Put those Nodding Donkeys Out to Pasture!

How Gas-Lift Compression Can Dominate in Liquids-Rich Horizontal Plays

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April 24, 2017

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Encline

- Engineering Consulting / R&D firm
  - Three founders have 80+ combined years of oil and gas experience
  - 6 patent applications filed, 2 in process
- Development relationship with a leading unconventional operator
  - Encline owns all IP
- IoT devices that automatically monitor, control and optimize the performance of wellsite production equipment

Good News! Operators having tremendous problems with rod pumping in horizontals!

- Tremendous Gas Interference
  - Propane, butane, and some pentanes vaporizing as they ascend
  - Difficult to keep gas from entering pump, and still boiling in the pump intake
  - Described by Murphy Oil senior engineers Fred Clarke and Leslie Malone at 2016 Southwestern Petroleum Shortcourse in “Case Study – Gas Interference, Manage or Mitigate”
    - Type 1 Well – Moderate Gas Interference
    - Type 2 Well – Severe Gas Interference
- Requires regular observation and adjustment of pumping speeds, consuming time and resources

Good News! Operators having tremendous problems with rod pumping in horizontals!

- Only way to solve gas interference is to operate at elevated BHP's
  - Propane and I-butane create 36.4 and 30.6 cubic feet vapor per gallon at 60F and 1 atm
  - Converting this using ideal gas law to 275F (above critical temp) shows how much volume increases when vaporized (volume gas/ volume liquid)

Compound	100 psig	250 psig	500 psig	750 psig	1000 psig
Propane	49.3	21.4	11.0	7.4	5.7
Iso-Butane	41.5	18.0	9.2	6.2	4.7

  - Rod pumps make poor gas compressors as they run less than 10 RPM, so they operate at higher BHP's (where gas takes less volume) hurting well production
  - Operators realizing that BHP's too high for proper reserve recovery

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Good News! Even more problems due to slug/wave flow

- Rod pump controllers were designed for vertical wellbores.
- Horizontal wells have fluctuating flow regimes.
- Short-term events (waves, slugs) can “mislead” a rod pump controller into making unwanted speed changes, rapidly cycling between maximum and minimum pump speeds.
- The result: Poor pump fillage, inefficient operation, rod buckling, increased wear

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Good news! Rod buckling due to gas compression causes rod and tubing wear, increasing failure rate

- Downhole pump is a single acting gas compressor, compressing gas on the downstroke
  - Much of force for compression provided by the weight of the steel rod string
  - Although efforts made to bulk up the rods directly above the pump, buckling tendencies exist, causing wear.
  - Wellbore deviation caused by driller's goals for speed adds to wear problem caused by rod side-loading
  - Cost to repair a tubing leak in the range of $100,000

Good news! Downhole pumps are not very good compressors

Downhole pumps not designed to be gas compressors

- Compression ratios for various BHP's and a 4000 psia pump discharge

100 Psia	250Psia	500 Psia	750 Psia	1000 Psia
40	16	8	5.3	4

- If minimal liquid is not in the pump to absorb the heat, high temperatures can cook the crude oil when BHP's below 500 psia
- Pump failure due to solids or sticking results
- Pump changeout in the range of $40,000

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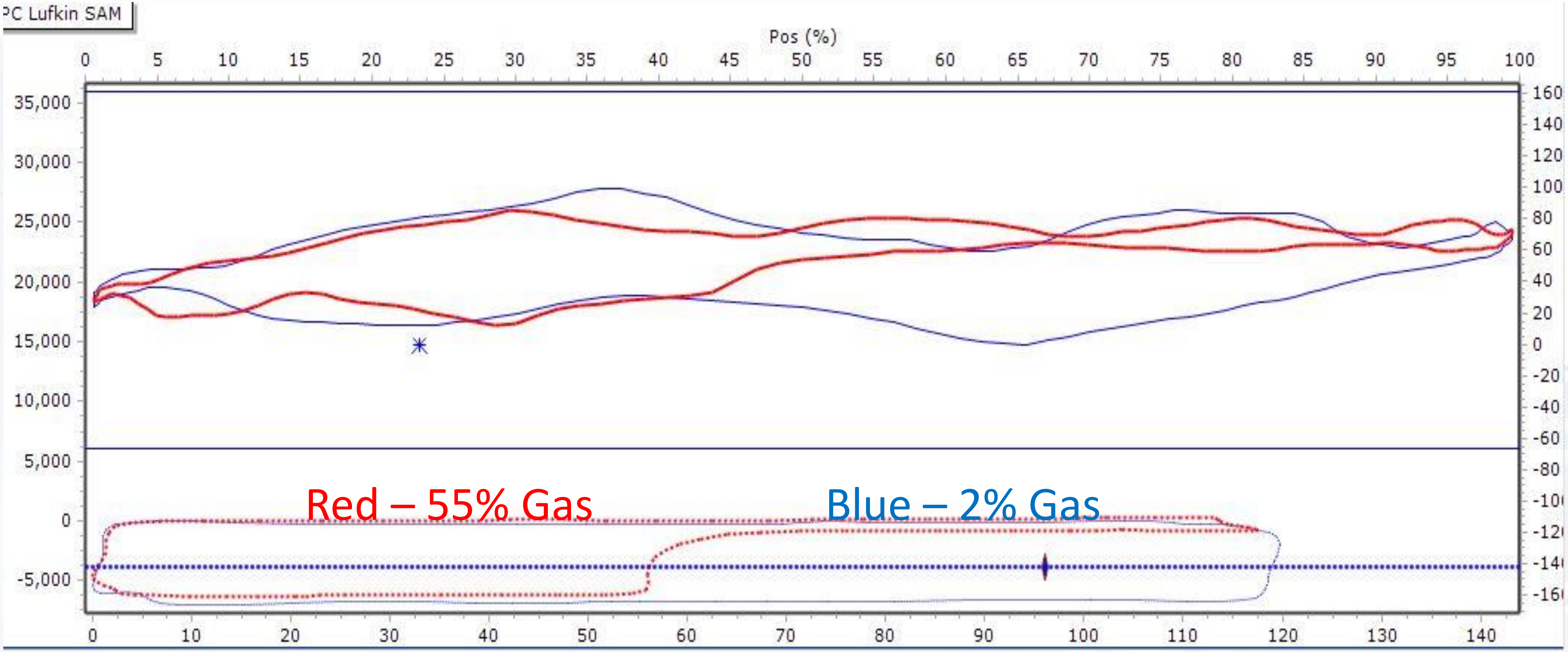
Downhole pump card looks like a compressor PV card when gas present (same well, but pre- and post-fluid slug)



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Good news! Super small sand now favored as frac sand

- At SPE 2016 Fracturing Conference in the Woodlands, Davidson, Shah, and Ailji said in SPE 179163:

  " One practice that has been gaining popularity as a method of… accelerating hydrocarbon recoveries in many shale plays is the combination of thin water-based fluids, small-mesh proppants (mostly 100 mesh sand with some 40/70 mesh sand) and a high intensity of injection points…"

Good news! Super small sand now tearing up pumps!

- Diameter of 100 mesh sand typically ranges from .0004 to .0008 inches
- Most sucker rod pumps do not have rings or seals
  - Use close tolerance and long sealing area to minimize fluid slippage
  - Typically 5 to 6 foot long plungers (pistons)
  - Depend on fluid leaking past to provide lubrication
- Clearance between the plunger and barrel (piston and cylinder) typically .0004 to .0006, same size as the frac sand
- Pump changeout in the range of $40,000

See the problem?

Good News Summary – Why rod pumping on the way out

- Tremendous Gas Interference Problem
  - Requires personnel to spend time monitoring and then changing pump speeds
  - Results in higher BHP than desired for proper reserves recovery (Huge)
  - Causes pump to act as a compressor, resulting in buckling forces, heating issues, which increase the failure rate
- Frac sand problem
  - Well performance trending towards using proppant that is the same size as downhole pump plunger-barrel clearance, increasing failure rate
- Deviation and Horizontal well behavior
  - Deviation causes side loading and wear, increasing failure rate
  - Goals for lower well costs outweigh getting a straight wellbore

Why is Gas-Lift Positioned to Claim this Market from Rod Pumping?

- Gas-Lift results in producing BHP's that are very competitive
  - Often less than 500 psi depending on fluid being lifted
  - When combined with plunger lift (GAPL), has demonstrated ability to achieve producing BHP's below 300 psi
    - "Enhanced Gas Lift Installations by Utilizing Two Piece Plunger Technology" by Perner & Lusk at February 2015 ALRDC Workshop in Denver
    - "Utilizing Gas Assisted Plunger Lift" by Young, Dahlgren, & Lima at February 2017 ALRDC Workshop in Denver
  - Practice of Continuous Gas Circulation and Intermittent Gas-Lift
    - Have potential to further reduce BHP

Why is Gas-Lift Positioned to Claim this Market from Rod Pumping?

- Gas-Lift not bothered by offset fracs, frac sand production, and wellbore deviation
  - April 2017 Journal of Petroleum Technology Magazine: Oil and Gas Producers Find Frac Hits in Shale Wells a **Major Challenge**

Sources: JPT - Marathon Oil/Eagle Ford Training San Antonio

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Why is Gas-Lift Positioned to Claim this Market from Rod Pumping?

- Compression costs pale in comparison to rod pumping failure costs
- Real comments:
  - "I haven't rod pumped a well in a year and a half."
    - Production engineer with Eagle Ford wells on how his operations are switching to gas-lift
  - "We have 300 wells on rod pump, and 50 of them have severe gas interference."
    - Production engineer with Bakken operations
  - "I'm the technical advisor for 12,000 wells on rod pump, and I can tell you every single one has issues with gas interference."
    - Senior rod pumping advisor for operator in multiple unconventional plays

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What is the market for new artificial lift installations?

- About 5000 horizontal oil wells were drilled in the U.S. in 2016
- World Oil expects about 6700 in 2017
- All horizontal oil wells require artificial lift within 0-3 years.
- Based on proprietary survey data, we expect 2600 new gas-lift installations in 2017
- Assuming a cost of $2000 a month based on a centralized compressor model, and $4000 a month for a wellhead based model, this is a $62 to $124 million annual market
- Market will likely be 20% higher in 2018, as gas-lift market share rises

This is a HUGE emerging market

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The Not-So-Good News is that for Liquids-Rich Gas Lift….

The Gas-Lift compressor design being furnished to operators is really a gas sales compressor package…

- Designed to keep the gas from being too hot
  - So that it can be dehydrated, when..
  - Most field gas-lift systems do not have glycol dehydrators due to condensate contamination caused by rich gas
- Not designed to prevent over-cooling, causing:
  - Rich gas condensing in inter-coolers, resulting in frozen scrubber dump lines
  - Rich gas condensing in after-coolers, resulting in hydrates in discharge piping
  - Both result in downtime, with the band-aid being methanol injection

We need compressors designed strictly for gas-lift application. The market can support this!

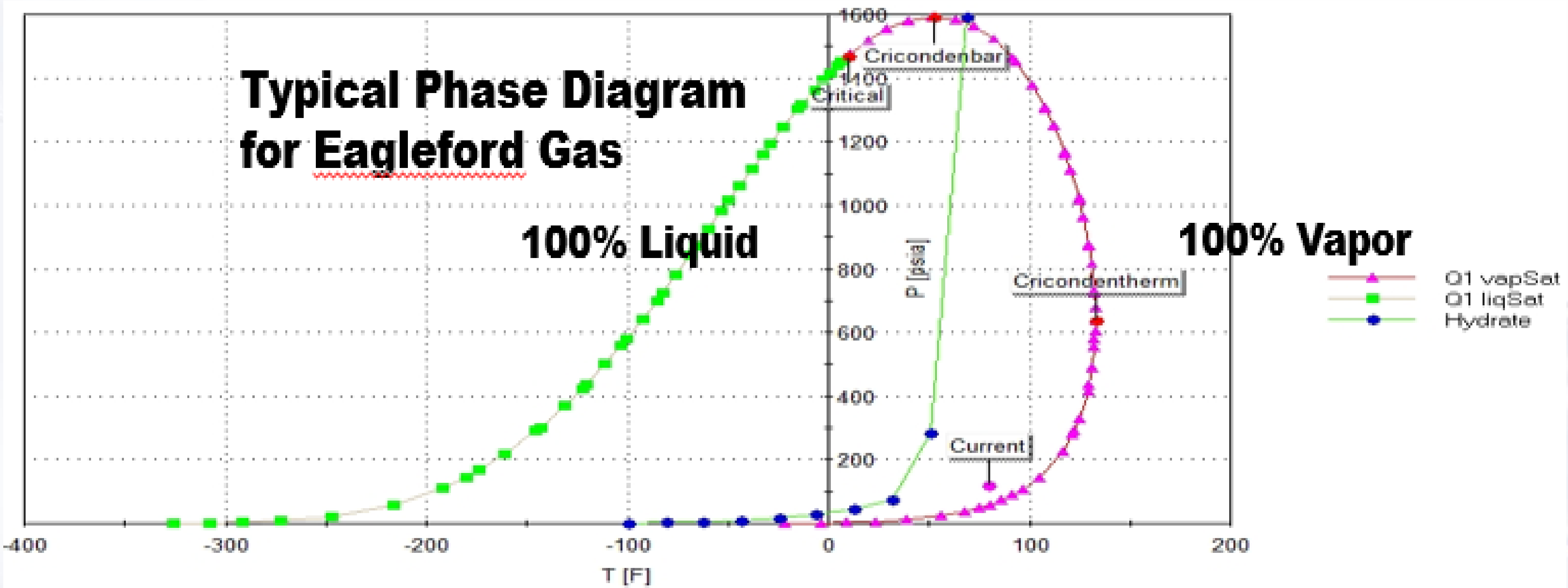
What is the problem with Methanol Injection?

- Difficult to determine the correct rates to pump, as dependent on gas volume and pressure drop. May still freeze up.
- Methanol burns without a flame, and is dangerous to people
- Natural Gas Hydrates: A Guide for Engineers, John Carroll 2009
  - When injected into well casings with corrosion inhibitors, they work against the corrosion inhibitor's proper film development
  - Methanol in surface tanks contains more dissolved oxygen than water, and will oxidize well tubulars over time
- From NACE 07663 by Park, Morello, Wong, and Maksoud, 2007
  - "High quantities of methanol may reduce the success of a corrosion inhibitor program. Although corrosion mitigation is used in conjunction with methanol injection, as an industry-wide and commonly accepted practice, there is very little literature on the subject." <u>There is a risk to wellbore integrity!</u>

Issues caused by Hydrocarbon Condensation in Intercoolers

- Although methanol can keep the dump line from freezing, when propane and butanes reach the atmospheric tanks…
  - Creates an instantaneous vapor cloud
  - If tank VRU capacity not designed for these events, valuable product is burned
    - Environmental implications
  - If tank VRU has capacity to handle, then a wasteful recycle stream is created
    - Cycle of compressing gaseous propane, condensing in coolers, then flashing in tanks
    - Witnessed 20% recycle stream in a North Dakota Gas-lift application where cascade dumps were utilized (subsequently stopped by using Encline PTC product)
- Compressor essentially leaning out gas stream
  - Enhances likelihood of paraffin formation in wellbore, wellhead, and flowline

Good News! There is a simple way to eliminate the problems caused by hydrocarbon condensation, as presented in SPE 181773: Maintain temperatures in the 100% Vapor range = No condensation



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Encline Designed Wellhead Gas-Lift Compressor to Maintain Temperatures in the 100% vapor range

- 75 HP Ariel JGP-2 Two stage with individual gas coolers for each stage, operating on PID controlled VFD’s
  - First stage cooler outlet temp setpoint of 125 F
  - Final stage cooler outlet temp setpoint of 155 F
- Set in footprint of pumping unit that was removed
- Capable of 450 MCFPD from 80 Ps to 1200 Pd

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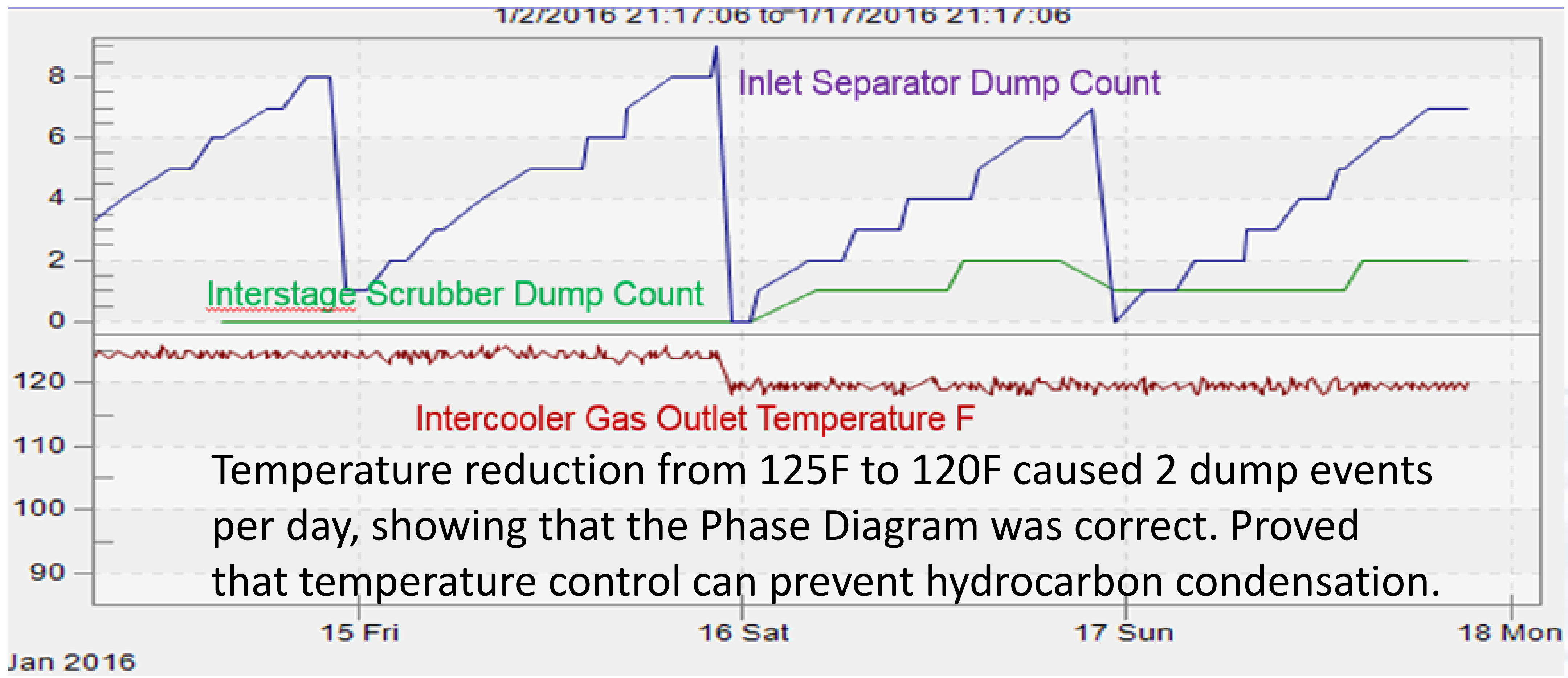
Scada data collected on number of interstage scrubber dump events, and intercooler outlet temperature



Temperature reduction from 125F to 120F caused 2 dump events per day, showing that the Phase Diagram was correct. Proved that temperature control can prevent hydrocarbon condensation.

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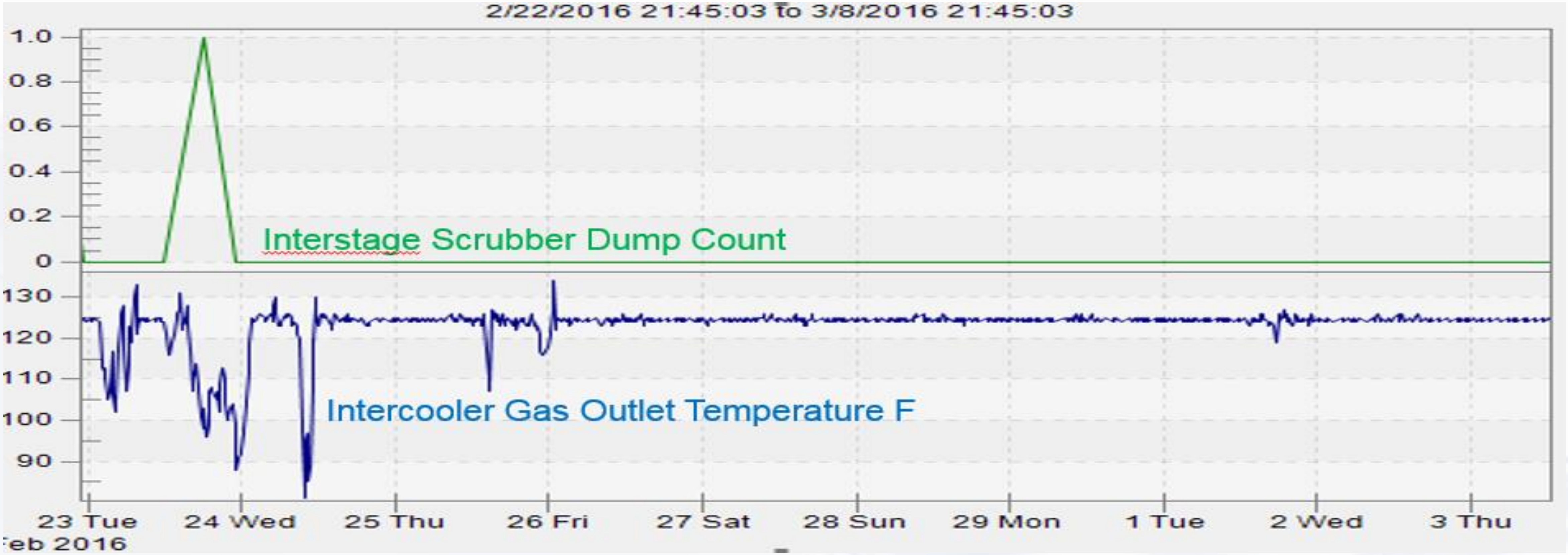
Five weeks later, a cold front blew through on February 23



- Compressor only went down when facility requested ESD, then restarted automatically
- No methanol tanks, nor tanks of any kind, are on this location

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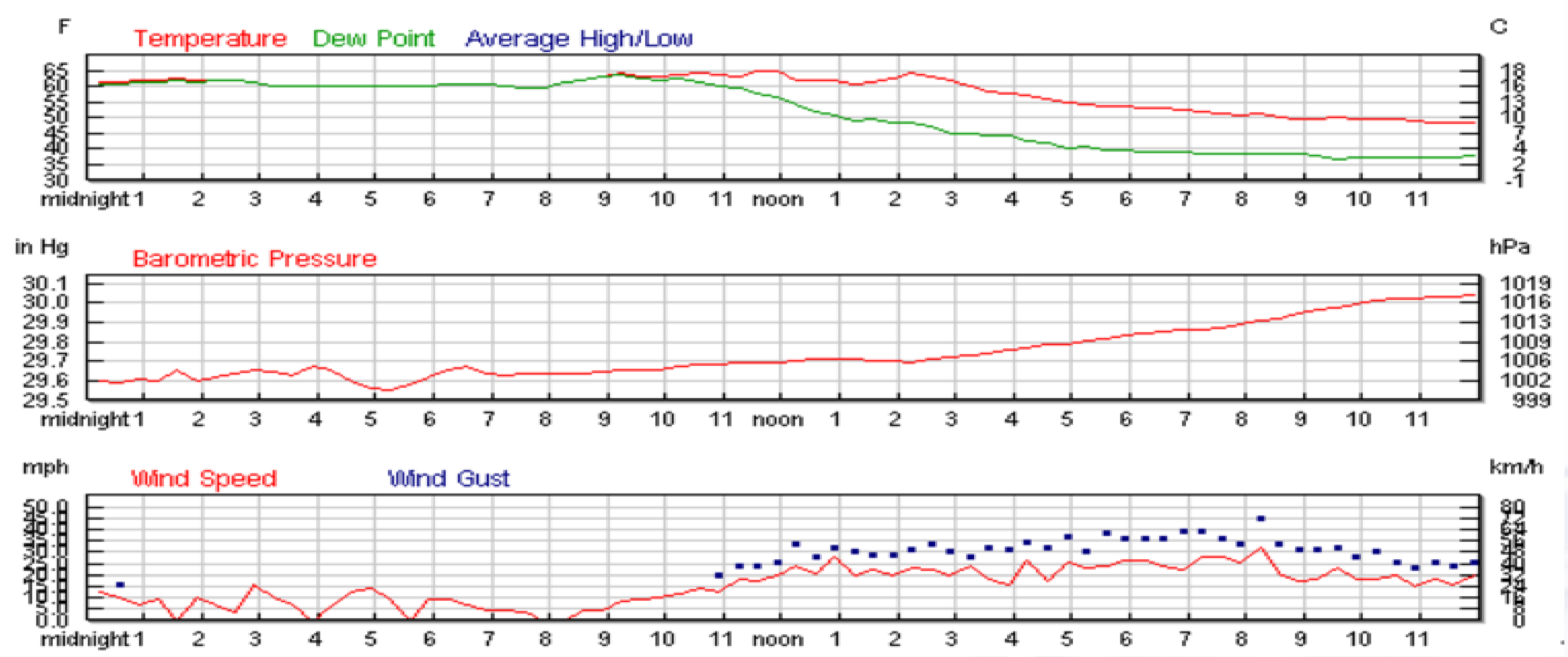
Weather data from local airport for February 23, 2016



- Despite 25 MPH winds with gust to 40, coolers with VFD and gravity-drop louvers did a good job preventing hydrocarbon condensation

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Injection Pressure Requirements for Gas-Lifting

- Typical well (9 of 10)
  - First Year: 1100 psig, reducing 50 psi per month
  - Years ***Two*** through ***Thirty***: 500 psig dropping to perhaps 300 with GAPL
- Atypical well (1 of 10)
  - Making lots of water from out of zone frac, or offset frac
  - Years One through Thirty: 1000 psig
- Centralized compressor must operate at 1000 psig for 30 years
  - 9 out of 10 wells take a 500 to 700 psi pressure drop through a choke
  - Drops temperature from earth temp of 70F to perhaps 20F
    - Much methanol required year-long, and far more corrosion chemical needed
    - Paraffin likely to form in cool tubing, requiring paraffin chemical
    - Substantial waste of compression energy
- Wellhead compressor operates at pressure of casing, not choked

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Wellhead vs Centralized: Wellhead Wins!

(or it would if proper evaluation done)

- Centralized Compression is favored by most facility engineers, as
  - Favor installing 1 compressor instead of 10
  - Don't like to install blowcases to avoid having tanks at wellsites
  - Believe they are saving money by renting compressor for $1500 per HP instead of $2500, although there is no chance compressor is right-sized
  - Have not considered the cost and maintenance of high pressure steel gas-lift distribution system, compared to low cost poly distribution system
  - Have not considered the varying casing pressure requirements, and that all gas must be pressured to that of the highest well
  - Have not considered that gas reaches earth temperature 1000 feet from centralized compressor

Wellhead vs Centralized: Wellhead Wins!

(or it would if proper evaluation done)

- Wellhead Compression should be favored by most production engineers, as
  - Simple compressors easy to install at wellhead
  - Incorporates integral blowcase in inlet separator, avoiding tank at wellsite
  - Reduces costs and danger by eliminating methanol injection (pumps too)
  - Can take hot discharge gas directly to casing at temps up to 250 F
  - Corrosion chemicals work better when methanol not there to thin them
  - Corrosion chemicals work better at temperatures between 150 and 200F
  - Paraffin eliminated or diminished by hot, un-lean gas injection
  - No corrosion program needed for low cost poly distribution system
  - Only compress gas to the pressure of the casing, no higher

Two Stage Versus Three Stage: Why does everyone think that a gas-lift compressor must be 3 stage?

- Ratio of specific heats is lower for liquids rich, so heats less
  - $T_d = T_s\,(r^{(k-1/k)})$
- Due to wave and slug flow regimes, primary separators normally operate at pressures above 100 psig to quickly pass liquid
  - Consequence of this is suction pressures (Ps) of 100 psig available
- When discharge pressure falls below 500 psi, third stage not working
  - Cooler still in place however, further hurting quest to maintain hot gas

Gas-lift for Liquids-Rich applications is very often a two stage job due to these factors

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Horsepower Comparison Using Web Calculator based on GPSA

Suction Pressure (psig) 30 (must not be less than -14 psig.)
Discharge Pressure (psig) 1000
Capacity (MMSCFD) 0.400 CALCULATE

Pressure Ratios :22.7
Number of Compression Stages :3
Pressure Ratios per Stage :2.83
Estimate Discharge Temp (Deg F) :290.17
Compressor Horsepower Estimation :82.23
Auxillary Horsepower Estimation :8.22
Total Horsepower Estimation :90.45

90.45 Horsepower

Suction Pressure (psig) 80 (must not be less than -14 psig.)
Discharge Pressure (psig) 1000
Capacity (MMSCFD) 0.400 CALCULATE

Pressure Ratios :10.71
Number of Compression Stages :2
Pressure Ratios per Stage :3.27
Estimate Discharge Temp (Deg F) :315.71
Compressor Horsepower Estimation :62.22
Auxillary Horsepower Estimation :6.22
Total Horsepower Estimation :68.44

68.33 Horsepower

Difference of 22 HP, 32% more HP required for 30 psig suction

History of Gas-Lift Compressors

- 20th Century Compression: Operator owned and Maintained
  - Operators staffed with engineers and mechanics
  - Rental compressors utilized minimally for short term needs
  - Large unitized fields with massive compressor stations
  - Gas plant stripped liquids and contaminants from gas stream prior to reinjection or sale
  - Clean gas allowed for minimal corrosion to well tubulars and gas lift components, such as bellows

History of Gas-Lift Compressors

- In the 90's came "Outsourcing" and "Alliances"
  - Indicator driven E&P industry favored spending capital on drilling wells instead of purchasing compression equipment
  - Compression experts were also retiring
  - Loss of control over compressor fleet and operational decisions was accepted

The Result:

Transition to 3rd party owned and operated compression

No control over compressor design

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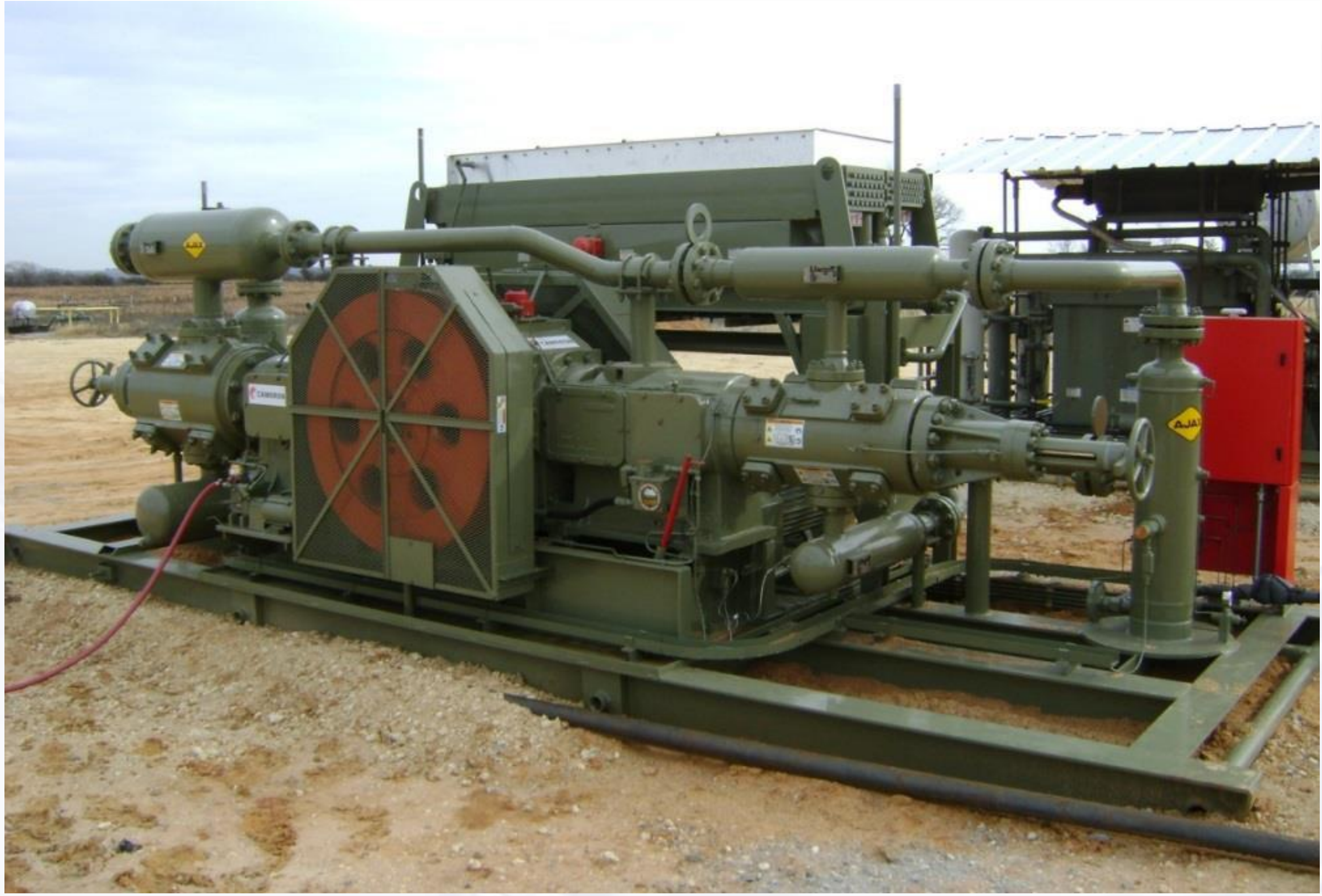
The Advent of the 21st Century

- Barnett Shale caused need for many more wellsite gas-lift compressors
  - Not available from rental companies
  - Packaging industry geared up and sold to operators
  - Eventually rental industry caught on and met demand
- Gas-Lift was back!!
  - But we had freezing issues
- Was there an opportunity for innovation?



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Innovation example from 2008 that should be repeated

- GE Oil & Gas Compressors desired to build an electric AJAX
- Tri-Star Compression willing to incorporate into rental fleet
- EOG wanted reliable two stage electric driven gas-lift compressors for hot gas at high or low discharge pressures
- Parties worked together and created a really great compressor for gas-lift, that is still operating on a 4 well pad

Can we get together on a larger scale and design compressor packages better suited for gas-lift?

- Operators needs not served by present gas sales design
  - Gas overcooled, causing hydrocarbon condensation, leaning out injection gas
  - Requires methanol injection that is unsafe, expensive, and has long term implications to operators wellbore integrity
  - Three stage designs very inefficient as they cannot handle high suction pressure
  - Additionally, operators want compressors that:
    - Will start and stop automatically (due to facility related ESD’s)
    - Have significant turndown and scalability (since well count constantly changing, as is prod)
    - Have the ability to take speed control signals from the operators gas-lift control system
    - Don’t need to be blown down to start, but can equilibrate through full flow bypass (blowing down is an unneeded, unsafe, and enviro-unfriendly practice whose time is past)
- Present surplus of gas-lift compression inventory is blinding industry to the huge market that awaits the outfit that makes this compressor

Good News! New Technology for Gas-Lift

- High Pressure Gas-Lift
  - A method to completely eliminate problematic gas-lift valves by adding one stage of compression
- Elimination of the Control Panel, with replacement by web based HMI
  - Why does a man have to be in front of the panel or HMI in this day and age?
  - Incorporation of engineering principles in creating realtime KPI's
  - Problems diagnosed and alarms created by analyzing realtime data, creating KPI's, and comparing to historic KPI's stored at machine level
  - "Cloud" not necessary (and operators don't like), but is supported
- Device to perform the above, and perform better temperature control for older existing 3 stage compressor packages

High Pressure Gas-Lift: What is it? Why now?

- Injecting gas into the casing at pressures up to 5000 psi
- Similar to what operators do with coiled tubing and nitrogen
- Practiced to a degree offshore
- Eliminates the need for gas-lift valves when BHP below 5000 psi
  - Can go much higher with just one gas-lift valve
- Could not do 40 years ago, but can today, since:
  - 2000 and 3000 psi was common casing pressure rating prior to fracing revolution
  - CNG compressor cylinders were not available

High Pressure Gas-Lift: Besides eliminating gas-lift valves, are there other benefits?

- Injection at the bottom lowers density of fluid throughout the entire tubing string, not just from the gas-lift valve up
  - Makes gas-lift much more efficient, as no short circuiting
- Corrosion inhibition improved as:
  - Entire tubing string is protected, not just from the valve up
  - Allows switching back to superior oil-based corrosion inhibitors
    - Oil based corrosion inhibitors tend to plug gas-lift valves
    - Water based corrosion inhibitors less effective, but used since they resist plugging
  - Atomizing of corrosion chemicals through gas-lift orifices is eliminated
    - Further improving their effectiveness at creating a film

What could these compressors look like?

Here is an one example application:

Ariel Performance Run – 3 Stage

- Based on industry standard JGQ-2 gas-lift package
- Industry standard Cat 3306NA engine
- Rich gas has temps all below 325 degrees
- 588 MSCFPD at 4000#
- Blows through 3rd stage when Pd below 1000 psig

Ariel Performance

ARIEL 7.7.2.2

Company:	Ariel Corporation	Customer:	[redacted]
Quote:		Inquiry:	
Remarks:		Project:	Eagleford Ga

Compressor Data:

Elevation,ft:	500.00	Barmtr,psia:	14.429	Ambient,°F:	100.00
Frame:	JGQ/2	Stroke, in:	3.00	Rod Dia, in:	1.125
Max RL Tot, lbf:	20000	Max RL Tens, lbf:	10000	Max RL Comp, lbf:	11000
Rated RPM:	1800	Rated BHP:	280.0	Rated PS FPM:	900.0
Calc RPM:	1782.0	BHP:	142	Calc PS FPM:	891.0

Disch Event

Services	**Gas Lift**		
Gas Model	Hall		
Stage Data:	**1 (SG)**	**2**	**3**
Target Flow, MMSCFD	0.600	0.600	0.600
Flow Calc, MMSCFD	0.588	0.588	0.586
BHP per Stage	48.8	46.5	40.2
Specific Gravity	0.7500	0.7499	0.7504
Ratio of Sp Ht (N)	1.2380	1.2469	1.2685
Comp Suct (Zs)	0.9809	0.9461	0.8344
Comp Disch (Zd)	0.9725	0.9440	0.9702
Pres Suct Line, psig	80.00	N/A	N/A
Pres Suct Flg, psig	78.00	348.19	1194.37
Pres Disch Flg, psig	354.69	1205.80	4040.14
Pres Disch Line, psig	N/A	N/A	4000.00
Pres Ratio F/F	3.994	3.365	3.354
Temp Suct, °F	80.00	130.00	130.00
Temp Clr Disch, °F	130.00	130.00	160.00
Cylinder Data:	**Throw 1**	**Throw 2**	**Throw 2**
Cyl Model	5-1/8M	3-3/4SG-CE	1-3/4SG10-HE
Cyl Bore, in	5.125	3.750	1.750
Cyl RDP (API), psig	454.5	2318.2	5545.5
Cyl MAWP, psig	500.0	2550.0	6100.0
Cyl Action	DBL	CE	HE
Cyl Disp, CFM	124.6	31.1	7.4
Pres Suct Intl, psig	72.24	319.10	1184.09
Temp Suct Intl, °F	86	135	134
Pres Disch Intl, psig	375.28	1294.85	4149.42
Temp Disch Intl, °F	268	320	313

Removes the Limitations of Traditional Gas-Lift

- Alternative of Reverse Flow addresses problem of friction loss, as cross-sectional area is up to 3 times greater
  - 5-1/2” 23# casing with 2-1/16” IJ tubing has annular capacity of .0957 ft3/ foot
  - 2-7/8” 6.5# , the largest size for 5-1/2” casing, has capacity of .0325 ft3/ foot
  - Annular area is 2.95 times the tubing area
  - High Pressure Gas-Lift enables large volumes to be transported to the bottom of the well through a small conduit such as 2-1/16” IJ tubing, or 1.5” coil tubing
- Great alternative to failure prone ESP’s
  - High flowrates possible due to less restrictive annular flow
  - Nothing downhole other than a tubing string limits risk
  - Compressor moved every six months to new wellsite
  - Eliminates huge ESP failure costs, appealing to operators

Why is Gas-Lift Positioned to Claim this Market from Rod Pumping?

- Gas-Lift not bothered by offset fracs, frac sand production, and wellbore deviation
  - April 2017 Journal of Petroleum Technology Magazine: Oil and Gas Producers Find Frac Hits in Shale Wells a **Major Challenge**

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High Pressure Gas-Lift can be used to prevent damage from Frac Hits

Quoting from the “Is Prevention Possible” section

- The current understanding of how frac hits develop is so limited that there is no consensus on how to prevent them. Many of the ideas tested so far have shown mixed results, according to those familiar with field operations.
- Another idea is to recharge the offset wells using gas, either natural gas or carbon dioxide, neither of which should lead to well damage. Though Barree is not aware of any companies that have tested this approach, he said “there is a good chance that it could help.”
- If gas compression facilities are available, operators could continuously pump natural gas into offset wells to increase their local pore pressure to ward off an oncoming fracture.
- Barree said the potential of this approach is supported by instances where wells have been shut in prior to an offset hydraulic fracturing operation and were shown to have built up enough pressure to reduce the frequency or severity of frac hits.

Where does industry stand on High Pressure Gas-Lift?

- These high pressure gas-lift concepts were introduced first to industry at the ALRDC 2016 Gas-Lift Workshop
- SPE 187433 covering this topic will be presented at the October 2017 SPE Annual Technical Conference and Exhibition in San Antonio
- Operators want to rent high pressure gas-lift compressors now
  - Some are willing to sign long term leases
  - Some have already purchased since they cannot rent them
  - Hydrocarbon condensation and other issues need to be resolved, and not extended into the high pressure gas-lift compressor design

I repeat, “Can we get together on a larger scale and design compressor packages better suited for gas-lift?”

The Internet of Things: Let's apply some engineering

SPE 181773 showed data from two 75 HP electric driven wellhead compressors where hydrocarbon condensation was prevented via temperature control. Not mentioned was:

- All compressor control functions could be accessed through a password protected webpage hosted by the PLC onboard fileserver
- KPI's were calculated by this powerful PLC based on engineering formulas, and compared to historic values for:
  - Actual versus theoretical discharge temperatures (valve indicator)
  - Actual versus theoretical compression ratios (another valve indicator)
  - Actual versus theoretical gas throughput (overall performance indicator)
  - Lubrication actual versus desired rates, realtime rod loads, etc
  - Predictions/alarms made on which components are under-performing/failed
- Scrubber dump counts used to adjust cooler setpoints

Phase Transition Control

Another Internet of Thing (IoT) device by Encline that pulls data from a Murphy Centurion, makes calculations as done on the preceeding slide

- Primary purpose is to eliminate hydrocarbon condensation by either:
  - Performing PID control of cooling fan speed (VFD's)
  - Performing PID control of internal louver position (fixed speed engine drive)
- Secondary purpose is to control individual air motors on each cooler
  - Utilizes Encline's patent pending Phase Transition Control method to push adiabatic heat of compression from first and second stages to third when negligible work being done on third stage (send hot gas to wellhead)
  - Realtime temperature setpoint adjustment based on cylinder outlet temps and cooler outlet temps

Final Thoughts

- I hope you were encouraged by the outlook for gas-lift taking a pre-eminent role as the artificial lift method of choice for horizontal wells
- I hope this industry and the E&P operators will get together, and come up with superior compressor designs that make gas-lift better
- Keep in mind that in this world driven by technology, the guy who has the better widget will get the business. There is enough new market for new companies to be created, and old companies to be rejuvenated. This is your wake-up call.

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