

ULTRA-MEOR®

Modern Microbial Enhanced Oil Recovery for Mature Conventional Oilfields

Historical Foundations, Differentiated Technology, and Modern Field Validation

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Executive Summary

Mature conventional oilfields remain an important component of global petroleum production. Production decline does not necessarily mean that a reservoir has exhausted its remaining oil. Significant hydrocarbons can remain after primary and secondary recovery because of capillary trapping, reservoir heterogeneity, unfavorable fluid-flow paths, wettability, declining reservoir energy, and other physical constraints.

The commercial challenge is therefore not simply determining whether oil remains, but whether additional oil can be mobilized and produced economically using infrastructure already in place.

Microbial Enhanced Oil Recovery (MEOR) has been investigated for decades as one potential approach. The term covers materially different technologies. Historical and modern MEOR programs have included stimulation of indigenous reservoir microorganisms with injected nutrient packages, injection of selected bacterial cultures, enzyme- or biosurfactant-oriented treatments, selective plugging approaches, and other biological strategies. Published reviews emphasize that microbial selection, reservoir screening, treatment design, placement, and field measurement materially affect results. [1-4]

Ultra-MEOR® represents a differentiated approach within this broader field. Rather than relying primarily on stimulation of whatever microorganisms are already present in a reservoir, the system introduces a proprietary Natural Microbial Consortium together with a purpose-designed Natural Support Component and Natural Activation Component. These elements are combined with a controlled field protocol involving preparation, injection, displacement, shut-in, restart, and production monitoring.

The scientific foundation extends back several decades. Historical government-supported and private field development evaluated related microbial systems for residual-oil recovery and paraffin reduction. The historical evidence includes four positive government-supported clastic lease applications, a 20-well PEMEX field program in which 15 wells increased oil production, a 13-well Trinidad program, and the 2026 North African pilot. In the PEMEX program, aggregate net oil production increased from approximately 447 to 874 BOPD at the post-treatment measurement snapshot, while two previously nonproducing wells were restored to oil production. Public well-depth data and representative field stratigraphy indicate that the PEMEX well population spans a mixed Jurassic reservoir section containing carbonate-rich intervals, platform carbonate, sandstone, and basal clastics, although lack of completion records restrict assigning individual well response to a specific producing formation. Commercial development later became dormant for more than three decades. Recent efforts have focused on recovering the technical knowledge, establishing modern operating procedures, improving candidate-well screening, and validating performance under contemporary oilfield conditions. [5-8]

A major milestone was achieved in 2026 in a mature conventional oil well operated by a North African National Oil Company. Using three accepted pre-treatment tests and ten post-treatment tests, average oil production increased from 196.7 BOPD to 330.2 BOPD during the 90-day monitoring period, while average produced water decreased from 134.7 BWPD to 54.9 BWPD. Average total fluid increased from 331.4 BFPD to 385.1 BFPD, meaning the produced-fluid composition shifted strongly toward oil. Aggregate water cut decreased from 40.6% to 14.3%. [5]

The oil response increased rapidly after treatment, peaked at 444 BOPD, and then declined toward the pre-treatment range over the remaining weeks. The water response remained substantial through the final reported test. The field trial was designed to measure production performance rather than isolate individual mechanisms. Biosurfactant and interfacial effects, oil-rock detachment, potential wettability or relative-flow changes, paraffin or wax modification, and selective modification of preferential flow paths are among the technically plausible contributors considered in this paper.

2026 Field Validation	Observed Result
Average oil production	196.7 BOPD increased to 330.2 BOPD (67.9%)
Average produced water	134.7 BWPD decreased to 54.9 BWPD (59.2%)
Average total fluid	331.4 BFPD increased to 385.1 BFPD (16.2%)
Water cut	40.6% decreased to 14.3%
Oil-to-water ratio	1.46:1 improved to 6.01:1
Peak reported oil production	444 BOPD
Infrastructure modification	None required in the field trial

Ultra-MEOR has demonstrated a strong modern single-well proof of concept supported by a broader historical record that includes positive clastic lease applications, a substantial 20-well PEMEX field response, and a Trinidad multi-well program. The PEMEX data are especially useful because they show response across individual wells rather than only an aggregate field total: 15 of 20 wells increased oil production, three were unchanged, and two declined at the post-treatment snapshot. The evidence does not yet establish statistically predictable performance across a broad range of reservoirs, but it strengthens the case for both repeat applications in comparable candidates and carefully selected trials in different reservoir settings to define repeatability and operating range.

1. The Remaining Potential of Mature Conventional Oilfields

Mature oilfields represent one of the petroleum industry's largest existing opportunities for incremental recovery. Unlike undeveloped resources, mature fields already possess wells, gathering systems, production facilities, operating personnel, reservoir history, and market access. Much of the capital required to establish the assets has already been invested.

Economic depletion and geological depletion are not the same. A well may become less attractive because oil production has declined, produced-water volumes have increased, artificial-lift requirements have grown, paraffin or other deposits have restricted flow, or operating costs have risen. None of these conditions necessarily means that all technically recoverable hydrocarbons have been removed.

Oil may remain trapped or bypassed because of reservoir heterogeneity, capillary forces, oil-rock affinity, preferential water flow, declining pressure, and unfavorable relative permeability. The more useful operator question is therefore: how much connected remaining oil can be recovered economically using infrastructure already in place?

Ultra-MEOR is being developed within this mature-field optimization framework. It is not intended as a substitute for mechanical repair, artificial-lift optimization, conventional stimulation, water shutoff, or other interventions when those are the actual constraints.

2. The Development of Microbial Enhanced Oil Recovery

Petroleum microbiology research developed during the first half of the twentieth century as scientists learned that microorganisms could interact with hydrocarbons and generate products capable of changing oil and its surrounding environment. By the mid-twentieth century, researchers were investigating whether these processes could be applied deliberately within petroleum reservoirs.

By the 1970s and 1980s, MEOR research had expanded internationally. Traditional approaches were not uniform. Many programs attempted to stimulate indigenous reservoir bacteria by injecting nutrient packages;

others injected selected microbial cultures, used enzymes or biosurfactant-producing systems, or sought gas, acid, polymer, or selective-plugging effects. Paraffin control was also investigated. Later reviews continued to document a wide range of in-situ and ex-situ biological approaches and field trials. [1-4]

The term MEOR therefore describes a family of technologies rather than one standardized treatment. Two treatments may differ materially in microbial source and diversity, whether the microbial population is indigenous or externally selected, reliance on nutrients or enzymes, metabolic pathway, oxygen availability, reservoir tolerance, placement strategy, shut-in time, and intended mechanism. Those differences are central to evaluating Ultra-MEOR against the historical reputation of MEOR as a category.

3. Why Historical MEOR Results Were Inconsistent

The historical MEOR record contains both encouraging responses and disappointing outcomes. That variability should not be simplified into a conclusion that MEOR either works or does not work. Several factors contributed.

Reservoir heterogeneity

Permeability distribution, porosity, lithology, fractures, water saturation, crude properties, temperature, salinity, pressure, wettability, and existing flow paths can all influence how an injected biological system behaves.

Microbial selection and support

Historical programs used indigenous populations, single strains, limited cultures, or mixed communities. Nutrient and support strategies also varied widely. Some traditional MEOR programs stimulated indigenous bacteria through injected nutrients, while other approaches used selected bacterial cultures, enzymes, surfactants, or combinations of these methods. A system that introduces a broad preselected consortium together with matched support and activation components should not be assumed to behave like a generic nutrient stimulation or single-strain program bacteria.

Oxygen availability

Many petroleum reservoirs are strongly reducing environments with limited free oxygen. This constrained aerobic hydrocarbon metabolism and led many traditional reservoir MEOR programs to focus on anaerobic or low-oxygen pathways. MEOR research, however, has included both anaerobic and aerobic approaches. Ultra-MEOR differs by incorporating a proprietary activation strategy intended to support localized aerobic or microaerophilic biological activity under reservoir conditions.

Compatibility, candidate selection, and measurement

Salinity, pH, temperature, biocides, oxidants, injectivity, mechanical condition, remaining-oil potential, and baseline quality can all determine whether a trial produces useful evidence. Modern evaluation must therefore treat candidate selection and measurement discipline as integral parts of the technology.

4. Ultra-MEOR - A Different Approach to MEOR

Ultra-MEOR is designed as an integrated biological treatment system in which microbial diversity, biological support, activation, placement, reservoir conditions, and operating procedures are coordinated for maximum performance.

Natural Microbial Consortium

The consortium contains a broad population of naturally occurring hydrocarbon-metabolizing microorganisms selected for collective capability across a range of petroleum environments. Historical source records

describe more than 100 naturally occurring microbial species. Individual identities and proportions are proprietary.

Natural Support Component

The Natural Support Component is specifically formulated to support the consortium after preparation and placement. The important distinction is that it was developed in conjunction with the consortium rather than being treated as a generic nutrient addition.

Natural Activation Component

The Natural Activation Component is intended to improve local conditions supporting microbial activation and metabolite production under reservoir conditions. Historical development work identified limited oxygen availability as an obstacle to aerobic hydrocarbon metabolism. Rather than assuming the reservoir's native low-oxygen environment will support every desired pathway, Ultra-MEOR incorporates an activation component intended to support localized aerobic or microaerophilic activity. The detailed activation chemistry remains proprietary. This is an important distinction from many traditional MEOR programs built primarily around indigenous stimulation or anaerobic reservoir processes.

Ultra-MEOR should therefore be understood as a complete system: the Natural Microbial Consortium, Natural Support Component, Natural Activation Component, and controlled field protocol operating together.

5. How Ultra-MEOR May Mobilize Remaining Oil

Ultra-MEOR is intended to operate through multiple biological and physicochemical pathways rather than one single recovery mechanism. The relative contribution of each pathway is expected to vary with reservoir and fluid conditions, and the 2026 field trial did not include diagnostics capable of allocating the response among them.

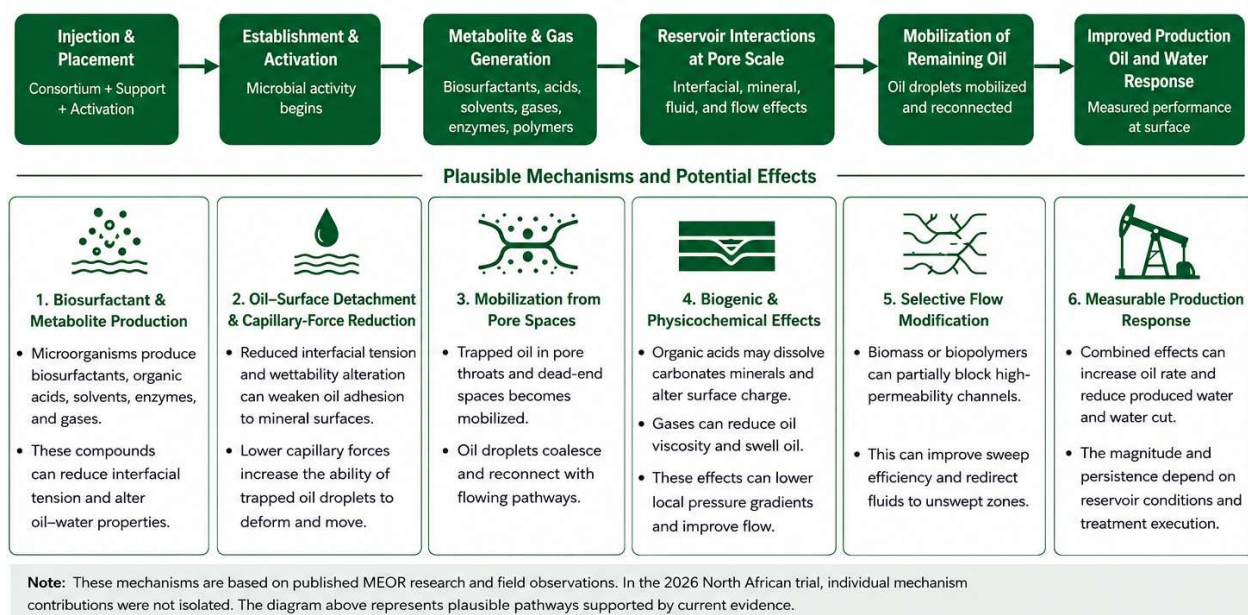


Figure 1. Conceptual representation of how Ultra-MEOR may mobilize remaining oil through multiple interacting biological and physicochemical mechanisms. Individual mechanism contributions were not isolated in the 2026 North African field trial.

Biosurfactants and metabolites

Published MEOR research identifies biosurfactants, acids, gases, solvents, enzymes, biomass, and polymers as possible contributors to enhanced recovery. Biosurfactants are especially relevant because they can reduce oil-water interfacial tension and affect wettability. [1-4]

Oil-surface detachment and capillary-force reduction

Microbial metabolites may modify hydrocarbon-surface interactions and reduce forces retaining oil at mineral and oil-water interfaces. Reduced interfacial tension can increase the ability of trapped droplets to deform through pore throats and reconnect with mobile oil pathways.

Biogenic effects and selective flow modification

Localized gas or acid generation may influence oil properties, mineral interactions, or pressure at pore scale. Microbial growth, biomass, or biopolymers may also alter preferential flow paths under some conditions. US Department of Energy/National Energy Technology Laboratory (DOE/NETL) research has specifically examined wettability, interfacial tension, adsorption, and permeability modification as variables controlling MEOR effectiveness. [4]

6. The Oil-Water-Rock System: Wettability, Aqueous Phase, and Residual Oil

Ultra-MEOR should be understood within the oil-water-rock system rather than as a treatment acting on oil alone. Microorganisms require an aqueous phase for transport and metabolism. Reservoir water therefore can serve as the medium through which microbes and their metabolites interact with oil and mineral surfaces.

Ultra-MEOR is not intended to remove connate or irreducible water. The more substantial reservoir-engineering hypothesis is that biological activity may influence interfacial behavior, wettability, capillary pressure, and relative flow within the existing pore-fluid system.

Water-wet, oil-wet, and mixed-wet behavior

Wettability controls how oil and water distribute within pore space and materially influences capillary pressure, residual oil saturation, and relative permeability. Many reservoirs are mixed-wet rather than purely water-wet or oil-wet. If microbial metabolites reduce oil adhesion or alter surface affinity, previously retained hydrocarbons may become easier to mobilize. Published MEOR reviews identify wettability alteration as a recognized mechanism, and DOE/NETL research has explicitly investigated this variable. [2-4]

Why this matters for the 2026 field result

The simultaneous increase in oil and reduction in water is consistent with a change in relative fluid behavior, but it does not prove a wettability or relative-permeability mechanism. Future pilots should consider interfacial-tension tests, contact-angle measurements, relative-permeability studies, pressure-transient analysis, production logging, and tracer studies where practical or possible.

7. Paraffin and Wax: A Second Recovery and Flow-Assurance Opportunity

Paraffin and wax deposition have been associated with microbial petroleum research for decades and are an important part of the historical development behind modern Ultra-MEOR. Paraffin deposits can restrict reservoir pore space near the wellbore, perforations, tubing, pumps, flowlines, valves, and surface equipment.

Historical government-supported and private development records reviewed by the Advanced Technology Group (ATG) describe microbial treatment programs specifically focused on paraffin reduction and report operator observations of reduced paraffin problems following treatment. These observations support continued evaluation but do not establish that every wax deposit will respond.

Potential mechanisms include direct interaction with selected long-chain hydrocarbons and modification of deposit adhesion or rheology by biosurfactants and other metabolites. Heavily accumulated deposits require engineering review because loosened material may create downstream operating problems.

Paraffin, asphaltenes, and mineral scale are not interchangeable. Ultra-MEOR effects on asphaltenes remain investigational, while mineral scale is inorganic and should not be represented as a proven microbial target.

8. Historical Field Evidence: What It Shows and What It Does Not

Historical field evidence is useful because it shows both measurable responses and non-responses. Four United States-government-supported clastic lease applications, a PEMEX 20-well program, a Trinidad 13-well program, and the 2026 North African pilot each reported positive oil-production responses at the program level. The studies differ in design, measurement quality, geology, and attribution, so they should not be pooled as if they were one controlled experiment. They nevertheless demonstrate that the underlying approach produced positive field responses across multiple locations and operating settings. [5-8]

The historical data also show meaningful variation in magnitude and duration. Three South Texas clastic lease applications reported oil-production improvements in the approximately 22% to 27% range, while an Illinois modified-waterflood lease reported a 41% increase and 2,212 incremental barrels. The PEMEX program is supported by well-level production data showing aggregate net oil production increasing from approximately 447 BOPD to 874 BOPD across 20 wells, a gain of approximately 428 BOPD or 95.8% at the post-treatment measurement snapshot. Fifteen of the 20 wells increased oil production, three were unchanged, and two declined. A Trinidad 13-well program reported approximately 29,000 incremental barrels over 18 months, although later review could not conclusively separate the proprietary treatment response from stimulation of indigenous microorganisms. Therefore, a subsequent Petrotrin MEOR experiment designed to stimulate the indigenous reservoir organisms using only an engineered nutrient package had fewer positive results, showing increased oil performance in less than half of the wells, indicating that the Ultra-MEOR program had more far-reaching impacts than indigenous stimulation alone. [6-8]

Application / setting	Reported oil-production result	Duration / other observation
Three South Texas clastic lease applications	DOE-reported increases of approximately 22% to 27%; reported incremental oil of 213 to 474 barrels per lease	One lease response was reported to persist for at least 15 months; operators also reported less paraffin-related maintenance at the field level.
Illinois modified-waterflood lease	DOE-reported increase of 41%; 2,212 incremental barrels	Production reportedly remained about 12-13 BOPD above expected for roughly 10 months after the initial response.
PEMEX 20-well program, Mexico	Aggregate net oil production increased from approximately 447 to 874 BOPD, a gain of approximately 428 BOPD or 95.8% at the post-treatment measurement snapshot; 15 of 20 wells increased.	Two previously nonproducing wells were restored to oil production. Public depth and field-stratigraphy data indicate a mixed carbonate/clastic setting, but producing intervals have not been confirmed.
Trinidad 13-well program	Approximately 29,000 incremental barrels reported across 13 wells over 18 months	Led to later Petrotrin study focused on separating the impact of proprietary treatment versus stimulation of indigenous organisms, which underperformed the Ultra-MEOR trial.
2026 North African sandstone well	Average oil increased from 196.7 to 330.2 BOPD, a 67.9% increase; peak test 444 BOPD	Average produced water decreased 59.2%; post-treatment monitoring covered approximately 90 days.

A historical carbonate application is also important to the evidence record: microbial populations increased and moved through the tested carbonate reservoir, but no significant oil-production increase was measured. The PEMEX analysis adds a different perspective. Public depth records and representative field stratigraphy indicate that the 20-well set spans a mixed reservoir section containing carbonate-rich Jurassic intervals, platform carbonate, sandstone, basal clastics, and wells that reached basement after traversing the Jurassic section. Strong gains occurred in wells whose total depths lie near several of these different stratigraphic intervals. Because total depth does not identify the perforated, producing, or treated interval, the PEMEX evidence supports carbonate applicability as a field-validation opportunity but does not yet prove formation-specific carbonate performance. [6,8]

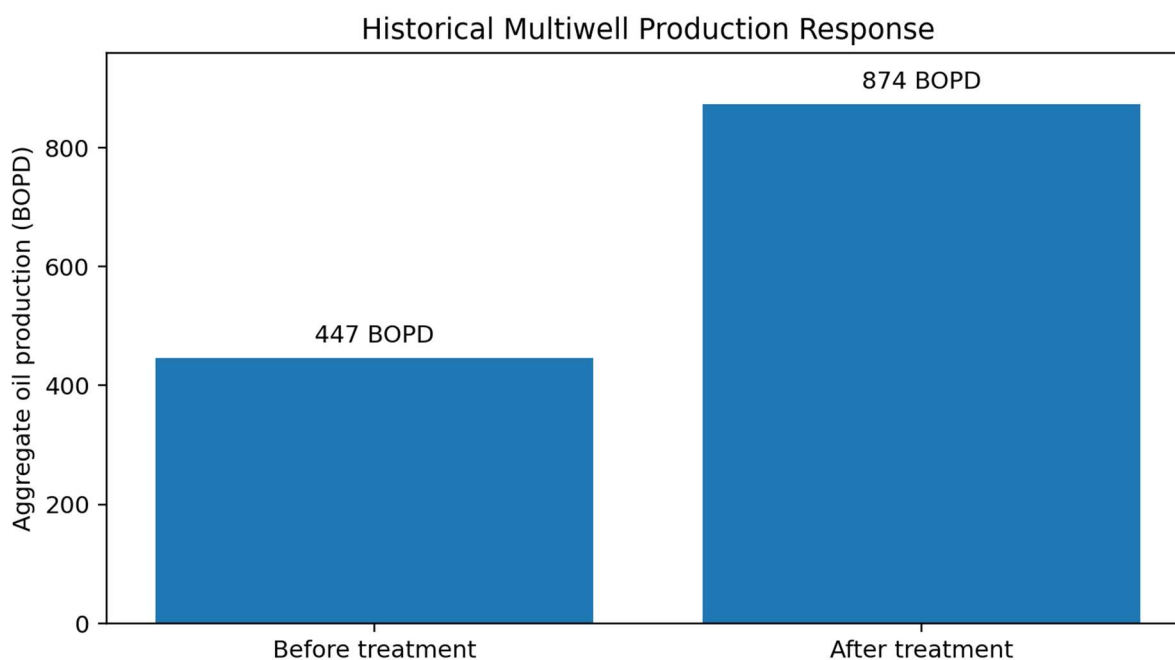


Figure 2. Modern ATG visualization of aggregate production totals reported in historical field documentation. Historical results presented as reported; not represented as modern independently verified performance.

PEMEX 20-Well Field Trial: A Strong Historical Multi-Well Result

The PEMEX Tamaulipas-Constituciones field application is the largest well-level historical dataset currently available in the ATG archive. At the July 1996 post-treatment measurement snapshot, combined net oil production increased from approximately 446.6 BOPD to 874.3 BOPD, a gain of approximately 427.7 BOPD or 95.8%. Fifteen of 20 wells increased oil production, three were unchanged, and two declined. Two wells that had been producing no net oil before treatment were restored to production and together contributed approximately 132 BOPD, or about 31% of the total field gain. [8]

PEMEX field-trial measure	Reported / calculated result
Wells evaluated	20
Wells with increased oil production	15 of 20 (75%)
Unchanged / declined	3 unchanged; 2 declined

Aggregate net oil production	Approximately 447 BOPD before treatment; 874 BOPD after treatment
Incremental oil rate	Approximately 428 BOPD
Field-level oil-rate increase	Approximately 95.8%
Reactivated wells	2 wells restored from zero net oil to a combined approximately 132 BOPD
Concentration of gain	Five largest responders supplied about 75% of the net gain; top eight supplied about 92.6%

The distribution of response is important. The program-wide increase was not caused by one exceptional well, but neither was the response uniform. The median well gained about 12.6 BOPD while the mean gain was about 21.4 BOPD, reflecting the concentration of value in several strong responders. This pattern supports the view that candidate selection, local reservoir quality, completion condition, fluid placement, and connectivity can materially influence outcome.[8]

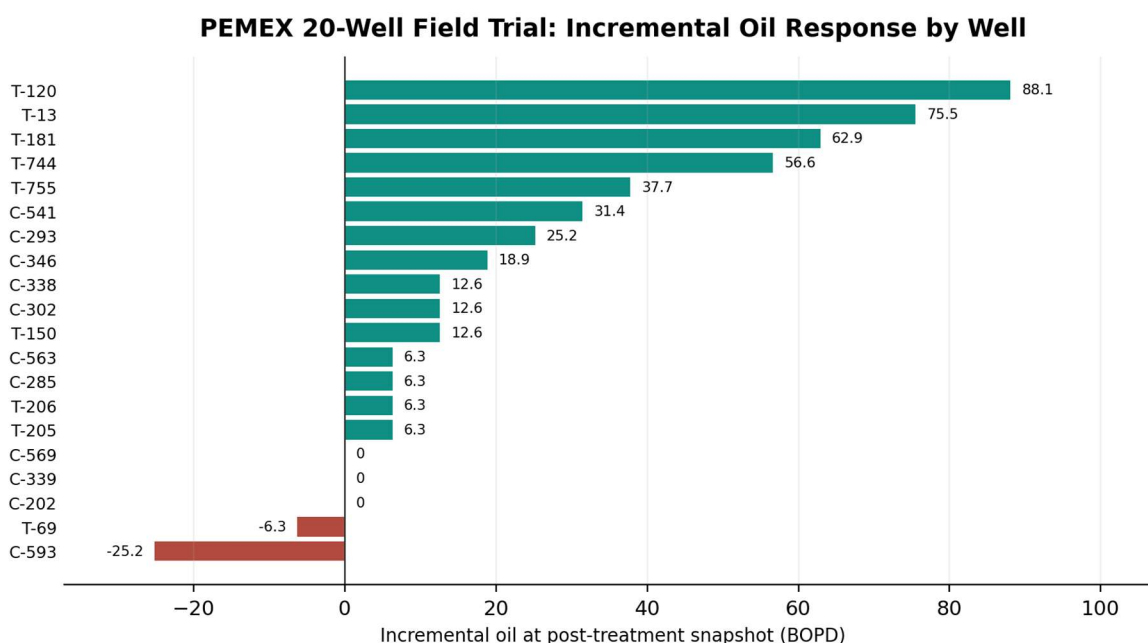


Figure 3. PEMEX 20-well incremental oil response at the post-treatment measurement snapshot. Values are calculated from the well-level net-oil data supplied using 6.29 barrels per cubic meter. The snapshot demonstrates broad but nonuniform response across the treated well population. [8]

Mixed-Reservoir and Carbonate Implications

The PEMEX trial is also important because it broadens the geological context of the historical field evidence. Public well-depth records and a representative field stratigraphic framework indicate that the 20-well population spans materially different portions of the Tamaulipas-Constituciones reservoir section, including carbonate-rich Upper Jurassic intervals, San Andrés platform carbonate, Areniscas Constituciones sandstone, basal clastics, and deeper wells that reached basement after traversing the Jurassic succession. Several strong responders have total depths near carbonate-rich or platform-carbonate intervals, while other strong responders lie near sandstone or deeper clastic intervals. [8]

This is encouraging evidence that carbonate lithology should not be treated as an automatic exclusion criterion for Ultra-MEOR screening. It is not, however, sufficient to claim that specific carbonate formations were successfully treated because total depth does not identify the perforated, producing, or treated interval. Lack of completion and intervention records temper the ability to make formation-specific attribution. Historical Ultra-MEOR results show field evidence from a mixed-reservoir mature-field setting and additionally determine that carbonate wells remain credible candidates for controlled modern validation.

Different Wells, Different Production Responses

The 20-well record also illustrates why Ultra-MEOR performance should not be reduced to a single expected mechanism. Two wells were reactivated from zero net oil. Several already-producing wells showed large increases consistent with improved deliverability. Constituciones-285 showed a selective-fluid response in which gross fluid remained approximately constant while reported water cut decreased from 70% to 52% and net oil increased. Constituciones-293 combined increased gross rate with reported water cut decreasing from 6% to about 1.4%. Conversely, Constituciones-541 increased oil materially while water cut also increased. [8]

At the field level, the PEMEX application should therefore be interpreted primarily as an oil-deliverability success rather than a universal water-reduction result. Aggregate gross fluid roughly doubled and aggregate implied water cut increased modestly from approximately 31.1% to 33.8%. This differs from the 2026 North African field validation, where average oil production increased while average produced water decreased substantially. The contrast reinforces the need to evaluate oil response, water response, and total-fluid behavior separately in each field application.

9. Dormancy and Modern Reintroduction

Despite promising historical development, the Ultra-MEOR predecessor technology became largely dormant for more than three decades. Broader MEOR activity also declined as oil prices changed, other recovery methods advanced, and the industry continued to face limitations in reservoir diagnostics and subsurface biological monitoring.

Modern reintroduction has required more than reproducing an old formulation. The current program adopted techniques used historically along with incorporating or improving defined treatment components, updated preparation procedures, controlled mixing and injection, new candidate-well screening, compatibility review, standardized baseline methodology, production monitoring, economic analysis, and a cross-well learning framework.

The modern evidence standard deliberately separates verified observations, calculated results, proposed mechanisms, and evidence gaps. This distinction is central to the current Ultra-MEOR technical program.

10. Modern Field Validation: North African National Oil Company

The principal modern field validation was conducted in 2026 on a mature conventional oil well operated by a North African National Oil Company. Consistent with the public-disclosure approach used throughout this paper, the operator, field name, and well identifier is withheld. The well was originally drilled in November 1964 to a total depth of 2,767 ft. The target is an Oligocene sandstone interval with approximately 30% porosity and 600 md permeability. The crude is 32.1° API, bottom-hole temperature is approximately 121°F, and the well produces with an electric submersible pump (ESP) artificial-lift system. The treatment was prepared and injected through existing surface and wellhead equipment, followed by a four-day shut-in and return to production using the existing ESP. No modifications to the producing completion or to the surface production facilities were required. [5]

Technical parameter	Reported value
Original drill date	November 1964
Total depth	2,767 ft
Target reservoir	Oligocene sandstone interval
Porosity	Approximately 30%
Permeability	Approximately 600 md
Oil gravity	32.1° API
Bottom-hole temperature	Approximately 121°F
Artificial lift	ESP

The accepted baseline uses three supplied pre-treatment tests dated November 16, November 26, and February 6. Those tests averaged 196.7 BOPD oil and 134.7 BWPD water. Ten post-treatment tests from April 6 through June 25 averaged 330.2 BOPD oil and 54.9 BWPD water. Average production is the arithmetic average of the accepted test values in each period. Aggregate water cut is calculated from average water divided by average total oil plus water. The individual test values used in the averages are shown below. [5]

Period / date	Oil (BOPD)	Water (BWPD)
Pre - 16 Nov 2025	173	187
Pre - 26 Nov 2025	154	30
Pre - 6 Feb 2026	263	187
Post - 6 Apr 2026	304	99
Post - 14 Apr 2026	390	33
Post - 19 Apr 2026	323	73
Post - 24 Apr 2026	334	56
Post - 4 May 2026	444	12
Post - 11 May 2026	318	66
Post - 15 May 2026	372	31
Post - 2 Jun 2026	346	44
Post - 15 Jun 2026	203	99
Post - 25 Jun 2026	268	36

Metric	Pre-Treatment Average	90-Day Post-Treatment Average	Observed Change
Oil production	196.7 BOPD	330.2 BOPD	+133.5 BOPD / +67.9%
Produced water	134.7 BWPD	54.9 BWPD	-79.8 BWPD / -59.2%
Total fluid	331.4 BFPD	385.1 BFPD	+53.7 BFPD / +16.2%
Water cut	40.6%	14.3%	-26.4 percentage points
Oil-to-water ratio	1.5:1	6.0:1	Approximately 4 times improvement

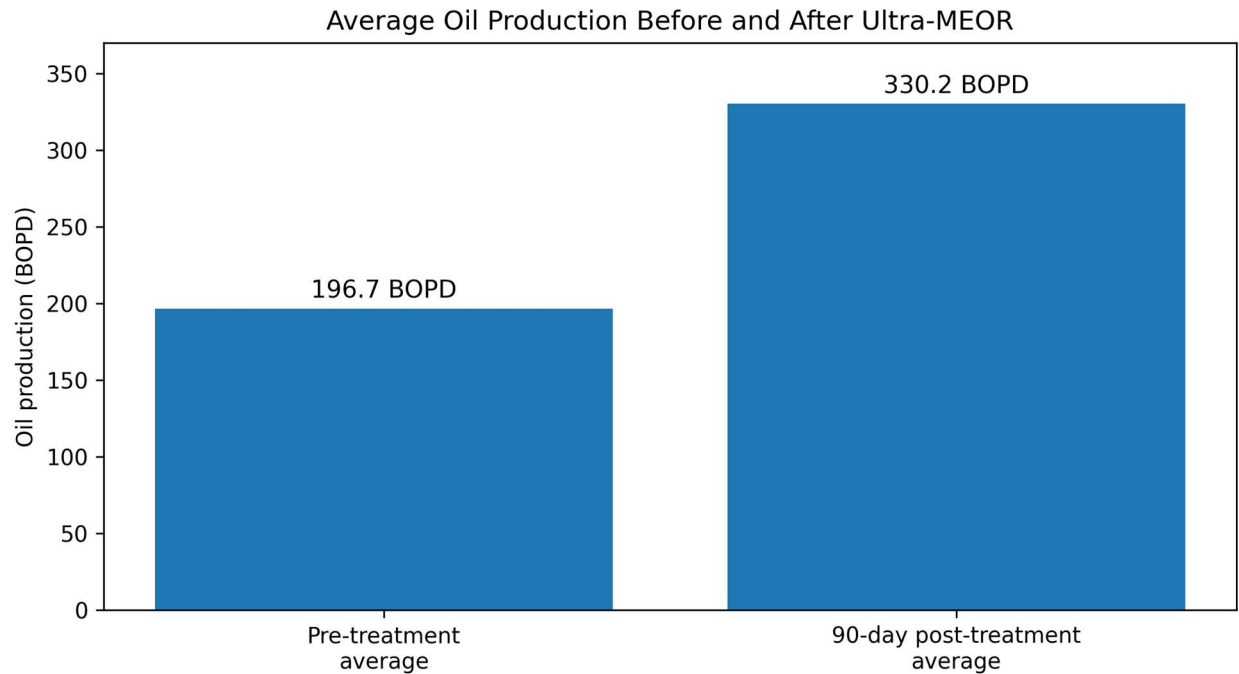


Figure 4. Average oil production increased from 196.7 BOPD before treatment to 330.2 BOPD during the 90-day post-treatment monitoring period.

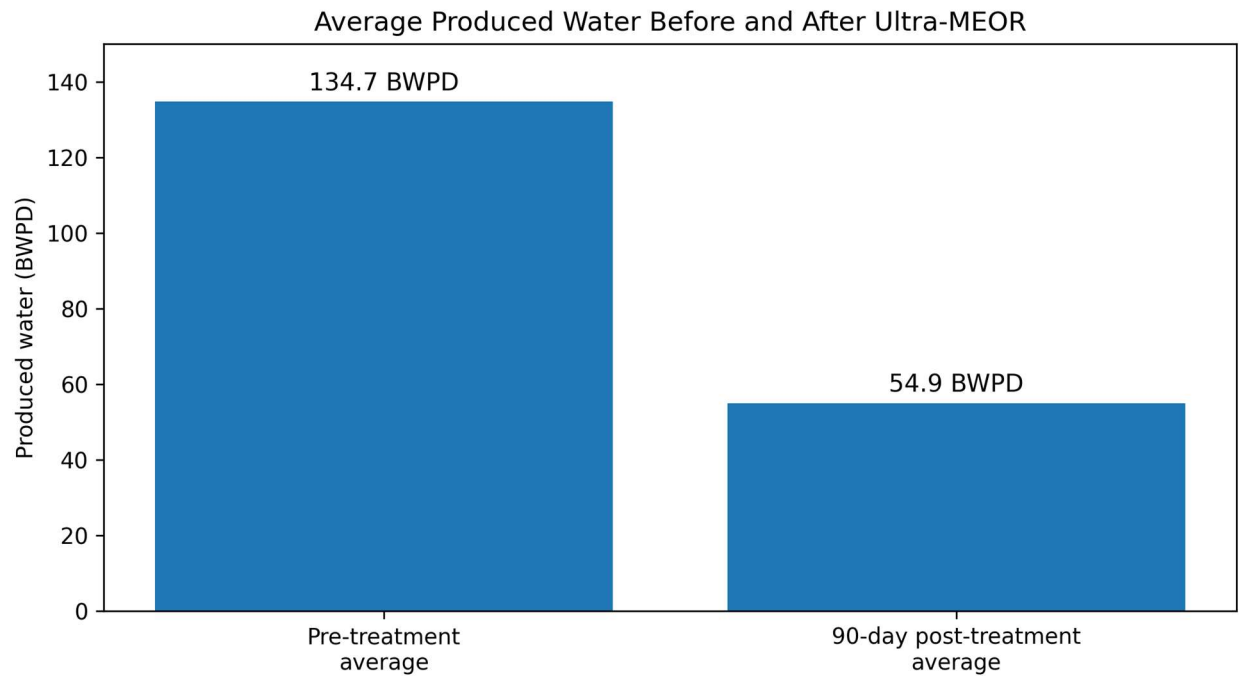


Figure 5. Average produced water decreased from 134.7 BWPD before treatment to 54.9 BWPD during the 90-day post-treatment monitoring period.

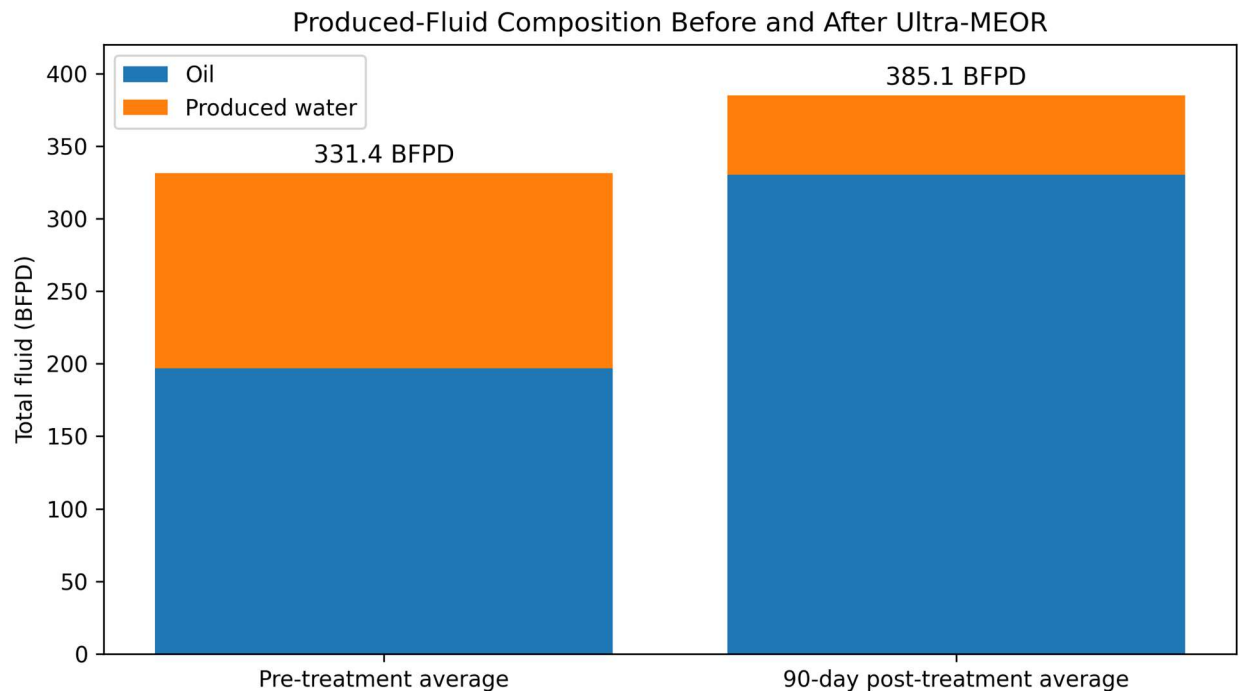


Figure 6. Average total fluid increased from 331.4 BFPD to 385.1 BFPD while the produced fluid composition shifted strongly toward oil.

Peak reported oil production reached 444 BOPD on May 4. The first post-treatment test was 304 BOPD, the response then rose above 300 BOPD for most of April and May, and oil later declined toward the pre-treatment range during June. The final test was 268 BOPD. The 90-day average therefore captures substantial incremental oil earned during the response period without assuming that the peak rate was sustained. Produced water remained materially below the final pre-treatment level through the final reported test. [5]

11. Understanding the Oil-Production Increase

The oil-production increase is the primary recovery result of the 2026 field validation. Average oil production increased from 196.7 BOPD during the accepted pre-treatment baseline to 330.2 BOPD across ten post-treatment tests, a gain of 133.5 BOPD or 67.9%. The first post-treatment test was already 54% above the baseline average, the peak test reached 444 BOPD, and the response remained above the baseline average through most of the 90-day monitoring period. [5]

Several mechanisms described in MEOR literature could contribute to such an oil response. Biosurfactants and other metabolites may reduce oil-water interfacial tension and capillary trapping. Changes at mineral surfaces may reduce oil adhesion and improve detachment from pore walls. Localized gas, acid, or metabolic effects may alter oil mobility, while microbial activity or biomass may modify preferential flow paths. In paraffin-prone systems, organic-deposit modification may also improve near-wellbore or tubular flow. Ultra-MEOR's activation strategy is intended to broaden the biological activity available to the introduced consortium compared with approaches that rely only on the native reservoir population.

The 2026 pilot did not include interfacial-tension measurements, contact-angle testing, production logging, metabolite analysis, microbial tracking, or deposit characterization, so the contribution of each mechanism cannot be allocated from the production data alone. The measured oil response nevertheless provides the strongest modern evidence that the treatment influenced production performance in this well. Future pilots can build on that result by adding targeted diagnostics designed to determine which mechanisms correlate most strongly with oil uplift and response duration. The PEMEX well-level record provides additional historical evidence that oil response can occur through more than one production pattern, including reactivation of nonproducing wells and large deliverability increases in already-producing wells. [8]

12. Understanding the Water-Reduction Response

The reduction in produced water may be as technically important as the increase in oil. Average produced water decreased from 134.7 BWPD before treatment to 54.9 BWPD during the 90-day monitoring period, while aggregate water cut declined from 40.6% to 14.3%. The final reported test showed 36 BWPD and 12% water cut compared with 187 BWPD and 42% water cut in the final pre-treatment test. [5]

Plausible explanations

One plausible explanation is a change in oil-water relative flow associated with interfacial or wettability effects. If biological activity changed surface affinity, capillary behavior, or relative permeability in portions of the reservoir, oil mobility could improve relative to water. A second possibility is selective modification of preferential water-flow pathways through biomass, biopolymers, or related biological effects, potentially redirecting some flow toward less-swept oil-bearing volume.

The water response may also reflect improved mobilization of previously retained oil, which would change the produced oil-to-water ratio even without a large increase in total fluid. Near-wellbore cleanup or organic-deposit modification could have changed inflow distribution as well. Future trials should also control artificial-lift settings, pressure, testing conditions, downtime, and other operating variables so non-biological explanations can be evaluated prospectively.

The field trial did not include production logging, tracers, wettability testing, relative-permeability measurements, or detailed metabolite diagnostics. The field results therefore establish a substantial reduction in produced water concurrent with higher oil production, while attribution among the possible reservoir and near-wellbore mechanisms remains a priority for future diagnostic work.

13. Response Duration and Retreatment

Ultra-MEOR is a biological recovery-enhancement treatment rather than a permanent reservoir modification. Historical operating experience suggests that a commercially meaningful response may persist for approximately six to fourteen weeks in suitable wells, although duration is expected to vary by well and reservoir. Historical records indicate that in one well, the response lasted 15 months.

The preferred approach is response-based retreatment rather than automatic calendar treatment. Historical experience suggests that some responsive wells may justify approximately four to five treatments per year, but this remains an operating expectation to be validated through modern multi-well data.

Future treatment records should capture anticipated decline curves, response onset, peak, average, treatment decline, water behavior, economic threshold, retreatment timing, and response to successive applications. The long-term objective is to determine the interval that maximizes cumulative incremental oil and economic return.

14. Economic Significance of the 90-Day Field Response

Using the precise underlying averages, approximately 12,018 incremental barrels of oil were calculated over the 90-day monitoring period. At an illustrative \$75 USD per barrel, gross incremental oil revenue is approximately \$901,350 USD. [5]

Economic Measure	Approximate Illustrative Result (Dollar values are USD)
Incremental oil over 90 days	12,018 barrels
Gross incremental oil revenue at \$75/bbl	\$901,350
Illustrative total intervention cost	\$50,000
Gross value above intervention cost	\$851,350
Revenue-to-cost multiple	18 times
Intervention cost per incremental barrel	\$4.16/bbl
Illustrative gross payout	5 days

These figures do not annualize peak production and do not include potential savings from reduced produced-water lifting, treatment, transportation, reinjection, disposal, chemical use, or facility loading.

15. Candidate Well Selection

Ultra-MEOR should not be defined by an arbitrary production-rate threshold. The preferred candidate is a mature conventional oil well in which credible connected oil remains and where production performance is being constrained by reservoir- or fluid-related conditions that the treatment may reasonably influence. The expanded PEMEX record also suggests that lithology alone should not be used as an exclusion criterion: strong historical responses occurred across a mixed-reservoir well population, while completion and local reservoir conditions remain more important to establish than total depth or broad rock label alone. [8]

Potentially favorable characteristics

Potentially favorable candidates have credible connected remaining oil and reservoir communication, declining oil production or increasing water production, and reservoir or fluid behavior that the treatment may reasonably influence. Paraffin or wax-related impairment may strengthen the case for evaluation. The completion should be mechanically serviceable with stable artificial lift, adequate injectivity for controlled placement, reservoir temperature and chemistry compatible with the treatment, and sufficient production history to establish a defensible baseline.

Conditions requiring additional review

Additional technical review is warranted where temperature, pH, or salinity is extreme; where biocides or strong oxidants have been used recently or remain in the system; where injectivity is severely limited or fractures may create uncontrolled communication; where casing, packer, or lift integrity is uncertain; where the production baseline is unstable or allocation is uncertain; or where there is limited evidence of connected remaining oil. Mechanical problems should be addressed mechanically before a biological recovery treatment is evaluated.

16. Traditional MEOR and Ultra-MEOR Are Not the Same

One of the most important lessons from the MEOR literature is that the category contains materially different technologies. Traditional MEOR has included indigenous microbial stimulation with injected nutrient packages, injection of selected bacterial cultures, enzyme- or biosurfactant-oriented systems, anaerobic microbial pathways, and selective-flow approaches. Ultra-MEOR uses a different system architecture: a pre-selected Natural Microbial Consortium is introduced together with matched Natural Support and Natural Activation Components under a controlled field protocol. The comparison below is intended to clarify those design differences, not to imply that every traditional MEOR program uses the same method. [1-3,7]

Comparison area	Traditional MEOR: common historical approaches	Ultra-MEOR
Microbial source	Often stimulates indigenous reservoir microorganisms or injects selected bacterial cultures; some approaches use isolated enzymes or biosurfactant systems.	Introduces a preselected, externally cultivated Natural Microbial Consortium with broad hydrocarbon-metabolizing capability.
Treatment package	May rely on carrier water plus nutrient packages, surfactants, enzyme products, or limited microbial cultures; composition varies widely.	Natural Microbial Consortium plus matched Natural Support and Natural Activation Components and a defined preparation/injection protocol.
Metabolic / oxygen strategy	Many reservoir programs emphasize anaerobic or low-oxygen pathways, although MEOR research also includes aerobic and ex-situ approaches.	Uses a proprietary activation strategy intended to support localized aerobic or microaerophilic activity in addition to the consortium's broader biological capabilities.
Dependence on reservoir ecology	Indigenous-stimulation approaches depend heavily on the organisms already present, their metabolic capability, and nutrient delivery.	Reduces dependence on the unknown native population by introducing a selected consortium, while still depending on reservoir compatibility, placement, connectivity, and remaining oil.
Typical field operation	Placement and shut-in vary by program. The supplied Petrotrin indigenous-stimulation pilot generally used a 14-day shut-in.	Historical guidance commonly used 5-10 days; the 2026 field validation used a four-day shut-in through existing wellhead infrastructure.
Field evidence in supplied record	Petrotrin indigenous-stimulation pilot: 3 of 8 wells increased, 4 were unchanged, and 1 was recompleted; laboratory response did not always translate into field response.	Positive oil responses in four government-supported clastic lease applications, the PEMEX 20-well program, the Trinidad 13-well program, and the 2026 North African pilot.

The comparison shows why results reported for one MEOR formulation or stimulation strategy should not automatically be used to predict another. Ultra-MEOR's distinguishing elements are the controlled introduction of a preselected consortium, the matched Support and Activation Components, and a standardized field protocol; its performance still depends on candidate quality, reservoir connectivity, placement, and a credible baseline.

17. Current Evidence Boundaries

The current evidence base includes historical government-supported and private development records, modern operating procedures and candidate-screening criteria, and a 2026 approximately 90-day field validation in a mature conventional well.

Supported now

The current record supports several conclusions. A controlled 2026 treatment was followed by materially higher average oil production, lower average produced water and water cut, and attractive illustrative 90-day economics. The treatment was deployed through existing infrastructure without modification to the producing completion or surface facilities. The historical record also documents positive oil responses across multiple clastic and non-carbonate programs. Taken together, these results justify additional controlled field validation.

Not yet established

The evidence does not yet establish which mechanism produced what share of the oil or water response, whether wettability or relative permeability changed, whether selective flow modification occurred, or how far the active treatment propagated into the reservoir. It also does not support universal paraffin-removal or water-control claims, statistically predictable performance across reservoir classes, or a universal retreatment interval. These remain subjects for additional field and laboratory work.

Commercial performance and mechanism proof are different evidence questions. A successful pilot can justify further use while mechanistic attribution remains under study.

18. Next-Generation Field Validation

The next evidence-building step should include additional controlled wells selected to test both repeatability and range. Some should resemble the successful 2026 sandstone candidate to test replication, while others should deliberately vary geology, permeability, oil gravity, water behavior, and other reservoir characteristics to define where the technology performs best. Each application should be treated as a standardized learning event rather than an unrelated one-off treatment. For mixed-reservoir and carbonate candidates, perforated intervals, producing formation, treatment placement, and completion architecture should be documented prospectively so future response can be attributed to the actual treated reservoir rather than inferred from total depth.

Before treatment, each pilot should define oil, water, duration, economic, safety, execution, and mechanism-learning objectives; document candidate-well evidence gates; and establish a comparable baseline. Matched untreated wells or credible decline counterfactuals should be used where practical. Preparation, injection, displacement, shut-in, restart, and monitoring should be standardized, and monitoring should continue through material decline or the retreatment decision.

Selected pilots should add diagnostics such as pressure-transient analysis, production logging, tracers, interfacial-tension testing, wettability testing, fluid or deposit analysis, and microbiological sampling when those measurements address priority questions. Every result should enter a cross-well performance database so candidate prediction, response duration, retreatment timing, and mechanism understanding improve with each application.

The persistent water response should be an important consideration. If repeatable, it may create value not only through incremental oil but also through lower lifting, separation, chemical, disposal, reinjection, and facility-capacity burdens.

19. Conclusions

Microbial enhanced oil recovery is not a new concept, and historical results have been mixed. That history demonstrates both the potential of microbial recovery mechanisms and the importance of microbial selection, reservoir compatibility, treatment design, candidate screening, and field measurement.

Ultra-MEOR represents a differentiated modern approach. It combines a broad Natural Microbial Consortium with purpose-designed Natural Support and Natural Activation Components and a controlled field protocol. By introducing a selected microbial population and an activation strategy intended to support localized aerobic or microaerophilic activity, the system differs materially from many traditional MEOR programs based primarily on indigenous microbial stimulation, nutrient injection, limited cultures, or anaerobic pathways.

The most important modern evidence is the 2026 field validation conducted on a mature conventional oil well operated by a North African National Oil Company. Average oil production increased from 196.7 BOPD to 330.2 BOPD, average produced water decreased from 134.7 BWPD to 54.9 BWPD, average total fluid increased from 331.4 BFPD to 385.1 BFPD, and aggregate water cut decreased from 40.6% to 14.3%. [5]

The significance of this result is the nuance that it was not simply an increase in total fluid production. The produced fluid composition shifted substantially toward oil while water production declined. The precise mechanism responsible remains unresolved and should be a priority in future controlled trials.

Ultra-MEOR has demonstrated a strong modern single-well proof of concept supported by a broader historical record that includes positive clastic lease applications, a substantial 20-well PEMEX field response, and a Trinidad multi-well program. The PEMEX data are especially useful because they show response across individual wells rather than only an aggregate field total: 15 of 20 wells increased oil production, three were unchanged, and two declined at the post-treatment snapshot. The evidence does not yet establish statistically predictable performance across a broad range of reservoirs, but it strengthens the case for both repeat applications in comparable candidates and carefully selected trials in different reservoir settings to define repeatability and operating range.

Many mature oilfields reach economic limits before they reach geological limits. The objective of Ultra-MEOR is to help operators economically recover more of the oil that remains.

20. References and Source Basis

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[5] North African National Oil Company field records and UltraTech International 90-day field performance and economic analysis, 2026. Operator identity and specific well/field identifiers withheld in this public draft.

[6] Advanced Technology Group historical technical archive. Government-supported and private microbial petroleum field-development records from the late 1980s through 1990s, including residual-oil recovery and paraffin-related observations. Supplier-identifying provenance and formulation details are intentionally omitted from this public document.

[7] Petrotrin. “MEOR Pilot Project at Petrotrin Using Indigenous Microorganisms.” 2000. Used in this paper to characterize a traditional indigenous-microbial stimulation approach and its reported field response.

[8] Advanced Technology Group. “PEMEX Tamaulipas-Constituciones 20-Well Field Trial: Production Response, Potential Geology and Mixed-Reservoir Interpretation.” August 2026. Analysis integrates a supplied 1996 PEMEX production table with public well-location and depth records and a representative field-level stratigraphic framework. Formation-specific attribution remains subject to completion-record confirmation.

Appendix A. 2026 North African Field Validation Summary

Item	Summary
Application	Mature conventional oil well operated by a North African National Oil Company
Original well drilling	1964
Treatment	One Ultra-MEOR application through existing infrastructure
Technical shut-in	Approximately four days
Post-treatment monitoring	Approximately 90 days
Average oil production	196.7 BOPD before treatment; 330.2 BOPD post-treatment
Average produced water	134.7 BWPD before treatment; 54.9 BWPD post-treatment
Average total fluid	331.4 BFPD before treatment; 385.1 BFPD post-treatment
Water cut	40.6% before treatment; 14.3% post-treatment
Peak reported oil	444 BOPD
Incremental oil	Approximately 12,018 barrels over 90 days using unrounded averages
Illustrative gross incremental revenue	Approximately \$901,350 at \$75/bbl
Target reservoir	Oligocene sandstone interval
Total depth	2,767 ft
Porosity / permeability	Approximately 30% / 600 md
Oil gravity / bottom-hole temperature	32.1° API / approximately 121°F
Artificial lift	ESP