

Process Analyzer Best Practices for Sulfur Recovery, Enhanced Claus and Tail Gas Treating Applications

Adel S. Misfer
Saudi Aramco, Kingdom of Saudi Arabia

Suryanarayana Vedula
Saudi Aramco, Kingdom of Saudi Arabia

Randy Hauer,
AMETEK Process Instruments, USA

Zaheer Juddy
Systems & Equipment, UAE

PRESENTED AT:

Sour Oil & Gas Advanced Technology (SOGAT)
5th International Conference
Abu Dhabi, UAE

March 2009

Process Analyzer Best Practices for Sulfur Recovery, Enhanced Claus and Tail Gas Treating Applications

Adel S Misfer
Saudi Aramco, Kingdom of Saudi Arabia

Suryanarayana Vedula
Saudi Aramco, Kingdom of Saudi Arabia

Randy Hauer
AMETEK Process Instruments, USA

Zaheer Juddy
Systems & Equipment, UAE

This paper discusses the practical aspects of the suite of analyzers used on a modern sulfur recovery unit (SRU) and tail gas treating unit (TGTU) installation. Seven analyzer applications are covered (Fig. 1) along with industry “best practice” recommendations based on maintenance history records and direct experience.

Analyzer function and SRU/TGTU process control are well-understood at the design and process engineering levels, sometimes less so at the operational level, and this is the challenge. The tail gas and emission (stack) gas analyzers have high visibility, but many other analyzer applications are abandoned because of perceived safety risks or low criticality. Good design, adherence to best practices, a comprehensive preventative maintenance program and process training are the keys to complete utilization of all the analyzer assets and improved operation. The paper is a collection of front-end engineering design (FEED) elements plus practical operational experience from analyzer maintenance, process engineering, and operational personnel. The objective is to extract every benefit from the suite of analyzers intended by the designer.

Some aspects pertaining to control and operation may seem basic to those who are conversant in sulfur recovery, including this audience. Each of the anecdotes has at least one example where a misunderstanding resulted in human error causing an upset, and in many cases, an environmental event, equipment damage, or both. The authors, as the end-user process engineer, end-user analyzer engineer, analyzer maintenance contractor, and analyzer vendor, strongly believe in training and retraining for operations and analyzer maintenance personnel so human error can be avoided, or at least, not repeated.

For this audience, we assume that the process basics of the modified Claus and TGTU are well-understood. The authors acknowledge that there are significant differences between the licensed processes, and the paper makes these distinctions where there are analyzer implications. The intention is not to generalize, except to say that in most cases, the analyzer function is the same for any given type of process. For clarification purposes the process descriptions cover the following:

- Conventional (Modified) Claus process, lean and rich feed acid gas.
- Enhanced Claus/Sub Dew Point (CBA™, Sulfreen™, Clinsulf™, MCRC™).
- Enhanced Claus/Selective Oxidation (Superclaus™).
- Reduction/Amine-based tail gas treating.
- Amine acid gas and sour water stripper (NH₃) acid gas in refinery SRUs.

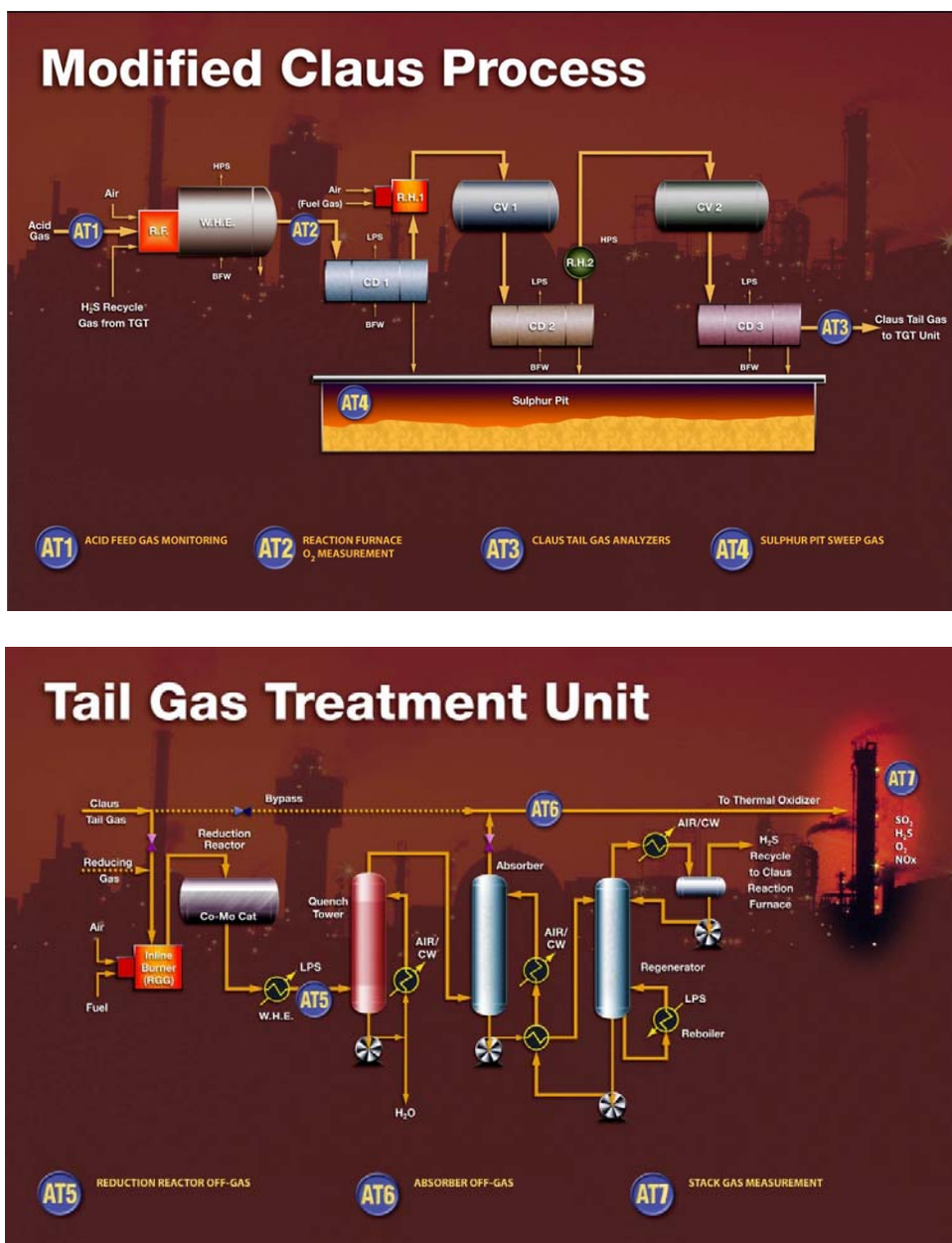


Fig. 1. Analyzer Applications in a SRU/TGTU Complex

1) TAIL GAS $\text{H}_2\text{S}/\text{SO}_2$

Modified Claus process chemistry appears simple, but a number of factors complicate the control of the process including:

- Contaminants in the acid gas.
- Varying feed composition and flow.
- Side reactions in the furnace and catalyst beds.
- Inherent inaccuracies in the control instrumentation and logic.

All of these items can be minimized or accounted for but never totally eliminated, and some deviation from perfect control is always encountered.¹

With relatively stable feed compositions, flows and properly operating feedback control of the combustion air flow, control of the excess air to within $\pm 0.5\%$ is generally achievable. This results in typical losses of 0.2% for a three stage SRU. Unstable feeds and poor or non-existent control can result in significant losses of 10% or more due to poor stoichiometry control in the worst cases. The tail gas analyzer and feedback control accounts for 2% to 4% of recovery efficiency and contributes more to overall SRU performance than does the third converter (Fig. 2).²

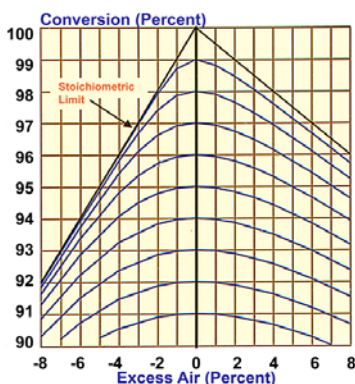


Fig. 2. Efficiency as a Function of Excess Air

In a plant designed for 94% recovery, a 1% loss of recovery will be observed if there is a 6% excess of combustion air. In a plant designed for 99% recovery (sub dew point type) a 1% loss of recovery will be observed if there is only a 3% excess of combustion air.³ It is worth noting that excess air is the “forgiving side” of the family of curves. On the air deficient side (high $\text{H}_2\text{S}/\text{low SO}_2$) the loss of recovery efficiency effect is 1.5 as much.³

1.1) COS/CS_2 Measurement with the Tail Gas Analyzer

Optimally, recovery efficiency losses due to COS and CS_2 could be kept under 0.1% assuming equilibrium conversion across the first converter. In the worst case, test results have shown plants in which reaction furnace COS and CS_2 formation rates account for up to 13% of the total inlet sulfur, and in which recovery efficiency losses due to COS and CS_2 have been greater than 6.5% .¹

Measurement of COS and CS_2 in tail gas is only possible with a non-dispersive dual beam/dual wavelength type UV analyzer.⁴ This is an important distinction as the tail gas analyzer is optimized for the (primary) measurement of percent level H_2S and SO_2 . The measurement of the

COS and CS₂ is adjunct to this. When the path length of the cell is optimized for H₂S and SO₂ and using a dual beam/dual wavelength, the resultant range for COS and CS₂ is 0 ppm-5000 ppm. The threshold limit is in the order of 100 ppm and both gases need to be measured if a full assessment of efficiency loss is to be made. Using the example above of keeping losses under 0.1 %, a measure of 500 ppm COS and 250 ppm CS₂ would approximate a loss of 0.1 % recovery efficiency and is well within the accuracy and sensitivity of this type of analyzer.

To be put to good use, COS and CS₂ should be trended and operators trained on their practical application. These measurements are widely used in gas plants that operate without the luxury of a tail gas treating unit (TGTU) and held to high recovery efficiency standards (> 98.0 %), as is the case with SRUs in Alberta, Canada. For SRUs with a TGTU, COS measurement at the top of the TGTU absorber is probably of greater utility than measurement of COS and CS₂ in the tail gas.

1.2) Running “Off Ratio”

There can be convincing reason to run the SRU at conditions other than a 2:1 H₂S/SO₂ ratio and the basic reason is to favor stable operation in the downstream unit. In the case of a Claus SRU with a thermal incinerator (no TGTU), a hydrocarbon increase at the reaction furnace results in a corresponding increase of H₂S in the tail gas causing an exotherm in the incinerator. The prevention mode for this is to operate at a ratio closer to 1:1.

More common is the opposite condition: When the SRU is followed by a TGTU with a reduction stage. In this case, the downstream unit is adversely affected by SO₂ excursions and for some TGTU designs it is standard operating procedure to run at a four or five to one ratio to prevent breakthrough of SO₂ to the absorber. It is worth noting that the high ratio operation is the “unforgiving side” of the control curves and SRU recovery efficiency can be compromised to the point where the TGTU recycle back to the front side of the SRU can restrict capacity. Another issue, addressed in the next section, is the possibility of confusing the operations people by talking in ratio, but controlling in “Air Demand.” The notion that a 5:1 ratio is far removed from “on ratio” is false, in fact it is only ~ negative 0.9 % air demand (on a 97 % Er SRU), a relatively small bias. This is why it is recommended to display air demand and ratio on the control screen and provide training for the operators so both concepts are understood and compared.

The other exception to the rule is Superclaus. The Superclaus process is based on conventional Claus chemistry where the H₂S/SO₂ ratio is controlled at a value well above 2:1 (where SO₂ is ~0.05 %) in combination with a selective oxidation in the final reactor.⁵ The control is not based on a notional concept of ratio or air demand, but on the absolute value of H₂S where the set point can be anywhere from 0.9% to 1.3 % H₂S depending on the acid gas composition and number of conventional Claus reactors. There can be cause to bypass the selective oxidation bed, at which time it makes sense to revert to conventional Claus mode in order to realize the maximum recovery efficiency. The control logic is configured so it can automatically revert from Superclaus to Claus mode and back. Since the normal (Superclaus) mode is in terms of absolute [H₂S], the control in Claus mode uses “excess H₂S” (not Air Demand) for the control signal, so scaling of air control is the same for both modes.

1.3) Derivation of Conventional “Air Demand” and “Excess H₂S” Expressions

The objective of the feedback control loop is to correct for the inadequacies of the feed-forward control system. If the feed-forward system added too much air, the feedback loop must subtract the appropriate amount (ΔA) of air to bring it to zero, and vice versa. Thus, the *Air Demanded* by the process to achieve this condition is the negative of the Excess Air. In the literature, this distinction (Excess Air) has not been made, and this has led to some confusion. Previously, the Air Demand was equated to the Excess Air without acknowledgment of the difference in sign. This needs to be noted when configuring the loop in the DCS since, as noted above, mistakes and misunderstandings have happened more than once.

The concept of making H₂S/SO₂ ratio into a linear expression was introduced in the 1970s with the advent of electronic controllers and distributed control systems.

$$\text{Air Demand} = -AD (2[\text{SO}_2] - \text{H}_2\text{S})$$

Where AD is the air demand factor that relates this to air flow and without the AD factor it is expressed in terms of “excess H₂S”. The AD component in this equation is strictly a scaling factor and ranges from ~3.0 to 4.5 depending on the [H₂S] concentration in the acid gas. In this sense it can be considered as a gain factor.

The following section discusses recommendations for configuring and scaling for air demand (control) as well as indicating outputs. While ratio is archaic as a control signal, becoming meaningless as SO₂ approaches zero, it has a place. Where “Air Demand” appeals to our “control engineer” side, “Ratio” appeals to the “chemist” side. Ratio is useful, as an indicating signal for off-ratio conditions and to compare to the air demand so the relationship between the two is better understood by operators.

Replacing an older tail gas analyzer with a new generation model deserves discussion. The typical life of an analyzer is 15 years or more. When the time comes to connect a new analyzer, the configuration of the control loop needs to be investigated and properly documented. It has happened where the control loop is configured for “excess H₂S” and the new analyzer set up to transmit “air demand” as well as the other way around. The result is that the loop has 2 to 3 times too much gain (or 1/3 to 1/2 of the gain depending on the direction of the mistake). Sometimes this is caught early. When noticed later the artifact is attributed to the analyzer (“your analyzer is noisy . . . your analyzer is slow”). Another mistake, getting the direction of the trim control action “toggled” in the wrong direction, has occurred more than once. The mistake in this case is immediately noted but sometimes not soon enough, causing in one instance we know of, a high temperature alarm in the reaction furnace. When all properly configured, ask the analyzer vendor to do some basic SRU process and control training for the operations and analyzer maintenance personnel so the differences between “old” and “new” are understood by all.

One last anomaly worth mentioning, oxygen enrichment and its effect on the feedback control loop. Oxygen enrichment is used to increase capacity in the SRU by rejecting nitrogen. It has been in use since the 1980s, with ~100 installations and is widely accepted technology. The enrichment can vary from low level (“burp-in” up to 28 % O₂), to mid level (45 % O₂) to high level (100 % O₂). On more than one occasion we have been called in as the analyzer vendor to explain why the analyzer is “noisy” during O₂ enrichment periods. The simple answer is

removing the N_2 introduced gain. From what we could tell from questioning, but without actually looking into the calculation block of the DCS, most do not account for increase in gain that O_2 enrichment brings and that is really what it is in terms of proportional control: N_2 is rejected, H_2S and SO_2 increase in concentration and this essentially adds gain (noise) to the loop. The calculation block in the DCS is certainly adjusted for the absolute amount of O_2 coming into the furnace, but the increase in gain is not accounted for. An adaptive gain feedback using O_2 enrichment level as an input could solve this if it is a problem.

1.4) Control and Indicating Signals, Use of H_2S/SO_2 “Over-Range”

The basic requirement for control of the modified Claus process is very much standardized on control of 10 % of the total process air flow by the trim air control loop. This has not changed in decades and neither has the instrument data sheet for tail gas analyzers. What the SRU designers do not acknowledge is that a modern tail gas analyzer is capable of over-range measurement. This can be used to great advantage and should be transmitted to the operator. The following example of an actual upset illustrates this point (Fig. 3)

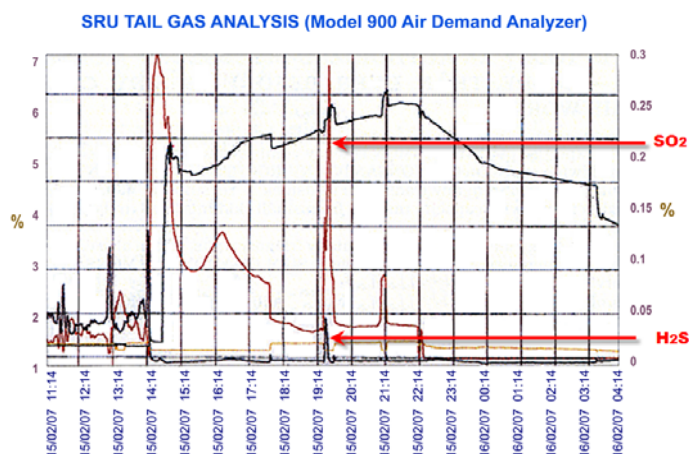


Fig. 3. SRU Process Upset and “Over Range” Event

The example is based on actual results from a refinery SRU.² After loss of the amine acid, an excess air condition existed for ~three hours while the operator struggled to maintain temperature in the reaction furnace and get the unit back to stable condition. The result at the tail gas was SO_2 going to 7 % (!!) and H_2S to zero. Problem being, none of this was evident to the operator because the transmitted range was 0-4% (H_2S) and 0-2% (SO_2). The information presented here was logged on a laptop at the local analyzer for service purposes.

When a post-event meeting was held the next day, the initial reaction was disbelief because the H_2S and SO_2 were not acting in a predictive fashion. The data, however, was proven to be quite valid when compared to air and acid gas flows. What appears to be a phenomenon can be easily explained; the catalyst saturates with SO_2 and equilibrium, at least at the outlet of the final converter, is not restored for hours. In non-equilibrium conditions the catalyst demonstrates its propensity to act like a sponge. Each gram of catalyst has ~250 m² of surface area and in this example it takes ~ five hours of cutting air and decreasing SO_2 before the H_2S comes off zero at the tail gas. The next stage of the event serves to reinforce the anecdote: At the first appearance of H_2S in the tail gas the operator dramatically increases the air, the SO_2 goes to 7 % again and H_2S to zero. During this event, the operator could only observe that the SO_2 flat lined at 2%, the H_2S flat lined at zero and he believed the analyzer had failed.

For operations, the lessons from this are:

- 1) H_2S and SO_2 can react in a non-predictive fashion during a gross upset.
- 2) By the time one of the signals “skies” (H_2S or SO_2), the other will be at zero.
- 3) The Air Demand (control signal) will be off scale but operations can react to the over range (indicating signal) of the H_2S or SO_2 .
- 4) The event can last for hours, but made shorter if the over range is there to see.
- 5) Observing SO_2 in over range it is enough to know “I am cutting the air and the SO_2 is coming down”... as SO_2 begins to level off expect the H_2S to reappear.
- 6) With UV tail gas analyzers, if just one of the indicating signals is moving, the analyzer is working. Trust in the analyzer is easier if the over range is observed.
- 7) Transmit the over-range scale to the DCS and tie in to the digital link.

Using the example above, the four available analog outputs should be configured as:

- 1) *Control Output: "Air Demand"* [-5%... 0 ...+5%]
 - This can also be expressed as "excess H_2S " [-1%...0...+1%], essentially the same as "air demand" but without the scaling factor that relates it to air flow.
 - Typically used in the calculation block, it is a linear signal in terms of control.
 - Make sure the logic matches the documentation and the operator's understanding.
- 2) *Indicating Output: "Ratio"* [0... 210]
 - Ratio helps us to understand the relationship to "air demand." For example 5:1 ratio is ~- 0.9% air demand; sometimes not well-understood by operators.
- 3) *Indicating Output: H_2S* [0...5%]
 - Once the H_2S is > than 2%, the SO_2 will be zero react to the over range.
- 4) *Indicating Output: SO_2* [0...5%]
 - Once the SO_2 is > than 1%, the H_2S will be zero react to the over range.
 - Train the operators on upset conditions and use of "over range."

1.5) Digital Link

The digital communication interface is an element of analyzer best practice that is largely ignored in SRU design. It is common for a gas processing project to have this as a mandatory requirement for GCs, even when they are grouped together in a large shelter. For unknown reasons, SRU analyzers lack acknowledgement in this regard, fewer than 1 in 10 instrument data sheets in a front-end engineering design list the digital link as a requirement. Every modern analyzer has remote digital communication capabilities and utilizing it has several advantages in the SRU/TGTU:

- Over range of $\text{H}_2\text{S}/\text{SO}_2$ is auto-scaling and can be observed to the full extent without compromising resolution of the normal values displayed on the screen.
- Complete diagnostics made available for fast, accurate troubleshooting.
- Safety. The question will be asked, “Why send personnel out to an operating unit and into possibly hazardous conditions during an upset to gather information when it can be done remotely and safely”?

1.6) Phase Behavior of Sulfur and Good Design for the Process Connection

Sulfur freezes at a range of 113°C-119°C (235°F-246°F) and the range is a function of the different molecular forms of both liquid and solid sulfur.⁶ It is not prudent to operate piping, vessels or analytical sample systems at temperatures below 135°C.

Analytical sample systems have problems and limitations beyond what is experienced in process piping and vessels. These go largely unnoticed and are the source of most problems. The first premise we need to accept is that the available heat duty in an analyzer sample system will nicely keep vapor as vapor and liquid as liquid, but it will not re-melt solid or re-vaporize liquid sulfur; at least not under flowing conditions.

The first limitation is exposed surface area. Relative to the gas flow the surface area of the process connection for a tail gas analyzer (close coupled or full extractive) is orders of magnitude, more than it is for the process pipe. A bit of surface cooling that causes a ¼" of solid sulfur in a 24" tail gas pipe is of little consequence, the same experience in a ½" probe or sample line is a plug. Pay considerable attention to impart bulk heat into the process nozzle in the form of steam jacketing. Sample system components, steam jacketed nozzles need protection from the weather. Cold spots, rain and wet insulation are known enemies as they transfer away heat.

The second limitation is the allowable surface temperature of the electrical heating elements for hazardous locations. The specification is "T3" and it allows for a maximum temperature of 200°C. This appears to be more than adequate, but there is a finite amount of heat available (150-200 watts) and the delta T between the temperature set point (~150°C) and the heating element (~190°C) will only make up for a minor amount of careless installation.

The third limitation is the steam used for the "bulk heat." It is typically low pressure ("LP") steam and can be inadequate if it is wet or not properly trapped. The problem is that LP steam is generated in the final SRU condenser and is already in thermal equilibrium with the process stream. The process gas (sample gas) is saturated with sulfur vapor and the LP steam has very little sensible heat it can impart into sample system. LP steam is "adequate" if it is dry, but if it is wet, it is not a heat medium but rather a heat sink and a source of problem because it robs heat from the gas. For this reason 5-8 barg (~75-125 psig) steam is recommended for heat tracing. Electrical tracing (rated for the area class) can provide an even better solution as it is easier to control the temperature.

Taking these points into consideration, design the process connection as follows:

- Keep the nozzle as short as possible, steam jacket the nozzle if longer than 15 cm.
- For close coupled type tail gas analyzers the nozzle can be as long as 1.5m.
- If steam jacketing is not possible, use Contro Trace™.
- Do not wrap with tubing; it does not work as it just expands away from the nozzle.
- Use 2" 150# flange, 3" maximum 4" flanges have more area).
- Insulate and cover all steam jacketed components.
- Sample line type analyzers using an "ASR" probe, come with a factory-provided insulating cover. Be sure to cover to prevent ingress of water.
- Remember the rule . . . cool here, plug there. Heat loss typically takes place at the process connection but the plugging occurs downstream in the analyzer.

- If the analyzer is plugging, look for a problem in the process connection. Take a piece of sulfur and “chalk” it onto an exposed metal flange. It should melt. If not, the process string is too cool.



Fig 4a. Typical Analyzer Installation “Top of Pipe” Type Analyzer



Fig. 4b. Typical Analyzer Installation “Sample Line Type” Analyzer

1.7) Ammonia Salts, Entrained Sulfur and other Adverse Process Conditions

It is generally agreed that with “moderate” levels of ammonia breaking through from the reaction furnace (>300 ppm), there is a significant risk of having ammonia salts form and deposit in downstream units.⁷ Ammonia is only found in refineries where sour water stripper (“SWS”) gas is burned in the reaction furnace, and this has implications for the tail gas analyzer. The salts form in the condensers (Fig. 5), the coldest spot in the process, at $\sim 150^{\circ}\text{C}$. The analyzer sample system runs cooler yet, at 135°C in the demister in order to condense and remove sulfur vapor. The salts will form there as well. Where the build up of salts is gradual, the process may not show ill effects for some time, and the evidence in the analyzer can be a slight hazing of the optics. This hazing does not normally impair analyzer performance, but the observation should be passed on to operations. Where the build-up of salts is more rapid, the effects can be seen as pressure drop in the analyzer as the salts form in the demister. A top of the pipe (transmitter) type of the tail gas analyzer has a cure for the symptom if not the disease. Hot condensate in the form of deadheaded LP steam is flushed through the demister on a periodic and automatic basis to dissolve the salts. The condensate back flush is not often needed (for example, it is not needed for entrained liquid sulfur) but when it is, it renders the analyzer more robust than the process.



Fig. 5. Ammonia Salts on Process Condenser Tube Sheet (courtesy of Sulphur Experts)

The formation of ammonia salts in the process can present an additional unintended problem for the tail gas analyzer. The temporary process “fix” for salts forming at 150°C in the condenser can be to raise the process condenser temperature to 160°C or higher. This can cause a dramatic increase in the sulfur vapor (S_V) content in the tail gas and can affect the analyzer; and can be an increase of 3x or more in the S_V content. The analyzer can be set up for adverse conditions (by adjusting the sample cooling rate, sample flow rate, zero-back flush) but operations needs to notify analyzer maintenance whenever they change the final condenser temperature for any reason.

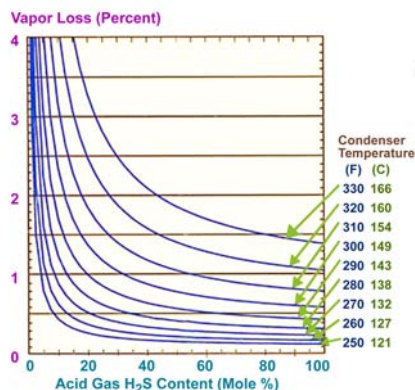


Fig. 6. Sulfur Vapor Losses vs Temperature

The other process condition that gives rise to fouling of the analyzer is entrained liquid sulfur. The degree of condensation is strictly a function of temperature (Fig. 6) while removal is more a function of design and kinetics. Any condensed sulfur not removed from the process can be drawn up into the analyzer and contributes directly to emissions. Some minor entrainment should be expected (2 kg to 4 kg of sulfur per 100 kmol is typical). Worst case scenario: sulfur entrainment levels of 50 % (due to fogging problems at extremely low mass velocities) to 100 % (due to mechanical blockage of the final rundown) from the final condenser have been measured, resulting in efficiency losses of 1% to 3 % .²

If the SRU is in turndown, or operations suspect liquid entrainment, they need to notify analyzer maintenance. There are remedies that can alleviate at least the sample problems. In one extreme instance, a refinery had to bypass the final condenser because of a leak on the tube side of a boiler feed water preheat. The tail gas analyzer was essentially drawing sample from the 3rd converter outlet, saturated with Sv at ~210 °C. After being made aware of the process change (not until the analyzer had fouled) the sampling parameters were adjusted to withstand the extreme sulfur loading. This is a testimony of the ability to adapt the sample handling parameters (cooling rate, flow rate and back flush) to overcome adverse process conditions. No matter if the change is short lived or long-term, the obligation is on operations to provide feedback and advance warning of any significant changes to the analyzer maintenance group so they can be proactive.

1.8) Sampling for Sub Dew Point Processes

Sub dew point processes obtain a high conversion of sulfur formation reaction due to a more favorable equilibrium attained at low temperature. The front end of the process (thermal reactor, waste heat boiler and first catalytic conversion stage) uses conventional modified Claus design; the back end of the process (the final two or three converter vessels) operates at cooler temperatures in cyclic fashion.³ Periodically the catalyst must be regenerated on a cycle (absorbing, regeneration, cooling) that takes place every 18-30 hours depending on various factors. The tail gas analyzer in this instance is not installed at the tail gas but after the first converter/condenser vessels. The reason for placing the analyzer after the first converter/condenser is because the regenerated catalyst preferentially absorbs H₂S over SO₂ for part of the cycle (then the reverse), and so the tail gas would not represent the true stoichiometry.

This impacts the operation and function of the tail gas analyzer in two ways. First is the process temperature, which can reach 280°C or higher. The process connection and sample handling have to be rated and designed for this duty, primarily the seals and O-rings. Also, the sample handling must take place external to the process; in-situ sample handling is limited in its cooling capacity. The gas, while not saturated with Sv at these elevated temperatures, does have higher sulfur loading than typical tail gas at 150°C. The sampling parameters for adverse conditions previously described were originally developed for the specific purpose of sub dew point processes.

The second impact is control. Precise control of the air/acid gas ratio is important for Claus and even more so for sub dew point. For a sub dew point process rated at 99.0 %, operating at -2 %, air demand will result in an efficiency loss of 1% (or stated another way, a 100 % increase in emissions). One of the compromises of sampling after the first converter is the loss of analytical resolution: the analyzer is measuring values of ~5 % H₂S and 2.5 % SO₂ vs values almost an

order of magnitude less at the tail gas. A modern NDUV-based analyzer gives up only a small degree of accuracy in this case. Some of this compromise is made up in the improvement in process dead time by sampling ~10 seconds after the reaction furnace vs. ~30 seconds at the tail gas.

1.9) Process Training

Sulfur is a co-product of hydrocarbon-based energy production and, as such, enjoys a lesser status compared to the prime product. The downside is that sulfur recovery gets little attention except when there is a problem. A positive benefit has been the open sharing of sulfur recovery information in the form of seminars, conferences, test data and open participation in applied research organizations. Catalyst, refractory, testing, and analyzer vendors make this information readily available, many times at no charge as a service to their customers in the form of mini seminars and “lunch and learns.” The training is most needed at the operational level, particularly on understanding the basic SRU chemistry and control. Take full advantage of what is available through your vendors and initiate a periodic training program for the operations staff. It provides the opportunity to dispel myths and misinformation handed down the line, over time and to establish a foundation of the process fundamentals. Training should be a continuous process and the people at the operational end are most deserving and appreciative. Include the analyzer maintenance and control people. It is fundamental for an analyzer maintenance person to understand the underlying process of any quantitative/qualitative measurement if they’re to communicate with operations.

1.10) Safety Considerations

The authors are of the firm belief that all sample conditioning for a tail gas analyzer needs to be external to the pipe. In-situ measurement and sample conditioning have merit in certain analyzer applications but SRU tail gas is not one of them. The prime reason sample conditioning needs to be done external to the process is because contamination, sample temperature and access cannot be controlled in-situ to the process pipe. Another consideration is safety. Isolation and removal of the probe under live process conditions is becoming mandatory at some sites.

Three different oil refining companies now require this at some of their sites.⁸ The requirements are isolation of the analyzer from the process and removal of the probe from the process under live conditions with zero egress of gas. This has always been a feature of the top of the pipe tail gas analyzer as it has a Conax fitting at the probe, which allows retraction/insertion. The sample line type analyzer that uses the “ASR” probe now has a steam jacketed Conax fitting as an option. Sometimes the notion of “double block and bleed” for relieving process gas from a sample system is requested, it has no place in SRU tail gas and should be avoided. A redundant (double) block valve is possible for both types of analyzers described above, but there is no way to “bleed” off sulfur without plugging.

Similar to “double block and bleed”, process analyzer shelter standards of many companies require the process gases entering the analyzer shelter pass through flow restrictors and solenoid valves to ensure safety of personnel who work inside the shelter. One has to keep in mind that no restrictions or valves should be used on electrically traced sample lines entering the process analyzer shelters to avoid cold spots and plugging problems. This most certainly applies to SRU tail gas but also SRU stack gas, feed gas and TGTU analyzer applications as well.

1.11) Analyzer Best Practices

This is a summary of the details that need to be considered at the detailed design phase of a project, before piping and platform design is set in stone. Analyzer and vendor specialists collaborating at a very early stage can avoid compromises later on.

Tail Gas/“Sample Line” type analyzer (Fig. 4b):

- Keep the sample lines as short possible (3m-7m is normal, can be up to 20m). Sample velocity (3m/sec) is not critical compared to process residence time (30 sec -40 sec) but does add to response time.
- Do not “pocket” the lines. Be careful not to measure the lines “too long” Analyzer above the sample point is preferable but it can be below (at grade).
- “Sample Line” type analyzer; typical for harsh climates ($<-20^{\circ}\text{C}/>40^{\circ}\text{C}$) as it can be installed or combined with other analyzers in an analyzer house.
- Sample connection can be installed in very tight locations. For example, where an SRU - TGTU is connected by only 0.5 m of vertical process pipe, a close coupled type cannot fit in that space or else piping costs are prohibitive.
- Safety considerations: The entire ASR probe can be “double blocked” from the process, removed under process conditions with zero egress of gas.

Tail Gas/“Close Coupled” type analyzer (Fig. 4a):

- Install the analyzer as close to the tail gas pipe as possible.
- The resulting connection “nozzle” should be $<\sim 5\text{ft}/1.5\text{m}$.
- Install a 3-sided shelter around the analyzer, (3ft/1m top + sides).
- For a refinery SRU burning SWS gas, take the “hot condensate” blowback option in case of salts; rarely needed, invaluable when it is.
- It can be installed on vertical pipe but horizontal is preferred.

Tail Gas/All analyzer types:

- Connection nozzle should be steam-jacketed or installed on (existing) steam jacketed ball valve or lagged with “Contro Trace™”. Do not wrap coiled tubing around the nozzle and expect it to work. It doesn’t.
- Steam for the nozzle + valve must be 75 psig (5 barg) minimum
- Connect up to digital link (Modbus, Ethernet). A vast amount of useful information is available, such as over range of $\text{H}_2\text{S}/\text{SO}_2$ during upsets. More important it reduces exposure of the analyzer maintenance personnel to an operating unit. Sadly, very few grass-root SRU projects specify the digital link.

2) STACK GAS/CONTINUOUS EMISSION MONITOR (CEM)

Depending on the process configuration, SO_2 emission can vary from up to, or more than, 8,000 ppm for a 3-stage Claus SRU; $\sim 1,500$ ppm for enhanced Claus; to ~ 120 ppm for standard design TGTU; to single digit ppm SO_2 in some local air quality districts. The measurement standards vary slightly with most SRU/TGTUs in the U.S. measuring SO_2 on a “cold-dry” basis according to the EPA part 60 guidelines. There are alternatives to measuring on a cold-dry basis that are well suited to SRUs and some environmental jurisdictions consider an SRU to be a special case in this regard.

2.1) Mass Emission

Many environmental permits are written with a mass emission (kg/h SO₂) as the prime requirement for reporting emissions from a SRU. In addition to the mass emission, overall SRU efficiency and ppm SO₂ are also included as part of the operating permit limits; failing any one of these three parameters can be an environmental exceedance. Mass emission (kg/h SO₂) is a sensible way to evaluate a straight Claus SRU. Mass emission requires the SO₂ analytical measurement be made on a “hot-wet” basis because the SO₂ and corresponding velocity measurement must be on the same basis. Mass emission measurement loses some of its utility when there is a TGTU, but for straight through Claus and enhanced Claus processes it can be very well-utilized as an optimization/material balance tool. By tracking mass emission process changes resulting in an improvement of 0.1 % or less of recovery efficiency, improvement can be quantified by the corresponding decrease in mass emission.¹

2.2) Measurement of Residual H₂S and Total Sulfurs in Stack Gas

It is well-known and accepted that equilibrium values of reduced sulfurs exist after incineration with the assumption these are negligible if the incinerator is operated according to design. Proposed EPA legislation, [sub part J(a)] was going to require measurement of residual H₂S for refinery SRPs (sulfur recovery plants, defined as SRU +TGTU), but the law was not been promulgated and is currently on hold.⁹ In addition, some gas plant SRUs, most notably in Alberta, Canada, have been allowed to increase the amount of reduced sulfur compounds in the interest of saving fuel gas in the incinerator and are required to measure un-combusted H₂S.¹⁰

There are several ways to make the measurement. Where the H₂S is present in higher concentrations such as the energy optimized incinerators in Alberta, H₂S is (and should be) measured separately from the SO₂. Where the incinerator is optimized for destruction of reduced sulfurs after a TGTU, the consensus method has been to oxidize any un-combusted H₂S and measure as total SO₂ thereby “accounting” for the H₂S. By oxidizing, the analyzer sample system essentially completes 100 % of the oxidation job of the incinerator. It is a simple method provided care is taken in delivering the sample to the analyzer without reaction, and ensuring total oxidation without SO₃ formation. Some users have reserved the option of segregating H₂S and measuring separately from SO₂ which can be done, but the challenge of resolving 7-8 ppm H₂S in a background of ~150 ppm SO₂ adds complexity. In-situ TDLAS laser techniques have been applied to this application with some success.

2.3) Measurement of NO_x and CO

Claus SRU incinerators are relative low temperature as compared to power generation, and the values of NO_x and CO are low. Very few jurisdictions require measurement of these parameters. It can be done as the methods are well-accepted. NO_x can be added to a UV-based analyzer already measuring SO₂. The question is why make the measurement, if it means nothing. It is not so much the capital cost of the additional measurement (~10 % per parameter the cost of the CEMs system), but that the cost of span gases and maintenance over the lifetime of the system increases with each additional measured parameter. Further, the low measured values are more difficult to validate by the standards of relative accuracy audit standards (RATA) applied to CEMs. The caution is, don’t add meaningless measurements to the operating permit without forethought.

3) FEED (ACID) GAS

Feed (acid) gas analyzers are widely applied if not well-understood or fully implemented. Approximately 15 % of existing SRUs and maybe twice that many from new design, have an H₂S analyzer, or one or a combination of, H₂S, NH₃ and hydrocarbon analyzers.

In refineries with rich amine acid gas streams, the H₂S tends to be slow moving in terms of change and the tail gas analyzer (feedback control) accounts for this. Gas plants can often make a case for an H₂S analyzer as changes in H₂S are faster and of significant proportion. As a secondary use (referring to the discussion on SO₂ mass emission to report recovery efficiency) an H₂S feed analyzer can be used in combination with a mass emission CEMs to calculate instantaneous recovery efficiency for reporting and optimization purposes.

There has recently been more interest in hydrocarbon analysis of acid gas in combination with the H₂S and an abundance of work done in this area. In the past there was something of a false emphasis on speciation of the hydrocarbon because of the nature of the increase in “air demand” for each hydrocarbon component as it increases in carbon count (table 1).¹¹ Techniques such as GC, mass spec and Fourier Transform IR have been applied. They were expensive and most were abandoned, but they are also too slow as the analysis time exceeds the process transit time (transit time of a SRU is ~30-40 seconds at full load).

Solutions have been developed that combine UV and IR detection to measure the H₂S and total hydrocarbon. At first glance, a total hydrocarbon (THC) result would have limited value for feed forward control. It is also true that most stand-alone IR analyzers that measure THC results are only used for indicating purposes. A single measuring wavelength in the infrared at 3.3 – 3.4 microns can quantify the carbon count up to C₅ (Fig 7). The utility lies in taking the THC result, expressing that as total carbon count and then converting it to “air demand” using the same scale and measure as the tail gas analyzer so it can be implemented into the control loop. That is where the challenge exists: using the H₂S + THC to modify the air to acid gas ratio and realize true feed forward control.

Compound	Moles of O ₂ per Mole HC	Ratio of O ₂ Needed per Mole HC Compared to per Mole H ₂ S
Methane	2	4
Ethane	3.5	7
Propane	5	10
Butane	6.5	13
Pentane	8	16
Hexane	9.5	19

Table 1. Oxygen to Burn Hydrocarbons Compared to that for an equal amount of H₂S

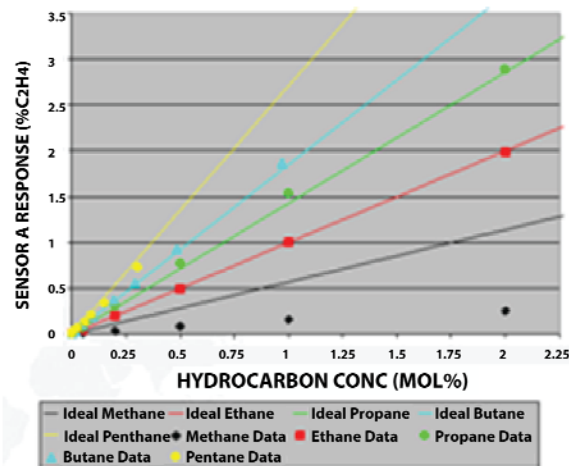


Fig. 7. Response of Infrared Sensor to a C₁ - C₅ Hydrocarbons

This process example (Fig. 8) shows the response during a hydrocarbon upset. The hydrocarbon range in steady state conditions is 0.02 % to 0.03 % and there is a diurnal variation, as one would expect from an amine treater based on daily temperature swings. The H₂S values (as measured by the NDUV section of the analyzer) indicate variations of 2-4 %. Some of these variations are quite sharp and could be useful in feed forward control in addition to the HC measurement. In June 2008 there was an upset where the HC spiked up from 0.02 to 0.25 % and then returns to 0.02% (Figure 8). There was a similar confirming change in the H₂S in the form of a peak-to-peak swing of 5 % (82% to 87 %) and then the HC returns to normal (~85 %) after about 20 minutes (Figure 8).

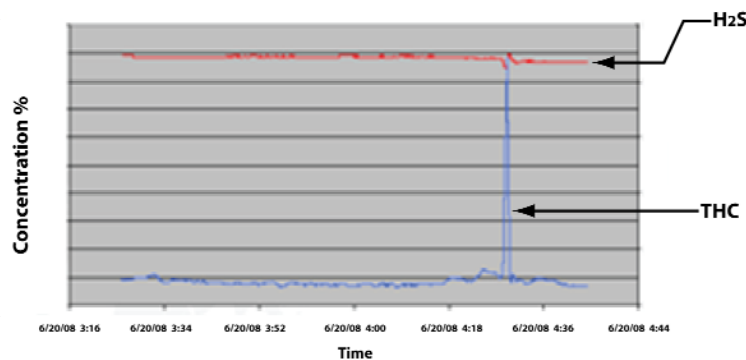


Fig. 8. H₂S and THC Measurements in SRU Amine Acid Gas During a Process Upset

The question is often asked as to how much improvement in recovery efficiency can be realized from the addition of feed gas analysis. Most of the quantification on this subject has been done on gas plants in western Canada where improvements such as feed characterization/feed forward control are commonplace and practiced to squeeze out that extra 0.2% to 0.4 % recovery efficiency. This is all about how much long-term benefit can be expected. Based on results, the observation may be: why bother? The answer is that the real benefit lies in the avoidance of short-lived, more serious upsets that result in the loss of 3%-5 % or more in recovery efficiency and cause emission violations and equipment damage. The next example illustrates how this applies not just to the SRU but also to the downstream TGTU.

An interesting anecdotal observation worth noting came from operators of SRU –TGTU while gathering customer input on feed gas analyzers. The operators said it was not the sudden appearance of hydrocarbons that gave them the most severe operational problems, but the sudden disappearance of the hydrocarbons. In the absence of feed composition information, the first indication of hydrocarbons in the acid gas can be the tail gas analyzer. When the H_2S in the tail gas spikes up, the SO_2 goes to zero, and the control response is to “add air” to come back to 2:1. Conversely, when the hydrocarbon episode suddenly ceases, the SO_2 in the tail gas spikes up and this causes damage in the TGTU, since it is difficult to get off the air before SO_2 breaks through the reduction reactor in the TGTU. The ability to anticipate the end of an HC episode at the front end before it transits the SRU to the TGTU is valuable in itself.

3.1) Sample Handling and The Heated Acid Gas Probe

Any discussion of acid gas analyzers has to include the sample system because of the toxic nature of the sample and in consideration of the technicians who work on it. During a survey of ~250 H_2S /hydrocarbon analyzers it was found that approximately half of those analyzers more than 10 years old had been abandoned; not because of analyzer failure, but because of fear of H_2S exposure. The solution has been the heated acid gas (HAG) probe (Fig. 9). It removes the fear factor because it isolates and purges the complete analyzer system prior to intervention.

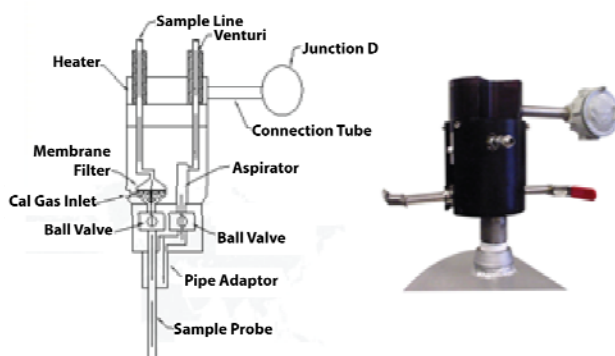


Fig. 9. Heated Acid Gas Probe

Sampling the acid feed gas presents unique challenges. Foremost, there is the toxicity of high concentration of H_2S . Second is the high water dew point that can be present in the sample gas. The third challenge of sampling the acid feed gas is the disposal of the analyzed sample. The sample gas cannot be vented to the atmosphere and transporting it any distance, to a flare header or incinerator for example, is a hazard.

The HAG sampling probe requires only a single process connection for both sample extraction and return. The HAG probe contains integrated shut-off valves that allow for complete isolation from the process for maintenance. This is done without removal from the process and it purges the entire sample system with N_2 for safety and confidence purposes. An integrated, serviceable membrane filter protects the downstream analyzer from entrained liquids and is temperature-controlled by an integrated electric heater to ensure that no sample condensation occurs within the probe. The HAG probe provides the motive force necessary to circulate the sample through the analyzer system. The sample is extracted and transported through the probe, analyzer, and sample system by a heated aspirator built into the probe's sample return path. It can be air, nitrogen, or steam-driven for flexible operation and safe sample transport.

Finally, the HAG probe has an associated benefit for the control and indicating functions of the compositional information. The typical sample point is after the acid gas knock out drum, directly before the reaction furnace. The HAG probe has a membrane filter to prevent the ingress of liquid and so the sample point can be located before the knock out drum. Using this to advantage, if the sample can be taken farther upstream, closer to the reflux accumulator the transit time of the process piping from sample point to the reaction furnace can be used for improved air control and warning of compositional changes.

4) TAIL GAS TREATING UNIT (TGTU)

The most important measured parameter in an amine TGTU is the hydrogen content in the gas exiting the reduction reactor. Good control and measurement of excess H_2 is important to provide stable operation and protect the amine from SO_2 breakthrough. H_2S is a secondary measurement and H_2S can be measured at one of two sample points (or both) depending on the design and requirements. The typical two sample points are the top of the quench tower and top of the absorber column. In addition, the measurement of COS can be made at the top of the absorber.

4.1) Sample Point Selection

The first (typical) sample point for H_2/H_2S is immediately after the CoMo reactor and quench tower. The H_2S measurement here quantifies all of the sulfur compounds in the SRU tail gas. This serves as a precise material balance (recovery efficiency measurement) that can be used as an optimization tool, serving much the same function as mass emission (CEMs) measurement mentioned earlier (Fig. 10).

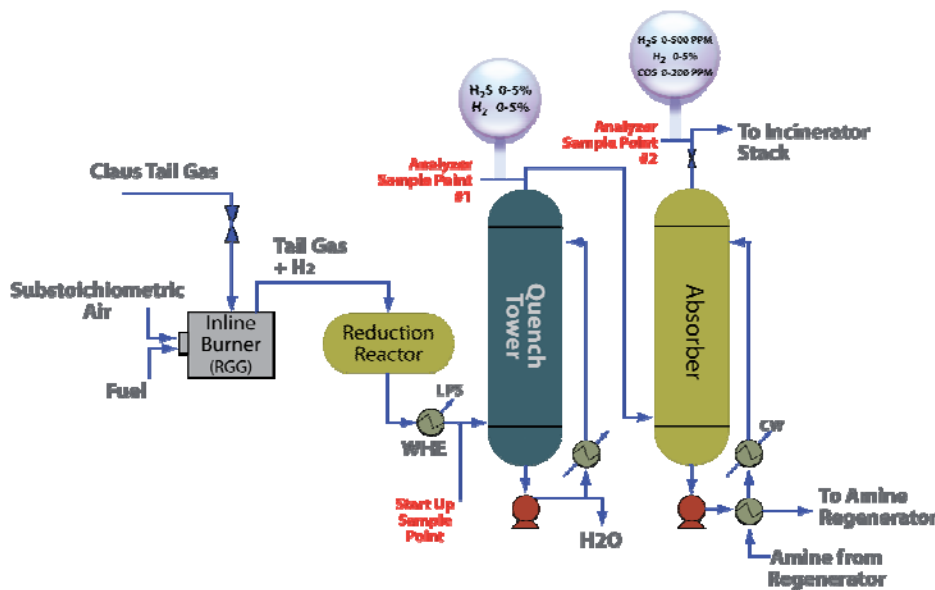


Fig. 10. TGTU Analyzer Sample Points

The second typical sample point for H_2/H_2S is after the absorber (before the incinerator) to monitor the operation of the amine treatment section (Fig. 10). By comparing the H_2S measurement here to the SO_2 CEM's value after the incinerator, the difference can be attributed to trace sulfur compounds including COS and CS_2 . COS (and CS_2) can also be measured at this sample point as COS is the first component to breakthrough the CoMo reduction reactor and the measurement here is useful in terms of CoMo catalyst evaluation. There are examples of TGTUs having H_2S measurements in both process locations with the H_2 measurement installed with the upstream and downstream analyzer. In any case, the sample point where the H_2 measurement is made is of no consequence, as the absolute amount does not change after the CoMo reactor.¹²

4.2) Using a Combined H_2/H_2S Analyzer

Until recently, a gas chromatograph (GC) was the most widely applied analytical method used to monitor hydrogen content. Although a GC gives accurate results, it has some disadvantages. The response time is long and it requires considerable maintenance. GCs are expensive, making it unattractive to install two analyzers at both the quench and absorber outlet. Two (redundant) H_2 analyzers can give a signal to the shutdown logic in case of low H_2 content. A new type of analyzer has been introduced that is fast, reliable and economical to operate.¹³

The design concept is based on combining a thermal conductivity detector (TCD) to measure the H_2 in combination with non-dispersive ultra violet (NDUV) to measure H_2S (COS, CS_2). The drivers for the development of the combined analyzer were based on collaboration with a TGTU designer who wanted faster speed of response, cost reduction and improved reliability. Direct measure thermal conductivity detectors had already started to replace GCs by ~1990. With this recent development, by operating the TCD at a higher temperature and characterizing the sensor for the specific TGTU gas composition made further improvements. The cross interference from CO_2 and H_2O on the H_2 measurement are reduced to insignificant levels.¹⁴

4.3) Sample Handling

There is a significant safety component to this application, in particular, if the sample point is before the absorber where H_2S is ~2.5 %. Technicians are more likely to maintain an analyzer with a simple and positive method to isolate the analyzer and where the sample system is specific to the application. The HAG probe mentioned in the acid gas feed analyzer is used here as well, and serves the same purpose. There is one addition for the application of TGTU. Field experience shows that sulfur and salts (caused by SO_2 breakthrough) were accumulating on the membrane filter. This membrane is only intended to serve as a prophylactic barrier to prevent the ingress of entrained liquid (amine). A modification was added in the form of a fiber filter. This was simple enough to machine into the functionality of the HAG probe to catch the salts. A subsequent SO_2 event deposited salts on the fiber filter (Fig. 11) but the HAG probe continued to draw sample and function as normal. This is one of those rare but pleasant experiences, at least for an analyzer engineer, where the analyzer proves more robust than the process. The following picture depicts this event.



Fig. 11. Sulfur on HAG Probe Particulate Filter After TGTU Process Upset

Measurement of SO_2 breakthrough into the quench tower is less common, but has been requested at the front-end engineering design and by users, typically after an event has damaged the amine. The measurement of the SO_2 can be combined with other parameters at downstream sample points, but it is only of practical use when the sample is taken upstream of the quench tower. The threshold limit of the measurement is 2-3 ppm SO_2 .

5) SULFUR PIT GAS

Hydrogen sulfide can exist in sulfur as dissolved H_2S and chemically bound hydrogen polysulfides. The liquid sulfur produced from Claus SRU typically contains 200-350 ppm of dissolved H_2S , mostly in the form of hydrogen polysulfides (Fig. 12). Spontaneous degassing and concentration of the H_2S in the gas phase can create serious personnel hazards. The problems occur due to decomposition of the polysulfides caused by agitation and temperature drop of the liquid sulfur.

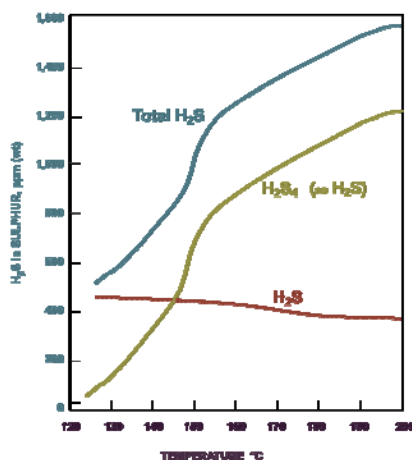


Fig. 12. Solubility of $\text{H}_2\text{S}/\text{H}_2\text{S}$ Polysulfides in Sulfur

Under these conditions, H_2S is emitted and accumulates in the gas space above the liquid sulfur. H_2S becomes progressively more dangerous as the levels incurred in handling of the sulfur and moving increases above toxic limits (70 ppm), becoming lethal at 600 ppm and reaching the lower explosive limit at ~3.5 %.¹⁵

Pit gas analyzers are more common in the Arabian Gulf region than in the U.S. or Europe, where large quantities of sulfur are handled and exported. Sulfur degassing and forming normally includes a pit gas analyzer in the scope. The measurement requirement is straightforward: H_2S is measured to warn of a build-up approaching the lower explosive limit (LEL). SO_2 is measured to give warning of a smoldering sulfur fire, often a pyrophoric reaction with exposed iron. The analyzer has to be designed and installed the same as a tail gas analyzer. The sample conditions

may not be quite as severe as tail gas, but the presence of sulfur vapor and the propensity for the sweep gas vent to plug, requires that the analyzer be immune from plugging under these conditions.

6) INTERSTAGE (PROCESS) OXYGEN MEASUREMENT

During start-up and shut-down, as an SRU transitions through fuel gas warm-up to the introduction of acid gas, the measurement of O₂ is required. Historically, operators have manually taken samples using a portable electrochemical type O₂ analyzer. While giving more or less satisfactory results, the requirement of more stringent operating limits and hazard exposure are reasons to consider a permanent solution.

A fixed system that draws a continuous sample during the operational transition period, without intervention from operations or analyzer maintenance, can be rationalized and has been developed specifically for start-up and shutdown purposes. The motivation from the operator's perspective is a combination of safety and operational requirements. The requirement for most refineries is to start up the entire sulfur recovery plant (SRU + TGTU) in a single sequence with zero tolerance for emission exceedences. More frequent manual sampling increases personnel exposure.

As it turns out, the continuous measurement of O₂ in an SRU process stream is not new. AMETEK developed and supplied ~45 systems for Superclaus where excess O₂ is measured in SRU tail gas before a subsequent generation of the catalyst obviated the need for the measurement. The detection principal is paramagnetic. It measures "bulk O₂" and is widely applied in process O₂ applications where the gas has flammable components.

The sample handling for the continuous measurement technique could be quite conventional provided fuel gas was the only mode. When acid gas is cut in, the sample conditioning must contend with sulfur vapor and liquid; therefore, the sample handling requirements are similar to a tail gas "ratio" analyzer. While the measurement is not required after acid gas has been introduced and in steady state, there is a period in which the paramagnetic sensor must be protected from exposure to sulfur vapor. The sample system is designed for this duty. It utilizes the "advanced sulfur reduction" (ASR) probe as well as a heated oven for a second level of pre-filtration before the paramagnetic O₂ cell. Samples can be taken from the outlet of the 1st, 2nd, 3rd or 4th (final) condenser. A single analyzer can switch between SRU trains or sample points depending on requirements.¹⁶

Sulphur Experts Inc. recommends that the fuel gas warm-up burn strategy should or no more than 0.1 % excess and to always prevent free oxygen from reaching the hot catalyst. This requires "city" gas as a fuel source and accurate flow metering for both air and fuel gas. The continuous O₂ measurement is a degree of detail that ensures protection of the catalyst, prevents emission episodes and most importantly provides a level of protection for operations personnel.

7) MAINTENANCE PROGRAMS AND AVAILABILITY EXPECTATIONS

Process analyzers require a maintenance program. Anything less than a dedicated department and philosophy to this end is certain to bring disappointment to operations, management, and the people responsible for the maintenance, as well as the vendor. This section discusses the metrics for establishing proper staffing levels.¹⁷

7.1) Analyzer Personnel Requirement

A supervisor for managing technicians, project coordination and interacting with other departments, depends on the size of the team and project. The supervisor manages the progression of direct reports and job planning. The supervisor's role is critical in maintaining the analyzers. Workload should be based on prior similar role experience and knowledge of analyzers. The size of the team for the fresh graduate, less-experienced supervisor needs to be limited to four or five direct reports.

An experienced supervisor with responsibility for a large number of analyzers would form teams and nominate a lead technician based on the number of technicians working in the same area. A lead technician would directly report to the supervisor on every day maintenance issues and guide/train the junior technicians. The experienced supervisor could manage a team of 15 to 20 technicians comprised of four lead technicians.

The number of technicians required can be calculated based on the number and type of analyzers maintained. Each analyzer type is graded in terms of maintenance function based on analyzer complexity (Table 2) to determine manpower needs. Based on the complexity factor, a man-hour estimate to perform the task can be quantified. Calculating exact man-hour estimates for an analyzer is difficult. Clearly, the amount of time allocated to a system can vary based on technician experience and the type of failure. Good timekeeping and statistical quality control (SQC) data is required to accurately calculate time. Analyzers can be classified in the following categories:

Complexity Factor	Type of Analyzer	Estimated Man-Hours
1~5 (Simple)	pH, conductivity, gas detection, O ₂	2
6~8 (Physical Property)	Boiling point, flash point, freeze point, RVP, viscosity, etc	3
9 (Environmental)	CEMs SO ₂ , CO, H ₂ S, Opacity,	2.5
10~15 (Complex)	<u>Tail gas</u> , GC, Mass Spec, NIR, FTIR	4

Table. 2. Grouping of Analyzer Categories for Maintenance Purposes

In the opinion of the analyzer engineer and his colleagues who developed this chart for multiple refinery sites within their organization, a tail gas analyzer is “10” in terms of complexity. This is on a par with or slightly less than a process GC.

To distribute the process analyzer maintenance workload equitably among analyzer technicians and to provide preventive/predictive maintenance, the various process analyzers in a large facility can be divided into analyzer types or geographic location. To determine the manpower

needs: Quantify the total number of analyzers needing to be maintained and calculate the total maintenance hours required per week. Total number of maintenance hours divided by the number of scheduled work hours gives us the manpower required to perform the work load. Following is an example of a modest size gas treating/SRU complex (Table 3).

Category	Number of Analyzers	Estimated Man-hours to perform the task	Total Maintenance Hours
Simple	20	2	40
Complex	14	4	64
Physical Property	1	3	3
Environmental	2	2.5	5
Total			112
Scheduled man-hrs per week = 40			
Staffing required = $110/40 = 2.8$ (~3-4 personnel to allow for training, vacation)			

Table. 3. Staffing Levels for Analyzer Maintenance for a Gas Treating SRU Complex

The number of analyzers maintained by each technician is determined by experience and skill set. Experienced technicians can manage more complex analyzers compared with junior technicians. The geographic area could be grouped and technicians could take responsibility of specific areas. Job rotation at specified time intervals will familiarize the technicians in all the areas and allow them to acquire knowledge on a wide variety of analyzers. This will also facilitate vacation, training and call out support. When calculating the maintenance personnel requirement remember to include time for vacation, training, safety and other periodic meetings. The total available time per year, per technician, is approximately 1600-1700 hours. When calculating maintenance personnel requirements remember to include time for vacation, training, safety and other periodic meetings. The total available time per year, per technician, is approximately 1,600-1,700 hours.

References:

- 1) Bohme, Gerald and John Sames. "The Seven Deadly Sins of Sulphur Recovery." Paper presented at the Sulphur Conference, Calgary, Alberta, Canada, October 1999.
- 2) Hunt, C., J. Sames, R. Hauer. "Understanding Claus Process Upsets Using Your Tail Gas Analyzer," *Sulphur Magazine*, no.256, (May/June 1998).
- 3) Stevens, D.K. and W. H. Buckhannan. "Enhanced Process Configurations for the CBA Process." *Sulphur Magazine*, no. 225, (March/April 1993).
- 4) Harris, P. and H. Adam. "The Design and Practical Application of UV Process Photometers." *L'Analyse Industrielle*, Paris (1996).
- (5) Boorsboom H., R. van Grinsven, P. van Nisselrooij and E. Butler. "Superclaus/Euroclaus," *The Latest Developments*, (February 2004).
- 6) Paskall, H.G. "Capability of the Modified Claus Process." 1979.
- 7) Klint B. and P. Dale. "Ammonia Destruction in Claus Sulphur Recovery Units." Presented at 49th Annual Laurance Reid Gas Conditioning Conference, 1999.
- 8) Potter D. and R. Hauer. "Sample Techniques for Process Analyzer Applications." Presented at International Forum Process Analytical Chemistry, Baltimore MD, January 2007.
- 9) Federal Register; Vol. 72/No. 92, Monday May 14, 2007. EPA 40 CFR Part 60, subpart J(a), Standards of Performance for Petroleum Refineries, Proposed Rules.
- 10) Klint, B. "Incinerator Optimization/Stack Top Temperature Reduction."
- 11) Harris K. and R. Hauer. "Measuring Total Hydrocarbon and H₂S in Amine Acid Gas Streams." *Hydrocarbon Processing Magazine*, February 2009.
- 12) AMETEK Process Instruments. 2007. *Reduction - Amine Tail Gas Treaters*. Pittsburgh, PA.
- 13) Bloemendal, Gerrit and E. Tisheler. "Low Temperature SCOT Catalyst Pays Off." *Hydrocarbon Engineering*, December, 2004.
- 14) Harris K., R. Hauer, D. Potter, P. Harris, and B. Lewis. "Field Experience with a Single NDUV + TCD Analyzer on Amine Based Tail Gas Treating Units." Presented at ISA Analysis Division Spring Symposium, April 2007.
- 15) "Controlling H₂S Evolution for Sulphur." *Sulphur Magazine*, no. 233, (July/August, 1994).
- 16) AMETEK Process Instruments. 2008. *Continuous Measurement of Process Oxygen for Claus Sulfur Recovery Unit (SRU) Start-ups and Shutdowns*. Pittsburgh, PA.
- 17) Neil Holmes, Chevron USA. Conversation, January 2009.