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RESMOD* STUDIES TO EVALUATE POTENTIAL
OF HORIZONTAL INFILL WELLS
(DOE Contract # DE-PS26-00BC15304)

by

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* Maurer Engineering Inc. software

Introduction

RESMOD, software developed by Maurer Engineering Inc., is a PC-based tool that can be used to estimate and history match production performance of vertical and horizontal wells. This tool models single-phase fluid flow in a homogenous close tank reservoir. In the PUMP project, RESMOD was used to evaluate the production performance of vertical and horizontal wells in a reservoir, and also to compare the relative potential of different prospects for horizontal infill drilling.

Model Assumptions

As in any other reservoir simulation study, the set of input parameters required to obtain a history match in RESMOD is non-unique. There will be several sets (combinations) of input parameters that will result in a close fit with the historic production data. The user manual makes an important note to this regard by stating, "site-specific understanding of the reservoir and production behavior will dictate which combination(s) is best for a given field." History matching performance of a vertical well or wells in a field helps to define various field-level parameters that effect production. These field-level parameters in combination with site-specific information about an infill location can be then used to predict the performance of the proposed horizontal well.

Homogenous reservoir

The model assumes that the input reservoir properties are uniformly valid over the entire drainage area of the well. Therefore, properties input must be representative of the area around the well that is being simulated by RESMOD.

Single-phase flow

RESMOD models flow of only one phase, i.e., oil in the reservoir. In real life, both oil and water flow simultaneously in most reservoirs. The fields taken up for this study have oil and water production from the vertical wells. Multi-phase flow is governed by the relative permeability characteristics of the reservoir rock and fluids. Suggested methods to account for the adverse effects of relative permeability on oil flow in the reservoir include increasing skin factor and reducing permeability.

Pseudo-steady state production

The model does not calculate the initial flush production that occurs during the transient flow period resulting in an underestimation of the initial production (IP) rates but this normally does not affect the cumulative production volumes significantly. In this study, the stabilized (later) flow rates were considered for history matching for wells that recorded high flush production.

Vertical and horizontal permeability

The model uses horizontal permeability to calculate flow into a vertical well, while both horizontal and vertical permeability is used to model flow into a horizontal well. Increases in the ratio between horizontal and vertical permeability results in lower predicted rates for the horizontal well. Horizontal wells are never absolutely horizontal along their productive length. The sinusoidal undulation of the well along the horizontal axis enables the well to connect potential reservoir pockets across permeability barriers.

Wellbore pressure

The model calculates fluid production in proportion to the pressure differential existing between the boundary of the drainage area and the wellbore. RESMOD does not include the pressure losses along the wellbore. However, these pressure drops become significant for wells that produce fluid in volumes exceeding 5000 barrels per day or in case of flow of heavy oil. Thus, pressure losses incurred by fluid flow in the wellbore can be deemed negligible in mature Mississippian reservoirs in the Midcontinent.

Horizontal well length

Production logs indicate non-uniform flow of fluids into the horizontal wellbore from the reservoir. The variation is the flow flux along the producing length of the well is dependent on the reservoir heterogeneity of the reservoir. Thus, horizontal wells produce from different sweet spots along its length, and more so in heterogeneous reservoirs.

Residual oil saturations

This parameter affects the shape of the production decline curve while leaving the IP rate unaffected. A full-field reservoir simulation study enables one to estimate this parameter at any prospective site for an infill horizontal well. Thus in the pre-simulation stage, this parameter is mostly unavailable.

Gravity effects

RESMOD assumes that the gravitational effects on fluid flow in the reservoir are negligible.

Reservoir Input Parameters

Drive mechanism scaling factor

One of the major factors that affect production is the drive mechanism charging the reservoir. This is particularly important for reservoirs that are being considered as candidates for infill horizontal drilling. Infill horizontal wells in mature reservoirs perform better when reservoir pressure is undepleted. One of the criteria used to short listed fields in this project was evidence of pressure support in the reservoir. One of the ways RESMOD inputs this influence of drive mechanism is through the specification of the drive mechanism scaling-factor (DMSF). The user manual of RESMOD defines DMSF as a fraction that "characterizes the combined drive mechanism of a reservoir, where 0 corresponds to solution-gas drive and 1 corresponds to active water drive." The model assumes that active water drives result in highest recoveries while solution-gas drives result in the lowest recoveries.

For vertical wells producing from reservoirs under active water drive, RESMOD assumes an exponential decline where oil depletion is proportional to remaining producible oil-in-place. The author of this report is of the opinion that production volumes from real wells show hyperbolic declines. Exponential and harmonic declines are end-member cases of the set of possible hyperbolic declines with the decline exponent "n" being equal to zero in first case and equal to 1 in the later case. As RESMOD uses exponential decline to model vertical well production, it can be considered as a conservative estimate of the production capability of the well. The fractional value of the DMSF can therefore be varied by the user during the process of history matching to represent drives mechanisms of different strengths, combinations and/or types. RESMOD by default, calculates the well performance under the bounding conditions, i.e., DMSF = 0 and DMSF = 1, and the user can select 3 other DMSF values within this range during each run.

For horizontal wells placed in actively water driven reservoirs, RESMOD assumes two large edge aquifers that are parallel to the horizontal well. It is of the opinion of the author of this report that multi-phase fluid (oil and water) flow is prevalent in real life non-idealized reservoirs. Thus, the DMSF factor used to obtain a history match with production volumes recorded at the well, also takes into account the effects of relative permeability on the flow of oil. DMSF combines the effects of both the strength of the reservoir drive and relative permeability affecting oil flow.

The suggested DMSF values in the RESMOD user manual are shown in Table 1. The DMSF factor for each field was determined through the process of history matching the production of select vertical well(s) in a field. In the limited number of wells that have been studied in this report, it was observed the DMSF factor required to history match vertical well performance varied only slightly between wells in a field. This implies that the DMSF factor that encapsulates the combined effect of reservoir drive and relative permeability of the reservoir rock is a field level property, and once determined by history matching vertical wells can be applied to predict performance of horizontal wells within the field.

Drainage area

For horizontal wells, 3 types of drainage areas are commonly mentioned in literature and these are an ellipse, a rectangle capped with semicircular ends, and a rectangle whose length coincides with that of the well. Factors that critically affect production from a horizontal well are the area that the well gets to drain, the length of the producing horizontal section of the well, and the thickness of the reservoir. The area drained by a horizontal well in an unlimited reservoir generally approximates that of an ellipse. Thus, this model is recommended for cases where the drainage radius is limited only by formation properties (such as permeability and porosity) and fluid viscosity. Rectangle model is recommended when the producing horizontal section of the well extends over the entire length of the pay and thereby making axial drainage into the ends of the well negligible. The capped rectangle model is recommended when the drainage is limited by boundaries that run parallel to the well and not by boundaries at the end of the well. In the fields/wells considered for this study, drainage has been mostly limited by geologic heterogeneity, and, therefore, the elliptical model of drainage was used.

Skin factor

Conventionally, a unit change in the skin value results in a 15% change in flow rate in a vertical well and about a 50% change in the flow rate from a horizontal well. RESMOD provides 2 options, namely the Joshi and Hall models, to input the skin values. The skin includes effects of both formation damage around the wellbore and also the dynamic effects arising out of fluid flow into the well.

The Hall model treats skin as a unit of pressure loss and decreases horizontal well productivity by the same relative magnitude as it would for a vertical well. Thus, if a skin factor of 1 reduces vertical well productivity by 20% then its use will also reduce the horizontal well productivity by 20%. The Hall model distributes this loss in production over the length of the horizontal well. The Joshi model theorizes that since the skin-related pressure drop in a vertical well is proportional to the flow rate per unit length (q/h) of a vertical well, the pressure loss due to skin in a horizontal well is proportional to flow rate per unit length (q/L) of the well. Thus, use of Joshi skin model results in significantly lower pressure losses for horizontal wells than in vertical wells.

It is not uncommon for the skin factor input to be used as a "fudge factor" to match the predicted rates with the history. The Hall skin model is more conservative than Joshi's model, and was to predict performance of horizontal wells in this study. For each field, the skin factor in a vertical well was estimated by history matching the production from the well. This skin factor, or one close to it in value, was then used to predict the performance of the infill horizontal well. The sensitivity of production from a horizontal well on the skin factor was determined by running the model with different skin values around the initial assumed value.

External drainage radius

The user manual recommends that this should represent the circular external boundary of the area drained by a vertical well, and the semi-minor axis of the elliptical area drained by a horizontal well. As per reservoir engineering conventions, drainage radius represents the distance from the well where the pressure transient, created by drawdown at the well, is unable to move fluids towards the well. In real geologic settings, the drainage is seldom circular in shape. In this study, an initial approximation of the drainage radius was obtained by volumetrics – i.e. by determining the volume of the reservoir that needs to drain in order to account for the cumulative production recorded at the well assuming uniform petrophysical properties within the drainage. In the volumetric calculation, these properties were set equal to that obtained from log analysis at the respective vertical well. If needed, this initial estimate of drainage radius was varied during the process of history matching.

Permeability

Permeability measured on core samples from Mississippian carbonate reservoirs were found to vary significantly at same (similar) porosity values. Permeability is heavily influenced by lithofacies, and at this preliminary screening stage detailed information about the reservoir rock was unavailable. The user manual recommends input of single-phase horizontal permeability. However, it is of the opinion of the author that input of effective (horizontal) permeability to oil is more appropriate in history matching or predicting oil production in a single-phase simulator like RESMOD. This would perhaps reduce unwarranted modification of different petrophysical parameters during the history matching exercise. The best estimate of effective permeability to oil at the input porosity (representative over the drainage area) was entered in each case. Lacking measured data, the vertical permeability was assigned to be 10% of the horizontal permeability value.

Formation thickness

The value entered in each case was the best estimate of the effective thickness of the producing zone, i.e., the net pay. Even for partially penetrating wells, the value entered was the effective thickness of the reservoir rock.

Residual oil saturation

A constant value of 30% was assigned in each case. From past and current studies at the KGS, this value was estimated to be representative of many Mississippian reservoir rocks in Kansas.

Length of horizontal well

This is the length of the horizontal well that is exposed to the producing formation. In consultation with the industry partner Mull Drilling Company Inc. (MDCI), a well length of 500 ft was assumed in each case.

Bottom hole pressure

The height of fluid column above the perforation varies during the producing life of a well, and this data is often hard to obtain in the mature fields of the Midcontinent. A set of guidelines, based on the prevalent operating practices of the region, was developed in consultation with MDCI in order to assign BHPs in producing wells where recorded data was unavailable. These guidelines stipulate that wells with cumulative production less than 75 MSTB can be assumed to produce under pumped off conditions while wells whose cumulative production exceeded 75 MSTB it is reasonable to assume a standing fluid column in the producing well.

Production history

RESMOD uses the IP value and an exponential decline to calculate the production history of a vertical well in aquifer driven reservoirs. Decline analyses are valid when a well produces under near constant BHP and when no changes occur in the near wellbore region (i.e., no stimulation jobs are carried out to result in permeability changes) or the production from a newly drilled neighboring well does not cause interference. Thus, the production history entered for history matching included data for the period where an uninterrupted decline was visible without any intervening production spikes. Also, the production data was smoothened by annually averaging monthly production volumes.

Oil Viscosity

The API of the oil produced from the studied fields is around 40 degrees. The reservoir temperatures for these fields are close to 120°F. Using standard correlation charts, the dead oil viscosity for such oils was estimated to be 2 cp. Most wells in this area have reported some gas production at the surface. However, gas produced is normally in quantities that did not merit metering or flaring. No data was available regarding the solution-gas-oil ratios in these fields. Thus, a low solution-gas-oil ratio of 200 scf/stb was assumed to have existed in these fields at bubble point pressure. Using this GOR, standard correlations were used to normalize the dead oil viscosity to an *in situ* viscosity of 1.1 cp.

Economic Input Parameters

These included $200,000 to drill and complete a vertical well and $100/day fixed operating costs. It also included, $400,000 to drill and complete a horizontal well and $125/day fixed well operating costs. The discount rate was assumed as 17.5% and the net sale price for the produced oil was assumed to be $19/barrel.

Calibration of RESMOD

RESMOD studies were carried out on 2 fields. The first field analyzed was Ness City North, Ness County, Kansas. History matching was carried on production data from 2 vertical wells from this field. It was followed by performance prediction of a horizontal well that had been drilled in this field as a part of a previous DOE project. This exercise was to ground-truth the ability of RESMOD to predict production of both vertical and horizontal wells. The second field analyzed is called Field A Two vertical wells were history matched in this field followed by production prediction of an infill horizontal well located in an area of interest of MDCI.

For each selected vertical well, different petrophysical properties representative over the drainage area were obtained from reservoir characterization studies. Inputs to RESMOD included these parameters along with the production history. Iterative runs were carried out to obtain a history match on the production data with minimal modifications of original input data. Initial flush production in the production history was neglected. A match was deemed OK when the calculated IP, cumulative production and shape of the cumulative curve (with time) matched historic values. This exercise helped to determine the field-level parameter – DMSF (assumed to combine the effects of the reservoir drive and relative permeability). The universality of the DMSF was checked by history matching production from 2 vertical wells within a field. As will be discussed later, in the 2 fields that were studied and reported here, similar DMSF values were used to attain history matches at different vertical wells from the same field. This field specific DMSF value was then input along with other petrophysical values relevant to specific locations in order to predict the performance of infill horizontal wells.

Ness City North field – application of RESMOD

The first field that was studied using RESMOD was Ness City North field, Ness County, Kansas. This field had been characterized and simulated, using Computer Modeling Group's IMEX simulator, as a part of a previous DOE project (KGS OFR 2000-80). The result of the simulation study was used to map the remaining potential in the field. As a part of this study, an infill horizontal well was also drilled in Ness City North field. The horizontal section of this well was left open hole due to restrictions inherent in re-entering an existing wellbore. The well produced, for about 2 months, at an average rate of 60 bopd with a 50% water cut. Thereafter, a sudden collapse occurred in the wellbore shutting off production of all fluids. All efforts to reclaim the well failed resulting in abandonment of the wellbore.

Ummel #1 is the best vertical producer in Ness City North, and it is the well immediately to the north of the horizontal well. Petrophysical properties input to RESMOD are representative of the drainage area of this well and were obtained from the IMEX data file (CMG column in Table 2). These input parameters were adjusted in order to history match (Figure 1) the production profile of Ummel #1. The final set of parameters used to obtain this match is listed in the match column of Table 2. It is apparent that minor changes were required on the values obtained from IMEX in order to get a match in RESMOD. The history match was obtained when a DMSF = 0.5 was assumed for Ummel #1.

Being a single-phase close tank model, RESMOD predicts well production by using a calculated IP and an exponential decline. One of the basic assumptions behind modeling any production decline profile, here exponential, is that the producing conditions must remain unchanged, i.e., BHP and/or skin or permeability can not be changed. The production history entered in RESMOD was until 1995 because a single decline was evident in the annual oil production till 1995. Post 1995, the oil production from the well showed an abrupt increase followed by another decline. It is interesting to note, that the match, though admittedly non-unique, was attained with a BHP (bottom hole pressure at the well) equal to 900 psi. There is no record of BHPs in this well. The simulation study showed that the average BHP for most of the producing life of the well, before 1995, was around 700 psi. Upon consultation with the Mull Drilling Company Inc. (MDCI) – the operator of Ness City North field, it was learned that Ummel #1 was a high fluid producing well, and thus a heavy-duty pump was installed at the well some time in 1995. Since the installation of this pump, low fluid columns had been maintained at the well. However prior 1995, MDCI opined that significant fluid columns existed in Ummel #1, and given their experience in operating this well they confirmed that a fluid column that resulted in a BHP of 900 psi was reasonable for this well. Upon history matching, production estimated by RESMOD is compared with the recorded data for Ummel #1 in Table 3.

The DMSF is a field level parameter. Thus, it is expected that another vertical well in Ness City North, such as Ummel #2, should be history matched in RESMOD by using a DMSF value close to 0.5. Ummel #2 is the closest well south of the infill horizontal well. Also, it is one of the mediocre producers in the field. Petrophysical parameters representative of the drainage area of this well are listed under the CMG column while those needed to history match its production are listed under match column in Table 4. Again, the IMEX parameters needed minor modifications to obtain a history match on production data from Ummel #2. The resultant history match (Figure 2) was obtained using a BHP = 850 psi and a DMSF = 0.4. Thus, the DMSF factors obtained from history matching two of the closest neighbors, Ummel #1 and Ummel #2, of the horizontal well are 0.5 and 0.4 respectively. MDCI also confirmed that this well was a high fluid producer, and, thus, it might have produced against a significant fluid column in the well. Table 5 compares the estimated production numbers with the historic values in Ummel #2.

History matching vertical well production in RESMOD enabled estimation of the DMSF range that is applicable for Ness City North field. A DMSF of 0.45 was used to predict the performance of the horizontal well in this field. The petrophysical parameters representative of the drainage area of this well were obtained from the IMEX model, and are listed in Table 6. The gamma ray log from this well revealed that the effective productive length of the horizontal leg in the well was about 450 ft. For most of the life of the well (the first 60 days), the standing fluid column in the well varied between 800 to 1200 ft. Table 7 summarizes the production profile that RESMOD predicts for the horizontal well in Ness City North. The production rate predicted for the initial months is comparable to that recorded during the brief life of the well.

Thus with limited available data, RESMOD was able to history match production data from vertical wells in a field using consistent DMSF values. Having defined the narrow range of possible DMSF values applicable for the field, it was used to predict at least the IP of an infill horizontal well. Thus, RESMOD could similarly be used as a screening tool for evaluating candidate reservoirs for horizontal infill drilling by calibrating it first on data from neighboring vertical well(s).

RESMOD studies on Field A

One of the short listed fields in the PUMP project is Field A (name withheld currently due to confidentiality reasons). Two vertical wells, namely Well M and Well L, were selected from this field for history matching in RESMOD, and, thus, to estimate the DMSF range applicable for the chosen field. MDCI, the field operator, is interested in evaluating the potential of a targeted horizontal infill well in the general vicinity of Wells L and M. Wells in this field either are high producers or are low oil producers. Well M is one of the most prolific producers of the field while Well L represents one of the poorer producers.

A detailed 3D geologic model was developed for this field by integrating all the available data – wireline logs, DST, production data, and core analysis from analog neighboring wells. Based on this geomodel, the representative petrophysical properties for the drainage area of Wells L and M were obtained. These properties are tabulated in Tables 8 and 9. Figure 3 shows the history match obtained in RESMOD for Well M. Table 10 compares the IP and cumulative production predicted by RESMOD for this well with that recorded in production history. The match, for Well M, was obtained by using a DMSF = 0.8 and with a BHP = 170 psi. Fluid level data during the producing life of the well was unavailable. Currently, this well is producing under pumped-off conditions. As per suggestions from MDCI in accordance to prevalent field practices, it was decided for simulation purposes that low oil producers (cumulative production < 75,000 bbl) would be assumed to be produced under pumped off conditions while high oil producers (cumulative production > 75,000 bbl) would be assumed to be produced with some fluid column in the well. It is common practice to produce a well under a backpressure in order to reduce the increasing water cuts, and water cuts in Mississippian wells normally increase with time. Thus, when a highly productive well is being produced under pumped off conditions today, it is likely that it has always produced with low fluid levels.

Figure 4 shows the match obtained for Well L. Here, the match was obtained using DMSF = 0.8 and a BHP = 20 psi. Well L is a low oil producer, and thus it is reasonable to assume that it was produced under pumped-off conditions. Table 11 compares the production volumes and IPs calculated by RESMOD against that recorded in field for Wells L. The exercise in Field A also showed that production data from two different vertical wells could be history matched in RESMOD using same/similar DMSF values.

Based on the geologic model constructed for this field, representative petrophysical properties were determined for a drainage area, which MDCI wants to evaluate for its potential for an infill horizontal well in Field A. The input parameters are listed under the column named as "Base" in Table 12. Using a DMSF = 0.8, a BHP = 300 psi, remaining oil saturation = 55%, a producing length = 500 ft, and a skin factor = 2.0, RESMOD predicted that the IP from such an infill well will be close to 150 bbl/d. Economic factors input into the model include $400,000 as cost of drilling the well, oil price = $19, and fixed operation costs = $120/day. The RESMOD model predicted that based on the above data, the producing life of the well would be about 40 months and the cumulative production obtained from this well would be about 60 Mbbls.

Table 12 also summarizes the results of a series of sensitivity studies carried out on the input parameters for the above horizontal infill well in Field A. In each case, only one parameter was varied, within a range thought to be relevant for Field A, relative to the Base data, and its effect on IP, well life, and cumulative production was tabulated. Table 13 summarizes the sensitivity of total cumulative production (estimated over the economic life of the horizontal well) on different input parameters. It shows that when the drainage radius is changed from 500 to 700 ft, the cumulative production calculated by RESMOD for the horizontal well changed from 43 to 79.7 Mbbl, i.e., resulted in an increase of 85.3%. As is evident from Table 13, the parameters that most affect cumulative production include drainage radius, initial oil saturation, average pay thickness, average porosity and the DMSF factor. Within the limits of the range of data (for each parameter) stated in Table 13, it appears that factors such as well length, permeability, external drainage pressure, skin, and BHP have relatively lesser effects on the cumulative production of the proposed horizontal infill well.

References:

User's Manual – RESMOD (Horizontal well reservoir model) by Maurer Engineering Inc., 2916 West T.C. Jester, Houston, TX 77018.

Table 1

Drive mechanism	DMSF from	DMSF to
Weak water drive	0.1	0.3
Partial pressure maintanence	0.1	0.4
Horizontal well under one edge water drive	0.2	0.4
Natural depletion followed by water injection	0.05	0.4

Table 2

Field - Ness City North			
Well - Ummel 1			
Data input to history match		Resmod	
	CMG's	**Match**	
Rock Properties			
Drainage Radius, ft	660	700	
Formation Thickness, ft	12	10	
Horizontal K, md	100	25	
Vertical K, md	10	2.5	
Porosity, %	27	24	
External Drainage Pr, psi	1350	1350	
Fluid Properties			
Oil Viscosity, cp	1.2	1.1	
Initial oil saturation, %	70	65	
Formation volume factor, RB/STB	1.04	1.05	
Drive Mechanism Scaling factor (DMSF)		0.5	
(DMSF = 1 for active water drive, DMSF = 0 for solution gas drive)			
Vertical well data			
Skin factor		4	
BHP, psi	700	900	
Residual oil saturation, %	30	30	
Well bore radius, inch	3.95		
Well cost, 1000 $	200		
Fixed Operational cost/day, $	100		

Table 3

DMSF	**0.5**				
RESMOD results			**Actual well performance**		
	bopd	MBBL		bopd	MBBL
Starting production rate	58.6		Avg first production (1st 10 months)	69.1	
			Avg Production from 11 to 23 months	49.1	
Rate after 204 months	4.1		Rate after 202 months	6.9	
Cumulative production after 204 months		127.5	Cumulative production after 202 months		125.2

Table 4

Field - Ness City North			
Well - Ummel 2 (production well)			
Data input to history match			
	CMG	Match	
Rock Properties			
Drainage Radius, ft	660	500	
Formation Thickness, ft	9.7	6	
Horizontal K, md	18	8	
Vertical K, md	1.8	0.8	
Porosity, %	17.5	15	
External Drainage Pr, psi	1350	1200	
Fluid Properties			
Oil Viscosity, cp	1.1	1.1	
Initial oil saturation, %	58	60	
Formation volume factor, RB/STB	1.04	1.05	
Drive Mechanism Scaling factor (DMSF)		0.4	
(DMSF = 1 for active water drive, DMSF = 0 for solution gas drive)			
Vertical well data			
Skin factor		5	
BHP, psi	700	850	
Residual oil saturation, %	30	30	
Well bore radius, inch	3.95	3.5	
Well cost, 1000 $		200	
Fixed Operational cost/day, $		100	

Table 5

DMSF	**0.4**				
BHP, psi	**850**				
RESMOD results			**Actual well performance**		
	bopd	MBBL		bopd	MBBL
Starting production rate	8.3		Avg first production (1st 7 months)	8.9	
			Avg Production from 8 to 20 months	6.5	
Rate after 132 months	1.6		Rate after 139 months	1.9	
Cumulative production after 132 months		16.3	Cumulative production after 139 months		16.8

Table 6

Field - Ness City North			
Well - Horizontal Infill well			
Data input to history match		Resmod	
		Match	
Rock Properties			
Drainage Radius, ft		500	
Formation Thickness, ft		9	
Horizontal K, md		10	
Vertical K, md		1	
Porosity, %		15	
External Drainage Pr, psi		1200	
Fluid Properties			
Oil Viscosity, cp		2.1	
Initial oil saturation, %		50	
Formation volume factor, RB/STB		1.05	
Drive Mechanism Scaling factor (DMSF)		0.45	
(DMSF = 1 for active water drive, DMSF = 0 for solution gas drive)			
Horizontal well data			
Skin factor		3	
BHP, psi		600	
Residual oil saturation, %		30	
Well bore radius, inch		3	
Horizontal well length, ft		450	
Well cost, 1000 $		400	
Fixed Operational costs, $/day		125	

Table 7

DMSF	**0.45**				
BHP, psi	**600**				
RESMOD results			**Actual well performance**		
	bopd	MBBL		bopd	MBBL
Starting production rate	66.1		Avg first production (1st 2 months)	60	
Life of well, months	24				
Cumulative production after 24 months		21.7			

Table 8

Field - A			
Well - M			
Data input to history match			
	Base	**Min**	**Max**
Rock Properties			
Drainage Radius, ft	750		
Formation Thickness, ft	7		
Horizontal K, md	20		
Vertical K, md	2		
Porosity, %	20		
External Drainage Pr, psi	1250		
Fluid Properties			
Oil Viscosity, cp	1.1		
Initial oil saturation, %	65		
Formation volume factor, RB/STB	1.04		
Drive Mechanism Scaling factor (DMSF)	0.8		
(DMSF = 1 for active water drive, DMSF = 0 for solution gas drive)			
Vertical well data			
Skin factor	2		
BHP, psi	170		
Residual oil saturation, %	30		
Well bore radius, inch	3.95		
Well cost, 1000 $	200		
Fixed Operational cost/day, $	100		

Table 9

Field - A	
Well L	
Data input to history match	
Rock Properties	
Drainage Radius, ft	550
Formation Thickness, ft	7.1
Horizontal K, md	5
Vertical K, md	0.5
Porosity, %	20
External Drainage Pr, psi	1250
Fluid Properties	
Oil Viscosity, cp	1.1
Initial oil saturation, %	50
Formation volume factor, RB/STB	1.04
Drive Mechanism Scaling factor (DMSF)	0.8
(DMSF = 1 for active water drive, DMSF = 0 for solution gas drive)	
Vertical well data	
Skin factor	1.5
BHP, psi	20
Residual oil saturation, %	30
Well bore radius, inch	3.95
Well cost, 1000 $	200
Fixed Operational cost/day, $	100

Table 10

Well M

DMSF	**0.8**				
BHP	**170**	**psi**			
RESMOD results			**Actual well performance**		
	bopd	MBBL		bopd	MBBL
Starting production rate	96.3		Avg first production (1st month)	98.1	
			Avg Production from 2 to 12 months	76.1	
Rate after 84 months	13.6		Rate after 84 months	12.7	
Cumulative production after 84 months		108.2	Cumulative production after 84 months		107.2

Table 11

Well L

DMSF	**0.8**				
BHP	**20**	**psi**			
RESMOD results			**Actual well performance**		
	bopd	MBBL		bopd	MBBL
			Avg first production (1st month)	57.6	
Starting production rate	30.3		Avg Production from 2 to 4 months	36.4	
Rate after 114 months	2.1		Rate after 112 months	4.3	
Cumulative production after 114 months		37	Cumulative production after 112 months		36.5

Table 12

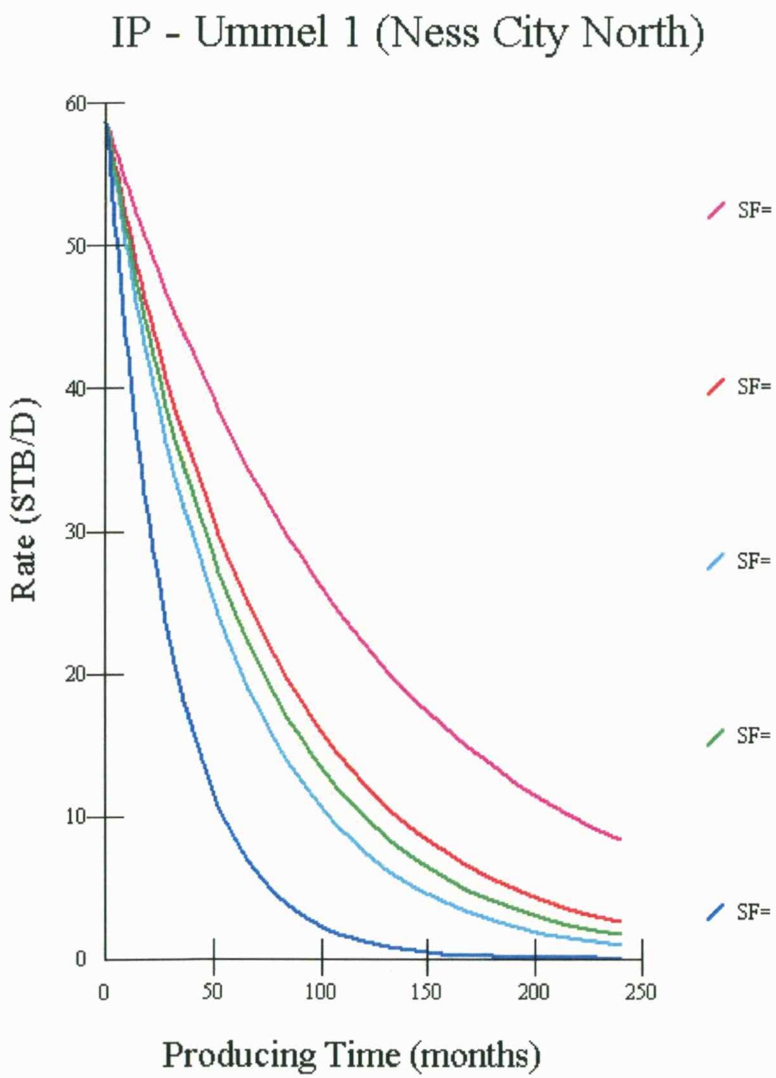
	Base	Well length Low	Well length High	BHP Low	BHP High	Skin Low	Skin High	DMSF Low	DMSF High	Initial oil sat Low	Initial oil sat High
External Drainage radius (ft)	600										
Formation Thickness (ft)	7										
Horizontal K (md)	10										
Vertical K (md)	1										
Porosity (%)	20										
External Drainage Pressure (psi)	1050										
Oil Viscosty (cP)	1.1										
Initial Oil saturation (%)	55									50	60
Formation volume factor (rb/stb)	1.04										
DMSF	0.8							0.6	0.9		
Skin	2					1	3				
BHP	300			200	400						
Residual oil saturation (%)	30										
Well radius, inch	3.5										
Well length, ft	500	400	600								
IP, bbl/d	150	131	168	170	130	167	136	150	150	150	150
Life of well, months	40	44	40	36	44	36	44	32	44	32	48
Cumulative recovery, Mbl	59.3	57.7	62	59.5	58.8	59.4	59.3	48.9	64.5	47.8	71.2

	Base	Res Pr Low	Res Pr High	Phi Low	Phi High	Permeability Low	Permeability High	Pay Low	Pay High	Drainage radius Low	Drainage radius High
External Drainage radius (ft)	600									500	700
Formation Thickness (ft)	7							6	8		
Horizontal K (md)	10					7	30				
Vertical K (md)	1					0.7	3				
Porosity (%)	20			18	22						
External Drainage Pressure (psi)	1050	900	1150								
Oil Viscosty (cP)	1.1										
Initial Oil saturation (%)	55										
Formation volume factor (rb/stb)	1.04										
DMSF	0.8										
Skin	2										
BHP	300										
Residual oil saturation (%)	30										
Well radius, inch	3.5										
Well length, ft	500										
IP, bbl/d	150	120	170	150	150	105	450	130	170	165	139
Life of well, months	40	48	36	36	44	52	18	40	44	28	60
Cumulative recovery, Mbl	59.3	58.9	59.5	53.4	65.3	58.3	61.5	51	68.7	43	79.7

Table 13

Change in	From	To	Cum, Mbbl From	Cum, Mbbl To	% change
Drainage radius, ft	500	700	43	79.7	85.3
Initial oil saturation, %	50	60	47.8	71.2	49.0
Pay, ft	6	8	51	68.7	34.7
Porosity, %	18	22	53.4	65.3	22.3
DMSF	0.7	0.9	54.1	64.5	19.2
Well length, ft	400	600	57.7	62	7.5
Permeability, md	7	30	58.3	61.5	5.5
External drainage pressure, psi	900	1150	58.9	59.5	1.0
Skin	1	3	59.4	59.3	-0.2
BHP, psi	200	400	59.5	58.8	-1.2

Figure 1


IP - Ummel 1 (Ness City North)
60
50
40
30
20
10
0
Rate (STB/D)
0
50
100
150
200
250
Producing Time (months)
SF=
SF=
SF=
SF=
SF=

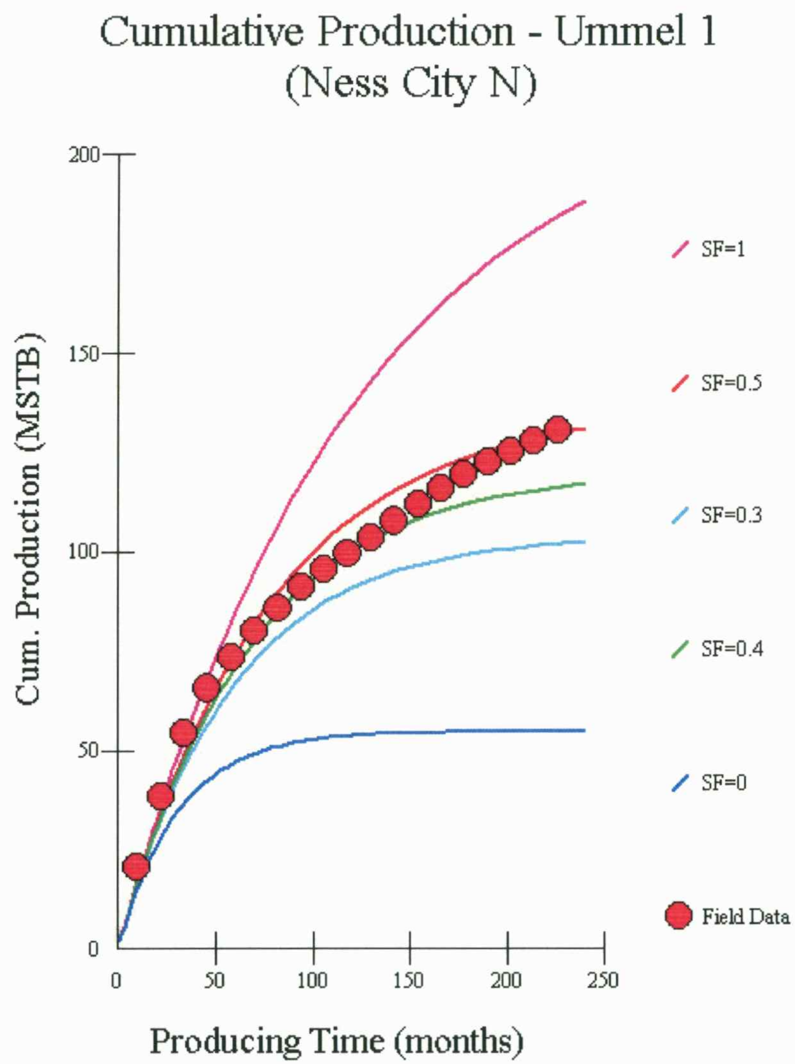
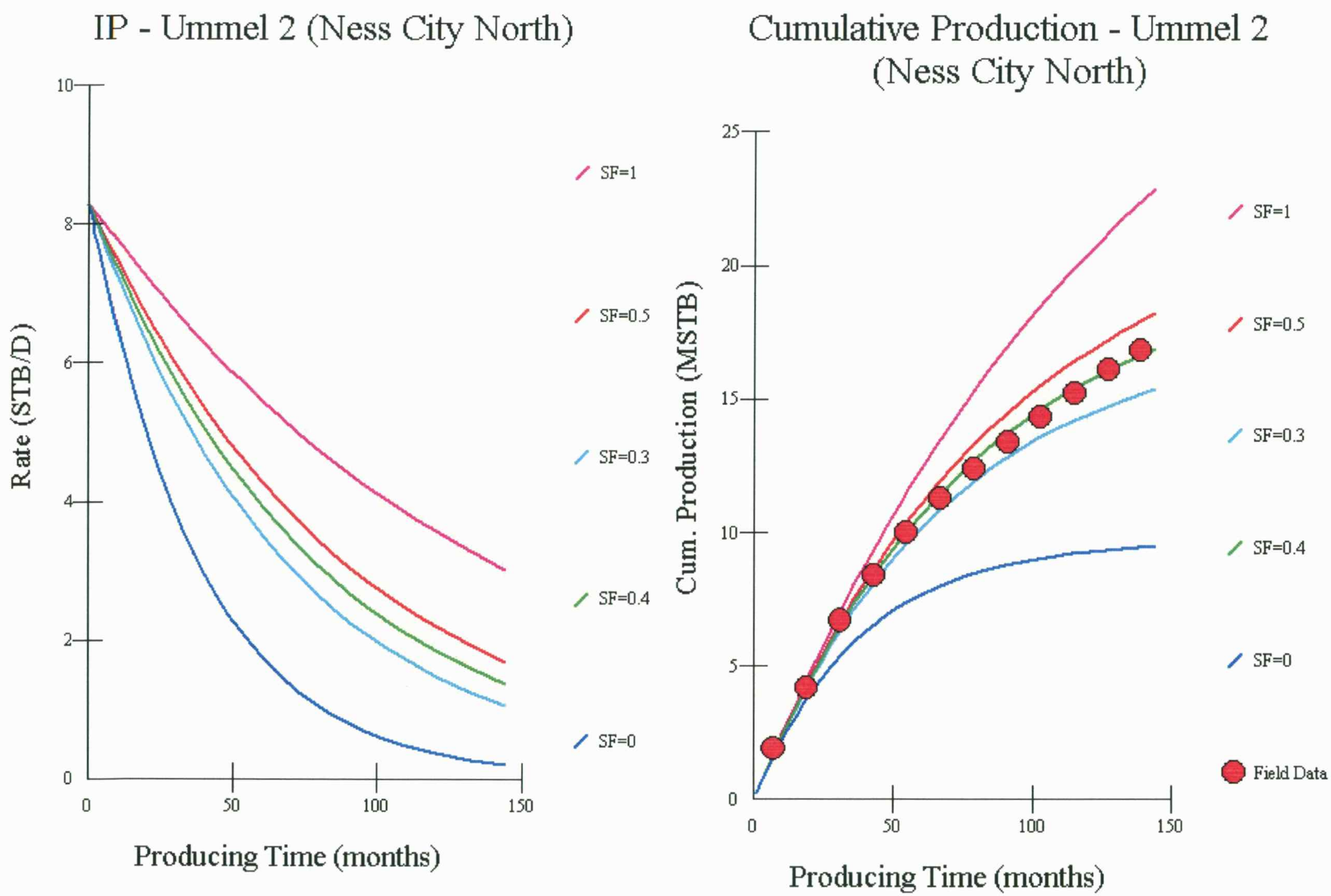
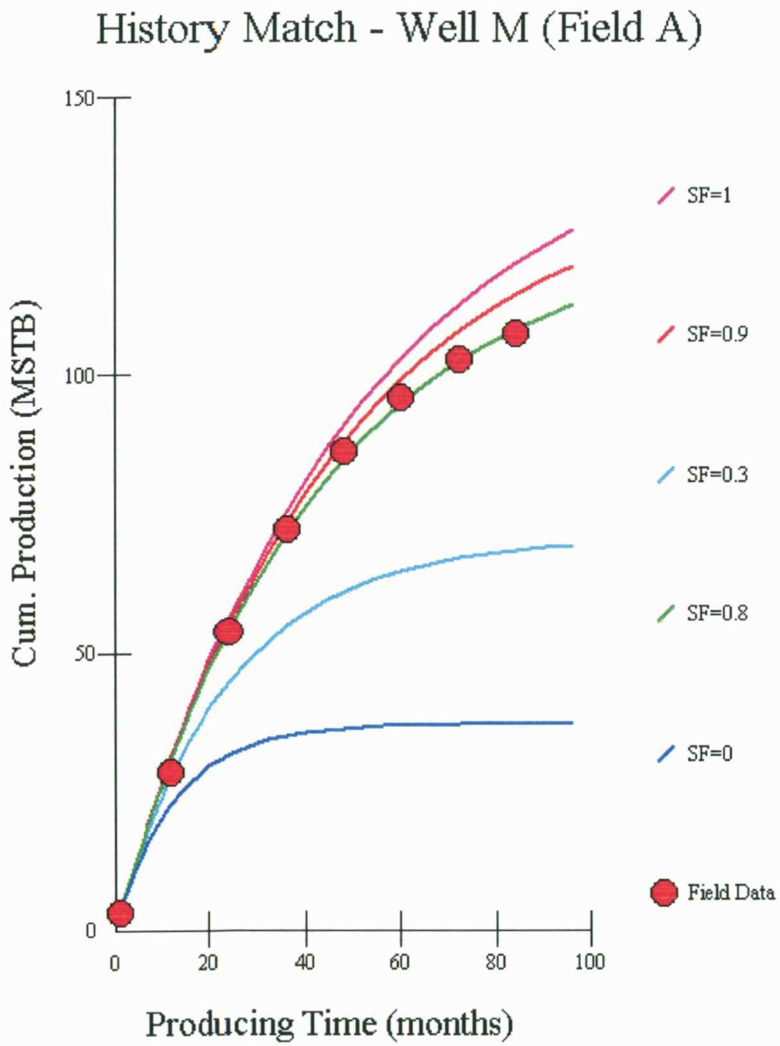

Cumulative Production - Ummel 1
(Ness City N)
200
150
100
50
0
Cum. Production (MSTB)
0
50
100
150
200
250
Producing Time (months)
SF=1
SF=0.5
SF=0.3
SF=0.4
SF=0
Field Data

Figure 2



IP - Ummel 2 (Ness City North)
Rate (STB/D)
10
8
6
4
2
0
0
50
100
150
Producing Time (months)
SF=1
SF=0.5
SF=0.3
SF=0.4
SF=0
Cumulative Production - Ummel 2 (Ness City North)
Cum. Production (MSTB)
25
20
15
10
5
0
0
50
100
150
Producing Time (months)
SF=1
SF=0.5
SF=0.3
SF=0.4
SF=0
Field Data

Figure 3


History Match - Well M (Field A)
Cum. Production (MSTB)
150
100
50
0
0
20
40
60
80
100
Producing Time (months)
SF=1
SF=0.9
SF=0.3
SF=0.8
SF=0
Field Data

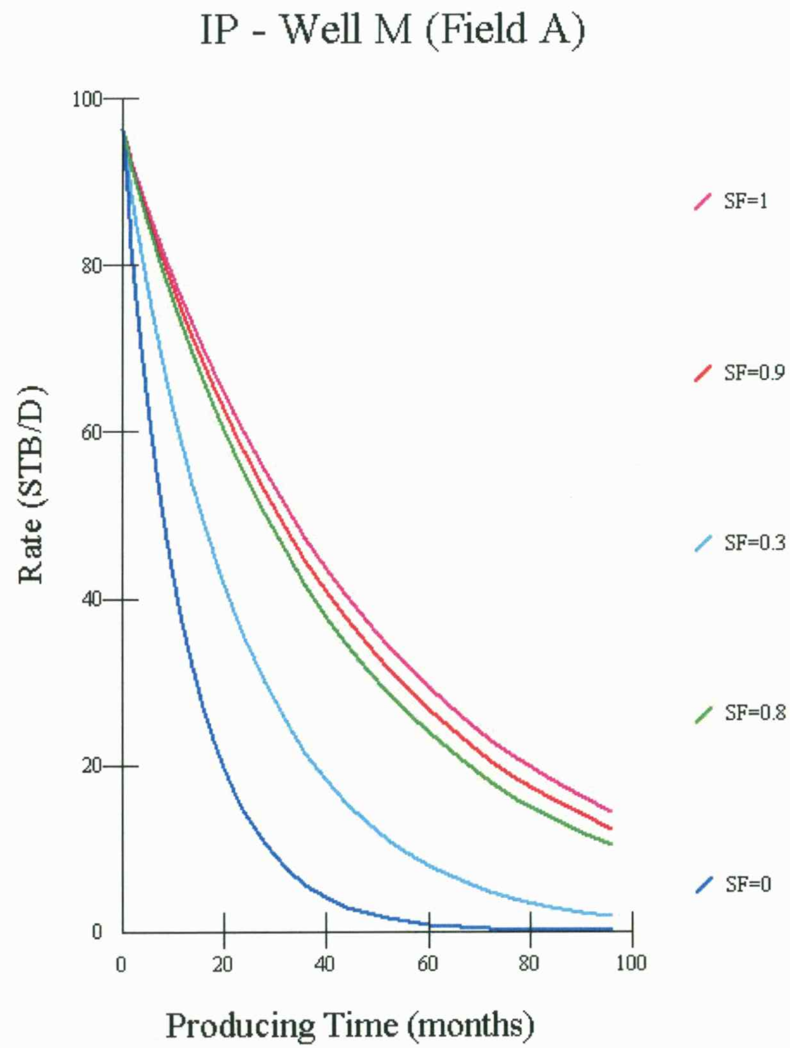
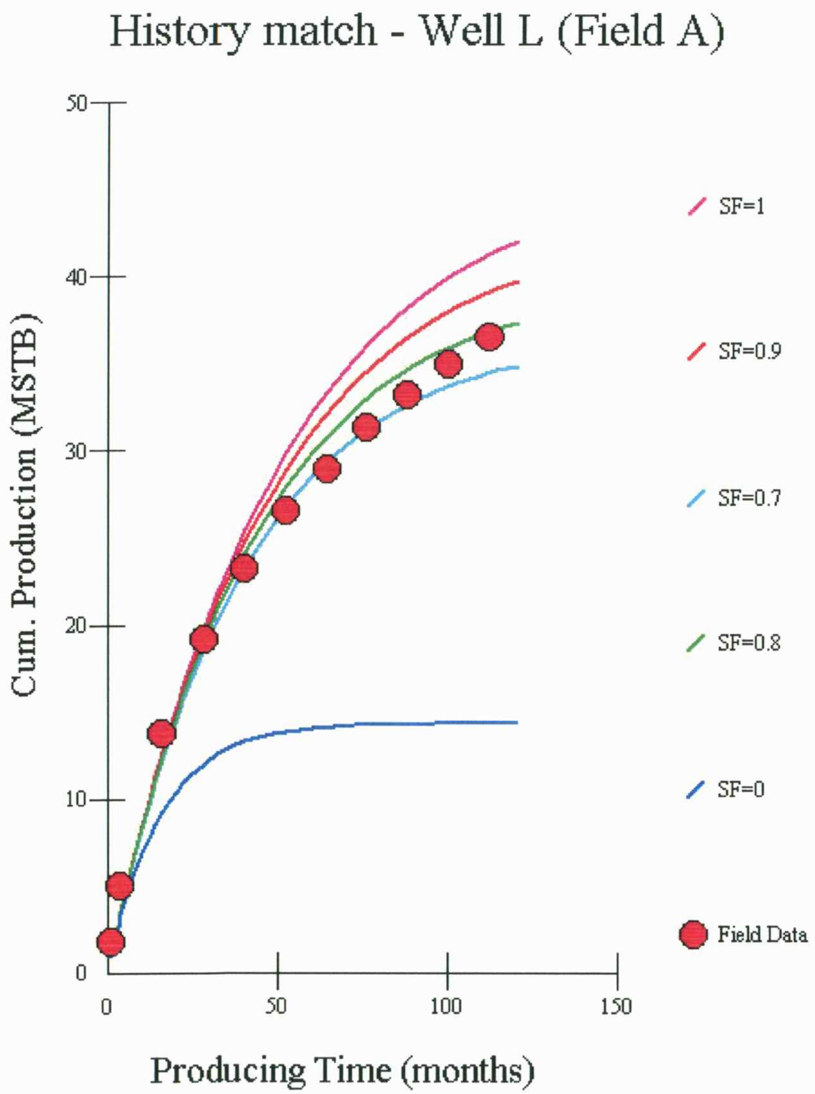
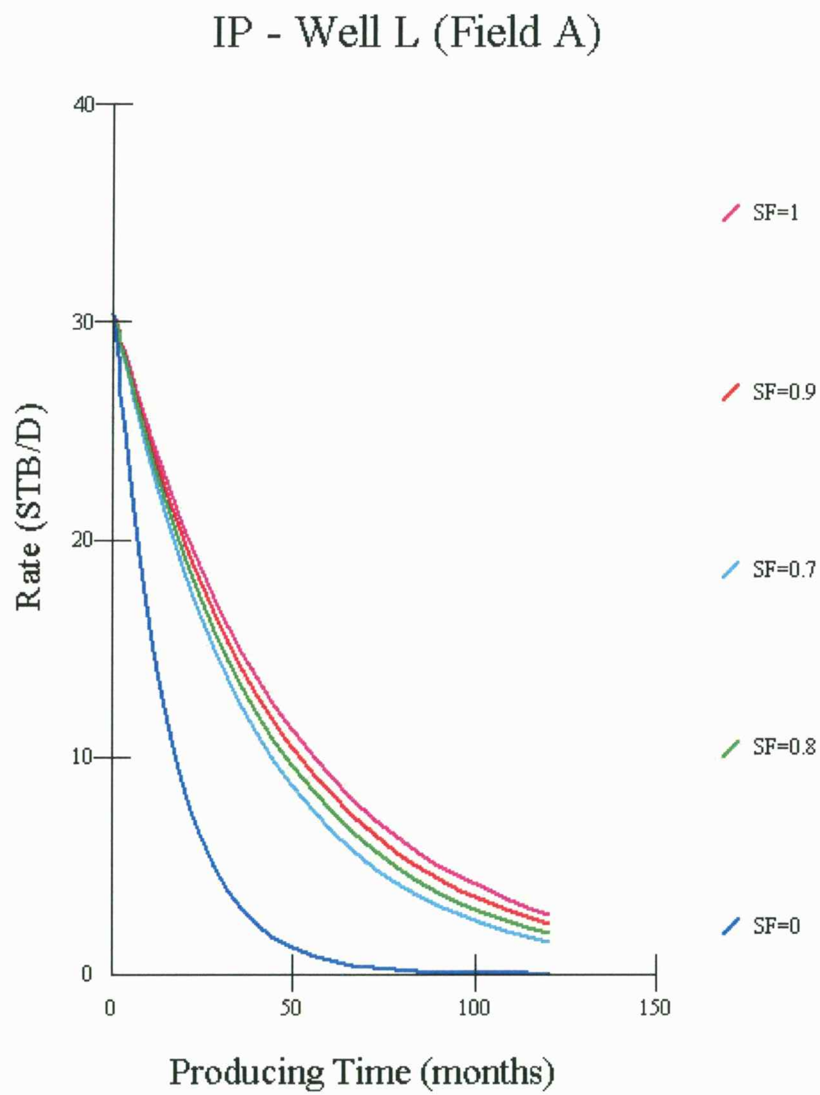

IP - Well M (Field A)
Rate (STB/D)
100
80
60
40
20
0
0
20
40
60
80
100
Producing Time (months)
SF=1
SF=0.9
SF=0.3
SF=0.8
SF=0

Figure 4


History match - Well L (Field A)
Cum. Production (MSTB)
50
40
30
20
10
0
0
50
100
150
Producing Time (months)
SF=1
SF=0.9
SF=0.7
SF=0.8
SF=0
Field Data


IP - Well L (Field A)
Rate (STB/D)
40
30
20
10
0
0
50
100
150
Producing Time (months)
SF=1
SF=0.9
SF=0.7
SF=0.8
SF=0