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SWD MANAGEMENT AND INJECTIVITY

Bob Long,

Director of Technology

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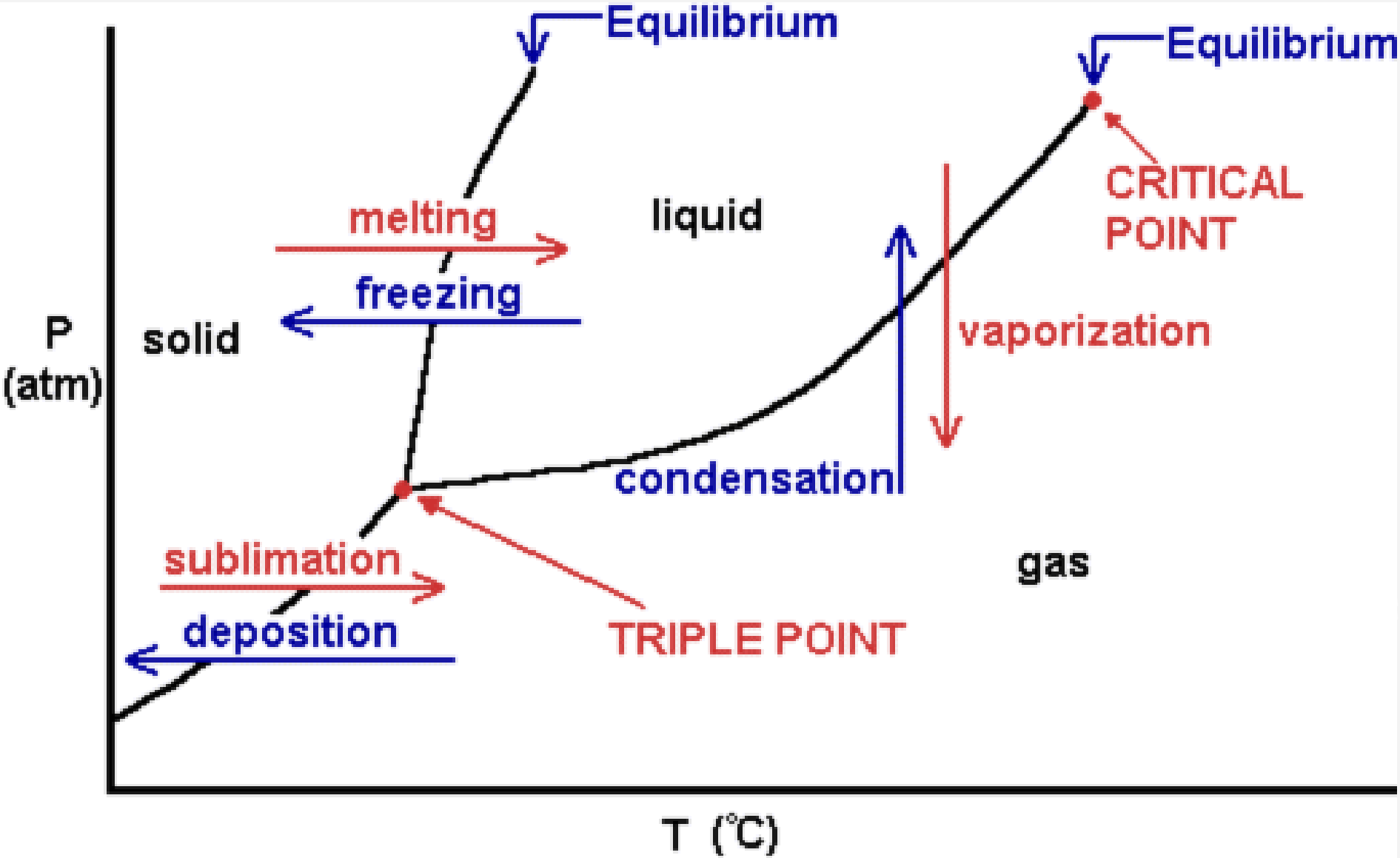
SOLIDS CONTROL

WHERE IS IT COMING FROM?

HOW TO TEST

Phase Change



Solids Collection

Methods used to quantify Solids and phase change

- Oil Analysis for Paraffin and Asphaltene content
- Water Analysis for Total Dissolved Solids
- BS&W centrifuge for % Suspended Solids
- Millipore for low level Total Suspended Solids
- Deposition coupons for what isn’t suspended
- Corrosion for increased corrosion by products
- Extended Filter studies for Suspended Solids

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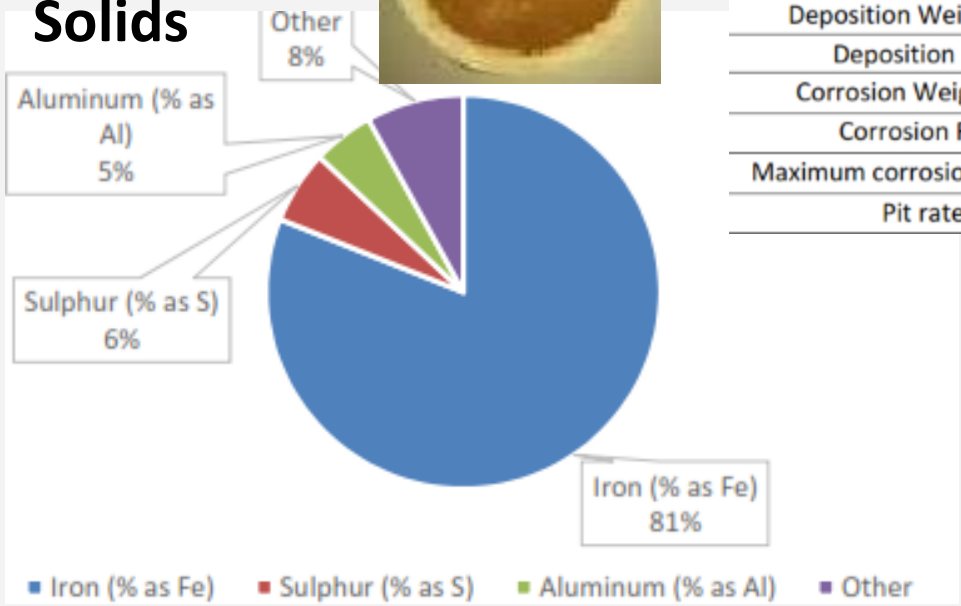
Coupon Before Cleaning
Coupon Number: G7115

Coupon After Cleaning
Coupon Number: G7115

Test	Results
Deposition Weight Gain	8.45 grams
Deposition Rate	232
Corrosion Weight Loss	0.274 grams
Corrosion Rate	7.52 mpy
Maximum corrosion/pit depth	6 mils
Pit rate	43.8 mils/year

Total Suspended Solids



Pressure

Solid

TDS

Liquid

Cations	Result	Unit
Iron	15.04	mg/L
Manganese	1.359	mg/L
Barium	34.73	mg/L
Strontium	58.88	mg/L
Calcium	1821	mg/L
Magnesium	568.0	mg/L
Sodium	35924.37	mg/L
Potassium	208.7	mg/L
Boron	30.09	mg/L
Lithium	3.773	mg/L
Copper	0.014	mg/L
Zinc	0.120	mg/L
Chromium	0.044	mg/L
Silicon	22.11	mg/L

Anions	Result	Unit
CHLORIDE	59986.48	mg/L
SULFATE	318	mg/L

Temperature

Oilfield Solids

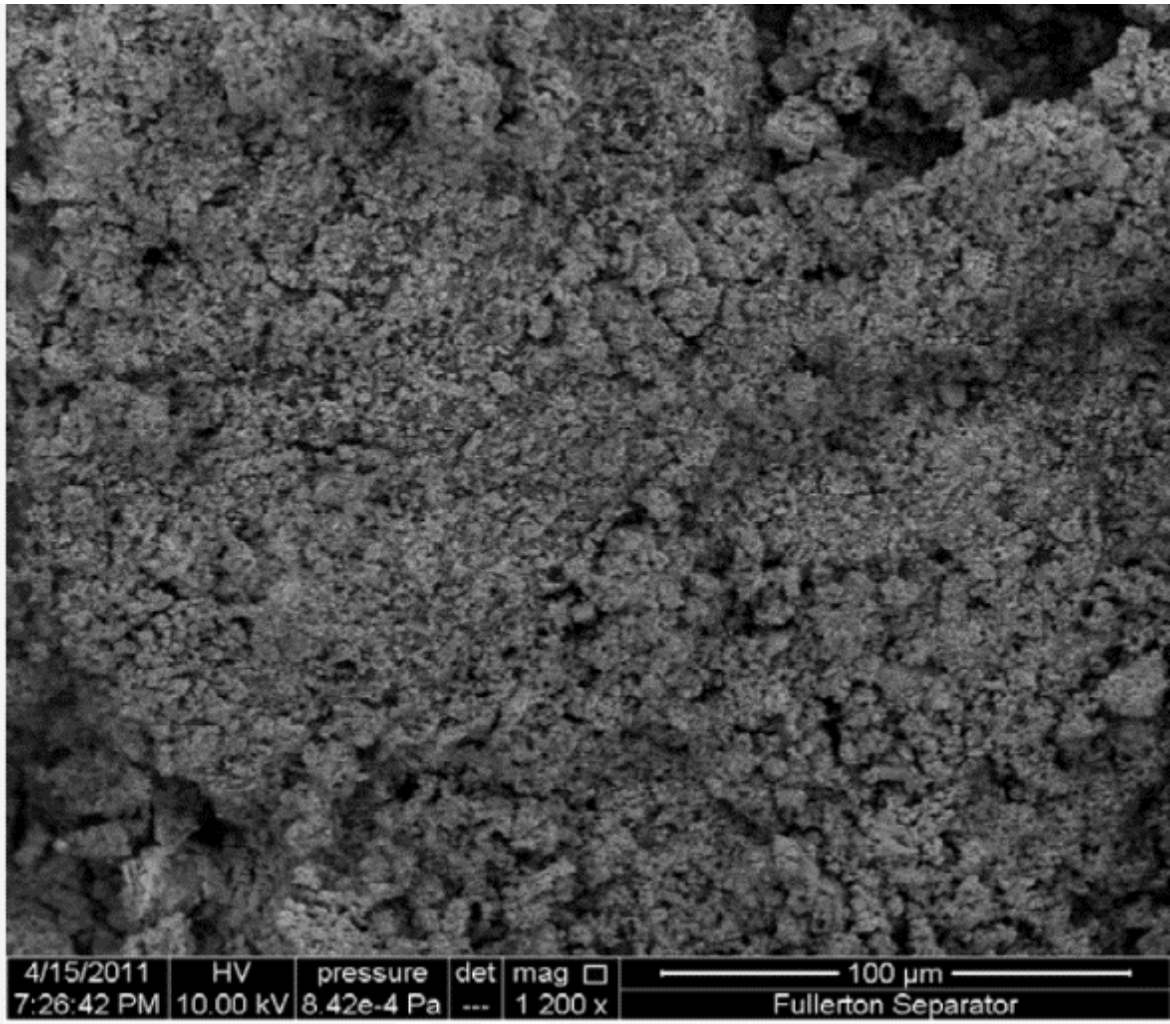
- Paraffin and Asphaltenes
- Mineral Scales such as Barite ($BaSO_4$)and Calcite ($CaCO_3$)
- Formation fines such as Sand and Silts
- Iron Scales such as:
  - Siderite ($FeCO_3$) commonly called Iron Carbonate
  - Ferrous Sulfide (FeS) or Iron Sulfide is Amorphous
  - Greigite (Fe_3S_4) is a crystalline Iron Sulfide Species
  - Magnetite (Fe_3O_4) or Iron Oxide
  - Pyrrhotite (Fe_7S_8) is another more stable crystal scale
  - Pyrite iron(II) disulfide, FeS2 (cubic), the more stable endmember, known as fool's gold.

What Is it? Methods to ID

- Wet Bench or Solvent Soak Tests
- X-ray Diffraction Molecular ID for crystalline
- EDX / XRF for amorphous Solids
- SEM for visual ID
- Particle Size Analysis

EDX / SEM – Deposit Analysis

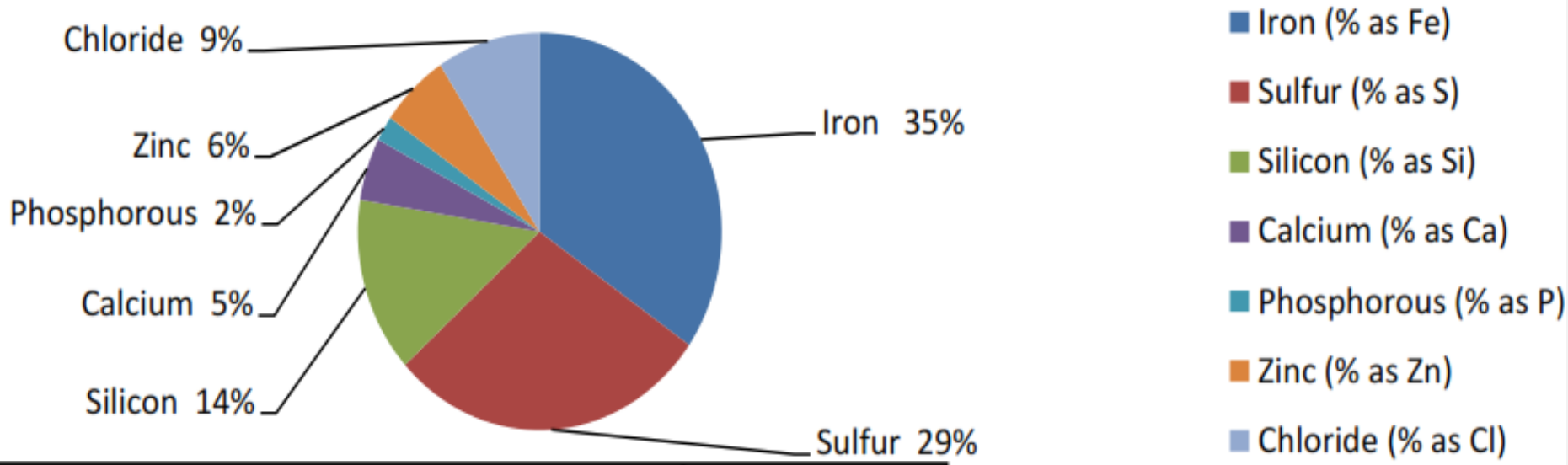
Element Line	Element Wt.%	Wt.% Error
C K	8.21	+/-0.21
O K	15.97	+/-0.21
Na K	5.12	+/-0.13
Si K	4.8	+/-0.10
P K	0.7	+/-0.07
S K	27.31	+/-0.25
Cl K	2.06	+/-0.19
Fe L	35.84	+/-0.81
Total	100.01	



Properly Identifying the debris and Quantity

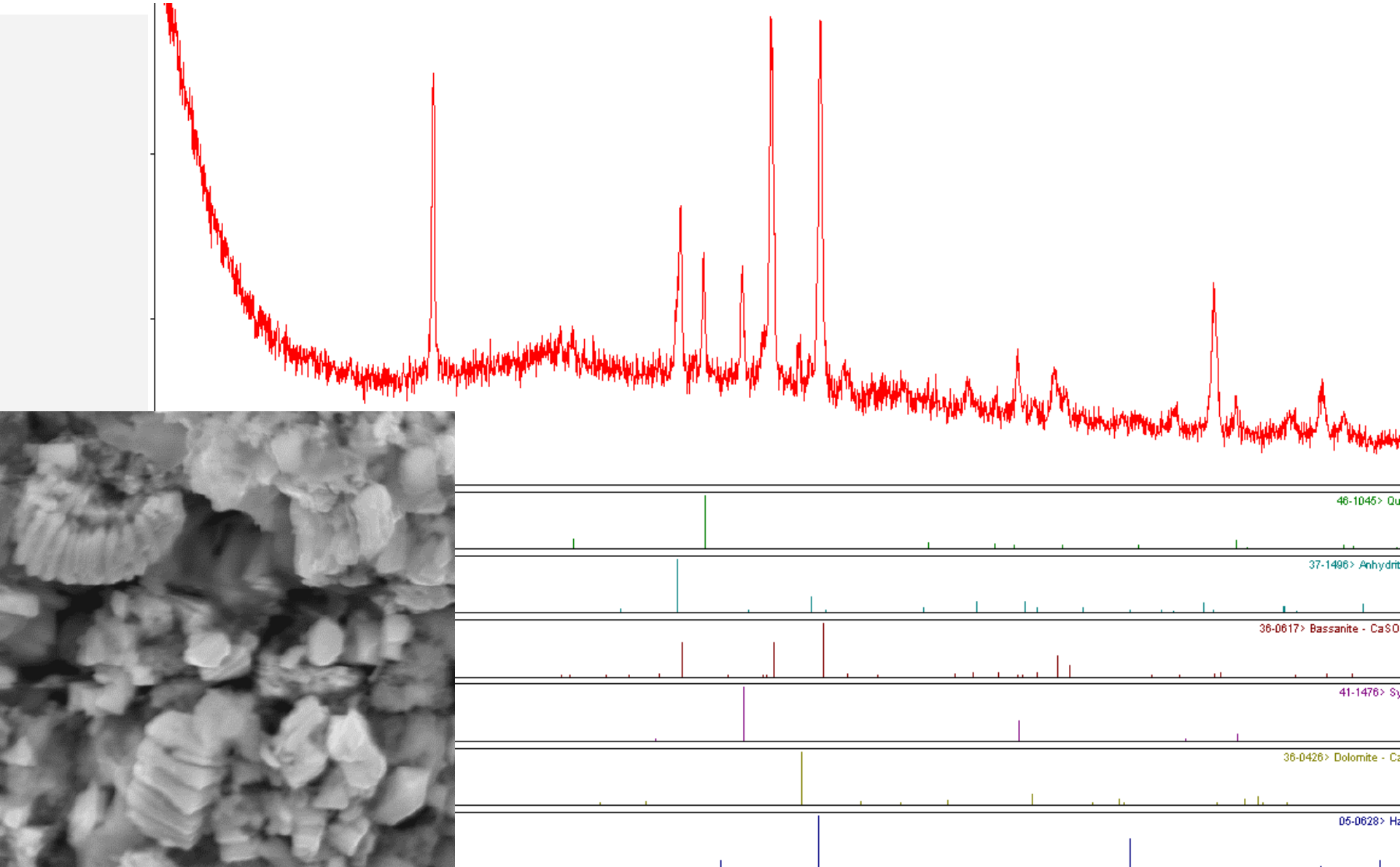
Millipore and XRF

Pre Filter



Iron (% as Fe)	34
Sulfur (% as S)	28
Silicon (% as Si)	14
Calcium (% as Ca)	5
Phosphorous (% as P)	2
Zinc (% as Zn)	6
Chloride (% as Cl)	9

X-Ray Diffraction



XRD – Deposit Analysis

Sample ID	Bulk Mineralogy (%)												
	Bassanite 2CaSO4•(H2O)	Quartz SIO2	Sr-Barite BaO0.75Sr0.25 5SO4	Aragonite CaCO3	K-Feldspar KAISI3O8	Mg-Calcite (Ca,Mg)CO3	Siderite Fe++CO3	Anhydrite CaSO4	Gypsum CaSO4•2(H2O)	Celestine SrSO4	Total Clay		
17C	60	0	0	0	0	0	0	12	0	28	0		
41C	0	0	36	0	0	0	0	0	0	64	0		
137C	46	0	0	50	0	0	0	0	4	0	0		
35D	0	5	0	71	0	9	0	0	0	0	15		
156D	9	24	0	13	0	0	0	54	0	0	0		
167D	0	55	0	35	3	4	3	0	0	0	0		

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DETERMINING THE ROOT CAUSE

AND MORE EFFECTIVE SOLUTIONS

TO PREVENT SOLIDS.

Root Cause Solutions

1. Map the Process Flow with T & P
2. Develop a monitoring and system survey plan
3. Walk the pipe & process flow with Operations
4. Compile all historical data and failure info
5. Methodically collect a baseline of statistically valid data.
6. Develop a root cause solution with operations
7. Implement a trial of one solution at a time
8. Minimizes other system changes while collecting comparative data

Investigative Tests

- CO_2 and H_2S Levels
- Water Analysis
- Millipore TSS
- BS / BS&W %
- Deposit ID
- Bacteria Survey
- Scale Deposition Rate
- Pitting Corrosion Rate
- General Corrosion Rate
- Dissolved Oxygen
- Chemical Residuals
- Oil Content in water
- Soluble oil & Grease
- Interfacial vessel pads

Finger Printing Sources

Well	Active Well	TotFld (BBLS)	BaSO4 Scale Index	CaCO3 Scale Index	TSS lbs/D	Paraffin lbs/D	Scale lbs/D	Sand lbs/D	Fe lbs/D	Emulsion	Highest Gas Vel	H2S
A002	No	0			0.00	0.00	0.00	0.00	0.00	0	0	0
A003	Yes	36			3.33	2.66	0.67	0.00	0.00	0	19	0
A004	Yes	455	0.00	0.00	2.10	0.88	0.93	0.29	2.71	0	83	4
A007	Yes	4472	0.46	-0.52	0.25	0.25	0.00	0.25	16.75	10	76	0
A008	Yes	1052	-0.062	-1.93	2.92	0.00	2.92	0.00	6.19	0	24	0
A010	Yes	29			0.00	0.00	0.00	0.00	0.00	0	84	0
A011	Yes	67	-0.02	-0.13	0.53	0.45	0.08	0.45	0.00	0	77	0
A012	Yes	433	0.9	0.46	2.56	2.16	0.40	2.16	0.00	20	112	0
A013	Yes	91	0.19	-2.19	1.01	0.50	0.45	0.56	0.59	0	55	0
A016	Yes	176	0.59	-1.63	19.58	19.42	0.12	19.46	0.00	50	22	0
A018	Yes	216	0.02	-2.39	8.91	8.53	0.38	8.53	0.00	0	86	1
A020	Yes	349			4.61	4.26	0.35	4.26	2.21	0	103	0
A021	No											
A024	Yes	2664	-0.06	-2.31	0.06	0.00	0.06	0.00	5.87	0	15	0
A027	Yes	26	-0.11	-1.62	0.02	0.02	0.00	0.02	0.19	0	57	0
A034	Yes	110			0.54	0.51	0.03	0.51	0.59	0	23	0
A036	Yes	5			0.00	0.00	0.00	0.00	0.00	0	53	0
A037	Yes	0	0.98	-1.65	0.00	0.00	0.00	0.00	0.00	0	99	0
A039	Yes	0	0	0	0.00	0.00	0.00	0.00	0.00	0	47	0
A048	Yes	228	-0.06	-2.31	48.43	26.32	7.41	41.02	2.18	0	76	0
A052	Yes	2			0.00	0.00	0.00	0.00	0.00	0	60	0
A054	Yes	240	0	0.34	18.48	0.00	0.00	0.00	1.17	0	45	6

Programs to Prevent Solids

- Iron Inhibitors to keep in solution
- Corrosion Inhibitors
- Scale Inhibitors
- Scavengers to prevent Sulfides and Oxides
- Salt Inhibitors and Fresh Water Wash
- Complete Kill Biocide programs
- Wax Inhibitors

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EXAMPLE CASE STUDIES

AND

RETURN ON INVESTMENT

ROI Benefits for Programs

- Reduced costs of solids waste handling
- Eliminating or reducing Acids, EBs and Clarifiers
- Preventing the need for Capital Expenses
- Prevention of decreased production / down time
- Reduced Operating costs like:
  - Energy Savings
  - Heating Emulsions
  - Pump maintenance.
  - Acid or Coil Tubing jobs

“Offshore– Case Study”

Operators Issues:

- Over Pressured Salt Water Disposal (SWD) wells
- Coil tubing remediationclean outs
- Loss of revenue, with high Oil PPM being disposed of
- Solids disposal and clean out of separators and Skimmer
- Increased water pump failures due to erosion
- Continued loss of well Injectivity after clean outs
- Field became production limited, with water disposal limitations

“Offshore– Case Study”

Survey result summaries:

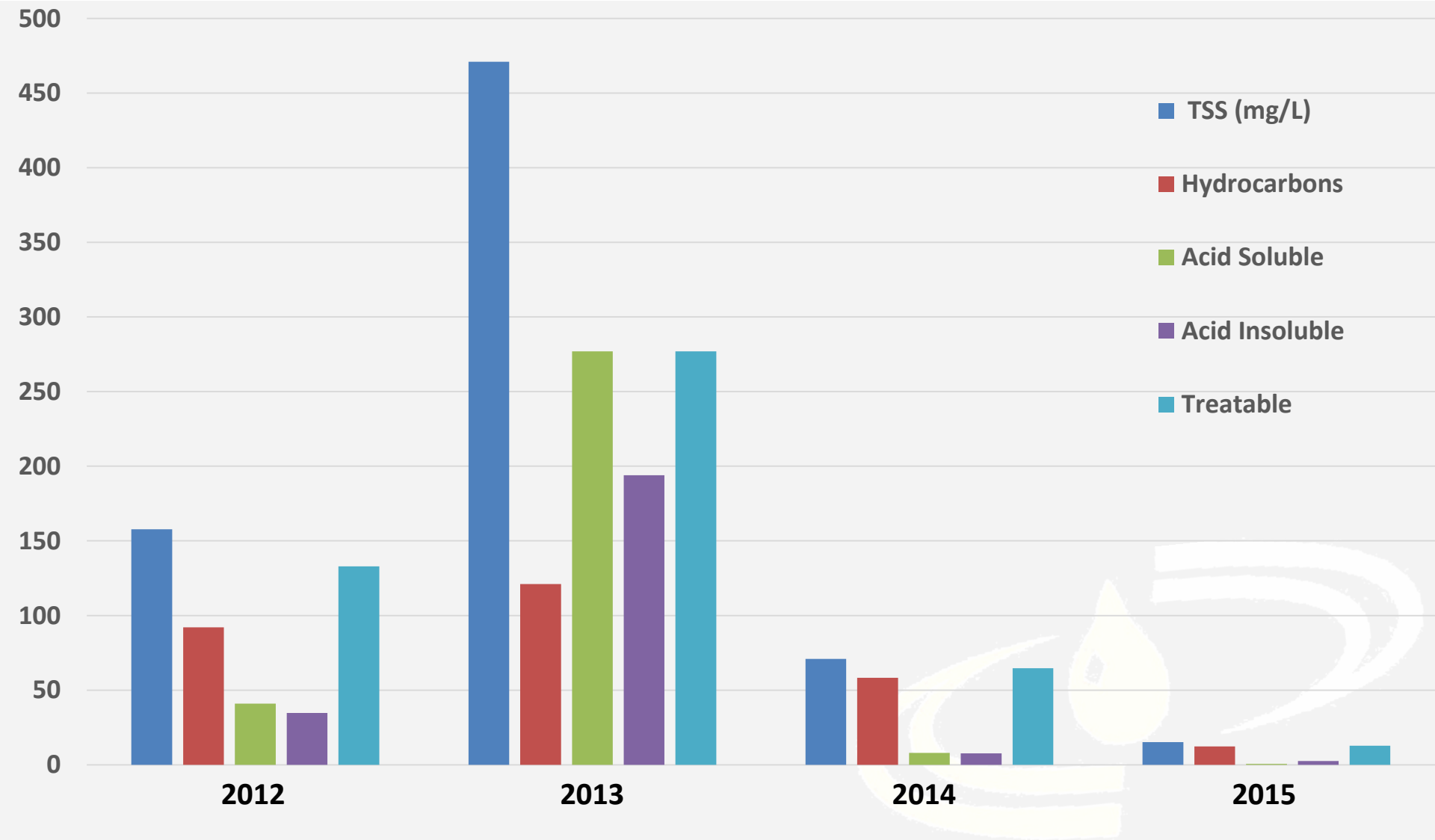
- Separators & vessels not functioning due to scale buildup
- Water was corrosive, adding Iron to the system
- Dissolved Oxygen intrusion was further precipitating Iron
- Ineffective biocide program applied downstream of contaminated vessels and equipment.
- Paraffin program was downstream of problem
- Scale Inhibitor, was applied after precipitation
- No effective KPIs to manage chemical programs

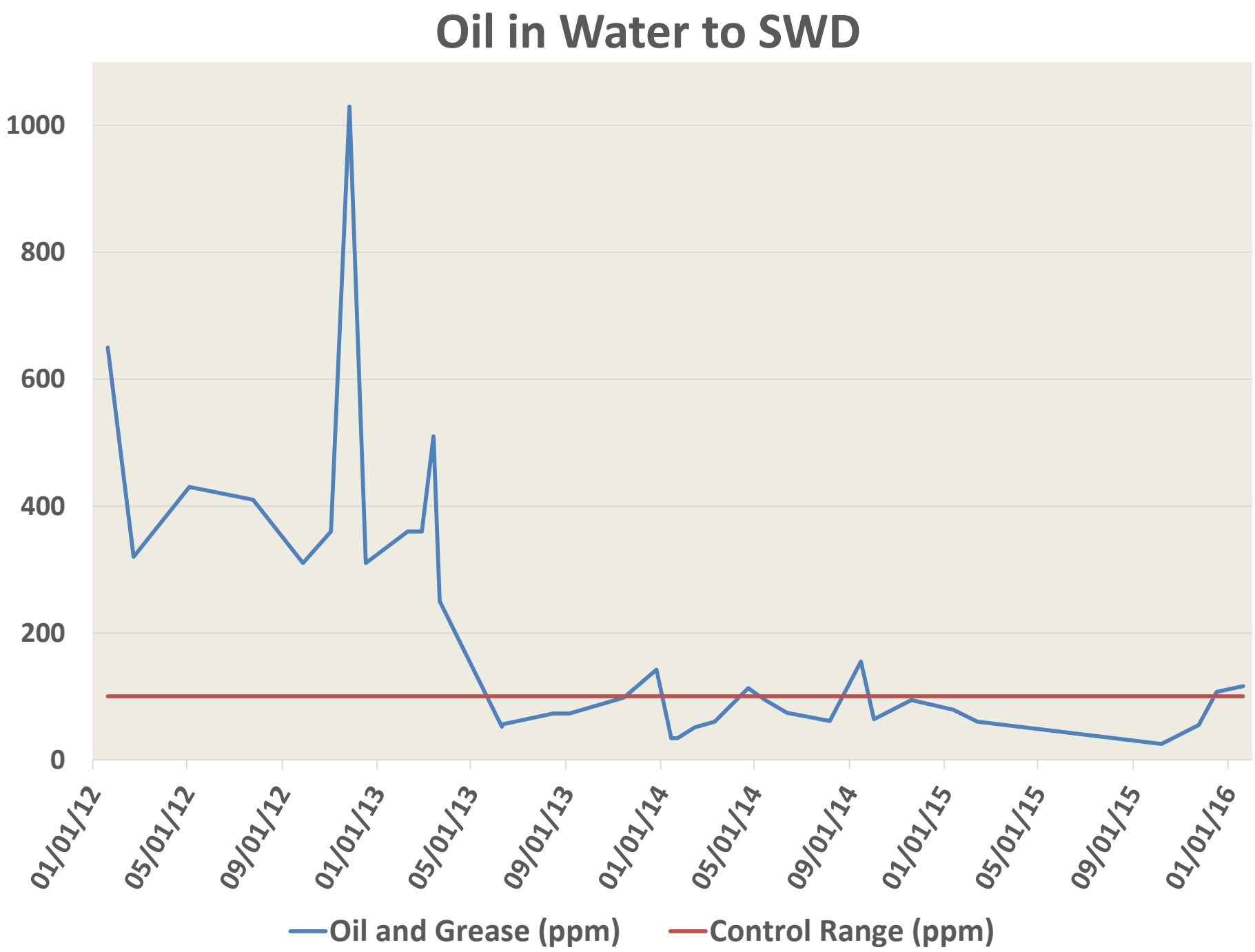
“Offshore– Case Study”

Solutions:

- Combination Iron, Corrosion and Scale Inhibitor was applied upstream of separators
- SWD surfactant program was discontinued
- Emulsion Breaker was discontinued in summer months and not needed on most separators during winter
- Separators and water skimmer were cleaned up
- Extensive monitoring was done with KPIs added
- Operator adding chemical captain to own programs

Annual Average TSS Summary




Oil in Water to SWD
1000
800
600
400
200
0
01/01/12
05/01/12
09/01/12
01/01/13
05/01/13
09/01/13
01/01/14
05/01/14
09/01/14
01/01/15
05/01/15
09/01/15
01/01/16
Oil and Grease (ppm)
Control Range (ppm)

Return on Investment

Manpower	$ Prior	$ After
Gains	$0	

Maintenance	$ Prior	$ After
Reparing SWD pumps	$40,000	$40,000
SWD Coil Tubing Job	$120,000	$60,000
Gains	$60,000	

Revenue Increase	$ Prior	$ After
Remove 400 ppm oil	$0	$233,600
Gains	$233,600	

Net Gain

$ 233,600

Environmental	$ Prior	$ After
Gains	$0	

Efficiency	$ Prior	$ After
Chemical Savings	$250,000	$150,000
Gains	$100,000	

Investment	$ Prior	$ After
10 pumps	$0	**$7,000**
Valves and gauges	$0	$3,000
Chemical Program		$150,000
New Investment	$160,000	

ROI = 146 Percent with a 0.41 Year Payback

ROI = [Gains ($160,000) + Revenue ($233,600) - Investment ($160,000)] / Investment($160,000) = 146 Percent

Payback Period = Investment ($160,000) / [Gains ($160,000) + Revenue ($233,600)] = 0.41 Years

COMMENTS:

Chemical Savings in 2014 over X-chem 2013 and 2012 usage	20,000 BWPD x 400 ppm x 365 x $80 barrel = $233,600
Projected Annual Usage Cost = $150000	
SWD Remediation clean out job with Coil Tubing job	
SWD Pump repair estiamet, need to decrease	**Note**: All dollar values must be annualized.

Revision: 2.1

“South Pass – Case Study”

Operators Issues:

- Plugging up Water Flood and SWD wells
- Oil wet Solids
- Solids causing high filter costs
- Coil tubing interventions at $5,000,000 / year
- Excessive filter costs
- lost revenue from Water Flood

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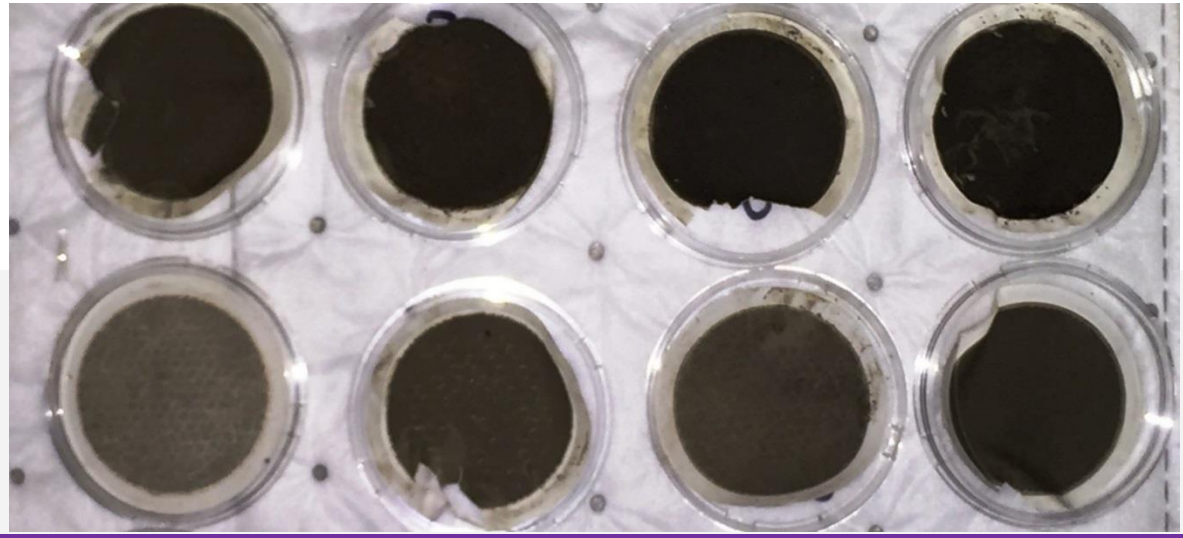
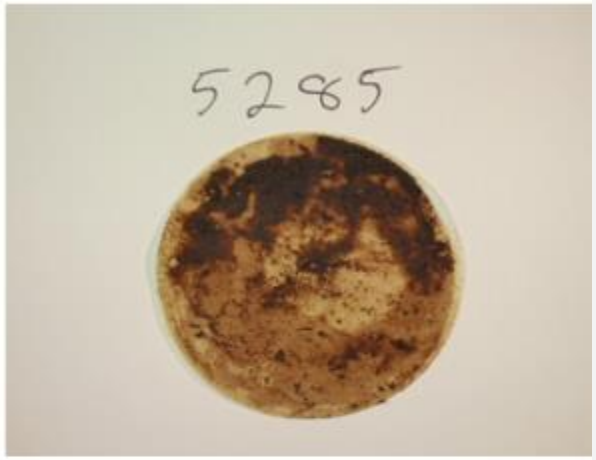
Filter Study



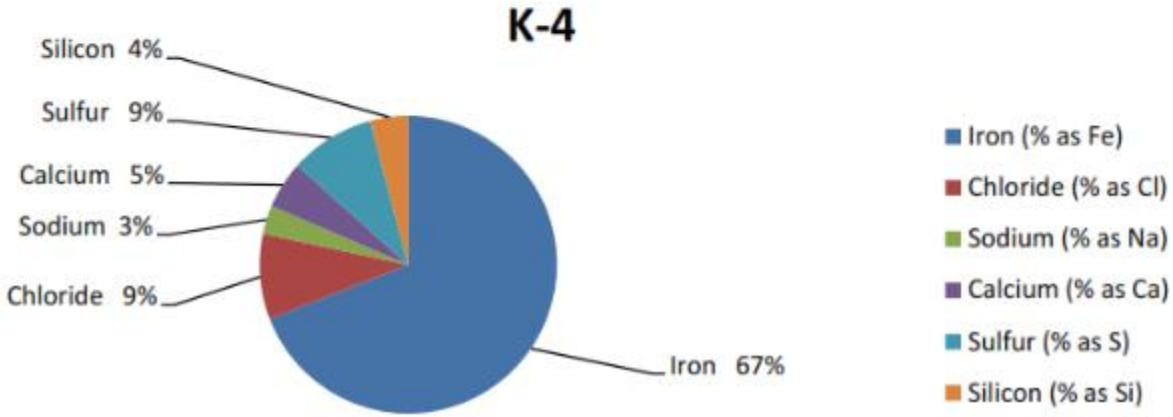
,000 BBLS/Day	Pre Weight	Post Weight	Delta	Volume (Liters)	TSS (mg/L)	TOTAL SOLIDS
0.45 Train II	0.0808	0.1336	0.0528	1	52.8	31,163 lbs/yr
r 0.45 Train II	0.0796	0.1440	0.0644	1	64.4	38,009 lbs/yr
r 1.2 filter Train II	0.0709	0.1076	0.0367	1	36.7	21,660 lbs/yr
1.2 filter	0.0700	0.1148	0.0448	1	44.8	26,441 lbs/yr
3.0 Filter	0.0625	0.1072	0.0447	1	44.7	26,382 lbs/yr
ost Filter 3.0 Filter	0.0634	0.0931	0.0297	1	29.7	17,529 lbs/yr
5.0 Filter Train II	0.1313	0.1566	0.0253	1	25.3	14,932 lbs/yr
train II 5.0 SVLP Filter	0.1315	0.1493	0.0178	1	17.8	10,505 lbs/yr
8.0 Filter	0.0596	0.1304	0.0708	1	70.8	41,904 lbs/yr
ost Filter 8.0 Fliter	0.0600	0.0940	0.0340	1	34	20,066 lbs/yr

Identifying the filtered solids

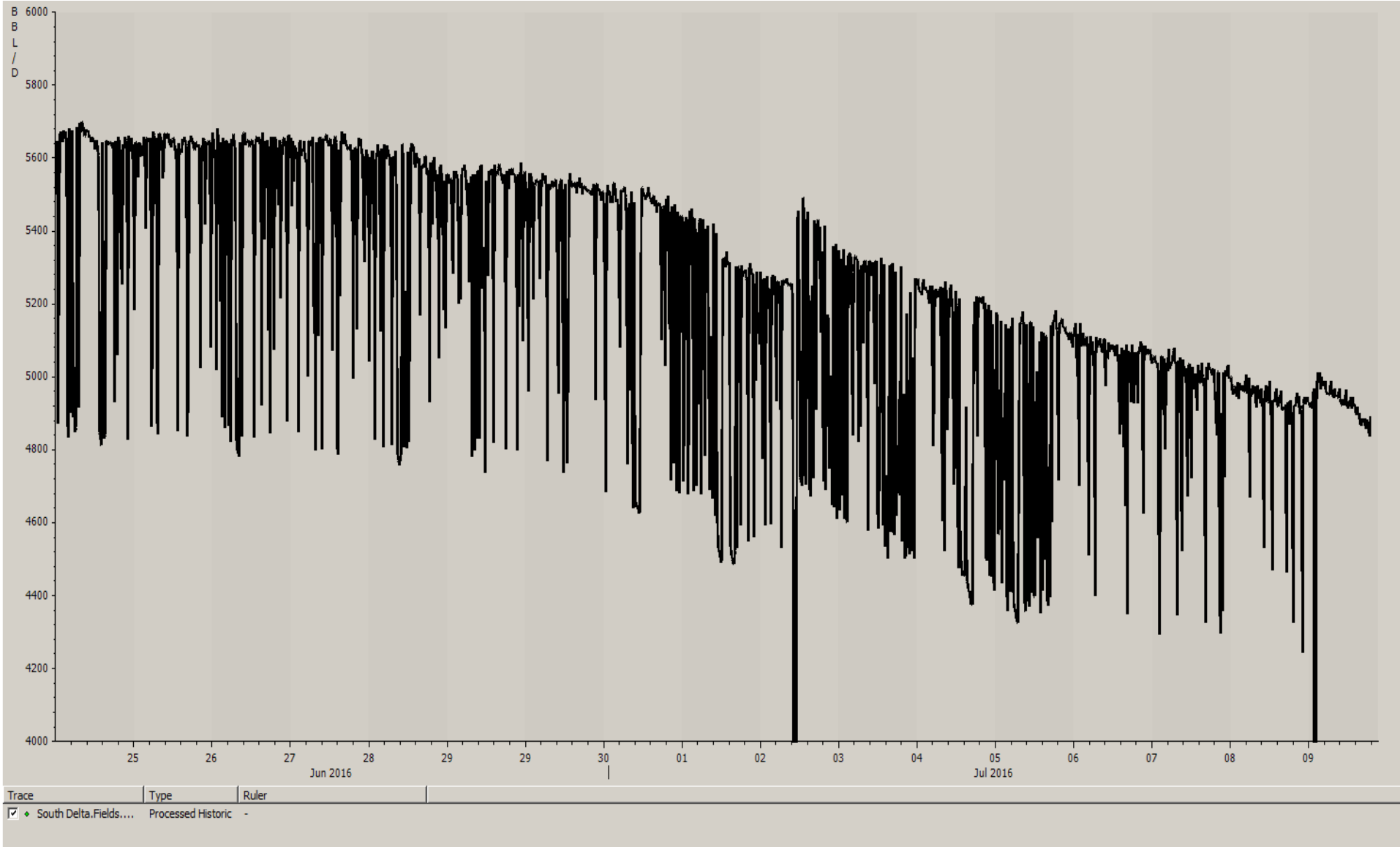
Results*	K-4
Iron (% as Fe)	67
Chloride (% as Cl)	9
Sodium (% as Na)	3
Calcium (% as Ca)	5
Sulfur (% as S)	9
Silicon (% as Si)	4



Beginning (weight in g)	N/A
Ending (weight in g)	N/A
Deposit (weight in g)	**N/A**
Volume (in mL)	N/A
TSS (mg/L)	**N/A**



Rate Loss


BBL/D
6000
5800
5600
5400
5200
5000
4800
4600
4400
4200
4000
25
26
27
28
29
29
30
01
02
03
04
05
06
07
08
09
Jun 2016
Jul 2016
Trace
Type
Ruler
South Delta.Fields....
Processed Historic
-

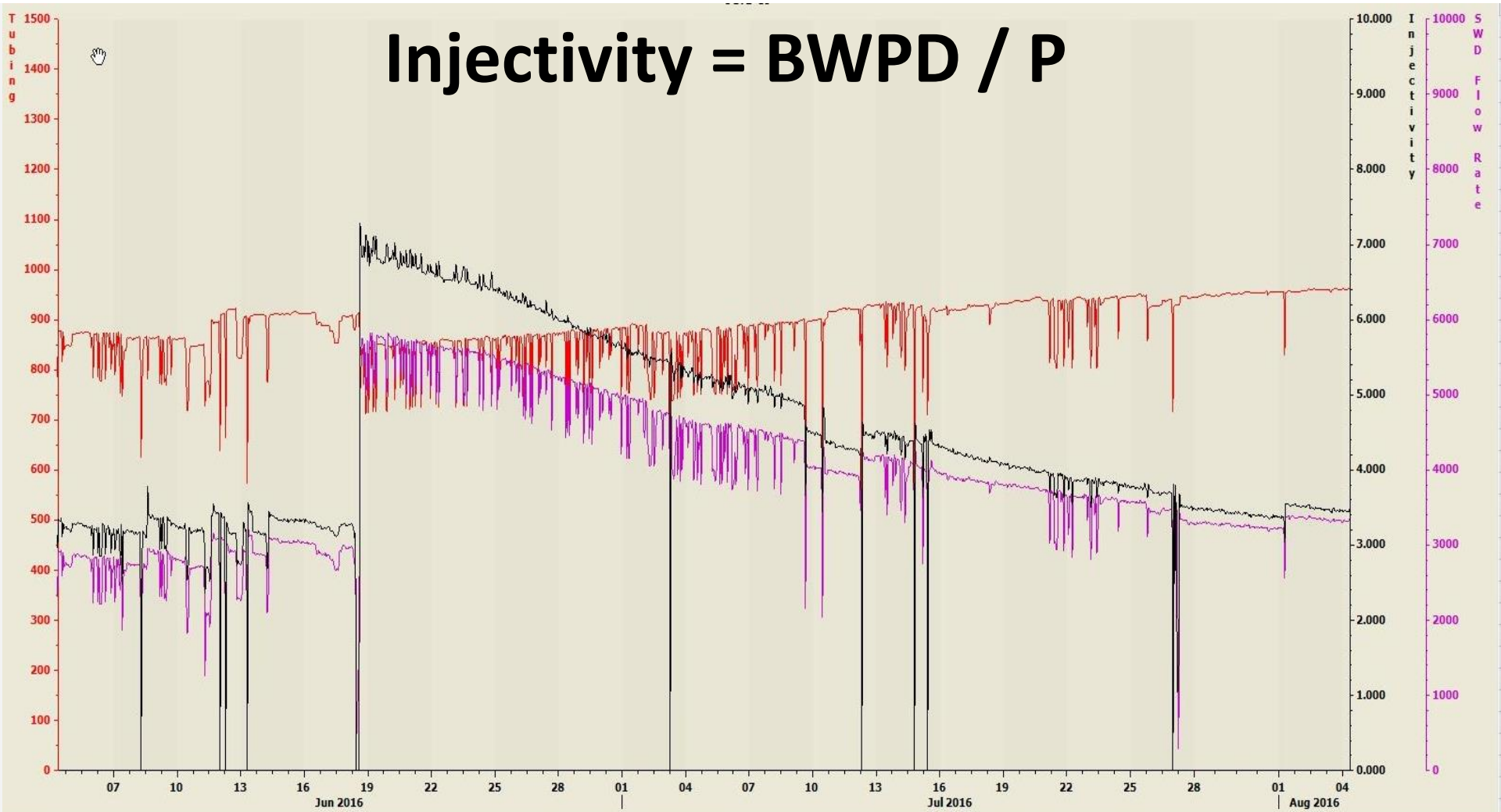
Injectivity Index Equation

Calculating the Injectivity index (*II*) is the most common way of analysing performance of injection wells. The calculation can be made from only the most basic data: injection rate (*Q*), injection pressure P_{wf} (corrected for bottom hole flowing conditions), and far-field reservoir pressure P_e. In oilfield units, the Injectivity index is commonly calculated as:

$$II = \frac{Q}{P_{bhi} - P_e} = \frac{k_w \cdot h_i}{141.2 \cdot \mu_w \cdot B_w \cdot \left(\ln {r_e}/{r_w} + S \right)}$$

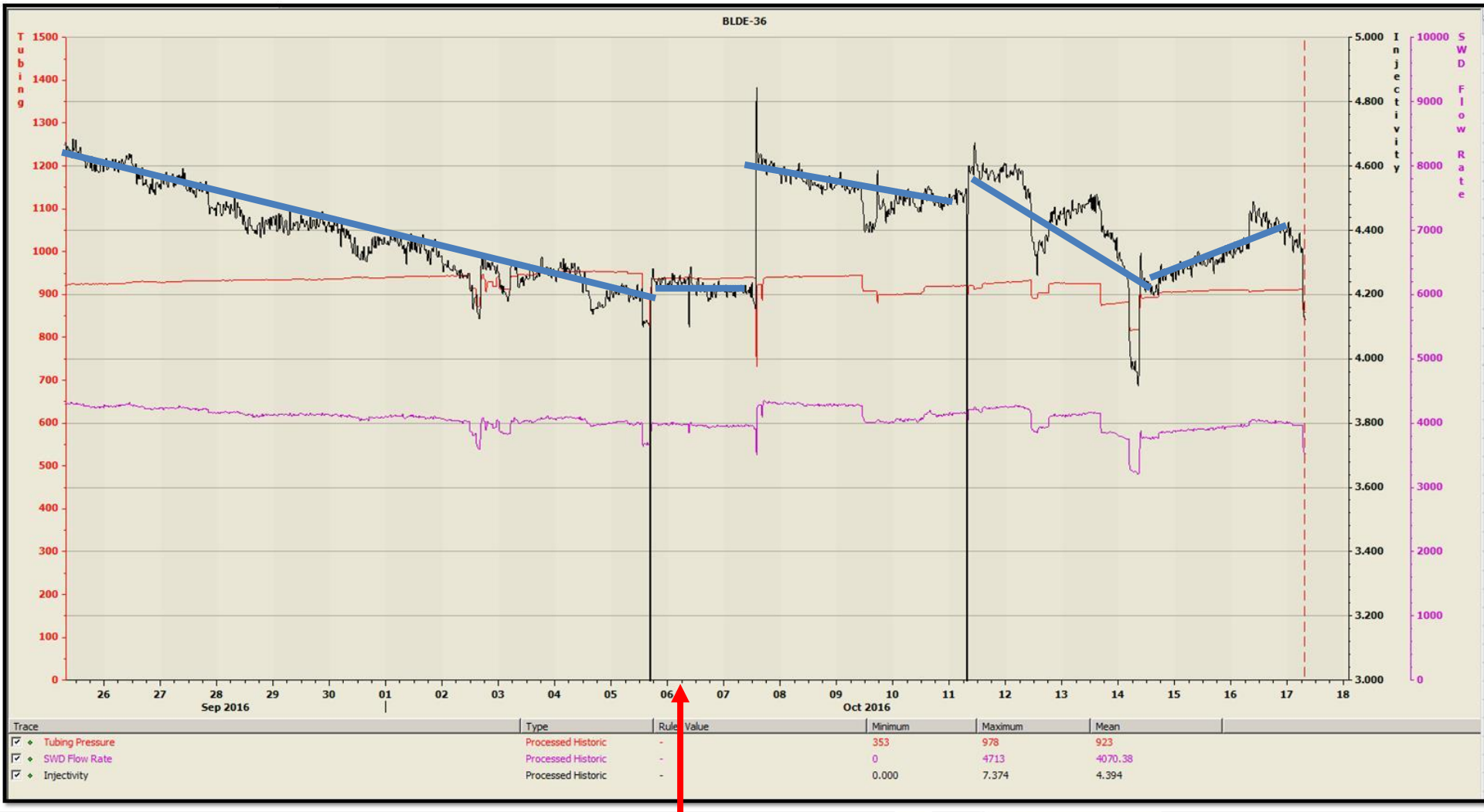
where *Q* is in STB/d and *P* in psia. Additional data required includes permeability k_w in md, water viscosity μ_w in cp, water FVF B_w (res vol/STC vol), wellbore and drainage radii r_w and r_e in ft, and injection height h_i in ft. The term S denotes the total near-wellbore skin which may be composed of mechanical (completion) skin, plugging, fracturing, and flow related skin (turbulence).

Injectivity Losses



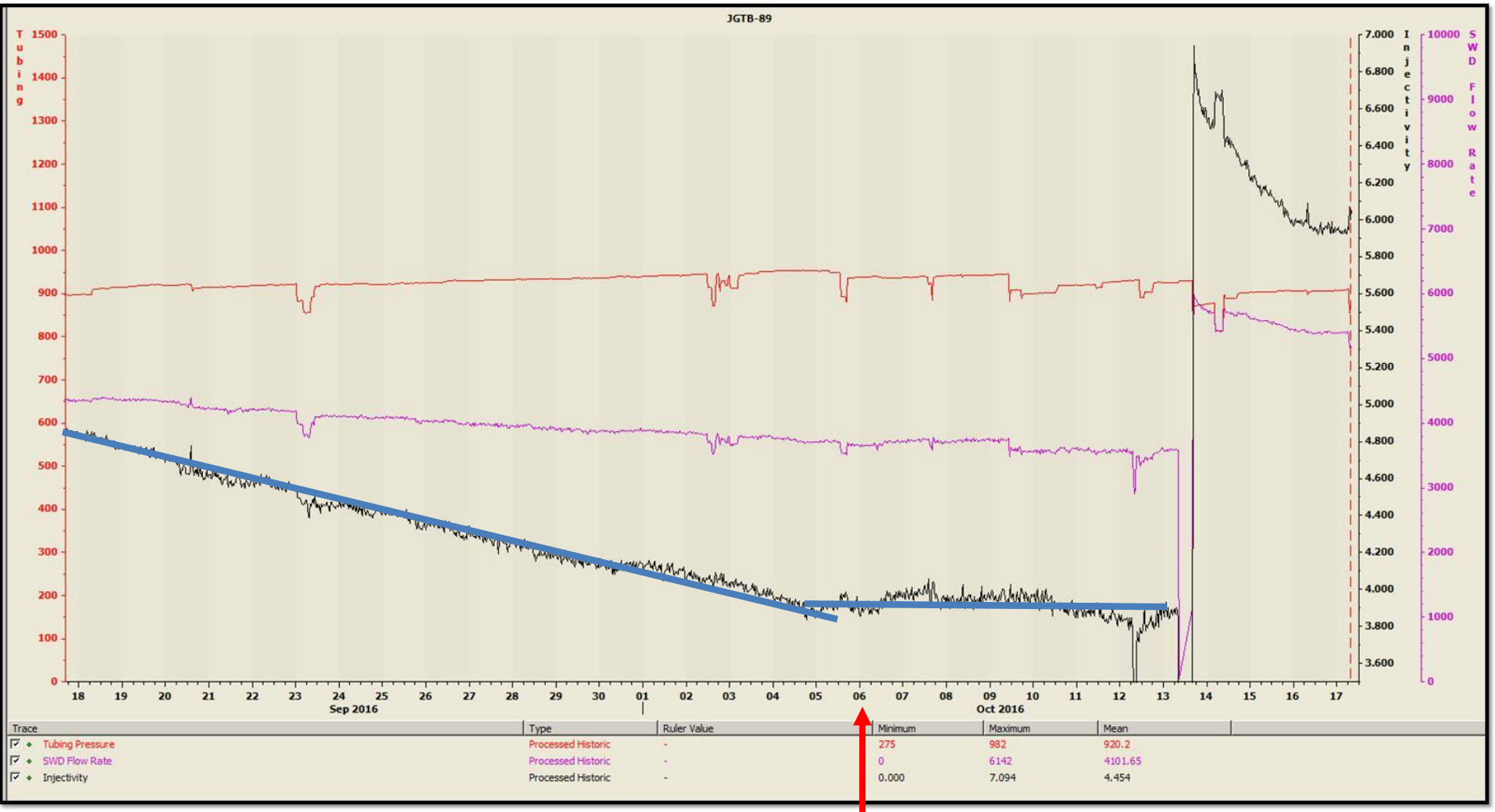
Trace	Type	Ruler Value	Minimum	Maximum	Mean
Tubing Pressure	Processed Historic	-	253	964	864.7
SWD Flow Rate	Processed Historic	-	0	6635	3895.24
Injectivity	Processed Historic	-	0.000	13.933	4.431

Injectivity Repair



Treated with 50 Gals E- 2410

Injectivity Repair



Treated with 50 Gals E- 2410

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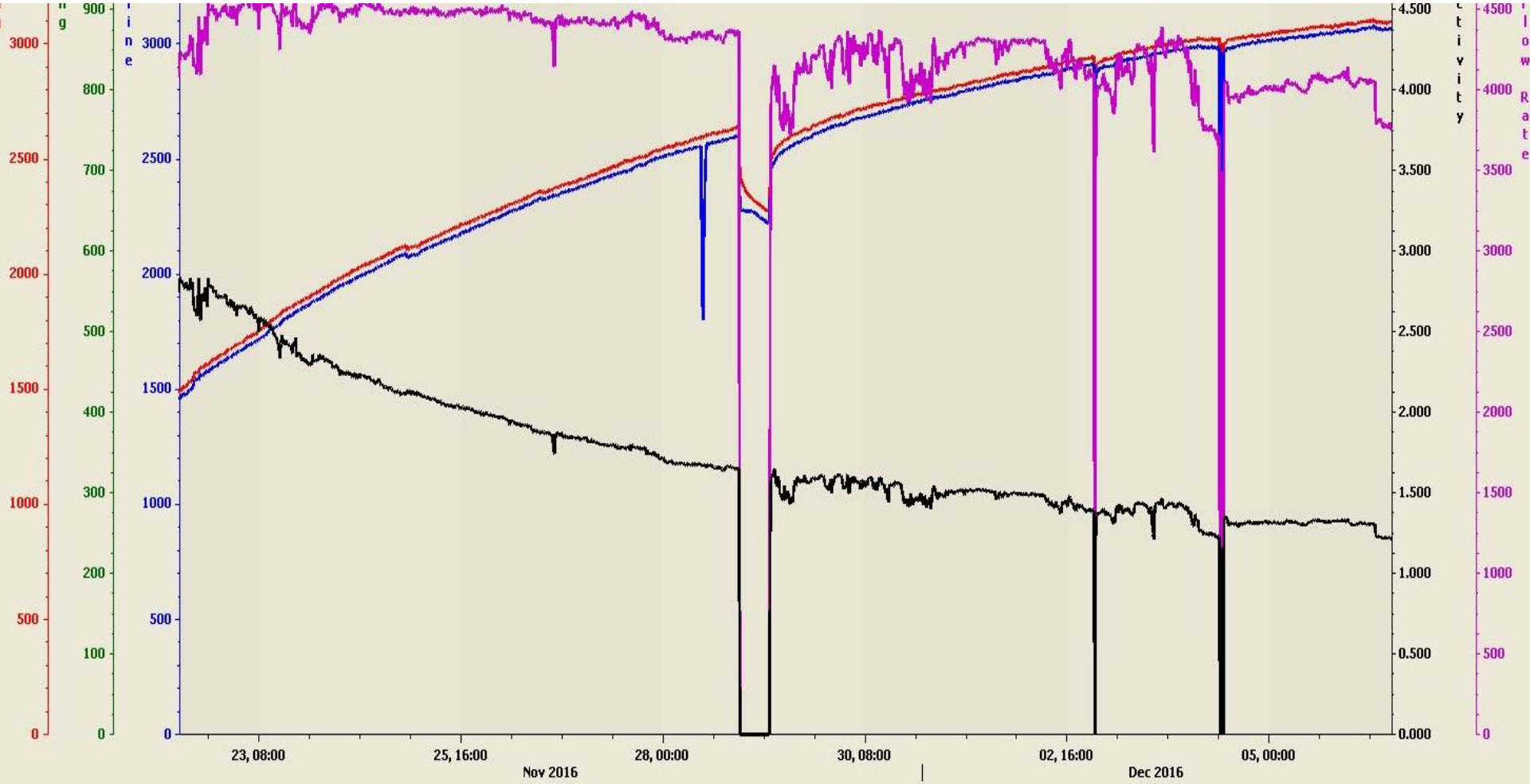

ace	Type	Ruler	Minimum	Maximum	Mean
Tubing Pressure	Processed Historic	-	1495	3112.2	2625.5
Casing Pressure	Processed Historic	-	-7.9	-5.7	-6.8
Flowline Pressure	Processed Historic	-	1464.1	3083.4	2587.2
SWD Flow Rate	Processed Historic	-	0	4608.51	4224.78
Injectivity	Processed Historic	-	0.000	2.850	1.672

Any questions?

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