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Impact Assessment of Wax Gelation Fluid Pressure and Temperature: Designing Long-Term Preventive Solutions

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ABSTRACT - Paraffinic precipitation presents a pervasive flow challenge, specifically impacting this light crude oil (API 34.85 °) system, particularly within a pipeline (length 1153 m) operating in cold environments. This study first rigorously assessed the critical impact of flow parameters, confirming the fluid's thermal profile drops below the pour point (31.67 °C) at a crucial distance of 439.24 m from the wellhead, initiating severe wax gelation. Flow analysis further confirms a detrimental laminar flow regime (N_{Re} = 1262), which, coupled with a significant total pressure drop of 0.155 psia/100 ft along the pipeline, exacerbates the tendency for solidified paraffins to accumulate due to insufficient shear stress. To address this, the research successfully validated a cost-effective, long-term preventative solution: a locally fabricated sand heater with an energy capacity of 175,000 kcal/h. Empirical field testing confirmed the intervention provides a substantial net thermal elevation of 8.5 °C. Subsequent thermal modeling for long-term operational reliability identified the optimal sand-heater placement distance to be within 300 m of the wellhead. This strategic placement ensures the fluid temperature consistently remains safely above the pour point, effectively mitigating the risk of premature wax gelation and guaranteeing uninterrupted system integrity and sustained hydrocarbon production.
Keywords: wax gelation, laminar flow, pressure drop, fluid temperature, sand heater.

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INTRODUCTION

The production and transportation of crude oil in cold environments pose significant challenges for the petroleum industry. This difficulty arises from two key issues: high oil viscosity at low temperatures, which impedes pumping, and a steep negative temperature gradient that significantly enhances wax molecular diffusion, causing severe deposition. (Sarica & Panacharoensawad 2012; Soedarmo et al., 2016). When hydrocarbon fluid temperature drops below the cloud point (paraffin solubility limit), the heaviest n-paraffin fractions precipitate as solid crystals. Wax Gelation occurs as these crystals interact, forming a volume-spanning network that traps the liquid oil and imparts solid-like properties. In pipelines, these wax-gel deposits form at the cold wall surface, increasing in thickness and hardness over time, potentially leading to catastrophic blockages and significant economic losses. (Agus et al., 2023; Paso et al., 2005).

Certain saturated compounds with high melting points readily solidify as the fluid temperature decreases, typically below 80 ^{o}C. This precipitation forms colloidal solids known as wax, primarily composed of normal and branched alkanes, though naphthenes with long side chains also contribute. This waxy precipitate is the precursor to wax gelation, which severely compromises fluid flow assurance. (Kiyingi et al., 2022).

The persistent challenges posed by paraffinic precipitation have necessitated the pursuit of alternative flow assurance technologies. Recently, significant progress has been made in thermal stimulation technology, specifically in utilizing the heat and pressure generated by exothermic chemical reactions. These chemically driven thermal methods are currently being assessed for their promising applications across several areas of petroleum engineering, including enhanced oil recovery (EOR), hydraulic fracturing, formation damage control, and, critically, mitigating the risks associated with severe wax gelation. (Al- nakhli et al., 2016; Alade et al., 2020; Pamungkas 2024). Timely, planned wax gelation deposit remediation is critical to sustaining normal operations, as severe wax gelation accumulations in the pipeline can cause numerous flow assurance issues. A modern removal technique, thermal heating and insulation, directly supplies thermal energy to melt the deposits, significantly reducing the wax's viscosity and improving overall fluid flowability. (Kiyingi et al., 2022; Pramana et al., 2025). Wax precipitation presents a pervasive flow assurance challenge across oil production assets, especially pipelines. The operational impediment stems from a critical temperature drop that causes the fluid to fall below its pour point over a specific distance from the wellhead to the gathering station, thereby triggering severe wax gelation.

This research's core finding is the successful empirical validation of a cost-effective thermal treatment methodology utilizing a locally fabricated sand heater. This intervention demonstrably increased temperature, establishing a robust, field-tested strategy to mitigate flow assurance risks and ensure long-term operational reliability.

METHODOLOGY

Operational parameters

The production fluid data for the wells are summarized in Table 1. Based on this information, the tendency for wax deposition has been explicitly identified and confirmed within that particular field's production well. The crude oil produced in Table 1 is characterised as light oil with an API gravity of 34.85, which, combined with a high pour point of 31.67 ^{o}C, indicates a significant susceptibility to wax deposition. The well-fluid characterization data suggest a substantial potential for wax deposition in the Well's production fluid. This susceptibility is supported by the physical property data, which specifically demonstrate a higher pour point, elevated oil viscosity, and greater sediment content, all of which collectively increase the likelihood of wax precipitation in the wellbore or flowlines.

The geometry and operational parameters of a sand-heater system designed for thermal treatment are likely to mitigate wax-gelation risks. The system utilizes a water tank (6900 mm long, 2600 mm in diameter) containing 29 m^3 of water, featuring paired 500 mm-diameter fire hoses at the base and a 5 m chimney. Operating at a constant

Table 1. The Production fluid data

Parameter	Result	Unit
Density @ 15ºC	0.850	gr/cc
SG @ 60 ºF/60 ºF	0.851	-
API @ 60 ºF	34.85	-
Kinematic Viscosity :		
@ 38 ºC	4.522	cSt
@ 50 ºC	3.413	cSt
@ 60 ºC	2.858	cSt
Pour point	31.67	ºC
Flash point	32.5	ºC
Water Content	79.4	% vol
Wax Content	6.78	% vol
BS & W	86.18	% vol
Distillation Results :		
Initial Boiling Point	82.0	ºC
End of Boiling Point	328.0	ºC
Total Distillation Vol.	59.0	% Vol.
Residu	41.5	% Vol.
Oil rate	22.644	BOPD
Water rate	87.431	BWPD
Mix rate	110.075	BFPD
SG Oil	0.8506	
SG Water	1	
Pipe length	1153	m
	3782.81	ft
ID Pipe	2.8	Inch
	0.233	ft

sand-heater temperature of 40 °C, the burner has a capacity of 175,000 kcal/h. The fuel, an inlet gas at 15 psig, is simulated across this capacity range; the minimum capacity of 175,000 kcal/h corresponds to a fuel mass flow rate of 0.0034 kg/s (≈ 20 m^3/h). Further process details include a gas stream entering at 40 °C and 1100 psi, passing through five 6-way coils, every 4 inches (101.4 mm) in diameter, at a flow rate of 60,000 m^3/h, and exiting via a 10-inch (254 mm) collector.

The influence of pressure drop

A reduction or shift in hydrostatic pressure along the flowline facilitates the exsolution (degassing) of the crude oil's lighter, volatile components. This thermodynamic change results in a residual crude stream that is relatively enriched in heavier molecular components, such as paraffins. This significant compositional shift inherently increases the fluid's propensity for phase separation and the formation of solid paraffinic structures within the flowline. Furthermore, the prevailing hydrodynamic regime within the pipe can be accurately characterized and modeled using the Darcy-Weisbach Equation, which is essential for predicting the shear forces that govern the behavior of these solidifying components and the subsequent risk.

$$\Delta P = \frac{\rho\, f\, L\, V^2}{144\, D\, 2\, g} \tag{1}$$

Determining the fluid density is the foundational step for calculating pressure loss in a pipeline, as density is required to determine the fluid's specific gravity (SG). Subsequently, the is used to determine the fluid's viscosity. Critically, this viscosity is a dependent variable, influenced by the magnitude of both the pressure drop and the temperature drop. Therefore, the interconnectedness of these variables implies a direct relationship where temperature changes are inherently linked to pressure changes within the system.

Table 2. Pressure drop data

Method	Nilai	Unit
Mix Density	60.4822	lb/ft^3
Mix Viscosity	0.0019	lb/ft-sec
Velocity	0.17	ft/sec
Reynold Number	1262.7	
Flow type	Laminer	
Friction Factor	0.0507	
Pressure Drop	0.155	Psia/100 ft

Based on the data presented in Table 2, the fluid analysis provides critical parameters for evaluating flow assurance and potential wax gelation risks. The measured fluid properties are a mix density of 60.4822 lb/ft^3 and a significantly low mix viscosity of 0.0019 lb/ft · s. With a calculated velocity of 0.17 ft/sec, the system's Reynolds number is determined to be 1262.7, definitively classifying the flow type as laminar.

Consequently, the friction factor is calculated to be 0.0507, resulting in a minimal pressure drop of 0.1549 psia/100 ft. These characteristics of low velocity and laminar flow are particularly relevant for assessing the fluid's thermal profile, as prolonged residence time and reduced mixing could exacerbate cooling and increase the susceptibility to severe wax gelation if the temperature approaches the pour point.

A detailed calculation using Equation (1) is required to model the pressure drop variation along the flowline in Table 3. The recorded total pressure drop spanning the 3782,81 ft from the wellhead to the collection station is significant, measuring 0,155 psia/100 ft. Crucially, the flow condition analysis reveals laminar flow (NRe = 1262).

This regime is inherently more susceptible to paraffinic precipitation and subsequent severe wax gelation than turbulent flow, as the reduced wall

Table 3. Pressure drop in pipeline

Distance well head to gathering station (m)	Distance well head to gathering station (ft)	Pressure drop
0	0.00	0.000
100	328.08	0.013
200	656.17	0.027
300	984.25	0.040
400	1312.34	0.054
439,24	1441.08	0.059
500	1640.42	0.067
600	1968.50	0.081
700	2296.59	0.094
800	2624.67	0.107
900	2952.76	0.121
1000	3280.84	0.134
1100	3608.92	0.148
1153	3782.81	0.155

shear stress is insufficient to re-entrain solidified wax crystals. Consequently, the rapid, progressive accumulation necessitates immediate intervention to effectively manage this persistent flow assurance issue.

The influence of variations in flow temperature

The reduction in oil flow temperature constitutes the principal mechanism driving wax deposition. When the oil temperature drops below the wax appearance temperature (WAT), wax crystallizes, leading to the precipitation and subsequent accumulation of wax deposits within the flowline. The degree of temperature loss across the system can be accurately determined by employing the Karge Method Equation.

$$\frac{T_0 - T_1}{T_2 - T_1} = e^z \quad (2)$$

$$z = \frac{2{,}54\, \pi\, K\, D\, L}{Q\, Cp\, 10^5} \quad (3)$$

The primary trigger for paraffinic precipitation is a reduction in the fluid's flow temperature. Should the oil temperature drop below its pour point (the temperature at which the oil ceases to flow), paraffinic components will solidify and accumulate on the internal surfaces of the flowline. Consequently, accurately predicting the potential for severe wax gelation requires generating a precise thermal profile, specifically an evaluation of the temperature decline along the pipeline.

Table 4. Temperature drop data

Method	Nilai	Unit
Q mix	0.73	m^3/hour
Pipe Length	3782.809	ft
K	0.9	Kcal/m^2-hour/ ºC
Cp	0.4	Kcal/(kg ºC)
D	2.8	inch

The flow temperature profile is determined along the flowline by performing calculations at various incremental lengths, covering the pipe length from the wellhead to the gathering station with Equations (2) and (3) using Table 4. The temperature profile (Figure 1) confirmed that the

Table 5. Oil Flow Temperature

Distance from the Well, m	Flow Temperature, ºC
0	35.00
100	34.14
200	33.35
300	32.61
400	31.93
439.24	31.67
500	31.29
600	30.70
700	30.15
800	29.64
900	29.17
1000	28.73
1100	28.32
1153	28.11

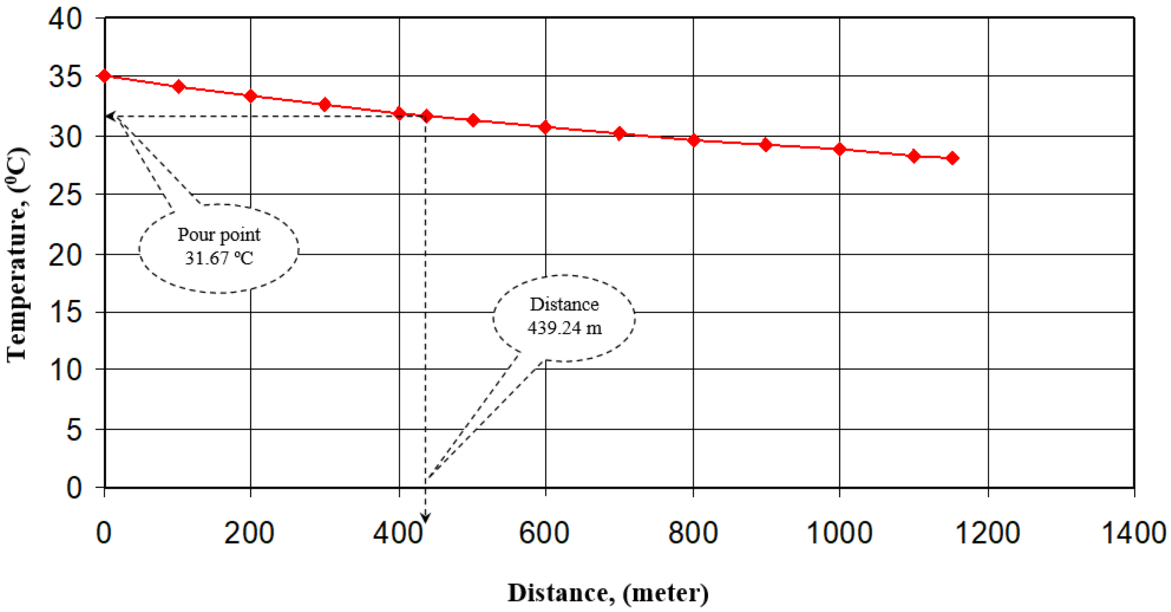

Figure 1. Fluid Temperature Drops

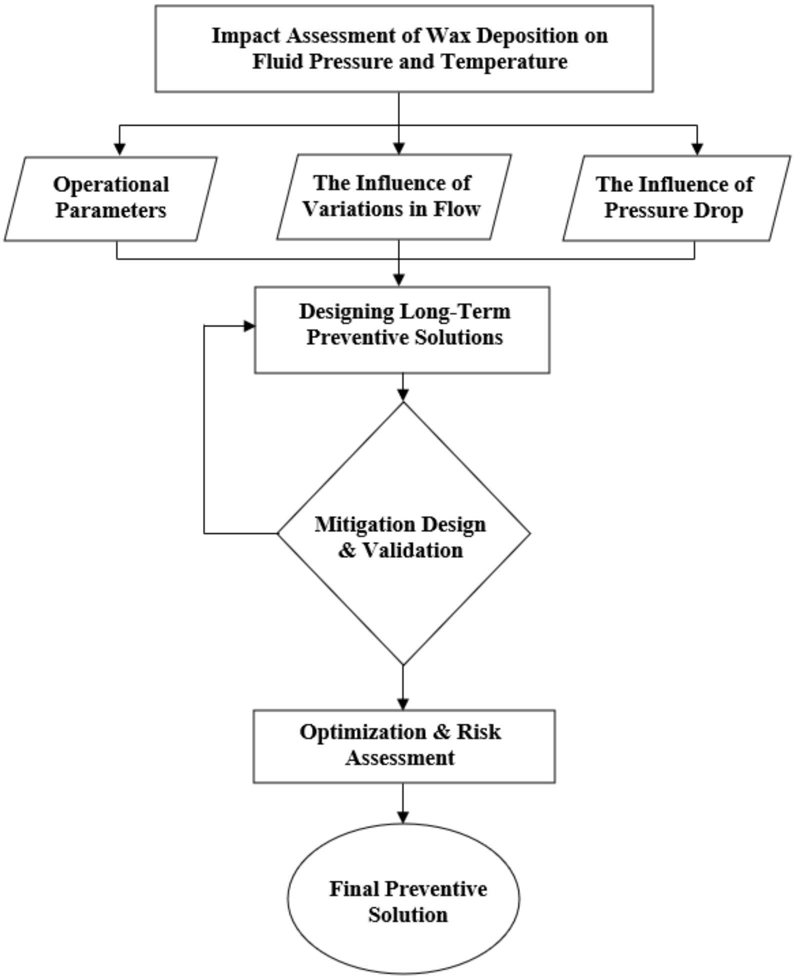

Figure 2. Workflow of activities

fluid temperature drops below the pour point of 31.67 °C at a critical distance of 439.24 m from the wellhead.

Beyond this point, wax crystallization and subsequent deposition are thermodynamically certain, which explains the operational issues observed near the gathering station. Prior research has established a strong inverse correlation between temperature and fluid viscosity in crude oil systems. Specifically, an increase in temperature decreases viscosity due to increased kinetic energy and greater molecular separation of the hydrocarbon chains. This change in viscosity, in turn, directly governs the crude oil's overall rheological properties. Crucially, the studies indicate that the pour point, the temperature below which the oil ceases to flow, is observed to decrease concurrently with the reduction in viscosity, signifying that thermal energy effectively stabilizes the fluid state and mitigates the risk of developing high-yield stress structures like those characteristic of severe wax gelation.

RESULT AND DISCUSSION

Designing and evaluating the long-term preventive solution

Sand heater implementation

The implementation of this sand heater primarily focuses on its energy capacity of 175,000 kcal/h. This specific energy output is precisely engineered to deliver the necessary heat input required for successful flow assurance remediation, particularly by raising the temperature sufficiently to dissolve solid structures and mitigate the risks associated with severe wax gelation. The observation highlights an essential principle in thermal engineering: boundary-layer manipulation can dramatically enhance system efficiency, particularly under reduced-load conditions. Mohammad & Banihashemi reported a low thermal capacity of 175,000 kcal/h; the introduction of excitation (likely referring to flow disturbance or induced motion) significantly promotes mixing and heat exchange near the solid-fluid interface. This excitation of the boundary layer effectively reduces the thermal resistance between the heater surface and the bulk fluid, minimizing the formation of an insulating static film. As a result, the system achieves a remarkable increase in thermal efficiency, reaching up to 90%. This high efficiency is crucial for ensuring that the maximum amount of generated heat is successfully transferred to the crude oil, which is vital for dissolving solidified components. Performance testing confirmed the sand heater's capacity to increase the fluid temperature by 5-10 °C.

The initial placement of the sand heater at 100 m from the wellhead was successful. The temperature of the fluid upon reaching the 1153 m gathering station was measured at 32 ^{o}C, representing a net temperature increase of 8.5 ^{o}C relative to the unheated system's gathering station temperature of 28.11 ^{o}C.

Optimization of sand heater placement distance

The flowline transporting fluid from the wellhead to the gathering station measures in total length. For this particular well, the sand heater was strategically installed downstream of the wellhead. Subsequent monitoring confirmed that the fluid temperature was the same as that recorded upon arrival at the collection station. The quantifiable net temperature increase provided by the sand heater can therefore be analytically determined by applying the Karge Method equations (2) and (3).

To ensure system redundancy and optimal long -term safety, the thermal decay was modeled for several potential sand heater placement distances: 100 m, 200 m, 300 m, and 400 m, assuming a constant temperature boost of 8.5 oC and an energy capacity of 175,000 kcal/h at the point of the sand heater. The goal was to ensure the terminal temperature at 1153 m remained safely above the 31.67 ^{o}C pour point. The results confirm that the thermal treatment method is highly effective, with all tested placement distances 100 m to 400 m resulting in a fluid temperature above the pour point at the gathering station. However, the analysis revealed a critical risk associated with placement at 400 m. At this distance, the flow temperature of the unheated fluid is 31.93 ^{o}C, which is extremely close to the 31.67 ^{o}C pour point.

This small 0.26 ^{o}C margin leaves the system highly vulnerable to premature wax precipitation upstream of the heater. Should there be a sudden

Table 6. Sand heater placement distance

Distance well head to gathering station (m)	Initial temperature (°c)	Heat 8,5°c distance 100 m	Heat 8,5 °c distance 200 m	Heat 8,5 °c distance 300 m	Heat 8,5 °c distance 400 m	Heat 8,5 °c at the pouring point
0	35,00	35,00	35,00	35,00	35,00	35,00
100	34,14	42,64	34,14	34,14	34,14	34,14
200	33,35	41,22	41,85	33,35	33,35	33,35
300	32,61	39,92	40,48	41,11	32,61	32,61
400	31,93	38,71	39,23	39,80	40,43	31,93
439,24	31,67	38,26	38,77	39,31	39,90	40,17
500	31,29	37,59	38,08	38,60	39,16	39,39
600	30,70	36,55	37,00	37,48	38,01	38,22
700	30,15	35,58	36,00	36,45	36,94	37,14
800	29,64	34,69	35,07	35,49	35,94	36,13
900	29,17	33,85	34,21	34,60	35,02	35,19
1000	28,73	33,08	33,41	33,77	34,16	34,32
1100	28,32	32,36	32,67	33,00	33,36	33,51
1153	28,11	32,00	32,30	32,62	32,97	33,11

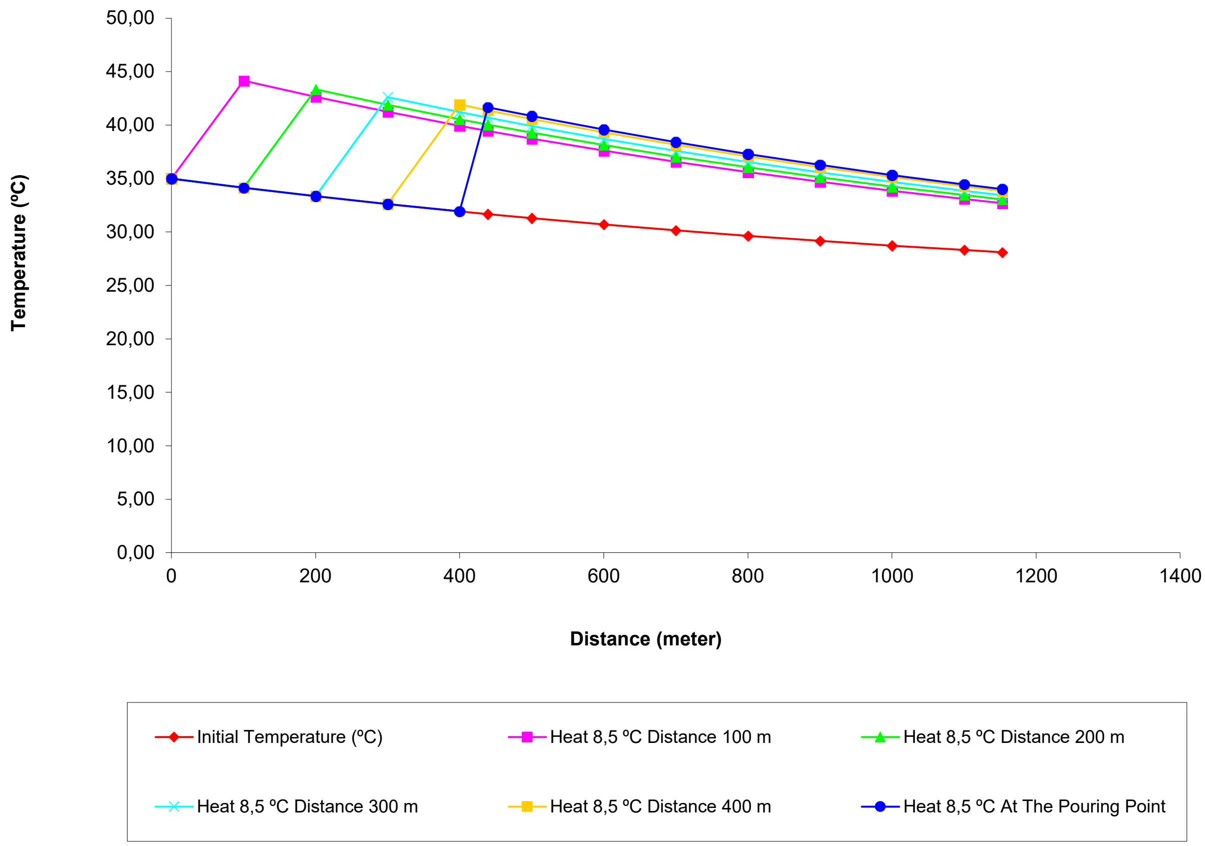

Figure 3. Graph of Fluid Temperature Decrease Distribution in Flow Pipes in Wells After Fluid Temperature Increase of 8.5°C at Distances of 100 m, 200 m, 300 m, 400 m, and at the Oil Pour Point.

drop in ambient temperature or a temporary flow stoppage, wax could deposit before the fluid reaches the sand heater, leading to a blockage. Therefore, the optimal and most robust long-term preventive strategy is to site the sand heater at 100 m, 200 m, or 300 m. These shorter distances ensure a wider safety margin between the pour point and the pre-heated fluid temperature, guaranteeing operational reliability and eliminating the high risk of premature deposition seen at the 400 m location.

CONCLUSION

The rigorous three-stage strategy, involving accurate assessment of wax deposition, the design of a targeted thermal prevention method, and performance evaluation, effectively resolves the identified flow assurance challenge in the production pipeline. By successfully correlating the critical temperature and pressure losses with the point of deposition inception and validating an optimal sand heater placement (<300 m), this study provides a robust, economically viable, and reliable long-term solution that ensures system integrity and maximizes hydrocarbon recovery by sustaining smooth, uninterrupted production operations.

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GLOSSARY OF TERMS

Unit	Definition	Symbol
Cp	specific heat capacity	BTU/lb°F
D	pipe diameter	m
e	exponential	
f	friction factor	
g	gravity constanta	m/sec^2
K	Coefficient of heat fluid separation from pipes	cal/m^2/hour/°C
L	pipe length	m
q	Heating capacity	BTU/H
Q	Flowing amount	m^3/hour
Qo	Oil Rate	bopd
Qw	Water Rate	bwpd
SG	Specific Gravity	
SG_{mix}	Mix Specific Gravity	
SG_{oil}	Oil Specific Gravity	
SG_{water}	Water Specific Gravity	
T_0	Oil initial temperature,	°C
T_1	Ambient temperature, °C	°C
T_2	pour point temperature	°C
V	Velocity	ft/sec
z	konstanta	
ΔP	Pressure Drop	psia
μ	Fluid Viscosity	lb-sec/ft
ρ	Density	lb/gl

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