



White Paper

OptiRamp[®] Real-Time Congealing and Pipeline Monitoring

Monitoring Pipelines with Advanced Analytics

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Introduction

Pipeline operators are currently challenged with operating pipelines safely in reduced production environments, which have been caused by declining brownfield operations, capital constraints brought on by oil prices, and the lack of drilling rigs to keep pipelines full. These present conditions result in pipelines operating well under their designed capacity and challenges such as congealing.

Congealing refers to the precipitation and nucleation of wax solids in a crude oil pipeline. It is initiated by a temperature gradient between the pipe wall and the centerline flow, leading to high-yield flow stress and causing changes in flow behavior.

This paper discusses the physical considerations contributing and necessary to detect congealing followed by a series of modeling steps to accurately simulate when and where congealing occurs in a pipeline while accounting for multiphase flow of differing compositions from multiple producers. In turn, this information can automatically be displayed as a visual pipeline profile, allowing operators to understand their entire pipeline operation from remote locations and view critical parameters and events, such as congealing, leak detection, and slugging.

These modeling and congealing algorithms were implemented and validated at a major oil and gas company’s site on a 150-km commercial pipeline network used to transport 50,000 BOPD from 11 gathering stations to a distribution tank farm. The main transportation pipeline was designed to transport 500,000 BOPD. Congealing events were detected and verified by comparing the simulated and assayed pipeline data. Prediction time averaged between three and six hours in advance of the congealing event, allowing the pipeline operator take appropriate mitigation actions and reduce lost production opportunity (LPO).

Scientific Foundation

The *OptiRamp* Congealing algorithms factor reservoir fluid temperatures, temperature gradients, pressure, elevation, product composition, phase differences, and flow behavior into monitoring for congealing, or the formation of wax solids in the pipeline. These wax deposits are typically composed of n-paraffins (linear chain alkanes containing more than 16 carbon atoms—typically 18 to 65 carbon atoms), small quantities of branched paraffins, and aromatic compounds. Concentration of paraffins in the fluid and temperature affect wax precipitation.

Wax Appearance

Wax solids appear due to temperature or other thermodynamic factors. Figure 1 illustrates a typical wax precipitation envelope, which shows a strong dependence on temperature.

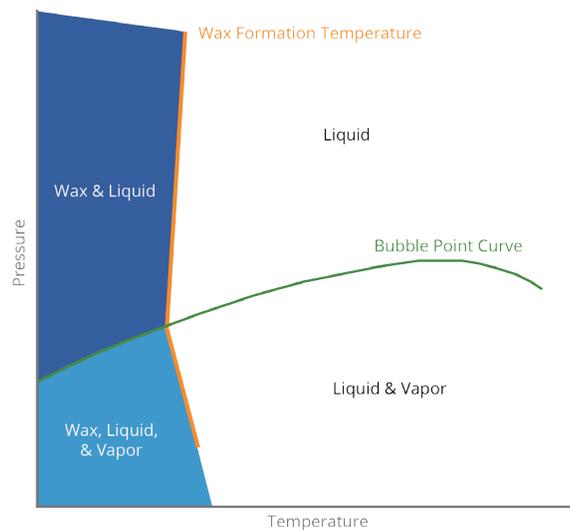


Figure 1. Typical wax precipitation envelope

- Wax formation temperature (WAT) or cloud point: Temperature at which wax crystals form and the fluid takes on a cloudy appearance
 - Below the WAT, a mixture of wax and liquid are present (wax zone)
 - Above the WAT, the fluid is a liquid (wax-free zone)
- Bubble point: Temperature at a given pressure where the first “bubble” of vapor is formed; below the bubble point curve, vapor is present as part of the mixture

A fluid’s propensity for wax appearance can also be characterized by the following measurements:

- Wax dissolution temperature (WDT): Temperature at which all wax precipitation has been dissolved in heated oil
- Pour-point temperature: Lowest temperature at which oil is mobile

- In crude oil, a high pour point typically corresponds to high paraffin content and vice versa
- In crude oil with a lower paraffin content, wax crystals form slower

Modeling these characteristics and creating the wax precipitation envelope is based on the fluid composition, which is determined through a comprehensive crude oil assay performed regularly by the field and pipeline operators.

Thermodynamic factors that may cause wax appearance include

- Fluid temperature is below the WAT
- Temperature gradient between the pipe wall and centerline flow is high
- High-yield flow stress occurring due to changes in flow behavior such as paraffin content, fluid viscosity, flow rates, gas/oil ratio, and heat transfer coefficient

Oil Assay

A crude oil assay is an evaluation that defines physical and chemical characteristics of crude oil feedstocks. Crude oil assays are used for marketing, forecasting, and business decisions, including whether the feedstock is compatible for a specific refinery.

Comprehensive crude oil assays may include properties such as molecular composition, viscosity, WAT, pour point temperature, wax dissolution temperature, and specific gravity. *OptiRamp* Congealing algorithms use crude oil assay data to calculate pure component properties.

Wax Residue Transport

The physical processes that have been investigated as contributing to wax residue lateral transport and deposition in pipelines are

- Molecular Diffusion
- Brownian Diffusion
- Shear Dispersion
- Gravity Settling

Molecular diffusion is the primary mechanism for transporting paraffins; Brownian diffusion, shear dispersion, and gravity settling may be ignored because the wax crystals are very small compared to the volume flow. The following steps (illustrated in Figure 2) describe the molecular diffusion and wax precipitation process in the pipe.

1. During fluid flow, the temperature is cooler near the pipe wall; paraffin molecules are dispersed in the fluid based on temperature, size, and fluid viscosity
2. When at WAT, a wax precipitation (deposit) layer begins to form on or near the colder pipe wall surface, causing a concentration gradient

3. Convective mass flux moves paraffin molecules from the liquid fluid toward the deposit
4. Internal diffusive flux diffuses paraffin molecules into the deposit layer, causing the wax deposit thickness to grow
5. Paraffin molecules in the wax deposit precipitate, increasing the deposit's solid wax fraction
6. Oil molecules (paraffin molecules above a critical carbon number) counter-diffusion out of the deposit

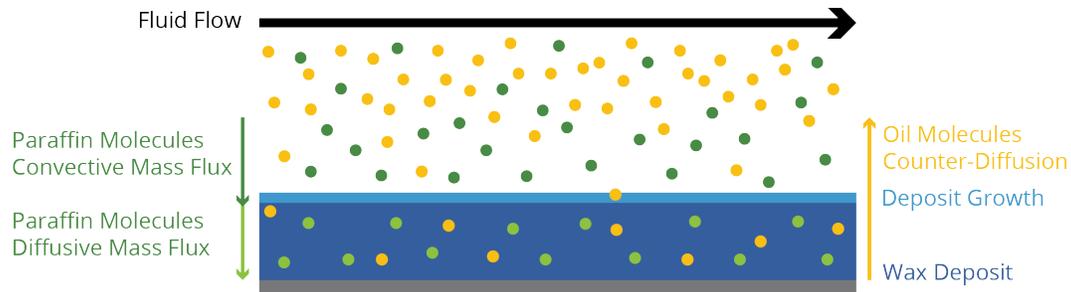


Figure 2. Molecular diffusion and wax precipitation

Thermodynamic Modeling

The thermodynamic behavior of diffused wax existing in equilibrium with the liquid enables model development for the real-time congealing and pipeline monitoring system using thermodynamic equations. Model development is based on the following assumptions:

- Pressure effect is only considered while evaluating fugacity coefficients
- Solid/liquid molar volume difference is constant
- Equal chemical potential is observed for each component in all phases
- Each component that precipitates forms a pure solid
- In the location where the wax deposit forms the oil mixture temperature is equal to the temperature of the pipe inner surface
- At a given temperature, the total amount of precipitated wax is the sum of all solid phases that exist in equilibrium with the liquid at that temperature

When the liquid phase exists in equilibrium with the solid phase at a fixed temperature and pressure, the fugacity (f_i) of component i in both the phases can be determined using equation (1).

$$f_i^L = f_i^S \quad (1)$$

We assume that each component precipitating out of the mixture forms a pure component; therefore, $f_i^S = f_{i0}^{Pure S}$.

In an oil mixture, component precipitation will occur when equation (2) is true.

$$f_i^L \geq f_i^{Pure S}, \quad (2)$$

where f_i^L is the fugacity of the i^{th} component in the liquid mixture and $f_i^{Pure S}$ is the fugacity of the pure solid formed by that component. According to reaction thermodynamics when a precipitate is formed, the component amount remaining in the solution will be determined by the equilibrium condition in equation (1).

Molecular thermodynamics and regular solution theory have been used to describe solid-liquid equilibrium with the following assumptions:

- Pressure (P) effect is only considered while evaluating fugacity coefficients and is usually neglected except at very high pressure and/or low temperature
- Heat capacity and thermal conductivity are considered independent of temperature
- Solid/liquid molar volume difference is very low and is, therefore, considered constant
- Chemical potential of each component in all phases is equal
- Several immiscible solid phases of pure components i are formed but are cumulatively considered as one pure solid component for simplification
- At a given temperature, the total amount of precipitated wax is the sum of the contribution of all solid phases that exist in equilibrium with the liquid at that temperature
- No vapor phase exists and only solid-solution equilibrium is considered

Based on solution theory, the liquid-phase fugacity can be calculated using equation (3), while the pure solid fugacity can be calculated using equation (4).

$$f_i^L = \gamma_i^L x_i^L f_i^{Pure L} e^{\int_0^P \frac{V_i^L}{RT} dP} \quad (3)$$

$$f_i^S = \gamma_i^S x_i^S f_i^{Pure S} e^{\int_0^P \frac{V_i^S}{RT} dP}, \quad (4)$$

where, x_i^L is the mole fraction of i^{th} component in the liquid mixture and γ_i^L and γ_i^S are the liquid- and solid-phase activity coefficients, respectively.

Solubility Model

The solubility model uses the molecular solubility approach to describe heavy hydrocarbon mixtures containing fluid with solute (paraffins) and solvent (bulk oil) in a homogeneous liquid state. Based on the solid-liquid equilibrium defined in equation (1), liquid- and solid-phase fugacity can be used to define the molar ratio by dividing equation (3) by equation (4), as given in equation (5).

$$\frac{x_i^S}{x_i^L} = \frac{\gamma_i^L}{\gamma_i^S} \frac{f_i^{Pure L}}{f_i^{Pure S}} e^{\int_0^P \frac{(V_i^L - V_i^S)}{RT} dP} \quad (5)$$

In crude oil, the volume differences between the liquid and dispersed wax solid is less than 10%; therefore, the volume difference has negligible influence on the equilibrium. Therefore, equation (5) may be written as shown in equation (6)

$$\frac{x_i^S}{x_i^L} = \frac{\gamma_i^L f_i^{Pure L}}{\gamma_i^S f_i^{Pure S}} \quad (6)$$

To define the fusion of a pure liquid of component i in a solid-liquid equilibrium, an equilibrium constant, K_i^{SL} , is defined as $K_i^{SL} = \frac{x_i^L}{x_i^S}$.

Equation (7) is used to calculate the fusion equilibrium constant for each component in the liquid mixture.

$$\left(\frac{f_i^L}{f_i^S}\right)_{Pure} = \exp\left(\frac{\Delta H_{f,i}}{RT}\left(1 - \frac{T}{T_{f,i}}\right) + \frac{\Delta H_{t,i}}{RT}\left(1 - \frac{T}{T_{t,i}}\right) + \frac{1}{R} \int_T^{T_{f,i}} \frac{\Delta C_{P,i} dT}{T} - \frac{1}{RT} \int_T^{T_{f,i}} \Delta C_{P,i} dT\right) \quad (7)$$

Using the regular solution theory for liquid phase given in equation (7) and expanding it for the multi-wax solid model gives equation (8).

$$K_i^{SL} = \frac{x_i^L}{x_i^S} = \frac{\gamma_i^S}{\gamma_i^L} \exp\left(\frac{\Delta H_{f,i}}{RT}\left(1 - \frac{T}{T_{f,i}}\right) + \frac{\Delta H_{t,i}}{RT}\left(1 - \frac{T}{T_{t,i}}\right) + \frac{1}{R} \int_T^{T_{f,i}} \frac{\Delta C_{P,i} dT}{T} - \frac{1}{RT} \int_T^{T_{f,i}} \Delta C_{P,i} dT\right), \quad (8)$$

where $\Delta C_{P,i}$ is the change in the heat capacity of component i when it melts, $\Delta C_{P,i} = \Delta C_{P,i}^L - \Delta C_{P,i}^S = 1.2739m_i - 0.0019467m_i T$, and m_i is the molecular mass of component i .

Activity Coefficient

Crude oil mixtures contain a variety of microscopic species interacting chemically. While ideal mixtures have enthalpy change of solution values of zero, in real-time crude oil transportation, enthalpy changes are encountered due to species transfer, viscosity, and diffusion. To compensate for these changes and deviations, solid- and liquid-phase activity coefficient values, γ , have been empirically determined in equations (9) and (10), respectively, using solubility parameter values.

$$\ln \gamma_i^L = V_i^L \frac{(\delta_m^L - \delta_i^L)^2}{RT} \quad (9)$$

$$\ln \gamma_i^S = V_i^S \frac{(\delta_m^S - \delta_i^S)^2}{RT}, \quad (10)$$

where $\delta_m^L = \sum \phi_i^L \delta_i^L$ and $\delta_m^S = \sum \phi_i^S \delta_i^S$.

Equation of State (EOS)

To determine the relative amount of wax precipitate along the pipe surface of a pipe, the fugacity coefficients, ϕ_i , for each component, i , in the oil mixture must be determined. The Peng-Robinson

EOS is used to determine the fugacity coefficients, ϕ_i^L and $\phi_i^{\text{Pure L}}$, for each component in the liquid mixture.

The Peng-Robinson EOS states that the pressure (P), volume (V), and temperature (T) of a pure liquid or gas of component i are related to one another in single-phase mixtures using equation (13).

$$P = \frac{RT}{V - b_{mix}} - \frac{a_{mix}}{V^2 + 2Vb_{mix} - b_{mix}^2}, \quad (13)$$

where $b_{mix} = \sum_{i=1}^N x_i b_i$, $a_{mix} = \sum_{i,j=1}^N x_i x_j a_{ij}$, $a_{ij} = (1 - k_{ij})\sqrt{a_i a_j}$, N is the number of components in the mixture, and k_{ij} is the binary interaction parameter between components i and j .

Based on equation (13), the fugacity coefficient of the i^{th} component of the fluid mixture is calculated using equation (14)

$$\ln \phi_i = (Z_{mix} - 1) \frac{b_i}{b_{mix}} - \ln(Z_{mix} - B_{mix}) - \frac{A_{mix}}{\sqrt{2B_{mix}}} \left(\frac{1}{a_{mix}} \sum_{i=1}^N x_i a_{ij} - \frac{b_i}{2b_{mix}} \right) \ln \left(\frac{Z_{mix} + (1 + \sqrt{2})B_{mix}}{Z_{mix} + (1 - \sqrt{2})B_{mix}} \right), \quad (14)$$

where Z_{mix} is the fluid mixture compressibility, $A_{mix} = \frac{a_{mix}P}{R^2T^2}$, and $B_{mix} = \frac{b_{mix}P}{RT}$.

Substituting fugacity equations (3) and (4) into equation (2) produces the inequality given in equation (15).

$$x_i^{\text{Feed}} \geq \frac{\phi_i^{\text{Pure L}} K_i^{SL}}{\phi_i^L}, \quad (15)$$

where x_i^{Feed} is the mole fraction of i^{th} component of the liquid mixture entering the pipe prior to wax precipitation.

Similarly, the equilibrium mole fractions for components in the liquid mixture that produce wax precipitates are determined empirically using equation (16).

$$x_i^L = \frac{\phi_i^{\text{Pure L}} K_i^{SL}}{\phi_i^L} \quad (16)$$

Using the x_i^{Feed} and x_i^L values determined in equations (15) and (16), the relative amount of wax precipitate (c_s) is calculated using equation (17).

$$c_s = \frac{\text{Moles Solid}}{\text{Moles Feed}} = \frac{\sum_i^{\text{Waxes}} (x_i^{\text{Feed}} - x_i^L)}{1 - \sum_i^{\text{Waxes}} x_i^L} \quad (17)$$

The OptiRamp Congealing algorithms use a wax precipitate (c_s) threshold to alert pipeline operators to congealing in the pipeline when the calculated c_s value is greater than the defined threshold. Therefore, pressure (P), temperature (T), and initial oil mixture composition (x_i^{Feed})

are required. Additionally, because wax deposits form along the pipe's inner surface, the oil mixture temperature will be approximately equal to the pipe inner surface temperature, T_w .

Modeling Performance of an Oil Pipeline

The *OptiRamp* Real-Time Congealing and Pipeline Modeling Solution was implemented and validated at a major oil and gas company's site on a 150-km commercial pipeline network used to transport 50,000 BOPD of oil from 11 gathering stations (referred to as Producers) to a distribution tank farm. Although *OptiRamp* can simulate wax precipitation in multiphase flow pipelines, the product in this example only considered oil. Figure 3 graphically illustrates the pipeline system model used for testing.

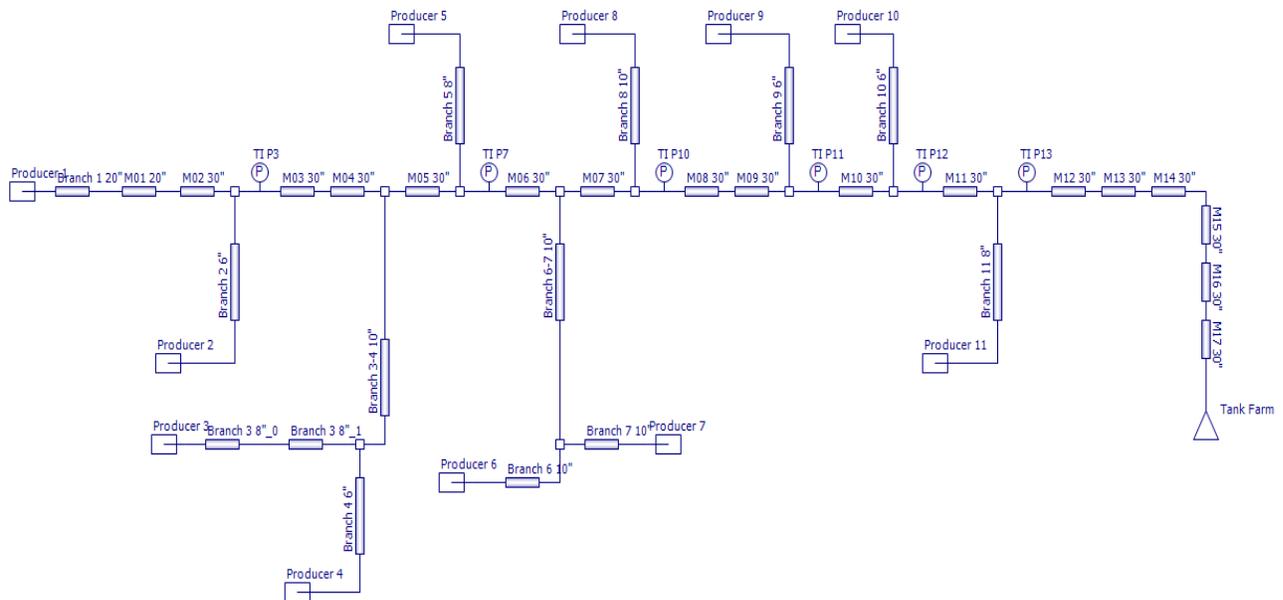


Figure 3. Pipeline system model

In this pipeline system, oil from the gathering stations flow through a single trunk line to the tank farm, encountering multiple T-junctions; tie-ins; elevation, flow rate, and pressure changes; control valves; and measuring devices. Pipeline sizes are indicated on each branch circuit and the main transportation pipeline in Figure 3.

Problem Statement

A simulation of the pipeline system model (in a pipe without wax precipitation) experimentally calculated the tank farm to be receiving 53140 BOPD from the gathering stations flowing to it. However, when the simulated value was compared to the real-time value, the customer determined it was experiencing a significant drop in gross production due to wax precipitation in the pipeline. The goal was to determine where congealing was occurring in the pipeline so that appropriate actions could be taken.

Initial Data

Initial data included the following:

- Crude oil assay to determine wax precipitation potential and for oil properties, including temperature and flow rate
- Oil composition (compositionally the same for all gathering stations)
- Transient flow rate from the field
- Pressure data from the field
- Ambient temperature at the station

Table 1 provides the initial data for each gathering station (Producer) collected from the crude oil assay.

Table 1. Crude oil properties at each gathering station

Station	Density (Kg/m ³)	Viscosity(cP)		Oil Temperature (°F)	Oil Flow (bbl/d)	Ambient Temperature (°F)
		μ ₁	μ ₂			
Producer 1	862.6	23.3	7.2	149	31461.6	75
Producer 2	862.6	23.3	7.2	148	0	75
Producer 3	870.2	31.8	9.9	148	2275	75
Producer 4	853.6	26.2	6	120	380	75
Producer 5	857.4	19.6	5.1	148	1840	76
Producer 6	863.5	22	6.6	151	1520.3	75
Producer 7	852.2	12.5	5.3	145	7061	75
Producer 8	868.4	25.7	6.2	155	2332	77
Producer 9	941.4	260.4	65.2	97	920	76
Producer 10	922.6	242.9	42.5	107	1540	75
Producer 11	861.8	19.4	6.5	135	3783	75

Simulation Results

The *OptiRamp* Congealing algorithms were applied to the model simulation, as shown in Figure 4. In this scenario, all gathering stations were contributing to the tank farm flow rate except for Producer 2. Additionally, real-time values for oil flow rate, oil temperature, and ambient temperatures were used for the simulation. Based on the real-time values, congealing was detected in the Producer 9 branch. As shown in Figure 4, the simulation alerts operators to a congealing event through an icon near the pipe experiencing congealing.

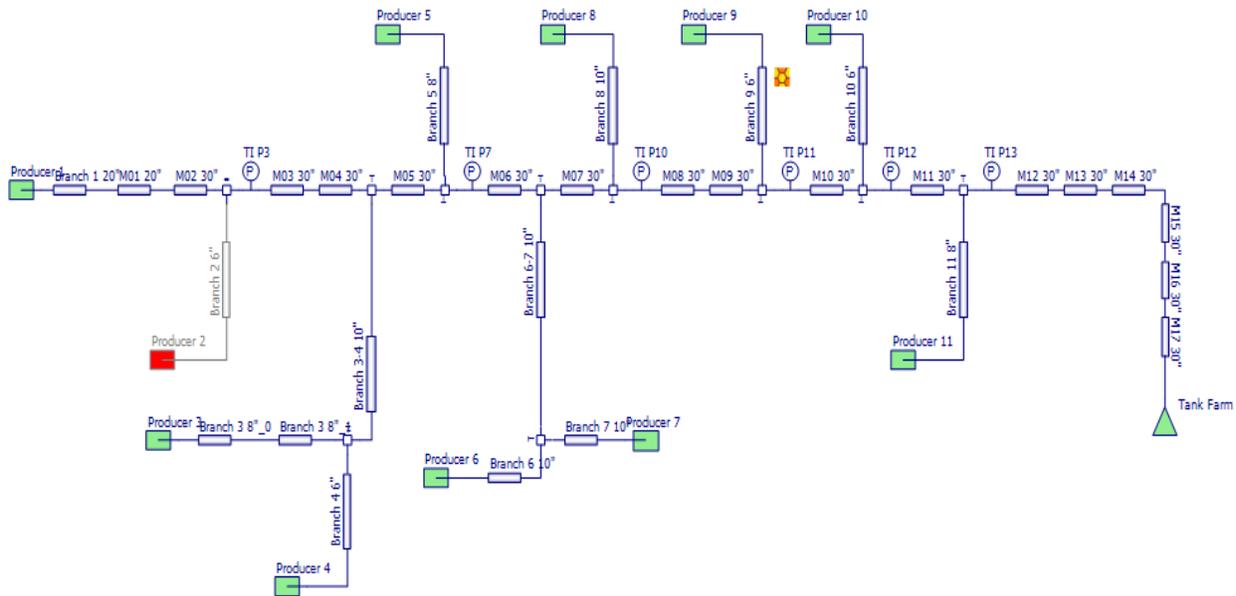


Figure 4. Pipeline network system simulation with *OptiRamp* Congealing algorithms

Based on the initial data in Table 1 and the simulation results, it can be seen that the oil temperature was substantially lower than the other gathering stations, leading to congealing. The lower temperature also changed the viscosity in the pipeline. *OptiRamp* Web Analytics displays pipeline profiles trending pipeline characteristics across the pipeline length. Figure 5 shows the oil’s viscosity change as it flowed from Producer 9 to the tank farm as a cumulative average of the net mass flowing through the pipe. The disturbance in the pipeline profile shows the location in the pipeline where congealing is occurring.

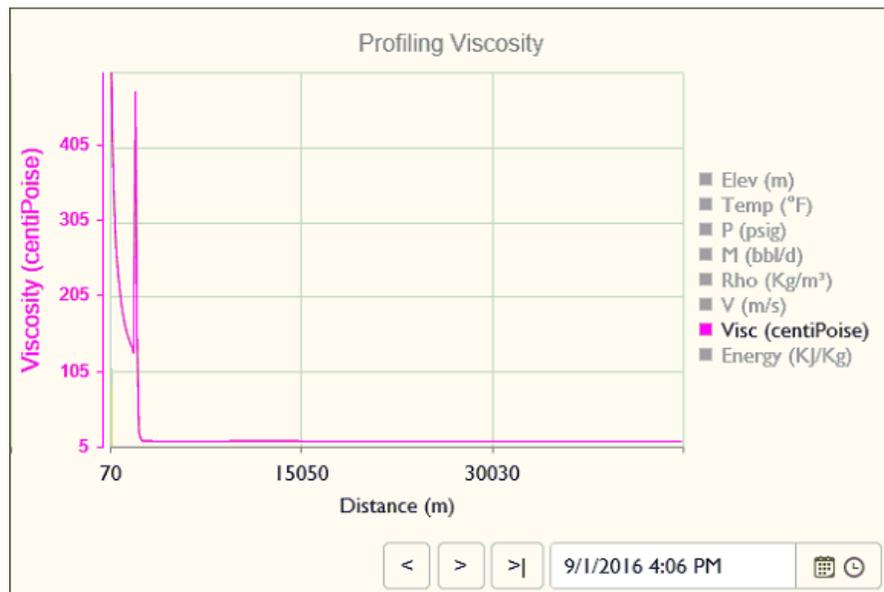


Figure 5. Pipeline profile highlighting viscosity for Producer 9 pipeline branch

Figure 6 shows the pipeline profile for the entire trunkline, from Producer 1 to the tank farm. Because of the contributions of oil from the remaining gathering stations, the pipeline profile uses a cumulative average of the net mass flowing through the pipe. The disturbance in Figure 6 is the transmitted increase of viscosity, in the congealed branch to the trunkline due to wax precipitation in fluid from Producer 9.

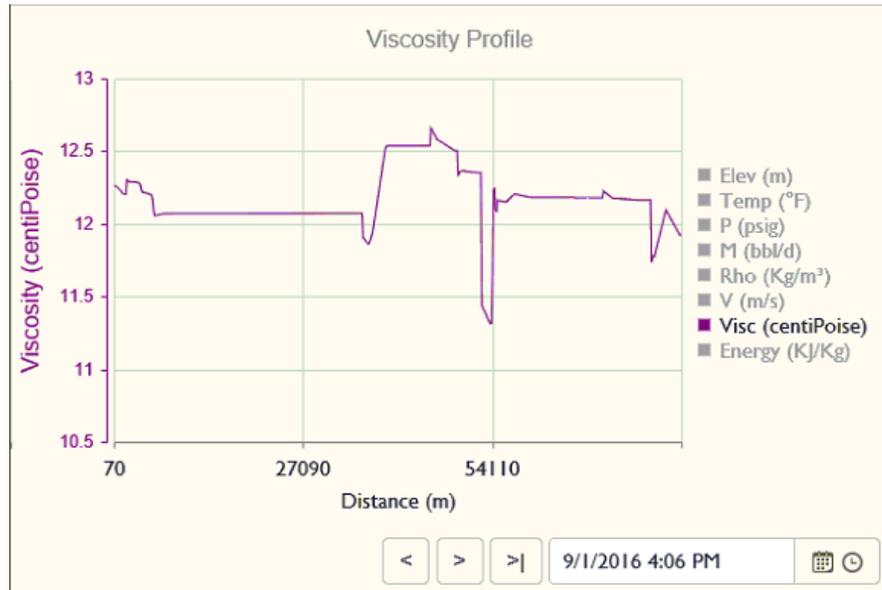


Figure 6. Pipeline profile highlighting viscosity for Producer 9 pipeline branch

Conclusion

Based on the results of the implementation and validation in the field, the *OptiRamp* Real-Time Congealing and Pipeline Modeling Solution allows pipeline operators to detect congealing in real time in pipelines with single-phase and multiphase flow. Congealing events were detected and verified by comparing the simulated and assayed pipeline data. Prediction time averaged between three and six hours in advance of the congealing event, allowing the pipeline operator to respond with the appropriate mitigation techniques and thereby reduce the lost production opportunity (LPO).

This paper discussed the physical considerations contributing and necessary to detect congealing followed by a series of modeling steps to accurately simulate when and where congealing occurs in a pipeline while accounting for multiphase flow of differing compositions from multiple producers. In turn, this information can be visually displayed as a pipeline profile (as shown in the example case given), allowing operators to understand their entire pipeline operation from remote locations and view critical parameters and events, such as congealing, leak detection, and slugging.



About Statistics & Control, Inc.

S&C—an engineering consulting and technology company headquartered in West Des Moines, IA—solves complex challenges for customers through its unique technology and its highly seasoned team of professionals. The company has a global portfolio spanning the energy, oil and gas, utility, and digital oil field industry sectors. S&C provides clients with turbomachinery control solutions that easily integrate with the existing system as well as *OptiRamp*[®] solutions, which focus on process and power analytics to optimize processes and, in turn, reduce costs and increase reliability. S&C also provides consulting, dynamic system studies, modeling, automation, training and OTS, and support services.

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