Question 61: In your experience, what is the effect of crude oil compatibility on crude unit preheat exchanger fouling? Are there any correlations used to predict fouling?

Doug Meyne (Champion)

Since there are only isolated instances of fouling in the “cold train” exchangers prior to the desalter(s), we will assume this question is directed more towards the “hot train” exchangers.

First, it needs to be understood that inorganics can provide a “substrate” for organic material to bind to and accelerate agglomeration. At higher temperatures, inorganics can also add a mild catalytic effect to condensation, i.e., dehydrogenation. If deposits show >10% ash, it’s an indication that inorganics may be playing more than a simple passive role. Better removal of solids at the desalter can have a strong impact on preheat fouling, to the extent of virtually eliminating it all together. That being said, an otherwise compatible blend could still foul the preheat train if the desalter isn’t doing a good enough job removing solids.

For the most part, preheat fouling is caused by asphaltene precipitation. At lower temperatures the asphaltene isn’t prone to stick (adsorb) onto equipment surfaces as long as sufficient velocity (>~5 fps) is maintained. A significant amount of literature and research suggests that asphaltene precipitation increases with temperature up to a limit, and then the asphaltene precipitation decreases. Although this temperature varies from unit to unit and with different crude blends, it usually happens in the 400 Deg F range. As the oil heats up, asphaltenes that have fallen out of solution can be resolubilized, but the time it takes them to go back into solution is longer than the preheat time. When encountering hot tubes, the asphaltenes become tacky and will adsorb onto them.

Some crudes can be considered to be “self-incompatible” in a crude unit if they can precipitate asphaltenes by themselves. This situation is rare but can happen. One of the concerns coming out of Canada today is the lack of a good standard for the diluents used in a DilBit. Lighter aliphatic diluents (C7-) at % levels are known to precipitate asphaltenes, but as the weight of the aliphatic increases, so does solubility of the asphaltene. However, in the preheat train as the temperature rises and the density of the diluent decreases, there could be some non-linear effect that could aggravate precipitation. Under this circumstance, this would be a “self-incompatible” crude. Diluent variability can make this hard to diagnose.

The “Dead” oils used in refining, those that have had oilfield gases removed, aren’t as susceptible to pressure variation as “live oils” that will “flash” oilfield gases at a pressure drop. This reduction in pressure and increase in gas is known to cause asphaltene precipitation in production. With insufficient backpressure on a hot oil in a crude preheat, an otherwise stable oil could experience a similar effect in the hotter exchangers. This would then also be a considered a “self-incompatible” crude.

One indication of the precipitation potential of asphaltenes is to run standard SARA (Saturates, Aromatics, Resins, and Asphaltenes) testing on each crude slate. As a rule of thumb, higher aromatics and resins decrease asphaltene precipitation and higher saturates and asphaltenes increase asphaltene precipitation.

There is not agreement in the industry as to the effect of temperature on asphaltene solubility. Some data suggests the solubility is improved with higher temperature, whereas other data suggests higher temperature causes the stabilizing resins to be pulled away from the asphaltenes. Regardless, if an asphaltene precipitates at some lower temperature but doesn't adsorb onto a tube surface, and if it could resolubilize into the oil, the time necessary to go back into solution is longer than the residence time available in a preheat. Inevitably the insoluble asphaltenes will adsorb (stick) onto hot tubes. Once that happens, at the higher temperatures, the asphaltenes and any still-associated resins will begin the process of dehydrogenating to coke, which cannot be resolubilized.

Different types of flocculation tests can be done, using varying ratios of heptane/toluene to provide a relative scale for the precipitation potential for any given sample of crude oil or crude oil blend. Similarly, the same tests can be used on blends of various crude oils. Since one crude oil may have a low asphaltene and resin content, and another may be rich in resins but with a different asphaltene structure, size and morphology, interpolating their values to determine the potential for fouling can't be done linearly. However, Irwin Wiehe with Soluble Solutions out of Gladstone, NJ, has published, with some authority, a procedure for testing individual crudes and predicting the precipitation potential of their blends.

Jim Johnson (Marathon Petroleum)

One of our refineries has experienced serious problems with oil and solids undercarry while processing bitumen crudes along with some asphalt destabilization due to mixing lighter paraffinic crudes with very heavy crudes. Increased fouling was observed in the pre-heat circuit during these episodes, however due to the effect on the wastewater treatment plant we were not able to assess the contribution of crude compatibility to the observed fouling. Efforts were concentrated on attacking the effect on the desalter operation. Marathon is a member of the Canadian Crude Quality Technical Association and through that group we understand that there are no correlations currently available that reliably predict fouling. The CCQTA is currently embarking on a project to better assess crude compatibility and one of the deliverables is to develop a fouling correlation.

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