



Data-Constrained Screening and Simulation Design of Alkali–Surfactant and Alkali–Surfactant–Polymer Flooding in the Bu-Attifel Lower Nubian Sandstone Reservoir

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Abstract

Background: Chemical enhanced-oil-recovery performance is reservoir-specific because IFT reduction, soap generation, adsorption, phase behavior, mobility control, and injectivity interact nonlinearly. The Bu-Attifel Field has a history-matched reservoir foundation, but its AS/ASP chemical description has not been calibrated.

Methods: This study preserves the field, well, geological, dynamic, and base-case information reported in the author's thesis. AS is defined as alkali plus surfactant without polymer; ASP adds polymer for mobility control. A mechanism-constrained screening workflow was developed from the documented base-case endpoints and published analogue evidence. The workflow explicitly separates thesis-derived data, external analogue observations, and new engineering assumptions. No original polymer-only result is reused as an AS/ASP result, and no executable CMG–STARS AS/ASP run is claimed.

Results: The documented base-case oil rate declines from 7,136 to 5,184 bbl/d between 1 October 2021 and 30 September 2031, while the reported model water cut at the start of prediction is 77.2%. The screening envelope indicates 0.5–4.0 percentage points of incremental recovery factor for AS and 1.5–7.0 percentage points for ASP. Assumed end-period oil-rate endpoints range from 5,443 to 6,480 bbl/d for AS and from 5,702 to 7,258 bbl/d for ASP. These values are engineering scenarios, not CMG–STARS outputs, measurements, or probabilistic quantiles. AS is expected to provide primarily microscopic-displacement benefits; ASP can add sweep improvement through polymer mobility control but carries higher risks of pressure increase, retention, degradation, incompatibility, and injectivity loss.

Conclusions: The central technical distinction is not the chemical label but the additional transport mechanism supplied by polymer. AS is the lower-complexity screening option. ASP should be advanced only after oil/brine compatibility, IFT, phase behavior, adsorption, polymer rheology, retention, coreflood, and injectivity data are available. The resulting manuscript is a transparent field-specific screening and simulation-design study; a Q1-level original numerical claim requires the missing chemical dataset and a verified CMG–STARS deck.

Research highlights

- A field-specific AS/ASP screening framework is built on the Bu-Attifel history-matched reservoir foundation.
- AS and ASP are separated by mechanism: IFT-driven microscopic displacement versus combined displacement and polymer mobility control.
- All new numerical values are labelled as engineering estimates rather than simulator outputs or probability quantiles.
- A falsifiable laboratory-to-CMG–STARS workflow is specified for upgrading the

screening study to a numerical investigation.

Keywords: alkali-surfactant flooding; ASP flooding; chemical EOR; Lower Nubian Sandstone; Bu-Attifel Field; CMG-STARS; interfacial tension; adsorption; mobility control; water cut.

التصميم القائم على البيانات لعمليات الفرز والمحاكاة لحقن القلويات-المواد الخافضة للتوتر السطحي والقلويات-المواد الخافضة للتوتر السطحي-البوليمر في مكن الحجر الرملي النوبي السفلي بحقل ابو الطفل

الملخص

الخلفية:

تختلف كفاءة الاستخلاص المعزز للنفط كيميائياً (Chemical Enhanced Oil Recovery, CEOR) من مكن إلى آخر، وذلك لأن خفض التوتر السطحي البيني (IFT) وتكون الصابون والامتزاز وسلوك الأطوار والتحكم في الحركة وقابلية الحقن تتفاعل فيما بينها بصورة غير خطية. ويتميز حقل أبو الطفل بوجود أساس موثق لنموذج المكن تمت مواعته تاريخياً (History Matched Reservoir Model)، إلا أن الوصف الكيميائي لعمليات AS/ASP لم تتم معابرته بعد.

المنهجية:

تحافظ هذه الدراسة على معلومات الحقل والآبار والبيانات الجيولوجية والديناميكية ومعلومات الحالة الأساسية (Base Case) الواردة في أطروحة الباحث. ويُعرّف نظام AS بأنه استخدام القلويات بالإضافة إلى المادة الخافضة للتوتر السطحي دون إضافة البوليمر، بينما يضيف نظام ASP البوليمر بهدف التحكم في حركة السوائل وتحسين كفاءة الاجتياح. وقد تم تطوير منهجية للفرز والتقييم (Screening Workflow) مقيّدة بالآليات الفيزيائية، بالاعتماد على مؤشرات الحالة الأساسية الموثقة والأدلة المنشورة من المكامن المماثلة. وتفصل المنهجية بشكل واضح بين البيانات المستمدة من الأطروحة، والملاحظات المستمدة من المكامن المماثلة الخارجية، والافتراضات الهندسية الجديدة. ولم يتم إعادة استخدام أي نتائج أصلية خاصة بالحقن بالبوليمر فقط على أنها نتائج لعمليات AS/ASP، كما لا تدعي الدراسة إجراء تشغيل فعلي قابل للتنفيذ باستخدام برنامج CMG-STARS لمحاكاة عمليات AS/ASP.

النتائج:

ينخفض معدل إنتاج النفط في الحالة الأساسية الموثقة من 7,136 برميل/يوم إلى 5,184 برميل/يوم خلال الفترة من 1 أكتوبر 2021 إلى 30 سبتمبر 2031، في حين بلغت نسبة الماء (Water Cut) في النموذج المبلغ عنها عند بداية فترة التنبؤ 77.2%. وتشير نافذة الفرز الهندسي (Screening Envelope) إلى زيادة متوقعة في معامل الاستخلاص تتراوح بين 4.0-0.5 نقاط مئوية لنظام AS، وبين 7.0-1.5 نقاط مئوية لنظام ASP. وتتراوح القيم المفترضة لمعدلات إنتاج النفط في نهاية الفترة بين 5,443 و6,480 برميل/يوم لنظام AS، وبين 5,702 و7,258 برميل/يوم لنظام ASP. وتُعد هذه القيم سيناريوهات هندسية وليست نواتج لمحاكاة CMG-STARS، أو قياسات فعلية، أو كميات احتمالية (Probabilistic Quantiles) ومن المتوقع أن يوفر نظام AS بصورة أساسية فوائد مرتبطة بتحسين الإزاحة المجهرية (Microscopic Displacement)، بينما يمكن لنظام ASP أن يضيف تحسناً في كفاءة الاجتياح (Sweep Efficiency) من خلال التحكم في حركة السوائل بواسطة البوليمر. ومع ذلك، يرتبط نظام ASP بمخاطر أعلى تشمل زيادة الضغط، واحتجاز البوليمر، والتحلل، وعدم التوافق، وانخفاض قابلية الحقن.

الاستنتاجات:

يتمثل الفرق التقني الأساسي بين النظامين ليس في التسمية الكيميائية بحد ذاتها، وإنما في آلية النقل الإضافية التي يوفرها البوليمر. ويُعد AS الخيار الأقل تعقيداً في مرحلة الفرز الأولي. أما ASP فينبغي الانتقال به إلى مراحل متقدمة فقط بعد توفر بيانات كافية حول توافق النفط/المحلول الملحي، والتوتر السطحي البيني (IFT)، وسلوك الأطوار، والامتزاز، وريولوجيا البوليمر، والاحتجاز، واختبارات الإزاحة اللبية (Coreflood)، وقابلية الحقن (Injectivity). وبناءً على ذلك، تمثل هذه المخطوطة دراسة شفافاً ومحددة الحقل لفرز الخيارات الكيميائية وتصميم المحاكاة. أما تقديم ادعاء رقمي أصلي بمستوى بحث مناسب لمجلة Q1 فيتطلب توفير مجموعة البيانات الكيميائية المفقودة ووجود نموذج CMG-STARS موثق وقابل للتحقق (Verified CMG-STARS Deck).

1. Introduction

Mature water flooded sandstone reservoirs can retain oil because of capillary trapping, unfavorable mobility ratio, vertical and areal heterogeneity, and early water breakthrough. Surfactants target the microscopic displacement problem by reducing oil-water IFT and increasing the capillary number. Alkali can react with acidic components of crude oil to generate in-situ soap, reduce surfactant adsorption under favorable conditions, and alter rock-fluid interactions. ASP flooding adds polymer to control the mobility of the aqueous phase and improve sweep. Laboratory and field studies show that the combined response is not necessarily the arithmetic sum of the individual chemicals; polymer rheology, alkali concentration, IFT,

multicomponent adsorption, and transport can interact nonlinearly (Chen et al., 2018).

The principal research gap for Bu-Attifel is not the absence of a reservoir model. The thesis provides a field-specific foundation, including the geological units, well configuration, dynamic history period, and base-case forecast. The gap is the absence of a calibrated chemical description and an executable chemical-flood deck. Replacing the word “polymer” in a thesis model with “AS” or “ASP” would not constitute a valid chemical-EOR study. A defensible conversion requires new chemical components, transport equations, phase-behavior data, adsorption and reaction functions, and laboratory or pilot calibration (Goudarzi et al., 2016; Douarche et al., 2012).

This paper therefore has two objectives:

1. To define a scientifically explicit AS and ASP formulation while preserving the Bu-Attifel reservoir foundation.
2. To quantify a conservative, transparent screening envelope and identify the measurements and simulation steps required before the estimates can be upgraded to numerical results.

The paper is intentionally positioned as a mechanism-constrained engineering forecast and simulation-design study. This positioning avoids false precision and separates documented thesis results, published analogue evidence, and new engineering estimates.

Chemical flooding is particularly relevant to mature reservoirs with high water cut because a substantial fraction of the remaining oil may be distributed as disconnected ganglia or bypassed by preferential water flow. Surfactant flooding addresses the capillary-trapping component by reducing oil–water interfacial tension, while alkaline flooding can create surface-active petroleum soaps when sufficient acidic species are present in the crude oil. Polymer addition addresses a different scale of the problem by increasing aqueous resistance and improving the conformance of the displacement front. These mechanisms should be evaluated separately before their combined effect is interpreted.

The distinction is important for the Bu-Attifel case. A field-scale model that was previously used to study polymer flooding cannot be converted into an AS or ASP model by changing only the injection label. The chemical formulation changes the transport equations, component balances, adsorption terms, phase behavior, relative-permeability response, and operational constraints. In addition, the reported reservoir temperature of 240 °F and the uncertainty in the stated brine salinity make chemical compatibility and thermal stability central design questions.

The engineering question is therefore not simply whether ASP is theoretically stronger than AS. The practical question is which mechanisms can plausibly survive transport through the Bu-Attifel sandstone and produce incremental oil without unacceptable pressure, injectivity, emulsion, scaling, or chemical-loss penalties. This study addresses that question using the thesis reservoir foundation and a conservative analogue-informed forecast envelope. It also identifies the laboratory measurements needed to convert the screening study into a calibrated numerical investigation.

The contribution of this paper is threefold. First, it establishes a transparent field-specific baseline from the reported history match. Second, it separates the expected AS response from the additional mobility-control response of ASP. Third, it provides a reproducible decision framework in which every new numerical value is labelled according to its evidence status. This approach is preferable to reporting unsupported precision when the original chemical data and executable simulator deck are unavailable.

2. Field and reservoir foundation

2.1 Geological and well framework

The study concerns the Bu-Attifel Field in the XX-Block of Concession 82, Libya. The target interval is the Upper Pool of the Lower Nubian Sandstone. The geological framework contains five principal sand bodies—C2, C1, B2, B1, and A2—represented by ten simulation layers: layer 1 for C2; layers 2–3 for C1; layers 4–6 for B2; layers 7–9 for B1; and layer 10 for A2. The wells are XX-1 through XX-6 and are described as vertical in the thesis. The original completion intervals, conversion history, well controls, and injector allocation must be retained when the chemical model is rebuilt (Algamody, 2024).

2.2 Fixed information retained from my master’s study.

Table 1: The fixed reservoir foundation used for the AS and ASP screening exercise and distinguishes verified study values from items that still require confirmation in the executable model or laboratory programme.

Model element	Value retained from my master’s study	Status in this study
Field	Bu-Attifel Field, XX-Block, Concession 82	Fixed foundation
Formation	Lower Nubian Sandstone, Upper Pool	Fixed foundation
Geological units	C2, C1, B2, B1, A2	Fixed foundation
Simulation layers	10	Fixed foundation
Wells	XX-1 to XX-6	Fixed foundation; completion details require deck verification
Simulator framework	CMG–STARS	Framework to be rerun
History period	1991–2021	Fixed foundation
Prediction period	1 October 2021–30 September 2031	Fixed foundation
Initial pressure	5,300 psia	Fixed foundation
Reservoir temperature	240 °F	Fixed foundation
Initial oil–water contact	11,437 ft	Fixed foundation
Overburden pressure	8,200 psia	Fixed foundation
Reported water salinity	230 gr/L in the thesis	Unit and ionic composition require verification
Water specific gravity	1.116	Fixed as reported; laboratory verification required
Water viscosity	0.3943 cP at 5,305 psia	Fixed as reported
Base-case cumulative oil	251.942 MMbbl	Base-case accounting anchor
Reported base recovery factor	46%	Thesis value; implied OOIP is not independently verified

The thesis history match reports an average model production rate of 7,091 bbl/d versus 7,136

bbl/d for the field data, an average percentage error of 2.063%, and an R^2 of approximately 0.942. On 1 October 2021, the model water cut was 77.2% versus 78.15% for the reported field data. These statistics support use of the reservoir model as a starting foundation; they do not validate any AS or ASP response.

2.3 Base-case arithmetic check

The reported oil-rate decline from 7,136 to 5,184 bbl/d is:

$$\left[100 \left(1 - \frac{5184}{7136} \right) = 27.35\% \right]$$

The relative difference between the reported field and model water cuts is:

$$\left[100 \frac{78.15 - 77.2}{78.15} = 1.22\% \right]$$

The thesis cumulative oil and recovery factor imply an approximate oil-in-place anchor of 547.7 MMbbl, calculated as $251.942/0.46$. This is an accounting inference only and must be replaced by the OOIP read directly from the executable model before publication of numerical AS/ASP results.

3. Materials and Methods

3.1 Chemical definitions and mechanisms

The AS case contains compatible brine, alkali, and surfactant, with no polymer. Surfactant reduces IFT and can mobilize capillary-trapped oil when the capillary number increases. Alkali can generate petroleum soap from acidic oil components and can reduce surfactant loss in some rock–brine–oil systems. The response is strongly dependent on total acid number, brine hardness, mineralogy, pH, optimum salinity, phase behavior, and adsorption. A low IFT measured in a vial does not by itself prove a high recovery response in a heterogeneous reservoir.

AS has no deliberate polymeric mobility-control mechanism. It can therefore mobilize oil without sufficiently improving the stability of the aqueous front. In high-permeability streaks, this may cause rapid chemical and water communication to producers. AS may nevertheless be attractive where injectivity, chemical simplicity, or polymer compatibility is a limiting concern.

3.1.1 ASP flooding

The ASP case contains the same alkali and surfactant functions and adds polymer. Polymer increases aqueous-phase viscosity and can reduce the mobility ratio, thereby improving areal and vertical sweep. The expected benefit is a combination of microscopic displacement improvement from alkali/surfactant action and macroscopic sweep improvement from mobility control.

The interaction is non-additive. Alkali can reduce polymer contribution to viscosity, while polymer can change surfactant transport and adsorption. Polymer can also be lost through adsorption, inaccessible pore volume, mechanical retention, and shear degradation. Salinity and divalent ions may reduce viscosity or destabilize the formulation. Consequently, polymer viscosity from the original polymer-only thesis case cannot be transferred into ASP without new measurements. The ASP case must be calibrated as a new multicomponent chemical system (Chen et al., 2018).

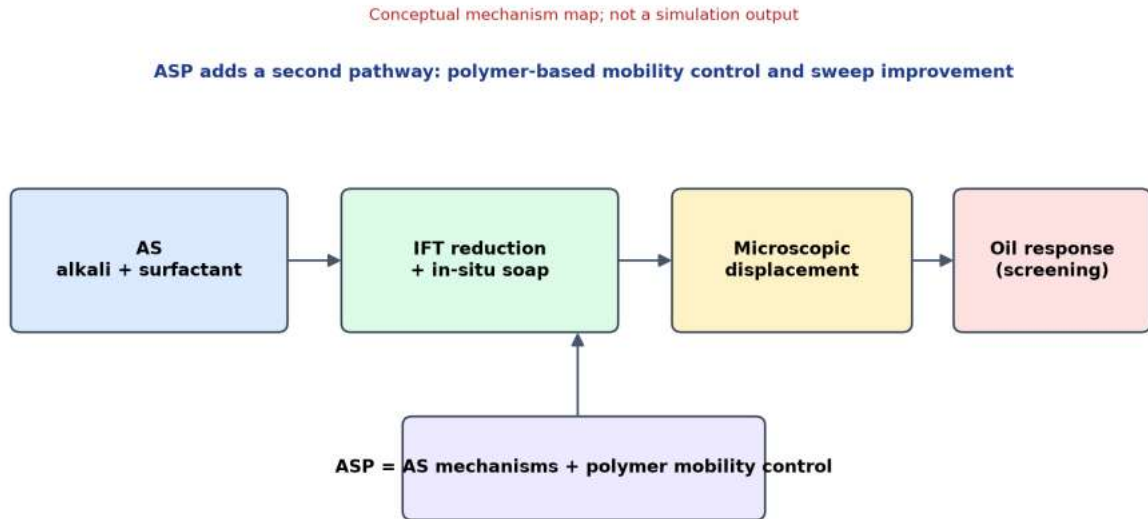


Figure 1. Conceptual mechanism map for AS and ASP. The figure summarizes the expected causal pathway and is not a simulator output.

3.1.2 Evaluation equations

Recovery factor is defined as:

$$[RF(t) = 100 \frac{N_p(t)}{OOIP}.]$$

Incremental cumulative oil relative to the base case is:

$$[\Delta N_p(t) = N_{p, \text{chemical}}(t) - N_{p, \text{base}}(t).]$$

The water-to-oil mobility ratio is represented conceptually by:

$$[M = \frac{\lambda_w}{\lambda_o} = \frac{k_{rw} \mu_o}{k_{ro} \mu_w},]$$

and the capillary number by:

$$[N_c = \frac{\mu v}{\sigma},]$$

where (k_r) is relative permeability, (μ) is viscosity, (v) is characteristic velocity, and (σ) is oil–water IFT. AS acts primarily through (σ), whereas ASP also changes the aqueous viscosity and therefore the mobility ratio. These equations describe the evaluation logic; the calibrated STARS model must provide the constitutive relationships used in the final calculations.

3.2 Evidence architecture and uncertainty language

The manuscript uses three evidence classes. Class A comprises values directly reported in the thesis, including the field description, history-match statistics, base-case endpoints, and reported reservoir conditions. Class B comprises observations from external studies, which constrain mechanism plausibility but are not transferred as Bu-Attifel measurements. Class C comprises the screening assumptions introduced in this study, including incremental recovery ranges, assumed end-period rates, and assumed water-cut targets. Every Class C value is labelled as an engineering estimate and is excluded from claims of validation.

The terms *Low*, *Central*, and *High* denote deterministic engineering cases. They are not P10, P50, or P90 values because no probability distributions, ensemble realizations, or uncertainty-weighting procedure was available. No statistical significance test is appropriate for the endpoint assumptions. The principal falsification tests are instead physical: formulation stability, IFT

response, adsorption and retention, polymer viscosity after brine contact, coreflood recovery, pressure response, and agreement between calibrated chemical-model outputs and laboratory data.

3.3 Reservoir-model preservation and simulation workflow

3.3.1 Base-model preservation

The first step is to duplicate the history-matched model and verify that the duplicate reproduces the reported base case. Grid geometry, porosity, permeability, PVT, relative permeability, transmissibility, well completion, well controls, dates, and operating constraints must remain unchanged. Any discrepancy must be diagnosed before adding chemical components. Reservoir parameters must not be returned to obtain a preferred AS or ASP response.

3.3.2 Required chemical characterization

The minimum chemical dataset is listed below. These data are not optional details; they determine whether a chemical front reaches the reservoir and whether the simulated response is physically meaningful.

Table 2: The data showed why ASP has a greater data burden than AS: polymer rheology, retention, and degradation must be characterized in addition to the alkali–surfactant system.

Required input	AS	ASP	Why it matters
Alkali identity and concentration	Required	Required	Controls pH, soap generation, reactions, scaling, and consumption
Surfactant identity and concentration	Required	Required	Controls CMC, IFT, adsorption, partitioning, and phase behavior
Polymer identity and concentration	Not used	Required	Defines ASP mobility control
Oil total acid number	Required	Required	Constrains in-situ soap generation
Formation/injection -brine ionic composition and hardness	Required	Required	Controls IFT, adsorption, viscosity, and scaling
IFT versus concentration, salinity, and pH	Required	Required	Converts chemical composition into capillary response
Phase behavior and optimum salinity	Required	Required	Determines microemulsion and solubilization behavior
Alkali and surfactant adsorption	Required	Required	Determines chemical loss and front retardation
Alkali consumption and ion exchange	Required	Required	Determines effective alkalinity at reservoir distance

Chemical relative permeability or capillary-desaturation data	Required	Required	Links IFT to residual oil displacement
Polymer rheology, retention, and degradation	Not used	Required	Determines ASP injectivity and mobility control
Dispersion and mixing parameters	Required	Required	Controls front spreading and concentration decay

The thesis reports water salinity as 230 gr/L, but the unit and ionic composition require verification. This value must not be used as a chemically complete brine description until calcium, magnesium, sulfate, bicarbonate, chloride, pH, and hardness are established.

3.3.3 Injection schedule and operational constraints

Each case should be represented explicitly as a preflush, chemical slug, mobility-control stage where applicable, and chase-water stage. AS should not be assigned a polymer buffer. ASP may include a polymer preslug or buffer only if justified by laboratory and injectivity data. The schedule must specify slug sizes in pore volumes, concentration histories, injector allocation, rate or BHP control, maximum allowable pressure, and post-flush duration.

The key operational discriminator is injectivity. The selected design must improve oil recovery without exceeding formation-integrity or fracture-pressure limits. Peak injector BHP, pressure gradient, resistance factor, chemical retention, and producer response should be reported for every realization.

3.3.4 Uncertainty design

After chemical calibration, the numerical study should vary adsorption, IFT response, alkali consumption, dispersion, residual-oil endpoints, slug size, injection rate, and well allocation. ASP cases should additionally vary polymer concentration, viscosity, retention, inaccessible pore volume, and shear degradation. P10/P50/P90 labels should be used only after a documented probabilistic workflow with distributions and independent realizations. The Low/Central/High cases in this paper are engineering cases, not statistical quantiles.

4. Results and Discussion

4.1 Evidence-status results

The study produces one documented baseline, one analogue-informed mechanism interpretation, and one screening envelope. The baseline is anchored to the thesis and is therefore field-specific but limited to the reported endpoints. The analogue evidence supports the existence of AS/ASP mechanisms under selected chemical and reservoir conditions, but it does not calibrate Bu-Attifel. The screening envelope is the only new quantitative output and is conditional on the assumed OOIP anchor, chemical propagation, and operational response.

This evidence structure is a deliberate quality-control measure. It prevents three common forms of overclaiming: treating an analogue as a field measurement, treating an endpoint assumption as a time-series curve, and treating a deterministic scenario as a probabilistic forecast. The missing chemical data are not a minor reporting gap; they determine whether the proposed

mechanisms survive transport through the reservoir.

4.2 Analogue evidence and forecast construction

Published work supports the mechanisms but does not provide a direct Bu-Attifel calibration. Chen et al. demonstrated experimentally and numerically that ASP viscosity can vary nonlinearly with polymer concentration; alkali can limit polymer contribution to viscosity; petroleum acid can generate soap; polymer can affect surfactant adsorption and IFT; and multicomponent adsorption is needed to reproduce laboratory behavior (Chen et al., 2018). These findings directly support treating ASP as a coupled chemical system rather than as polymer flooding with an added label.

A chemical-screening study for a mature Kazakhstani sandstone field reported that sodium carbonate reduced surfactant adsorption by approximately 9–21% in its tested system, and that an optimized formulation reached a Winsor III microemulsion with IFT of 0.2 mN/m. The same study found that the AS coreflood response was lower than the corresponding nanoparticle–surfactant case (Dauyltayeva et al., 2023). These are measurements for a different field and cannot be assigned to Bu-Attifel; they are used only to demonstrate the scale and importance of chemical screening.

The Daqing pilot record reports two ASP pilots, more than 20% OOIP incremental recovery over waterflood in the pilot/coreflood context, reduced water cut, increased oil production, and manageable emulsions (Demin et al., 1996). A separate high-temperature, high-water-cut sandstone application reported 24.2% OOIP incremental recovery in coreflooding under its optimal formulation and an estimated 14.2% OOIP ultimate recovery increase for the field application (Li et al., 2020). These results are upper-context analogues, not direct estimates for Bu-Attifel. Their reservoir conditions, chemical formulations, and calibration evidence differ materially.

To avoid transferring analogue performance without calibration, the present study uses a conservative engineering envelope. The central values are intentionally below the strongest analogue responses and are presented only as decision-screening estimates.

4.3 Screening-level forecast envelope

The table below is the principal new quantitative output of this paper. It is an **analogue-constrained engineering estimate**, not a CMG–STARS result, field measurement, or statistical P10/P50/P90 forecast. Incremental oil is calculated using the inferred 547.7 MMbbl OOIP anchor and therefore must be recalculated when the executable deck provides the verified OOIP.

4.3.1 Audit of oil-rate and water-cut comparisons

The available thesis material provides two oil-rate endpoints for the base case—7,136 bbl/d at the beginning of the prediction period and 5,184 bbl/d at its end—but it does not provide the complete monthly or yearly base-case time series in the supplied files. It reports the model water cut at the start of prediction as 77.2%; a verified end-of-period base-case water cut is not available. Consequently, this paper does not claim that it contains simulated oil-rate or water-cut curves, nor does it claim a measured time of oil-bank arrival, curve crossing, water-cut minimum, or chemical breakthrough.

The endpoint oil-rate comparisons are arithmetically consistent with the documented base-case end rate of 5,184 bbl/d. The implied uplifts are 5.0%, 15.0%, and 25.0% for the AS Low, Central,

and High cases, respectively, and 10.0%, 25.0%, and 40.0% for the corresponding ASP cases. These are endpoint assumptions used to construct the screening envelope. The water-cut values in the next table are also assumed end-period screening values; their differences are measured against the reported initial model water cut of 77.2%, not against a verified end-of-period base-case water cut. They must therefore not be described as simulated water-cut reductions relative to the base case. They are intended to define a transparent range for laboratory and simulation design, not to support investment sanctioning.

Table 3 records the evidence boundary for each comparison before the numerical screening table is introduced.

Comparison item	What is documented	No claim can be made about curve shape, breakthrough time, oil-bank arrival, or water-cut minimum
Base oil-rate behavior	7,136 bbl/d at the start and 5,184 bbl/d at the end of prediction	
AS/ASP oil-rate response	Screening endpoint assumptions	
Base water cut	77.2% at prediction start; 78.15% field value at the same reference date	
AS/ASP water cut	Assumed end-period values in the screening envelope	
Curves and breakthrough	No chemical time-series outputs supplied	

Table 4: Oil-rate and water-cut evidence audit and separates documented base-case endpoints from assumed AS/ASP screening endpoints.

Method	Engineering case	Assumed incremental RF (percentage points)	Incremental cumulative oil (MMbbl)	Assumed end-period oil rate (bbl/d)	Oil-rate uplift vs base end (%)	Assumed end-period water cut (%)	Implied RF (%)
AS	Low	0.5	2.74	5,443	5.0	77.2	46.5
AS	Central	2.0	10.95	5,962	15.0	75.2	48.0
AS	High	4.0	21.91	6,480	25.0	72.2	50.0
ASP	Low	1.5	8.22	5,702	10.0	75.2	47.5
ASP	Central	4.0	21.91	6,480	25.0	71.2	50.0
ASP	High	7.0	38.34	7,258	40.0	66.2	53.0

The table implies that AS could deliver a modest incremental response if IFT reduction, soap generation, adsorption, and chemical propagation are favorable. Its high case requires unusually favorable chemistry and should not be used for project sanctioning. ASP has a larger upside because it adds mobility control, but its high case is also conditional on acceptable pressure, retention, and polymer rheology. In particular, the ASP central rate is not a new simulation output and must not be cited as a predicted production rate in an investment decision.

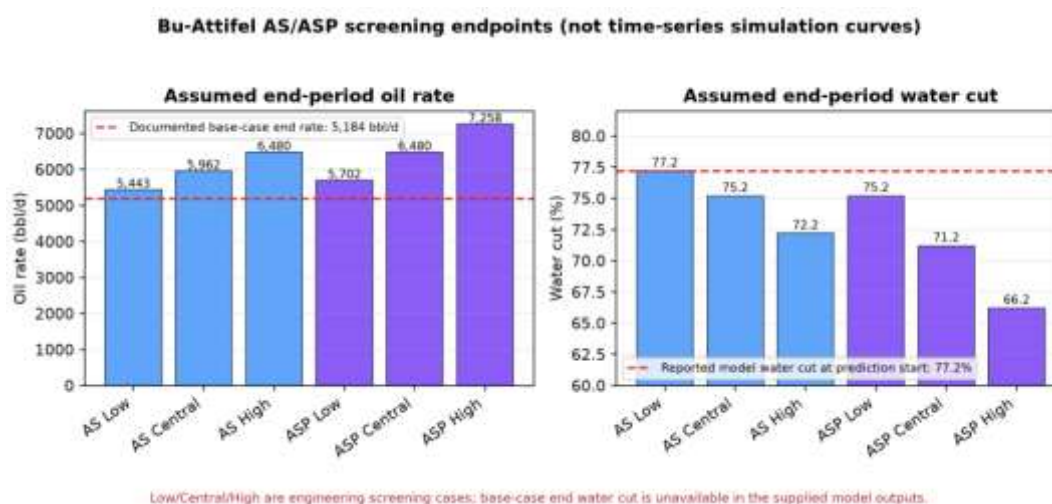


Figure 2. Assumed end-period oil-rate and water-cut screening endpoints. The red reference lines represent different documented base-case reference dates; they do not define a simulated time-series curve. The figure must not be interpreted as a history-match or CMG–STARS production plot.

4.3.2 Expected behavior of AS

AS should exhibit a delayed response associated with chemical-front arrival and reaction. If the IFT is reduced sufficiently, an oil bank may form and water cut may decline after an initial transient. However, the water front can continue to move rapidly through high-permeability streaks because AS does not provide polymeric mobility control. Pressure may increase because of emulsion formation, scaling, phase trapping, or changes in relative permeability, even when the injected aqueous viscosity remains low.

The most credible AS advantage is operational simplicity and potentially better injectivity than ASP. Its main technical risk is that microscopic mobilization occurs without adequate sweep, causing the mobilized oil or chemical front to bypass poorly swept reservoir volume.

4.3.3 Expected behavior of ASP

ASP should provide a more sustained oil response and a stronger delay in water-cut increase when the polymer maintains its designed viscosity through the reservoir. The combination of IFT reduction and mobility control can improve both microscopic displacement and sweep. The main penalty is a greater probability of injectivity loss, pressure increase, polymer retention, mechanical degradation, and chemical incompatibility.

The high ASP case is unacceptable without a demonstrated pressure margin. If the polymer is degraded or strongly retained, ASP may produce the cost and injectivity penalty of polymer without delivering the expected sweep benefit. If the formulation is unstable in the reported brine, AS and ASP can both underperform the screening envelope.

4.3.4 Comparative decision logic

The engineering implications of the preceding mechanism, calibration hierarchy, and uncertainty analysis are

consolidated in Table 5. This comparison is a screening decision aid: it identifies the principal trade-offs between chemical simplicity, recovery upside, mobility control, injectivity, and data burden rather than ranking a final field-development project. It should be read together with the acceptance criteria in Section 3.6; no method is advanced on endpoint recovery alone.

Table 5. Comparative Decision Logic for AS and ASP Chemical EOR Screening.

Decision criterion	AS	ASP
Main recovery mechanism	IFT reduction, in-situ soap, wettability/capillary effects	AS mechanisms plus mobility control and sweep improvement
Expected oil-rate response	Smaller and more delayed	Potentially larger and more sustained
Water-cut control	Limited by heterogeneity and lack of polymer	Stronger if mobility control survives transport
Injectivity	Potentially better, but sensitive to scaling/emulsions	More exposed to viscosity, retention, and plugging
Chemical complexity	Lower	Higher
Data burden	High	Very high
Main screening recommendation	Evaluate as a lower-complexity chemical option	Prioritize only after polymer/brine compatibility and injectivity are proven

4.4 Economic implications and implementation readiness

No defensible NPV, IRR, or profitability index can be calculated from the supplied thesis because AS/ASP chemical prices, water-treatment costs, produced-water handling, demulsifier, scale control, corrosion control, discount rate, and oil-price assumptions are absent. Economic evaluation must be rebuilt rather than copied from the polymer-only case.

The cash-flow model should include incremental oil revenue relative to the base case and deduct chemical purchase, brine preparation, injection, produced-water treatment, demulsifier, scale and corrosion control, additional surveillance, and workover exposure. A design should pass a technical screen—chemical stability, injectivity, pressure margin, and reproducible oil response—before economic ranking.

The implementation sequence is: (1) verify the original STARS deck and OOIP; (2) characterize Bu-Attifel oil and brine; (3) screen alkali and surfactant combinations; (4) measure IFT, phase behavior, adsorption, and chemical consumption; (5) perform AS and ASP corefloods; (6) history-match the chemical model; (7) run field-scale sensitivities and uncertainty; and (8) perform a pilot or phased implementation subject to surveillance and pressure limits.

5. Critical Limitations, Reproducibility, and Upgrade Path

This manuscript preserves the field-specific reservoir foundation but does not claim that new AS or ASP simulations have been completed. The supplied material lacks the executable grid

and well-control deck, the chemical identity and concentration schedule, TAN, ionic brine composition, IFT maps, phase behavior, adsorption isotherms, alkali consumption, chemical relative permeability or capillary-desaturation data, polymer rheology and degradation data, and current chemical economics.

The forecast table is therefore reproducible only as a transparent accounting calculation from the stated base-case anchor and assumed engineering ranges. It is not reproducible as a CMG–STARS simulation until the missing deck and chemical inputs are supplied. This limitation is scientifically material and must remain visible in any submission. The work can be upgraded to a field-scale numerical paper only after the calibrated chemical model is rerun and the production, water-cut, pressure, retention, and uncertainty outputs are reported.

6. Conclusions

1. The Bu-Attifel history-matched model is a suitable reservoir foundation for a new chemical-EOR study, but the AS and ASP chemical models must be built independently rather than obtained by relabeling the thesis polymer case.
2. AS means alkali plus surfactant without polymer. Its principal expected effects are IFT reduction, in-situ soap generation, adsorption modification, and possible wettability/capillary improvement. It does not automatically improve mobility control or sweep.
3. ASP means alkali plus surfactant plus polymer. It combines the AS mechanisms with polymer-based mobility control and therefore has greater technical upside, but also greater sensitivity to salinity, rheology, retention, shear, injectivity, pressure, and formation damage.
4. A conservative screening envelope based on the available foundation is 0.5–4.0 percentage points of incremental recovery factor for AS and 1.5–7.0 percentage points for ASP. These are engineering cases, not probability quantiles and not simulator results.
5. The central screening cases correspond to approximately 5,962 bbl/d for AS and 6,480 bbl/d for ASP at the end of the stated prediction period. These values are design targets for calibration, not field predictions or investment-grade production forecasts.
6. The most defensible near-term decision is to retain AS as a lower-complexity option and prioritize ASP only if laboratory testing demonstrates stable chemistry, adequate polymer viscosity after mixing with the Bu-Attifel brine, acceptable adsorption and retention, and an injectivity/pressure margin.
7. The present contribution is suitable for consideration only as a transparent field-specific screening and simulation-design study. It should not be submitted as a completed numerical AS/ASP paper until the original CMG–STARS deck, chemical laboratory data, and calibrated production outputs are available.

Recommendation

The AS process should be assessed first because it is less complex and needs fewer chemical inputs. ASP should be considered if laboratory tests confirm good polymer–brine compatibility, acceptable viscosity, retention, and injectivity. The current recovery and production standards should be treated as screening estimates, not final simulation results. The original CMG–STARS

model and chemical laboratory data must be used to develop and validate the final AS/ASP simulations.

Nomenclature

Symbol	Definition
AS	Alkali–surfactant flooding
ASP	Alkali–surfactant–polymer flooding
BHP	Bottomhole pressure
IFT	Interfacial tension
M	Water-to-oil mobility ratio
MMbbl	Million stock-tank barrels
N _p	Cumulative oil production
N _c	Capillary number
OOIP	Original oil in place
RF	Recovery factor
STARS	CMG advanced-process reservoir simulator
TAN	Total acid number

Data availability and declarations

Data availability: The field and base-case values are derived from the author’s thesis. The executable CMG–STARS deck and chemical laboratory dataset are not included in the supplied material. The screening table and input checklist are provided as supplementary engineering artifacts.

Declaration regarding simulated results: No new AS/ASP CMG–STARS production result is claimed in this manuscript. All new numerical values are explicitly labelled as screening-level engineering estimates.

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Author contributions: Ali Soliman Algamody: study conception, reservoir-foundation interpretation, methodology, analysis, and manuscript preparation.

Ethics statement: Not applicable; the study uses reservoir-engineering data and does not involve human or animal subjects.

Conflict of interest: No conflict of interest is declared.

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