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ORIGINAL ARTICLE

Integrated sand management: modeling of sand erosion in a mature oil field in Malaysia

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Abstract Sand production can lead to various problems, including erosion in production flow lines that may lead to total production loss for extended periods and costly workover operations. The extent of erosive damage is determined by many factors, among which the flow and sand rates are the most significant. Three main issues must be addressed to ensure an efficient production operation: Sand erosion estimation, Sand monitoring (settling and deposition), and maintaining optimum production rates. If sand production exceeds certain levels, i.e., allowable sand rate, the erosion in the production network becomes problematic. Sand production has been problematic in some wells in Reservoir X. Core, and historical production data was used to build a comprehensive model using Schlumberger PIPESIM™ hydraulic modelling. The software allows for detailed modelling of the production network by which erosion rate, erosion hotspots, and deposition of the produced sand can be quantitatively analyzed. Considering an allowable erosion rate of 0.3 mm/year, the model outcomes indicate that sand erosion is critical in wells J-1, J-2, and L-2. The next step was identifying the hotspots where the produced sand is deposited in the abovementioned wells. The modelling results indicated that sand deposition is primarily severe in the teeline between the platforms. Moreover, the gas-oil ratio was identified as the most influential factor in the sand deposition. Lastly, a sensitivity analysis was conducted on the allowable flow rates and maximum (technical) allowable sand production and erosion rates to find optimum production rates from reservoir X.

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Article Highlights

- Quantification of sand production and erosion rate in a mature oil field in Malaysia
- Sand deposition/transport in the production network was modelled.
- Sand deposition hotspots in the production network were investigated.

Keywords Sand production · Erosion rate · Settling rate · Production network · Sand management

Abbreviations

E_r	Erosion rate
S_r	Sand Rate
API	American Petroleum Institute
FDP	Field development planning
RCAL	Routine core analysis
SCAL	Special core analysis
PSD	Particle size distribution
GOR	Gas oil ratio
PED	Petroleum engineering department
CPP	Central processing platform
NTG	Net to gross
PED	Petroleum Engineering department
PIPESIM	Pipesim steady-state Multiphase flow simulator
pptb	Pounds per thousand barrels

1 Introduction

Sand production is often inevitable in fields with formation strength lower than 1000 psia. It is considered a severe issue that can be determinantal to the production processes and could lead to several complications such as filling, blocking, and collapse of the wellbores, plugging of perforation channels and flowline, failure of downhole and surface equipment, and lastly, costly remedial and workover operations (Rahmati, Jafarpour et al. 2013). Sand production is expected once the rock stress exceeds the formation strength, leading to rock failure. Rock failure can occur due to tectonic activities, overburden pressure, pore pressure, and stress-induced during the drilling or production phase due to a fluid drag force (Vincent, Abiola et al. 2012). Factors affecting the tendency to produce sand can be classified into fluid flow and rock strength effects. Sand particle production can consist of load-bearing solids and formation fines. The production of formation fines not included in the mechanical formation framework is beneficial as they can be transported easily within the formation rather than plugging it. One primary way to mitigate the sand production rate is to keep the production rates low to eliminate the production of particles; in several situations, the already low production rates are marginal or uneconomical. At a high production rate, oil and gas produced at high velocity is highly erosive and can erode through parting, tubing, and other accessories.

It is currently widely accepted that controlled, acceptable quantities of sand can enhance the conductivity and productivity of the near-wellbore formation. However, failure to manage sand production will likely result in production issues and even catastrophic consequences (Garolera et al. 2019). For years, sand control techniques have been utilized to control and address sand production issues. These measures often include using mechanical tools to block sand particles physically with screen or gravel packing; chemical methods are also part of the sand management method by which the formation can be reconsolidated. Moreover, resin or other chemical agents can prevent sand from flowing. (Parlar et al. 2016; Garolera et al. 2019). An essential aspect of sand management is the prediction of sand production; thus, it is necessary to clarify the sand production mechanisms to devise a robust plan for sand control optimization (Dong et al. 2017). Sand can be eliminated at the subsurface or surface using sand control methods or a multiphase desander. The combination of both will result in a much more efficient elimination. However, economics will have to be taken into consideration, and in so doing, surface management has proven to be more cost-efficient than subsurface control methods in mature fields.

Sand Erosion is another crucial effect of sand production that requires attention. In general, sand erosion is defined as the physical removal of material from a surface due to fluid flow. Various types of erosion have been identified, including liquid and solid particle impingement, cavitation, wear, and abrasion (Preece and Macmillan 1977) and (Liu et al. 2021). In the production phase and the current research, erosion is referred to as the damage to the production system due to sand production. A few parameters can significantly affect the rate of erosion: the velocity of the fluid, the nature of the fluid and its composition, the size of the particle, the direction of the flow, the pressure, and the temperature. Increasing velocity is commonly believed to increase the erosion rate (Habib et al. 2007) and (Akramian Zadeh and Rashidi 2020). Hence, there is a need to find the critical velocity below which erosion-free production is occurring (Wang and Zheng 2021). The number of flowing phases significantly affects the erosion rate (E_r). E_r is minimal for single-phase fluid, increasing markedly as other phases are added. Moreover, the erosion rate is also related to the composition of the dominant fluid (Odan, Ben Rajeb et al. 2020). Hence, evaluating independent damage due to erosion without considering corrosion is a complex problem (Samimi 2012). Another critical parameter is the size of the particle, either in the form of liquid or solid. Particle sizes ranging from lower than 20 μ to higher than 100 μ have little or no impact on the rate of erosion even though the velocity reaches 350 ft/sec, which is much higher than what is often experienced in petroleum production systems (Goodwin et al. 1969) and (Nguyen et al. 2016). The direction of the flow is another critical factor impacting E_r; the rate of erosion is less critical in straight flowlines when compared to elbow, bends, or spots at which the flow direction is changed (Finnie 1978; Finnie and McFadden 1978; Vieira et al. 2016). Lastly, numerous studies have reported elevated E_r at lower pressure and temperatures (Hoff et al. 1970, Tsai 1981), while in some cases, an increase in the temperature may also lead to an increase in erosion rates (Tabakoff and Wakeman 1979). Various equations are developed in the literature by which Er can be estimated. API 14e and Salama (2000) are the most used among those. The American Petroleum Institute (API) erosion velocity model (14 E) is used to estimate the velocity of erosion rather than its rate. The erosion velocity V_e is hence defined as: (Salama 2000)

$$V_e = \frac{C}{\sqrt{\rho_f}} \tag{1}$$

where C has dimensions of [mass/ (length × time^2)].$^{0.5}$, its default value in engineering units is 100 and 122 for continuous and intermittent streams, respectively. One of the current solutions to alleviate erosional issues in piping networks is to lower the flow velocity estimated by the above equation. Several researchers have questioned the accuracy of the API equation. Salama (Salama 2000) developed an equation to rectify the shortcomings of the widely used API correlation, neglecting essential parameters such as particle size and fluid velocities. The equation requires sand production ratio and grain size, geometry constant, and efficiency (Salama 2000)

$$\mathrm{Er} = \frac{1}{S_m}\frac{WV^2 d}{D^2\rho_m} \tag{2}$$

where E_r is the rate of erosion (mm/yr); W denotes the rate of sand flow (kg/d); V_m the velocity of the fluid(s) (m/s); d is the sand size (μm); D represents the internal diameter of the conduit (mm); ρ_m is fluid mixture density in kg/m3; S_m is a geometry parameter equal to 5.5 for pipe bends (Salama 2000)**.** It should be noted that this equation assumes a sand density of 2.5 kg/m3. Due to the importance of sand management strategies in the industry, much work has been done on analyzing and modelling sand management, sand control, and erosion damage to understand how sand production works, control sand erosion, and classify erosion types. Table 1 summarizes some of the previous studies on sand production and management. The damage arising from liquid and sand particles has been mostly experimentally studied in previous studies. In most earlier studies, some simplifications were required to investigate various sand production and erosion aspects experimentally. Moreover, most literature has limited discussion about how the research outcomes can be upscaled for the field studies. In addition, sand production and erosion rate require case-specific studies for the wells or fields with the possibility of having the abovementioned problems (Khamehchi and Reisi 2015).

Hence, there is a requirement for qualitative and quantitative study of E_r and its potential damages to any well and field throughout the life of the field (from development to monitoring and management). Therefore, accurate sand erosion prediction models are required to estimate the tolerable sand rates (S_r) and maximum allowable well flow rates and devise inspection strategies for the production facilities. Additionally, sand monitoring must be carefully conducted to implement adequate sand control procedures. This study focuses on the simulation and analysis of sand-related problems in Field Y, a mature oil

Table 1 Previous studies on Sand management / Sand production/erosion

Author (year)	Type of study	Parameters	Remarks
Preece and Macmillan (1977)	Review/experimental	Erosion quantification	Erosion carries an implicit connotation of material removal via impact events
Liu et al. (2021)	Simulation/experimental	Erosion damage	Damage of liquid–solid flow in pipe dependent on the velocity of particle and impact angle
Habib et al. (2007)	Simulation/experimental	Velocity effect on erosion rate	The velocity of fluids boosts the erosion rate
Akramian Zadeh (2020)	Experimental	Velocity effect on erosion rate	The impact of erosion on Ck45 steel was studied in detail
Wang and Zheng (2021)	Experimental	Critical flow velocity	A specific velocity limit exist, which will prevent the erosion from occurring
Odan et al. (2020)	Experimental	Number of phase effects on erosion rate	The erosion rate is increasing because the phase number is increasing
Samimi (2012)	Review/experimental	Composition effect on erosionrate	Acidic components like H_2S in water make corrosive fluid and boost the erosion rate
Goodwin et al. (1969)	Experimental	Particle size effect on erosion rate	Increase erosion with increased particle size
Nguyen et al. (2016)	Simulation/experimental	Geometry and size of particles	Particle size affects the erosion pattern, rate, and mechanism
Finnie (1978)	Simulation/experimental	Effect of flow direction on erosion rate	Damage is maximum in the bend and elbow
Vieira et al. (2016)	Experimental/ theoretical/ simulation	Quantification of erosion in gas/solid flows	A new erosion equation was developed
Decarso and Kothmann (1961)	Experimental	Effect of pressure on erosion	Higher erosion rates can be observed at higher pressures

field in the Malay basin affected by sand production. Detailed modelling is carried out to quantify sand erosion and determine the erosion risk, erosion hotspot, and sand deposition hotspot in the production network. Moreover, the acceptable flow rate and sand rate limit are proposed based on the modelling results and the historical production data.

2 Methodology

2.1 Field description

The data used in this study was obtained from clastic field Y, located in the Malay Basin, as shown in Fig. 1. The basin is situated in the southern part of the Gulf of Thailand, between Vietnam and Peninsular Malaysia, with about 500 km length and 250 km width formed in NW–SE trending via Eocene through Oligocene extension. The primary lithology of the Malay basin is sandstone that is compressed, folded, and faulted during the early Miocene to Pliocene. In the southeast portion of the basin, there is a significant thinning over the crest of growing anticlines and an unconformity near the top of the middle Miocene. Figure 2 shows the general stratigraphy and the structural history of the field. The Malay basin strata are subdivided informally into several stratigraphic units. Each unit is a group from A to M. The best reservoir quality can be seen in Group J estuarine sandstones and mid-lower Group K braided stream deposits. Shoreface sandstones in the lower Group J sandstones in Field Y have permeabilities between 200 and 300 mD (Goh, Alimat et al. 2011), whereas Group K sandstones in the nearby field have 18–31% porosity and

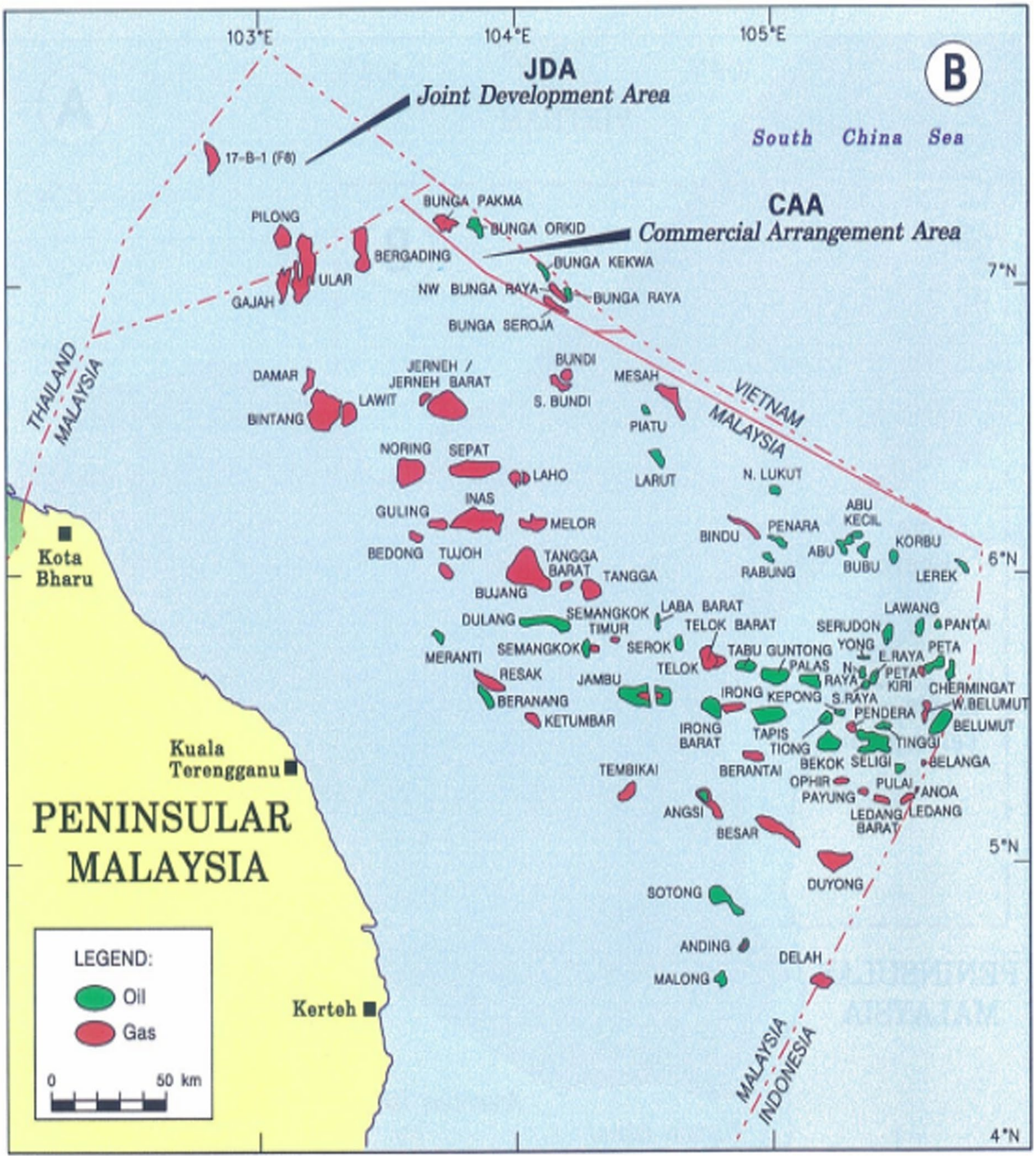


Fig. 1 The location of the Malay basin (Madon 2021)

300–3000 mD permeabilities (Flores 1982). The good candidates in reservoir X that will be investigated and modelled for sand production are listed in Table 2.

The current rejuvenation plans for the field include completing new infill wells and from both.

Current and a new platform. Figure 3 illustrates the wells and platform arrangements in field Y.

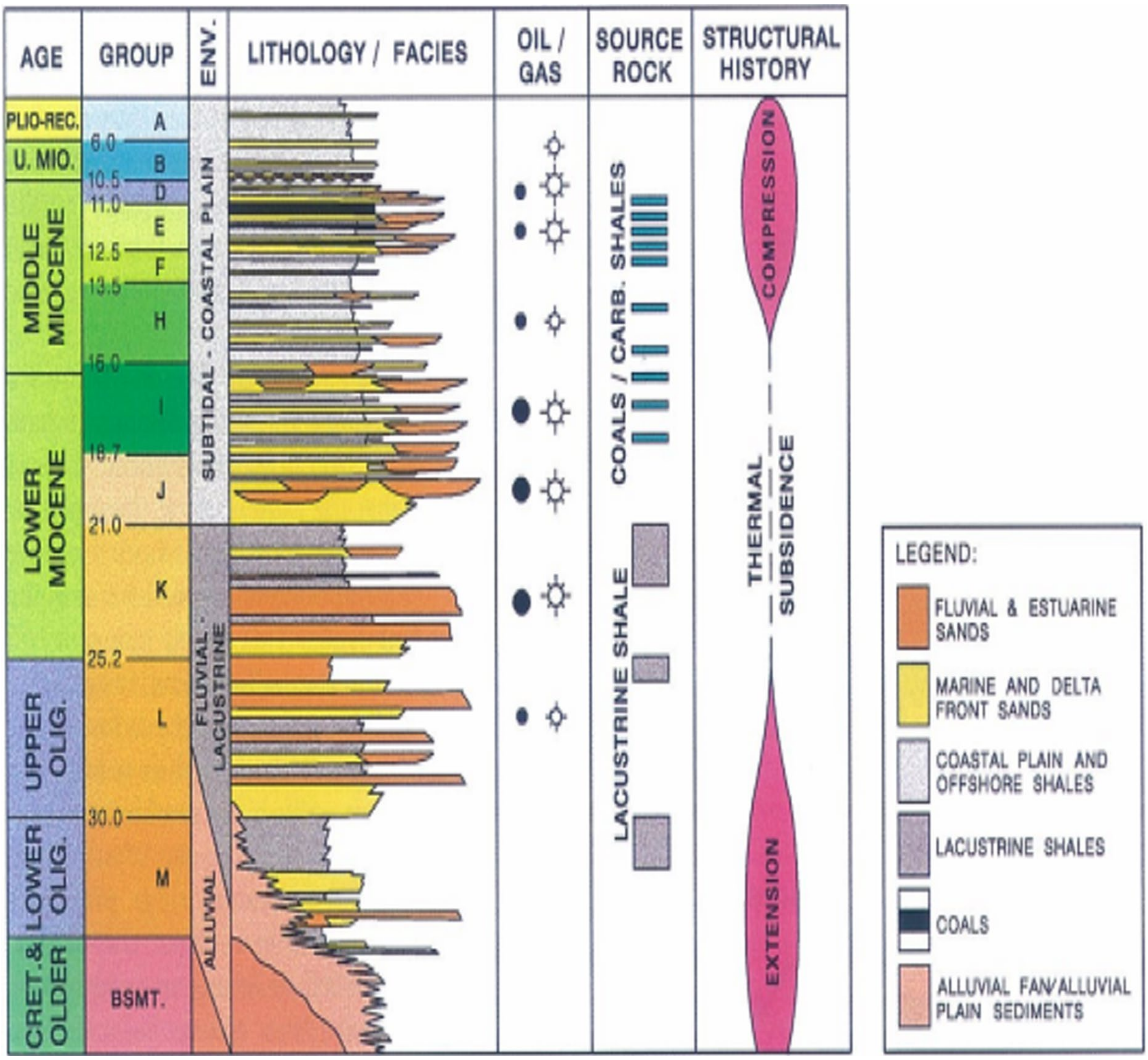


Fig. 2 Generalized stratigraphy and structural history of the Malay basin (Madon 2021)

Most wells produce sand, and no sand control tools have been installed in the wells. Sand production has resulted in a variety of erosion-related problems. Hence, there is a need for regular separator cleanouts in some existing and new wells. A multidisciplinary team was assembled to work on the root of the problem and devise a suitable solution for the mature field's sand management strategy. The properties of the produced sand from field Y are reported in Table 3.

The overall workflow of the research is shown in Fig. 4. The workflow starts with a data-gathering phase. The data includes production information based on the latest well test analysis, routine core analysis (RCAL) and special core analysis (SCAL) core sample data, Particle Size Distribution (PSD) flowrates, gas-oil ratio (GOR), water cuts, and tubing and header pressures. Table 4 summarizes the data for creating the hydraulic model for wells J-1 to L-2. The abovementioned data was then used to develop a comprehensive well and flowline configuration model in the PIPESIM hydraulic simulator. PIPESIM is a steady-state multiphase flow software with many features that make it suitable for flow

Table 2 Summary of Well Candidates and Modeling Sections

Field	Platform	Well Candidates
Y	J	J-1
		J-2
		J-3
		J-4
	K	K-1
		K-2
		K-3
		K-4
	L	L-1
		L-2

assurance simulation. The steps involved in developing a PIPESIM model are mainly identical for different modules. The previously mentioned data is inserted to build the model. The model components, including borehole and perforation properties, borehole size, perforation diameter and direction, are set. Moreover, the pipeline design field equipment (choke sizes) and well constraints must be adjusted. If any artificial lift program is planned for the wells, it could also be defined in this section.

For the model execution phase, a 1-D mechanical earth model was first created. The model was run, and the results were reported as tables, figures, and schematics. Sand management is first performed over an interval, completing different drawdown pressures for different rates. The critical drawdown pressure is computed for a particular well if a single depth mode is used. The zones of low and high risk of sand production are then identified. For a single depth, a sensitivity analysis on various parameters can be done and superimposed onto the curve of any well to better understand each parameter's effects, such as the effects of borehole parameters on the critical drawdown pressure. There is an option to regenerate well curves during the model's running if flow properties such as GOR and water cut change due to the pressure drawdown. The Salama

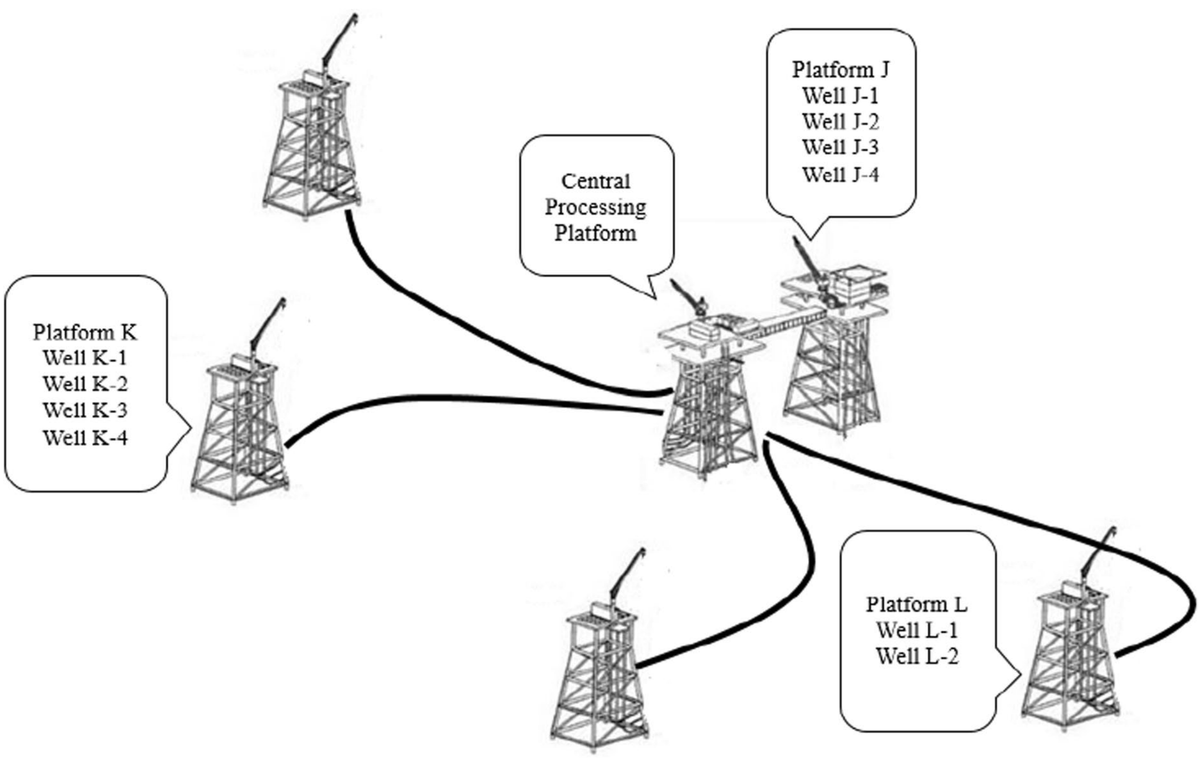


Fig. 3 Field Y Layout (Location of Platforms, Number of Wells and Flow Line Connection)

Table 3 Physical Properties of Sands and Fines obtained from production data

	Sand	Fines
Specific Gravity(γ)	2.5	2.6–2.7
Shape Factor(S)	0.2–0.5	0.1–0.3
Size range (micron)	45–500	< 45
Concentration (pptb)	4–30	< 1

equation (Eq. 2) was used in the PIPESIM to calculate Er and allowable production rates. Like almost all modelling studies in petroleum engineering, the following essential part is the history matching. The parameters are tuned to achieve a minimum difference (lowest error) between simulated and actual pressure measurements at the tubing head and wellhead. The model was then fine-tuned to improve match accuracy. Simulation scenarios were then run to test various flow conditions. Gas-and-oil flow scenarios were simulated with a flow assurance

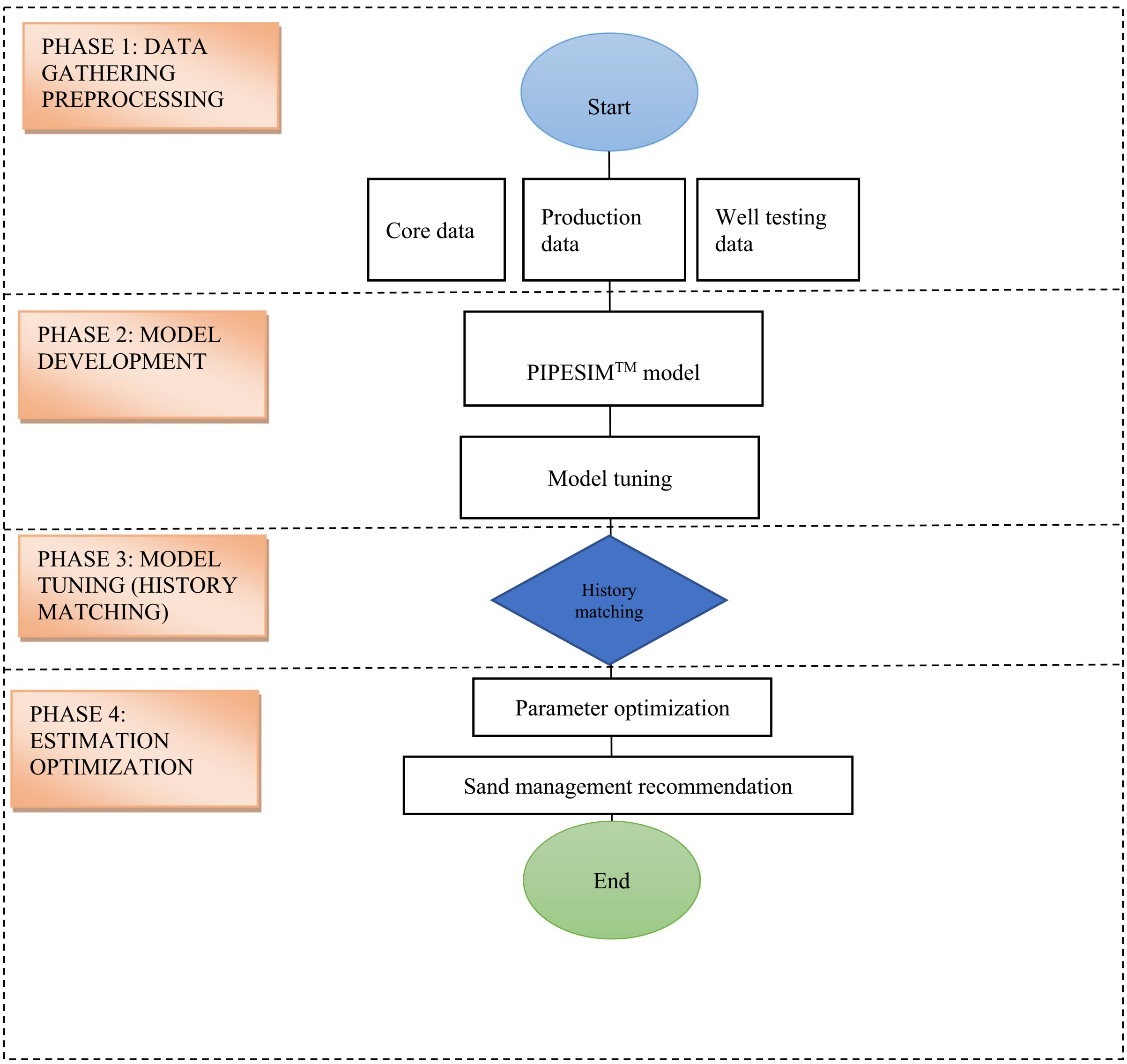


Fig. 4 Workflow of this research

Table 4 Input Data: Production Data for Hydraulic Modeling

Field	String	PSD ranges (micron)	Flowrate (bbl/day)	GOR (SCF/STB)	Water cut (%)
Field Y	J-1	45–350	830	10,150	38
	J-2	45–280	3005	1520	0.3
	J-3	45–350	270	6300	46
	J-4	45–280	70	11,500	63
	K-1	45–500	1138	2350	50
	K-2	45–500	2472	1743	90
	K-3	45–500	3298	1137	55
	K-4	45–280	3072	506	40
	L-1	45–350	1003	2200	50
	L-2	45–350	1200	3500	25

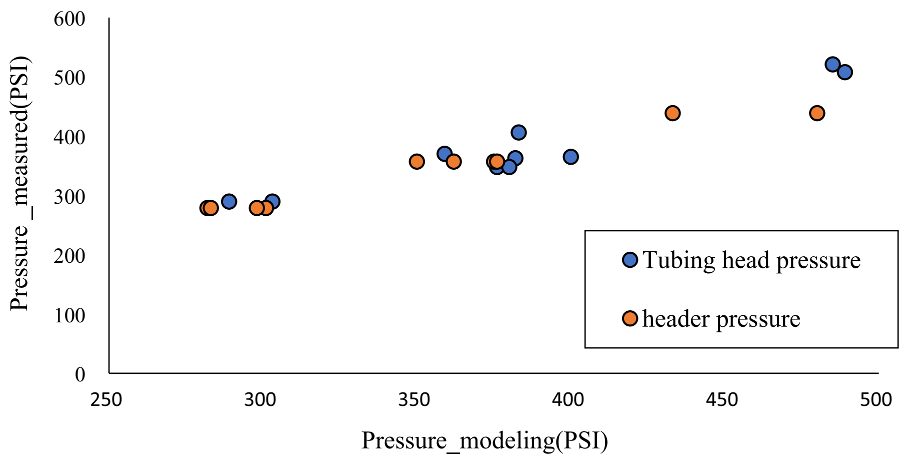


Fig. 5 Measured versus modeling THP and HP in psia

simulation focused on erosion. Figure 5 summarizes the history-matching results for all the wells based on header and tubing head pressures. The mean percentage difference between the measured and simulated pressures for tubing head pressure and well header pressure were 4.5 and 5.6, respectively. This indicates that the history matching has less than 6% error, and the model can accurately represent the reservoir conditions.

Once the history matching results are satisfactory, a sensitivity analysis can be conducted to study the effects of various parameters, including well constraints, completions detail, and boundary conditions. An enhanced production program that results in the lowest sand production for a well or a cluster of wells can be selected using this method. The workflow can minimize production risks, and an effective sand management plan can be considered.

3 Results and discussion

It is of great significance to accurately determine sand production so that a sand-free production rate or allowable production rate can be specified to decide optimum production and sand management strategies. Therefore, there is a need for a careful analysis of various parameters that contribute to sand production, quantifying the problematic section of the production network (from production tubing to separators) and estimating the erosion as accurately as possible. This section investigates and quantifies the erosion in risk in multiple parts of the production network. The critical (high-risk) locations can be identified, and necessary steps could be taken to ensure efficient production.

3.1 Erosion risk (well to production header)

E_r, can be defined as the ratio between the volume of metal loss and the mass of sand hitting the target material. Numerous factors affect the erosion rate of a producing string, including production rate, GOR, sand count, and each string's maximum liquid and gas velocity. Table 5 summarizes each sting's sand erosion simulation results from the well to the production header. The E_r (mm/year) resulting from sand production is estimated based on the earlier model outcomes. Based on the PED's latest well-test data, the table shows each string's production rate, GOR, sand count, and maximum liquid and gas velocity. The last column is the simulation result showing the erosion rate of each string. Ideally, zero sand production is desirable. However, some sand production in reservoirs with unconsolidated sand is inevitable. Hence, the maximum allowable sand production is defined to maintain the optimum production rates without damaging the production string. The results indicate that only three wells are producing at an erosion rate higher than the maximum allowable sand rate of 0.3 mm/year, namely J-1, J-2, and L-2, with an erosion rate of 1.4 mm/year, 1.02 mm/year and 0.52 mm/year, respectively. Of all the factors listed in Table 5, it can be observed that the highest erosions occurred in areas with the highest gas velocities. The sand erosion in well J-4 is still within the safe range despite high GORs and production rates. The same can be observed for maximum liquid velocity; Well K-2 has relatively high liquid velocities of 6.2 m/s, an elevated sand count, and a low erosion rate of 0.03 mm/year. Hence, Max gas velocity seems to be the most influential parameter on sand erosion rate of all the factors listed. Therefore, care should be taken to maintain production in those strings within the safe range of production to avoid excess workover and treatment costs.

3.2 Erosion hotspots

To identify the exact location where erosion impact is most dire, a comprehensive erosion hotspot analysis was conducted on wells J-1, J-2, and L-2, in which the sand erosion was above the permissible range. Figure 6a-c shows the flowline configuration model from the well to the production header for the above-mentioned wells. Modelling results indicate that the erosion in each well occurs along the production tubing and the flowline between the choke and production header. The erosion along the production tubing was well below the acceptable range (< 0.3 mm/ year) and hence is not considered as critical as that in flowlines between the choke and production header, which range from 0.44 to 1.4 mm/year. Therefore, the critical erosion hotspot in this modelling can generally be identified in two places: near the choke and at the end of the flow line.

Table 5 Erosion risk assessment in Reservoir Y

String	Production rate (bbl/day)	GOR (SCF/STB)	Sand count (pptb)	Max liquid velocity (ft/s)	Max gas velocity (ft/s)	Choke size (1/64")	Choke size %	Erosion rate (mm/year)
J-1	830	10,150	11.9	22.3	63.60	100	63	1.4
J-2	3005	1520	6.3	33.4	51.80	100	63	1.02
J-3	568	6300	19.6	6.2	10.4	110	70	0.02
J-4	70	11,500	26.6	3.28	7.2	100	63	0.0007
K-1	1138	2350	15.4	10.8	12.7	128	81	0.04
K-2	2427	1743	18.9	20	7.2	128	81	0.03
K-3	3298	1137	9.4	17.7	18.7	128	81	0.07
K-4	3072	506	20.3	16	15.74	128	81	0.09
L-1	1003	2200	4.2	8.5	7.8	136	71	0.02
L-2	1200	3500	30	13.7	24.6	160	83	0.52

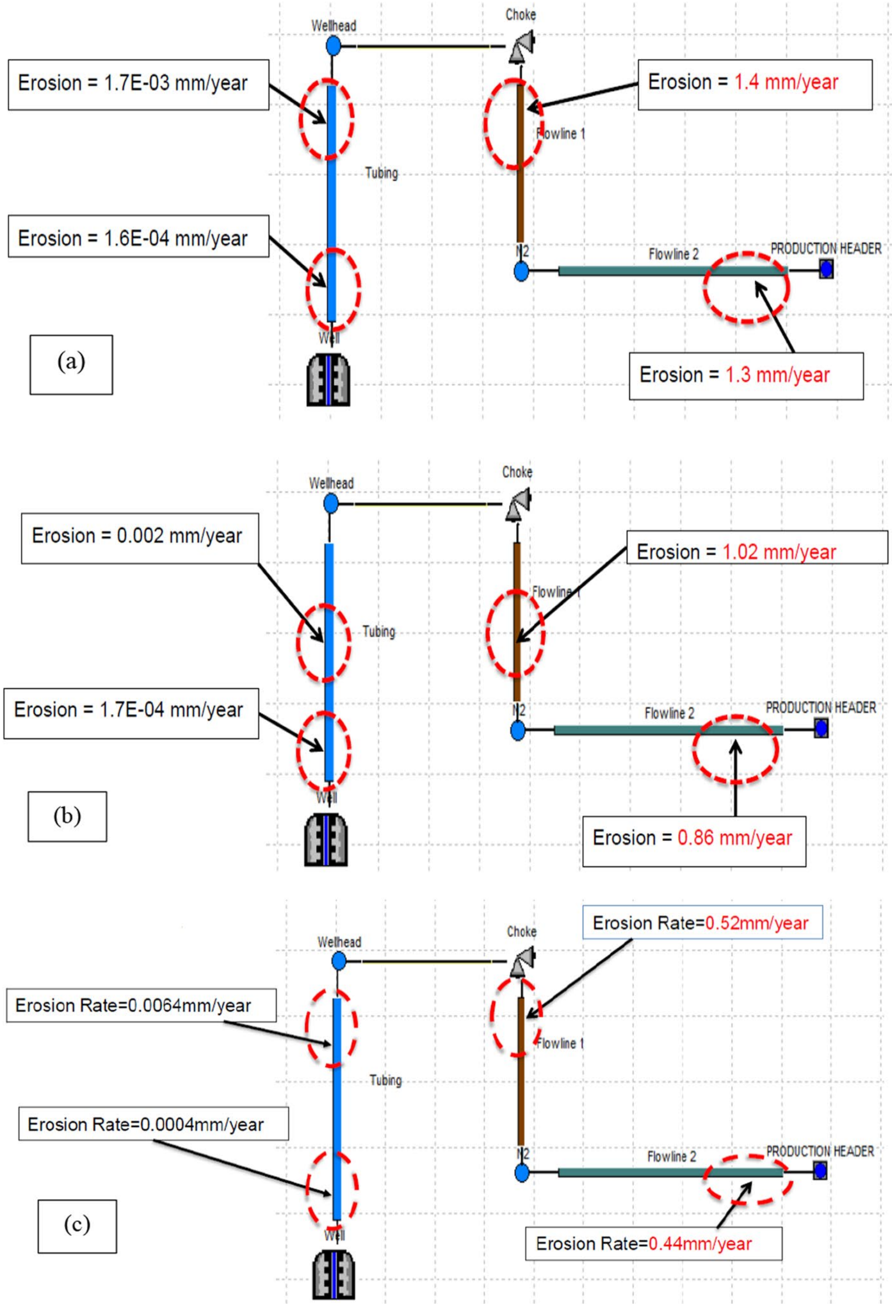


Fig. 6 Erosion hotspots in J-1 **a**, J-1 **b**, and L-2**c**

Erosion in choke is usually caused by impingement of particles, high velocity of droplets, bubbles, and even liquids on solid surfaces. Reducing fluid rates is recommended to reduce erosion in the choke. If wells must be brought online without a choke, outer wing valves of suitable ratings are recommended. Micron-sized fines and high-velocity gas flow can cause erosion in a positive bean choke. The velocity profile and pressure drop across a choke with a significant pressure drop lead to a high erosion opportunity. One solution is the stepwise pressure drop in series and maintaining slight backpressure (Paggiaro, Friedemann et al. 2013). In addition to chokes, tees are often considered the highest erosion area in production strings. As the direction of the flow changes in the tees, the particle will hit the tees wall instead of following the fluid flow. The latter increases the probability of erosion. In the case of the tees, the parameters that contribute the most are the dimensions of the tees and the production rates.

3.3 Deposition hotspots

A minimum velocity for fluid is required to hinder the deposition of solid particles in horizontal pipelines. The deposition of solid particles can form accumulations at the bottom of the line. Solid deposits can result in partial or complete line blockage, accelerating the pipes' corrosion and trapping the pigs (Salama 2000). Hence, this section investigates the deposition hot spots in the production network, from the production header to the separator. Table 6 summarizes the input (production rate, GOR, water cut, PSD, sand particle size) and output (deposition/transportation of produced sand) data from the header to the joint production line for each platform. The last column is the simulation result showing whether the produced sand is transported or deposited in the line. The result indicates that all the produced sand particles, regardless of their particle size, were deposited at the bottom of the pipeline rather than transported to other sections of the production network. Figure 7 (a-c) shows the comprehensive well and flowline configuration model from the production header to the production joint line of Platforms J, K, and L, which were affected by the deposition of sand.

Although the deposition spots differ for each platform, sand deposition in the tie lines between each media set can be seen. Moreover, Platform K suffers from deposits in more spots than all three. There are similarities among the production data of the platforms. For instance, they all have high GOR and water cuts, as is expected from mature fields. In the case of GOR, gas in solution will reduce both oil and brine velocities, thus leading to the deposition of sand in the pipeline due to sand not being transported higher than its critical velocity. Sand deposition in pipelines in mature fields is most likely due to higher water cuts leading to lower fluids' viscosity. The liquids with lower viscosity have a lower potential to suspend and transport the produced sand, thus allowing the sand to settle down at the bottom of pipelines. If the amount of sand in pipelines is not considerable, pigging or altering the velocities of the flow to above the sand settling flow rate can remove them from the pipeline. In cases where large quantities of sand are deposited, sand removal could be both technically challenging and slow.

The next investigated deposition hotspot is between the Production joint line and the separator inlet. Table 7 summarizes the simulation results for this section of the production network based on the deposition hotspot for the central processing platform (CPP) from the production joint line to the inlet of the separator. The data shows that the production rate, the GOR, water cut, PSD, and particle size influence sand transport/deposition. The last

Table 6 Summary of Deposition Hotspot (Prod Header to Prod Joint Line)

Platform	Production rate (bbl/day)	GOR (SCF/stb)	Water cut %	PSD	Particle size (micron)	Transported/deposited
J	12,300	3752	34	D50	205	Deposited
				D75	190	Deposited
				D90	110	Deposited
				D95	80	Deposited
K	32,289	1475	38	D50	210	Deposited
				D75	170	Deposited
				D90	70	Deposited
				D95	45	Deposited
L	13,178	59	59	D50	300	Deposited
				D75	250	Deposited
				D90	180	Deposited
				D95	100	Deposited

Fig. 7 Deposition Hotspots in platforms J a, K b, and L c

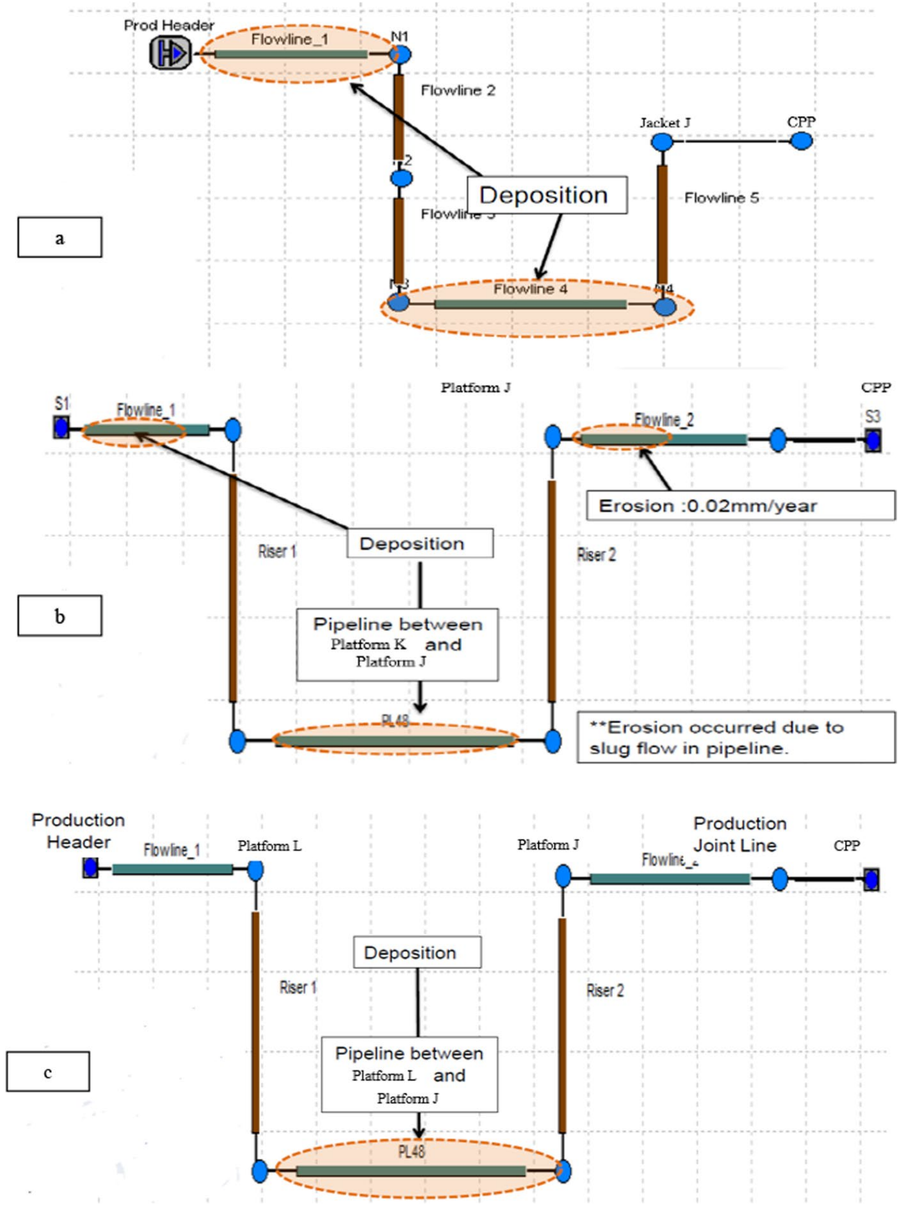


Table 7 Summary of Deposition Hotspot (Prod Joint Line to Inlet of Separator)

platform	Production rate (bbl/day)	GOR (SCF/stb)	Watercut %	PSD	Particle size (micron)	Trans-ported / deposited
CPP (central production Platform)	68,021	2145	46			
				D50	300	Deposited
				D75	190	Deposited
				D90	110	Deposited
				D95	73	Deposited

column in the table is the simulation results showing that none of the sand particles of various sizes are transported and instead deposited at the bottom of the pipeline. The simulation results indicate that all the sand particles are deposited at the bottom of the pipelines instead of being transported, regardless of their size. This could mainly be attributed to high water cuts (46%) and GOR in those reservoirs that fail particle transport. Figure 8 illustrates a comprehensive well and flowline configuration model from the production joint line to the inlet of the separator of CPP, which is affected by the deposition of sand. Therefore, limiting the maximum production flow rates is crucial to prevent additional erosion damage. The presence of sand in production is the primary cause of erosion damage, and reducing the production rate is one of the management methods that can be used to avoid erosion damage. The operation of these pipelines requires reliable estimates of erosion rates. Production rates are usually limited to keep the erosion effect at acceptable levels. Gas in solution will reduce both oil and brine velocities, thus leading to the deposition of sand in the pipeline due to sand not being transported higher than the critical velocity. The erosion rate is higher at higher sand rates due to the sand impact velocity and angle. The maximum production rate is limited to a threshold value called erosional velocity, in which excessive erosion may occur at higher velocities. As a result, sand production rate and particle impact velocities similarly affect the erosion rate. The reduction of the flow velocity and the sand production rates results in a decrease in erosion rate. Thus, reducing the production rate is a viable measure to mitigate erosion problems resulting from sand production.

3.4 Sensitivity analysis of the allowable annual erosion rate

This section conducts a sensitivity analysis of the annual allowable erosion rate. Initially, the 0.3 mm/year allowable erosion rate was considered. However, the possibility of setting a stricter sand control program with an erosion rate of 0.1 mm/year was investigated for wells critically affected by sand production, i.e., J-1, J-2, and L-2. Figure 9a-c shows the production details with the current sand production rate of 1.4 and allowable rates of 0.1 and 0.3 mm/year for wells J-1, J-2, and L-2.

Well J-1 is producing at a corrosion rate of 1.4 mm/year. For this well to be produced safely at an allowable rate of 0.3 mm/year, the production rate has to be lowered by 16% to 695 bbl/day. If a more severe corrosion policy of 0.1 mm/year is to be implemented, production must be reduced by an additional 14% to 580 bbl/day. Similar reductions are needed for wells J-1 and J-2. Implementing the strict erosion rate of 0.1 mm required the current production rates to be reduced by 30 and 45% for J-1 and J-2, respectively. The same goes for well J-2 with the initial sand count of 6.3 pptb. To comply with the safe erosion rates of

Fig. 8 Production Joint Line to Inlet of Separator Deposition Hotspot

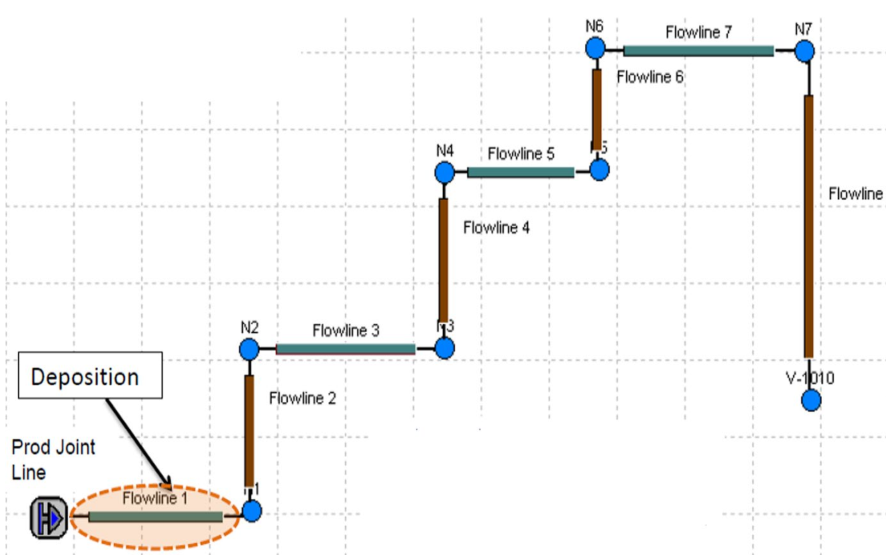
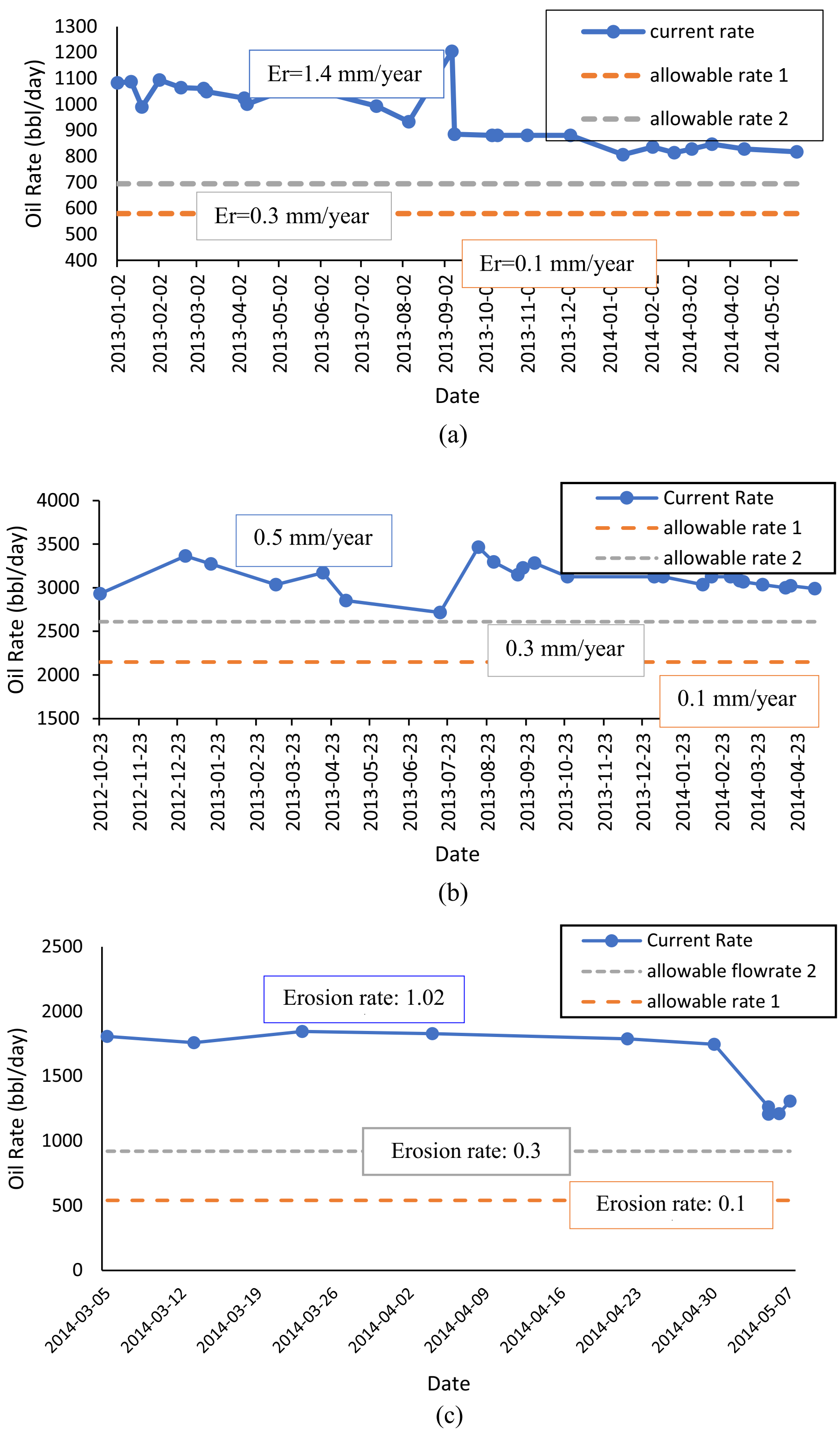


Fig. 9 Well L-2 Allowable Production Rate at different erosion rates for **a**: well J-2 with a constant sand production rate of 11.9 pptb, **b**: well J-2 with a constant sand production rate of 30 pptb, and **c**: well L-2 with a constant sand production rate of 6.3 pptb



0.1 and 0.3 mm/year, the production rate needs to be decreased from an initial value of 3005 to 2150 and 2610 bbl/day, respectively. On the other hand, the reason for such drastic cuts in the production rate of L-2 is the considerable amount of produced sand (30 pptb) in contrast to 6.3 and 11.9 pptb for wells J-1 and J-2, respectively. In well L-2, a very high sand rate of 30 pptb results in a high erosion rate of 0.515 mm/year. Consequently, the gross production rate needs to be decreased from 1200 bbl/day to 540 and 920 bbl/day to comply with the 0.1 and 0.3 mm/year erosion rates, respectively.

3.5 Allowable sand rate at technical potential

Technical potential refers to the achievable petroleum production of a particular technology, given system performance limitations and constraints. Figure 10a-c shows the production rates at an allowable sand rate and erosion rates for wells J-1, J-2, and L-2, which are critically affected by the production of sand higher than the maximum allowable sand rate of 0.3 mm/year. By maintaining E_r of 0.3 mm/year, the operator can technically reduce the sand rate from 11.91 pptb to 1.6 pptb, allowing the gross production rate to increase from 830 bbl/day to 1022 bbl/day for well J-1. The production rate of Well J-2 can be increased to 3167 from the current values of 3005 (+5%) by reducing the sand production from 6.3 pptb to 1.7 pptb. In the case of well L-2, at the current technical potential, the sand rate can be technically reduced from 30 pptb to 2.84 pptb, allowing the gross production rate to increase from 1200 bbl/day to 1757 bbl/day (+46%) while minimizing the erosion rate to 0.3 mm/year. The reason for such a high increment in production was that this well was highly affected by the S_r in contrast to the other two. Hence, controlling the sand rate could significantly affect the efficiency of the production process.

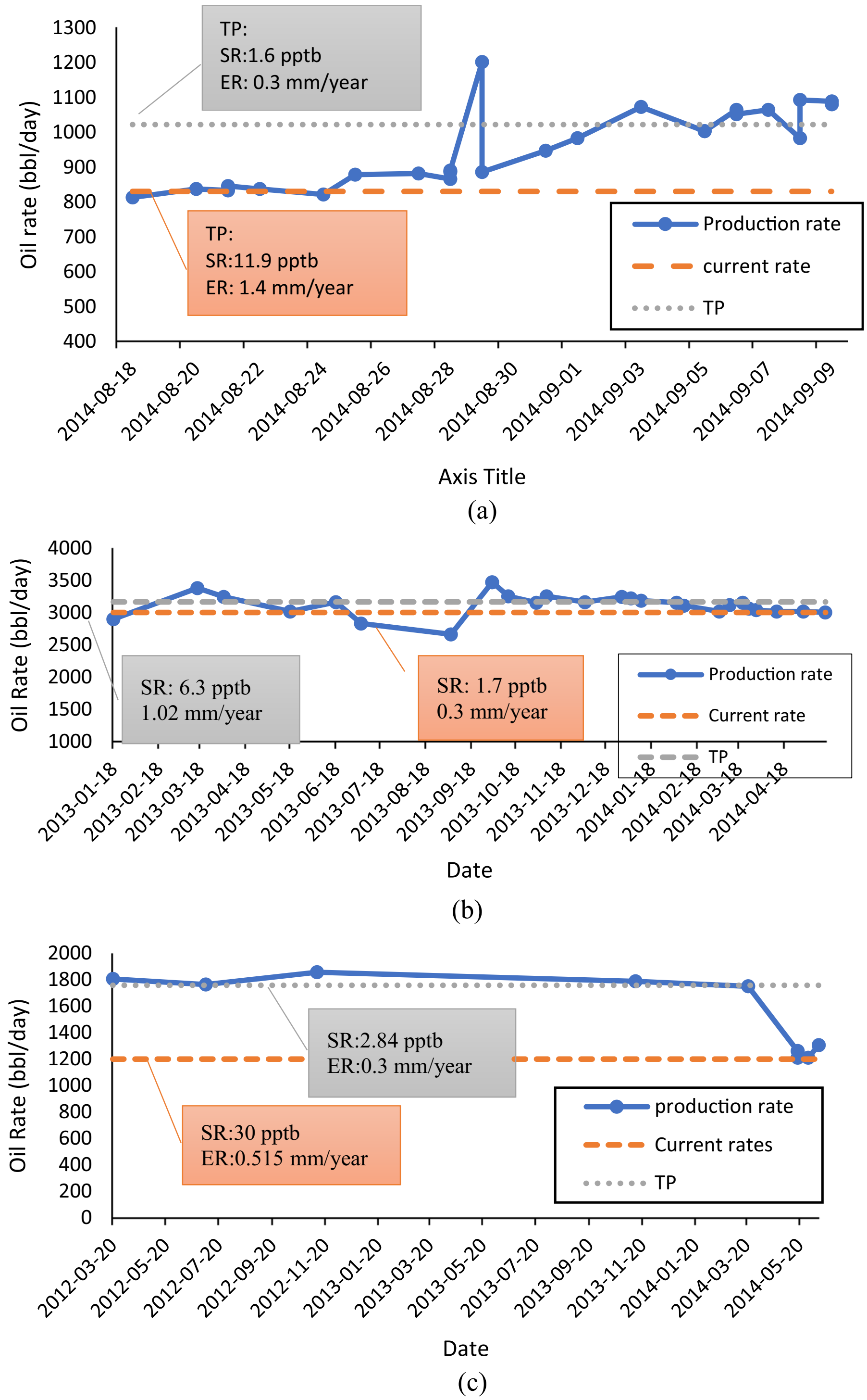
4 Summary of the sand management strategy for field Y

After careful sand monitoring, a sand management option can be devised for the well, considering several parameters: first, the nature of sand failure has to be studied. The historical sand production data in the field, the amount produced, and the nature of failure must be investigated. A decision can be made on whether to handle the sand at topside equipment or if there is a need for downhole equipment. Next, PSD plays a significant role in deciding what sand control measures to choose. The coarser sands are less likely to be lifted to the surface and must be dealt with in situ if the sand production is severe. Wellbore condition is another essential aspect of sand management. The existing well should have adequate annular clearance for expandable screens. Moreover, various shale sections can be problematic in open-hole completions. Another critical parameter is rock and fluid properties. Reservoir NTG (net to gross), porosity, permeability, number of production zones, reservoir pressure, and temperature will impact the sand management strategy. Lastly, the production and reservoir management of the current field affects the sand management program. Expected production rates, the need for intervention, logging or well stimulation, and sting's water cuts play a role in decision-making. Therefore, the critical issues for sand control center around longevity, impairment, erosion, and plugging risks. Good sand management requires an integrated approach to significantly benefit increased productivity, reduced capital, and operational costs. So, it is highly recommended to establish a baseline wall thickness assessment and conduct periodic wall thickness inspections on the identified and potential high erosion risk hotspots, respectively. It is also recommended to study operational pigging frequency optimization to address the issue of sand deposition in the pipelines and utilize an online sand monitoring tool to have real-time sand production rate and behaviour monitoring throughout the production system. Lastly, it is recommended to consider tracking the sand accumulation rate in the three-phase separator to estimate the total amount of sand produced to establish a more systematic vessel cleanout schedule.

5 Conclusion

Pipe erosion is a critical challenge in fields/reservoirs, with sand production affecting both technical and economic aspects of production. The current work modelled a mature reservoir using PIPESIM to assess the severity of sand production-related problems such as erosion, sand deposition/transport, and deposition hotspots in the production network. The outcomes of

Fig. 10 Allowable sand rates for wells: J-1 **a**, well J-2 **b**, and J-3 **c**.



this study can be used for field production optimization and management in similar scenarios.

- Firstly, based on field characteristics and production history, the allowable Er was estimated at 0.3 mm/year. Hence, out of the 10 wells modelled, Wells J-1, J-2 and L2 were identified as problematic strings with a server sand erosion rate above 0.3 mm/year.

- If a stricter policy of 0.1 mm/year is to be implemented, other wells, such as K-3 and K-4, are also considered problematic as they have high erosion rates close to 0.1 mm/year and must be monitored carefully.
- Once the problematic string is identified, the location of the high-risk areas of the production network (production hotspots) needs to be recognized. The simulation outcomes revealed that the high erosion mainly occurred after the choke to the production header in the case of the file in question. On the other hand, the sand deposition was primarily detected in the pipelines and conduits between the production header towards the separator, i.e., pipeline 48 between platform L-J and pipeline 43 between platform K-J.
- The results show that the production rate, the GOR, water cut, PSD, and the particle size influence the sand transport/deposition.
- A sensitivity analysis on erosion risk of 0.3 mm/year and 0.1 mm/year was conducted for all the strings critically affected by the production of sand higher than the maximum allowable sand rate of 0.3 mm/year.
- The maximum allowable sand rates for different strings help identify the optimum flow rates from wells J-1, J-2, and K-2, considering their critical erosion and sand production rates. Based on the sand production rate of the abovementioned wells, a 16–45% reduction was required if the tighter Er policy of 0.1 mm/year was needed. This would help maintain the production at optimum rates from the point of view of sand erosion risks.
- The outcomes of this study reveal that regulating sand erosion via controlling the production rate is the most technically and economically viable option for the mature field in question.

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Declarations

Conflict of interest The authors have no competing interests to declare that are relevant to the content of this article.

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