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Real-Time Sand Deposition Prediction in Multiphase Flow

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ABSTRACT

Sand management technology has become more prevalent in the petroleum industry to increase well production. Sand may deposit on pipeline walls, causing problems such as pipe blockage, reduced flow area, structural pipe issues, abrasion, corrosion, and low production in wells. This paper explores the multiphase model and computation algorithms used to simulate multiphase flow with sand particles through a subsea pipeline to predict the pressure gradient, transport velocity, and sand deposition. Being able to predict sand accumulation and understanding real-time sand velocity in a pipeline can help define design cirtieria for subsea pipelines and help pipeline operators maximize production while miniminizing well and pipeline downtime.

INTRODUCTION AND BACKGROUND

Sandstone reservoirs happens to be the source for most of the worlds hydrocarbons. Several gas and oil fields are challenged with sand production. Sand production is the migration of formation sand caused by the flow of the reservoir fluids. It begins when the rock around the perforations fails, and the fluid can push the sand or solid material into the wellbore.

This paper discusses the physical considerations that contribute and are necessary to detect sand deposition followed by a series of modeling steps to accurately simulate how far down the pipeline sand deposits occur in a pipeline while accounting for multiphase flow of differing wells from the same platform. 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 sand deposition and erosional velocity.

The modeling and sand deposition algorithms were implemented and validated at a major oil and gas company's site on an offshore platform that had an undersea pipeline running to the platform gathering station to be shipped to onshore. The main transportation pipeline was designed to transport 10,000 BOPD. Sand deposition events and erosional velocity were detected and verified by comparing the simulated and real-time pipeline data and examining the pressure loss that is theoretically supposed to happen in the pipeline and the actual pressure loss in the pipeline. Sand deposition and erosional velocity were detected, allowing the pipeline operator to take appropriate mitigation actions and reduce lost production opportunity (LPO).

SCIENTIFIC FOUNDATION

Modifying the Conservation Equations to Handle Sand

The staring point for modelling the transfer of sand through a pipeline is the development of reliable conservation equations for the sand/fluid mixture. When developing these equations, it is also important to consider the complexity of the algorithm that will be used to solve these equations. In principle, separate equations of motion should be specified for the sand particles and then surrounding fluid. However, within those equations are terms, such as the pressure gradient, which bind the equations together forming a large system of coupled differential equations. Unfortunately, even using the most recent advancements in computer design, a direct solution of the full set of differential equations cannot be applied to real world pipelines. Great care must also be applied to the solution of these equations to ensure the algorithm remains numerically stable. A single set of conservation equations were developed for the sand/fluid mixture that describes the conservation of the mixture's density and momentum as seen in the equations below:

$$\frac{\partial \rho}{\partial t} + \frac{\partial}{\partial x}(\rho_m v_m) = \frac{\partial \rho_m}{\partial P}\frac{\partial P}{\partial t} + \frac{1}{A}\frac{\partial \dot{M}_{total}}{\partial x} = 0$$

$$\frac{\partial}{\partial t}(\rho_m v_m) + \frac{\partial}{\partial x}[(\rho_m v_m)^2] = \frac{1}{A}\frac{\partial \dot{M}_{total}}{\partial t} + \frac{\dot{M}_{total}}{\rho_m A^2}\frac{\partial \dot{M}_{total}}{\partial x} = f_{total}$$

Where at a given time t and location X:

- A specifies the cross-sectional area of the pipe
- F_{total} specifices the annular component of the total force that is action on the mixture per unit of volume
- P, ρ_m, υ_m, and $\dot{M}_{total}$ specify the pressure, density, average superficial velocity, and total mas flow rate of the mixture

Unfortunately, conservation equations cannot be directly used to detect sand deposition because they were developed on the assumption that the mass fractions of the sand and fluid components of the mixture remain constant. See the Detection of Sand Deposition for how S&C detects sand deposition.

The Density of the Sand/Fluid Mixture

The density of the sand/fluid mixture is computed from the following experession

$$\rho_m = \rho_s H_s + \rho_f(1 - H_s)$$

Where ρ_m denotes the average density of each sand particle, ρ_f denotes the density of the multiphase (or single phase) fluid, and H_s specifies the franction of the pipe's volume that is occupied by sand particles (sand holdup). The sand holdup is determined by solving the following quadratic equation

$$v_c H_s^2 + (v_{ss} + v_{sf} - v_c)H_s - v_{ss} = 0$$

Where υ_c specifies the critical velocity that the mixture needs to have to move sand particles along the pipeline and υ_{ss} and υ_{sf} are the scaled velocities that are determined by multiplying the superficial sand and fluid velocities by the sand and fluid holdups. The function dependence that the scaled velocities have on H_s can be removed by using the following experessions for υ_s and υ_f

$$v_s = \frac{x_s \dot{M}_{Total}}{\rho_s A H_s}$$

$$v_f = \frac{(1 - x_s)\dot{M}_{Total}}{\rho_f A(1 - H_s)}$$

Where x_s denotes the mass fraction of the sand component of the sand fluid mixture. Finally, an empirical formula that Danielson[1] proposed can be used to determine υ_c.

The Total Force Operating on the Sand/Fluid Mixture

The forces that influence the motion of the mixture can be separated into two groups:

1. Standard forces that act on the entire fluid mixture (i.e. forces that will continue to exist even when the mixture does not contain sand particles)
2. Particle/fluid interaction forces (i.e. forces that depend on the presence of sand particles within the fluid.)

If $f_{standard}$ and $f_{interaction}$ denote the annular components per unit volume of the standard and particle/fluid interaction forces, then

$$f_{Total} = f_{Standard} + f_{Interaction}$$

The standard forces include: a hydrostatic force that is produced by the pressure differential across the pipe segment; a gravitational force that pulls the mixture downwards; and a frictional force that opposes the flow of the mixture

$$f_{Standard} = \frac{\partial P}{\partial x} - g\rho_m \sin\theta - \frac{(\emptyset_m \rho_m v_m)^2}{2D}$$

Where g denotes the acceleration due to gravity, θ denotes the inclination angle of the pipe, and $\emptyset_m$ denotes the friction factor of the mixture. The friction factor of the mixture is computed as the sum of the friction factor of the fluid, $\emptyset_f$, and the friction factor of the sand particles, $\emptyset_s$

$$\emptyset_m = \emptyset_f + \emptyset_s$$

Standard empirical formulas can be used to compute $\emptyset_f$. The value of $\emptyset_s$ can be determined from the following expression below

$$\emptyset_s = 0.046\left(\frac{\mu_f}{\rho_m v_m d_s}\right)^2 \cos\theta$$

Where μ_f denotes the average viscosity of the fluid and d_s denotes the average diameter of the sand particles. The remaining forces describe the interactions that occur between the sand particles with each other and with the fluid. The value of $f_{Interaction}$ (the annular component of the total interaction force per unit volume) is related to F_{Int}, the annular component of the total interaction force that is action on a single sand particle, through the following expression

$$f_{Interaction} = \frac{H_s F_{Int}}{\frac{\pi}{6}{d_s}^3}$$

Three forces contribute to F_{Int}: a fluid/particle drag force; a fluid/particle turbulence force; and a particle/particle interaction force

$$F_{Int} = F_{Drag} + F_{Turb} + F_{Part}$$

The drag force is the main interaction force that occurs between the fluid and the particle. When the fluid and particle travel at different speeds the friction that occurs between those two objects will cause the slower object (usually the particle) to speed up and the fast object to slow down. The value of F_{Drag} can be calculated from the following expression

$$F_{Drag} = \frac{1}{2}\rho_f\left(v_f - v_s\right)^2 C_{Drag}\ x\ \frac{\pi}{4}{d_s}^2$$

Where C_{Drag} is an empirical parameter known as the drag coefficient. The fluid/particle turbulence force accounts for addition fluid interations that are produced by eddy currents that exist during turbulent flow conditions. The contribution that the turbulence force makes to F_{Int} is determined from the following expression

$$F_{Turb} = \rho_f(v_{turb})^2\ x\ \frac{\pi}{4}{d_s}^2$$

Where υ_{Turb} denotes the turbulent fluctuation velocity. The value of υ_{Turb} depends on υ_{min}, the smallest value of υ_f that will keep the sand particles suspended inside the fluid, through the following expression

$$v_{Turb} = \frac{(16d_s)^{\frac{1}{3}}}{D^{0.42}}\left(\frac{\mu_f}{\rho_f}\right)^{\frac{1}{12}}(v_{min})^{0.92}$$

Finally, the following expression determines the contribution that particle/particle interactions make to F_{Int}

$$F_{Part} = \frac{1}{A}M_S\left(v_f - v_s\right)\ x\ \frac{\pi}{4}{d_s}^2$$

Detecting Erosion and Sand Deposition

Only having pressure, temperature, and mass flow rate the pipe erosion and sand deposition cannot be determined directly from the conservation equations. Instead additional empirical formulas must be developed to perform those tests.

In 1991 the American Petroleum Institute endorsed procedure 14E[3] as a simple means of detecting sand erosion in pipes. Under that procedure a critical velocity is determined from the following expression

$$v_E = \frac{C_E}{\sqrt{\rho_m}}$$

Where C_E is an empirical constant. If the superficial velocity of the mixture is larger than υ_E the pipes are at an increased risk of erosion. If $\upsilon_M << \upsilon_E$, there is only a minimal risk of damage. Since that time additional methods have been developed to quantitatively track the amount of erosion that occurs at each point of the pipeline. Despite those advances procedure 14E still provides one of the most reliable and universal gauges for the danger of pipe erosion. The robustness of procedure 14E comes from the fact that the equation for υ_E is derived from the established formula for frictional pressure loss

$$\left(\frac{\Delta P}{\Delta X}\right)_{Fric} = \frac{(\emptyset_m\rho_m v_m)^2}{2D}$$

A test that is like the erosion detection test can be developed for sand deposition. Under that test the superficial velocity is comprared to a threshold velocity that must be exceeded to prevent sand deposition from occurring. A warning would be issued whenever the superficial velocity is below the threshold value. Based on the ideas that were discussed earlier, one of the following velocities could be used as the threshold which is υ_c, the minimum velocity needed to move sand particles across the pipeline and υ_{min}, the minimum velocity needed to keep sand particles suspended within the fluid.

Case Study: Modeling Performance of an Oil Pipeline

The modeling and simulation techniques presented were implemented and validated in an oil and gas company's site on a 5-km (~3.11 mi) subsea commercial pipeline network used to transport 4,000 BOPD (636 m3/day) from two oil platforms to a platform gathering point. The figure below shows the two platforms and gathering point.

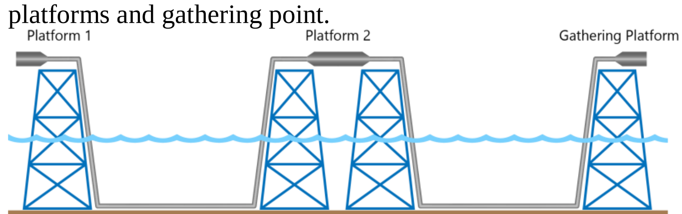


Figure 1 – Pipeline system model

In this pipeline system, different oil properties from different wells cause mixing and sand deposition in the subsea pipeline. Sand filtering is limited when sand deposition is at 20% or lower, but still cause a significant amount of pressure drop in the pipeline and damage to the inside of the pipeline. Platform 1 has two active wells and Platform 2 has 3 active wells and have different sand rates, oil properties, and gas composition for each well and is being shipped by the subsea pipeline which also mixes the properties.

Problem Statement

A simulation of the pipeline system model (in a pipe without sand deposition) experimentally calculated the gathering platform pressure to be 150 psig. However, the real-time value was significantly lower than this simulated value, leading to the conclusion that sand and possibly congealing was slowing down the fluid velocity and causing a significat pressure drop when sand was occurring in the system. Goals of this study were to confirm the modeling and simulation techniques described and to determine where sand deposition and erosional velocity of sand was occurring in the pipeline so that appropriate actions could be taken.

Initial Data

Initial data included was

- Oil properties for 3 phase flow
- Gas composition for 3 phase flow
- Oil well initial data
- Piping geometry and elevation changes

The oil properties were given to us by the end user and are in the table below:

Oil Properties	
Viscosity 1	30.9 cP @ 80 °F
Viscosity 2	19.9 cP @ 120 °F
Density	900 kg/m^3
Elasticity	1.2x10^9 Pa
Cp	2 KJ·K/Kg

Where Cp is the specific heat coefficient of the oil. The gas composition was given as

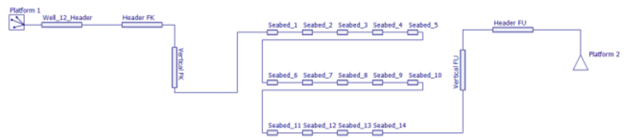
Mole fraction	Formula	Name	Cp/Cv	Cv
88.36	CH4	Methane	1.31	1.7
1.44	CO2	Carbon Dioxide	1.32	0.655
3.9	C2H6	Ethane	1.19	1.48
3.36	C3H8	Propane	1.14	1.48
0.69	C4H10	i Butane (Isobutane)	1.1	1.53
1.07	C4H10	n Butane	1.09	1.53
0.34	C5H12	i Pentane	1.08	
0.22	C5H12	n Pentane	1.08	
0.22	C6H12	1-Hexene		
0.08	C7H16O	1-Heptanol		
0.05	C8H16	1-Octene		
0.23	N2	Nitrogen	1.4	0.743
0.04	O2	Oxygen	1.41	0.659

Now to set up our model some initial parameters are needed from the previous well test. The experimental data to be used for the wells is given by the table below:

Platform	Well	Oil (BPD)	Water (BPD)	Fluid (BPD)	W (%
1	Well 1	60	501	561	
1	Well 2	546	182	728	
2	Well 1	174	65	239	
2	Well 2	102	0	102	
2	Well 3	486	0	486	

For the piping geometry we need to look at the Figure again and see that they have a subsea pipeline:

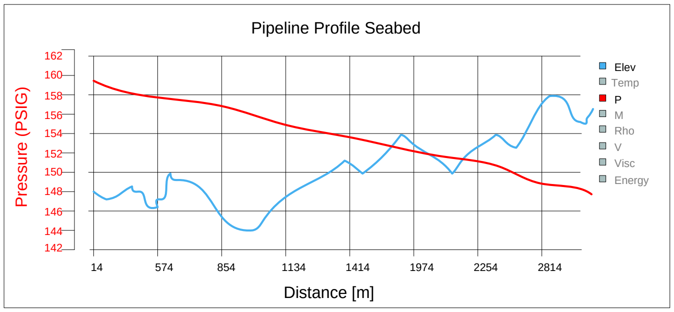
The subsea pipeline from platform 1 and platform 2 is about 2.83 km and the diameter is 12”. The pipeline is 50 meters below the water line and we neglect the change in water temperature from the surface to the seabed since it is only 50 meters. The subsea pipeline from platform 2 to the gathering station platform is 2.34 km and 12”. Below is showing a picture of the model elements that were used.



Now that the model is set up a test case can be set up in the simulation for the baseline and when we introduce our sand detection algorithm to see how it changes in our simulation.

Results

The main part of the system is looking at the pressure drop along the pipeline and how it should work theoretically before we implement our sand detection algorithm. Looking at our pipeline profile we are able to see the pressure and different elevation changes in the pipeline that happen as well as the pressure drop that occurs on the pipeline.

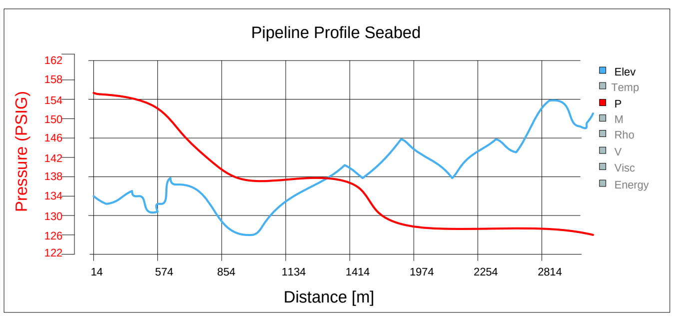


Here we can see that at the platform gathering station it is

supposed to have a pressure of 150 PSIG and that is what the pipeline was designed for. In the theoretical view it looks like the flow and pressure match up correctly to what the end user was expecting at the end of the pipeline. Now the next step is to introduce our sand detection to the pipeline and use our sand interaction that we set up in the scientific foundation section.
In our Sand Management Case the initial info we need to fill in the average sand particle density, the average sand particle diameter, and the erosional velocity.

Description	Value	Unit
Average Sand Particle Density	2500	kg/m^3
Average Sand Particle Diameter	300	µm
Erosion Velocity Empirical Constant	122	

The Erosion Velocity Empirical Constant is a recommendation from API and ISO recommend values (see API 14E and ISO 13703). Using the sand velocity in our simulation we can see that the sand deposition occurs really at the drop point going from Platform 1 to the seabed and it collects at the riser point going up to Platform 2. The pressure changes from the first pipeline profile to the second pipeline profile shows based on the elevation change where sand influences the pressure and also on the flow of the pipeline.



Having the sand deposition also comes with sand flowing through the pipeline. When sand is flowing through the pipeline it can damage the interior of the pipeline and cause erosion on the inside of the pipeline causing the pipeline to have a shorter lifespan. When the sand velocity hits a certain point then it erodes the inside of the pipeline, but if the fluid is slowed down then congealing is a large concern when the pipeline is under the water causing the end user to have a small operational range where oil can flow naturally and not cause damage to the pipeline.

CONCLUSIONS

Based on the results of the case study, the described modeling and simulation techniques effectively detect sand deposition in real time in pipelines with multiphase flow. Sand deposition events were detected and confirmed by being able to compare the pressure loss that is happening in the system from a theoretical stand point and from comparing the simulation to the live pressure that is happening in the pipeline. It was noted that when sand deposition happens the sand velocity cannot reach a certain limit because of the possible damage to the inside of the pipeline.

REFERENCES

1. TJ Danielson, Proceedings of the Offshore Technology Conference, Houston, USA, OTC 18691 (2007)
2. P. Doron, D. Garnicia, D. Barnea, International Journalism Multiphase Flow 13, 4, 535-547 (1987)
3. API RP 14E: Recommend Practice for Design and Installation of Offshore Production Platform Piping Systems, 1991.

AUTHOR BIOGRAPHY

Dr. Daniel P. Theis is a software engineer working at Statistics & Control, Inc. He has a Bachelor of Science in Chemistry from Bethel College, a Master of Science in Physical Chemistry from the University of Minnesota, and a Doctorate in Computational Chemistry from the University of North Dakota. Daniel has over 10 years of experience in the development and use of computer software designed to predict the properties and behavior of complex chemical systems.

John Hooker is a systems engineer and the *OptiRamp* group manager at Statistics & Control, Inc. He has a Bachelor of Science in Aerospace Engineering from Iowa State University. Over the past 7.5 years, John has participated in several global projects in the oil & gas and power generation sectors and has implemented numerous applications for control solutions, equipment monitoring, design testing, data analysis, and brownfield optimization.