



COUPLED DIAGNOSIS OF WELL DELIVERABILITY DECLINE IN MASSIVE OIL RESERVOIRS: QUANTIFYING NEAR-WELLBORE DAMAGE, DEPLETION, AND WATER-ENCROACHMENT EFFECTS

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Abstract. Massive oil accumulations, particularly those hosted by thick carbonate bodies with bottom-water support and strong vertical heterogeneity, often exhibit a progressive loss of well deliverability that cannot be attributed to a single mechanism. The observed decline is commonly the coupled outcome of reservoir-pressure depletion, stress-sensitive permeability reduction, increasing multiphase flow resistance during water encroachment or gas liberation, and an additional near-wellbore pressure loss represented by the skin factor. This study develops an integrated diagnostic framework for separating and quantifying these effects without relying on unverified field data. A transparent parametric model is constructed from radial inflow theory, the classical skin concept, Corey-type oil relative permeability, and a pressure-dependent permeability term. The framework is evaluated through six representative scenarios and a local sensitivity analysis. The calculations show that a moderate positive skin of 4 reduces the single-phase geometric productivity component to approximately 64% of its clean-well value, whereas an increase in near-wellbore water saturation from 0.22 to 0.36 reduces the oil relative-permeability component to approximately 54%. When depletion, viscosity change, water encroachment and skin act simultaneously, normalized productivity falls to about 0.30 in the coupled-moderate scenario and to about 0.11 in the coupled-severe scenario. The results demonstrate that diagnosing productivity decline only from rate history can misidentify the dominant mechanism: similar production losses may



originate from substantially different combinations of formation damage and saturation redistribution. A practical workflow is therefore proposed that links pressure-transient interpretation, production logging, water-cut evolution, fluid sampling, scale/fines diagnostics and stimulation history to a mechanism-based intervention decision. The study provides a reproducible engineering basis for distinguishing reversible near-wellbore impairment from reservoir-scale depletion and water-encroachment effects in massive oil reservoirs.

Keywords: *massive oil reservoir; well productivity; near-wellbore damage; skin factor; water encroachment; relative permeability; pressure depletion; diagnostic workflow; carbonate reservoir.*

1. INTRODUCTION

Maintaining stable production from mature oil reservoirs requires an understanding of how the reservoir, near-wellbore region and well completion evolve together. In a newly completed well, the productivity index may be controlled mainly by formation permeability, net pay, fluid viscosity and the geometric relation between drainage radius and wellbore radius. During continued operation, however, the same well can lose a substantial fraction of its initial deliverability even when no obvious mechanical failure is present. Classical well-test theory represents the additional pressure drop concentrated around the wellbore by the dimensionless skin factor, a concept introduced to reconcile ideal radial-flow theory with actual well performance [1,2]. Formation-damage literature subsequently showed that drilling and completion fluids, fines migration, scale and organic deposition, emulsions, wettability changes and other physical or chemical processes can all increase this local resistance [3-5].

The diagnostic problem is more difficult in massive oil accumulations. In this paper, the term massive reservoir is used in the petroleum-engineering sense of a thick, commonly carbonate, hydrocarbon-bearing body in which production is influenced by three-dimensional vertical flow and by a common oil-water contact rather than by a sequence of hydraulically isolated thin layers. Such systems may



exhibit bottom-water rise, water coning, gravity segregation, vertical permeability contrasts, natural fractures and uneven sweep. Muskat and Wyckoff demonstrated long ago that a sufficiently high withdrawal rate can deform the oil-water interface and ultimately cause water to enter a producing well [6]. Once water or liberated gas occupies part of the pore space near the well, oil effective permeability decreases and the simple linear relation between rate and drawdown may no longer hold. Vogel's inflow-performance relationship and Standing's extension to damaged wells formalized the importance of multiphase inflow and skin in productivity calculations [7,8].

A decline in oil rate can therefore have at least four conceptually different causes. First, average reservoir pressure may fall, reducing the available driving force and, in stress-sensitive rock, the permeability itself. Second, the oil relative permeability can decrease as water saturation or free-gas saturation grows around the well. Third, additional near-wellbore resistance can develop because pore throats and perforations are partially blocked. Fourth, operating constraints such as excessive drawdown, partial penetration or poor vertical inflow distribution can amplify coning and make the previous mechanisms interact. The practical consequence is that a single measured quantity, for example daily oil rate, does not uniquely identify the underlying cause. A well with skin damage can display a rate decline similar to a clean well experiencing severe water encroachment, but the correct remedial action is completely different.

This distinction matters economically. If the dominant limitation is a reversible skin caused by carbonate scale, acid-soluble solids or near-wellbore plugging, matrix stimulation or targeted cleanout can restore a significant part of the lost productivity. Carbonate-acidizing theory shows that properly placed reactive fluids can generate highly conductive dissolution channels and reduce near-wellbore resistance [9-11]. By contrast, acidizing a well whose principal problem is reservoir-wide pressure depletion or high water saturation may deliver only a short-lived response and can even accelerate unwanted water production. Recent regional studies



emphasize both the importance of waterflood-system management and the need to account explicitly for near-wellbore geology when selecting stimulation parameters [15-18].

The purpose of the present study is to develop a compact but quantitative framework for diagnosing productivity decline in massive oil reservoirs. Rather than presenting unverifiable field numbers, the work uses a transparent parametric model based on established equations. This approach is appropriate when the objective is to study mechanisms and their interactions, because every assumed parameter and every mathematical contribution can be traced. The specific objectives are: (1) to express productivity loss as the product of pressure/stress, fluid-viscosity, multiphase-mobility and skin components; (2) to investigate how water saturation and skin interact nonlinearly; (3) to compare representative depletion-dominant, damage-dominant, water-encroachment and coupled scenarios; (4) to rank the local sensitivity of normalized productivity to uncertain parameters; and (5) to translate the results into a practical diagnostic and intervention workflow for massive carbonate oil reservoirs.

The central hypothesis is that the largest productivity losses occur when reservoir-scale and near-wellbore mechanisms act simultaneously, and that the relative importance of those mechanisms can be separated using a normalized-productivity decomposition. This hypothesis is tested below with a model in which the clean initial state is defined as the reference condition. All numerical results are therefore dimensionless or normalized and should be interpreted as engineering sensitivities rather than as production forecasts for a named field.

2. MATERIALS AND METHODS

2.1. Conceptual representation of productivity decline

The analysis treats the producing system as a series of coupled flow resistances. The far-field reservoir supplies oil toward the drainage volume; pressure depletion and stress sensitivity modify the absolute permeability available for that flow. Within the saturation-transition region, the mobility of the oil phase is reduced



by water encroachment or gas liberation. Finally, the immediate near-wellbore zone and completion add a localized pressure loss that is represented by skin. This separation is deliberately simple: it does not replace a full compositional or three-dimensional reservoir simulator, but it makes the contribution of each mechanism explicit and is therefore suitable for diagnosis and screening.

For a slightly compressible single oil phase under pseudo-steady radial flow, productivity is proportional to permeability-thickness and inversely proportional to viscosity, formation volume factor and a logarithmic geometric denominator. A positive skin adds directly to that denominator. In SI form, a generic productivity expression can be written as Eq. (1), where the constant multiplier depends on the unit system. Because the present study focuses on normalized productivity, the unit-dependent constant cancels.

$$J = \frac{q_o}{p_r - p_{wf}} = C \frac{kh}{\mu_o B_o [\ln(r_e/r_w) - 0.75 + S]} \quad (1)$$

Here, J is the oil productivity index; q_o is oil rate; p_r and p_{wf} are average reservoir and flowing bottom-hole pressures; C is a unit-system constant; k is permeability; h is effective thickness; μ_o is oil viscosity; B_o is oil formation volume factor; r_e is drainage radius; r_w is wellbore radius; and S is total skin. In a massive reservoir, S should be interpreted as an effective lumped parameter that may contain true formation damage as well as completion and partial-penetration effects. Pressure-transient interpretation is required before equating a positive total skin entirely with remediable formation damage.

2.2. Near-wellbore damage and skin representation

The most useful feature of the skin concept is that it converts a complicated near-wellbore permeability distribution into an equivalent pressure-loss term. For a radially damaged zone of radius r_d and permeability k_d surrounding a formation of permeability k , Hawkins' relation gives Eq. (2) [2]. Although real damage is rarely a perfectly uniform annulus, the equation demonstrates why even a shallow invasion radius can be important when permeability impairment is severe.



$$S_d = \left(\frac{k}{k_d} - 1\right) \ln\left(\frac{r_d}{r_w}\right) \quad (2)$$

Formation damage can originate during drilling, cementing, perforating, completion, workover, stimulation and production. Krueger and Bennion classify the principal mechanisms as particulate plugging and fines migration, incompatible-fluid reactions, precipitation of inorganic scales, organic deposition, emulsion or water blocking, clay-related effects, wettability alteration and mechanically induced impairment [3,4]. In carbonate reservoirs, the most actionable subset commonly includes acid-soluble mineral scale, mud or completion-fluid solids, fines concentrated in perforations, and organic/inorganic deposits. Conversely, high water saturation created by coning is not itself a conventional positive skin in the mineral-damage sense; it primarily reduces oil effective permeability and should be diagnosed separately.

The normalized skin multiplier used in this study follows directly from Eq. (1). If the clean-well geometric denominator is $D_0 = \ln(r_e/r_w) - 0.75$, the fraction of clean productivity retained after adding skin S is given by Eq. (3). This expression is especially convenient for sensitivity analysis because it isolates the near-wellbore pressure-loss contribution.

$$f_S = \frac{D_0}{D_0 + S}, \quad D_0 = \ln\left(\frac{r_e}{r_w}\right) - 0.75 \quad (3)$$

2.3. Multiphase mobility and water-encroachment term

When bottom water rises toward a producing interval, the local water saturation increases and oil relative permeability decreases. The same principle applies when free gas forms below bubble-point pressure, although the present model focuses on the water-related term because massive carbonate oil accumulations frequently interact with strong bottom water. The oil relative-permeability ratio is represented by a Corey-type function [12]. Using irreducible water saturation S_{wi} , residual oil saturation S_{or} and Corey exponent n_o , the normalized water saturation and relative oil mobility are calculated from Eqs. (4) and (5).

$$S_w^* = \frac{S_w - S_{wi}}{1 - S_{wi} - S_{or}} \quad (4)$$



$$\frac{k_{ro}(S_w)}{k_{ro}(S_{wi})} = (1 - S_w^*)^{n_o} \quad (5)$$

The Corey equation is not claimed to represent a specific field's measured relative-permeability curves. It is used here as a physically consistent screening relation. Its important diagnostic implication is general: the relationship between water saturation and oil mobility is nonlinear. Therefore, a seemingly moderate increase in near-wellbore water saturation may cause a disproportionately large reduction in oil deliverability. This also explains why a well can remain at acceptable average reservoir pressure while its oil productivity deteriorates sharply after water breakthrough.

2.4. Depletion and stress-sensitive permeability

Reservoir depletion affects productivity in two different ways. The most direct effect is a reduction of available drawdown for a fixed minimum bottom-hole pressure. In addition, an increase in effective stress can reduce pore and fracture conductivity. Carbonates containing compliant fractures or vug-fracture networks may be particularly sensitive. For the normalized model, the pressure-dependent absolute-permeability ratio is approximated by an exponential stress-sensitivity expression, Eq. (6).

$$\frac{k(p)}{k_i} = \exp[-c_k(p_i - p)] \quad (6)$$

In Eq. (6), k_i and p_i are initial permeability and initial pressure, and c_k is an effective stress-sensitivity coefficient expressed per unit pressure. The coefficient is a screening parameter and should be calibrated from core stress tests, pressure-transient data, or history matching for field application. In the baseline calculations $c_k = 0.01 \text{ MPa}^{-1}$ is used, a value selected to produce a moderate rather than extreme permeability reduction over the evaluated pressure range. Oil viscosity is allowed to change through a simple ratio μ/μ_i ; detailed pressure-dependent PVT behavior can replace this factor in a field-specific model.



2.5. Integrated normalized-productivity model

Combining the previous mechanisms yields Eqs. (7) and (8). The formulation assumes that the separate multipliers are first-order separable for screening purposes. This is an approximation because, in reality, saturation distribution, relative permeability, pressure and formation damage influence one another. Nevertheless, a multiplicative decomposition is valuable because it reveals which mechanism is responsible for the largest loss in a given scenario.

$$\frac{J}{J_0} = f_k f_\mu f_{kr} f_S \quad (7)$$

$$f_k = \frac{k(p)}{k_i}, \quad f_\mu = \frac{\mu_i}{\mu(p)}, \quad f_{kr} = \frac{k_{ro}(S_w)}{k_{ro}(S_{wi})}, \quad f_S = \frac{D_0}{D_0 + S} \quad (8)$$

The reference state J_0 corresponds to the initial clean well at $p_i = 25$ MPa, $S_w = S_{wi} = 0.22$, $S = 0$ and $\mu/\mu_i = 1$. A wellbore radius of 0.108 m and drainage radius of 300 m give $D_0 = 7.18$. These dimensions are representative engineering values used only to define the skin multiplier. Because the analysis is normalized, the conclusions do not depend on a particular value of net pay or absolute permeability.

Table 1. Productivity-decline mechanisms, observable signatures and preferred diagnostic evidence

Mechanism	Typical production signature	Primary diagnostic evidence	Typical response
Reservoir depletion / stress sensitivity	Long-term pressure decline; broad field-wide rate reduction	Static/buildup pressure, material balance, transient tests	Pressure support; drawdown optimization; reservoir management



Near-wellbore plugging / positive skin	Rate loss at similar pressure; excess transient-test pressure drop	Pressure buildup, Cleanout, injectivity/step-rate, fluid/solid analysis	matrix stimulation, scale/fines treatment
Water encroachment / coning	Increasing water cut; oil rate falls faster than total liquid	Production log, water chemistry, saturation log, PLT	Rate control, selective shutoff, conformance treatment
Free-gas development / gas blocking	Rising GOR; curved IPR below bubble point	PVT, GOR history, pressure data	Drawdown control, pressure support, artificial lift optimization
Completion / partial penetration	Nonuniform vertical inflow; local high velocity	PLT, temperature/noise logs, completion schematic	Reperforation, selective stimulation, recompletion

2.6. Parameter set, scenarios and numerical procedure

Table 2 lists the baseline parameters used in the calculations. The parameter values are not attributed to a named field. They were chosen to span realistic engineering conditions while keeping the analysis transparent. The six scenarios in Table 3 are then evaluated using Eq. (7). The 'depletion-dominant' case keeps water saturation close to irreducible conditions and uses only a small skin increase. The 'damage-dominant' case assigns a large positive skin but little water encroachment. The 'water-encroachment' case raises S_w substantially while retaining only mild skin. The final two scenarios combine the mechanisms.

Table 2. Baseline parameters used for the transparent parametric model

Parameter	Value	Role in model
Initial reservoir pressure, p_i	25 MPa	Reference state



Wellbore radius, r_w	0.108 m	Defines geometric denominator
Drainage radius, r_e	300 m	Representative screening value
Irreducible water saturation, S_{wi}	0.22	Corey endpoint
Residual oil saturation, S_{or}	0.25	Corey endpoint
Oil Corey exponent, n_o	2.0	Screening value
Stress-sensitivity coefficient, c_k	0.01 MPa ⁻¹	Moderate stress response
Clean geometric denominator, D_0	7.18	$\ln(r_e/r_w) - 0.75$

Table 3. Representative scenarios and calculated normalized productivity

Scenario	p , MPa	S_w	S	μ/μ_i	J/J_0
Initial clean	25.0	0.22	0.0	1.00	1.000
Depletion-dominant	17.0	0.22	0.5	1.05	0.822
Damage-dominant	23.0	0.24	6.0	1.02	0.485
Water-encroachment	22.0	0.40	1.5	1.05	0.333
Coupled moderate	18.0	0.36	4.0	1.08	0.300
Coupled severe	15.0	0.46	8.0	1.12	0.114

The interaction of skin and water saturation is mapped over $-1 \leq S \leq 12$ and $0.22 \leq S_w \leq 0.50$. A second response surface is evaluated over 14-25 MPa at fixed $S = 4$ and $\mu/\mu_i = 1.08$. To illustrate how similar endpoint declines can arise from different causes, three five-year dimensionless operating trajectories are generated: depletion-dominant, damage-dominant and fully coupled. These trajectories are not forecasts; time is merely used as an ordering variable. Finally, a local one-at-a-time sensitivity test is carried out around the coupled-moderate state

($p = 18$ MPa, $S_w = 0.36$, $S = 4$, $\mu/\mu_i = 1.08$, $c_k = 0.01$ MPa⁻¹). The perturbations are ± 2 skin units, ± 0.05 water saturation, ± 3 MPa reservoir pressure, ± 0.20 viscosity ratio, and ± 0.005 MPa⁻¹ stress coefficient.

3. RESULTS

3.1. Interaction between skin and near-wellbore water saturation

Figure 1 demonstrates that positive skin and water encroachment compound rather than substitute for one another. At irreducible water saturation ($S_w = 0.22$), increasing skin from 0 to 4 reduces the normalized geometric productivity multiplier from 1.00 to approximately 0.64. At $S_w = 0.40$, however, the same skin increase is superimposed on an already reduced oil mobility. The resulting J/J_0 is less than one third of the initial value even though neither parameter alone has reached an extreme value. The figure also illustrates a diagnostic asymmetry: negative skin from successful stimulation can improve deliverability, but it cannot fully offset severe oil-mobility loss caused by high water saturation. This is why repeated stimulation of a strongly watered well may show declining incremental benefit.

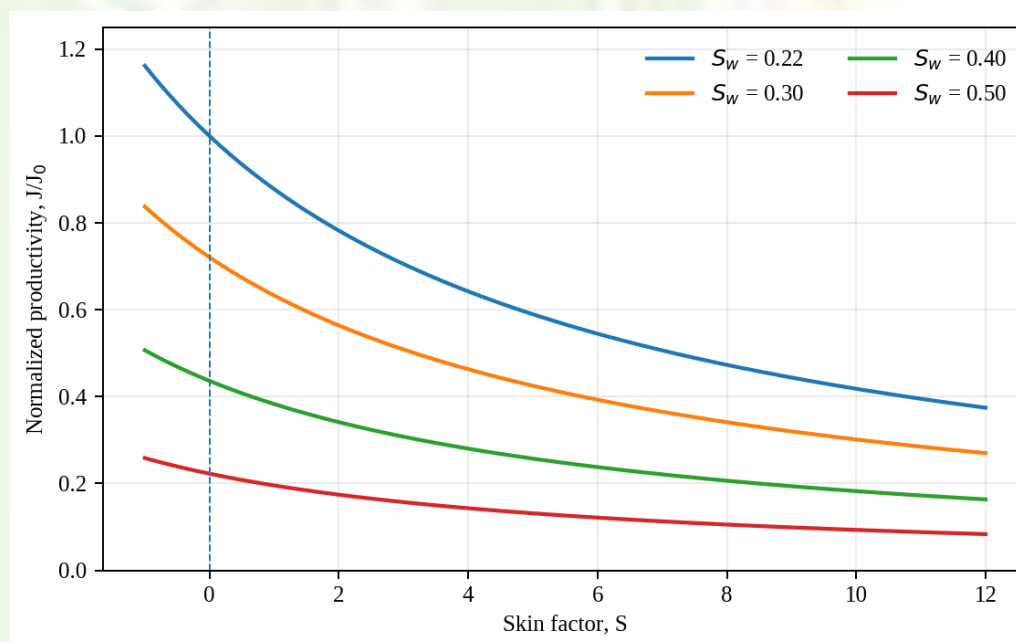


Figure 1. Modeled interaction of skin factor and near-wellbore water saturation on normalized productivity at initial pressure.

The shape of the curves is governed by the relevant multipliers in Eqs. (7) and (8). The skin effect has a hyperbolic dependence through $D_0/(D_0 + S)$, while

the relative-permeability term follows a nonlinear Corey function. Near irreducible water saturation, a small change in S_w has only a modest effect. Once saturation rises farther into the mobile-water range, each additional increment removes a larger fraction of oil mobility. Operationally, this suggests that the timing of water-control measures matters: preventing or delaying saturation growth may preserve more productivity than attempting to compensate later with progressively stronger stimulation.

3.2. Coupled effect of depletion and water encroachment

Figure 2 maps normalized productivity as a function of average reservoir pressure and near-wellbore water saturation for a moderate fixed skin of 4. The pressure axis changes the stress-sensitive permeability term, whereas the saturation axis changes oil relative permeability. The steepest gradient is oriented primarily along the saturation direction, indicating that under the selected baseline parameters water encroachment has a stronger local effect than stress sensitivity. This should not be generalized to every reservoir; a naturally fractured formation with strong fracture closure can exhibit a much larger pressure dependence. The value of the map is that it makes the competing effects visible and provides a template for calibration to local data.

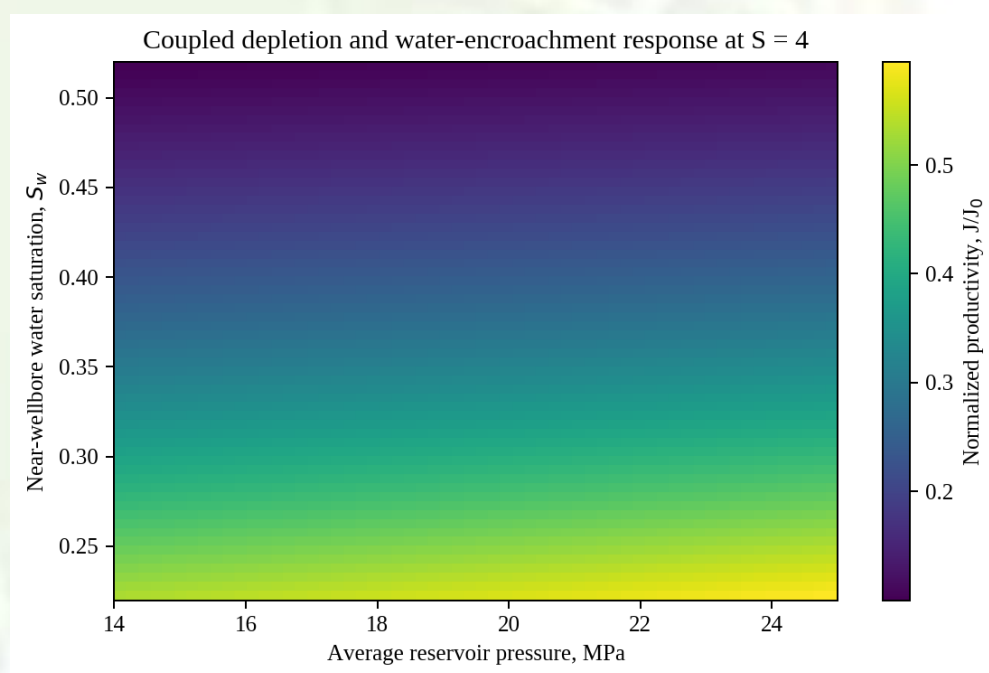




Figure 2. Normalized productivity as a function of pressure and water saturation for $S = 4$ and $\mu/\mu_i = 1.08$.

At high pressure and low water saturation, the well retains approximately 60-65% of clean productivity because the moderate skin remains the principal penalty. Moving toward lower pressure and $S_w > 0.40$ pushes J/J_0 below 0.25. Such a result has a practical diagnostic meaning. A post-stimulation well may exhibit a demonstrably lower skin on pressure buildup, yet the oil rate may not recover proportionally if the treated interval is already surrounded by a high-water-saturation bank. Conversely, a low-water-cut well with a large positive skin is a better candidate for stimulation because the removed resistance is more directly converted into oil mobility.

3.3. Scenario comparison and decomposition of the moderate coupled case

The six scenarios in Table 3 show that similar-looking production declines can emerge from different physics. Depletion alone, represented by a pressure decline to 17 MPa with only minor skin and viscosity changes, retains about 82% of reference productivity. A damage-dominant well with $S = 6$ but little saturation change retains about 48%. A water-encroachment case with $S_w = 0.40$ and only mild skin retains about 33%. The coupled-moderate and coupled-severe scenarios fall to approximately 30% and 11%, respectively. The severe case therefore represents a nearly ninefold loss of normalized productivity even though the model does not include catastrophic mechanical failure.

For the coupled-moderate state, the separate multipliers are: pressure/stress $f_k = 0.932$, viscosity $f_\mu = 0.926$, relative oil permeability $f_{kr} = 0.541$, and skin $f_s = 0.642$. Their product is 0.300. This decomposition shows that the largest individual loss in the selected state is associated with saturation-dependent oil mobility, followed by skin. Pressure/stress and viscosity changes are secondary. A field team that examined only the declining average reservoir pressure could

therefore misdiagnose the dominant limitation and invest in a pressure-related solution while leaving the near-wellbore mobility problem unresolved.

3.4. Evolution trajectories: different pathways to productivity loss

Figure 3 compares three illustrative evolution pathways. In the depletion-dominant trajectory, pressure falls rapidly but water saturation stays near its initial value and skin grows only slightly. Productivity declines gradually and remains comparatively high. In the damage-dominant trajectory, reservoir pressure is better preserved but skin grows steadily; the result is a stronger decline that can in principle be partially reversible. The fully coupled trajectory is most damaging because it combines increasing skin with progressive water saturation and continuing depletion. After several dimensionless operating years, the coupled response becomes much lower than either single-mechanism trajectory.

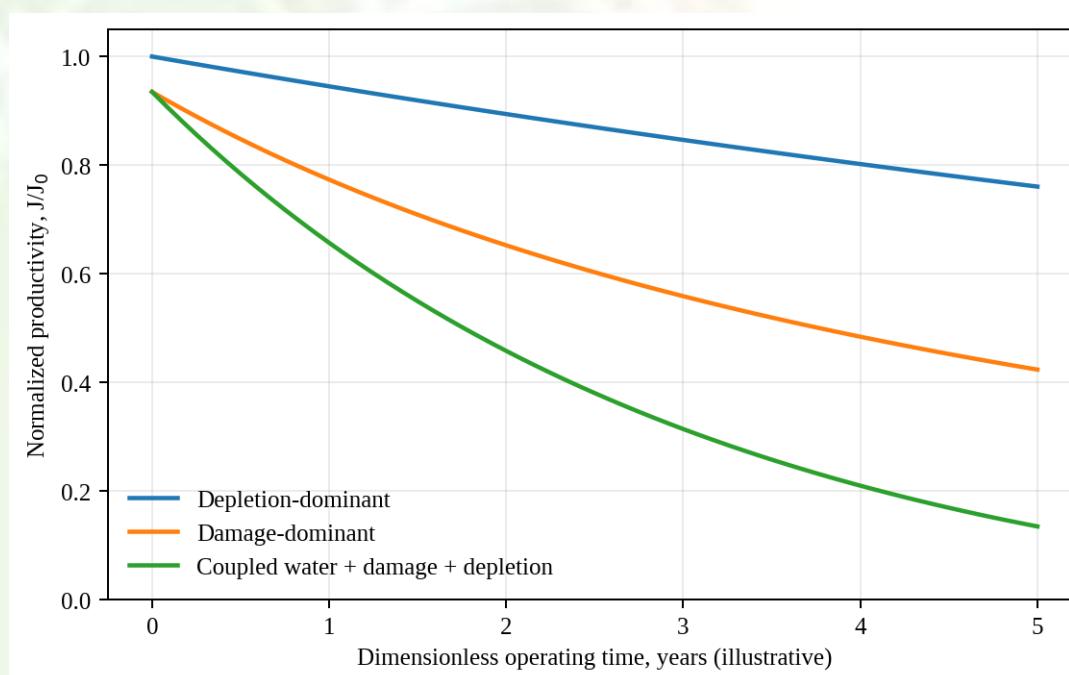


Figure 3. Illustrative normalized-productivity trajectories for depletion-, damage-, and coupled-dominant evolution. The curves are mechanism demonstrations, not field forecasts.

The trajectories also emphasize why intervention timing changes the value of stimulation. If a well is treated during the earlier part of the damage-dominant trajectory, reducing skin can return it toward the depletion baseline. If the same treatment is postponed until the well has entered a strongly watered coupled state,

the maximum achievable benefit is constrained by the low relative oil permeability. The practical implication is that surveillance should track not only production rate but also the mechanism indicators that determine whether the lost productivity is reversible.

3.5. Sensitivity ranking

The local sensitivity analysis around the coupled-moderate state is shown in Figure 4. Within the selected perturbation ranges, water saturation and skin cause the largest changes in normalized productivity. Reservoir pressure has a smaller but still material effect, while the viscosity and stress-sensitivity perturbations are less influential locally. The ranking should be interpreted as conditional on the selected baseline and perturbation size. It is not a universal ordering; rather, it demonstrates a reproducible method for identifying which uncertain measurements deserve the most diagnostic attention in a particular well.

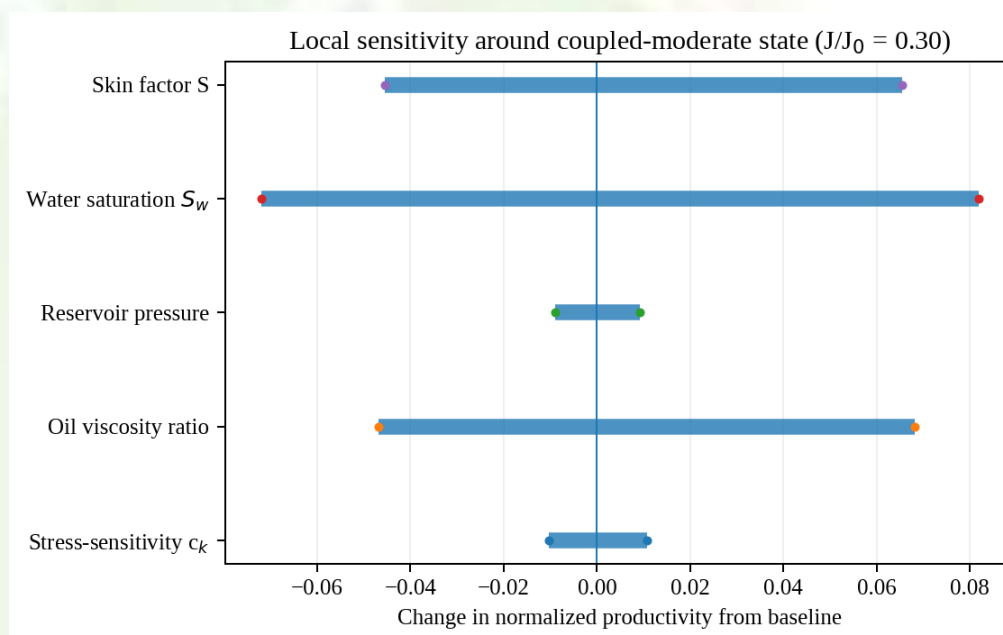


Figure 4. One-at-a-time local sensitivity of normalized productivity around the coupled-moderate state.

The sensitivity result supports a practical data-prioritization rule. If water saturation near the well is poorly constrained, acquiring production logging, saturation logging, water-cut history and water-source diagnostics may provide more decision value than refining a secondary PVT parameter. If skin is uncertain, a



properly designed pressure buildup or multi-rate test can sharply improve the diagnosis. Once these two variables are constrained, pressure and fluid-property effects can be incorporated with greater confidence.

4. DISCUSSION

4.1. Physical interpretation for massive carbonate oil accumulations

The numerical results are consistent with the physical behavior expected in massive carbonate accumulations. Thick carbonate bodies commonly contain vugs, fractures, high-permeability streaks and low-permeability matrix domains. These features make vertical and radial flow strongly nonuniform. A high-conductivity pathway may initially improve deliverability but can also accelerate bottom-water advance toward the completion. Once water enters preferential pathways, local oil saturation and oil relative permeability fall, and the effective inflow area shifts. The well can then show both a water-control problem and an apparent skin problem because scale, fines or emulsions develop in the high-flux near-wellbore zone.

Water coning is fundamentally rate dependent. The classic coning concept [6] implies that excessive drawdown increases the vertical pressure gradient that pulls bottom water upward. Therefore, an aggressive attempt to compensate for declining oil rate by lowering bottom-hole pressure can create a feedback loop: higher drawdown temporarily increases total fluid rate, the water cone rises, oil relative permeability near the well decreases, water cut increases, and net oil deliverability subsequently deteriorates. The modeled saturation multiplier captures the mobility consequence of this process even though the model does not explicitly solve the moving oil-water interface.

Formation damage creates a second feedback loop. Increased pressure gradient near a damaged well can mobilize additional fines or accelerate precipitation where pressure, temperature and composition change. This increases skin, which requires more drawdown to sustain the same rate, which in turn may worsen coning and near-wellbore velocities. Krueger's observation that almost every field operation can introduce some form of productivity damage remains relevant [3]. The



engineering task is therefore not merely to measure a total skin value, but to decide which part of the observed additional pressure loss is treatable and which part is a consequence of multiphase or completion geometry.

Regional studies included in the reference set reinforce this integrated view. Ermatov et al. [15] discuss the continuing importance of waterflood management for sustaining oil recovery, while Maxmudov et al. [16] and Axatova et al. [17] emphasize how near-wellbore geological structure controls stimulation efficiency. Samatov and Mahmudov [18] similarly note that fines, scale and precipitate accumulation in carbonate reservoirs can reduce near-wellbore permeability and that acid placement must be matched to geological and hydrodynamic conditions. These works do not by themselves quantify the coupled decline analyzed here, but they provide a local research context for connecting reservoir management with near-wellbore treatment decisions.

4.2. Diagnostic workflow before selecting a treatment

A mechanism-based diagnosis should proceed from the least ambiguous measurements to the more interpretive ones. First, the production history should be normalized for operating constraints: choke position, pump setting, surface pressure, artificial-lift condition and downtime. A rate decline that disappears after correcting an artificial-lift problem is not reservoir damage. Second, average and flowing bottom-hole pressures should be reconstructed. If $q_o/(p_r - p_{wf})$ falls materially, the productivity index itself is changing; if rate falls mainly because available drawdown has disappeared while productivity remains similar, depletion is the first-order cause.

Third, the water and gas fractions should be examined. A rising water cut combined with a falling oil productivity index suggests mobility loss and possibly coning or channeling. Production logs can identify whether water enters from a restricted interval, while water chemistry may distinguish injected water from aquifer water. A rising gas-oil ratio below bubble point should trigger a two-phase IPR interpretation rather than a single-phase linear PI assumption [7,8]. Fourth, pressure-



transient analysis should estimate total skin and permeability-thickness. A high positive skin with stable water cut and preserved reservoir pressure is a strong indicator of a remediable near-wellbore limitation.

Fifth, the composition of recovered solids and fluids should be investigated. Scale mineralogy, iron content, acid solubility, particle-size distribution, emulsion tendency and crude-oil organic stability can determine whether acid, solvent, chelant, dispersant or mechanical cleaning is appropriate. In carbonate reservoirs, acidizing can be highly effective when the treatment creates conductive channels through a genuinely damaged zone. However, the reaction-transport literature shows that acid volume and injection rate must be selected to promote efficient wormholing rather than face dissolution or excessive uniform dissolution [9,10]. Heterogeneity further complicates placement, because acid preferentially enters high-conductivity paths and may bypass damaged low-permeability sub-volumes [11,16-18].

Table 4. Mechanism-based intervention matrix for productivity decline in massive oil reservoirs

Observed state	Most dominant mechanism	likely	Minimum confirming evidence	Preferred engineering response
High skin; low/stable water cut; pressure adequate	Near-wellbore damage dominant	likely	Pressure buildup + solids/scale analysis	Targeted stimulation or cleanout
Low/moderate skin; rising water cut	Water encroachment/coning dominant		PLT, log, chemistry	Drawdown saturation reduction, selective water water shutoff, conformance control



Pressure depleted; low skin; saturation stable	Reservoir limitation	energy	Pressure survey, material balance	Pressure support or economic drawdown optimization
High skin + rising water cut	Coupled damage and water pathway	Buildup + PLT + fluid analysis	Sequence control and selective stimulation; avoid indiscriminate acid	
Rising $p_{wf} < p_b$	GOR; Two-phase liberation / gas loss	PVT + GOR + IPR analysis	Drawdown optimization; pressure support; lift redesign	
Nonuniform inflow / partial penetration	Completion geometry contribution	PLT + completion review	Reperforation or interval-selective recompletion	

4.3. Implications for acid stimulation and near-wellbore remediation

The model can be used to define an upper bound on the benefit of skin removal. Suppose a coupled-moderate well has $S = 4$ and all other conditions remain unchanged. Removing skin to zero increases the skin multiplier from 0.642 to 1.0, so normalized productivity would rise from about 0.30 to only about 0.47. This is a meaningful increase, but the well would still produce at less than half of its original normalized productivity because high water saturation and depletion remain. Such an upper-bound calculation is useful before stimulation because it prevents the engineering team from assigning unrealistic production expectations to a treatment that addresses only one component of the problem.

The same logic can be applied to water control. If a conformance treatment reduces effective near-wellbore water saturation while leaving skin unchanged, the



oil relative-permeability multiplier improves. In a heterogeneous carbonate, however, a water shutoff can redirect flow into lower-permeability oil-bearing rock, increasing the relative importance of any existing skin. Thus, combined treatments should be sequenced. In a well with obvious channelized water and acid-soluble plugging, water-source isolation should generally be evaluated before a broad matrix-acid job, whereas a low-water-cut well with high positive skin may benefit from direct stimulation.

Acid treatment design also requires a separate reaction-transport optimization. Fredd and Fogler showed that wormhole structure depends on the balance of reaction and transport expressed through a Damköhler-type relationship [9], while the two-scale continuum model of Panga, Ziauddin and Balakotaiah provides a rigorous framework for coupling Darcy-scale flow with pore-scale reaction and evolving porosity/permeability [10]. These concepts explain why simply increasing acid volume is not equivalent to improving stimulation. The regional studies [16-18] similarly emphasize geological heterogeneity and hydrodynamic conditions. For the present productivity framework, the output needed from an acid-design model is the expected reduction in effective skin and, ideally, the stimulated interval coverage. That output can then be inserted into Eq. (7) to estimate a realistic post-treatment productivity range.

4.4. Limitations and path toward field calibration

The main limitation of the current study is intentional simplicity. The model is not a full reservoir simulator and does not explicitly solve the three-dimensional movement of the oil-water contact, fracture flow, capillary pressure, gas liberation, hysteresis, changing completion inflow profile, non-Darcy effects or artificial-lift hydraulics. The separability of the multipliers in Eq. (7) is a first-order approximation. In field conditions, damage can alter saturation distribution, water can carry scale-forming ions, and pressure decline changes fluid properties and phase behavior simultaneously.



A second limitation is that Corey parameters and stress sensitivity are assumed rather than measured. Before field use, relative-permeability curves should be taken from SCAL or history-matched saturation functions, and the stress coefficient should be calibrated to core or transient-test evidence. The skin factor should be decomposed where possible into mechanical/completion skin, formation-damage skin and non-Darcy components. For fractured carbonates, a dual-porosity or discrete-fracture representation may be required because the matrix and fracture systems can have very different pressure and saturation dynamics.

Despite these limitations, the framework is useful because it is auditable. A field-calibrated implementation requires only a small set of data: reservoir pressure, oil PVT, an estimate of near-wellbore water saturation or an equivalent mobility indicator, transient-test skin, and representative relative-permeability behavior. Uncertainty can then be handled with Monte Carlo sampling rather than a single deterministic scenario. The output should be reported as a range of normalized productivity and a range of treatment benefit. This approach is more defensible than assigning the entire decline to 'formation damage' without demonstrating how much rate could actually be recovered by removing skin.

5. CONCLUSIONS

1. Well deliverability decline in massive oil reservoirs is inherently multi-mechanistic. Pressure depletion, stress-sensitive permeability reduction, water- or gas-induced mobility loss and near-wellbore skin can produce similar rate trends but require different engineering responses.

2. The normalized model developed in this study separates the major contributions into four physically interpretable multipliers. For the representative geometry, a skin factor of 4 retains about 64% of the clean geometric productivity, while increasing near-wellbore water saturation from 0.22 to 0.36 retains about 54% of the initial oil relative-permeability component.

3. Coupling is more damaging than any single mechanism evaluated alone. The modeled coupled-moderate state retains approximately 30% of initial



normalized productivity, and the coupled-severe state about 11%. These values are parametric results, not field observations, but they quantify the magnitude of the interaction.

4. In the local sensitivity test, near-wellbore water saturation and skin are the most influential uncertain variables around the coupled-moderate state. This finding supports prioritizing saturation/water-source diagnostics and pressure-transient skin estimation before selecting a stimulation treatment.

5. Skin removal has a calculable upper-bound benefit. In a strongly watered or depleted well, even complete removal of positive skin cannot restore the original productivity because the remaining multiphase and reservoir-scale penalties persist. This explains why indiscriminate repeated stimulation may yield diminishing returns.

6. A robust diagnostic sequence should integrate corrected production history, reservoir and bottom-hole pressure, water-cut and GOR trends, pressure-transient analysis, production logging, fluid/solid characterization and treatment history. Intervention should be selected only after the dominant mechanism is confirmed.

7. For carbonate massive reservoirs, near-wellbore stimulation should be linked to geological heterogeneity and reactive-transport design. Acidizing is most defensible when a treatable positive skin has been identified and when water-entry behavior does not dominate the well response.

8. The proposed framework can be upgraded to a field-calibrated probabilistic model by replacing assumed relative-permeability and stress parameters with SCAL, pressure-transient and history-matched data. In that form, it can support treatment ranking, expected-benefit calculations and surveillance planning.

NOMENCLATURE

B_o – oil formation volume factor

c_k – effective permeability stress-sensitivity coefficient

D_0 – clean radial-flow geometric denominator



h – effective reservoir thickness

J – productivity index

J_0 – reference clean-well productivity index

k – absolute permeability

k_d – damaged-zone permeability

k_{ro} – oil relative permeability

n_o – Corey oil exponent

p_r – average reservoir pressure

p_{wf} – flowing bottom-hole pressure

q_o – oil rate

r_d – damage radius

r_e – drainage radius

r_w – wellbore radius

S – total skin factor

S_w – water saturation

S_{wi} – irreducible water saturation

S_{or} – residual oil saturation

μ_o – oil viscosity

DATA AND MODEL TRANSPARENCY STATEMENT

No proprietary field dataset was used in the numerical results of this article.

All plotted and tabulated numerical outputs were generated from the equations and parameter values stated in the Materials and Methods section. Locally supplied publications were used to ground the regional literature review and reference list, not as a source of undisclosed production data.

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