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Original article

A pragmatic approach to polymer flooding to accelerate field implementation

Antoine THOMAS
Independent consultant, France

ABSTRACT

Background: Polymer flooding is a well-known enhanced oil recovery technique which can increase recovery factors in mature oilfields above 10% of the oil originally in place. Despite a lengthy history and many published field cases, the speed of deployment is still rather slow. With the need to boost energy production while minimizing energy wastes and carbon emissions, considering this technique known to reduce water usage and accelerate oil recovery should be a must.

Aim: This short publication aims at providing guidelines to accelerate deployment of polymer injection in various oilfields and a couple of pragmatic approaches recognizing the need for field data instead of poorly constrained simulations or incomplete laboratory studies.

Materials and methods: After a brief review of the technique and current implementation workflows, we will discuss new approaches to foster the deployment of injection pilots by showing how polymer injection can reduce emissions and energy wastes while accelerating oil production.

Results: We provide a different perspective on polymer injection with pragmatic tools and ideas showing that going to the field fast provides more information than any laboratory study.

Conclusion: Given the current need for mitigating oil production declines, polymer flooding is a technique of choice which can be deployed fast if basic criteria explained in this paper are met

Keywords: *polymer flooding, incremental oil, energy savings, efficiency,* CO_2.

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Оригинальное исследование

Прагматичный подход к ускоренному внедрению полимерного заводнения на месторождениях

Антуан Тома
Независимый консультант, Франция

АННОТАЦИЯ

Обоснование. Полимерное заводнение является широко известным методом увеличения нефтедобычи, который позволяет повысить коэффициент извлечения нефти на зрелых месторождениях более чем на 10% от объема первоначально добытой нефти. При этом, несмотря на продолжительную историю и множество опубликованных примеров из практики, темп внедрения метода по-прежнему довольно медленный. Принимая во внимание необходимость увеличения производства энергии при одновременном сведении к минимуму потерь энергии и выбросов углекислого газа, рассмотрение этого метода, который, как известно, позволяет сократить использование воды и значительно ускорить добычу нефти, должно быть обязательным.

Цель. В данной статье поставлена задача предложить рекомендации по ускоренному внедрению закачки полимеров на различных месторождениях и предложить пару прагматичных подходов, учитывающих необходимость использования промысловых данных вместо недостаточно точного моделирования или неполных лабораторных исследований.

Материалы и методы. Работа рассматривает новые подходы к стимулированию развертывания пилотных проектов по закачке, демонстрирующие, каким образом закачка полимеров может сократить выбросы и энергетические потери при одновременном ускорении добычи нефти.

Результаты. В работе рассмотрен несколько иной взгляд на метод закачки полимеров с применением прагматичных инструментов и идей, показывающих, что оперативный выезд на месторождение позволяет получить больше информации, чем любые лабораторные исследования.

Заключение. Принимая во внимание актуальную потребность в сдерживании падения добычи нефти, полимерное заводнение является наиболее предпочтительным методом, который может быть оперативно внедрен при соблюдении базовых критериев, изложенных в данной статье.

Ключевые слова: *полимерное заводнение, прирост нефтедобычи, экономия энергии, эффективность,* CO_2.

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Түпнұсқа зерттеу

Кен орындарда полимерлі суландыруды жедел енгізуге прагматикалық тәсіл

Антуан Тома
Тәуелсіз кеңесші, Франция

АННОТАЦИЯ

Негіздеу. Полимерлі суландыру – бұл жетілген кен орындарында мұнай өндіру коэффициентін бастапқы өндірілген мұнай көлемінің 10%-нан астам арттыруға мүмкіндік беретін мұнай өндіруді ұлғайтудың кеңінен танымал әдісі. Бұл ретте, ұзаққа созылған тарихқа және тәжірибеден жиналған көптеген жарияланған мысалдарға қарамастан, әдісті енгізу қарқыны әлі де баяу. Энергия шығыны мен көмірқышқыл газының шығарындыларын азайта отырып, энергия өндірісін ұлғайту қажеттілігін ескере отырып, суды пайдалануды азайтуға және мұнай өндіруді айтарлықтай жылдамдатуға мүмкіндік беретін осы әдісті қарастыру міндетті болуы тиіс.

Мақсат. Бұл мақалада әртүрлі кен орындарында полимерлерді айдауды жеделдетіп енгізу бойынша ұсыныстар беру және жеткіліксіз дәл үлгілеу немесе толық емес зертханалық зерттеулердің орнына кәсіпшілік деректерді пайдалану қажеттілігін ескеретін бірнеше прагматикалық тәсілдерді ұсыну міндеті қойылған.

Материалдар мен тәсілдер. Жұмыс полимерлерді айдау мұнай өндіруді жеделдету кезінде шығарындылар мен энергия шығындарын қалай азайтатынын көрсететін айдау пилоттық жобаларын күшейтуді ынталандырудың жаңа тәсілдерін қарастырады.

Нәтижелер. Жұмыста прагматикалық құралдар мен идеяларды қолдана отырып, полимерлерді айдау әдісіне сәл өзгеше көзқарас қарастырылған, бұл кен орнына жедел шығу кез-келген зертханалық зерттеулерге қарағанда көбірек ақпарат алуға мүмкіндік береді.

Қорытындылар. Мұнай өндірудің құлдырауын тежеудің өзекті қажеттілігін ескере отырып, полимерлі суландыру осы мақалада көрсетілген базалық критерийлерді сақтай отырып, жедел енгізілуі мүмкін ең қолайлы әдіс болып табылады.

Негізгі сөздер: *полимерлі суландыру, мұнай өндірудің өсуі, энергияны үнемдеу, тиімділік,* CO_2.

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Introduction

The challenging energy context with skyrocketing prices is forcing several countries to revisit their strategies and investments. As for oil, which remains a major raw material and source of energy, the lack of investments in exploration and the slow speed of the industry will not help alleviate the concerns over the stability of societies and economies in the upcoming years. Interestingly enough, solutions exist to maintain decent production plateaus and tap into existing and well-defined resources, but they are still barely considered. These solutions can be grouped under the umbrella of enhanced oil recovery techniques to recover more oil from existing reservoirs [1]. It is less risky and capital-intensive than exploration and has the potential to recover large volumes of bypassed oil from known and already exploited fields. One of these techniques is the injection of viscous water known as polymer flooding [2]. It helps improve the displacement of oil in reservoirs with heterogeneities and/or a mobility contrast between water and oil [3, 4]. The number of field realizations is steadily increasing with countries like China, India [5] and Argentina [6] leading the way in terms of incremental production. In Kazakhstan, 3 projects are successfully demonstrating the benefits of this approach in Nuraly, Zaburunie and Kalamkas oilfields [7–10]. But the speed of deployment remains relatively modest despite these successes and the need to slow the decline of global oil production while developing alternative sources of energy. In this short paper, we will try to address several questions regarding the deployment of polymer flooding and the remaining challenges, while providing a series of guidelines to accelerate the deployment of this technique in maturing oilfields.

Technical vs. economic efficiency, is there a conundrum?

We can reasonably say that polymer flooding is a mature technique with a relatively large envelope of application and low risks of failure [the risks are known and can be mastered). Polymers are now injected in high temperature, low permeability, and high salinity reservoirs [11, 12]. The degradation issues can be well accounted for and prevented and, eventually, the only remaining challenge remains the adsorption of molecules on the rock which can highly delay oil recovery and jeopardize the economics of the project, without any easy mitigating option. Given the technical end economic successes of many projects around the world, one can wonder why this approach is not used more often to improve oil recovery in an era with dramatically low exploration budgets? Why is water flooding still the most common technique despite its low recovery efficiency?

The answers are numerous and complex, but one that seems to stand out and rank first in all projects is an economic one: profitability. The development decision and choice of a technology, especially waterflooding, is first dictated by how much money can be made, and how fast. This is generally measured by considering parameters such as discounted cash flow or net present value, NPV. The issue is that a large NPV is not necessarily synonymous with a maximum recovery efficiency and, worse, it can be energetically unfavorable [13–15].

Considering the case of water injection [13–18], have shown using the exergy concept that there is a direct correlation between the CO_2 intensity of the oil production by water injection and field water cut. Above water cuts of 90%, a large fraction of the energy obtained from oil is used in handling the injected and produced water, which also leads to large amounts of CO_2 emission [19]. In short, above 90% water-cut, the exergy to handle large volumes of water and little oil increases dramatically.

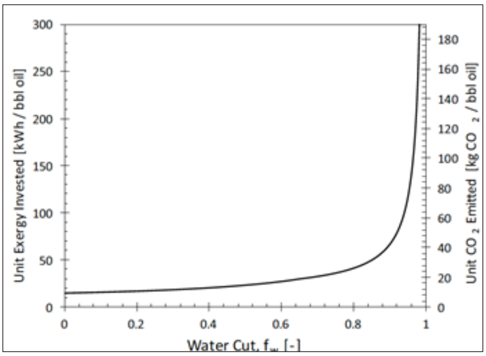

Figure 1. Unit exergy consumed, and CO_2 emitted as functions of water cut for the water injection case

The authors have compared the exergy for waterflooding and polymer flooding and show that the project time-averaged energy invested to produce one barrel of oil from polymer flooding is smaller than that of the

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prolonged water flooding because of handling of large water volumes. In other words, considering polymer flooding [early in the life of the field) helps save money, energy and CO_2 on the long term. Also, for mature fields, a decrease of water cut below 80% can really help decrease the energy wasted and CO_2 emissions given the exponential profile of the exergy curve, as shown on Figure 1. In that case, one can see that polymer injection (when it impacts the water cut) can be beneficial to maximize oil recovery while minimizing energy wastes and CO_2 emissions.

Waterflooding is very often considered for two simple reasons: water is available almost everywhere and is relatively cheap to "process". Considering the current average recovery factor in the world (between 30 and 40%), we can reasonably say that water injection has generally not been considered for its ability to maximize oil recovery, but rather because of its cost and simplicity. The issue is that, by considering the reservoir engineering principles and the experience from decades of hydrocarbon production [20–22], we know that water injection will undoubtedly end up with early field shut-in, or with the production of a couple of barrels of oil drowned in an ocean of produced water. By not investing into efficient oil recovery techniques at the beginning, we pay a higher price later in the life of the field. Higher price because it is not easy to mitigate the damages of early breakthrough or fingering once the water cut has reached high values. But with a more viscous water for instance, it is possible to greatly delay the issues linked to water production and handling while maximizing the recovery and energy use.

For future developments, it will be necessary to better balance the oil recovery and energy efficiency with profitability, for oilfield development is a long-term game, for all stakeholders. Not investing in a disciplined and technically sound approach will result in spending more money in attempting to fix a predictable problem. Because, eventually, money will be spent.

What is a good candidate for polymer injection?

To make it simple, a good candidate for polymer injection is any field with:

– An on-going or planned water injection;

– A low recovery factor and/or zones with high remaining oil saturation

An oil saturation above residual is required for polymer flooding to be technically and economically efficient. This is often the case if the field:

– Is at the early stage of development,

– Presents a high oil/water viscosity contrast, and/or;

– Presents heterogeneities.

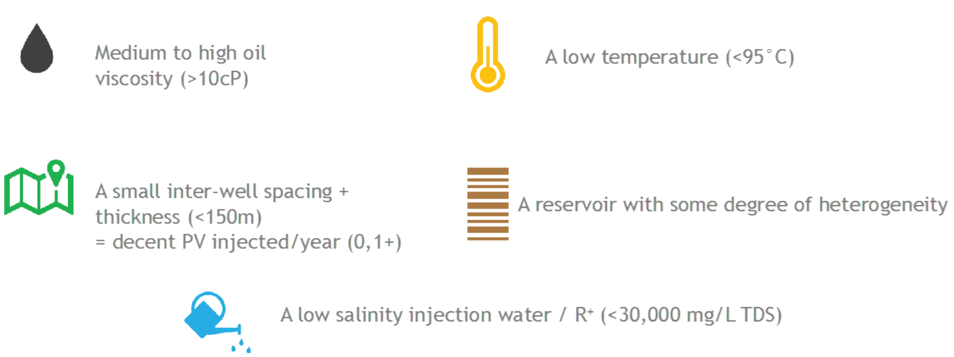

Figure 2. An illustration summarizing the "easy" conditions for a technical and economic success

To quickly screen a large portfolio and focus on the best candidates, we propose to consider several parameters to rank them from high potential of success (technical and economic) to low potential (Figure 2). The parameters considered are:

– Current recovery factor (%), using the median or average (since zones in the field can have high recovery factors while other remain unswept);

– Current reservoir temperature (Celsius);

– Injection water salinity (g/L);

– Reservoir thickness (m);

– Average spacing between injectors and producers (m);

– Permeability (mD);
– Pore volume injectable per year (PVinj/year, %);
– Dykstra Parson coefficient;
– Mobility ratio.

Table 1 and Figure 3 show an example of plot for two extreme cases, hard and easy. This Polymer Web Ranking chart (Figure 2) allows a quick visualization of the potential of several fields.

Table 1. Parameters and values used to illustrate the quick ranking process using a Web graph

Parameters	Good candidate for PF	Hard	Easy
Current recovery factor, %	Should be low = high oil saturation	0,55	0,05
Current temperature, C	The lower, the less expensive the chemistry	140	15
Salinity, g/L	The lower, the less expensive the chemistry	300	1
Thickness, m	The bigger, the longer the response	60	5
Spacing, m	The bigger, the longer the response	400	100
Permeability, mD	The lower, the lower the molecular weight and potential injectivity	1	2000
PV inj/year, %	The lower, the longer the response	0,01	0,2
Dykstra Parson	The lower, the more the polymer flood should be a viscosity control one	0,1	0,8
Mobility ratio	The lower, the more the polymer flood needs to be a heterogeneity control one	0,1	100

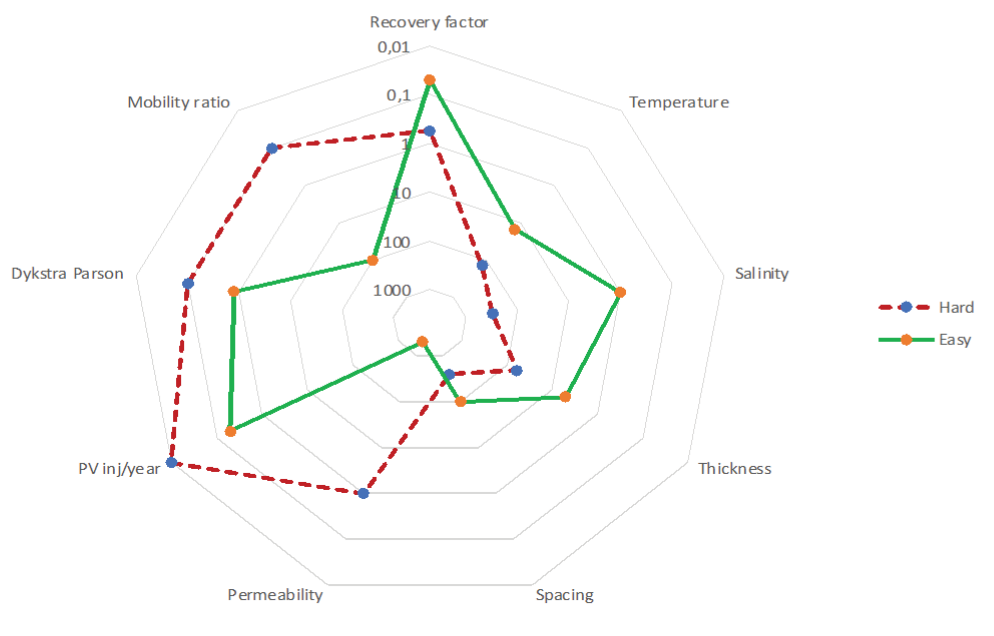

Figure 3. Polymer Web Ranking chart to quickly screen field candiates for polymer injection. Logarithmic scale

From this graph, we quickly see that the “easy candidates” (green, circle) will be located on the right side of the graph, and centered, while the difficult candidates will tend to appear on the left side of the graph (red, dashed line). This first rough ranking should help select 2 or 3 candidates for further investigations (completions, surface facilities, etc.) and fast-track the deployment of the technology to improve oil recovery.

Fast-track implementation of polymer flooding

Polymer flooding is a low risk / high reward enhanced oil recovery technique: in the worst case it can transform into water injection, and, in the best case it can yield up to 20% incremental oil after waterflooding – more if applied as secondary recovery. The reasons behind potential or real failures are various, numerous and well identified.

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Management issues

– Poorly defined objectives and goal;

– Project is of low priority to management;

– Inexperienced personnel.

Reservoir-related issues

– Poor knowledge of the reservoir (heterogeneity, fractures…);

– Poor pattern selection – interference, injection out of zone, no geological continuity;

– Endless pilot because of large spacing/thickness, low injectivity;

– Creation of fingers after extensive water injection prior to polymer injection;

– Average permeability in the field too low (< 5 mD);

– Very high permeability contrast (>100), fractures.

Fluid-related issues (water/polymer)

– Poor water quality;

– Not enough polymer injected, concentration too low (<400 ppm);

– Degradation (shear, chemical) ;

– Inject low quality solution or polymer with too high molecular weight;

– Viscosity reduction due to mixing between injection and formation waters;

– Too high resistance factor causing unacceptable injectivity decrease;

– Much higher polymer retention than expected

Among all these potential reasons for failure, the cost, possibility, or simplicity to fix or avoid them can vary greatly. While it is easy to define a goal for instance, it is much harder to predict the real retention in the field and mitigate this issue. But, globally speaking, it is reasonable to say that most challenges can be overcome with a proper design.

Fast-tracking field implementation means that it is possible to recognize all questions that laboratory tests will not answer to avoid spending time and money gathering useless information. And, basically, the most important questions are not addressed by laboratory experiments:

– What will be my injectivity in the field? Injection into a core doesn’t tell how much viscous fluid the reservoir will accept;

– How much oil will be recovered? By injecting a viscous solution into a core swept with water, you will automatically recovery more oil if the core restoration process is correct. But it won’t tell you how much a given field pattern will yield;

– What will be the real retention value? Cores are oversimplistic representations of the geology. Therefore, retention values are often underestimated.

Knowing that the most important parameters needed to build a solid business case are not obtained from laboratory studies, why would a company spend so much time, money and efforts conducting such tests? It is again a complex question but one of the answers is: because companies, like human beings, are risk-adverse and believe that more data equals less uncertainty. But this is forgetting that we don’t know what we don’t know.

To make things more reliable, it is necessary to minimize the time spent in the laboratory and run small field tests. Laboratory tests should help compare the viscosity, retention, injectivity and stability of several polymer candidate – not to build business cases.

To rank polymers, one should compare several industrial samples with the same molecular weight, adapted to the reservoir permeability. For each polymer, the following tests should be performed:

– Dissolution, filtration, and short-term stability in synthetic field brine (including filter ratio) (1 day);

– Viscosity curves vs. concentration (2 days);

– Injectivity test in a 100% water saturated analog core with a permeability (permeabilities) statistically representative of the field (1 day per polymer).

After these tests, the best two candidates can be tested for retention. By best candidate, we mean the polymers giving the lowest concentration for the target viscosity, no insoluble, and the best injectivity (fastest pressure drop stabilization, after 1 or 2 pore volumes injected for instance).

The retention tests can be carried out in reservoir cores (or analog), at residual oil saturation, using a dynamic method (2-fronts with tracer for instance). Each test usually lasts a week. At the end, the polymer with the lowest retention will be the candidate of choice.

Therefore, choosing a polymer is (and should be) a matter of weeks. Once a candidate has been selected, the time comes to select a zone for injection and design a proper strategy to maximize the return on investment in a timely fashion. Technically speaking, the main parameters behind success are:

– Sufficient injected viscosity over a large pore volume;

– Good injectivity (pore volume injected per year): above 0,1 PV/year;

– Oil saturation above residual;

– Connectivity and flow paths between wells are well-known.

For a valuable field test, one should select a zone with the following characteristics:

– A zone where polymer has the potential to recover oil (high mobile oil saturation). Not all zones in a field will be candidates for polymer injection. So, it is not necessary to design a silver bullet for the whole field but rather a valid solution for sweet spots where the potential is known;

– Hydraulically constrained pattern, not influenced by external variations (5-spot preferred to inverted 5-spot for instance);

– Correct injectivity: above 0,1 pore volume injected per year. It means that spacing, thickness and injection rate allow such rates. Large spacing are prohibitive and delay response while increasing the risk of polymer losses through retention. But small spacing can result in earlier polymer breakthrough, especially if extensive water injection has taken place;

– Issues with sweep efficiency in the pattern because of heterogeneities and/or viscosity contrast, leading to earlier than expected water breakthrough;

– Clean and proper completions allowing injection without degradation (designed to minimize high local shear rates).

The most important objectives for a pilot are twofold:

– How much polymer solution can be injected without compromising the project (technically and economically speaking)?

– How much oil can be recovered and how fast?

This is the most valuable data one can gather to build a solid business case. A field test will give information about injectivity, maximum rates, and viscosity, while providing information on incremental oil, and water cut reduction (if applicable).

The target viscosity for injection should help reach a mobility ratio of 1 when possible (i.e., when the oil viscosity is not too high), or lower when the heterogeneity is important (Dykstra-Parson coefficient above 0,7, as a rule of thumb). The limits should be tested during the pilot itself, always working from a low viscosity to a higher one.

As for the pore volume injected, people often consider a fix value ranging from 30 to 100% of reservoir pore volume swept by the polymer slug [23]. We think that no value should be considered beforehand. It is preferrable to review the project every year considering two things:

– Is it technically working?

– If yes, is the project economically viable, i.e., is the oil produced paying for the CAPEX/OPEX of the project in the current environment?

An example of success criterion was given by Poulsen et al. [24] showing the results of Captain polymer injection where was plotted the “Cumulative polymer injected / Cumulative (incremental) oil” vs. “Cumulative (incremental) oil production (stb). The economic success criterion was given for 5 lbs of polymer per barrel of oil produced or 2.27 kg/bbl. Basically, the curve looks like a parabola: increasing volumes of oil per kg of injected polymer are produced until an inflexion point is reached where the efficiency starts its descent. The project is stopped when the curve crosses the economic limit.

It is possible to add to such graph other parameters to better represent the reality of each project (Figure 4):

– Cumulative injected polymer vs. cumulative incremental oil;

– Recovery factor at the time "t";

– Injected pore volume at time "t";

– Profitability index (PI): $ selling oil / $ spent on injection get a global picture by updating a 3-axis graph with in Y1 the cumulative injected polymer/cumulative incremental oil (kg/bbl), in Y2 the profitability index ($oil/$polymer), and in X the cumulative incremental oil (Figure 2).

Once the inflexion point is reached, it is time to determine if the project is over or if something went wrong. For instance, if at the inflexion point only 20% of PV have been injected and polymer is already all over the producers, it means the design was not optimal or something not understood: low injected viscosity, fractures, high permeability streaks… In that case, it is possible to correct the trajectory and make it work again. If the profitability sinks because of oil price decrease for instance, but it was technically working, then the best option (when possible) is to decrease both injection and production rates but keep injecting the polymer. In any

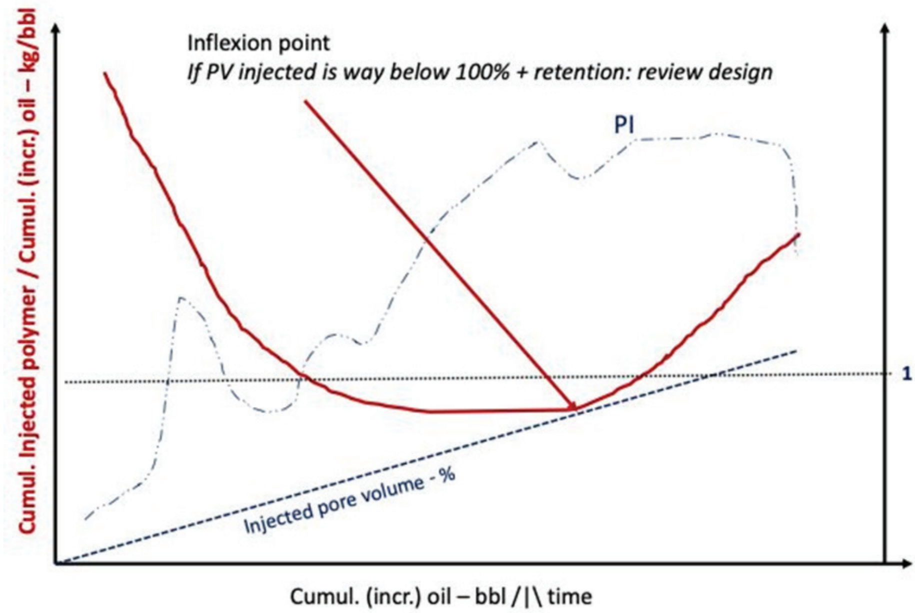

Figure 4. Suggestion of updatable chart to decide when to stop polymer injection without having to decide for a fixed pore volume number berforehand

case, this approach requires a change in the way projects are budgeted: for polymer, it would be reasonable to review the project on a yearly basis and provision for the following year (polymer, equipment, and personnel). Such flexibility has several advantages:

– It allows the scheduling of regular management reviews, with a careful and thorough review of project efficiency;

– It gives the possibility to summarize, share and archive the knowledge within and outside the company, on a regular basis;

– It provides the flexibility to stop, continue, change pattern or injection parameters depending on the results.

The field test is here to address topical questions

Many companies run simulation before going to the field to validate or invalidate the feasibility beforehand and minimize the risks of failure. But, as we briefly discussed above, since the most important parameters are not obtained during the laboratory tests, it is not surprising to see many attempts to model the reservoir response being far away from the actual pilot results. Take injectivity predictions for instance: how many were correct in the end?

A recent literature review showed that among dozens of field cases, none reported a dramatic injectivity loss [25], contrary to the fears expressed by engineers after running simulations. The main reasons behind are threefold: an oversimplified reservoir model (geology, grid), inaccurate mathematical equations [26] and an improper use of polymer-related inputs.

We believe that input data for qualifying the recovery potential should be gathered during the pilot and not from the laboratory. Simulation runs can be run to assess the influencing parameters and obtain orders of magnitude in terms of recovery or potential. But the models should not be trusted “à priori”, and rather be validated during the injection itself, then used to conclude on the business potential for a larger deployment. Indeed, companies have back away from field testing or lowered their ambition just by listening to models whose outputs showed it would be impossible to inject polymer solution with a viscosity as low as 5 cP in a multi-Darcy reservoir.

Starting with a baseline

Injecting polymer in secondary or tertiary mode requires different baselines and metrics to measure success. We will focus here on tertiary recovery as it is the most common application for polymer flooding given the large number of mature fields.

Before starting polymer flooding, it is recommended to run several tests to obtain valuable information about the efficiency:

– Confirming connectivity: tracer, pulse tests;

– Assessing flow behavior and boundaries: pressure fall-off;

– Assess initial sweep/conformance: Injection logging tool (ILT/PLT);

– Confirm fracturing pressure: step rate test. This test can provide misleading results in unconsolidated formation as dilation can occur when the reservoir has enough time to accommodate the deformation.

With a proper baseline, it is possible to start the injection and monitor other parameters. To validate the models and business case, it is common practice to record the following:

– Injection rate vs. time, continuously;

– Pressure vs. time, continuously;

– Injected viscosity, 1 time per day minimum. Better with inline device for continuous monitoring and quick troubleshooting;

– Total injected and produced fluids vs. time, continuously;

– Injected pore volume vs. time, continuously;

– Cumulative polymer injected, continuously;

– Cumulative oil produced, continuously;

– Water and oil cuts vs. time, continuously;

– Polymer presence in producers (kaolinite test for presence, lab test for concentration), minimum 1 time per week and then more frequently when polymer breakthrough is observed. Frequency should be adapted based on reservoir history and tracer tests;

– Water quality (oil, solids, contaminants), 2 or 3 times per week, day, and night.

Is it working?

As discussed in the previous paragraph, and given the investment required to mobilize equipment, chemicals, and people, it is better to start with a pilot with an aim is to assess how much extra oil can be produced. This would also provide an overview of the full injection process including logistics, delivery, equipment, injection, produced effluents and their treatment.

In theory, the reservoir response after the beginning of polymer injection in a mature field can be chronologically divided in 3 parts:

– Pressure response at the injector;

– Water cut decrease in the “nearest” producer (hydrodynamically speaking);

– Oil cut increase in the area where oil saturation is high.

But, in practice, observations vary and it is possible for example not to observe a pressure increase or a water cut decrease;

– Pressure response: it depends on the reservoir pressure before injection, heterogeneities, injected viscosity, voidage replacement ratio, and presence of fractures, among other parameters. An absence of pressure response doesn’t necessarily mean that it is not working or that the polymer solution has been degraded. Sometimes, it takes a long time before observing any reaction. If the polymer solution is correctly protected and the well completion is appropriate, then waiting remains the best option. It is also possible to increase rate or viscosity alternatively to assess the reservoir response on a Hall plot for instance;

– Water cut decrease. Logically, a water cut decrease should be observed in cases where the water in the producer is the same one that was injected (see example of Milne Point field, Alaska [27]) If the water originates from an aquifer, then it is likely that a water cut decrease will not occur and it should not be taken as success criterion. Moreover, in extensively flooded reservoirs, the polymer slug will displace the previously injected water and it might take some time before seeing any reversal in the producers;

– An oil cut increase can happen much faster than anticipated in a thick, multilayered reservoir in which large zones have remained unswept by water. It can also occur thanks to a “producer effect”: if the main flow paths connecting an injector and producers are “shut” by polymer, then the production streamlines will change, and oil can be drawn from other zones (especially if the oil is light). It is like the producer goes back in a “primary production mode” for a short period of time, until the pressure field stabilizes, and the oil bank moves forward.

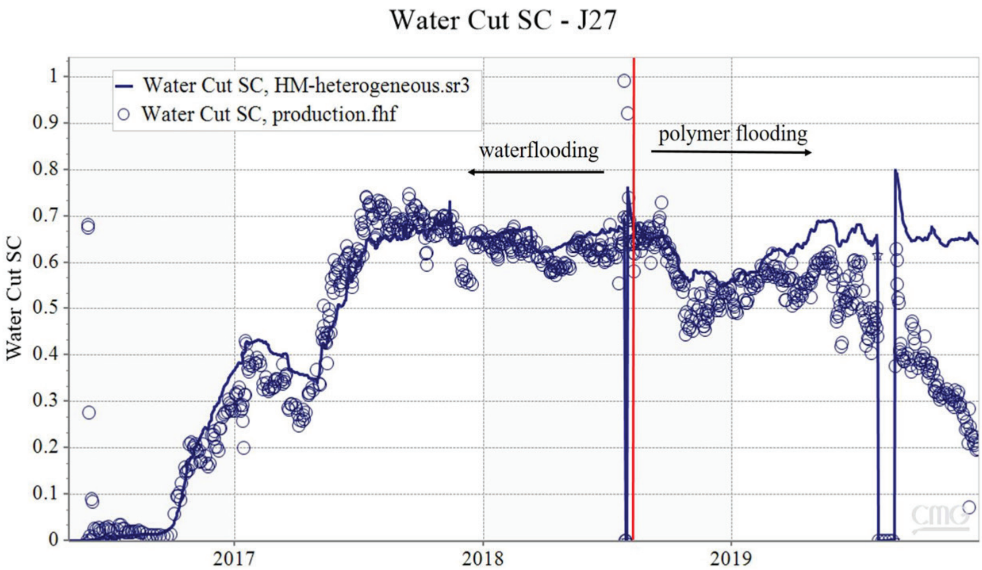

Figure 5. Significant water cut decrease in the Milne Point polymer flooding – dots. The value decreases from 70% during waterflooding down to 20% during polymer injection [27]

In summary, the only true success criterion for a pilot is incremental oil. Pressure and water cut variations are dependent on each field's production history and characteristics, and they should be used as performance indicators rather than true success criteria.

Regarding economic thresholds, two numbers should be considered at minimum:

– The increase in recovery factor;

– The polymer utilization factor i.e., how much incremental oil is produced per ton of polymer injected.

An example was given in Figure 4, and it should help decide when to stop or slow down polymer injection for a chosen economic threshold based on each field's expenditures. On average, polymer helps recover +10% OOIP in tertiary mode with utilization factors above 50 tons incremental oil per ton of polymer over the project's duration. Many projects show results above 90 tons/ton, up to 200 tons/ton. Obviously, the economic thresholds are highly dependent on the country, tax regime, oil price and local costs.

Conclusion

Most engineers agree about the relative inefficiency of water to recover large volumes of oil, leaving more than 50% in the ground at a time where exploration budgets have been cut and global production declines. Still, the deployment of proven and more efficiency approaches lags. Polymer flooding for instance is a proven low risk and high reward technique which can improve oil recovery while minimize energy use and CO_2 emissions. By considering rapid and sound screening techniques, it is possible to accelerate the testing and deployment by redistributing the money spent in the laboratory tests towards field trials. Indeed, only the latter will give valuable inputs on injectivity and recovery to build a solid and fact-based business case. Considering that the main technical hurdles can be overcome, the principal hindrance remaining is cost. But considering that polymer flooding is expensive is overlooking several important facts:

– Waterflooding is cheap but inefficient at recovering high percentages of oil;

– Above 85% water cut, the energy used for injection and production is wasted to handle large water volumes;

– Once water breakthrough has occurred it is very difficult to fix it, even with polymer flooding;

– The money which has not been spent for a disciplined production will eventually be spent to fix issues related to increasing water cuts and declining oil production.

For this reason, investing in efficient recovery methods should be seen as paying a premium to help delay what we know are unavoidable problems: those inherent to oil production when pressure support using water is required. This clearly requires a shift from a pure profitability approach to a long-term investment that could help countries maintain production plateaus and fuel their economies.

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ИНФОРМАЦИЯ ОБ АВТОРАХ

Антуан ТОМА
e-mail: *antoinethom@gmail.com*.

AUTHOR'S INFO

Antoine THOMAS
e-mail: *antoinethom@gmail.com*.