KANSAS GEOLOGICAL SURVEY
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RESERVOIR CHARACTERIZATION AND SIMULATION – MCDONALD FIELD, NESS COUNTY, KANSAS

by

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Introduction

An integrated reservoir characterization study was carried out on McDonald field, Ness County, Kansas, to build a 3D-geomodel, which served as the basis for reservoir simulation. McDonald produces from a Mississippian carbonate reservoir with production commencing in February 1977. Simulation studies were initially carried out to history-match well-level fluid production. Upon completion of history matching, a map of remaining reserves was generated for the field. Thereafter, the remaining reserves map was used to spot different targeted horizontal infill trajectories. Simulation studies were carried out to evaluate the production potential of each of these infill horizontal wells. For a comparative evaluation of productivity, a vertical infill well was also simulated.

Geologic Model

Appendix A contains figures that describe the final reservoir geomodel that was used for simulation studies. Figure A1 shows the location and the boundary (area bounded by the red rectangle) of the study area for this project. Petrophysical well logs, seismic data, cutting description, DST test results, and geologic reports from wells within and around the study area were used to build a geomodel for the reservoir. Tops of marker beds above and below the reservoir interval and the layers describing the reservoir were identified at each well within and around the study area. A series of cross-sections were generated from different directions and this helped to crosscheck and fine tune the geomodel. For the simulation study, 3 layers were used to model the reservoir. All the three layers are productive and intervening shale streaks are not evident. The field has no recorded gas production. Based on reservoir pressure data from development wells it appears that the reservoir produces under an active water drive. Thus in order to model fluid saturation changes due to fluid flow in the vertical direction, more than one layer was used to represent the reservoir.

Figure A2 shows study area from close. The wells with a full suite of petrophysical logs are circled in red. Also, cumulative oil production from each well is stated below the name of the well. Figure A3 displays the subsea structure (feet) of the top layer (Layer 1). Figures A4 to A12 display the isopach, porosity, and initial water saturation (Sw) maps of each of the 3 reservoir layers.

Production data

This field was discovered and developed by Mull Drilling Company (MDC), and unlike many other independent operators of the Mid-continent this company carried out production tests at regular intervals on most of their wells. Thus, a complete fluid production history was available for all but three wells, namely, McDonald #3 (MDC, Sec 4), Borger #1 and #2 (MDC, Sec 5). These were relatively older wells and regular production test data was not available. Thus, decline curve analyses was used to match the initial production (IP) rate and the later recorded (tested) oil rates and thereby generate the decline equation for the well. This equation was then used to estimate the missing oil production rates.

For wells with a complete production history, monthly production volumes of both oil and water was available. For each well, an average annual production rate (barrels per day, BPD) was calculated from the monthly oil and water production volumes. Figure B1 (Appendix B) tabulates the cumulative oil production from each well within the study area.

Decline Curve Analysis

One of the critical inputs to a simulation model for history matching is the bottom-hole pressure (BHP) history under which a well is produced over its life. This field was owned and managed by MDC from the beginning and based on the operating policy of the company it was possible to determine that all the wells were produced under minimal standing fluid columns. Thus, it was assumed that each well was produced under a bottom hole pressure (BHP) of 100 psi throughout their life. Hence, decline curves were not applied to determine if wells were produced under unchanging bottom hole conditions. Rather as mentioned earlier, decline curve analyses was carried out to fill in missing oil production at 4 wells.

At each of the wells with missing oil production rates, decline curve analysis was carried out by plotting the IP and the available average annual oil production rates on a plot whose axes coincided (in cycle-length) with that of the standard Fetkovich decline curve (SPE-AIME, 1980). Figure C1 (Appendix C) shows the results for Borger 1 and 2 (MDC, Sec 5). Single decline curves (blue line) were found to represent the available well production histories (red circles) in case of both wells. It is evident from Figure C1 that no oil production rates were available between the month 1 and the 60th month. The decline equation for each well was used to estimate production during this missing period for each well. A similar exercise (Figure C2) was carried out for McDonald 3 and 4 (MDC, Sec 4). For McDonald 4 (MDC, Sec 4), an increase in production took place during the 261st month from 1.8 to 9.4 BOPD. Lacking additional information, it was assumed that a single decline equation (shown by the blue line) affected production between the 1st and the 260th month, and this equation was used to estimate the missing oil production rates for McDonald 4 (MDC, Sec 4). A linear equation that fit the IP water-oil ratio (WOR) and the first recorded WOR from barrel test was used to estimate water production rate corresponding to the period of missing oil production rates.

Petrophysical log analysis - Super-Pickett plots

Wells with a complete suite of petrophysical logs are marked in Figure A2. Super-Pickett cross-plots were used to analyze available petrophysical logs. Appendix D displays the Super-Pickett plots constructed for wells in the study area. Standard values of m (=2.0) and n (=2.0) were used to analyze the logs. Based on the water salinity information (Cl^- ppm of 17,000) from Borger 4 (MDC, Sec 5), the formation water resistivity (Rw) was calculated as 0.14. It appears that bulk volume water (BVW) values have to be less than 0.07 for water-free production or production with minimal water (Figures D1 and D3).

Perforated zones with BVW values greater than 0.07 (Figures D2, D4, D5, and D6) produce significant quantities of water in comparison to the produced oil rate. Average values for porosity, effective pay, and initial water saturations (Sw) were obtained from the Super-Pickett analysis at each of the well. These values were used to map the distribution pay, porosity and initial saturations (Figures A4 to A12) in the three layers that describe the reservoir.

DST Analysis

Appendix E summarizes the details of the DST analysis. Table E1 shows the effective pay thickness and corresponding porosity used to analyze DST data at each well. DST pressure-time data was available for 9 wells within the study area. Figures E1 to E9 and Tables E2 to E10 summarize the DST analyses carried out for all these wells. Figure E10 shows the initial pressure (Pi) psi calculated from DST test analysis. Based on this pressure profile, the initial reservoir pressure was assumed to be 1350 psi.

PVT and Relative Permeability/Capillary Pressure Inputs

Appendix F summarizes the PVT and relative permeability/capillary pressure inputs to the simulation model. There is no mention of any gas production at McDonald field, and MDC operates most wells under minimal standing fluid columns. Thus, the bubble point pressure is low given that no gas production has been recorded at the wells even when they are produced under pumped off conditions. The reservoir produces under a strong water drive. Within the simulation model, each well is produced under a BHP of 100 psi and to prevent any three-phase flow from occurring a low bubble point of 50 psi was assumed (at subsea –2031 feet) in this study. There was no measured bubble point data available. Other oil PVT properties are listed in Table F1. Bubble point pressure, reservoir temperature, and oil and gas gravities were input to the inbuilt PVT calculator within the reservoir simulator (Computer Modeling Group's IMEX) to generate other necessary PVT tables.

No cores were available from McDonald field. However, a Mississippian core from McClure Antenen #1 well (Sec 6, T19S, R24W, Ness County, Kansas) was available from a neighboring field. Routine and advanced core analyses was carried out on this core to develop representative permeability-porosity correlation (Tables F2) for both the reservoir and non-reservoir rock. Also, capillary pressure measurements were carried out on representative core plugs along with recordings of end-point saturations. Data collected from these core studies integrated with the data set on Mississippian core plugs that has been built by virtue of studies, carried out at the KGS, on other Mississippian fields of the Mid-continent. Porosity was found to correlate with end-point saturations such as Swi (irreducible water saturation) and Sorw (irreducible oil saturation to water). Using these correlations and measured capillary pressure curves, relative-permeability/capillary pressure calculator was created using Corey-type equations. This type of interactive calculator helped to input a consistent set of relative-permeability/capillary pressure tables into the simulator upon making changes in effective permeability over the drainage area of a well during the history matching phase. Thus, changing the permeability input in the calculator resulted in updating the table by changing the saturation end points while conforming to the shape of the capillary pressure curve. Also, the relative permeability exponents (m and n) enable changing the relative ease of flow between the two fluid phases in the reservoir, i.e., the oil and water, especially during history-matching well-level production. Table F2 shows the calculator for the reservoir rock (Layers 1, 2, and 3).

Figure F1 compares the calculated permeability from DST analyses and the corresponding (log-derived) porosity of the tested interval with the permeability-porosity values measured on Antenen core plugs. The permeability-porosity values from the DST analyses fits within the body of corresponding data obtained from the core plugs. Such a match indicates that the heterogeneity captured by the core plugs are representative of that existing at a larger scale, i.e., within the drainage area of the wells. Thus, core plug measurements can be considered representative of effective reservoir properties.

Simulation study – History matching

The reservoir was simulated as a 3-layer model using 110 feet by 110 feet grid cells and an analytical bottom aquifer. The aquifer properties were fine-tuned so that the calculated current reservoir pressure was close to 1000 psi. Initial saturation (Sw) and pressure distributions in the drainage area of each well was input with the help of capillary pressure curves and having the simulator perform gravity-capillary equilibrium calculations. The initial permeability in each layer was populated using the permeability-porosity correlations generated from core analysis. The correlation for the reservoir rock is stated in Table F2. Each well was produced under a constant BHP = 100 psi throughout its life with the simulator calculating the oil and water production at the end of every time step. Parameters that were fine-tuned to history match individual well performance included effective permeability in the drainage area of the well and relative permeability exponents "m" and "n". Table G1 summarizes the layers each well was perforated within the simulator and is based on recorded perforation depth range(s) and the top and bottom of each of the reservoir layers.

Figures G1 to G8 show the history matches obtained at each well in the study area. History matching was started with Borger 3 (MDC, Sec 5) and proceeded in a counter-clockwise direction by following Borger 4 (MDC, Sec 5), Borger 2 (MDC, Sec 5), Borger 5 (MDC, Sec 5), and Borger 6 (MDC, Sec 5). Upon completion of production history matches at the above wells, the simulator was directed to output its calculated production history for Borger 1 (MDC, Sec 5) without making any additional modifications. Figure G6 shows match obtained for Borger 1 (MDC, Sec 5). The match appears to be reasonable given the fact that it had not necessitated any modifications of the model within the related drainage areas. Also, Borger 4 (MDC, Sec 5) has historically produced significantly high water volumes (Figure G2), compared to other wells in the field, and MDC suspects that it the result of a bad cement job. Under such circumstances, part of the water produced at this well is coming from a layer (zone) outside the purview of this model. The history match obtained for McDonald 4 (MDC, Sec 4) is shown in Figure G8. Water production records from the onset of production till 1989 are unavailable. The simulator is able to reasonably predict the initial water production, the few available measured data points, but fails to match the increased water production after 1992. MDC carried out a major stimulation job at this well in 1992-93, which resulted in a significant increase in produced fluid volumes. Though no records are available, MDC suspects that the well produced with a significant standing fluid column for some time after the stimulation job. At present, the well produces under pumped off conditions. Lacking any recorded history of how the standing fluid column varied over time in this well, a constant BHP = 100 psi was used in the simulation study and it proved to be insufficient to model the recorded water production history.

Figure G9 shows the calculated distribution of reservoir pressure as of January 2003. The average reservoir pressure is around 850 psi. MDC's records indicate that a shut-in fluid level measurement was carried out at Borger 1 (MDC, Sec 5) in the recent past (exact date unavailable) and it recorded about 2300 feet of standing fluid column above the perforations. Thus, MDC estimates that the current reservoir pressure is the range between 1000 and 1100-psi. However, lacking the exact date of the above shut-in test it is difficult to fine-tune the aquifer strength in the simulator model. A current shut-in fluid column record is awaited and based on its results the current model will be fine-tuned to increase the average reservoir pressure from 850 psi to that which is determined as more representative of the reservoir.

<u>Simulation study – Performance evaluation of different horizontal infill trajectories</u>

Appendix H summarizes the results of the performance evaluation studies carried out with the help of the simulator on different horizontal infill trajectories. Upon completion of well history matches, a map of residual reserves (oil-ft, product of porosity, oil saturation and grid thickness) was generated as of January 2003. Figure H1 maps the remaining potential (oil-ft - product of porosity, oil saturation and pay thickness) as of January 2003 in McDonald field. Figures H2 and H3 show the distribution of remaining potential in layers 2 and 1, and it becomes apparent that most of the remaining potential resides in Layer 2. Based on this map (Figure H4), the productive potential of two infill horizontal trajectories, namely "Hwell 1" and "Hwell 2", was studied. In each case, the horizontal well was assumed to be 6 inch in diameter and to have been produced for 5 years (starting January 1, 2003) under a constant BHP = 100 psi and a skin factor of 1.5.

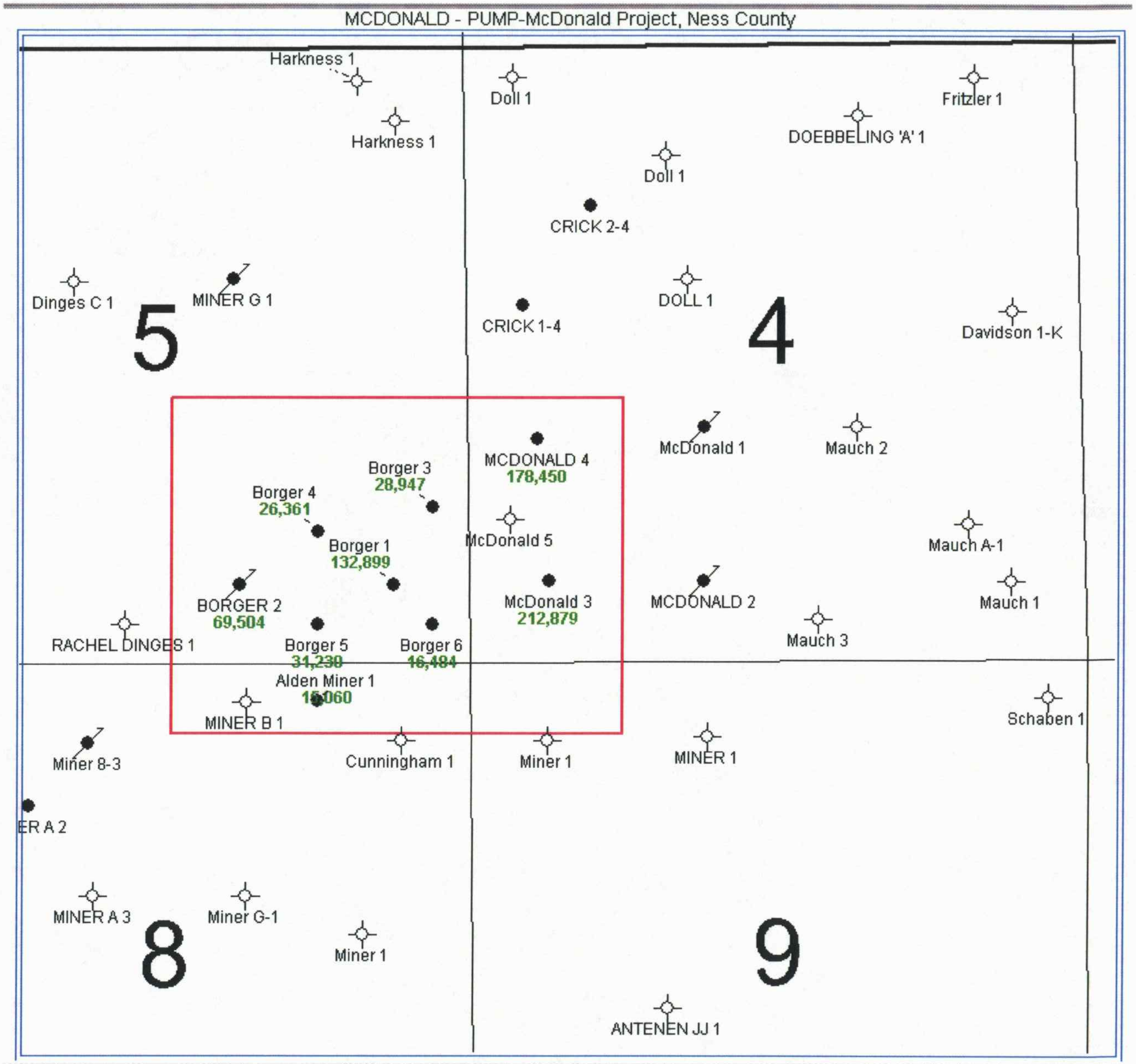
The expected drainage of residual reserves by "Hwell 1" over 5 years of production is shown in Figure H5. The expected production from this well is plotted in Figure H6. Simulation studies indicate that after 5 years the expected cumulative production from this well will be in the range of 30 MSTB while requiring to move about 400 MSTB of water. Figures H7 and H8 plot the productive potential of the second horizontal infill trajectory "Hwell 2", and this well is expected to produce about 25 MSTB after 5 years of production.

As of July 1994, a 3-day shut-in test was carried out at this well and the fluid level was found to be only 122 feet above the pump at the end of the test. Thereafter, the well was acidized resulting in a significantly higher standing fluid column in the well. MDC anticipates that the acid treatment opened up communication with the underlying aquifer. Thus, MDC believes that Borger 3 (MDC, Sec 5) drained from a pocket (before the acid treatment) that is isolated from the main reservoir.

The above simulation studies indicate that most of the remaining potential is in area lying among and around the wells Borger 1, 2, and 3 (MDC, Sec 5). However, production and pressure data collected by MDC from Borger 3 (MDC, Sec 5) indicate that the drainage area of this well was originally isolated from the main body of the reservoir in McDonald field. Added geologic complexities, such as the flow barrier existing between the drainage area of Borger 3 (MDC, Sec 5) and the rest of the reservoir further reduces the productive potential of any horizontal trajectories placed within this area.

Appendix A

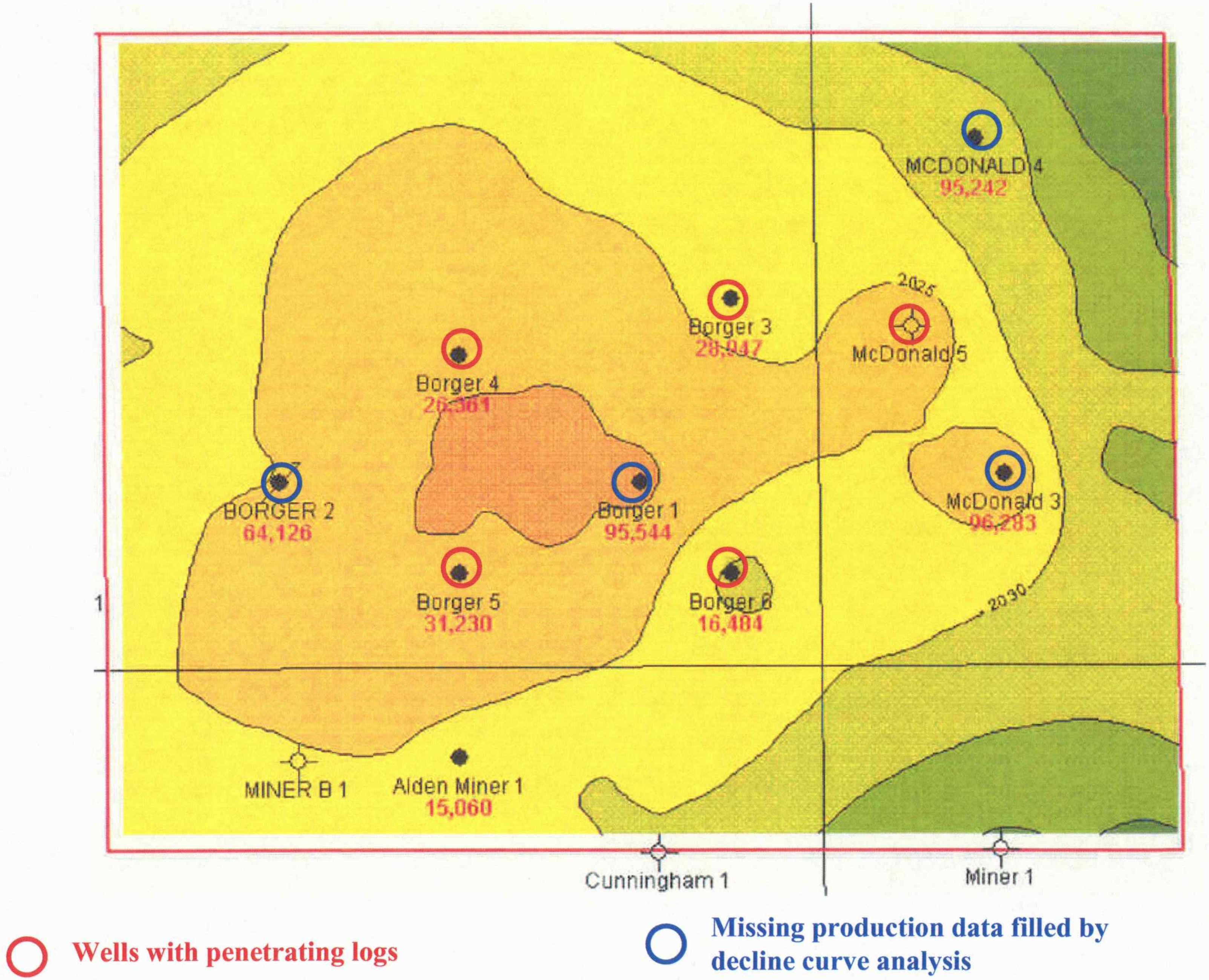
Geologic Model



MCDONALD - PUMP-McDonald Project, Ness County
Harkness 1
Harkness 1
Doll 1
Fritzler 1
DOEBBELING 'A' 1
Doll 1
CRICK 2-4
Dinges C 1
MINER G 1
5
CRICK 1-4
DOLL 1
4
Davidson 1-K
McDonald 1
Mauch 2
MCDONALD 4
178,450
Borger 3
28,947
Borger 4
26,361
McDonald 5
Borger 1
132,899
Mauch A-1
Mauch 1
BORGER 2
69,504
McDonald 3
212,879
MCDONALD 2
Mauch 3
RACHEL DINGES 1
Borger 5
31,230
Borger 6
16,484
Alden Miner 1
15,060
MINER B 1
Schaben 1
Miner 8-3
Cunningham 1
Miner 1
MINER 1
ER A 2
MINER A 3
Miner G-1
8
Miner 1
9
ANTENEN JJ 1

Figure A1

Figure A2


MCDONALD 4
95,242
2025
Borger 3
28,047
McDonald 5
Borger 4
26,361
BORGER 2
64,126
Borger 1
95,544
McDonald 3
96,283
Borger 5
31,230
Borger 6
16,484
2030
1
MINER B 1
Alden Miner 1
15,060
Cunningham 1
Miner 1
Wells with penetrating logs
Missing production data filled by decline curve analysis

L1 Structure top (subsea, feet) with Grid

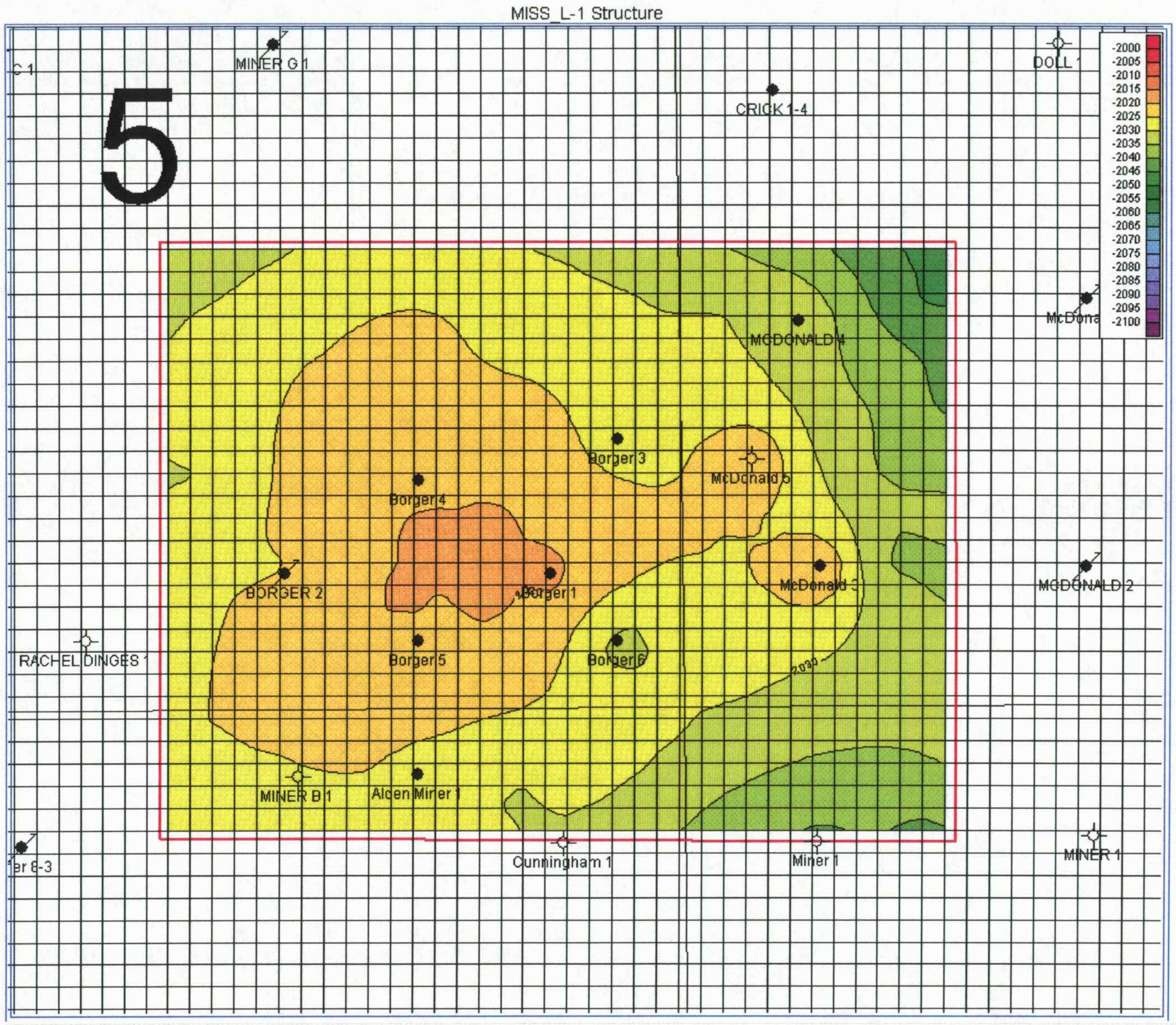


Figure A3

L1 Isopach, feet

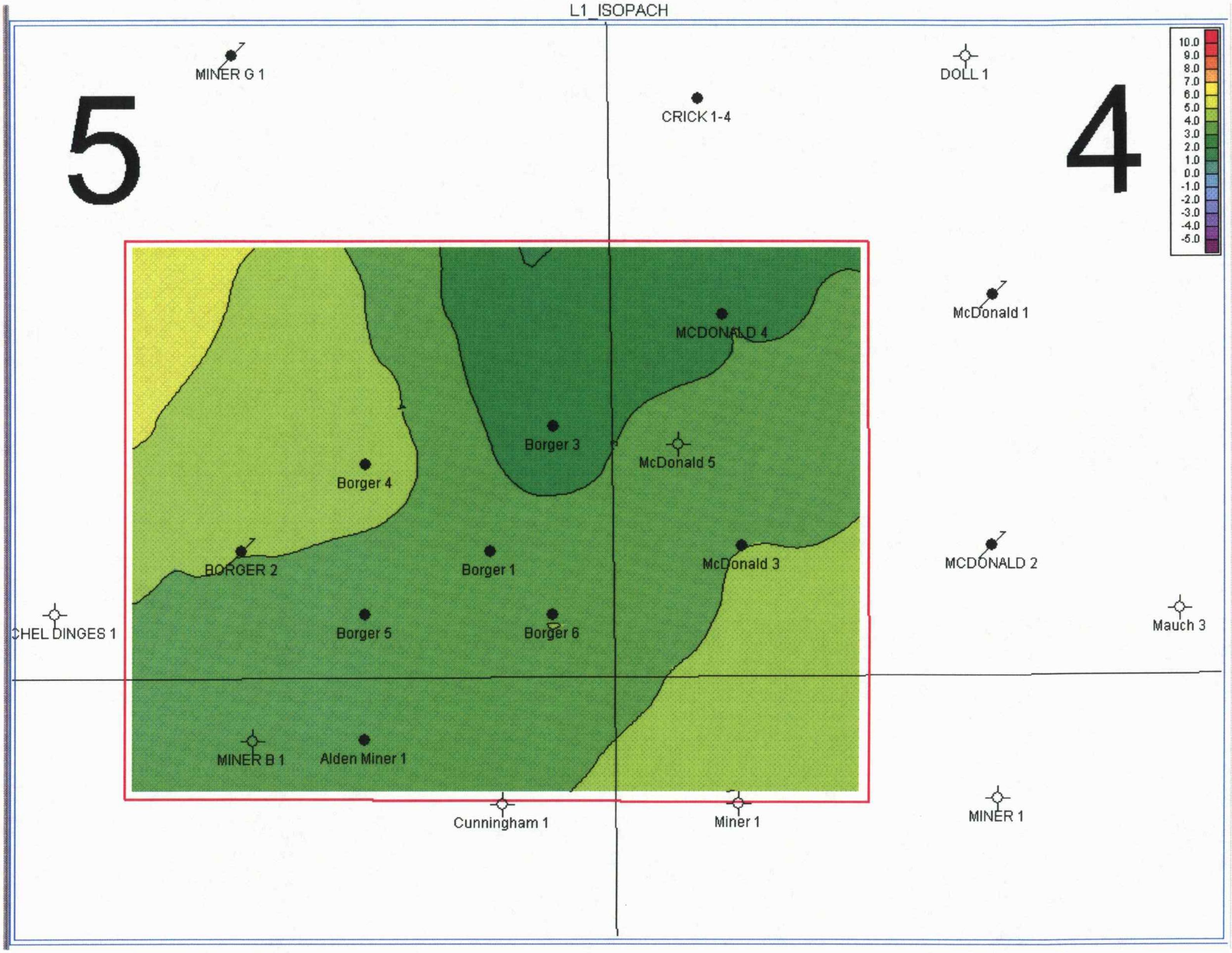


Figure A4

L2 Isopach, feet

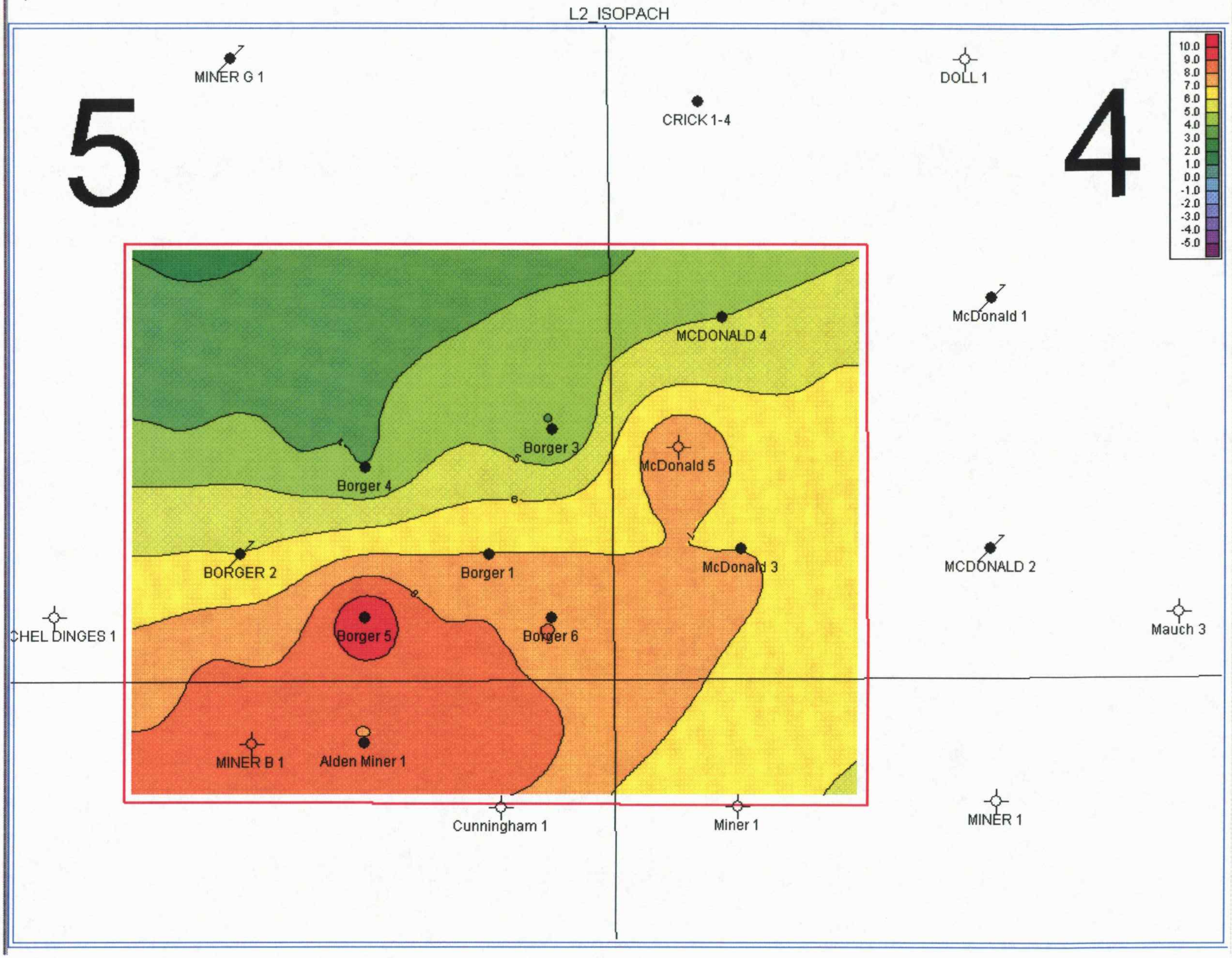


Figure A5

L2 Isopach, feet

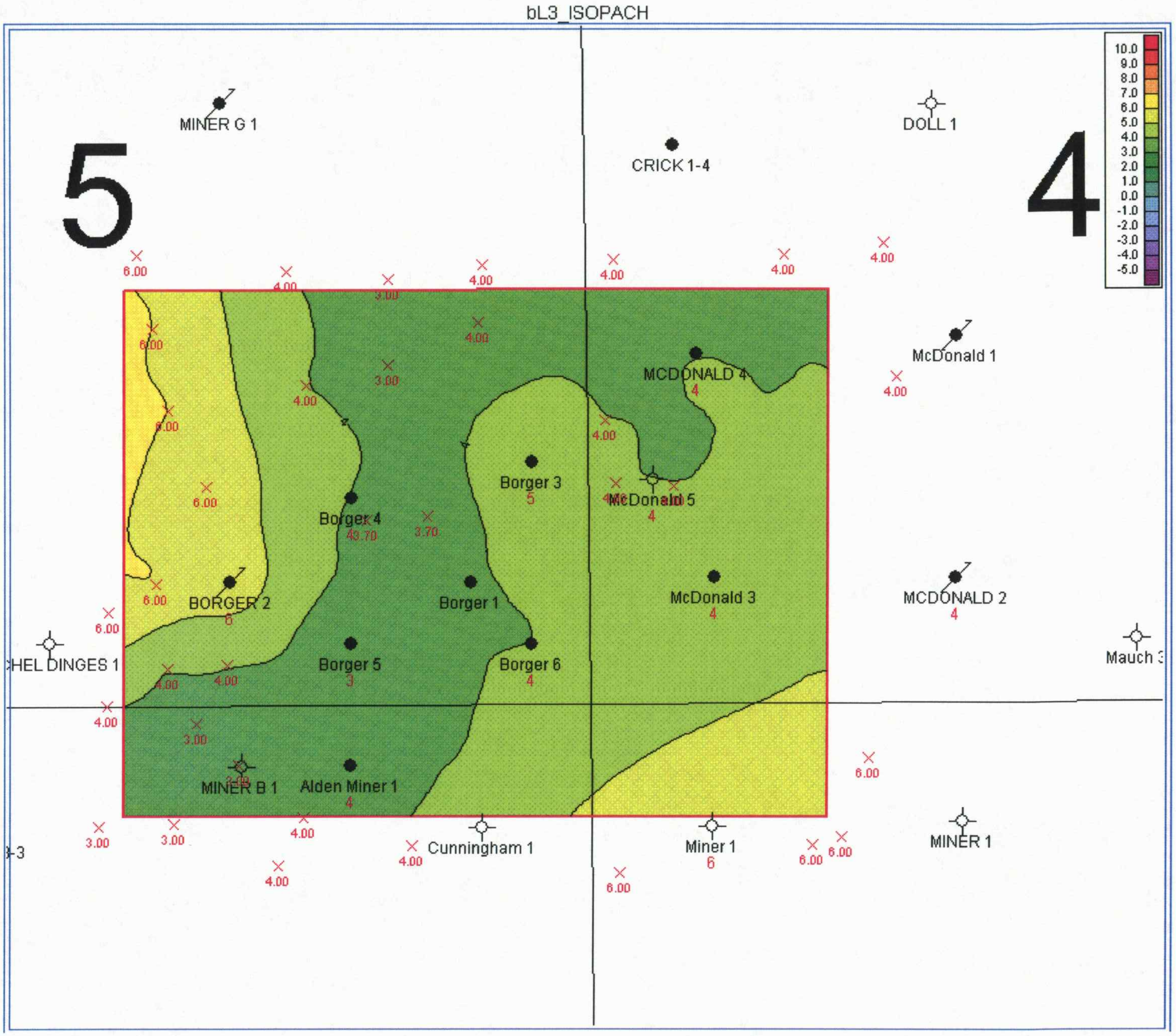


Figure A6

L1 Porosity

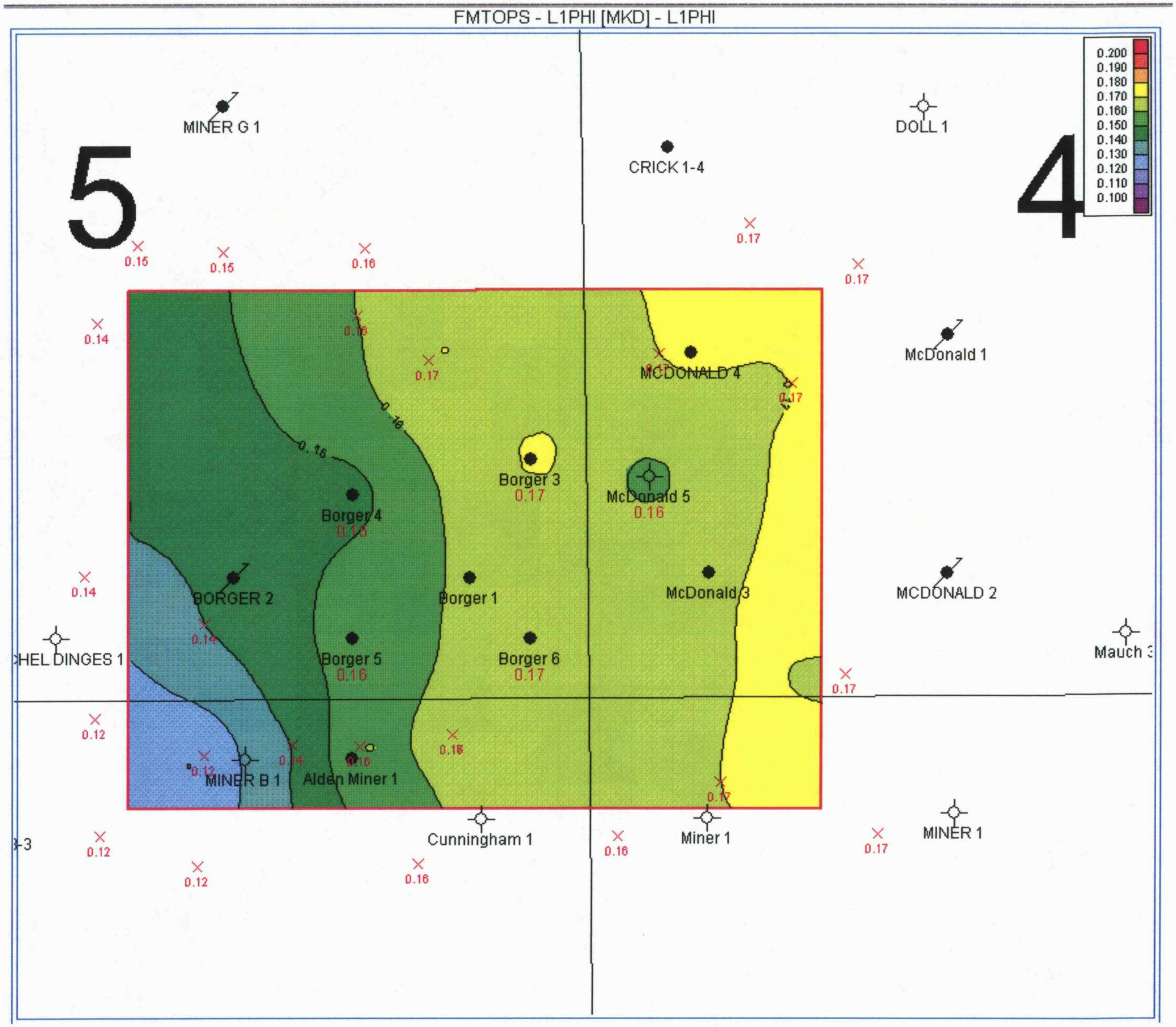


Figure A7

L2 Porosity

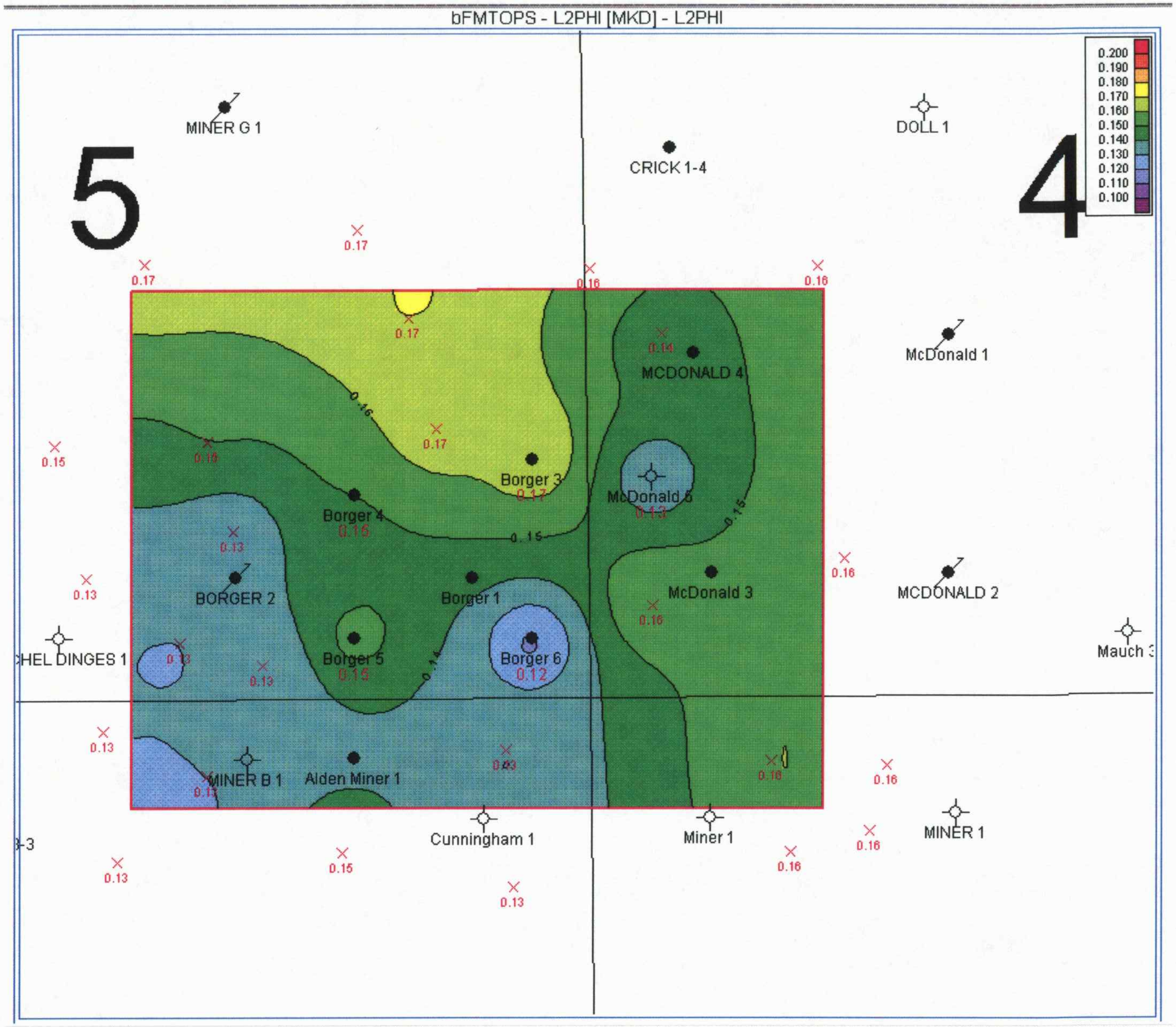


Figure A8

L3 Porosity

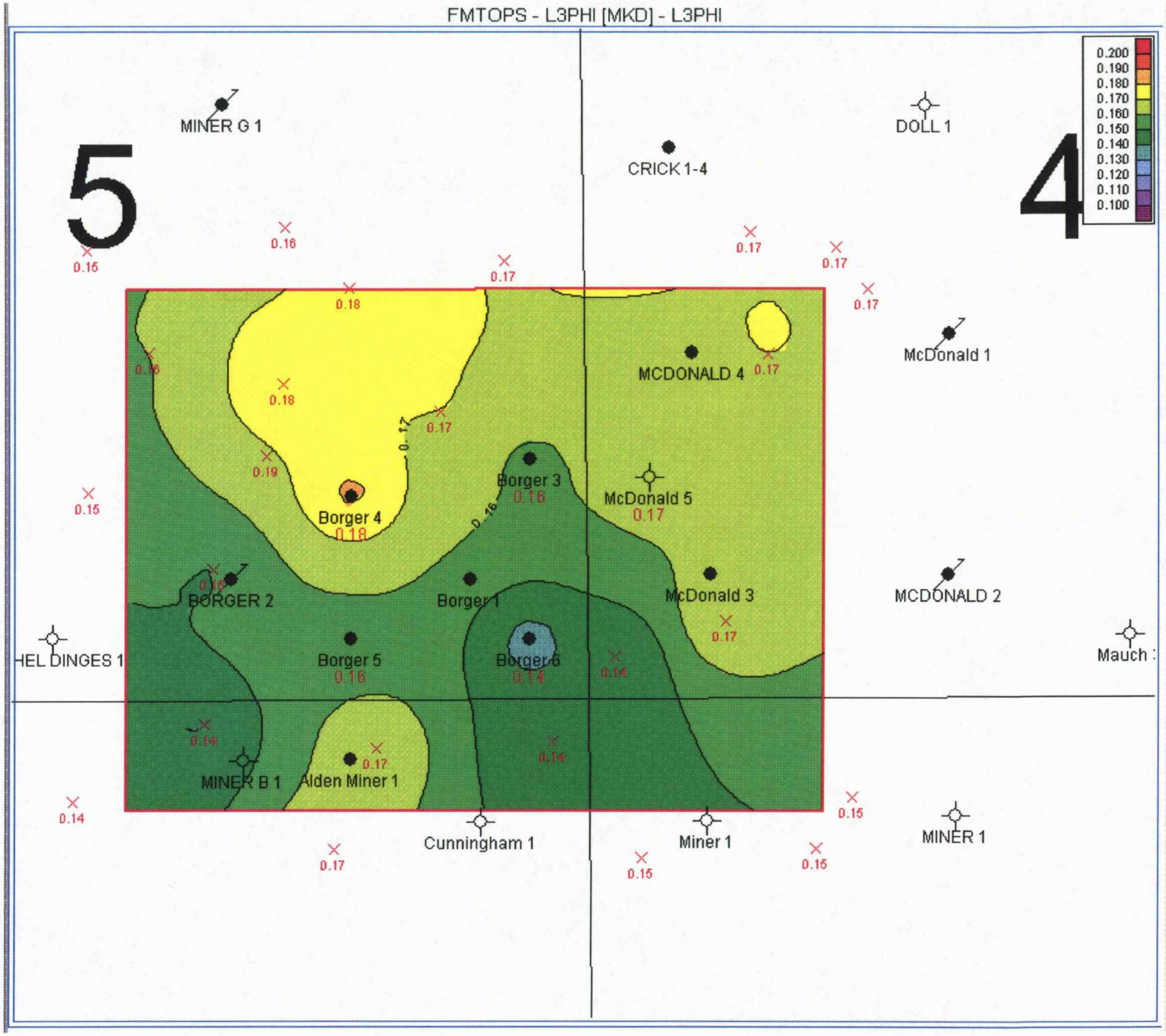


Figure A9

L1 Sw

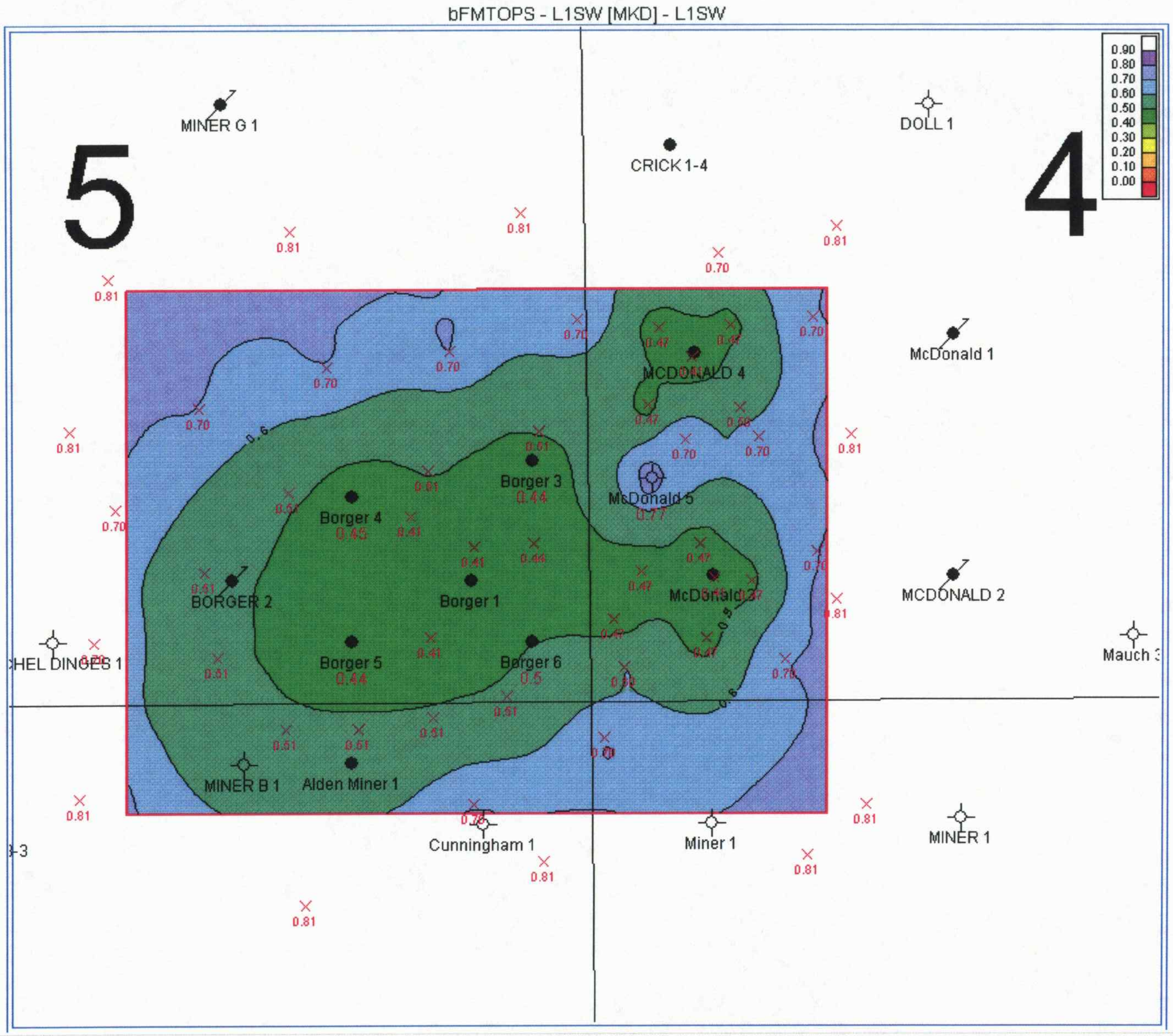


Figure A10

L2 Sw

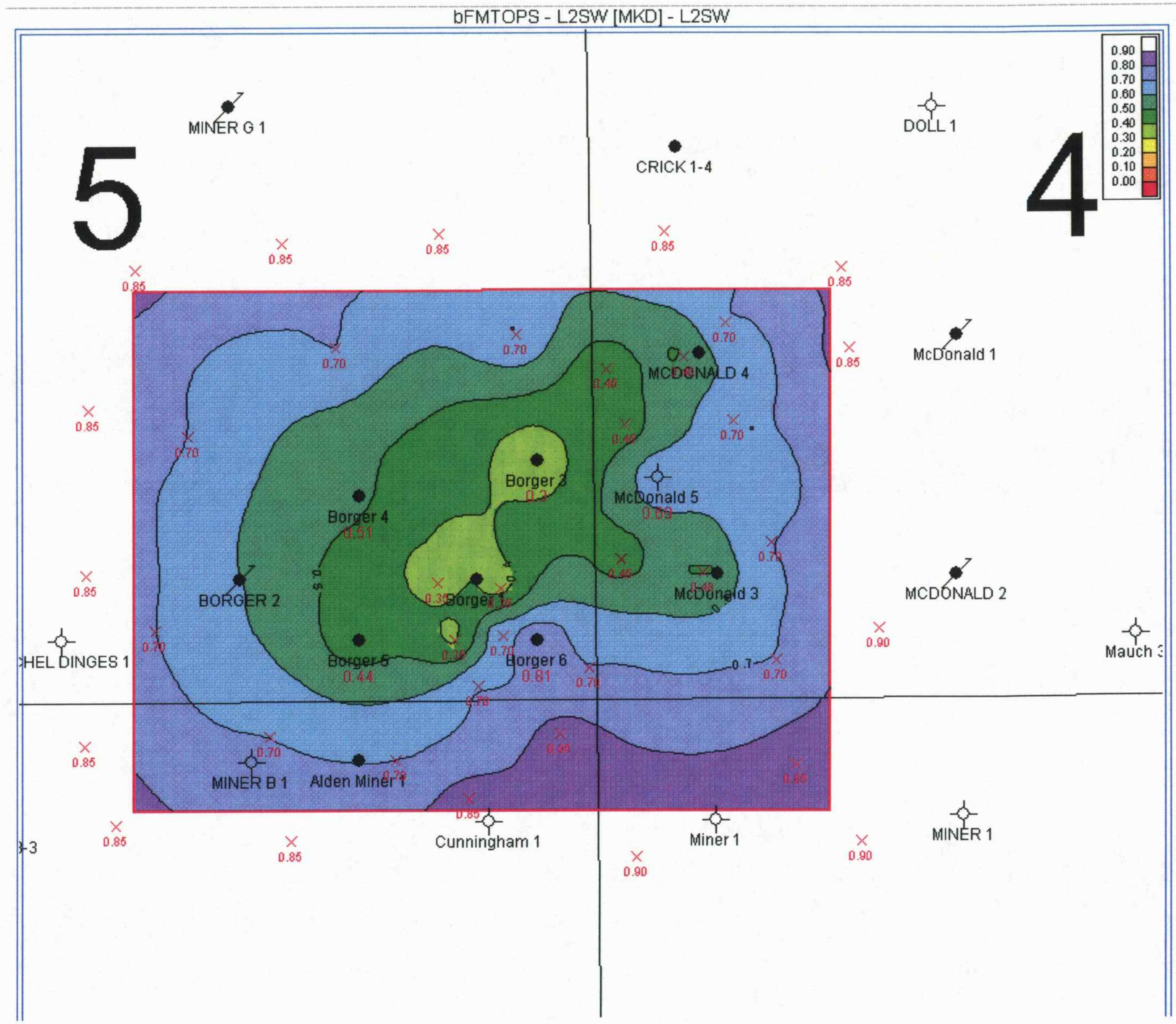


Figure A11

L3 Sw

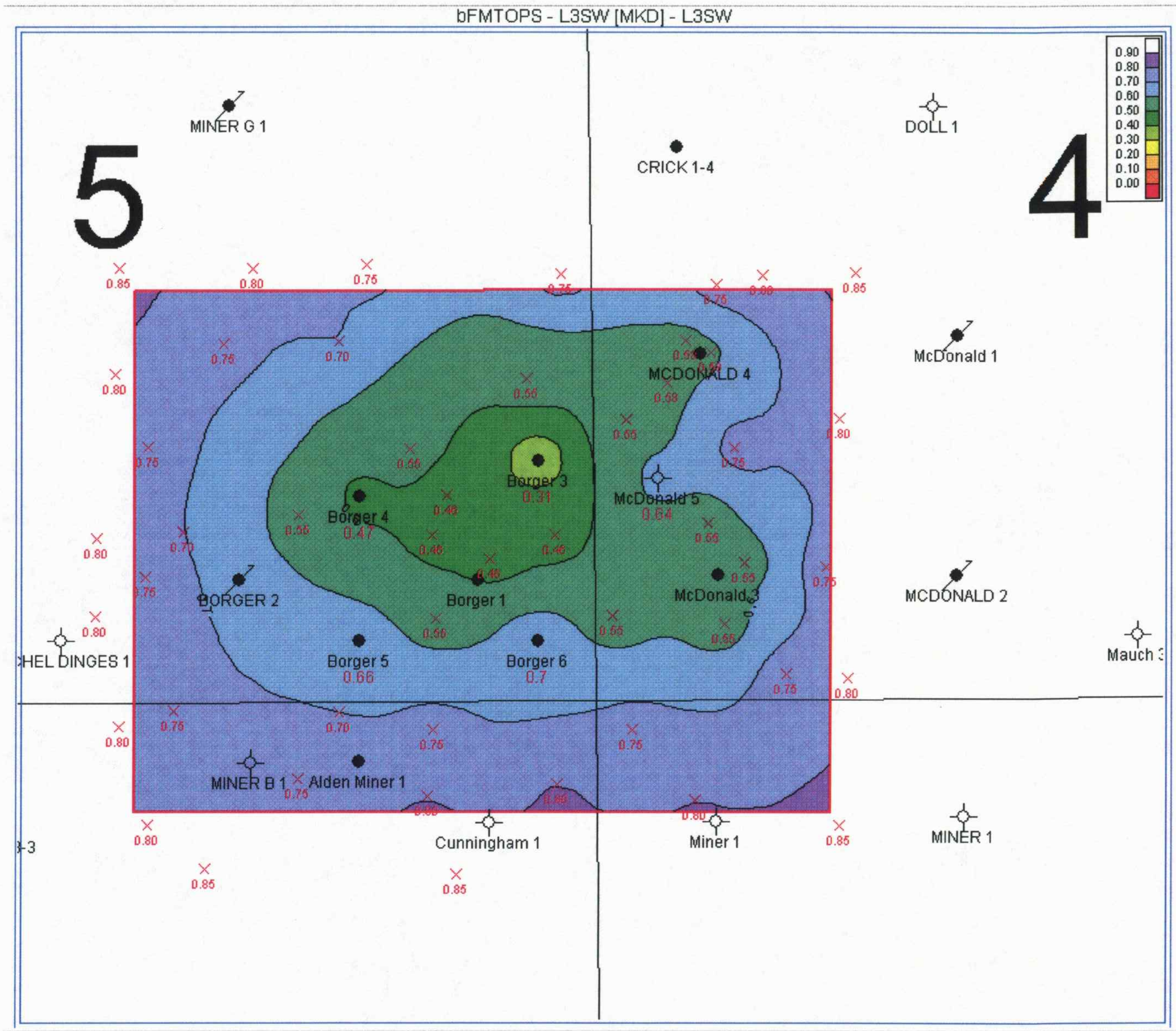


Figure A12

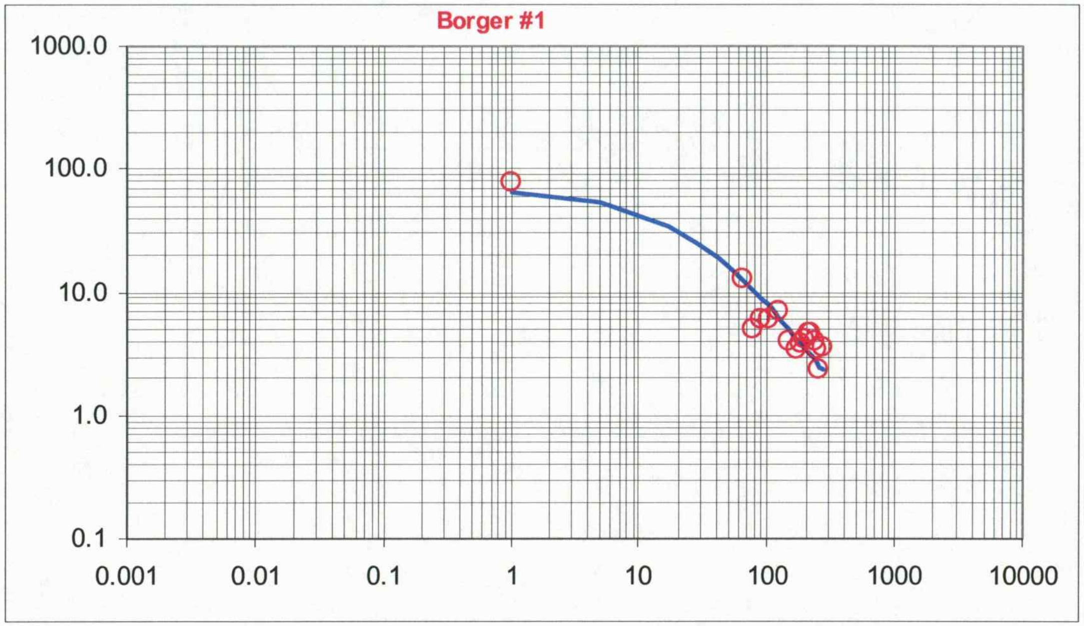
Appendix B
Production data

Well		Cum Oil, bbls		Prod start
Borger 1		95,544		8/1/1971
Borger 2		64,126		1/1/1972
Borger 3		28,947		4/1/1993
Borger 4		26,361		12/1/1993
Borger 5		31,230		5/1/1995
Borger 6		16,484		12/1/1996
McDonald 3		96,283		4/1/1971
McDonald 4		95,242		4/1/1971
Alden Miner 1		15060		8/1/1997

Figure B1

Appendix C

Decline Analyses


Borger #1
1000.0
100.0
10.0
1.0
0.1
0.001
0.01
0.1
1
10
100
1000
10000

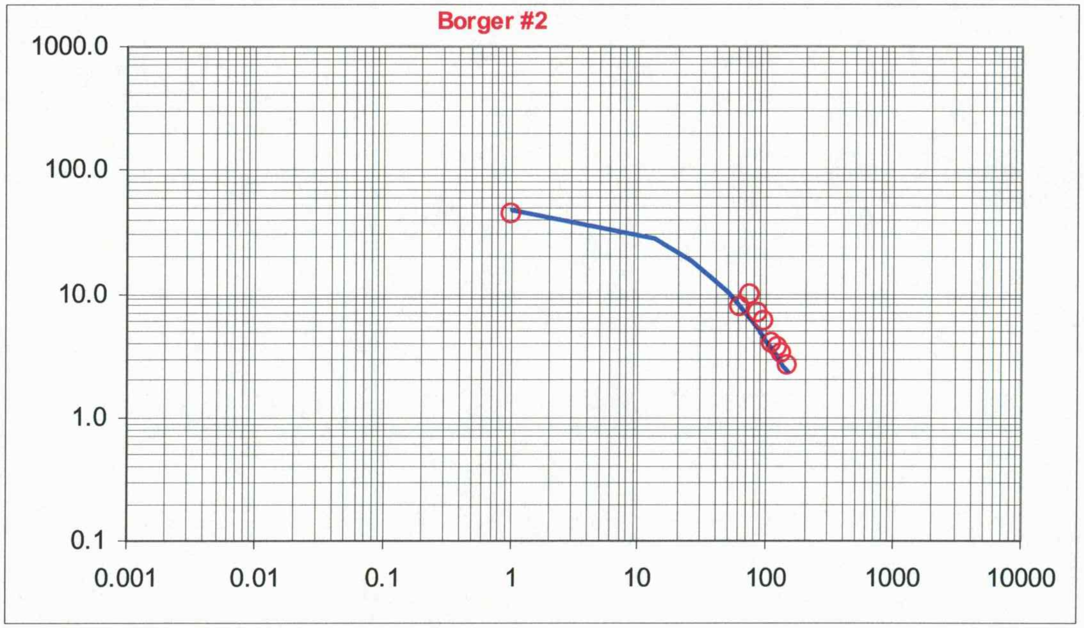

Borger #2
1000.0
100.0
10.0
1.0
0.1
0.001
0.01
0.1
1
10
100
1000
10000

Figure C1


McDonald #3
1000.0
100.0
10.0
1.0
0.1
0.001
0.01
0.1
1
10
100
1000
10000


McDonald #4
1000.0
100.0
10.0
1.0
0.1
0.001
0.01
0.1
1
10
100
1000
10000

Figure C2

Appendix D

Petrophysical log analyses

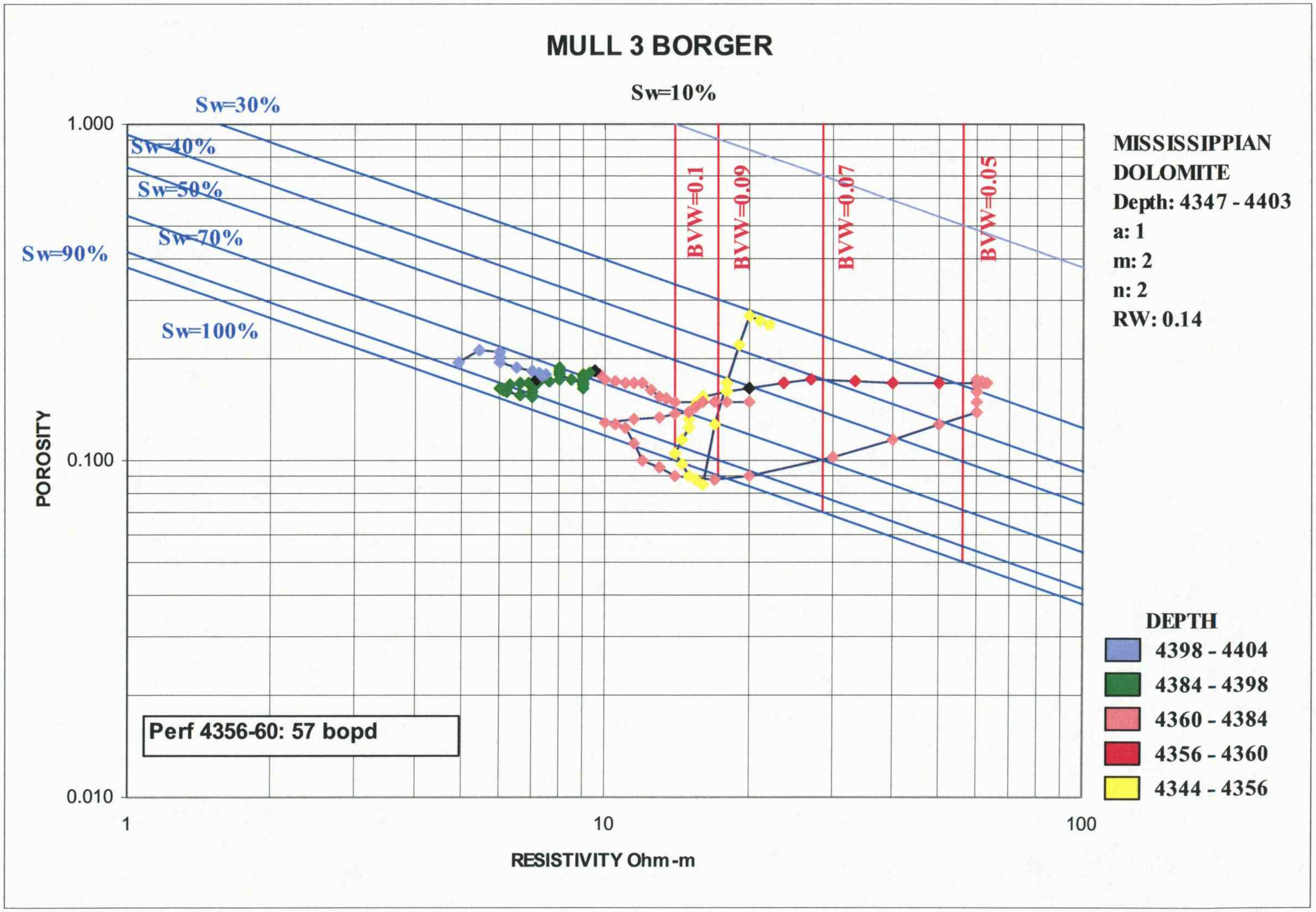
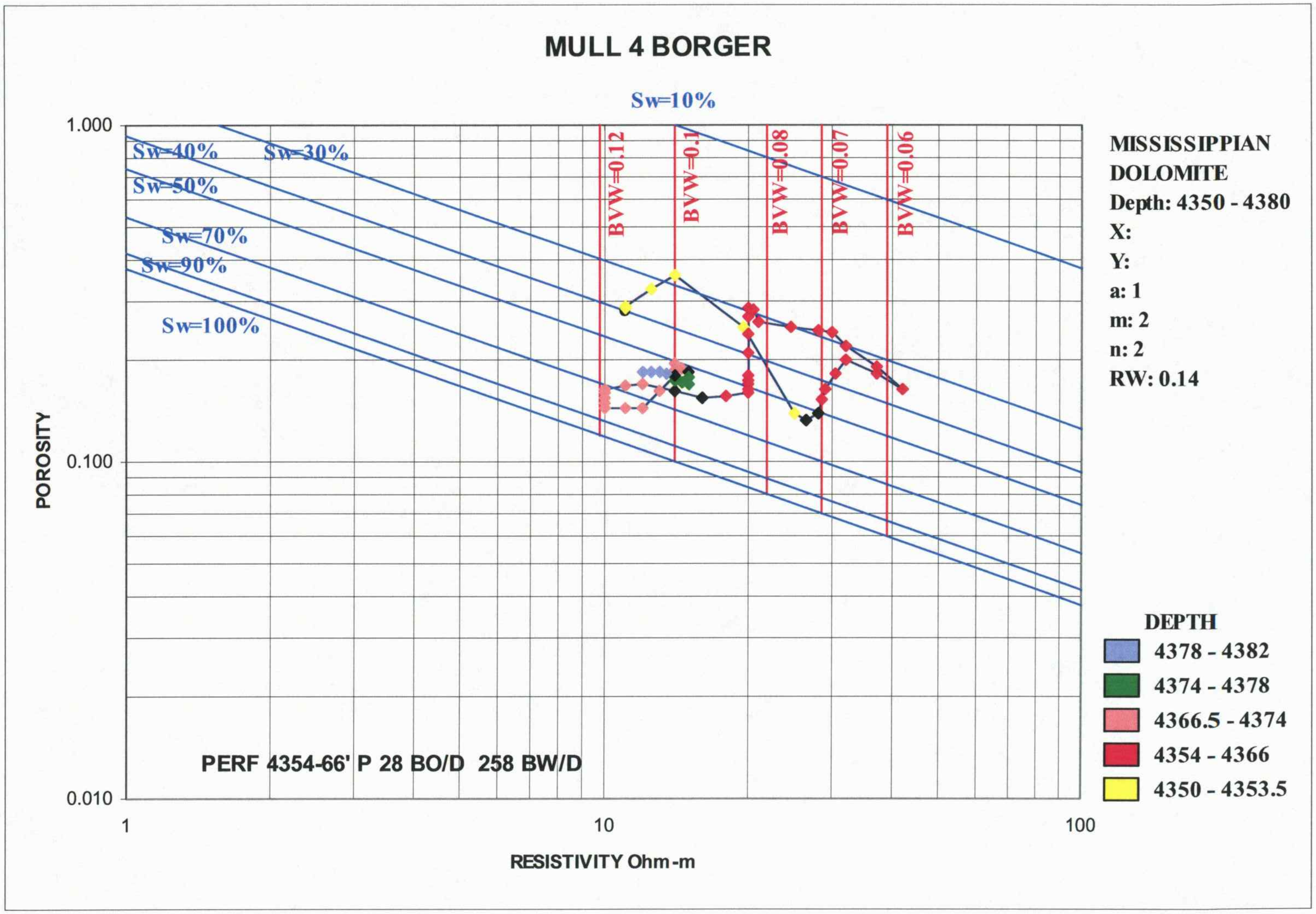
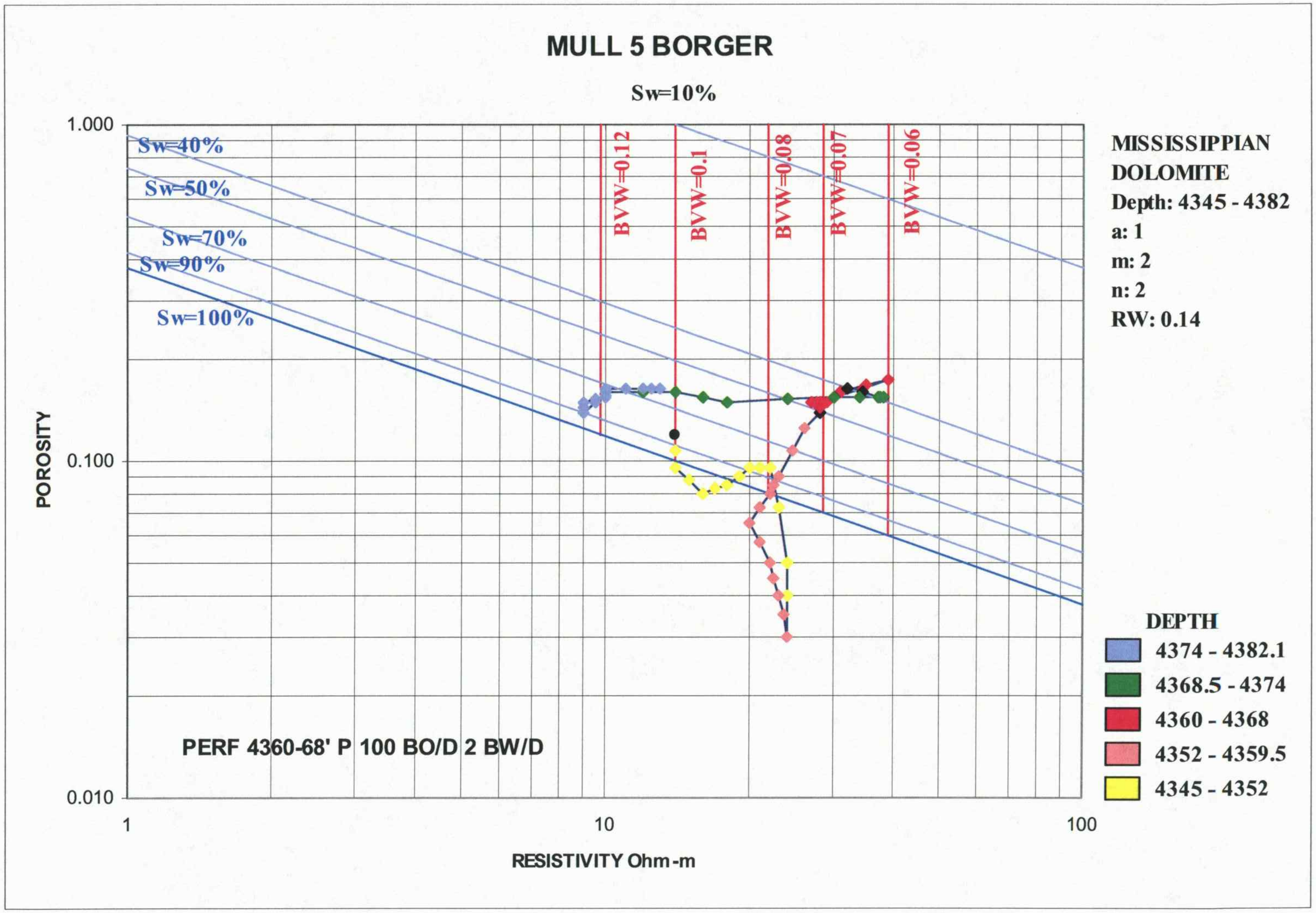

MULL 3 BORGER
Sw=10%
Sw=30%
Sw=40%
Sw=50%
Sw=70%
Sw=90%
Sw=100%
BVW=0.1
BVW=0.09
BVW=0.07
BVW=0.05
1.000
0.100
0.010
POROSITY
1
10
100
RESISTIVITY Ohm-m
Perf 4356-60: 57 bopd
MISSISSIPPIAN
DOLOMITE
Depth: 4347 - 4403
a: 1
m: 2
n: 2
RW: 0.14
DEPTH
4398 - 4404
4384 - 4398
4360 - 4384
4356 - 4360
4344 - 4356

Figure D1



MULL 4 BORGER
Sw=10%
Sw=40%
Sw=30%
Sw=50%
Sw=70%
Sw=90%
Sw=100%
BVW=0.12
BVW=0.1
BVW=0.08
BVW=0.07
BVW=0.06
1.000
0.100
0.010
POROSITY
1
10
100
RESISTIVITY Ohm-m
PERF 4354-66' P 28 BO/D 258 BW/D
MISSISSIPPIAN
DOLOMITE
Depth: 4350 - 4380
X:
Y:
a: 1
m: 2
n: 2
RW: 0.14
DEPTH
4378 - 4382
4374 - 4378
4366.5 - 4374
4354 - 4366
4350 - 4353.5

Figure D2



MULL 5 BORGER
Sw=10%
Sw=40%
Sw=50%
Sw=70%
Sw=90%
Sw=100%
BVW=0.12
BVW=0.1
BVW=0.08
BVW=0.07
BVW=0.06
1.000
0.100
0.010
1
10
100
POROSITY
RESISTIVITY Ohm-m
PERF 4360-68' P 100 BO/D 2 BW/D
MISSISSIPPIAN
DOLOMITE
Depth: 4345 - 4382
a: 1
m: 2
n: 2
RW: 0.14
DEPTH
4374 - 4382.1
4368.5 - 4374
4360 - 4368
4352 - 4359.5
4345 - 4352

Figure D3

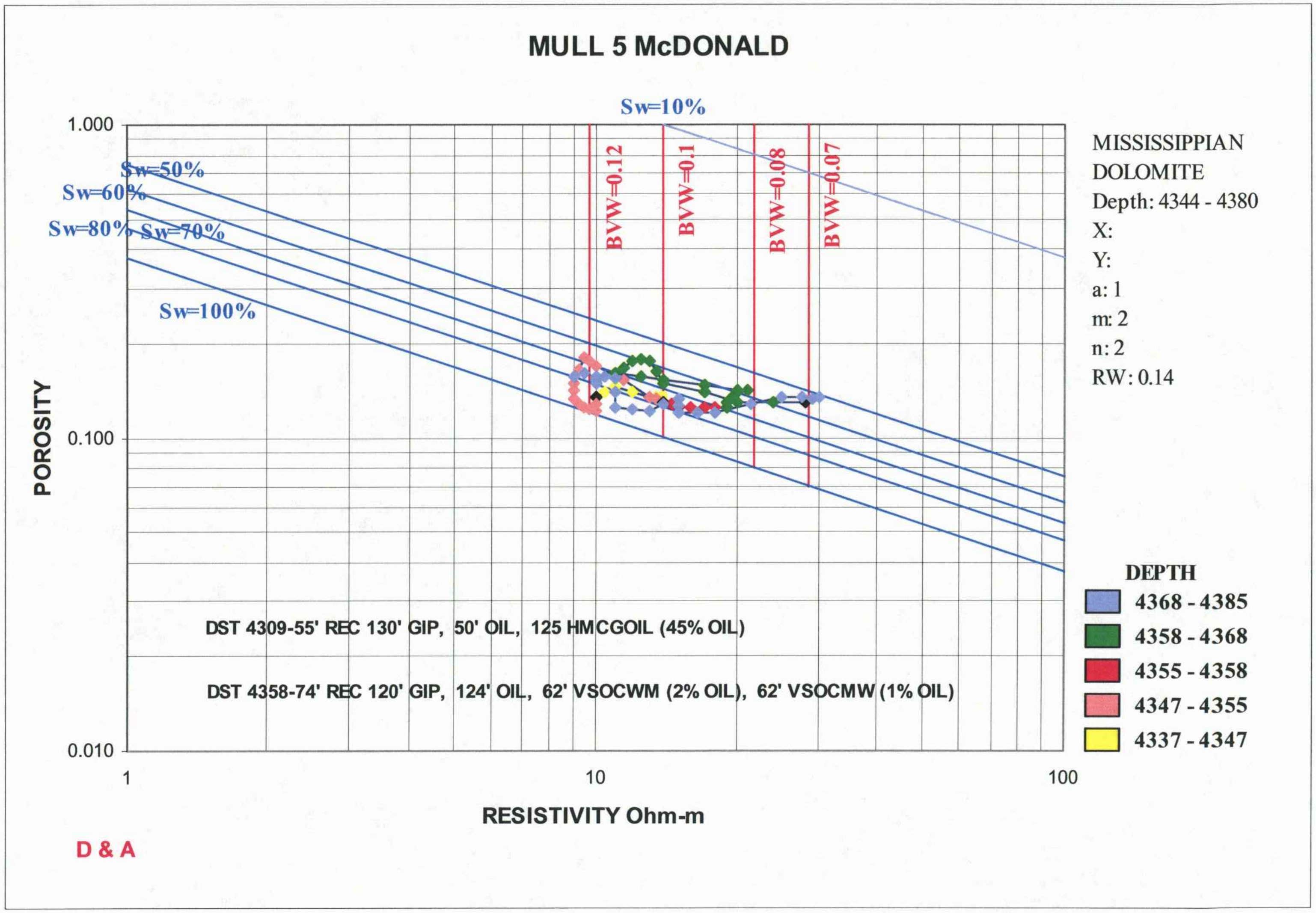

MULL 5 McDONALD
Sw=10%
1.000
0.100
0.010
Sw=50%
Sw=60%
Sw=80%
Sw=70%
Sw=100%
BVW=0.12
BVW=0.1
BVW=0.08
BVW=0.07
POROSITY
1
10
100
RESISTIVITY Ohm-m
MISSISSIPPIAN
DOLOMITE
Depth: 4344 - 4380
X:
Y:
a: 1
m: 2
n: 2
RW: 0.14
DST 4309-55' REC 130' GIP, 50' OIL, 125 HMCGOIL (45% OIL)
DST 4358-74' REC 120' GIP, 124' OIL, 62' VSOCWM (2% OIL), 62' VSOCMW (1% OIL)
DEPTH
4368 - 4385
4358 - 4368
4355 - 4358
4347 - 4355
4337 - 4347
D & A

Figure D4

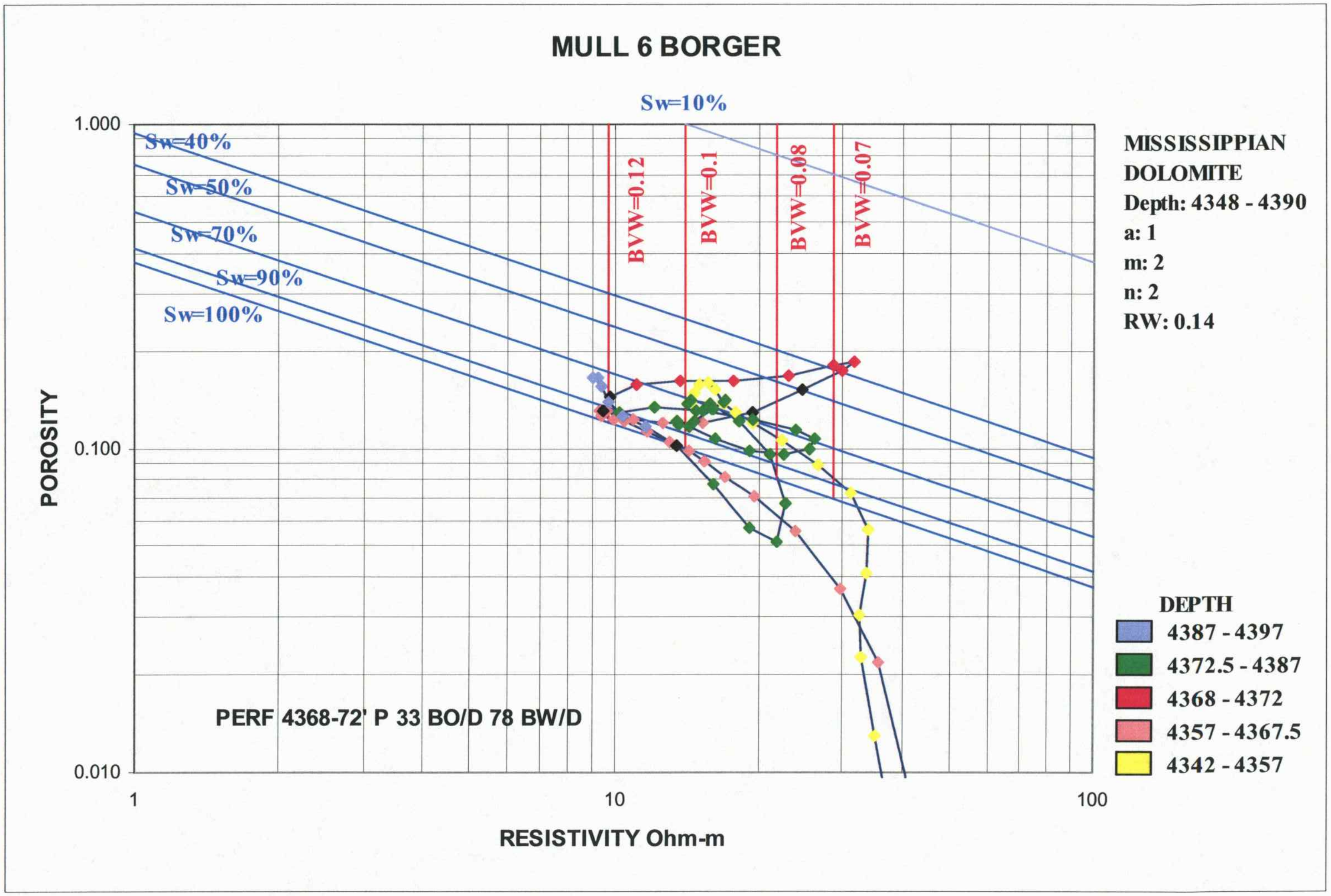

MULL 6 BORGER
Sw=10%
Sw=40%
Sw=50%
Sw=70%
Sw=90%
Sw=100%
BVW=0.12
BVW=0.1
BVW=0.08
BVW=0.07
1.000
0.100
0.010
POROSITY
1
10
100
RESISTIVITY Ohm-m
PERF 4368-72' P 33 BO/D 78 BW/D
MISSISSIPPIAN
DOLOMITE
Depth: 4348 - 4390
a: 1
m: 2
n: 2
RW: 0.14
DEPTH
4387 - 4397
4372.5 - 4387
4368 - 4372
4357 - 4367.5
4342 - 4357

Figure D5

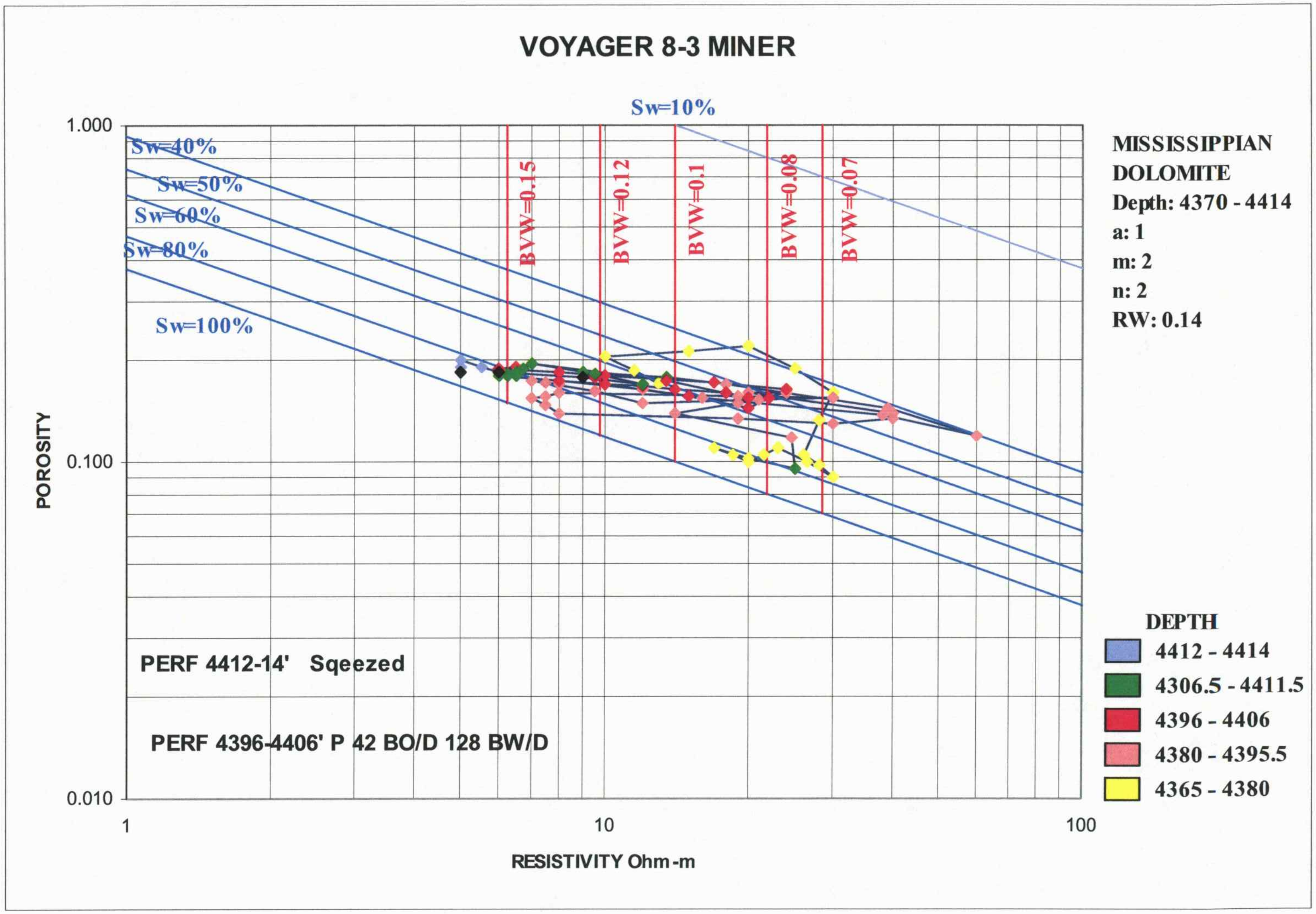

VOYAGER 8-3 MINER
Sw=10%
1.000
0.100
0.010
POROSITY
Sw=40%
Sw=50%
Sw=60%
Sw=80%
Sw=100%
BVW=0.15
BVW=0.12
BVW=0.1
BVW=0.08
BVW=0.07
MISSISSIPPIAN
DOLOMITE
Depth: 4370 - 4414
a: 1
m: 2
n: 2
RW: 0.14
DEPTH
4412 - 4414
4306.5 - 4411.5
4396 - 4406
4380 - 4395.5
4365 - 4380
PERF 4412-14' Sqeezed
PERF 4396-4406' P 42 BO/D 128 BW/D
1
10
100
RESISTIVITY Ohm-m

Figure D6

Appendix E

DST Analyses

							Logs did not penetrate - Marty extrapolated to obtain these											
WELLNAME	**Miss L1**	**Miss L2**	**Miss L3**	**Base** Miss		**L1 Iso**	**L1 Phi**	**L2 Iso**	**L2 Phi**	**L3 Iso**	**L3 Phi**		**DST Eff phi**	**DST Pay**	**DST T**	**DST B**	**KB**	**Subsea DST T**
McDonald 3	-2021	-2025	-2032	-2036		4	0.17	7	0.15	4	0.16		0.170	4	4300	4357	2332	-1968
McDonald 4	-2031	-2034	-2039	-2043		3	0.17	5	0.15	4	0.17		0.158	8	4323	4370	2327	-1991
McDonald 5	-2021	-2025	-2033	-2037		4	0.158	8	0.132	4	0.166		0.143	12	4358	4374	2329	-2029
Borger 1	-2019	-2022	-2030.2	-2033.8		3	0.165	8.2	0.155	3.6	0.16		0.165	3	4314	4351	2326	-1985
Borger 2	-2025	-2029	-2035	-2041		4	0.145	6	0.14	6	0.16		0.150	12	4360	4370	2335	-2031
Borger 3	-2027	-2029	-2033	-2038		2	0.171	4	0.17	5	0.158		0.171	2	4327	4358	2329	-1998
Borger 4	-2021	-2026	-2030	-2032		5	0.165	4	0.257	2	0.201		0.201	2	4362	4372	2332	-2033
Borger 5	-2023	-2026	-2036	-2039		3	0.155	10	0.154	3	0.157		0.155	16	4338	4390	2336	-2009
Borger 6	-2031	-2035	-2043	-2047		4	0.167	8	0.118	4	0.136		0.167	4	4321	4370	2337	-1984
Alden Miner 1	-2026	-2030	-2038	-2042		4		8		4			0.000	16				
Avg Top L1	-2024.5				avg	3.6		6.8		3.96								
Avg Bot L1	-2028.1																	
					avg total thickness			14.4	ft									
	Reference depth		-2026.3															

Table E1

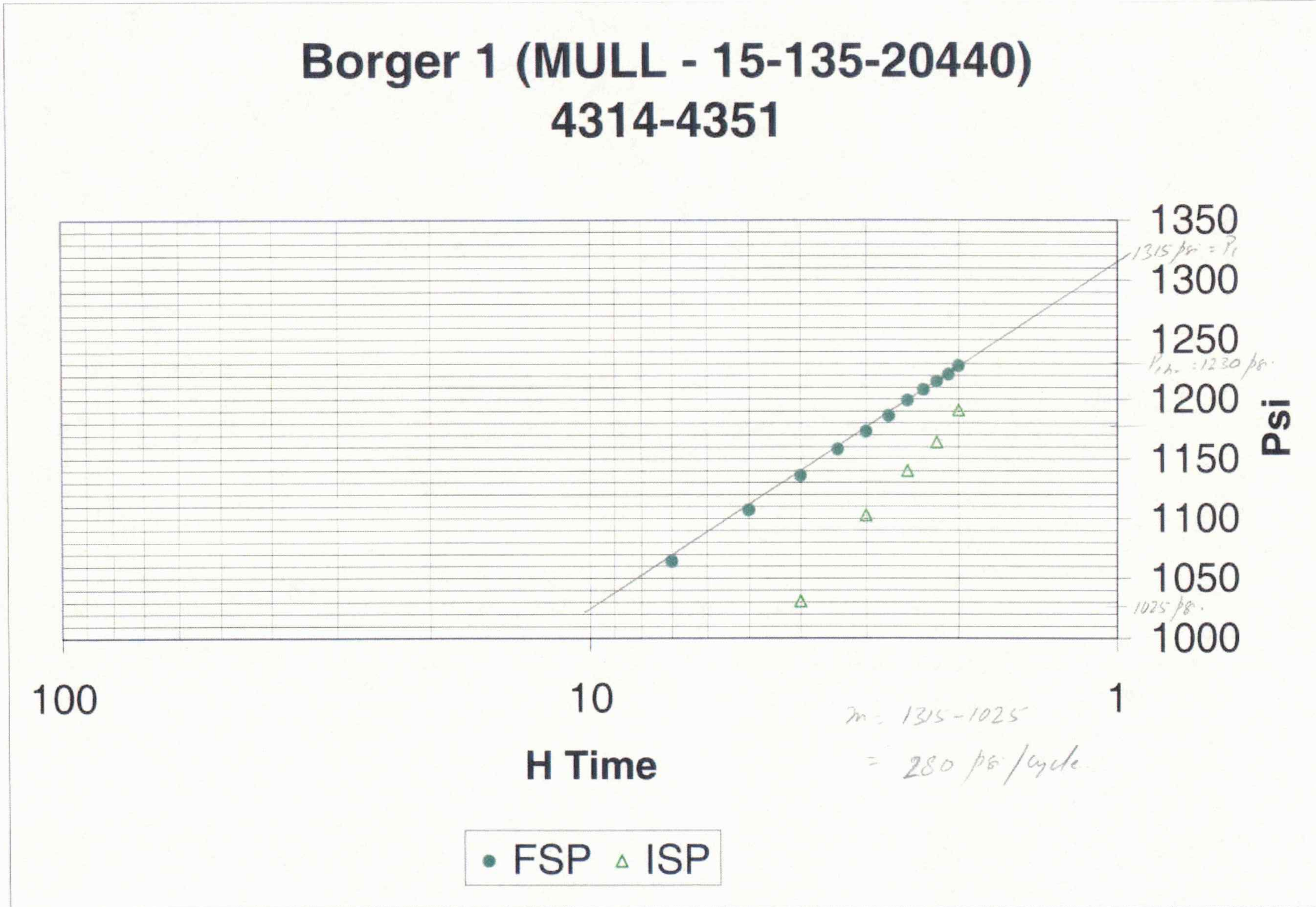

Borger 1 (MULL - 15-135-20440)
4314-4351
1350
1315 psi = Pi
1300
1250
Pi.h. :1230 psi
1200
1150
1100
1050
1025 psi
1000
Psi
100
10
1
m = 1315-1025
= 280 psi/cycle
H Time
FSP
ISP

Figure E1

Table E2

	Feet	oil %	
CO	560	100	
MO	360	50	
Production rate calculation:			
Liquid recovery:			
Total =	740	ft	
Collar length =		1046	feet
Drill collar ID =		2.76	inch
Wt pipe length =			feet
Wt pipe ID =			inch
Drill Pipe ID =		3.822	inch
Fluid in drill collar =		740	feet
Fluid in Wt Pipe =		0	feet
Fluid in Drill pipe =		0	feet
Effective ID =		2.76	inch
Effective capacity =		0.00740	bbl/ft
Pre-flow recovery:			
FFP - end of pre-flow =		238	psi
FFP - end of main flow =		386	psi
Recovery from pre-flow =		456.3	ft
Pre-flow volume =		3.4	bbl
Pre-flow time =		30	min
Pre-flow rate =		162.1	bbl/d
Main-flow recovery:			
Recovery from main-flow =		283.7	ft
Main-flow volume =		2.10	bbl
Main flow time =		30	mins
Main-flow rate =		100.8	bbl/d

	Values in Blue - from McDonald 2			
				entered data
Well:	**Borger 1**			read from correlations
	from, ft	to, ft	Pay, ft	read from Horner plot
DST range:	4314	4351	3	calculation
Perf	4341	4351		
DST analysis - Oil/Water:				
Pi =	1315	psi		
m =	280	psi/cycle		
P l hr =	1230	psi	(pressure on straight line @ del T = 60 mins)	
Qo =	100.8	bbl/d	(main flow rate)	
Pwf =	386	psi	(related to Qo - end of second flow)	
B =	1.04	RB/STB		
Phi =	0.165	(decimal)	**(eff Phi - refer Phi-from-log worksheet)**	
Mu =	1.90	cp (viscosity)		
ct =	0.000003	1/psi		
Hole diam =	7.88	inch		
rw =	0.328125	ft		
BHT =	116	oF		
Transmissibility:				
Kh/Muo =	162.6*Qo*Bo/m			
Kh/Mu =	**60.89**	**md-ft\cp**		
In-situ capacity:				
Kh =	**115.70**	**md-ft**		
Average effective permeability:				
K =	**38.6**	**md**		
Skin:				
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]				
S =	**-2.69**			
Pressure drop across skin:				
del Ps = 0.867*m*s				
del Ps =	**0.0**	**psi**		
Damage ratio:				
D.R. = (Pi - Pwf)/(Pi - Pwf - del Ps)				
D.R. =	**1.00**			

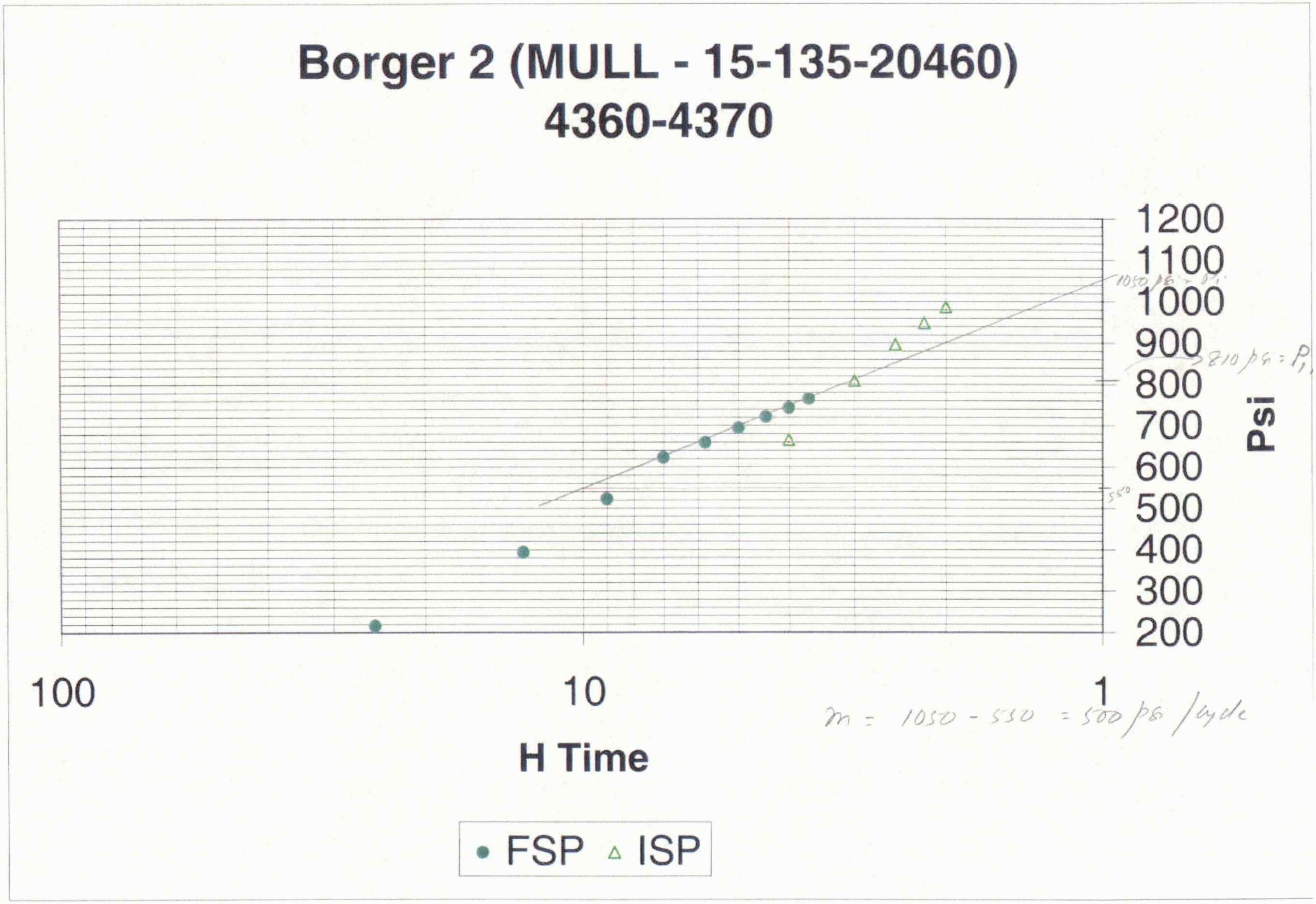

Borger 2 (MULL - 15-135-20460)
4360-4370
1200
1100
1000
900
800
700
600
500
400
300
200
Psi
100
10
1
H Time
FSP
ISP
1050 psi = Pi
810 psi = P1
550
m = 1050 - 550 = 500 psi/cycle

Figure E2

Table E3

	Feet	oil %	
CO	160	100	
MO	120	50	
Production rate calculation:			
Liquid recovery:			
Total =	220	ft	
Collar length =		947	feet
Drill collar ID =		2.76	inch
Wt pipe length =			feet
Wt pipe ID =			inch
Drill Pipe ID =		3.822	inch
Fluid in drill collar =		220	feet
Fluid in Wt Pipe =		0	feet
Fluid in Drill pipe =		0	feet
Effective ID =		2.76	inch
Effective capacity =		0.00740	bbl/ft
Pre-flow recovery:			
FFP - end of pre-flow =		41	psi
FFP - end of main flow =		111	psi
Recovery from pre-flow =		81.3	ft
Pre-flow volume =		0.6	bbl
Pre-flow time =		30	min
Pre-flow rate =		28.9	bbl/d
Main-flow recovery:			
Recovery from main-flow =		138.7	ft
Main-flow volume =		1.03	bbl
Main flow time =		90	mins
Main-flow rate =		16.4	bbl/d

	Values in Blue - from McDonald 2				
					entered data
Well:	**Borger 2**				read from correlations
	from, ft	to, ft	Pay, ft		read from Horner plot
DST range:	4360	4370	12		calculation
Perf	4360	4370			
DST analysis - Oil/Water:					
Pi =	1050	psi			
m =	500	psi/cycle			
P I hr =	810	psi	(pressure on straight line @ del T = 60 mins)		
Qo =	16.4	bbl/d	(main flow rate)		
Pwf =	111	psi	(related to Qo - end of second flow)		
B =	1.04	RB/STB			
Phi =	0.15	(decimal)	**(eff Phi - refer Phi-from-log worksheet)**		
Mu =	1.90	cp (viscosity)			
ct =	0.000003	1/psi			
Hole diam =	7.88	inch			
rw =	0.328125	ft			
BHT =	116	oF			
Transmissibility:					
Kh/Muo =	162.6*Qo*Bo/m				
Kh/Mu =	**5.56**	**md-ft\cp**			
In-situ capacity:					
Kh =	**10.56**	**md-ft**			
Average effective permeability:					
K =	**0.9**	**md**			
Skin:					
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]					
S =	**-2.71**				
Pressure drop across skin:					
del Ps = 0.867*m*s					
del Ps =	**0.0**	**psi**			
Damage ratio:					
D.R. = (Pi - Pwf)/(Pi - Pwf - del Ps)					
D.R. =	**1.00**				

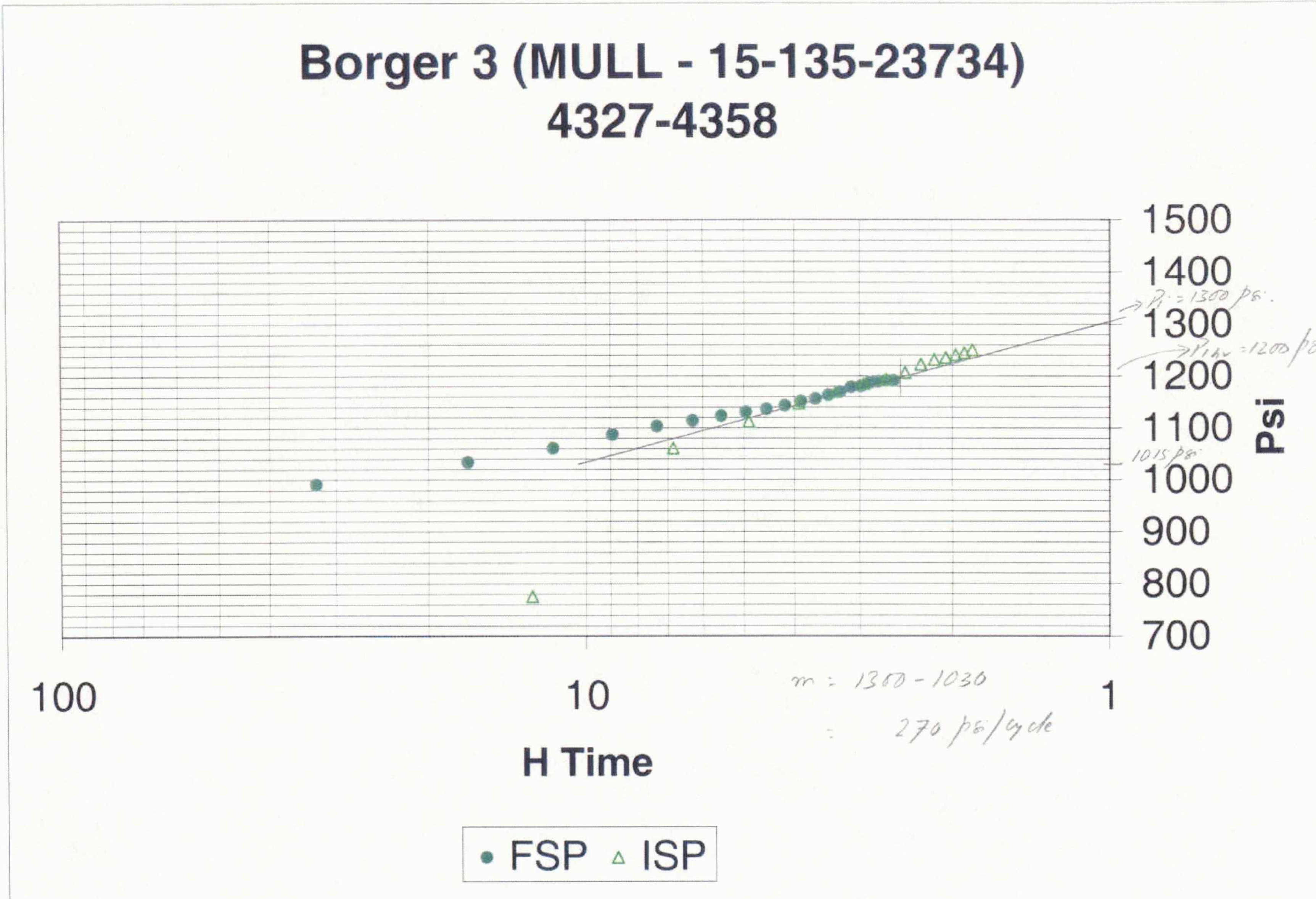

Borger 3 (MULL - 15-135-23734)
4327-4358
1500
1400
P_i = 1300 psi.
1300
P_{1hr} = 1200 psi.
1200
1100
1015 psi
1000
900
800
700
Psi
100
10
1
m = 1300 - 1030
= 270 psi/cycle
H Time
FSP
ISP

Figure E3

Table E4

	Feet	oil %
CGO	660	100
HOGCM	210	35

Production rate calculation:

Liquid recovery:

Total =	733.5	ft	
Collar length =			feet
Drill collar ID =			inch
Wt pipe length =		192	feet
Wt pipe ID =		2.7	inch
Drill Pipe ID =		3.8	inch
Fluid in drill collar =			feet
Fluid in Wt Pipe =		192	feet
Fluid in Drill pipe =		541.5	feet
Effective ID =		3.55	inch
Effective capacity =		0.01221	bbl/ft

Pre-flow recovery:

FFP - end of pre-flow =	148	psi
FFP - end of main flow =	333	psi
Recovery from pre-flow =	326.0	ft
Pre-flow volume =	4.0	bbl
Pre-flow time =	35	min
Pre-flow rate =	163.8	bbl/d

Main-flow recovery:

Recovery from main-flow =	407.5	ft
Main-flow volume =	4.98	bbl
Main flow time =	60	mins
Main-flow rate =	119.5	bbl/d

Values in Blue - from McDonald 2

Legend
entered data
read from correlations
read from Horner plot
calculation

Well:	**Borger 3**		
	from, ft	to, ft	Pay, ft
DST range:	4327	4358	2
Perf	4356	4360	

DST analysis - Oil/Water:

Pi =	1300	psi	
m =	270	psi/cycle	
P I hr =	1200	psi	(pressure on straight line @ del T = 60 mins)
Qo =	119.5	bbl/d	(main flow rate)
Pwf =	333	psi	(related to Qo - end of second flow)
B =	1.04	RB/STB	
Phi =	0.171	(decimal)	**(eff Phi - refer Phi-from-log worksheet)**
Mu =	1.90	cp (viscosity)	
ct =	0.000003	1/psi	
Hole diam =	7.88	inch	
rw =	0.328125	ft	
BHT =	122	oF	

Transmissibility:

Kh/Muo = 162.6*Qo*Bo/m

Kh/Mu = 74.82 md-ft\cp

In-situ capacity:

Kh = 142.16 md-ft

Average effective permeability:

K = 71.1 md

Skin:

S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]

S = -2.75

Pressure drop across skin:

del Ps = 0.867*m*s

del Ps = 0.0 psi

Damage ratio:

D.R. = (Pi - Pwf)/(Pi - Pwf - del Ps)

D.R. = 1.00

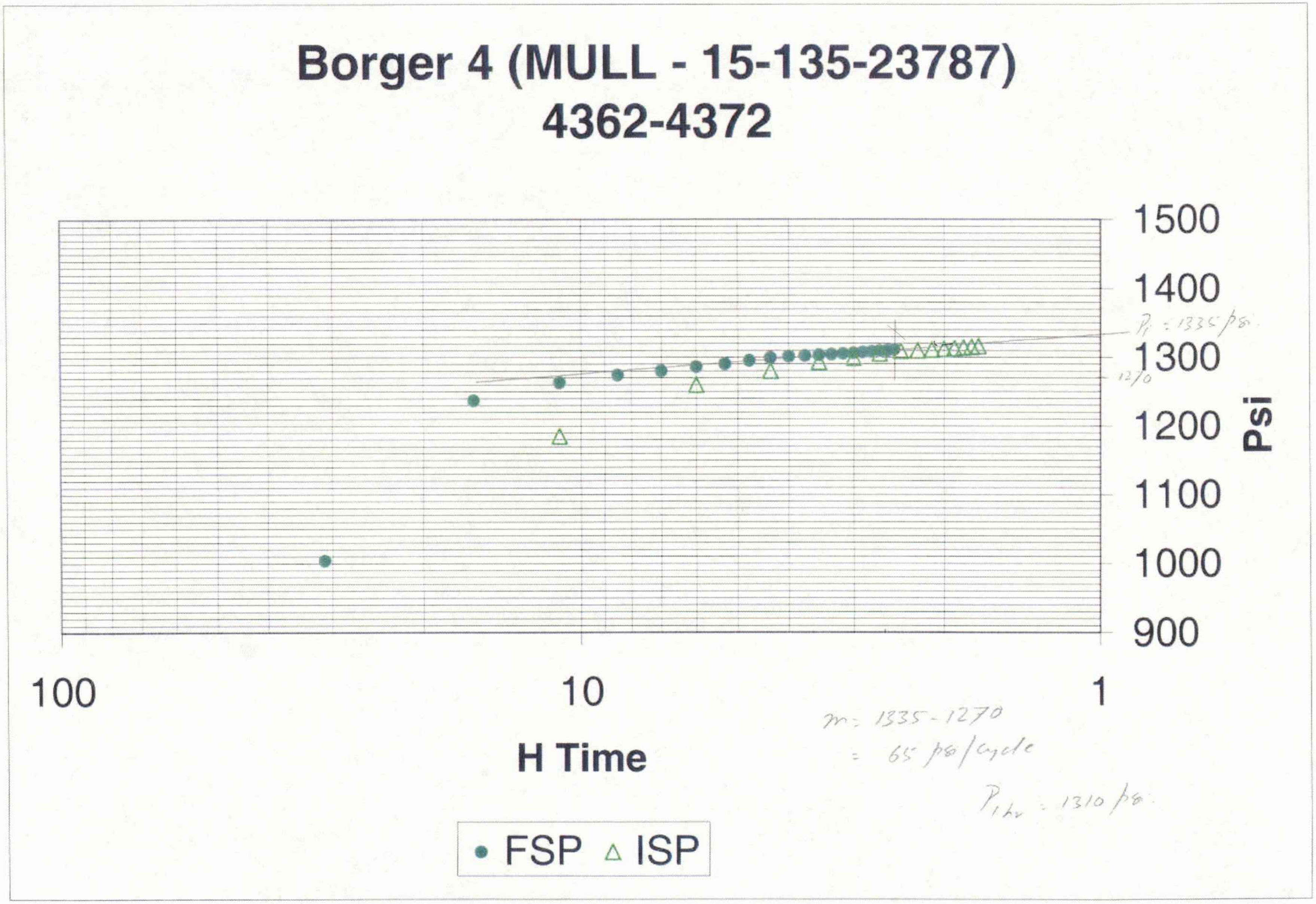

Borger 4 (MULL - 15-135-23787)
4362-4372
1500
1400
1300
1200
1100
1000
900
Psi
100
10
1
H Time
FSP
ISP
Pi = 1335 psi
1270
m = 1335 - 1270
= 65 psi/cycle
P1hr = 1310 psi

Figure E4

Table E5

	Values in Blue - from McDonald 2			
Well:	**Borger 4**			
	from, ft	to, ft	Pay, ft	
DST range:	4362	4372	2	
Perf	4354	4366		
DST analysis - Oil/Water:				
Pi =	1335	psi		
m =	65	psi/cycle		
P I hr =	1310	psi	(pressure on straight line @ del T = 60 mins)	
Qo =	72.0	bbl/d	(main flow rate)	
Pwf =	369	psi	(related to Qo - end of second flow)	
B =	1.04	RB/STB		
Phi =	**0.201**	(decimal)	**(eff Phi - refer Phi-from-log worksheet)**	
Mu =	**1.90**	cp (viscosity)		
ct =	0.000003	1/psi		
Hole diam =	7.88	inch		
rw =	0.328125	ft		
BHT =	131	oF		
Transmissibility:				
Kh/Muo =	162.6*Qo*Bo/m			
Kh/Mu =	**187.44**	**md-ft\cp**		
In-situ capacity:				
Kh =	**356.13**	**md-ft**		
Average effective permeability:				
K =	**178.1**	**md**		
Skin:				
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]				
S =	**9.84**			
Pressure drop across skin:				
del Ps = 0.867*m*s				
del Ps =	**554.4**	**psi**		
Damage ratio:				
D.R. = (Pi - Pwf)/(Pi - Pwf - del Ps)				
D.R. =	**2.35**			

entered data
read from correlations
read from Homer plot
calculation

	Feet	oil %	
GO	298	95	
MGO	72	85	
O&GCWM	62	20	
O&GCMW	186	2	
Production rate calculation:			
Liquid recovery:			
Total =	360.42	ft	
Collar length =			feet
Drill collar ID =			inch
Wt pipe length =			feet
Wt pipe ID =			inch
Drill Pipe ID =		3.8	inch
Fluid in drill collar =			feet
Fluid in Wt Pipe =			feet
Fluid in Drill pipe =		360.42	feet
Effective ID =		3.80	inch
Effective capacity =		0.01403	bbl/ft
Pre-flow recovery:			
FFP - end of pre-flow =		150	psi
FFP - end of main flow =		369	psi
Recovery from pre-flow =		146.5	ft
Pre-flow volume =		2.1	bbl
Pre-flow time =		30	min
Pre-flow rate =		98.7	bbl/d
Main-flow recovery:			
Recovery from main-flow =		213.9	ft
Main-flow volume =		3.00	bbl
Main flow time =		60	mins
Main-flow rate =		72.0	bbl/d

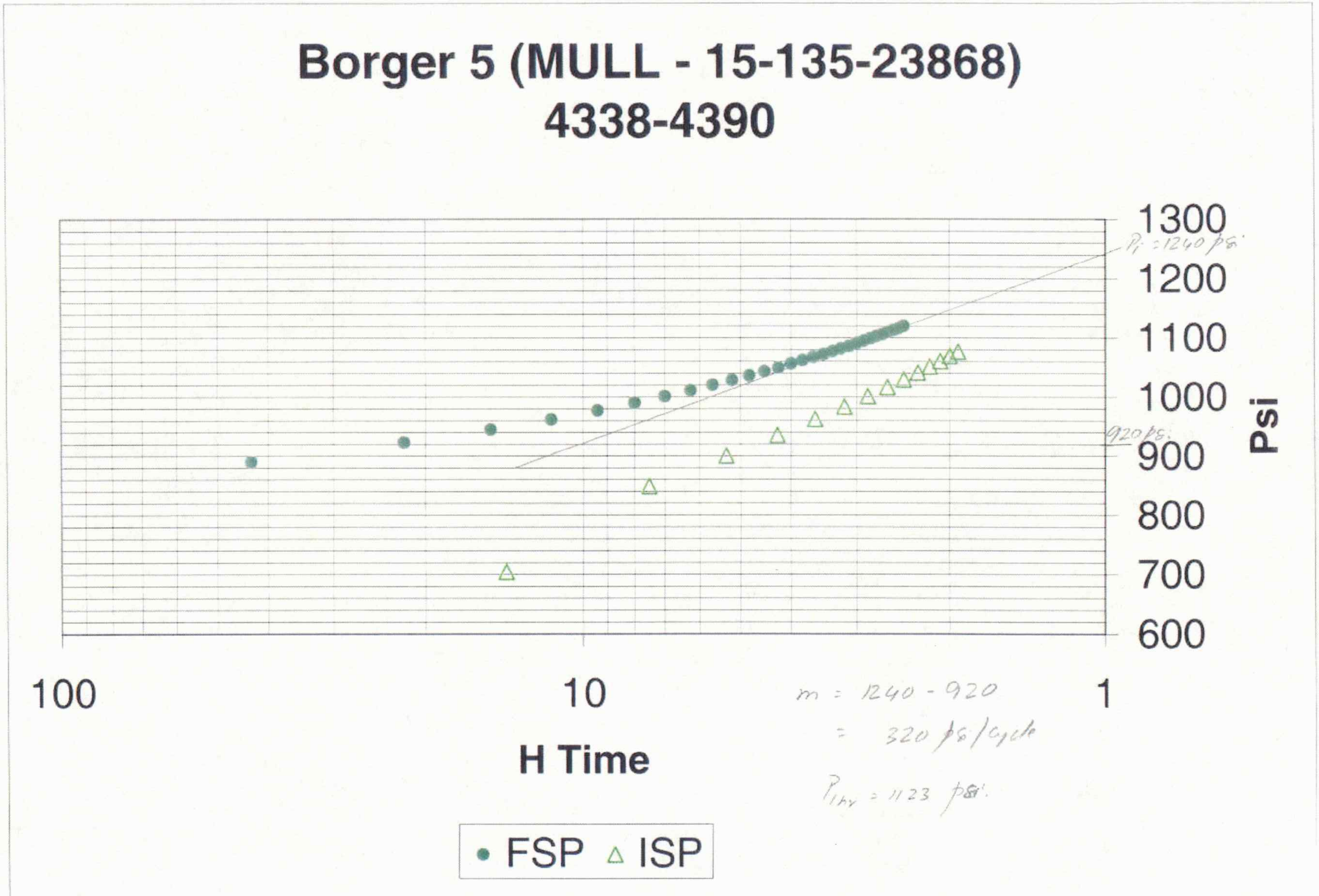

Borger 5 (MULL - 15-135-23868)
4338-4390
1300
1200
1100
1000
900
800
700
600
Psi
100
10
1
H Time
FSP
ISP
P_i = 1240 psi
920 psi
m = 1240 - 920
= 320 psi/cycle
P_{iHr} = 1123 psi

Figure E5

Table E6

	Values in Blue - from McDonald 2			
Well:	**Borger 5**			
	from, ft	to, ft	Pay, ft	
DST range:	4338	4390	16	
Perf	4360	4368		

entered data	
read from correlations	
read from Horner plot	
calculation	

DST analysis - Oil/Water:			
Pi =	1240	psi	
m =	320	psi/cycle	
P I hr =	1123	psi	(pressure on straight line @ del T = 60 mins)
Qo =	76.4	bbl/d	(main flow rate)
Pwf =	650	psi	(related to Qo - end of second flow)
B =	1.04	RB/STB	
Phi =	0.155	(decimal)	**(eff Phi - refer Phi-from-log worksheet)**
Mu =	1.90	cp (viscosity)	
ct =	0.000003	1/psi	
Hole diam =	7.88	inch	
rw =	0.328125	ft	
BHT =	128	oF	
Transmissibility:			
Kh/Muo =	162.6*Qo*Bo/m		
Kh/Mu =	**40.37**	**md-ft\cp**	
In-situ capacity:			
Kh =	**76.71**	**md-ft**	
Average effective permeability:			
K =	**4.8**	**md**	
Skin:			
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]			
S =	**-3.45**		
Pressure drop across skin:			
del Ps = 0.867*m*s			
del Ps =	**0.0**	**psi**	
Damage ratio:			
D.R. = (Pi - Pwf)/(Pi - Pwf - del Ps)			
D.R. =	**1.00**		

	Feet	oil %
GCO	40	95
GMCO	660	50
GMOCW	240	25
Production rate calculation:		
Liquid recovery:		
Total =	428	ft
Collar length =		feet
Drill collar ID =		inch
Wt pipe length =		feet
Wt pipe ID =		inch
Drill Pipe ID =	3.8	inch
Fluid in drill collar =		feet
Fluid in Wt Pipe =		feet
Fluid in Drill pipe =	428	feet
Effective ID =	3.80	inch
Effective capacity =	0.01403	bbl/ft
Pre-flow recovery:		
FFP - end of pre-flow =	317	psi
FFP - end of main flow =	650	psi
Recovery from pre-flow =	208.7	ft
Pre-flow volume =	2.9	bbl
Pre-flow time =	26	min
Pre-flow rate =	162.2	bbl/d
Main-flow recovery:		
Recovery from main-flow =	219.3	ft
Main-flow volume =	3.08	bbl
Main flow time =	58	mins
Main-flow rate =	76.4	bbl/d

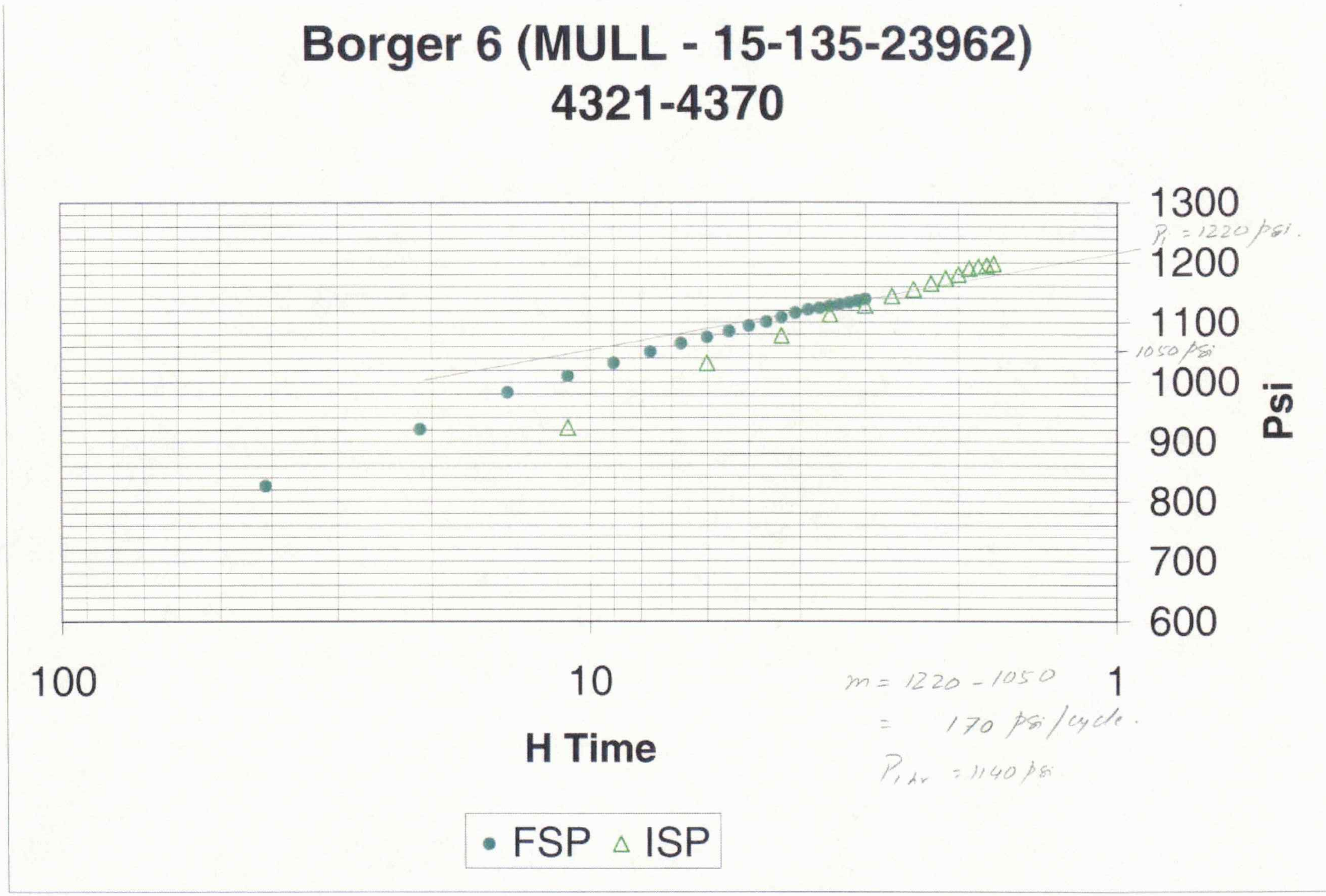
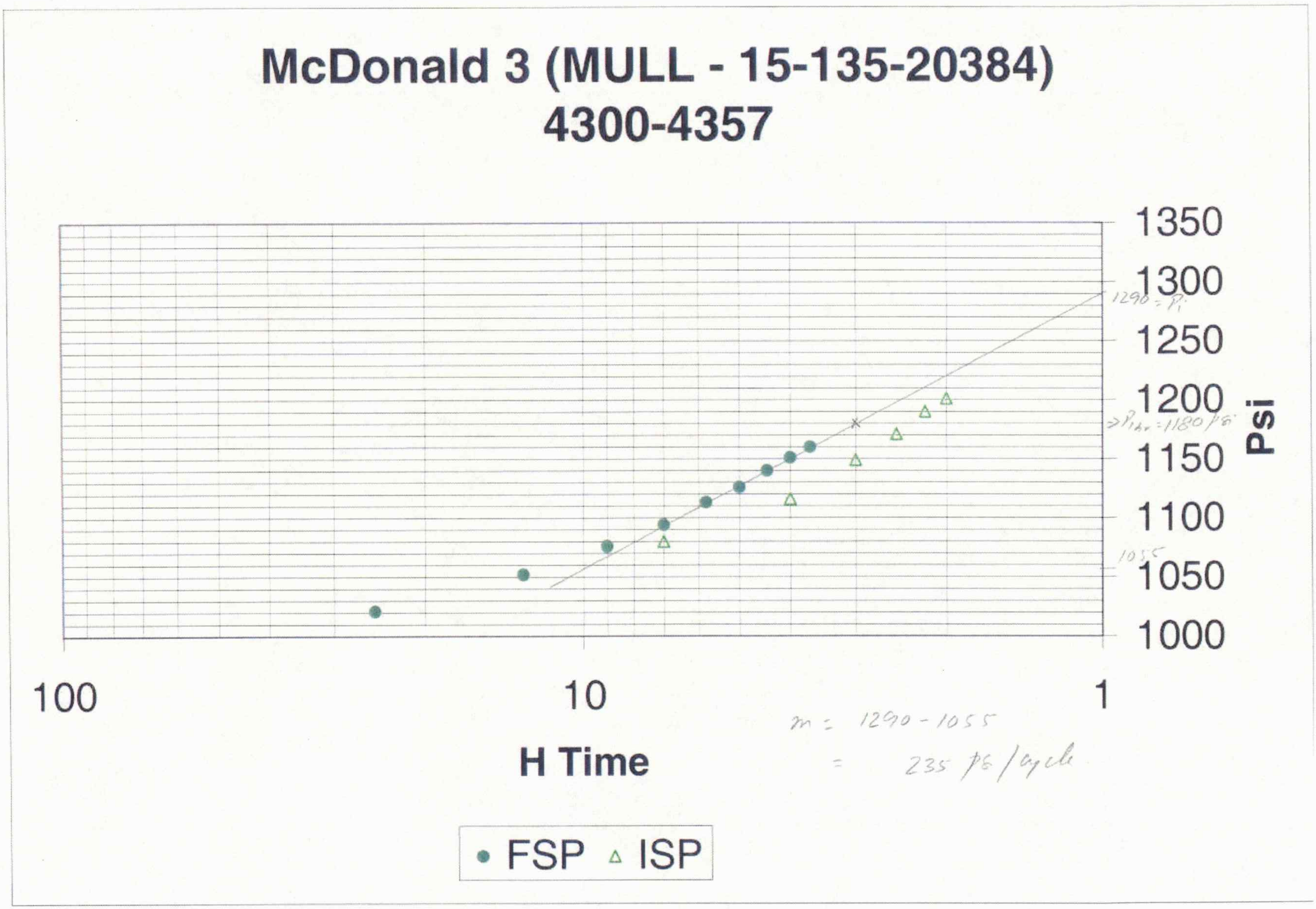

Borger 6 (MULL - 15-135-23962)
4321-4370
1300
1200
1100
1000
900
800
700
600
Psi
100
10
1
H Time
FSP
ISP
P_i = 1220 psi.
1050 psi
m = 1220 - 1050
= 170 psi/cycle.
P_{1hr} = 1140 psi

Figure E6

Table E7

	Values in Blue - from McDonald 2									
					entered data					
Well:	**Borger 6**				read from correlations					
	from, ft	to, ft	Pay, ft		read from Horner plot					
DST range:	4321	4370	4		calculation					
Perf	4368	4372								
								Feet	oil %	
							CGO	380	100	
DST analysis - Oil/Water:							GOCM	104	3	
							GHOCM	124	32	
Pi =	1220	psi					GVSOCWM	124	2	
m =	170	psi/cycle								
P I hr =	1140	psi	(pressure on straight line @ del T = 60 mins)				**Production rate calculation:**			
Qo =	40.4	bbl/d	(main flow rate)							
Pwf =	296	psi	(related to Qo - end of second flow)				***Liquid recovery:***			
B =	1.04	RB/STB								
Phi =	**0.167**	(decimal)	**(eff Phi - refer Phi-from-log worksheet)**				Total =	425.28	ft	
Mu =	1.90	cp (viscosity)								
ct =	0.000003	1/psi								
Hole diam =	7.88	inch					Collar length =			feet
rw =	0.328125	ft					Drill collar ID =			inch
BHT =	121	oF					Wt pipe length =			feet
							Wt pipe ID =			inch
							Drill Pipe ID =		3.25	inch
Transmissibility:							Fluid in drill collar =			feet
							Fluid in Wt Pipe =			feet
Kh/Muo =	162.6*Qo*Bo/m						Fluid in Drill pipe =		425.28	feet
Kh/Mu =	**40.14**	**md-ft\cp**					Effective ID =		3.25	inch
							Effective capacity =		0.01027	bbl/ft
In-situ capacity:										
							Pre-flow recovery:			
Kh =	**76.27**	**md-ft**								
							FFP - end of pre-flow =		125	psi
Average effective permeability:							FFP - end of main flow =		296	psi
K =	**19.1**	**md**					Recovery from pre-flow =		179.6	ft
							Pre-flow volume =		1.8	bbl
Skin:							Pre-flow time =		30	min
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]							Pre-flow rate =		88.5	bbl/d
S =	**-0.09**						***Main-flow recovery:***			
Pressure drop across skin:							Recovery from main-flow =		245.7	ft
							Main-flow volume =		2.52	bbl
del Ps = 0.867*m*s							Main flow time =		90	mins
del Ps =	**0.0**	**psi**					Main-flow rate =		40.4	bbl/d
Damage ratio:										
D.R. = (Pi - Pwf)/(Pi - Pwf - del Ps)										
D.R. =	**1.00**									



McDonald 3 (MULL - 15-135-20384)
4300-4357
1350
1300
1250
1200
1150
1100
1050
1000
Psi
100
10
1
H Time
FSP
ISP
1290 = Pi
P1hr = 1180 psi
1055
m = 1290 - 1055
= 235 psi/cycle

Figure E7

Table E8

	Values in Blue - from McDonald 2									
					entered data					
Well:	**McDonald 3**				read from correlations					
	from, ft	to, ft	Pay, ft		read from Horner plot					
DST range:	4300	4357	4		calculation					
Perf	4349	4357								
								Feet	oil %	
							CO	615	100	
DST analysis - Oil/Water:							MO	300	60	(emulsified)
Pi =	1290	psi								
m =	235	psi/cycle								
P I hr =	1180	psi	(pressure on straight line @ del T = 60 mins)				**Production rate calculation:**			
Qo =	52.7	bbl/d	(main flow rate)							
Pwf =	375	psi	(related to Qo - end of second flow)				***Liquid recovery:***			
B =	1.04	RB/STB								
Phi =	**0.17**	(decimal)	**(from Marty's Phi map)**				Total =	795	ft	
Mu =	1.90	cp (viscosity)								
ct =	0.000003	1/psi								
Hole diam =	7.88	inch					Collar length =		979	feet
rw =	0.328125	ft					Drill collar ID =		2.76	inch
BHT =	116	oF					Wt pipe length =			feet
							Wt pipe ID =			inch
							Drill Pipe ID =		3.822	inch
Transmissibility:							Fluid in drill collar =		795	feet
							Fluid in Wt Pipe =		0	feet
Kh/Muo =	162.6*Qo*Bo/m						Fluid in Drill pipe =		0	feet
Kh/Mu =	**37.95**	**md-ft\cp**					Effective ID =		2.76	inch
							Effective capacity =		0.00740	bbl/ft
In-situ capacity:										
							Pre-flow recovery:			
Kh =	**72.10**	**md-ft**								
							FFP - end of pre-flow =		165	psi
Average effective permeability:							FFP - end of main flow =		375	psi
K =	**18.0**	**md**					Recovery from pre-flow =		349.8	ft
							Pre-flow volume =		2.6	bbl
Skin:							Pre-flow time =		30	min
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]							Pre-flow rate =		124.3	bbl/d
S =	**-1.82**						***Main-flow recovery:***			
Pressure drop across skin:							Recovery from main-flow =		445.2	ft
							Main-flow volume =		3.30	bbl
del Ps = 0.867*m*s							Main flow time =		90	mins
del Ps =	**0.0**	**psi**					Main-flow rate =		52.7	bbl/d
Damage ratio:										
D.R. = (Pi - Pwf)/(Pi - Pwf - del Ps)										
D.R. =	**1.00**									

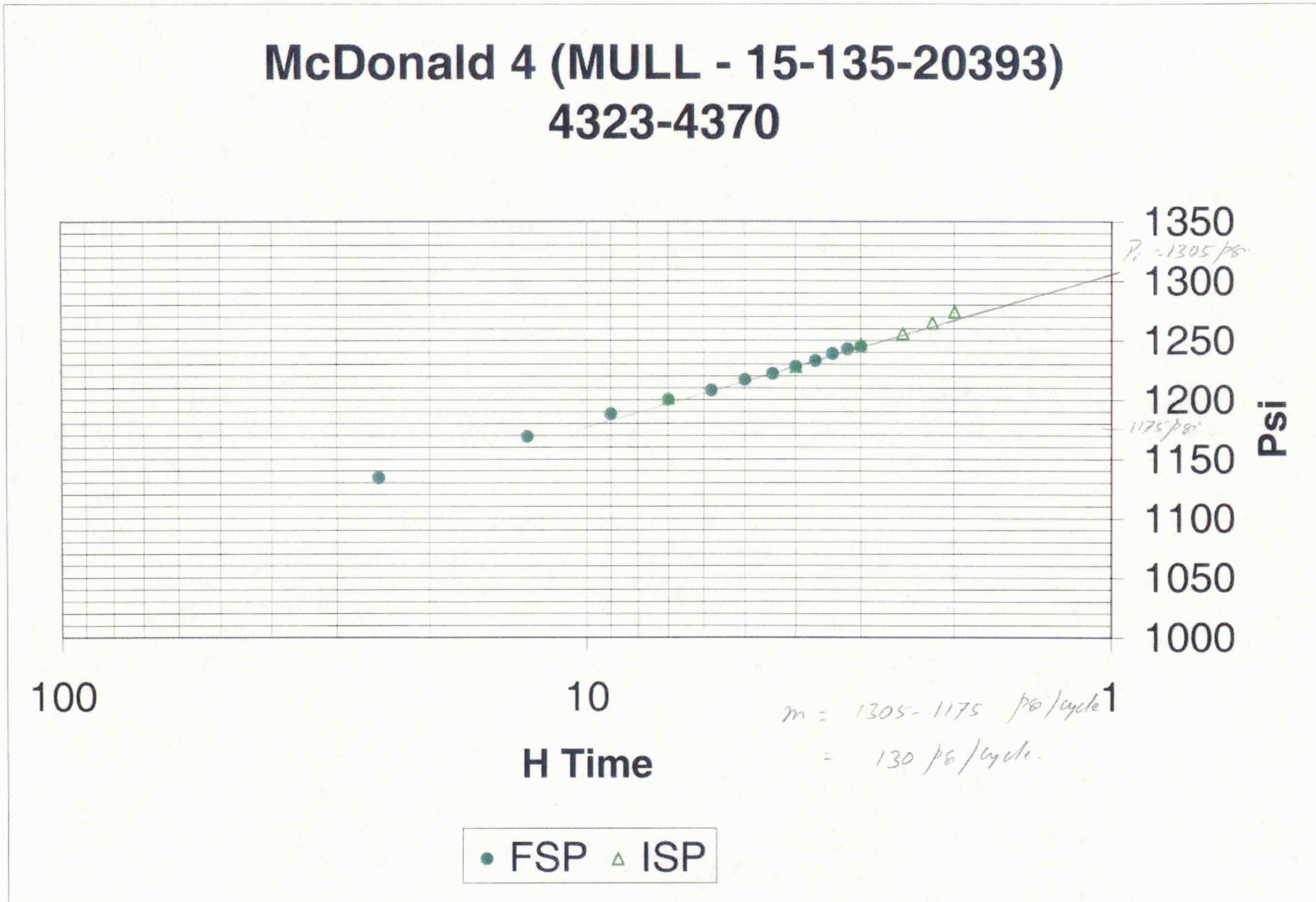

McDonald 4 (MULL - 15-135-20393)
4323-4370
1350
1300
1250
1200
1150
1100
1050
1000
Psi
100
10
1
H Time
FSP
ISP
P_i = 1305 psi
1175 psi
m = 1305 - 1175 psi/cycle
= 130 psi/cycle.

Figure E8

Table E9

Values in Blue - from McDonald 2				
				entered data
Well:	McDonald 4			read from correlations
	from, ft	to, ft	Pay, ft	read from Horner plot
DST range:	4323	4370	8	calculation
Perf	4358	4370		

	Feet	oil %
CO	1370	100

DST analysis - Oil/Water:

Pi =	1305	psi	
m =	130	psi/cycle	
P I hr =	1245	psi	(pressure on straight line @ del T = 60 mins)
Qo =	85.2	bbl/d	(main flow rate)
Pwf =	644	psi	(related to Qo - end of second flow)
B =	1.04	RB/STB	
Phi =	0.158	(decimal)	**(eff Phi - refer Phi-from-log)**
Mu =	1.90	cp (viscosity)	
ct =	0.000003	1/psi	
Hole diam =	7.88	inch	
rw =	0.328125	ft	
BHT =	115	oF	

Transmissibility:

Kh/Muo =	162.6*Qo*Bo/m	
Kh/Mu =	**110.79**	**md-ft\cp**

In-situ capacity:

Kh =	**210.51**	**md-ft**

Average effective permeability:

K =	**26.3**	**md**

Skin:

S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]

S =	**-0.67**

Pressure drop across skin:

del Ps = 0.867*m*s

del Ps =	**0.0**	**psi**

Damage ratio:

D.R. = (Pi - Pwf)/(Pi - Pwf - del Ps)

D.R. =	**1.00**

Production rate calculation:

Liquid recovery:

Total =	1370	ft
Collar length =	1815	feet
Drill collar ID =	2.76	inch
Wt pipe length =		feet
Wt pipe ID =		inch
Drill Pipe ID =	3.822	inch
Fluid in drill collar =	1370	feet
Fluid in Wt Pipe =	0	feet
Fluid in Drill pipe =	0	feet
Effective ID =	2.76	inch
Effective capacity =	0.00740	bbl/ft

Pre-flow recovery:

FFP - end of pre-flow =	306	psi
FFP - end of main flow =	644	psi
Recovery from pre-flow =	651.0	ft
Pre-flow volume =	4.8	bbl
Pre-flow time =	30	min
Pre-flow rate =	231.3	bbl/d

Main-flow recovery:

Recovery from main-flow =	719.0	ft
Main-flow volume =	5.32	bbl
Main flow time =	90	mins
Main-flow rate =	85.2	bbl/d

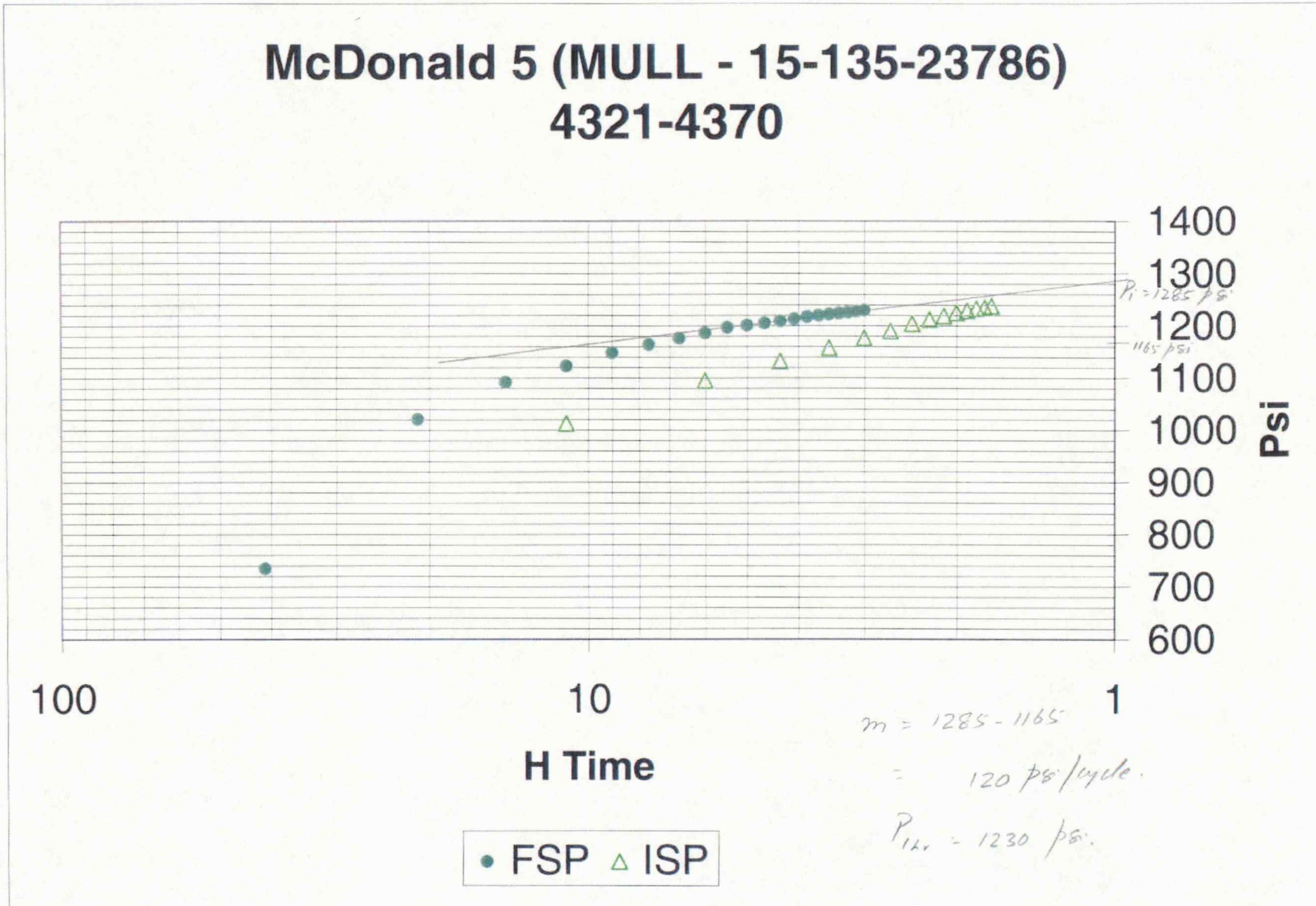

McDonald 5 (MULL - 15-135-23786)
4321-4370
1400
1300
1200
1100
1000
900
800
700
600
Psi
100
10
1
H Time
FSP
ISP
Pi = 1285 psi
1165 psi
m = 1285 - 1165
= 120 psi/cycle.
P1hr = 1230 psi.

Figure E9

Table E10

	Values in Blue - from McDonald 2								
					entered data				
Well:	**McDonald 5**				read from correlations				
	from, ft	to, ft	Pay, ft		read from Horner plot				
DST range:	4358	4374	12		calculation				
Perf	D&A								
							Feet	oil %	
						CO	124	100	
DST analysis - Oil/Water:						SOCWM	62	2	
						SOCMW	62	1	
Pi =	1285	psi							
m =	120	psi/cycle							
P I hr =	1230	psi	(pressure on straight line @ del T = 60 mins)			**Production rate calculation:**			
Qo =	17.3	bbl/d	(main flow rate)						
Pwf =	101	psi	(related to Qo - end of second flow)			***Liquid recovery:***			
B =	1.04	RB/STB							
Phi =	0.143	(decimal)	**(eff Phi - refer Phi-from-log worksheet)**			Total =	125.86	ft	
Mu =	1.90	cp (viscosity)							
ct =	0.000003	1/psi							
Hole diam =	7.88	inch				Collar length =			feet
rw =	0.328125	ft				Drill collar ID =			inch
BHT =	130	oF				Wt pipe length =			feet
						Wt pipe ID =			inch
						Drill Pipe ID =		3.8	inch
Transmissibility:						Fluid in drill collar =			feet
						Fluid in Wt Pipe =			feet
Kh/Muo =	162.6*Qo*Bo/m					Fluid in Drill pipe =		125.86	feet
Kh/Mu =	**24.45**	**md-ft\cp**				Effective ID =		3.80	inch
						Effective capacity =		0.01403	bbl/ft
In-situ capacity:									
						Pre-flow recovery:			
Kh =	**46.45**	**md-ft**							
						FFP - end of pre-flow =		39	psi
Average effective permeability:						FFP - end of main flow =		101	psi
K =	**3.9**	**md**				Recovery from pre-flow =		48.6	ft
						Pre-flow volume =		0.7	bbl
Skin:						Pre-flow time =		30	min
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]						Pre-flow rate =		32.7	bbl/d
S =	**5.75**					***Main-flow recovery:***			
Pressure drop across skin:						Recovery from main-flow =		77.3	ft
						Main-flow volume =		1.08	bbl
del Ps = 0.867*m*s						Main flow time =		90	mins
del Ps =	**598.0**	**psi**				Main-flow rate =		17.3	bbl/d
Damage ratio:									
D.R. = (Pi - Pwf)/(Pi - Pwf - del Ps)									
D.R. =	**2.02**								


Reservoir pressure profile - McDonald
Pi, psi
1600
1400
1200
1000
800
600
400
200
0
1/1/70
6/24/75
12/14/80
6/6/86
11/27/91
5/19/97

Figure E10

Appendix F

PVT & Relative Permeability/Capillary Pressure Inputs

Table F1

Additional reservoir properties		
Reservoir temp	125	F
Oil gravity	36	API
Gas gr (Air = 1)	0.8	
Water salinity	17000	ppm
Initial reservoir pressure	1400	psi
Bubble point pressure	50	psi

Table F2

K, md

Phi (%)

k=2.6792*10^(-13)*Phi^11.4236

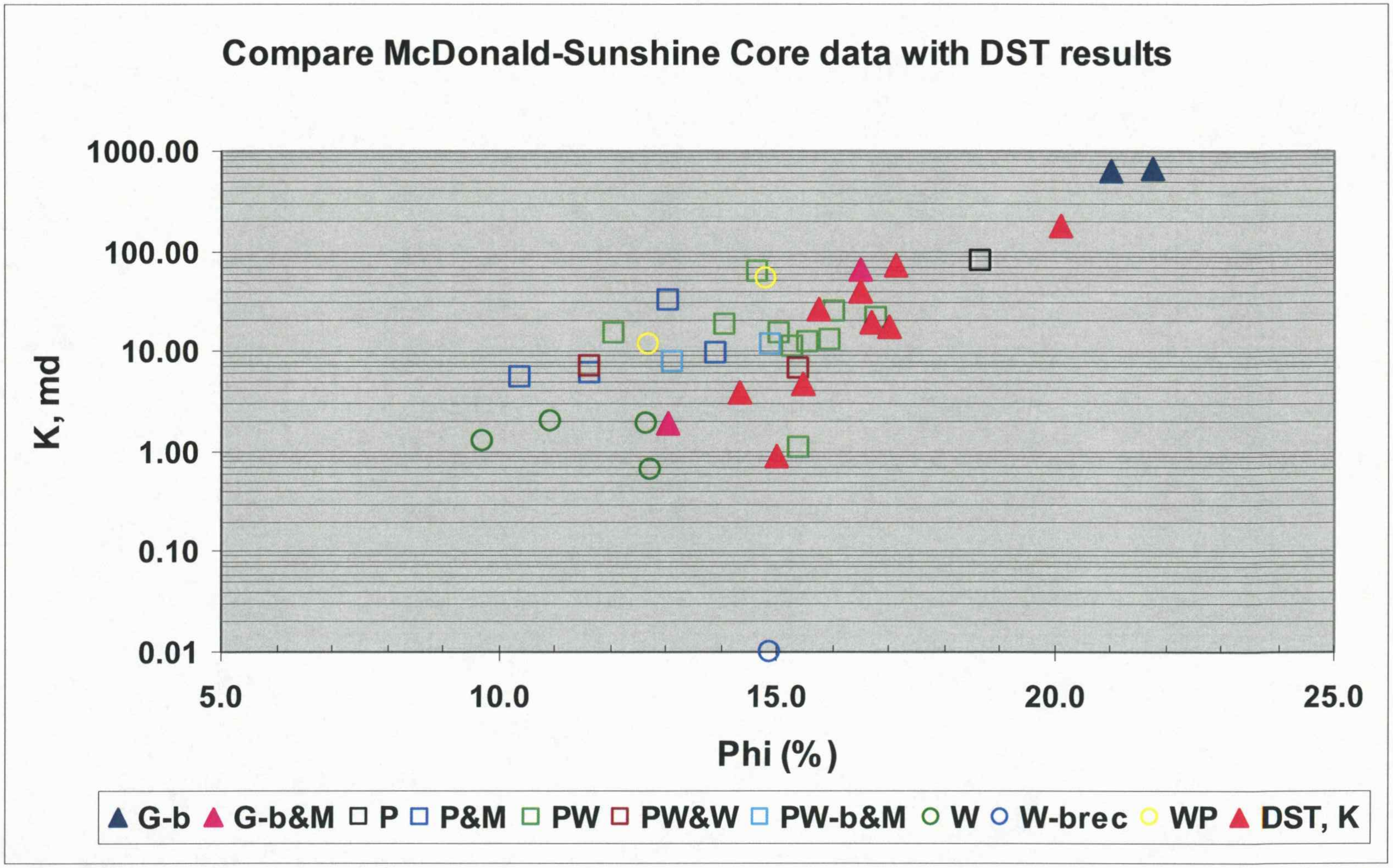
K(md)=	21.68	Phi(%)=	16.5		
Krwmax=	0.22	Kromax=	1	Pcentry=	0.690
Krw -m=	0.5	Swi=	0.239	Pcslope=	-1.002
Kro - n=	3.1	Sorw=	0.261	PcSwiH(ft)=	40.0
water grad	0.438	W sp grav=	1.0111	input value	
oil grad	0.365	Oil sp grav=	0.8439	calc value	
Krgmax=		Kromax=			
Krg -m=		Sgc for kro=		Sgc for krg=	
Kro - n=		Sorg for kro=		Sorg for krg=	
IFTgo/IFTow=		Sorg for kro=			

Note: krg calculated using SwDkrg to allow Sgc>0 while still allowing kro approach 1 below Sgc

Calculator for McDonald/Sunshine Fields

SW	KRW	KROW	PCOW	Height above free water (ft)	SwD
0.2388	0.000000	1.000000	2.896	40.00	0.00000
0.2500	0.032862	0.932441	2.766	38.21	0.02231
0.3000	0.076941	0.667352	2.305	31.83	0.12231
0.3500	0.103730	0.458667	1.975	27.28	0.22231
0.4000	0.124899	0.299360	1.728	23.86	0.32231
0.4500	0.142968	0.182495	1.535	21.21	0.42231
0.5000	0.158996	0.101239	1.382	19.08	0.52231
0.5500	0.173551	0.048878	1.256	17.35	0.62231
0.6000	0.186976	0.018838	1.151	15.90	0.72231
0.6500	0.199499	0.004720	1.062	14.67	0.82231
0.7000	0.211282	0.000363	0.986	13.62	0.92231
0.7500	0.220000	0.000000	0.920	12.71	1.00000
0.8000	0.220000	0.000000	0.863	11.92	1.00000
0.8500	0.220000	0.000000	0.812	11.21	1.00000
0.9000	0.220000	0.000000	0.767	10.59	1.00000
0.9500	0.220000	0.000000	0.726	10.03	1.00000
1.0000	0.220000	0.000000	0.690	9.53	1.00000
1.0000	0.220000	0.000000	0.690	9.53	1.00000
1.0000	0.220000	0.000000	0.690	9.53	1.00000
1.0000	0.220000	0.000000	0.690	9.53	1.00000
1.0000	0.220000	0.000000	0.690	9.53	1.00000

Figure F1



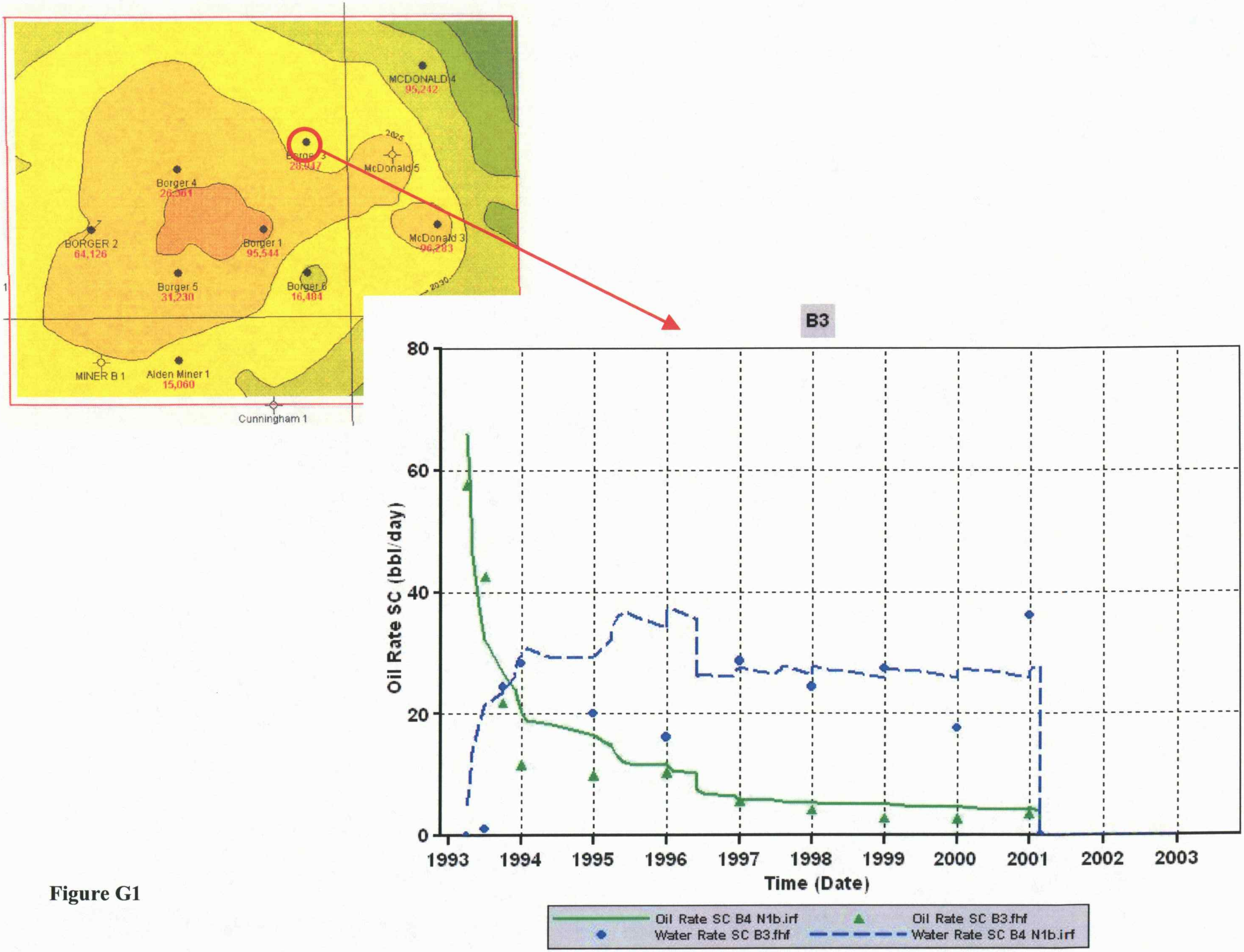
Compare McDonald-Sunshine Core data with DST results
1000.00
100.00
10.00
1.00
0.10
0.01
K, md
5.0
10.0
15.0
20.0
25.0
Phi (%)
G-b
G-b&M
P
P&M
PW
PW&W
PW-b&M
W
W-brec
WP
DST, K

Appendix G
Simulation Study
- History Match

Table G1

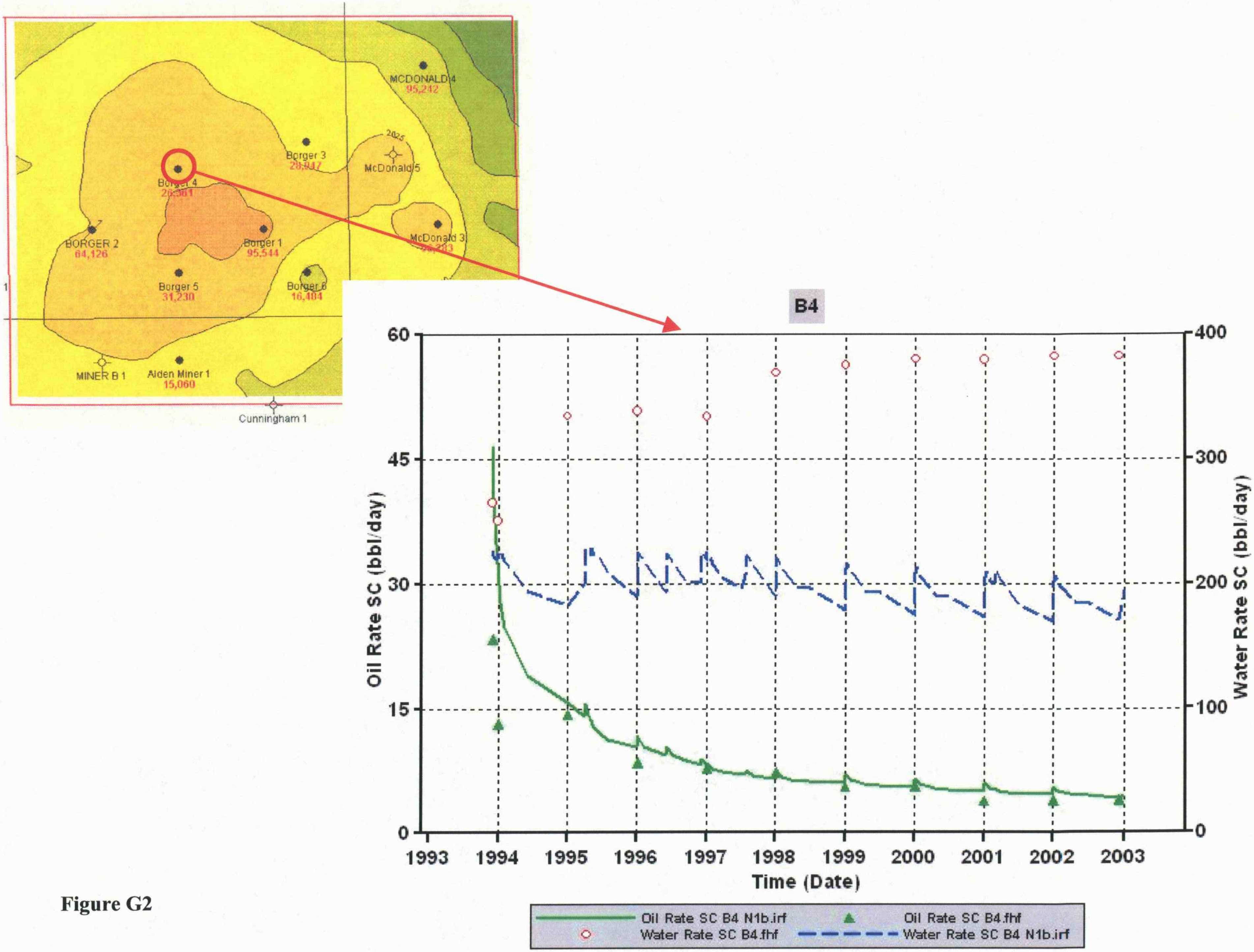
Well completions in reservoir simulation model

WELLNAME	Miss L1	Miss L2	Miss L3	Base Miss	Perf T	Perf B	KB	Perf T	Perf B	Perforations in Sim		
McDonald 3	-2021	-2025	-2032	-2036	4349	4357	2332	-2017	-2025	L1	L2	
McDonald 4	-2031	-2034	-2039	-2043	4358	4370	2327	-2031	-2043	L1	L2	L3
McDonald 5	-2021	-2025	-2033	-2037			2329	2329	2329			
Borger 1	-2019	-2022	-2030.2	-2033.8	4341	4351	2326	-2015	-2025	L1	L2	
Borger 2	-2025	-2029	-2035	-2041	4360	4370	2335	-2025	-2035	L1	L2	
Borger 3	-2027	-2029	-2033	-2038	4356	4360	2329	-2027	-2031	L1	L2	
Borger 4	-2021	-2026	-2030	-2034	4354	4366	2332	-2022	-2034	L1	L2	L3
Borger 5	-2023	-2026	-2036	-2039	4360	4368	2336	-2024	-2032	L1	L2	
Borger 6	-2031	-2035	-2043	-2047	4368	4372	2337	-2031	-2035	L1		
Alden Miner 1	-2026	-2030	-2038	-2042	4370	4374	2340	-2030	-2034		L2	



MCDONALD 4
95,242
2025
McDonald 5
Borger 4
BORGER 2
64,126
Borger 1
95,544
McDonald 3
Borger 5
31,230
Borger 6
16,484
2030
MINER B 1
Alden Miner 1
15,060
Cunningham 1
B3
80
60
40
20
0
Oil Rate SC (bbl/day)
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
Time (Date)
Oil Rate SC B4 N1b.irf
Oil Rate SC B3.fhf
Water Rate SC B3.fhf
Water Rate SC B4 N1b.irf

Figure G1



MCDONALD 4
95,242
McDonald 5
Borger 3
Borger 4
BORGER 2
64,126
Borger 1
95,544
McDonald 3
Borger 5
31,230
Borger 6
16,404
MINER B 1
Alden Miner 1
15,060
Cunningham 1
B4
60
45
30
15
0
400
300
200
100
0
Oil Rate SC (bbl/day)
Water Rate SC (bbl/day)
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
Time (Date)
Oil Rate SC B4 N1b.irf
Oil Rate SC B4.fhf
Water Rate SC B4.fhf
Water Rate SC B4 N1b.irf

Figure G2

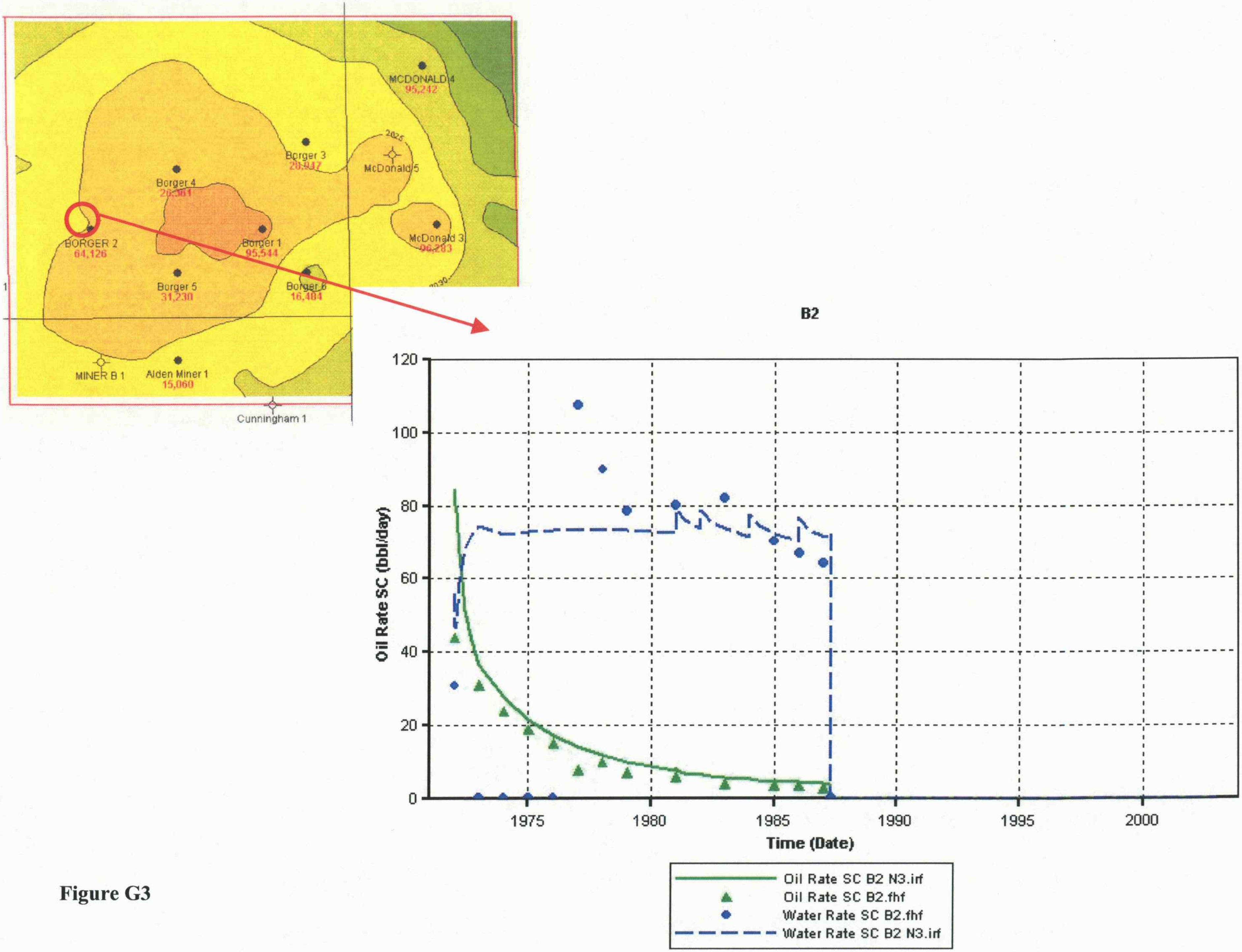

MCDONALD 4
95,242
2025
Borger 3
McDonald 5
Borger 4
BORGER 2
64,126
Borger 1
95,544
McDonald 3
96,283
Borger 5
31,230
Borger 6
16,484
MINER B 1
Alden Miner 1
15,060
Cunningham 1
B2
Oil Rate SC (bbl/day)
120
100
80
60
40
20
0
1975
1980
1985
1990
1995
2000
Time (Date)
Oil Rate SC B2 N3.irf
Oil Rate SC B2.fhf
Water Rate SC B2.fhf
Water Rate SC B2 N3.irf

Figure G3

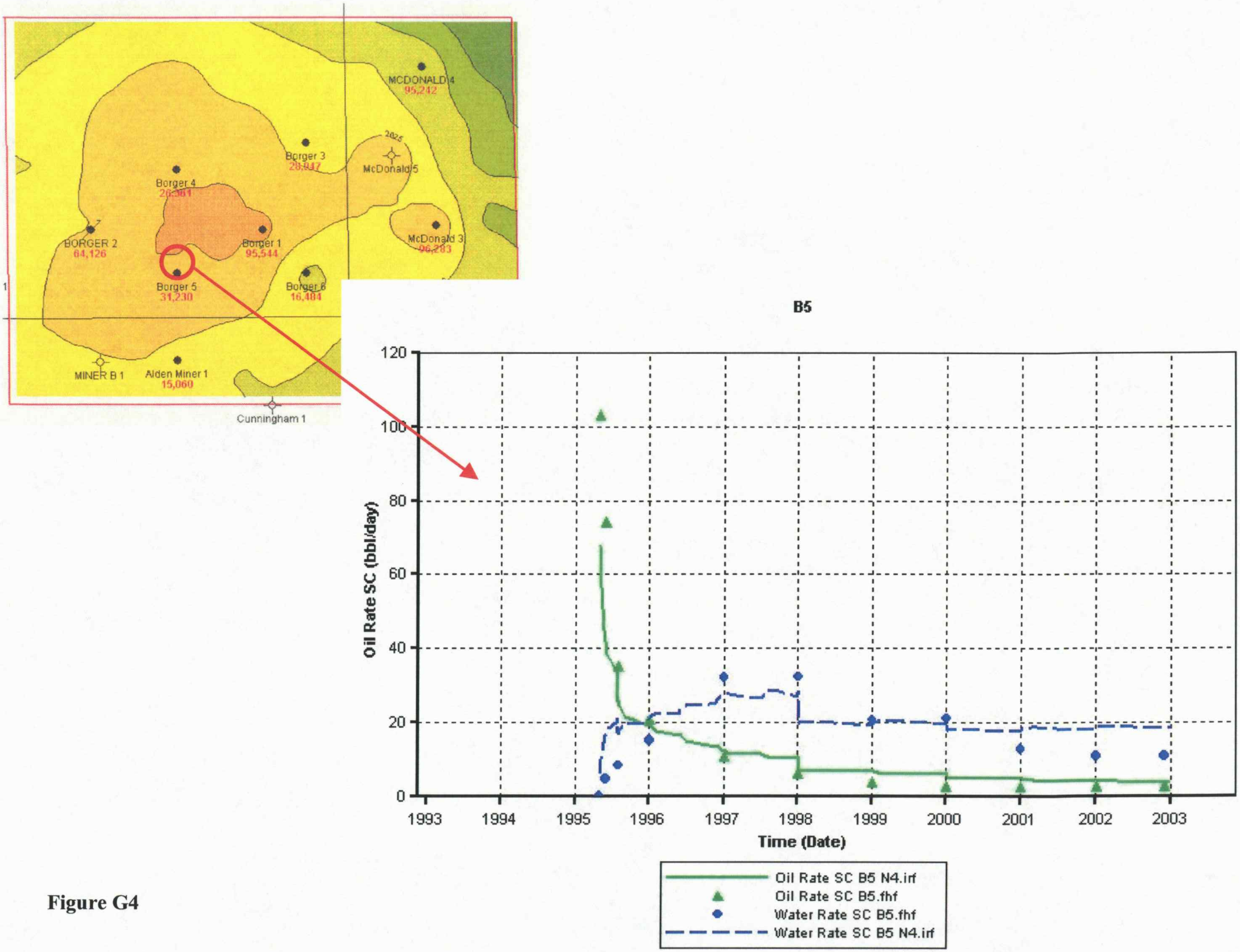
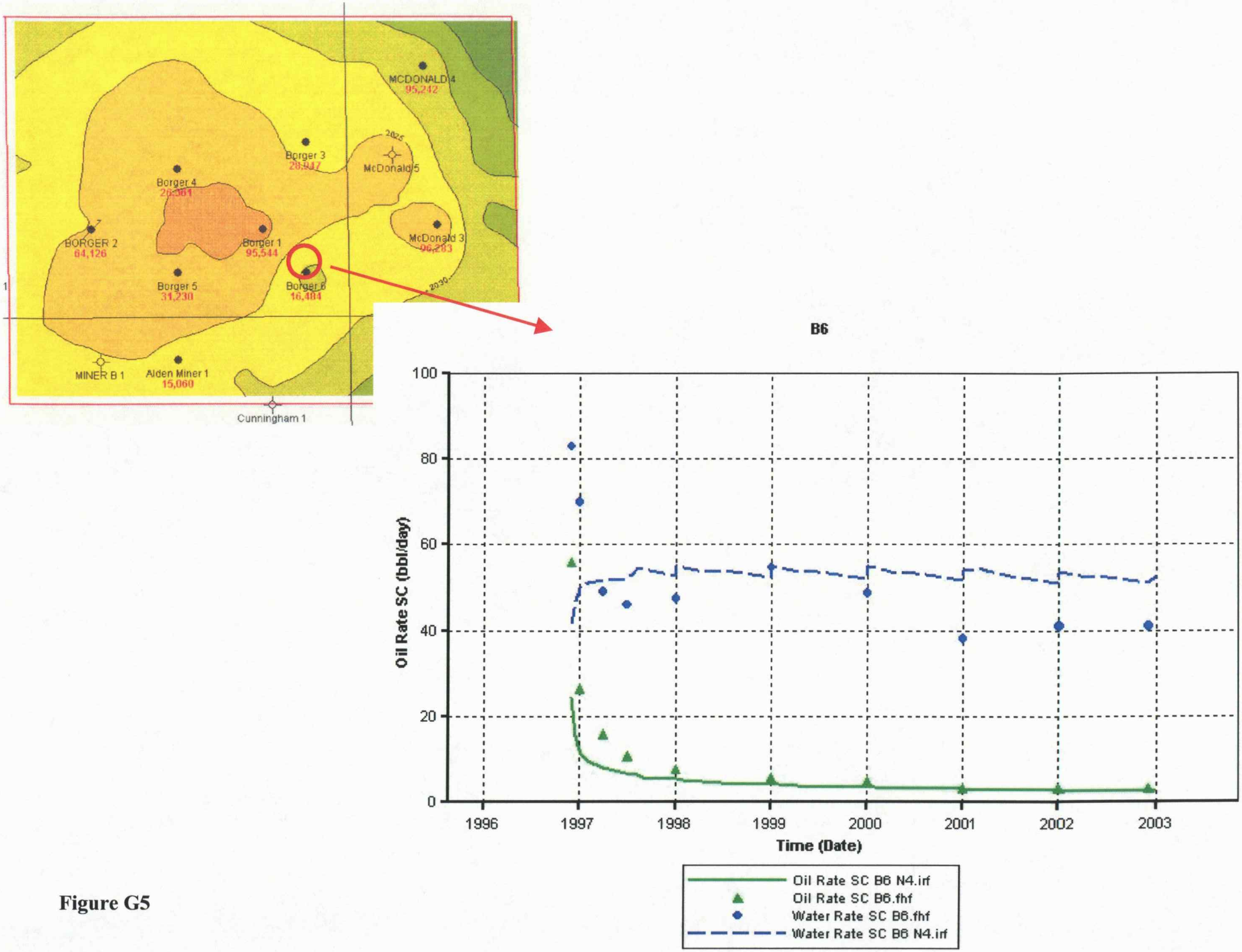
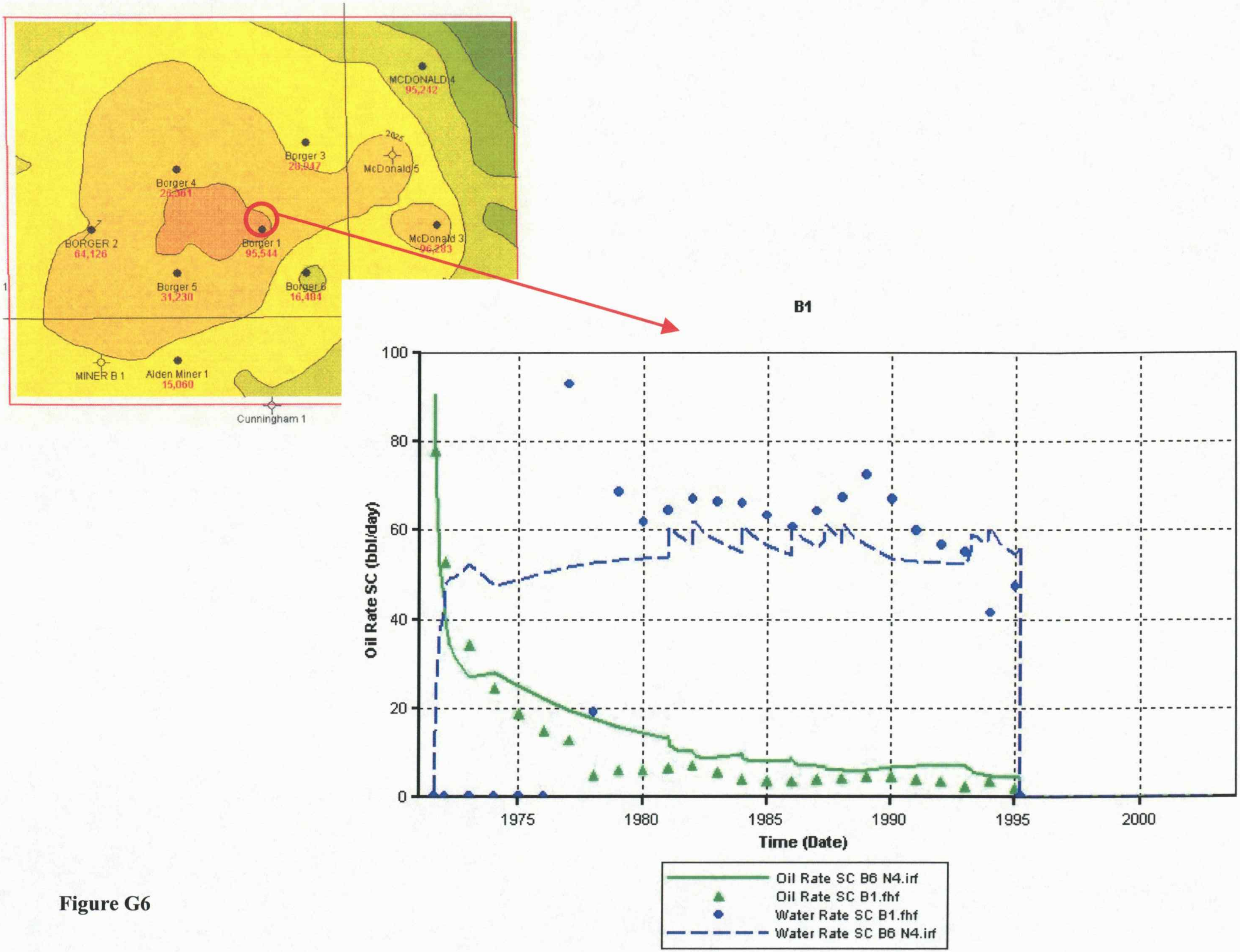

MCDONALD 4
95,242
Borger 3
28,047
McDonald 5
2025
Borger 4
26,361
BORGER 2
64,126
Borger 1
95,544
McDonald 3
96,283
Borger 5
31,230
Borger 6
16,484
MINER B 1
Alden Miner 1
15,060
Cunningham 1
B5
Oil Rate SC (bbl/day)
120
100
80
60
40
20
0
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
Time (Date)
Oil Rate SC B5 N4.irf
Oil Rate SC B5.fhf
Water Rate SC B5.fhf
Water Rate SC B5 N4.irf

Figure G4



MCDONALD 4
95,242
2025
Borger 3
McDonald 5
Borger 4
BORGER 2
64,126
Borger 1
95,544
McDonald 3
96,283
Borger 5
31,230
Borger 6
16,484
2030
MINER B 1
Alden Miner 1
15,060
Cunningham 1
B6
Oil Rate SC (bbl/day)
0
20
40
60
80
100
1996
1997
1998
1999
2000
2001
2002
2003
Time (Date)
Oil Rate SC B6 N4.irf
Oil Rate SC B6.fhf
Water Rate SC B6.fhf
Water Rate SC B6 N4.irf

Figure G5



MCDONALD 4
95,242
2025
Borger 3
28,947
McDonald 5
Borger 4
26,361
BORGER 2
64,126
Borger 1
95,544
McDonald 3
96,283
Borger 5
31,230
Borger 6
16,484
MINER B 1
Alden Miner 1
15,060
Cunningham 1
B1
Oil Rate SC (bbl/day)
100
80
60
40
20
0
1975
1980
1985
1990
1995
2000
Time (Date)
Oil Rate SC B6 N4.irf
Oil Rate SC B1.fhf
Water Rate SC B1.fhf
Water Rate SC B6 N4.irf

Figure G6

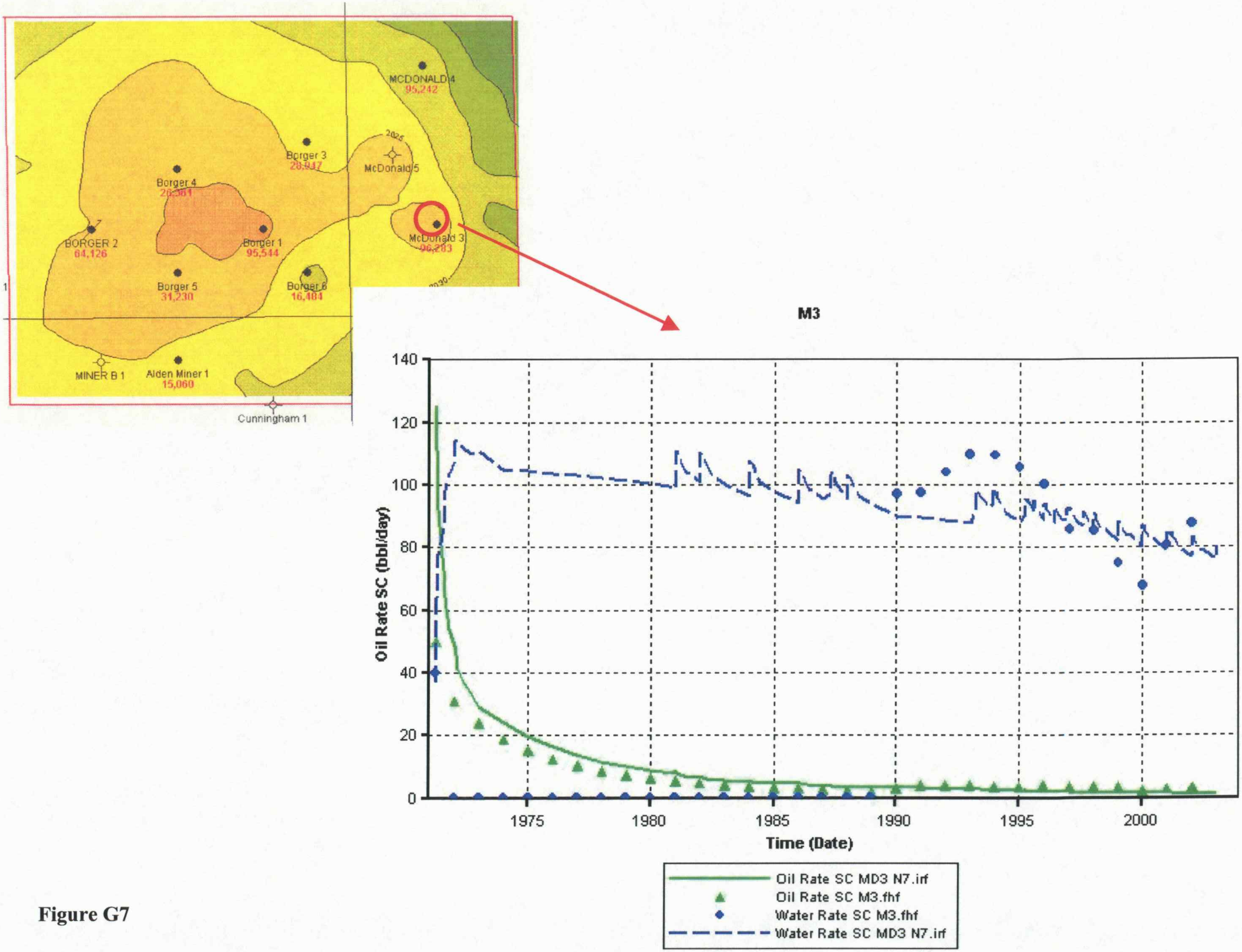
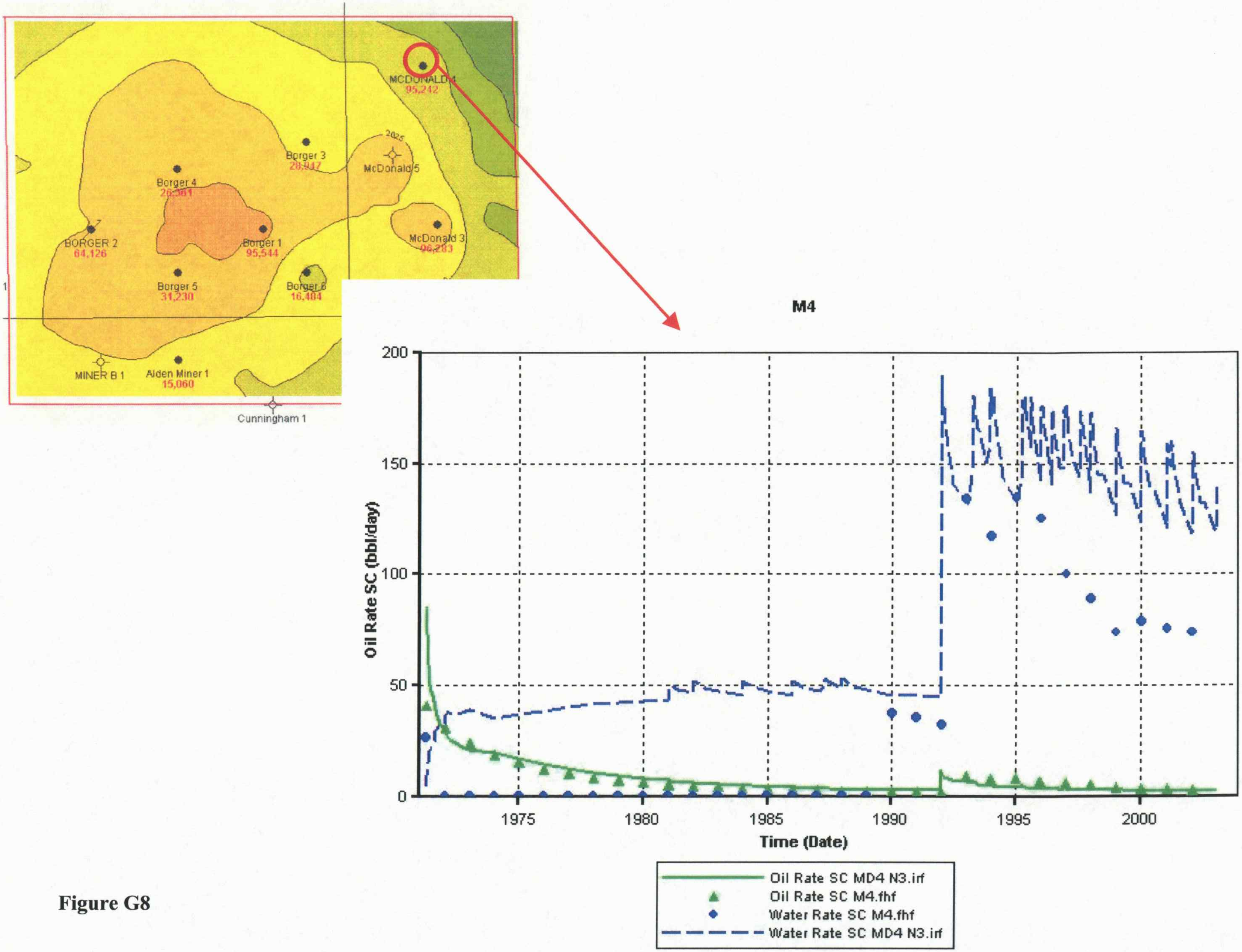

MCDONALD 4
95,242
2025
Borger 3
McDonald 5
Borger 4
BORGER 2
64,126
Borger 1
95,544
McDonald 3
Borger 5
31,230
Borger 6
16,484
MINER B 1
Alden Miner 1
15,060
Cunningham 1
M3
Oil Rate SC (bbl/day)
Time (Date)
Oil Rate SC MD3 N7.irf
Oil Rate SC M3.fhf
Water Rate SC M3.fhf
Water Rate SC MD3 N7.irf

Figure G7

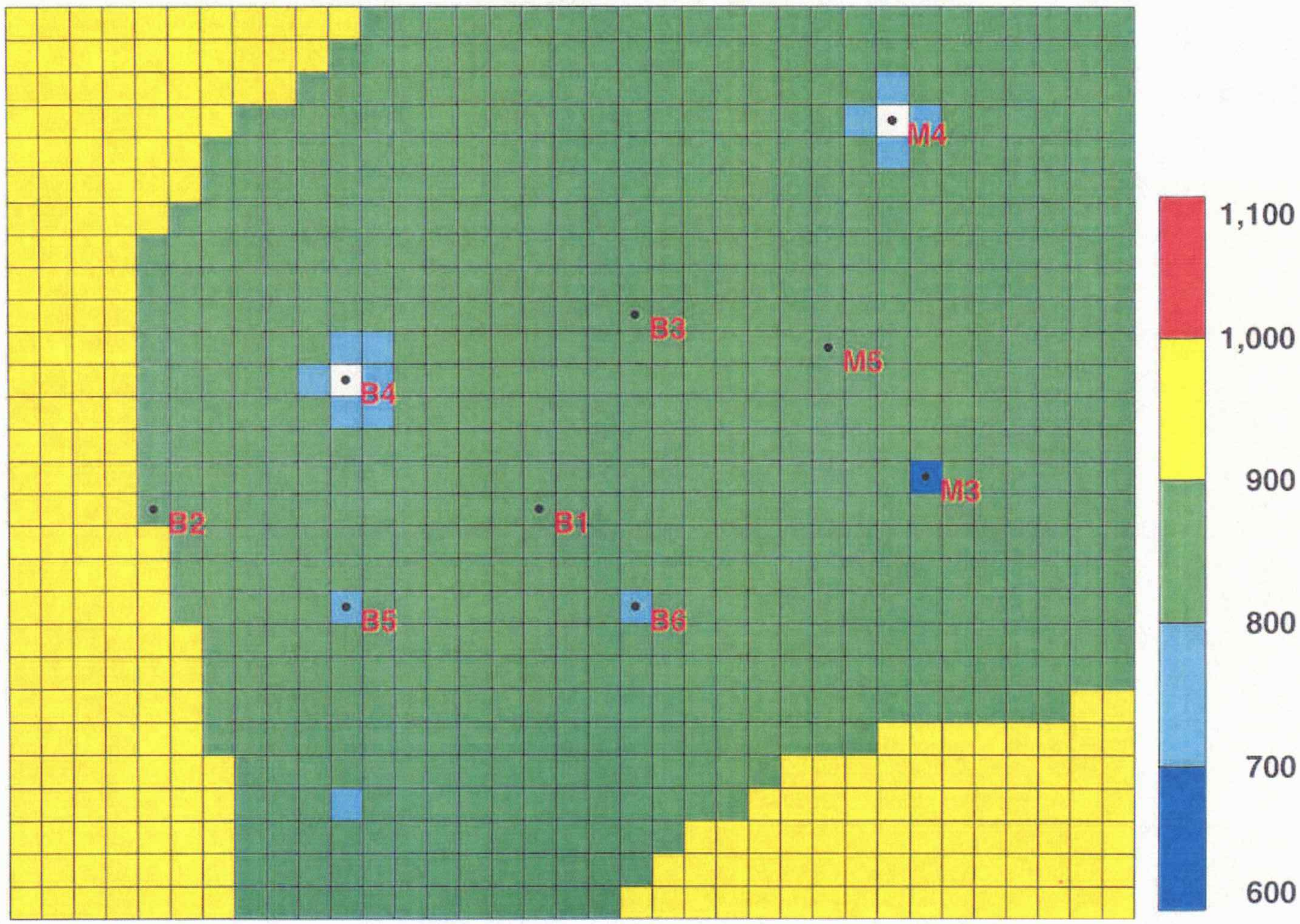


MCDONALD 4
95,242
Borger 3
28,047
McDonald 5
Borger 4
BORGER 2
64,126
Borger 1
95,544
McDonald 3
96,283
Borger 5
31,230
Borger 6
16,404
MINER B 1
Alden Miner 1
15,060
Cunningham 1
M4
Oil Rate SC (bbl/day)
Time (Date)
Oil Rate SC MD4 N3.irf
Oil Rate SC M4.fhf
Water Rate SC M4.fhf
Water Rate SC MD4 N3.irf

Figure G8

Figure G9

Average reservoir pressure (Layer 1) – Jan 2003



Average reservoir pressure prevalent over most of the reservoir is around 850 psi. Pwf at a well can be 14.7 psi, but the reservoir pressure around the well is about 850 psi. It is the drawdown of (850-Pwf) that causes fluids to flow into each well.

Appendix H

Simulation Study

- Evaluate performance of different horizontal infill wells

Total Remaining-oil-in-place (ROIP, phi*So*H, ft) – Jan 2003

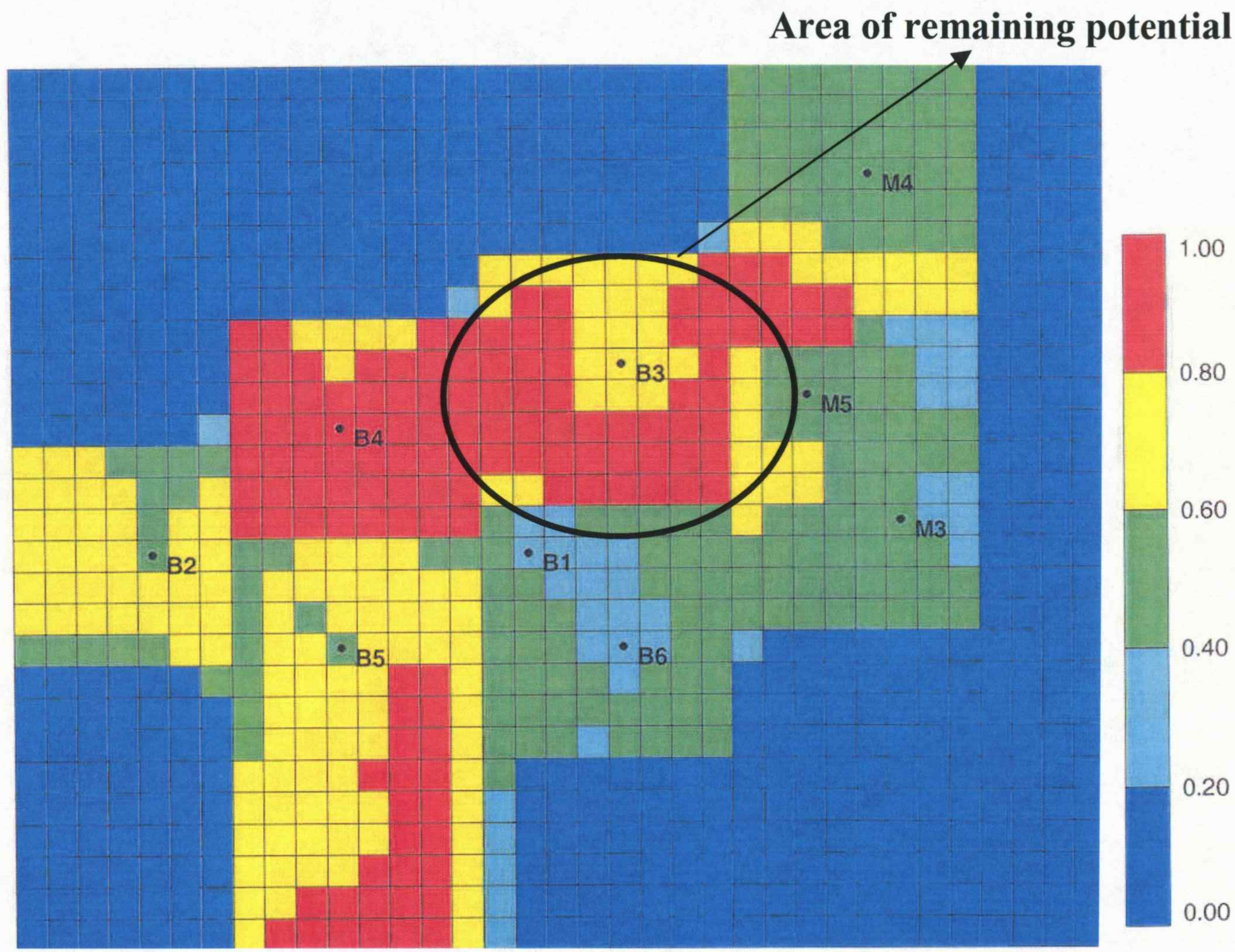


Figure H1

Remaining-oil-in-place (phi*So*H, ft) in Layer 2 – Jan 2003

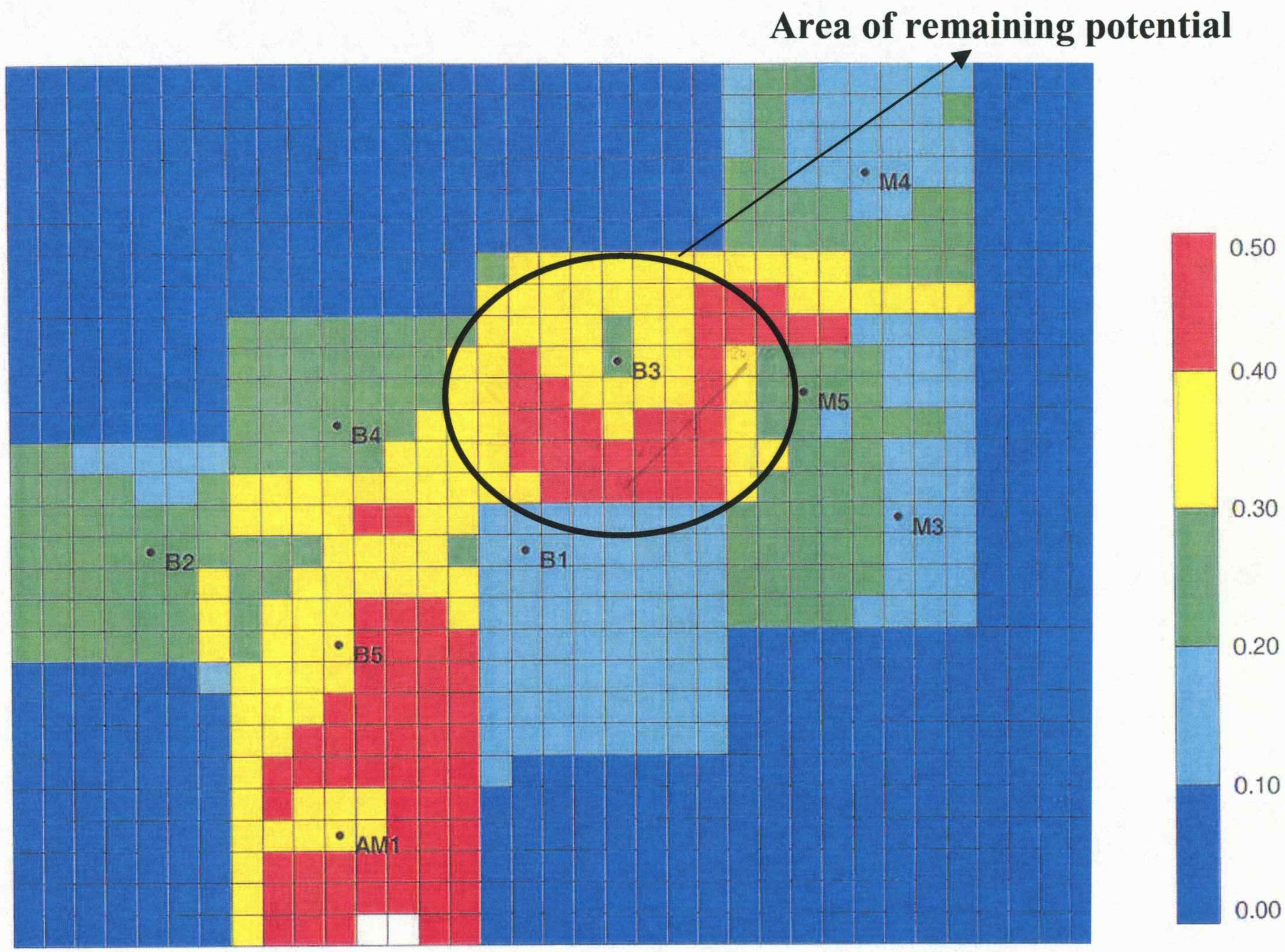
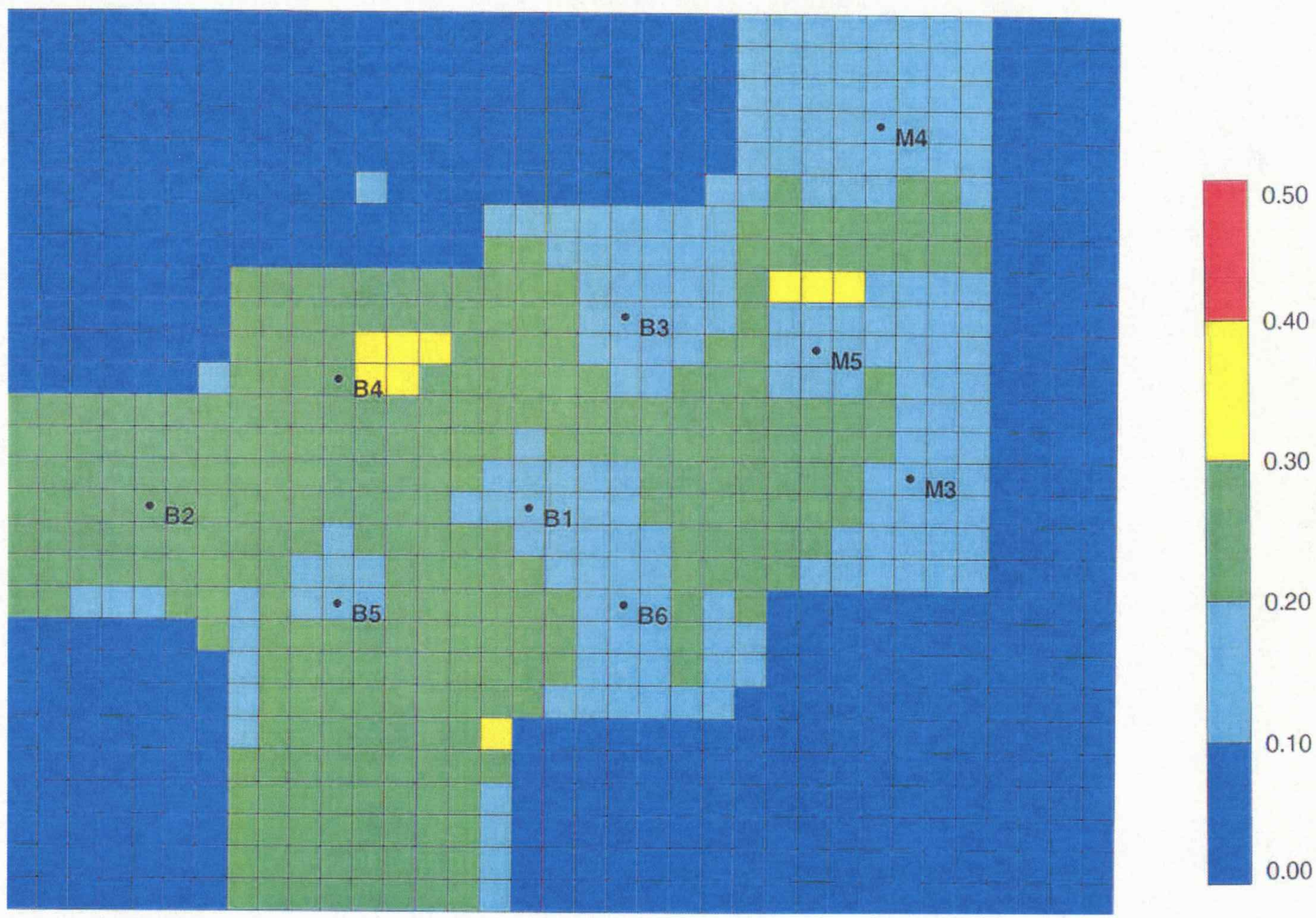


Figure H2

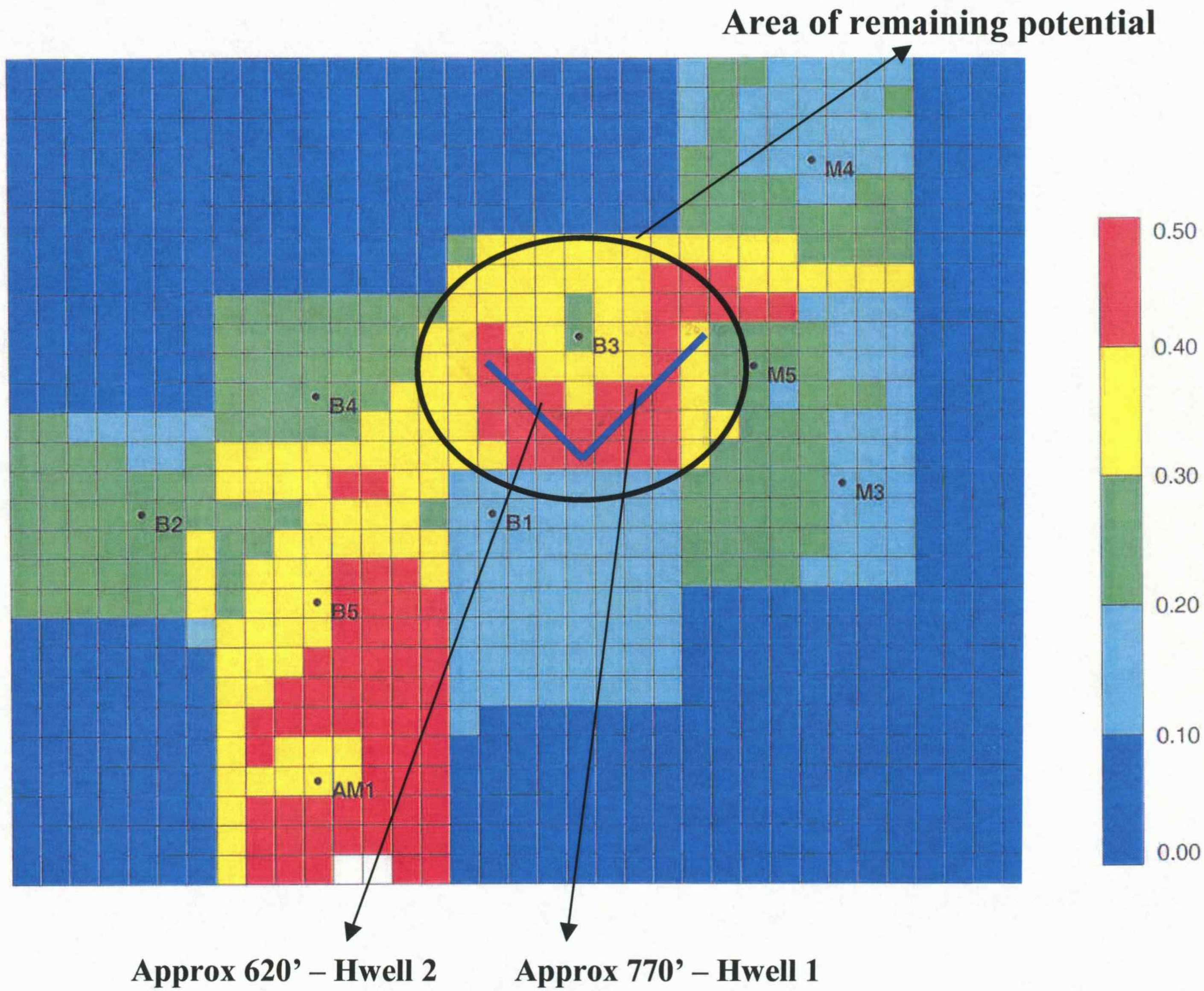
Remaining-oil-in-place (phi*So*H, ft) in Layer 1 – Jan 2003



Thus, Layer 2 appears to have the most ROIP.

Figure H3

Remaining-oil-in-place (phi*So*H, ft) in Layer 2 – Jan 2003

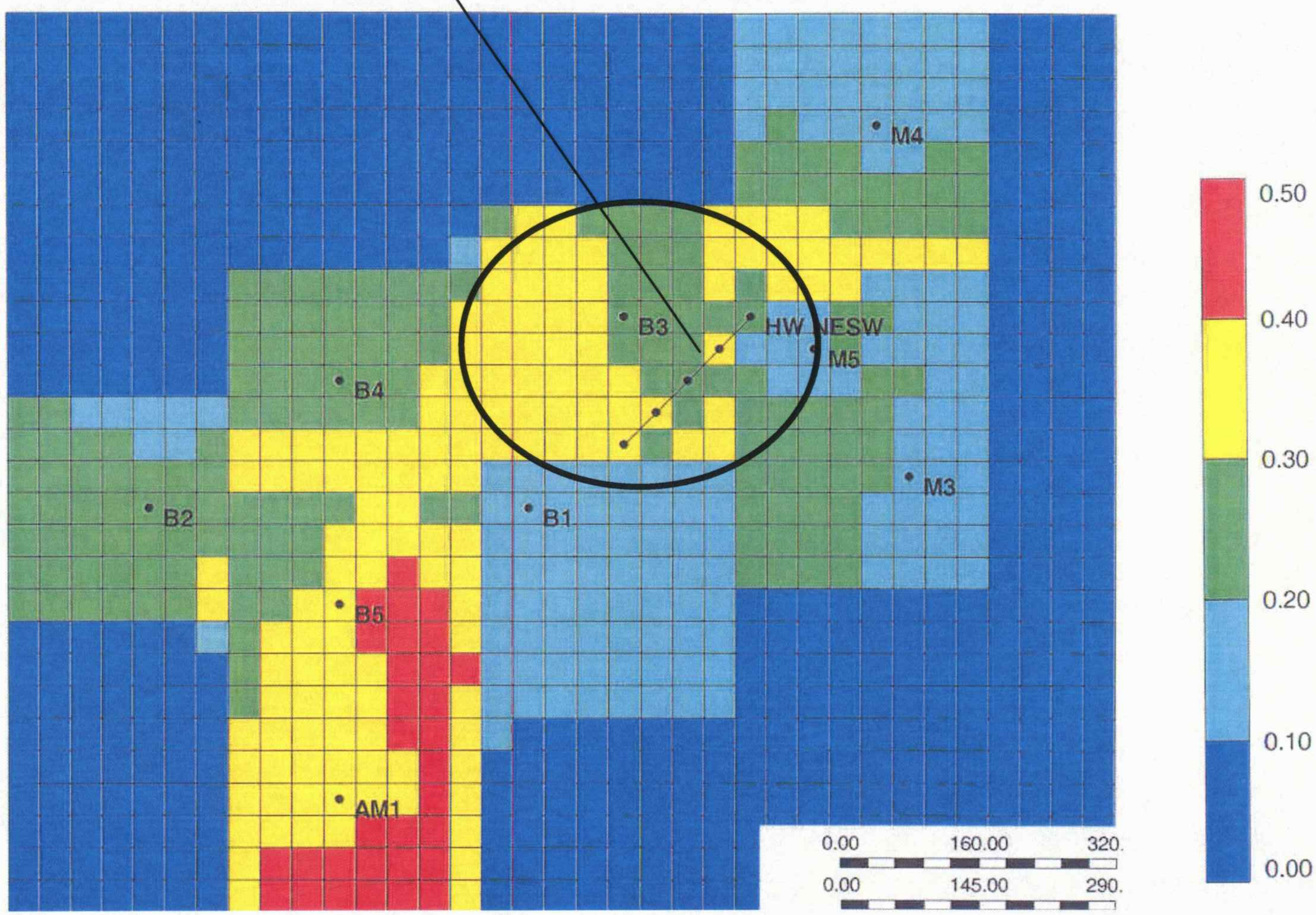


Possible locations of infill wells

Figure H4

Hwell 1 - Remaining-oil-in-place (phi*So*H, ft) in Layer 2 – Jan 2008

Hwell 1 – NE to SW – recovery of remaining reserves



Shows incremental recovery by Hwell 1 after 5 yrs.

Figure H5

Production performance of Hwell 1

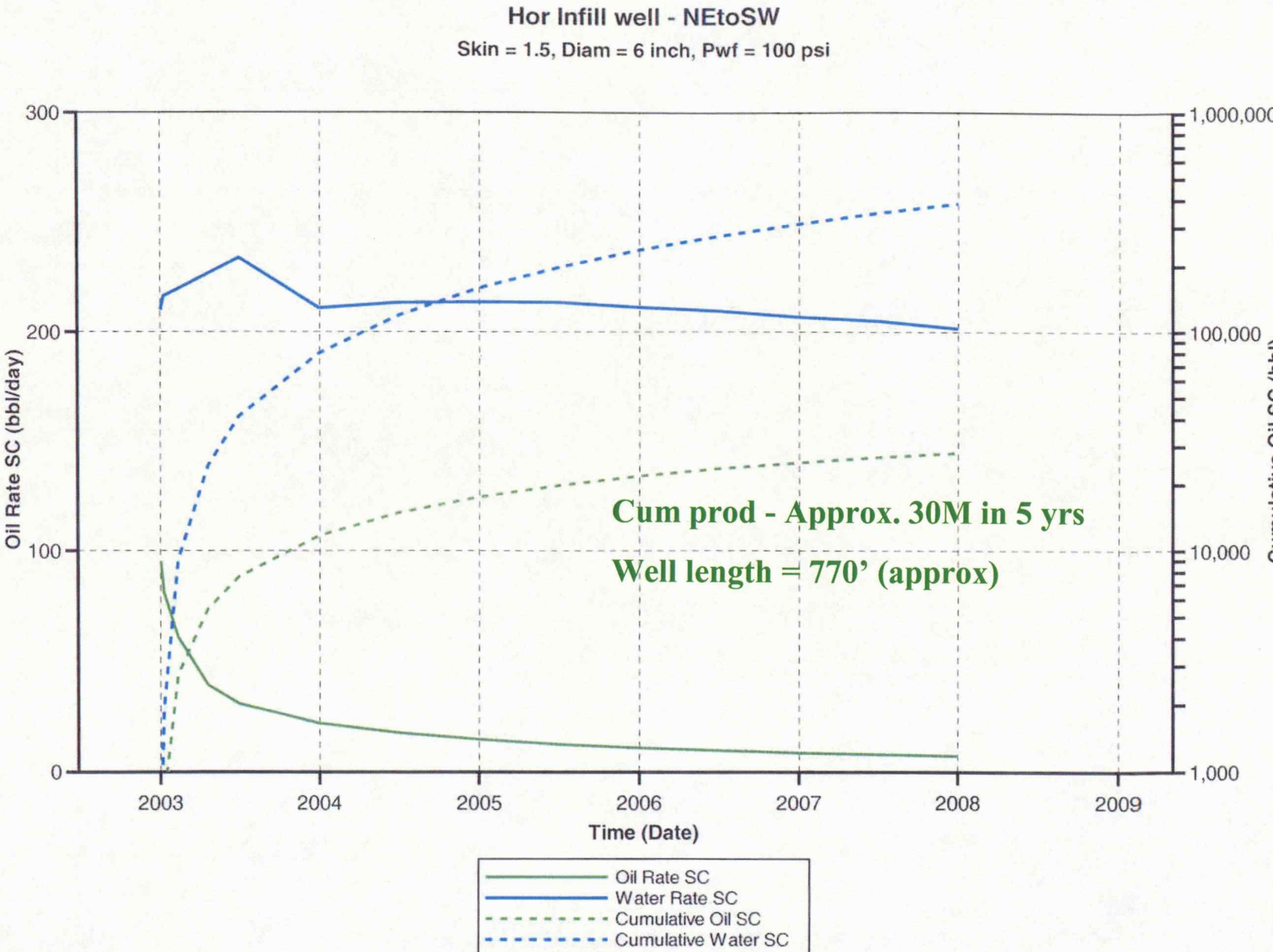


Figure H6

Hwell 2 - Remaining-oil-in-place (phi*So*H, ft) in Layer 2 – Jan 2008

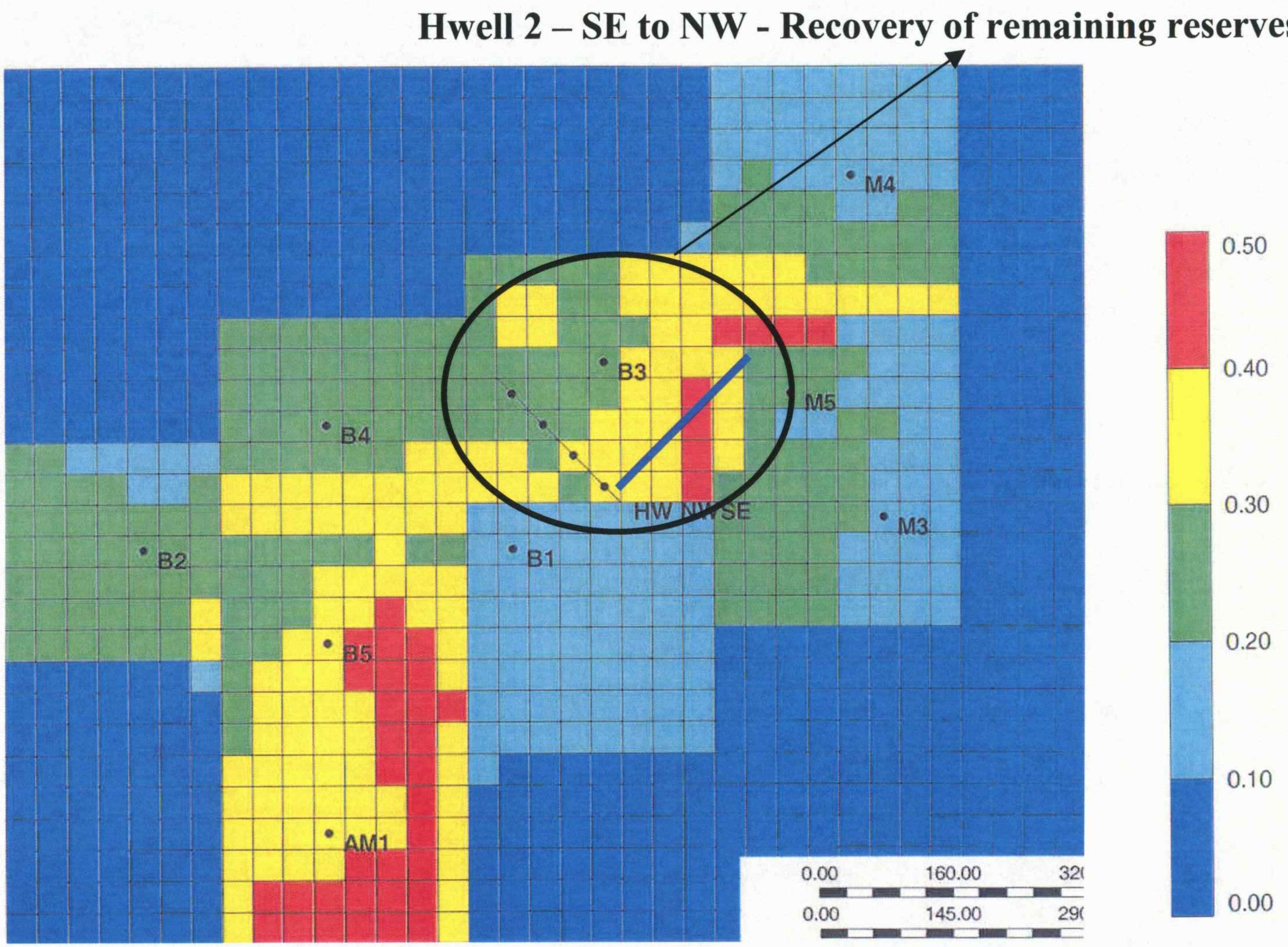


Figure H7

Production performance of Hwell 2

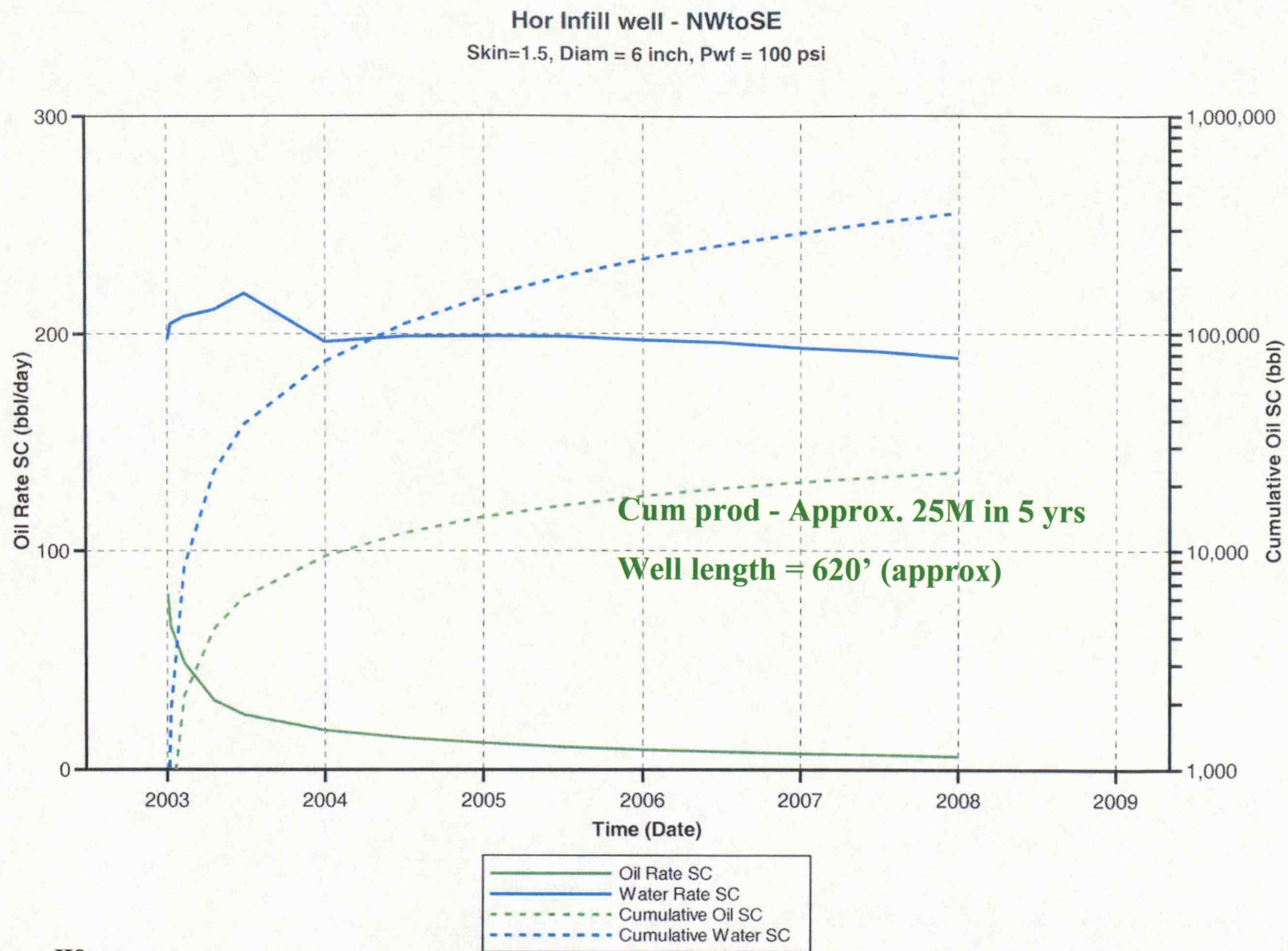


Figure H8