Question 29: What level measurement technology is used in the hydrotreater high-pressureseparator? Is the recommendation different if the unit runs in block modes (with feeds of varying densities)? What design considerations should be taken into account when selecting a high-pressure separator level control valve?

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Level Measurement

Like any instrumentation, there are advantages and disadvantages for different types of instrumentation in almost any service; therefore, there is no single choice of a Best Practice in all situations. Experiences vary from refiner to refiner, and even sometimes from unit to unit within a refinery depending on many factors, both technical and non-technical. It is important to understand the choices within both contexts. As the non-technical factors –such as instrument technician experience, refinery standards, etc. –are too general, they will not be addressed directly.

From a technical perspective, there are multiple types of level instruments that can be used in a high-pressure separator.

1.Displacer level instruments are an old technology and are rarely specified today for straight level measurement. They are subject to maintenance issues, depending on the material and operating changes, and can have mechanical issues with the displacer.

Displacers are calibrated/configured for a specific liquid density; and as such, if the density changes, they will not indicate the level accurately, except at 0 percent: the further away from the liquid design density, the greater the error of indication. Additionally, in high-pressure services, the vapor density may become a factor and the service can behave more like an ‘interface level’ instrument as opposed to a straight ‘level’ instrument. In this case, the vapor density should be considered as part of the level calculation and displacer configuration/calibration.

Displacers are still utilized in interface level service (water accumulator between the water phase and the hydrocarbon phase). Depending on how dirty the water phase/hydrocarbon phase is, however, the mechanical issues with the displacer element ‘sticking’ can become problematic. If the level range is small and the service relatively clean, a displacer can be a good choice in this area. A calibration procedure at service pressure should be developed and executed, as interface level displacers are particularly subject to calibration shifts, away from common wet calibrations performed at atmospheric pressure.

2.Differential pressure transmitters are also an older technology, but they are relatively inexpensive and can be effective as long as they are configured and maintained properly. Characterized “Smart” dP transmitters are very easy to set up and maintain and easy to reconfigure for the case of changing liquid densities. Like displacer instruments, they are configured for a specific liquid density; and as such, if the density changes, they will not indicate the level accurately: the further away from the liquid design density, the greater the error of indication. Also, like displacers, in high-pressure services, the vapor density may become a factor and the vapor density should be considered as part of the level calculation and dP configuration/calibration.

The most significant issue for dP transmitters being set up for level measurement in a pressurized vessel is the “reference leg” connection to the vessel above the liquid level. This “wet” leg needs to be filled with a fluid of a known density. Common fill liquids are 100% glycol and 50/50 glycol/water mixture. Over time, due to various reasons (leaks, process upsets, unit depressures, maintenance mistakes), this fill fluid can become missing and/or displaced with process and the resulting density change results in a measurement error.

For a fouling service or service with very heavy liquid with a high viscosity, capillary seals would generally be recommended for dPlevel transmitters. Capillary seals also address the filled “wet” leg issues listed above, since the seal liquid is not subject to liquid displacement, unless the seals are damaged. Capillary seals are very effective when installed properly but are expensive and fragile and if damaged, require factory repair. They are also subject to thermal expansion from variations in ambient temperature (i.e., one leg in the sun and the other leg in the shade), but this variation is typically less significant than the issues that come with “wet”legs. Installation of capillary seals should include “calibration rings” between the capillary flange and the piping isolation valve. These are necessary to enable checking functionality of the transmitter without the very difficult effort of disconnecting and removal of the capillary pancake/flange.

Both wet leg dPtransmitters and connections to capillary seals need to be heat-traced, especially if there is the potential for hydrates in the service. If hydrates are a potential, the heat-tracing must bevery thorough and cover all points of the process connections. Even seemingly insignificant gaps in tracing and insulation on piping and/or impulse line tubing have resulted in process connection freezes, totally erroneous level measurement signals, and resulting process upsets.

In an interface level service, a differential pressure instrument can be effective, but the differential range required may be very small depending on the density difference between the water phase and the hydrocarbon phase. If the process density difference is small, reference leg density errors (either wet leg or capillary seals) can be very significant, relative to the configured range of the transmitter. For this reason, using dPtransmitters for interface measurement needs special attention paid to the reference leg design in order to stabilize the reference leg density.

3.Magnetic level gauges have been almost entirely replacing glass level gauges over the past 20 years. Once the decision has been made to install a magnetic level gauge, the incremental cost of an integral transmitter is essentially insignificant, compared to the total installed cost of the magnetic level gauge itself. Due to the small additional cost of the transmitter, magnetic level transmitters can make a good secondary “diverse” measurement transmitter. Magnetic level transmitters use actual floats, so they are less susceptible to changing liquid densities than displacers or dPtransmitters, as long as the liquid density is adequate to keep the float from sinking. Magnetic level gauges (hence, the transmitters) are subject to sticking in fouling service. The technology used to monitor and transmit the float position is not as straightforward as a simple displacer or dPtransmitter.

4.Guided wave radar instruments are gaining popularity. They can require more initial setup attention than a differential pressure transmitter and can be more difficult to troubleshoot, thereby requiring special equipment/software. Often a manufacturer’s representative is needed to optimize the application. The benefit is that when guided-wave transmitters have been set up properly and there is an adequate difference in the dielectric constant between the liquid and vapor phases, they have proven very effective. For some existing troublesome level measurement applications, guided-wave transmitters have been applied. Good success has been observed when there has been dedicated case-by-case application engineering. An additional benefit to guided-wave radar is that their measurement is not subject to changes in liquid or vapor density as they measure the exact liquid-vapor interface (the change in dielectric constant). Fouling can be a problem for these instruments if the liquid has the potential to leave a ‘coating’ on the instrument probe. There is some concern regarding reliability of these instruments.

Guided wave radar instruments are being used for interface level applications as the dielectric constant between hydrocarbon and water is typically quite high. The interface needs to be well defined as it is difficult to anticipate how an emulsion or “rag layer” will be interpreted by the instrument. As with straight level measurement, case-by-case setup is often the key to success for interface measurement with guided-waveradar instruments.

Because guided-wave radar is less common at many locations, the non-technical factors –such as instrument technician training, operations comfort, and general aversion to new technologies –must be considered.

While there are other technologies available that are more exotic and more expensive, the four listed above are the most reasonable choices for cost, reliability, and commonality.

For the letdown control valve from either the hydrocarbon liquid and/or water boot, several factors need to be considered:

1.This service typically has a very high-pressure drop such that a multiple-stage or angle-type control valve body would be most appropriate.

2.If there is potential for fouling, particulates, or chunks of solids in the material, the valve vendor must be made aware of this potential. If the pressure drop is driving a multiple stage-type valve selection, it will require specialized trim that has holes/channels large enough to pass the solids.

3.There is typically significant off-gassing across the hydrocarbon control valve that must be considered in the sizing calculation and the valve design.

4.The actuator sizing must be robust enough to handle the required shutoff pressure, and flow-to-open versus flow-to-close configuration must be considered in the actuator sizing.

5.The usual considerations for corrosion must also be considered as these services, especially the sour water service, which may be prone to NH4HS (ammonium hydrosulfide) or chloride corrosion depending on the expected composition of the water.

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