This guide will take the reader through the typical operation of a gas processing plant, summarize the key applications, the commonly used solutions, and targeted applications for MRO upgrades or replacements.

Processing of natural gas is used to separate natural gas from other impurities to meet certain quality requirements such as heating value, moisture and other contaminants. There are many variations of natural gas processing plants that can include separation of liquids, water and contaminants such as sulfur and carbon dioxide.

What is a Natural Gas Processing Unit?

Natural gas fed into mainline gas transportation systems or used as the feed for natural gas liquids (NGL) recovery or liquefied natural gas (LNG) must meet specific quality measures. This is due to the fact that most natural gas contains contaminants that must be removed before the natural gas can be safely delivered for its intended use. Natural gas that is not within certain pressures, BTU content or moisture content can cause operational problems with downstream units or pipeline deterioration and potential failure.

The natural gas processing facilities consist of a number of different units, but all typically possess a receiving area, a treatment area, a dehydration unit, a sulfur recovery unit and discharge compression. While not discussed in this guide, natural gas processing units can also be combined with gas fractionation units that are used to separate specific natural gas liquids fractions.

Natural gas processing began in the early 1850s, but became more common in the 1920s as reliable pipe welding techniques were developed. With the development of plastics in the early 1950s, the demand for natural gas as an industrial feedstock and fuel grew dramatically.

Natural gas processing plants are classified by the input capacity of the plant by a MMcfd or MMcmd basis. The capacity of the plant can vary from as little as five (5) MMcfd to as great as 1500 MMcfd. The processing capacity will depend heavily upon the type and size of the equipment utilized. Similar to the scale up required in the plant’s processing units, the size of the valves will increase accordingly.

The United States and Canada have the largest installed base of natural gas processing units. There is over 250,000 MMcfd of natural gas processing capacity in the world with over 100,000 MMcfd split between these two countries. However, as the demand for LNG and NGL continues to rise, additional gas processing capacity will be developed. Unlike the units being installed in developing areas, most of the natural gas processing units in Canada and the U.S. have much lower capacities typically ranging from 50 MMcfd to 500 MMcfd.

Natural Gas Processing Facilities

Natural gas processing is a process in which natural gas and other components are separated from each other to produce natural gas that meets certain quality requirements in terms of BTU content, moisture, and other contaminants. The process can be rather complex as it can involve separation of liquids (oil and LPGs), water, and elements/compounds such as sulfur, helium, and carbon dioxide.

A typical natural gas processing facility consists of:

- Inlet receiving and/or compression
- Gas treating
- Sulfur removal
- Dehydration
- Hydrocarbon recovery
- Outlet compression

Figure 1 below shows the various processes in a natural gas processing unit. Each of the major processes and functions will be discussed in the subsequent text.
Inlet Gas Receiving and/or Compression

After production at the wellhead, the natural gas will undergo initial separation and will be compressed prior to arrival at the processing plant. At the inlet of the plant, an initial separator or slug catcher will be present depending upon plant design. The separator is designed to allow any condensate to fall out prior to further processing.

For smaller scale plants (100 MMcfd and less) and plants with feed gas that has received some initial separation, the presence of a large separator on the front end of the plant is common. In processing plants being fed directly from the well heads, it is more common to see large slug catchers that are designed to handle any amount of liquid produced at the wellhead.

No matter the type, the upstream separator is critical to the operation of the plant as it prevents the introduction of liquids in the downstream treatment process.

It is also possible that a compressor may be present after the initial separator to boost the gas pressure to the appropriate level for processing (300 to 1000 psig or 20 to 68 bar). However, in many cases, the gas is compressed before arriving at the plant.

Gas Treatment

The gas treatment unit is the heart of the processing plant. Gas treatment involves the reduction or elimination of acid gases in the flow stream. The most common contaminants removed are hydrogen sulfide (H₂S) and carbon dioxide (CO₂) and are commonly referred to as acid gases. There are other contaminants, such as Nitrogen and Helium that may be removed as well. It is necessary these components be removed as they can damage downstream piping and equipment, especially in the presence of water. If water is introduced into the system, the formation of weak acids is possible. These acids will corrode piping systems and any processing equipment.

Because of the additional demand for natural gas, new sources are being tapped around the world and higher prices are making the economics of producing sour gas fields more attractive. The sour gas fields contain a relatively high amount of H₂S that can be deadly, therefore, it must be removed from the natural gas before being transported for industrial or residential use.

There are a number of different means to remove acid gases from the flow streams. The most common is the use of solvent absorption that involves a combination of chemical and physical absorption methods. Other viable techniques include solid absorption, membrane, direct conversion, and cryogenic fractionation. There are two common ways solvent absorption removes acid gases from the flow stream: chemical absorption can reduce both H₂S and CO₂ to low levels while physical absorption can be selective between H₂S and CO₂. However, with physical absorption, meeting tight H₂S specifications can be more difficult. Because it’s used more commonly, focus will be placed upon solvent absorption techniques.

Amines are commonly used to remove the acid gases from the flow stream. This is accomplished by absorption of the acid gases in the liquid amine and the reaction of the slightly acidic dissolved gas reacting with the weakly basic amine derivatives. Commonly used amines used in gas treatment include monoethanolamine (MEA), diethanolamine (DEA) and methyldiethanolamine (MDEA). Each can be used to meet an outlet specification. For example, MEA is generally used when complete removal of H₂S and CO₂ is required. DEA is slightly less reactive than MEA, but can operate at higher acid gas loadings. MDEA can selectively remove H₂S to pipeline specifications, while not capturing all of the CO₂. It is likely,
however, that a combination of amines will be used to achieve the desired product.

In order to remove the acid gases, the sour gas enters the bottom of the absorption tower, more typically called a contactor, where the sour gas flows countercurrent to the lean amine solution that enters near the top of the tower. The inlet temperature of the amine is maintained at higher than the vapor leaving the top of the contactor to prevent condensation of heavy liquids. As a result, the majority of the reaction between the sour gas and the amine occurs near the bottom of the tower. The treated gas will then leave the contactor as a saturated gas still to be dehydrated (discussed below) while the rich amine (amine plus sour components) leaves the bottom of the tower.

After the rich amine leaves the bottom of the contactor, the acid gases must be separated from the amine. To begin initial separation, the rich amine enters a flash tank where the pressure is reduced to remove (flash off) any dissolved hydrocarbons. The gases removed can be used for fuel gas or subjected to additional treating to further remove any impurities. The additional treating process will be a smaller scale version of that previously discussed.

After initial flash off of the gases, the rich amine passes through the rich/lean amine exchanger and enters the solvent stripper. The solvent stripper uses low pressure steam to strip the acid gases away from the lean amine. The lean amine from the bottom of the stripper is then pumped back to the contactor, cooled in the rich/lean amine exchanger, and flows to the top of the contactor to repeat the process.

As previously noted, this process is extremely scalable and can be found in many gas processing units of varying sizes.

**Sulfur Recovery**

After removal from the gas in the primary contactor and downstream contacts, the H₂S must be properly disposed. Two methods commonly utilized include injection into underground formations, which in turn enhances product recovery by maintaining well pressure, and conversion to elemental sulfur. The majority of elemental sulfur produced is used in the production of sulfuric acid. Both technologies are commonly utilized, especially in areas with high sour gas content. This section, however, will be focused upon the recovery of element sulfur, as this is common in many large processing units.

The Claus process, or a modification of such, is the most common method of conversion of H₂S to elemental sulfur. There are several variations of the process, but all Claus units involve an initial combustion step in a furnace. The combustion products then pass through a series of catalytic converters. At the exit of the converters, the gas is condensed to remove the sulfur that is formed. The vapor leaving the condenser is at the sulfur dew point requiring reheating before passing to additional converters that may be present.

The residual tail gas can then be combusted or cleaned in a number of ways with the amine process commonly used. Whether the tail gas is combusted at this point or subjected to further cleaning is directly related to the environment restrictions at the plant.

**Dehydration**

The treated gas stream leaving the contactor must be dried to meet either pipeline or other production specifications. There are a number of approaches to removing any water from the gas, which will vary depending upon the downstream uses of the treated natural gas. The two methods of removal involve absorption or adsorption techniques.

The most commonly used method is absorption, where the natural gas stream is contacted with a liquid that preferentially absorbs water vapor. Glycols (ethylene glycol, diethylene glycol, and triethylene glycol) are most commonly used with triethylene glycol (TEG) being the choice for most applications. The use of TEG typically provides a natural gas product with less than 10 ppm of water vapor.

The adsorption approach utilizes molecular sieves that use solids with a high surface contact area. This approach, while more costly, does yield a greater degree of dehydration than can be achieved with absorbents. This process is typically seen in LNG and NGL cryogenic fractionation processes.

While there are some control valves used with molecular sieves (regeneration process), this section will focus upon the absorption technology.

In the glycol absorption process, the wet gas will pass through an inlet scrubber to remove any solids and free liquids from the process. At this point, the gas enters the bottom of the glycol contactor where the gas flows upward while the lean glycol flows down through the contactor. The lean glycol absorbs the water and leaves at the bottom of the tower while the dry gas exits at the top of the tower.

The rich glycol solution is then warmed and then goes to a flash tank where the dissolved gases (water) are flashed and removed. The solution is then further heated to remove any residual water vapor. Lean glycol is removed from the bottom of the boiler, cooled, and pumped back to the contactor to repeat the process.

**Hydrocarbon Recovery**

In any processing unit, the liquids separated from the gas in the process will be collected and can be used in a number of ways. Some facilities use the heavier hydrocarbons to modify the BTU content of the exiting natural gas stream to meet product specification requirements.
The most commonly used process to capture the liquids is to pass the treated gas through a turbo-expander or a Joule-Thompson (J-T) valve. The expansion process allows the liquids to fall out of the gas stream. Other processes include further separation in a de-methanizer or cryogenic fractionation to separate the liquid products into marketable liquefied petroleum gases (LPGs) such as propane and butane. This guide focuses on the main liquid recovery techniques using expansion/J-T solutions, but does not cover cryogenic fractionation.

Discharge Compression
After treatment, the natural gas will be compressed and injected into a high pressure gas distribution network at pressures ranging from 1200 to 1700 psig (82 to 117 bar). The gas will then be used for industrial or residential purposes.

Gas Processing Application Review
Depending upon the processing capacity of the plant, the number of control valves will vary between 50 for a smaller plant (100 MMcfd) and up to 300 for larger units (1000 MMcfd). The majority of the valves utilized will be Class 600 and less, but the sizes will vary from small to large constructions based upon the throughput capacity of the unit. The materials noted below are found in many processing plants, but given the greater emphasis on the development of sour gas fields globally, it may be possible to see a shift to high-nickel alloy materials.

Below is a summary of each of the key areas of the processing plant and the critical valves associated with each area. The typical service conditions and valve selections will be outlined.

Inlet Separation
From the wellhead and gathering systems, the raw natural gas will flow into the natural gas processing unit. Prior to treatment of the natural gas, any liquids and solids in the flow stream must be removed. This is accomplished via a large inlet separator or slug catcher. Figure 2 below shows the valves commonly associated with the inlet separation system.

1. Feed gas inlet pressure control valve
This valve controls the inlet pressure of the gas into the inlet separator. Pressure drop across the valve will be minimal, but the flows can be somewhat high depending upon the capacity of the plant. A large globe or ball valve is commonly used, but a high performance butterfly valve may be found in this application.

- Typical process conditions:
  - Fluid: natural gas
  - P1 = 300 - 1050 psig (20 - 72 bar)
  - P2 = 285 - 1035 psig (19 - 71 bar)
  - T = 20°F – 100°F (-6°C - 37°C)
  - W = 500,000 – 4,000,000 lb/hr

- Typical valve selection:
  - NPS 10 to NPS 30 EU/EW/V260/8532/8560/A31A/A11 Class 150/300/600
  - WCC-HT or 316 SST body and trim
  - Equal percentage characteristic
  - Class IV or V shutoff

What to look for:

Does the customer have a spare parts strategy for this valve?
- The reliability of this valve is absolutely critical. Any unexpected downtime with this valve will bring the operation of the entire plant to a halt.
- The customer should consider stocking spare parts or a spare assembly to minimize any unexpected downtime.

Is the customer familiar with the benefits of the FIELDVUE DVC6200 digital valve controller?
- Legacy valves in this application may have an older digital positioner or analog positioner installed.
- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.
- Online, in-service diagnostics are particularly valuable in this application to prevent unexpected maintenance needs and associated downtime.

Has the valve trim suffered erosion damage due to the presence of sand or other particulate in the feed gas?
- Consider upgrading to harder trim materials to prevent future erosion damage.

2. Inlet separator level control valve
This valve controls liquid level in the inlet separator. Depending upon the inlet pressure to the facility, this valve may experience high pressure drops. It is common to find...
multiple level valves on a given separator. A globe or angle valve with anti-cavitation trim is generally used in this application.

- Typical process conditions:
  - Fluid: natural gas liquids and/or water
  - P1 = 300 – 1050 psig (20 - 72 bar)
  - P2 = 50 – 400 psig (3 - 27 bar)
  - T = 20°F – 100°F (-6°C - 37°C)
  - W = 50 – 2000 lb/hr

- Typical valve selection:
  - NPS 1 or NPS 2 ET Class 150/300/600
  - WCC-HT or 316 SST body and trim
  - Cavitrol™ III trim anti-cavitation trim
  - Class V shutoff

**What to look for:**

_Has the trim suffered erosion damage due to sand or other solids in the separator liquids?_

- Upgrade to a NotchFlo™ valve construction or DST retrofit to prevent erosion damage.

_Is the customer familiar with the benefits of the FIELDVUE™ DVC6200 digital valve controller?_

- Legacy valves in this application may have an older digital positioner or analog positioner installed.
- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.

3. Heat exchanger temperature control valve

If a heat exchanger is present, this valve controls the flow of steam or other heat transfer fluids to the inlet heat exchanger, thus controlling outlet temperature of the feed gas. There is not a tremendous amount of heat added to the system, therefore, the valve sizes are not typically large. A globe valve is commonly utilized in this application.

- Typical process conditions:
  - Fluid: steam
  - P1 = 100 – 225 psig (6 - 15 bar)
  - P2 = 90 – 215 psig (6 - 14 bar)
  - T = 250°F – 350°F (121°C - 176°C)
  - W = 2000 – 25,000 lb/hr

- Typical valve selection:
  - NPS 2 to NPS 6 ET Class 150/300
  - WCC body and trim
  - Linear characteristic
  - Class IV or V shutoff

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*Figure 3. Gas treatment unit*
The gas treatment unit is the heart of the processing plant. Gas treatment involves the reduction or elimination of acid gases in the flowstream. The most common contaminants removed are hydrogen sulfide (H₂S) and carbon dioxide (CO₂) and are commonly referred to as acid gases. There are other contaminants such as Nitrogen and Helium that may be removed as well. Removal of these components is necessary as they can damage downstream piping and equipment, especially in the presence of water. If water is introduced into the system, the formation of weak acids is possible. They will corrode piping systems and additional processing equipment.

There are a number of different means to remove acid gases from the flow streams. The most common is the use of solvent absorption that involves a combination of chemical and physical absorption methods. Other viable techniques include solid absorption, membrane, direct conversion, and cryogenic fractionation. There are two common ways solvent absorption removes acid gases from the flow stream: chemical absorption can reduce both H₂S and CO₂ to low levels while physical absorption can be selective between H₂S and CO₂. However, with physical absorption, meeting tight H₂S specifications may be more difficult. Because of its common use, focus will be placed on solvent absorption techniques. Figure 3 above shows the layout of an amine treatment unit and the common control valves in the process.

1. Rich amine letdown control valve
This valve is used to control level in the bottom of the contactor. Given the low downstream pressure needed to drive off the gases, this valve can experience severe outgassing effects. As a result, the trim selection will vary depending on the pressure drop and the amount of gas entrained in the solution. While the recommendation below is commonly seen, it is important that each application be reviewed in detail to ensure proper valve selection.

- Typical process conditions:
  - Fluid: amine with entrained gases
  - P1 = 300 - 1020 psig (2 - 70 bar)
  - P2 = 20 – 120 psig (1 - 8 bar)
  - T = 100° F – 160° F (37°C - 71°C)
  - W = 20,000 – 4,200,000 lb/hr
- Typical valve selection:
  - NPS 1 to NPS 20 ET/EWT Class 150/300/600
  - WCC-HT or 316SST body and trim
  - Whisper Trim™ I, Whisper Trim III or NotchFlo™ DST trim
  - Class V shutoff

What to look for:
Is this valve experiencing vibration issues or trim damage?

2. Flash drum lean solvent control valve
This valve controls the flow of lean solvent into the flash drum. The introduction of lean solvent is used to facilitate the removal of the acid gases entrained in the rich amine. A small globe valve is typically used in this application.

- Typical process conditions:
  - Fluid: lean amine
  - P1 = 40 – 165 psig (2 - 165 bar)
  - P2 = 30 – 135 psig (2 - 9 bar)
  - T = 100°F – 120°F (37°C - 48°C)
  - W = 3000 – 55,000 lb/hr
- Typical valve selection:
  - NPS 1 to NPS 3 EZ/ET Class 150/300/600
  - WCC-HT body and trim
  - Linear characteristic
  - Class IV shutoff

3. Flash drum water control valve
This valve controls the flow of water to the flash drum, which in turn, helps to drive off the acid gases entrained in the rich amine. A small globe valve is commonly used in this application.
Typical process conditions:
- Fluid: water
- P1 = 40 – 165 psig (2 - 11 bar)
- P2 = 30 – 135 psig (2 - 9 bar)
- T = 90°F – 120°F (32°C - 48°C)
- W = 500 – 12,000 lb/hr

Typical valve selection:
- NPS 1 to NPS 2 EZ Class 150/300/600
- WCC-HT body and trim
- Equal percentage characteristic
- Class IV shutoff

4. Flash drum level control valve
This valve controls the liquid level in the flash drum. Similar to the rich amine letdown valve, this valve can experience varying degrees of outgassing. Therefore, it is necessary that each application is appropriately reviewed to determine the proper body and trim selection to handle the outgassing effects. This valve may be located downstream of the rich/lean amine exchanger, which can potentially lead to increased outgassing.

- Typical process conditions:
  - Fluid: rich amine
  - P1 = 30 – 135 psig (2 - 9 bar)
  - P2 = 20 – 60 psig (1 - 4 bar)
  - T = 90°F – 120°F (32°C - 48°C)
  - W = 500 – 12,000 lb/hr

- Typical valve selection:
  - NPS 4 to NPS 24 ET/EWT/FBT Class 150/300/600
  - WCC-HT or 316 SST body and trim
  - Whisper Trim I or Whisper Trim III
  - Class V shutoff

What to look for:

Has this valve experienced vibration issues or trim damage?
- This application encompasses many of the same challenges as the rich amine letdown valve, though generally not as severe.
- This valve is commonly undersized to handle the volume of gas, which outgasses from the amine solution. Vibration is a common result.
- Utilize Fisher global sales support to conduct a full application review and select an appropriate valve solution to address the outgassing that is occurring.

Has the customer experienced plugging issues with Whisper Trim I or Whisper Trim III in this valve due to the buildup of scale or other solids in the contactor bottoms?
- Upgrade to a NotchFlo valve construction or DST retrofit to prevent plugging issues.

Is the customer familiar with the benefits of the FIELDVUE DVC6200 digital valve controller?
- Legacy valves in this application may have an older digital positioner or analog positioner installed.
- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.
- Consider a Remote-Mount DVC6200 positioner if vibration is an issue.

5. Flash drum pressure control valve
This valve controls pressure in the flash drum, which is critical to driving off the acid gases entrained in the rich amine and to maintain pressure in the contactor. The sour gases driven off at this point will likely be subjected to additional processing. A globe valve with standard trim is generally used in this solution.

- Typical process conditions:
  - Fluid: sour gas
  - P1 = 30 – 105 psig (2 - 7 bar)
  - P2 = 20 – 90 psig (1 - 6 bar)
  - T = 90°F – 120°F (32°C - 48°C)
  - W = 500 – 11,000 lb/hr

- Typical Valve Selection:
  - NPS 2 to NPS 6 ET/EWT Class 150/300/600
  - WCC-HT or 316 SST body and trim
  - Linear characteristic
  - Class IV Shutoff

6. Flash gas to flare control valve
This valve controls flash gas to the flare header in the event of an upset in the process. It will normally remain closed during operation and can experience relatively substantial pressure drops. This may lead to high noise and vibration if not properly attenuated. A globe valve with Whisper Trim is commonly used in this application.

- Typical process conditions:
  - Fluid: sour gas
  - P1 = 30 – 105 psig (2 - 7 bar)
  - P2 = 5 – 15 psig (0.3 - 1 bar)
  - T = 90°F – 120°F (32°C - 48°C)
— W = 500 – 11,000 lb/hr
- Typical valve selection:
  — NPS 2 to NPS 6 ET/EWT Class 150/300/600
  — WCC-HT or 316 SST body and trim
  — Whisper Trim I or Whisper Trim III
  — Class V shutoff

What to look for:

Does this valve provide adequate shutoff during normal operation of the plant when the valve is closed?
- Leakage past the valve can lead to unwanted flaring.
- If leakage is excessive, consider upgrading to a Class V trim and actuator configuration.

Is the customer familiar with the benefits of the FIELDVUE DVC6200 digital valve controller?
- Legacy valves in this application may have an older digital positioner or analog positioner installed.
- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.

7. Lean amine booster pump recirculation control valve

If a booster pump is present, this valve bypasses flow around the lean amine booster pump to protect the pump from cavitation damage. Because of the high pressure drop across the valve, cavitation protection is required. A globe valve with Cavitrol III trim can typically be found in this application.

- Typical process conditions:
  — Fluid: Lean amine
  — P1 = 150 – 225 psig (10 - 15 bar)
  — P2 = 40 – 60 psig (2 - 4 bar)
  — T = 90°F – 120°F (32°C - 48°C)
  — W = 20,000 – 650,000 lb/hr
- Typical valve selection:
  — NPS 2 to NPS 8 ET/EWT/HPT Class 300/600/900
  — WCC-HT or 316 SST body and trim
  — Cavitrol III trim
  — Class V shutoff

What to look for:

Does the valve provide sufficient shutoff?
- Any leakage past this valve when it is closed will result in lower pump efficiency.
- If the valve was not originally specified with tight shutoff, offer an upgrade with trim and actuator to provide Class V shutoff.

Has the valve experienced cavitation damage?
- Upgrade to Cavitrol III trim if the valve was originally specified with standard trim.

Is the customer familiar with the benefits of the FIELDVUE DVC6200 digital valve controller?
- Legacy valves in this application may have an older digital positioner or analog positioner installed.
- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.

8. Lean amine main pump recirculation control valve

This valve bypasses flow around the main lean amine pump to protect the pump from cavitation damage. Because of the high pressure drop across the valve, cavitation protection is required. A globe valve with Cavitrol III trim is commonly used in this application.

- Typical process conditions:
  — Fluid: Lean amine
  — P1 = 400 – 1600 psig (27 - 110 bar)
  — P2 = 150 – 225 psig (10 - 15 bar)
  — T = 90° F – 120° F (32°C - 48°C)
  — W = 20,000 – 650,000 lb/hr
- Typical valve selection:
  — NPS 2 to NPS 8 ET/EWT/HPT Class 300/600/900
  — WCC-HT or 316 SST body and trim
  — Cavitrol III trim
  — Class V shutoff

What to look for:

Does the valve provide sufficient shutoff?
- Any leakage past this valve when it is closed will result in lower pump efficiency.
- If the valve was not originally specified with tight shutoff, offer an upgrade with trim and actuator to provide Class V shutoff.

Has the valve experienced cavitation damage?
- Upgrade to Cavitrol III trim if the valve was originally specified with standard trim.

Is the customer familiar with the benefits of the FIELDVUE DVC6200 digital valve controller?
- Legacy valves in this application may have an older digital positioner or analog positioner installed.
- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.

9. Lean amine to contactor control valve
This valve controls the flow of lean amine to the top of the contactor. Proper flow control is critical in this application to ensure the proper ratio of amine to gas coming into the contactor. A globe valve is typically utilized in this application.

- Typical process conditions:
  - Fluid: lean amine
  - P1 = 400 – 1600 psig (27 - 110 bar)
  - P2 = 350 – 1080 psig (24 - 74 bar)
  - T = 90°F – 120°F (32°C - 48°C)
  - W = 20,000 – 4,200,000 lb/hr
- Typical valve selection:
  - NPS 2 to NPS 20 ET/EWT Class 300/600/900
  - WCC-HT or 316 SST body and trim
  - Linear characteristic
  - Class IV shutoff

10. Lean gas to flare control valve
This valve controls the flow of lean gas to the flare header in the event of an upset in the process. It will remain closed during normal operation and can experience relatively high pressure drops that may lead to high noise and vibration if not properly attenuated. A globe valve with Whisper Trim is commonly used in this application.

- Typical process conditions:
  - Fluid: lean gas
  - P1 = 300 – 1020 psig (20 - 70 bar)
  - P2 = 30 – 45 psig (2 - 3 bar)
  - T = 110°F – 155°F (43°C - 68°C)
  - W = 500 – 5500 lb/hr
- Typical valve selection:
  - NPS 3 to NPS 24 ET/ES Class 300/600
  - WCC-HT or 316 SST body and trim
  - Linear or Cavitol III trim
  - Class V shutoff

What to look for:
Does the valve provide adequate shutoff during normal operation of the plant when the valve is closed?

- Any leakage past this valve can lead to unwanted flaring.
- If leakage is excessive, consider upgrading to a Class V trim and actuator configuration.

Is the customer familiar with the benefits of the FIELDVUE DVC6200 digital valve controller?

- Legacy valves in this application may have an older digital positioner or analog positioner installed.
- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.

11. Lean gas separator level control valve
Because the gas leaving the contactors is normally saturated, a downstream separator is used to capture any carry over liquids (hydrocarbons and water) prior to dehydration. This valve is utilized to control the liquid level in the separator. A small globe valve is typically used.

- Typical process conditions:
  - Fluid: liquid hydrocarbon
  - P1 = 300 – 1020 psig (20 - 70 bar)
  - P2 = 45 – 405 psig (3 - 27 bar)
  - T = 110°F – 155°F (43°C - 68°C)
  - W = 500 – 5500 lb/hr
- Typical valve selection:
  - NPS 1 to NPS 2 ET/ES Class 300/600
  - WCC-HT or 316 SST body and trim
  - Linear or Cavitol III trim
  - Class V shutoff

What to look for:
Has the valve experienced cavitation damage?
- If the valve was not originally specified with anti-cavitation trim, it may experience cavitation damage due to the large pressure drop across this valve.
- Upgrade to a Cavitol III cage if the hydrocarbon stream is free of particulate.
- Upgrade to a NotchFlo valve or DST retrofit if the hydrocarbon stream is suspected of containing particulate.

Is the customer familiar with the benefits of the FIELDVUE DVC6200 digital valve controller?

- Legacy valves in this application may have an older digital positioner or analog positioner installed.
- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.

What to look for:
Does the valve provide adequate shutoff during normal operation of the plant when the valve is closed?
12. Lean gas separator sour water letdown

Because the gas leaving the contactors is normally saturated, a downstream separator is used to capture any carry over liquids (hydrocarbons and water) prior to dehydration. This valve is utilized to control the liquid level in the separator. A small globe valve is generally used.

- Typical process conditions:
  - Fluid: sour water
  - $P_1 = 300 - 1020$ psig (20 - 70 bar)
  - $P_2 = 45 - 150$ psig (3 - 10 bar)
  - $T = 110^\circ F - 155^\circ F$ (43°C - 68°C)
  - $W = 500 - 5500$ lb/hr
- Typical valve selection:
  - NPS 1 to NPS 2 ET/ES Class 300/600
  - WCC-HT or 316 SST body and trim
  - Linear or Cavitrol III trim
  - Class V shutoff

What to look for:

Has the valve experienced cavitation damage?

- Legacy valves in this application may have an older digital positioner or analog positioner installed.
- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.

Gas Dehydration

After the initial treatment step, the gas needs to be dehydrated. As previously mentioned, the method of dehydration depends upon the type of plant and any additional processing that may occur. Figure 4 above shows the conventional method employing tri-ethylene glycol (TEG). The main valves associated with the system are those controlling the glycol solution into and out of the dehydration unit.

1. Lean glycol to glycol contactor control valve

This valve controls the flow of lean glycol from the glycol regeneration unit to the contactor. The glycol will enter the top of the contactor and, as it moves down the column, will strip the water from the gas stream flowing up through the bottom of the column. This valve may not be present if a variable speed pump is used. A globe valve is the most common solution for this application.

- Typical process conditions
  - Fluid: lean glycol
  - $P_1 = 600 - 1100$ psig (41 - 75 bar)
  - $P_2 = 500 - 900$ psig (34 - 62 bar)
  - $T = 100^\circ F - 125^\circ F$ (37°C - 51°C)
  - $Q = 10 - 250$ gpm
- Typical valve selection:
  - NPS 1 to NPS 3 EZ/ET Class 300
  - WCC body and trim
  - Equal percentage trim
  - Class IV shutoff

2. Gas dehydration inlet separator level control valve

The inlet separator is used to remove as much water and other liquids as possible prior to glycol dehydration. This valve controls the level in the separator. A globe valve is the most common solution for this application.

- Typical process conditions
  - Fluid: hydrocarbon condensate
  - $P_1 = 600 - 1100$ psig (41 - 75 bar)
  - $P_2 = 150 - 350$ psig (10 - 24 bar)
  - $T = 100^\circ F - 125^\circ F$ (37°C - 51°C)
  - $Q = 100 - 750$ gpm
- Typical valve selection:
  - NPS 1 to NPS 3 EZ or ET Class 300

Is the customer familiar with the benefits of the FIELDVUE DVC6200 digital valve controller?
3. Glycol contactor level control valve

This valve controls the glycol-water interface level in the glycol contactor. This valve will experience a relatively high pressure drop requiring anti-cavitation trim. A globe valve with Cavitrol III trim is typically used.

- Typical process conditions
  - Fluid: glycol / water mixture
  - P1 = 600 – 1050 psig (41 - 72 bar)
  - P2 = 30 – 200 psig (2 - 13 bar)
  - T = 100°F – 125°F (37°C - 51°C)
  - Q = 10 – 250 gpm
- Typical valve selection:
  - NPS 1 to NPS 3 ET Class 300/600
  - WCC body and trim
  - Cavitrol III trim
  - Class V shutoff

Tail Gas Treatment

The tail gas driven from the amine during regeneration must be further treated prior to sulfur recovery. The process is very similar to that previously discussed in the gas treatment section, but typically utilizes a different set of amine derivatives such as MDEA. Figure 5 below shows the tail gas treatment process and the commonly associated control valves.

1. Rich amine recirculation to acid gas enrichment control valve

This valve is used to bypass flow around the rich amine pump to prevent the pump from the potential for cavitation. This valve can experience relatively high pressure drops, thus increasing the potential for the formation of damaging cavitation. To eliminate the potential for cavitation, a globe valve with Cavitrol III trim is commonly used.

Figure 5. Tail gas treatment system
Typical process conditions:
- Fluid: rich amine
- \( P_1 = 75 – 135 \text{ psig} \) (5 - 9 bar)
- \( P_2 = 20 – 30 \text{ psig} \) (1 - 2 bar)
- \( T = 100°F - 140°F \) (37°C - 60°C)
- \( W = 20,000 – 1,000,000 \text{ lb/hr} \)

Typical valve selection:
- NPS 2 to NPS 8 ET/EWT Class 150/300
- WCC-HT or 316SST body and trim
- Cavitrol III trim
- Class V shutoff

What to look for:

What to look for:
Does the valve provide sufficient shutoff?
- Any leakage past this valve when it is closed will result in lower pump efficiency.
- If the valve was not originally specified with tight shutoff, offer an upgrade with trim and actuator to provide Class V shutoff.

Has the valve experienced cavitation damage?
- Upgrade to Cavitrol III trim if the valve was originally specified with standard trim.

Is the customer familiar with the benefits of the FIELDVUE DVC6200 digital valve controller?
- Legacy valves in this application may have an older digital positioner or analog positioner installed.
- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.

2. Regeneration lean amine pump recirculation control valve

This valve is used to bypass the lean amine from the bottom of the regeneration tower. Bypassing the flow around the pump prevents the pump from cavitating. This, in turn, requires the valve to take a relatively high pressure drop, which can lead to the formation of damaging cavitation. This valve must be able to eliminate the formation of cavitation. A globe valve with anti-cavitation trim is generally used.

- Typical process conditions:
  - Fluid: rich amine
  - \( P_1 = 150 – 240 \text{ psig} \) (10 - 16 bar)
  - \( P_2 = 30 – 45 \text{ psig} \) (2 - 3 bar)
  - \( T = 125°F - 175°F \) (51°C - 79°C)
  - \( W = 20,000 – 1,320,000 \text{ lb/hr} \)

- Typical valve selection:
  - NPS 1 – 4 ET/EWT Class 150/300
  - WCC-HT or 316SST body and trim
  - Equal percentage trim
  - Class IV shutoff

3. Rich amine pump discharge to regeneration control valve

This valve controls the flow of amine back to the regeneration tower. Given the lower pressure drop, a globe valve with equal percentage trim is typically used.

- Typical process conditions:
  - Fluid: rich amine
  - \( P_1 = 75 – 105 \text{ psig} \) (5 - 7 bar)
  - \( P_2 = 60 – 75 \text{ psig} \) (4 - 5 bar)
  - \( T = 95°F – 125°F \) (35°C - 51°C)
  - \( W = 5000 – 135,000 \text{ lb/hr} \)

- Typical valve selection:
  - NPS 1 – 4 ET/EWT Class 150/300
  - WCC-HT or 316SST body and trim
  - Equal percentage trim
  - Class IV shutoff

4. Free acid gas drum level control valve

This valve controls the level of liquid in the free acid gas drum. It will experience relatively low pressure drops and a globe valve is a typical solution.

- Typical process conditions:
  - Fluid: rich amine
  - \( P_1 = 90 – 105 \text{ psig} \) (6 - 7 bar)
  - \( P_2 = 75 – 85 \text{ psig} \) (5 bar)
  - \( T = 95°F – 125°F \) (35°C - 51°C)
5. Lean amine flow control valve

This valve controls the flow of lean amine to the acid gas enrichment absorber. Similar to other applications, this valve experiences relatively low pressure drops, but has the potential to see relatively high flow rates. A globe valve is generally used in this application.

- Typical process conditions:
  - Fluid: lean amine
  - $P_1 = 150 – 240$ psig (10 - 16 bar)
  - $P_2 = 30 – 60$ psig (2 - 4 bar)
  - $T = 125°F – 175°F$ (51°C - 79°C)
  - $W = 20,000 – 3,500,000$ lb/hr

- Typical valve selection:
  - NPS 2 to NPS 16 ET/EWT Class 150/300
  - WCC-HT or 316SST body and trim
  - Equal percentage or characterized Cavitrol III trim
  - Class IV shutoff

6. Tail gas quench water control valve

The gas leaving the acid gas enrichment absorber is subjected to a water quench prior to additional treatment. This valve controls the quench water flow to the quench tank. A globe valve is commonly used with the potential for anti-cavitation trim dependent upon the pressure drop.

- Typical process conditions:
  - Fluid: quench water
  - $P_1 = 50 – 140$ psig (3 - 9 bar)
  - $P_2 = 30 – 45$ psig (2 - 3 bar)
  - $T = 90°F – 120°F$ (32°C - 48°C)
  - $W = 50,000 – 1,750,000$ lb/hr

- Typical valve selection:
  - NPS 2 to NPS 16 ET/EWT Class 150/300
  - WCC-HT or 316SST body and trim
  - Linear or Cavitrol III trim
  - Class IV shutoff

7. Lean amine to tail gas absorber control valve

This valve controls the flow of lean amine to the tail gas absorber in order to scrub the gas one last time prior to use as fuel or incineration. The valve and trim combination will depend upon the pressure drop, but a globe valve with linear or anti-cavitation trim is typically used.

- Typical process conditions:
  - Fluid: lean amine
  - $P_1 = 75 – 195$ psig (5 - 13 bar)
  - $P_2 = 60 – 75$ psig (4 - 5 bar)
  - $T = 90°F – 120°F$ (32°C - 48°C)
  - $W = 30,000 – 1,550,000$ lb/hr

- Typical valve selection:
  - NPS 3 to NPS 16 ET/EWT Class 150/300
  - WCC-HT or 316SST body and trim
  - Linear or Cavitrol III trim
  - Class IV shutoff

8. Tail gas treater semi-lean amine letdown control valve

This valve controls the level of amine in the tail gas absorber. There is potential for some relatively light outgassing in this application dependent upon the amount of gas entrained in the solution. A globe valve is typically seen in this application.

- Typical process conditions:
  - Fluid: semi-lean amine
  - $P_1 = 75 – 195$ psig (5 - 13 bar)
  - $P_2 = 65 – 160$ psig (4 - 11 bar)
  - $T = 100°F – 130°F$ (37°C - 54°C)
  - $W = 30,000 – 1,550,000$ lb/hr

- Typical valve selection:
  - NPS 2 to NPS 16 ET/EWT Class 150/300
  - WCC-HT or 316SST body and trim
  - Linear trim
  - Class IV shutoff

9. Tail gas knockout drum level control valve

This valve controls the level of liquid in the tail gas knockout drum. A small globe valve is commonly used in this application.

- Typical process conditions:
  - Fluid: hydrocarbons
  - $P_1 = 45 – 165$ psig (3 - 11 bar)
  - $P_2 = 40 – 150$ psig (2 - 10 bar)
  - $T = 90°F – 125°F$ (32°C - 51°C)
  - $W = 2000 – 25,000$ lb/hr

- Typical valve selection:
  - NPS 1 to NPS 2 EZ Class 150/300
  - WCC-HT or 316SST body and trim
  - Equal percentage trim
  - Class IV shutoff
Sulfur Recovery System

After removal from the gas in the primary contactor and downstream contactors, the H₂S must be properly disposed. The Claus process, or a modification of such, is the most common method of conversion of H₂S to elemental sulfur. There are several variations of the process, but all Claus units involved an initial combustion step in a furnace. The combustion products then pass through a series of catalytic converters. At the exit of the converters, the gas is condensed to remove the sulfur that is formed. The vapor leaving the condenser is at the sulfur dew point requiring reheating before passing to additional converters that may be present. The residual tail gas can then be combusted or cleaned in a number of ways with the amine process being commonly used. Whether the tail gas is combusted at this point, or subjected to further cleaning, is directly related to the environment restrictions at the plant. Figure 6 shows a common Claus process and the commonly associated control valves.

1. Acid gas knockout drum level control valve

This valve controls the liquid level in the upstream knockout drum. A globe valve with standard trim is commonly utilized in this application.

- Typical process conditions:
  - Fluid: hydrocarbons
  - P₁ = 20 – 30 psig (1 - 2 bar)
- Typical valve selection:
  - NPS 2 EZ Class 150/300
  - WCC-HT or 316SST body and trim
  - Equal percentage trim
  - Class V shutoff

2. Acid gas preheater temperature control valve

This valve controls the flow of steam to, in turn, control the discharge temperature of the acid gas leaving the preheater. Flow rates are commonly low, but inlet pressures can be somewhat high depending upon the source of steam in the plant. A small globe valve is commonly used.

- Typical process conditions:
  - Fluid: steam
  - P₁ = 450 – 675 psig (31 - 46 bar)
  - P₂ = 50 – 125 psig (3 - 8 bar)
  - T = 400°F – 500°F (204°C - 260°C)
  - W = 1000 – 16,500 lb/hr
- Typical valve selection:
  - NPS 1 to NPS 2 EZ Class 600
  - WCC body and trim

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**Figure 6. Sulfur recovery system**

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Equal percentage trim
- Class IV shutoff

3. Air preheater temperature control valve
This valve controls the flow of steam to in turn control the discharge temperature of the combustion air leaving the preheater. Flow rates are commonly low, but inlet pressures can be somewhat high depending upon the source of steam in the plant. A small globe valve is generally used.

- Typical process conditions:
  - Fluid: steam
  - P1 = 450 – 675 psig (31 - 46 bar)
  - P2 = 50 – 125 psig (3 - 8 bar)
  - T = 400°F – 500°F (204°C - 260°C)
  - W = 1000 – 16,500 lb/hr

- Typical valve selection:
  - NPS 1 to NPS 2 EZ Class 600
  - WCC body and trim
  - Equal percentage trim
  - Class IV shutoff

4. Waste Heat Boiler (WHB) feedwater level control valve
This valve controls drum level in the waste heat boiler downstream of the reaction furnace. Depending upon startup conditions, a globe valve with equal percentage or characterized anti-cavitation trim is used.

- Typical process conditions:
  - Fluid: boiler feedwater
  - P1 = 550 – 1000 psig (37 - 68 bar)
  - P2 = 475 – 675 psig (31 - 46 bar)
  - T = 225°F – 275°F (107°C - 135°C)
  - W = 20,000 – 200,000 lb/hr

- Typical valve selection:
  - NPS 2 to NPS 4 ET Class 600
  - WCC body and trim
  - Equal percentage or Cavitrol III trim
  - Class V shutoff

What to look for:
- Has the valve experienced cavitation damage?
- Trim damage can occur in this application if it was not specified with anti-cavitation trim.
- Upgrade to Cavitrol III trim if the valve was originally specified with standard trim.
- Upgrade to a NotchFlo valve or DST retrofit if the feedwater is suspected of containing particulate.

- Legacy valves in this application may have an older digital positioner or analog positioner installed.
- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.

5. Reaction furnace waste heat boiler steam pressure control valve
This valve controls the steam pressure in the WHB. The valve selection will depend upon the intended use of the steam, but a globe valve is commonly used.

- Typical process conditions:
  - Fluid: steam
  - P1 = 475 – 675 psig (31 - 46 bar)
  - P2 = 150 – 240 psig (10 - 16 bar)
  - T = 400°F – 500°F (204°C - 260°C)
  - W = 20,000 – 200,000 lb/hr

- Typical valve selection:
  - NPS 2 to NPS 8 ET Class 600
  - WCC body and trim
  - Linear or Whisper Trim III
  - Class V shutoff

6. #1 Sulfur Condenser Boiler Feedwater Control Valve
This valve controls boiler feedwater flow to the sulfur heat exchanger/condenser to facilitate fallout of sulfur from the flowstream. This is the same boiler feedwater used in the WHB, but typically experiences much higher pressure drops leading to the need for anti-cavitation trim.

- Typical process conditions:
  - Fluid: boiler feedwater
  - P1 = 550 – 1000 psig (3 - 68 bar)
  - P2 = 50 – 75 psig (3 - 5 bar)
  - T = 225°F – 275°F (107°C - 135°C)
  - W = 2000 – 35,000 lb/hr

- Typical valve selection:
  - NPS 2 to NPS 3 ET Class 600
  - WCC body and trim
  - Cavitrol III trim
  - Class V shutoff

What to look for:
- Has the valve experienced cavitation damage?
- Trim damage can occur in this application if it was not specified with anti-cavitation trim.
- Upgrade to Cavitrol III cage if the boiler feedwater is free of particulate.

Is the customer familiar with the benefits of the FIELDVUE DVC6200 digital valve controller?
- Upgrade to a NotchFlo valve or DST retrofit if the feedwater is suspected of containing particulate.

Is the customer familiar with the benefits of the FIELDVUE DVC6200 digital valve controller?

- Legacy valves in this application may have an older digital positioner or analog positioner installed.

- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.

7. #1 Reactor/Reheater Steam Temperature Control Valve

Because the gas leaving the #1 Sulfur Condenser is at its dew point, it must be reheated for further sulfur separation. This valve controls the flow of steam to control discharge temperature from the reheater. A globe valve is commonly used in this application.

- Typical process conditions:
  - Fluid: steam
  - $P_1 = 475 – 675$ psig (31 - 46 bar)
  - $P_2 = 450 – 650$ psig (31 - 44 bar)
  - $T = 400\degree F – 500\degree F$ (204\degree C - 260\degree C)
  - $W = 1000 – 15,000$ lb/hr

- Typical valve selection:
  - NPS 2 to NPS 6 ED Class 600
  - WCC body and trim
  - Linear trim
  - Class IV shutoff

8. #2 Sulfur Condenser Boiler Feedwater Control Valve

This valve controls boiler feedwater flow to the sulfur heat exchanger/condenser to facilitate fallout of sulfur from the flowstream. This is the same boiler feedwater used in the WHB, but typically experiences much higher pressure drops leading to the need for anti-cavitation trim.

- Typical process conditions:
  - Fluid: boiler feedwater
  - $P_1 = 550 – 1000$ psig (3 - 68 bar)
  - $P_2 = 50 – 75$ psig (3 - 5 bar)
  - $T = 225\degree F – 275\degree F$ (107\degree C - 135\degree C)
  - $W = 2000 – 35,000$ lb/hr

- Typical valve selection:
  - NPS 2 to NPS 3 ET Class 600
  - WCC body and trim
  - Cavitrol III trim
  - Class V shutoff

What to look for:

Has the valve experienced cavitation damage?

- Trim damage can occur in this application if it was not specified with anti-cavitation trim.

- Upgrade to Cavitrol III cage if the boiler feedwater is free of particulate.

- Upgrade to a NotchFlo valve or DST retrofit if the feedwater is suspected of containing particulate.

Is the customer familiar with the benefits of the FIELDVUE DVC6200 digital valve controller?

- Legacy valves in this application may have an older digital positioner or analog positioner installed.

- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.

9. #2 Reactor/Reheater Steam Temperature Control Valve

Because the gas leaving the #2 sulfur condenser is at its dew point, it must be reheated for further sulfur separation. This valve controls the flow of steam to control discharge temperature from the reheater. A globe valve is commonly used in this application.

- Typical process conditions:
  - Fluid: steam
  - $P_1 = 475 – 675$ psig (32 - 46 bar)
  - $P_2 = 450 – 650$ psig (31 - 44 bar)
  - $T = 400\degree F – 500\degree F$ (204\degree C - 260\degree C)
  - $W = 1000 – 15,000$ lb/hr

- Typical valve selection:
  - NPS 2 to NPS 6 ED Class 600
  - WCC body and trim
  - Linear trim
  - Class IV shutoff

10. Inlet air flow control valve

This application will typically be a two-valve solution with one valve acting as a main and the other acting as a trim valve. These valves control the combustion air flow into the reactor burner. Very sensitive control is required to prevent burner trips and damage to the catalyst, the latter of which can be caused by excess combustion air flow. Ball valves and butterfly valves are commonly used in this application.

- Typical process conditions:
  - Fluid: air
  - $P_1 = 25 – 27$ psig (1 bar)
  - $P_2 = 24 – 25$ psig (1 bar)
  - $T = 80\degree F – 100\degree F$ (26\degree C - 37\degree C)
  - $W = 2000 – 80,000$ lb/hr
Typical valve selection:
- NPS 2 to NPS 20 V150 Vee-Ball™ valve or 8560/8532 Class 150
- WCC body and trim
- Linear trim
- Class IV shutoff

What to look for:
Does the valve provide accurate throttling throughout the full range of process conditions required?
- Tight control of combustion air flow into the furnace is needed to prevent burner trips or catalyst damage.
- If a standard butterfly is installed in this application and does not provide sufficient rangeability, offer an upgrade to the Control-Disk valve.

Is the customer familiar with the benefits of the FIELDVUE DVC6200 digital valve controller?
- Legacy valves in this application may have an older digital positioner or analog positioner installed.
- Sell the benefits of an upgrade to the DVC6200 positioner: non-contact feedback, diagnostics, superior throttling performance, etc.

11. Acid gas flow control valve
This valve controls the acid gas flow into the reactor burner. Extremely sensitive control is required to prevent burner trips. Ball valves and butterfly valves are typically used in this application.

Typical process conditions:
- Fluid: Acid gas
- P1 = 25 – 27 psig (1 bar)
- P2 = 24 – 25 psig (1 bar)
- T = 80°F – 100°F (26°C - 37°C)
- W = 1000 – 65,000 lb/hr

Typical valve selection:
- NPS 2 to NPS 16 V150 Vee-Ball valve or 8560/8532 Class 150
- WCC-HT or 316 SST body and trim
- Linear trim
- Class IV shutoff
<table>
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<tr>
<th>Application</th>
<th>Common Issues</th>
<th>Impact to Plant</th>
<th>Fisher Solution &amp; Performance Impact</th>
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</table>
| Contactor (rich amine) letdown control valve | • Severe body and trim erosion due to outgassing effects  
• Plugging of drilled hole cages due to lack of upstream filtration  
• Valve can be undersized as a result of not accounting for outgassing effects | • Unit reliability and availability impacted caused by repeated maintenance. Issue exacerbated due to lack of bypass control valve in parallel  
• Undersizing of valve and plugging of trim can minimize throughput causing contactor fouling and potential carryover into downstream equipment, which can impact performance of downstream units | • Fisher EWT, D4 or V500 Vee-Ball valve can be designed to withstand erosive effects  
• Fisher proprietary outgassing sizing methodology ensures the valve has adequate capacity to handle outgassing effects and to prevent undersizing and oversizing of the valve  
• Fisher NotchFlo™ DST Trim can be used to handle outgassing effects while eliminating the potential for trim plugging due to large passages |
| Flash drum level control valve    | • Severe body and trim erosion due to outgassing effects  
• Plugging of drilled hole cages due to lack of upstream filtration  
• Valve can be undersized as a result of not accounting for outgassing effects | • Unit reliability and availability impacted caused by repeated maintenance. Issue exacerbated due to lack of bypass control valve in parallel  
• Undersizing of valve and plugging of trim can minimize throughput causing contactor fouling and potential carryover into downstream equipment, which can impact performance of downstream units | • Fisher EWT, D4 or V500 can be designed to withstand erosive effects  
• Fisher proprietary outgassing sizing methodology ensures the valve has adequate capacity to handle outgassing effects and to prevent undersizing and oversizing of the valve  
• Fisher NotchFlo DST trim can be used to handle outgassing effects while eliminating the potential for trim plugging due to large passages |
| Flash drum pressure control valve | • Sluggish performance caused by inadequate actuation system  
• Valve exhibits stick/slip-type performance caused by particulate buildup due to foaming of the contactor  
• Inability of valve to accurately maintain required small pressure drops | • Poor control can cause pressure fluctuations in the contactor, which in turn can negatively impact acid gas removal process | • Fisher EWT or D4 with properly selected actuation system ensures smooth performance to prevent pressure fluctuations in the contactor |
| SRU Acid gas flow control        | • Valve exhibits stick/slip-type performance caused by particulate buildup due to foaming of the contactor  
• Inability of valve to accurately maintain required small pressure drops | • Unstable flow control caused by overshoot can cause burner trip requiring a restart of the burner (2 – 24 hour impact)  
• Poor controllability can negatively impact H₂S to SO₂ ratio at the back-end of the unit | • Fisher Vee-Ball can accurately control acid gas flow while providing wiping action in the event of particle buildup  
• Over-sized actuator prevents overshoot of the valve in the event of particle build-up in the bearings and packing |
| SRU combustion air flow control  | • Inability of valve to accurately maintain required small pressure drops  
|                                                                 | • Unstable flow control caused by poor performance can cause burner trip requiring a restart of the burner (2 – 24 hour impact)  
• Poor controllability can negatively impact H₂S to SO₂ ratio at the back-end of the unit  
• Poor controllability can lead to excess combustion air, which can damage the downstream catalyst | | • Fisher Vee-Ball and Control-Disk™ can accurately control air flow to ensure proper discharge H₂S to SO₂ ratio  
• Improved controllability minimizes the need for hot and cold re-starts of the burner and protects the catalyst from pre-mature failure |