HIT THE GROUND RUNNING
TROUBLESHOOTING WITHIN A RECENTLY MODIFIED AMINE UNIT

Laurance Reid Gas Conditioning Conference
February 17-20, 2026 – Norman, Oklahoma USA

Matthew Cunningham
Williams
One Williams Center
Tulsa, OK 74103
matthew.cunningham@williams.com

ABSTRACT

Operating amine plants have one thing in common: change is challenging. Mitigating existing mechanical issues while introducing new process challenges continues to be a great learning experience for new engineers entering the gas processing field. At a Williams treatment plant in Northern Louisiana, a myriad of mechanical debottlenecking projects started to culminate in the installation of a new amine still. Under pressure to complete the project in a timely manner to fix problems and increase capacity, a new team including a young engineer transition into the driver's seat to get the plant in service.

This paper intends to present an operating case study with a focus on the challenges that arise from deciphering process issues (new solvent) vs mechanical issues (regenerator hydraulics, thermosiphon loop, pulsation mitigation) for an existing amine plant that recently adopted a proprietary amine. A key subject is using sound engineering judgement and problem-solving skills to create a clear path through the mechanical debottlenecking process to fully realize the capability of a new solvent.

Key focus points of this paper:

- Attacking a multifaceted troubleshooting situation while transitioning into an ongoing project.
- Deciphering process vs. mechanical issues as a new engineer in the amine treating field.
- Leveraging PI systems and operator input to make educated decisions (data to be shared).

The author is aware of the value of firsthand experience, and would like to share engineering calculations, data, and firsthand experience gained as part of this project.

As with all projects, when balancing multiple variables, where do you start? Thankfully, the end is in sight.

HIT THE GROUND RUNNING
TROUBLESHOOTING WITHIN A RECENTLY MODIFIED AMINE UNIT

Matthew Cunningham, Williams, Project Execution, Facilities and Engineering, Tulsa, Oklahoma

INTRODUCTION AND BACKROUND

The North Desoto Treatment Facility in the Louisiana Haynesville shale has three inlet gas treating trains with a combined operating capacity of 650 MMSCFD of amine treating as depicted in Figure 1. The inlet gas treaters at this plant treat lean gas from domestic Haynesville shale wells by removing CO2 content to reach pipeline specification. Amine treaters in Train 1 and Train 2 feature individual treater trains, "A" and "B", each with an independent contactor and still set. Each treater "A" and "B" features a gas bypass to blend inlet gas with treated gas downstream. There are two total inlet separation trains upstream of treating and two total trains of TEG dehydration on the outlet of the amine treating trains prior to compression.

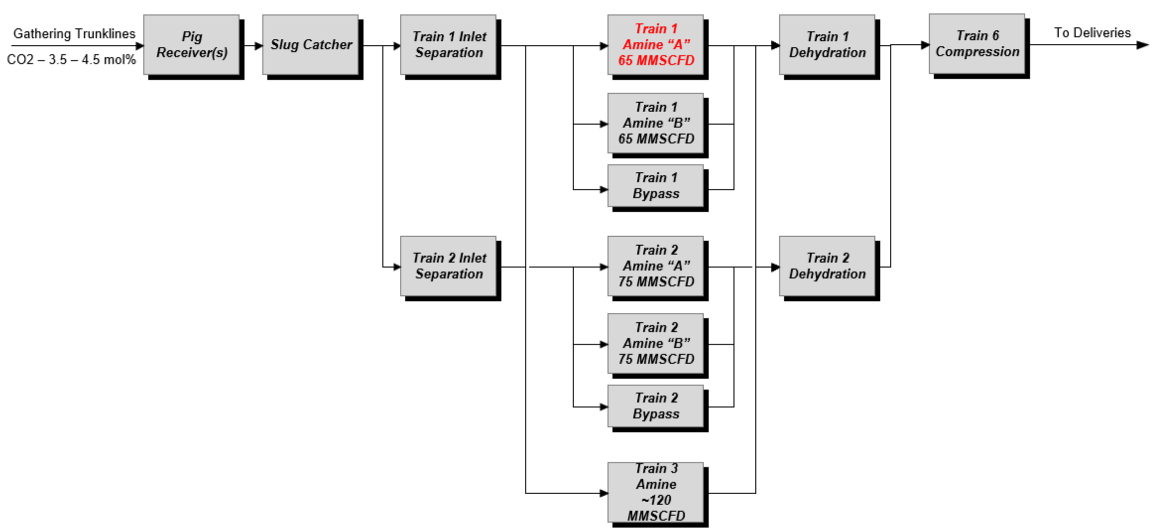


Figure 1 *– Facility Block Flow Diagram*

This paper focuses on the challenges faced when working to mitigate existing mechanical issues while commissioning a new Amine Still after recently introducing a new solvent for increased capacity in Amine Treater 1A. Treater 1A has an installed nameplate capacity of 65 MMSCFD, at 350 GPM circulation rate of amine. Each Amine Train features 1 stage of inlet filtration followed by an amine contactor, 1 stage of post contactor filter separation, and then TEG dehydration. Excess gas above 130 MMSCFD for the treating train (1A and 1B combined) is bypassed to blend out with treated gas to meet required outlet pipeline CO2 specification. The solvent is a proprietary alkanolamine, which contacts the inlet gas stream that has a varying CO2 composition of 3.5-4.5%. This plant serves to remove acid gas content to meet pipeline tariff prior to compression into the sales gas pipelines. Amine Treater 1A's amine regeneration system features a flash tank, lean / rich exchanger, still, horizontal reboiler, reflux condenser, reflux accumulator, and CO2 vent stack. Refer to the block flow diagram in Figure 2 below.

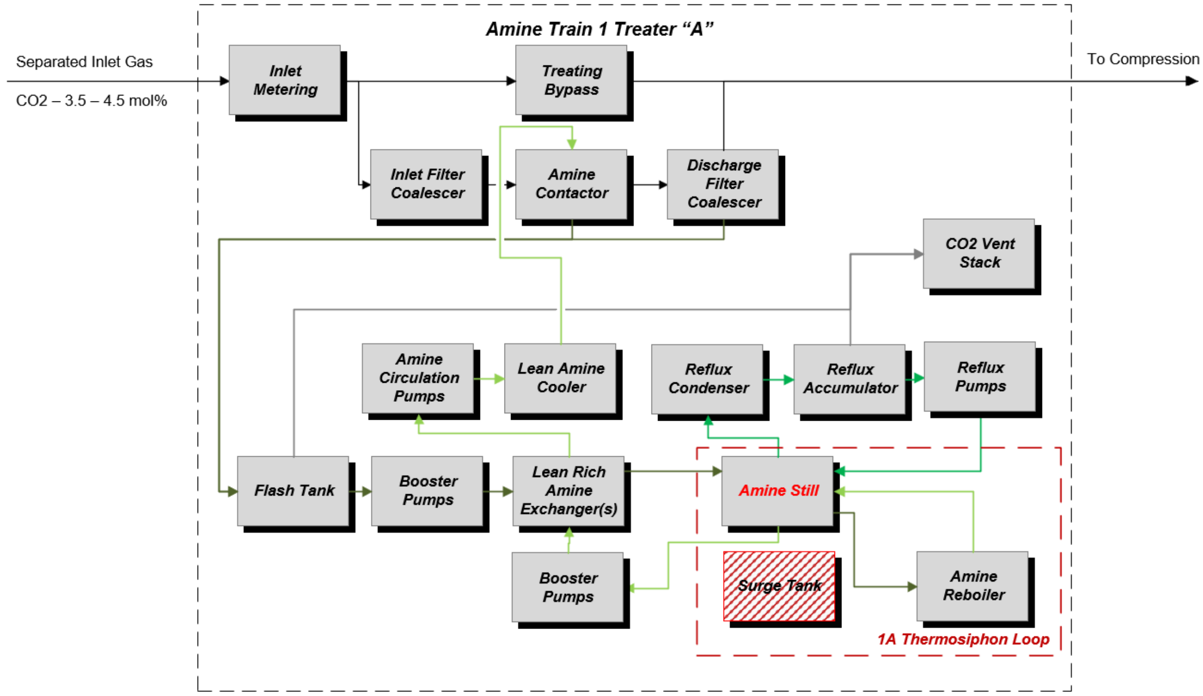


***Figure 2 –** Amine Train 1 "A" Block Flow Diagram*

AMINE TREATER BACKGROUND

Amine Treater 1A has been in service and operating since 2008, roughly seventeen years of runtime. The treater has operated previously with an MDEA plus piperazine amine mixture. In 2022, Train 1A switched to a proprietary MDEA and TEA blend as a part of a nameplate capacity enhancement effort. The value proposition of this change was to gain additional capacity (30% target) out of the treating system via the increased performance of the amine and reduced energy intensity requirement for regeneration.

Several projects have been completed within the past 3 years for the Train 1A Amine Regeneration system to debottleneck the process, culminating in a project to replace the Amine Still to mitigate mechanical integrity issues that coincided with this solvent change. This paper intends to document the troubleshooting process of bringing Amine Train 1A back online after the installation of the Amine Still, identifying root causes for vibrational and process issues encountered during the commissioning phase and addressing performance unknowns of a new solvent within the system.

Historical Operating Issues

Several existing operational issues have been experienced and/or identified within the with Amine Train 1A prior to mechanical debottlenecking projects and the amine swap including the following specific issues:

1. Cavitation in Amine Booster Pumps and excessive corrosion in booster pump suction piping
2. Fouling and redundancy concerns within the Lean / Rich Exchangers

3. Foaming in the Amine Contactor/Still
4. Iron presence in the Amine stream

The issues experienced above collectively resulted in excessive Train 1A downtime due to accelerated equipment failure, reduction in treating capacity and throughput for the unit, increased operating costs, and mechanical integrity concerns leading to several projects to reduce the impact of each concern.

Amine Booster Pump Piping / Surge Vessel Head

Historical operating knowledge demonstrated that the piping configuration on the inlet of the booster pumps and available liquid head from the amine surge vessel was insufficient to prevent cavitation in booster pump suction piping. Increased localized corrosion in the 90 degree elbows on the inlet of the booster pumps was observed and mechanical integrity concerns with piping due to a measured loss of wall thickness. Intermittent failure of pump impellers leading to reduced asset life was a symptom of the hydraulic design, leading to unplanned loss in redundancy of the 2-pump amine booster system; and at worst a system throughput limitation due to loss of pumping capacity.

Lean / Rich Exchanger Fouling / Redundancy

The existing design of Amine Train 1A featured a single shell and tube Lean / Rich Exchanger. Fouling of the shell and tube exchangers led to reduced heat transfer and increased differential pressure across the exchanger passes. Paired with inlet filtration issues in the gas stream, this led to increased fouling and downtime of Train 1A Amine Regeneration for exchanger cleanouts.

Foaming in Original Design

Foaming in the Train 1A Amine Contactor and Amine Still was observed previously via level disagreement between the level float and the level transmitter on the Amine Contactor / Amine Still. Foaming within these systems resulted in loss of gas treatment capacity, gas throughput, and occasional amine carryover into the gas discharge filtration. This foaming had been ascribed to poor gas inlet filtration and channeling in the Amine Contactor and Amine Still. This led to increased use of defoamer within the inlet treater trains for the entire facility.

Iron Presence in the Amine Stream

During routine amine quality testing, increased iron presence was observed in the amine stream. This triggered Mechanical Integrity checks for affected equipment in the regeneration system. Mechanical integrity concerns in the Amine Still surfaced due to reduced wall thickness in the vessel. These mechanical integrity concerns are what prompted the project specific modifications discussed below.

Recent Train 1A and 1B Modifications

The following modifications have been made to Amine Treater 1A & 1B in the past 4 years to mitigate the operating issues and design concerns above:

- Like-in-kind replacement of horizontal Amine Reboiler on Train 1B due to loss of wall thickness in reboiler tubes at the top of the reboiler as indicated by the presence of iron in the amine stream.
- Replacement of Inlet Filter Coalescers upstream of amine contactors with new vessel style, filter elements, and level measurement techniques to combat foaming within the facility.
- Single Lean / Rich Exchanger replacement with two (2) plate and frame exchangers in both Train 1A & Train 1B for ease of cleaning for fouling, and to provide a spare exchanger to mitigate downtime concerns.
- In addition to the modifications intended to address the operating issues described above, Williams also decided to change the amine in Train 1A from a MDEA and Piperazine blend to a proprietary MDEA and TEA blend.

The solvent change above was completed while the engineering and design phase of the mechanical modifications of the Amine Still replacement project were ongoing. This allowed increased acid gas treating capacity of the amine, increased gas throughput of the train, and reduction in reboiler duty of the existing train due to the reduced heat input required to reject the CO2 in the amine regeneration system as a part of the proprietary amine design. However, the performance testing of this new amine was not completed immediately after the solvent swap, as amine still replacement project was ongoing. This allowed the project to complete the performance testing after the final mechanical debottlenecking and troubleshooting of the modification scope was completed.

Project Specific Modifications

The scope of the current project that this paper will focus on was to install a new Amine Still that featured an integrated internal surge tank within it to increase liquid head and benefit booster pump suction pressure by locating the surge capacity of the regen system higher in the air (approximately 15 ft) relative to grade. The replacement Amine Still vessel was purchased by the previous plant engineer during earlier project phases and so was already fixed. The new vessel featured a larger diameter Amine Still with an integrated surge vessel. The existing independent Surge Tank was removed as a part of this scope as indicated in Figure 2. Piping was also modified in this project to reduce pressure loss through simplified pipe routing with a decreased number of fittings from the integral surge tank in the new Amine Still to the Amine Booster Pumps. The booster pump suction line remained the same nominal pipe size.

This project also installed a Lean Amine Pre-Exchanger Filter as an additional layer of protection for any fouling in the plate and frame Lean / Rich Exchangers installed in the previous phase of the debottlenecking effort of Amine Train 1A. This scope was added part of the way though the Amine Still replacement project. Material compatibility issues were discovered in the Lean Amine Pre-Exchanger Filter elements and associated valving soft goods after construction was completed, and the unit startup was in the troubleshooting process.

CHALLENGES OF TRANSITION DURING PROJECT EXECUTION

Project transitions are always difficult, but none are more difficult than starting fresh in a process you are unfamiliar with. As an engineer recently introduced into the gas treating field via amines in the Haynesville shale, navigating the startup and troubleshooting process for gas treating proved a great project experience to the author. The previous project team (project manager and project engineer) rotated off the project while commissioning efforts of the new Amine Still were about to take place. Both were taking new roles within the company which required the current project team to onboard just as design and construction were completed.

As mentioned above, the replacement Amine Still was purchased prior to the previous project team taking over the replacement maintenance capital project. The previous project team worked with a 3rd party engineering firm to complete the engineering for the plate and frame Lean / Rich Exchanger project, the gas inlet filtration upgrade project, and had managed the engineering design firm through the detailed design and Process Hazard Analysis portion to the completion of the construction process for the Amine Still replacement. Engineering support completed by the 3rd party engineering firm included: mechanical piping design, pipe stress, civil structural design, and electrical design. Process engineering was combined as an in-house validation of overpressure protection design (OPP), 3rd party process validation with the solvent vendor that had been completed as a part of the initial solvent swap scope, and vendor validation of vessel internals with the original Amine Still vessel internal manufacturer with the new still design. Construction was completed by a traditional construction contractor, separate from the 3rd party engineering firm. There were a lot of different players involved in this project with complex integration.

The largest issue during the transition process of the project execution teams was the transference of material and general understanding of engineering assumptions that went into the original project scope specific design. Entering the project process late in the construction and commissioning sequence left little time to completely understand the design considerations. Process engineering support is crucial for the success of any project, and lack of documentation of all engineering assumptions used during the design phase can quickly lead to gaps during both the design and startup phases of projects. An example of some of the items that were not readily available at the time the new project team transitioned to the project include:

- Nozzle connection size and self-relieving criteria considered within the vessel procurement process.
- Final turnover of native files of pipe stress analysis (via CAESAR II or similar) in addition to the pipe stress analysis reports.
- Process engineering validation of solvent interaction for material compatibility reports for soft goods within the affected solvent swap system.

These items were missing, would have served as a great input for the troubleshooting process that followed the project transition. The author and new project team took over the Amine Still replacement project with the understanding that all engineering and design details had been completed, and that the only steps to complete at the point of receiving the project were commissioning related items prior to startup. The project documents were Issued for Construction (IFC), mechanical installation was complete, and the operations team was in the process of commissioning and completing any outstanding Pre-Startup Safety Review (PSSR) items prior to startup when the new project team took over.

Initial Startup After Amine Still Replacement

After completing the design and installation of the new Amine Still under the previous project team (which was located at a different physical location than the original Amine Still in order to minimize unit downtime during construction), the PSSR process was completed, and the proprietary amine was introduced back into the system.

As commissioning commenced, the reboiler skid and associated piping to/from the Amine Still experienced visible and concerning vibration, which appeared to be the result of liquid slugging in the liquid draw line to the reboiler and in the 2-phase return line from the reboiler to the Amine Still. Movement was visually prominent and confirmed with a high-speed vibrational amplification camera as shown in Figure 4 below. The 24” main reboiler return piping and the 8” reboiler liquid draw line were both demonstrating a movement that exceeded operations comfort level led to the shutdown of the unit. This triggered further evaluation of the process and support design for the thermosiphon loop. After shutdown of the unit, the original 3rd party engineering design firm was consulted and suggested an additional support, which was installed on the 8” liquid draw line shown in Figure 4. Unfortunately, this support installation did not improve the vibration issues within the system, and the new project team was left to find a solution to overcome the issues encountered in a project largely completed by others before them.

Figures 3 & 4 – *Reboiler Piping Vibration in the ZX Plane, Liquid Draw Piping Vibration around the X & Z axis.*

POST-STARTUP TROUBLESHOOTING

When engaging in a troubleshooting process akin to the work completed as a part of this Amine Still project, the main focus must always remain: what is the end goal?

In the case of this project, the end goal of the project team is to successfully place the unit back into service and operate the unit beyond the commissioning phase after so many variables have been adjusted. The balance of focus is intended to reduce risk and attack multifaceted troubleshooting situations in a logical manner. The new project team leveraged several resources initially, but the steps started as follows:

1. Observe "what" is occurring in the field. Take detailed notes of time specific information, operations observations, and any relevant historian system(s) for process data at the time of instances. The more information you collect at this stage, the better.
2. Refine key concern points. "How" did the concern occur? Consult operations field knowledge, as operators may have seen similar dynamic situations. Seek advice from process SMEs for processes you are unfamiliar with. If the scenario is unique enough, contact a 3rd party SME support service to guide you in resolving the issue.
3. Perform engineering calculations, either internally or via a 3rd party, to confirm your initial hypothesis. Use real time data gathered previously to validate calculations. Observations can support this data as well.
4. Plan a path forward. Work to gather input from all stakeholders in the project, including SMEs, operations, and project team input. Dice ideas into bite size solutions that highlight key benefits.
5. Execute the agreed upon plan in phases; clearly identify the items that provide the best benefit with the quickest timeline or gather consensus that the "right" solution is the best solution pending timeframes. Benefits of this approach allow for capital expenditure to be reduced and risks to be mitigated on a solution-by-solution basis.

Project Specific Troubleshooting Process

Amine Still replacement project scope after startup attempts followed this troubleshooting process, which are detailed further in the engineering design and mitigations sections further below:

1. Field observation of startup disturbances.
    a. Witnessing details of installed supports.
    b. Witnessing vibration direction and amplitude.
2. Design and installation of additional support as recommended by the initial project mechanical design engineering firm.
3. Field observation of piping vibration at subsequent startup.
    a. Witnessing 2-phase flow in reboiler liquid draw piping.
    b. Witnessing vibration direction and amplitude.
4. Evaluation of thermosiphon loop (Engineering firm / internal), tower self venting criteria, and pipe stress.
5. Inspection of installed tower internals.
6. Design and installation of recommended nozzle and tower internals modifications on Amine Still.
    a. Upsized liquid draw nozzle and piping to thermosiphon reboiler.
    b. Replacement of seal pan tray with chimney tray for increased liquid resonance time.
7. Unit performance testing and field observation of startup disturbances.
    a. Witnessing of vibration direction and amplitude.
8. Installation of recommended piping supports on reboiler 2-phase return.

DETERMINATION OF TROUBLESHOOTING MODIFCATIONS

Still Location Relative to Reboiler and Two-Phase Flow in Liquid Draw Line

During initial design of the replacement Amine Still (previous work to the author transitioning on to the project), the following construction & design preferences were considered:

1. Re-use the existing Amine Still foundation and recertify it to the new Amine Still load.
2. Knock out the existing Amine Still foundation and replace with a new foundation.
3. Reduce Train 1A outage time for Amine Still install.

As a result of these constraints, a new amine still foundation location approximately 30 ft away from the current foundation was proposed and found to be acceptable. The initial project mechanical design engineering firm would not recertify the existing foundation could support the new tower while the project 3rd party design firm completed the new still install scope. This location for the new still foundation was selected by the previous project team as the primary option to meet the time and fiscal impacts mentioned above. This resulted in increased thermosiphon loop piping to/from the existing horizontal shell and tube heat exchanger.

After the initial installation of the new Amine Still and Surge Tank removal, process issues were discovered in the liquid draw line to the horizontal reboiler. It was observed that 2-phase flow was occurring in the reboiler draw nozzle. 2-phase flow was verified by venting off an existing transmitter port upstream of the reboiler entry point as identified on the piping isometric in Figure 5. Intermittent vapor built up on a 10-20 second cycle and would vent as steam through the tubing line to the containment of the skid below the tubing. This process was repeated on 2 other startup attempts in the first 3 weeks of the unit being placed back into service.

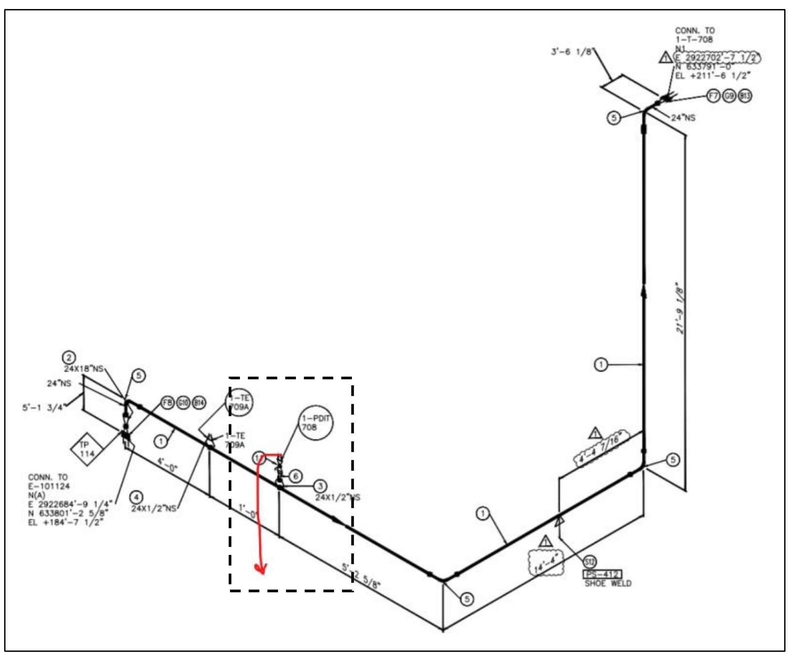


***Figure 5** – Isometric of Liquid Draw Line and Sample Point for 2 Phase Flow Verification*

To evaluate this scope in more detail, the project team leveraged process simulation via BR&E's Promax software via interaction with the solvent vendor. This approach led to modeling the piping runs to get a better understanding of whether the piping hydraulic (pressure) losses were a root cause of flashing within the line, leading to pressure buildup into the reboiler. Figure 6 shows the use of the "pipe" process tools being used to validate the pressure drop of the reboiler liquid draw piping. Analysis of this piping with process data and real-world piping configuration (line size, pipe schedule, actual lengths, heights and fittings) was used to validate that under the operating case that there was not a concern of flashing in either line. Supply pressure at the reboiler inlet nozzle was validated to meet the required pressure after piping losses were accounted for. The next step considered was vapor entrainment in the liquid draw nozzle to the reboiler.

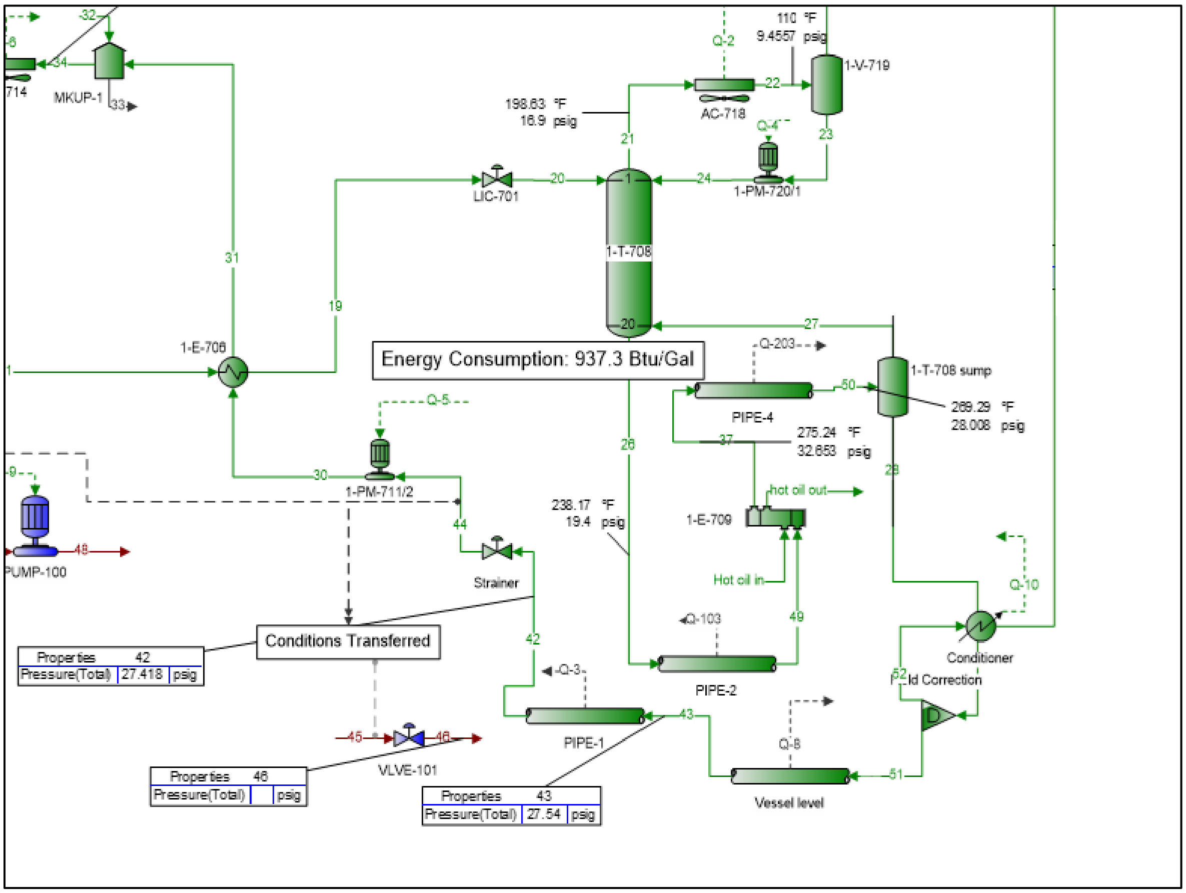


Figure 6 – *Process Model Snapshot for Thermosiphon Hydraulic Flashing Check*

Amine Still Liquid Draw Nozzle and Piping Upsize

To validate vapor entrainment concerns in the liquid draw line to the reboiler, a separate 3rd party process engineering firm was contracted to complete an evaluation in addition to an internal check of the self-venting flow sizing of the liquid draw nozzle and tray internals of the Amine Still. 3rd party engineering firm guidance laid out a target Froude number <0.3 to maintain self-venting flow. The Froude number for this nozzle was determined to be between 0.18 at full turndown, 0.72 at design, and 0.81 at turn-up conditions. These calculations suggest that the piping is not sized for self-venting flow, and that vapor is being entrained in the liquid at the high velocities exiting the tower. This calculation is demonstrated in Figure 8 and Figure 9 below shows calculation of the Froude number of the draw line to the reboiler.

Evaluation of self-venting characteristics of the draw line to the reboiler for the NDS T1A amine still

Constants:

$g_c := 9.81 \frac{m}{s^2}$ $\quad Q_{liq} := 600 \frac{gal}{min}$ max actual amine flow rate assumed

$\rho_{liq} := 61.1 \frac{lb}{ft^3}$ assumed amine density

Current (assume Sch 40 pipe ID)::

$D_{current} := 7.981\ in$ $\quad A_{current} := \frac{\pi}{4} \cdot D_{current}{}^2$

$u_{current} := \frac{Q_{liq}}{A_{current}} = 3.848 \frac{ft}{s}$ nominal liquid velocity in pipe

$Fr_{current} := \frac{u_{current}}{\sqrt{D_{current} \cdot g_c}} = 0.832$ Froude number in pipe target: Fr <= 0.3

Proposed (assume Sch 40 pipe ID)::

$D_{proposed} := 12.0\ in$ $\quad A_{proposed} := \frac{\pi}{4} \cdot D_{proposed}{}^2$

$u_{proposed} := \frac{Q_{liq}}{A_{proposed}} = 1.702 \frac{ft}{s}$ nominal liquid velocity in pipe

$Fr_{proposed} := \frac{u_{proposed}}{\sqrt{D_{proposed} \cdot g_c}} = 0.3$ Froude number in pipe target: Fr <= 0.3

***Figure 7** – Self Venting Flow Internal Calculation for Backcheck*

Process Data Considering 100% Liquid Draw, Liquid from Tray 20

- Liquid Mass Flow: 214982 lb/h
- Liquid Mass Density: 56.3675 lb/ft3
- Volumetric Flowrate: 475.5 gpm
- Volumetric Flowrate 110%: 523.05 gpm

Process Data Considering Vapor From Tray 20 as approximate for vapor above chimney tray

- Vapor Mass Density: 0.0723979 lb/ft3

Existing 8" Sch XS/80 Bore 7.625"ID – Self Venting Flow Calc.

Pipe diam	
(in)	(m)
7.63	0.193675
A (sq/ft)	0.317

	lb/ft3	kg/m3
Lid den	56.3675	902.9
Vap den	0.072398	1.2

VL=0.31(g D)^0.5

OPERATING RATES	QL (volumetric flow)				V_L (Sup. Velocity)		Froude number	
	gpm	ft^3/s	m^3/s	m^3/h	ft/s	m/s	Fr_L	$Fr_{L,D}$
TURNDOWN	119	0.3	0.008	27	0.84	0.25	0.18	0.18
DESIGN	476	1.1	0.030	108	3.34	1.02	0.74	0.74
TURNUP	523	1.2	0.033	119	3.68	1.12	0.81	0.81

Result: Froude Number > 0.3, Not sized for self-venting flow.

***Figure 8** – Self Venting Flow Calculation performed by Third Party Process Engineering*

To mitigate the existing 2-phase flow issues identified by this analysis and by field witnessing, an in-field Amine Still liquid draw nozzle modification, vessel internals change, and piping upsize to the reboiler was completed. The vessel nozzle size was increased on the Amine Still to a diameter of 12" versus the existing 8" nozzle supplied with the vessel. The field modification of the Amine Still required the cutout of the old nozzle, hydrogen bakeout heat pre-treatment prior to welding the new nozzle in, field welding of the new nozzle in via an ASME R2 stamp certification of repair, and post-weld heat treat of the heat affected zone of the nozzle weld area. The new nozzle was located with the same bottom of inner diameter elevation (nozzle growing upwards) to retain the same tray location per Figure 10.

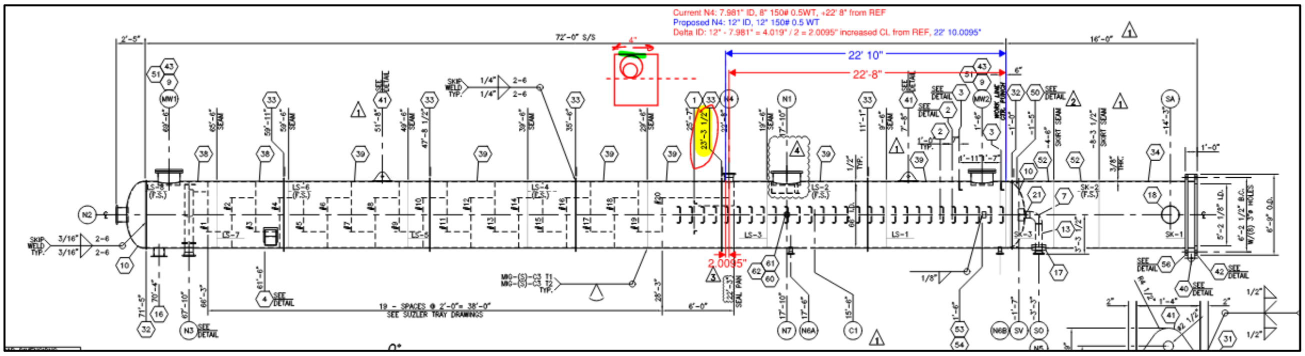
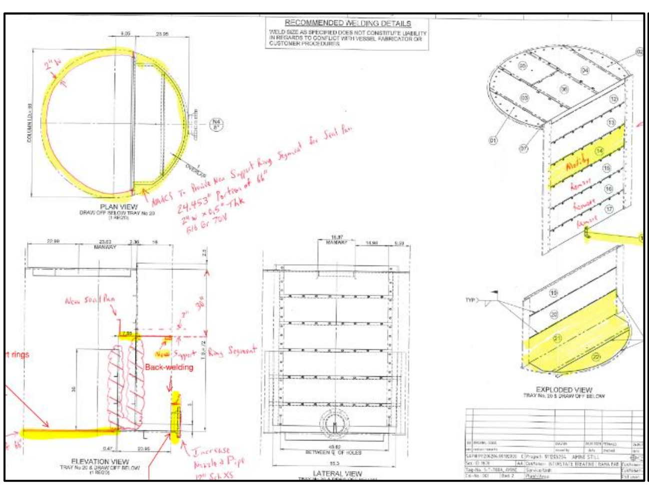


Figure 9 – *12" Nozzle Location to Maintain Bottom of Opening Elevation*

Tower Hydraulics and Chimney Tray Installation

Amine Booster Pump hydraulics experienced considerable benefits due to the Amine Surge Vessel being relocated to an integral surge with the new Amine Still, resulting in a higher liquid level / head available to the booster pumps. The Amine Booster Pumps liquid head increase reduced the cavitation / flashing in the booster pump suction piping previously experienced. After the initial piping support recommendation was installed and observed to not have reduced the impact of the vibration, the process engineering firm evaluating the Amine Still nozzles above also reviewed the tower internals and discovered that the original Amine Still chimney tray design had not been replicated as a part of the replacement Amine Still. This triggered design of a new chimney tray and downcomer seal pan to replace the liquid downcomer seal pan currently supplying flow to the liquid draw line of the amine reboiler. Process review of this design revealed an approximately 300% increase in resonance time with the addition of the chimney tray design shown in Figure 11. Special consideration was kept maintaining the same tray elevation in the Amine Still by expanding the existing downcomer seal pan support ring around the vessel. Modifications to the existing downcomer were completed per the redlines in Figure 10. The tray was maintained, but the downcomer sections were reduced to meet a new elevation above the proposed chimney tray.



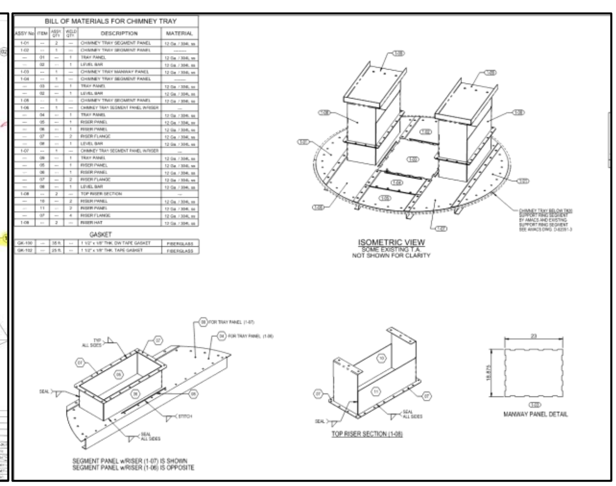


Figure 10 – *Existing Downcomer Seal Pan Tray and Support Ring Modifications*
Figure 11 – *New Chimney Tray Design*

After completing the tray internals modifications, Amine Still nozzle upsize, piping upsize, and re-inventorying the Amine Still, another startup was attempted. Vibration was reduced by approximately 40% but still fell outside of acceptable levels. 2-phase flow was then checked again during startup in the liquid draw line, and no steam/cyclical pressure buildup was observed in the line. The process modifications were successful in mitigating the process issues, and the larger focus then became constraining the reboiler outlet piping, which was now the main driver of vibration in the piping system.

Support Mitigation

Vibration / pulsation readings were taken via a high-speed camera for 3 locations on the 24" reboiler return piping to the Amine Still. These readings depicted a system that was still unconstrained and dealing with slugging in the 2-phase return line from the reboiler back to the Amine Still due to directional changes in the horizontal and vertical elbows. This, combined with the new Amine Still location and support methodology, effectively left horizontal forces unaccounted for, and only supported the vertical loads. New pipe stress analysis was completed the 3rd party engineering firm supporting the thermosiphon loop analysis and as a result proposed two additional support mitigations as depicted in Figure 13. These support mitigations were installed on the 24" reboiler return piping to resolve pulsation issues due to the increased length of piping and unaccounted for 2-phase slugging support for the vessel piping mentioned above.

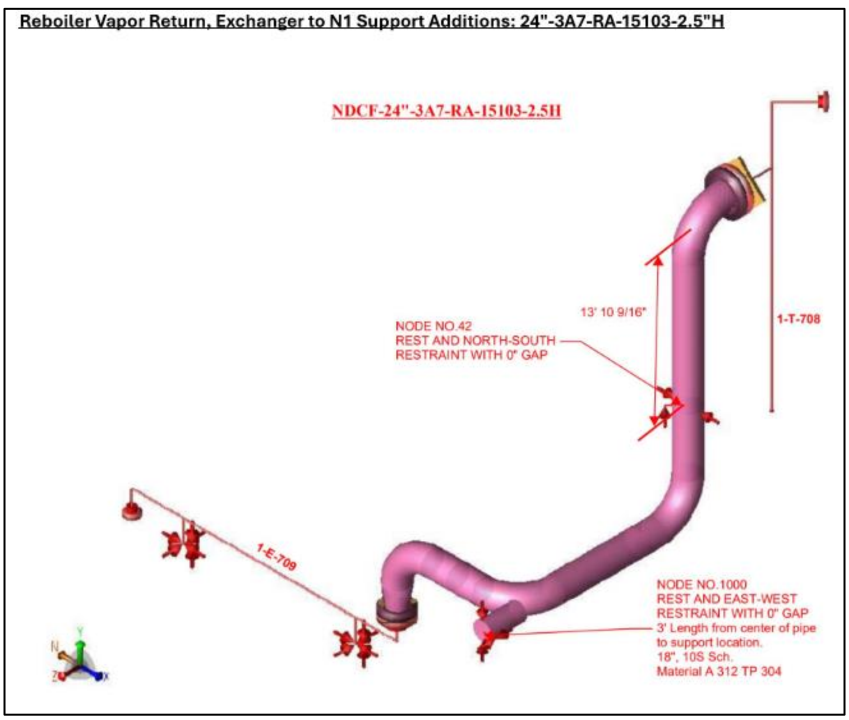


Figure 12 – *Support Mitigation Locations on 24" Reboiler 2-Phase Return Line*

Plotted below in Figure 13 are the observed vibration points on the reboiler return pipe, both pre- and post-support installation. Point 1 (circle) above the top line is the starting point of vibration observed, while the second point that the arrow points to (diamond) is below the action required line for Y-axis vibration measured in amplitude (mils peak-to-peak). The vibrational limitation is based on Williams internal standards within Williams Integrated Management System (WIMS). The X-axis in Figure 14 is the frequency represented in hertz (hz). Field documented vibrational data in the X, Y, and Z axis on the reboiler and its associated return piping was crucial input into support mitigation design. Stress analysis for the thermosiphon loop took careful evaluation of constraints via thermal growth of the reboiler and the return piping to the Amine Still to not exceed the nozzle loadings of either vessel.

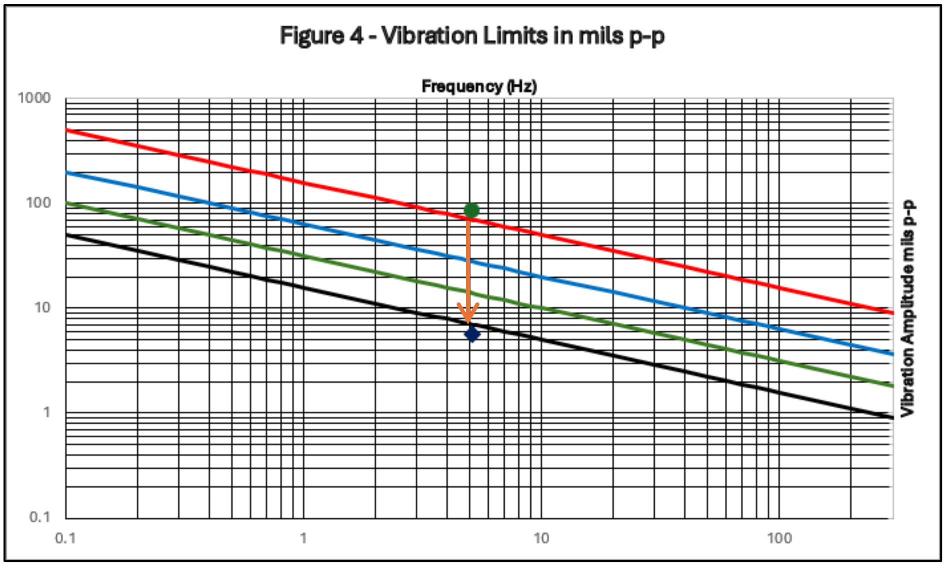


Figure 13 – *Vibration Limits Observed in Reboiler Return Piping*

After installation and subsequent startup of Train 1A with the modifications, the process and mechanical issues experienced as a part of the initial commissioning effort for the new Amine Still were resolved. 2 phase flow was not documented in the reboiler liquid draw line, demonstrating the effectiveness of the newly installed tower internals paired with the upsized liquid draw nozzle ensuring self-venting flow was achievable. Vibration was reduced to within acceptable limits with the newly installed supports, reducing loading on the vessel nozzles and allowing for thermal expansion while constraining potential 2 phase slugging experienced in the return line from the Reboiler to the Amine Still.

PERFORMANCE TESTING

With the mechanical issues identified during startup resolved, performance testing was completed to validate new nameplate capacity of the solvent and that debottlenecking projects inclusive of the Amine Still replacement have been successful in increasing the potential treating capacity of Amine Train 1A. This occurred after the completion of all troubleshooting mitigations discussed above, successful unit startup, and with piping vibration confirmed to be within acceptable limits.

Observations of Performance

- Held treated gas to <50 ppm CO_2 (non-detection) at the outlet of the Amine Contactor with no amine carryover at previous nameplate of 65 MMSCFD.

- Increased nameplate throughput by approximately 20 MMSCFD to 85 MMSCFD before system instability in flash tank limited progressing further.
- Evaluated acid gas in process model at throughput to see if metered combined acid gas stream exceeded theoretical content of acid gas in the inlet stream to Amine Contactor.
- Increased nameplate from throughput approximately 23 MMSCFD to 88 MMSCFD before system instability in the Amine Contactor shut down on high differential Pressure DP (see Foaming section below).

Performance testing of the unit went well, with the amine remaining within the rich amine loading bounds at all throughputs per the solvent vendor requirements and circulation rates tested for the unit. Several issues were identified with regards to potential foaming in the Amine Contactor and excess flash gas pressure that are discussed below.

The trend information on Figure 14 is as follows: Section 1; Amine 1A Inlet Gas Flow. Section 2; Amine Reflux / Acid Gas Flow, (FI-719), Calculated Max Acid Gas Flow (discussed in the sections following this), and Calculated Methane Flow in Acid Gas (Net difference in Reflux / Acid Gas Flow vs Calculated Max Acid Gas Flow). Section 3; % Over Acid Gas (categorized as Calculated Methane Flow over Calculated Max Acid Gas Flow).

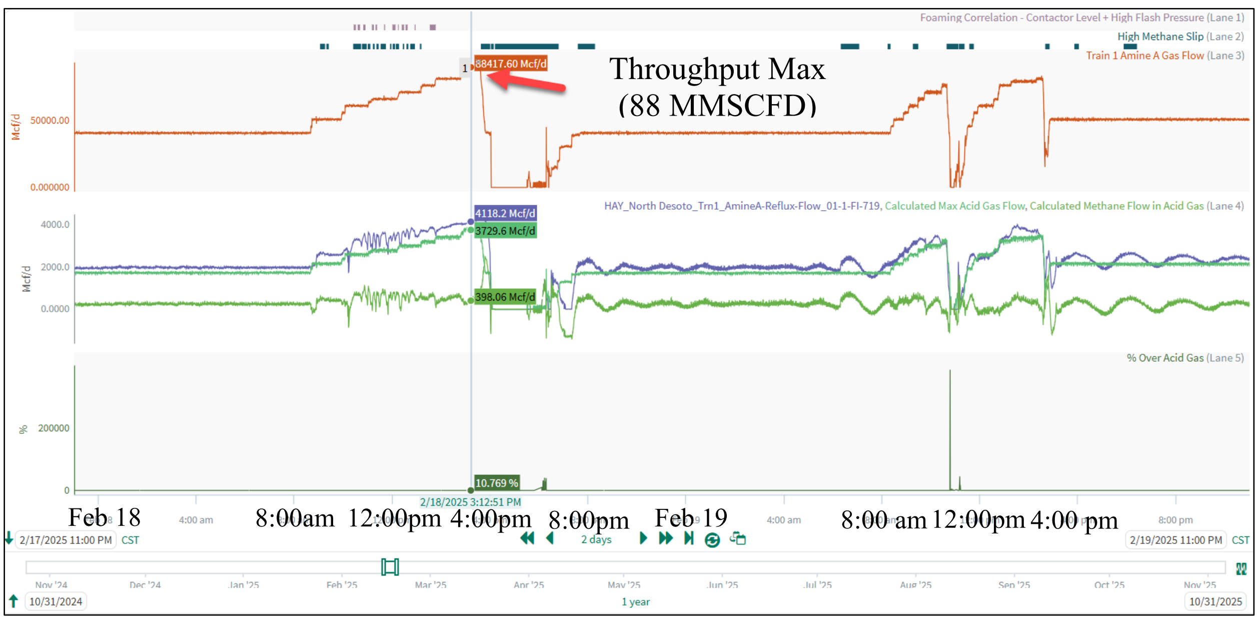


Figure 14 *– Operating Data Showing Highest Nameplate without CO2 Slip on Day 1*

Flash Tank Pressure Control

During performance testing on Day 1, the Flash Tank was observed to be at increased pressure and struggling to control with the pressure control valve PID loop PIC-701 (depicted on the upper trend line of the third lane in Figure 15 below). The operations team changed out the valve trim for flash gas control valve to see if increased capacity would help smooth out flash gas cycles demonstrated in Figure 15. The change was successful as the valve came into the control range and ceased behaving erratically on the PID loop, while the peak flash tank pressure was no longer observed to exceed 90 PSIG on Day 2 of performance testing, as shown on trend section 4 of Figure 20.

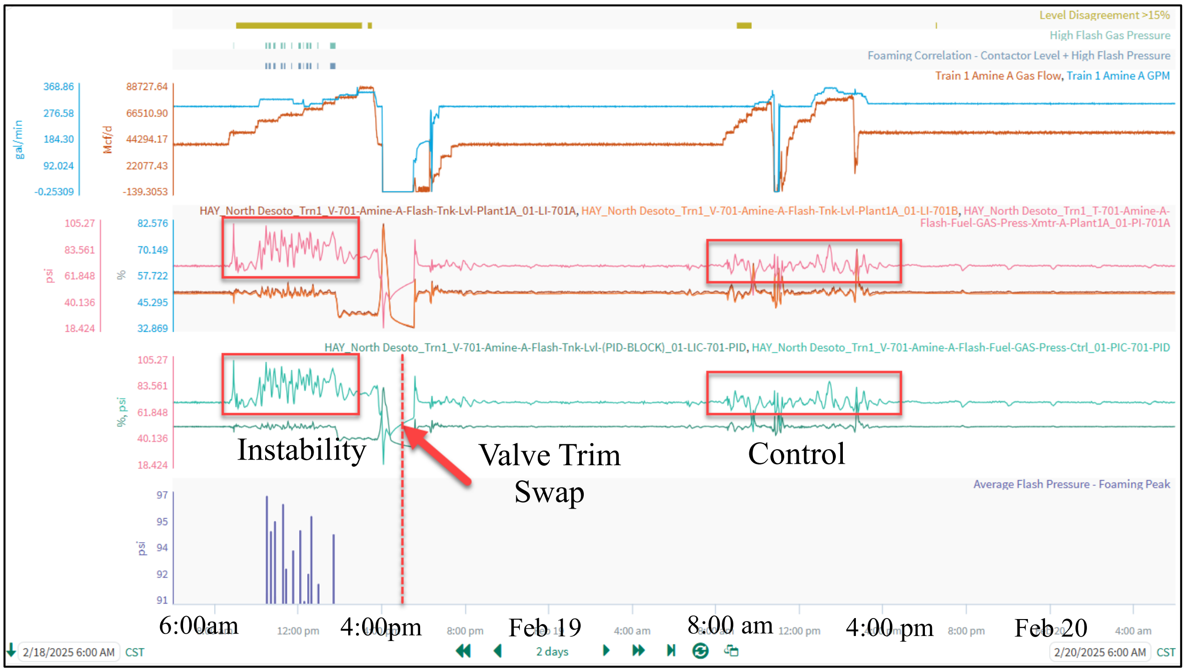


Figure 15 – Operating Data Showing Erratic Flash Tank Pressure Behavior via PI-701A on Day 1, and Calm System after Valve Trim Swap on Day 2

The trend information on Figure 15 (above) is as follows: Top Time Segments; Level Disagreement >15% (Trend of Contactor Level Disagreement >15%), High Flash Gas Pressure (Pressure > 90 PSIG), Foaming Correlation (Intersection of Contactor Level Disagreement and High Flash Gas Pressure). Section 1; Train 1 Amine A Gas Flow, Train 1 Amine A GPM. Section 2; Flash Tank Level (LI-701A), Flash Tank Level (LI-701B), Flash Gas Pressure (PI-701A). Section 3; Flash Gas Level Controller PID (LIC-701), Flash Gas Pressure Controller PID (PIC-701). Section 4; Average Flash Pressure – Foaming Peak (Average Pressure during Foaming Correlation Time Capsules).

Contactor Foaming

During performance testing several issues in the rich amine side of the system were observed:

1. The amine contactor levels between the mag float level transmitter and the guided wave radar transmitter reached up to 34% level disagreement (the guided wave radar was maxed out at 100%) during performance testing.
2. High pressure in the amine flash tank (PIT-701A).
3. Low control of pressure in the amine flash tank (PCV-701A 100% open, pressure still swinging).
4. Increased acid gas flow out of the flash tank (FIT-719).

Due to the original unit configuration, flash gas is comingled with the acid gas from the amine still prior to FIT-719 and sent to the CO2 scrubber. An additional calculated analysis was performed on the acid gas flow meter (FIT-719) to the CO2 vent stack of the unit to demonstrate if excess flash gas flow to the CO2 vent stack was exceeding the calculated flash from the process model and also exceeding the physical acid gas content of the inlet gas stream to the contactor shown in Figure 16 compared to the process data from the process model for the anticipated acid gas flow to the vent stack. This data is on a wet basis in the process model. Using the facility CO2 and H2S dedicated analyzers at the inlet of the plant and the inlet flow meter to the amine contactor T-432, a reasonable assumption was made that any acid gas flow through the acid gas meter exceeding the CO2 and H2S content in the wet inlet gas stream to the contactor could be assumed to be hydrocarbon slip due to foaming making its way into the amine flash tank and flashing off into the acid gas vent stream, as shown in Figure 16. Additional analysis is recommended for engineers pursuing this approach in the future.

18-Feb									19-Feb
Full CO2 Acid Gas Flow (CO2 % * Gas Flow) (units: MMSCFD)									Full CO2 Acid Gas Flow
1.72	2.15	2.58	2.795	2.73	2.94	3.15	3.36	3.696	3.222205
CO2 % of Acid Gas Flow									CO2 % of Acid Gas Flow
0.893506	0.811321	0.791411	0.807803	0.752066	0.86217	0.837766	0.837905	0.875829	0.944928
Flash Flow (1-CO2 Flow %) * Total Acid Gas Meter Flow (units: MMSCFD)									Flash Flow
0.205	0.5	0.68	0.665	0.9	0.47	0.61	0.65	0.524	0.187795
Modeled Flash Gas Flow (MMSCFD)									Modeled Flash Gas Flow
		0.085				0.203358			0.203358
% Flash Gas vs Modeled (Target - 1.0)									% Flash Gas vs Modeled
		799.86%				299.96%			108%

Figure 16 – Acid Gas Backflow Calculation to Evaluate Excess Acid Gas Flow and Fash Tank Hydrocarbon Slip

The trend information on Figure 17 is as follows: Top Time Segments; High Methane Slip (categorized as Calculated Methane Flow exceeding 20% of Calculated Max Acid Gas Flow). Section 1; Amine 1A Inlet Gas Flow. Section 2; Amine Reflux / Acid Gas Flow, (FI-719), Calculated Max Acid Gas Flow (discussed above), and Calculated Methane Flow in Acid Gas (Net difference in Reflux / Acid Gas Flow vs Calculated Max Acid Gas Flow). Section 3; Over Acid Gas (categorized as Calculated Methane Flow over Calculated Max Acid Gas Flow).

Figure 17 – Operating Data Showing Flow and Combined Reflux Acid Gas Flow with Calculated Excess Flow

The initial hypothesis was that the cause of the issues above were due to foaming in the contactor. Data was trended to demonstrate level disagreement between LI-432A (guided wave) and LI-432B (magnetic level); this is shown on trend Sections 2 (% disagreement between each level device) and 3 (readings of level and contactor dump level control) on Figure 18.

The next day of testing, the operations team elected to inject defoamer into the system during performance testing, trying to resolve the apparent foaming / level issues demonstrated in the contactor the day prior. As a test to this theory, defoamer injection was removed at approximately 10:21AM at 75 MMSCFD of gas throughput. Following this defoamer removal, the gas contactor began to behave erratically as shown in Figure 17, leading to carry-over into the downstream filtration and shutting down the unit on high tower DP.

The trend information on Figure 19 is as follows: Top Time Segments; Level Disagreement >15% (Trend of Contactor Level Disagreement >15%), High Contactor DP (Differential Pressure > 4.5 PSID), High Level – LI-432A (Level in LI-432A > 80%), High Level – LI-432B (Level in LI-432B > 80%), High Level – Contactor (Intersection of both High Levels). Section 1; Train 1 Amine A Gas Flow, Train 1 Amine A GPM, Contactor Outlet Temperature (TI-432), Contactor Differential Pressure (PDI-432). Section 2; Contactor Level Difference % (net difference in level %). Section 3; Contactor Level Transmitter (LI-432A), Contactor Level Controller % (LY-432A), Contactor Level Transmitter (LI-432B).

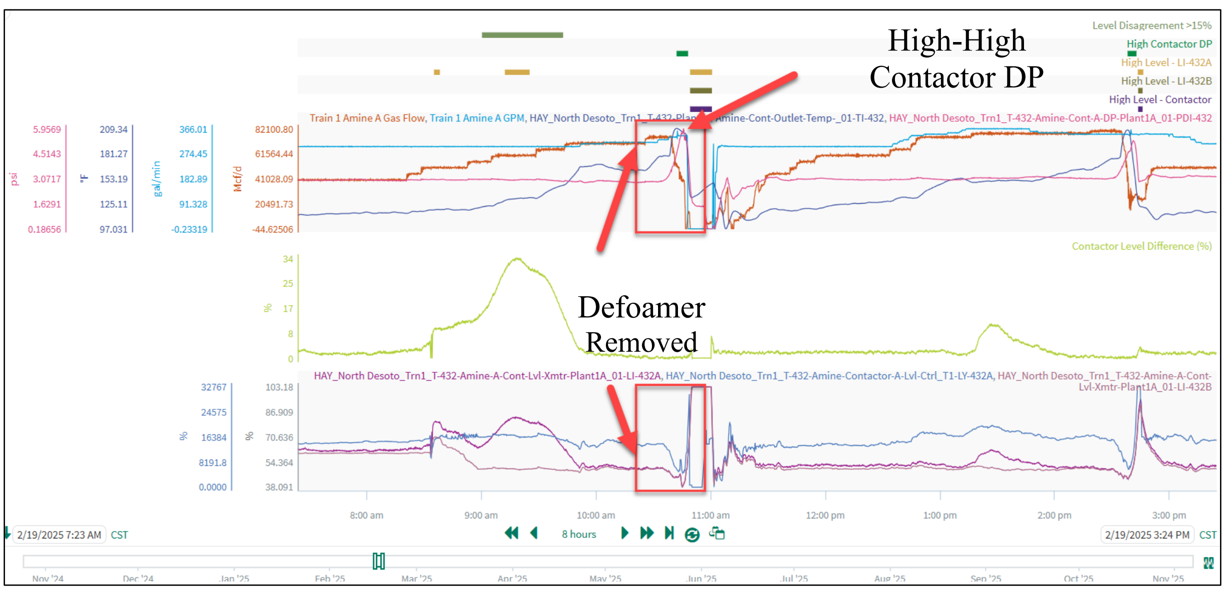


***Figure 18** – Operating Data Showing Gas Flow, Circulation Rate, Contactor Outlet Temperature, and Level Differences in the Contactor*

Documented issues with level measurement and foaming supported by operational data is the groundwork on which additional projects can continue to be supported. For level measurement and foaming issues, the operations and plant engineering teams now have firm data on how the new solvent reacts to high throughput, and a basis in which to refine inlet separation at Train 1A. Instrumentation can prove to be an extremely valuable tool combined with operating experience and process knowledge.

CONCLUSIONS AND CONSIDERATIONS FOR FUTURE PROJECTS

A project team is only as successful as its ability to collaborate, communicate, and elaborate with the resources and processes available to it. Especially in troubleshooting scenarios, make sure to lay out a clear sequence of events for both what to observe, and decision paths forward that stem from any data gathered during startup attempts.

The author recommends the following design considerations and execution focus points in the future:

- Multifaceted troubleshooting situations require focus on historical data, process data, and operations feedback as the core of the troubleshooting process.
- Data and process engineering go hand in hand. Anything collected in the field or observed directly is key to focusing on credible causes of issues and allow for a methodical process of elimination for additional changes.
- Focus on verifying all available process data for systems you are unfamiliar with. Organized basis of design assumptions and process engineering calculations, whether internal or via an external resource, should be located together with any applicable Recognized and Generally Accepted Good Engineering Practice (RAGAGEP).
- Reduce piping length and directional changes within the Amine Still thermosiphon loop (see nozzle calculations, vibration mitigation).
- When utilizing proprietary solvents, ensure all material compatibility testing has been completed by the solvent vendor and is readily available.

As for the Amine Still; the plant is running smoothy, operators are actively learning the complexity of the solvent, and the amine continues to increase capacity and performance of Train 1A as a useful asset. For future engineers facing a similar challenge, remember, always be ready to hit the ground running.