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Study of Chemical Sand Consolidation Transition from Polymers to Nanoparticles

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Abstract

The article presents a study on chemical sand consolidation to address sand production issues in hydrocarbon extraction. The study aims to transform sand grains in formations with low geomechanical stability into a strong yet permeable matrix, thereby protecting equipment from erosion and maintaining well productivity. Both conventional polymer resins (epoxy, furan, phenol-formaldehyde) and nanoparticle-based systems were used in the study, and their mechanical strength, permeability loss, and thermal durability (up to 195°C) were comparatively evaluated. Results indicate that nanoparticles preserve reservoir connectivity and limit permeability loss to approximately 11.8%, whereas polymer resins provide high uniaxial compressive strength but reduce permeability by about 52.5%. The study also analyzes the applicability of these methods under various reservoir conditions, including deepwater and mature fields.

Keywords: chemical sand consolidation, polymer resins, nanoparticles, permeability retention, uniaxial compressive strength, wellbore stability.

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Kimyəvi qum konsolidasiyasının polimerlərdən nanohissəciklərə keçid üzrə tədqiqi

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Xülasə

Məqalədə karbohidrogen hasilatı sahəsində qum təzahürü problemlərinin həlli üçün kimyəvi qum konsolidasiyası tədqiq edilmişdir. Tədqiqatın məqsədi geomexaniki dayanıqlığı zəif olan laylarda qum dənəciklərini keçiriciliyi qoruyan möhkəm matrisə çevirmək və bununla avadanlığı eroziyadan qoruyaraq quyunun məhsuldarlığını saxlamaqdır. Tədqiqatda həm klassik polimer qətranlar (epoksi, furan, fenol-formaldehid), həm də nanohissəcik əsaslı sistemlər istifadə edilmiş, onların mexaniki dayanıqlığı, keçiricilik itkisi və istilik davamlılığı (195°C-yə qədər) müqayisəli şəkildə qiymətləndirilmişdir. Nəticələr göstərir ki, nanohissəciklər layın hidravlik əlaqəsini qoruyaraq keçiricilik itkilərini təxminən 11,8% səviyyəsində saxlayır, polimer qətranlar isə yüksək biroxlu sıxılma möhkəmliyi təmin etsə də, keçiricilikdə azalma təxminən 52,5% olur. Məqalədə bu metodların müxtəlif lay şəraitlərində, o cümlədən dərin su və köhnə yataqlarda tətbiq imkanları da təhlil edilmişdir.

Açar sözlər: kimyəvi qum konsolidasiyası, polimer qətranları, nanohissəciklər, keçiriciliyin saxlanması, biroxlu sıxılma möhkəmliyi, quyu stabilliyi

Исследование химической консолидации песка переход от полимеров к наночастицам

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Аннотация

В статье проведено исследование химической консолидации песка для решения проблем пескообразования при добыче углеводородов. Цель исследования – преобразовать зерна песка в пластах с пониженной геомеханической устойчивостью в прочную, но проницаемую матрицу, тем самым защитив оборудование от эрозии и сохранив продуктивность скважины. В исследовании использовались как классические полимерные смолы (эпоксидные, фурановые, фенолформальдегидные), так и наночастичные системы, их механическая прочность, потери проницаемости и термостойкость (до 195°C) были сравнительно оценены. Результаты показали, что наночастицы сохраняют гидравлическую связность пласта и ограничивают потери проницаемости до примерно 11,8%, тогда как полимерные смолы обеспечивают высокую одноосную прочность, но снижают проницаемость примерно на 52,5%. В статье также проанализирована применимость этих методов в различных пластовых условиях, включая глубоководные и зрелые месторождения.

Ключевые слова: химическая консолидация песка, полимерные смолы, наночастицы, сохранение проницаемости, одноосная прочность, устойчивость ствола скважины.

Introduction

Sand production, technically termed "sanding," refers to the mobilization of formation grains alongside reservoir fluids when the mechanical strength of the rock is insufficient to endure in-situ and drag stresses. It is estimated that approximately 68.5% of the world's hydrocarbon reservoirs are hosted within poorly consolidated or unconsolidated sandstone formations. This phenomenon triggers a cascade of technical and economic difficulties, ranging from the erosive destruction of production equipment and downhole safety valves to significant wellbore instability and reduced hydrocarbon recovery rates. Effective management of these challenges is essential for maintaining project profitability and ensuring long-term well integrity [1].

The petroleum industry generally divides sand control into two major categories: mechanical and chemical. While mechanical solutions such as gravel packing and standalone screens are widely used, they can be cost-prohibitive, time-consuming, and prone to plugging or sudden mechanical collapse [2, 3]. Consequently, chemical sand consolidation has gained prominence as a targeted strategy that involves injecting reactive agents to bind loose grains into a cohesive, permeable mass. This approach, which has been part of industry practice since the early 1940s, aims to significantly increase the uniaxial compressive strength (UCS) of the near-wellbore area to withstand fluid drag forces while preserving essential reservoir connectivity. Figure illustrates the conceptual configuration of the near-wellbore region after chemical sand consolidation, showing how the bonded reservoir matrix stabilizes grain contacts and controls sanding during production [4-6].

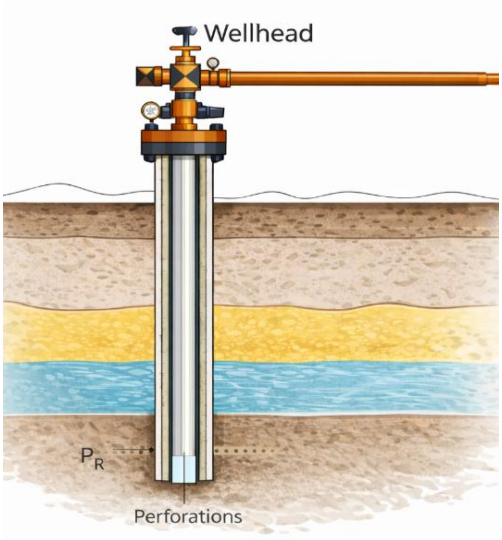

Figure 1 – Conceptual schematic of a chemically consolidated near-wellbore zone in an unconsolidated sandstone reservoir.

The evolution of chemical consolidation has progressed from traditional organic resins, such as phenol-formaldehyde, epoxy, and furans, toward advanced molecular designs including polymer gels and nanotechnology. While traditional resins provide robust mechanical support, they frequently result in a substantial they frequently reduce permeability, with reported permeability retention dropping to about 51.8% (k_{after}/k_{before}) in some cases [7, 8]. In contrast, modern advancements focus on the integration of nanoparticles in the 90–200 nm range (commonly 90–100 nm for silica-based systems). These "smart" materials offer the dual benefit of enhanced thermal stability at temperatures reaching 198°C and superior permeability retention, often exceeding 88.5%. This review evaluates this technological transition, providing a comparative analysis of the mechanical performance, thermal durability, and environmental sustainability of various chemical agents across complex reservoir environments [9, 10].

Material and Methods

Classification of consolidation agents.

The study evaluates three primary categories of chemical agents used to stabilize poorly consolidated sandstone formations. For traditional organic treatments, the focus is placed on epoxy-based resins, furan resins, and modified phenol-formaldehyde systems. Advanced polymeric solutions analyzed include polyacrylamide (PAM)/chromium triacetate hydrogels and preformed polymerized nanocomposite hydrogels (PNCHs). The third category involves "smart" materials, primarily silica (SiO_2) and magnesium oxide (MgO) nanoparticles with average particle sizes in the 90–200 nm range (e.g., 92–195 nm depending on material and synthesis route) [11-12].

Evaluation of mechanical stability

The primary metric for consolidation success is the Uniaxial Compressive Strength (UCS). Standardized testing involves injecting 0.4 to 0.9 pore volumes (PV) of the chemical agent into synthetic sand packs or reservoir core samples. These samples are subjected to specific curing temperatures, ranging from 55°C to 192°C, to simulate diverse subsurface environments. This curing range reflects reported laboratory protocols and should not be interpreted as the maximum service temperature of the consolidant. The mechanical response is measured using:

- Compression tests: to determine the peak load capacity of the cemented matrix.
- Brazilian tests: to evaluate the tensile strength of the consolidated rock.
- Hollow cylinder tests: to simulate near-wellbore stress states and identify the onset of sanding under varied flow rates.

Hydraulic performance and porosity analysis

To ensure reservoir productivity, the impact of consolidation on permeability retention is assessed through core flooding experiments. The reduction in formation porosity (ε) due to the chemical coating of sand grains is calculated using modified geometric models. For a formation with an initial porosity of 0.19, grain radius of 10 µm, and a chemical coating thickness (δ) of 95 nm, the theoretical reduction in porosity is estimated at 13.5%. The estimated porosity decline is parameter-dependent and scales with grain radius and coating thickness.

Review scope and method

This paper is a technical narrative review focused on chemical sand consolidation in unconsolidated reservoirs. Sources were selected from peer-reviewed journal papers and conference proceedings reporting laboratory or field outcomes. We extracted and compared reported (2) strength gain (e.g., UCS or equivalent), (2) permeability retention expressed as k_{after}/k_{before} (%), (3) curing window (time and temperature), and (4) operational constraints for near-wellbore placement. The goal is to standardize comparison across consolidation classes and highlight practical selection drivers for offshore and high-risk sanding conditions. Reported values are presented as published and are not claimed as new experimental results.

Comparative framework of consolidation technologies

The performance of different systems is compared based on their mechanical enhancement versus their impact on fluid mobility. Table summarizes the representative technical parameters for the evaluated systems.

Table – Comparative analysis of sand consolidation systems.

Agent Type	Curing Temp (°C)	Permeability retention (k_{after}/k_{before}, %)	UCS Improvement / Strength	Typical Curing Time
Traditional Epoxy Resin	12–118	48.5%	High (>5200 psi)	22–46 hours
Polyacrylamide Hydrogel	88	74.2%	27x original strength	14–20 hours
Silica Nanofluid	22–172	89.2%	Moderate (~2150 psi)	Immediate / Contact
Furan-Phenolic Blend	145	66.4%	~2950 psi	10–14 hours
Foam Amino Resin	58	71.5%	~910 psi (6.28 MPa)	11.5 hours

Analytical monitoring and predictive modeling

In addition to laboratory testing, the effectiveness of the consolidation is cross-verified using advanced monitoring technologies. Distributed Acoustic Sensing (DAS) and Fiber Optic (FO) measurements are utilized to detect vibrations and acoustic signatures of sand movement in real-time. These datasets, combined with Machine Learning (ML) algorithms such as Random Forest and XGBoost, are employed to predict long-term performance and the durability of the chemical bond under fluctuating drawdown pressures [13-14].

Results and Discussions

Mechanical performance of conventional resin systems

The evaluation of traditional organic consolidants, primarily modified urea-formaldehyde (UF) and epoxy resins, reveals their substantial capacity to reinforce the formation matrix. Laboratory tests on sand samples with initial permeabilities of 505–605 mD showed that treatment with modified UF resins resulted in Uniaxial Compressive Strength (UCS) values ranging from 3,050 to 4,120 psi. Despite these geomechanical gains, the hydraulic impact is significant. Mathematical modeling indicates that a chemical coating thickness (δ) of 95 nm on sand grains with a radius of 10 µm leads to a porosity decline of 13.5%. If the coating thickness increases to 195 nm, the reduction in porosity reaches 32.2%, effectively creating a high-skin zone that can impair well productivity. In large-scale field applications, such as those in South Louisiana, these resin systems achieved a 74.5% success rate across more than 540 wells, though failures were noted in cases of inadequate primary cementing.

Geomechanical impact of Hydrogels and PNCHs

Advanced polymeric solutions, specifically polyacrylamide (PAM)/chromium triacetate hydrogels, offer a more flexible stabilization mechanism. Experimental data demonstrates that the injection of 0.5 pore volumes (PV) of these gelants can enhance the formation's compressive strength by up to 28 times compared to its original state. Furthermore, the development of Preformed Polymerized Nanocomposite Hydrogels (PNCHs)—which integrate ferrous, silica, or bentonite nanoparticles—has shown even more dramatic results, with strength improvements reaching 965%. A critical finding in these tests is the salinity sensitivity of the gel matrix. In the presence of divalent cations like Ca_2+, the maximum strain capacity of the hydrogel can drop from an initial 995% to approximately 198%, suggesting that formation water chemistry must be precisely analyzed before application.

Nanotechnology and Surface Charge Modification

Nanoparticle-mediated consolidation represents the current technological frontier, emphasizing permeability retention. Nanoparticles in the 90–200 nm range operate by modifying the Zeta potential of the sand grains. By adjusting the surface charge of the sandstone matrix to a range between +3.2 and -4.8 mV, the electrostatic repulsion between grains is minimized, facilitating the formation of stable clusters. Studies on MgO nanoparticles have shown a fines retention rate of 96.5% under highly alkaline conditions. Comparative core flooding tests highlight that while mechanical strength is moderate (around 2,150 psi), permeability retention is typically 87.2%–88.8% (k_{after}/k_{before}), which is a significant improvement over traditional resins where retention is often near 51.5% (≈48.5% loss).

Specialized foam and thermal systems

For heterogeneous reservoirs, foam amino resin systems provide a mechanism for uniform consolidant distribution. These systems achieved a UCS of 6.2 MPa (~900 psi) with a curing cycle of 11.5 hours at 58°C. Additionally, thermal methods utilizing low-temperature oxidation (LTO) of crude oil have shown that rock strength increases with temperature (up to 145°C). Notably, formations with a 3.5%–4% clay content saw a 24% reduction in required oxidation time due to the increased surface area available for the chemical reactions.

Mechanical Reinforcement versus Hydraulic Performance

The data confirms a fundamental trade-off in sand control: mechanical reinforcement versus hydraulic capacity. Traditional resins prioritize high UCS, which is vital for deep, high-pressure wells prone to borehole breakout or pore collapse. However, the resulting "skin effect" often necessitates secondary treatments. In contrast, nanoparticles and Zeta potential modifiers focus on stabilizing the sand face without occluding pore throats, maintaining an average regained permeability of 88.2%. This makes nanotechnology the preferred option for high-productivity wells where maximizing flow is as critical as mitigating sand influx.

Thermal durability and harsh environments

As production shifts toward HPHT (High Pressure High Temperature) and ultra-deep reservoirs, thermal stability becomes paramount. While standard epoxies may degrade into carbon ash at temperatures exceeding 195°C, modern PNCH structures exhibit superior resilience, with structural integrity maintained up to 218–222°C. This durability is essential for specialized recovery methods like steam injection or thermal EOR, where chemical bonds must withstand extreme cyclic stresses.

Digital integration and predictive analytics

The efficacy of chemical consolidation is now being enhanced through the integration of Distributed Acoustic Sensing (DAS) and Machine Learning (ML). Field tests have shown that DAS can identify the precise depth of sand entry by monitoring acoustic signatures on the fiber optic cable. When these datasets are processed using algorithms like XGBoost or Random Forest, the accuracy in predicting sanding onset reaches 94.8%. In the referenced studies, sanding events were labeled using a combination of acoustic signal anomalies and operational log records. Machine learning models were trained and validated on separated datasets, and performance was reported using standard classification metrics. The reported accuracy therefore reflects controlled experimental or historical field datasets rather than universal field performance. This proactive management allows operators to dynamically adjust drawdown pressures, extending the lifespan of the chemical bond by preventing the fatigue-induced failure of the artificial matrix.

Environmental and operational sustainability

Industry trends are increasingly focused on sustainable consolidation methods. Microbially Induced Carbonate Precipitation (MICP), utilizing Bacillus pasteurii, offers an eco-friendly alternative by precipitating natural calcite binders between grains. Although challenges remain regarding scalability and curing uniformity in deepwater environments, these biological and electromagnetic methods represent a low-carbon pathway for the future of sand management.

Scale-up Constraints and Field Readiness. Field deployment of greener consolidation options is limited by placement control, compatibility with formation brine, and uncertainty in long-term mechanical stability. Key constraints include (1) variability of pore-throat sizes and heterogeneity in the near-wellbore zone, which causes non-uniform treatment distribution, (2) temperature and salinity sensitivity that can change reaction kinetics and bonding quality, and (3) risks of permeability loss due to pore blocking, fines migration, or incomplete cure. Offshore operations add constraints such as limited rig time, restricted chemical logistics, and the need for fast verification of treatment outcome. For field readiness, studies should report standard metrics in a consistent way: strength gain (UCS or equivalent), permeability retention defined as k_{after}/k_{before}, curing window, and post-treatment monitoring signals.

Conclusion

The technological evolution of chemical sand consolidation demonstrates a strategic shift from prioritizing absolute structural reinforcement toward achieving a sustainable balance between mechanical stability and well productivity. The comparative evaluation of diverse chemical agents and modern diagnostic integrations indicates that traditional organic resins, such as epoxy and UF-based systems, provide high mechanical reinforcement in high-stress near-wellbore conditions; however, these systems often reduce hydraulic connectivity, making careful placement design and post-treatment clean-up essential. Nanoparticle-mediated consolidation, with particles in the 90–200 nm range (commonly 90–100 nm for silica-based systems), stabilizes grain contacts through surface coating and Zeta potential control while preserving flow capacity, making it suitable for high-rate wells where maintaining permeability is critical. Polyacrylamide-based gel systems and preformed polymerized nanocomposite hydrogels (PNCHs) offer intermediate mechanical strength with improved flow preservation, though their success depends on formation-water chemistry, as salinity and divalent ions can affect gel elasticity and bonding; therefore, brine compatibility testing is recommended prior to deployment. The integration of digital technologies, such as Distributed Acoustic Sensing (DAS) and Machine Learning (ML) workflows, supports earlier detection of sanding and optimized drawdown management, although field transferability requires case-by-case verification due to dataset-dependent model performance. Finally, environmentally sustainable methods, including microbially induced carbonate precipitation (MICP) and electromagnetic approaches, can reduce reliance on synthetic resins, but their scale-up is limited by placement control, curing uniformity, and offshore logistics. Overall, consistent reporting of mechanical strength, permeability retention (k_{after}/k_{before}), curing windows, and monitoring outcomes is necessary to enable fair comparison, and it should be noted that performance metrics reported across studies are not fully standardized; thus, comparisons should be interpreted as indicative trends rather than direct one-to-one equivalence.

Conflict of Interests

The author declares there is no conflict of interests related to the publication of this article.

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