All management systems and all safety techniques are useless unless the people using them have knowledge, experience, and ability.

Trevor Kletz, "By Accident… A Life Preventing Them in Industry"

The application of inherently safer design strategies (ISD) in Acid Gas Injection (AGI) Flare Systems

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INTRODUCTION

Pressure-relieving systems are required to be installed on process equipment, to prevent internal pressures from increasing to levels that could cause catastrophic equipment failure. They are intended to operate only in emergency situations, when a failure, accident, or mis-operation has caused an overpressure condition that the basic system design and its associated control systems cannot manage.

This article will make an attempt to be more direct, definitive, and highly specific regarding these systems, with emphasis on actual project examples. At the same time, generalization on the subject of pressure relief system design and ISD is unavoidable. The readers must recognize that pressure relief system design can be an extremely complex subject, and often requires that cost and complexity be balanced against safety and hazard assumption. There are many areas in pressure relief system design where there may be more than one approach or solution to a problem. Therefore, the pragmatic use of both engineering judgment and common sense is the recommended approach to pressure relief system design.

INHERENTLY SAFER DESIGN (ISD)

The American Institute of Chemical Engineers' Center for Chemical Process Safety (CCPS) defines the intent of Inherently Safer Design as "to eliminate the hazard completely, or reduce its magnitude sufficiently, to eliminate the need for elaborate safety systems and procedures. Furthermore, this hazard elimination or reduction would be accomplished by means that were inherent in the process, and thus permanent and inseparable from it".

However, it goes beyond elimination or reduction of a hazard. It also applies to layers of protection: "In the broad sense, the strength of a layer of protection can be improved by features that are permanent and inseparable from that layer".

The application of ISD strategies results in a smaller number of inherent hazards along with optimal capital investment, with a view to minimizing the risks for the lifecycle of a facility.

Kletz, IChemE and others proposed to use the following strategies for ISD:

- **Minimize** - use smaller quantities of harmful materials.
- **Substitute** - replace a material with a less hazardous substance.
- **Moderate** - use less hazardous conditions, a less hazardous form of a material, or facilities that minimize the impact of a release of hazardous material or energy.
- **Simplify** - design facilities that eliminate unnecessary complexity and make operating errors less likely, and that are forgiving of errors which are made.

The following categorized approach should be applied to risk reduction (in order of preference from 1 to 4):

1. Elimination - completely remove the hazard by choosing another design.
2. Prevention - minimize the likelihood and eliminate causes, if possible, to reduce the probability of the hazard from occurring (e.g. minimizing activities and thus the chance of human error).
3. Control - minimize the severity of an event, thus minimizing damage and the likelihood of escalation.
4. Mitigation - minimize the exposure of personnel and critical equipment to the effects of any initiating events, such as fires, explosions, or toxic releases.

ACID GAS INJECTION (AGI)

Waste gas from natural gas sweetening plants often contains high concentrations of hydrogen sulfide (H_2S) and carbon dioxide (CO_2). Downhole acid gas disposal schemes become a more feasible option by reducing the release of CO_2 and sulfur compounds to the atmosphere that result from combustion of acid gas vapors or sulfur recovery systems.

Acid gases (mixtures of CO_2 and H_2S), coupled with elevated injection pressures, present design, and operational challenges for overpressure protection systems in the following areas:

Toxic gas relief. Toxic components, including combustion reaction compounds (e.g. SO_2), shall be controlled below levels specified by applicable local and national standards.
Corrosive relief. Design engineers shall consider the impact(s) of corrosive entrained gases in disposal fluids. If H_2S, CO_2, or any corrosive compound is dissolved in water, the resulting liquid stream becomes very corrosive.
Low temperature relief and relief of materials with plugging tendencies. Due to the nature of the acid gases, depressurisation can cause very low temperatures (i.e. auto-refrigeration), which can form ice and/or hydrates that may plug the flare system or create the need for more expensive materials to avoid brittle fracture failures.

Pressure relief systems are emergency systems whose only function is to prevent internal pressures in process vessels and equipment from rising to levels which could cause severe damage or catastrophic failure. These systems are relied upon for ultimate protection when normal process system interlocks, controls, and operating practices have failed to maintain a process at safe conditions. In essence, they are intended to perform only when the operation of a process runs out of control, and equipment and personnel safety can only be maintained through emergency (and rapid) release of the process material. Operation of a pressure relief system may pose hazards in and of itself, but these hazards are usually overshadowed by the greater danger of continued and uncontrolled pressure build-up.

ISD STRATEGIES

Specific applications by the system design are grouped into following blocks:

- Reduction in the frequency and/or severity of flare relief discharges.
- Minimizing loss of product through relief valve action.
- Elimination of a particular relief scenario,

Reduction in the frequency and/or severity of flare relief discharges

The mechanical design pressure and temperature are normally set at some nominal amount above the maximum expected process conditions. Although the designer may not fully appreciate all the implications of the design condition selection, pressure relief system design starts with the selection of the pressure and temperature conditions that each piece of equipment will be designed to withstand. The choice of appropriate design margins involves both cost and safety considerations and should include a preliminary assessment of potential overpressure cases. Once equipment design pressures and temperatures are set, the basic pressure relief system requirements are also established.

It is important to ensure that equipment has a sufficient margin in its design to allow for normal and upset fluctuations in operating pressure, or to allow for a sufficient margin between operating pressure and the set pressure of pressure relief devices.

For example, PSVs within an AGI Compressor are installed upstream of the coolers, which allow acid gas (AG) to be relieved in the vapour phase into the flare system if PSV A is lifted (see Figure 1 below, where only the final stage of compression is shown). However, there is also PSV B, installed on the common discharge header/injection line, whose activation can potentially result in two-phase flow scenarios where slugs of acid gas may impact the mechanical integrity of the flare piping. Another potential consequence is considerable Joule-Thomson cooling at the point of pressure letdown, which can result in ice/hydrate formation inside the downstream relief piping and equipment. AGI system design needs to reduce the probability of the event where cold acid gas is relieved into the plant flare system.

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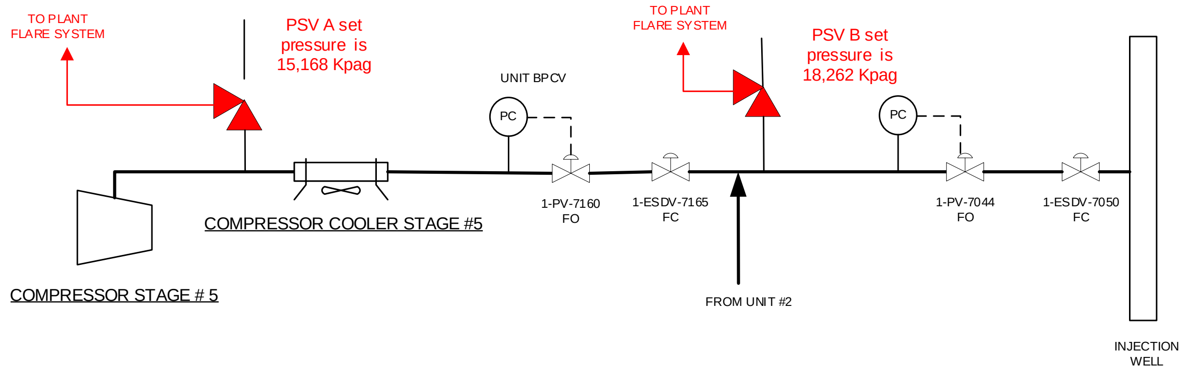

Figure 1: AGI System PSV Schematic

The design pressure/piping class for the common injection line was selected to be ANSI Class 1500#, while the piping class for the final stage of the AGI Compressor is ANSI Class 900#. The higher pressure rating for the injection system does not result in higher cost, due to the similar costs for small bore piping (up to 3" NPS), fittings, valves, and instrumentation for both piping class 900# and 1500#.

Figure 2 illustrates the normal discharge pressure of the Acid Gas Compressor (green bar) at 11,000 kPag. The Compressor PSV setpoint (yellow bar) at 15,168 kPag, and the high-pressure injection line PSV setpoint (orange bar) is 18,262 kPag. If there is a blockage along the injection line or at the injection wellhead, the proposed system configuration can eliminate or reduce the probability of overpressure incidents. Blockage of the injection system will likely result in lifting the Compressor vapour phase PSV first, relieving hot gas into the flare system and keeping the PSV on the injection line closed.

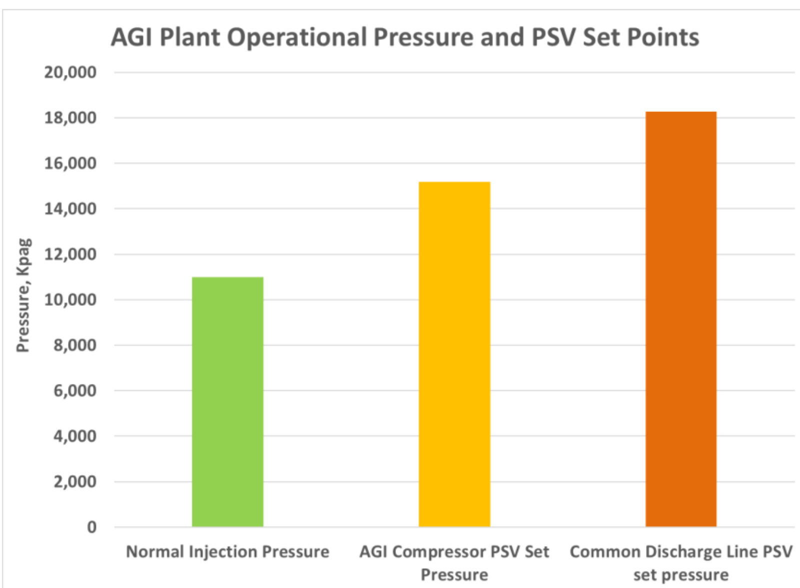

Figure 2: AGI System PSV setpoints

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Minimizing loss of product through relief valve action.

Emergency releases from process equipment into the flare system contribute to the loss of product, additional pollution, and potential regulatory non-compliance. Flaring acid and sour gas attracts the most regulatory attention; therefore, every attempt in the design shall be made to minimize the time of release or limit continuous flaring.

With few exceptions, positive displacement pumps and compressors require discharge pressure relief devices. Their set pressure is normally governed by the need to protect the outlet piping or downstream equipment. Subject only to power limitations, the pressure relief devices on positive displacement equipment are typically sized for full flow at maximum operating speed. However, on a recently completed AGI project in Alberta the design team decided to minimize/reduce flare events at the injection wellsite by directing the pressure relief stream back into a process. This allowed the wellsite flare system to be intentionally designed to handle only small reliefs associated with potential thermal expansion in the acid gas equipment and piping, along with maintenance blowdowns of the process equipment. This AGI project involved the design and installation of three (3) acid gas pipelines to deliver the acid gas stream (96% H_2S) to an injection wellsite located approximately 8 km from the processing plant, where it will be pumped into two (2) injection wells using positive displacement pumps.

Acid gases can potentially form solids (hydrates) when they are discharged through the relieving device, and currently "No uniformly accepted method has been established for reducing the possibility of plugging" (API 521 6 edition page 76). Mitigation measures to prevent hydrate formation in the flare system, as the result of a PSV lifting on an AGI line, would likely result in a rather complex relieving system: PSV, methanol injection, and/or electrical tracing would be required to ensure that fluids in the flare header will be above the hydrate formation temperature. The associated instrumentation to indicate relief system function, plus the capital and operational costs, may create greater hazards than the original emergency condition itself.

Two (2) options were considered for overpressure protection (OPP) of the discharge piping and discharge bottles of the pumps: 1) a conventional-type PSV relieving to flare, and 2) a pilot-operated PSV relieving to the common suction header.

<u>Conventional-type PSV</u>: PSV discharge is re-routed to the flare system. With stainless steel materials utilized for the flare sub-header, the flare system design would be able to address a short duration/low volume event of acid gas relief. Even though the individual pump discharge PSV will be sized for "blocked outlet" conditions, the PSV set pressure can be reached quickly with a blocked wellhead or process piping and AGI pumps running. Therefore, system safeguards may not react fast enough to prevent the PSV from lifting.

<u>Pilot-operated PSV:</u> PSV outlet is routed to the common suction header. Routing a pressure relief stream back into a process rather than to a disposal system may be the lowest-cost and safest alternative for many streams. This is particularly true of liquid streams ("dense phase" acid gas properties at both suction and discharge conditions resemble liquid behaviour). However, the decision to route a relief stream back into a process should address the considerations listed below.

Destination Pressure. The potential backpressure caused by the receiving process must be considered in sizing pressure relief devices, their operation, and their mechanical design limitations. For example, the AGI project design team proposed to use pilot-operated pressure safety valves (PSVs) with 1500# inlet and 600# outlet flanges. Figure 3 below shows a snapshot of the Pump Skid 3D Model with a pilot-operated PSV installed on the pump discharge line.

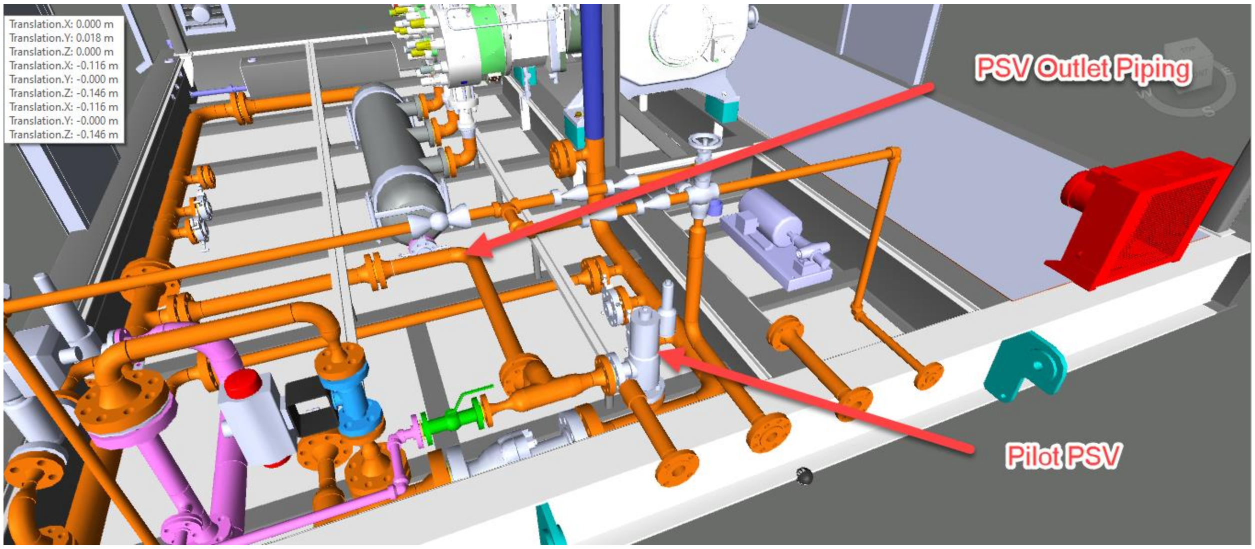

Figure 3: AGI Pump Pilot PSV

Temperature and pressure rise. If the pressure relief valve discharges back to the suction of the pump, an analysis should be performed to verify that the temperature and pressure of both the pump suction and process fluid do not exceed their maximum safe operating limits. Safeguards shall be in place to safely shut down equipment if the temperature limit is exceeded. Additional temperature transmitters were installed on both the suction and discharge piping to monitor the process temperatures within the pump system.

Elimination of a particular relief scenario

Gas Blowby. A typical water management system within a multi-stage AGI Compressor is accomplished with cascade dumps on suction scrubbers, where the higher-stage suction scrubber liquids are re-routed to the previous stage suction scrubber (e.g. Stage 5 scrubber liquids re-routed to the Stage 4 vessel, the Stage 4 liquids re-routed to the Stage 3 vessel, and so on). This proposed configuration allows the avoidance of "gas blowby" scenarios on all stages of compression. Stage 1 typically operates in the range of 48 – 69 kPag (7-10 psig), and any remaining liquids are typically pumped out to Sour Water Storage.

A typical cascade dump PFD is shown in Figure 4 below.

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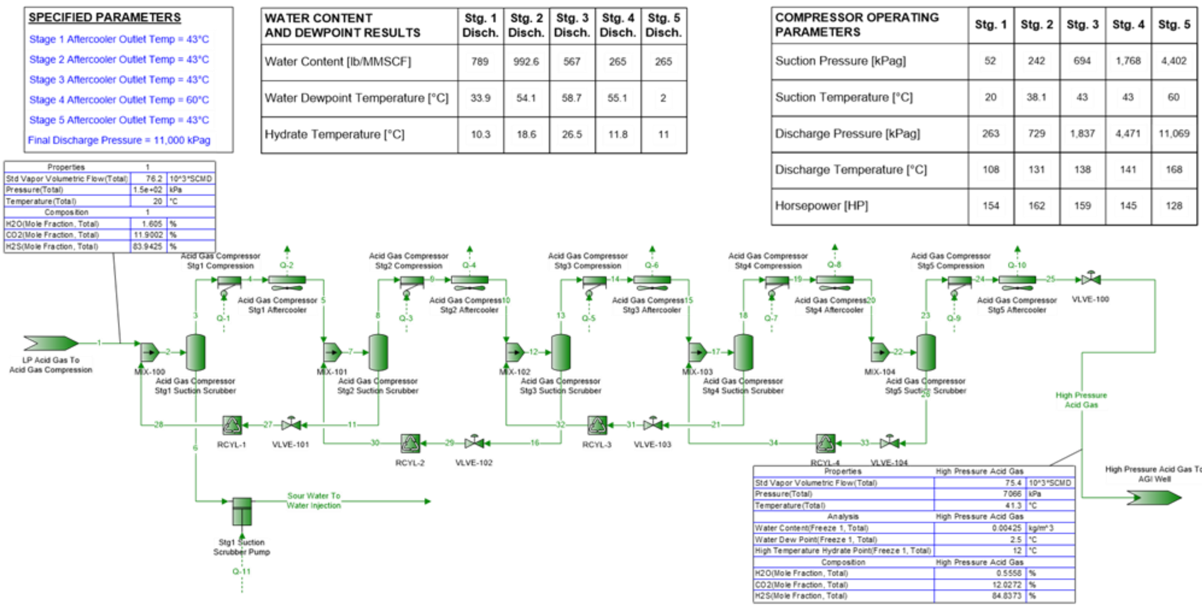

Figure 4: PFD of AGI Compressor Cascade Dumps

If a conventional water management arrangement is used, where individual vessels dump directly to the drain system, the design of the flare system shall then need to address the potential consequences associated with the release of low temperature fluid (e.g. low temperature embrittlement through auto-refrigeration, hydrate/ice formation in the flare system, etc.). It should be noted that relieving rates at high pressures can be considerable. The cascade system allows for a more controlled fluid rate.

Because the operating state of the dump valve(s) is uncertain, no credit is allowed for the favorable response of automatic controls, as discussed in API RP-521. However, it is permissible to take credit for the correct operation of SIL-rated Safety Instrumented Systems (SIS) systems in elimination of a particular relief or overpressure scenario. Therefore, to reduce the likelihood of the "gas blowby" scenario additional automated emergency valves are typically installed along with additional level instrumentation on the vessels.

For any credit to be taken, the SIS must be in operation during all operating modes (i.e. start-up, shutdown, and normal operation) when the relief scenarios could occur. The SIS must be SIL-rated at the appropriate level and undergo maintenance and testing consistent with the specified integrity level. Lifecycle economics should also be factored into the overall decision.

It should be noted that, compared to the installation of a cascade dump system, there are a number of obstacles with respect to pursuing protection by system design using SIL-rated components. For one, there is far more work involved in getting the system design approach documented and approved by both the Client and the local technical authorities. Secondly, a significant portion of the supporting documentation is not available until engineering has already reached an advanced stage. Finally,

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responsibility for the final decision rests with outside parties. Therefore, the likelihood of receiving an unfavorable result late in the project cycle is cause for considerable concern.

Shell & Tube Heat Exchanger Tube rupture

On a project for a Client in the Middle East, an Acid Gas Blowdown Heat Exchanger was included in the facility design to manage an Acid Gas Pipeline inventory maintenance depressurization. It was recommended to use the high-pressure (HP) side MAWP (maximum allowable working pressure) for the low-pressure (LP) side (process hot oil) to exclude a "tube rupture" relief case from consideration. To mitigate potential small leaks from the HP side to the LP side, the following features were proposed:

- Use low temperature (i.e. MDMT of -45 °C) seamless tubes.
- Use a shell and tube heat exchanger design configuration(s) with less vibration forces.
- Locating the exchanger in a relatively safe location, as well as orienting exchanger heads to minimize potential damage in the event of failure, are additional precautions to consider should a tube rupture occur.
- Rigorous maintenance program for the exchanger.

Design conditions of the Acid Gas Blowdown Heat Exchanger are provided below:

- ➢ Tube Side (Acid Gas): Carbon Steel (MDMT -45 °C), design pressure: 21,304 Kpag, design temperature: 230 °C. Piping Class 1500.
- ➢ Shell Side (Therminol 55): Carbon Steel (MDMT -45 °C), design pressure: 21,304 Kpag, design temperature: 230 °C. Piping Class 1500.

Even if the exchanger itself satisfies the design pressure criterion, tube failure can still occur, and the rest of the piping and equipment on the low-pressure side may need protection. There are also other potentially hazardous aspects of leakage/tube breakage, and subsequent mixing of the high- and low-pressure fluids, which cannot be addressed by overpressure protection measures alone. These risks associated with cross-contamination, corrosion, chemical reaction, etc., should be reviewed as part of the unit's Process Hazard Analysis.

If the Acid Gas Blowdown Heat Exchanger is to be used only to support the AGI Pipeline blowdown, it can potentially be isolated from both the plant heat medium system and the acid gas process piping during normal plant operation. This should greatly reduce the chances of potential contamination of the plant process heat system or standalone heat medium system from the acid gas piping and pipeline.

The provision of overpressure protection for the heat exchanger and associated pipework does not eliminate the need for a Process Hazard Analysis (i.e. HAZOP) to consider the wider process implications of any interstream leakage. There is a risk associated with potential contamination of the plant process hot oil system, as well as potential exposure of the personnel to H_2S if small leaks occur from the HP side (Acid Gas) to the LP side (hot oil). This same risk exists for a closed-loop hot oil system (if a standalone system is selected), which will not result in plant-wide contamination, but the severity can still be high.

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Therefore, suitable lower-cost alternatives to the shell and tube exchanger design should be considered, such as compact and lighter types of heat exchangers (e.g. double-pipe and multi-tubular hairpin heat exchangers).

Because of their generally heavier construction, the breakage of mechanical components other than those made of gauge tubing is unlikely. For this reason, double-pipe heat exchangers are not considered susceptible to tube breakage, as the inner pipe is considered equivalent in wall thickness to schedule pipe. API 521 Section 4.4.14.3 Double-pipe Heat Exchangers states: “it is not necessary to consider a complete tube rupture as requiring a provision for pressure relief.”

While directed mainly at the needs of new systems, similar measures to those described above may also be a cost-effective and safer approach for existing designs in lethal /toxic service.

Segregation of headers and hydrates mitigation strategies

Relief header design should eliminate hazards associated with mixing various relief streams in a common relief header.

Mixing of water-wet fluids with cold streams shall be evaluated to prevent ice/hydrate formation inside the downstream relief piping and equipment.

If water-wet streams and cold streams are relieved simultaneously, or if relief valves leak simultaneously, hydrate or ice formation may occur at or downstream of the mixing point and restrict or block the header. There have been instances in which relief systems were compromised (i.e. plugged or severely restricted) due to mixing cold and wet gases in a common header. This will, obviously, compromise a critical safety system.

An incident in which the freezing of fluids, along with liquid accumulation in knockout drums and low ambient temperatures, impaired relief system functionality is described in more detail below.

The ambient air temperature was near -30 °C, and it had been consistently cold for several days. There was a liquid level in the vertical Flare Knock Out Drum (FKOD) (Figure 5), and a small level in the horizontal FKOD (Figure 6).

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Figure 5: Vertical FKOD

Figure 6: Vertical FKOD

A pressure transmitter located on the piping between the vertical and horizontal FKOD registered a pressure rise to 30 kPa. Operations investigated and injected methanol into all of their key points. They started at the furthest injection point (closest to the flare stack) and injected for over one (1) hour. Methanol was then injected at the second injection point, and within five (5) minutes the pressure suddenly dropped. This location is at the top of the 45 Deg elbow piece (Figure 7).

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Figure 7: Flare piping between FKOD and Flare Stack

Similar incidents with gas plant flare system freezing have occurred before during cold weather, usually after a sustained temperature drop. Investigation that was done earlier in the year found that the flush water system, which uses produced water to purge the FKOD pump lines, had been backflowing into the horizontal FKOD, as seen by looking at the FKOD liquid level. Due to the condition of the produced water check valve integrity has been an issue, and despite many valve changes and replacements produced water has still leaked back to the FKOD.

The presence of produced water (PW) in the FKOD is undesirable in winter due to the possibility of water aspirating into the gas and forming hydrates, so Operations decided to isolate the pump suction from the horizontal FKOD.

It is hard to determine what factor(s) contributed the most to the flare header blockage. A list of possible causes can be seen below:

- Presence of water in the system.
- A large number of bends and direction changes in the flare piping.
- Low ambient conditions.
- Composition of the gas flared through the system at the time of the incident.
- The FKOD is fully traced and insulated, which may contribute to the formation of additional water vapors.
- The flare piping is steam-traced, but plant personnel mentioned having issues with the integrity of the existing steam-tracing system.

The design of flare system components must incorporate features required by Code or safety practices. Some features which should be incorporated into flare piping designs are described below:

- Bends and other fittings should be kept to a minimum. Where practical, long-radius bends should be used.
- Flare piping should avoid pockets.

- Water and hydrocarbons management: liquid levels in FKODs should be kept as low as practical.
- Heat tracing and insulation requirements for vessels and piping should be analyzed based on project requirements. Excessive heat addition to the vessel and/or piping may introduce more safety hazards as described above.

In applications involving existing systems, it may not always be practical to meet the same design and installation criteria as for new applications.

If any of the above is economically prohibitive, impractical, or unreliable, the designer should follow prudent professional engineering judgment to determine an approach or solution to a problem. At the same time, capital and operational costs and complexity must be balanced against safety and risk assumptions.

CONCLUSIONS

Acid gas applications pose certain challenges for the design of overpressure protection and relief systems. In the past, project/design decisions may have had greater focus on minimizing capital expenses (CAPEX) than on operating expenses (OPEX) over the full lifecycle. However, a focus on inherently safer design may increase CAPEX, but also decrease OPEX.

Finally, early project decisions should have the presence of major stakeholders (i.e. Engineering, Regulatory, and Operations) to ensure that the operational costs and complexities are considered.

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