ALTERNATIVE DESIGN CONCEPTS TO IMPROVE SULFUR FACILITY RELIABILITY

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Abstract

The reliability of the sulfur recovery facilities in today's gas processing plants is crucial to their economic success. National and state emission standards simply will not allow these processing facilities to operate for any significant period without the sulfur recovery facilities operating at or above the required recovery efficiency.

Ortloff has maintained a constant effort since the late 1960s to develop design concepts for sulfur recovery, tailgas cleanup, and tailgas incineration units that would improve the reliability and operability of these often troublesome process units. Many of these design concepts run counter to the accepted "industry practice", yet operating history has proven them to be as good as or better than the concepts employed in other more conventional sulfur recovery facilities. This paper presents these alternative design concepts in the hope that it will stimulate other plant designers and operators to reevaluate some of the "industry practice" design standards.

Introduction

Throughout the world, the production rates in gas processing plants are increasingly dictated by the capacity of the sulfur recovery facilities operated at these plants. It is common now for outages in the sulfur recovery facilities to force curtailment and even cessation of production in gas plants because of the emission standards regulating these processing facilities. As a result, it is of paramount importance to design sulfur recovery facilities to be reliable and trouble-free.

Although the process units that comprise the typical sulfur recovery facility (Claus sulfur recovery unit, tailgas cleanup unit, and tailgas incinerator) are generally familiar to those in the industry, many of the design practices used for these units are unknown to all but the relatively few of us who specialize in this niche of the industry. Because there are so few firms that design sulfur recovery facilities, sulfur plant design practices are not widely documented and the reasoning behind many of these practices is often no longer available to those in the industry today. This lack of documentation is no doubt due in part to fear of giving away competitive advantage, but may also be due to the air of mystery that surrounds sulfur plants and often makes sulfur plant design appear to be as much superstition as it is science. A welcome recent addition to the body of knowledge has been the section on sulfur recovery now included in the GPSA Engineering Data Book[1], which placed a wealth of valuable information on the subject in one easily accessible location.

Such was not the case thirty years ago when our predecessor company, The Ortloff Corporation, began designing sulfur plants for production companies and for our sister company, National Sulfur Company. What little design information we had then came from a few meager industrial publications, the modest design manual that came with the proprietary technology we licensed from Amoco Production Company, and the personal experience of some of the engineers staffing the company. The dozen sulfur plants Ortloff designed and built in the 1960s were typical of the plants of that era, and suffered many of the same operating problems that hurt the reliability of most of the sulfur plants in our industry.

Since both Ortloff and National Sulfur were owned by the same parent company, Ortloff was made keenly aware of the reliability problems experienced in the plants operated by National Sulfur and the impact this made on plant profitability. Ortloff began a program of extensive study in 1969 to examine the recurring problems in our sulfur plants, determine the root causes of these problems, and engineer solutions to these problems so that future plant designs would have much greater reliability.[2] The design concepts we developed have been used in all of the plants designed and/or built by Ortloff since 1970, and operating experience has demonstrated the improvements this has made in plant reliability and operability. Even so, these design concepts often contradict the prevailing design standards that most accept as "industry practice".

This paper will discuss the Ortloff sulfur recovery facility design concepts that differ most from "industry practice". While we make no claim that our design concepts are the best solutions available, we do believe that these concepts offer some significant advantages over the more conventional design practices in terms of plant reliability, operability, and cost. Our hope is that the alternative design concepts discussed in this paper will stimulate others to reexamine the conventional design practices, and in so doing perhaps lead to even better design concepts for use in our industry.

Sulfur Recovery Unit Design Concepts

Cold Reactor Bed Startup

It is accepted by most sulfur plant designers and operators that the catalyst beds in a sulfur recovery unit (SRU) must be above 300°F before introducing acid gas into the SRU in order to avoid plugging the reactors with sulfur. In conventional SRU designs, the reactor beds are heated by firing the acid gas burner with fuel gas and allowing the fuel gas combustion products to flow through the catalyst beds and heat them. If the catalyst in the reactors is not new, it will contain a significant amount of elemental sulfur in its pores from previous operations, even if a "sulfur strip" was performed on the reactors when the SRU was shut down. If free oxygen is present in the combustion products and comes in contact with the catalyst, this residual sulfur will begin to oxidize and cause sulfation of the catalyst. If sufficient oxygen is available, the catalyst and the reactor vessels can be damaged by the extreme temperatures created as the sulfur burns on the catalyst.

In order to minimize the amount of oxygen reaching the catalyst beds, most operating procedures require that the fuel gas combustion be controlled very close to stoichiometric air, so that the combustion products contain little or no oxygen. This mandates very close operator attention during the warmup procedure to keep the air:fuel gas ratio from being too high (which would allow free oxygen to reach the catalyst) or too low (which will cause the burner to form soot and foul the catalyst with carbon). Also, if the reaction furnace is not already up to operating temperature, the operators must inject quench steam or inert gas to keep the temperatures in the furnace low enough to prevent damaging the furnace refractory by heating it too rapidly.

We concluded that these problems (catalyst sulfation, heat damage, furnace overheating) could all be eliminated if the catalyst beds were not warmed up prior to introducing acid gas into the SRU. The question to be answered was whether the reactors could sustain the Claus reaction if the catalyst was not hot when process gas began flowing into the reactors. Consider what happens when hot process gas containing H_2S and SO_2 begins flowing across cold catalyst:

(1) Reaction initiation temperature is not critical. It is widely known that the Claus reaction can take place at ambient temperature (albeit slowly) even without a catalyst present. For instance, sulfur fouling is a common problem in sour gas pipelines connected to vacuum gathering systems because air leaking into the system allows oxygen and H_2S to react to form sulfur.

(2) The H_2S and SO_2 immediately begin to react to form sulfur. Because the catalyst is cold, the sulfur as it forms will condense (perhaps even solidify) on the catalyst, blocking the pores of the catalyst and rendering it inactive.

(3) The Claus reaction is very exothermic, so the catalyst begins to heat up due to the heat release from the reaction. The latent heat of the condensing sulfur and the sensible heat of the hot process gas also help heat the catalyst.

Thus, there are two competing processes taking place. The condensing sulfur is beginning to deactivate the catalyst bed, while the heat of reaction, latent heat, and sensible heat are heating the catalyst to get it above the sulfur dewpoint so that it stays active. Ortloff made calculations for several typical plant designs using reasonable assumptions to compare the catalyst heating rate with the sulfur deposition rate on the catalyst, and concluded that the temperature of the top layer of catalyst would increase above the sulfur dewpoint before enough sulfur deposited in the catalyst pores to completely deactivate the catalyst. Encouraged by these calculations, Ortloff then attempted a plant startup with cold catalyst beds and demonstrated that the procedure worked.

The key to applying this cold bed startup procedure is to bring all of the other equipment in the SRU (furnace, reheaters, condensers) up to operating temperature before commencing acid gas flow. For the furnace, its boiler, and the first sulfur condenser, this is accomplished by combusting fuel gas in the acid gas burner much like in a conventional plant. However, these combustion products are diverted to the incinerator before reaching the first catalyst bed as shown in Figure 1 below. Since the combustion products do not flow through any of the reactors, the burner can be operated with excess air to control the desired temperature in the furnace and follow the prescribed heating schedule. With no flow to the reactors, there is no chance of starting a sulfur fire in the catalyst beds, so there is no need to operate the burner close to stoichiometric and risk forming soot. There is also no need to add large volumes of steam or nitrogen to the furnace to control the furnace temperature as is necessary for conventional plants.

Before flowing to the incinerator, the hot combustion products flow through the waste heat boiler and the first sulfur condenser. As the gas flows through the tubes in these boilers, it heats the water in the boilers and begins to generate steam. For smaller SRUs where the reheat pass tubes are incorporated in a common shell with the waste heat boiler and all the sulfur condenser passes are in another common

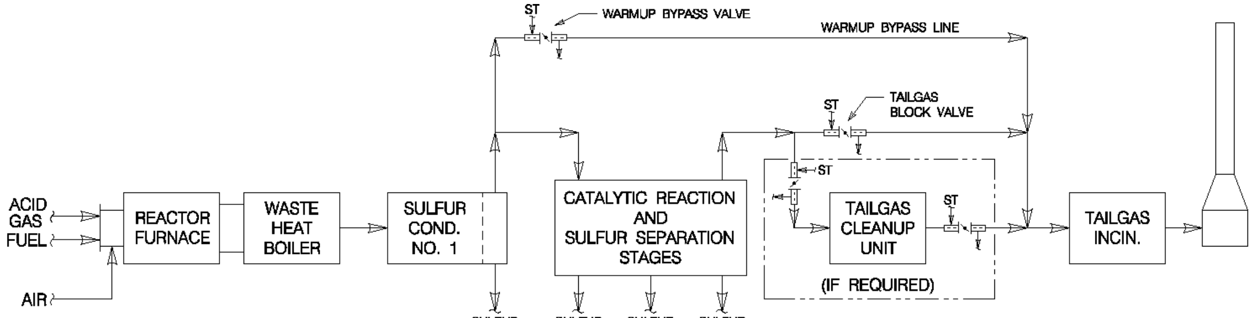

Figure 1 — Cold Reactor Bed Startup Design

shell, this brings all the heat exchanger surfaces up to operating temperature. For plants with the different services in separate shells, the high pressure steam produced by the waste heat boiler is used to heat the reheater tubes and to circulate and heat the water in the other sulfur condensers (using steam-driven eductors, for instance). Once the furnace is up to operating temperature, the tailgas block valve to the incinerator can be opened and the warmup bypass valve closed, acid gas flow can be established into the sulfur plant, and fuel gas firing discontinued to bring the sulfur plant on-line.

The design features incorporated in this cold bed startup technique offer the following advantages over conventional plant designs:

1. The catalyst beds are not exposed to warmup gases containing free oxygen, eliminating sulfur fires in the catalyst beds that cause overheating damage to both equipment and catalysts.

2. The catalyst beds are not exposed to warmup gases that contain free carbon (soot), eliminating contamination and plugging of the beds with soot.

3. The catalyst activity level remains high for much longer. Deactivation has been shown to be caused primarily from sulfate contamination of the catalyst surface. The catalyst sulfation rate is very much lower when the catalyst is not exposed to typical warmup conditions and gases.

4. Catalysts that cannot be safely exposed to gases containing free oxygen at elevated temperatures can be used in the SRU. (Some of these products contain binders that are oxidation sensitive.)

5. The sulfur plant can be kept on hot standby, firing on fuel gas, without exposing the catalyst beds to overheating, carbon deposition, or sulfation damage. The hot fuel gas combustion products (and other design features) keep all process heat exchange surfaces at normal operating temperatures. Since most corrosion damage in sulfur plants occurs when the plants are allowed to cool down and stand cold, these cold bed startup design features can greatly extend the service life of sulfur plants which require considerable standby time.

All of the Ortloff-designed sulfur plants built since 1970 (more than 50 now) have been designed for cold bed startup. The "coldest" startup so far has been at the plant installed in Tioga, North Dakota in 1991. This plant has been successfully restarted during the winter after most of the bed temperatures had fallen below 0°F. The more severe test of the startup technique, however, has been restarting a plant at low processing rates, since heat losses to the surroundings are much more significant and channeling through the catalyst beds is much more likely when operating at low flow rates. Figure 2 below shows a plot of the reactor bed temperatures for a 50 LT/D plant during its initial startup with cold reactor beds, operating at about 25% of design throughput due to lack of feed. Even at this feed rate (and with adsorbed water still in the catalyst initially), the top of the catalyst bed was up to operating temperature within 3 hours after acid gas flow began.

The plants that have consistently employed this cold reactor bed startup technique have obtained much longer service lives from the catalyst charges in the reactors than comparable units using conventional startup procedures. We believe this is directly related to the much lower incident rate of exposing the catalyst beds to oxygen (which causes sulfation and fires) and to combustion products (which causes carbon fouling and plugging). At least two of our plants, one in a gas plant and the other in a refinery, have gone nine years before replacing the original catalyst charge.

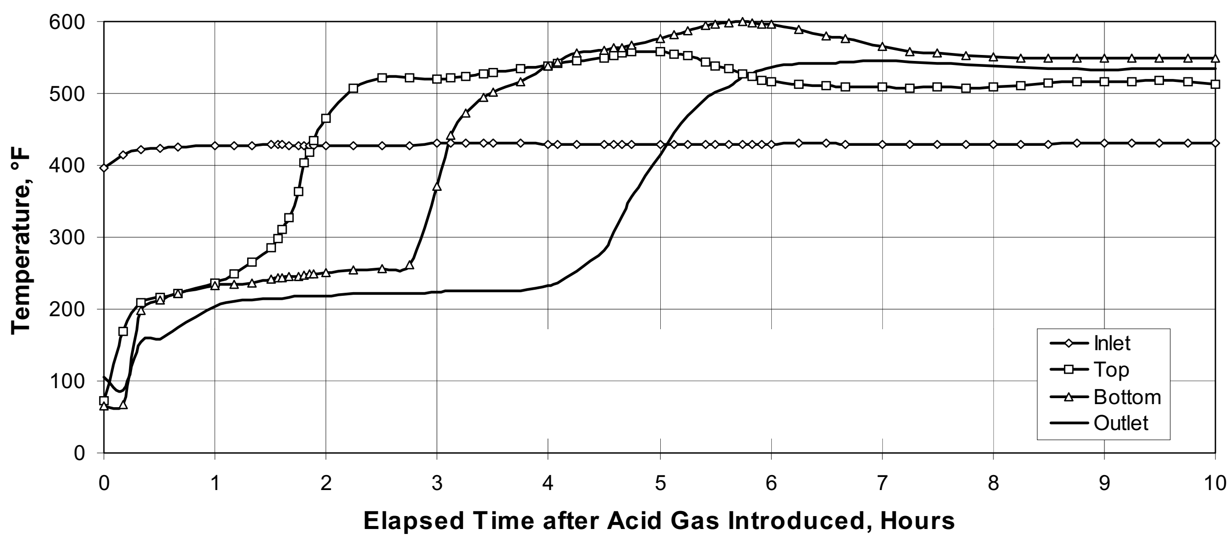

Figure 2 — Catalyst Bed Temperatures during Startup

Sulfur Vapor Line Block Valves

In order to implement cold bed startup in a sulfur plant and to ensure that the plant operators will use the technique, there must be an easy, reliable means of switching the flow path of the process gas through the SRU. Early attempts at this included slip-blinds and steam-traced butterfly valves. The slip-blinds were not convenient to use since a pipefitter was needed to reposition the blinds, and the steam-traced valves seldom operated because of solid sulfur deposition. Because there were no economical large-diameter steam-jacketed valves available on the market at the time, Ortloff began developing special steam-jacketed sulfur vapor line block valve assemblies that would be both operationally and functionally reliable so that this cold bed startup procedure could be used successfully.

Our sulfur vapor valve assemblies (SVVs) use a conventional high performance trunnion valve that is noted for its eccentrically-mounted shaft, seal design, and specially machined seat. The eccentric shaft mounting causes the valve disk to pull away from the seat before the disks begins to turn, reducing the possibility of scoring the sealing surfaces if any foreign solids are present. The disk sealing surface is a laminate of stainless steel and a resilient, high-temperature fiber that gives a metal-to-metal seal that can adapt to imperfections that may develop on the seating surface during service. The seat is machined into the valve body with a slightly oval shape so that as the valve disk is seated, hoop stress is created in the seat to form a tight seal around the disk. The result is a tough, durable valve that is capable of bubble-tight shut-off throughout years of service.

Our authorized SVV fabricators take this standard valve and modify it using our specifications to produce a valve assembly for dependable service in sulfur vapor service. Some of the more important modifications made to the valves include forming an integral steam jacket in the valve body to place live steam directly in contact with the valve body in key areas to ensure that sulfur cannot solidify on any moving surfaces, and modifying the shaft bearings to prevent accumulation of solids when subjected to cyclic temperature service like CBA (Cold Bed Adsorption) switching valves.

After these modifications are completed, the valve is reassembled and the operator/actuator, solenoid valves, and limits switches are installed. The valve is then placed in a test stand to confirm that it has retained its shutoff capability. If necessary, adjustments are made so that the valve seals bubble-tight. The valve is then bolted between jacketed pipe spools to create a fully-jacketed valve assembly. The jackets on the pipe spools absolutely ensure that solid sulfur cannot form and block the valve disk in the upstream or downstream piping. Steam tubing "jumpers" are added to connect the pipe and valve jackets into one continuous circuit, then the assembly is crated for shipment to the job site. These assemblies are ready to be installed in the plant piping as soon as they arrive in the field, and require no disassembly or assembly by field personnel.

This basic valve assembly design was first developed by Ortloff in 1970. We have continued to improve the design to reduce cost, increase reliability, and take advantage of better valve designs from the valve manufacturers as they become available. Our SVVs have been used in CBA sulfur plants for more than fourteen years. Although CBA plants use a cyclic process that employs switching valves in very demanding sulfur vapor services, our SVVs have allowed these CBA SRUs to perform as expected without the switching valve failure and/or sulfur vapor leakage problems that have plagued some of the other valve designs that have been used for this type of plant.

Waste Heat Boiler Design

The single most common cause of unscheduled downtime in the SRUs built by Ortloff and the other designers in the 1960s was failure of the waste heat boiler tubes at the inlet tubesheet connection. This tube/tubesheet connection was fabricated using the general practice of the time for firetube boilers as shown in Figure 3 below.[3] A carbon steel tube with a moderate amount of corrosion allowance was rolled and expanded into the hole in the tubesheet and then seal welded. A ceramic ferrule was inserted in the tube so that it extended into the tube slightly more than the tubesheet thickness, and protruded from the tube by about 3". A castable refractory lining was then installed over the tubesheet and around the ferrules.

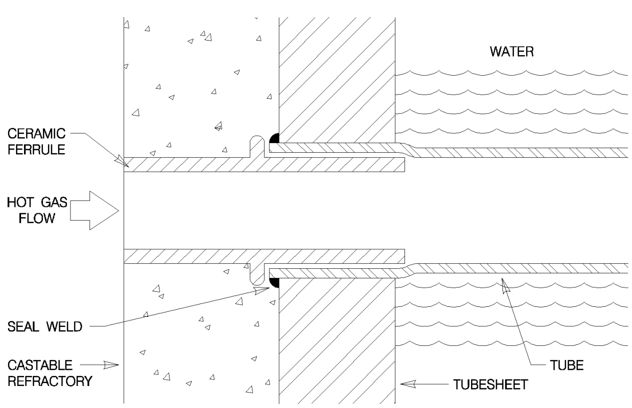

Figure 3 — Typical WHB Tube Attachment

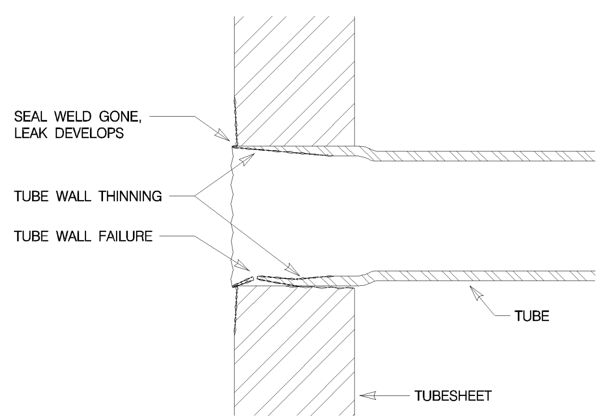

Figure 4 — Typical WHB Tube Deterioration

In the most troublesome boilers, the service life of the waste heat boiler tubes was sometimes as short as six months. Other boilers had service lives as long as three years. Careful inspections were made of the failed boilers in hopes of determining the failure mechanism. Although in some cases the refractory and ferrules had been damaged severely by the leaking water that resulted when the tubes failed, in some cases these heat shields were still intact. When the refractory and ferrules were removed, however, the tubes exhibited the deterioration shown in Figure 4. The tube end projection beyond the face of the tubesheet and the seal weld typically would be completely gone. The tube wall would be very thin at the hot face of the tubesheet, gradually increasing to the original wall thickness near the back side of the tubesheet. There would be no significant deposition of corrosion products in place of the missing tube metal. Leaks would be observed in one of two locations: between the tube and tubesheet where the seal weld had disappeared, or at a tube wall rupture just beyond the seal weld inside the tubesheet.

One of the more important facts that came to light during our inspections and our consultations with various experts was that high velocity flow of hot gas in direct contact with the metal surfaces was not necessary for metal loss to occur. High temperature sulfide corrosion of carbon steel in a sulfur plant atmosphere will occur at a significant rate whenever the metal temperature exceeds about 700°F, and increases rapidly as the temperature increases. Examining the differences in the geometry of the troublesome boilers compared to the better boilers led to the following observations:

(1) With gas temperatures in the range of 2000-2500°F at the tube inlet, very high heat fluxes exist in this area of the tubes.

(2) In examining the mechanisms of heat flow into and out of this region, the area of the tube where the seal weld is attached will experience the highest surface temperature.

(3) The resistance to heat flow through the tube/tubesheet connection has a direct impact on the surface temperatures of the tube ends inside the tubesheet.

(4) The ratio of the tube wall area inside the tubesheet (heat absorption into the tube wall) to the surface area on the back side of the tubesheet (heat dissipation away from the tube wall) is a key design parameter.

(5) The degree of steam "blanking" that occurs on the back side of the tubesheet and outside the tubes just past the tubesheet strongly influences how quickly heat is removed from the tube inlet ends.

Ortloff developed a calculation model that used the tube/tubesheet geometry, thermal properties of materials, and appropriate heat transfer correlations to predict the temperatures along the insides of the tube ends. The calculation results were compared to actual temperature measurements obtained with thermocouples attached to the tube ends and the tubesheet to confirm that the model was sufficiently accurate for use as a design tool. When this calculation model was applied to a centrally positioned tube in one of the problem boilers using the tube attachment method shown earlier in Figure 3, the temperature profile of the tube end was as shown by the upper curve in Figure 5 below. As the figure shows, the calculated temperature of the tube wall at the tube inlet was in excess of 1100°F, explaining why the service life of the tubes located in the central area of this boiler was only about six months.

Ortloff felt that the key to long service life would be keeping all of the metal temperatures below 700°F so that there would be no significant high temperature sulfide corrosion of the tubes. We used the calculation model to examine the effect of changing the heat shielding of the tubes (refractory materials, refractory thicknesses, etc.), but found that the maximum tube wall temperatures could not be reduced below 900°F without creating excessive pressure drop in the tube inlets. The next step was to examine what changes in the tube/tubesheet geometry were needed to bring the tube wall temperatures down. This led to the tube/tubesheet design shown in Figure 6 below. The key features of this design are: a full depth weld attaching the tubes to the tubesheet to improve heat transfer from the tube walls, use of

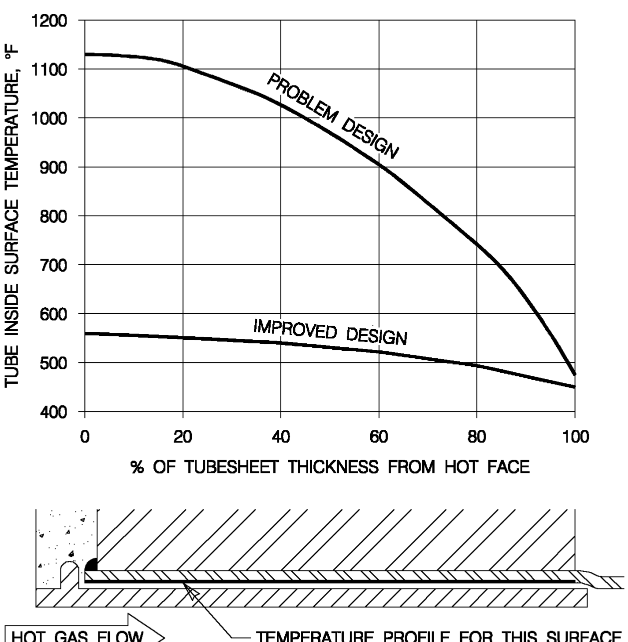

Figure 5 — Calculated WHB Tube Temperature Profile

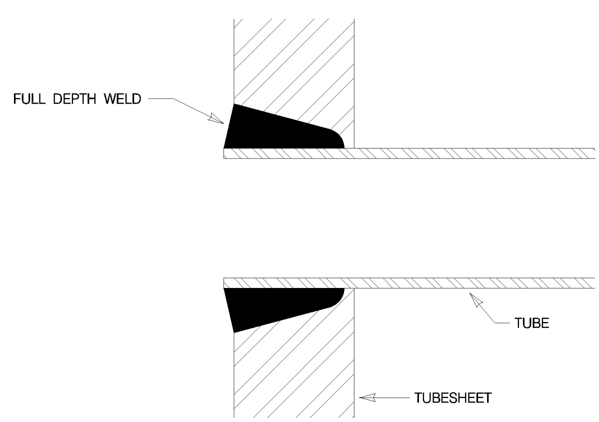

Figure 6 — Improved Tube/Tubesheet Design

stay rods to stiffen the tubesheet so that relatively thin tubesheets can be used while still complying with ASME Section I Code, and wider tube spacing than customary to provide a significantly higher ratio of heat dissipation surface relative to the heat absorption surface. The calculated temperature profile of this improved design is shown by the lower curve in Figure 5 for comparison purposes.

With the improved tube/tubesheet design, the maximum tube wall temperature is less than 600°F with 435°F (i.e., 350 PSIG) boiling water inside the WHB shell. Even if the heat shielding were to be completely removed, the maximum tube wall temperatures would still be lower than the conventional design because of the vastly superior heat transfer achieved with this design. The first boiler using this improved design was placed in service in 1971. Its first boiler inspection was performed in 1976, and the tubes, attachment welds, and tubesheet were all found to be in excellent condition with no detectable metal loss. All of our subsequent waste heat boilers have also used this design, and none have failed due to high temperature sulfide corrosion of the hot end tubesheet attachments.

Sulfur Condenser Outlet Separator Design

Following each conversion stage in the SRU, the sulfur vapor that is formed must be condensed and separated. Many plants are designed to separate the liquid sulfur in the outlet channel of the sulfur condenser using either woven wire pads or chevron elements to remove sulfur droplets from the outlet gas, as shown in Figure 7 below. Due to the high viscosity and surface tension of liquid sulfur, we do not feel that these impingement devices are very effective for removing small sulfur droplets. Consequently, there will be significant carry-over of liquid sulfur from the condensers into the downstream catalyst beds or process units. (Many plant designers place a coalescer vessel downstream of the final sulfur condenser to guard against excessive sulfur losses due to entrainment in the vapor.)

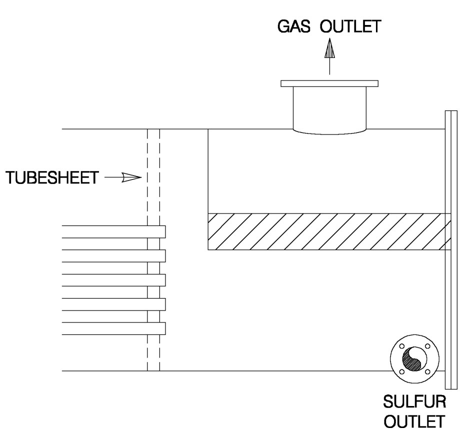

Figure 7 — Typical Condenser Outlet Channel

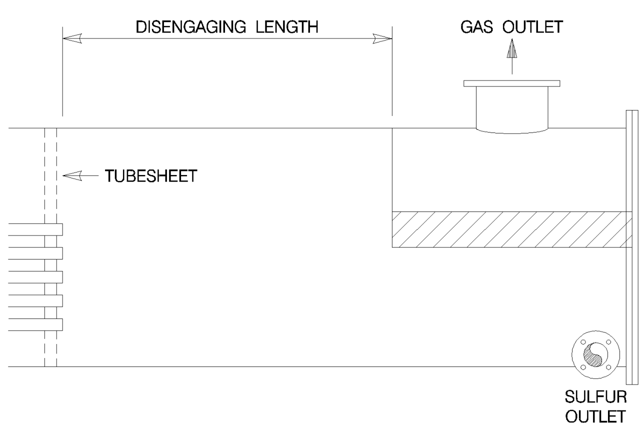

Figure 8 — Improved Condenser Outlet Channel

When liquid sulfur droplets enter a catalyst bed, the droplets are drawn into the catalyst pores by capillary action. The result is nonpermanent deactivation of the catalyst as the sulfur droplets block the active sites of the catalyst, reducing the conversion efficiency of the catalyst. This reduction in catalyst activity has been attributed by some to catalyst sulfation which could be reduced by certain catalyst "rejuvenation" procedures.[4] Ortloff personnel were present during the field testing of this rejuvenation procedure where the reactor operating temperatures were raised by about 50°F for a day, followed by operation of the SRU with a high $H_2S{:}SO_2$ ratio for a day in an effort to reduce the sulfation level of the catalyst. What we observed were extremely high sulfur flow rates from the condensers at first when the temperatures were raised, and higher reactors ΔTs for some time period following the procedure. Over time, however, the reactors ΔTs gradually dropped to their levels prior to the procedure. Contrary to the opinion in the cited article, we concluded that the true cause of the catalyst deactivation was loading the catalyst with liquid sulfur, and that the only thing accomplished by "rejuvenation" was to vaporize this sulfur out of the catalyst, temporarily restoring catalyst activity until more sulfur accumulated in it.

If our conclusion was correct, then the key to maintaining good long-term catalyst activity without the need for periodic "rejuvenation" would be to keep the amount of liquid sulfur entering the catalyst beds to a minimum. The most reliable means for doing so, we felt, would be to design the sulfur separators following the condensers for gravity separation of the sulfur droplets from the gas. This could still be accomplished in the outlet channel of the sulfur condenser simply by extending the channel to provide sufficient disengaging length in the channel for the sulfur droplets to fall to the bottom of the channel before removing the gas stream, as shown in Figure 8. (The mist eliminator shown in Figure 8 is probably not needed, but most of our condenser designs still include one as an additional safeguard.)

Field experience has demonstrated the effectiveness of this sulfur separator design philosophy. Catalyst activity levels do not diminish over time in our plants, and there is no need for periodic catalyst rejuvenation. Sulfur losses from the SRU due to liquid carry-over are minimal without installing a coalescer vessel downstream of the final sulfur condenser. When the catalyst beds are "stripped" with inert gas prior to a scheduled shutdown, the residual sulfur is typically removed from the beds in less than one hour. This is significantly shorter than the time required in many other plants for sulfur stripping, meaning that the total duration of the plant shutdown can be correspondingly shorter.

Suction-Throttling of Air Blowers

Most conventional sulfur plants regulate the air flow to the reactor furnace on ratio control with the feed gas flow by throttling the discharge of the blower as shown in Figure 9 below. A separate "trim air" valve is typically used to make minor adjustments to the air:acid gas ratio using the feedback from the tailgas analyzer and its controller. Since most air blowers will go into "surge" if the air flow drops below 60-80% of design, a blow-off valve is needed on the blower discharge to vent air to atmosphere when the process requirement is low so that the total air flow through the blower keeps it to the right of the surge line (see Figure 10).

The blower design is set by the discharge pressure needed to overcome the pressure drop through the SRU and downstream equipment at the design flow rate (point A in Figure 10). If the SRU is operating at 50% throughput, however, the blower cannot be regulated to 50% flow rate (point C in Figure 10) because it would go into surge. Instead, the blower must be controlled at point B in Figure 10 by opening the blow-off valve to vent some of the air to atmosphere. This is wasteful for two reasons. First, more air must be compressed than the process requires (the difference between points C and B in Figure 10). Second, because the pressure drop through the SRU is much less at lower flow rates (ΔP is roughly proportional to the square of the flow rate, as shown by the system resistance curve in Figure 10), the air must be compressed to much higher pressure than is required (the difference between points C and D in Figure 10).

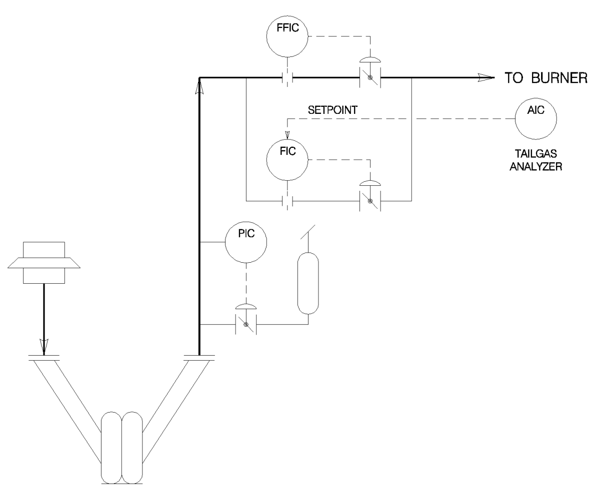

Figure 9 — Discharge-Throttled Design

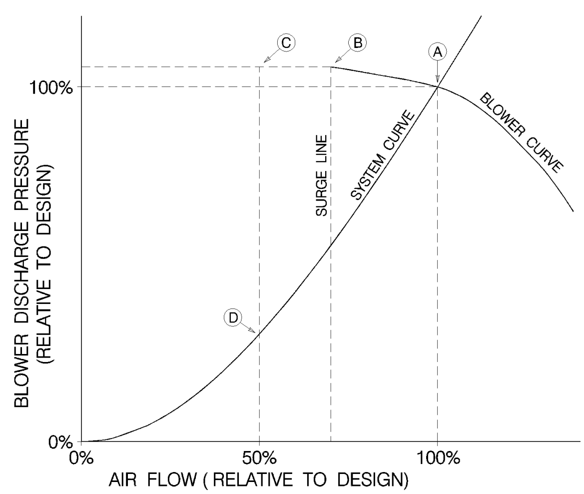

Figure 10 — Discharge-Throttled Blower Curve

As an alternative to this, the blower can instead be controlled by throttling its suction as shown in Figure 11 below. As the suction is throttled to reduce the air flow through the blower, the air density in the blower is also reduced, giving a higher actual volumetric air flow rate through the blower for a given mass flow rate than if the blower is discharge-throttled. This effectively shifts the surge line to the left at lower throughput as show in Figure 12, allowing the blower to operate through a much wider range of air flow rates without surging. Also, power usage by the air blower is significantly reduced since it is not necessary to discharge as much (if any) excess air to the atmosphere to control surge, since the lower air density existing in the blower causes the blower efficiency to be significantly improved, and since the pressure ratio across the blower is reduced because the blower discharge pressure adjusts to the lower ΔP in the SRU.

There are secondary benefits to suction-throttling as well. The pressure drop across the control valve is much lower than when discharge-throttling is used, which reduces the forces acting across the valve and allows for smoother control. This in turn allows the feedback from the tailgas analyzer to be an adjustment to the flow ratio controller, eliminating the separate "trim air" control valve. Since the air flow is measured at nearly the same pressure as the acid gas feeds to the SRU, pressure compensation of the acid gas and process air flow rates is not needed for good ratio control, eliminating some of the instrumentation found in conventional control schemes.

Many of these same benefits apply to suction-throttling the air blowers in tailgas cleanup units as well. Our standard practice is to use suction-throttling for the air blowers in the SRU and in the TGCU. Field experience has confirmed the improvements this makes in both controllability and power consumption.

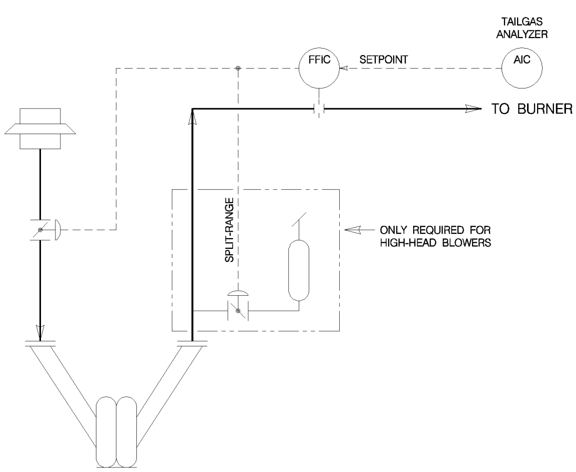

Figure 11 — Suction-Throttled Design

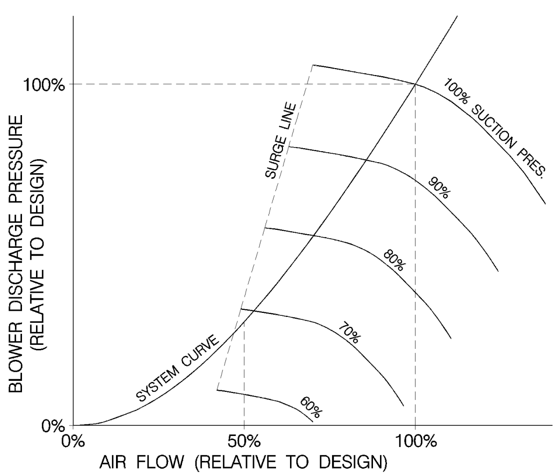

Figure 12 — Suction-Throttled Blower Curve

Tailgas Cleanup Unit Design Concepts

Cold Reactor Bed Startup

Due to the presence of sulfur in the inlet to the hydrogenation reactor in a tailgas cleanup unit (TGCU), iron sulfide forms on the walls of the reactor and the catalyst bed support and accumulates in the catalyst. Iron sulfide is pyrophoric even at ambient temperature in the presence of oxygen, so restarts of the TGCU should avoid passing oxygen through the reactor to prevent reactor and/or catalyst damage. Like the sulfur plant, the TGCU can also be designed for cold catalyst bed startup.

Our typical design uses a block and bypass arrangement for the TGCU reactor similar to that shown in Figure 13 below to allow cold bed startup. (The bypass line has a double block with purge configuration to prevent SO_2 from leaking past the reactor during normal operation.) Before starting the in-line heater, the two valves in the bypass line are opened and the block valve is closed to divert flow around the reactor. The in-line heater is then started up with excess air, adjusting the amount of excess air as necessary to control the heating rate of the in-line heater (for a cold restart). Once the in-line heater is up to operating temperature and the air:fuel ratio has been trimmed below stoichiometric, the reactor block valve can be opened and the two bypass valves closed to switch the gas flow into the reactor.

If the catalyst bed in the reactor is cold, introduction of tailgas into the TGCU should be delayed until the top layer of catalyst comes up to operating temperature. Once it has done so, reducing gas and tailgas flow to the TGCU can commence and the heat of reaction will help bring the rest of the catalyst bed up to operating temperature. Because the "thermal mass" of the catalyst bed and reactor vessel is large relative to the gas flowing through it, heating rates are not excessive and we have not found it necessary to take any steps to slow down the heating during startup.

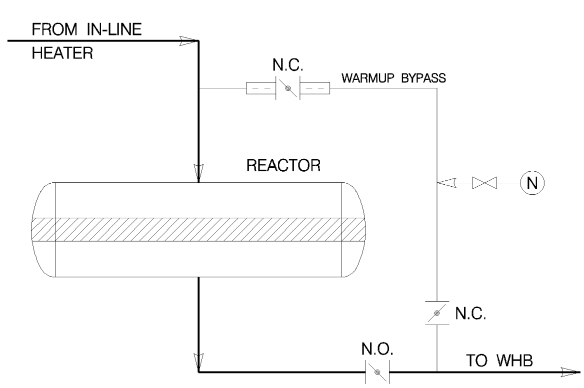

Figure 13 — Cold Bed Startup Design

Using a cold reactor bed startup design for the TGCU offers many of the same advantages for the TGCU as in the SRU, and the benefits are similar. Catalyst service life in the TGCU is improved and there is much less risk of overheating damage to catalyst or equipment during startup. In addition, the startup procedures themselves are simpler to implement and require much less operator attention without compromising safety or reliability.

Startup Blower Location

Figure 14 below shows a common equipment configuration in many TGCUs where an in-line fired heater is used to heat the reactor feed streams and generate reducing gas. For clarity, the quench column pumps and coolers, the solvent pumps, and the regeneration system are not shown. The major process gas block valves are shown, along with the startup blower located downstream of the quench column. During normal operation, the SRU tailgas is heated in the reducing gas generator, hydrogenated and hydrolyzed in the reactor, partially cooled in the waste heat boiler, further cooled in the quench column, then contacted with solvent in the contactor to remove H_2S before flowing to the incinerator.

During startup, however, the SRU tailgas cannot be routed to the TGCU until the reducing gas generator is firing on-ratio and the reactor is ready, so valve A is closed and valve B is opened. The reducing gas generator and reactor would be overheated by the extreme temperature (3000+°F) of the combustion products leaving the burner on the reducing gas generator unless there is some type of gas flowing through the system to quench it, so the startup blower is used to recirculate a portion of the process gas leaving the quench column back to the reducing gas generator. This is accomplished by closing valve C

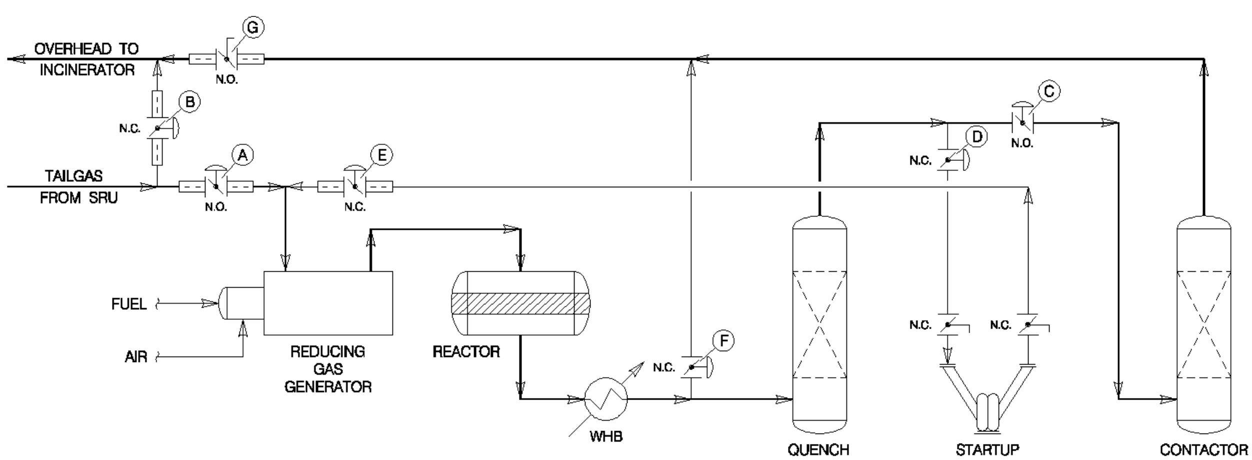

Figure 14 — Conventional Startup Blower Location

and opening valves D and E, with valve F open to vent the excess gas to the incinerator through the TGCU outlet block valve, valve G. Once sulfur plant tailgas is routed to the reducing gas generator (by opening valve A and closing valve B), valves D and E can be closed and the startup blower can be shut down. After operation of the front end of the TGCU has stabilized, valve C can be opened and valve F closed to route the gas to the contactor and bring the TGCU fully on-line.

This location of the startup blower in the flow sheet and its typical location in the plot plan both lead to operating problems. First, during initial operation of the reducing gas generator, there is oxygen present in the burner effluent which dissolves in the circulating quench water and causes corrosion. Second, the startup blower is typically installed at grade for easy access. This makes it a low point in the piping to which it is connected, and invariably results in water from the process gas condensing and accumulating in the blower casing while it is not in service. Exposure to this condensed water causes corrosion products to form on the impeller and/or casing, leading to blower imbalance or failure. There have even been cases of shearing the blower impeller from its shaft because the blower was started while full of water. Purging the blower with nitrogen when it is not running has not proven completely effective, most likely because the purge was not always placed in service whenever the blower was not operating.

Figure 15 shows an alternative arrangement of the TGCU equipment that eliminates both of these problems. The startup blower is mounted above the piping to which it is connected (typically by locating it on top of the piperack or an upper module), and takes its suction upstream of the quench column.

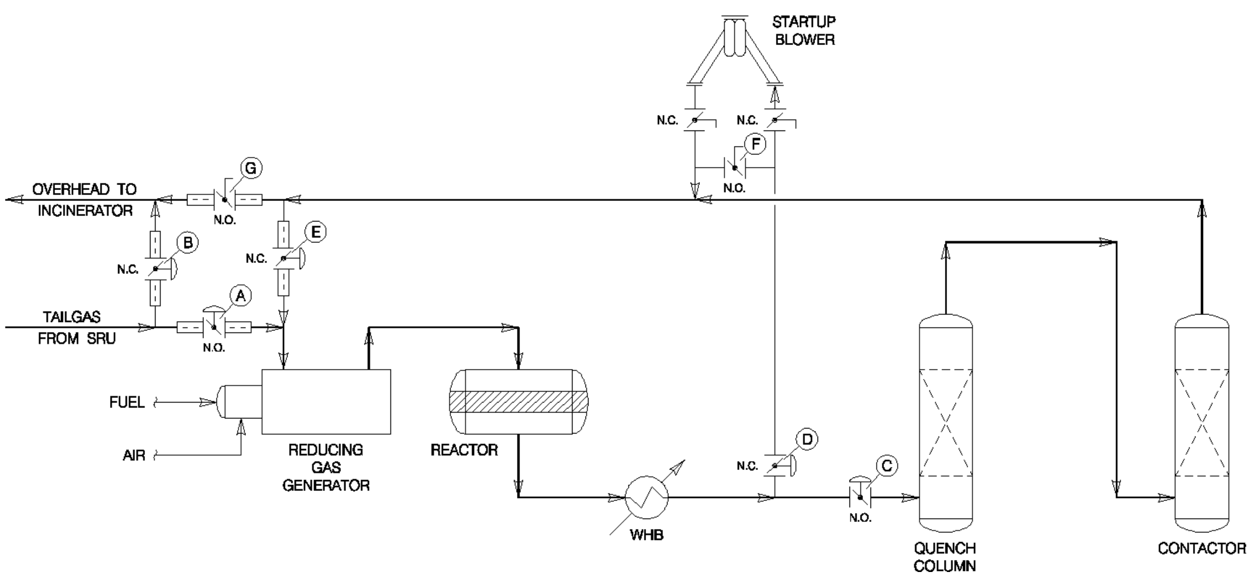

Figure 15 — Alternative Startup Blower Location

During startup, valves C and F are closed and valves D and E are opened so that the blower can recirculate the gas leaving the waste heat boiler back to the reducing gas generator. Since the contactor overhead line is used to route the gas this direction, the TGCU outlet block valve (valve G) vents the excess gas to the incinerator. Once sulfur plant tailgas is routed to the heater (by opening valve A and closing valve B), valve E can be closed, valve F can be opened, and the startup blower can be shut down. After operation of the front end of the TGCU has stabilized, valve C can be opened and valve D closed to route the gas to the quench column and contactor to bring the TGCU fully on-line. Should any upsets develop later, valves C and D can be used to divert the process gas to the incinerator (via valve F bypassing the blower).

With this arrangement, gas is not introduced into the quench column until the front end of the TGCU is lined out. This means that fouling the quench water system is much less likely to occur during startup. With the blower mounted at the high point in the system, any water that might condense in the blower will instead free-drain back into the process piping, even if the nitrogen purge system for the blower is inadvertently not placed in service. We have found that designing the startup blower for the 300°F gas leaving the waste heat boiler does not increase its cost significantly.

Locating the blower at this point in the flow sheet also means that the blower can be used to recirculate gas to the SRU by installing a recycle line as shown in Figure 16 below, which offers several significant advantages. First, when throughput in the SRU and TGCU is low, process gas can be recirculated through the SRU and the front-end of the TGCU. Not only does this provide a remedy for the low-flow

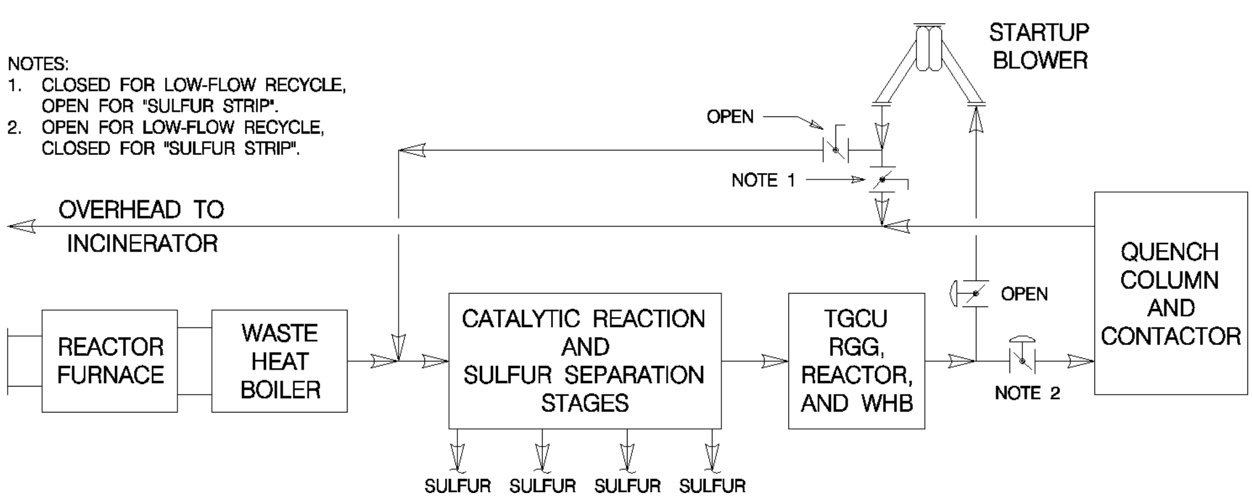

Figure 16 — Recycle to the SRU with the Startup Blower

operating problems encountered in the TGCU (mainly excessive operating temperatures in the reducing gas generator and reactor), it will prevent sulfur "fogging" in the sulfur condensers of the SRU. This will allow the SRU and TGCU to operate at rates as low as 5-10% of design throughput without significant operating problems.

Second, this recycle line to the SRU provides a very convenient means for safely performing a sulfur "strip" and cool-down of the catalyst beds in the SRU. The reducing gas generator in the TGCU can be fired with fuel gas to generate inert gas, which the startup blower then circulates to the SRU to vaporize the residual sulfur in the catalyst and strip it from the beds. Since the burner on the reducing gas generator is designed to operate with less than stoichiometric air, controlling it to generate inert gas is much simpler and more reliable than using the fuel gas warmup tips on the acid gas burner in the SRU. Once the sulfur has been stripped from the catalyst beds, the feed temperatures to the reactors in the SRU and the TGCU can be brought down (by dropping the steam pressure in the sulfur condensers and stopping steam flow to the reheaters, for instance) to cool all of the reactors beds simultaneously and begin preparing the reactors for entry.

It is also possible to accomplish the sulfur strip and bed cooling without firing a burner at all, using only a modest amount of nitrogen or other inert gas. Once enough inert gas has been added to displace the process gas from the system, the blower can be used to circulate it through the SRU and TGCU, with only a small amount of additional inert gas needed during the procedure to counteract the shrinkage as the plant cools.

Tailgas Incineration Unit Design Concepts

Waste Heat Boiler Design

Figure 17 shows a typical tailgas incinerator. A natural-draft or forced-draft burner is used to heat the SRU tailgas or TGCU effluent to high temperature so that the sulfur compounds in the stream are all oxidized to sulfur dioxide. In some locations, the incinerator must also oxidize carbon monoxide, which often requires a significantly higher operating temperature (1400-1500°F versus 1000-1200°F), more residence time, and more excess air. An enlarged section in the lower part of the stack provides residence time for the oxidation reactions before dispersion of the incinerated effluent from the top of the stack. Of necessity, the entire stack must be lined with refractory.

An alternative is to design the incineration system to capture the "waste heat" in the incinerated effluent by generating high pressure steam as shown in Figure 18. A forced-draft burner is used to heat the SRU tailgas or TGCU effluent to high temperature in a refractory-lined vessel that provides residence time for the oxidation reactions. The hot effluent from the furnace then enters a waste heat boiler and is cooled to 500-550°F as it generates steam, before the cooled effluent is dispersed to the atmosphere from the top of the vent stack. Since both SRU tailgas and TGCU effluent ordinarily contain a considerable amount of combustibles, it is often possible to generate more steam in an incinerator waste heat boiler than is possible burning the same amount of fuel gas in an ordinary boiler.

Assuming that the Figure 17 incinerator is natural-draft, the equipment differences for the Figure 18 incinerator are:

(1) A forced-draft fan is required for the burner.

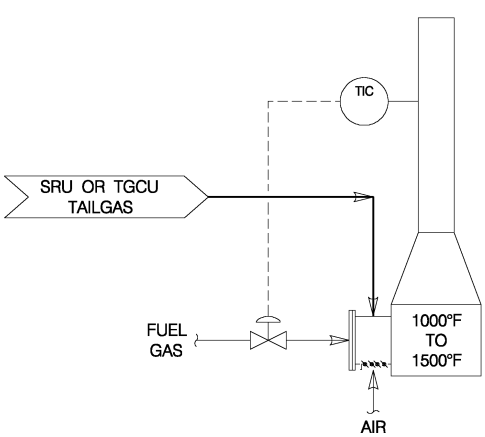

Figure 17 — Typical Tailgas Incinerator

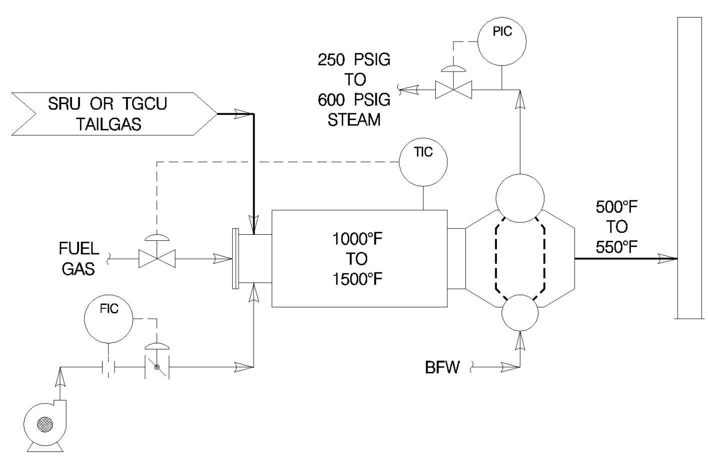

Figure 18 — Incinerator with Waste Heat Recovery

(2) A boiler is required (typically a water-tube style).

(3) The stack is externally insulated rather than lined with refractory.

A capital cost comparison between the two arrangements typically shows that the lower cost of the stack for the WHB system (since it can be smaller in diameter and does not require an internal lining) offsets the cost of the waste heat boiler. This means that including waste heat recovery usually adds only the cost of the forced-draft fan, a very minor cost that will quickly be paid out by the value of the produced steam (six month pay-out or less, typically). If the incinerator must be designed to oxidize carbon monoxide, the Figure 18 design may even cost less to install than the Figure 17 design because of the more expensive refractory required in the stack by the higher operating temperature necessary to combust the carbon monoxide.

Ortloff first installed an incinerator with waste heat recovery in 1974, and its boiler is still in service today. Except for a few special circumstances, service life from these boilers has been excellent. One boiler was converted to low pressure steam service by the client, and failed within a few months due to acid corrosion of the tubes. (Because incinerators are operated with excess air, a portion of the sulfur in the feed gas is oxidized to sulfur trioxide, SO_3. This SO_3 will combine with the water in the effluent gas to precipitate as sulfuric acid if it comes in contact with surfaces that are cooler than the acid dewpoint.) A few boilers in refineries have suffered carbon fouling of the finned tubes in the boiler due to excessive heavy hydrocarbons (perhaps even liquid hydrocarbons) in the fuel gas. In general, however, proper attention to the steam pressure in the boiler, the insulation on the boiler outlet and stack, and the fuel gas to the burner are all that is needed for reliable long-term performance.

Conclusions

This paper describes a number of design concepts that have been developed over the past 30 years at Ortloff to improve the reliability and operability of sulfur recovery facilities. Although many of these concepts are quite different from the usual "industry practice", we have found that in most cases these alternative concepts have not only improved reliability, but have also reduced the capital and/or operating costs of these units.

While these alternative design concepts have been effective in the plants we have designed and built, there is no doubt that further improvements are possible. We hope that this discussion of the basis for these concepts will stimulate others to reconsider the state-of-the-art in sulfur plant design and lead to even better design concepts in the future.

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