# Section 7

# Injection Gas Delivery Considerations

# In this section:

- Surface injection pressure constraints
- Gas quality issues
- Injection rate constraints

# Survey Question –

What is the “normal” Gas Lift Compressor Discharge Pressure in the fields you operate/normally deal with?

**2020 ALRDC Artificial Lift Workshop**

**Cox Convention Center, Oklahoma City, OK**

**February 17 - 20, 2020**

# Optimizing Gas Lift Pressures to Increase Production and Lower Costs


Larry Harms - Optimization Harmsway LLC

Tom Nations - Nations Consulting Inc.

# How did we get 1000-1200 psig design pressure for gas lift?

- Casing Max. Working Pressure was a factor early days
- Slow Speed Reciprocating Compressors used onshore had big cylinders with limited working pressure (centrifugal compressors used offshore and Alaska)
  - Now we have high speed recips, smaller cylinders, CNG pressures (4000+ psig)

***Jim Hall Gas Lift Best Practices/Suggestions (JH)*** **Increase Lift Depth**

- More production for the same gas.
- Requires less gas for the same production.
- Fully use available lift gas pressure.

# ANSI Piping and Flange Ratings



| ANSI Class | 150 | 300 | 400 | 600 | 900 | 1500 | 2500 |
|---|---|---|---|---|---|---|---|
| Temperature °F | Maximum Allowable Non-Shock Pressure PSIG | | | | | | |
| -20 to 100 | 285 | 740 | 985 | 1480 | 2220 | 3705 | 6170 |
| 200 | 260 | 680 | 905 | 1360 | 2035 | 3395 | 5655 |
| 300 | 230 | 655 | 870 | 1310 | 1965 | 3270 | 5450 |

From www.piping-designer.com

**CAUTION These pressures vary depending on different rating factors. Do your own Checking, these values are only rough estimates**

# What Should Determine Injection Pressure?

- Well Performance

- Probable that for unconventionals 8000'+ TVD that ANSI 900 (1800+ psig) is the optimum

# Incremental Cost ANSI 600 Upgrade to ANSI 900 on compressor package

- Before unit is built- $5 to15,000
  - (in rental terms $2-600/month)
- Retrofit existing units much more expensive
  - New compressor cylinder required

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## The Compressor Rental Dilema

- Dominated by bidding/low price
- If you ask for it, they will build it
  - If its not “normal” expect required 3-year rental term
- Facilities and Prod Eng., Operations/ Maintenance and Procurement must agree
- On the plus side, Pressures on some units may be already be higher than ANSI 600

# Getting Pressure from the Compressor Discharge to the Wellhead

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- ***Jim Hall Gas Lift Best Practices/Suggestions (JH)*** - Fully use available lift gas pressure.

- Minimize pressure drop in the injection gas lines – usually not a problem except long lines
  - Minimize low spots that will trap liquids

- JH - Calculate line pressure upstream of the flow control valve and assume a minimum 10% pressure loss across the flow control valve.
  - JH - Maintain at least 10% pressure drop across a gas flow control device in order to have stable flow. Less differential than 10% of upstream pressure will result in surging flow.
  - Obviously in tension with first suggestion above. Work with controls design to minimize pressure drop needed
  - Question for facilities/systems – How can we get good injection rate control and maximum injection pressure at the wellhead?

# Getting Gas from the Compressor Discharge to the Wellhead

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- JH - Do not try to lift two wells with a lift gas line that splits downstream of the flow control valve.
- JH - Every well should have it's own remotely actuated flow control valve, flow meter, line pressure sensor, and line temperature sensor.
- JH -  For Injection Pressure Operated (IPO) GL valves you must decrease injection pressure to lift deeper.
  - **MUST have injection rate control.**

# Gas Quality Issues - Liquids

- JH - Dry your lift gas - Lift gas should be dried to a dewpoint which is less than any temperature expected in the system. This includes temperature loss across the flow control valve (check at expected pressure and temperature).
  - Rich HC means you would have to have gas treatment on every installation

**Probably Impossible for Onshore Unconventional Wells**

# Gas Quality Issues - Liquids

**Realistically for Onshore Unconventional Wells**

- If you can get high pressure gas downstream of a dehy (or gas plant/JT skid) for normal options, use it.
  - 7#/MM standard water content in gas contracts, not adequate for Low temps, Design adjust dehy for Temp. needed
  - Dehy must have adequate working pressure
- Put a separator directly upstream of the injection control valve
- Best practice for pad and WH Compression, keep gas hot on discharge of cooler to minimize liquids
- Minimize/Insulate the pipe from control valve to WH

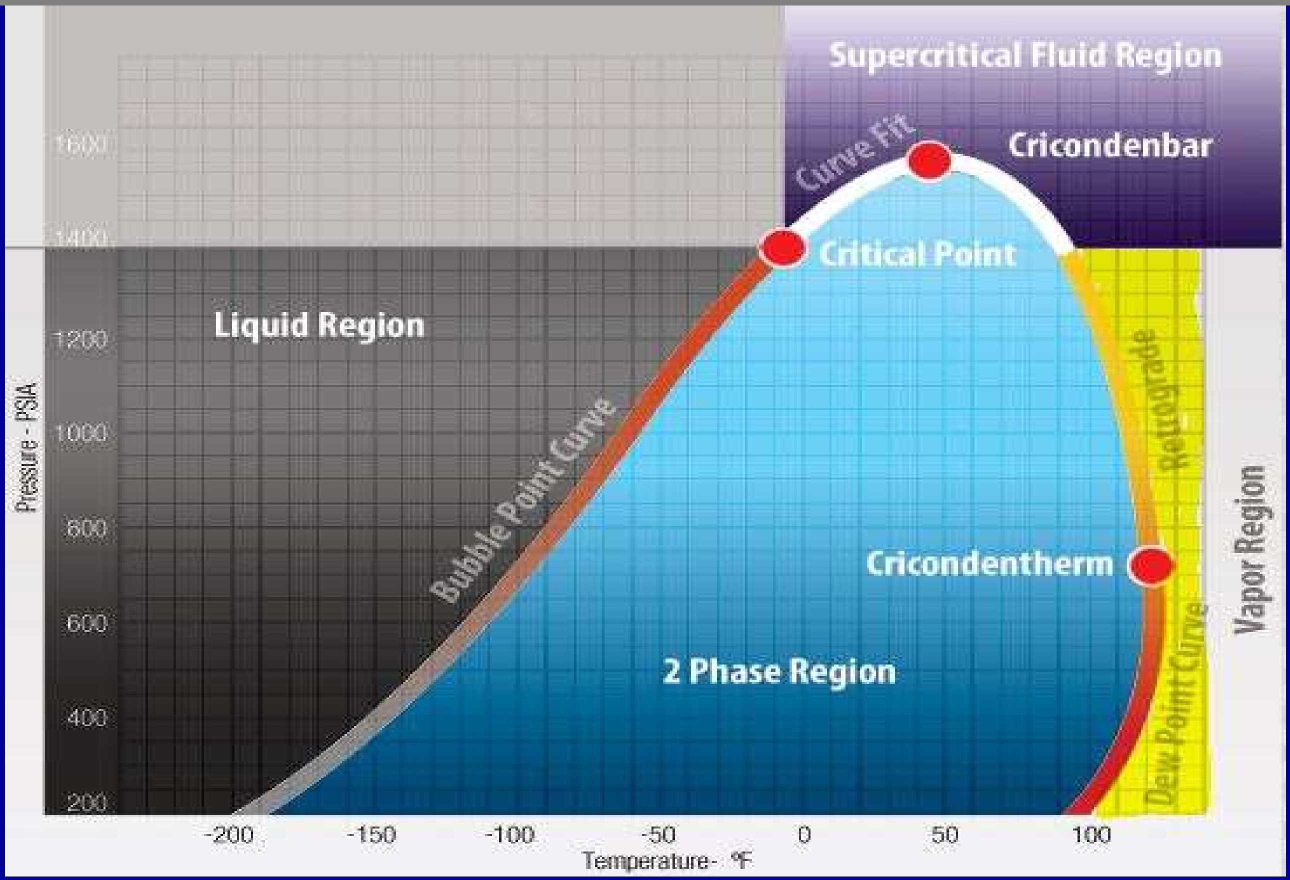
# What about liquid "specs" – gal/MM, etc., the cynical realist view…

- There is no way to easily measure this
- Separation very difficult to design with this as a spec.
  - Coalescing filter separators would probably be needed on every well to meet "common specs"
- Suggestion is do the best you can to minimize liquids and
- If you want minimum liquids, the way to get it is to keep the gas HOT

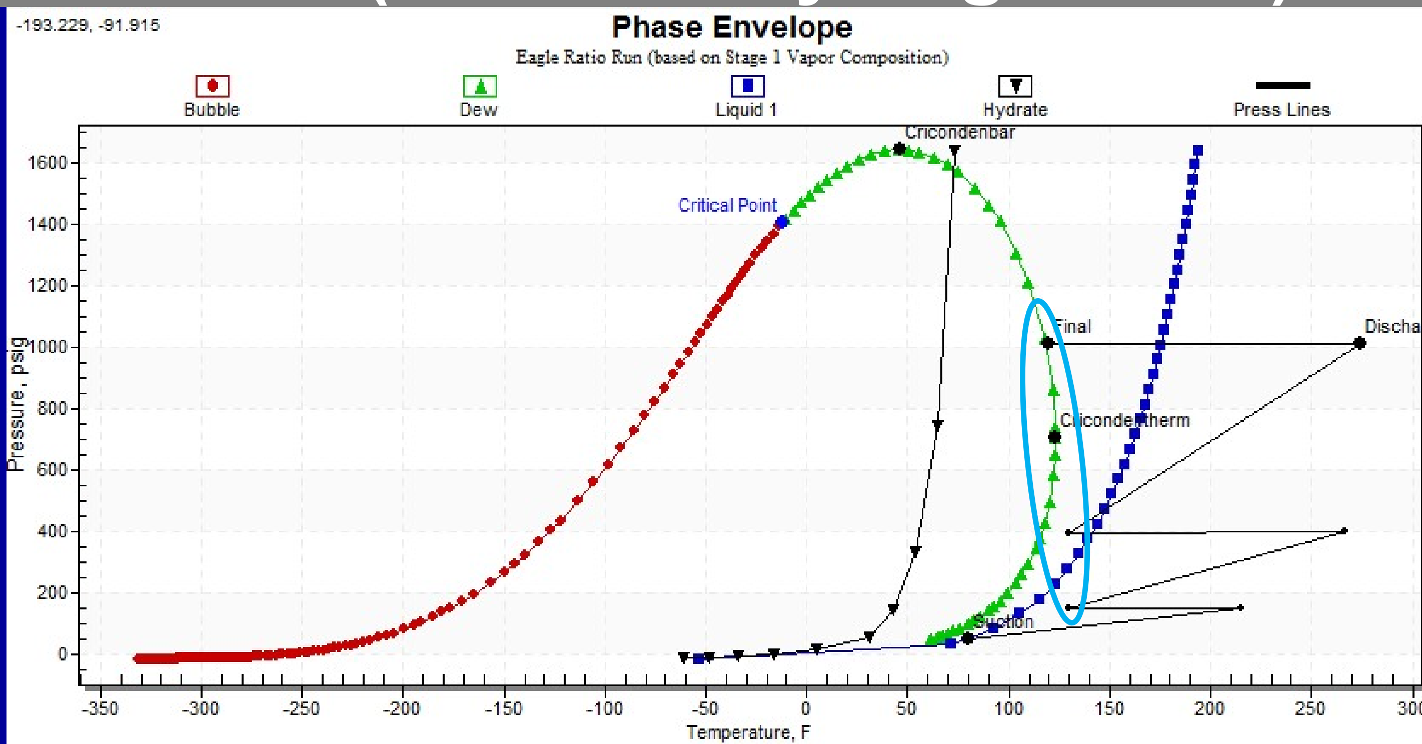
# Improving Performance of Gas Lift Compressors in Liquids-Rich Gas Service

- **Will Nelle** Estis Compression
- **Bill Elmer, P.E.** Encline Artificial Lift Technologies

# Understanding Compression: The Phase Diagram



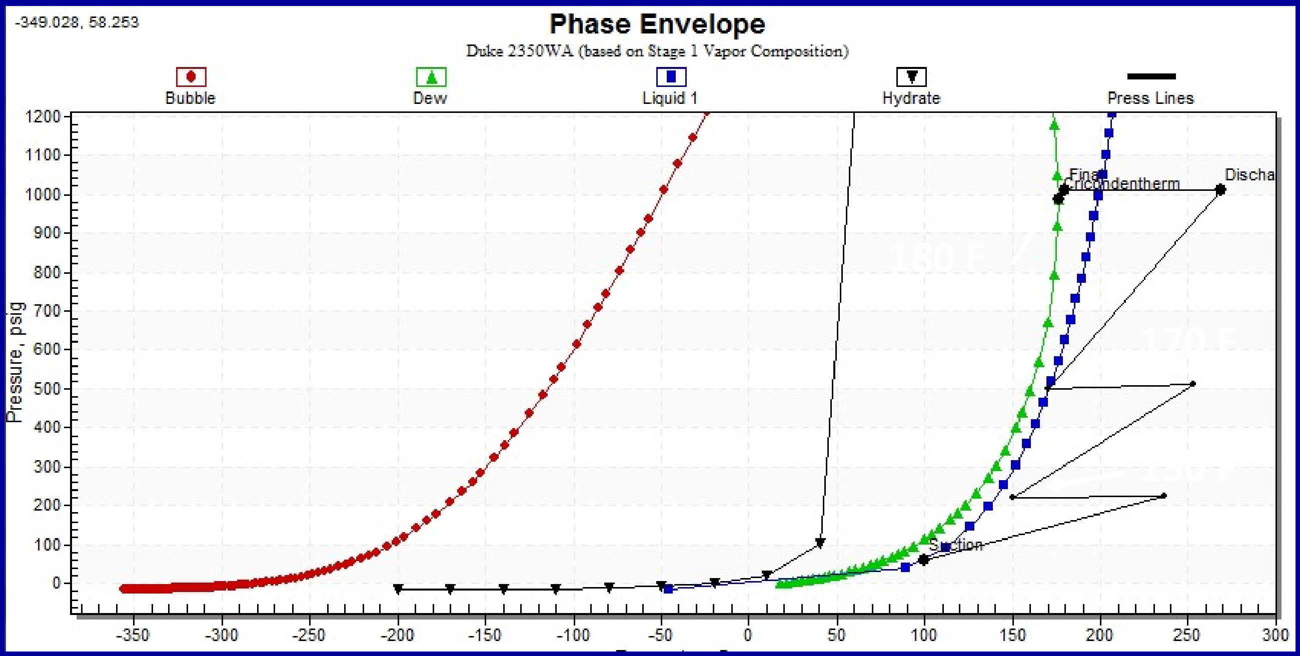
# How does this change for richer gas? 100 F Ambient (0.76 Gravity Eagle Ford)




- **Temps kept above 120 F, no hydrocarbons condense**

# Obvious Solution: Prevent by Elevating Gas Temperatures

- **Even super-rich 0.97 gravity gas can remain vapor with 150 to 180 F temps**



# What if temps could be kept in 100% Vapor range to the wellhead?

- Increased compressor uptime
- Minimize hydrate formation
- No increase in VRU load or flare emissions
- No need for methanol injection
- Warm corrosion chemicals work better
- No mess when blowing down compressor
- No need to oversize compressor
- Well performance improved
- Paraffin deposition prevented

# Reality: Facility Engineers prefer old ways of centralized compression

- **Pipelines may cool gas to earth temp ~ 70F**

| Gas Type | Gas Gravity | Condensation % | BBL per MM |
|---|---|---|---|
| Eagle Ford | 0.76 | 3.85% | 23.1 |
| Permian - Rich | 0.80 | 8.46% | 52.4 |
| Permian - Rich+ | 0.97 | 34.5% | 216.6 |

- **Some of this will re-vaporize as reaches downhole temps, but how much?**

***Wellsite compression mitigates this problem***

# Condensed liquids to tank?

– Can overwhelm TVRU capability
  - 5% of 5000 MCFPD is 250 MCFPD (45 HP)
  - Results in excessive flaring, less gas sales
– Plumb interstage scrubbers to low pressure separator upsteam of sales meter, relieving TVRU, reducing recycle
– Inlet and fuel scrubbers still dump to tanks
– Are your compressors pre-plumbed for this?

# Presence of Liquid at Wellsites

– Reduces gas measurement accuracy

– Gas lift valves may handle slug of liquid
  - If centralized compression, slugging an issue
  - Significant slug may cut orifice, or multipoint

– Last well on common line may receive 100% of condensation

# Other Contaminants in Lift Gas

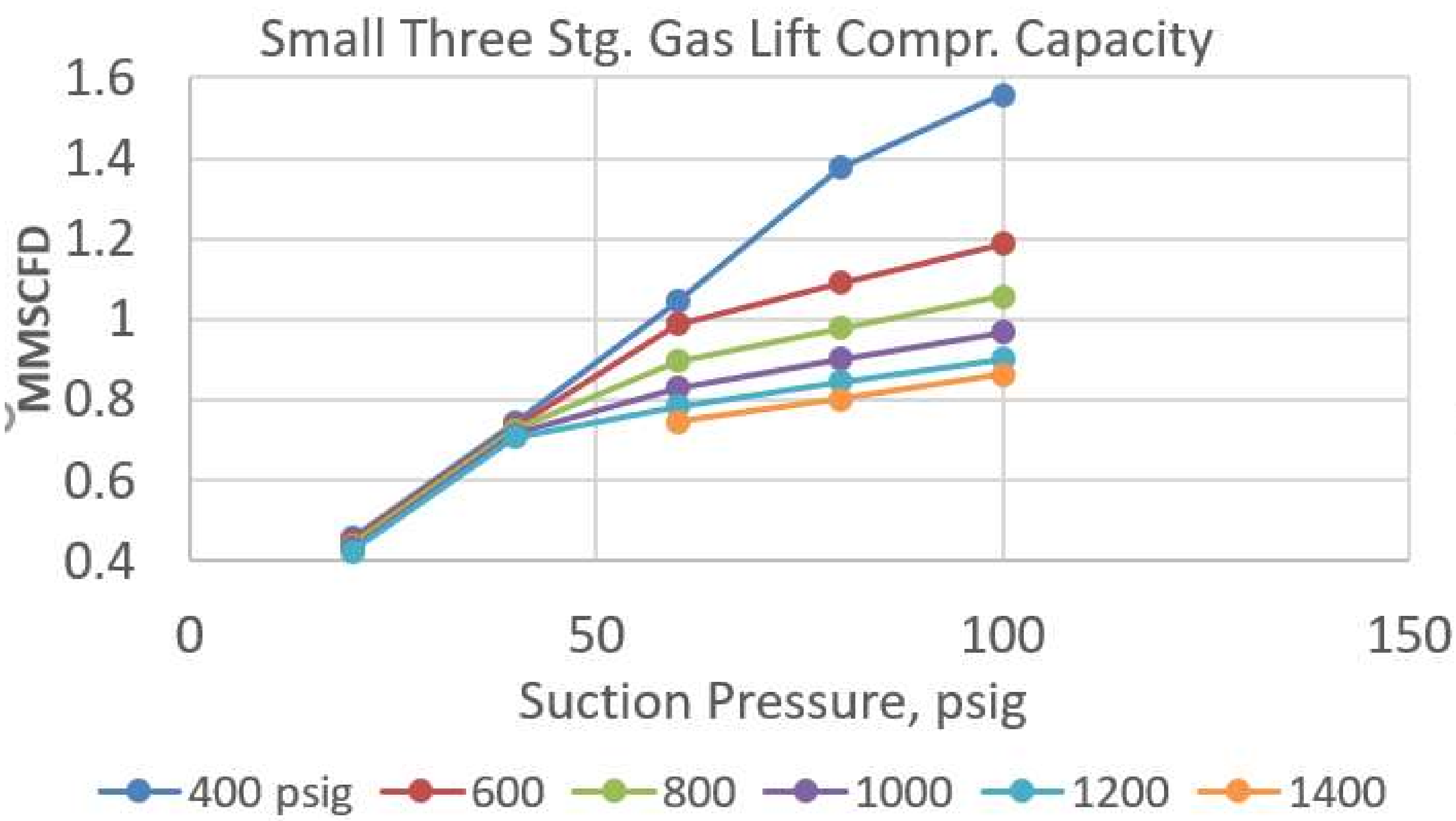
- $CO_2$ – Hard to remove without major treatment cost, better to treat with corrosion inhibition as needed
- $H_2S$ – Most unconventionals have low amounts but concentration may increase over time, not always the worst corrosion agent
  - Higher Concentrations can form a corrosion resistant surface layer on carbon steel pipe
  - Most use scavenger/bubble towers if necessary
- May need to treat for Sulfur Reducing Bacteria (SRB's)
- All Equipment, surface and downhole needs to be designed to handle $CO_2$/$H_2S$ expected/possible

# Corrosion and Hydrate Treatment

- JH - Do not inject Hydrate inhibitors (or Corrosion Inhibitors) into the lift gas manifold. The liquids will not split up the same way as the gas. Inject hydrate inhibitors into individual well injection lines.

- Monitor corrosion rates and treatment rates over time and adjust treatment as necessary

# Injection Rate Constraints - Example of Compressor Flexibility/Options



# Est. Compression Horsepower (adiabatic, k=1.2) for 1 MMSCFD Capacity (lift gas and/or sales)



| | Suction Pressure, psig | | | |
|---|---|---|---|---|
| ***Discharge Pressure, psig*** | **20** | **50** | **100** | **200** |
| ***500*** | 153 | 111 | 76 | 42 |
| ***1000*** | 204 | 157 | 118 | 79 |
| ***1500*** | 236 | 186 | 144 | 103 |
| ***2000*** | 261 | 208 | 164 | 121 |
| ***4000*** | 325 | 266 | 217 | 169 |

# Max. gas lift rates in Unconventionals



- Annular lift
- Bakken 7” Casing
- 4 MMCFD is about max. needed on an individual well with “normal” gathering pressures

# Constraints Injection rate and pressure

- JH - More Gas = More Oil, but only to a point. You may lose oil with more injection gas after that point. (Assumption that FTP is constant)
- JH - Maximum production does not mean maximum efficiency, or maximum profit.
- Compression Limits in Horsepower, Cylinder Size, Working Pressure
- Piping limits – Pressure Rating/Pressure losses
- Must have enough compression to lift wells at optimal rates

# Section 8 Surface facilities design concepts

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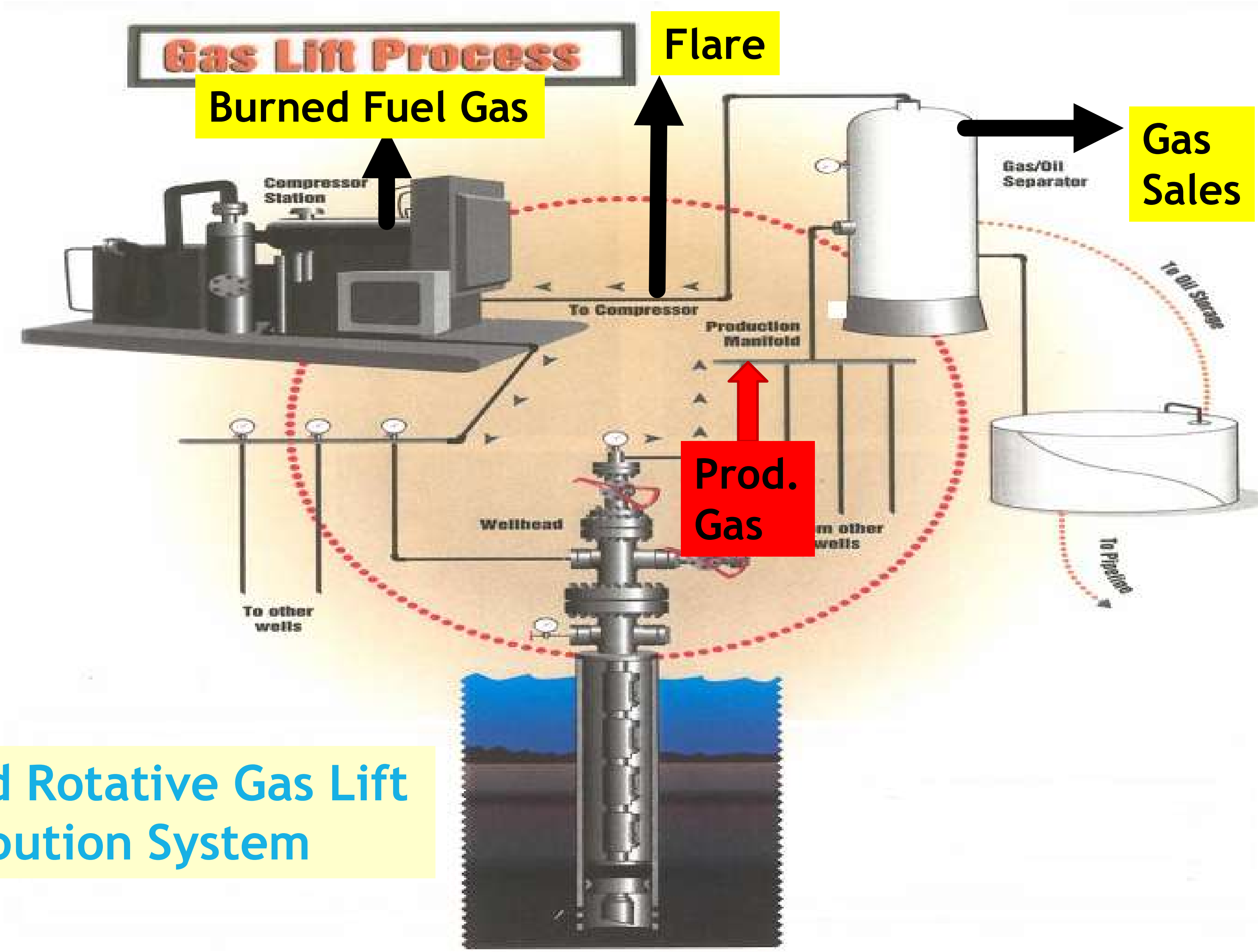
# In this section:

- Closed rotative gas lift gas distribution system
- Pad, comingled, or single well compressor systems
- Gas quality impact on surface facilities
- Effects of zero tolerance for venting or flaring of natural gas
- Equipment reliability
- System backpressure
- Well testing / flow measurement

# Survey - Which of these best describes you?




# Closed Rotative Gas Lift Distribution System

# How much gas do we need to run a gas lift system?



Natural Gas Mass Balance **In - Out = Accumulation**

- In = Produced Gas from the well
- Out = Fuel Gas + Sales Gas + Flare

For steady state operations

- Accumulation = 0
- Sell Gas/ Flare only used when excess gas is entering the system
- New Gas Mass Balance is In – Out = 0, Produced Gas – Fuel Gas = 0
- Produced Gas = Fuel Gas

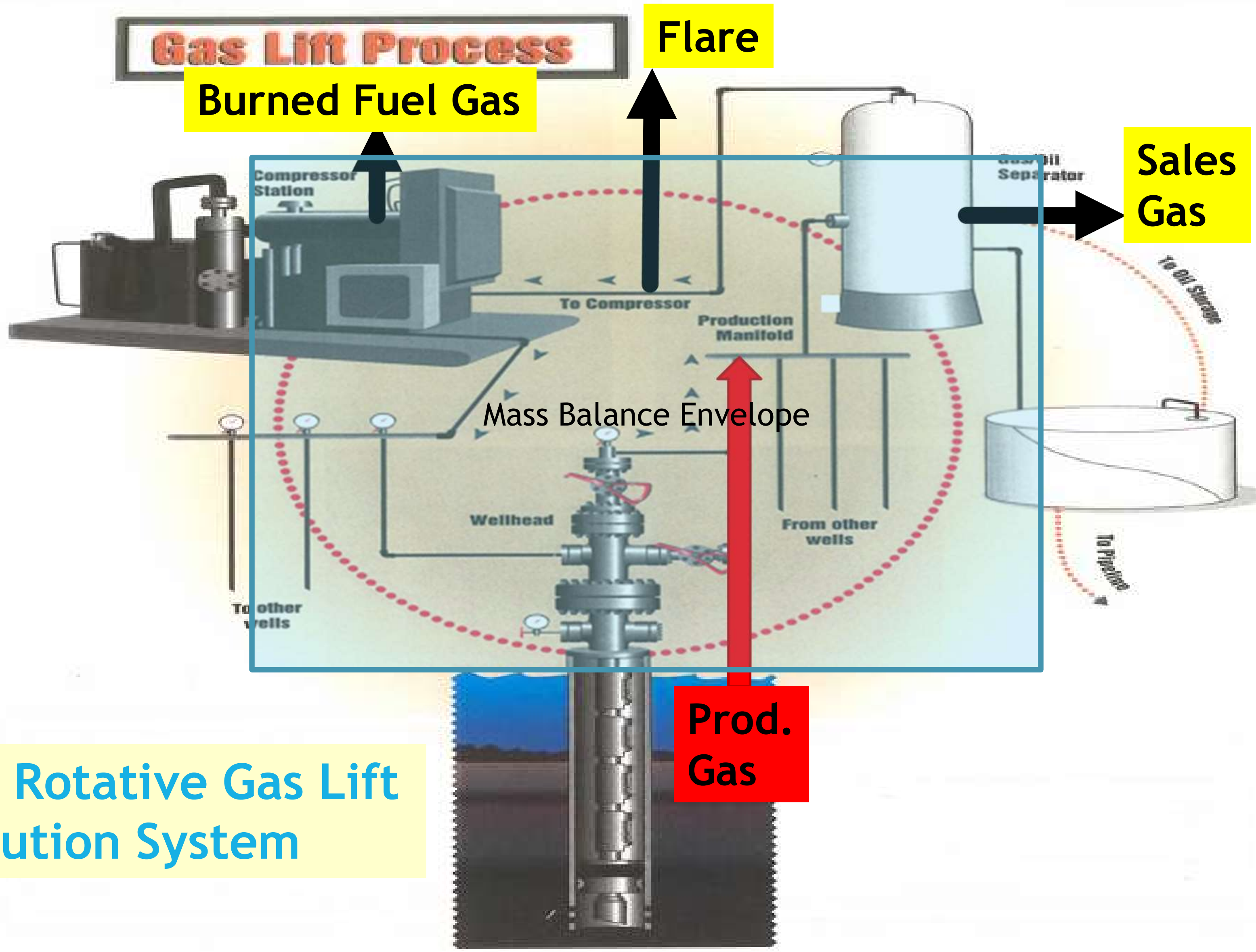
**So as long as you keep from flaring and only sell gas when there is excess, IF Produced Gas is equal to or more than Fuel Gas the system will operate. (e. g. Early Life 80 MCFD max, late 15 MCFD)**

# Fuel Gas Rule of Thumb

100 Horsepower =

**18 MCFD of 1300 btu/scf fuel gas**

**Is burning more fuel gas a cost or a benefit???**




# Closed Rotative Gas Lift Distribution System

# Other Items from the Mass Balance

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- To charge up the system, Produced Gas must be more than flare gas
- When you “blow the system down” it takes more time to charge the system back up
- Sales Gas Has to be controlled to keep steady system pressure

# Single Well vs Multi-well pads and Facilities

## Single-well

- Advantages
  - Lower up-front capex
  - Continuous fluid measurement
  - Compressor near wellhead
  - Reduced back-pressure
- Disadvantages
  - Higher long-term capex/opex
  - HSE Issues
  - Greater downtime
  - Less flexibility / redundancy

## Multi-well

- Advantages
  - Lower overall capex
  - Improved operational efficiency
  - Easier fluid management
  - Greater flexibility
  - Reduced downtime
- Disadvantages
  - Less frequent well testing
  - Greater back pressure
  - Higher up-front capex with upfront planning
  - What affects one well affects many
  - Simultaneous Operations

# Pad, Central (larger), or single well (smaller) compressor systems

- Large compressors are 10-15% more efficient that small compressors
- Costs are less for larger units
- Smaller compressors much easier to set/move
- In general, large compressors are monitored closer and get higher priority/quicker response than smaller compressors
- Logistics of operating, maintaining and optimizing single well compressors for big fields can be overwhelming

# Gas quality impact on surface facilities Covered some in Section 7

- If you have specific questions, please put in the Q&A

# Survey - What do you see causing the most problems in surface equipment?

# Equipment Reliability - Compressors

- Compressor reliability is KEY to all GL operations
- Design reliability into the compressor – Remember the rental dilemma
- Remotely monitor and alarm compressor operations

# Equipment Reliability - Compressors

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- Monitor, document  and track all causes of compressor downtime and focus proper resources on reducing the major causes

- Eliminate finger pointing, it doesn’t matter if compressor downtime is “on or off skid”, caused by compressor company or due to routine maintenance/overhauls – **Minimize downtime**

What should run time be (not mechanical availability)?

  - Below 90% - Unacceptable
  - 90-95% - You can do better
  - 95-98% - Good
  - 98%+ - Excellent

# Equipment Reliability - Compressors

- Engine driven
  - Minimize liquids in fuel gas
  - Always use actual fuel gas analysis to set up compressor
  - Engine horsepower adequate with actual elevation of location over entire range of ambient temperature operating (high temp. and elevation derate horsepower)

- Compressor/scrubbers
  - Keep temp. of gas above HC Dewpoint
  - Monitor cylinder discharge temperature and compression ratio to identify and proactively fix valve problems
  - Set suction and recyle controllers correctly
  - Use RPM control to control compressor suction or discharge pressure/rate
  - Clean out scrubbers/mesh pads as routine maintenance

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# Redundancy of equipment could help…

- Because upstream operations can endure "shut downs" (no loss in reserves) fairly easily, have "decent" run time and "flush" production, economics almost never favor redundant equipment
  - Critical spare availability needed.
- In general need **at least** 20% excess capacity to work through surges
- Consider staging in compressor capacity, provide flexibility over time and prevent having one compressor trip result in complete shut down.
  - Pad compression – 2 units at peak
  - Large Central compression – more than 2 units at peak
  - Develop plan up front!

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# System Backpressure

- JH - Remember that your well lives in a system. Everything you do to a single well affects the other
  - Surging is the same, anything that changes rate/pressure affects all other wells
- JH - Remove wellhead chokes.
- JH - Streamline surface flowlines.
  - Use 45 Degree elbows and the fewest number/shortest pipe run length possible
  - Minimize places liquid can accumulate
- Use compressor horsepower available optimally to lower FTP

# Effect of Surface Pressure on Gas Lift System- 4 conventional wells (Integrated Production Model)

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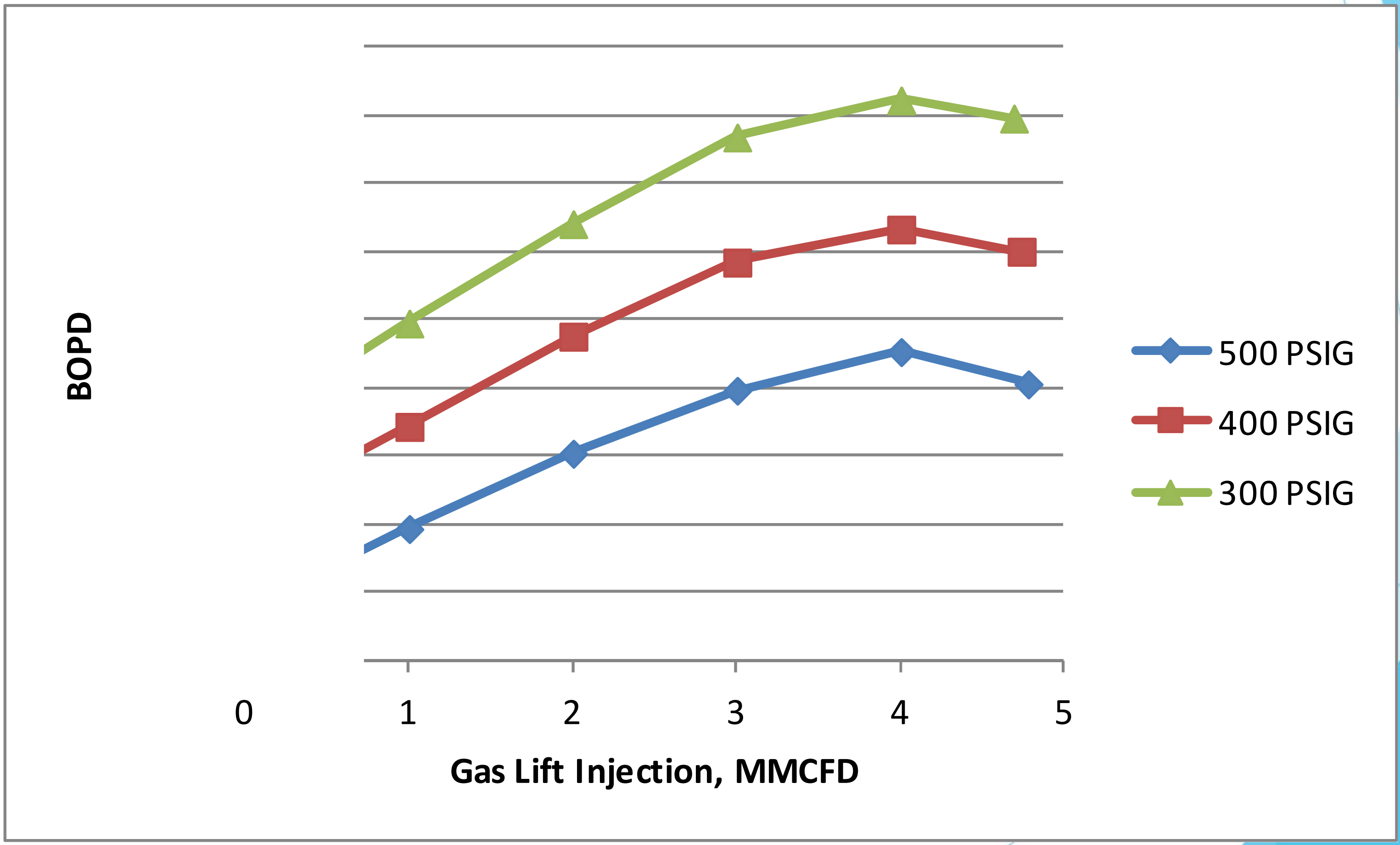


# Effect of FTP on well performance

| FTP, psig | BLPD | Lift Gas, MCFD |
|---|---|---|
| 260 | 660 | 2000 |
| 50 | 830 | 800 |

# SPE 52207
# Improved Blowcase Operation and Design

William G. Elmer
EOG Resources, Inc.

# What is a ‘Blowcase’?

- Definition: a pressure vessel that collects fluid at low pressure, but when full, utilizes high pressure gas to dispel the collected fluid into a medium pressure system.
- A blowcase performs the same function as a pump, only utilizes high pressure gas as the energy supply.

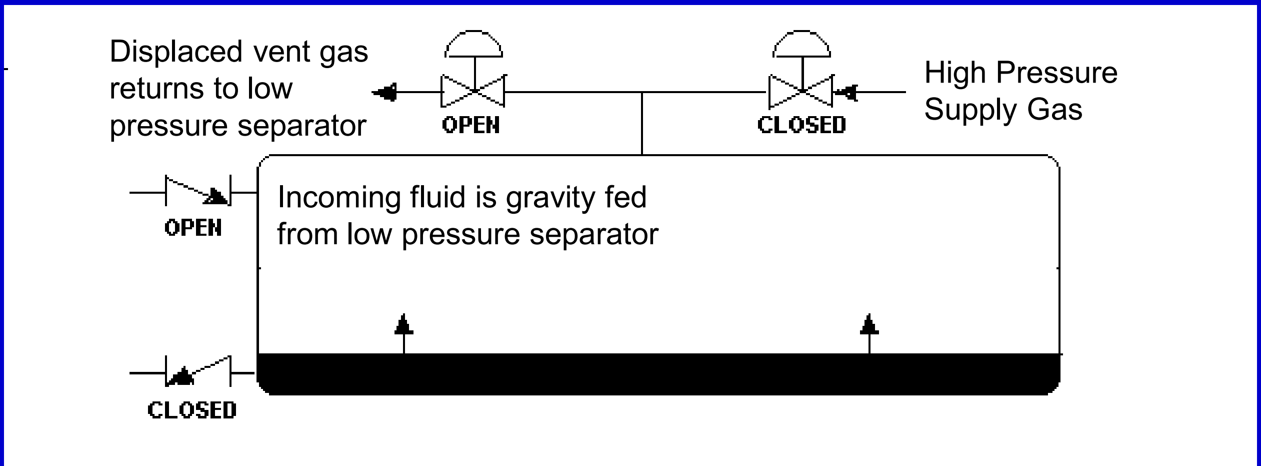
# Blowcase Advantages

## over conventional pump and tanks

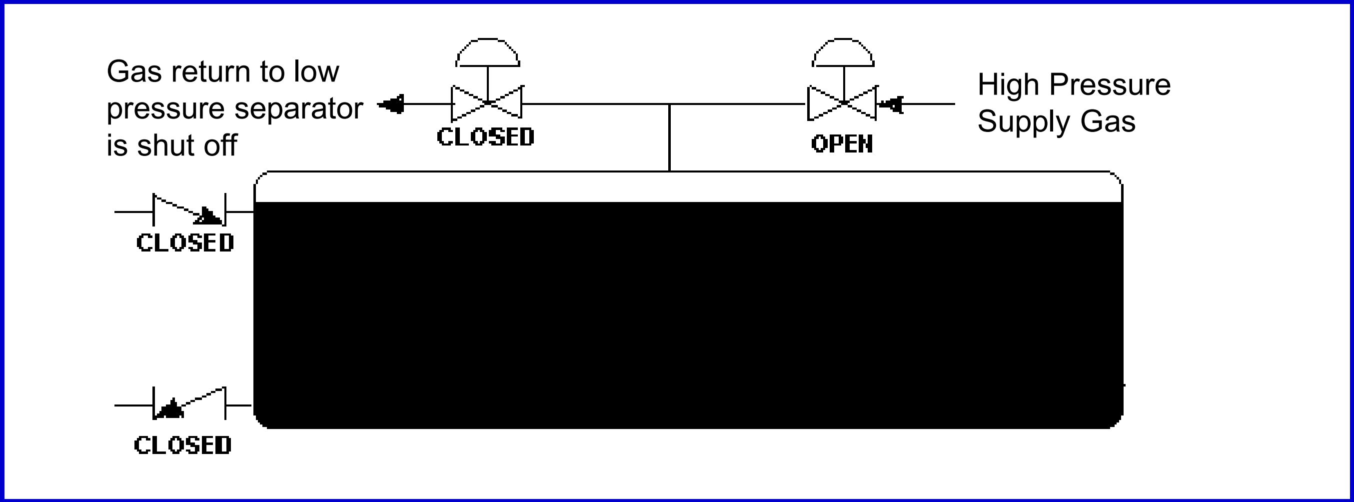
- Elimination or downsizing of tank battery
  - tanks, gas blankets, TVRU, permitting
- Elimination of pump and electric power construction
- Elimination of oxygen related corrosion from faulty gas blankets and TVRU's.

**Can minimize System Pressure in Centralized Systems**

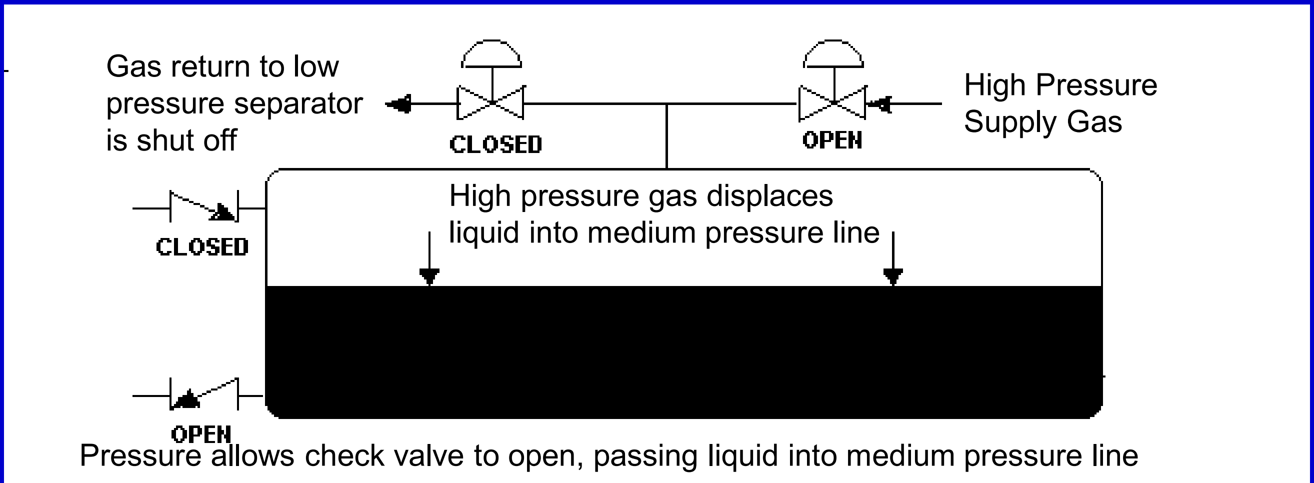
# Step One - Fill



# Step Two - Pressurization

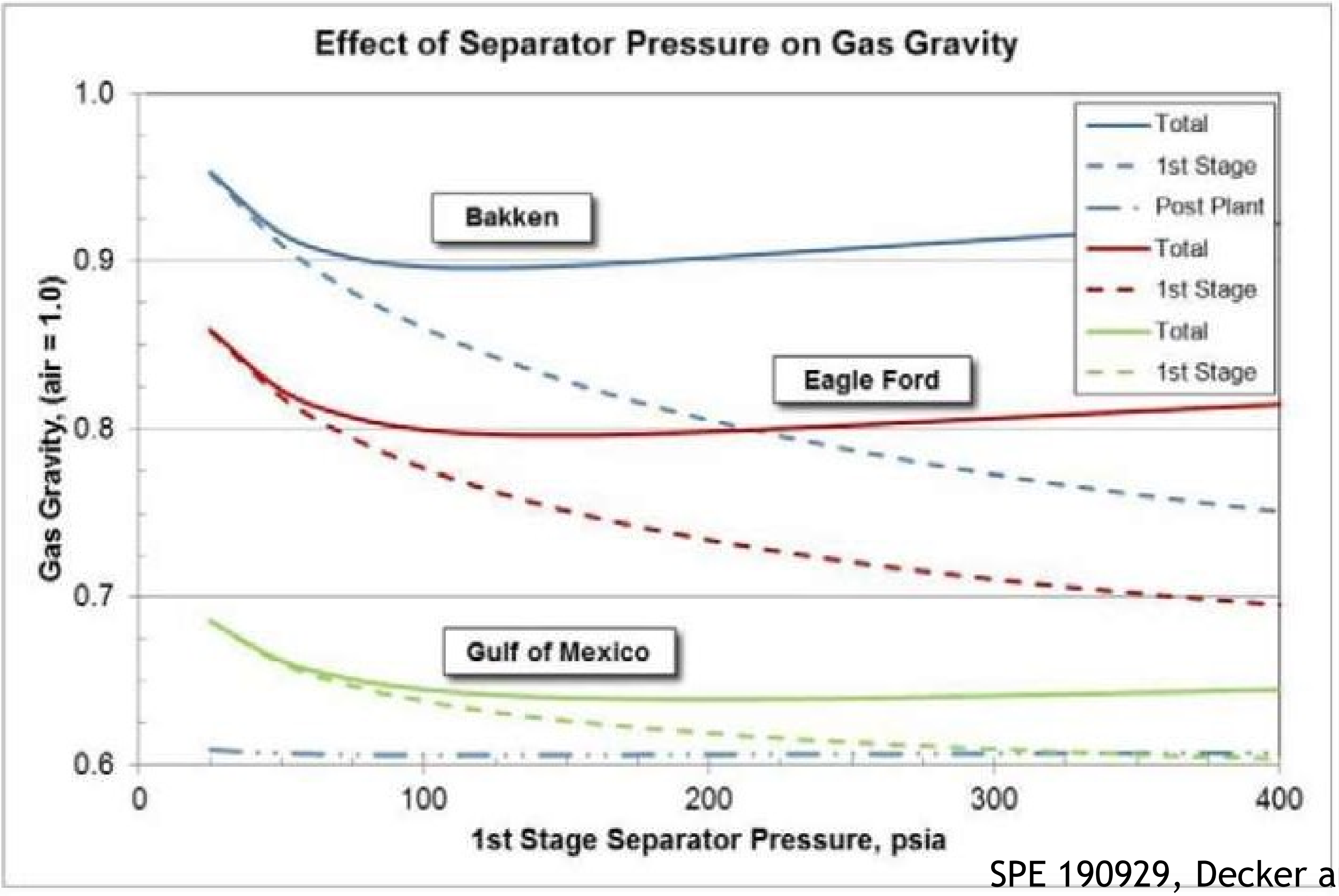


# Step Three - Evacuation



# Conclusions

1. The blowcase is a viable alternative for transferring fluid, providing a source of high pressure gas is available.
2. A blowcase may be preferred to conventional tanks and pumps when containment of tank vapors and elimination of oxygen is desired.
3. Blowcase capacity is a function of level control setpoints, the pressure difference available for displacing fluid, and piping limitations.




SPE 190929, Decker and Sutton

**Figure 4—Gas specific gravity from Gulf Coast and unconventional resource play sources**

# Effects of zero tolerance for venting or flaring of natural gas

# Getting Real on Emissions - Pause

- Methane about 24 times worse than $CO_2$ as a greenhouse gas
- Ethane, Propane, Butane, etc. get progressively worse

# What if you decided to not have any hydrocarbon/CO2 emissions on site

**Wells**

- Never swab or "unload" well to a tank
- Shut in wells when compression goes down

**Relief Valves**

- Make sure all working pressures guarantee that no relieving occurs
- Consider using Rupture Disks as relief valves may leak

**Controls**

- Use air (or electric) for all controllers

**Run all Vents to Vapor Recovery or flare**

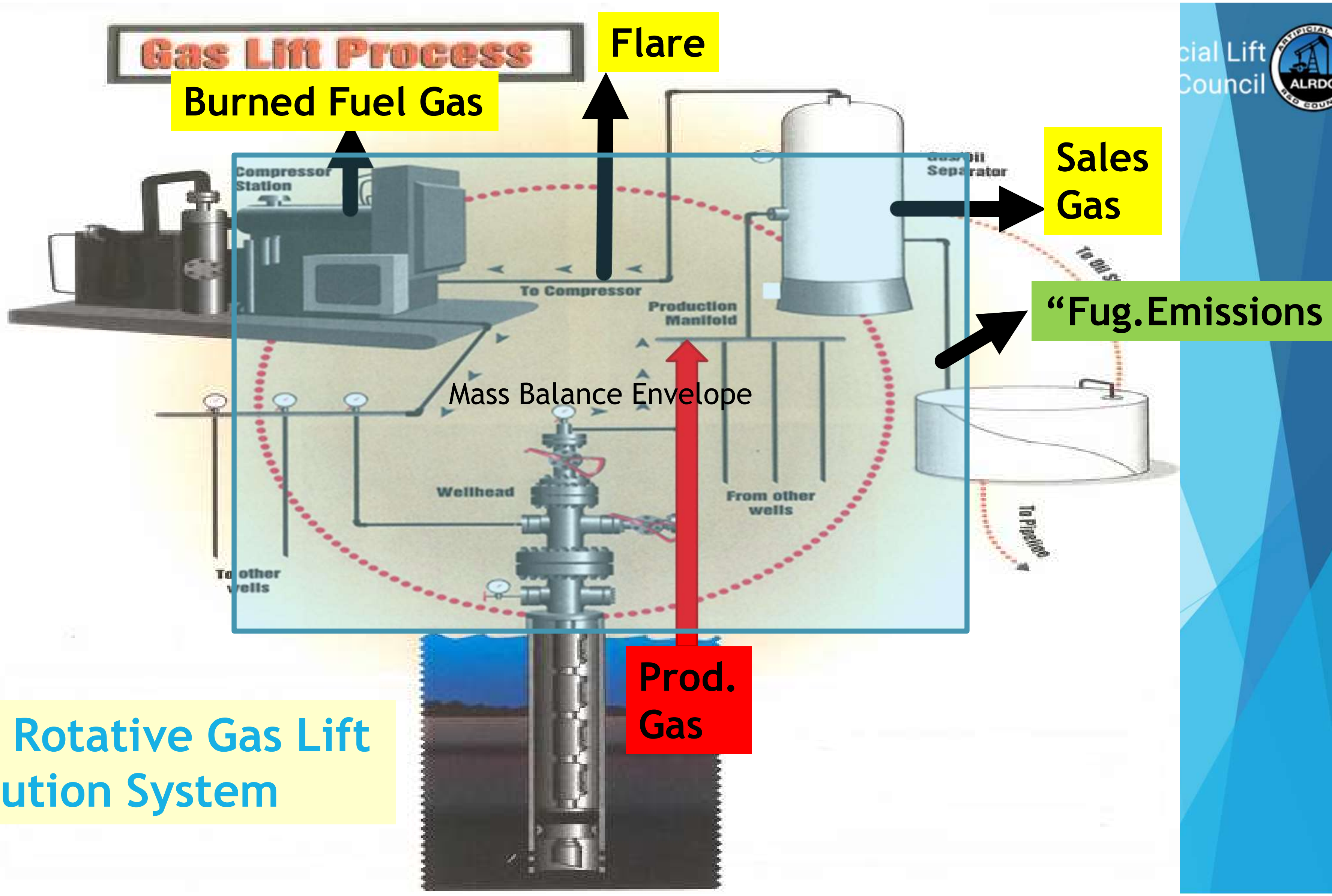
# What if you decided to not have any hydrocarbon/CO2 emissions on site

**Compressor**

- Driver – Electric
  - If electric not possible - lowest fuel consumption natural gas driver, centralized system
- Minimize need to blowdown and run all blowdowns to flare and limit rates
  - Design send high pressure gas to the suction side (upgrade scrubber/separator pressure) and startup with substantial pressure on the unit.
  - Recover gas leaking from valve packing, engine

**Tanks**

- Put a positive pressure gas blanket and VRU on all tanks
  - Must have enough flow to keep up with tank loading
  - Eliminates Oxygen/minimizes corrosion and static concerns




Closed Rotative Gas Lift Distribution System

# Measurement/Metering

- Almost everything (optimization and engineering wise) depends on having reasonable estimates of individual well production!

# Well Testing – From JH GLBP’s

- Monitor FGOR repeatability as a QC method.
- Obtain BS&W samples at a turbulent point, close to the wellhead.
  - (Better yet, produce to a tank for better BS&W numbers and rates)
- If Test Separator Pressure is different from Production Separator Pressure, the test will not be representative of normal conditions.

# Well Testing Additional Items

- You must have a way of determining individual well production rates
  - Continuous is best for quick response to drops in production and easy remote production optimization
- Use ratio of actual production to test/individual well rates as a QC method of measurement and monitor over time
  - What happens to liquid meter downstream of a separator?
  - Meter should be upstream of the dump valve
- Determine if you value “absolute” or “relative” production numbers
- Keep in mind protecting royalty owners interest

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# Thanks!