Producer Best Management Practices

Lessons Learned from the
Natural Gas STAR Program

ConocoPhillips
The Colorado Oil and Gas Association, and
The Independent Petroleum Association of Mountain States

Producers Technology Transfer Workshop
Durango, Colorado
September 13, 2007

epa.gov/gasstar

Best Management Practices: Agenda

- Plunger Lifts and Smart Automation Well Venting
  - Methane Losses
  - Methane Savings
  - Is Recovery Profitable?
  - Industry Experience
- Vapor Recovery Units
  - Methane Losses
  - Methane Savings
  - Is Recovery Profitable?
  - Industry Experience
  - Lessons Learned
- Discussion

Smart Automation Well Venting

- Automation can enhance the performance of plunger lifts by monitoring wellhead parameters such as:
  - Tubing and casing pressure
  - Flow rate
  - Plunger travel time
- Using this information, the system is able to optimize plunger operations
  - To minimize well venting to atmosphere
  - Recover more gas
  - Further reduce methane emissions

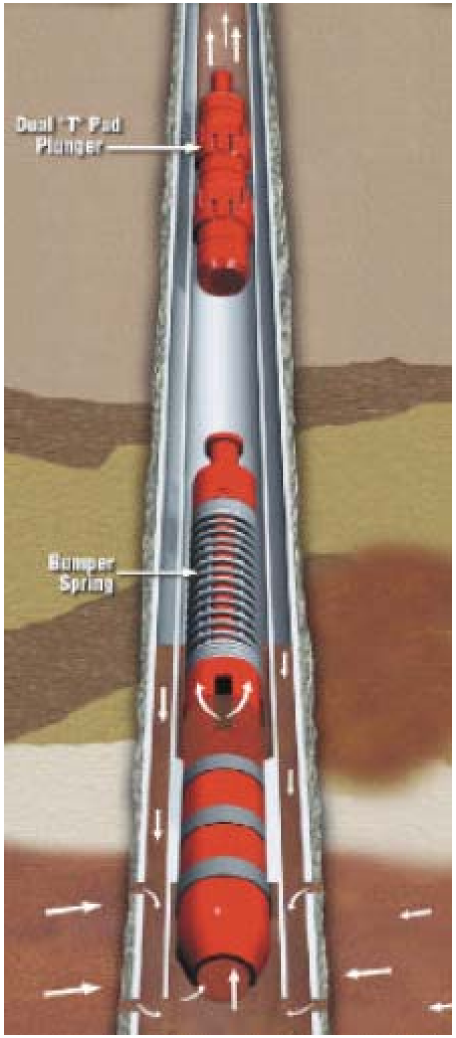
Methane Losses

- There are 395,000 natural gas and condensate wells (on and offshore) in the U.S.[1]
- Accumulation of liquid hydrocarbons or water in the well bores reduces, and can halt, production
- Common "blow down" practices to temporarily restore production can vent 80 to 1600 Mcf/year[2] to the atmosphere per well
- Estimate 9 Bcf/year methane emissions from U.S. onshore well venting[1]

1 - Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 - 2004
2 - Mobil Big Piney Case Study 1997

What is the Problem?

- Conventional plunger lift systems use gas pressure buildups to repeatedly lift columns of fluid out of well
- Fixed timer cycles may not match reservoir performance
  - Cycle too frequently (high plunger velocity)
    - Plunger not fully loaded
  - Cycle too late (low plunger velocity)
    - Shut-in pressure can't lift fluid to top
    - May have to vent to atmosphere to lift plunger



Source: Weatherford

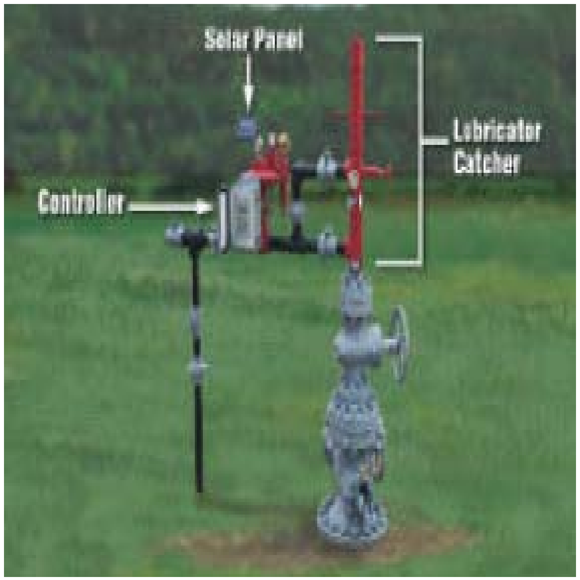
Conventional Plunger Lift Operations

- Manual, on-site adjustments tune plunger cycle time to well's parameters
  - Not performed regularly
  - Do not account for gathering line pressure fluctuations, declining well performance, plunger wear
- Results in manual venting to atmosphere when plunger lift is overloaded

Methane Recovery: How Smart Automation Reduces Methane Emissions

- Smart automation continuously varies plunger cycles to match key reservoir performance indicators
  - Well flow rate
    - Measuring pressure
  - Successful plunger cycle
    - Measuring plunger travel time
- Plunger lift automation allows producer to vent well to atmosphere less frequently

Automated Controllers



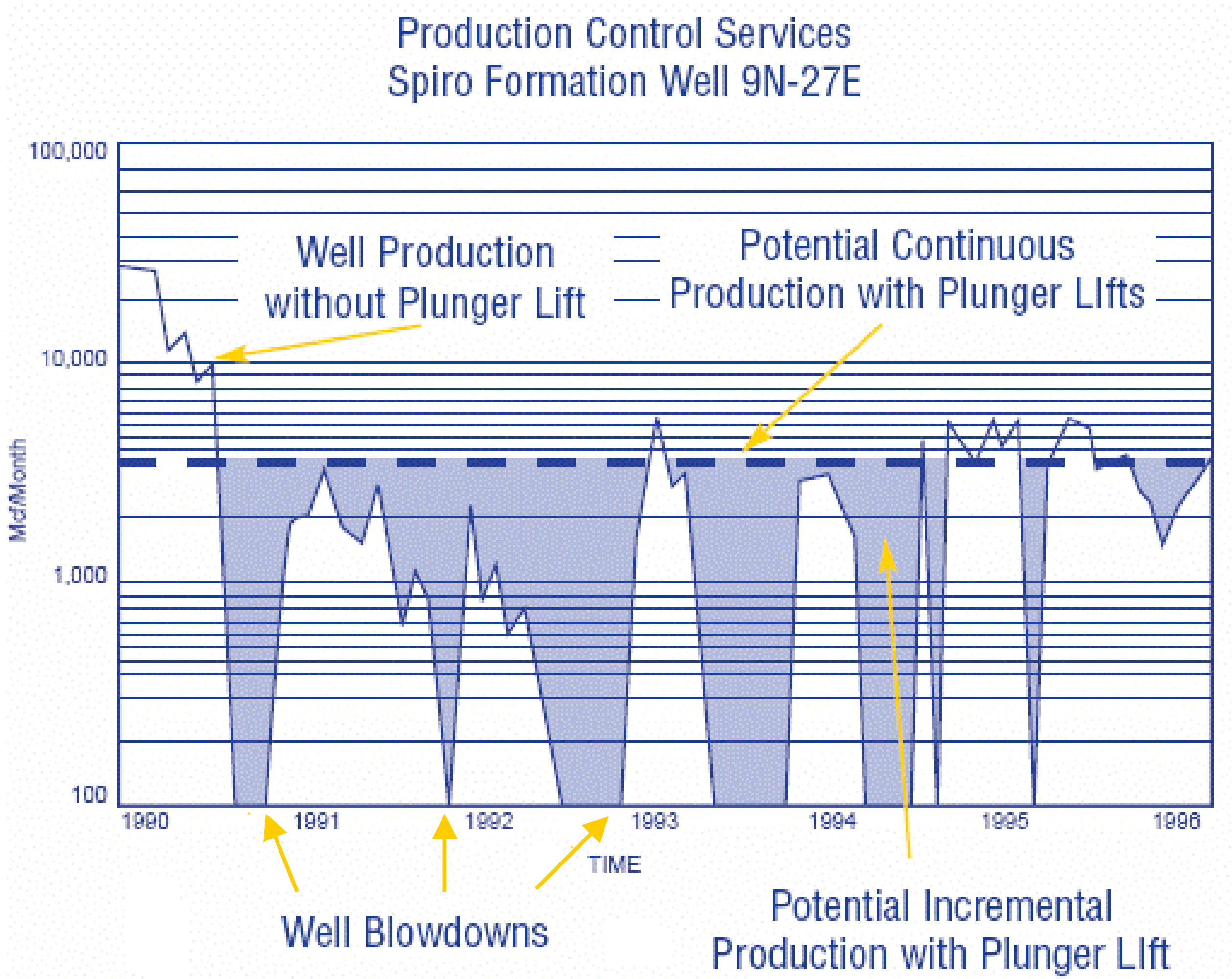
Source: Weatherford

- Low-voltage; solar recharged battery power
- Monitor well parameters
- Adjust plunger cycling

- Remote well management
  - Continuous data logging
  - Remote data transmission
  - Receive remote instructions
  - Monitor other equipment

Source: Weatherford

Plunger Lift Cycle



Methane Savings

- Methane emissions savings a secondary benefit
  - Optimized plunger cycling to remove liquids increases well production by 10 to 20%[1]
  - Additional 10%[1] production increase from avoided venting
- 500 Mcf/year methane emissions savings for average U.S. well

1 - Reported by Weatherford

Other Benefits

- Reduced manpower cost per well
- Continuously optimized production conditions
- Remotely identify potential unsafe operating conditions
- Monitor and log other well site equipment
  - Glycol dehydrator
  - Compressor
  - Stock Tank
  - Vapor Recovery Unit

Is Recovery Profitable?

- Smart automation controller installed cost: ~$11,000
  - Conventional plunger lift timer: ~$5,000
- Personnel savings: double productivity
- Production increases: 10% to 20% increased production

- Savings =

  (Mcf/year) x (10% increased production) x (gas price)

  \+ (Mcf/year) x (1% emissions savings) x (gas price)

  \+ (personnel hours/year) x (0.5) x (labor rate)

  $ savings per year

Economic Analysis

- Non-discounted savings for average U.S. Well =

  (50,000 Mcf/year) x (10% increased production) x ($7/Mcf)
+ (50,000 Mcf/year) x (1% emissions savings) x ($7/Mcf)
+ (500 personnel hours/year) x (0.5) x ($30/hr)
 - ($11,000) cost

    $35,000 savings in first year

3 month simple payback

Industry Experience

- BP reported installing plunger lifts with automated control systems on ~2,200 wells
  - 900 Mcf reported annual savings per well
  - $12 million costs including equipment and labor
  - $6 million total annual savings
- Another company shut in mountaintop wells inaccessible during winter
  - Installed automated controls allowed continuous production throughout the year[1]

1 - Morrow, Stan and Stan Lusk, Ferguson Beauregard, Inc. Plunger-Lift: Automated Control Via Telemetry. 2000.

Vapor Recovery Units

- Methane Losses
- Methane Savings
- Is Recovery Profitable?
- Industry Experience
- Lessons Learned

Sources of Methane Losses

- A storage tank battery can vent 5,000 to 500,000 thousand cubic feet (Mcf) of natural gas and light hydrocarbon vapors to the atmosphere each year
  - Vapor losses are primarily a function of oil throughput, gravity, and gas-oil separator pressure
- Flash losses
  - Occur when crude is transferred from a gas-oil separator at higher pressure to a storage tank at atmospheric pressure
- Working losses
  - Occur when crude levels change and when crude in tank is agitated
- Standing losses
  - Occur with daily and seasonal temperature and barometric pressure changes

Methane Savings: Vapor Recovery

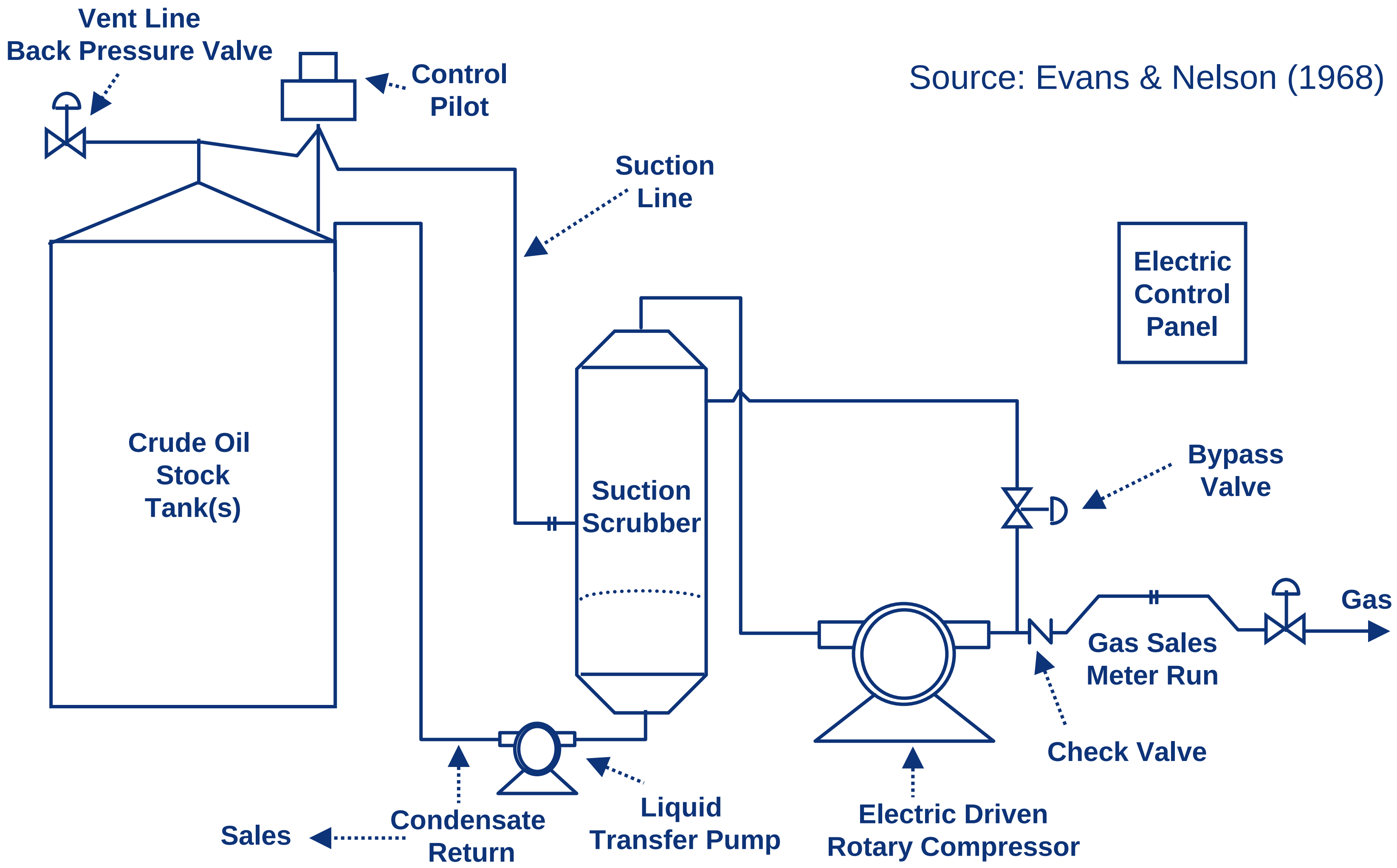
- Vapor recovery can capture up to 95% of hydrocarbon vapors from tanks
- Recovered vapors have higher heat content than pipeline quality natural gas
- Recovered vapors are more valuable than natural gas and have multiple uses
  - Re-inject into sales pipeline
  - Use as on-site fuel
  - Send to processing plants for recovering valuable natural gas liquids

Types of Vapor Recovery Units

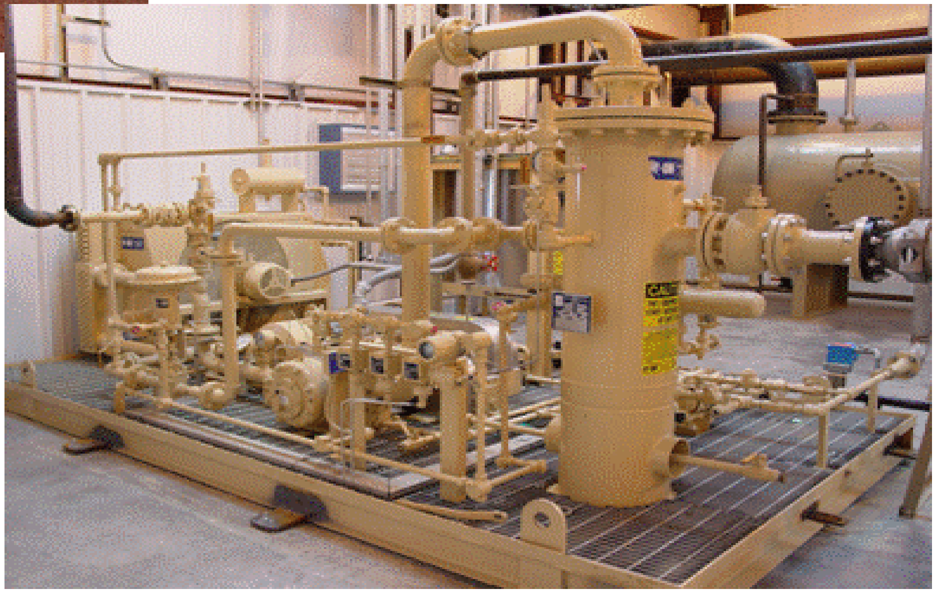
- Conventional vapor recovery units (VRUs)
  - Use rotary or vane compressor to suck vapors out of atmospheric pressure storage tanks
  - Scroll compressors are new to this market
  - Require electrical power or engine driver
- Venturi ejector vapor recovery units (EVRU^{TM}) or Vapor Jet
  - Use Venturi jet ejectors in place of rotary compressors
  - Contain no moving parts
  - EVRU^{TM} requires a source of high pressure motive gas and intermediate pressure discharge system
  - Vapor Jet requires a high pressure water motive

Conventional Vapor Recovery Unit

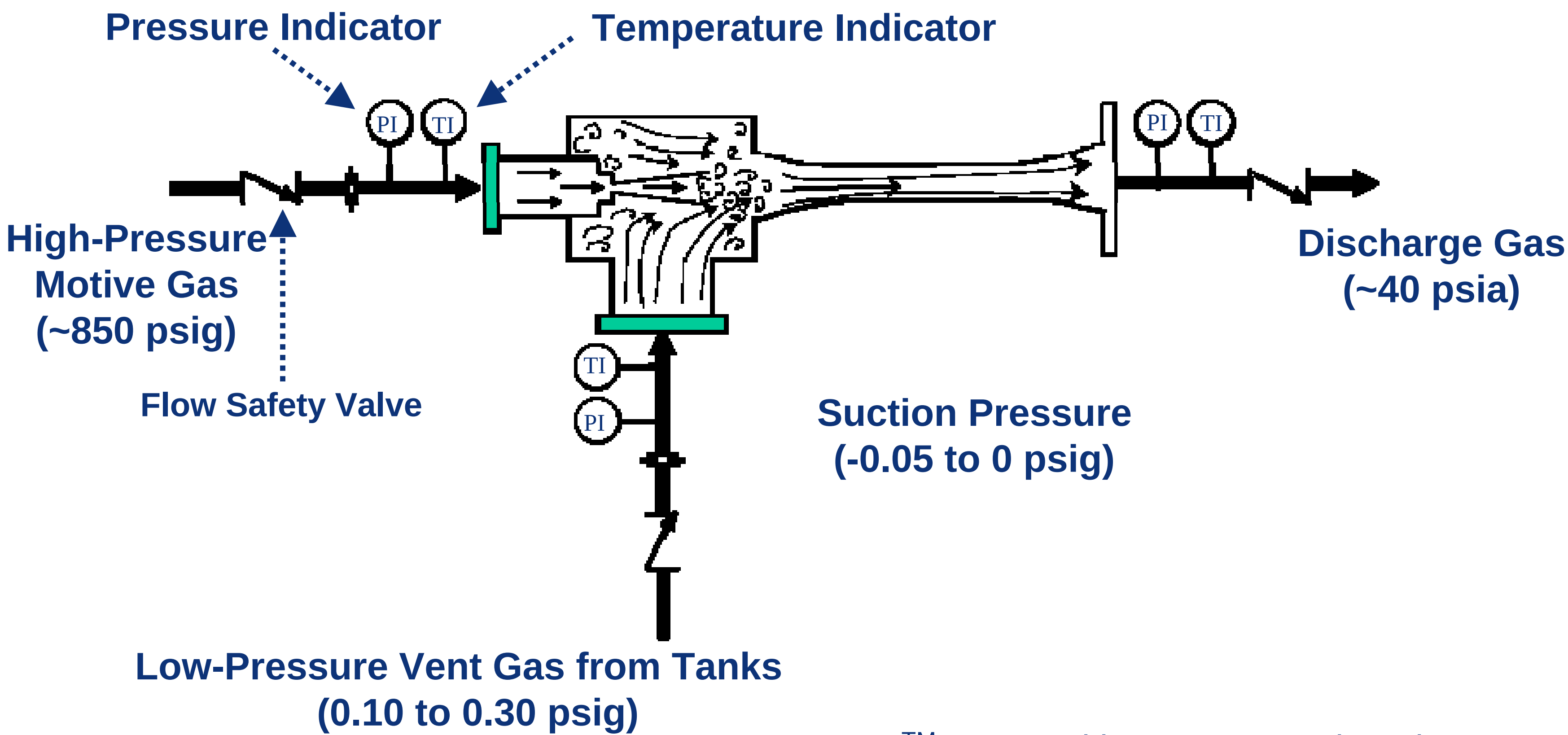
Source: Evans & Nelson (1968)



Vapor Recovery Installations



Venturi Jet Ejector*



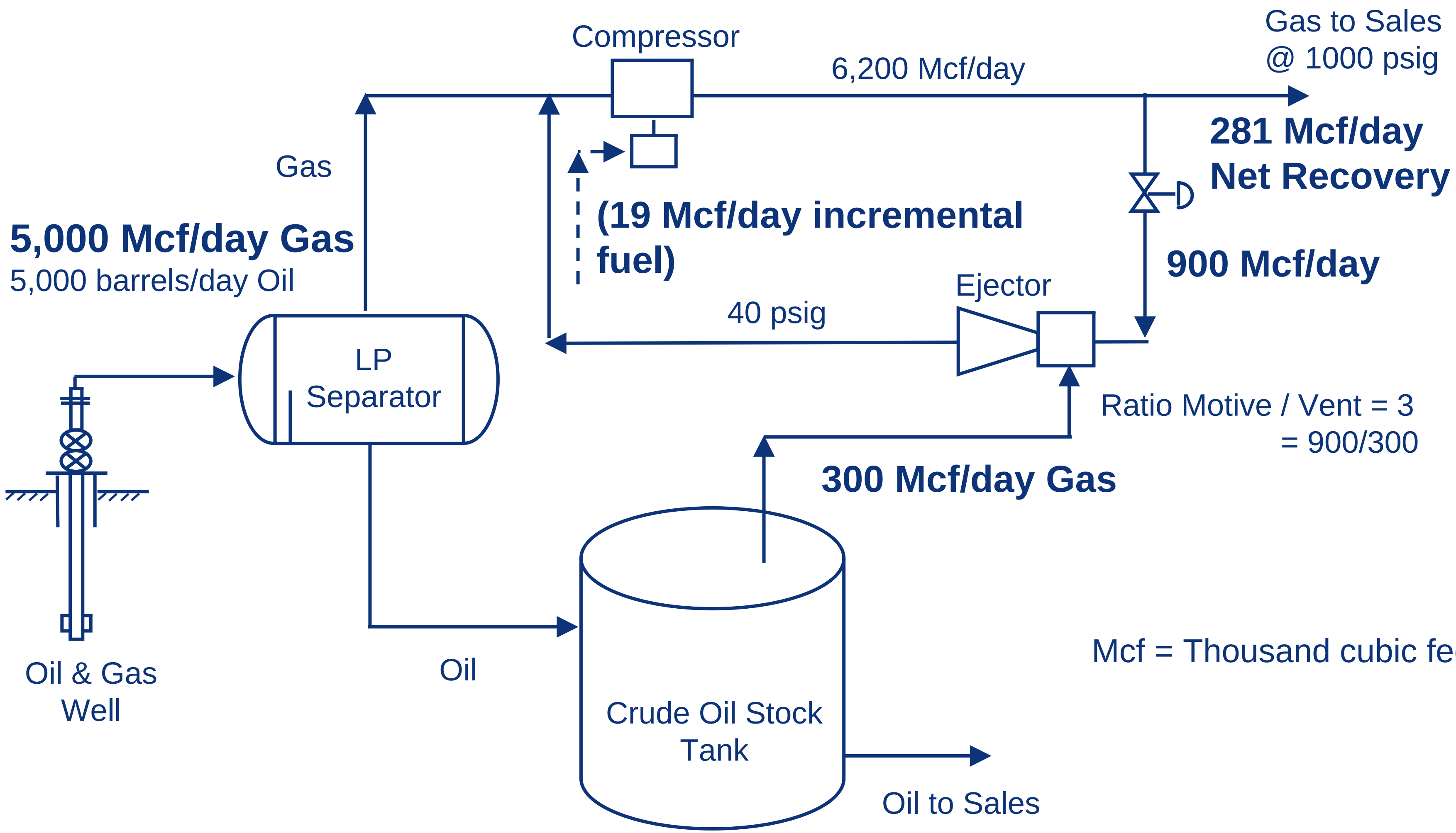
*EVRU™ Patented by COMM Engineering

Adapted from SRI/USEPA-GHG-VR-19

psig = pound per square inch, gauge

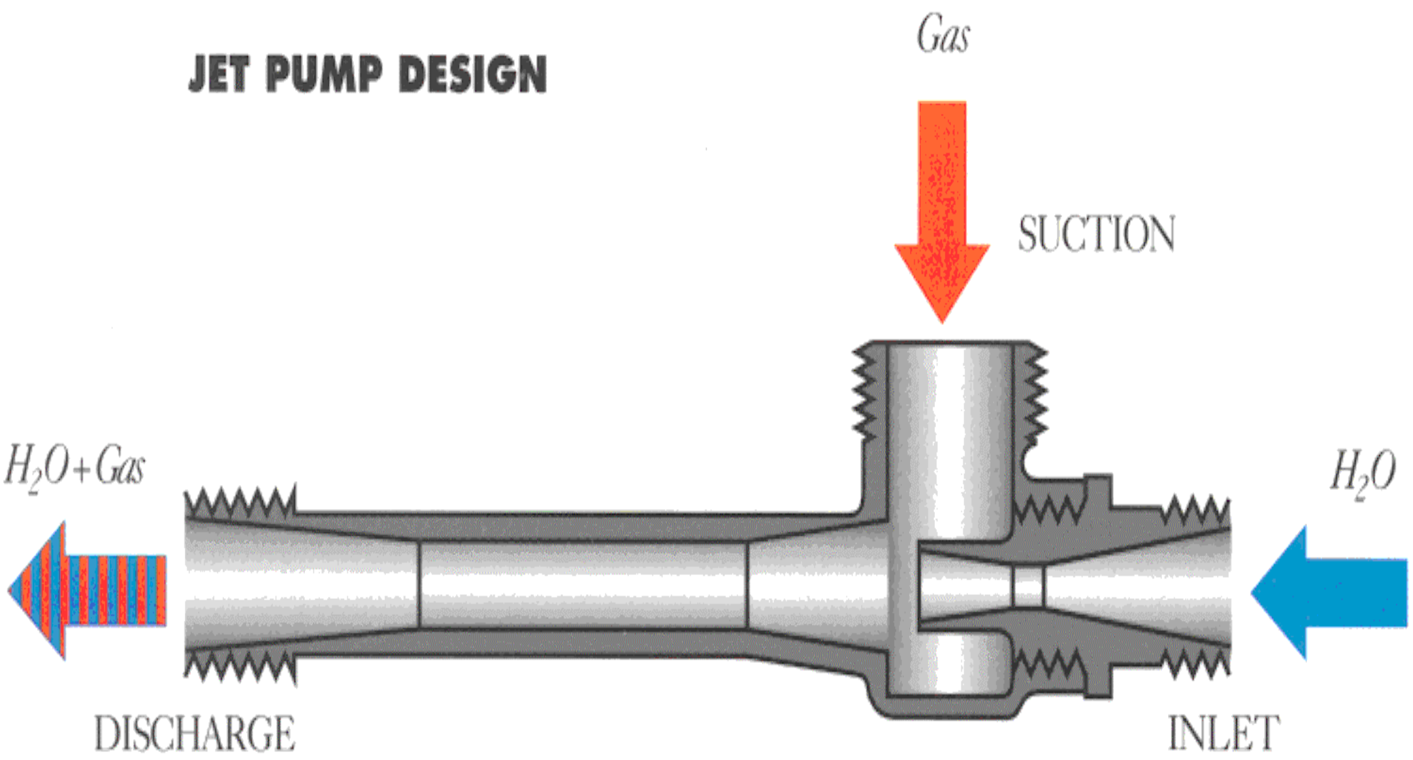
psia = pounds per square inch, absolute

Vapor Recovery with Ejector



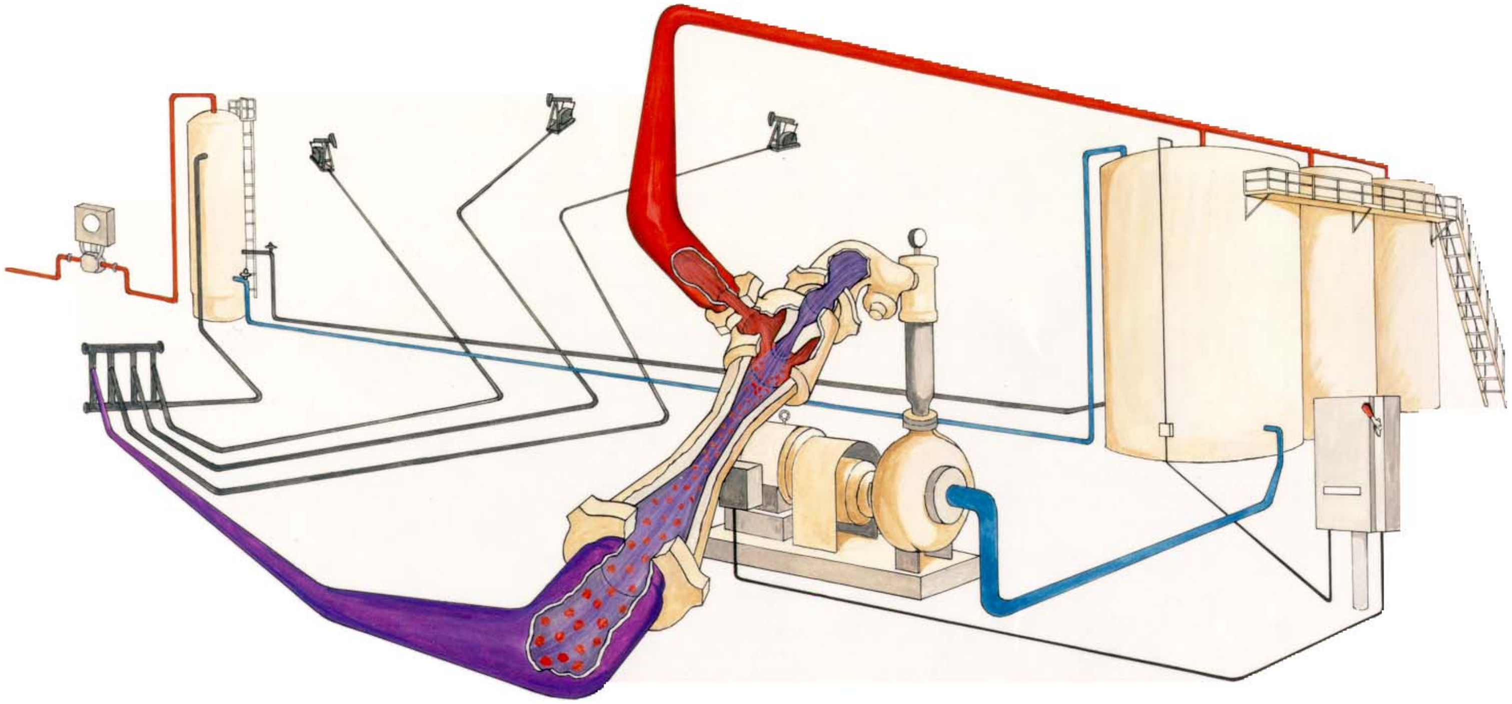
Mcf = Thousand cubic feet

Vapor Jet System*



*Patented by Hy-Bon Engineering

Vapor Jet System*



- Utilizes produced water in closed loop system to effect gas gathering from tanks
- Small centrifugal pump forces water into Venturi jet, creating vacuum effect
- Limited to gas volumes of 77 Mcf/day and discharge pressure of 40 psig

*Patented by Hy-Bon Engineering

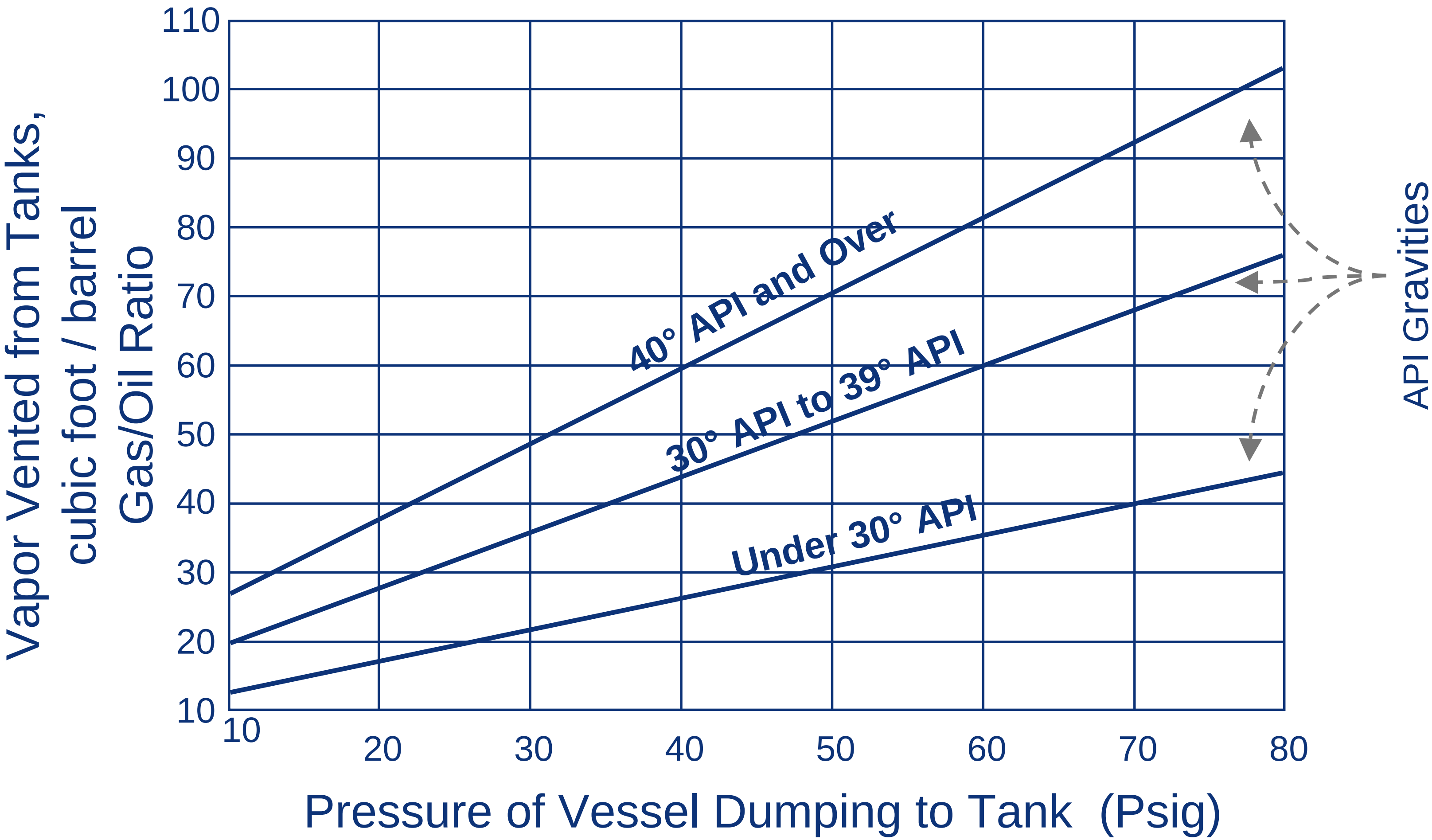
Criteria for Vapor Recovery Unit Locations

- Steady source and sufficient quantity of losses
  - Crude oil stock tank
  - Flash tank, heater/treater, water skimmer vents
  - Gas pneumatic controllers and pumps
- Outlet for recovered gas
  - Access to low pressure gas pipeline, compressor suction, or on-site fuel system
- Tank batteries not subject to air regulations

Quantify Volume of Losses

- Estimate losses from chart based on oil characteristics, pressure, and temperature at each location (± 50%)
- Estimate emissions using the E&P Tank Model (± 20%)
- Engineering Equations – Vasquez Beggs (± 20%)
- Measure losses using recording manometer and well tester or ultrasonic meter over several cycles (± 5%)
  - This is the best approach for facility design

Estimated Volume of Tank Vapors



° API = API gravity

Estimated Volume of Tank Vapors

- Atmospheric tanks may emit large amounts of tank vapors at relatively low separator pressure

Vasquez-Beggs Equation

$$GOR = A \times (G_{flash\ gas}) \times (P_{sep} + 14.7)^{B} \times \exp\left(\frac{C \times G_{oil}}{T_{sep} + 460}\right)$$

where,

GOR	=	Ratio of flash gas production to standard stock tank barrels of oil produced, in scf/bbl oil (barrels of oil corrected to 60°F)
$G_{flash\ gas}$	=	Specific gravity of the tank flash gas, where air = 1. A suggested default value for $G_{flash\ gas}$ is 1.22 (TNRCC; Vasquez, 1980)
G_{oil}	=	API gravity of stock tank oil at 60°F
P_{sep}	=	Pressure in separator, in psig
T_{sep}	=	Temperature in separator, °F

For $G_{oil} \leq 30°API$: A = 0.0362; B = 1.0937; and C = 25.724

For $G_{oil} > 30°API$: A = 0.0178; B = 1.187; and C = 23.931

psig – pounds per square inch, gauge
scf – standard cubic feet
bbl – barrels

What is the Recovered Gas Worth?

- Value depends on heat content of gas
- Value depends on how gas is used
  - On-site fuel
    - Valued in terms of fuel that is replaced
  - Natural gas pipeline
    - Measured by the higher price for rich (higher heat content) gas
  - Gas processing plant
    - Measured by value of natural gas liquids and methane, which can be separated
- Gross revenue per year = (Q x P x 365) + NGL
  - Q = Rate of vapor recovery (Mcf per day)
  - P = Price of natural gas
  - NGL = Value of natural gas liquids

Value of Natural Gas Liquids

	1 Btu/gallon	2 MMBtu/ gallon	3 $/gallon	4 $/MMBtu[1,2,3] (=3/2)
Methane	59,755	0.06	0.43	7.15
Ethane	74,010	0.07	0.64	9.14
Propane	91,740	0.09	0.98	10.89
n Butane	103,787	0.10	1.32	13.20
iso Butane	100,176	0.10	1.42	14.20
Pentanes+	105,000	0.11	1.50	13.63

	5 Btu/cf	6 MMBtu/Mcf	7 $/Mcf (=4*6)	8 $/MMBtu	9 Vapor Composition	10 Mixture (MMBtu/Mcf)	11 Value ($/Mcf) (=8*10)
Methane	1,012	1.01	$7.22	7.15	82%	0.83	$5.93
Ethane	1,773	1.77	$16.18	9.14	8%	0.14	$1.28
Propane	2,524	2.52	$27.44	10.89	4%	0.10	$1.09
n Butane	3,271	3.27	$43.16	13.20	3%	0.10	$1.32
iso Butane	3,261	3.26	$46.29	14.20	1%	0.03	$0.43
Pentanes+	4,380	4.38	$59.70	13.63	2%	0.09	$1.23
Total						1.289	$11.28

1 – Natural Gas Price assumed at $7.15/MMBtu as on Mar 16, 2006 at Henry Hub
2 – Prices of Individual NGL components are from Platts Oilgram for Mont Belvieu, TX January 11, 2006
3 – Other natural gas liquids information obtained from Oil and Gas Journal, Refining Report, March 19, 2001, p. 83
Btu = British Thermal Units, MMBtu = Million British Thermal Units, Mcf = Thousand Cubic Feet

Cost of a Conventional VRU

Vapor Recovery Unit Sizes and Costs				
Capacity (Mcf/day)	Compressor Horsepower	Capital Costs ($)	Installation Costs ($)	O&M Costs ($/year)
25	5 to 10	20,421	10,207 to 20,421	7,367
50	10 to 15	26,327	13,164 to 26,327	8,419
100	15 to 25	31,728	15,864 to 31,728	10,103
200	30 to 50	42,529	21,264 to 42,529	11,787
500	60 to 80	59,405	29,703 to 59,405	16,839
Cost information provided by United States Natural Gas STAR companies and VRU manufacturers, 2006 basis.				

Is Recovery Profitable?

Financial Analysis for a Conventional VRU Project						
Peak Capacity (Mcf/day)	Installation & Capital Costs[1] ($)	O&M Costs ($/year)	Value of Gas[2] ($/year)	Annual Savings ($)	Simple Payback (months)	Internal Rate of Return
25	$35,738	$7,367	$51,465	$44,098	10	121%
50	$46,073	$8,419	$102,930	$94,511	6	204%
100	$55,524	$10,103	$205,860	$195,757	4	352%
200	$74,425	$11,787	$411,720	$399,933	3	537%
500	$103,959	$16,839	$1,029,300	$1,012,461	2	974%

1 – Unit cost plus estimated installation of 75% of unit cost
2 – $11.28 x ½ peak capacity x 365, Assumed price includes Btu enriched gas (1.289 MMBtu/Mcf)

Industry Experience: Anadarko

- Vapor Recover Tower (VRT)
  - Add separation vessel between heater treater or low pressure separator and storage tanks that operates at or near atmospheric pressure
    - Operating pressure range: 1 psi to 5 psi
  - Compressor (VRU) is used to capture gas from VRT
  - Oil/Condensate gravity flows from VRT to storage tanks
    - VRT insulates the VRU from gas surges with stock tank level changes
    - VRT more tolerant to higher and lower pressures
    - Stable pressure allows better operating factor for VRU

Industry Experience: Anadarko

- VRT reduces pressure drop from approximately 50 psig to 1-5 psig
  - Reduces flashing losses
  - Captures more product for sales
  - Anadarko netted between $7 to $8 million from 1993 to 1999 by utilizing VRT/VRU configuration
- Equipment Capital Cost: $11,000
- Standard size VRTs available based on oil production rate
  - 20” x 35’
  - 48” x 35’
- Anadarko has installed over 300 VRT/VRUs since 1993 and continues on an as needed basis

VRT/VRU Photos

Courtesy of Anadarko

Lessons Learned

- Vapor recovery can yield generous returns when there are market outlets for recovered gas
  - Recovered high heat content gas has extra value
  - Vapor recovery technology can be highly cost-effective in most general applications
  - Venturi jet models work well in certain niche applications, with reduced operating and maintenance costs
- Potential for reduced compliance costs can be considered when evaluating economics of VRU, EVRU™, or Vapor Jet

Lessons Learned (continued)

- VRU should be sized for maximum volume expected from storage tanks (rule-of-thumb is to double daily average volume)
- Rotary vane, screw or scroll type compressors recommended for VRUs where Venturi ejector jet designs are not applicable
- EVRU™ recommended where there is a high pressure gas compressor with excess capacity
- Vapor Jet recommended where there is produced water, less than 75 Mcf per day gas and discharge pressures below 40 psig

Discussion

- Industry experience applying these technologies and practices
- Limitations on application of these technologies and practices
- Actual costs and benefits