

**OVERVIEW OF THE DESIGN AND TROUBLESHOOTING EFFORTS
AT REGENCY'S WAHA AND TILDEN ACID GAS INJECTION
FACILITIES**

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Brimstone Sulfur Symposium
September 2010
Vail, Colorado

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ABSTRACT

This paper discusses two sites where acid gas injection (AGI) facilities were started up in mid-2007. Both initial design and subsequent startup/operation of the units are discussed. This paper is an update to a previous version presented at the 2009 Laurance Reid Gas Conditioning Conference¹.

For both sites, factors in choosing the design of the surface facilities are discussed. For example, some of the information covered includes: i) why a glycol dehydration unit was chosen at one site and simple gas cooling and water condensation chosen at the other; ii) why acid gas is a relatively clean and easy glycol dehydration unit application from an operations standpoint as compared to a typical field natural gas stream; iii) designing the system with a glycol pre-contactor with minimum pressure drop to allow use of a carbon steel dehydration tower; iv) why the glycol dehydration unit was designed without a glycol flash tank in this service; v) the guideline used for maximum allowable relative water saturation of the gas streams to prevent corrosion of carbon steel; and vi) how the design had to balance the need to condense water yet avoid hydrates at the site with simple gas cooling.

The paper also discusses lessons learned during troubleshooting efforts at the site that had acid gas cooling and positive displacement pumping of the acid gas. Operating data showing compressor discharge pressure and acid gas cooler temperature are used in reviewing NPSH as it relates to high-pressure liquid and dense-phase fluids. High gas cooler pressure drops are compared with predicted hydrate forming conditions.

I. Introduction

In mid-2007, Regency Gas Services (Regency) started up acid gas injection (AGI) facilities at two sites, Waha (in West Texas near Pecos) and Tilden (in South Texas near San Antonio). The Waha AGI design basis was 2 MMscfd of sour acid gas containing 10% H₂S and 87% CO₂ (with the balance being other hydrocarbons). The acid gas at Waha was compressed from ~6 psig to the wellhead injection pressure of 1200 to 1400 psig. The Tilden facility design basis was of similar capacity (2.6 to 2.9 MMscfd), but the sour acid gas had much higher H₂S content (~34% H₂S and ~65% CO₂). The acid gas at Tilden was compressed and pumped to a wellhead pressure of ~2500 psig.

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Trimeric participated to varying degrees in the design and/or troubleshooting of these two facilities. For the Waha facility, Trimeric helped Regency sort through the possible acid gas injection surface equipment schemes to remove water and prevent corrosion in the AGI equipment and downstream piping (glycol dehydration unit selected), and analyzed cooling and pumping options. Once the base process flow scheme was chosen, Trimeric prepared a process design package (PDP) for the unit and assisted the detailed engineering firm with process details associated with the purchase of the glycol dehydration unit and with the construction of the overall facility. Trimeric created operating procedures, training materials, and then gave Regency's employees training on the acid gas injection system. Startup of the Waha AGI facility occurred relatively trouble free.

Trimeric's involvement at the Tilden AGI facility was limited by comparison, and initially only included doing a study to identify water removal schemes (in this case gas cooling and water condensation was selected). Trimeric did not otherwise participate in the design phases of the Tilden AGI unit. However, as a result of poor performance during startup, Trimeric did later assist Regency with troubleshooting and with post startup process and equipment optimization activities. The primary startup problems at Tilden included net positive suction head (NPSH) issues with an acid gas pump, and control issues with the downstream injection pump skid.

Safety, health, and environment considerations with AGI units are very important given the toxic nature of the CO₂ and H₂S stream. Because of this, there are many issues that need to be addressed even before an AGI unit can be built, such as: dispersion modeling to determine radius of exposure in event of a leak, permitting issues to meet both air and underground well / reservoir requirements, acid gas injection safety systems (e.g., monitoring, alarms, health and safety response plans), etc.. All of these need to be considered in the location of an AGI facility and in the design and layout of the unit, and were considered for both Waha and Tilden sites. Although these items are beyond the scope of this paper, they have been addressed in other literature^{2,3}. Note - Both sites discussed in this paper are remote sites with a large amount of unoccupied land around them.

The remainder of this paper discusses the design of both units as well as troubleshooting efforts at one of the two sites to assist those designing AGI units in the future.

II. Regency Waha AGI Unit

As mentioned above for the Regency Waha site, Trimeric helped Regency sort through water removal approaches and trade-offs of compressors versus pumps, Trimeric prepared a PDP for the AGI unit and provided process oversight to detailed engineering, and Trimeric provided operator training and startup assistance. This section next discusses the Waha unit design basis, some features of the design of the facility, and touches on the relatively uneventful startup of the AGI unit.

A. Waha Design Basis

The feed to the Waha AGI unit was a sour acid gas stream from an alkanolamine process (an ‘amine unit’) used to remove CO₂ and H₂S from natural gas. The design acid gas stream had the following dry-basis composition: 10.19 mol% H₂S, 87.48% CO₂, 1.82% methane, 0.103% ethane, 0.085% propane, 0.015% i-butane, 0.047% n-butane, 0.018% i-pentane, 0.023% n-pentane, 0.029% hexane, 0.179% C₇₊ and 0.008% N₂. The design assumed that the 2 MMscfd acid gas stream was saturated with water at nominally 6 psig and 120°F exiting the amine unit.

A portion of the phase diagram for the sour acid gas, water-free basis, is shown in Figure 1. The phase diagram shows that the critical point of the dry acid gas is at approximately 92°F and about 1100 psia. At combinations of temperature and pressure above the critical point, the stream is considered to be a supercritical or “dense-phase” fluid where it is neither a gas nor a liquid.

The hydrate curve is shown in Figure 2. A hydrate results from the combination of water with other small molecules (i.e., H₂S, CO₂, and CH₄) producing a solid that has an “ice-like” appearance but possesses a different structure than ice. Hydrates can create blockages in flow streams. As shown in the figure, Waha acid gas hydrates can exist at temperatures less than about 73°F at ~1400 psig (76°F at 2000 psig). Therefore, prevention of hydrate formation requires that temperatures be maintained above 73°F or that the gas be sufficiently dried to ensure that there is not enough water available for hydrates to form.

The pressure at the wellhead was expected to be about 1200 to 1400 psig and an average well head flowing (surface) temperature of 64.5°F and a temperature gradient of 0.76°F/100 ft was assumed per information supplied by Regency. The reservoir depth is 6,300 feet and the tubing ID is 2.5 inches. The reservoir pressure and temperature are 3220 psia and 111°F, respectively.

B. Waha Surface Facility Design

Using the design basis information, a matrix was assembled of different possible acid gas injection configurations with key variables including: the number of compression stages, presence or absence of a glycol dehydration unit prior to the last stage of compression, cooling (with cooling water or, in some cases, with chilled water) prior to and /or after the last stage of compression, and use of a booster pump for the dense-phase gas after the last stage of compression. Next, the general feasibility for each case was evaluated by considering three key parameters: 1) the potential for water formation and, hence, corrosion in the carbon steel acid gas injection system; 2) the potential for hydrate formation in the wellhead and downhole piping; and 3) the overall impact on the power requirement of the compression train. The actual water content of the acid gas going to the wellhead was determined first and then compared to the maximum water content of the acid gas at a “worst-case” shutdown temperature for above ground (38°F) and buried pipe (64°F).

Each case was modeled to evaluate power and cooling requirements for the flow schemes. Pressure profile in the well bore was modeled, and the wellhead pressure was varied depending on the process flow scheme and the density of the column of fluid in the well. Hydraulics of the surface facility design and well bore were simulated using Winsim’s Design II software.

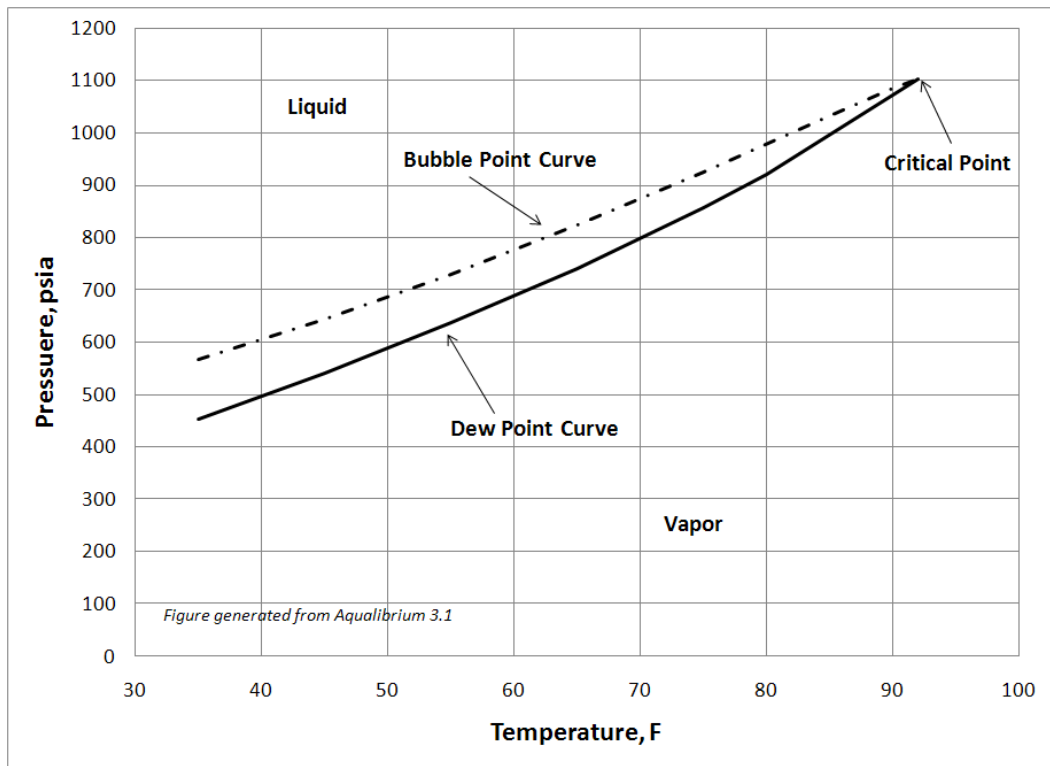


Figure 1. Waha Acid Gas Phase Diagram, Water-free Basis

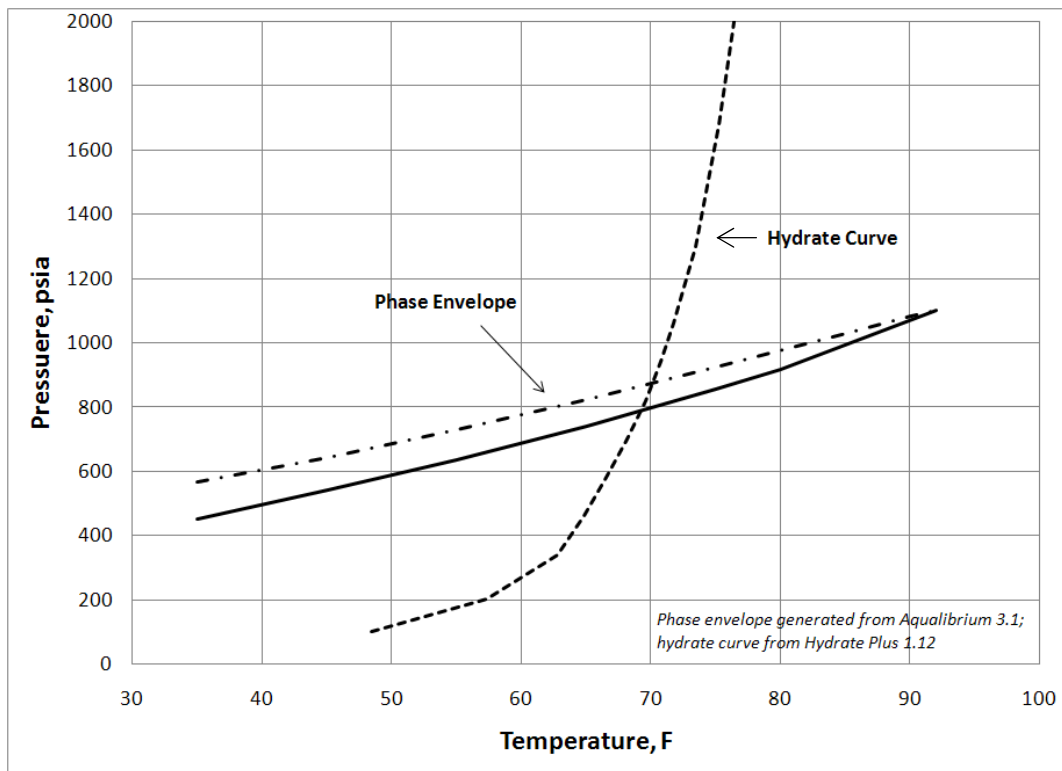


Figure 2. Waha Acid Gas Phase Diagram (Water-free Basis) with Hydrate Curve

To evaluate the water issue, an independent corrosion science expert was consulted with the following results. Due to the presence of H₂S, all materials contacting the CO₂/H₂S must conform to the requirements of NACE Standard MR0175/ISO 15156 – *Materials for use in H₂S-Containing Environments in Oil and Gas Production*. Conformance to this standard is intended to assure that the materials of construction will not be susceptible to sulfide stress cracking (SCC). This standard does not address other potentially serious forms of corrosion.

It is generally accepted that carbon and low alloy steels exposed to high partial pressures of CO₂ and CO₂/H₂S mixtures are prone to patchy, localized corrosion in the presence of sufficient moisture to support electrochemical corrosion reactions. It is well known that moisture films sufficient to support corrosion form at relative saturations below 100% due to the hydrophilic nature of the steel surface. It was determined that formation of moisture films sufficient to support serious corrosion is rare below about 70% relative saturation. One other study⁴ showed very low corrosion rates (0.02 mils per year, mpy) at somewhat lower (~40%) relative saturation levels and another⁵ also recommended the use of 60% relative saturation for protecting against corrosion.

To account for upset conditions where high humidity and/or free liquid water might be present, the consultant also estimated the rate of attack on unprotected carbon and low alloy steel. Excessively high corrosion rates were estimated for acid gas with a high humidity or with free liquid water present. Corrosion under these conditions tends to occur in irregular patches. Modeling showed that corrosion rates within these areas were on the order of 250 mpy at 50°F and 2500 mpy at 120°F.

As a result of the study, it was recommended that Regency maintain water contents below 60% relative saturation at all conditions, including winter shutdown wellhead conditions. Some may take issue with using such a conservative criterion, arguing that no free water (i.e., <100% saturation) may be a more reasonable design basis. However, for the reasons stated above, the 60% relative saturation limit was chosen for this work to ensure that the Waha AGI unit was operated safely away from conditions where significant corrosion could occur over time and potentially compromise public safety.

As discussed in more detail below, a glycol dehydration unit using triethylene glycol (TEG) was necessary to ensure meeting the 60% relative water saturation. Otherwise, most of the other potential options (e.g., deep cooling to increase density, use of pumps instead of 5th stage of compression, etc.) showed only marginal reduction of the total power requirement. Therefore, it was recommended that these options be avoided and a single compressor be used at Waha.

Figure 3 shows a process flow diagram for the AGI unit installed at the Waha facility. As shown in the figure, the acid gas is compressed from 6 psig to 1200-1400 psig using a reciprocating compressor with 5 stages of compression. An initial large separator, called the sour water vapor and receiver drum, both protects the compressor from liquid surges, and functions to allow condensed liquid streams to degas. After each of the first 4 stages of compression, the hot discharge gas is cooled to ~120°F in an air-cooled exchanger and the condensed liquids (if any) are separated prior to the next stage of compression. The

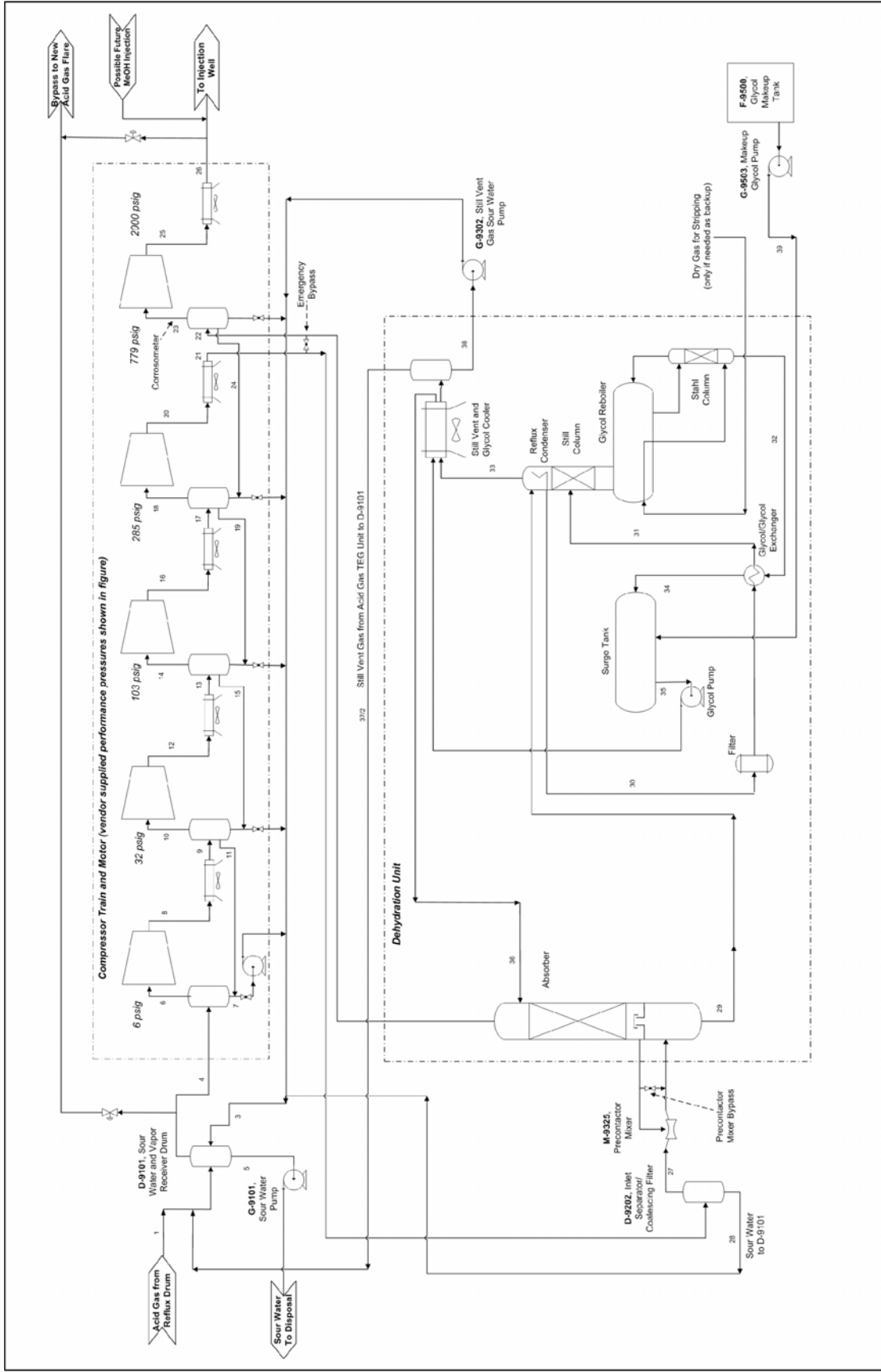


Figure 3. Process Flow Diagram for the Acid Gas Injection System at Regency's Waha Facility

condensed sour water from the interstage separators is sent to the sour water and vapor receiver drum and then pumped to the on-site sour water collection tank.

Between the 4th and 5th stages of compression, after the air-cooled exchanger, the acid gas stream flows to a coalescing filter / separator prior to entering the glycol dehydration unit. The purpose of this vessel is to remove any condensed liquids and possibly lube oil from the acid gas compressor that might carry over into the dehydration unit. The glycol dehydration unit reduces the water content of the gas from about 205 lb/MMscf to about 55 lb/MMscf or less to stay safely below the 60% relative water saturation specification from that point forward. The glycol contactor has pall ring packing, and the lean TEG specification is 98%. Since the overhead stream from the glycol still contains some H₂S, the stream cannot be vented. Liquids are condensed from the glycol still overhead stream, and the gas is recycled to the front of the compression train while the condensed liquids are pumped to the sour water and vapor receiver drum. The glycol still operates at ~10 psig so that the still overhead vapors can recycle to the compressor train first stage suction, which operates at 6 psig.

The dry acid gas leaving the glycol dehydration unit flows to the 5th stage suction scrubber, through a 5th stage of compression, through a 5th stage discharge air cooler, then to the injection well. There is no separator after the 5th stage discharge cooler, because the gas is a dense-phase supercritical fluid and is subsaturated with respect to water.

Figure 4 shows the acid gas phase diagram and approximate operating conditions for the compressor train. Although condensation and removal of water is desirable following each interstage cooling step, it is very important to avoid partial or total liquefaction of the acid gas itself during compression and cooling. As shown in Figure 4, the acid gas will not condense at temperatures greater than 92°F, the critical temperature. Since lower temperatures could result in acid gas condensation, depending on the pressure, the compressor must be operated with sufficiently high interstage temperatures to remain well away from the two-phase region.

C. Reasons for Use of Glycol Dehydration Unit

Rapid corrosion of carbon steel (such as that used in the injection well tubing) may occur if liquid water or high humidity acid gas is present. If temperatures are near or below the hydrate temperature, then both hydrates and corrosion are issues. Thus, it is necessary to either keep the water content safely low or use corrosion resistant materials and/or hydrate inhibitors. At Waha, the choice was made to keep the water content safely low in order to avoid corrosion.

For reference, a water content curve for the Waha acid gas stream is shown in Figure 5 for a temperature of 120°F. The figure represents the maximum amount of water the gas can hold when saturated with water. For this particular acid gas mixture, the water content of the saturated acid gas drops as the pressure is increased until a minimum water content of approximately 160 lb/MMSCF is reached at about 1000 psia. The water content is predicted to remain near this minimum through about 1200 psia, after which the water content increases again. Since the water content is lowest in the 700-1200 psia range for this gas stream, it is desirable to remove water (whether that be by simple cooling and knockout, by

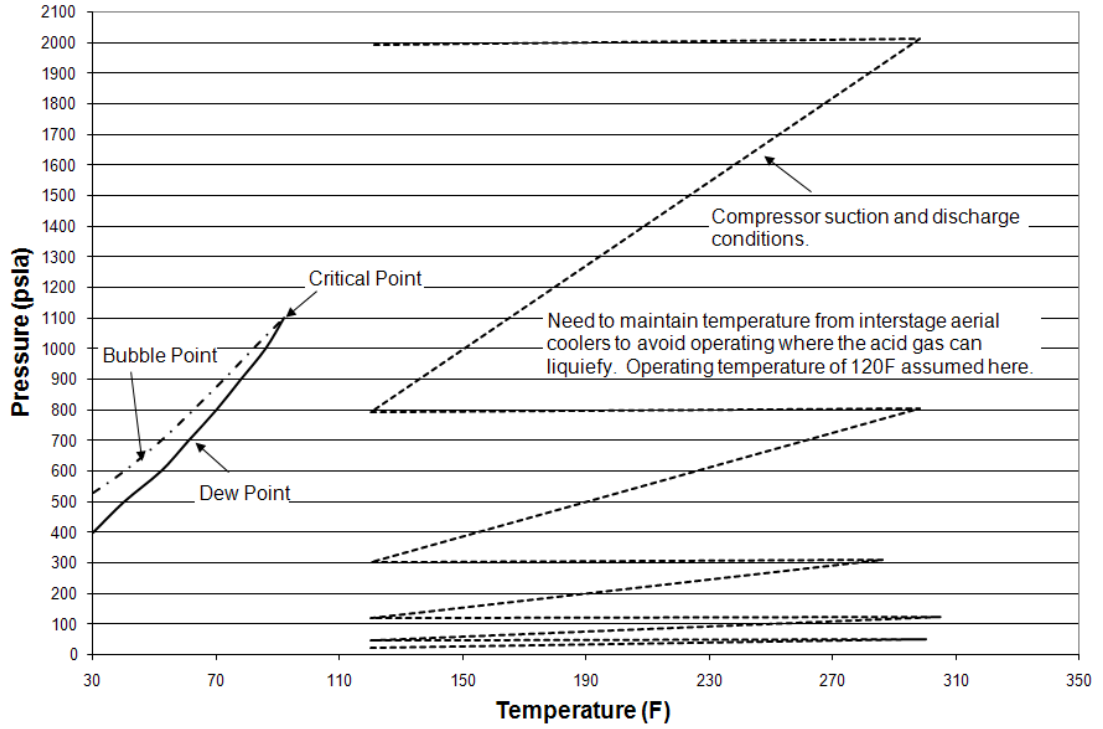


Figure 4. Waha Acid Gas Phase Diagram (Water-free basis) with Compressor Conditions

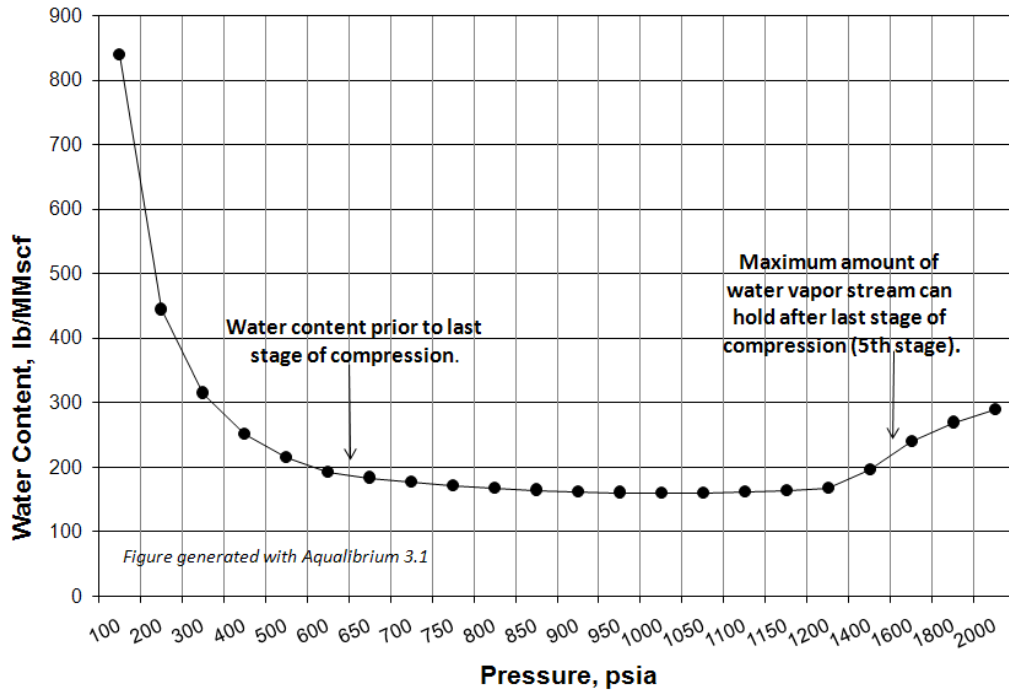


Figure 5. Waha Water Content Diagram at 120F

glycol dehydration unit, or by other means) prior to the last stage of compression, which is near the area of minimum water content.

The glycol dehydration unit for the Waha acid gas was required for a number of reasons. The following section discusses one of those reasons, namely how winter shutdown partially drove the decision to use a glycol dehydration unit. A later section describes why the glycol dehydration unit was required to operate in all seasons, including summer.

One might think that since the acid gas has a higher solubility for water at high pressures, one could consider simply cooling the acid gas and knocking out water after the 4th stage of compression, as is done at a number of other AGI installations. Then, when the acid gas is compressed in the 5th stage, the relative saturation may drop low enough that no further dehydration is needed. However, the coolest condensing temperature that can be considered (without use of a hydrate inhibitor) is a temperature somewhat above the ~73°F hydrate temperature. When a shutdown occurs, the wellhead and any other exposed pipe begin to approach ambient temperature. The design winter ambient temperature for the Waha site was about 28°F. It was found that if one simply cooled the Waha gas stream to near the hydrate temperature and knocked out water, the water content of the acid gas was still above the 60% maximum relative water saturation guideline; both corrosion and hydrates were concerns. Thus, a glycol dehydration unit was required. At certain other AGI sites, the acid gas composition and shape of the water content curve are both markedly different and the shape of the water content curve is the reason some sites can use simple cooling and knockout water while others must use another method, e.g., a glycol dehydration unit.

The previous reason for choosing glycol dehydration unit dealt with wintertime conditions. However, due to the use of ambient air for interstage cooling, the glycol dehydration unit must also be run all the time, including in summer, as discussed below.

First, during continuous summertime operation, the acid gas after the 4th stage of compression can be reliably cooled to only about 120°F with ambient air. Per Figure 5, cooling to 120°F gives a water content of about 180 lb/MMscf at 650 psia. After compression to 1400 psia in the 5th stage and cooling to 120°F, the Waha acid gas stream can hold about 200 lb/MMscf, giving a relative water saturation of about 90%. Since it is not possible to achieve the guideline of 60% maximum relative water saturation needed to reliably avoid corrosion, the glycol dehydration unit needs to operate even in the summer.

Second, the average ground temperature several feet below grade is in the vicinity of 64°F, year round. Thus, if one used simple cooling and knocking out water, then there would be a chance that water could condense on the inside of the injection well tubing, especially if the AGI system were shut down in the summer long enough for the well to reach ground temperature.

Possible mitigation steps for some of these potential problems might be to use methanol injection to prevent hydrates or to fill the well with a dry gas (e.g. CO₂ or nitrogen) when it is shut down. However, in the end, Regency opted to install and operate the glycol dehydration unit continuously, especially after reports from another AGI operator with a glycol dehydration unit indicated that it was a clean and easy application from an operations standpoint.

D. Types of Dehydration Used for Different Acid Gas Streams

The Waha acid gas stream contains a relatively low H₂S (10%) content. With boundary conditions represented by pure H₂S and CO₂, as shown in Figure 6, the saturated water content of acid gas streams with high H₂S/CO₂ ratios can be significantly higher than for low ratio streams, particularly at high injection pressures which often exceed 1200 psia. (Note – A similar figure with additional detail can be found in reference 2.) Therefore, for certain AGI installations with high H₂S content, dehydration may consist of simply cooling the gas and knocking out water at an appropriate pressure where the water content is near the minimum. Then, as the acid gas is compressed further, the water solubility in the acid gas rises so that the acid gas is subsaturated with respect to water from that point forward. For other AGI installations with low H₂S content (like Waha), it may not be possible to remove enough water by simply cooling and knocking out water.

Readily available public literature^{6,7} appears to show that most of the AGI installations that do not use a glycol dehydration unit are places where the acid gas stream has an H₂S content greater than ~25%. Generally, those sites with lower H₂S contents (like Waha) appear to use a glycol dehydration unit much more frequently. Due to the low H₂S content and injection conditions, the decision to use a glycol dehydration unit at the Waha facility was deemed appropriate.

With Waha, an issue that had to be overcome was a perception (perhaps a common one) that glycol dehydration units on acid gas streams are troublesome from an equipment operations standpoint and extremely expensive. However, the terms ‘troublesome’ and ‘expensive’ both appear to be relative to one’s other experiences. In reality, other than the safety issues associated with the acid gas, dehydrating an acid gas stream at pressures below the critical pressure isn’t much different than dehydrating any other gas.

Regarding the troubles associated with a glycol dehydration unit, an acid gas dehydration unit may be less difficult to operate than a field natural gas dehydration unit because the AGI dehydration unit generally sees less ingress of foreign liquids and particulates than a natural gas field dehydrator. For example, engineers and operators of several glycol dehydration units applied to acid gas noted that the units were relatively easy to operate, from their perspective. One plant superintendent and operator even noted that the glycol dehydration unit in his AGI facility was much easier to operate than the many glycol dehydration units operating on natural gas out in the field that he had dealt with previously. The operator noted that this was because the acid gas that reaches a glycol dehydration unit in an AGI facility generally does not have slugs of hydrocarbon, produced water, and particulates. On the other hand, a natural gas field glycol dehydration unit may routinely suffer from ingress of each of these materials.

(Clearly, there are safety concerns that have to be considered for dehydrating acid gas streams, but these can usually be managed with appropriate mitigation measures [e.g., H₂S monitors at key places, proper O&M procedures, etc.]. Acid gas injection safety systems, dispersion modeling to determine radius of exposure in event of a leak, other safety measures, permitting issues, and such were beyond the scope of this paper, but have been addressed in other literature^{2,3}. Note - Both sites discussed in this paper are remote sites with a large amount of unoccupied land around them.)

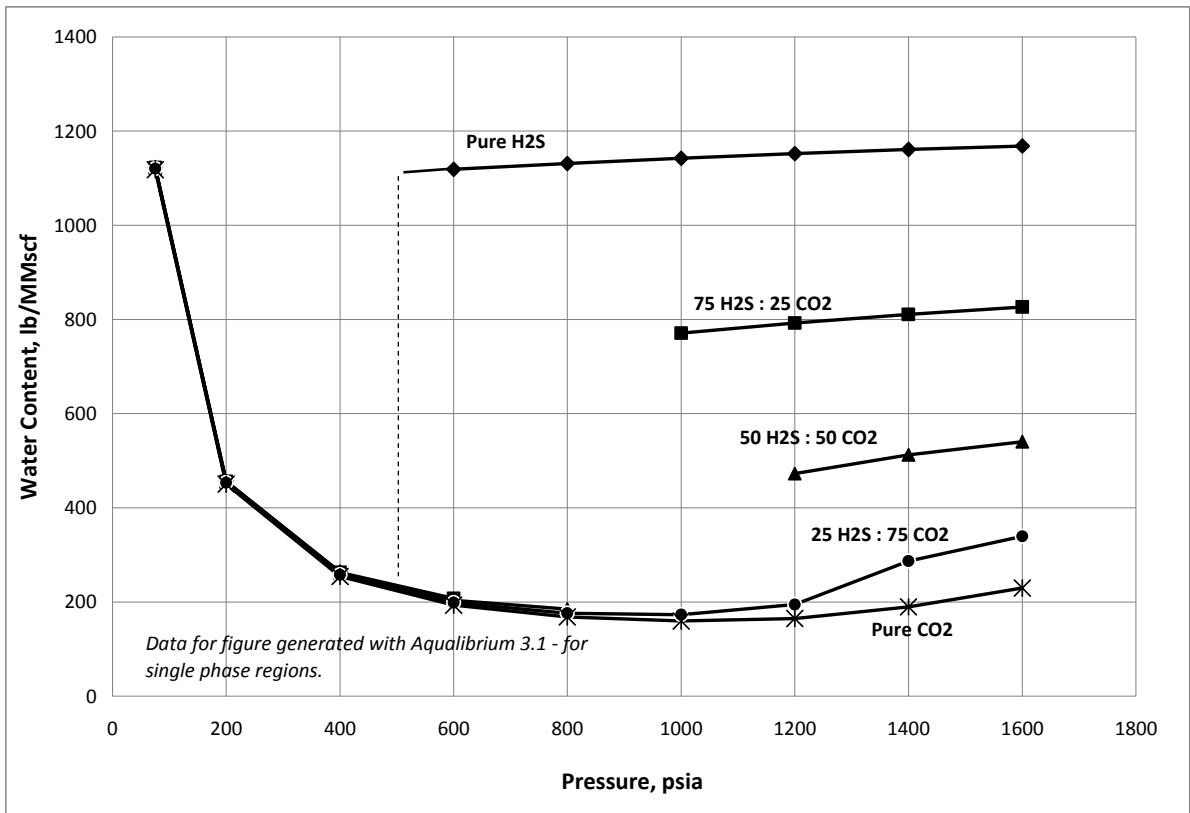


Figure 6. Water Holding Capacity as a Function of Pressure for Acid Gas with Varying H₂S Content at 120°F

Regarding the expense associated with an AGI glycol dehydration unit, it is possible to minimize expense by making use of certain design features. At Waha, a glycol pre-contactor approach and elimination of the glycol flash tank were both used. These features are discussed more completely in a later section of this paper.

Another point to consider when choosing a dehydration method is the accuracy of water dewpoint predictions. Even when using the best methods or tools available, there can be some uncertainty in the water content and dewpoint calculations. Knowing the composition of the inlet gas stream to a high level of accuracy is also important since other components (i.e., substantial hydrocarbon content) can significantly change the acid gas properties including water solubility. Compared to simple cooling and condensation of water, a glycol dehydration unit using TEG provides a significant safety margin with respect to avoiding corrosion and hydrates, even if operating at conditions other than design.

As mentioned above, it is critical that AGI systems are modeled using software that can accurately predict the physical properties of such streams. There are many software programs that do a poor job of predicting the acid gas properties, especially water content, but some of the tools that are generally considered to do a good job are Aqualibrium and Hydrate Plus. Depending on the software, modeling glycol dehydrators in acid gas service

may require regression of appropriate vapor / liquid equilibrium data to ensure accurate water removal predictions. Vendors of glycol dehydration units typically have their own in-house models to simulate the performance for such systems, but it may be worthwhile to inquire as to what data are used to support the predictions. However, in the case of the Waha dehydration unit, extremely low-level water removal (i.e., 7 lb/MMscf pipeline spec) was not required (only 55 lb/MMscf), so there was some flexibility if the modeling results were off.

Most commercial software packages can do a reasonable job of predicting compressor and pump performance as well as cooling duties, but the results should be checked with available data to be certain before finalizing the design of the system.

E. Important Design Features of the Waha AGI Facility

A few of the important design features that were implemented at the Waha AGI facility are presented below.

Interstage Cooler Auto Louvers – To avoid the possibility of hydrates or freezing, the compressor interstage condensers were equipped with automatically adjustable louvers and thermostats on the gas so that the acid gas / liquid water mixture was not cooled to below ~80°F. This was done in order to stay safely above the ~73°F hydrate point (see Figure 2). The automatic louvers work by restricting air flow through the air-cooled exchanger. While it was possible to gain enough control with automatic louvers at Waha, other AGI facilities at sites with colder winters might require more than just automatic louvers and thermostats, e.g. warm air recirculation.

Coalescing Filter / Separator – Although use of glycol dehydration units in AGI facilities is believed to be relatively clean service (relative to glycol dehydration units used on field natural gas), a potential source of contamination and glycol dehydration unit operating problems was compressor lube oil. Thus, a coalescing filter / separator was used to collect condensed liquids and compressor lube oil. Lube oil can concentrate in the glycol system and result in foaming, excessive glycol loss, reduced efficiency, and increased maintenance. A coalescing-filter type separator was used for this application because aerosols or fine compressor oil droplets might be present in the gas stream.

Glycol Pre-contactor – A special pre-contactor mixer was used to promote initial contact of the wet acid gas with the rich TEG solution upstream of the glycol contactor. The purpose of the pre-contactor is to reduce the inlet water content and thus the corrosiveness to the extent that less expensive carbon steel metallurgy can be used for the glycol contactor.

There are several methods of implementing a glycol pre-contactor, some involving controls and pumps to circulate a slipstream of glycol to the pre-contactor, others involving simpler controls. In considering glycol pre-contactor approaches, an AGI site was visited that had a glycol pre-contactor that used a pump to transfer glycol to a static mixer in the gas line ahead of the glycol contactor. The pre-contactor at this site was no longer in use; the pump had been turned off. A desire of the Waha design team was that the pre-contactor at Waha be less susceptible to inactivation.

At the 2000 Laurance Reid Gas Conditioning Conference, Paul Carmody of Amerada Hess presented a pre-contactor concept where glycol from the bottom tray of a glycol dehydration unit was passed into the low pressure area of an orifice flange, which acted to promote mixing of glycol and acid gas prior to a standard carbon steel glycol contactor⁸. The benefit of using an orifice flange or mixer in this fashion is that it reduces the water content so that less expensive carbon steel can be used for the absorber and portions of the downstream equipment. In this particular application, the entire stream of glycol is taken from a hat tray at the bottom portion of the glycol contactor and passed through the pre-contactor. Since all the glycol from the contactor passes through the pre-contactor automatically, and since there are no pumps or active controls, this pre-contactor approach is conducive to constant and long-term operation. Paul Carmody was contacted and permission was received to use a version of this pre-contactor approach at Waha. The energy to provide contact via mixing comes from the raw gas stream. In order to minimize permanent pressure drop, a venturi was chosen for the Waha application instead of an orifice arrangement. The permanent pressure loss through the venturi was estimated to be 2-4 psi.

Absence of Glycol Flash Tank – The glycol dehydration unit at Waha was purposely built without a flash tank. Flash tanks are commonly used in most natural gas glycol dehydration systems for several reasons. With a natural gas dehydration unit, a flash tank allows physically dissolved natural gas to come out of solution and be collected at a pressure where the gas can be used, possibly as fuel, rather than being vented along with the water vapor in the glycol still vent stream. A flash tank also allows a place to skim off heavy hydrocarbon liquids, if such liquids are present. However, in the Waha AGI design, the flash gas has neither fuel value nor any heavy hydrocarbons that might need to be skimmed off. Due to its H₂S content, any gas exiting the glycol dehydration unit must be recycled to the 1st or 2nd stage of the AGI compressor. If a flash tank were used, it would just be another stream to tie into the vent gas collection system. Thus, it was deemed simpler (and less expensive) to design the glycol dehydration unit without a flash tank and, instead, to allow the glycol to flash across the absorber level control valve and into the still column. As a result, all gases evolved at the Waha glycol dehydration unit exit the glycol still vent, pass through a still vent condenser to remove water, and then flow back to the suction of the 1st stage of the AGI compressor. The rich/lean exchanger was designed to accommodate the additional gas that evolves from the rich glycol as it is heated, and the potential for erosion was considered in the design of the piping after the absorber level control valve. The additional flash gas passing through the glycol still column also helps somewhat in stripping water in the glycol still.

Stahl Column – The glycol dehydration unit was also equipped with a Stahl column to further increase the lean glycol concentration, if needed to improve dehydration performance. A Stahl column is an extra stripping column between the glycol reboiler and the glycol surge tank. Lean glycol flows through the Stahl column as it passes from the reboiler and into the surge tank. Stripping gas flows up through the Stahl column, counter current to the glycol, in order to strip additional water from the lean glycol. Compared to bubbling stripping gas directly into the reboiler, the use of a Stahl column allows one to use a reduced amount of stripping gas to achieve the same lean glycol water content due to the increased number of contact stages in the Stahl column. The Stahl column was not expected to be needed, and it has not been used because the reboiler was capable of providing sufficiently dry TEG without the use of the Stahl column. However, the Stahl column was inexpensive, and thus

was included in the design as an extra precaution. If the Stahl column is used in the future, a slipstream of dry acid gas will be used as stripping gas. The stripping gas will be routed through a tube that runs through the reboiler to heat the stripping gas, which will then flow into the bottom of the Stahl column.

Corrosion Resistance Probes – A corrosion resistance probe or corrosimeter was installed in the dry gas stream, between the glycol dehydration unit and the 5th stage suction scrubber in the compressor train. Another was installed near the well head. The purpose of these instruments is to measure the change in resistance produced as a result of corrosion in the line. If the meter detects a sudden jump in resistance, an alarm will trigger to notify an operator to investigate the glycol dehydration unit for operating conditions that could be causing a decrease in drying.

Compressor / TEG Metallurgy – The materials specialist also reviewed the acid gas injection system metallurgy, worked with the project team on the materials of construction that could be used in certain portions of the process, and recommended a corrosion minimization / inspection program. Table 1 shows a summary of this analysis. As referred to in Table 1, “stainless steel” refers to 316L or 2205 duplex stainless steels. It should be noted that different sites may require different materials of construction and each AGI facility should be individually evaluated in detail.

The project team noted that in many cases it is common industry practice to use carbon steel for low pressure acid gas streams. Thus, the acid gas line from the amine reflux condenser drum to the sour water and vapor receiver drum was built of carbon steel, as was the horizontal fired glycol still, and as were a few other areas containing humid acid gas at just a few psi above atmospheric pressure. Annual UT surveys of such equipment are strongly recommended.

F. Waha AGI Unit Startup

The Regency Waha AGI unit began operation in mid-June 2007. There were few startup issues with the unit. The main problem that was observed was some sticking of the dump valves in the separators in the compressor train. The dump valve problem waned after a period of time and is no longer an issue. The glycol dehydration unit, with the upstream pre-contactor mixer, was brought on line with few issues. A relief valve on the glycol still that was designed for steam service was found to leak on the downstream side whenever the flare header pressure rose, and an issue with burner controls caused overheating of the glycol in the glycol still a couple of times in the first few months of operation. These and several other minor issues were eventually resolved. The Waha AGI unit has been successfully injecting acid gas ever since.

After three years of operation, the AGI facility continues to operate reasonably well, but some modifications have been made. A separate back pressure controller was added to the amine still that is not linked with the compressor VFD to provide better control and reduce downtime/flaring. An automated recycle valve and recycle cooler were also added from the final compressor stage outlet back to the first stage to make the compressor more reliable. Very few problems have been experienced with the acid gas dehydration unit and site staff claim that the acid gas dehydrator operates more reliably than a field unit.

Table 1. Waha Materials and Corrosion Monitoring

Stream	Material of Construction	Monitoring
Category 1 – dry gas process streams: hot compressor discharge gas and dry gas downstream of glycol dehydration unit	Carbon steel if enough external insulation to keep the process envelope metallurgy above the water dewpoint; stainless steel used in compressor train to be conservative	Annual ultrasonic thickness (UT) measurements at indexed UT inspection points in the dry gas piping where any moisture condensate could pool or collect
Category 2 – gas process streams near moisture dewpoint: still vent gas and noncondensable gas, inlet amine acid gas, and interstage compressor separator offgas	Carbon steel if the internal surfaces of the process envelope remain dry. However, since there is a high likelihood of moisture condensation occurring in these areas that could cause severe localized corrosion with carbon steel pipe, stainless steel was selected to be conservative	If carbon steel piping were used, a maximum practical corrosion allowance should be used and pipe replaced when 33% of this corrosion allowance is consumed. Quarterly UT measurements are recommended for carbon steel piping and vessels
Category 3 – high CO ₂ vapor with aqueous liquid phase: piping from interstage ariel coolers prior to glycol dehydration unit	Severe corrosion is expected anywhere the liquid phase contacts carbon steel. Stainless steel required in these areas.	If carbon steel were used, the same corrosion allowance and UT thickness measurements described with Category 2 would apply
Category 4 – aqueous liquid process streams: all sour water streams in AGI unit	It is highly unlikely that carbon steel will be able to form protective corrosion layers at the anticipated pH of these streams and corrosion rates on the order of 50 mpy may occur. Only stainless steel should be used in these areas.	If carbon steel were used, then the same corrosion allowance and UT measurements with Category 2 would apply
Category 5 – non-aqueous liquid process streams: all liquid lines in the dehy unit	Carbon steel contactor based on use of upstream glycol pre-contactor	Annual UT measurements required in parts of unit based on application and vendor materials

III. Regency Tilden AGI Unit

As mentioned in the Introduction section, Trimeric had much less involvement in the design of the Tilden AGI facility than at the Waha facility. Although Trimeric helped Regency sort through water removal approaches, Trimeric did not otherwise participate in the design phases of the Tilden AGI unit. The design of the Tilden AGI unit, including the physical layout and pump control schemes discussed later, was performed by third parties. However, as a result of poor performance during startup, Regency requested Trimeric's assistance with troubleshooting and with process and equipment optimization activities. One

of the primary startup problems at Tilden was net positive suction head (NPSH) issues with an acid gas pump, which was intertwined with control issues with the injection pump skid.

A. *Tilden Design Basis*

The original design basis for the Tilden AGI unit was a water-saturated acid gas stream from an amine unit with the following dry-gas composition: 33.8 mol% H₂S, 64.7% CO₂, 0.62% methane, 0.37% ethane, 0.23% propane, 0.004% isobutane, 0.01% n-butane, 0.001% isopentane, 0.001% n-pentane, and 0.212% hexanes+. The 2.4 MMscfd acid gas stream was to be at nominally 6 psig with a temperature of up to 120°F.

The final well design had a depth of 6,900 ft, a reservoir pressure of 3150 psig, reservoir temperature of 160°F, and a nominal wellhead injection pressure of 1400-1500 psig. Regency purchased a compressor train with a maximum discharge pressure for the compressor that was thought to be 1250 psig, so a pump skid was required downstream of the compressor discharge to provide the anticipated wellhead pressure of 1400-1500 psig.

When the AGI unit was brought on line in July 2007, it was discovered that the actual well head pressure was 2000-2400 psig. After several discussions with the compressor vendor, it was also realized that the compressor was in fact capable of a higher discharge pressure. A pressure slightly less than the 1350 psig (the 5th stage high-pressure shutdown setpoint) was immediately possible, and the compressor could go to ~1870 psig with some additional relatively minor modifications. The actual gas flow was also higher (2.6 to 2.9 MMscfd) and additional gas analyses showed the H₂S content of the acid gas could vary from 25% to 55% H₂S on a dry basis. These deviations from the design basis point out the importance of considering off-design conditions. For example, as discussed in section “D. Types of Dehydration Used for Different Acid Gas Streams”, the H₂S content needs to be above a certain level for simple cooling and condensation to be widely applicable. If the actual H₂S content is much lower than design, then there may be a problem getting the acid gas dry enough with simple cooling and condensation. If the actual H₂S content is higher than design, then the simple cooling and condensation approach will work better than originally thought, but there may be other issues.

B. *Tilden Surface Facility Design*

In the case of the Tilden AGI unit, Trimeric’s scope during the design phase was limited to performing a study to determine the best alternative for water removal (including dehydration, cooler, pump, etc.). At the time that the Tilden water removal study was performed, Regency had already ordered the compressor and pump skid mentioned above, and there was limited ability to make changes to that equipment.

For water removal at Tilden, it was found that use of aerial cooling to condense water between the 4th and 5th stages of compression left the acid gas with a relative saturation of about 69% at the anticipated wellhead conditions. Since this was above the guideline 60% maximum relative saturation, aerial cooling alone was ruled out. Trimeric recommended installing an exchanger between the fourth and fifth stages and using cooling water from an existing evaporative cooling tower to cool the acid gas and reduce the water content of the vapor phase to acceptable levels. By installing the water-cooler after the 4th stage of compression (the last stage where water is knocked out in the compressor train), the relative

saturation of water in the acid gas is lowered to roughly 35% at the anticipated wellhead conditions and any concerns with downstream corrosion should be minimized.

Unlike Regency’s Waha facility, glycol dehydration was not required at Tilden because the acid gas, which was expected to contain ~34% H₂S, had a higher solubility for water at the expected 5th stage discharge conditions. Figure 7 shows the water content of saturated Tilden acid gas with notes identifying the conditions that would be present with and without the fourth-stage water-cooled exchanger and at the anticipated and actual wellhead conditions.

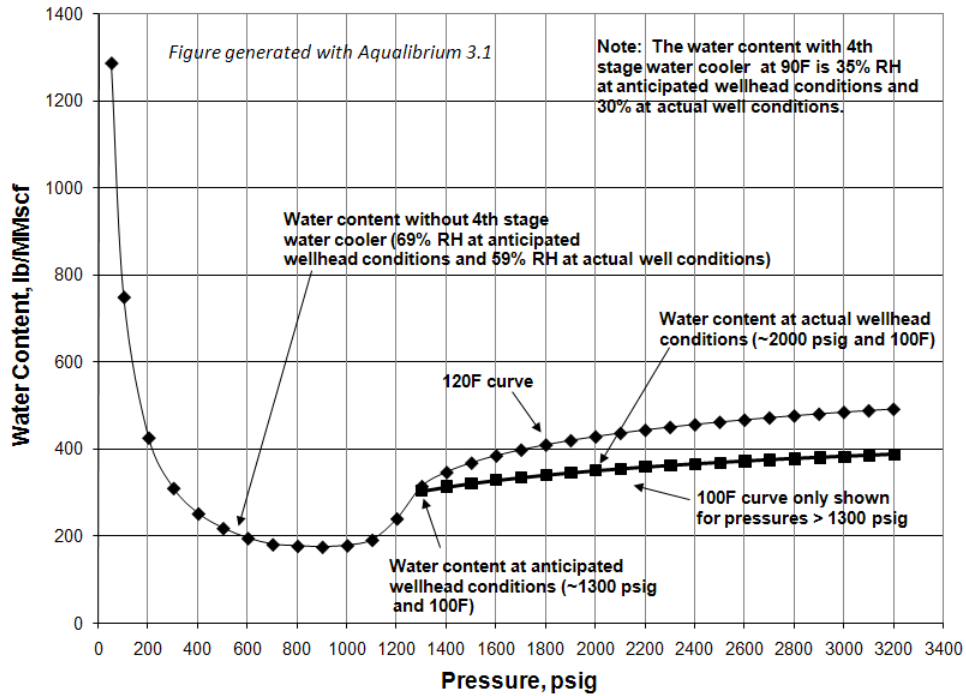


Figure 7. Tilden Saturated Water Curve with Varying Pressure

Figure 8 shows the process flow diagram for the Tilden AGI system. The acid gas from the amine unit flows to a pre-existing knockout drum and then to the first stage suction scrubber of the compressor train. The 2.6 to 2.9 MMscfd acid gas stream is compressed to 1200-1320 psig using 5-stages of compression. (The compressor discharge pressure is limited to somewhat less than the 5th stage PSV setting at 1350 psig.) After each of the first 3 stages of compression, the hot discharge gas is cooled in an air-cooled exchanger to roughly 120°F (in summer) and any condensed liquids are separated prior to entering the next stage of compression. In order to avoid the possibility of hydrates or freezing, the interstage condensers were equipped with fan speed control, auto louvers, and temperature controllers on the gas so that mixtures of acid gas and liquid water would not fall below ~95°F in order to stay safely away from the hydrate region and the acid gas dewpoint curve. The condensed sour water from the interstage separators is sent to an existing sour water separator on site.

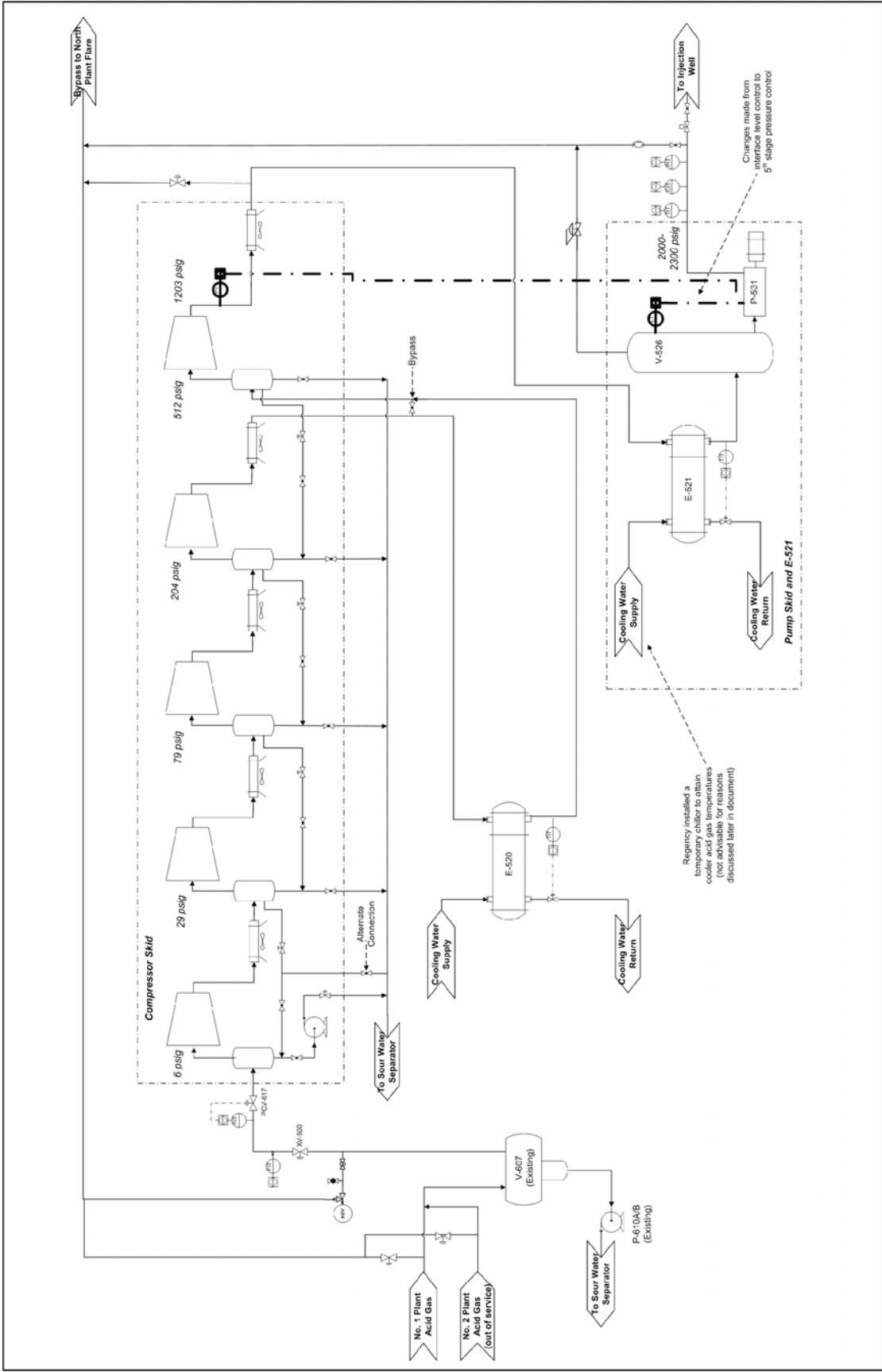


Figure 8. Process Flow Diagram for the Acid Gas Injection System at Regency's Tilden Facility

Between the 4th and 5th stages of compression, after the air-cooled exchanger, the acid gas stream flows to a water-cooled exchanger (marked “E-520” in Figure 8) to lower the water content in the acid gas to safe levels to avoid corrosion of downstream equipment. The temperature of the cooled acid gas leaving the water-cooled exchanger is monitored and regulated by controlling the cooling water flow rate to the exchanger. The acid gas flows back to the compressor 5th stage separator where the condensed water is separated. The acid gas is compressed in the 5th stage to 1200-1320 psig, cooled with an air-cooler and sent to the pump skid, which contained another exchanger (marked “E-521” in Figure 8). The purpose of the exchanger on the pump skid is to increase the density of the acid gas exiting the compressor 5th stage by cooling it (cooling could take place after the vessel instead). Higher density fluid can be more easily pumped to the injection well pressure (1400-1500 anticipated, 2200-2400 psig actual). The pump is required due to the limitations on the compressor discharge pressure (1350 psig 5th stage PSV limit). An accumulator vessel was also included on the pump skid along with a triplex plunger pump with speed / volume control and corrosion resistant materials. The plunger pump was to increase the dense-phase fluid to injection well pressures. Pulsation dampeners (not shown in Figure 8) were present on the suction and discharge sides of the injection pump.

In Figure 8, the dotted line from V-526 to P-531 shows how the pump skid was attempted to be controlled during initial startup of the Tilden AGI unit. The dotted line from P-531 to the 5th stage discharge line shows how the pump skid was eventually controlled after troubleshooting. Control of the pump skid is discussed in detail below.

C. Tilden AGI Startup Observations

During initial startup of the Tilden AGI unit, many problems were observed, a few of which included: actual wellhead pressure was 2000 to 2400 psig, much higher than the 1400 to 1500 psig that was expected; frequent venting of acid gas to flare causing air permitting concerns; compressor 5th stage discharge pressure fluctuations and lower pressures (780 to 1200 psig) than the design pressure of ~1250 psig; injection pump apparent vapor lock problems; and concerns with potential for corrosion at new actual operating conditions. The most severe of these problems appeared to be the pump operating problems, which prevented the plant from injecting acid gas into the well.

Because of the pump problems above, site staff had decided to install a temporary chiller in an attempt to improve the performance of the pump skid. It had been noted in the field that the pump skid seemed to operate better and longer with colder acid gas fluid temperatures. Once installed, the chiller initially decreased the temperature of the acid gas feeding the pump to the mid-70°Fs or lower. However, after a few hours during a run, the temperature of the acid gas from the chiller would slowly rise, indicating some sort of heat transfer problem. In the end, the long-term stable operation of the AGI unit was still not achieved even with the chiller in place. As a result of these problems, Regency requested that Trimeric help troubleshoot the unit.

D. Reasons for Poor AGI Unit Operation with Accumulator Level Control

This section D discusses the reasons for observed startup problems. Modifications to fix some of the observed problems are discussed in section F.

As shown in Figure 8, the pump skid controls were designed assuming that the accumulator operated as a two-phase vessel. The level of the gas/liquid interface in the accumulator was to be controlled by varying the injection pump speed with a variable frequency drive (VFD). However, the physical layout of the pump skid made such an approach infeasible, as described further below.

To measure an interface level in the accumulator, there would need to be two-phases in the vessel. Figure 9 shows a phase diagram for the Tilden acid gas and the compression path up to the pump suction. If there is no acid gas flow from the top of the accumulator, then two-phases can only occur if the accumulator is held right on the bubble point curve, which is the only place on the phase diagram where a two-phase mixture could theoretically be maintained without generating any net vapor. Actually, operating along the bubble point curve is possible and is practiced in certain other types of process units, notably reflux accumulators on some distillation systems with total condensers. However, doing so with the Tilden pump skid proved to be unstable due to its physical arrangement. As an example of instability, Tilden staff observed that the accumulator level reading would suddenly rise or drop without apparent explanation, or the pump would just stop pumping.

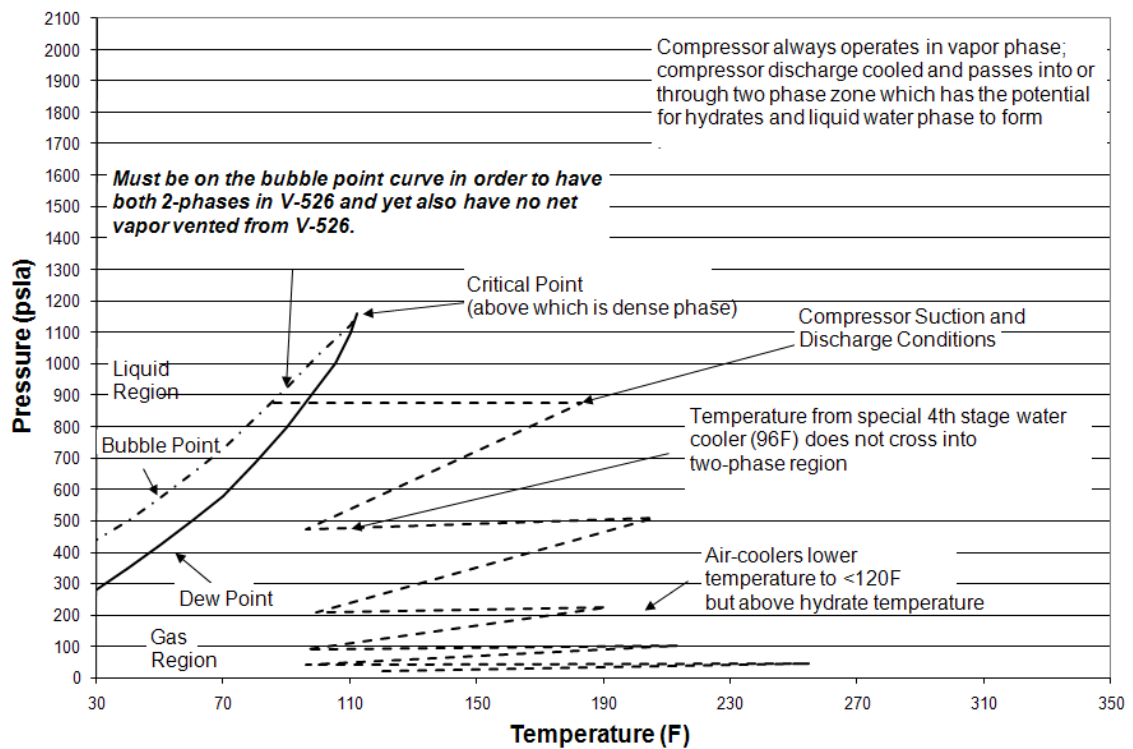


Figure 9. Tilden Dry Acid Gas Phase Diagram (Water-free Basis) with Accumulator Level Control and Chiller (July 07 Data)

There are several reasons this mode of operation would not work reliably at Tilden. Some of the problems include: net positive suction head (NPSH) problems with the injection pump; potential for hydrate formation in E-521 when using chilled water; and difficulty

operating accumulator in two-phase region to measure level interface. Each of these is discussed in more detail below.

NPSH Problems with Injection Pump – Regency Tilden had a positive displacement plunger-type pump to increase the pressure of the acid gas from the 5th stage compressor discharge (1200-1320 psig) up to the actual injection well conditions (2200-2400 psig). After startup of the AGI unit, clatter and knocking noises were observed from the acid gas injection pump as it attempted to control the interface level in the accumulator. The reason the pump performed this way was due to net positive suction head (NPSH) issues.

If the accumulator was operated as a vessel containing two acid gas phases, then the liquid coming from it was by definition very close to its bubble point. Plunger type pumps typically require a significant NPSH to work properly. If a two-phase vessel is upstream of such a pump, then there has to be a significant elevation difference between the interface level of the upstream vessel and the pump suction flange. For the pump at Tilden, the pump manufacturer recommended a minimum of ~20 feet of NPSH, but there was only about 2 feet of head difference due to the physical layout of the pump skid. The lack of NPSH resulted in pump cavitation as observed by the clatter and knocking heard in the field and the inability to pump reliably. Having a suction pressure (NPSH) issue with a pump that had 1000 psig of total pressure at its suction was unfamiliar territory for some, perhaps most, of the operations and engineering personnel. As a result, it took careful explanation to convince staff that inadequate NPSH was indeed the issue.

As mentioned previously, a rental chilled water unit had been brought in because it was thought by some that if the temperature of the inlet acid gas to the pump was lowered a little further (i.e., with a chiller), then the NPSH would increase. This is not correct, because if the liquid level in the accumulator vessel is constant, then the NPSH available to the pump is also constant, regardless of temperature.

Instead, lowering the temperature only lowers the compressor 5th stage discharge pressure the same way that cool weather lowers the discharge pressure of a refrigeration compressor, if it is followed by an air-cooled condenser. By operating with the chiller, Tilden was essentially controlling the 5th stage discharge pressure with the temperature achieved across the pre-pump exchanger (E-521). Reiterating, if the gas / liquid interface height in the accumulator remains the same, then the NPSH available to the pump remains unchanged, regardless of temperature.

Although the pump appeared to operate much longer (e.g., for a few hours instead of a few minutes) with the lower accumulator temperature, the NPSH did not increase. Per guidance from the pump vendor, the pump would be expected to suffer premature failure due to operating with inadequate NPSH. It may be tolerable to operate a pump in this mode for short periods of time, but the acid gas injection pump at Tilden needed to operate continuously since it is a critical piece of equipment in the Tilden AGI unit.

It might have been possible to operate the AGI pump with the accumulator in level control if the accumulator 1) had been elevated 20 to 40 feet above the pump similar to the way that reflux accumulators are usually located above the reflux pump in an NGL plant and 2) had been appropriately sized for two-phase operation. Otherwise, the AGI unit would

need to operate at high enough pressure or low enough temperature to have a single phase in the accumulator.

In summary, problems observed with the Tilden AGI pump were not related to the fact that it was an acid gas application. Rather, the problems were related to NPSH issues caused by improper design. For example, a liquid propane pumping system designed with inadequate NPSH would be expected to exhibit the same types of problems.

Hydrate Formation with Chiller – As shown in Figure 10, hydrate formation was predicted to be possible in this acid gas mixture at temperatures up to about 85°F, depending on the pressure. The temperature of the acid gas leaving E-521 with the chiller in operation

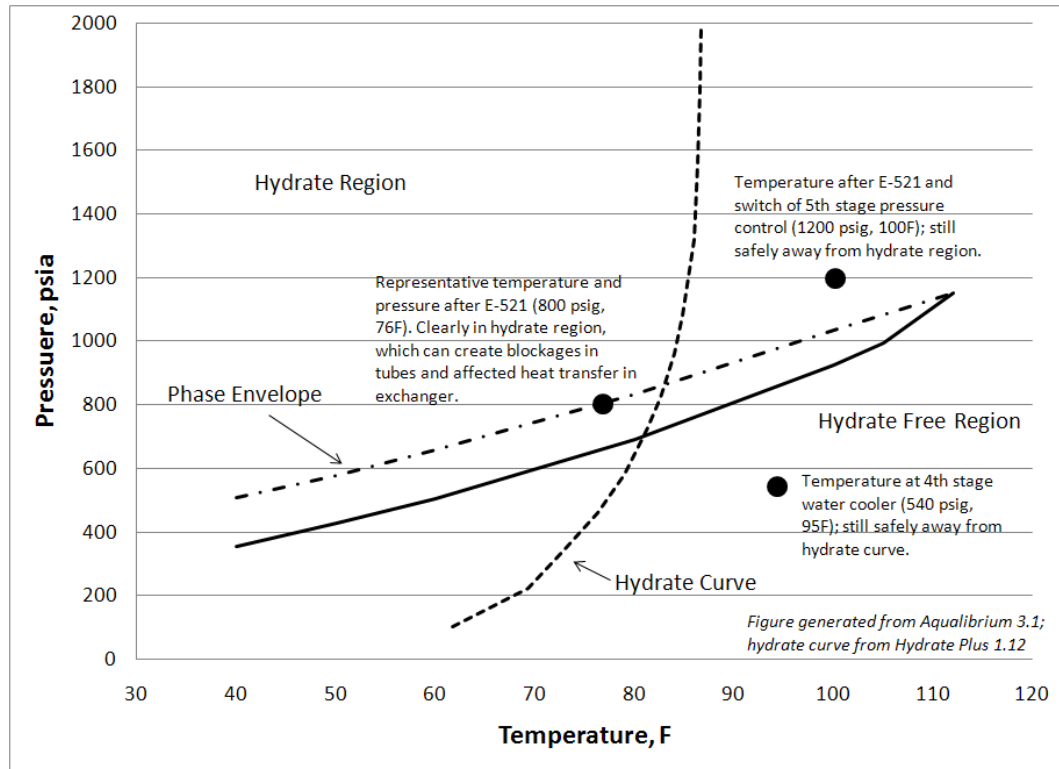


Figure 10. Hydrate Curve with Level Control and Chiller

ranged from 69 to 107°F. This indicates that there were definitely times when the Tilden AGI unit was operating with temperatures lower than the hydrate curve. Field observation was that the acid gas would be cooled to a low temperature (e.g., 70°F) for a few hours upon starting up the chiller, and then the acid gas would slowly warm up to a temperature in the 80-85°F+ range, even though the chilled water flow and temperature were not observed to change. It was theorized that hydrates were forming a film that reduced the heat transfer coefficient in the exchanger and limited cooling of the gas to temperatures at or above the hydrate temperature. Although the exchanger pressure drop was not observed to increase, pressure instrumentation around the exchanger consisted of local gages that were not very sensitive, and the pressure drop in the exchanger may or may not have been large enough to

measure. Also, when the exchanger was depressurized and opened for examination, the hydrates would melt or evaporate away, leaving no visual evidence.

Methanol injection to prevent hydrates was considered. But, in the end, as discussed below, another approach that focused on staying away from the hydrate forming region was chosen instead.

Formation of Liquid Water in E-521 – Modeling was conducted to see if a separate liquid water phase would form in E-521 since E-521 was operating at much lower temperatures than originally expected, and since the compressor was operating at lower 4th & 5th stage discharge pressures than originally expected. The highest 5th stage discharge pressure and dewpoint temperature above which no liquid water phase forms were estimated for different Tilden gas compositions. The results of this analysis were the following: design gas (34% H₂S/65% CO₂): 860 psig and 97°F; low H₂S (25% H₂S/75% CO₂): 910 psig and 93°F; and high H₂S (55% H₂S/45% CO₂): 585 psig and 94°F. If operating below these pressures and temperatures, which very likely occurred with the accumulator level control and use of chiller, then a separate liquid water phase could potentially form in E-521.

In addition to the hydrates issue, acid gas that contains liquid water can be highly corrosive to any carbon steel components. A materials survey identified a few places where carbon steel components were present in wet high pressure acid gas service at Tilden. “NACE valves” were among the carbon steel components found in high-pressure wet service. Construction staff may have thought that a valve would be suitable due to its NACE rating. However, the NACE rating means that the material is not likely to suffer hydrogen sulfide stress cracking corrosion and sudden catastrophic failure; while such a valve may not crack, it will still corrode away rapidly and fail under the right conditions.

E. Pump Skid Operations at Other Sites

As a check, experience at other AGI sites, including CO₂-flood enhanced oil recovery (EOR) sites, was reviewed. The manufacturer of the Tilden pump skid had built two other virtually identical acid gas pump skids for other clients. As it turned out, one of these sites had never used their pump skid because the wellhead pressure was lower than expected and the AGI compressor provided all the pressure that was necessary. The other site only used the pump skid for ~1 hour at a time during startups, after which they shut it down for months at a time. Other known sites that use pumps on acid gas were found to operate at temperatures and pressures that are safely into the supercritical region or at conditions where the acid gas exists as a sub-cooled liquid (single phase).

F. Modifications to Improve Tilden AGI Unit Performance

After reviewing the startup data and operations, it was determined that the pump at the Tilden AGI unit needed to operate in a single-phase region of the phase diagram. That is, either to the left of the bubble point curve as a sub-cooled liquid or well-above the critical point as a dense-phase that really is neither a gas nor a liquid, but is a fluid that has a high enough density and low enough compressibility that it can be pumped to the injection well pressure. Given the availability of cooling water on site, the desire to get rid of the rental chiller, and the desire to keep the acid gas at low relative water saturation, it was decided that it would be best to operate with the accumulator acting as a single-phase vessel at a pressure well above the critical pressure of the acid gas mixture.

To do this, the control system was modified so that the compressor 5th stage pressure was controlled by adjusting the VFD / pump speed as shown in Figure 11. A set point of about 1300 psia, well above the critical pressure, was initially chosen. As the compressor 5th stage pressure started to rise, the pump would speed up to keep the pressure constant. As the pressure fell, the pump would slow down to maintain a constant pump suction pressure (i.e., a constant compressor 5th stage discharge pressure). With this modification, the accumulator would only act as a large void spot in the line. Removing the temporary chiller was also part of the modification, and the pre-pump exchanger was supplied with cooling tower water instead.

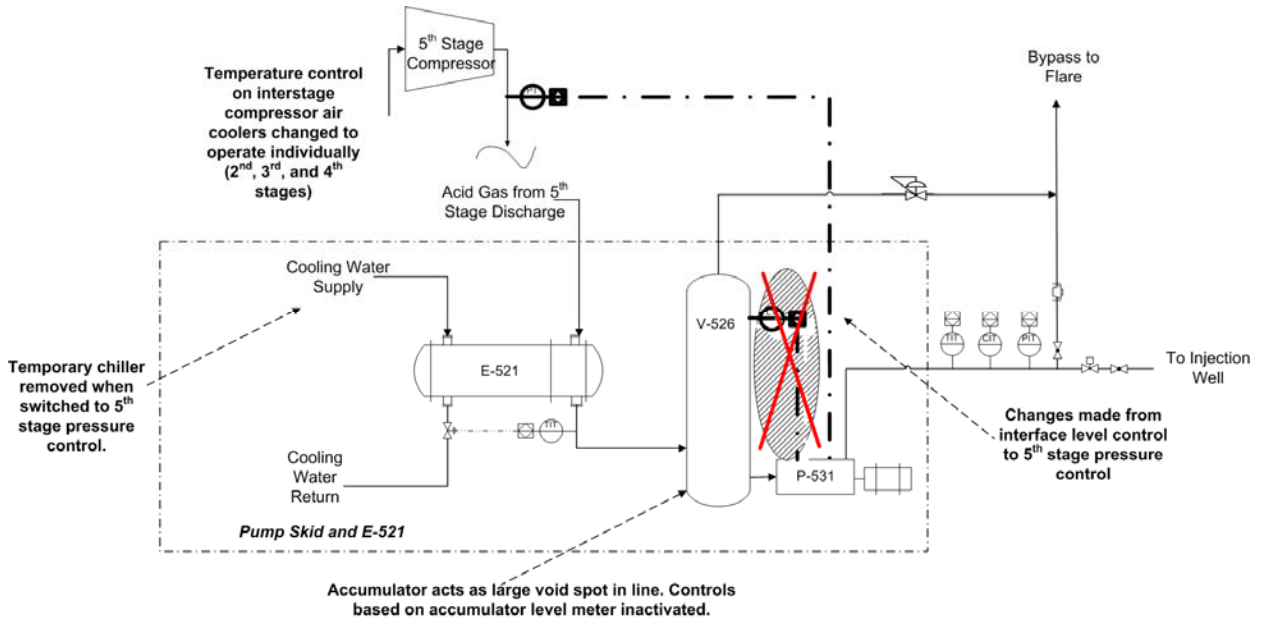


Figure 11. Tilden Pump Skid Modifications to Operate in Single Dense-Phase Mode

Figure 12 shows the Tilden acid gas phase diagram with lines of compression and cooling after the change to 5th stage pressure control and water cooling. As shown in the figure, the compressor always operates in the vapor or dense-phase regions and never crosses into the two-phase region. The interstage air-coolers are controlled to keep the temperature above the hydrate point and the final water-cooler temperature is controlled to keep the density of the acid gas mixture high enough to pump (e.g., greater than roughly 40 lb/ft³).

In summary, operating with compressor 5th stage pressure well above the critical point is beneficial for the following reasons: no NPSH issue with the pump; single, dense-phase operation is easier to control; water cooling alone (100-110°F) provides reasonable densities for pumping (no need to purchase permanent chiller); eliminates concern of hydrate formation; and prevents formation of separate water phase in E-521.

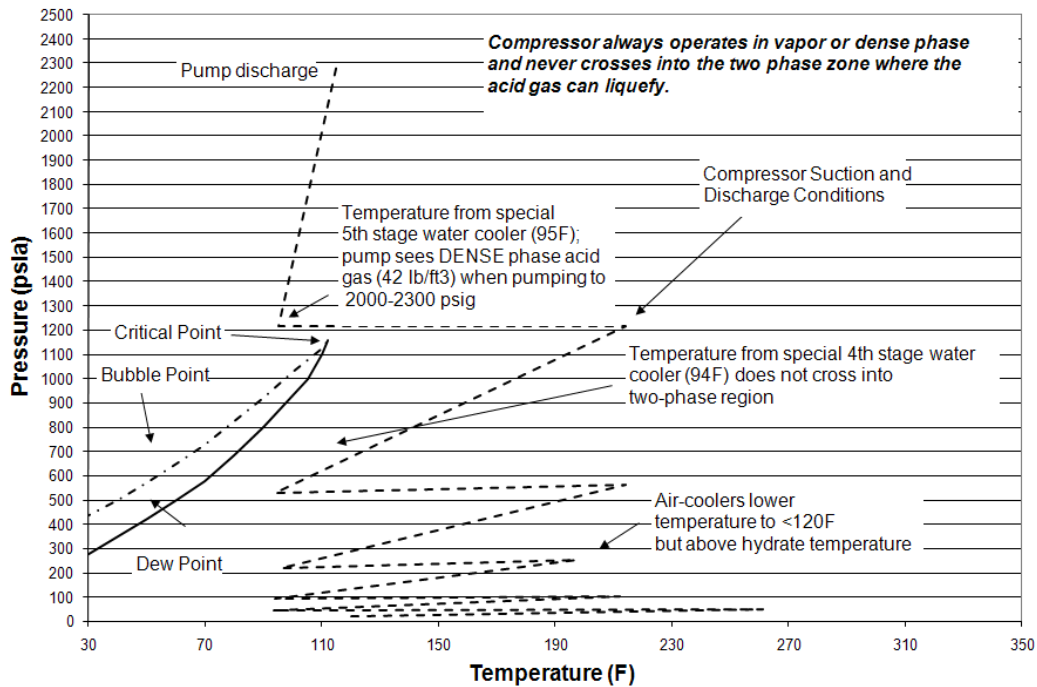


Figure 12. Tilden Dry Acid Gas Phase Diagram with 5th Stage Pressure Control and Water Cooling

G. Tilden AGI Unit Operation after Modifications

After these modifications, the acid gas pump speed was adjusted based on the compressor 5th stage discharge pressure. The site started up, and from that point forward, the pump was always fully capable of pumping all of the acid gas into the injection well. Before the modification, the AGI system was down more than 50% of the time, and afterward, the AGI system met Regency's expectations for on-stream time and regulatory requirements. Downtime after this modification was primarily for pump packing change outs (an issue that is beyond the scope of this paper) and compressor valve replacements and related items. The AGI unit operated much more reliably with consistent compressor operation and injection well pressures (see Table 2) for a number of months after conversion to pressure control. The injection pump and precooler were performing well in that there are no signs of continued NPSH / cavitation problems or hydrate formation in the exchanger. (It should be noted that the positive displacement injection pump never provided reliable operation, due to packing issues and other items, and was eventually replaced with a successfully operating centrifugal pump instead.)

More recent modifications to the plant include 1) adding a second compressor train [3.7-3.8 MMscfd total to the two compressors], 2) adding a coalescing filter prior to the pre-pump exchanger to reduce observed buildup of materials in the exchanger, 3) replacing the piston pump with a multi-stage centrifugal pump and 4) including a post-pump chiller to drop the well head pressure for injection.

Table 2. Tilden Plant Operating Data After Pressure Control Change (Average Data from 08/15/07 to 1/13/08)

	FLOW Mscfd	WELL PRESSURE	WELL TEMP	COMPR RPM	1st STG SUCTION PRESS.	1st STG DISCH TEMP	1st STG. SUCTION TEMP.	2nd STG SUCTION PRESS.	2nd STG DISCH PRESS.	2nd STG SUCTION TEMP	2nd STG DISCH TEMP	3rd STG SUCTION PRESS.	3rd STG DISCH PRESS.	3rd STG SUCTION TEMP	3rd STG DISCH TEMP
Average	2232.6	2375.5	112.7	1118.2	5.0	244.9	91.0	28.7	85.4	86.9	194.0	81.2	220.1	86.1	225.5
	4th STG SUCTION PRESS.	4th STG DISCH PRESS.	4th STG SUCTION TEMP	4th STG DISCH TEMP	5th STG SUCTION PRESS.	5th STG SUCTION TEMP	5th STG DISCH TEMP	TE-535 FINAL DISCH TEMP	TE-521 ACCUM. TEMP	V-526 ACCUM. PRESSURE	INJECTION PUMP SPEED %	3rd STG SUCTION PRESS.	3rd STG DISCH PRESS.	3rd STG SUCTION TEMP	3rd STG DISCH TEMP
Average	211.7	551.7	95.5	247.4	544.0	131.4	234.1	148.2	95.5	1221.5	61.2	73.7			

IV. Summary of Important AGI Unit Design Considerations

Some of the important AGI unit design considerations learned from Regency's Waha and Tilden sites are listed below to aid others when constructing their AGI facilities.

- Water removal from acid gas streams is very important and must be evaluated closely to prevent corrosion of carbon and low alloy steels in the AGI unit and downstream injection well. A maximum 60% relative saturation limit was recommended by an independent corrosion scientist to help evaluate water removal options at operating conditions and during startup and shutdown situations;
- From reviewing readily available public data on previously installed AGI systems^{6,7}, it can be observed that low-H₂S acid gas streams (less than roughly 25%) are generally associated with the use of glycol dehydration. This is done in order to achieve low enough water content to avoid hydrates and/or corrosion of carbon and low alloy steels in the AGI equipment and injection well. The plant data also shows that higher H₂S streams (greater than roughly 25%) appear to use glycol dehydration much less frequently. Other, simpler water removal options (e.g., simple cooling and separation at the right pressure) are more applicable at higher acid gas H₂S concentrations;
- From an equipment operations perspective, using a glycol dehydration unit on acid gas streams is a relatively easy and clean application compared to field natural gas streams; and costs for glycol dehydration units can be minimized (e.g., by using a pre-contactor instead of stainless steel contactor, no flash tank);
- If simple cooling and condensation of water is chosen, then it is important to control and operate coolers above hydrate points;
- Careful and early review of the design of AGI units is advised to make sure that compressors and/or pump skids are operating clearly in a region where one can avoid NPSH and downstream pressure control issues;
- An analysis of multiple samples of acid gas stream taken over time is important to ensure that composition is accurately known. Variations in H₂S and hydrocarbon content can dramatically impact the properties of the acid gas stream and subsequent design; and
- Use simulation software that can predict acid gas properties as accurately as possible; then also leave room in the AGI unit design in case predictions are off.

V. Acknowledgements

The authors of the paper would like to thank Paul Carmody for his assistance in the design of the pre-contactor mixer used in the dehydration unit for the Waha AGI facility. Special appreciation is also given to the operators of the AGI facilities that provided helpful insights in the design of the units and data collected during troubleshooting efforts.

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