Calculation of Confined Injection Zone Capacity

DJS Properties #2-14 Injection Zone

Calculation of Reservoir Volumes:

Porosity	0.23	fraction	from well log
Sw	0.80	fraction	water saturation - evidence of gas in swab testing and water analysis
Sg	0.20	fraction	gas saturation - evidence of gas in zone from swab testing - residual gas
Gross Volume	94,700	acre-ft	from planimetry calculations below
Net/Gross Ratio	0.90	fraction	from well logs
Pore Volume	19,603	acre-ft	

Reservoir Isopach Area Planimeter Readings:

CONTOUR LINE VALUE	AREA > (acres)	RATIO OF AREAS	DELTA CONTOUR (ft)	DELTA VOLUME (acre-ft)	
0	269.00				
100	234.00	0.8699	100	25,150.0	
200	205.00	0.8761	100	21,950.0	
300	173.00	0.8439	100	18,900.0	
400	144.00	0.8324	100	15,850.0	
500	113.00	0.7847	100	12,850.0	
		TOTAL ==>		94,700.0	acre-ft - gross bulk reservoir volume

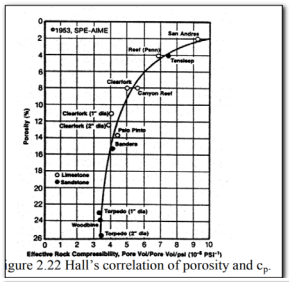
Injection Zone Capacity

Item	Value	Units	Comments - notes
Datum Depth:	5150	ft, BGL	average depth of injection zone
Average Temperature	251	deg F	ML Investments 1-3 production log
Initial Pressure:	2276	psi	8.6 ppg equivalent pore pressure at datum depth
Fracture Pressure:	3214	psi	12 ppg equivalent pore pressure at datum depth
Maximum Allowable Pressure	2892	psi	90% of fracture pressure
Maximum Pressure Increase (dP)	616	psi	maximum allowable pressure less initial pressure
Average Pressure	2584	psi	average of initial pressure and maximum allowable pressure
Water Salinity	750	ppm Cl	estimated average
Water Compressibility	3.48E-06	1/psi	Osif's Correlation
Gas Compressibility	3.87E-04	1/psi	Meehan et al, Gas gravity = 0.65 from ML Investments 1-10 Well
Rock pore volume compressibility	3.50E-06	1/PSI	Hall's Correlation
Reservoir Water Volume Initial	15,682	acre-ft	Pore Volume * Sw
Reservoir Water Volume Initial	121,663,439	RBbls	Pore Volume * Sw
Reservoir Water Volume Compression	261,022	RBbls	dP * water compressibility* initial water volume
Reservoir Gas Space Volume Initial	3,921	acre-ft	Pore Volume * Sg
Reservoir Gas Space Volume Initial	30,415,860	RBbls	Pore Volume * Sg
Gas Pore Space Compression	7,250,191	RBbls	dP * gas compressibility * initial gas volume
Pore Space Volume Increase	262,281	Rbbls	dP * pore space compressibility
Total Pore Space volume increase	7,773,494	RBbls	sum of water, gas, and pore space compression
Bw (water formation volume factor):	1.055	RBbl/STBb	McCain's Correlation
Total Stock Tank Barrels Capacity	**7,368,241**	**STBbls**	adjust to surface conditions by dividing by water formation volume factor (Bw)

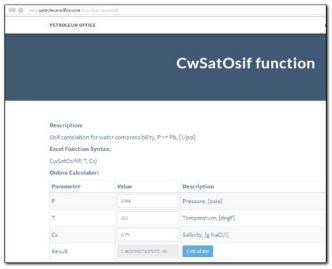
Z	#NAME?	
OGIP:	#NAME?	MMCF
OGIP:	#NAME?	

Formation Water Factor: McCain Correlation

Datum Temperature:	251	deg F	ML Investments 1-3 production log
Datum Pressure:	2276	psi	8.6 ppg equivalent pore pressure estimate
dVwp:	0.05814		
dVwT:	-0.00333		



igure 2.22 Hall's correlation of porosity and c_p.



http://petrowiki.org/Produced_water_formation_volume_factor

$$B_w = (1 + \Delta B_{wp})(1 + \Delta B_{wT}) \quad (2)$$

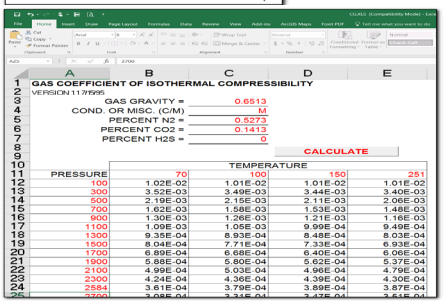
where

$$\Delta B_{wp} = -1.0001 \times 10^{-2} + 1.33391 \times 10^{-4}T + 5.50654 \times 10^{-7}T^2, \quad (3)$$

and

$$\Delta B_{wT} = -1.95301 \times 10^{-9}pT - 1.72834 \times 10^{-13}p^2T - 3.58922 \times 10^{-7}p - 2.25341 \times 10^{-10}p^2, \quad (4)$$

where p = pressure in psia, and T = temperature in °F. McCain reported that this correlation agrees with a limited set of published experimental data to within 2%. The correlation is considered valid for temperatures to 260°F, and pressures to 5,000 psia. An increase in dissolved solids causes a slight increase in ΔV_{wT}, and a slight decrease in ΔV_{wp}, which offset each other to within 1%.



GAS COEFFICIENT OF ISOTHERMAL COMPRESSIBILITY
VERSION 11/7/95

GAS GRAVITY = 0.6513
COND. OR MISC. (C/M) M
PERCENT N2 = 0.5273
PERCENT CO2 = 0.1413
PERCENT H2S = 0

CALCULATE

PRESSURE	TEMPERATURE 70	100	150	251
100	1.02E-02	1.01E-02	1.01E-02	1.01E-02
300	3.52E-03	3.49E-03	3.44E-03	3.40E-03
500	2.19E-03	2.15E-03	2.11E-03	2.06E-03
700	1.62E-03	1.58E-03	1.53E-03	1.48E-03
900	1.30E-03	1.26E-03	1.21E-03	1.16E-03
1100	1.09E-03	1.05E-03	9.99E-04	9.49E-04
1300	9.35E-04	8.93E-04	8.48E-04	8.03E-04
1500	8.04E-04	7.71E-04	7.33E-04	6.93E-04
1700	6.89E-04	6.68E-04	6.40E-04	6.06E-04
1900	5.88E-04	5.80E-04	5.62E-04	5.37E-04
2100	4.99E-04	5.03E-04	4.96E-04	4.79E-04
2300	4.24E-04	4.36E-04	4.39E-04	4.30E-04
2584	3.61E-04	3.79E-04	3.89E-04	3.87E-04
2700	3.08E-04	3.31E-04	3.47E-04	3.61E-04

SG:	0.6513
N2%	0.5273
CO2%	0.1413
H2S%	0

Aquifer Production for Drinking Water Scenario

Item	Value	Units	Comments - notes
Datum Depth:	5,150	ft, BGL	average depth of injection zone
Average Temperature	251	deg F	ML Investments 1-3 production log
Initial Pressure:	2276	psi	8.6 ppg equivalent pore pressure at datum depth
Gas Gravity:	0.6513	Air=1	
Nitrogen content:	0.5273	mol%	
CO2 content:	0.1413	mol%	
H2S content:	0	mol%	
Supercompressibility Factor => Zi	#NAME?	N/A	
Gas Formation Volume Factor => Bg	#NAME?	SCF/RCF	
Initial Reservoir Pore Volume	19,603	acre*ft	
Initial Gas Saturation	0.20	fraction	
Initial Water Saturation	0.80	fraction	
Original Gas In Place	3920.58	acre*ft	
Original Water in Place			

G = 43560 * A * h * Sg * Pr/Z * Psc

Calculation of Confined Injection Zone Capacity

DJS Properties #2-14 Injection Zone

Calculation of Reservoir Volumes:

Porosity	0.23	fraction	from well log
Sw	0.80	fraction	water saturation - evidence of gas in swab testing and water analysis
Sg	0.20	fraction	gas saturation - evidence of gas in zone from swab testing - residual gas
Gross Volume	94,700	acre-ft	from planimetry calculations below
Net/Gross Ratio	0.90	fraction	from well logs
Pore Volume	19,603	acre-ft	

Reservoir Isopach Area Planimeter Readings:

CONTOUR LINE VALUE	AREA > (acres)	RATIO OF AREAS	DELTA CONTOUR (ft)	DELTA VOLUME (acre-ft)	
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100	234.00	0.8699	100	25,150.0	
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		TOTAL ==>		94,700.0	acre-ft - gross bulk reservoir volume

Injection Zone Capacity

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Datum Pressure:	2276	psi	8.6 ppg equivalent pore pressure estimate
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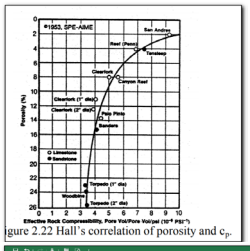

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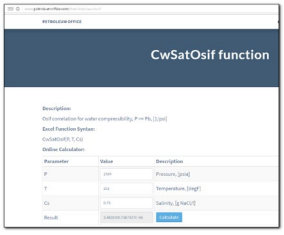

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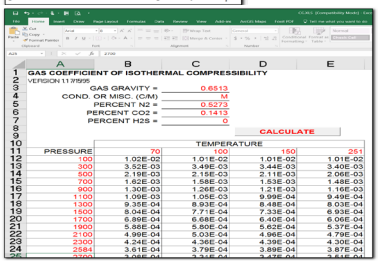
where p = pressure in psia, and T= temperature, in °F. McCain reported that this correlation agrees with a tested set of published experimental data to within 2%. The correlation is considered valid for temperatures to 260°F, and pressures to 5,000 psia. An increase in dissolved solids causes a slight increase in ΔV_{wp}, and a slight decrease in ΔV_{wT}, which offset each other to within 1%.



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900	1.30E-03	1.26E-03	1.21E-03	1.16E-03
1100	1.09E-03	1.05E-03	9.99E-04	9.49E-04
1300	9.35E-04	8.93E-04	8.48E-04	8.03E-04
1500	8.04E-04	7.71E-04	7.33E-04	6.93E-04
1700	6.89E-04	6.68E-04	6.40E-04	6.06E-04
1900	5.88E-04	5.80E-04	5.62E-04	5.37E-04
2100	4.99E-04	5.03E-04	4.96E-04	4.79E-04
2300	4.24E-04	4.36E-04	4.39E-04	4.30E-04
2584	3.61E-04	3.79E-04	3.89E-04	3.87E-04
3000	3.08E-04	3.31E-04	3.47E-04	3.51E-04

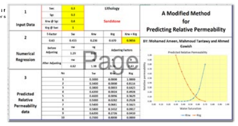
Snake River Oil and Gas, LLC
Aquifer Exemption Request
Fault Block E
7/26/2020, Dale R. Hayes, PE

Aquifer Production Model:
Assumptions:

Confined Aquifer - Pressure Depletion
Assume initial water and gas saturation, porosity, Scritical, pressure, temperature
Calculate reservoir volumes of water and gas in place.
Assume zero water and rock compressibilities. Only consider gas compressibility for simplification.
Use stepwise material balance for each assumed pressure drop
Use relative permeability from saturations to determine flow of gas and water.
Calculate the new saturation resulting from the production and pressure drop.
Repeat until abandonment is reached, based on gas flow and bottom hole pressure considerations.
Gas Material Balance Equation - Page 84 - Craft and Hawkins - ignoring formation and water compressibilities:
G * (Bg - Bgi) + We = Gp * Bg + Bw * Wp
GIPresvr - OGIPresvr + WATERINresvr = GASPRODresvr +WATERPRODresvr
For confined aquifer, We = 0
Bg = (Psc * Z * T) / ([RCF/SCF]
Use relative permeability for gas / water / sandstone system. See "A Modified Method for Predicting Relative Permeability, Ameen, Tantawy, Gawish; Int. Journal of Recent Technology and Engineering, Volume 8 Issue ...

Conclusion:
Based on this model, approximately 25 MMBW will be produced before well produces significant gas that will interefere with artificial lif
Note that this is a simple 1D model and does not consider heterogenities in permeability, geometry, intra-reservoir permeability barriers

Intial Conditions:		
Reservoir Temperature:	251	deg F
Gas Specific Gravity:	0.6513	Air=1
Nitrogen mole%	0.5273	mole%
CO2 mole%	0.1413	mole%
H2S mole%	0	mole%
Initial Pressure:	2276	psia
Sw	0.80	decimal
Sg	0.20	decimal
Reservoir Bulk Volume:	94,700	acre-ft
Reservoir Net/Bulk Factor:	0.90	decimal
Reservoir Porosity:	0.23	decimal
Reservoir Pore Space	19,603	acre-ft
Reservoir Pore Space	##########	cubic feet
Psc	14.7	psia
Tsc	520.0	degR
Water Salinity:	0.75	g/l
Zi =	#NAME?	
Bgi =	#NAME?	RCF/SCF
Bwi =	#NAME?	RBBL/STB



1	Swc	0.3	Lithology			A Modified Method for Predicting Relative Permeability
	Sgc	0.3	Sandstone			
Input Data	Krw @ Sgc	0.8				
	Krg @ Swc	1				
2	T-Factor	Sw	Krw	Krg	Krw + Krg	
	0.63305976	0.45506101	0.23564	0.670004069	0.9056485	BY: Mohamed Ameen, Mahmoud Tantawy and Ahmed Gawish
NumericalReg	Before Adjust	nw	ng	Adjusting Factors		
		1.28981485	0.81653			
	After Adjusting	nw	ng	A	B	
		4.82390756	1.98417	3.74	2.43	
3	No		Sw	Krw	Krg	
	1		0.3	0	1	
	2		0.34	1.2E-05	0.8113523	
Predicted Rel	3		0.38	0.000339878	0.6422651	
	4		0.42	0.002403097	0.4927749	
	5		0.46	0.009626406	0.3629233	
	6		0.5	0.02824549	0.2527587	
	7		0.54	0.068063163	0.1623381	
	8		0.58	0.143171723	0.091732	
			0.59	0.17554122	0.079057	
			0.6	0.207910717	0.066382	
			0.61	0.240280215	0.053707	
	9		0.62	0.272649712	0.0410323	
	10		0.63	0.338568498	0.035903	
			0.64	0.404487284	0.030774	
			0.65	0.47040607	0.025645	
			0.66	0.536324856	0.020516	
			0.67	0.602243642	0.015387	
			0.68	0.668162428	0.010258	
			0.69	0.734081214	0.005129	
			0.7	0.8	0	

Barrels	cubic ft	Acre ft	Total supply in basin		%
2.5E+07	1.4E+08	3222.57	5300000	acre feet per year	0.06080%
					365
5000 bpd					0.221931472
5000 days					5.32635532
13.6893 years		total acre ft/years production			
		235.408 acre feet/year			
			4.44167E-05	fraction of total basin supply	
			0.00444%		
			365.25		
			24		
			0.389356756	hours	
j			60		
			23.361405	minutes	

fw = 1/(1+(krg *uw)/(ug*krw))

Step	Pressure [psia]	Water in Place - reservoir volume [Reservoir cubic-feet]	Bw RBBL/STB	Water in Place - Stock Tank Barrels [STB]	Gas in Place - reservoir volume [Reservoir cubic-feet]	Z [decimal]	Bg [RCF/SCF]	Remaining Gas in Place [SCF]	Pore Fraction Water [decimal]	Pore Fraction Gas [decimal]	Reservoir Pressure stage depletion delta [psia]	Final Pressure [psia]	Z final [decimal]	Bg final [RCF/SCF]	Bw final [RV/SV]	G * (Bg-Bgi) [cubic feet]	Water/Gas Fraction Reservoir Production in Fraction [decimal]	Gp [SCF]	Cumulative Gas Production [SCF]	Wp [SCF]	Wp [STB]	Cumulative Water Production [STB]	GWR [SCF/STB]	Gp*Bg + Bw*Wp Reservoir CF	delta RWIP	delta RGIP	ug	uw	Krw	Krg	Fw	Fw adj Water Fraction Flowing in Reservoir	WG Ratio WG Ratio in Reservoir	Comments
Initial Condit	2276	###########	#NAME?	#NAME?	170,780,465	#NAME?	#NAME?	#NAME?	0.8	0.2	50	2226	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?			#NAME?	#NAME?	0.8	0	#NAME?	#NAME?	#NAME?	
1	2226	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	2176	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
2	2176	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	2126	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
3	2126	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	2076	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
4	2076	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	2026	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
5	2026	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1976	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
6	1976	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1926	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
7	1926	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1876	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
8	1876	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1826	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
9	1826	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1776	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
10	1776	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1726	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
11	1726	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1676	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
12	1676	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1626	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
13	1626	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1576	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
14	1576	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1526	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
15	1526	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1476	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
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17	1426	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1376	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
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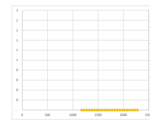
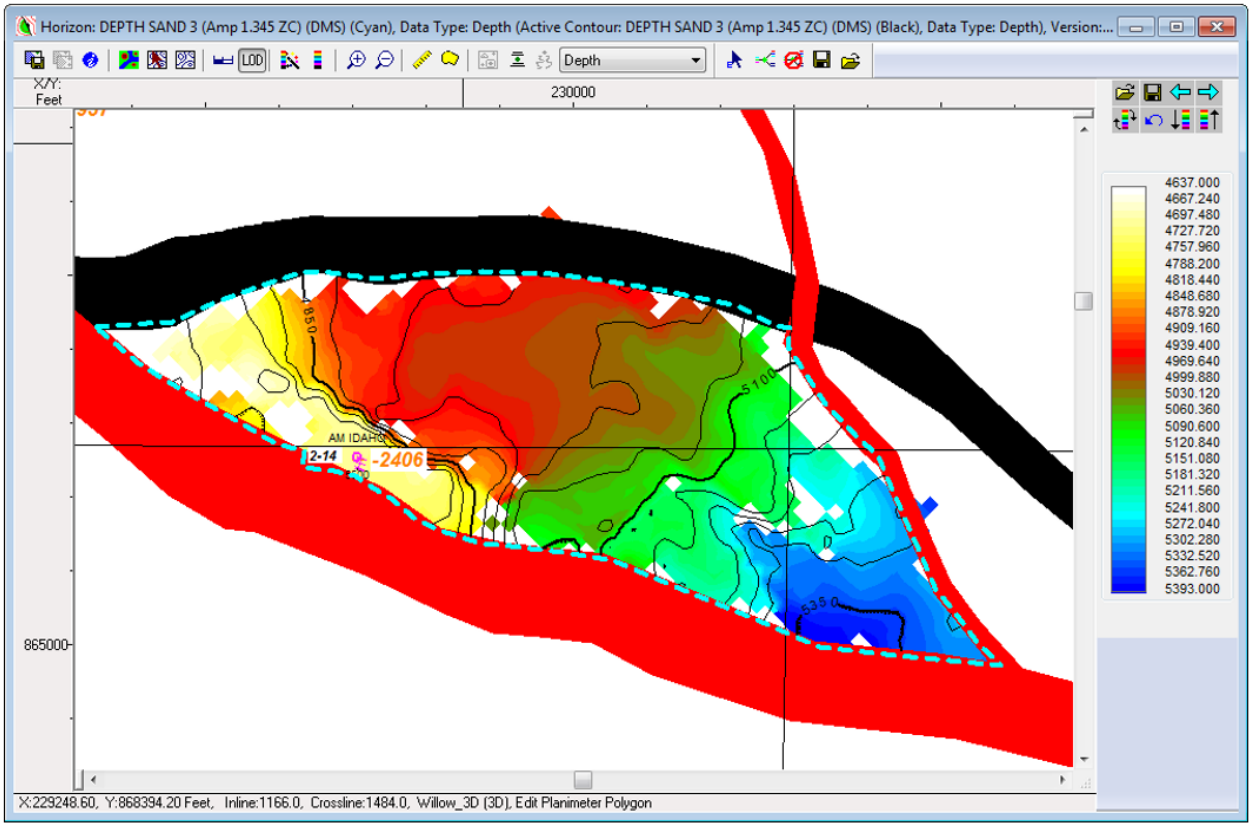
20	1276	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1226	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
21	1226	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1176	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
22	1176	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1126	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	potential gas interference issues and loss in water productivity
23	1126	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1076	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
24	1076	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	1026	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
25	1026	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	976	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
26	976	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	926	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
27	926	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	876	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
28	876	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	826	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
29	826	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	776	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
30	776	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	726	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
31	726	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	676	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	
32	676	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	50	626	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	#NAME?	

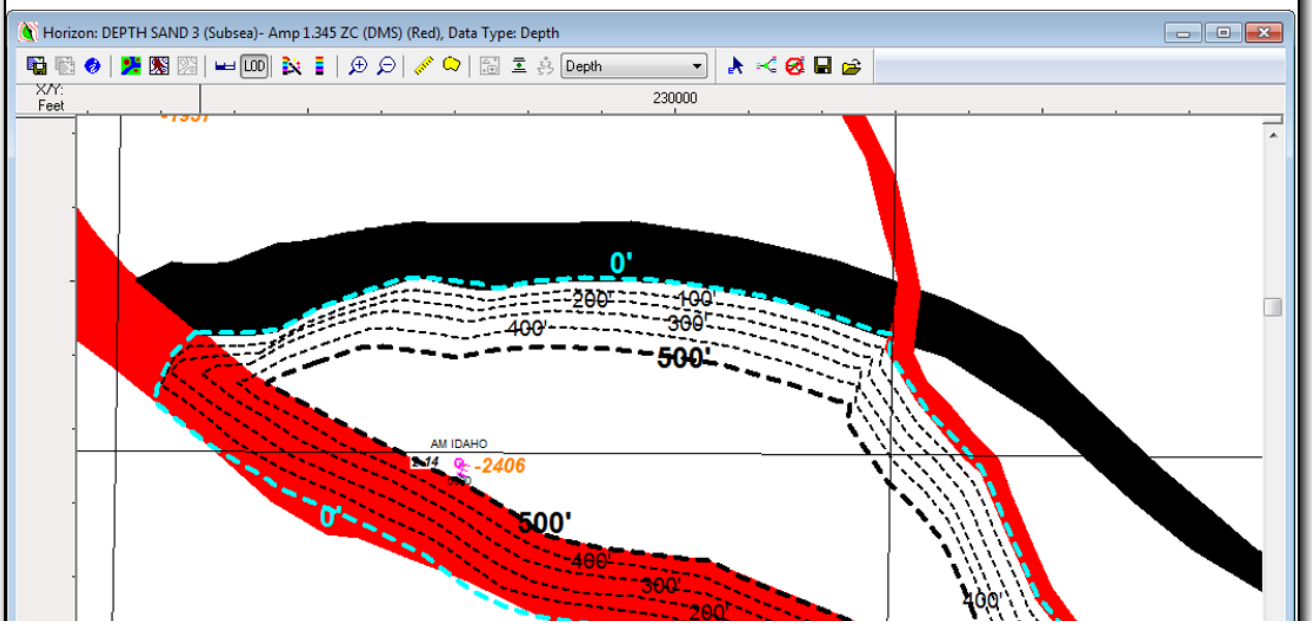


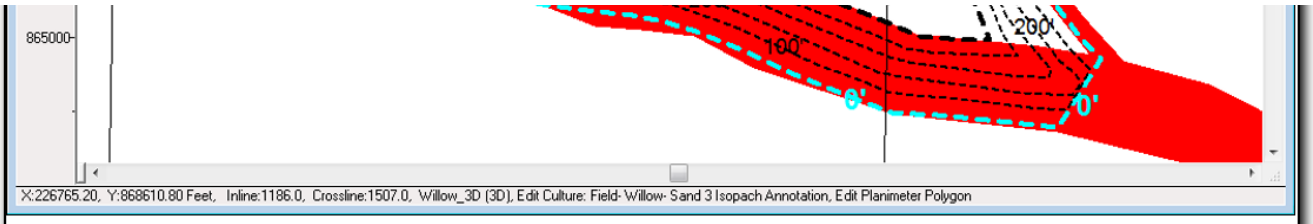
Structure Map (below Ground level datum of 2300' ASL): Top Sand 3
Proposed Injection Zone - Scale 1": 600'



DMS 9/2017

Isopach Map of Sands 3,4,5 –showing Faulting
100' Contour Interval – Scale 1":600'





DMS 9/2017

Reply Reply All Forward IM

Wed 9/20/2017 12:07 PM

David M. Smith

RE: Geologic support for proposed injection well DJS #2-14

To Dale R. Hayes; Mofazzal Bhuiyan; Michael Christian

Cc Mike H. McMennamy

Conversation Filer TeamViewer + Get more add

I can have Karl Planimeter a hard copy to calculate gross volumes using different methods.

Areas are:

0' contour – 269 acres
100' - 234 ac.
200' – 205 ac.
300' – 173 ac.
400' – 144 ac.
500' – 113 ac.

The volume should be the same as **500' x 188 acres = 94,000 ac. ft.**

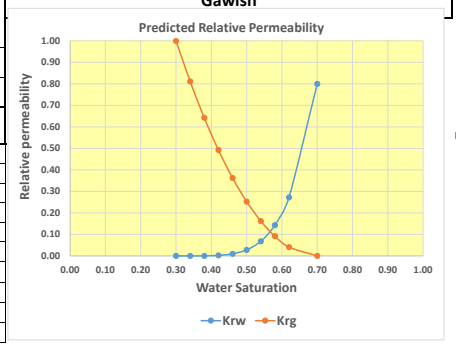
Regards,
Dave

A Modified Method for Predicting Relative Permeability

BY: Mohamed Ameen, Mahmoud Tantawy and Ahmed Gawish

1 Input Data	Swc	0.3	Lithology		
	Sgc	0.3	Sandstone		
	Krw @ Sgc	0.8			
	Krg @ Swc	1			
2 Numerical Regression	T-Factor	Sw	Krw	Krg	Krw + Krg
	0.63	0.455	0.236	0.670	0.9056
	Before Adjusting	nw	ng	Adjusting Factors	
		1.29	0.82		
	After Adjusting	nw	ng	A	B
		4.82	1.98	3.74	2.43

3 Predicted Relative Permeability data	No	Sw	Krw	Krg
	1	0.3000	0.0000	1.0000
	2	0.3400	0.0000	0.8114
	3	0.3800	0.0003	0.6423
	4	0.4200	0.0024	0.4928
	5	0.4600	0.0096	0.3629
	6	0.5000	0.0282	0.2528
	7	0.5400	0.0681	0.1623
	8	0.5800	0.1432	0.0917
	9	0.6200	0.2726	0.0410
	10	0.7000	0.8000	0.0000



$$Fw = 1 / [\ 1 + (Krg^* \mu go) / (Krw^* \mu w)\ ]$$

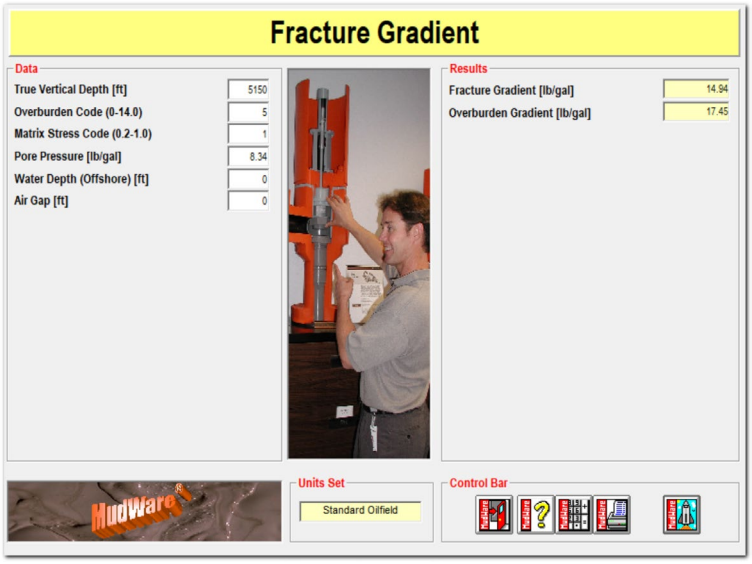
Fw

Fault Slip Potential:

Scale: 47.5 mm = 3000 feet

	X	Y	X	Y	x	x	x	/	/	dy	dx	dy/dx	Radians	Degrees
	mm	mm	km	km	mm	ft/mm	in/ft	cm/in	cm/m	m/km	1	1	1	0.785398	45
Well Location:	41.5	33.5	0.798897	0.644893	33.5	63.15789	12	2.54	100	1000					
					mm	ft	in	cm	m						
						2115.789	25389.47	64489.26	644.8926	0.644893					

	Beginning X	Beginning Y	End X	End Y	Beginning X	Beginning Y	End X	End Y	dy	dx	dy/dx	Radians	Degrees	Mid Point of Fault			Length of Fault
	mm	mm	mm	mm													
Fault 1	8	47.9	46.75	22.9	0.154004	0.9221	0.899962	0.440837	-0.48126	0.745958	-0.64516	-0.57297	-32.8285	122.8285	0.526983	0.681469	0.887732
Fault 2	46.75	22.9	108.5	7.5	0.899962	0.440837	2.088682	0.144379	-0.29646	1.18872	-0.24939	-0.24441	-14.0035	104.0035	1.494322	0.292608	1.22513
Fault 3	108.75	7.5	82.25	49.25	2.093495	0.144379	1.583356	0.948088	0.803709	-0.51014	-1.57547	-1.00523	-57.5955	147.5955	1.838425	0.546234	0.95194
Fault 4	82.25	49.25	8	47.9	1.583356	0.948088	0.154004	0.9221	-0.02599	-1.42935	0.018182	0.01818	1.041627	88.95837	0.86868	0.935094	1.429588



Used Mudware and Miocene - Oligocene OB and MS codes 5 and 1

14.94 0.052 0.77688