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Intelligent Completion Systems -- The Reservoir Rationale

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Abstract

Two reservoir displacement scenarios are analyzed, wherein control of downhole flow conditions has a marked effect on production performance. The first relates to depletion of a two-layer gas reservoir disposed toward development of crossflow, and the second relates to control of the injectivity profile in a rate-sensitive waterflood. For each scenario a conceptual control architecture is proposed, and the impact of this architecture on production performance is assessed.

Introduction

Intelligent Completion Systems (ICS) integrate reservoir sensors and remotely controllable inflow/outflow devices deployed permanently in the wellbore. The immediate benefits of such systems relate to minimizing interventions needed to ascertain critical changes and alter downhole flow conditions; this is particularly relevant to offshore operations and subsea developments. Preliminary investigations indicate, however, that tangible benefits may also be realized over a longer horizon through punctuated or periodic modulation of ICS. The present study delineates two relatively generic categories of displacement problems where the deployment of ICS architectures of minimal complexity has a pronounced effect on production performance.

The features of the first category are epitomized by a deepwater gas field consisting of two main producing intervals – a relatively thin permeable interval with Gas-In-Place of 3 TCF, and a relatively thick tight interval with GIP of 7 TCF. The two intervals are separated by a thick layer of shale. The economic feasibility of this project depends largely on reducing the number of wells to be drilled, avoidance of workovers/recompletions, and maximizing production from each well. There are two broad alternatives for field development – exploitation of the top interval only (not tapping 70% of GIP), or the exploitation of the two intervals using dual completion (tubing-limited production), dedicated wells (CAPEX constraint), hydraulic fracturing of the lower interval (aquifer communication), or commingled production (crossflow). *In this context, ICS can be a means to achieve commingled production without crossflow.* This can be achieved by modulating the production of the lower interval to maintain pressure parity with the top interval, which is the more productive interval. Using material balance and nodal techniques we forecast the performance of the reservoir-wellbore system under a state of controlled commingled production. It is observed that a stable plateau of gas production can be achieved, which is in sharp contrast with a declining production if only the top interval is exploited. A simple economic analysis is proposed to quantify the benefits.

The second category relates to the control of the injection profile in a waterflood, such that each zone that is intersected by the completed interval receives an injection volume commensurate with the zone's requisite critical rate. Injection beyond the critical rate results in premature breakthrough of injected water, whereas injection below this rate results in deceleration of the displacement process. The notion of critical rate is based on the interplay of viscous and gravitational forces, and has particular relevance to dipping formations. To illustrate this concept, we compare the performance of a simple waterflood (a tilted two-layer reservoir with one producer and one injector), where in the base case the total injected water partitions naturally and spontaneously between the two layers, and in the other each layer receives an amount equal to its critical rate using a simple ICS architecture. The performance of the two cases is compared in terms of the oil recovery profile, cumulative water production, duration, and NPV characteristics.

The Crossflow Problem

The basic characteristics of the two-layer system are summarized in Table 1. The two layers are considered to be non-communicating; we therefore assume that crossflow can take place only through the wellbore. Figure 1 is a nodal representation of the inflow-outflow characteristics. There are two Inflow Performance Relationship (IPR) curves, one for each layer, both at initial reservoir pressure (6200 psi & 6250 psi), and one Tubing Intake Curve (TIC) corresponding to 51/2" tubing with a TVD of 12500 ft, and wellhead pressure of 4000 psi. The two points of intersection indicate a deliverability of about 95 mmscf/d *if only the top layer is completed*, and 20 mmscf/d *if only the bottom layer is completed.* Production under commingled conditions, however, would not yield the sum of the above rates, as the sandface pressures are distinctly different, 5700 psi for the top layer and 5200 psi for the bottom layer. Initially, therefore, there will be crossflow from the top layer to the bottom layer, with a corresponding reduction in well deliverability. Without delving into the specifics of the crossflow phenomenon, we surmise it is desirable to circumvent the problem of wellbore crossflow.

The ICS architecture proposed consists of an Intelligent Flow Control Device (IFCD) positioned above the bottom layer, and sensors monitoring the pressure of the two layers (see Figure 2). As the top layer is the more productive layer, it will be produced without downhole restriction. The bottom layer can be initially shut-off via the IFCD. The IFCD can then be actuated to allow a phased contribution from the bottom layer, such that a state of equilibrium is attained between the two sandface pressures. The modulation mechanism of the IFCD is non-discrete, hence pressure parity between the two layers can be achieved. (A difference must exist to account for the flowing pressure gradient; this difference can be ascertained within a limit that is dictated by the metrological characteristics of the sensors.) As production proceeds and the pressure of the top interval declines, the IFCD can progressively unchoke the bottom layer. This process can continue until such time that the sandface pressure is no longer sufficient to ensure the minimum required pressure at wellhead, or until the sandface pressure reaches the dew point pressure, or until some prescribed abandonment criterion is met.

What is noteworthy about the outcome of this recursive manipulation is that as the deliverability of the top layer declines, that of the bottom layer rises, producing a relatively constant plateau of gas production from the well (see Figure 3). The bottom layer, in effect, compensates for the decline in the top layer. The reason for this is that the bottom layer maintains an elevated reservoir pressure (due to its larger volume and lower withdrawal rate), and hence yields an increasing deliverability as the well-flowing pressure is reduced. Table 2 summarizes the deliverability forecast from material balance and nodal calculations. Table 3 and Figure 4 present a simplified economic analysis of this problem, comparing commingled production to production from only the top layer. (Sequential production of the top and the bottom layers would prolong the project inordinately and necessitate intervention; it is therefore not considered here.)

The Injectivity Problem

We consider a linear waterflood in a two-layer tilted reservoir with one injector and one producer (see Figures 5-6). Injection takes place in the updip direction. The layers are assumed to be non-communicating. According to the theory of frontal advance (for uniform permeability fields) the displacement is stable if the water-oil mobility ratio is equal to or less than unity, and conditionally stable if $M>1$. The endpoint relative permeability characteristics and viscosities are so chosen to yield a mobility ratio greater than unity ($M=1.2$); this is quite common in waterflood operations. Therefore the displacement is only conditionally stable. This means that if the injection rate is equal to or less than the critical rate, the displacement is stable, and conversely, if the injection rate is in excess of the critical rate, the displacement is unstable. Unstable displacement refers to premature breakthrough of water, or an incomplete or partial sweep of the reservoir when water breakthrough occurs. The reason for this is that at super-critical rates, the viscous forces (governed by the pressure gradient between the injector and the producer) outweigh the gravitational forces, which in this case, with the flood taking place in the updip direction, would tend to retard the movement of the water phase more than the oil phase. Therefore, the balance of viscous and gravitational forces determines whether or not the flood is stable.

Figure 7 summarizes results of Buckley-Leverett[1] calculations (using a commercial software), indicating the oil recovery at breakthrough for various injection rates. The critical injection rate is the rate beyond which a sharp drop in breakthrough recovery takes place. This descent takes place around 5000 bpd for the top layer, and 8000 bpd for the bottom layer. Therefore, the optimum injection rate for this well, from a sweep point of view, is 13000 bpd.

We now consider the two cases of uncontrolled and controlled injection. Before doing so, it should be noted that the two alternatives shall yield exactly the same figure of ultimate recovery, since the theory of frontal advance for linear (1-D) displacement in uniform permeability fields, does not account for the phenomenon of fingering which would result in bypassed oil. The only difference between the two alternatives is that one shall require a greater quantity of water to displace the same quantity of oil, with an impact on flood duration and volume of produced water requiring processing/disposal.

For the case of uncontrolled injection, the apportioning of the total injection rate will be in accordance with the injectivity indices of the two layers. From the ratio of the product of permeability and cross sectional area (k.h.w) for each layer, we obtain a spontaneous injection rate of 10000 bpd for the top layer and 3000 bpd for the bottom layer. This is in contrast to 5000 bpd and 8000 bpd, in accordance with critical rate considerations. Therefore, for the case of uncontrolled injection, the top layer shall be flooded at super-critical rate and the bottom layer at sub-critical rate.

The *minimal* architecture proposed to achieve a critical rate split between the two layers consists of an IFCD positioned opposite the top layer, and a Flow Measurement Unit; see Figure 8. The FMU is an assembly of a venturi nozzle and two permanent pressure gauges. The gauges monitor the pressures upstream of the nozzle (above it) and at the nozzle throat. For the minimal configuration we can consider that the injection rate is monitored at the surface. Upon commencement of injection the IFCD is gradually opened and the rate passing through the FMU is monitored. The set-point of the IFCD shall then correspond to an FMU rate equal to the critical rate of the bottom layer.

Figure 9 shows the composite production profile for the two cases of uncontrolled and controlled injection. The former exhibits a 3-yr plateau averaging at about 10000 bpd followed by a 10-yr plateau at about 2500 bpd. (The sudden drop corresponds to depletion of the top layer.) The latter exhibits a 5-yr plateau at about 10500 bpd. The cumulative recovery in both cases is identical (Figure 10). The difference between the two alternatives, therefore, is that with the deployment of downhole control the project is accelerated (from 4456 to 1789 days) and water production is substantially reduced (from about 0.8 to 0.17 mmSTB; see Figure 11). An example comparison of the NPV profiles, accounting only for project acceleration (using the discrete form of the expression presented earlier), is depicted in Figure 12.

Conclusion

No two reservoir displacement problems are identical, hence the theme of this study has been to illustrate conceptual scenarios where application of simple ICS architectures could have a positive impact on the performance of the displacement process. Needless to say, any prospect that might be a candidate for such technology, must be carefully examined to determine the expected performance as well as the architecture which may be appropriate. From our preliminary investigation, however, it appears that layered formations are promising fields for further exploration, with respect to both production and injection problems. Problems of non-stratified formations, particularly in relation to coning and cresting behavior toward horizontal and multilateral wells, could very well also exhibit the virtues of downhole control.

Nomenclature

B = formation volume factor, RB/STB
c = ICS capex
CAPEX = capital expenditure
FMU = flow measurement unit
GIP = gas-in-place, L^3, mmscf
G_p = gas production, L^3, mmscf
h = layer thickness, L, ft.
i = discount rate, %
ICS = intelligent completion system
IFCD = intelligent flow control device
IPR = inflow performance relationship
k = permeability, L^2, md
$k_{ro}{}'$ = endpoint oil relative permeability
$k_{rw}{}'$ = endpoint water relative permeability
k_{rw} = water relative permeability
L = length of reservoir block, L, ft.
M = mobility ratio
N = net revenue per unit production
NPV = net present value
n = Corey relative permeability exponent
OIP = oil-in-place, L^3, STB
P_r = reservoir pressure, m/Lt^2, psi
P_{wf} = well-flowing pressure, m/Lt^2, psi
P_{wh} = wellhead pressure, m/Lt^2, psi
q = flowrate, L^3/t, STB/day or mscfd or mmscfd
S_g = gas saturation
S_{or} = residual oil saturation
S_{wc} = connate water saturation
TCF = trillion cubic feet
TIC = tubing intake curve
TVD = true vertical depth, L, ft.
W = width of reservoir block, L, ft.
WC = water cut
$\Delta\gamma$ = water-oil specific gravity difference
α = decline exponent, 1/t, day^{-1}
ϕ = porosity
μ = viscosity, m/Lt, cp
ρ = density, m/L^3, lb_m/ft^3
τ = variable of integration, t

Acknowledgments

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References

1. Buckley, S.E. and Leverett, M.C.: "Mechanism of Fluid Displacement in Sands," *Trans. AIME.* (1942) **146**, 107-116.

SI Metric Conversion Factors

cp × 1.0*	E-03	= Pa . s
ft × 3.048*	E-01	= m
ft^2 × 9.290 304*	E-02	= m^2
ft^3 × 2.831 685	E-02	= m^3
in. × 2.54*	E+00	= cm
lbf × 4.448 222	E+00	= N
md × 9.869 233	E-04	= μm^2
psi × 6.894 757	E+00	= kPa

*Conversion factor is exact.

Table 1 – Characteristics of the Two-Layer Gas Reservoir

Parameter	Top Layer	Bottom Layer
GIP, TCF	3	7
k, md	30	1
h, ft	105	405
S_g, %	35	47
ϕ, %	22	12
P_r, psi	6200	6250

Table 2 -- Deliverability Forecast with ICS (Single Well)

t, days	P_{r1}, psi	P_{r2}, psi	P_{wf}, psi	q_1, mmscfd	q_2, mmscfd	G_{p1}, tcf	G_{p2}, tcf	$G_{p(1+2)}$, tcf
0	6200	6250	5906	104.1	6.4	--	--	--
669	6000	6244	5709	102.3	9.7	.069	.004	.073
1359	5800	6235	5511	100.7	12.9	.139	.011	.150
2070	5600	6224	5313	99.1	16.0	.210	.020	.230
2844	5400	6207	5115	97.4	18.8	.286	.032	.318
3610	5200	6189	4916	95.7	21.5	.360	.047	.407
4453	5000	6166	4718	94.1	24.0	.440	.065	.505
5310	4800	6140	4519	92.4	26.3	.520	.086	.606
6239	4600	6108	4320	90.8	28.3	.605	.110	.715
7184	4400	6074	4121	89.1	30.3	.690	.137	.827
8203	4200	6035	3922	87.5	32.0	.780	.168	.948
9242	4000	5995	3722	85.8	33.6	.870	.201	1.071

Table 3 -- Example Economic Analysis

$$NPV = \int_0^t [\, q\, N\, e^{-i\tau} \,]\, d\tau - c$$

NPV – net present value, million $
q – gas flowrate, mscfd
N – net revenue per unit production, $/mscf
i – discount rate, day^{-1}
t – time, days
τ – variable of integration, days
$d\tau$ – time differential, days
c – ICS CAPEX, million $

$$q = q_o\, e^{-\alpha\tau}$$

q_o – initial flowrate, mscfd
α – decline exponent, day^{-1}

$$NPV(t) = [q_o N/(\alpha+i)]\,[\,1 - e^{-(\alpha+i)t}] - c$$

$$NPV(0) = -c$$

$$NPV(\infty) \rightarrow [q_o N/(\alpha+i)] - c$$

Without ICS	With ICS
q_o=104.1 mmscfd (Fig. 3)	$q_o \approx$115 mmscfd (Fig. 3)
α=1.84x10^{-5} day^{-1} (Fig. 3)	α=0 day^{-1} (Fig. 3)
$i_{10\%/yr}$=2.74x10^{-4} day^{-1}	$i_{10\%/yr}$=2.74x10^{-4} day^{-1}
N=$1.5/mscf	N=$1.5/mscf
c=0	c=$1,000,000
payout time = --	payout time = 6 days (Fig. 4)
breakeven time=--	breakeven time = 63 days (Fig. 4)

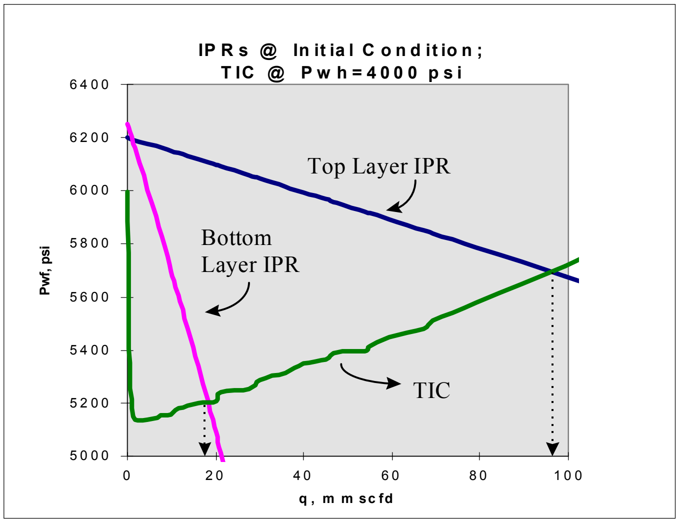

Figure 1 – Inflow/Outflow Characteristics

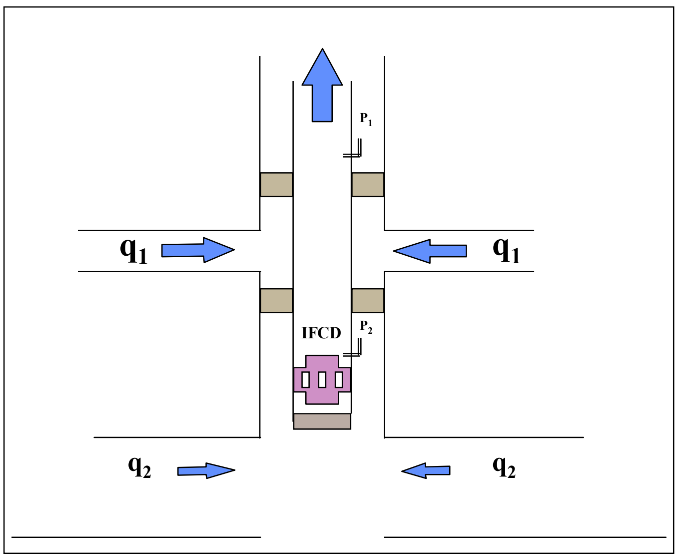

Figure 2 – ICS Architecture to Overcome Crossflow

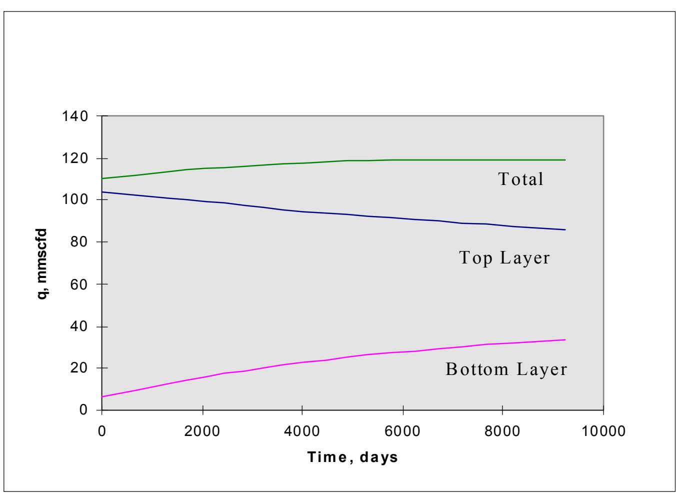

Figure 3 – Production Forecast

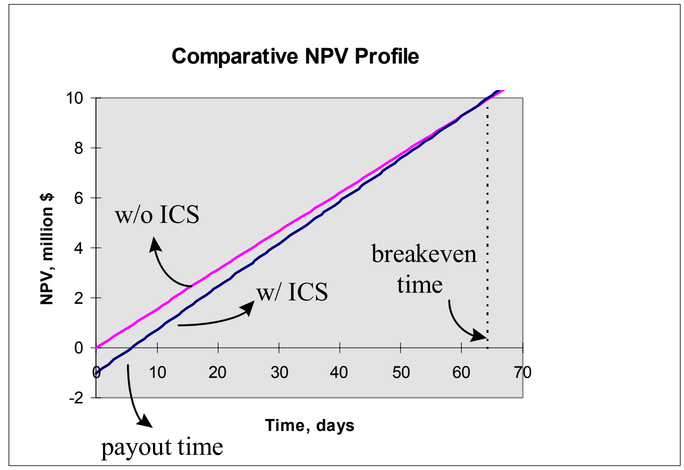

Figure 4 – Comparative NPV Profile

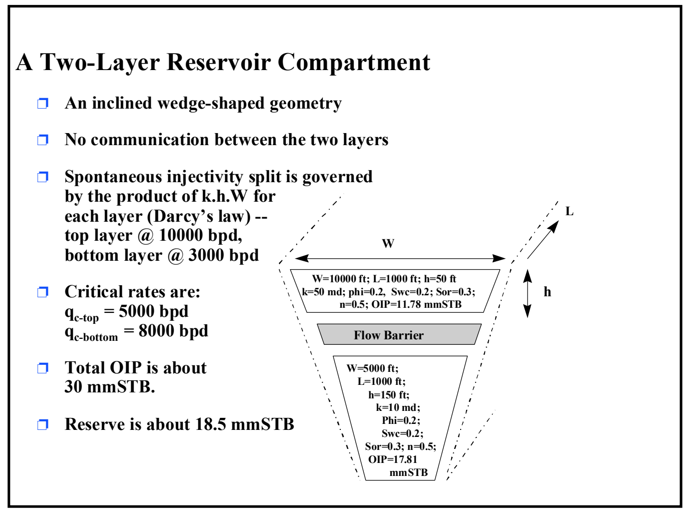

Figure 5 – Schematic of Waterflood Problem (I)

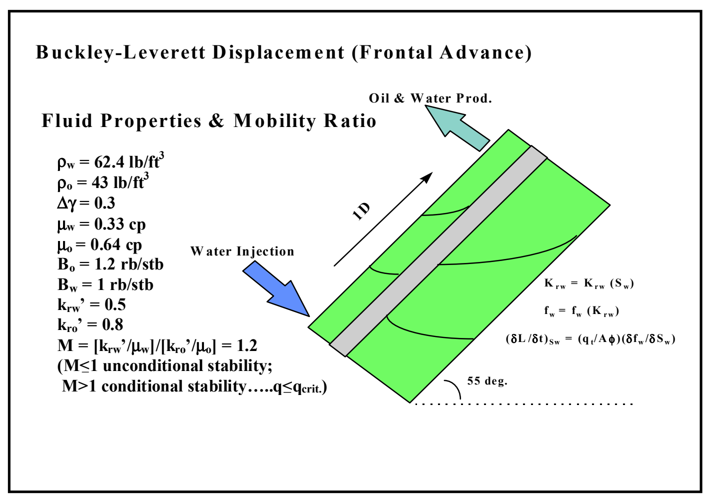

Figure 6 – Schematic of the Waterflood Problem (II)

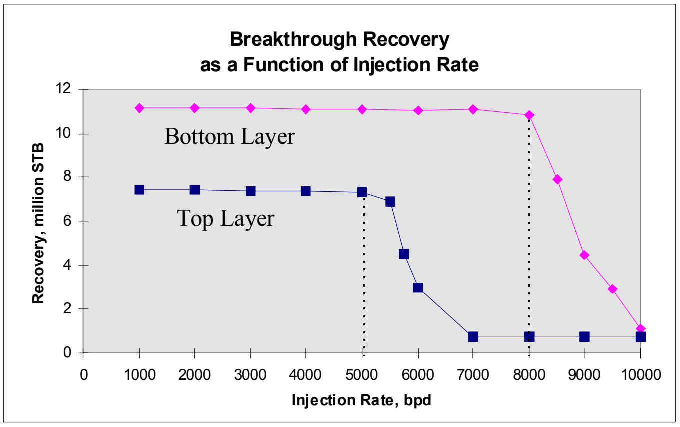

Figure 7 – Critical Rate Determination

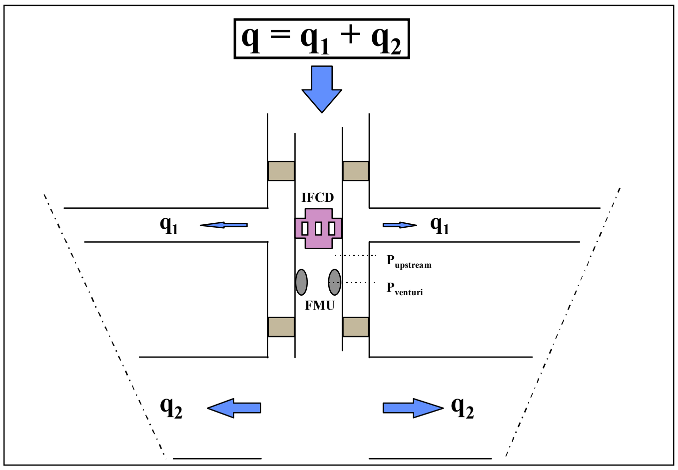

Figure 8 – ICS Architecture to Control Injection

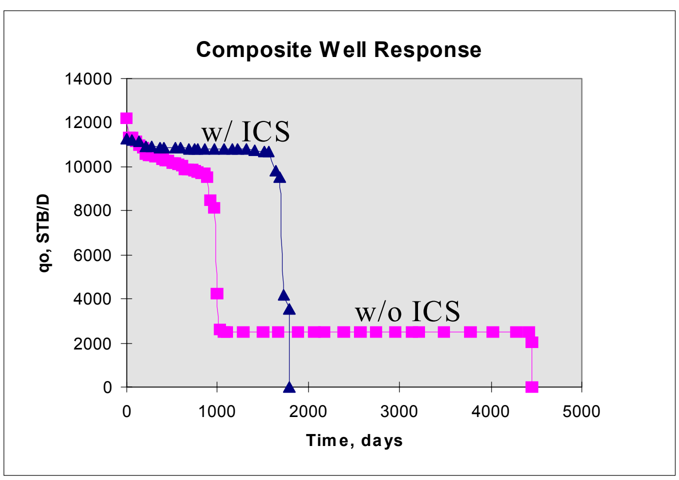

Figure 9 – Comparison of Production Profiles

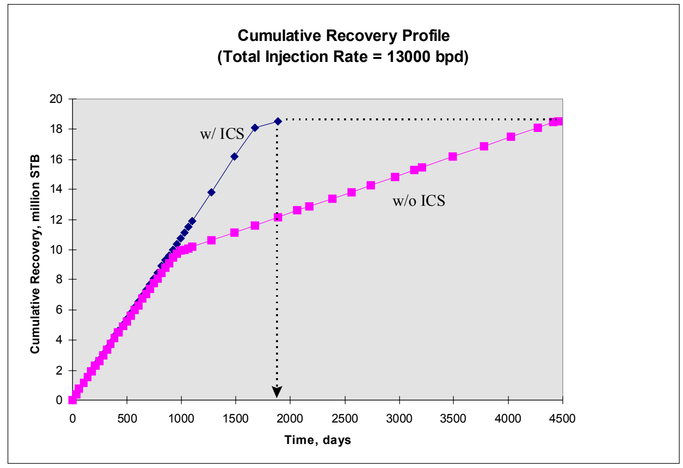

Figure 10 – Comparison of Cumulative Recovery Profiles

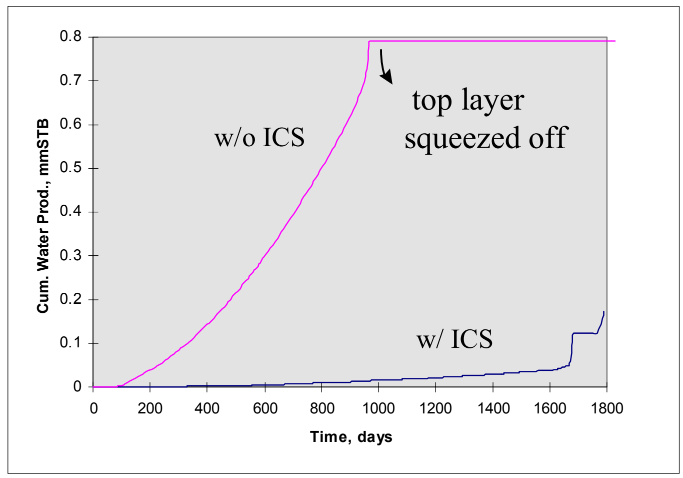

Figure 11 – Cumulative Water Production Profiles

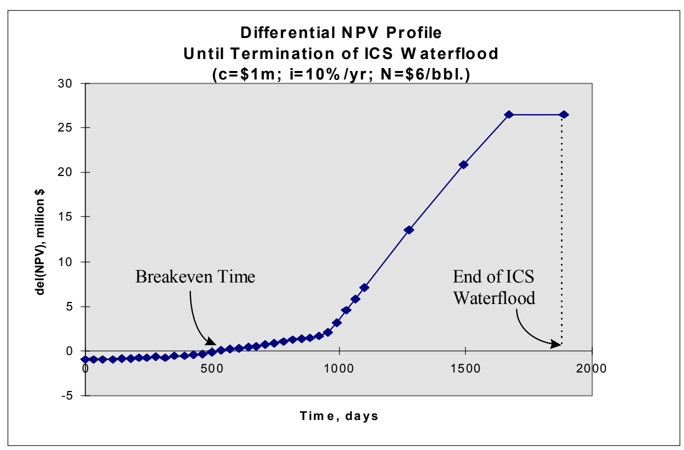

Figure 12 – Differential NPV Profile