Control Valve Sourcebook — Refining

FISHER

EMERSON
Process Management

1

Introduction

Refinery Control Valves

The petroleum refining industry is an industry that is most vital to our modern global economy. Almost constantly, you are in close contact with products that once were distilled through columns like those shown on the left. Some of these materials and products are so important that their rapidly fluctuating market values are reported every day on television, radio, Internet, and newspapers.

The products go through many phases from crude oil and other raw materials to the final products you use every day. On the following page is a chart showing . . .

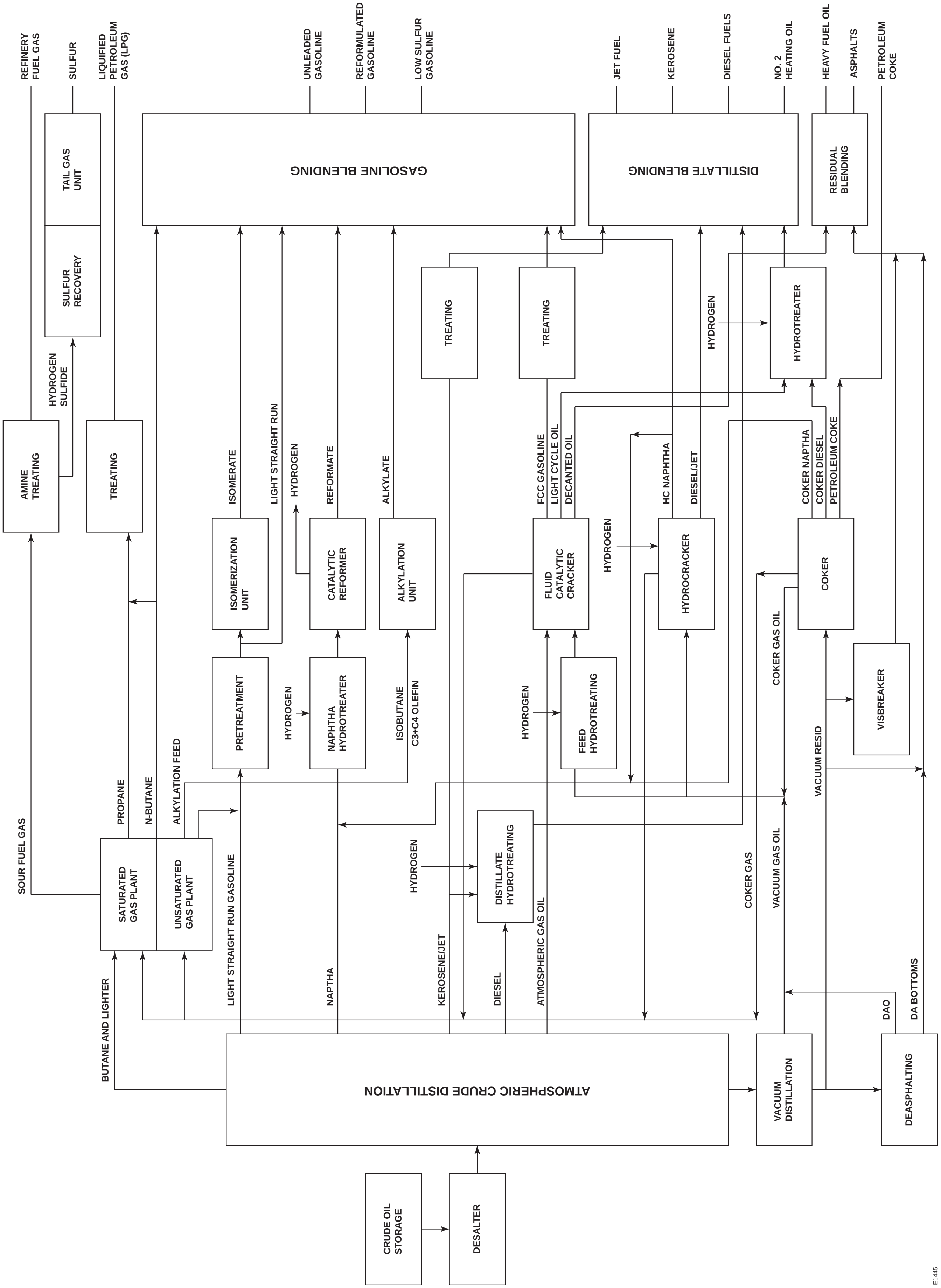


Figure 1.1.1. Complete Refinery

the raw materials, some of the intermediate petroleum product phases, and some of the final products that reach you as a consumer. Many of the products on the next page are further processed and become part of too many items to mention.

The products are all processed and made ready for the market in refineries. Efficient operation of refineries has a tremendous impact on profit, final consumer price, and wise use of limited resources. Efficient refinery operation depends on well-planned and well-executed control strategies, responsive control systems, and tough, reliable control valves.

This sourcebook is a primer on the use of control valves in many refining processes. It is intended to help you:

- Understand the types of refining processes,
- Learn where control valves are typically located within the process,
- Identify the operational problems that might be caused by poor valve performance,
- Identify Fisher® valves that are commonly used for the applications in a refinery.

A standard format is used to present the information on each refining process. The information provided is:

- Other commonly-used names for the described process
- The basis (feed rate) for the example process
- A short description of the process
- A list and description of each important process valve in the unit
- A functional drawing of the process
- Typical process conditions
- Names of Fisher valves that can be considered for each process
- Potential process impacts and special considerations for each valve

Other Names

It is not possible to make an all-inclusive list of commonly-used process names. Many refineries have developed specific process names based on local preference or the preferences of the licensor or designer that developed the process.

Process Descriptions

Many processing units within a refinery contain furnaces and distillation columns, which makes these pieces of equipment and their operation fairly universal. The valve requirements for these units are presented in Chapters 1 and 2, respectively, and are not repeated in the chapters that follow.

Chapters 3 through 5 discuss refining processes, with the valve information presented in each chapter applying directly to the specific process being described.

Valve Selection

The information presented in this sourcebook is intended to assist in understanding the control valve requirements of general refining processes.

Since every refinery is different in its unit makeup and the technologies it utilizes, the control valve requirements and recommendations presented by this sourcebook should be considered as general guidelines.

The information in this sourcebook is intended to assist with understanding general refining process requirements and general control valve considerations.

Under no circumstances should this information alone be used to select a control valve without ensuring that the proper valve construction is identified for the application and process conditions.

All valve considerations should be reviewed with your Emerson sales office or representative as part of any valve selection or specification activity.

Control Valves

Valves described within a chapter are labeled and numbered corresponding to the identification used in the process flow chart for that chapter. The order in which they are discussed is from left-to-right and top-to-bottom.

If a valve is controlling feed, intermediate or final product streams, the U.S. dollar value of that stream (as recorded at the time of sourcebook publication) and typical feed rate are provided. The valve function also is described, and a specification section gives added information on process conditions, names of Fisher valves that can be considered, process impact of the valve and any special considerations.

Process Drawing

The process drawing within each chapter shows major equipment items, their typical placement within the processing system and process flow direction. Utilities, pumps and most heat exchangers are not shown. Valves are numbered in sequence from left-to-right and top-to-bottom.

Problem Valves

Often there are references to valve-caused problems or difficulties. The litany of problems includes valve stickiness caused by excessive friction (called "stiction"), excessive play in valve-to-actuator linkages (typically in rotary valves) that causes deadband, excessive valve stem packing leakage, and valve materials that are incompatible with the flowing medium. Any one or a combination of these difficulties can affect process quality and throughput, with a resulting negative impact on refinery profitability.

Many of these problems can be avoided or minimized through proper valve selection. Consideration should be given to valve style and size, actuator capabilities, analog vs. digital instrumentation, materials of construction and the like. Although not being all-inclusive, the information that this sourcebook provides should facilitate the valve selection process.

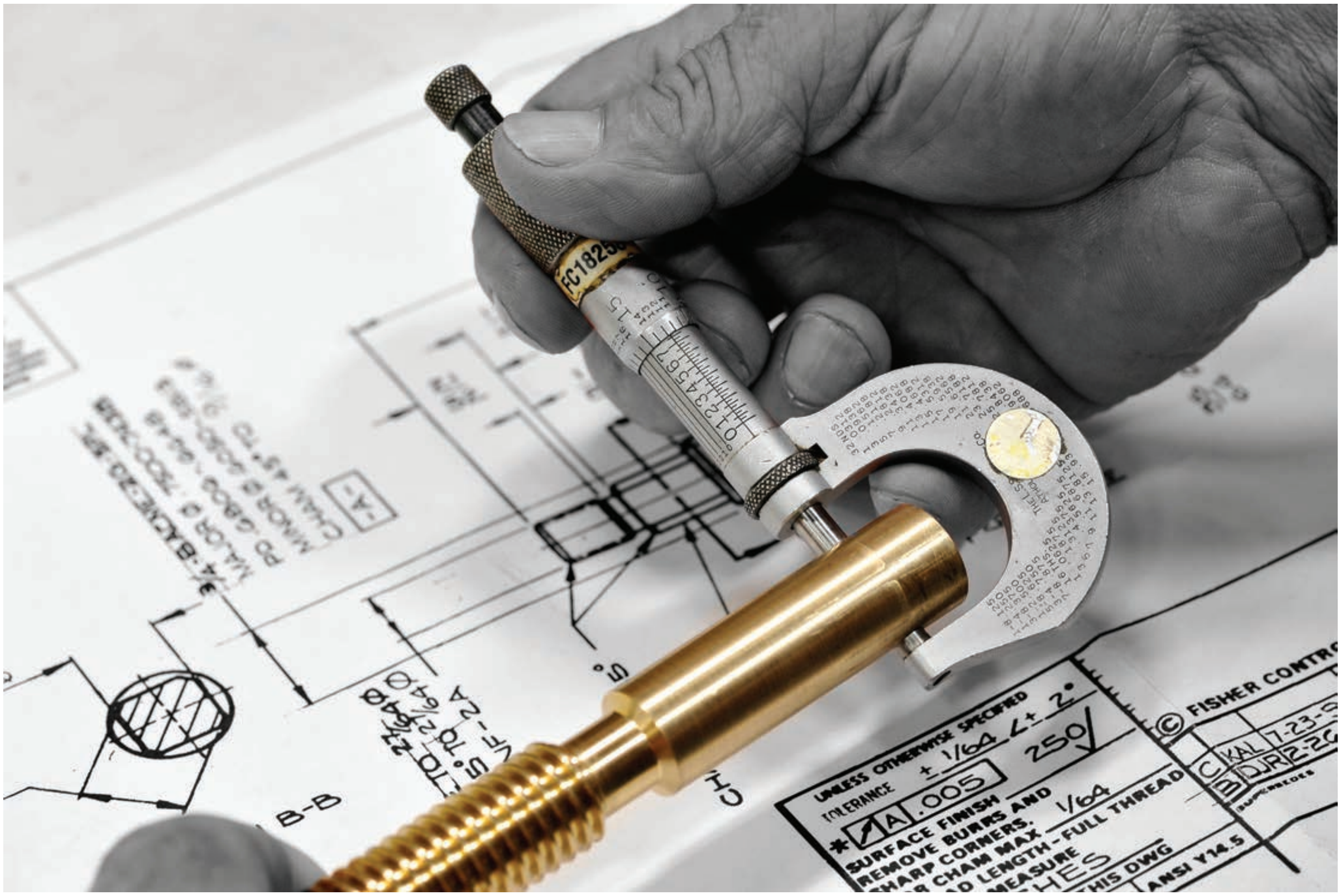
2

Fisher Product Tools and Documentation

In the day-to-day operation of your plant you have a long list of concerns, like meeting production schedules, maintaining product quality, and improving the efficiency of plant utilities, to name just a few. The last thing you should have to worry about is the performance of your plant's control valves.

Serving You for the Life of Your Plant

For nearly 40 years, Emerson has been a provider of trusted expertise for reliability centered control valve maintenance. A network of service centers, manufacturing sites, and sales representatives puts experienced professionals where and when they are needed. . .



Contact your local sales office to get in touch with the Service Center nearest you. Highly skilled technicians provide cost effective maintenance, valve reliability, and increased process availability through flexible, local service.

Manufacturing

One thing all control valve buyers have in common is a desire to know as much as possible about their prospective purchase and the company that manufactures it. Fisher valve operations started in 1880 in Marshalltown, Iowa, United States. Since then, the company has grown to more than 8,000 people worldwide. Emerson is the largest control valve and regulator manufacturer in the world.

To meet local product and delivery needs, Fisher product manufacturing plants are located in each world area. Each manufacturing site is tied directly to Fisher product design centers via the latest communication links, helping ensure that manufacturing operations utilize the most up-to-date product information. This means that each Fisher product meets design specifications and performs as intended, regardless of where it's individual or component parts were manufactured.

Design Verification through Lab Testing

Emerson engineers conduct tests that analyze cavitation, materials, fatigue, wear, high and low temperatures, valve actuators, loop variability, leakage, hydrostatic forces, gaskets, seals, and control system compatibility. In the controlled lab environment, special tests are also commonly performed to solve customers' toughest challenges.

Results from flow variability testing, hydrostatic pressure testing, capacity verification, metallurgical development, and cycle life testing all lead to one conclusion—the valve meets or exceeds the demanding requirements established by the process control industry.

Emerson Innovation Center

The Emerson Innovation Center for Fisher Technology in Marshalltown, Iowa, USA, is home to the world's largest flow lab used to evaluate control valves. It incorporates flow testing capabilities up to NPS 36 and 240 bar (3,500 psig). Final control elements are tested in conformance to IEC and ISA standards in real-world plant conditions to ensure production reliability, efficiency, environmental compliance, and safety.

Application Assistance

Control valves are an investment, so you want to speak with someone one-on-one who knows about you and your business. The Emerson sales network has extensive application experience and can recommend the most suitable products for your application. Go to www.Fisher.com and click on Fisher Sales Contacts to find the sales office nearest you. Because of the technical nature of the Fisher product line, most of the Emerson network are engineers with substantial factory training. At Emerson,

Lab Tested
Our control valves have undergone thorough and extensive testing. Test engineers determine sizing coefficients, stem force requirements, and investigate actual performance.

we've built our reputation not just on our quality Fisher products, but also on our people and their dedication to service. Wherever you are, there's an Emerson salesperson to discuss your control needs.

OEM Replacement Parts

The Emerson manufacturing network supports Fisher parts needs in any emergency. The integrated sales channel and business partner networks offer a local point of customer contact with delivery of process control application knowledge and complimentary capabilities. Flexible deployment of highly skilled, factory-trained Emerson technicians strategically located near customer process plants provide repair capabilities for all types of control valves and associated field instruments. Emerson's comprehensive quick ship programs, along with a supporting distribution network of process control products and spare parts, guarantee immediate response to customer needs.

Diagnostic Services

When precision is critical to keep your process in peak performance, you need your valves to perform to industry and factory specifications. Emerson's skilled, certified field technicians carefully analyze control valves using diagnostic services to identify maintenance priorities and develop a proactive plan detailing when devices should be repaired or replaced with next generation technologies. After diagnostic service, technicians produce a clear report indicating asset health, areas of potential risks, and a prioritized recommend action plan.

Training

Today, the need for training is more critical than ever to achieve and maintain cost-effective process operations. So whether it's at your site, our site, or the website, we work hard to ensure you know how to get the best from your Fisher products through a selection of valve and instrument training courses. Emerson offers comprehensive customer training and education programs that cover a wide range of process topics. The programs consist of structured courses that are geared to real-world situations. Customer training is provided at our educational facilities located near you. In addition to standard programs, tailored courses designed for the specific needs of an organization can be conducted on-site. Prepackaged training courses are available in video format, making selftraining convenient and cost-effective. www.EmersonProcess.com/Education

Sizing and Specification

Fisher Specification Manager software is available through your local salesperson. The software offers a powerful set of tools for quickly producing an ISA specification sheet, improving noise prediction calculations and exporting dimensional data for Fisher and Baumann™ control valves. You'll find it easy to learn and use.

PRECISE ACTUATION

Antisurge valves must be responsive in order to protect critical and costly compressors from damage during transients. Fisher precision actuation technology enables a full stroke up to 50.8 cm (20 inches) in less than one second and better than 1% positioning accuracy.

LOW-EMISSIONS PERFORMANCE

Fisher ENVIRO-SEAL™ low emissions packing is designed and tested for Fisher control valves to keep fugitive emissions below 100 parts per million volume (ppmv) in your throttling application for tens of thousands of cycles.

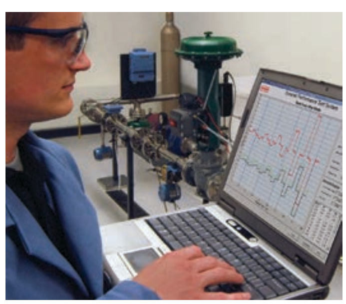
HIGH-CYCLE TESTING

Many of Emerson's standard Fisher products are used in extremely high-cycle applications, and must be tested to more than one million cycles. Those same standard products are used in your refinery to enhance reliability.

WITHSTANDING VIBRATION

Fisher control valves are designed and tested for robustness in vibration applications. They are subjected to additional testing for millions of cycles at their resonant (worst case) frequency to enhance performance in your facility.

REDUCING PROCESS VARIABILITY



Fisher control valve assemblies are subjected to on-line, dynamic performance testing to evaluate their ability to reduce your process variability. These tests replicate how control valves are used in your plant.

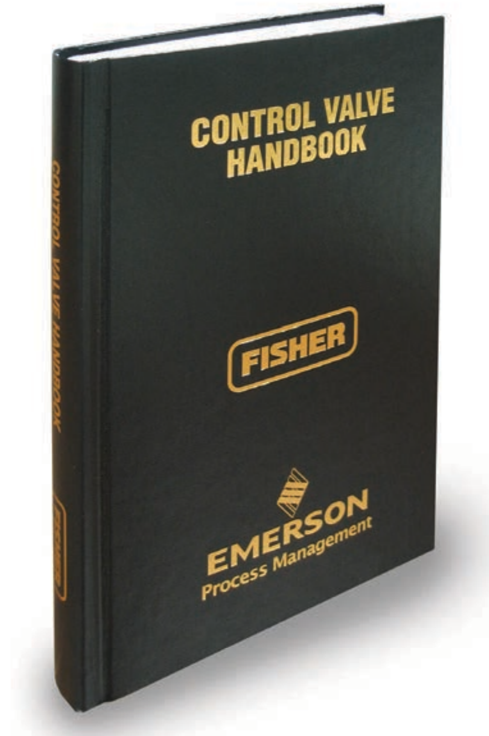
QUIETING NOISE

Supported with a 4,738 m^2 (51,000 ft^2) facility and a unique 2, 415 m^2 (26,000 ft^2) sound chamber, Emerson can quantify noise from valves, piping, and vents. This capability provides insight to ensure highly accurate noise prediction and helps you comply with regulatory (IEC) requirements.

Other Resources

Fisher Control Valve Handbook

The Control Valve Handbook is both a textbook and a reference on the strongest link in the control loop: the control valve and its accessories. This book includes extensive and proven knowledge from leading experts in the process control field including contributions from the ISA and the Crane Company.



The Fisher Story—125 Years of Process Control Experience

This book is a compilation of photos, heritage items, memories, facts and experiences from the first 125 years.

Sliding-Stem Control Valves

We have the broadest range of sliding-stem control valves available anywhere in a variety of construction materials, flow characteristics, and end connections. Complementary actuators and accessories are also available. Popular sliding-stem valve product lines include: Fisher easy-e™ globe valves and Baumann valves.

UNIVERSAL

Fisher easy-e™ valve line popularized the concept of one valve body with interchangeable trim. Can be used effectively, plantwide, in a number of applications.

HIGH PRESSURE, HIGH FLOW

Built-to-last design with rugged cage guiding and hardened trim materials. Fisher ENVIRO-SEAL™ and HIGH-SEAL packing systems in the valve provide a tight stem seal for fugitive emissions control.

STEAM CONDITIONING

Enhanced pressure reduction capabilities as well as highly efficient and accurate steam conditioning performance in a single valve. Provides the ultimate combination of performance and maintainability.

CHEMICAL AND GENERAL SERVICE

Unmatched innovation, technology, and reliability. Compact size, anti-corrosion finish, certified emission control packing and integrated digital technology.

UTILITY AND LOW FLOW SERVICE

Compact, low-weight Baumann control valves help ensure reduced installation and maintenance costs. Designs include patented low flow technology and exceptional deadband and hysteresis characteristics.

SANITARY

Designed to satisfy the stringent demands of the pharmaceutical and biotechnology industries. Includes FDA, USP CLVI, and 3A Sanitary Standards, Inc. certifications.

ENVIRONMENTAL REQUIREMENTS

Fisher ENVIRO-SEAL valve packing systems are designed to control emissions below 100 ppmv. Provide extended service life.

SWEET OR SOUR OIL AND GAS APPLICATIONS

Special deep-bore hammer nut for increased safety. Fisher Micro-Form valve plug is sour gas compatible. Fisher easy-Drive™ electric actuator was designed to protect the environment from methane gas venting.

HIGH-PRESSURE GAS SERVICE

Innovative Fisher FloPro selectable flow rate feature. Designed for high-pressure separators, scrubbers, and other gas processing equipment.

Rotary Control Valves

When capacity and performance are the requirements, the Fisher line of rotary valves is the answer. Popular rotary valve products include ball, eccentric disc, eccentric plug, and butterfly valves with such familiar tradenames as Vee-Ball™ and Control-Disk.™

PROVEN PERFORMANCE

Fisher Vee-Ball™ control valves feature the Fisher-pioneered V-notch ball for nonclogging, high capacity flow control. Designed for gas, steam, liquids and fibrous slurries where reducing process variability is a must.

HARD-TO-HANDLE FLUIDS

Fisher V500 and CV500 control valves offer low operating torque and combine the ruggedness of a globe valve with the efficiency of a rotary valve. Well suited to erosive, coking and other hard-to-handle fluids.

HIGH PERFORMANCE

Fisher 8580 control valves are reliable, high performance butterfly valves suitable for throttling applications that require extremely low leakage rates.

WIDE CONTROL RANGE

Fisher Control-Disk™ valves have a wide control range and offer excellent throttling performance to control closer to target set point, regardless of process disturbances.

PIPELINE CONTROL

Designed from the ground up with features for optimized pressure, flow, and process control. Used in gas and oil flow streams. Special Fisher Aerodome or Hydrodome attenuators reduce noise and cavitation effects that cause pipeline vibration.

TIGHT SHUTOFF

Fisher high performance valves survive in extreme pressure and temperature conditions. Exceptional shutoff rates with birdirectional soft seal ring. Special Fisher NOVEX and Phoenix III metal seals offer added shutoff capabilities.

AUTOMATED ON-OFF PERFORMANCE

Fisher 8580 rotary valves with FieldQ™ rack-and-pinion actuators offer automated on-off, quarter-turn performance and feature either a soft or metal seal for enhanced shutoff.

Field Instruments and Valve Accessories

A wide selection of Fisher digital, pneumatic and electronic instruments control valve position and variables such as level, pressure, or temperature. Popular Fisher products include: FIELDVUE™ digital valve controllers, FIELDVUE digital level transmitters, ValveLink™ software, and pressure and temperature controllers.

DIGITAL VALVE CONTROLLER

The Fisher FIELDVUE digital valve controller family has powerful diagnostic capabilities. Patented modular design and minor loop feedback.

DIGITAL VALVE CONTROLLER

Non-contact, linkage-less travel feedback and local user interface with LCD and four pushbuttons for menu navigation. Powerful FIELDVUE diagnostic capabilities.

VALVE DIAGNOSTICS SOFTWARE

ValveLink software is the configuration, calibration, and diagnostic tool used with FIELDVUE Instrumentation. It uses predictive intelligence to improve the availability and performance of control valves.

WIRELESS POSITION MONITOR

Rugged, reliable, easy-to-use measurement device that monitors equipment position with a percent of span plus on/off indication.

DIGITAL LEVEL TRANSMITTER

Provides installation flexibility. Built-to-last design. HART® and FOUNDATION™ fieldbus certified, bringing digital advantages to liquid level control.

PRESSURE CONTROLLER

Offers long-lasting dependability. Simply constructed. Can reduce steady-state air/gas consumption to as little as 1/10th that of other products.

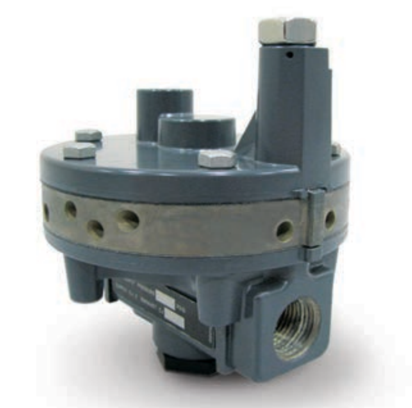
ELECTRO-PNEUMATIC TRANSDUCER

Special free-flow design resists plugging. Approved for use with natural gas as the supply medium.

LIQUID LEVEL CONTROLLER

Designed for controlling level on gas separators and scrubbers. Sour gas service ready. Low bleed relays conserve energy and reduce impact on the environment.

VOLUME BOOSTER



Used in conjuction with a positioner on a throttling control valve to increase stroking speed. Connectors and piping can be installed for diagnostic testing.

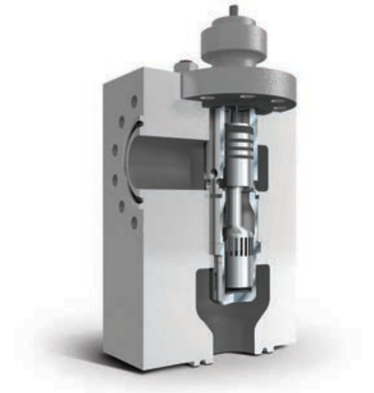
Severe Service Solutions

For decades, we have been providing solutions for severe service control valve applications in the power and hydrocarbon industries. Special control problems—either anticipated or existing—that involve extremes in temperature, pressure, corrosion, erosion, noise, flashing or cavitation, have a Fisher valve solution.

CAVITATING LIQUID

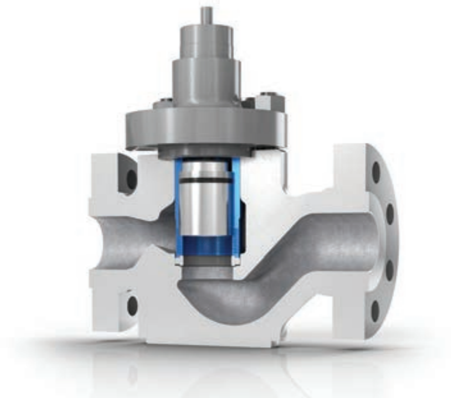
Cavitrol™ III trim contains a multitude of specially shaped holes that reduce flow turbulence. The holes are radially aligned to flow from one restriction to another. Both features dissipate the fluid pressure and prevent cavitation.

OUTGASSING



Dirty Service Trim for Outgassing (DST-G) is used in services where the fluid has dissolved gases that are released from solution due to a reduction in pressure. DST-G trim allows large 6.35 mm (¼-inch) particulate to pass.

DRILLED HOLE NOISE TRIM



Whisper Trim™ III is a drilled hole trim available in a variety of control valve sizes and styles. It delivers excellent noise reduction. The design architecture even allows for flexibility of size, pressure class, materials, rangeability, and attenuation.

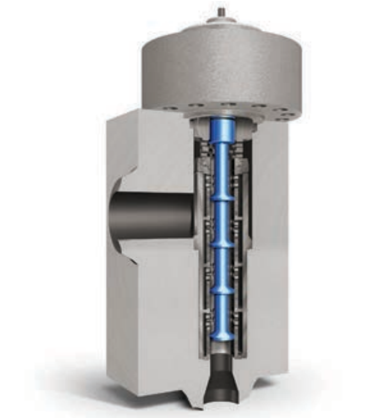
CAVITATING DIRTY FLOW

NotchFlo™ DST trim uses a series of flow restrictions and expansions to control the pressure drop of the fluid. The notched plug allows up to 12 mm (½-inch) particulate to flow through the trim without plugging.

CAVITATING DIRTY FLOW, CUSTOMIZED

Dirty Service Trim (DST) provides cavitation-control for applications with entrained particulate. It uses a combined axial and radial flow path that features large openings allowing particulate up to 19 mm (¾-inch) in diameter to pass through the valve.

LARGE PRESSURE DROPS



Each of the Cavitrol IV trim stages has a successively large flow area. The results is very efficient operation because more than 90 percent of the overall pressure drop is taken in the initial stages where there is little danger of cavity formation.

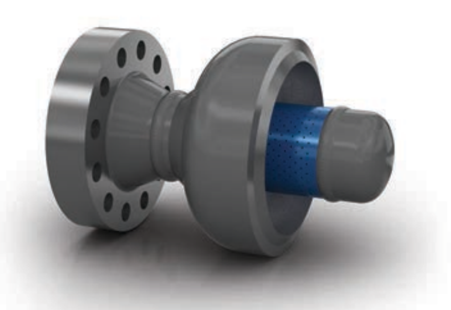
STACKED DISK NOISE TRIM

WhisperFlo trim offers state-of-the-art noise attenuation in vapor, gas, or steam applications involving high pressure drops. It is a laser cut, stacked-disk cage assembly that is available in globe and angle bodies for the most severe applications.

SLOTTED NOISE TRIM

Whisper Trim I offers proven attenuation of aerodynamic noise in vapor, gas, or steam applications involving low to medium pressure drops. It offers economical, dependable noise attenuation. It offers great application flexibility.

DIFFUSERS



The 6010 inline diffuser places back pressure on the control valve, thereby reducing the turbulence and pressure drop across the valve, which are main contributors in damaging noise and vibration.

3

Available Technologies

This section will go through available Fisher technologies commonly used in the refining industry.

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3. Control Valves

The control valve regulates the rate of fluid flow as the position of the valve plug or disk is changed by force from the actuator. To do this, the valve must:

- Contain the fluid without external leakage
- Have adequate capacity for the intended service
- Be capable of withstanding the erosive, corrosive, and temperature influences of the process
- Incorporate appropriate end connections to mate with adjacent pipelines and actuator attachment means to permit transmission of actuator thrust to the valve plug stem or rotary shaft

Many styles of control valve bodies have been developed through the years. Some serve a wide application range; others meet specific service conditions and are used less frequently. The following chapter describes control valve bodies and trim styles.

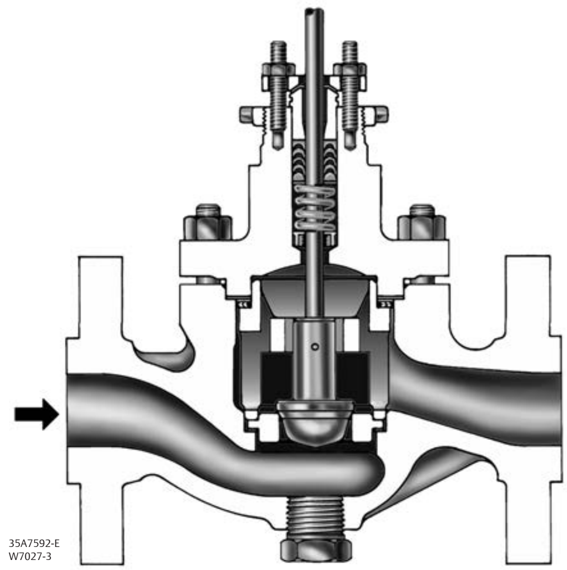

Figure 3.1.1. Single-Ported Globe-Style Valve Body

3.1 Sliding-Stem Valves

Unbalanced Single-Port Valve Constructions

Single-port is the most common valve body style and is simple in construction. These valves are available in various forms, such as globe, angle, and split constructions.

Generally, single-port valves are specified for applications with stringent shutoff requirements. They use metal-to-metal seating surfaces or soft-seating with PTFE or other composition materials forming the seal. Single-port valves can handle most service requirements.

Because high-pressure fluid is normally loading the entire area of the port, the unbalance force created must be considered in selecting actuators for single-port control valve bodies.

Although most popular in the smaller sizes, single-port valves can often be used in NPS 4 to NPS 8 with high-thrust actuators.

Many modern single-seated valve bodies use cage or retainer style constructions to retain the seat ring, provide valve-plug guiding, and provide a means for establishing particular valve flow characteristics. Retainer-style trim also offers ease of maintenance with flow characteristics altered by the plug contour. Cage or retainer-style single-seated valve bodies can also be easily modified by changing trim parts to provide reduced-capacity flow, noise attenuation, or reduction or elimination of cavitation.

Figure 3.1.1 shows two styles of single-ported or single-seated globe-type control valve bodies. They are widely used in process control applications, particularly in sizes from NPS 1 through NPS 4.

Angle valves are typically single-ported (figure 3.1.2). Normal flow direction is up through the seat ring. They are commonly used in boiler feedwater and heater drain service and in piping schemes where space is at a premium and the valve can also serve as an elbow. The valve shown has cage-

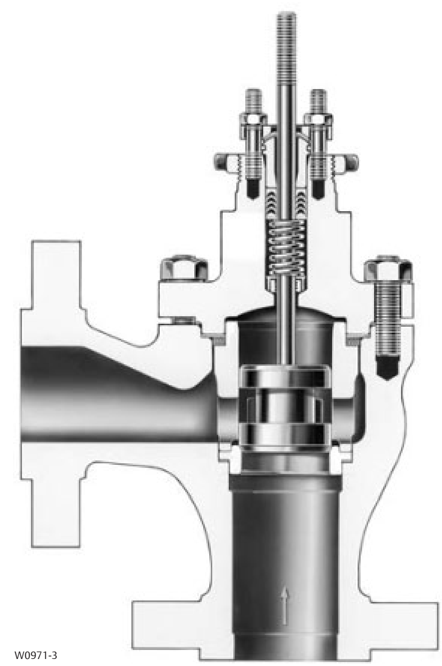

Figure 3.1.2. Angle-Style Valve Body

style construction. Others might have screwed-in seat rings, expanded outlet connections, restricted trim, and outlet liners for reduction of erosion damage.

High pressure, single-ported globe valves are often used in refineries. Variations available include cage-guided trim, bolted body-to-bonnet connection, and self-draining angle versions.

Flanged versions are available with ratings to ASME CL2500 and greater.

Balanced-Plug, Cage-Style Valve Constructions

This single-ported valve body style uses one seat ring and provides the advantages of a balanced valve plug often

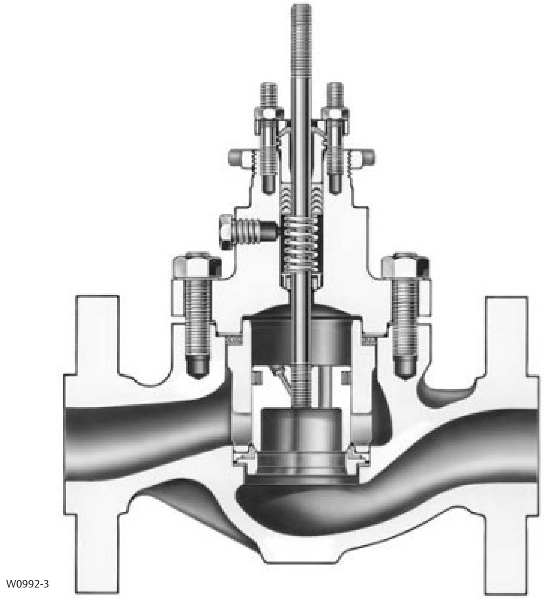

Figure 3.1.3. Balanced-Plug, Cage-Style Valve Construction

associated only with double-ported valve bodies (figure 3.1.3.). Cage-style trim provides valve plug guiding, seat ring retention, and flow characterization. In addition, a seal between the upper portion of the valve plug and the wall of the cage cylinder virtually eliminates leakage from the upstream to downstream pressures. Downstream pressure acts on the top and bottom sides of the valve plug, thereby reducing the static unbalance force. Reduced unbalance force permits operation of the valve with smaller actuators than those necessary for conventional single-ported valve bodies. Interchangeability of trim permits choice of several flow characteristics, noise attenuation, or anti-cavitation components. For most available trim designs, the standard direction of flow is in through the cage openings and down through the seat ring. These are available in various material combinations, sizes beyond NPS 36, and pressure ratings to CL 2500 and greater.

Expanded End Connection, Cage-Guided Valve Constructions

This adaptation of the cage-guided valve bodies mentioned above was designed for noise applications such as high pressure gas reducing stations where sonic gas velocities are often encountered at the outlet of conventional valve bodies (figure 3.1.4). The design incorporates oversized end connections with a streamlined flow path and the ease of trim maintenance inherent with cage-style constructions. Use of noise abatement trim reduces overall noise levels by as much as 40 decibels (dB). Flow direction depends on the intended service and trim selection, with unbalanced constructions normally flowing up and balanced constructions normally flowing down.

Port-Guided Single-Port Valve Constructions

These valve bodies are usually limited to 10 bar (150 psig) maximum pressure drop. They are susceptible to velocity induced vibration. Port-guided single-port valve bodies are

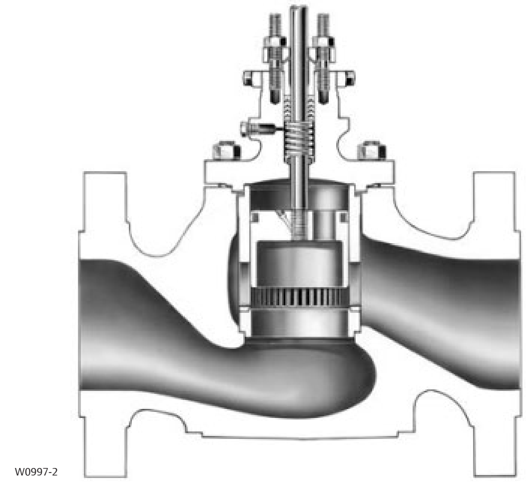

Figure 3.1.4. Expanded End Connection Valve with Noise Abatement Trim

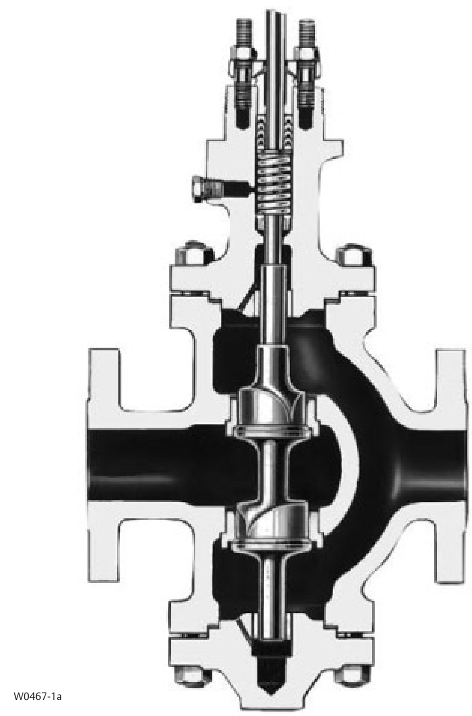

Figure 3.1.5. Double-Ported Globe-Style Valve Body

typically provided with screwed in seat rings which might be difficult to remove after use.

Double-Ported Valve Constructions

Dynamic force on the plug tends to be balanced as flow tends to open one port and close the other. Reduced dynamic forces acting on the plug might permit choosing a smaller actuator than would be necessary for a single-ported valve body with similar capacity.

Valve bodies are usually furnished only in the larger sizes—NPS 4 or larger and bodies normally have higher capacity than single-ported valves of the same line size. Many double-ported bodies reverse, so the valve plug can be installed as either push-down-to-open or push-down-to-close (figure 3.1.5). Metal-to-metal seating usually provides only Class II shutoff capability, although Class III capability is also possible.

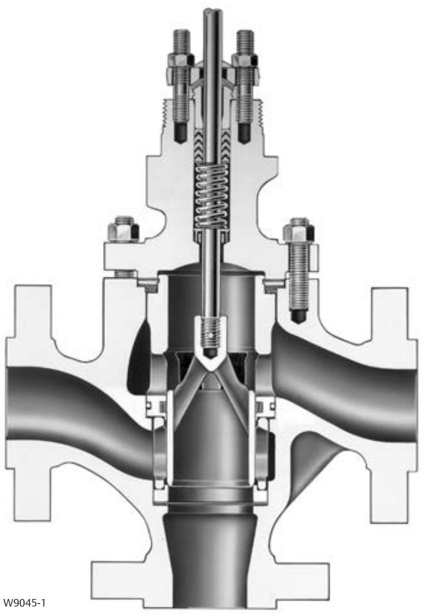

Figure 3.1.6. Three Way Valve with Balanced Valve Plug

Figure 3.2.1. High-Performance Butterfly Control Valve

Port-guided valve plugs are often used for on-off or low-pressure throttling service. Top-and-bottom-guided valve plugs furnish stable operation for severe service conditions. The control valve body shown in figure 3.1.5 is assembled for push-down-to-open valve plug action. The valve plug is essentially balanced and a relatively small amount of actuator force is required to operate the valve. Double-ported designs are typically used in refineries on highly viscous fluids or where there is a concern about dirt, contaminants, or process deposits on the trim.

Three-Way Valve Bodies

Three pipeline connections provide general converging (flow-mixing) or diverging (flow-splitting) service. Preferred designs use cage-style trim for positive valve plug guiding and ease of maintenance. Variations include trim materials selected for high temperature service. Standard end connections (flanged, screwed, butt weld, etc.) can be specified to mate with piping schemes. Actuator selection demands careful consideration, particularly for constructions with unbalanced valve plug. Balanced valve plug style three-way valve body is shown in figure 3.1.6 with the cylindrical valve plug in the down position.

3.2 Rotary Valves

Butterfly Valve Constructions

Butterfly valve constructions require minimum space for installation (figure 3.2.1.). They provide high capacity with low pressure loss through the valves. Butterfly valve constructions offer economy, particularly in larger sizes and in terms of flow capacity per investment dollar. They exhibit an approximately equal percentage flow characteristic and can be used for throttling service or for on-off control. Soft-seat construction can be obtained by using a liner or by including an adjustable soft ring in the body or on the face of the disk.

Conventional contoured disks provide throttling control for up to 60-degree disk rotation. The Fisher Control-Disk valve features a proportional gain disk design suited for applications requiring 90-degree disk rotation and extended control range.

Butterfly valve constructions mate with standard raised-face pipeline flanges. Large butterfly valves and smaller valves with high pressure drops typically require large actuators to handle the high operating torque.

Standard liners, such as Nitrile or PTFE liners, can provide tight shutoff and corrosion protection while maintaining cost effective base materials, such as cast iron.

Butterfly valves are available in sizes through NPS 72 for control valve applications. Smaller sizes can use versions of traditional spring-and-diaphragm or piston pneumatic actuators, including the modern rotary actuator styles. Larger sizes might require high-output electric or long-stroke pneumatic cylinder actuators.

V-Notch Segmented Ball Valve Constructions

The Fisher Vee-Ball valve construction is similar to a conventional ball valve, but with a contoured V-notch ball in a segmented ball valve (figure 3.2.2). The V-notch ball produces a modified equal-percentage flow characteristic and provides excellent rangeability in excess of 300:1. These control valves have good rangeability, control, and shutoff capability. Their straight-through flow design produces little pressure drop.

V-notch segmented ball valve constructions are suited to control erosive or viscous fluids, or other slurries containing entrained solids. They use standard spring-and-diaphragm or piston rotary actuators. The V-notch segmented ball remains in contact with the seal during rotation, which produces a shearing effect as the ball closes and minimizes clogging.

Figure 3.2.2. V-Notch Segmented Ball Valve

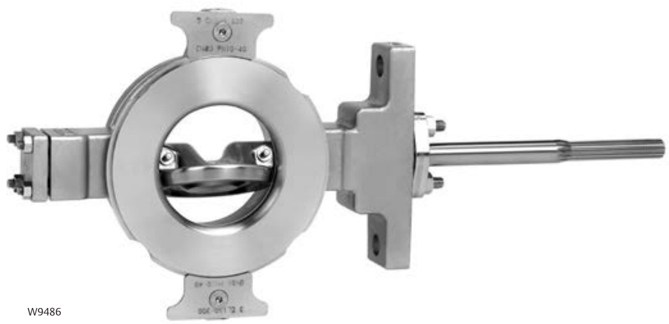

Figure 3.2.3. Eccentric Disk Control Valve

Constructions are available with either heavy-duty metal or PTFE-filled composition ball seal ring. They are available in flangeless or flanged body end connections. Both flanged and flangeless valves mate with CL150, CL300, CL600 flanges, or DIN flanges.

Eccentric Disk Control Valve Constructions

Eccentric disk control valve constructions offer effective throttling control. They provide a linear flow characteristic through 90 degrees of disk rotation (figure 3.2.3). Eccentric mounting of the disk pulls the disk away from seal after it begins to open, minimizing seal wear. Eccentric-disk control valve bodies are available in sizes through NPS 24 and are compatible with standard ASME flanges. They use standard pneumatic spring-and-diaphragm or piston rotary actuators.

Flow direction is dependent on the seal design. They are frequently applied in applications requiring large sizes and high temperatures due to their lower cost relative to other styles of control valves. Optimum control range for this style of valve is approximately one third as large as a ball or globe style valve. Consequently, additional care is required in sizing and applying this style of valve to eliminate control problems associated with process load changes.

Eccentric Plug Valve Constructions

Eccentric plug valve constructions combat erosion. The rugged body and trim design handle temperatures to 427°C (800°F) and shutoff pressure drops to 103 bar (1500 psig). The path of the eccentric-plug minimizes contact with the seat ring when opening, reducing seat wear and friction, prolonging seat life, and improving throttling performance (figure 3.2.4). Its self-centering seat ring and rugged plug

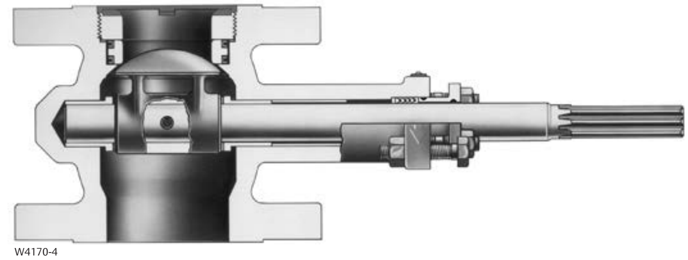

Figure 3.2.4. Eccentric Plug Valve

allow forward or reverse flow with tight shutoff in either direction. For erosive applications, reverse flow is preferred. In addition, plug, seat ring, and retainer are available in hardened materials, including ceramics. Designs offering a segmented V-notch segmented ball in place of the plug for higher capacity requirements are available.

This style of rotary control valve suits erosive, coking, and other hard-to-handle fluids, providing either throttling or on-off operation. The flanged or flangeless valves feature streamlined flow passages and rugged metal-trim components for dependable service in slurry applications.

3.3 Actuators

Pneumatically operated control valve actuators are the most popular type in use. Other actuator types include electric, hydraulic, and manual. The spring-and-diaphragm pneumatic actuator is most commonly specified due to its dependability and simplicity of design. Pneumatically operated piston actuators provide high stem force output for high thrust applications. Adaptations of both spring-and-diaphragm and pneumatic piston actuators are available for direct installation on rotary valve constructions. Electric and electro-hydraulic actuators can be used where no air supply source is available, where low ambient temperatures could freeze condensed water in pneumatic supply lines, or where unusually large stem forces are needed.

Spring-and-Diaphragm Actuators

Spring-and-diaphragm actuators are simple, dependable, and economical. Pneumatically operated spring-and-diaphragm actuators use air supply from a controller, positioner, or other source. Various styles include:

- Direct-acting: increasing air pressure pushes the diaphragm down and extends the actuator stem (figure 3.3.1)
- Reverse-acting: increasing air pressure pushes the diaphragm up and retracts the actuator stem (figure 3.3.2)
- Reversible: actuators that can be assembled for either direct- or reverse-action (figure 3.3.3)
- Direct-acting unit for rotary valves: increasing air pressure pushes the diaphragm down, which may either open or close the valve, depending on the orientation of the actuator lever on the valve shaft (figure 3.3.4)

The net output thrust is the difference between diaphragm force and opposing spring force. Molded diaphragms provide linear performance and increased travels. Output thrust is

W0363-2

Figure 3.3.1. Direct-Acting Diaphragm Actuator

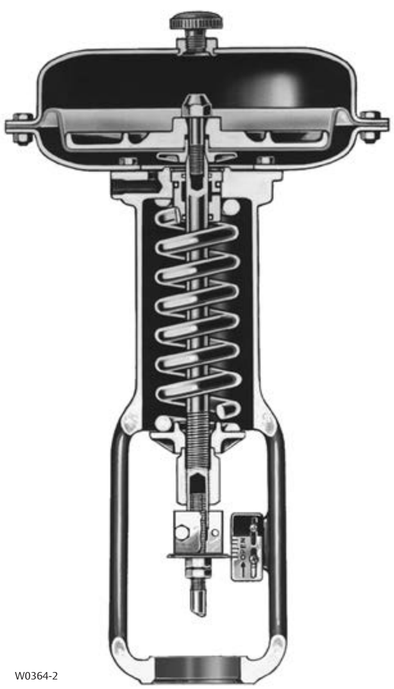

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Figure 3.3.2. Reverse-Acting Diaphragm Actuator

required and the supply air pressure that is available will dictate the size.

Piston Actuators

Piston actuators are pneumatically operated using high pressure plant air (up to 11 bar or 150 psig), often eliminating the need for supply pressure regulator. Piston actuators furnish maximum thrust output and fast stroking speeds. They can be double-acting to give maximum force in both directions or they can be spring-return to provide fail-open or fail-closed operation (figure 3.3.5).

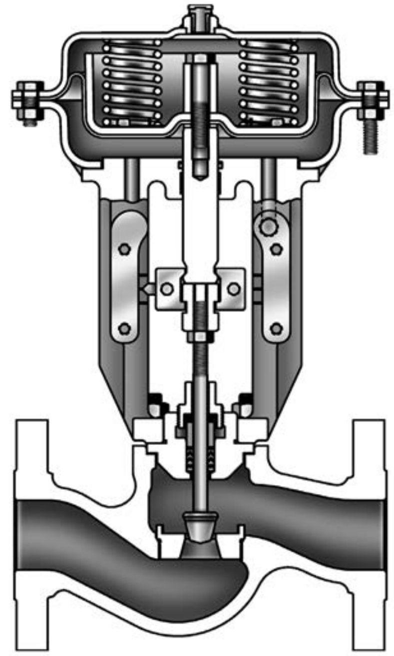

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Figure 3.3.3. Reversible Diaphragm Actuator

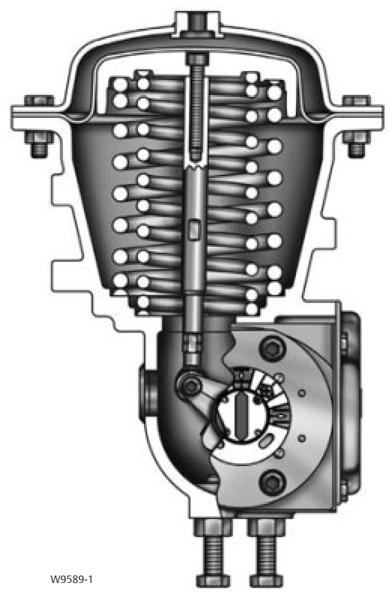

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Figure 3.3.4. Direct-Acting Rotary Diaphragm Actuator

Various accessories can be incorporated to position a double-acting piston in the event of supply pressure failure. These include pneumatic trip valves, volume tanks, and lock-up systems. Also available are handwheels and units without yokes, which can be used to operate butterfly valves, louvers, and similar industrial equipment. Other versions for service on rotary valve constructions include a sliding seal in the lower end of the cylinder. This permits the actuator stem to move laterally, as well as up and down without leakage of cylinder pressure. This feature also permits direct connection of the actuator stem to the actuator lever mounted on the rotary valve shaft; thereby, eliminating one joint or a source of lost motion.

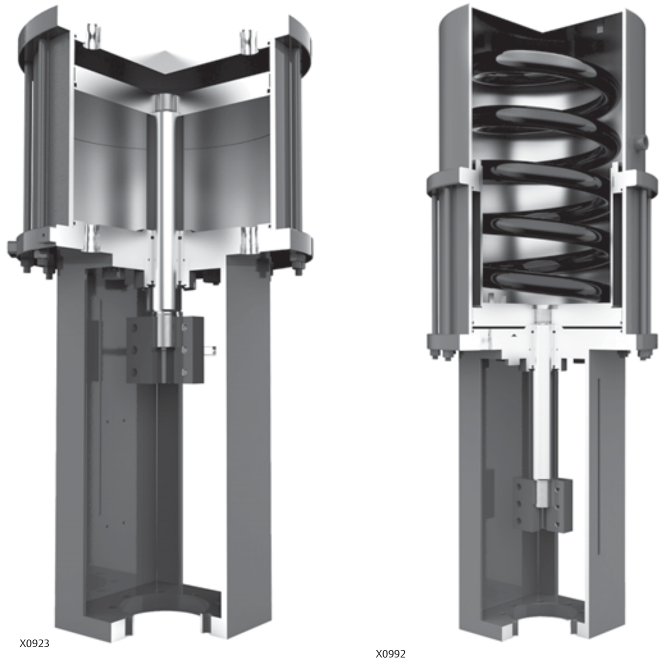
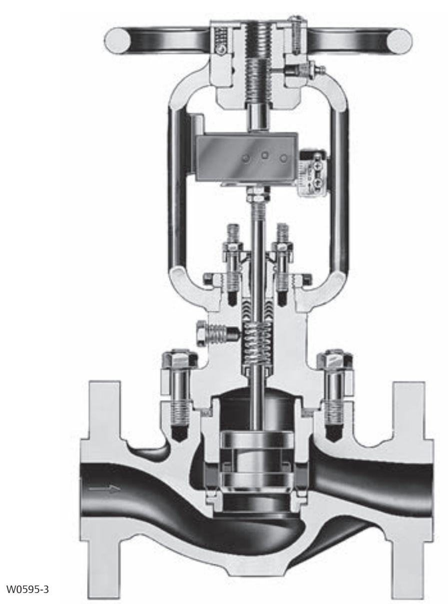
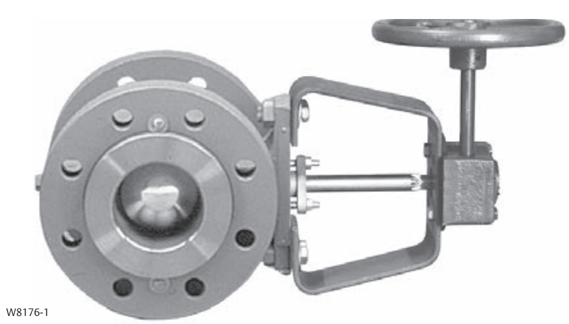


Figure 3.3.5. Piston Actuators



FOR SLIDING-STEM VALVES



FOR ROTARY-SHAFT VALVES

Figure 3.3.6. Typical Manual Actuators

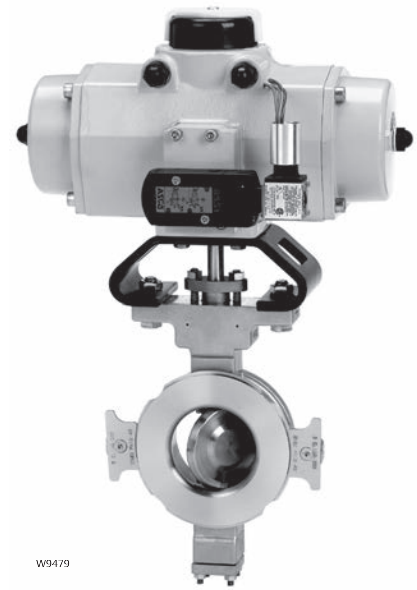


Figure 3.3.7. Rack-and-Pinion Actuator with HPBV

Manual Actuators

Manual actuators are useful where automatic control is not required, but where ease of operation and good manual control is still necessary (figure 3.3.6). They are often used to actuate the bypass valve in a three-valve bypass loop around control valves for manual control of the process during maintenance or shutdown of the automatic system. Manual actuators are available in various sizes for both globe and rotary valve constructions. Dial-indicating devices are available for some models to permit accurate repositioning of the valve plug or disk. Manual actuators are much less expensive than diaphragm, piston, and electro-hydraulic actuators and are often used on bypass lines in a refinery.

Rack-and-Pinion Actuators

Rack-and-pinion designs provide a compact and economical solution for rotary shaft valves (figure 3.3.7). They are typically used for on-off or control applications requiring simple compact solutions.

Electric Actuators

Traditional electric actuator designs use an electric motor and some form of gear reduction to move the valve. These mechanisms have been used for continuous control (figure 3.3.8).

Electro-hydraulic Actuators

Electro-hydraulic actuators require only electrical power to the motor and an electrical input signal from the controller. Electrohydraulic actuators are ideal for isolated locations where pneumatic supply pressure is not available but where precise control of valve plug position is needed. Units are normally reversible by making minor adjustments and are self-contained, including motor, pump, and double-acting hydraulically operated piston within a weatherproof or explosion-proof casing. Other than a few specific

W9797-3

Figure 3.3.8. Electric Actuator with Dump Valve

applications, electrohydraulic actuators are not typically used in refining applications.

3.4 Control Valve Packing

Packing is part of the control valve assembly used to seal against leakage around the valve disk or stem. Most control valves use packing boxes with the packing retained and adjusted by a flange and stud bolts. Packing selection is driven by service conditions, performance, as well as governmental regulations focused on fugitive emissions. Packing materials and arrangements discussed below are the most commonly specified for Fisher valve constructions. Fisher rotary and sliding-stem packing constructions are shown in figure 3.4.1.

PTFE V-Ring

PTFE packing is constructed of a plastic material with an inherent ability to minimize friction. PTFE material is molded in v-shaped rings that are spring loaded and self-adjusting in the packing box. Packing lubrication is not required. PTFE packing is resistant to most known chemicals and requires extremely smooth (two to four micro-inches RMS) stem finish to seal properly. Sealing can be compromised if the stem or packing surface is damaged. Recommended packing box temperature limits are –40 to +232°C (–40 to +450°F).

Laminated and Filament Graphite

Laminated and filament graphite material is suitable for high temperature or where low chloride content is desirable. It typically produces higher stem friction and is impervious to challenging fluids. Recommended packing box temperature limits for laminated and filament graphite are cryogenic temperatures up to 649°C (1200°F). Lubrication is not required, but an extension bonnet should be used when packing box temperature exceeds 427°C (800°F).

Low Emission Packing

Fugitive emissions are non-point source volatile organic emissions that result from process equipment leaks. For example, strict government regulations, that were developed by the US, dictate leak detection and repair programs (LDAR). Valves and pumps have been identified as key sources of fugitive emissions. For valves, this is the leakage to atmosphere due to packing seal or gasket failures. LDAR programs require monitoring all valves (control and non-control) at an interval that is determined by the percentage of valves found to be leaking above a threshold level ranging from 100 to 500 ppmv depending on industry and local regulations. Packing systems designed for extremely low leakage requirements also extend packing-seal life and performance to support an annual monitoring objective. The Fisher ENVIRO-SEAL packing system is one example. Its enhanced seals incorporate four key design principles:

1. Containment of the pliable seal material through an anti-extrusion component
2. Proper alignment of the valve stem or shaft within the bonnet bore
3. Applying a constant packing stress through Belleville springs
4. Minimizing the number of seal rings to reduce consolidation, friction, and thermal expansion

Please reference Table 3.4.1 for sliding stem and Table 3.4.2 for rotary for pressure temperature limits for environmental sealing capabilities for each of the following packing styles.

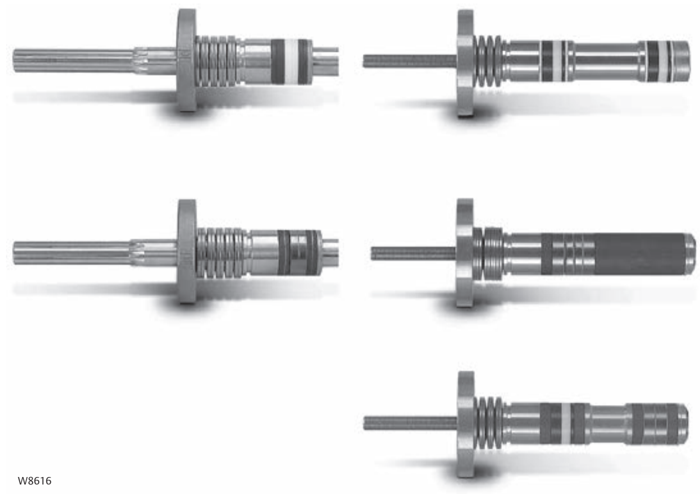


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Figure 3.4.1. Control Valve Packing

Single PTFE V-Ring Packing

The single PTFE V-ring arrangement uses a coil spring between the packing and packing follower. It offers very good sealing performance with the lowest operating friction.

ENVIRO-SEAL PTFE Packing

ENVIRO-SEAL PTFE packing system is an advanced packing method that utilizes a compact, live-load spring design. While it most typically is thought of as an emission reducing packing system, ENVIRO-SEAL PTFE packing is also suited to non-environmental applications with higher temperatures and pressures, yielding the benefit of longer, ongoing service life.

Table 3.4.1 Sliding-Stem Packing Selection Guidelines

Packing System	Maximum Pressure and Temperature Limits for 100 PPM Service(1)		Application Guideline for Nonenvironmental Service(1)		Seal Performance Index	Service Life Index	Packing Friction (2)
	Metric	Imperial	Metric	Imperial			
Single PTFE V-Ring	20.7 bar -18 to 93°C	300 psi 0 to 200°F	See figure 3 -46 to 232°C	See figure 3 -50 to 450°F	Better	Long	Very low
Double PTFE V-Ring	- - -	- - -	See figure 3 -46 to 232°C	See figure 3 -50 to 450°F	Better	Long	Low
ENVIRO-SEAL PTFE	See figure 2 -46 to 232°C	See figure 2 -50 to 450°F	See figure 3 -46 to 232°C	See figure 3 -50 to 450°F	Best	Very long	Low
ENVIRO-SEAL Duplex	51.7 bar -46 to 232°C	750 psi -50 to 450°F	See figure 3 -46 to 232°C	See figure 3 -50 to 450°F	Best	Very long	Low
KALREZ® with Vespel® CR-6100 (KVSP 500)(3)	24.1 bar 4 to 260°C	350 psig 40 to 500°F	See figure 3 -40 to 260°C	See figure 3 -40 to 500°F	Best	Long	Low
ENVIRO-SEAL Graphite ULF	103 bar -7 to 315°C	1500 psi 20 to 600°F	207 bar -198 to 371°C	3000 psi -325 to 700°F	Best	Very long	Medium
HIGH-SEAL Graphite ULF	103 bar -7 to 315°C	1500 psi 20 to 600°F	290 bar(4) -198 to 538°C	4200 psi(4) -325 to 1000°F	Best	Very long	Medium
Graphite Composite / HIGH-SEAL Graphite	- - -	- - -	290 bar(4) -198 to 649°C(5)	4200 psi(4) -325 to 1200°F(5)	Better	Very long	Very high
Braided Graphite Filament	- - -	- - -	290 bar -198 to 538°C(5)	4200 psi -325 to 1000°F(5)	Good	Moderate	High
Graphite ULF	- - -	- - -	290 bar -198 to 538°C	4200 psi -325 to 1000°F	Better	Very long	Medium

1. The values shown are only guidelines. These guidelines can be exceeded, but shortened packing life or increased leakage might result. The temperature ratings apply to the actual packing temperature, not to the process temperature.
2. Contact a local Emerson sales office for actual friction values.
3. The KALREZ pressure/temperature limits referenced are for Fisher valve applications only. DuPont may claim higher limits.
4. Except for the 9.5 mm (3/8 inch) stem, 110 bar (1600 psi).
5. Except for oxidizing service, -198 to 371°C (-325 to 700°F).

Table 3.4.2 Rotary Packing Selection Guidelines

PACKING SYSTEM	MAXIMUM PRESSURE AND TEMPERATURE LIMITS FOR 100 PPM SERVICE(1)		APPLICATION GUIDELINE FOR NONENVIRONMENTAL SERVICE(1)		SEAL PERFORMANCE INDEX	SERVICE LIFE INDEX	PACKING FRICTION
	Metric	Customary U.S.	Metric	Customary U.S.			
Single PTFE V-Ring	- - - - - -	- - - - - -	103 bar -46 to 232°C	1500 psig -50 to 450°F	Better	Long	Very low
ENVIRO-SEAL PTFE	103 bar -46 to 232°C	1500 psig -50 to 450°F	207 bar -46 to 232°C	3000 psig -50 to 450°F	Excellent	Very long	Low
ENVIRO-SEAL PTFE for V250 Valves	69 bar -29 to 93°C	1000 psig -20 to 200°F	155 bar -46 to 232°C	2250 psig -50 to 450°F	Excellent	Very long	Low
KALREZ® with Vespel® CR-6100 (KVSP 500)(3)	24.1 bar 4 to 260°C	350 psig 40 to 500°F	51 bar -40 to 260°C	750 psig -40 to 500°F	Excellent	Long	Very low
ENVIRO-SEAL Graphite	103 bar -7 to 315°C	1500 psig 20 to 600°F	207 bar -198 to 371°C	3000 psig -325 to 700°F	Excellent	Very long	Moderate
Graphite Ribbon	- - - - - -	- - - - - -	103 bar -198 to 538°C(2)	1500 psig -325 to 1000°F(2)	Acceptable	Acceptable	High

1. The values shown are only guidelines. These guidelines can be exceeded, but shortened packing life or increased leakage might result. The temperature ratings apply to the actual packing temperature, not to the process temperature.
2. Except for oxidizing service, -198 to 371°C (-325 to 700°F).
3. The KALREZ pressure/temperature limits referenced are for Fisher valve applications only. DuPont may claim higher limits.

ENVIRO-SEAL Duplex Packing

This sliding-stem packing system provides the capabilities of both PTFE and graphite components to yield a low friction, low emission, fire-tested solution for applications with process temperatures up to 232°C (450°F).

ENVIRO-SEAL Graphite ULF for Sliding-Stem Valves

This sliding stem packing system is designed primarily for environmental applications at temperatures in excess of 232°C (450°F). The ULF packing system incorporates thin PTFE layers inside the packing rings as well as thin PTFE washers on each side of the packing rings. This strategic placement of PTFE improves control, reduces friction, promotes sealing and extends the cycle life of the packing set.

ENVIRO-SEAL Graphite for Rotary Valves

This rotary packing system is designed primarily for environmental applications at temperatures from −6°C to 316°C (20°F to 600°F) or for those applications where fire safety is a concern.

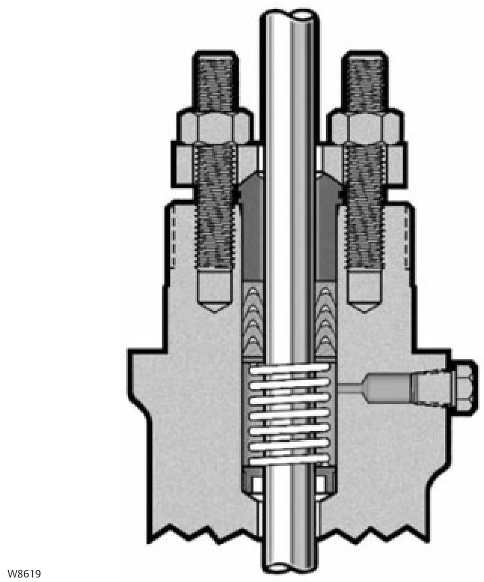

Figure 3.4.2. Single PTFE V-Ring Packing

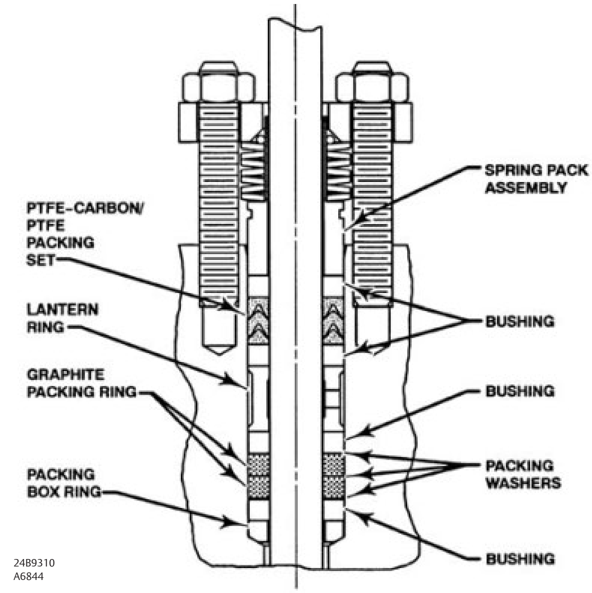

Figure 3.4.4. ENVIRO-SEAL Duplex Packing System

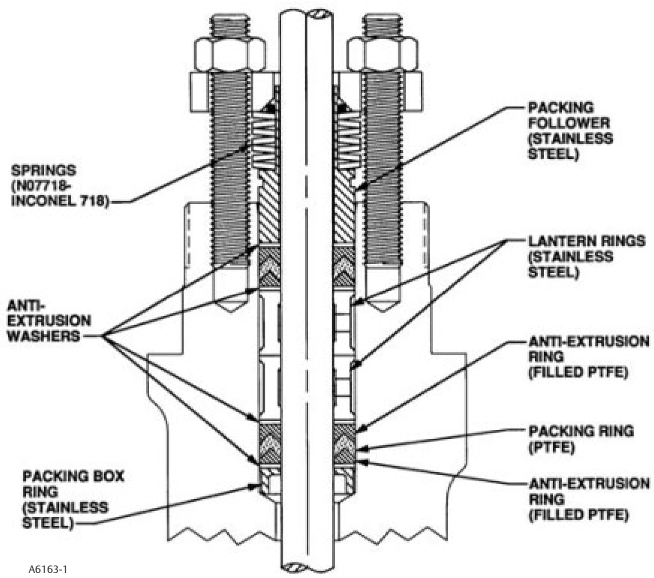

Figure 3.4.3. ENVIRO-SEAL PTFE Packing System

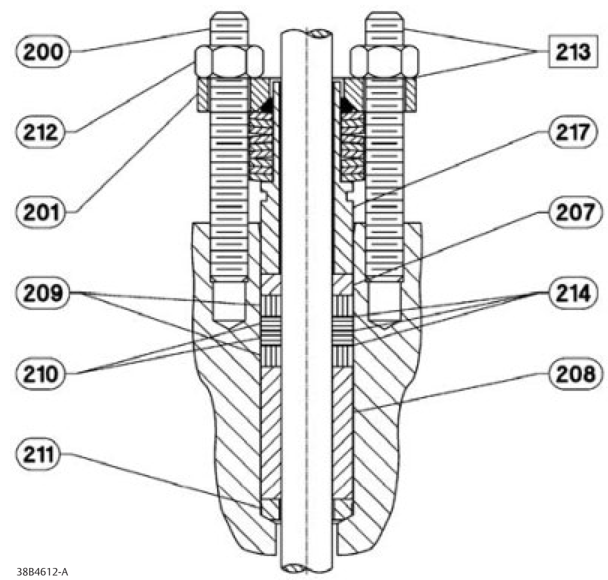

Figure 3.4.5. ENVIRO-SEAL Graphite ULF Packing System

HIGH-SEAL Graphite ULF

Identical to the ENVIRO-SEAL graphite ULF packing system below the packing follower, the HIGH-SEAL system utilizes heavy-duty, large diameter Belleville springs. These springs provide additional follower travel and can be calibrated with a load scale for a visual indication of packing load and wear.

While ENVIRO-SEAL packing systems have been designed specifically for fugitive emission applications, these technologies also should be considered for any application where seal performance and seal life have been an ongoing concern or maintenance cost issue.

Given the wide variety of valve applications and service conditions within industry, variables such as sealing ability, operating friction levels, and operating life are difficult to quantify and compare.

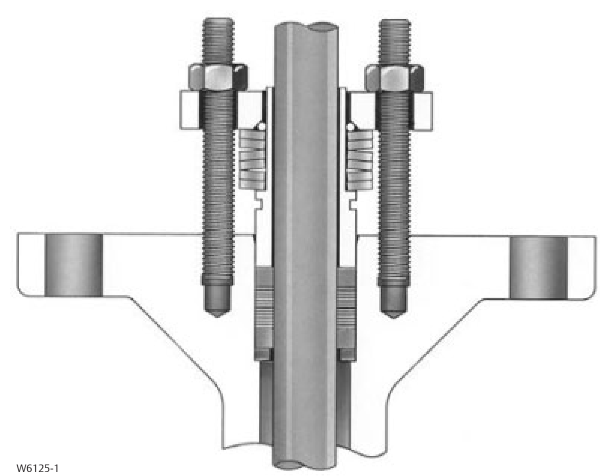

Figure 3.4.6. ENVIRO-SEAL Graphite Packing System for Rotary Valves

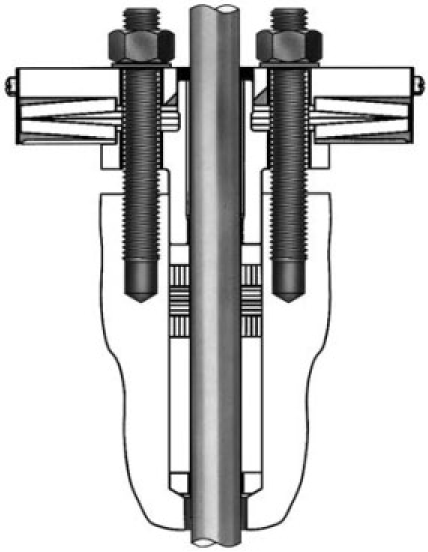

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Figure 3.4.7. HIGH-SEAL Graphite ULF Packing System

3.5 Positioners and Diagnostic Capabilities

Pneumatically operated valves depend on a positioner to take an input signal from a process controller and convert it to valve travel. These instruments are available in three configurations:

1. Pneumatic Positioners: A pneumatic signal (usually 3-15 psig) is supplied to the positioner. The positioner translates this to a required valve position and supplies the valve actuator with the required air pressure to move the valve to the correct position.

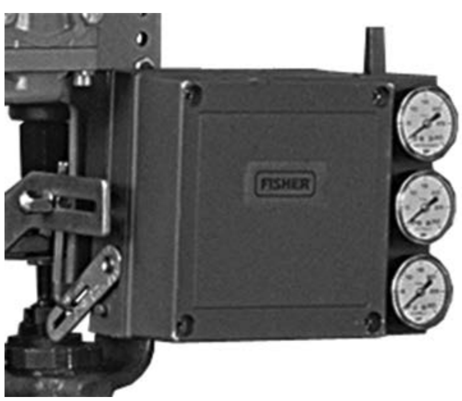

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Figure 3.5.1. Pneumatic Positioner

2. Analog I/P Positioner: This positioner performs the same function as the one above, but uses electrical current (usually 4-20 mA) instead of air as the input signal.
3. Digital Valve Controller: Although this instrument functions very much as the analog I/P described above, it differs in that the electronic signal conversion is digital rather than analog. The digital products cover communicating and non-communicating solutions:

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Figure 3.5.2. Analog I/P Positioner

X0338

Figure 3.5.3. Fisher FIELDVUE Digital Valve Controller

1. Digital Non-Communicating: A current signal (4-20 mA) is supplied to the positioner, which powers both the electronics and controls the output.
2. Digital Fieldbus Communications:
    a. HART: Like the analog I/P positioner, a 4-20 mA signal is used to control the instrument. However, an additional digital signal over the wires is used for two-way communication to enable diagnostic capabilities.
    b. FOUNDATION fieldbus— Fieldbus is an all-digital protocol that provides control, reduced wiring, data, and diagnostic capabilities.
    c. Profibus—This is largely found in on/off applications that use PLC control, but has evolved to be used in control applications as well.

There are several distinct advantages of using a digital valve controller over a pneumatic or analog positioner:

- Reduced cost of loop commissioning, due to automated configuration and calibration capability.
- Use of diagnostics to maintain valve and loop performance levels.
- Access to valve diagnostics through the Distributed Control System (DCS) or commonly used maintenance tools.
- Improved process control accuracy that reduces process variability.

FIELDVUE instruments enable diagnostic capabilities that can be accessed remotely. With the aid of Performance Diagnostics (PD), diagnostic tests can be performed without taking the instrument out of service (on-line diagnostics). Off-line diagnostics (valve signature and step response testing) are also available. Watching performance decline over time enables an optimized maintenance program.

Pneumatic and analog instruments also have diagnostic capabilities. An in-plant person, with the aid of the FlowScanner system (Figure 3.5.4), can diagnose the health of a valve through a series of off-line tests. The FlowScanner™ system consists of a portable, ruggedized computer and travel and pressure sensors. The sensors are connected to the valve to enable diagnostic tests, which are conducted with the valve off-line. A skilled maintenance technician can determine whether to leave the valve in the line or to remove the valve for repair.

Figure 3.5.4. FlowScanner System

3.6 Levels

Level transmitters are used in the refining industry to measure level of the fluid in the tank. There are various methods of doing this. A displacement method is used in the level transmitters. These are called “displacer type level transmitters.”

Figure 3.6.1 shows the major parts of the level transmitter. As the displacer “tends” to move up on raising fluid level, the resistive force is transmitted through the torque tube to the transmitter, which is mounted at the end of the torque tube. This type of level transmitter uses the displacement principles for level measurement. The displacer, when submerged in the fluid, gets a force exerted on it that is transmitted via a torque tube assembly to the transmitter, which correspondingly sends a signal to the control room indicating the level of the fluid.

The displacer type level transmitter is designed to measure liquid level, interface level, or density/specific gravity inside a process vessel.

Caged sensors (figure 3.6.2) provide more stable operation than do cageless sensors (figure 3.6.3) for vessels with internal obstructions or considerable internal turbulence.

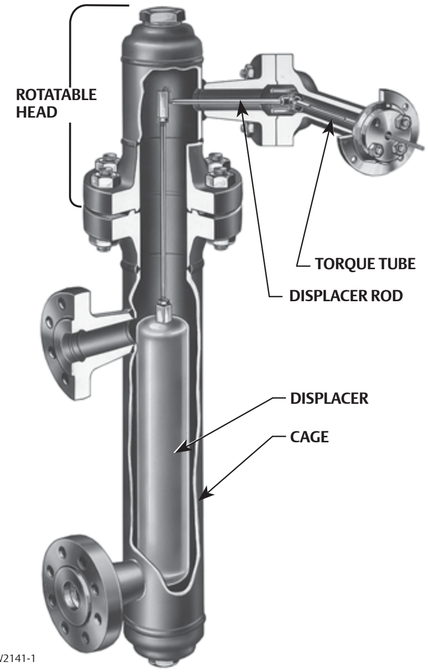

Figure 3.6.1. Displacer Level Transmitter Schematic

Cageless sensors are generally used on specific gravity and interface control applications requiring large displacers that are more easily accommodated by flange connections. The availability of many different displacer stem lengths permits lowering the displacer down to the most advantageous depth in the vessel.

Displacer type level transmitters can have design temperatures as high as 454°C (850°F). High design temperature and pressures may require special design considerations.

Figure 3.6.2. Caged Sensor

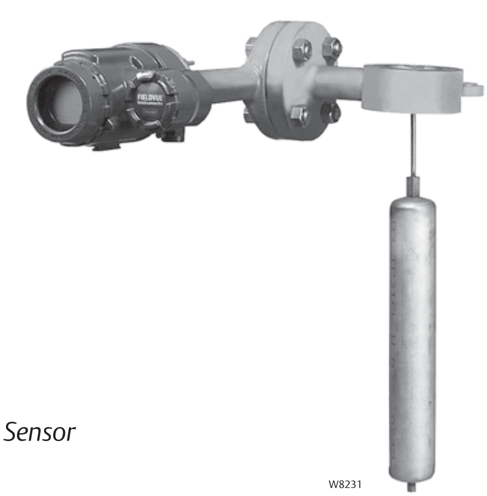

Figure 3.6.3. Cageless Sensor

4

Control Valves

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4. Refinery Control Valve Application Reviews

4.1 Furnace

Other Names—Fired heater, cracking furnace, reboiler heater

Furnaces are used to heat process feed material. Heat is created by burning fuel in burners on the floor and/or walls of the furnace. There are many different types of fuel that can be used by a furnace, such as natural gas, liquefied petroleum gas (LPG), refinery waste gas, and fuel oil.

The process feed stream to a furnace is usually broken into multiple tube passes to improve heat transfer. The most common configurations are two and four-pass furnaces. The passes are recombined into a single effluent stream after they exit the furnace.

The outlet temperature of a furnace is normally dictated by the requirements of a downstream process, usually a reactor, fractionator column, or distillation column. Adjusting the amount of fuel burned controls the outlet temperature.

In some cases, the furnace provides enough heat to thermally crack the feed stream from large hydrocarbon molecules to smaller molecules. In these cases, the outlet temperature is used to control the amount of cracked components in the effluent stream. It is important to understand whether or not cracking is occurring, as coke can build up resulting in less efficient heat transfer and requiring routine maintenance to the furnace if cracking occurs.

Figure 4.1.1. Furnace

Furnace Application Review

Furnaces are used in many refining process units and will be discussed specifically in the Delayed Coker Unit (Section 4.6). This section will discuss the typical critical control valve applications common to all furnaces in a refinery used to heat process feed.

Figure 4.1.2 shows the typical layout of a furnace with the critical control valves identified. Depending on the process fluid being heated and the design temperature required, care must be taken in material selection for valves in a furnace.

1, 2, 3, and 4. Feed Valves

Feed valves are usually set up as flow-control loops. They are configured to fail open so that a valve failure will protect the furnace radiant section tubes. If a radiant tube loses flow or has insufficient flow, the tube can quickly become so hot that the metal can melt. This can have disastrous consequences, as most process feeds make excellent fuels. A furnace can be destroyed very quickly if a ruptured tube is dumping into the firebox of the furnace.

Problem valves can lead to difficulties with controlling the outlet temperature of the furnaces. Also, many process feeds slowly build layers of coke on the inside of the radiant tubes. Coking is a non-linear reaction, and in some processes even a few extra degrees of temperature can lead to excessive coke buildup. If a flow valve provides inconsistent feed, the temperature will also swing and will usually lead to excessive coke buildup. This will shorten the furnace cycle time between decoking procedures, which will normally require the process unit downstream to shutdown.

Feed valves can typically be bypassed when necessary. A combination of the measured flow and any measured pass temperatures can be used to regulate the bypass valve.

Control is critical to maintaining integrity of furnace tubes (such as preventing coke lay-down), safe operations, and overall reliability of the furnace. While the furnace is firing, process fluid flow is required at all times, therefore a FIELDVUE digital valve controller with PD tier diagnostics is recommended to predict valve sticking or build up issues.

- **Typical Process Conditions:**
  - Fluid: Heavy gas oil, Naphtha, Flashed crude, etc.
  - P1 = 14 – 50 bar (200 - 725 psig)
  - T = 260 – 370°C (500 - 700°F)
  - Q = dependent on process design
- **Typical Control Valve Selection:**
  - Lower Flow Rates: NPS 1 to NPS 4 easy-e EZ or ED
  - Higher Flow Rates: NPS 3 to NPS 8 V500
  - Materials of Construction: sour feedstocks may require NACE trim materials

5. Fuel Gas Valve

Depending on the furnace service and configuration this valve will normally be part of a loop that controls either the fuel flow or pressure. These valves are specified as fail closed so that a control loop failure will not allow excessive fuel to be dumped into a hot furnace. Instrumentation may include a loop to bypass the digital valve controller in case of power failure to cut off fuel to furnace. A fuel valve failure will almost always shut down the processing unit downstream. Although many fuel valves have bypass circuits, refinery operations personnel are usually reluctant to run a furnace on bypass for any significant time because of safety concerns.

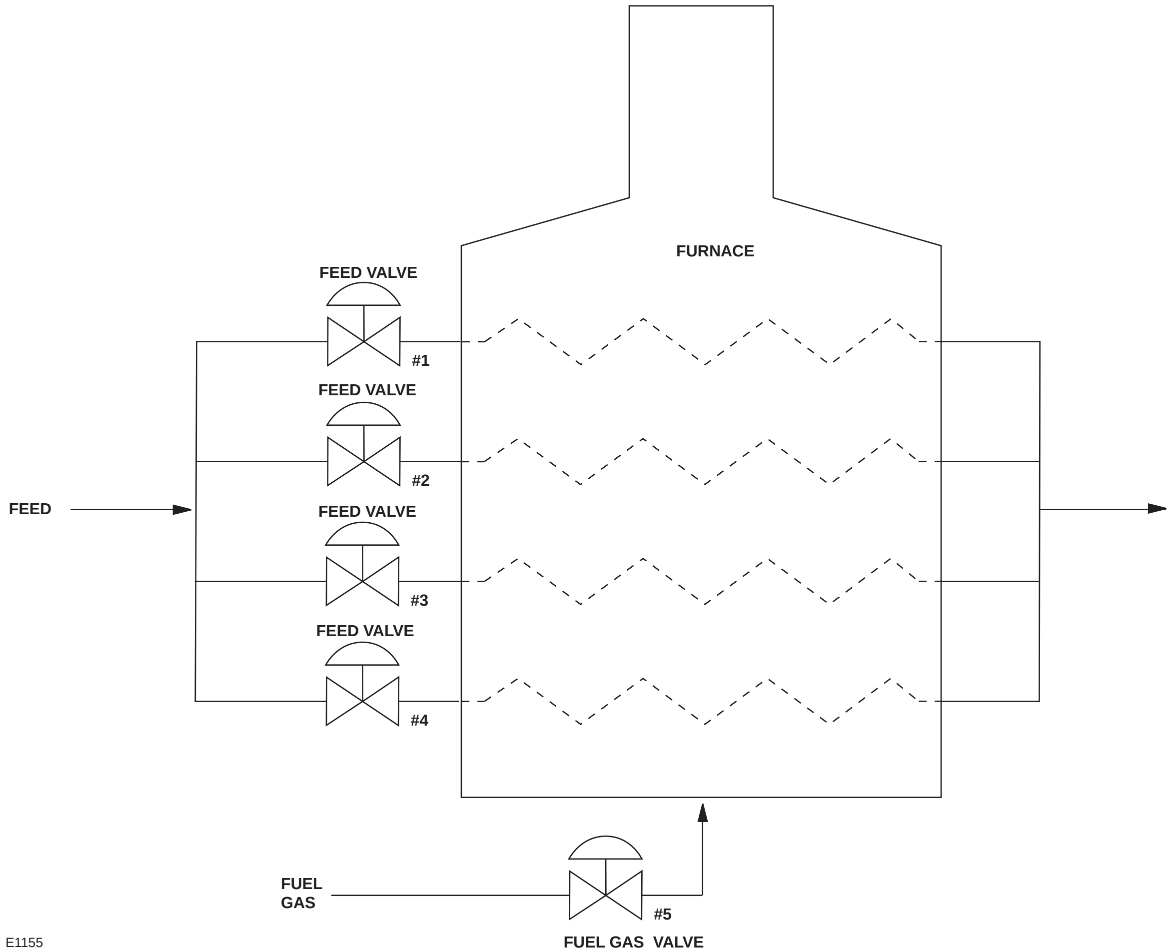


Figure 4.1.2. Furnace Process Flow Diagram

The preferred control loop configuration for the outlet temperature is a cascade to the set point of the loop controlling the fuel valve. Many furnaces will be set up such that the temperature control loop directly manipulates the fuel valve. This direct connection usually provides control performance that is inferior to a cascade configuration. It is extremely susceptible to any valve deadband such as that caused by a sticking valve. This can be detected by excessive oscillation of the outlet temperature.

When the fuel valve is manipulated by the temperature loop or by a flow control loop, there will often be a pressure control valve upstream of the fuel valve. This valve will also fail closed and will have the same consequences as a failure of the fuel valve. However, with this configuration, refinery operations personnel will be more willing to run a fuel valve in bypass as they still have a way to quickly shut off the fuel in an emergency.

Because this valve is critical to unit operation, FIELDVUE DVC6200 with PD tier diagnostics is recommended. Because monitoring valve position is so critical to this valve when it is supposed to fail close, it may be desirable to include the position transmitter option in the FIELDVUE DVC6200 to provide position feedback to the Distributed Control System (DCS), upon loss of power to the digital valve controller, assuring whether or not the valve actually closed.

- **Typical Process Conditions:**
  - — Fluid: Fuel gas
  - — P1 = 2 – 4 barg (30 - 60 psig)
  - — T = 40°C (100°F)
  - — Q = dependent on process design
- **Typical Control Valve Selection:**
  - — NPS 1 to NPS 6 easy-e EZ, ET, ED, or GX 3-way
  - — ENVIRO-SEAL duplex packing may be required for fire-safe construction, with reduced friction when compared to graphite packing
  - — Materials of Construction: WCC body with 300-series SST trim, sour fuel gas may require NACE trim materials

4.2 Distillation Column

Other Names—Tower, stripper, stabilizer, splitter, demethanizer, deethanizer, depropanizer, debutanizer, DIB (deisobutanizer) tower, precut tower, fractionator

Distillation columns are found in all refineries and many industrial processes. The objective for any distillation column is to separate a feed stream into light-component and heavy-component product streams. Distillation columns are inherent to many units in a refinery so specific product

Figure 4.2.1. Distillation Column

streams can be drawn off and either further processed or used as blending elements in final product streams. Throughout this text, you will see them frequently referred to as fractionators. There are two sections that cover specific distillation columns: crude distillation in 4.4 and vacuum distillation in 4.5. The distillation process relies on the relative volatility between the components that make up the feed stream. The high-volatility (lighter) components will boil at a lower temperature than the low-volatility (heavier) components. Therefore, when heat is added to the column through a bottom reboiler, the lighter materials are vaporized and rise to the top of the column. The overhead vapors are cooled until they condense and become a liquid again.

Reflux & Reboil

The efficiency of the distillation depends on the amount of contact between the vapor rising and the liquid falling down through a column. Therefore, some of the overhead liquid product is sent back (refluxed) to the top of the column. This assures that fewer of the heavy components come off the top of the column, thereby improving the purity of the overhead product. However, this process also requires more heat from the reboiler to re-vaporize the lighter components in the reflux stream. The reboiler is responsible for re-circulating the bottom product of the distillation column and removing any light hydrocarbons from the bottom product stream. The operation of a distillation column is a balancing act between product purity and energy use.

Flooding

If the amount of vapor and liquid traveling through the column (often referred to as "traffic") becomes too great, the column can "flood." Too much reflux flow or too much reboil heat resulting in too much vapor, (or both) can cause flooding. When flooding occurs, the efficiency of the distillation column is dramatically reduced, with corresponding drops in product purities. Column flooding can be prevented through good control practices, including many Fisher final control elements.

Distillation Column Application Review

Since distillation columns are used in many refining process units, the control valve selection is heavily dependent on the process fluid being distilled. However, across most process units the valve functions in distillation columns are similar. In the subsequent text, a summary of each of the critical control valves in these units is discussed. This selection is based on what is typically expected, there may be some variations due to specific user requirements. Figure 4.2.2 shows the typical layout of a distillation column with the critical control valves identified.

1. Feed Valve

This valve controls the feed going into the distillation column. Feed valves are usually set up as flow or level control loops. An upstream unit or process often controls the valve.

Unstable feed flow will make the distillation column difficult to control. A problem valve will often cause the feed flow to oscillate. As a result, the column will alternate between too little and too much reboil heat. Depending on the size and number of trays in the column, the effect of a swing in the feed will take anywhere from several minutes to more than an hour to reach the ends of the column. Sometimes, the reboil and reflux controls will amplify the swings. The final result is that meeting product purity targets becomes more difficult. Refinery operations personnel will normally respond by over-purifying the products, wasting energy to compensate for the problematic feed control valve.

- **Typical Process Conditions:**
  - Fluid: Primary reactor effluent
  - P1/P2 = dependent on process design
  - T = dependent on process design
  - Q = dependent on process design
  - Flashing may be present depending on process variables
- **Typical Control Valve Selection:**
  - Lower Flow Rates: NPS 1 to NPS 4 easy-e EZ, ED, ET, or GX
  - Higher Flow Rates: NPS 6 to NPS 12 easy-e EWD or NPS 6 to NPS 12 Vee-Ball
  - Materials of Construction: WCC with standard trim (400-series stainless for easy-e or 300-series stainless for Vee-Ball) unless process fluid requires sour service trim.

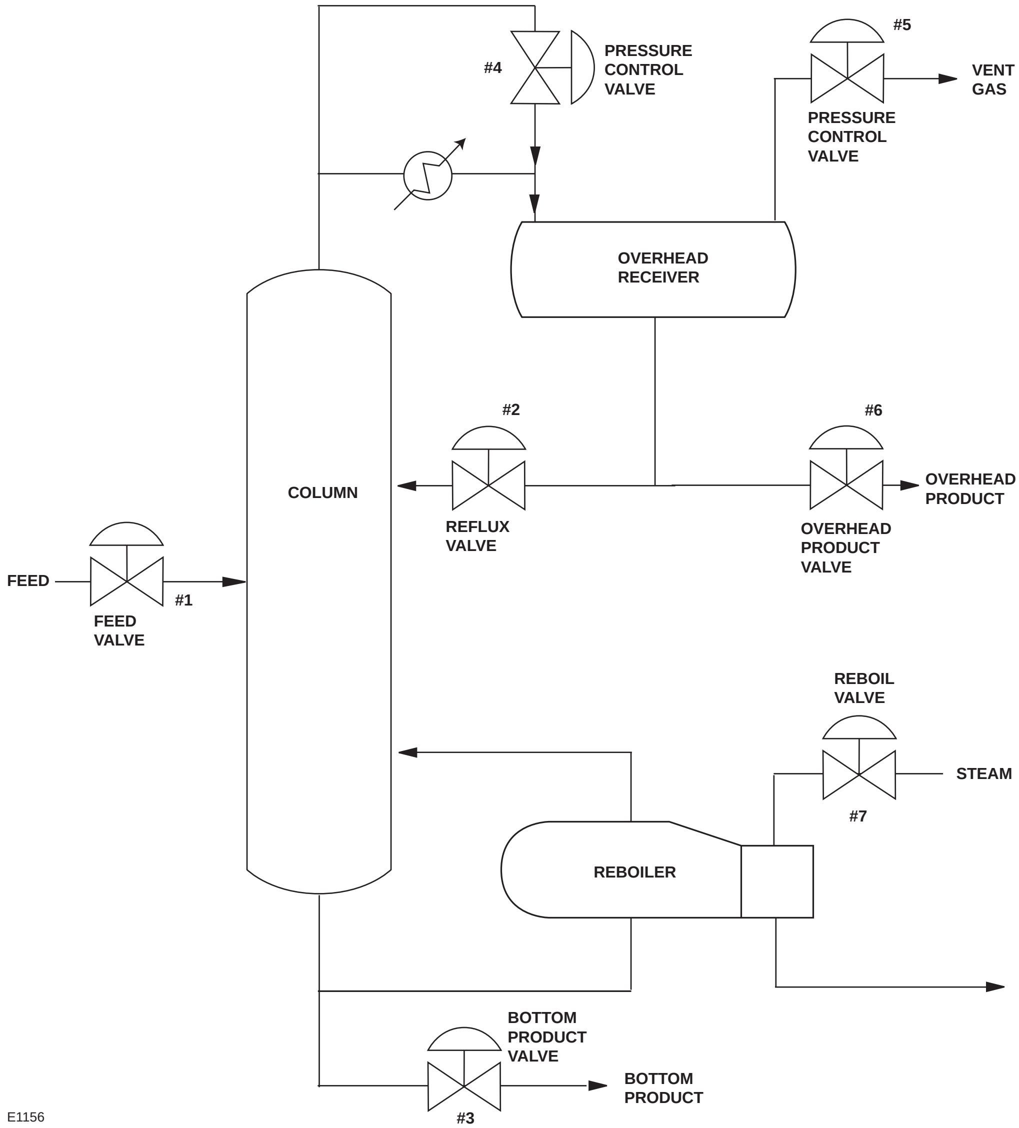


Figure 4.2.2. Distillation Column Process Flow Diagram

2. Reflux Valve

The reflux valve is typically either a flow or column temperature-control loop. It is used to adjust the purity of the overhead product. The higher the reflux rate, the purer the overhead product will become. However, raising the reflux rate also will require more reboil heat and eventually will flood the tower.

A poorly operating reflux valve will have the same effects as a bad feed valve. Product purities will oscillate, and the column will be difficult to control. This valve has a direct impact on the efficiency of the column.

- **Typical Process Conditions:**
  - Fluid: Reflux fluid
  - P1/P2 = dependent on process design
  - T = dependent on process design
  - Q = dependent on process design
- **Typical Control Valve Selection:**
  - Lower Flow Rates: NPS 1 to NPS 4 easy-e EZ or GX
  - Higher Flow Rates: NPS 3 to NPS 12 Control-Disk or NPS 3 to NPS 12 Vee-Ball
  - Materials of Construction: dependent on process design

3. Bottom Product Valve

The bottom product valve is typically used to control the level in the bottom of the column. It normally has no effect on column operation unless it causes the level to change quickly and dramatically.

- **Typical Process Conditions:**
  - Fluid: Distillation bottoms
  - P1/P2 = dependent on process design
  - T = dependent on process design
  - Q = dependent on process design

- **Typical Control Valve Selection:**
  - — Lower Flow Rate, Clean Fluids: NPS 1 to NPS 4 easy-e EZ, ED, or ET
  - — Higher Flow Rate: NPS 3 to NPS 12 Vee-Ball
  - — Viscous or Dirty Fluid: NPS 1 to NPS 8 V500
  - — Materials of Construction: dependent on process design, may require satellite or ceramic trim materials for ball valve or eccentric plug designs

4., 5. Hot Vapor Bypass and Pressure Control Valves

The pressure control valves are used to control the column pressure. Higher column pressures will yield better product purities, but require more energy to operate. Normal operating procedure is to minimize the pressure to lower energy costs while maintaining product specifications. There is a low limit because lower pressures reduce the amount of vapor/liquid traffic the column can handle and can make it more likely to flood.

The simplest way to control pressures is to continuously vent gas from the system (valve #5). This sizing of this valve is critical. If the valve is too large, a small valve movement will cause a large pressure swing. If the valve is too small, the pressure response will be very sluggish. It is likely that a valve that is too small will operate from completely closed to completely open. In either scenario, oscillating column pressure and difficult column control result. A sticking pressure control valve presents the same problem. A sticking valve is a common concern on vent gas service because the valve packing is normally tight to prevent fugitive emissions.

Many distillation columns also use what is known as a “hot vapor bypass” valve (#4) to control pressure. In these instances, some of the hot overhead vapors are bypassed around the overhead condenser heat exchanger. The amount of bypass will control the pressure. This eliminates the constant venting of process gas, which usually goes to a low-value refinery waste fuel gas system. Unfortunately, the pressure response on a hot vapor bypass valve is normally very sluggish due to slow process response time. Like the vent gas valve, this valve is a concern for fugitive emissions, and the packing is likely to be tight. A sticking valve causes wide, slow oscillations in column pressure, and product purities likewise swing widely and slowly. The response of refinery operations personnel is usually to over-purify.

A majority of columns with hot-vapor bypass valves also utilize a vent gas valve. In these cases, a single pressure control loop manipulates both valves. At lower pressures, the hot vapor bypass valve is used. As the pressure rises, there is a transition point where the hot vapor bypass valve closes fully and the vent gas valve starts to open.

At high pressures, the vent gas valve controls the pressure. This configuration often leads to pressure control problems, since the hot vapor bypass and vent gas valves have different control characteristics. Also, it is unlikely that one valve will close precisely at the same time the other valve opens. If the column is constantly making a transition between using the hot vapor bypass and vent gas valves, the pressure will normally oscillate. This is a tuning rather than a valve problem, but it should be kept in mind for column design or valve resizing. A FIELDVUE DVC6200 digital valve controller with PD tier diagnostics is recommended for both of these valve constructions to alert users to any required maintenance in these valves.

These valves are very important to control the stability of the distillation column. Many columns use tray temperature to control overhead composition, thus stable pressure is required to ensure that temperature changes reflect composition changes, not pressure changes.

- **Typical Process Conditions:**
  - — Fluid: Dependent on process design
  - — P1/P2 = dependent on process design
  - — T = dependent on process design
  - — Q = dependent on process design
- **Typical Control Valve Selection:**
  - — Lower Flow Rate: NPS 1 to NPS 4 easy-e EZ, ED, or ET
  - — Higher Flow Rate: NPS 3 to NPS 12 Vee-Ball
  - — ENVIRO-SEAL PTFE or graphite packing, depending on process design conditions
  - — Materials of Construction: dependent on process design, if gas is acidic, special materials may be required

6. Overhead Product Valve

The overhead product valve is typically used to control the level in the overhead receiver. It normally has no effect on column operation unless it causes the level to change quickly and dramatically.

- **Typical Process Conditions:**
  - — Fluid: Distillation overhead product
  - — P1/P2 = dependent on process design
  - — T = dependent on process design
  - — Q = dependent on process design
- **Typical Control Valve Selection:**
  - — Lower Flow Rate: NPS 1 to NPS 4 easy-e EZ, ED, ET, or GX
  - — Higher Flow Rate: NPS 3 to NPS 12 Vee-Ball
  - — Materials of Construction: dependent on process design

7. Reboil Valve

The reboil valve controls the amount of heat put into the column by the reboiler. In many cases, steam is used as a heat source. The service is very clean, and fugitive emissions are not a concern. Steam valves are usually very reliable. However, a problematic valve will make the column difficult to control precisely. This will be especially true if the column feed is subject to frequent changes.

Not all reboilers use steam as a heat source. To save energy, many refineries have integrated their units so that higher-temperature process streams are used to provide heat for lower-temperature processes. In these cases, the reboil valve will foul more easily and might create fugitive emission concerns.

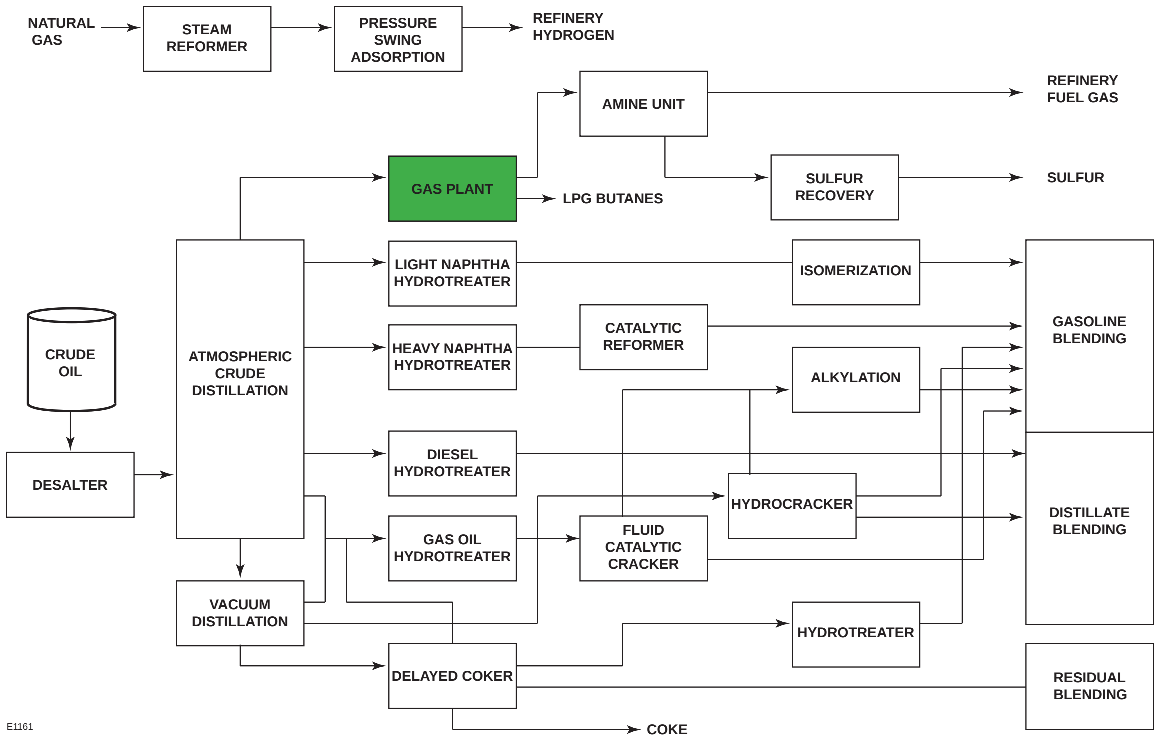


Figure 4.3.1. Gas Plant Location

This valve is important because it drives the vapor back up through the column. Vapor through the column affects column efficiency. Reboiler steam will have a direct effect on overhead reflux flow.

- **Typical Process Conditions:**
  - Fluid: Steam
  - P1 = dependent on process design, typically 10.3 bar (150 psig) saturated steam
  - T = dependent on process design
  - Q = dependent on process design
- **Typical Control Valve Selection:**
  - NPS 1 to NPS 6 easy-e ET or ES
  - Class V shutoff may be utilized to minimize energy usage
  - Materials of Construction: steam application materials or materials compatible with the process gas

4.3 Gas Plant

Other Names—Light-ends unit, saturated (sats) gas plant, vapor recovery unit, unsaturated gas plant

The main function of the refinery gas plant is to recover valuable C3, C4, C5, and C6 components from various gas streams generated by refinery processing units such as the crude unit, delayed coker, fluid catalytic cracker, reformer, and hydrocracker. This recovery is done by using fractionators and absorbers. Recovered light hydrocarbon gases C1 and C2 are used as refinery fuel in various fired heaters.

Most reactive processes in a refinery create light-end material in addition to the desired products (gasoline, kerosene, diesel, etc.). These light-ends include hydrogen, methane, ethylene, ethane, propylene, propane, and various butanes and butenes. Light-ends are usually a low-value process stream, and are often used as fuel gas for process heaters. However, if enough light-end materials are produced, there is economic incentive to separate the light-ends into component streams. The exact product streams depend on refinery needs as well as any potential external marketing opportunities.

Some cracking units produce enough light-ends that a gas plant is built specifically as part of the unit. (Delayed cokers and fluid catalytic crackers are units that usually have an integral gas plant.) In other cases, gas plants are built to handle the combined light-ends of several process units.

Almost all valves in a light-ends gas plant are a possible source of fugitive emissions. Therefore, it is very likely that the valve packing will be kept very tight. This can lead to excessive control valve deadband. Packing selection and actuator sizing might play a critical role in valve performance for this type of service.

The example used for this section is a typical FCC gas plant. The light-ends that come from the FCC fractionator overhead are separated by this plant into fuel gas (hydrogen, methane, and ethane), C3 (propylene and propane), C4 (butenes and butanes), and naphtha.

Figure 4.3.2 shows the layout of the vapor recovery system and the commonly associated control valves. This depiction includes a depropanizer, which may or may not be present. Other units may be present, such as a depentanizer. However, this depends upon the overall desired final products.

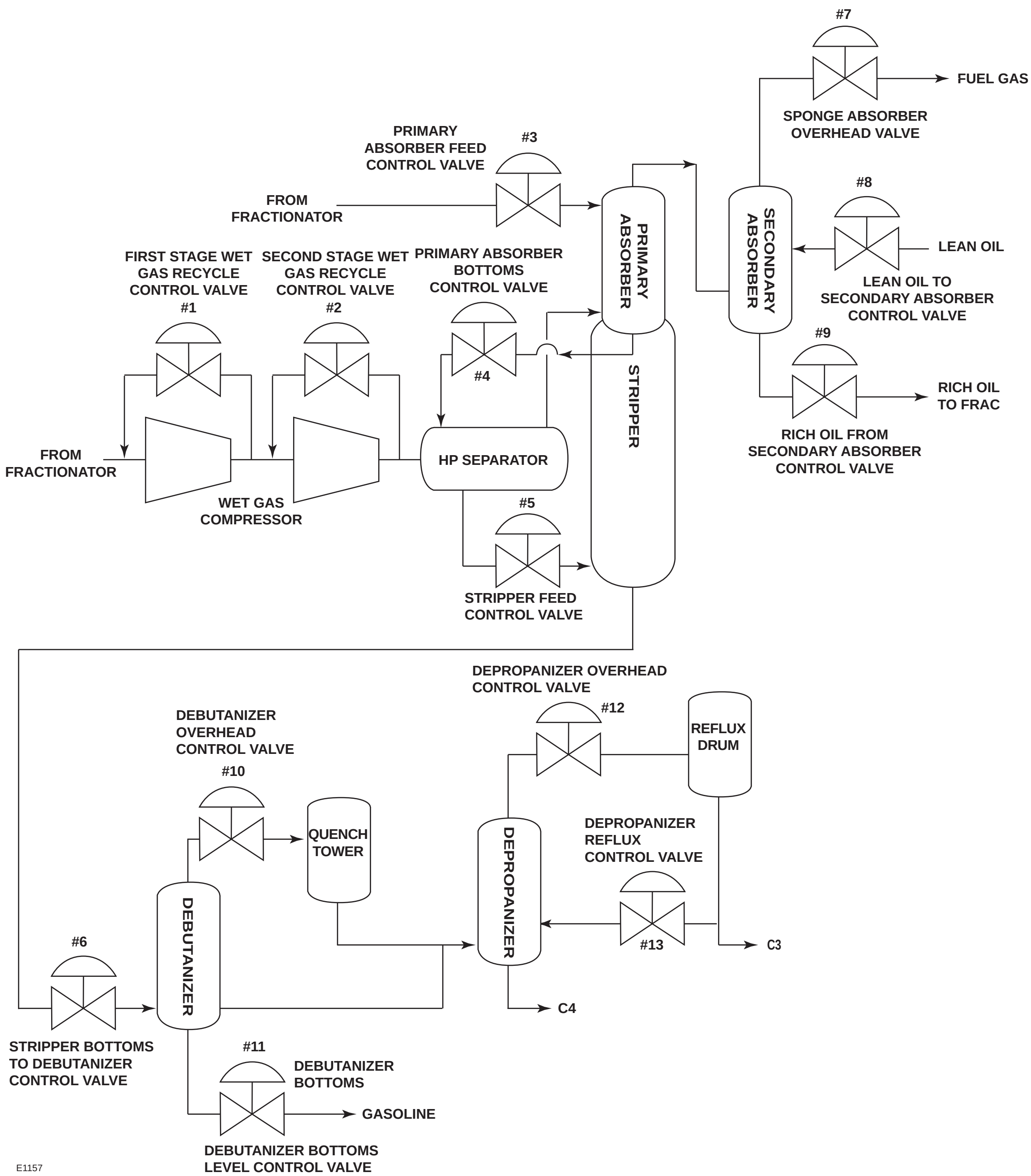


Figure 4.3.2. Gas Plant Process Flow Diagram

Gas Plant Application Review

The gas plant is used to reject fuel gas, recover C3 and C4 liquid products, and produce debutanized gasoline within the required vapor pressure levels. The main fractionator overhead vapors are compressed in the wet gas compressor, which is typically a two-stage device. The high pressure gas and liquids from the low pressure knock out drum are cooled and combined with liquid from the primary absorber and flow to the high pressure separator.

Liquid from the high pressure separator is pumped to the top of the stripper. The stripper removes C2 and lighter products, which then go to the primary absorber. The C3 and heavier products are removed in the stripper bottoms.

In the primary absorber, vapor from the high pressure separator flows to the bottom while raw gasoline and lean oil from the debutanizer flow to the top. The liquids absorb C3 and heavier components from the vapor. The gases leaving the top of the primary absorber are sent the secondary absorber.

In the secondary absorber, heavy naphtha from the main fractionator is used to recover any liquids left in the vapor stream. Fuel gas leaves the top of the absorber and is typically subjected to further treatment in an amine treatment unit. The bottoms return to the main fractionator.

Liquid from the bottom of the stripper flows to the debutanizer. The overhead liquids can be treated and sent to storage or further separation of C3 and C4 products can occur. Further separation of the bottoms products is possible, but will vary from plant to plant.

1. First Stage Wet Gas Recycle Control Valve

This valve is used to protect the first stage of the wet gas compressor from the effects of surge that can occur during startup, shutdown, and process upsets. The performance of this valve is critical to the operation and efficiency of the compressor. There is the potential for coke buildup on the internals of the valve, thus it is critical that a multi-stage trim is not present in this application. A globe valve with Whisper Trim is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: Wet gas
  - P1 = 6 – 10 bar (72 – 130 psig)
  - P2 = 2 – 4 bar (14 – 43 psig)
  - T = 110°C – 130°C (23°F - 266°F)
  - W = 85,000 – 350,000 kg/hr
- **Typical Control Valve Selection:**
  - NPS 8 to NPS 16 easy-e ET, EW, or EU
  - WCC body and 316/Alloy 6 trim
  - Noise attenuation may be required
  - Class V shutoff

2. Second Stage Wet Gas Recycle Control Valve

This valve is used to protect the second stage of the wet gas compressor from the effects of surge that can occur during startup, shutdown, and process upsets. The performance of this valve is critical to the operation and efficiency of the compressor. Potential for coke buildup is present on the internals of the valve, thus the use of a multi-stage trim must not be present in this application. A globe valve with Whisper Trim is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: Wet gas
  - P1 = 13 – 21 bar (173 – 289 psig)
  - P2 = 6 – 10 bar (72 – 130 psig)
  - T = 110°C – 130°C (230°F - 266°F)
  - W = 85,000 – 350,000 kg/hr
- **Typical Control Valve Selection:**
  - NPS 10 to NPS 16 easy-e ET, EW, or EU
  - WCC body and 316/Alloy 6 trim
  - Noise attenuation may be required
  - Class V shutoff

3. Primary Absorber Feed Control Valve

This valve controls the flow of overhead liquids from the main fractionator to the primary absorber. Accurate control is needed in this application to ensure proper vapor to liquid ratio in the absorber. A globe or rotary valve is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: Distillate
  - P1 = 13 – 21 bar (173 – 289 psig)
  - P2 = 12 -18 bar (159 – 246 psig)
  - T = 40°C – 60°C (104°F - 140°F)
  - Q = 200 – 850 m^3/hr
- **Typical Control Valve Selection:**
  - NPS 8 to NPS 12 easy-e EU, EW, or Vee-Ball
  - WCC body and 316/Alloy 6 trim
  - Equal percentage characteristic
  - Class IV shutoff

4. Primary Absorber Bottoms Control Valve

This valve controls the liquid level in the primary absorber. Accurate control is required in this application to ensure the proper interaction of liquid and vapor streams. A globe or rotary valve is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: Distillate
  - P1 = 12 – 19 bar (159 – 260 psig)
  - P2 = 11 – 17 bar (144 – 231 psig)
  - T = 40°C – 60°C (104°F – 140°F)
  - Q = 250 – 950 m^3/hr
- **Typical Control Valve Selection:**
  - NPS 8 to NPS 12 easy-e ET, EW, or Vee-Ball
  - WCC body and 316/Alloy 6 trim
  - Equal percentage characteristic
  - Class IV shutoff

5. Stripper Feed Control Valve

This valve controls level in the high pressure separator and flow to the stripper to remove C2 and lighter components. Accurate level control in the high pressure separator is necessary to prevent liquid carryover into the primary absorber. A globe or rotary valve can be used in this application.

- **Typical Process Conditions:**
  - Fluid: Light hydrocarbons
  - P1 = 18 – 24 bar (246 – 333 psig)
  - P2 = 15 – 23 bar (202 – 318 psig)
  - T = 50°C – 80°C (122°F - 176°F)
  - Q = 200 – 2000 m^3/hr
- **Typical Control Valve Selection:**
  - NPS 6 to NPS 16 easy-e ET valve, CV500, V500, or easy-e EUT
  - WCC body and 316/Alloy 6 trim
  - Equal percentage characteristic
  - Class IV shutoff

6. Stripper Bottoms to Debutanizer Control Valve

This valve controls the level of light hydrocarbons in the stripper column. This operation is critical to removal of C2 and lighter components. A rotary or globe valve can be used in this application.

- **Typical Process Conditions:**
  - — Fluid: Light hydrocarbons
  - — P1 = 15 – 20 bar (202 – 275 psig)
  - — P2 = 12 – 14 bar (159 – 188 psig)
  - — T = 120°C – 130°C (248°F - 266°F)
  - — Q = 250 – 2000 m^3/hr
- **Typical Control Valve Selection:**
  - — NPS 6 to NPS 16 easy-e ET or EUT, CV500, or V500
  - — WCC body and 316/Alloy 6 trim
  - — Equal percentage characteristic
  - — Class IV shutoff

7. Sponge Absorber Overhead Valve

This valve serves as the pressure controller for the gas plant. Because it is setting the pressure for the entire gas plant, it is important that this valve perform well. This is a minor stream in terms of flow (less than 1 MBPD) and has a value equal to that of fuel gas.

It is also possible that the debutanizer or the C3/C4 splitter will have a pressure control valve as well.

The pressure control valve is used to control the column pressure. Higher column pressures will yield better product purities but require more energy to operate. The goal of normal operating procedure is to minimize the pressure to lower energy costs while maintaining product specifications. The low energy limit exists because lower pressure reduces the amount of vapor/liquid traffic the column can handle and make it more likely to flood.

The simplest way to control pressures is to continuously vent gas from the system. The sizing of the vent valve is critical. If the valve is too large, a small valve movement will cause a large pressure swing. Likewise, if the valve is too small, the pressure response will be sluggish. It is likely that an undersized valve will operate from completely closed to completely open. In either scenario, an oscillating column pressure and difficult column control are the result. A sticking pressure control valve will present the same problem. A sticking valve is a common concern on vent gas valves because the valve packing will normally be tight to prevent fugitive emissions.

Many distillation columns also use what is known as a “hot vapor bypass” valve to control pressure. In this case, some of the hot overhead vapors are bypassed around the overhead condenser heat exchanger. The amount of bypass will control the pressure. This eliminates the constant venting of process gas, which usually goes to a low value refinery waste fuel gas system. Unfortunately, the pressure response on a hot vapor bypass valve is normally very sluggish due to slow process response time. Like the vent gas valve, this valve is a concern for fugitive emissions, and the packing is likely to be tight. A sticking valve will cause wide, slow oscillations in column pressure. The product purities will likewise swing widely and slowly. The response of refinery operations personnel will usually be to over-purify.

A majority of columns with a hot vapor bypass valve will use it in combination with a vent gas valve. In these cases, a single pressure control loop will manipulate both valves. At lower pressures, the hot vapor bypass valve is used. As the pressure rises, there will be a transition point where the hot vapor bypass valve closes fully and the vent gas valve starts to open. At high pressures, the vent gas valve controls the pressure. This configuration often leads to pressure control problems, as the hot vapor bypass and vent gas valves will have different control characteristics. It is also unlikely that one valve will close precisely at the moment the other valve opens. If the column constantly transitions between using the hot vapor bypass and vent gas valves, the pressure will normally oscillate. This is a tuning rather than a valve problem but it should be kept in mind for column design or valve resizing.

- **Typical Process Conditions:**
  - — Fluid: Distillate light-end hydrocarbon liquid and non-condensable gas
  - — P1/P2 = dependent on process design
  - — T = less than 93°C (200°F)
- **Typical Control Valve Selection:**
  - — NPS 2 – NPS 6 easy-e EZ, ED, or ET; NPS 4 – NPS 8 Vee-Ball
  - — ENVIRO-SEAL PTFE packing
  - — Materials of construction: dependent upon presence of acid in gas

8. Lean Oil to Secondary Absorber Control Valve

This valve is used to control the flow of lean oil (heavy naphtha) to absorb heavier components in the secondary absorber. Proper flow control is necessary to capture as much of the heavier components as possible. A rotary or globe valve can be successfully used in this application.

- **Typical Process Conditions:**
  - — Fluid: Lean oil (heavy naphtha)
  - — P1 = 18 – 24 bar (246 – 333 psig)
  - — P2 = 13 – 18 bar (173 – 246 psig)
  - — T = 40°C – 50°C (104°F - 122°F)
  - — Q = 30 – 150 m^3/hr
- **Typical Control Valve Selection:**
  - — NPS 3 to NPS 4 easy-e ET or V500
  - — WCC body and 316/Alloy 6 trim
  - — Equal percentage characteristic
  - — Class IV shutoff

9. Rich Oil from Secondary Absorber Control Valve

This valve controls the liquid level in the secondary absorber enabling proper capture of the heavier components in the gas stream from the primary absorber. A globe or rotary valve can be used successfully in this application.

- **Typical Process Conditions:**
  - Fluid: Rich oil
  - P1 = 12 – 18 bar (159 – 246 psig)
  - P2 = 4 – 6 bar (43 – 72 psig)
  - T = 60°C – 80°C (140°F - 176°F)
  - Q = 50 – 150 m^3/hr
- **Typical Control Valve Selection:**
  - NPS 3 to NPS 4 easy-e ET or V500
  - WCC body and 316/Alloy 6 trim
  - Equal percentage characteristic
  - Class IV shutoff

10. Debutanizer Overhead Control Valve

This valve controls the flow of the vapor driven off in the debutanizer to be quenched and subjected to further separation to capture C3 and C4 components. A medium-sized rotary valve is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: C3 and C4 hydrocarbons
  - P1 = 12 – 14 bar (159 – 188 psig)
  - P2 = 11 – 13 bar (144 – 173 psig)
  - T = 60°C – 80°C (140°F - 176°F)
  - Q = 30,000 – 120,000 Nm^3/hr
- **Typical Control Valve Selection:**
  - NPS 10 to NPS 12 Control-Disk or Vee-Ball
  - WCC body and 316/Alloy 6 trim
  - Equal percentage characteristic
  - Class IV shutoff

11. Debutanizer Bottoms Level Control Valve

This valve controls the liquid level in the debutanizer ensuring proper separation of the lighter components from the heavier components. A rotary valve is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: Gasoline
  - P1 = 12 – 14 bar (159 – 188 psig)
  - P2 = 8 – 10 bar (101 – 130 psig)
  - T = 100°C – 110°C (212°F - 230°F)
  - Q = 70 – 350 m^3/hr
- **Typical Control Valve Selection:**
  - NPS 6 to NPS 10 V500 or Vee-Ball
  - WCC body and 316/Alloy 6 trim
  - Equal percentage characteristic
  - Class IV shutoff

12. Depropanizer Overhead Control Valve

This valve controls the overhead vapor flow into the reflux drum to facilitate separation of C3 and C4 components. A medium sized rotary valve is generally utilized in this application.

- **Typical Process Conditions:**
  - Fluid: Propane
  - P1 = 16 – 18 bar (217 – 246 psig)
  - P2 = 15 – 17 bar (202 – 231 psig)
  - T = 50°C – 60°C (122°F - 140°F)
  - Q = 50,000 – 100,000 Nm^3/hr
- **Typical Control Valve Selection:**
  - NPS 12 to NPS 16 8532, Control-Disk, or V300
  - WCC body and 316/Alloy 6 trim
  - Equal percentage characteristic
  - Class IV shutoff

13. Depropanizer Reflux Control Valve

This valve controls the propane reflux back into the depropanizer. Proper control is required in this application to ensure adequate separation of the C3 and C4 components in the depropanizer. A medium sized globe or rotary valve can be utilized in this application.

- **Typical Process Conditions:**
  - Fluid: Propane
  - P1 = 16 – 18 bar (217 – 246 psig)
  - P2 = 13 – 15 barg (173 – 202 psig)
  - T = 50°C – 60°C (122°F - 140°F)
  - Q = 1000 – 2000 m^3/hr
- **Typical Control Valve Selection:**
  - NPS 8 to NPS 10 easy-e ET or NPS 6 to NPS 8 V500
  - WCC body and 316/Alloy 6 trim
  - Equal percentage characteristic
  - Class IV shutoff

4.4 Crude Desalter/Distillation Unit

Other Names—Crude unit, crude fractionator, crude column, pipestill, atmospheric crude column

The atmospheric crude distillation unit (CDU) is the first processing unit in a refinery downstream of the desalter. The unit is a complex column that fractionates crude oil into the basic product streams. These basic product streams from the crude distillation unit can vary widely depending on the refinery operating objectives. Typical boiling point cuts from the atmospheric crude unit include: naphtha, kerosene, diesel, gas oil, heavy gas oil, and residue, which is fed to the vacuum crude unit for further distillation and separation under vacuum. Normally, these product streams are sent to downstream units for further processing before being sent to product tanks.

The crude oil is sent through a process heater and is partially vaporized before entering the fractionator near the bottom of the column. Refer to section 4.1 covering the furnace

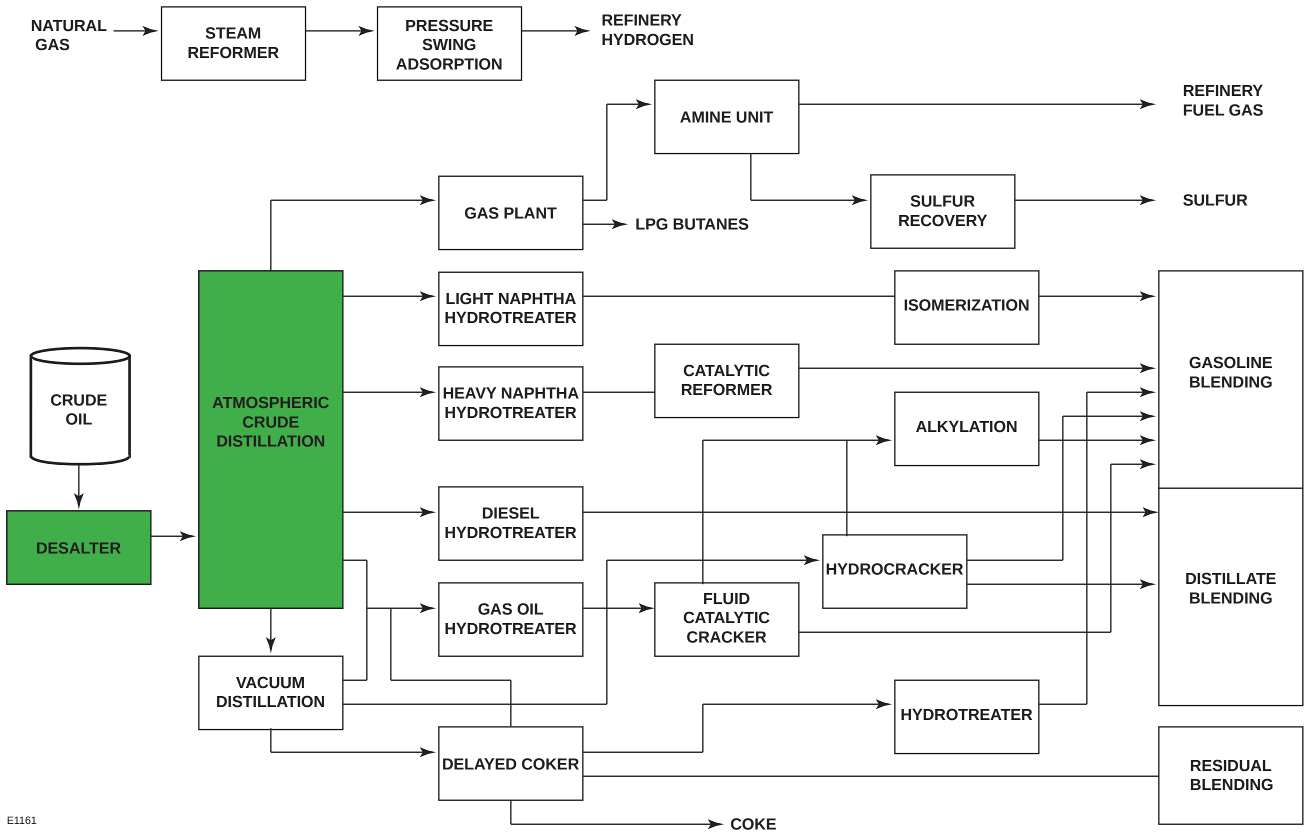


Figure 4.4.1. Crude Desalter and Distillation Unit Location

(process heater). Stripping steam also is injected at the bottom of the column. One or more process pump-around heat exchanger loops and a top reflux stream are used to cool the rising vapors, which separates the crude mixture into product streams. Product streams are extracted through side draws to the steam stripping columns. The column pressure and product draw temperatures are used to control the product streams to quality specifications, usually to the final or 95% of the boiling point for the product stream.

Desalter

Raw crude oil often contains water, inorganic salts, suspended solids, and water-soluble trace metals. These contaminants must be removed to reduce corrosion, plugging and fouling of equipment, and prevent poisoning of catalyst in downstream processing units. Desalting, the first step and one of the most critical processes in refining, removes these contaminants. Desalter efficiency can have dramatic impact on nearly every downstream unit.

Crude oil desalting is the process of “washing” the crude with water to extract salts and solids. The two most typical methods of crude-oil desalting, chemical and electrostatic separation use hot water as the extraction agent. In chemical desalting, water and chemical surfactant (demulsifiers) are added to the crude, heated so that salts and other impurities dissolve into the water or attach to the water, and then held in a tank where they settle out. Electrical desalting is the application of high-voltage electrostatic charges to concentrate suspended water globules in the bottom of the settling tank. Surfactants are added only when the crude has a large amount of suspended solids. Both methods of desalting are continuous.

1. Mixing valve (upstream of the desalter unit)

This valve is considered to be a severe service application valve. It serves to mix water and crude oil together prior to entering the desalter. The crude oil is dirty since it comes from the ground, so there will be sand and sediment along with water and salts.

- **Typical Process Conditions:**
  - — Fluid: Crude oil, wash water, and emulsifiers
  - — P1 = 20 – 23 barg (300 – 325 psig)
  - — P2 = 16 – 19 barg (230 – 275 psig)
  - — T = 232 – 315°C (450 - 600°F)
  - — Q = 310 – 600 kg/h
- **Typical Control Valve Selection:**
  - — NPS 6 to NPS 16 butterfly or NPS 6 to NPS 16 Vee-Ball (reverse flow)
  - — Cage guided valves are not recommended
  - — ENVIRO-SEAL graphite packing
  - — Materials of Construction: WCC body with 300-series or solid stellite trim, NACE may be required if crude is sour
  - — Class IV shutoff

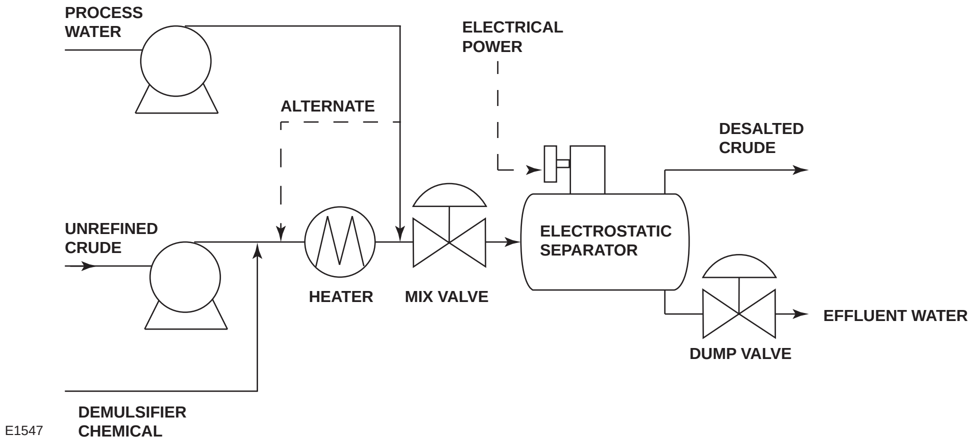


Figure 4.4.2. Crude Desalter Process Flow Diagram

Crude Distillation Unit

The CDU is common to all refineries, as it begins the process of converting crude oil into valuable products. Because this unit is inherent to all refineries, there are certain control valve trends that are beneficial to understand.

1. Feed Valve to Furnace (Pass Flow Control Valves)

The feed to a crude distillation unit is crude oil from the oil fields. Feed valves are usually set up as flow-control loops. They are configured to fail open so that a valve failure will protect the furnace radiant section tubes. If a radiant tube loses or has insufficient flow, the tube can quickly become so hot that the metal can melt. This can have disastrous consequences, as most process feeds make excellent fuels. A furnace can be destroyed very quickly if a ruptured tube is dumping into the firebox of the furnace.

There are a series of four to six valves in parallel that are used to split the flow from the desalter into several streams for better heat transfer or to break process stream into multiple stream “passes” to improve heat transfer.

Problem valves can lead to difficulties controlling the outlet temperature of the furnaces. Also, many process feeds slowly build layers of coke on the inside of the radiant tubes. Coking is a non-linear reaction and in some processes even a few extra degrees of temperature can lead to excessive coke build-up. If a flow valve is oscillating, the temperature will also swing and will usually lead to excessive coke buildup. This will shorten the furnace cycle time between decoking procedures, which normally requires the process unit downstream to shut down.

Feed valves can easily be bypassed when necessary. A combination of the measured flow and any available pass temperatures can be used to regulate the bypass valve.

- **Typical Process Conditions:**
  - — Fluid: Crude oil
  - — P1 = 20 – 23 barg (300 – 325 psig)
  - — P2 = 16 – 19 barg (230 – 275 psig)
  - — T = 232 – 340°C (450 - 600°F)
  - — Q = 545 – 680 m^3/h (2400 – 3000 gpm)
  - — Flashing may be present depending on process variables
- **Typical Control Valve Selection:**
  - — Lower Flow Rates: NPS 1 to NPS 4 easy-e ED
  - — Higher Flow Rates: NPS 6 to NPS 12 EWD or NPS 3 to NPS 8 V500 (reverse flow)
  - — ENVIRO-SEAL graphite packing
  - — Materials of Construction: WC9 body with 300-series or solid stellite trim, NACE may be required if crude is sour
  - — Class IV shutoff

2, 3. Pump-Around Valve Function

A crude fractionator will always have at least one pump-around heat exchanger loop for controlling the heat balance. Most fractionators will have more than one pump-around loop. The pump-around loop is used to extract heat from the column, creating the separation between the product draws immediately above and below the pump-around loop. The pump-around valves are usually flow controllers.

A poorly performing or bypassed pump-around valve will increase the variability in the quality specifications of the product draws. A valve failure most likely will create an upset lasting from 30 minutes to a few hours depending on the severity of the failure.

- **Typical Process Conditions:**
  - — Fluid: Hydrocarbon liquid
  - — P1 = 10 barg (150 psig)
  - — T = 95 – 340°C (200 - 644°F)
  - — Q = dependent on process design
- **Typical Control Valve Selection:**
  - — Lower Flow Rates: NPS 1 to NPS 4 easy-e EZ, ET or ED
  - — Higher Flow Rates: NPS 3 to NPS 8 Vee-Ball
  - — ENVIRO-SEAL packing
  - — Materials of Construction: NACE materials are likely required
  - — Class IV shutoff

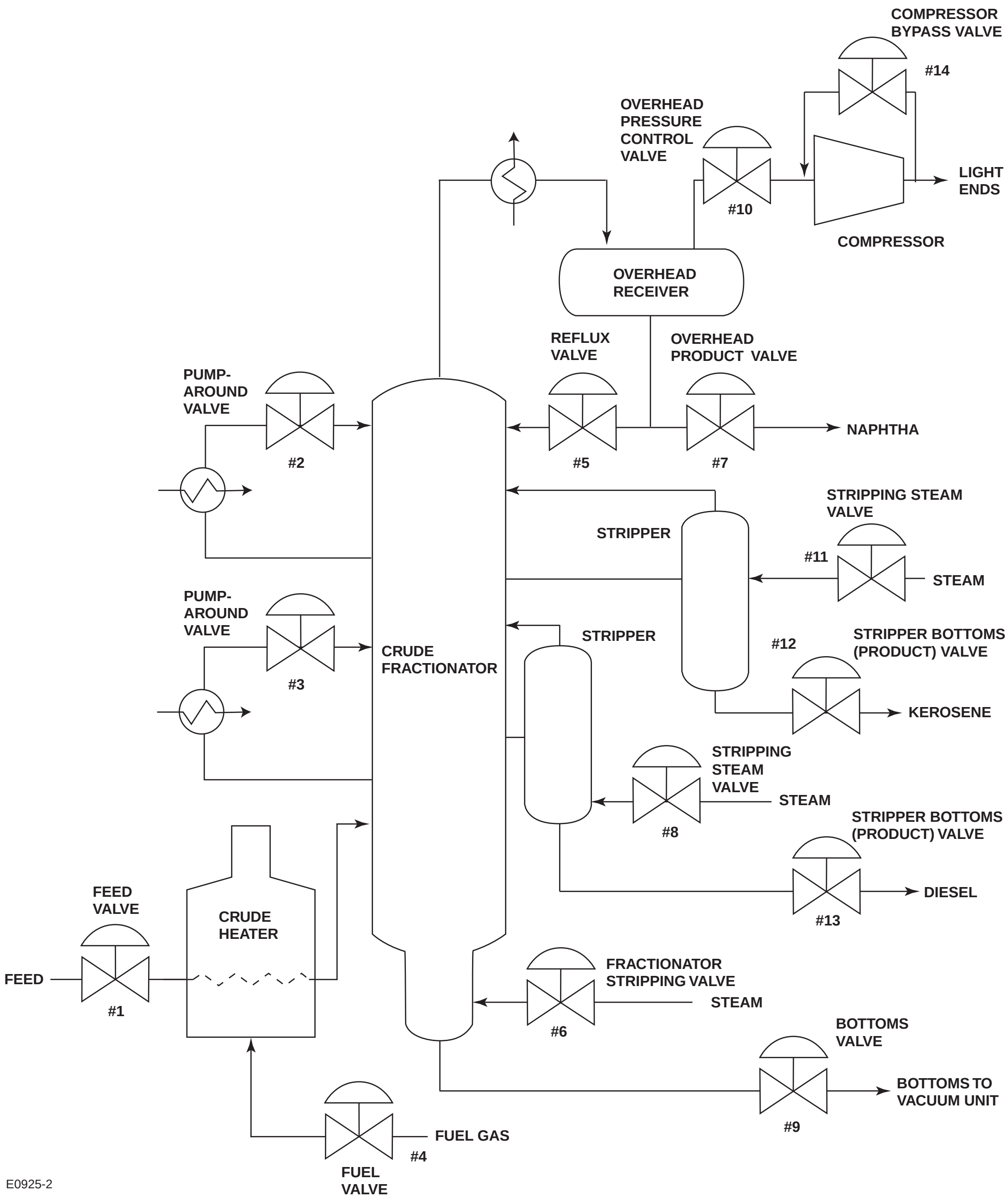


Figure 4.4.3. Crude Distillation Column Process Flow Diagram

4. Fuel Valve

Depending on the furnace service and configuration, this valve will normally be part of a loop that controls either the fuel flow or pressure. These valves are specified as fail closed so that a control loop failure will not allow excessive fuel to be dumped into a hot furnace. Instrumentation may include a loop to bypass digital valve controller in case of power failure to cut off fuel to furnace. A fuel valve failure will almost always shut down the processing unit downstream. Although many fuel valves have bypass circuits, refinery operations personnel are usually reluctant to run a furnace on bypass for any significant time because of safety concerns.

The preferred control loop configuration for the outlet temperature is a cascade to the set point of the loop controlling the fuel valve. Many furnaces will be set up such that the temperature control loop directly manipulates the fuel valve. This direct connection usually provides control performance that is inferior to a cascade configuration. It is extremely susceptible to any valve deadband such as that caused by a sticking valve. This can be detected by excessive oscillation in the outlet temperature.

When the fuel valve is manipulated by the temperature loop or by a flow control loop, there will often be a pressure control valve upstream of the fuel valve. This valve will also fail closed and will have the same consequences as a failure of the fuel valve. However, with this configuration, refinery operations personnel will be more willing to run a fuel valve in bypass as they still have a way to quickly shut off the fuel in an emergency.

Since this valve is critical to unit operation, a Fisher FIELDVUE DVC6200 digital valve controller with PD tier diagnostics is recommended. Monitoring valve position is critical to this valve when it is supposed to fail close, it may be desirable to include the position transmitter option in the FIELDVUE DVC6200 instrument. This provides position feedback to the DCS, upon loss of power to the FIELDVUE DVC6200 instrument, assuring whether or not the valve actually closed.

- **Typical Process Conditions:**
  - Fluid: Fuel gas
  - P1 = 3 - 4 barg (40 - 60 psig)
  - P2 = 2 – 3 barg (30 – 35 psig)
  - T = 32°C (90° F)
  - Q = 3700 – 5900 sm^3/h (130,000 – 208,000 scfh)
- **Typical Control Valve Selection:**
  - NPS 1 to NPS 6 easy-e EZ, ET, EWT, or GX
  - If low noise trim is required, use caution if the fuel gas is dirty
  - ENVIRO-SEAL duplex packing may be required for firesafe construction, with reduced friction when compared to graphite packing
  - Materials of Construction: WCC body with 300-series SST trim, sour fuel gas may require NACE trim materials
- **Process Impact:**
  - Valve performance is critical to controlling furnace temperature
- **Special Requirements:**
  - Steam jacketing might be required to maintain the viscosity of the fuel oil low enough so that it atomizes well enough in the burner.
  - Steam jacketing may also be required in fuel gas application to prevent water from condensing. If water condenses it might be acidic depending on the H_2S content in fuel gas.

5. Reflux Valve Function

The reflux valve is used to control the separation between the top product (usually naphtha) and the highest-side draw product. The reflux valve can be either a flow or a temperature controller.

A poorly performing or bypassed reflux valve will increase the variability in the quality specifications of the overhead product and the top side draw. A valve failure will most likely create an upset lasting from thirty minutes to a few hours, depending on the severity of the failure. To minimize the occurrence of a valve failure, a FIELDVUE DVC6200 digital valve controller with PD diagnostics is recommended for this valve. Due to the location of this valve, if wired diagnostics are not available, installation of an Emerson Smart Wireless THUM may be desirable.

- **Typical Process Conditions:**
  - Fluid: Naphtha and gas mixture
  - P1 = 5 - 6 barg (70 - 100 psig)
  - P2 = 4 - 5 barg (40 - 80 psig)
  - T = 93 - 250°C (200 - 480° F)
  - Q = 150 – 175 m^3/h (670 – 760 gpm)
- **Typical Control Valve Selection:**
  - Lower Flow Rates: NPS 2 to NPS 12 Vee-Ball
  - Higher Flow Rates: NPS 6 to NPS 12 Control-Disk
  - ENVIRO-SEAL graphite packing
  - Materials of Construction: WCC body with standard 400-series or 300-series SST trim

6. Fractionator Stripping Steam Valve

Stripping steam is injected into the bottoms of the fractionator to strip out lighter components from the crude bottoms stream. This valve drives the vapor back up through the column, which impacts column efficiency. Reboiler steam will have a direct effect on overhead reflux flow and the column flooding parameters.

A valve failure most likely will create an upset lasting from thirty minutes to a few hours depending on the severity of the failure.

- **Typical Process Conditions:**
  - Fluid: Steam
  - P1 = 10 - 17 barg (150 - 250 psig)
  - T = 232 - 300°C (450 - 575° F)
  - Q = dependent on process design
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 8 easy-e ED or NPS 6 to NPS 12 easy-e EWD
  - ENVIRO-SEAL graphite packing
  - Materials of Construction: Materials compliant with steam service, 300-series SST body with 300-series/ Alloy 6 trim
- **Process Impact:**
  - The amount of stripping steam also affects the separation efficiency of the crude fractionator
  - Valve is important as it drives the vapor through the column
  - Reboiler steam will have direct effect on overhead reflux flow

7. Overhead Product Valve Function

The overhead product is naphtha, a blending component in gasoline.

The overhead product valve is usually on level control from the overhead receiver, and may be used in conjunction with a Fisher Level-Trol liquid level controller (Figure 4.4.4). This valve does not usually have any impact on the operation of the crude fractionator unless a failure causes the liquid level in the overhead receiver to over fill or empty. In this case,

Figure 4.4.4. Typical Level-Trol Application

the column pressure would be affected, and the fractionator would experience an upset until the pressure stabilized. Usually, level alarms on the unit would allow the operator to catch this before it becomes an upset.

It is more likely that a poorly performing product valve could cause stability problems to a downstream processing unit in configurations where there is no surge tank between the units.

- **Typical Process Conditions:**
  - Fluid: Naphtha
  - P1 = 7 barg (100 psig)
  - T = 93°C (200° F)
  - Q = dependent on process design
- **Typical Control Valve Selection:**
  - NPS 4 to NPS 8 easy-e ET or NPS 6 to NPS 12 Vee-Ball
  - Materials of Construction: generally WCC body with standard 400-series SST trim, but consideration of special materials is required if it is acidic

8., 11. Stripping Steam Valves

The stripper uses steam to establish (control) the initial boiling point of the material leaving the bottom of the stripper.

Steam enters the bottom of the stripper tower and reduces the hydrocarbon partial pressure. The process fluid partially vaporizes to reestablish vapor-liquid equilibrium. The heat of vaporization comes from the process fluid itself, not from the stripping steam.

Each side-draw product stream usually feeds a product stripper. The stripper uses steam to drive off any light components remaining in the product stream. Poor steam valve performance can lead to variability in the quality specifications for the product stream.

- **Typical Process Conditions:**
  - Fluid: Steam
  - P1 = 10 - 17 barg (150 - 250 psig)
  - T = 232 - 300°C (450 - 575° F)
  - Q = dependent on process design
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 8 easy-e ED or NPS 6 to NPS 12 easy-e EWD
  - ENVIRO-SEAL graphite packing
  - Materials of Construction: Materials compliant with steam service, 300-series SST body with 300-series/ Alloy 6 trim

9. Bottoms Valve Function

The bottom material becomes the vacuum distillation unit charge. The process fluid could be viscous and likely has entrained particulate, which needs to be taken into consideration in valve selection.

The bottoms flow does not usually have any impact on the operation of the crude fractionator unless a failure causes the liquid level of the bottoms to overfill or empty. Usually, level alarms on the unit allow the operator to catch this before it causes an upset.

- **Typical Process Conditions:**
  - Fluid: Heavy vacuum gas oil, slop wax, heavy bottoms
  - P1 = 4 - 18 barg (50 - 260 psig)
  - P2 = 2 - 15 barg (30 – 220 psig)
  - T = 332 - 400°C (630 - 750° F)
  - Q = 430 – 480 m^3/h (1,900 – 2,100 gpm)
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 12 Vee-Ball or reverse flow V500
  - Materials of Construction: WC9 or 300-series SST body with 300-series SST trim, NACE is likely required. Solid stellite or ceramic trim may be used to reduce damage from entrained particulate.

10. Overhead Pressure Control Valve Function

The overhead pressure control valve releases gases including H_2, H_2S, methane, ethane, propane, and butane. Typically, this stream is very small (one to three percent of feed).

The column pressure has a significant effect on fractionator operation. A valve failure that allows the column to over or under pressure can cause an upset that might take hours of recovery time. A problem valve can create pressure oscillations that prevent the fractionator from optimal operation. Valve sizing is critical for this service. If the valve is

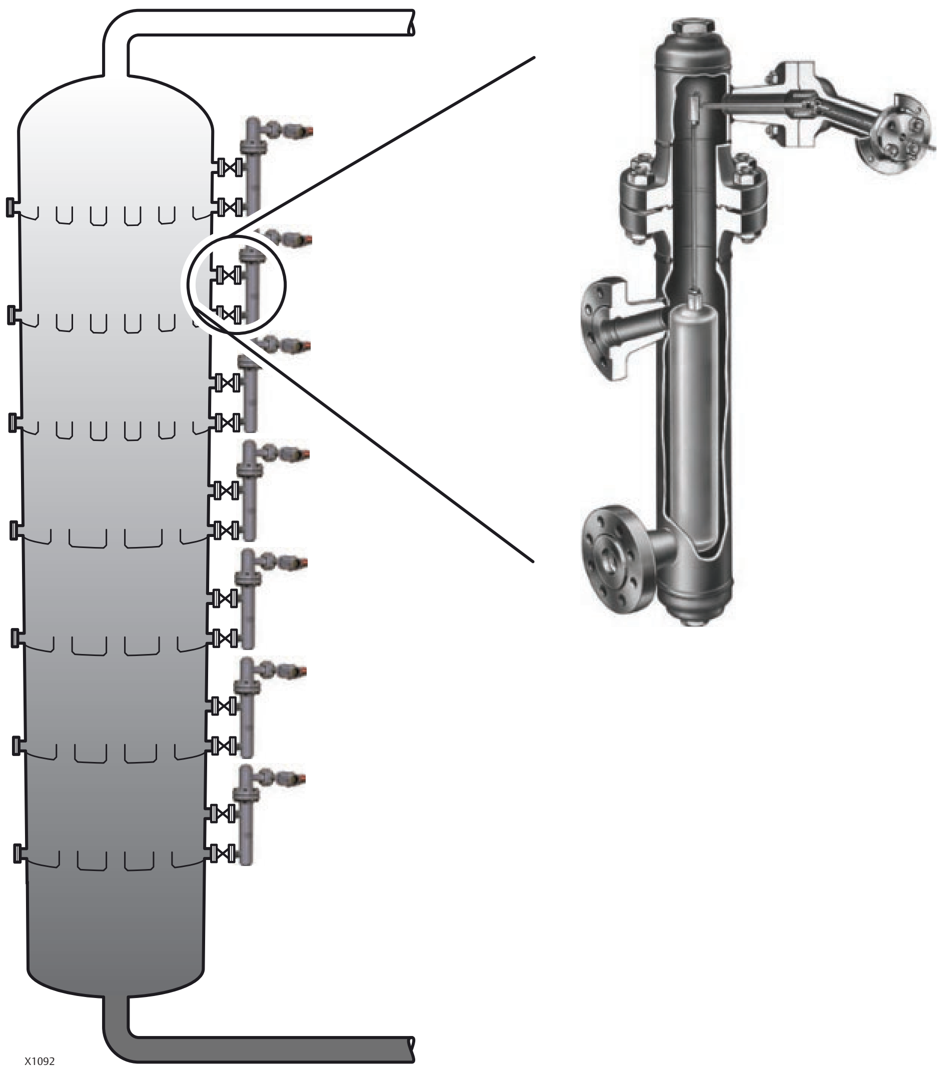


Figure 4.4.5. Liquid Level Installation Schematic

too large, the column pressure will be prone to rapid swings. If the value is too small and has a large response time, it can cause long slow swings.

In order to minimize unit downtime, a FIELDVUE DVC6200 digital valve controller with PD diagnostics is recommended for this application. Position feedback inherent to the FIELDVUE DVC6200 instrument may also be desirable to validate valve position.

This valve controls the pressure to the distillation column and is very important in controlling the stability of the tower. Many columns use tray temperature to control overhead composition, thus stable pressure is required to ensure that temperature changes reflect composition changes, not pressure changes.

■ **Typical Process Conditions:**

— Fluid: Mixture of gases including H_2, H_2S, ethane, propane, and butane

— P1 = 6 barg (90 psig)

— T = 80°C (175° F)

— Q = dependent on process design

■ **Typical Control Valve Selection:**

— NPS 2 to NPS 6 easy-e ET

— ENVIRO-SEAL PTFE packing

— Materials of Construction: generally WCC body with standard 400-series SST trim, but consideration of special materials is required if it is an acidic gas environment

12, 13. Stripper Bottoms (Product) Valves

The stripper bottoms valves are used to control the bottoms level in the strippers. These valves do not usually have any impact on the operation of the strippers unless a failure causes the liquid level of the bottoms to overfill or empty. Usually, level alarms on the unit allow the operator to catch this before it causes an upset.

These valves can be used in conjunction with a Level-Trol liquid level controller. Depending on the size and complexity of the stripper, the liquid level installation may be similar to Figure 4.4.5. A level alarm system can be programmed into the Fisher DLC3000 digital level controller.

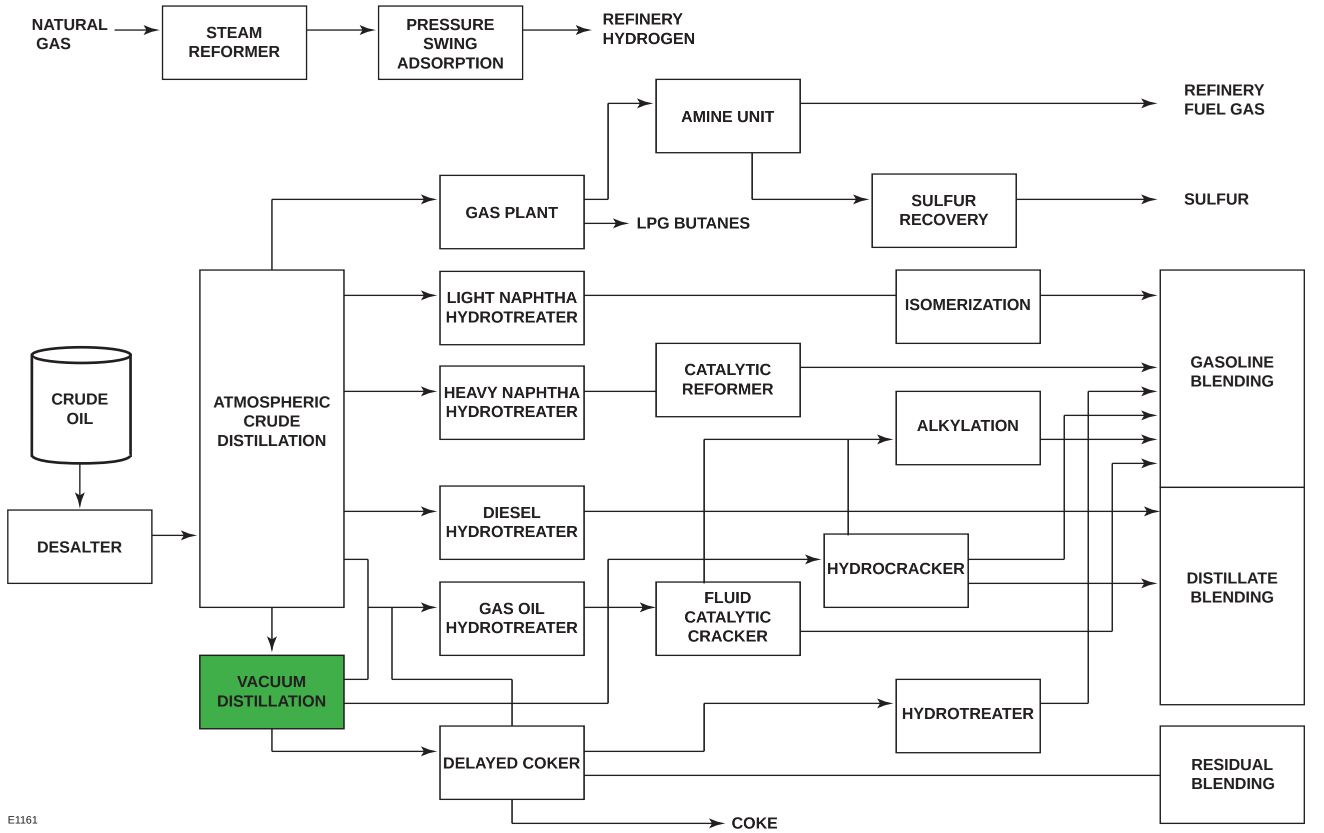


Figure 4.5.1. Vacuum Distillation Unit

- **Typical Process Conditions:**
  - — Fluid: Kerosene or diesel with particulate
  - — P1 = 7 barg (100 psig)
  - — T = 200 - 300°C (400 - 575° F)
  - — Q = dependent on process design
- **Typical Control Valve Selection:**
  - — NPS 2 to NPS 12 Vee-Ball or V500
  - — Low flow or clean fluid applications could use a globe valve solution (easy-e EZ or ED)
  - — ENVIRO-SEAL packing
  - — Materials of Construction: 300-series SST body with 300-series SST/Alloy 6 trim. For fluids with high viscosity or entrained particulate, solid Alloy 6 or ceramic trim may be considered.

4.5 Vacuum Crude Column

Other Names—Vacuum tower, vacuum flash, vacuum fractionators, vacuum crude column

The vacuum crude column unit is fed the bottoms from the crude distillation unit. The unit is a complex column that fractionates the crude bottoms under vacuum conditions to improve separation into basic product streams. The basic product streams from a vacuum crude unit can vary widely depending on the refinery operating objectives. Typical basic product streams are gas oil, light vacuum gas oil (LVGO), heavy vacuum gas oil (HVGO), and residual (resid) bottoms. Normally, these product streams are sent on to downstream units for further processing.

The crude bottom stream is sent through a process charge heater and is partially vaporized before entering the vacuum fractionator near the bottom of the column (refer to section 4.1 related to the furnace). Stripping steam is also injected at the bottom of the column. One or more process pump-around exchanger loops are used to cool the rising vapors, separating the crude bottom mixture into the product streams. The product streams are extracted through side draws to steam stripping columns. The column vacuum is controlled by an overhead ejector system. The column vacuum pressure and product draw temperatures are used to control the product streams to quality specifications, usually viscosity or flash point.

Vacuum Crude Column Application Review

The overall process of the vacuum crude column looks nearly identical to the crude distillation column. However, the two are unique since the vacuum crude column is run at vacuum pressures. Due to the vacuum pressures these valves are exposed to, certain process valves may require alternative packing arrangements to account for vacuum pressure conditions.

1. Feed Valve

The feed to a vacuum crude unit is the bottoms from the crude distillation unit. It has not undergone any processing other than being split based on relative volatility.

Feed valves are usually set up as flow-control loops. They are configured to fail open so that a valve failure protects the

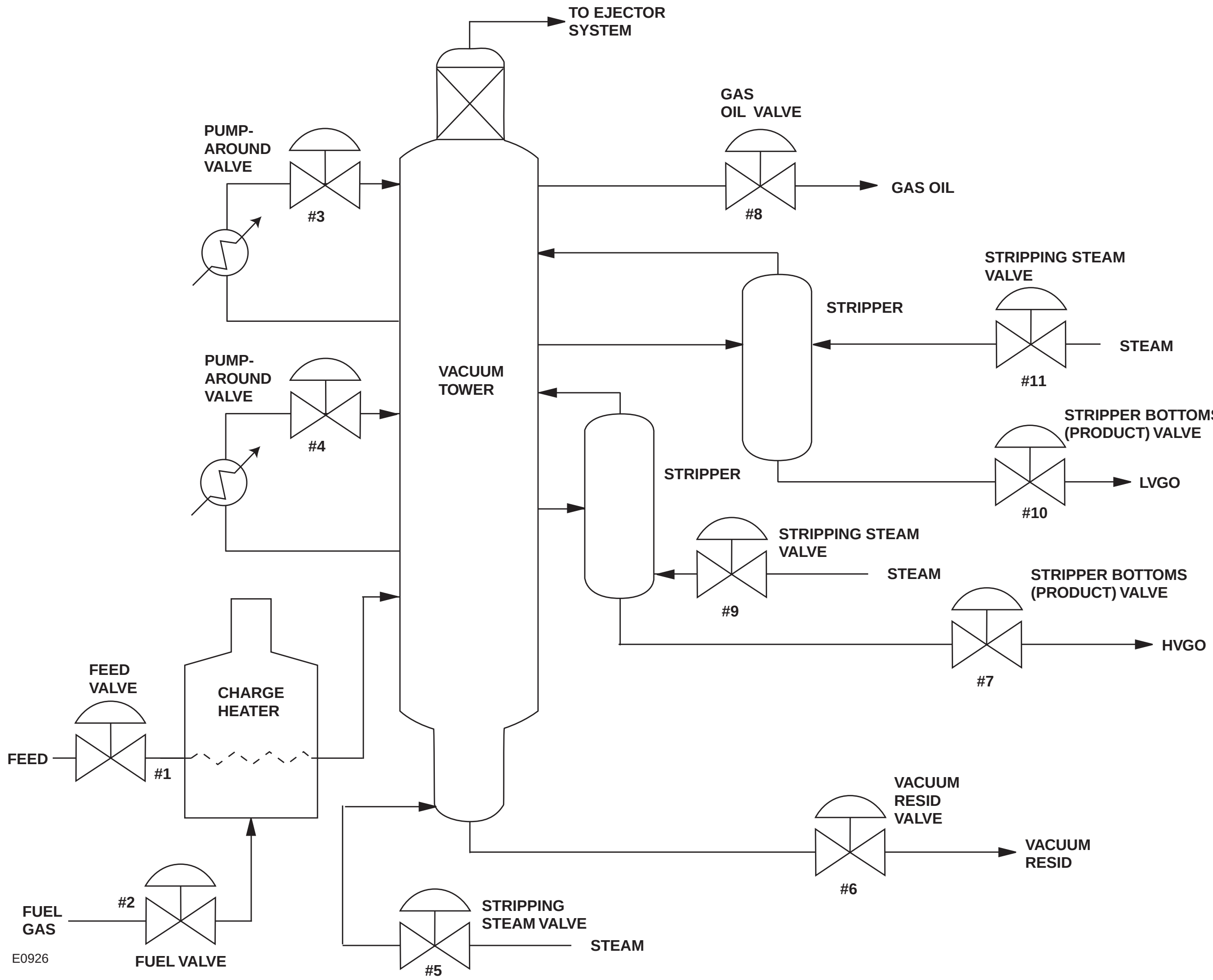


Figure 4.5.2. Vacuum Crude Column Process Flow Diagram

furnace radiant section tubes. If a radiant tube loses or has insufficient flow, the tube can quickly become so hot that the metal can melt. This can have disastrous consequences as most process feeds make excellent fuels. A furnace can be destroyed very quickly if a ruptured tube is dumping into the firebox of the furnace.

Problem valves can lead to difficulties with controlling the outlet temperature of the furnaces. Also, many process feeds slowly build layers of coke on the inside of the radiant tubes. Coking is a non-linear reaction and in some processes even a few extra degrees of temperature can lead to excessive coke build-up. If flow valves are alternately providing too much and then too little flow, the temperature will also swing, and usually leads to excessive coke buildup. This typically shortens the furnace cycle time between decoking procedures, which normally requires the process unit downstream to shutdown.

Feed valves can easily be bypassed when necessary. A combination of the measured flow and any available pass temperatures can be used to regulate the bypass valve.

- **Typical Process Conditions:**
  - — Fluid: Crude unit bottoms
  - — P1 = 10 – 21 barg (150 – 300 psig)
  - — P2 = 9 – 10 barg (147 – 298 psig)
  - — T = 332 - 360°C (630 - 680°F)
  - — Q = 37 – 50 m^3/h (164 – 219 gpm)
  - — Flashing may be present (although not severe) depending on process variables
- **Typical Control Valve Selection:**
  - — Lower Flow Rates: NPS 1 to NPS 4 easy-e EZ
  - — Higher Flow Rates: NPS 6 to NPS 12 easy-e EWD or NPS 3 to NPS 8 V500 (reverse flow)
  - — ENVIRO-SEAL graphite packing
  - — Materials of Construction: WC9 body with 300-series or solid stellite trim. NACE may be required if crude is sour. Also C12 and 347 SST body materials.
  - — Class IV shutoff

2. Fuel Valve

Depending on the furnace service and configuration, this valve will normally be part of a loop that controls either the fuel flow or pressure. These valves are specified as fail closed so that a control loop failure will not allow an excessive amount of fuel to be dumped into a hot furnace. A fuel valve failure will almost always shut down the processing unit downstream. Although many fuel valves have bypass circuits, refinery operations personnel are usually reluctant to run a furnace on bypass for any significant time because of safety concerns.

The preferred control loop configuration for the outlet temperature is a cascade to the set point of the loop controlling the fuel valve. Many furnaces will be set up such that the temperature control loop directly manipulates the fuel valve. This direct connection usually provides inferior control performance to a cascade configuration. It is extremely susceptible to any valve deadband such as that caused by a sticking valve. This can be detected by excessive oscillation in the outlet temperature.

When the fuel valve is manipulated by the temperature loop or by a flow control loop, there will often be a pressure control valve upstream of the fuel valve. This valve will also fail closed and will have the same consequences as a failure of the fuel valve. However, with this configuration, operations will be more willing to run a fuel valve in bypass as they still have a way to quickly shut off the fuel in an emergency.

Since this valve is critical to unit operation, a Fisher FIELDVUE DVC6200 digital valve controller with PD tier diagnostics is recommended. Monitoring valve position is critical to this valve when it is supposed to fail close, it may be desirable to include the position transmitter option in the FIELDVUE DVC6200 instrument. This provides position feedback to the DCS, upon loss of power to the FIELDVUE DVC6200 instrument, assuring whether or not the valve actually closed.

- **Typical Process Conditions:**
  - Fluid: Fuel gas
  - P1 = 3 - 4 barg (40 - 60 psig)
  - P2 = 2 – 3 barg (30 – 35 psig)
  - T = 32°C (90° F)
  - Q = 3700 – 5900 sm³/h (130,000 – 208,000 scfh)
- **Typical Control Valve Selection:**
  - NPS 1 to NPS 6 easy-e EZ, ET, ED, or GX
  - If low noise trim is required, use caution if the fuel gas is dirty
  - ENVIRO-SEAL duplex packing may be required for firesafe construction, with reduced friction when compared to graphite packing
  - Materials of Construction: WCC body with 300-series SST trim, sour fuel gas may require NACE trim materials

3., 4. Pump-Around Valve

A vacuum tower will always have at least one pump-around heat exchanger loop for controlling the heat balance. Many towers will have more than one pump-around loop. The pump-around loop is used to extract heat from the column, creating the separation between the product draws immediately above and below the pump-around loop. The pump-around valves are usually flow controllers.

A poorly performing or bypassed pump-around valve will increase variability in the quality specifications of the product draws. A valve failure will most likely create an upset lasting from thirty minutes to a few hours, depending on the severity of the failure.

- **Typical Process Conditions:**
  - Fluid: Hydrocarbon liquid
  - P1 = 6 - 21 barg (85 - 300 psig)
  - P2 = 4 - 20 barg (65 - 280 psig)
  - T = 66 - 149°C (150 - 300° F)
  - Q = 265 – 370 m³/h (1,165 – 1635 gpm)
- **Typical Control Valve Selection:**
  - Lower Flow: NPS 1 to NPS 4 easy-e EZ, ET, ED, or GX
  - Higher Flow: NPS 3 to NPS 8 Vee-Ball
  - ENVIRO-SEAL PTFE packing
  - Materials of Construction: WCC body with 400-series or 300-series SST trim, sour service trim materials may need to be considered.

5., 6., 8. Stripping Steam Valves

Stripping steam is injected into the bottoms of the tower to strip out lighter components from the crude bottom stream. The amount of stripping steam also affects the separation efficiency of the vacuum tower.

Stripping steam is also used in the product strippers. The stripper uses steam to drive off any light components remaining in the product stream. Poor steam valve performance can lead to variability in the quality specifications for the product stream. A valve failure will most likely create an upset lasting from thirty minutes to a few hours, depending on the severity of the failure.

These valves are important because they drive the vapor back up through the column or the strippers. Vapor through the column affects column efficiency. Reboiler steam will have a direct effect on overhead reflux flow.

- **Typical Process Conditions:**
  - Fluid: Steam
  - P1 = 2 - 17 barg (28 - 250 psig)
  - P2 = 1 – 15 barg (1 – 200 psig)
  - T = 232 - 300°C (450 - 575° F)
  - Q = 450 – 910 kg/h (1,000 – 2,000 lb/h)
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 8 easy-e ED or NPS 6 to NPS 12 EWD
  - ENVIRO-SEAL graphite packing
  - Materials of Construction: Materials compliant with steam service, 300-series SST body with 400-series SST or 300-series SST/Alloy 6 trim

7. Vacuum Resid Valve

The bottom material exiting the vacuum crude unit is vacuum resid.

The bottoms do not usually have any impact on the operation of the vacuum tower unless a failure causes the liquid level of the bottoms to overfill or empty. Usually, level alarms on the unit allow the operator to catch this before it causes an upset. Because this is a level control valve, it would be used in conjunction with a level controller, like a Fisher Level-Trol liquid level controller.

- **Typical Process Conditions:**
  - Fluid: Vacuum resid
  - P1 = 13 - 21 barg (190 - 300 psig)
  - P2 = 10 – 20 barg (150 – 295 psig)
  - T = 332 - 400°C (630 - 750° F)
  - Q = 270 – 310 m^3/h (1,200 – 1,350 gpm)
- **Typical Control Valve Selection:**
  - NPS 3 to NPS 8 V500 (reverse flow) or NPS 6 to NPS 12 Vee-Ball
  - ENVIRO-SEAL graphite packing
  - Materials of Construction: WCC or 316 SST body with 300-series SST trim or solid Alloy 6 trim. Ceramic trim may also be considered. Also C12 and 347 SST body materials.
  - Class IV shutoff

9., 10. Stripper Bottoms (Product) Valve

The stripper products are light vacuum gas oil (LVGO) and heavy vacuum gas oil (HVGO).

The stripper bottoms valves are used to control the bottoms level in the strippers. These valves do not usually have any impact on the operation of the strippers unless a failure causes the liquid level of the bottoms to overfill or empty. Usually, level alarms on the unit would allow the operator to catch this before it causes an upset.

- **Typical Process Conditions:**
  - Fluid: LVGO or HVGO
  - P1 = 10 - 16 barg (140 - 225 psig)
  - P2 = 1 – 12 barg (10 - 175 psig)
  - T = 43 - 80°C (110 - 175° F)
  - Q = 34 – 230 m^3/h (150 - 1000 gpm)
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 6 easy-e ET or NPS 6 to NPS 12 EWT or NPS 3 to NPS 8 Vee-Ball
  - ENVIRO-SEAL PTFE packing
  - Anti-cavitation trim may be required depending on process conditions; for clean fluids, Cavitrol III trim may be used, for dirty fluids a NotchFlo DST may be required
  - Materials of Construction: WCC or 316 SST body with 400-series SST trim or 300-series SST trim if service is sour. NACE may be required.
  - Class IV or Class V shutoff

4.6 Delayed Coker Unit

Other Names—Coker, delayed coking unit

Similar Process Units

Visbreaker, fluid coker, flexicoker, thermal cracker

The delayed coker unit (DCU) processes very heavy vacuum residual, which is heated to over 480°C (900°F) and put into the coke drums. It undergoes thermal cracking as the oil decomposes under extreme heat. Products include butane and lighter material naphtha for reforming, turbine and diesel fuel, gas oil for catalytic cracking, and fuel grade petroleum coke.

The delayed coker unit process thermally cracks heavy feedstocks, such as crude unit bottoms, vacuum unit bottoms, or other heavy gas oils. The products are sponge or needle coke, gas oil, naphtha, and light ends. Delayed cokers are used to process as much product as possible from the bottom of the barrel. Visbreaking is a similar process to the delayed coker. It has many of the same control valve applications, but is generally less severe than the DCU. Therefore, it will not be discussed specifically in this text.

The delayed coker unit consists of four sections:

1. Product fractionator
2. Coker furnace and coke drums
3. Vapor recovery
4. Overhead and hydraulic systems

In this section, we will discuss the applications surrounding the product fractionator, coker furnace, and coke drums. Applications in the vapor recovery unit are similar to those discussed in section 4.3 on gas plants. Applications in the overhead and hydraulic systems are dependent on the process licensor, and will not be included in this publication.

There are two ways incoming feed is delivered to the delayed coker unit:

1. Combined with coke drum vapors to the bottom of the coker product fractionator
2. Pre-heated and fed to the coke drums

For the purpose of this discussion, we will assume the incoming feed from the vacuum tower bottoms is sent, along with coke drum vapors, to the bottom of the product fractionator. The coke drum vapors are the products of thermal cracking that occurs in the coke drum at around 480°C (900°F). There are side streams drawn off specific trays of the fractionator that are sent on to other units for further processing.

The overhead stream of the coker fractionator is sent to a vapor recovery unit (gas plant) or sent to other process units in the refinery. The fractionator separates the drum vapors into typical product streams. For this example, the streams are light ends, naphtha, light gas oil, and heavy gas oil.

The fractionator bottoms are sent to the coker furnace. In this furnace, the feed is rapidly heated and partially vaporized. Steam is often injected into the feed oils to control the furnace residence time. Some thermal cracking occurs

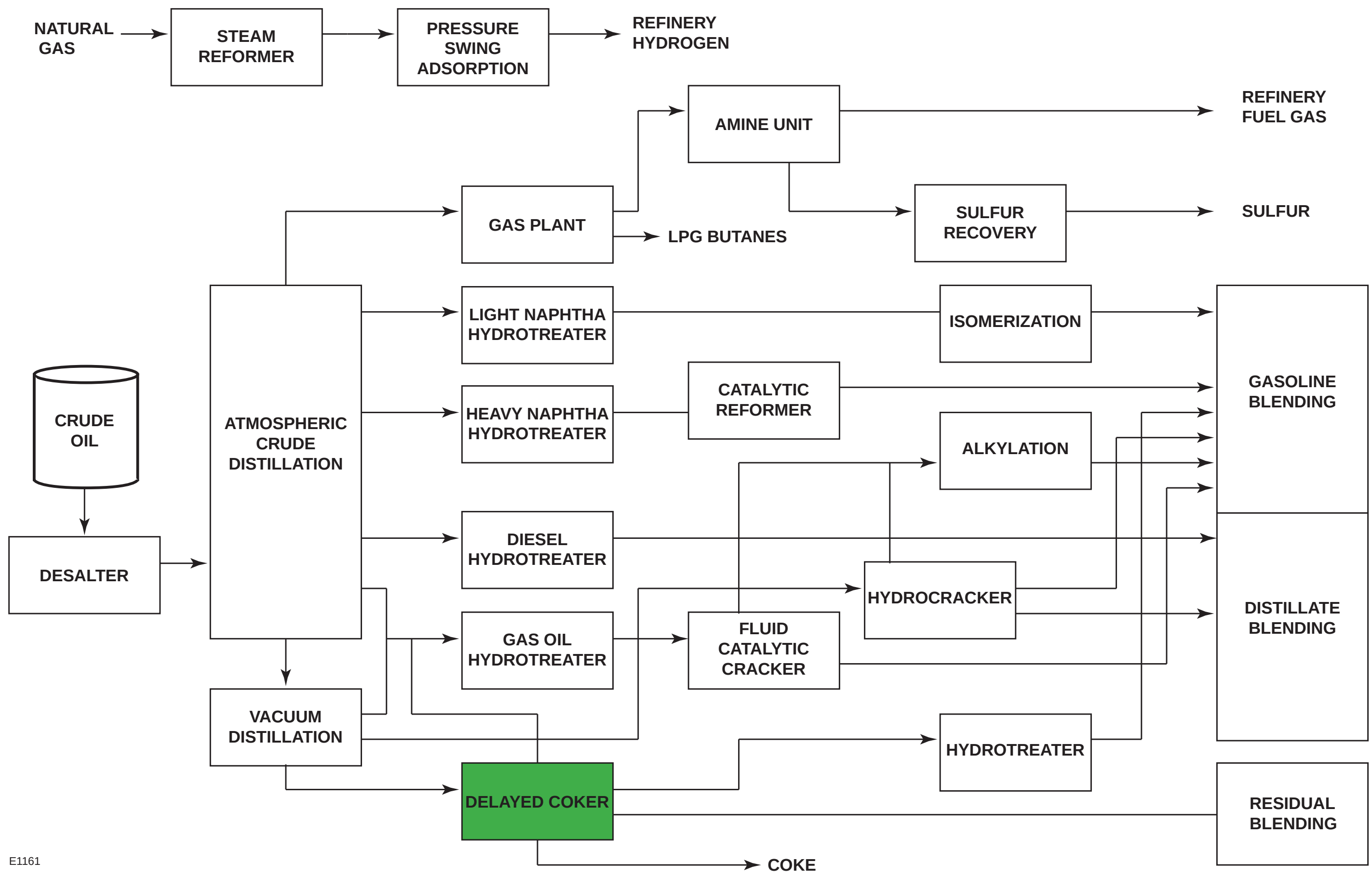


Figure 4.6.1. Delayed Coker Unit Location

in these furnaces; however, that is minimized to prevent excessive coke build-up in those units. Feed through the heaters needs to be tightly controlled. If it is fed too slowly, coke build up will occur in the heaters. If it is fed too quickly, high velocity coke particulate can damage the equipment. The vapor-liquid mixture leaves the furnace and enters the bottom of a coke drum. In the coke drum the entrained liquid is thermally cracked to coke and other vapor products. As the coke drum fills, the cracked vapors leave the top of the coke drum and enter the bottom of the fractionator.

Over the course of several hours, the coke drum will fill with coke. When a drum is full, the furnace effluent will be switched to another drum. After the drum is filled, the coke drum is steamed to remove any residual oil, and then it is cooled with water, to a temperature around 90°C (200°F). The water is drained from the drum, and then the top and bottom heads are removed to prepare for coke removal. Coke is removed from the drum through hydraulic drills (decoking). Once empty, the drums are tightened, purged, and pressure tested before being put back into service when the second drum is filled. Typical drum cycle times are 12 to 24 hours depending on the unit design.

Delayed Coker Application Review

Control valves in the delayed coker unit need to be selected appropriately. Common selection issues include high temperatures, large particulate, material compatibility, viscous fluids, and corrosive environments. It is important for users to provide all details to control valve vendors to help ensure valves are properly selected.

There are many special valves within a delayed coker that are not control valves. These include the 4-way switching valve, which directs the coker furnace output to the coke drums and the block valves between the coke drums. Typically, the block valves are full bore metal ball valves.

1. Decoke Water Valve

This valve delivers water to the coke drum during the decoke portion of the drum cycle. It is not normally critical to coker operation. Sometimes, coke will block the valve and prevent water from entering the coke drum.

Process conditions vary widely for this application. It is not a critical valve, and either sliding-stem or rotary valves can be used. Use caution when selecting a sliding-stem valve, due to the small clearances inherent to the construction.

- **Typical Process Conditions:**
  - — Fluid: Water
  - — P1 = 11 – 14 barg (155 - 200 psig)
  - — P2 = 3 – 12 barg (40 - 170 psig)
  - — T = 85 - 232°C (190 - 450°F)
  - — Q = Dependent on process design

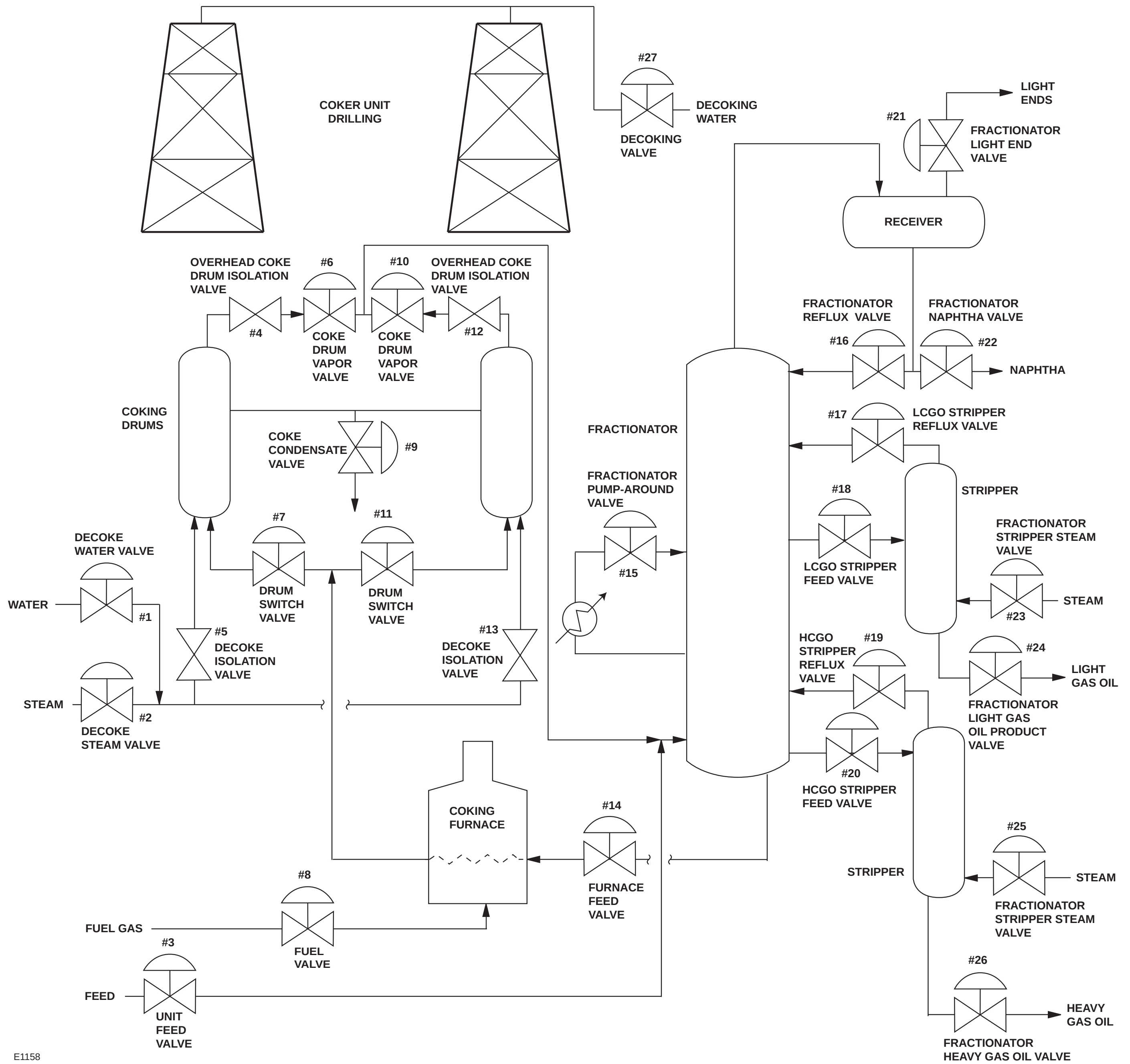


Figure 4.6.2. Delayed Coking Unit Process Flow Diagram

- **Typical Control Valve Selection:**
  - NPS 3 to 4 V500 or NPS 3 to 6 easy-e ET
  - Materials of Construction: WCC body with 400-series SST or 300-series/Alloy 6 or solid stellite trim.
  - Class IV shutoff

2. Decoke Steam Valve

This valve delivers steam to the coke drum during the decoker portion of the drum cycle. It is not critical to coker operation.

- **Typical Process Conditions:**
  - Fluid: Steam
  - P1 = barg (150 - 575 psig)
  - P2 = barg (20 – 535 psig)
  - T = °C (416 - 800°F)
  - Q = Dependent on process design
- **Typical Control Valve Selection:**
  - Lower Flow: NPS 1.5 to NPS 2 easy-e EZ
  - Higher Flow: NPS 4 to 8 easy-e ED or easy-e ET
  - Materials of Construction: WCC body with 400-series SST or 300-series/Alloy 6 trim.
  - Class III or Class IV shutoff

3. Unit Feed Valve

This valve feeds the bottom product from the vacuum tower to the coker fractionator. It requires large flow passages due to potential particulate and must be able to handle high temperatures. Swings in control can cause upsets to the coker heater feed and the coker heater fuel requirements.

Feed valves are usually set up as flow control loops. Feed valves can be bypassed when necessary. A combination of the measured flow and any available pass temperatures can be used to regulate the bypass valve.

- **Typical Process Conditions:**
  - Fluid: Vacuum bottoms
  - P1 = 14 – 20 barg (200 – 290 psig)
  - P2 = 12 – 18 barg (180 – 270 psig)
  - T = 200 - 225°C (390 - 450°F)
  - Q = 299 – 340 m^3/h (1310 – 1500 gpm)
- **Typical Control Valve Selection:**
  - NPS 4 to NPS 8 V500 or NPS 4 to NPS 12 Vee-Ball
  - ENVIRO-SEAL packing
  - Materials of Construction: WCC or WC9 body with 300-series or solid stellite trim. NACE may be required if crude is sour.
  - Class IV shutoff

4., 12. Overhead Coke Drum Isolation Valves

These are actually block valves, not control valves. They are used in the coking process when residual gases are drawn off the coke drums as they are being filled as well as when the coke drums are steamed out. In many cokers, these two lines are different. Because it is important to have the position of this valve verified at several points during the delayed coker process, a TopWorx™ 4310 (on/off service) or Fisher 4320 (throttling service) wireless position monitor can be used to verify valve position.

5., 13. Decoke Isolation Valves

These are also block valves, not control valves. However, if they are leaking through into a hot drum, they can cause a significant upset to the fractionator as steam will cause the column pressure to rise or fluctuate. Like the overhead isolation valves, verifying valve position is very useful here, and the 4310 or 4320 wireless position monitor could be used to provide that feedback to the user's DCS.

6., 10. Coker Drum vapor Valves

These valves control the vapors off of the top of the coke drum. Traditionally, this has been an on-off butterfly valve. However, more recently throttling control has become a requirement for this application. This valve will need to be able to open quickly in the event that a chunk of coke needs to pass. The actuator and accessories should be selected with this in mind.

- **Typical Process Conditions:**
  - Fluid: Hydrocarbon gas, steam, possibly coke particulate
  - P1 = 2.8 – 3.5 barg (40 - 50 psig)
  - P2 = 2.7 – 3.4 barg (39 - 49 psig)
  - T = 440 - 505°C (825 - 940°F)
  - Q = Dependent on process design
- **Typical Control Valve Selection:**
  - NPS 20 to NPS 30 High-Performance Butterfly Valve (HPBV)
  - ENVIRO-SEAL packing
  - Materials of Construction: C12 or WCC body with high temperature, hard faced trim.
  - Class IV shutoff

7., 11. Coker Drum Switching Valves

Most users have a preference for full bore metal ball valves in this application. They are generally on/off constructions, which are not required to throttle. Typically, this is not a Fisher control valve application. It is important for a refiner to know whether or not these valves are open. As such, it would be suggested to have on/off position feedback provided through a TopWorx 4310 wireless position monitor in this application.

8. Coker Heater Fuel Gas Valve

Depending on the furnace service and configuration, this valve normally will be part of a loop that controls either the fuel flow or pressure. These valves are specified as fail–closed so that a control loop failure will not allow an excessive amount of fuel to be dumped into a hot furnace. A fuel valve failure will almost always shut down the downstream processing unit. Although many fuel valves have bypass circuits, some refinery operations personnel are reluctant to run a furnace on bypass for any significant time because of safety concerns.

The preferred control loop configuration for the outlet temperature is a cascade to the setpoint of the loop controlling the fuel valve. Many furnaces will be set up such that the temperature control loop directly manipulates the fuel valve. This direct connection usually provides inferior control performance to a cascade configuration. It is extremely susceptible to any valve deadband such as that caused by a sticking valve. This can be detected by excessive oscillation in the outlet temperature.

When the fuel valve is manipulated by the temperature loop or by a flow control loop, there will often be a pressure control valve upstream of the fuel valve. This valve will also fail closed and will have the same consequences as a failure of the fuel valve. However, with this configuration, operations personnel may be more willing to run a fuel valve in bypass, as they still have a way to quickly shut off the fuel in an emergency.

Since this valve is critical to unit operation, a FIELDVUE DVC6200 digital valve controller with PD tier diagnostics is recommended. Monitoring valve position is critical, especially when it is to fail close. It may be desirable to include the position transmitter option in the FIELDVUE DVC6200. This option provides position feedback to the DCS, upon loss of power to the digital valve controller.

- **Typical Process Conditions:**
  - — Fluid: Fuel gas
  - — P1 = 2.8 – 10 barg (40 - 150 psig)
  - — P2 = 1.4 – 5.2 barg (21 - 76 psig)
  - — T = 65 – 232°C (150 - 450°F)
  - — Q = Dependent on process design
- **Typical Control Valve Selection:**
  - — NPS 1.5 to 3 easy-e EZ or ET or NPS 2 to NPS 3 Vee-Ball
  - — ENVIRO-SEAL packing
  - — Materials of Construction: WCC body with 400-series SST or NACE compliant trim if fuel is sour
  - — Class IV or V shutoff

9. Coke Condensate Valve

This valve is used to handle the coke condensate and water that is drawn off the coke drums during the cooling process. It has to handle liquids with particulate

- **Typical Process Conditions:**
  - — Fluid: Coke condensate
  - — P1 = 2 – 4.5 barg (30 - 65 psig)
  - — P2 = 0.3 – 2.8 barg (5 - 40 psig)
  - — T = 150 - 400°C (300 - 750°F)
  - — Q = Dependent on process design
- **Typical Control Valve Selection:**
  - — NPS 1.5 to NPS 4 V500 or NPS 1.5 to 4 easy-e EZ or ET
  - — Materials of Construction: WCC body with solid Alloy 6 or 300-series SST trim
  - — Class IV shutoff

14. Furnace Feed Valve

Feed valves are usually set up as flow-control loops. They are configured to fail open so that a valve failure will protect the furnace radiant section tubes. If a radiant tube loses or has insufficient flow, the tube can quickly become so hot that the metal can melt. This can have disastrous consequences, as most process feeds make excellent fuels. A furnace can be destroyed very quickly if a ruptured tube is dumping into the furnace firebox.

Problem valves can lead to difficulties with controlling the outlet temperature of the furnaces. Also, many process feeds slowly build layers of coke on the inside of the radiant tubes. Coking is a non-linear reaction, and in some processes even a few extra degrees of temperature can lead to excessive coke build-up. If a flow valve provides inconsistent feed, the temperature also swings and usually leads to excessive coke buildup. This shortens the furnace cycle time between decoking procedures, which normally requires the downstream process unit to shut down.

Feed valves can easily be bypassed when necessary. A combination of the measured flow and any available pass temperatures can be used to regulate the bypass valve.

Special considerations are required when selecting valves and actuators in this section of the delayed coker due to the large amount of particulate. Overheating will cause excess coke formation. This impact can be reduced by utilizing diagnostics and oversizing actuators to compensate for coke formation. Licensors frequently dictate over-sizing the actuator by 1.5 times the required force. This is true for both sliding-stem and rotary valves.

Since valves are required to both pass and shut off against the coke particles, cage-guided solutions are avoided and actuators are usually oversized. Rotary valves should be oriented in reverse flow with hardened trims. Both valve types should be selected with high temperature hardened trim. Commonly the V500, V500FFD, or 461 are selected for use in these units.

Emerson has worked with our users to develop a special version of the V500 called the V500FFD. The V500FFD is a furnace feed design V500, which has a few unique features that make it a good solution for these applications:

- Hard-faced slotless retainer to resist erosion
- Body insert to protect the seat and body from high velocity erosive flows and to ease maintenance
- Plug construction with wear resistant seating surface made of Tungsten Carbide to maximize service life
- Abrasion-resistant Tungsten Carbide coating applied to the internal flow passage

Figure 4.6.3 highlights the characteristics of the V500 and V500FFD.

- **Typical Process Conditions:**
  - — Fluid: Coker feed
  - — P1 = 26 – 45 barg (385 - 645 psig)
  - — P2 = 10 - 33 barg (145 - 475 psig)
  - — T = 295 - 425°C (565 - 800°F)
  - — Q = 36 – 39 m^3/h (159 – 175 gpm)
- **Typical Control Valve Selection:**
  - — NPS 2 to NPS 3 V500 or V500FFD (Figure 4.6.3)
  - — ENVIRO-SEAL packing
  - — Materials of Construction: Chrome Moly or 300-series SST body with 300-series SST, solid Alloy 6, or ceramic trim. Special grades of 300-series SST may be required if feed is acidic.
  - — Class IV shutoff

15. Fractionator Pump-around Valve

A coker fractionator will have at least one pump-around heat exchanger loop for controlling the heat balance. Most fractionators will have more than one pump-around loop (often a heavy oil and light oil pump-around). The pump-around loop extracts heat from the column, creating the separation between the product draws immediately above and below the pump-around loop. The pump-around valves are usually flow controllers.

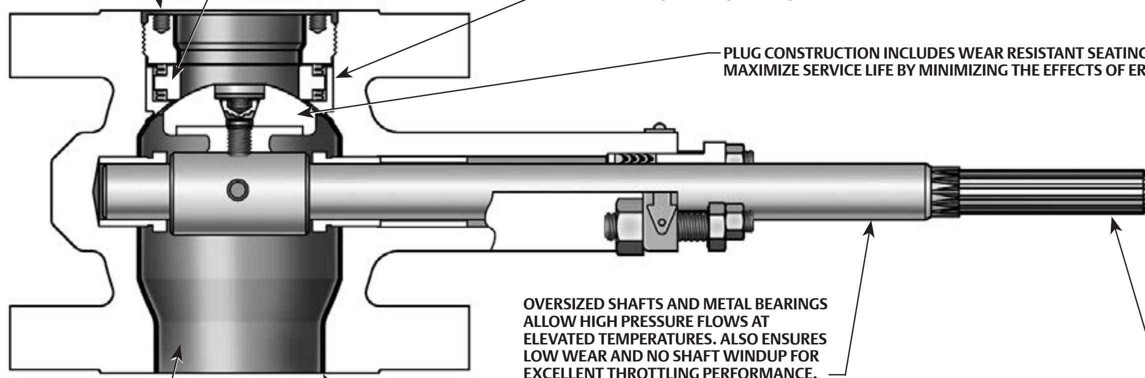


Figure 4.6.3. Fisher V500FFD Features

A poorly performing or bypassed pump-around valve will increase the variability in the quality specifications of the product draws. A valve failure will most likely create an upset lasting from thirty minutes to a few hours depending on the severity of the failure.

- **Typical Process Conditions:**
  - — Fluid: Heavy oil or light oil
  - — P1 = barg (89 – 200 psig)
  - — P2 = barg (45 – 177 psig)
  - — T = °C (405 - 795°F)
  - — Q = Dependent on process design
- **Typical Control Valve Selection:**
  - — NPS 6 to NPS 8 V500 or NPS 6 to NPS 12 High-Performance Butterfly Valve; depending on process design conditions, a Control-Disk valve may be used.
  - — Materials of Construction: WCC or Chrome Moly body with 300-series SST or solid Alloy 6 trim. C12 bodies commonly used on HCGO applications due to high temperature and corrosion resistance. WC9 should not be substituted without user acceptance.
  - — Class IV shutoff

16. Fractionator Reflux Valve

The reflux valve is used to control the separation between the top product (usually naphtha), and the highest-side draw product. The reflux valve can be either a flow or a temperature controller.

A poorly performing or bypassed reflux valve will increase the variability in the quality specifications of the overhead product and the top-side draw. A valve failure will most likely create an upset lasting from thirty minutes to a few hours, depending on the severity of the failure.

- **Typical Process Conditions:**
  - — Fluid: Naphtha
  - — P1 = 8 – 21 barg (115 - 300 psig)
  - — P2 = 3.6 – 19 barg (50 - 280 psig)
  - — T = 35 – 180°C (100 - 360°F)
  - — Q = Dependent on process design
- **Typical Control Valve Selection:**
  - — NPS 2 to NPS 4 easy-e ED, EZ, or ET or NPS 3 Vee-Ball
  - — Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - — Class IV shutoff

17, 19. Light Coker Gas Oil (LCGO) & Heavy Coker Gas Oil (HCGO) Stripper Reflux Valves

The stripper reflux is responsible for sending the coker gas oil back to the product fractionator for a purer product.

- **Typical Process Conditions:**
  - — Fluid: LCGO or HCGO reflux
  - — P1 = barg (82 - 339 psig)
  - — P2 = barg (55 – 240 psig)
  - — T = °C (105 - 567°F)
  - — Q = Dependent on process design
- **Typical Control Valve Selection:**
  - — NPS 3 to 4 easy-e ET or ED or NPS 2 to NPS 8 V500
  - — Materials of Construction: WCC Body with 400-series SST or 300-series SST or solid Alloy 6 trim
  - — Class IV shutoff

18., 20. LCGO & HCGO Stripper Feed Valves

These valves pull a stream of light coker gas oil (LCGO) or heavy coker gas oil (HCGO) from the product fractionator and send that stream to a stripper unit. The stripper unit uses superheated steam to remove any residual gas oils from the process streams. Stripper bottoms are sent to the coker heater and eventually to the coke drum.

- **LCGO Typical Process Conditions:**
  - Fluid: LCGO
  - P1 = 1 – 12 barg (17 - 170 psig)
  - P2 = 0.5 – 6 barg (8 – 85 psig)
  - T = 210 - 235°C (405 - 455°F)
  - Q = Dependent on process design
- **LCGO Typical Control Valve Selection:**
  - Lower Flow: NPS 3 to NPS 8 easy-e ET
  - Higher Flow: NPS 6 to NPS 10 Vee-Ball
  - Materials of Construction: WCC with 400-series SST or 300-series SST or solid Alloy 6 trim
  - Class IV shutoff
- **HCGO Typical Process Conditions:**
  - Fluid: HCGO
  - P1 = 2 – 2.5 barg (27 - 35 psig)
  - P2 = 0.6 – 2 barg (9 – 28 psig)
  - T = 350 - 455°C (660 - 850°F)
  - Q = Dependent on process design
- **HCGO Typical Control Valve Selection:**
  - NPS 3 to NPS 8 V500 or NPS 3 to NPS 6 easy-e ET or EZ
  - Materials of Construction: C12 Body with 300-series SST or solid stellite trim. C12 bodies commonly used on HCGO applications due to high temperature and corrosion resistance. Often, WC9 is an acceptable alternative.
  - Class IV shutoff

21. Fractionator Light End Valve

The overhead pressure control valve releases gases including H_2, H_2S, methane, ethane, propane, and butane. This stream is typically very small (less than 3% of feed).

The column pressure has a significant effect on fractionator operation. A valve failure that allows the column to over or under pressurize can cause an upset that might take hours of recovery time. A problem valve can create pressure oscillations that prevent the fractionator from optimal operation. Valve sizing is critical for this service. If the valve is too large, the column pressure will be prone to rapid swings. If the value is too small and has a large response time, it can cause long slow swings.

- **Typical Process Conditions:**
  - Fluid: Light gas
  - P1 = 17 - 23 barg (250 - 340 psig)
  - P2 = 16 - 20 barg (240 - 290 psig)
  - T = 68 - 71°C (155 - 160°F)
  - Q = Dependent on process design
- **Typical Control Valve Selection:**
  - NPS 1.5 to NPS 2 easy-e EZ
  - Materials of Construction: WCC body with 400-series SST trim
  - ENVIRO-SEAL packing
  - Class IV shutoff

22. Fractionator Naphtha Valve

The fractionator naphtha valve, also known as the overhead product valve, is usually on level control from the overhead receiver. This valve does not usually have any impact on the operation of the crude fractionator unless a failure causes the liquid level in the overhead receiver to over fill or empty. In this case, the column pressure would be affected, and the fractionator would experience an upset until the pressure became stable again. Usually, level alarms on the unit allow the operator to catch this before it becomes an upset.

It is more likely that a poorly performing product valve could cause stability problems to a downstream processing unit in configurations where there is no surge tank between the units.

- **Typical Process Conditions:**
  - Fluid: Naphtha
  - P1 = 9.5 – 18 barg (140 - 265 psig)
  - P2 = 5.1 – 12 barg (75 - 180 psig)
  - T = 37 - 215°C (100 - 420°F)
  - Q = Dependent on process design
- **Typical Control Valve Selection:**
  - NPS 1 to NPS 4 easy-e ED, ET, or EZ
  - Materials of Construction: WCC body with 400-series SST or 300-series SST or solid Alloy 6 trim
  - Class II or IV shutoff

23., 25. Fractionator Stripping Steam Valves

Each side-draw product stream usually feeds a product stripper. The stripper uses steam to separate any light components remaining in the product stream. Poor steam valve performance can lead to variability in the quality specifications for the product stream.

- **Typical Process Conditions:**
  - Fluid: Steam
  - P1 = 7.5 – 27 barg (110 - 395 psig)
  - P2 = 0.5 – 26 barg (8 – 374 psig)
  - T = 260 - 370°C (500 - 700°F)
  - Q = Dependent on process design

- **Typical Control Valve Selection:**
  - — NPS 1.5 to NPS 8 easy-e ED, ET, EZ, or ES
  - — Materials of Construction: WCC body with 400-series stainless or 300-series stainless trim appropriate for steam service.
  - — Class IV shutoff

24, 26. Fractionator Gas Oil Valve (HCGO & LCGO)

These valves are used to control the bottoms level in the strippers. These valves do not usually have any impact on the operation of the strippers unless a failure causes the liquid level of the bottoms to overfill or empty. Usually, level alarms on the unit allow the operator to catch this before it causes an upset. They can be used in conjunction with a Fisher Level-Trol liquid level controller.

- **24 LCGO Typical Process Conditions:**
  - — Fluid: LCGO
  - — P1 = 1.4 – 20 barg (20 – 290 psig)
  - — P2 = 1.3 – 19 barg (19 – 270 psig)
  - — T = 71 - 260°C (160 - 500°F)
  - — Q = Dependent on process design
- **24 LCGO Typical Control Valve Selection:**
  - — NPS 2 to NPS 8 easy-e ET or NPS 6 to NPS 8 V500
  - — Materials of Construction: WCC body with 400-series SST or 300-series SST or solid Alloy 6 trim
  - — Class IV shutoff
- **26 HCGO Typical Process Conditions:**
  - — Fluid: HCGO
  - — P1 = 1.4 – 20 barg (20 – 290 psig)
  - — P2 = 1 – 15 barg (15 - 220 psig)
  - — T = 150 - 425°C (300 - 795°F)
  - — Q = Dependent on process design
- **26 HCGO Typical Control Valve Selection:**
  - — NPS 3 to NPS 6 V500 or NPS 2 to NPS 3 easy-e ES or ET
  - — Materials of Construction: C12 or WC9 or WCC body with 300-series SST or solid Alloy 6 trim.
  - — Class IV shutoff

27. Decoking Valve

This valve controls the flow from the decoking jet pump, which provides high pressure water for the final process of coke cutting. There are three functions that this valve performs. The first function is bypass mode. When water is not needed at the coke drum it is directed back towards the suction tank. The second function is prefill mode. This mode allows reduced flow and pressure water to fill up the decoking equipment. The third and final function is the cutting mode. This mode will provide the jet pump full flow to the coke drum for coke cutting.

Contact your local sales representative for a potential Fisher solution.

4.7 Hydrotreater

Other Names—Hydroprocesser, unifining, unifiner, desulfurizer, hydrodesulfurizer (HDS)

The purpose of hydrotreating operation is to remove contaminants and impurities in various refinery streams by using hydrogen to bind with sulfur and nitrogen in the presence of a catalyst. Hydrotreating helps meet low sulfur specification in transportation fuels and provides low sulfur feed to downstream units.

The hydrotreating process removes undesirable materials from a feedstock by selective reactions with hydrogen in a heated catalyst bed. Sulfur, nitrogen, and certain metal contaminants are removed from the feed. Olefins and aromatics are converted to saturated hydrocarbons. Hydrotreating is often used to remove catalyst poisons from a feedstock before downstream processing. It also is used to remove contaminants from product streams to meet environmental standards.

The incoming feed is assumed to be naphtha for this description. The untreated feed is combined with a recycle hydrogen stream before flowing through a charge heater to reaction temperature. The feedstock is reacted with hydrogen at elevated temperature in the range of 300-450°C (500 – 750°F) and elevated pressures, in the range of 8 – 150 barg (120 - 2200 psig) under the presence of hydrogenation catalyst, typically cobalt-molybdenum, nickel-molybdenum, or alumina. The reactor effluent is sent to a separator. The vapor from the separator, often amine treated, is recycled through a compressor back to the feed. Makeup hydrogen is added to this stream as necessary. The liquid from the separator is sent to a stripper. In the stripper, hydrogen sulfide (H_2S), ammonia (NH_3), and light ends are sent overhead as vapors. Naphtha is produced as the overhead liquid product. Desulfurized distillate is the treated stripper bottom, treated naphtha is sent downstream to catalytic reformer, cat cracker, and hydrocracker units.

There are several types of hydrotreating units including: jet fuel hydrotreating, distillate hydrotreating, gasoline hydrotreating, pyrolysis gas hydrotreating, cat feed and reformer feed hydrotreating, and residual hydrotreating. Depending on the type of crude being processed, the desired products, and the size of the plant, a single refinery may have one or more of these types of hydrotreaters.

Hydrotreater Application Overview

1. Unit Feed Valve

The unit feed valve is a challenging valve in this service, which can cause swings in the amount of conversion through the unit. If the swings are wide enough, this will actually limit unit throughput and lead to increased coke laydown on the catalyst, potentially shortening reactor life.

Feed valves usually are set up as flow-control loops. They are configured to fail open so that a valve failure will protect the furnace radiant section tubes. If a radiant tube loses or has insufficient flow, the tube can quickly become so hot that the metal can melt. This can have disastrous consequences, as most process feeds make excellent fuels. A furnace can be

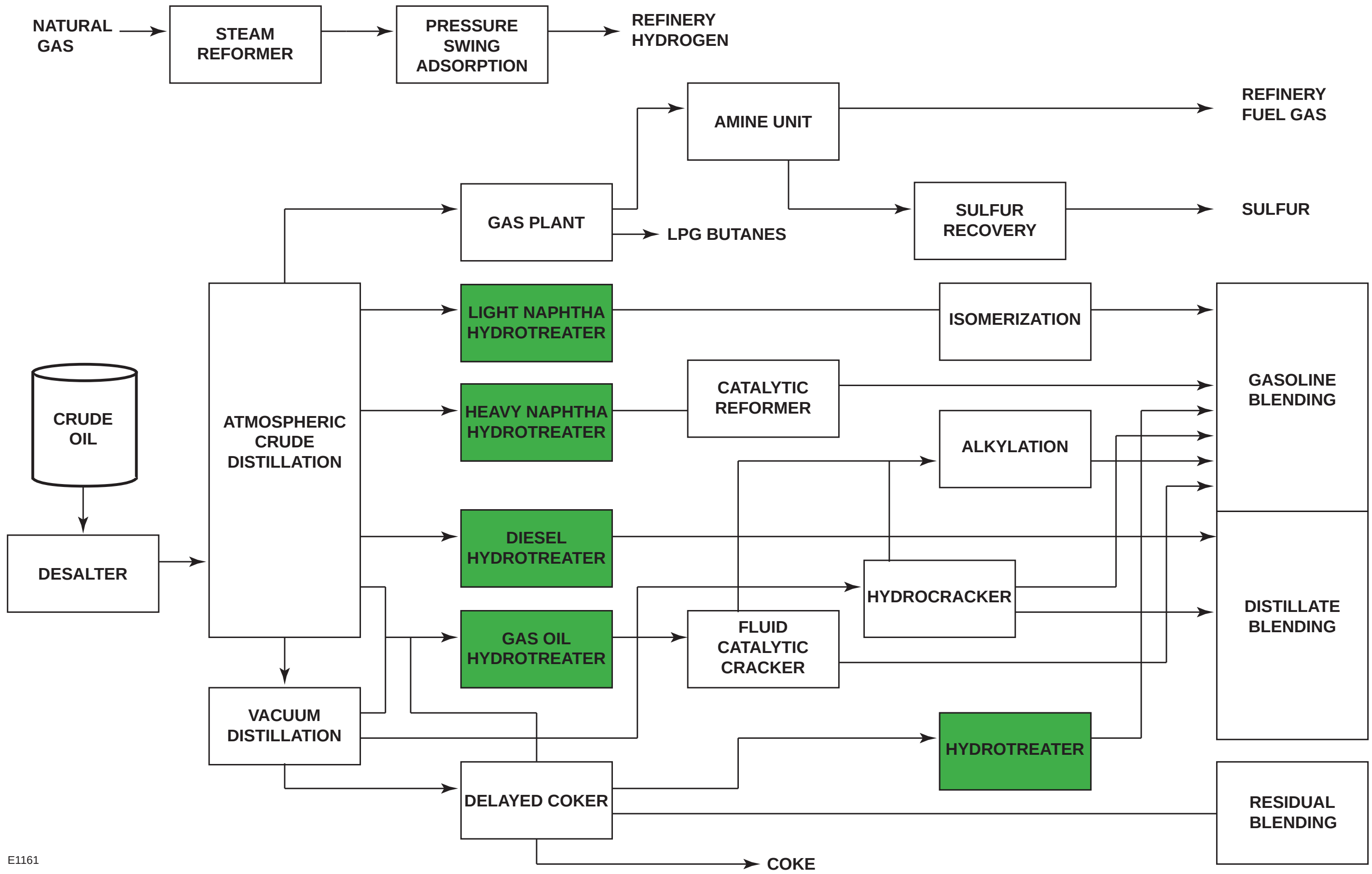


Figure 4.7.1. Hydrotreater Locations

destroyed very quickly if a ruptured tube is dumping into the firebox of the furnace.

Unit feed valves can lead to difficulties with controlling the outlet temperature of the furnace. Many process feeds slowly build layers of coke on the inside of the radiant tubes. Coking is a non-linear reaction, and in some processes even a few extra degrees of temperature can lead to excessive coke build-up. If a flow valve provides inconsistent feed, the temperature may swing and lead to excessive coke build-up. This shortens the furnace cycle time between decoking procedures, which normally require the process unit downstream to shut down.

Feed valves can be bypassed when necessary. A combination of the measured flow and pass temperatures can be used to regulate the bypass valve.

- **Typical Process Conditions:**
  - Fluid: Untreated feed from various upstream units
  - P1 = 5.7 – 122 barg (85 – 1,775 psig)
  - P2 = 2.8 - 87 barg (40 - 1265 psig)
  - T = 38 - 425°C (100 - 800°F)
  - Q = 2 – 265 m^3/h (9 – 1165 gpm)
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 3 HPT or HPS or NPS 2 to NPS 8 easy-e ET or EZ
  - Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - ENVIRO-SEAL packing
  - May require NACE compliance
  - Class IV or V shutoff

2. Fuel Valve

Depending on the furnace service and configuration this valve will normally be part of a loop that controls either the fuel flow or pressure. These valves are specified as fail closed so that a control loop failure will not allow an excessive amount of fuel to be dumped into a hot furnace. A fuel valve failure will almost always shut down the processing unit downstream. Although many fuel valves have bypass circuits, refinery operations personnel are usually reluctant to run a furnace on bypass for any significant time due to safety concerns.

The preferred control loop configuration for outlet temperature is a cascade to the set point of the loop controlling the fuel valve. Many furnaces will be set up such that the temperature control loop directly manipulates the fuel valve. This direct connection usually provides inferior control performance to a cascade configuration as it is extremely susceptible to valve deadband, such as that caused by a sticking valve. This can be detected by excessive oscillation in the outlet temperature.

When the fuel valve is manipulated by the temperature loop or by a flow control loop, there will often be a pressure

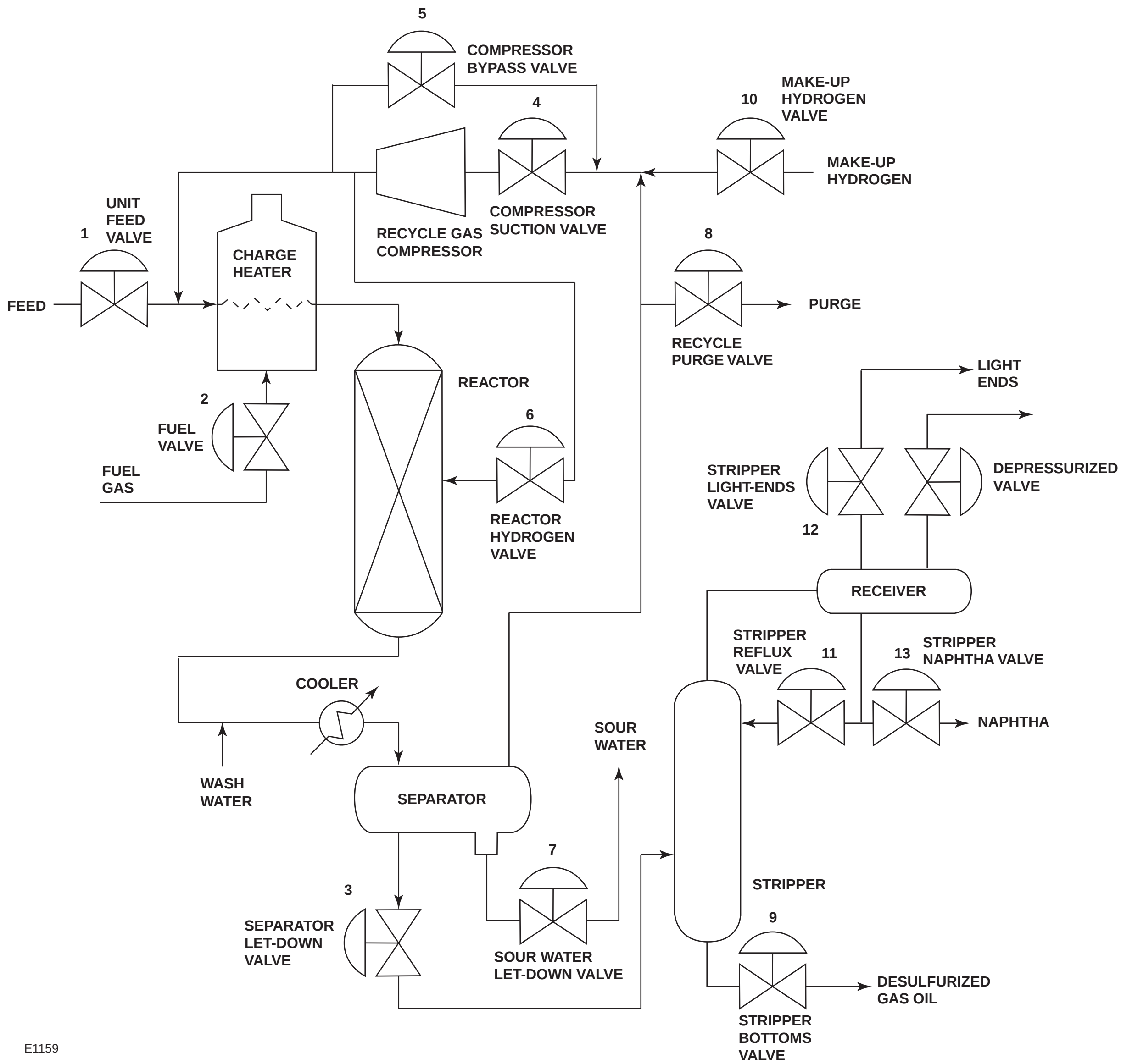


Figure 4.7.2. Hydrotreater Process Flow Diagram

control valve upstream of the fuel valve. This valve will also fail closed and will have the same consequences as a failure of the fuel valve. However, with this configuration, operations personnel will be more willing to run a fuel valve in bypass as they still have a way to shut off the fuel quickly in an emergency.

Since this valve is critical to unit operation, a FIELDVUE DVC6200 instrument with PD tier diagnostics is recommended. Monitoring valve position is critical to this valve when it is supposed to fail close, it may be desirable to include the position transmitter option in the FIELDVUE DVC6200 instrument to provide position feedback to the DCS, upon loss of power to the FIELDVUE DVC6200 instrument, assuring whether or not the valve actually closed.

■ **Typical Process Conditions:**

— Fluid: Fuel gas
— P1 = 2.4 – 3.9 barg (35 - 55 psig)
— P2 = 0.9 – 1.9 barg (15 - 25 psig)
— T = 38°C (100°F)
— Q = 0.498 – 1.38 MMscfd

■ **Typical Control Valve Selection:**

— NPS 2 to NPS 3 easy-e EZ or ET
— Materials of Construction: WCC body with 400-series SST trim(soft seated trim may be required for tight shutoff)
— ENVIRO-SEAL PTFE or duplex packing
— May require NACE compliance if gas is sour
— Class IV or VI shutoff

3. Separator Let-Down Valve

The separator let-down valve controls the liquid level in the high-pressure separator. Products from the reactor are cooled in a heat exchanger and led to a high pressure separator where ammonia and hydrogen sulfide are removed. After leaving the reactor, excess hydrogen is separated from the treated product and recycled through the reactor after removal of hydrogen sulfide. The liquid product is passed into the stripping tower, where steam removes dissolved hydrogen and hydrogen sulfide. After cooling, the product is run to finished product storage. This application involves high pressure drops where flowing particulate, outgassing, cavitation, and flashing can cause damaging process or system vibration.

- **Typical Process Conditions:**
  - Fluid: Hydrocarbon with entrained hydrogen
  - P1 = 31 - 76 barg (450 - 1100 psig)
  - P2 = 14 - 62 barg (200 – 900 psig)
  - T = 43 – 290 °C (110 - 555°F)
  - Q = 50 – 415 m^3/h (215 - 1815 gpm)
- **Typical Control Valve Selection:**
  - See the following section on outgassing application valve sizing and selection

Outgassing

Outgassing is one of several severe service applications that are encountered in refining applications. In order to identify a process that is outgassing, it is important to have an understanding of the other severe service applications that experience the same problems or symptoms. The table below shows the physical phases of flow-media and how they are classified. It also gives a description of what is causing these phenomena to occur.

Flow Media Phases

Type: Outgassing **Upstream:** Liquid **Downstream:** Liquid and Gas **Description of Process:** Outgassing is a process that involves a flow media consisting of at least two different constituents. One is a liquid and the other is a gas that is entrained in that liquid. The two components begin to separate upon the slightest change in pressure. The best example of this would be a bottle of soda. The bottle is pressurized and appears to be a homogeneous liquid but when a reduction in pressure occurs, i.e. opening the bottle, the CO_2 gas begins to come out of the liquid solution. The final product downstream is two elements, one liquid soda and the other carbon dioxide gas.
Type: Flashing **Upstream:** Liquid **Downstream:** Liquid and Vapor **Description of Process:** When the pressure within a single component system drops to the vapor pressure of the liquid, the liquid begins to absorb heat and changes to a vapor phase. This process is time dependent because it is a thermodynamic process. The latent heat of vaporization must be absorbed, which is not an instantaneous process.

Flow Media Phases

Type: Cavitation **Upstream:** Liquid **Downstream:** Liquid **Description of Process:** Like flashing, cavitation involves the thermodynamic process of vaporization. Formation of bubbles occurs when the pressure at the vena contracta falls below the vapor pressure. As pressure recovers, the downstream pressure becomes greater than the liquid's vapor pressure. This causes the newly formed cavities to collapse and implode, creating cavitation with noise and possible damage. As long of the pressure downstream stays above the vapor pressure of the liquid, all of the vapor bubbles will collapse and the final product further downstream will be 100% liquid.
Type: Two-Phase (G/L) **Upstream:** Liquid and Gas **Downstream:** Liquid and Gas **Description of Process:** This is a flowing media that contains at least two different components, where one component is in the liquid phase and the other is in the compressible (gas) phase. Both of these phases are present when entering and exiting the valve. Although this should be easy to identify, it is still a severe service that presents many problems.

Outgassing and flashing behave in similar manners and in many cases outgassing is thought to be flashing. This is because outgassing and flashing both have a fluid that enters a valve as a liquid and exits the valve as a liquid and gas. These two processes can impose the same types of damage, but this is where the similarities end. Shown below are the major differences that separate outgassing from flashing.

Outgassing

- Fluid contains at least two substances of completely different makeup (i.e. crude oil and natural gas).
- Undergoes a depressurization process that causes the entrained gas to be released separate from the liquid.
- Outgassing can occur at any point in the system. It only takes a minimal drop in pressure for the gas to come out of suspension. If outgassing occurs prior to the throat of the valve, damage to the valve and trim would occur. This would occur if an outgassing application were misdiagnosed as a flashing application.
- The standard application of the ISA/IEC sizing equations do not accurately account for this situation.

Flashing

- One homogenous substance that changes from a liquid state to a gas state (i.e. water to steam).
- Undergoes a thermodynamic process and becomes two phase at the vena contracta.
- Flashing occurs when the pressure of the liquid drops to its vapor pressure. It is easier to predict this compared to outgassing and is modeled by the ISA/IEC Liquid Sizing Equations.

Identifying Outgassing Applications

The ability to identify an outgassing application is important because outgassing is handled very differently than any other application. Listed below are some good indicators that outgassing is occurring.

Note A: Vapor Pressure

- If the vapor pressure (PV) listed on the specifications sheet is similar to that of the inlet pressure (P1). The assumption is that this practice will compensate for the gas that is known to be present downstream of the valve although the gas is not the same composition as the upstream liquid. This is an incorrect assumption.

Note B: Critical Pressure

- If the vapor pressure listed on the spec sheet is greater than the critical pressure listed. From a thermodynamic perspective, this is impossible. When considering a pressure/temperature diagram, the vaporization line depicts the vapor pressure for a given temperature. The saturation pressure terminates at the vapor line, above which the fluid becomes supercritical. Hence, if the control valve data sheet has PV>PC, then the customer may be unknowingly trying to model an outgassing application.

Note C: Gas/Vapor Percentage

- There are times when the customer's valve data sheet will specify the percentage of gas/vapor for their process.
- If the application data sheet indicates that the inlet conditions are liquid and the outlet conditions are liquid and gas.

Note D: Application Indicator

- If any of the previous stated indicators are present, check to see if it is being used in a level controller application by checking the tag on the spec sheet. The tag may have an "LC," "LCV," or sometimes "LV" to represent that it is a level control valve.

Valve Sizing and Selection

Outgassing two-phase flow in control valve applications requires a special sizing procedure. The potential existence of both a compressible (gas or vapor) element and non-compressible (liquid) element in the flowing media prior to the throttling orifice cannot be accurately modeled using the standard ANSI/ISA S75.01, IEC 6053421 or other proprietary liquid control valve sizing equations. Therefore, in order to successfully arrive at a reasonable CV that is neither undersized nor oversized, contact your Emerson Sales office to learn more.

Valves and Trims for Outgassing Applications with Low Outlet Gas Volume Ratio and Shows Little Potential to Cavitate

Process Conditions	Pressure Class	
	CL150-600	CL1500 and above
Contact your Emerson sales office to obtain a copy of the "Fisher Outgassing Process Data Sheet"	Whisper Trim I Whisper Trim III Levels A1, B1, and C1 Cavitrol III trim, 1 stage V500 reverse flow control valve NotchFlo DST DST trim	Whisper Trim III Levels A1, B1, and C1 NotchFlo DST DST trim

Valves and Trims for Outgassing Applications with High Outlet Gas Volume Ratio Where a Multi-Stage Solution is requested

Process Conditions	Pressure Class
	CL150 and above
Contact your Emerson sales office to obtain a copy of the "Fisher Outgassing Process Data Sheet"	DST-G trim

Valves and Trims for Outgassing Applications with High Outlet Gas Volume Ratio and There is No Valve Trim Preference

Process Conditions	Pressure Class	
	CL150-600	CL1500
Contact your Emerson sales office to obtain a copy of the "Fisher Outgassing Process Data Sheet"	Whisper Trim I Whisper Trim III Levels A1, B1, and C1 Cavitrol III trim, 1 stage V500 reverse flow control valve 461 Sweep-Flo valve DST-G trim	Whisper Trim III Levels A1, B1, and C1 461 Sweep-Flo valve DST-G trim

4. Compressor Suction Valve

The amount of hydrogen delivered to the hydrotreater often limits the unit throughput. The hydrogen/oil ratio is a major parameter for determining the treating conversion of the unit. If the ratio is too low, an excessive amount of coke can build upon the catalyst, shortening reactor life. If the ratio is too high, throughput on the unit is wasted.

The hydrogen flow can be set manually or through a bypass if necessary. If swings in the hydrogen are wide enough, this will not only limit unit throughput, but also lead to increased coke laydown on the catalyst, potentially shortening reactor life.

- **Typical Process Conditions:**
  - Fluid: Hydrogen
  - P1/P2 = Dependent on process design
  - T = Dependent on process design
  - Q = Dependent on process design
- **Typical Control Valve Selection:**
  - Valve selection is dependent on process conditions, however many times butterfly valves are selected for these applications

5. Compressor Bypass

The primary purpose of compressor bypass valves is to protect the most critical and expensive pieces of equipment in the plant, the compressors. During a surge event, the valve must respond quickly and accurately in order to recycle the discharge flow back to the suction side of the compressor. Failure of the valve to react quickly can result in severe damage to the impellers of the compressor.

- **Typical Process Conditions:**
  - Fluid: Treated gas
  - P1 = 50 – 65 barg (700 – 945 psig)
  - P2 = 32 – 60 barg (465 – 885 psig)
  - T = 100 - 101°C (213 - 215°F)
  - Q = m^3/h (4.9 MMscfd, 509000 scfh)
- **Typical Control Valve Selection:**
  - NPS 3 easy-e ET
  - Materials of Construction: WCC body with 400-series SST or 316/Alloy 6 trim
  - NACE may be required
  - ENVIRO-SEAL duplex packing
  - Class IV shutoff

6. Reactor Hydrogen Valve

This valve is used to control the reactor bed temperature. The reactor bed temperatures are another major parameter in determining the unit treating conversion. If the temperatures are allowed to get too high, then the reactor catalyst life will be shortened, as excessive amounts of coking will occur. Therefore, it is important that this valve functions properly.

- **Typical Process Conditions:**
  - — Fluid: Recycle hydrogen
  - — P1 = barg (878 - 1286 psig)
  - — P2 = barg (790 - 1224 psig)
  - — T = °C (139 - 215°F)
  - — Q = 12275 Nm^3/h (10 – 10.14 MMscfd 458333 scfh)
- **Typical Control Valve Selection:**
  - — NPS 2 HPS or NPS 2 to NPS 3 easy-e ET or EZ
  - — Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - — ENVIRO-SEAL duplex or PTFE packing
  - — Class V or VI shutoff

7. Sour Water Letdown Valve

The liquid phase in a separator is split into recoverable products and sour water. Sour water is collected in a separator boot, since it is denser than oil. Sour water is directed to a sour water flash drum (not depicted) where H_2S and NH_3 are removed.

The sour water letdown valve can be exposed to mild outgassing and flashing. Due to the entrained H_2S and NH_3, the water can be both erosive and corrosive – attacking both the body and trim materials. This valve is usually a level control valve, to maintain a level of interface between the sour water and recoverable product in the separator.

- **Typical Process Conditions:**
  - — Fluid: Hydrocarbon with entrained hydrogen
  - — P1 = 13 – 48 barg (185 - 690 psig)
  - — P2 = 1.7 – 7.9 barg (25 – 115 psig)
  - — T = 38 - 60°C (100 - 140°F)
  - — Q = 1.4 – 7.8 m^3/h (6 -34 gpm)
- **Typical Control Valve Selection:**
  - — See outgassing discussion as previously discussed in this section

8. Recycle Purge Valve

This valve, along with the makeup valve, is used to control hydrogen purity. As the hydrogen is recycled through the unit, it eventually becomes dirty with light hydrocarbons such as methane and ethane. A continuous purge is taken from the recycle gas and is replaced with makeup hydrogen to prevent the recycle gas from becoming too heavy.

Generally this valve is not critical to unit operation since it is possible to run the unit on total recycle without makeup or purge for short periods of time. A sticking valve could cause pressure swings that could affect the conversion reaction and catalyst coking rate.

- **Typical Process Conditions:**
  - — Fluid: Hydrogen and light hydrocarbons
  - — P1 = 42 – 74 barg (610 - 1080 psig)
  - — P2 = 23 – 25 barg (330 - 365 psig)
  - — T = 38 - 60°C (100 - 140°F)
  - — Q = 7 – 8.5 MMscfh
- **Typical Control Valve Selection:**
  - — NPS 2 to NPS 3 easy-e ET or EZ
  - — Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - — Noise attenuation trim may be required
  - — ENVIRO-SEAL graphite packing
  - — May require NACE compliance
  - — Class V shutoff

9. Stripper Bottoms Valve

The bottom product valve is typically used to control the level in the bottom of the column. It normally has no effect on column operation unless it causes the level to change quickly and dramatically.

- **Typical Process Conditions:**
  - — Fluid: Treated product
  - — P1 = 8.5 – 12 barg (125 - 175 psig)
  - — P2 = 5.2 – 10 barg (75 - 150 psig)
  - — T = 38 - 100°C (100 - 215°F)
  - — Q = 60 – 200 m^3/h (255 – 865 gpm)
- **Typical Control Valve Selection:**
  - — NPS 6 to NPS 8 easy-e ET
  - — Materials of Construction: WCC with 400-series SST trim
  - — ENVIRO-SEAL packing
  - — Class IV shutoff

10. Makeup Hydrogen Valve

This valve, along with the recycle purge valve, is used to control hydrogen purity. Makeup hydrogen is high purity, usually above 90% hydrogen. This valve is usually not critical to short-term operation because the unit can run totally on recycle gas for short periods.

- **Typical Process Conditions:**
  - — Fluid: Hydrogen
  - — P1 = 40 – 125 barg (575 - 1850 psig)
  - — P2 = 23 – 88 barg (330 - 1280 psig)
  - — T = 38 – 96 °C (100 - 205°F)
  - — Q = 36800 – 566350 m^3/hr (1.3 - 20 MMscfh)

- **Typical Control Valve Selection:**
  - — NPS 2 HPS or NPS 1.5 to NPS 2 easy-e EZ
  - — Materials of Construction: WCC body with 300-series SST trim
  - — ENVIRO-SEAL duplex packing
  - — Class IV or V shutoff

11. Stripper Reflux Valve

The reflux valve is typically either a flow or column temperature-control loop. It is used to adjust the purity of the overhead product. The higher the reflux rate, the purer the overhead product will become. However, raising the reflux rate also will require more reboil heat and if too high can flood the tower.

A poorly operating reflux valve will have the same effects as a bad feed valve—product purities will oscillate and the column will be difficult to control. This valve is critical to maintaining vapor/liquid balance in the column, ultimately affecting the efficiency of the column.

- **Typical Process Conditions:**
  - — Fluid: Unstabilized naphtha
  - — P1 = 11 – 16 barg (155 - 240 psig)
  - — P2 = 3.9 – 12 barg (60 – 180 psig)
  - — T = 45 - 60°C (115 - 135°F)
  - — Q = 4.5 – 20 m^3/h(20 – 90 gpm)
- **Typical Control Valve Selection:**
  - — NPS 1.5 to NPS 3 easy-e ET, EZ or NotchFlo DST
  - — Anti-cavitation trim may be required depending on service conditions
  - — Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - — ENVIRO-SEAL duplex packing
  - — Class IV or V shutoff

12. Stripper Light-Ends Valve

Stripper light-ends valves are used to control the column pressure. Higher column pressures yield higher product purities, but require more energy to operate. Normal operating procedure is to minimize the pressure to lower energy costs while maintaining product specifications. There is a lower column pressure limit because lower pressures reduce the amount of vapor/liquid traffic the stripper can handle and can increase the likelihood of flooding.

The simplest way to control pressures is to continuously vent gas from the system. Sizing of this valve is critical. If the valve is too large, a small valve movement will cause a large pressure swing. If the valve is too small, the pressure response will be very sluggish. It is likely that a valve that is too small will operate from completely closed to completely open. In either scenario, an oscillating column pressure and difficult column control are the result. A sticking pressure control valve will present the same problem. A sticking valve is a common concern on vent gas valves because the valve packing will normally be tight to prevent fugitive emissions.

Many strippers also use what is known as a “hot vapor bypass” valve to control pressure. In this case, some of the hot overhead vapors are bypassed around the overhead condenser heat exchanger. The amount of bypass will control the pressure. This eliminates the constant venting of process gas, which usually goes to a low-value refinery waste fuel gas system. Unfortunately, the pressure response on a hot vapor bypass valve is normally very sluggish due to slow process response time. Like the vent gas valve, this valve is a concern for fugitive emissions, and the packing is likely to be tight. A sticking valve will cause wide, slow oscillations in column pressure. The product purities will likewise swing widely and slowly. The response of refinery operations personnel will usually be to over-purify.

A majority of strippers with hot-vapor bypass valves will use it in combination with a vent gas valve. In these cases, a single pressure control loop will manipulate both valves. At lower pressures, the hot vapor bypass valve is used. As the pressure rises, there will be a transition point where the hot vapor bypass valve closes fully and the vent gas valve starts to open. At high pressures, the vent gas valve controls the pressure. This configuration often leads to pressure control problems, as the hot vapor bypass and vent gas valves will have different control characteristics. Also, it is unlikely that one valve will close precisely at the same time the other valve opens. If the column is constantly making a transition between using the hot vapor bypass and vent gas valves, the pressure will normally oscillate. This is a tuning problem rather than a valve problem, but it should be kept in mind for column design or valve resizing.

This valve controls the back pressure to the stripper and is very important in controlling the stability of the tower. Many columns use tray temperature to control overhead composition, thus stable pressure is required to ensure temperature changes reflect composition changes not pressure changes.

- **Typical Process Conditions:**
  - — Fluid: Stripper offgas
  - — P1 = 8.3 – 9.1 barg (120 - 130 psig)
  - — P2 = 6.9 – 7.2 barg (100- 105 psig)
  - — T = 45 - 60°C (115 - 135°F)
  - — Q = 1,180 – 4,825 m^3/h (1.0 – 4.1 MMscfd)
- **Typical Control Valve Selection:**
  - — NPS 1.5 to NPS 4 easy-e ET
  - — Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - — NACE may be required
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV shutoff

13. Stripper Naphtha Valve

This valve is typically used to control the level in the overhead receiver. It normally has no effect on column operation unless it causes the level to change quickly and dramatically. The naphtha product is fed to downstream units.

- **Typical Process Conditions:**
  - — Fluid: Treated naphtha
  - — P1 = 10 – 15 barg (150 - 225 psig)
  - — P2 = 8.8 – 14 barg (125 - 200 psig)
  - — T = 40 – 105 °C (105 - 220°F)
  - — Q = 4 – 290 m^3/h (18 – 1290 gpm)
- **Typical Control Valve Selection:**
  - — NPS 1 to NPS 6 easy-e ET or EZ
  - — Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - — ENVIRO-SEAL duplex or PTFE packing
  - — Class IV shutoff

4.8 Hydrocracker

Other Names—Unicracker, H-Oil, LC-Fining, Hydrocracking Unit

Hydrocracking breaks or "cracks" heavier hydrocarbons into gasoline, jet fuel, and diesel stocks. This is accomplished by using heat, catalyst and hydrogen under very high pressure.

Hydrocracking is quite simply catalytic cracking in the presence of hydrogen. In hydrocrackers, feed from the FCC, coker, and distillation columns are upgraded to middle distillates and gasoline blending components. Hydrocrackers are capable of producing these products, without any leftovers (coke, pitch, resid). However, not all refineries have a hydrocracker since they require significant capital investment due to the high pressure piping, vessels, valves, and instruments.

In the hydrocracker unit, incoming gas oil feed is heated in a furnace to reaction temperature. It is combined with a recycled hydrogen stream before flowing through the reactor with multiple catalyst beds. Additional recycled hydrogen is added between each bed to control the cracking conversion. The reactor effluent is sent to high-pressure, then low-pressure separators. Extremely high pressures are required, often over 170 barg (2500 psig), to crack benzene ringed compounds from the gas oils. The vapor from the separators is recycled through a compressor back to the feed. Makeup hydrogen is added to this stream as necessary. The liquid from the low pressure separator is sent to a fractionator where the reactor effluent is separated into component product streams.

The unit depicted in Figure 4.8.1 is representative of a fixed bed unit. Although fluidized beds are available, the fixed bed design represents around 75% of the world's hydrocracking units.

Hydrocracker Application Review

Most hydrocrackers have the flexibility to produce a wide range of final products. This allows the refinery to have the flexibility to increase gasoline or diesel production in the summer months and distillates in the winter. Catalyst influences the ability to maximize one yield over another. This also means that the process equipment in these units needs to have flexibility – including the possibility of covering a range of temperatures and material compatibility. These various process conditions need to be considered in control valve and all process equipment selection.

Control Valves

1. Feed Valve

The unit feed valve is a challenging valve in this service, which can cause swings in the amount of conversion through the unit. If the swings are wide enough, this will actually limit unit throughput and lead to increased coke laydown on the catalyst, potentially shortening reactor life.

Feed valves usually are set up as flow-control loops. They are configured to fail open so that a valve failure will protect the furnace radiant section tubes. If a radiant tube loses or has insufficient flow, the tube can quickly become so hot that the metal can melt. This can have disastrous consequences, as most process feeds make excellent fuels. A furnace can be destroyed very quickly if a ruptured tube is dumping into the firebox of the furnace.

Unit feed valves can lead to difficulties with controlling the outlet temperature of the furnace. Many process feeds slowly build layers of coke on the inside of the radiant tubes. Coking is a non-linear reaction, and in some processes even a few extra degrees of temperature can lead to excessive coke build-up. If a flow valve provides inconsistent feed, the temperature may swing and lead to excessive coke build-up. This shortens the furnace cycle time between decoking procedures, which normally require the process unit downstream to shut down.

Feed valves can be bypassed when necessary. A combination of the measured flow and pass temperatures can be used to regulate the bypass valve.

- **Typical Process Conditions:**
  - — Fluid: Heavy Gas Oil
  - — P1 = 3.6 – 13 barg (50 - 190 psig)
  - — P2 = 3.0 – 12 barg (45 - 175 psig)
  - — T = 80 - 325°C (180 - 620°F)
  - — Q = 75 - 315 m^3/h (335 – 1,385 gpm)
- **Typical Control Valve Selection:**
  - — NPS 4 to NPS 8 V300 or NPS 3 to NPS 6 easy-e ET or NPS 6 to NPS 10 easy-e EWD or EWT
  - — Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - — NACE may be required
  - — ENVIRO-SEAL graphite or PTFE packing
  - — Class IV shutoff

2. Recycle Hydrogen Valve

The amount of hydrogen delivered to the hydrocracker often limits the unit throughput. The hydrogen/oil ratio is an important parameter for determining the cracking conversion of the unit. If the ratio is too low, an excessive amount of coke can build up on the catalyst, shortening reactor life. If the ratio is too high, throughput on the unit is wasted.

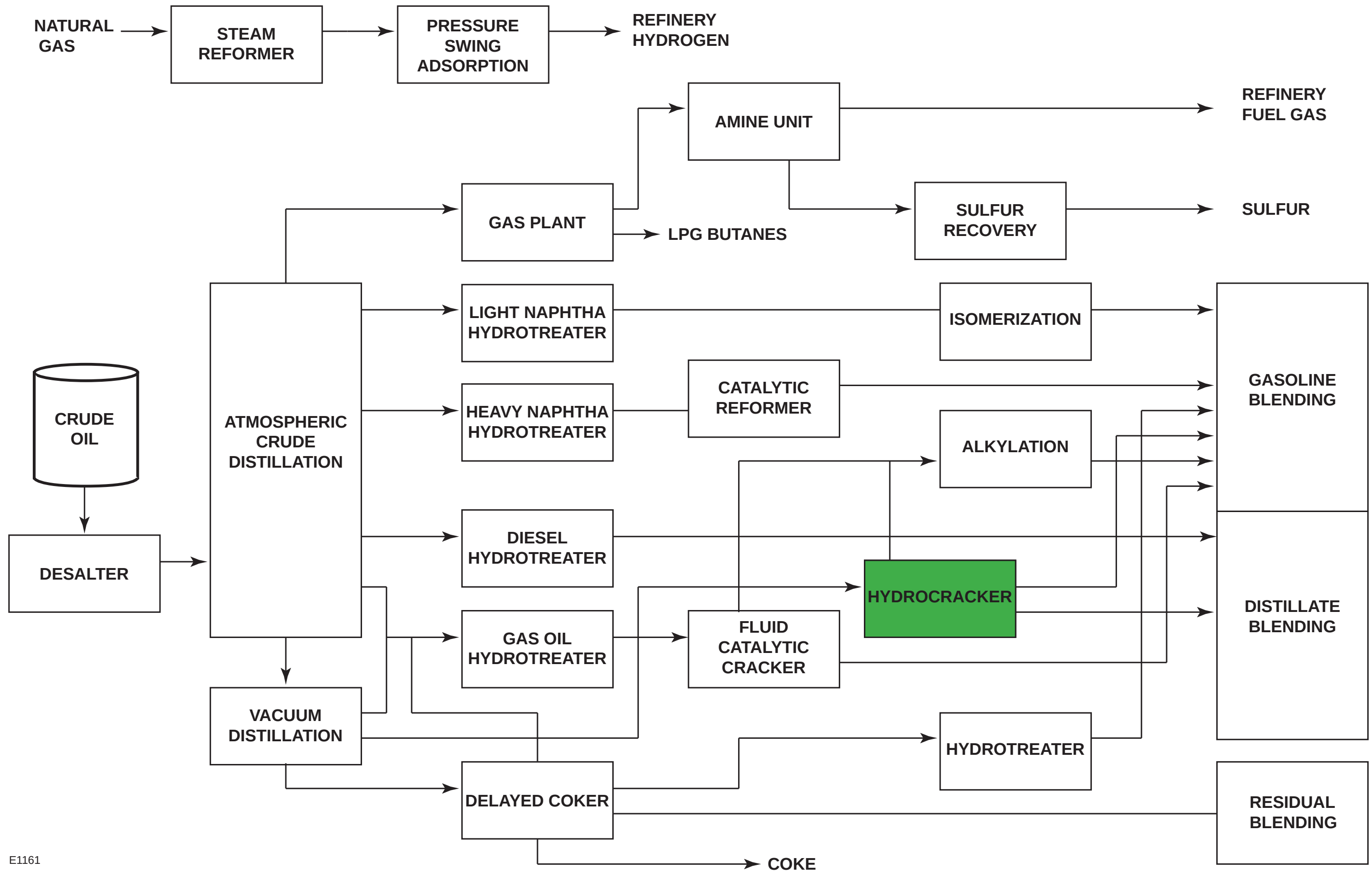


Figure 4.8.1. Hydrocracker Location

The hydrogen flow can be set manually or through a bypass if necessary. If swings in the hydrogen parameters are wide enough, this will not only limit unit throughput, but also lead to increased coke laydown on the catalyst, potentially shortening reactor life.

Because this valve may be a manual or bypass valve, it is not called to move very often. Iron oxides can build up in the presence of the light hydrocarbons. Regular maintenance is important for this valve.

- **Typical Process Conditions:**
  - — Fluid: Hydrogen and Light Hydrocarbons
  - — P1 = 150 – 205 barg (2175 - 2975 psig)
  - — P2 = 145 - 200 barg (2105 - 2900 psig)
  - — T = 65 - 110°C (150 - 230°F)
  - — Q = 6800 - 10,775 kg/h (15,000 - 23,755 lb/h)
- **Typical Control Valve Selection:**
  - — NPS 3 to NPS 10 HPT, easy-e EHT, HPAT, or EHAT
  - — Materials of Construction: WCC body with 400-series SST trim
  - — Noise attenuation trim may be required
  - — ENVIRO-SEAL PTFE packing
  - — Class IV shutoff

3, 15. Fuel Valve

Depending on the furnace service and configuration this valve will normally be part of a loop that controls either the fuel flow or pressure. These valves are specified as fail closed so that a control loop failure will not allow an excessive amount of fuel to be dumped into a hot furnace. A fuel valve failure will almost always shut down the processing unit downstream. Although many fuel valves have bypass circuits, Refinery operations personnel are usually reluctant to run a furnace on bypass for any significant time due to safety concerns.

The preferred control loop configuration for outlet temperature is a cascade to the set point of the loop controlling the fuel valve. Many furnaces will be set up such that the temperature control loop directly manipulates the fuel valve. This direct connection usually provides inferior control performance to a cascade configuration as it is extremely susceptible to valve deadband, such as that caused by a sticking valve. This can be detected by excessive oscillation in the outlet temperature.

When the fuel valve is manipulated by the temperature loop or by a flow control loop, there will often be a pressure control valve upstream of the fuel valve. This valve will also fail closed and will have the same consequences as a failure of the fuel valve. However, with this configuration, operations personnel will be more willing to run a fuel valve in bypass as they still have a way to shut off the fuel quickly in an emergency.

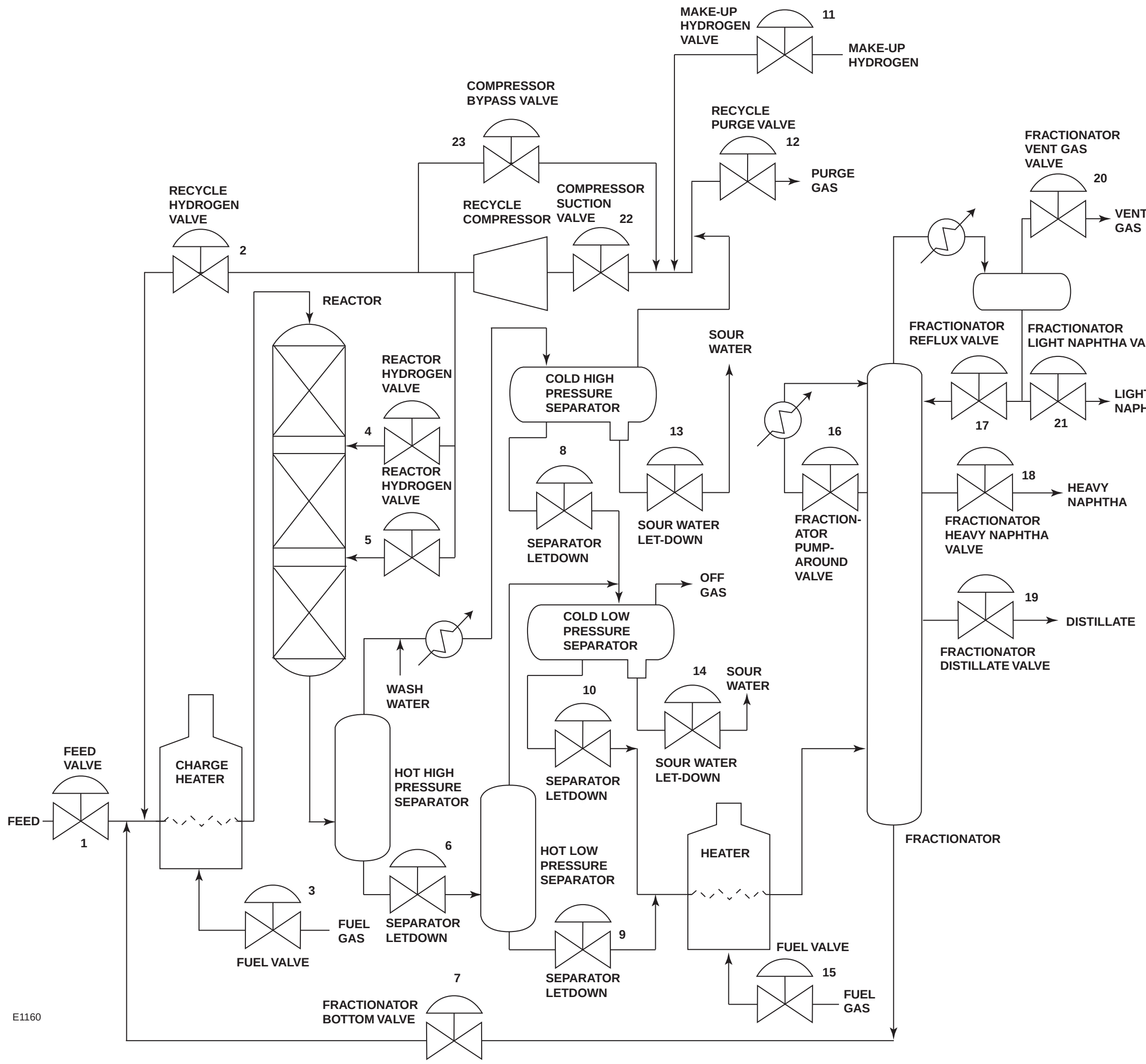


Figure 4.8.2. Hydrocracker Process Flow Diagram

Since this valve is critical to unit operation, FIELDVUE DVC6200 with PD tier diagnostics is recommended. Monitoring valve position is critical to this valve when it is supposed to fail close, it may be desirable to include the position transmitter option in the FIELDVUE DVC6200 to provide position feedback to the DCS, upon loss of power to the FIELDVUE DVC6200 instrument, assuring whether or not the valve actually closed.

- **Typical Process Conditions:**
  - — Fluid: Fuel Gas
  - — P1 = 3.2 – 4.0 barg (45 – 60 psig)
  - — P2 = 0.14 – 2.4 barg (2 - 35 psig)
  - — T = 38°C (100°F)
  - — Q = 1.0 – 6.5 MMscfd (1180 – 7670 m^3/h)
- **Typical Control Valve Selection:**
  - — NPS 2 to NPS 4 easy-e EZ or ET
  - — Materials of Construction: WCC with 400-series SST trim
  - — NACE may be required if fuel gas is sour
  - — ENVIRO-SEAL PTFE packing
  - — Class IV shutoff

4, 5. Reactor Hydrogen Quench Valve

These valves are used to control the reactor bed temperatures. These temperatures are another major parameter in determining the unit cracking conversion. If the temperatures are allowed to get too high, a runaway reaction may occur. Therefore, it is important that these valves function properly.

These valves inject a cool hydrogen quench between the reactor interbeds to maintain control of the exothermic reaction. Tight temperature control is required to maximize catalyst life.

An upset of this valve can shut the entire hydrocracker down. These valves are not required to move frequently, so they can be subject to sticking when iron oxides build up in the process line and around the valve. A sticking valve will cause the bed temperature oscillate. Depending on the severity of the oscillations, this can lead to accelerated coking on the affected bed.

It is a good idea to oversize the actuator for this application to “push through” the potential build up. Historically, many of these applications used a high pressure double ported globe valve (HS) for this application. Some refiners have successfully replaced their HS valve with a balanced trim design (HPD or EHD); however, due to the small cage holes, build up can occur. One way to avoid the small hole cage design, is to provide a special post guided high pressure valve design; however, this will require design assistance from your local Emerson sales office.

It is recommended that PD diagnostics be installed on this application with alerts set up to notify operators of increased friction. In addition, the FIELDVUE digital valve controller can be set up to “bump” travel every few days to keep the valve from sticking when it is required to move significantly.

- **Typical Process Conditions:**
  - Fluid: Hydrogen and light hydrocarbons
  - P1 = 140 - 200 barg (2030 - 2900 psig)
  - P2 = 135 - 175 barg (1960 - 2540 psig)
  - T = 85 - 100°C (185 - 210°F)
  - Q = 10 – 65.9 MMscfd (11800 – 77755 m^3/h)
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 4 HPT or HPD
  - Materials of Construction: WCC with 400-series or 300-series SST trim
  - NACE may be required
  - ENVIRO-SEAL PTFE packing
  - Class IV shutoff

6, 8. High-Pressure Separator Letdown Valve

This is one of the most severe control valve applications in a refinery.

- **Hot High Pressure Separator (HHPS) Letdown Valve Typical Process Conditions:**
  - Fluid: Sour cracked hydrocarbon with entrained gas & particulate
  - P1 = 129 - 169 barg (1865 - 2450 psig)
  - P2 = 28 – 45 barg (405 - 680 psig)
  - T = 245 – 425 °C (470 - 800°F)
  - Q = 320 m^3/h (48,225 bpd)
- **HHPS Letdown Valve Typical Control Valve Selection:**
  - See the following section on outgassing application valve sizing and selection
- **Cold High Pressure Separator (CHPS) Letdown Valve Typical Process Conditions:**
  - Fluid: Sour cracked hydrocarbon with entrained gas & particulate
  - P1 = 126 - 166 barg (1,825 – 2,410 psig)
  - P2 = 28 – 45 barg (405 - 650 psig)
  - T = 51 – 54 °C (125 - 130°F)
  - Q = 192 - 195 m^3/h (28,935 – 29,435 bpd)
- **CHPS Letdown Valve Typical Control Valve Selection:**
  - See the following section on outgassing application valve sizing and selection

Outgassing

Outgassing is one of several severe service applications that are encountered in refining applications. In order to identify a process that is outgassing, it is important to have an understanding of the other severe service applications that experience the same problems or symptoms. The table below shows the physical phases of flow-media and how they are classified. It also gives a description of what is causing these phenomena to occur.

Flow Media Phases

Type: Outgassing **Upstream:** Liquid **Downstream:** Liquid and Gas **Description of Process:** Outgassing is a process that involves a flow media consisting of at least two different constituents. One is a liquid and the other is a gas that is entrained in that liquid. The two components begin to separate upon the slightest change in pressure. The best example of this would be a bottle of soda. The bottle is pressurized and appears to be a homogeneous liquid but when a reduction in pressure occurs, i.e. opening the bottle, the CO_2 gas begins to come out of the liquid solution. The final product downstream is two elements, one liquid soda and the other carbon dioxide gas.
Type: Flashing **Upstream:** Liquid **Downstream:** Liquid and Vapor **Description of Process:** When the pressure within a single component system drops to the vapor pressure of the liquid, the liquid begins to absorb heat and changes to a vapor phase. This process is time dependent because it is a thermodynamic process. The latent heat of vaporization must be absorbed, which is not an instantaneous process.
Type: Cavitation **Upstream:** Liquid **Downstream:** Liquid **Description of Process:** Like flashing, cavitation involves the thermodynamic process of vaporization. Formation of bubbles occurs when the pressure at the vena contracta falls below the vapor pressure. As pressure recovers, the downstream pressure becomes greater than the liquid’s vapor pressure. This causes the newly formed cavities to collapse and implode, creating cavitation with noise and possible damage. As long as the pressure downstream stays above the vapor pressure of the liquid, all of the vapor bubbles will collapse and the final product further downstream will be 100% liquid.
Type: Two-Phase (G/L) **Upstream:** Liquid and Gas **Downstream:** Liquid and Gas **Description of Process:** This is a flowing media that contains at least two different components, where one component is in the liquid phase and the other is in the compressible (gas) phase. Both of these phases are present when entering and exiting the valve. Although this should be easy to identify, it is still a severe service that presents many problems..

Outgassing and flashing behave in similar manners and in many cases outgassing is thought to be flashing. This is because outgassing and flashing both have a fluid that enters a valve as a liquid and exits the valve as a liquid and gas. These two processes can impose the same types of damage, but this is where the similarities end. Shown below are the major differences that separate outgassing from flashing.

Outgassing

- Fluid contains at least two substances of completely different makeup (i.e. crude oil and natural gas).
- Undergoes a depressurization process that causes the entrained gas to be released separate from the liquid.
- Outgassing can occur at any point in the system. It only takes a minimal drop in pressure for the gas to come out of suspension. If outgassing occurs prior to the throat of the valve, damage to the valve and trim would occur. This would occur if an outgassing application were misdiagnosed as a flashing application.
- The standard application of the ISA/IEC sizing equations do not accurately account for this situation.

Flashing

- One homogenous substance that changes from a liquid state to a gas state (i.e. water to steam).
- Undergoes a thermodynamic process and becomes two phase at the vena contracta.
- Flashing occurs when the pressure of the liquid drops to its vapor pressure. It is easier to predict this compared to outgassing and is modeled by the ISA/IEC Liquid Sizing Equations.

Identifying Outgassing Applications

The ability to identify an outgassing application is important because outgassing is handled very differently than any other application. Listed below are some good indicators that outgassing is occurring.

Note A: Vapor Pressure

- If the vapor pressure (PV) listed on the specifications sheet is similar to that of the inlet pressure (P1). The assumption is that this practice will compensate for the gas that is known to be present downstream of the valve although the gas is not the same composition as the upstream liquid. This is an incorrect assumption.

Note B: Critical Pressure

- If the vapor pressure listed on the spec sheet is greater than the critical pressure listed. From a thermodynamic perspective, this is impossible. When considering a pressure/temperature diagram, the vaporization line depicts the vapor pressure for a given temperature. The saturation pressure terminates at the vapor line, above which the fluid becomes supercritical. Hence, if the control valve data sheet has PV>PC, then the customer may be unknowingly trying to model an outgassing application.

Note C: Gas/Vapor Percentage

- There are times when the customer's valve data sheet will specify the percentage of gas/vapor for their process.
- If the application data sheet indicates that the inlet conditions are liquid and the outlet conditions are liquid and gas.

Note D: Application Indicator

- If any of the previous stated indicators are present, check to see if it is being used in a level controller application by checking the tag on the spec sheet. The tag may have an "LC," "LCV," or sometimes "LV" to represent that it is a level control valve.

Valve Sizing and Selection

Outgassing two-phase flow in control valve applications requires a special sizing procedure. The potential existence of both a compressible (gas or vapor) element and non-compressible (liquid) element in the flowing media prior to the throttling orifice cannot be accurately modeled using the standard ANSI/ISA S75.01, IEC 6053421 or other proprietary liquid control valve sizing equations. Therefore, in order to successfully arrive at a reasonable CV that is neither undersized nor oversized, contact your Emerson sales office to learn more.

Valves and Trims for Outgassing Applications with Low Outlet Gas Volume Ratio and Shows Little Potential to Cavitate

Process Conditions	Pressure Class	
	CL150-600	CL1500 and above
Contact your Emerson sales office to obtain a copy of the "Fisher Outgassing Process Data Sheet"	Whisper Trim I Whisper Trim III Levels A1, B1, and C1 Cavitrol III trim, 1 stage V500 reverse flow control valve NotchFlo DST DST trim	Whisper Trim III Levels A1, B1, and C1 NotchFlo DST DST trim

Valves and Trims for Outgassing Applications with High Outlet Gas Volume Ratio Where a Multi-Stage Solution is requested

Process Conditions	Pressure Class
	CL150 and above
Contact your Emerson sales office to obtain a copy of the "Fisher Outgassing Process Data Sheet"	DST-G trim

Valves and Trims for Outgassing Applications with High Outlet Gas Volume Ratio and There is No Valve Trim Preference

Process Conditions	Pressure Class	
	CL150-600	CL1500
Contact your Emerson sales office to obtain a copy of the "Fisher Outgassing Process Data Sheet"	Whisper Trim I Whisper Trim III Levels A1, B1, and C1 Cavitrol III trim, 1 stage V500 reverse flow control valve 461 Sweep-Flo valve DST-G trim	Whisper Trim III Levels A1, B1, and C1 461 Sweep-Flo valve DST-G trim

7. Fractionator Bottom Valve

The bottom product becomes the vacuum distillation unit charge.

This usually does not have any impact on the operation of the crude fractionator unless a failure causes the liquid level of the bottoms to overfill or empty. Typically, level alarms on the unit allow the operator to catch this before it causes an upset.

This valve could encounter higher viscosity materials, sludge, and process media with entrained particles.

- **Typical Process Conditions:**
  - Fluid: Fractionator Bottoms
  - P1 = 8.8 – 18 barg (125 - 260 psig)
  - P2 = 8.3 – 17 barg (120 – 250 psig)
  - T = 130 – 350 °C (270 - 665°F)
  - Q = 56 – 235 m^3/h (8,420 – 35,500 bpd)
- **Typical Control Valve Selection:**
  - NPS 6 Vee-Ball or NPS 6 HPT
  - Materials of Construction: WCC or chrome-moly body with 400-series SST or 300-series SST trim
  - NACE may be required
  - ENVIRO-SEAL Graphite packing
  - Class IV shutoff

9., 10. Low Pressure Separator Valve

Using a low-pressure separator allows for additional removal of hydrogen and light hydrocarbons. The low-pressure separator letdown valve controls the liquid level in the low–pressure separator flowing to the fractionation tower. This application involves moderate pressure drops where erosion, flowing particulate, and cavitation or outgassing can cause severe valve damage if not properly selected. Normally, two valves are used. Both will be piped with bypass valves and can be rapidly switched between to ensure continuous process operation in the event one of the valves requires repair.

- **Hot Low Pressure Separator (HLPS) Letdown Valve Typical Process Conditions:**
  - Fluid: Hydrocarbon with entrained gas & particulate
  - P1 = 26 - 45 barg (375 – 655 psig)
  - P2 = 10 - 11 barg (145 - 160 psig)
  - T = 245 – 250 °C (475 - 485°F)
  - Q = 304 – 463 m^3/h (45,890 – 69,890 bpd)
- **HLPS Letdown Typical Control Valve Selection:**
  - See outgassing discussion from high-pressure separator letdown valve section
- **Cold Low Pressure Separator (CLPS) Letdown Valve Typical Process Conditions:**
  - Fluid: Hydrocarbon with entrained gas & particulate
  - P1 = 26 - 45 barg (375 – 655 psig)
  - P2 = 10 - 11 barg (145 - 160 psig)
  - T = 54 - 71°C (130 - 160°F)
  - Q = 304 – 463 m^3/h (45,890 – 69,890 bpd)
- **CLPS Letdown Typical Control Valve Selection:**
  - See outgassing discussion from high-pressure separator letdown valve section

11. Makeup Hydrogen Valve

This valve, along with the recycle purge valve, is used to control hydrogen purity. Makeup hydrogen is high purity, usually above 90%. This valve is usually not critical to operation because the unit can run completely on recycle gas for short periods of time.

- **Typical Process Conditions:**
  - Fluid: Hydrogen
  - P1 = 12 - 209 barg (175 - 3030 psig)
  - P2 = 4 - 205 barg (60 – 2975 psig)
  - T = 38 - 49°C (100- 120°F)
  - Q = 10 to 500 MMscfd (11800 – 589935 m^3/h)
- **Typical Control Valve Selection:**
  - NPS 4 to NPS 8 easy-e ET or NPS 3 to NPS 6 HPT
  - Materials of Construction: WCC body with 400-series SST trim
  - Class IV or V shutoff

12. Recycle Purge Valve

This valve, along with the makeup valve, is used to control hydrogen purity. As the hydrogen is recycled through the unit, it eventually becomes dirty with light hydrocarbons such as methane and ethane. A continuous purge is taken from the recycle gas and is replaced with makeup hydrogen to prevent the recycle gas from becoming too heavy.

Generally this valve is not critical to unit operation since it is possible to run the unit on total recycle without makeup or purge for short periods of time. A sticking valve could cause pressure swings that could affect the conversion reaction and catalyst coking rate.

- **Typical Process Conditions:**
  - Fluid: Hydrogen and light hydrocarbons
  - P1 = 50 – 125 barg (700 - 1807 psig)
  - P2 = 5 – 120 barg (100 - 1750 psig)
  - T = 60 - 64°C (140 - 147°F)
  - Q = 1 - 7 MMscfd (1180 – 8260 m^3/h)
- **Typical Control Valve Selection:**
  - NPS 1 to NPS 2 HPS
  - Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - Micro-trim may be required to meet low flow rates
  - NACE may be required
  - ENVIRO-SEAL PTFE packing
  - Class V shutoff

13., 14. Sour Water Letdown Valve

The liquid phase in a separator is split into recoverable products and sour water. Sour water is collected in a separator boot, since it is more dense than oil. Sour water is directed to a sour water flash drum (not depicted) where H_2S and NH_3 are removed.

The sour water letdown valve can be exposed to mild outgassing and flashing. Due to the entrained H_2S and NH_3, the water can be both erosive and corrosive – attacking both the body and trim materials. This valve is usually a level control valve, to maintain a level of interface between the sour water and recoverable product in the separator.

- **13 High Pressure Sour Water Letdown Typical Process Conditions:**
  - Fluid: Hydrocarbon with entrained hydrogen
  - P1 = 125 - 165 barg (1815 - 2395 psig)
  - P2 = 8.5 - 26 barg (125 - 380 psig)
  - T = 50 - 55°C (125 - 130°F)
  - Q = 45 – 70 m^3/h (200 - 305 gpm)
- **13 High Pressure Sour Water Letdown Typical Control Valve Selection:**
  - See outgassing discussion from high-pressure separator letdown valve section
- **14 Low Pressure Sour Water Letdown Typical Process Conditions:**
  - Fluid: Hydrocarbon with entrained hydrogen
  - P1 = 7.9 – 45 barg (115 – 650 psig)
  - P2 = 3.3 – 11 barg (50 – 160 psig)
  - T = 55 - 57°C (130 - 135°F)
  - Q = 1.3 – 70 m^3/h (6 - 305 gpm)
- **14 Low Pressure Sour Water Letdown Typical Control Valve Selection:**
  - See outgassing discussion from high-pressure separator letdown valve section

16. Fractionator Pump-Around Valve

A crude fractionator will always have at least one pump-around heat exchanger loop for controlling the heat balance. Most fractionators will have more than one pump-around loop. The pump-around loop is used to extract heat from the column, creating the separation between the product draws immediately above and below the pump-around loop. The pump-around valves are usually flow controllers.

A poorly performing or bypassed pump-around valve will increase the variability in the quality specifications of the product draws. A valve failure will most likely create an upset lasting from thirty minutes to a few hours, depending on the severity of the failure.

- **Typical Process Conditions:**
  - Fluid: Depends on process design
  - P1 = 8.0 - 12 barg (115 - 175 psig)
  - P2 = 5.6 – 9.8 barg (80 – 140 psig)
  - T = 175 – 225 °C (350 - 440°F)
  - Q = 150 – 600 m^3/h (22,650 – 90,575 bpd)
- **Typical Control Valve Selection:**
  - NPS 4 to NPS 8 High Performance Butterfly Valve with Control-Disk or NPS 6 to NPS 8 easy-e ET or ED
  - Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - ENVIRO-SEAL Graphite packing
  - Class IV shutoff

17. Fractionator Reflux Valve

The reflux valve is used to control the separation between the top product, usually naphtha, and the highest side-draw product. The reflux valve can be either a flow or a temperature controller.

A poorly performing or bypassed reflux valve will increase the variability in the quality specifications of the overhead product and the top side draw. A valve failure will most likely create an upset lasting from thirty minutes to a few hours, depending on the severity of the failure.

- **Typical Process Conditions:**
  - Fluid: Depends on process design
  - P1 = 6.8 – 18 barg (100 - 260 psig)
  - P2 = 5.2 – 15 barg (75 - 220 psig)
  - T = 38 - 60°C (100 - 140°F)
  - Q = 13 – 310 m^3/h (1,960 – 46,800 bpd)
- **Typical Control Valve Selection:**
  - NPS 1 to NPS 6 easy-e ET or EZ
  - Materials of Construction: WCC body with 400-series SST or 300-series/Alloy 6 trim
  - NACE may be required
  - ENVIRO-SEAL PTFE packing
  - Class IV shutoff

18. Fractionator Heavy Naphtha Valve

The stripper bottoms valves are used to control the bottoms level in the strippers. These valves do not usually have any impact on the operation of the strippers unless a failure causes the liquid level of the bottoms to overfill or empty. Usually, level alarms on the unit allow the operator to catch this before it causes an upset.

- **Typical Process Conditions:**
  - Fluid: Naphtha
  - P1 = 4.6 – 18 barg (65 – 260 psig)
  - P2 = 3.9 – 16 barg (55 - 230 psig)
  - T = 38 - 190°C (100 - 375°F)
  - Q = 17 – 240 m^3/h (2568 – 36330 bpd)
- **Typical Control Valve Selection:**
  - NPS 4 HPBV or NPS 3 to NPS 4 easy-e ET or NPS 4 Vee-Ball
  - Materials of Construction: WCC body with 400-series or 300-series SST trim
  - ENVIRO-SEAL PTFE packing
  - Class IV shutoff

19. Fractionator Distillate Valve

The stripper bottoms valves are used to control the bottoms level in the strippers. These valves do not usually have any impact on the operation of the strippers unless a failure caused the liquid level of the bottoms to overfill or empty. Usually, level alarms on the unit allow the operator to catch this before it causes an upset.

- **Typical Process Conditions:**
  - Fluid: Distillate (or other product depending on process design)
  - P1 = 3.7 – 13 barg (54 - 190 psig)
  - P2 = 3.4 – 8.2 barg (49 - 119 psig)
  - T = 38 – 285 °C (100 - 546°F)
  - Q = 40.4 – 492 m^3/h (6100 – 74270 bpd)
- **Typical Control Valve Selection:**
  - NPS 1.5 to 6 easy-e EZ or ET or NPS 4 to NPS 8 Vee-Ball
  - Materials of Construction: WCC body with 316/Alloy 6 trim
  - NACE may be required
  - ENVIRO-SEAL duplex or Graphite packing
  - Class III or IV shutoff

20. Fractionator Vent Gas Valve

The overhead pressure control valve releases gases including H_2, H_2S, methane, ethane, propane, and butane. This stream is normally very small (1 to 3 % of feed).

The column pressure has a significant effect on fractionator operation. A valve failure that allows the column to over or under pressure can cause an upset that might take hours of recovery time. A problem valve can create pressure oscillations that prevent the fractionator from being operated optimally. Valve sizing is critical for this service. If the valve is too large, the column pressure might be prone to rapid swings. If the valve is too small and has a large response time, it could cause long, slow swings.

- **Typical Process Conditions:**
  - Fluid: Vent Gas
  - P1 = 1.1 – 42.4 barg (16 - 615 psig)
  - P2 = 0.25 – 40.3 barg (4 - 584 psig)
  - T = 38 – 98 °C (100- 208°F)
  - Q = 680 - 1005 kg/hr 1500 – 2212 lb/h
- **Typical Control Valve Selection:**
  - NPS 1 to NPS 6 easy-e EZ or ET
  - Materials of Construction: WCC body with 400-series or 300-series SST trim
  - NACE may be required
  - ENVIRO-SEAL PTFE packing
  - Class IV shutoff

21. Fractionator Light Naphtha Valve

The overhead product valve is usually on level control from the overhead receiver. This valve does not usually have any impact on the operation of the crude fractionator unless a failure causes the liquid level in the overhead receiver to over fill or empty. In this case, the column pressure would be affected and the fractionator would experience an upset until the pressure became stable again. Usually, level alarms on the unit allow the operator to catch this before it becomes an upset.

It is more likely that a poorly performing product valve could cause stability problems to a downstream processing unit in configurations where there is no surge tank between the units.

- **Typical Process Conditions:**
  - Fluid: Light Naphtha
  - P1 = 2.5 – 17 barg (35 – 245 psig)
  - P2 = 1.8 – 16 barg (26 - 230 psig)
  - T = 38 – 94 °C (100 - 200°F)
  - Q = 20 – 180 m^3/h (3020 – 27,170 bpd)
- **Typical Control Valve Selection:**
  - NPS 8 to NPS 16 easy-e ET/EUT or NPS 2 to NPS 12 HPBV
  - Materials of Construction: WCC body with 400-series SST trim
  - Noise attenuation trim may be required
  - ENVIRO-SEAL PTFE packing
  - Class IV shutoff

22. Compressor Suction Valve

The amount of hydrogen delivered to the hydrocracker often limits the unit throughput. The hydrogen/oil ratio is a major parameter for determining the conversion of the unit. If the ratio is too low, an excessive amount of coke can build upon the catalyst, shortening reactor life. If the ratio is too high, throughput on the unit is wasted.

The hydrogen flow can be set manually or through a bypass if necessary. If swings in the hydrogen are wide enough, this will not only limit unit throughput, but also lead to increased coke laydown on the catalyst, potentially shortening reactor life.

- **Typical Process Conditions:**
  - Fluid: Hydrogen
  - P1/P2 = Dependent on process design
  - T = Dependent on process design
  - Q = Dependent on process design
- **Typical Control Valve Selection:**
  - Valve selection is dependent on process conditions, however many times butterfly valves are selected for these applications

23. Compressor Bypass

The primary purpose of compressor bypass valves is to protect the most critical and expensive pieces of equipment in the plant, the compressors. During a surge event, the valve must respond quickly and accurately in order to recycle the discharge flow back to the suction side of the compressor. Failure of the valve to react quickly can result in severe damage to the impellers of the compressor.

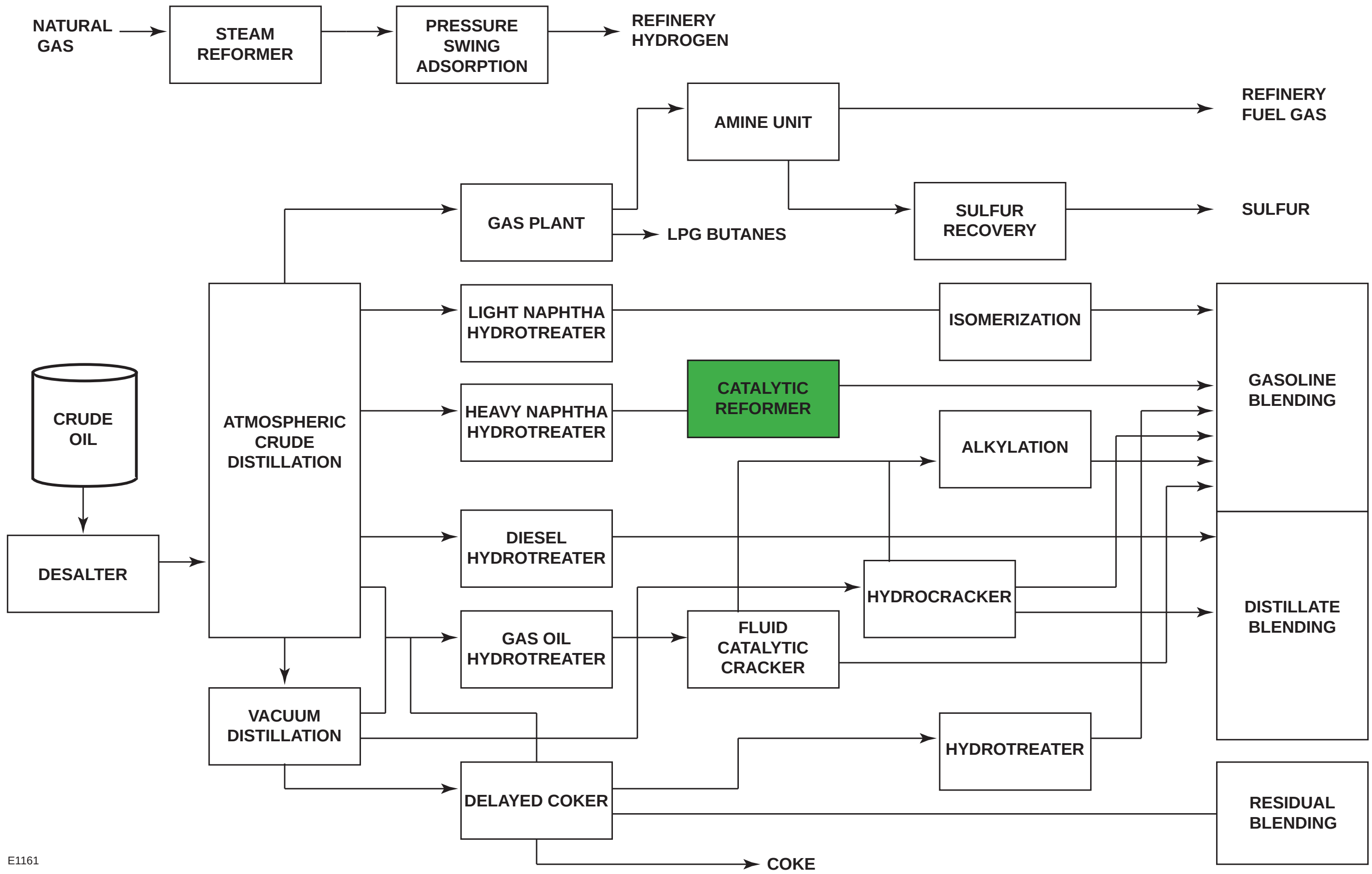


Figure 4.9.1. Catalytic Reformer Unit Location

- **Typical Process Conditions:**
  - — Fluid: Treated Gas
  - — P1/P2 = Dependent on process design
  - — T = Dependent on process design
  - — Q = Dependent on process design
- **Typical Control Valve Selection:**
  - — Valve selection is dependent on process conditions, however many times a globe valve with noise attenuation trim is selected

4.9 Catalytic Reformer Unit

Other Names—Reformer, cat reformer, platformer, CCR (continuous catalytic reformer). Other less common licenses include: rheniforming, powerforming, magnaforming, ultraforming, houdriforming, octanizing.

The catalytic reformer unit uses heat, catalyst and moderate pressure to convert crude and coker naphtha into a high octane blendstock called reformate. The process is endothermic, requiring multiple reactors and heaters in between each reactor to reheat the process. This process rearranges paraffinic and cyclic hydrocarbon molecules into products that are higher in aromatic content. This unit is also a net hydrogen producer that is used elsewhere in the refinery.

The catalytic reforming process upgrades low-octane naphtha feedstocks to high octane reformate for the gasoline blending pool. Heated naphtha is reacted with hydrogen in the presence of a catalyst to reform the naphtha components into a stream that is rich with high octane aromatic and branched hydrocarbons, usually using a platinum catalyst. The incoming naphtha is pretreated in a hydrotreater to protect the catalyst used in this process, which can be poisoned by sulfur and nitrogen. The unit is also a net hydrogen producer, as the reactions strip hydrogen away from saturated hydrocarbons to create the aromatics.

Prior to the evolution of catalytic reforming, lead was used as an additive to increase octane in gasoline. After it was discovered that lead created air pollution and became a monitored pollutant, catalytic reformers were developed. Cat reformers change long carbon chains into aromatics, which, like lead, also increase octane. However, a common aromatic produced by cat reformers is benzene. Benzene is a known carcinogen, and now is also highly regulated. This means that today's reformers have to be closely monitored either by controlling the feed into the reformer, or extracting benzenes from the reformate after the process is complete.

There are two general types of cat reformers: fixed bed and continuous. In a fixed bed reformer, there are reactors in series with fixed catalyst beds. Originally, most units were built with three reactors and separate heaters. However, these three reactors need to run simultaneously to provide the best conversion to reformate. Because the catalyst becomes inactive over time, this 3-bed unit required annual

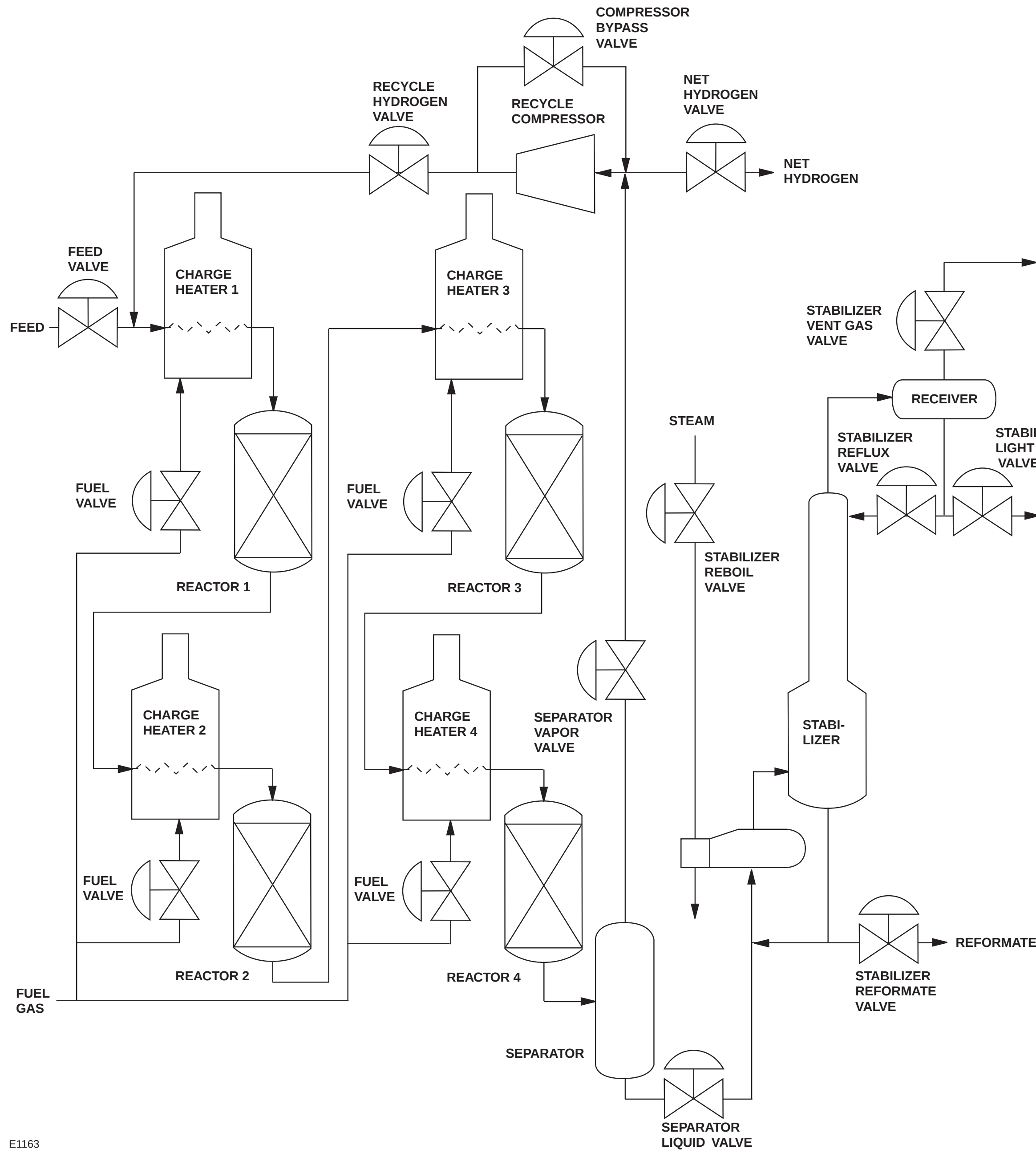


Figure 4.9.2. Fixed 4-Bed Catalytic Reformer Process Flow Diagram

maintenance to clean and regenerate the catalyst. Overtime, refiners realized that the fixed-bed reformer could be upgraded to a 4-bed system. This allowed them to change out catalysts one reactor at a time, eliminating the lengthy annual shutdown.

A fixed 4-bed cat reformer is depicted in Figure 4.9.2. However, the valve applications identified will not be discussed in this text.

In a fixed 4-bed reformer, the incoming naphtha feed is heated in a furnace to reaction temperature. It is combined with a recycle hydrogen stream before flowing through the first of four reactors. This process repeats, and after the fourth reactor the effluent is sent to a separator. Vapor from the separators is recycled through a compressor back to the feed, or it becomes export hydrogen. Liquid from the separator is sent to a stabilizer. In the stabilizer, the reactor effluent is separated into vent gases, light end liquids, and high octane reformate product streams. Makeup hydrogen is used only to start up the unit.

The second type of cat reformer is a continuous catalytic reformer (CCR). It will be used as the basis for this text. However, you will notice many of the valve applications are similar to the fixed bed version. The continuous catalytic reformer was developed in 1971 to improve efficiency, extend run life, and reduce cat reformer maintenance. In this design, catalyst is constantly fed into the first stage of a stacked reactor, and flows down through three stages. Simultaneously, treated naphtha feed is heated and enters the first stage of the reactor, exits the first stage, and is reheated before moving on to the next stage. The spent catalyst enters a separate regenerator where coke is removed and catalyst is reconditioned through treatment with oxygen

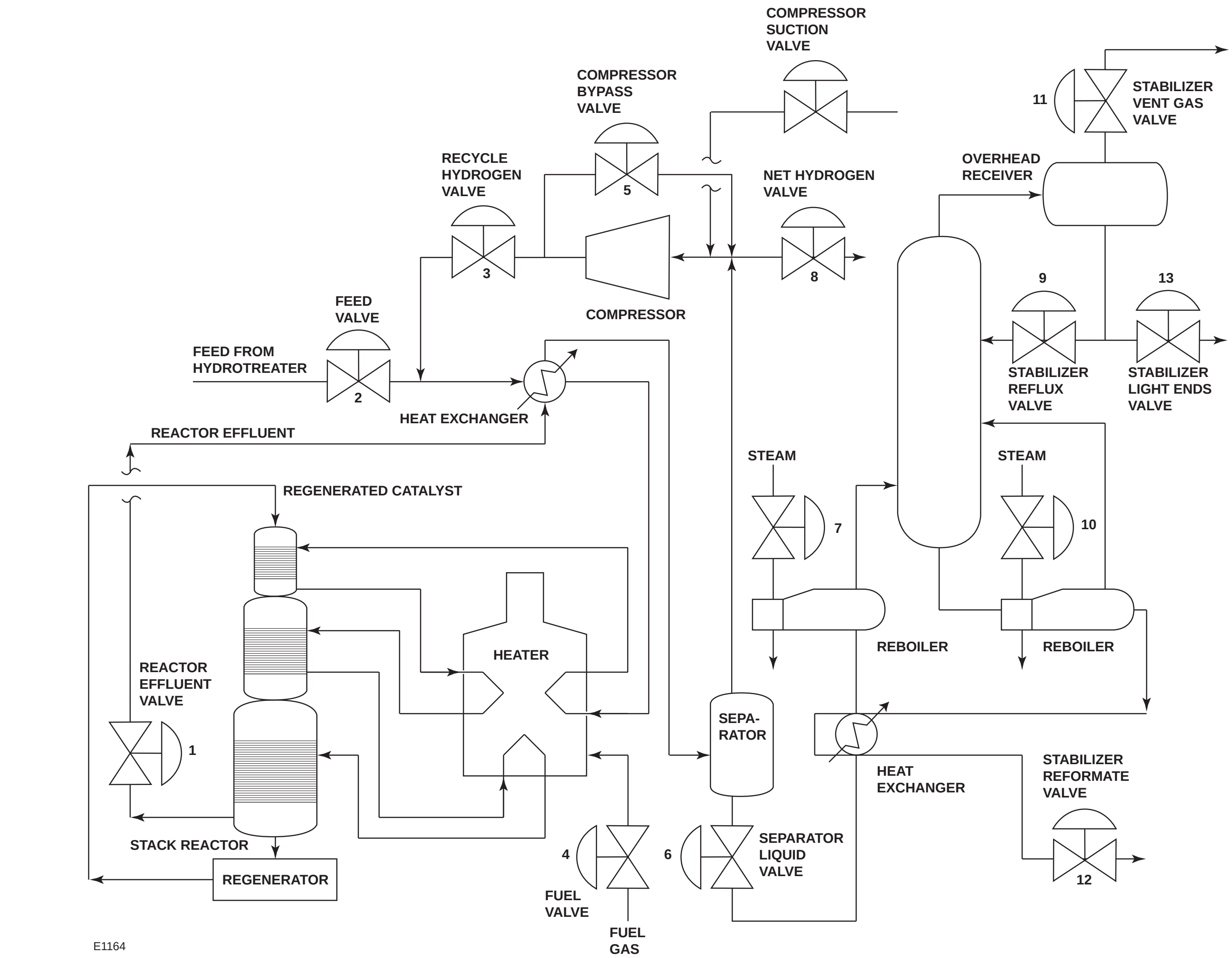


Figure 4.9.3. Continuous Catalytic Reformer Process Flow Diagram

and chlorides. This continuous regeneration of catalyst allows up to six years between maintenance shutdowns. A diagram of the CCR is depicted in Figure 4.9.3. Downstream of the reactor, the fixed bed and continuous cat reformers are nearly identical – in fact, some refiners have changed their fixed bed reformer to a CCR and left most of the downstream infrastructure intact.

A continuous catalytic reformer can be split into two sections: reformer and regenerator. Due to the tightly licensed nature of the regenerator section in a CCR, this text will only discuss the reformer valve applications.

The majority of the valves used in this process unit are general service valve styles, but they are still very critical to the operation of the unit. Because the feed to this unit is pretreated, NACE should not be required.

1. Reactor Effluent Valve

This valve controls the product off of the final stage of the catalytic reactor unit. This valve is usually in a level loop.

- **Typical Process Conditions:**
  - — Fluid: Hydrocarbon and hydrogen
  - — P1 = 21 – 45 barg (305 - 650 psig)
  - — P2 = 12 – 14 barg (175 - 205 psig)
  - — T = 38 - 46°C (100 - 115°F)
  - — Q = 430 – 490 m^3/h (1,805 – 2,150 gpm)
- **Typical Control Valve Selection:**
  - — NPS 6 to NPS 8 easy-e ET or EWT
  - — Materials of Construction: WCC body with 300-series SST/Alloy 6 trim
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV shutoff

2. Feed Valve

A problem valve in this service can cause swings in the amount of conversion through the unit. If the swings are wide enough, this will actually limit unit throughput and lead to increased coke laydown on the catalyst, potentially shortening reactor life.

Feed valves are usually set up as flow control loops. They are configured to fail open so that a valve failure will protect the furnace radiant section tubes. If a radiant tube loses or has insufficient flow, the tube can quickly become so hot that the metal can melt. This can have disastrous consequences, as most process feeds make excellent fuels. A furnace can be destroyed very quickly if a ruptured tube is dumping into the firebox of the furnace.

Problem valves can lead to difficulties with controlling the outlet temperature of the furnaces. Also, many process feeds slowly build layers of coke on the inside of the radiant tubes. Coking is a non-linear reaction, and in some processes even a few extra degrees of temperature can lead to excessive coke build-up. If a flow valve provides inconsistent feed, the temperature will also swing and will usually lead to excessive coke buildup. This will shorten the furnace cycle time between decoking procedures, which will normally require the process unit downstream to shut down.

Feed valves can easily be bypassed when necessary. A combination of the measured flow and any available pass temperatures can be used to regulate the bypass valve.

- **Typical Process Conditions:**
  - Fluid: Treated naphtha
  - P1 = 11 – 13 barg (160 – 190 psig)
  - P2 = 9.4 – 11 barg (135 – 160 psig)
  - T = 91 - 105°C (195 - 220°F)
  - Q = 175 – 475 m^3/h (765 – 2100 gpm)
- **Typical Control Valve Selection:**
  - NPS 3 to NPS 6 easy-e ET or NPS 3 to NPS 6 V500
  - Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - ENVIRO-SEAL PTFE packing
  - Class IV shutoff

3. Recycle Hydrogen Valve

The amount of hydrogen delivered to the reformer helps to control conversion and catalyst degradation caused by coking. The hydrogen/oil ratio is a major parameter for determining the catalyst life of the unit as well as maintaining on-spec product. If the ratio is too low, an excessive amount of coke can build up on the catalyst, shortening reactor life. If the ratio is too high, throughput of the unit is wasted as yields drop.

The hydrogen flow can be set manually or through a bypass if necessary. If swings in the hydrogen are wide enough, this will not only limit unit throughput, but also lead to increased coke laydown on the catalyst, potentially shortening reactor life.

Precise control of this valve is essential in extending catalyst and reactor life, therefore a FIELDVUE DVC6200 instrument with PD tier is recommended for this application. Traditionally, a high performance butterfly valve has been used in this service, but due to the need for good control in this application, a Control-Disk valve is an appropriate solution.

- **Typical Process Conditions:**
  - Fluid: Hydrogen
  - P1 = 7.8 – 14 barg (115 - 205 psig)
  - P2 = 6.0 – 7.7 barg (85 – 110 psig)
  - T = 88 - 94°C (190 - 200°F)
  - Q = 31150 – 232200 m^3/h (1.1 – 8.2 MMscfh)
- **Typical Control Valve Selection:**
  - NPS 12 to NPS 30 Control-Disk
  - Materials of Construction: WCC body with 300 series SST soft seated trim
  - ENVIRO-SEAL PTFE packing
  - Class VI shutoff

4. Fuel Valve

Depending on the furnace service and configuration, this valve will normally be part of a loop that controls either the fuel flow or pressure. These valves are specified as fail closed so that a control loop failure will not allow an excessive amount of fuel to be dumped into a hot furnace. A fuel valve failure will almost always shut down the processing unit downstream. Although many fuel valves have bypass circuits, refinery operations personnel are usually reluctant to run a furnace on bypass for any significant time due to safety concerns.

The preferred control loop configuration for outlet temperature is a cascade to the set point of the loop controlling the fuel valve. Many furnaces will be set up such that the temperature control loop directly manipulates the fuel valve. This direct connection usually provides inferior control performance to a cascade configuration as it is extremely susceptible to valve deadband, such as that caused by a sticking valve. This can be detected by excessive oscillation in the outlet temperature.

When the fuel valve is manipulated by the temperature loop or by a flow control loop, there will often be a pressure control valve upstream of the fuel valve. This valve will also fail closed and will have the same consequences as a failure of the fuel valve. However, with this configuration, operations personnel will be more willing to run a fuel valve in bypass as they still have a way to shut off the fuel quickly in an emergency.

Since this valve is critical to unit operation, a FIELDVUE DVC6200 instrument with PD tier diagnostics is recommended. Monitoring valve position is critical to this valve when it is supposed to fail close. it may be desirable to include the position transmitter option in the FIELDVUE DVC6200 instrument to provide position feedback to the DCS, upon loss of power to the FIELDVUE DVC6200 instrument, assuring whether or not the valve actually closed.

This is one of the few applications in a reformer unit that may require NACE compatible trim, in the event that the refiner's fuel gas is sour.

- **Typical Process Conditions:**
  - — Fluid: Fuel gas
  - — P1 = 2.5 – 5.0 barg (35 – 75 psig)
  - — P2 = 0.2 – 2.6 barg (3 – 40 psig)
  - — T = 30 - 120°C (85 - 250°F)
  - — Q = 495 – 28200 m^3/h (17,524 – 995,924 scfh)
- **Typical Control Valve Selection:**
  - — Lower Flow Rates: NPS 1 to NPS 3 easy-e EZ
  - — Higher Flow Rates: NPS 6 to NPS 10 easy-e ET or EWT
  - — Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - — Noise attenuation trim may be required
  - — NACE may be required
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV or V shutoff

5. Compressor Bypass Valve

There may be one stage or multiple stages of compressors in a reformer unit. In this example, we are considering a single stage compressor. This recycle control valve is used to protect the recycle hydrogen compressor from the effects of surge that can occur during startup, shutdown, and process upsets. The performance of this valve is crucial to the operation and efficiency of the compressor.

These valves must operate quickly, accurately, and reliably to protect the compressor and the process. Typically, the combination of fast action and accuracy is missing in installed anti-surge valves, which may also utilize an unreliable instrumentation scheme. Noise attenuation trim can be both beneficial and detrimental to this installation. It is required to address potential vibration during normal operation and to prevent pipe fatigue issues caused by vibration. The solution to this challenge is to use a Fisher Optimized Anti-Surge Valve. This assembly combines fast action, accuracy, and reliability in one package. The valve trim is designed to meet specific compressor design requirements, along with an actuation system designed for stroking speed and accurate control. The ODV FIELDVUE instrument is designed with anti-surge specific tuning and control algorithms, as well as the capability to predict issues like sticking or friction, and other anti-surge specific diagnostics.

- **Typical Process Conditions:**
  - — Fluid: Hydrogen and hydrocarbon
  - — P1 = 8.6 – 50 barg (125 - 725 psig)
  - — P2 = 5.7 – 26 barg (80 – 380 psig)
  - — T = 82 - 120°C (180 - 250°F)
  - — Q = 135700 – 351640 m^3/h (115 – 298 MMscfd)
- **Typical Control Valve Selection:**
  - — NPS 6 to NPS 20 easy-e ET or EWT
  - — Materials of Construction: WCC body with 400-series or 300-series SST trim
  - — Noise attenuation trim may be required
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV or V shutoff

6. Separator Liquid Valve

The separator liquid valve controls the separator level and is also the feed valve of the stabilizer. It normally does not affect the recovery of the recycle gas. A problem valve can create stability problems for the stabilizer.

These valves are usually set up as flow or level control loops. An upstream unit or process often controls the valve.

Unstable feed flow will make the stabilizer difficult to control. A problem valve will often cause the feed flow to oscillate. As a result, the column will alternate between too little and too much reboil heat. Depending upon the size and number of trays in the stabilizer, the effect of a swing in the feed will take anywhere from several minutes to more than an hour to reach the ends of the column. Sometimes, the reboil and reflux controls will amplify the swings. The final result is that meeting product purity targets will become more difficult. Refinery operations personnel will normally respond by over-purifying the products, wasting energy to compensate for the bad separator liquid control valve.

- **Typical Process Conditions:**
  - — Fluid: Complex hydrocarbons
  - — P1 = 51 – 56 barg (740 – 815 psig)
  - — P2 = 6.1 – 48 barg (90 – 695 psig)
  - — T = 46 – 49°C (115 - 120°F)
  - — Q = 210 – 455 m^3/h (925 – 2,005 gpm)
- **Typical Control Valve Selection:**
  - — NPS 3 to NPS 8 easy-e ET or NotchFlo DST
  - — Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - — Anti-cavitation or multi-stage trim may be required
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV of V shutoff

7., 10. Stabilizer Steam Valve

The reboil valve controls the amount of heat put into the column by the reboiler. In many cases steam is used as a heat source. Steam valves are usually very reliable. The service is very clean, and fugitive emissions are not a concern. However, a problem valve will make the column difficult to control precisely. This will be especially true if the column feed is subject to frequent changes.

Not all reboilers use steam as a heat source. To save energy, many refineries integrate the units so that higher-temperature process streams are used to provide heat for lower temperature processes. In these cases, the reboil valve may foul more easily and might create fugitive emissions concerns.

This valve is important because the reboiler drives the vapor back up through the column. This affects column efficiency. Reboiler steam will have a direct effect on overhead reflux flow.

- **Typical Process Conditions:**
  - Fluid: Steam
  - P1 = 10 – 41 barg (145 - 595 psig)
  - P2 = 8.8 – 41 barg (125 - 595 psig)
  - T = 185 - 400°C (365 - 750°F)
  - Q = 24,750 – 74,890 kg/h (54,560 – 165,100 lb/h)
- **Typical Control Valve Selection:**
  - NPS 6 to NPS 8 easy-e ED or ET or NPS 8 to NPS 12 HPBV
  - Materials of Construction: WCC body with 400-series SST or high temp 300-series SST trim, appropriate for steam service
  - Graphite packing
  - Class IV shutoff

8. Net Hydrogen Valve

This valve normally has no effect on reformer operation. If the valve is sticking badly, it is possible for it to create pressure swings in the recycle hydrogen supplied to the reformer. If it becomes stuck, it can eventually cause the reformer to pressure up or down depending on the valve's last position.

In many refineries, the reformer supplies enough hydrogen to operate most of the process units that are net hydrogen users. Due to the increased regulations for cleaner transportation fuels, refiners have had to add other hydrogen processing units. An example is Pressure Swing Adsorption (PSA), which supplements purified hydrogen feeds for other units in the refinery. PSA is a unit that takes hydrogen rich product streams and removes the impurities to extract ultra-pure hydrogen. This will be discussed in depth in section 4.14, Pressure Swing Adsorption.

- **Typical Process Conditions:**
  - Fluid: Hydrogen and light hydrocarbons
  - P1 = 44 – 45 barg (635 - 655 psig)
  - P2 = 43 barg (625 psig)
  - T = 38 - 43°C (100 - 110°F)
  - Q = 106200 – 177000 m^3/h (90 - 150 MMscfd)
- **Typical Control Valve Selection:**
  - NPS 6 to NPS 8 easy-e ET
  - Materials of Construction: WCC body with 300-series SST or 400-series SST trim
  - ENVIRO-SEAL PTFE or duplex packing
  - Class IV shutoff

9. Stabilizer Reflux Valve

The reflux valve is typically either a flow or column temperature-control loop. It is used to adjust the purity of the overhead product. The higher the reflux rate, the more pure the overhead product will become. However, raising the reflux rate also will require more reboil heat and will eventually flood the tower.

A poorly operating reflux valve will have the same effects as a bad feed valve. Product purities will oscillate, and the column will be difficult to control. A PD tier FIELDVUE DVC6200 instrument is recommended for this application since it directly affects product quality.

- **Typical Process Conditions:**
  - Fluid: Light hydrocarbons
  - P1 = 13 – 26 barg (190 – 375 psig)
  - P2 = 9.3 barg (135 psig)
  - T = 38 - 200°C (100 - 390°F)
  - Q = 55 m^3/h (8,330 bpd)
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 6 easy-e EZ or ET
  - Materials of Construction: WCC body with 400-series SST trim
  - ENVIRO-SEAL PTFE or duplex packing
  - Class IV shutoff

11. Stabilizer Vent Gas Valve

The pressure control valves are used to control the stabilizer pressure. Higher stabilizer pressures will yield better product purities, but require more energy to operate. Normal operating procedure is to minimize the pressure to lower energy costs while maintaining product specifications. There is a low limit because lower pressures reduce the amount of vapor/liquid traffic the stabilizer can handle, which also makes the stabilizer more likely to flood.

The simplest way to control pressure is to continuously vent gas from the system. Sizing of a vent valve is critical. If the valve is too large, a small valve movement will cause a large pressure swing. If the valve is too small, the pressure response will be very sluggish. It is likely that a valve that is too small will operate from completely closed to completely open. Additionally, a sticking valve is a common concern on vent gas valves because the valve packing will normally be tight to prevent fugitive emissions.

Many stabilizers also use what is known as a "hot vapor bypass" valve to control pressure. In this case, some of the hot overhead vapors are bypassed around the overhead condenser heat exchanger. The amount of bypass will control the pressure. This eliminates the constant venting of process gas, which usually goes to a low-value refinery waste fuel gas system. Unfortunately, the pressure response on a hot vapor bypass valve is normally very sluggish due to slow process response time. Like the vent gas valve, this valve is a concern for fugitive emissions, and the packing is likely to be tight. A sticking valve will cause wide, slow oscillations in column pressure. The product purities will likewise swing widely and slowly. The response of refinery operations personnel will usually be to over-purify.

A majority of stabilizers with a hot vapor bypass valve will use it with a vent gas valve. In these cases, a single pressure control loop will manipulate both valves. At lower pressures, the hot vapor bypass valve is used. As the pressure rises, there will be a transition point where the hot vapor bypass valve closes fully and the vent gas valve starts to open. At high pressures, the vent gas valve controls the pressure. This configuration often leads to pressure control problems, as the hot vapor bypass and vent gas valves will have different control characteristics. Also, it is unlikely that one valve will close precisely at the same time the other valve opens. If the stabilizer is constantly making a transition between using the hot vapor bypass and vent gas valves, the pressure will normally oscillate. This is a tuning problem rather than a valve problem, but it should be kept in mind for column design or valve resizing.

- **Typical Process Conditions:**
  - Fluid: Vent Gas
  - P1 = 9.3 – 9.7 barg (135 - 140 psig)
  - P2 = 8.1 – 8.8 barg (115 - 125 psig)
  - T = 38°C (100°F)
  - Q = 7445 – 12507 m^3/h (262,917 - 441,667 scfh)
- **Typical Control Valve Selection:**
  - NPS 4 to NPS 6 Vee-Ball or NPS 3 to NPS 6 easy-e ET
  - Materials of Construction: WCC body with 400-series SST or 300-series SST soft seated trim
  - ENVIRO-SEAL PTFE or duplex packing
  - Class IV or VI shutoff

12. Stabilizer Reformate Valve

This valve will have no effect on the stabilizer operation unless it causes level problems. There is no consequence for any downstream unit because the reformate is sent to a component blend tank in the gasoline blender unit. This valve can be run in manual or bypass without significant problems.

The bottom product valve is typically used to control the level in the bottom of the column. It normally has no effect on column operation unless it causes the level to change quickly and dramatically.

- **Typical Process Conditions:**
  - Fluid: Reformate
  - P1 = 8 – 8.3 barg (117 - 120 psig)
  - P2 = 4.1 barg (60 psig)
  - T = 38 – 60 °C (100 - 140°F)
  - Q = 2092 gpm 71712 bpd
- **Typical Control Valve Selection:**
  - NPS 8 to NPS 10 easy-e EWT
  - Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - ENVIRO-SEAL PTFE or duplex packing
  - Class IV Shutoff

13. Stabilizer Light-Ends Valve

The overhead product valve is typically used to control the level in the overhead receiver. It normally has no effect on column operation unless it causes the level to change quickly and dramatically.

- **Typical Process Conditions:**
  - Fluid: Light hydrocarbons
  - P1 = 6.8 – 9.0 barg (100 - 130 psig)
  - P2 = 1.8 barg (26 psig)
  - T = 74 - 120°C (165 - 245°F)
  - Q = 27140 m^3/h (23 MMscfd)
- **Typical Control Valve Selection:**
  - NPS 6 to NPS 8 easy-e EWT
  - Materials of Construction: WCC body with 300-series SST trim
  - Noise attenuation trim may be required
  - ENVIRO-SEAL PTFE packing
  - Class V Shutoff

4.10 Fluidized Catalytic Cracking

Other Names—FCC, cat cracker, fluid unit

Fluidized Catalytic Cracking (FCC) is a process with the objective of cracking heavy oil into gasoline and distillate and to increase the yield of light (C3/C4) olefins. The unit continuously circulates a fluidized catalyst that allows rapid cracking reactions to occur. These reactions are typically carried out in an up-flowing reactor/riser where the liquid oil stream contacts the hot catalyst. The oil vaporizes and is cracked as it moves with the catalyst up the riser/reactor. The reactions occur in a matter of seconds and the product is a mixture of light hydrocarbons that are separated into the desirable products.

The first FCC unit came into operation in 1942 and went through a series of advancements that improved the reaction time and product selectivity and yield. These advancements helped develop the side-by-side FCC design noted in Figure 4.10.1. These include the converter section on the left, the fractionation section in the middle, and vapor recovery unit on the right. The side-by-side configuration consists of a reactor vessel situated slightly above and next to the catalyst regeneration section. This breakthrough, combined with advancements in catalyst technology, has dramatically improved yield and reaction selectivity.

There are several major licensors of the FCC process. While there are differences in each process design, most of the terminology and applications are the same.

The production capacity of FCC units can range from 10,000 b/d to nearly 200,000 b/d. Depending upon the design, an FCC can convert atmospheric gas oils, vacuum gas oils, coker gas oils, hydrocracker bottoms, and lube extracts into distillates and other products. These products include fuel gas, C3/C4 LPG and olefins, gasoline, light cycle oil, heavy cycle oil, and slurry oil. While gasoline is the most commonly produced product, an FCC can be operated to maximize production of gasoline, olefins, or light cycle oil by adjustment of operating parameters. Each mode of operation is discussed in the subsequent text.

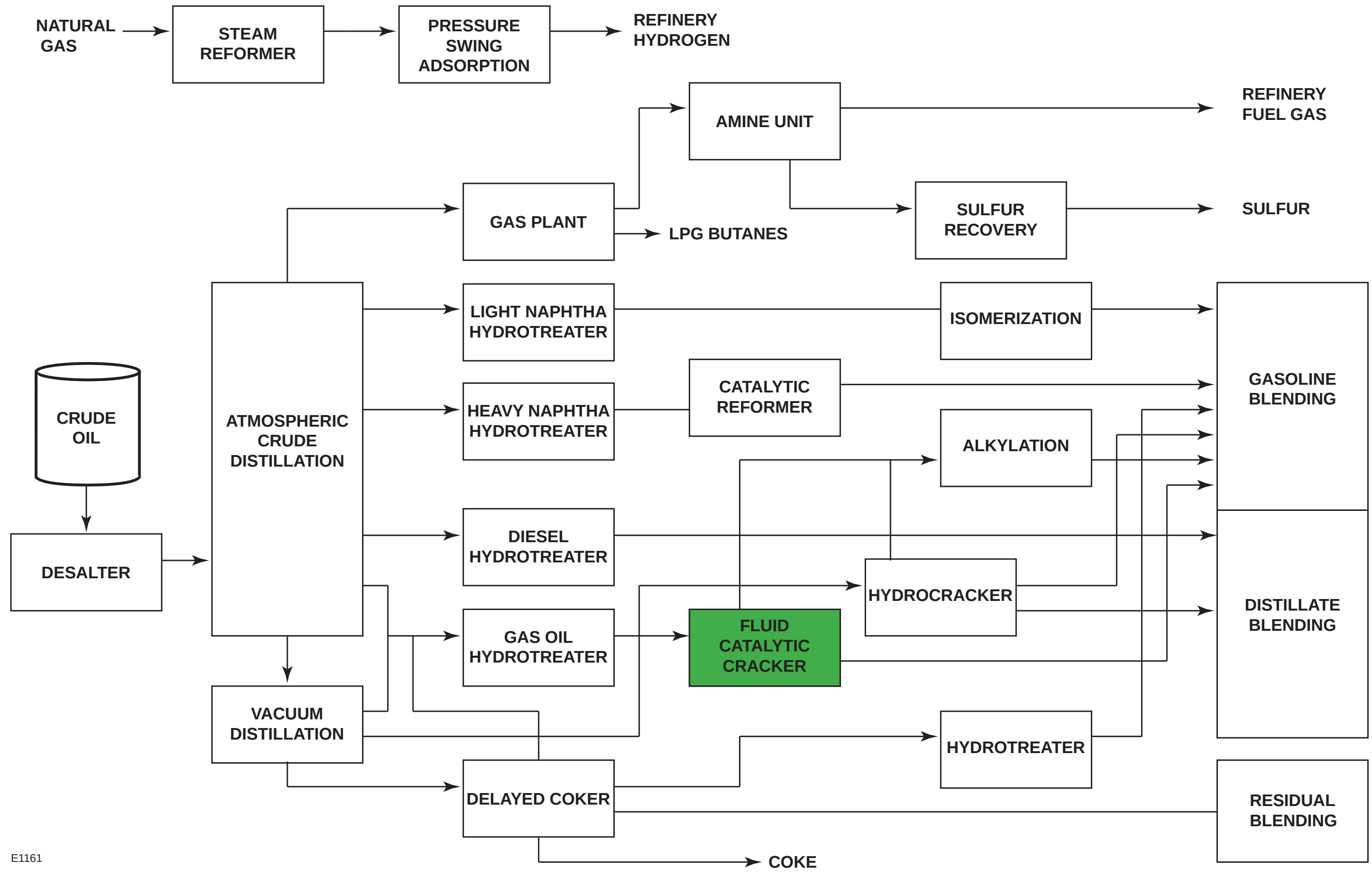


Figure 4.10.1. Alkylation Unit Location

Maximum Gasoline Mode

This is the most common mode of FCC operation and is aimed at maximizing gasoline production of a specific octane number. This mode of operation consists of an intermediate cracking temperature of 510°C - 540°C (950°F - 1005°F) combined with a high catalyst/oil ratio and high catalyst activity and selectivity. The reaction time is short as well, but must rely on high conversion in the riser section.

Maximum Distillate Mode

If the goal is to maximize production of light to middle distillates, the operation of the FCC changes when compared to maximum gasoline mode. The cracking severity is reduced reaction at less than 510°C (950°F) along with a reduction in the catalyst/oil ratio. This, in turn, reduces the first pass conversion in the riser, which restricts recracking of light cycle oil. Because a substantial portion of the feedstock remains unconverted, recycle of heavy cycle oil from the fractionator is required.

Maximum Light Olefin Mode

When high propylene (C3) and butylene (C4) yields and improved gasoline octane levels are desired, the cracking temperature is raised above 540°C (1005°F). This case is sometimes referred to as maximum LPG mode.

No matter the operation mode, as the severity (temperature) increases, the production of coke and light ends increases. Along with this, gasoline octane levels increase and the liquid products become hydrogen deficient. The higher severity operation also overcracks a fair amount of gasoline to C3/C4 products.

It should be noted that there is a related FCC process called Residual Fluidized Catalytic Cracking (RFCC). This type of unit can process varying atmospheric and vacuum based residues along with varying degrees of gas-oils. While the feedstocks may vary, the process and end products are similar.

As can be expected, North America makes up nearly 50% of the world's FCC capacity with the rest of the capacity heavily centered in Western Europe and Asia. However, that trend is likely to shift over time due to the lack of gasoline demand in Europe and the increased chemical feedstock demand in the Middle East and Asia. The trends indicate that there will be additional FCC capacity added globally, but it will be used for more than just gasoline production.

FCC Process Overview

The FCC process converts higher molecular weight hydrocarbons to lighter, more usable products through contact with a powdered catalyst. The historic purpose of this process has been to produce gasoline, distillate, and C3/C4 olefins from low-value gas oils and heavy product streams.

The reaction process is accomplished by using a fluidized catalyst that allows rapid cracking to occur in a vapor phase. This is commonly carried out in an upflowing vertical reactor

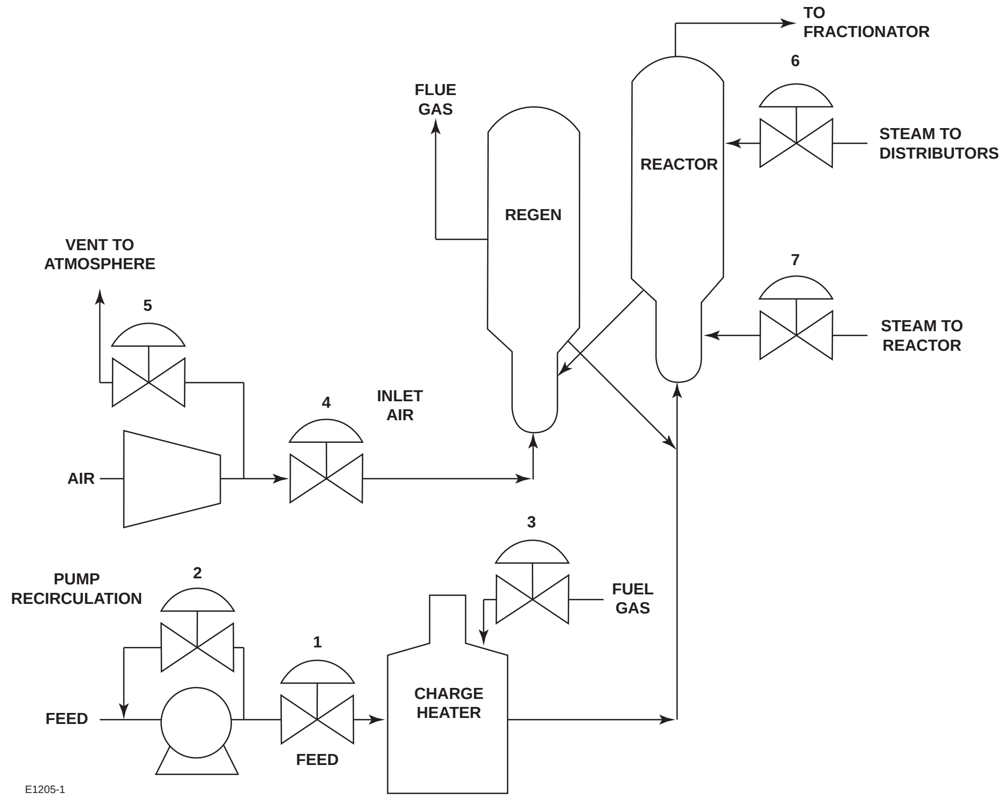


Figure 4.10.2. FCC Converter Section Process Flow Diagram

in which a liquid oil stream contacts the hot powdered catalyst. At this point, the oil vaporizes and cracks to lighter products as it moves up the reactor and carries the catalyst along with the stream. This process takes only a few seconds. Coke will deposit on the catalyst making it less active. After the reaction, the catalyst and product vapors are separated in a disengaging vessel. Here, the catalyst is regenerated for additional use via burning the coke off the catalyst.

The vapors that are separated from the catalyst are then quenched and subjected to further fractionation to separate the lighter and heavier components. The lighter components are then further separated to produce varying cuts of gasoline, distillate, and olefins.

FCC Application Review

Depending upon the capacity of the unit and the type of end products being produced, the number of control valves in a FCC unit will vary between 175 up to 250 units. The majority of the valves will be Class 600 and less. There will be a great deal of variability in the selection between globe and rotary valves due to the erosive nature of the fluids in a number of applications.

In the subsequent text, a summary of each of the key areas of the FCC and the critical control valves in these key areas is discussed. These selections are based upon what can be typically expected, there may be some variations due to rotary versus globe valve selection criteria.

Converter Section

In the reactor, the main conversion of the heavier feedstock to lighter components occurs. The feedstock flows to the reactor riser where it is contacted with hot catalyst. This cracks the feedstock into a number of different components. The product vapors flow from the reactor to the main fractionator for further separation.

The spent catalyst flows via the stripper to begin the regeneration process. In the stripper, the hydrocarbon vapors from within and around the catalyst are displaced by steam. The catalyst is moved by steam to the spent catalyst distributor and then into the regeneration section.

In the regenerator, coke is burned off the catalyst with hot air in a fluidized bed. The catalyst is introduced into the bed by the spent catalyst distributor with hot air introduced at the bottom. The generated flue gas exits from the top of the regenerator where it is typically subjected to further sulfur recovery and other cleaning prior to release.

Figure 4.10.2 shows the common layout of the converter section of the FCC and the commonly associated control valves.

1. Charge Oil Flow Control Valve

This valve controls the flow of feedstock into the charge heater and then to the reactor. Proper flow control is important for maintaining outlet temperature from the charge heater, which, as a result, can affect the reaction performance. Poor control can result in excessive buildup on the tubes in the charge heater, thus reducing its efficiency. A medium sized ball valve is generally used in this application.

- **Typical Process Conditions:**
  - Fluid: Charge oil
  - P1 = 18 – 24 barg (260 – 350 psig)
  - P2 = 6 – 15 barg (85 – 220 psig)
  - T = 70°C – 80°C (160°F – 175°F)
  - Q = 150 – 1500 m3/hr (660 – 6600 gpm)
- **Typical Control Valve Selection:**
  - NPS 6 to NPS 14 Vee-Ball V500, CV500, easy-e ET, or EWT
  - WCC body and 316/Alloy 6 trim
  - Class IV shutoff

2. Charge Pump Spillback Control Valve

This recirculation valve is used to prevent cavitation in the charge pump. The pressure drop can be high enough to warrant the use of anti-cavitation trims, but some facilities utilize a rotary valve with hardened trim to resist the cavitation damage. A rotary or globe valve with hardened trim or a globe valve with anti-cavitation trim are commonly used solutions in this application.

- **Typical Process Conditions:**
  - Fluid: Charge oil
  - P1 = 18 – 24 barg (260 – 350 psig)
  - P2 = 1.5 – 2 barg (20 – 30 psig)
  - T = 70°C – 80°C (160°F – 175°F)
  - Q = 75 – 225 m3/hr (330 – 1000 gpm)
- **Typical Control Valve Selection:**
  - NPS 3 or NPS 4 V500, easy-e ET, or NotchFlo DST
  - WCC Body and 316/Alloy 6 trim
  - Anti-cavitation trim may be required
  - Class V shutoff

3. Charge Oil Heater Fuel Gas Control Valve

This valve controls the flow of fuel to the furnace to heat the charge oil before injection into the reactor. Proper flow control is important for maintaining discharge temperature of the charge oil. A small globe or ball valve is generally used in this application. It should be noted that not all units will utilize a separate charge heater.

- **Typical Process Conditions:**
  - Fluid: Fuel gas
  - P1 = 3 – 13 barg (45 – 190 psig)
  - P2 = 3 – 7 barg (45 – 100 psig)
  - T = 30°C – 40°C (85°F – 105°F)
  - Q = 250 – 300 m3/hr (1100 – 1320 gpm)
- **Typical Control Valve Selection:**
  - NPS 2 easy-e EZ or V300
  - WCC body and trim
  - Class IV or V shutoff

4. Inlet Air to Regenerator Control Valve

This valve controls the flow of air to the regenerator to burn the coke off the catalyst. Poor performance can lead to pressure swings, which, as a result, can affect the pressure balance between the reactor and regenerator. This can potentially result in reactor products flowing into the regenerator, which can cause catalyst flow reversal. This can potentially lead to mechanical damage to the vessel or internal components. A large butterfly valve is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: Air
  - P1 = 3 – 5 barg (45 – 75 psig)
  - P2 = 3 – 5 barg (45 – 75 psig)
  - T = 150°C – 220°C (300°F – 430°F)
  - Q = 300,000 – 600,000 Nm3/hr (10.5 – 21 MMscfh)
- **Typical Control Valve Selection:**
  - NPS 36 to NPS 48 A11
  - WCC body and trim
  - Class IV shutoff

5. Inlet Air Vent to Atmosphere Control Valve

This valve, potentially referred to as the “snort valve,” is utilized to protect the inlet air compressor from surge during startup, shutdown, and normal operation. A number of configurations can be used in this application ranging from globe, angle, and rotary valves. Globe and angle valves are most commonly used, but a butterfly valve or V260A rotary control valve may be used in isolated situations. In the event of a process upset, this valve must provide fast, accurate control to maintain the pressure balance between the reactor and regenerator.

- **Typical Process Conditions:**
  - Fluid: Air
  - P1 = 3 – 5 barg (45 – 75 psig)
  - P2 = 1 barg (1 psig)
  - T = 30°C – 40°C (85°F – 105°F)
  - Q = 80 – 220 m3/hr (2,800 – 7,800 scfh)
- **Typical Control Valve Selection:**
  - NPS 16 to NPS 24 easy-e EW or FB
  - WCC body and trim
  - Noise attenuation trim may be required
  - Class V shutoff

6. Stripping Steam to Distributors Control Valve

There will typically be separate valves that control steam flow to the upper, middle, and lower distributors. These valves control the flow of stripping steam to the reactor to remove the hydrocarbons from the catalyst prior to regeneration. A small to medium sized globe valve will be used in all three cases.

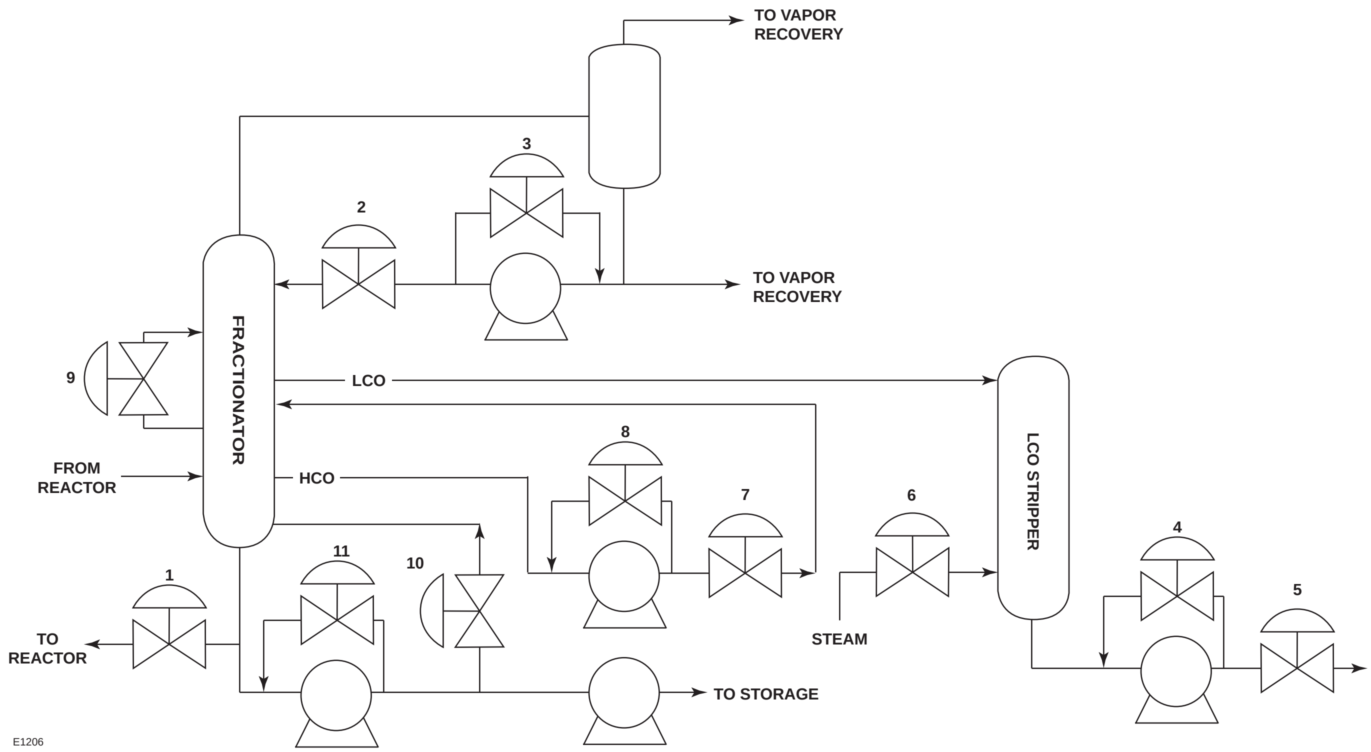


Figure 4.10.3. FCC Fractionation Section

- **Typical Process Conditions:**
  - — Fluid: Steam
  - — P1 = 5 – 7 barg (75 – 100 psig)
  - — P2 = 3 – 5 barg (45 – 75 psig)
  - — T = 200°C – 220°C (390°F – 430°F)
  - — W = 700 – 5000 kg/hr (1545 – 11000 lb/hr)
- **Typical Control Valve Selection:**
  - — NPS 1.5 to NPS 6 easy-e ET
  - — WCC body and 316/Alloy 6 trim
  - — Noise attenuation trim may be required
  - — Class IV or V shutoff

7. Steam to Reactor Flow Control Valve

This valve controls the flow of steam to the upper portion of the reactor. A small globe valve is typically used in this application.

- **Typical Process Conditions:**
  - — Fluid: Steam
  - — P1 = 6 – 9 barg (85 – 130 psig)
  - — P2 = 2 – 4 barg (30 – 60 psig)
  - — T = 200°C – 220°C (390°F – 430°F)
  - — W = 2000 – 36,000 kg/hr (4,400 – 79,400 lb/hr)
- **Typical Control Valve Selection:**
  - — NPS 4 to NPS 6 NPS easy-e ET
  - — WCC body and 316/Alloy 6 trim
  - — Noise attenuation trim may be required
  - — Class IV or V shutoff

Main Fractionation System

The main fractionation system condenses superheated reaction products from the FCC reactor to separate liquid hydrocarbons. The unit also serves to recover the waste heat from the reactor products.

The overhead wet gas is compressed and sent to the vapor recovery unit. Some of the raw gasoline is pumped to the primary absorber and serves as lean oil. Heavy naphtha from the upper portion of the column can be used as absorber oil in the secondary absorber in the vapor recovery unit. The light cycle oil from the middle sections of the column can be removed for further use and the heavier bottom components are recycled to the reactor.

The heat recovered from the condensing vapors at the top of the column is used to preheat fresh feed into the reactor while also providing heat for the stripper and debutanizer reboilers in the vapor recovery unit.

Figure 4.10.3 shows the layout of the fractionation section and the commonly associated control valves.

1. Fractionator Bottoms to Reactor Control Valve

This valve recycles some of the bottoms slurry back to the reactor for further processing. While used for level control in the fractionator, it possesses the potential to create a great deal of erosion in the control valve due to entrained catalyst. A Fisher V500 valve is installed in many applications, but a Fisher 461 control valve is the most rugged solution.

- **Typical Process Conditions:**
  - Fluid: Slurry with entrained catalyst
  - P1 = 5 – 8 barg (75 – 115 psig)
  - P2 = 3 – 5 barg (45 – 75 psig)
  - T = 280°C – 360°C (535°F – 680°F)
  - Q = 30 – 115 m3/hr (130 – 500 gpm)
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 8 Vee-Ball, V500, or 461
  - C5 or 316SST body and Alloy 6 trim
  - Class IV or V shutoff

2. Main Column Reflux Control Valve

This valve controls the liquid reflux flow from the overhead vapor back to the main column. Poor performance of this valve can impact the quality of the overhead product, thus accurate control is required. Depending upon the inlet pressure, cavitation protection may be required. A globe or rotary valve is generally used in this application.

- **Typical Process Conditions:**
  - Fluid: Distillate
  - P1 = 6 – 9 barg (85 – 130 psig)
  - P2 = 3 – 5 barg (45 – 75 psig)
  - T = 40°C – 60°C (105°F – 140°F)
  - Q = 80 – 380 m3/hr (350 – 1700 gpm)
- **Typical Control Valve Selection:**
  - NPS 4 to NPS 8 V500, easy-e ET, or NotchFlo DST
  - WCC or 316SST body and 316/Alloy 6 trim
  - Anti-cavitation trim may be required
  - Class IV or V shutoff

3. Main Column Reflux Spillback Control Valve

This valve recycles flow around the main column reflux pumps to prevent the pump from cavitating. Therefore, a valve selection that can withstand the cavitation or eliminate its formation is necessary. A globe valve with anti-cavitation trim is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: Distillate
  - P1 = 6 – 9 barg (85 – 130 psig)
  - P2 = 2 – 3 barg (30 – 45 psig)
  - T = 40°C – 60°C (105°F – 140°F)
  - Q = 100 – 140 m3/hr (440 – 615 gpm)
- **Typical Control Valve Selection:**
  - NPS 3 to NPS 4 easy-e ET or NotchFlo DST
  - WCC or 316SST body and 316/Alloy 6 trim
  - Anti-cavitation trim may be required
  - Class V shutoff

4. Lean Cycle Oil Pump Spillback Control Valve

This valve controls recycle flow around the lean cycle oil stripper bottoms pump to prevent the pump from cavitation damage. As a result, a valve that can eliminate the formation of cavitation to prevent damage to the valve is necessary. A globe valve with anti-cavitation trim is commonly used in this application. Sludge and other heavier components may be present, thus, a NotchFlo DST solution would be the appropriate selection.

- **Typical Process Conditions:**
  - Fluid: Lean cycle oil
  - P1 = 20 – 22 barg (290 – 320 psig)
  - P2 = 2 – 3 barg (30 – 45 psig)
  - T = 200°C – 220°C (390°F – 430°F)
  - Q = 40 – 175 m3/hr (175 – 770 gpm)
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 4 easy-e ET or NotchFlo DST
  - WCC body and 316/Alloy 6 trim
  - Anti-cavitation trim may be required
  - Class V shutoff

5. Lean Cycle Oil to Storage Control Valve

This valve controls the flow of lean cycle oil to storage or to its intended downstream location. The flow stream can be somewhat viscous so a ball valve is commonly used, but a globe valve is an acceptable choice as well.

- **Typical Process Conditions:**
  - Fluid: Lean cycle oil
  - P1 = 20 – 22 barg (290 – 320 psig)
  - P2 = 9 – 18 barg (130 – 260 psig)
  - T = 40°C – 50°C (105°F – 120°F)
  - Q = 60 – 300 m3/hr (265 – 1320 gpm)
- **Typical Control Valve Selection:**
  - NPS 3 to NPS 6 Vee-Ball, V500, or easy-e ET
  - WCC body and 316/Alloy 6 trim
  - Class IV shutoff

6. Steam to Lean Cycle Oil Stripper Control Valve

This valve controls steam flow to the bottom of the lean cycle oil stripper. Proper flow control is necessary to achieve the desired product from the bottom of the stripper. A small globe valve is generally utilized in this application.

- **Typical Process Conditions:**
  - Fluid: Steam
  - P1 = 9 – 17 barg (130 – 245 psig)
  - P2 = 1 – 3 barg (15 – 45 psig)
  - T = 200°C – 235°C (390°F – 455°F)
  - W = 900 – 4000 kg/hr (2000 – 8,800 lb/hr)

- **Typical Control Valve Selection:**
  - — NPS 2 to NPS 3 easy-e ET
  - — WCC body and 316/Alloy 6 trim
  - — Noise attenuation trim may be required
  - — Class IV or V shutoff

7. Heavy Cycle Oil Pump-around Control Valve

This valve controls the flow of heavy cycle oil back to the fractionation tower. Proper flow control is necessary to ensure the proper product specification in the column. A rotary valve is commonly used in this application due to the viscous nature of the fluid, but a large globe valve may also be used.

- **Typical Process Conditions:**
  - — Fluid: Heavy cycle oil
  - — P1 = 10 – 17 barg (145 – 245 psig)
  - — P2 = 4 – 13 barg (60 – 190 psig)
  - — T = 220°C – 270°C (430°F – 520°F)
  - — Q = 300 – 1200 m3/hr (1320 – 5,300 gpm)
- **Typical Control Valve Selection:**
  - — NPS 8 to NPS 12 Vee-Ball V500, CV500, easy-e ET or EWT
  - — C5 or 316 SST body and 316/Alloy 6 trim
  - — Class IV shutoff

8. Heavy Cycle Oil Pump-around Spillback Control Valve

This valve bypasses flow around the heavy cycle oil pump-around pump to prevent the pump from cavitating. This valve experiences relatively high pressure differentials that can result in the formation of damaging cavitation. A control valve that can eliminate the formation of cavitation is commonly used.

- **Typical Process Conditions:**
  - — Fluid: Heavy cycle oil
  - — P1 = 10 – 17 barg (145 – 245 psig)
  - — P2 = 3 – 4 barg (45 – 60 psig)
  - — T = 190°C – 220°C (375°F - 430°F)
  - — Q = 75 – 200 m3/hr (330 – 880 gpm)
- **Typical Control Valve Selection:**
  - — NPS 3 to NPS 4 easy-e ET or NotchFlo DST
  - — C5 or 316 SST body and trim
  - — Anti-cavitation trim may be required
  - — Class V shutoff

9. Main Column Pumparound Control Valve

There can be a number of variations in this application. Some units may use only one pump-around system, but others may incorporate several. Each is used as a type of reflux to improve the separation of the products. Poor performance of this valve results in variations of the product quality, thus reliability and performance are key factors. The valve selection will vary depending upon the point of withdrawal from the column. A rotary valve, Fisher 461, or a globe or angle valve with unbalanced trim is used.

- **Typical Process Conditions:**
  - — Fluid: Varying hydrocarbons
  - — P1 = 6 – 8 barg (85 – 115 psig)
  - — P2 = 4 – 5 barg (60 – 75 psig)
  - — T = 170°C – 200°C (340°F - 390°F)
  - — Q = 200 – 2400 m3/hr (880 – 10,600 gpm)
- **Typical Control Valve Selection:**
  - — NPS 8 to NPS 12 Vee-Ball, V500 or CV500, NPS 8 to NPS 12 A-body or large easy-e
  - — WCC or 316 SST body and 316/Alloy 6 trim
  - — Class IV shutoff

10. Main Column Bottoms Circulation Control Valve

This valve circulates flow from the bottom of the column to the reboiler and back to the column to facilitate separation. Accurate control is required in this application to ensure the proper product specification. Because of the high-viscosity slurry, a rotary valve is commonly used. Entrained catalyst may be present in the flow stream and can damage the valve.

- **Typical Process Conditions:**
  - — Fluid: Hydrocarbon slurry
  - — P1 = 6 – 8 barg (85 – 115 psig)
  - — P2 = 4 – 5 barg (60 -75 psig)
  - — T = 270°C – 360°C (520°F - 680°F)
  - — Q = 150 – 300 m3/hr (660 – 1320 gpm)
- **Typical Control Valve Selection:**
  - — NPS 6 to NPS 8 Vee-Ball or V500
  - — C5 or 316 SST body and Alloy 6 trim
  - — Class IV shutoff

11. Main Column Bottoms Pump Spillback Control Valve

This valve recycles flow around the main column bottoms pump to prevent the pump from cavitating. While there is potential for cavitation formation in the valve, because of the high-viscosity slurry, a rotary valve with hardened trim is typically utilized.

- **Typical Process Conditions:**
  - — Fluid: Hydrocarbon slurry
  - — P1 = 7 – 9 barg (100 – 130 psig)
  - — P2 = 3 – 5 barg (45 – 75 psig)
  - — T = 270°C – 360°C (520°F – 680°F)
  - — Q = 150 – 700 m3/hr (660 – 3100 gpm)
- **Typical Control Valve Selection:**
  - — NPS 4 to NPS 8 V500
  - — C5 or 316 SST body and Alloy 6 trim
  - — Class IV shutoff

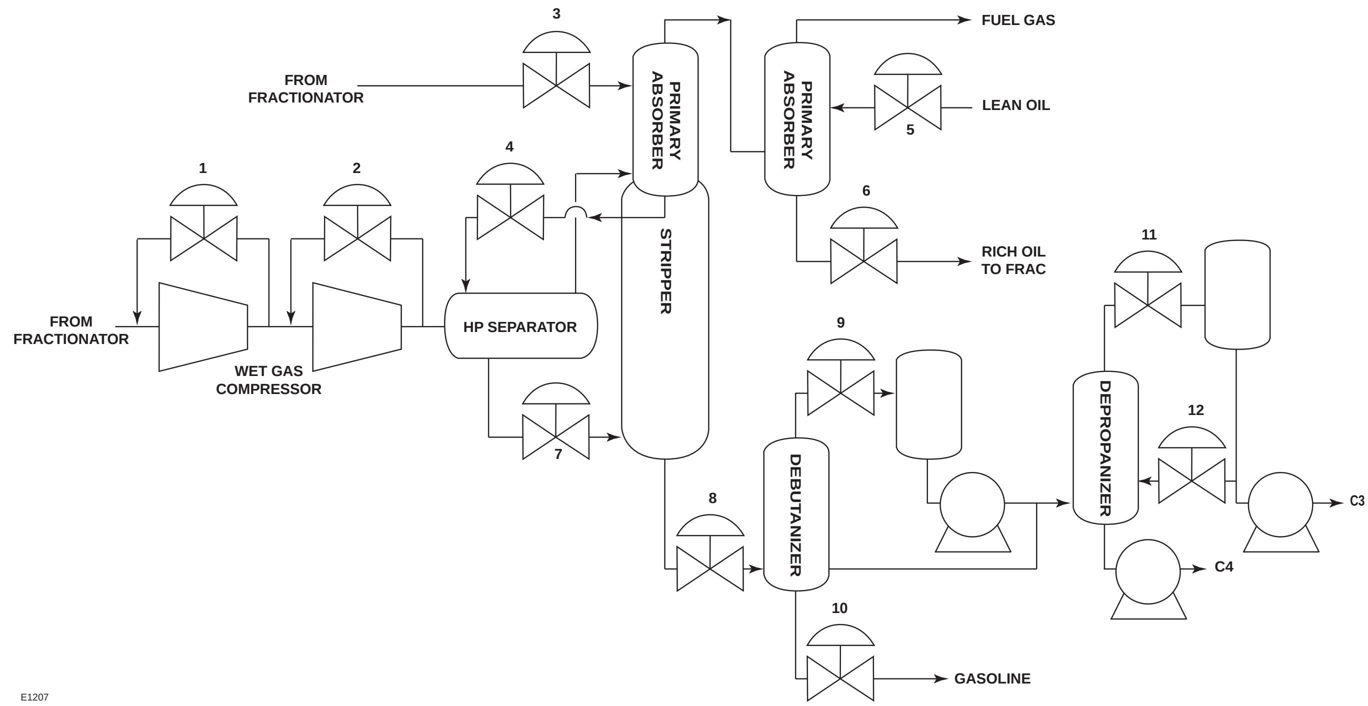


Figure 4.10.4. FCC Vapor Recovery Section

Vapor Recovery Unit

The vapor recovery unit is used to reject fuel gas, recover C3 and C4 liquid products and produce debutanized gasoline within the required vapor pressure levels. The main fractionator overhead vapors are compressed in the wet gas compressor, which is typically a two-stage device. The high pressure gas and liquids from the low pressure knock out drum are cooled and combined with liquid from the primary absorber and flow to the high pressure separator.

Liquid from the high pressure separator is pumped to the top of the stripper. The stripper removes C2s and lighter products that go to the primary absorber. The C3 and heavier products are removed in the stripper bottoms.

In the primary absorber, vapor from the high pressure separator flows to the bottom of the absorber while raw gasoline and lean oil from the debutanizer flow to the top of the absorber. The liquids absorb C3 and heavier components from the vapor. The gases leaving the top of the primary absorber are sent the secondary absorber.

In the secondary absorber, heavy naphtha from the main fractionator is used to recover any liquids left in the vapor stream. Fuel gas leaves the top of the absorber and is typically subjected to further treatment in an amine treatment unit. The bottoms return to the main fractionator.

Liquid from the bottom of the stripper flows to the debutanizer. The overhead liquids can be treated and sent to storage or further separation of C3 and C4 products can occur. Further separation of the bottoms products is possible, but will vary from plant to plant.

Figure 4.10.4 shows the layout of the vapor recovery system and the commonly associated control valves. This depiction includes a depropanizer, which may or may not be present.

Other units may be present, i.e. depentanizer; however, this depends upon the overall desired final products.

1. First Stage Wet Gas Recycle Control Valve

This valve is used to protect the first stage of the wet gas compressor from the effects of surge that can occur during startup, shutdown, and process upsets. The performance of this valve is critical to the operation and efficiency of the compressor. There is the potential for coke buildup on the internals of the valve, thus it is critical that a multi-stage trim is not present in this application. A globe valve with Whisper Trim is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: Wet gas
  - P1 = 6 – 10 barg (85 – 145 psig)
  - P2 = 2 – 4 barg (30 – 60 psig)
  - T = 110°C – 130°C (230°F - 265°F)
  - W = 85,000 – 350,000 kg/hr (185,000 – 770,000 lb/hr)
- **Typical Control Valve Selection:**
  - NPS 8 to NPS 16 easy-e ET or EW
  - WCC body and 316/Alloy 6 trim
  - Noise attenuation trim may be required
  - Class V shutoff

2. Second Stage Wet Gas Recycle Control Valve

This valve is used to protect the second stage of the wet gas compressor from the effects of surge that can occur during startup, shutdown, and process upsets. The performance of this valve is critical to the operation and efficiency of the compressor. Potential for coke buildup is present on the internals of the valve, thus the use of a multi-stage trim must not be present in this application. A globe valve with Whisper Trim is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: Wet gas
  - P1 = 13 – 21 barg (190 – 305 psig)
  - P2 = 6 – 10 barg (85 – 145 psig)
  - T = 110°C – 130°C (230°F - 265°F)
  - W = 85,000 – 350,000 kg/hr (185,000 – 770,000 lb/hr)
- **Typical Control Valve Selection:**
  - NPS 10 to NPS 16 easy-e ET or EW
  - WCC body and 316/Alloy 6 trim
  - Noise attenuation trim may be required
  - Class V shutoff

3. Primary Absorber Feed Control Valve

This valve controls the flow of overhead liquids from the main fractionator to the primary absorber. Accurate control is needed in this application to ensure proper vapor to liquid ratio in the absorber. A globe or rotary valve is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: Distillate
  - P1 = 13 – 21 barg (190 – 305 psig)
  - P2 = 12 - 18 barg (175 – 260 psig)
  - T = 40°C – 60°C (105°F - 140°F)
  - Q = 200 – 850 m3/hr (880 – 3750 gpm)
- **Typical Control Valve Selection:**
  - NPS 8 to NPS 12 easy-e EW or V300
  - WCC body and 316/Alloy 6 trim
  - Class IV shutoff

4. Primary Absorber Bottoms Control Valve

This valve controls the liquid level in the primary absorber. Accurate control is required in this application to ensure the proper interaction of liquid and vapor streams. A globe or rotary valve is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: Distillate
  - P1 = 12 – 19 barg (175 – 275 psig)
  - P2 = 11 – 17 barg (160 – 245 psig)
  - T = 40°C – 60°C (105°F - 140°F)
  - Q = 250 – 950 m3/hr (1100 – 4200 gpm)
- **Typical Control Valve Selection:**
  - NPS 8 to NPS 12 easy-e ET, EW, or V300
  - WCC body and 316/Alloy 6 trim
  - Class IV shutoff

5. Lean Oil to Secondary Absorber Control Valve

This valve is used to control the flow of lean oil (heavy naphtha) to absorb heavier components in the secondary absorber. Proper flow control is necessary to capture as much of the heavier components as possible. A rotary or globe valve can be successfully used in this application.

- **Typical Process Conditions:**
  - Fluid: Lean oil (heavy naphtha)
  - P1 = 18 – 24 barg (260 – 350 psig)
  - P2 = 13 – 18 barg (190 – 260 psig)
  - T = 40°C – 50°C (105°F - 120°F)
  - Q = 30 – 150 m3/hr (130 – 660 gpm)
- **Typical Control Valve Selection:**
  - NPS 3 to NPS 4 easy-e ET or V500
  - WCC body and 316/Alloy 6 trim
  - Class IV shutoff

6. Rich Oil from Secondary Absorber Control Valve

This valve controls the liquid level in the secondary absorber enabling proper capture of the heavier components in the gas stream from the primary absorber. A globe or rotary valve can be used successfully in this application.

- **Typical Process Conditions:**
  - Fluid: Rich oil
  - P1 = 12 – 18 barg (175 – 260 psig)
  - P2 = 4 – 6 barg (60 – 90 psig)
  - T = 60°C – 80°C (140°F - 175°F)
  - Q = 50 – 150 m3/hr (220 – 660 gpm)
- **Typical Control Valve Selection:**
  - NPS 3 to NPS 4 easy-e ET or V500
  - WCC body and 316/Alloy 6 trim
  - Class IV shutoff

7. Stripper Feed Control Valve

This valve controls level in the high pressure separator and flow to the stripper to remove C2 and lighter components. Accurate level control in the high pressure separator is necessary to prevent liquid carryover into the primary absorber. A globe or rotary valve can be used in this application.

- **Typical Process Conditions:**
  - Fluid: Light hydrocarbons
  - P1 = 18 – 24 barg (260 – 350 psig)
  - P2 = 15 – 23 barg (220 – 330 psig)
  - T = 50°C – 80°C (120°F - 175°F)
  - Q = 200 – 2000 m3/hr (880 – 8800 gpm)
- **Typical Control Valve Selection:**
  - NPS 6 to NPS 16 easy-e ET, NPS 6 to NPS 8 V500, or NPS 6 to NPS 12 CV500
  - WCC body and 316/Alloy 6 trim
  - Class IV shutoff

8. Stripper Bottoms to Debutanizer Control Valve

This valve controls the level of light hydrocarbons in the stripper column. This operation is critical to removal of C2 and lighter components. A rotary or globe valve can be used in this application.

- **Typical Process Conditions:**
  - Fluid: Light Hydrocarbons
  - P1 = 15 – 20 barg (220 – 290 psig)
  - P2 = 12 – 14 barg (175 – 205 psig)
  - T = 120°C – 130°C (250°F - 265°F)
  - Q = 250 – 2000 m3/hr (1100 – 8800 gpm)
- **Typical Control Valve Selection:**
  - NPS 6 to NPS 16 easy-e ET, NPS 6 to NPS 12 CV500 or V500
  - WCC body and 316/Alloy 6 trim
  - Class IV shutoff

9. Debutanizer Overhead Control Valve

This valve controls the flow of the vapor driven off in the dubutanizer to be quenched and subjected to further separation to capture C3 and C4 components. A medium-sized rotary valve is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: C3 and C4 hydrocarbons
  - P1 = 12 – 14 barg (175 – 205 psig)
  - P2 = 11 – 13 barg (160 – 190 psig)
  - T = 60°C – 80°C (140°F - 175°F)
  - Q = 30,000 – 120,000 Nm3/hr (1 – 4 MMscfh)
- **Typical Control Valve Selection:**
  - NPS 10 to NPS 12 8580 or V300
  - WCC body and 316/Alloy 6 trim
  - Class IV shutoff

10. Debutanizer Bottoms Level Control Valve

This valve controls the liquid level in the debutanizer ensuring proper separation of the lighter components from the heavier components. A rotary valve is commonly used in this application.

- **Typical Process Conditions:**
  - Fluid: Gasoline
  - P1 = 12 – 14 barg (175 – 205 psig)
  - P2 = 8 – 10 barg (115 – 145 psig)
  - T = 100°C – 110°C (210°F - 230°F)
  - Q = 70 – 350 m3/hr (310 – 1540 gpm)
- **Typical Control Valve Selection:**
  - NPS 6 to NPS 8 V500 or NPS 6 to NPS 10 V300
  - WCC body and 316/Alloy 6 trim
  - Class IV shutoff

11. Depropanizer Overhead Control Valve

This valve controls the overhead vapor flow into the reflux drum to facilitate separation of C3 and C4 components. A medium sized rotary valve is generally utilized in this application.

- **Typical Process Conditions:**
  - Fluid: Propane
  - P1 = 16 – 18 barg (230 – 260 psig)
  - P2 = 15 – 17 barg (220 – 245 psig)
  - T = 50°C – 60°C (120°F - 140°F)
  - Q = 50,000 – 100,000 Nm3/hr (1.7 – 3.5 MMscfh)
- **Typical Control Valve Selection:**
  - NPS 12 to NPS 16 8532 or V300
  - WCC body and 316/Alloy 6 trim
  - Class IV shutoff

12. Depropanizer Reflux Control Valve

This valve controls the propane reflux back into the depropanizer. Proper control is required in this application to ensure adequate separation of the C3 and C4 components in the depropanizer. A medium sized globe or rotary valve can be utilized in this application.

- **Typical Process Conditions:**
  - Fluid: Propane
  - P1 = 16 – 18 barg (230 – 260 psig)
  - P2 = 13 – 15 barg (190 – 220 psig)
  - T = 50°C – 60°C (120°F - 140°F)
  - Q = 1000 – 2000 m3/hr (4400 – 8800 gpm)
- **Typical Control Valve Selection:**
  - NPS 8 to NPS 10 easy-e ET or NPS 8 V500
  - WCC body and 316/Alloy 6 trim
  - Class IV shutoff

4.11 Alkylation Unit

Other Names—Alky, HF, Sulfuric Acid Unit, SAAU, HFAU, Alky Unit

The alkylation unit is used to convert light olefins, usually propylene or butylene, produced by a FCC or delayed coker unit into a gasoline blending component called alkylate. Alkylate is one of the more valuable blending components for gasoline because it has a high octane rating coupled with a low Reid vapor pressure. It consists of branched chain paraffinic hydrocarbons (isoheptane and isooctane).

There are two types of alkylation units: hydrofluoric acid (HF) alkylation and sulfuric acid alkylation. Both will be discussed in this section. Alkylation is a catalyzed reaction that uses acid as the catalyst – this is not a solid catalyst that we see in most other refining applications. This liquid catalyst is efficient, but hazardous. There have been many attempts made over the years to use a solid acid catalyst, but this has resulted in reduced conversion and deactivated catalyst.

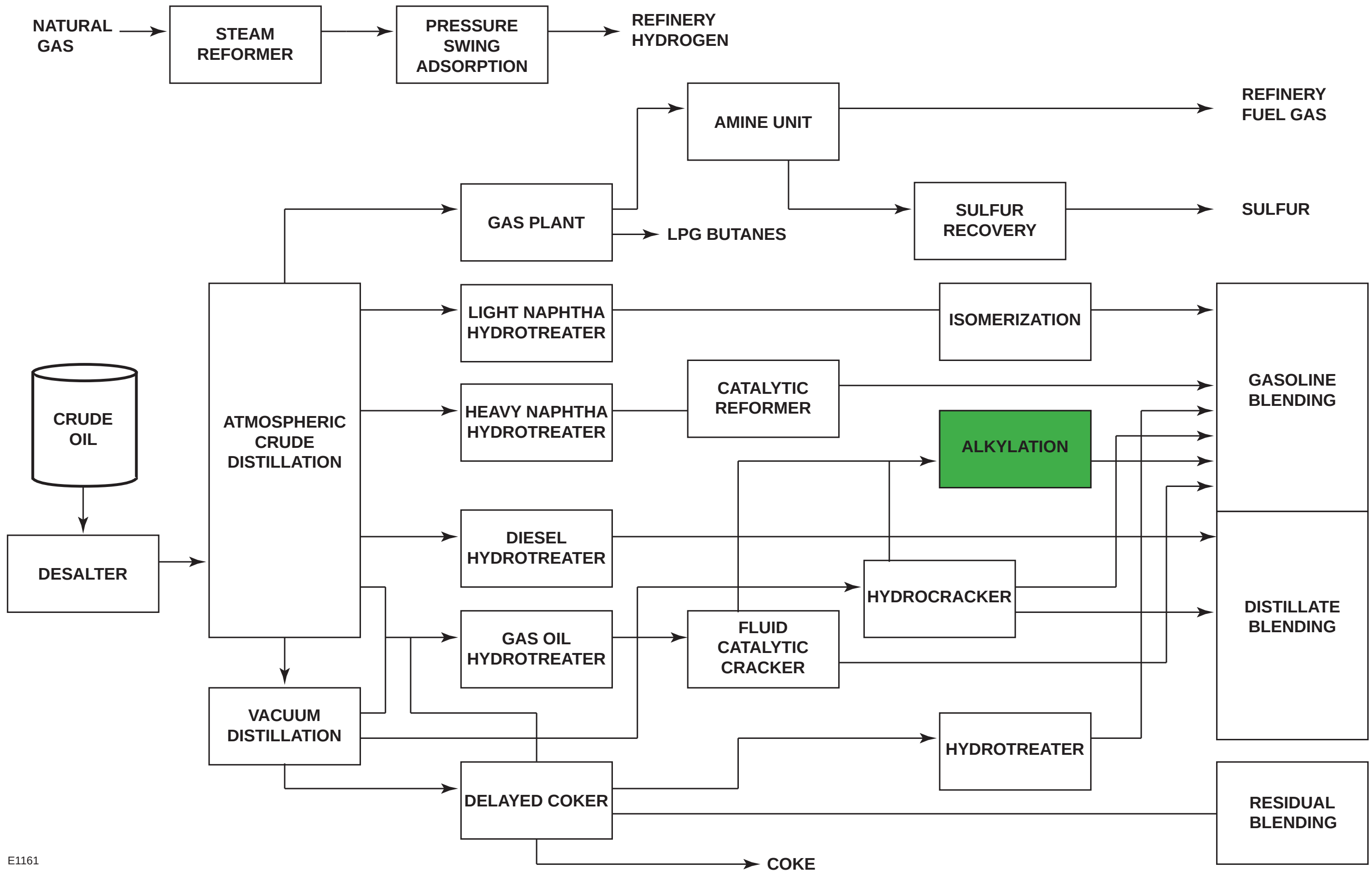


Figure 4.11.1. Alkylation Unit Location

The overall process is similar between an HF alky unit and a sulfuric acid alky unit. The major differences are the reactor style and the reaction temperature. Either type of alkylation plant consists of seven sections: chiller, reactor, acid separator, caustic wash, and three distillation columns.

In an HF Alky unit (Figure 4.11.2), isobutane feed, olefin feed, and recycled isobutane are chilled (using refinery cooling water), then fed into an acid reactor. Acid is fed into this reactor in a separate stream. The alkylation reaction takes place in this unit, and the resulting product is then sent to a series of separators and acid strippers to split out the resulting product streams, including propane, N-butane, and alkylate. Simultaneously, the acid is separated in the reactor and recycled through the unit. After separating the propane, n-butane, and alkylate product, any unreacted isobutane is recycled back to the acid reactor.

In a sulfuric acid alky unit (Figure 4.11.3), the isobutane-olefin mixture, along with sulfuric acid and refrigerant, is sent to a cascade reactor. In the presence of the acid, the olefins and isobutane react, forming the alkylate compounds and generating heat. There are several systems for removing the heat. The process illustrated uses an auto-refrigeration system where some of the isobutane is vaporized to provide cooling. The vapors are routed through a compression section and are condensed before being returned to the reactor.

Any propane that is produced in the reactor is concentrated in the refrigeration system and, after caustic and water washes, is sent to a depropanizer. The depropanizer overhead is a propane product, and the bottom stream is returned to the process.

The reactor effluent is sent to a settler, where acid is removed from the hydrocarbon. The acid is recycled to the reactor. The hydrocarbon continues through caustic and water washes before entering the deisobutanizer (DIB) tower. Any makeup isobutane is generally added as feed to the DIB tower. The DIB overhead stream is mostly isobutane and is returned to the reactor. The DIB bottom stream becomes the feed to the debutanizer. The debutanizer overhead is a butane product stream. The debutanizer bottom stream is the alkylate product for gasoline blending.

Alkylation Application Review

In an alkylation unit, tight process control is required to maintain temperature, acid strength and isobutane concentration. If temperature drops too low, sulfuric acid will become viscous and will inhibit complete mixing of acid and olefins. If the temperature is too high, compounds other than isoheptane and isooctane will be formed, decreasing the overall alkylate quality.

Acid strength is also important to maintain. If the acid is diluted with water, the acid can pick up tar and become less reactive. It is known that as the process unit operates over time, acid concentration decreases. When the concentration drops below 89%, it loses efficiency. In addition, weaker acids

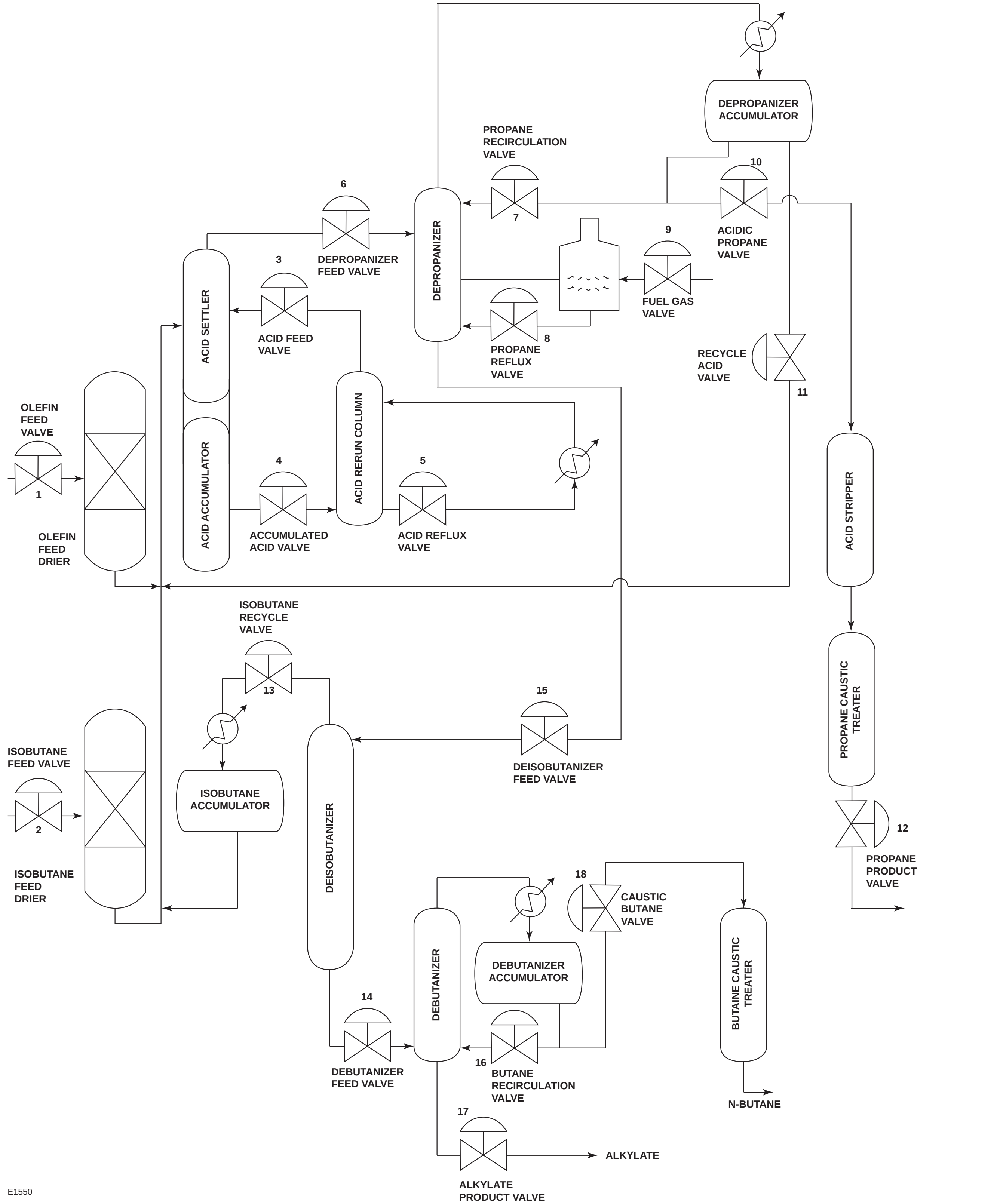


Figure 4.11.2. Hydrofluoric Acid Alkylation Process Flow Diagram

can lead to additional undesired side reactions, decreasing alkylate quality.

The preservation of isobutane concentration is essential to proper operation of the unit. Both propylene and butylene are reactive in the presence of the acid catalyst – even with each other. If the isobutane concentration is not maintained at a high concentration, they will react with each other rather than with the isobutane. Typically, about ten times the amount of isobutane is used to prevent this from happening.

Hydrofluoric Acid Alkylation Control Valve Selection

Hydrofluoric acid, whether in the form of dry liquid, gas, or water solution, is a strong acid that rapidly attacks many substances - including ordinary glass. While seemingly contrary, carbon steel is the most widely used material for most control valve bodies. A thin film of purplish-colored fluoride compound builds up on iron and steel surfaces exposed to HF acid. This plating is fairly hard and durable. In the right circumstances, it protects the metal against further attack by the acid, so that the corrosion is self-limiting. The main concern with fluoride plating is that it takes up more space than the thin surface layer of metal that it replaced. For this reason, cage guided valves are generally not specified due to the narrow clearances between trim parts. However, some sites have had success with both the GX and cage-guided constructions in these applications for globe valve trims, Monel grades N04400 and N05500 alloys are generally accepted as optimum. Fisher valves provide additional clearance for these applications to account for the buildup of fluoride.

Rotary valves can be specified for hydrofluoric alkylation acid service. In these applications a rotary valve (Vee-Ball) may replace the larger globe valves (A-Bodies or split globe bodies) on current specifications or as replacements in existing applications.

Most HF acid applications are at or around ambient temperature. However, there may be a few applications at elevated temperatures (66°C [150°F] or higher). In those instances, a site or process licensor may require a solid nickel alloy body in addition to the alloy trim.

Note that typical process conditions are not provided in this section as these are dictated by the process licensor.

1. Olefin Feed Valve

The amount of flow and composition of this stream establish the isobutane and acid makeup requirements. Therefore, it is desirable to have this flow and composition as steady as possible. Extremely erratic valve movement, such as sticking, could make the reactor conversion cycle. However, because the reactor is continuously mixed, the effect of any small swings in flow will probably go unnoticed.

Traditionally, this has been a large double ported A-body.

- **Typical Control Valve Selection:**
  - NPS 4 to NPS 10 Vee-Ball
  - Materials of Construction: WCC body with Monel trim and TCM seal
  - ENVIRO-SEAL PTFE packing
  - Class III shutoff or better

2. Isobutane Feed Valve

This valve does not see any acid, and therefore is not subject to the hydrofluoric acid service requirements. It is used to continuously supplement the required isobutane into the alkylation reactor.

- **Typical Control Valve Selection:**
  - NPS 1 to 3 easy-e ES or ED
  - Materials of Construction: WCC body with 400-series SST trim
  - ENVIRO-SEAL PTFE or duplex packing
  - Class IV shutoff

3. Acid Feed Valve

This valve controls the acid being fed to the reactor. It is important that it is always operational to provide conversion from olefins to alkylate in the reactor. Due to the high (pure) acid content, the valve construction will be all Monel.

- **Typical Control Valve Selection:**
  - NPS 4 to NPS 10 Vee-Ball
  - Materials of Construction: Monel valve body with monel trim and TCM seal
  - ENVIRO-SEAL PTFE packing
  - Class III shutoff or better

4. Accumulated Acid Valve

This valve controls the acid level in the acid accumulator. Spent acid is constantly circulating from the acid accumulator to the rerun column. An upset in this valve could cause a leakage of hydrofluoric acid, which would be a major environmental and health risk.

- **Typical Control Valve Selection:**
  - NPS 1 to 2 easy-e EZ
  - Materials of Construction: Monel valve body with monel trim
  - ENVIRO-SEAL PTFE or duplex packing
  - Class IV shutoff

5, 8. Acid and Propane Reflux Valves

The reflux valve is typically either a flow or column temperature-control loop. It is used to adjust the purity of the overhead product. The higher the reflux rate, the purer the overhead product will become. However, raising the reflux rate will also require more reboil heat and eventually will flood the tower.

A poorly operating reflux valve will have the same effects as a bad feed valve. Product purities will oscillate and the column will be difficult to control. This valve has a direct impact on the efficiency of the column.

Traditionally, the propane reflux valve has been a high performance butterfly valve. Good control of this valve is required to produce high quality alkylate, and upgrading to a Control-Disk valve may aid in this conversion rate.

- **Acid Reflux Typical Control Valve Selection:**
  - NPS 1 to NPS 2 easy-e EZ
  - Materials of Construction: Monel valve body with monel trim
  - ENVIRO-SEAL PTFE or duplex packing
  - Class IV shutoff

- **Propane Reflux Typical Control Valve Selection:**
  - — NPS 8 to NPS 12 Control-Disk
  - — Materials of Construction: WCC body with 400-series SST trim
  - — ENVIRO-SEAL PTFE packing
  - — Class IV shutoff

6., 14., 15. Depropanizer feed, Debutanizer feed, and Deisobutanizer Feed Valves

These valves control the feed going into the depropanizer, the debutanizer, and deisobutanizer columns. Feed valves are usually set up as flow or level control loops. An upstream unit or process often controls the valve.

Unstable feed flow will make the column difficult to control. A problem valve will often cause the feed flow to oscillate. As a result, the column's reboil heat will fluctuate. Depending on the size and number of trays in the column, the effect of a swing in the feed will take anywhere from several minutes to more than an hour to reach the ends of the column. Sometimes, the reboil and reflux controls will amplify the swings. The final result is that meeting product purity targets becomes more difficult. Refinery operations personnel will normally respond by over-purifying the products, wasting energy to compensate for the problematic feed control valve.

- **Typical Control Valve Selection:**
  - — NPS 8 to NPS 12 Vee-Ball
  - — Materials of Construction: WCC valve body with monel trim and TCM seal
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class III shutoff or better

7.,16. Propane and Butane Recirculation Valves

In order to prevent column flooding, the alkylation unit is built with accumulators. This allows a refiner to operate their unit as efficiently as possible and convert as many light olefins to alkylate as possible. These valves control the recirculation back to the depropanizer and debutanizer columns.

- **7. Propane Recirculation Typical Control Valve Selection:**
  - — NPS 4 easy-e EZ or NPS 6 to NPS 8 Vee-Ball
  - — Materials of Construction: WCC valve body with monel trim
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV shutoff
- **16. Butane Recirculation Typical Control Valve Selection:**
  - — NPS 2 to NPS 4 easy-e EZ
  - — Materials of Construction: WCC valve body with monel trim
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV shutoff

9. Fuel Gas Valve

Depending on the furnace service and configuration this valve will normally be part of a loop that controls either the fuel flow or pressure. These valves are specified as fail closed so that a control loop failure will not allow an excessive amount of fuel to be dumped into a hot furnace. A fuel valve failure will almost always shut down the processing unit downstream. Although many fuel valves have bypass circuits, refinery operations personnel are usually reluctant to run a furnace on bypass for any significant time due to safety concerns.

The preferred control loop configuration for outlet temperature is a cascade to the set point of the loop controlling the fuel valve. Many furnaces will be set up such that the temperature control loop directly manipulates the fuel valve. This direct connection usually provides inferior control performance to a cascade configuration as it is extremely susceptible to valve deadband, such as that caused by a sticking valve. This can be detected by excessive oscillation in the outlet temperature.

When the fuel valve is manipulated by the temperature loop or by a flow control loop, there will often be a pressure control valve upstream of the fuel valve. This valve will also fail closed and will have the same consequences as a failure of the fuel valve. However, with this configuration, operations personnel will be more willing to run a fuel valve in bypass as they still have a way to shut off the fuel quickly in an emergency.

Since this valve is critical to unit operation, a FIELDVUE DVC6200 digital valve controller with predictive diagnostics (PD) is recommended. Monitoring valve position is critical to this valve when it is supposed to fail close. It may be desirable to include the position transmitter option in the FIELDVUE DVC6200 instrument to provide position feedback to the DCS, upon loss of power to the FIELDVUE DVC6200 instrument, assuring whether or not the valve actually closed.

- **Typical Control Valve Selection:**
  - — NPS 1 to NPS 4 easy-e EZ
  - — Materials of Construction: WCC body with 300-series SST trim, sour fuel gas may require NACE trim materials
  - — ENVIRO-SEAL duplex or PTFE packing
  - — Class IV shutoff

10. Acidic Propane Valve

This valve controls the propane product before acid has been removed from the process fluid. It is a level valve drawing propane stream from the depropanizer accumulator. It is likely to be used in conjunction with a Level-trol controller for HF Acid service.

- **Typical Control Valve Selection:**
  - — NPS 2 to NPS 4 easy-e EZ
  - — Materials of construction: WCC body with monel trim, for HF Alky service
  - — ENVIRO-SEAL duplex or PTFE packing
  - — Class IV shutoff

11. Recycle Acid Valve.

This valve draws the acid off of the bottom of the depropanizer accumulator and recycles it to the combined inlet stream.

- **Typical Control Valve Selection:**
  - — NPS 1 to NPS 2 easy-e EZ
  - — Materials of construction: WCC or Monel body with monel trim, for HF Alky service
  - — ENVIRO-SEAL duplex or PTFE packing
  - — Class IV shutoff

12. Propane Product Valve

This valve will have no effect on the process operation unless it causes level problems. There is no consequence for any downstream unit because the propane is routed to the refinery fuel system. This valve can be run in manual or bypass without significant problems.

- **Typical Control Valve Selection:**
  - — NPS 1 to NPS 3 easy-e ED
  - — Materials of Construction: WCC body with 400-series SST trim
  - — ENVIRO-SEAL duplex or PTFE packing
  - — Class II shutoff

13. Isobutane Recycle Valve

Because the concentration of isobutane is kept high in the combined feed to prevent side reactions, this recycle valve is important to the overall process operation. A significant amount of isobutane will be unreacted in the process, so this is a substantial stream to maintain.

- **Typical Control Valve Selection:**
  - — NPS 4 easy-e EZ or NPS 4 to NPS 8 Vee-Ball
  - — Materials of Construction: WCC body with Monel trim
  - — ENVIRO-SEAL duplex or PTFE packing
  - — Class IV shutoff

17. Alkylate Product Valve

This valve will have no effect on the process operation unless it causes level problems. There is no consequence for any downstream unit because the alkylate is sent to the gasoline blending pool. This valve can be run in manual or bypass without significant problems.

- **Typical Control Valve Selection:**
  - — NPS 6 to NPS 10 Vee-Ball
  - — Materials of Construction: WCC body with 300-series SST trim
  - — ENVIRO-SEAL PTFE packing
  - — Class IV shutoff

18. Caustic Butane Valve

This valve is usually in a level loop, drawing the caustic butane fluid off of the debutanizer accumulator. The butane is sent to a treatment plant where the fluid is cleaned and n-butane is sent to the refinery fuel gas system.

- **Typical Control Valve Selection:**
  - — NPS 1 to NPS 2 easy-e EZ
  - — Materials of Construction: WCC body with Monel trim
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV shutoff

Sulfuric Acid Alkylation Control Valve Selection

When alloy 20 material is specified for sulfuric acid alkylation, please note that Emerson complies with ASTM A990 material specification for pressure boundary castings.

1. Olefin Feed Valve

The amount of flow and composition of this stream establish the isobutane and acid makeup requirements. Therefore, it is desirable to have this flow and composition as steady as possible. Extremely erratic valve movement, such as sticking, could make the reactor conversion cycle. However, because the reactor is continuously mixed, the effect of any small swings in flow will probably go unnoticed.

- **Typical Control Valve Selection:**
  - — NPS 2 to NPS 6 GX, easy- e EZ or ET
  - — Materials of Construction: WCC body with 300-series SST trim
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV shutoff

2. Makeup Isobutane Valve

The Alkylation unit requires approximately 16 MBPD of isobutane to react with the 10 MBPD of olefin feed. The isobutane feed to the reactor is a combination of makeup and recycle isobutane recovered in the DIB and depropanizer towers. The makeup isobutane is usually added to the DIB tower and sent with the recycle material to the feed coalescer.

- **Typical Control Valve Selection:**
  - — NPS 2 to NPS 4 GX or easy-e EZ
  - — Materials of Construction: WCC body with 300-series SST trim
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV shutoff

3. Makeup Acid Valve

The acid strength effects the octane rating of the alkylate, as well as the likelihood of an acid runaway reaction. Increasing the recycle acid strength will increase octane, but it also increases operating costs. Lowering the acid strength will increase the chance of a runaway reaction. However, as long as this valve is not swinging wildly, the effect on the reactor conversion will be slow to appear as this is a makeup flow and is mixed with the recycled acid before going to the reactor.

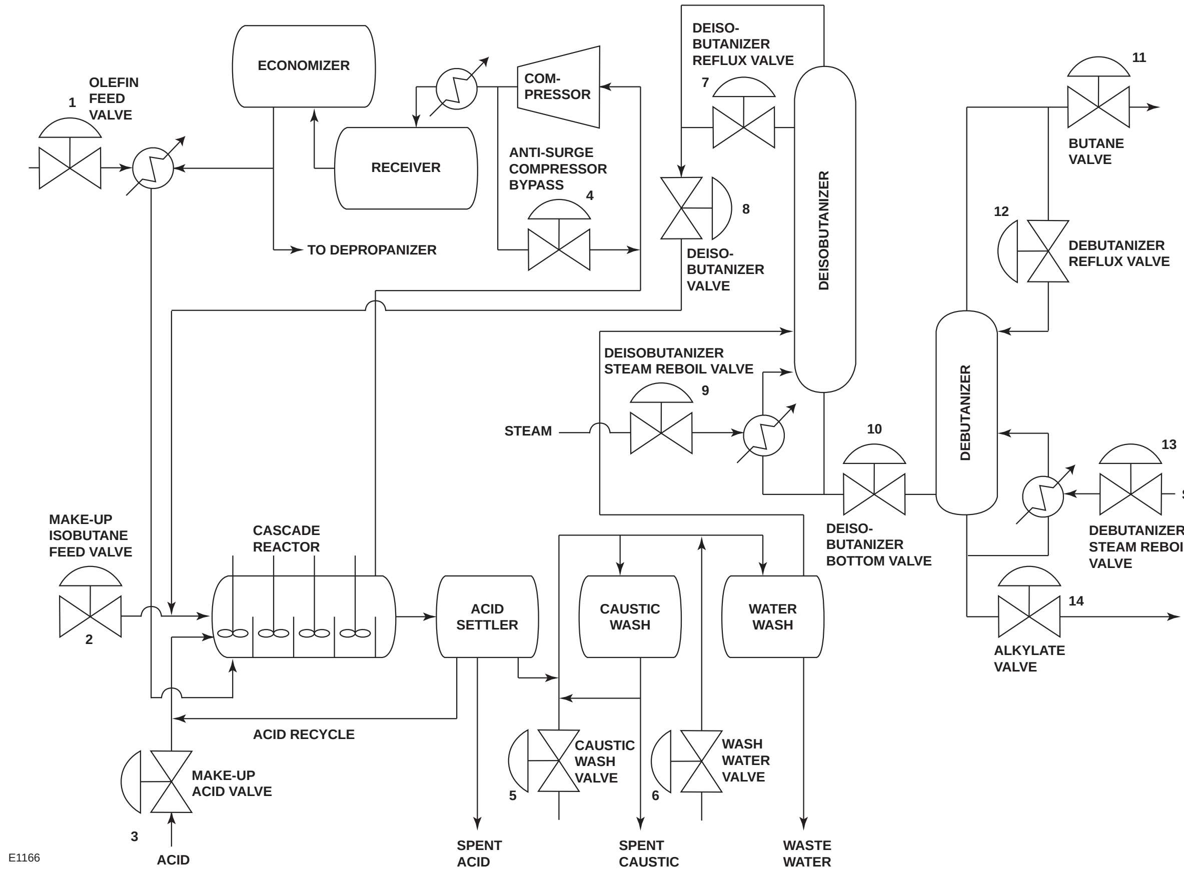


Figure 4.11.3. Sulfuric Acid Alkylation Process Flow Diagram

- **Typical Control Valve Selection:**
  - — NPS 1 to NPS 4 GX or easy-e EZ
  - — Materials of Construction: Alloy 20 or Hastelloy C body with alloy 20 or Hastelloy C trim
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV shutoff

4. Compressor Bypass

There may be one stage or multiple stages of compressors in an alkylation unit. In this example we are considering a single stage compressor. This bypass control valve is used to protect the compressor from the effects of surge than can occur during startup, shutdown, and process upsets. The performance of this valve is crucial to the operation and efficiency of the compressor.

These valves must operate quickly, accurately, and reliably to protect the compressor and the process. Typically, the combination of fast action and accuracy is missing in installed antisurge valves, which may also utilize an unreliable instrumentation scheme. Noise attenuation trim is required to address potential vibration during normal operation and to prevent associated pipe fatigue issues.

The solution to this issue is to use a Fisher Optimized Antisurge Valve. This assembly combines fast action, accuracy, and reliability in one package. The valve trim is designed to meet specific compressor design requirements, along with an actuation system designed for stroking speed and accurate control. The ODV FIELDVUE unit is designed with antisurge-specific tuning and control algorithms, as well as the capability to predict issues like sticking or friction, and other antisurge specific diagnostics.

- **Typical Control Valve Selection:**
  - — NPS 6 to NPS 10 easy-e ET or EWT
  - — Materials of construction: Dependent on process design
  - — Noise attenuation trim may be required
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV or V shutoff

5. Caustic Wash Valve

This valve is typically not adjusted very often. All that is required is that enough caustic is being delivered to neutralize the leftover acidic material. It is important for neutralizing acid and keeping corrosion to a minimum downstream

- **Typical Control Valve Selection:**
  - — NPS 1 to NPS 4 GX or easy-e EZ or NPS 2 to NPS 4 Vee-Ball
  - — Materials of Construction: Compatible with caustic fluid
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV shutoff

6. Water Wash Valve

These valves are similar to the caustic valves in that they are not adjusted very often and only need to have enough flow to neutralize any remaining acidic components.

- **Typical Control Valve Selection:**
  - NPS 1 to NPS 4 GX or easy-e EZ
  - Materials of Construction: WCC body with 300-series SST trim
  - ENVIRO-SEAL PTFE or duplex packing
  - Class IV shutoff

7, 12. Deisobutanizer and Debutanizer Reflux Valves

The reflux valves are typically either a flow or column temperature-control loop. They are used to adjust the purity of the overhead product. The higher the reflux rate, the purer the overhead product will become. However, raising the reflux rate will also require more reboil heat and will eventually flood the tower.

A poorly operating reflux valve will have the same effects as a bad feed valve. Product purities will oscillate and the column will be difficult to control.

- **7. DIB Reflux Typical Control Valve Selection:**
  - NPS 1 to NPS 4 GX or easy-e EZ
  - Materials of Construction: WCC body with 300-series SST trim
  - ENVIRO-SEAL PTFE or duplex packing
  - Class IV shutoff
- **12. Debutanizer Reflux Typical Control Valve Selection:**
  - NPS 3 to NPS 6 Vee-Ball or Control-Disk
  - Materials of Construction: WCC body with 300-series SST trim
  - ENVIRO-SEAL PTFE or duplex packing
  - Class IV shutoff

8. Deisobutanizer Valve

This is one of the more important valves in the alky unit. This stream is recycled as part of the isobutane feed to the reactor and has an effect on the reactor conversion.

This valve is typically used to control the level in the overhead receiver. It normally has no effect on column operation unless it causes the level to change quickly and dramatically.

- **Typical Control Valve Selection:**
  - NPS 2 to NPS 6 easy-e ET or EZ, or NPS 3 to NPS 6 Vee-Ball
  - Materials of Construction: WCC body with 300-series SST trim
  - ENVIRO-SEAL PTFE or duplex packing
  - Class IV shutoff

9, 13. Deisobutanizer & Debutanizer Steam Reboil Valves

The reboil valves control the amount of heat put into the deisobutanizer and debutanizer columns by the reboiler. In many cases, steam is used as a heat source. Steam valves are usually very reliable. The service is very clean and fugitive emissions are not a concern. However, a problem valve will make the column difficult to control precisely. This will be especially true if the column feed is subject to frequent changes.

Not all reboilers use steam as a heat source. To save energy, many refineries have integrated their units so that higher temperature process streams are used to provide heat for lower temperature processes. In these cases, the reboil valve will foul more easily and might have fugitive emissions concerns.

- **Typical Control Valve Selection:**
  - NPS 2 to NPS 4 easy-e ED
  - Materials of Construction: WCC body with 400-series SST or high temp 300-series SST trim, appropriate for steam service
  - Graphite packing
  - Class III shutoff

10. Deisobutanizer Bottom Valve

The bottom product valve is typically used to control the level in the bottom of the DIB. It normally has no effect on column operation unless it causes the level to change quickly and dramatically.

- **Typical Control Valve Selection:**
  - NPS 3 to NPS 8 Vee-Ball or V500
  - Materials of Construction: WCC body with 300-series SST trim, appropriate for potentially high viscosity fluid. Alloy 6 or ceramic trim may be required.
  - ENVIRO-SEAL PTFE packing
  - Class IV shutoff

11. Butane Product Valve

This valve has little impact on the overall process unit. It controls the light butane product from the debutanizer. The butane is usually sent to the refinery fuel gas system.

- **Typical Control Valve Selection:**
  - NPS 1 to NPS 2 easy-e EZ
  - Materials of Construction: WCC body with 300-series SST trim
  - ENVIRO-SEAL PTFE or duplex packing
  - Class IV shutoff

14. Alkylate Valve

The bottom product valve is typically used to control the level in the bottom of the column. It normally has no effect on column operation unless it causes the level to change quickly and dramatically.

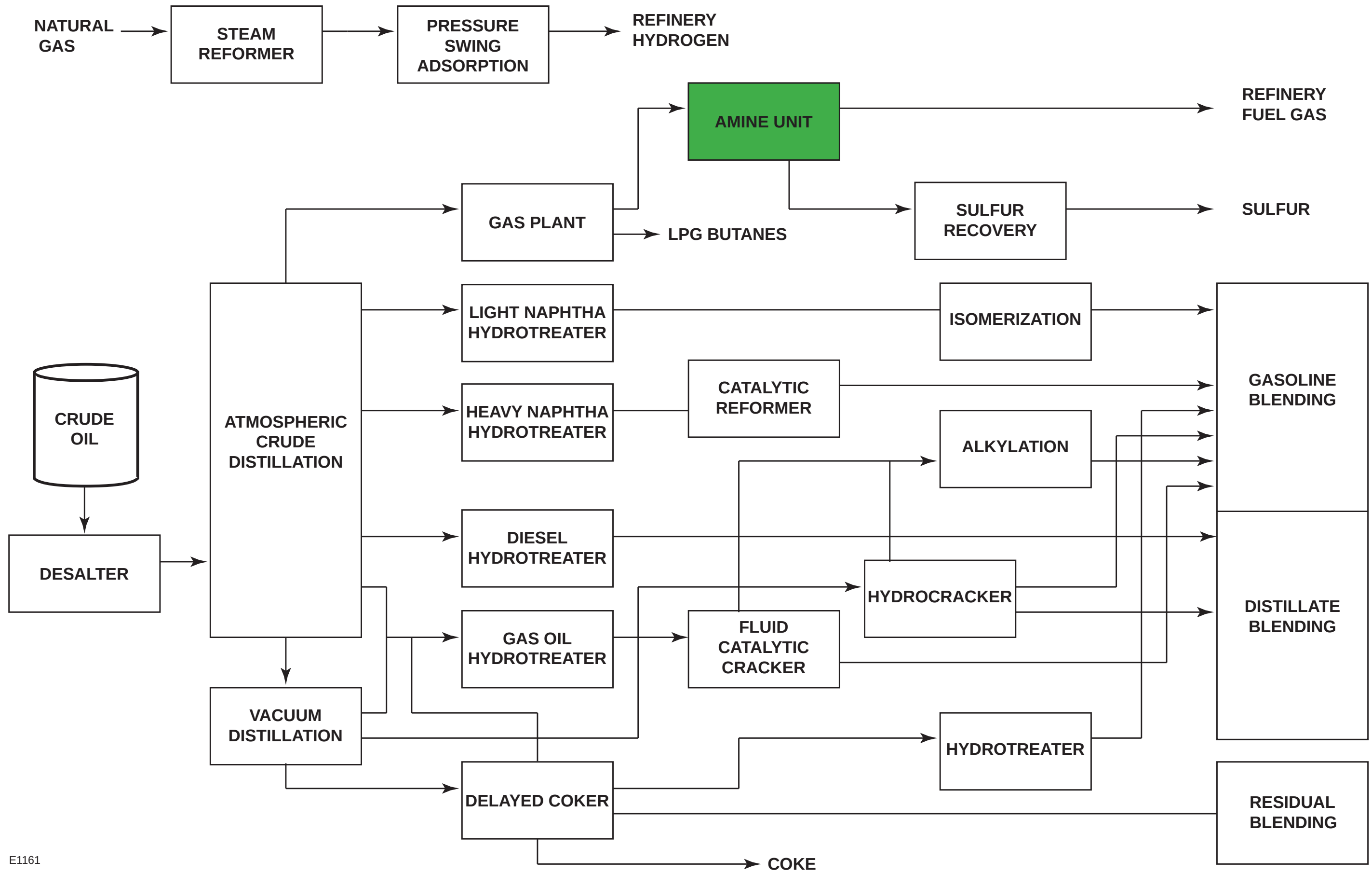


Figure 4.12.1. Amine Unit Location

- **Typical Control Valve Selection:**
  - NPS 6 to NPS 10 Vee-Ball
  - Materials of Construction: WCC body with 300-series SST trim
  - ENVIRO-SEAL PTFE packing
  - Class IV shutoff

4.12 Amine Unit

Other Names—Amine contactor, amine scrubber, amine treater

Amine units are used to clean up the various sour light-gas streams created by the refinery cracking and treating units. The objective of an amine unit is to strip hydrogen sulfide (H_2S), sulfur dioxide (SO_2), and other environmental poisons from sour light gas streams. This prepares the light gas streams to be used in other processing units, to be sold as products, or to be burned as fuel gas.

The term "amine unit" can be misleading. Rarely is amine treating considered to be a standalone unit in a refinery. In many cases, each processing unit will have a small amine scrubber located within its unit boundaries or will share a scrubber with a few other units. Several of these scrubbers will receive and return amine to a central regenerator located within one of the units.

The most widely used process to remove acid gases from natural gas is the alkanolamine process. The term alkanolamine encompasses the family of specific organic compounds or monoethanolamine (MEA), diethanolamine (DEA), and triethanolamine (TEA). Recently, newer amine units use methyl diethanolamine (MDEA).

This is a continuous operation liquid process. Using absorption, acid-gas components are removed via amine and the addition of heat. The schematic flow diagram (figure 4.12.2) shows the basic process.

After any free liquids are removed from the gas in an inlet scrubber, the gas passes to the absorber section. Here it rises counter-currently in close contact with the descending amine solution. Purified gas flows from the top of the absorber.

Lean amine enters the tower at the top where it flows across trays downward, against the flow of the gas. At the bottom, the acid-gas-rich amine (aka rich amine) leaves the absorber through a dump valve (rich amine letdown valve) that is actuated by a liquid-level controller. The rich amine then goes to the flash tank, operating at a reduced pressure, where a great portion of the physically absorbed gases are flashed off. From there the rich amine goes through various processes to be regenerated by removing the H_2S and CO_2 from the amine solution and starts the cycle over again as lean amine.

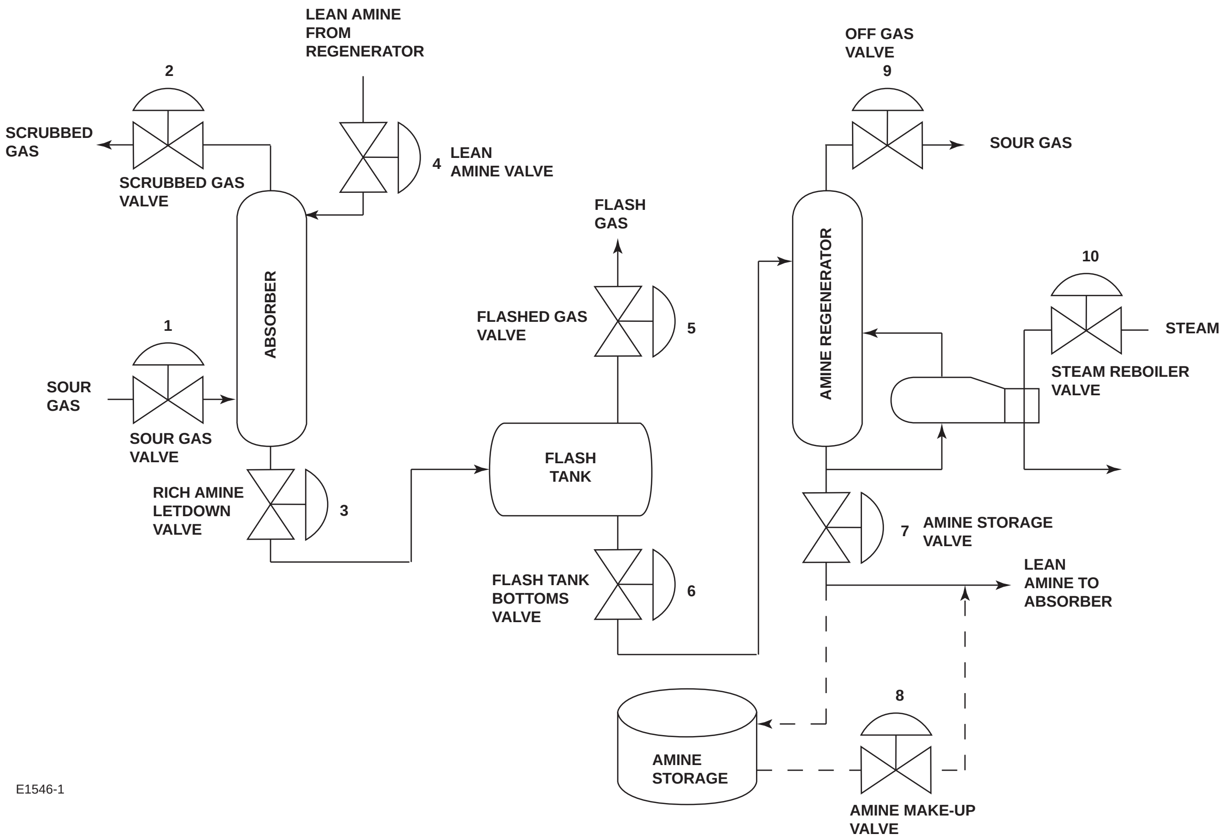


Figure 4.12.2. Amine Unit Process Flow Diagram

1. Sour Gas Valve

This valve supplies the incoming sour gas to the amine unit. It is a combination of the sour gas streams from the process unit (or units) being scrubbed by the amine unit. It is somewhat unique in the refinery, since the inlet stream is in a vapor state.

Feed valves are usually set up as flow-control loops. They are configured to fail open so that a valve failure will protect the furnace radiant section tubes. If a radiant tube loses or has insufficient flow, the tube can quickly become so hot that the metal can melt. This can have disastrous consequences, as most process feeds make excellent fuels. A furnace can be destroyed very quickly if a ruptured tube is dumping into the firebox of the furnace.

Problem valves can lead to difficulties controlling the outlet temperature of the furnaces. Also, many process feeds slowly build layers of coke on the inside of the radiant tubes. Coking is a non-linear reaction and in some processes even a few extra degrees of temperature can lead to excessive coke build-up. If a flow valve is oscillating, the temperature will also swing and will usually lead to excessive coke buildup. This will shorten the furnace cycle time between decoking procedures, which normally requires the process unit downstream to shut down.

Feed valves can easily be bypassed when necessary. A combination of the measured flow and any available pass temperatures can be used to regulate the bypass valve.

- **Typical Process Conditions:**
  - Fluid: Sour gas
  - P1 = 5.8 – 7.8 barg (85 - 115 psig)
  - P2 = 1 – 6.6 barg (15 - 95 psig)
  - T = 38°C (100°F)
  - Q = 10,350 - 14580 kg/h (22,820 – 32,145 lb/h)
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 8 easy-e ET or EZ
  - Materials of Construction: WCC body with 300-series SST/Alloy 6 trim
  - NACE required
  - ENVIRO-SEAL PTFE packing
  - Class IV shutoff

2. Scrubbed Gas Valve

As lean amine picks up the sour gas component in the inlet stream, light, clean hydrocarbons are removed from the process stream. This valve has little effect on the rest of the process unit. The resulting process stream is usually sent to the refinery's fuel gas system.

- **Typical Process Conditions:**
  - Fluid: Scrubbed gas
  - P1 = 38 – 45 barg (550 – 650 psig)
  - P2 = 36 – 43 barg (525 - 625 psig)
  - T = 50 - 65°C (120 - 150°F)
  - Q = 885 – 1180 m^3/h (750,000 – 1,000,000 scfh)

- **Typical Control Valve Selection:**
  - — NPS 2 to NPS 4 easy-e ET
  - — Materials of Construction: WCC body with 300-series/ Alloy 6 trim
  - — NACE required
  - — Noise attenuation may be required
  - — ENVIRO-SEAL PTFE packing
  - — Class IV shutoff

3. Rich Amine Letdown (Scrubber Bottoms) Valve

This application is demanding because the process fluid (rich amine) has entrained gas in solution. As the fluid passes through the control valve, it takes a pressure drop due to the pressure differential between the tower and the flash tank. As this pressure drop takes place in the valve, large amounts of outgassing (entrained gas coming out of solution) occurs.

- **Typical Process Conditions:**
  - — Fluid: H_2S Rich Diethylamine (Fat DEA)
  - — P1 = 45 - 155 barg (650 - 2250 psig)
  - — P2 = 8.8 - 12 barg (127 - 175 psig)
  - — T = 55 - 75°C (130 - 165°F)
  - — Q = 78 - 286 m^3/h (345 – 1260 gpm)
- **Typical Control Valve Selection:**
  - — See the following section on outgassing application valve sizing and selection

Outgassing

Outgassing is one of several severe service applications that are encountered in refining applications. In order to identify a process that is Outgassing, it is important to have an understanding of the other severe service applications that experience the same problems or symptoms. The table below shows the physical phases of flow-media and how they are classified. It also gives a description of what is causing these phenomena to occur.

Flow Media Phases

Type: Outgassing **Upstream:** Liquid **Downstream:** Liquid and Gas **Description of Process:** Outgassing is a process that involves a flow media consisting of at least two different constituents. One is a liquid and the other is a gas that is entrained in that liquid. The two components begin to separate upon the slightest change in pressure. The best example of this would be a bottle of soda. The bottle is pressurized and appears to be a homogeneous liquid but when a reduction in pressure occurs, i.e. opening the bottle, the CO_2 gas begins to come out of the liquid solution. The final product downstream is two elements, one liquid soda and the other carbon dioxide gas.
Type: Flashing **Upstream:** Liquid **Downstream:** Liquid and Vapor **Description of Process:** When the pressure within a single component system drops to the vapor pressure of the liquid, the liquid begins to absorb heat and changes to a vapor phase. This process is time dependent because it is a thermodynamic process. The latent heat of vaporization must be absorbed, which is not an instantaneous process.
Type: Cavitation **Upstream:** Liquid **Downstream:** Liquid **Description of Process:** Like flashing, cavitation involves the thermodynamic process of vaporization. Formation of bubbles occurs when the pressure at the vena contracta falls below the vapor pressure. As pressure recovers, the downstream pressure becomes greater than the liquid's vapor pressure. This causes the newly formed cavities to collapse and implode, creating cavitation with noise and possible damage. As long as the pressure downstream stays above the vapor pressure of the liquid, all of the vapor bubbles will collapse and the final product further downstream will be 100% liquid.
Type: Two-Phase (G/L) **Upstream:** Liquid and Gas **Downstream:** Liquid and Gas **Description of Process:** This is a flowing media that contains at least two different components, where one component is in the liquid phase and the other is in the compressible (gas) phase. Both of these phases are present when entering and exiting the valve. Although this should be easy to identify, it is still a severe service that presents many problems..

Outgassing and flashing behave in similar manners and in many cases outgassing is thought to be flashing. This is because outgassing and flashing both have a fluid that enters a valve as a liquid and exits the valve as a liquid and gas. These two processes can impose the same types of damage, but this is where the similarities end. Shown below are the major differences that separate outgassing from flashing.

Outgassing

- Fluid contains at least two substances of completely different makeup (i.e. crude oil and natural gas).
- Undergoes a depressurization process that causes the entrained gas to be released separate from the liquid.
- Outgassing can occur at any point in the system. It only takes a minimal drop in pressure for the gas to come out of suspension. If outgassing occurs prior to the throat of the valve, damage to the valve and trim would occur. This would occur if an outgassing application were misdiagnosed as a flashing application.
- The standard application of the ISA/IEC sizing equations do not accurately account for this situation.

Flashing

- One homogenous substance that changes from a liquid state to a gas state (i.e. water to steam).
- Undergoes a thermodynamic process and becomes two phase at the vena contracta.
- Flashing occurs when the pressure of the liquid drops to its vapor pressure. It is easier to predict this compared to Outgassing and is modeled by the ISA/IEC Liquid Sizing Equations.

Identifying Outgassing Applications

The ability to identify an outgassing application is important because outgassing is handled very differently than any other application. Listed below are some good indicators that outgassing is occurring.

Note A: Vapor Pressure

- If the vapor pressure (PV) listed on the specifications sheet is similar to that of the inlet pressure (P1). The assumption is that this practice will compensate for the gas which is known to be present downstream of the valve although the gas is not the same composition as the upstream liquid. This is an incorrect assumption.

Note B: Critical Pressure

- If the vapor pressure listed on the spec sheet is greater than the critical pressure listed. From a thermodynamic perspective, this is impossible. When considering a pressure/temperature diagram, the vaporization line depicts the vapor pressure for a given temperature. The saturation pressure terminates at the vapor line, above which the fluid becomes supercritical. Hence, if the control valve data sheet has PV>PC, then the customer may be unknowingly trying to model an outgassing application.

Note C: Gas/Vapor Percentage

- There are times when the customer's valve data sheet will specify the percentage of gas/vapor for their process.
- If the application data sheet indicates that the inlet conditions are liquid and the outlet conditions are liquid and gas.

Note D: Application Indicator

- If any of the previous stated indicators are present, check to see if it is being used in a level controller application by checking the tag on the spec sheet. The tag may have an "LC," "LCV," or sometimes "LV" to represent that it is a level control valve.

Valve Sizing and Selection

Outgassing two phase flow in control valve applications requires a special sizing procedure. The potential existence of both a compressible (gas or vapor) element and non-compressible (liquid) element in the flowing media prior to the throttling orifice cannot be accurately modeled using the standard ANSI/ISA S75.01, IEC 6053421 or other proprietary liquid control valve sizing equations. Therefore, in order to successfully arrive at a reasonable CV that is neither undersized nor oversized, contact your Emerson sales office to learn more.

Valves and Trims for Rich Amine Applications

Process Conditions	Pressure Class	
	CL150-600	CL1500
Contact your Emerson sales office to obtain a copy of the "Fisher Outgassing Process Data Sheet"	Flow down standard style, hardened trim Hardened Whisper Trim I Hardened Whisper Trim III Levels A1, B1, and C1 Cavitrol III trim, 1 stage Solid alloy 6 cage Whisper Trim I	Flow down standard style, hardened trim Hardened Whisper Trim III Levels A1, B1, and C1 S17400 Solid alloy 6 cage Whisper Trim III Level A1

Valves and Trims for Outgassing Applications with Low Outlet Gas Volume Ratio and Shows Little Potential to Cavitate

Process Conditions	Pressure Class	
	CL150-600	CL1500 and above
Contact your Emerson sales office to obtain a copy of the "Fisher Outgassing Process Data Sheet"	Whisper Trim I Whisper Trim III Levels A1, B1, and C1 Cavitrol III trim, 1 stage V500 reverse flow control valve NotchFlo DST DST trim	Whisper Trim III Levels A1, B1, and C1 NotchFlo DST DST trim

Valves and Trims for Outgassing Applications with High Outlet Gas Volume Ratio Where a Multi-Stage Solution is requested

Process Conditions	Pressure Class
	CL150 and above
Contact your Emerson sales office to obtain a copy of the "Fisher Outgassing Process Data Sheet"	DST-G trim

Valves and Trims for Outgassing Applications with High Outlet Gas Volume Ratio and There is No Valve Trim Preference

Process Conditions	Pressure Class	
	CL150-600	CL1500 and above
Contact your Emerson sales office to obtain a copy of the "Fisher Outgassing Process Data Sheet"	Whisper Trim I Whisper Trim III Levels A1, B1, and C1 Cavitrol III trim, 1 stage V500 reverse flow control valve 461 Sweep-Flo Valve DST-G trim	Whisper Trim III Levels A1, B1, and C1 461 Sweep-Flo Valve DST-G trim

4. Lean Amine Valve

Lean Amine is added to the scrubber to hold an amine/gas ratio. A scrubber is much like a distillation column. Too much vapor or liquid traffic can cause the scrubber to flood. When this happens, the sulfur compounds are no longer completely stripped from the sour gas. If a scrubber is being operated close to loading constraints, and the lean amine valve is sticking badly, then this could cause the scrubber to flood.

- **Typical Process Conditions:**
  - — Fluid: Lean Amine
  - — P1 = 8 - 160 barg (115 – 2,320 psig)
  - — P2 = 6.4 - 125 barg (95 – 1,815 psig)
  - — T = 55 - 60°C (130 - 140°F)
  - — Q = 6 – 210 m^3/h (25 – 925 gpm)
- **Typical Control Valve Selection:**
  - — NPS 2 to NPS 4 HPAS or HPT or NPS 1 to NPS 2 easy-e EZ
  - — Materials of Construction: WCC body with 300-series/ Alloy 6 trim
  - — NACE may be required
  - — Micro-trim may be required depending on flow rate
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class IV Shutoff

5. Flashed Gas Valve

After rich amine enters the flash tank, the absorbed gases are flashed off. Although this gas may contain some sulfur, it is usually sent to the refinery fuel gas system after further processing.

- **Typical Process Conditions:**
  - — Fluid: Light hydrocarbon gas
  - — P1 = 7.9 – 12.1 barg (115 - 175 psig)
  - — P2 = 6.9 – 7.6 barg (100 – 110 psig)
  - — T = 58 - 65°C (137 - 148°F)
  - — Q = 38 – 1451 m^3/h (32,000 - 1,230,000 scfh)

- **Typical Control Valve Selection:**
  - — NPS 1.5 to NPS 2 easy-e ET or EZ
  - — Materials of Construction: WCC body with 300-series/ Alloy 6 trim
  - — Noise Attenuation trim may be required
  - — ENVIRO-SEAL packing
  - — Class IV or V shutoff

6. Rich Amine Flash Tank Bottoms Valve

The bottom product of the flash tank is a sulfur rich amine liquid. This fluid is sent to the separator (amine regenerator) where the H_2S and CO_2 are separated from the amine carriers.

- **Typical Process Conditions:**
  - — Fluid: Rich amine
  - — P1 = 8.0 - 12 barg (115 - 175 psig)
  - — P2 = 5.6 - 10 barg (80 – 145 psig)
  - — T = 58 - 65°C (135 - 150°F)
  - — Q = 225 – 490 m^3/h (990 – 2160 gpm)
- **Typical Control Valve Selection:**
  - — NPS 6 V500 or NPS 4 to NPS 8 easy-e ET or EWT
  - — Materials of Construction: WCC body with 300-series/ Alloy 6 or solid Alloy 6 trim
  - — NACE may be required
  - — ENVIRO-SEAL PTFE packing
  - — Class IV Shutoff

7. Amine Storage Valve

This valve, along with the amine makeup valve, is used to hold the regenerator bottom level. If a scrubber shuts down, some of the circulating amine will be sent to storage. Also, if fresh amine is being added to the system, the excess amine will be eliminated through this valve.

The valve typically is used to control the level in the bottom of the column. It normally has no effect on column operation unless it causes the level to change quickly and dramatically.

- **Typical Process Conditions:**
  - — Fluid: Lean amine
  - — P1 = 8 - 10 barg (115 – 145 psig)
  - — P2 = 7.5 – 9 barg (110 – 130 psig)
  - — T = 55 - 60°C (130 - 140°F)
  - — Q = 80,000 – 90,000 kg/h (176,370 – 198,415 lb/h)
- **Typical Control Valve Selection:**
  - — NPS 6 to NPS 8 easy-e EWT or NPS 4 to NPS 8 Vee-Ball
  - — Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - — ENVIRO-SEAL PTFE packing
  - — Class IV shutoff

8. Amine Make-up Valve

The amine generally degrades as it is circulated to the scrubbers. Lab tests are run occasionally to check the strength of the amine. When it becomes low, fresh amine is added to the system to restore the circulating amine. This valve is not critical, as the amine system can run for long periods of time without makeup.

Poor operation of the scrubber can easily double or triple the cost of amine to the refinery on an annual basis.

- **Typical Process Conditions:**
  - — Fluid: Lean amine
  - — P1 = 25 – 160 barg (360 – 2,320 psig)
  - — P2 = 24 – 155 barg (350 – 2,250 psig)
  - — T = 55 - 60°C (130 - 140°F)
  - — Q = 0.7 - 480 m^3/h (3 - 2115 gpm)
- **Typical Control Valve Selection:**
  - — NPS 2 to 6 HPT or NPS 1 to NPS 3 easy-e EZ
  - — Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - — PTFE packing
  - — Class IV shutoff

9. Off Gas Valve

This valve controls the back pressure to the distillation column and is very important in controlling the stability of the tower. Since many columns use tray temperature to control overhead composition, stable pressure is required to ensure that temperature changes reflect composition changes.

- **Typical Process Conditions:**
  - — Fluid: Sulfur gas
  - — P1 = 7.3 – 43 barg (105 – 625 psig)
  - — P2 = 2.5 – 42 barg (35 – 610 psig)
  - — T = 39 - 115°C (100 - 240°F)
  - — Q = 18,350 – 43,980 kg/h (40,455 - 96,960 lb/h)
- **Typical Control Valve Selection:**
  - — NPS 1 to 4 easy-e ET or EZ
  - — Materials of Construction: WCC body with 300-series SST trim
  - — NACE required
  - — ENVIRO-SEAL PTFE or duplex packing
  - — Class V shutoff

10. Steam Reboiler Valve

The reboil valve controls the amount of heat put into the column by the reboiler. In many cases, steam is used as a heat source. Steam valves are usually very reliable. The service is very clean, therefore fugitive emissions are not a concern. However, a problem valve will make the column difficult to control precisely. This will be especially true if the column feed is subject to frequent changes.

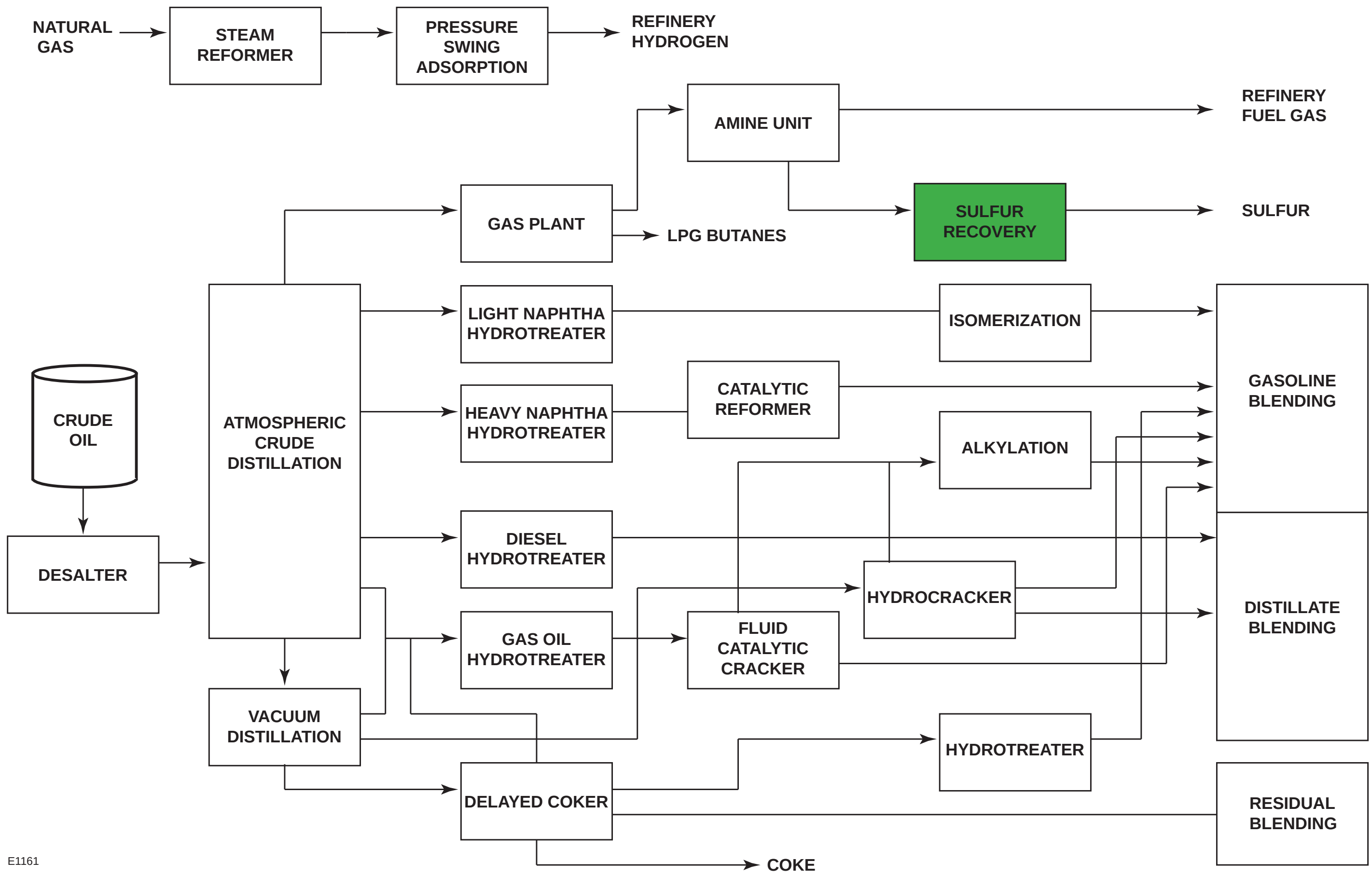


Figure 4.13.1. Sulfur Recovery Unit Location

Not all reboilers use steam as a heat source. To save energy, many refineries have integrated their units so that higher-temperature process streams are used to provide heat for lower-temperature processes. In these cases, the reboil valve will foul more easily and might create fugitive emissions concerns.

- **Typical Process Conditions:**
  - Fluid: Steam
  - P1 = 15 - 30 barg (215 – 435 psig)
  - P2 = 12 - 19 barg (175 – 275 psig)
  - T = 150 - 230°C (300 - 445°F)
  - Q = 4,400 – 6,200 kg/h (9,700 – 13,670 lb/h)
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 4 easy-e EZ
  - Materials of Construction: WCC body with 400 series SST trim, appropriate for steam service
  - Graphite packing
  - Class IV shutoff

4.13 Sulfur Recovery Unit

Other Names—SRU, Claus unit

The crude oil processed by refineries contains varying amounts of sulfur. The sulfur is removed during processing, mostly as hydrogen sulfide (H_2S). Environmental regulations restrict the amount of H_2S and other sulfur compounds that can be released to the environment. The sulfur recovery unit (SRU) is used to convert H_2S to elemental sulfur through a series of reactors. The Claus process is most commonly used to recover sulfur from various refinery gases that contain high concentration (more than 25%) of H_2S.

The feed sources for an SRU are acid gases from the amine unit(s) and sour gas from the sour water strippers. The acid and sour gases are burned in a reaction furnace in the presence of enough air and /or oxygen to combust approximately one third of the incoming H_2S plus any remaining hydrocarbons and ammonia. The combustion products are cooled in the waste heater boiler / thermal sulfur condenser. After the thermal reaction and condensation, there are three catalytic reactor stages. Each reactor stage consists of a reheater, catalytic converter, and condenser. The elemental sulfur recovered from each condenser is run down into a sulfur pit. The final tail gas stream can be sent to an incinerator or, depending on local environmental regulations, a tail gas treating unit.

The SRU is usually viewed by refinery operations personnel as an “overhead” or utility unit. However, because of the environmental regulations, this unit is extremely important to total refinery production. Most refineries have multiple SRUs so that a shutdown does not stop the entire refinery. If an SRU does shut down, the refinery typically has to back off on production to keep from producing more acid gas than can be processed by the remaining SRUs. Also, the SRU capacity in many refineries dictates what types and how much high sulfur crudes can be processed. A small incremental gain in capacity for these refiners can yield significant profit.

The need for recovering sulfur is increasing globally. In the US, sulfur content in crude oil input to refineries has increased from approximately 0.9 wt% to 1.4 wt%. However, in that same time frame, sulfur content allowed in transportation fuels has reduced from 450 ppm to 15 ppm and will continue to decrease to 10 ppm by 2020. Other countries are seeing the same trends as sweet (low sulfur) crude becomes less available.

Sulfur Recovery Unit Application Review

Control valves in the sulfur recovery unit will be prone to corrosion from sulfur. Fluids with high concentrations of sulfur also require very stable temperature control, due to the potential for solidification. Many refiners have added steam jackets to both their control valves and process equipment to prevent sulfur solidification.

1. Acid Gas from Amine Valve

These valves belong to the various amine contactors located throughout the refinery. The SRU normally has no direct control on the amount of acid gas coming to the SRU.

- **Typical Process Conditions:**
  - Fluid: Acid gas
  - P1 = 0.24 - 2.8 barg (3.5 - 41 psig)
  - P2 = 0.14 - 2.7 barg (2.0 - 39 psig)
  - T = 45 - 90°C (115 - 195°F)
  - Q = 505 - 7670 Nm^3/h (0.43 - 6.5 MMscfd)
- **Typical Control Valve Selection:**
  - NPS 14 Vee-Ball, NPS 8 to NPS 16 Control-Disk, or High Performance Butterfly
  - Materials of Construction: WCC body with 300-series SST trim
  - NACE required
  - ENVIRO-SEAL PTFE or graphite packing
  - Class VI shutoff

2. Sour Gas from Sour Water System (SWS) Valve

These valves belong to the various sour water strippers located throughout the refinery. The SRU normally has no direct control on the amount of sour gas coming to the SRU.

- **Typical Process Conditions:**
  - Fluid: Sour Gas
  - P1 = 0.9 - 2.7 barg (13 – 40 psig)
  - P2 = 0.8 - 2.6 barg (12 – 38 psig)
  - T = 85 - 86°C (185 - 187°F)
  - Q = 1,420 – 7,435 Nm^3/h (1.2 – 6.3 MMscfd)
- **Typical Control Valve Selection:**
  - NPS 6 to NPS 8 easy-e EWT or NPS 8 to NPS 10 Vee-Ball
  - Materials of Construction: WCC body with 300-series/ Alloy 6 trim
  - ENVIRO-SEAL PTFE or graphite packing
  - NACE required
  - Class V shutoff

3. Fuel Gas Valve

This valve is typically used only during startup. It may be necessary to use fuel gas when there are significant amounts of ammonia in the sour gas or significant amounts of hydrocarbons from either gas source.

- **Typical Process Conditions:**
  - Fluid: Fuel gas
  - P1 = 2.0 – 5.7 barg (30 – 85 psig)
  - P2 = 1.0 – 4.6 barg (15 - 65 psig)
  - T = 34 - 38°C (95 - 100°F)
  - Q = 580 – 1,420 Nm^3/h (0.49 – 1.2 MMscfd)
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 3 GX or NPS 1.5 to NPS 4 easy-e ET or EZ
  - Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - ENVIRO-SEAL PTFE or duplex packing
  - May require NACE compliance if gas is sour
  - Class IV shutoff

4. Oxygen Valve

This is an optional process stream for an SRU. It is sometimes used to boost the capacity of an SRU when another SRU is down.

- **Typical Process Conditions:**
  - Fluid: Oxygen
  - P1 = 2.0 barg (30 psig)
  - P2 = 1.0 barg (15 psig)
  - T = 43°C (110°F)
- **Typical Control Valve Selection:**
  - NPS 2 to NPS 4 easy-e EZ
  - Materials of Construction: 300-series SST or Monel body and trim
  - ENVIRO-SEAL PTFE packing
  - Oxygen service cleaning may be required
  - Class VI shutoff

5. Main Air Valve

The main air valve sets a bulk air flow rate to the thermal reactor. It is only adjusted to keep the trim air valve in the middle of its control range. Many units use butterfly valves in this service because of low pressure drop requirements, making flow control difficult at best. One way to increase throttling range is to use a Control-Disk valve in this application.

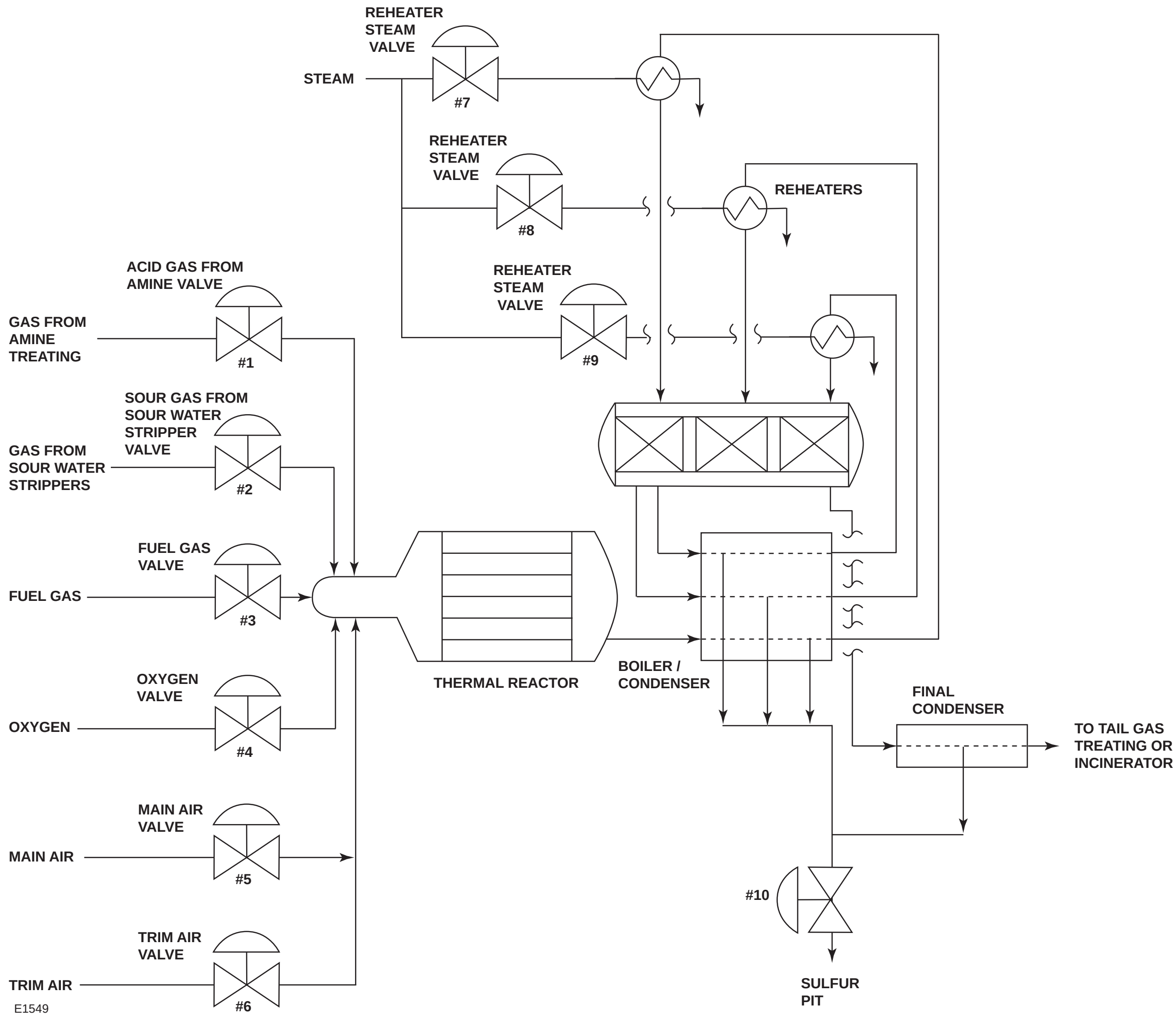


Figure 4.13.2. Sulfur Recovery Unit Process Flow Diagram

- **Typical Process Conditions:**
  - Fluid: Air
  - P1 = 0.13 – 2.2 barg (1.9 - 32 psig)
  - P2 = 0.07 – 2 barg (1 - 30 psig)
  - T = 50 - 120°C (120 - 250°F)
  - Q = 5,780 – 16,520 Nm^3/h (4.9 - 14 MMscfd)
- **Typical Control Valve Selection:**
  - NPS 10 to NPS 16 Control-Disk or NPS 12 to NPS 16 Vee-Ball
  - Materials of Construction: WCC body with soft seal standard trim
  - PTFE packing
  - Class VI shutoff

6. Trim Air Valve

This valve is typically tied to a tail gas analyzer and is used to set the total air flow rate precisely to the thermal reactor. The valve also receives feedforward inputs on the sour gas and acid gas flow rates.

- **Typical Process Conditions:**
  - Fluid: Air
  - P1 = 2.6 – 2.8 barg (38 – 41 psig)
  - P2 = 2.2 – 2.7 barg (32 – 39 psig)
  - T = 110 - 230°C (230 - 445°F)
  - Q = 462 - 1770 Nm^3/h (0.39 – 1.5 MMscfd)
- **Typical Control Valve Selection:**
  - NPS 4 to NPS 8 easy-e ET or NPS 3 to NPS 6 GX
  - Materials of Construction: WCC body with 400-series SST or 300-series SST trim
  - Graphite or PTFE packing
  - Class IV or V shutoff

7., 8. , 9. Reheater Steam Valves

These valves are used to control the reaction temperature to the Claus reactors. If valve performance is erratic, it can result in swings in the sulfur conversion, possibly causing an environmental excursion or putting more load on the tail gas treater.

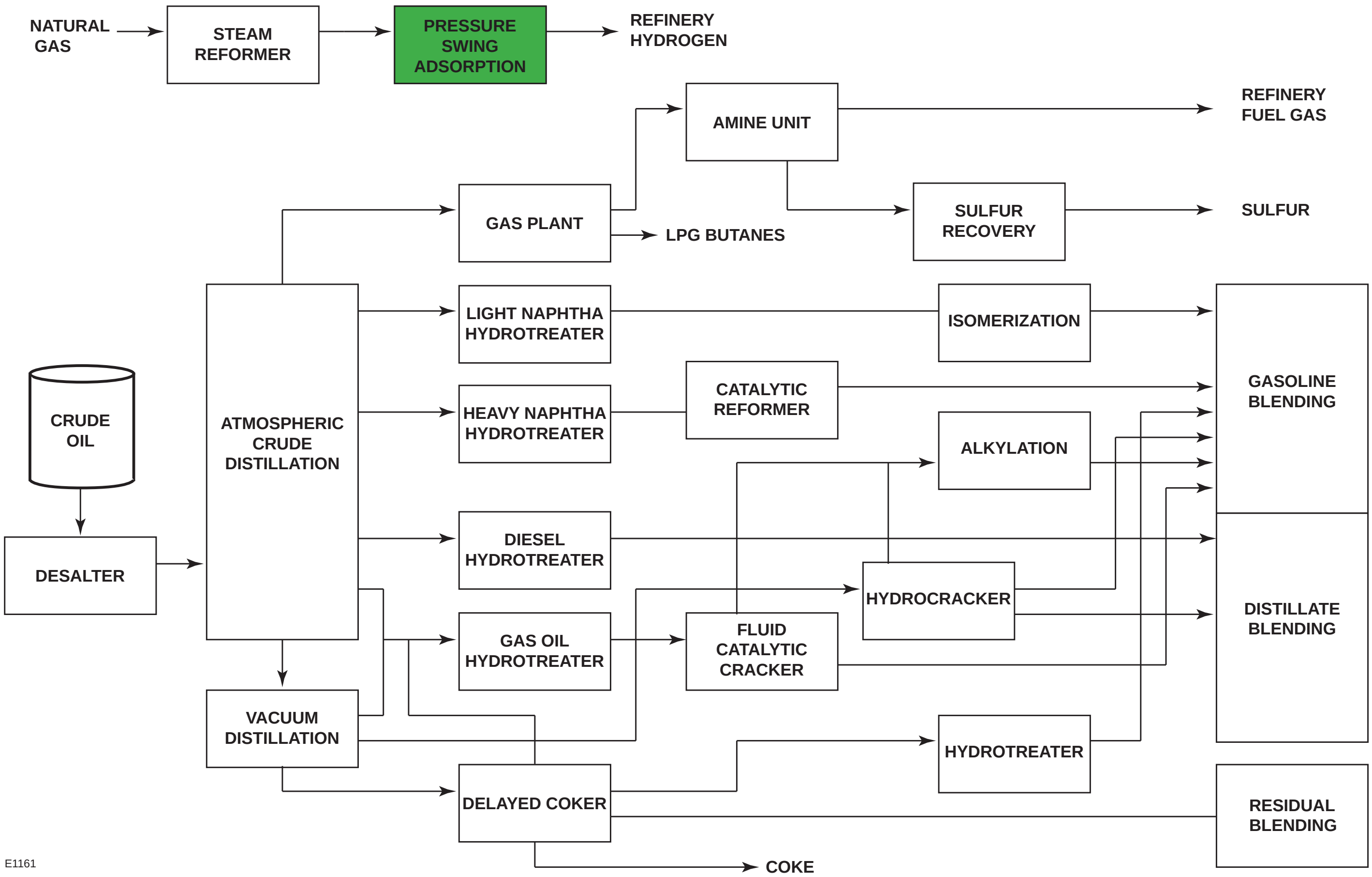


Figure 4.14.1. Pressure Swing Adsorption Unit Location

- **Typical Process Conditions:**
  - — Fluid: Steam
  - — P1 = 41 - 48 barg (595 - 695 psig)
  - — P2 = 10 – 47 barg (145 – 680 psig)
  - — T = 255 - 260°C (490 - 500°F)
  - — Q = 700 – 1,910 kg/h (1,545 – 4,210 lb/h)
- **Typical Control Valve Selection:**
  - — NPS 1 to NPS 2 easy-e EZ or ES
  - — Materials of Construction: WCC body with 300-series SST trim, appropriate for use with steam service
  - — Graphite packing
  - — Class IV shutoff

10. Liquid Sulfur Product Valves

These level valves handle the molten sulfur from the condensers. It is essential that these valves stay over 135°C (275°F) to keep the sulfur flowing, so steam jackets are often used.

- **Typical Process Conditions:**
  - — Fluid: Molten sulfur
  - — T = 165°C (330°F)
- **Typical Control Valve Selection:**
  - — NPS 4 to NPS 8 Vee-Ball
  - — Materials of Construction: WCC body with 300-series SST trim
  - — ENVIRO-SEAL graphite packing
  - — Class IV shutoff

4.14 Pressure Swing Adsorption

Other Names—PSA, hydrogen purification

Pressure Swing Adsorption (PSA) is a process in which a feed gas is separated into a product gas, usually hydrogen, and an off-gas. This is done by alternately pressurizing and depressurizing large vessels containing an adsorption media in a complex sequence. As a result, valves in PSA service see high cycle counts, bi-directional flow, and must achieve tight bi-directional shutoff.

The PSA process is based on the principle that adsorbents are capable of adsorbing more impurities at a higher gas-phase partial pressure than at a lower partial pressure. The impurities are adsorbed in a fixed-bed adsorber at high pressure and then rejected as the system pressure “swings” to a lower level. Hydrogen is not adsorbed. The ability to completely adsorb impurities allows the production of a hydrogen product with very high purity (99.9%).

The basic flow scheme of the PSA process is shown in figure 4.14.3. The process operates at ambient temperature on a cyclic basis. The PSA process is a semi-batch-type process that uses multiple adsorbers to provide constant feed, product, and offgas flows. The high purity hydrogen product leaves the system close to the feed gas pressure. The off-gas (impurities and the hydrogen losses) is available at low pressure as fuel.

In refining, high purity hydrogen is commonly required for sulfur removal and improvement of hydrocarbon products. While sulfur restrictions on gasoline and diesel become increasingly stringent, the demand for hydrogen continues to grow.

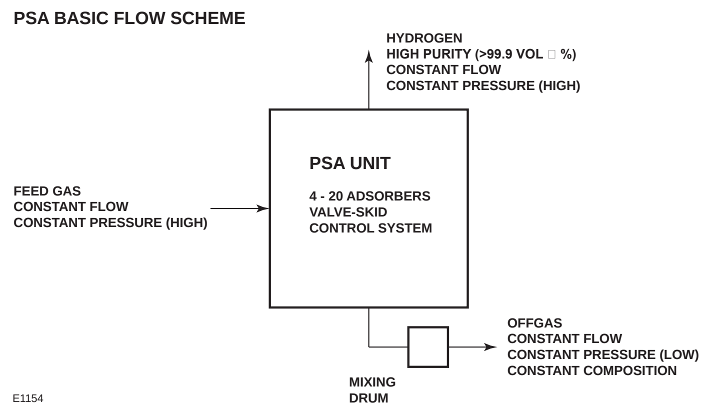


Figure 4.14.2. PSA Basic Flow Scheme

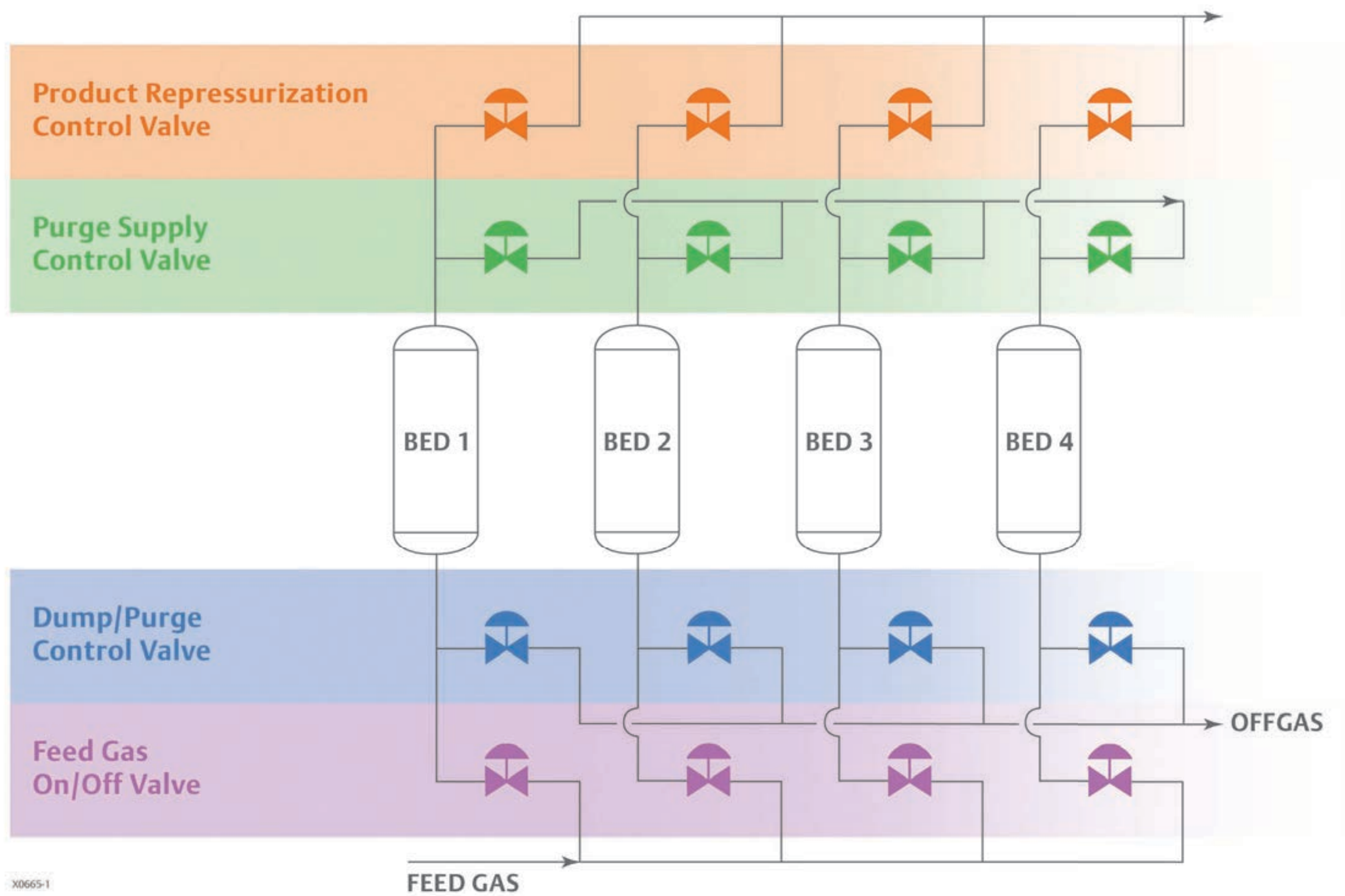


Figure 4.14.3. Four Bed PSA Process Flow Diagram

Maintaining constant hydrogen supply is a challenge in the preparation for production of clean fuels. Additionally, hydrogen management practices impact operating costs, refinery margin and CO_2 emissions considerably. An efficient hydrogen management plan must address issues that encompass the entire refinery in an organized and inclusive way. Effective hydrogen management has improved refinery profitability by millions of dollars annually and helps to avoid the capital cost of new hydrogen production. Profitability improvements and better hydrogen management have been achieved by extending the PSA control valve maintenance interval with modern Fisher valve technologies designed for PSA applications.

PSA Process Overview

A PSA installation consists of four major parts:

1. Adsorber vessels made from carbon steel and filled with adsorbent

2. Valve and piping skid, including all valves and instrumentation, prefabricated and tested in the workshop

3. Control system, which is normally located in a remote control room and contains the cycle controls

4. Mixing drum to minimize the composition variation of the off-gas

A packaged system approach is often used. The process valves and piping are shop mounted on a steel frame and transported to the site as one or more pieces for quick and simple installation.

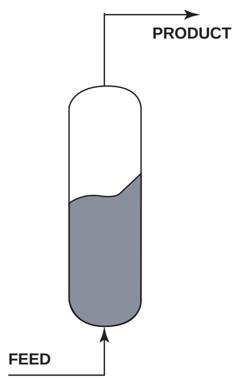
The PSA process is a semi-batch process that uses multiple adsorbers to provide constant feed, product, and off-gas flows. A complete pressure-swing cycle consists of the following five basic steps:

1. Adsorption
2. Co-current Depressurization
3. Counter-current Depressurization
4. Purge at low pressure
5. Repressurization

These basic steps apply to all PSA units regardless of the number of adsorber vessels.

Adsorption (Step 1 to 2)

Feed gas is allowed to pass co-currently through the clean adsorbent bed. Here the impurities are selectively adsorbed, while pure hydrogen product at high pressure exits from the adsorbent bed.



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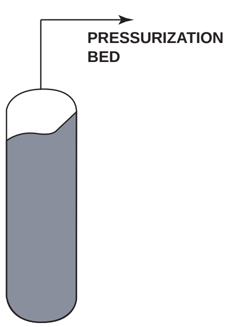

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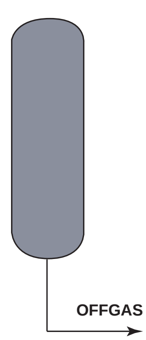
Co-current Depressurization (Step 2 to 3)

After adsorption, the bed has been saturated with impurities and regeneration is needed. For recovering the hydrogen trapped in the void spaces, co-current depressurization makes hydrogen to pass into the repressurizing beds.

Countercurrent Depressurization (Step 3 to 4)

Final depressurization is counter-current and it is able to blow down impurities into the offgas stream.



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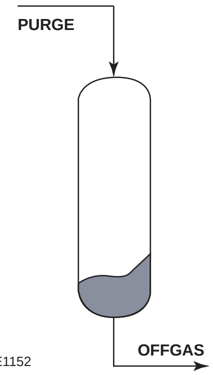
Purge at Low Pressure (Step 4 to 5)

The bed is cleaned at low pressure using hydrogen rich stream that was obtained from another adsorber during the step of co-current depressurization. Impurities are subsequently removed into the offgas stream.



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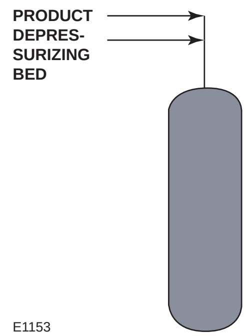

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Repressurization (Step 5 to 1)

To prepare the bed again for adsorption it is repressurized with hydrogen rich gas obtained from a depressurizing adsorber and pure hydrogen product.

PSA Control Valve Application Review

The PSA unit is the backbone of many industries, providing uninterrupted vapor processing to meet the demand for high purity hydrogen. Unfortunately, process facilities are often impacted by control valve problems, which decrease the efficiency of the PSA unit. The PSA unit is a demanding process for control valves. The constant production of vapor requires an extremely high number of cycles, which can lead to damaging effects on the PSA process equipment. Valves and actuators are expected to stroke as often as once every three minutes. Depending on the type and size of the PSA unit, the quantity and type of control valves will vary, creating diverse control valve issues. Control valve shutoff is a major concern because it affects PSA unit efficiency. If valve leakage causes contamination from one PSA bed to another, industrial gas purity can be compromised. Improper selection of control valves can be the limiting factor in achieving PSA purity and longevity requirements.

1A – 1D. Feed Valves

These valves provide the feed gas into the clean adsorbent bed. This valve is either wide open or fully closed, so throttling control is not important. However, it is important that the valve reliably opens or closes when required to do so.

- **Typical Process Conditions:**
  - — Fluid: Hydrogen and light hydrocarbons
  - — P1 = 11 barg (160 psig)
  - — dP = 0.03 bar (0.45 psig)
  - — T = -28 - 45°C (-18 - 115°F)
- **Typical Control Valve Selection:**
  - — NPS 6 8580 with FieldQ actuator
  - — No valve positioner is used on this valve, but a stroking

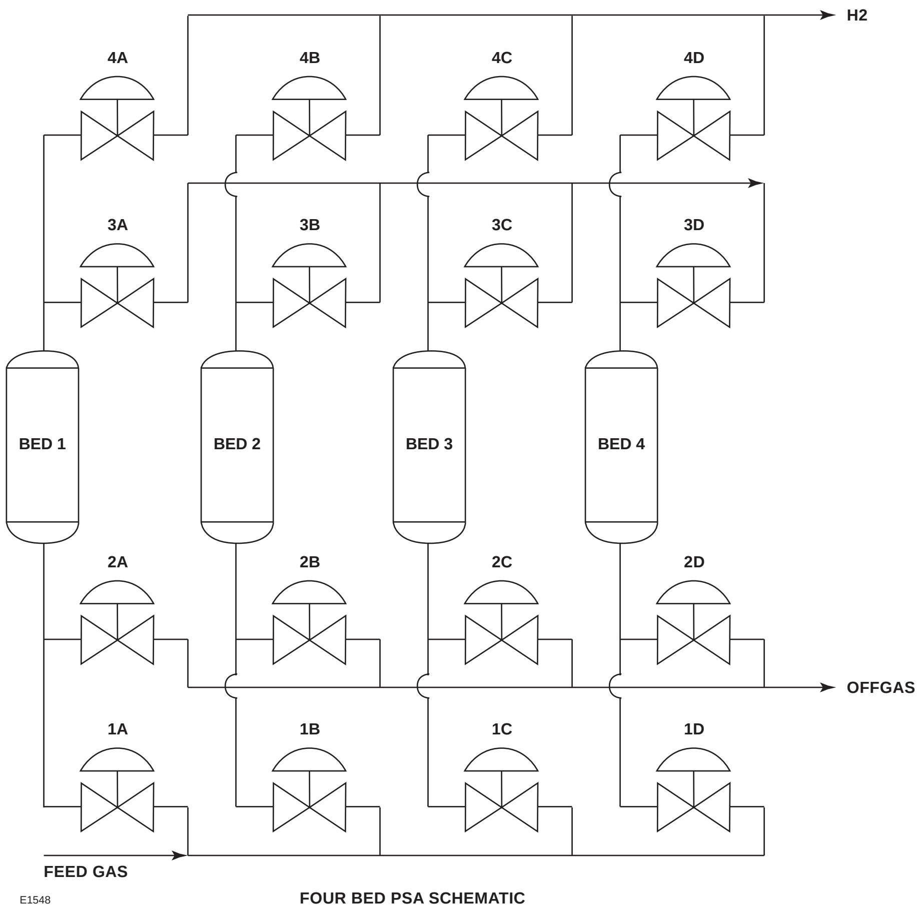

Figure 4.14.4. Four Bed PSA Process Flow Diagram with valve numbers

speed requirement of 2 seconds or less

— Materials of Construction: WCC body with 316 SST disk with reinforced PTFE seal

— ENVIRO-SEAL PTFE packing

— Class VI shutoff

2A – 2D. Dump/Purge Valves

These valves are opened during the depressurization handling the off gas from the adsorbent bed. To remove the off gas, a hydrogen rich stream is purged to the adsorbent bed from another adsorber.

■ **Typical Process Conditions:**

— Fluid: Off gas

— P1 = 0.54 – 2.1 barg (8 – 30 psig)

— dP = 0.02 – 1.6 bar (0.3 – 23 psi)

— T = -28 - 45°C (-18 - 115°F)

■ **Typical Control Valve Selection:**

— NPS 10 8580 with FieldQ actuator

— Stroking speed requirement of 2 seconds or less

— Materials of Construction: WCC body with 316 SST disk with reinforced PTFE seal

— ENVIRO-SEAL PTFE packing

— Class VI shutoff, bi-directional flow

3A – 3D. Providing Purge Valves

These valves provide a hydrogen rich purge stream from one adsorber to a second adsorber to remove off gas from the second adsorbent bed.

■ **Typical Process Conditions:**

— Fluid: Hydrogen

— P1 =2.1 – 6.6 barg (30 – 95 psig)

— dP = 0.66 – 5.5 bar (10 – 80 psi)

— T = -28 – 45°C (-18 - 115°F)

■ **Typical Control Valve Selection:**

— NPS 3 GX

— Stroking speed requirement of 2 seconds or less

— Materials of Construction: WCC body with 316L SST Ion Nitrided plug and PTFE seat

— Live-loaded PTFE packing

— Class VI shutoff, bi-directional flow

4A – 4D. Equalization Valves

■ **Typical Process Conditions:**

— Fluid: Hydrogen

— P1 = 11 barg (160 psig)

— dP = 0.12 – 5.2 bar (1.7 – 75 psi)

— T = -28 – 45°C (-18 - 115°F)

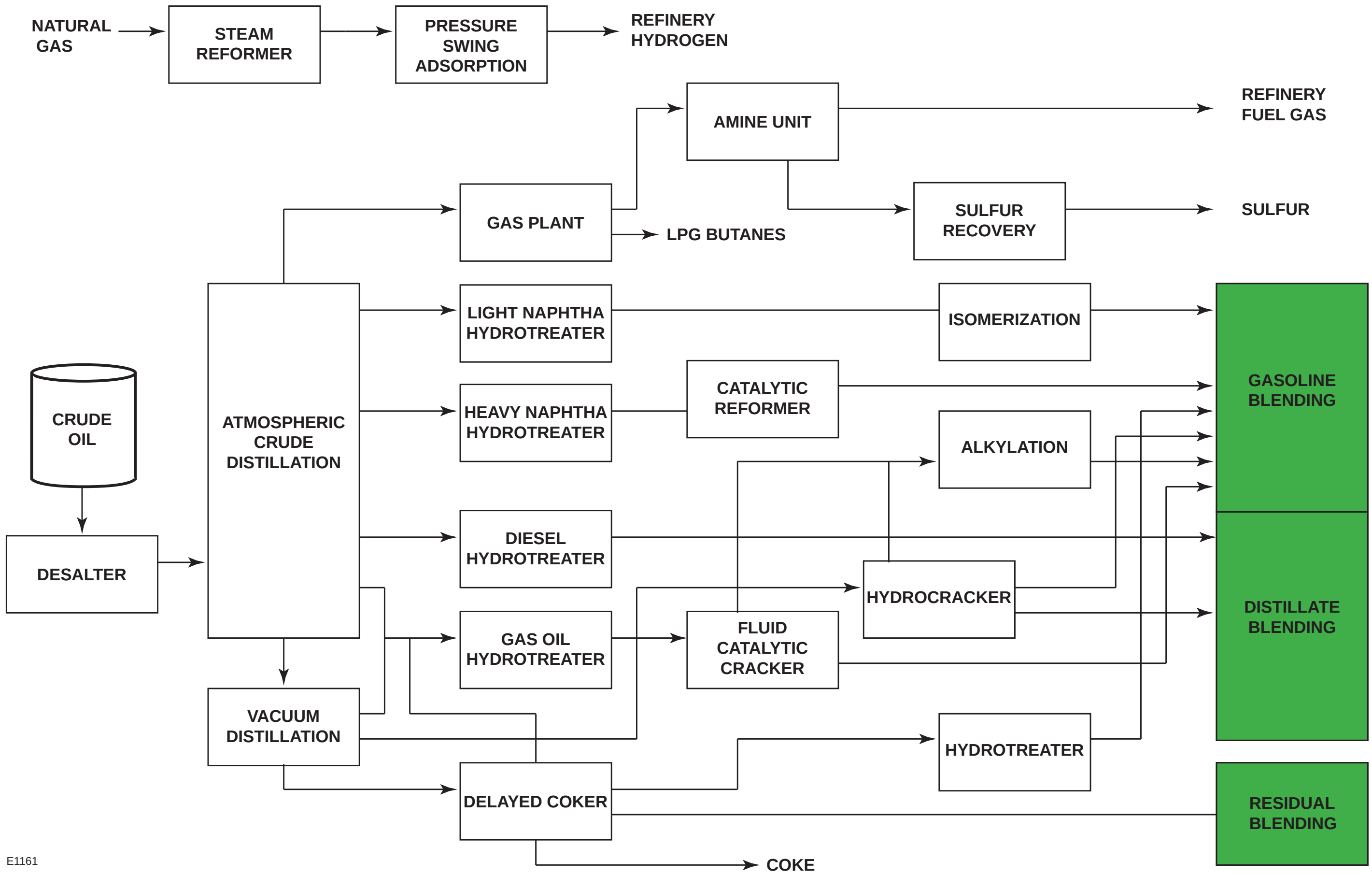

Figure 4.15.1. Blending Unit Locations

- **Typical Control Valve Selection:**
  - — NPS 3 8580 with FieldQ actuator
  - — Stroking speed requirement of 2 seconds or less
  - — Materials of Construction: WCC body with 316 SST disk and reinforced PTFE (RPTFE) seal
  - — ENVIRO-SEAL PTFE packing
  - — Class VI shutoff, bi-directional flow

5A-5D. Product/Repressurization Valves

These valves control the pure hydrogen product processed in the PSA unit. Hydrogen from the PSA unit is used in many refining processes.

- **Typical Process Conditions:**
  - — Fluid: Hydrogen
  - — P1 = 11 barg (160 psig)
  - — dP = 0.12 – 5.22 bar (1.7 – 75 psi)
  - — T = -28 – 45°C (-18 - 115°F)
- **Typical Control Valve Selection:**
  - — NPS 3 8580 with FieldQ actuator
  - — Stroking speed requirement of 2 seconds or less
  - — Materials of Construction: WCC body with 316 SST disk and reinforced PTFE (RPTFE) seal
  - — ENVIRO-SEAL PTFE packing
  - — Class VI shutoff

4.15 Blending Unit

Other Names—Blender

Products made in various refining units are blended in appropriate ratios to meet final product specifications of gasoline, diesel, or other products that are shipped out of the refinery via pipelines, trucks, trains, or barges.

A blending unit creates a finished refinery product stream. The most common type is a gasoline blender. However, blenders are also used for other products, such as diesel or jet fuel.

A gasoline blender can create several different products from the same available components. For example, most refineries produce three octane grades of unleaded gasoline. There are different specifications on gasoline vapor pressure depending on whether it is summer or winter. Also, different regional environmental requirements exist depending on where the gasoline is to be marketed. Each of these considerations requires a different mix of the gasoline components produced by the refinery.

For a given gasoline product there will be a calculated recipe for how much of each component should go into the product tank. The flow controller from each component tank will be set accordingly.

Note that the most frequent problems encountered within blenders are not usually caused by control valves. Inaccurate lab, faulty on-line analyzer results, or biased flow indications pose far greater problems. In addition, there are lineup valves used to connect tanks that are either opened or closed. The lineup valves, whether manually or automatically manipulated, have the potential for ruining an entire tank (or tanks) of product if not set to the correct position.

The consequence of poor blending can be severe. Product specification giveaway can easily cost $0.05 to $0.10/BBL of gasoline, or $150M to $300M per year for every 10 MBPD of gasoline produced.

Blending Unit Application Review

1.,2.,3.,4. Component Valves

The example above is based on 20 MBPD of gasoline production. These valves are manipulated by flow control loops. The flows are set according to product recipe requirements. Many blenders have advanced control algorithms to monitor the flow through these valves.

A sticking valve is usually of no consequence to blending operation as long as the average flow target is met. A stuck valve is a bigger problem if it goes unnoticed and the blend is being done manually.

Once discovered, the control valve can be blocked in and bypassed. However, the amount of flow for that component must be recalculated to make up for the deviation from flow setpoint by the end of the blend for that product tank. Most blend control packages can pick up and correct this particular problem.

- **Typical Process Conditions:**
  - — Fluid: Gasoline
  - — P1 = 4.8 – 5.9 barg (70 - 85 psig)
  - — P2 = 3.4 – 4.1 barg (50 - 60 psig)
  - — T = 27 - 38°C (80 - 100°F)
  - — Q = 200 – 665 m3/h (880 – 2930 gpm)
- **Typical Control Valve Selection:**
  - — NPS 2 to NPS 6 Control-Disk or NPS 3 to NPS 6 Vee-Ball
  - — Materials of Construction: WCC body with 300-series SST trim
  - — PTFE packing
  - — Class IV or V shutoff

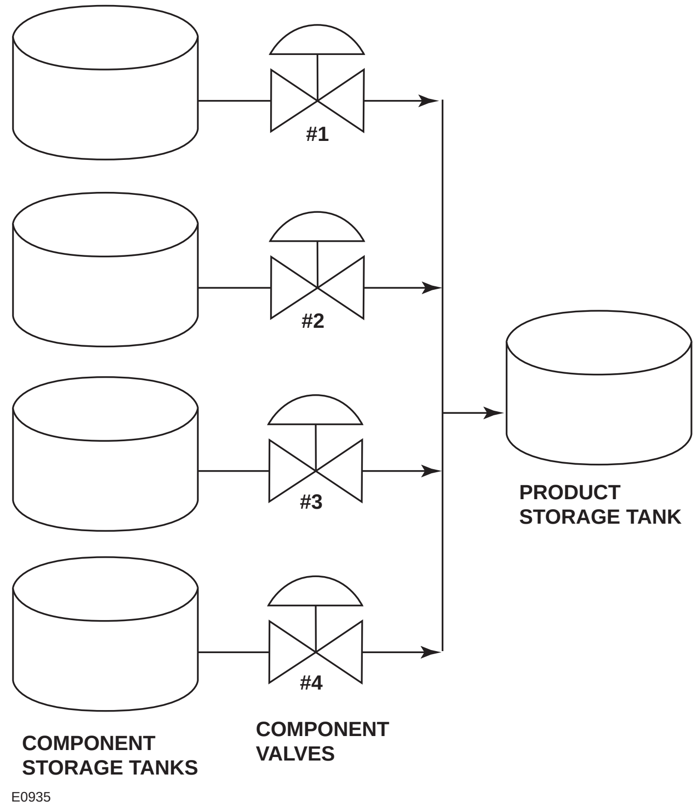

Figure 4.15.2. Blending Unit Process Flow Diagram

Terminology

5

This section will go through common terminology for key applications and solutions in the refining industry.

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5.1 Refining Terminology

Acid Gas: Gas stream containing hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2).

Adsorbents: Special materials like activated charcoal, alumina or silica gel, used in an adsorption process that selectively cause some compounds, but not others, to attach themselves mechanically as liquids.

Adsorption: A separation process in which gas molecules condense or liquid molecules crystallize onto a solid that has a porous surface. The pore size dictates the selectivity of the solid for a particular solute.

Alkylate: The product of an alkylation process. Alkylate Bottoms: A thick, dark-brown oil containing high-molecular-weight polymerization products of alkylation reactions.

Alkylation: A polymerization process uniting olefins and isoparaffins, particularly, the reacting of butylene and isobutane, with sulfuric acid or hydrofluoric acid as a catalyst, to produce a high-octane, lowsensitivity blending agent for gasoline.

Amines: Chemical solvent for the removal of H_2S and CO_2 from natural gas streams. Common amines include monoethanolamine (MEA) and diethanolamine (DEA).

Aromatics: Cyclic hydrocarbons in which five, six, or seven carbon atoms are linked in a ring structure with alternating double and single bonds. Common aromatics in refinery streams are benzene, toluene, xylene, and naphthalene.

Asphalt: A heavy, semi-solid petroleum product that gradually softens when heated and is used for surface cementing. Typically, brown or black in color, it is composed of high carbon-to-hydrogen hydrocarbons plus some oxygen. It occurs naturally in crude oil or can be distilled or extracted. Also, The end product used for area surfacing consisting of refinery asphalt mixed with aggregate.

Barrel: A standard of measurement in the oil industry: equivalent 42 US gallons, 35 Imperial gallons, or 159 liters.

Benzene (C_6H_6): A chemical consisting a six-carbon ring connected by with double and single bonds. Benzene has excellent octane characteristics but it is carcinogenic and therefore it's content in gasoline is limited severely by regulation. Benzene is used in a large number of chemical processes including styrene and detergents.

Blending: One of the final operations in refining in which two or more components are mixed to obtain a specified range of properties in the finished product.

Boiling point: The temperature at which a liquid will boil. (See end point and initial boiling point.)

Bottoms: In general, the higher boiling residue that is removed from the bottom of a fractionating column.

Bubble cap tray: The trays in a fractionator consisting of a plate with hole and bubble caps. The latter cause the vapor coming from the bottom to come in intimate contact with the liquid sitting on the tray.

Catalyst: A substance present in a chemical reaction that will promote or cause the reaction, but not take part in it by chemically changing itself. Sometimes used to lower the temperature or pressure at which the reaction takes place or speed it up.

Catalytic cracking: A central process in refining in which heavy gas oil range feeds are subjected to heat in the presence of a catalyst and large molecules crack into smaller molecules in the gasoline and surrounding ranges.

Catalytic reforming: The process in refining in which naphthas are changed chemically to increase their octane numbers. Paraffins are converted to iso-paraffins and naphthenes are converted to aromatics. The catalyst is platinum and sometimes palladium.

Catalyst Activity: A catalyst sample is reacted, under standard cracking conditions with a standard feedstock. The yield of gasoline obtained is a measure of the activity of the catalyst, i.e., its tendency to convert feedstock to gasoline.

Coke: A product of the coking process in the form of solid, densely packed carbon atoms. Various forms of coke include green coke , a run of the mill coke from most cokers; sponge coke, the same as green coke and notable by its fine, sponge-likestucture; calcinable coke, a high grade of coke that is suitable for making industrial product; needle coke, avery high grade of coke characterized by crystalline structure. Also, deposits of carbon that settle on catalysts in cat crackers, cat reformers, hydrocrackers, and hydrotreaters and degrade their effectiveness.

Coker: A refinery process in which heavy feed such as flasher bottoms cycle oil from a cat cracker or thermal crack gas oil cooked at high temperatures. Cracking creates light oils; coke form in the reactors and needs to be removed after they fill up.

Condensate: The relatively small amount of liquid hydrocarbon, typically C4's through naphtha or oil gas that gets produced in the oil patch with an unassociated gas. Also, the liquid formed when a vapor cools.

Conversion: A measure of quantity of feed converted into lighter products. Conversion is calculated by subtracting the percent yield of material heavier than gasoline from 100. Standard conversion is based on a 430°F TBP cut point gasoline.

Cracked gas: The C4 stream coming from a cat cracker, coker or thermal cracker, containing olefins in addition to the saturated paraffins.

Cracked gas plants: The set of column and treaters in refinery that handle separation and treating of the cracked, olefinic gases.

Cracking: The breaking down of higher molecular-weight hydrocarbons to lighter components by application of heat. Cracking in the presence of a catalyst improves product yield and quality over those obtained in simple thermal cracking.

Cycle Gas Oil: This designation is given to all liquid products from the cracking process boiling above gasoline.

Debutanizer: A tower in which butane is removed by distillation from a hydrocarbon stream.

De-coking: The process of removing coke from catalyst in a cat cracker, cat reformer, hydrocracker, or hydrotreater. Usually heated air will oxidize the coke to carbon monoxide or carbon dioxide.

Delayed coker: A process unit in which residue is cooked until it cracks to coke & light products.

Deisobutanizer: A distillation column in which isobutane is removed from a petroleum fraction.

Diesel: 1. An internal combustion engine in which ignition occurs by injecting fuel in a cylinder where air has been compressed and is at a very high temperature, causing self-ignition. 2. Distillate fuel used in a diesel engine.

Distillate: A product of distillation, or the fluid condensed from the vapor driven off during distillation. Gasoline, naphtha, kerosene, and light lubricating oils are examples of distillates.

Distillation: A physical separation process in which different hydrocarbon fractions are separated by means of heating, vaporization, fractionation, condensation, and cooling.

Endothermic Reaction: A reaction in which must be added to maintain reactants and products at a constant temperature.

Exothermic Reaction: A reaction in which heat is evolved. Alkylation, polymerization, and hydrogenation reactions are exothermic.

Fixed bed: A place in a vessel for catalyst through or by which feed can be passed for reaction; as opposed to a fluid bed, where the catalyst moves with the feed.

Fluid catalytic cracking (FCC): The most popular design of cat cracking in which a powdery catalyst that flows like a fluid is mixed with the feed and the reaction takes place as the feed/ catalyst is in motion.

Fractionation: A counter-current operation in which a vapor mixture is repeatedly brought in contact with liquids having nearly the same composition as the respective vapors, liquids are at their boiling points; hence part of the vapor is condensed and part of the liquid is vaporized during each contact. In a series of contact treatments, the vapor finally becomes rich in low boiling components, and the liquid becomes rich in high-boiling components.

Fractionator: A closed cylindrical tower arranged with trays through which distilled gas/liquid is caused to bubble. The trays retain a portion of the condensed liquid and thus separate the heavier fractions of the gas/liquid from the lighter fractions of gas/liquid. Also called stabilizer column, fractionating tower, or bubble tower.

Fuel oil: Usually residual fuel but sometimes distillate fuel.

Furnace oil: A distillate fuel made of cracked or straight run light gas oils, primary for domestic heating because of its ease of handling and storing.

Gas Oil: That material boiling within the general range of 150°C to 400°C (300°F to 750°F). This range usually includes kerosene, diesel fuel, heating oils, and light fuel oils. Actual initial and final cut points are determined by specifications of the desired products.

Gasoline: A light petroleum product in the range of approximately 25° C to 205° C (80°F to 400°F) for use in spark ignited internal combustion engines.

Heat exchanger: An apparatus of transferring heat from one liquid or vapor stream to another. A typical heat exchanger will have a cylindrical vessel through which one stream can flow and a set of pipes or tubes in series in the cylinder through which the other can flow. Heat transfers through the tubes by conduction.

Heating oil: Any distillate or residual fuel.

Heavy Gas Oil: A distillate product composed of material having a cut point of 345°C to 425°C (650°F to 800°F). The heavy gas oil is then sent to the catalytic cracker as feed.

HF alkylation: Alkylation using hydrofluoric acid as a catalyst.

Hydrocarbon: Any organic compound comprised of hydrogen and carbon, including crude oil, natural gas, and coal.

Hydrocracking: The breaking of hydrocarbon chains into smaller compounds in the presence of hydrogen and a catalyst. The end result is high quality gasoline and isobutene, which is then used in the alkylation plant.

Hydrodesulfurization: A sub-process of hydrotreating. Used primarily to remove sulfur from the crude feedstock and finished products utilizing a selected catalyst in a hydrogen environment.

Hydrogeneration: Filling in with hydrogen the “free” places around the double bonds in an unsaturated hydrocarbon molecule.

Hydrotreating: A process used to saturate olefins and improve hydrocarbon streams by removing unwanted materials such as nitrogen, sulfur, and metals utilizing a selected catalyst in a hydrogen environment.

Isomerization: The rearrangement of straight-chain hydrocarbon molecules to form branched-chain products. Pentanes and hexanes, which are difficult to reform, are isomerized by the use of aluminum chloride or precious-metal catalysts to form gasoline-blending components of high octane value. Normal butane may be isomerized to provide a portion of the isobutane feed needed for alkylation processes.

Isomers: Two compounds composed of the identical atoms, but with different configurations, giving different physical properties.

Kerosene: A middle-distillate product composed of material of 150°C to 285°C (300°F to 550°F). The exact cut is determined by various specifications of the finished kerosene.

Light Ends: Hydrocarbon fractions in the butane and lighter boiling range.

Light Gas Oil:A distillate product composed of material having a cut point of 230°C to 345°C (450°F to 650°F).

Liquified Petroleum Gas (LPG): Liquified light-end gases used for home heating and cooking. This gas is usually 95 percent propane, and the remainder consists of equal parts of ethane and butane.

Middle Distillates: Atmospheric pipe-still cuts boiling in the range of 150°C to 370°C (300°F to 700°F). The exact cut is determined by the specifications of the products.

Naphtha: A pipe-still cut in the range of 70°C to 215°C (160°F to 420°F), Pentanes (C5) are the lower boiling naphthas, at approximately 70°C (160°F). Naphthas are subdivided according to the actual pipe-still cuts into light, intermediate, heavy and very heavy virgin naphthas. The quantity of the individual cut varies with the crude. A typical pipe-still operation would yield:

C5- 70°C (160°F) - Light virgin naphtha

70°C to 140°C (160°F to 280°F) - Intermediate virgin naphtha

140°C to 165°C (280°F to 330°F) - Heavy virgin naphtha

165°C to 215°C (330°F to 420°F) - Very heavy virgin naphtha

Naphthas, the major constituents of gasoline, generally must be further processed to make suitable quality gasoline.

Naphthenic acids: Organic acids occurring in petroleum that contain a naphthene ring and one or more carboxylic acid groups. Naphthenic acids are used in the manufacture of paint driers and industrial soap.

Natural Gas: Naturally occurring gas consisting predominantly of methane, sometimes in conjunction with crude (associated gas), sometimes alone(unassociated gas).

Octane number: An index measured by finding a blend of iso-octane and normal heptane that knocks under the identical conditions as the gasoline being evaluated. It is a measure of the resistance to ignition of the fuel without the aid of a spark plug. The higher the octane number, the more resistance to pre-or self-ignition.

Petroleum coke: (See coke).

Polymerization: The combination of two or more unsaturated molecules to form a molecule of higher molecular weight. Propylenes and butylenes are the primary feed material for refinery polymerization processes, which use solid or liquid phosphoric acid catalysts.

Quench: Hitting a very hot stream coming out of a reactor, with a cooler stream to stop immediately the reaction underway.

Reactor: The vessel in which the chemical reaction takes place.

Reboiler: A heat exchanger used towards the bottom of a fractionator to re-heat or even vaporize a liquid and introduce it several trays higher to get more heat into the column to improve separation.

Reflux: A heat exchanger, which takes vapor from the upper parts of a fractionator, cools it to liquefy it and reintroduces it lower column. The purpose is to assure sufficient downward liquid flow meeting the rising vapor to improve separation.

Reformate: A high octane, primary product of reforming naphtha.

Reforming: See catalytic reforming or steam methane reformer.

Regenerator: The vessel in the catalytic process where a spent catalyst is brought back up to strength before being recycled back to the process. An example is the cat cracker regenerator where coke is burned off the catalyst.

Regenerated Catalyst: Catalyst after the carbon has been burnt off. Specifically, it refers to catalyst after it has passed through the regenerator.

Reid vapor pressure (RVP): The pressure necessary to keep a liquid from continually vaporizing as measure in an apparatus design by Reid himself. Use as a standard measure for gasoline specification.

Riser: A pipe used to carry the catalyst to a higher level under the lifting force of an aerating medium such as air, steam, or oil vapors. The unit has two risers: spent catalyst and reactor.

Residue: The bottoms from a crude oil distilling unit, vacuum flasher, thermal cracker, or visbreaker. See long residue and short residue.

Sats gas plant: The sets of columns and treaters in a refinery that handle separation and treatment of the saturated gases.

Sour or Sweet Crude: A general classification of crudes according to sulfur content. Various definitions are available:

Sour Crude: A crude that contains sulfur in amounts greater than 0.5 to 1.0 percent or that contains 0.05 ft^3 or more of hydrogen sulfide (H_2S) per 100 gallon. The exception is West Texas crude, which is always considered sweet regardless of content. Although of high sulfur content, this crude does not contain highly active sulfur compounds.

Sweet Crude: A sweet crude contains little or no dissolved hydrogen sulfide and relatively small amounts of mercaptans and other sulfur compounds.

Spent Catalyst: Catalyst after use in the cracking reaction. Specifically it refers to catalyst leaving the reactor stripper.

Sponge oil: The liquid used in an absorption plant to soak up the constituent to be extracted.

Stabilization: A fractionation operation conducted for the purpose of removing high-vapor-pressure components.

Stabilizer: A fractionator use to remove most of the light ends from straight run gasoline or natural gasoline to make them less volatile.

Steam methane reformer: A primary source of hydrogen in a refinery, this operating units converts methane and steam to hydrogen, with by product carbon monoxide and carbon dioxide.

Stripping: An operation in which the significant or desired transfer of material is from the liquid to the vapor phase.

Sweet crude: Crude typically containing 0.5% (by weight) or less sulfur.

Sweetening: The removal of sulfur compounds or their conversion to innocuous substances in a petroleum product by any of several processes (doctor treating, caustic and water washing, etc.).

Tail Gas: Light gases (C1 to C3 and H_2) produced as byproducts of refinery processing.

Thermal Cracking: The breaking of hydrocarbon molecules into smaller compounds. Coking and visbreaking are severe forms of thermal cracking.

Topped crude: Crude that has been run through a distilling unit to remove the gas oil and lighter streams. The so-called simple refineries that do this sell the long residue as residual fuel.

Topping: Removal by distillation of the light products from crude oil, leaving in the still all the heavier constituents.

Unsaturated: A class of hydrocarbons similar to paraffins and naphthenes but that has double bonds or triple bonds replacing the missing hydrogen.

Vacuum distillation: Distillation under reduced pressure in order to keep the temperature low and prevent cracking. Most often used to distill lubricant feedstock.

Vapor pressure: (See Reid vapor pressure).

Visbreaking: Mild thermal cracking aimed at producing sufficient middle distillates to reduce the viscosity of the heavy feed.

Viscosity: The property of liquids under flow conditions that causes them to resist instantaneous change of shape or instantaneous rearrangement of their parts due to internal friction. Viscosity is generally measured as the number of seconds, at a definite temperature, required for a standard quantity of oil-to-flow through a standard apparatus. Common viscosity scales in use are Saybolt Universal, Saybolt Furol, and Kinematic (Stokes).

Volatile: A hydrocarbon is volatile if it has a sufficient amount of butanes and lighter material to noticeable give off vapors at atmospheric conditions.

Wet Gas: Natural gas that has not had the C4 and natural gasoline removed. Also, the equivalent of refinery gas stream.

Yield: Either the amount of the desired products or all the products resulting from a process involving chemical change of the feed.

5.2 Process Control Terminology

Accessory: A device that is mounted on the actuator to complement the actuator's function and make it a complete operating unit. Examples include positioners, supply pressure regulators, solenoids, and limit switches.

Actuator: A pneumatic, hydraulic, or electrically powered device that supplies force and motion to open or close a valve.

Actuator Assembly: An actuator, including all the pertinent accessories that make it a complete operating unit.

Backlash: The general name given to a form of dead band that results from a temporary discontinuity between the input and output of a device when the input of the device changes direction. Slack, or looseness of a mechanical connection, is a typical example.

Capacity (Valve): The rate of flow through a valve under stated conditions.

Closed Loop: The interconnection of process control components such that information regarding the process variable is continuously fed back to the controller set point to provide continuous, automatic corrections to the process variable.

Controller: A device that operates automatically by use of some established algorithm to regulate a controlled variable. The controller input receives information about the status of the process variable and then provides an appropriate output signal to the final control element.

Control Loop: (See Closed Loop.)

Control Range: The range of valve travel over which a control valve can maintain the installed valve gain between the normalized values of 0.5 and 2.0.

Control Valve: (See Control Valve Assembly.)

Control Valve Assembly: Includes all components normally mounted on the valve: the valve body assembly, actuator, positioner, air sets, and transducers, limit switches, etc.

Deadband: The range through which an input signal can be varied, upon reversal of direction, without initiating an observable change in the output signal. Dead band is the name given to a general phenomenon that can apply to any device. For the valve assembly, the controller output (CO) is the input to the valve assembly and the process variable (PV) is the output. When the term Dead Band is used, it is essential that both the input and output variables are identified, and that any tests to measure dead band be under fully loaded conditions. Dead band is typically expressed as a percent of the input span.

Dead Time: The time interval (Td) in which no response of the system is detected following a small (usually 0.25% - 5%) step input. It is measured from the time the step input is initiated to the first detectable response of the system being tested. Dead Time can apply to a valve assembly or to the entire process. (See T63.)

Disk: A valve trim element used to modulate the flow rate with either linear or rotary motion. Can also be referred to as a valve plug or closure member.

Equal Percentage Characteristic: An inherent flow characteristic that, for equal increments of rated travel; will ideally give equal percentage changes of the flow coefficient (Cv).

Final Control Element: The device that implements the control strategy determined by the output of the controller. While the final control element can be a damper, a variable speed drive pump, or an on-off switching device, the most common final control element in the process control industries is the control valve assembly. The control valve manipulates a flowing fluid, such as gasses, steam, water, or chemical compounds, to compensate for the load disturbance and keep the regulated process variable as close as possible to the desired set point.

First-Order: A term that refers to the dynamic relationship between the input and output of a device. A first-order system or device is one that has only one energy storage device and whose dynamic transient relationship between the input and output is characterized by an exponential behavior.

Friction: A force that tends to oppose the relative motion between two surfaces that are in contact with each other. The friction force is a function of the normal force holding these two surfaces together and the characteristic nature of the two surfaces. Friction has two components: static friction and dynamic friction. Static friction is the force that must be overcome before there is any relative motion between the two surfaces. Once relative movement has begun, dynamic friction is the force that must be overcome to maintain the relative motion. Running and sliding friction are colloquial terms that are sometimes used to describe dynamic friction. Stick/slip or “stiction” are colloquial terms that are sometimes used to describe static friction. Static friction is one of the major causes of dead band in a valve assembly.

Gain: An all-purpose term that can be used in many situations. In its most general sense, gain is the ratio of the magnitude of the output change of a given system or device to the magnitude of the input change that caused the output change. Gain has two components: static gain and dynamic gain. Static gain is the gain relationship between the input and output and is an indicator of the ease with which the input can initiate a change in the output when the system or device is in a steady-state condition. Sensitivity is sometimes used to mean static gain. Dynamic gain is the gain relationship between the input and output when the system is in a state of movement or flux. Dynamic gain is a function of frequency or rate of change of the input.

Hysteresis: The maximum difference in output value for any single input value during a calibration cycle, excluding errors due to dead band.

Inherent Characteristic: The relationship between the flow coefficient and the closure member travel as it is moved from the closed position to rated travel with constant pressure drop across the valve. Typically these characteristics are plotted on a curve where the horizontal axis is labeled in percent travel and the vertical axis is labeled as percent flow (or Cv). Because valve flow is a function of both the valve travel and the pressure drop across the valve, conducting flow characteristic tests at a constant pressure drop provides a systematic way of comparing one valve characteristic design to another. Typical valve characteristics conducted in this manner are named Linear, Equal-Percentage, and Quick Opening.

Inherent Valve Gain: The magnitude ratio of the change in flow through the valve to the change in valve travel under conditions of constant pressure drop. Inherent valve gain is an inherent function of the valve design. It is equal to the slope of the inherent characteristic curve at any travel point and is a function of valve travel.

Installed Characteristic: The relationship between the flow rate and the closure member travel as it is moved from the closed position to rated travel as the pressure drop across the valve is influenced by the varying process conditions.

Installed Valve Gain: The magnitude ratio of the change in flow through the valve to the change in valve travel under actual process conditions. Installed valve gain is the valve gain relationship that occurs when the valve is installed in a specific system and the pressure drop is allowed to change naturally according to the dictates of the overall system. The installed valve gain is equal to the slope of the installed characteristic curve, and is a function of valve travel.

I/P: Shorthand for current-to-pressure (I-to-P). Typically applied to input transducer modules.

Linearity: The closeness to which a curve relating to two variables approximates a straight line. (Linearity also means that the same straight line will apply for both upscale and downscale directions. Thus, dead band as defined above would typically be considered a non-linearity.)

Linear Characteristic: An inherent flow characteristic that can be represented by a straight line on a rectangular plot of flow coefficient (Cv) versus rated travel. Therefore equal increments of travel provide equal increments of flow coefficient, Cv.

Loop: (See Closed Loop.)

Loop Gain: The combined gain of all the components in the loop when viewed in series around the loop. Sometimes referred to as open-loop gain. It must be clearly specified whether referring to the static loop gain or the dynamic loop gain at some frequency.

Manual Control: (See Open Loop.)

Open Loop: The condition where the interconnection of process control components is interrupted such that information from the process variable is no longer fed back to the controller set point so that corrections to the process variable are no longer provided. This is typically accomplished by placing the controller in the manual operating position.

Packing: A part of the valve assembly used to seal against leakage around the valve disk or stem.

Positioner: A position controller (servomechanism) that is mechanically connected to a moving part of a final control element or its actuator and that automatically adjusts its output to the actuator to maintain a desired position in proportion to the input signal.

Process: All the combined elements in the control loop, except the controller. The process typically includes the control valve assembly, the pressure vessel or heat exchanger that is being controlled, as well as sensors, pumps, and transmitters.

Process Gain: The ratio of the change in the controlled process variable to a corresponding change in the output of the controller.

Process Variability: A precise statistical measure of how tightly the process is being controlled about the set point. Process variability is defined in percent as typically (2s/m), where m is the set point or mean value of the measured process variable and s is the standard deviation of the process variable.

Quick Opening Characteristic: An inherent flow characteristic in which a maximum flow coefficient is achieved with minimal closure member travel.

Relay: A device that acts as a power amplifier. It takes an electrical, pneumatic, or mechanical input signal and produces an output of a large volume flow of air or hydraulic fluid to the actuator. The relay can be an internal component of the positioner or a separate valve accessory.

Resolution: The minimum possible change in input required to produce a detectable change in the output when no reversal of the input takes place. Resolution is typically expressed as a percent of the input span.

Response Time: Usually measured by a parameter that includes both dead time and time constant. (See T63, Dead Time, and Time Constant.) When applied to the valve, it includes the entire valve assembly.

Second-Order: A term that refers to the dynamic relationship between the input and output of a device. A second- order system or device is one that has two energy storage devices that can transfer kinetic and potential energy back and forth between themselves, thus introducing the possibility of oscillatory behavior and overshoot.

Sensor: A device that senses the value of the process variable and provides a corresponding output signal to a transmitter. The sensor can be an integral part of the transmitter, or it may be a separate component.

Set Point: A reference value representing the desired value of the process variable being controlled.

Shaft Wind-Up: A phenomenon where one end of a valve shaft turns and the other does not. This typically occurs in rotary-style valves where the actuator is connected to the valve closure member by a relatively long shaft. While seal friction in the valve holds one end of the shaft in place, rotation of the shaft at the actuator end is absorbed by twisting of the shaft until the actuator input transmits enough force to overcome the friction.

Sizing (Valve): A systematic procedure designed to ensure the correct valve capacity for a set of specified process conditions.

Stiction: (See Friction.)

T63 (Tee-63): A measure of device response. It is measured by applying a small (usually 1-5%) step input to the system. T63 is measured from the time the step input is initiated to the time when the system output reaches 63% of the final steady-state value. It is the combined total of the system Dead Time (Td) and the system Time Constant (t). (See Dead Time and Time Constant.)

Time Constant: A time parameter that normally applies to a first-order element. It is the time interval measured from the first detectable response of the system to a small (usually 0.25% - 5%) step input until the system output reaches 63% of its final steady-state value. (See T63.) When applied to an open-loop process, the time constant is usually designated as τ (Tau). When applied to a closed-loop system, the time constant is usually designated as λ (Lambda).

Transmitter: A device that senses the value of the process variable and transmits a corresponding output signal to the controller for comparison with the set point.

Travel: The movement of the closure member from the closed position to an intermediate or rated full open position.

Travel Indicator: A pointer and scale used to externally show the position of the closure member typically with units of opening percent of travel or degrees of rotation.

Trim: The internal components of a valve that modulate the flow of the controlled fluid.

Valve: (See Control Valve Assembly.)

Volume Booster: A stand-alone relay is often referred to as a volume booster or simply booster because it boosts, or amplifies, the volume of air supplied to the actuator. (See Relay.)

5.3 Sliding-Stem Control Valve Terminology

Actuator Spring: A spring, or group of springs, enclosed in the yoke or actuator casing that moves the actuator stem in a direction opposite to that created by diaphragm pressure.

Actuator Stem: The part that connects the actuator to the valve stem and transmits motion (force) from the actuator to the valve.

Actuator Stem Extension: An extension of the piston actuator stem to provide a means of transmitting piston motion to the valve positioner.

Actuator Stem Force: The net force from an actuator that is available for actual positioning of the valve plug.

Angle Valve: A valve design in which one port is co-linear with the valve stem or actuator, and the other port is at a right angle to the valve stem. (See also Globe Valve.)

Bellows Seal Bonnet: A bonnet that uses a bellows for sealing against leakage around the closure member stem.

Bonnet: The portion of the valve that contains the packing box and stem seal and can guide the stem. It provides the principal opening to the body cavity for assembly of internal parts or it can be an integral part of the valve body. It can also provide for the attachment of the actuator to the valve body. Typical bonnets are bolted, threaded, welded, pressure-seals, or integral with the body. (This term is often used in referring to the bonnet and its included packing parts. More properly, this group of component parts should be called the bonnet assembly.)

Bonnet Assembly (Commonly Bonnet, more properly Bonnet Assembly): An assembly including the part through which a valve stem moves and a means for sealing against leakage along the stem. It usually provides a means for mounting the actuator and loading the packing assembly.

Bottom Flange: A part that closes a valve body opening opposite the bonnet opening. It can include a guide bushing and/or serve to allow reversal of the valve action.

Bushing: A device that supports and/ or guides moving parts such as valve stems.

Cage: A part of a valve trim that surrounds the closure member and can provide flow characterization and/or a seating surface. It also provides stability, guiding, balance, and alignment, and facilitates assembly of other parts of the valve trim. The walls of the cage contain openings that usually determine the flow characteristic of the control valve.

Closure Member: The movable part of the valve that is positioned in the flow path to modify the rate of flow through the valve.

Closure Member Guide: That portion of a closure member that aligns its movement in a cage, seat ring, bonnet, bottom flange, or any two of these.

Cylinder: The chamber of a piston actuator in which the piston moves.

Cylinder Closure Seal: The sealing element at the connection of the piston actuator cylinder to the yoke.

Diaphragm: A flexible, pressure responsive element that transmits force to the diaphragm plate and actuator stem.

Diaphragm Actuator: A fluid powered device in which the fluid acts upon a flexible component, the diaphragm.

Diaphragm Case: A housing, consisting of top and bottom section, used for supporting a diaphragm and establishing one or two pressure chambers.

Diaphragm Plate: A plate concentric with the diaphragm for transmitting force to the actuator stem.

Direct Actuator: A diaphragm actuator in which the actuator stem extends with increasing diaphragm pressure.

Extension Bonnet: A bonnet with greater dimension between the packing box and bonnet flange for hot or cold service.

Globe Valve: A valve with a linear motion closure member, one or more ports, and a body distinguished by a globular shaped cavity around the port region. Globe valves can be further classified as: two-way single-ported; two-way double-ported; angle-style, three-way; unbalanced cage-guided; and balance cage-guided.

Lower Valve Body: A half housing for internal valve parts having one flow connection. The seat ring is normally clamped between the upper valve body and the lower valve body in split valve constructions.

Offset Valve: A valve construction having inlet and outlet line connections on different planes but 180 degrees opposite each other.

Packing Box (Assembly): The part of the bonnet assembly used to seal against leakage around the closure member stem. Included in the complete packing box assembly are various combinations of some or all of the following component parts: packing, packing follower, packing nut, lantern ring, packing spring, packing flange, packing flange studs or bolts, packing flange nuts, packing ring, packing wiper ring, felt wiper ring, Belleville springs, anti-extrusion ring.

Piston: A movable pressure responsive element that transmits force to the piston actuator stem.

Piston Type Actuator: A fluid powered device in which the fluid acts upon a movable piston to provide motion to the actuator stem. Piston type actuators are classified as either double-acting, so that full power can be developed in either direction, or as spring-fail so that upon loss of supply power, the actuator moves the valve in the required direction of travel.

Plug: A term frequently used to refer to the closure member.

Port: The flow control orifice of a control valve.

Retaining Ring: A split ring that is used to retain a separable flange on a valve body.

Reverse Actuator: A diaphragm actuator in which the actuator stem retracts with increasing diaphragm pressure. Reverse actuators have a seal bushing installed in the upper end of the yoke to prevent leakage of the diaphragm pressure along the actuator stem.

Rubber Boot: A protective device to prevent entrance of damaging foreign material into the piston actuator seal bushing.

Seal Bushing: Top and bottom bushings that provide a means of sealing the piston actuator cylinder against leakage. Synthetic rubber O-rings are used in the bushings to seal the cylinder, the actuator stem, and the actuator stem extension.

Seat: The area of contact between the closure member and its mating surface that establishes valve shut-off.

Seat Load: The net contact force between the closure member and seat with stated static conditions. In practice, the selection of an actuator for a given control valve will be based on how much force is required to overcome static, stem, and dynamic unbalance with an allowance made for seat load.

Seat Ring: A part of the valve body assembly that provides a seating surface for the closure member and can provide part of the flow control orifice.

Separable Flange: A flange that fits over a valve body flow connection. It is generally held in place by means of a retaining ring.

Spring Adjustor: A fitting, usually threaded on the actuator stem or into the yoke, to adjust the spring compression.

Spring Seat: A plate to hold the spring in position and to provide a flat surface for the spring adjustor to contact.

Static Unbalance: The net force produced on the valve stem by the fluid pressure acting on the closure member and stem with the fluid at rest and with stated pressure conditions.

Stem Connector: The device that connects the actuator stem to the valve stem.

Trim: The internal components of a valve that modulate the flow of the controlled fluid. In a globe valve body, trim would typically include closure member, seat ring, cage, stem, and stem pin.

Trim, Soft-Seated: Valve trim with an elastomeric, plastic or other readily deformable material used either in the closure component or seat ring to provide tight shutoff with minimal actuator forces.

Upper Valve Body: A half housing for internal valve parts and having one flow connection. It usually includes a means for sealing against leakage along the stem and provides a means for mounting the actuator on the split valve body.

Valve Body: The main pressure boundary of the valve that also provides the pipe connecting ends, the fluid flow passageway, and supports the seating surfaces and the valve closure member. Among the most common valve body constructions are: a) single-ported valve bodies having one port and one valve plug; b) double-ported valve bodies having two ports and one valve plug; c) two-way valve bodies having two flow connections, one inlet and one outlet; d) three-way valve bodies having three flow connections, two of which can be inlets with one outlet (for converging or mixing flows), or one inlet and two outlets (for diverging or diverting flows). The term valve body, or even just body, frequently is used in referring to the valve body together with its bonnet assembly and included trim parts. More properly, this group of components should be called the valve body assembly.

Valve Body Assembly (Commonly Valve Body or Valve, more properly Valve Body Assembly): An assembly of a valve, bonnet assembly, bottom flange (if used), and trim elements. The trim includes the closure member, which opens, closes, or partially obstructs one or more ports.

Valve Plug: A term frequently interchanged with plug in reference to the closure member.

Valve Stem: In a linear motion valve, the part that connects the actuator stem with the closure member.

Yoke: The structure that rigidly connects the actuator power unit to the valve.

5.4 Rotary Control Valve Terminology

Actuator Lever: Arm attached to rotary valve shaft to convert linear actuator stem motion to rotary force to position disk or ball of rotary-shaft valve. The lever normally is positively connected to the rotary shaft by close tolerance splines or other means to minimize play and lost motion.

Ball, Full: The flow-controlling member of rotary-shaft control valves using a complete sphere with a flow passage through it. The flow passage equals or matches the pipe diameter.

Ball, Segmented: The flow-controlling member of rotary shaft control valves using a partial sphere with a flow passage through it.

Ball, V-notch: The most common type of segmented ball control valve. The V-notch ball includes a polished or plated partial-sphere surface that rotates against the seal ring throughout the travel range. The V-shaped notch in the ball permits wide rangeability and produces an equal percentage flow characteristic.

Disk, Conventional: The symmetrical flow-controlling member used in the most common varieties of butterfly rotary valves. High dynamic torques normally limit conventional disks to 60 degrees maximum rotation in throttling service.

Disk, Dynamically Designed: A butterfly valve disk contoured to reduce dynamic torque at large increments of rotation, thereby making it suitable for throttling service with up to 90 degrees of disk rotation.

Disk, Eccentric: Common name for valve design in which the positioning of the valve shaft/disk connections causes the disk to take a slightly eccentric path on opening. This allows the disk to be swung out of contact with the seal as soon as it is opened, thereby reducing friction and wear.

Flangeless Valve: Valve style common to rotary-shaft control valves. Flangeless valves are held between ANSI-class flanges by long through-bolts (sometimes also called wafer-style valve bodies).

Plug, Eccentric: Style of rotary control valve with an eccentrically rotating plug which cams into and out of the seat, which reduces friction and wear. This style of valve has been well suited for erosive applications.

Reverse Flow: Flow from the shaft side over the back of the disk, ball, or plug. Some rotary-shaft control valves are capable of handling flow equally well in either direction. Other rotary designs might require modification of actuator linkage to handle reverse flow.

Rod End Bearing: The connection often used between actuator stem and actuator lever to facilitate conversion of linear actuator thrust to rotary force with minimum of lost motion. Use of a standard reciprocating actuator on a rotary-shaft valve body commonly requires linkage with two rod end bearings. However, selection of an actuator specifically designed for rotary-shaft valve service requires only one such bearing and thereby reduces lost motion.

Rotary Control Valve: A valve style in which the flow closure member (full ball, partial ball, disk or plug) is rotated in the flowstream to control the capacity of the valve.

Seal Ring: The portion of a rotary-shaft control valve assembly corresponding to the seat ring of a globe valve. Positioning of the disk or ball relative to the seal ring determines the flow area and capacity of the unit at that particular increment of rotational travel. As indicated above, some seal ring designs permit bi-directional flow.

Shaft: The portion of a rotary-shaft control valve assembly corresponding to the valve stem of a globe valve. Rotation of the shaft positions the disk or ball in the flowstream and thereby controls capacity of the valve.

Sliding Seal: The lower cylinder seal in a pneumatic piston-style actuator designed for rotary valve service. This seal permits the actuator stem to move both vertically and laterally without leakage of lower cylinder pressure.

Standard Flow: For those rotary-shaft control valves having a separate seal ring or flow ring, the flow direction in which fluid enters the valve body through the pipeline adjacent to the seal ring and exits from the side opposite the seal ring. Sometimes called forward flow. (See also Reverse Flow.)

Trunnion Mounting: A style of mounting the disk or ball on the valve shaft or stub shaft with two bearings diametrically opposed.

5.5 Control Valve Functions and Characteristics Terminology

Bench Set: The calibration of the actuator spring range of a control valve to account for the in-service process forces.

Capacity: Rate of flow through a valve under stated conditions.

Clearance Flow: That flow below the minimum controllable flow with the closure member not seated.

Diaphragm Pressure Span: Difference between the high and low values of the diaphragm pressure range. This can be stated as an inherent or installed characteristic.

Double-Acting Actuator: An actuator in which power is supplied in either direction.

Dynamic Unbalance: The net force produced on the valve plug in any stated open position by the fluid pressure acting upon it.

Effective Area: In a diaphragm actuator, the effective area is that part of the diaphragm area that is effective in producing a stem force. The effective area of a diaphragm might change as it is stroked, usually being a maximum at the start and a minimum at the end of the travel range. Molded diaphragms have less change in effective area than flat sheet diaphragms; thus, molded diaphragms are recommended.

Equal Percentage Flow Characteristic: (See Process Control Terminology: Equal Percentage Flow Characteristic.)

Fail-Closed: A condition wherein the valve closure member moves to a closed position when the actuating energy source fails.

Fail-Open: A condition wherein the valve closure member moves to an open position when the actuating energy source fails.

Fail-Safe: A characteristic of a valve and its actuator, which upon loss of actuating energy supply, will cause a valve closure member to be fully closed, fully open, or remain in the last position, whichever position is defined as necessary to protect the process. Fail-safe action can involve the use of auxiliary controls connected to the actuator.

Flow Characteristic: Relationship between flow through the valve and percent rated travel as the latter is varied from 0 to 100 percent. This term should always be designated as either inherent flow characteristic or installed flow characteristic.

Flow Coefficient (Cv): A constant (Cv) related to the geometry of a valve, for a given travel, that can be used to establish flow capacity. It is the number of U.S. gallons per minute of 15°C (60°F) water that will flow through a valve with a one pound per square inch pressure drop.

High-Recovery Valve: A valve design that dissipates relatively little flow-stream energy due to streamlined internal contours and minimal flow turbulence. Therefore, pressure downstream of the valve vena contracta recovers to a high percentage of its inlet value. Straight-through flow valves, such as rotary-shaft ball valves, are typically high-recovery valves.

Inherent Diaphragm Pressure Range: The high and low values of pressure applied to the diaphragm to produce rated valve plug travel with atmospheric pressure in the valve body. This range is often referred to as a bench set range because it will be the range over which the valve will stroke when it is set on the work bench.

Inherent Flow Characteristic: The relationship between the flow rate and the closure member travel as it is moved from the closed position to rated travel with constant pressure drop across the valve.

Installed Diaphragm Pressure Range: The high and low values of pressure applied to the diaphragm to produce rated travel with stated conditions in the valve body. It is because of the forces acting on the closure member that the inherent diaphragm pressure range can differ from the installed diaphragm pressure range.

Installed Flow Characteristic: The relationship between the flow rate and the closure member travel as it is moved from the closed position to rated travel as the pressure drop across the valve is influenced by the varying process conditions.

Leakage: (See Seat Leakage.)

Linear Flow Characteristic: (See Process Control Terminology: Linear Characteristic.)

Low-Recovery Valve: A valve design that dissipates a considerable amount of flowstream energy due to turbulence created by the contours of the flow path. Consequently, pressure downstream of the valve vena contracta recovers to a lesser percentage of its inlet value than is the case with a valve having a more streamlined flow path. Although individual designs vary, conventional globe-style valves generally have low pressure recovery capability.

Modified Parabolic Flow Characteristic: An inherent flow characteristic that provides equal percent characteristic at low closure member travel and approximately a linear characteristic for upper portions of closure member travel.

Normally Closed Valve: (See Fail-Closed.)

Normally Open Valve: (See Fail-Open.)

Push-Down-to-Close Construction: A globe-style valve construction in which the closure member is located between the actuator and the seat ring, such that extension of the actuator stem moves the closure member toward the seat ring, finally closing the valve. The term can also be applied to rotary-shaft valve constructions where linear extension of the actuator stem moves the ball or disk toward the closed position. (Also called direct acting.)

Push-Down-to-Open Construction: A globe-style valve construction in which the seat ring is located between the actuator and the closure member, so that extension of the actuator stem moves the closure member from the seat ring, opening the valve. The term can also be applied to rotary-shaft valve constructions where linear extension of the actuator stem moves the ball or disk toward the open position. (Also called reverse acting.)

Quick Opening Flow Characteristic: (See Process Control Terminology: Quick Opening Characteristic.)

Rangeability: The ratio of the largest flow coefficient (Cv) to the smallest flow coefficient (Cv) within which the deviation from the specified flow characteristic does not exceed the stated limits. A control valve that still does a good job of controlling when flow increases to 100 times the minimum controllable flow has a rangeability of 100 to 1. Rangeability can also be expressed as the ratio of the maximum to minimum controllable flow rates.

Rated Flow Coefficient (Cv): The flow coefficient (Cv) of the valve at rated travel.

Rated Travel: The distance of movement of the closure member from the closed position to the rated full-open position. The rated full-open position is the maximum opening recommended by the manufacturers.

Relative Flow Coefficient: The ratio of the flow coefficient (Cv) at a stated travel to the flow coefficient (Cv) at rated travel.

Seat Leakage: The quantity of fluid passing through a valve when the valve is in the fully closed position with pressure differential and temperature as specified.

Spring Rate: The force change per unit change in length of a spring. In diaphragm control valves, the spring rate is usually stated in pounds force per inch compression.

Stem Unbalance: The net force produced on the valve stem in any position by the fluid pressure acting upon it.

Vena Contracta: The portion of a flow stream where fluid velocity is at its maximum and fluid static pressure and the cross-sectional area are at their minimum. In a control valve, the vena contracta normally occurs just downstream of the actual physical restriction.

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