A Review of Field Oil-Production Response of Injection-Well Gel Treatments

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Summary

As life-span extenders, bulk gels have been widely applied to rejuvenate oil production from uneconomic producers in mature oil fields by improving the sweep efficiency of improved-oil-recovery (IOR)/enhanced-oil-recovery (EOR) floods. This paper presents a comprehensive review of the responses of injection-well gel treatments implemented between 1985 and 2014. The survey includes 61 field projects compiled from SPE papers and US Department of Energy reports. Seven parameters related to the oil-production response were evaluated according to the reservoir lithology, formation type, and recovery process, using univariate analysis and stacked histograms. The interquartile-range (IQR) method was used to detect the underperforming and overperforming gel projects. Scatterplots were used to identify the effects of the injected-gel volume and the treatment timing on the treatment response. Pretreatment water cut, recovery factor, and flood life were used as indicators for the treatment timing.

Results indicated that gel treatments have very wide ranges of response for injection and production wells and for oil and water rates and profiles. When successfully applied, they, on average, respond after 3.5 months, increase the oil-production rate by 32%, and additionally recover 116,000 STBO per treatment, 15 STBO per gel barrel, or 10 STBO per polymer pound. We identified that gel treatments perform more efficiently in carbonate (CB) than in sandstone (SS) reservoirs and in naturally fractured (NF) formations than in other formation types. In addition, the incremental oil production considerably increases with the channeling strength and the injected-gel volume for all formation types, not just for the matrix-rock (MR) reservoirs. Moreover, gel treatments applied in NF formations have lower productivities in SS than in CB reservoirs using normalized performance parameters.

Declining trends were identified for all parameters of the oil-production response with the treatment-timing indicators. The sooner the gel treatment is applied, the faster the response, and the larger the incremental oil production and its rate. It is recommended to allow longer evaluation times for gel treatments applied in MR formations because their response times might extend to several months. Gel treatments will perform more efficiently if they are conducted at water cuts of less than 70%, flood lives of fewer than 20 years, or recovery factors of less than 35%. For different application environments, the present review provides reservoir engineers with updated ideas regarding the low, typical, and high performances of gel treatments when successfully applied, as well as how other treatment aspects affect performance.

Introduction

Excessive water production significantly hinders the technical and economic feasibilities of IOR/EOR floodings by limiting production-well lives and increasing operational costs. This problem demands planning and conducting more-efficient water-control treatments with optimized designs to obtain more-attractive outcomes. However, the planning of optimized gel treatments requires evaluating and comparing treatment performances for various application environments and implementation scenarios.

Bulk gels have proved to be effective in addressing water-production problems and improving oil recovery from mature oil fields. They improve the vertical conformance of IOR/EOR floodings by blocking the high conductive zones and diverting subsequently injected drive fluids into the low-permeability zones. These gels are formed using high concentrations of hydrolyzed-polyacrylamide polymers with either a metallic or an organic crosslinking agent. For MARCIT^{SM} gels developed by Marathon Oil Company, polyacrylamides are crosslinked using Chromium(III) (Sydansk and Smith 1988) and applied at a formation temperature less than 220°F (Sydansk and Southwell 2000). For high-temperature applications, polyacrylamide polymers of medium molecular weight are crosslinked with an organic agent and a stabilizer. An example of this specialized chemistry is the UNOGEL technology developed by Union Oil Company of California, which can be applied at temperature ranges of 200 to 300°F (Norman et al. 2006).

In the literature, gel-treatment responses were mostly reviewed in the form of a few region-specific illustrative case histories (Sydansk and Moore 1990; Borling 1994; Southwell and Posey 1994; Hild and Wackowski 1998). In addition, the project reviews were mostly concentrated on oil-production responses and frequently involved simple comparative analyses of some application environments. In the presentation of their extensive field experiences, Sydansk and Southwell (2000) presented examples of the production responses of 1,400 MARCIT gel treatments conducted in the Big Horn Basin, Wyoming. On the basis of results of 29 remedies, they compared the oil responses of gel treatments between production and injection wells, CB and SS lithologies, and waterflooding and carbon dioxide (CO_2) flooding. In addition to treatment-sizing strategies, Smith (1999) introduced some guidelines to predict the treatment-response time, response duration, and response magnitude depending on seven gel treatments implemented in SS-MR reservoirs with crossflow. To highlight the extreme importance of pretreatment-problem diagnostics, Soliman et al. (2000) analyzed the success rate of 900 different conformance-improvement treatments with respect to several diagnostic and analysis techniques. Hinds et al. (2015) performed a look-back analysis for the performance of 110 gel-treated patterns from 1980 to 2013. This analysis was the first part of their effort to develop a proactive conformance program in the Central Permian Basin.

There is evidently a shortage in the number and quality of surveillance studies for the responses of gel treatments. This study provides a specialized updated survey for the performance of profile-modification gel treatments according to their field applications in injection wells from 1985 to 2014. The paper presents project distributions with respect to each performance parameter in general and according to the reservoir type and the recovery process. The underperforming and overperforming gel trials are identified and examined for possible commonalities. The effects of gel volume and treatment timing on different responses of gel treatments are examined

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using scatterplots. Extensive comparisons of gel-treatment results with respect to the previously discussed influential aspects are provided, and differences are discussed as well.

Database Compilation and Data Analysis

The data of 61 bulk-gel projects published in SPE papers and US Department of Energy reports were summarized in a specialized extensive conformance database. Some public EOR databases and technical papers were also reviewed to extract missing data and to update some case histories. The database includes 612 gel treatments and consists of four main sections: general information, reservoir-rocks/fluids properties, treatment-operational parameters, and treatment-performance parameters. The data set involves seven gel projects for organically crosslinked bulk gels and six gel applications that were considered as unsuccessful pilots by the oilfield operators/gel-service companies. During the data-collection stage, concentrated attention was paid to obtain a representative sample for the population of gel-field applications and to avoid any biases toward particular application regions. It is important to remark that the authors did not evaluate the technical or economic feasibilities of the reviewed gel projects. They only compiled what was reported in the gel-history case studies. However, the authors carefully examined the reported performances of successful applications to ensure that they considered actual field performances, not pretreatment projections, especially for the incremental oil production.

In a gel treatment, the injector of a well pattern is treated by bulk gels and the oil-production response is observed at the offset producers. Normally, one or more injection patterns are treated in a gel project that belong to the same field, reservoir, and lithology, and have the same conformance-problem type. In this project review, it was noted that in most case histories, the composite or total estimates of the performance parameters were supplied for all treated injection patterns. Alternatively, the performances of a representative gel treatment were reported in a few gel projects. Before the data analysis described later, the provided gross values of the performance parameters were averaged with respect to the number of treated injection wells to obtain per-well or per-treatment estimations. Then, the average estimations of some performance parameters were also normalized to enable more-equable comparisons.

In this project review, 14 parameters related to the treatment oil-production response, water-injection/production response, and economic assessments were statistically evaluated. The response time, average incremental oil production, productivity of a barrel of gel, water-cut reduction, and the cost of an incremental barrel of oil were assessed in this study. Initially, each parameter data set was analyzed using univariate descriptive analysis to present the central and dispersion tendencies of the data. Because the standard deviation is affected by the parameter unit, the coefficient of variation (standard deviation/mean) was also used in this study to present the data heterogeneity. Second, the IQR method for outlier identification was used to detect gel projects that have very low or very high responses. Such applications were termed herein as underperforming and overperforming gel projects. These special cases were then extensively examined to highlight the most-shared or common aspects between them. The statistical attributes of the univariate analysis and the IQR method are illustrated in **Fig. 1.** Furthermore, project distributions according to each parameter range were presented using stacked histograms to detect the most-expected responses. Finally, the analyses were also performed according to the reservoir lithology, formation type, and IOR/EOR process to identify the best application conditions for bulk gels depending on their field responses.

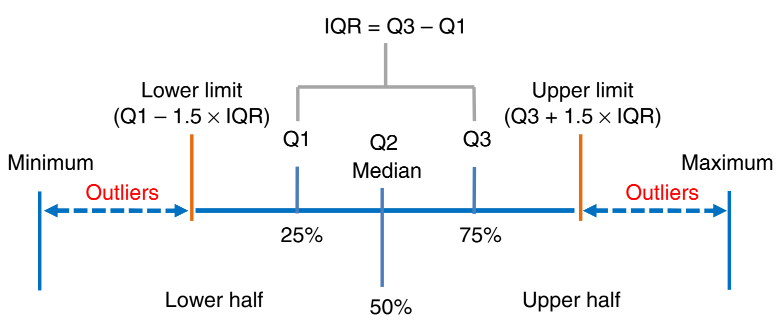

Fig. 1—Illustration of the parameters of univariate descriptive analysis and the IQR outlier-detecting method. Q1, Q2, Q3 = first, second, and third quartile, respectively.

Several scatterplots of the performance parameters against three production indicators were used to identify the effect of treatment timing on the treatment responses. The timing indicators used in this study include the pretreatment water cut, recovery factor, and flood life. The flood life refers to the duration of the flooding process being applied in an oil reservoir. This parameter was estimated as the time period from the beginning of the injection operation in the targeted injection wells to the implementation date of the gel treatments (Aldhaheri et al. 2017). The gel projects that were identified as underperforming or overperforming applications (extreme values) were removed from the scatterplots to eliminate biases of parameter means toward these points so that balanced trends were obtained. To obtain more-convincing conclusions regarding the gel-treatment responses, the trends of performance parameters against the timing indicators were taken into consideration only when a coefficient of determination (R^2) greater than 0.1 was obtained. The trends were further verified by reasonably examining the number of data points and the data position in the scatterplots to ensure that not just one or two points (extreme values) were affecting the resulted trends.

It is important to remark that all statistics and project percentages presented in the next sections are derived from the amount of available data for each parameter in successful gel projects (total of 55), if they are not mentioned elsewhere. In addition, the treatment responses are simultaneously influenced by many aspects; thus, to study the effect of one factor (e.g., the treatment timing), it was assumed that other affecting variables are constants or relaxed for this purpose.

Oil-Production Response in Bulk-Gel Projects

Injection-well gel treatments have multiple responses that are observed at both injection and production wells and in both water- and oil-flow rates/profiles, as summarized in **Table 1.** Most treatment responses are often graphically evaluated as the differences between the pretreatment and the post-treatment values or the trends of performance parameters. In this project survey, we noticed that maximum parameter changes (peaks and troughs) were used in evaluations of some production parameters, such as flow rates and water/oil ratio, in a number of case histories.

This paper presents the field responses of gel treatments related only to the oil-production parameters (in Table 1, the parameters listed under Production Response and Oil Production) because of limited space. The treatment performances related to water production, water injection, and economic assessments are summarized in a separate publication (Aldhaheri et al. 2018). In the next subsections, we will present seven oil-response parameters from 55 successful gel projects. We will also briefly discuss the effects of the gel volume and the treatment timing. Furthermore, the treatment responses will be compared for different reservoir types and recovery processes, and the differences will be provided and discussed. In this study, the term "channeling strength" refers to the severity of the interwell connectivity and the communication of the injected drive fluid between the injector and the producer. This property of conformance problems is often assessed with the term "correlation coefficient" of water-injection/production rates.

Injection Response:		
	Injection-pressure increase	
	Injection-rate reduction	
	Hall-plot slope increase	
	Injection-profile improvement	
Production Response:		
	Oil Production:	
		Treatment-response time
		Incremental oil-production rate
		Incremental cumulative oil production
		Normalized incremental oil production
		Incremental oil production per polymer pound
		Incremental recovery factor
	Water Production:	
		Post-treatment water cut
		Water-cut reduction
		Water-cut increase
Treatment effective time		
Economic Assessments:		
	Project payout time	
	Cost per incremental barrel of oil	

Table 1—Summary of performance and economic parameters of injection-well bulk-gel treatments.

Treatment-Response Time. Gel treatments have an immediate injection response that is realized at the injection wells as injectivity reductions and/or improved injection profiles. In contrast, the production response might take some time to be observed at production wells. The response time of gel treatments is graphically estimated, mostly using the oil-production rate and when it starts to noticeably deviate from the pretreatment values or their extended trends.

The results of the univariate descriptive analysis of the oil-response parameters are shown in **Table 2.** Table 2 shows that only 55% of the projects provided the response time, and mostly for SS reservoirs (25 of 30). The analysis noted that the response time of gel treatments widely ranges between 0.9 and 18 months, with an average of 3.5 months, a median of 2 months, and a coefficient of variation of 1.06. The IQR method identified one underperforming gel application (long response time) in which bulk gels were placed in an SS-MR reservoir. Project distributions in **Fig. 2a** illustrate that 13 and 57% of gel treatments responded immediately or after 1 to 5 months (most-expected response). Figs. 2a and 2b display that most gel applications that immediately responded were performed in SS reservoirs, and two of the four projects were unexpectedly applied in MR formations. Further, Figs. 2a and 2b show that both gel trials which responded after >10 months were executed in SS-MR reservoirs. Using the mean and median times shown in **Table 3,** reservoir types can be ordered in terms of shorter response time as SS-MR, SS-NF, CB-NF, and unconsolidated sandstones (SS-UC).

These remarks signal that it is important to allow longer evaluation times for gel treatments in cases of MR formations because their response times might extend to several months. In addition, they indicate that the treatment-response time reduces as channeling strength increases because shorter extents of low-permeability zones are being swept before gel treatments. Noting reservoir-engineering considerations, it is thought that the treatment-response time increases with the problem-zone volume and the treatment timing, and decreases with the injected-gel volume. The summarized data in this project review support these expectations by showing increasing trends for the response time (longer times) against the problem-zone volume and treatment-timing indictors and a decreasing trend against the gel volume. However, the association of the treatment-response time with those three factors was very weak, with R^2 being significantly less than 0.1. For SS-MR reservoirs with crossflow, Smith (1999) analyzed eight treatments to demonstrate that response time is between 1 and 18 months and mostly within 1 to 6 months (most-expected response).

Incremental-Oil-Production Rate. Different numbers of injection wells are treated in gel projects where the increments in oil-production rate are totally evaluated from all gel-treated injection patterns. To draw meaningful insights regarding the oil-production-rate response of gel treatments, the data were averaged with respect to the number of treated injection patterns. It is noteworthy that all incremental rates analyzed in this study were assessed in the history case studies with respect to the pretreatment rates, not the extrapolated rate trends. The pretreatment oil-production rates are shown in Table 2 for comparison purposes.

Table 2 shows that the average incremental oil-production rate in gel projects broadly ranges between 1 and 1,333 BOPD, with a median of 40 BOPD and high heterogeneity (1.83). Table 2 also presents that the average increment in the oil-production rate is

129 BOPD, and only one overperforming gel project was identified. **Fig. 3a** shows that polymer-gel projects are generally skewed to the left, and 40% of them have an incremental rate between 1 and 25 BOPD. It also illustrates that 69% of the gel projects have an incremental rate less than 100 BOPD (most-expected response). For incremental-rate ranges > 100 BOPD, 82 and 45% of gel projects were applied in SS reservoirs and NF formations, as shown in Figs. 3a and 3b. From these observations, the mean or median values, and the performance ranges in **Table 4,** the reservoir types can be ordered by increasing incremental rate as CB-MR, SS-UC, CB-NF, SS-MR, and SS-NF. Interestingly, a strong association was indicated between the pretreatment and the post-treatment oil-production rates, with R^2 of 0.69, as shown in **Fig. 4.** Fig. 4 notes that the post-treatment oil-production rate increases as the pretreatment rate increases. On average, the correlation illustrates that the oil-production rate increases by a percentage of 32% ($q_{\text{after}} = 1.324 \times q_{\text{before}}$) after the remediation when gel treatments are successfully applied.

Parameter	Treatment-Response Time (months)	Oil-Production Rate		Incremental Oil Production			Total Incremental Recovery Factor (%)
		Pretreatment (BOPD)	Incremental (BOPD)	Average (MSTBO)	Normalized (STBO/bbl gel)	Per Pound (STBO/lbm)	
Point count	30	30	35	38	38	30	15
Mean	3.5	357	129	116	15	10	1.4
Median	2	85	40	64	7.3	6.5	0.7
Minimum	0.9	0	1	1	0.85	0.5	0.01
Q1	1	19	18	23	4.3	3.3	0.2
Q3	5	306	183	129	16	12	1.9
Maximum	18	4,000	1,333	758	149.4	66.7	5.4
SD	3.7	769	236	153	25	13	1.8
Coefficient of variation	1.06	2.15	1.83	1.32	1.63	1.25	1.26
Most expected	1–5	10–500	1–100	1–200	2.5–25	1–10	0.1–1

Table 2—Summary of oil-production-response parameters in successful bulk-gel projects. SD = standard deviation; Q1 = first quartile; Q3 = third quartile.

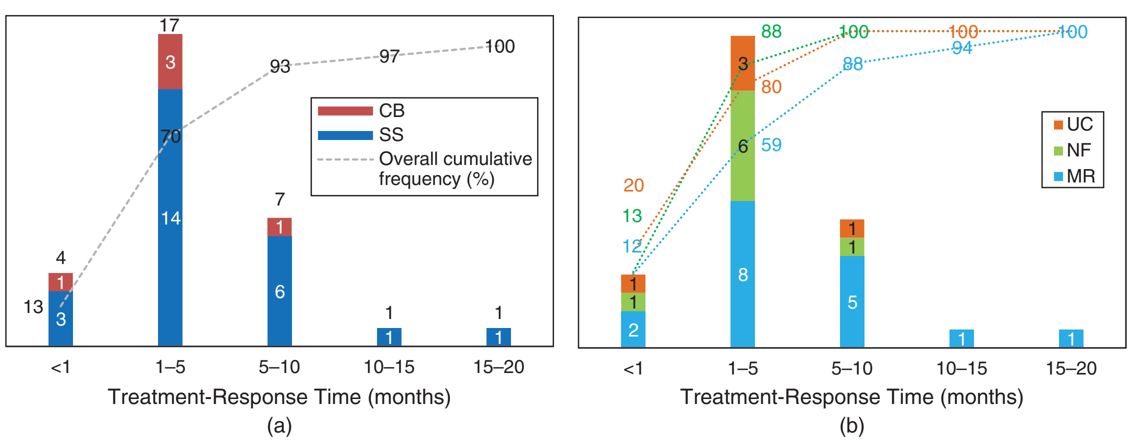

Fig. 2—Distribution and cumulative frequency of treatment-response time in successful gel projects for different reservoir types.

Parameter	Treatment-Response Time (months)				
	CB-MR	CB-NF	SS-MR	SS-NF	SS-UC
Point count	1	4	16	4	5
Mean	6	2	4.3	2.8	2.4
Median	6	2	2.5	2	1
Minimum	6	1	1	2	1
Q1	6	1	1	2	1
Q3	6	3	6	3	3
Maximum	6	3	18	5	6
SD	–	1.2	4.7	1.5	2.2
Coefficient of variation	–	0.60	1.10	0.55	0.93

Table 3—Summary of treatment response time in successful bulk-gel projects per reservoir type. SD = standard deviation; Q1 = first quartile; Q3 = third quartile.

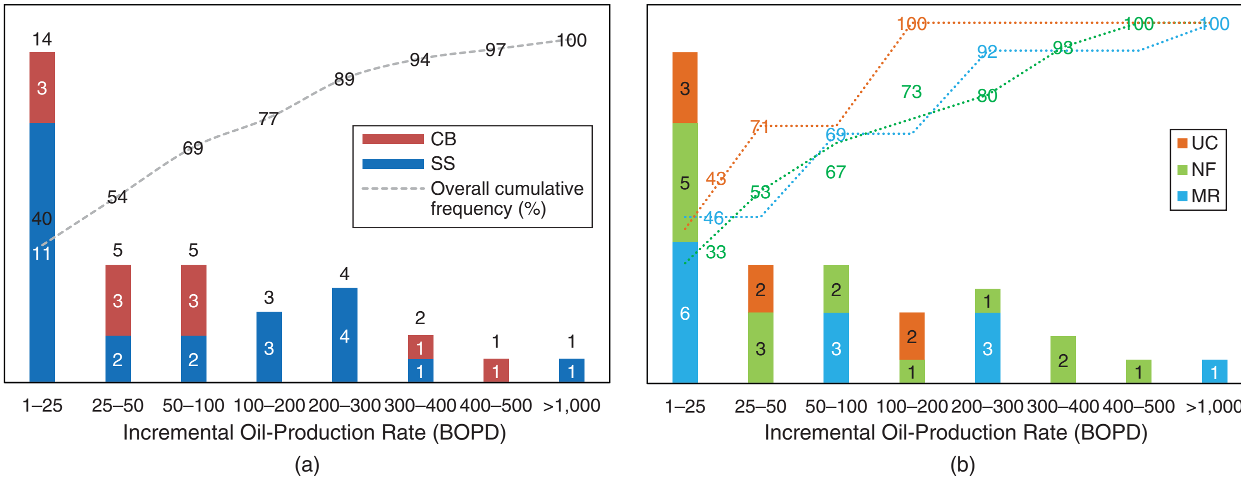

Fig. 3—Distribution and cumulative frequency of average incremental-oil-production rate in successful bulk-gel projects for different reservoir types.

Parameter	Average Incremental Oil-Production Rate (BOPD)				
	CB-MR	CB-NF	SS-MR	SS-NF	SS-UC
Point count	2	9	11	6	7
Mean	51	111	198	134	62
Median	51	43	60	99	39
Minimum	13	1	1	14	5
Q1	32	25	13	16	21
Q3	71	94	207	239	79
Maximum	90	400	1,333	320	189
SD	55	148	387	137	67
Coefficient of variation	1.06	1.33	1.95	1.02	1.08

Table 4—Summary of average incremental-oil-production rate in successful bulk-gel projects according to reservoir type. SD = standard deviation, Q1 = first quartile; Q3 = third quartile.

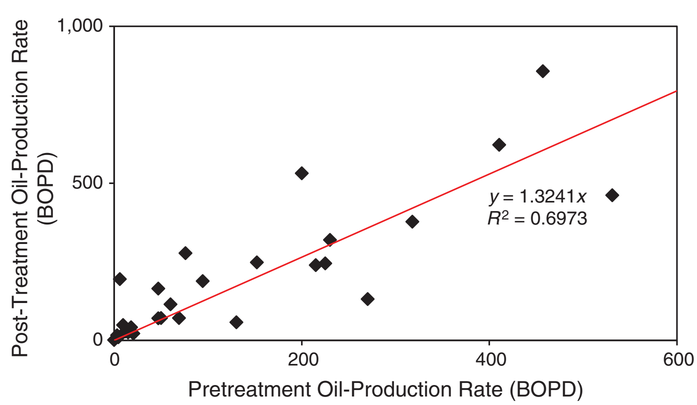

Fig. 4—Crossplot of pretreatment and post-treatment oil-production rate in successful bulk-gel projects.

A question might be raised here on why gel treatments have greater oil-rate increments when applied in NF formations of SS reservoirs than of CB reservoirs. From Darcy's law, the flow rate increases as the permeability of porous media increases. If it is assumed that polymer gels blocked all formation fractures, then the flow of fluids will definitely be through the matrix block of reservoir rocks. First, this assumption implies that for a certain rock type, the incremental production rate increases as the MR permeability increases. Remarkably, the field application data clearly support this implication, as shown in **Fig. 5** for CB reservoirs. Second, the assumption indicates that the SS reservoirs produce at higher rates because they would have larger MR permeabilities than CB if other affecting factors are relaxed. A descriptive summary of the average MR permeabilities for both reservoir types is shown in **Table 5.** Indeed, Table 5 verifies the preceding implication because it shows that SS reservoirs have higher MR permeabilities than CB, according to all statistical measures of data position.

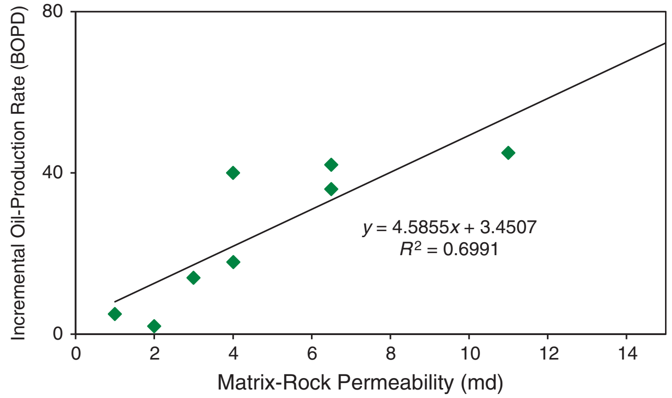

Fig. 5—Scatterplot showing trend of average incremental-oil-production rate against mean MR permeability for NF formations in successful gel projects.

Parameter	Permeability (md) CB	SS
Point count	16	7
Mean	18.7	81
Median	11	68
Minimum	2	10
Q1	4	22
Q3	23	125
Maximum	62	193
SD	20	71
Coefficient of variation	1.06	0.88

Table 5—Summary of MR permeabilities for NF formations in successful bulk-gel projects. SD = standard deviation; Q1 = first quartile; Q3 = third quartile.

To evaluate the effect of treatment timing on the oil-production-rate response, the average incremental rate was plotted against the pretreatment water cut and the flood life, as shown in **Fig. 6.** Both scatterplots display clear decreasing trends for the incremental rate with the treatment-timing indicators. This implies that higher increments in the oil-production rate can be obtained when gel treatment is applied at early times in the flooding life of a reservoir. This observation can be attributed to the existence of large oil saturations or quantities everywhere in the reservoir at the early stages of the field life. Regarding the effect of injected-gel volume, an increasing trend was observed for the incremental rate; however, the association was weak, with R^2 less than 0.1.

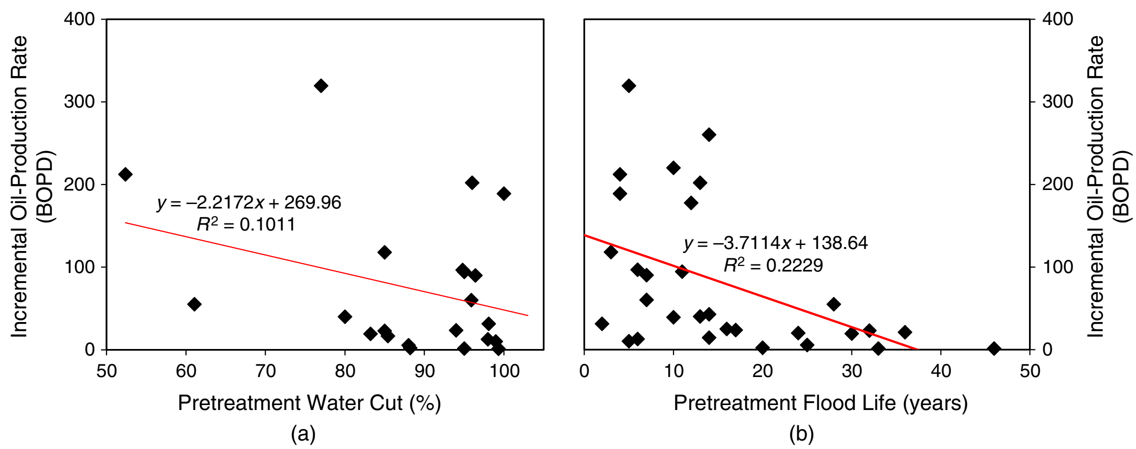

Fig. 6—Scatterplots showing trends of average incremental-oil-production rate in successful bulk-gel projects vs. (a) pretreatment water cut and (b) pretreatment flood life.

Average Incremental Oil Production. The incremental oil production stimulated by gel treatments is graphically evaluated as the difference between the pretreatment and post-treatment oil-production trends. The water/oil-ratio vs. cumulative-oil-production (WOR/N_p) plot and/or the conventional decline-curve plots are used in this evaluation. In this study, the incremental production estimates from the WOR/N_p plots were used in the analysis for most gel projects (24). For case histories (16) that did not provide the WOR/N_p plot evaluations, the decline-curve estimations were adopted instead. The reported total quantities of the incremental production were averaged with respect to the number of the treated injection patterns in a project to obtain the per-well or per-treatment production increments.

The analysis showed that gel treatments have a very wide range for average incremental oil production: 1.1 to 758 MSTBO, with a median of approximately 64 MSTBO and a coefficient of variation of 1.3, as shown in Table 2. Table 2 also presents that the average production increment is approximately 116 MSTBO. Project distributions in **Fig. 7a** illustrate that 84% of gel projects are in incremental-production intervals between 1 and 200 MSTBO (most-expected response). Fig. 7a also clearly shows that 90% of gel projects applied in SS reservoirs are in incremental production intervals <200 MSTBO. Furthermore, it displays that 33% of gel projects applied in CB reservoirs are in intervals >200 MSTBO. This implies that gel treatments have higher incremental oil production in CB than in SS reservoirs. For formation types, Fig. 7b illustrates that gel projects implemented in UC and MR formations are mainly allocated in the MSTBO intervals of 1 to 25 and 25 to 200, respectively. In addition, Fig. 7 shows that gel projects applied in NF formations have the highest percentage (27%) in incremental production ranges >200 MSTBO. In contrast, only 13% of gel applications in MR formations present in >200 MSTBO ranges, and there are no trials for SS-UC. This indicates that gel treatments have higher incremental oil production in NF formations than in MR and UC reservoirs. **Table 6** shows that all gel-treated CB reservoirs are NF formations, whereas SS reservoirs include all formation types. This explains why larger oil-production increments are produced by gel treatments in CB than in SS reservoirs.

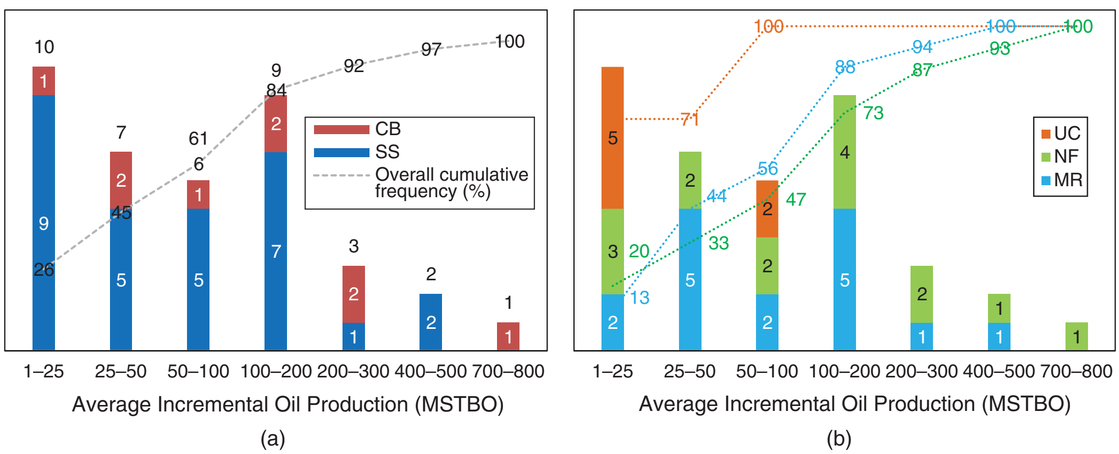

Fig. 7—Distribution and cumulative frequency of average incremental oil production in successful gel projects for different reservoir types.

Parameter	Average Incremental Oil Production (MSTBO)				
	CB-MR	CB-NF	SS-MR	SS-NF	SS-UC
Point count	0	9	16	6	7
Mean	–	182	106	146	28
Median	–	110	76	102	13
Minimum	–	6	4	15	1
Q1	–	42	37	36	6
Q3	–	261	135	162	37
Maximum	–	758	450	460	96
SD	–	235	110	166	35
Coefficient of variation	–	1.29	1.03	1.13	1.26

Table 6—Summary of average incremental oil production in successful bulk-gel projects according to reservoir type. SD = standard deviation; Q1 = first quartile; Q3 = third quartile.

To confirm the preceding two observations regarding the treatment performances, the incremental production estimations were compared for different reservoir types in terms of the six statistical measures of the data position shown in Table 6. Using all six measures, the reservoir types can be ordered in terms of increasing incremental oil production as SS-UC, SS-MR, SS-NF, and CB-NF. It is obvious that gel treatments perform more efficiently in CB than in SS reservoirs and in NF formations than in other formation types. This means that larger oil quantities are produced by gel treatments as the channeling strength increases. The high oil productivity of gel treatments in NF formations is thought to be attributed to the existence of extreme permeability contrasts between the high-permeability thief zones (fractures) and low-permeability zones (MR). Such high heterogeneities would result in severe channeling and highly disproportionate distributions/profiles for the injected drive fluids. Therefore, at the implementation time of gel treatments, there are still high quantifiable mobile-oil quantities in low-permeability zones despite the long-time flooding of the NF formations. This performance behavior emphasizes that NF formations of both lithologies, and especially CB reservoirs, are the best candidates for conformance-improvement treatments with bulk gels.

The question that remained unanswered herein is why gel treatments have better oil-production increments in CB-NF than in SS-NF formations, whereas SS-NF reservoirs have higher MR permeabilities, incremental production rates, and injected-gel volumes, as discussed previously. Using the earliest gel treatments (1985 to 1988) in NF formations in Big Horn Basin, Wyoming, Sydansk and Southwell (2000) also showed that gel treatments have larger oil productivity in CB than in SS reservoirs. They believed that the performance differences mostly resulted from differences in fracture characteristics. We think that the incremental oil production resulting from profile-modification gel treatments is more affected by the volume of the post-treatment swept zone and the possibility and strength of water rechanneling beyond gel treatments than by the mean MR permeability. In addition, the performance differences between the two lithologies are attributed to the effects of the fracture characteristics on the influential factors of the incremental oil production.

Table 2 illustrates that three gel projects were identified as overperforming field projects according to the IQR method. The projects were applied in the Tello (Maya et al. 2014), Weyburn Midale (Kshirsagar 2014), and Kuparuk River (Mishra et al. 2016) oil fields. The most-obvious commonalities between these three oil fields are the treating of severe channeling problems, low-recovery injection patterns, and the injection of large gel volumes, as shown in **Table 7.**

Field	Reservoir Type	Recovery Method	Channeling Strength	Recovery Factor (%)	Gel Volume (bbl/well)	Total Incremental Oil-Production Rate (BOPD)	Average Incremental Oil Production (STBO)
Kuparuk River	CB-NF	Miscible gasflooding	Strong	5	20,694	630	460,000
Tello	SS-MR	Waterflooding	Strong	22	43,400	202	450,000
Weyburn Midale	CB-NF	Miscible CO_2 flooding	Strong	18	6,000	995	757,793

Table 7—Some reservoir and treatment data for overperforming gel projects according to average incremental oil production.

Effect of Gel Volume. For profile-modification gel treatments, conformance-engineering principles illustrate that the amount of incremental oil production depends on and increases with the injected volume of gels exclusively for the cases of MR multilayered reservoirs with crossflow between reservoir strata (Sydansk and Romero-Zeron 2011). In other words, the incremental oil production is proportional to the gel volume only when in-depth fluid-diversion action is needed. By analyzing real field applications, Smith (1999) showed that the incremental oil production increases as the injected-gel volume increases for SS-MR reservoirs with significant crossflow. However, this trend was observed between the normalized incremental oil production with respect to the gel volume and the normalized gel volume with respect to the moveable pore volume of thief zones. Because of the difficulty of the estimation of the moveable pore volume, especially for NF reservoirs, and the high uncertainty involved in available methods, the effect of gel volume on the incremental oil production remained unexamined for other reservoir types.

In this study, we have identified a very clear increasing trend for the average incremental oil production against the injected-gel volume, as shown in **Fig. 8.** In addition, a strong relationship between the incremental oil production and gel volume was obtained where 60% (R^2) of the variation in the incremental oil production is explained by the gel volume. Most importantly, it has been identified that the incremental oil production increases as the gel volume increases for NF and UC formations as with the MR reservoirs, as shown in **Fig. 9.** The explanation behind this observation can be similar to the realization proposed for the effect of crossflow in MR reservoirs. In NF and UC formations, thief zones are not simple, single, uniform, limited-volume flow features. They are complex, extensive, branched, intersected, and varied-aperture configurations, such as a fracture network, conduits, and wormholes. Therefore, these large-volume problem zones might cause the rechanneling of drive fluids after passing the gel-treated regions of the reservoir. This explains that as the injected-gel volume increases, a further portion of high-permeability zones is plugged off, and thus the recovered incremental oil production increases. In other words, the potential sweepable zones by subsequently injected drive fluids increase as larger gel volumes are placed in problematic zones, as in the case of MR reservoirs.

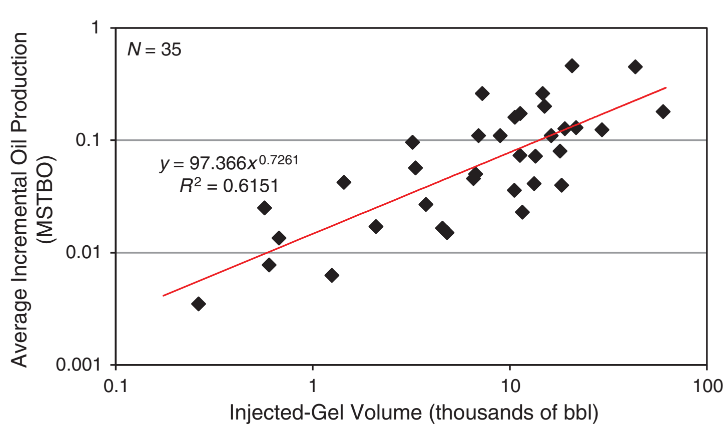

Fig. 8—Scatterplot showing trend of average incremental oil production against injected-gel volume in bulk-gel projects.

Effect of Treatment Timing. Rationally, any IOR/EOR process would result in better oil recovery when it is applied at the early times of a field life. This simply is because it targets larger oil reserves compared with late-stage application. Similarly, it is thought that this reasoning is also true for conformance-improvement technologies, without the exception of bulk-gel systems. However, bulk gels have been mostly applied to control water production and improve oil production from fully developed conformance problems (water cut of 50 to 100%). This application tendency gives the impression that the treatment timing has little effect on the oil-production response of profile-modification gel treatments because they are applied over a limited range for the treatment-timing indicators. Practically, several studies have emphasized that the early application of EOR processes, and especially polymer-based technologies, would help in the recovery of larger incremental oil volumes (Thyne et al. 2010; Mack and Lantz 2013; Lantz and North 2014).

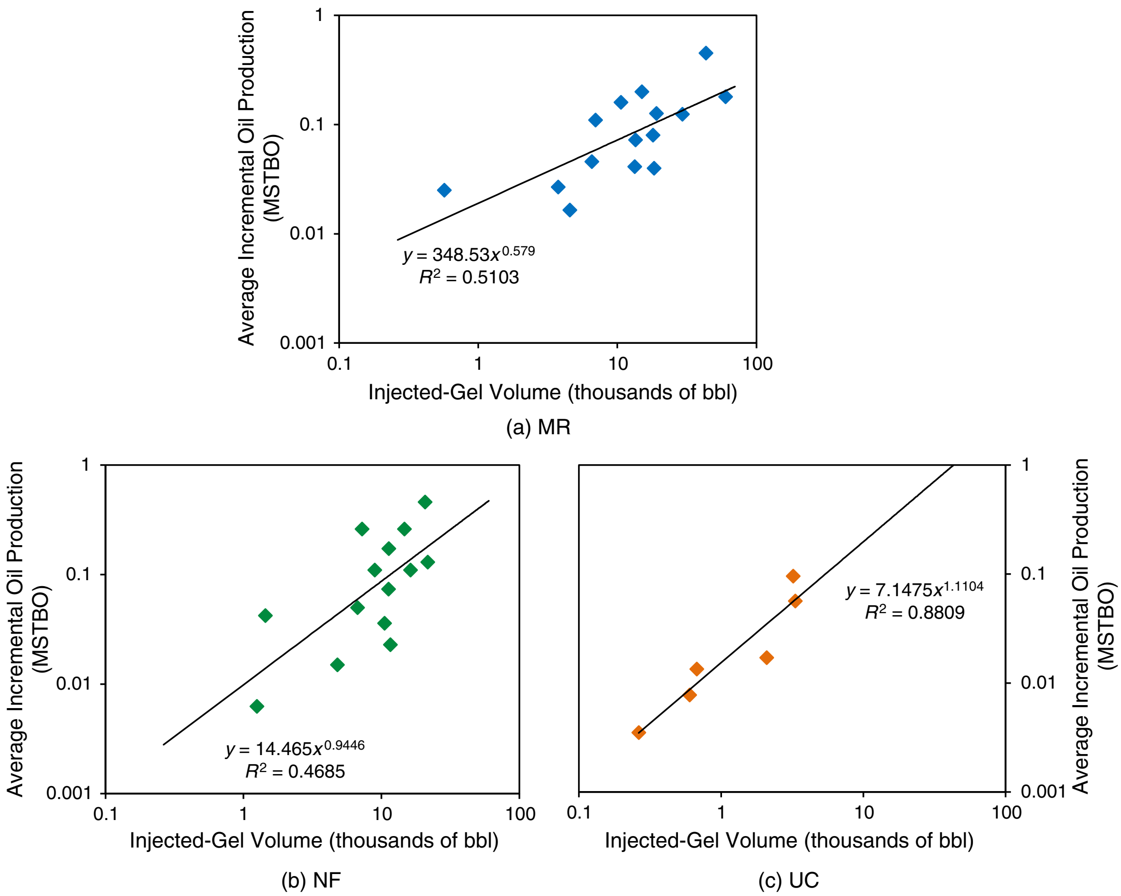

Fig. 9—Scatterplots showing trends of average incremental oil production against injected-gel volume in bulk-gel projects for different reservoir types.

To validate this realization regarding the effect of the treatment timing on the oil-production response, the average incremental oil production was plotted vs. the treatment-timing indicators, as shown in **Fig. 10.** It can be seen that all three crossplots confirm that the average incremental oil production significantly reduces as the treatment timing is delayed in the flooding life. In other words, the sooner the application of bulk gels, the larger the incremental oil production. Although all treated injection patterns involved developed problems (limited timing range), large negative slopes resulted for all incremental-production trends against the treatment-timing indicators. For example, the incremental oil production reduces by an amount of approximately 2,900 STBO when water cut increases by 1%, as shown in Fig. 10a. This highlights the appreciable effect of the treatment timing on the incremental oil production, an effect that opposes the aforementioned impression. Moreover, the scatterplots also suggest that gel treatments would perform more efficiently if they are implemented at water cuts of less than 70%, flood lives of fewer than 20 years, or recovery factors of less than 35%.

Normalized Incremental Oil Production. In practice, it is preferable to know how many oil barrels would be recovered by a gel barrel. Therefore, the average incremental oil production was normalized with respect to the injected-gel volume in field projects. Both oil and gel volumes were already averaged for the number of treated injection wells before the normalization step. The use of the normalized incremental oil production would result in more-accurate analysis and even comparisons of gel-treatment performances because it eliminates the effect of the injected-gel volume. In this study, the term "oil productivity of gel barrel" is sometimes used as a synonym for the normalized incremental oil production.

In general, gel projects have a very wide range of normalized incremental oil production (0.85 to 149 STBO/bbl gel) and high data variability (1.6), as shown in Table 2. Although the mean oil productivity of a gel barrel is approximately 15 STBO/bbl gel, the median illustrates that 50% of gel projects have productivity less than 7.3 STBO/bbl gel. Three overperforming projects were identified that share being applied in reservoirs with either natural or induced fractures. Project distributions in **Fig. 11a** illustrate that approximately 76% of gel applications resulted in the recovery of oil quantities between 2.5 and 25 STBO/bbl gel (most-expected response).

Fig. 11a also shows that only gel trials in SS reservoirs are present in oil-productivity ranges that are less than 2.5 STBO/bbl gel (approximately 14% of them), whereas applications in CB reservoirs have productivities that are in general greater than 2.5 STBO/bbl gel. This shows that three of the five projects in productivity ranges that are greater than 25 STBO/bbl gel were applied in CB reservoirs. Fig. 11b shows that gel trials in NF and UC formations tend to collect in higher productivity ranges than applications in MR reservoirs. For ranges that are greater than 25 STBO/bbl gel, three out of the five projects were applied in NF formations. These observations indicate that bulk-gel treatments have better oil productivities in CB than in SS reservoirs and in NF and UC reservoirs than in MR formations.

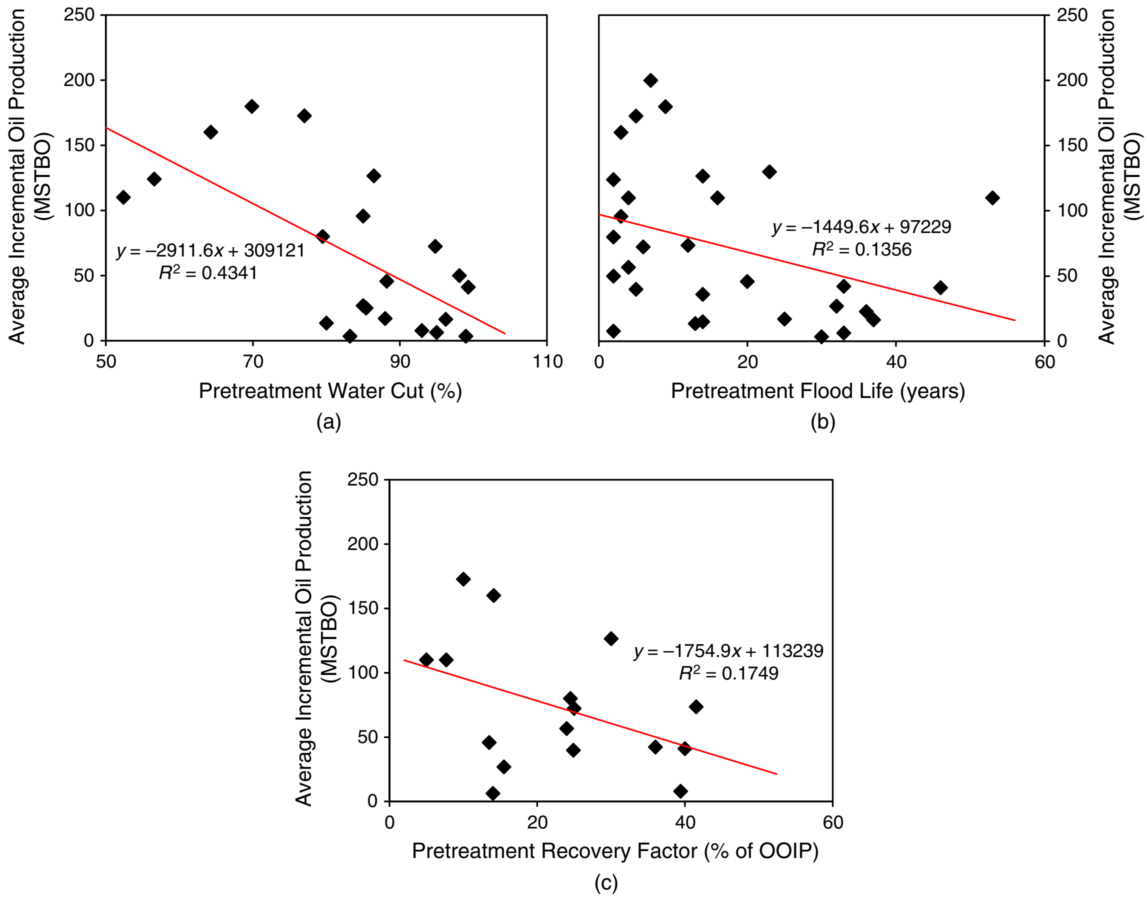

Fig. 10—Scatterplots of average incremental oil production and treatment-timing indicators in successful bulk-gel projects. OOIP = oil originally in place.

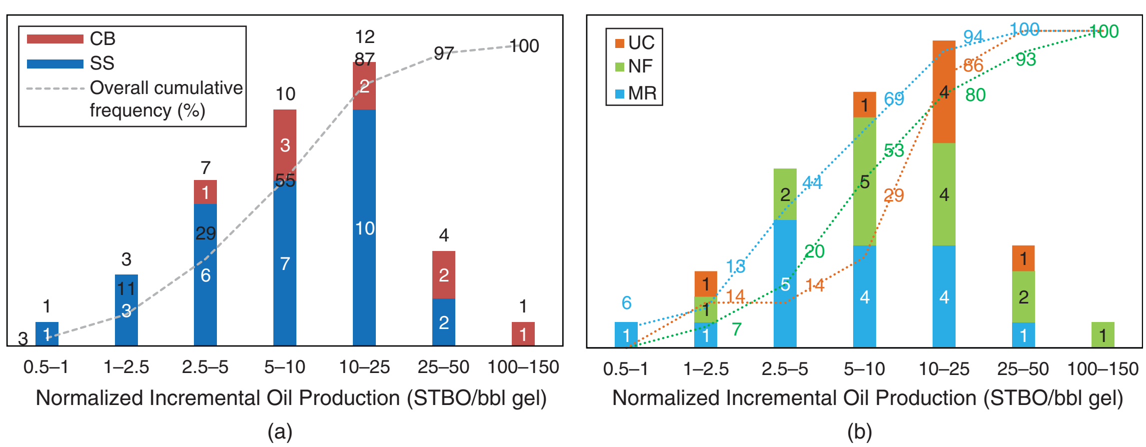

Fig. 11—Distribution and cumulative frequency of normalized average incremental oil production in successful gel projects for different reservoir types.

However, for NF formations, the mean and median values shown in **Table 8** reveal that only gel applications in CB-NF reservoirs have greater productivities than applications in other reservoir types. They clearly illustrate that gel applications in SS-NF reservoirs have mean and median productivities (9.2 and 6.3, respectively) that are significantly lower than those in CB-NF reservoirs (30 and 12, respectively) and are nearly similar to those in SS-MR formations (9.1 and 6, respectively). For SS-MR reservoirs, Smith (1999) provided that the normalized incremental oil production is expected to be between 2 and 3 bbl oil per bbl of gel if 10% of the channel volume is blocked by bulk gels.

Regarding the effect of treatment timing, declining trends of the normalized incremental oil production were observed against the pretreatment flooding life and recovery factor, but not with the water cut, as shown in **Fig. 12.** The scattering pattern of data points in Fig. 12a suggests that there is more than one collection of points and there are multiple parallel decreasing trends, not just a single trend, for the normalized incremental oil production with the water cut. This observation (i.e., multiple collections and trends) is also clear for this parameter with the recovery factor. To illustrate these decreasing trends, the areas of the plots in Fig. 12 were patterned with downward diagonal lines so the trends can be easily observed and followed. We are identifying these data behaviors (forming separated clouds of points that each demonstrate the expected tendency for the parameter) for some design and performance parameters when they are normalized and plotted against ratio/percentage parameters, such as water cut and recovery factor. This promising observation is currently being further investigated.

Parameter	Normalized Incremental Oil Production (STBO/bbl gel)				
	CB-MR	CB-NF	SS-MR	SS-NF	SS-UC
Point count	0	9	16	6	7
Mean	–	29.7	9.1	9.2	14.6
Median	–	12.3	6.0	6.3	13.3
Minimum	–	3.4	0.9	2.0	1.2
Q1	–	6.8	3.5	3.8	10.6
Q3	–	29.3	11.1	13.1	18.5
Maximum	–	149.4	43.9	22.2	29.8
SD	–	46.3	10.3	7.9	9.0
Coefficient of variation	–	1.56	1.13	0.86	0.62

Table 8—Summary of normalized average incremental oil production in successful gel projects according to reservoir type. SD = standard deviation; Q1 = first quartile; Q3 = third quartile.

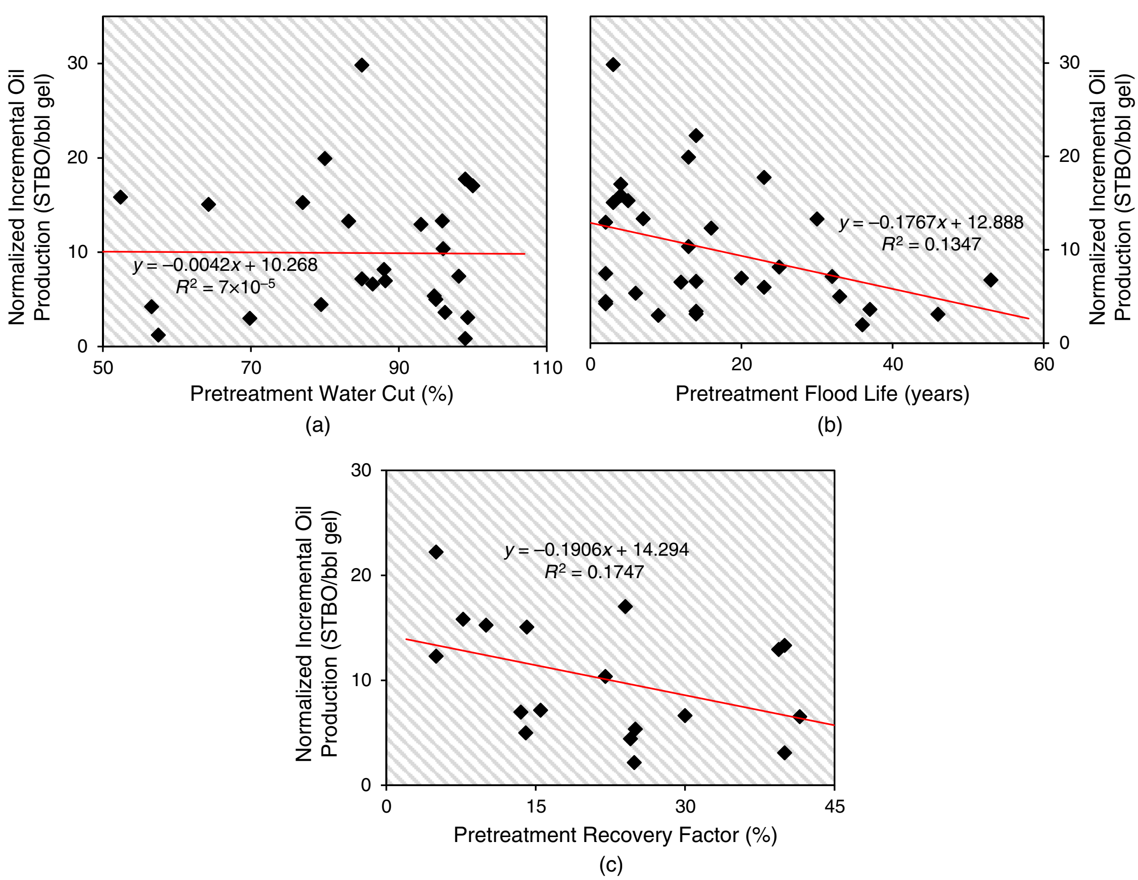

Fig. 12—Scatterplots of normalized incremental oil production and treatment-timing indicators in successful bulk-gel projects.

Incremental Oil Production per Pound of Polymer (IOPPP). Similar to polymer flooding, the incremental oil production of gel treatments is also evaluated according to the quantities of polymers used in the preparation of injected gels. In this study, the dry polymer weights of bulk gels were estimated from their average injected volumes and concentrations. Then, the IOPPP was evaluated as a ratio of the average incremental oil production to the average polymer weight. The IOPPP is also a normalized parameter and is referred to as "treatment efficiency" in some field-project reviews.

Because of limited data availability, it was possible to estimate this performance parameter for only 55% of the surveyed gel projects. The statistics of Table 2 present that gel treatment provoked a wide IOPPP range of 0.5 to 67 STBO/lbm, with mean and median values of 10 and 6.5 STBO/lbm, respectively. Further, the data set has a high coefficient of variation of 1.3, and two outliers were identified as unlike overperforming projects. **Fig. 13a** shows that distributions of gel applications are left-skewed, and approximately 57%

of them have IOPPP values between 1 and 10 STBO/lbm (most-expected response). Fig. 13a also presents that gel applications in CB reservoirs generally have IOPPP values greater than 1 STBO/lbm, and approximately 50% of these projects are in IOPPP ranges that are greater than 10 STBO/lbm. Fig. 13b illustrates that 6 of 11 gel treatments that have IOPPP values greater than 10 STBO/lbm were conducted in NF formations. This implies that gel treatments have higher IOPPP values in CB than in SS mineralogies and higher IOPPP values in NF than in MR and UC formations.

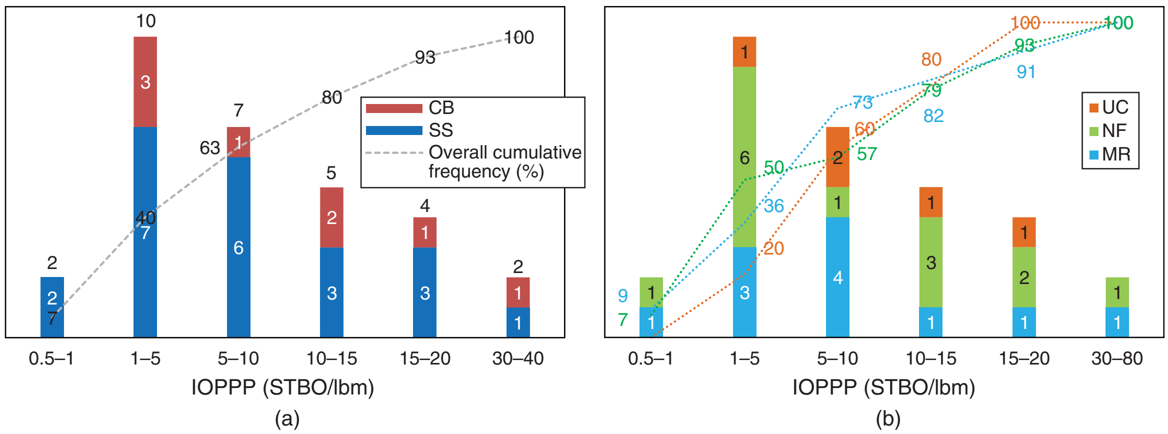

Fig. 13—Distribution and cumulative frequency of incremental oil production per polymer pound in successful gel projects according to reservoir type.

For SS reservoirs, **Table 9** illustrates that gel projects applied in UC and MR formations have appreciably higher average and median IOPPP values than applications in NF reservoirs. We think that these averages and medians are affected by the amount of available data for SS-NF reservoirs. In addition, gel treatments applied in SS-NF reservoirs would have at least identical, if not larger, IOPPP estimations to those of MR and UC formations. To verify this belief, the polymer weight, IOPPP, and normalized incremental oil production for different reservoir types were estimated using the median values of the incremental oil production, gel volume, and polymer concentration, as shown in **Table 10.** It is obvious that gel trials in SS-NF reservoirs have larger normalized incremental production and IOPPP than trials in SS-MR and SS-UC reservoirs, especially for the normalized incremental production.

	IOPPP (STBO/lbm)				
Parameter	CB-MR	CB-NF	SS-MR	SS-NF	SS-UC
Point count	18	3	7	2	18
Mean	9.2	8.2	14.6	4.7	9.2
Median	7.2	5.7	6.6	4.7	7.2
Minimum	0.5	3.3	1.0	1.0	0.5
Q1	4.3	4.5	2.8	2.9	4.3
Q3	12.2	10.7	11.3	6.5	12.2
Maximum	31.3	15.7	66.7	8.3	31.3
SD	7.6	6.5	23.5	5.2	7.6
Coefficient of variation	0.83	0.79	1.60	1.10	0.83

Table 9—Summary of IOPPP in successful gel projects according to reservoir type. SD = standard deviation; Q1 = first quartile; Q3 = third quartile.

				Incremental Oil Production		
Reservoir Type	Gel Volume (bbl)	Polymer Load (ppm)	Polymer Weight (lbm)	Average (MSTBO)	Normalized (STBO/bbl gel)	Per Pound (STBO/lbm)
CB-NF	5,890	5,750	11,854	110	18.7	9.3
SS-NF	11,600	5,117	20,775	102	8.8	4.9
SS-MR	13,303	3,500	16,296	76	5.7	4.7
SS-UC	2,091	4,363	3,193	13.5	6.4	4.2

Table 10—Median-based estimation of normalized performance parameters of gel treatment for different reservoir types.

Interestingly, Table 10 reveals two additional valuable points regarding the gel-treatment oil-production response in different reservoir types. Previously, it was indicated that gel treatments have performances in SS-NF that are similar to those in CB-NF reservoirs and higher than those in SS-MR and SS-UC reservoirs according to the unnormalized performance parameters, such as the average incremental production and incremental production rate. However, taking a close look at the normalized incremental production and

IOPPP in the last two columns of Table 10 would yield different observations. First, gel applications in SS-NF reservoirs have much lower productivities than the gel implementations in CB-NF reservoirs because larger gel volumes are injected in the treatment of SS-NF formations. Second, gel-treatment efficiencies in SS-NF reservoirs are comparable with or of the same magnitude as those in SS-MR and SS-UC according to the normalized parameters because higher polymer concentrations are used in the remediation of the SS-NF reservoirs. It is noteworthy that these performance tendencies of gel treatments were also recognized in the evaluation of the normalized-incremental-production data set. In addition, it seems that the median-based analysis results in more-trustworthy observations when the treatment responses are compared for different reservoir types. As with the average incremental production (the numerator), the IOPPP exhibited clear decreasing trends against the treatment-timing indicators, with $R^2 > 0.1$ in general.

Total Incremental Recovery Factor. The oil-production response of gel treatments is also assessed in the term of incremental recovery factor. This parameter is compositely estimated for all treated injection patterns in a field as the difference between the pretreatment and post-treatment recoveries. It is more frequently used in evaluations of fieldwide floodings than in gel treatments. Thus, few case histories reported the incremental recovery factor (15 projects), especially for CB reservoirs (two projects) and NF formations (five projects).

Table 2 shows that gel treatments produced incremental recoveries between 0.01 and 5.4%, with a median of 0.7% and a coefficient of variation of 1.3. Although the mean value is 1.4%, approximately 60% of gel applications have incremental recovery factors of less than 1%. The IQR method detected two overperforming projects that were implemented in highly heterogeneous SS-MR reservoirs (Dykstra-Parsons coefficient of 0.8), with adverse mobility ratios (approximately 9) at early times after the start of waterflooding.

The low number of data points for this parameter does not allow the establishment of well-supported observations regarding the distribution of gel projects with respect to the reservoir type and the recovery method. Once more, the scatterplots showed declining trends for the incremental recovery factor against all treatment-timing indictors, as shown in **Fig. 14.** In addition, an increasing tendency of the incremental recovery factor with the injected-gel volume was recognized, but with low R^2 (less than 0.1). However, it is important to remember that this parameter is not averaged with respect to the number of gel-treated injection patterns (i.e., composite).

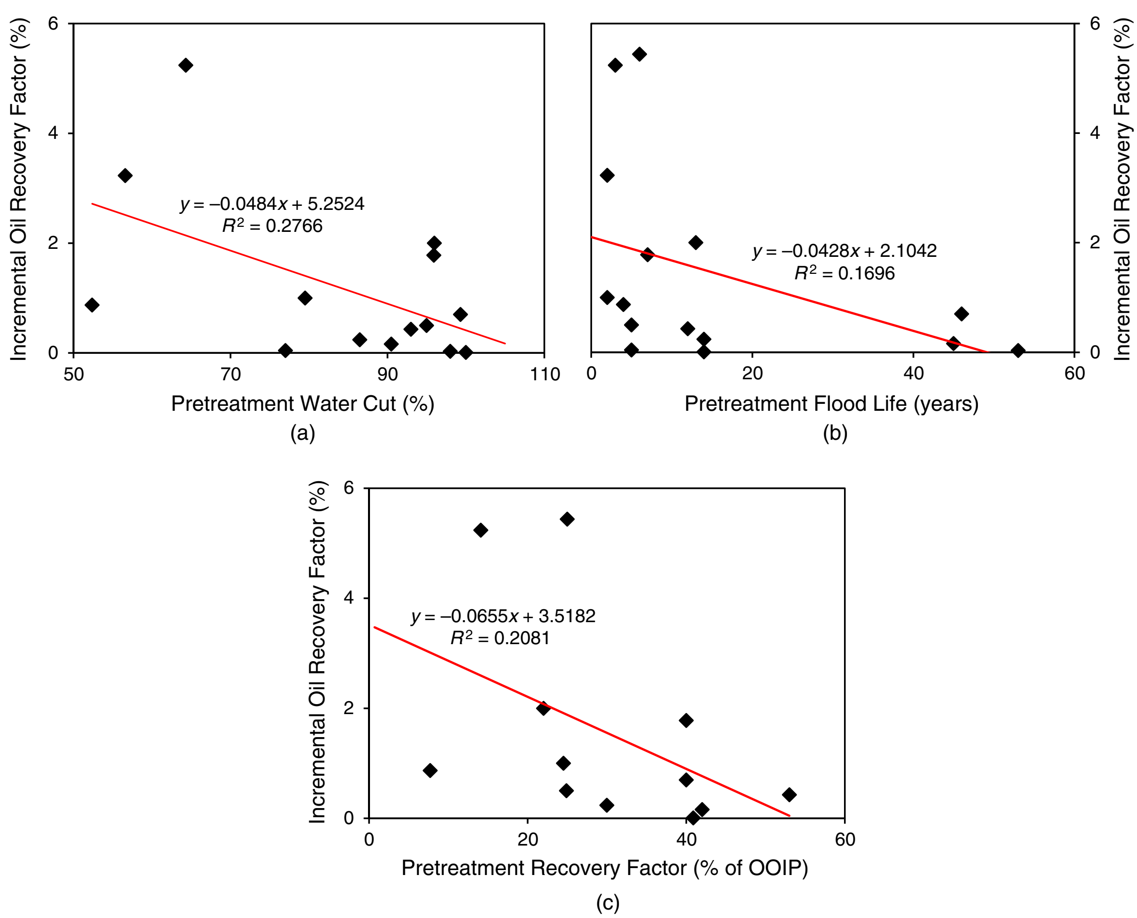

Fig. 14—Scatterplots showing declining trends of total incremental oil-recovery factor in successful bulk-gel projects against treatment-timing indicators. OOIP = oil originally in place.

Analysis of Oil-Production-Response Parameters per Recovery Process. Concerning the IOR/EOR recovery process, the analysis showed that most summarized data are for gel projects applied in waterfloods (22 on average). In contrast, only three data points are typically available for gel applications in steamfloods or polymer floods. The low number of data points for these EOR techniques would not help in inferring the likely effects of such recovery processes on the performances of gel treatments. On the other hand, the performances of gel projects applied during waterflooding were widely distributed over the parameter ranges, and clear collecting tendencies were rarely observed. Consequently, no fair conclusions regarding gel-treatment performances with respect to the IOR/EOR process were obtained for most of the analyzed parameters. Therefore, the analysis results of gel-treatment responses with respect to the recovery process were not included in this paper because they are of limited benefit.

Conclusions

1. On average, profile-control gel treatments respond after 3.5 months, increase the oil-production rate by 32%, and additionally recover 116 MSTBO per treatment, 15.6 STBO per gel barrel, or 10 STBO per polymer pound when successfully applied in oil reservoirs.
2. Gel treatments have better oil-production responses in CB than in SS reservoirs, and in fractured formations than in other formation types. For NF formations, gel treatments stimulate higher oil-production-rate increments in SS than in CB, but comparable final incremental cumulative oil production.
3. For NF formations, gel treatments have much-higher oil productivities in CB than in SS reservoirs according to the normalized performance parameters. The normalized oil productivities in NF-SS are of the same magnitude as those in MR and UC-SS reservoirs.
4. Gel treatments generate faster and better oil-production responses as the channeling strength and the gel volume increase. As in MR reservoirs characterized by substantial crossflow, the incremental oil production increases as more gels are injected in NF and UC formations as well.
5. The performance behavior of gel treatments emphasizes that NF formations of both lithologies, and especially of CB reservoirs, are the best candidates for conformance-improvement treatments by bulk gels. It is recommended to allow longer evaluation times for gel treatments applied in MR formations because their response times might extend to several months.
6. The treatment timing significantly influences all oil-production-response parameters. The sooner the application of gel treatments, the faster the response and the larger the incremental oil production and its rate. Gel treatments will perform more efficiently if they are implemented at water cuts of less than 70%, flood lives of fewer than 20 years, or recovery factors of less than 35%.

Nomenclature

N_p = cumulative oil production
R^2 = coefficient of determination

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