Reservoir Simulation Studies in Smoky Creek field, Cheyenne County, Colorado

Kansas Geological Survey
Open File Report – 2007-31

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Smoky Creek Field – Engineering Studies

Summary

A primary reason for this study was to understand the significant variation in well productivity in Smoky Creek field where most wells are drilled on 40-acre spacing. Based on standard log analysis and 40-acre drainage, some wells show more than 100 percent recovery.

Attribute analysis of 3D seismic data reveal presence of possible compartments of various sizes in the reservoir. One of the larger compartments, containing two productive wells, was characterized and simulated to determine if such a drainage volume could support the historic production and pressure performance of the constituent wells. Initial results show reasonable history matches of both production and pressure for these two wells. Lacking core data from Smoky Creek, permeability was estimated by reconciling log-derived water saturation and generalized capillary pressure formulation for Mississipian rocks. However, a permeability multiplier of 3 was required to obtain the history matches at the modeled wells.

Introduction

Smoky Creek field is located in Cheyenne County, Colorado. Figure 1 is a structure map of the Spergen showing the general lay out of the field including well locations. Most of the wells in the middle to southern half of the field are drilled on 40-acre spacing. Initial drilling commenced in the early 1970s with majority of the wells drilled in early 1990s. One of the major reasons for this work is to explain why adjacent wells show significant variation in oil production. 3D seismic data shot over part of the field were made available for this study, and attribute analysis (detailed in previous sections) on this data revealed existence of possible compartments (Figure 2) of varying sizes. Incidentally, barring one compartment, which houses Crosby 1 and Crosby 2 wells, a single well produces from each of the other compartments. The intent of this simulation study was to test whether varying drainage areas, as a result of compartmentalization, contributed to significant production variation between the wells in Smoky Creek field.

Reservoir Pressure, Temperature, API

The initial reservoir pressure was estimated from DSTs run in the wells. Figures 3A and 3B plot the final shut-in pressures (FSPs) and initial shut-in pressures (ISPs) recorded in DSTs in wells from Smoky Creek field and the Cheyenne field located immediately south of the study area. The plotted DST pressures were recorded over different intervals, namely Spergen A, B, and C or any combination of the above. These two plots show a remarkable consistency in pressure in the 3 zones for all the wells, and that the reservoir has undergone minimal pressure decline between 1973 and 1993, indicating the presence of a strong water drive. The initial reservoir pressure was estimated to be 1100 psi. Well records indicate that measured reservoir temperature varied between 115 to 160F, and that oil API varied between 38 to 41 degrees.

Log Analysis

A suite of modern wireline logs was available from all the wells drilled during the 1990s. Logs from each well were analyzed with Pfeffer software developed by the Kansas Geological Survey using m = n = 2.0 and R_w = 0.08 ohm-m. Cut-off parameters (porosity = 8%, water saturation = 52%, Vshale = 0.45, and BVW = 0.049) that discriminated between dry and productive wells from the Smoky Creek field were used to delineate effective pay in each well. No cores were available from the Smoky Creek field, and thus, lacking additional petrophysical data, the same cutoffs were applied to Spergen A, B, and C zones. Table 1 lists the thickness, porosity, and S_w of effective pay in Spergen A, B, and C.

Free-Water Level (FWL)

Compilation of the DST recovery descriptions (Table 2) revealed lack of water production when intervals above -1179 feet (subsea) were tested. Thus, the FWL was initially estimated to be around -1180 feet (subsea). The validity of this FWL assumption was tested by plotting log-derived water saturation (S_w) and R_{wa} (apparent resistivity) against depth (Figures 4A and 4B). As expected, the S_w values hovered between 0.8 and 1.0 and the R_{wa} values stabilized to a narrow band below the estimated FWL of -1180 feet (subsea).

Permeability Estimation

Measured rock permeability data are unavailable for the Smoky Creek field, and core data from nearby Cheyenne field exhibited permeability values and permeability-porosity trends that are not consistent with well production histories in the Smoky Creek field. Permeability for effective pay intervals was estimated from published permeability-porosity trends for Mississippian rocks in Kansas. However, there is no assurance that these trends are appropriate for the field nor is there lithologic information necessary to know which of several lithologically-specific permeability-porosity relationships to use. To predict permeability the wireline-log calculated S_w and assumed capillary pressure (P_c) relations that relate S_w and permeability were utilized. Using generalized capillary pressure curves for Mississippian rocks, Byrnes and Bhattacharya (2006) have shown that

S_w at any given height above FWL is related to capillary pressure using the following relation:

$$S_w = \left[\frac{[Bh(\rho_w - \rho_o]}{\frac{P_{ce}}{100^{Pcf}}} \right]^{1/Pcf}$$

where B is a proportionality constant (= 0.433 psi cc/ft g), *h* is the oil column height (ft), ρ_w and ρ_o are the water and oil specific gravity (g/cc), P_{ce} is the oil-water capillary threshold entry pressure (psi), P_{cf} is the dimensionless measure of pore size heterogeneity, and S_w is the water saturation at height, *h*. In this equation P_{ce} and P_{cf} have been empirically related to permeability (*k*) for Mississippian rocks using the following relationships:

$$P_{ce} = 2.30\ k^{-0.42}$$

$$P_{cf} = 0.168\ \ln(k) - 1.985$$

To predict permeability, S_w at each half-foot interval was calculated from wireline log response. In addition, from field data the elevation of the FWL was estimated at -1180 feet (subsea). The elevation above the FWL for each half-foot of the effective pay was calculated (*h*). Inserting the P_{ce} and P_{cf} equations into the S_w equation and solving for permeability it is possible to predict permeability given S_w and height above FWL (*h*).

Figure 5 crossplots calculated permeability versus log-calculated porosity. This permeability-porosity trend is consistent with trends exhibited by Mississippian rocks on the Central Kansas Uplift by packstone lithology (blue line), packstone-grainstone lithology rocks (red line), and packstone-wackestone lithology rocks (green line). In general, using this methodology permeability was predicted at half-foot within each well's effective pay interval in the Smoky Creek field. Predicted permeabilities for a well interval were generally within 50% of the mean permeability for the interval.

Production Performance

Table 1 lists the recovery efficiencies (REs) of wells from the Smoky Creek field assuming that each well drained 40 acres. Majority of the wells show a RE less than 50%. However, 3 wells show unrealistically high RE values confirming the concerns of the field operator, i.e., significant variation in productivity between nearby wells. Figure 6A shows plots of water-oil-ratios (WORs) versus time for wells from the Smoky Creek field with the Crosby 4 data scaled to the secondary (right) Y-axis. A closer look (Figure 6B) at Crosby 1 and Kern 1 data show that the WORs for these two wells almost overlap until 1993 after which the water production from Kern 1 well shows a steep and sudden increase. Well records show a pump change in 1994 at Kern 1, and the operator suspects higher water cuts as a result of the larger pump put in place. Figure 6C plots the WOR data for the other wells and it is apparent that Crosby 4 (scaled to secondary Y-axis) and Hiss 2 show high water cuts. Figure 6D compares WORs from Crosby 4 and Hiss 2, and it shows that the water cuts from these 2 wells traced each other until 2001, thereafter Crosby 4 showed a sudden and significant increase in water production to a level that proved uneconomic for operation of this well in September 2003. Again well records indicate a pump change in May 2001, and the operator suspects that installation of a larger pump resulted in significant increase in water production. The WOR plots indicate the following: a) continuous increase in WOR with time at all wells suggestive of a strong water drive, b) differences in WOR profiles between wells, and c) very high

WORs recorded at few wells are probably due to mechanical reasons such as installation of large pump units rather than due to reservoir driven causes.

Reservoir Simulation

Previously discussed attribute analyses of 3D data from Smoky Creek field reveal possible compartmentalization of the reservoir. Also, the REs at some of the wells are unrealistically high assuming 40-acre drainage areas. One explanation for uneven production from adjacent wells is varying sizes of drainage compartments. To test this hypothesis, one of the larger compartments, marked in green, was simulated. This compartment is the only compartment delineated in the Smoky Creek field that appears to house two wells, namely, Crosby 1 and Crosby 2. Figures 7A and 7B plot the oil and water production along with the WORs for these two wells.

Table 3 summarizes some of the important input parameters for the reservoir and the aquifer system used during simulation studies of the above mentioned compartment in the Smoky Creek field. Geologic studies, detailed earlier, reveal that the Spergen interval in Smoky Creek field comprises three layers, i.e., A, B, and C. Log analysis and perforation histories show that the primary production interval in this field is the Spergen A layer which is present in all the wells. Some of the wells show additional effective pay in Spergen B and/or C. Thus, the reservoir modeled in this study comprise 3 layers using 100 feet by 100 feet grid cells.

Based on the reconciliation of log-S_w and P_c, the permeability estimated in the Spergen effective pay varied between 20 to 40 md. However, permeability multipliers had to be used to bring the permeability in the range of 75 to 110 md in order to match the cumulative oil and water production at Crosby 1 and 2 wells (Figures 8 and 9). Four day static buildup tests were carried out at both these wells in 2001 revealing a reservoir pressure close to 1000 psi. Also, flowing bottom hole pressures (FBHPs) of 475 psi (as of Sep 2001) and 461 psi (as of Sep 2005) were recorded at Crosby 2 while that of 543 psi (as of May 2004) was measured at Crosby 1. Figure 10 shows that the simulator calculated average reservoir pressure was slightly less than 1000 psi while FBHPs at Crosby 1 and 2 hovered around 600 psi. Thus, when permeability values in the Spergen layers varied between 75 to 110 md, a reasonable history match was attained for Crosby 1 and 2 wells assuming that they produced from a single compartment as demarked in Figure 2.

Future Studies

The average porosity in the most productive parts of the effective pay is close to 12 percent, which results in an estimated permeability between 30 and 40 md (Figure 5). However, if the formation porosity was 2 (percent) units higher, say 14 percent, then the estimated permeability in the best parts of the effective pay would be between 60 to 80 md – a range close to that required to obtain performance history matches. Thus, one course of action for future studies would be to confirm if the wireline logs were underestimating the formation porosity in Smoky Creek field. Another obvious course of action will be to simulate all the compartments with wells (in Figure 2) to confirm if the compartments delineated from attribute analyses are realistic, and if such compartmentalization could explain the wide differences in productivity between the wells.

LIST OF TABLES

LIST OF FIGURES

		1st Prod		MBO	MBW										Pfeffer	
		Completion		Cum	Cum	Spr A -------------------			Spr B ---------------			Spr C ----------------			MBO	
UWI	**Well Name**	**DATE**	**Elev**	**Oil**	**Wtr**	**H, ft**	**Phi**	**Sw**	**H, ft**	**Phi**	**Sw**	**H, ft**	**Phi**	**Sw**	**HC Vol**	**RE, %**
15-017-06138	**Champlin Kern 1**	12/13/1973	4241	**1.9**	**363.4**											
15-017-06143	**Kern A1**	3/22/1974	4249	**333.5**	**381.6**											
		3/22/1974														
15-017-06133	**Crosby 1**	5/29/1973	4215	**255.2**	**1950.6**	2	0.11	0.36	2	0.12	0.39	2.5	0.12	0.4	**142.9**	**178.6**
05-017-06134	**Kern 1**	6/28/1973	4229	**74**	**1067.1**	5.5	0.122	0.38	1.5	0.131	0.338				**163.4**	**45.3**
15-017-07409	**Mull UPRC-HISS 2**	7/6/1994	4259	**80.9**	**1365.8**	8	0.11	0.36							**166.6**	48.6
15-017-07395	**Mull UPRC-HISS 1-X**	10/6/1993	4227	**228**	**938.2**	15.5	0.134	0.153	3	0.087	0.49				**561.5**	40.6
05-017-07392	**Crosby 4**	9/16/1993	4241	**64.2**	**1105.5**	8.5	0.117	0.393							**178.5**	36.0
05-017-07376	**Crosby 3**	8/4/1993	4209	**209**	**216.2**	9	0.133	0.278							**255.6**	**81.8**
05-017-07337	**Crosby 2**	12/8/1992	4257	**97.8**	**888.4**	13.5	0.122	0.236	9	0.109	0.35	6	0.092	0.486	**658.1**	14.9
05-017-07293	**Kern A4**	2/26/1992	4258	**85.8**	**99.9**	9.5	0.087	0.305							**169.9**	**50.5**
05-017-07292	**Kern 3**	3/27/1992	4193	**101.2**	**272.3**	7	0.096	0.364	8	0.131	0.288				**358.1**	28.3
05-017-07239	**Kern 2**	9/25/1991	4223	**173.6**	**282.4**	2.5	0.096	0.416	7	0.152	0.274				**281.3**	**61.7**

Table 1

		Completion	KB	DST 1	DST 1	Subsea	Subsea	Rec	DST 2	DST 2	Subsea	Subsea	
UWI	Well Name	DATE	Elev	From	To	From	To		From	To	From	To	Rec
15-017-06138	Champlin Kern 1	12/13/1973	4251	5404	5443	-1153	-1192	CO, SMO, FCO, MO, OCRM, OCM, MW					
15-017-06143	Kern A1	3/22/1974	4259	5366	5409	-1107	-1150	SOCM	5405	5440	-1146	-1181	M
		3/22/1974											
15-017-06133	Crosby 1	5/29/1973	4225	5357	5387	-1132	-1162	G, CGO, SMO	5387	5411	-1162	-1186	G, CGO, GOM
		5/29/1973											
05-017-06134	Kern 1	6/28/1973	4239	5347	5390	-1108	-1151	CGO, MGO					
15-017-07409	Mull UPRC-HISS 2	7/6/1994	4271	5404	5450	-1133	-1179	GIP, GMCO, GOCM, OCM					
15-017-07395	Mull UPRC-HISS 1-X	10/6/1993	4239	5345	5415	-1106	-1176	MCO, MCGO, GOCM					
05-017-07392	Crosby 4	9/16/1993	4253	5387	5432	-1134	-1179	GO, SMCGO, HGOCM					
05-017-07376	Crosby 3	8/4/1993	4221	5330	5395	-1109	-1174	GIP, CGO, MCGO, SMCGO, VSOCM					
05-017-07337	Crosby 2	12/8/1992	4269	5385	5450	-1116	-1181	DM, WM, MWWTO					
05-017-07293	Kern A4	2/26/1992	4270	5360	5430	-1090	-1160	CO, HOCM, GOCM, GMCO					
05-017-07292	Kern 3	3/27/1992	4205	5306	5373	-1101	-1168	MCO					
05-017-07239	Kern 2	9/25/1991	4235	5340	5410	-1105	-1175	GIP, CGO, HGCMO					

No wtr prod when test interval stops at	-1179	subsea
Wtr prod when test interval extends to atleast	-1181	subsea
Estimated OWC	-1180	subsea

Table 2

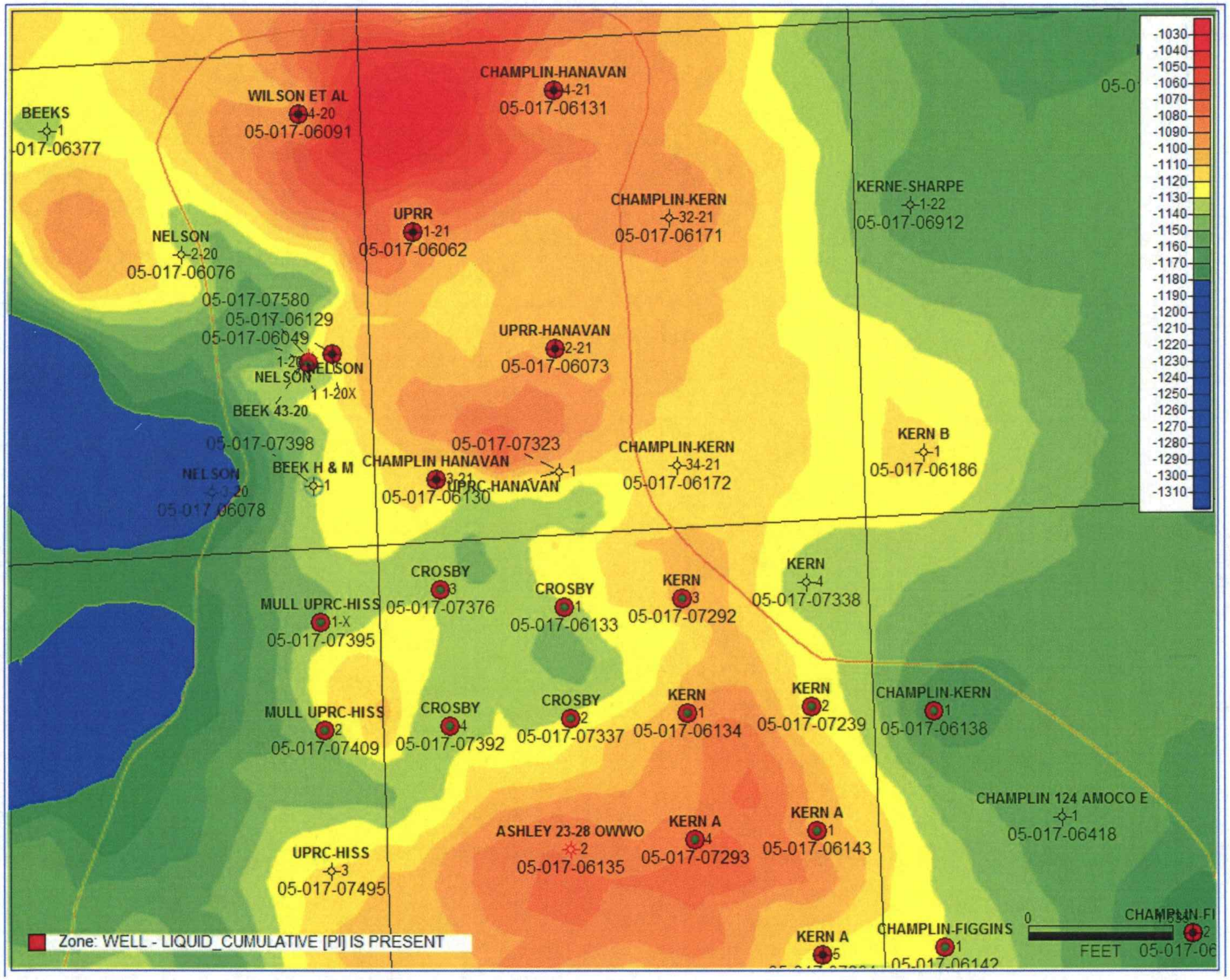
Reservoir Properties

Rock compressibility	2.00E-06	1/psi	
Ref pressure for rock compressibility	1200	psi	
Reservoir Temperature	135	F	
Oil gravity	40	API	
Water salinity	28,000	ppm	(estimated from Rw = 0.08 ohm-m)

Aquifer definition

Thickness	50
Porosity	0.1
Permeability	100

Table 3



BEEKS
1
017-06377
WILSON ET AL
4-20
05-017-06091
CHAMPLIN-HANAVAN
4-21
05-017-06131
NELSON
2-20
05-017-06076
UPRR
1-21
05-017-06062
CHAMPLIN-KERN
32-21
05-017-06171
KERNE-SHARPE
1-22
05-017-06912
05-017-07580
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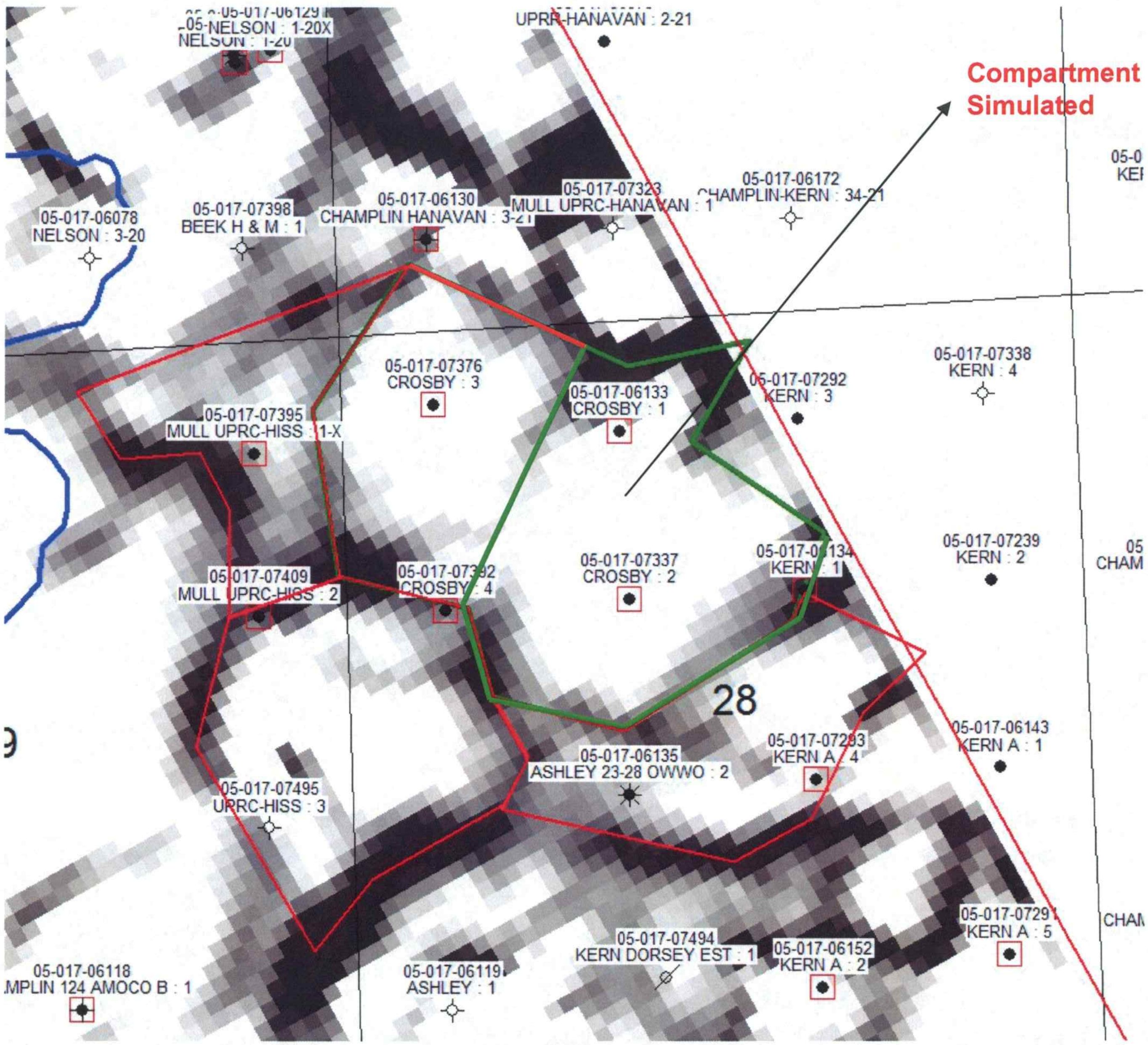
05-017-06049
NELSON
NELSON
1 1-20X
BEEK 43-20
UPRR-HANAVAN
2-21
05-017-06073
05-017-07398
NELSON
05-017-06078
BEEK H & M
1
CHAMPLIN HANAVAN
05-017-06130
05-017-07323
UPRC HANAVAN
CHAMPLIN-KERN
34-21
05-017-06172
KERN B
1
05-017-06186
CROSBY
3
05-017-07376
MULL UPRC-HISS
1-X
05-017-07395
CROSBY
1
05-017-06133
KERN
3
05-017-07292
KERN
4
05-017-07338
MULL UPRC-HISS
2
05-017-07409
CROSBY
4
05-017-07392
CROSBY
2
05-017-07337
KERN
1
05-017-06134
KERN
2
05-017-07239
CHAMPLIN-KERN
1
05-017-06138
CHAMPLIN 124 AMOCO E
1
05-017-06418
ASHLEY 23-28 OWWO
2
05-017-06135
KERN A
4
05-017-07293
KERN A
1
05-017-06143
UPRC-HISS
3
05-017-07495
KERN A
5
CHAMPLIN-FIGGINS
1
FEET
Zone: WELL - LIQUID_CUMULATIVE [PI] IS PRESENT
-1030
-1040
-1050
-1060
-1070
-1080
-1090
-1100
-1110
-1120
-1130
-1140
-1150
-1160
-1170
-1180
-1190
-1200
-1210
-1220
-1230
-1240
-1250
-1260
-1270
-1280
-1290
-1300
-1310

Figure 1



Compartment Simulated
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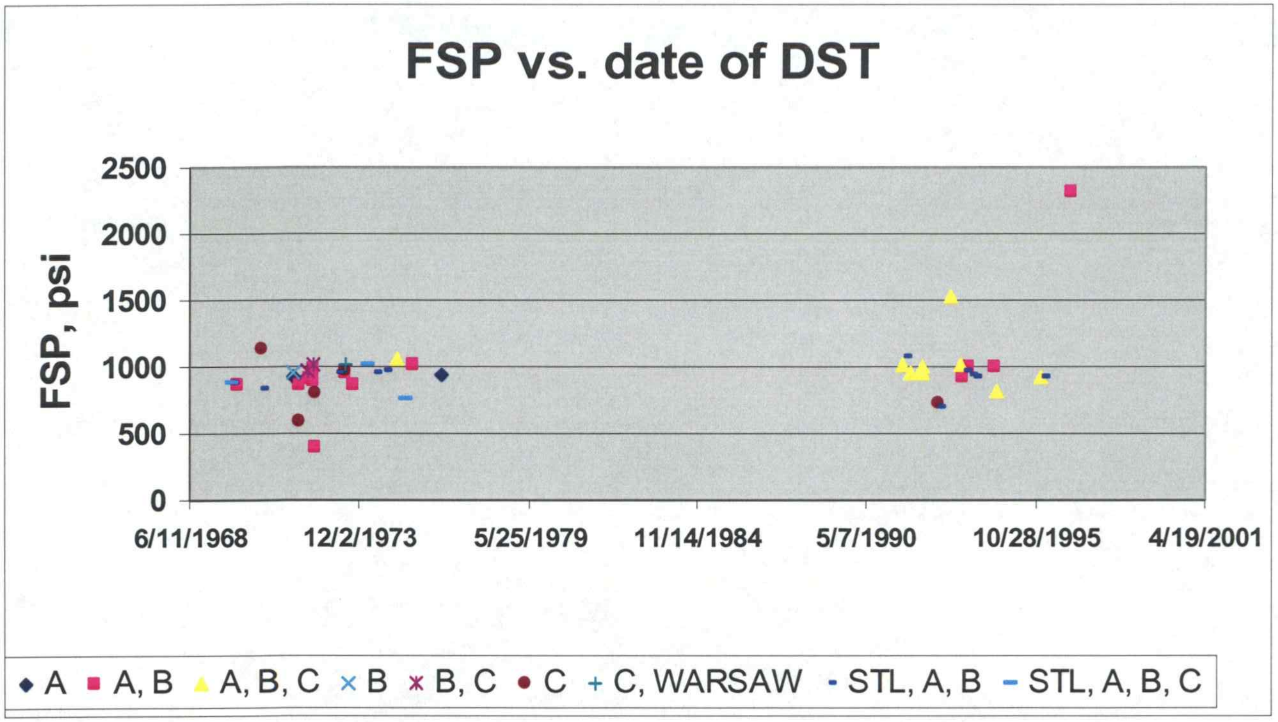
NELSON : 1-20X
NELSON : 1-20
05-017-06078
NELSON : 3-20
05-017-07398
BEEK H & M : 1
05-017-06130
CHAMPLIN HANAVAN : 3-21
05-017-07323
MULL UPRC-HANAVAN : 1
05-017-06172
CHAMPLIN-KERN : 34-21
05-017-07376
CROSBY : 3
05-017-06133
CROSBY : 1
05-017-07292
KERN : 3
05-017-07338
KERN : 4
05-017-07395
MULL UPRC-HISS : 1-X
05-017-07409
MULL UPRC-HISS : 2
05-017-07392
CROSBY : 4
05-017-07337
CROSBY : 2
KERN : 1
05-017-07239
KERN : 2
28
05-017-06143
KERN A : 1
05-017-06135
ASHLEY 23-28 OWWO : 2
KERN A : 4
05-017-07495
UPRC-HISS : 3
05-017-07494
KERN DORSEY EST : 1
05-017-06152
KERN A : 2
KERN A : 5
05-017-06118
05-017-06119
ASHLEY : 1

Figure 2


FSP vs. date of DST
FSP, psi
2500
2000
1500
1000
500
0
6/11/1968
12/2/1973
5/25/1979
11/14/1984
5/7/1990
10/28/1995
4/19/2001
A
A, B
A, B, C
B
B, C
C
C, WARSAW
STL, A, B
STL, A, B, C

A.

B.

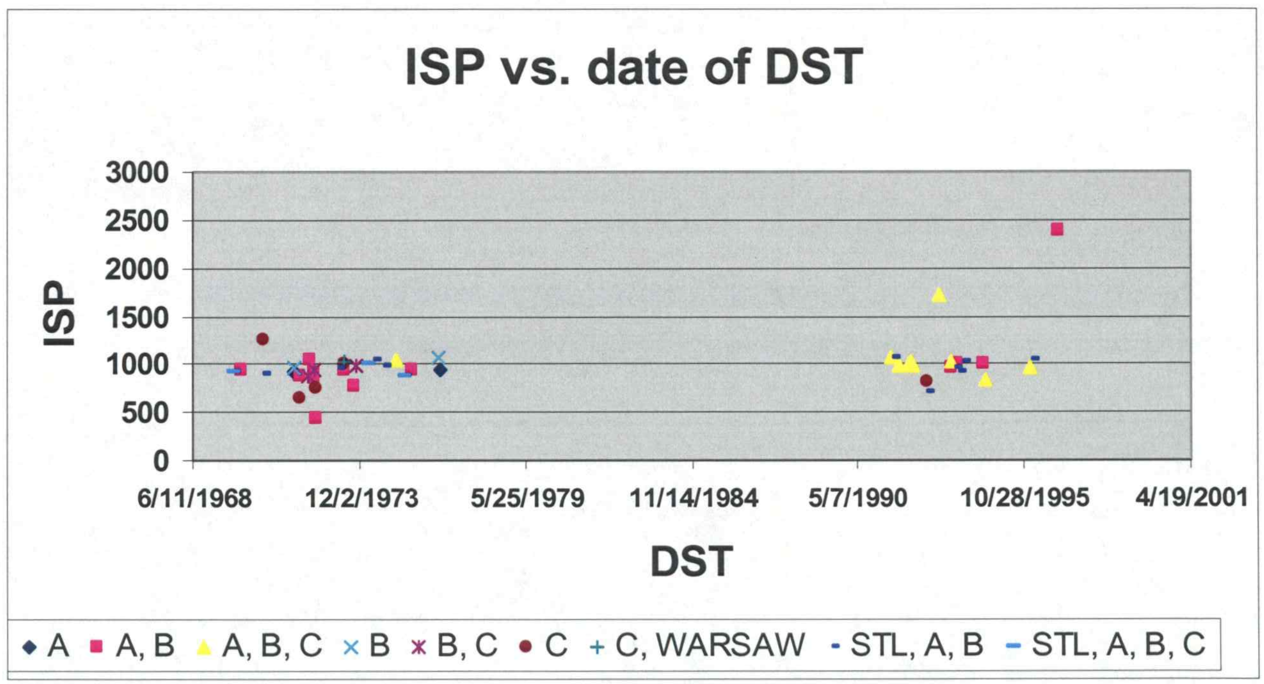
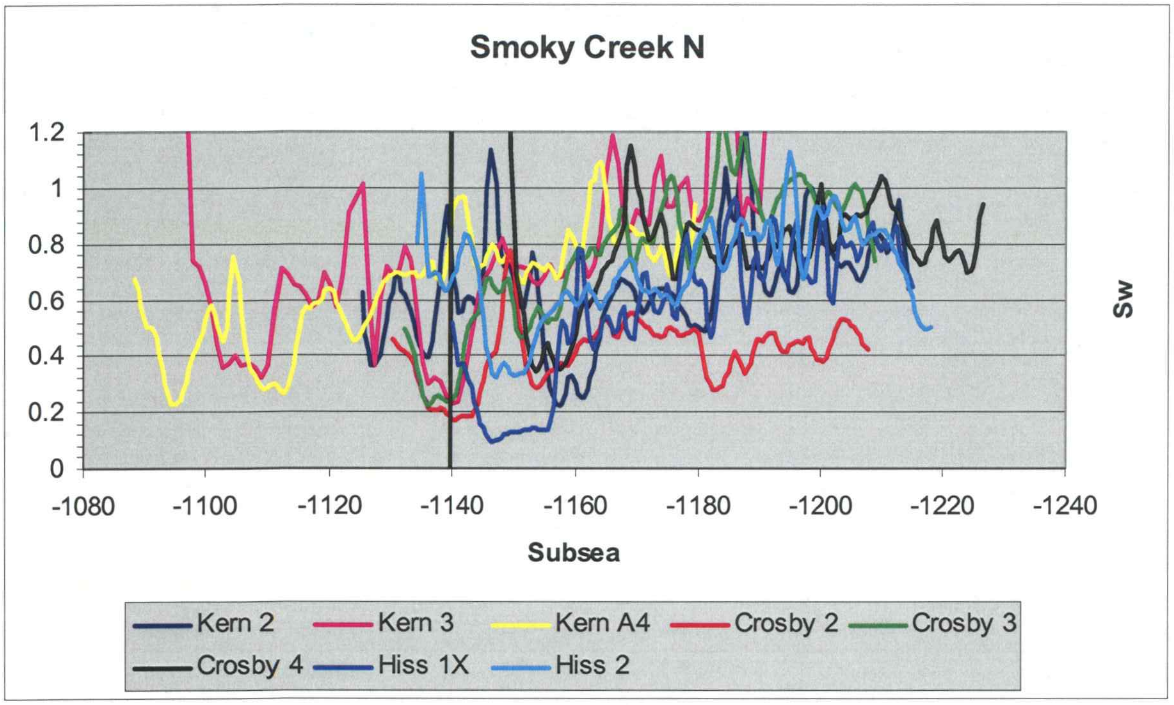

ISP vs. date of DST
ISP
3000
2500
2000
1500
1000
500
0
6/11/1968
12/2/1973
5/25/1979
11/14/1984
5/7/1990
10/28/1995
4/19/2001
DST
A
A, B
A, B, C
B
B, C
C
C, WARSAW
STL, A, B
STL, A, B, C

Figure 3


Smoky Creek N
1.2
1
0.8
0.6
0.4
0.2
0
-1080
-1100
-1120
-1140
-1160
-1180
-1200
-1220
-1240
Subsea
Sw
Kern 2
Kern 3
Kern A4
Crosby 2
Crosby 3
Crosby 4
Hiss 1X
Hiss 2

A.

B.

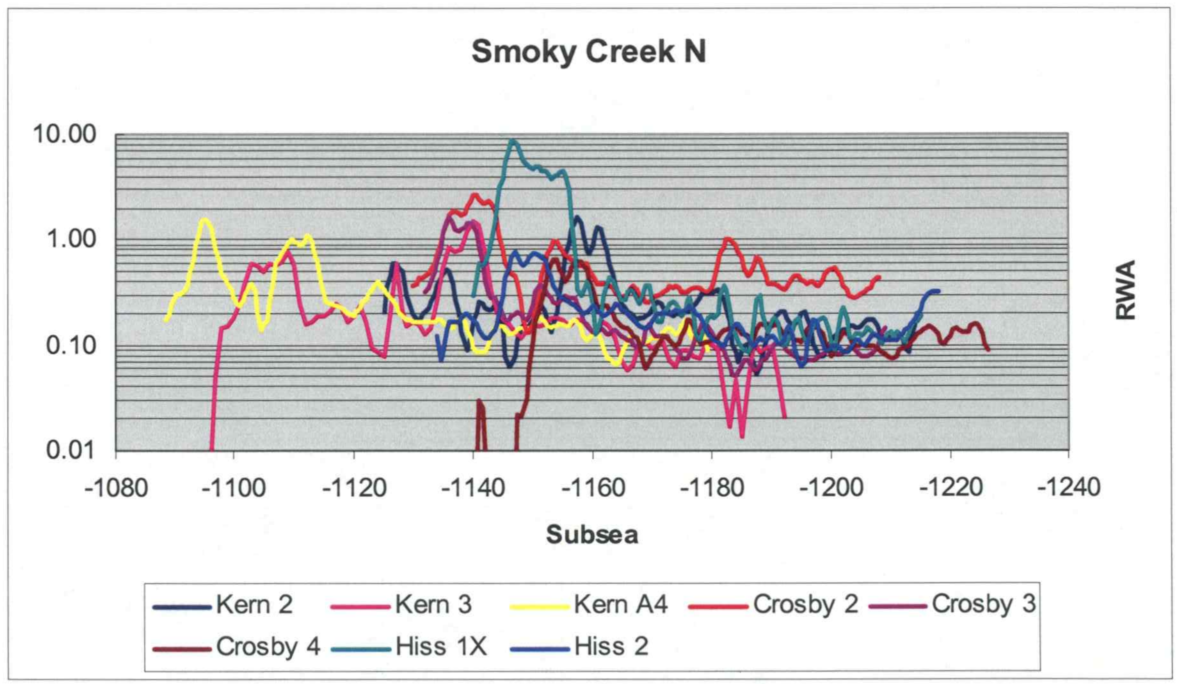

Smoky Creek N
10.00
1.00
0.10
0.01
-1080
-1100
-1120
-1140
-1160
-1180
-1200
-1220
-1240
Subsea
RWA
Kern 2
Kern 3
Kern A4
Crosby 2
Crosby 3
Crosby 4
Hiss 1X
Hiss 2

Figure 4

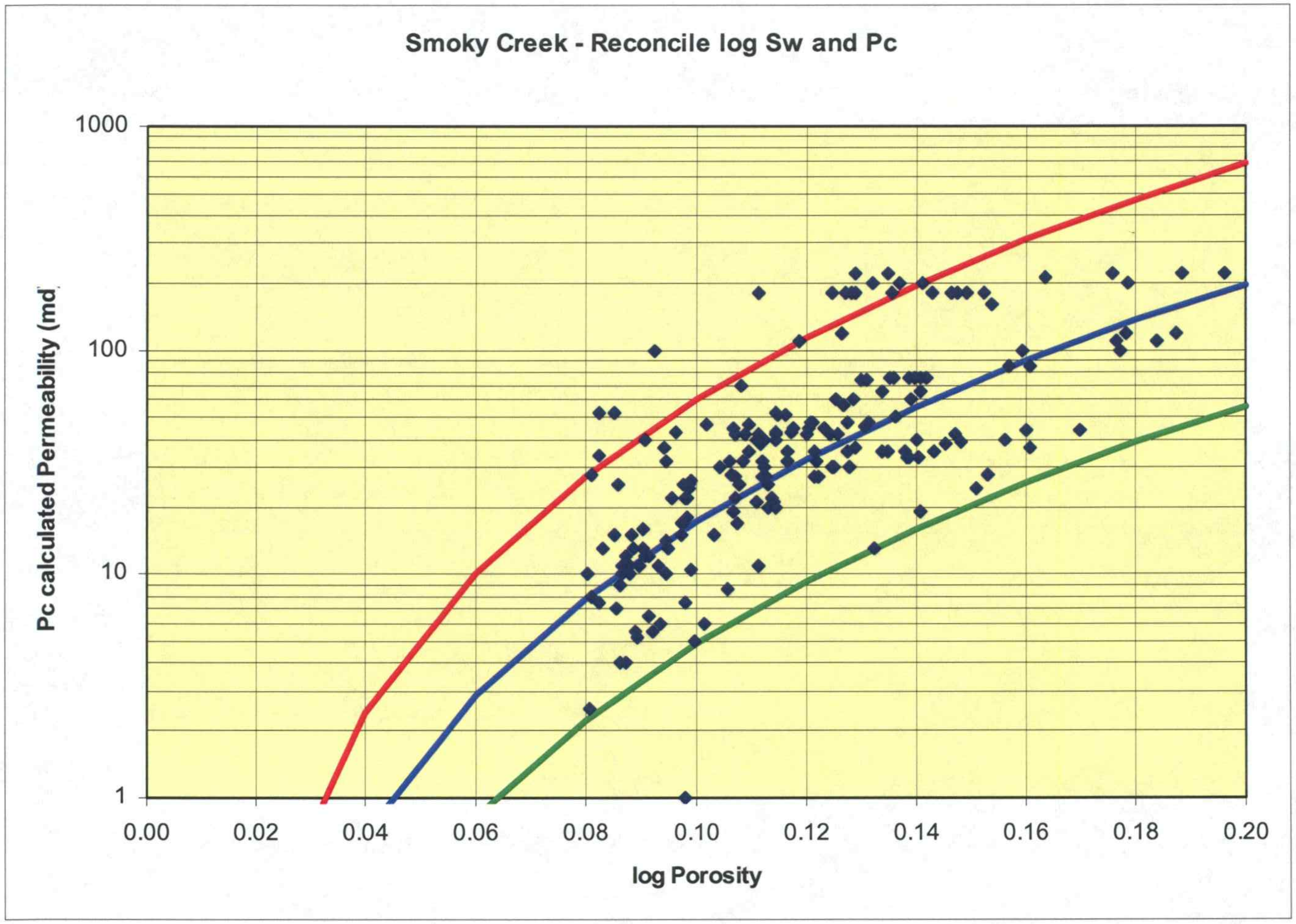
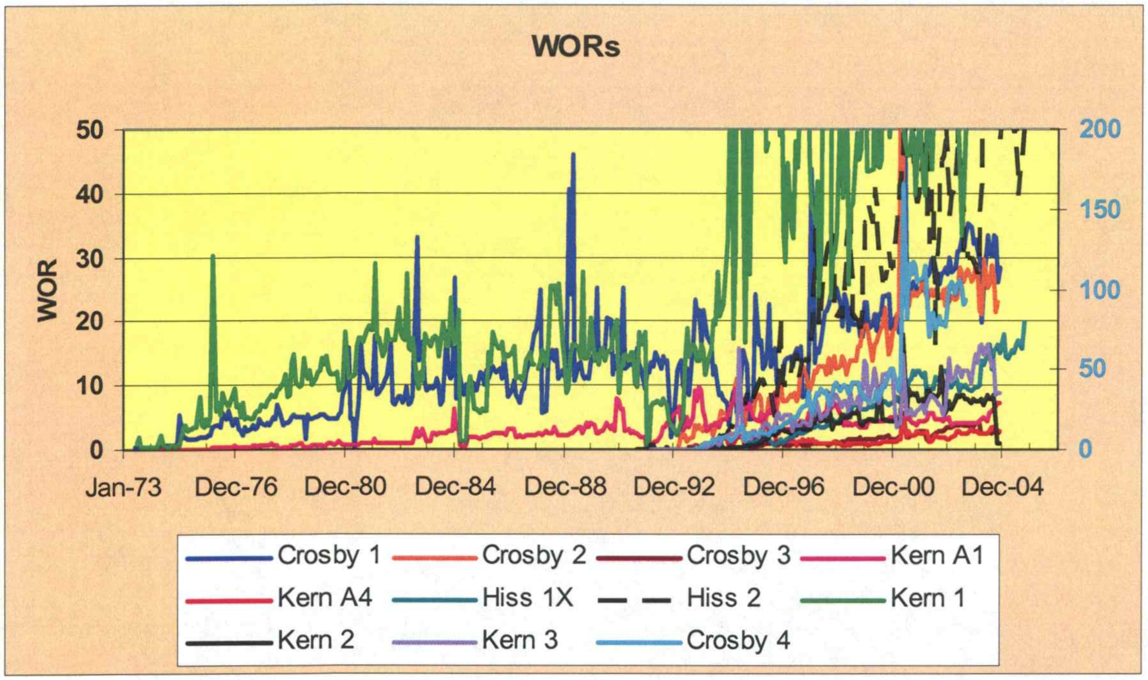

Smoky Creek - Reconcile log Sw and Pc
Pc calculated Permeability (md
1000
100
10
1
0.00
0.02
0.04
0.06
0.08
0.10
0.12
0.14
0.16
0.18
0.20
log Porosity

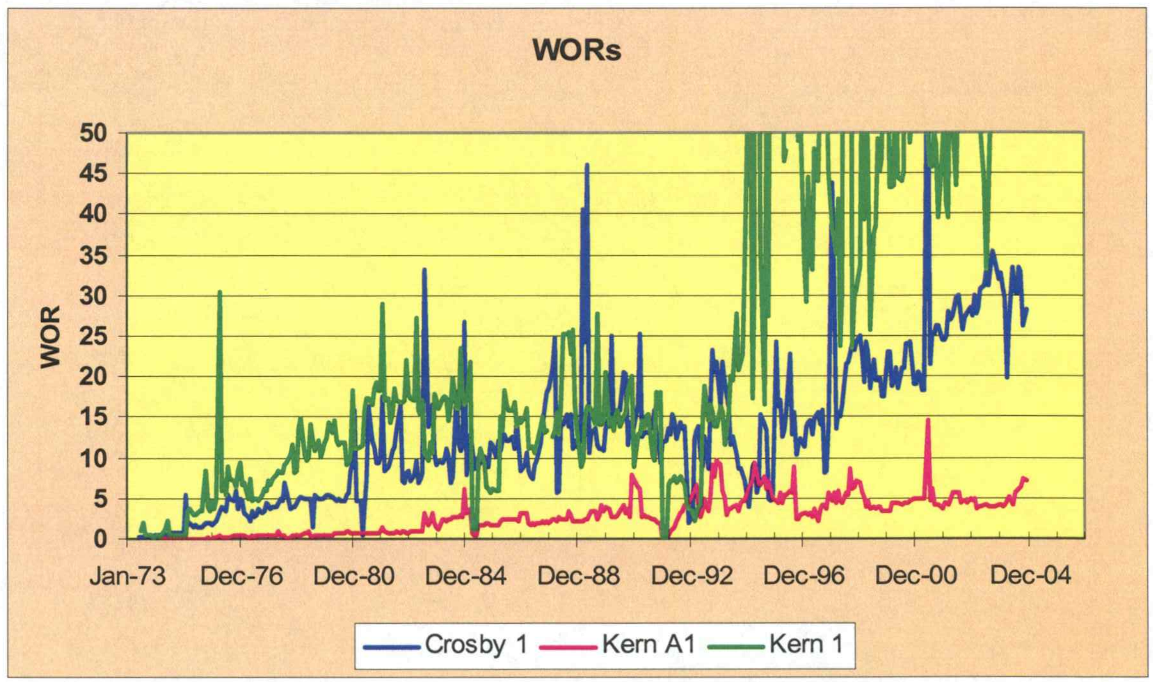
Figure 5



WORs
WOR
50
40
30
20
10
0
200
150
100
50
0
Jan-73
Dec-76
Dec-80
Dec-84
Dec-88
Dec-92
Dec-96
Dec-00
Dec-04
Crosby 1
Crosby 2
Crosby 3
Kern A1
Kern A4
Hiss 1X
Hiss 2
Kern 1
Kern 2
Kern 3
Crosby 4

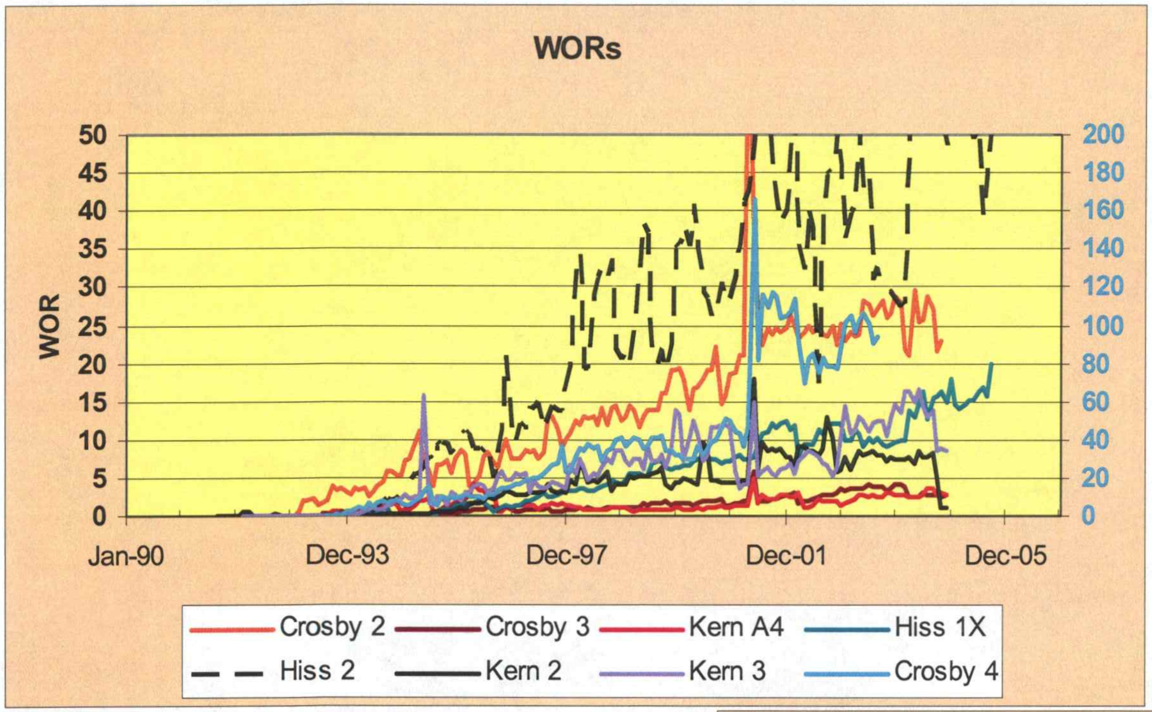
A.

B.



WORs
WOR
50
45
40
35
30
25
20
15
10
5
0
Jan-73
Dec-76
Dec-80
Dec-84
Dec-88
Dec-92
Dec-96
Dec-00
Dec-04
Crosby 1
Kern A1
Kern 1

Figure 6


WORs
WOR
50
45
40
35
30
25
20
15
10
5
0
200
180
160
140
120
100
80
60
40
20
0
Jan-90
Dec-93
Dec-97
Dec-01
Dec-05
Crosby 2
Crosby 3
Kern A4
Hiss 1X
Hiss 2
Kern 2
Kern 3
Crosby 4

C.

D.

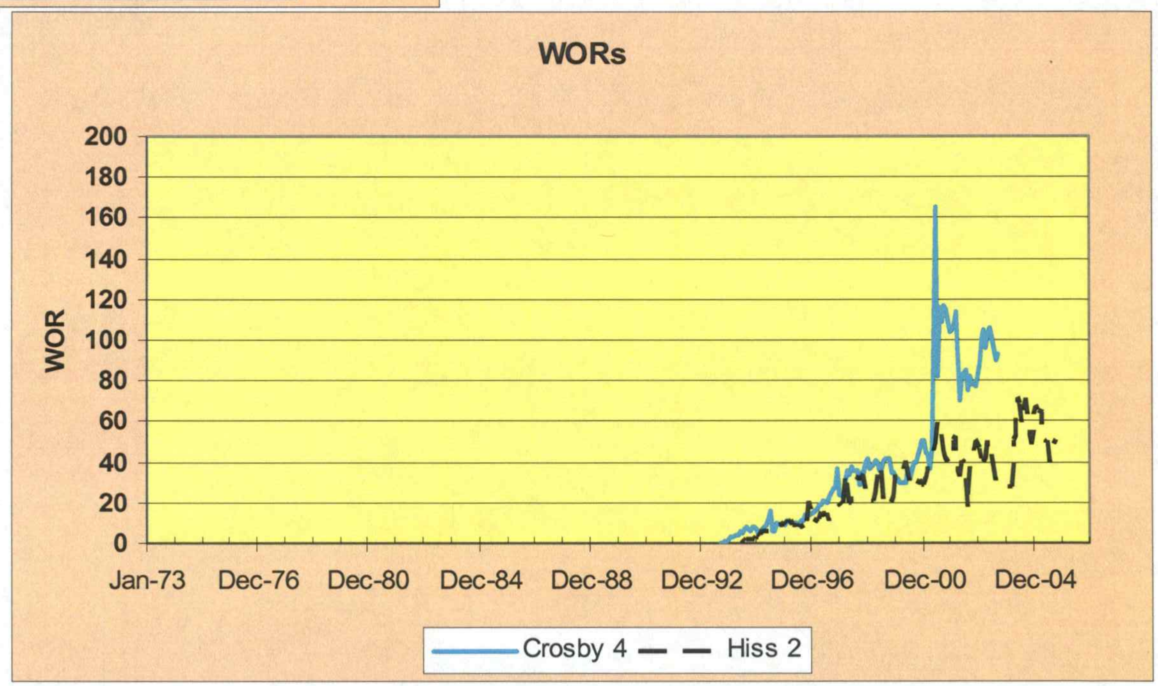
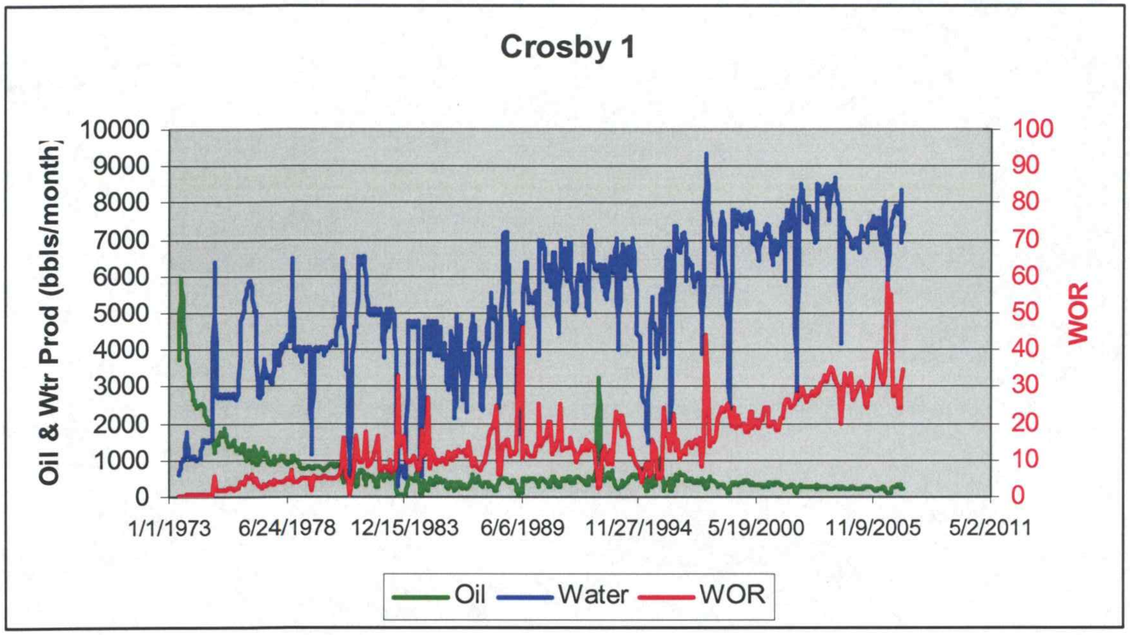

WORs
WOR
200
180
160
140
120
100
80
60
40
20
0
Jan-73
Dec-76
Dec-80
Dec-84
Dec-88
Dec-92
Dec-96
Dec-00
Dec-04
Crosby 4
Hiss 2

Figure 6


Crosby 1
Oil & Wtr Prod (bbls/month)
WOR
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
100
90
80
70
60
50
40
30
20
10
0
1/1/1973
6/24/1978
12/15/1983
6/6/1989
11/27/1994
5/19/2000
11/9/2005
5/2/2011
Oil
Water
WOR

A.

B.

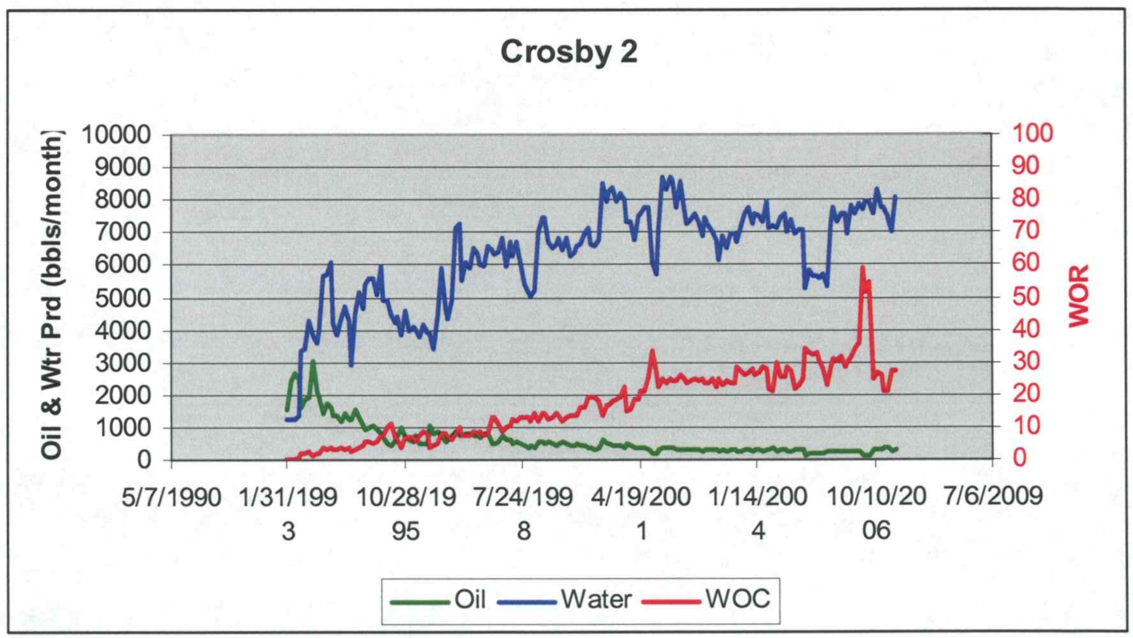
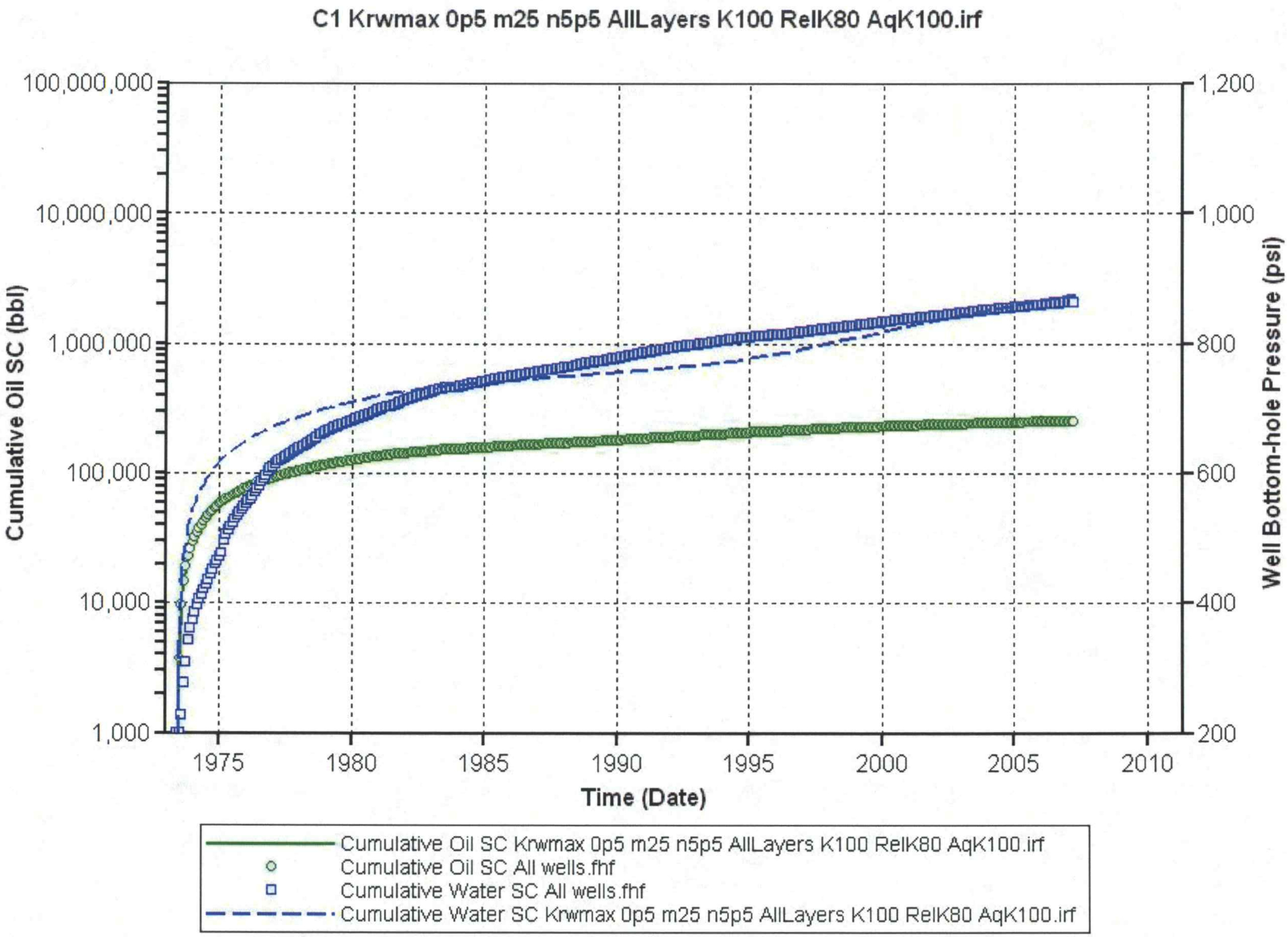

Crosby 2
Oil & Wtr Prd (bbls/month)
WOR
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
100
90
80
70
60
50
40
30
20
10
0
5/7/1990
1/31/1993
10/28/1995
7/24/1998
4/19/2001
1/14/2004
10/10/2006
7/6/2009
Oil
Water
WOC

Figure 7



C1 Krwmax 0p5 m25 n5p5 AllLayers K100 RelK80 AqK100.irf
100,000,000
10,000,000
1,000,000
100,000
10,000
1,000
Cumulative Oil SC (bbl)
1,200
1,000
800
600
400
200
Well Bottom-hole Pressure (psi)
1975
1980
1985
1990
1995
2000
2005
2010
Time (Date)
Cumulative Oil SC Krwmax 0p5 m25 n5p5 AllLayers K100 RelK80 AqK100.irf
Cumulative Oil SC All wells.fhf
Cumulative Water SC All wells.fhf
Cumulative Water SC Krwmax 0p5 m25 n5p5 AllLayers K100 RelK80 AqK100.irf

Figure 8

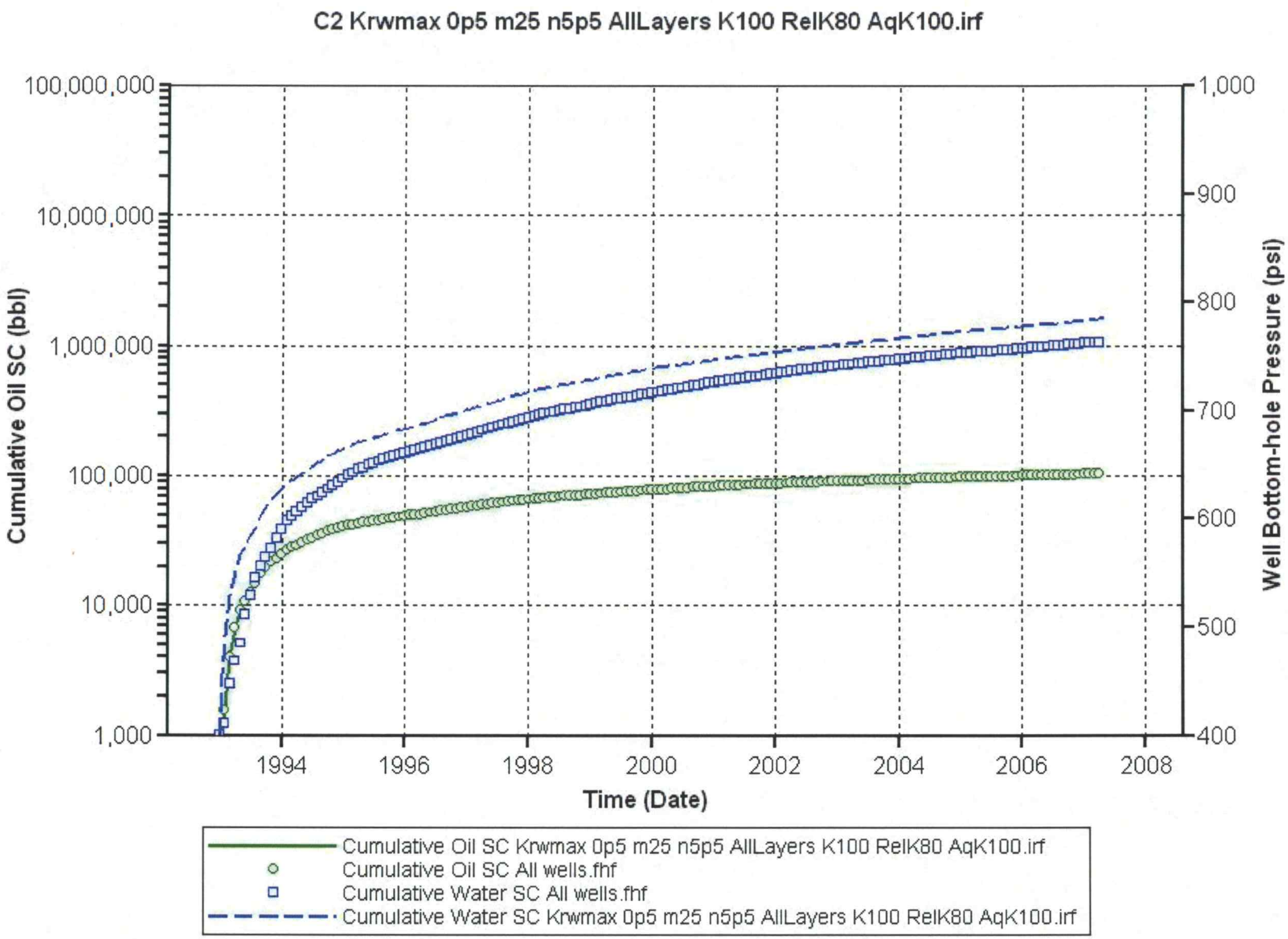

C2 Krwmax 0p5 m25 n5p5 AllLayers K100 RelK80 AqK100.irf
100,000,000
10,000,000
1,000,000
100,000
10,000
1,000
Cumulative Oil SC (bbl)
1,000
900
800
700
600
500
400
Well Bottom-hole Pressure (psi)
1994
1996
1998
2000
2002
2004
2006
2008
Time (Date)
Cumulative Oil SC Krwmax 0p5 m25 n5p5 AllLayers K100 RelK80 AqK100.irf
Cumulative Oil SC All wells.fhf
Cumulative Water SC All wells.fhf
Cumulative Water SC Krwmax 0p5 m25 n5p5 AllLayers K100 RelK80 AqK100.irf

Figure 9

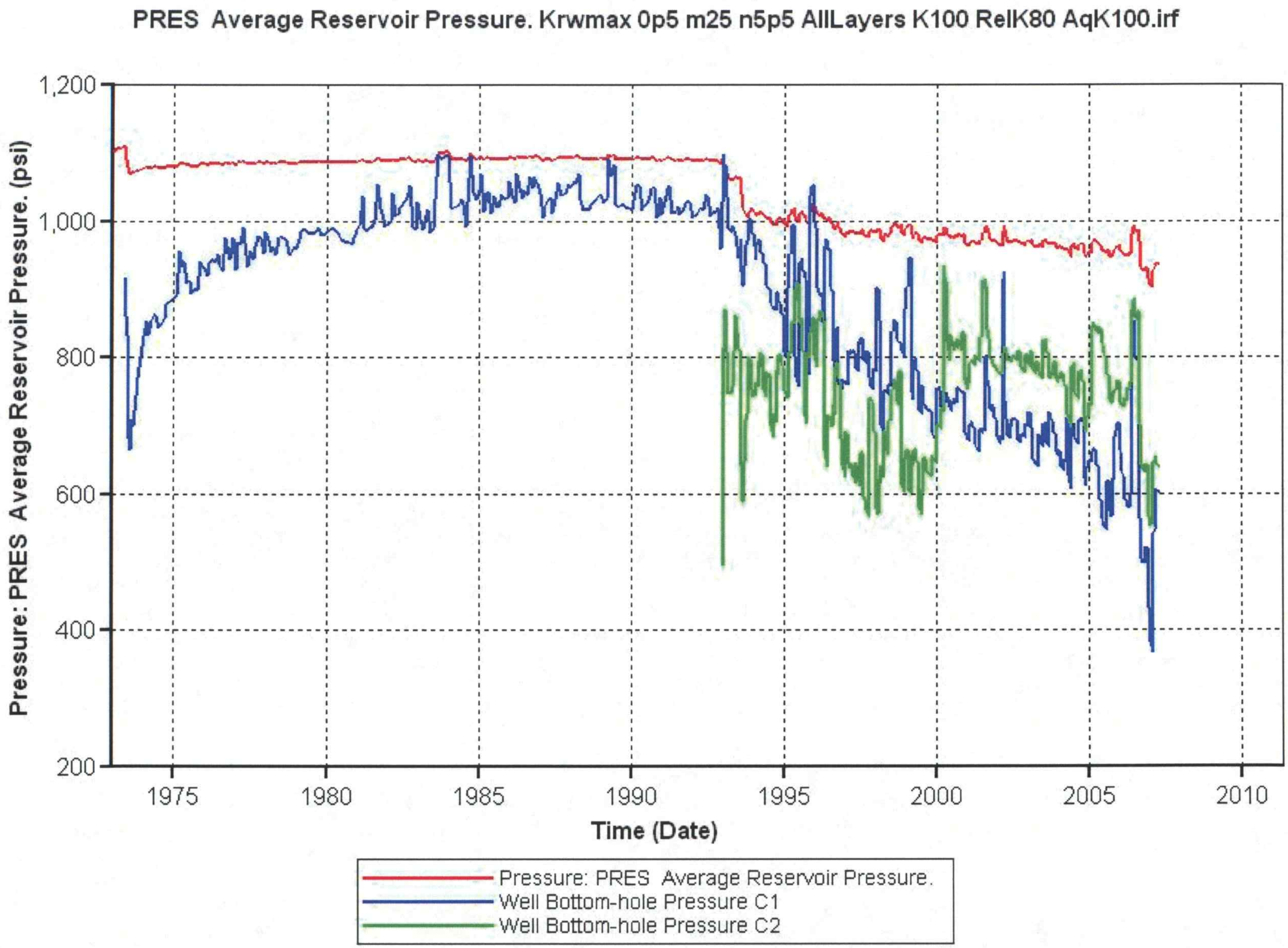

PRES Average Reservoir Pressure. Krwmax 0p5 m25 n5p5 AllLayers K100 RelK80 AqK100.irf
Pressure: PRES Average Reservoir Pressure. (psi)
1,200
1,000
800
600
400
200
1975
1980
1985
1990
1995
2000
2005
2010
Time (Date)
Pressure: PRES Average Reservoir Pressure.
Well Bottom-hole Pressure C1
Well Bottom-hole Pressure C2

Figure 10