Moving Targets: How Ever Changing Air Quality Regulations are Driving Process Decisions

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Abstract

Historically, the concern of process engineers was the design and operation of plants to do primarily one thing, efficiently meet product specifications. In today's changing regulatory environment, there are additional concerns design engineers may neglect.

These concerns include Volatile Organic Compounds (VOCs) and Hazardous Air Pollutants (HAPs) emissions as exceeding thresholds can limit throughput, increase liability to the operator, and add significant lead time to plant construction or modifications. A case study aimed at debottlenecking a large cryogenic gas plant is presented to investigate a legacy VOC and HAP issue as well as maximize overall plant production. The debottlenecking study focused on multiple amine sweeting units and their associated still vent emissions. Interestingly, methanol was found in surprising amounts in the still vent emissions. Control devices were assessed and subsequently installed to alleviate any future VOC and/or HAP issues and allow for increased production.

The regulation of Green House Gases (GHGs) has changed significantly of late, with the likely outcome that treating will be performed in the field at "minor sources". Producers operating large plants already categorized as "major sources" of air pollutants must pay careful attention to these GHGs. A case study of a cryogenic gas plant is presented where increasing plant throughput was potentially bottlenecked due to emissions of CO_2 in excess of Prevention of Significant Deterioration (PSD) permitting thresholds. A thorough analysis was performed of the plant to manage CO_2 emissions while still maintaining product specifications. This allowed the operator to avoid a long, costly regulatory review and permitting process while still increasing production.

With current GHG regulations likely to push gas treating into the field, sour gas streams may be the new bottleneck as SO_2 emissions may curtail production due to the National Ambient Air Quality Standard (NAAQS) for SO_2. Designers will need to begin evaluating the technologies best suited to work around this issue.

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Introduction

Historically, the primary concern of process engineers has been optimizing plant design and operation for two purposes: to make product specifications and to do so as economically as possible. However, with ever increasing regulatory rules on the operation of various upstream/midstream facilities, it is no longer sufficient to focus solely on product specifications and operating costs. There is another design parameter-namely air quality permitting and regulatory compliance-that should be considered at the front end engineering design (FEED) stage, if not earlier. Not doing so can create bottlenecks or unanticipated delays in obtaining construction permits in facilities and fields, even though the facilities may otherwise be able to meet product specification economically.

Air quality issues can have a variety of direct impacts on facilities. For starters, bumping up against thresholds for particular contaminants can limit plant expansion if emissions are directly proportional to plant throughput. A plant with emissions approaching a threshold for a given contaminant may not be able to increase throughput without triggering lengthy delays and costly environmental reviews.

Likewise, a design project that does not address emissions thresholds at the FEED stage could find itself greatly delayed by regulatory permitting. Not being aware of the regulatory framework can delay projects unnecessarily by months, if not years, hurting profitability and unduly adding to operating costs.

If air emissions regulations are considered at the pre-FEED stage, operators and designers can take advantage of the current regulatory conditions and “optimize” their facility designs, so to speak, to avoid unnecessary costs and add considerable operational flexibility.

Overview of Current Air Quality Regulations

Air quality regulations are a complex and continuously evolving issue that should be considered in all phases of a project from initial design to final hand-off to operators. The first regulatory consideration is obtaining authorization to construct a facility. There are multiple permit types and each varies from state to state, with permitting lead time increasing as larger emission thresholds are exceeded. The highest level of pre-construction air permit is known as a Prevention of Significant Deterioration (PSD) permit. [1] If a PSD permit is required, construction of new or modifications of an existing facility may not begin until the permit is issued. The elapsed time between applying for a permit and final issuance can be long, taking up to 24 months, potentially creating a prohibitive delay in the execution of a project. If PSD emission thresholds are considered in the initial design of facility, changes could be made to the design to ensure emissions are held below the thresholds, allowing the operator to avoid PSD permitting entirely and apply for a more streamlined permit. Avoiding PSD permitting will reduce the required lead time to obtain a permit and potentially avoid onerous operating restrictions and monitoring requirements that could significantly hinder the economics of a project.

A second regulatory consideration is initial and ongoing compliance with Federal and state air quality rules and the potential requirement to obtain a federal operating permit. For example, if a new gas processing plant has potential to emit (PTE) emissions of Criteria Pollutants (NOx, CO, & VOC) greater than 100 tpy or Hazardous Air Pollutants (HAPs, generally BTEX, n-Hexane and Methanol) greater than 25 tpy, the facility will be considered a major source and therefore subject to significantly more stringent emission control standards, monitoring, recordkeeping and reporting. An initial design optimized to reduce VOC & HAP emissions in conjunction with emission controls may allow the owner/operator to avoid a lengthy permitting process and significantly lower compliance costs in the future. **Table 1** contains a list of PSD major thresholds for facilities that are not on the list of 28 named stationary sources.

Table 1: Major Contaminants and Thresholds of Concern to Oil & Gas Processors [2]

Pollutant	PSD Major Source Threshold (tpy)	PSD Major Modification Threshold (tpy)	Title V Major Source Threshold Attainment Area (tpy)
NO_X	250	40	100
VOC	250	40	100
CO	250	100	100
SO2	250	40	100
GHG	100,000	75,000	N/A
HAPs (combined)	-	-	25
HAPs (single)	-	-	10

As new strategies to reduce air pollution have been developed, they have become standard practice, or what the EPA calls “Best Available Control Technology”, or BACT. A project subject to PSD permitting undergoes a lengthy “BACT Review”, a pollutant-by-pollutant analysis of available control technologies to ensure that the most effective method is chosen without being prohibitively expensive. If the project is not using the current BACT, the owner/operator will be required to demonstrate why current BACT is prohibitively expensive and that the use of somewhat less effective emission controls are justified.

The evolution of BACT marches on, year by year, as the regulatory environment continually changes. BACTs, though, are not simply “end of pipe” controls. Optimizing facility operations to mitigate emissions is one of many effective strategies of preventing a BACT review by a regulatory agency. So designers and operators should investigate in detail what avenues they have available to reduce the additional costs of air quality issues, especially in terms of operation. This optimization requires a full understanding not only of the process, but also the regulatory environment in which the plant will operate.

Case Study 1: Large Cryoplant Expansion Bottlenecked by HAPs Emissions

An example of how the regulation of VOC and HAP emissions directly impacts the operation of plants can be demonstrated from a large cryogenic processing facility located in the lower 48-states. This facility receives field gas from both conventional and unconventional sources. As new wells began coming on line, the processor had a strong need to increase throughput in the facility.

For most facilities, treatment units, whether glycol dehydration units or amine sweetening units, are potentially a large source of VOCs, HAPs, and other regulated contaminants. Emissions result from a variety of other sources, such as fugitive emissions, engines, compressors, etc., however gas treating systems can be large contributors to emissions from central processing facilities. Gas treating systems must be operated to meet product specifications without exceeding emissions thresholds. This can be achieved either by optimizing plant operation, by the installation of control devices, or by some combination of the two.

In this case study, the gas being treated was relatively free of H_2S, and the regenerator overheads were simply vented to the atmosphere, a past common practice. The inlet compositions and operating parameters of these amine units can be found in **Table 2** and **Table 3**.

After the FEED stages of the project, Air Quality personnel undertook a simulation of the plant using ProMax® [3] to predict the plant emissions during current operations, and then to predict emissions after expansion. To confirm the predicted results, direct measurements were taken from the amine sweetening unit overhead vents. A comparison of the data taken and the simulation results can be found in **Table 4**.

Table 2: Composition of Absorber Feed Gas

	Gas Treater	Liquid Treater
T (F)	100	85
P (psig)	360	810
Flow	30 MMSCFD	7.4 Mbbl/d
Mol %		
CO2	2.97	2.89
C1	2.00	0.24
C2	62.68	54.75
C3	31.76	20.66
iC4	n/a	5.70
nC4	0.59*	6.07
C5	n/a	5.18
C6+ alkanes	n/a	3.94
BTEX	n/a	0.57

*Modeled as “C4+”

Table 3: Operating Conditions

	Gas Treater	Liquid Treater
Circulation (sgpm)	190	35
Solvent Strength (wt %)	45	45
Lean Amine Temp (F)	135	122

Table 4: Comparison of Simulated Emissions Results to Direct Measurement

	VOCs (tpy)		Benzene (tpy)		Propane (tpy)	
	Meas.	ProMax	Meas.	ProMax	Meas.	ProMax
Gas Treater	98.3	85.0	0.72	n/a	94.42	83.1
Liquid Treater	10.06	10.49	5.29	5.55	2.39	3.26

The data confirmed what ProMax predicted; mainly that the facility could not be expanded without a change to the design and operation.

What was surprising to all was the amount of methanol measured in the amine regenerator overheads. Methanol is considered a HAP, and therefore has a threshold of 10 tpy as an individual component. It also contributes to the combined HAP threshold of 25 tpy. In the upstream industry, it is quite common for producers to inject methanol into pipelines and processes for hydrate inhibition. What was unknown was how much of this methanol actually makes its way into the amine system and eventually into the process emissions. In general, the presence of methanol is seldom indicated on a plant's heat and material balance if methanol is not intentionally being added in the facility.

As indicated in **Table 5**, very small amounts of methanol in the feed to the amine system can generate substantial emissions. A change of as little as 0.001 mol% methanol in the feed gas can result in changes of several tons per year for this particular system. A small error in measuring the feed composition can therefore cause large swings in the predicted emissions.

Table 5: Methanol in Feed and Regenerator Overhead

	Gas Treater	
	Meas.	ProMax
Feed (mol %)	0.005	0.005
Regen. Ovhd (tpy)	14.16	11.0

While in small amounts methanol is not detrimental to the operation of an amine sweetening unit, given time, methanol can accumulate within the unit. In some ways similar to ammonia in refinery sweetening units, methanol has no quick outlet. Methanol is readily washed from the gas by the amine and carried over to the regenerator. From there, it spreads through the system, accumulating in the regenerator overhead loop as well as in the circulated amine. This accumulation can have obvious negative effects, such as a depression in the boiling point of the liquid in the reboiler, a reduction in the overall capacity of the amine circulated, as well as an increase in the methanol emission from the overheads. A purge from the reflux system can bring these values down considerably.

Without the presence of a sulfur recovery unit, simply elevating the temperature of the condenser may seem an obvious choice to the process engineer. A cold reflux pushes the methanol back into the system in the circulated amine, effectively driving it into the sweetened product. A warmer reflux allows the methanol to leave in the regenerator overheads.

Again, the third design parameter, air quality, should be included in the process decisions. It is important to keep the methanol out of the regenerator overheads as best as possible since flare or thermal oxidizer systems can reduce emissions by a maximum of 98%. Elevating the condenser temperature could mean exceeding the 10 tpy threshold for methanol or unnecessarily contributing to the combined HAPs threshold of 25 tpy. Operating the condenser at a lower temperature, and then running a purge, allows the producer to remove the methanol in an aqueous form to be shipped off for reprocessing or disposal.

For this case study, the presence of methanol was a major concern for emissions, but operationally was of smaller concern due to the configuration of the amine regenerator and the relatively small levels of methanol in the feed.

With a baseline simulation and full understanding of all the contaminants in question, a new simulation was performed showing the effects of plant expansion, as shown in **Table 6**.

Table 6: Comparison of Emissions before and after Expansion of the Entire Facility

	Before Expansion	After Expansion	Net Increase	PSD Threshold
VOCs	320	400	80	40
Benzene	34	42	8	10
HAPs	147	185	38	25
Methanol	102	128	26	10

Comparing the simulated results to **Table 1**, it can be seen that expansion of the facility would require major changes in operation as well as the installation of control devices to avoid a costly PSD review.

In order to continue operations and allow for plant expansion, emissions controls were installed on all amine still overhead vents. An expansive duct system was constructed to gather all of the overheads to a common direct fired thermal oxidizer. A direct fired thermal oxidizer was chosen due to its ability to handle amine plant upsets and potential swings, even though the fuel costs were higher than for a regenerative thermal oxidizer. In the case of a plant upsets, a regenerative thermal oxidizer had the potential to overpressure the combustion and regeneration chambers, an unacceptable risk. The addition of the direct fired thermal oxidizer lowered all VOC and HAP emissions by 98%.

Table 7: Comparison of Plant Emissions before and after Optimization and Control Devices

	After Expansion	With TO	Threshold
VOCs	400	8	40
Benzene	42	1	10
HAPs	185	4	25
Methanol	128	2.5	10

While the addition of the thermal oxidizer drastically reduced the criterion pollutants emitted from the facility, it did so by converting them to CO_2. This, of course, raises new concerns.

GHG Emissions are Different

Similar to HAPs, Green Houses Gases (GHGs), specifically CO_2 and Methane, are becoming more stringently regulated. In the past, CO_2 was seen as a compound that could be freely emitted as it was not classified as a pollutant under the Clean Air Act. On December 15, 2009, the EPA determined that greenhouse gas emissions endanger the public health and welfare of current and future generations. [4] This decisions paved the way for the EPA to regulate GHGs. [5]

The regulation of CO_2, however, is an ever changing question, and it carries some caveats that are not present with the regulation of HAPs. In general, if an operator is looking to either construct a new facility or expand throughput for an existing facility, the operator must address any increase in CO_2 emissions. Current GHG permitting rules require a GHG BACT review if emissions are increased by more than 100,000 tpy for a new source, or 75,000 tpy for a modification of an existing facility. However, this rule only applies to facilities which are considered a major source due to other criteria pollutants. Exceeding the major source threshold for GHGs alone does not make a facility a major source or trigger PSD permitting requirements.

Confusion could be expected here, but the explanation is as simple as this. An increase in CO_2 emissions is *only* regulated if the facility itself is *already* a major source. If the facility is a minor source, CO_2 and GHG emissions are not regulated.

Case Study 2: Major Source Gas Plant Expansion Bottlenecked by GHG Emissions

An example of how this rule can affect a facility that is already a major source can be taken from a different case study. This facility was already a PSD major source as NOx and CO emissions were in excess of 250 tpy. The implication is that the facility was subject to the threshold of 75,000 tpy maximum increase of GHGs for a major modification. It was therefore required to not only review criteria pollutant and HAP emissions, but also GHG emissions if the facility was to be expanded.

Expansion of the facility would increase GHG emissions by projects that added engines, compressors, etc., as well as by increasing emissions from CO_2 recovered from the sweetening unit. The project emissions totaled approximately 60,000 tpy, leaving 15,000 tpy to spare for the amine system before crossing the 75,000 tpy threshold. Given the current methods of operation, ProMax runs showed that simply increasing throughput in the amine systems as currently operated was inadequate. The material balance for this facility can be found in **Table 8**. If air quality was not a concern at the FEED stage for this expansion, a lengthy, PSD review could have been triggered after the engineering design was complete. That would mean up to two full years, extra engineering time, plus construction time, before the increased capacity would be available in the plant.

Table 8: CO_2 Balance for Facility with Additional Throughput at Current Operating Conditions

	Base	Expanded	Change
	GHG, tpy	GHG, tpy	GHG, tpy
Inlet Gas	142,700	179,800	37,100
Residue Gas	47,500	59,800	12,400
Y-Grade	1,200	1,500	300
Emissions	**94,000**	**118,500**	**24,400**

A workaround was required to adjust the design to meet the three primary goals: continue to make product specification, keep emissions below required thresholds, and do so as economically as possible.

To reduce emissions thresholds, the plant needed to be considered as a whole. CO_2 enters the facility and primarily would leave in the amine regenerator overheads. As emitting all of the CO_2 from the regenerator overheads would exceed GHG thresholds, a workaround was to find other outlets, mainly in the various products.

Doing so, of course, meant the danger of having products that were off specification for CO_2. A thorough examination was performed, with the goal of maximizing the residual CO_2 in the products, thereby maximizing the reduction in GHG emissions due to the expansion. A material balance is shown in **Table 9** indicating the new operational regime, as well as the reduced GHG emissions from the plant.

This particular facility had rather generous specifications for CO_2 for both treated vapor and liquid products. As a result, amine circulation was reduced considerably, allowing the CO_2 to escape in the residue gas and Y-Grade product. This also resulted in reduced VOC emissions, an added benefit as these emissions are combusted and form additional CO_2. Using ProMax to model the amine system as well as the VOC combustion, process modifications were made to reduce the total GHG emissions for the expansion.

Table 9: CO_2 Balance for Facility with Revised Operating Parameters

	Base	Expanded	Change
	GHG, tpy	GHG, tpy	GHG, tpy
Inlet Gas	142,700	179,800	37,100
Residue Gas	47,700	67,800	20,100
Y-Grade	1,000	2,000	1,000
Emissions	**94,000**	**110,000**	**16,000**

Even after optimization, the 75,000 tpy was still being exceeded. The decision was then made to cancel a few parts of the expansion projects and to swap out older, less efficient equipment for newer equipment. This equipment modification resulted in a net CO2 offset of 6,000 tpy, meaning that the equipment contribution was now only 54,000 tpy. This amount, added to the new amine emissions of 16,000 tpy, came in below the regulated threshold.

As can be seen, the means of staying under thresholds was adjusting the process operation itself, not an end of pipe control device. While control devices are important, they may not be the sole solution in and of themselves. Many times emissions problems can be avoided if they are considered in the front end of design and operation. If this were not done in this case, again a lengthy, PSD review would be required, delaying the project as well as operational profits.

GHG Rules: Effect on Upstream Facility Planning Strategies – Minor Sources

The rules on CO_2 are indeed interesting in their current state. The above example is for a facility that was already defined as a major source and the GHG rules strictly applied. But what if the designer took a step further back? What if it were possible to construct facilities that are not major sources, or at least separate the units that are large GHG emitters but minor criteria pollutant emitters? What would the implication be? A recent Supreme Court decision decided that GHG PSD rules only apply to major sources of criteria pollutants and that a source cannot be major for GHGs alone. [6]

As a result of this Supreme Court decision, industry implications are clear. Steadily, more and more upstream and midstream operators are pushing various product treatment plants out into the field. Not bringing them “inside the fence” means that they do not share the same major source tag that the large facility does. The distance required to have the emissions from these units counted separately from the larger facility could be as little as one-quarter mile. [7]

However, simply spacing the facilities for separate permitting and reporting is not enough. It is important that these facilities remain minor sources and do not cross any criteria pollutant threshold. The most common way that amine units cross into the major source category on their own is through over-circulation.

In a busy industry undergoing rapid growth, a perfectly optimized design can take a back seat to getting equipment online and running as quickly as possible. Installing an amine unit that is clearly too large may still meet requirements for product specification. Likewise, the economic advantage of getting the unit running sooner rather than later may offset any unnecessary operating costs that the larger unit entails. However, the costs could rise rapidly if the third design parameter, air quality, is not also considered.

As an example, a typical amine sweetening plant can produce or can have production expanded by up to around 85 MMSCFD without crossing the 25 tpy threshold for HAPs (assuming gas contains 0.25% BTEX and 98% control efficiency is implemented). Note that, for gas containing 6% CO2, the GHG emission increase would have been over 100,000 tpy. A major source would have been limited at 75,000 tpy of increased GHG emissions equating to a loss of 25 MMSCFD of potential plant expansion.

These round figures assume an appropriate rich loading of around 0.4-0.5. If the plant is over circulating, the available expansion diminishes rapidly, as evidenced in Figure 1.

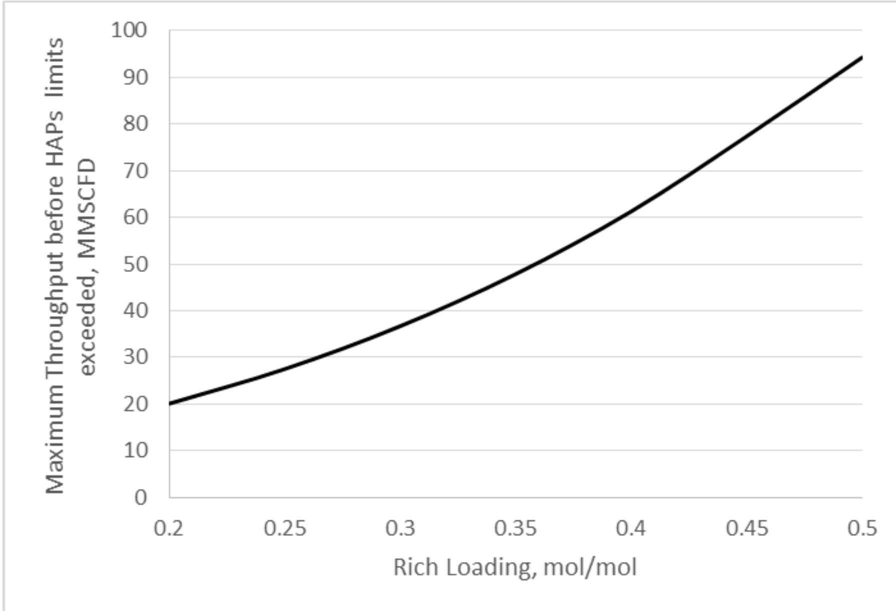

Figure 1: Effect of Over Circulation on BTEX Emissions from an MDEA unit, 0.25% BTEX in feed gas

This is another reason why it is important for designers to consider air quality at the FEED stage, and perhaps even the pre-FEED stage. Beyond control devices, adjustment to plant operations and the physical location of the plant can be extremely important for operators to efficiently meet their goals of: meeting product specifications, remaining under emissions thresholds, and doing so as economically as possible.

If the trend continues and more and more amine sweetening units are isolated from other facilities, a new set of concerns may arise that will limit throughput for the various fields, a new bottleneck.

Future Obstacles due to Air Quality Regulatory Effects on Industry Behavior

For the past few years, as producers have moved through the various plays, they have generally avoided the sour portions of their leases. In this case, sour is specifically referring to the presence of H_2S. As more and more leases are becoming fully utilized, producers have no choice but to begin moving into the more sour areas, thereby producing more H_2S. Until now, sulfur has been of minimal concern to producers since the shale revolution began some seven to eight years ago.

Historically, H_2S is removed in amine sweetening units and is later converted to elemental sulfur using the Claus Process. The Claus Process, also known as a Sulfur Recovery Unit, is typically a large plant with a high capital cost and appropriately fits at large processing facilities. As such, it is typically not an economic choice for small sources of H_2S. On top of this, with very high CO_2:H_2S ratios in the acid gas, Claus units are not as effective.

The question then becomes, as more and more treating is pushed out into the field and away from central processing facilities, what technologies will be best suited to fill the void? While many producers may currently flare their acid gas or otherwise convert H_2S into SO_2, eventually these facilities will approach their emissions limitations for this pollutant and will subsequently find production growth stymied.

Other technologies are available for extremely small H_2S levels, such as solid and liquid scavengers. However, many non-regenerable technologies become uneconomical as H_2S levels increase. So the next challenge the industry may face will be the best technologies to handle these remote, small quantities of H_2S in developed leases and fields and do so economically. Something between a scavenger system and a traditional sulfur recovery unit may be needed, such as a direct conversion system. There are many interesting technologies that have been developed that may be suited for this application. A thorough assessment of the available options would be of considerable benefit to operators going forward.

Conclusion

Over the decades since the implementation of the Clean Air Act, industry has seen a constantly shifting regulatory environment with expectations and controls increasing year after year. Practices that have been acceptable in the past are no longer so, and the industry is ever adjusting to the current state of affairs from regulators. In recent years, due to various EPA and court rulings, an interesting development has occurred where operators can, within the bounds of the law, take advantage of favorable conditions and adjust their operations accordingly. Doing so, however, requires consideration of the air quality rules very early in field development, well before facilities have been built. It is in every operator's best interest to consider these hurdles as one of their primary design goals, along with meeting product specifications and optimizing facility economy.

References

[1] ProMax, 3.2.13330, Process Simulation Software, Bryan Research & Engineering, Inc., 2014.

[2] Clean Air Act, Title I, Part C

[3] 40 CFR Part 52.21

[4] *CO_2 Endangerment Finding*, Federal Register, Vol. 74, No. 239, December 15, 2009

[5] *Action to Ensure Authority To Issue Permits Under the Prevention of Significant Deterioration Program to Sources of Greenhouse Gas Emissions: Finding of Substantial Inadequacy and SIP Call; Final Rule*, Federal Register, Vol. 75, No. 238, December 13, 2010.

[6] *Utility Air Regulatory Group v EPA,* 134 S. Ct. 2427 (2014)

[7] *Summit Petroleum Corp. v EPA,* 690 F.3d 733 (6th Circuit) (2012)