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Research paper

Hydraulic fracturing design considerations, water management challenges and insights for Middle Eastern shale gas reservoirs

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ABSTRACT

Water is one of the most important commodities in the world and plays an essential role in the hydrocarbon industry. With increased agricultural production, rapid industrialization, population growth and climate change, the world is facing an extreme water crisis in many regions. Coupled with a surge in energy demand and consumption, this has greatly influenced the hydrocarbon industry. With increasing stress on water resources, it is essential to examine how water is managed within the hydrocarbon industry and devise ways to utilize water more efficiently, especially within water scarce regions such as the Middle East.

Augmented by the recent activities in the oil and gas industry, it can be seen that an economical and efficient hydraulic fracturing job has become crucial for the successful development of unconventional reservoirs. However, exploitation of unconventional reservoirs is heavily water-intensive as compared to conventional reservoirs. In this study, a comprehensive investigation that deals with quantification of changes with respect to the variation in prime contributors within a traditional fracture design process is presented.

To understand the significance of key design parameters, factors that affect productivity within typical Middle Eastern shale gas reservoirs were analyzed through simple constrained cases. Investigations reveal that parameters such as fracture aperture, natural fracture distribution, fracturing fluid viscosity and Young's modulus are crucial to the overall production and water requirement. Furthermore, an outline for resource management within a traditional fracture design process is presented along with potential challenges for the region. Enhancing existing methodologies and incorporating key parameters highlighted within this study can contribute to the overall value chain. In addition to ultimately assisting in the verification of modern best practices, this investigative approach will create a paradigm for future studies for the region to assist in a simplistic prediction of fracture propagation and associated response to augment water usage.

1. Introduction

Water is regarded as one of the most valuable commodities required for the sustenance and development of life and livelihood. Though water has not yet been termed as a scarce commodity globally, a significant amount of human population is already facing water stress, i.e. lack of access to potable water resources. Approximately 1.2 billion people live in areas of physical water scarcity with around 500 million people approaching a similar outcome. It has been reported that Middle East and North Africa regions are amongst the most water scarce regions in the world (Anon, 2007, 2009).

Oil and gas, while one of the prime contributors for the retention, advancement and upheaval of the world economy, is a large consumer of water. With the growth in population coupled with rapid urbanization, energy demand is projected to increase by as much as 55% through 2030, thus additionally increasing water demand (Anon, 2009). Hydrocarbons contribute significantly to the global energy production and there is a need for tapping hydrocarbon resources efficiently and economically (Annual Energy Outlook, 2018; Khlaifat et al., 2011).

Conventional reservoirs have been widely regarded as reservoirs with values for porosity and permeability that allow them to flow naturally without any external stimulation. However, unconventional reservoirs are often very tight in nature (extremely low permeability) which restricts the ability to flow at economic or desired rates. In such cases, hydraulic fracturing or 'fracking' is a well stimulation technique that involves injection of engineered fluids, sands, polymers and/or chemicals under extremely high pressure to targeted zones. Hydraulic fracturing enables improved oil and/or gas flow from such reservoirs. However,

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Nomenclature

q	Injection flow rate (general)
q_L	Injection flow rate (liquid)
t	Time
t_p	Time (Pumping)
τ	Time (fracture leak-off area creation)
f	Darcy Friction Factor
C	Leakoff coefficient (total)
ρ	Density
W	Width of fracture
H_ξ	Half height (characteristic)
v	Poisson's Ratio
V_f	Volume (fracture)
V_l	Fluid Loss
V_{sp}	Spurt Fluid Loss
A	Area (leakoff)
S_p	Spurt loss coefficient
α_a	Leakoff parameter
α_τ	Leakoff parameter (at fracture)
α_c	Leakoff parameter (at pumping)
α_{c_2}	Reservoir compressibility and viscosity coefficient
π	Pi
Φ	Porosity
θ	Dimensionless time
ε	Relative wall toughness
Γ	Generalized function (influence)
G	Generalized function (fluid loss)
$\vec{\nabla}.P$	Change in pressure
Re	Reynolds Number
x	Coordinates (along fracture length)
y	Coordinates (perpendicular to fracture direction)
z	Coordinate (vertical)

extraction through hydraulic fracturing use a significant amount of water (Saldungaray and Palisch, 2012; Al-Muntasheri, 2014; Sirat et al., 2014; Corrin et al., 2015; Janszen et al., 2015).

In 2016, it was estimated that a typical well in the United States might use up to 8 million gallons of water during its entire life cycle. Fig. 1 depicts water use for drilling and fracturing for some of shale plays in the United States. United States Geological Survey further reports that for conventional hydraulic fracturing jobs in the Bakken and Three Forks Formations, the mean estimated yearly water usage in 2016 was approximately 170.2 billion gallons of water (Haines et al., 2017). It is to be noted that this may depend on a number of factors such as the required number of fractures, reservoir characteristics and its suitability to re-fracturing. It was also suggested a significant amount of the injected water is left behind consequently leading to potential formation damage.

With the looming water scarcity and rising stern regulations governing withdrawal of water resources in the hydrocarbon industry, there is an increased necessity for exploring an efficient, effective and economic hydraulic fracturing technique. This is more relevant in regions such as the Middle East where fresh water resources for fracturing are not abundant. With the reducing economic margins accompanying unconventional resources, identifying limitations and evolving current practices can provide significant advantages in the current volatile market conditions.

Some field reports indicate that even after successful implementation of hydraulic fracturing, the desired permeability, geometry and productivity is often not realized. Inaccuracies in modeling flow behavior and accurately depicting natural fracture distribution and geometry further add to the complexities. Premature water breakthrough, lower recovery rates, increased fracture flowback, injected fluid channeling and fracture collapse are a few of the reported detrimental effects due to the presence of natural fractures (Ogbechie, 2011).

Even with the recent unconventional boom and multiple hydraulic fracturing operations globally, shale reservoirs are still associated with a high degree of risk and uncertainty. As the demand for energy rises steadily, a significant amount of resources, efforts and time is involved for the successful exploitation of unconventional fields. Multiple studies have shown that for an effective, efficient and economical hydraulic fracture treatment design, the impact of various in-situ parameters along with the design parameters must be analyzed in depth to better understand the fracture propagation behavior (Khlaifat et al., 2011; Valko and Economides, 1995; Rahman et al., 2003; Economides and Martin, 2007).

This investigation presents an outline and potential for a water-based fluid management scheme within a traditional fracture design process. The factors that affect productivity are analyzed through simple constrained cases. In addition, the investigation also reviews and presents concerns within challenging and evolving markets such as the Middle East. Potential strategic drivers such as efficient resource usage, water management practices, evolving technologies along with their potential are also highlighted. Coupled with water sourcing, transportation, treatment, storage and disposal approaches and costs for such arid regions, this study can considerably contribute to the value chain.

Hence, the major objectives for the presented investigation are as follows:

1. Investigate hydraulic fracture propagation behavior and their response in the presence of natural fractures within Middle Eastern shale gas reservoirs through industrial simulators and numerical modeling.
2. Develop an adaptable simulation model to easily identify the contributing parameters within a traditional fracture design process.
3. Analyze and quantitatively characterize the behavior and response of fracture design parameters to link it to a water-based fluid management scheme.
4. Examine, identify and quantify the relative significance of dominating parameters to the fracture geometry along with a sensitivity analysis.
5. Propose a unique sustainable operational workflow highlighting key components for a water scare region such as the Middle East.

2. Methodology

Horizontal wells, frac and pack, hydra-jet perforation, zipper fracking, synthetic proppants and fracture mapping coupled with innovative geo-modeling techniques are just a few of the technologies that greatly assisted in the advancement in tapping unconventional reservoirs (Haines et al., 2017; Sorrells and Mulcahy, 1986; Veatch Jr and Moschovidis, 1986; Meese et al., 1994; McDaniel et al., 2006; Rafiee et al., 2012a,b). With respect to hydraulic fracturing mechanics, investigations related to the fundamentals of fracture initiation, propagation, and breakdown, have primarily focused on in-situ stresses. These can be categorized into three major components, specifically, compressive, isotropic and non-homogeneous stresses. Since a fracture is

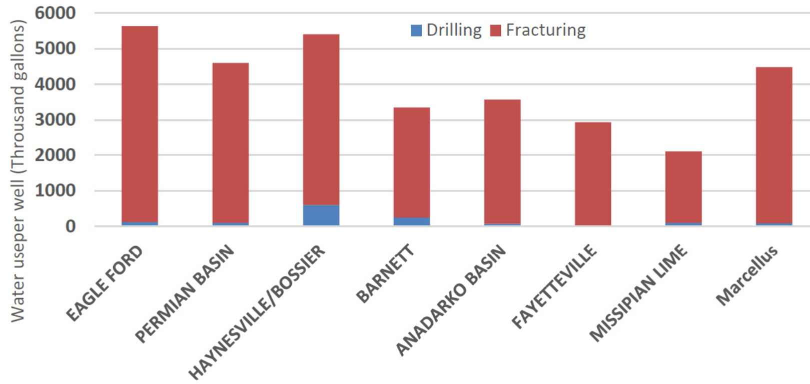

Fig. 1. Water use in fracturing and drilling for shale plays in US (Saldungaray and Palisch, 2012).

generated in a direction perpendicular to the minimum stress, multiple factors such as overburden stress, pore pressure, formation properties, temperature, diagenesis, tectonics etc. can greatly influence the propagation behavior within a reservoir (Gidley et al., 1989).

Over the past few decades, various modeling techniques have been published to predict fracture growth and geometry along with productivity. The Perkins-Kern-Nordgren (PKN), Khristianovic–Geertsma–de Klerk (KGD), Radial, Pseudo Three-Dimensional, Wiremesh and Unconventional Fracture Model (as illustrated in Fig. 2), are a few of the widely used models in the industry today, with each having their own limitations and advantages. Numerous literature and field studies have shown the significance of natural fracture interaction with hydraulic fractures and the associated fracture propagation response (Jang et al., 2015; Cai et al., 2017). Investigations reveal that hydraulic fracture propagation in a naturally fractures reservoir is also dependent on additional factors such as the natural fracture distribution, density, orientation, reservoir heterogeneity, composition and stress distribution.

For modeling the flow behavior and mass transport in such a porous media, multiple solutions exist within the industry, the most notable among them being the Dual-continuum Method and Discrete Fracture Networks (DFN). Under the dual-continuum method, the matrix and fracture are modeled as two distinct continua possessing the same control element or volume with respect to space (Warren and Root, 1963). But the geometry of the discrete fractures are not explicitly modeled along with the solution or flow pathway, resulting in inaccurate flow predictions in regions where well control is limited (Dershowitz et al., 2004). The Discrete Fracture Network (DFN) model involves 'analysis and modeling which explicitly incorporating the geometry and properties of discrete features as a central component controlling flow and transport', thus addressing some of the shortcomings of the Dual-continuum method (Cai et al., 2017). This can lead to a more realistic description of the network, as they are stochastic models that incorporate statistical scaling rules derived from analysis of fracture length, height, spacing, orientation, and aperture (Guohai and Pashin, 2008). The recently developed Unconventional Fracture Model (UFM) incorporates the stress fields, natural fracture orientation and rock deformation that are critical to analyze the hydraulic fracture propagation behavior in an unstructured grid (Weng et al., 2011). Hence, for this study, which further expands on the investigation conducted by Suboyin et al. (2018), UFM was the preferred model to analyze the fracture propagation and production in the presence of natural fractures. The methodology is as follows:

1. An extensive literature review was conducted on published studies, modeling techniques and field applications within unconventional reservoirs, specifically for the Middle Eastern region.
2. Along with field data acquisition, the potential of current industrial simulators tailored for shale gas reservoirs were evaluated. The industrial simulator used in this study is also capable of modeling three-dimensional hydraulically induced fracturing propagation in ultra-low permeable unconventional reservoirs along with discrete fracture networks.
3. This was followed by the construction of a simplistic base case within the simulator to
    a. Understand the fundamentals of hydraulic fracture propagation and its associated response in the presence of natural fractures.
    b. Examine and identify the key parameters with respect to the hydraulic fracturing treatment design. Furthermore, this allowed to categorize the parameters are controllable and non-controllable, which is further elaborated in the Results and Discussion section of this study.
4. Once the constructed model was successfully validated and history matched with constrained cases, operator data from within the region was incorporated. Fig. 3 shows a simplistic representation of the constructed field model that demonstrates hydraulic fracture propagation behavior within a horizontal well in the presence of natural fractures.
5. Fracture propagation, the response and the cumulative gas produced with respect to changes in fracture treatment design properties and natural fracture interaction are investigated.
6. Through a closed loop iterative process, this allowed to quantitatively identify the dominance and analyze deviations among the key contributing parameters. The parameters incorporated for this investigation and proposed for consideration in the operational workflow are depicted in Fig. 4.
7. A sensitivity analysis was conducted to analyze the relative significance of dominating parameters with respect to the fracture geometry.

Prior to proceeding with the analysis, it is imperative to understand the underlying mechanisms and major governing equations within the simulation process. The equation for mass conservation for an incompressible slurry to be injected into the fracture of a constrained media is represented by Eq. (1) (Meyer, 2012; Meyer et al., 2010).

$$\int_0^t q(\tau)\,d\tau - V_f(t) - V_l(t) - V_{sp}(t) = 0 \tag{1}$$

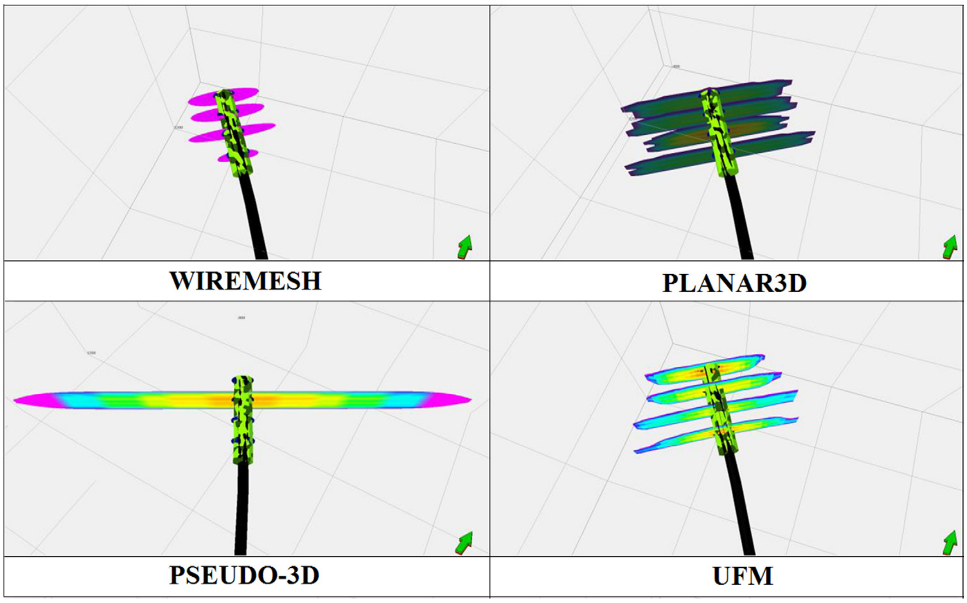

Fig. 2. Simplistic representation of widely used fracturing models.

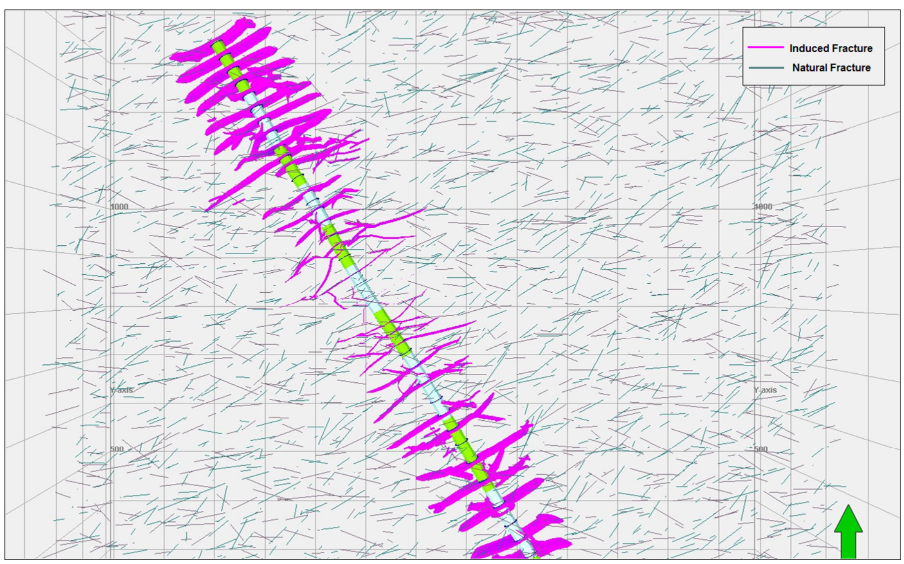

Fig. 3. Simplistic representation of constructed model.

where,

$$V_l(t) = 2\int_0^t \int_0^A \frac{C\,(A,t)}{[t-\tau\,(A)]^{\alpha_\tau}} dAdt \tag{2}$$

$$V_{sp}\,(t) = 2S_p A\,(t) \tag{3}$$

$$\tau\,(A) = t\left[\frac{A}{A\,(t)}\right]^{\alpha_a} \tag{4}$$

For any hydraulic fracturing treatment, fluid loss due to leak off (pre and post pumping) is a critical parameter to be considered. This is represented by Eqs. (5) and (6): (Meyer, 2012)

$$V_l\,(t) = \pi C\,(t)\,A\,(t)\,\sqrt{t}\Phi\,(\alpha_a\alpha_c) \tag{5}$$

$$V_l\,(\theta) = 2C\left(t_p\right)A\left(t_p\right)\sqrt{t_p}G\left(\alpha_a\alpha_{c_2},\theta\right) \tag{6}$$

where,

$$\theta = \frac{t}{t_p} \tag{7}$$

In addition, the mass continuity equation with respect to flow rate per unit length ($q = vW$) can be represented by Eqs. (8) and (9): (Meyer, 2012)

$$\vec{\nabla}.\vec{q} + 2q_L + \frac{\partial W}{\partial t} = 0 \tag{8}$$

where,

$$\vec{\nabla}.\vec{q} = \frac{\partial q_L}{\partial x} + \frac{\partial_z}{\partial z} \tag{9}$$

Furthermore, the equation for momentum with respect to steady state flow is expressed as Eq. (10): (Meyer, 2012)

$$\vec{\nabla}P = -\frac{1}{2}\frac{fp\vec{q}^{\,2}}{w^3} \tag{10}$$

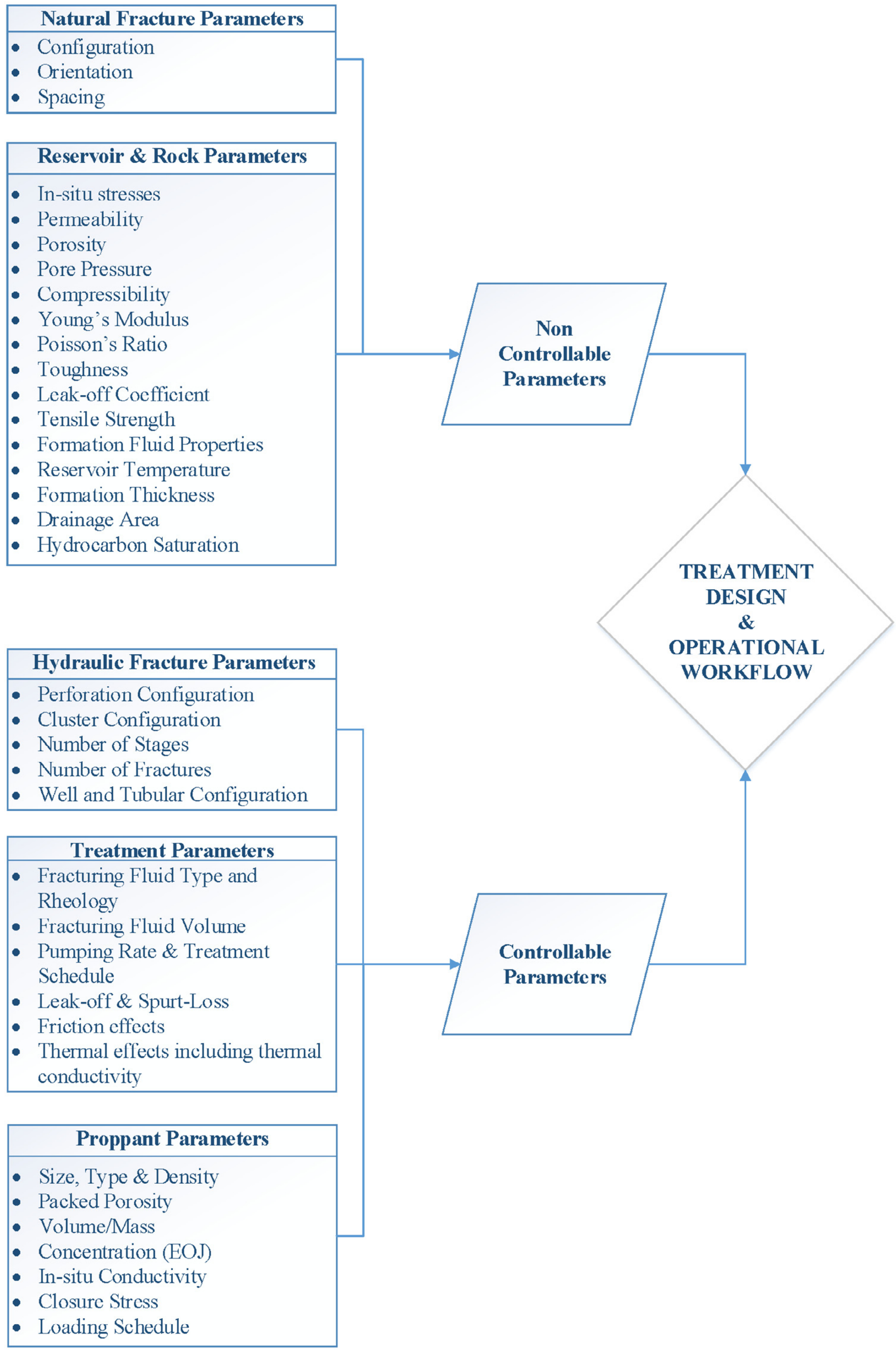

Fig. 4. Parameters incorporated for proposed workflow – Fracturing.

where,

$f = \dfrac{24}{\mathrm{Re}}$ intended for laminar flow, and

$f = fR\,(e, \varepsilon)$ intended for turbulent flow

The fracture opening and associated pressure can be written as Eq. (11): (Dershowitz et al., 2004)

$$W\,(x, z, t) = \Gamma_w\,(w, y, z, t)\,\frac{2\,(1-\upsilon)}{G} H_\xi\, \Delta P\,(x, 0, t) \tag{11}$$

With these fundamental equations under consideration and based on a closed loop iterative process, a comprehensive analysis was conducted on the constructed field model. This model was divided into two sub-models, namely a reservoir model and a fracture model. This can greatly assist in effectively identifying the contribution, dominance and interdependency of the key fracture design parameters. The model was verified by screening and validating the field data with the simulated results in addition with history matching as shown in Fig. 5 (Suboyin et al., 2018). In addition, matching production data with the simulated results, i.e., the measured rate vs simulated fracture flow rate, help to

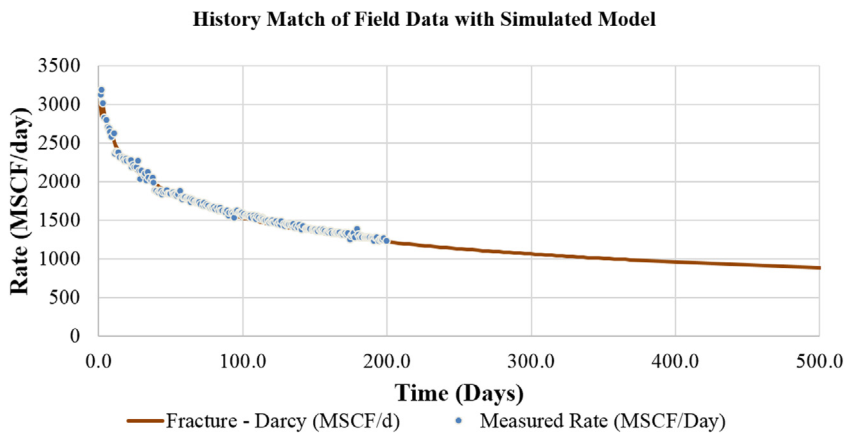

Fig. 5. History matching of constructed model.

verify the accuracy of the model. The constructed model was then compared with data from field and literature.

Upon successful validation, the accuracy and relevance of these prediction models are tested by constructing constrained scenarios. The comprehensive results were examined and illustrated to actively identifying the individual contribution of an element. Furthermore, the dominant parameters were isolated and thoroughly analyzed to create a significance distribution to the overall process and subjected to a sensitivity analysis. To conclude, a comprehensive parametric investigation that deals with the quantification of changes with respect to the variation in prime contributors within traditional fracture design process is presented. The deviation between the constrained simulation results and field responses are described as well. The study concludes with investigation of the results obtained, comparison with field strategies and proposal of an operational workflow for water scare regions such as the Middle East.

Fig. 6 depicts a simplistic representative view of fracture propagation of a horizontal well in the presence of a simplistic natural fracture set. As illustrated, the influence of a single natural fracture (indicated by gray lines) can be easily isolated in such a case for a given cluster of fracture (as shown in purple). This was the foundation for the initial phase of investigation to characterize fracture geometry and propagation in bounded scenarios. This was followed by evaluating the pressure distribution of the production zone as shown in Fig. 7, which allowed for screening with respect to stress requirements, proppant compatibility and anticipated reservoir response. Fig. 8 illustrates a scenario with respect to proppant placement in the presence of natural fractures, where different types of proppants are indicated by different colors. In some of these simulated cases, the presence of a natural fracture led to poor or unsuitable proppant placement resulting in poor productivity. In addition, stress shadow and cross-fracturing effect was investigated in brief, as illustrated in Fig. 9. This is crucial to optimize the overall fracture extension area along with reaching the production zone targets. In addition, multiple sets of natural fractures were constructed to represent the highly heterogeneous nature of the Middle Eastern reservoirs and to investigate the hydraulic fracture propagation behavior in such regions. Figs. 10 and 11 shows two such two-dimensional DFN sets within the constructed model. Fig. 11 gives a representation of the final outlook, which was validated closely with the field model.

A significant part of this investigation is based on data from the Middle Eastern region. Based on literature survey, the properties for the most notable shale plays are summarized in Tables 1 and 2. The input parameters used to construct this model are presented in Tables 3–6. Table 1 consists of the input data for

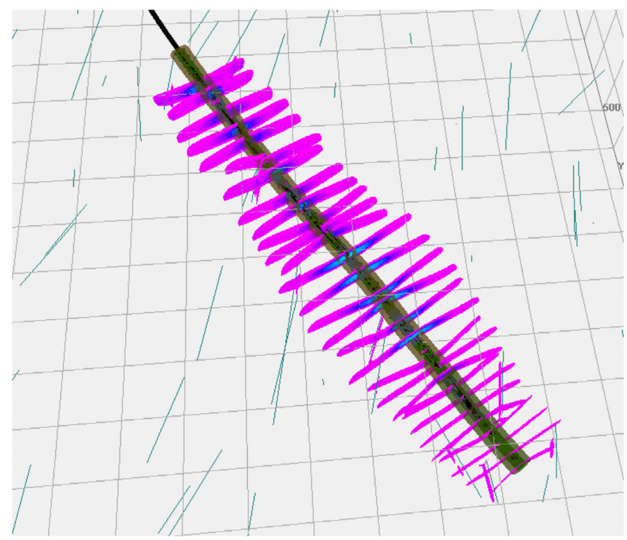

Fig. 6. Extended model — Fracture propagation [View A].

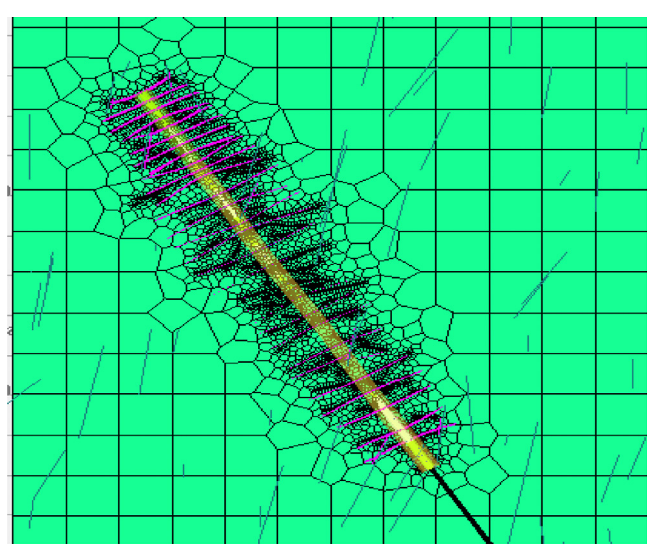

Fig. 7. Extended model — Pressure distribution [View B].

the simulation model. Additional parameters required for the formation zones are listed under Table 2. Corrected values for

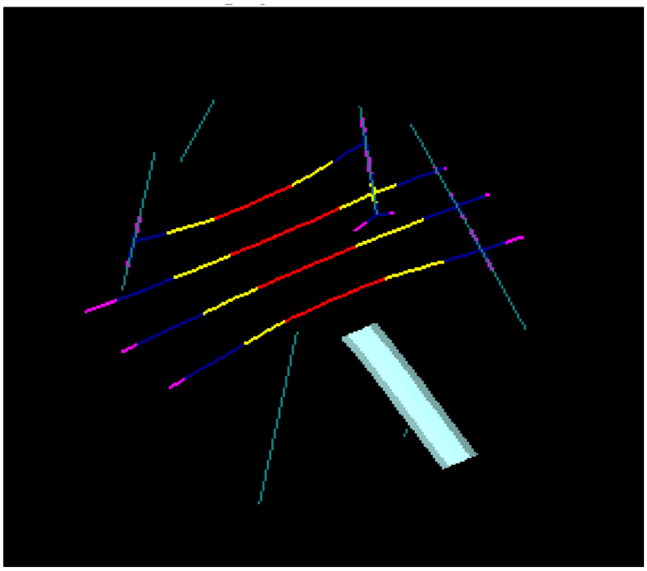

Fig. 8. Extended model — Proppant settling and distribution [View C].

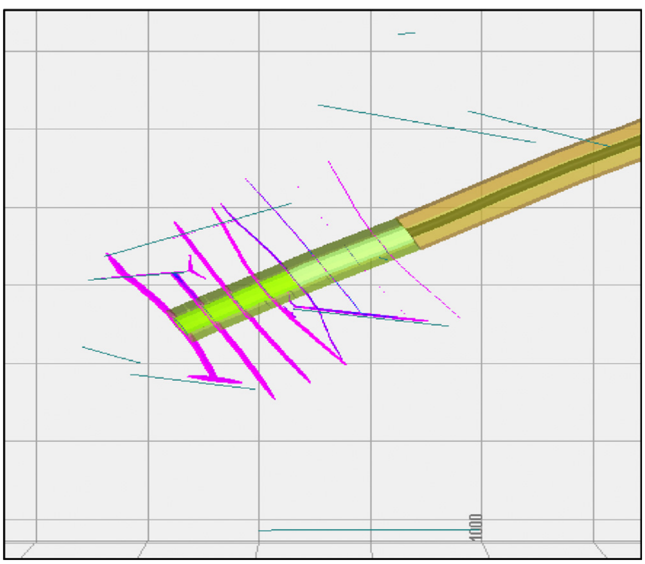

Fig. 9. Extended model — Fracture distribution [View D].

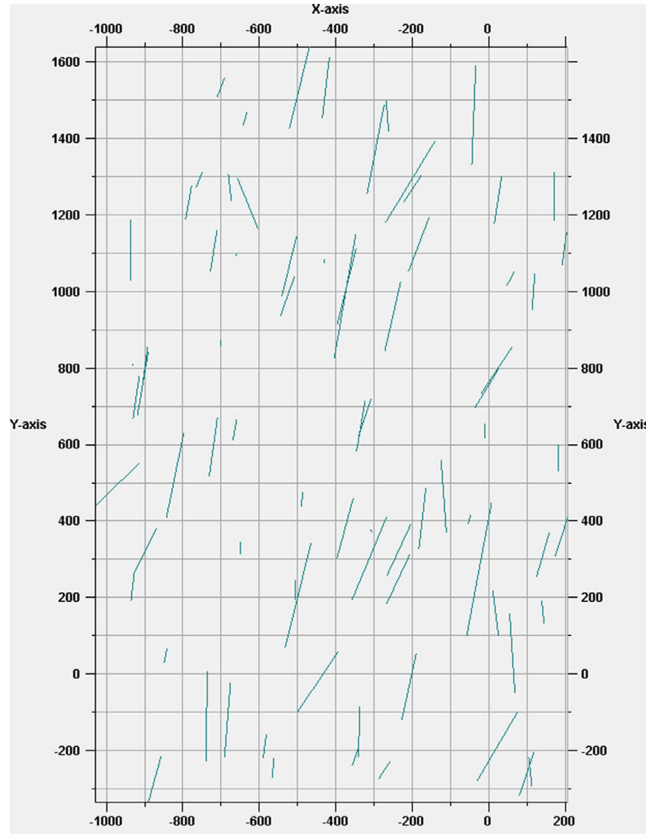

Fig. 10. 2D Discrete Fracture Network (DFN) with multiple orientation — Simplistic model.

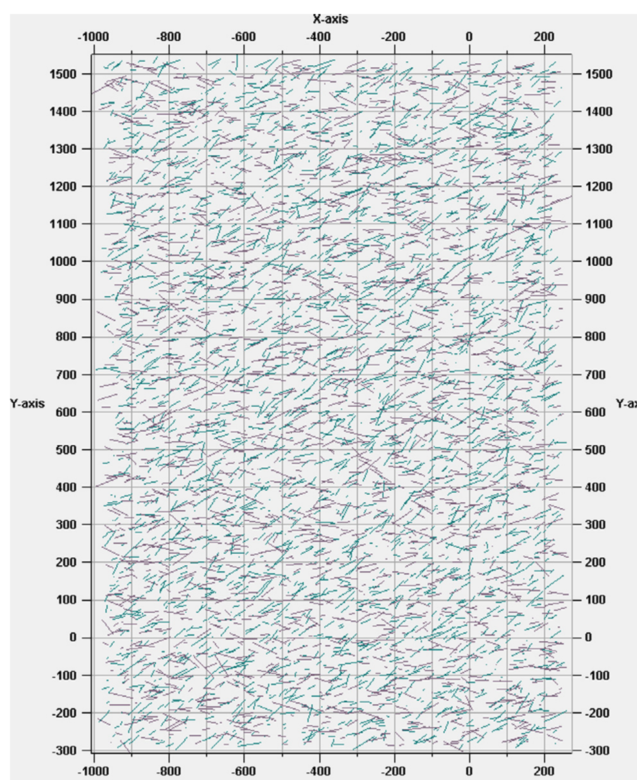

Fig. 11. 2D Discrete Fracture Network (DFN) with multiple orientation — Realistic model.

some parameters may have been used due to inaccuracies in measurement or lack of data. The natural fracture and proppant distribution properties used for this investigation are shown in Tables 3 and 4 respectively. The key evaluation criterion for the success within this investigation is the cumulative gas produced with respect to amount of water required for a given operation. Coupled with the amount of resources used and sourcing techniques, a favorable strategy can be identified that makes it economical.

This investigation is unique in multiple aspects and expands on a number of key findings acquired by Suboyin et al. (2018). Based on the 301 simulation cases run, following are some major highlights under this study.

(a) Investigate hydraulic fracture propagation behavior and their response in the presence of natural fractures within Middle Eastern shale gas reservoirs through industrial simulators and numerical modeling to generate a flexible workflow

Table 1
Shale play summary (Middle East & United States) (Ba Geri et al., 2019).

Shale Play Name	Basin	Location	Areal Extent (km2)	Net Thickness (feet)	Depth (feet)	TOC (%)	Thermal Maturity (%Ro)
Qusaiba	Eastern Arabian Gulf Basin	Kuwait, Saudi Arabia, Oman, Iran	60,000	72–245	7874–16,404	[5.5–20]	0.6
Silurian Hot Shale	Arabian Gulf Salt Basin	W. Qatar, Kuwait, Saudi Arabia, Iraq	1600,000	32–245	7874–16,404	[4–18]	2.6
Qusaiba/basal Rhuddanian Hot Shale	Rhb Al Khali	S. Saudi Arabia, W. UAE NWOman, NE Yemen	650,000	65–230	9843–14,764	[4–12]	0.5–1.2
Eagle Ford	Texas	United States	8606	200	7000	4.25	0.45–1.4
Bakken	North Dakota	United States	16,892	22	6000	11	0.44–0.5

Table 2
Shale play summary and comparison (United Arab Emirates & United States) (Ba Geri et al., 2019).

Play	Depth (ft)	Thickness (ft)	Permeability (md)	Porosity (%)	TOC (wt%)	Temperature (°F)	Fluid Phase	Resource Concentration (MMBOE/m2)
Diyab	11,000	135	0.05–0.50	2.00–3.00	5.00–7.00	315.00	Condensate	10.3
Shilaif	6500	330	N/A	N/A	4	N/A	Oil	58.5
Qusaiba	15,000	80	N/A	N/A	4	N/A	Dry gas	38.1 × 103
Bakken	6000	22	0.1–0.001	8	11	240	Oil	0.6
Eagle Ford	7000	200	0.1–0.007	8.00–12.00	4	170–231	Oil	0

Table 3
Input data (Suboyin et al., 2018).

Reservoir Drainage Area	80	acres
Dimensionless Reservoir Aspect Ratio	0.25	
Total Pay Zone Height	162	ft.
Equivalent Reservoir Permeability	0.00048	mD
Initial Reservoir Pressure	4726	psi
Equivalent Reservoir Porosity	4.2	%
Gas Specific Gravity	0.58	
Reservoir Temperature	175	°F

Table 4
Typical and modified rock properties of shale (Suboyin et al., 2018).

Property	Shale	Ranges
Young's modulus (psi)	4351,132	[1450,377–11,603,019]
Poisson's ratio (-)	0.2	[0.1–0.3]
Permeability (mD)	0.0003	[0.0001–1]
Porosity (%)	5	[0–10]
Fracture toughness (psi-in$^{\frac{1}{2}}$)	1370	[910–1820]
Tensile strength (psi)	580	[290–870]
Compressibility (1/psi)	2.28×10^{14}	[2.07×10^{14}–2.48×10^{14}]
Reservoir fluid viscosity (cP)	0.02	
Reservoir Pressure (psi)		[2832–2930]
Fracture spacing (ft)	80	[16–1000]
Fracture width (inches)	0.0001575	[0.00003–0.01]
σV (psi)	9427	[9282–9572]
σh (psi)	5076	[4206–6092]
σH (psi)	8076	[4206–9572]
σH-σh (psi)	0	[0–4351]

Table 5
DFN input.

Fracture Set Number	Property	Length (ft)	Orientation (deg)	Spacing (ft)
1	Average	65.616	60	65.616
	Standard Deviation	65.616	20	65.616
2	Average	98.425	90	65.616
	Standard Deviation	65.616	20	65.616

(b) Develop an adaptable simulation model to easily identify the contributing parameters within a traditional fracture design process.

(c) Analyze and quantitatively characterize the behavior and response of fracture design parameters to link it to a water-based fluid management scheme.

Table 6
Proppant used for candidate formation [FracCADE database].

Proppant Name	−80 + 100 Mesh Sand	Badger Sand 40/70
Mesh Size (ratio)	80/100	40/70
Mean Diameter (inch)	6.47E−003 in	0.01 in
Specific Gravity (ratio)	2.64	2.64
Bulk Density (lb/gal)	13.3681 lb/gal	13.9368 lb/gal
Propped Fracture Conc. (lbm/ft2)	1	1
Young's modulus (psi)	3000,000	3000,000
Stress on Proppant (psi)	3085	3085
Pack Porosity (%)	35	35

(d) Examine, identify and quantify the relative significance of dominating parameters to the fracture geometry along with a sensitivity analysis.

(e) Propose a unique operational workflow for a water scare region such as the Middle East from the analysis. The results of this assessment are in reasonable agreement (quantitatively and qualitatively) with literature and other field data.

(f) Simulation results confirmed the significance of fracture aperture and fluid viscosity when it comes to hydraulic fracturing treatments along with the effect of well placement. This is crucial in water stressed regions such as the Middle East with highly heterogeneous reservoirs.

(g) In addition to ultimately assisting in the verification of modern best practices approach, this investigative approach will create an example for future studies in water scarce regions to assist in a simplistic prediction of fracture propagation behavior and its associated response while better addressing water requirement.

3. Results and discussion

A comprehensive investigation was conducted to examine and identify key parameters for treatment design and operational workflow. As illustrated in Fig. 4, the parameters are subdivided into two categories:

1. **Controllable:** Dependent properties capable of being directed or influenced such as hydraulic fracture design parameters, drilling activities etc.
2. **Non-Controllable:** Parameters to which there is no direct control or influence over, such as natural fracture distribution, orientation etc.

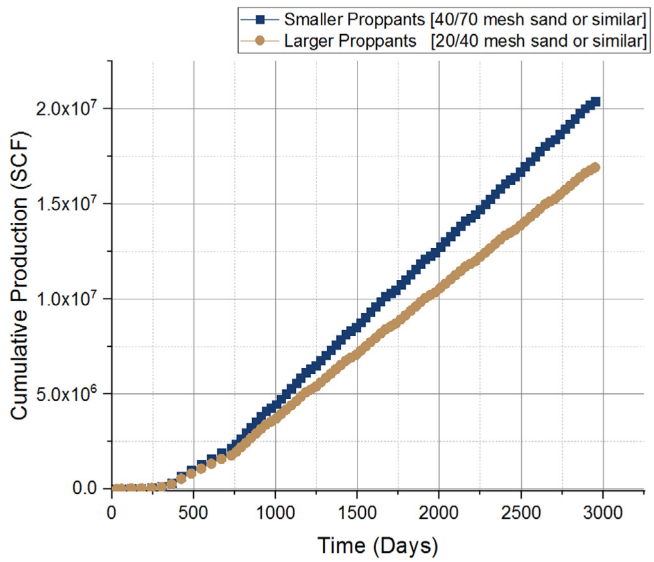

Fig. 12. Change in production w.r.t. proppant size — Single Proppant Injection.

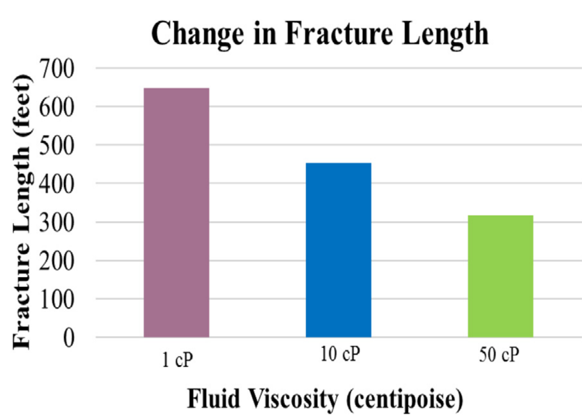

Fig. 13. Change in fracture length w.r.t. fluid viscosity.

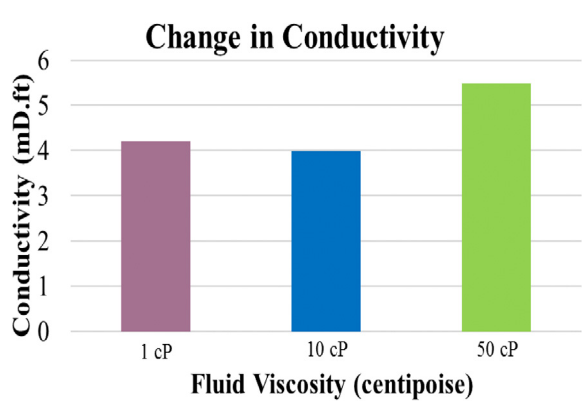

Fig. 14. Change in fracture conductivity w.r.t. fluid viscosity.

Based on the systematic methodology developed and the subsequent application to field data (Tables 1–6), the key observations are as follows. Figs. 12–18, further supports the observations.

For the properties categorized as **controllable**, following are the major observations:

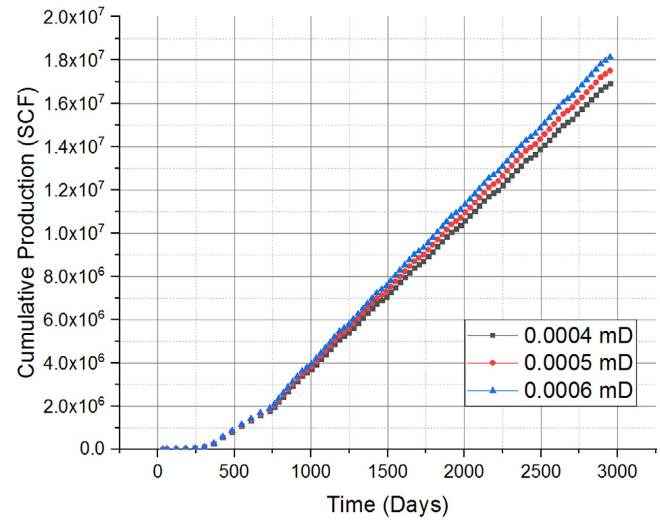

Fig. 15. Change in production w.r.t. permeability.

1. **Proppant:** Proppants are materials intended to keep a hydraulically induced fracture open or from collapsing. These can typically be sand, artificially made ceramics, treated materials etc. Major observations with respect to proppant properties are as follows:

   a. **Proppant Size**

      i. One of the preliminary investigations involved the injection of a single size proppant with a predetermined viscosity for a controlled and hypothetical case. This was varied to analyze the behavior with respect to different proppants based on size.

      ii. It was observed, as shown in Fig. 12, that smaller proppants (40/70 mesh sand or similar) indicate a lower rate of decline for production while larger proppants (20/40 mesh sand or similar) indicate a higher initial production. However, the lower cumulative production for the larger proppants was mainly attributed to proppant placement, settling and flowback.

      iii. Hence, the treatment design can be further tailored to an individual reservoir for further optimization.

   b. **Proppant Concentration**

      i. A base case was constructed to analyze the effect of proppant concentration. This involved the injection of a single proppant with a predetermined viscosity under a controlled operation. The only variable within this study was the proppant concentration, which ranged from 1 to 4 ppg.

      ii. Larger proppant (20/40) sizes along with a moderately low viscosity contributes to a favorable production for the given reservoir conditions.

      iii. Fluid viscosity plays a critical role as concentration increases and this needs to be investigated in depth based on the reservoir conditions.

   c. **Proppant Sequence**

      i. A base case was constructed to analyze the effect of proppant sequence. This involved the injection of a multiple proppants with a predetermined viscosity under a controlled operation. The only variable within this study was the proppant sequence, which ranged from 40/70 to 20/40.

ii. Injection of smaller proppants (40/70 and smaller) first contributes to better production and this is validated by field practices. This is further elaborated under the earlier studies by Suboyin et al. (2018).

2. **Treatment Parameters:** These are parameters with respect to the treatment design for a hydraulic fracturing operation. Major observations with respect to treatment parameters are as follows:

a. **Injection Rate**

i. A base case was constructed to analyze the effect of pumping/injection rate. This involved the injection of a multiple proppants with a predetermined viscosity under a controlled operation. The only variable within this study was the pumping rate, which ranged from 30 to 150 barrels per minute.
ii. There is a linear increase in production with an increase in pumping rate as for a constrained case, higher injection results in higher production.
iii. Coupling the fluid viscosity to the pumping rate can assist in identifying a favorable viscosity for a given reservoir.

b. **Treatment Volume**

i. This can be defined as the total fluid that is pumped into the formation.
ii. A base case was constructed to analyze the effect of treatment volume. This involved the injection of a multiple proppants with a predetermined viscosity under a controlled operation. The only variable within this study was the treatment volume.
iii. For an idealistic constrained case with minimal interference and loss, the cumulative production increases in a linear manner with respect to treatment volume.
iv. Heterogeneities that exists within reservoirs should be investigated to find an optimum design criterion as fluid leak-off significantly affects the design considerations.

c. **Fluid Viscosity**

i. Fluid viscosity affects the fluids capability to suspend/transport proppants, and is critical to the overall effectiveness of the hydraulic fracture treatment design.
ii. A base case was constructed to analyze the effect of fluid viscosity. This involved the injection of a multiple proppants viscosity under a controlled operation. The only variable within this study was the fluid viscosity, which ranged from 1 cP to 50 cP.
iii. There can be a specific range based on the reservoir conditions along with identifying the best approach to achieve the targeted fracture geometry as illustrated in Figs. 13 and 14.
iv. Fig. 13 shows the variation in fracture length with respect to fluid viscosity. It was observed that, for a controlled idealistic scenario, less viscous fluids lead to greater fracture length. As the viscosity increases, the fracture propagation length decreases but is also accompanied with an increase in fracture width. This results in an increase in wellbore conductivity as depicted in Fig. 14.
v. Incorporating the proppant properties, proppant concentration and treatment design are critical for a successful fracturing operation.

For the properties categorized as **non-controllable**, following are the major observations:

1. **Permeability**

(a) A base case was constructed to analyze the effect of reservoir permeability. This involved the injection of a multiple proppants with a predetermined viscosity under a controlled operation. The only variable within this study was the permeability, which ranged from 0.0001 mD to 1 mD.
(b) As expected, the rate of production increases with an increase in permeability. This is illustrated in Fig. 15.
(c) Based on the heterogeneity of the reservoir, the associated increase or decrease in production due to permeability can be accounted for.

2. **Young's Modulus**

(a) A critical parameter for hydraulic fracturing design, as it can be a reference point to analyze key contributing parameters.
(b) Coupling this with fluid properties and affinity can lead to productivity enhancements as depicted by simulations and field studies.
(c) This is further elaborated under the earlier studies by Suboyin et al. (2018).

3. **Poisson's Ratio**

(a) A base case was constructed to analyze the effect of Poisson's Ratio. This involved the injection of a multiple proppants with a predetermined viscosity under a controlled operation. The only variable within this study was the permeability, which ranged from 0.15 to 0.30.
(b) As the variation of Poisson's Ratio is often restricted to an extent within the same reservoirs, the overall contribution to the cumulative production is minimal.

4. **Overburden Stress**

(a) Since the variation of stresses are limited within this investigation, the overburden stress was the only stress analyzed in general.
(b) Based on increase in overburden stress while other stresses and associated parameters remained constant, there is a slight reduction in fracture geometry.
(c) An extensive investigation can be further conducted in this domain.

5. **Natural Fracture Distribution**

(a) A base case was constructed to analyze the effect of Natural Fracture Distribution. This involved the injection of a multiple proppants with a predetermined viscosity under a controlled operation. The only variable within this study was the DFN distribution, as described in Tables 4 and 5.

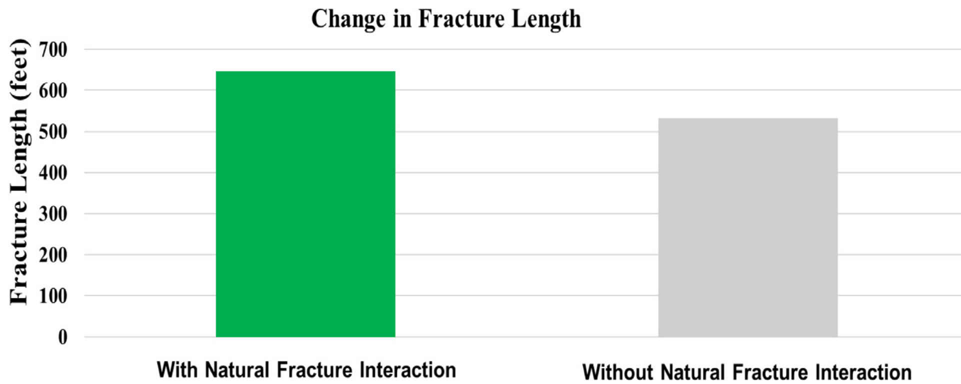

Fig. 16. Change in fracture length w.r.t. fracture interaction.

(b) Propagation behavior is heavily dependent on the distribution of the natural fracture network.
(c) For an idealistic case, the presence of a single set of natural fracture (as defined in Table 4 and illustrated in Fig. 9) can lead to a significant increase in the fracture length as shown in Fig. 16.
(d) Length, spacing and orientation alters the fracture propagation behavior significantly. These are critical parameters influencing the overall fracture design.

6. **Natural Fracture Density**

(a) Propagation behavior altered considerably with an increase in the natural fracture density.
(b) An increase in production is reported with respect to an increase in fracture density. However based on a given set of reservoir data, there can be a range beyond which the natural fracture density may not influence the fracture propagation behavior.

Based on the contribution and interdependency of these parameters to the fracture geometry, the following parameters were quantified to assess the dominance of the major parameters contributing to the fracture geometry and in-turn to the overall production. Hence, for the given set of data, it is observed that the following hydraulic fracture parameters have an impact in the given order.

1. **Fracture Aperture/Width**

(a) There is a significant increase in production as the width of fracture increases.
(b) The impact of fracture width on cumulative production is higher than of the impact of fracture length for the given set of reservoir conditions.

2. **Fracture Length**

(a) There is an associated increase in production as length of fracture increases.
(b) The contribution of this increase is less dominant than an associated increase in fracture width.

3. **Number of Stages**

(a) There exists an optimum number of stages, beyond which the number of stages do not contribute to efficient cumulative production.
(b) This is reservoir and economic dependent. A brief case study is elucidated in later section of this study. It indicated that beyond a certain number of transverse fractures, it did not contribute significantly to the overall production. This is crucial to the overall economics.

4. **Well Placement**

(a) Simulations reveal that well placement is a key success factor in hydraulic fracturing operations. Aligning it with the fracture geometry and orientation may lead to higher productivity.
(b) Regional and geological constraints, Reservoir Heterogeneities and economics play a critical role for successful well placement.

To further expand upon the contribution of these parameters, a sensitivity analysis, as shown in Fig. 17, was also constructed based on the 301 simulations conducted in this study. This was done by comparing the effect of each parameter while varying them from a 50% decrease to a 50% increase. The criteria assigned for the comparison is the cumulative gas produced as this relates to the overall economic feasibility of the hydraulic fracturing treatment. As shown, fluid viscosity, Young's modulus, treatment volume and proppant configuration are the most sensitive variables that are critical to the overall productivity.

Fig. 18 further illustrates a simplistic range that is linked to significance of each of the simulated parameter. This can easily assist in the identification of parameters that may lead to complexities and for an efficient development of the overall fracture design process for a given reservoir. The given parameters greatly contributed to the cumulative gas production and showed strong interdependency with other parameters. This was in line with the reported results and can provide a reasonable range for the quantification of change in the prime contributors. Hence, analyzing these parameters can be a starting point during the preliminary phases of hydraulic fracture treatment design along with identifying the best possible approach for the given set reservoir and well conditions. Overall, the results indicate that hydraulic fracture propagation behavior is not uninhibited in deep reservoirs as some studies may suggest and minor variations of variables such as in-situ rock properties, fluid properties etc. are often detrimental to fracture propagation in some conditions.

It is imperative to highlight that the representative percentages of each parameter does not indicate a direct dominance over the other parameters. The significance distribution intends to be a baseline that will assist in a simplified prediction of fracture propagation behavior and anticipated response for the given reservoir. Further simulations show how such a workflow can easily assist in identifying the optimum number of transverse fractures for a given field as shown in Fig. 19. As a result, this would also assist to enhance the overall economics and further reduce the cost along with resource consumption.

Literature further reports additional concerns that are prevalent in stimulation operations within the Middle Eastern region. These include high pressure, high temperature, presence of hydrogen sulfide, stability and compatibility of fracturing fluid in

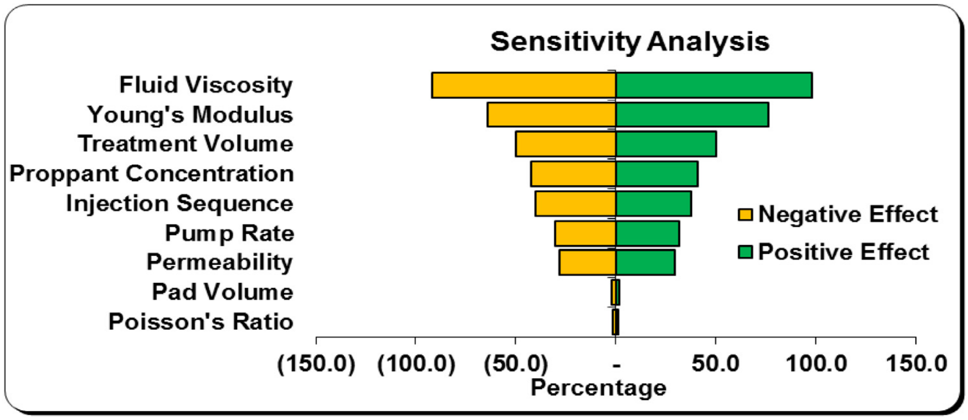

Fig. 17. Sensitivity analysis on design parameter conducted.

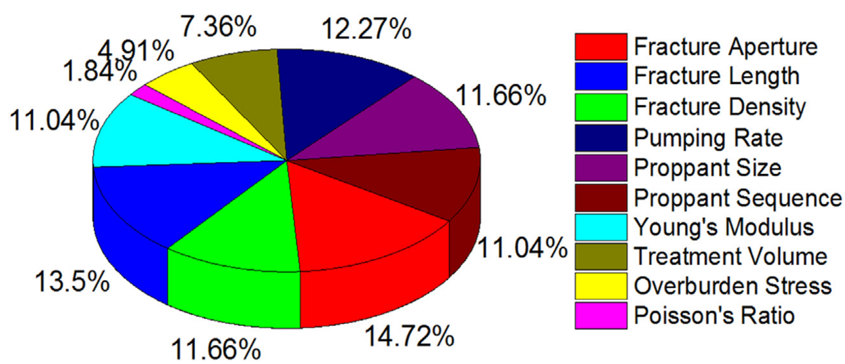

Fig. 18. Significance distribution based on the contributing parameters.

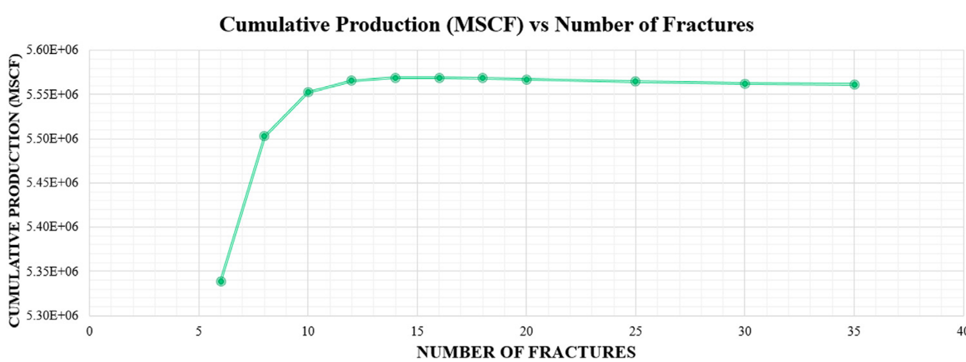

Fig. 19. Cumulative production with respect to number of transverse fracture.

such conditions (Ba Geri et al., 2019). With the presented findings, addressing the concerns that are specific to Middle Eastern region would require further understanding with respect to available resources, framework and regulations for the region. Investigations clearly demonstrated that water sourcing and management seems to the most critical factor for a successful hydraulic fracturing operation in such regions. With the limited availably of such resources and water management processes working in silos, a streamlined and efficient approach is much needed in the industry. This can significantly alter the status of tapping unconventional resources for the region along with increasing the success factor of such operations.

To elaborate, for the 301 simulation cases conducted in this study, the amount of required water based on simulation results, ranged from 4.5–6.0 million gallons of water for a traditional horizontal well hydraulic fracturing operation. This is in line with studies which have reported that a typical Marcellus formation may require 4.0–5.6 million gallons of water per well (Xylem, 2005). However, this water requirement may make it uneconomical in water stressed areas with limited infrastructure. A deeper investigation revealed that a key factor that makes it economical within Marcellus is the fact that up to 85% of the flowback water may have been reused in 2016 (Oraki Kohshour et al., 2016). This is a significant shift as compared to the other shale plays as shown in Table 7. This has greatly allowed many operators in the region to have an adaptable approach with respect to water sourcing while being economical.

Further analysis was conducted to identify and extend these approaches to the Middle Eastern region. A comprehensive review suggested that using of an array of methods, in a customizable, adaptable workflow that would fit better with the needs of the operator for a given region. The key parameters to account within water management strategies are presented in Fig. 20. In

Table 7
Summary for shale plays in US (Oraki Kohshour et al., 2016).

Shale play	Percentage of flowback water (initial weeks)	Typical TDS range (thousands ppm)	Percentage of Water Reused (2016)		
			Fresh	Brackish	Recycle/Reuse
Eagle Ford	3%–15%	80–250	60%–70%	20%–25%	0%–10%
Permian basin	40%–60%	20–200	50%–60%	0%–5%	5%–10%
Marcellus	10%–40%	100–300	5%–10%	5%–10%	85%

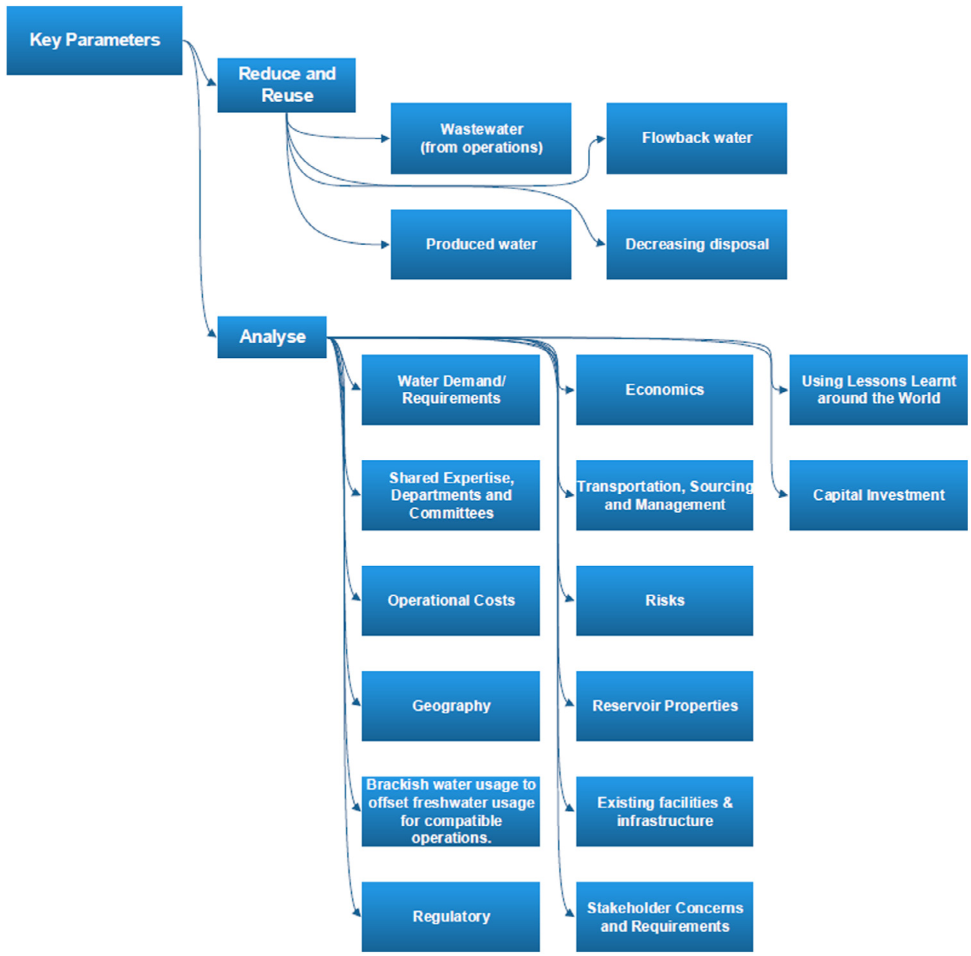

Fig. 20. Parameters incorporated for proposed workflow — Water Management.

addition, an operational strategy that summarizing the overall significance is illustrated in Fig. 21.

The key operational strategies are briefly summarized as follows:

- **Reduce & Reuse:** Water management within the oil and gas industry can greatly assist from reducing and reusing existing water sources. This includes reducing, treating and reusing wastewater from operations, flowback water, produced water and disposal water.
- **Analyze:**
    - **Demands & Requirements:** Evaluating current demands and requirements along with strategies in place would greatly identify potential opportunities to make the process more efficient.
    - **Economics**:
        i. The cost per barrel of water treated has to be economical with respect to procurement, storage and disposal along with the field location.
        ii. Operational costs can be reduced based on field location, optimizing existing processes and infrastructure
        iii. Application of innovative technologies to make existing methodologies for efficient and economical.
    - **Risks:** This includes identifying and mitigating risks with respect to environment, operations, technology, logistics, investment, stakeholders and the region.
    - **Environmental Impact:** This include water supply chain, contamination, geological alterations and potential pollution risks.
- **Constraints — Water Treatment**
    - **Volumetric Capacity**: At the point of operation, it has to be adequate to meet the required flow rate for the planned operation without any interruptions.
    - **Quality**: The output feed quality and rate has to be consistent and uninterrupted. This can be considered as a variable factor that can be adjusted in real-time.

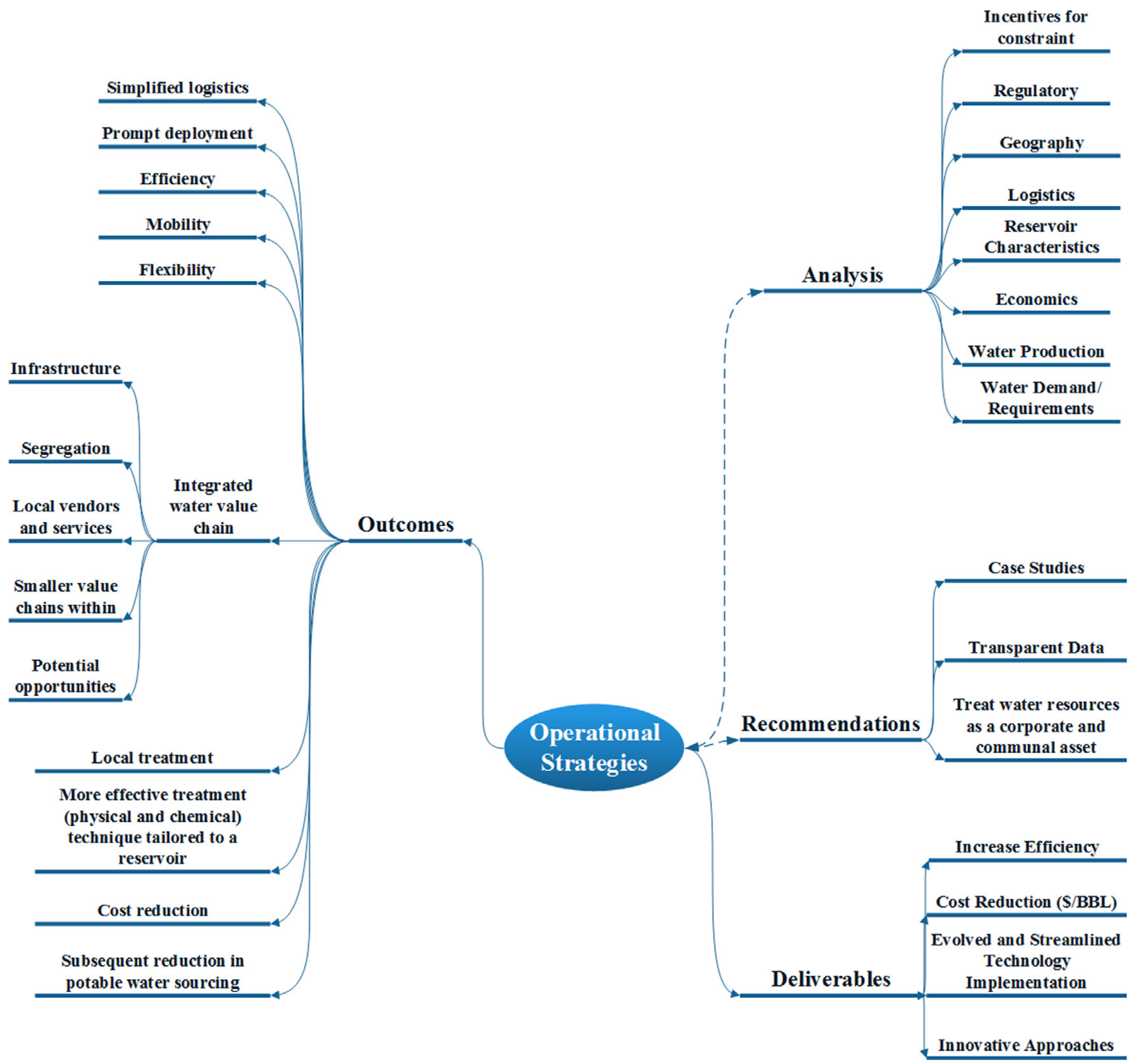

Fig. 21. Parameters incorporated for operational strategies — Water Management.

- **Efficiency**: The overall treatment efficiency needs to be satisfactory. A greater recovery rate can greatly assist hydraulic fracturing operations. The recovery rate can be defined as quantity of clean water with respect to quantity of raw feed. Any untreated water has be to be disposed in most regions that adds to wasted resources.
- **Mobility**: Simplified logistics, prompt deployment, mobility and flexibility of the technology/process in place presents a definite advantage when it comes to arid regions.
- **Footprint**: As well sites and operation zones are constrained, a localized treatment facility can be considered with the above parameters in mind. However, the footprint for such facilities must be minimal.
- **Geographical**: This is mainly dependent on the region/location. Compliance with respect to the regional regulatory policies are mandatory.

- **Transparency and Social Responsibility:** Improving transparency and communications with respect to unconventional operations while addressing public and environmental concerns on a public platform has played a major role in regions such as the United States. It is imperative to strike a balance among regulatory and societal requirements to enhance the social responsibility of such organizations.

To examine the effectiveness of such an approach, a rough analysis was conducted in-house, on geological data from a candidate field in the Middle East by incorporating the presented techniques. One of the analysis showed the potential to reduce the require water for an operation by 1.39 million gallons or nearly 25% for the same amount of cumulative gas produced for the same zone. The major contributors for this was using a suitable viscosity tailored for the reservoir and reusing water (50% freshwater + 50% treated water) along with treatment. It is to be noted that this was based on field costs as of 2019 and reasonable estimations wherever necessary.

As shown in Table 8, a brief cost analysis with respect to the water sourcing cost within the region was also conducted. Based on internal data and studies conducted within the region, the major cost categories were identified and given a weightage factor depending on their cost contribution. The key highlight was that the transportation and disposal costs within the Middle East is much lower than that of United States. However, due to constraints with respect to sourcing and quality of resources (such as treating high salinity seawater), the costs for withdrawal and treatment are significantly higher in comparison with other regions. As a result, an integrated approach such as re-cycling and re-using water from the field along with fresh water may be more economical than sourcing solely from fresh water resources.

These findings further highlights the need to fine-tune and tailor a similar workflow for water scarce region such as the

Table 8
Rough cost analysis — Water Sourcing.

Source	Withdrawal Cost	Transportation Cost	Storage Cost	Treatment Cost	Disposal Cost	Total
	($/gal coefficient)	($/gal coefficient)	($/gal coefficient)	($/gal coefficient)	($/gal coefficient)	($/gal coefficient)
100% Fresh Water	1.00x	0.05x	0.20x	0.40x	0.25x	1.9x
Mixed (50% Fresh + 50% Reuse)						
Low Treatment	0.60x	0.05x	0.20x	0.60x	0.25x	1.7x
Medium Treatment	0.60x	0.05x	0.20x	0.80x	0.25x	1.9x
High Treatment	0.60x	0.05x	0.20x	1.00x	0.25x	2.1x

Middle East. This can also be coupled with the most economically viable treatment methods that may be regionally specific, to obtain the quantity and quality of water desired. Incorporating these factors, may further contribute to the overall effectiveness on field scale implementation in the Middle Eastern region, where requirements, restrictions and regulations are stringent due to the limited availability of water resources. This can lead to further studies for an effective, efficient and economic operational workflow for such a region.

4. Conclusion

The hydrocarbon industry with its highly advanced technology and significant capital can play a key role in championing the efforts towards efficient water management strategies. This study involved a comprehensive investigation to understand hydraulic fracture propagation behavior in the presence of natural fractures within Middle Eastern shale gas reservoirs. The factors that affect productivity were analyzed through simple constrained cases to understand the significance of key design parameters. An outline for a water-based fluid management scheme within a traditional fracture design process was also presented along with concerns within challenging and evolving markets such as the Middle East.

Although there is no single solution to the challenges identified in this study, a workflow tailored to the region may assist in a more efficient and reliable approach. Enhancing existing methodologies and incorporating the key parameters noted above can contribute to the overall value chain.

The key conclusions from this study are listed below:

- A flexible and adaptable simulation model was created using commercial simulators to easily identify the contributing parameters for a given reservoir through the proposed workflow.
- This approach could assist in optimizing hydraulic fracturing treatment design such as the required number of transverse fractures along with the identification of key dominating parameters in heterogeneous reservoir that may lead to complexities during a fracturing operation.
- Parameters such as the natural fracture distribution, fracturing fluid viscosity and Young's modulus also play crucial role to the overall production and water requirement. Additional simulations indicated that these parameters depict strong interdependencies with respect to the fracture design parameters, reservoir properties and well geometry. This is crucial for a successful and efficient fracturing operation while reducing cost, resources and water consumption.
- Coupling the defined controllable parameters with the non-controllable parameters will lead to a desired design range for the given reservoir conditions in any region. Furthermore, the relative significance of dominating parameters to the fracture geometry was also presented along with a sensitivity analysis.
- Key components for a unique sustainable operational workflow within the Middle Eastern region was analyzed and presented. The investigative approach and the constructed model mentioned in this research can greatly assist in a simplified prediction of fracture propagation behavior, in providing a better understanding of its associated response and enhancing the fracturing treatment for water scare regions such as the Middle East.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

CRediT authorship contribution statement

Abhijith Suboyin: Conceptualization, Methodology, Software, Data curation, Writing - original draft, Visualization, Investigation. **Md Motiur Rahman:** Supervision, Writing - review & editing, Investigation, Validation, Project administration. **Mohammed Haroun:** Supervision, Writing - review & editing, Investigation.

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