Current Challenges in Midstream Facility Operations

Mahdi Nouri, Triumph Gas

David Engel, Nexo Solutions

Michael Sheilan, SGS Amine Experts

Sjoerd Hoogwater, Phillips 66

UNVEILING THE MAGIC OF MIDSTREAM INNOVATION
2025
GPA MIDSTREAM CONVENTION

GPA MIDSTREAM ASSOCIATION

About Speakers

Speakers Brief Bio

- Mahdi Nouri is a Charter Engineer, IChemE Fellow, AIChE Fellow President of Triumph Gas with over 25 years of experience in Engineering and Construction across upstream, midstream, LNG, and low carbon industries. He has held key leadership roles at Worley, Jacobs, and Bechtel, with a global career spanning the Americas, Europe, Saudi Arabia, UAE, Oman, Australia, Kazakhstan, West Africa, India, and Indonesia. Mahdi is also the principal author of a new reference book, Life Cycle of a Process Plant, 1st Edition (Elsevier), and holds a US patent on the condensate stabilization process. He has been recognized with several prestigious awards, including the AIChE F&PD Chair Award 2024 and the GPA Midstream Leadership Award 2021.
- Michael Sheilan is a Senior Principal Engineer at SGS with 43 years of experience in the gas processing industry. Known for his expertise in training and troubleshooting upstream gas treating processes, Michael has focused on dehydration and amine sweetening. He has provided technical support to over 500 facilities worldwide and is a well-regarded speaker and author in the field of gas processing.

Speakers Brief Bio

- David Engel has over 25 years of industrial experience in chemical engineering, chemistry and material science. David is the inventor in more than 20 United States Invention Patents and author of over 100 technical and scientific papers, and conferences. David has worked in several technical and business capacities for several corporations. David specializes in process optimization and innovative technology development. Dr. Engel is the Managing Director of Nexo Solutions. He holds a B.S. in Chemistry, and a Ph.D. in Organic Chemistry. He is Six-Sigma certified and is a member of industrial committees and company board of directors.
- Sjoerd Hoogwater is a Consulting Process Engineer at Phillips 66 with over 30 years of experience in process and chemical engineering. He has worked on various projects, including gas treatment, NGL extraction, crude oil processing, and refinery relocation and expansion across the globe. Sjoerd has been instrumental in troubleshooting and optimizing gas processing facilities for DCP Midstream and Phillips 66 since 2019.

Agenda

#	Description	Speakers	minutes
1	Welcome/Speakers/Introduction to Midstream	Mahdi Nouri	10
2	Feed Contamination Challenges	David Engel	30
3	Amine Units Challenges	Michael Sheilan David Engel	40
4	Dehydration Challenges	Michael Sheilan David Engel	40
5	Cryogenics Gas Processing Challenges	Mahdi Nouri Sjoerd Hoogwater	40
6	NGL Fractionation Challenges	Mahdi Nouri Sjoerd Hoogwater	25
7	Condensate Stabilizers Challenges	Mahdi Nouri	25
	Closing Remarks (all 4 say a few comments round table format)	All	10
	Q&A: round table format	All	20
	Total: 240 minutes approx		240

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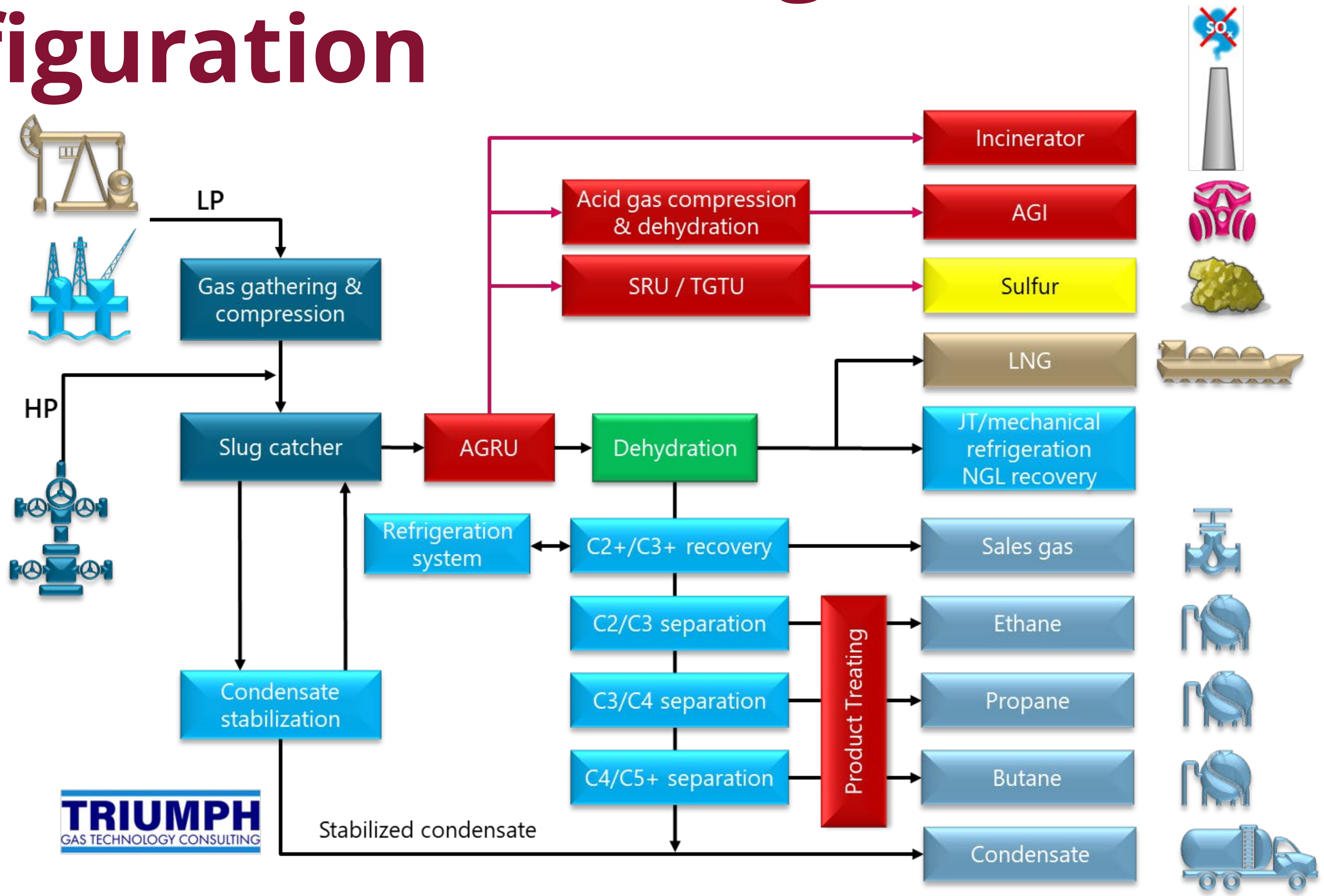
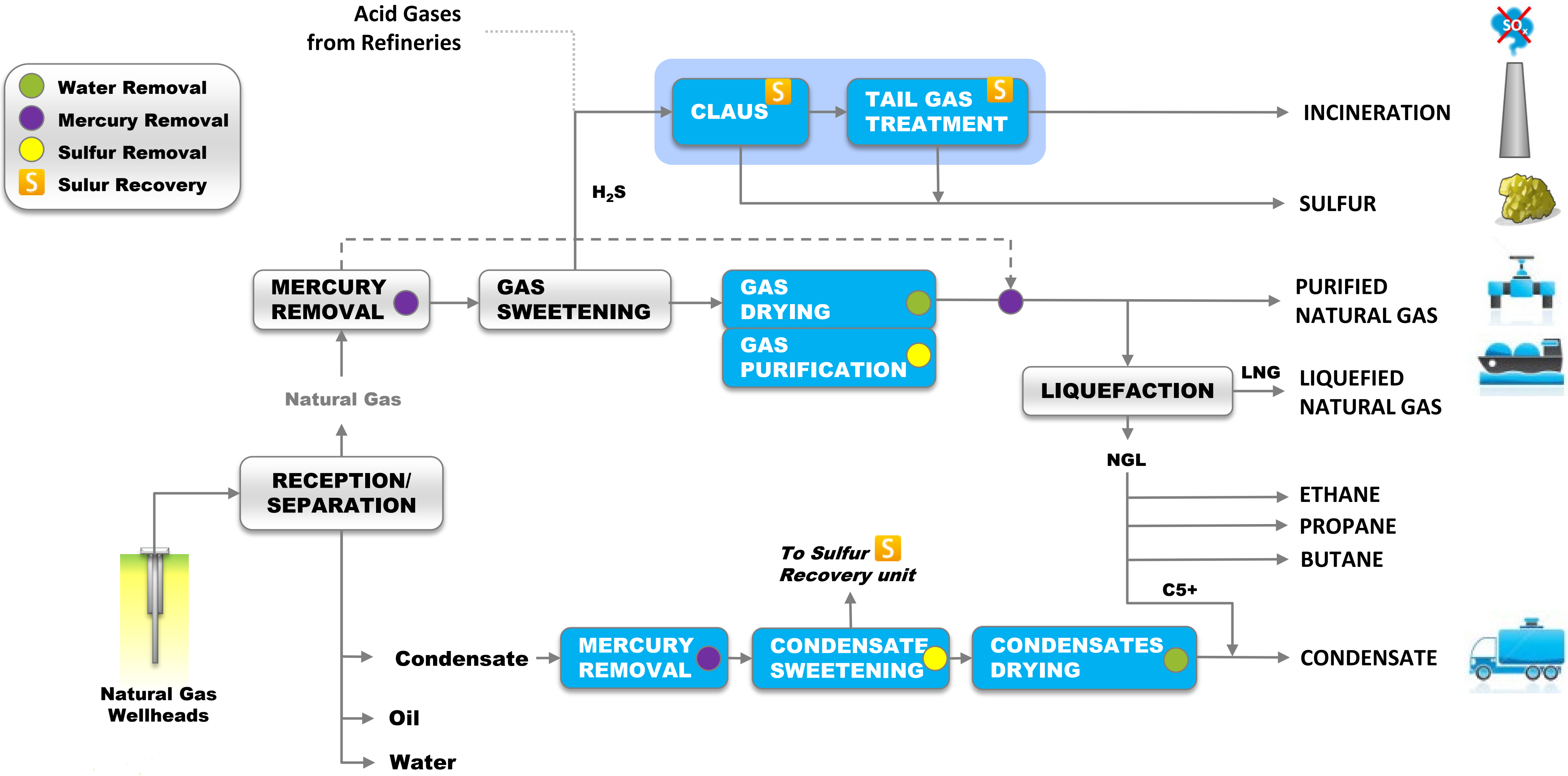
Midstream Challenges Troubleshooting

Typical Gas Processing Facilities Configuration



Natural Gas Contaminants



Common Operating Issues in Cryogenic Gas Processing

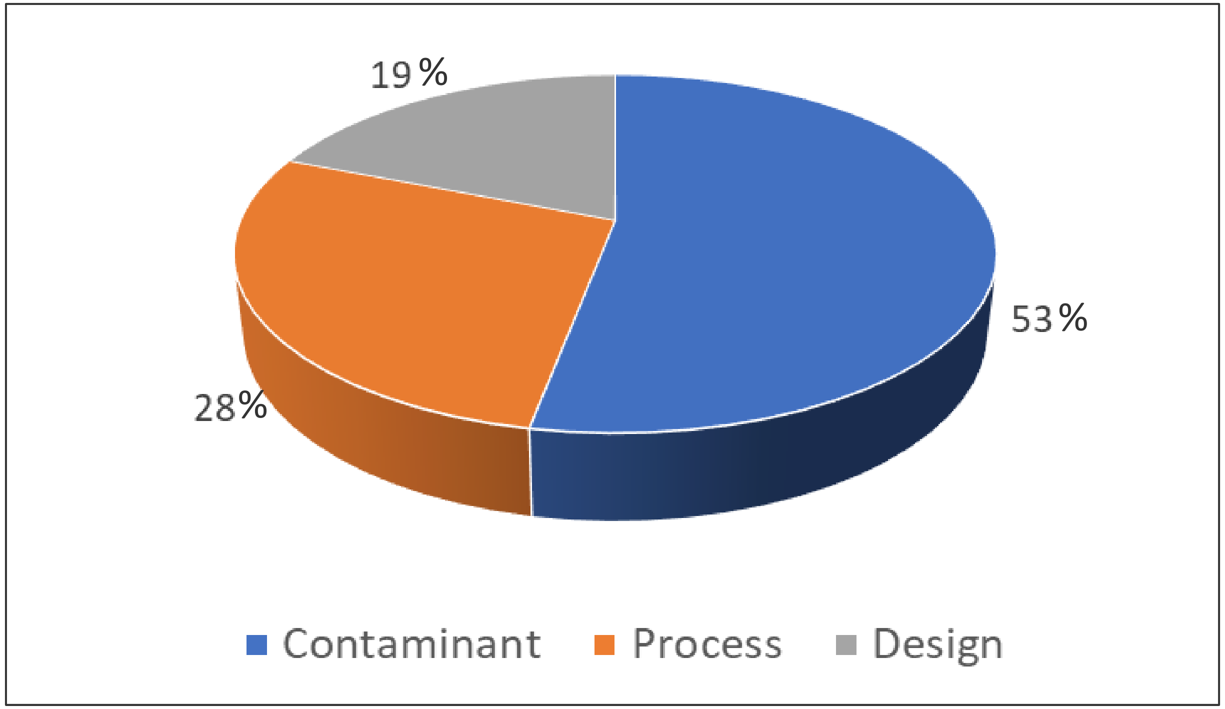
- **Inlet feed separator**
  - maldistribution issues in finger-type slug catchers
  - separation from water, glycol, and liquid hydrocarbon
- **Condensate stabilizer**
  - off-spec stabilized condensate;
  - higher vapor pressure and presence of contaminations; e.g., water, sulfur, glycol, mercury, etc.
- **Acid gas removal**
  - off-spec treated gas at design case conditions
  - severe foaming tendency through absorber
  - high anti-foam injection consumption
  - high amine make-up
  - high number of unplanned shut-downs
  - high active carbon consumption
  - high degradation products
  - high corrosion rate
  - SRU maloperation by hydrocarbon carry-over
- **Dehydration**
  - off-spec treated gas (further moisture in dry gas stream)
  - desiccant design life (less than four years)
  - solvent quality
- **NGL recovery and fractionation**
  - pretreatment operating issues before feeding to Liquidation Unit and produce more NGL and LNG
  - De-C1 performance and different mode of operations
  - freezing issues through cold boxes & De-C1 (CO_2 / BTEX / heavy hydrocarbon)
  - reduced the refrigeration system load
  - high NGL feed quality variation to NGL fractionation
  - columns performance: off spec products (concentration and purity)
  - high equipment downtime
  - high energy consumption

Filtration Challenges Troubleshooting

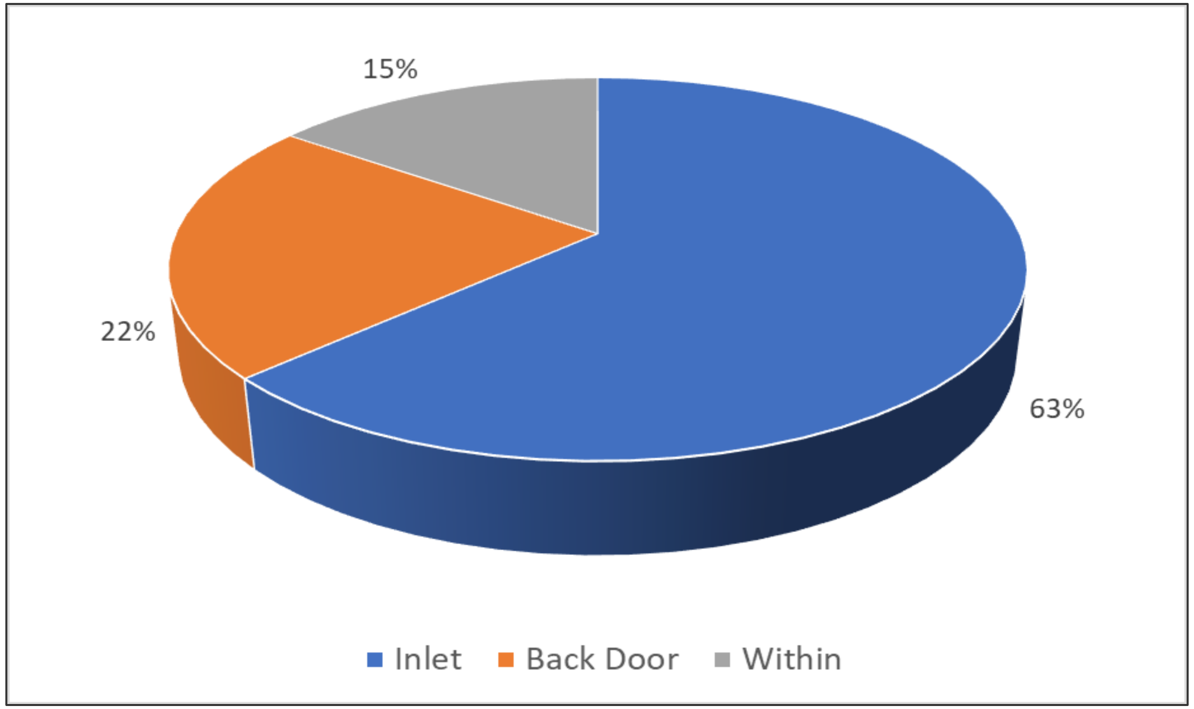
Case Studies

The Challenges in the Past Year

Plant General Challenges



Contamination Ingression Modes

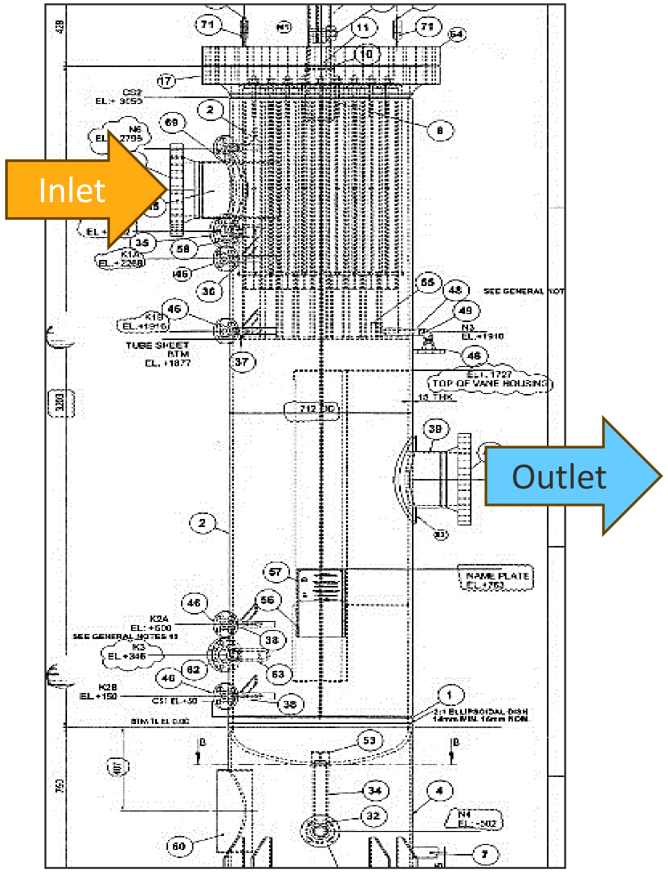


Feed Gas Contaminants (The Usual Suspects)

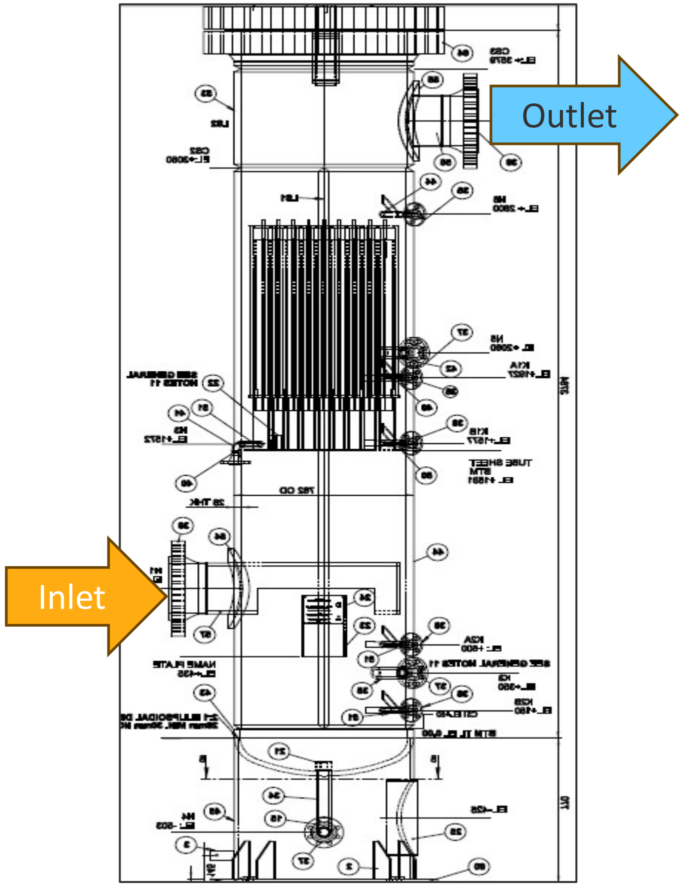
Solids	Liquids	Gases
Corrosion Products	Compressor Lubrication Oil	Acid Gases (H2S/CO2)
Mineral Scale	Heavy Hydrocarbons	Methanol
Formation Solids	Produced Water	Mercaptans/COS/CS_2
Waxes, Paraffins & Asphaltenes	Solvent Carryover	Mercury
Catalysts, Desiccants & Carbon Fines	Chemical Additives	Oxygen
Black Powder	Organic Acids and Surfactants	Ammonia (NH3)

Case Study 1–
Deficient Vessel Designs

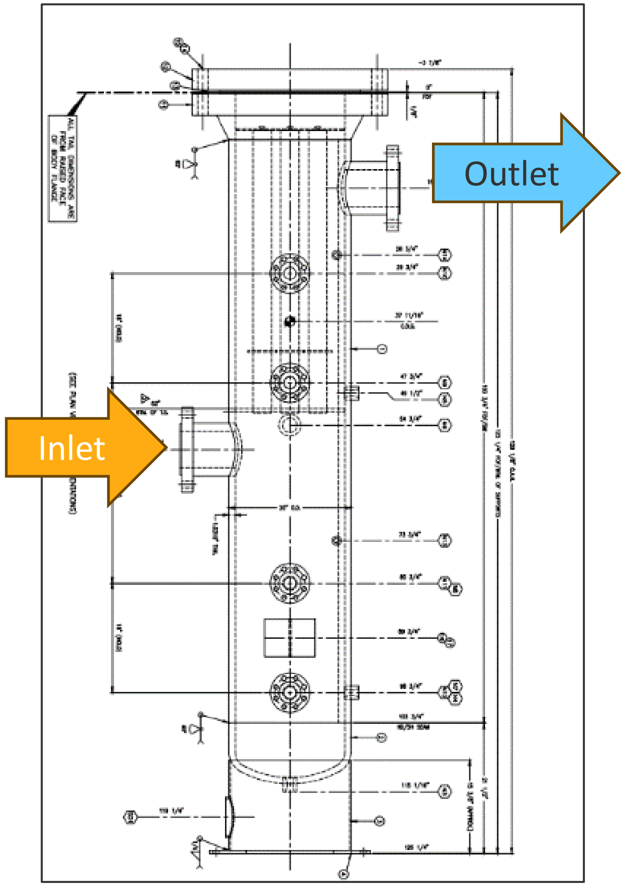
Vessel Design is a Key Consideration



Inlet at the top. Coalescing is co-current to gas flow. Level control nozzles incorrectly positioned. Vessel too short.



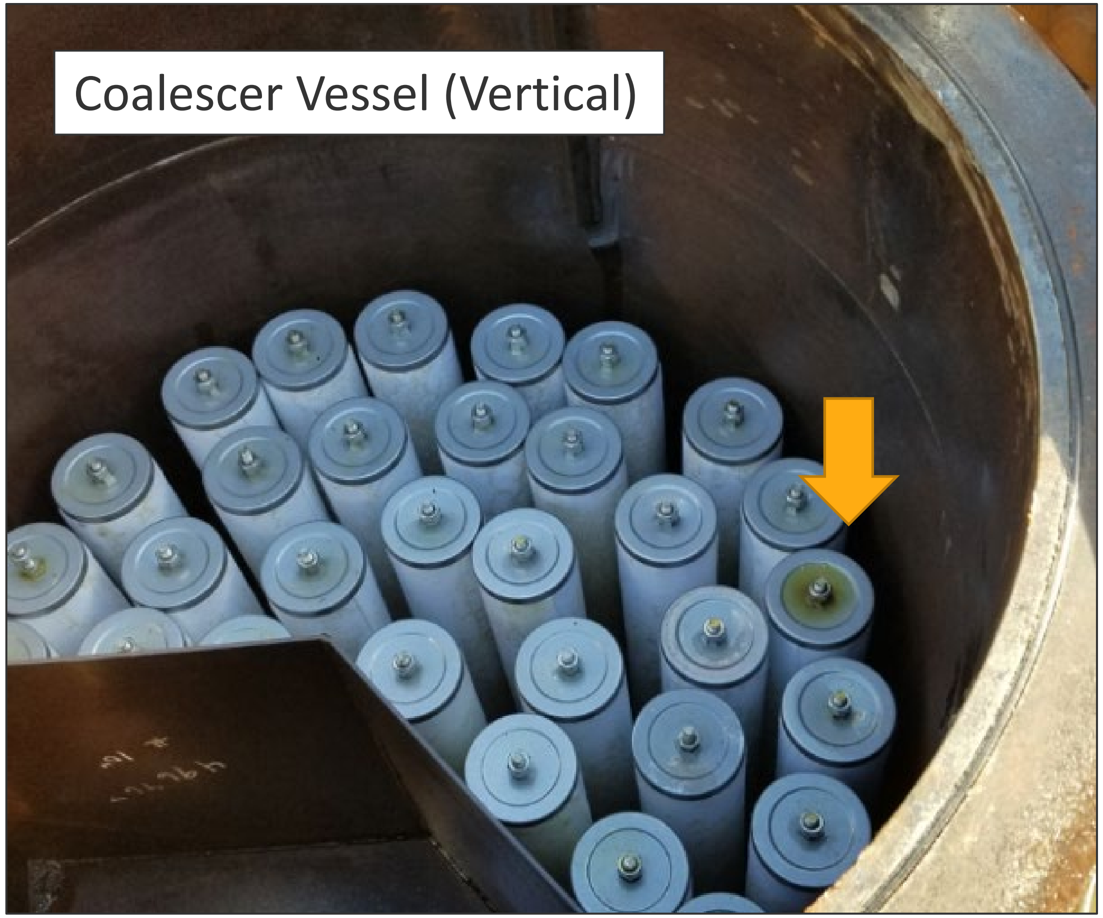
Inlet distributor at the bottom often times produce unbalanced gas flow. Level control nozzles incorrectly positioned. Vessel too short.

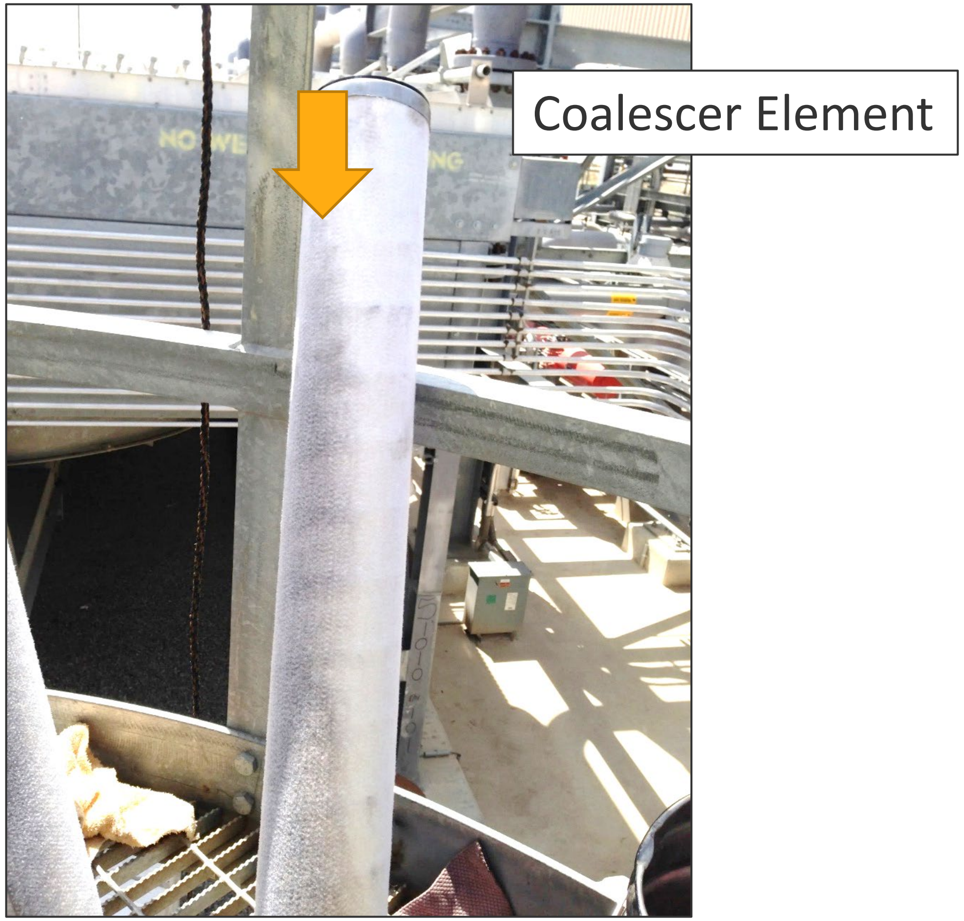


Level control nozzles incorrectly positioned. Vessel too short. No disengagement space. Lateral gas flow will produce liquid suction into the outlet

Case Study 2 –
Unbalanced Internal Vessel Flow

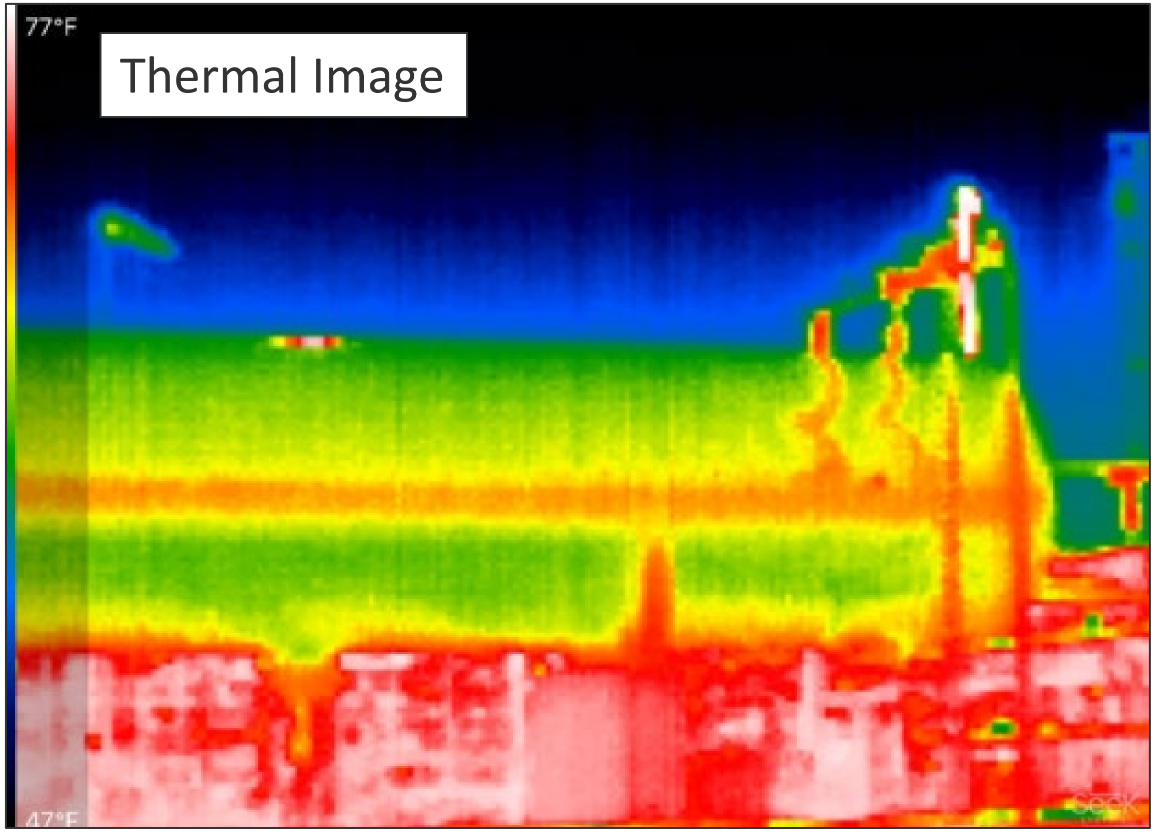
Lateral Element Liquids Flow (Carryover)



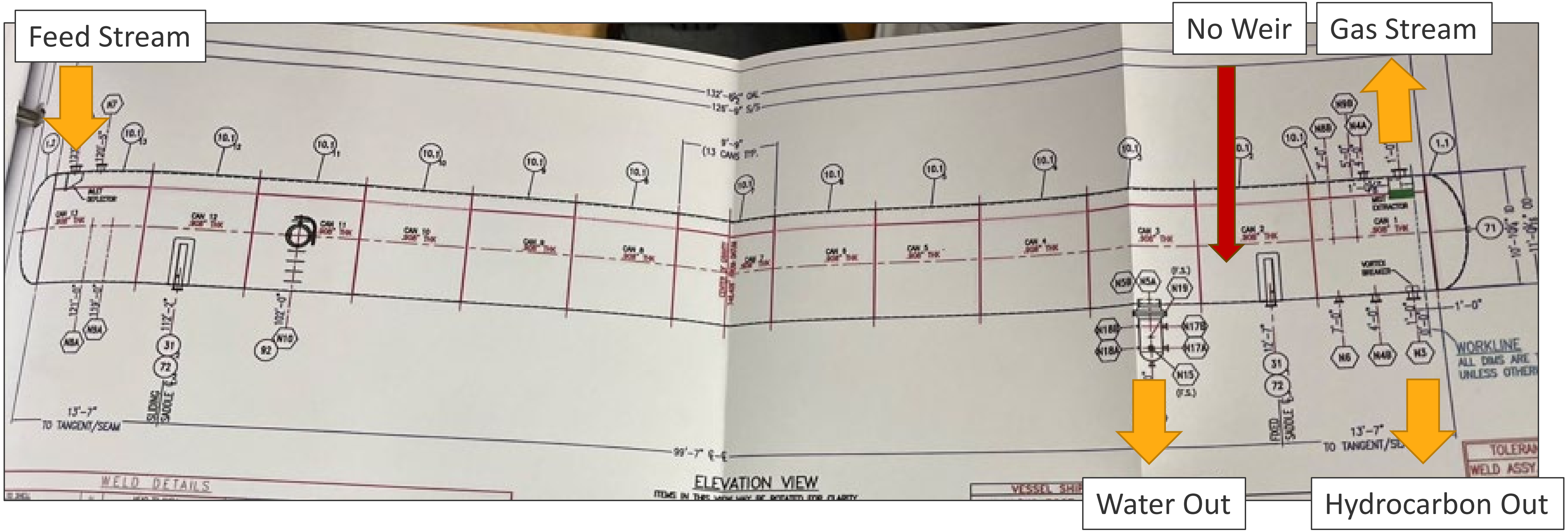


Case Study 3 – Deficient Vessel Designs

Slug Catchers For Bulk Liquid Removal



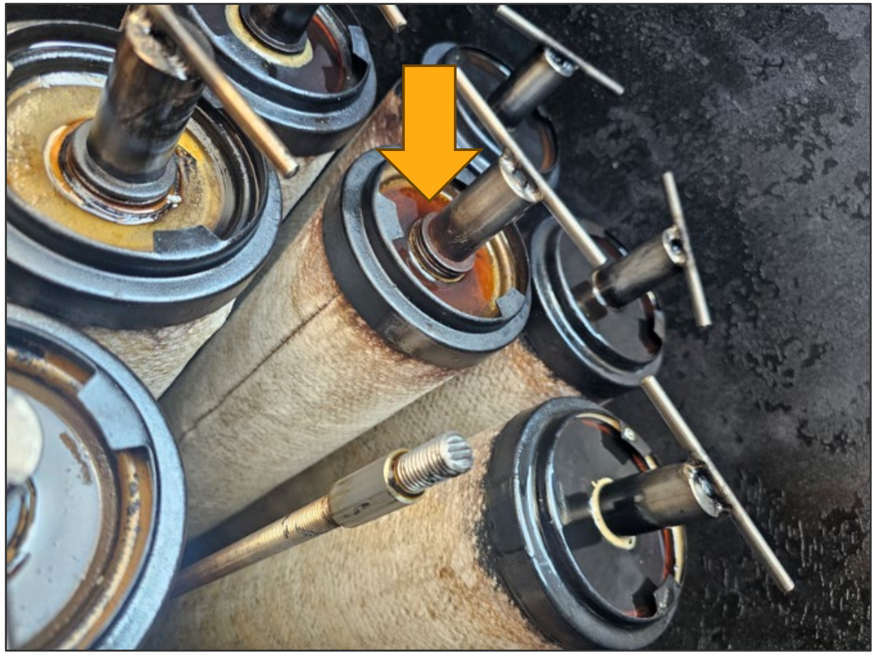
Condensate + Water Sent to Stabilizer



Case Study 4 – Coalescer Liquids Bypass

Coalescing Element Top End Liquid Bypass

Coalescer Vessel (Vertical)



Coalescer Vessel (Vertical)

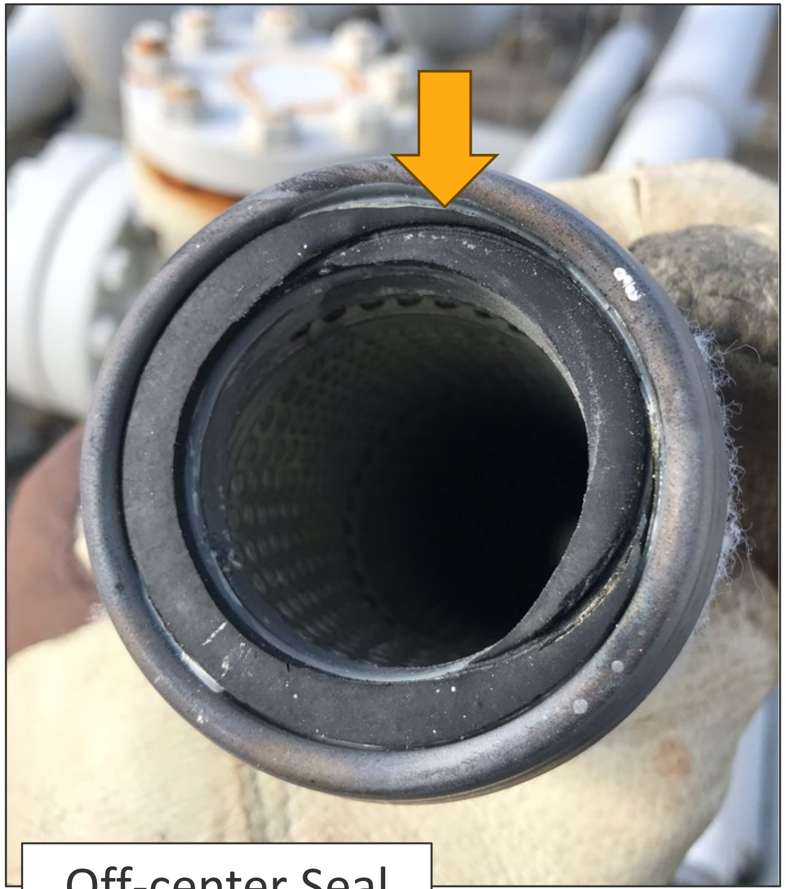
Coalescer Vessel (Vertical)

Case Study 5 – Chemical and Mechanical Incompatibilities

Elastomer Deformation and Degradation

Case Study 6 –
Off-center Coalescing Elements

Elements Engaging Off-center into the Vessel



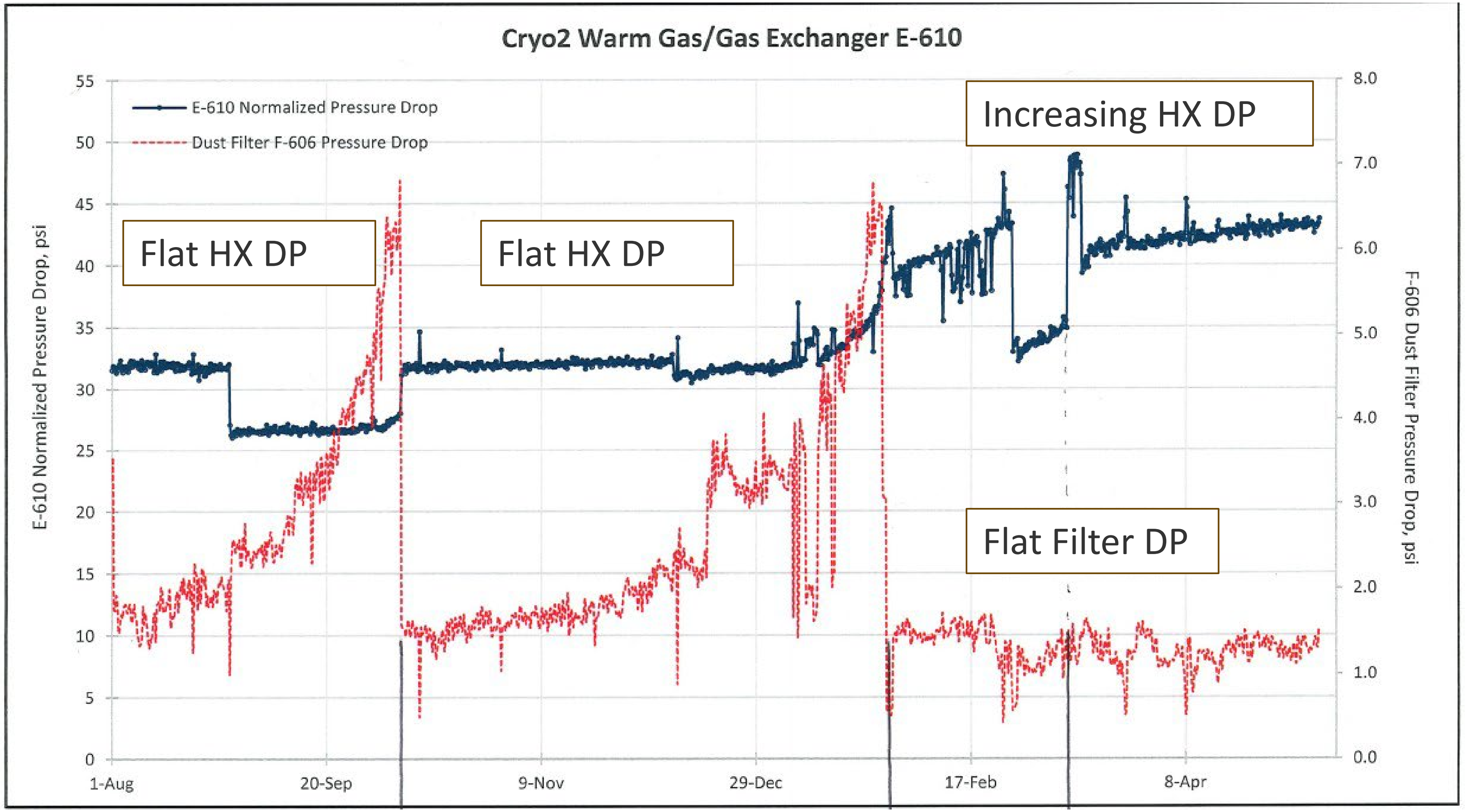
Off-center Seal

Off-center Seal

Off-center Seal

Case Study 7 –
Incorrect Filter Element Install

Filtration Upstream of Heat Exchanger (HX)

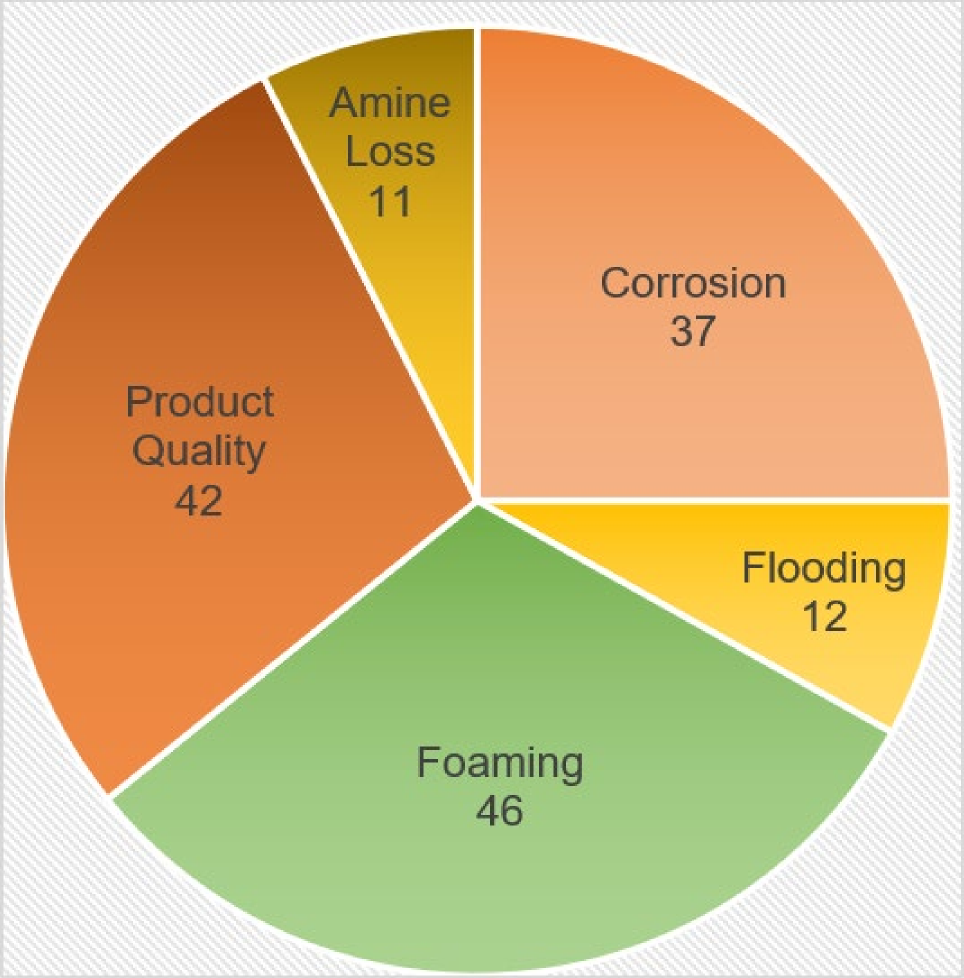


Amine Process Troubleshooting

Case Studies

Why Amine Systems Fail

- Most prevalent troubleshooting requests
  - Foaming
  - Product Quality – Meeting Spec
  - Corrosion
  - Flooding
  - Amine Losses

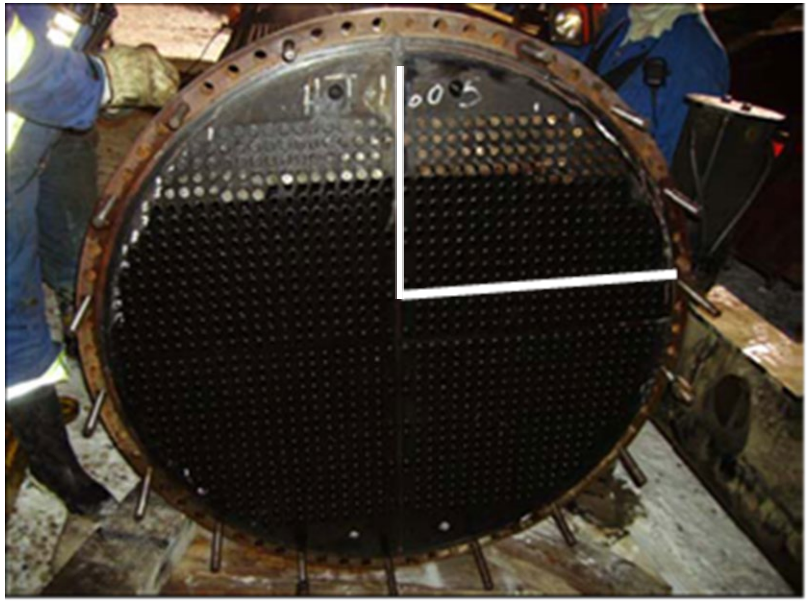


Case Study 1 –
Formulated MDEA System Reboiler Tube Failure

Reboiler Tube Failures

- Original troubleshooting request – provided with:
  - photo of reboiler tube sheet showing plugged tubes (top 5.5 rows)
    - upper right quadrant was first pass – tubes plugged equally because of U-Tube shape
  - photo of tubes showing some poorly adhering scale/deposit
- Previous bundle lasted 13 years – this bundle only 6 years
- Asked to determine the corrosion mechanism leading to the tube failure and heat medium leak into the amine solution

How would you proceed?



Reboiler Tube Failures – Gather Data!

- Because of holiday delays, couldn't get to the plant site for two weeks
  - asked for operating and equipment data
- Sample of scale sent to a lab for interim XRD analysis
  - results as expected for this location
  - primarily high temperature iron sulfide
- By this time, the bundle had been removed and was laying down on the ground
- New photos taken showing a much different story than from the original photos.

X-ray Diffraction of Scale

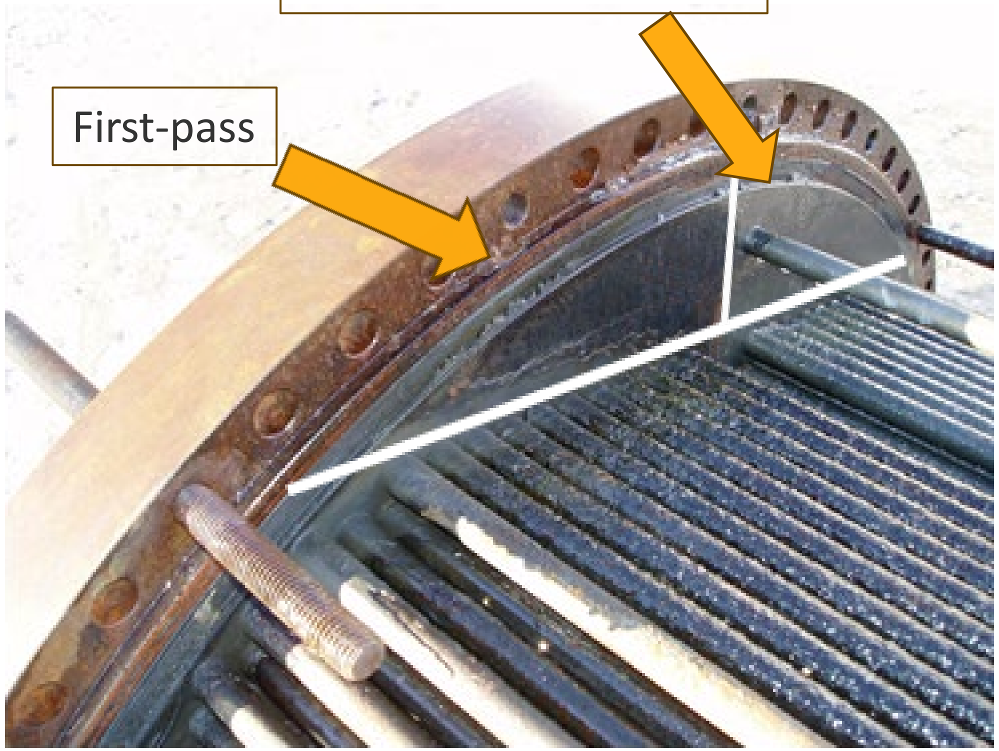
Compound	Chemical Formula	Abundance
Pyrite	FeS_2	65-75%
Marcasite	FeS_2	10-15%
Pyrrhotite	Fe_7S_8	10-15%
Quartz	SiO_2	1-5%
Sulphur	S_8	1-5%

Marcasite is a polymorph of pyrite – same chemistry as pyrite but a different structure and, therefore, different symmetry and crystal shapes

Reboiler Tube Failures

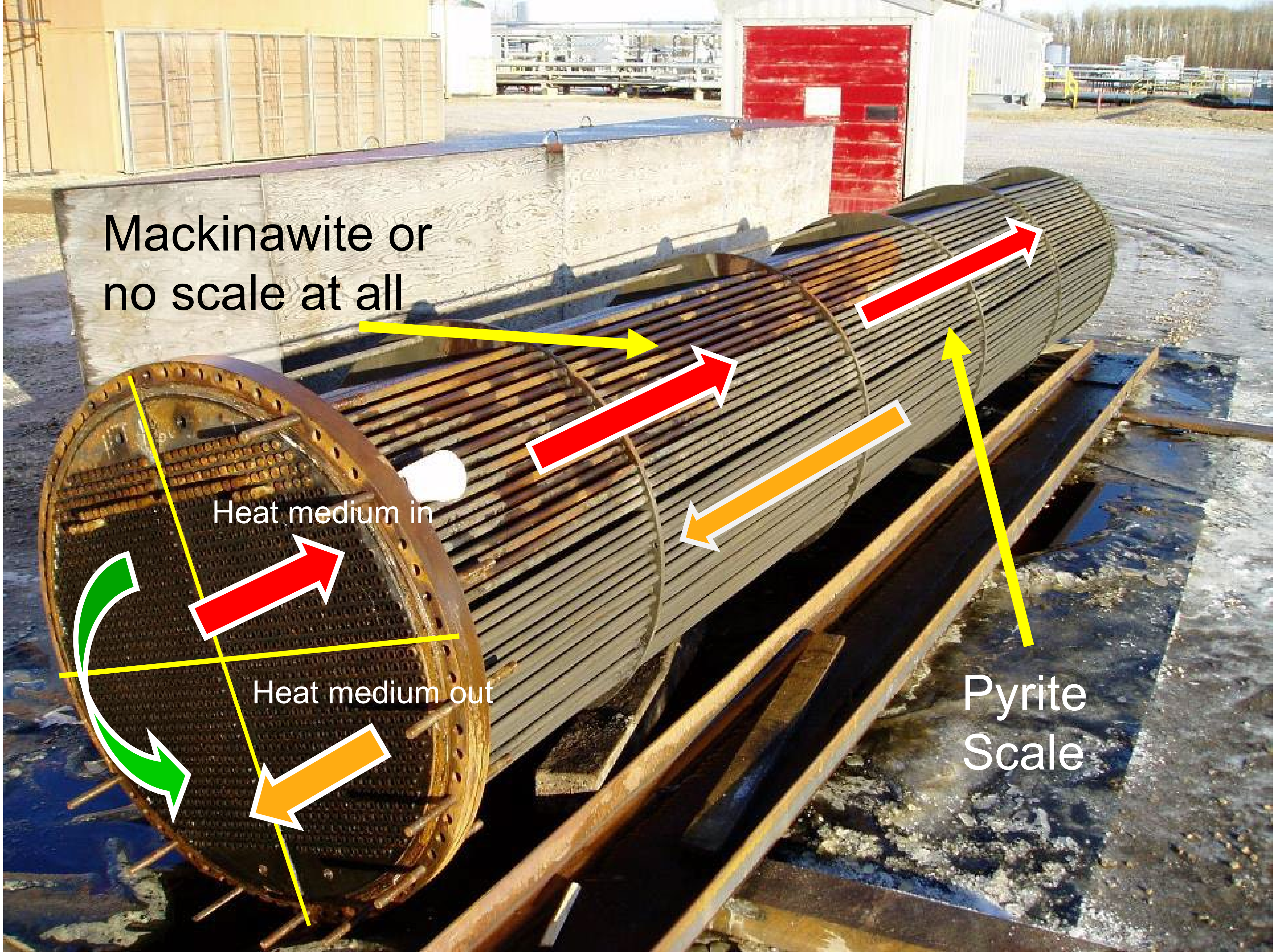
Note lack of damage on second-pass tubesheet and tubes

First-pass



Rust color - more recent laydown of Mackinawite (Fe_2S) or bare metal – poor/no protection

Greyish scale – Pyrite (FeS_2). Normally seen in reboilers. Good corrosion protection when present – however, is very brittle


Mackinawite or
no scale at all
Heat medium in
Heat medium out
Pyrite
Scale

Reboiler Tube Failures – Data Assessment

- Corrosion concentrated to inlet of first bundle pass
- Mechanism appears to be scale buildup followed by loss of scale
- What could cause scale delamination?
  - tube vibration from excessive boiling
- What causes excessive boiling?
  - too high a heat flux
  - recommended max flux is 6300-7400 BTU/hr/ft^2
  - calculated heat flux is 11,500 BTU/hr/ft^2
- Why was the heat flux so high?
  - Heat medium flow and temperature increased
    - to accommodate new users in the heat medium loop
- Previous bundle was 2-pass; new bundle was a 4-pass (major contributor!)
  - despite comments that the new bundle was identical, it was not
  - had it been still 2-pass, heat flux on first pass would have been half of 11,500 BTU/hr/ft^2, which is below the recommended max flux

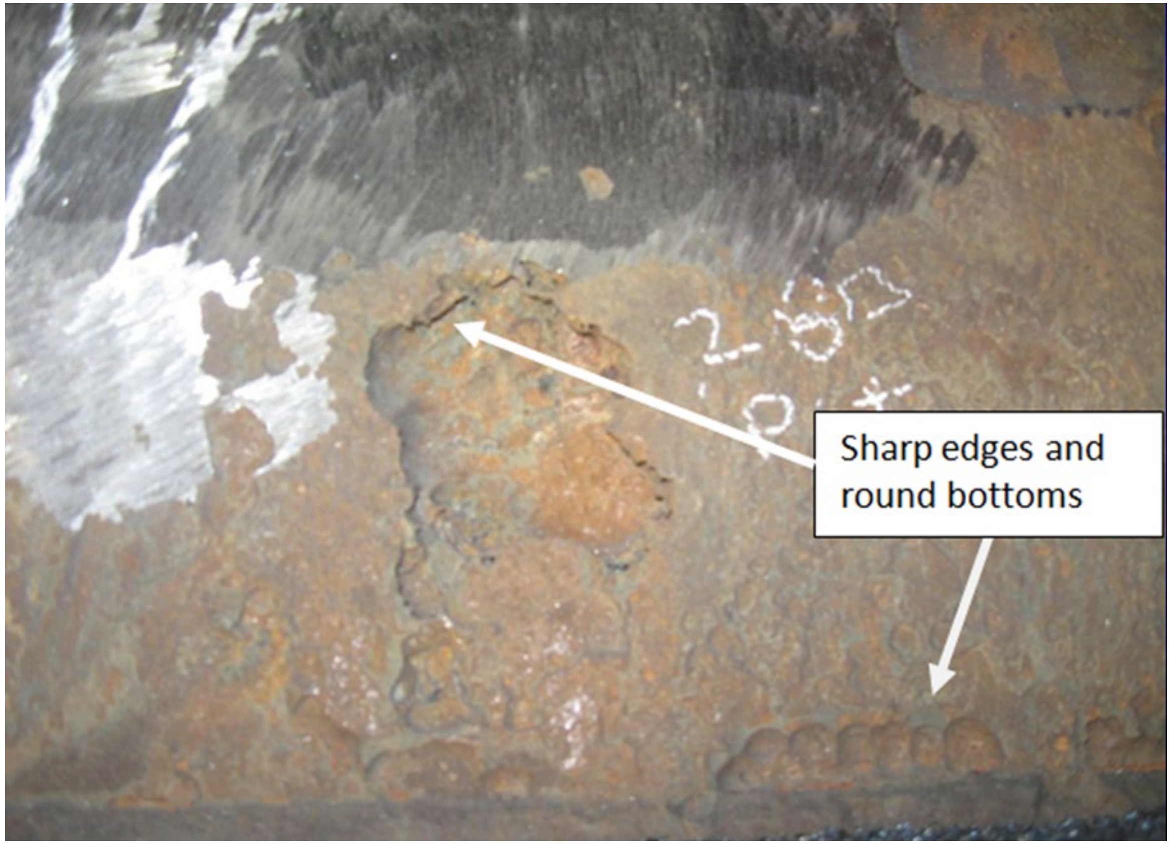
Reboiler Tube Failures – Recommendations

- Install a new **2-pass** bundle
- Change reboiler metallurgy to stainless steel
- Clean lean/rich exchanger
  - rich feed temperature only 185°F (85°C)
  - resulted in poor stripping in the regenerator column
  - forced too much acid gas into the reboiler
  - generated too much H_2S-related corrosion products that could break off
- Monitor rich outlet temperature from L/R exchanger to determine fouling rate and cleaning schedule
- Optimize lean amine circulation rate to control rich loading
- Optimize heat medium flow rate to control flux and reboiler temperature
  - Set a new regenerator overhead target temperature to ensure stripping in the column and not the reboiler

Case Study 2 – Aggressive Contactor Corrosion in CO_2 Removal Service

Contactor Corrosion

- First train of a three-train CO_2 removal facility had a turnaround after three years of production
- Absorber inspection showed massive corrosion in the midpoint of the contactor
  - most corrosion focused between trays 8 and 11
  - lower 1/3 and upper 1/3 showed no excessive corrosion activity
  - corrosion had characteristic CO_2 attack appearance
    - sharp edged – rounded bottoms
- Corrosion in absorber LCV and indication of rich side fouling
  - flash drum, L/R exchanger



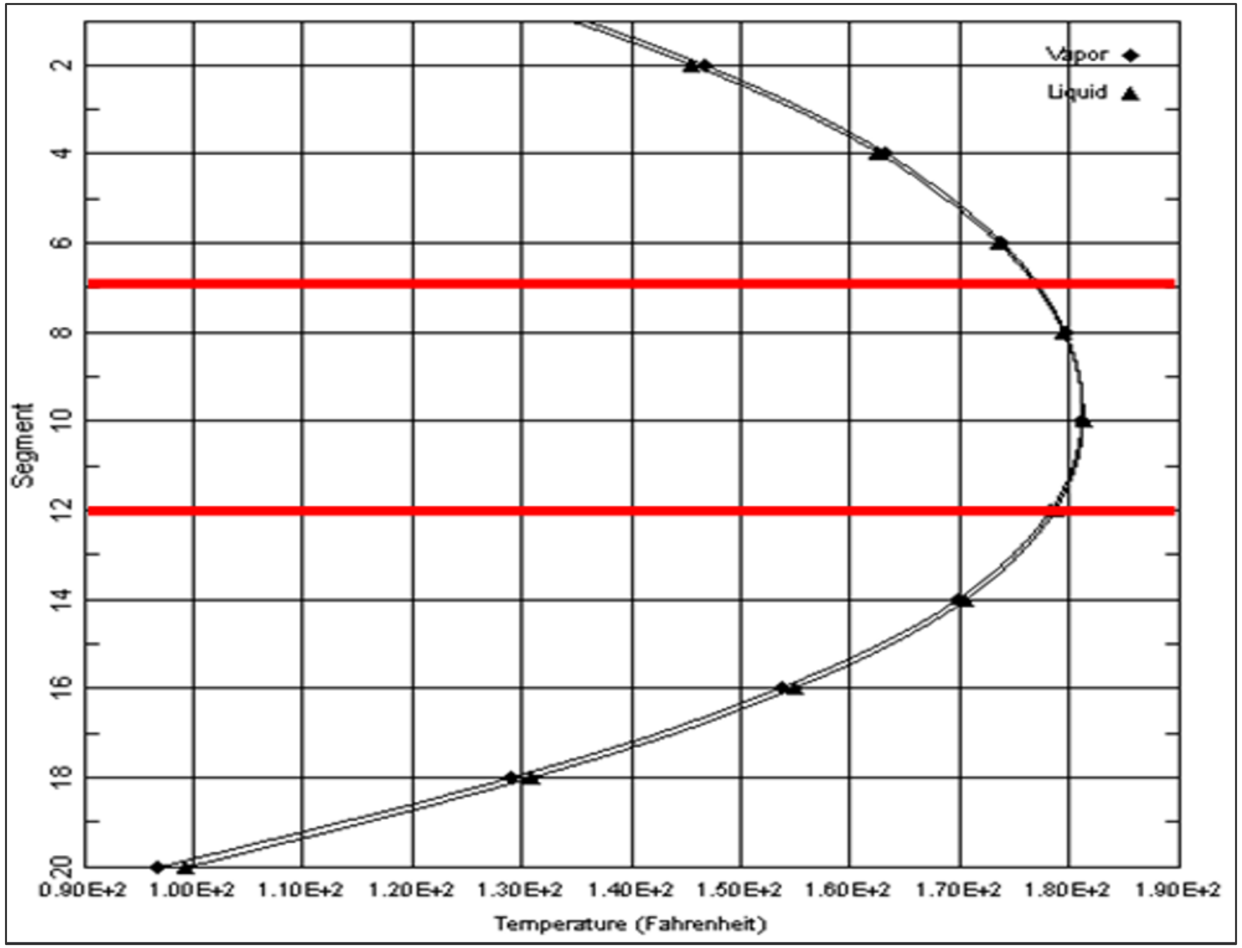
Contactor Corrosion – Gather data!!

- Amine plant was using a generic formulation blend of MDEA and DEA
  - DEA added to enhance CO_2 removal requirements of the solvent
- No temperature probes to measure temperature profile within the column
- No direct measurement of rich loading or effective control of amine circulation rate vs feed gas composition and flow rate
  - feed gas composition assumed to be consistent with design case
- Summer issues with lean amine coolers
- Amine blend composition only known during quarterly amine analyses

Contactor Corrosion – More Pictures

Contactor Corrosion – Simulate and Assess

- Simulation Outputs
  - High temperature bulges possible
    - in excess of 180°F during the summer months
    - bulge exactly at midpoint of column where most of the CO_2 attack occurred
  - Very high rich loadings
    - greater than 0.65 mol/mol
    - 95% of the equilibrium loading capacity
  - CO_2 removal profile shows poor efficiency as column temperature rises
    - Too much CO_2 still in column at midpoint



Contactor Corrosion – Recommendations

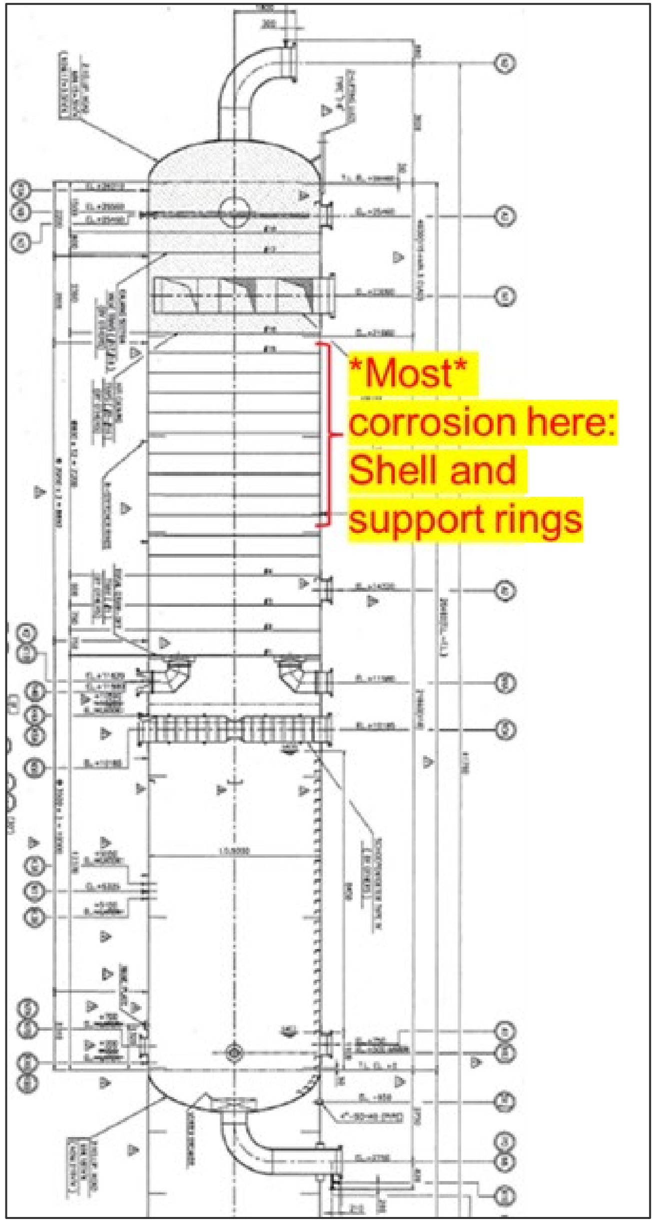
- Convert solvent from MDEA:DEA blend to a piperazine activated chemistry
  - faster CO_2 absorption
  - easier to predict and control bulge point and temperature
    - will be lower in the column and cooler with better control
- Improve lean amine cooling capacity

- More frequent feed gas and amine analysis
- Optimize circulation rate for bulge temperature control
  - control rich loading to max 0.55 mol/mol
  - control equilibrium loading below 80%

Case Study 3 – Control Logic and Corrosion

Upper Regenerator Corrosion

- Amine system (Sulfinol-D in an LNG plant) experiencing elevated corrosion of the upper trayed section of their regenerator column
  - mostly focused between trays 7-13 from the bottom
  - corroded walls and support rings are all in the carbon steel section of the column
- Upper section walls are stainless steel cladded so no corrosion at these tray locations in the tower
- Corrosion rates accelerating every year
- Need to determine cause and set a course of action to extend vessel life

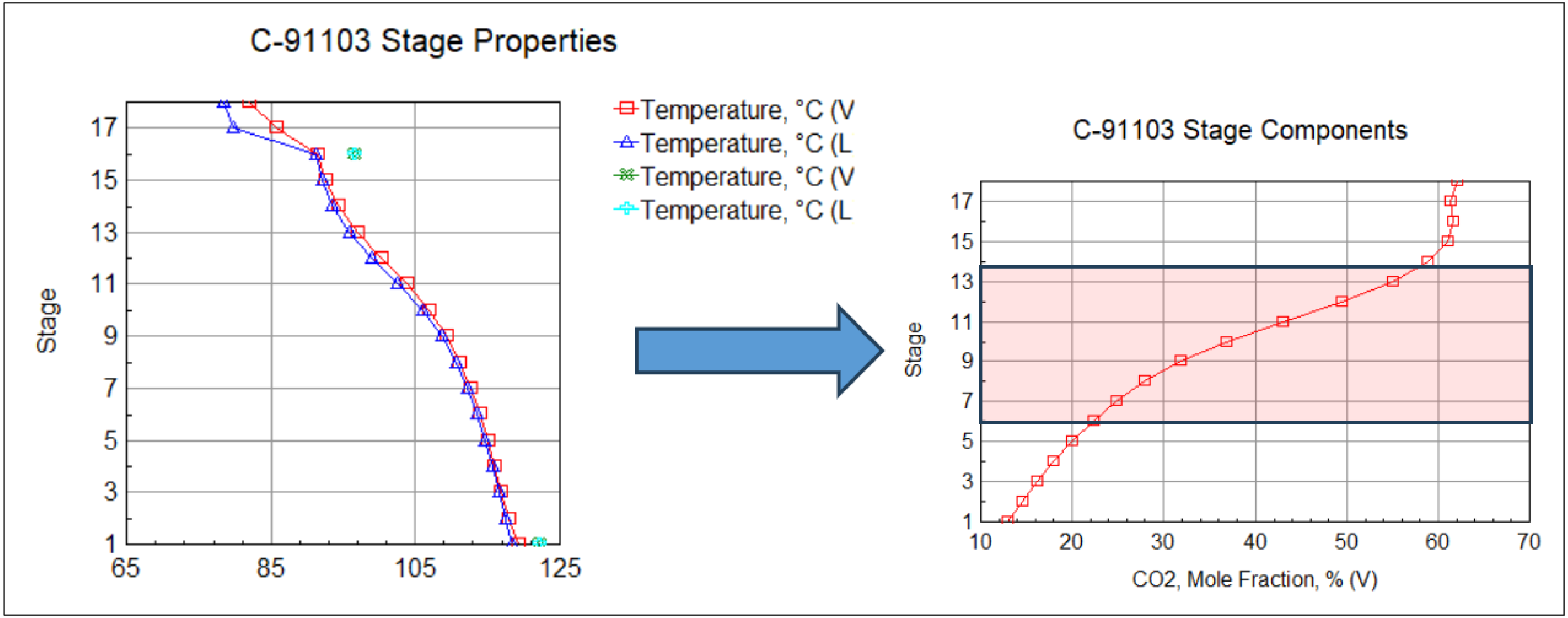


Upper Regenerator Corrosion

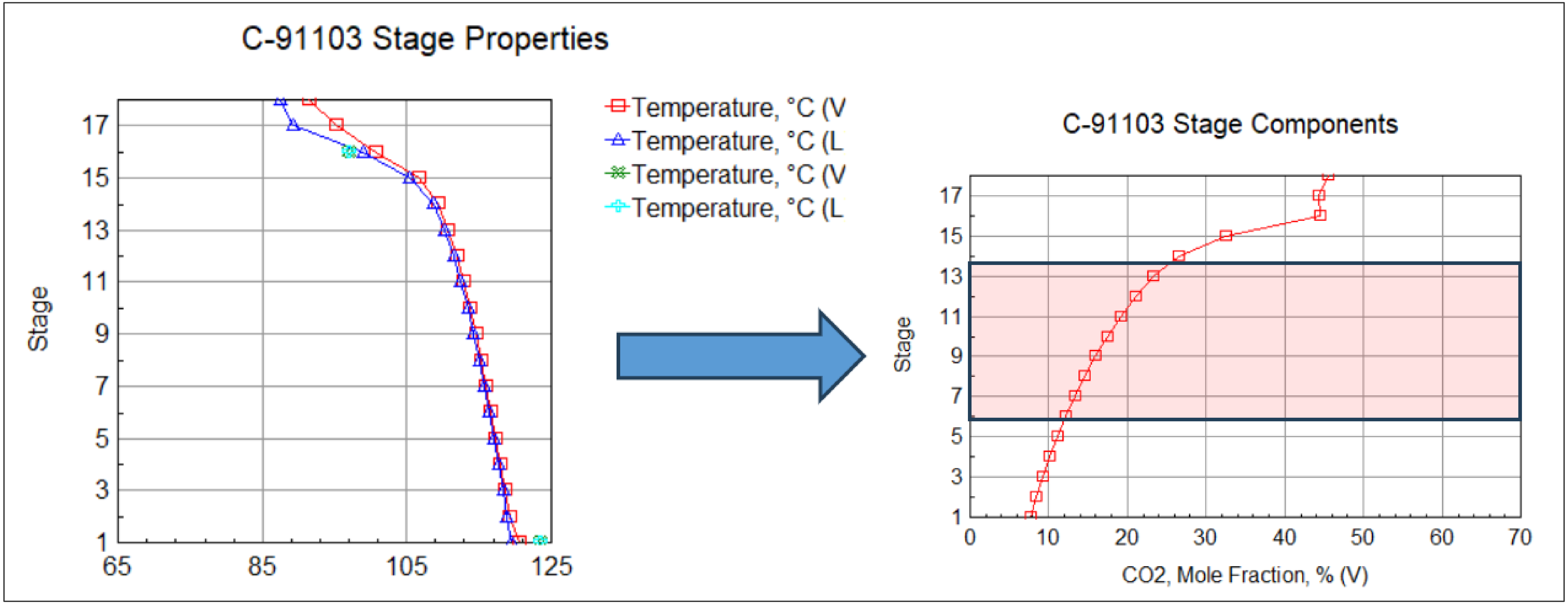
- **Gather Data!!!**
  - Plant design conditions
  - Equipment specifications
  - Historical operating data
  - Review inspection reports and photographs
  - Discussions with operations and engineering to determine if any process changes occurred before the escalating corrosion rates
    - YES! Reboiler Control Strategy

- **Assess Data**
  - Inspection and photos make clear it is CO_2 attack
  - Simulate plant to determine possible cause
    - failure to properly regenerate within the column leaving too much CO_2 at the top of the column
    - change in reboiler control strategy from overhead T to reboiler T
    - solution degradation leading to a change in boiling point (245°F vs 252°F)
    - insufficient steam traffic to maintain required temperature profile

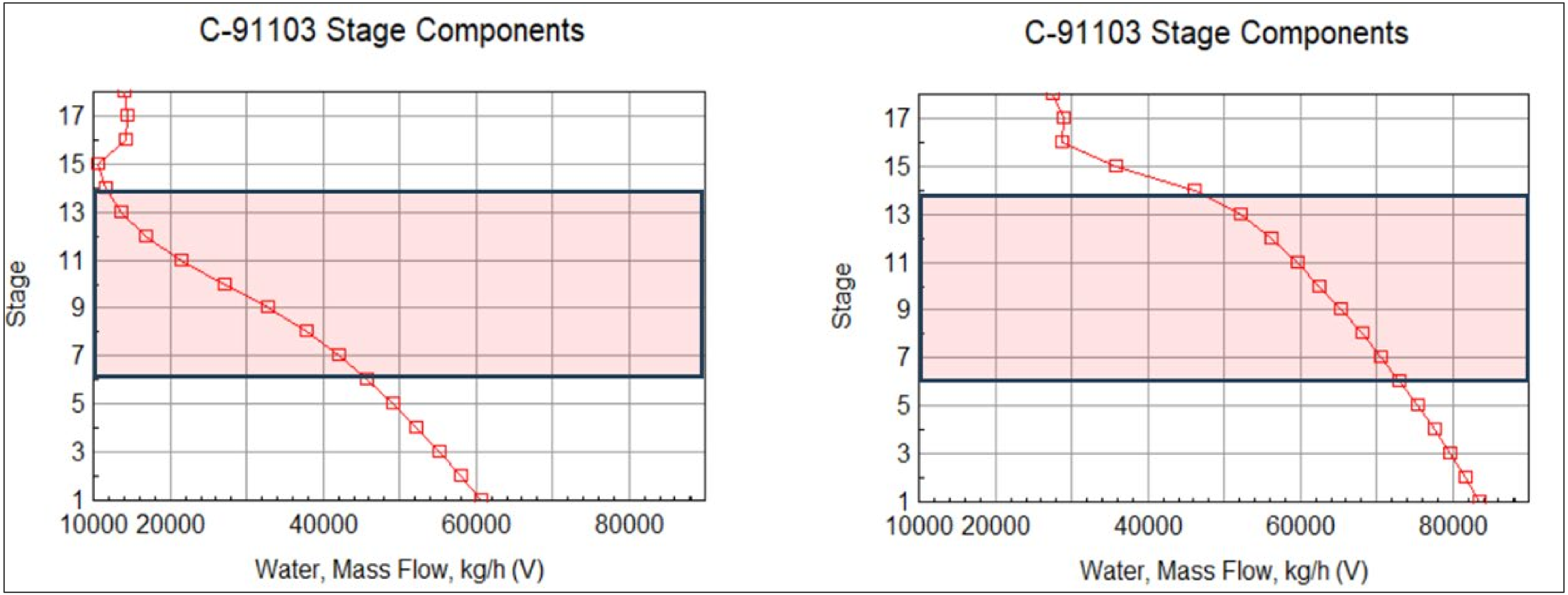
Upper Regenerator Corrosion



Upper Regenerator Corrosion



Upper Regenerator Corrosion



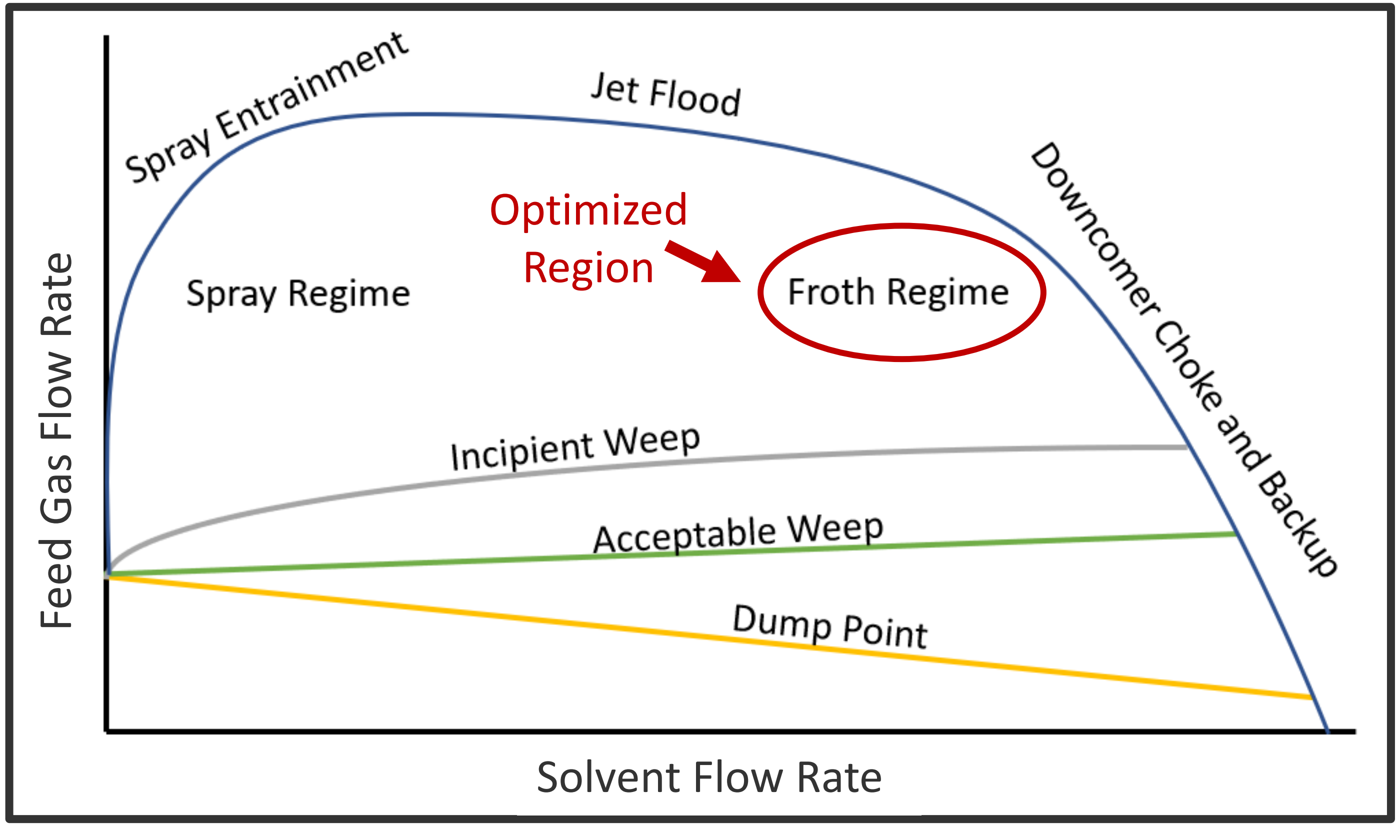
Upper Regenerator Corrosion

- **Cause**
  - Main: Reboiler T as control point
    - reboiler T is simply boiling point of fluid at pressure and composition
    - as composition degraded solution boiling point rose, resulting in less steam generation at setpoint T
    - degradation products formed by reaction of excess CO_2 in the reboiler – self-generating degradation and corrosion mechanism
    - Insufficient steam traffic resulted in poor wall-wetting for extra corrosion protection
- **Recommendations**
  - Return reboiler control point to regenerator overhead temperature
    - New target T to ensure sufficient steam traffic to regenerate 95% plus in the regenerator
  - More attention to the rich amine feed temperature – watch for L/R exchanger fouling
  - Optimize circulation rates to minimize reboiler duty load

Case Study 4 – Unbalanced Contactor Operation

Constant Solvent Losses

- Amine solvent losses are high (80% inventory/year)
- Liquids in after-scrubber periodically
- Lean Amine not showing any foaming
- Contactor damage was discussed as a possibility



Contactor Data as Operating

Table 13 Simulation results from the contactor at 12 m^3/hr amine solvent flow rate.

Parameter	Value
Foam Derating Factor	0.8
Diameter	4.0 ft
Percent Vapor Flood	4.15
Percent Downcomer Flood	12.41
Tray Active Area As % Column Area	71.78
Tray Active Area	9.02 sqft
Total Downcomer Area As % Column Area	28.22
Total Downcomer Area	3.55 sqft
Side Downcomer Width	9.54 in
Side Weir Length	3.19 ft
Weir Load	16.60 gpm/ft

53 gpm Amine Solvent Recirculation Flow Rate

Low % Vapor/Downcomer Flood and Weir Load

➔ Inside Spray Flow Regime (below 20 gpm/ft)

Contactor Data as Operating is Improved

Table 15 Simulation results from the contactor at 85 gpm amine solvent flow rate.

Parameter	Value
Foam Derating Factor	0.80
Diameter	4.00 ft
Percent Vapor Flood	79.02
Percent Downcomer Flood	19.17
Tray Active Area As % Column Area	71.78
Tray Active Area	9.02 sqft
Total Downcomer Area As % Column Area	28.22
Total Downcomer Area	3.55 sqft
Side Downcomer Width	9.54 in
Side Weir Length	3.19 ft
Weir Load	26.60 gpm/ft

85 gpm Amine Solvent Recirculation Flow Rate

Higher % Vapor/Downcomer Flood and Weir Load

➔ Outside Spray Flow Regime (above 20 gpm/ft)

Dehydration Process Troubleshooting

Case Studies

Why Dehydration Systems Fail

TEG Dehydration

- Can be divided into two categories
  - Contamination – inadequate inlet separation
  - Process – operating parameters

- Leading to four major problems
  - Inability to meet water dew point specification
  - Glycol losses - foaming
  - Corrosion
  - Emissions

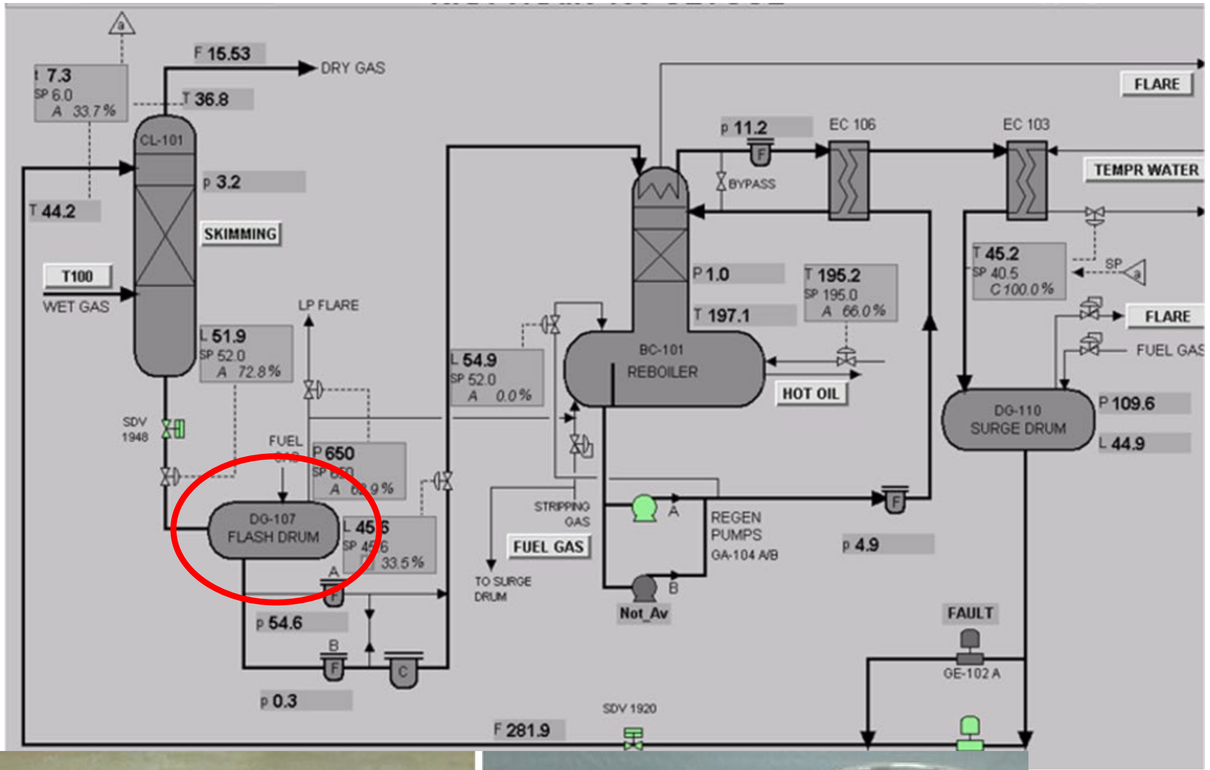
Desiccant Systems

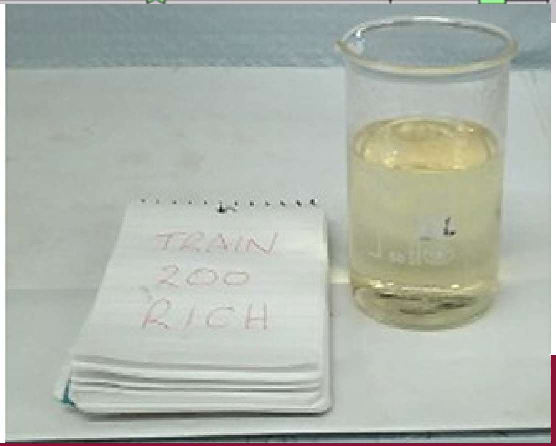
- Most prevalent troubleshooting requests
  - Poor outlet water dewpoint
  - Bed fouling
  - Bed life decay
  - High pressure drop
  - Bed refluxing
  - Switching valve problems

Case Study 1 – TEG System Unusual Erratic Foaming Events

Foaming Flash Drum – Offshore Plant

- Plant was having intermittent but violent foaming episodes – no chance to catch the problem before upset
  - glycol sent to LP flare; lost system levels; environmental issue (ocean contamination)
  - no foaming in contactor or still
- Glycol in good condition – foam tests done by client lab showed no foaming tendency
- Forced to cut back on feed gas – dry gas sent onshore to large LNG plant – process reduction not an option - need to solve the problem immediately!



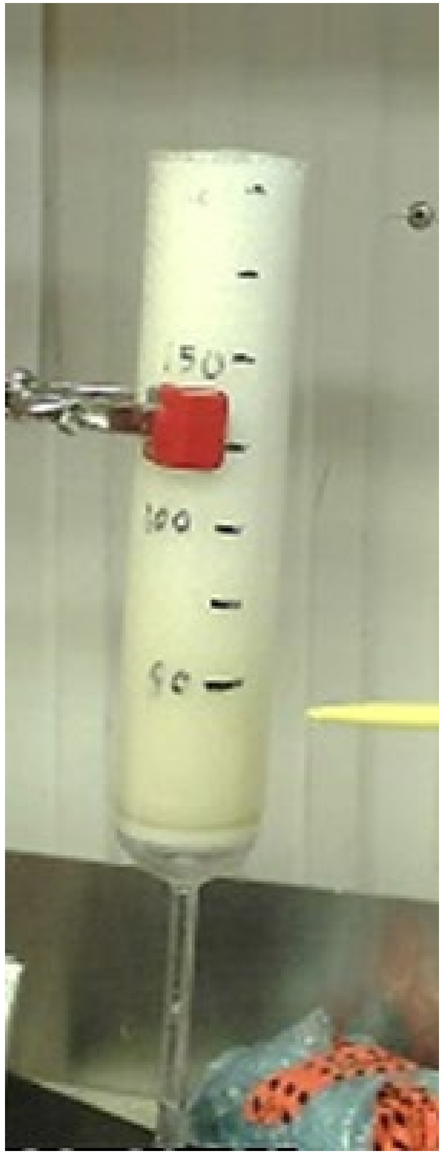


What are your recommended troubleshooting steps?

TEG Foaming – Properties

What do we know about TEG and Foaming?

- Low surface tension associated with high foaming tendency
  - allows the surface of a bubble to expand easily
  - HCs have low surface tension
  - **TEG has relatively high surface tension**
- Also requires the introduction of a <u>surfactant</u>
  - **<u>Inlet fluids carryover</u>**
  - corrosion inhibitor, soap sticks, compressor lube oil, etc.
- Viscosity increases stability
  - TEG viscosity very high (15.8 cP at 68°F)
  - makes it hard for bubble wall to get thin and collapse once formed



TEG Foaming – Findings

- Re-tested the glycol (L and R) for foam tendency
  - confirmed low foam tendency for both lean and rich TEG (as sampled)
  - noticed very stable foam after flushing frit with DI water
    - glycol seemed to contain tenacious water-based surfactant
    - added water to the rich TEG and noted that at 5 wt% water the TEG foamed badly
    - Rich TEG typically 3.5 – 4 wt% water

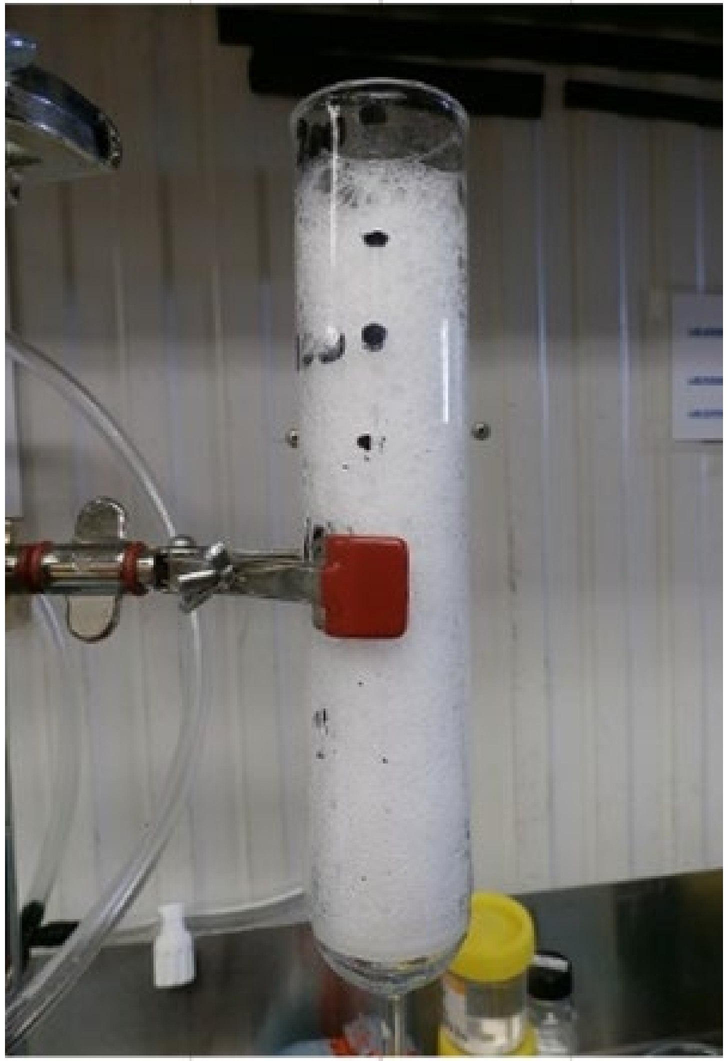
Lean

Rich

Flush

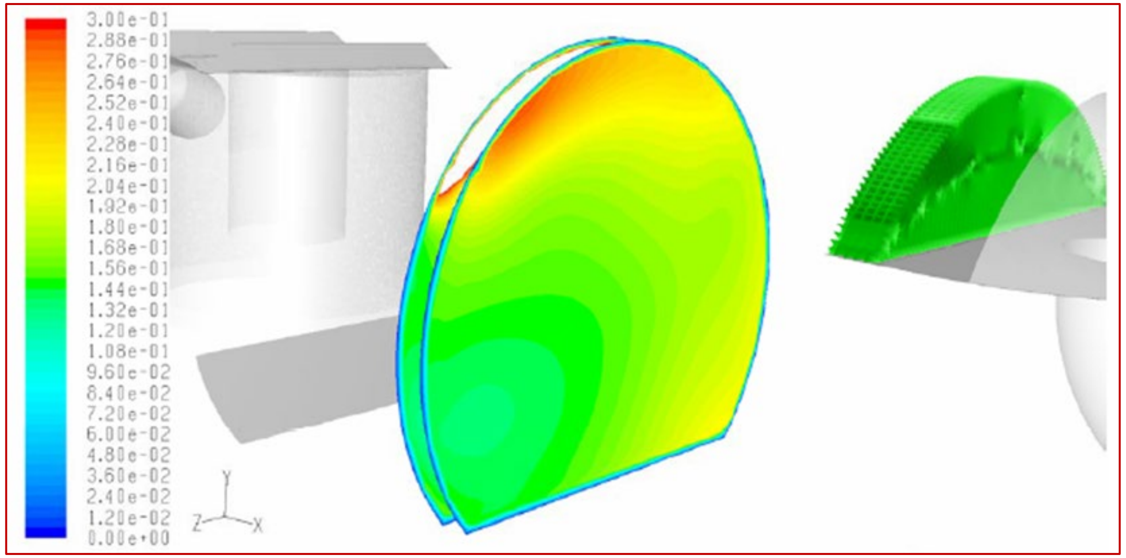
TEG Foaming – Findings

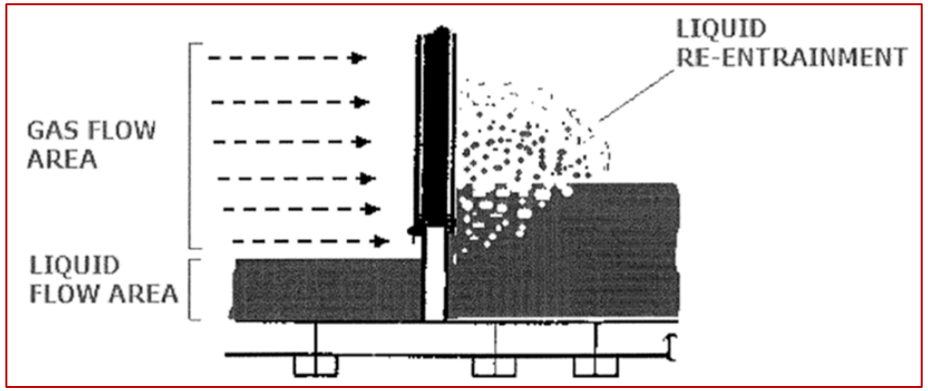
- Looked for surfactant by testing potential addition chemicals for foaming
  - Upstream corrosion inhibitor caused increased foaming <u>tendency</u>
  - In-plant corrosion inhibitor – TEA – caused increased foam <u>stability</u>
    - blend of the two formed very high and stable foam



TEG Foaming – Engineering

- Water ingress – or at least high rich glycol water content appeared to be the culprit – need to look for water source
  - Inlet separator is obvious source
    - 'Carryover' events linked to foam episodes – assumed to be dump cycles
    - except LCV's didn't open!
      - level loss was a carryover event
    - CFD work showed high flow rates through mesh pads (0.3 m/s vs recommended max 0.15 m/s)





TEG Foaming – Recommendations

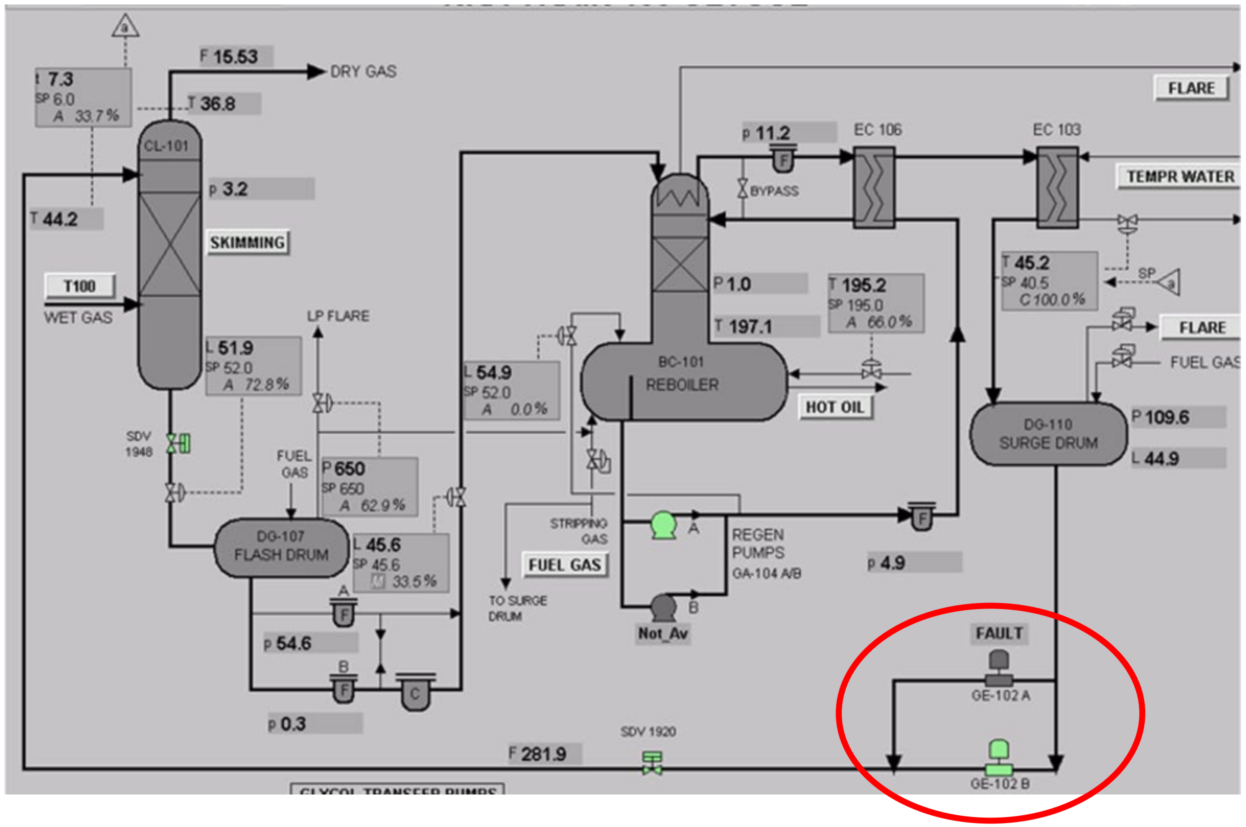
- In Process
  - Prevent inlet separator fluids carryover
    - raise feed gas pressure to reduce volume of feed gas
    - monitor inlet separator levels to ensure that the level is actually dumping and not carrying over
    - increase glycol circulation slightly to ensure rich loading doesn’t ever approach 5 wt% water content

- Chemistry
  - see if the pipeline corrosion inhibitor can be replaced with a less-problematic formulation
  - if there is a carryover event, be quicker with antifoam addition (on-site product is effective)
  - consider different corrosion inhibitor to replace the TEA (Triethanolamine)

Case Study 2 –
TEG System Charge Pump and Water Dewpoint Issues

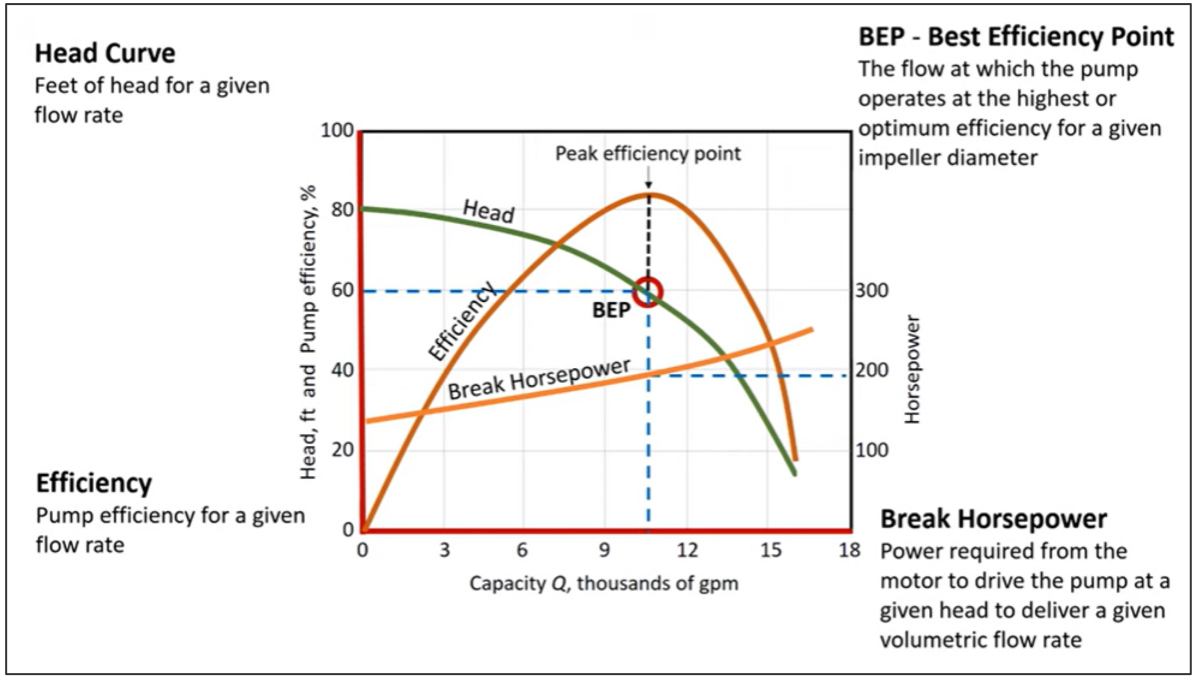
Pump / Dewpoint Issues

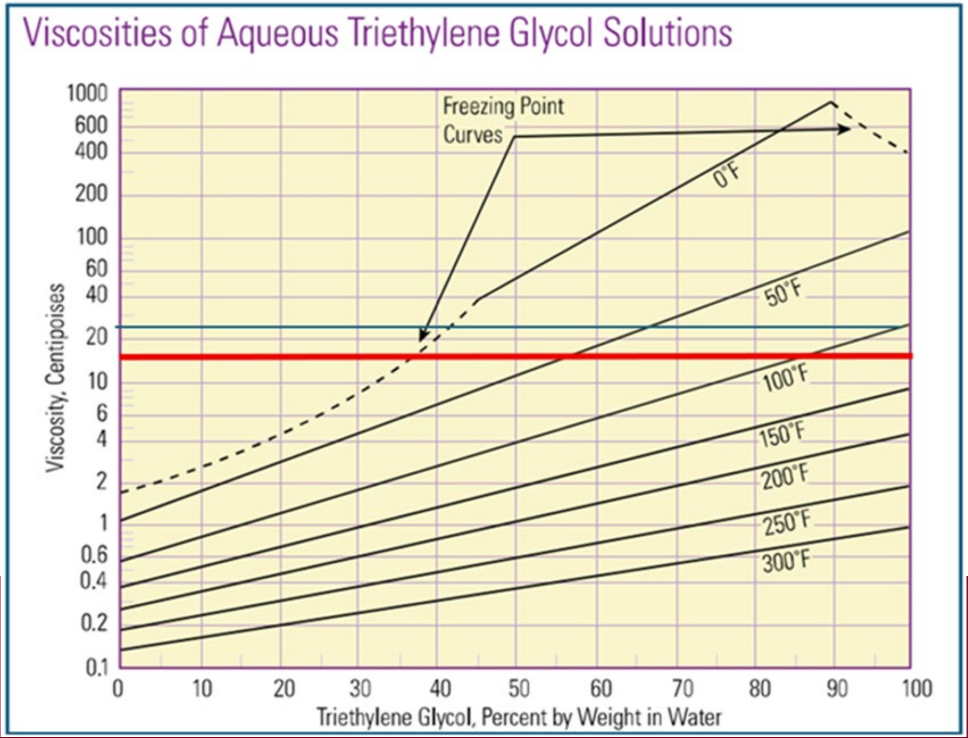
- Lean glycol was stacking up in the surge drum because the lean glycol charge pumps could not produce enough flow to reach rated capacity
  - offshore site – high pressure operation, so lots of head required by pump (>1100 psig)
- Resultant lower glycol rates were not enough to provide the dewpoint depression required to meet the treated gas water content
  - had to increase glycol strength
  - forced to reduce feed gas flow rate to match pump output
- Sales go onshore to large LNG plant – need to solve the problem <u>immediately</u>!



Pump / Dewpoint Issues

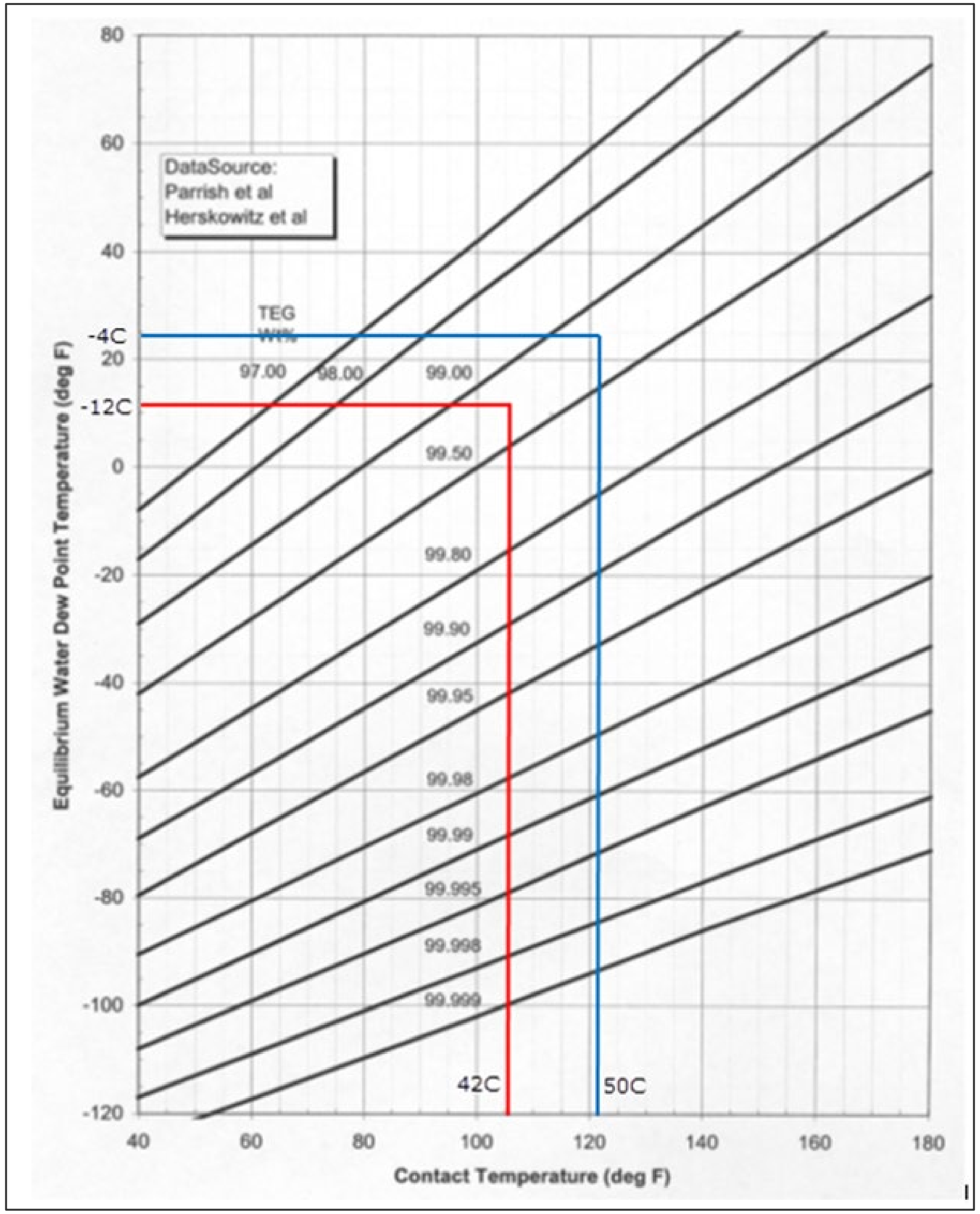
- High gas rates - needed to run at very high TEG strength and circulation rates to meet dewpoint requirements
- Pump issues related to loss of head at high flow rates
  - impellers maxed out ($H \propto D^2$)
  - higher viscosity fluids create more internal friction, causing a reduction in the head (pressure) the pump can produce for a given flow rate.
  - only remaining option was to try to reduce solution viscosity – needed to get close to 15 cP from the current 25 cP.





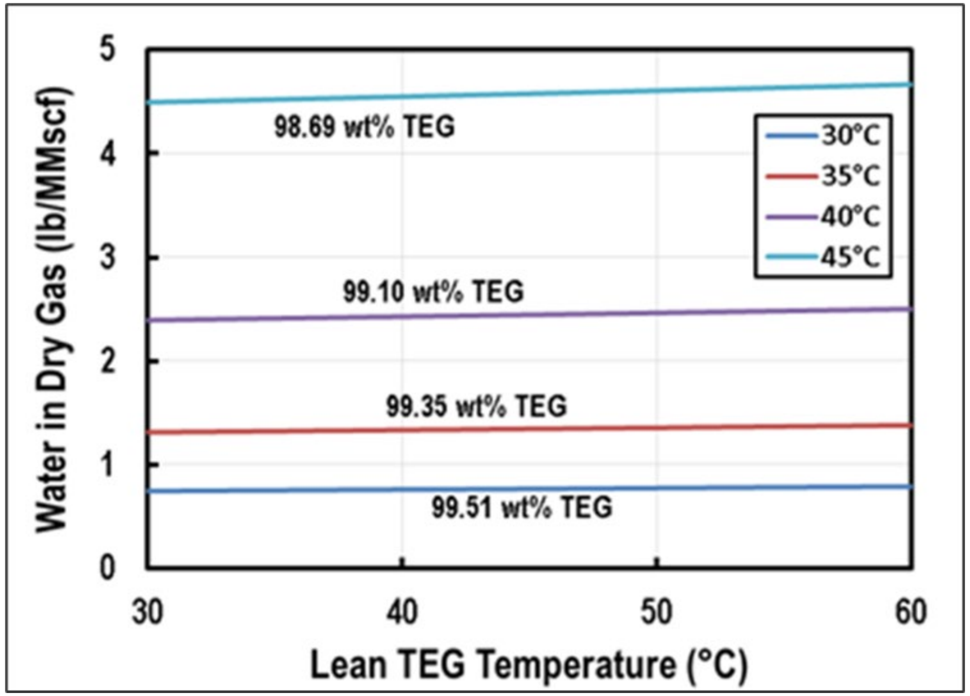
Pump / Dewpoint Issues

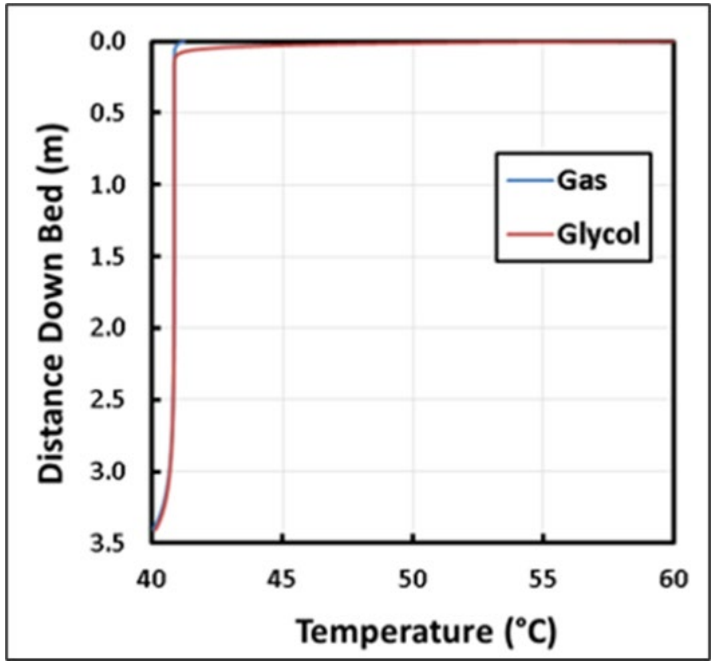
- Needed to increase lean TEG temperature to ensure pump performance (viscosity issue)
- Lean TEG had to be increased from 42°C to 50°C to satisfy viscosity requirements
- Historical charts indicated a failure to meet dewpoint (-10°C) if the temperature increased
  - initial recommendation was to come up with another solution (or reduce feed rates until turnaround and install a larger capacity pump)
  - Rate-based TEG simulation tool became available – cases were run to determine potential for temperature increase



System Simulation

- Simulations predicted an increase in lean TEG absorber feed temperature would have no effect on treated gas water dewpoint – turned out to be right



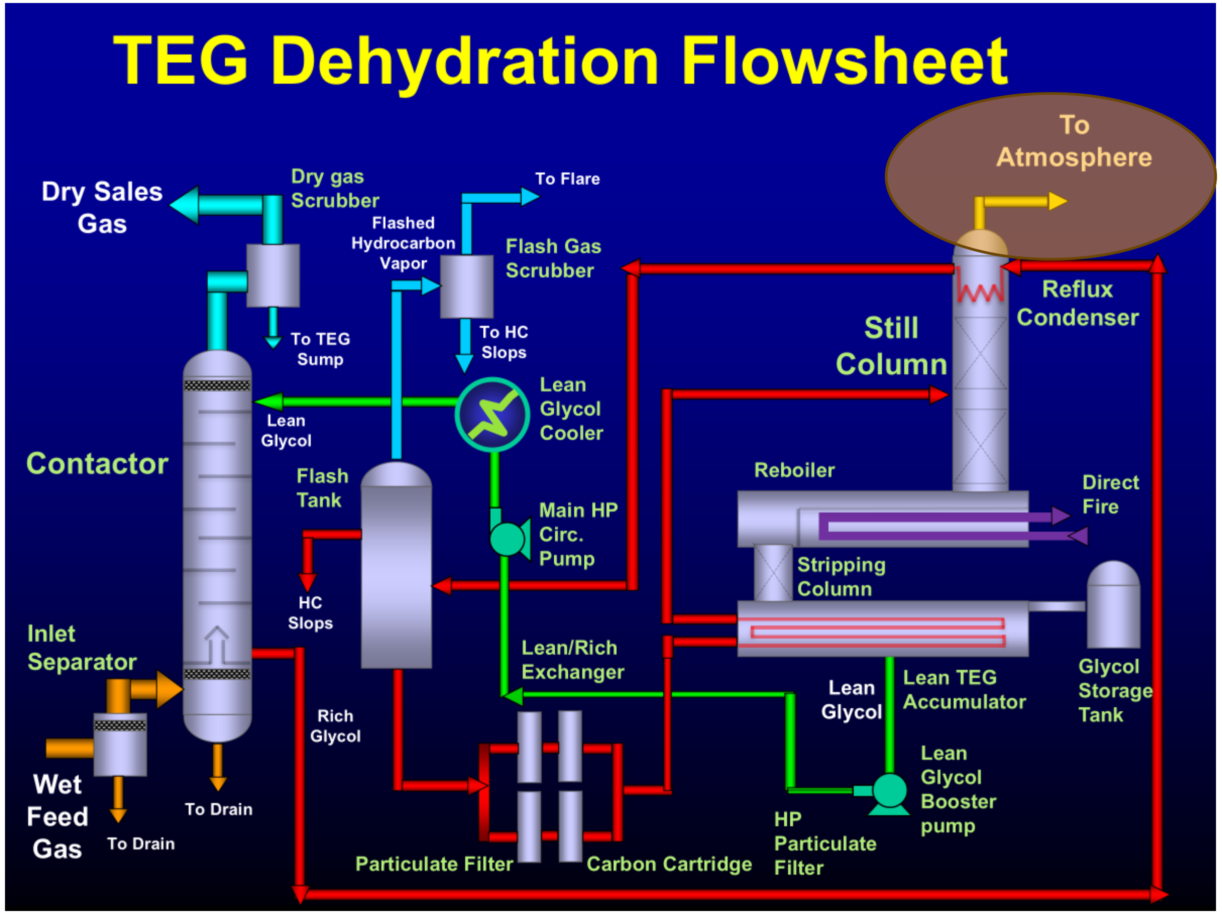


- Tower T was gas-phase limited – high G/V ratio – top of packing became very short heat exchanger
- TEG temperature was irrelevant
- Lean TEG temperature increased, and plant met all dewpoint requirements
- lean TEG concentration important

Case Study 3 –
Still Column Corrosion, Fouling and Carryover

TEG Still Column Corrosion / Fouling / Carryover

- TEG Dehydration Unit experiencing heavy glycol carryover from still vent column – *environmental issue*
  - Assumed water hangup in the still column that eventually sprayed out the top of the still with sufficient pressure buildup – *potential plugged still packing*
- Odor complaints from facility operations – *health and wellness concern*
- Poor / inconsistent treated water spec
- Lots of issues to troubleshoot



TEG Still Column Corrosion / Fouling / Carryover

- Shut down and inspect still
  - corrosion damage to rich glycol distributor
  - completely plugged packing
- **Gather Data!!!**
  - analyze solids, glycol and feed gas
    - composition and size distribution
    - pH, Fe, TSS
    - CO_2, H_2S
    - inlet separator/coalescer

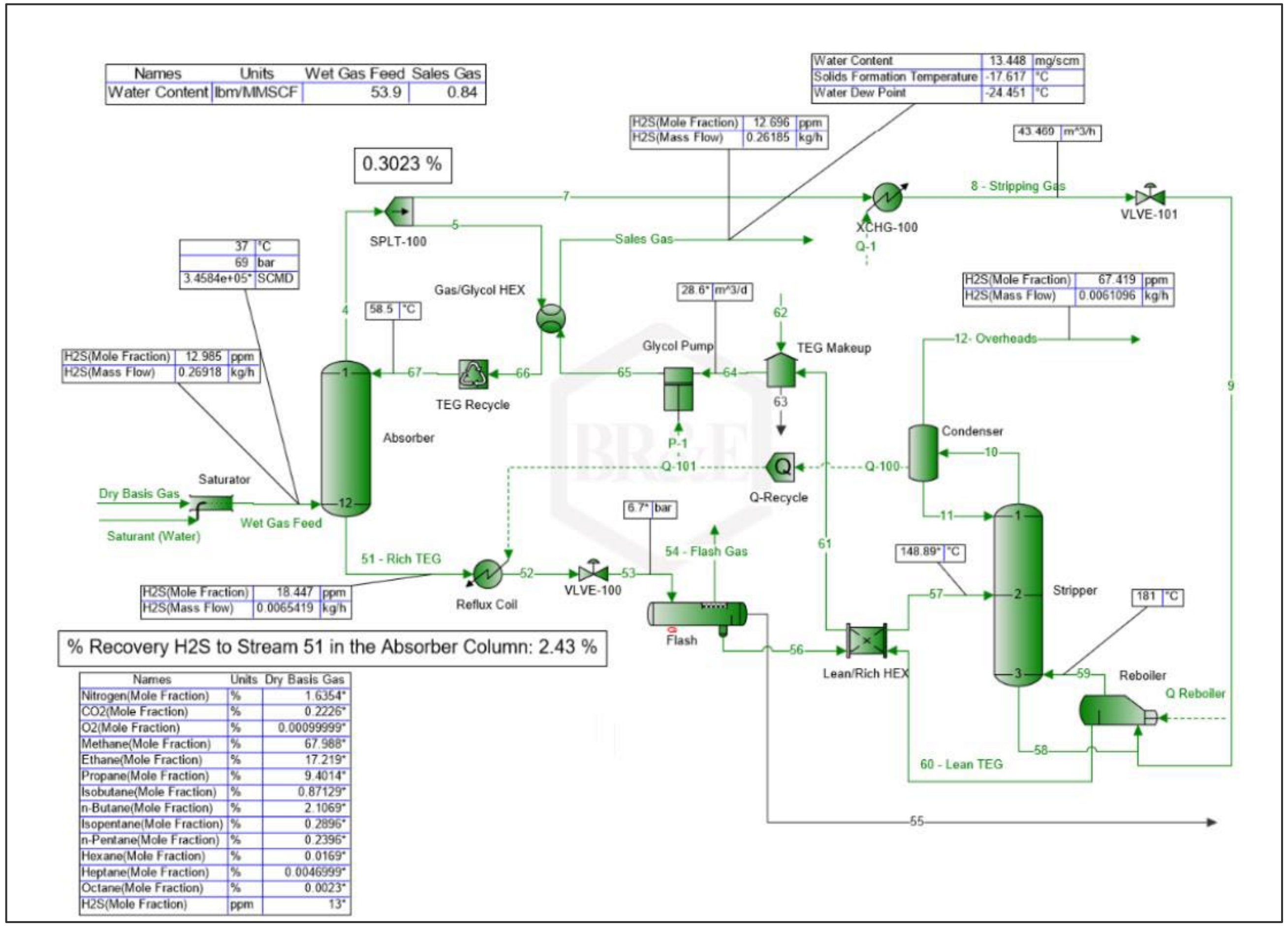
TEG Still Column Corrosion / Fouling / Carryover

- **Solids Analysis**
  - corrosion damage to rich glycol distributor
  - completely plugged packing
  - About 95% iron sulfide corrosion products and rust – ***how is this possible in a sweet system?***

Component	Iron Sulphide (FeS_2)	Ferric Oxy-Hydroxide III ($Fe_3O(OH)$)	Ferrous Sulfate Monohydrate ($FeSO_4 \bullet H_20$)	Oxidized Iron (Fe_3O_2)	Sulphur (S)
Wt%	76	4	14	5	1
Source	H_2S corrosion byproduct	Oxidized FeS_2 (sample care or in-process?)	Oxidized FeS_2 (sample care or in-process?)	Rust	Reaction of H_2S and Oxygen

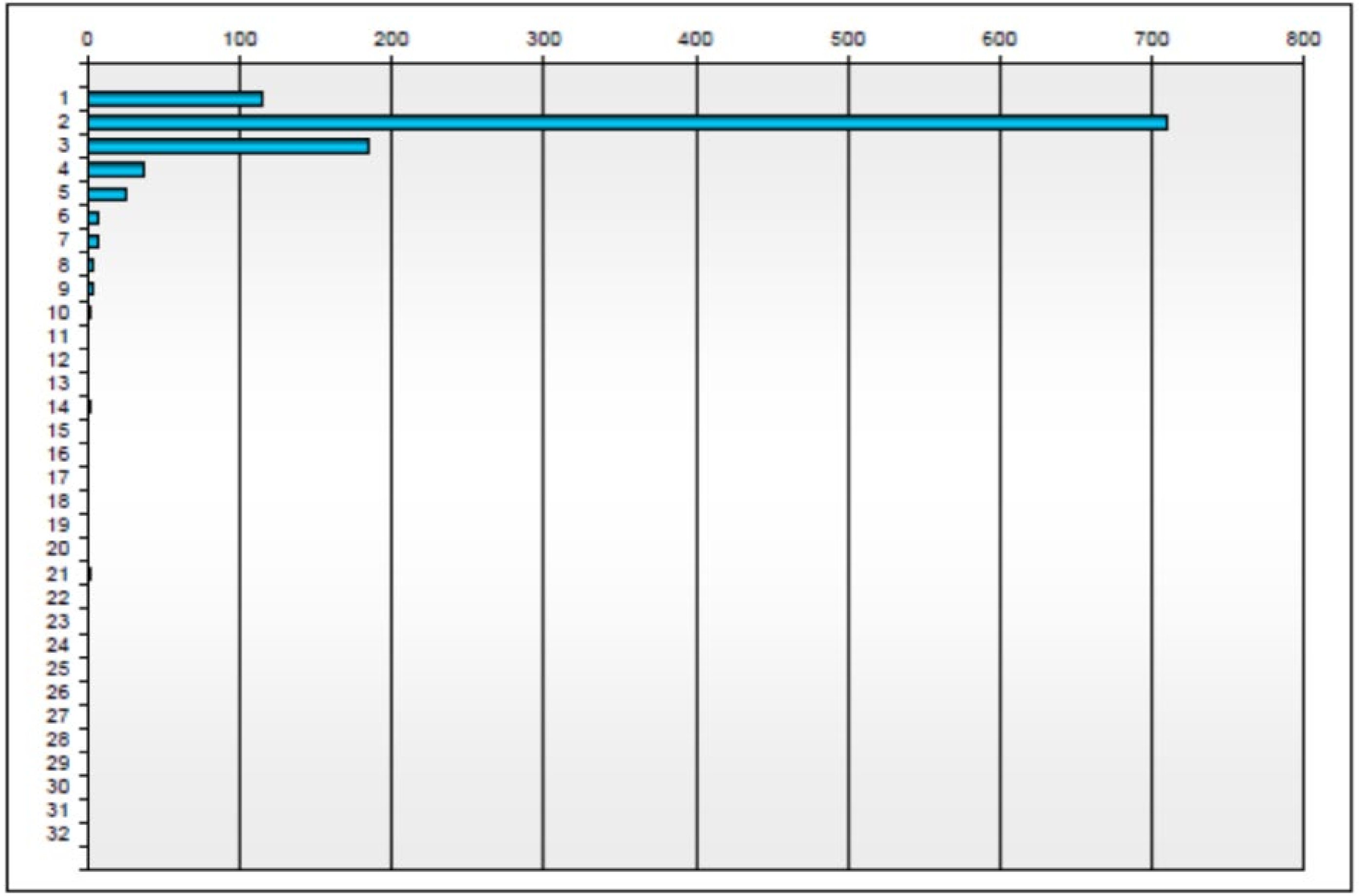
TEG Still Column Corrosion / Fouling / Carryover

- **Where did the H_2S come from?**
  - Test of feed gas found 13 ppmv H_2S
  - Simulation showed that the predicted H_2S in the still overhead vent could be almost 70 ppmv H_2S
  - Still internals all carbon steel – prone to H_2S attack at the high reboiler/still temperatures
    - Solids formed as a result of the corrosion of the internals
    - Supplemental solids from low pH corrosion of the rest of the system
    - Still packing made excellent impingement filter



TEG Still Column Corrosion / Fouling / Carryover

- **Solids Analysis**
  - Particle size distribution tests were quite eye-opening
  - About 98% of the solids were <5 ppmw
  - Makes sense as early iron sulfide corrosion forms particles in the range of 0.5 to 5 micron.
    - not enough H_2S to form larger particles – no agglomeration
    - makes it extremely difficult to filter out of the solution



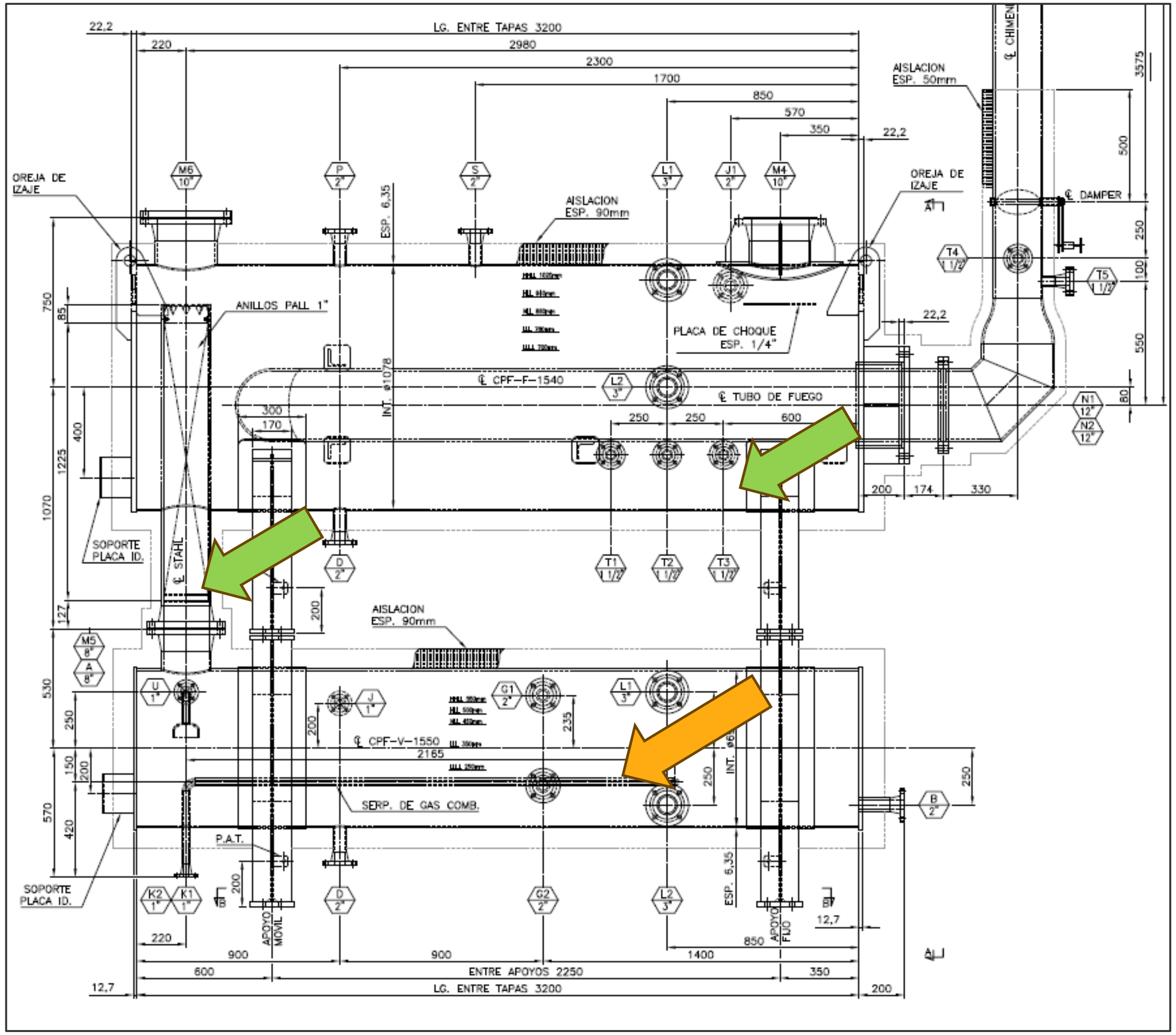
TEG Still Column Corrosion / Fouling / Carryover

- **Solution Analysis**
  - Extremely low pH – basically circulating acid through the system
  - Elevated solids content – also high soluble iron
  - Poor lean TEG concentration considering this unit is equipped with stripping gas
  - Rich water content shows lower than expected water content
    - suggests over-circulation

Analysis	Units	Lean TEG	Rich TEG	Specification Limits
Relative Density		1.0813	1.0680	
Total Fe	mg/l	14	26	<10
Hydrocarbon Content	mg/l	35.2	352	<500
Total Suspended Solids	mg/l	4760	3260	<100
pH		4.5	4.5	7.5 – 9.5
Chloride	mg/l	212.7	142	<250
Water content	wt%	1.74	3.15	<1.5

TEG Still Column Corrosion / Fouling / Carryover

- **Poor Regeneration**
  - Predicted lean strength with available stripping gas is 99.5 wt%
    - actual 98.3 wt%
  - Should be injected into the reboiler via sparger tube or into packed section exiting reboiler
    - injected into colder accumulator via sparger tube
    - doesn't improve stripping when the fluid temperature is colder
    - should be injected into packed bed
      - injection point changed and lean loading as expected



TEG Still Column Corrosion / Fouling / Carryover

- **Evaluate Data**
  - missed H_2S in the feed gas
    - corrosion potential not understood
    - potential toxic gas release from still vent
  - poor solution monitoring
    - pH control failure
    - lack of understanding of no reserve alkalinity for a TEG solution
      - no ability to withstand acid ingress
  - incorrect filtration micron rating
    - tough one to catch until a particle size distribution study completed

- **Evaluate Data**
  - Stripping gas shortfall
    - not enough stripping gas
    - incorrect injection point
  - Inlet coalescer failure
    - Level control valve hydrating off
      - No dumping when expected
    - liquids saturated elements –
      - leading to HC carryover
    - HCs in still vent contributed to fouling matrix

TEG Still Column Corrosion / Fouling / Carryover

- **Recommendations**
  - Equipment
    - Replace still internals with 316LSS components (packing, reflux coil, distributor)
    - move stripping gas to packed column
    - consider 5-micron absolute filtration
    - heat trace inlet coalescer CVs to avoid hydrates
  - Operating conditions
    - drop flash drum pressure to 50 psig from 80 psig
    - optimize TEG circulation rates and stripping gas rates

- **Recommendations**
  - Chemistry
    - control solution pH to 7.5-9.0 with inhibitor/pH booster addition
    - injection guidelines provided
  - Monitoring
    - take frequent pH readings on both the lean and rich solutions
    - monitor solution appearance for color, clarity and solids
    - HCs in still vent contributed to fouling matrix

Case Study 4 –
Short Molecule Sieve Life

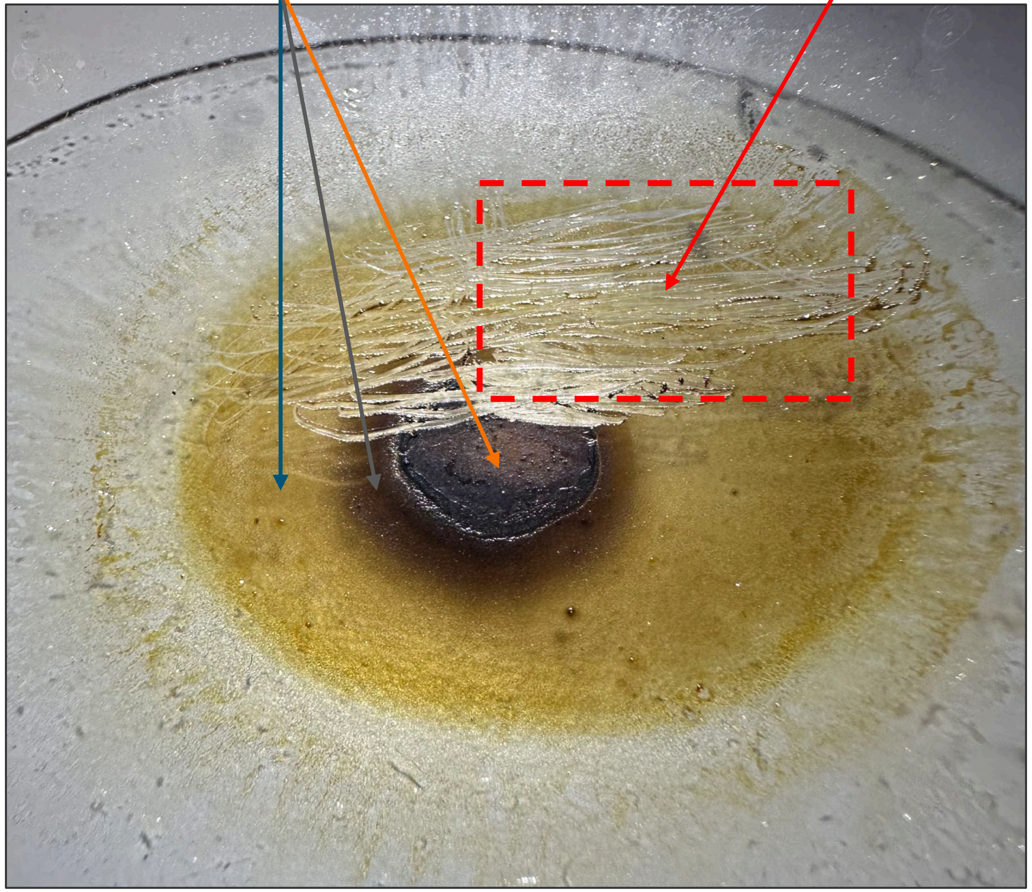
Sample as Received

- The sample appeared to contain two or three different mesh sizes.
- The larger mesh sizes varied in color from off-white, tan, brown and gray.
- The small mesh size had a more consistent off-white color.
- A small portion of the large mesh size molecular sieves showed signs of cracking and erosion.
- A large portion of the smaller mesh size molecular sieves showed signs of cracking/breaking, and erosion.

Extracted Material from Sieves

Increasing molecular weight

Sample taken for analysis

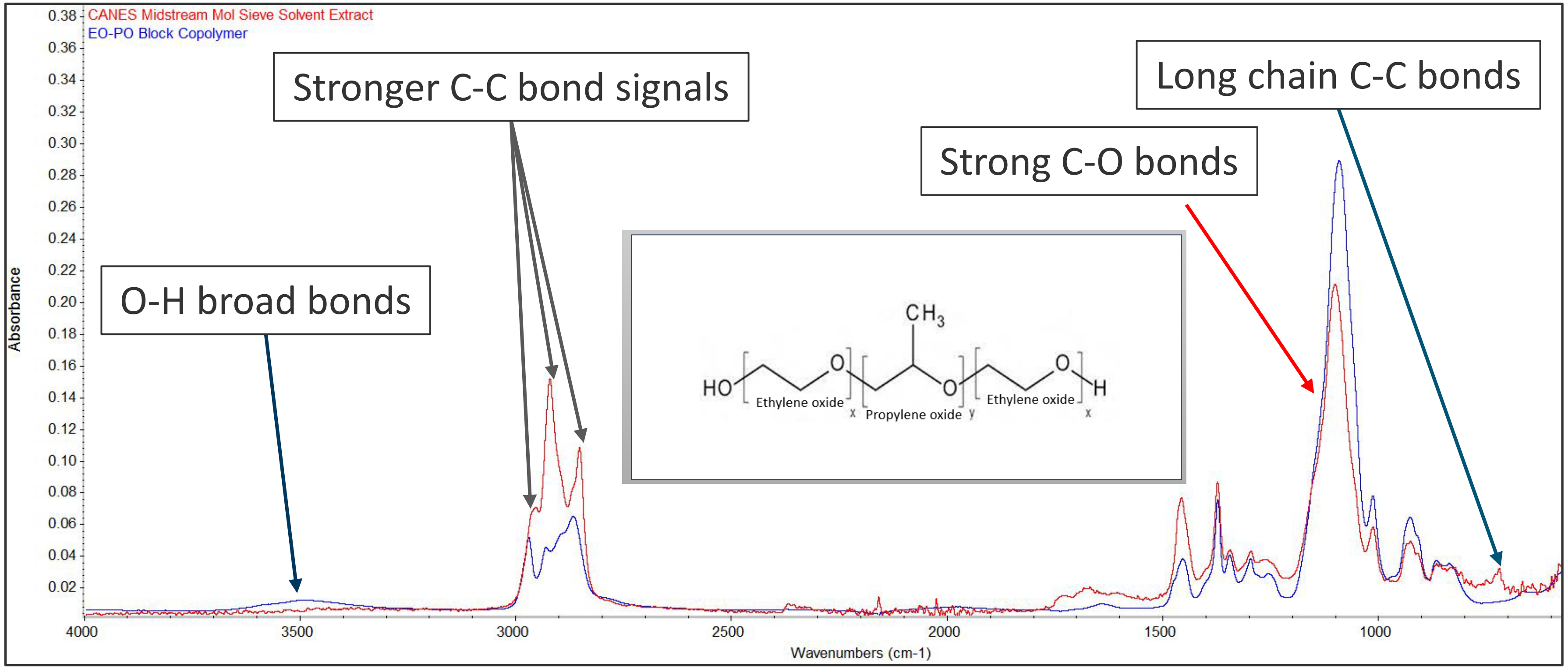


Spent molecular sieves extract residue

- The DCM was filtered to remove solid residues then poured onto a watch glass to evaporate the DCM.
- Once the DCM fully evaporated the extracted components remained on the watch glass.
- The extracted components were analyzed using Infrared Spectroscopy (IR) and microscopy.
- The extracted components consisted of viscous yellow liquids, and dark brown/black semi-solids.
- Lighter components will deposit on the outer portions of the watch glass, heavier components towards the center.

Material Identification

EO-PO Polymer



Cryogenic Gas Processing Challenges Troubleshooting

Case Studies

Common Operating Issues

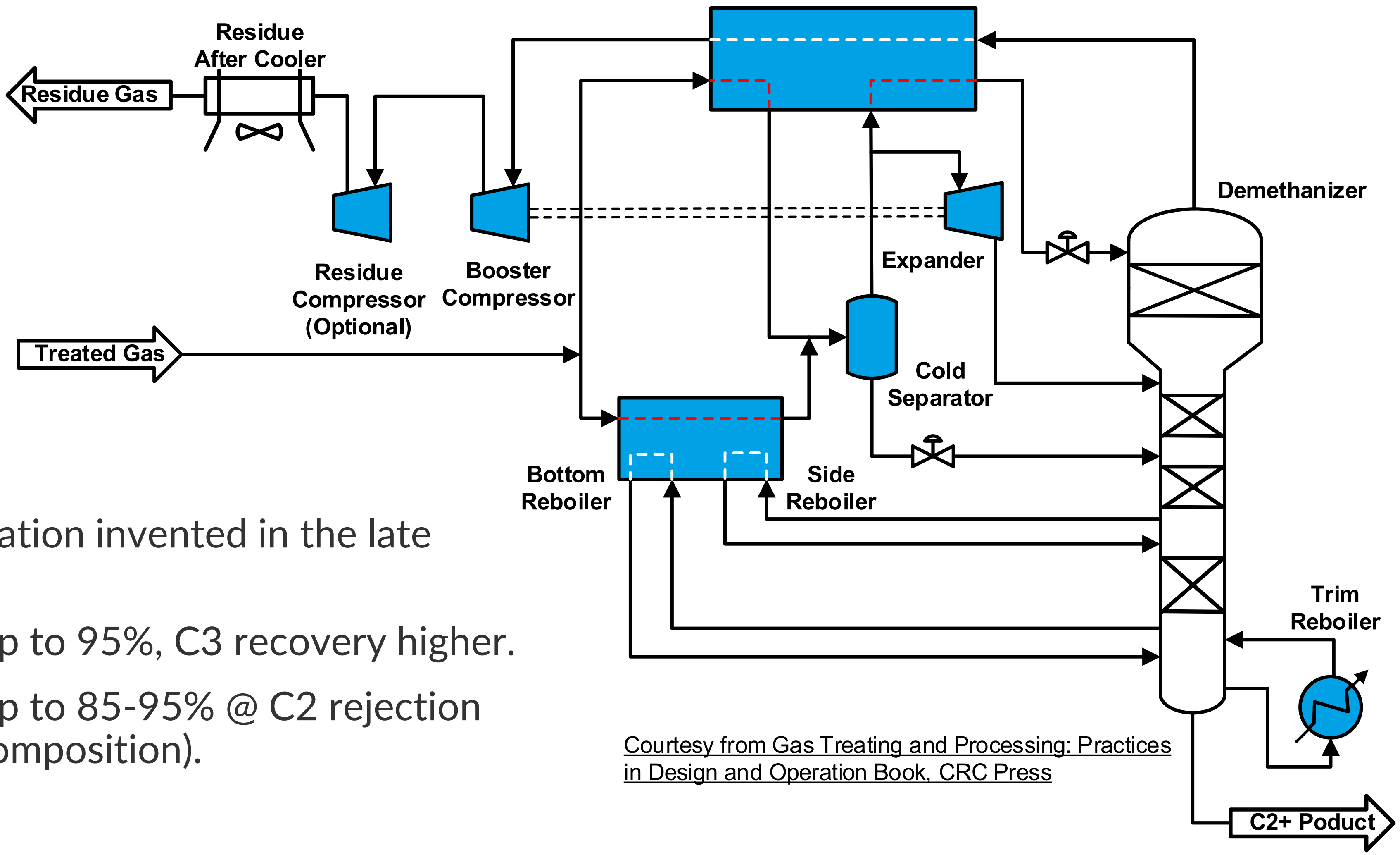
- Pretreatment operating issues before feeding to Cryo Unit and produce more NGL and LNG
- De-C1 performance and different mode of operations
- Freezing issues through cold boxes & De-C1 (CO_2 / BTEX / heavy hydrocarbon)
- Reduce the refrigeration system load

Common Capacity Limits for Cryo Plants

- Dehy Mole Sieves, especially in the summer
- Tower hydraulic limits, especially during rejection
- Residue Compression
  - Tower pressure: trade-off between recovery and capacity
- Expander
  - Different wheel designs
  - Utilizing more reflux (with sacrifice to recovery)
- Refrigeration
  - Typically, recovery limiting
- Exchangers
  - Typically, recovery limiting

Case Study 1 –
Process Selection Challenges

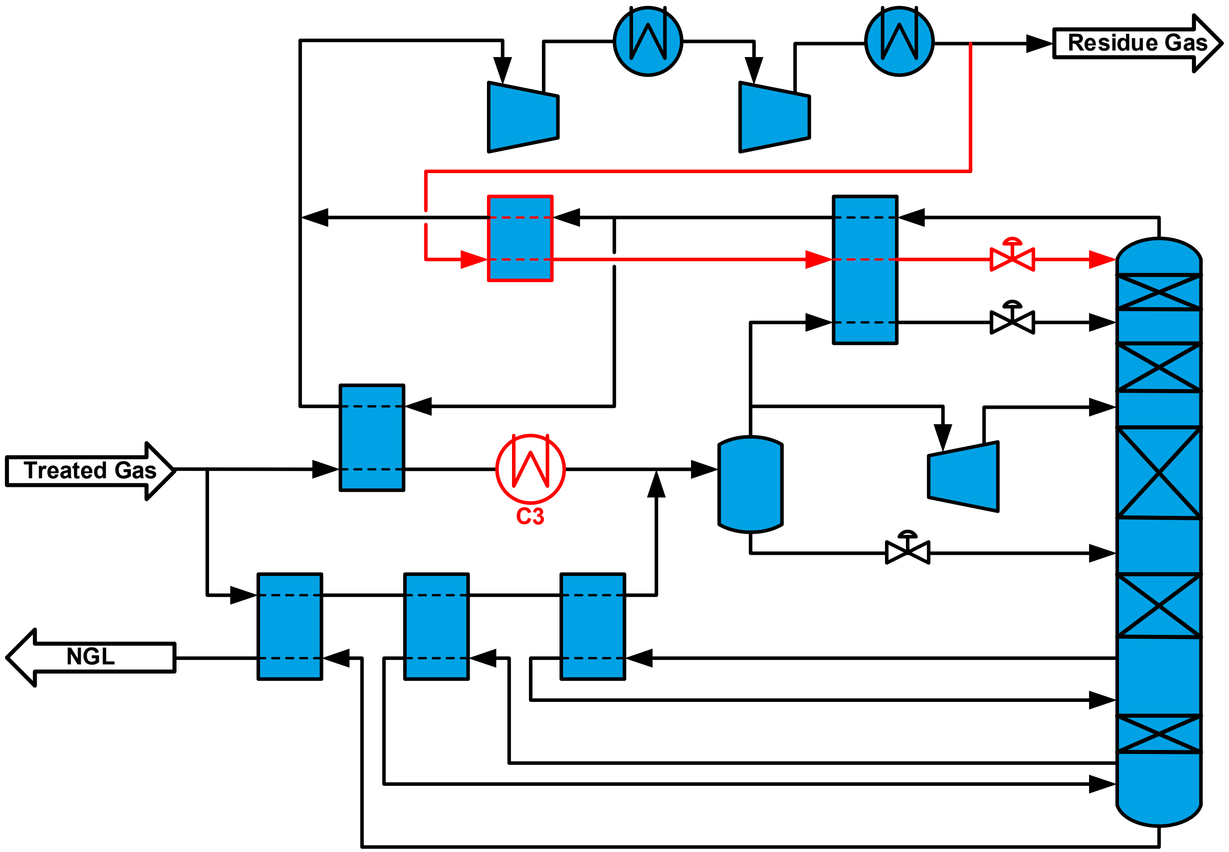
Gas Subcooled Process (GSP)



- The GSP process configuration invented in the late 1970s by Ortloff
- Achieves C2 recovery is up to 95%, C3 recovery higher.
- Achieves C3 recovery is up to 85-95% @ C2 rejection mode (depends on feed composition).

Courtesy from Gas Treating and Processing: Practices in Design and Operation Book, CRC Press

Recycle Split Vapor (RSV)



Courtesy from Gas Treating and Processing: Practices in Design and Operation Book, CRC Press

- RSV uses a portion of RG to obtain pure reflux.
- Achieves C2 recovery is greater than 98%, with higher C3 recovery.
- RSV can also operate in C2 rejection mode while maintaining high C3 recovery.
- The RG compressor is bigger due to RG recycle.
- Like GSP, in this mode it may need an additional trim reboiler.
- For heavy feeds, there may be a need for additional mechanical refrigeration, such as propane.

NGL Recovery Process Selection

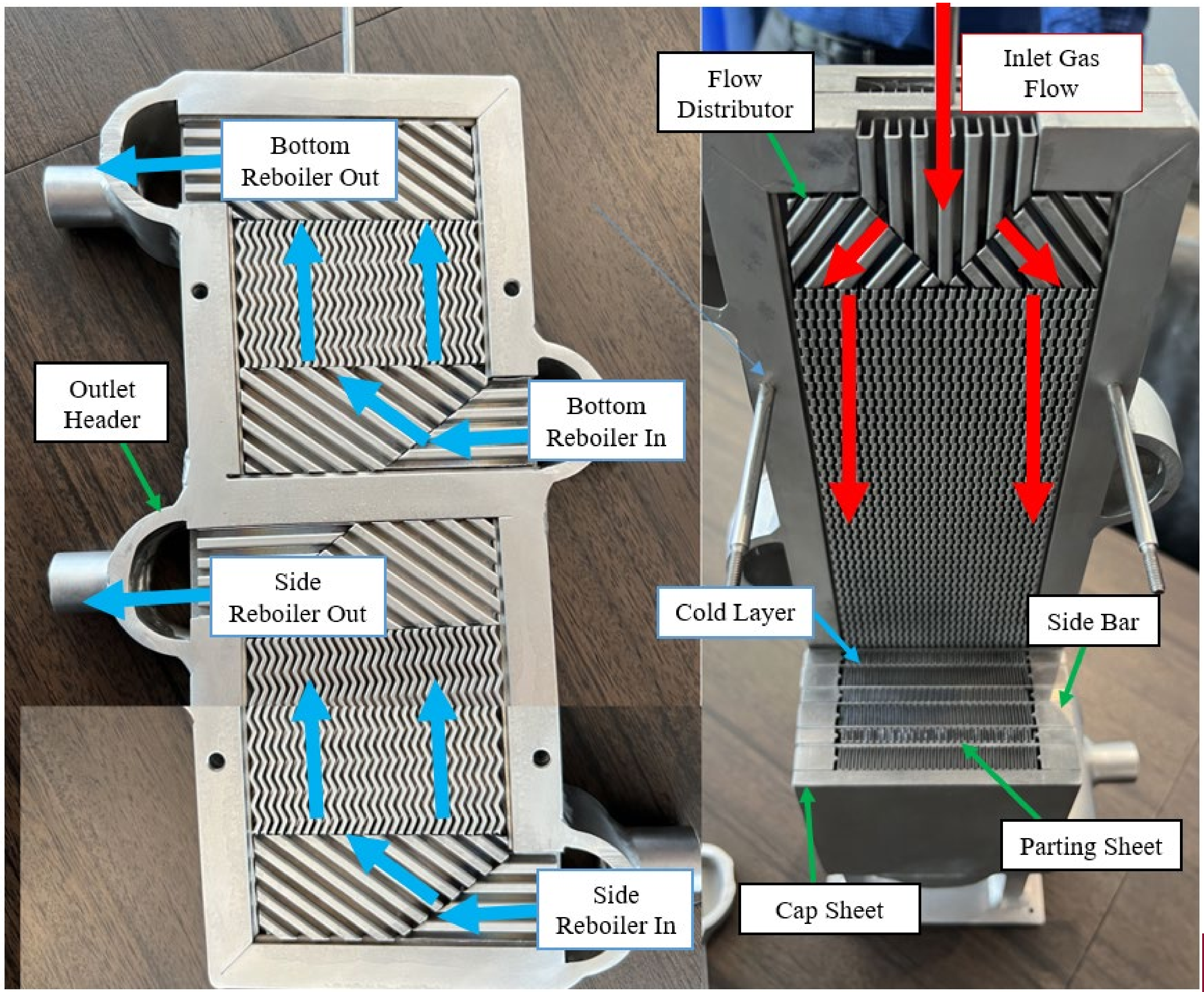
Process Design		GSP	RSV	Licensor
Feedstock				
Flow rate	MMSCFD		400	
Ethane content	mol%		~8.5%	
Propane content	mol%		~2.5%	
CO2 content	mol%		~0.20%	
Temperature	C		25	
Pressure	Barg		40	
Summary				
Ethane Recovery	%	0.50%	0.50%	0.50%
Propane Recovery	%	97.00%	97.00%	97.00%
RG Flow Rate	MMSCFD	385	385	385
Power				
Residue Gas Compressor	kW	**36,450**	**34,125**	**28,252**
CO_2 Emissions				
Metric Tons of CO_2 emissions per kWh		**25.8**	**24.2**	**20**

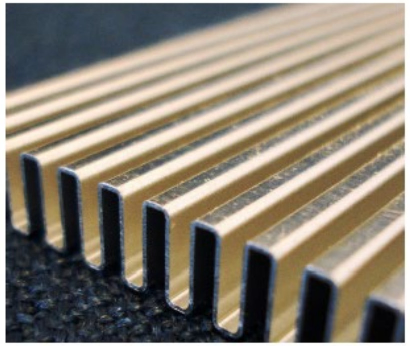
Case Study 2 – BAHX Failures

What is a BAHX?

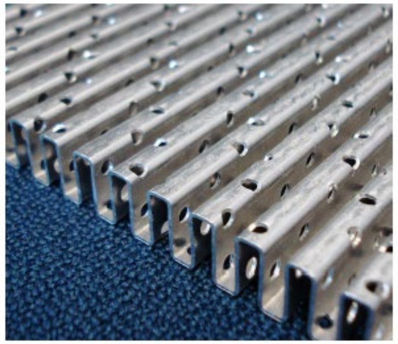
- Compact heat exchangers, sometimes also referred to as "Plate-Fin Exchangers"
- A "core" is made by stacking layers of corrugated fins separated by parting sheets
- The "core" is brazed in a furnace and sealed along the edges with side and end bars.
- Headers and nozzles are welded onto the brazed core
- Up to 10 streams in single unit
  - Counterflow
  - Crossflow

BAHX – A look inside

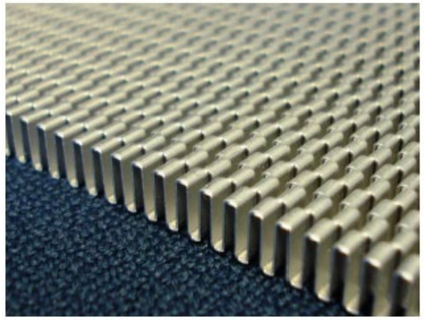




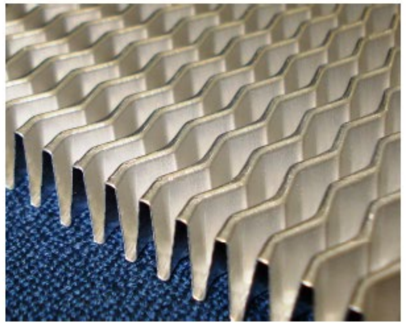
Plain fins



Plain-perforated fins



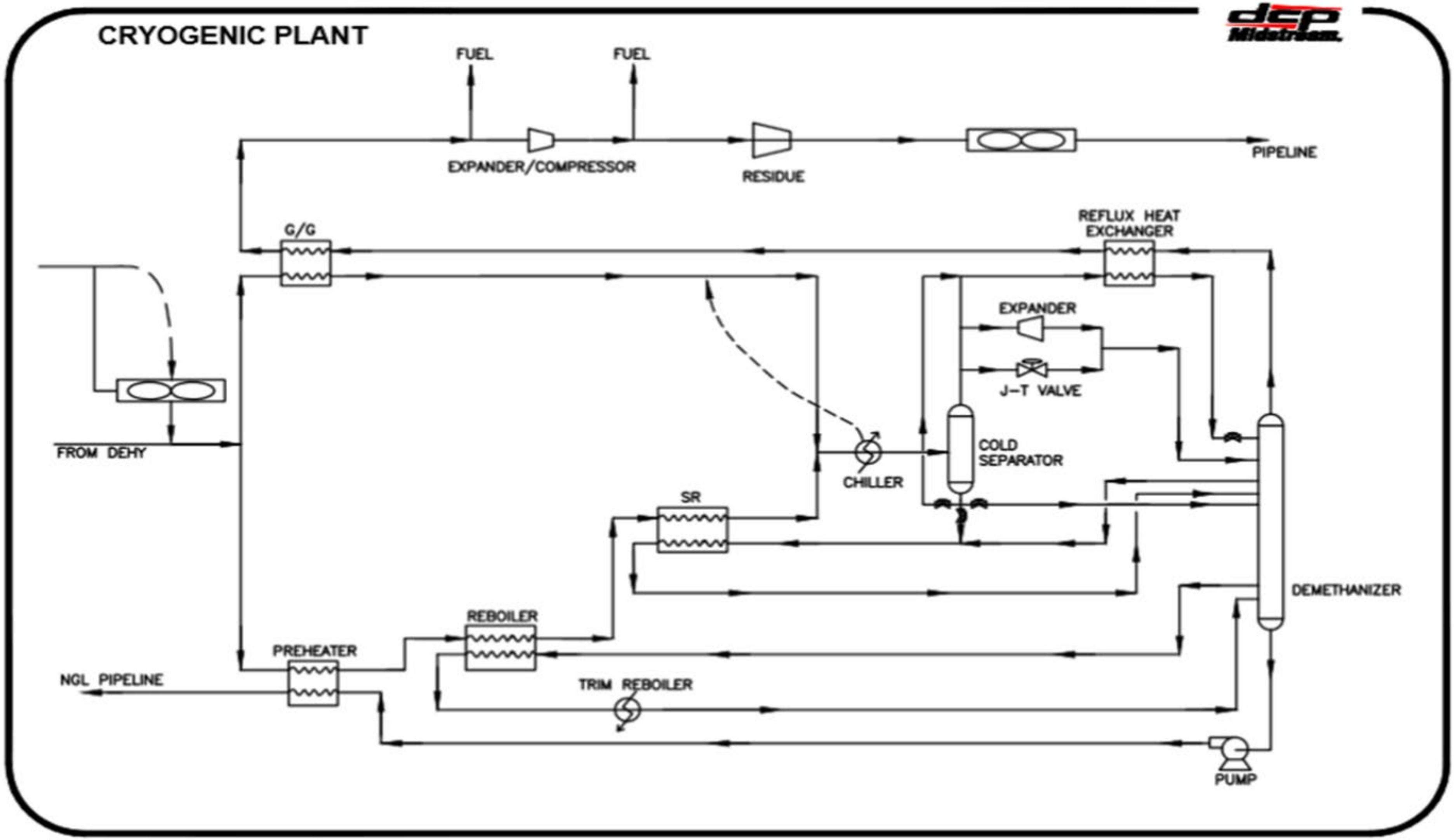
Serrated fins



Herringbone or wavy fins

Source (fin picture): The Standards of The Brazed Aluminum Plate-Fin Heat Exchanger Manufacturers' Association 4th edition, 2024

Where do we use BAHX?



Causes of Failure in BAHX

- Ice formation, most notably from pockets of water
- Chemical attack
  - Mercury: < 0.1 micrograms/Nm3
  - (12.2 parts per trillion (ppt)) mol Hg/mol gas
- Thermal fatigue
  - Temperature rate of change
  - Temperature differential
  - Maldistribution (fouling)

ALPEMA Recommendations:

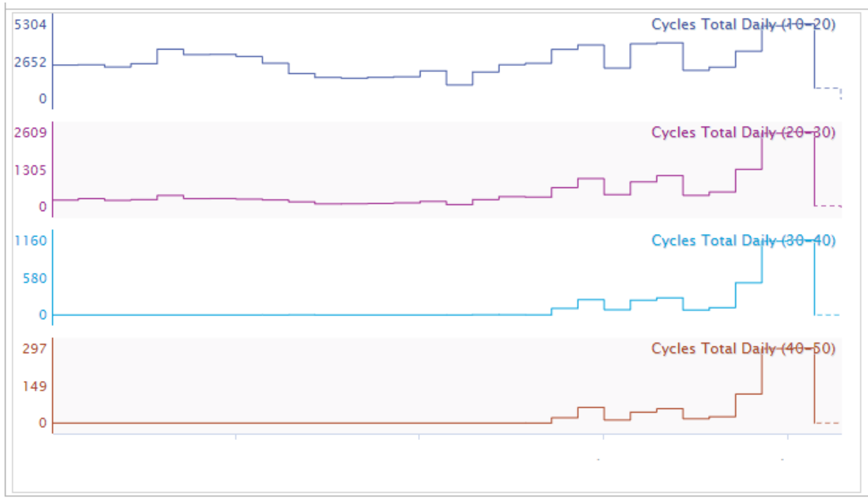
- 90°F max dT b/t adjacent single phase streams in SS operation
- 36-54°F max dT b/t adjacent two-phase or cyclic streams in SS operation
- ±1.8°F/min max rate of change in SS operation
- ±9°F/min max rate of change in transient operation and not to exceed 108°F/hour

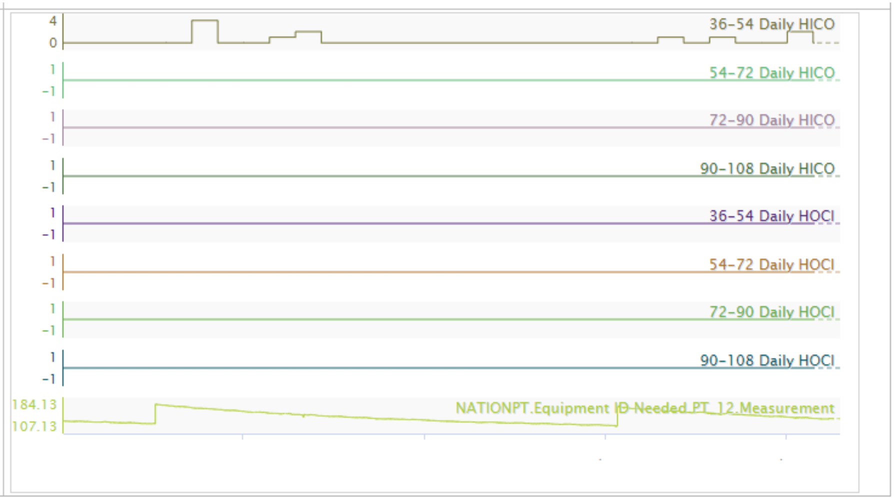
Transient operation:

- Startup / Shutdown
- Switching modes (recovery / rejection)
- Warmup / Cooldown

- Source: The Standards of The Brazed Aluminium Plate-Fin Heat Exchanger Manufacturers' Association, 4th edition, 2024
- ALPEMA® IOW for BAHX June 2025

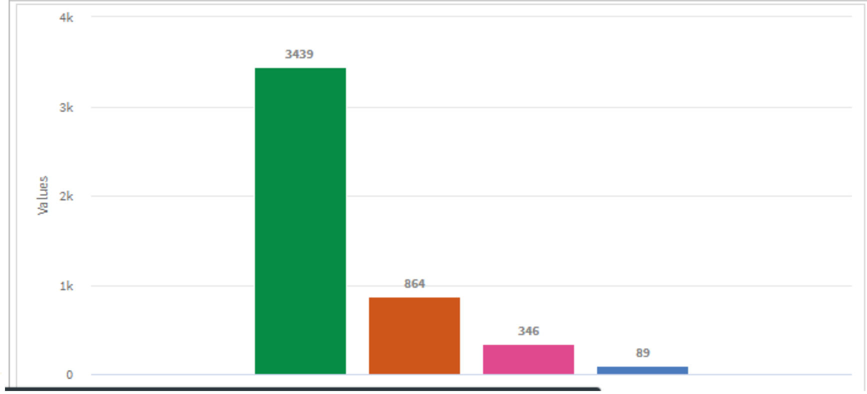
Thermal Fatigue Monitoring





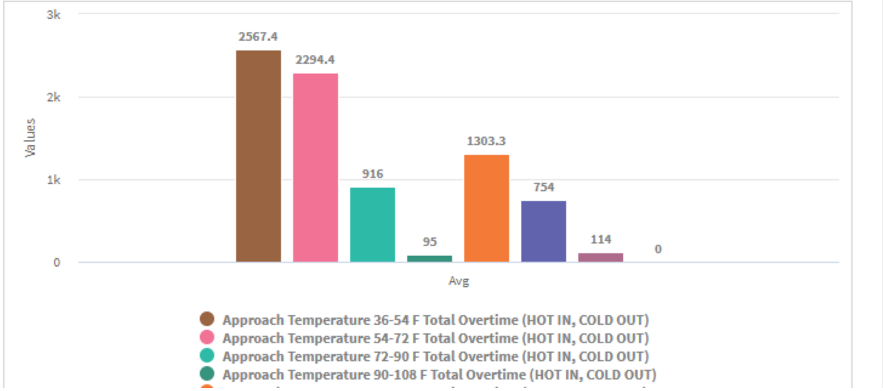
Total Cycle Counts [redacted]

NGL exchanger



Total Approach temperature counts [redacted]

NGL exchanger



Conditions Leading to Thermal Fatigue

Unstable thermosyphon hydraulics (slug flow)

Operation outside of design conditions

- Flow
- Composition

Swinging operations (rejection to recovery, compressor trips)

Technology Comparison

	BAHX	S&T	PCHE
Reasonable Min Approach Temp, °F	2-4 °F	15-30 °F	5-9 °F
Relative Equip Cost	1	1.5-2x	3x
Relative Weight	1	3.4x	1.4x
Advantages	• Compact • Low cost • Heat transfer efficiency • Weight	• Shorter delivery times • More suppliers • Not prone to thermal fatigue • Integrity not meaningfully impacted by off design operation • High design temperatures	• Compact • Less susceptible to thermal fatigue • Integrity not meaningfully impacted by off design operation • High design temperatures • Better heat transfer efficiency that S&T

Technology Comparison

	BAHX	S&T	PCHE
Reasonable Min Approach Temp, °F	2-4 °F	15-30 °F	5-9 °F
Relative Equip Cost	1	1.5-2x	3x
Relative Weight	1	3.4x	1.4x
Disadvantages	• Long lead time • Limited domestic suppliers • Integrity suffers with off design operation • Prone to plugging • Susceptible to mercury attack • More susceptible to damage from ice • Limited to 150°F	• Plot space • Lowest heat transfer efficiency, could impact refrig load or recoveries • Weight	• Unfamiliar technology to midstream • Cost • Long lead time • Limited suppliers • More at risk of plugging than S&T

When to Consider Alternative Heat Exchangers

GREENFIELD

BAHX in reboiler service and….

- It is planned to be a swing plant
- It is known that compositions will vary over time
- The plant may not always operate at design capacity
- Upsets / transients from sources upstream of the cryo unit are anticipated and cannot be avoided
- Strong desire to minimize risk
- Note: circumstances leading up to most failures were not anticipated at start of project

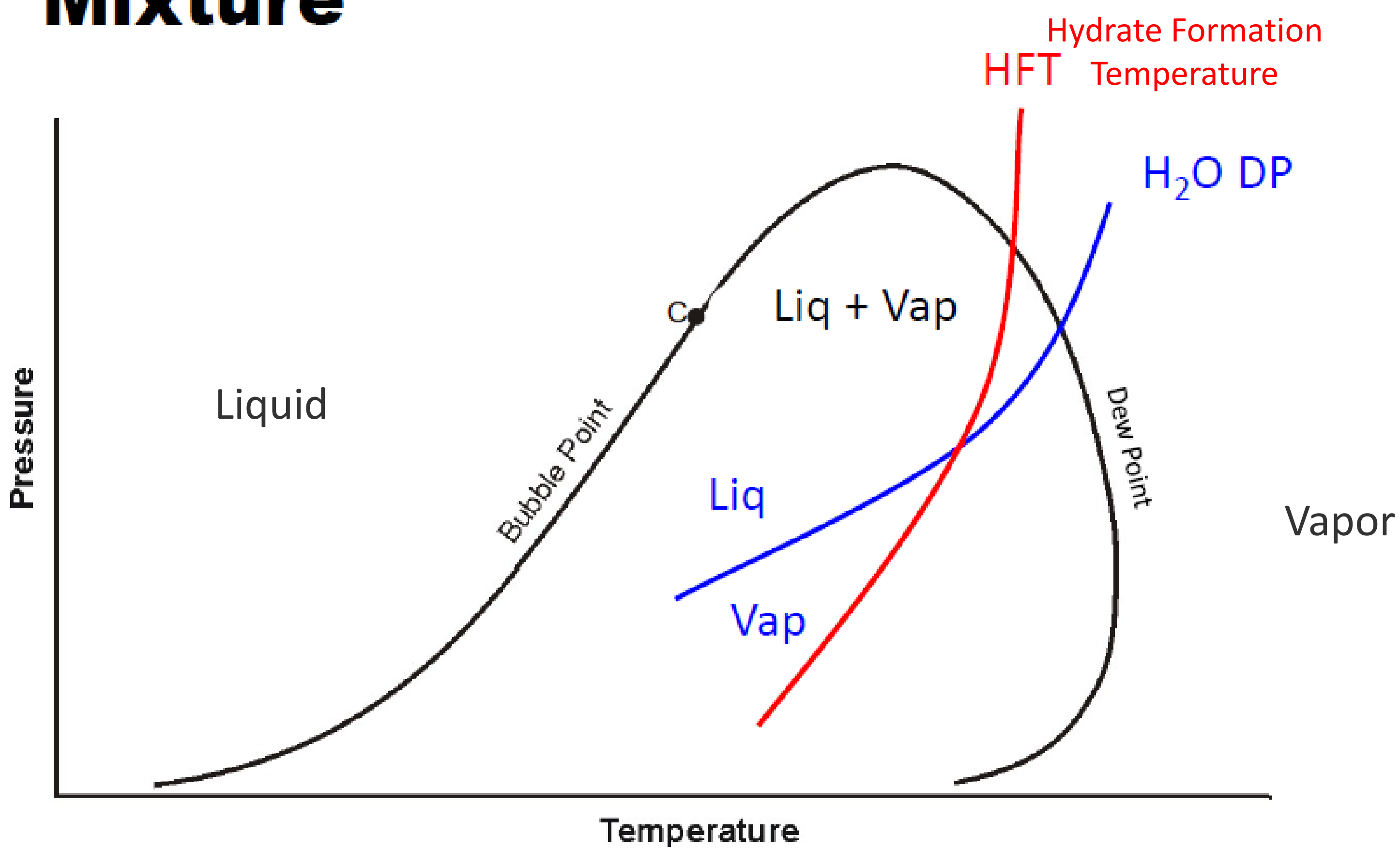
BROWNFIELD

- Failure(s) have occurred and
  - Conditions / physical design cannot be adjusted to avoid thermal fatigue
  - The composition or throughput will continue to differ from the original design
  - Regular upsets / transients cannot be avoided
- Alternatively, consider a spare BAHX

If none of these circumstances apply to your application,
BAHX are still an <u>excellent</u> choice for cryogenic NGL recovery plants.

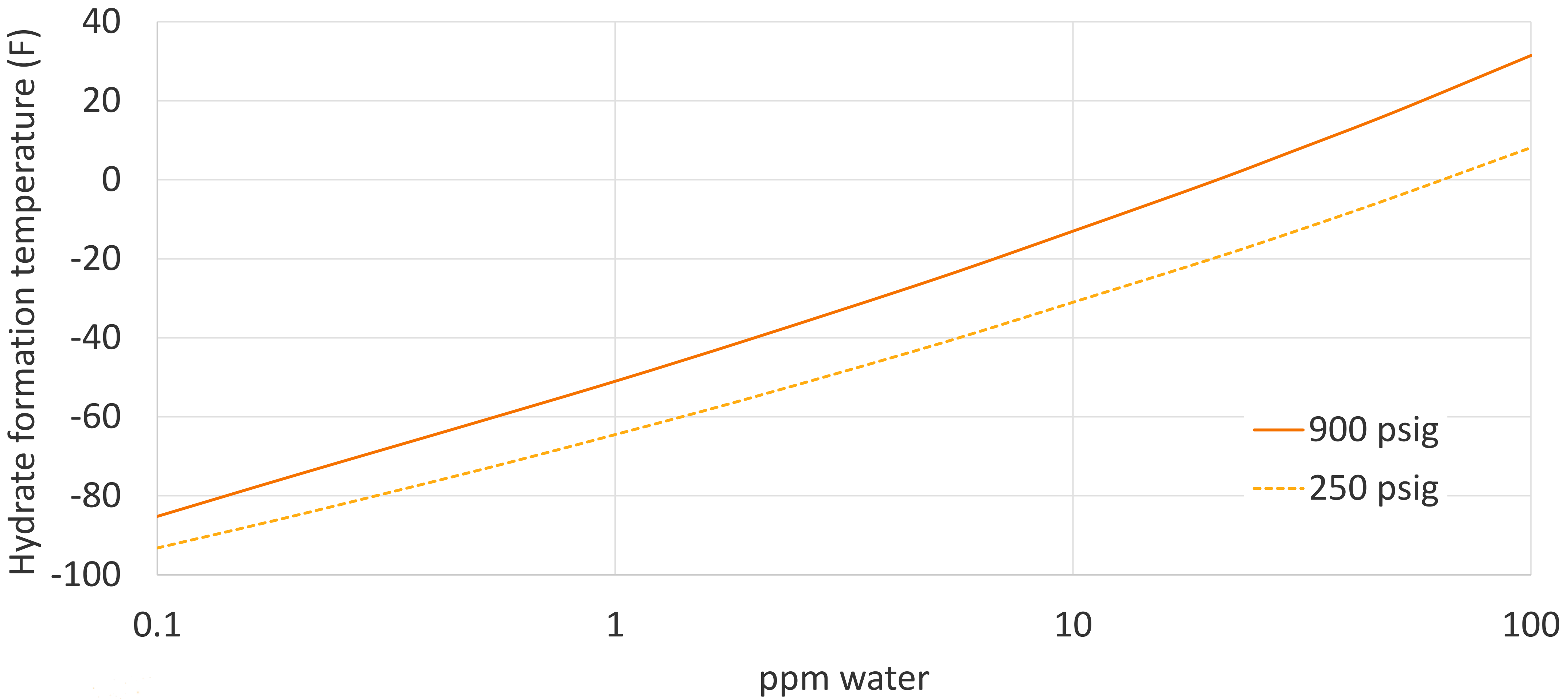
Case Study 3 – Freezing in the Cryo

Hydrate Formation of a Gas Mixture



Hydrates can form before water condenses

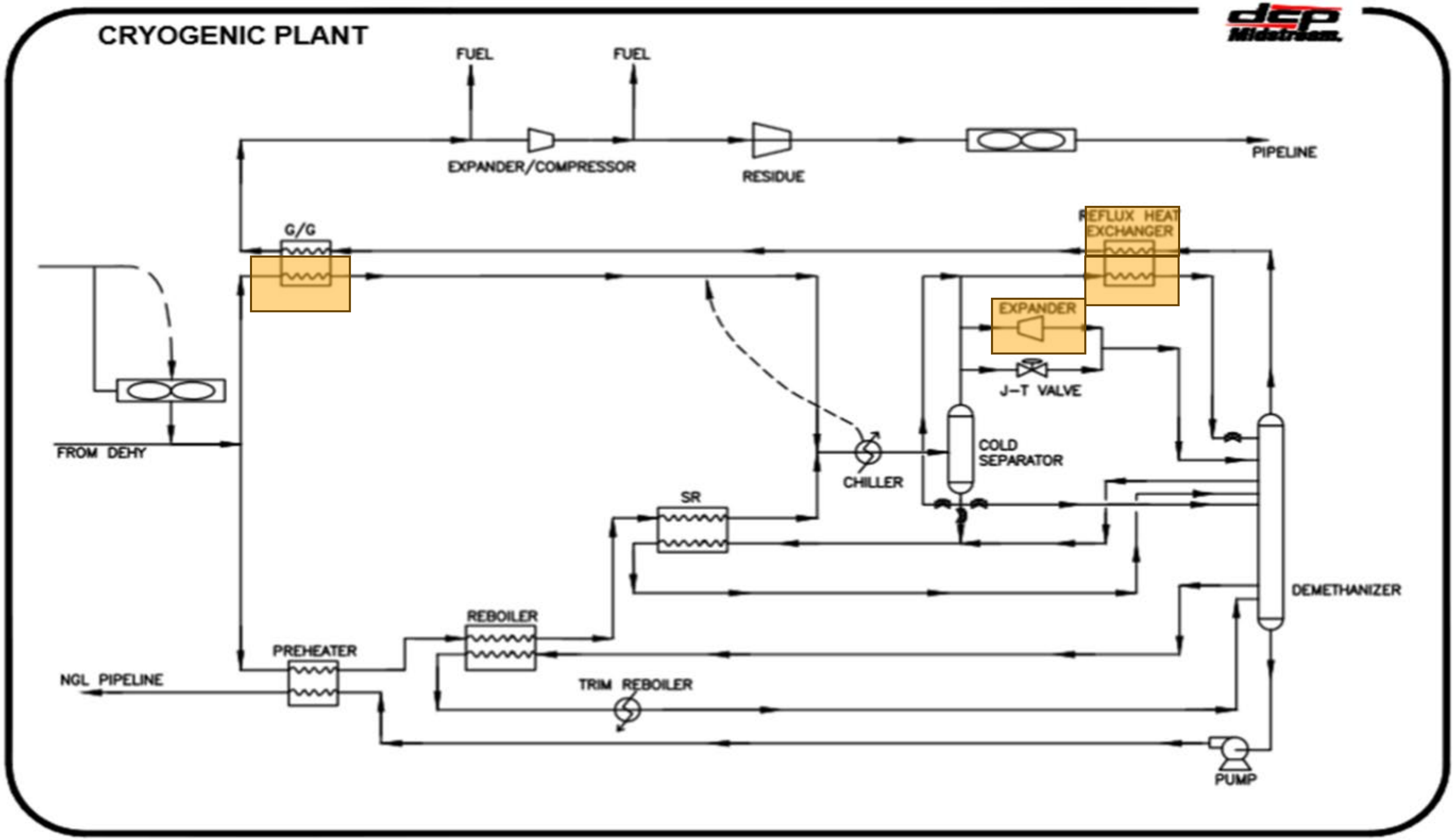
Hydrate Formation for a typical lean gas (2.25 GPM)



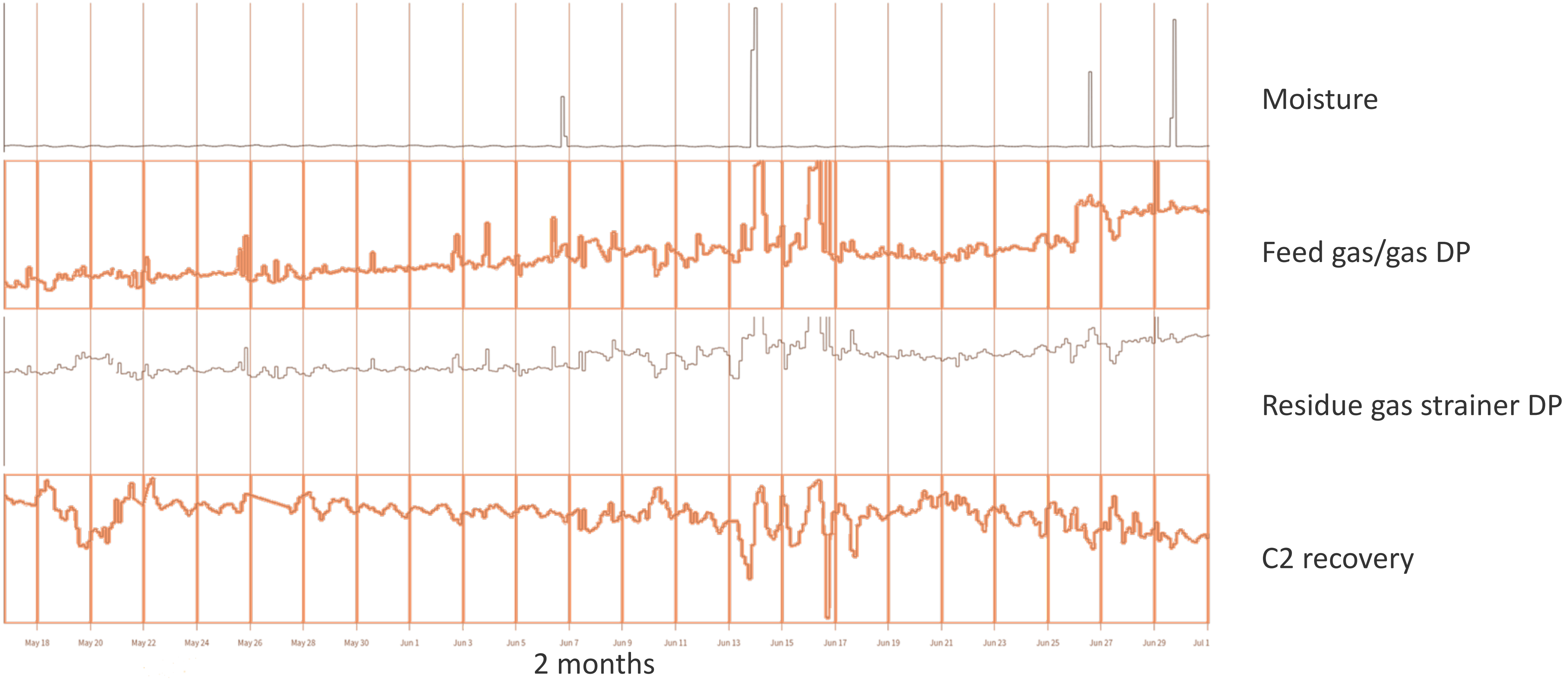
What is Our Target?

- Ideally <0.1 ppmv
- Aim for 1 ppmv max, which by experience we know usually doesn’t cause a problem, or maybe just a slow freeze
- Most moisture analyzers measure ppmv, and if they report dewpoint, it’s a conversion based on an extrapolation from dewpoint charts.
- NOTE: Dewpoint conversion is empirical, not adjusted for our exact gas composition and pressure. Often based on atm pressure and air. Dewpoint T is good for trends but not necessarily indicative of freezing T in cryo.
- The term “dewpoint” itself should cause some question – we are worried about solid formation, not liquid. Common industry terminology, but ppmv has no ambiguity.

How do we know there is a freeze?



How do we know there is a freeze?



How do we get rid of a freeze?

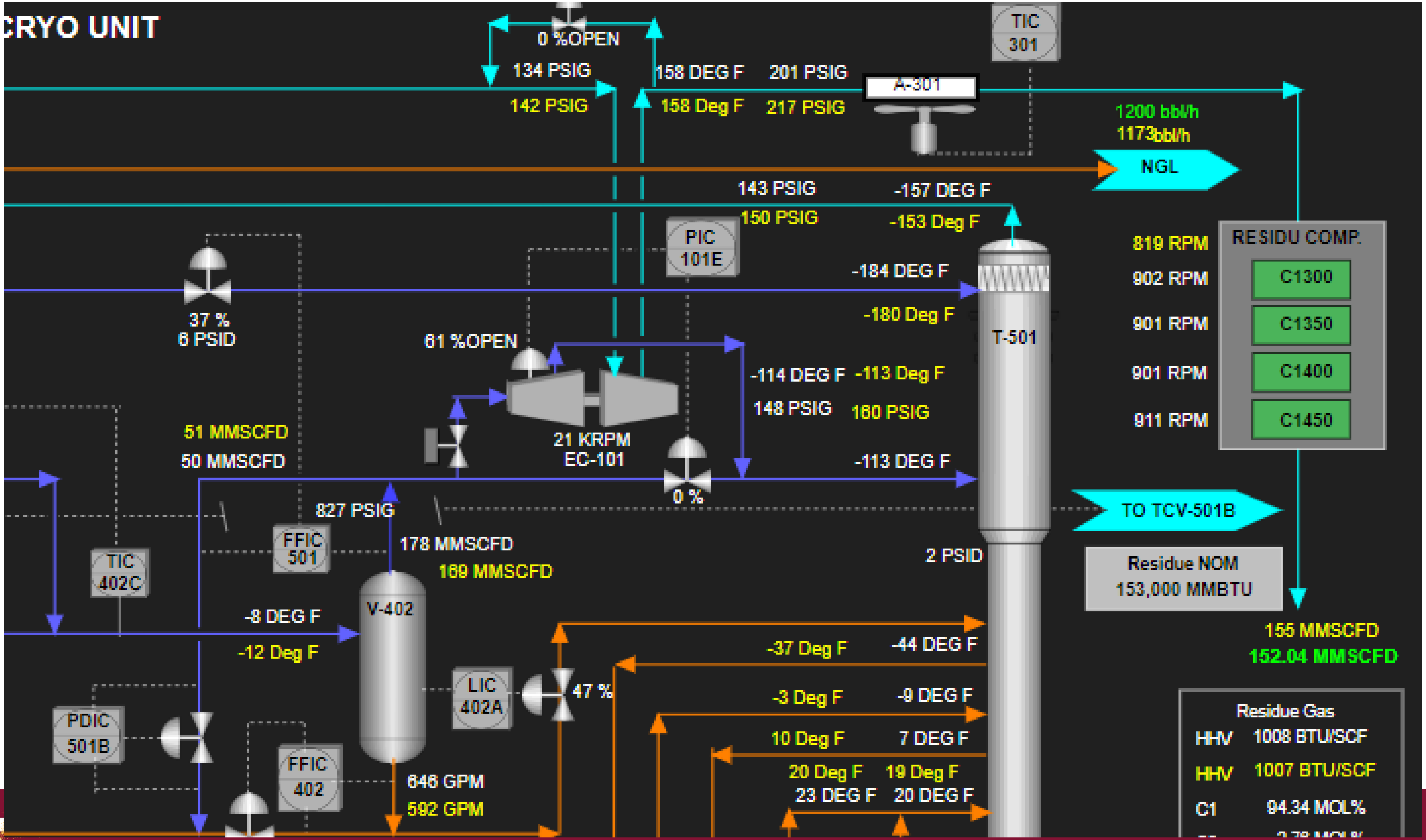
- Warm-up
  - Thorough dry-out requires 24-72 hour shutdown
- Inject methanol
  - Methanol freezes at -144 °F
  - NGL methanol spec is typ. 200 ppmw
  - Will move the hydrates to a colder point
  - Eventually water will exit via NGL or residue gas (see also Energy Transfer presentation at GPA 2023)

Case Study 4 – Turboexpander Guide Vanes Challenges

Simulation Setup

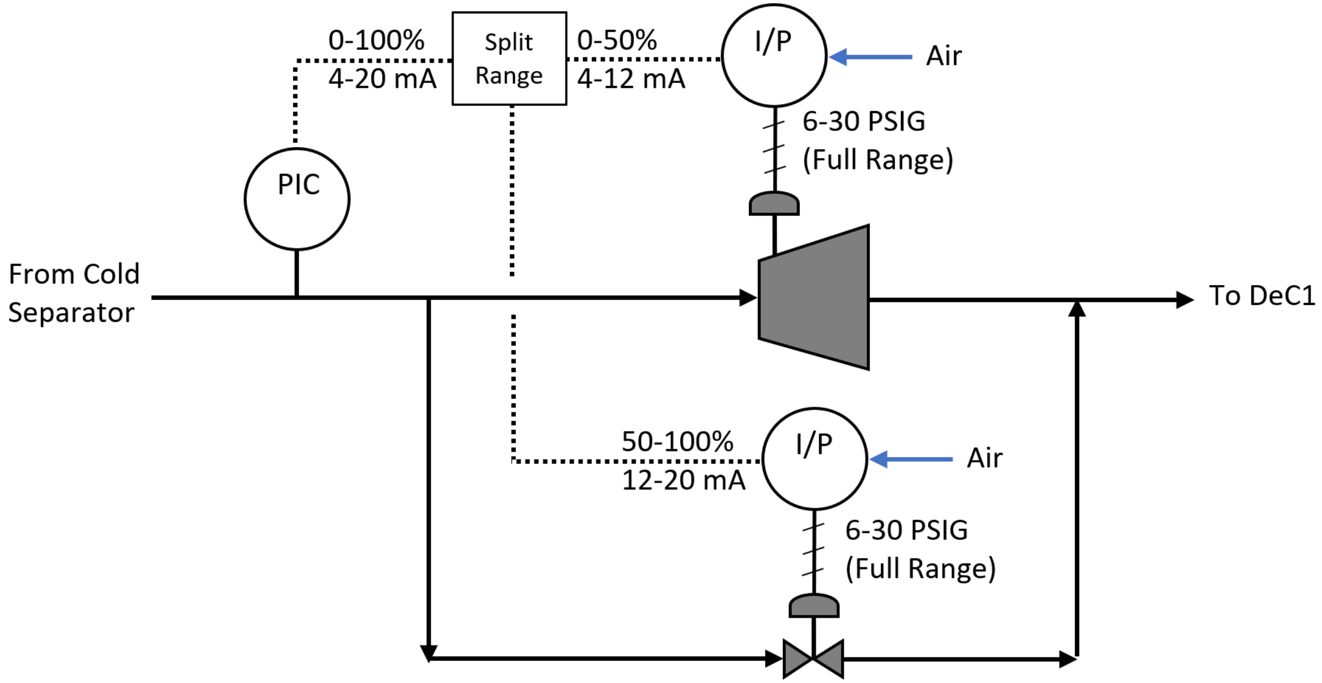
- Every cryo plant has a representative simulation continuously running in the background
- The process simulation predicts plant performance based on
  - Feed gas rate
  - Feed gas composition
  - Feed gas temperature and pressure
  - Ambient conditions
  - Plant engineering data (e.g., expander/compressor curves)

ICC PI Screen with Simulation Data

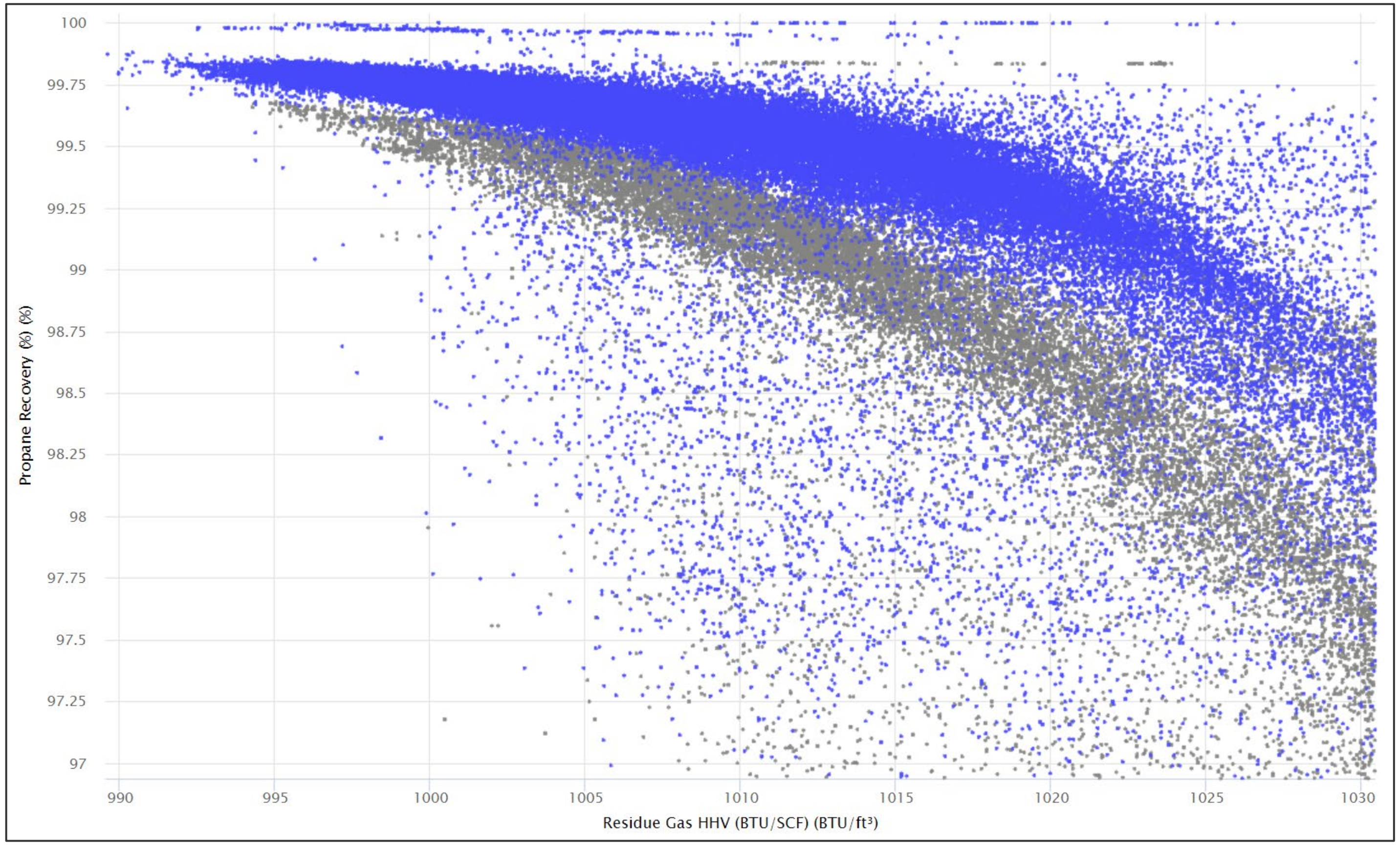


Example – Turboexpander Guide Vane Control

- Plant operates with turboexpander and JT valve on upstream pressure control and split range



Example – Turboexpander Performance



- Propane recovery improved by as much as 1% after correcting the guide vane control system, and allowed for deeper recovery overall

Case Study 5 – Recovery Optimization Challenges

Recovery optimization for a GSP plant variables

- Tower pressure
- Reboiler duty
- Feed temperature (i.e. cold separator temperature)
- Cryo inlet pressure

Demethanizer Pressure

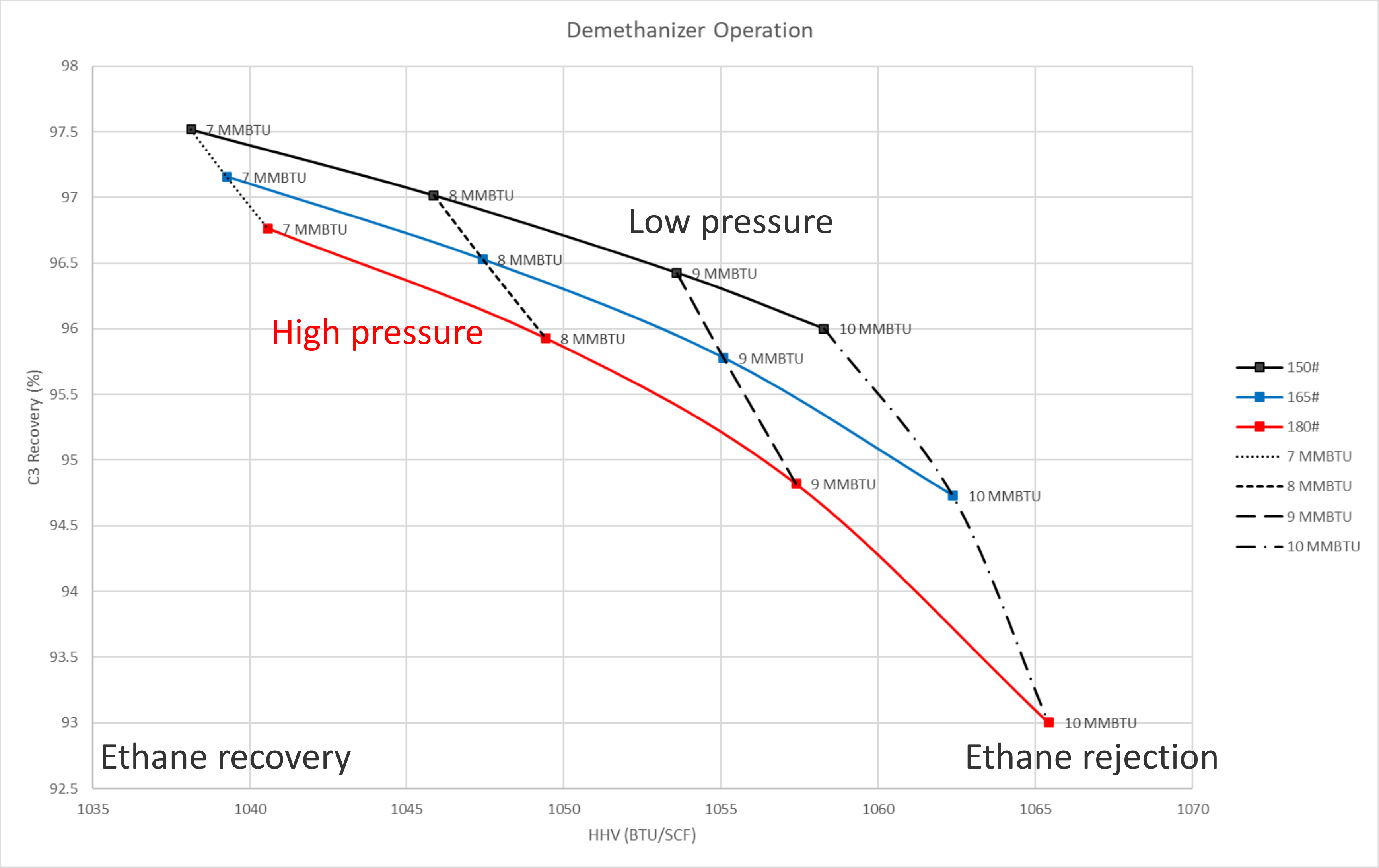
Higher Pressure

- Less chance of CO_2 freezing b/c warmer
- Less residue compressor horsepower

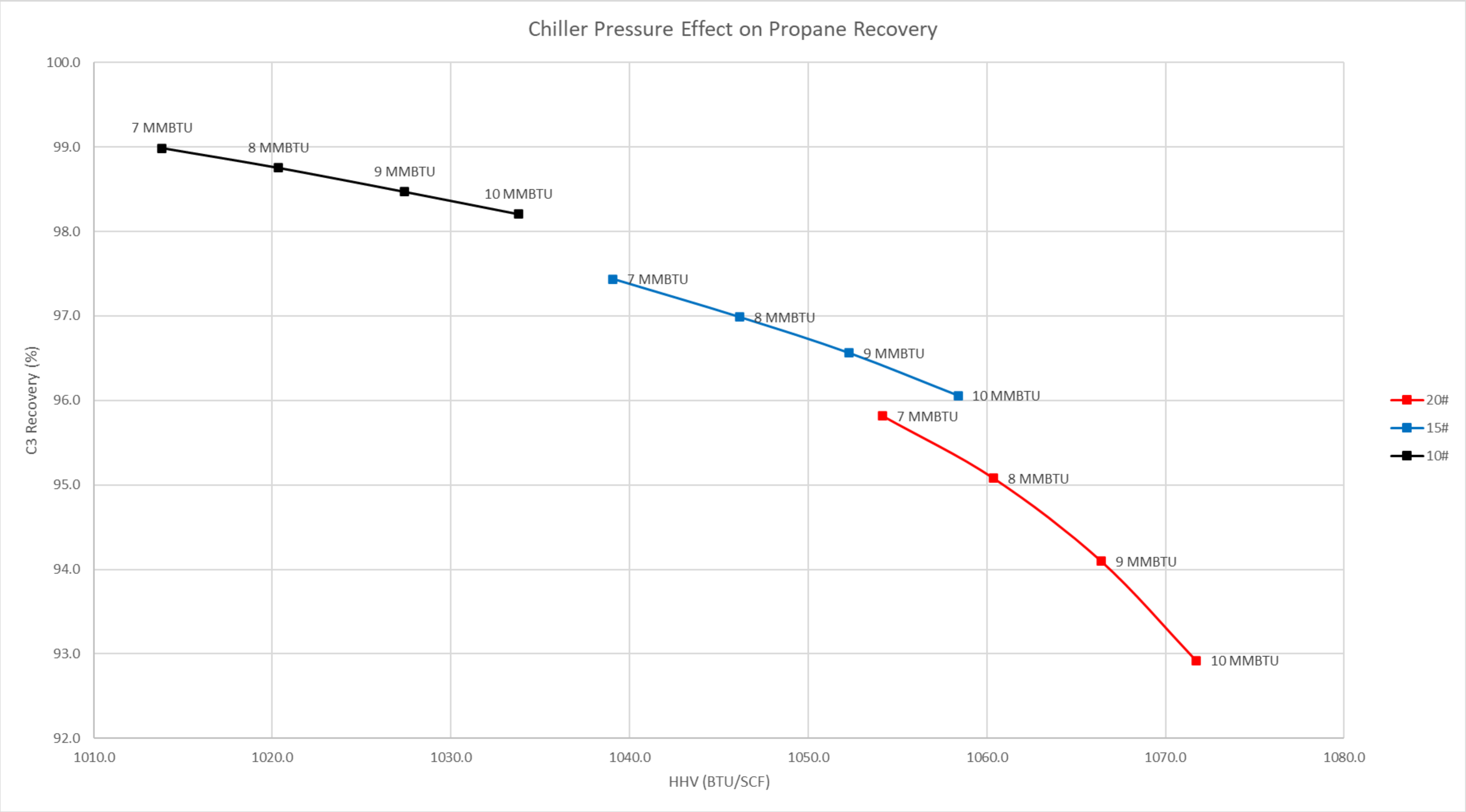
Lower Pressure

- Better split between C1 and C2
- Better split between CO_2 and C2
- Better split between C2 and C3
- More expander power
- Colder operation

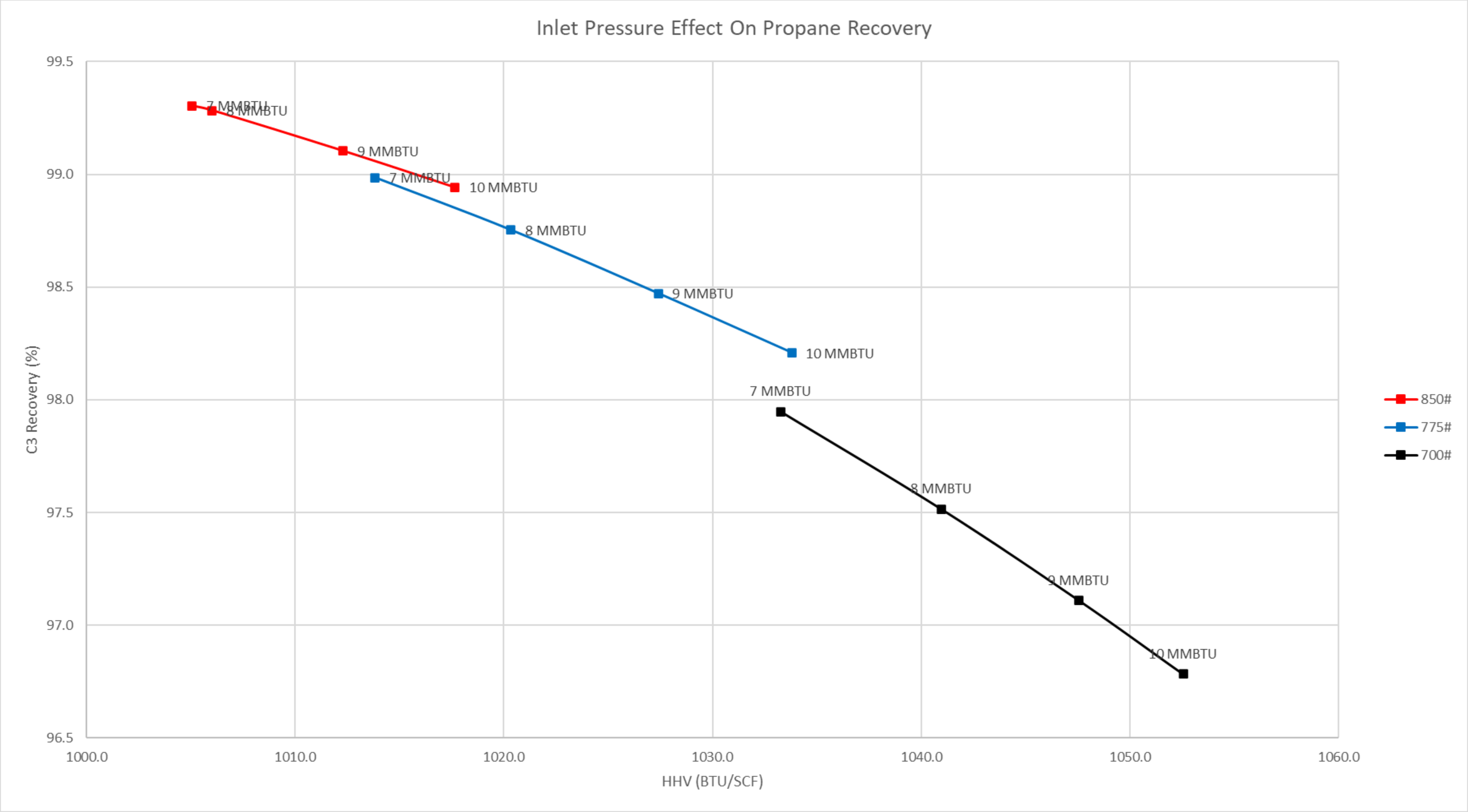
Demethanizer pressure



Chiller pressure



Inlet pressure



Cryo optimization

Targets

- Operate the Demethanizer tower at lowest possible pressure
- Operate the propane chiller at the lowest possible pressure
- Operate at the highest possible inlet pressure

Constraints

- Residue compression
- Refrigeration compression
- Inlet compression
- Tower and reboiler hydraulics

Case Study 6 –
NGL Recovery: Change of Operation Mode Challenges

Change of Operation Mode

Challenge Faced

- Client wanted to increase the gas plant performance (more profit)
- Client wanted to save energy:
  - No ethane demand
  - Deep ethane recovery system

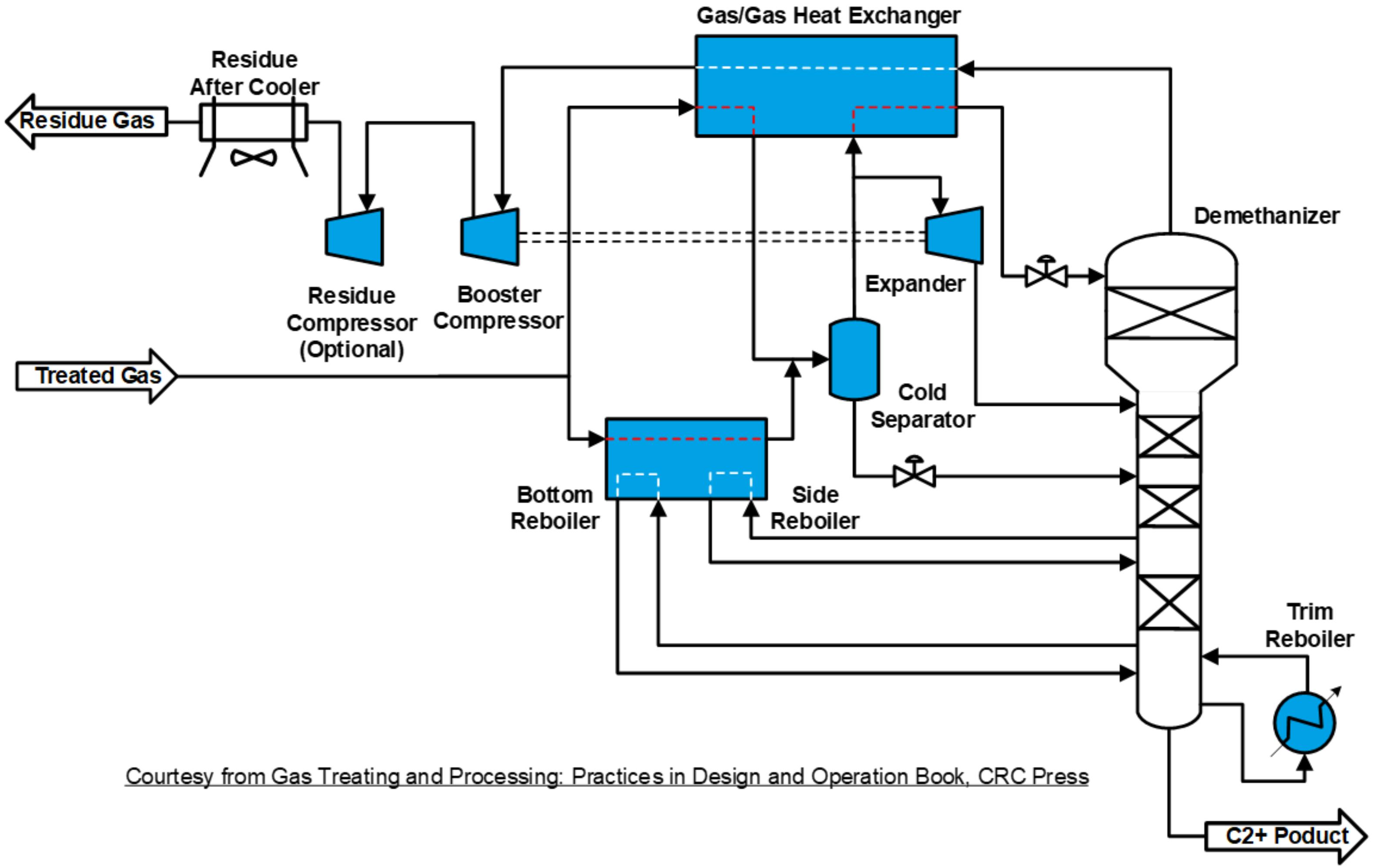
Our solutions

- Analyzed plant performance at different modes of operation
- Developed simulation models for C2 recovery and C2 rejection modes
- Changed the mode of operation from deep C2 recovery to C2 rejection
- Proposed the appropriate level of ethane rejection
- Identified operating issues for client

Value delivered

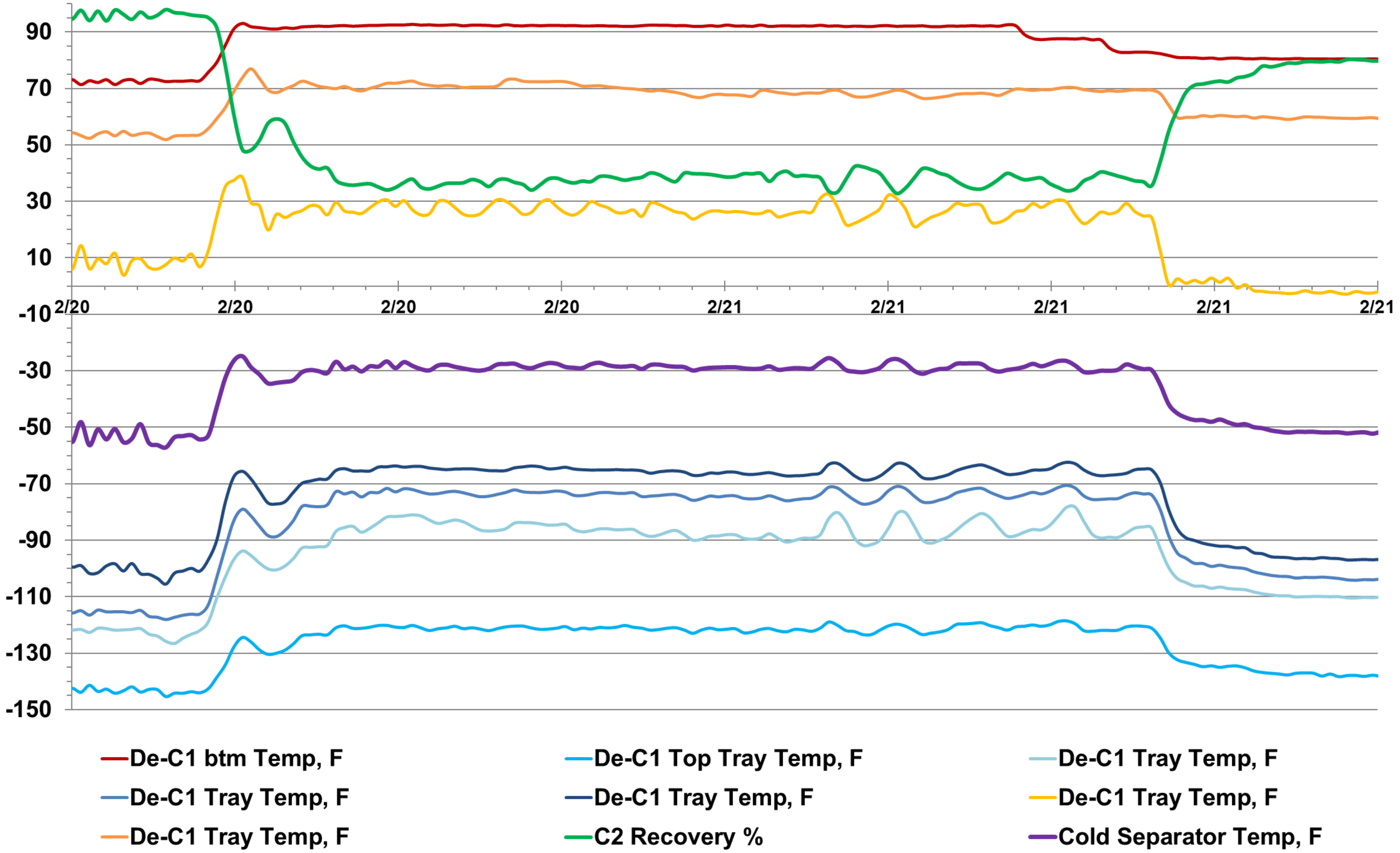
- Changed the mode of operation successfully with on-spec residue gas and NGL
- Resolved the CO_2 freezing in top of the demethanizer
- Reduced the refrigeration system load

Change a Mode of Operation – GSP



Courtesy from Gas Treating and Processing: Practices in Design and Operation Book, CRC Press

Plant Data (Transition Mode of Operation)



NGL Fractionation Challenges Troubleshooting

Case Studies

Common Operating Issues

- High NGL feed quality variation to NGL fractionation
- Columns performance: off spec products (concentration and purity)
- High equipment downtime
- High energy consumption

Challenges

- Increase further throughput
- Handle various feedstock impurities
- Save energy
- Reduce production cost

Case Study 1 –
Process Selection Challenges

Deethanizer

Description	Unit	Designer A	Designer B	Designer C
Diameter	mm	4100/6100	**4200**	4419/5486
Length	mm	29,500	46,000	36,576
No of Tray	#	36	51	45
Top Temperature	degC	3.1	5.5	-5.3
Top Pressure	Barg	25.7	28.5	22.4
Bottom Temperature	degC	108.4	113.4	98.3
Bottom Pressure	Barg	25.9	29.4	22.6
Reboiler Duty	kW	29,898	**26,455**	28,172
Condenser Duty	kW	12,001	10,390	**9,084**
Shell Weight	Tone	296	**226**	255

Depropanizer

Description	Unit	Designer A	Designer B	Designer C
Diameter	mm	5100	3400	4752/5334
Length	mm	32,000	49,000	36,576
No of Tray	#	41	56	45
Top Temperature	degC	60.7	60.0	60.7
Top Pressure	Barg	20.5	20.6	20.8
Bottom Temperature	degC	149.8	145.2	146.7
Bottom Pressure	Barg	20.9	21.5	20.9
Reboiler Duty	kW	20,460	15,642	19,824
Condenser Duty	kW	17,520	16,953	18,316
C3 Pump Capacity	m3/hr	140	N/A	130
Shell Weight	Tone	196	133	246

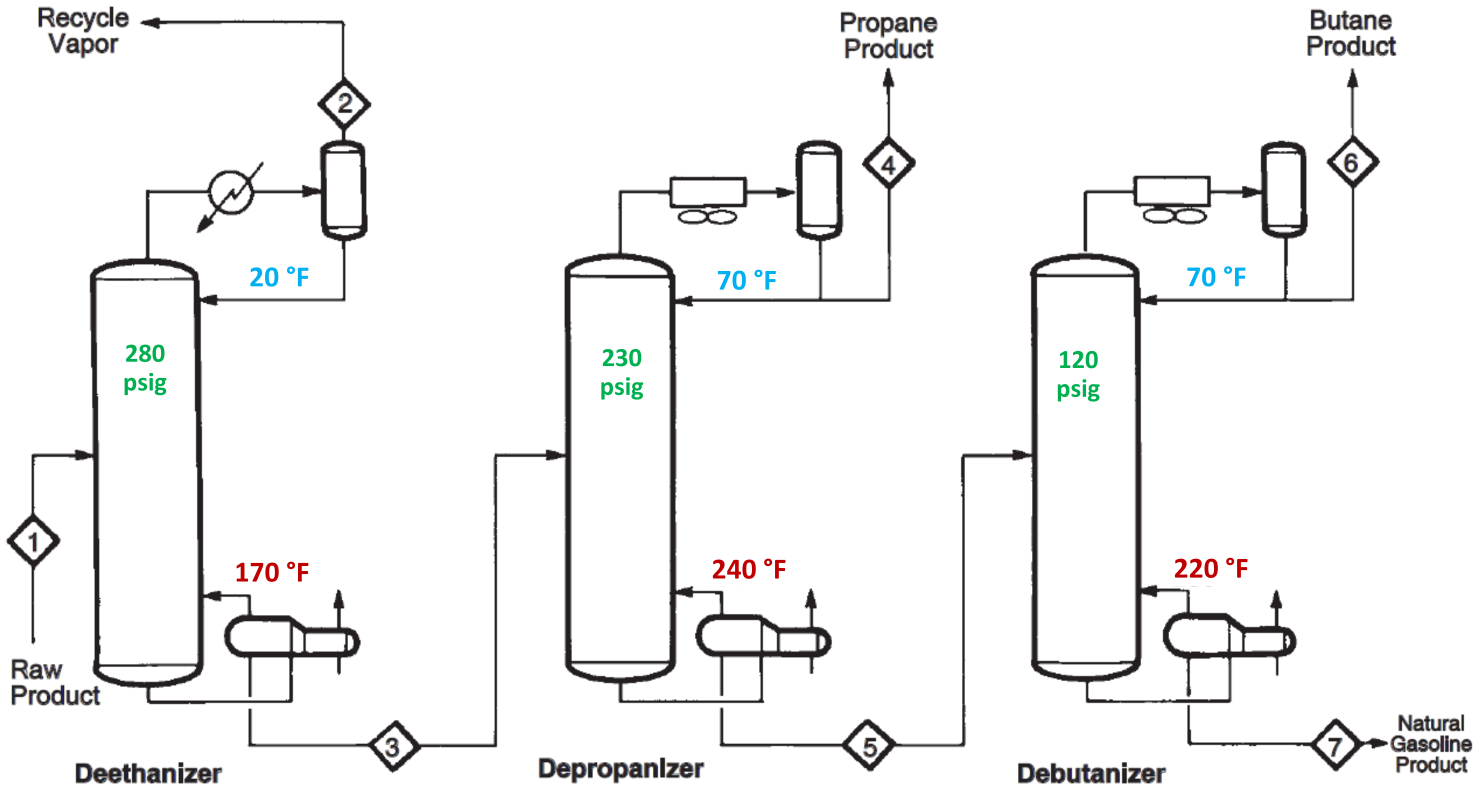
Debutanizer

Description	Unit	Designer A	Designer B	Designer C
Diameter	mm	2900	**2500**	3048
Length	mm	32,100	38,000	27,432
No of Tray	#	40	41	35
Top Temperature	degC	59.5	59.7	43.3
Top Pressure	Barg	6.3	6.4	6.6
Bottom Temperature	degC	143.9	137.6	135.0
Bottom Pressure	Barg	6.8	7.2	6.6
Reboiler Duty	kW	8,624	**6,941**	8,007
Condenser Duty	kW	11,120	**10,984**	11,710
C4 Pump Capacity	m3/hr	84	N/A	80
Shell Weight	Tone	38.5	**35**	38

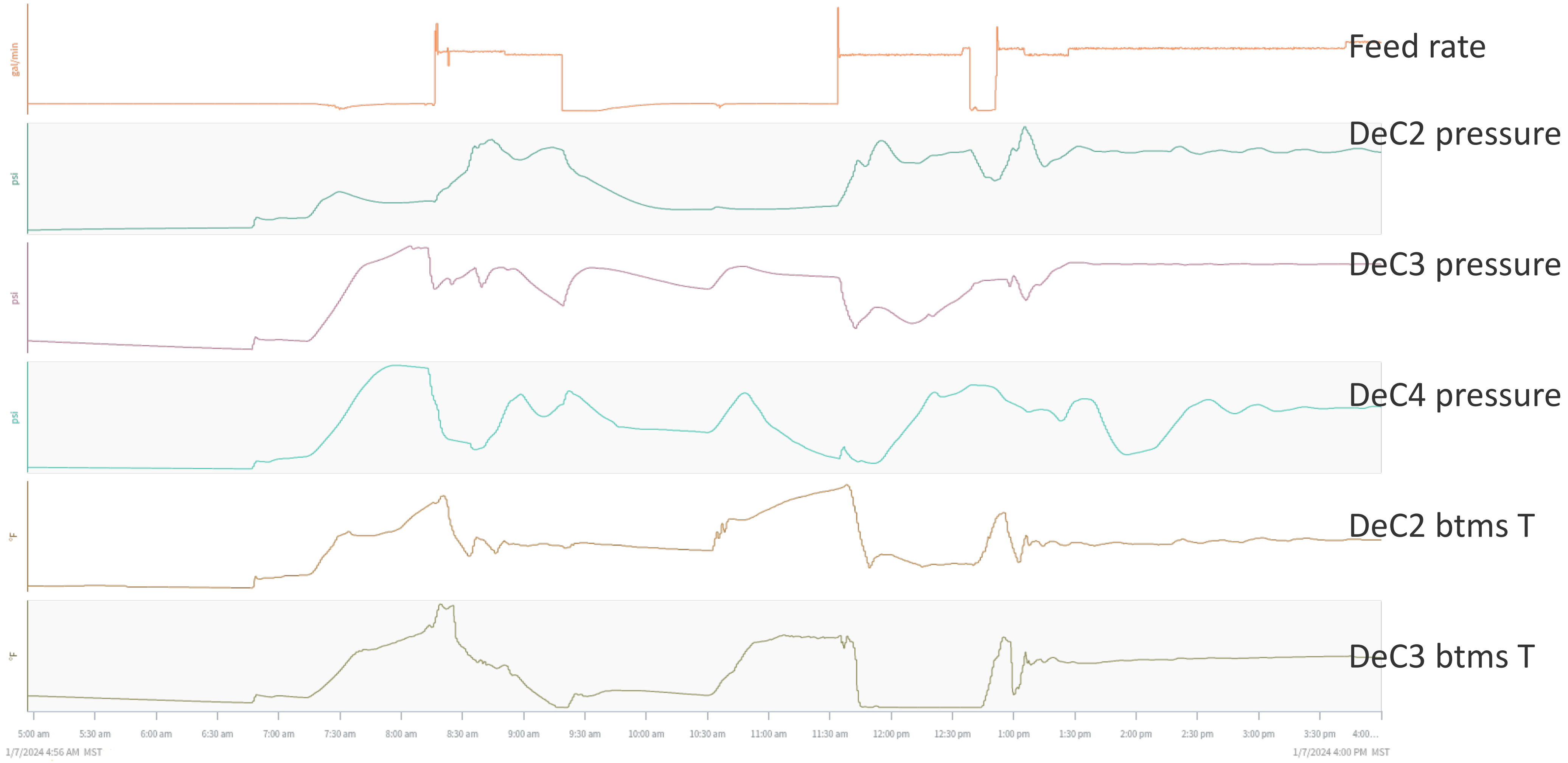
Case Study 2 –
Frac Unit Power Failure

Frac unit power failure

- Separate NGL into
  - Ethane
  - Propane
  - Isobutane
  - Butane
  - Natural Gasoline



Restarting after a power failure



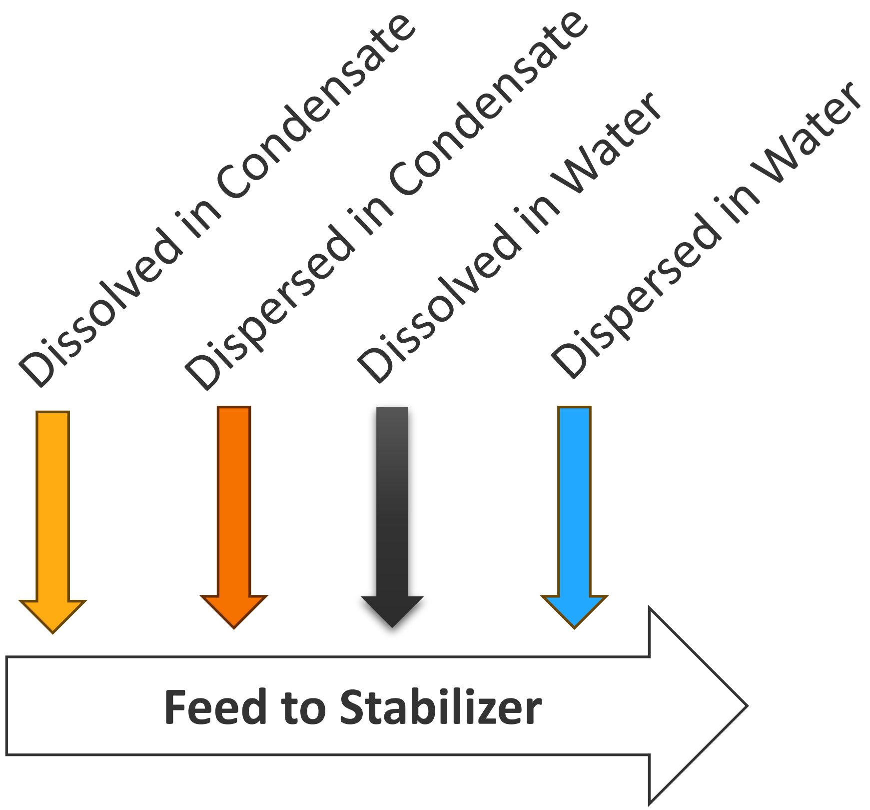
Condensate Stabilization Challenges Troubleshooting

Case Studies

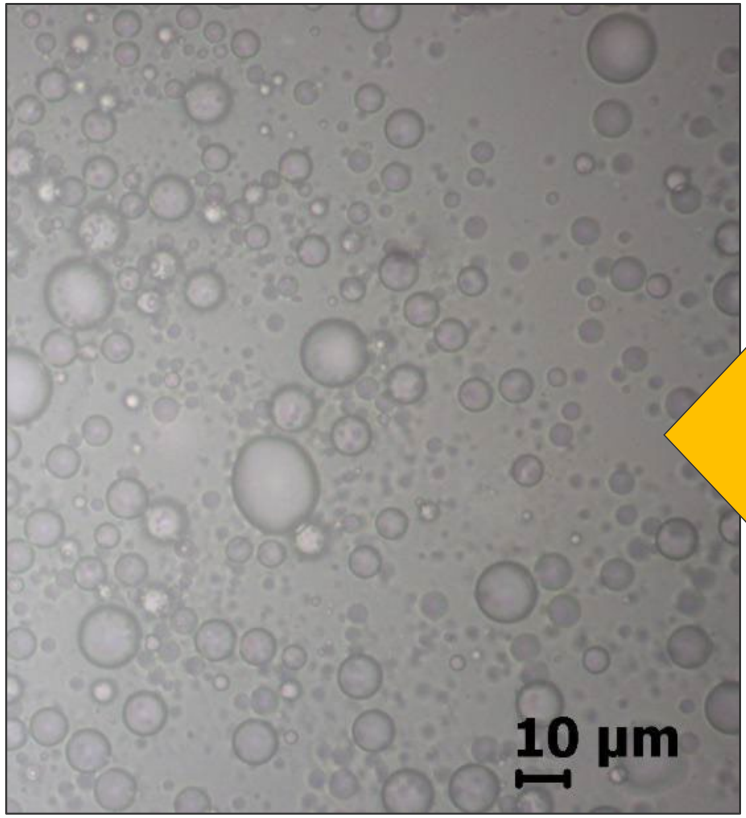
Common Operating Issues

- Maldistribution issues in finger-type slug catchers
- Separation from water, glycol, and liquid hydrocarbon
- Off-spec stabilized condensate:
  - Higher vapor pressure (RVP)
  - Presence of contaminations; e.g., water, salts, sulfur, glycol, mercury, black powders, suspended solids, corrosion products etc.

Condensate Contaminant Phases



Emulsions & Suspended Solids



Emulsions

Feed to Coalescer | Outlet of Coalescer

Suspended Solids

Feed Contaminants

Solids	Liquids	Dissolved
Upstream Corrosion Products	Compressor Lubrication Oil	Chemical Additives
Calcium/Magnesium Scale	Heavy Hydrocarbons	Salts (Ca/Mg)
Formation Solids	Produced Water	H_2S Scavenger By-Products
Waxes, Paraffins & Asphaltenes	Solvent Carryover, Pipeline Foam	Olefins
Catalysts, Desiccants & Carbon Fines	Chemical Additives (Drag Reducers)	H_2S + Oxygen
DRUs	Emulsions	Organic Acids

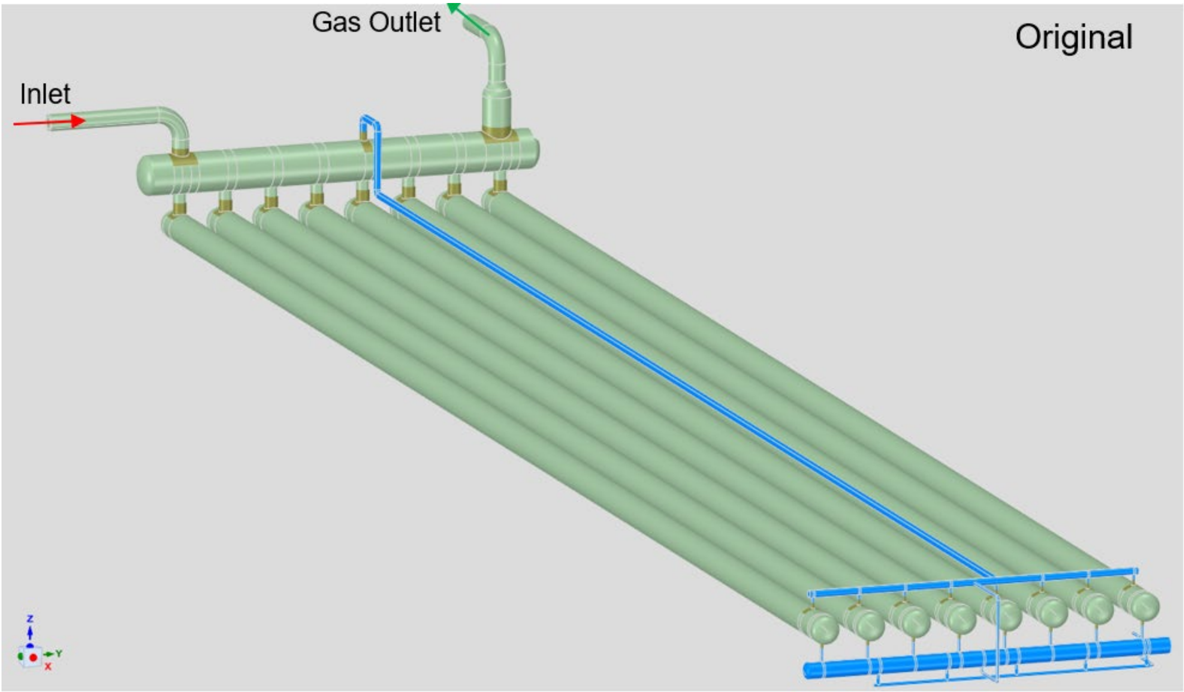
Common Problem – Fouling

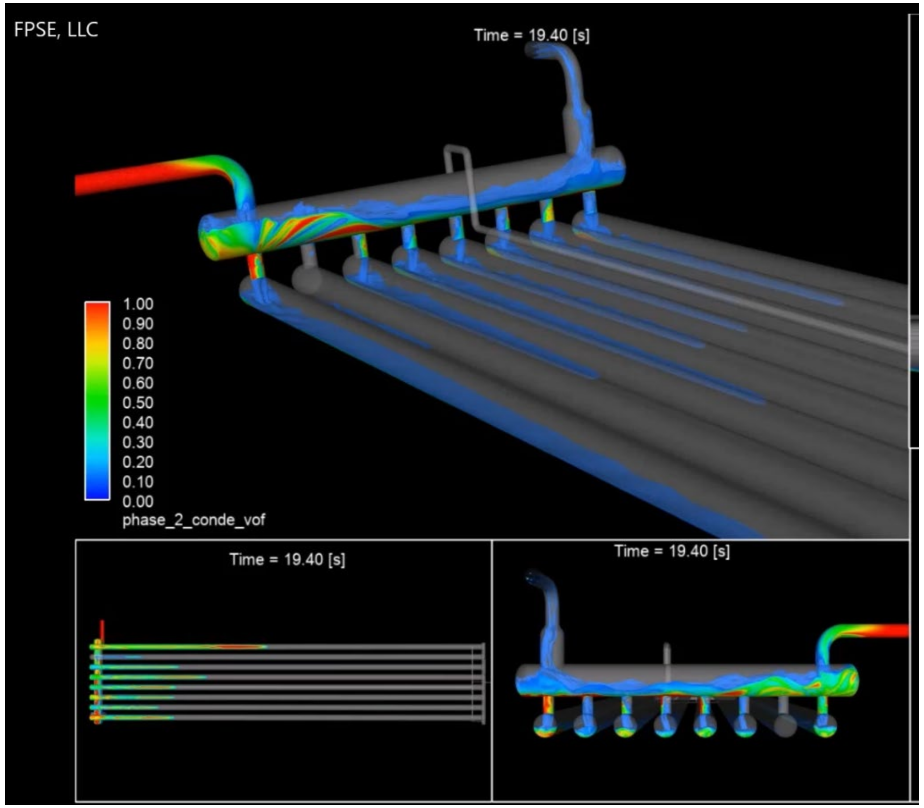
Accumulation of unwanted materials on a given surface

- Flow and capacity restrictions
- Process specifications not met
- High maintenance costs
- SEVERAL FOULING MECHANISMS
- Under deposit corrosion
- Metal loss by under deposit corrosion
- Low reliability
- Downtime

Case Study 1 – Maldistribution in Slug Catcher

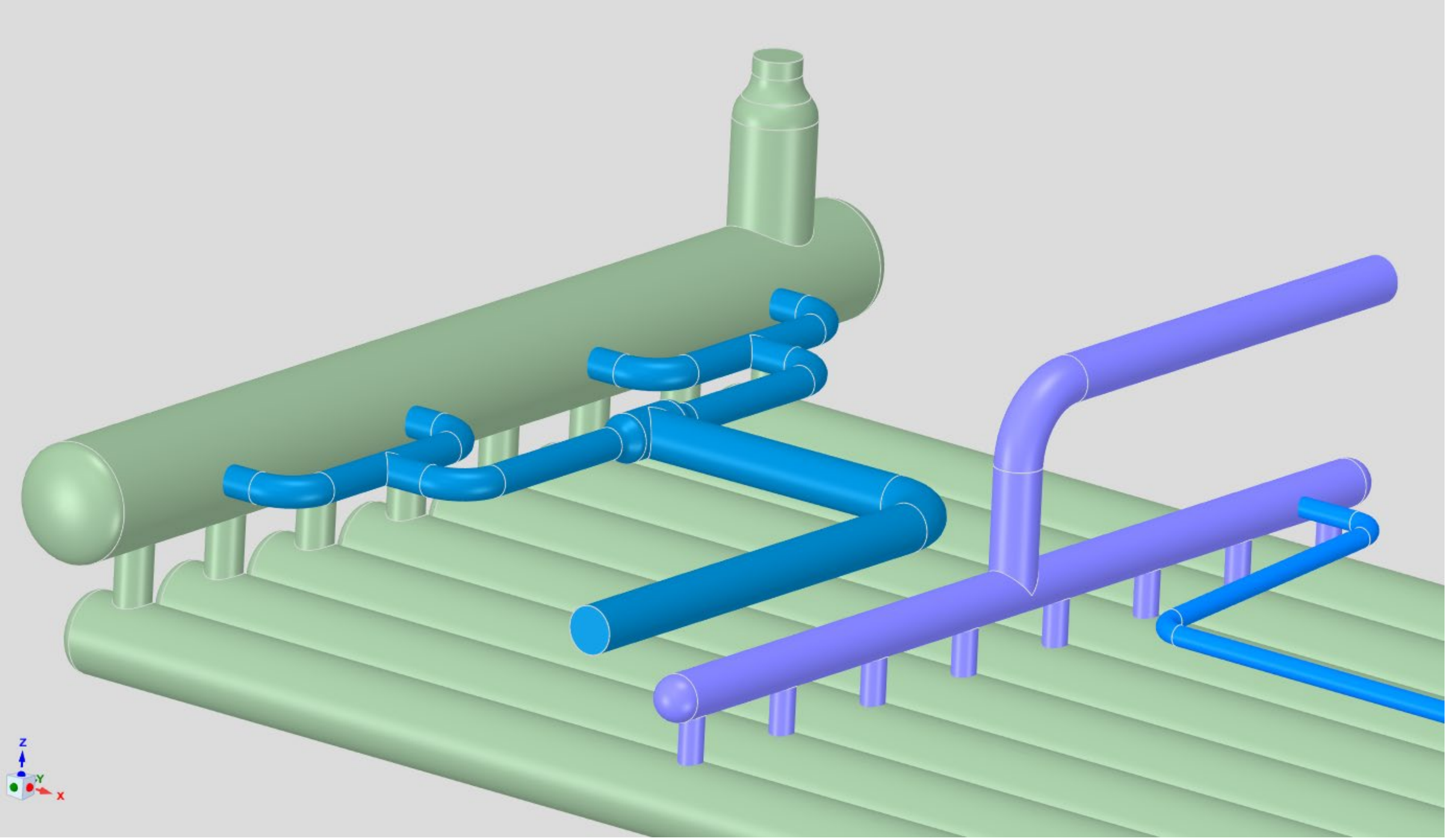
Slug Flow Maldistribution





Adam Murray & JackSmith, GPA/2023

Corrected Inlet Feed Piping



Case Study 2 – Condensate Stabilization Troubleshooting

F-001 Inlet Feed Filter

V-001 Water/Hydrocarbon Separator

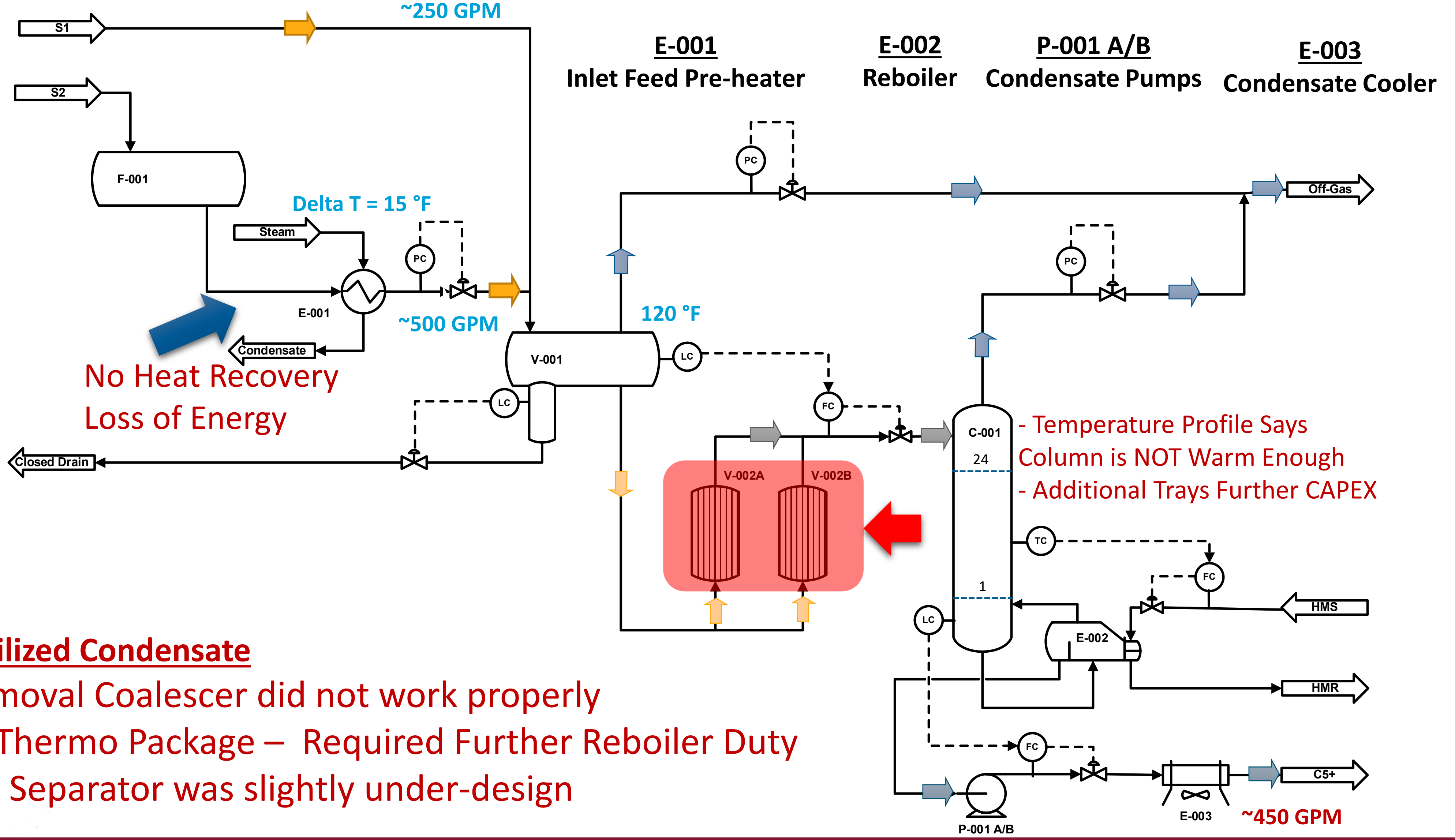
V-002 A/B Water Removal Coalescer

E-001 Inlet Feed Pre-heater

E-002 Reboiler

P-001 A/B Condensate Pumps

E-003 Condensate Cooler



Off-Spec Stabilized Condensate

- Water Removal Coalescer did not work properly
- Incorrect Thermo Package – Required Further Reboiler Duty
- Water/HC Separator was slightly under-design

Case Study 3 –
Process Selection Challenges

Process Configuration Alternatives

	Non-Refluxed Column	Non-Refluxed LP Column	Feed Preheating	Feed Splitting	Side Reboiler	Refluxed Column	Feed Preheating LP Flash
Alternative 1	X						
Alternative 2	X		X				
Alternative 3	X		X	X			
Alternative 4	X	X	X	X			
Alternative 5	X		X	X	X		
Alternative 6			X			X	
Alternative 7							X

Alternative 1

C-001
Stabilizer

V-001
Slug Catcher

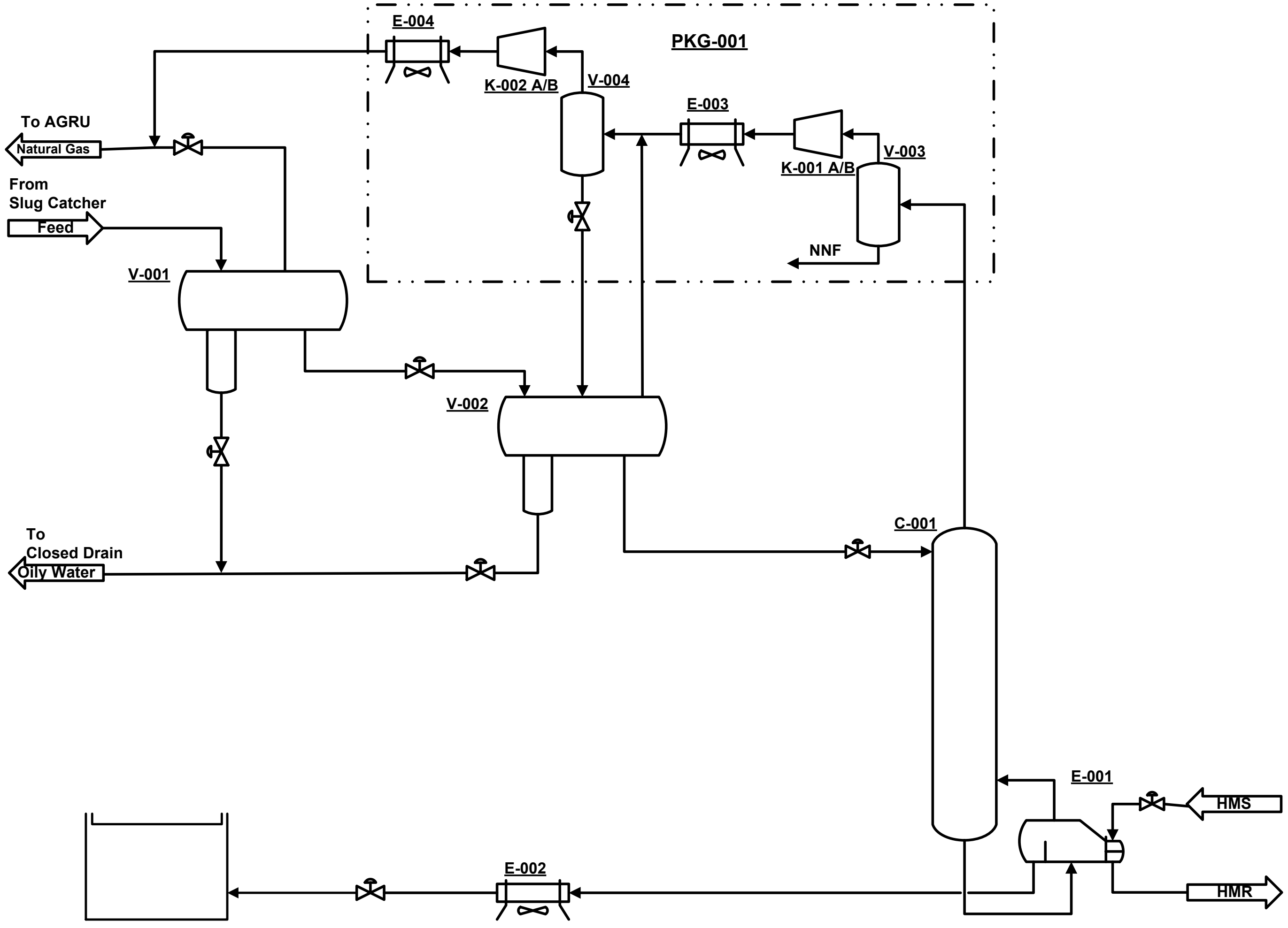
V-002
Hydrocarbon/Water Separator

TK-001
Stabilized Condensate Storage

E-001
Reboiler

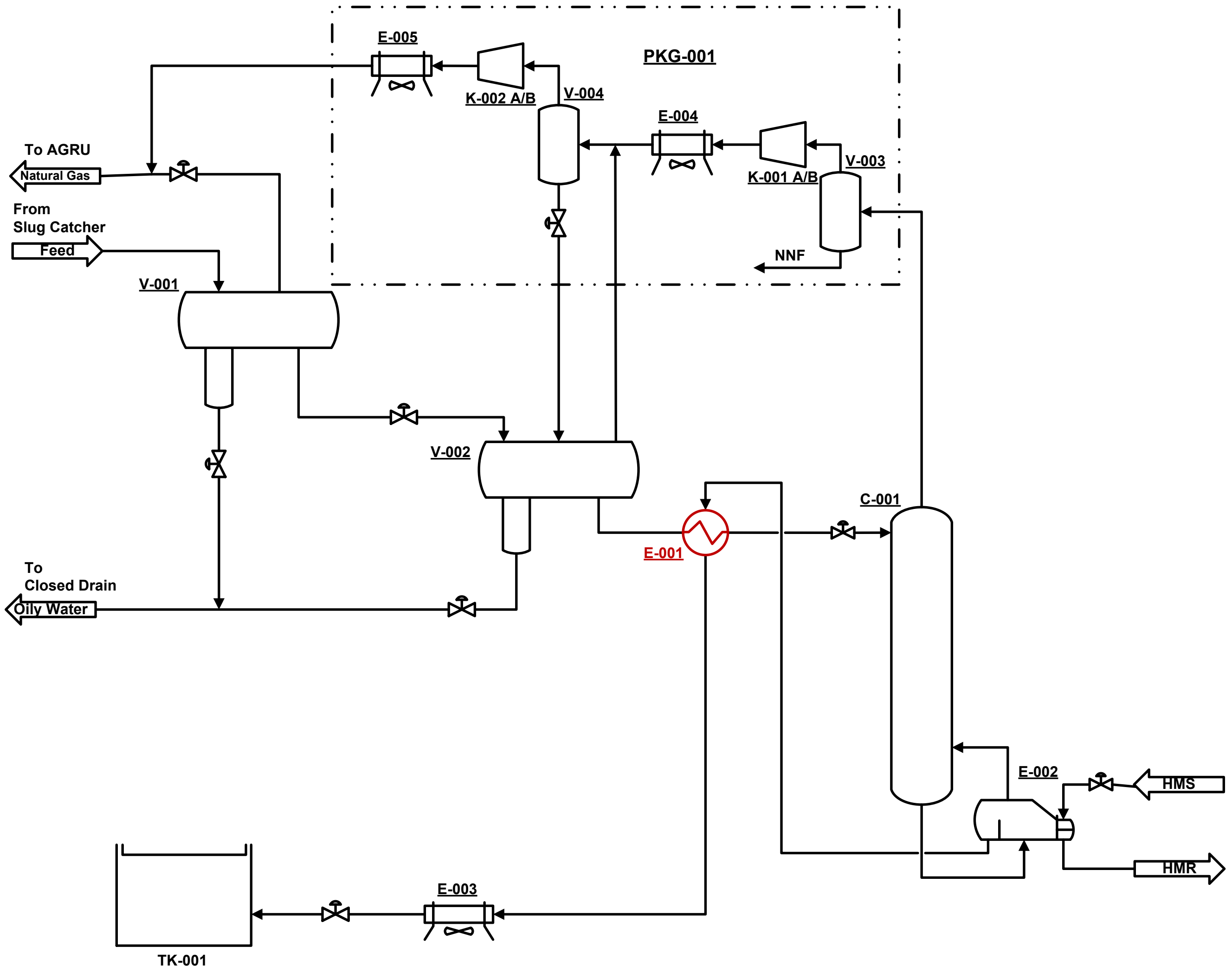
E-002
Stabilized Condensate Cooler

PKG-001
Off-Gas Compression Package



Alternative 2

C-001 Stabilizer	V-001 Slug Catcher	V-002 Hydrocarbon/Water Separator	TK-001 Stabilized Condensate Storage
E-001 Feed & Bottom Heat Exchanger	E-002 Reboiler	E-003 Stabilized Condensate Cooler	PKG-001 Off-Gas Compression Package



Alternative 3: Base Case Design Approach

1 Design Slug Catcher Correctly

2 Appropriate Retention Time for Proper Hydrocarbon/Water Separation

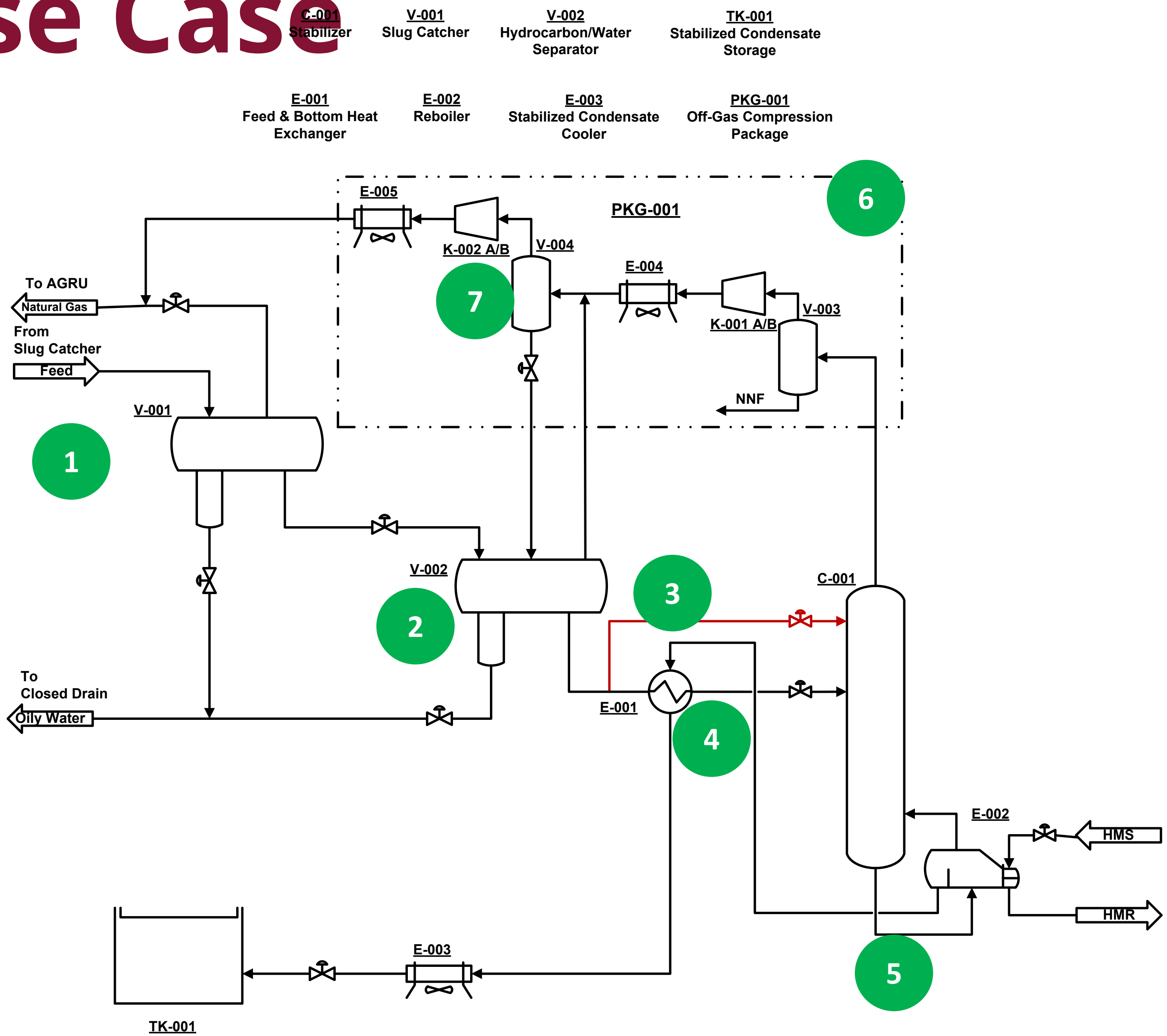
3 Fraction of Feed

4 Temperature Limit

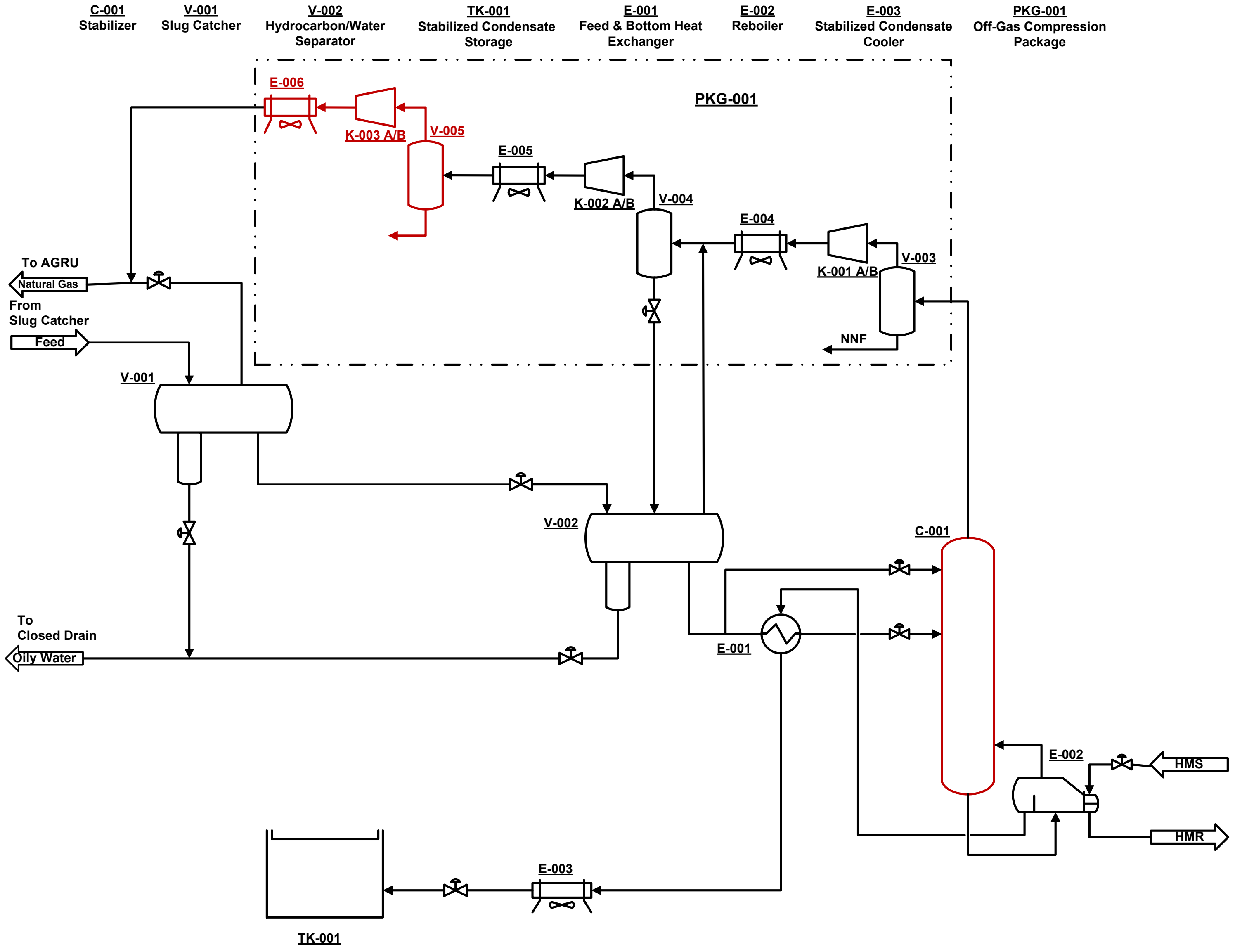
5 Column Pressure
   Theoretical stages
   Temperature Profile

6 Type and Number of Compressors

7 Interstage Compressor Pressure



Alternative 4



Alternative 5

C-001
Stabilizer

V-001
Slug Catcher

V-002
Hydrocarbon/Water Separator

TK-001
Stabilized Condensate Storage

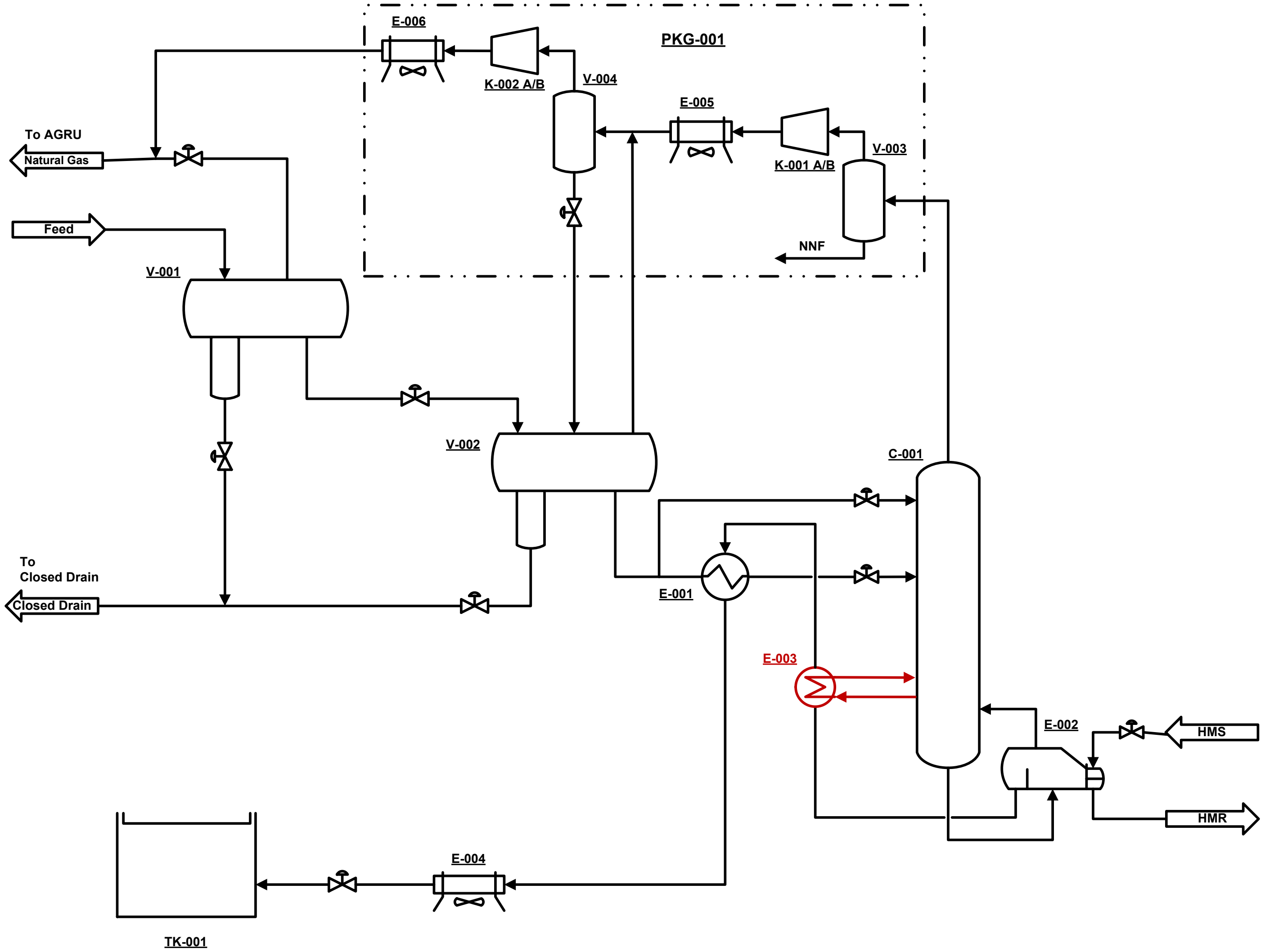
E-001
Feed & Bottom Heat Exchanger

E-002
Reboiler

E-003
Side Reboiler

E-003
Stabilized Condensate Cooler

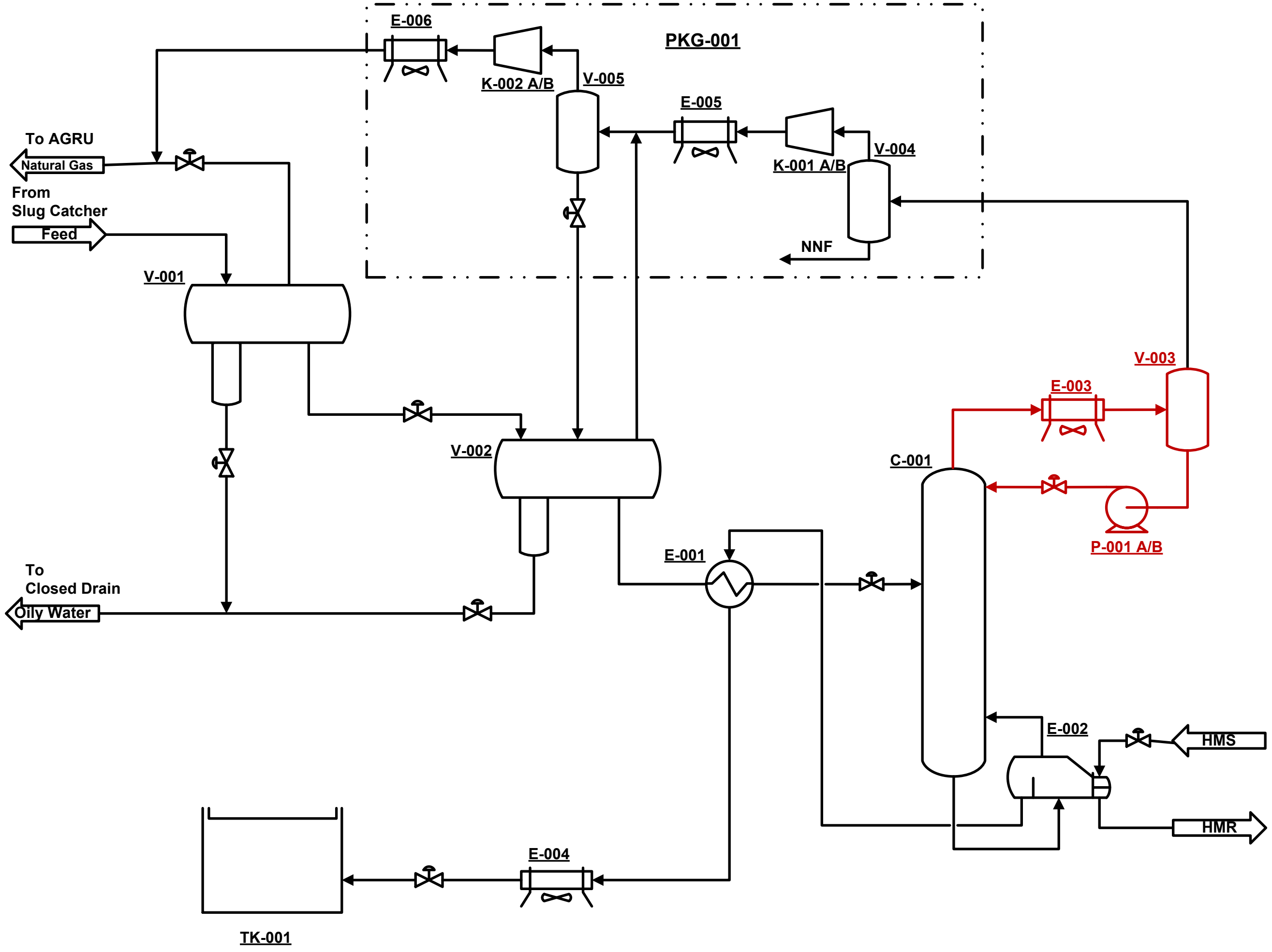
PKG-001
Off-Gas Compression Package



Alternative 6

C-001 Stabilizer
V-001 Slug Catcher
V-002 Hydrocarbon/Water Separator
V-003 Stabilizer Reflux Drum
TK-001 Stabilized Condensate Storage

E-001 Feed & Bottom Heat Exchanger
E-002 Reboiler
E-003 Stabilizer Condenser
E-004 Stabilized Condensate Cooler
PKG-001 Off-Gas Compression Package

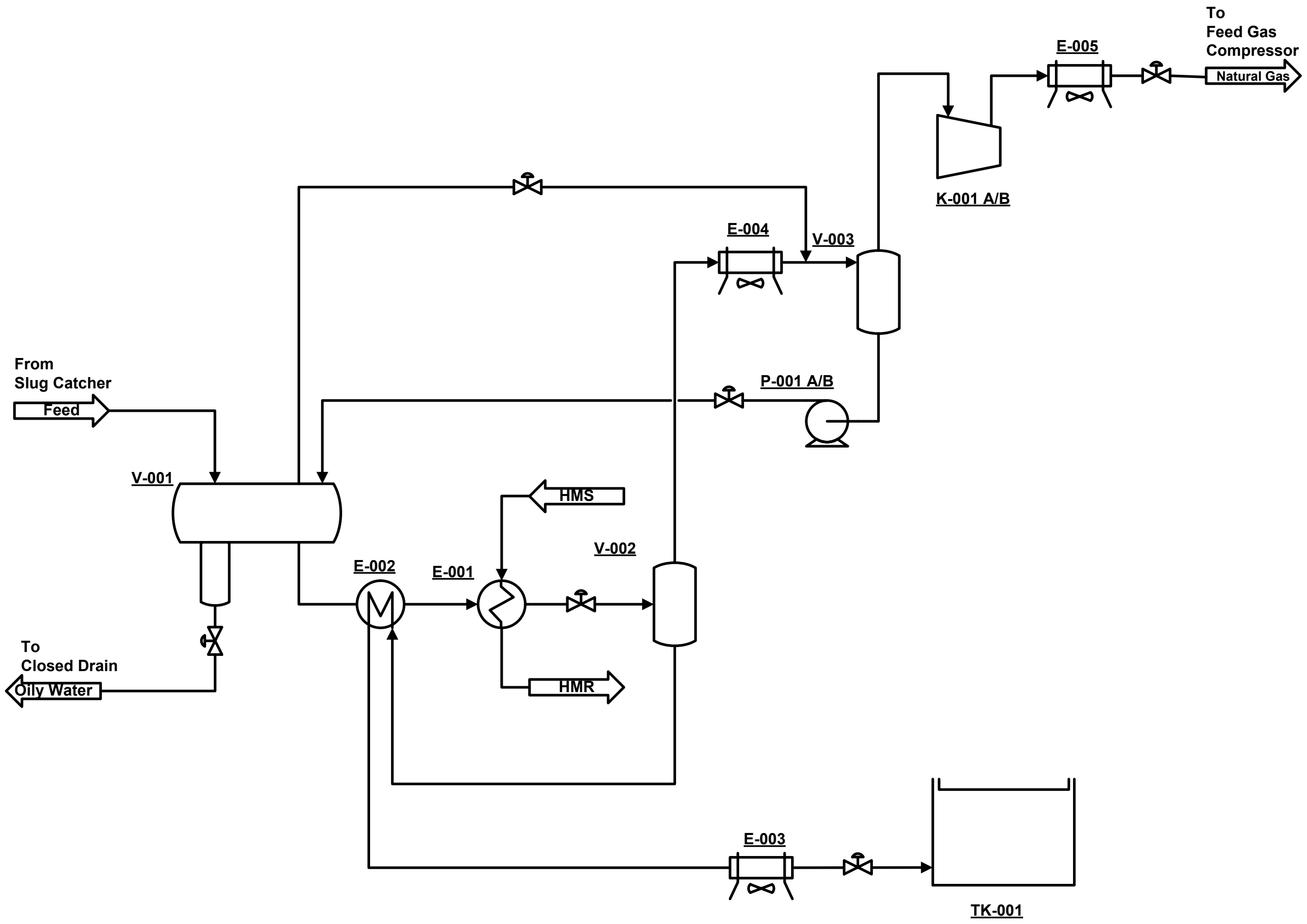


P-001 A/B Reflux Pump

Alternative 7

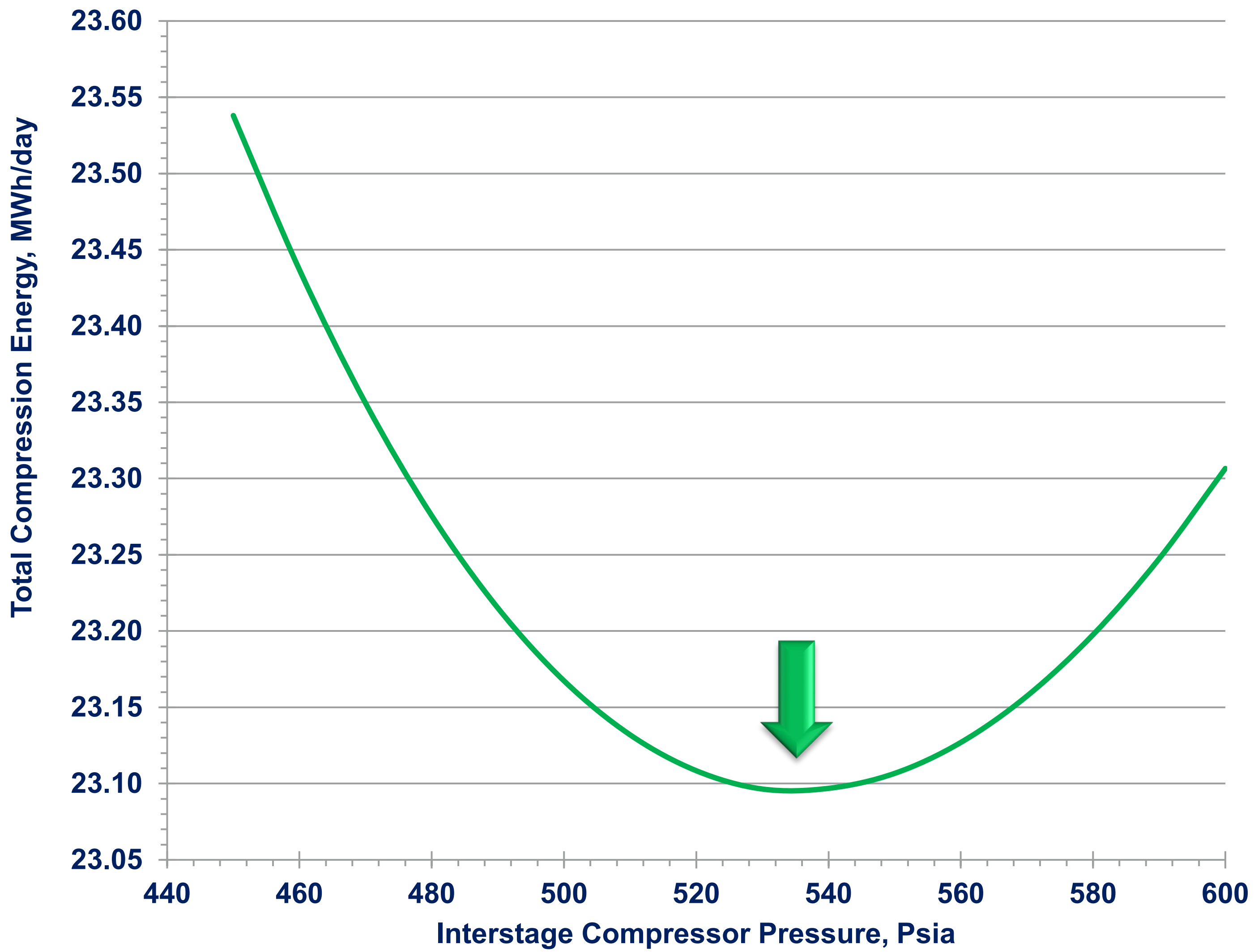
V-001 Condensate Feed Separator
V-002 Condensate Flash Drum
V-003 Off-Gas Compressor Suction Drum
TK-001 Stabilized Condensate Storage

E-001 Condensate Heater
E-002 Cross Exchanger
E-003 Stabilized Condensate Cooler
E-004 Off-Gas Cooler
E-005 Off-Gas Compressor Cooler

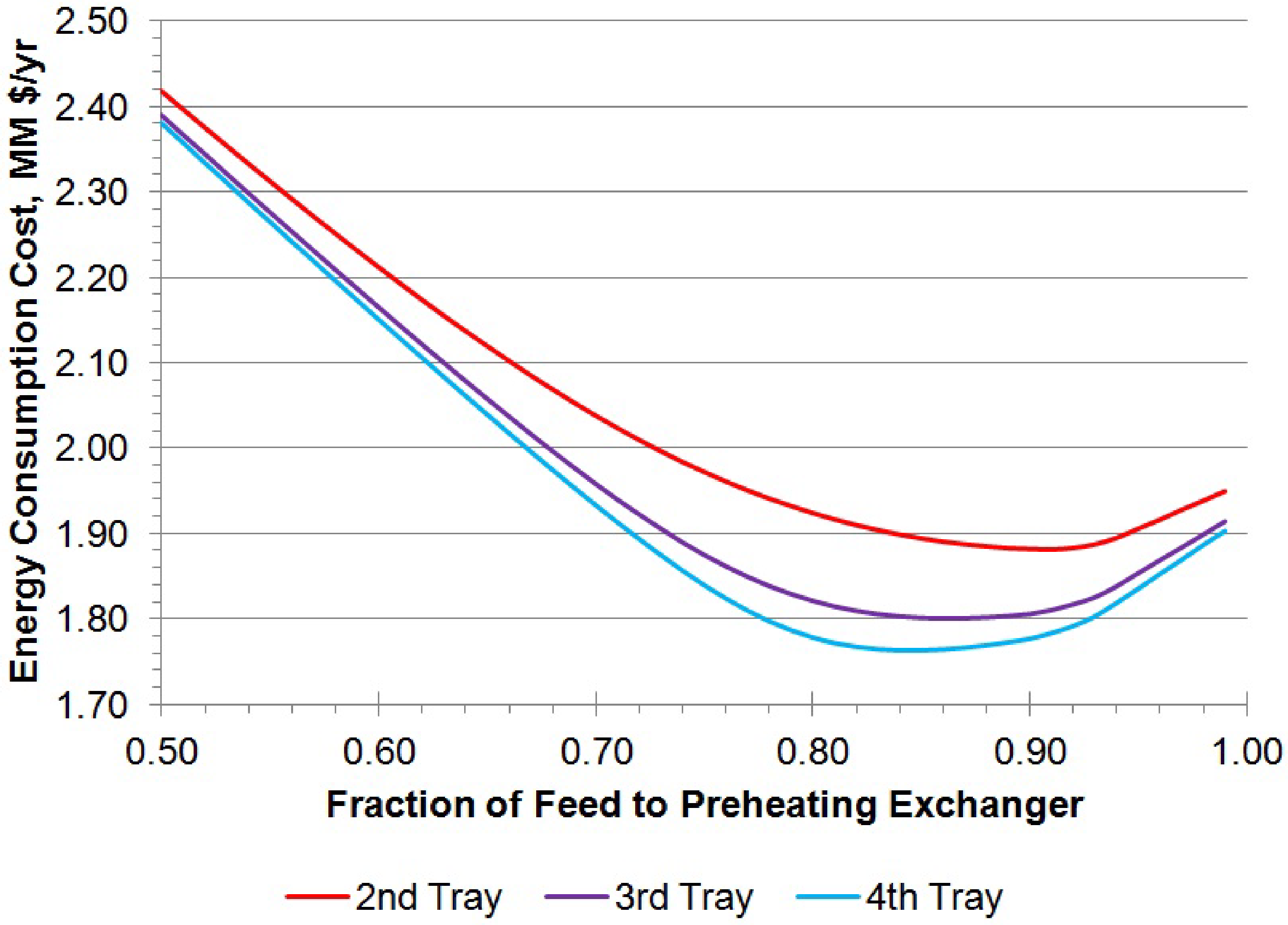


K-001 A/B Off-Gas Compressor
P-001 A/B Condensate Recycle Pump

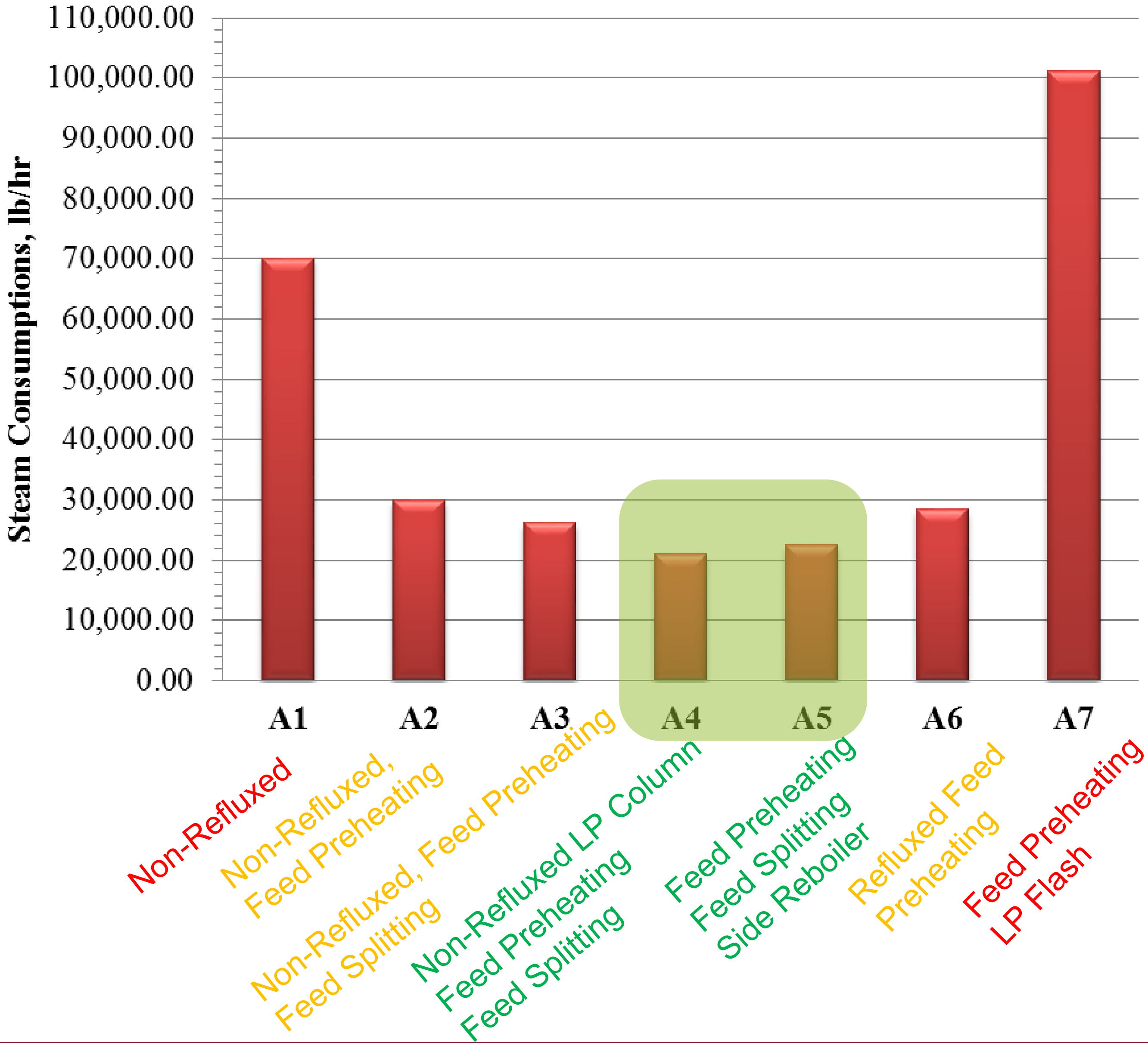
Off gas compressor power optimization



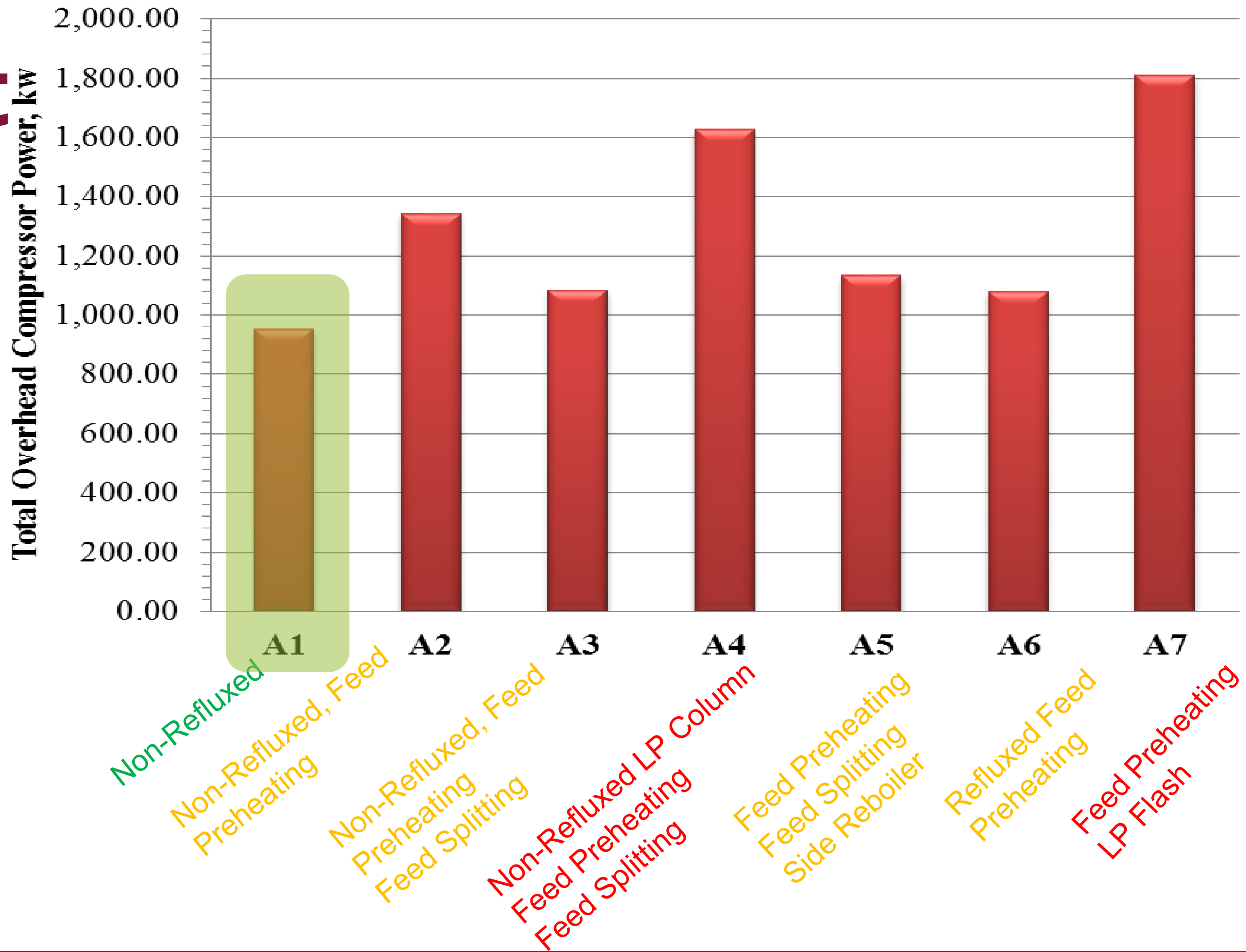
Reboiler Duty Optimization by Splitting Feed & Feed Stage Sensitivity



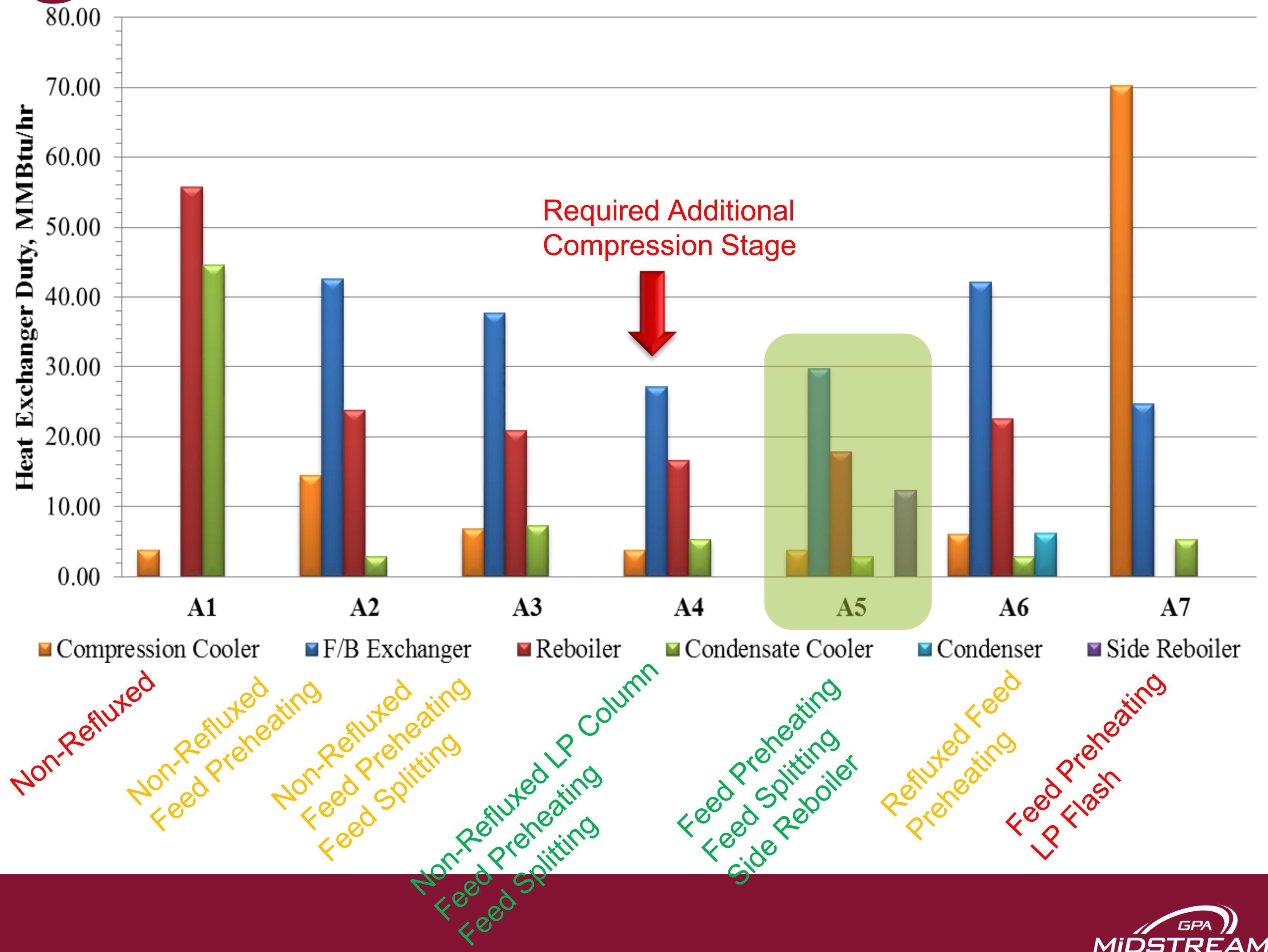
Steam Consumption



Power Requirement



Heat Exchangers Duty



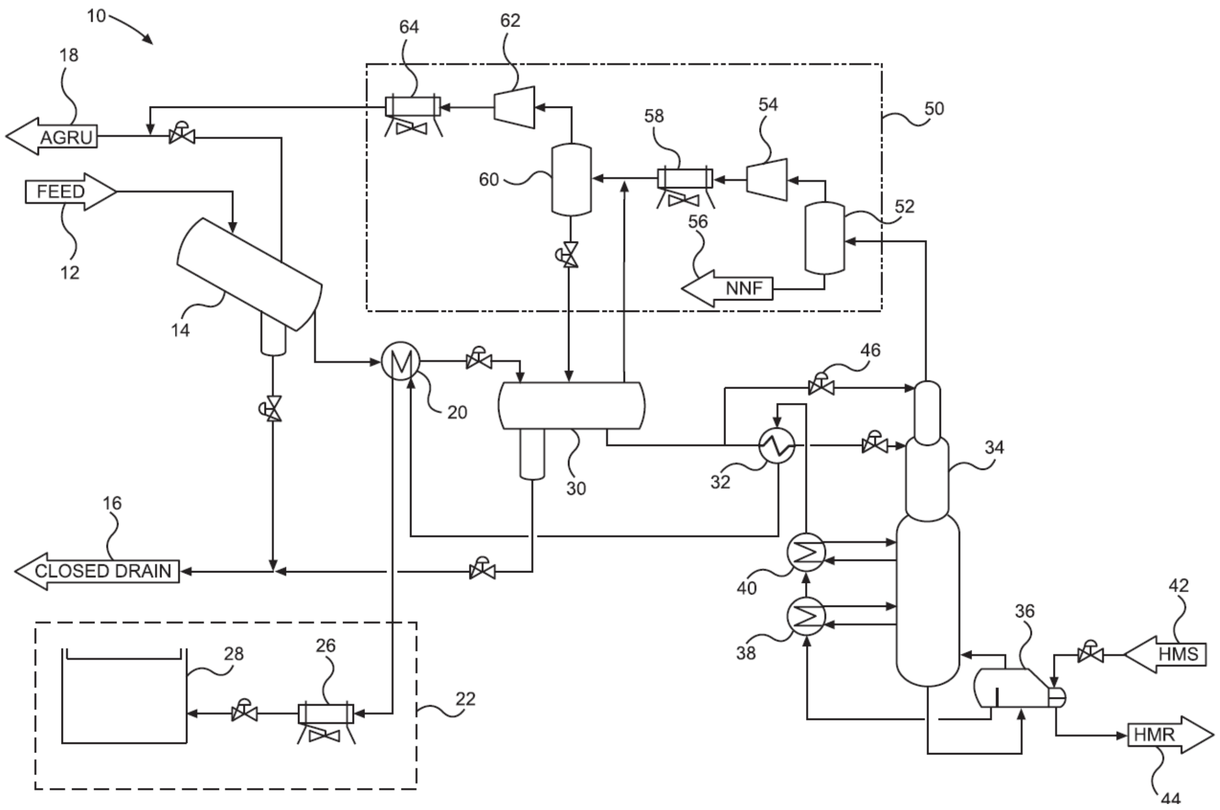
Comparison for Alternatives

Alternatives	Capital Cost	Operating Cost	Utility Cost [2]	Product Sales	Metric Tons of CO_2/kWh
Alternative 1 [3]	0.89	1.68	2.16	1.02	2.69
Alternative 2	0.89	1.07	1.09	1.00	1.28
Alternative 3	0.97	1.06	1.08	1.00	1.10
Alternative 4	1.24	1.18	1.07	1.00	1.06
Alternative 5	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**
Alternative 6	1.07	1.08	1.14	1.00	1.46

(1) The utilities costs cover the heating and cooling.
(2) Operational experiences show that the stabilized condensate specifications are achieved with difficulty with higher water content.
(3) Alternative 5 – Mahdi Nouri & Eberhard Luke, Optimized Condensate Stabilization Process – US Patent 11,339,339 May 2022

Alternative 5 Optimum Process

- Select Appropriate Process Configuration
- Select Appropriate Process Simulator & Thermo Package
- Design Slug Catcher Correctly
- Appropriate Retention Time for Proper Hydrocarbon/Water Separation
- Cross Exchanger Temperature Limit
- Fraction of Feed
- Column Pressure
- Colum Theoretical Stages
- Column Temperature Profile
- Type and Number of Compressors & Interstage Compressor Pressure



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