Tube rupture in a natural gas heater

Dynamic simulation supports the use of a pressure safety valve over a rupture disk in the event of a tube rupture

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A fast pressure surge will occur during the tube rupture of a shell and tube exchanger, where a big pressure difference exists between the tube (high pressure) and shell (low pressure) sides. The pressure rise can be so fast that a conventional pressure safety valve (PSV) may not be able to open properly to accommodate the pressure surge. Dynamic simulation of tube ruptures in a shell and tube exchanger generates the time related pressure and temperature profile for the exchanger when the rupture happens. The results can provide a solid basis for process design, whereby whether or not a rupture disk should be used instead of a PSV if the pressure rise is too quick for the PSV to open. A dynamic simulation for tube rupture analysis of a natural gas heater is conducted in this study. The heater is a shell and tube exchanger, which utilises low pressure steam (shell side) to heat the tube side high pressure natural gas (113 barg). A detailed Hysys simulation model was built to reflect the external and internal configurations of the exchanger.

A tube rupture scenario was set up by assuming one full bore rupture at the back side of the tube sheet (per API Std 521 – 5.19.3). The dynamic simulation model was validated with the heat and material balance before running the case scenarios. The pressure and temperature profile, as well as the relief load, were recorded versus time during the event. The results support the process design of a spring loaded PSV as a means of protection of heat exchanger shell side instead of the rupture disk, in the case of tube rupture of the natural gas heater.

Shell and tube exchangers are widely used in the oil, gas, and petrochemical industries. Depending on the application, the tube side fluid pressure can be significantly different from the shell side pressure. According to ASME Sec. VIII Div. 1, a vessel has to be hydrotested at 130% of its maximum allowable working pressure.[1] This would allow for design pressure excursion by 130%, hence the 10/13th rule. Based on this requirement, if the design pressure of the low pressure side is inside the envelope of 10/13th of the high pressure side, no extra protection on the low pressure side is warranted. For systems where the low pressure side is below the 10/13th criteria, the tube rupture scenario can be mitigated by increasing the design pressure of the low pressure exchanger side, and/or assuring that an open flow path can pass the tube rupture flow without exceeding the stipulated pressure, and/or providing pressure relief (API Std 521[2]). However, for a heat exchanger with a large pressure difference between the high pressure and low pressure side, increasing the low pressure side's design pressure can be expensive and evaluation of a tube rupture scenario is required.

When a tube rupture occurs within a heat exchanger, high pressure fluid expands into the low pressure side through the ruptured tube bore and creates a pressure surge on the low pressure side. Depending on the nature of the fluids on both

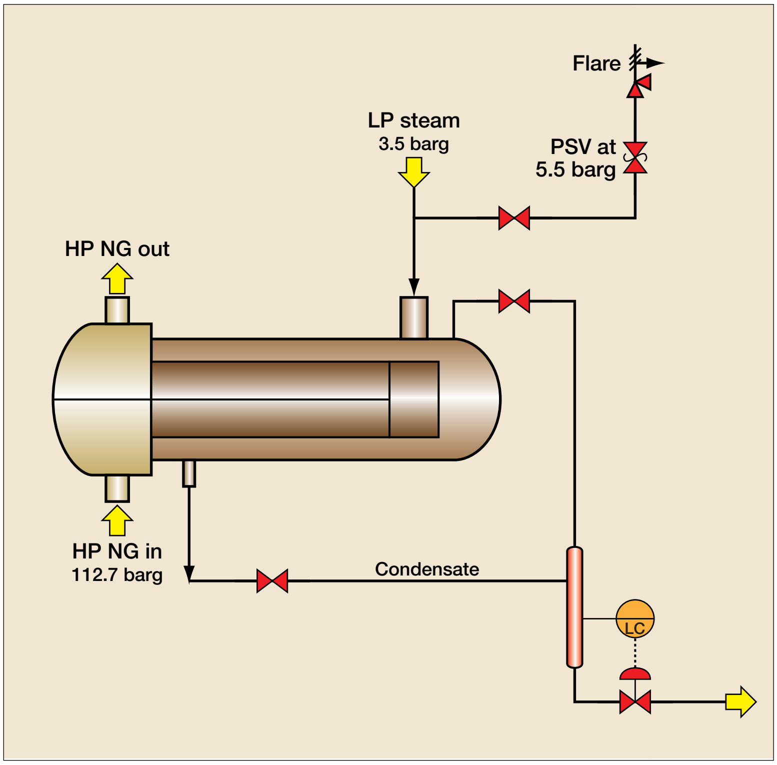

Figure 1 Systematic sketch of a natural gas heater

sides, the pressure surge on the low pressure side can be instantaneous. When both tube and shell sides are in liquid service, the pressure surge is faster than the response time for a PSV to open so that a rupture disk has to be installed.[3] From an operation and maintenance point of view, it is less desirable to use rupture discs for a service since rupture disks require more maintenance and the relief is also uncontrollable once it is broken. However, when both shell and tube sides are in vapour service, a PSV might have enough response time to react to the pressure surge caused by tube rupture, considering the compressibility of vapour.

This study will demonstrate such a case by dynamic simulation, where the high pressure natural gas in the tube side is heated by low pressure steam on the shell side. The dynamic simulation will capture the pressure rise profile over time, which provides a solid basis to support the installation of a PSV instead of a rupture disk for a tube rupture scenario in a natural gas heater.

System description and model setup

The system studied here is a typical natural gas heater in the inlet line of a LNG plant. The heat exchanger is a TEMA BEU type exchanger with high pressure natural gas passing through the tube side and low pressure steam condensing on the shell side. High pressure natural gas enters the tubes at 112.7 barg and 3.2°C, and leaves the exchanger at 80°C. Low pressure steam condenses on the shell side at 3.5 barg and 147°C. The exchanger operates under no-flooding condition. The condensate is drained to a condensate pot and leaves the system on level control (see **Figure 1**). The intended exchanger configuration includes a PSV (6R8) with a set pressure of 5.5 barg installed on the steam inlet line.

The BEU heat exchanger is the ideal choice for heating low fouling fluids like natural gas. The U-Tube bundle is attached to a single tube sheet, allowing the tubes to expand and contract freely under the influence of temperature variations. The tube bundle is removable and allows cleaning of the outside surfaces of the tubes. Lateral baffles are inserted to provide sufficient residence time for segmental heating. The steam flows horizontally from one segment to the next. The studied exchanger has eight baffles, which separate the shell side into nine horizontal sections (see **Figure 2**).

The shell side of the exchanger is modelled as nine separate vapour sections to match the baffled shell segments of the exchanger design. These vapour sections are modelled as horizontal cylinders in the dynamic model. The segment length matches the distance between two baffles, and the segment diameter is calculated based on the total shell side volume. The heating steam is assumed to be evenly condensed as it passes through the nine baffled segments of the shell. The steam may condense unevenly as it passes through each segment. However, the impact of condensing load distribution on tube rupture simulation is insignificant since the heat exchanger operates under no-flooding condition. The condensed steam is removed from each segment by using flow controllers to simulate the operation of the exchanger in a no-flood condition, with the condensate being routed to the condensate pot.

A control valve set to 100% open is used to simulate the tube rupture event. The valve is sized to allow the maximum (choked) flow from the high pressure tube side into the low pressure shell side. The maximum flow is calculated from an assumed orifice. The orifice has the equivalent open area that is twice the internal cross-sectional area of one tube to allow for the entrance of the high pressure fluid through a single tube rupture (per API STD 521 - 5.19.3).

Tube rupture dynamic runs and simulation results

The dynamic simulation model is tuned to match the steady state simulation results before running the tube rupture scenario. Once the dynamic simulation reaches the steady state condition and consistent results have been established (key operating parameters become constant with time), an event scheduler is initiated to run the tube rupture case. The tube rupture case considers a sharp break in one tube and the tube rupture is assumed to occur at the back side of the tubesheet (API Std 521 – 5.19.3).

The following tube rupture assumptions are programmed into the event scheduler:

a) One tube ruptures at one second integration time.

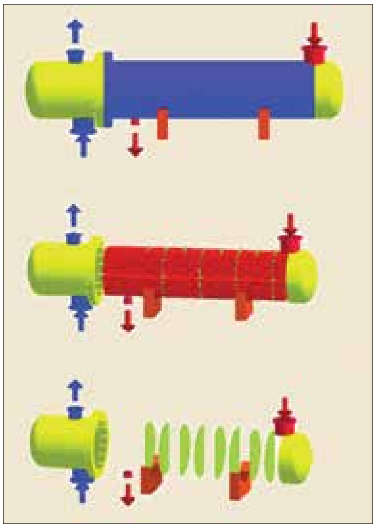

Figure 2 3D depiction of a BEU exchanger configuration

b) All flow control valves for diverting segmental flow stay in position when the tube rupture happens (assume the steam passing across the shell side with the same flow pattern as normal).

c) Back flow of the high pressure natural gas to steam is not allowed when the shell pressure reaches the steam supply pressure and, therefore, steam flow is stopped at this condition. This is a conservative approach for PSV relief load calculation.

The dynamic simulation integrates in one millisecond intervals to record the pressure waves. The simulation runs until a stable relief load and relief pressure are reached. For this system, the stable relief load occurs at approximately 10 seconds.

The pressure profiles at the PSV inlet, as well as the exchanger shell inlet, midpoint, and outlet sections, are recorded with time to show the pressure surge of the tube rupture event. The mass relief load is also recorded together with the physical properties required for the PSV sizing. **Figure 3** shows the pressure profile of the PSV inlet and the mass relief load as a function of time from the onset of the tube rupture event. **Figure 4** illustrates the pressure profiles at the exchanger shell inlet, middle section, and outlet for the same tube rupture event.

As **Figures 3** and **4** show, tube rupture occurs at one second and the shell side pressure rises to 5.5 barg set point in 0.4 seconds. The PSV starts to open and the relief load increases gradually. The PSV opens fully in two seconds and

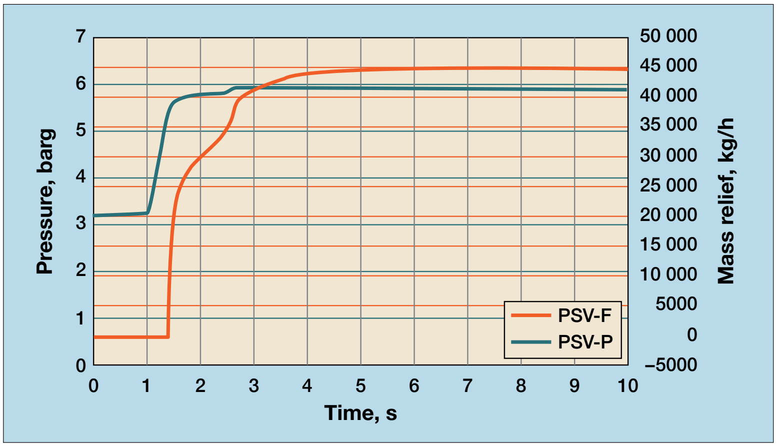

Figure 3 Pressure profiles at the PSV inlet and the mass relief load versus time

PSV performance by dynamic simulation

PSV performance	Pressure rise, bar	Time, sec	Rate, bar/s	Note
Dynamic pressure rising rate to set pressure	2.0	0.40	5.0	Pressure rises rapidly with the PSV closed
Dynamic pressure rising rate from set pressure to fully open with 10% over-pressure	0.55	2.0	0.28	Pressure rising is mitigated once the PSV starts to open
PSV open rate	0.55	0.1	5.5	Calculated from a typical PSV opening time

Table 1

the relief pressure and relief load have been stabilised. The recorded system pressure rising rate (surge) is 5.0 bar/s before the PSV starts to open. The rising rate drops to 0.28 bar/s once the PSV opens (see **Table 1**).

The opening time for a spring-loaded valve is between 50 and 100 milliseconds (API 521 HSE Report-023, 2002).[4] Single PSV installations, with non-fire relief scenarios, are designed to open fully with 10% over-pressure. The PSV opening rate is defined as the over-pressure divided by 0.1 seconds (assuming it takes 100 milliseconds to open).

For the tube rupture case in this study, the PSV opening rate is 5.5 bar/s, which is greater than the simulated pressure surge during the tube rupture. The result supports the engineering option of using a PSV instead of a rupture disk for over-pressure protection of the heat exchanger under study.

In the case studied here, the PSV is to be installed on the shell inlet piping, which is at the opposite end of the exchanger from the tube rupture. Depending on the piping arrangement and the configuration of the shell and tube exchanger, the pressure profile along the shell paths can be different. As **Figure 4** shows, the pressure profiles of the shell side near the rupture point (tube sheet), at the middle section, and at the shell side inlet are slightly different. The pressure profile at the shell inlet (where the PSV is installed) stays approximately 0.5 bar lower than the pressure profile of the middle section and near the tube sheet, where the tube rupture is assumed to occur. This suggests that an engineering margin (~10%) should be taken between the exchanger shell side design pressure and the PSV set pressure, to provide proper protection for shell side over pressure.

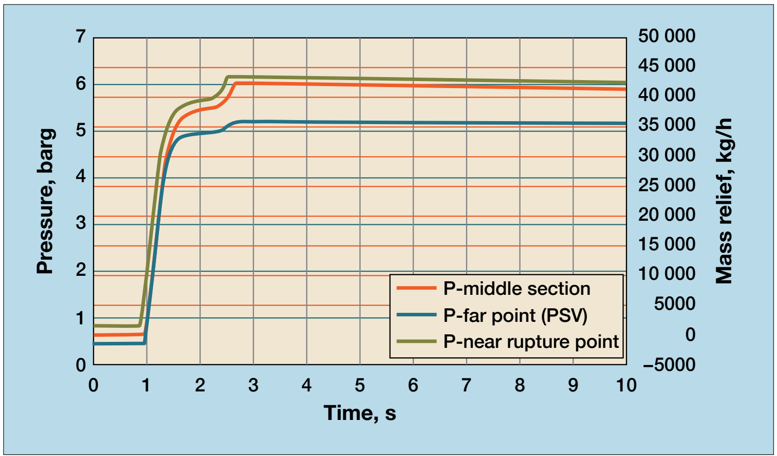

Figure 4 Shell side pressure profiles at different locations versus time

Conclusion

A dynamic simulation for the tube rupture analysis of a natural gas heater is conducted in this study. The heater is a shell and tube exchanger, which utilises low pressure steam (shell side) to heat high pressure natural gas (tube side – 112.7 barg). A detailed Hysys simulation model was built to represent the external and internal configurations of the exchanger. The tube rupture scenario was set up by assuming one full bore rupture at the back side of the tube sheet (per API Std 521 – 5.19.3). The pressure and temperature profile versus time, as well as the relief load, were recorded during the event. An immediate pressure surge was observed after the tube rupture. It takes approximately 0.4 seconds for the shell side pressure to reach the PSV set pressure. This pressure rise in the shell of the natural gas heater needs to be maintained within the 10% over-pressure limit allowed by code. The pressure response of this system, as determined by the dynamic simulation, requires the PSV to fully open within approximately two seconds to meet this criterion. A typical spring-loaded PSV with an expected opening time of 100 milliseconds is capable of meeting this requirement.

The study results support the process design: a spring-loaded PSV instead of a rupture disk can be used to protect the shell side of the exchanger in case of tube rupture in the natural gas heater.

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Reference

1 ASME Boiler and Pressure Vessel Code, Section VIII, Div. 1, 2008, UG 99(b).

2 *API Standard 521*, *Pressure Relieving and Depressuring Systems*, 6th Ed, Jan 2014.

3 *API Standard 520, Sizing, Selection, and Installation of Pressure Relieving Devices in Refineries Part I – Sizing and Selection*, 8th Ed, Dec 2008.

4 *API 521 HSE Report – Offshore Technology Report 023*, Testing and analysis of relief device opening times, prepared by PSI (Pipeline Simulation and Integrity) Ltd for the Health and Safety Executive, UK, 65, 2002.

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