Optimization of Well Rates under Gas Coning Conditions

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Presents an algorithm which minimizes field gas-oil ratio when wells are coning.

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SUMMARY

This paper develops a method for optimizing well rates when wells are coning gas and field rates are constrained. Since each well's GOR depends on its rate, then well rates must be individually specified. This method maximizes field oil rate when gas rate is fixed and minimizes field gas rate when oil rate is fixed. The method can be used for (1) field operation, (2) reservoir simulation forecasting, or (3) simple material balance applications (as shown in the paper).

INTRODUCTION

Optimization of well rates involves the allocation of rates to individual wells while, perhaps, maximizing field oil rate or minimizing field gas rate. When a well is operating under gas coning conditions (above the critical rate), its gas-oil ratio (GOR) depends upon its rate. In order to optimize rates for a group of wells, it is necessary to relate the GOR of each well to its rate.

Addington[1] published the first practical method for calculating a GOR for wells producing gas above the critical rate. Most previous work on well coning has been directed at determining critical rates, but failed to predict the GOR above the critical rate. Addington presented a method for use in conjunction with reservoir simulation. His method is useful for any rate and level of gas-oil contact (GOC). The GOC changes with time and is computed during the simulation.

Killough and Foster[2] introduced the procedure in the Abo Field that Addington would later use for Prudhoe Bay. They modeled gas production in a field constrained by gas plant capacity. Their procedure met the gas constraint by shutting in the highest GOR wells first. Killough, *et al.*[3] used Addington's method in simulating the Prudhoe Bay Field. Their simulator's well and field management routine optimized oil rate by applying well, facility, and field constraints. Again, their routine shut in the highest GOR wells first, until the gas constraint was met.

Several authors[4-6] have addressed the optimization of gas lift operations. This optimization involves maximizing oil rates on either an economic basis or a constrained gas lift injection rate basis. Their problems and methods are somewhat related to the gas coning problem. Kanu[5] introduced the "equal slope" method for optimizing economic return on gas lift injection. These authors only addressed the gas lift optimization at a particular moment in time. However, their techniques could easily be adapted to reservoir simulation with well and operating conditions changing with time.

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The current work considers the rate dependency of GOR under coning conditions and its effect on field GOR.[7] The objective is to develop a general algorithm for allocating rates to individual wells at any particular time. The result of this optimization is equivalent to the minimization of field GOR.

MATHEMATICAL FORMULATION OF THE PROBLEM

Consider an oil field with a gas cap. Each well near the gas cap is capable of gas coning if produced above its critical rate. Each well's GOR is rate dependent above its critical rate. In other words, $q_{gi} = f(q_{oi})$, and can be represented by some coning relationship for each well.

The complicated part of the problem, of course, is determining the relationship between gas rate and oil rate for each well. These relationships change with time. If forecasting is required, these changes must be determined. This requires modelling the reservoir behavior.

Early in the life of the field, it is expected that field oil rate will meet the pipeline capacity, $(q_o)_{max}$. Then field gas rate should be minimized. Later, wells will tend to cone and well GORs increase. When the field gas rate reaches the plant capacity (or pipeline capacity), $(q_g)_{max}$, then the field oil rate will be curtailed. During this later time, field oil rate should be maximized. This optimization applies at any particular time.

Now consider that (1) oil has a high value, (2) gas has no market, but instead represents a relatively small cost, (3) the field oil rate is constrained by a maximum rate, $(q_o)_{max}$, such as pipeline capacity, and (4) the field gas rate is constrained by a maximum rate, $(q_g)_{max}$, such as plant capacity. Then the optimization problem can be stated as follows:

$$\text{Maximize } \Sigma\, q_{oi} - \varepsilon\, \Sigma\, (q_g)_i \qquad \ldots\ldots (1)$$

Subject to the constraints:

$$\Sigma\, (q_o)_i \leq (q_o)_{max} \qquad \ldots\ldots (2)$$

$$\Sigma\, (q_g)_i \leq (q_g)_{max} \qquad \ldots\ldots (3)$$

This optimization applies at any time. When forecasting, these conditions must be satisfied at all times, for example each timestep in a simulation or material balance calculation. Meanwhile, each well's GOR relationship is continually changing. (It is assumed that ultimate recovery is not rate sensitive for this problem, so there is no "global" optimization other than maintaining the optimization at all timesteps.)

The problem described here is similar to the Prudhoe Bay Field and certain other fields located overseas.

Optimization Criterion

The development of an optimization algorithm requires that the optimal solution be recognized by some criterion. The following criterion, when satisfied, allocates rates to each well in order to meet the constraints:

$$\left(\frac{dq_g}{dq_o}\right)_i = \left(\frac{dq_g}{dq_o}\right)_j \quad ; \; i,j = 1, \cdots ,n \qquad \ldots\ldots (4)$$

This criterion is found using an iteration procedure. It should be pointed out that $(dq_g/dq_o)_i$ is a derivative and not the same as a GOR. This derivative shows the change in the gas rate with respect to an incremental change in the oil rate, and is a function of rate under coning conditions.

Without further justification, lets consider a "demonstration" of this optimal condition. Consider two wells coning gas with the following derivatives:

$$\left(\frac{dq_g}{dq_o}\right) = 583 \quad \text{scf/STB}$$

$$\left(\frac{dq_g}{dq_o}\right) = 565 \quad \text{scf/STB}$$

Shifting an incremental amount of oil, dq_o = 1 STB/D, from the first well to the second well results in an 18 scf/D reduction in the total gas rate. This is calculated as follows:

$(583 - 565)(1) = 18$ scf/D

Whenever the two derivatives are unequal, such a shift of rates reduces the total gas rate while maintaining the total oil rate. The derivatives themselves depend on rate, and must be recalculated after each shift. The shifts in oil rate are continued on a trial and error basis until the derivatives for both wells are equal. Then the optimal rate allocation has been achieved.

This procedure and optimal condition apply for any number of wells. It also applies to maximization of oil rate when gas rate is held constant. In either case, the field GOR is minimized.

The Coning Optimization Algorithm

This algorithm satisfies the optimization problem stated in Eqs. 1, 2, and 3. Each well's total rate is adjusted until Eq. 4 is satisfied for all wells. A method must be available to compute each well's GOR at a specified rate. (In our model, we used the Addington method to find a well's GOR, as in the Appendix.)

The algorithm is as follows for each timestep:

1. Start with the wells' total rates, $(q_t)_i$, from the previous timestep.
2. Determine the wells' oil and gas rates, $(q_o)_i$ and $(q_g)_i$, from their total rate, $(q_t)_i$, and a GOR vs. rate relationship.
3. Calculate the individual derivatives $(dq_g/dq_o)_i$ (using finite difference), and the average derivative $(dq_g/dq_o)_{avg}$.
4. Determine the departure of each well's derivative from the average derivative: $err_i = (dq_g/dq_o)_i - (dq_g/dq_o)_{avg}$.
5. If the maximum absolute departure is less than a preset tolerance, then STOP: Otherwise,
6. Adjust each well's rate by iterating on $(q_t)_i$ within its preset range:
   a. If $(dq_g/dq_o)_i < (dq_g/dq_o)_{avg}$, then increase that well's rate until $(dq_g/dq_o)_i = (dq_g/dq_o)_{avg}$.
   b. If $(dq_g/dq_o)_i > (dq_g/dq_o)_{avg}$, then decrease that well's rate until $(dq_g/dq_o)_i = (dq_g/dq_o)_{avg}$.
7. Determine new $(q_o)_i$ and $(q_g)_i$ for the wells at their new values of $(q_t)_i$. Then, calculate either the ratio $[\Sigma\, (q_o)_i \,/\, (q_o)_{max}]$ or, $[\Sigma\, (q_g)_i \,/\, (q_g)_{max}]$, subject to the controlling constraint.
8. Multiply the wells' $(q_t)_i$ by this ratio to force the sum of their rates to converge to the maximum field rate.
9. Go to step 2.

Steps 2 through 5 determine the derivatives and test the convergence. Step 6 adjusts the well rates until the derivatives are equal. Steps 7 and 8 force the sum of the wells rates to satisfy one of the maximum field production constraints, Eqs. 2 or 3. It is assumed, in the above algorithm, that GOR increases monotonically with rate, Fig. 1. If this were not true, the algorithm would require modification.

A DEMONSTRATION MODEL FOR CONING OPTIMIZATION

A computation model was developed to demonstrate the coning optimization algorithm. The model combined (1) the Addington Method for calculating GORs, (2) a "vertical tank" material balance model to calculate the GOC level, and (3) the optimization algorithm just presented.

Addington[1] developed a method for calculating the GOR of a well under coning conditions. Although he used his method in a 3-D simulator, it was also suitable for our vertical tank model. Fig. 1 shows an example of a rate sensitive GOR that might be computed using his method. The GOC level, for each timestep, was determined from the material balance model. This level was affected by previous production, but was always assumed to be horizontal. Fig. 2 shows the heights and volumes as related to the initial GOC for the material balance in a reservoir with arbitrary geometry. (Pore volume is a function of elevation.)

The computation was carried out in a timestep fashion, much like a reservoir simulator. The coning optimization algorithm was applied at the end of each timestep to determine the optimal allocation of well rates.

Description of Test Cases

Three test cases are presented as demonstrations. The first case has two wells in a horizontal reservoir to demonstrate the principles of optimization of well rate during gas coning. The next two cases represent a field situation with twenty wells in a dipping reservoir for optimal and non-optimal production strategies. These cases have been compiled from the information obtained from Refs. [1 and 8]. The non-optimal strategy reflects the normal field practice of shutting in the highest GOR wells first. Tables 1, 2, and 3 give the input data used for each of the three cases, including the following: (1) reservoir properties, (2) fluid properties, (3) well parameters, and (4) the pore volume as a function of depth.

Two Wells. This case demonstrates how the optimization affects performance. Table 2 shows the first well is perforated closer to the GOC than the second well. The maximum field rates for oil and gas are 20,000 STB/D and 18,000 Mscf/D, respectively. The wells' initial rates are assigned by the optimization procedure during the first timestep.

Twenty Wells - Optimal Production Strategy. The next two cases represent a field scenario. The wells are completed on 160 acre spacings. Fig. 3 shows both an areal perspective and a cross-sectional view of the well locations. The reservoir dips one degree from the lower left-hand corner to the upper right-hand corner. The reservoir is 550 feet thick with the GOC spanning horizontally across the model as displayed in Tables 1 and 3. The reservoir properties remain the same as above with the exception of the horizontal permeability.

Since the reservoir is dipping, pore volume vs. elevation is entered as a table. These wells are perforated 25 feet off the bottom of the reservoir, causing F_1 to change (F_1 is the geometric factor related to the perforation location). The maximum field rates for the oil and gas are 73,000 STB/D and 95,000 Mscf/D, respectively. The initial well rates are randomly set between 2,000 and 16,000 RB/D, as seen in Table 3.

Non-Optimal Production Strategy. This case (uses the same data) demonstrates an alternative production strategy. It represents the field (management) practice of shutting in a well when its GOR exceeds 10,000 scf/STB. The remaining well rates are proportionally adjusted to maintain the maximum field rates (Eqs. 2 and 3) for each timestep.

DISCUSSION OF RESULTS

The results of this work are in the form of computer runs. These runs produce a series of time plots of the field and well rates. Fig. 4 shows the field rates for the first case (which are the sums of the well production rates for the oil and gas), whereas, Figs. 5 and 6 compare the individual well rates to the field rate for oil and gas, respectively. The following discussion explains the five production phases associated with the field optimization, as seen in Table 4. The optimization procedure minimizes the field gas rate in Phases I, II, and III, and maximizes the field oil rate in Phases IV and V.

Phase I: The rates are arbitrarily set for each well prior to gas coning. None of the wells are above nor near their critical rates. The optimization procedure assigns rates to minimize the field rate for gas while keeping the oil pipeline full. Fig. 5 confirms the oil rates equals the maximum field rate for oil. The field GOR remains at the solution-gas ratio.

Phase II: The first well is on the verge of coning gas while the other well remains below its critical rate. Fig. 5 shows this as a decrease in the first well's oil rate and increase in the second well's. The optimization procedure prevents coning by shifting the oil production between wells to maintain the maximum field rate for oil. There is sufficient slack in the second well's oil rate to raise it without exceeding its critical rate, thereby compensating for the lost oil production from the first well. In Fig. 4, the field GOR remains constant at the solution-gas ratio.

Phase III: Now, both wells are on the verge of coning. The optimization procedure adjusts the well rates to minimize the field gas rate. Figs. 4 and 6 show the field gas rate increasing, while Fig. 5 shows that the second well's oil rate increasing to make up for the lost production from the first well.

Phase IV: Both wells are coning. The optimization procedure switches to maximizing the field oil rate. Fig. 4 shows that as field oil rate declines, the field gas rate remains constant at the gas plant's capacity. The optimal conditions are achieved when the derivatives are equal. In Fig. 6, the optimization procedure decreases the first well's gas rate while only slightly increasing the second well.

Phase V: The first well shuts in as the GOC reaches its perforations (Figs. 5 and 6). The optimization procedure continues to maximize the oil rate even though the second well is above its critical rate. The optimization makes up for the lost oil production by increasing the second well's gas rate.

Twenty Well - Optimal Production Strategy

The optimization procedure is extended to a larger problem. Fig. 7 displays the field performance for twenty wells. All five phases are contained in Fig. 7. The optimization procedure minimizes the field gas rate in the first three phases and maximizes the oil rate in the last two phases by shifting the oil production from the high GOR wells to the low GOR wells. Wells are shut-in when the GOC reaches the top of the perforations. After 60 years, eight wells have shut in.

Non-Optimal Production Strategy

Production is adjusted using either Eqs. 2 and 3, instead of using Eq. 4 to optimize. Fig. 8 shows the field performance of the non-optimal strategy overlain on top of optimal strategy's results. It is easy to see that the ultimate recovery is lower for the non-optimal strategy than for the optimal strategy. The oil production is at the maximum field rate for 4.7 years, and it starts an earlier decline, resulting in lost oil production. In the 32th year, the non-optimal strategy's field production ceases when the final well exceeds the GOR limit (10,000 Mscf/D). More oil is lost because of the early shut in of the wells.

Fig. 9 displays the cumulative oil and gas production for both cases. Comparing the ultimate recoveries after 20 years shows the optimal case produced +11% more oil and -13% less gas. The optimal strategy's wells continues to produce long after the non-optimal strategy's wells have shut in.

Extension to Other Simulations

The Addington Method has been used in Prudhoe Bay and in the Middle East. The Addington Method and variations of the optimization procedure can be easily added to the well management routine of any 3-D finite difference simulator. The optimization procedure can use well rates from any rate dependant coning method or actual well test data.

CONCLUSIONS

1. Under coning conditions at any time, the optimal rates are achieved when Eq. 4 is satisfied for all wells not constrained by individual well limits:

$$\left(\frac{dq_g}{dq_o}\right)_i = \left(\frac{dq_g}{dq_o}\right)_j \quad ; \; i,j = 1, \cdots, n$$

2. Otimal model produced 11% more oil than the non-optimal model for the test case at 20 years.
3. The optimization algorithm can be added to the well management routine of any 3-D finite difference simulator to optimiize simulated well rates.
4. The optimization algorithm can optimize actual field rates using well test data rather than the Addington Method.

NOMENCLATURE

B_g = Gas formation volume factor, RB/scf
B_o = Oil formation volume factor, RB/STB
B_w = Water formation volume factor, RB/STB
F_{wo} = Water-oil ratio, STB/STB
F_1 = $h_p + h_{ap} / h_{oi}$, Geometric factor, fraction
F_2 = Well spacing factor, fraction
F_3 = Well spacing factor, fraction
GOC= Gas-oil contact
h_{ap} = Average oil column height above perforations, ft
h_{bp} = Average oil column height below perforations, ft
h_{gb} = Average oil column height above perforations at gas break through, ft
h_{inv} = Effective height of gas invasion, ft
h_{oi} = Initial oil column height, ft
h_p = Perforation thickness, ft
h_t = Total height, ft
k_H = Horizontal permeability, md
k_V = Vertical permeability, md
m_{BT} = GOR slope after gas breakthrough, ft^{-1}
q_g = Gas rate, Mscf/D

q_o = Oil rate, STB/D
q_w = Water rate, STB/D
q_t = Total reservoir rate, RB/D
R_p = Gas-oil ratio, scf/STB
R_s = Solution gas ratio, scf/STB
$\bar{S}_o$ = Average oil saturation, fraction
$\bar{S}_w$ = Average water saturation, fraction
S_g = Gas saturation, fraction
S_{gc} = Critical gas saturation, fraction
S_o = Oil saturation, fraction
S_{or} = Residual oil saturation, fraction
S_{iw} = Connate water saturation, fraction
V_{pin} = Gas invaded pore volume, MMRCF
V_{poi} = Initial pore volume filled with oil, MMRCF
V_{pt} = Total reservoir pore volume, MMRCF
Z = Elevation, ft
ϕ = Porosity, fraction
μ_o = Oil viscosity, cp
ε = Arbitrarily small constant << 1, STB/Mscf

Subscripts:
c = Critical (well rate)
i = Well index
i = Initial
j = Well index
max = maximum (field rate)
n = Number of wells

SI Metric Conversion Factors:

bbl	X	1.589 873	E-01	=	m³
cp	X	1.0	E-01	=	Pa·s
ft	X	3.048	E-01	=	m
ft³	X	2.831 685	E-02	=	m³
md	X	9.869 233	E-04	=	μm²

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APPENDIX - THE DEMONSTRATION MODEL

This Appendix shows the details of the demonstration model. It should not be thought that the principles of the gas coning optimization is limited to the following assumed relationships.

Addington's Coning Method

Addington[1] presented a method for calculating GOR for a well: determined from the current reservoir conditions, such as the GOC elevation and other parameters. His method was based on correlations developed from the results of coning simulation runs. This method was developed specifically for the Prudhoe Bay field, but has been found to apply to other fields which have similar properties, mainly high permeability. The following discussion demonstrates how three calculations are used to determine production rate and the associated derivative.

Gas/Oil Ratio

The GOR is determined in Eq. A-1 from the total rate and the well parameters in Eqs. A-2 and A-3 along with a material balance:

$$R_p = R_s \exp[2.303\ m_{BT}(h_{gb} - h_{ap})] \qquad \text{...... (A-1)}$$

The term h_{ap} is defined as the height above the perforations to the GOC. It changes with time, of course, and must be determined by material balance or simulation. h_{gb} and m_{BT} are empirical variables which are developed for each well. They are a function of total rate:

$$h_{gb} = 137.9[q_t\,(k_V/k_H)^{0.1}\,\mu_o\,F_1\,F_2/k_H(h_p)^{0.5}]^{0.429} \qquad \text{...... (A-2)}$$

$$m_{BT} = 0.00905[q_t\,(k_V/k_H)^{0.5}\,\mu_o\,F_1\,F_3/k_H(h_p)^{0.5}]^{-0.307} \qquad \text{...... (A-3)}$$

The numerical values in Eqs. A-2 and A-3 were developed for the Prudhoe Bay field and were used in our model. Both of these equations are functions of q_t, making GOR rate dependent.

Material Balance for the Calculation of h_{ap}

The demonstration model uses a material balance to calculate the GOC level at each timestep. The basic assumptions are that (1) the oil is displaced by gas in piston-like displacement, and (2) the GOC is horizontal.

For a reservoir with an arbitrary geometry and multiple wells (i.e. the vertical tank model), Fig. 2 shows how a well's height of invasion, h_{inv}, relates to its height above perforation of the GOC, h_{ap}. The vertical tank model contains three regions: the gas cap, the gas invaded zone, and the oil column. Performing an oil material balance around these three regions gives the following equation:

$$\bar{S}_o V_{pt} = (V_{pt}-V_{poi})0.0 + V_{pinv}S_{or} + (V_{poi}-V_{pinv})(1-\bar{S}_w-S_{gc}) \qquad \text{... (A-4)}$$

The average oil saturation, $\bar{S}_o$, is determined from the pore volume-weighted oil saturation. Rearranging Eq. A-4 in terms of the volume of gas invasion, V_{pinv}, yields:

$$V_{pinv} = \frac{\bar{S}_o V_{pt} - V_{poi}\left(1 - \bar{S}_w - S_{gc}\right)}{1 - \bar{S}_w - S_{gc} - S_{or}} \qquad \text{...... (A-5)}$$

The height of invasion, h_{inv}, is found from a table of pore volumes. The average oil column height above perforations for each well is given by:

$$h_{ap} = h_{oi} - h_{inv} - h_p - h_{bp} \qquad \text{...... (A-6)}$$

A well's h_{ap} is adjusted each timestep to reflect the changing GOC level, and wells are shut in when the GOC falls below the top of their perforations.

Rate Calculation

The total rate (reservoir volumetric), q_t, is defined as:

$$q_t = q_o B_o + (q_g - q_o R_s) B_g + q_w B_w \qquad \text{...... (A-7)}$$

which can be rearranged to give a simple expression of q_o, once the R_p has been determined.

$$q_o = \frac{q_t}{B_o + (R_p - R_s) + B_w F_{wo}} \qquad \text{...... (A-8)}$$

The procedure for using this method in our algorithm is as follows: (1) specify q_t, (2) calculate R_p, (3) calculate q_o and q_g, (4) repeat for a small increment in q_t to determine (dq_g/dq_o).

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TABLE 1 - RESERVOIR, FLUID AND WELL PROPERTIES

Well spacing, acres/well	160
Thickness, h_t, ft	550
Vertical to Horizontal Permeability Ratio, k_v/k_h	0.3
Porosity, ϕ, fraction	0.224
Oil FVF, B_o, RB/STB	1.37
Gas FVF, B_g, RB/scf	0.00064
Solution gas-oil ratio, R_s, scf/STB	736
Oil viscosity, μ_o, cp	0.9
Residual oil saturation, S_{or}	0.25
Connate water saturation, S_{iw}	0.19
Critical gas saturation, S_{gc}	0.0
Perforation thickness, h_p, ft	25
Well spacing factor, F_2	1.0
Well spacing factor, F_3	1.0

TABLE 2 - FIELD AND WELL DATA FOR THE FIRST CASE

Maximum Field Rates:	
Oil, $(q_o)_{max}$, STB/D	20,000
Gas, $(q_g)_{max}$, Mscf/D	18,000
Area, acres	320
Original gas cap thichness, ft	200
Original oil in place, MMSTB	115.1
Original gas in place, Bscf	140.8
Total pore volume, V_{pt}, MMRB	305.8
Horizontal permeability, k_H, md	1000
Initial oil column height, h_{oi}, ft	350

Well	Top* ft	Bottom* ft	h_{bp} ft	F_1	q_{ti} RB/D
1	-200	350	125	0.62	7,829
2	-200	350	0	1.00	19,571

	Elevation* ft	Pore Volume MMRCF
	-200	624.88
GOC	0	0.00
	350	1092.83

* Referenced to the initial GOC at 0 ft elevation.

TABLE 3 - FIELD AND WELL DATA FOR THE TWENTY WELL CASES

Maximum Field Rates:	
Oil, $(q_o)_{max}$, STB/D	73,000
Gas, $(q_g)_{max}$, Mscf/D	95,000
Area, acres	3200
Original oil in place, MMSTB	1200.7
Original gas in place, Bscf	1300.6
Total pore volume, V_{pt}, MMRB	3058.4
Horizontal permeability, k_H, md	200
Dip angle, degrees	1.0
Oil column height below perfs, h_{bp}, ft	25

Well	Top* ft	Bottom* ft	h_{oi} ft	F_1	q_{Ti} RB/D
1**	-288	262	262	0.905	2,617
2+	- 70	480	480	0.948	3,171
3	-277	273	273	0.908	2,894
4	-265	285	285	0.912	3,213
5	-254	296	296	0.916	3,523
6	-242	308	308	0.919	3,916
7	-231	319	319	0.922	4,299
8	-219	331	331	0.924	4,739
9	-209	342	342	0.927	5,163
10	-196	354	354	0.929	5,650
11	-185	365	365	0.932	6,118
12	-173	377	377	0.934	6,654
13	-162	388	388	0.936	7,165
14	-150	400	400	0.936	7,750
15	-139	411	411	0.939	8,308
16	-127	423	423	0.941	8,942
17	-116	434	434	0.942	9,547
18	-104	446	446	0.944	1,902
19	- 93	457	457	0.945	2,537
20	- 81	469	469	0.947	1,902

	Elevation* ft	Pore Volume MMRCF
	300	5,770.01
GOC	0	0.00
	250	7,805.95
	275	8,544.17
	300	9,197.70
	325	9,766.53
	350	10,250.66
	375	10,650.09
	400	10,964.83
	425	11,194.87
	450	11,340.21
	475	11,400.85
	480	11,402.83

* Referenced to the initial GOC at 0 ft elvation.
** Highest well
\+ Lowest well

TABLE 4 - THE FIVE PRODUCTION PHASES DURING OPTIMIZATION

Phase #	Condition	Individual well rates	Field oil rate $\Sigma(q_o)_i$	Field gas rate $\Sigma(q_g)_i$	GOR R_p
I	Arbitrary allocation of rates, no coning.	$< (q_o)_c$	$= (q_o)_{max}$	$< (q_g)_{max}$	$= R_s$
II	Arbitrary production with the first well on the verge of coning, no coning.	$\leq (q_o)_c$	$= (q_o)_{max}$	$< (q_g)_{max}$	$= R_s$
III	All wells coning.	$> (q_o)_c$	$= (q_o)_{max}$	$\leq (q_g)_{max}$	$> R_s$
IV	All wells coning.	$> (q_o)_c$	$< (q_o)_{max}$	$= (q_g)_{max}$	$> R_s$
V	All wells coning, the first well shuts in.	$> (q_o)_c$	$< (q_o)_{max}$	$= (q_g)_{max}$	$> R_s$

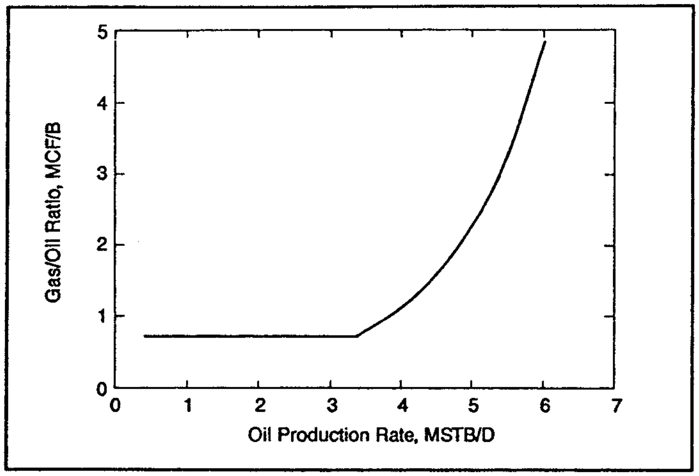

Figure 1 - Influence of production rate on gas/oil ratio

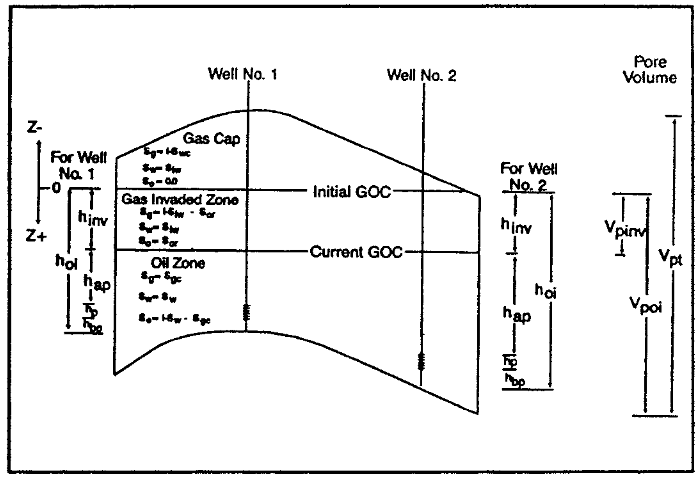

Figure 2 - Schematic of coning correlation calculation for a reservoir with multiple wells and an arbitrary geometry

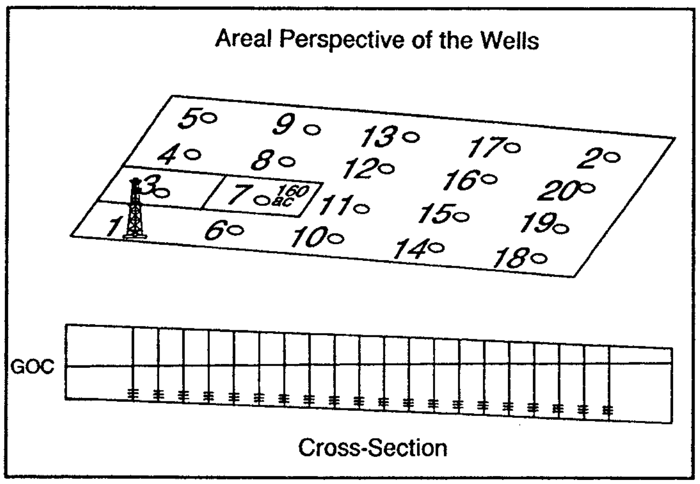

Figure 3 - Well location for cases 2 and 3

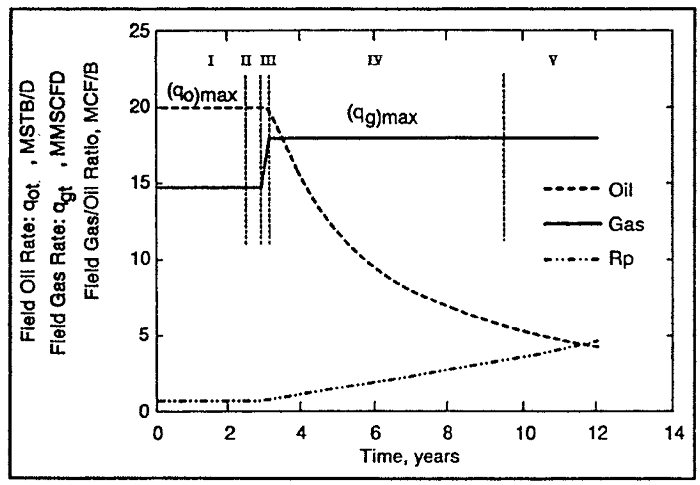

Figure 4 - Field performance for two wells in horizontal reservoir

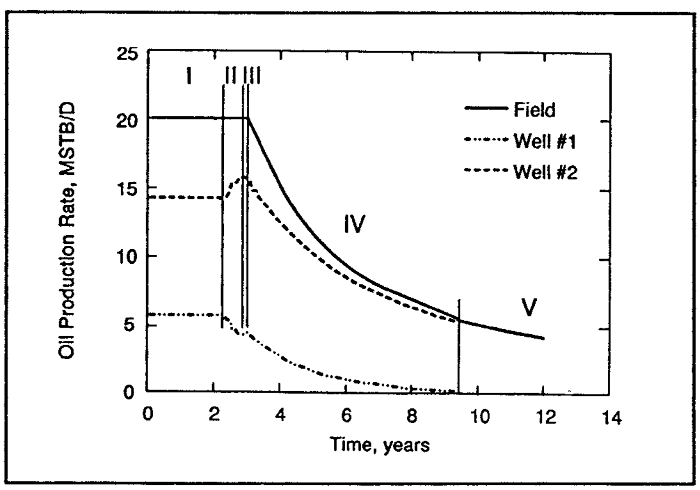

Figure 5 - Comparison of field and well performance for oil in case 1

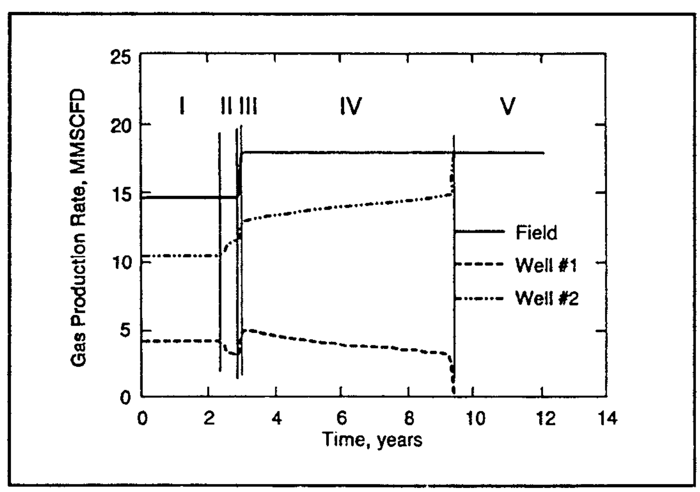

Figure 6 - Comparison of field and well performance for gas in case 1

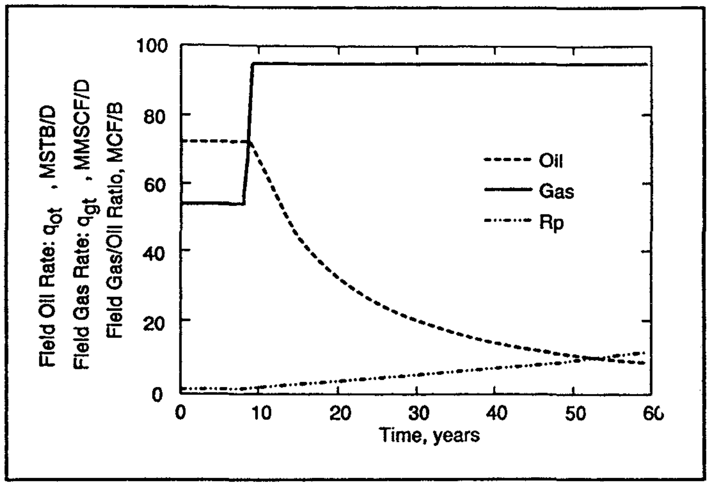

Figure 7 - Field performance for twenty wells in inclined reservoir

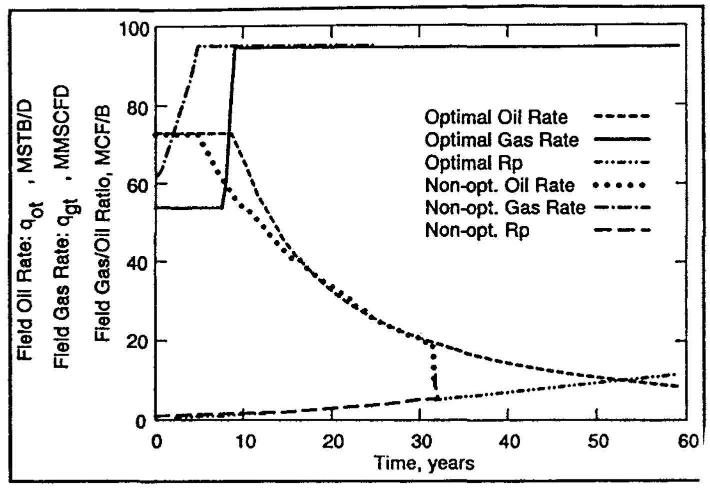

Figure 8 - Comparison of the optimal and non-optimal field performance

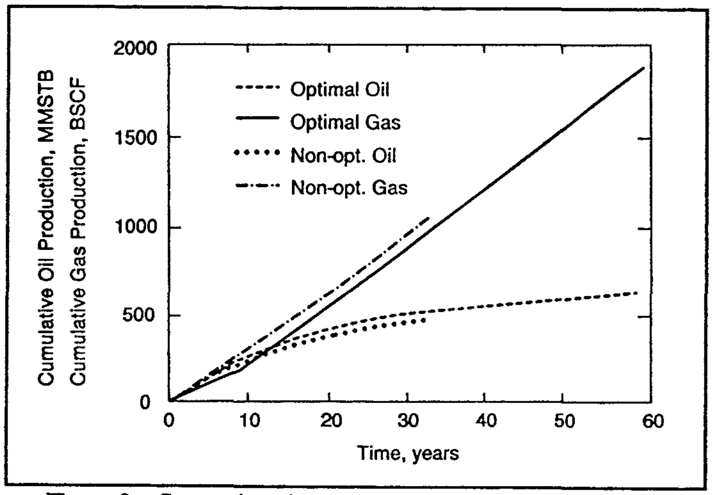

Figure 9 - Comparison between the optimal and non-optimal cumulative production