Input data for Reservoir Simulation

3 Layer model of the reservoir
Analytical aquifer below the bottom layer
Grid cell size 110 ft by 110 ft

Reservoir temperature = 120°F
Oil Gravity = 40 API
Gas gravity = 0.8 (Air = 1.0)
Water salinity = 75,000 ppm
Initial reservoir pressure = 2,000 psi

Wells produced at 100 psi bottomhole pressure

Aquifer porosity = 0.15
Aquifer permeability = 0.1 md

Initial permeability estimated from Permeability-porosity cross plot

$K = 0.746\ e^{18.9}$ or $K = 10^{(Phi*100)*0.082 - 0.127}$
where Phi is in fraction

How to generate intial S_w distribution lacking resistivity logs at most wells?

Step 1.

Starting permeabilities in Layers 1, 2, and 3 were 8 md, 12 md, and 8 md. The relative permeability-capillary pressure control panel for Layer 1 (K = 8 md) is shown below. The starting Rel K exponents were m = 0.5 and n = 3.1.

These values result in too high an oil and water production.

Swi and Sorw linked with K

K(md)=	8.00				
Krwmax=	0.22	Kromax=	1	Pcentry=	1.672
Krw -m=	0.5	Swi=	0.37	Pcslope=	-0.879
Kro - n=	3.1	Sorw=	0.134	PcSwiH(ft)=	60.0
water grad	0.454	W sp grav=	1.047938	input value	
oil grad	0.357	Oil sp grav=	0.825	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=			

SW	KRW	KROW	PCOW
0.3661	0.000000	1.000000	4.044
0.4000	0.057292	0.804362	3.741
0.4500	0.090124	0.565817	3.373
0.5000	0.113853	0.380468	3.075
0.5500	0.133426	0.241329	2.828
0.6000	0.150474	0.141509	2.619
0.6500	0.165778	0.074228	2.441
0.7000	0.179784	0.032829	2.287
0.7500	0.192776	0.010816	2.153
0.8000	0.204945	0.001886	2.034
0.8500	0.216431	0.000024	1.929
0.9000	0.220000	0.000000	1.834
0.9500	0.220000	0.000000	1.749
1.0000	0.220000	0.000000	1.672
1.0000	0.220000	0.000000	1.672
1.0000	0.220000	0.000000	1.672
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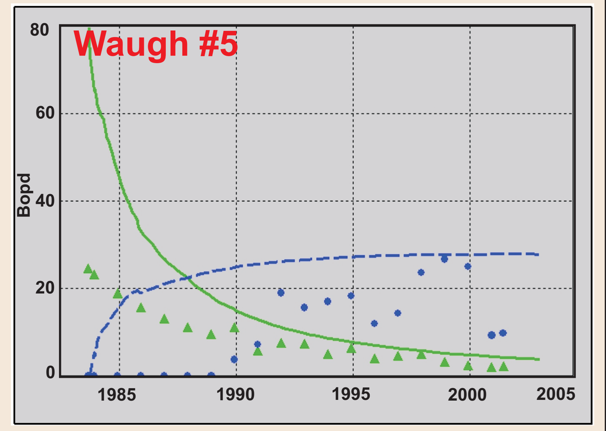

Step 2.

To reduce fluid production, the permeabilities in Layers 1, 2, and 3 were changed to 4 md, 6 md, and 8 md. The result of changing K from 8 md to 4 md on Swi and Sorw is shown below.

Rel K exponents:
m = 0.2, n = 4.5

Swi and Sorw changes with K

K(md)=	4.00				
Krwmax=	0.22	Kromax=	1	Pcentry=	2.304
Krw -m=	0.2	Swi=	0.45	Pcslope=	-0.879
Kro - n=	4.5	Sorw=	0.100	PcSwiH(ft)=	60.0
water grad	0.454	W sp grav=	1.047938	input value	
oil grad	0.357	Oil sp grav=	0.825	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=			

SW	KRW	KROW	PCOW
0.4527	0.000000	1.000000	4.623
0.5000	0.140356	0.604914	4.237
0.5500	0.162146	0.331688	3.896
0.6000	0.176170	0.165756	3.609
0.6500	0.186776	0.072972	3.364
0.7000	0.195409	0.026734	3.152
0.7500	0.202740	0.007325	2.967
0.8000	0.209143	0.001181	2.803
0.8500	0.214845	0.000052	2.657
0.9000	0.220000	0.000000	2.527
0.9500	0.220000	0.000000	2.410
1.0000	0.220000	0.000000	2.304
1.0000	0.220000	0.000000	2.304
1.0000	0.220000	0.000000	2.304
1.0000	0.220000	0.000000	2.304
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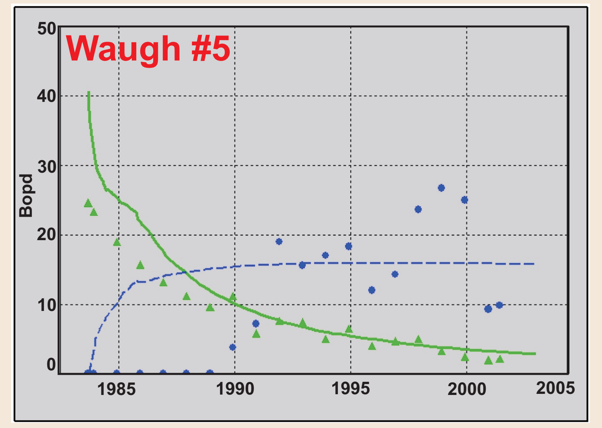

Step 3.

Finally, the decline curves were matched by adjusting the Rel K exponents, m = 0.2 and n = 5.0. Change of these exponents did not effect the Swi and Sorw but changed the Krw and Krow values.

K(md)=	4.00				
Krwmax=	0.22	Kromax=	1	Pcentry=	2.304
Krw -m=	0.2	Swi=	0.45	Pcslope=	-0.879
Kro - n=	5	Sorw=	0.100	PcSwiH(ft)=	60.0
water grad	0.454	W sp grav=	1.047938	input value	
oil grad	0.357	Oil sp grav=	0.825	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=			

SW	KRW	KROW	PCOW
0.4527	0.000000	1.000000	4.623
0.5000	0.140356	0.572054	4.237
0.5500	0.162146	0.293412	3.896
0.6000	0.176170	0.135751	3.609
0.6500	0.186776	0.054555	3.364
0.7000	0.195409	0.017877	3.152
0.7500	0.202740	0.004242	2.967
0.8000	0.209143	0.000559	2.803
0.8500	0.214845	0.000017	2.657
0.9000	0.220000	0.000000	2.527
0.9500	0.220000	0.000000	2.410
1.0000	0.220000	0.000000	2.304
1.0000	0.220000	0.000000	2.304
1.0000	0.220000	0.000000	2.304
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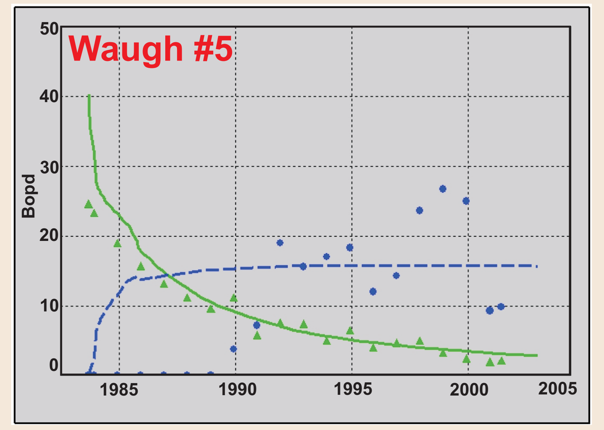
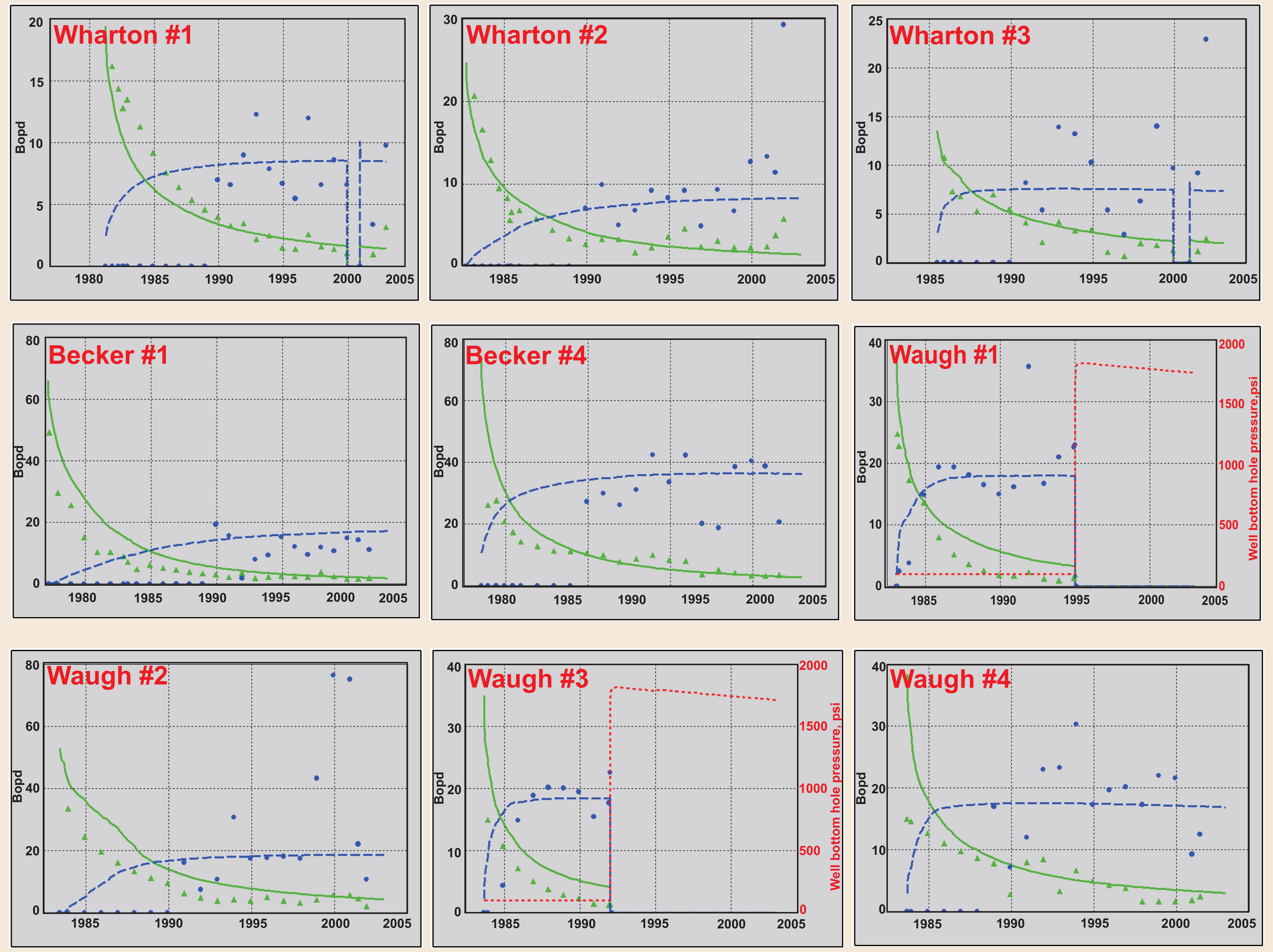


History Match Results



Confirmation of reservoir geo-model Material Balance Calculations

Critical question: Given the OOIP (original oil in place in the reservoir), the known PVT properties, and aquifer description, can the reservoir produce the historic fluid volumes by undergoing the recorded pressure depletion?

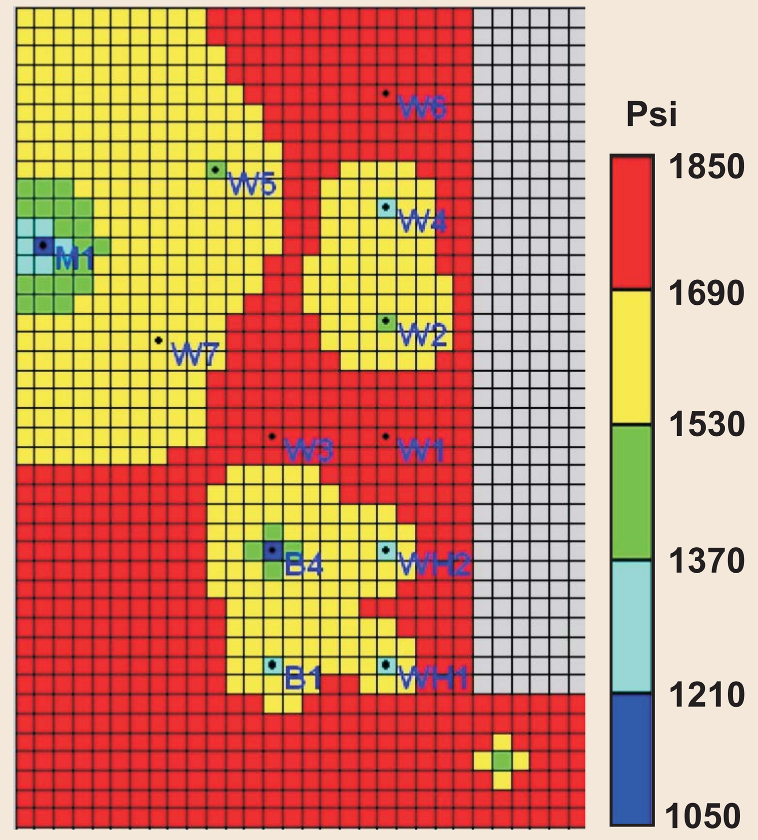
Fluid column measurements at Waugh #1 and #3, as of May 2002, indicate a reservoir pressure of 1,750 psi.

The simulator predicts the average reservoir pressure to be 1,800 psi as of Jan 2003.

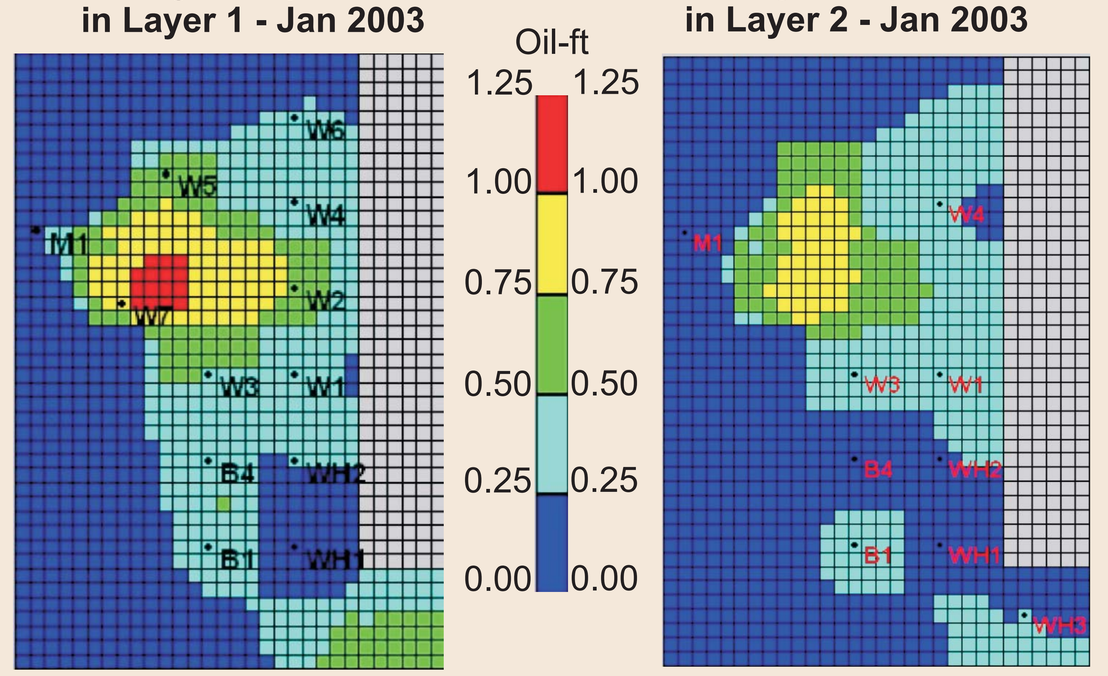
DST Analysis - Initial reservoir pressure and effective permeability

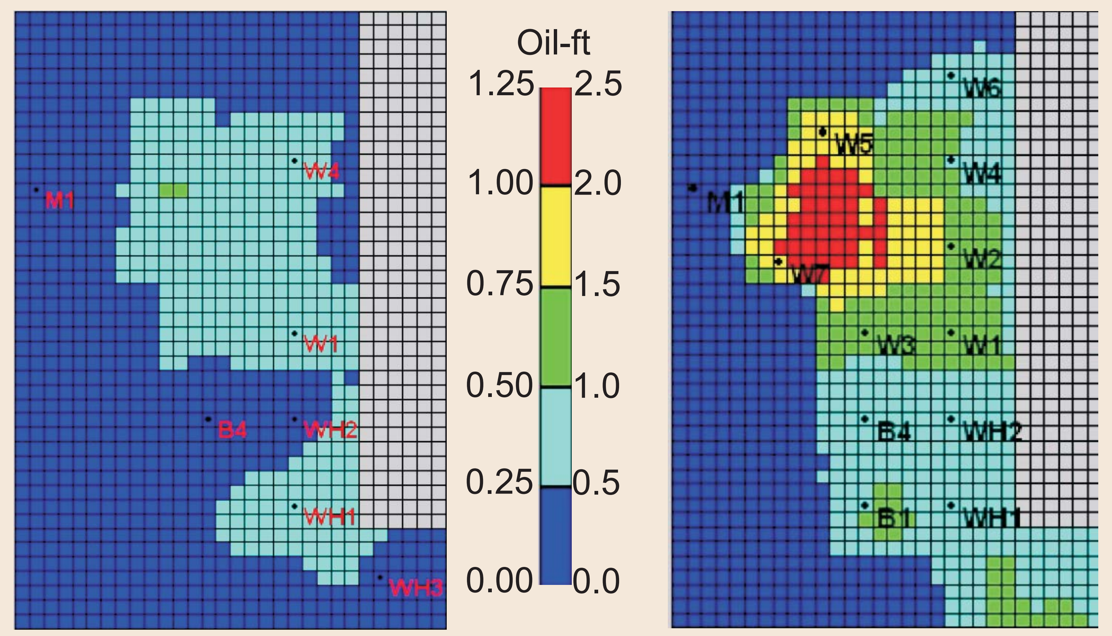
Well	Comp date	FSIP	P*	Eff Perm md
Waugh 1	1/24/83	1635	1825	0.1
Waugh 2	6/15/83	1793	1845	16.3
Waugh 4	8/15/83	1485	1555	7
Becker 1	2/28/77	1556	1722	0.3
Becker 4	6/1/83	1681	1758	1

Average Reservoir Pressure map
Jan 2003 - Wellington West field



Residual Reserve Maps





Incremental recovery schemes

Important observations, about Wellington West field, to be noted are:
1) The field has a very active bottom water drive
2) The average reservoir permeability is low (<10 md)

Different reservoir management schemes were simulated to predict the incremental reserves that could be recovered from Wellington West field. Reservoir production scenarios that were simulated include:

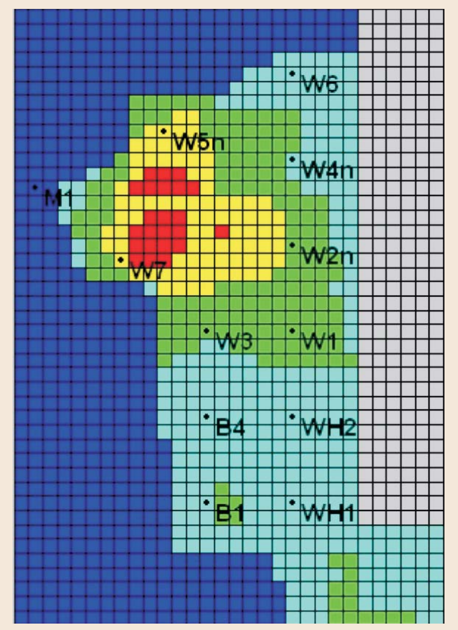
A) What will be additional recovery from Waugh #2, #4, &, #5 if these were to produce without intervention?

B) How much additional oil will be recovered if an infill well is drilled in the residual reserve pocket between Waugh #2 and Waugh #7?

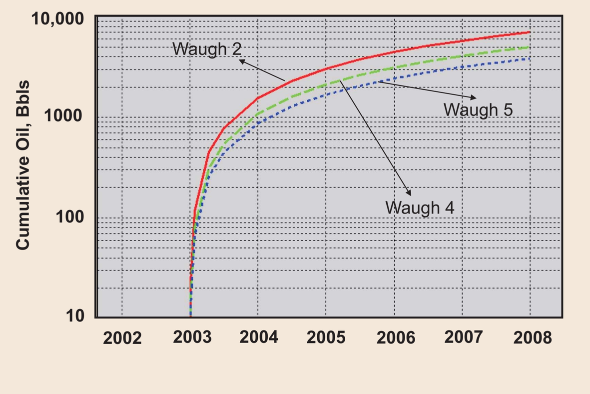
C) Is there any need to consider the option of converting Waugh #7, a water disposal well, into a water injection well to displace the residual oil pocket to its north-east into producing wells such as Waugh #2, #4, and #5?

Performance without intervention

Remaining oil-ft per unit area
in Layers 1 to 3 - Jan 2008



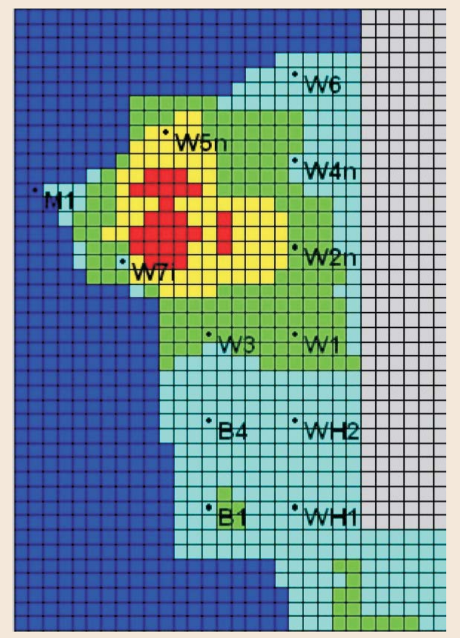
Individual well performances



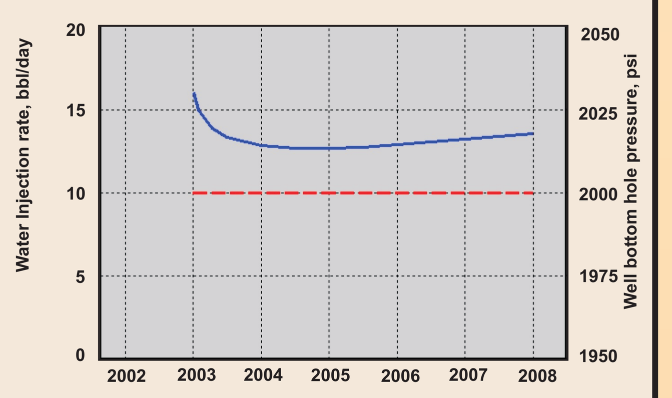
Over 5 yrs, Waugh #2, #4, and #5 produce a total of 10Mbl (approx.)

Convert Waugh 7 to injector

Remaining oil-ft per unit area
in Layers 1 to 3 - Jan 2008

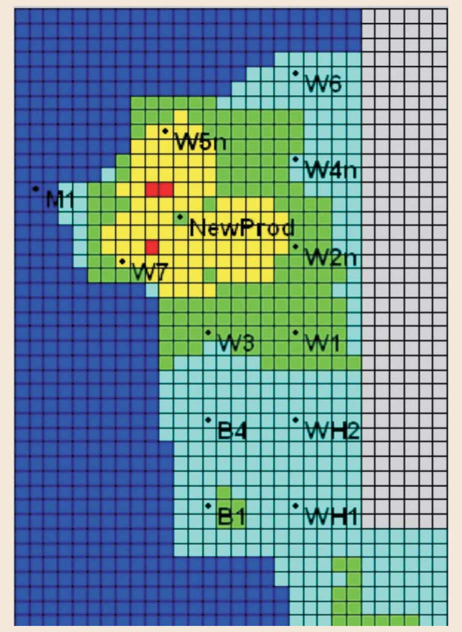


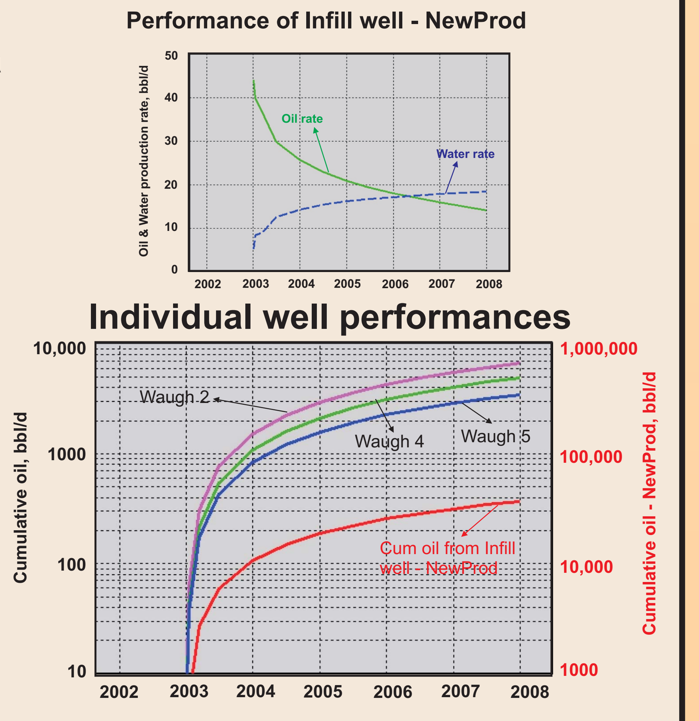
Injection volumes & pressures



Drill an Infill well - "NewProd"

Remaining oil-ft per unit area
in Layers 1 to 3 - Jan 2008





Over 5 yrs, infill well expected to produce about 40Mbl, while Waugh #2, #4, and #5 produce a total of 10Mbl (approx.).
Infill well has minimal interference effects.

Conclusions

1. Available oil production history was incomplete (missing) for Wellington West field. Advanced decline curve (Fetkovich's Type Curve) analyses was used to complete missing production data and to allocate lease production to the well level.

2. Type curve analysis was used to identify if the wells produced under uniform bottom hole pressure. This information is critical for building a reservoir simulation model.

3. Limited water production data indicated that in most wells there was little to no water production initially. Thus, it was assumed that the initial water saturation in the field was at S_{wcrit} - where $K_{rw} = 0$.

4. Permeability-porosity data used for Wellington were obtained from a neighboring analogous field and are consistent with regional Mississippian trends for dolomite.

$$K, md = 10^{((\ \ *100)0.082-0.127)} \text{ where } \ \text{ is in fraction.}$$

5. Capillary pressure curve shapes are similar for a wide range of K but show a relationship of increasing threshold entry pressure and increasing Swi with decreasing permeability.

$Pcow_{entry}$ (psi) = 4.374*K (md) - 0.4625
Swi (%) = $-28.8*\log_{10}K + 62.6$

6. Relative K was modeled using using Corey-type equations. Corey equation exponents, m and n, were initially obtained from measured data and were modified during history matching.

7. Initial S_w distribution could not be mapped in the field due to limited availability of resistivity logs. An interactive relative permeability-capillary pressure table and iterative history matching process were used to estimate the S_w distribution in the field. The IP rate and the characteristic decline curve shape for a well is related to the effective K and the fluid volume within the area of drainage. During the history matching process, the K value in the drainage area was changed. Any change in K resulted in a change in the S_{wi} and S_{orw} due to the interactive links in the relative permeability-capillary pressure table. Simultaneous changes in K, S_{wi} and S_{orw} in a drainage area were effective in obtaining reasonable matches with the well production histories, and in the process delineated the volume of OOIP (original oil in place) or the initial distribution of S_w.

8. Reservoir simulation indicated that the average reservoir pressure, excluding the aquifer, as of Jan 2003 was 1,800 psi. Fluid column measurements at 2 wells in Apr 2002 indicated reservoir pressures close to 1,750 psi. Thus from a material balance standpoint, the described reservoir was able to match both the production and the limited pressure history.

9. The results from the simulation study were used to map the residual reserves in the field.

10. Different schemes were simulated to estimate the recovery potential of the remaining reserves.

11. The low prevailing permeability of the reservoir coupled with a very strong bottom water drive makes the option of water injection ineffective.

12. Incremental reserve recovery is likely to be maximized by drilling an infill well between Waugh #2 and Waugh #7.

Acknowledgements

Project Sponsor

United States Department of Energy

Industry Partner

American Energies Corporation

Simulation Software

CMG Computer Modelling Group Ltd.