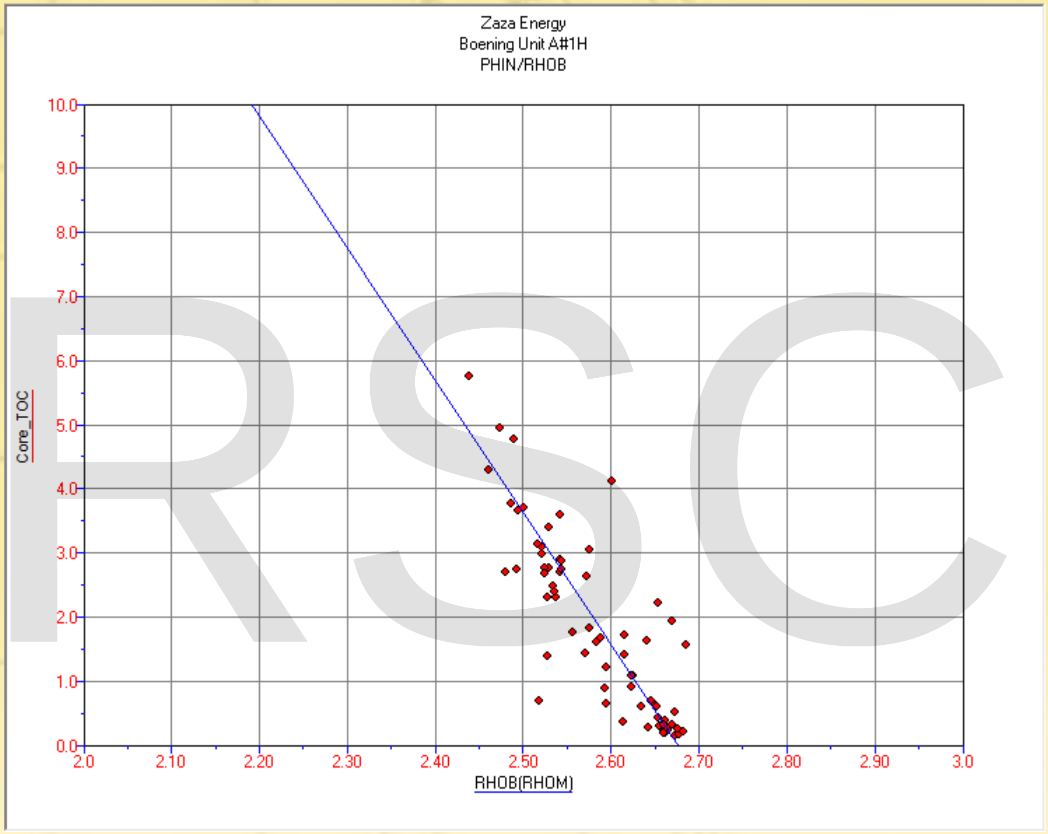
Petrophysical Workflow

- Presently dominated by core – log crossplot calibrations.





Petrophysical Workflow: TOC and RHOB



TOCrhob = 55.134605 - 20.606903*RHOB

Petrophysical Workflow: Corrected Porosity

Calculate kerogen corrected porosity for each curve

PHIDc = PHID – (Vker * PHIDker)

PHINc = PHIN – (Vker * PHINker)

PHISc = PHIS – (Vker * PHISker)

We need to know PHIDker and Vker

Petrophysical Workflo: Corrected Porosity

Calculate kerogen corrected porosity for each curve

PHIDker = (RHOma – RHOker) / (RHOma – RHOfl)

PHINker = .50 to .65 (or from TOC / PHIN xplot)

PHISker = (DTker – DTma) / (DTfl – DTma)

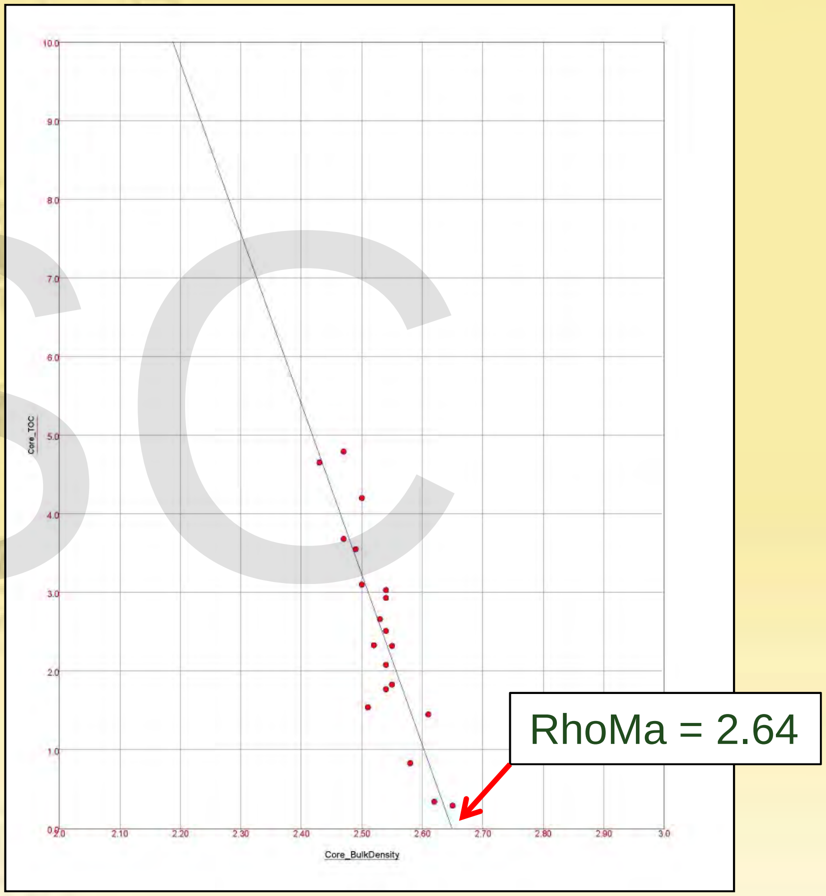
(DTker 105 to 160 usec/ft or from xplot)

RHOma and RHOker can be determined using crossplots

Petrophysical Workflow: Corrected Porosity

RhoMa can be determined by plottiing Core TOC and Core Bulk Density

The X Intercept gives you your RhoMa value



Petrophysical Workflo: Corrected Porosity

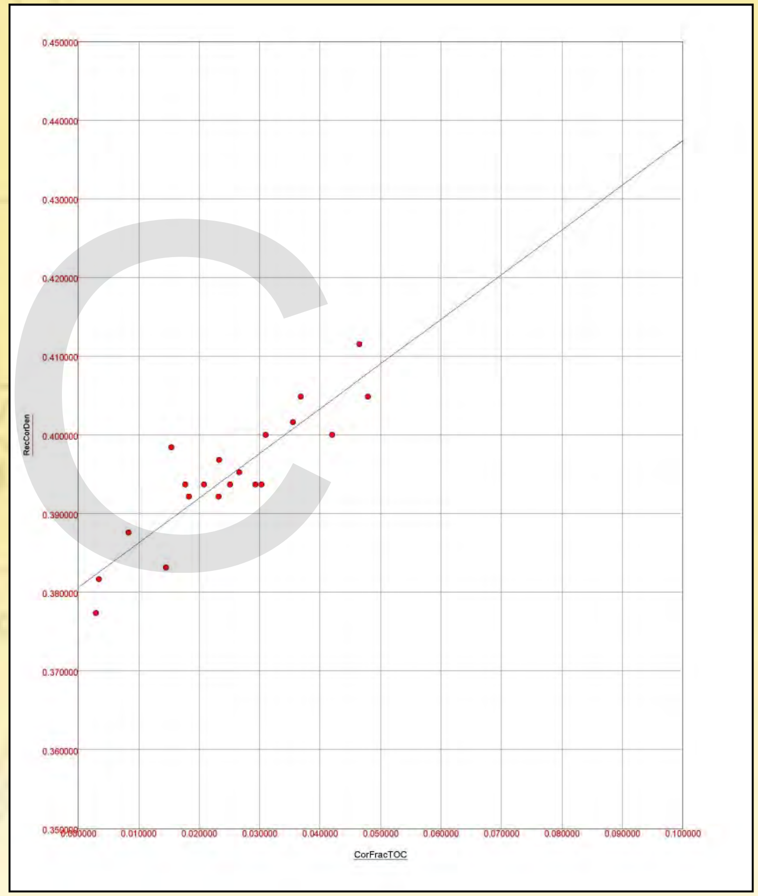
RhoMa and RhoKer can also be determined by plotting Inverse Grain Density and Core Fraction TOC

First convert TOC wt% to TOC wt fraction

CorFracTOC[] = Core_TOC[] / 100

; Reciprocal of Core Bulk Density

RecCorDen[] = 1 / Core_BulkDensity[]

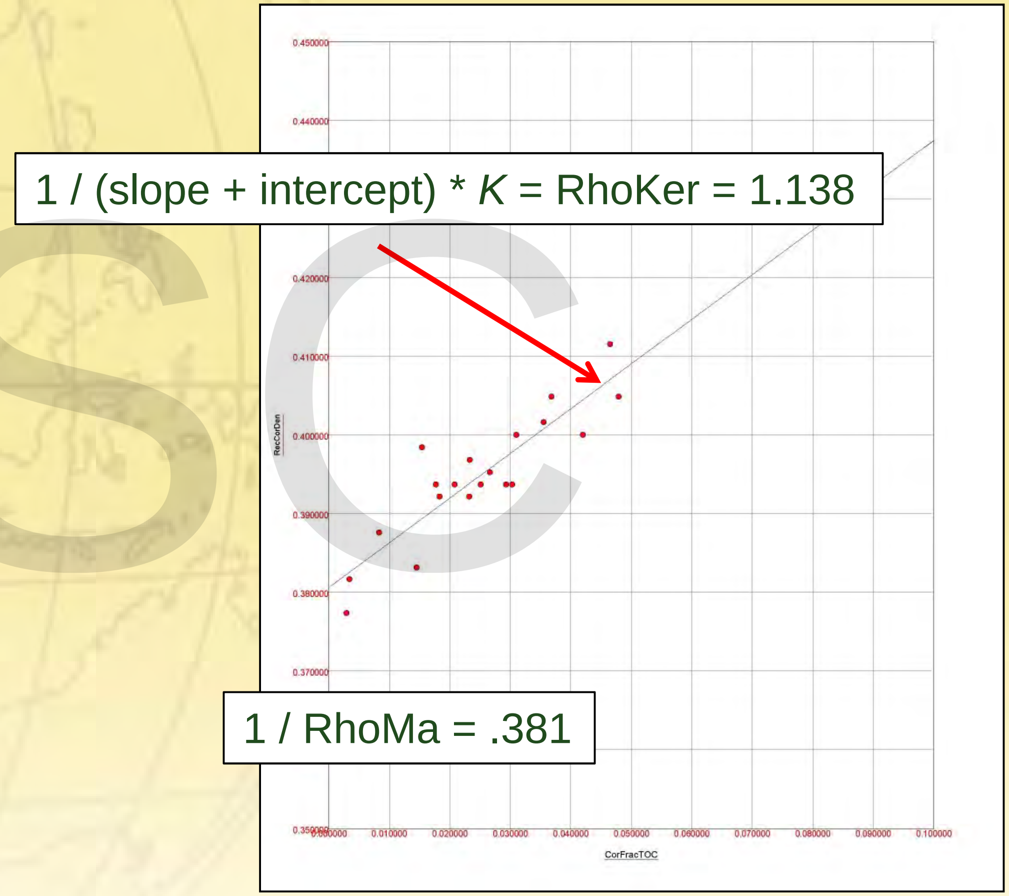


Petrophysical Workflo: Corrected Porosity

RhoMa = 1 / Intercept

RhoToc = 1 / (Slope + Intercept)

RhoKer = RhoToc / K



Petrophysical Workflo: Corrected Porosity

Now we have values for RHOker and RHOma we can calculate PHIDker and Vker:

PHIDker = (RHOma – RHOker) / (RHOma – RHOfl)

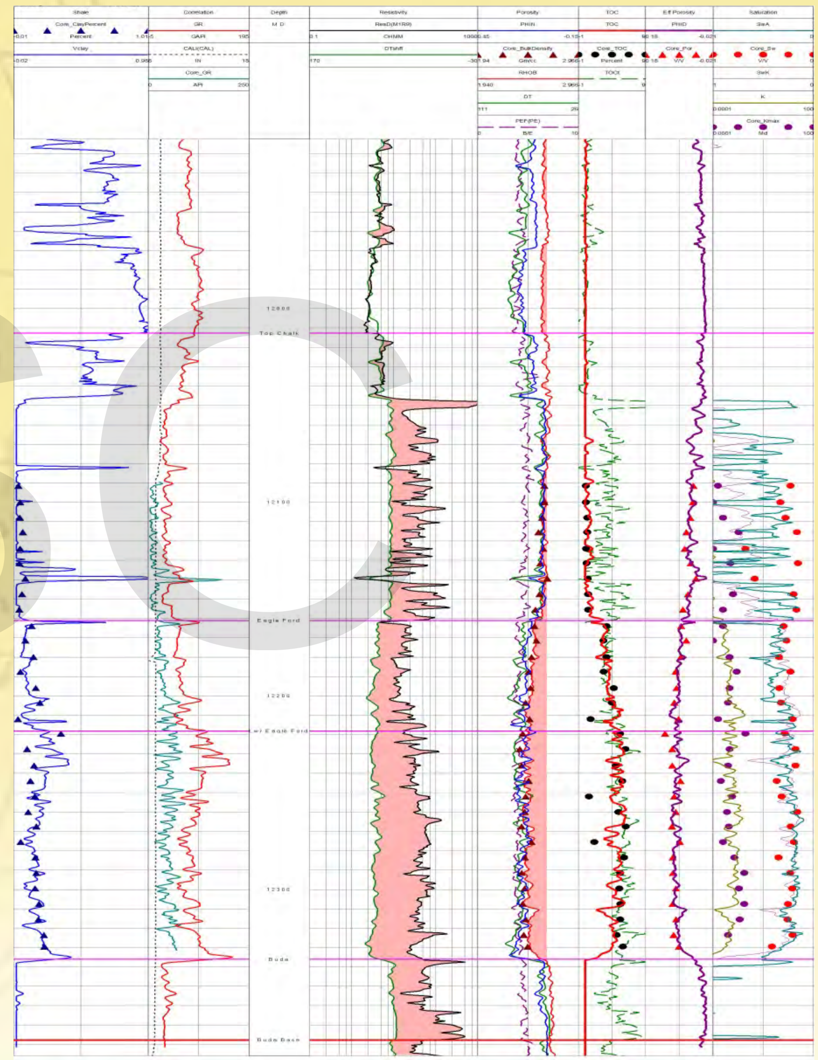
Vker = [(TOCrhob / 100) * (1.2 * RHOB)] / RHOker

Now we can calculate kerogen corrected porosity:

PHIDc = PHID – (Vker * PHIDker)

Petrophysical Workflow - Saturation

- Open question whether to use Archie equation or one of the various shaley sand equations
  - Core porosity and saturation are total system measurements, calibration easier with Archie
  - Assume m = n
    - Range could be 1.5 – 2.5



Core Expansion

Compare core bulk density to log bulk density to determine if significant “expansion effects”

Correct core porosity if needed

Core Expansion Correction

CorBlkVol[] = 1 / Core_BulkDensity[]

CorPorVol[] = Core_Por[] * CorBlkVol[]

CorGrnVol[] = CorBlkVol[] - CorPorVol[]

LogBlkVol[] = 1 / RHOB[]

CorPorC[] =min(Core_Por[], (LogBlkVol[] - CorGrnVol[]) / LogBlkVol[])

Correct for core water saturation if needed.

modified from Lapierre SPWLA

Petrophysical Workflow

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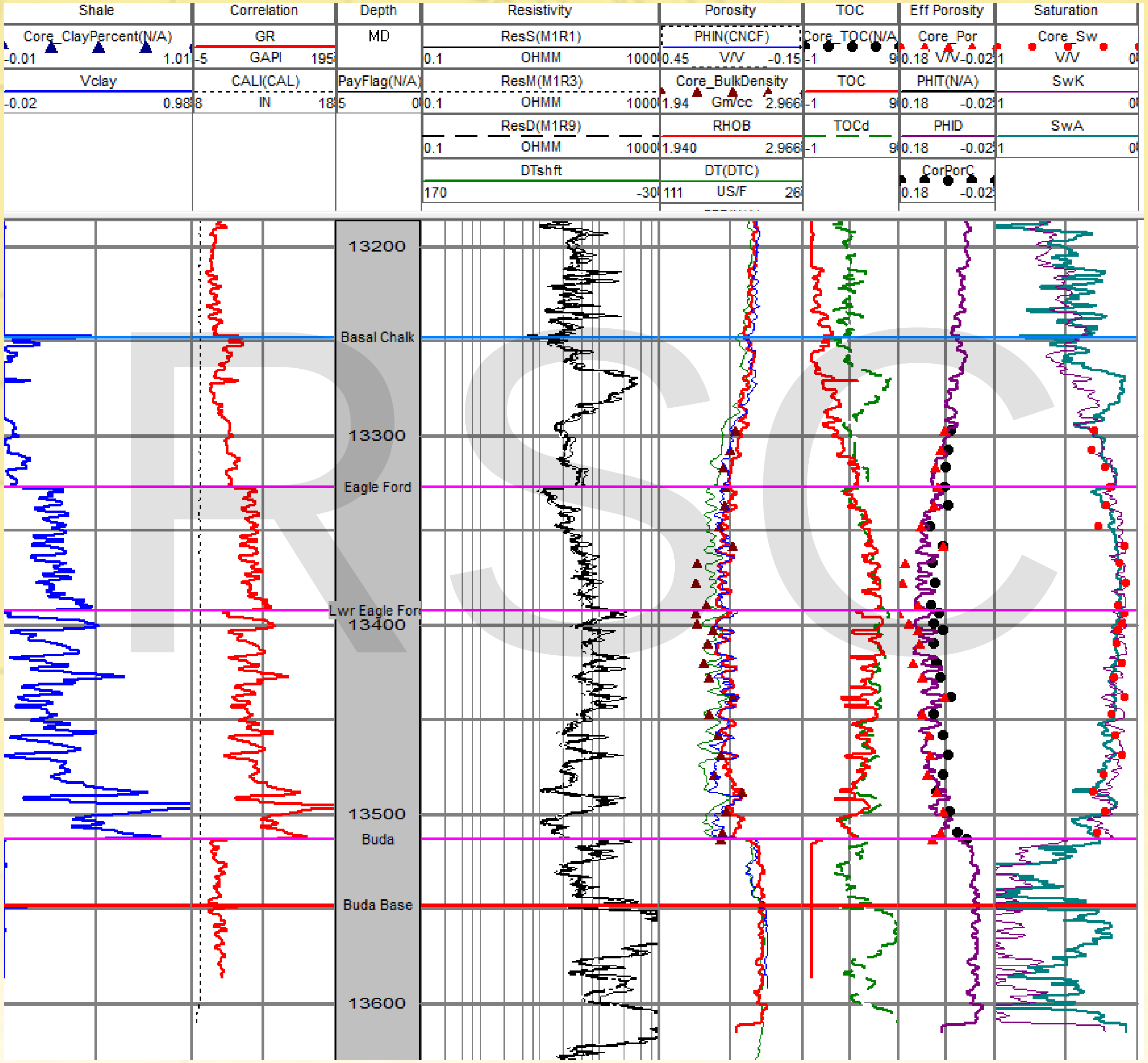
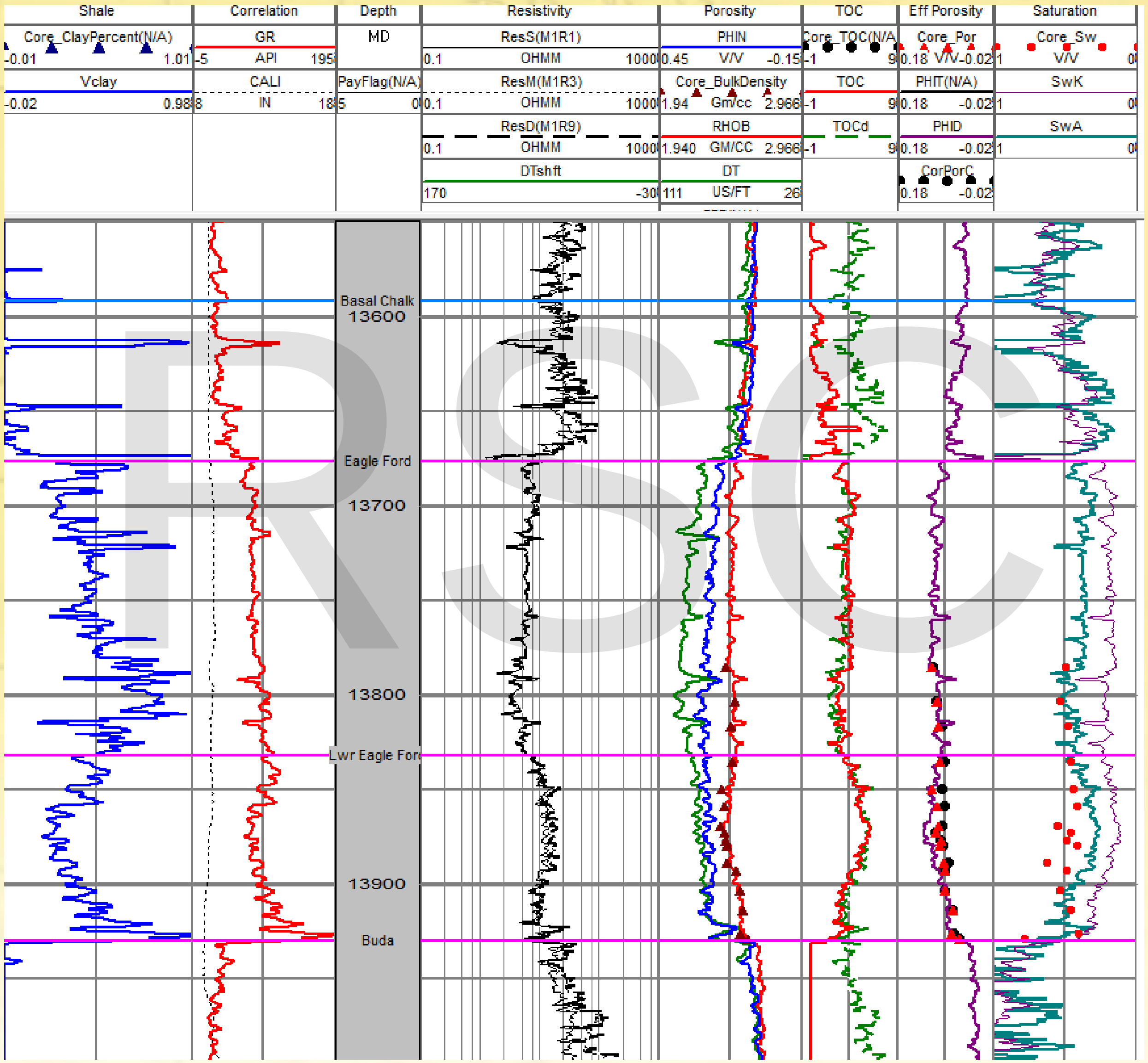
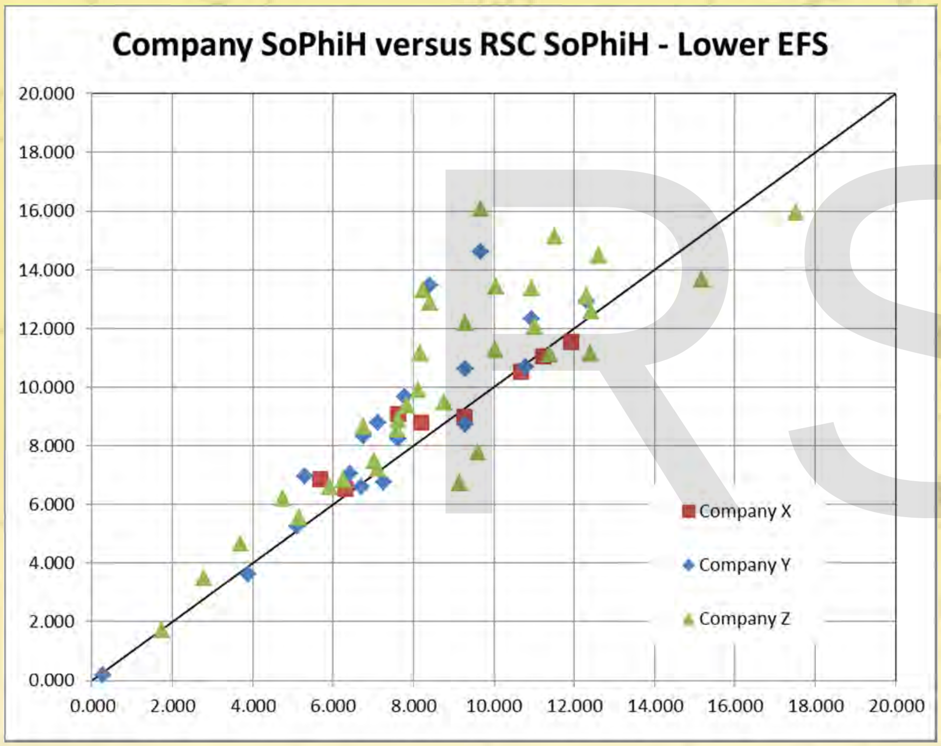


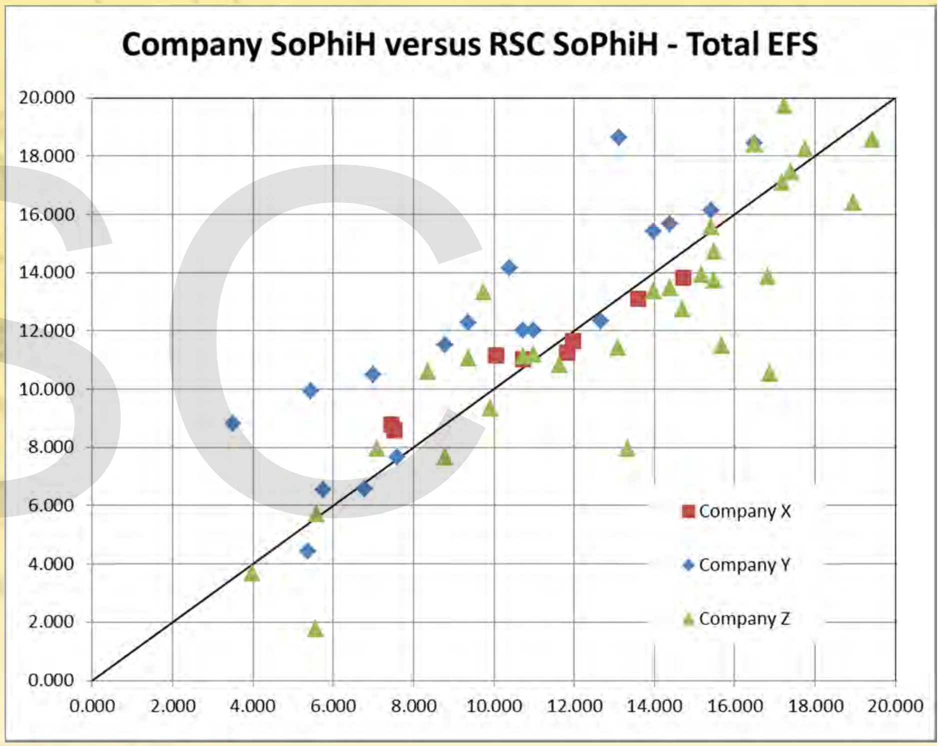
Petrophysical Workflow



Petrophysical Results

- Found good agreement of RSC So*Phi*H log evaluation calculations with other company estimates.





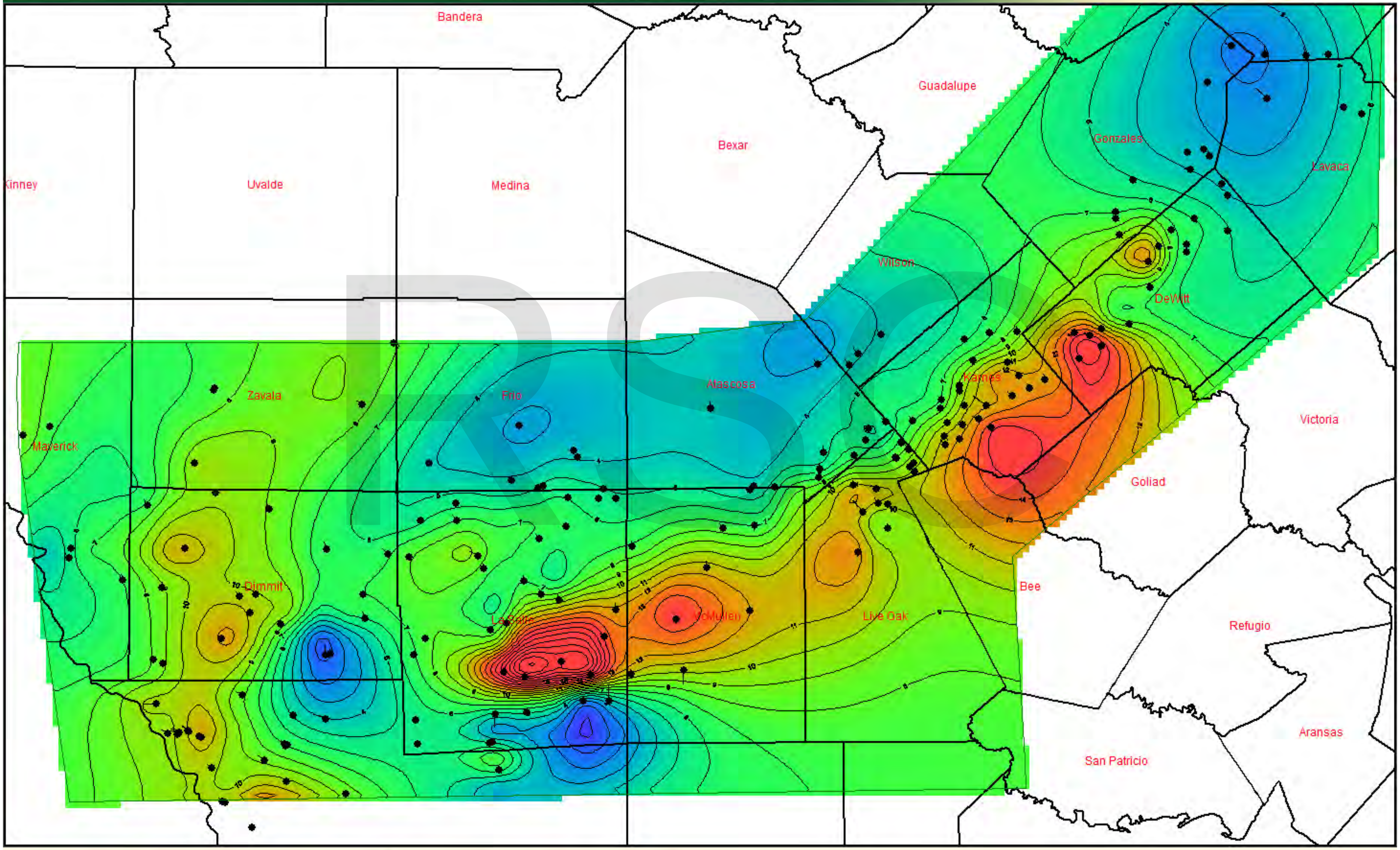
Mapping the Log Results

- So*Phi*H Maps show the variation of in-place volumes across the field.

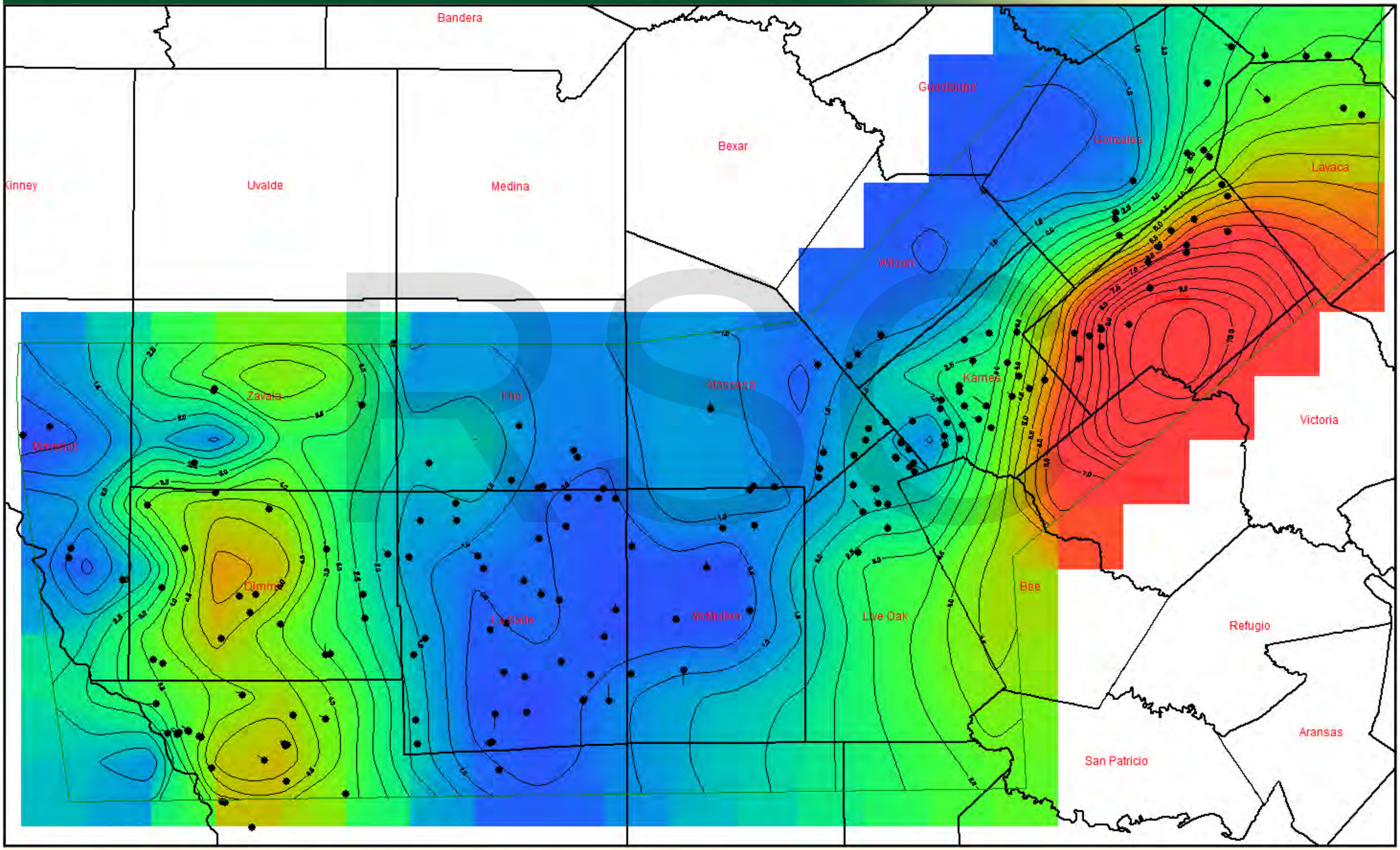
- The magnitude of So*Phi*H in an area generally correlates to average well production.

- Good Log versus Core relationships give good reliability of hydrocarbon-in-place estimates.

Lower EFS SoPhiH



Upper EFS SoPhiH



Total EFS SoPhiH

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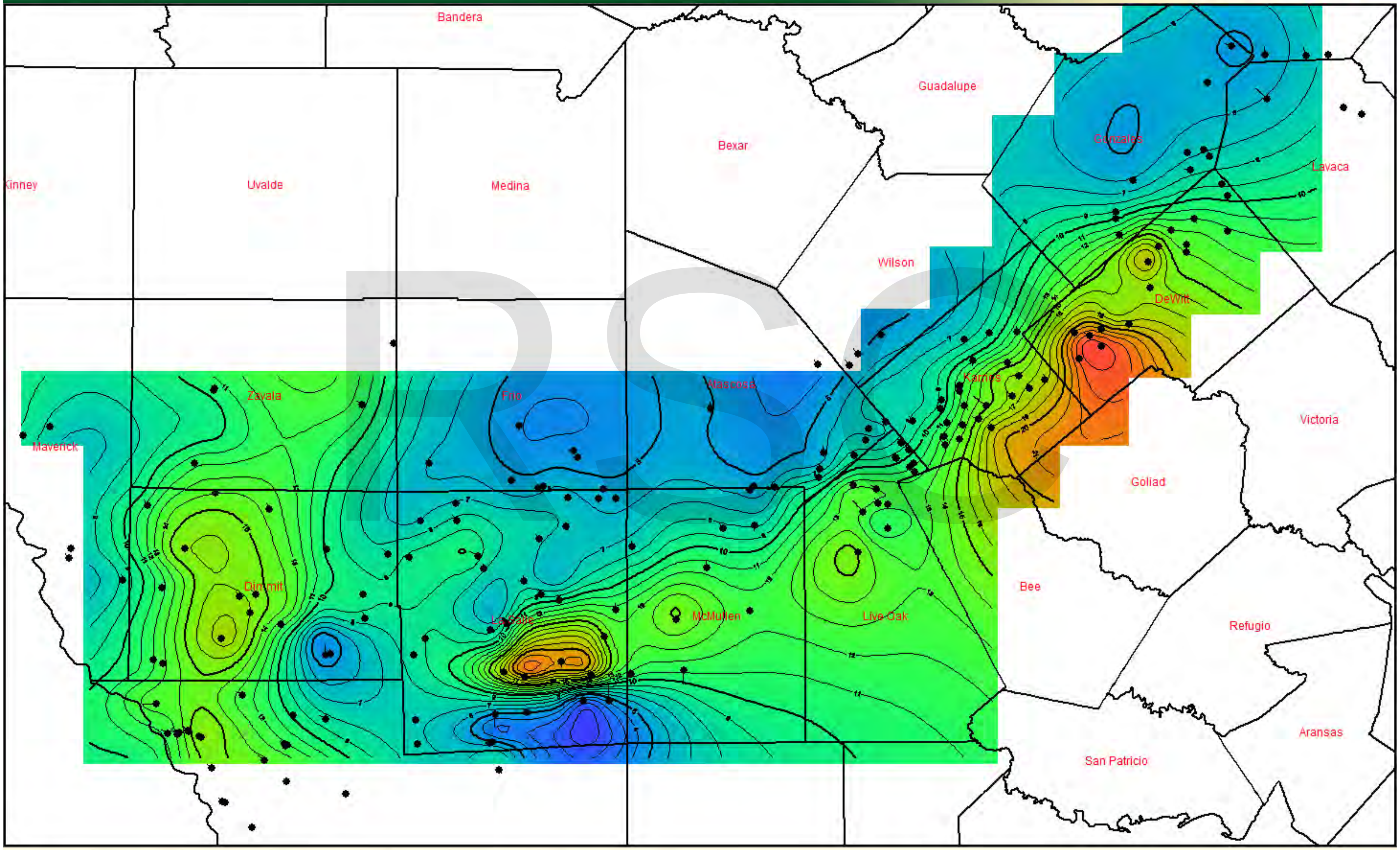
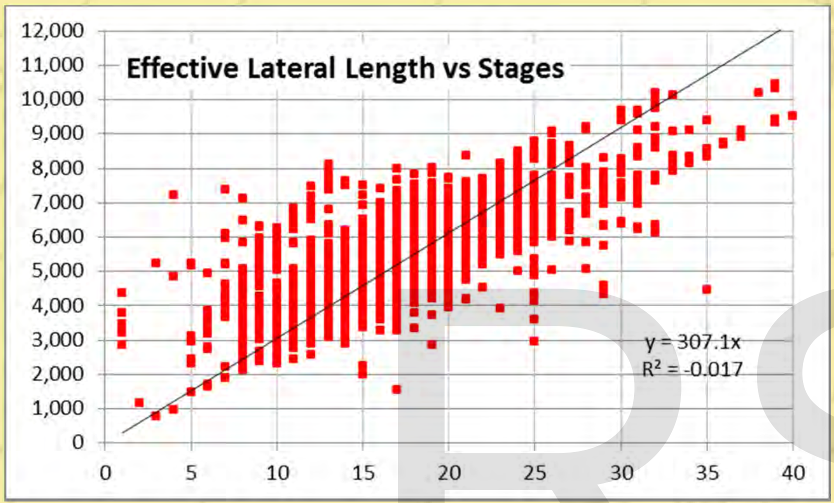


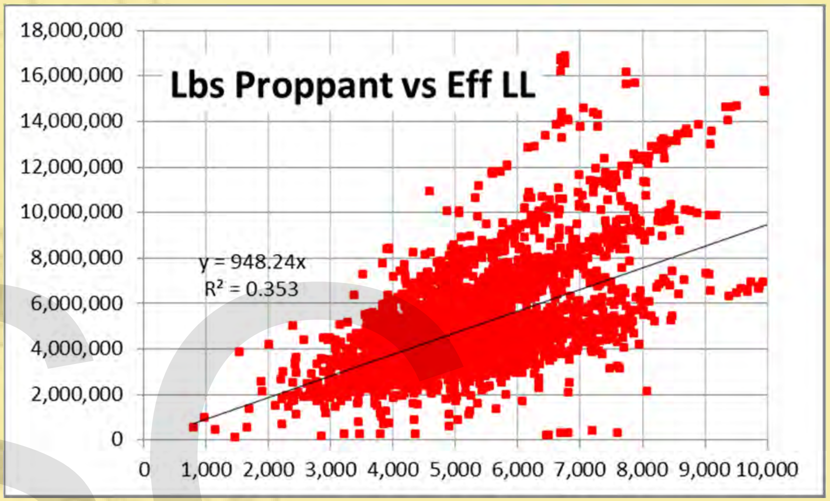
Completions

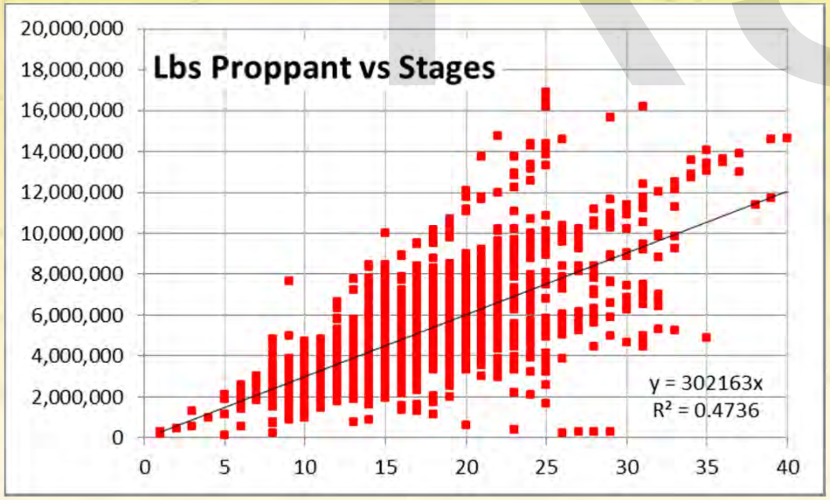
Completions

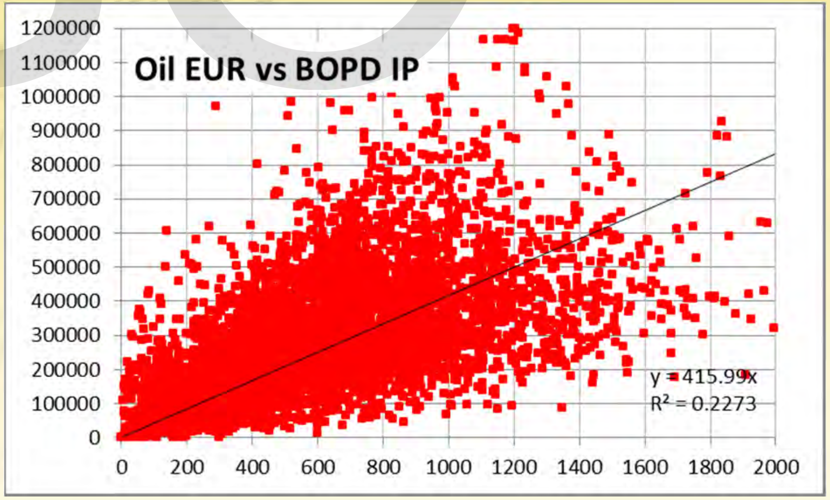
- Lateral Length
- Pounds of Proppant
- Stages
- Initial Rates

Completions

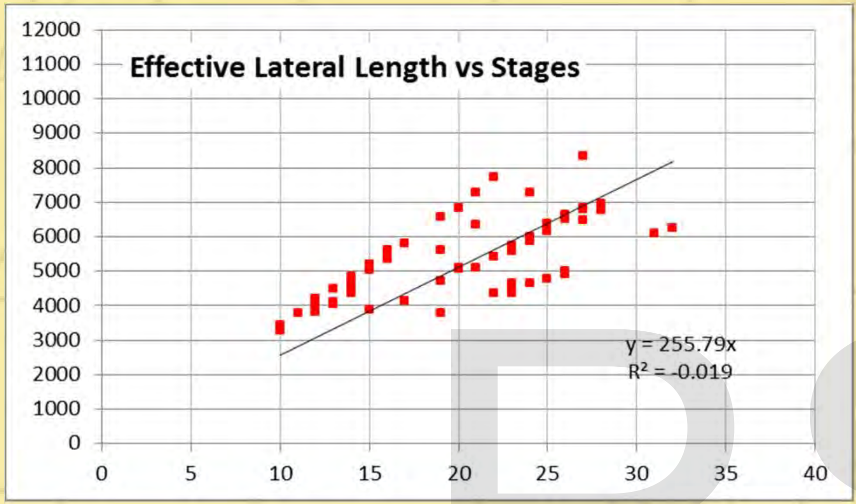


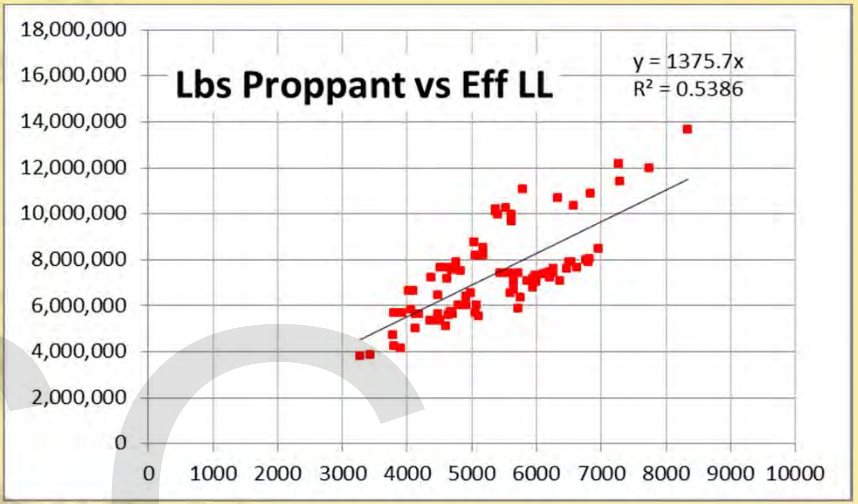


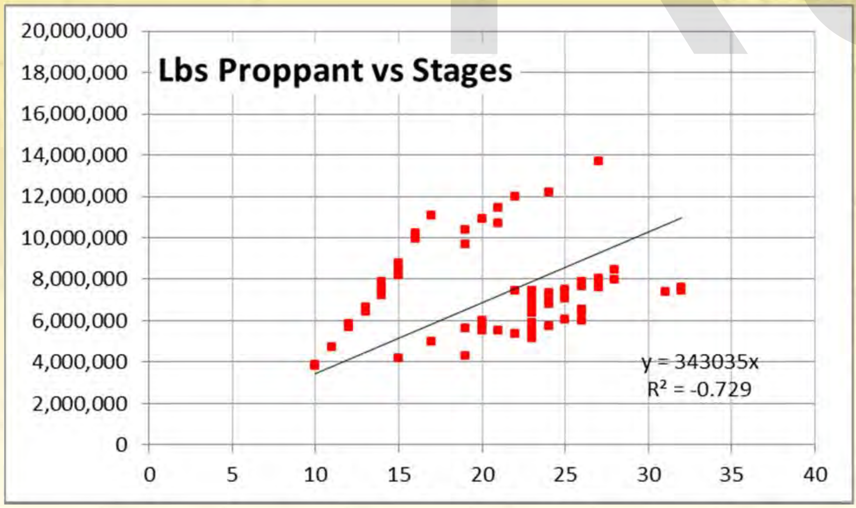


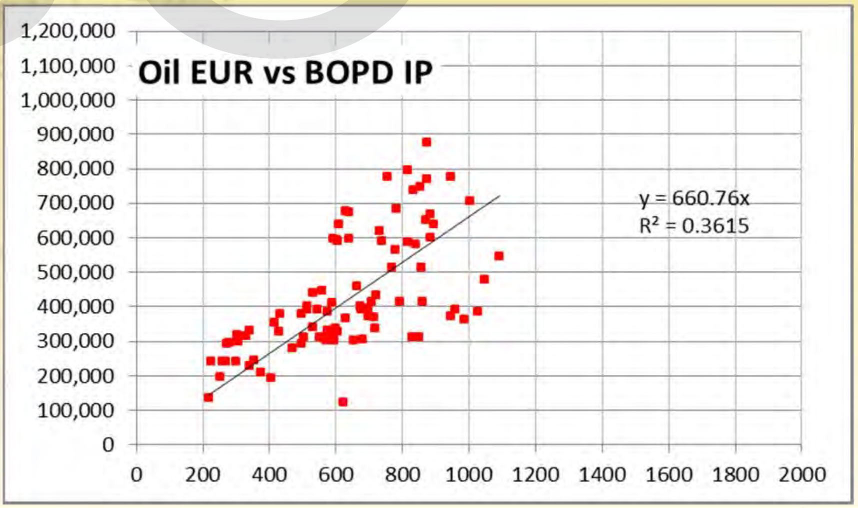


Completions – Recent Karnes/Dewitt Wells







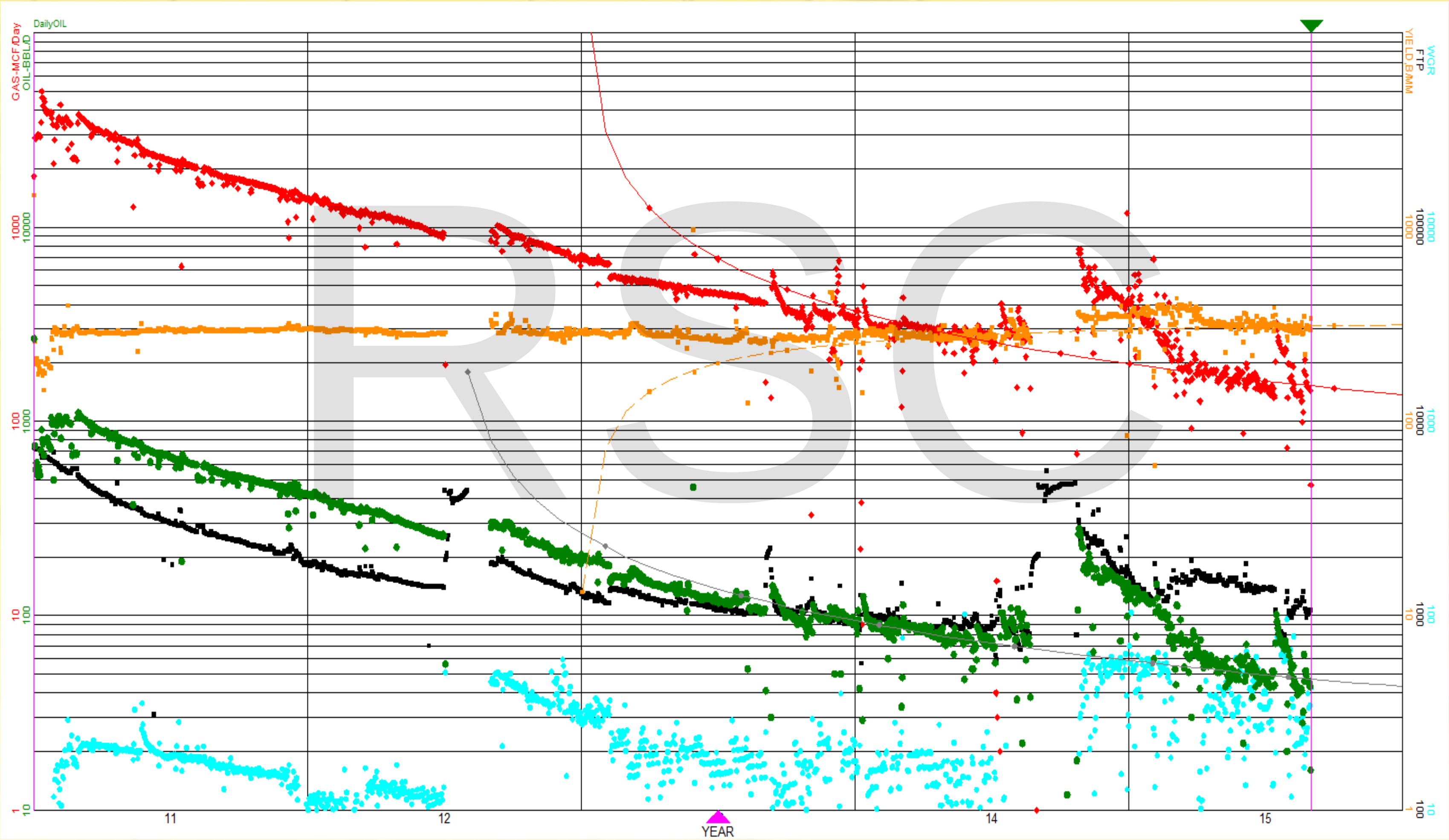


Performance

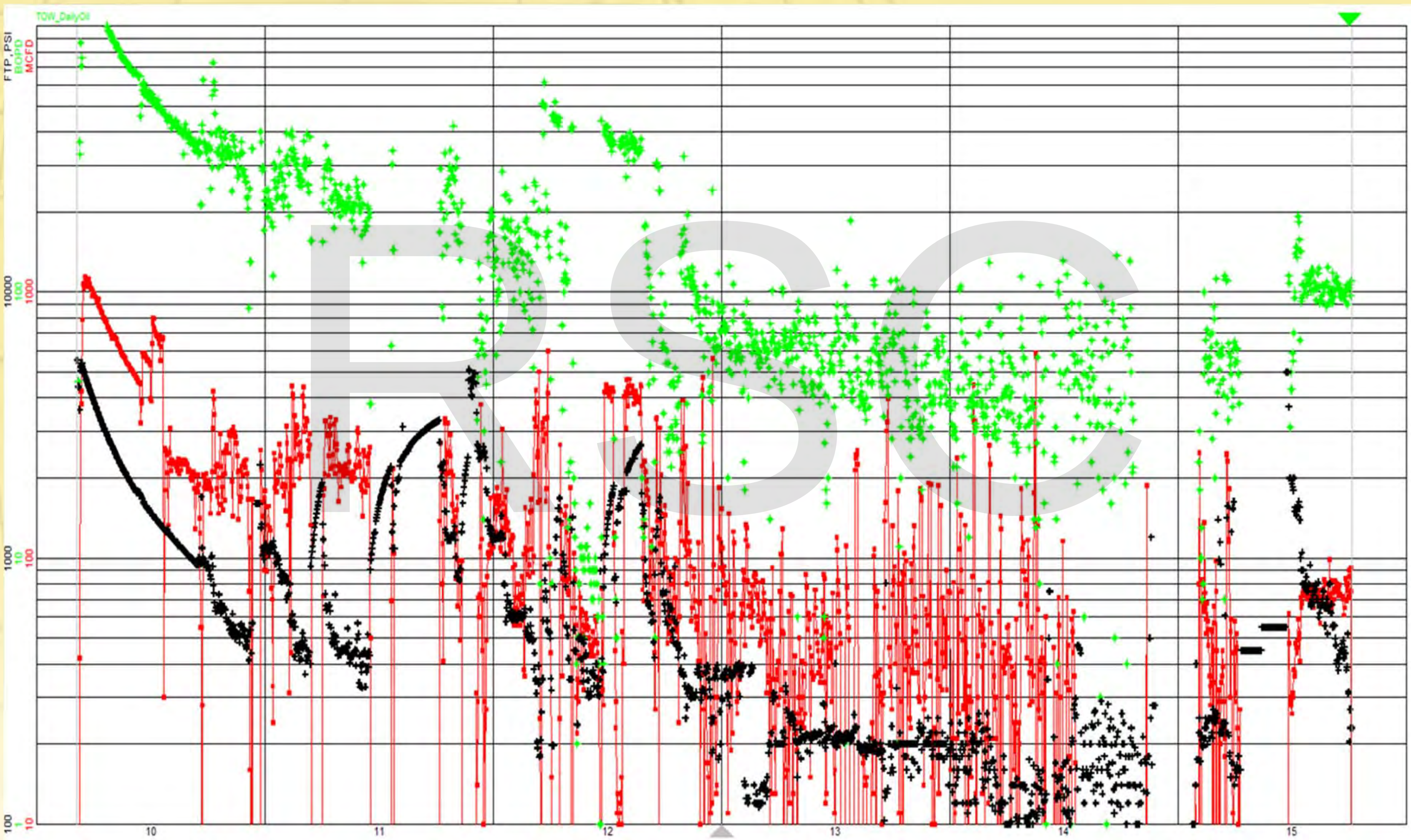
- Type Curves
- PVT
- Modelling
- Example

Well Defined Performance Example

Well Defined Performance Example



Erratic Performance Example

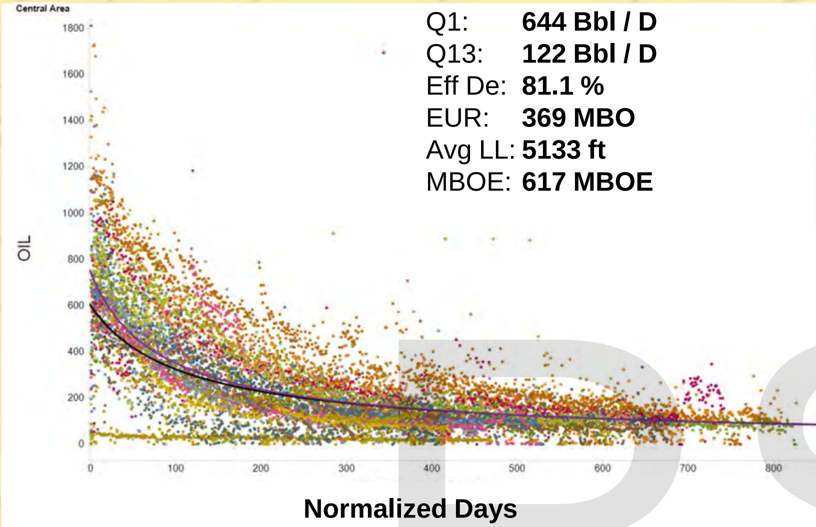


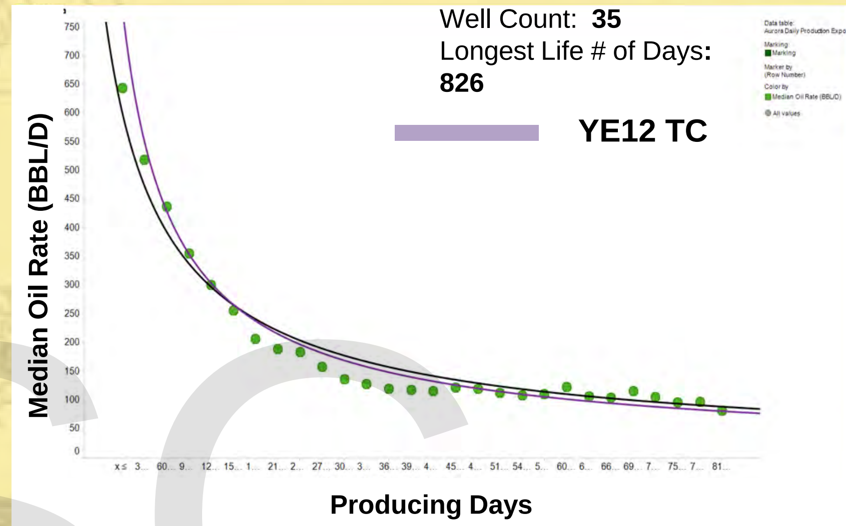
Complicating Factors

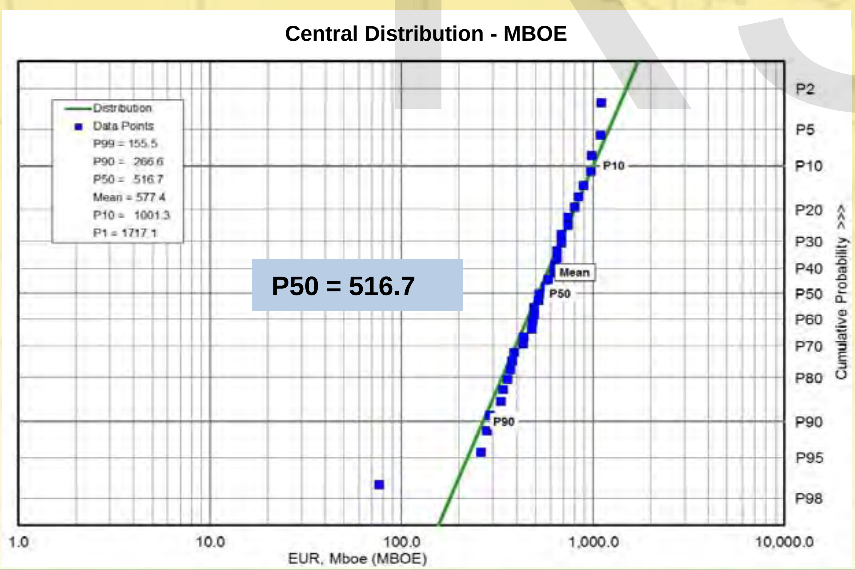
- Frac Hits
- Artificial Lift
- Choke Management
- Down Spacing
- Landing Interval
- Completion Method
- Production Allocations
- Measurement Points

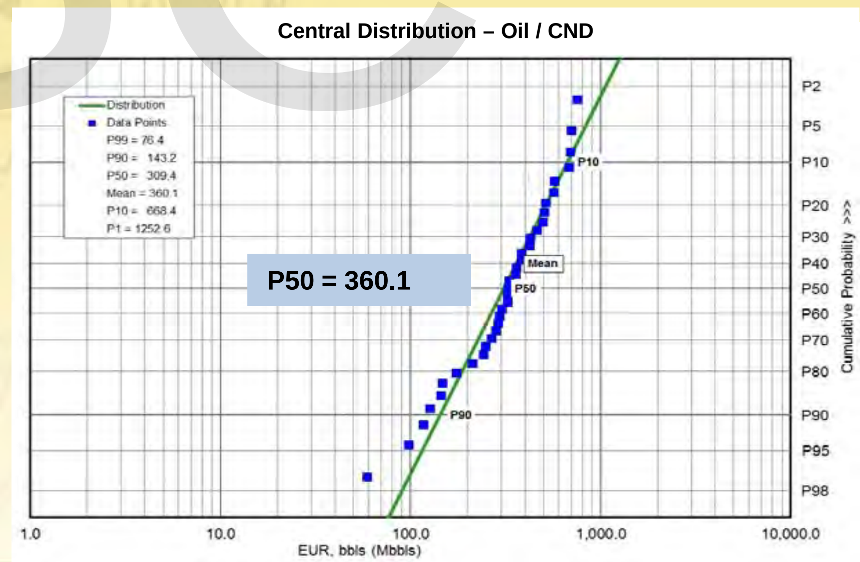
Multiple Well Time Normalized

Multiple Well Time Normalized

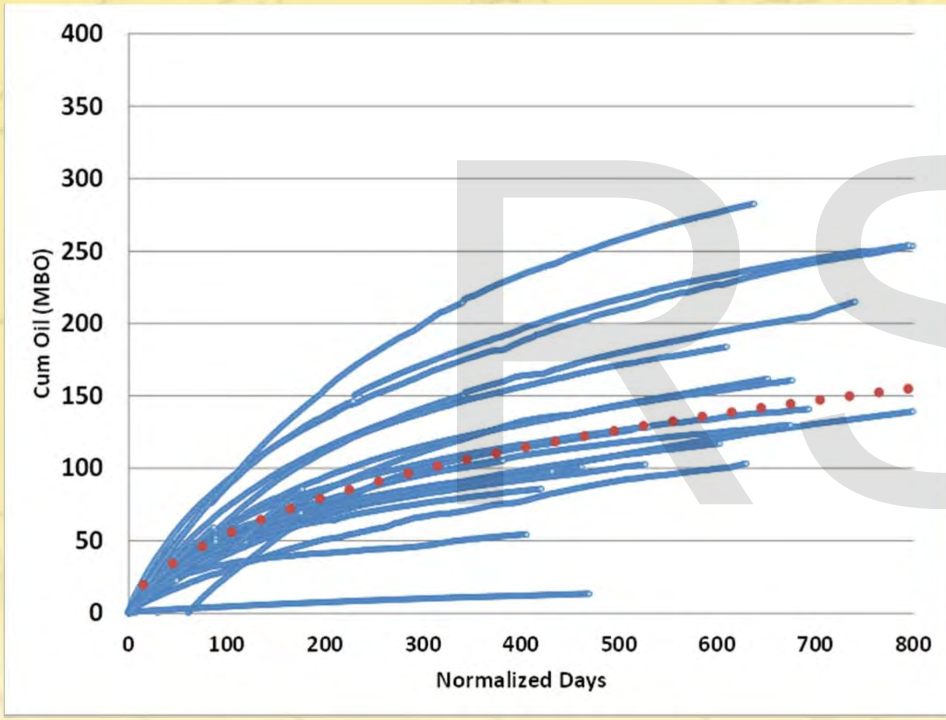


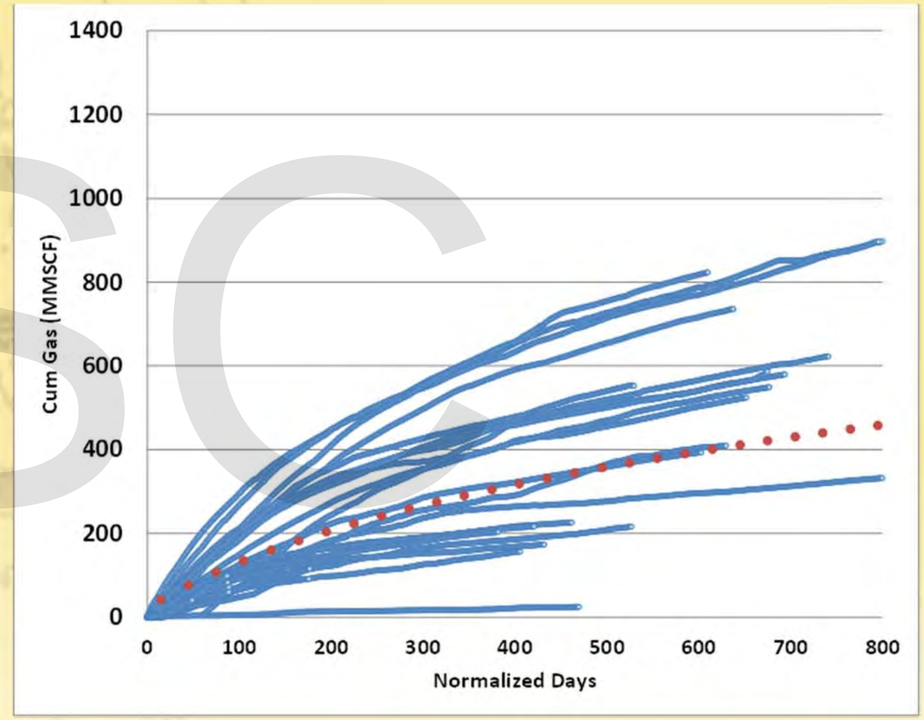




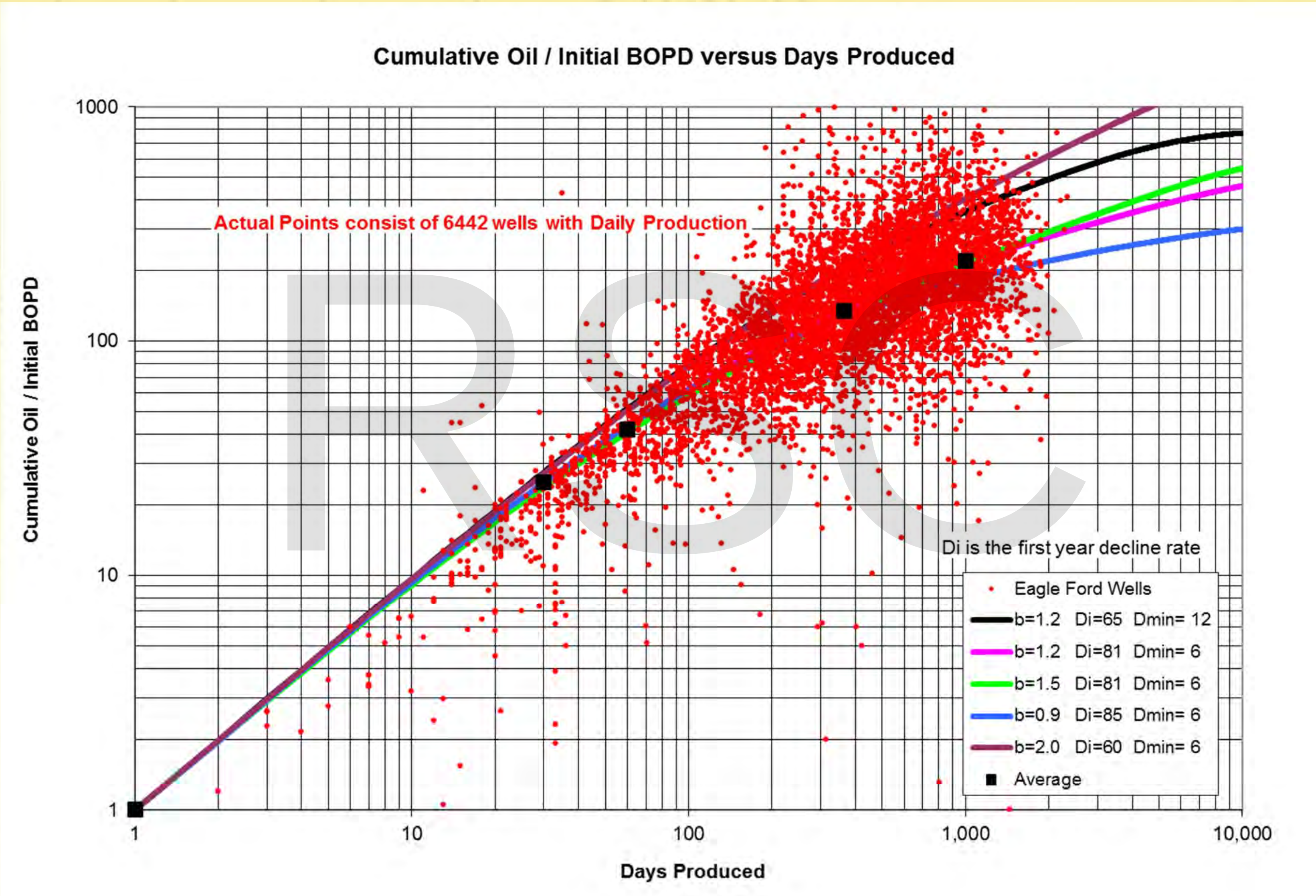


Multiple Well Time Normalized



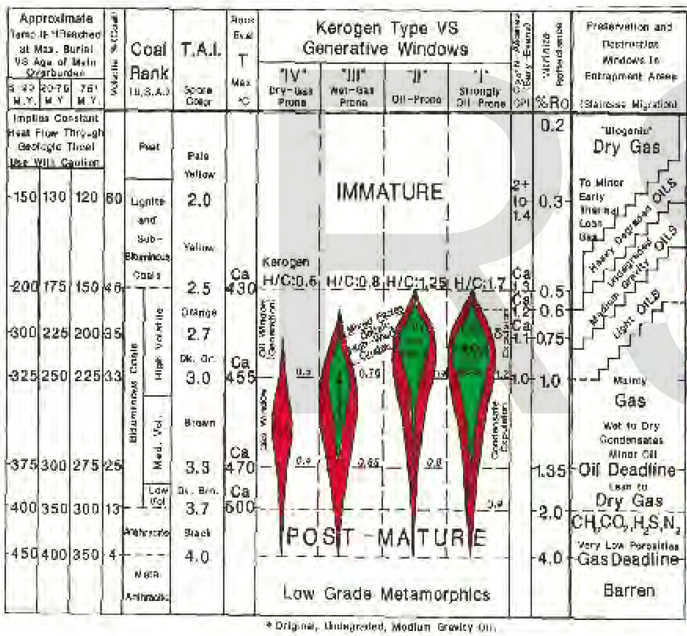


Type Curve Performance



PVT Properties

Fluid Properties & Maturation



McCain, W.D. 1994

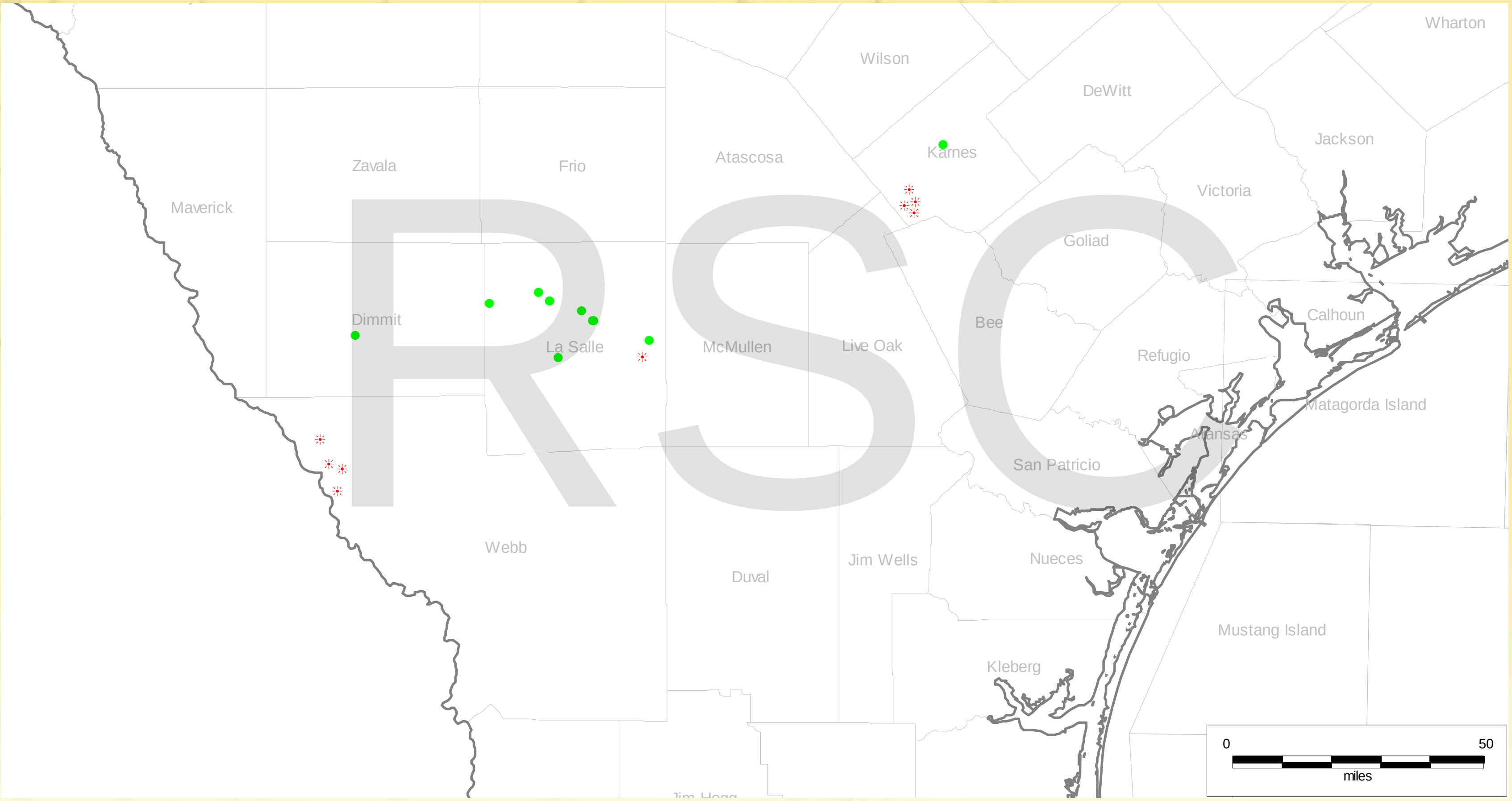
Reservoir Fluid	BBL/MMSCF	GOR (scf/stb)	API Gravity	Mol% C7+	FVF (RB/STB)
Black Oil	>650	<1500	< 45	> 30	< 2.0
Volatile Oil	300 – 650	1500 – 3300	> 40	12.5 – 30	> 2.0
Retrograde Gas	20 – 300	3300 – 5000	40 – 60	< 12.5	N/A
Gas Condensate	10 – 20	>5000	> 55	< 5	N/A
Dry Gas	<9	N/A	> 55	N/A	N/A

Volatile Oil ~ 0.9 to 1.1 % Ro

Reservoir Fluid	(% Ro)
Immature	< 0.6
Black Oil	0.6 - 0.9
Volatile oil	0.9 - 1.1
Retrograde Gas - Gas Condensate	1.1 - 1.4
Dry Gas	> 1.40

Source: AAPG/DPA Reserves Forum 2015, Thomas G. Harris

PVT Wells



Wharton
Wilson
DeWitt
Jackson
Zavala
Frio
Atascosa
Karnes
Victoria
Maverick
Goliad
Dimmit
Calhoun
La Salle
McMullen
Live Oak
Bee
Refugio
Matagorda Island
Aransas
San Patricio
Webb
Jim Wells
Nueces
Duval
Mustang Island
Kleberg
0
50
miles
RSC

PVT Analysis

RYDER SCOTT

County	FormationTop	Oil API	Gas Gravity	Initial Pressure	Initial Temp	GOR	Yield	MW	Wellstream SG
Dimmit	7995	48.9	0.83	4850	210	6990	143	35.248	1.217
Dimmit	6271	47.1	0.83	3769	182	2677	374	50.229	1.734
Dimmit	5710	45.1	0.77	3700	170	2898	345	48.859	1.687
Dimmit	5954	44.8	0.76	3720	180	6082	164	36.031	1.244
La Salle	10854	49.2	0.74	7328	282	2172	460	47.861	1.652
Karnes	12300	45.8	0.75	9620	279	607	1647	88.271	3.048
Webb	7483	59.4	0.76	4600	202	20060	50	26.163	0.903
Webb	7868	64.2	0.60	4970	199	463132	2	20.91	0.722
Webb	8464	0.0	0.58	5216	208			16.873	0.584
La Salle	10960	54.7	0.76	6527	291	9308	107	30.054	1.038

C1	C2	C3	C4-C6	C7+	Psat	RF Gas @1300psi	RF Oil @1300psi	Type	Shrink
64.21	12.90	6.05	8.52	8.32	4807	70.0%	19.5%	RG	90.1%
56.60	11.65	6.34	9.09	16.32	4618			BO	
60.90	10.80	5.65	7.74	14.91	5532			VO	
69.34	11.21	5.36	5.87	8.22	7988			RG	
59.00	12.40	5.92	9.01	13.67	4584	70.8%	7.4%	VO	82.1%
35.57	10.22	7.37	12.77	34.07	2680			BO	
71.79	12.92	5.49	6.40	3.41	3345			RG	
80.16	11.46	3.75	3.19	0.44	2404			DG	
94.54	2.96	0.26	0.10	0.00				DG	
68.71	12.63	4.81	7.98	5.87	3910	63.9%	37.3%	RG	92.0%

PVT Analysis

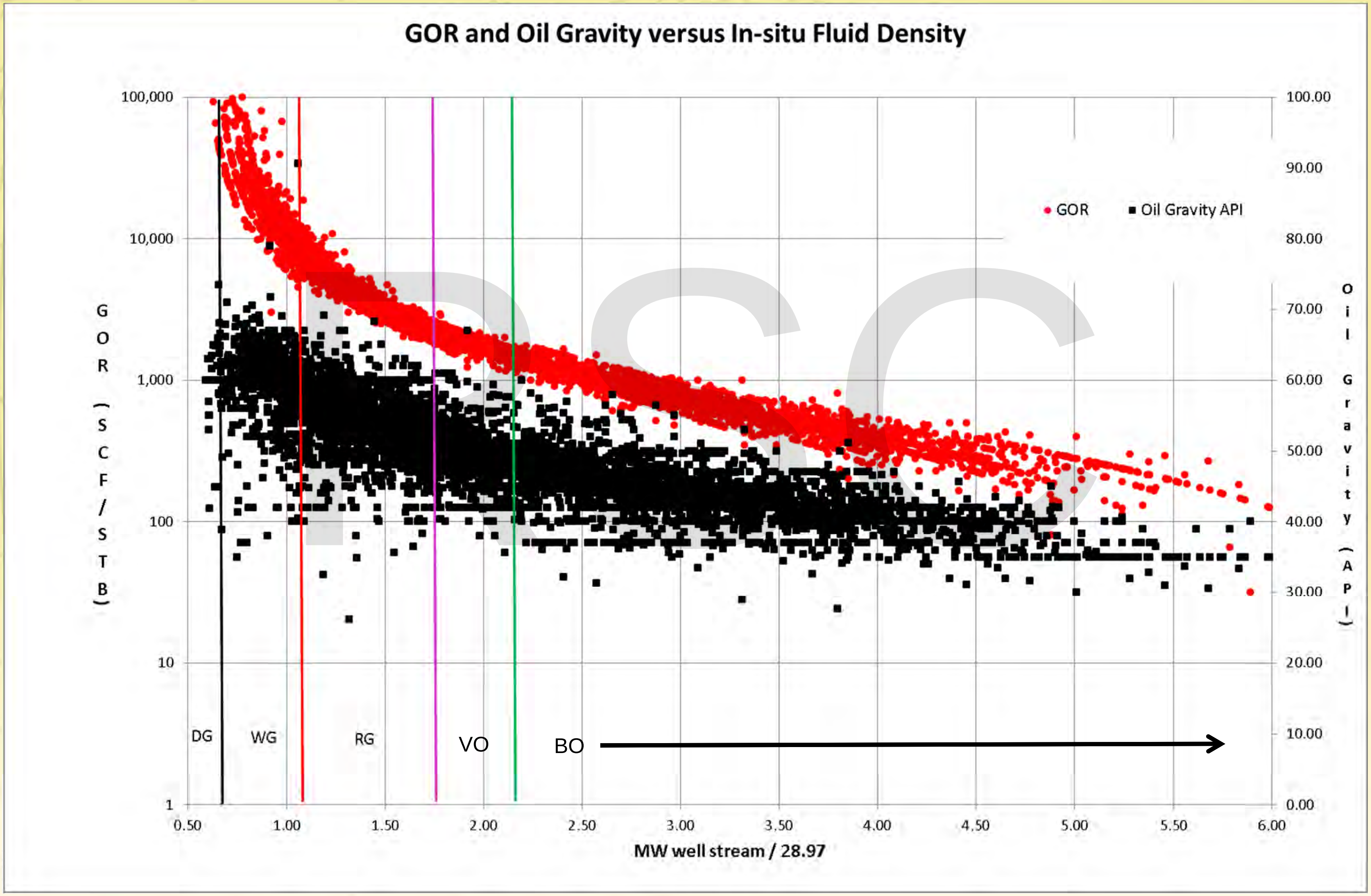
$$SGws = \frac{Rsi * SGg + 4584 * SGo}{Rsi + 132800 * SGo/Mo}$$

$$SGo = \frac{141.5}{API + 131.5}$$

$$Mo = \frac{6084}{API - 5.9}$$

$$\frac{Np}{N} = \frac{(Bo - Boi) + (Rsi - Rs) * Bg}{Bo + (Rp - Rs) * Bg}$$

PVT Analysis

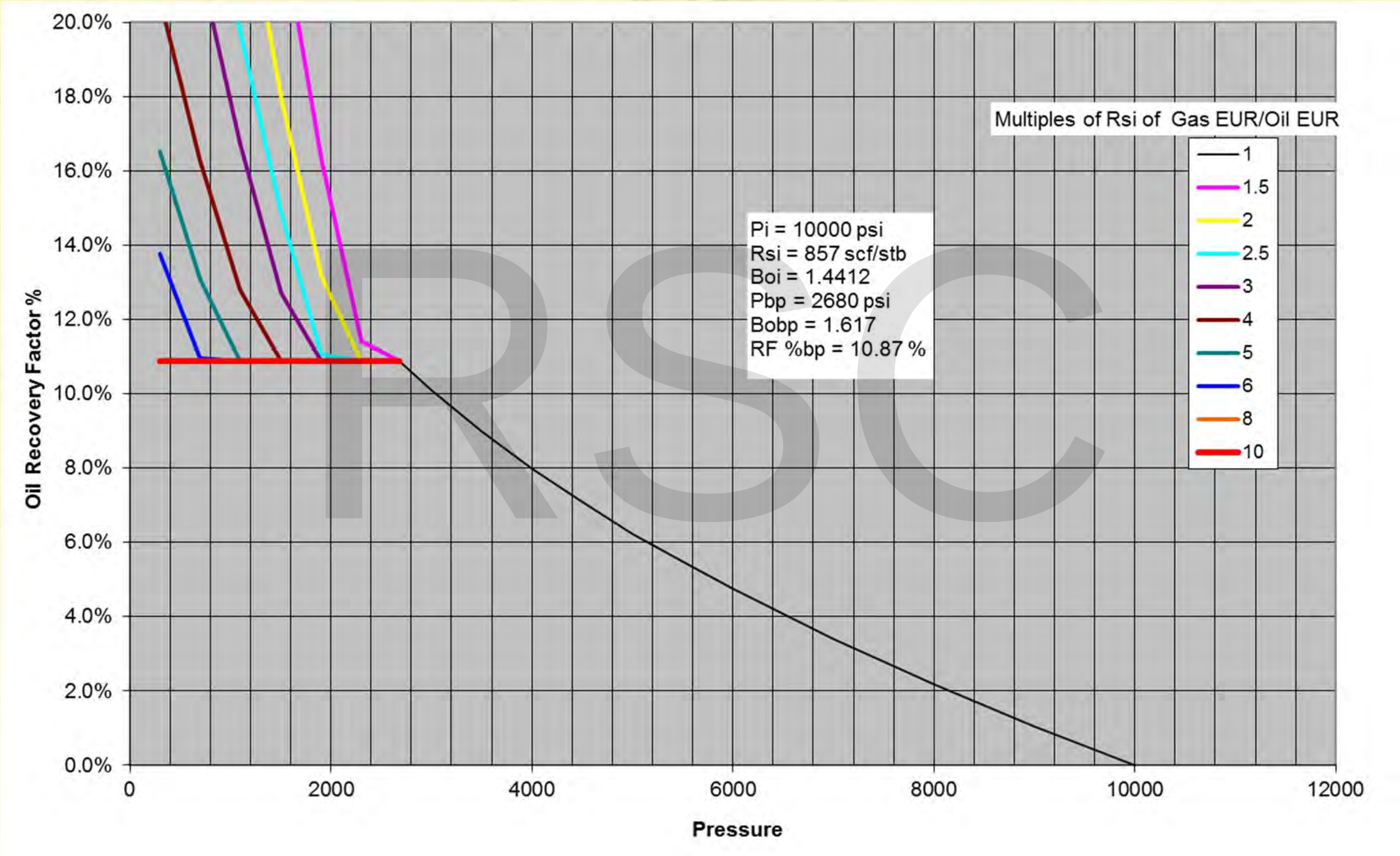


PVT Analysis

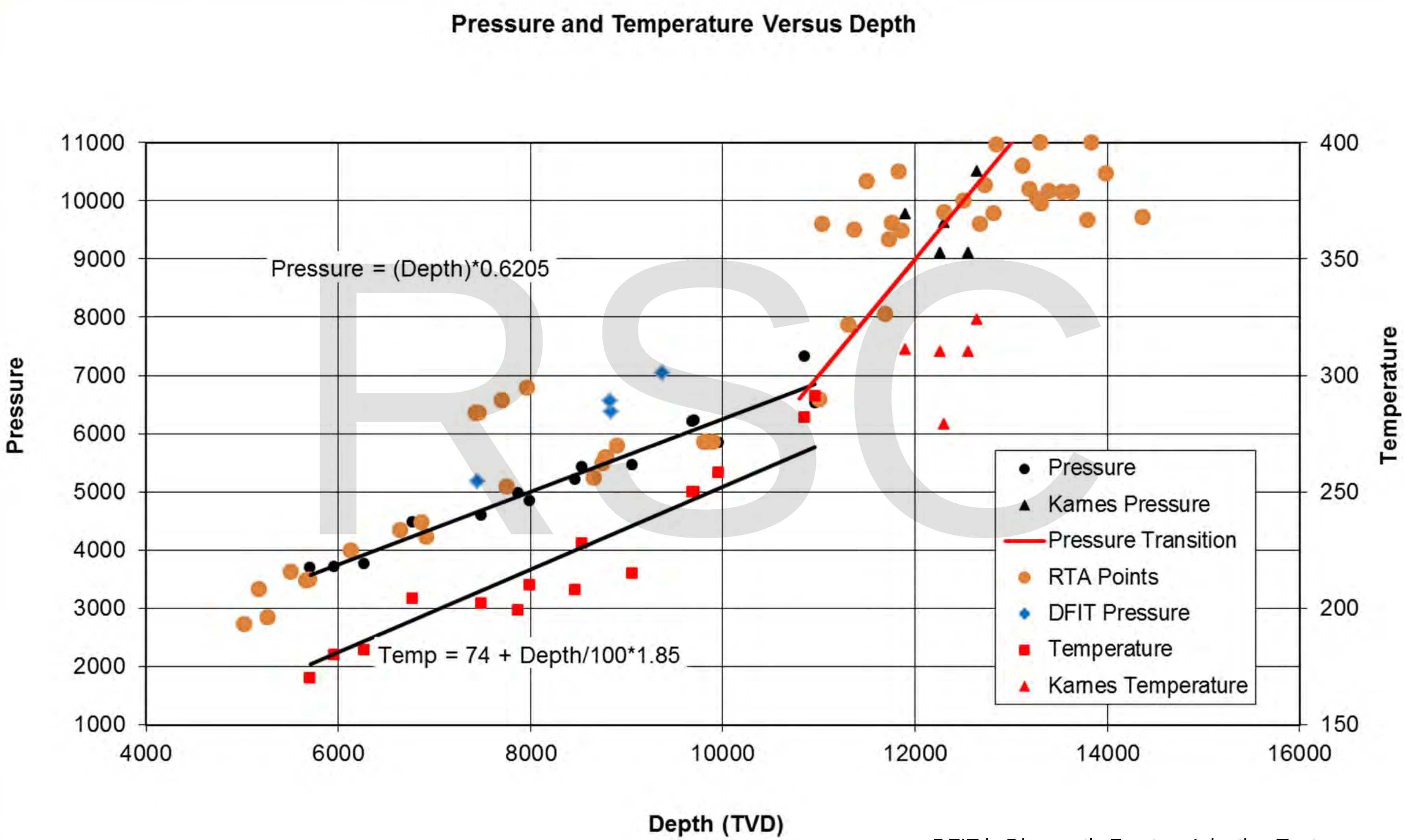
CALCULATED CUMULATIVE RECOVERY
DURING DEPLETION AT 210 °F

Cumulative Fluid Recovery per MMScf of Original Dew Point Gas	Initial Gas in Place	Reservoir Pressure - psig					
		(D.P.) 4807	3900	3000	2100	1300	500
Well Stream (Mcf)	1000.00	0.00	97.33	250.57	453.72	652.98	840.62
*** Normal Temperature Separation**							
Stock Tank Liquid (Bbls)	134.78	0.00	8.19	16.79	23.71	26.22	30.38
Primary Separator Gas (Mcf)	899.18	0.00	90.66	236.26	432.84	629.64	813.22
Second Stage Gas (Mcf)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Stock Tank Gas (Mcf)	1.81	0.00	0.12	0.27	0.43	0.50	0.58
Cumulative Total GOR (Scf/STB)	6685	0	11091	14089	18274	24029	26791
Instantaneous Total GOR (Scf/STB)	6685	0	11091	16941	28425	78301	44229
Total Gallons of Ethane Plus (C_{2+}) Plant Products Produced in:							
Well Stream	12644.56	0.00	1044.53	2503.21	4300.69	5988.16	7652.95
Primary Separator Gas	6960.86	0.00	699.50	1798.82	3324.17	4958.42	6481.24
Second Stage Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Stock Tank Gas	27.14	0.00	1.81	3.98	6.32	7.35	8.68

PVT Analysis



Pressure and Temperature

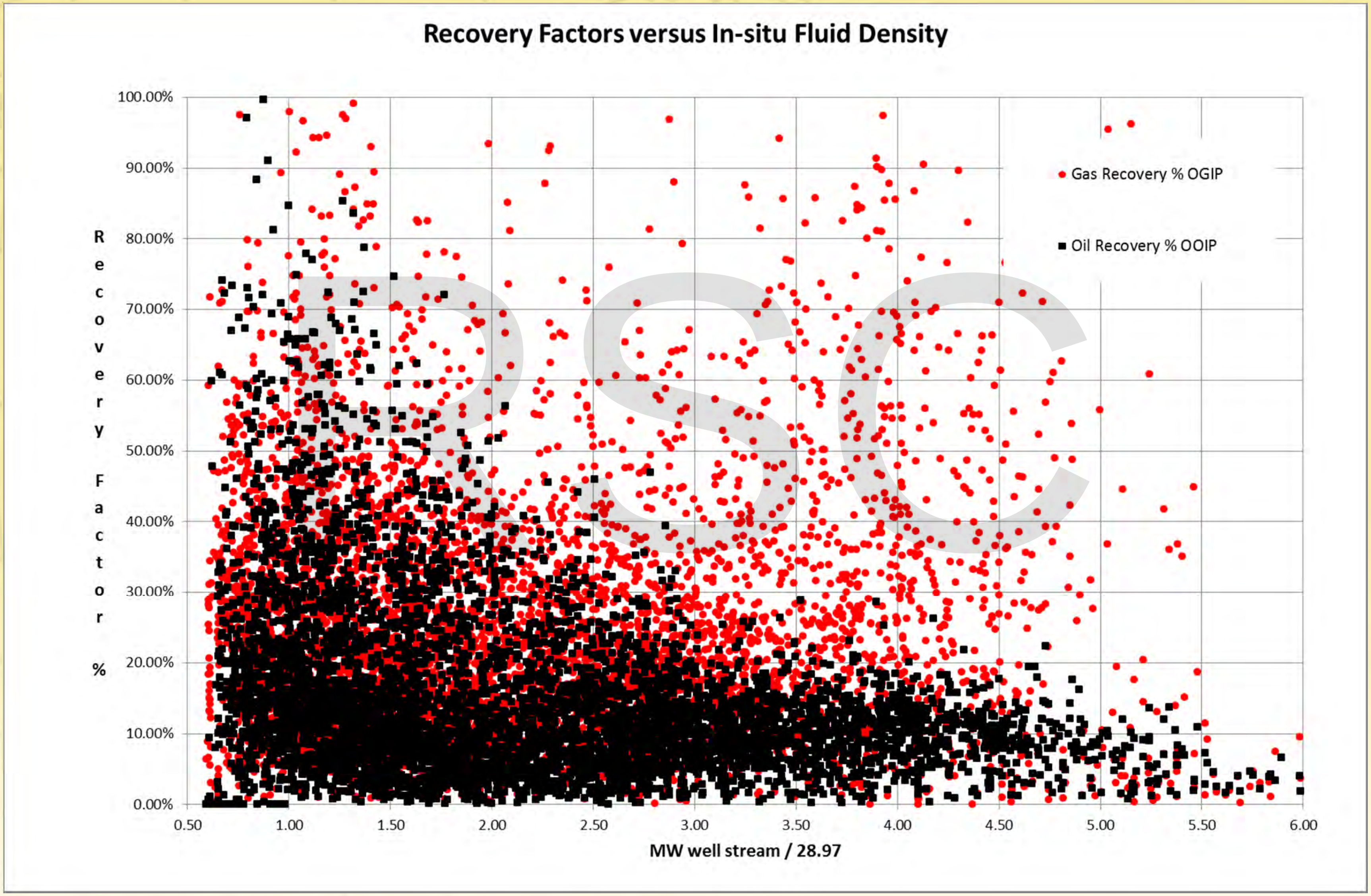


DFIT is Diagnostic Fracture Injection Test

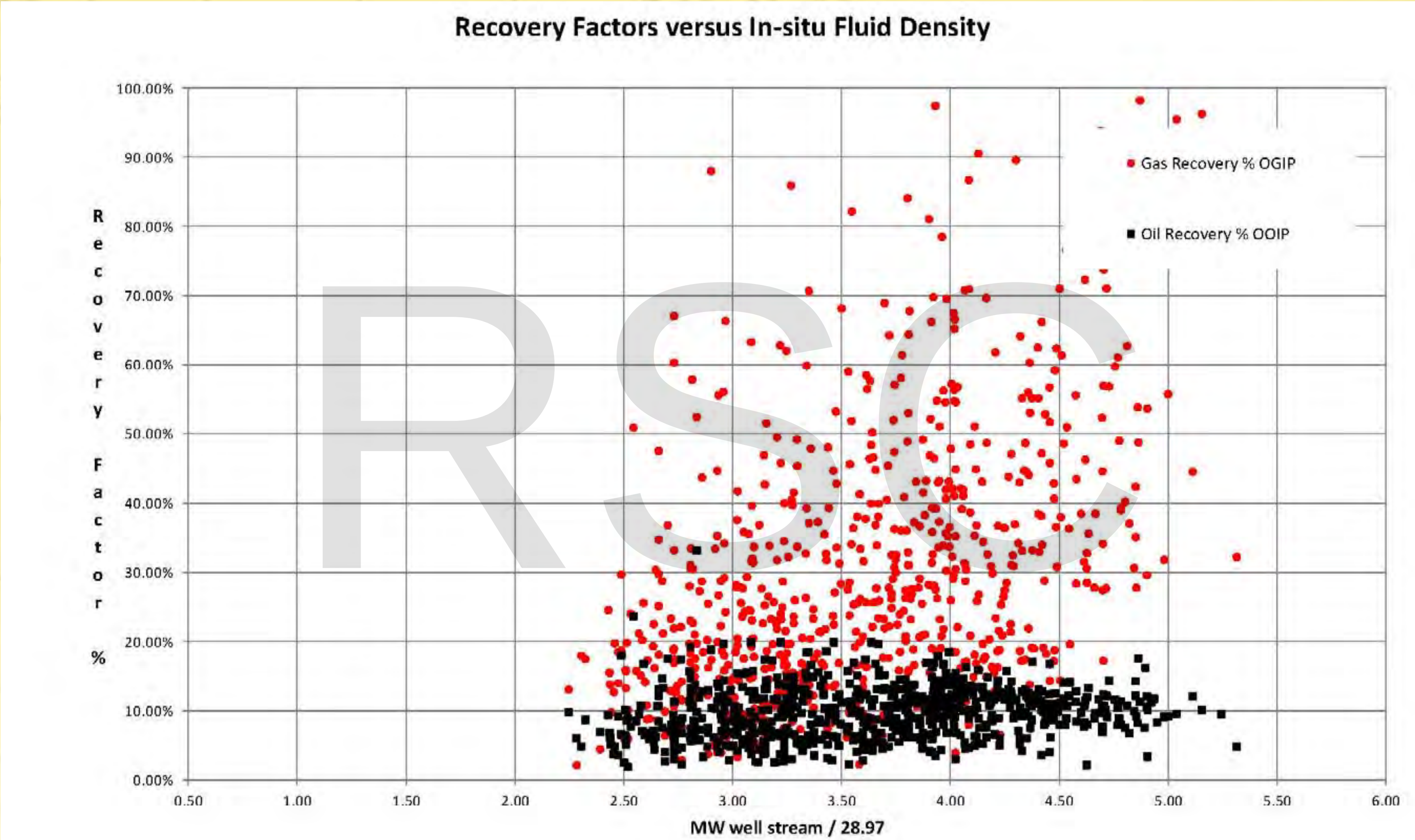
Volumetric Methodology

- The Bo and Bg from PVT reports or correlations based on surface gravities.
- SophiH was from our map
- Drainage area assumed to be well spacing times gross perforated interval length in feet
- Pressure and Temperature from TVD depth

EUR Recovery Factors



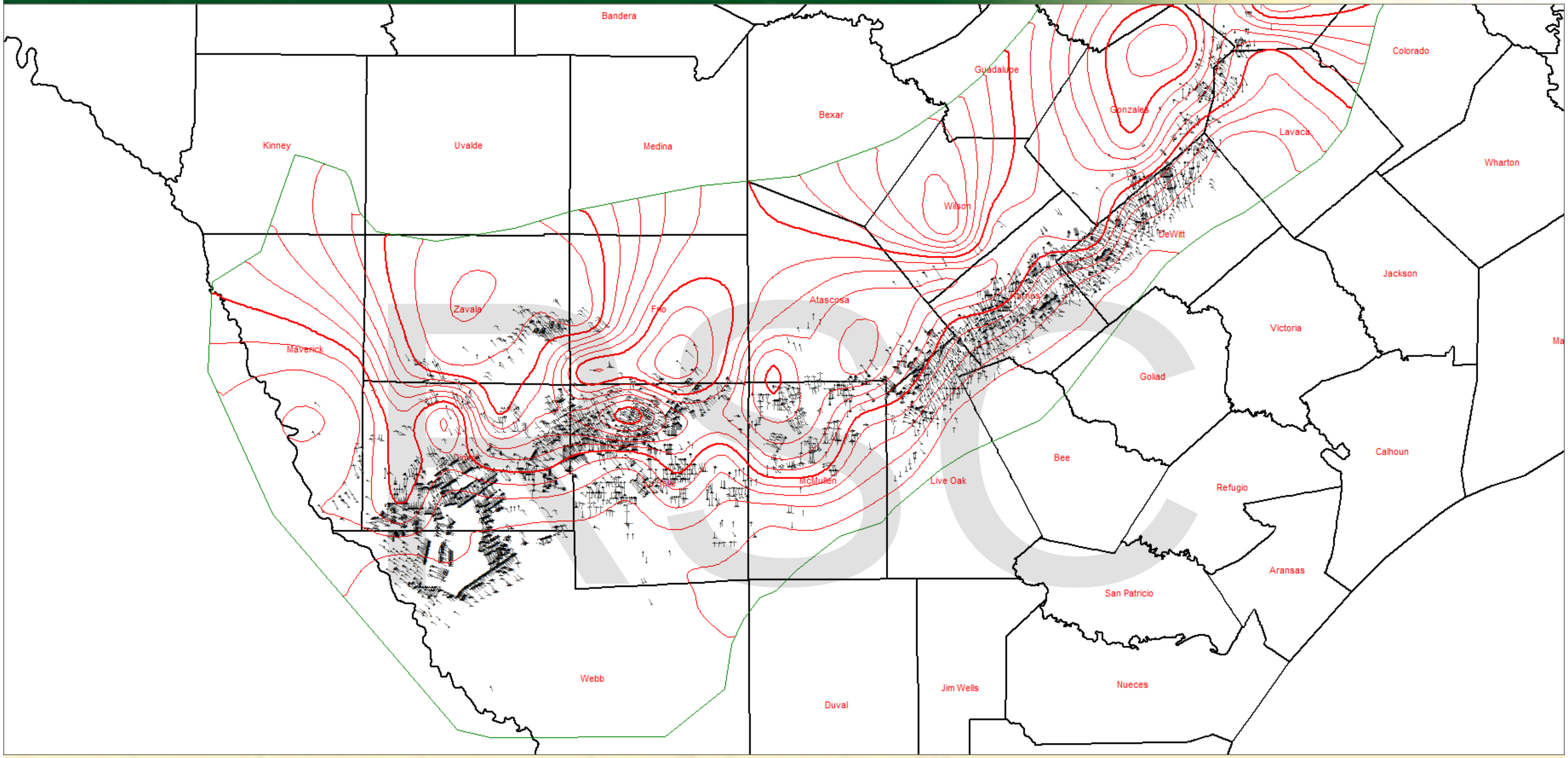
EUR Recovery Factors – LaSalle Black Oil



Performance Mapping

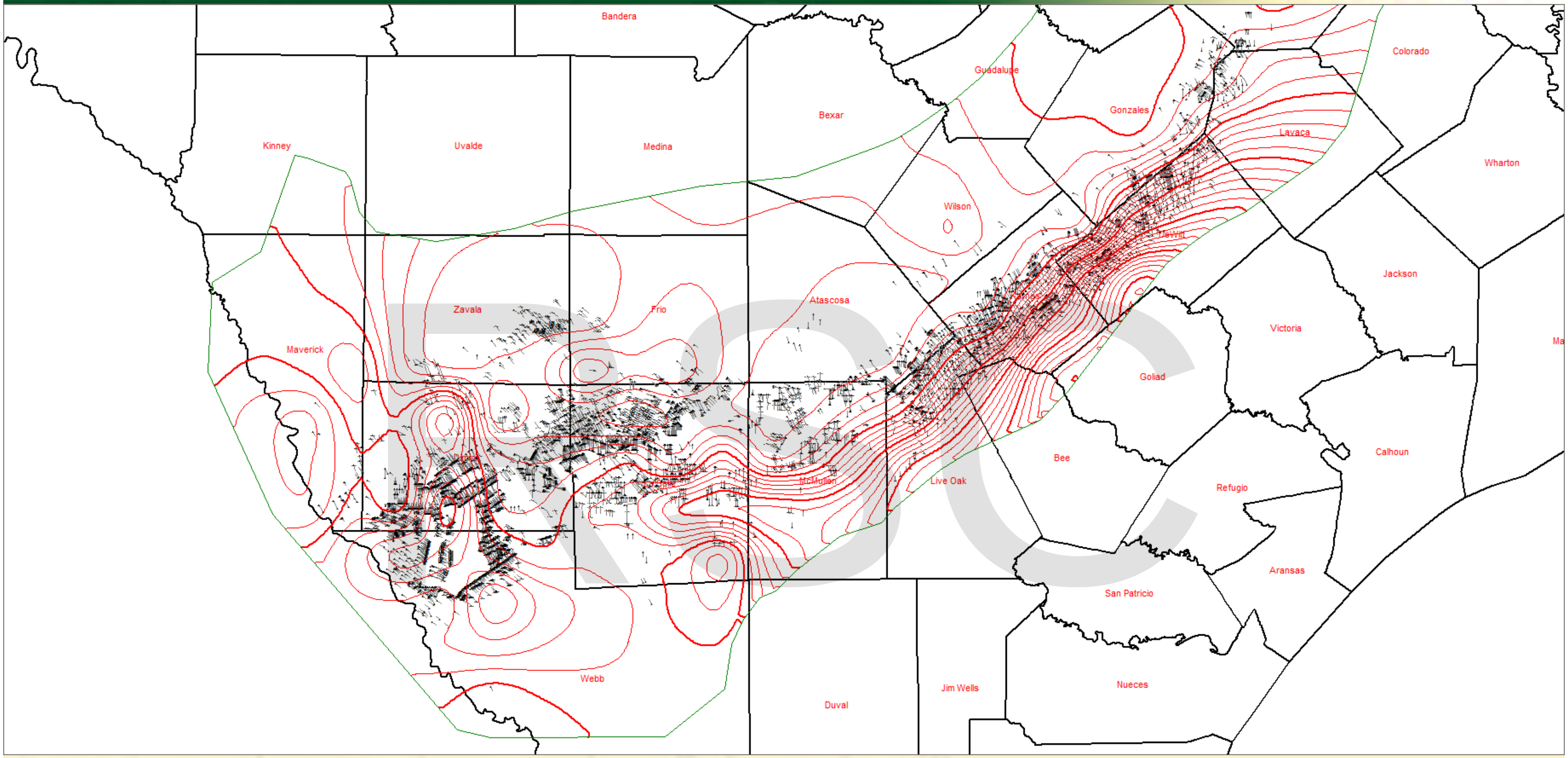
- Extract mapped values for:
  - Gmix
  - OOIP and BCF per Section
  - Oil Per Foot
  - Oil EUR

Gmix



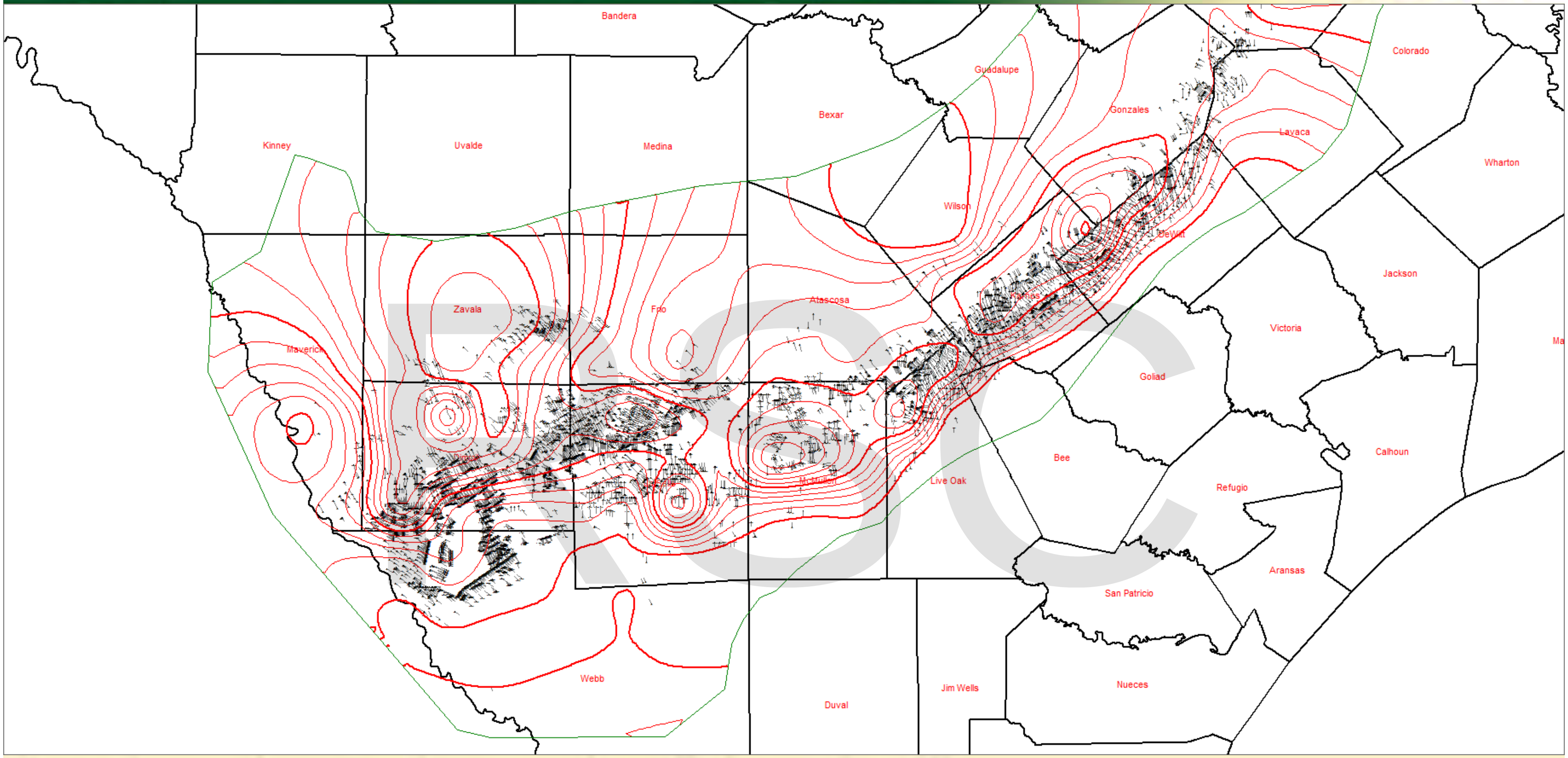
Bandera
Colorado
Guadalupe
Kinney
Uvalde
Medina
Bexar
Gonzales
Lavaca
Wharton
Wilson
DeWitt
Jackson
Zavala
Frio
Atascosa
Victoria
Maverick
Goliad
Calhoun
Bee
McMullen
Live Oak
Refugio
Aransas
San Patricio
Webb
Duval
Jim Wells
Nueces

OGIP-Section

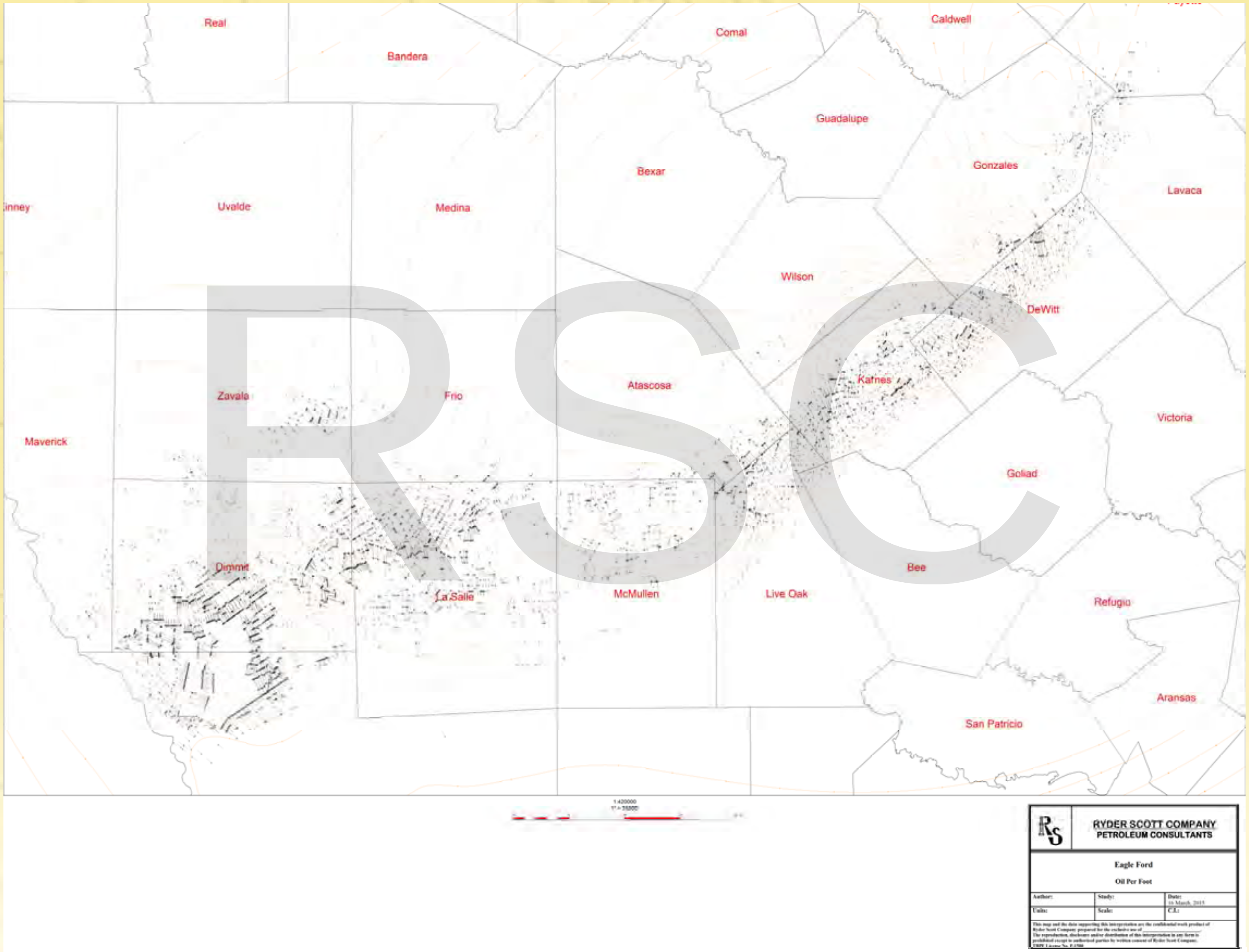


Geoscientists • Petroleum Engineers • Technical Analysts

OOIP-Section



Oil per Foot Lateral



Oil EUR Map

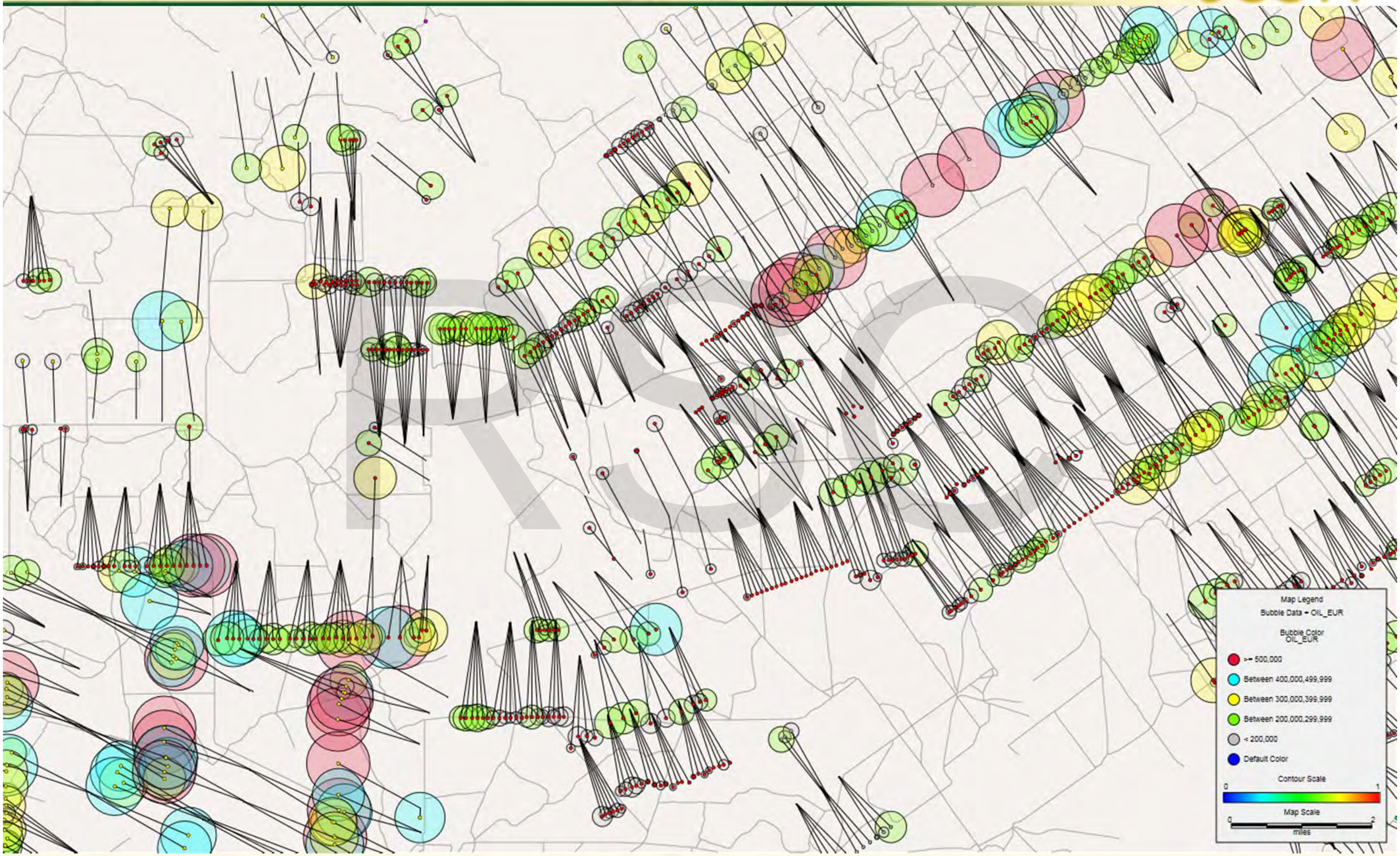
PDP Analysis Methodology

- The Oil and Gas EUR's for producing wells determined using DCA on daily data
- There is a lot of room for interpretation based on the scatter of data
- Nearby wells that have more history may help guide projections

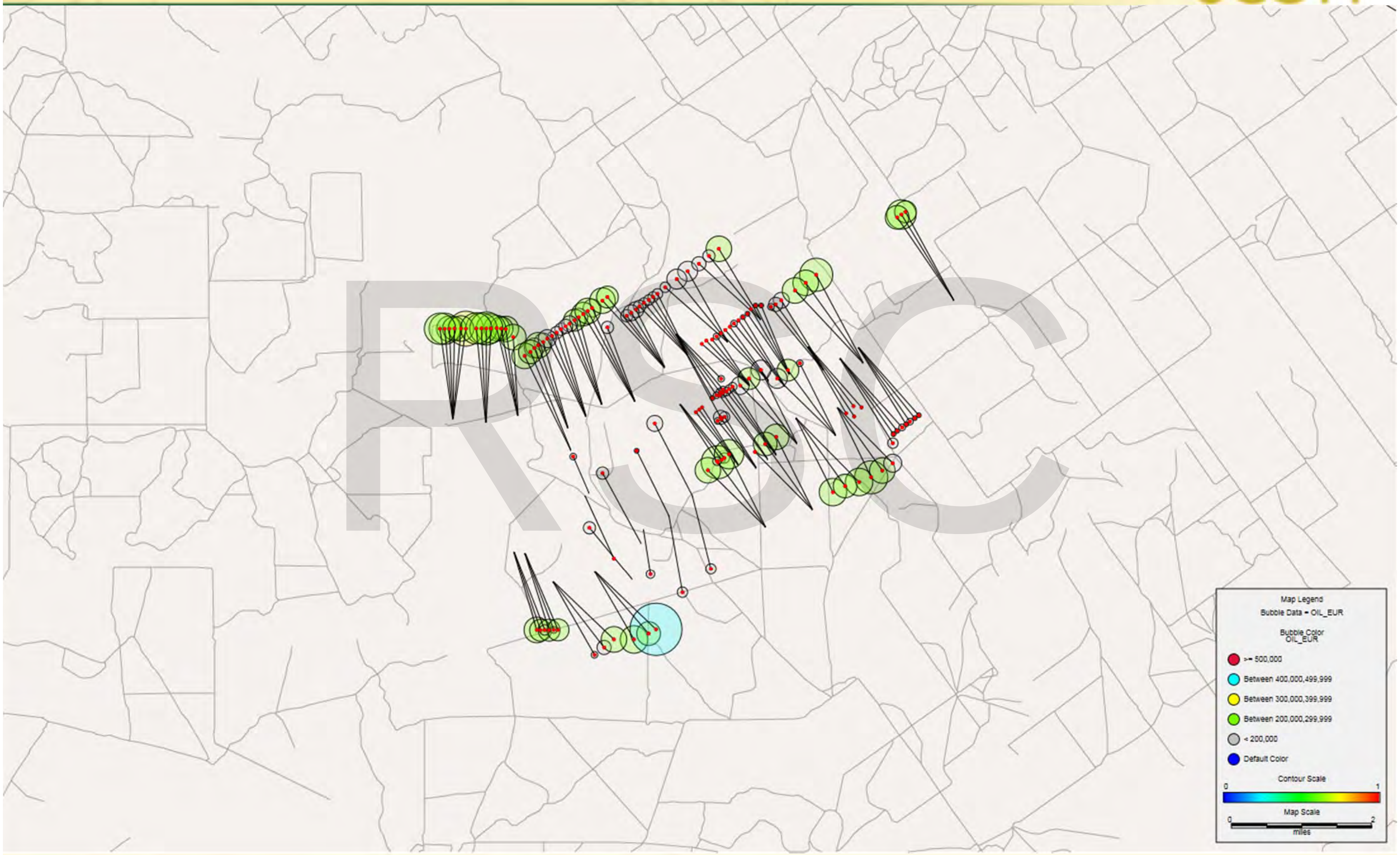
PUD Analysis Methodology

- Bubble EUR plots are used for illustration purposes to help determine trends
- PUD assignments were made by statistical analysis of the EUR's and initial rates for a given area deemed to be analogous to the PUD area
- May normalize wells based on lateral lengths or other completion parameters.
- Did not use volumetrics for determining the EUR's, but as a cross check for reasonableness.
- RF % compared in the area of interest for consistency

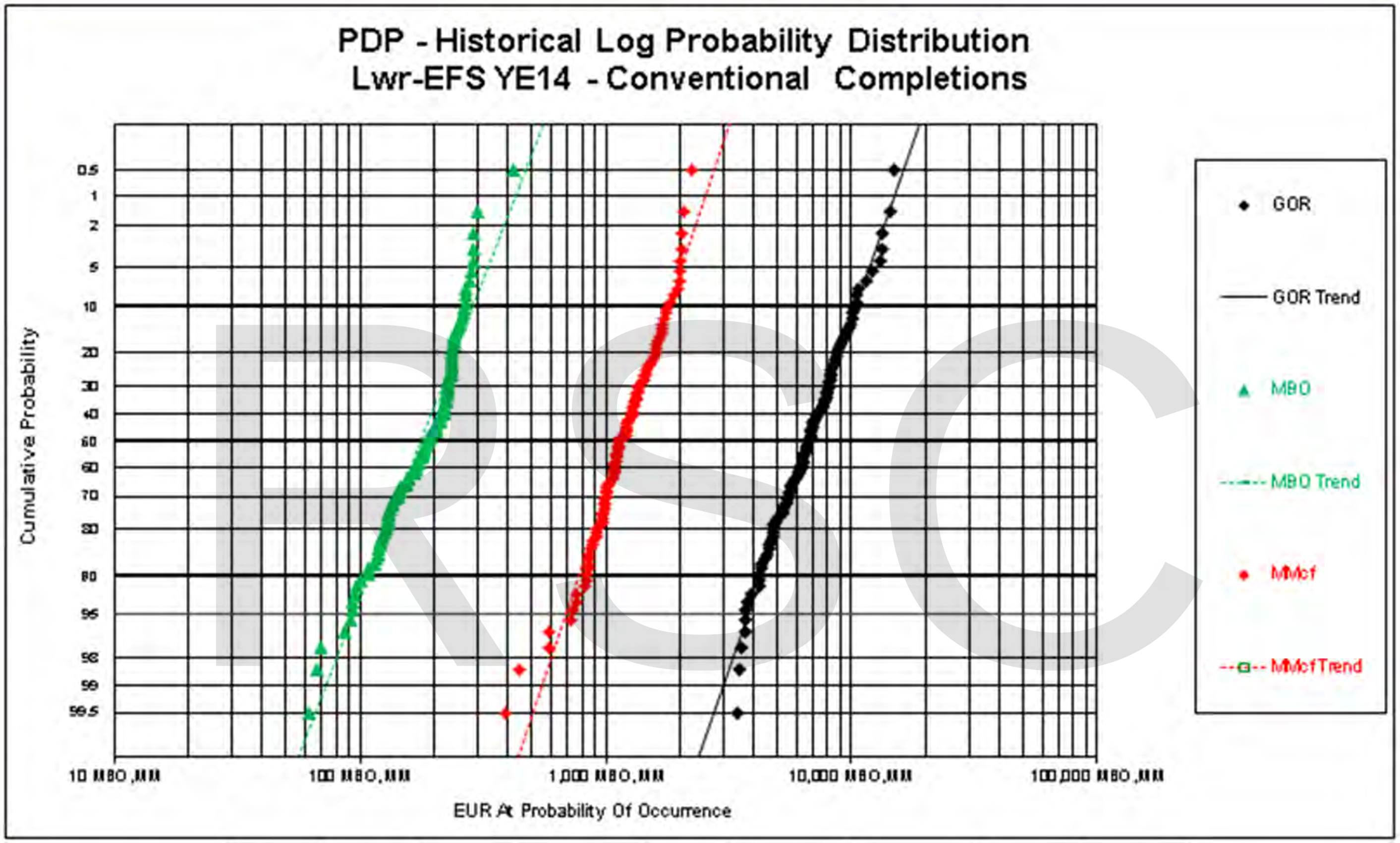
Example 1 – Bubble Map



Example 1 – Bubble Map



Example 1 – Probability Distribution

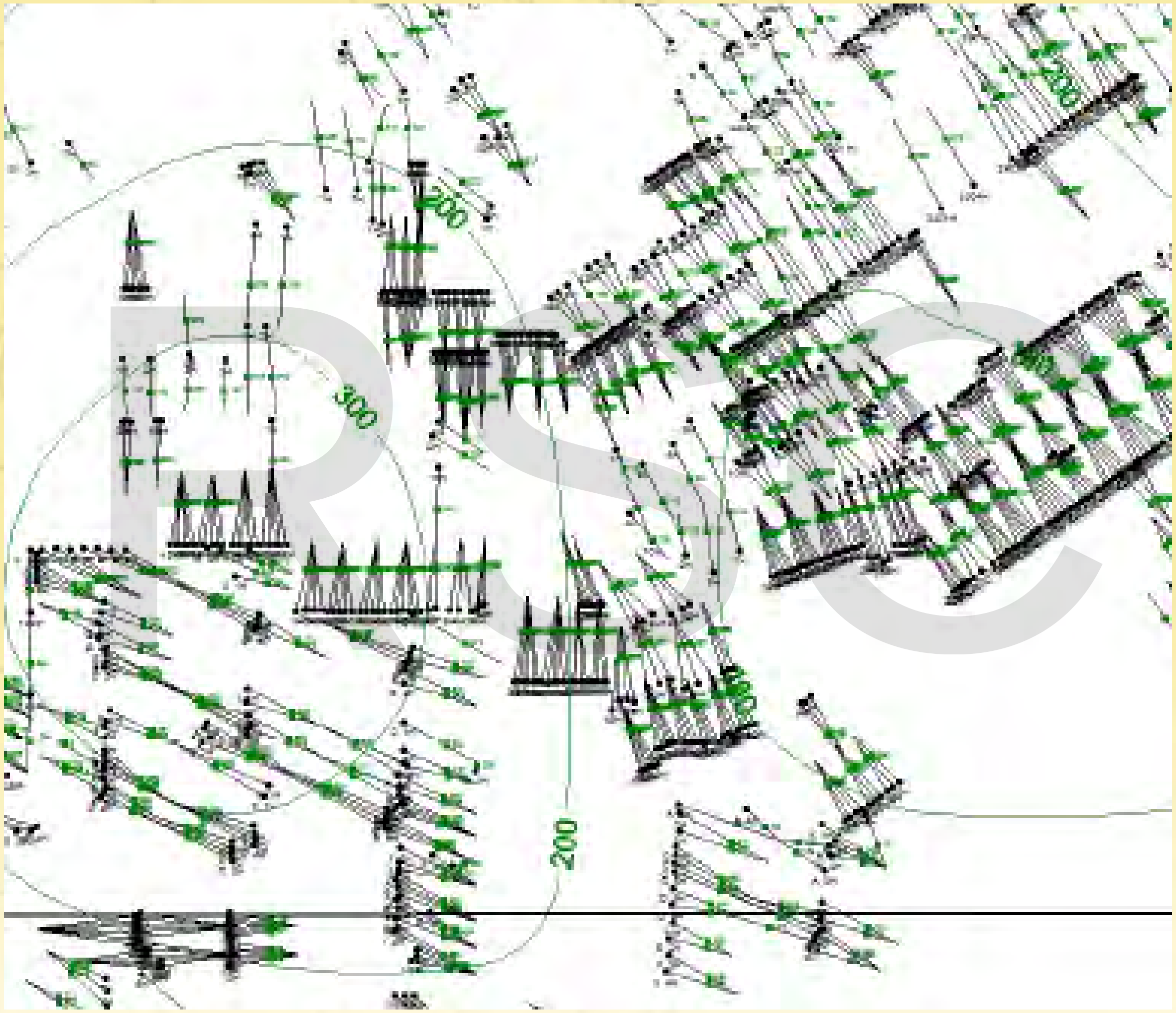


Well Count
102

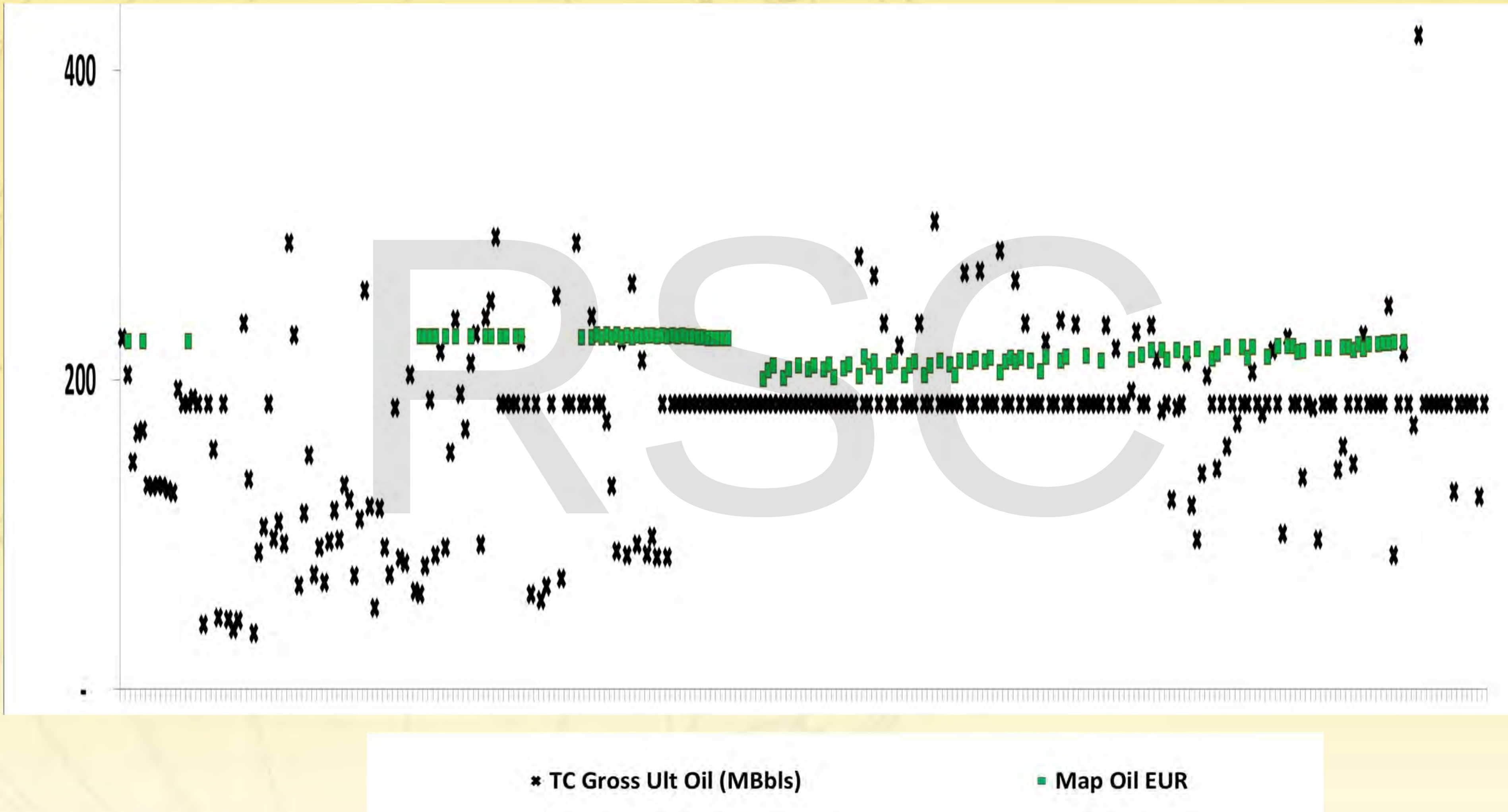
	MBO	MMcf	GOR
P90 =	108	772	4,299
P50 =	176	1,177	6,687
P10 =	287	1,795	10,401

	MBO	MMcf	GOR
Mean	188	1,237	7,090
P10/P90	3	2	2
P*	182	1,207	6,888

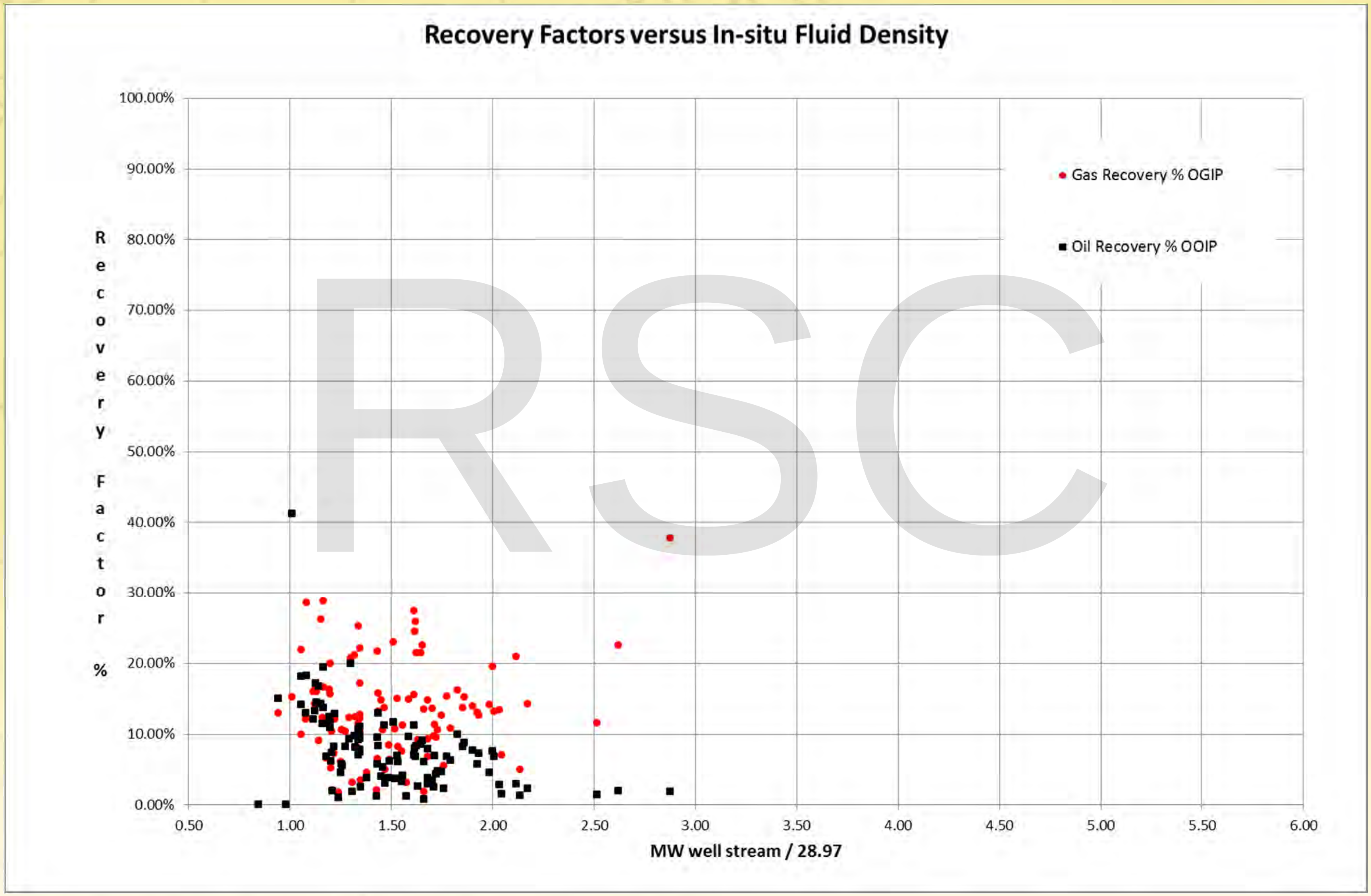
Example 1 – Oil EUR Map



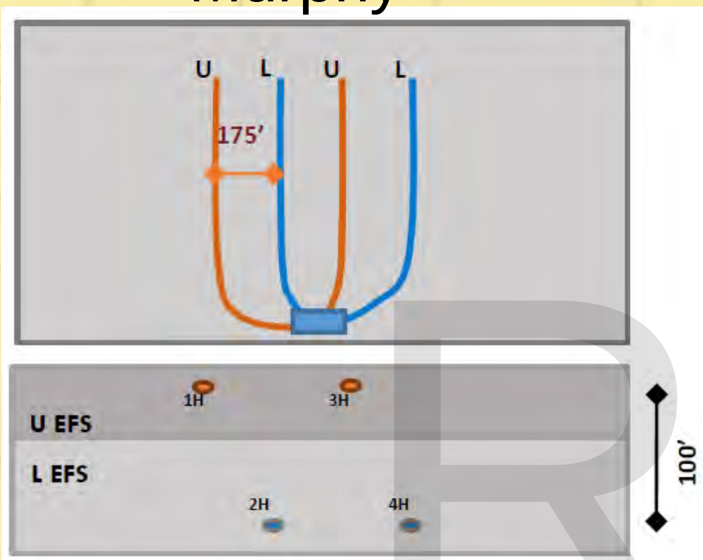
Example 1 – Oil EUR Map vs Probability



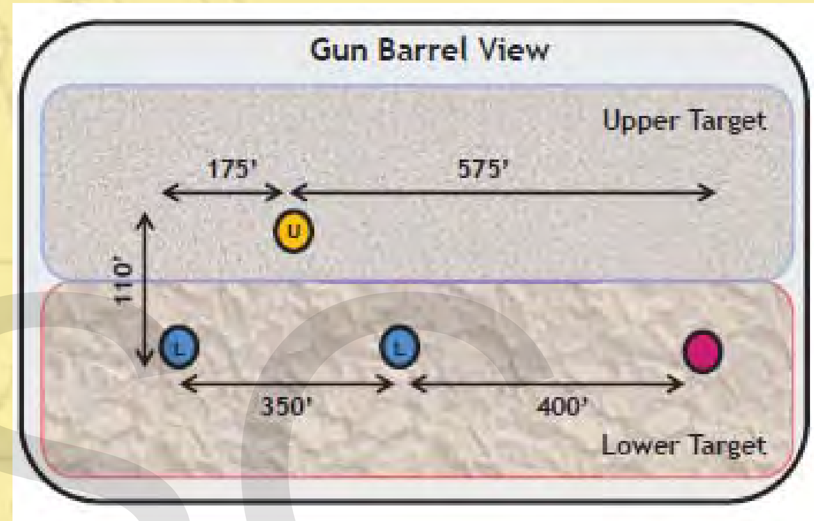
Example 1 – Recovery Efficiency %



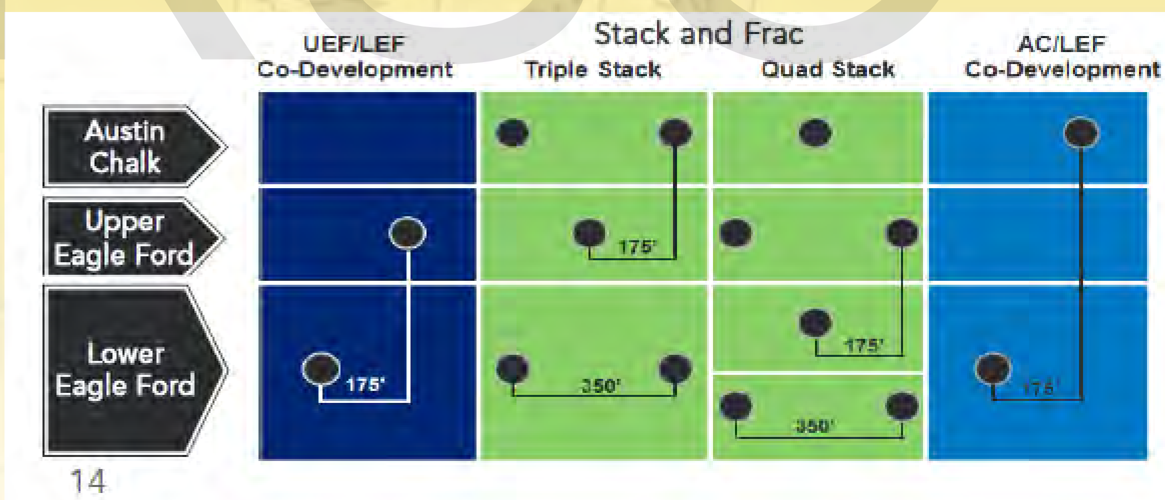
Murphy



Pioneer

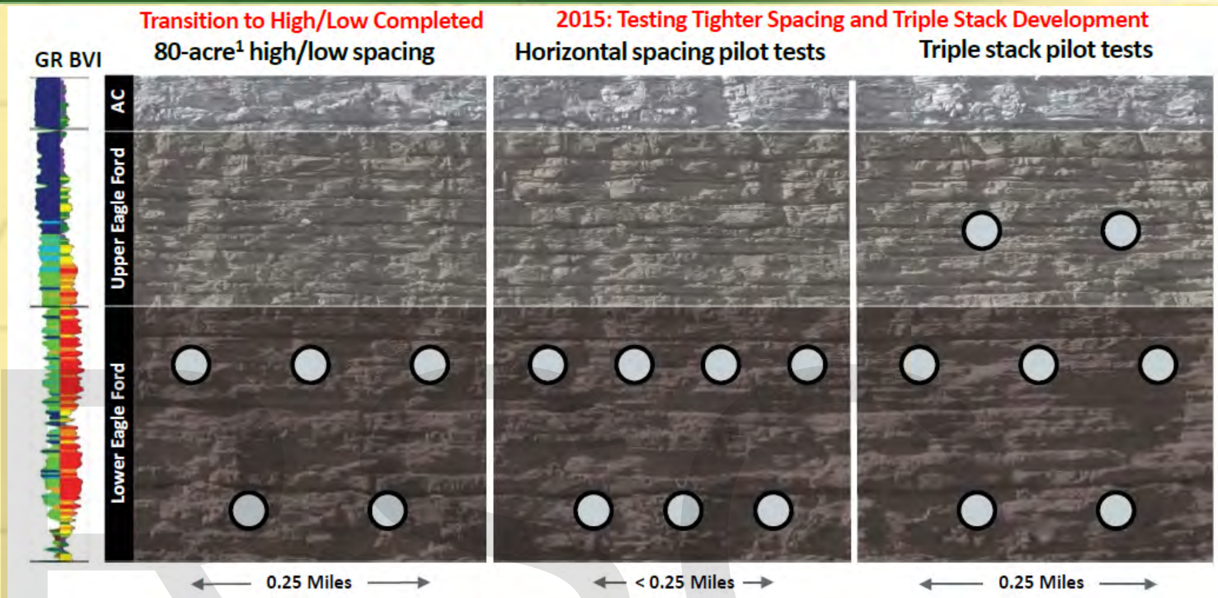


Marathon

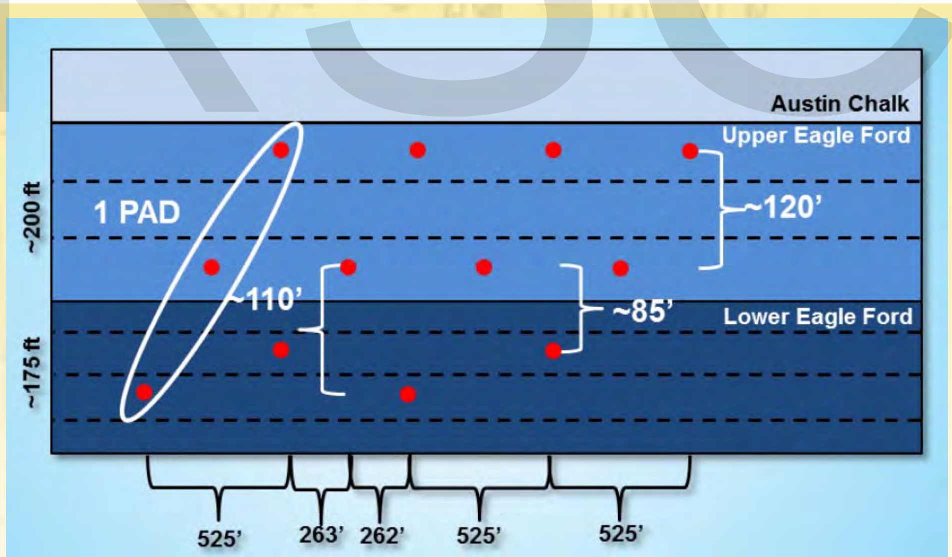


New Development Schemes From Investor Presentations

Conoco



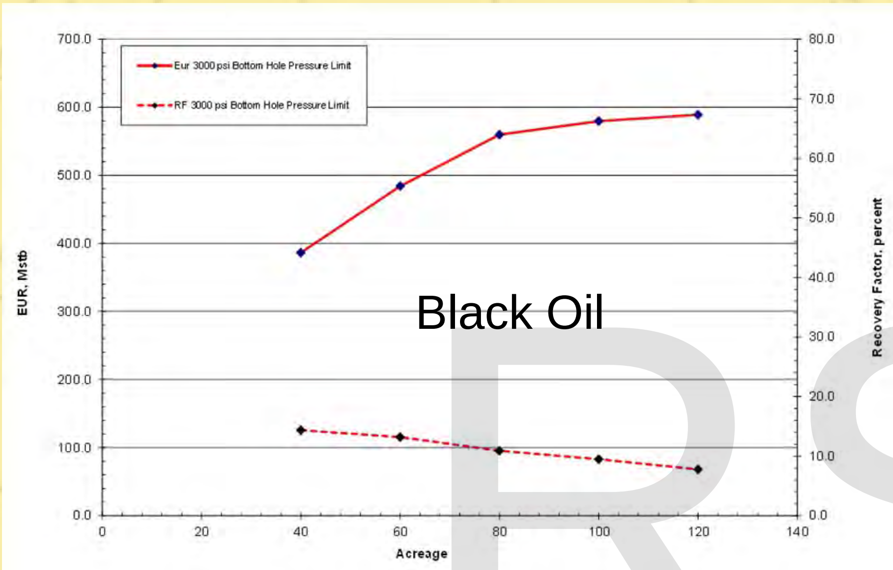
SM Energy

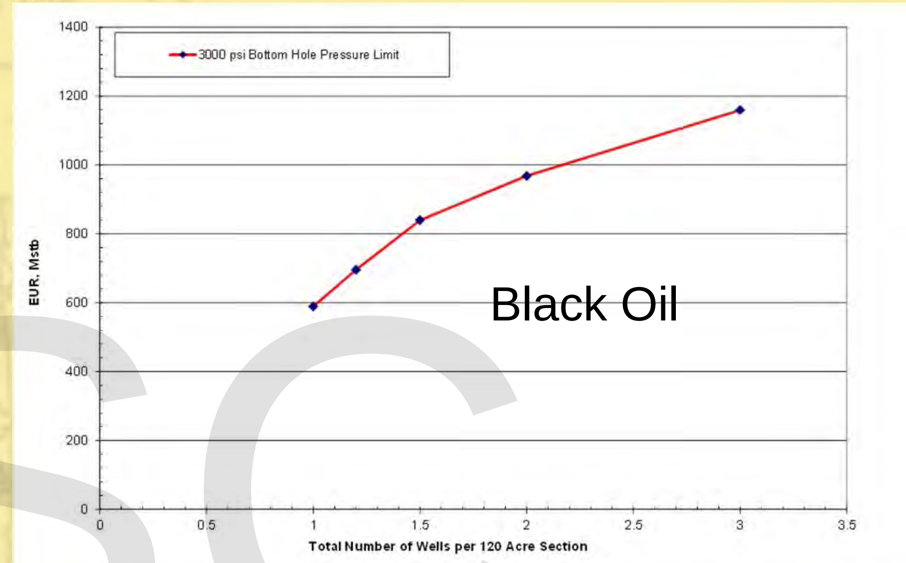


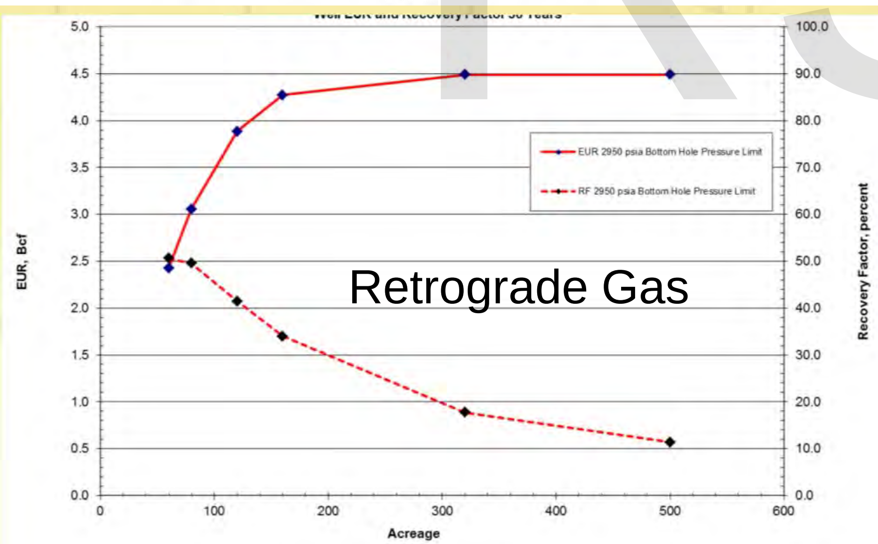
Reservoir Modelling

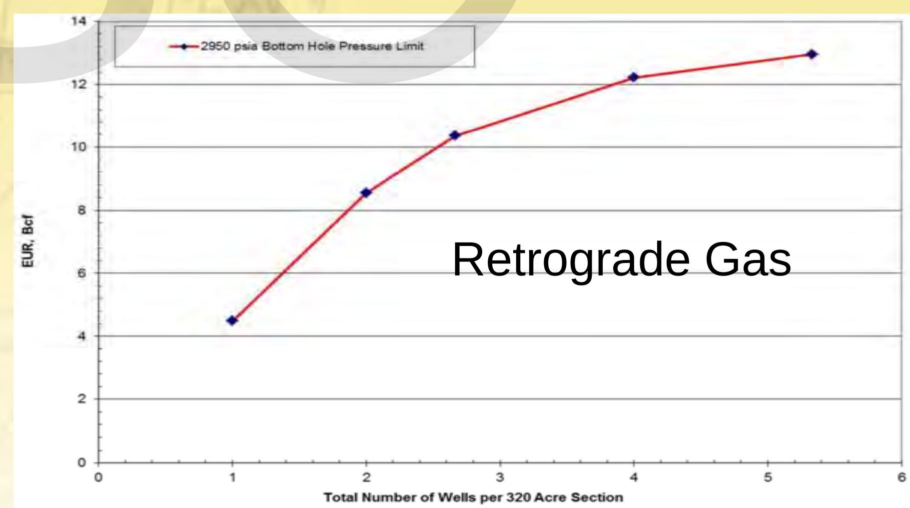
- Recovery Factors from expected model may be applied to proved volumetric in place estimates.
- Models may be used to support drainage area estimates
- Models may be used in combination with other estimates

Reservoir Modelling Results

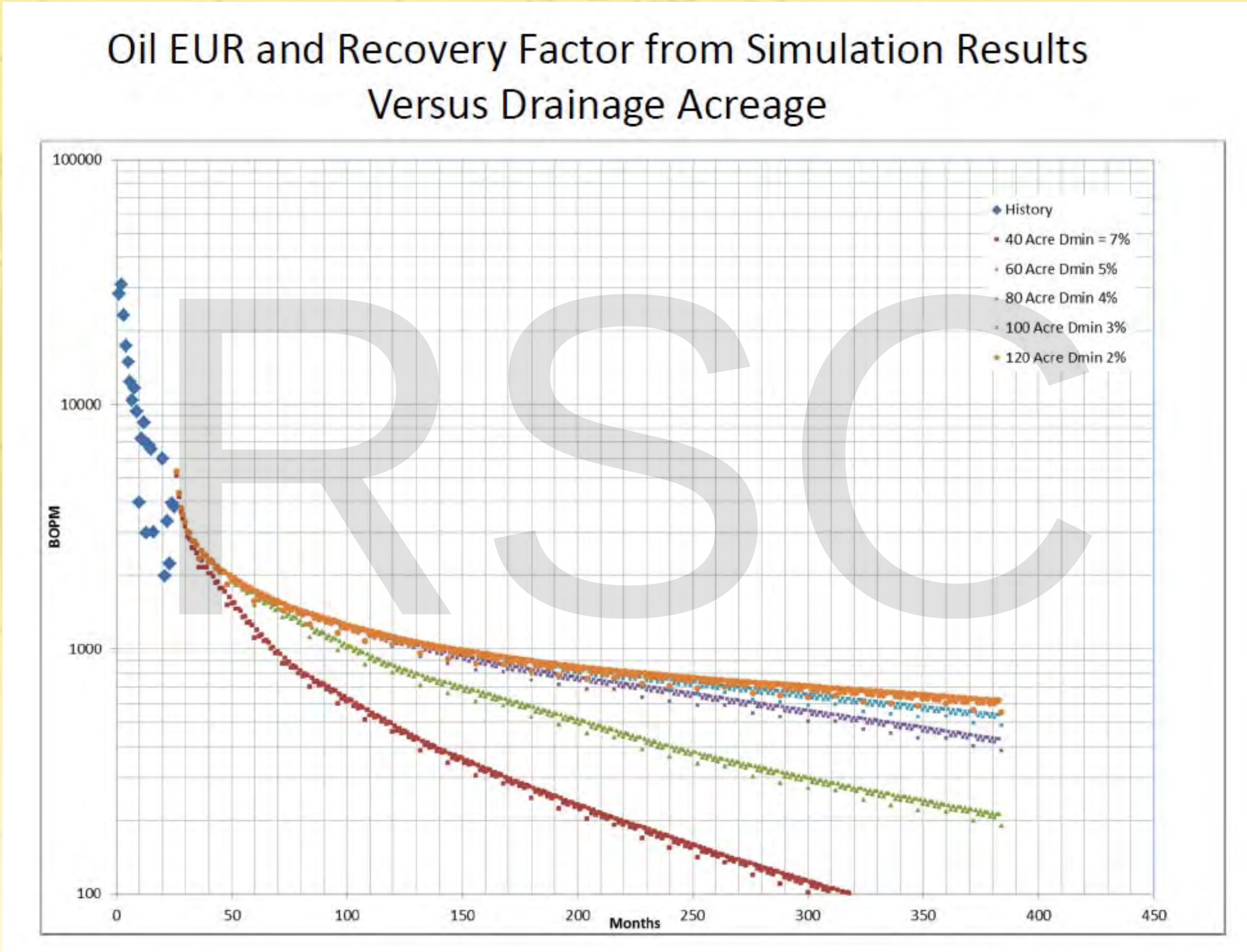




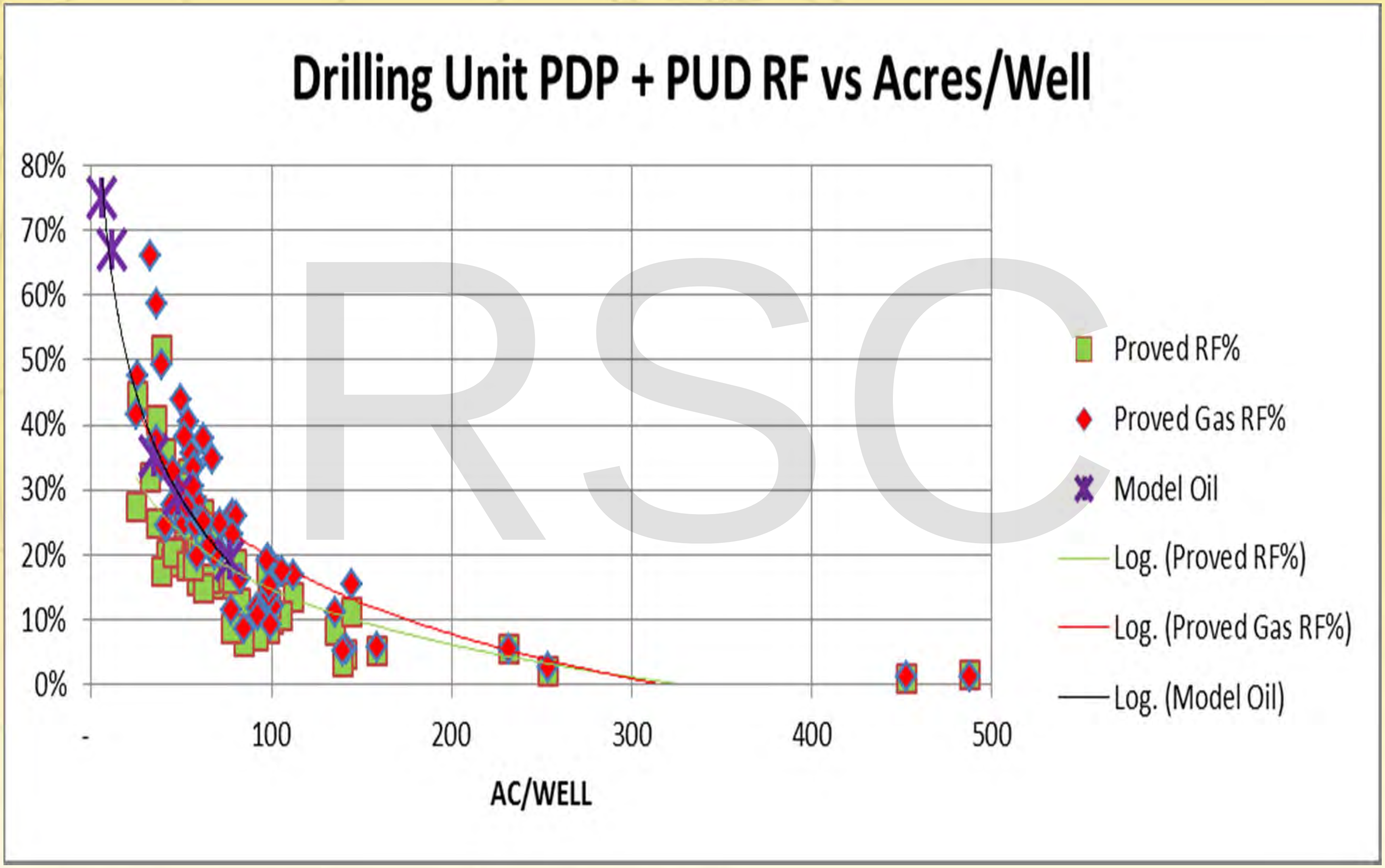




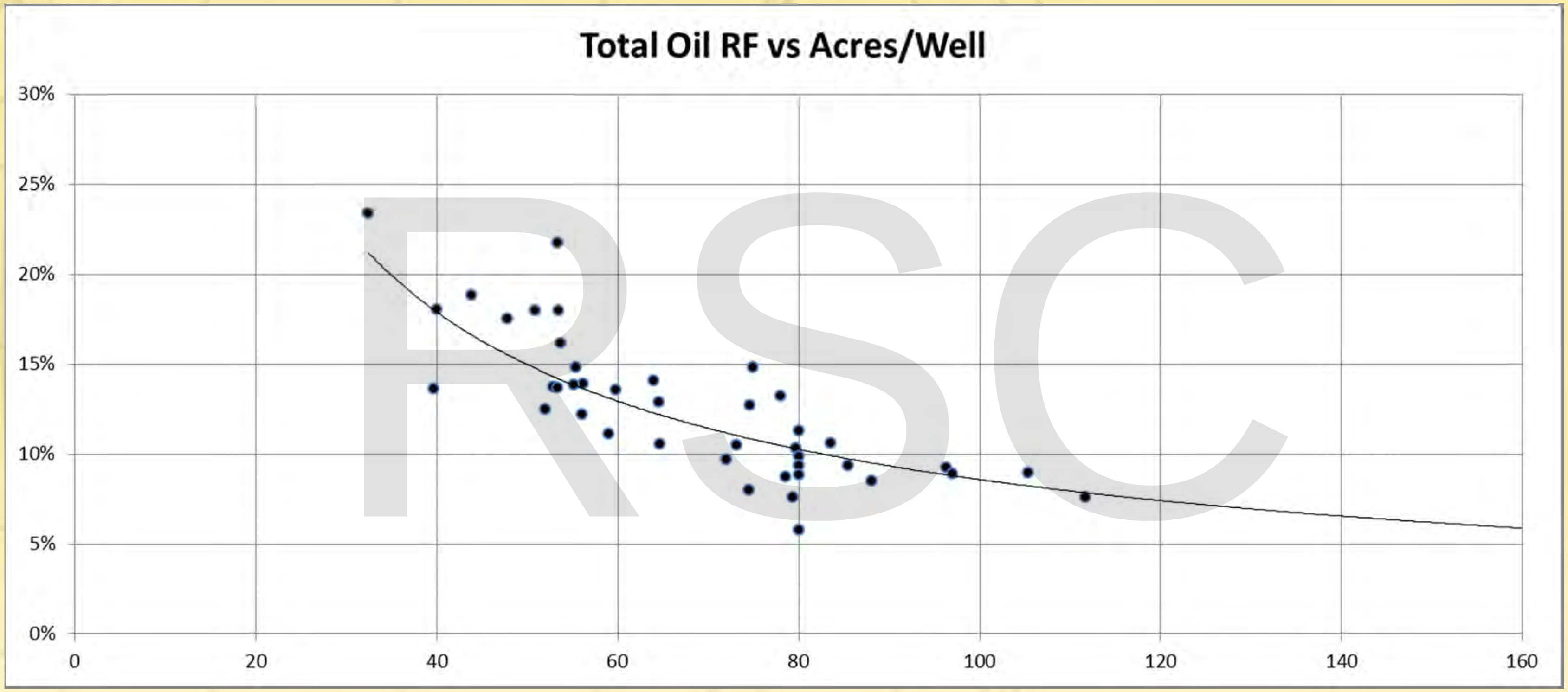
Reservoir Modelling Results



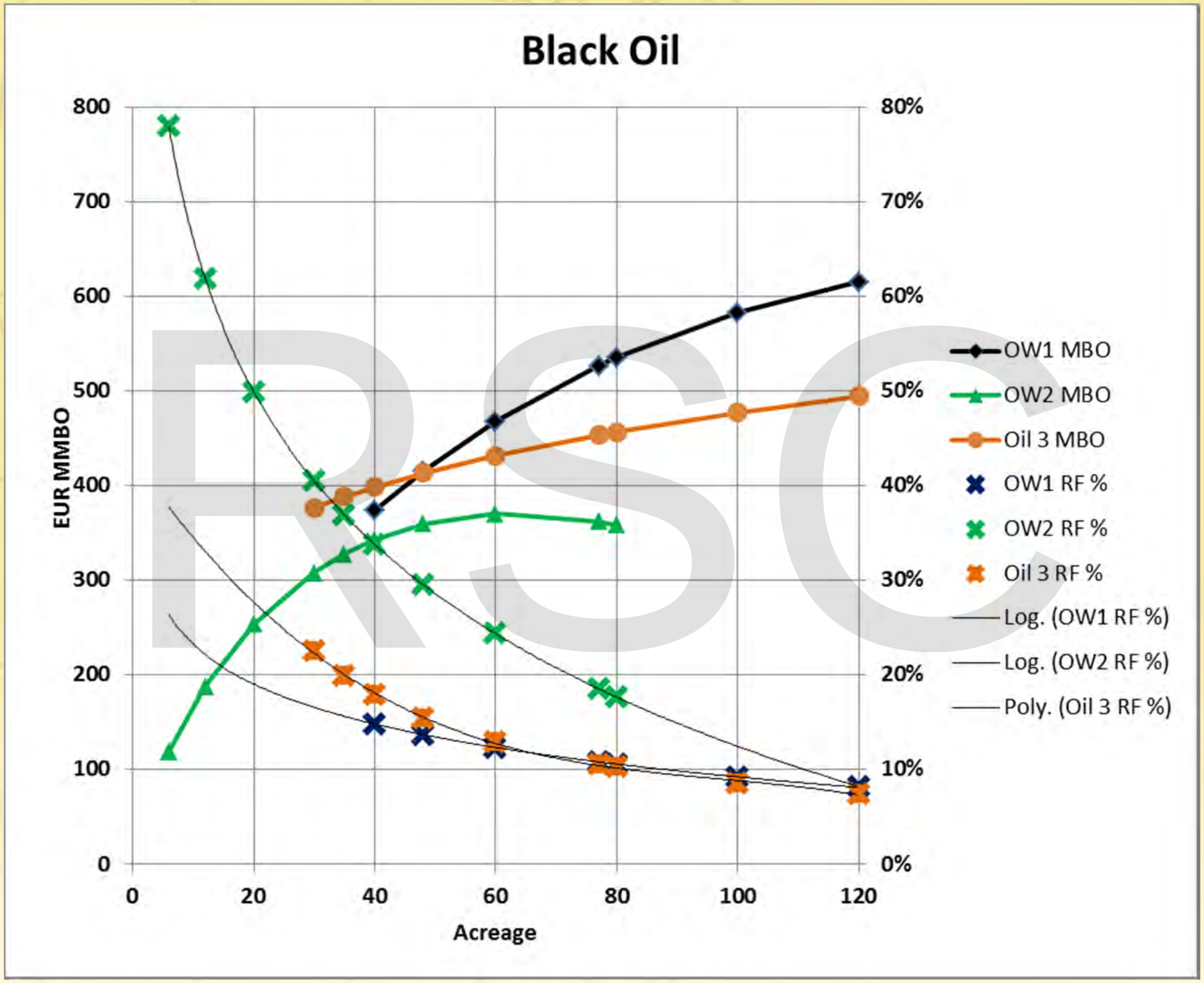
Reservoir Modelling Results



Reservoir Modelling Results



Reservoir Modelling Results



Economic Parameters

Company	Abandonment	Salvage	Net	$/well	$/BO	$/MCF	$/BW	Drilling Cost M$	Lateral	Stages	$/LL
A	80	25	55	8300	4.0	0.3		8416	7737	32	1.09
B	85	6	79	10569	2.6	0.0		7350	5000	16	1.47
C	75	70	5	2500	3.7	0.6	3.1	7427	7000	22	1.06
D	114	0	114	11332	4.3	0.0		6283	6000	22	1.05
E	60	0	60	4100	3.6	1.8		5710	5000	16	1.14
F	65	5	60	6500	0.0	0.6	3.0	6500	5000	16	1.30
G	100	0	100	3800	10.0	1.4		5840	6000	18	0.97
H	80	0	80	9925	2.0	1.2		7398	6500	23	1.14
I	100	0	100	8000	2.5	0.5		9000	5000	16	1.80
J	60	0	60	10000	5.4	1.0		7100	5000	16	1.42
K				5600	0.8	0.0	2.5	8100	7500	22	1.08
L				8850	1.3	1.3		6500	5000	15	1.30
M				6007	3.8	0.0		8000	6000	20	1.33
N	60	0	60	12344	1.6	0.3		7250	5000	16	1.45
	79.9	9.6	70.3	7702	3.3	0.65		7205	5838	19	1.23

Drilling cost were for year end 2014

Current cost have been reduced by 20 to 25 %

Reserve Considerations

17 CFR Parts 210, 211 et al and SPE 123793 John Lee

Reliable technology must have been demonstrated in practice to provide on a repeatable and consistent basis, reasonable certainty.

This demonstration must be based on persuasive empirical evidence from a reasonable sample size. Oil shale must have evidence that provides the basis for a geological model indicating continuous economic producibility out to a distance X feet from a control point in a given direction and to the distance from the control point to the filer claims to be proved.

Reserve Considerations

- Economic producing wells surrounding the area of interest
- Well log control surrounding area of interest that shows continuity of the reservoir
- Resonable certainity of type curve
- Structure, Depth, T and P are well known
- PVT samples taken and compared to correlations
- Some model and volumetric analysis to establish drainage areas
- Completion parameters reviewed for consistency

Future Possibilities

- Geostatistics
- Kriging
- Variograms
- Interesting Paper- URTeC 2147795
  Improved Reserve Estimates Using Spatial Averaging
  (Shah and Kelker)

Questions

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  Philip_Jankowski@ryderscott.com