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RESERVOIR CHARACTERIZATION AND SIMULATION – JUDICA FIELD, NESS COUNTY, KANSAS

by

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Introduction

An integrated reservoir characterization study was carried out on Judica field, Ness County, Kansas, to build a 3D-geomodel, which served as the basis for reservoir simulation. Judica produces from a Mississippian carbonate reservoir with production commencing from February 1979. Simulation studies were initially carried out to history-match well-level fluid production while also matching the limited available pressure decline. 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 few vertical infill wells were 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 rectangle) of the study area for this project. Petrophysical well logs, analogous core data (from a neighboring well), core cuttings 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 built from different directions to cross-check and fine tune the geomodel. The reservoir was modeled with 5 layers, and Figure A2 shows that subsea structure top (feet) of the top layer (Layer 1). Layers 1, 3, and 5 contribute to the production while the intermediate layers 2 and 4 are water saturated shale streaks. Figures A3 to A17 display the isopach, porosity, and initial water saturation (Sw) maps of each of the 5 reservoir layers.

Production data

As most leases in the study area are single-well leases, well-level oil sales data was available on a monthly basis from most wells. However, Thornburg M1 and M2 (Kansas Oil Corp, Section 35) belonged to the same lease and thus no record of individual production was available from these two wells. Lacking any other data, the Thornburg M lease sales data was proportioned in ratio of the initial production (IP) rates recorded at these two wells. The leases sales history includes mention of only oil volumes sold every month. An average annual production rate (barrels per day, BOPD) was calculated from the monthly sales data for each well. Available water production data included data over a ten-year period (January 1989 to July 1999) at Thornburg Q1 (Slawson, Sec 35), and current (January 2003) barrel test data from Thornburg Q1 (Slawson, Sec 35) and Thornburg M1 (Slawson, Sec 3). Figure B1 (Appendix B) plots the water-oil-ratio (WOR) with time for the above named two wells that have limited water production data. It is evident from the plot for Thornburg Q1 (Slawson, Sec 35), that a best-fit linear line correlates the WOR with days from the start of production. Even the unforced best-fit line (broken line in red) passes within 365 days from the origin. Thus lacking any other data, this linear WOR-time correlation was used to estimate water production at other wells in the study area. Thornburg M1 (Slawson, Sec 3) is the highest producing well within the study area and the current measured WOR is low compared to the long production life of this well. Thus for Thornburg M1 (Slawson, Sec 3), the water production history was estimated using the WOR-time correlation depicted in well specific the WOR-time plot (Figure B1).

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. Unfortunately, a regular record of BHPs was not available for any of the wells in the study area. The industry partner in this project, an operator of some wells within and around the study area, advised as per prevalent practices that given the volumes of oil produced from each well it would not be uncommon for these wells to be produced under minimal BHPs, (back pressure in the range of 100 psi). To test this assumption, decline curve analysis was carried out by plotting the average annual oil production rate at each well 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 Thornburg 1 (Foxfire, Sec 35). As a single decline curve is found to represents the well production history neglecting the (minor) production increase midway through the well life. Thus lacking any other data, it is reasonable to assume that this well produced under near unchanging bottom hole conditions (skin and/or BHP). Figure C2 shows that a similar assumption is reasonable for well Thornburg L1 (Slawson, Sec 3). Figure C3 plots the production data from Thornburg M1 (Slawson, Sec 3). The production history shows two distinct decline trends. The value of the decline exponents (b) for the both the curves is same (b=0.4) which suggests that the production data is from the same well producing out of the same reservoir. As mentioned earlier, no information is available about the BHP under which the well produced during the first decline curve. Currently, the well produces under pumped off conditions. Thus in absence of any BHP data, it is not unreasonable to change (reduce) the skin to history match the increased production (second decline) while keeping the BHP unchanged at 100 psi. Thornburg Q1 (Slawson, Sec 35) shows a similar behavior (Figure C4). Thus, all wells in the simulation study were produced under a constant BHP = 100 psi, and production increases (bumps) were matched by changing the skin.

DST Analysis

Appendix D summarizes the details of the DST analysis. DST pressure-time data was available for 3 wells within the study area, namely, Thornburg M1 (Slawson, Sec 3), Thornburg B1 (Kansas Oil Corp, Sec 4) and Thornburg Q1 (Slawson, Sec 35). Figures D1 to D3 and Tables D1 to D3 summarize the DST analyses carried out for these three wells. DST data was available from two others wells, namely Thornburg N2 (Slawson, Sec 4) and Muchmore (Slawson, Sec 34) and their analyses have been detailed in Figures D4 to D7 and Tables D4 to D7 respectively. Figure 8 shows the initial pressure (Pi) psi calculated from the DSTs along with the final shut in pressures (FSIPs) from the above wells. Based on this pressure profile, the initial reservoir pressure was assumed to be 1350 psi. The most current pressure data is from Thornburg F1 (Kansas Oil Corp, Sec 4). Static fluid column was recorded at this well after a 5-day shut-in in November 2002, and it revealed a reservoir pressure of 1030.5 psi. Though this well is located just outside the study area, this pressure was used as an estimate of current reservoir pressure in Judica lacking any other available data.

PVT and Relative Permeability/Capillary Pressure Inputs

Appendix E summarizes the PVT and other field wide inputs to the simulation model. There is no mention of any gas production at Judica. 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 100 psi was assumed (at subsea –1938 feet) in this study. There was no measured bubble point data available. Other oil PVT properties are listed in Table E1, while the water PVT properties are listed in Table E2. 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. Other field wide assumptions, particularly relating to each well, that were input to the simulator are listed in Table E1. Given the nature of the reservoir rocks, all wells were perforated in layers 1, 3, and 5, if present, within the simulator during the history matching.

No cores were available from Judica field. However, a Mississippian core from Beardmore Clifton #1 well (Sec 1, Hodgeman County, Kansas) was available from Lippoldt – a neighboring field. Routine and advanced core analyses was carried out on this core to develop representative permeability-porosity correlations (Tables E3 & E4) 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. These calculators help 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 updates the table by changing the saturation end points while preventing dramatic changes in the capillary pressure curve shapes. 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 E3 shows the calculator for the reservoir rock (Layers 1, 3, and 5) while Table E4 displays that for the non-reservoir rock (Layers 2 and 4).

<u>Simulation study – History matching</u>

The reservoir was simulated as a 5-layer model with 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 in the range between 1000 and 1100 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 E3 while Table E4 shows the relevant correlation for the non-reservoir rock. 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".

Figure F1 summarizes the data constraints under which the simulation study was performed. Only limited water production data was available at 2 wells - Thornburg Q1 (Slawson, Sec 35) and Thornburg M1 (Slawson, Sec 3). DST fluid recovery at Thornburg A1 (Slawson, Sec 3) indicates that a productive zone possibly exists atop the layer 1. However, there is no evidence available to show the extension of this layer to other areas of the study area, and thus some of the production recorded at this well may come from a layer that has not been modeled in this study. Individual well production data is not available for Thornburg M1 and M2 (Slawson, Sec 35) as these wells produce to one lease. Finally, the current geomodel explains the existence of 3 dry wells (Thornburg N1, I1, and S1 in Sec 35) at the top of the structure due to low permeability resulting from degradation of porosity of the reservoir rock.

Figures F2 to F10 show the history matches obtained at each well in the study area. Figure F11 shows the calculated distribution of reservoir pressure as of January 2003. The average reservoir pressure is around 1070 psi and this is close to the BHP obtained at Thornburg F1 (Slawson, Sec 4) in November 2002 after a 5-day shut-in. Thus, from a material balance standpoint it appears that the given reservoir geomodel acting under a strong water drive can deliver the historically recorded fluid production and undergoing a pressure decline from 1350 psi to 1070 psi.

Simulation study – Performance evaluation of different horizontal infill trajectories

Appendix G 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. Most of the remaining potential was found to reside in Layer 5 (L5), and the remaining oil-ft map as of January 2003 is shown in Figure G1. Productive potential of different infill trajectories was studied. In each case, the horizontal was assumed to be 6 inch in diameter and to have been produced for 10 years (starting January 1, 2003) under a constant BHP = 200 psi and a skin factor of 1.5. One of the first infills, a 1100 feet long North-south well, that was evaluated is shown in Figure G1. Thus, the effects of the drainage capability of this well is shown in the residual reserve (oil-ft) map as of January 2013, particularly when compared with that of January 2003. The expected production from this well is tabled and plotted in Figure G2. Simulation studies indicate that after 10 years the expected cumulative production from this well will be in the range of 76 MSTB while requiring to move about 962 MSTB of water. The location of this infill is in close proximity to Thornburg M1 (Slawson, Sec 3), and thus interference effects of this well on the production of Thornburg M1 is shown in Figure G3. Figures G4 and G5 show the drainage effects of a second infill trajectory (south-west to north-east) called MULL 1, it cumulative production and interference on Thornburg M1 (TM1s, Slawson, Sec 3). Figures G6 to G13 plots the productive potential of other horizontal infill trajectories, i.e., MULL 2 to MULL 5.

Uncertainties are inherent in any geomodel because at times boundaries between the reservoir layers are difficult to identify at some wells. Also, the interpolation technique of the mapping process relies on the assumption of depositional continuity between two wells and often times geologic processes result in more complex depositional patterns. Finally, a horizontal well is never perfectly horizontal and thus has the possibility of not being confined within a model layer (such as layer 5) all along its length. Thus, the effects of the infill trajectory intersecting different layers was studied by placing the well MULL 5 solely in layer 5 (Figure 13, cumulative production around 175 MSTB), in layer 3 (Figure 14, cumulative production around 174 MSTB), and in layer 1 (Figure 15, cumulative production around 162 MSTB). Thus, the production potential of trajectory MULL 2 is not significantly affected by the possibility of it perhaps not being confined to layer 5 along its total length.

Finally, a couple of vertical infill wells were simulated in the areas where most of the horizontal infills were targeted in order to ground-truth if the simulator predictions for the horizontal infills were within the realms of expectations. The industry partner with its significant operating experience had a general expectation (idea) about the expected production potential from a vertical infill well in this type of a mature Mississippian field, and therefore wanted to validate the reservoir model by having it predict the performance of vertical infill wells. Thus, two vertical infill wells were simulated with each being located in the general areas where most of the horizontal wells had been placed. Figures G16 and G17 show the drainage and the expected production from the first vertical infill, named MULL Vertical East ("Vwell" in the residual reserve map). This well was perforated only in layer 5 and the expected cumulative production from this well was in the range of 23 MSTB after 10 years. Upon completing this well in Layers 1, 3, and 5, the cumulative production increased to 31.4 MSTB (Figures G18 and G19) after 10 years. The location of the second vertical infill well, MULL Vertical West (Vwell on oil-ft map), is shown on Figure G20. This well was completed in all the three reservoir layers and expected cumulative production after 10 years is 25.9 MSTB. The expected cumulative production volumes for these vertical infill wells were within the range of expectation of the industry partner.

Appendix A

Geologic Model

General layout of the study area

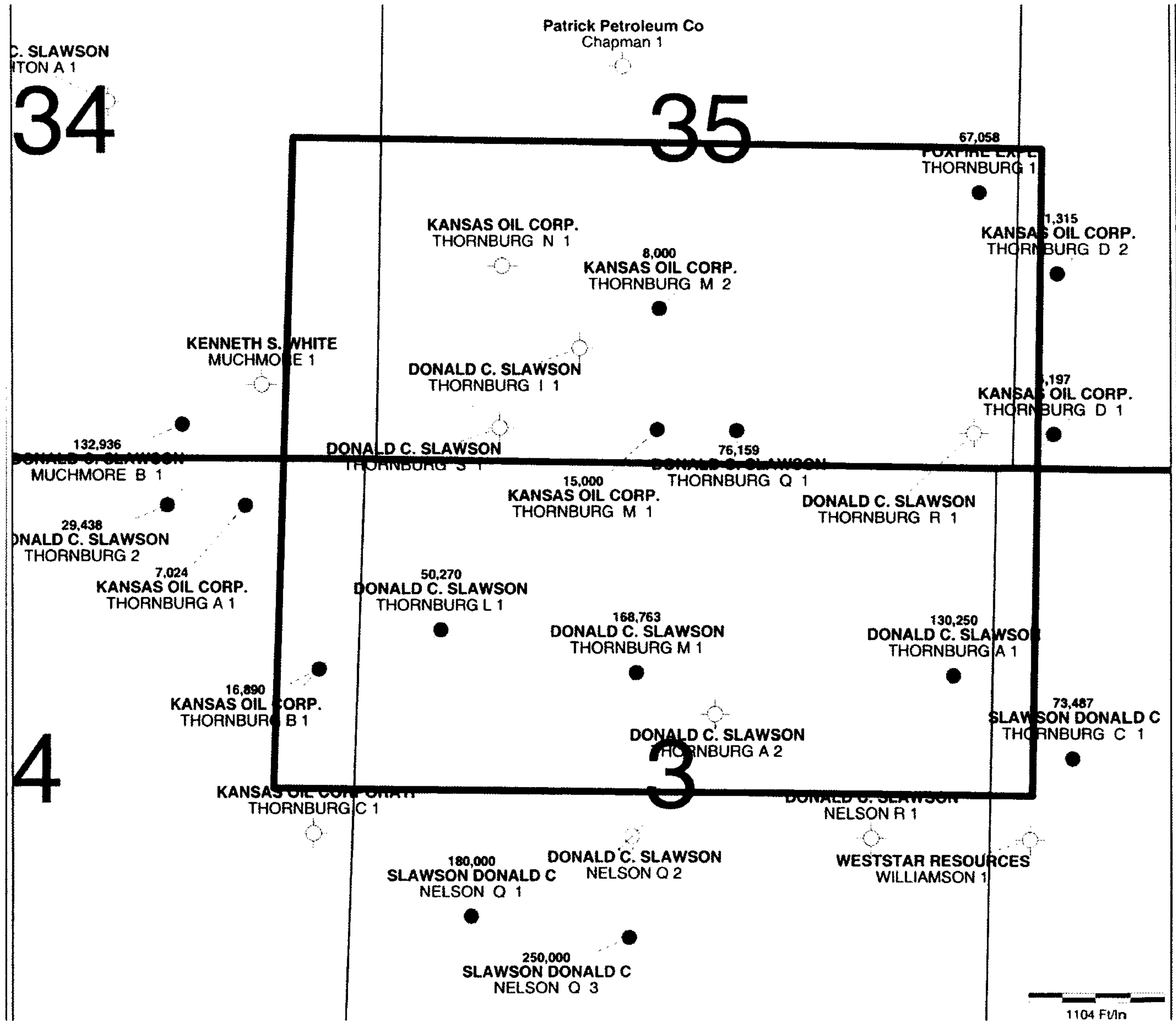


Figure A1

Structure top (subsea, feet) of Layer 1. Layers numbered in ascending order from top.

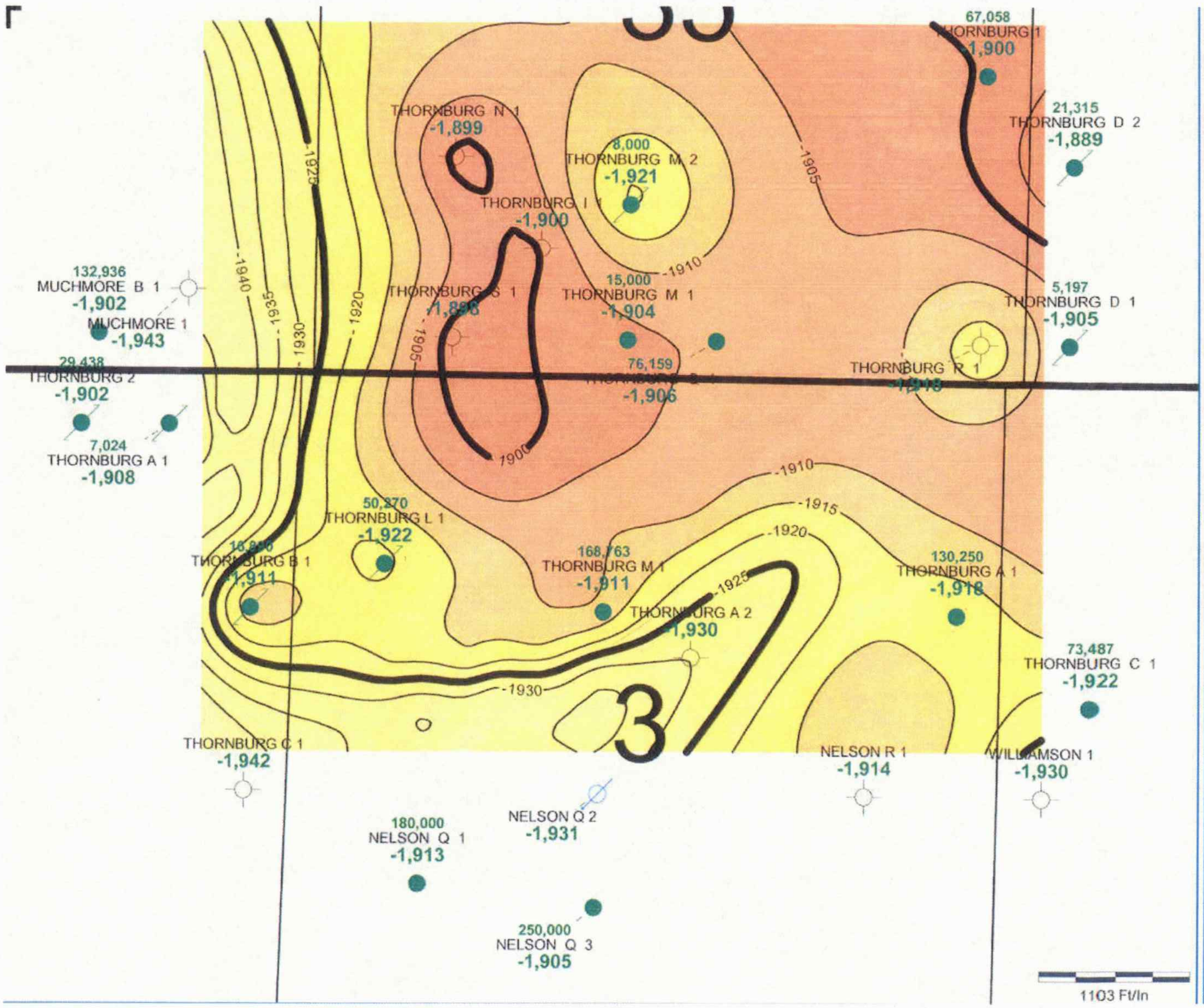


Figure A2

Isopach of Layer 1, feet

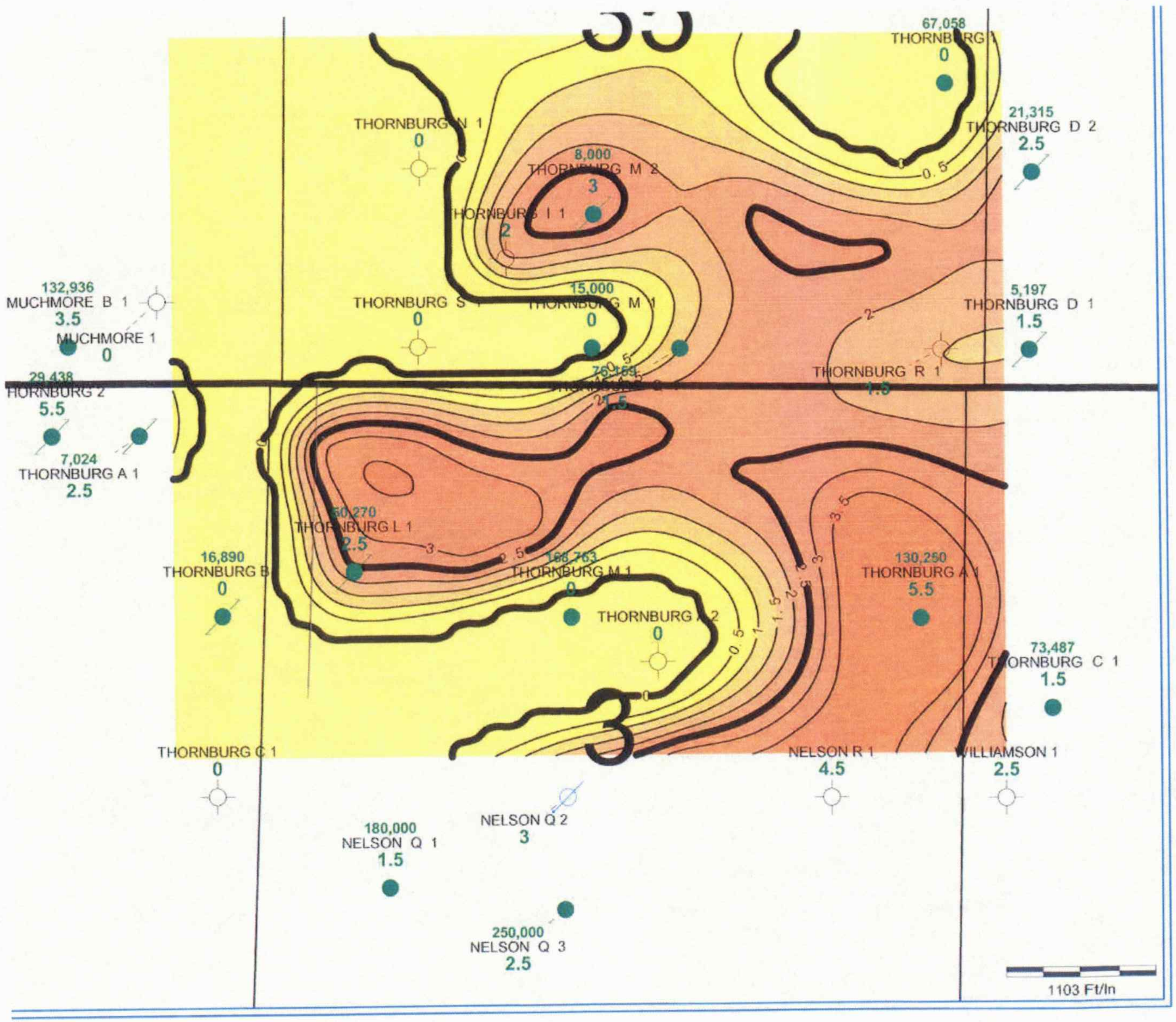


Figure A3

Porosity distribution in Layer 1.

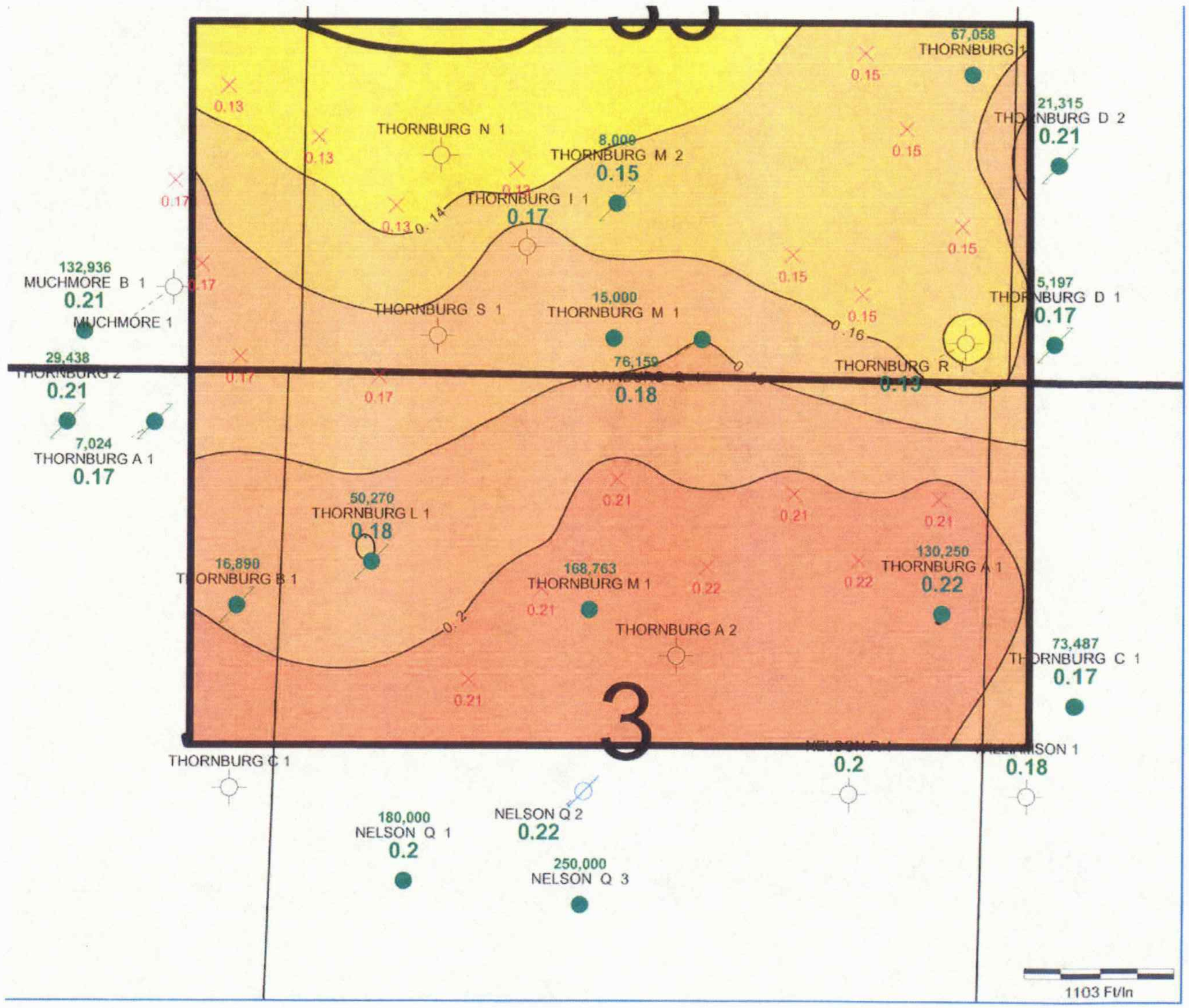


Figure A4

Initial water saturation in Layer 1

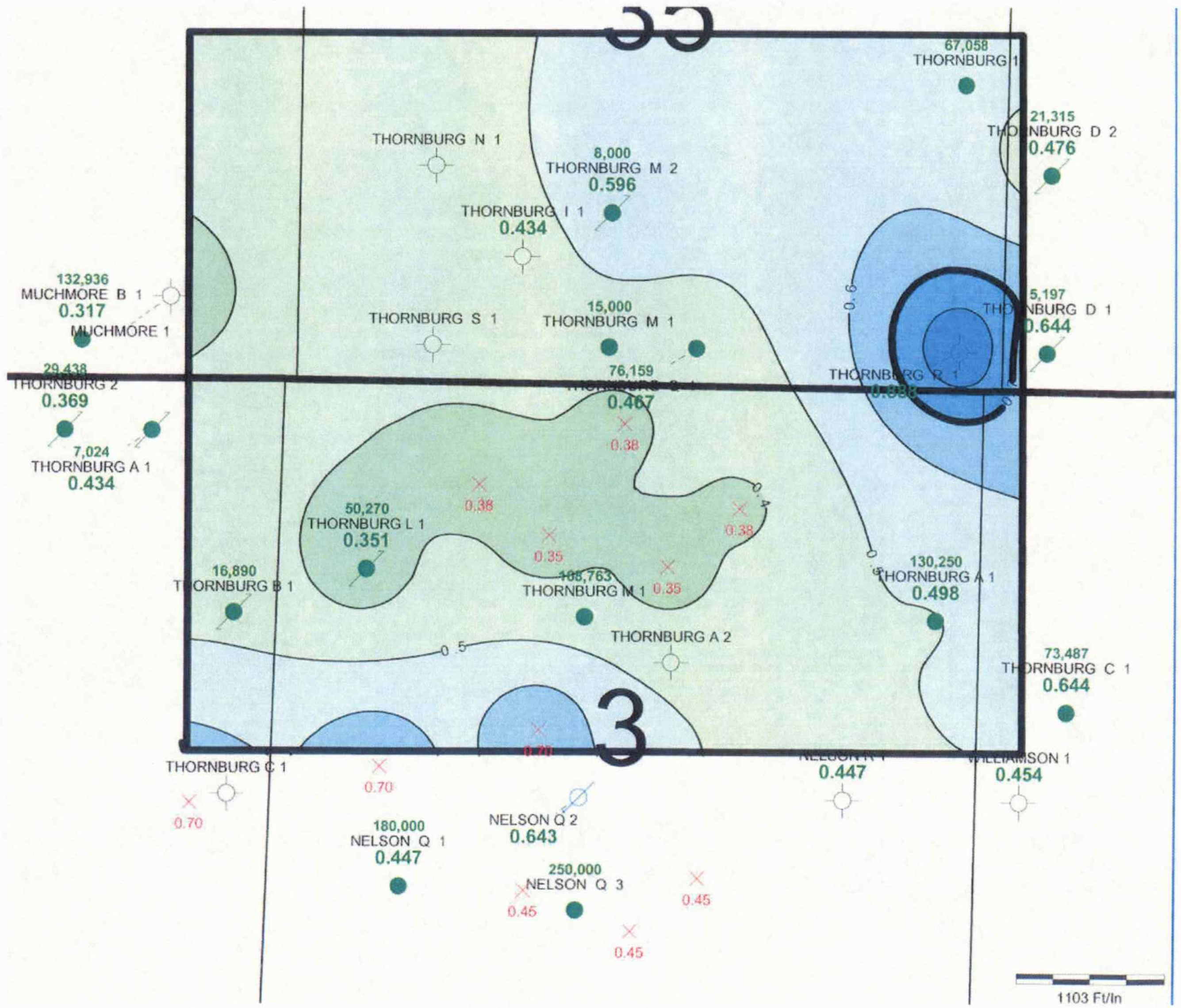


Figure A5

Isopach of Layer 2, feet

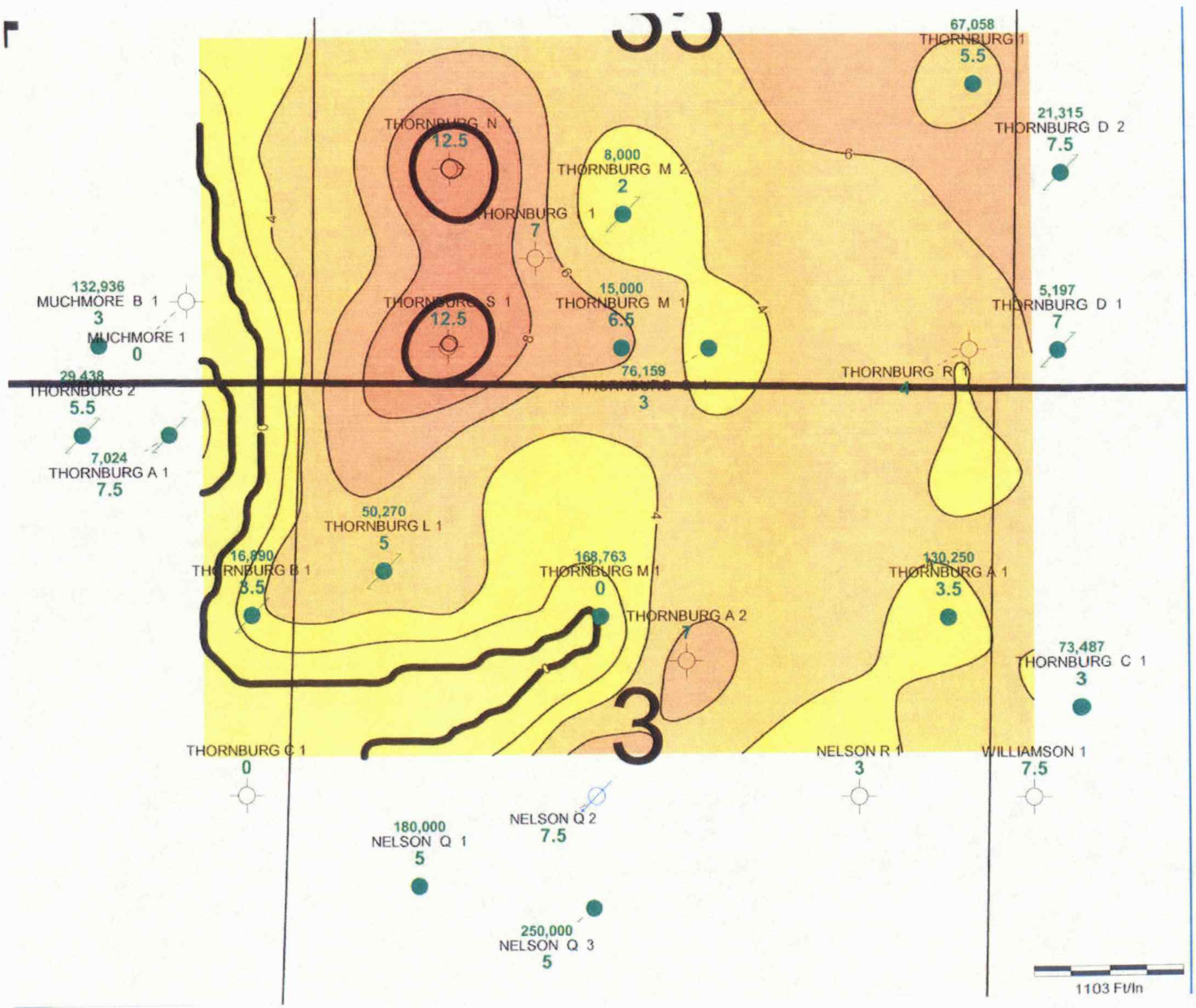


Figure A6

Porosity distribution in Layer 2.

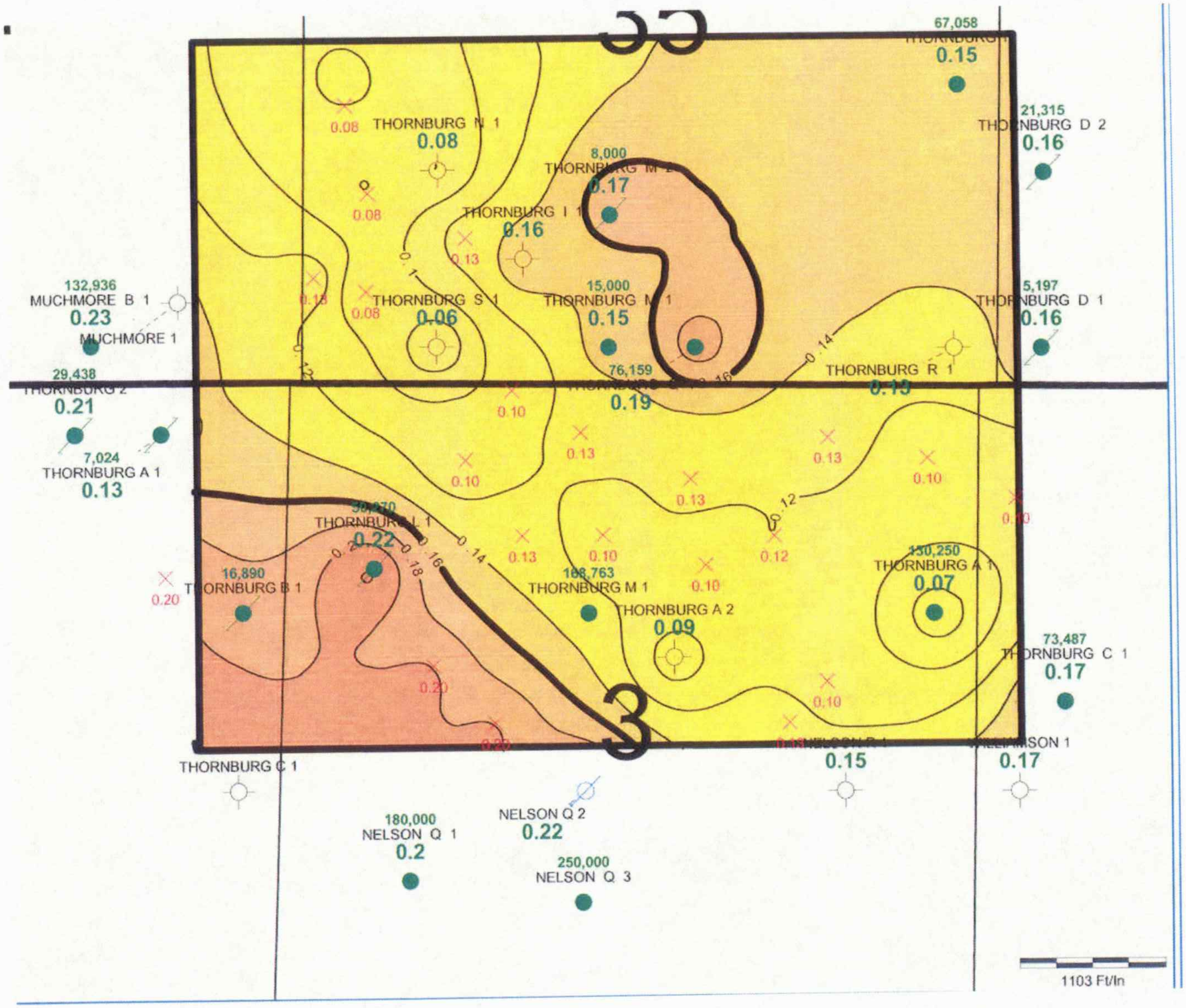


Figure A7

Initial water saturation in Layer 2

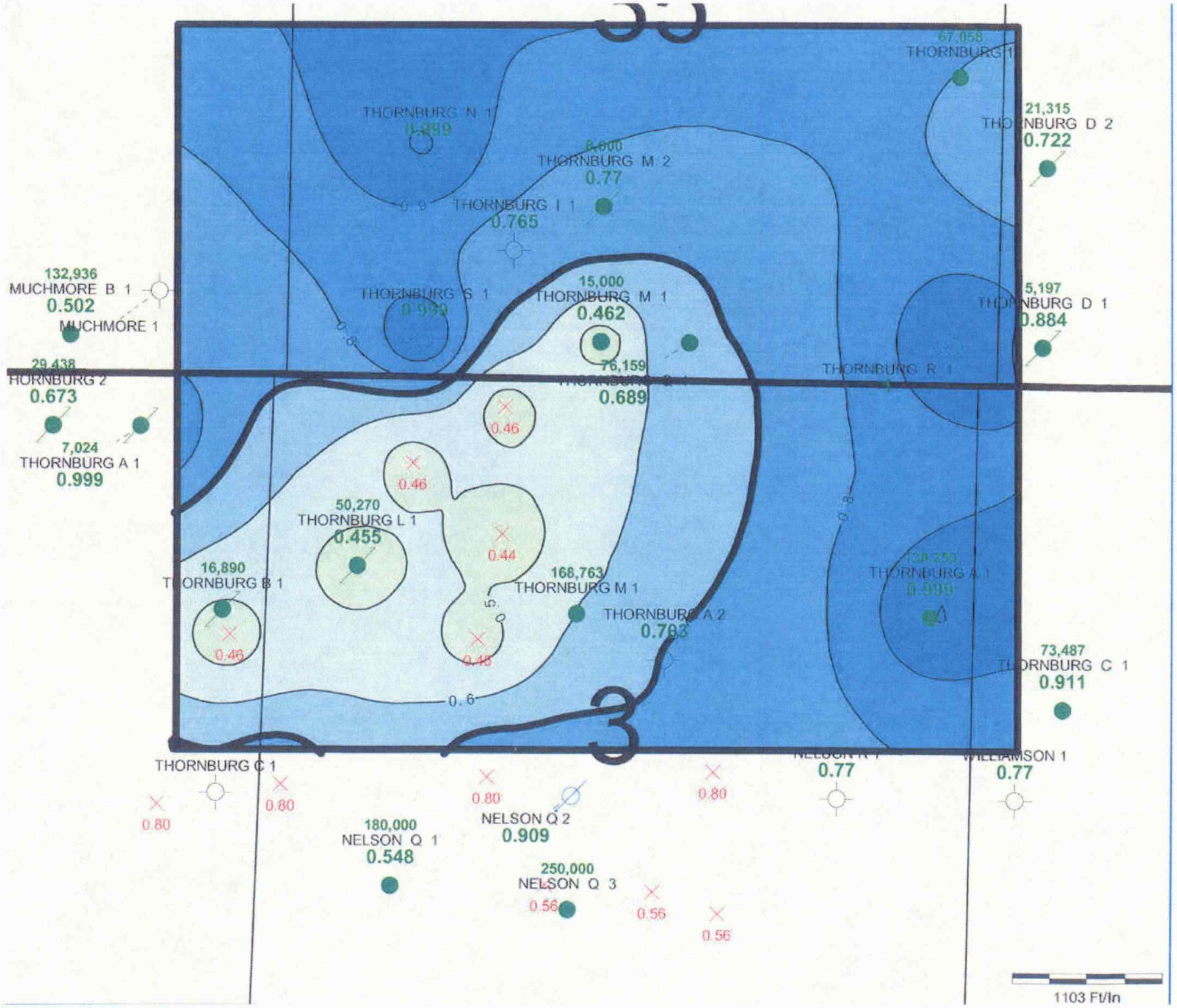


Figure A8

Isopach of Layer 3, feet

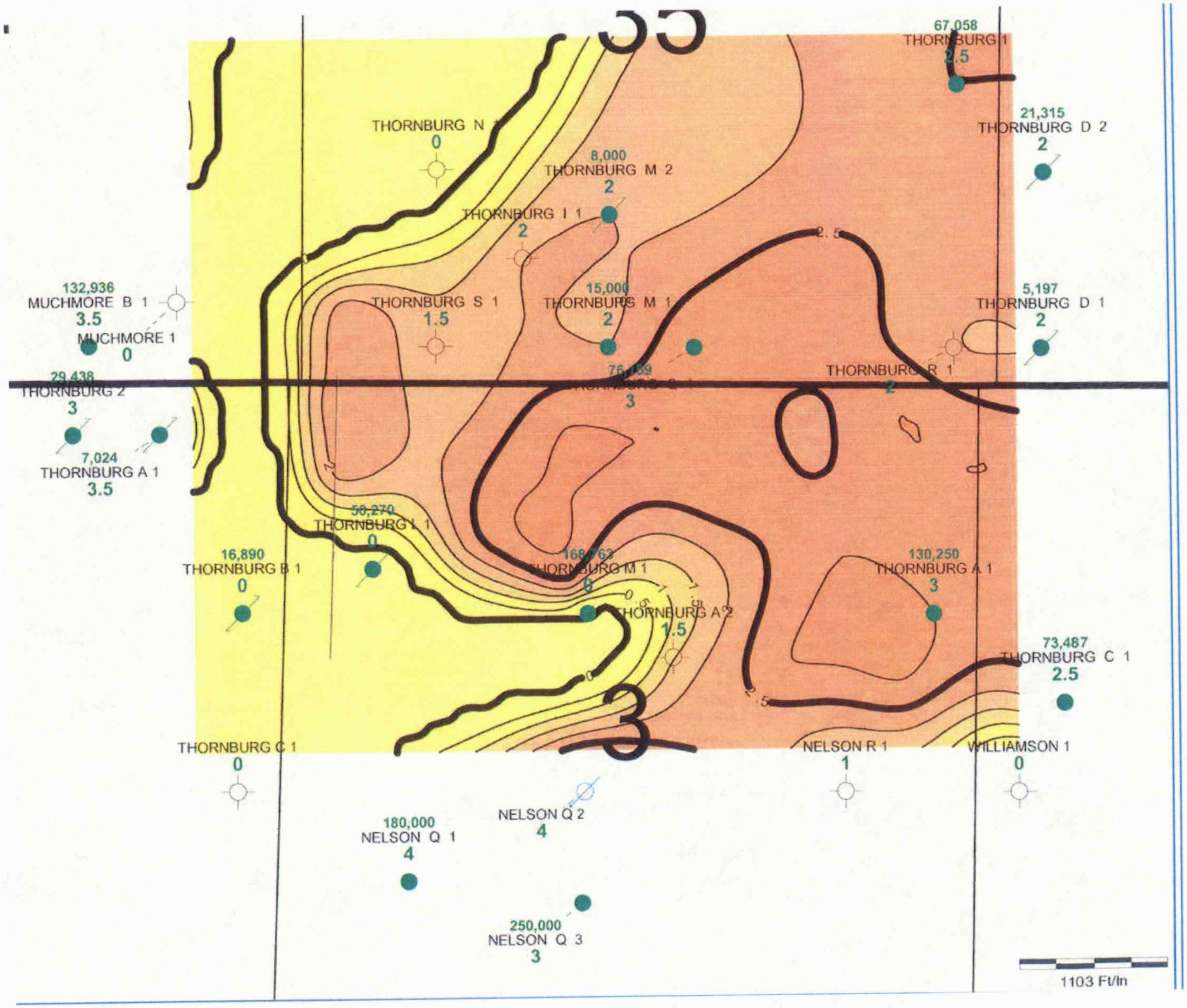


Figure A9

Porosity distribution in Layer 3

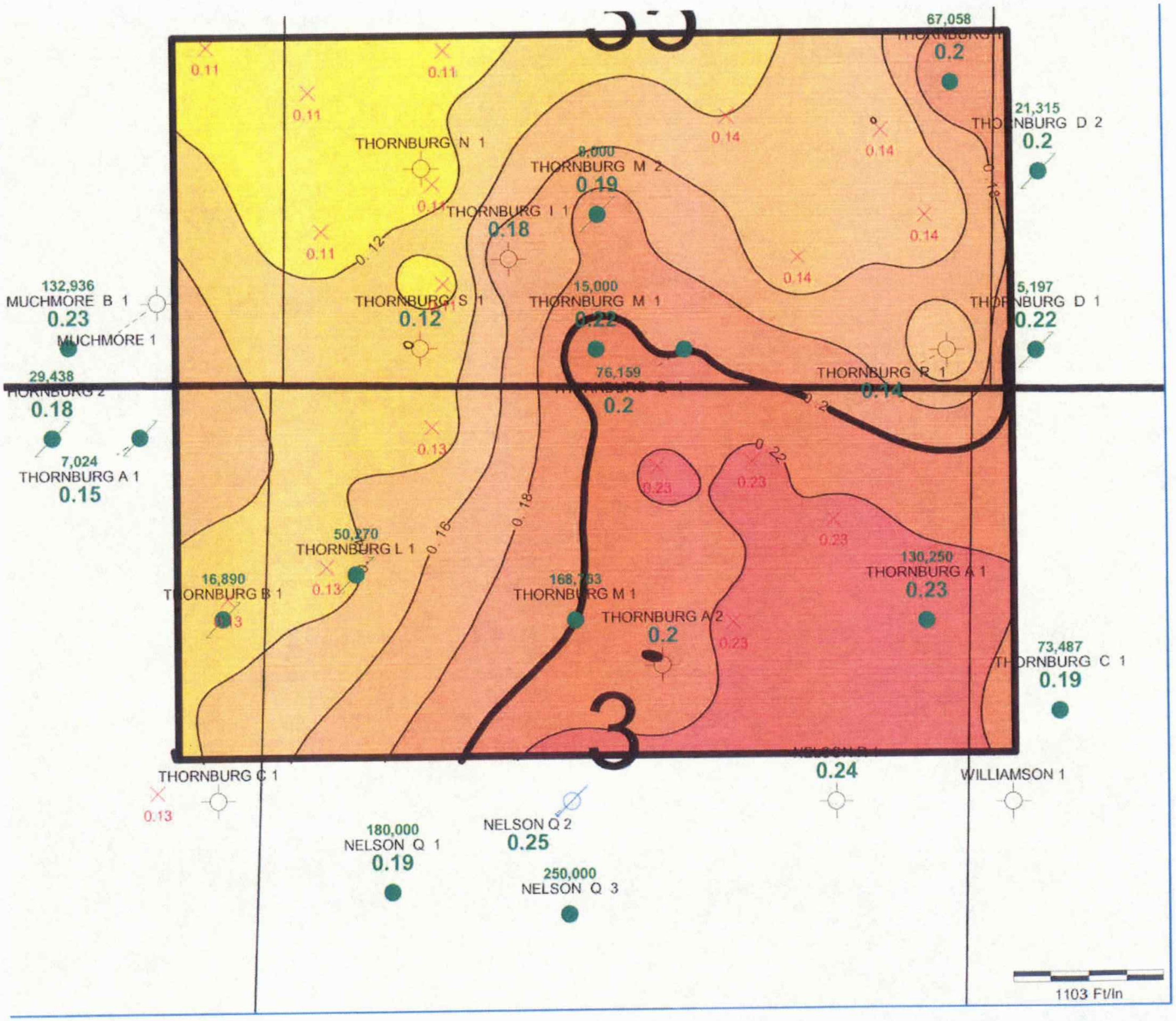


Figure A10

Initial water saturation in Layer 3

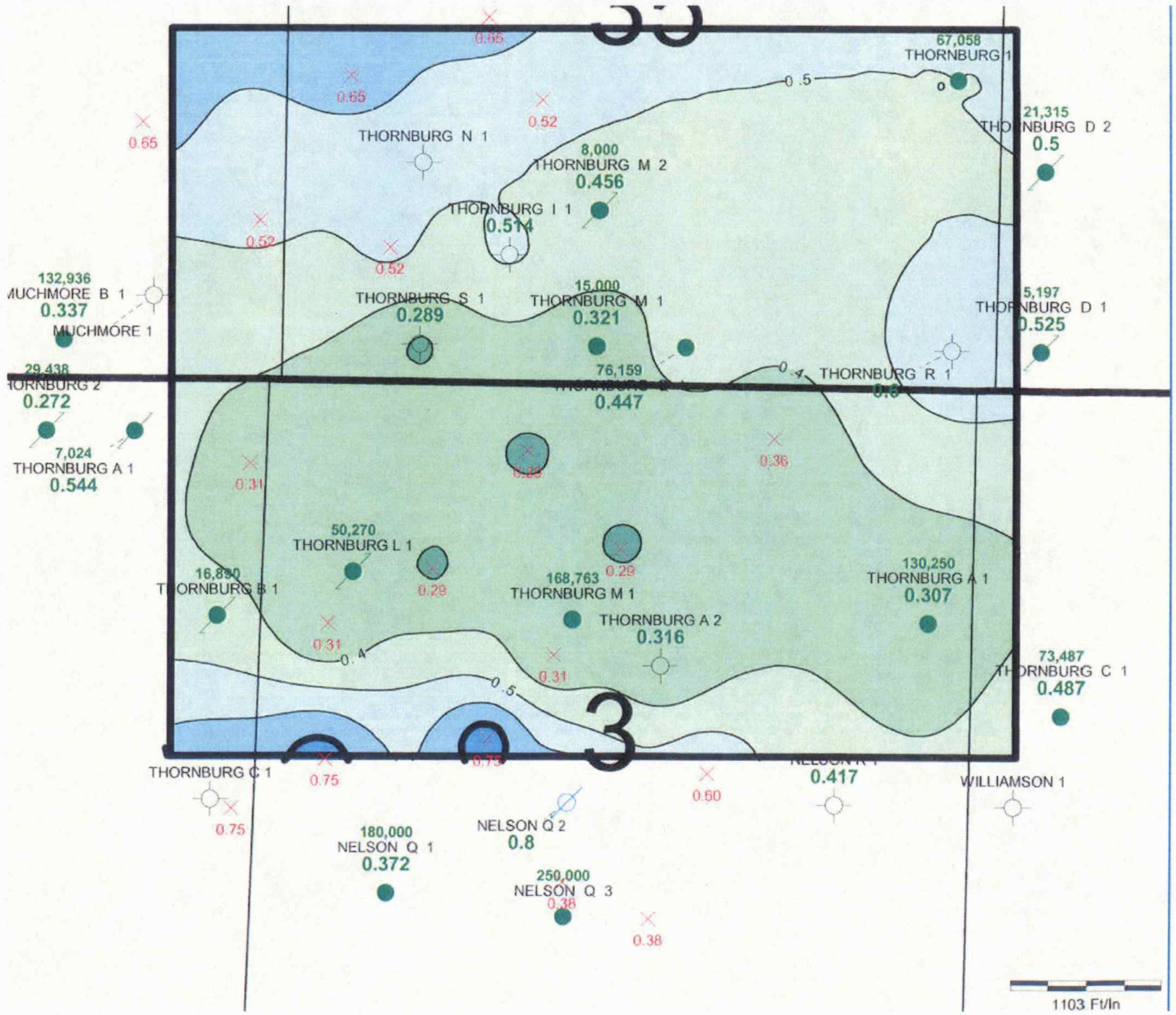


Figure A11

Isopach of Layer 4, feet

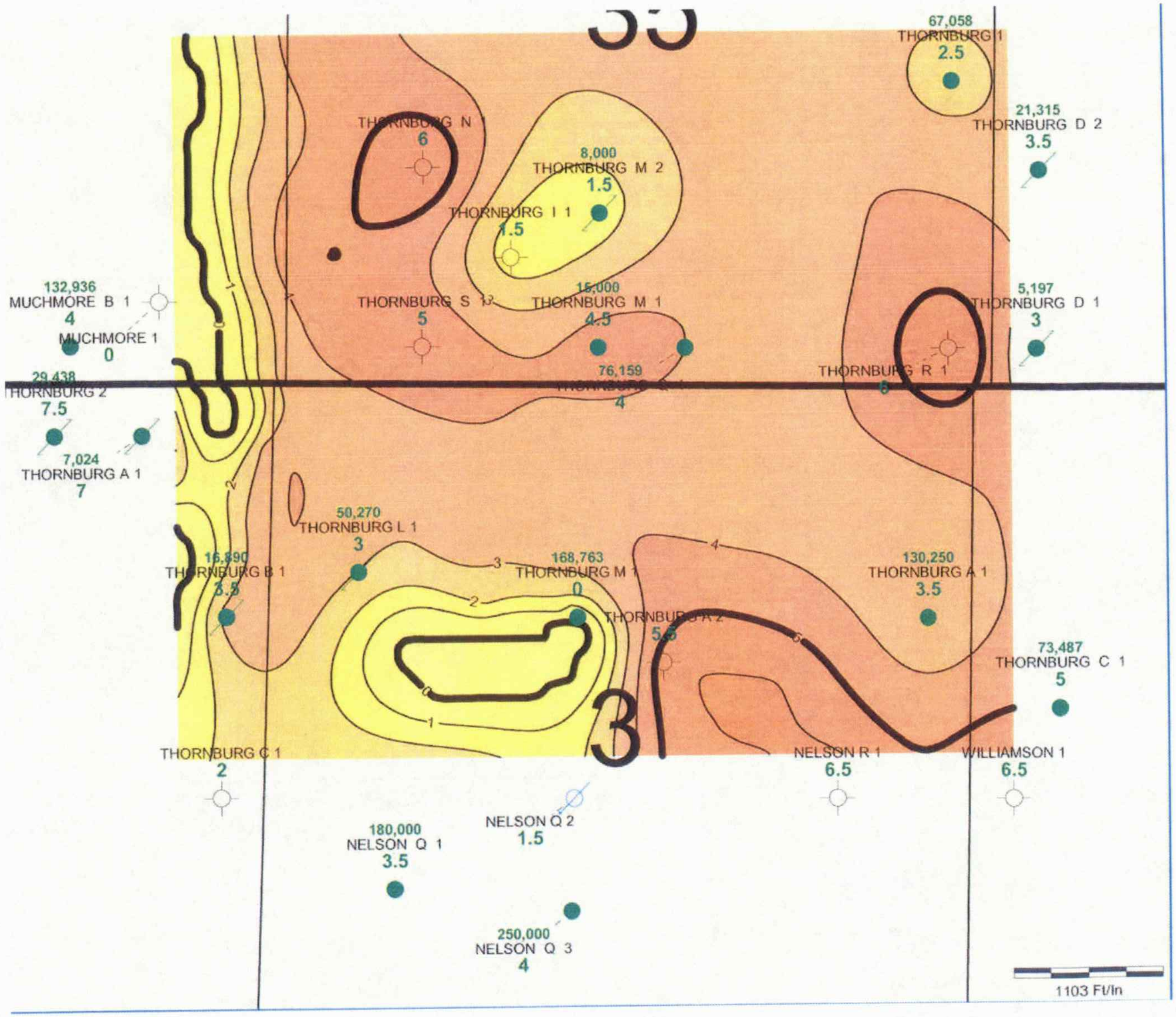


Figure A12

Porosity distribution in Layer 4

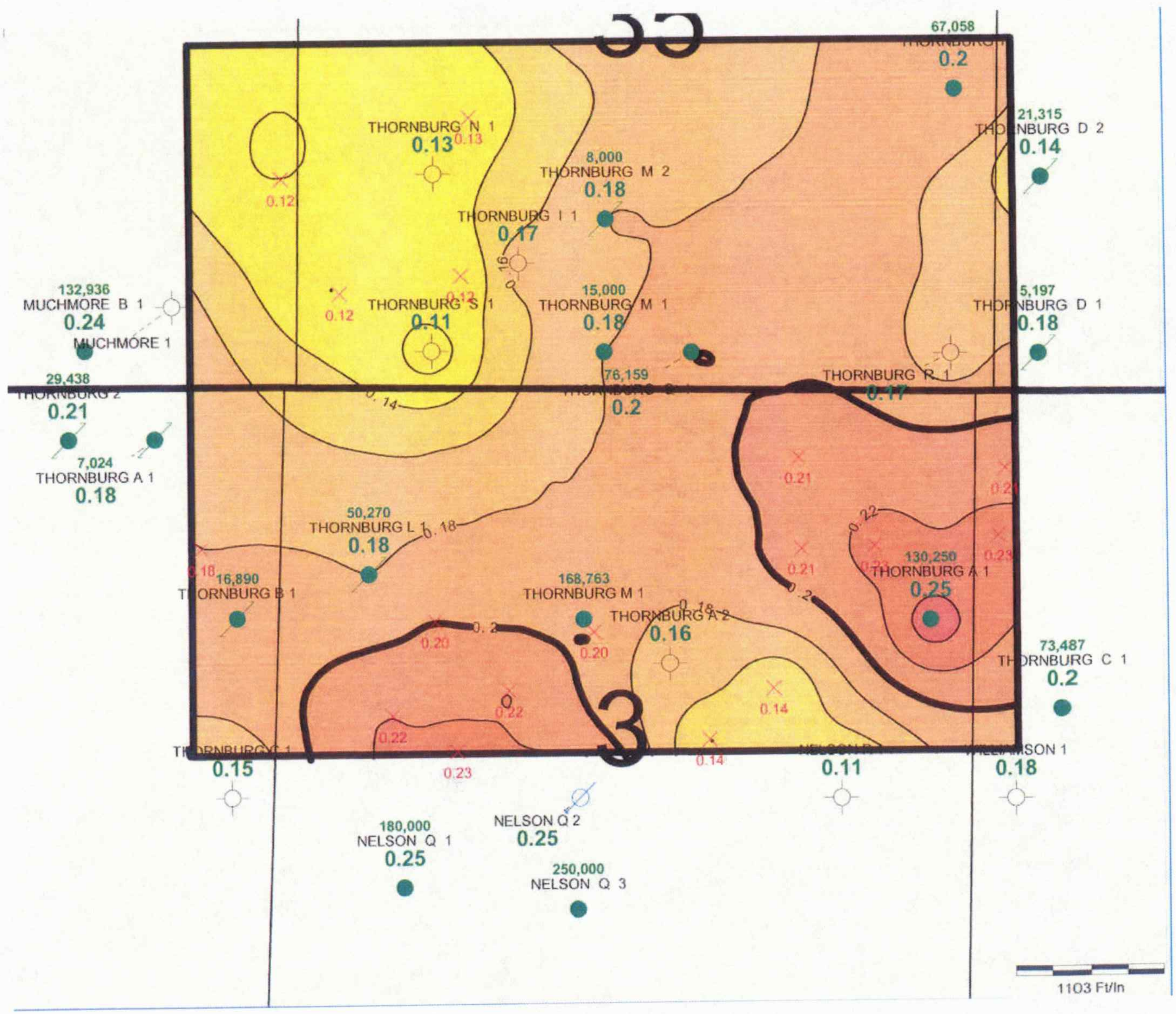


Figure A13

Initial water saturation in Layer 4

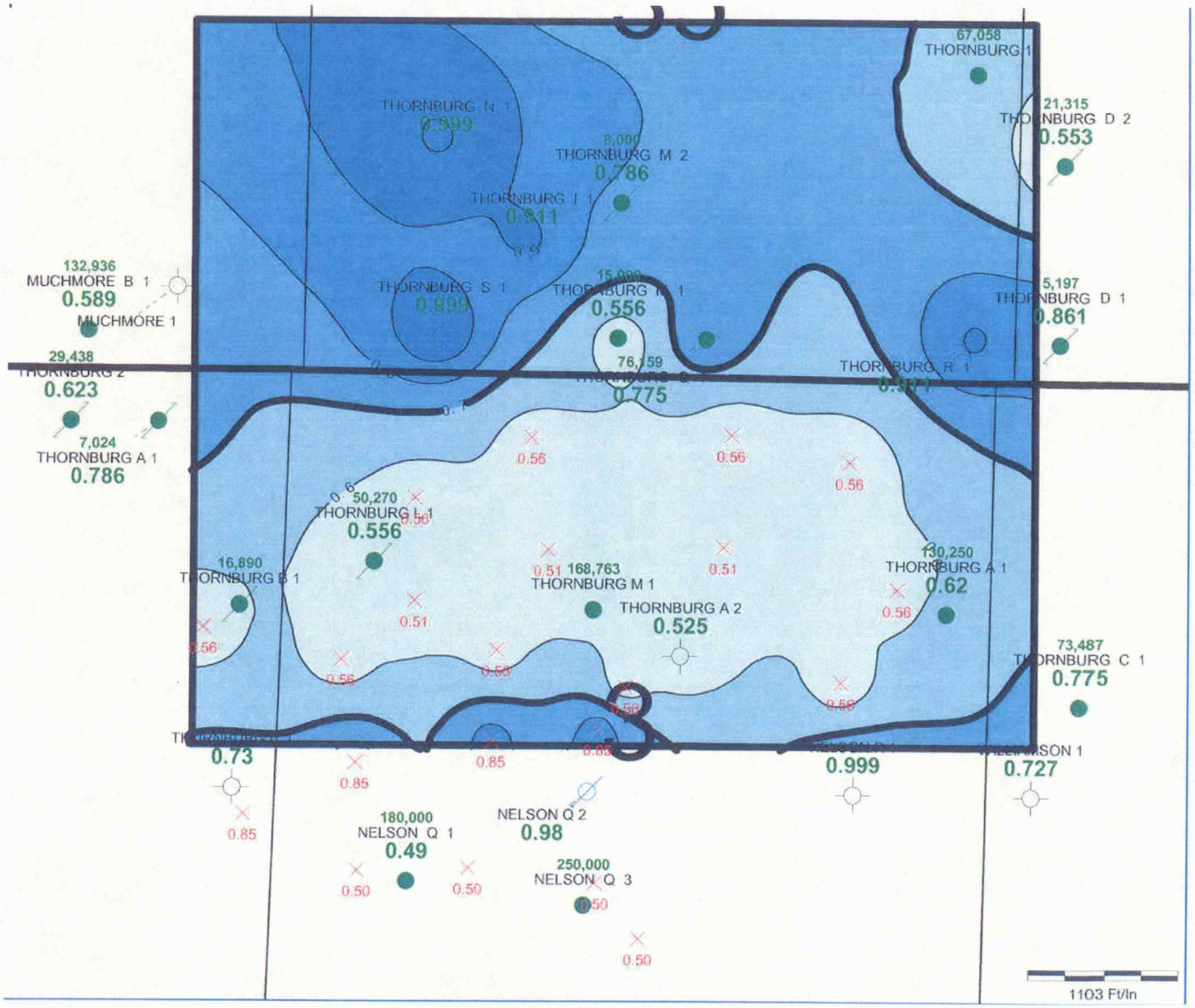


Figure A14

Isopach of Layer 5, feet

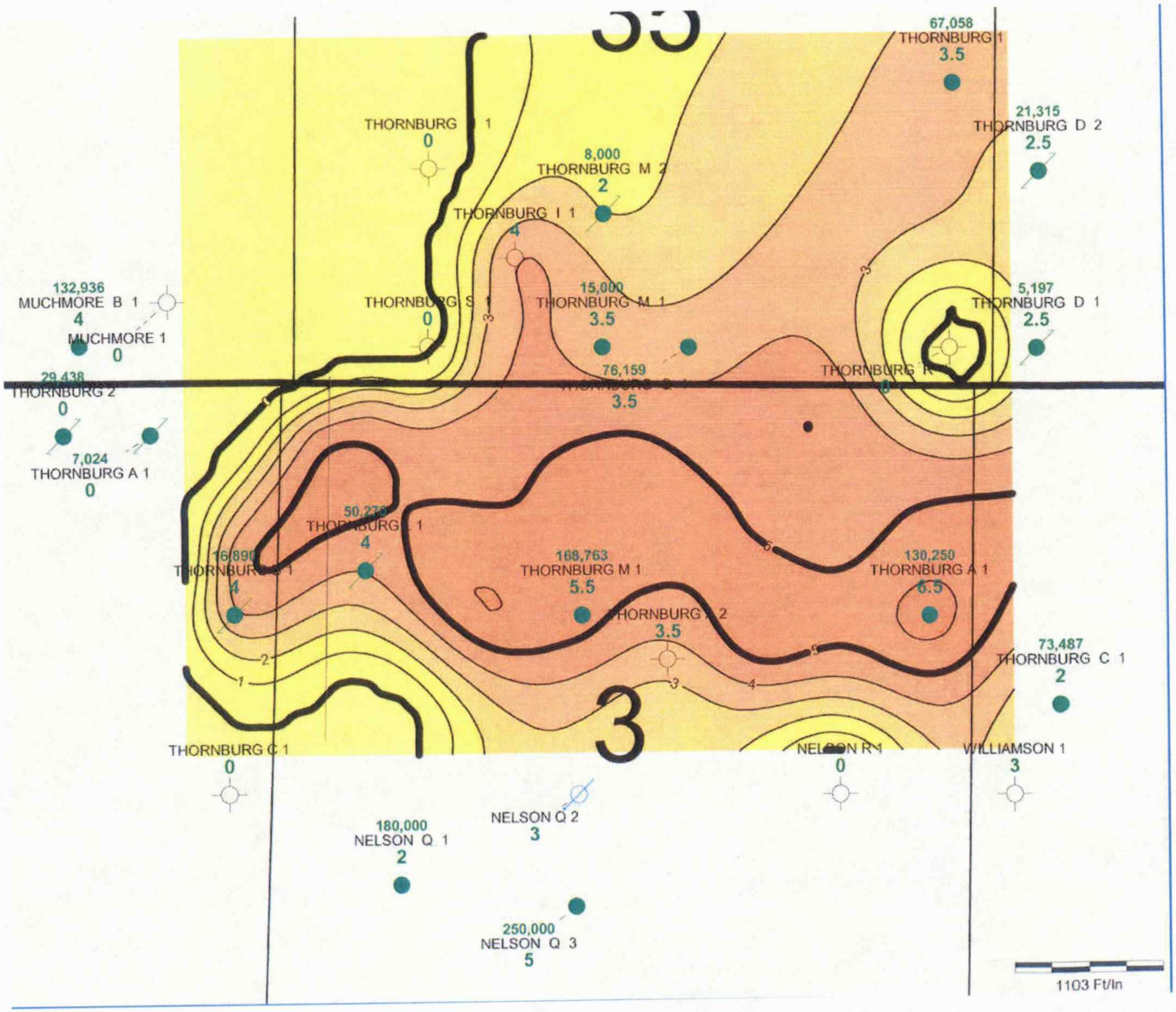


Figure A15

Porosity distribution in Layer 5

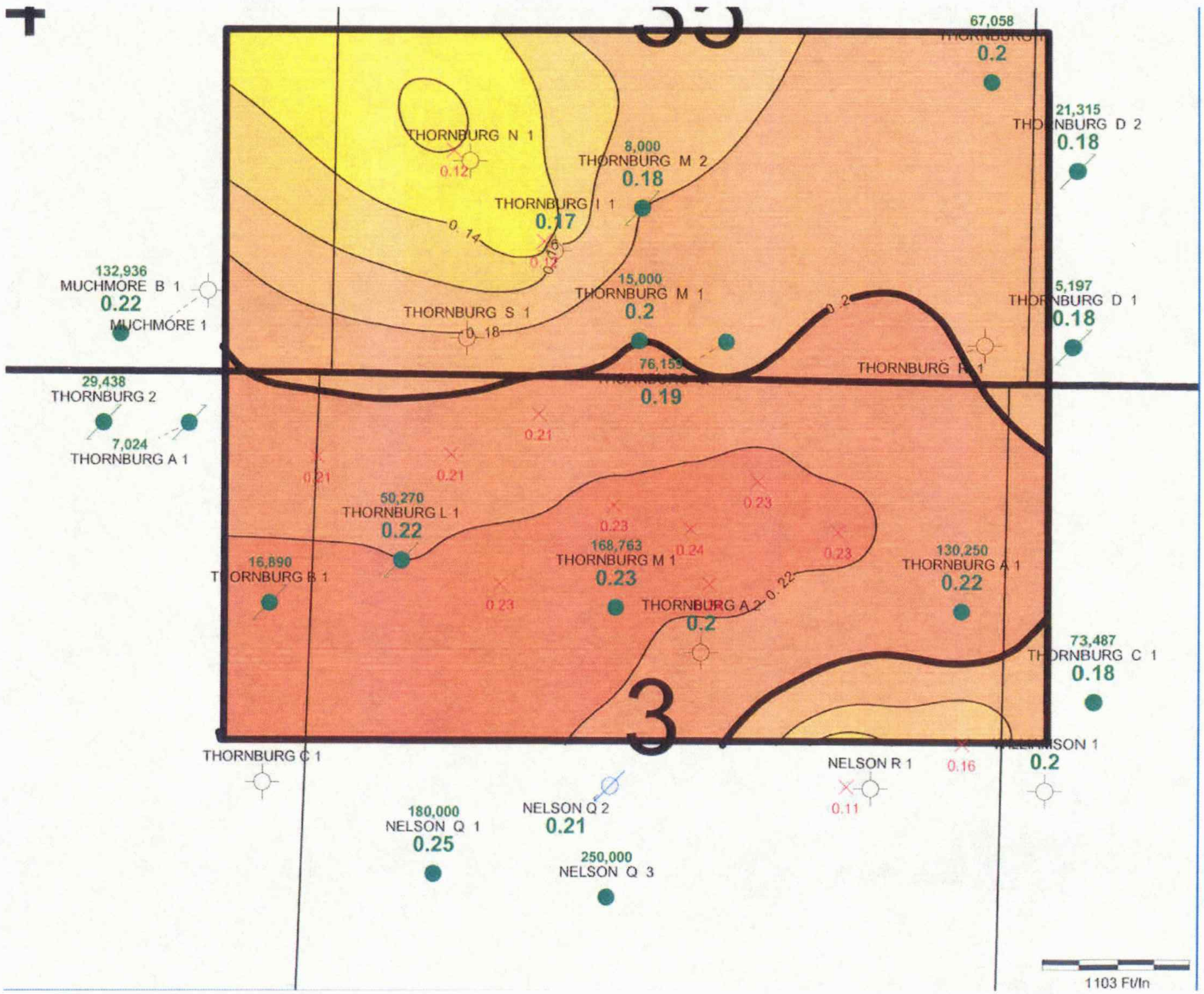


Figure A16

Initial water saturation in Layer 5

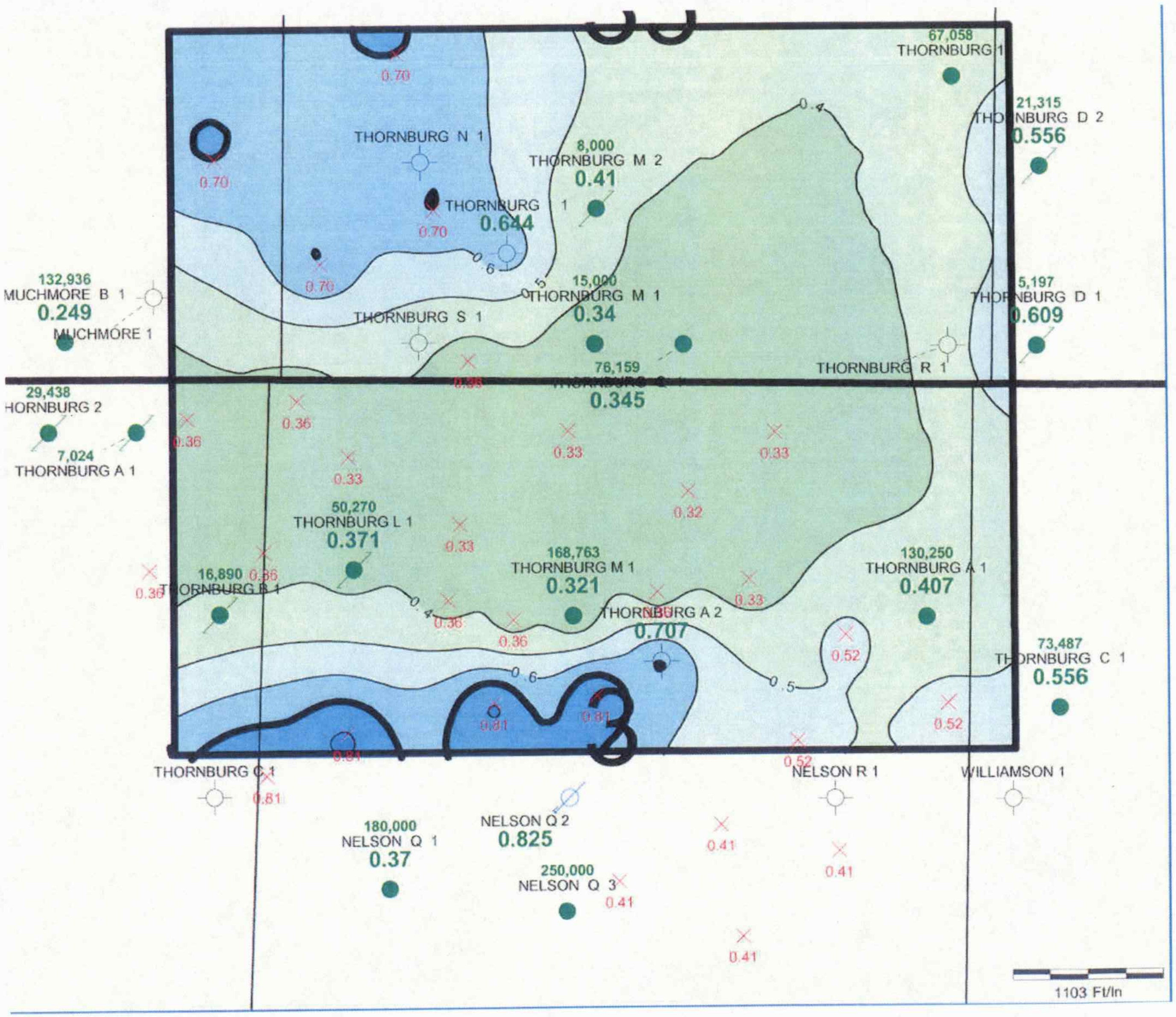


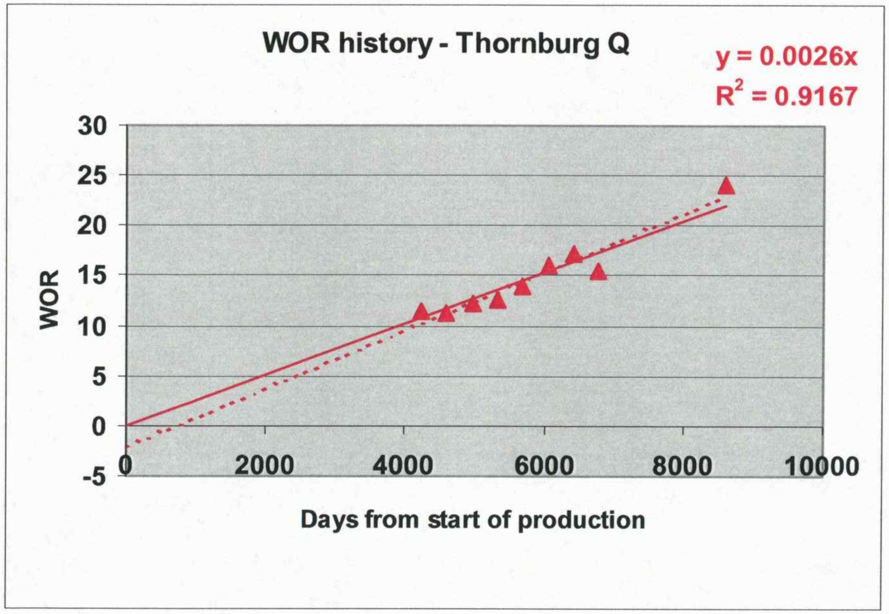
Figure A17

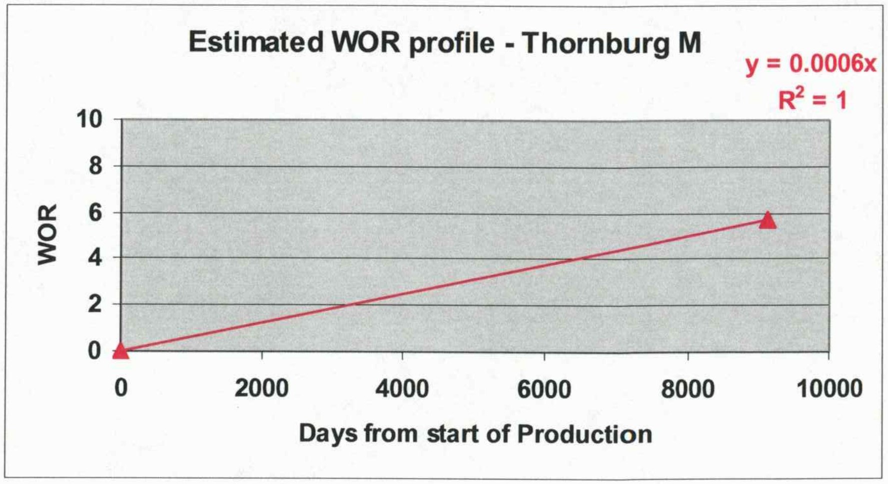
Appendix B
Production data

Estimation of water production history - Judica wells

WOR-time relationship established from TQ1 data was used to estimate the water production of all wells except TM1s (Thronburg M1 Slawson).

MULL's observation - Judica wells have historically produced less water than other Mississippian field wells.

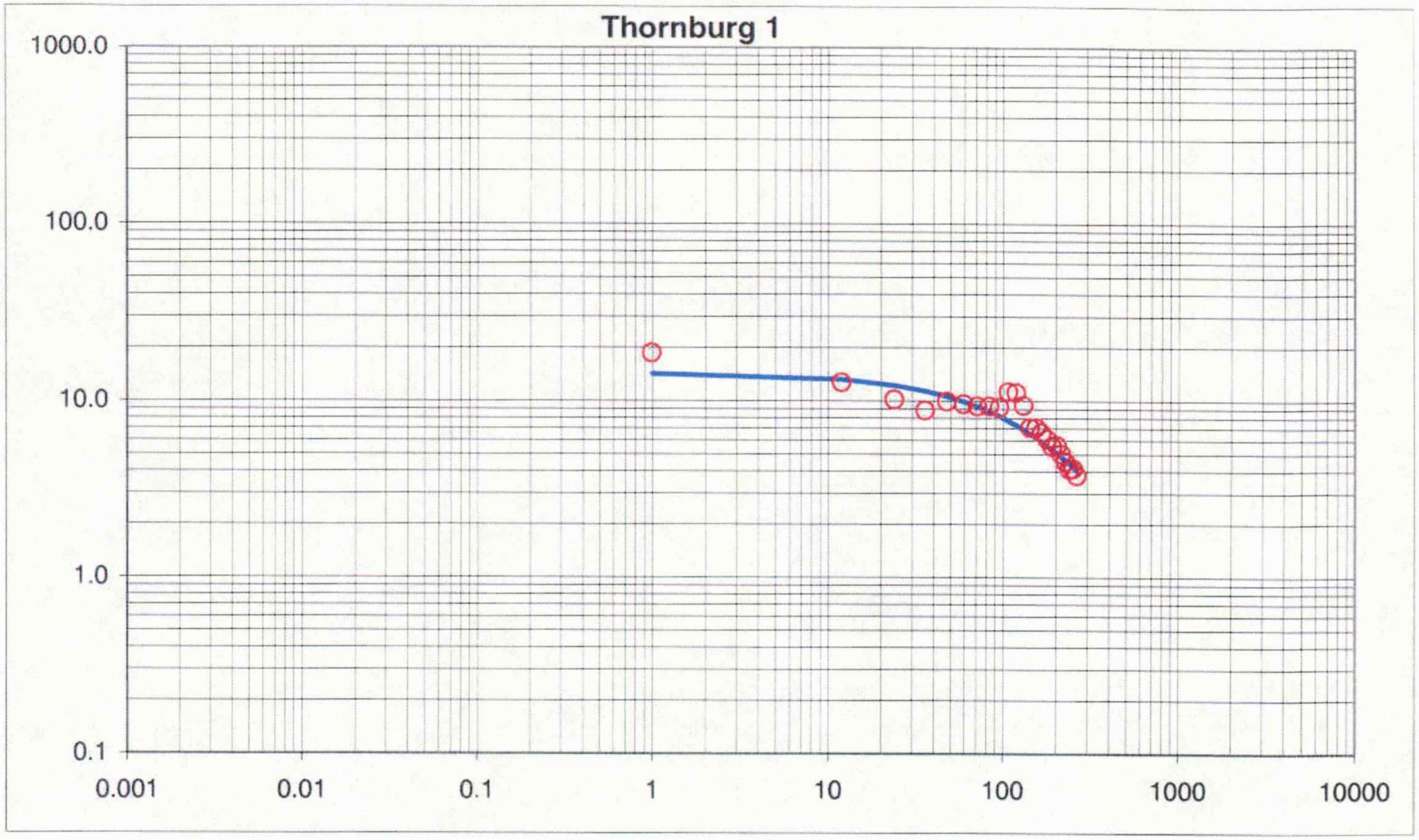




The unforced best-fit line passes within 365 days from the origin.

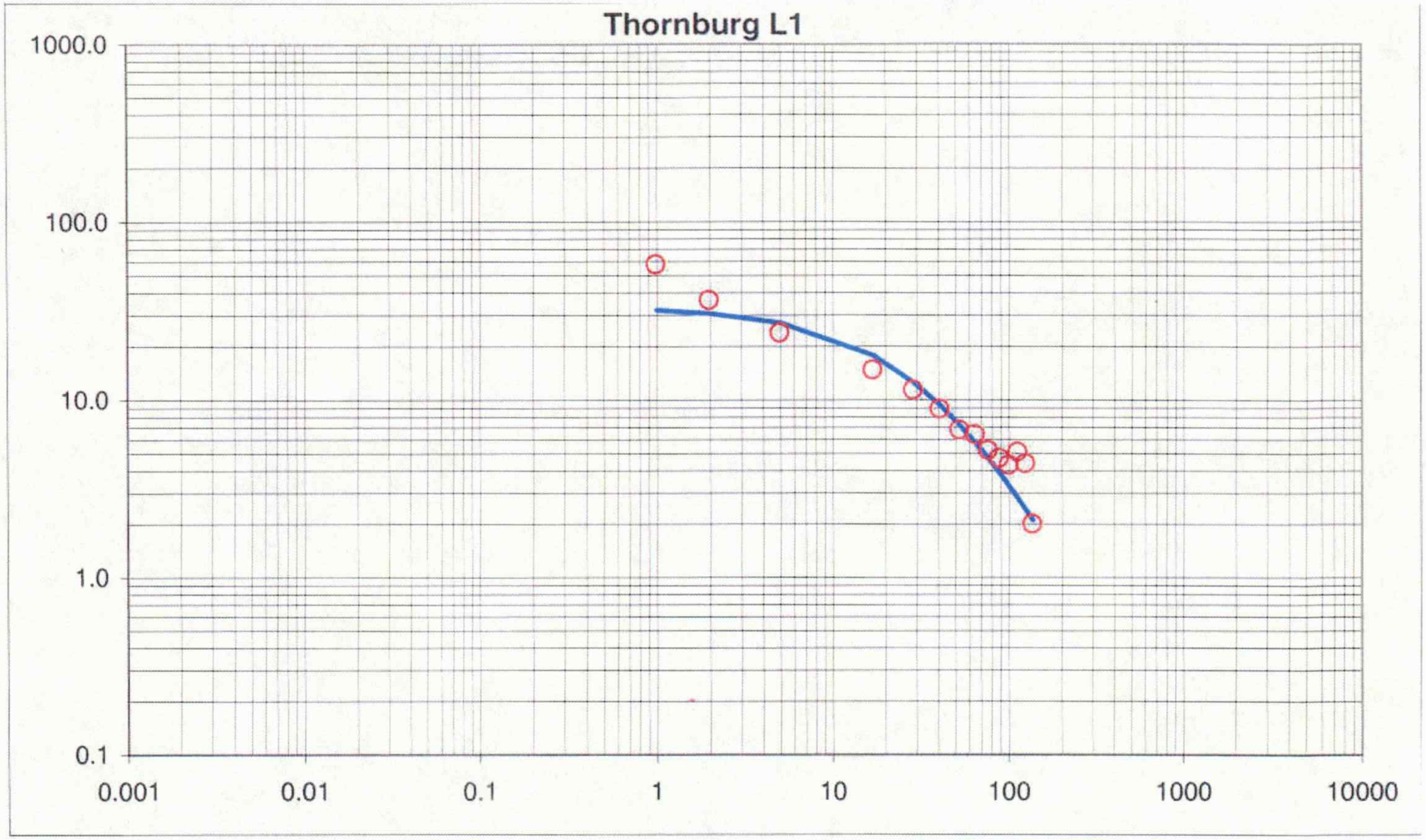
Figure B1

Appendix C
Decline Analyses



A single decline curve appears to represent the production history – well produced under unchanging conditions (skin and/or Pwf constant) is a reasonable assumption.

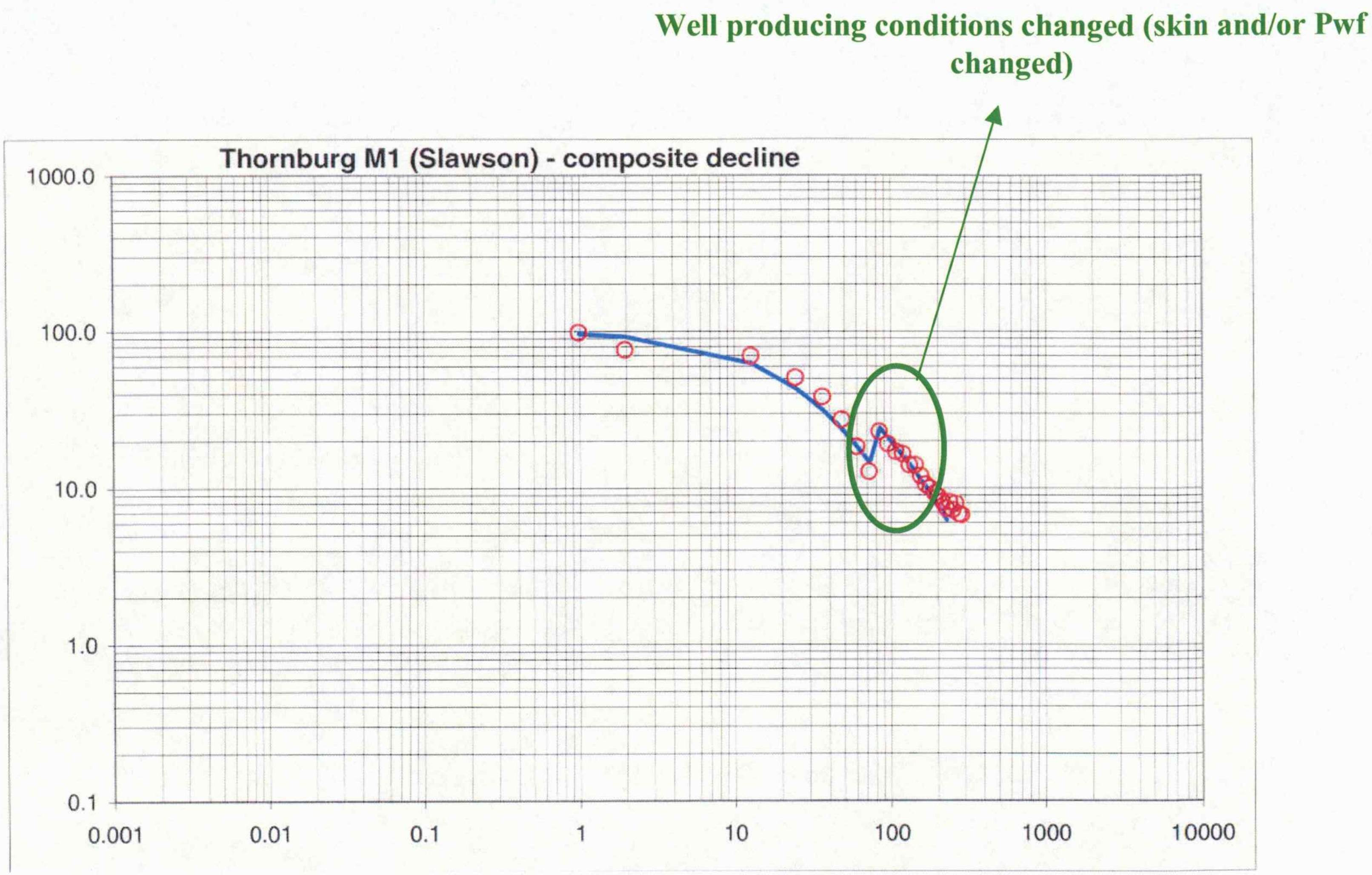
Figure C1



A single decline curve appears to represent the production history – well produced under unchanging conditions (skin and/or Pwf constant) is a reasonable assumption.

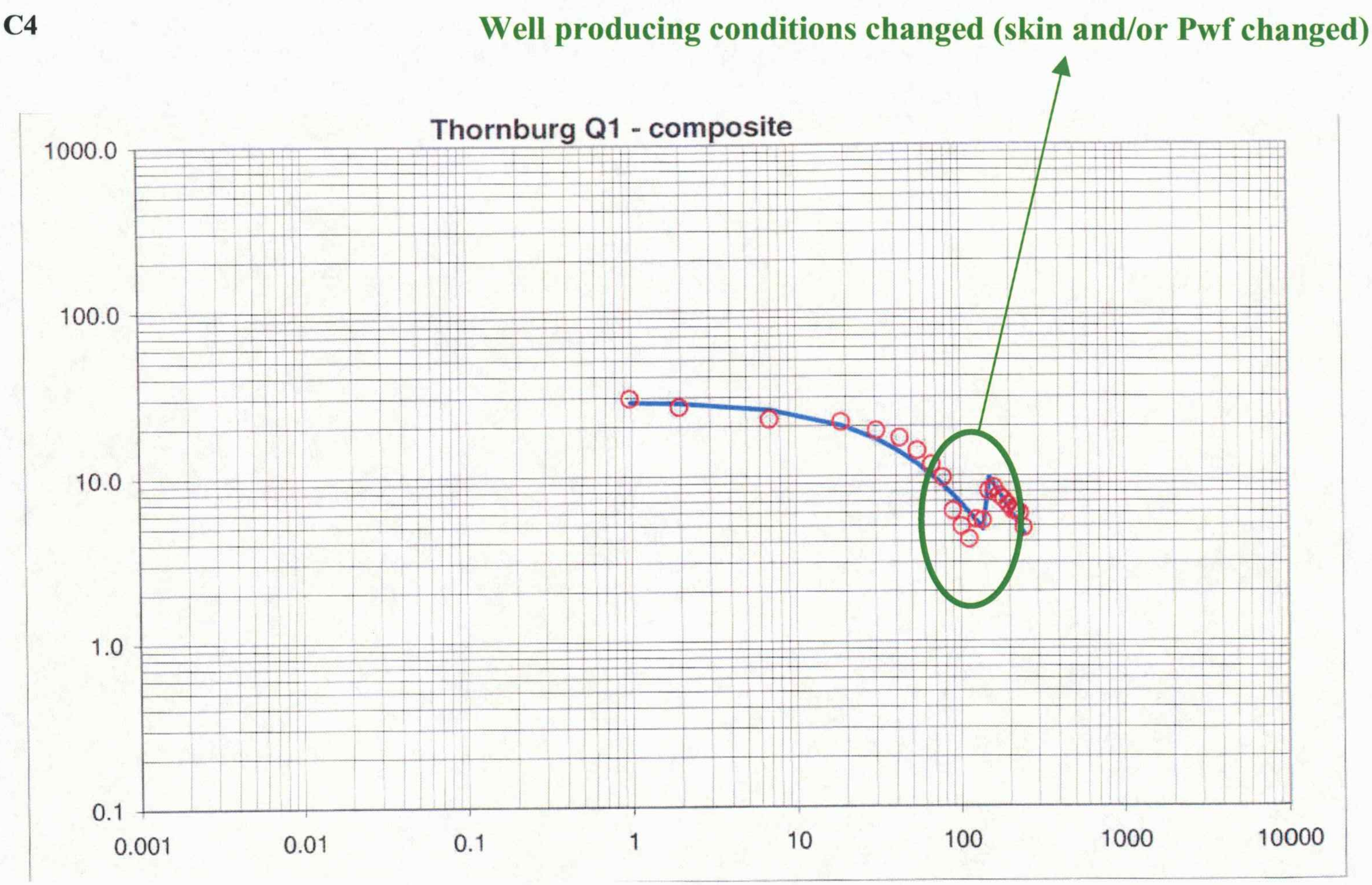
Figure C2

Figure C3



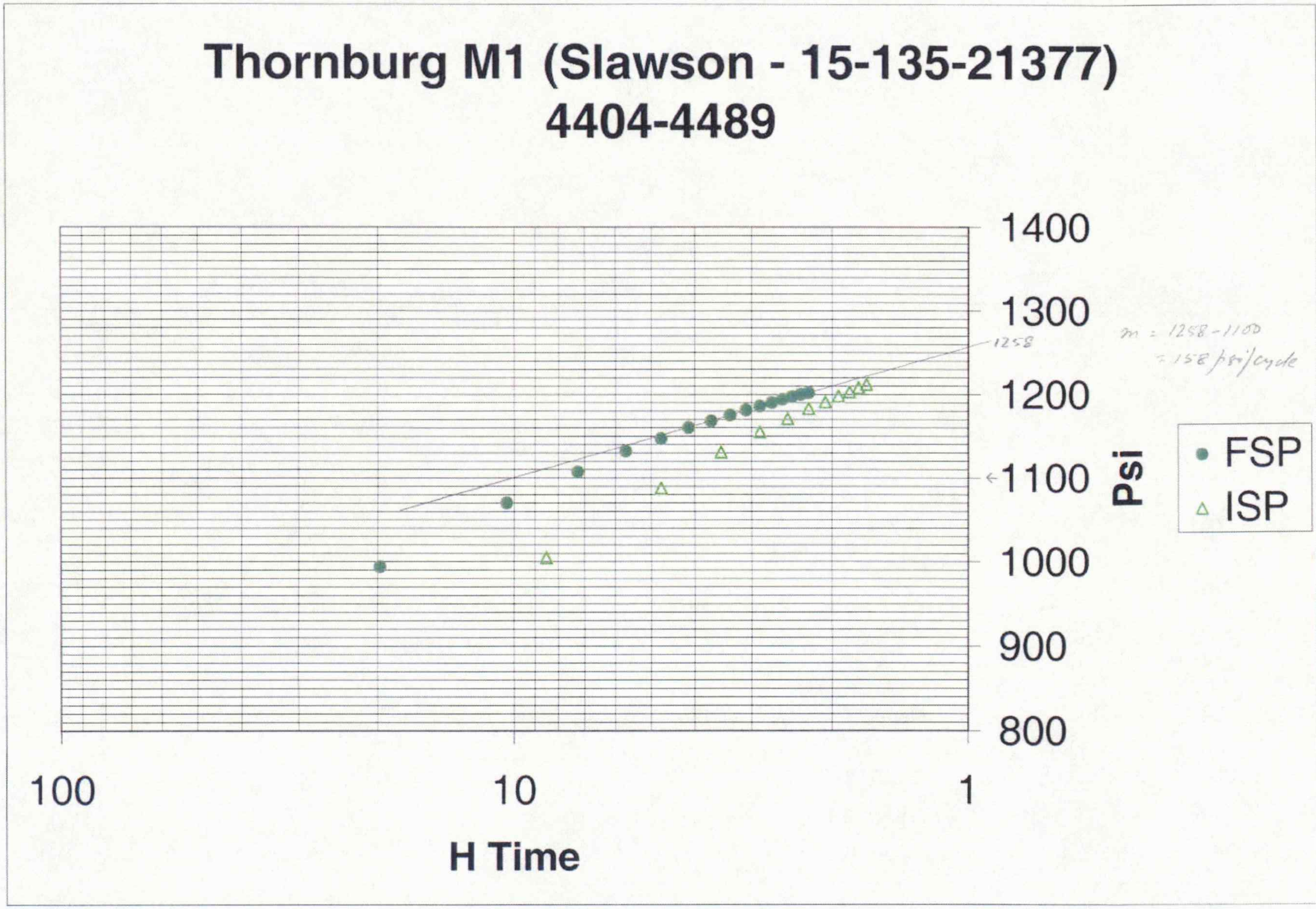
Production history shows 2 different decline trends. The value of the decline exponents (b) for both the curves are same (b=0.4) which is suggestive of the fact that the production data is from the same well and reservoir. No information is available about Pwf in the 1st decline. Currently, the well produces under pumped off conditions. It might not be unreasonable to attempt to history match the 2nd decline phase of this well by reducing skin (keeping Pwf constant) in the absence of Pwf data.

Figure C4



Production history shows 2 different decline trends. The value of the decline exponents (b) for both the curves are same (b=0.45) which is suggestive of the fact that the production data is from the same well and reservoir. No information is available about Pwf in the 1st decline. Currently, the well produces under pumped off conditions. It might not be unreasonable to attempt to history match the 2nd decline phase of this well by reducing skin (keeping Pwf constant) in the absence of Pwf data.

Appendix D
DST Analyses



Thornburg M1 (Slawson - 15-135-21377)
4404-4489
1400
1300
1258
m = 1258-1100
= 158 psi/cycle
1200
1100
1000
900
800
Psi
FSP
ISP
100
10
1
H Time

Figure D1

Table D1

	Feet	oil %	
HO&GCM	345	60	
MO	315	50	
OCM	63	30	
Production rate calculation:			
Liquid recovery:			
Total =	383.4	ft	
Drill collar length =		312	feet
Drill collar ID =		2.26	inch
Wt pipe ID =		2.764	inch
Fluid in drill collar =		312	feet
Fluid in Wt. pipe =		71.4	feet	Wt pipe length = 315'
Effective ID =		2.36	inch
Effective capacity =		0.00542	bbl/ft
Pre-flow recovery:			
FFP - end of pre-flow =		200	psi
FFP - end of main flow =		312	psi
Recovery from pre-flow =		245.8	ft
Pre-flow volume =		1.3	bbl
Pre-flow time =		30	min
Pre-flow rate =		64.0	bbl/d
Main-flow recovery:			
Recovery from main-flow =		137.6	ft
Main-flow volume =		0.75	bbl
Main flow time =		45	mins
Main-flow rate =		23.9	bbl/d

					entered data
Well:	**Thornburg M1**				read from correlations
	from, ft	to, ft	Pay, ft		read from Horner plot
DST range:	4404	4489	6		calculation
Perf	4472	4478			
DST analysis - Oil/Water:					
Pi =	1258	psi			
m =	158	psi/cycle			
P I hr =	1202	psi	(pressure on straight line @ del T = 60 mins)		
Qo =	23.9	bbl/d	(main flow rate)		
Pwf =	312	psi	(related to Qo - end of second flow)		
B =	1.04	RB/STB			
Phi =	0.23	(decimal)			
Mu =	0.80	cp (viscosity)			
ct =	0.000003	1/psi			
Hole diam =	7.88	inch			
rw =	0.328125	ft			
Transmissibility:					
Kh/Muo =	162.6*Qo*Bo/m				
Kh/Mu =	**25.56**	**md-ft\cp**			
In-situ capacity:					
Kh =	**20.45**	**md-ft**			
Average effective permeability:					
K =	**3.408**	**md**			
Skin:					
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]					
S =	**1.27**				
Pressure drop across skin:					
del Ps = 0.867*m*s					
del Ps =	**174.1**	**psi**			
Damage ratio:					
D.R. = (Pi - Pwf)/(Pi - Pwf - del Ps)					
D.R. =	**1.23**				

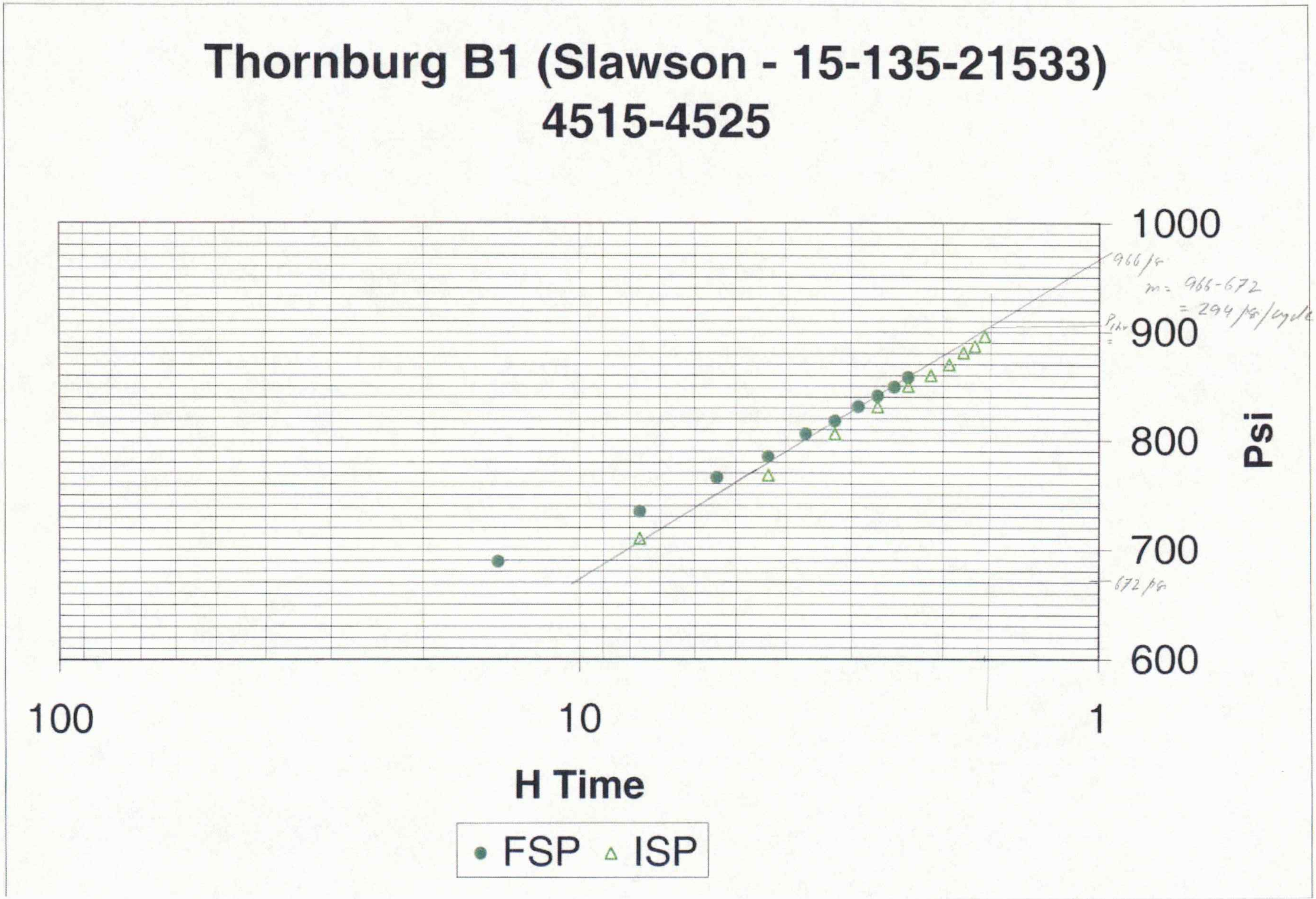

Thornburg B1 (Slawson - 15-135-21533)
4515-4525
1000
900
800
700
600
Psi
100
10
1
H Time
FSP
ISP
966 psi
m = 966-672
= 294 psi/cycle
P1hr =
672 psi

Figure D2

Table D2

	Feet	oil %	
MCO	200	92	
HOCM	170	40	
OCM			
Production rate calculation:			
Liquid recovery:			
Total =	252	ft	
Wt Pipe length =		317	feet
Wt Pipe ID =		2.76	inch
Drill pipe ID =		3.8	inch
Fluid in Wt Pipe =		252	feet
Fluid in pipe =		0	feet
Effective ID =		2.76	inch
Effective capacity =		0.00740	bbl/ft
Pre-flow recovery:			
FFP - end of pre-flow =		133	psi
FFP - end of main flow =		152	psi
Recovery from pre-flow =		220.5	ft
Pre-flow volume =		1.6	bbl
Pre-flow time =		20	min
Pre-flow rate =		117.5	bbl/d
Main-flow recovery:			
Recovery from main-flow =		31.5	ft
Main-flow volume =		0.23	bbl
Main flow time =		20	mins
Main-flow rate =		16.8	bbl/d

					entered data
Well:	**Thornburg B1**				read from correlations
	from, ft	to, ft	Pay, ft		read from Horner plot
DST range:	4515	4525	9		calculation
Perf	4516	4525			
DST analysis - Oil/Water:					
Pi =	966	psi			
m =	294	psi/cycle			
P I hr =	905	psi	(pressure on straight line @ del T = 60 mins)		
Qo =	16.8	bbl/d	(main flow rate)		
Pwf =	152	psi	(related to Qo - end of second flow)		
B =	1.04	RB/STB			
Phi =	0.18	(decimal)			
Mu =	0.80	cp (viscosity)			
ct =	0.000003	1/psi			
Hole diam =	7.88	inch			
rw =	0.328125	ft			
Transmissibility:					
Kh/Muo =	162.6*Qo*Bo/m				
Kh/Mu =	**9.66**	**md-ft\cp**			
In-situ capacity:					
Kh =	**7.73**	**md-ft**			
Average effective permeability:					
K =	**0.858**	**md**			
Skin:					
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]					
S =	**-1.70**				
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**				

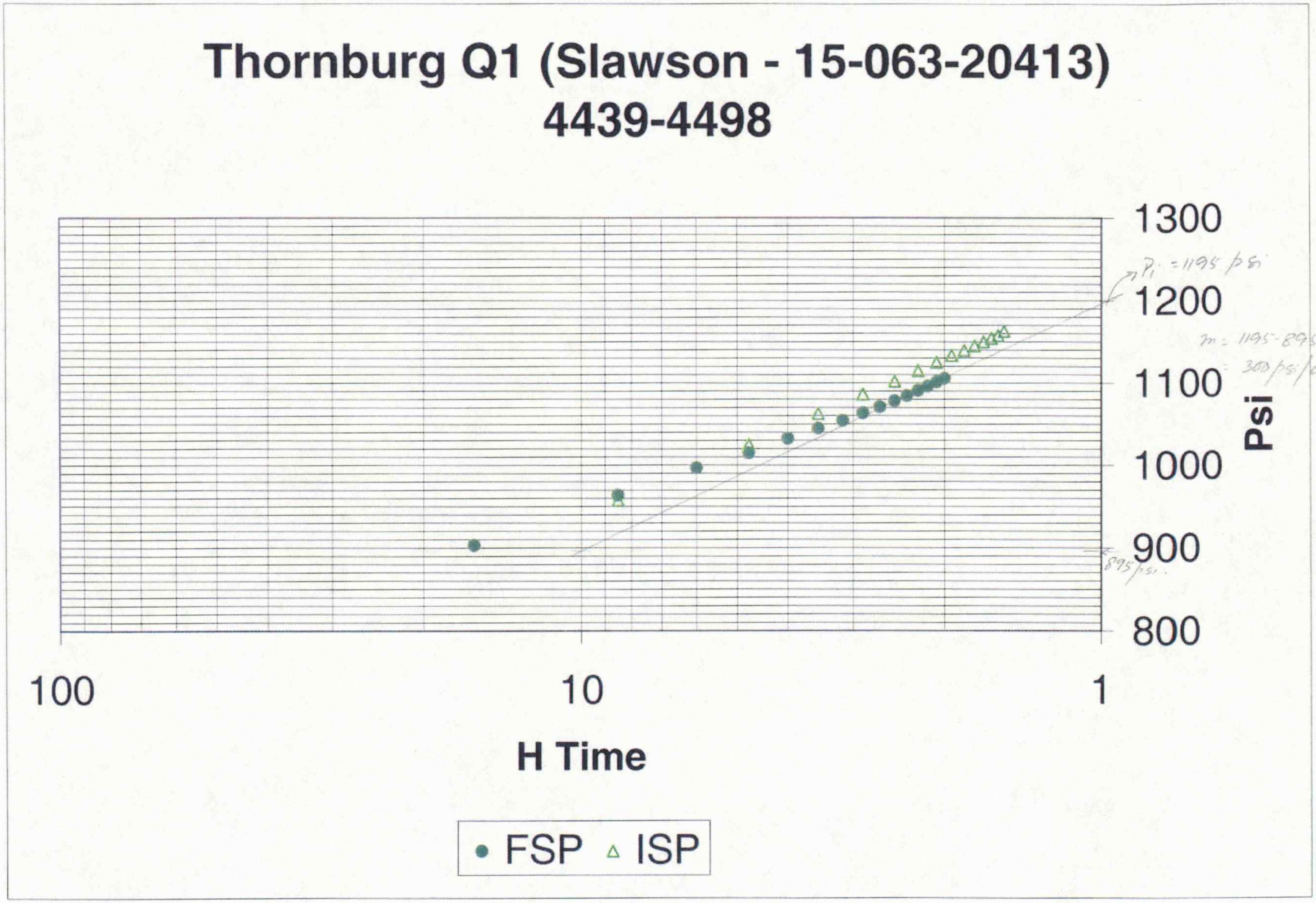

Thornburg Q1 (Slawson - 15-063-20413)
4439-4498
1300
1200
1100
1000
900
800
Psi
100
10
1
H Time
FSP
ISP
Pi = 1195 psi
m = 1195-895
= 300 psi/cycle
895 psi

Figure D3

Table D3

	Feet	oil %	
CGO to SGO	315	100	
MO	186	60	
SOCM	189	14	
Production rate calculation:			
Liquid recovery:			
Total =	453.06	ft	
Collar length =		217	feet
Drill collar ID =		2.25	inch
Wt pipe length =		126	feet
Wt pipe ID =		2.764	inch
Drill Pipe ID =		3.826	inch
Fluid in drill collar =		217	feet
Fluid in Wt Pipe =		126	feet
Fluid in Drill pipe =		110.06	feet
Effective ID =		2.85	inch
Effective capacity =		0.00788	bbl/ft
Pre-flow recovery:			
FFP - end of pre-flow =		188.2	psi
FFP - end of main flow =		296	psi
Recovery from pre-flow =		288.1	ft
Pre-flow volume =		2.3	bbl
Pre-flow time =		30	min
Pre-flow rate =		108.9	bbl/d
Main-flow recovery:			
Recovery from main-flow =		165.0	ft
Main-flow volume =		1.30	bbl
Main flow time =		45	mins
Main-flow rate =		41.6	bbl/d

					entered data
Well:	**Thornburg Q1**				read from correlations
	from, ft	to, ft	Pay, ft		read from Horner plot
DST range:	4439	4498	10		calculation
Perf	4481	4491			
DST analysis - Oil/Water:					
Pi =	1195	psi			
m =	300	psi/cycle			
P I hr =	1090	psi	(pressure on straight line @ del T = 60 mins)		
Qo =	41.6	bbl/d	(main flow rate)		
Pwf =	296	psi	(related to Qo - end of second flow)		
B =	1.04	RB/STB			
Phi =	0.18	(decimal)			
Mu =	0.80	cp (viscosity)			
ct =	0.000003	1/psi			
Hole diam =	7.88	inch			
rw =	0.328125	ft			
Transmissibility:					
Kh/Muo =	162.6*Qo*Bo/m				
Kh/Mu =	**23.45**	**md-ft\cp**			
In-situ capacity:					
Kh =	**18.76**	**md-ft**			
Average effective permeability:					
K =	**1.876**	**md**			
Skin:					
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]					
S =	**-1.99**				
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**				

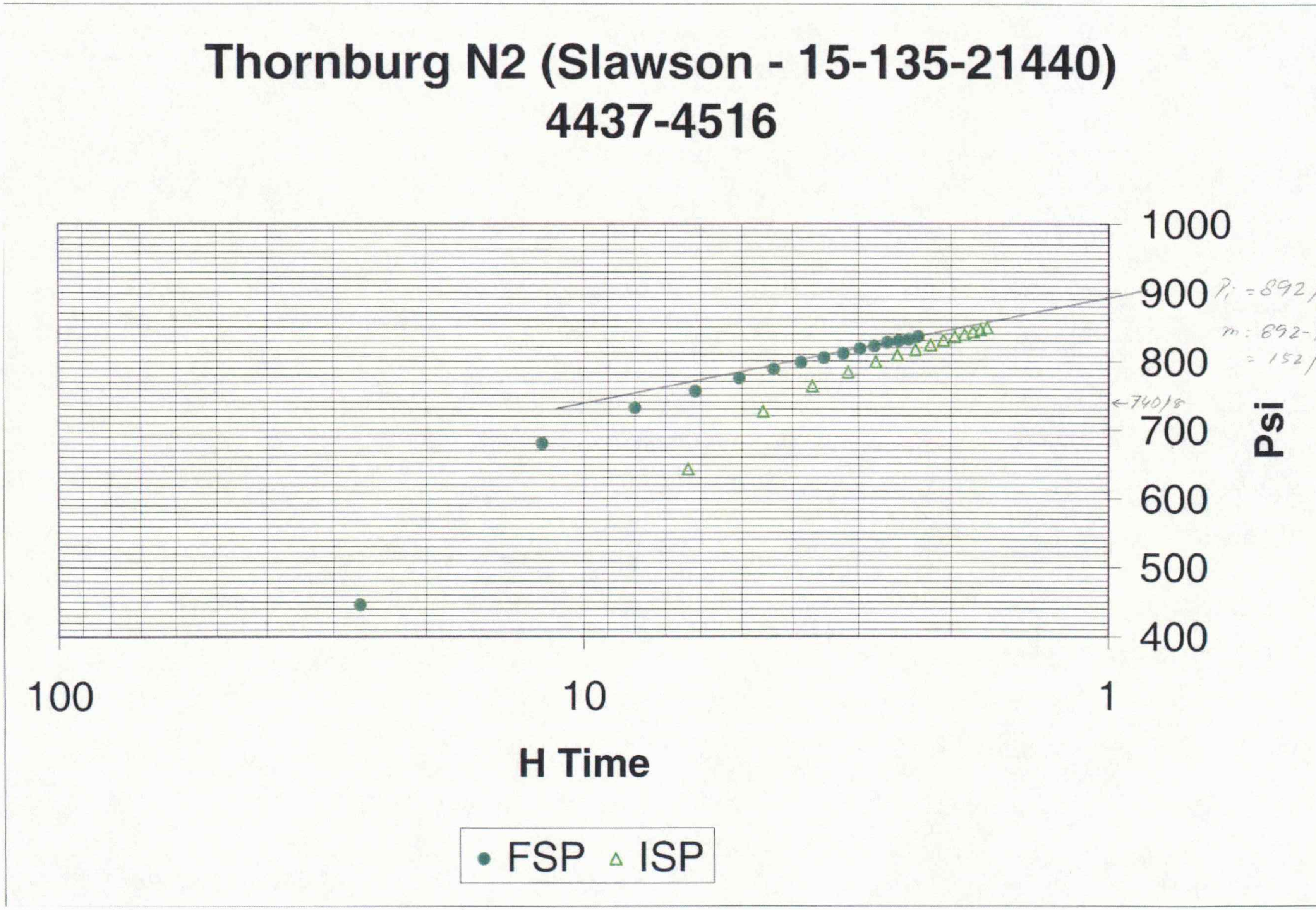
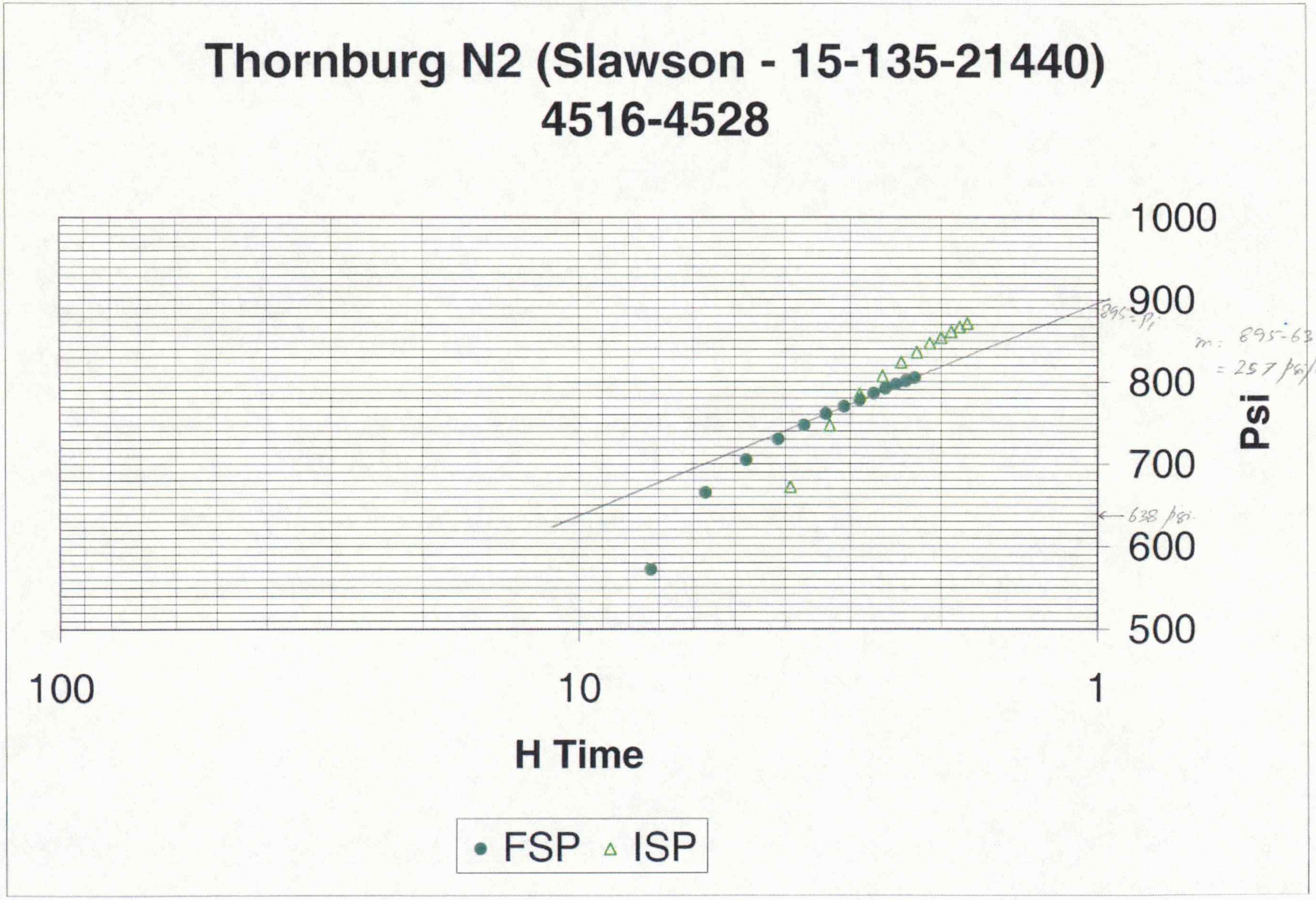

Thornburg N2 (Slawson - 15-135-21440)
4437-4516
1000
900
800
700
600
500
400
Psi
100
10
1
H Time
FSP
ISP
Pi = 892 psi
m: 892-740
= 152 psi/cycle
← 740 psi

Figure D4

Table D4

	Feet	oil %	
CO	10	100	
HOCM	15	60	
MWSO	217	30	
Production rate calculation:			
Liquid recovery:			
Total =	84.1	ft	
Collar length =		284	feet
Drill collar ID =		2.76	inch
Drill pipe ID =		3.826	inch
Fluid in drill collar =		84.1	feet
Fluid in pipe =		0	feet
Effective ID =		2.76	inch
Effective capacity =		0.00740	bbl/ft
Pre-flow recovery:			
FFP - end of pre-flow =		68	psi
FFP - end of main flow =		132	psi
Recovery from pre-flow =		43.3	ft
Pre-flow volume =		0.3	bbl
Pre-flow time =		32	min
Pre-flow rate =		14.4	bbl/d
Main-flow recovery:			
Recovery from main-flow =		40.8	ft
Main-flow volume =		0.30	bbl
Main flow time =		45	mins
Main-flow rate =		9.7	bbl/d

					entered data	
Well:	**Thornburg N2**				read from correlations	
	from, ft	to, ft	Pay, ft		read from Horner plot	
DST range:	4515	4525	6		calculation	
Perf	4499	4505				
DST analysis - Oil/Water:						
Pi =	892	psi				
m =	152	psi/cycle				
P I hr =	836	psi	(pressure on straight line @ del T = 60 mins)			
Qo =	9.7	bbl/d	(main flow rate)			
Pwf =	132	psi	(related to Qo - end of second flow)			
B =	1.04	RB/STB				
Phi =	0.18	(decimal)				
Mu =	0.80	cp (viscosity)				
ct =	0.000003	1/psi				
Hole diam =	7.88	inch				
rw =	0.328125	ft				
Transmissibility:						
Kh/Muo =	162.6*Qo*Bo/m					
Kh/Mu =	**10.75**	**md-ft\cp**				
In-situ capacity:						
Kh =	**8.60**	**md-ft**				
Average effective permeability:						
K =	**1.433**	**md**				
Skin:						
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]						
S =	**0.43**					
Pressure drop across skin:						
del Ps = 0.867*m*s						
del Ps =	**56.6**	**psi**				
Damage ratio:						
D.R. = (Pi - Pwf)/(Pi - Pwf - del Ps)						
D.R. =	**1.08**					



Thornburg N2 (Slawson - 15-135-21440)
4516-4528
1000
900
800
700
600
500
Psi
100
10
1
H Time
FSP
ISP
895 = p_i
m: 895-638
= 257 psi/cycle
638 psi

Figure D5

Table D5

	Feet	oil %	
CO	30	100	
HOCM	15	60	
WCM	62	0	
Production rate calculation:			
Liquid recovery:			
Total =	39	ft	
Collar length =		315	feet
Drill collar ID =		2.76	inch
Drill pipe ID =		3.826	inch
Fluid in drill collar =		39	feet
Fluid in pipe =		0	feet
Effective ID =		2.76	inch
Effective capacity =		0.00740	bbl/ft
Pre-flow recovery:			
FFP - end of pre-flow =		23	psi
FFP - end of main flow =		48	psi
Recovery from pre-flow =		18.7	ft
Pre-flow volume =		0.1	bbl
Pre-flow time =		32	min
Pre-flow rate =		6.2	bbl/d
Main-flow recovery:			
Recovery from main-flow =		20.3	ft
Main-flow volume =		0.15	bbl
Main flow time =		43	mins
Main-flow rate =		5.0	bbl/d

					entered data
Well:	**Thornburg N2**				read from correlations
	from, ft	to, ft	Pay, ft		read from Horner plot
DST range:	4516	4528	12		calculation
Perf	4499	4505			
DST analysis - Oil/Water:					
Pi =	895	psi			
m =	257	psi/cycle			
P I hr =	805	psi	(pressure on straight line @ del T = 60 mins)		
Qo =	5.0	bbl/d	(main flow rate)		
Pwf =	48	psi	(related to Qo - end of second flow)		
B =	1.04	RB/STB			
Phi =	0.18	(decimal)			
Mu =	0.80	cp (viscosity)			
ct =	0.000003	1/psi			
Hole diam =	7.88	inch			
rw =	0.328125	ft			
Transmissibility:					
Kh/Muo =	162.6*Qo*Bo/m				
Kh/Mu =	**3.31**	**md-ft\cp**			
In-situ capacity:					
Kh =	**2.65**	**md-ft**			
Average effective permeability:					
K =	**0.221**	**md**			
Skin:					
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]					
S =	**-0.58**				
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**				

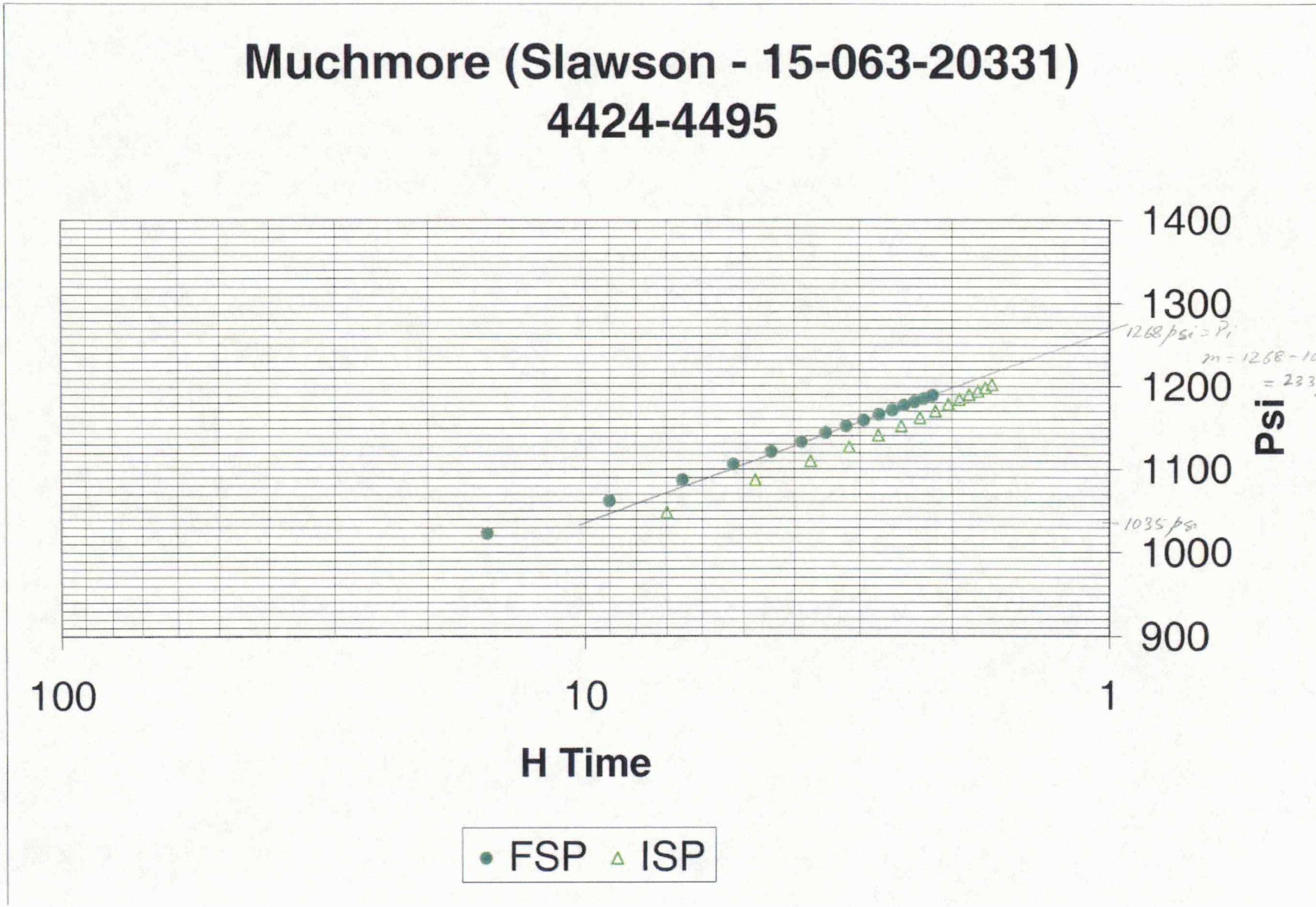

Muchmore (Slawson - 15-063-20331)
4424-4495
1400
1300
1200
1100
1000
900
100
10
1
H Time
Psi
FSP
ISP
1268 psi = Pi
m = 1268 - 1035
= 233 psi/cycle
1035 psi

Figure D6

Table D6

	Feet	oil %	
FGCMO	692	80	
CGO	124	100	
SOCM			
Production rate calculation:			
Liquid recovery:			
Total =	677.6	ft	
Collar length =		220	feet
Drill collar ID =		2.764	inch
Wt pipe length =			feet
Wt pipe ID =			inch
Drill Pipe ID =		3.826	inch
Fluid in drill collar =		220	feet
Fluid in Wt Pipe =			feet
Fluid in Drill pipe =		457.6	feet
Effective ID =		3.52	inch
Effective capacity =		0.01202	bbl/ft
Pre-flow recovery:			
FFP - end of pre-flow =		173	psi
FFP - end of main flow =		310	psi
Recovery from pre-flow =		378.1	ft
Pre-flow volume =		4.5	bbl
Pre-flow time =		30	min
Pre-flow rate =		218.1	bbl/d
Main-flow recovery:			
Recovery from main-flow =		299.5	ft
Main-flow volume =		3.60	bbl
Main flow time =		42	mins
Main-flow rate =		123.4	bbl/d

					entered data
Well:	**Muchmore B1**				read from correlations
	from, ft	to, ft	Pay, ft		read from Horner plot
DST range:	4424	4495		11	calculation
Perf	4484	4507			
DST analysis - Oil/Water:					
Pi =	1268	psi			
m =	233	psi/cycle			
P I hr =	1188	psi	(pressure on straight line @ del T = 60 mins)		
Qo =	123.4	bbl/d	(main flow rate)		
Pwf =	310	psi	(related to Qo - end of second flow)		
B =	1.04	RB/STB			
Phi =	0.18	(decimal)			
Mu =	0.80	cp (viscosity)			
ct =	0.000003	1/psi			
Hole diam =	7.88	inch			
rw =	0.328125	ft			
Transmissibility:					
Kh/Muo =	162.6*Qo*Bo/m				
Kh/Mu =	**89.55**	**md-ft\cp**			
In-situ capacity:					
Kh =	**71.64**	**md-ft**			
Average effective permeability:					
K =	**6.513**	**md**			
Skin:					
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]					
S =	**-1.32**				
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**				

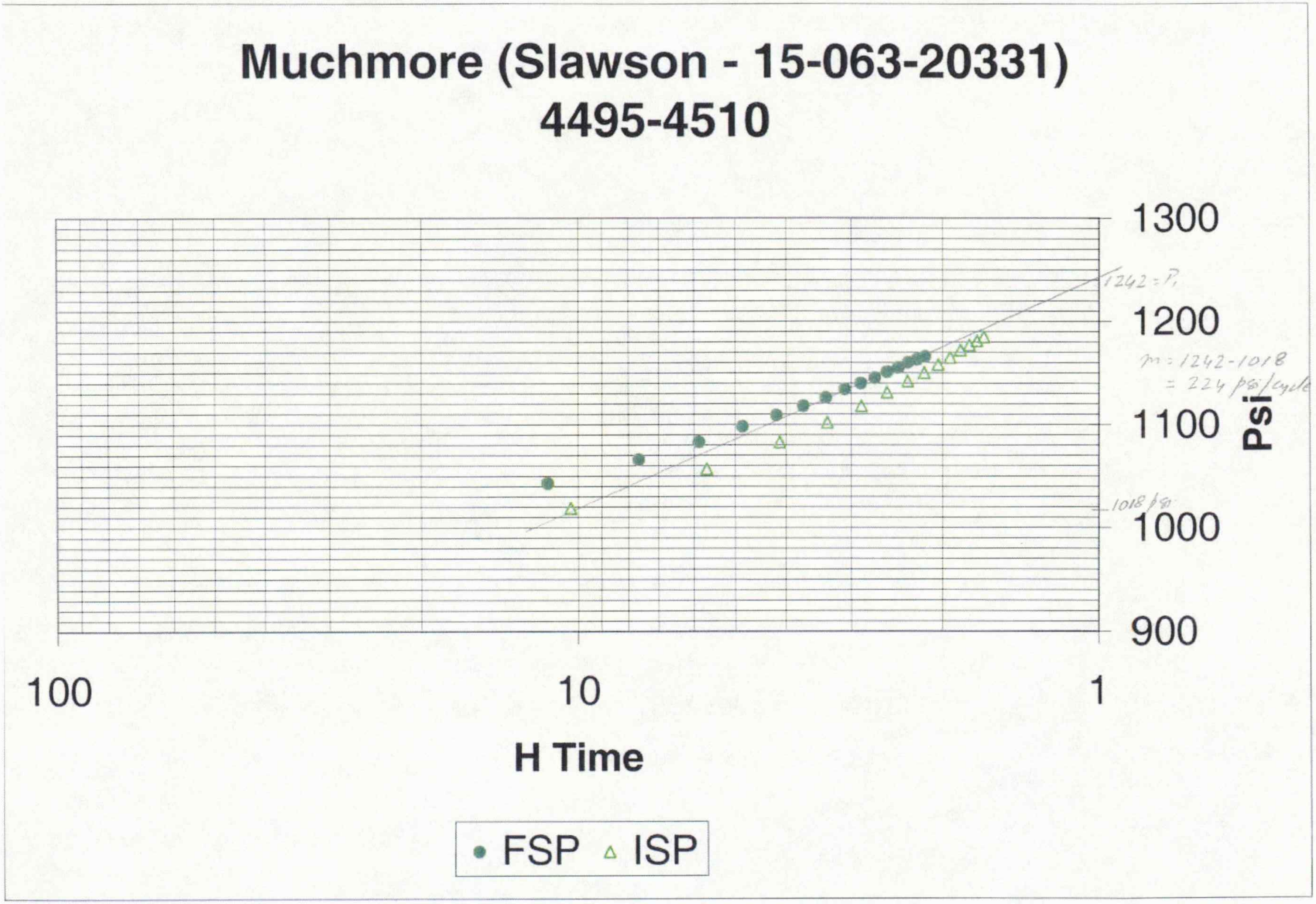

Muchmore (Slawson - 15-063-20331)
4495-4510
1300
1200
1100
1000
900
Psi
100
10
1
H Time
FSP
ISP
1242 = Pi
m = 1242-1018
= 224 psi/cycle.
1018 psi

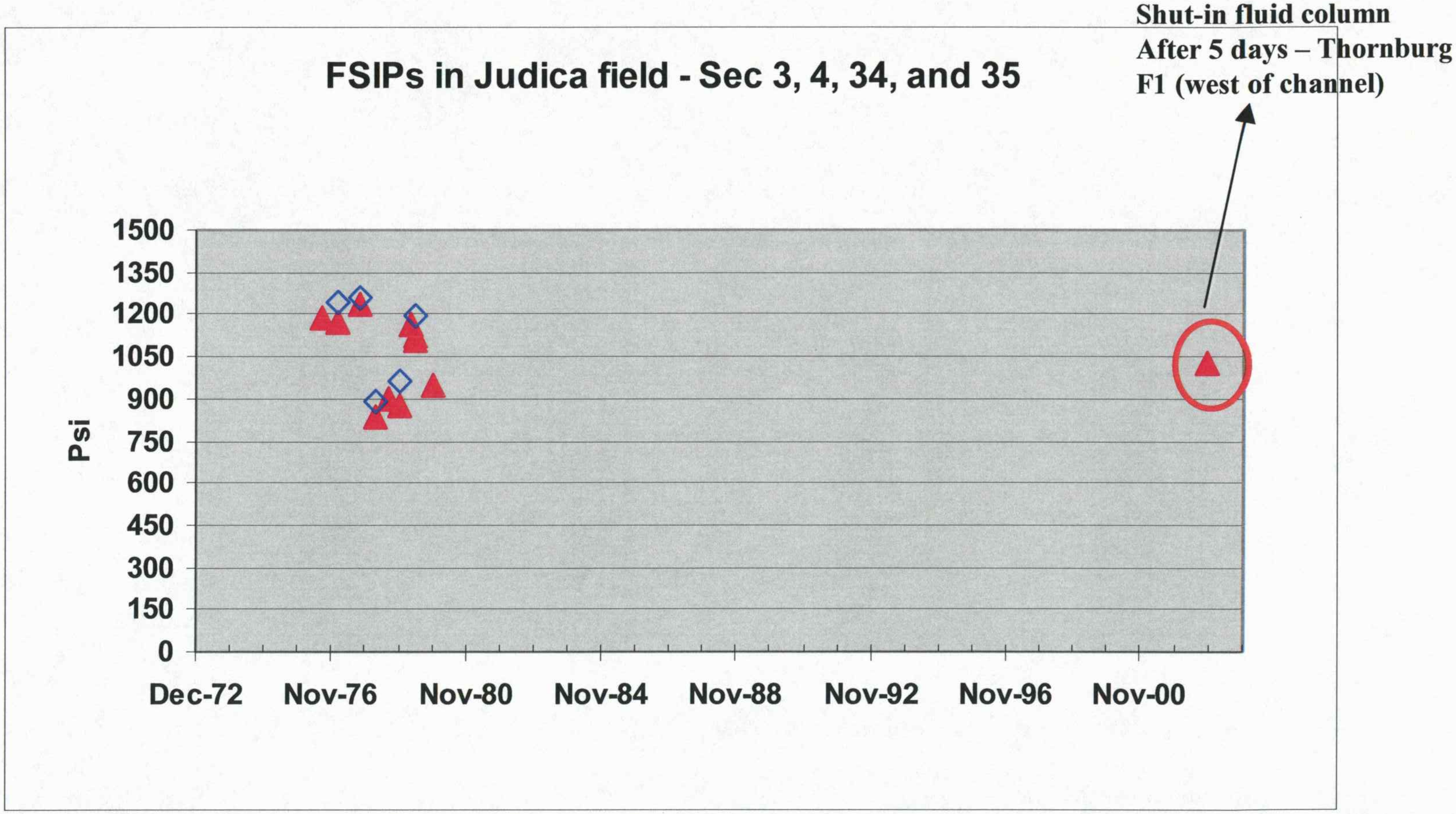
Figure D7

Table D7

	Feet	oil %	
CGO	1500	98	
MO			
SOCM			
Production rate calculation:			
Liquid recovery:			
Total =	1470	ft	
Collar length =			feet
Drill collar ID =			inch
Wt pipe length =		280	feet
Wt pipe ID =		2.764	inch
Drill Pipe ID =		3.826	inch
Fluid in drill collar =			feet
Fluid in Wt Pipe =		280	feet
Fluid in Drill pipe =		1190	feet
Effective ID =		3.65	inch
Effective capacity =		0.01293	bbl/ft
Pre-flow recovery:			
FFP - end of pre-flow =		282	psi
FFP - end of main flow =		538	psi
Recovery from pre-flow =		770.5	ft
Pre-flow volume =		10.0	bbl
Pre-flow time =		28	min
Pre-flow rate =		512.4	bbl/d
Main-flow recovery:			
Recovery from main-flow =		699.5	ft
Main-flow volume =		9.05	bbl
Main flow time =		45	mins
Main-flow rate =		289.4	bbl/d

					entered data
Well:	**Muchmore B1**				read from correlations
	from, ft	to, ft	Pay, ft		read from Horner plot
DST range:	4495	4510	15		calculation
Perf	4484	4507			
DST analysis - Oil/Water:					
Pi =	1242	psi			
m =	224	psi/cycle			
P I hr =	1165	psi	(pressure on straight line @ del T = 60 mins)		
Qo =	289.4	bbl/d	(main flow rate)		
Pwf =	538	psi	(related to Qo - end of second flow)		
B =	1.04	RB/STB			
Phi =	0.18	(decimal)			
Mu =	0.80	cp (viscosity)			
ct =	0.000003	1/psi			
Hole diam =	7.88	inch			
rw =	0.328125	ft			
Transmissibility:					
Kh/Muo =	162.6*Qo*Bo/m				
Kh/Mu =	**218.51**	**md-ft\cp**			
In-situ capacity:					
Kh =	**174.81**	**md-ft**			
Average effective permeability:					
K =	**11.654**	**md**			
Skin:					
S = 1.151*[(P1hr - Pwf)/m - log(k/(phi*Mu*ct*rw^2)) + 3.23]					
S =	**-2.73**				
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**				

FSIPs from Miss DSTs – data plotted belongs to Judica wells located in Secs 3N, 4 NE, 34S, and 35S (on both sides of the channel). No data available after 1980.



Red triangles are FSIPs while blue diamonds represent Pi calculated from actual DST pressure profiles.

Figure D8

Appendix E

PVT &

Relative Permeability/Capillary Pressure

Inputs

Field-wide PVT Properties

PVT Input data - Judica		
Bubble point	100	psi
API oil	38	
Gas density	0.8	(Air = 1.)
First estimate of Free water level	-1938	ft (sub-sea)
Constant assumptions for all wells:		
Well diameter	7.875	inch
First estimate of skin	1.5	
BHP	below 100 psi during most of production life	
All wells perforated in layers 1, 3 and 5 (if all of these layers are present)		

Table E1

Water PVT properties

Water PVT								
(Refer: Properties of Petroleum Fluids by William D. MCCain, 2nd Edition, Pennwell Books)								
Water Compressibility								
	Res temp		115	F				
	Res pr		1300	psi				
	Salinity		35,000	ppm				
			3.5	%				
(average from KGS database for Miss waters in and around Judica)								
	Fig 16-12 (Page 453)							
	Co-eff of isothermal compressibility of pure water							
							0.16875	
			3.04	* 10^(-6)	1/psi			
	Fig 16-13 (Page 454)							
	Cw of brine/(Cw pure water)			0.95				
	Cw brine		**2.9**	*** 10^(-6)**	**1/psi**			
Water Viscosity								
	Res temp		115	F				3.9
	Salinity		3.5	%				
	Res pr		1300	psi				0.002308
	Fig 16-16 (Page 457)							4.47
					cp			
	Water viscosity at 1 atm			0.63				0.000429
	Fig 16-17 (page 458)							
	(Vis water at Res pr)/(Vis water at 1 atm) =				1.01			
	Water vsicosity at res pr			**0.64**	**cp**			

Formation volume factor for water						
	Res temp			115	F	
	Figure 16-6 (page 447)					
	Del Vwt			0.0123		
	Fig 16-7 (page 448)					
	Res pr		1300	psi		
	Del Vwp			-0.0008		
	Formation volume factor of water =					
					1.01	**res bbl/stb**
Water Density						
	Salinity			3.5	%	
	Fig 16-8 (page 449)					
	Brine density at 14.7 psi and 60oF					63.7 lb/cu ft
	Formation volume factor of water				1.01	res bbl/stb
	Density of brine =				**62.9**	**lbs/cu ft**

Table E2

Relative Permeability & Capillary Pressure Calculator – Reservoir rock (Layers 1, 3, & 5)

Note: this has a Krwmax equation for drainage					
k=0.00200*Phi^3.514					
K(md)=	34.06	Phi(%)=	16		
Krwmax=	0.22	Kromax=	1	Pcentry=	0.678
Krw -m=	0.5	Swi=	0.312	Pcslope=	-1.246
Kro - n=	3.1	Sorw=	0.188	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 Judica Field

SW	KRW	KROW	PCOW	Height above free water (ft)	SwD
0.3118	0.000000	1.000000	2.896	40.00	0.00000
0.3500	0.060830	0.781492	2.507	34.63	0.07645
0.4000	0.092414	0.547818	2.123	29.32	0.17645
0.4500	0.115673	0.366732	1.833	25.32	0.27645
0.5000	0.134982	0.231258	1.608	22.21	0.37645
0.5500	0.151856	0.134514	1.428	19.72	0.47645
0.6000	0.167034	0.069727	1.281	17.69	0.57645
0.6500	0.180943	0.030256	1.159	16.01	0.67645
0.7000	0.193856	0.009617	1.057	14.60	0.77645
0.7500	0.205962	0.001530	0.970	13.40	0.87645
0.8000	0.217394	0.000009	0.895	12.36	0.97645
0.8500	0.220000	0.000000	0.830	11.46	1.00000
0.9000	0.220000	0.000000	0.773	10.68	1.00000
0.9500	0.220000	0.000000	0.723	9.98	1.00000
1.0000	0.220000	0.000000	0.678	9.36	1.00000
1.0000	0.220000	0.000000	0.678	9.36	1.00000
1.0000	0.220000	0.000000	0.678	9.36	1.00000
1.0000	0.220000	0.000000	0.678	9.36	1.00000
1.0000	0.220000	0.000000	0.678	9.36	1.00000
1.0000	0.220000	0.000000	0.678	9.36	1.00000
1.0000	0.220000	0.000000	0.678	9.36	1.00000

Table E3

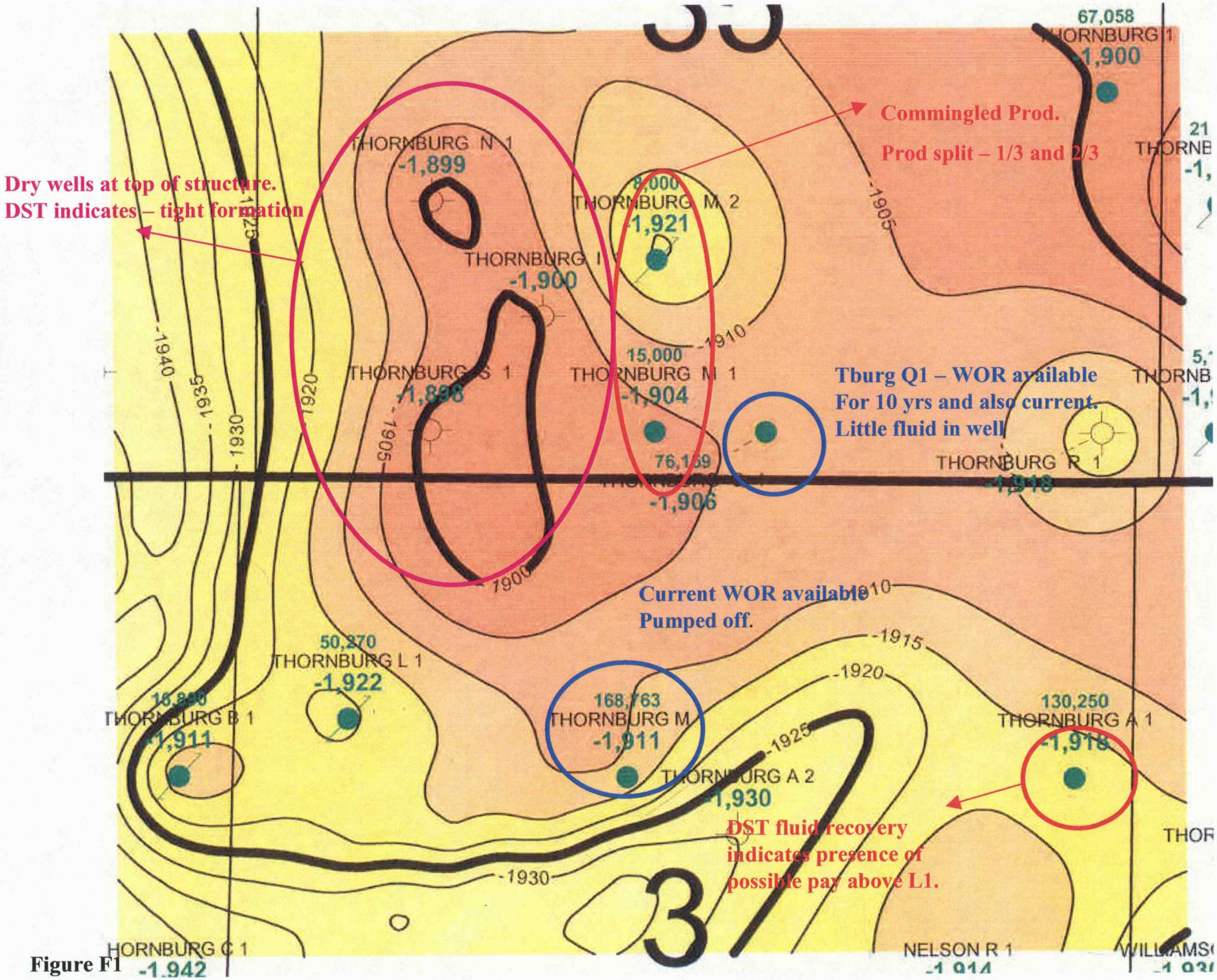
Relative Permeability & Capillary Pressure Calculator – Non-reservoir rock (Layers 2 & 4)

Note: this has a Krwmax equation for drainage					
k=0.000262*Phi^3.3702					
K(md)=	3.7	Phi(%)=	17		
Krwmax=	0.8121	Kromax=	1	Pcentry=	1.951
Krw -m=	0.5	Swi=	0.880	Pcslope=	-3.076
Kro - n=	3.1	Sorw=	0.100	PcSwiH(ft)=	40.0
water grad	0.438	W sp grav=	1.0111	input value	tan
oil grad	0.365	Oil sp grav=	0.8439	calc value	yellow
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					

SW	KRW	KROW	PCOW	Height above free water (ft)	SwD
0.8795	0.000000	1.000000	2.896	40.00	0.00000
0.9000	0.812078	0.000000	2.698	37.27	1.00000
0.9500	0.812078	0.000000	2.285	31.56	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000
1.0000	0.812078	0.000000	1.951	26.95	1.00000

Table E4

Appendix F
Simulation Study
- History Match



Commingled Prod.
Prod split – 1/3 and 2/3
Dry wells at top of structure.
DST indicates – tight formation
Tburg Q1 – WOR available
For 10 yrs and also current.
Little fluid in well
Current WOR available
Pumped off.
DST fluid recovery
indicates presence of
possible pay above L1.
67,058
THORNBURG 1
-1,900
THORNBURG N 1
-1,899
8,000
THORNBURG M 2
-1,921
THORNBURG I
-1,900
THORNBURG S 1
-1,898
15,000
THORNBURG M 1
-1,904
76,159
-1,906
THORNBURG R 1
-1,918
50,270
THORNBURG L 1
-1,922
THORNBURG B 1
-1,911
168,763
THORNBURG M
-1,911
THORNBURG A 2
-1,930
130,250
THORNBURG A 1
-1,918
HORNBURG C 1
-1,942
NELSON R 1
-1,914
1905
1910
1900
1915
1920
1925
1930
1935
1940

Figure F1

Thornburg M1 Slawson (TM1s)

Phi: L1= absent, L3 = 0.197, L5 = 0.229

Swi: L1 = absent, L3 = N/a, L5 = 0.32

Most prolific producer. Current WOR indicates very low water production over the life of the well.

Thus, Relative K water exponent m (= 2.5) was used to lower water production.

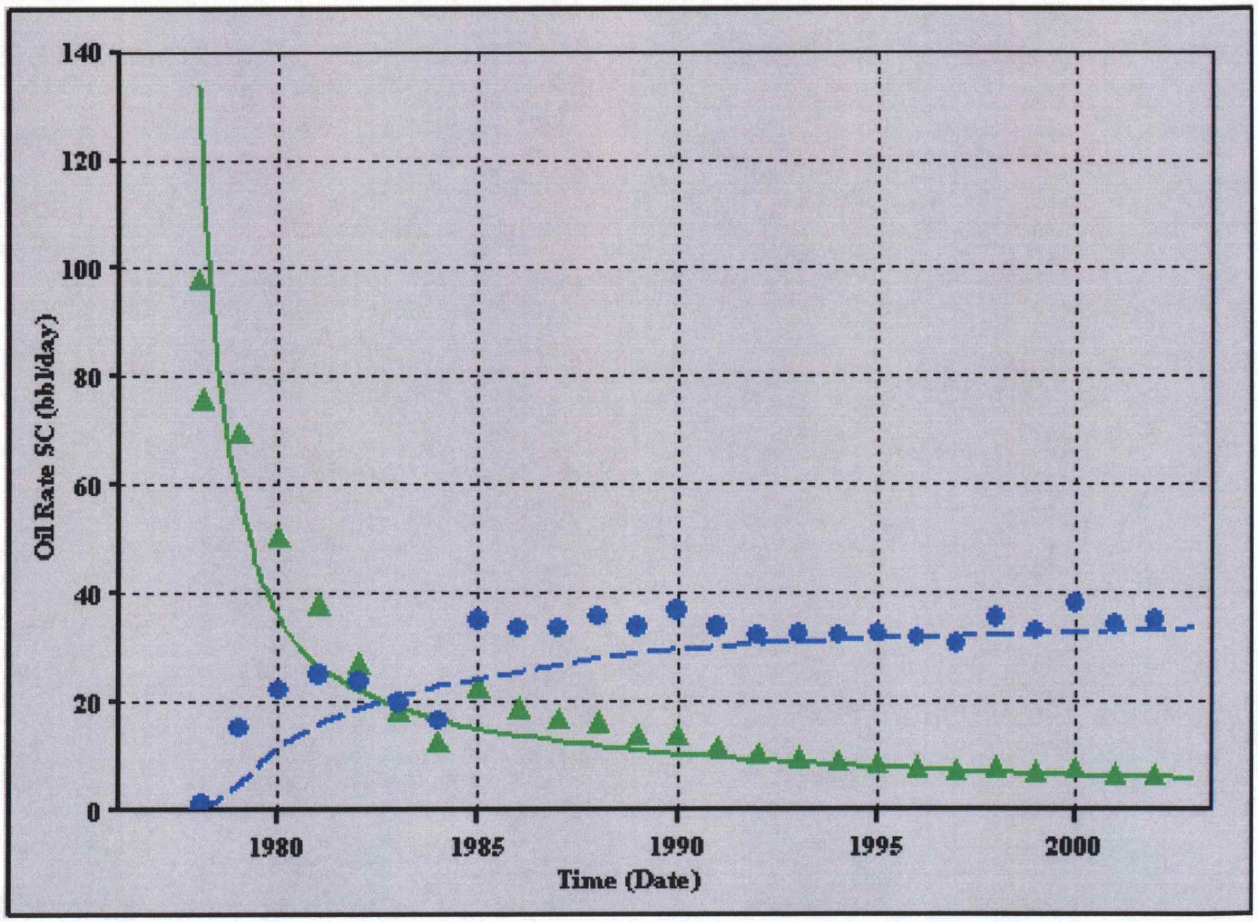


Figure F2

Thornburg L1 (TL1)

Phi: L1= 0.18, L3 = absent, L5 = 0.22

Swi: L1 = 0.35, L3 = absent, L5 = 0.37

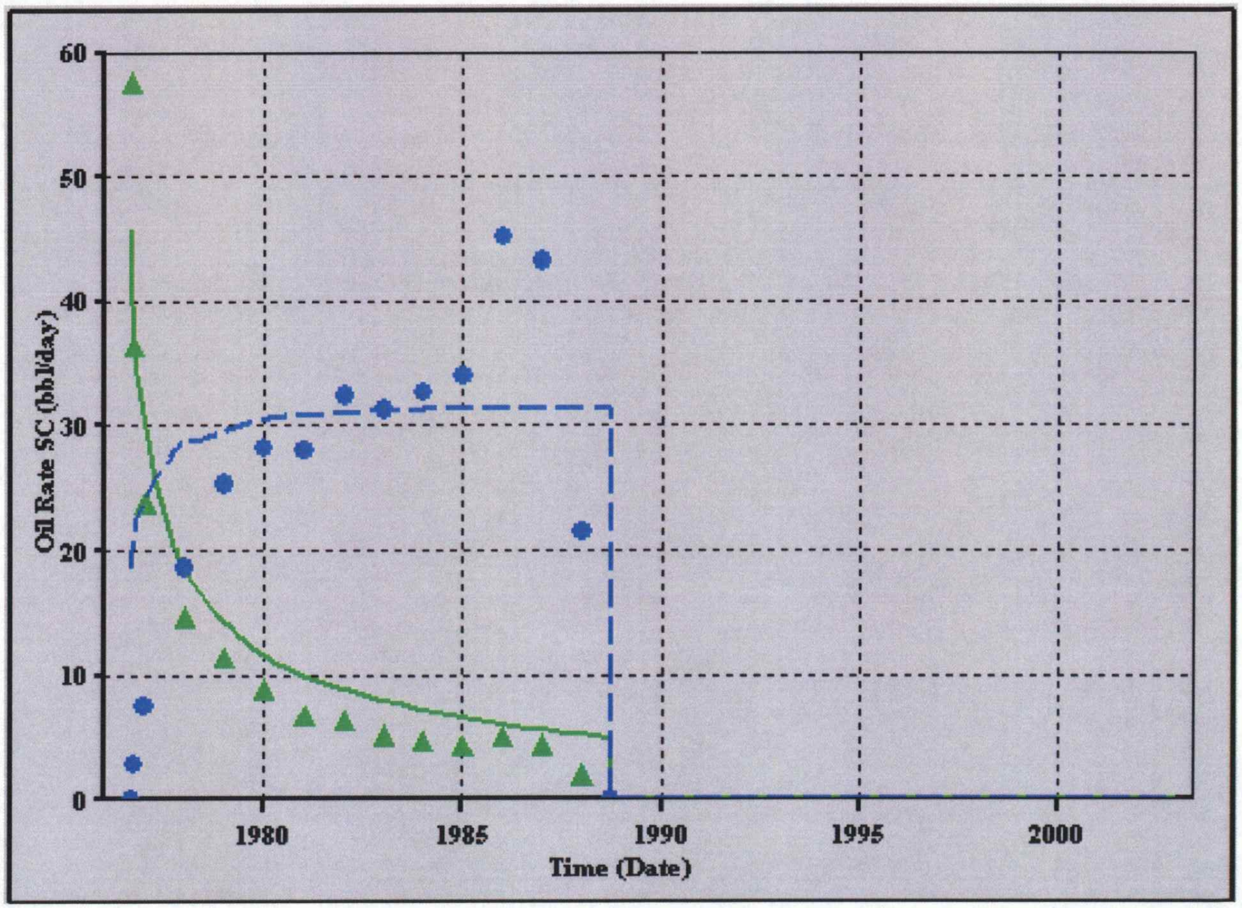


Figure F3

Thornburg A1 (TA1)

Phi: L1= 0.22, L3 = 0.23, L5 = 0.22

Swi: L1 = 0.49, L3 = 0.30, L5 = 0.41

Geologic model indicates presence of pay above L1. Match obtained by allocating well production to L1, L3, & L5.

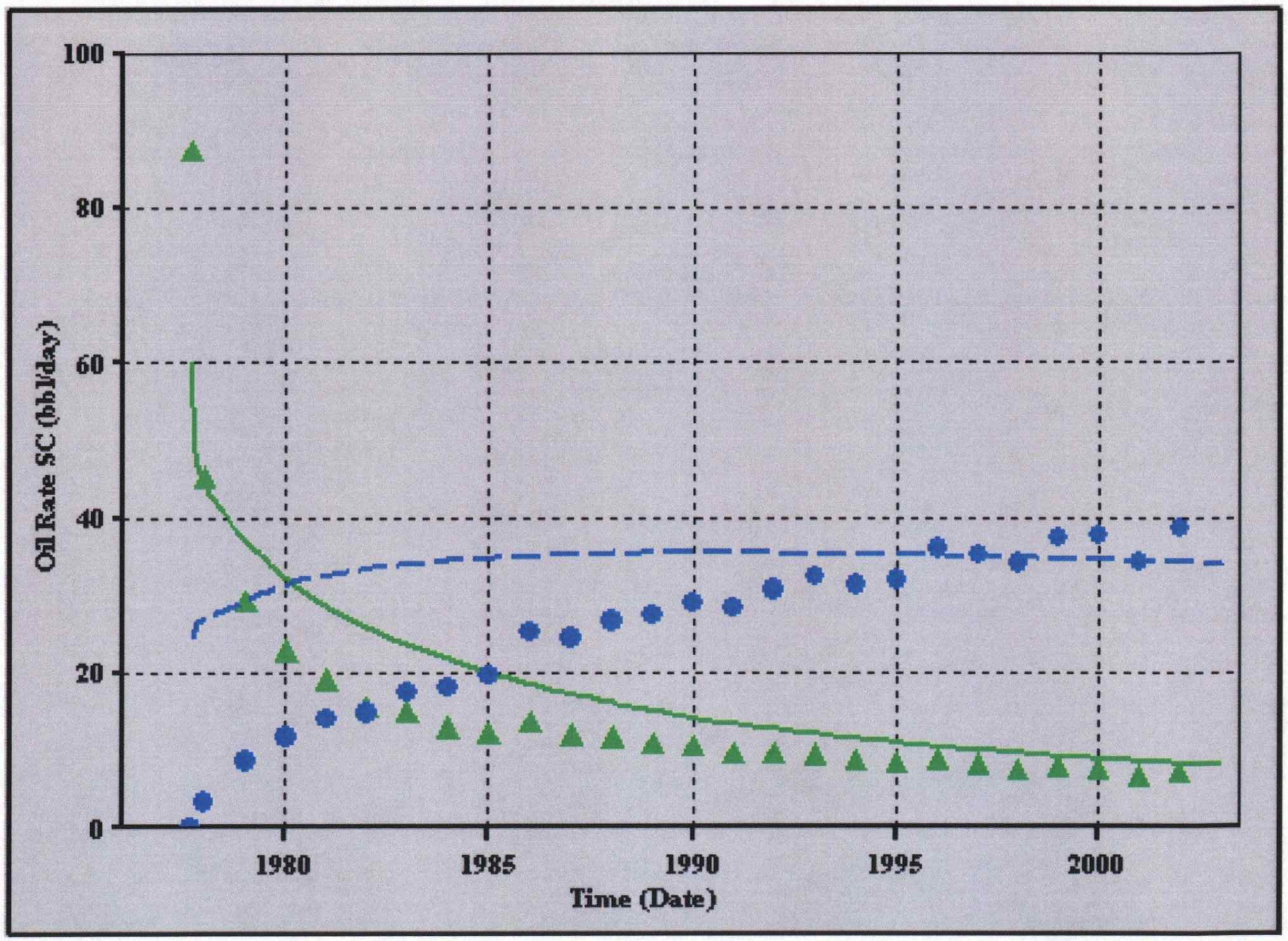


Figure F4

Thornburg 1 (T1)

Phi: L1= absent, L3 = 0.2, L5 = 0.2

Swi: L1 = absent, L3 = N/a (assume 0.40), L5 = N/a (assume 0.45)

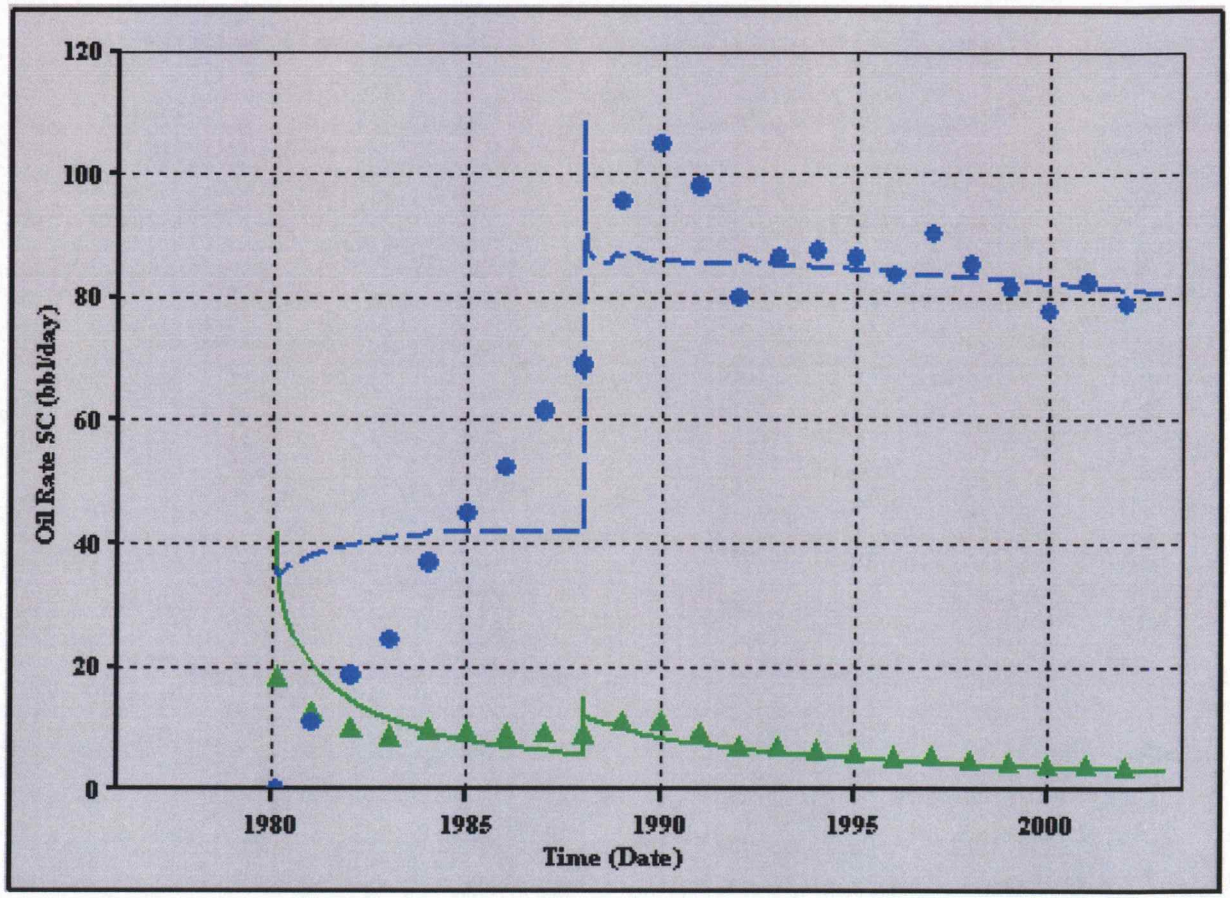


Figure F5

Thornburg B1 (TB1)

No logs are available

Phi: L1= absent, L3 = absent, L5 = 0.226 (extrapolated while mapping)

Swi: L1 = absent, L3 = absent, L5 = N/a (assume 0.55)

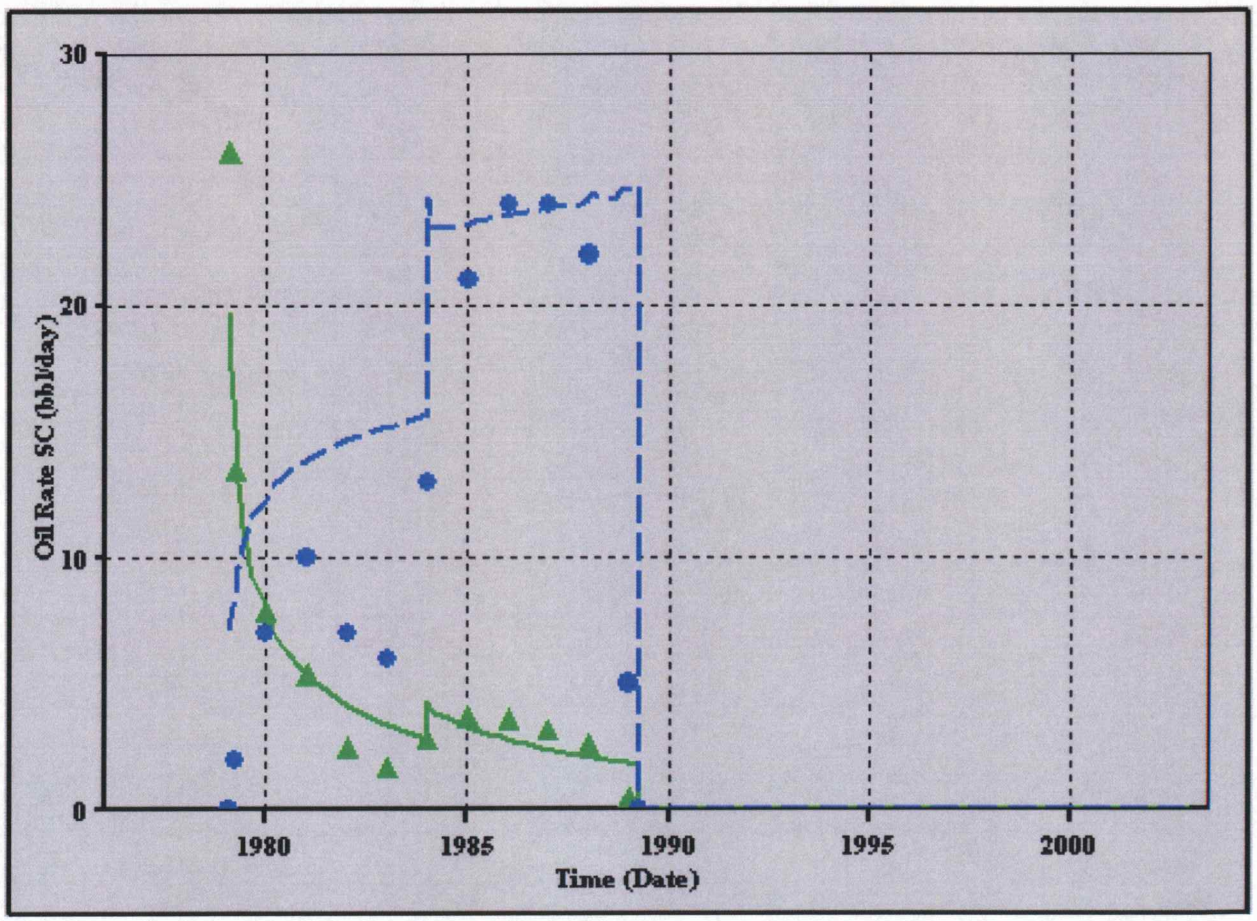


Figure F6

Thornburg M1 (TM1)

Well production data N/A. Thornburg lease production allocated between TM1 and TM2 in ratio of 60:40

Phi: L1= absent, L3 = 0.22, L5 = 0.2

Swi: L1 = absent, L3 = 0.32, L5 = 0.34

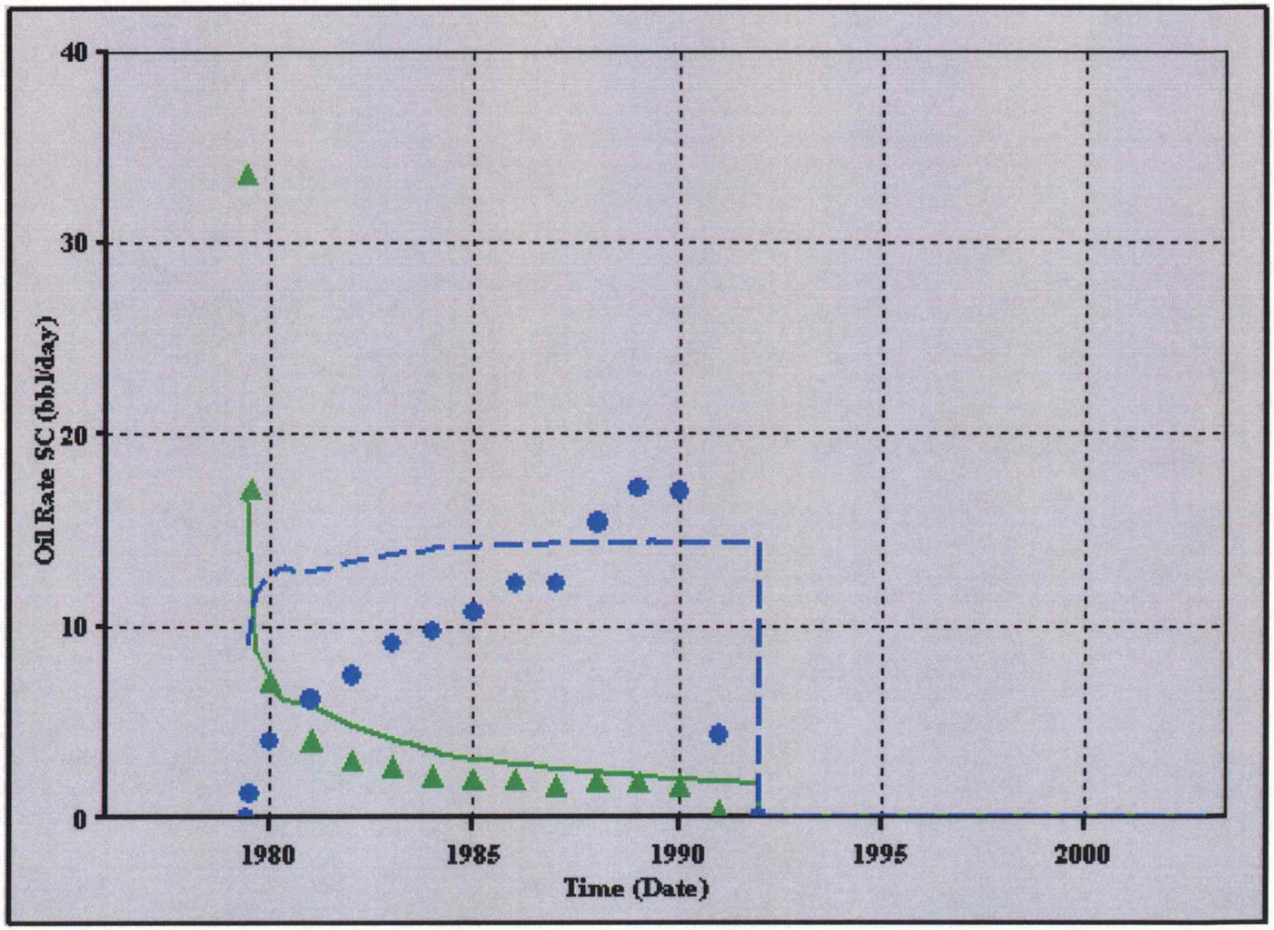


Figure F7

Thornburg M2 (TM2)

Well production data N/A. Thornburg lease production allocated between TM1 and TM2 in ratio of 60:40

Phi: L1= 0.15, L3 = 0.19, L5 = 0.18

Swi: L1 = 0.60, L3 = 0.46, L5 = 0.41

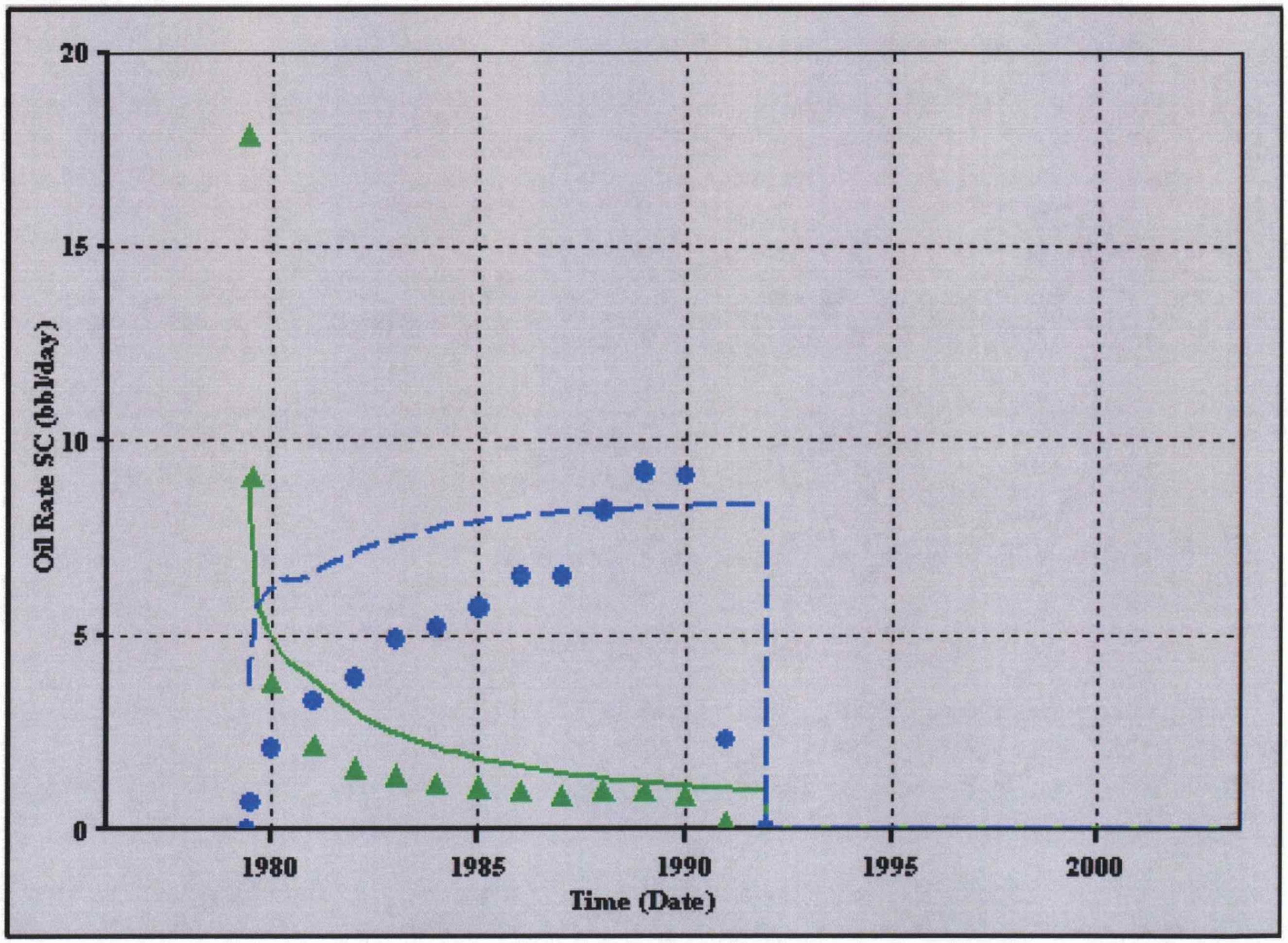
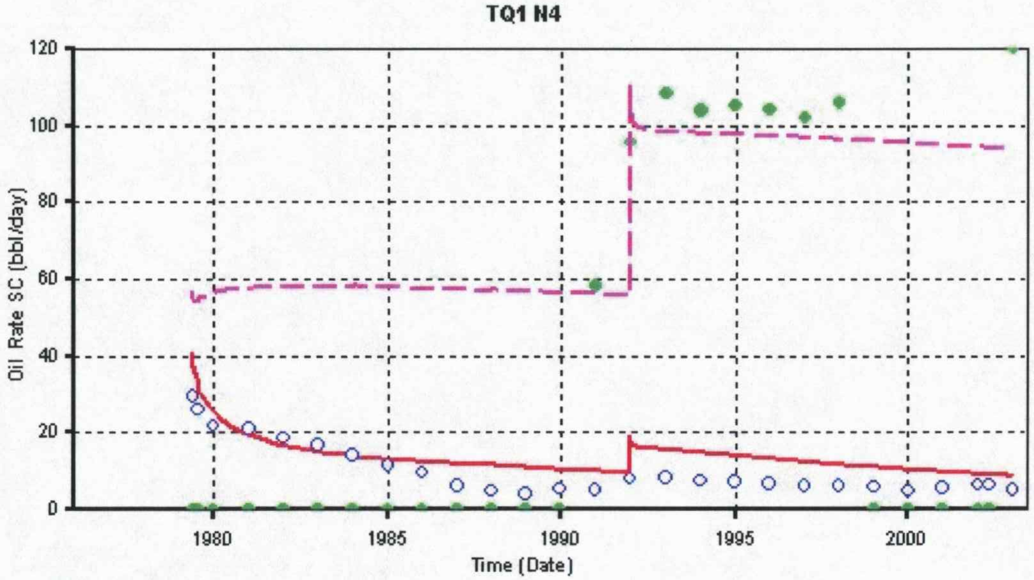


Figure F8

Thornburg Q1 (TQ1) - history matching

Phi: L1= 0.18, L3 = 0.2, L5 = 0.19

Swi: L1 = 0.47, L3 = 0.45, L5 = 0.35



Initial oil saturations - same as that estimated from logs

L1 = 0.47, L3 = 0.45, L5 = 0.35

Porosity - same as that estimated from logs

L1 = 0.178, L3 = 0.198, L5 = 0.190

Relative permeability exponents: n = 0.2 and m = 6.0 (minimize oil flow and maximize water flow)

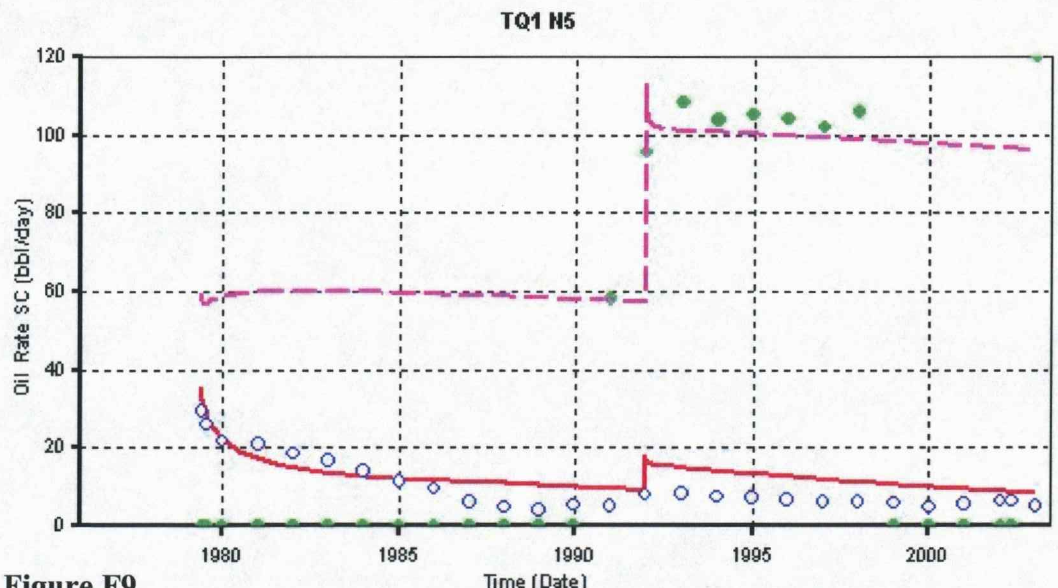


Figure F9

Phi is L3 (0.198) is greater than L5 (0.190) and yet Swi in L3 is greater than L5. Maybe Swi needs to be higher in L5.

New oil saturations:

L1 = 0.47, L3 = 0.45, L5 = 0.51

Relative permeability exponents: n = 0.2 and m = 6.0 (minimize oil flow and maximize water flow)

Thornburg Q1 (TQ1) final - from TQ1 N6b.dat

Initial oil saturations - same as that estimated from logs

Net/gross = 0.9 from L1, L2, L3

Relative permeability exponents: n = 0.2 and m = 6.0 (minimize oil flow and maximize water flow)

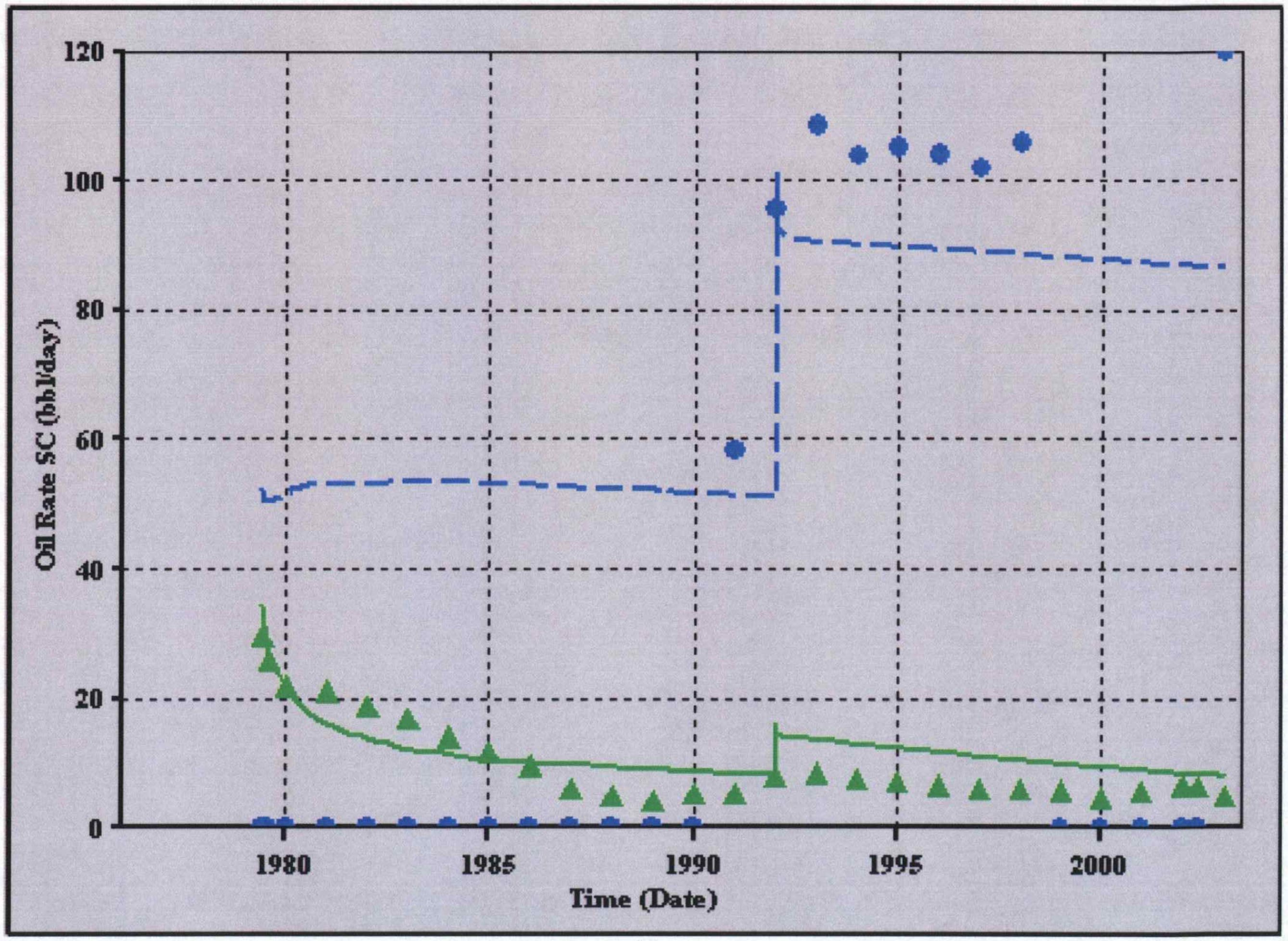


Figure F10

Average reservoir pressure as of Jan 2003 (L5) in psi.
Current reservoir pressure data is available from Thornburg #F1 (located west of the study area) - as of Nov 2002, a BHP of 1030 psi was recorded at this well after a 5-day shut-in.

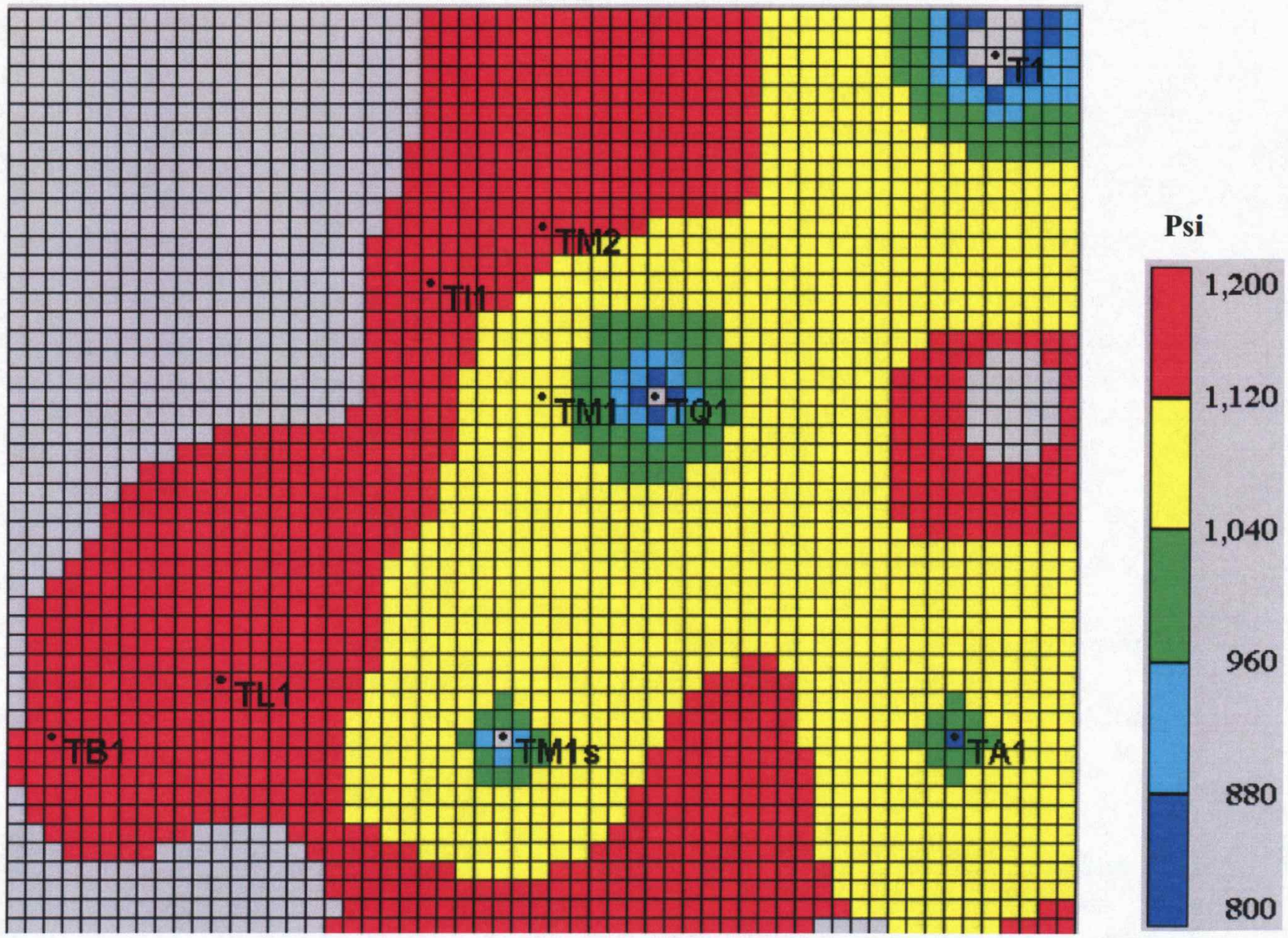


Figure F11

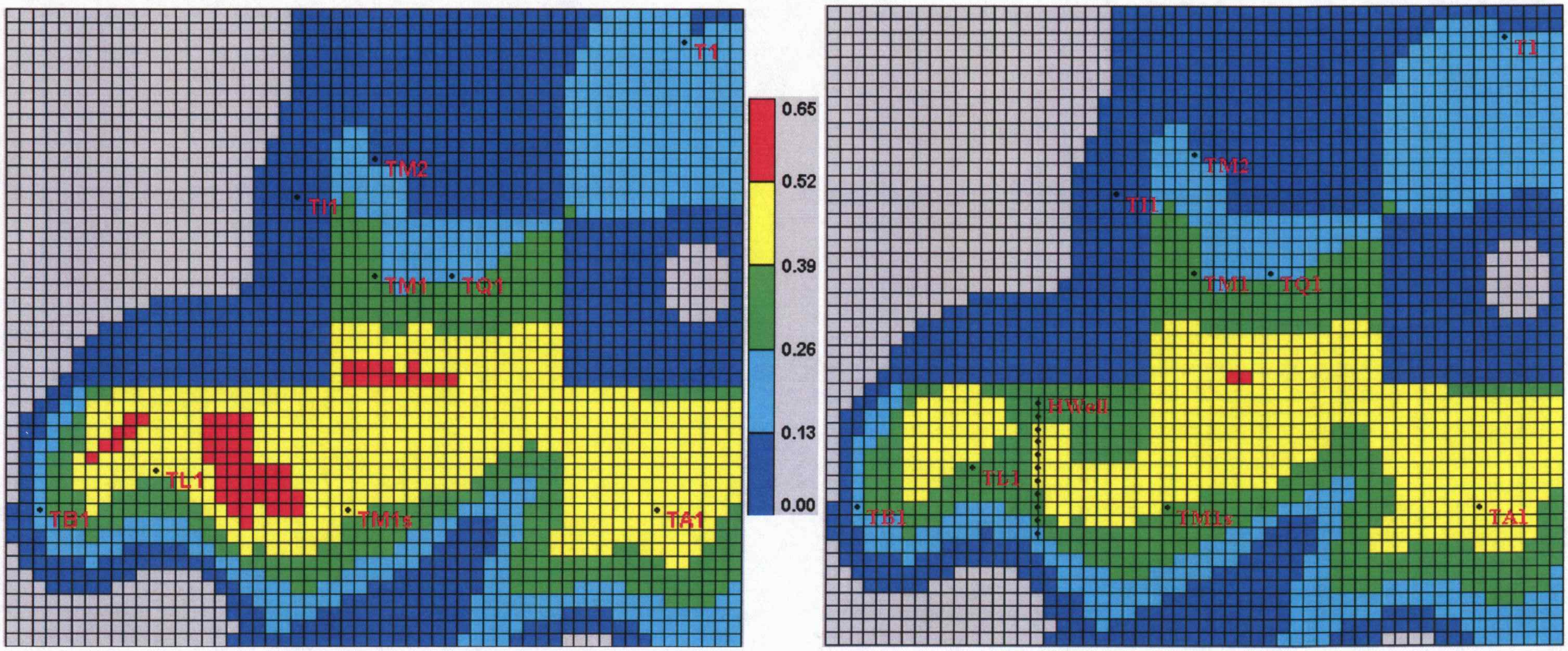
Appendix G

Simulation Study

- Evaluate performance of different horizontal infill wells

Jan 1, 2003 - remaining reserves (oil-ft) in Layer 5

Jan 1, 2013 - remaining reserves (oil-ft) in layer 5 after drilling an infill horizontal well - Hwell Location: (17,31) to (17,41)



Well length =1100 ft
skin = 1.5
Well diameter = 6”
Bottom hole pressure = 200 psi (P_{wf})
Completed on Jan 1, 2003

Figure G1

Horizontal infill well productivity estimate - based on TQ1 N6b.dat

Well name: Hwell, Location: (17,31) to (17,41)

Length: 1100'

Well completed on Jan 1, 2003

Year	Cum Oil	Cum Wtr
	MO	MW
2004	19.1	98.3
2006	40.7	294.5
2008	54.8	490
2010	64.9	682.5
2012	72.9	870.1
2013	76.2	962.1

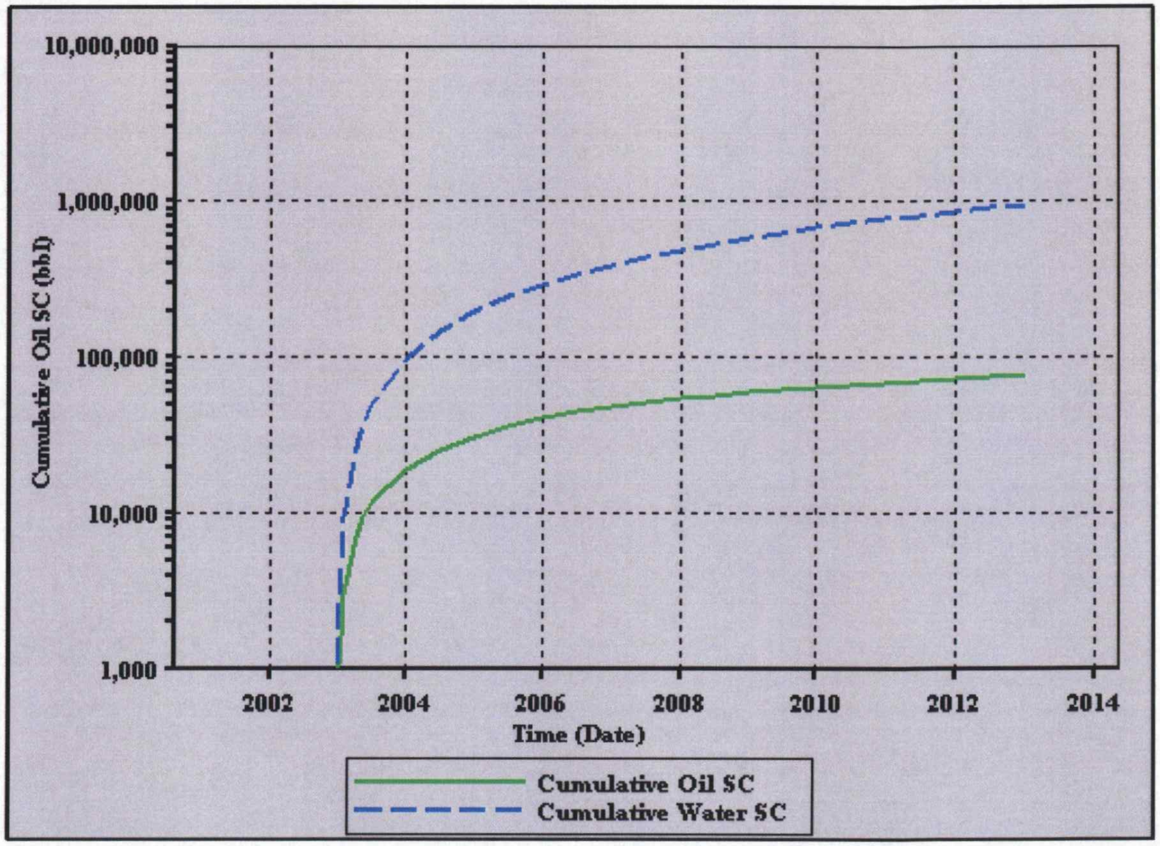


Figure G2

Effect of Horizontal Infill well on the productivity loss at Thornburg M1, Slawson (TM1s)

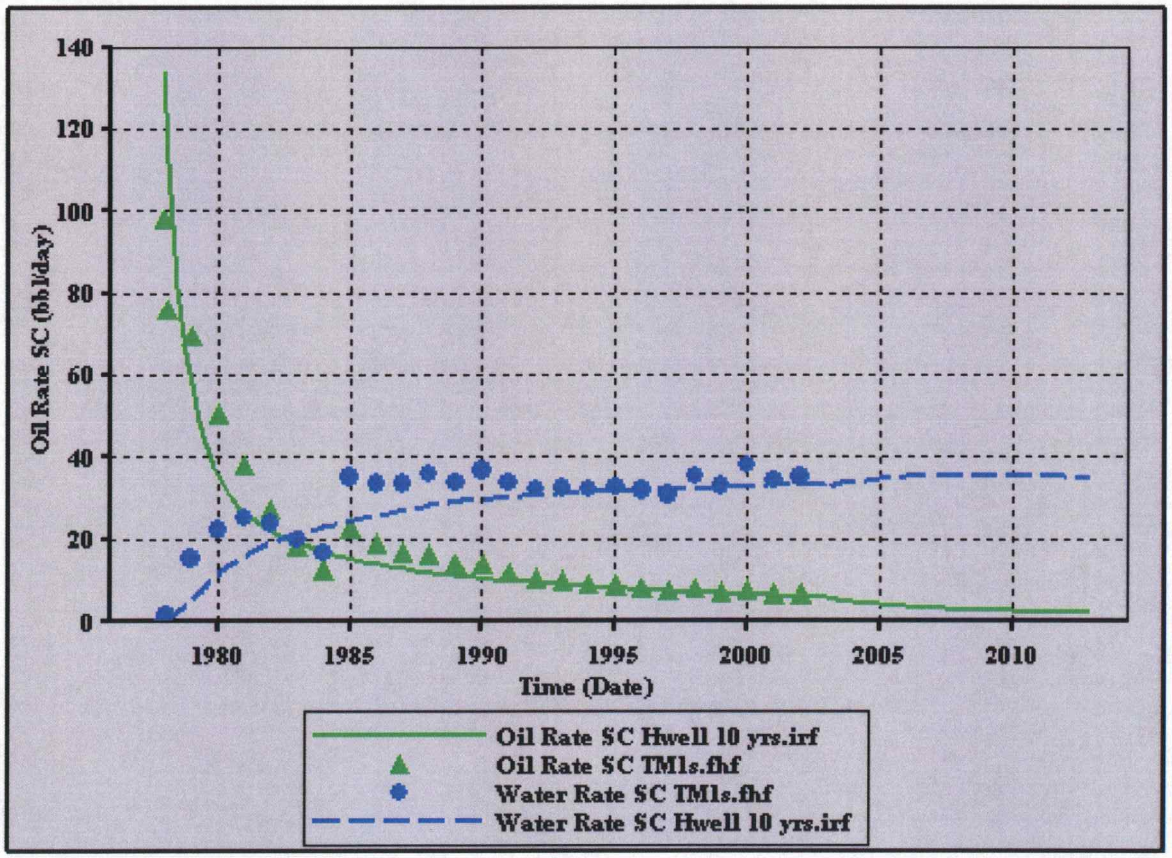
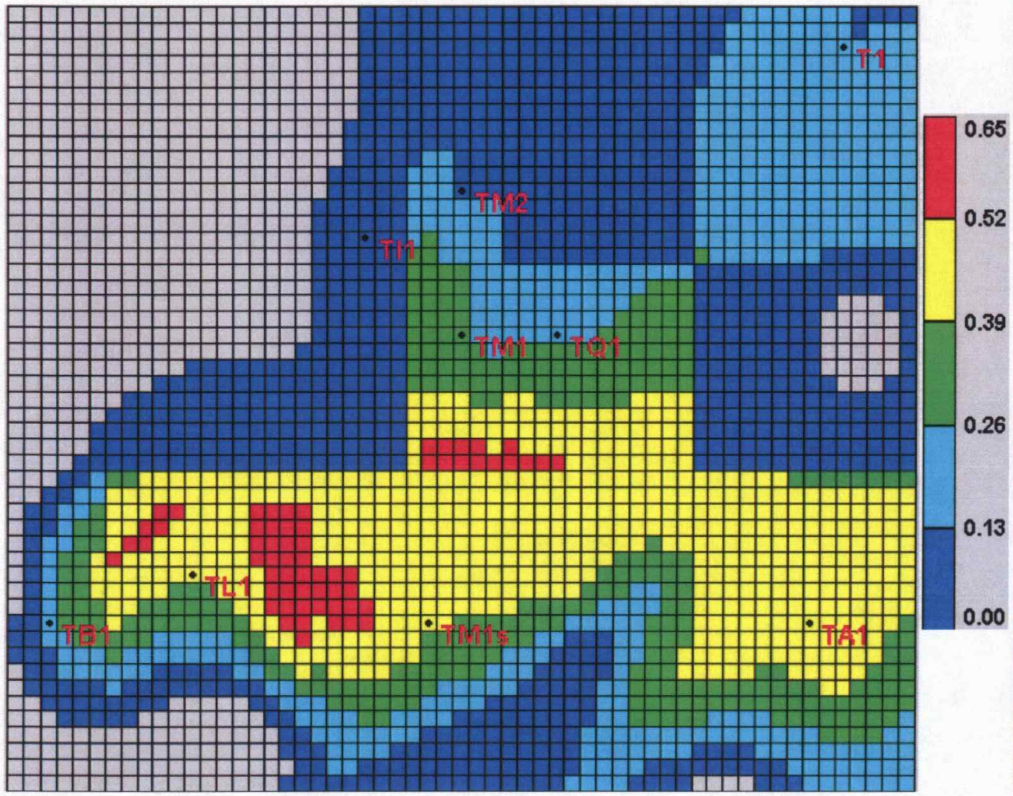


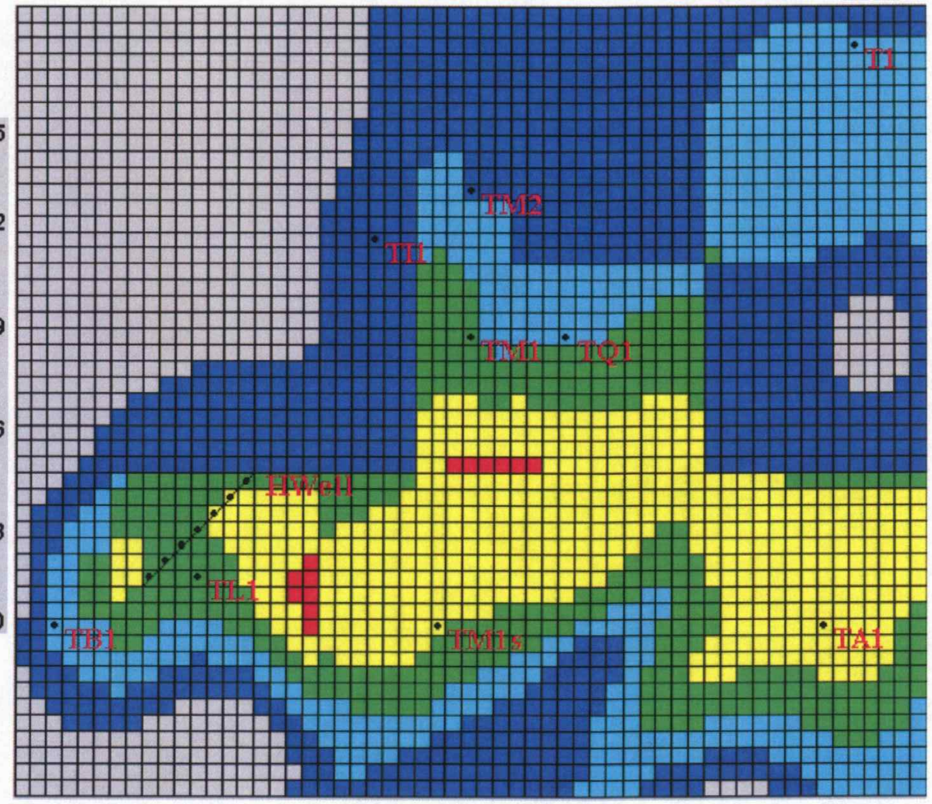
Figure G3

MULL 1

Jan 1, 2003 - remaining reserves (oil-ft) in
Layer 5 (L5)



Jan 1, 2013 – L5 remaining reserves (oil-ft) after
drilling an infill horizontal well - MULL1
Location: (15,30), (14,31), (13,32), (12,33), (11,34),
(10,35), and (9,36)



Well length =1089 ft
skin = 1.5
Well diameter = 6”
Bottom hole pressure = 200 psi (P_{wf})
Completed on Jan 1, 2003

Figure G4

Based on TQ1 N6b.dat

Well name: Hwell, Location: (15,30), (14,31), (13,32), (12,33), (11,34), (10,35), and (9,36)

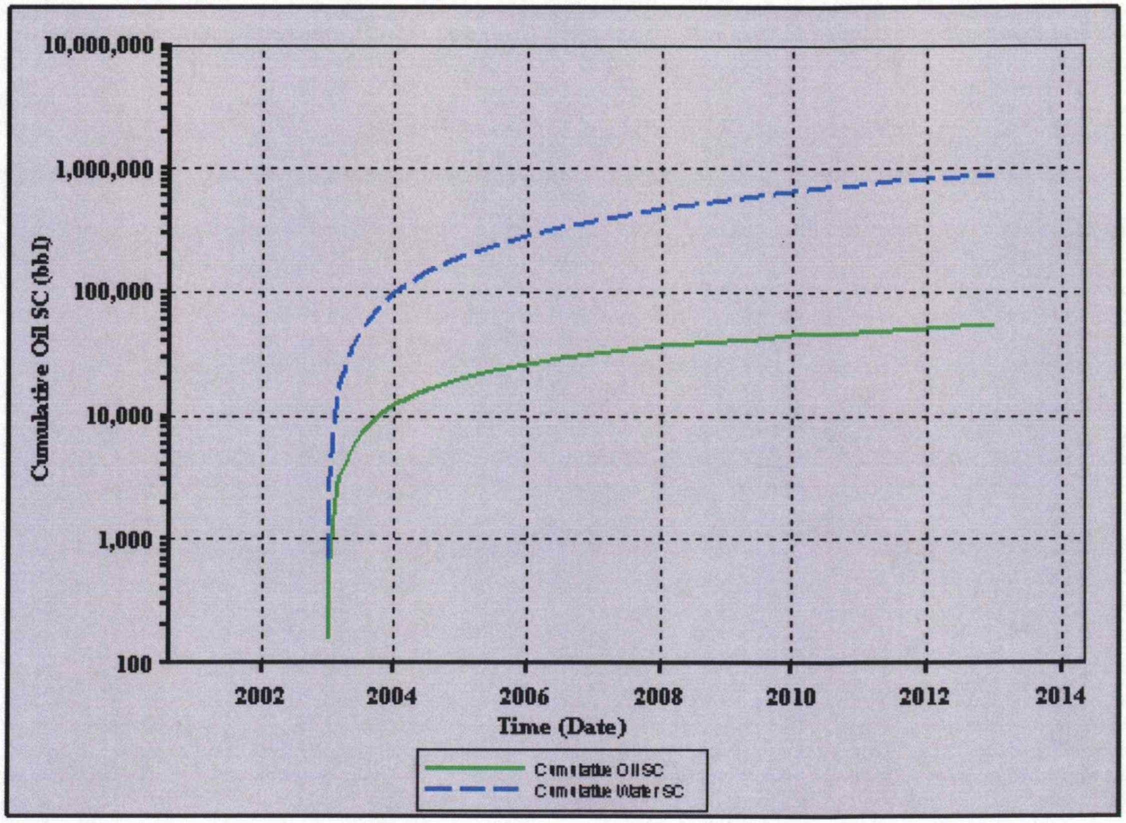
Length: 770'

MULL 1

Well completed on Jan 1, 2003

Estimated Production from Infill

Year	Cum Oil	Cum Wtr
	MO	MW
2004	12.5	99.2
2006	26.7	288.4
2008	36.8	473.5
2010	44.8	654.2
2012	51.2	829.6
2013	53.9	915.5



Estimated Production Loss at neighboring well

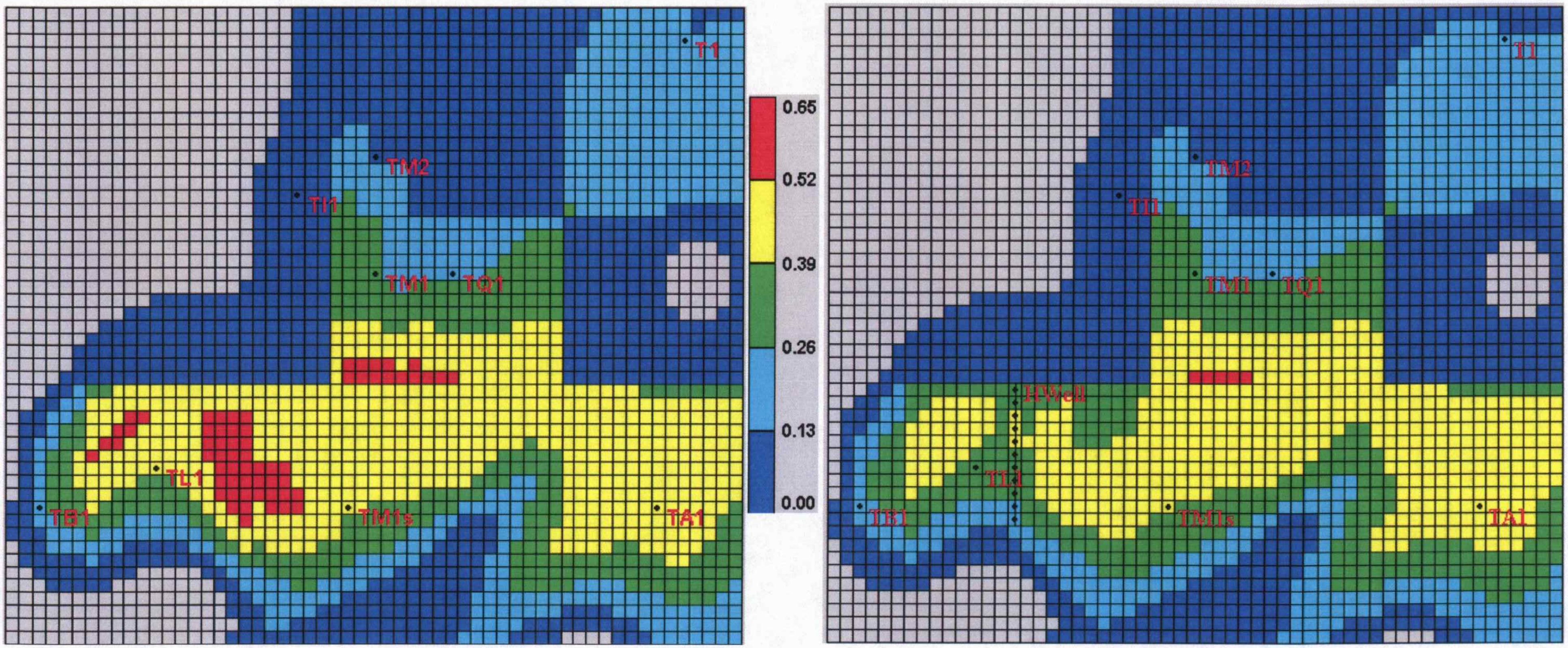
	With Infill	No Infill	Prod loss at TM1s
Year	TM1s Cum Oil, MO	TM1s Cum Oil, MO	due to infill, MO
2003	141.2	141.1	
2004	143.2	143.3	0.1
2005	145.1	145.3	0.2
2010	152.8	154.6	1.8
2013	156.6	159.6	3

Figure G5

MULL 2

Jan 1, 2003 - remaining reserves (oil-ft) in Layer 5 (L5)

Jan 1, 2013 – L5 remaining reserves (oil-ft) after drilling an infill horizontal well - MULL2 Location: (15,30) to (15,40)



Well length = 1210 ft
skin = 1.5
Well diameter = 6"
Bottom hole pressure = 200 psi (P_{wf})
Completed on Jan 1, 2003

Figure G6

Based on TQ1 N6b.dat

Well name: Hwell, Location: (15,30) to (15,40)

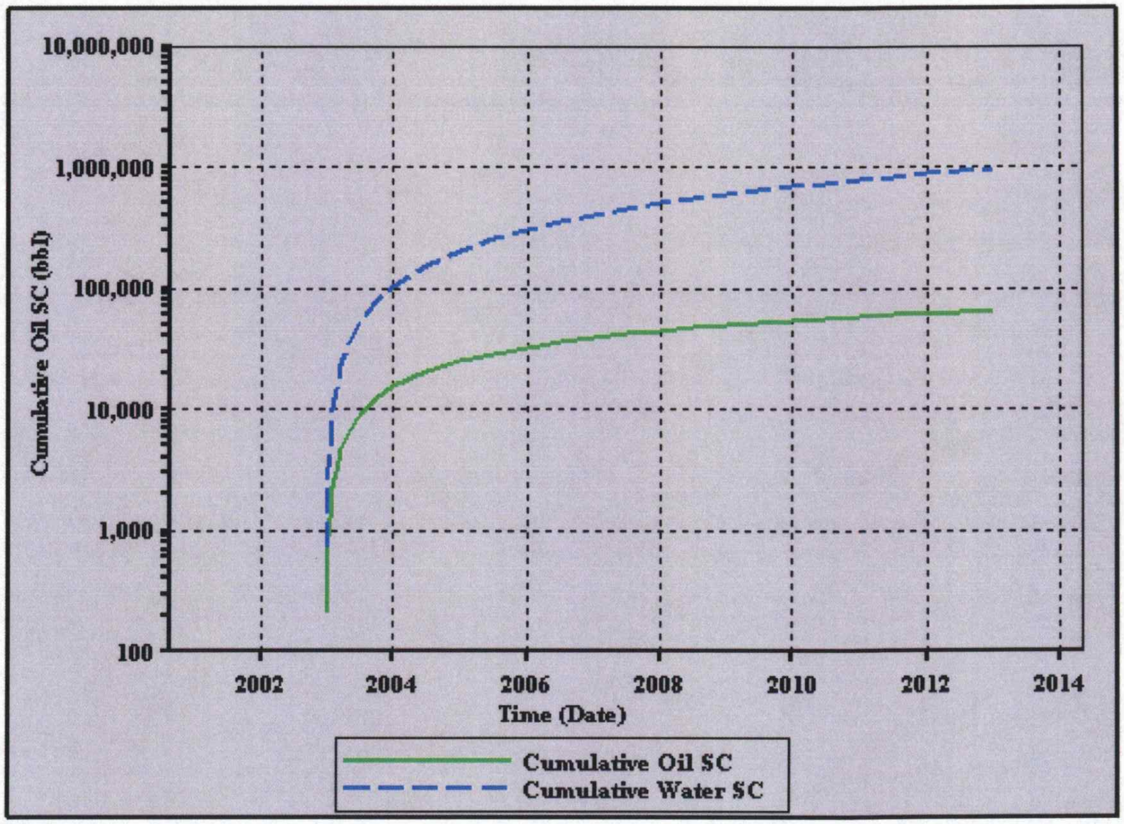
Length: 1210'

MULL 2

Well completed on Jan 1, 2003

Estimated Production from Infill

Year	Cum Oil MO	Cum Wtr MW
2004	15.4	103.6
2006	32.5	303
2008	44.8	498.5
2010	54.1	689.6
2012	61.5	875.3
2013	64.6	966.2



Estimated Production Loss at neighboring well

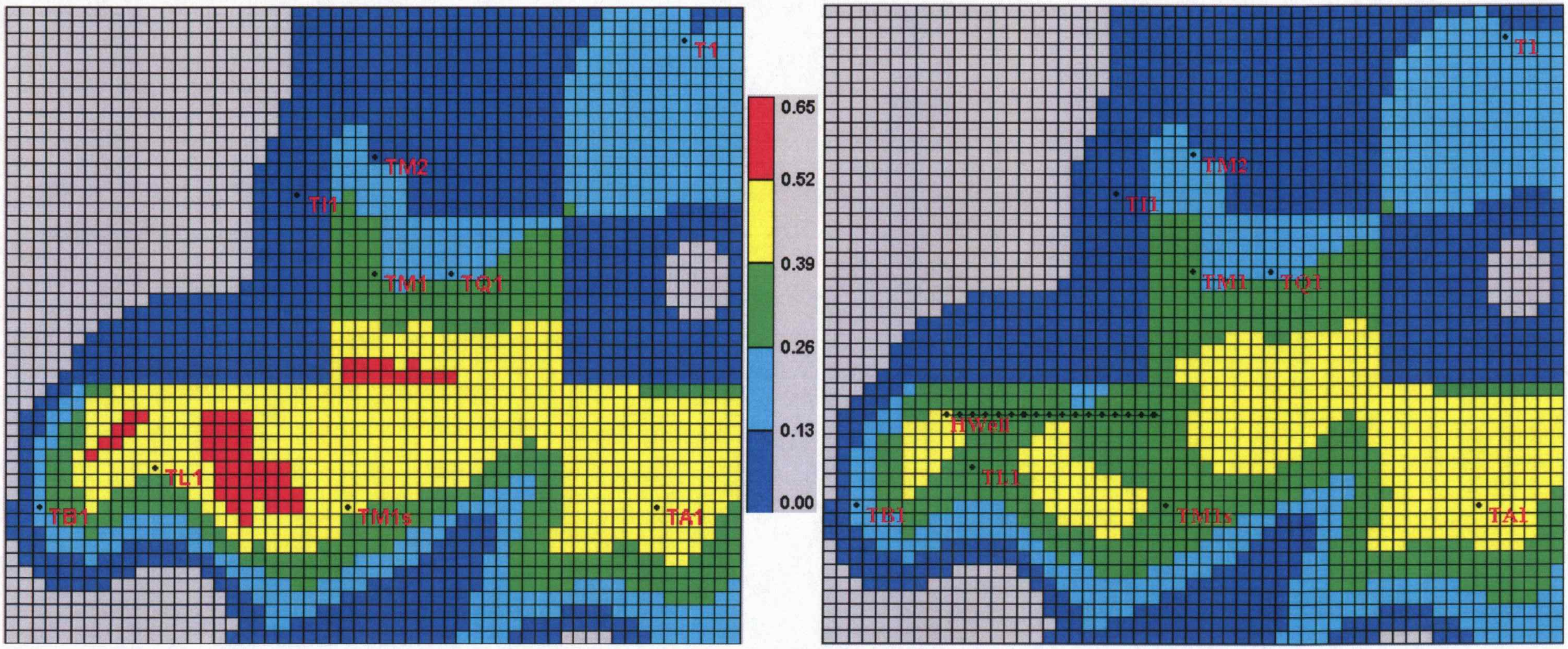
Year	With Infill TM1s Cum Oil, MO	No Infill TM1s Cum Oil, MO	Prod loss at TM1s due to infill, MO
2003	141.1	141.1	
2004	143.1	143.3	0.2
2005	144.8	145.3	0.5
2010	151.6	154.6	3
2013	154.7	159.6	4.9

Figure G7

MULL 3

Jan 1, 2003 - remaining reserves (oil-ft) in Layer 5 (L5)

Jan 1, 2013 – L5 remaining reserves (oil-ft) after drilling an infill horizontal well - MULL3 Location: (10,32) to (26,32)



Well length = 1870 ft
skin = 1.5
Well diameter = 6”
Bottom hole pressure = 200 psi (P_{wf})
Completed on Jan 1, 2003

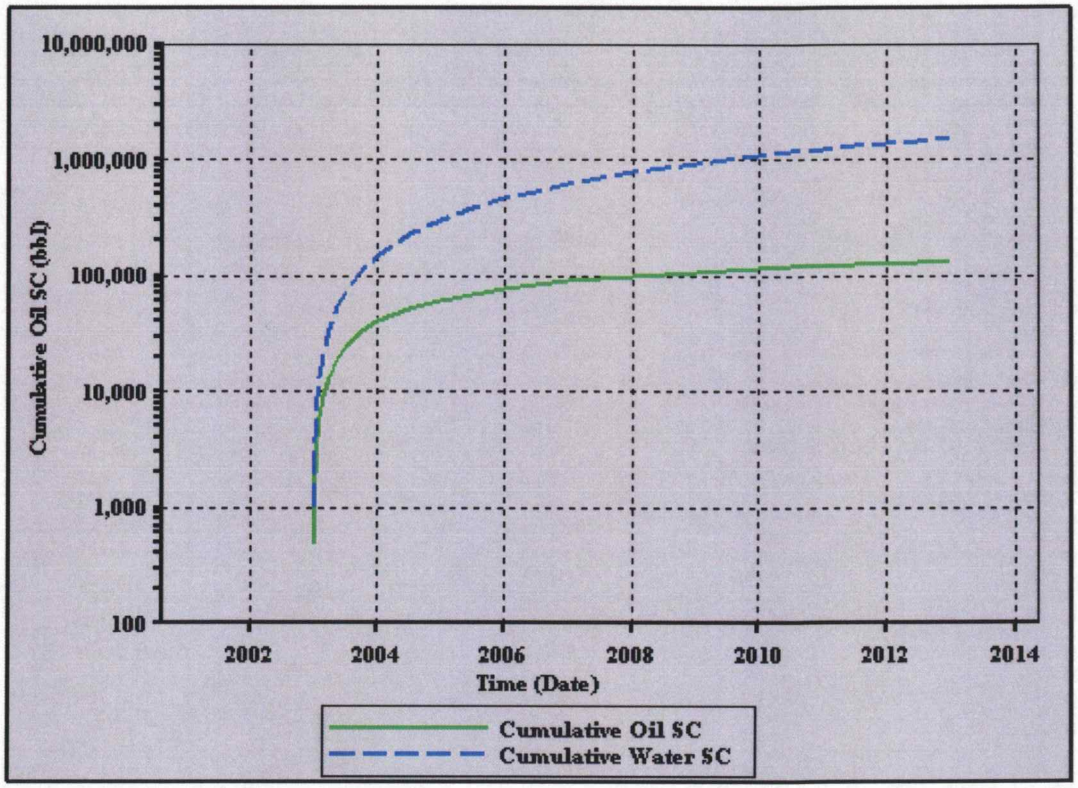
Figure G8

Based on TQ1 N6b.dat

Well name: Hwell, Location: (10,32) to (26,32)

Length: 1870'

MULL 3



Well completed on Jan 1, 2003

Estimated Production from Infill

Year	Cum Oil MO	Cum Wtr MW
2004	40	149.3
2006	77.1	460.8
2008	99.6	775.2
2010	115.5	1084.1
2012	127.6	1383.1
2013	132.8	1529

Estimated Production Loss at neighboring well

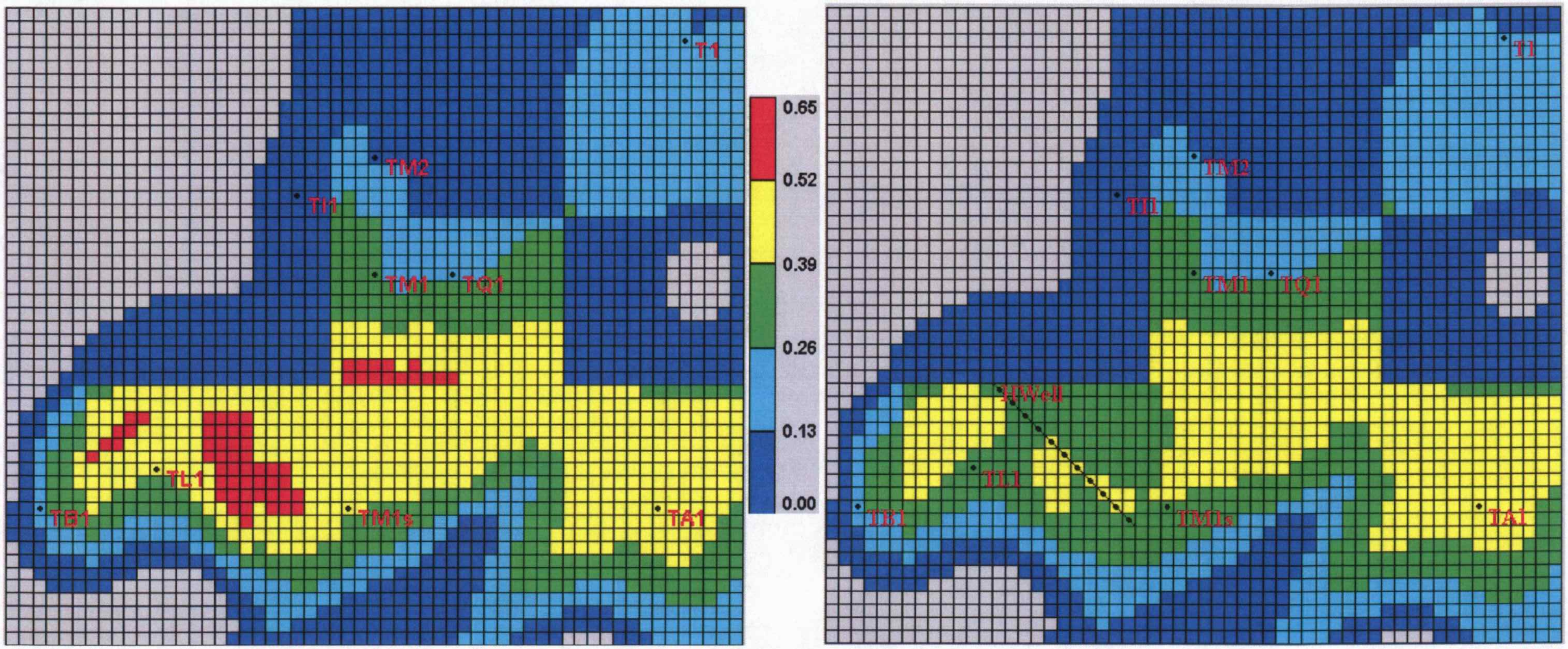
Year	With Infill TM1s Cum Oil, MO	No Infill TM1s Cum Oil, MO	Prod loss at TM1s due to infill, MO
2003	141.2	141.1	
2004	142.6	143.3	0.7
2005	143.6	145.3	1.7
2010	146.7	154.6	7.9
2013	147.9	159.6	11.7

Figure G9

MULL 4

Jan 1, 2003 - remaining reserves (oil-ft) in Layer 5 (L5)

Jan 1, 2013 – L5 remaining reserves (oil-ft) after drilling an infill horizontal well - MULL4
Location: (14,30), (15,31), (16,32), (17,33), (18,34), (19,35), (20,36), (21,37), (22,38), (23, 39), & (24,40)



Well length = 1711 ft
skin = 1.5
Well diameter = 6”
Bottom hole pressure = 200 psi (P_{wf})
Completed on Jan 1, 2003

Figure G10

Based on TQ1 N6b.dat

Well name: Hwell, Location:

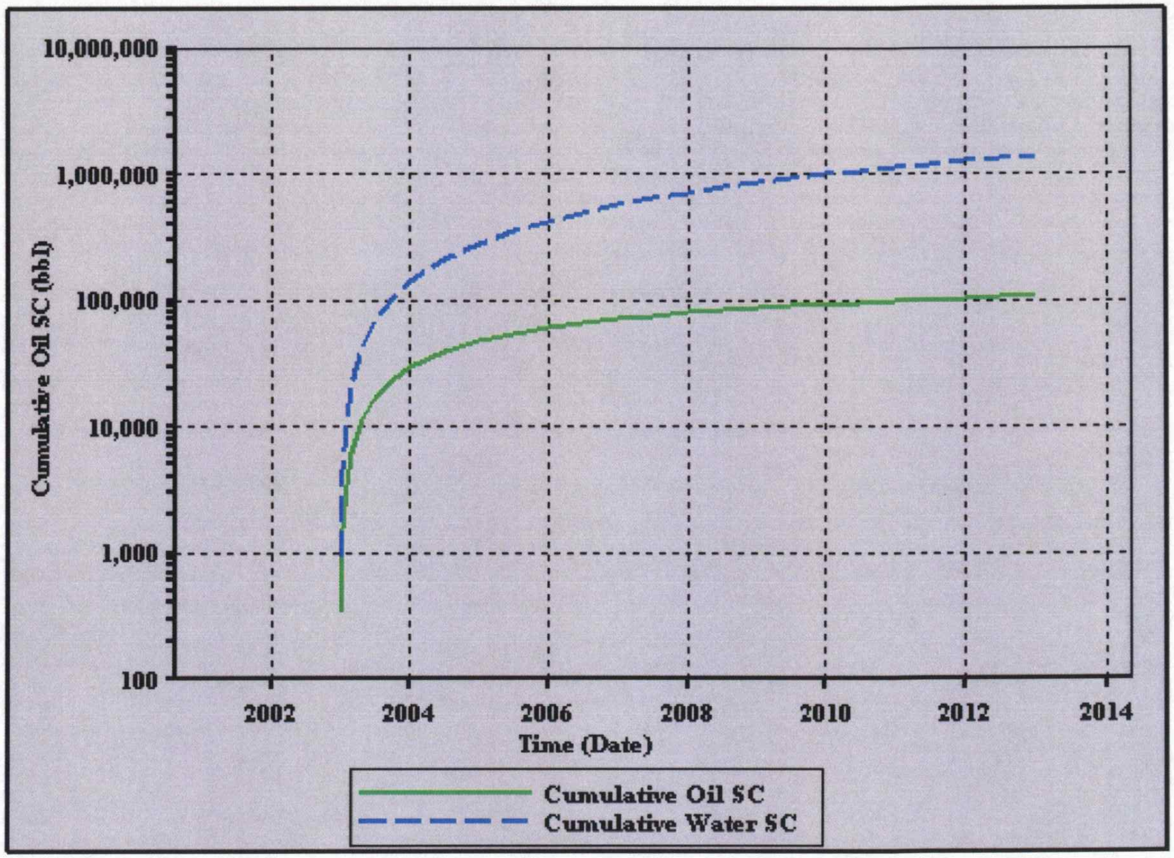
(14,30), (15,31), (16,32),

(17,33), (18,34), (19,35), (20,36), (21,37),

(22,38), (23, 39), & (24,40)

Length: 1210'

MULL 4



Well completed on Jan 1, 2003

Estimated Production from Infill

Year	Cum Oil MO	Cum Wtr MW
2004	29.3	138.9
2006	60.3	422.8
2008	79.3	710.4
2010	92.5	994.2
2012	102.5	1269.9
2013	106.8	1404.6

Estimated Production Loss at neighboring well

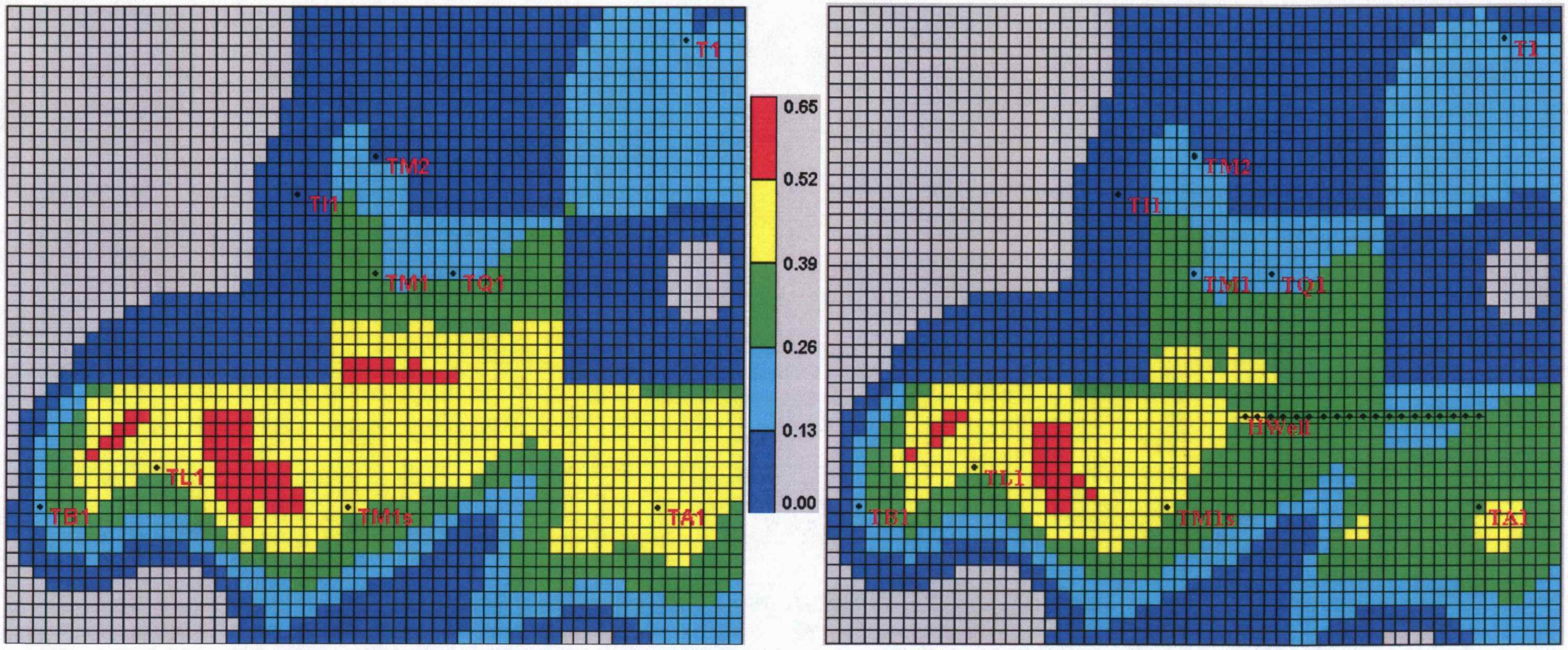
Year	With Infill TM1s Cum Oil, MO	No Infill TM1s Cum Oil, MO	Prod loss at TM1s due to infill, MO
2003	141.1	141.1	
2004	142.4	143.3	0.9
2005	143.3	145.3	2
2010	146.1	154.6	8.5
2013	147.2	159.6	12.4

Figure G11

MULL 5 in L5

Jan 1, 2003 - remaining reserves (oil-ft) in Layer 5 (L5)

Jan 1, 2013 – L5 remaining reserves (oil-ft) after drilling an infill horizontal well - MULL5
Location: (33,32) to (51,32)



Well length = 2090 ft
skin = 1.5
Well diameter = 6”
Bottom hole pressure = 200 psi (P_{wf})
Completed on Jan 1, 2003

Figure G12

Figure G13

MULL 5 in L5

Based on TQ1 N6b.dat

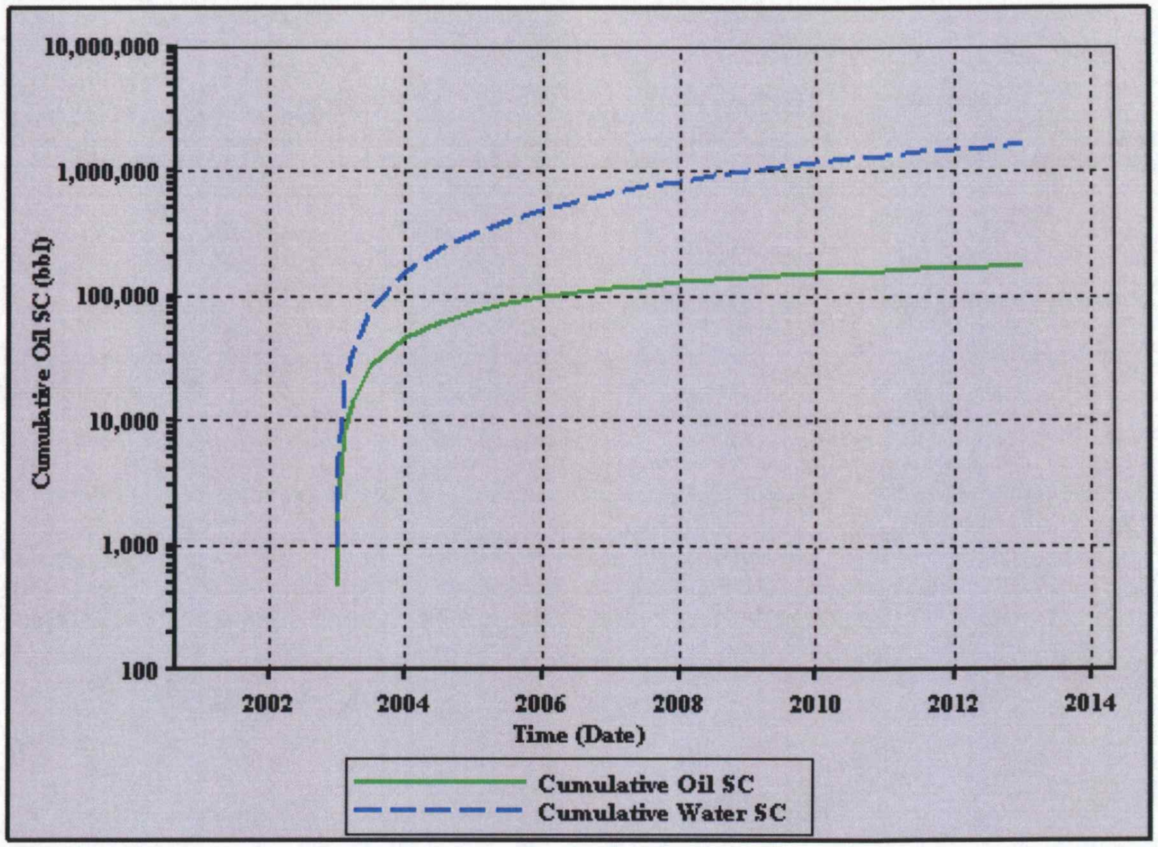
Well Location: (33,32) to (51,32)

Length: 2090'

Well completed on Jan 1, 2003

Estimated Production from Infill

Year	Cum Oil MO	Cum Wtr MW
2004	46	155
2006	96.8	488.8
2008	128.2	831.3
2010	150.9	1169.4
2012	168.4	1497.1
2013	175.9	1656.7



Estimated Production Loss at neighboring wells

Year	With Infill TM1s Cum Oil, MO	No Infill TM1s Cum Oil, MO	Prod loss at TM1s due to infill, MO
2003	141.1	141.1	
2004	143.1	143.3	0.2
2005	144.8	145.3	0.5
2010	151.6	154.6	3
2013	154.6	159.6	5

Year	With Infill TA1 Cum Oil, MO	No Infill TA1 Cum Oil, MO	Prod loss at TA1 due to infill, MO
2003	158.3	158.3	
2004	160.9	161.1	0.2
2005	163.3	163.9	0.6
2010	172.8	176.6	3.8
2013	177.2	183.4	6.2

Horizontal well productivity estimate - Based on TQ1 N6b.dat

Well Location: (33,32) to (51,32)

Length: 2090'

MULL 5 in L3

Well completed on Jan 1, 2003

Estimated Production from Infill

Year	Cum Oil	Cum Wtr
	MO	MW
2004	48.3	132.3
2006	97.6	429.3
2008	127.9	738.1
2010	149.8	1045.6
2012	166.7	1345.1
2013	173.9	1491.7

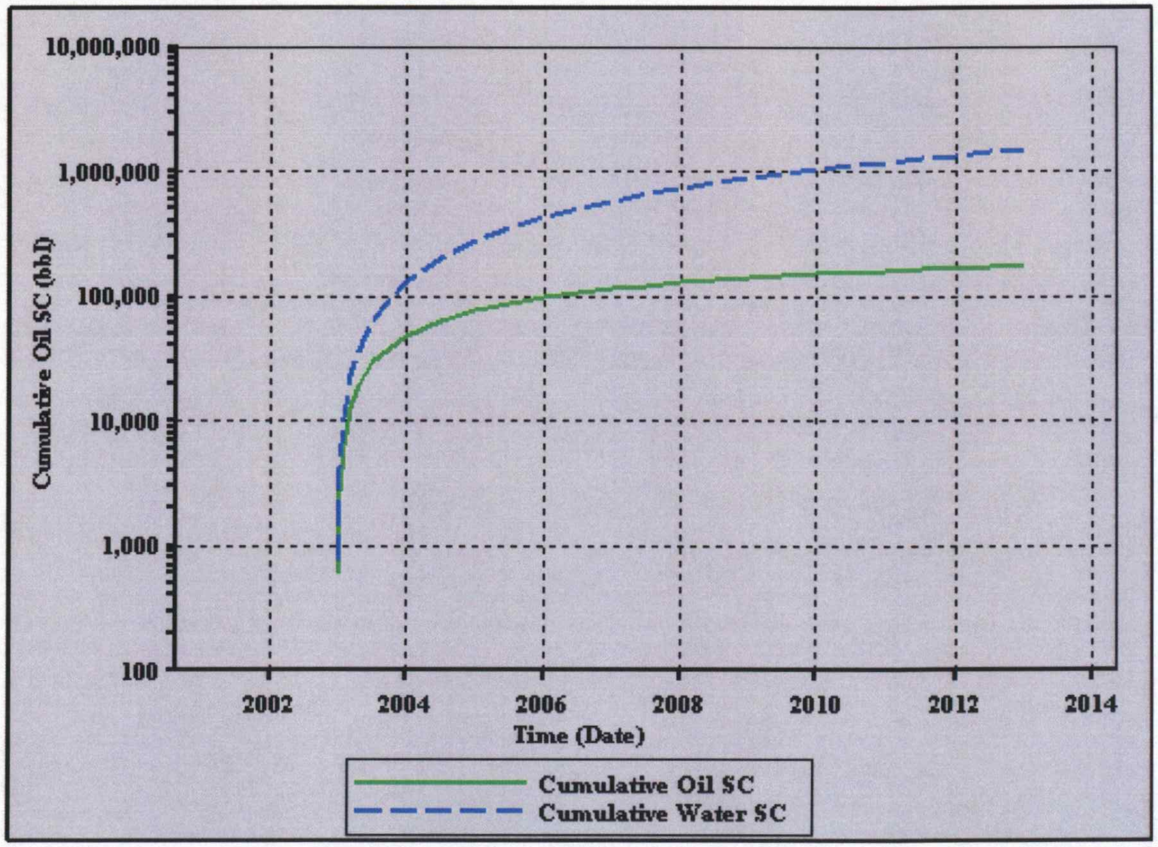


Figure G14

Horizontal well productivity estimate - Based on TQ1 N6b.dat

Well Location: (33,32) to (51,32)

Length: 2090'

MULL 5 in L1

Well completed on Jan 1, 2003

Estimated Production from Infill

Year	Cum Oil	Cum Wtr
	MO	MW
2004	45.1	103.3
2006	90.6	346.3
2008	118.9	602.9
2010	139.4	861.6
2012	155.4	1116.1
2013	162.2	1241.3

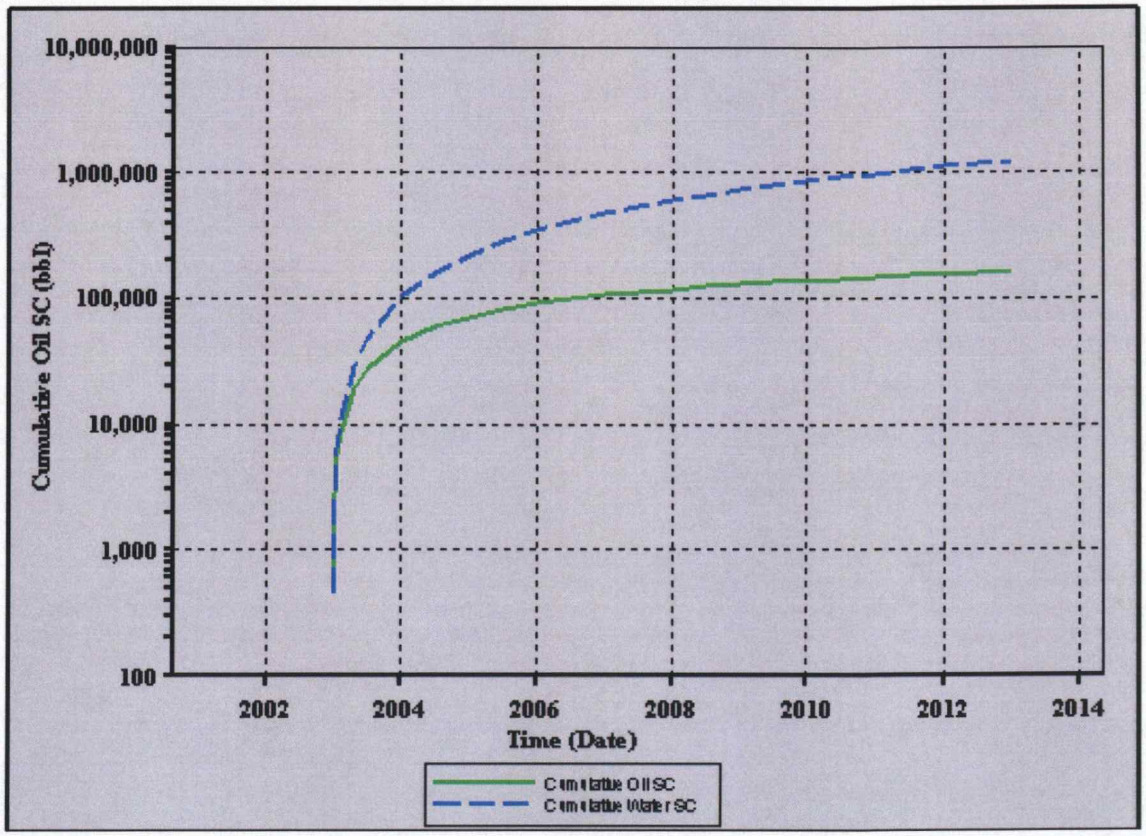
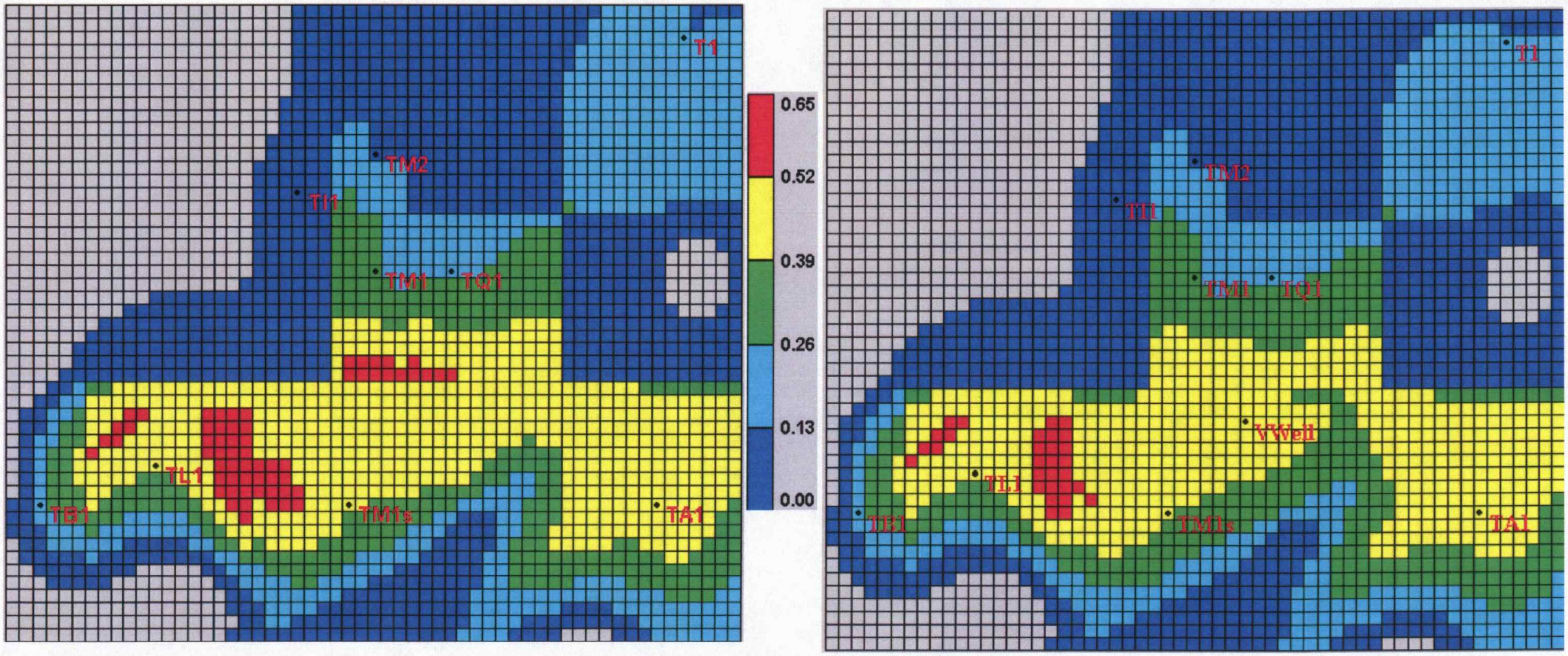


Figure G15

MULL Vertical (East) in L5

Jan 1, 2003 - remaining reserves (oil-ft) in Layer 5 (L5)

Jan 1, 2013 – L5 remaining reserves (oil-ft) after drilling an infill vertical well - Vwell
Location: (33,32)



skin = 1.5
Well diameter = 6”
Bottom hole pressure = 200 psi (P_{wf})
Completed on Jan 1, 2003

Figure G16

Vertical well productivity estimate - Based on TQ1 N6b.dat

Well name: Vwell, Location: (33,32)

Perforated in L5

Vertical well in L5 - East location

Well completed on Jan 1, 2003

Estimated Production from Infill

Year	Cum Oil MO	Cum Wtr MW
2004	3.5	6.7
2006	9.4	21.5
2008	14.3	37.6
2010	18.5	54.4
2012	22.1	71.8
2013	23.8	80.6

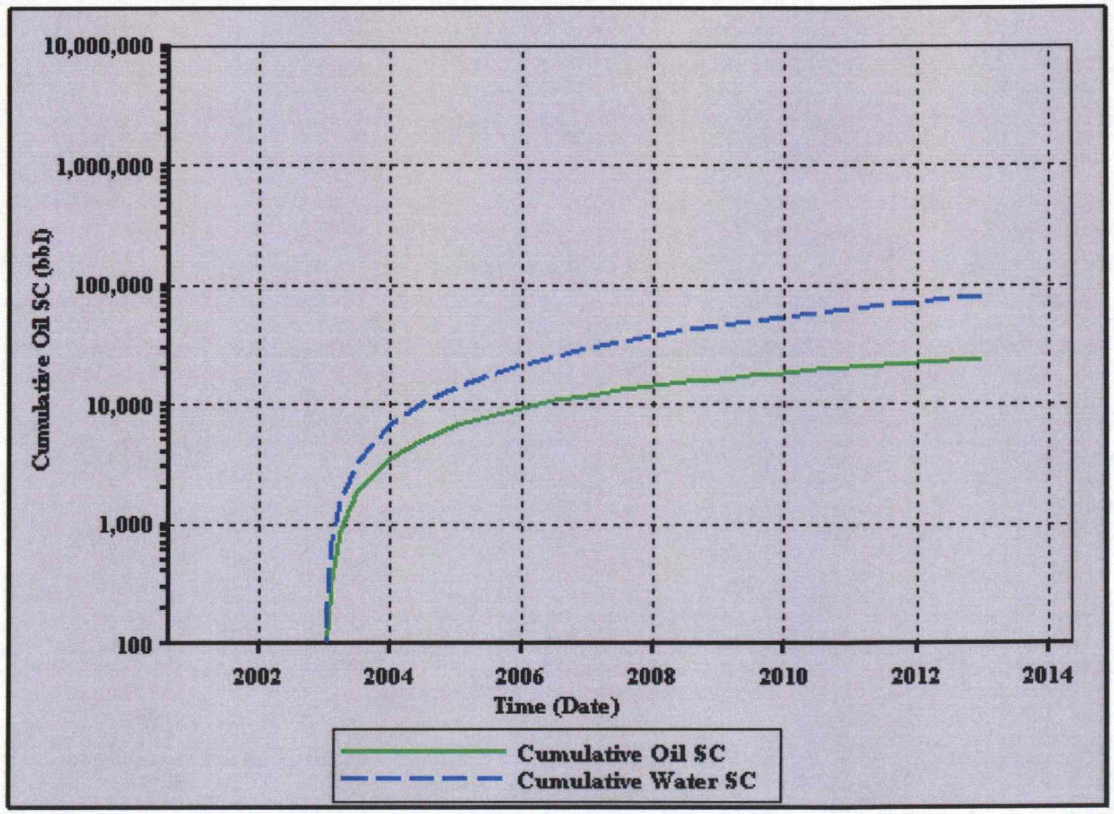
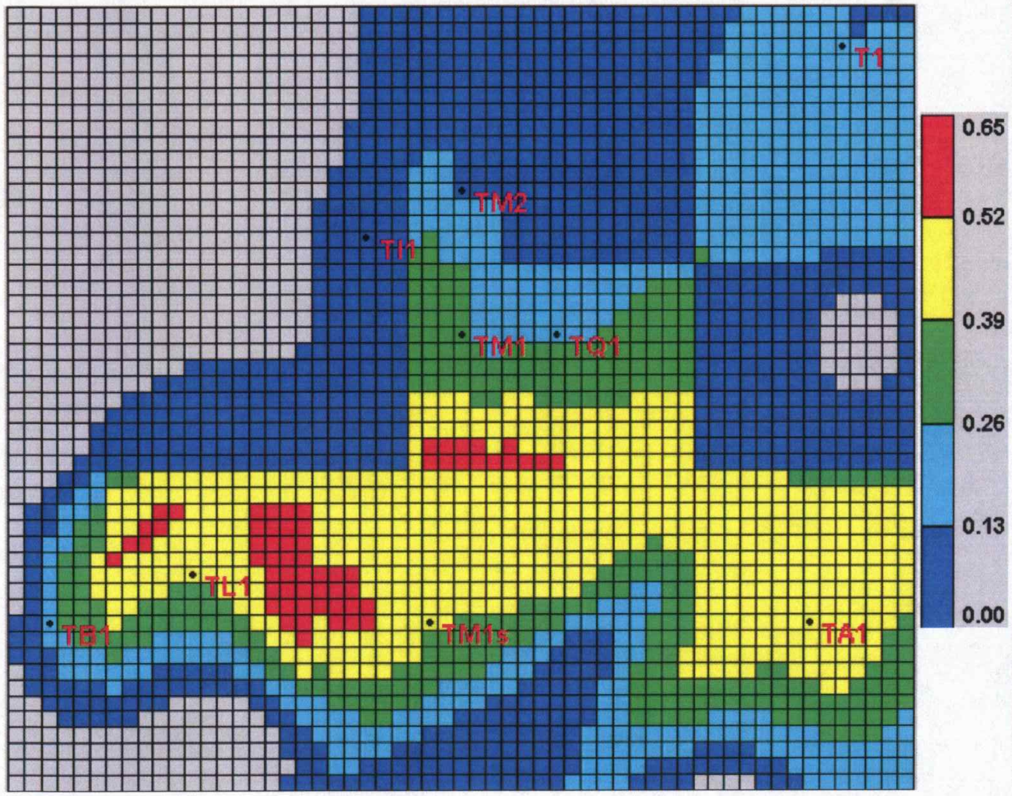


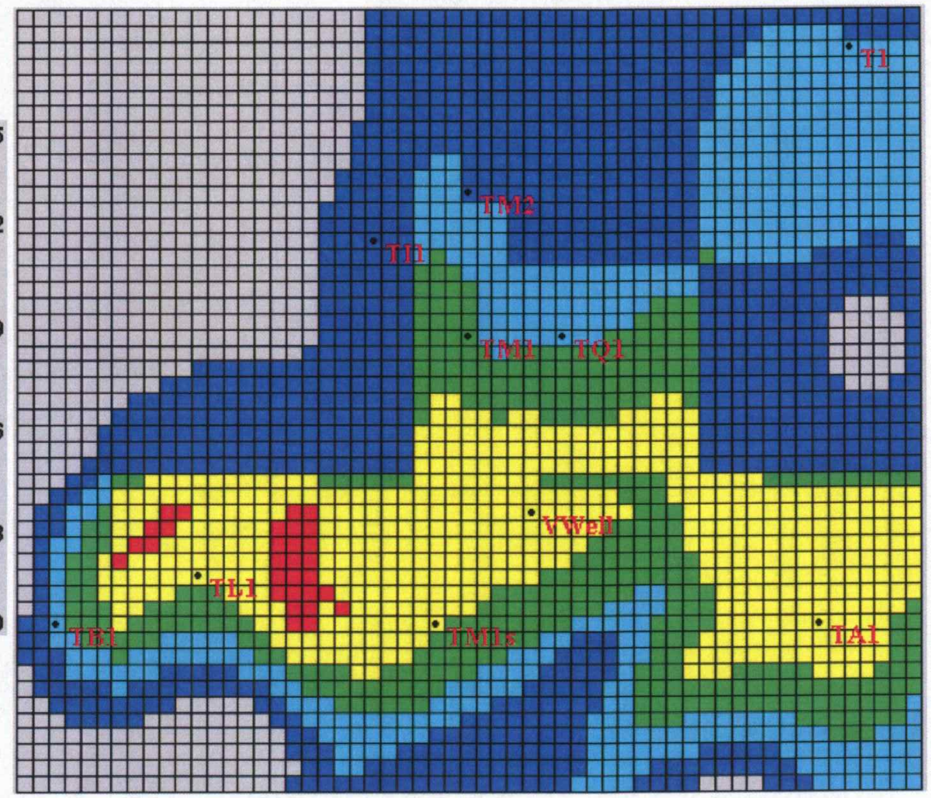
Figure G17

MULL Vertical (East) in L1, L3, & L5

Jan 1, 2003 - remaining reserves (oil-ft) in Layer 5 (L5)



Jan 1, 2013 – L5 remaining reserves (oil-ft) after drilling an infill vertical well - Vwell
Location: (33,32)



skin = 1.5
Well diameter = 6”
Bottom hole pressure = 200 psi (P_{wf})
Completed on Jan 1, 2003

Figure G18

Vertical infill well productivity estimate - based on TQ1 N6b.dat

Well name: Vwell, Location: (33,32)

Perforated in L1, L2, and L5

Vertical well in L1, L3, & L5 - East location

Well completed on Jan 1, 2003

Estimated Production from Infill

Year	Cum Oil MO	Cum Wtr MW
2004	5.2	8.9
2006	13.3	29.2
2008	19.6	51.6
2010	24.8	75.3
2012	29.3	99.9
2013	31.4	112.5

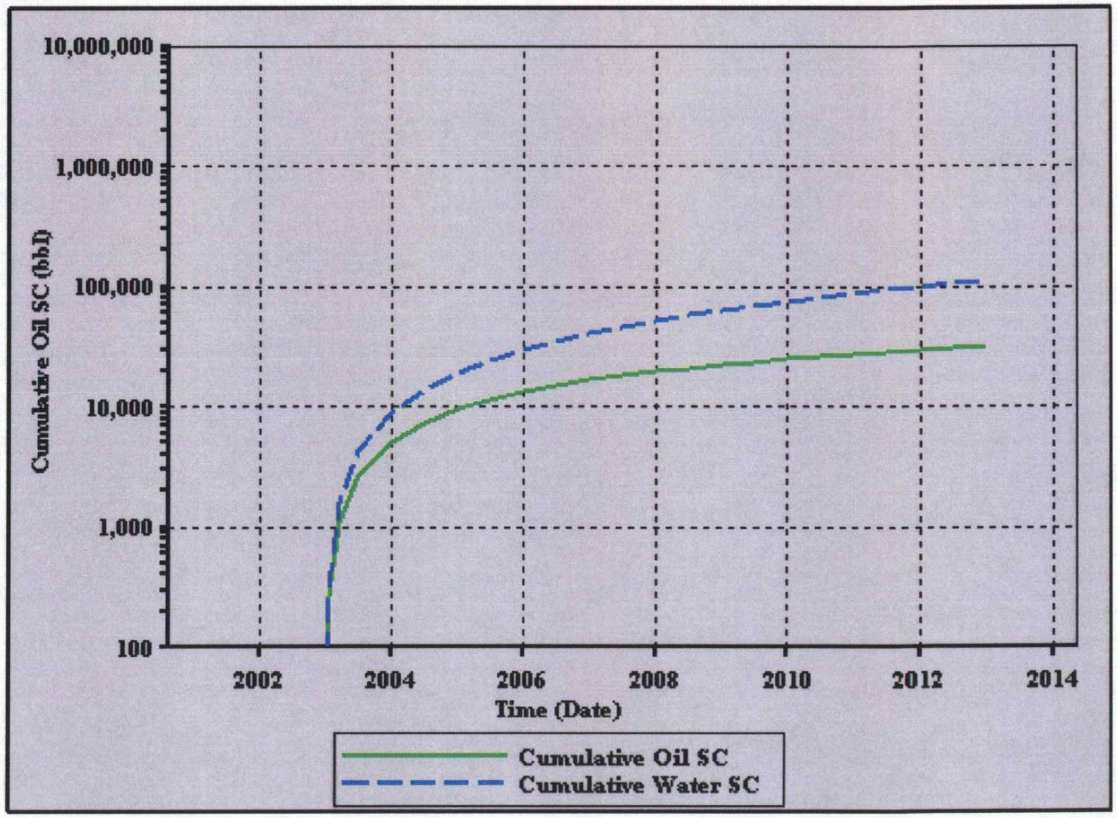
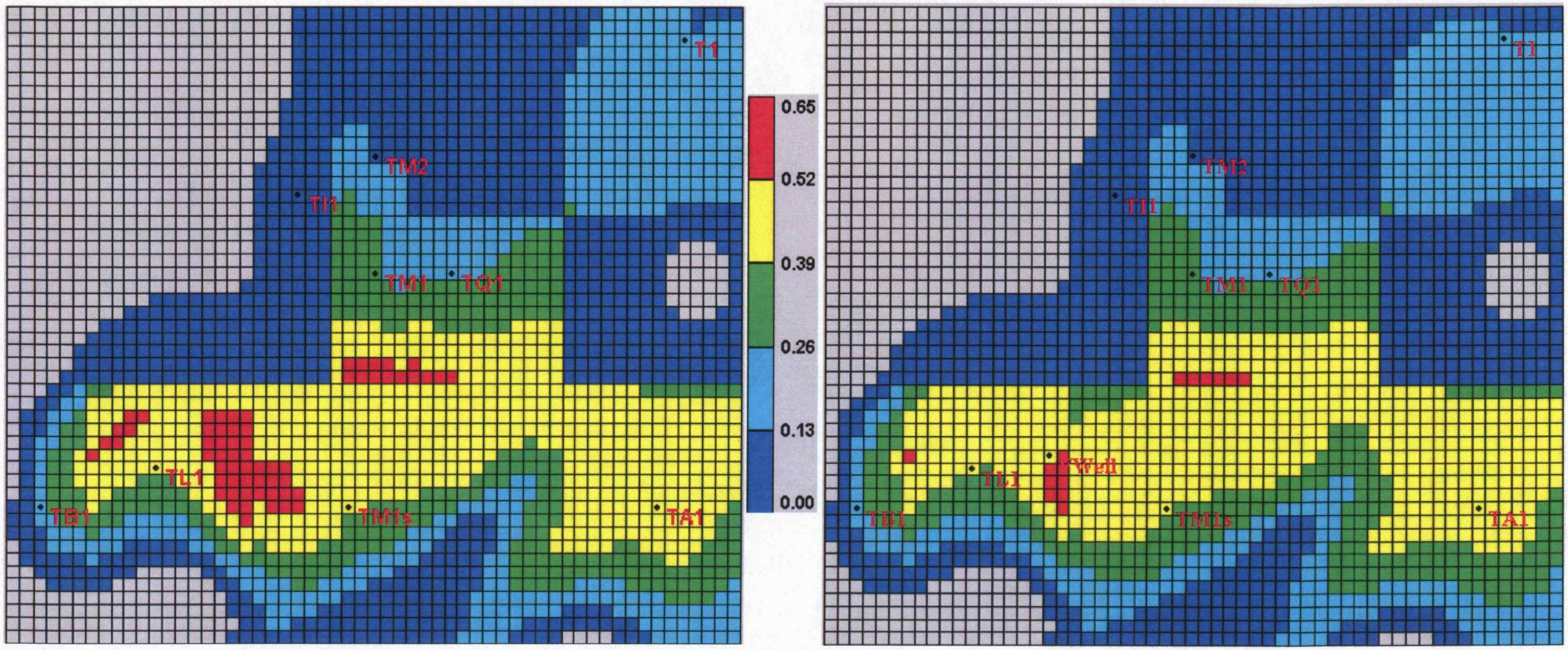


Figure G19

MULL Vertical (West) in L1, L3, & L5

Jan 1, 2003 - remaining reserves (oil-ft) in Layer 5 (L5)

Jan 1, 2013 – L5 remaining reserves (oil-ft) after drilling an infill vertical well - Vwell
Location: (18,35)



skin = 1.5
Well diameter = 6”
Bottom hole pressure = 200 psi (P_{wf})
Completed on Jan 1, 2003

Figure G20

Vertical well productivity estimate - Based on TQ1 N6b.dat

Well name: Vwell, Location: (18,35)

Perforated in L1, L2, and L5

Vertical well in L1, L3, & L5 - West location

Well completed on Jan 1, 2003

Estimated Production from Infill

Year	Cum Oil	Cum Wtr
	MO	MW
2004	3.9	10.4
2006	10.4	31.4
2008	15.8	52.4
2010	20.3	73.5
2012	24.2	94.5
2013	25.9	104.9

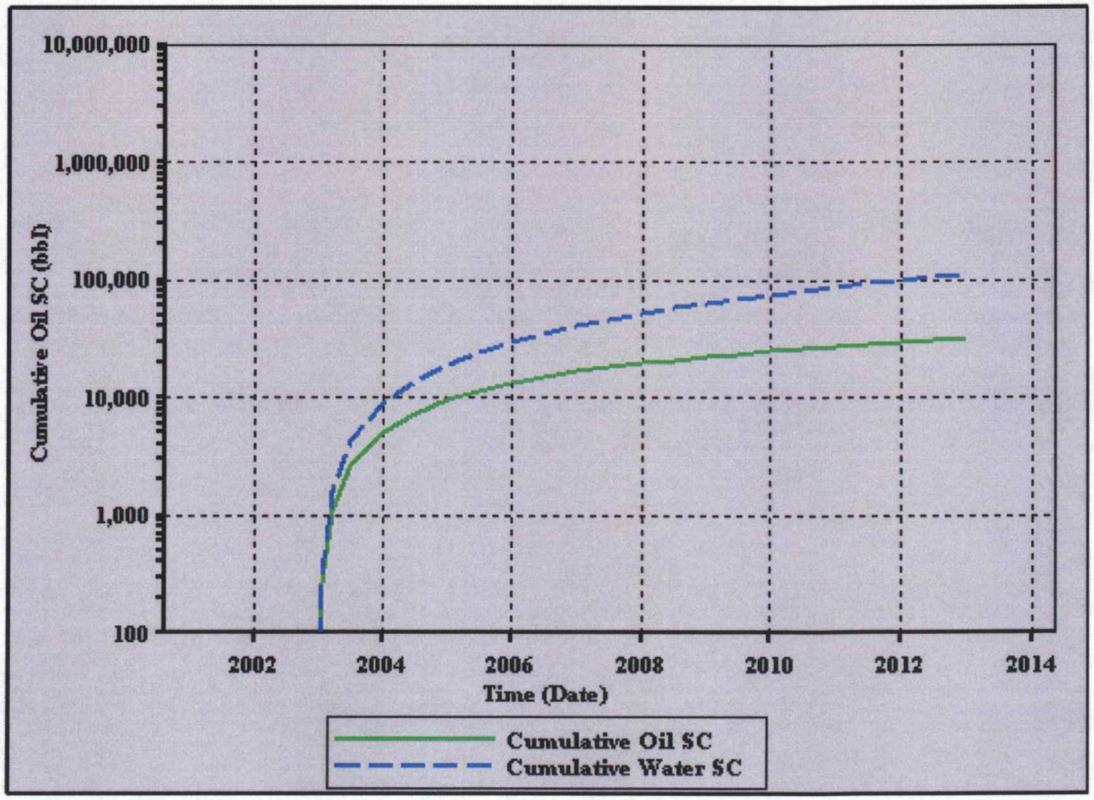


Figure G21