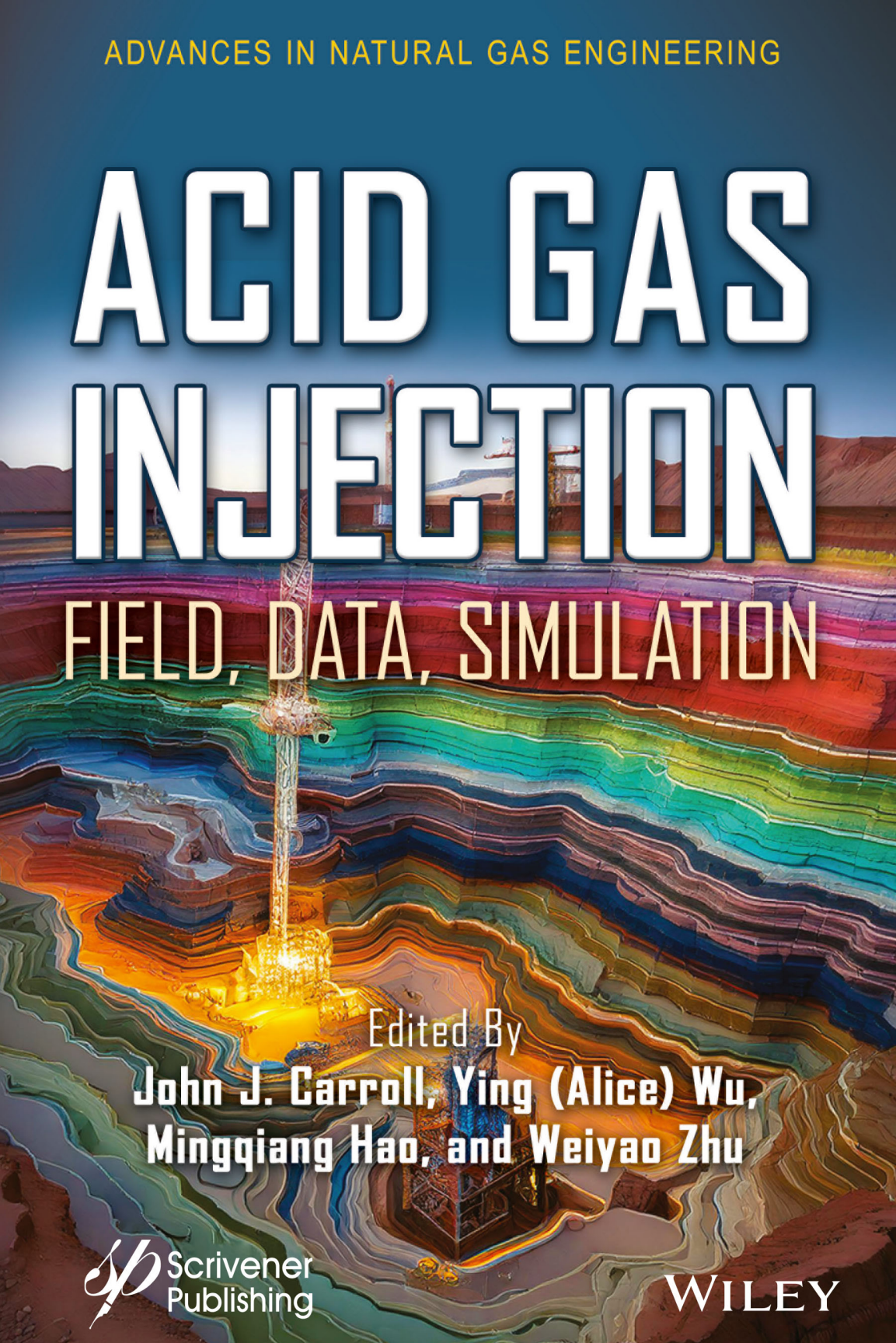
ADVANCES IN NATURAL GAS ENGINEERING

ACID GAS INJECTION

FIELD, DATA, SIMULATION



Edited By
John J. Carroll, Ying (Alice) Wu,
Mingqiang Hao, and Weiyao Zhu

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Preface

This volume compiles the papers presented at the 9th International Acid Gas Injection Symposium (AGIS IX), which was held in Calgary, Canada in May 2023. The Symposium focused on three related technologies: acid gas injection (AGI), carbon capture and storage (CCS), and CO_2 injection for enhanced oil recovery (EOR). Virtually all topics related to these technologies were discussed.

Among the key highlights are the first three chapters, which provide data from plants that actively inject acid gas. These papers where the cornerstones of the Symposium and explore both the successes and challenges associated with AGI, giving a balanced view of its implementation and results.

Additionally, the volume features contributions from companies that manufacture pumps and compressors, detailing their application in acid gas injection and related processes. These papers provide insights into the technical equipment used in AGI, CCS, and EOR, contributing to a comprehensive understanding of these technologies.

This volume also includes several papers that delve into the wells and subsurface aspects of these technologies. These papers focus on topics such as reservoir simulation, offering a deeper understanding of how these technologies interact with subsurface formations.

Finally, the volume contains papers addressing auxiliary topics that are integral to the successful application of these technologies. These include discussions on solvents for acid gas removal and solvents for carbon capture, which are critical for improving the efficiency and effectiveness of both AGI and CCS processes.

JJC, YW, MH, & WZ
June 2023

1

Acid Gas Injection from Startup to Stability—A Recap of 3 Years of Operation and Troubleshooting

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Abstract

The following work summarizes operational challenges encountered at the Tidewater Pipestone facility during startup and first years of operation, specific to AGI. Challenges commonly associated with facility startups were experienced at PSGP (Pipestone Sour Gas Plant) and this was also true for acid gas treatment and handling units. Some of the challenges we encountered in the first few years of operation include maintaining amine unit stability, compressor control/loading, temperature control, well tubing failure, diaphragm failures in acid gas pumps, management of acid gas compression/injection during maintenance and unplanned outages, and development of site-specific maintenance and operational best practices. A combination of operational experience, modeling, fluid analysis, equipment failure analysis, and engineering expertise from multi-disciplinary teams was utilized to mitigate and resolve operational challenges including adaptations to the operational procedures utilized at PSGP to minimize process upsets and equipment downtime based on operational history and experience, engagement with third party vendors and strategies developed for improved unit performance, and use of process simulation as a tool to predict the potential impact of deviant operating conditions and their possible contribution to areas of challenge.

John J. Carroll, Ying (Alice) Wu, Mingqiang Hao and Weiyao Zhu (eds.) Acid Gas Injection: Field, Data, Simulation, (1–18) © 2025 Scrivener Publishing LLC

1.1 Introduction

The Tidewater Midstream Pipestone Sour Gas Plant (PSGP) is located approximately 20 km west of Wembley, Alberta. Startup commenced in September 2019 of the facility that was designed to process 100 MMSCFD of sour gas from Montney shale production and its associated liquids.

The amine unit was designed to utilize DGA® (Huntsman) for sweetening gas at 5% H_2S and 0.3% CO_2, with a resulting target composition of the processed dry acid gas of 95% H_2S and 5% CO_2. As such, acid gas dehydration occurs via two five-stage compression and cooling trains. After the last stage of compression, diaphragm pumps are utilized to raise the fluid to injection pressures of approximately 20 MPa. Dense phase fluid is then

Table 1.1 Design and current conditions.

	Design	**Current**
Acid gas flow rate	160 E3m3/day 5.66 MMSCFD	
Composition		
H_2S	90 mol%	80–85 mol%
CO_2	5 mol%	9–13 mol%
H_2O	5 mol%	6 mol%
Water content after 4th stage	3.4 g/Sm^3 214 lb/MMSCF	4.3–4.8 g/Sm^3 275–305 lb/MMSCF
1st stage suction temperature	43.3°C	40–45°C
1st stage suction pressure	34.5 kPa [g]	42–45 kPa [g]
5th stage discharge pressure	6,895 kPa [g]	5,250–5,600 kPa [g]
Injection temperature	60°C	40°C
Injection pressure	23 MPa [g] (max pump SD)	15–20 MPa [g]

injected into two acid gas wells, both in the Stoddart formation (carbonate aquifer) at ~3,000-m depth, with a reservoir pressure of 28 MPa, with an approximate permeability of 10 mD. Power is generated onsite by two gas turbines.

The original design and current operating range for the acid gas compression/injection train are as shown in Table 1.1.

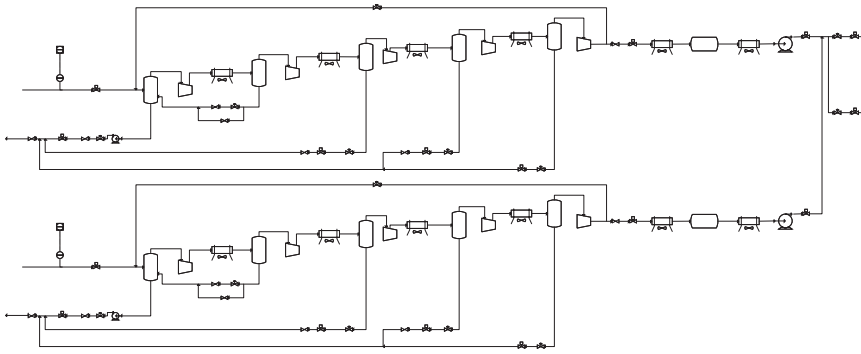


Figure 1.1 Schematic of acid gas injection train.

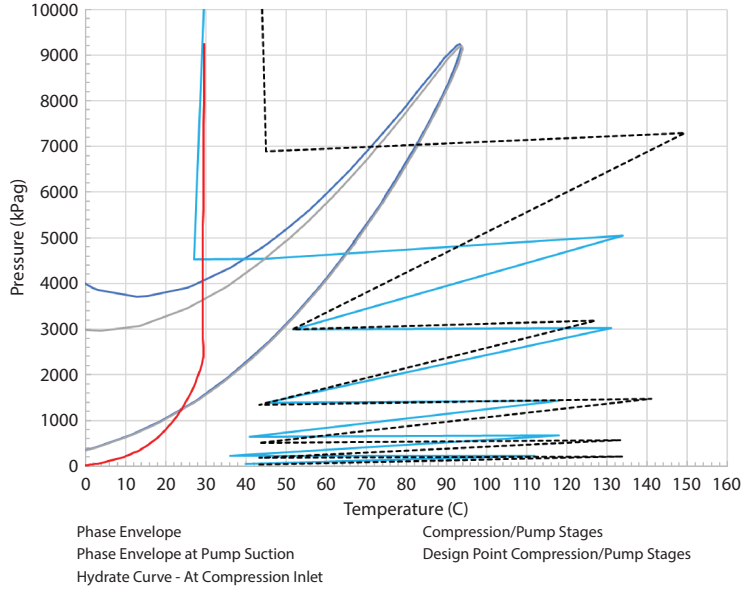


Figure 1.2 Design vs. current compression stages.

The acid gas injection train is comprised of three sections/skids—acid gas compression (2X50%), acid gas pump (2X50%), and acid gas injection. Figure 1.1 shows the major pieces of equipment and points of control.

Given the high H_2S concentration expected in the acid gas processed at PSGP dehydration was expected to be reasonably achieved via compression and cooling even if CO_2 concentration should increase, as can occur in area production. In 2019 acid gas H_2S content was ~90 mol% (dry basis) but since late 2022 this has dropped to 85 mol% (dry basis) as CO_2 concentration has increased. Figure 1.2 shows the design and a potential current operating curve, along with two operational phase envelopes and the hydrate curve at compressor suction. The difference in 5th stage discharge pressure is a function of both composition and temperature exiting the cooler upstream of the accumulator on the pump skid.

1.2 Startup: Ideal vs. Actual

The startup of a new facility, let alone a sour gas plant, is always going to be an enlightening experience. Operation is not steady, not typical and not tuned. Every design "assumption" is simultaneously tested under circumstances where even the best design can be challenged at times. It is also an opportunity for the more mundane best practices around valving and isolation to standout as commissioning, startup activities and frequent process trips will direct flow at conditions that are far from ideal and modifications to better align actual and ideal will be frequent and require immediate attention and alteration. An isolation philosophy that considers timely repairs and maintenance will be invaluable. This includes isolation on flare, drain, and utility connections as these are sometimes less considered but can add substantial downtime to repairs and maintenance if no isolation is available to allow for safe work. Also, it is vital that compressor drains on acid gas package be protected with check valves so there is no potential back flow into the compressor/pump skid. The cost of clean-up alone is far greater than that of a few check valves let alone the associated downtime.

During the initial facility startup interactions between the startup sequence and permissives of the separate compressor-pump-injection skids caused some challenges. When operating an acid gas injection system similar to that at PSGP, where each of the three segments are designed as individual packages, it would be helpful for design teams to carefully review the startup and shutdown sequences with the operations team, with vendor and programming support on hand. As one example, a minimum

accumulator level will be required to start the acid gas pumps. Once that permissive is met the pumps need to start before the accumulator hits high-level shutdown. The default timer setting for the pump to complete its startup may be calculation based, but what is experienced in a facility processing inconsistent volumes at variable conditions can be quite different than these calculated rates and startup timings or shutdown ranges may need to be adjusted.

The amine unit has a significant impact on the stability of an AGI unit at a gas processing facility. If this unit has a design optimized strictly to design conditions the supply of and condition of acid gas entering the AGI train can be problematic during the startup period as flows may be low and quality poor. Even once amine operation is stabilized adequately, appropriately placed telemetry and control devices on the amine reflux condenser is critical to maintaining acid gas quality. Something as simple as ensuring temperature transmitters are placed as close to the cooler outlet as possible or adding positioners to control valves assemblies can make a significant difference to acid gas feed stability. Once volumes at PSGP were sufficient to operate both acid gas compression trains it became quite apparent that modifications to the original compressor loading philosophy were required to avoid significant operator intervention to manage loading oscillation. This prevented smooth transition anytime units were taken down or started before/after maintenance, leading to additional downtime and flaring. This was resolved at PSGP with the addition of a common suction line pressure transmitter and a Master PID loop and some logic for load sharing/unit selective control.

For sites like PSGP that produce their own power there is an additional startup complication of power stability. After 3 years in operation problems with power stability are infrequent to the point of non-existent, but at startup gas turbines are another piece of equipment that adds to the complexity of startup as there are operational and programming systems to streamline and troubleshoot. In our experience most of these challenges centered around communications between power generation and waste heat recovery, but whatever the cause, loss of power can have serious implications to an acid gas injection train and strategies around unplanned downtime for any reason, including loss of main power should be considered. Will any blowdowns be triggered in the AGI train? Is it possible that any area of the system could drop to temperatures where the acid gas is now over saturated? Is mitigation required if this does occur and what is the mitigation? Is there adequate redundancy/protection via back up power, line insulation? How much time offline is acceptable before blowdown is initiated?

1.3 Pump Diaphragm Failures

After a few months of more stable operation pump diaphragms began to fail with a high frequency. Diaphragm failures even included a double failure where hydraulic oil was contaminated with acid gas. This prompted a series of reviews involving operations and both the skid and pump vendors. Initial assessments focused on the potential for hydrate formation and cavitation. However, after a thorough review of operating data both were determined to be unlikely based on available information. Double diaphragm failures were thought to potentially be attributed to the replacement of failed solenoid valves on the leak detection system with needle valves, but double failures continued to occur (albeit infrequently) even after replacement parts were installed and confirmation that leak detection was functioning as intended. Alarm actions and maintenance/repair procedures were also reviewed and changes implemented as required. A pump teardown did also not lead to any significant indication of root cause.

We did note that failures would often be associated with maintenance events (i.e., failure of a diaphragm post repair of a different diaphragm) so one area of focus was blowdown and startup procedures for the pumps. This failure pattern indicated that the blowdown and/or startup procedures were contributing to diaphragm losses and after a review of our own blowdown/startup procedures it was noted there was a potential for high velocities/flow rates across the diaphragm face which could contribute to accelerated wear. After a review of previous blowdown/startup related issues in similar systems Tidewater opted to modify the acid gas pump skids to accommodate a low impact blowdown and startup. This was approached in stages as time was required to design and construct some portions of the modifications. The first stage was to modify the methanol injection system to delivery to the suction of either acid gas pump in order to deliver batch volumes of methanol during the manual unit blowdown. Batch rates will not exceed the normal fluid rate of the pumps. In conjunction the pump skid is prepped for maintenance by completing sectional blowdowns—accumulator/suction bottle/discharge bottle to avoid high velocities across the pump heads/diaphragms during the blowdown process. The second stage of modifications was the addition of controlled fuel gas flow. A simple system with a regulator, rotameter and throttling valve was tested first, but results were inconsistent. A more automated system with a flow controller was then installed on each pump skid to ensure consistent flow and blowdown time for every event. Since implementing these changes diaphragm replacements have decreased by nearly 70%. The associated

saved downtime for repairs is approximately 250 h a year for average repair times or 500 E3m3 equivalent potential flared AG volume.

1.4 Corrosion

After about 2 years in operation both acid gas injection wells had new tubing installed as the original coated carbon steel tubing failed due to corrosion. An assessment was completed of the failed tubing to determine likely root cause and based on the observed type of corrosion it was determined that the presence of a water phase must have occurred. Some coating defects were also identified, which could have contributed to accelerating corrosion as water could be trapped between the coating and tubing wall. The failed tubing was replaced with uncoated L80 carbon steel tubing.

There are limited sources of water—either flowback from the aquifer (unlikely) or from the process. Given the H_2S composition it should be unlikely that the fluid is entering the well at risk of being over-saturated as long as design conditions are satisfied. However, as discussed earlier, the acid gas injection train has not always been able to operate at "design conditions". It is these deviations that the acid gas is not undersaturated for a part of the process, allowing a water phase to form. Figure 1.3 demonstrates this with some typical water content curves at operating conditions that could be common during amine process instability, particularly in the winter months. Ideal dehydration point is the lowest point in the 55°C water content curve (90% H_2S). A typical operating pressure after 4th stage compression is circled and to the left of the "ideal" dehydration point. This is equivalent to a calculated water content of about 280 lb/MM. The water content curves for 65 and 70°C are representative of short term high temperatures measured on fourth stage compression during an upset. If temperatures remain high through the remainder of the acid gas injection train and into the well the formation of a water phase is perhaps unlikely. However, this is not what occurs. And, particularly through winter months, it is quite likely to see temperatures of 25°C or lower through the latter part of the acid gas injection train. Example cooling events could include:

- Over cooling in pump subcooler at low winter ambient
- Cooler injection line temperatures
    - Times of low/no flow in injection line
        - Outages
        - Loss of heat trace/gaps in insulation

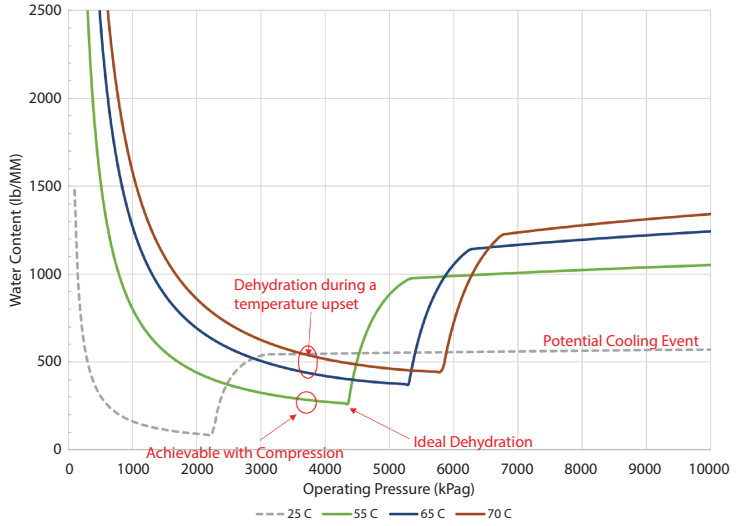


Figure 1.3 Potential water content crossover at unstable operating conditions.

Events that can concur with high 4th stage cooler outlet temperatures:

- Amine reflux condenser outlet temperatures are severely elevated
- Transitions from recycling to flowthrough on acid gas compression
- Temperature swings on 3rd and 4th stage compression

As we have been focused on continuously improving reliability and operability at PSGP many of these issues are gone or significantly reduced:

- Additional measurement and automation for better reflux condenser control
- Acid gas compressor loading control
- Acid gas cooler freeze protection modifications
- Additional heat tracing and insulation on AG injection lines
- Frequent checks of EHT panels by on instrumentation and operator rounds
- Improved plant stability and less frequent shutdowns/trips
- Amine unit improvements to stabilize its operation
- Inlet volume control

Additional strategies that we have contemplated:

- Determine if measured water content is in line with expectations
- Integration of a water content/phase envelope module to inform board operators of degree of deviance/act as control variable in control loop.

1.5 Acid Gas Sampling

ASRL (Alberta Sulfur Research Limited) has developed an analytical procedure for measuring water content in pressurized acid gas samples. In order to determine if the water content of the acid gas was within thermodynamic expectations two samples were taken at available points on each injection line. Samples were collected in 150 mL stainless cylinders rated to 5,000 psig. These cylinders were prepped by a local lab for testing to remove trace amounts of air and water before sampling. A laboratory sampling technician also worked with our operations staff to develop an appropriate sampling procedure and review the connections that were in place would provide a means to purge and collect a representative sample. They then returned to site on the day of testing, collected the samples and ensured their delivery in an insulated vessel to ASRL. At the time of sampling one compressor train was fully loaded and operating at stable, typical conditions while the second train had was recycling some flow (due to an upstream problem that required a partial throughput reduction to the plant). The third and fourth stage cooler outlets were oscillating about 5°C–10°C but otherwise operating conditions were reasonably consistent between the two trains. Both samples were tested and the results were 225 lb/MM in one cylinder and 221 lb/MM (~3.5 g/m^3) in the second sample, proving that under typical operating conditions (even with a bit of recycling) that the expected water content is reasonable.

1.6 Acid Gas Simulation

A dynamic model of the acid gas compression system representative of the PSGP was created using the Symmetry Platform modeling tool. The model was used to analyze plant behavior and obtain more insight into plant operations. A few different scenarios were studied, particularly the

impact of inter-stage temperature variations and inlet flow deviations on important product parameters, such as water content due to the importance of this parameter.

The modeling effort is focused on the acid gas compression system only. At this stage in the process, the acid gas is being compressed from ~45 kPa to ~5,200 kPa before being cooled and sent to the acid gas pump to attain a discharge pressure of ~16,900 kPa and transport the gas through a pipeline to the acid gas injection well.

The model is set up to be representative of the PSGP acid gas compression and injection process. The compression system consists of five stages of compression. Each compression stage includes an inlet scrubber, compressor, and an inter-stage air cooler. First compression stage compressor contains two cylinders, and the other four stages have one cylinder. In addition, the system contains a recycle to ensure stable first stage compression inlet pressure.

An important step in the compression process is removal of water via cooling the compressed gas after each compression stage. Water is then collected in the suction scrubber of the next compression stage. The accumulated water is then sent to the produced water storage via the liquid outlet piping of the inlet scrubber. Each inlet scrubber has a level control incorporated into the model to ensure a certain level % is kept inside of each stage's inlet scrubbers. In addition, the vapor outlet is connected to a relief device to represent connection to the flare system.

In order to maintain a certain outlet temperature after each cooling stage each inter-stage air cooler has a temperature control incorporated into the model. Additionally, there are multiple pressure and temperature indicators between compression stages, to track these important parameters and provide with additional flexibility if setting up a controller is required.

The inlet stream has dry gas composition specified, as obtained from the lab analyses. At the inlet to the first stage compression inlet scrubber, the model contains a saturator in order to saturate the acid gas with water at the inlet pressure and temperature, which will depict the real case scenario. The model process flow diagram as seen in the modeling tool is presented in Figure 1.4.

Information from the plant operations and engineering documents was utilized to model the acid gas compression system. The first step in modeling the system was to input all the equipment data. For the compressors' information, data such as the cylinder bore diameters and cylinder stroke distance was specified, as well as the compressor design speed and clearances, where known.

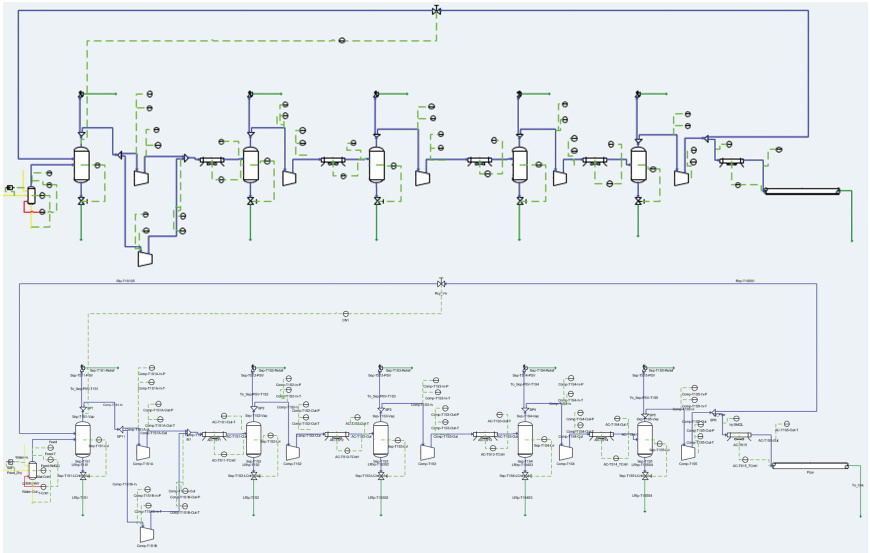


Figure 1.4 Model layout.

The volumes for the following vessels were considered and specified to represent the system, based on the plant documentation:

- Suction scrubbers
- Intercoolers
- Suction and discharge bottles

Operating parameters were specified where necessary, and calculated results were checked versus real plant performance to ensure accuracy.

1.7 Acid Gas Compression Modeling

One of the most important acid gas properties is the water content. Water presence in acid gas can cause multiple issues especially if condensation of the present water occurs, which can lead to increased pressure drop in the pipeline and corrosion problems. Thus, water content is an important design consideration, and a certain limit must be maintained regarding acid gas water content.

It is important to discuss phase equilibria of H_2S + CO_2 + water systems and their behavior. In addition, presence of methane can influence

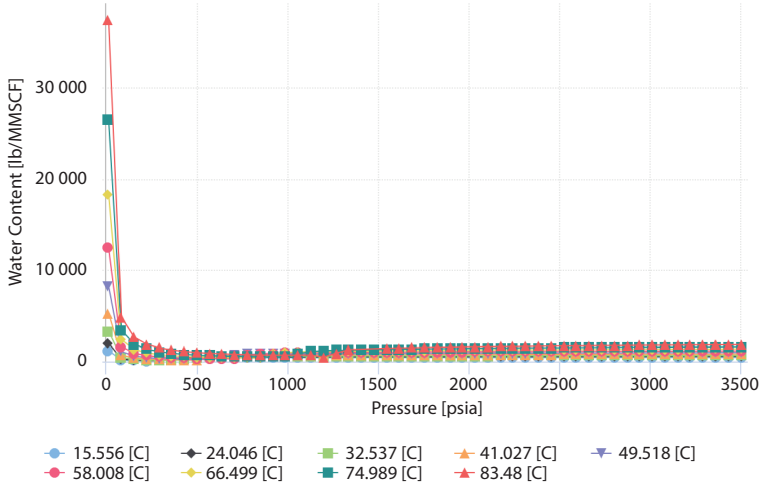


Figure 1.5 Acid gas water content (Y-axis, unit: lb/MMSCF) variation with pressure (X-axis, unit: psia) at different temperatures (unit: °C).

the behavior of the system further, even in small quantities. There are many methods that exist to calculate water content of acid gas and a few various thermodynamic models can be used to characterize the system. For the purposes of this modeling exercise, the symmetry thermodynamic model Advanced Peng Robinson (APR) for Natural Gas 2 was utilized, which contains extensive validation with experimental data for various phase equilibria systems.

For reference, a water content map was created which depicts the water content variation with pressure and temperature for the acid gas composition of the PSGP. The water content graph is presented in Figure 1.5.

PSGP has previously had operational issues surrounding water content. The model was utilized to gain further understanding of the impact of certain operational disturbances on acid gas water content.

There were several scenarios that were run using the model:

a. Third stage temperature controller upset which causes a variation of around 10°C–15°C every 3 min.
b. Inlet feed variation +/-5% to represent frequent amine reflux separator outlet stream variation.

Prior to discussing each of the analyzed scenarios, an interesting observation is worth noting, which has been identified during the model results vs