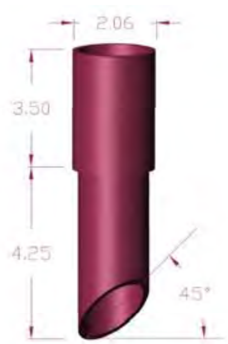
CBM and Shale Gas Upstream Facilities



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CBM and Shale Gas Upstream Facilities
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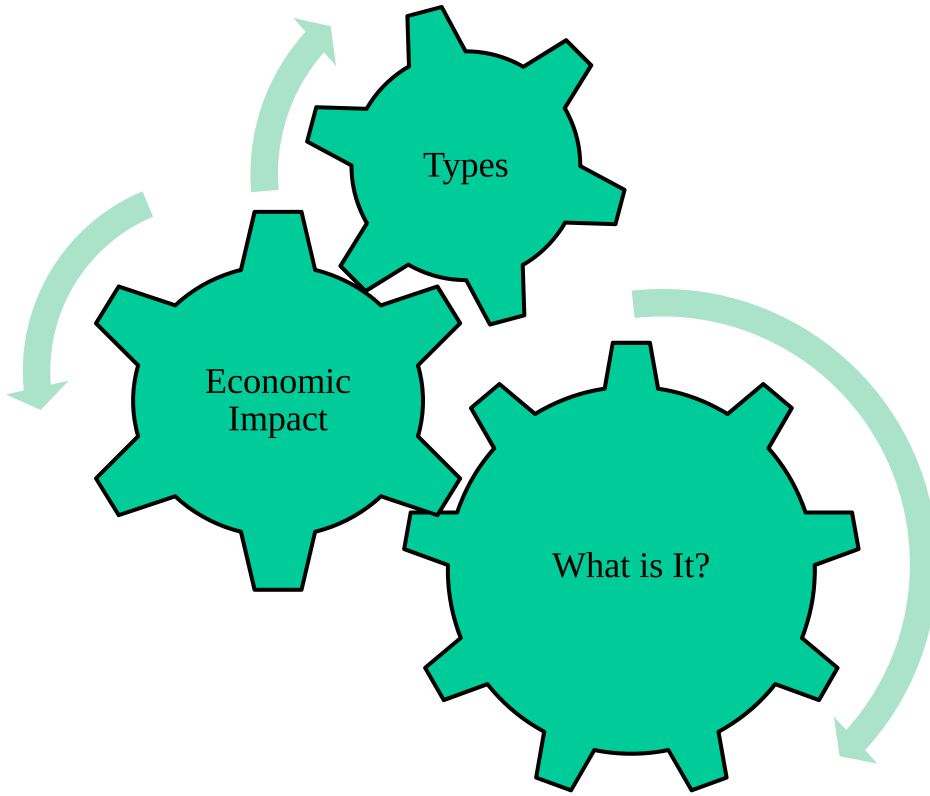
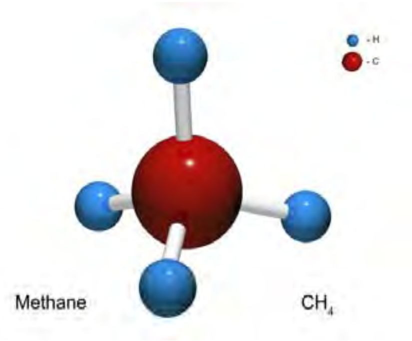
Unconventional Gas

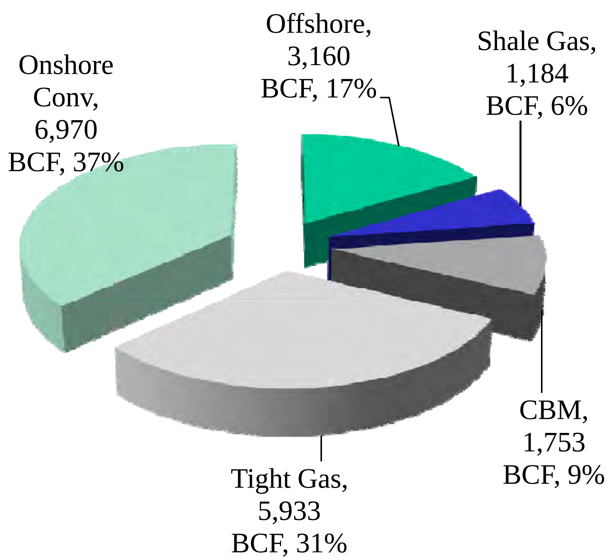


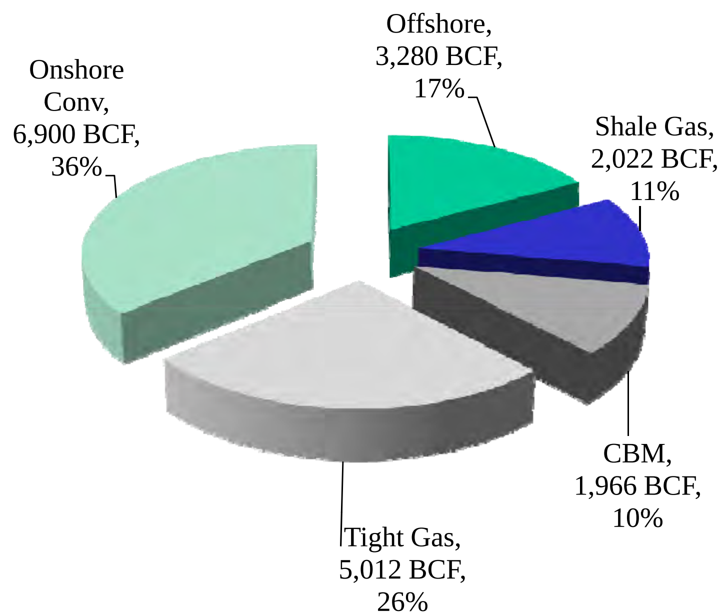
What is Unconventional Gas?

- Unconventional gas is the stuff that the industry tended to skip over when there was anything else to recover
- It requires non-oilfield techniques to exploit
- It is often very expensive to develop and produce
- So far it is primarily:
  - Tight gas
  - CBM
  - Shale Gas
- But hydrate mining, and land fill gas will eventually fit into this category



U.S. Gas Production





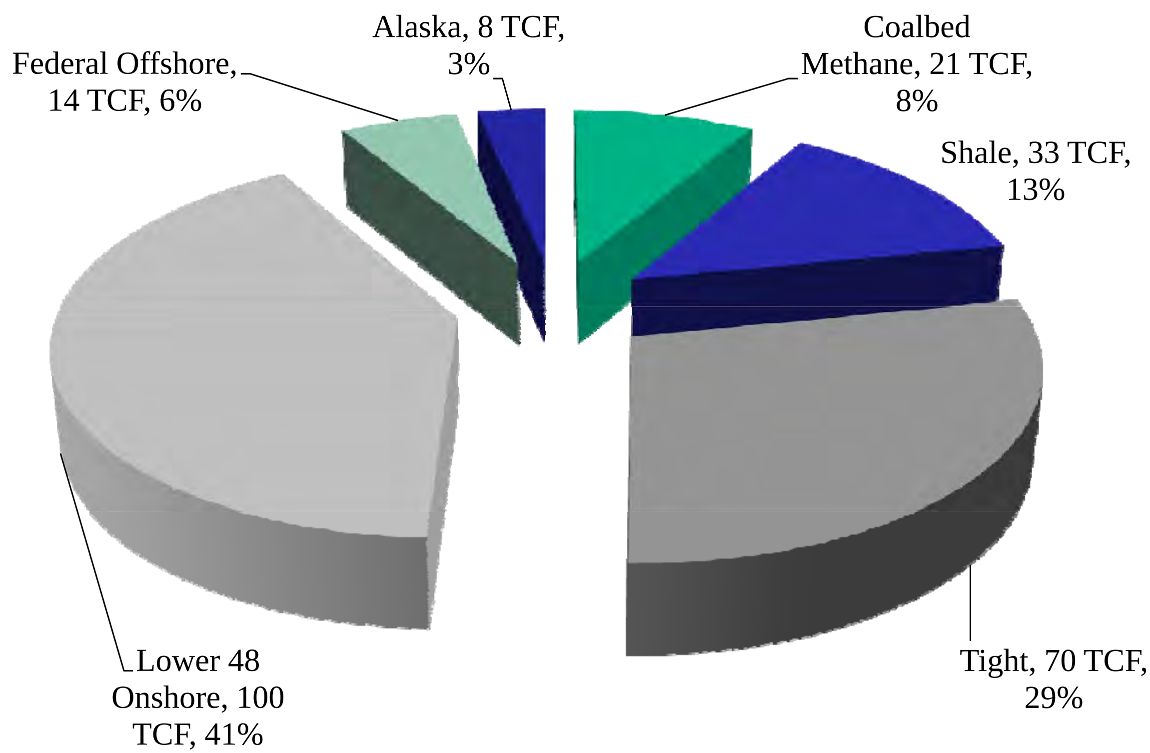
2007
Unconventional Gas Total, 46%

2008
Unconventional Gas Total, 47%

2007 total 19.0 TCF

2008 total 19.2 TCF

2008 Year-End Reserves



Source: EIA 2009

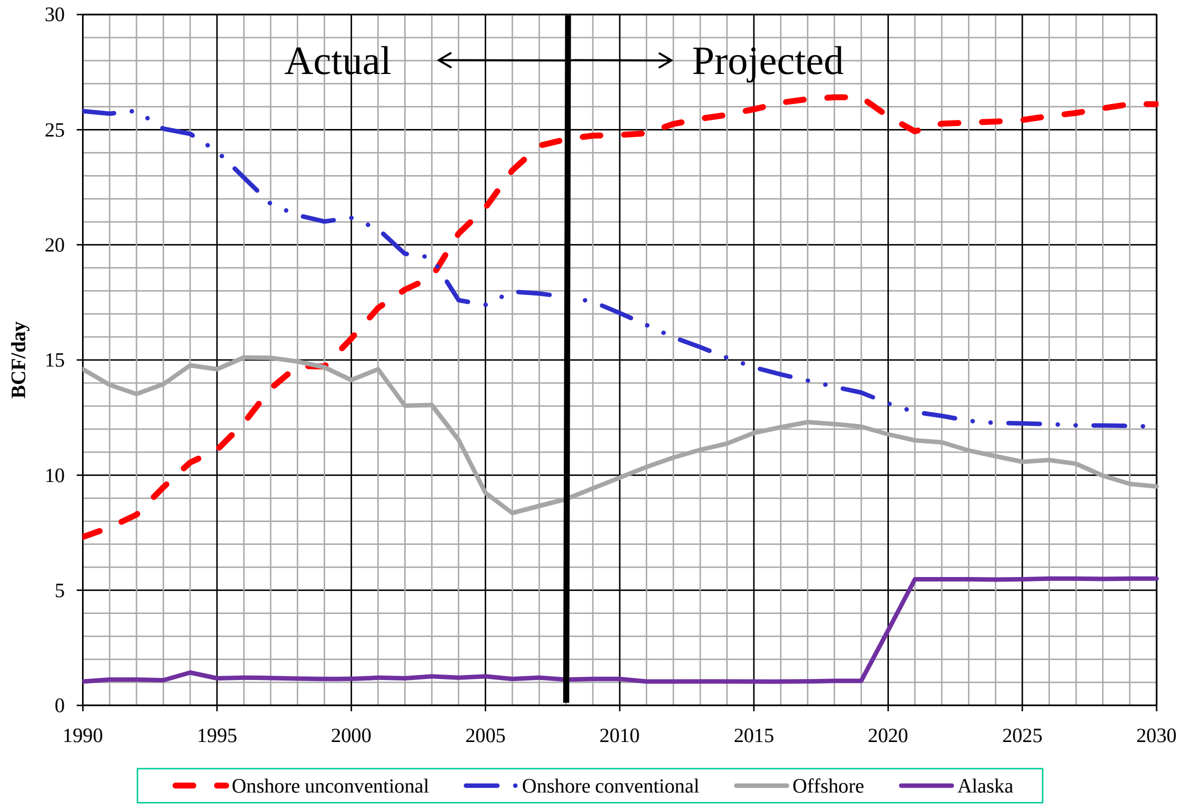
Top 10 US Fields in 2007

(Ranked by 2007 Production)

Basin	Type Reservoir	2007 Production (BCF/day)
San Juan Basin	71% Coal, 29% Tight	3.616
Newark East	Shale Gas (Barnett)	3.040
Powder River	CBM	1.210
Jonah, WY	Tight Gas	1.003
Hugoton	Conventional	0.980
Pinedale, WY	Tight Gas	0.858
Carthage, TX	Tight Gas	0.634
Natural Buttes, UT	CBM	0.467
Wattenberg, CO	Tight Gas	0.463
Prudhoe Bay	Conventional	0.462

Data from EIA 2007 Top 10 Fields Report

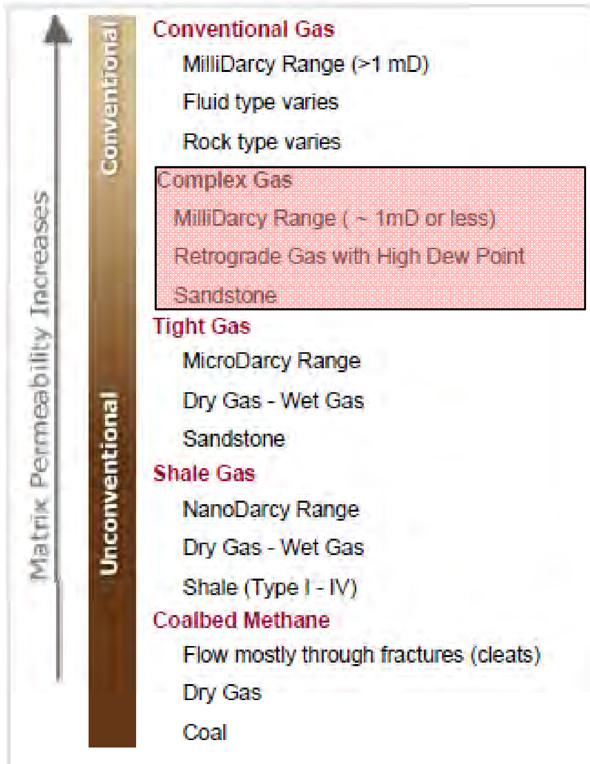
Natural Gas Production



Source: EIA 2008 Energy Outlook

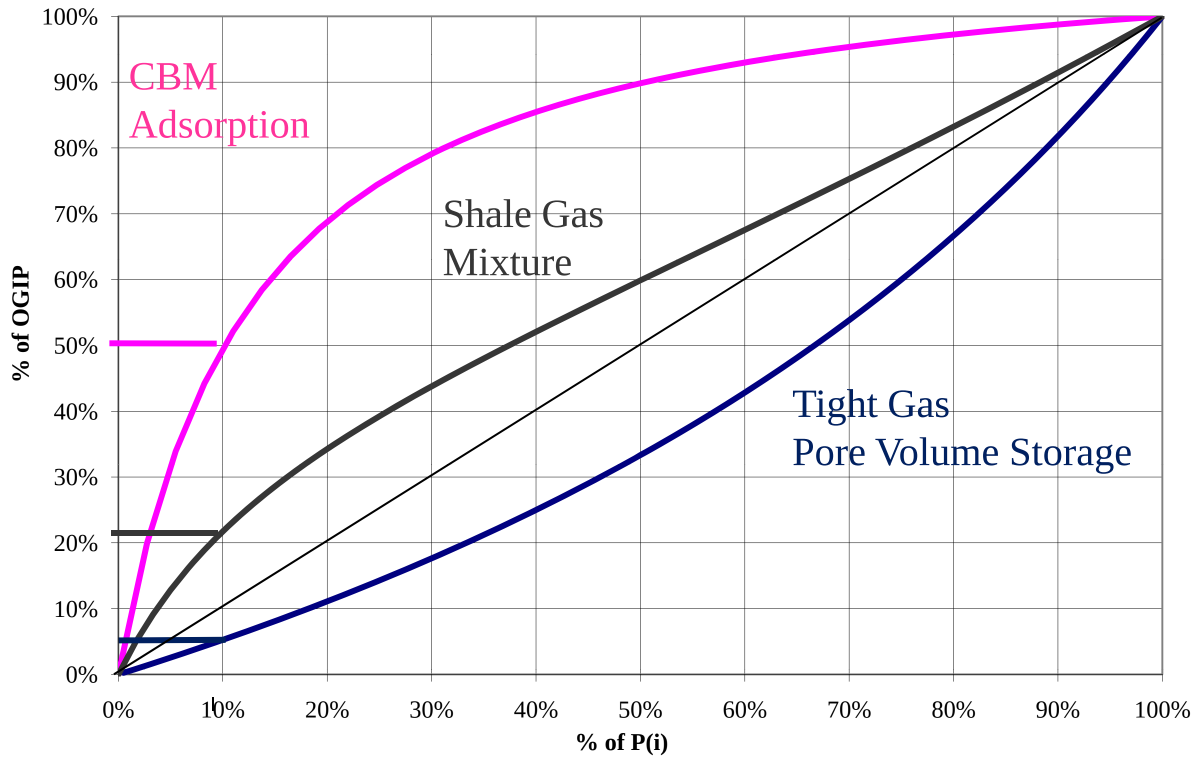
Unconventional Gas Continuum

- The lines are not very clear between the various kinds of gas production
- Halliburton breaks the continuum down into five types of gas by adding a “Complex Gas” between “Conventional Gas” and “Tight Gas”
  - This extra category helps to differentiate where Conventional Gas ends and Unconventional Begins
  - Complex Gas is reasonably rare and quite difficult to produce
  - Performance is predictable with the application of extraordinary techniques
  - Complex Gas production is a specialized field beyond the scope of this class



Courtesy of Halliburton Inc.

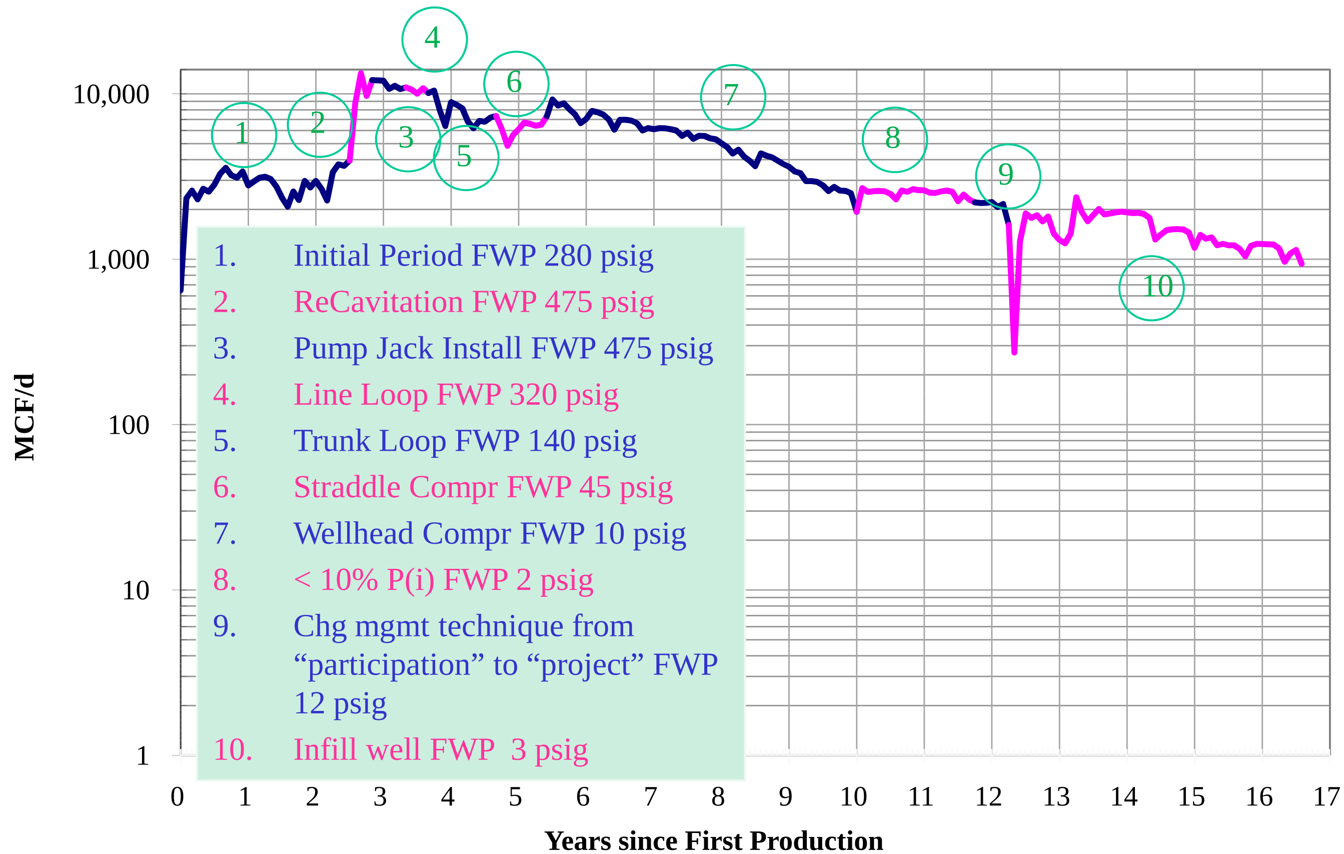
Reservoir Pressure vs. OGIP



Key Points

	Tight Gas	Shale	CBM
Gas content (SCF/ton)	N/A	50-400	300-1,000
Storage mechanism	Pore Volume	Mixed	Adsorption
Ultimate Recovery	30% of OGIP	70% of OGIP	95+% of OGIP
Flow Method	Darcy	Channel	Channel
Permeability	10 µD-1 mD	<10 nD to 10 µD	<10 nD
Porosity	0.5-10%	0.1-4%	<0.1%
Response to low pressure	Minimal	Good	Excellent
Liquid Hydrocarbons	Some	Rare	None
Water production	Low	Variable	Variable
Water Quality	Tends to be poor	Variable	Variable
Price Environment to develop	$0.80/MCF	$6.84/MCF	$2.00/MCF

Case Study



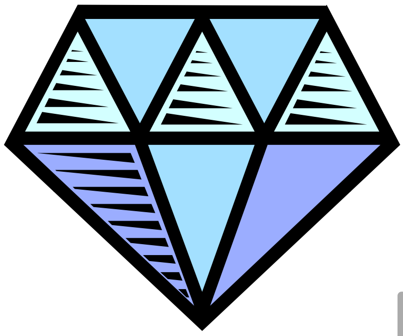
10,000
1,000
100
10
1
MCF/d
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
Years since First Production
1
2
3
4
5
6
7
8
9
10
1. Initial Period FWP 280 psig
2. ReCavitation FWP 475 psig
3. Pump Jack Install FWP 475 psig
4. Line Loop FWP 320 psig
5. Trunk Loop FWP 140 psig
6. Straddle Compr FWP 45 psig
7. Wellhead Compr FWP 10 psig
8. < 10% P(i) FWP 2 psig
9. Chg mgmt technique from “participation” to “project” FWP 12 psig
10. Infill well FWP 3 psig

Interventions

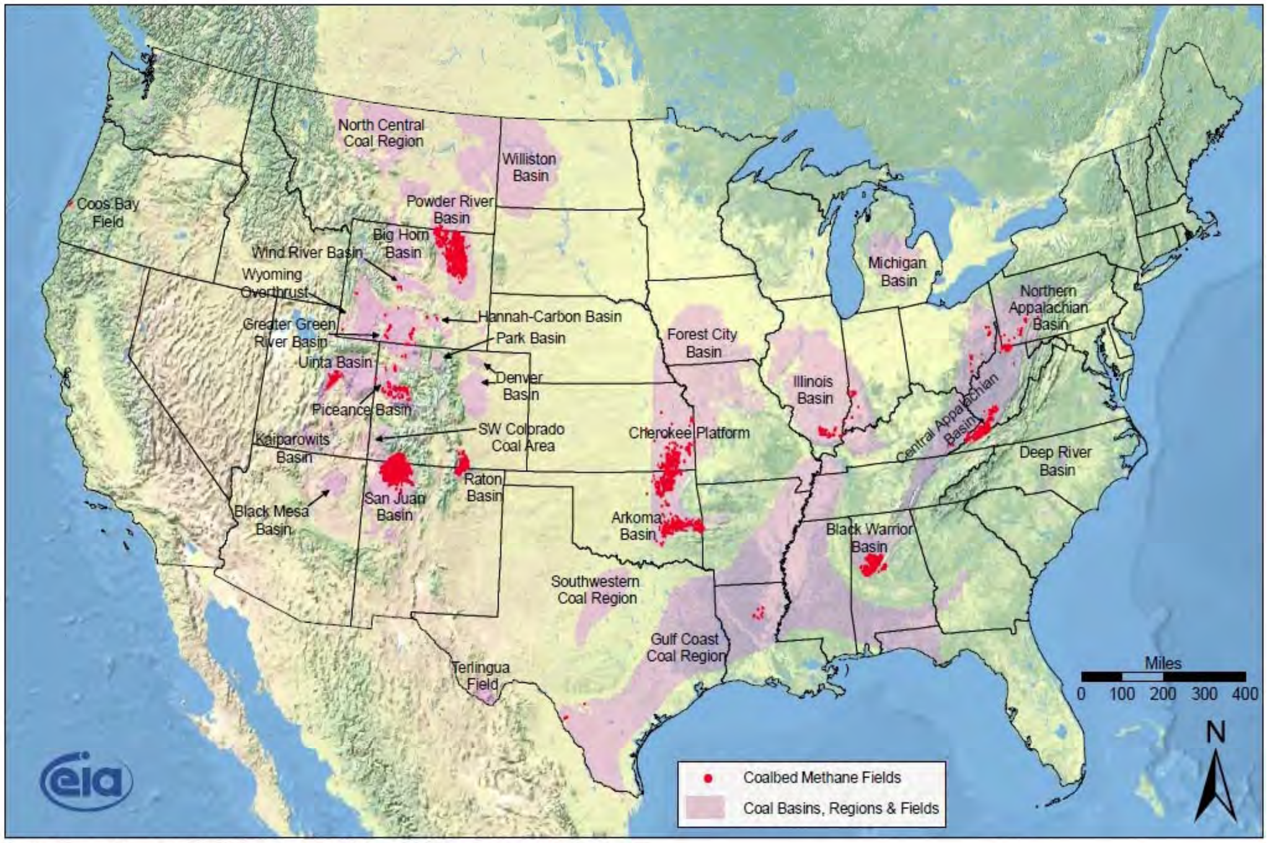
- Every change in the example resulted in a different flowing bottom hole pressure
- After the re-cavitation, the biggest changes in both BHP and gas rate came from surface interventions
- The surface interventions would not have been effective without good downhole work, but the best downhole work was ineffective without surface interventions
- Effective tools of production include:
  - Downhole work
  - Deliquification
  - Wellsite facilities
  - Compression
  - Gas and water gathering system mods
- Use the ones that give you the best bang for your buck

CBM

- Introduction
- CBM Economic Impact
- CBM Reservoirs
- CBM Production



CBM Fields



Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

Introduction

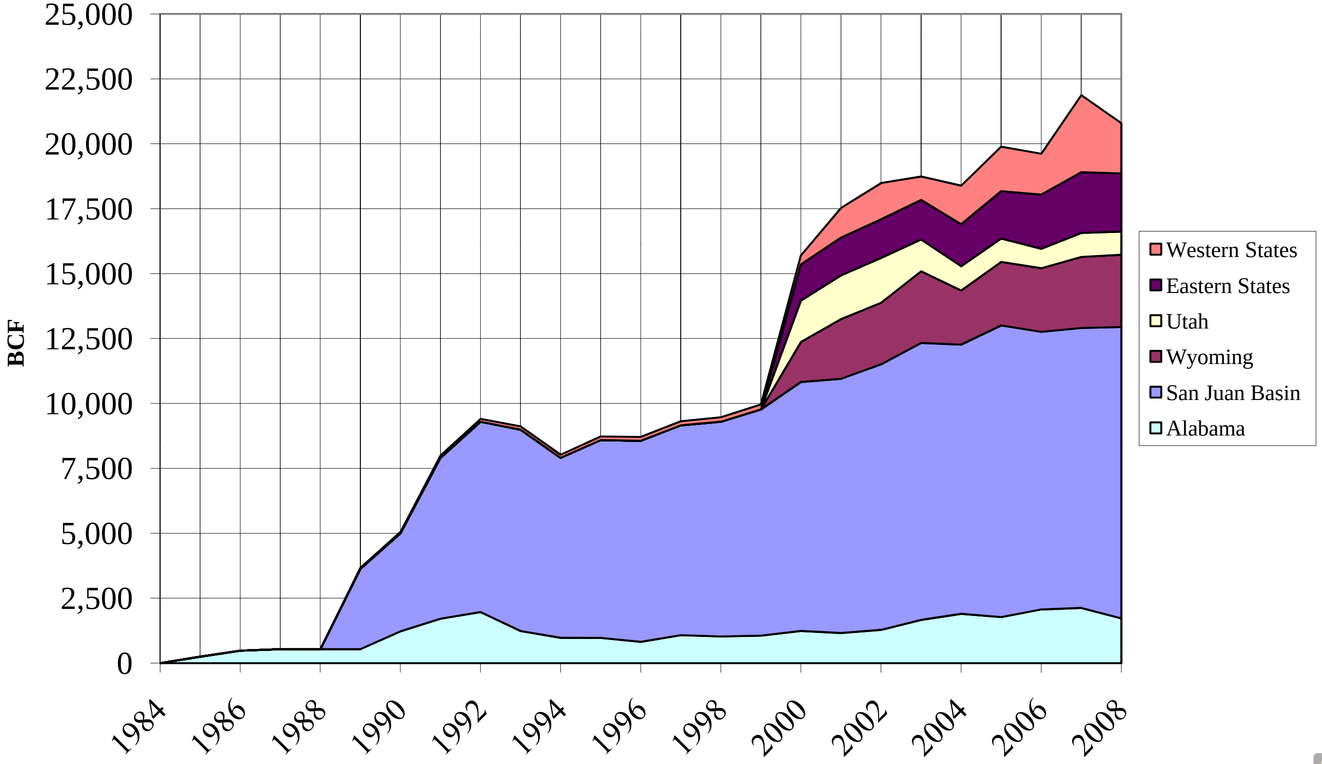
- CBM reservoir characteristics are unique:
  - Almost none of the gas is in the void space
  - Production rate is very dependent on connectivity between face cleats (permeability near zero)
  - Very low bottom-hole pressures are required to reach reserves targets
- Stimulation is a difficult issue:
  - Miners talk about coal being self-healing
  - No “Silver Bullet” has been found yet for all situations
    - Where Cavitation works, it is always best, but it doesn’t work often
    - Every sort of Hydraulic Fracture Stimulation has been tried and all have “worked” sometimes, nothing works all the time
- How you produce is more important than how you frac

Economic Impact

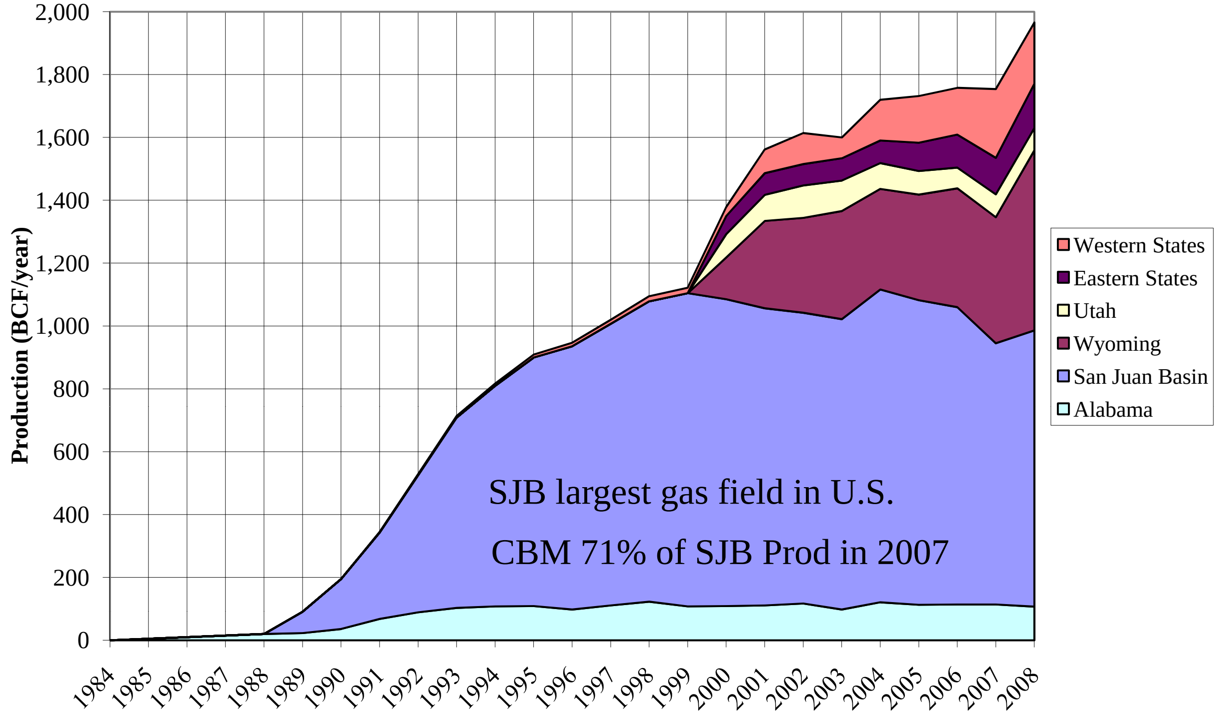
- CMM has always had an impact on the coal-mining industry:
  - Methane has regularly created an oxygen-poor/explosive atmosphere
  - Mining solutions have ranged from:
    - A canary in a cage
    - Forced fresh air
    - Drilling CMM wells in front of the mine tunnels
  - No universal solution has ever been found

- Today, CBM is far more important than CMM
- In 2008, CBM:
  - Made up 10% of U.S. gas production
  - Represented 8% of U.S. gas net reserves
  - Was a significant factor in global development activities

CBM Year-End Reserves



Annual U.S. CBM Production



Why the San Juan Basin?

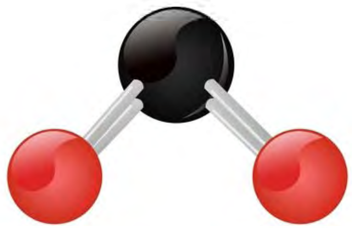
- The Fruitland Coal seam was encountered in 20,000 wellbores between 1927 and 1988
- Drillers knew it was there and hated it (often got a significant kick)
- Section 29 Tax Credits offered a real incentive to try to make the Fruitland productive (tax credit was about equal to current market price)
  - We expected significant water that there was no infrastructure to handle
  - We expected out of spec CO_2
  - "Discovery" well produced 16,000 bbl/day of water and little gas (9% CO_2)
- Factors for success:
  - Fairway Coal rock mechanics suitable for Cavitation (big wells encouraged enthusiasm)
  - Existing take-away pipelines provided exceptional access to markets
  - Gathering companies unwilling to take gas (forced producer-owned gathering)
  - Producers big enough to "encourage" development of necessary sweetening plant capacity

CBM Completions

- Mechanical strength of coal is very low:
  - In the SJB fairway friability has been measured at 15 psi
  - Other coals are stronger, but none is very strong
  - Coal is "self healing" so propants have limited effectiveness
- Completions that have worked:
  - Sculpting a cavity with pressure surges has only worked in limited fields so far
  - Cased horizontal wells (open-hole wells always risk collapse)
  - Every sort of stimulation has had successes and failures, but bigger carrier volumes have tended to scour bigger channels that are less likely to heal and are more conductive

CBM Contamination

- CBM is adsorbed to the surface of the coal
- The adsorption sites will accommodate any molecule that sort of fits:
  - CO_2 molecules fit perfectly
  - Methane and N_2 molecules sort of fit
  - Heavier hydrocarbons don't fit at all



- CO_2 production very confusing:
  - Initial production significantly below average reservoir levels
  - Late-life production higher than average reservoir levels
- Hypothesis:
  - Methane will desorb at a lower pressure than CO_2 for a given GIP
  - Every time a methane molecule desorbs it leaves a vacant adsorption site
  - Free CO_2 in the cleats will occupy the vacant site up to the CO_2 isotherm
- The hypothesis allows prediction of peak CO_2 and facilities requirements over the life of the well

Corrosion Issues

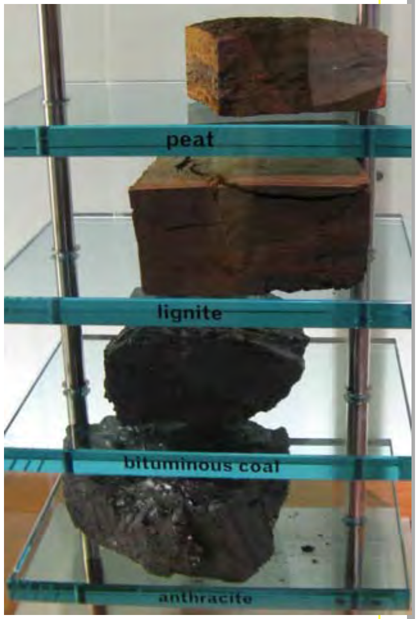
- Everyone looks at CO_2 content in CBM and begins worrying about corrosion issues:
  - Dissolved CO_2 reacts with water and becomes carbonic acid
  - Spent carbonic acid becomes bicarbonate (a base)
  - Typically, produced water is alkaline (pH > 7.0)
  - CO_2 corrosion is very rare in CBM operations
- MIC is much more common
- Avoiding both CO_2 corrosion and MIC can be done by:
  - Mechanically removing condensed water (pigging)
  - Using corrosion resistant pipe (non-metalic is better than stainless steel)

Conventional Reservoirs

- Rock formations important to Oil & Gas are:
  - Source rock—formations rich in organic material that become hydrocarbon products
  - Reservoir rock—formations with pore volume adequate to store hydrocarbons
  - Cap rock—formations resistant to hydrocarbon flow that seal reservoirs
- Gas within a conventional reservoir acts like a gas and tends to flow as described by the gas laws (i.e., PV=ZnRT)
- Pressure within the reservoir acts as the driving force to push the gas into the wellbore
- Permeability is a key characteristic that allows flows to be predicted
- Porosity allows definition of gas volume

CBM Reservoirs

- Applying the definitions to CBM:
  - Source rock—Coal is rich in organic matter and meets the definition
  - Reservoir rock—Coal does not have appreciable void volume
  - Cap rock—the Coal matrix is very resistant to gas flows and is frequently a cap rock for conventional reservoirs
- Gas in a CBM reservoir is part of the solid and does not follow the gas laws (i.e., $PV \neq ZnRT$)
- Pressure within the cleat system determines how much gas will desorb and flow to the wellbore (pull instead of push)
- Permeability is largely meaningless
- Porosity is insignificant



CBM Reservoir

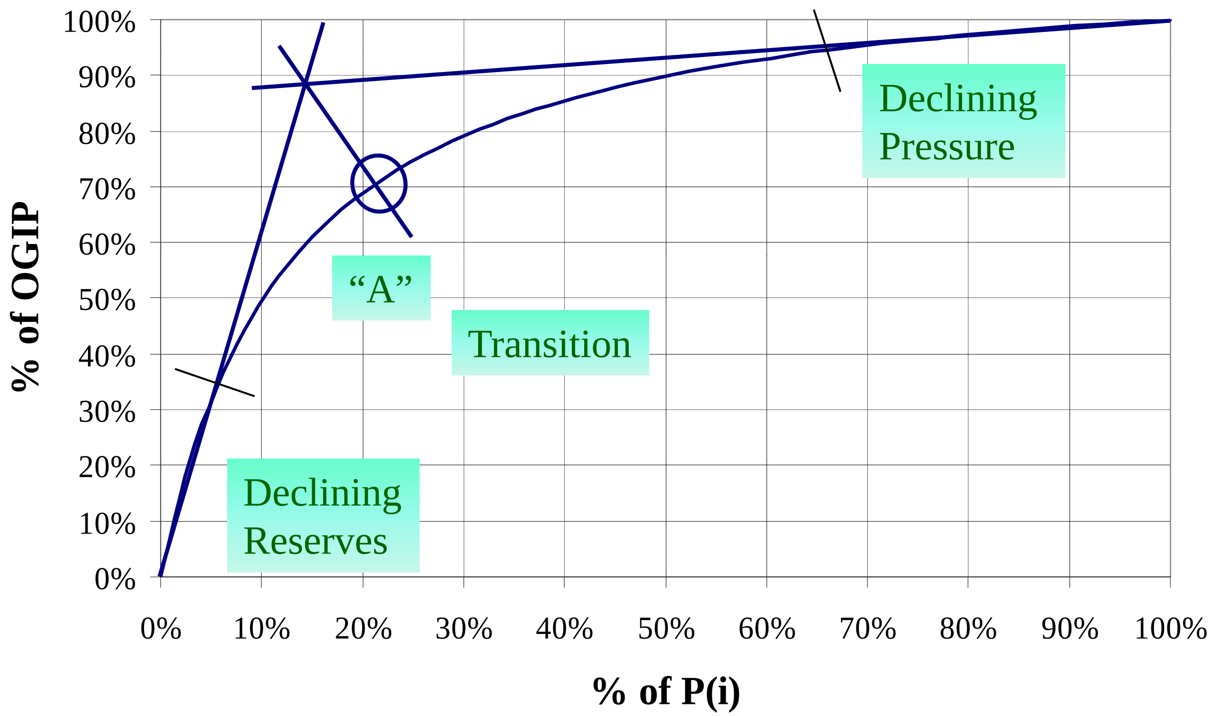
- While the Gas Laws don't apply to CBM, other relationships do apply
- Since the reservoir temperature is approximately constant with time, the *Langmuir Isotherm* describes the relationship between pressure and stored gas

$$OGIP = 0.031214 A h V_m y \rho \frac{bP_i}{1 + bP_i}$$

- The parameters in this equation are all either acquired during drilling, subject to regulatory definition (e.g., drainage area), or can be predicted from offsets or analogs
- Plotting the equation for a particular well results in a very useful graph

Langmuir Isotherm

(San Juan Basin Fairway)



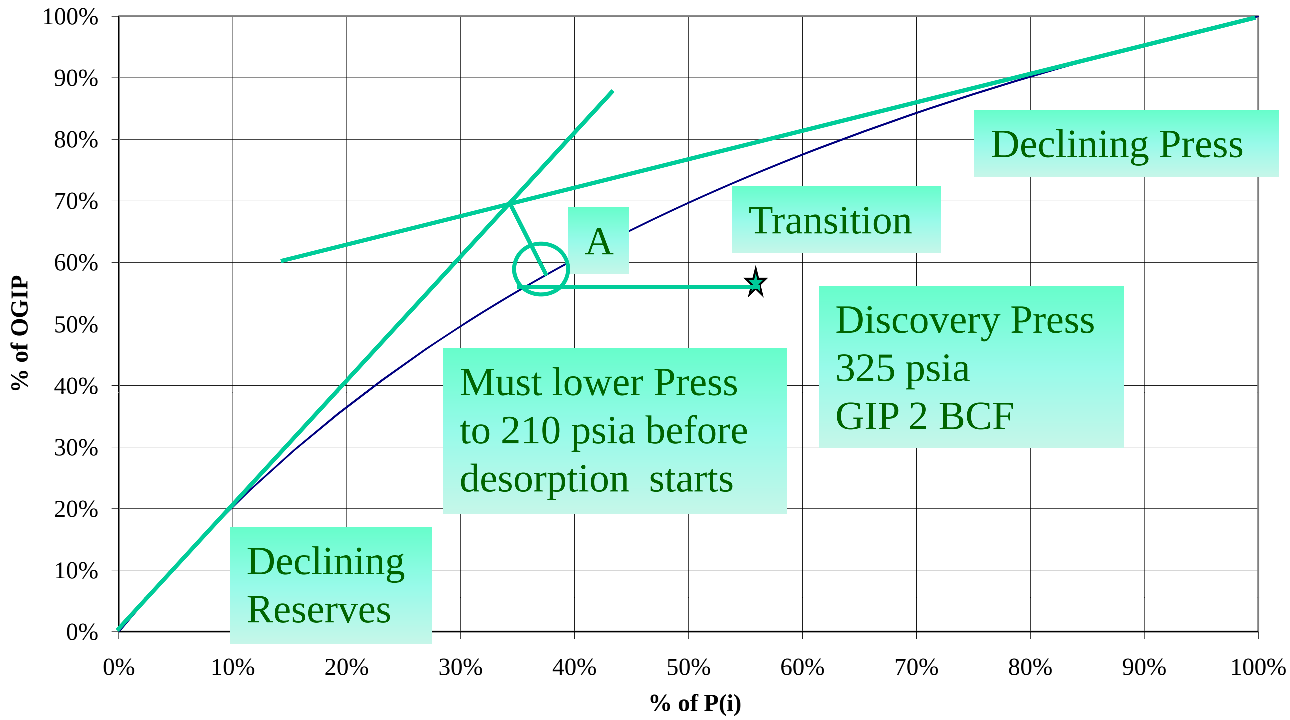
Isotherm

- Declining Pressure Region:
  - Pressure falls very rapidly for "small" reductions in GIP
  - In the Fairway example well, this period lasted 7 months and used 40% of initial reservoir pressure to produce 7% of OGIP
  - Wells in this region typically don't respond to compression, but may require early-life deliquification
- Declining Reserves Region:
  - Pressure changes very slowly while GIP changes relatively quickly
  - In the Fairway example well this period started at 11 years 3 months and 93% of initial reservoir pressure had been consumed to recover 64% of OGIP
  - The only way to get the remaining gas is to achieve very low flowing bottomhole pressure

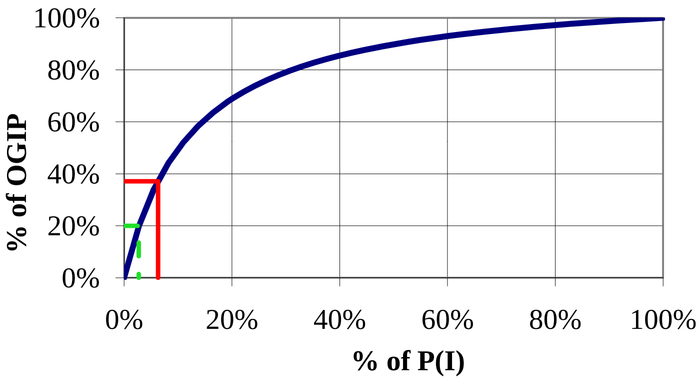
Transition Region

- This is the transition from “easy” to “difficult”
- At the beginning of the period:
  – Most wells don’t need deliquification assistance
  – Few wells need compression
- At the end of the period:
  – All wells need a coherent deliquification strategy
  – All wells need very low wellhead pressures
- The period is pretty long (about 10 years in the Fairway example well)
- The key to this region is to determine Point “A”:
  – Prior to that point, the target flowing bottomhole pressure should be about equal to Point “A” pressure (about 350 psig in the Fairway example well, 210 psig in a typical CBM well)
  – As the well approaches Point “A” it will tend to stop acting like an early-life well and start acting like a late-life well and will require progressively lower pressures

Langmuir Isotherm
(Typical CBM Well)



Determining Reservoir Pressure



$$OGIP = 0.031214 A h V_m y \rho \frac{bP_i}{1 + bP_i}$$

$$GIP = 0.031214 A h V_m y \rho \frac{b\overline{P}}{1 + b\overline{P}}$$

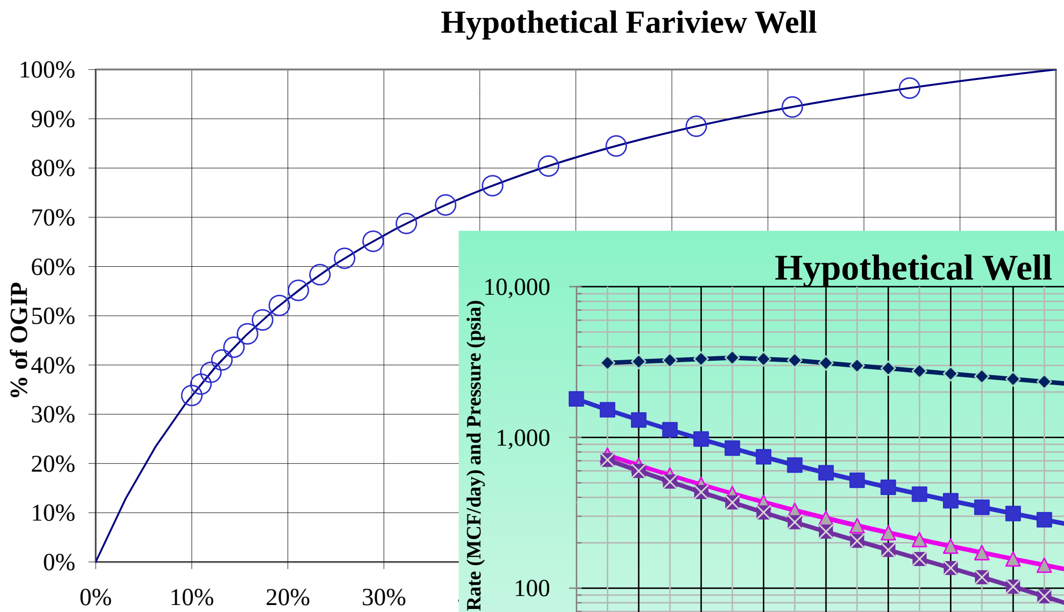
$$\overline{P} = \frac{-500000(OGIP - Cum)}{500000(OGIP - Cum)b - 15607 A h V_m y b \rho}$$

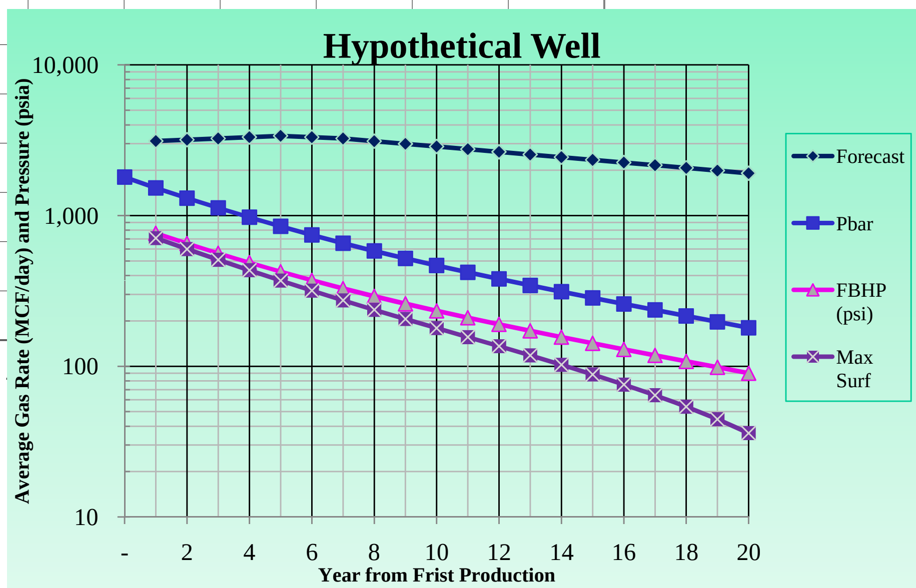
- Start with Langmuir Isotherm calculation
- Change it from P_i to P_{bar}
- Rearrange equation to solve for P_{bar}
- Allows calculation of reservoir pressure at any point in time

Ramifications of Langmuir Isotherm

- Most wells flow best when BHP is around ½ of the saturation pressure on the Isotherm
  - Lower than half costs money and doesn't usually increase production
  - Higher than half costs production
  - Remember, BHP is a function of both wellhead pressure and liquid level
- While the isotherm does not speak to production rate:
  - Applying cum production to the isotherm will tell you remaining pressure at a given time
  - Applying production forecasts can allow estimates of the timing of future capital requirements
- Calibrating drainage area for a specific well can be done during shut-in periods

What Pressure is Needed When?





- Delaying Compression improves NPV(15) by 6%

Flow within CBM Reservoirs

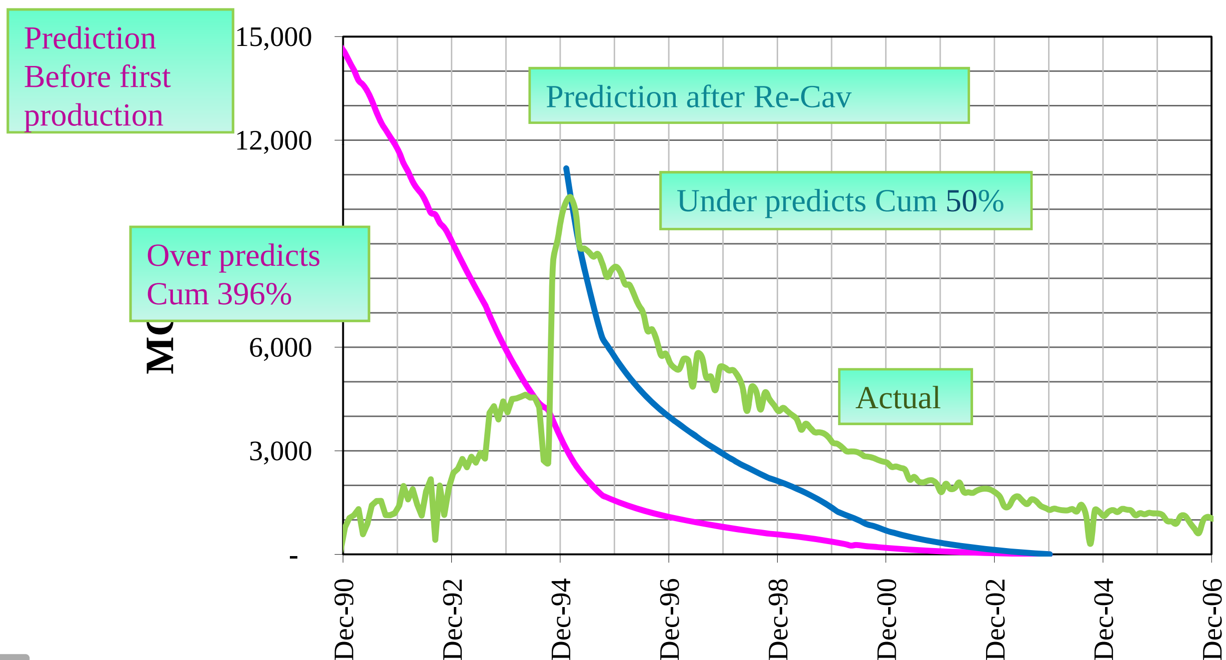
- CBM has few of the characteristics of reservoir rock:
  - All flow is through face cleats toward channels
  - Permeability is not defined (although Reservoir Engineers have defined made-up constructs like “cleat permeability” to allow conventional reservoir equations to work after a fashion)
- Bureau of Mines Method of predicting flow rate (also known as “AOF Equation” or “Backpressure Equation”):

$$q = c_p \left(\bar{P}^2 - P_{bh}^2 \right)^n$$

- Assumes the “c_p” and “n” terms are constant over the life of the well

Production Forecasting
Bureau of Mines Method

$$q = c_p \left(\overline{P}^2 - P_{bh}^2 \right)^n$$



Refinement of AOF Equation

- It is clear that a constant c_p wasn't going to work for the Fairway wells, so you have to look at what c_p is:

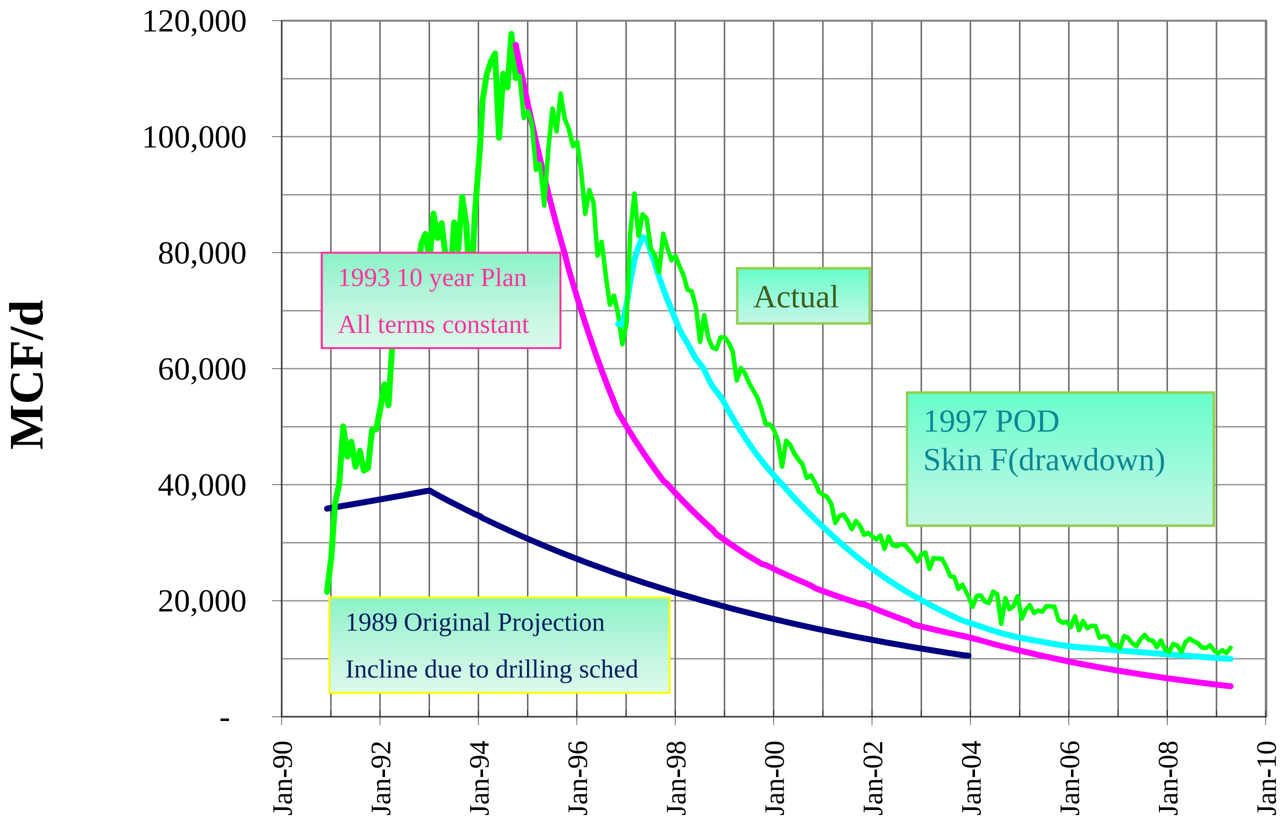
$$c_p = \frac{kh}{1422\mu ZT\left(\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + Skin\right)}$$

- Our solution was to calculate Skin using an empirical rock mechanics model

$$Skin = -13.42 + 4.92\phi_0^{-0.167}\left(\frac{c}{b}\right)^{-0.438}\left(\overline{P} - P_{bh}\right)^{0.2636}$$

- All of the parameters except drawdown are fixed at their initial value
- Drawdown can be predicted iteratively

Production Forecasting
(With variable skin)



Producing Coalbed Methane at High Rates at Low Pressures SPE84509

by

David Simpson, MuleShoe Engineering

Mike Kutas, BP America Production Co.

CBM Plan of Depletion (POD)

- Reservoir
- Production Forecasting
- POD Approach
- Interventions
- Conclusions

Project Starting Point

- San Juan Basin CBM growth:
  - 2% of basin production in 1986 (0.024 BCF/d out of 1.3 BCF/d)
  - 64% of basin production in 1996 (2.4 BCF/d out of 3.6 BCF/d)
- By late 1996 it was becoming clear that:
  - Production incline was mostly over
  - Wells on decline could see 60-80% annual decline rate
  - None of the traditional reservoir performance models adequately described either the incline or the decline
  - We needed an unconventional reservoir, wellbore, and pipeline model to determine what was next

POD Well-by-Well Approach

- Calibrate A, b, ϕ_0, and kh for each of 62 wells
- Hold calibrated parameters constant with time and calculate Skin using the empirical rock mechanics model
- Model system from first production to abandonment
- Compute pressure drops
  - From reservoir into near wellbore (develop an “equivalent pipe length” to typify reservoir for each well)
  - Up wellbore (standard nodal-analysis)
  - Across well site (convert to “equivalent pipe length”)
  - Down gathering system (commercial model)

Interventions
Wellbores

- Cleanouts and/or re-cavitations
  - Wells with positive *Skin*
  - Wells with history of bridging/fill
- Wellbore tubulars
  - Run liners where possible
  - Small tubing for water management
  - Gas flow up the annulus
  - Tubing set-depth critical

Interventions Deliquification

- Installed when fluid velocity < 36 ft/sec up the tubing in model
- Rod Pumps
  - Beam unit with gas engine – difficult to do pump-off control
  - Pneumatic-ram driven – easy pump-off control, requires high line pressure
- Eductors/Ejectors
  - Very effective for ongoing maintenance
  - Difficult to restart after an upset

Interventions Wellsites

- Converted pressure drop & rate to a length of 3-inch pipe:
  - >1,000 ft, 1997 de-bottlenecking
  - <100 ft, no problem
  - Otherwise, fix when other work is done
- Wellsite design included:
  - Three lines from wellhead to separator
  - Separators with two inlet nozzles
  - Many vent/drain valves installed for future (unspecified) maintenance activities
  - Manifolds for compressor installations
  - Blowcases to move water from the separators to the water system

Interventions--Compression

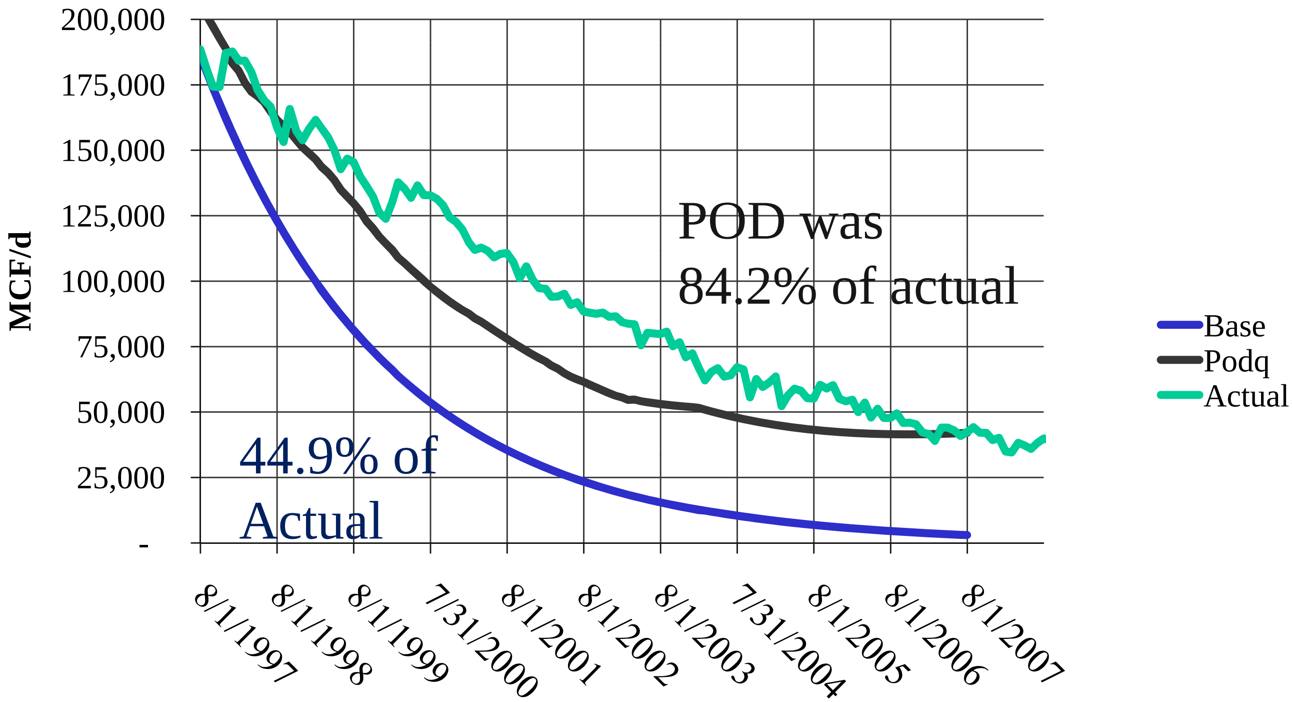
- Compared well site compression to lateral compression
- Three well site compression cases:
  - Immediate compression (highest NPV on 23 wells)
  - No compression (highest NPV on 21 wells)
    - First three wells to get compressors were in this group
    - All three provided significant uplift, so other 18 scheduled for 1998
    - Further work showed all the wells in this group had wellbore problems
  - Staged compression (highest NPV on 17 wells)
    - Start with no-compression case
    - Develop empirical equations for q(t), cp(t), and decln(t)
    - Take d/dt and d^2/d^2t of each equation
    - Install compressors at distinct local minimum of either derivative

Results

Actual Compared to Target	Target 2/1/04 Gas Rate (MMCF/d)	Actual 2/1/04 Gas Rate (MMCF/d)	Well Count
<-50%	3.3	1.3	5
-50% < x < -10%	10.7	6.9	10
±10%	9.4	9.4	10
+10% >x>50%	12.5	15.8	16
Sub-total	35.8	33.6 (94%)	41
>50% **	10.8	19.2	21
Total	46.6	52.8 (113%)	62

** This group is predominantly those wells that the model said not to compress and that were compressed anyway. The model category was actually a reflection of wellbore damage and all required major well work

Project Post Appraisal



Results

- Initial field development was authorized on 176 BCF EUR with production through Jan, 2004
- In January, 2004:
  - Predicted rate without the project 13 MMCF/d
  - Model rate 52 MMCF/d
  - Actual rate 67 MMCF/d
- Project verified that very low abandonment pressures were achievable in the coal (80 psia used for reserves)
- May, 2009 Status of 62 POD wells:
  - Gas rate 30 MMCF/d
  - Cum-weighted average reservoir pressure of model wells was 74 psia
  - 36 wells below 80 psia making 18 MMCF/d (0.5 MMCF/d avg)
  - 22 wells below 50 psia making 13 MMCF/d (0.6 MMCF/d avg)
  - Wells have a cumulative production of 820 BCF (13 BCF/well, one well has accumulated 44 BCF)

Case Study Conclusions

- Unconventional analysis is required for unconventional reservoirs
- It is profitable to manage a reservoir from the burner tip
- Late-life CBM operations require a different mind-set than early-time operations

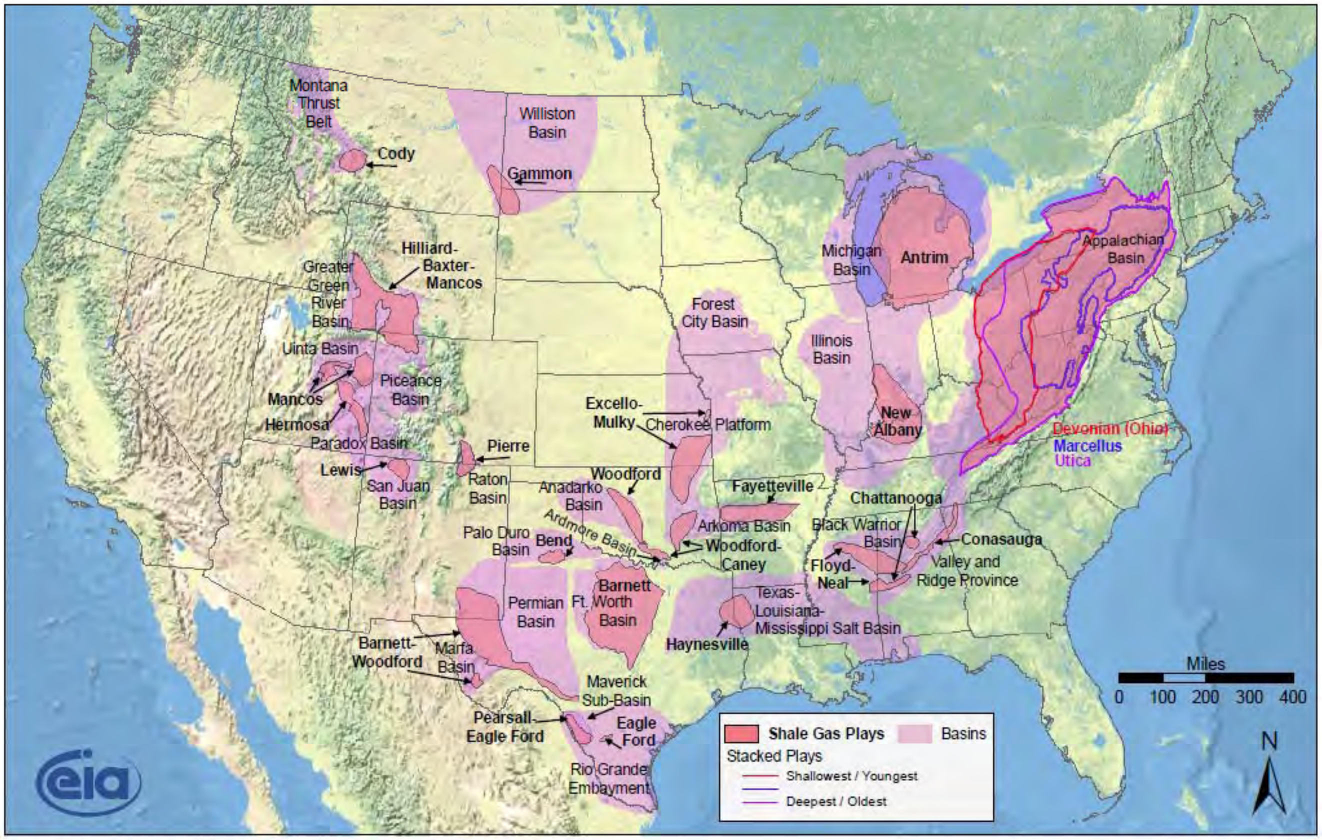
CBM Conclusion

- CBM is one of the fastest growing segments of worldwide Oil & Gas operations
- Most conventional wisdom does not apply:
  - D'Arcy flow equations are irrelevant
  - Oil field Artificial Lift techniques have very limited application after the initial de-watering period
  - Very small pressure differences can make huge impact on recovery
  - Surface Facilities are crucial to success
- CBM is an area that will change many fundamentals of our business

Gas Shale

- Introduction
- Key Issues
- Shale Reservoir
- Shale-specific challenges

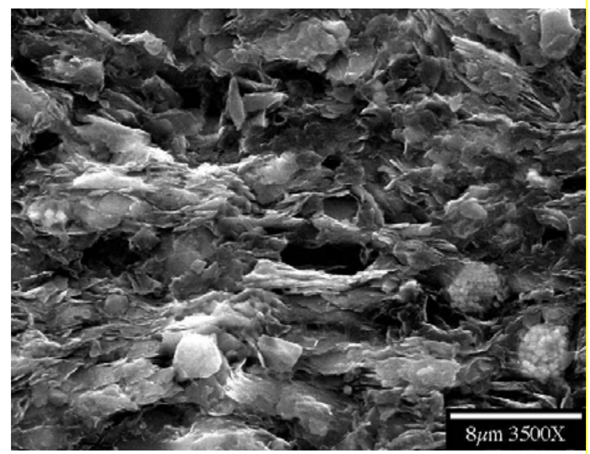
U.S. Shale Gas Plays



Source: Energy Information Administration based on data from various published studies
Updated: May 28, 2009

Introduction

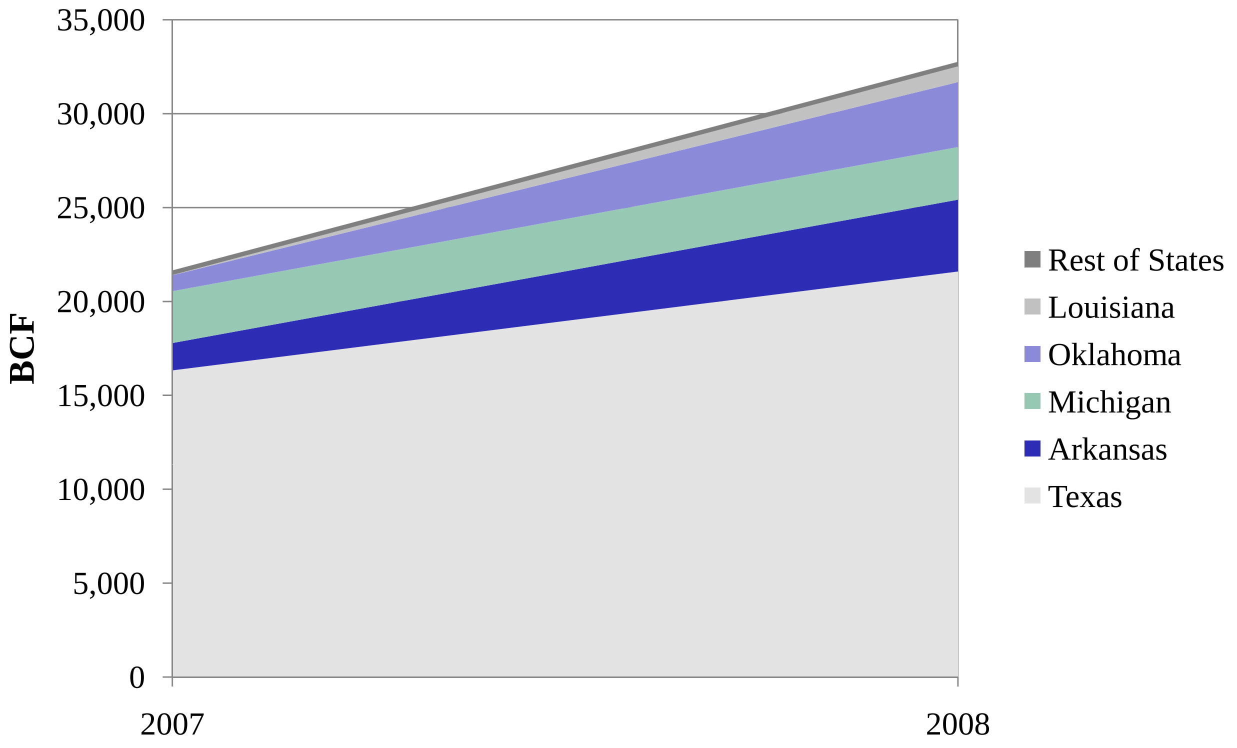
- The first commercial well in the U.S. was a Gas Shale well in Fredonia, New York in 1821 (30 years before the first oil well in Pennsylvania)
  – 27 ft deep in Devonian Shale
  – D'Arcy flow was so slow that the output was only suitable for gas lights
  – Water production could be ignored (flow rate so low little water moved)
- Photomicrograph shows sand, quartz, organic material (peat, coal, etc.), beer cans(?)



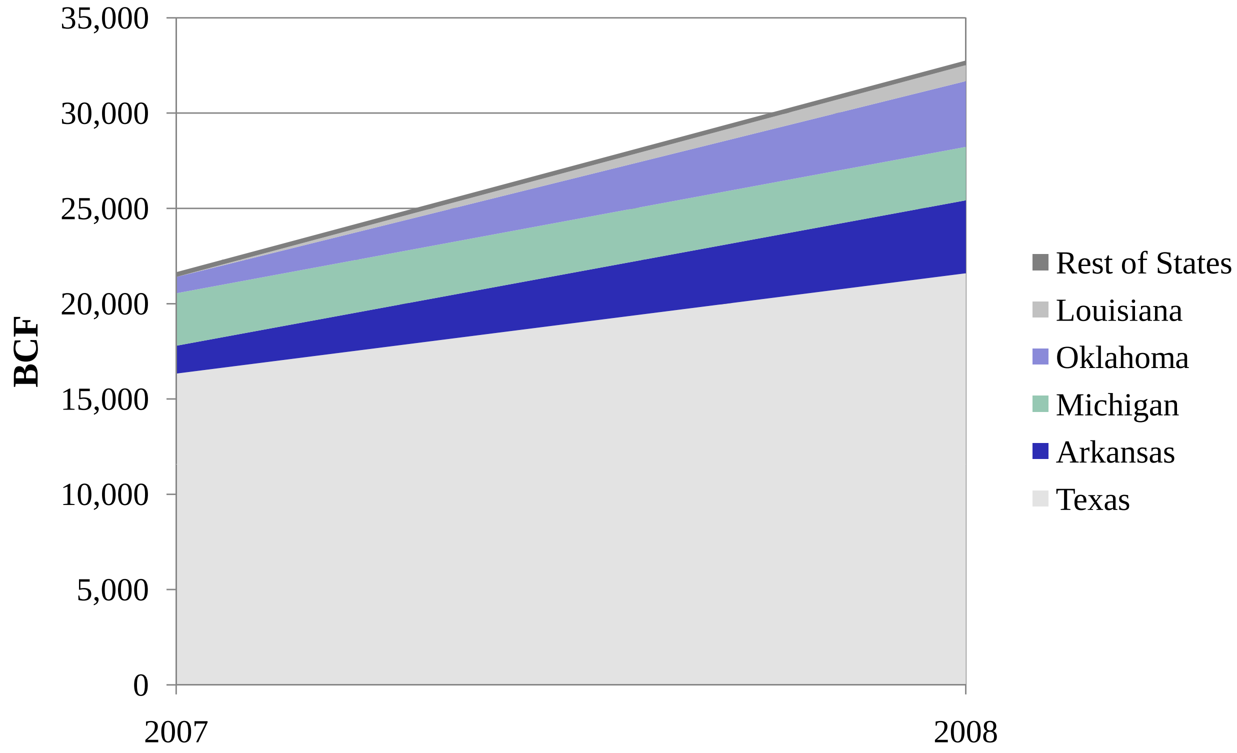
Shale Gas Introduction

- Gas from Shale is a mixture
  - Thermogenic gas (gas from breaking down organic material under high temperature and high pressure) which can start as oil and heavy gases and ends up as methane
  - Biogenic gas (gas from biological processes that has not been modified by heat and pressure) tends to be primarily methane
- The more mature the reservoir, the larger percentage of methane
- Important Producing Areas
  - Antrim Shale in Michigan (first prod 1965) produces nearly 400 MMCF/d
  - Barnett Shale in Texas (1981) produces 3 BCF/d
  - Fayetteville Shale in Arkansas (2004) produces 250 MMCF/d
  - Marcellus Shale covers 95,000 square miles and has an OGIP around 550 TCF. No significant production as of 2008

U.S. Shale Gas Year-End Reserves



U.S. Shale Gas Production



Shale Gas Key Issues

- Without fracture stimulation, flow through pore throats is very slow (<10nD-10 μD permeability)
- Gas storage:
  - Some gas is stored in Pore Volume (largest component at discovery)
  - Some gas is adsorbed to the matrix (largest component late in life)
  - Some gas is stored in the natural fractures (smallest component)
- Mechanical strength of Shale considerably higher than CBM so:
  - Horizontal wells are less risky, and
  - Proppant is much more effective
- Shale Gas is a technology play:
  - Wasn't viable until high-accuracy horizontal drilling was possible
  - Production requires massive hydraulic fracture stimulation

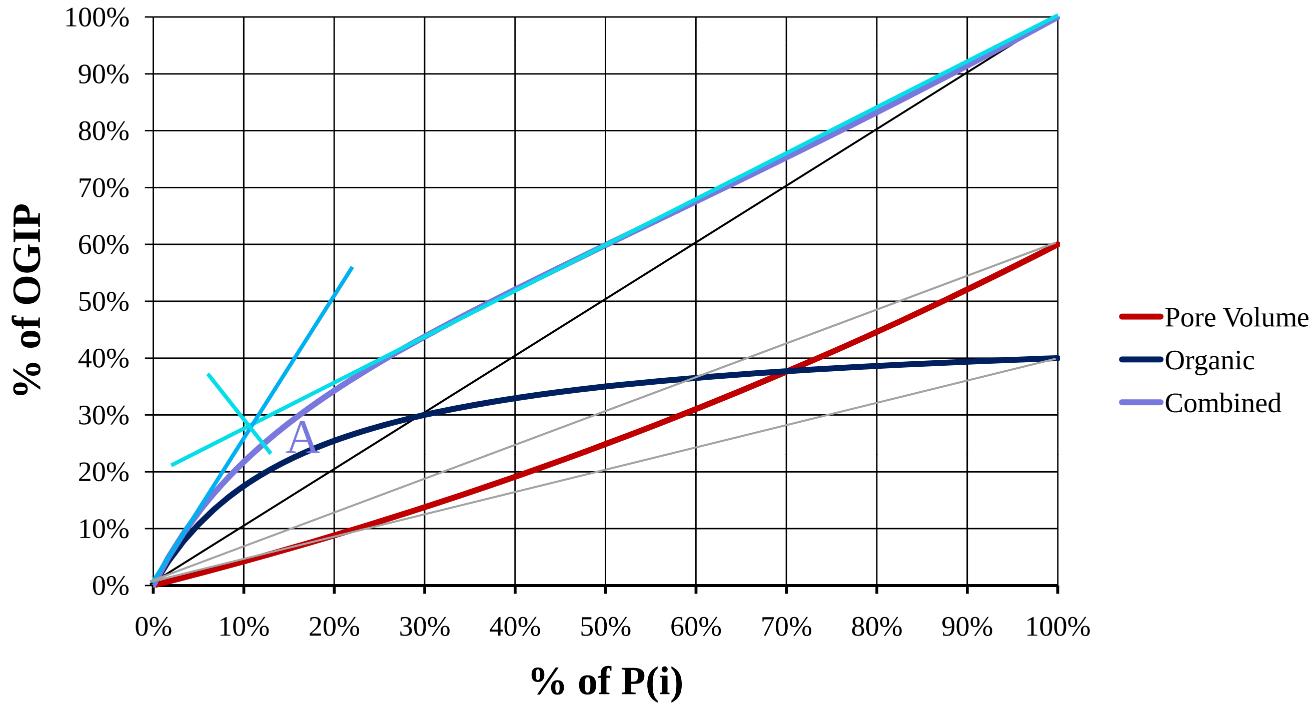
Shale Key Issues

- Shale tends to be very thick
  - 100-300 ft minimum to be productive
  - Some wells in the Barnett have over 1,000 ft of shale
  - Thickness suggests very long well lives (50-75 years is predicted for Horn River and Marcellus)
- Gas Shale tends to be quite variable from basin to basin
  - Antrim Shale has 30 SCF/ton and acts like a tight gas field
  - Barnett Shale has 300 SCF/ton and acts like a CBM field
  - Shallow shales (800-3,000 ft) have water rates and quality much like CBM
  - Deep shales (2,500-8,000 ft) tend to have much poorer quality water and it can sometimes be excessive (1,000 bbl/day of 150,000 mg/L TDS is common in the Barnett when fraced into Ellenburger)

Shale Reservoirs

- Applying the Conventional Reservoir definitions to Shale Gas:
  - Source rock—Shale is rich in organic matter and meets the definition
  - Reservoir rock—Shale has a significant void volume and meets the definition
  - Cap rock—the Shale matrix is very resistant to gas flows and meets the definition
- Gas Storage
  - Significant gas in a Shale reservoir is in the void space ($PV=ZnRT$ for that part)
  - Much of the gas is part of the solid and does not follow the gas laws (i.e., $PV \neq ZnRT$)
- Pressure
  - Gas in the void space flows like conventional gas (push to wellbore)
  - Gas on the organic material flows like CBM (pull from wellbore)
- Matrix permeability is very low
- Porosity is low
- Isotherm, like everything else, is a mixture

Shale Gas Storage



Shale "Isotherm"

- The large pore volume acts as a dampener to temper the early-life performance (i.e., the Declining Pressure period is very long and much steeper than CBM)
- The Declining Reserves period is similar to CBM
- The Transition period is very short
- Ramifications of this storage profile:
  - Many wells will be abandoned prior to point "A"
  - The wells that are still economic after point "A" will tend to have very flat decline, and very long lives
  - The period from first production to point "A" will be pretty long (maybe 20+ years)
  - The period after point "A" could easily be much longer

Shale Ultimate Recovery

- EIA estimates less than 20% of OGIP is recoverable
  - This is the same value they assigned to CBM in 1991
  - It will certainly be revised upwards over time
- It is difficult to predict well-response to deliquification and pressure reduction, but:
  - Wells with high organic content should act like CBM wells earlier in their life, and low pressures should recover a very large percentage of OGIP
  - Wells with lower organic content should act like tight gas wells until much later in their life—they respond to a steady pressure, and if you can minimize variability you should be able to get above 60% of OGIP

Active Shale Plays

Play	Country	GIP (TCF)	Organic Content (SCF/ton)	Depth (ft)	Expected rates (MCF/d)
Antrim	USA	76	30	600-2200	200
Barnett	USA	327	300	6500-8500	350
Fayetteville Shale	USA	52	150	1500-6500	550
Horn River Basin	Canada	500	450	8000-10000	5,000+
Marcellus	USA	550	90	4000-8500	3,000
Utica Shale	Canada	40	65	6000-9000	700

Potential Shale Plays

Play	Country	GIP (TCF)	Primary Developer
Lower Saxony	Germany	30	ExxonMobil
Makó Trough	Hungary	40	ExxonMobil
Baltic Basin	Poland	700	ConocoPhillips
Alum Shale	Sweden	60	Shell Oil
Weald Basin	England		Eurenergy Resource
Horton Bluff	Canada		Triangle Petroleum
South China Basin	China		Shell & Petro China
Dnieper-Donents Basin	Ukraine		
Gambay Basin	India		
Vienna Basin	Austria	240	OMV

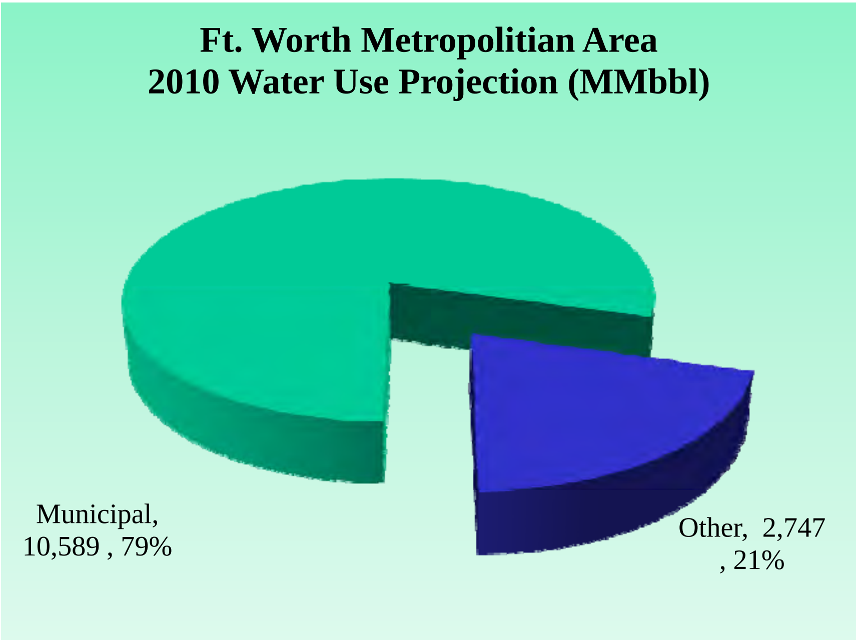
Shale Specific Challenges

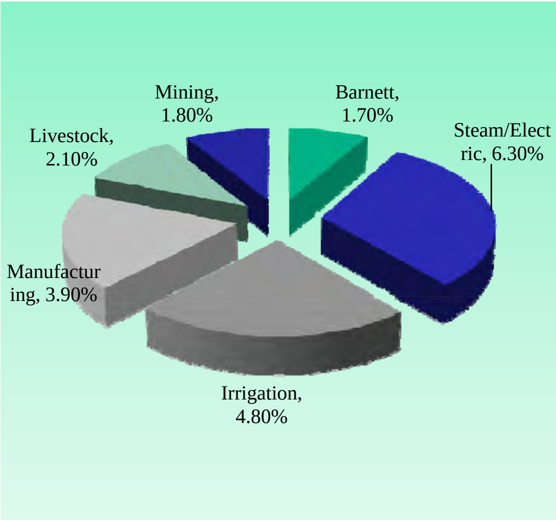
- Abrasive solids
- Water Acquisition
- Infrastructure

Abrasive Solids

- Both the nature of the Shale and the massive hydraulic fractures in the shale contribute to abrasive solids getting to surface
  - Frac sand production tends to taper off with time
  - Formation solids tend to be smaller volumes that are manageable
- Sands can
  - Cut pipes
  - Damage valve internals
  - Prevent flow through dump valves and other nozzles
- Options
  - Downhole options (screens, frac pack, gravel pack etc.)
  - Basket strainers on surface (need to be around 4 micron)
  - Separators (need cleanout ports)
- Should try to reduce damage prior to removal point (e.g., if strainer on surface, then use hot bends instead of fittings)

Example Water Usage





Source: Gas Technology Institute 4/2007

Water Acquisition

- A slickwater frac can take as much a 250,000 bbl of water
- Removing water from a water supply for several wells in a short period can cause disruption in municipal availability or river flow
- Start with relatively pure water, then add up to one half percent of the volume in chemicals (friction reducers, biocides, scale inhibiters, etc)
- Techniques to minimize water supply disruption include
  - Stockpiling water during wet periods
  - Treating and reusing flow-back water
- It is always appropriate to try to work with local jurisdictions to minimize impacts of water acquisition

Source: Oil & Natural Gas Technology Report
Argonne National Laboratory

Infrastructure

- Shale Gas development is happening in places that have not historically had natural gas production
- This creates barriers to development
  - Pipelines can take years to permit and build
  - Plants and compressor stations can be very difficult to permit in places where Oil & Gas operations are new
  - States without a tradition of Oil & Gas will often try to apply regulations from other industries that can be unreasonably restrictive
  - Water management infrastructure causes regulators considerable difficulty
- All of the barriers can be overcome, but it often requires significant time, money, and public-relations effort

Shale Gas Conclusion

- Shale Gas development is in its early stages
  - We don’t know how the wells will respond over time
  - We don’t know how the water rates will change with time
  - We don’t have a clear strategy for what pressures will be required over time
  - We don’t know how we are going to do mid-life and late-life deliquification
- Some of this information may require 30-50 years to develop
- Beware of the idea that you can design your Shale Gas field once and facilities will last forever—we will make about the same number of mistakes in Shale as we made in CBM, but hopefully they will be different mistakes

Unconventional Operations

- Field Development Planning
- Low Pressure Operations
- Compression
- Gas Well Deliquification
- Produced Water

Field Development Planning

- Before starting full-field development, you need to have a Plan
- Plan needs two major components:
  - Deliquification plan
    - Early Life
    - Mid-Life
    - Late Life
  - Surface Facility plan
    - Wellsite facilities
    - Gas gathering
    - Compression
    - Water handling

Deliquification Plan



- Removing liquid from the wellbore will be an important process in the life of most unconventional wells
- Plans for removing it need to be incorporated into:
  - Drilling design
  - Wellsite facilities design
  - Capital budgets
- Each stage in the well's producing life has different design parameters

Initial Deliquification

- Start-up water can be a very large volume:
  - Some wells produce hundreds or thousands of barrels of water per day for weeks
  - Removing this initial liquid can be done with little regard for minimum Net Positive Suction Head Requirements (NPSH-r) because reservoir pressure is still very high
- It is common for initial water to begin declining in a few weeks and for high rates to be gone in a few months:
  - Many wells that need a 500 bbl/day pump in the first few weeks will produce 10-30 bbl/day in 6 months
  - Many wells will be able to free-flow for much of their early life

Initial Deliquification Plan

- Plan needs to anticipate:
  - How to identify wells that need help
  - What technology will be deployed if gas flow is less than expected
  - How pumps will be powered (often the gas flow is intermittent and unreliable)
  - How to identify if pump has completed the initial deliquification
- Need to confirm that drilling/ completions design is consistent with planned pumps:
  - Is casing big enough?
  - Has the possibility of providing rat hole been considered?
  - Where will you set the pump in an extended completion interval or multiple seams?

Mid-Life Deliquification

- From the end of the initial period to the beginning of Low Pressure Operations can be several years
- WGR will tend to stabilize during this period to a value that will remain more or less constant for the remaining life of the well
- Reservoir pressure declines more slowly during this period
- With the "right" flowing tubing pressure most wells will free-flow during this period (determining "right" can be a challenge)
- Deliquification methods that derived from oil fields become progressively less effective during this period

Mid-Life Deliquification Plan

- Wellbore configuration should be evaluated:
  - Every item (pipe, nipples, packers, etc.) should be looked at critically
  - Ask the question “why is this here?”
  - If the only answer is “because that is the way we do it” then remove it.
  - If there really is a reason for it to be there, then ask “can this task be done with a lower pressure drop?”
  - Be prepared to reposition tubing several times to find what works best in a particular well (and try to develop rules for the whole field)
- Develop quick and easy techniques to compare actual production to production forecasts often (at least monthly, weekly is better):
  - “Small but persistent” deviations can indicate onset of liquid loading
  - Increased variability can be loading
- Pick a technology to apply when wells start loading (not after they log off)

Late Life Deliquification

- Late-life wells can produce at commercial rates at very low reservoir pressure, only if:
  - Flowing tubing pressure is low enough, and
  - There is no standing water above the formation
- Late life deliquification technology is key:
  - A hydraulic jet pump has about 300 psig NPSH-r so with a 50% drawdown, recoverable reserves are around 25-50% of OGIP
  - Change to PCP reduces NPSH-r to under 30 psig and increases recovery to nearly 80% of OGIP
  - Using evaporation or a zero NPSH-r pump can get you to 96% of OGIP (requires deep vacuum on the wellhead, but it is possible)

Late Life Deliquification Plan

- Pick a target abandonment pressure
- Coordinate facilities plan with deliquification plan
- Be very careful of tubing design in late life:
  - A velocity string is very expensive in terms of pressure drop
  - If tubing is in the hole, it must be associated with mechanical pumping or chambered gas lift

Wellsite Facilities Plan

- This plan needs to prepare to accommodate the well's entire life:
  - Remove large volumes of liquid in initial period
  - Have small pressure drops during mid-life period
  - Be able to handle liquids at very low pressure in late-life period
- Prepare for vacuum operations from the beginning:
  - Separator Blowcases (more on that later)
  - Check valves under PSVs
  - All open-ended lines plugged or double valved
  - Minimize the number of threaded connections (e.g., don't allow couplings on instrument tubing lines)

Gas Gathering

- Required flowing wellhead pressure changes with time for both CBM and Shale Gas:
  - Until point "A" on Langmuir Isotherm, there is no economic benefit of lowering flowing bottom hole pressure much below Point "A"
  - After Point "A" pressure needs to fall steadily over the years
- Key is informed trade-off between adding pipe, central compression, and wellhead compression

Gas Gathering

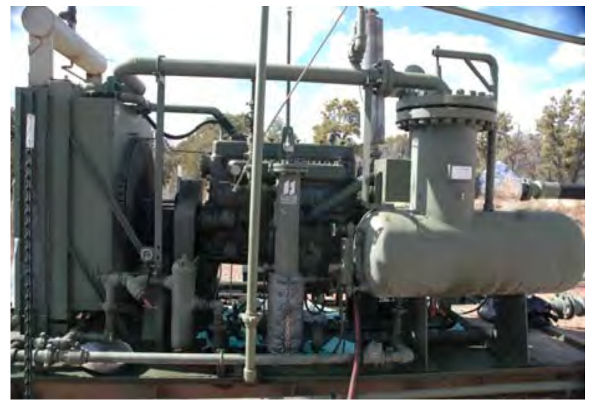
- Prior to first production, the best assumption is that every well will be "average", but they never are
- Producer-operated gathering systems will always out perform Third-Party gathering systems (more on that later)
- You have to think of gathering facilities as a "tool of production", not as an "evil", necessary or not

Gathering Plan

- Initial system layout:
  - Do the best job you can, it will still be "wrong"
  - Make sure every line is piggable
  - Budget line loops in the second and third years of operation
  - Focus line loops to develop "straddle compressor" sites
- Determine pressure targets for the first 10 years of operation:
  - As wells approach Point "A" evaluate lowering central compressor delivery pressure or setting straddle compressors
  - As wells approach "Reservoir Depletion" phase, start deploying wellhead compressors
  - As required wellhead pressures approach 10 psig, start process to go into vacuum operations
- It is important to include this plan in new-field economic evaluation

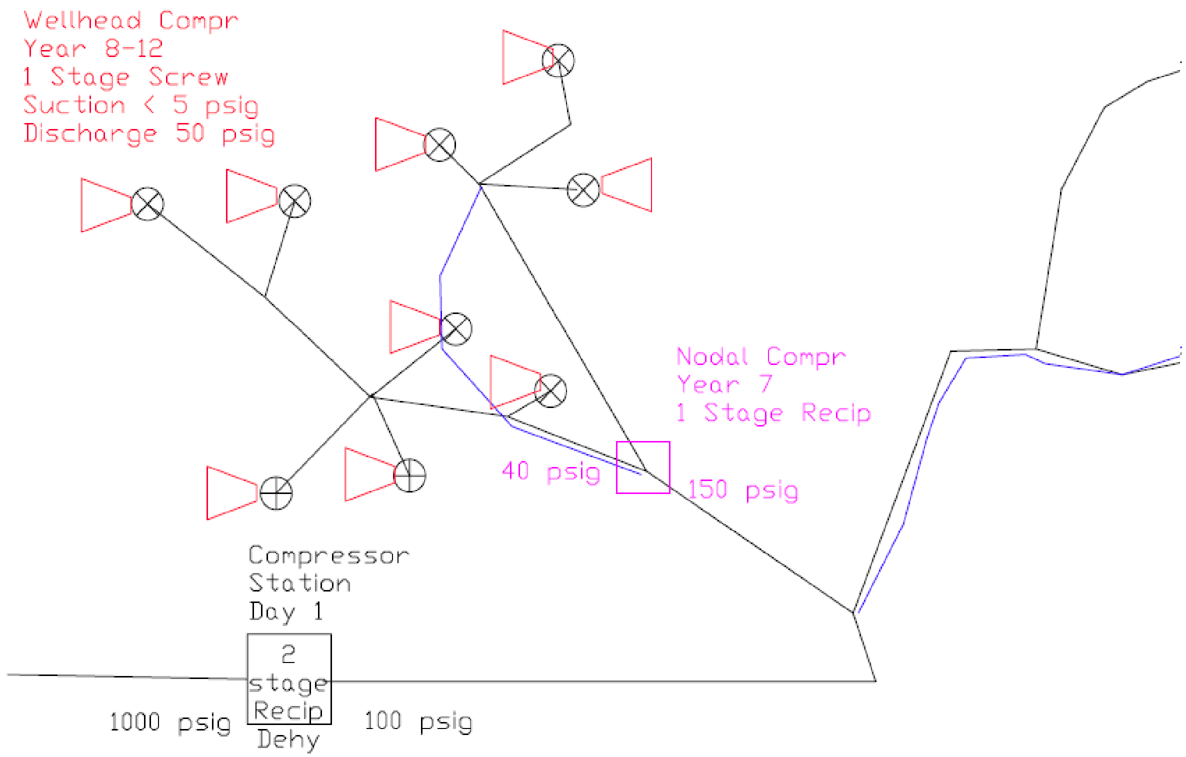
Compression Plan

- Compression is required to recover the last 30-50% of OGIP
- Compression plan should:
  - Address the location, capacity, and target pressure at each major milestone in first 10 years
  - Recommend technology, stages, and any dehydration requirements at each station



- Compressor plan must work with gathering plan (remember, pipe efficiency drops rapidly as pressure decreases)
- Compressor technology:
  - Sites with a target inlet pressure < 40 psig should be flooded screws
  - Most other sites will be recips

Compression Plan



Water Plan

- Virtually all CBM and Shale Gas wells will produce some amount of water over their entire life
- The Water Plan must describe:
  - Whether aggregation is necessary or desirable (often untreated surface discharge works better without aggregation)
  - Where water will be disposed of (commercial facility or private facility)
  - How water will be disposed of (UIC well, evaporation pond, treated surface discharge, or untreated surface discharge)
  - Whether water will be piped or trucked to disposal
- Every decision in the plan has impacts on initial capital, permitting time, and ongoing LOE

Final Word on Unconventional Gas Planning

- Even with the best planning, coordination, and execution in the world:

- The creeks will still rise and the plan will need to change

Low Pressure Operations

Role of Low Pressure in Well Performance

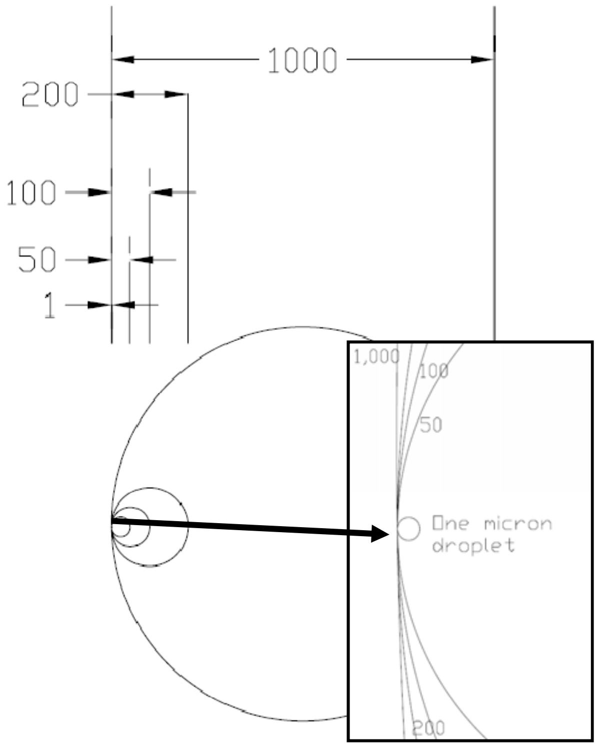
- Low surface pressures can impact:
  - Inflow rate by lowering BHP
  - Liquid level by increasing gas velocity (to increase liquid-lifting capacity of the gas)
  - Liquid level by lowering dew point and increasing evaporation
- Liquid level is often the controlling factor in production rate from a “dry gas” well:
  - Water exerts 0.43 psi/ft (condensate is somewhat less)
  - 2-3/8 tubing holds 0.162 gal/ft
  - 1/2 bbl (130 ft) of water will increase sand face pressure >50 psi
- Low pressures can have a role in deliquification:
  - Small problems (<20 bbl/MMCF) it can be the whole answer
  - Large problems it can participate in the answer

General Questions

- What constitutes low pressure operations?
  - As pressure drops below 2 atm (11-15 psig) the flowing gas begins behaving less like an incompressible fluid and the flow stream's ability to act on the environment declines rapidly
- Will piping ingest air during vacuum ops?
  - Probably. Can be reduced by plugging open-ended lines.
- Can ingested air cause the line to blow up?
  - No, you have to be between the LEL and UEL for an explosion.
  - If a well makes 100 MCF/d, you would have to ingest 650-2,000 MCF/d of air which would be a very large hole (that couldn't sustain vacuum operations).
- Can ingested air cause corrosion problems?
  - The gathering companies claim that it can (more on that later)

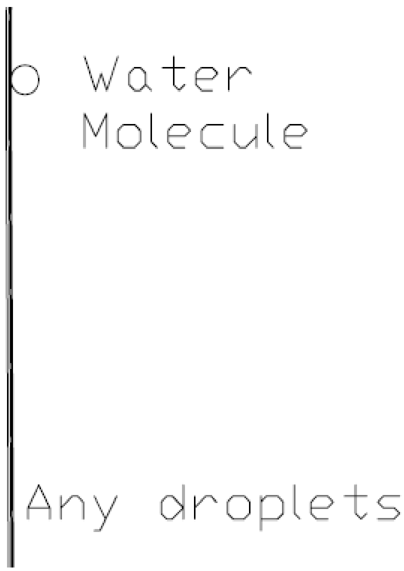
Water Droplets

- Coarse Spray
  - 201-1,000 microns (0.2-1 mm)
  - Terminal velocity as a raindrop 7 ft/s so it would tend to fall at separator velocities
  - Will sheet or pool at normal temps
- Fine Spray
  - 101-200 microns
  - Terminal velocity as drizzle 0.5 ft/s (won't tend to fall at sep velocities)
  - Will pool at normal temps
- Mist
  - 51 -100 microns
  - Terminal velocity as fog 0.05 ft/s
  - Will bead at normal temps
- Aerosol
  - 1-50 microns
  - Terminal velocity as cloud 0.003 ft/s
  - Will collect on a mirror at normal temps



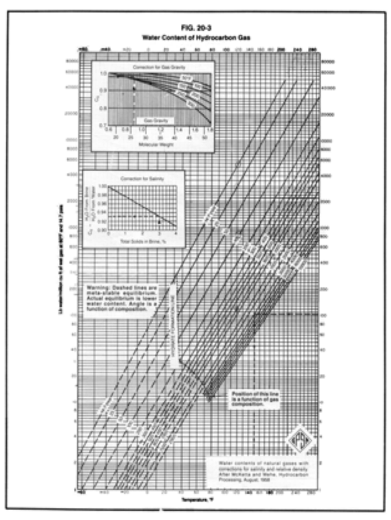
Water Vapor

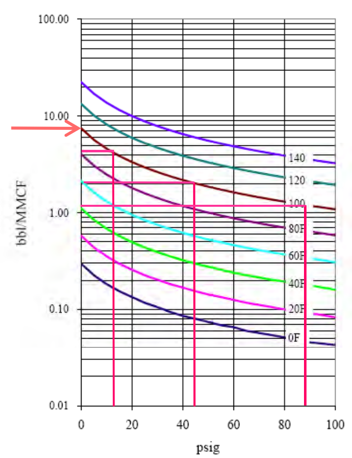
- A water vapor molecule is 0.00038 microns
- If a one micron droplet was blown up to the size of the earth,
  - A water molecule would be 4 ft diameter
  - A methane molecule would be 6.4 ft diameter
- Any filter that can stop a water vapor molecule would not allow a methane molecule through



Evaporation

- Whenever there is a coherent gas/liquid interface, liquid will evaporate until the gas at the surface of the liquid is at 100% relative humidity
- As wellhead pressures diminish, the amount of water that gas can carry as “humidity” increases dramatically





- At 100°F
  - 90 psig holds 1.3 bbl/MMCF
  - 46 psig holds 2.2 bbl/MMCf
  - 16 psig holds 4.4 bbl/MMCf
  - 0 psig holds 8.8 bbl/MMCF

Phase-Change Scale

- Produced water is usually at least 10,000 mg/L TDS
- Flashing a barrel of 10,000 mg/L water deposits 3.5 pounds of solids somewhere
  - NaCl turns into salt blocks (eventually soluble in hot water)
  - Bicarbonate (HCO3) turns into Nahcolite (NaHCO3) that is granite hard and barely soluble in strong acid

Salt Inhibition

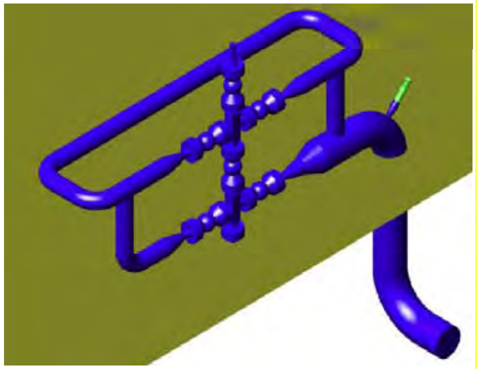
- Intent is to form soft, mobile "slurry" instead of rocks and gravel
- The flow stream must have enough energy to move slurry to some convenient location
- Salt inhibition does not work well in gas wells:
  - The mass of the dissolved solids is still there
  - The mass of the added chemical is now there
  - Total mass deposited is greater with the chemicals
  - Flow-stream lacks the total energy needed to move the slurry and it becomes immobile "sludge"
- Facility design needs to support flushing piping/vessels with hot water and/or strong acid

Low Pressure Facilities

- Wellsites
- Low Pressure Gathering

CBM Well Example

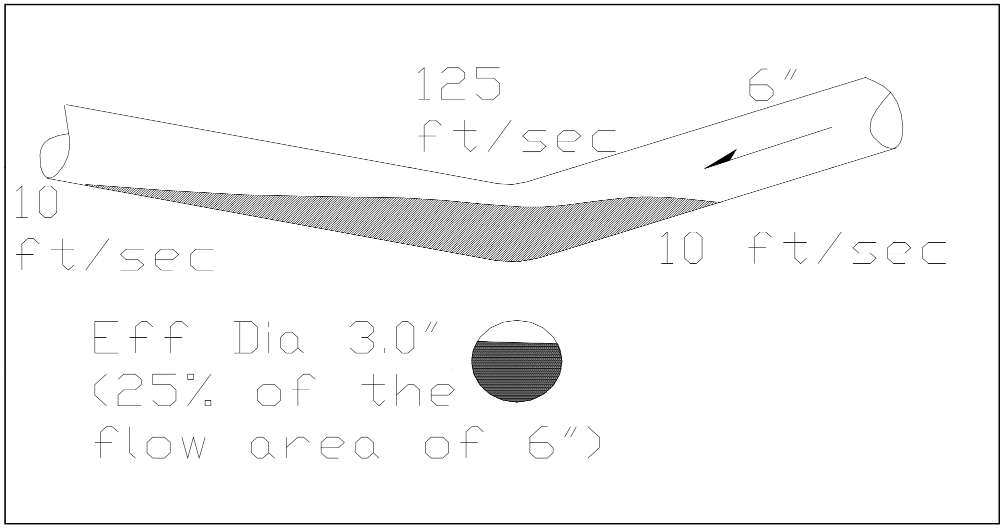
- Big Well
  - 28 MMCF/d
  - 1,000 hp of compression
  - 90 ft of 12” pipe from wellhead to separator
  - 90” X 25’ vertical separator
  - 110 ft of 12” pipe from separator to compressor
  - Compressor suction 4 psig



- What is pressure at wellhead?
  - Model predicts 6 psig at wellhead
  - Actual:
    - 47 psig at separator (effective pipe size 5.0 in)
    - 86 psig at wellhead (eff pipe size 4.25 in)

Water in Piping

- Standing water requires gas to do work
  - Gas wants to drag water surface along the pipe
  - Result is white caps on the water and big pressure drop
- Piping too big leaves water behind.



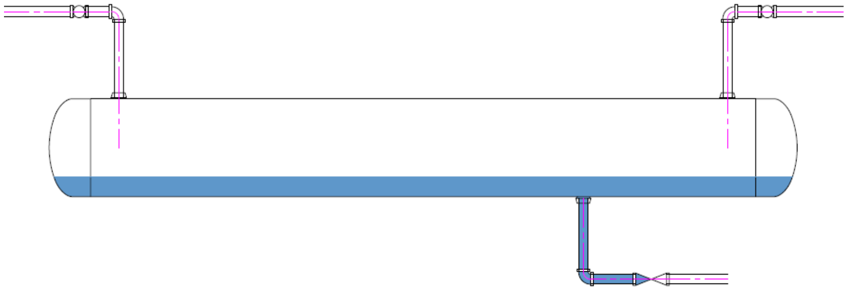
Choice of Production Unit

- A production Unit should
  - Separate gas and liquids
  - Automatically remove accumulated liquid
  - Be able to operate at full range of pressures over well's life
- At beginning of life
  - It is not unreasonable to take a pressure drop across a choke into the production unit
  - The MAWP of the vessel needs to be higher than Point "A" on the Langmuir Isotherm, but doesn't have to be higher than initial reservoir pressure
- At end of life:
  - How are you going to get liquid out of a vessel at 5 psig?
  - Is the gas-liquid interface going to resaturate the gas with water vapor?

Re-saturation Example

- At the bottom of the wellbore
  - 20 psig
  - 180°F
  - 11,728 lbm/MMCF

5 psig
160°F
88% RH

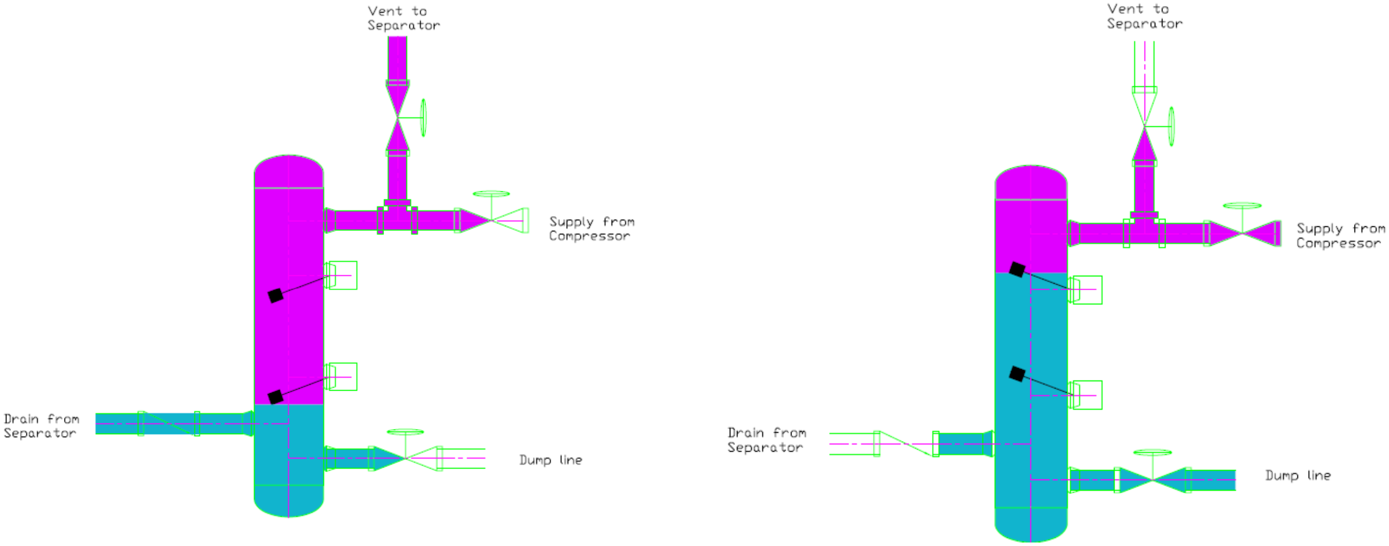


2 psig
160°F
16,123
lbm/MMCF

Considerations for Moving Water from Separator

- Separator Pressures
  - <15 psig, probably can’t dump to an above-ground tank
  - <0 psig can’t dump to a buried pit
- Options
  - Transfer Pump (auto-start required)
  - Remove separator
  - Blowcase

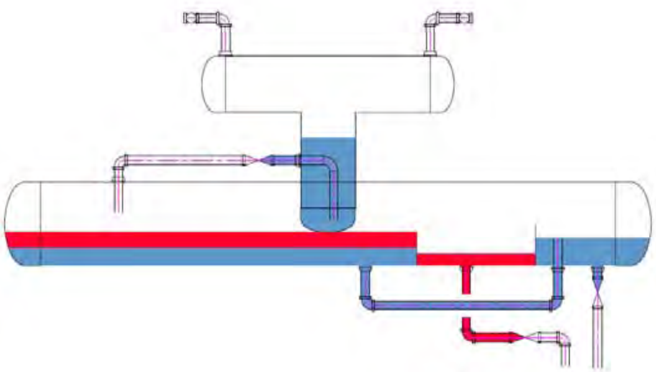
Blowcase

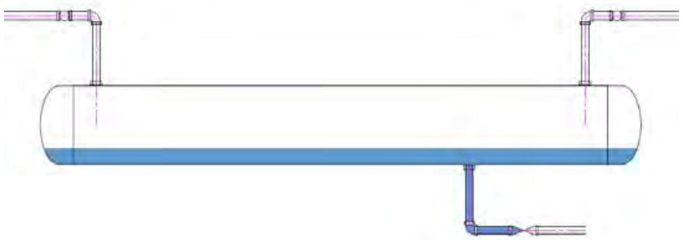


- 8-inch blowcase, 3.917 gal/dump
- Vent size controls capacity
  - 2-inch vent—5,000 bbl/day
  - 1-inch vent—900 bbl/day
  - ¼-inch vent –25 bbl/day

Types of production units found on Unconventional wells

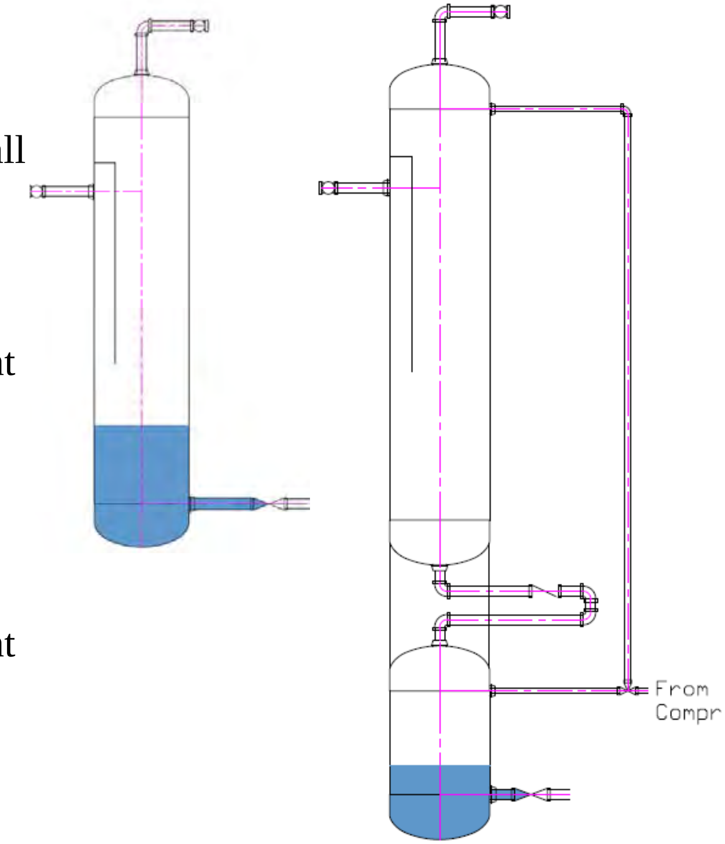
- HLP
  - Three phase vessel with small liquid-gas contact area
  - Min high side pressure around 60 psig
  - In late life, high side can be compr discharge scrubber, compr suction blowcase can dump to low side
- Horizontal
  - Two or three phase vessel with large liquid-gas contact area





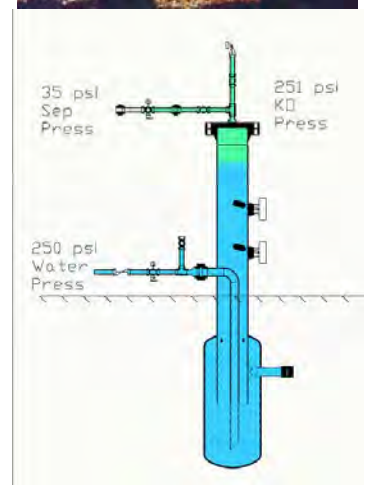
Types of Production Units

- Vertical
  - Two phase vessel with fairly small liquid-gas contact area
  - Change of direction at entrance improves performance
  - Motive force for liquid movement is wellhead pressure
- Vertical w/integral blow case
  - Two phase vessel with no liquid-gas contact area
  - Motive force for liquid movement is compressor discharge pressure



Wells with Downhole Pumps

- Where do you go with a pump discharge?
  - To Separator?
    - Minimum Separator pressure limited to water line pressure unless you have a blowcase or a pump
  - To water line?
    - Every pump makes some gas (some pumps make a lot of gas), you don't want it in your water system
    - Getting gas out of the water system can be a chore
- There seems to be fewer problems when the pump goes to the water system, but even these can be solved with a gas knock out

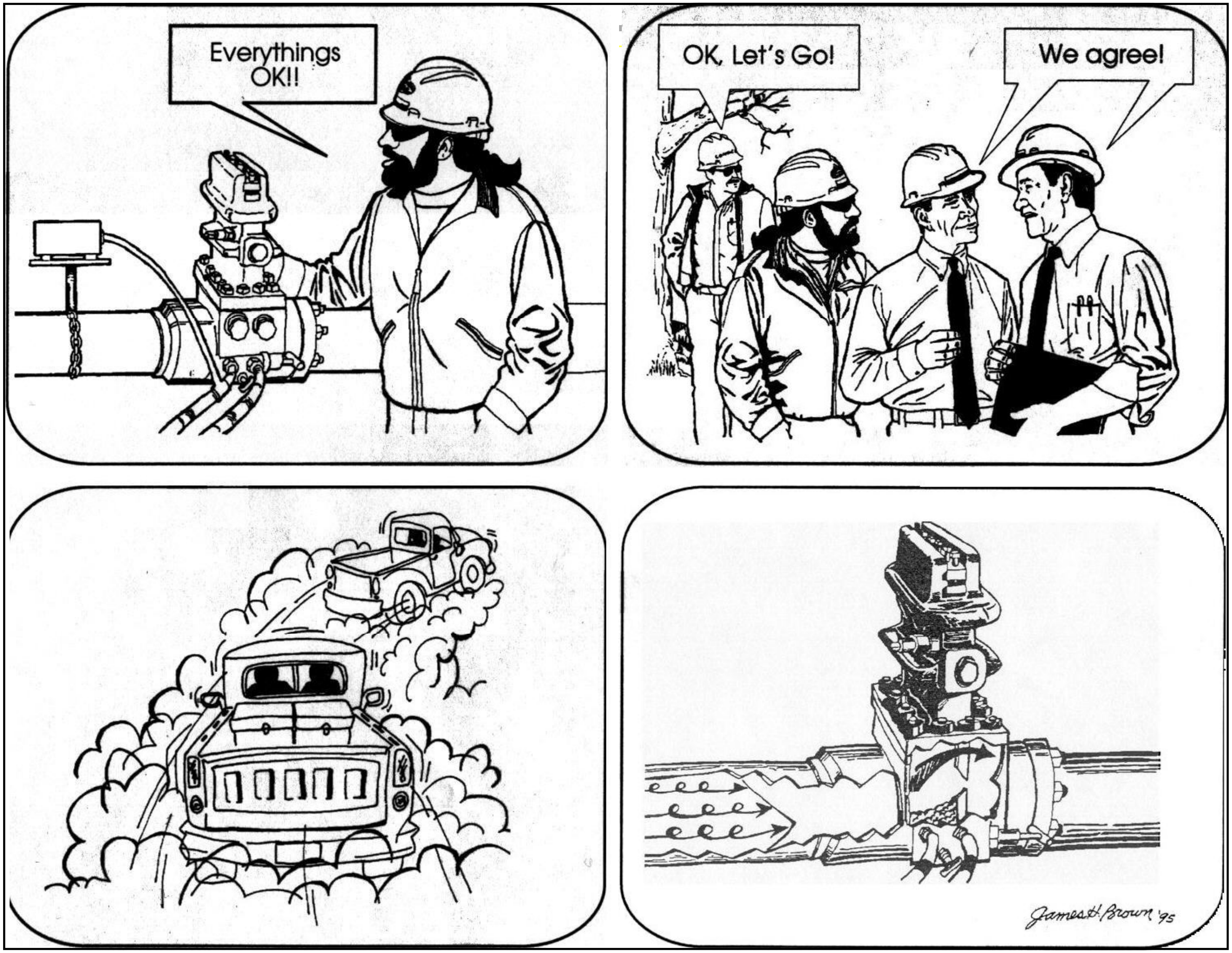


Fluid Measurement

- All unconventional wells require volume information to be related to specific wells
  - Many regulatory agencies require monthly reporting by well
  - Many contracts require settlement by well
  - Reservoir analysis requires knowledge of the material removed from the reservoir
- Both gas and liquids need to be measured, but the requirements for gas measurement tend to be much more stringent than liquid measurement

Liquid Measurement

- No one does a very good job of measuring produced water
  - Any volume reported tends to be accepted as accurate, especially when everyone knows that it is not
  - A material balance comparing produced volume to disposed volume is never close
- Technologies used
  - Turbine meter—most common world-wide, tend to over range when dump valves open, very poor accuracy on separator dumps
  - Tank gauging—only useful with tanks on each well, very accurate eventually, not so good on a month-by-month basis
  - Vortex Meter—reasonably new application of this technology, good accuracy and repeatability, not as prone to over ranging, sand cutting can be a problem
  - Blowcase Dump Counter—most accurate by far, the blowcase dumps the same volume every time, and the counter can go into the "turbine meter" inputs on EFM


Everythings OK!!
OK, Let's Go!
We agree!
James H. Brown '95

Elements of a *Differential Producer*

- Primary Element—mostly steel; sees pressure, temperature, and flow velocity, but no electronics
- Sensing Element—electronics and exotic metals; sees pressure and temperature, but not flow; generates electronic signals or pen movements.
- Recording Element—Electronics or pen & ink; only sees electronic signals or pen movements
- Differential Producers are *Inferential Devices*
  - Assuming all conditions match reference conditions you can use *Bernoulli's Equation* to infer a flow rate from a differential pressure across a known restriction

Assumptions in Calculations

- Constant density
- No friction
- Tube is straight and level
- Gas does no work
- Flow profile matches power law
- Single phase flow
- Atmospheric pressure known precisely
- Fluid properties known and constant
- Enough friction to dampen swirl
- Press and Temp known
- Tube roughness in narrow range
- Plate condition meets specs




- Square edged orifice meters are most common by a long margin
  - We pretend we understand them
  - We think we know how to operate them
- They always give us numbers

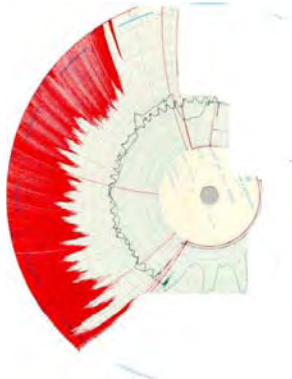


Gas Measurement

- Actually, considerable expertise is required to care for any measurement technology
- Most common technology:
  - Square edged orifice meter—very good measurement if station is built right and equipment properly maintained
  - V-Cone—excellent measurement, not as prone to flow-profile errors, not as much to go as wrong
    - When the meter plugs, the dP looks like a big flow rate
    - They plug with coal, shale, salt, and ice just like a square-edged orifice meter

Capturing Flow Data

- Historically, flow-measurement data has been captured on paper charts
  - Charts are pulled periodically
  - Sent to an “integrator” to convert analog lines into discrete data points
- Trade-off between fast clocks and less frequent visits usually falls toward slow clocks
  - Minimum resolution on 16 day clock about 3.5 hours
  - Maximum duration of pressure transient a few seconds
  - Integrator can only draw line through middle of blob
  - This chart understated volume by 38% (1.7 MMCF/d)
- Choice between Paper Charts and EFM needs to consider avoiding painted charts as a benefit of EFM



Other Gas Measurement Technologies

- Pitot Tubes
  - Fair measurement in laboratory
  - Not tolerant of trash
  - Must be calibrated for a specific fluid and specific pressure
- Coriolis
  - Measures shift in bent pipe caused by fluid momentum
  - Requires considerable momentum to give repeatable results
  - Needs more flow energy than low pressure gas has to offer
- Vortex
  - Measures perturbations in flow caused by flow around a bluff body
  - Works much better in liquid than gas, and better in hp gas then lp gas

- Ultrasonic
  - Measures Doppler shift in sound waves as gas moves away
  - Can see shift in liquids and hp gas, not in lp gas

Wellsite Facilities

- Best practices:
  - Use multiple flow lines from wellhead to separator instead of one big line
  - Include an integral blowcase on vertical separator
  - Include a compressor manifold for the possibility of a wellsite compressor
  - Include many points for pressure gauges on piping and vessels
  - Include clean-out ports for removing coal fines and sand
  - Use Vortex meters or blowcase dump counters for water measurement
  - Use V-cone meters for gas measurement if your contract allows

Low Pressure Gathering

- Gathering System Equipment
- Project Design
  - Acquiring ROW
  - Detailed Design
  - Construction
  - Operation

Gathering Systems

- Unconventional wells will all need very steady and carefully managed wellhead pressure
  - Steady pressure requires that the system
    - Be producer operated
    - Be regularly pigged
  - Very low pressures
    - Are required for the last 50% of recoverable gas
    - Are often not a good idea for the first 50%
- At low pressure:
  - Water vapor represents a significant mass
  - Dehydrators are not economical

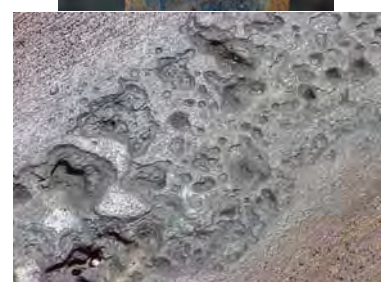
Effect of Pressure on Dehydration

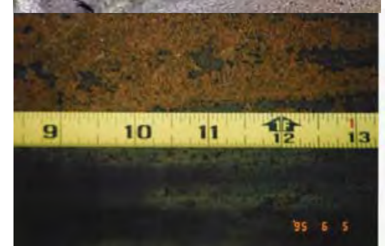
- A TEG dehydrator contact process is not pressure dependent
- On the other hand the reboiler and TEG pump have a fixed capacity:

	1000 psig	100 psig	10 psig	0 psig
Water Content at 100°F (lbm/MMCF)	60.4	466.3	1,819.3	3,077.1
Reboiler size (BTU/hr) for 1 MMCF/d	14,000	125,000	491,000	875,000
Glycol Flow Rate (gal/hr) for 1 MMCF/d (to get to 7 lbm/MMCF)	3.8	29.1	282.1	2,811

Corrosion

- Low-pressure gathering lines are subject to four flavors of corrosion:
  - External anodic (or galvanic)
  - Internal Microbiological Influenced Corrosion (MIC)
  - Internal CO_2
  - Internal Oxygen
- Every one of these is an anode/cathode reaction that requires:
  - Cathode (material with a less negative or more positive electrical potential than the pipe)
  - Anode (steel pipe)
  - Electrolyte (standing water)





Oxygen Corrosion

- Gathering companies claim Oxygen incursion creates “high risks”
  - Old contracts are held hostage to new limits
  - New contracts are being executed with outrageous limits
  - The “science” supporting gatherer’s position is very poor
- Oxygen participates in three kinds of corrosion
  - General “rust” type corrosion poses approx zero Integrity Management risk due to the formation of a passivation layer
  - Stress Corrosion Cracking, oxygen will accelerate cracking in stainless-steel pipes and carbon-steel pipes under high stress
  - Cathodic pitting, dissolved oxygen can create cathodic cells that can cause aggressive pitting
    - Cathode is dissolved oxygen in water above 9 ppb (equivalent to 450 ppm in gas),
    - Anode is unprotected steel, and
    - Electrolyte is standing water
- Oxygen increases risk, but the risk is significantly less than the gatherers would have you believe

Corrosion Control

- External Anodic
  - Happens where there is standing ground water coincident with a holiday in the pipe coating
  - Generally addressed by applying an external current to the pipe to make it less negative than the earth
- Internal
  - All four kinds require standing water
  - The most common source of water is condensation so the pH will be very close to neutral (i.e., 7.0) but can quickly become acidic by absorbing acid gases
  - Adjusting the water chemistry or adding biocides requires access to the pools of liquid (very difficult)

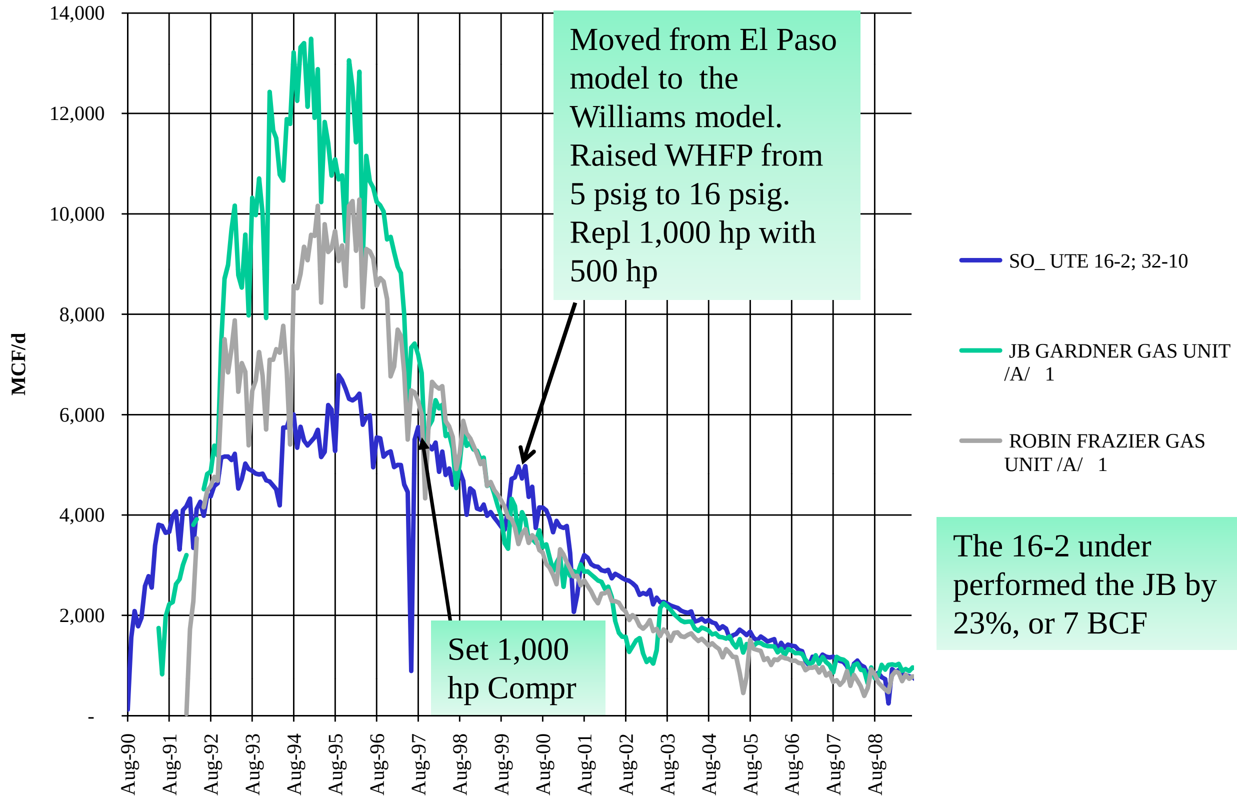
Chemical Injection

- People **want** to add chemicals to gas lines (maybe so they feel they're doing something?)
- Common chemicals
  - Corrosion inhibitors and biocides
  - Salt inhibitors
  - Hydrate inhibitors
  - Friction reducers
- Chemicals need to be transported:
  - "Aerosol" injection tends to coalesce and drop out within a few dozen feet of injection point
  - Liquid injection just follows the bottom of the pipe to the first sag
- If you just **have** to put in a chemical, chase it with a pig to try to get it to the walls (not terribly effective, but it has a chance and running the pig is worthwhile by itself)

Who Should Build Gathering?

- Three major models, I call them:
  - *El Paso Model*—Third party picks up the gas at the wellhead
  - *Williams Model*—Producer brings gas to Central Delivery Points for compression and dehydration
  - *Burlington Model*—Producer brings gas all the way to the plant for final processing
- Both the Williams and Burlington models out perform El Paso Model
  - Line looping projects are much more attractive at \$3-10/MCF than at a gathering fee of \$0.50/MCF
  - Pigging lines is hard, dirty work that costs a lot of LOE, if the prize is 100 MCF/d then it is attractive to the producer, not to the third party gatherer
- You get what you measure, so:
  - Pipeline techs tend to operate the system to minimize LOE
  - Production techs tend to operate a gathering system to maximize production

Who's Gathering to Use?



The 16-2 under performed the JB by 23%, or 7 BCF

Affiliates

- Gathering systems built and operated by an affiliate of the Producing Group underperform all other models because:
  - Gathering Group has different goals from Producing Group and
  - Producing Group has no recourse for non-performance of Gathering Group (legitimate complaints sound like "whining" and you can't invoke a "gathering agreement" as the final authority)
- Even when Production and Gathering report to the same boss it is too easy to:
  - Call the Production Group a "profit center" and set goals accordingly
  - Call the Gathering Group a "cost center" and set goals accordingly
  - Mediate conflicts in favor of reducing LOE
- All the seemingly valid reasons for this organization turn out to be rationalizations in the end

What do you need to know to get your gas to market?

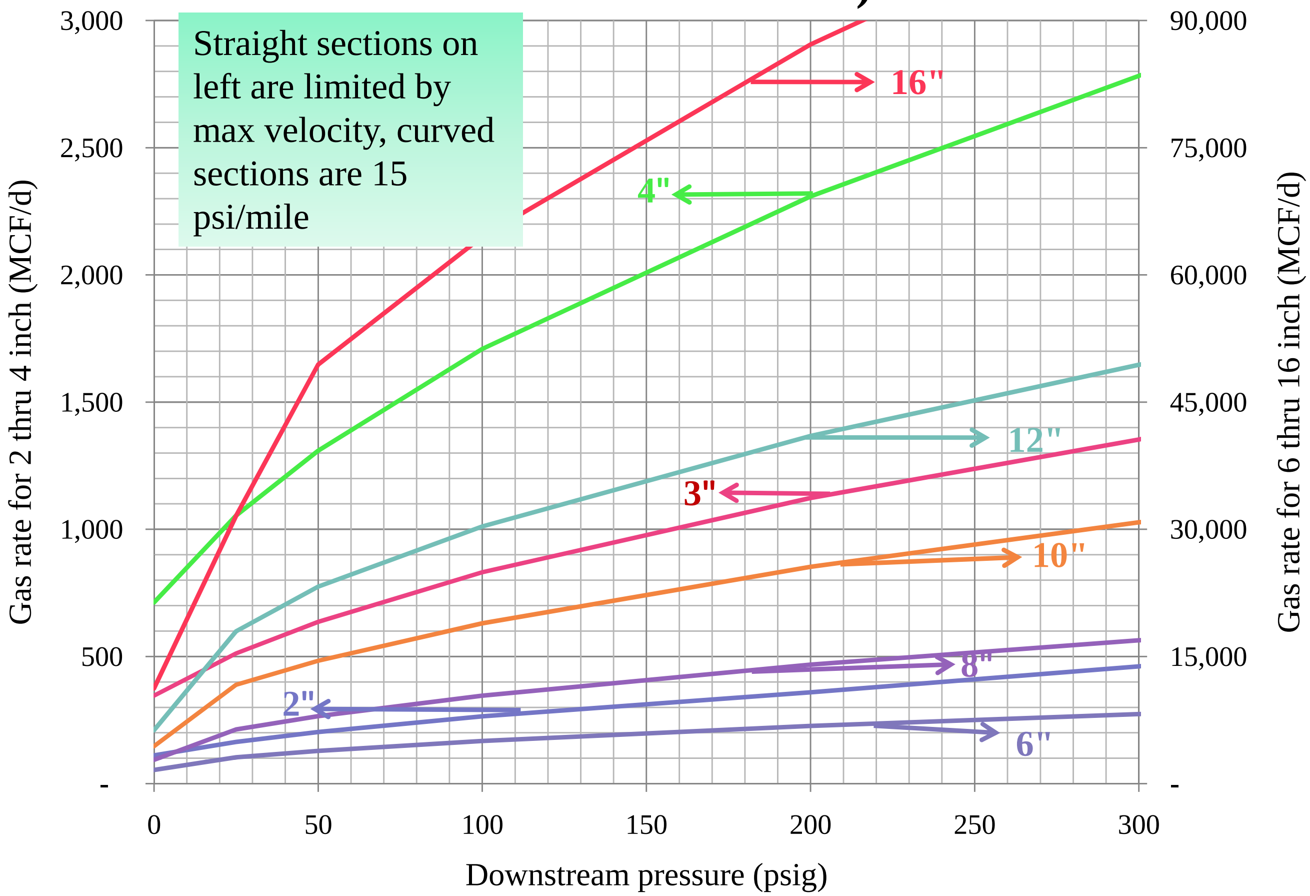
- El Paso Model
  - What the gatherer is obligated to do
  - How to “influence” him if he doesn’t do it
  - Your lawyer’s phone number
- Burlington Model
  - Everything there is to know about primary gathering
  - Everything there is to know about regulated compressor stations
  - Everything there is to know about mid-stream pipelines
- Williams Model
  - Everything there is to know about primary gathering
- What does “everything” include
  - Selection of Gathering System Equipment
  - Acquiring Rights of Way, System Design, and Permitting
  - Construction
  - Operation

Gathering System Equipment
Gathering Pipe

- You’ll always have to trade off pipe size against:
  - Cost
  - Fluid Velocity
  - Pressure Drop
- Whatever technique you use to select the line size, it needs to be done prior to starting the design and permitting work for a construction project
- Flow lines need to be built to:
  - Connect new wells
  - Access to new markets
  - Correct capacity constraints
- For the third option, full-blown hydraulic models are needed to evaluate complex interrelations
- For the first two you can sometimes get away with a simple chart

Flow Line Capacity

(based on 15 psi/mile pressure drop limited to velocity between 11-100 ft/sec)

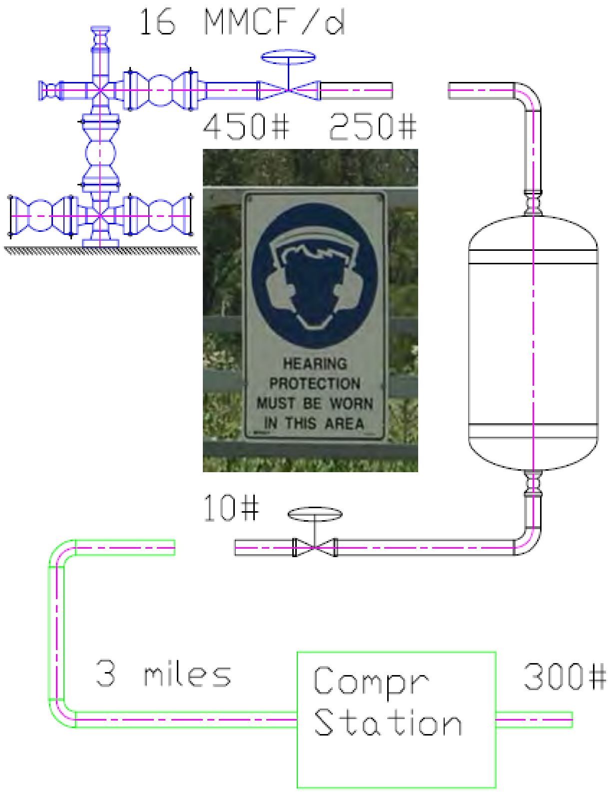


Flow Line Material Selection

- Gathering system materials are changing rapidly with the problems of CBM and Shale
  - Serious corrosion concerns
  - Large-pipe diameters required for big volumes at low pressure
- Many operators mistakenly assume that since CBM and Shale wells will spend most of their life at low pressure they can build very low MAWP gathering systems
  - Requires significant throttling for first 8-10 years
  - Requires major capital investments in compression from day 1 to make up the energy discarded at wellhead chokes
- Rule of Thumb: Gathering system MAWP should be greater than the pressure at Point "A" on the isotherm

Example

- One solution would be to build wellsite and gathering equipment strong enough to eliminate the compressor
- There is another "solution" that only treats the symptoms (and people ignore the hazardous noise signs)



Pipe Selection

- Pipe selected must be compatible with:
  - Design pressures
  - Expected temperatures
  - Expected Chemicals
- It is useful to check with local contractors to find out what they have experience with:
  - If they've used the material you are considering and like it, then installation might go smoother
  - If they've used it and hate it, then you might find out if there is a hidden shortcoming
  - If they've never used it then you have to be prepared for a learning curve

Flow Line Materials

Material	Largest size typically used	Typical MAWP	Comments
Steel	20 inch	570 psig	Requires external coating, internal surface subject to corrosion
HDPE (SDR-7)	16-inch	110 psig	All sizes of an HDPE SDR number have the same MAWP
HDPE (SDR-13.5)	16-inch	53 psig	Much thinner wall than SDR-7
FRP (stick)	6-inch	1440 psig	Delicate to install
FuturePipe	4-inch	1440 psig	Spool, non-corrosive, end connections require considerable skill
FlexSteel	6-inch	1440 psig	Spool, steel imbedded in HDPE, non corrosive
FlexPipe	4-inch	1440 psig	Spool, non corrosive, end connections easy to install

Roadbore Casing

- A “roadbore casing” is a carrier pipe placed under a roadway, the pressurized pipe is run inside the casing
- Purpose is to protect the pressurized pipe from external forces superimposed by road traffic
- Casing must:
  - Have centralizers to prevent metal-to-metal contact
  - Have some sort of seal on both ends (generally a rubber “boot” is used) or be filled with something like wax to minimize water collection
  - Be vented to atmosphere (or be rated to the pipeline MAWP)
- Operational considerations
  - Boots always leak and casings always stand full of water
  - Two vents can create a “thermal siphon” that can freeze your pipe

Roadway Crossings

- Design codes
  - Do not prescribe when casings are required, but
  - If they are used, there are extensive and complex requirements for sealing, venting, and dealing with water incursion.
  - Design factors are different for cased vs. uncased crossings
- Transportation department regulations mostly follow design codes
- My recommendation is:
  - Always case highway and railroad crossings
  - Never case other crossings unless required by regulation

River Crossings

- Rivers are generally a major concern
  - You can go over them
  - You can bore under them
  - You can go through them
  - You really can't go around them

River Crossings

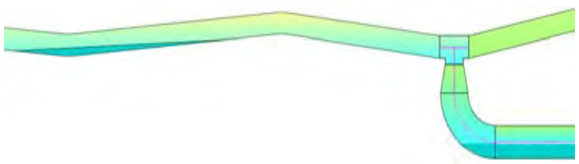
- Regardless to how you cross you need to:
  - Notify regulators (often get permits)
  - Notify downstream water users and upstream landowners
  - Make sure that the water turbidity doesn't change
- If you cut the river bed then you also have to:
  - Slow the flow of the river so it doesn't cave in your ditch (and you have to work fast, dam flooded in 40 minutes)
  - Ensure that the pipe has adequate buoyancy (if not then the pipe will float)

Un-Evaporation

- Condensation is not instantaneous
  - A compressor can drop the 100% RH point from 3,000 to 200 lbm/MMCF
  - The excess water may not condense for several minutes
  - That is enough time for the condensation to happen some distance into the gathering system
- After the gas leaves the wellsite
  - Temperature of the gas will drop
  - The gas' ability to carry water vapor drops
- Water vapor will condense in the line
  - With wellhead pressures under 15 psig, the amount of water available to condense is huge (2,000 lbm/MMCF in a 20 MMCF/d gathering system is 114 bbl/day)
  - If you don't have a plan to remove it, it will stand in the line

Water in Gathering System

- Water that finds itself near a line drip will tend to fall into it
- Problem is that there are many sags in the line that are not near the line drips
- Every sag will collect water
- Also, it is quite rare for line-drips to be automated
  - Pumpers will come by several times a year and blow the water out of them
  - They get water every time, so they're sure the drips are effective
  - Problem is that they never know how full the drip was (typically full to the trunk) or how long it has been overflowing
- Water accumulation adds to system pressure drop and corrosion risk
- Line drips are never the sole solution to water accumulation

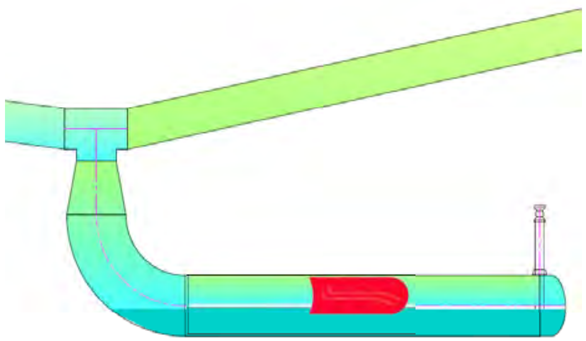


Drip Example

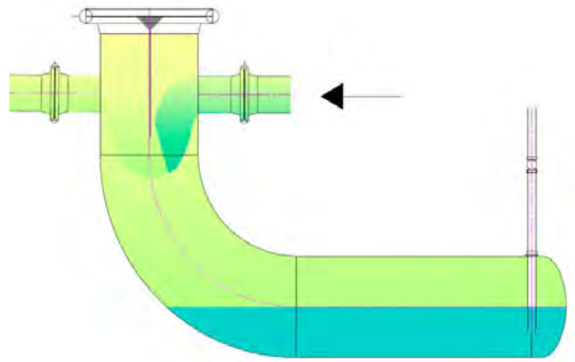
- Sub-system had 16 wells making 85 MMCF/d
- Three highly effective 2 line piggable drips with automated dumps (and dump counters) were removing 150 bbl/week
- We felt that with that much water being removed, pigging wasn't necessary
- One Thursday in December, the water that was being accumulated in the sags and low points "launched"
  - All three drips were flooded
  - The slug carried into the compressor station doing major damage to filters, compressors, and dehy's
  - We recovered over 1,000 bbl of water, probably a small fraction of the slug size
- We started pigging when the mess was cleaned up and averaged 100 bbl/week over and above what the drips were getting

Types of Line Drips

- Side Stream:
  - Basically a tee in the line that tries to direct liquid into a sump
  - Not very effective
  - Sometimes piggable
  - Sometimes not
  - Almost always manual dump

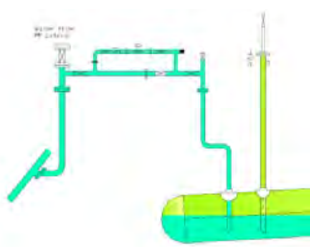


- Insert Drip
  - Larger pipe in line, insertion plate redirects flow downward and back up
  - Very effective, but not piggable
  - Sometimes (rarely) have automated dump



Types of Drips

- Single line Piggable:
  - Pipeline flows inside large pipe
  - Slots in pipeline create a low-velocity area that drains to a sump, quite effective
  - Piggable
- Dual line Piggable:
  - Brings two lines together into a drip
  - Interference makes it very effective
  - Piggable, allows two launchers to share a receiver
- Both types always have automated dumps



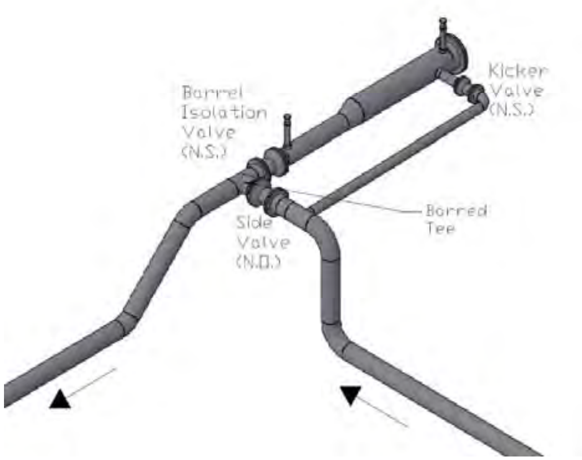
Launchers and Receivers

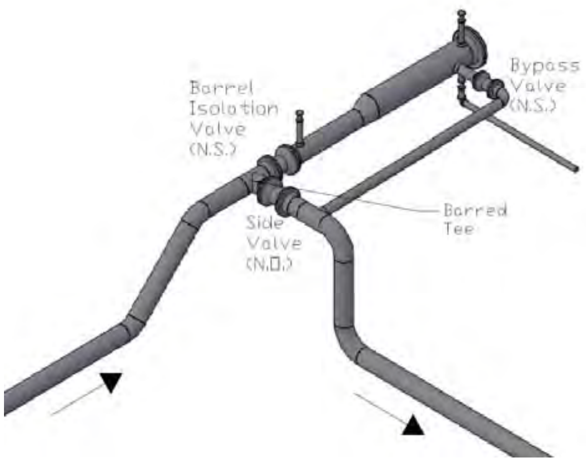
- A launcher must:
  - Facilitate launching the pigs that are required
  - Facilitate batch chemical treatment
  - Operate quickly
- A receiver must:
  - Facilitate receiving pigs that are required
  - Allow for disposal of liquids that come in
  - Operate quickly
- Types of launcher:
  - Gravity launch – inclined launcher barrel, small line to pressurize barrel. Open barrel-isolation valve and the pig "falls" into the line
  - Pressure launch – entire flow stream directed behind the pig

Gravity Launcher

- Load pig
- Open barrel-isolation valve
- Pig “falls” into line
- Can take a very long time to fall past main flow
- Launching long pigs requires the launcher to be very high

Pressure Launch

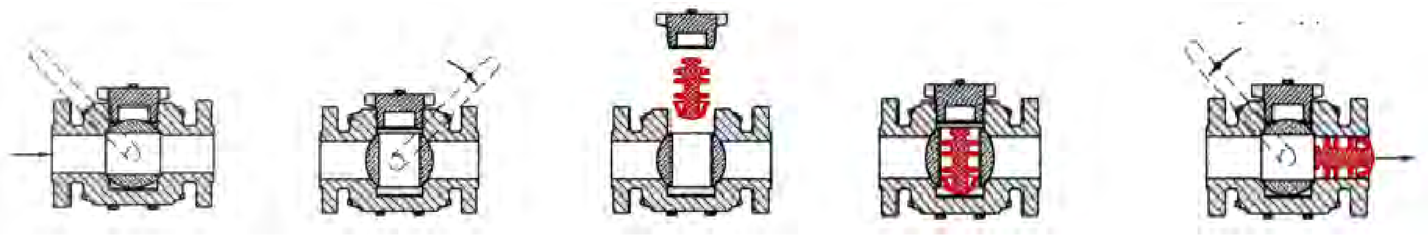




- Benefits of pressure launcher are:
  - You can run longer pigs (e.g., smart pigs)
  - You can run tight pigs (e.g., aggressive brush pigs, and cup pigs)
  - Launch much faster
  - No total disruption of flow during launching or receiving

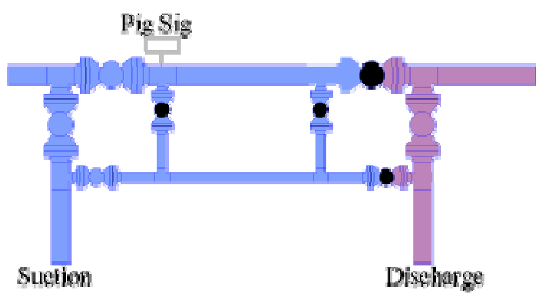
Pigging Alternative
Pigging Valve

- Launches like a pressure launcher
- Fits in the space of a ball valve (slightly longer, so it is not a direct swap)
- Disrupts flow while launching and receiving
- Reasonably priced up to 4-inch, 6-inch is marginal, 8-inch is a bad cost/benefit ratio



What does a compressor station do to pig runs?

- At a compressor station most operators install a pig receiver on the suction and a pig launcher on the discharge
  - Difficult to keep the station running when the pig arrives
  - Takes a fair bit of manpower to receive and then launch the pig
- An alternative is a piggable bypass



Positive Energy Isolation

- Certain kinds of work require "positive energy isolation" to lower the risk:
  - Welding on a line that has had hydrocarbons in it (i.e., "hot line")
  - Grinding on a hot line
  - Electrical work around an open hot line
- Techniques for Positive Energy Isolation for gas lines:
  - Double Block and Bleed—two valve seating surfaces separated by a vented space
  - Insert Blind—blind flange placed in flow line between the work and the energy source
  - Misalign/remove piping—remove a section of pipe

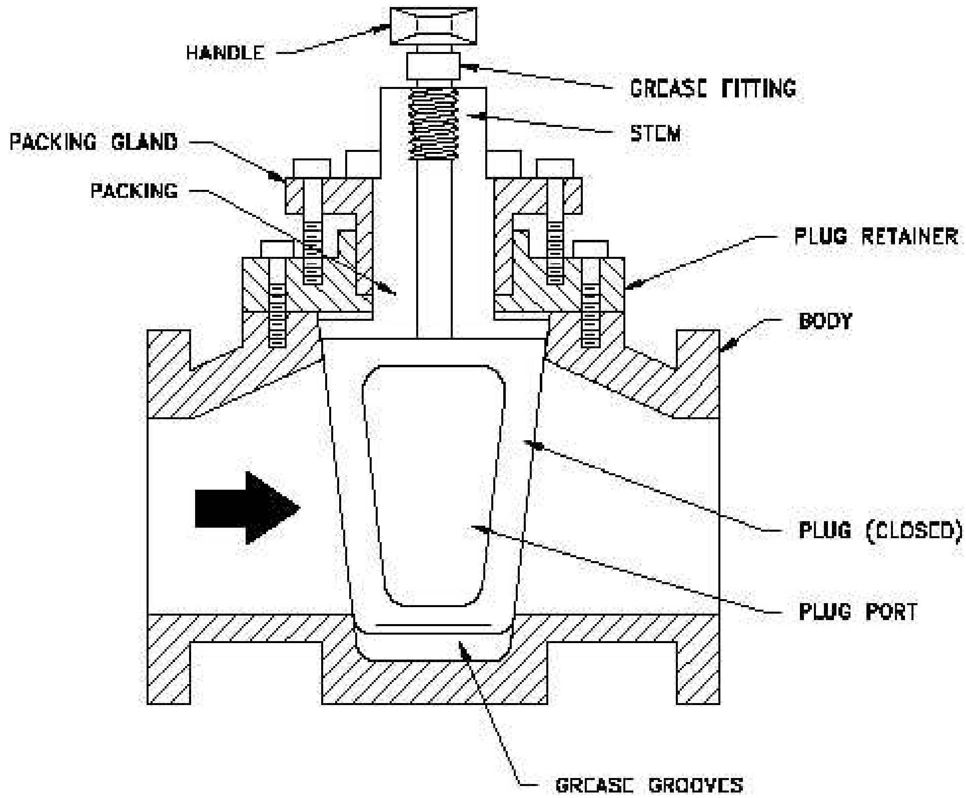
Gathering System Valves

- Often the third largest cost on a gathering system is valves (#1 is always labor and #2 is usually pipe)
- Valve technology can be daunting and conflicting claims can be confusing
- The three most important decisions regarding valves are:
  - What kind of valve to use?
  - Which valves will be actuated?
  - Will block valves be placed in valve cans (culverts) or on dog legs?

Valve Selections

- Almost every sort of valve has places where it should be chosen
- Some valve choices are “Ford vs. Chevy”, but most are not
- If you specify “I need 20 8-inch valves” you’ll get what you deserve (unless a valve is built to a standard design the flange-to-flange length is up to the manufacturer)
- Any sort of valve that is hydraulically suitable can be put either in a can or a dogleg

Plug Valve


HANDLE
GREASE FITTING
STEM
PACKING GLAND
PACKING
PLUG RETAINER
BODY
PLUG (CLOSED)
PLUG PORT
GREASE GROOVES

Plug Valve

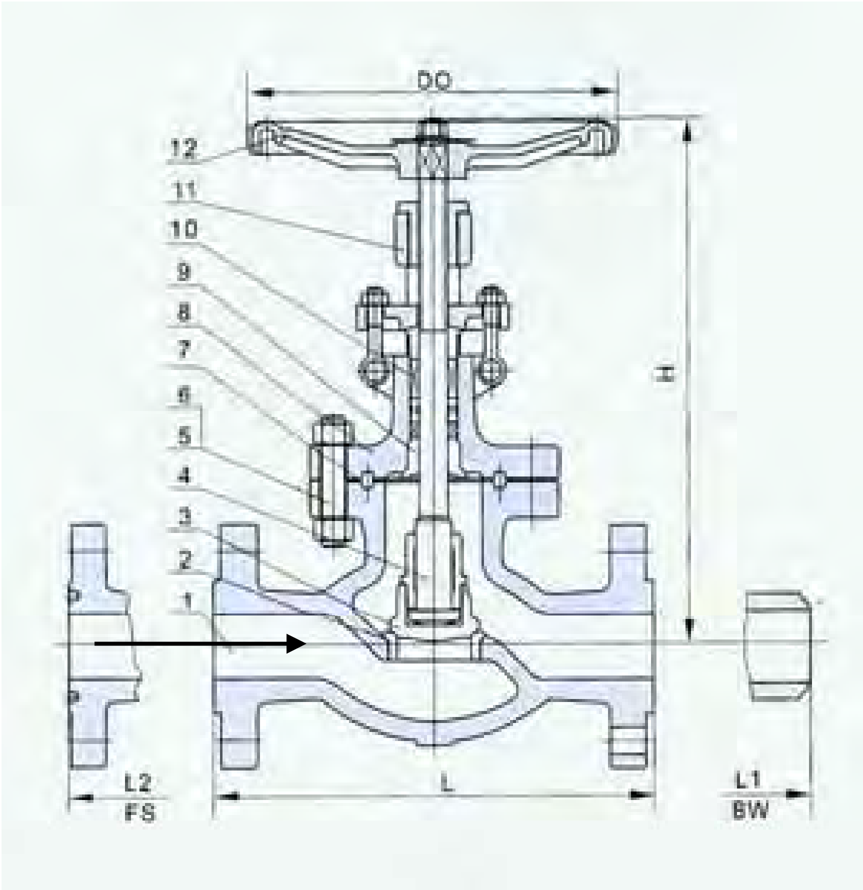
- **Operating mechanism**: a drilled, cone-shaped stem (the plug) rotates in a matching seat. When the valve is opened, the plug is jacked off the seating surface and rotated 90°. When shutting the valve, the plug is rotated and pushed down on the seat.
- **Primary Use**: none, it has been sold as an alternative to gate and/or ball valves, but the seating characteristics and the tendency to jam make them a very poor device for field operations.
- **Throttling characteristics**: very poor
- **Method of actuation**: quarter-turn piston actuators can be used, but they need significantly over-sized torque characteristics to lift the plug off the seat.
- **Flow path**: straight through the valve, but the hole in the plug is smaller than the pipeline diameter so they are not generally piggable.
- **Advantages**: none.
- **Disadvantages**: difficult to operate, poor sealing characteristics, require frequent maintenance.

Gate Valve

Gate Valve

- **Operating mechanism**: a wedge-shaped gate slides between matching seats. Seal is metal-to-metal. In larger sizes some manufactures use a gate that is two separate plates separated by springs to hold the gate more firmly on the seat.
- **Primary Use**: liquids and steam. Used in natural-gas applications where a bubble-tight seal is not required.
- **Throttling characteristics**: very poor
- **Method of actuation**: actuators are rarely used on gate valves outside of steam plants and then they are configured to simulate turning a valve handwheel.
- **Flow path**: directly through the valve, generally larger than the pipeline ID.
- **Advantages**: somewhat lower costs.
- **Disadvantages**: extremely tedious to operate (e.g. a 12-inch Grove gate valve requires almost 100 turns of the handwheel to operate), no provisions for double-block-and-bleed.

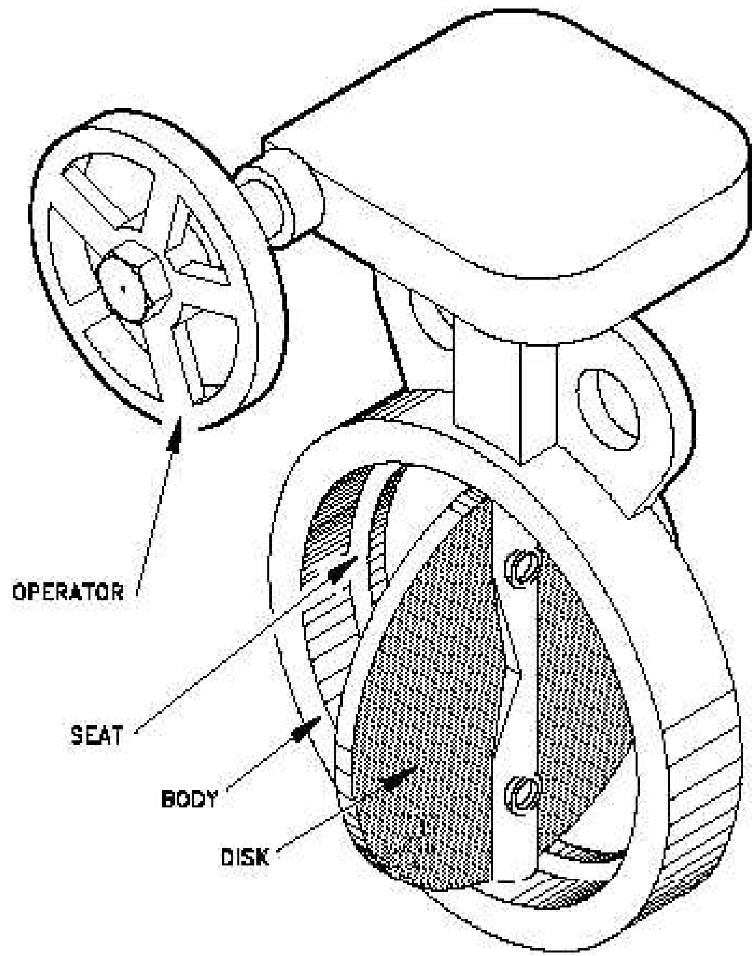
Globe Valve



Globe Valve

- Includes “motor valves”, needle valves, and backpressure valves.
- **Operating mechanism**: a plug-shaped stem seats in a matching seat that is oriented 90° (relative to the flow direction) from the pipe centerline.
- **Primary Use**: throttling any fluid.
- **Throttling characteristics**: good across almost half the valve travel.
- **Method of actuation**: actuators in the oil and gas industry are usually diaphragms.
- **Flow path**: up through the seat, across the chamber, and down into the outlet. This flow path causes a pressure drop across even a fully opened valve.
- **Flow symmetry**: While a globe valve can be installed in either direction, the manufacturer’s generally recommend that they be installed with the upstream flow under the seat to minimize the pressure on the stem-packing.
- **Advantages**: throttling and easy actuation.

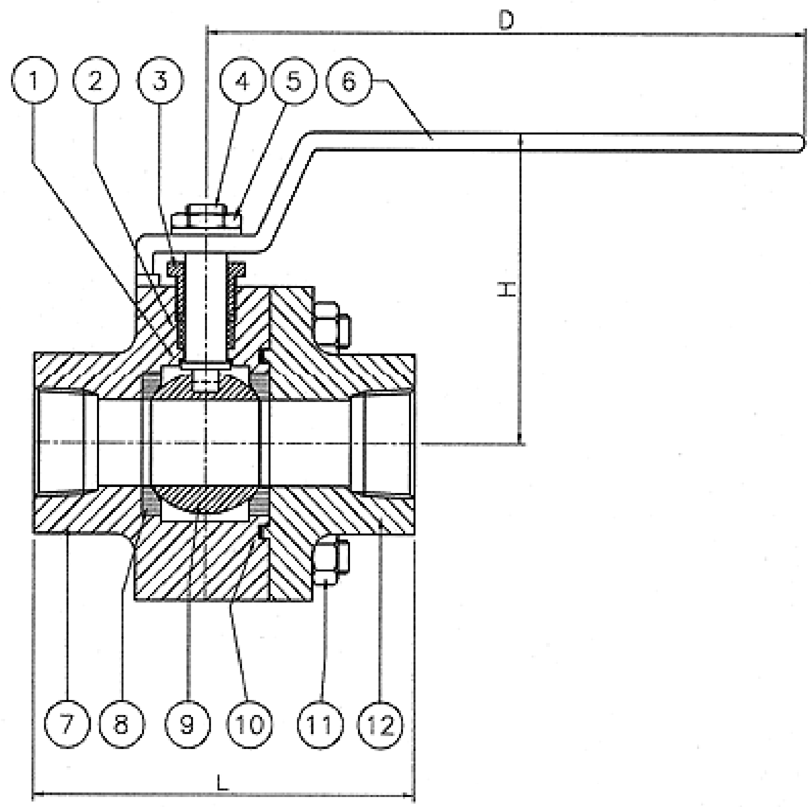
Butterfly Valve



Butterfly Valve

- **Operating mechanism**: a flat plate that pivots about its centerline is placed in the flow. Rotating the plate ¼ turn towards shut will put the plate against the seating surfaces.
- **Primary Use**: on/off in applications where considerable leakage is acceptable.
- **Throttling characteristics**: very poor.
- **Method of actuation**: quarter-turn piston actuators can be used.
- **Flow path**: straight through the valve, but the plate in the flow prevents them from being piggable.
- **Flow symmetry**: can be installed in either direction.
- **Advantages**: very inexpensive.
- **Disadvantages**: poor seal and not piggable.

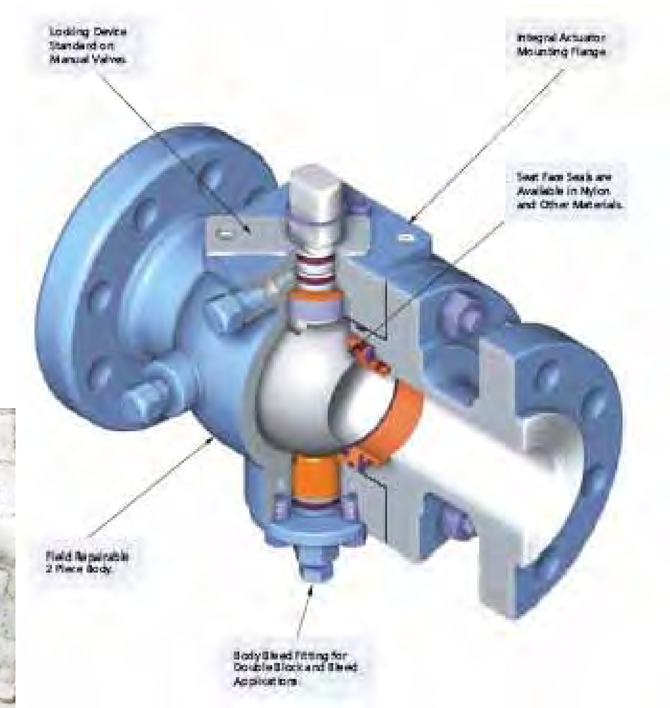
Floating Ball Valve

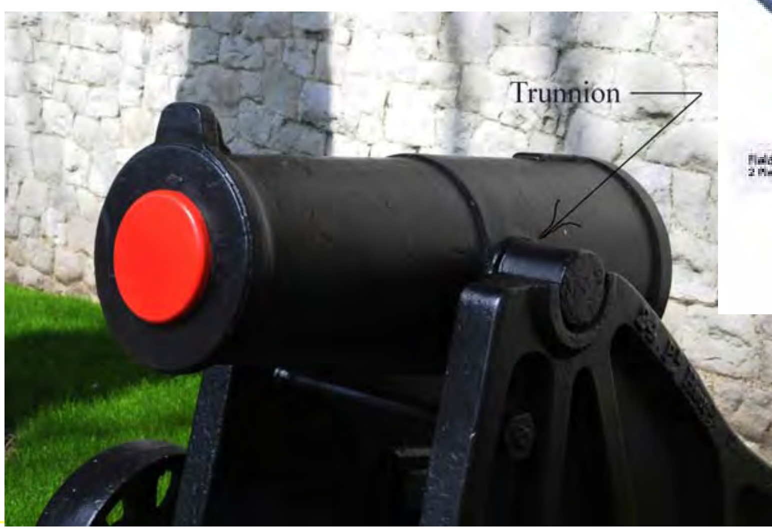


Floating Ball Valve

- **Operating mechanism**: a drilled ball rotates between seating surfaces. The ball is coupled to the valve body on the top only.
- **Primary Use**: low-replacement-cost on/off applications
- **Throttling characteristics**: poor.
- **Method of actuation**: quarter-turn piston actuators.
- **Flow path**: through the ball. Many floating-ball valves have reduced ports so they are often not easily piggable (e.g., a reduced port valve on Tenneco’s 36-inch main into New York City requires 3-5 hours for the pig to traverse)
- **Flow symmetry**: can be installed in either direction.
- **Advantages**: are cheaper than trunion-mounted ball valves.
- **Disadvantages**: lack of a body bleed, they have more of a tendency to leak through (because of lateral ball movement as seals wear), and they have poor sealing characteristics in very-low dP installations.

Trunnion Ball Valve





Trunnion Ball Valve

- **Operating mechanism**: a drilled ball rotates between seating surfaces. The ball is held rigid top and bottom by trunnion bearings.
- **Primary Use**: on/off applications
- **Throttling characteristics**: poor.
- **Method of actuation**: quarter-turn piston actuators.
- **Flow symmetry**: can be installed in either direction.
- **Advantages**: body bleeds allow a single valve to serve in many double-block-and-bleed applications. Sealing surfaces are very durable. Work well with very low differential pressure.
- **Disadvantages**: purchase cost is about 12% higher.

Valve Summary

	Use	Throttle	Actuate	Application
Plug	On/Off	No	Piston	None
Gate	On/Off	No	Pneumatic Spinner	Steam/hot water
Globe	Throttling	Yes	Diaphragm	Flow Control
Butterfly	On/Off	No	Piston	Trash service
Floating Ball	On/Off	No	Piston	Moderate to high pressure
Trunnion Ball	On/Off	No	Piston	All pressures

Valve Actuation

- Most valves can be actuated, but the question is "should they be?"
  - Valve actuators are always expensive
  - Most valves are rarely operated and their manual operation is not a huge burden on field staff
- Limit actuation to
  - Safety issues (e.g., an Emergency Shutdown Valve)
  - Control issues (e.g., a compressor suction controller)
  - Frequently operated big valves (e.g, the barrel-isolation and side valve on a 16-inch launcher should be actuated)

Types of Actuators

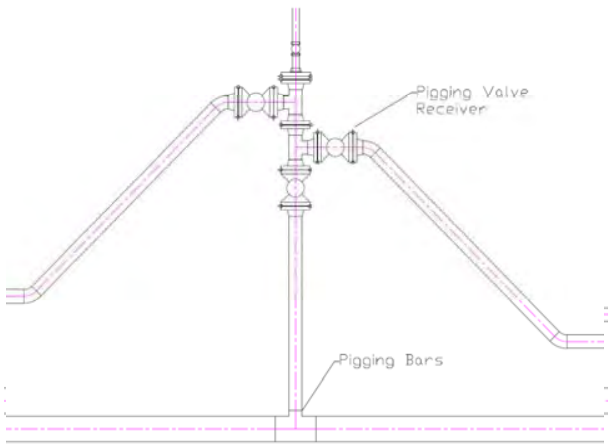
- Open/Shut
  - Pneumatic or electric rams on ¼ turn valves
  - Pneumatic on rising-stem valves
- Throttling
  - Pneumatic diaphragm actuators are a good choice for both globe valves and chokes like a Fisher V-Ball

Valve Cans

- A subterranean structure to allow access to system valves
  - Pros
    - Some protection from freezing
    - Good protection from vehicular traffic
  - Cons
    - Can is an OSHA “confined space”
    - Rodents and snakes nest in them (biohazard risk)
    - They fill up with water and mud
    - They are attractive locations for children to “play fort”

Doglegs

- Aboveground structure including block valves and possibly vents
- Pros of cans are cons of doglegs and vice versa
- Many companies have designs that work
- And some have designs that don't



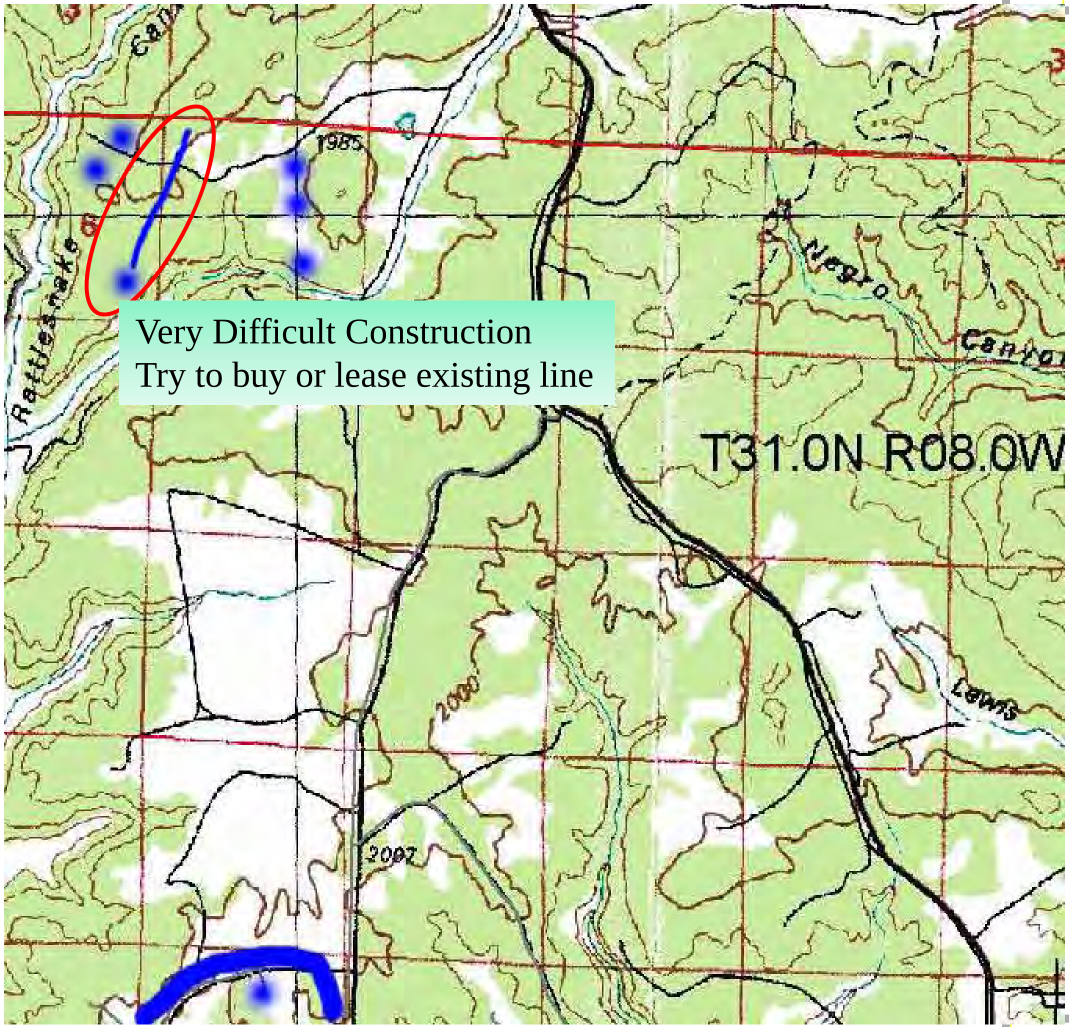
Acquiring ROW
Route Selection

- Once you've picked the materials of construction you have to pick the pipeline route to get from the wells to the delivery point
- Today's tools make the mechanics of this considerably easier
  - Geographical Information Systems
  - GPS units
  - Computerized topographic maps
- Whatever tools you use, you need to be aware of the constraints of your world

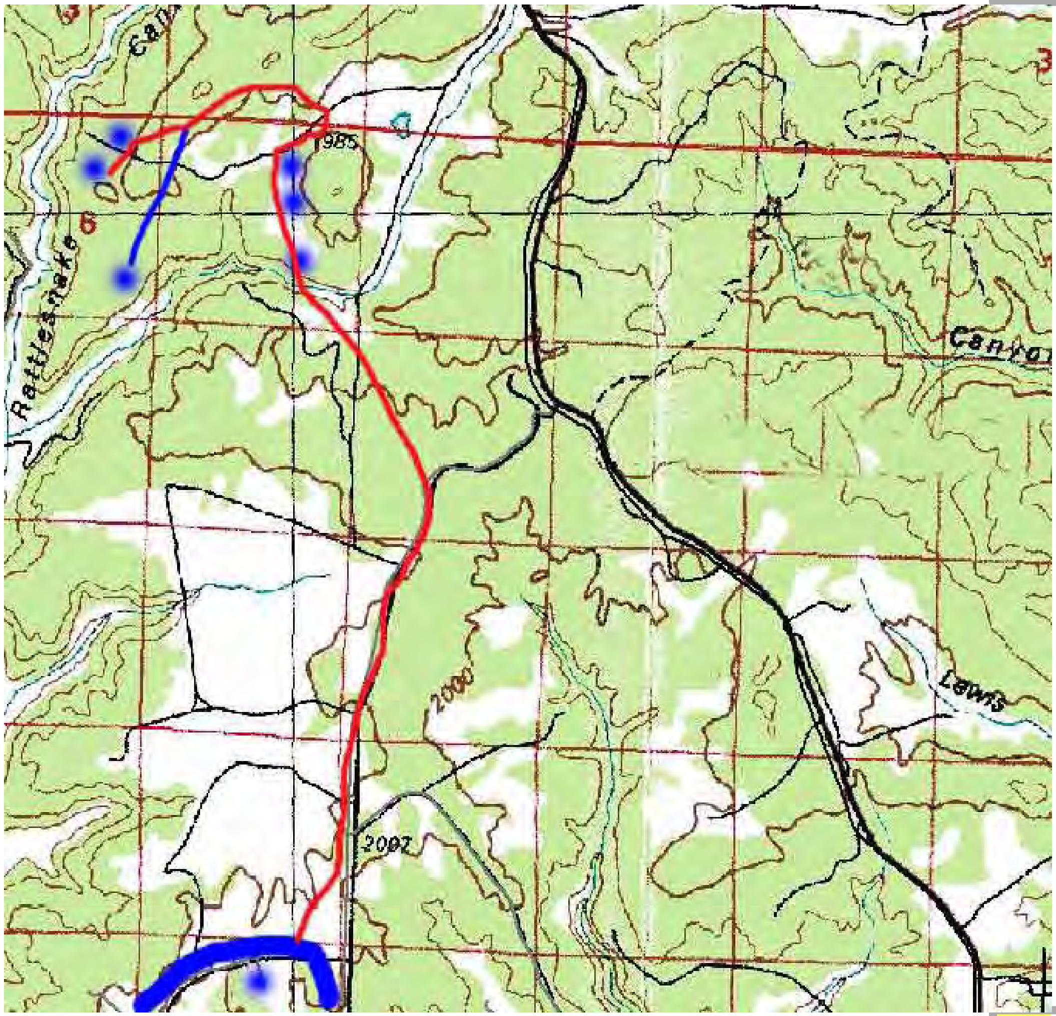
Route Selection

- Start with an awareness of regulatory "hot buttons":
  - New disturbance is a tough issue for the regulators. Consequently, a line with minimal new disturbance will be easier to permit than one with a lot of new disturbance
  - Avoid known, documented "Sites of Historic Interest" (arch sites)
  - Avoid Wetlands
  - Work on or across a numbered road requires Transportation Department (state or federal) permits
  - Crossing a river or a named dry wash probably needs Federal Government permission
- Some private landowners are known to be difficult to work with and useful to avoid

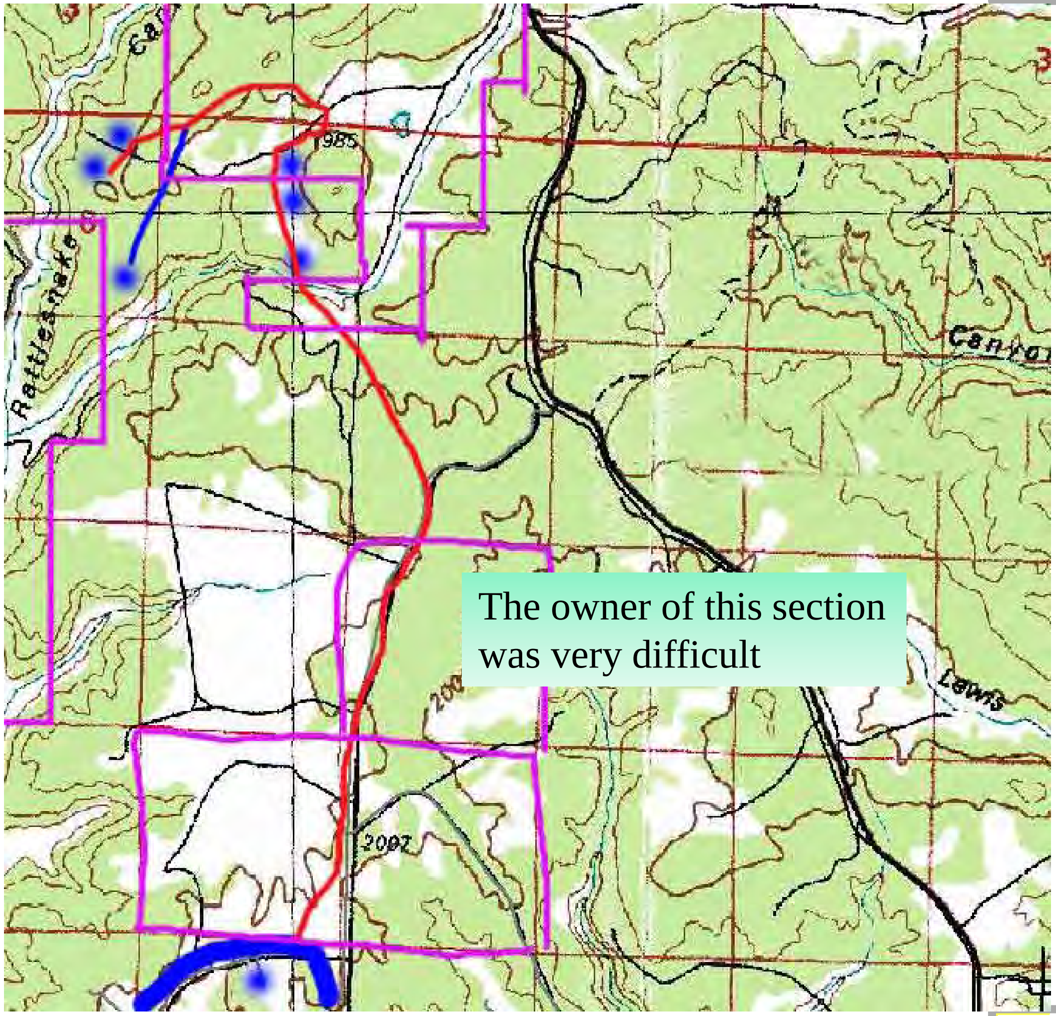
Terrain Issues



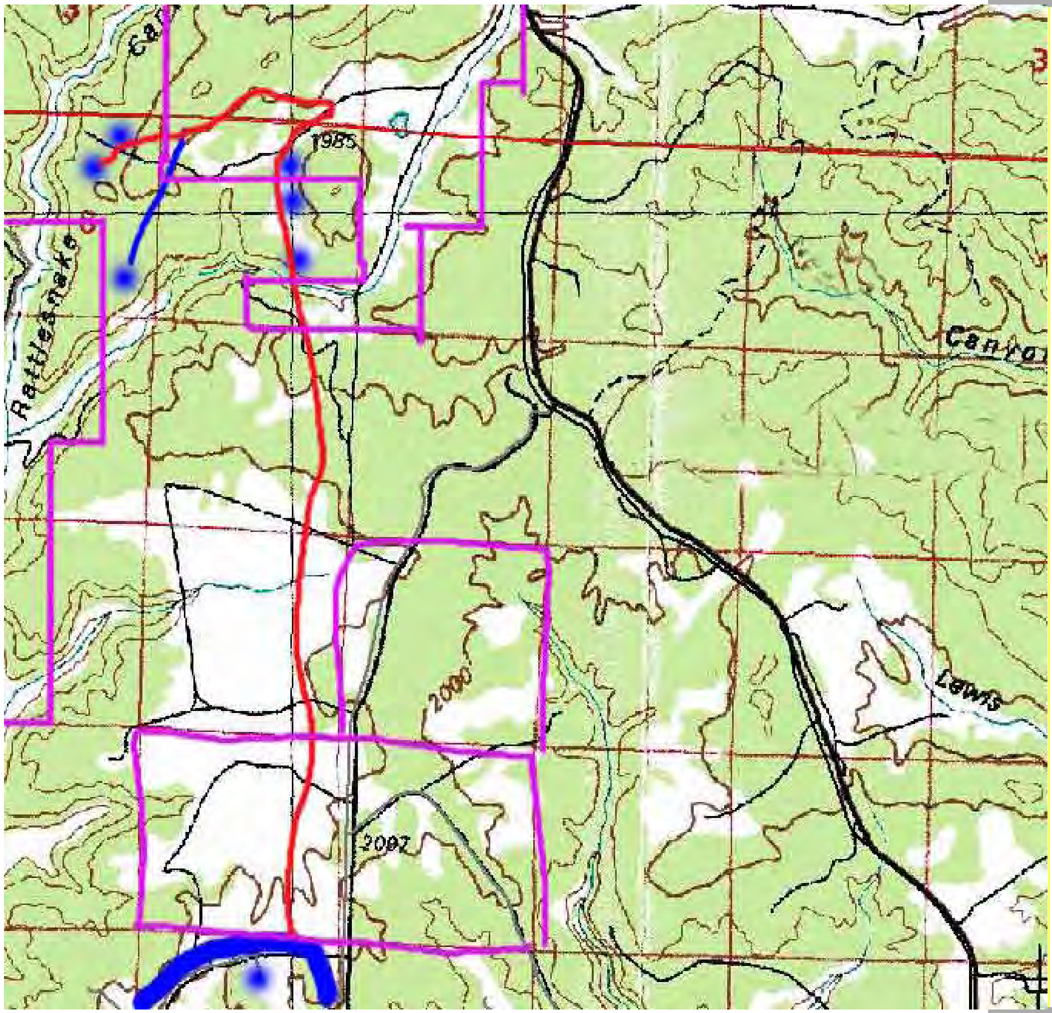
Preliminary Route



Land Ownership



Route for Permitting



ROW Acquisition

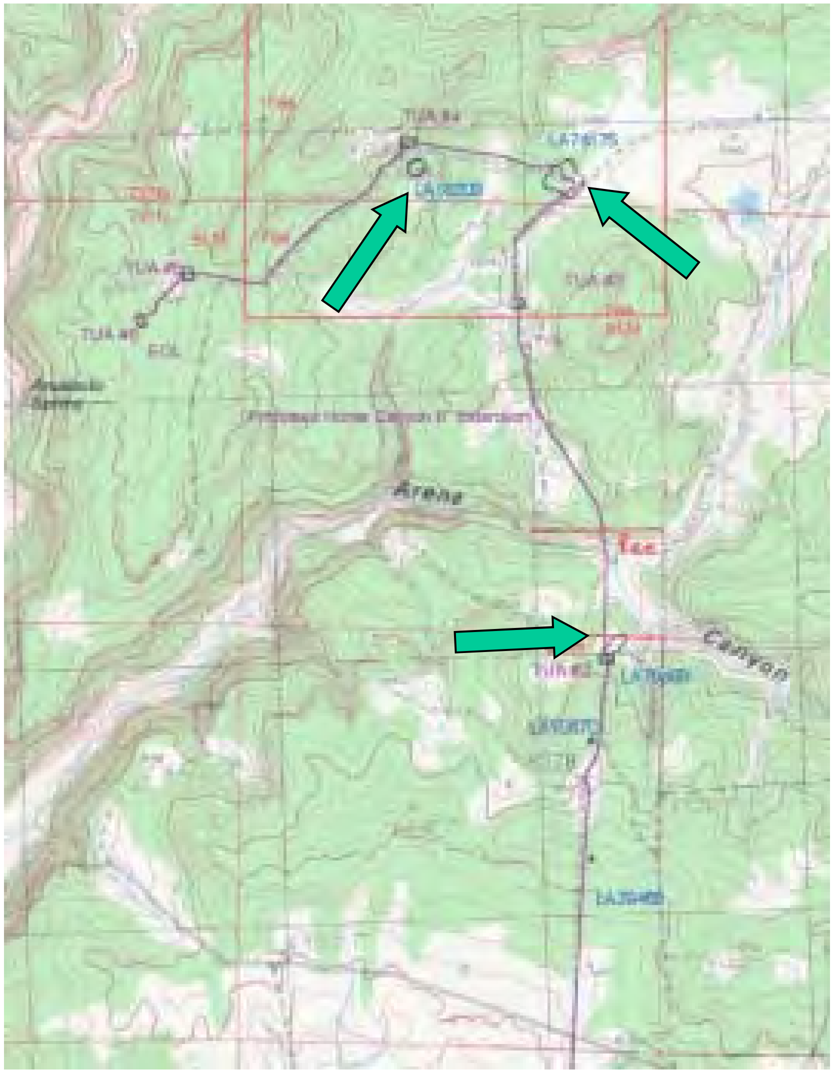
- Remember, access to someone's land requires their permission. Asking first can save headaches later
- Once you pick a route on a Topo you need Survey
- Once you have a survey, you can get
  - Archeology
  - Environmental Assessment

Cultural Resources Inventory (Arch Report)

- Detailed description of:
  - Literature searches
  - Site surveys
- Conducted by licensed archaeologist
- Report is not negotiable (once a site is documented it must be dealt with)
- Sites require a combination of:
  - Avoidance
  - Monitoring
  - Protection

Arch Report

- Some sites you avoid
- Some sites have been damaged by others
- Some sites you skirt
- NEVER enter an Arch Site



Environmental Assessment

- Omnibus document to show compliance with regulations
- EA should include:
  - Arch Report
  - T&E Report
  - Climate at project site
  - Site Topography
  - Geology
  - Soils
  - Surface and sub-surface water
  - Grazing allotee impacts
  - Health and Safety
  - Air-Quality impact of construction activities and completed project
  - Visual impacts
  - Noise impacts
  - Recreation impacts
  - Transportation of equipment and workers
  - Waste management

ROW Acquisition

- With a route that has dealt with
  - Arch
  - Environmental issues
  - Disturbance issues
- You can purchase your ROW
  - Federal Surface
    - Options are strictly limited by law
    - Varying from the law will delay your project and could kill it
  - Private surface:
    - Anything that is not illegal or unsafe is negotiable
    - Work in lieu of cash is often a reasonable compromise
    - Avoid any activity that will create a long-term maintenance
    - **NEVER** agree to creating a wetlands

Detailed Design

- The project must be documented to:
  - Communicate with managers
  - Communicate with regulators
  - Communicate with contractors
  - Communicate with operators (and future Engineers)
- Documentation must include:
  - Reference to standard(s), regulations, and company policies including required calculatons
  - Job-specific procedures including:
    - Safety Plan
    - Scheduled system shutdowns
    - Isolation procedures
    - Purging and Return to service

Design Standards

- A gathering system is a pipeline that carries pressurized fluid
  - It can be regulated by local, provincial, or federal authorities
  - Often is has public-safety ramifications
- Consequently, an objective standard is required to provide a basis for decision making
  - ASME Codes
  - ISO Codes
  - Regulations
  - Company Policies
- Most often a mix of these will be used

ASME Codes

- ASME B31.1 – Power piping
- ASME B31.2 – Fuel gas piping
- ASME B31.3 – Gas processing plants
- ASME B31.4 – Oil pipelines
- ASME B31.5 – Refrigeration and heat transfer components
- ASME B31.7 – Nuclear power piping
- ASME B31.8 – Gas Transmission and Distribution Piping
- ASME B31.9 – Building services piping
- Complementary Standards
  - ISO 13623:2009 (also known as EN 14161:2003)
  - CSA Z662-2007

ASME B31.8
Scope

- "This Code covers the design, fabrication, installation, inspection, and testing of pipeline facilities used for the transportation of gas. This Code also covers safety aspects of the operation and maintenance of those facilities."
- Code does <u>not</u> apply to:
  - Pressure vessels
  - Piping above 450°F or below -20°F
  - Piping beyond the outlet of the customer's meter set assembly
  - Piping in oil refineries or natural gasoline extraction plants, gas treating plant piping
  - Vent piping
  - Liquid petroleum piping systems.
  - Liquid slurry piping systems.
  - Proprietary items of equipment, apparatus, or instruments
  - The design and manufacture of heat exchangers
  - CO_2 transportation piping systems
  - LNG piping systems.
  - Wellhead assemblies, including control valves, flow lines between wellhead and trap or separator, offshore platform production facility piping, or casing and tubing in gas or oil wells.

Safety Plan

- The Design Document can simply reference **your** *Safety Manual*, but that is very ineffective because:
  - Each contractor has it’s own safety standards and you need to clearly reconcile differences
  - Not all workers have access to the company’s *Safety Manual*
  - The *Safety Manual* was written to cover all contingencies of all activities, there is a lot of material that will not apply to your specific project
- It is effective to do a JHA in the design stage and break all hazards into:
  - Ordinary Hazards
  - Extraordinary Hazards

Ordinary Hazards

- These are hazards that will occur on virtually every task an oilfield worker ever does such as:
  - Hand injuries
  - Driving hazards
  - Eye injuries
- Address the ordinary hazards with:
  - List of required PPE
  - List of required safety meetings
  - JHA requirements
  - Isolation Requirements
  - Lock-out/Tag-out Procedures
- If necessary, tell the safety inspector that his weight will not keep a side boom from tipping

Extraordinary Hazards

- These hazards are either unique to major construction or unique to a specific project
- Some areas that are frequently included as extraordinary hazards:
  - Static Testing
  - Purging Flow Lines

Static Testing

- The static test is one of the most significant safety issues in a project
  - Loading test media has risks ranging from brittle fracture during cold weather to environmental impacts of a contaminated water spill
  - Raising pressure has the risk of catastrophic failure with shrapnel
  - Reducing pressure and removing test media can result in spill risk or cooling piping into brittle-fracture region
- Most of the testing issues need to be resolved in the design stage to establish procedures for a safe test

Preparation for Static Tests

- Calculations:
  - Determine maximum operating pressure (MOP) from expected operating conditions
  - Determine area "Location Class"
  - Set MAWP
  - Set nominal test pressure
  - Calculate hoop stresses during test
- Isolation:
  - Identify segments of pipe that will not be tested and specify NDT for that piping
  - Determine isolation points and methods
  - Select test medium

Hydrostatic Tests

- Quantity of water required
  - Remember when ordering water that 80 bbl trucks never hold 80 bbl
  - Water requirement (in bbl per 1,000 ft) equals Pipe ID (in inches) squared
- Source of liquid and liquid quality (river, pond, or produced water **must** be treated for microbes prior to introduction)
- Verify that the terrain will allow a test (for a 1,000 ft elevation change, pressure at the top is 431 psi lower than pressure at the bottom)
- Verify that pipe supports for above-ground piping will bear the weight of the pipe full of water
- Select a monitoring point, fill point, vent point
- Define a water degasification period and pressure
- Determine the water-disposal method and ensure that it complies with Federal and state regulations

Pneumatic Tests

- Procedures are similar for air, inert gas, or natural gas
- For natural gas tests, ASME B31.8 requires hoop stress to be less than 30% of SMYS
- For any pneumatic test:
  - Verify that the location class and applied stresses are compatible
  - Calculate the required gas volume
  - Select a type of gas and a gas source
  - Select an injection, vent, and monitoring point
  - Define "soak" periods at increasing stress levels and set limits on approach distances at each soak point

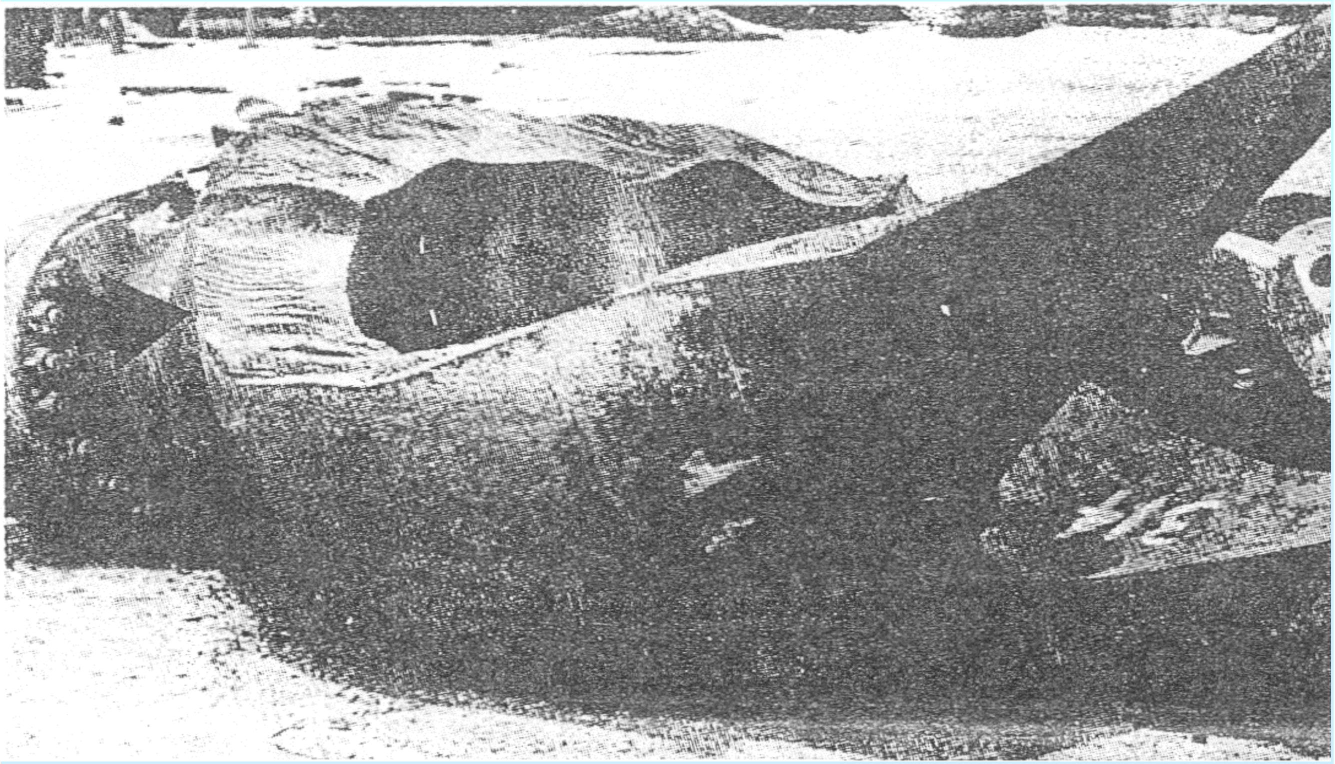
Test Execution

- Rate of pressurization – you need to determine the safe rate of pressurization and document it
- Test duration – in many operations and jurisdictions, the test duration is defined. If it is not defined elsewhere, ASME B31.8 calls for 2 hours
- Test Success Criteria – some change in pressure during a test is inevitable. You should state the minimum acceptable pressure at the monitor station
- Test Media Removal – for any test, you must specify the technique and rate of removal of the test media

Purging

- Improper purging of flow lines is the Number 2 cause of death in Oil & Gas (No. 1 is Driving)
  - The industry averages one fatality a month from improper purges
  - This number has not changed significantly since records started being kept
- There is considerable confusion about this subject
  - Most safety manuals don’t cover it
  - Few Engineers consider it in their design
  - Every field tech thinks he understands it

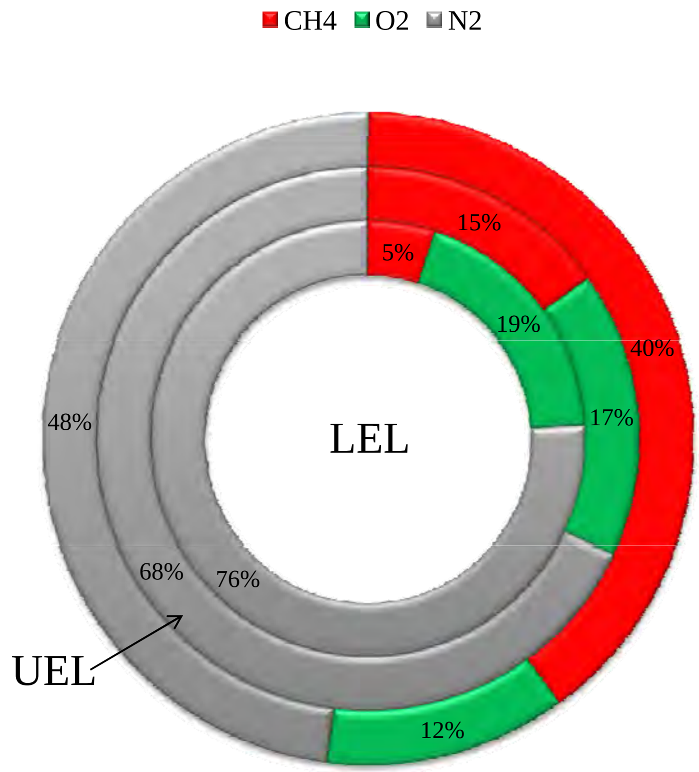
Figure 7
These detonation fragments from a 51/2-inch-thick drum (8 times thicker than needed for operating pressure) illustrate that it is impractical to design for detonative forces. A shell that was 30 to 50 times thicker than needed probably could not have resisted the detonation!



Purging air from flow lines Ignition

- Requirements for ignition:
  - Enough Oxygen
  - Fuel
  - Ignition source
- If any one of the three is missing or not in the right proportion, then there is no chance of fire or explosion

Explosive Mixtures



400 psig

Note: Published LEL and UEL Values are at atmospheric pressure and 60°F. Higher pressures extend the range and lower the auto ignition temperature.

Types of Flow

- Laminar
  - All flow roughly in same direction as main flow
  - Reynolds numbers < 2,000
- Turbulent
  - Random, 3-dimensional motion superimposed on main flow
  - Compressible up to 0.6 Mach (3.2MMCF/d in a 4” line at 15 psig)
  - Reynolds Numbers > 4,000
- Sonic
  - Very smooth, very high density, incompressible flow
  - Reached whenever pressure upstream of a choke (or a throttled valve) is at least twice (in psia) downstream pressure.
  - Gas will remain at sonic velocity until enough energy has been expended pushing other gas out of the way to slow it below sonic.

Mixing

- A sonic stream:
  - will not mix with another sonic stream, a turbulent stream, laminar stream, or static volume
  - will act like a piston until downstream pressure exceeds 1/2 upstream pressure
- A turbulent stream:
  - will not mix with a laminar stream or static volume
  - will act like a piston as long as main velocity >0.6 M
- A laminar stream will mix with a static volume

Purging into Service

- Goal is to ensure that:
  - No mixture will be exposed to an ignition source
  - An explosive mixture will not form

Avoid Ignition Sources

- Control "normal" ignition sources
  - Welding
  - Electrical sparks and arcs
  - etc...
- Gas flow in a pipe can generate static sparks
  - Very likely in a sonic stream
  - Possible in a turbulent stream (likely > 0.6 Mach)
  - Very unlikely in a laminar stream
- Heat of Compression
  - A turbulent stream above 0.6 Mach will compress downstream gas until it slows below about 0.6 Mach
  - A sonic stream will act as a "pseudo piston" if dead-ended

Pseudo-Piston Example

- If you had a air-filled system at 80F and atmospheric pressure (e.g., 12 psia) and a source of natural gas at 650 psig what would the temperature of the gas be when mixing begins?

$$T_D = \left[\frac{\left(\frac{650+12}{2} \right)}{12} \right]^{\left(\frac{1.4-1}{1.4}\right)} (80+460) - 460 = 933^{\circ} F$$

- This temperature is below ignition temp at STP (999°F), but at 319 psig it is above ignition temp so a fire is likely and an explosion is possible
- Since sonic velocity in methane is 1,315 feet/second (almost 900 miles/hour), if the system is going to explode it happens <u>very</u> quickly

Avoid an Explosive Mixture

- <u>Dilution</u>: introducing enough inert gas to ensure that an explosive mixture can't form (closed ended, laminar injection rate)
- <u>Displacement</u>: replacement of one substance with another without appreciable mixing (open ended, slow turbulent injection rate)
- <u>Clearing</u>: replacement of one substance so rapidly that there is a minimum of mixing, thus reducing the duration of any explosive mixture (open ended, turbulent injection rate)

Clearing

- ASME B 31.8-1992 841.275
  - “When a pipeline or main is to be placed in service, the air in it shall be displaced. The following [is an] acceptable method:
  - “Introduce a moderately rapid and continuous flow of gas into one end of the line and vent the air out the other end. The gas flow shall be continued without interruption until the vented gas is free of air
- From Amoco Oil *Process Safety Standard No. 8:*
  - “Air blowing of lines involves contact of air with hydrocarbons in a closed system. The higher pressure which can be developed in a line system broadens the flammable range and lowers the ignition temperature. The usual result of air blowing ... is an internal fire and overheated piping. It is possible that an explosion can occur

Clearing

- Can be very dangerous if you:
  - Introduce gas is at sonic or near-sonic rates,
  - Dead-end the line, or
  - Subject liquid hydrocarbons to high pressure/high temperature air.
- Can be done safely by:
  - Ensuring that the gas source is O_2 free
  - Double checking that all valves are properly positioned (including one open vent) and can't operate automatically
  - Starting gas flow very slowly to ensure flow out the vent.
  - Slowly increasing gas flow until the pressure rises over 2 atm
  - Not stopping (or slowing significantly) the flow until the purge is complete

Vent Selection

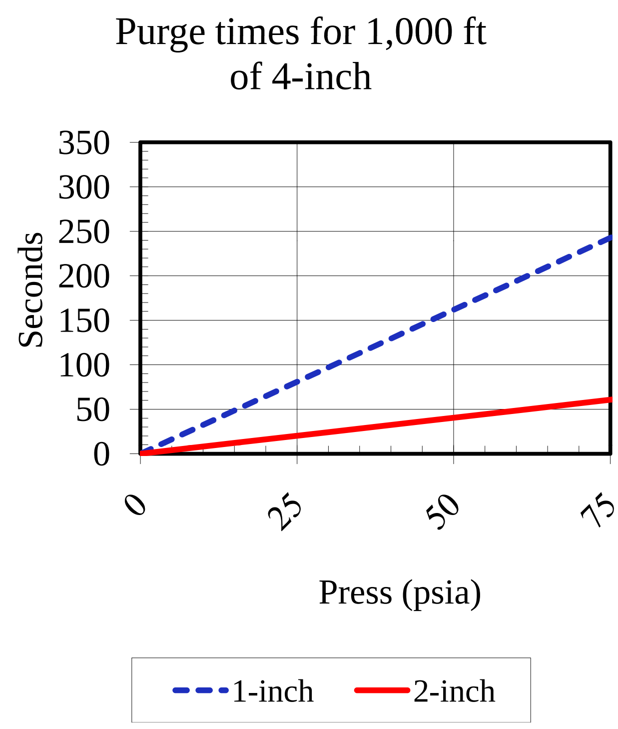
- Vent size
  - Must be big enough to induce turbulent flow in the line being purged
  - Sizing based on <u>biggest</u> cross section in system being purged and pressure in system

Pressure	Largest line purged w/1”	Largest line purged w/2”
15 psig	>36”	>48”
100 psig	10”	>36”
200 psig	4”	24”

- Vent location
  - As close to end as possible (8-feet of 4-inch pipe holds enough air to explode)
  - Only one vent open (more than one can “breathe” and suck in air)

More Pressure is Better—Right?

- To guarantee that a line is swept, the entire volume must be emptied and refilled three times
- Purge rate is based on velocity thru purge line
- Purge volume is based on pressure in line being purged
- Consequently, higher pressures purge slower than lower pressures <u>with no improvement in purge efficiency</u>



Purge Times

- Purge rate based on
  - Pressure in the pipe
  - Sonic velocity as long as $P_f > P_{cf}$
  - Vent valve diameter (ID_{vent}) in inches
- Purge time is based on
  - Volume of piping
  - Clearing factor (3 pipe volumes)

$$t = 3\left(\frac{\sum ID_{seg}^2 L_{seg}}{ID_{vent}^2 v}\right)\left(\frac{P_f T_S Z_S}{P_S T_f Z_f}\right)$$

Purging times for 3 volumes at 15 psig (minutes/1000 ft)

Pipe Size	Vol/1000	1-inch Valve	2-inchValve
2	21.8	0.40	0.10
3	49.1	0.91	0.23
4	87.3	1.62	0.40
6	196.3	3.64	0.91
8	349.1	6.47	1.62
10	545.4	10.11	2.53
12	785.4	14.56	3.64
16	1,396.3	25.89	6.47
20	2,181.7	40.46	10.11
24	3,141.6	58.26	14.56
30	4,908.7	91.03	22.76

Purge Conclusions

- Assume that an ignition source is always present
- Key to safe purge is control
- Dilution and displacement purges must be designed for each specific application
- For a "Clearing purge" ensure:
  - That source gas is O_2 free
  - Every valve can be operated
  - That automatic valves are disabled
  - Pressure is over 2 atm
  - Only one vent open and it is at least 1-inch
- Need to purge 3 pipe volumes of gas
  - Less than 2 atm, you don't know how long it will take to purge
  - Greater than 2 atm, purge rate is very well known
  - Much greater than 2 atm purge takes too long

Bidding Projects

- If a project is to be bid, then every bidder needs to be bidding on the same project
- Complete Design Documents, drawings, and maps prior to requesting bids
- Include **detailed** lists of inclusions/exclusions
  - Anything that is not included is excluded
  - Anything that is not excluded is included
- Bidding a job requires considerable effort
  - By the Engineer
  - By the contractors bidding
  - By the review team
- Often any perceived benefit of bidding a job is eaten up in the bid/bid-exception process

Design Document Conclusion

- Designing and building a gathering project is a significant undertaking
- The better job you do in the design:
  - The easier permitting is
  - The easier ROW acquisition is
  - The easier construction is
- If there is some part of the process you don’t understand – don’t guess, ask

Construction
Construction Issues

- The contractor is the expert
  - If you don't believe that then you've hired the wrong contractor
  - Even "experts" will have several ways to accomplish a given task (depending on circumstances (some are more effective than others)
- Equipment Inventory
  - For a Bid job, you really don't care what equipment the contractor decides to stage as long as it is adequate size and there is enough to meet the job schedule
  - For a Time and Materials Job it is a good idea to track equipment closely (if a D9 has been sitting idle for 3 weeks, it probably should come off the bill)

Inspection

- Some jobs require both a welding inspector and a ROW/Ditch inspector
- Some jobs require a “QA/QC inspector”, but they:
  - Don’t usually specify the required qualifications
  - Don’t say if it is an outside inspector or the Construction Manager
- If you use outside inspectors watch closely for:
  - Unreasonable tension between the inspector and the contractor
  - The inspector trying to “stretch” a job for personal financial reasons

Trenching Equipment

- Wheel ditching machine
  - very good speed,
  - very good ditch bottom and fixed ditch width,
  - high per-hour fee often offset by productivity,
  - not good around foreign lines
- Track hoe
  - good speed,
  - poor ditch bottom and variable ditch width,
  - low per-hour fee often offset by productivity,
  - very good around foreign lines

Trenching Equipment

- Bulldozer with ripper
  - very good speed,
  - poor ditch bottom and poor ditch width
  - low per-hour fee
  - very bad around foreign lines
- Rubber-tired Hoe
  - very poor speed,
  - poor ditch bottom,
  - very low per-hour fee,
  - bad around foreign lines (not enough horsepower to be effective)
  - should only be used for materials movement

Trenching – Rock

- Rock is generally defined as "ditch that cannot be dug by the means described above under normal excavation"
- The "cannot be dug …" phrase is important, often a contractor will need a rock saw for a portion of the job and use it for much of the job – and expect to be paid the rock rate.
- The contractor and the company need to agree on what is rock **prior to** digging it. After the ditch is made you have to pay for whatever the contractor's expectations were.

Cross-Country Ditch

- Ditch should fit the contours of the land
  - The bottom should be flat
  - The depth should be consistent
- The pipe should be bent to fit the ditch
- Building up sandbags to avoid pipe bending puts localized stresses on the pipe that can lead to problems
- Cover requirements are specified in B31.8 (companies may require greater depths)
- Often, you will be required to store the topsoil and put it back on the top of the ditch (always on agricultural and Forest Service land)

Open Ditch

- The amount of open ditch is often an issue:
  - The contractor wants to finish the ditch and get the equipment to the next job
  - Open ditch is a hazard to cattle and wildlife
  - In a storm event, open ditch is a liability that can often require the ditch to be re-dug
- Trenching more than 3-5 days ahead of lowering-in is a liability that should be avoided

Foreign Crossings

- A “foreign crossing” any line that you have to cross that isn’t part of your project
- The “rules” for crossings are more guidelines than laws
- The important thing is that you get it done without breaking anything or hurting anyone
- There are devices to help with line locating—none of them are foolproof

Foreign Crossings Issues

- Inspection – the line owner has the right to be present when you're working around his line (but if he fails to show, you should call him, then start without him)
- Over or Under – usually you'll have to go under to get adequate cover, but over is not "illegal"
- Clearance – each company has their own standards for how close they'll "let" someone encroach. The standards are not binding. I like to use 12-inches to minimize cathodic interference
- Test leads - everyone puts test leads on steel pipe crossing steel pipe. This is a good practice, but never install a test lead on a foreign pipe without the owner's explicit permission

Welding - Firing line

- Bulk of welds on job
- Often one welder does bead and hot pass, then later welders do rest of beads and cap
- If the procedure calls for Pre-Weld or Post Weld heat treat, make sure it is done
- You need to make sure the delay between passes is consistent with the procedure

Welding

- Tie-ins
  - The firing line will stop at all road crossings, all foreign-pipe crossings, and many fence crossings
  - When the long lines are lowered in, the tie-in crew will connect them
  - Welds made in a ditch take 5-10 times the time and cost of a firing-line weld
  - Generally you will need to do 100% x-ray on tie-in welds
- Fabrication
  - Done on the surface
  - Generally complex structures go faster if you do a good job on drawings
  - Fabrications require 100% x-ray

Bell-Hole Issues

- Tie-in welds are made in “bell holes”
- If the bell hole is:
  - >4 ft deep – the hole must be inspected by an OSHA “Competent Person” and you must meet the OSHA inspection requirements
  - >20 ft deep – the hole must be designed by a licensed PE and inspected each 8-hours
- Any bell hole must have two means of egress
  - Sloped enough that a worker can walk upright without using hands
  - Located on both sides of the pipe
- The spoil pile must always be at least 2 ft from the edge

Tie-ins in Hot Ditches

- A “hot ditch” is defined as hot work being performed below ground level on piping that has had flammable gas in it in the past.
- Procedures need to lay out that the crew needs to:
  - Minimize the number of people in ditch
  - Ensure all personnel who enter the ditch must be in FRC Coveralls
  - Assign a fire watch who must remain with no other duties for at least 30 minutes after welding is complete

Some Hot Ditches are Hotter than Others

Taping and Holiday Checking

- Before lowering in you have to protect the pipe around the welds:
  - Don't apply any coating until the weld is cool
  - Any coating will require a primer that must be properly applied
  - Shrink sleeves are much tougher than tape, but tape is an acceptable alternative
- The field of the coating can be damaged during transport or handling:
  - Use a portable "holiday detector" to find gaps in the coating
  - Make sure that the pipe is primed 360° and taped over about 4-inches either side of any holiday's detected
  - Run the holiday detector over the repair

Backfill and Cleanup

- Backfill
  - Padding must be consistent with the pipe material
    - Steel is harder to damage than PVC or Fiberglass
    - Using a bucket padder is usually adequate for steel
  - If stipulations require saving topsoil, then make sure it goes on last
- Cleanup
  - The ground must be restored to original contours
  - Water bars and traffic bars must be installed
  - The project must be re-seeded
  - Inspections for Storm Water Plans continue until ground is 70% re-vegetated

Gathering System Operation

- Once you build it, you've got to operate it
- Need to start with Procedures
  - Pig Launching and Receiving (including any system valves that must be shut)
  - Drip Operation
  - Gas Measurement procedures
  - Corrosion Control processes
- Schedules
  - How often must things be done?
  - How do you change the schedule?
  - Who do you have to notify of a procedure being executed?
- And Qualifications
  - What training is required for an operator?
  - What Industry Certifications are required?

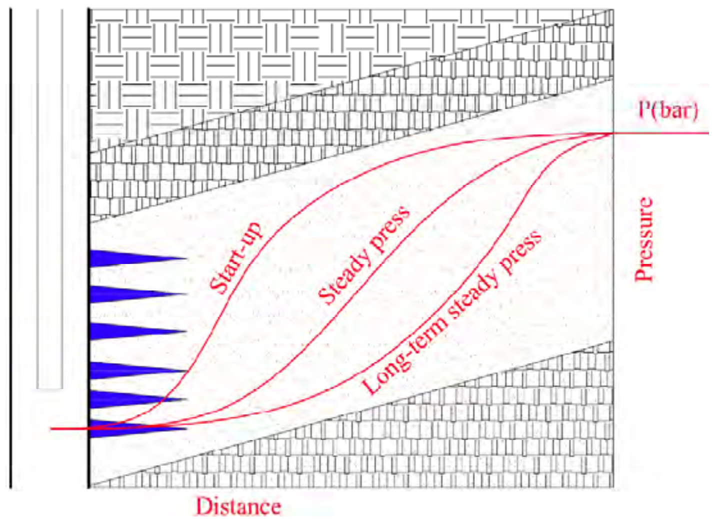
Low Pressure Operations Conclusion

- Low pressure operations are a pain in the posterior
  (But can be very profitable)
- Every solution to a problem will cause a new problem
  (That may be worse)
- Every symptom is masking another symptom
  (Which is masking still another symptom)
- What worked yesterday may not work tomorrow
  (But may work next month at a different pressure)
- NEVER say “we tried that and it didn’t work”
  (Those words taste nasty when you have to eat them)
- Design for flexibility because you never know what the next problem will require

COMPRESSION

Pressure Consistency

- Steady FBHP:
  - Increases the well's drainage area
  - Increases the volume recharged during shut-in



- Wellhead compressors can give you long term steady pressure while line pressure varies

Typical Compressor Types

	Eff	Limit	Max Ratio	Typical Use
Liquid Ring	40-50%	Disch Press	5	Deep vacuum to < 5 psig
Eductor/Ejector	40-70%	Power fluid flow rate	10	Focus hp
Dry Screw	60-72%	Disch Temp	5	Control air
Centrifugal	65-75%	Disch temp	2.5/stage	Offshore (small foot print)
Flooded Screw	70-72%	Max suction pressure	10-20	Varying Suction
Recip	78-88%	Rod load or disch temp	4.5/stage	Varying discharge

Comparison of Recips vs. Flooded Screws

Compare two technologies
  - Operating principles
  - Strengths/Weaknesses
  - Basis for a Decision
- Conclusion

Operating Principles Recip Compressor

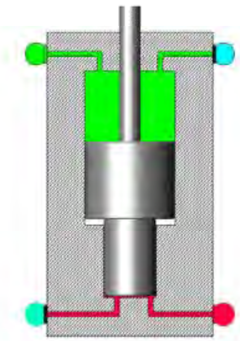
- Recip compressors used since 1800's (steam driven, air service)
- Pistons moving inside cylinders draw gas in, then raise gas pressure above required discharge
- Recip compressors are categorized by:
  - Number of "throws" (each throw has two compression chambers)
  - Number of stages
  - Separable or integral
  - High speed vs. low speed

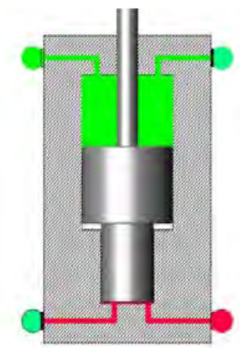
Operating Principles Recip Compressor

- Suction and discharge valves are operated by differential gas pressure (spring-loaded check valve):
  - Valve stiffness and gas density control valve operating speed
  - At low suction pressures, valve-speed and valve-leakage will control compressor efficiency
- 2.5-4.5 ratios/stage, limited by:
  - Allowable discharge temp for each stage (4.5 ratios result in gas temp going from 60°F to 256°F or 125°F to 355°F)
  - Allowable rod load
- Suction pressure (in absolute units) must be ±5% of design
  - 5% of 30 psia is 1.5 psi—about 3 ft of liquid level, or 2 quarts of water in 2-3/8 tubing
  - Selecting/changing valves is complex and time consuming

Recip Compressor Suction Pressure

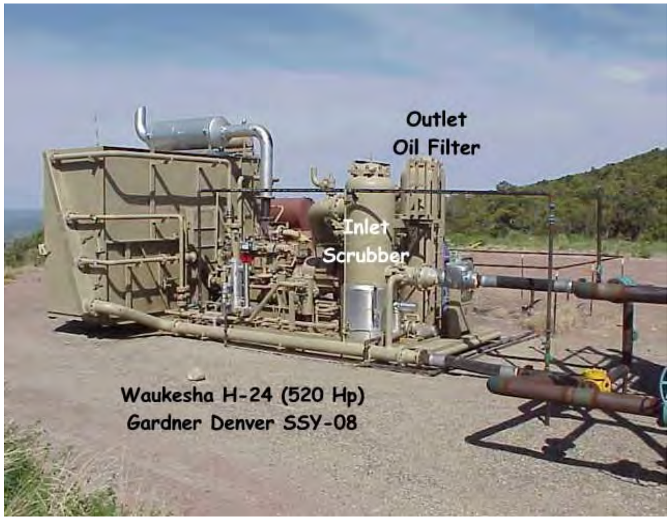
- This cylinder is properly configured for:
  - 1st stage suction 40 psig, discharge 209 psig @ 272°F
  - 2nd stage suction 197 psig, discharge 760 psig @ 298°F
  - 130 MCF/d
  - It has the right clearance and spring stiffness for these conditions
- What happens if a half barrel of water comes into the wellbore and the suction pressure drops to 20 psig?
  - 1st stage discharge 136 psig @ 345°F
  - 2nd stage discharge 760 psig @ 411°F
  - Machine is down on high discharge temp





Flooded Screw Compressor

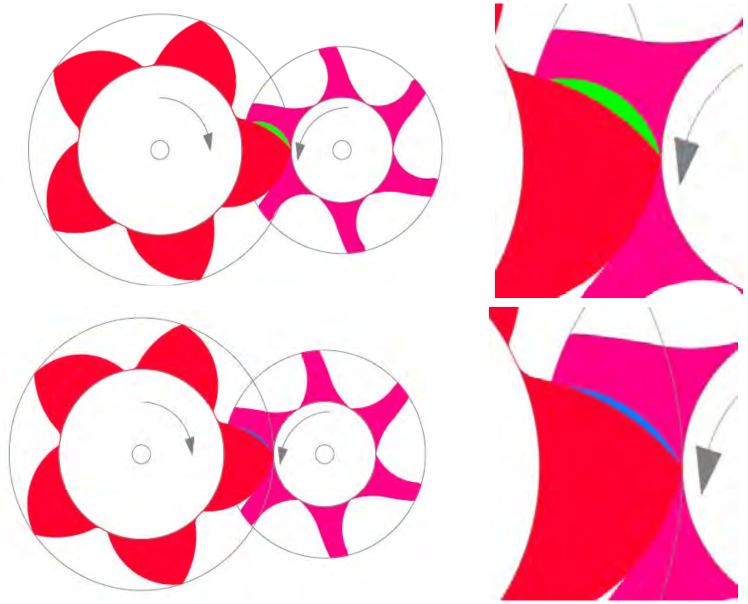
- First flooded screw made by Howden in 1977
- Male rotor is driven by engine or motor
- Female rotor driven by male rotor
- Oil flood
  - Prevents metal-to-metal contact between rotors
  - Seals area around rotors
  - Lubricates
  - Cools



Flooded Screw Compressor

- Initially used exclusively within plants
  - Process Derivative: Air conditioning service, compressing propane or ammonia
  - Air Derivative: Air compressors
  - Precisely controlled suction/discharge pressure/temperature
  - Very low water vapor content
- Packages did not have to be very flexible
- In the early 90's they started moving screws to wellsites
  - Very large water vapor content
  - Not much control over either suction/discharge pressure/temperature or fluids
- Plant packages perform poorly in field use
  - Oil selection often not compatible with condensible hydrocarbon vapors
  - Oil temperature too cool to cook water off
  - Often do not have oil pump (rely on dP across skid to drive oil)
  - No way to deal with accumulated solids
- Packager is key to getting a field package instead of a plant package

Screw Compressor Operation



- The two rotors are different sizes and the female rotor has more lobes
- The compression chamber on the suction end is much bigger than on the discharge end
- The relationship is called the VI (Volume Index)
- The larger the VI (the bigger difference between the suction area and the discharge area), the higher discharge pressure is reached for a given suction pressure

Flooded Screw

- Oil Selection
  - Mineral Oil: Least expensive, not compatible with liquid hydrocarbons
  - Synthetic Oil: Most expensive, generally has the best compatibility with liquid hydrocarbons and will perform slightly better with adsorbed water
  - Semi-synthetic: Mixture of the other two and has intermediate properties
- Screw oil is hydrophilic and will absorb water vapor
- When the oil absorbs water it:
  - Becomes more viscous
  - Loses lubricity
  - Increases surface tension (allowing bigger droplets to fail to coalesce)
- You have to cook the water out of the oil like a reboiler
  - Adjust oil flow and cooling to achieve 205-215°F out of the screw
  - If you can't reach that temperature, you can install a backpressure valve to increase compression ratios (and heat of compression)

Flooded Screw Temp Example

- The temperature of the fluids in a screw is confusing
  - Temperature is much lower than predicted by compression ratios
  - ΔT of the oil is fairly low
- To understand it, you have to start with the BTU's of the heat of compression (assume methane at sea level and atmospheric pressure at 80°F, discharging at 50 psig, moving 500 MCF/d)

$$T_{out} = T_{in}\left(\frac{P_{out}}{P_{in}}\right)^{(k-1)/k} = (80+460)\left(\frac{50+14.73}{0+14.73}\right)^{(1.28-1)/1.28} = 770R - 460R = 310F$$

$$Q_{gas} = mc_{gas}\Delta T = 500000\frac{ft^3}{day}\left(\frac{day}{24hr}\right)\left(0.046\frac{lbm}{ft^3}\right)*\left(0.52669\frac{BTU}{lbm*R}\right)*(770R-540R) = 116000\frac{BTU}{hr}$$

$$\Delta T_{oil} = \frac{Q_{gas}}{mc_{oil}} = \frac{116000\frac{BTU}{hr}}{40\frac{gal}{\min}*\left(6.84\frac{lbm}{gal}\right)\left(\frac{60\min}{hr}\right)\left(0.45\frac{BTU}{lbm*R}\right)} = 15.7R$$

$$T_{out} = T_{in} + \Delta T_{oil} = (180+460)R + 15.69R = 655.7R - 460R = 195.7F$$

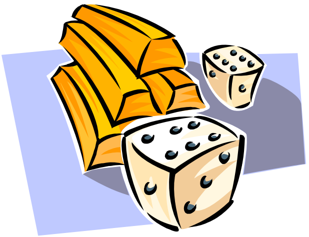
Too Cool, can raise discharge to 150 psig or lower q(oil) to 22 gpm or raise oil inlet to 190F

Compressor Comparison

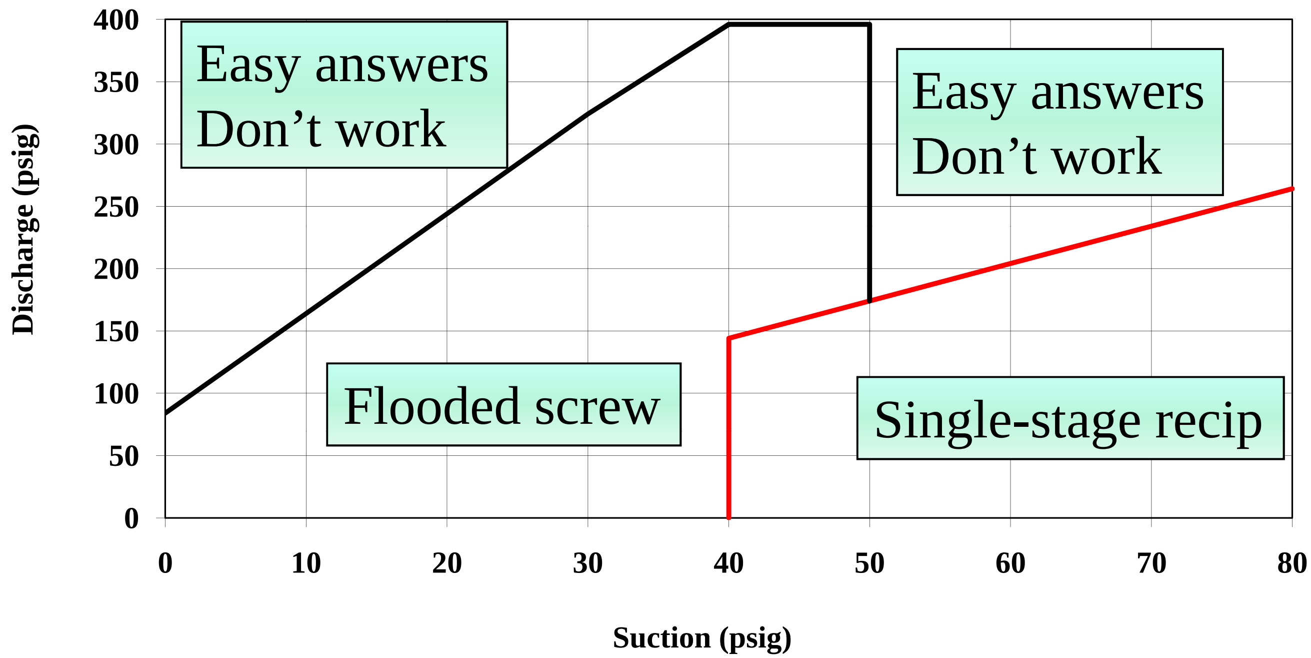
Recip		Flooded Screw	
Strengths	**Weaknesses**	**Strengths**	**Weaknesses**
Best use of Hp -1 stage best -2 stage 8% more hp -3 stage 15% more hp	Narrow suction range	Wide range of suction pressures	Moving oil requires energy (screw about same efficiency as 2-stage recip)
Rugged and Reliable	Valves high maint	No valves	
Operating staff thinks they understand them	Not tolerant of changing conditions	Few moving parts	Operating staff uncomfortable
Few consumables	High temps	Very low temps	Oil is expensive
Some packagers do field machines well	Difficult to balance stages	No rods or stages to balance	Packagers don't do field machines well
	High maintenance	Low maintenance	
	Higher Purchase cost	Lower Purch cost	

Decision

- Small Hp 2- or 3-stage recips are rarely the best choice for wellsite use
  - Can't afford personnel to optimize small units
  - Sub-optimized units prone to mechanical failures
- Suction
  - Above 40 psig single stage recip generally better
  - Below 40 psig flooded screw considerably better
- Ratios
  - Below 4 ratios single stage recip has better use of Hp
  - Screws work well up to about 20 ratios



Recip vs. Screw Decision



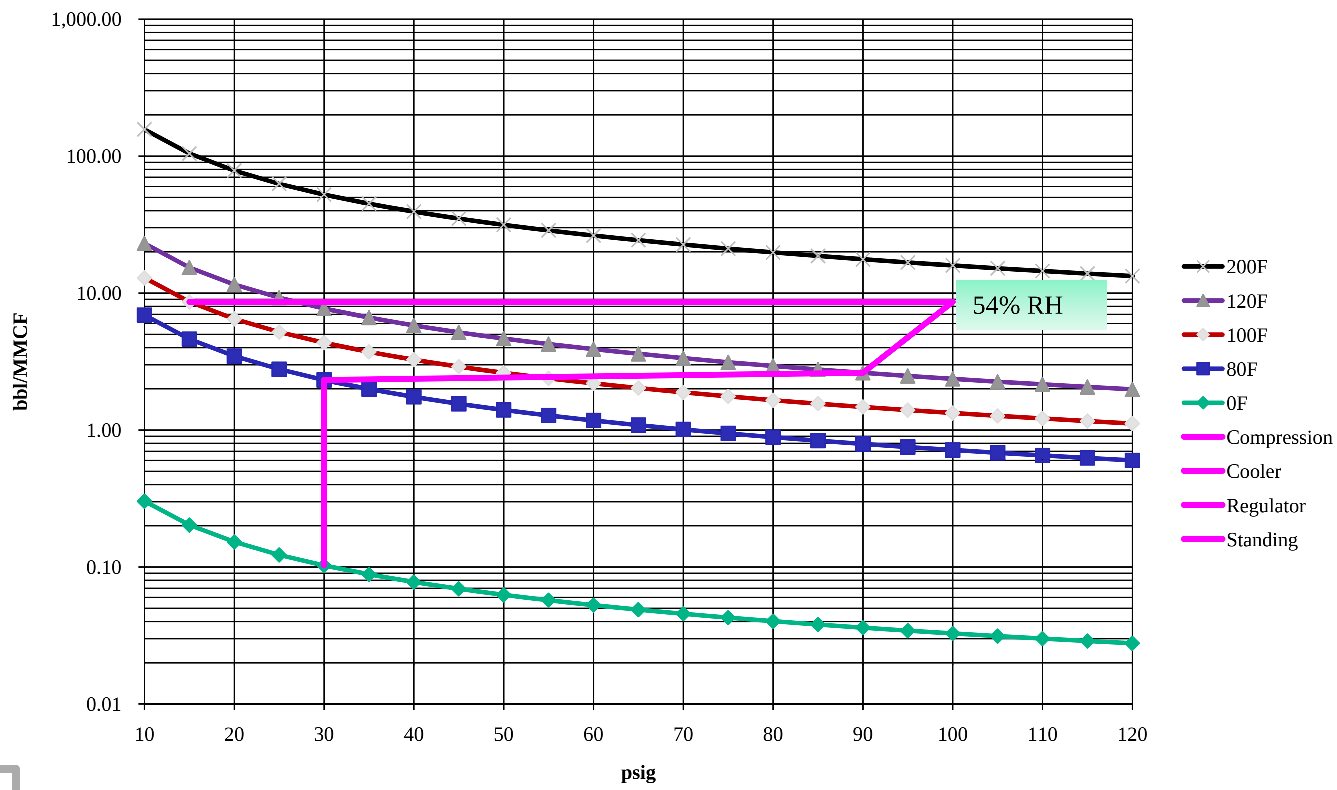
Lots of Ratios

- Recips can do about 4.5 ratios per stage
  - Three stage can do 4.5^3=91 ratios (zero to 1340 psig at sea level)
  - But every stage needs to be within ±5% of design suction pressure to work properly
- Flooded Screws can do 20 ratios
  - Easily go from zero to 265 psig at sea level
  - Handle varying suction pressure well, want to have a fairly constant discharge pressure
- What happens if you put a screw in front of a recip?
  - A machine that wants a constant discharge pressure dumps into a machine that wants a constant suction pressure
  - A screw in front of a 2-stage recip can do 405 ratios (zero to 5,900 psig)
- The first hp a well sees should be a screw, but recips truly have a place in low pressure operations

Fuel Gas

- Wellhead compression is generally engine-driven and fueled by well gas
- Well gas is:
  - Wet (generally saturated with condensable vapors)
  - Dirty (things like coal fines, compressor oil, sand)
- We use fuel-scrubbers to pretend to get the water out
  - They don't work very well (very little of the gas is liquid at that point, but some is)
  - Few of them have automated dumps, so if they fill up overnight they can slug the engine before anyone can get there to dump them
- Recommendations on fuel-gas scrubbers:
  - If they don't have an automated dump, remove the scrubber
  - If it does have an automated dump, keep the dump working
  - For cold weather applications it is better to do more (e.g., salt driers, chillers, Ranke-Hilsche tubes, etc) and remove the scrubbers

Fuel Gas



1,000.00
100.00
10.00
1.00
0.10
0.01
bbl/MMCF
10
20
30
40
50
60
70
80
90
100
110
120
psig
54% RH
200F
120F
100F
80F
0F
Compression
Cooler
Regulator
Standing

Compressor Control

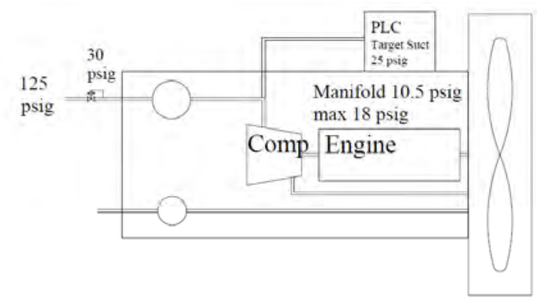
- Suction Controllers come in two flavors
  - Max-Inlet Control
    - Used to protect compressor from too much pressure on inlet plenum
    - Should have nearly zero dP when upstream pressure less than max
  - Range Control
    - Used to keep multi-stage machines in a narrow suction range
    - Will always have a non-zero dP and will limit compressor capacity
- Discharge controllers are rarely necessary
  - Can be used to increase dP across a skid (e.g.,
    - To ensure that a flooded screw without an oil pump has enough dP
    - Raise the heat of compression on a flooded screw to cook water vapor out
  - There are generally other options that waste less hp

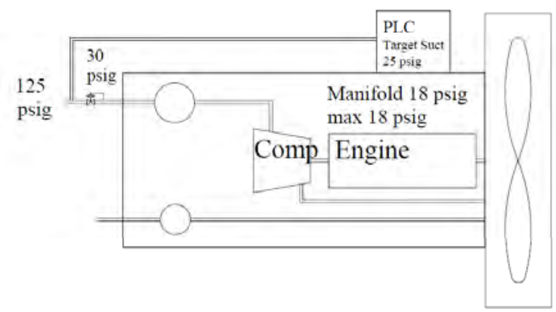
Capacity Control

- Capacity control schemes are used to match compressor performance with system delivery capacity
- Primarily used when system delivery volume is less than design
- Schemes have a wide range of hp cost
  - Reducing speed (within a design range) is most efficient
  - Adjusting engine manifold pressure is next most efficient
  - Unloader valves are less efficient, but still viable
  - Recirc valves are the least efficient and should be a very last resort
- Schemes generally limited to
  - Suction Control—try to maintain a target suction pressure
  - Manifold Pressure Control—try to maintain a target engine hp
  - Suction Control with Manifold Pressure Override—PLC tries to maintain a target suction pressure up to the point that a maximum engine manifold pressure is reached, then control on manifold

Control Example

- Standard configuration
  - Suction control w/manifold override
  - Well shut in for 2 days
  - PLC "thinks" everything is fine and lightly loads engine
  - Flow rate 2.8 MMCF/d (suction 25 psig)
  - 4 days required to pull well down to fully open Suction Controller
- Improved configuration
  - Same control, but sensing outside Max-Inlet suction controller
  - PLC "knows" it needs to pull the well down and goes to manifold override
  - Hp at max, flow rate 4.9 MMCF/d (suction 24 psig)
  - Controller fully open in 8 hours





Compressor Conclusion

- Select appropriate technology
  - Wells won't give you constant suction pressure so machines with narrow suction band are inappropriate as first hp
  - Compression technology after first hp should be based on efficiency and capacity requirements
- Choice of packager is key—a packager that understands your needs is much better than one that wants you to take a "standard package"

Thermocompressors

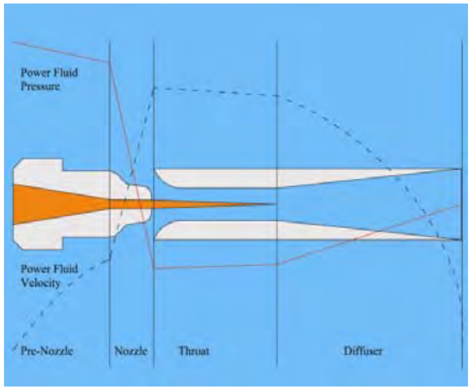
- Thermocompressor theory
- Case studies
- Equipment operation

Eductor, Ejector, or Venturi?

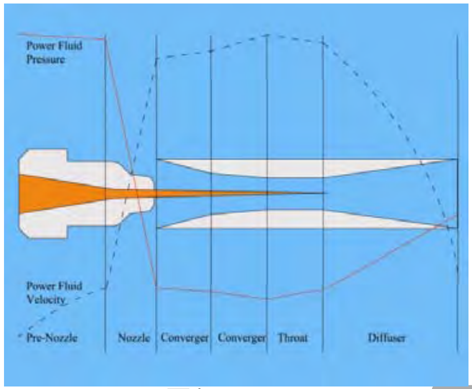
- Terminology can be really confusing
  – A “Venturi” is a constricted area of a pipe
  – An “Eductor” is a thermocompressor designed for liquid power fluid
  – An “Ejector” is a thermocompressor designed for gaseous power fluid
- Mostly terminology doesn’t matter, but:
  – An ejector can develop super-sonic velocities that significantly improve performance of a gaseous power fluid
  – Running liquid power fluid in an ejector will have poor efficiency (the nozzle configuration won’t accelerate a liquid very well and the mixing chamber is too short)
  – Running gas power fluid in an eductor won’t get supersonic flow and the gas won’t do much work and the long mixing chamber has too much pressure drop

Eductors/Ejectors

- From the family of thermocompressors that includes Air Ejectors, Evacuators, Sand Blasters, Jet Pumps, and Eductors
- High pressure fluid entrains and boosts the pressure of suction fluid and the combined stream is left at an intermediate pressure
- Ratio of suction pressure to discharge pressure:
  - For an eductor, exhaust pressure limited to about 1.5-3 times suction pressure
  - For an ejector, ratio of exhaust to suction pressure can be as much as 10:1 in absolute terms (psia)
- Efficiency 30-70%
  - More ratios mean better efficiency, but
  - More ratios also means more power fluid required



Eductor



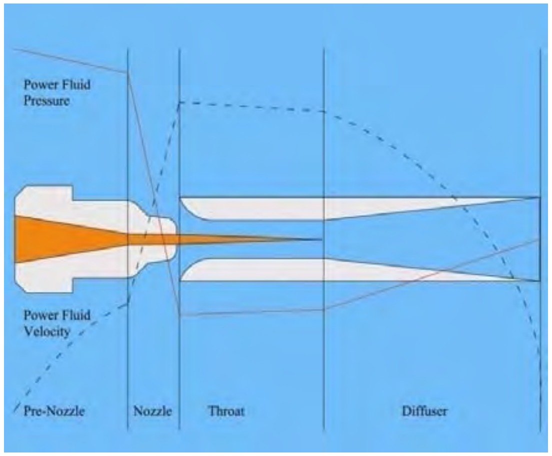
Ejector

Cases

- Downhole Jet Pumps
- Critical Flow Case
- Casing Flow Control Case
- Add-a-Stage Case
- Add-a-Compressor Case

Downhole Jet Pump

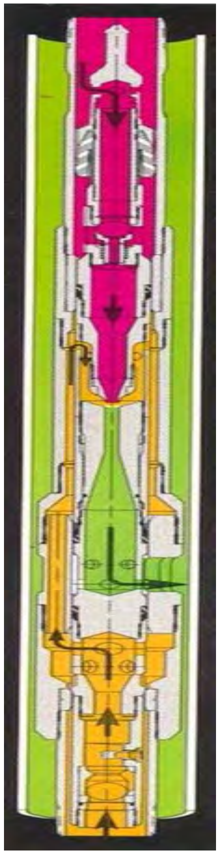
- Have been used in oil fields for over 50 years
- Eductor—designed for liquid power fluid
- Traditional Oil Field Pump:
  - Seats in a packer
  - Power liquid usually down tubing
  - Well production and Power Fluid exhaust up tubing/casing annulus



- Traditional jet pumps are rarely effective in gas wells because:
  - All well and power fluids must go through pump
  - Ports and nozzles are too small for gas and liquid flow rates

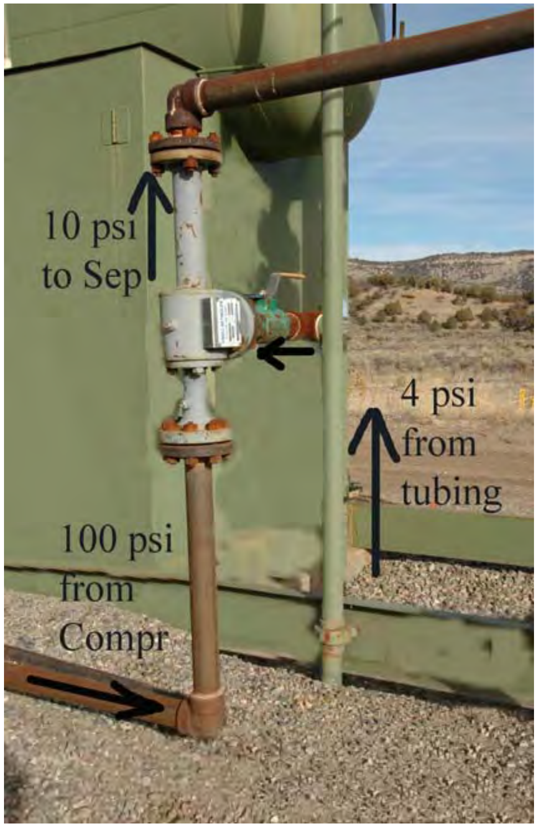
Jet Pump

- Tubing Pumps better suited for gas wells:
  - Two tubing strings (either dual or concentric)
  - Power liquid down inner or side string
  - Well liquid and exhausted power liquid up tubing/tubing annulus (or main tubing)
  - Gas production up casing/tubing annulus
  - NPSH-r varies by nozzle/throat combination, but it is seldom less than 460 ft (200 psig)
- Gas as Power fluid
  - Shape of the throat is wrong for efficient ejector operation
  - An effective configuration should have zero NPSH-r
  - At least 3 patents are pending on variations of this configuration
  - One bench test showed about 46% efficiency

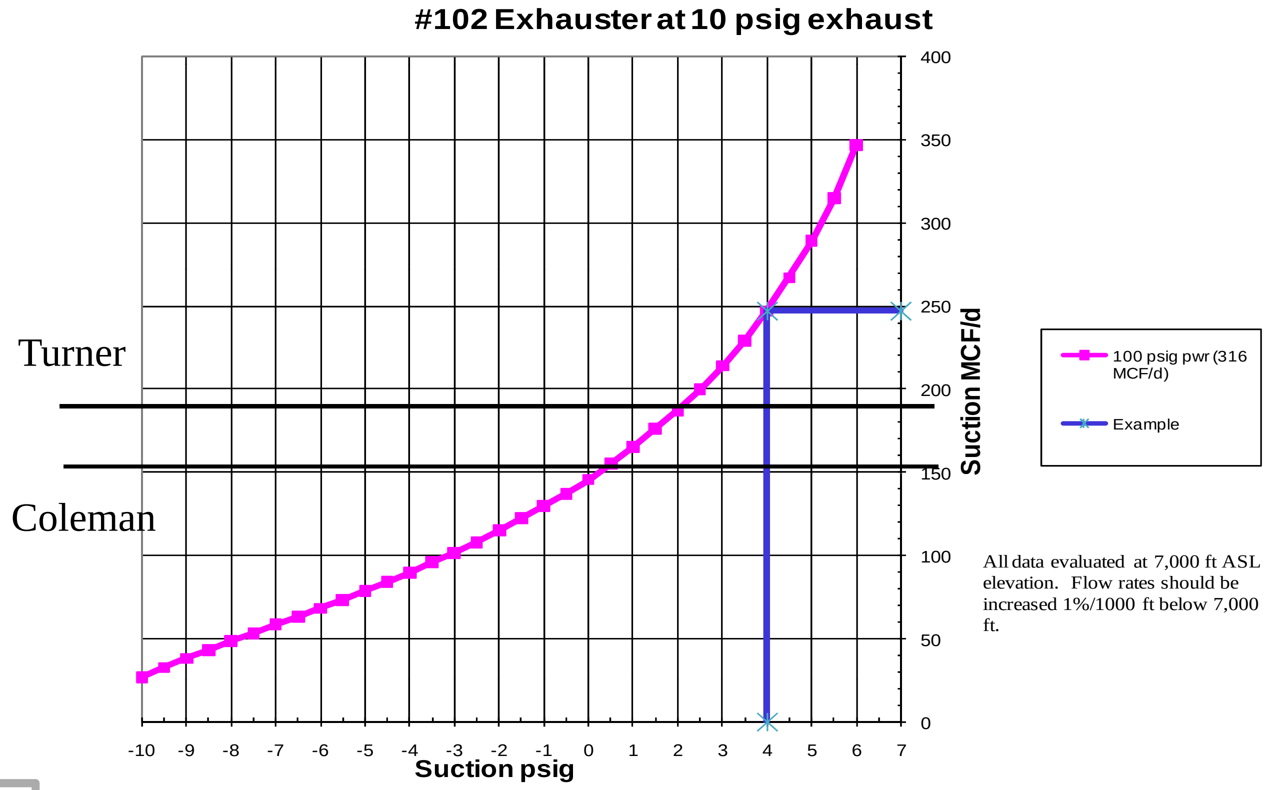


Critical Flow Case

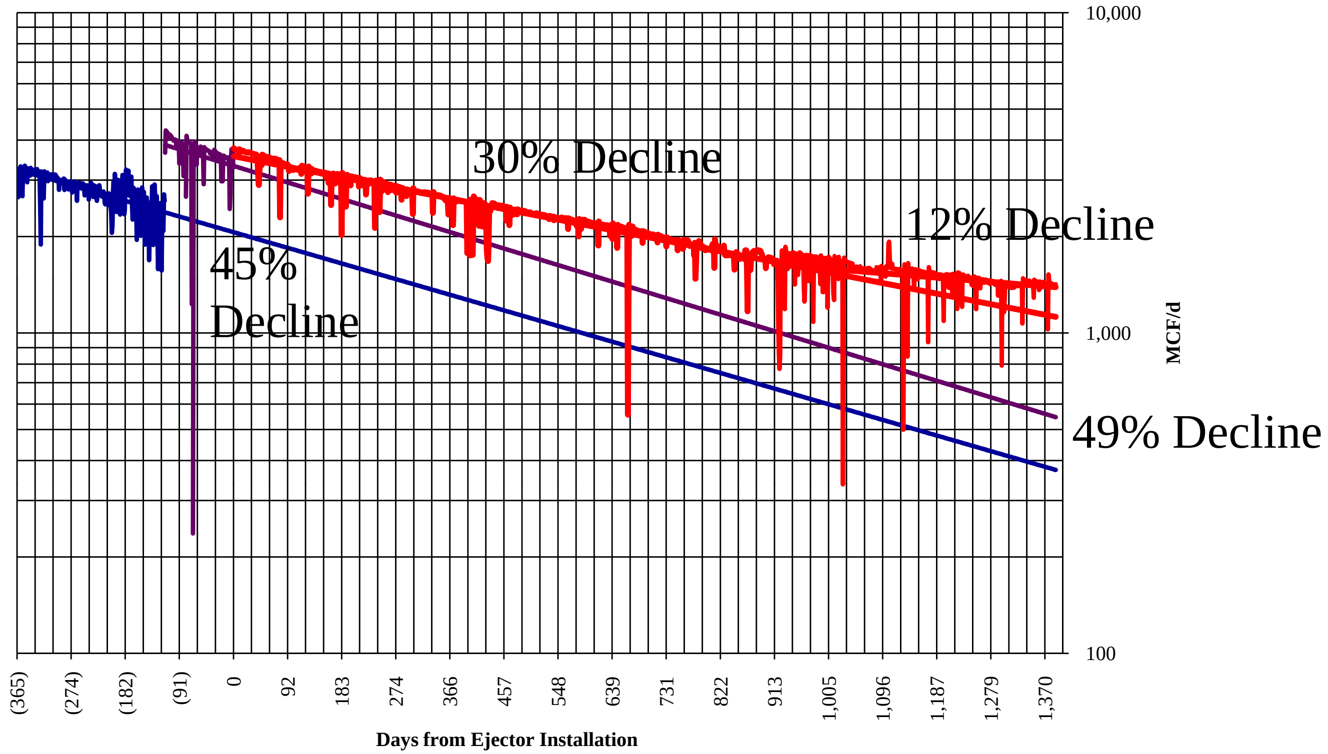
- Use an Ejector to force tubing to critical flow
- Small amount of hp
  - 28 hp for power gas
  - 10 hp used in ejector
  - η=36%
- Slow to react (can take 2-3 weeks or longer to stabilize water level)
- Pretty effective in maintenance mode



Ejector Performance



Critical Flow Case Studies

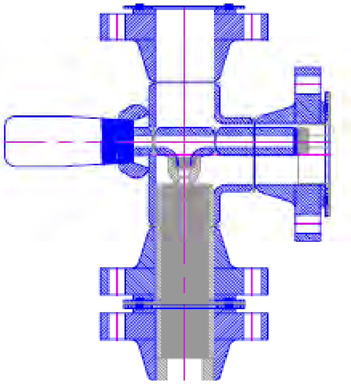


First 4 years
5/1998 - 8/2002

- Installations
  - 32 Coal wells (all show flatter decline)
  - 1 drip (line pressure too low to empty it)
  - 1 conventional well to run a plunger
- Cost $4.5K/site installed (total WI costs $90k)
- Contribution to Net Income $16.2 million

Casing Flow Control Case

- Uses friction in tubing to drive an ejector
- V-cone monitors tubing flow to stay above critical
- If above critical:
  - Flow cntl valve starts to open, sending power gas to Ejector Tee
  - If csg pressure > 45 #, BP regulator dumps extra
  - Compressor maintains exhaust at 5 psig
- Initial rate 25% higher than before installation (project had an 8 day payout)

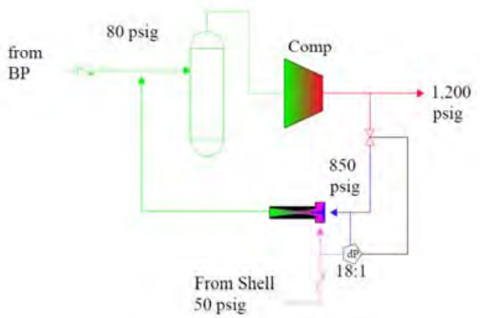


Add-A-Stage Ejector

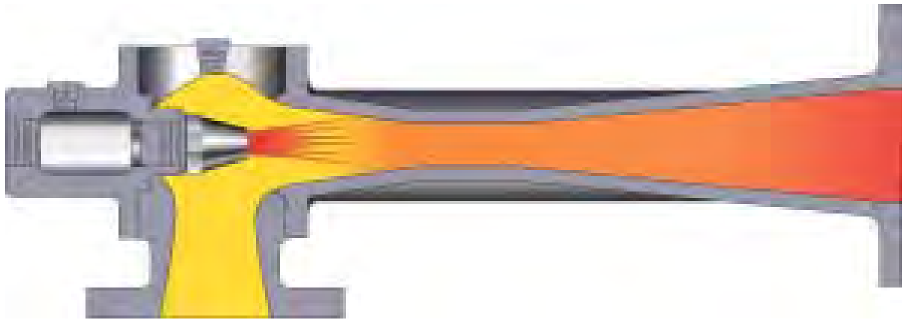
- Problem:
  - Well limited to 600 MCF/d with 9 psig wellhead pressure
  - Recip had plenty of hp, but cylinders were too small to reduce pressure further
- Solution:
  - Added full-stream ejector as zeroth stage
  - Wellhead pressure -5 psig
  - Separator pressure +9 psig (3.3 ratios)
  - Power Gas pressure 60 psig (12:1 HP/LP)
  - Well production 900 MCF/d
  - Power Gas 1,700 MCF/d
  - Compressor throughput 2,600 MCF/d
  - η=48%

Add-A-Compressor Case

- Problem:
  - BP Indefatigable 23A Platform handled its own gas plus 11 satellite platforms
  - 120,000 hp of compression plus separators, dehy's etc. took most available space
  - Compression designed for 80 psig suction
  - Two Shell platforms needed 50 psig line press
- Solution:
  - Ejector designed by Caltec, LTD (www.caltec.com)
  - Utilized extra compressor capacity (at 80 psig suction) to allow lower pressure at Shell platforms
  - dP sensor used to maintain HP/LP ratio at 18:1
  - Shell platforms increased 20% to 70 MMCF/d
  - Project paid out in 10 days



Equipment Operation



Drawing from Croll Reynolds at www.croll.com

- Power fluid comes from a pump, compressor, higher pressure pipeline, or higher pressure well.
- Typically, an exhaust path must be provided at a pressure less than half (in psia) of the power fluid pressure
- Suction pressure and flow rate are a function of:
  - Power fluid pressure
  - Power fluid flow rate
  - Exhaust pressure
  - Equipment design (the more flexible, the less hp can be used and the fewer compression ratios developed)

Ejector Response to Changes

	Power Fluid Pressure	Exhaust Pressure	Suction Pressure	Suction Flow Capacity
Decrease Power fluid Pressure		Constant	Increase	Decrease
Increase Power fluid Pressure		Constant	Constant	Decrease
Increase Exhaust Pressure	Constant		Increase	Decrease
Decrease Exhaust Pressure	Constant		Constant	Unchanged
Increase Suction Pressure	Constant	Constant		Increase
Decrease Suction Pressure	Constant	Constant		Decrease

Thermocompressor Conclusions

- Look for “wasted hp”:
  - Compressor you can’t load to hp
  - Well being choked back
  - Pump too large
- Find someplace that needs a little hp:
  - Wellsite too close to housing for compressor
  - VRU
  - Focused hp required (e.g., want tubing press lower than casing)
  - Sump pump
- See if there is enough hp being wasted to do at least part of the task that needs to be done

Gas Well Deliquification
Deliquification vs. Artificial Lift

- Introduction
- Deliquification methods that evolved from Artificial Lift
- Gas-specific deliquification methods
- Conclusion

Introduction

- In the last 50 years, gas has gone from being a waste product that hindered oil production to a primary, sought after product
  - Recent gas prices are causing operators to rethink the terms "economic limit" and "abandonment pressure"
  - Operators are reaching original abandonment pressure while fields are still profitable
- What do they have to do differently to remain profitable down to very low reservoir pressures?
- The biggest difference is "Deliquification"

Working Definitions

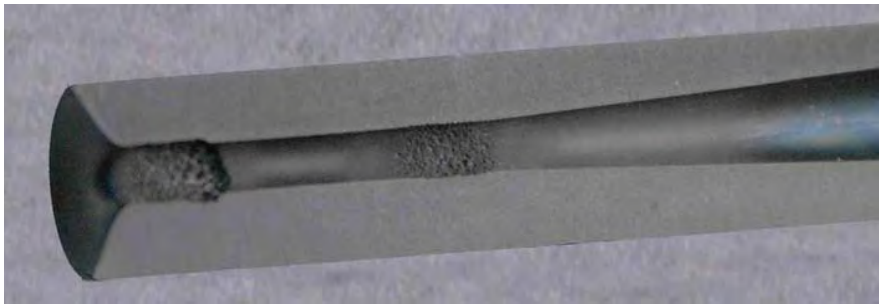
- Artificial Lift: application of external energy to lift a commercial product from reservoir depths to the surface
- Deliquification: application of energy to remove an interfering liquid to enhance gas production
- The key difference is that it matters where and in what condition artificially-lifted oil ends up, but water just needs to be gone
  - Evaporation is a reasonable deliquification method, but it would be an artificial-lift failure
  - Pump discharge below a packer is reasonable deliquification but not good for artificial lift

Net Positive Suction Head (NPSH)

- Net Positive Suction Head is the amount of external pressure at the inlet to a pump.
- The *Required* NPSH (NPSH-r) is the amount of external pressure required to ensure the pump operates full of liquid.
- The *Available* NPSH (NPSH-a) is the amount of external pressure available at the pump suction.
- It generally doesn’t matter if the NPSH comes from an actual hydrostatic head or an applied pressure (as long as the pump sees continuous-phase liquid).
- NPSH-r is very dependent upon fluid properties (mainly the boiling point, gas solubility, and vapor pressure)

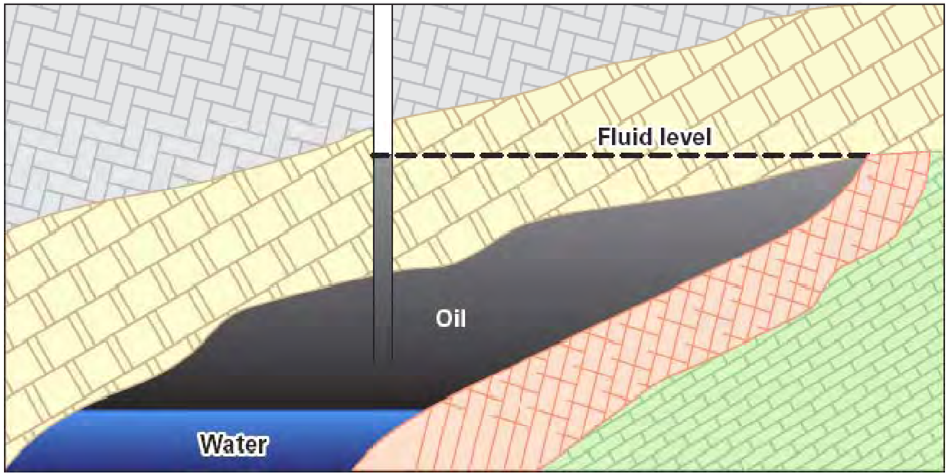
Cavitation

- Failure to provide adequate NPSH-a to dynamic pumps (e.g., ESP or jet pumps) can result in cavitation
- Definition: the formation and subsequent collapse of bubbles in a liquid
  - This results from localized boiling caused by low pressures (cavitation is a phase-change phenomena)
  - Dissolved and entrained gases have nothing to do with cavitation
- The momentum of high-velocity liquids rushing into the “hole” created when a bubble collapses can rip steel from the surface of pump



NPSH in Oil Fields

- When the completions are downstructure, the oil will try to “seek its own level”
- Often, several hundred feet of fluid will sit above the pump inlet without harming reservoir performance



NPSH in Gas Fields

- Any fluid above the perfs will add to the backpressure on the formation
- Backpressure is a significant factor in production rate, but it is not simple:
  - Many wells have a “pressure window” that maximizes production
  - The window is defined by the sum of all sources of restriction to flow (e.g., friction, fluid interference within reservoir, condensation, etc.)
  - Going outside of this pressure window will reduce gas rate
  - The pressure window moves with time
- There is never a simple relationship between production rate and backpressure—providing NPSH complicates the situation even more

Where do you go to get more NPSH?

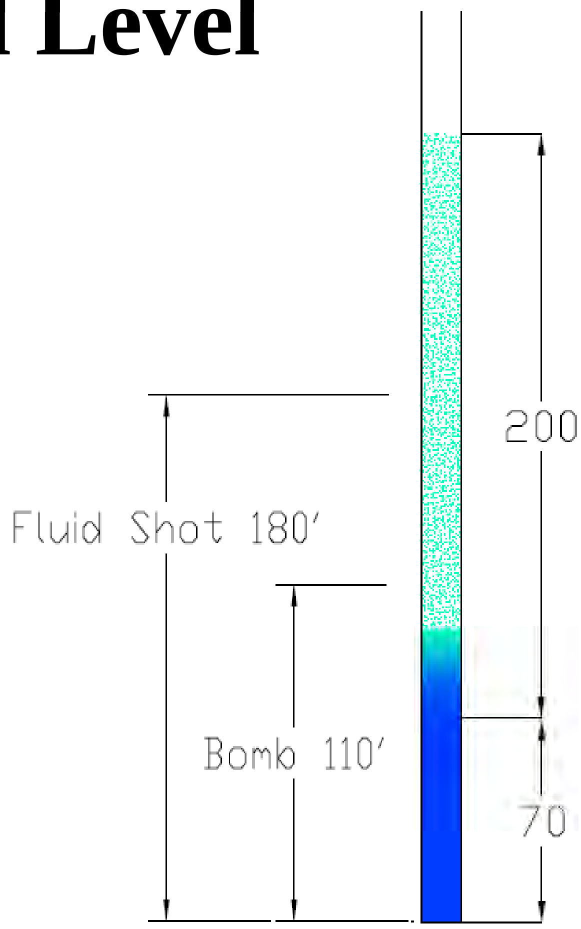
- Change technology:
  - A rod pump needs less NPSH than a jet pump
  - A progressing-cavity pump needs less than a rod pump
- Downhole equipment:
  - Gas separators
  - Mechanical devices to trip traveling valves
  - Vent piping, holes in tubing or pump
- Remove pressure drops (screens, tail pipes, standing valves). CAUTION:
  - Each of these devices has a reason for being there
  - Removing them is not without risks

Rat Hole

- Defined: space within the wellbore below the producing strata.
- Functions:
  - Collect fill and other wellbore trash
  - Raise NPSH-a without adding hydrostatic head on the formation
- Downside of placing pump in the rat hole:
  - Can concentrate solids in the pump suction
  - Harder to remove pump heat in the small volume of liquids around the pump

Finding Fluid Level

- The environment downhole is tumultuous and no condition exists for more than a few seconds
- Liquid Water exerts 0.43 psi/ft
- Methane at 100 psig and 110°F exerts 0.00012 psi/ft
- A froth of gas and water is somewhere between
- A pressure bomb or surface reading can only see effective height
- A fluid shot will give you its best return and will usually be somewhere within the froth (generally will pick a height in the midst of the froth and overstate backpressure)



Technologies that evolved from Artificial Lift

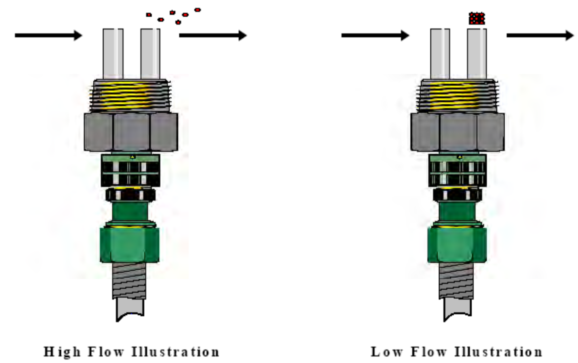
- Pump-off control
- Stroking pumps
- Progressing cavity pumps (PCP)
- Electric submersible pumps (ESP)
- Gas lift
- Jet pumps (discussed under Thermocompressors)
- Surfactants

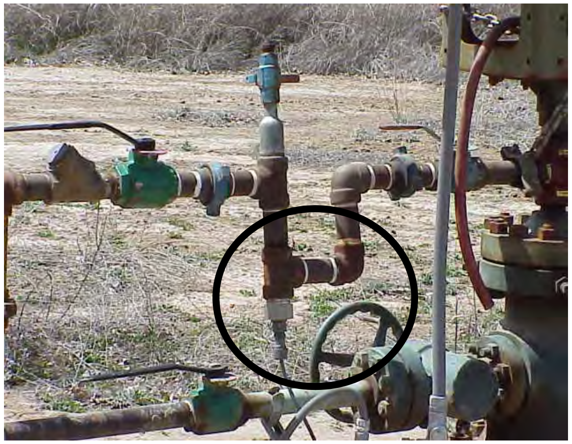
Pump-off Control

- Stop/start control works well in oil wells:
  - Often you can pump off the wellbore-storage down to NPSH-r
  - Leave the pump off while casing refills (fluid shots are very effective)
- Start/stop control can often be a bad idea in gas wells:
  - Inflow to gas wells is never very constant
  - Pump-capacity requirements will change many times per hour
  - Using periodic fluid level shots will result in a pump set-up based on non-representative data
  - Gross-level surface indications (e.g., flow rate, tubing-casing differential, etc.) happen too late to support needed changes
- Variable speed schemes:
  - Will often work well in oil wells
  - Will generally work better in gas wells than start/stop

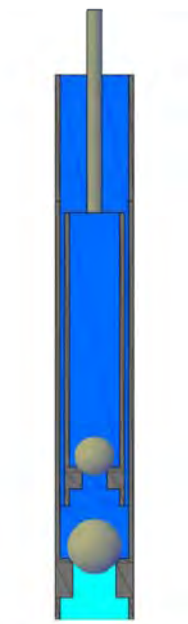
Pump-off Control

- Oil & Gas Instruments, Inc.
  - Two probes
  - Upstream probe just an RTD
  - Downstream has RTD and heating element
  - Flow past the probes carries some of the heat away
  - If the heated probe gets hotter, then the fluid has less liquid and element sends signal to slow the pump down
  - If it gets cooler then it sends signal to speed the pump up
- Setting the device in a dip helps prevent false negatives

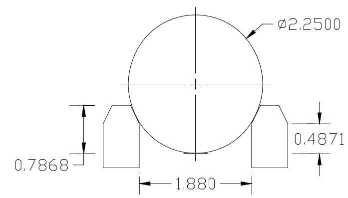


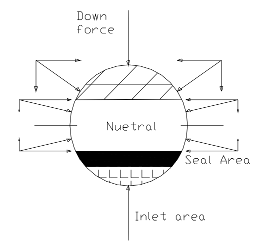


Rod Pump

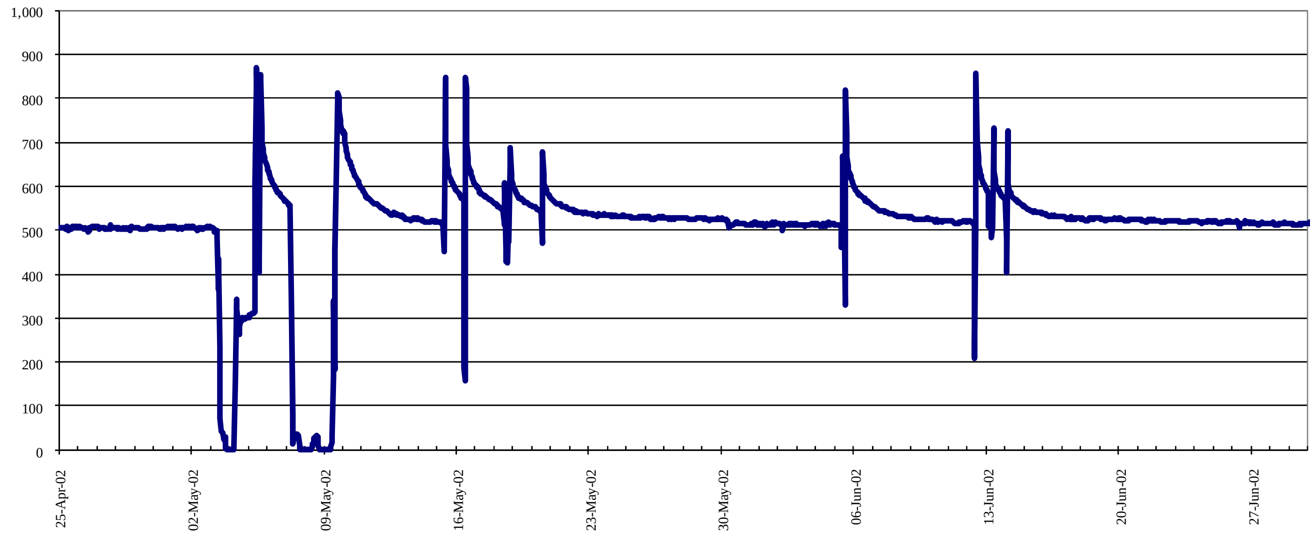


- Simple chamber with two valves
  - Chamber empties on downstroke
  - Chamber fills on upstroke
- With the pump liquid-filled, very little plunger movement is required to start pumping
- Effective area of ball above seal is 57% of net surface
- Residual pressure in barrel is based on
  - Pump leakage
  - Amount of gas in pump
  - Boiling point of liquid
- NPSH-r is:
  - At least 14% higher than residual pressure
  - Typically 75-100 ft



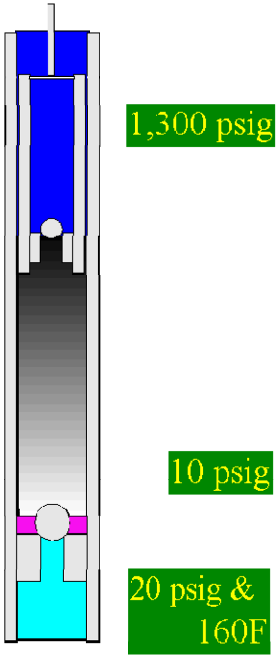


Rod Pump
What does a Gas Lock look like?



Rod Pump Gas Lock

- Pump must compress any gas in the chamber to above discharge hydrostatic head before the traveling valve will open.
- At 3,000 ft depth with 20 psig bottom-hole pressure the gas must compress to over 40 ratios (raising temp from 160°F to 1,300 °F in the animation)
- Heat of compression will boil the liquid
- The pump will travel up and down without pumping until:
  - Leakage past the plunger fills the barrel with enough liquid to open the traveling valve, or
  - Bottom-hole pressure rises enough to open standing valve



Effect of backpressure on rod pumping

- Assume:
  - Flowing Casing pressure 0 psig
  - Pump set up for 20 bbl/day
  - Pump set depth 3,000 ft

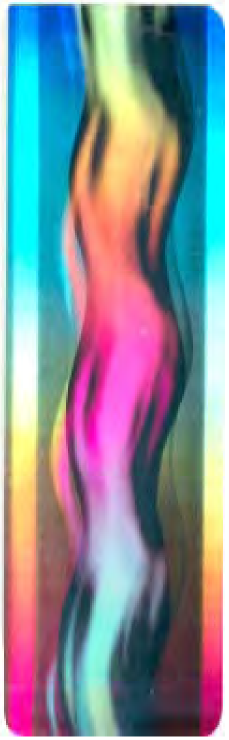
	Zero MCF/d		1.0 MCF/d	
	0 psig	200 psig	0 psig	200 psig
Pump disch at 3,000 ft	1,311	1,511	41	1,248
dP across Plunger	1,280	1,480	38	1,245
Slippage (gal/day)	7.9	9.1	0.04	7.3
Time to break gas lock	4 hours	3.5 hours	5 days	4 hours

Alternatives to Pump Jacks on Rod Pumps

- Pneumatic and hydraulic surface-equipment is replacing Pump Jacks in many operations because:
  - They can have longer stroke lengths (which helps with both pump capacity-management and gas locking)
  - The transition at the bottom of the stroke is gentler
- Pneumatic example:
  - Pump in well 3 years without being pulled, decline less than 4%, pump action good
  - Pumper quit and replacement wouldn't baby it and didn't understand it, well logged off
  - Replaced it with pump jack and average pump run-time fell, production down significantly
  - Moral: Nobody can make a bad idea work, but anyone can kill a good idea
- Hydraulic surface units like the DynaPump are much more forgiving

Progressing Cavity Pump (PCP)

- Rotor has a profile with a slight pitch.
- Each revolution causes the liquid in the cavities to move up the pump barrel.
- PCP's are positive displacement pumps and can develop very high discharge pressures
- Pumps turn fairly slowly (60-300 rpm):
  - Very resistant to damage from solids in a slurry.
  - Not resistant to damage from running dry.
- NPSH-r is about 60 ft
- New pump-off controls can be very effective



Progressing Cavity Pump

PCP

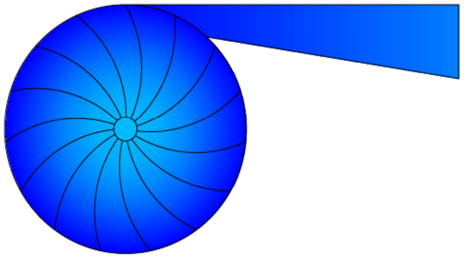
- Have gotten a bad reputation because:
  - Can be a significant mechanical load on wellhead
  - Stators have been prone to burning out
- Burnt out stators generally caused by turning the pump into a compressor
- Heat of compression:

$$T_{out} = T_{in}\left(\frac{P_{out}}{P_{in}}\right)^{\frac{k-1}{k}}$$

BHP (psia)	BHT	1000 ft	2000 ft	3000 ft	5000 ft
15	100°F	809°F	1,018°F	1,160°F	1,362°F
50	100°F	494°F	651°F	758°F	910°F
100	100°F	350°F	483°F	574°F	703°F

Electric Submersible Pump (ESP)

- Multi-stage centrifugal pump
- The impellor slings water from the eye at the center to the volute at outside edge to trade decreasing pressure for increasing velocity
- The volute has an increasing cross section to trade decreasing velocity for increasing pressure
- Intermediate stages discharge into next stage



ESP

- NPSH-r typically 150 ft
- Without adequate NPSH:
  - The first stage will cavitate.
  - The surface of the first-stage impellor will lose efficiency.
  - Subsequent stages will cavitate.
- Sometimes you can intermit the pump to align capacity with well performance:
  - Stopping pump will empty tubing back into formation
  - A standing valve can prevent emptying, but allows solids to settle out and can seize the pump and or/seal the standing valve.
  - A hole in the tubing above standing valve will let the pump backflush, but it steals capacity.
- Sand screens, standing valves, and filters decrease NPSH-a.

Gas Lift

- High pressure/high velocity gas is injected into annulus above a packer through gas-lift valves in tubing
- Very popular in oil operations
  - Small footprint (one compressor can serve a number of wells)
  - High minimum-liquid-level often less than hydraulic fluid-level in reservoir
  - Flow interference is minimal when the only gas in the tubing is gas-lift gas
- Rarely successful in gas operations
  - Energy requirements about 5 times larger than rod pumps and PCP’s
  - Very high minimum FBHP-achievable
  - Significant interference between injected gas and produced gas
  - Balance between injection and production VERY sensitive to small changes

Gas Lift in Gas operations

- Chamber Lift
  - Standing valve set in production tubing
  - Concentric string run inside production tubing
  - Periodically send high-pressure gas down tubing-tubing annulus to blow the water out through the inner tubing string
  - Primary production up tubing-casing annulus
  - Success can be significantly enhanced by using an ejector to pull on inner tubing during the fill-cycle to overcome standing valve
- "Po Boy Gas Lift"
  - Gas lift without a packer or gas lift valves
  - Inject high pressure gas down annulus and hope that it comes back up the tubing instead of into the formation
  - It has been tried many times
    - It seldom increases liquid production at all
    - Both gas and liquid production usually increase when it is turned off

Surfactant

- Soaps, foamers, and other surfactants are designed to foam and:
  - Introduce voids that lighten the liquid column
  - Reduce the surface tension of the liquid drops to minimize their size/weight
- All soaps have to be activated by agitation
- Care must be exercised to ensure that the soaps are activated downhole
  - Unactivated liquid soap will often activate and foam in the production/measurement equipment
  - Foaming in the gathering system will tend to increase the condensation surface and increase water problems
  - Liquid soap is "gummy" and can increase skin

Technologies that evolved from Artificial Lift

	Typical Capacity (BBL/day)	NPSHr (ft)	Failure method
PCP	4-600+	60-100	Heat of Compression
Beam Pump	20-500+	75-100	Gas Lock
Gas Lift	1,000+	200-500	Fall below critical rate
Jet Pump	10-45+	450-1,000	Cavitation
ESP	70-1,000+	150-2000	Cavitation

Deliquification Techniques

- Velocity String
- Tubing-flow controller
- Plunger
- Evaporation
- Emerging technologies

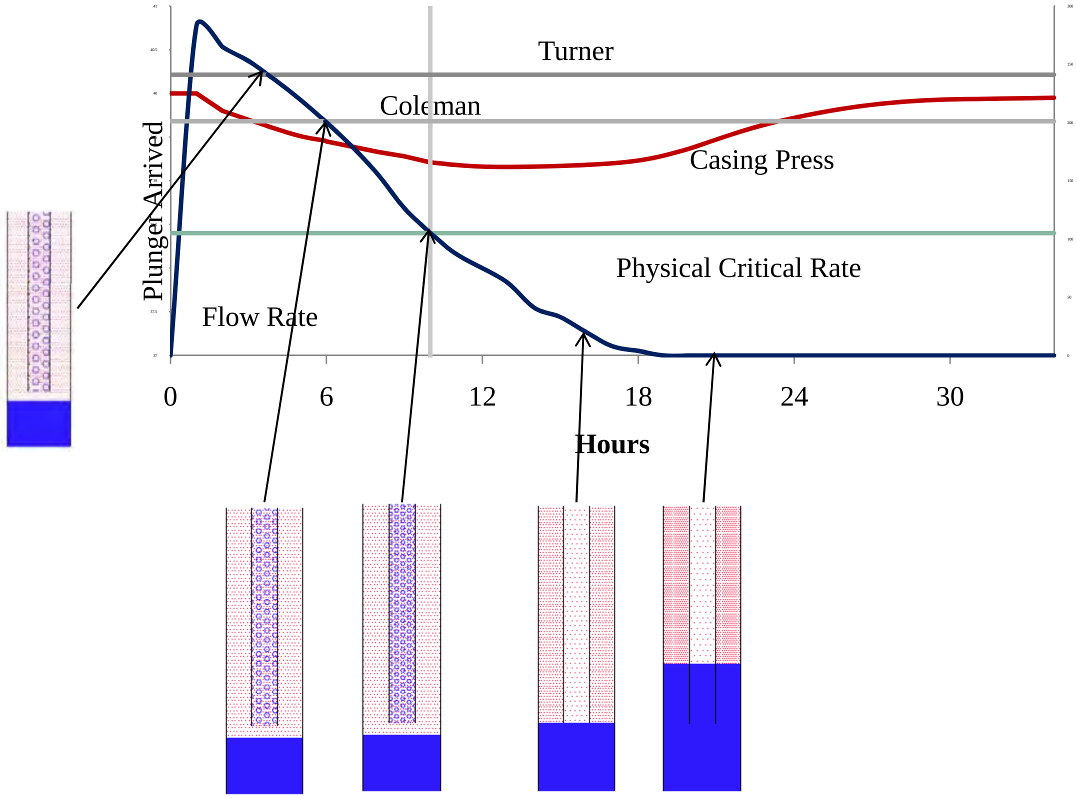
Velocity String

- Critical Flow—R.G. Turner et al published a JPT paper in November, 1969 coining the term "Critical Flow"
  - Showed liquid volume that reached surface to be a function of gas velocity which is a function of interfacial tension and fluid density
  - Virtually all data taken above 1,300 psig
- Many other researchers have built on this concept with new interpretations of Turner's data and some new data sets
- It is certain that at some increasing velocity, liquid volume transported to the surface will begin to increase
- The magnitude of that number and the method of determining it will continue to be a source of heated academic debate

Critical Flow Example

- For a particular well:
  - Tubing set-depth = 3,000 ft (2-3/8” 4.7 lbm/ft J-55)
  - Flowing wellhead Pressure = 4 psig
  - Flowing wellhead temperature = 80°F
  - Flowing bottom-hole temperature = 105°F
  - Production (just up tubing) = 130 MCF/d, 5 bbl/MMCF
- Critical Flow
  - Turner = 158 MSCF/d (loading)
  - Coleman = 132 MSCF/d (onset of loading)
- Flowing bottom-hole pressure
  - Gray Correlation = 55 psig
  - Cullender-Smith Dry Gas Correlation= 30 psig
  - Duns-Ros Correlation = 135 psig
- Measured flowing bottom-hole pressure = 8 psig (no sign of loading there)
- Take anyone’s “correlations” with healthy skepticism and a complete understanding of their underlying assumptions

How can you Really Determine Critical Flow

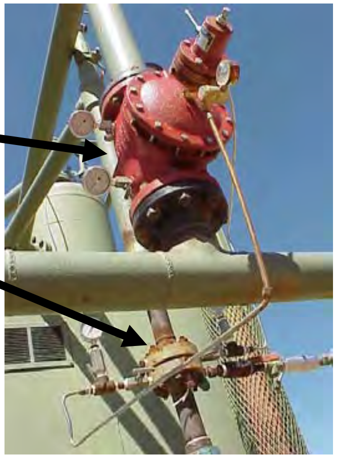


Velocity String

- A “velocity string” is a string of tubing that is intended to force normal gas flow rate to have a velocity greater than the “critical velocity”
- Higher velocity equates to higher friction drop
- Wells with velocity strings are very unforgiving:
  - If rate increases, friction will rapidly raise FBHP
  - If rate decreases slightly, you can drop below the actual critical rate and load up
  - A cold section in the wellbore can condense water vapor and upset the balance on a near-critical well
  - Aggressive velocity strings preclude both plungers and swabbing
- It is not a good idea to fully open the casing with a velocity string
  - Flow in the velocity string will drop to very near zero
  - The well is assured of loading up and can be difficult to restart

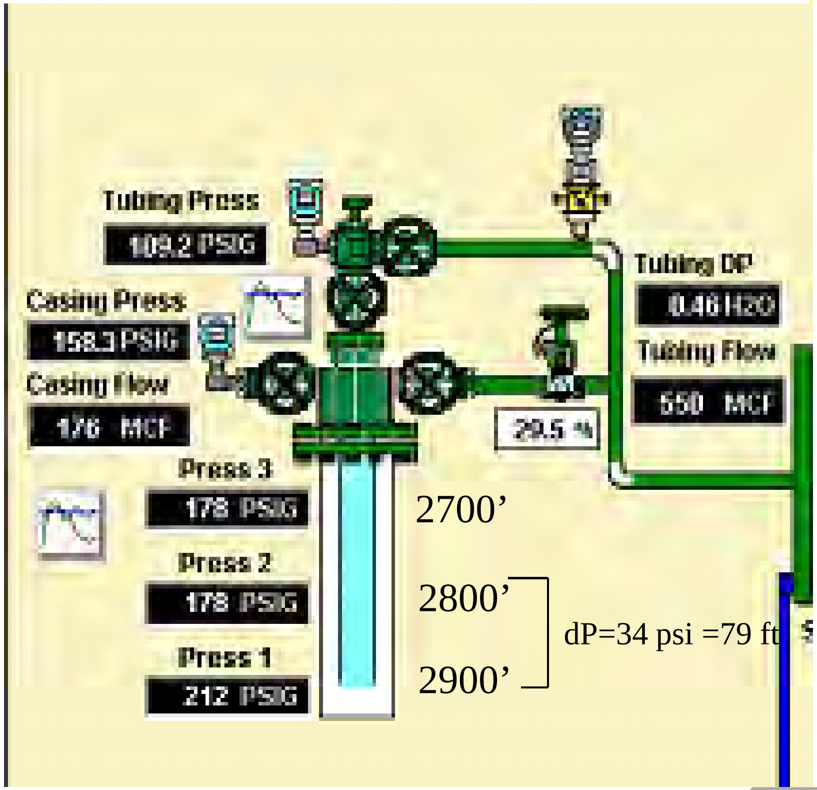
Tubing-Flow Controller

- If you're using a velocity string and the tubing/casing differential pressure is "excessive" then you can alleviate high friction drop by allowing some casing flow:
  - Must monitor tubing flow to make sure you stay above critical
  - Must throttle casing flow carefully to ensure that you don't upset the tubing flow too much
- Most installations use:
  - Pneumatic control valve on casing
  - Orifice meter on the tubing
- This rarely works probably due to:
  - Relatively large dP caused by the meter
  - Sluggishness of the pneumatic valve



Tubing-Flow Controller

- You can use:
  - V-Cone measurement
  - Electric V-Ball flow control
- This makes the system much more responsive
- A number of wells have seen sustained performance improvements with this configuration over several years



Plungers

- A plunger operates like a pipeline pig
  - Differential pressure across the plunger moves it up the wellbore
  - Any solids or liquids it encounters are pushed in front of it
- Differential pressure determines how much liquid a given well can lift
  - Disregarding friction, 10 psid can move:
    - No more than 2.5 gallons per trip in 2-3/8
    - No more than 4.4 gallons per trip in 2-7/8
  - To move 5 bbl/day with 10 psid in 2-3/8 requires at least four trips per hour (closer to 6 with a safety factor)

Plungers

- The various types of plungers are differentiated by:
  - Fall rate
  - Quality of seal
  - Efforts to clean pipe
- There is a narrow window in reservoir pressure where plungers are the best choice:
  - Early in life, there tends to be enough FBHP that the well doesn't need assistance
  - Late in life the pressure required to lift a plunger plus a load of water is greater than the pressure available

Plunger Operation

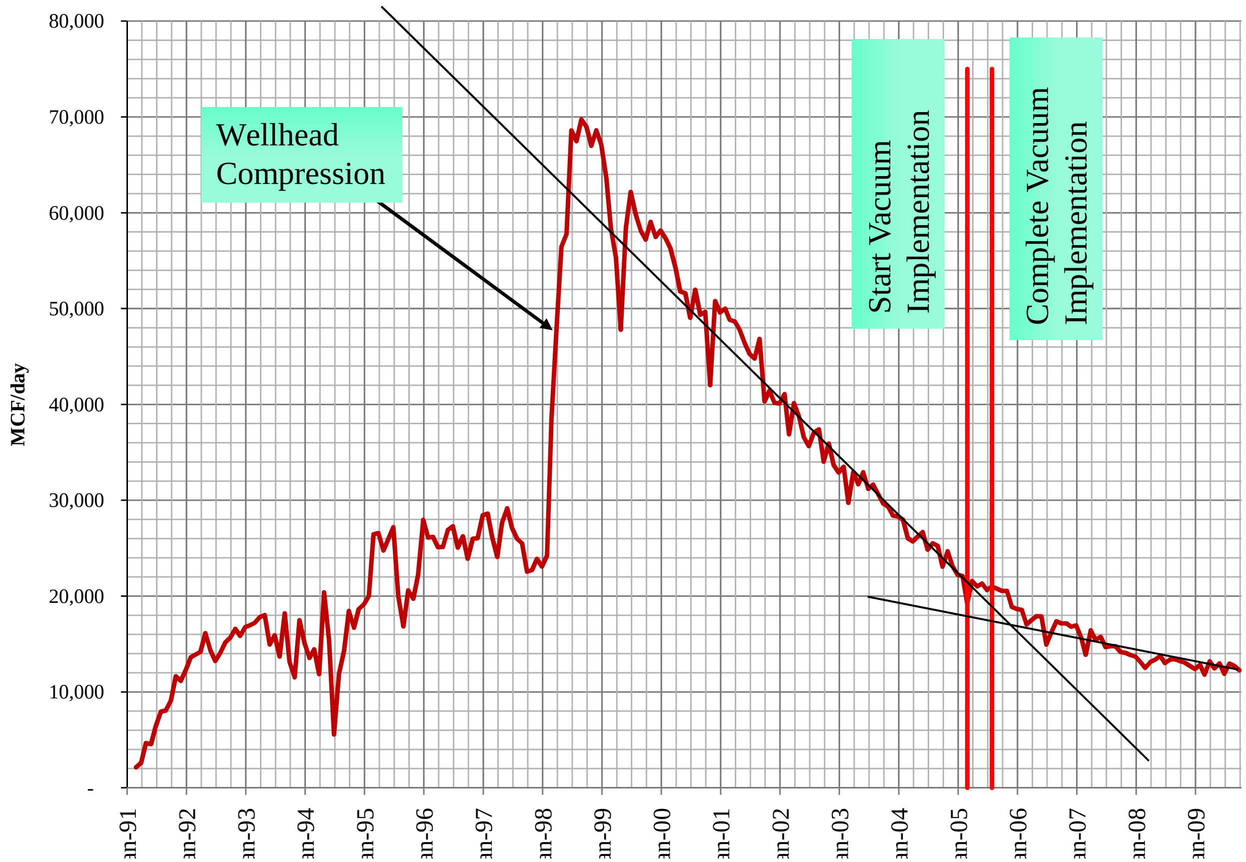
- Plungers are operated more as “art” than “science”
  - Some operators shut the well in for extended period to build up pressure
  - Other operators use bypass plungers to let the plunger fall against flow
  - Some operators wait until tubing/casing differential is “big enough” to run the plunger
- One technique that has a significant potential is:
  - As soon as a plunger arrives, shift flow to tubing/casing annulus and drop the plunger
  - Let it fall for at set time, then shut the annulus until the plunger arrives again and start over
  - This technique will reduce slugging, move more liquid, and access more of the reservoir

Evaporation as Deliquification

- If your pressure is low enough, then it is sometimes possible to evaporate all of the liquid that flows into the wellbore
- This technique works, but it requires that you:
  - Be willing/able to operate under vacuum conditions
  - Remove production tubing to maximize the flow area (and minimize velocity)
- One major concern is that the evaporating water will leave salt behind that can plug the formation
  - There is no theory that would predict this won't happen
  - Experience to date has not shown it to be a problem

Evaporation Example

(22 wells on vacuum)



Vacuum Lessons Learned

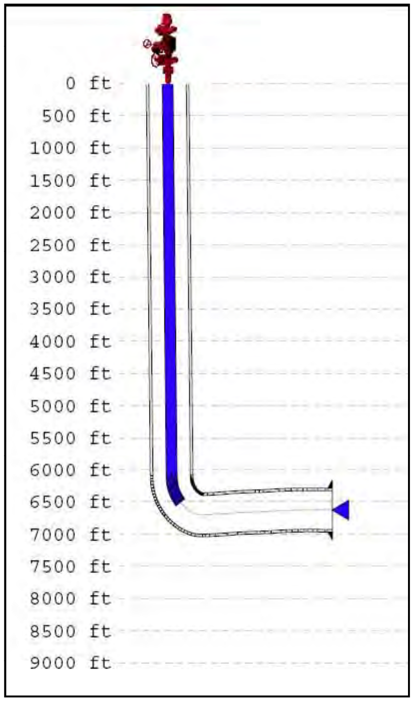
- You need to think about how much leakage is acceptable
  - We started by installing oxygen detectors and slam valves
  - Slam setting was a spike to 10 ppm
  - Most wells shut in most of the time
  - Changed to >25 ppm for 30 seconds (that helped a lot)
- We found that
  - All PSV leak with "high" pressure above seat (fixed by putting check valves under PSV)
  - Old sight-glass packing very prone to leak (and very hard to find leak)
  - Finger-tight plugs are worse than worthless (they do nothing to stop leakage and make you think the open-ended line is plugged)
  - Valve packing on dump valves significant leak point
  - Every threaded connection subject to leak and leaks can be really hard to find (minimize them as much as possible)
- Most problems were resolved within 6-months and haven't come back

Accelerating Evaporation

- Change thermodynamic conditions:
  - Raise temperature
  - Lower Pressure
- You can usually change pressure more economically than you can change temperature so your options are:
  - Reduce gathering-system pressure
    - Pipe becomes less efficient
    - Pneumatic wellsite equipment may not work anymore
    - Very difficult to shift liquid from vessels
  - Install wellsite compression
    - Less efficient than central compression, but it allows workable solutions to the other problems

Implications for Horizontal Wells

- Most of today's pumps will not traverse the bend in a horizontal well
- If a pump is set in straight pipe, minimum reservoir pressure is determined by pump technology NPSH:
  - If a Jet Pump requires 600 ft NPSH-r, then minimum flowing bottom hole pressure is about 270 psig (with zero psig on surface)
  - With 50% drawdown, minimum abandonment pressure is 550 psig
  - In unconventional reservoirs something like 50-75% of OGIP will be left in the ground at 550 psig.
  - Changing from Jet Pump to PCP lowers NPSH to around 30 psig, minimum abandonment pressure drops to around 70 psig, and recovery goes to over 85%.
- Advances in Deliquification technology will be required to meet the needs of the industry in the future



Emerging Technologies

- Research directions seem to be toward adapting gas-compression equipment to moving liquid
  - Liquid quantities pretty low (5-200 bbl/day)
  - Varying strategies to manage discharge pressure
  - Depth limitations somewhere between 2,500 and 5,300 ft (but everyone is working on extending this)
- Several people are working on thermocompressors that can handle large quantities of gas
  - Liquid limited to 5-30 bbl/day
  - Discharge pressure minimized by keeping gas close to critical velocity
- There are a couple of screw pumps on the market with limited success

Emerging Technologies

- Global Energy Services, Ltd of Calgary has developed a hydraulic submersible pump (HSP) that looks like a recip compressor
  - Slow stroke speed to allow liquid to change direction without pump-damage
  - Uses hydraulic fluid and surface hydraulic pump
  - Liquid limited to about 120 bbl/day
  - If it runs out of liquid it becomes a compressor
  - Current pump limited to about 5,300 ft (deeper designs are being tested)

Deliquification Technologies

	Typical Capacity (BBL/day)	NPSHr (ft)	Failure method
Velocity String	<100	0	Well capacity falls below critical
Tubing Flow Controller	<100	0	Well capacity falls below critical
Plunger	<10	0	Reservoir pressure falls below min required
Evaporation	<20	0	Scale plugging formation
HSP	<150	0	Wear

Deliquification Conclusion

- Deliquification is different from Artificial Lift and it requires different:
  - Tools (gas wells want much gentler handling)
  - Mind set (e.g., pipeline operation is a valid tool of production, pigging is not a "necessary evil", it is critical)
  - Staffing levels (more stuff to do takes more folks)
- No technology is set-and-forget:
  - Be prepared for any given technology to work or fail to work on any given well (regardless of "similar" wells in the same field)
  - Expect to spend considerable field and engineering effort to "get it right" only to find that as pressures change it doesn't work any more
- The only "silver bullet" for deliquification is great data, appropriate staffing, and a flexible approach

Produced Water

- Introduction
- Infrastructure for accumulation
- Disposal options
  - Underground injection
  - Evaporation
  - Beneficial Use
- Conclusions

Scope

- Managing produced water is the subject of thousands of pages of regulations and millions of pages of legal decisions
- The intent of this presentation is to give you the feel for the magnitude of the subject, not prepare you to deal with its complexities—get help from environmental, regulatory/legal, and engineering professionals early in the process
- This presentation is not intended to provide engineering or legal advice on your specific problems, any recommended practices in it are subject to be poor advice for certain conditions
- The data and examples are focused on U.S. operations to provide examples of how things can work. A review of the requirements in any particular jurisdiction is required prior to committing resources to a project.

Introduction

- At today's product prices:
  - Wells remain economical with much higher LOE than in the past
  - A big part of the increased LOE is lifting and disposing of water
- More water is getting to the surface today than ever before
- The regulatory environment is getting more strict all of the time

Introduction

- According to the U.S. DOE
  - Non-CBM onshore water production in the US is 14 million bbl/day
  - Some estimates add about 1 million bbl/day of CBM water
  - Wild guesses put the Gas Shale water over 1 million bbl/day
  - Disposal costs average $0.80/bbl
  - Industry explicit and implicit costs of lifting and disposing of produced water is at least $5 billion/year in the U.S.
- All of these numbers are suspect since recording accurate water volumes is not a priority with either the producers or the regulators—produced water is a waste product that is seldom accurately tied to wellhead production
  - Operators that say they're doing a good job of measuring wellhead water volumes tend to never do a full-system material balance
  - No one has the obligation to reconcile reported wellhead water to reported injection or evaporated volume
  - Efforts to do that reconciliation have always met with dismal failure

Water Quality

	EPA Safe Drinking Water Act Maximums	Typical surface discharge limits	San Juan River	Typical Coal
pH	6.5-8.5	6.5-8.5	8.5	7.8
Dissolved O_2 (mg/L)	No limit set	No Limit Set	11	0
Turbidity	5	5	3.5	3
TDS (mg/L)	500	5,000	250	10,000
Oil & Grease (mg/L)	ND	35	ND	50

Infrastructure for Accumulation Transport

	Trucking	Pipeline
Capital Cost	Very Low	High
Operating Cost	Very High	Very Low
Main Risk	Road accidents	Line Failure

- The trade off is never clear or obvious
- A hybrid system is often the best economics
  - Strategically placed water-transfer stations with pumps
  - Water is trucked to transfer station
  - Pipeline runs from transfer station to central location

Transportation Example

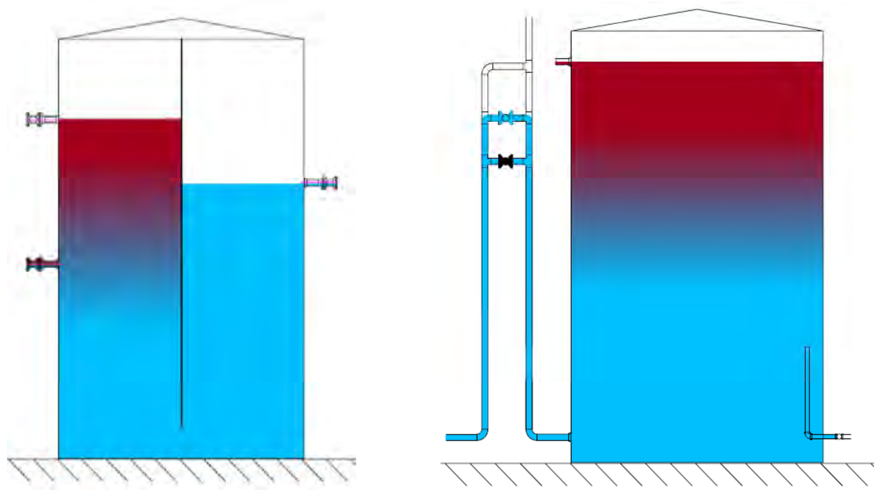
- A company drills a new well:
  - Expected water production 200 bbl/day (can be piped with 2-inch pipe, requires 3 trucks/day)
  - 5 miles from a transfer station
  - Trucking requires 3 days on-site storage (600 bbl)
  - Their trucking costs average $0.20/bbl/mile ($200/day)
  - Pipelines cost $35k/inch-mile ($300k) and no on-site storage
- Two companies do the same analysis
  - Company “A”—build pipeline (threshold 150 bbl/day)
  - Company “B”—truck water (threshold 225 bbl/day)

Site-Entry Facilities

- Solids can be difficult for pumps and injection wells
  - Filters and strainers require monitoring
  - Filters designed for water tend to fail in oil
- Oil causes a problem with any sort of produced water facilities
  - Surface discharge limited by regulation to 35 mg/L
  - Oil in downhole injection wells will shorten the injection life of the well
  - Oil in an evaporation pond will reduce evaporation rate and is a hazard for birds

Dealing with Oil

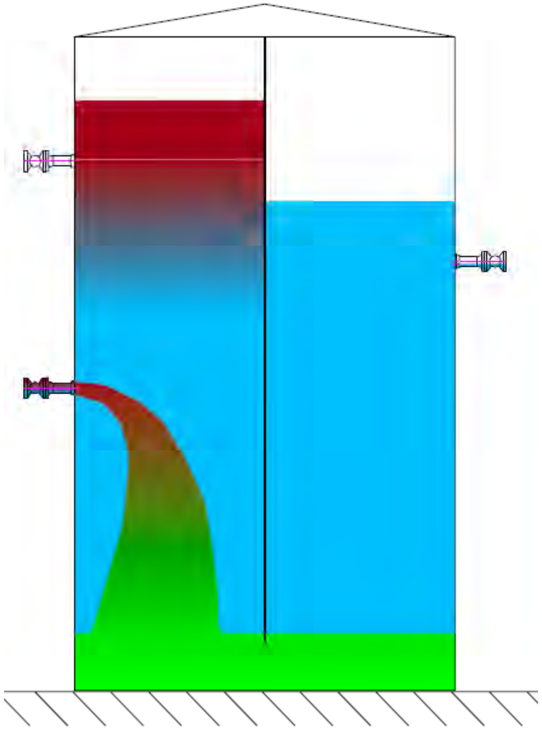
- Gun barrels are the typical solution to oil in gas fields



- When the fluids are exactly at design conditions:
  - Oil level is at the oil-outlet
  - Water level is at the water outlet
  - If a quart of liquid comes in, a quart must go out

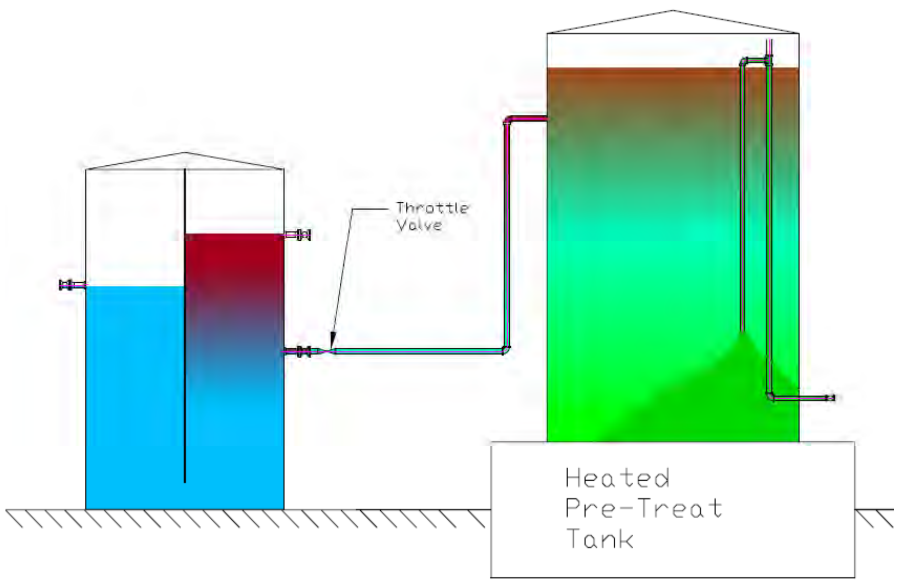
Gun Barrels

- Example design conditions
  - 160°F
  - Water SG 0.96
  - Oil SG 0.75
- Fluid from truck
  - Fluid quantity 80 bbl at 35°F
    - 78 bbl water, 1.07 SG
    - 2 bbl oil, 0.98 SG
  - Empty truck in 15 minutes (7,600 bbl/day rate)
  - Incoming fluid drops like a stone
  - Treated fluid leaves
  - Oil finds its way to the water side



Gun Barrel

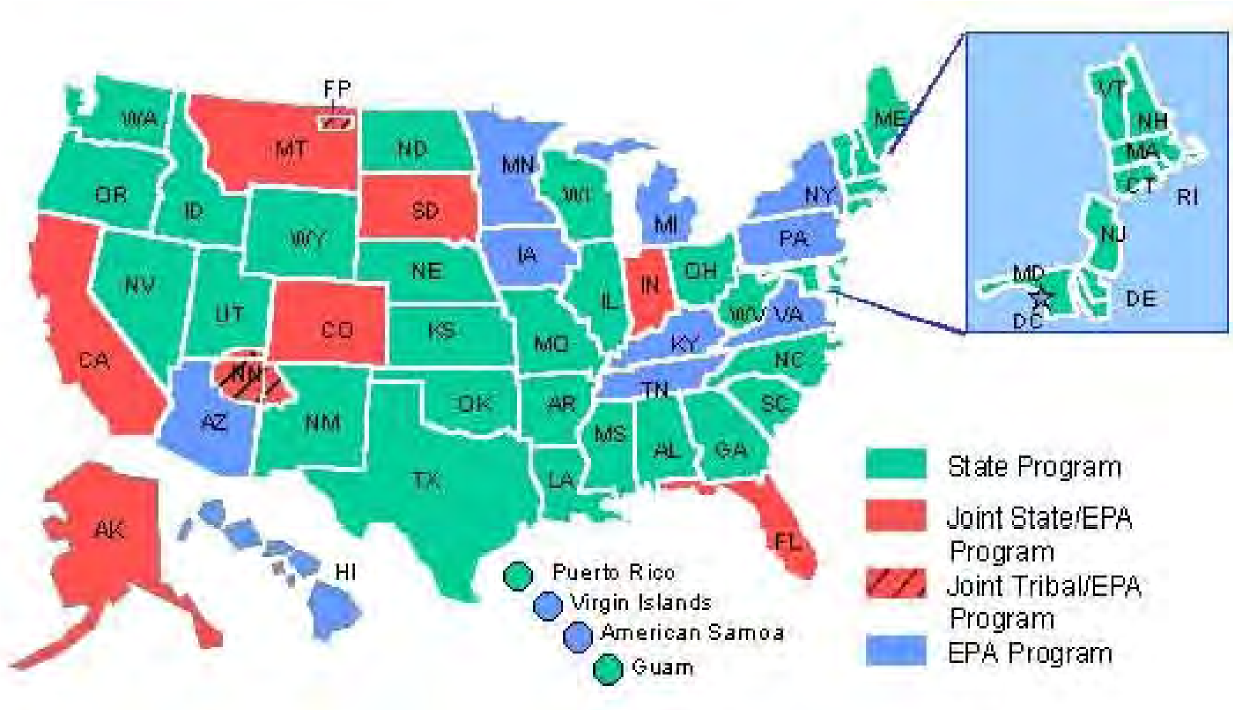
- Problem can be fixed by converting from batch to continuous:
  - Trucks unload into heated pre-treat tank
  - Throttle valve controls flow rate of warm liquid into gun barrel
  - Set throttle valve at about twice the normal daily in-flow rate



Underground Injection

- Deep-well injection must satisfy the requirements of the 1974 *Safe Drinking Water Act (SDWA)*
- The intent of the SDWA *Underground Injection Control (UIC)* protocols is to protect aquifers from contamination
- EPA estimates that 91% of all produced water is injected into a UIC well
- Overall responsibility for the SDWA rests with EPA, but states can elect to manage parts or all of it

UIC Primacy



* The Fort Peck (FP) Tribes and the Navajo Nation (NN) are currently the only Tribes with UIC Primacy

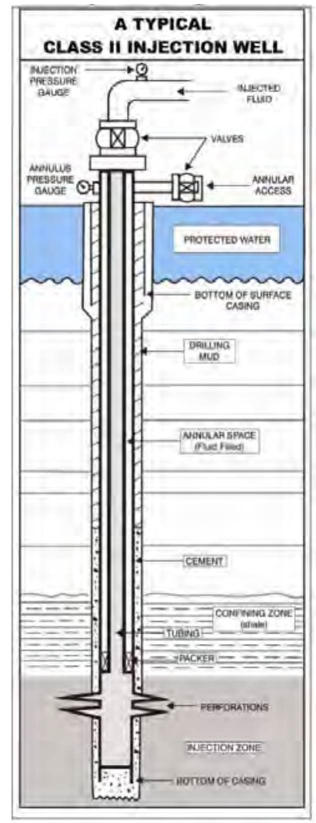
Source: EPA web site

UIC Well Classes

- Class I, Deep Wells – used for hazardous and non-hazardous industrial waste and non-hazardous municipal waste
- Class II, Oil & Gas Injection Wells – used for any well accepting Oil & Gas produced fluids (includes secondary and tertiary recovery projects in addition to produced water)
- Class III, Mining Wells – wells that are used for mining
- Class IV, Shallow hazardous and Radioactive Injection wells – these wells are mostly prohibited
- Class V, Shallow Injection Wells – wells that don't fit into any of the other categories

Required Permit Information

- A map showing all nearby wells that penetrate the injection formation with detailed information on each well
- Average and maximum daily injection rate
- Total volume of fluids to be injected
- Detailed geologic data on the injection zone
- Detailed wellbore and facilities design
- Proposed well-stimulation program
- Actions required on nearby wells that penetrate the injection formation
- P&A Plan



Stipulations

- Permit stipulations can include almost anything, but typically they have at least:
  - Requirements for a Mechanical Integrity test, including requirements for periodic re-tests (typically every 5 years)
  - Approval of operating procedures including
    - Calculated fracture gradient
    - Injectivity tests to establish fracture pressure
    - Steps required in a failure of either mech integrity or injectivity
    - Filling and verifying that tubing/casing annulus is liquid-full
  - Instrumentation to continuously record injection pressure and volume along with calibration frequency
  - Annual bradenhead test

New Mexico Common Reasons for UIC Permit Rejection

- Using the wrong address for the OCD
- Not including enough data on the adjacent wells, they want a spreadsheet with
  - API Numbers
  - Cement Tops and method of verifying tops
- Not notifying adjacent well operators or mineral owners
- Application protested

Equipment Needed for UIC Well

- Tanks – it is a good idea to have about 1-2 days of storage
- Filtration – most successful UIC operations filter the water to about 25 microns
- Pumps
  - Charge pump – required for long-term operation of plunger injection-pumps (not needed for progressing cavity or multi-stage centrifugal injection pumps).
  - Injection pump – needs to be able to pump the daily volume into the permitted injection pressure
- Automation
  - Need to be able to stop the process if injection pressure approaches UIC limit or tank level gets too low

Evaporation

- 6% of all produced water is disposed of through evaporation
- Evaporation ponds are regulated:
  - By State agencies in most Oil & Gas producing States
  - By the EPA if the State doesn't want to do it
- Any water that is evaporated will fall as uncontaminated rain somewhere, injected water is lost to the biosphere

Typical Permitting Requirements

- Operating and maintenance procedures with monitoring and inspection plans
- Pit closure plan
- Hydrologic report which includes sufficient information on the site's topography, soils, geology, surface hydrology, and groundwater hydrology
- Dike protection and structural integrity
- Leak detection
- Liner inspection procedures and compatibility report
- Freeboard and overtopping prevention
- Nuisance and hazardous odor prevention
- Emergency response plan
- Type of waste stream (including chemical analysis)
- Climatological factors including freeze/thaw cycles

Typical Construction Standards

- Each Pond must be designed, constructed, and operated so as to contain liquids and solids in a manner that will prevent contamination of fresh water and protect public health and the environment
- Foundation of firm, unyielding base free of rocks, debris, sharp edges, or irregularities
- Dike
  - 2H:1V maximum slope inside pond
  - 3H:1V maximum slope outside pond
  - Wide enough to include anchor trench, room for inspection and maintenance
- May not be larger than 10 acre-ft (larger than that puts under “Dams and Dikes” regulations which are much more stringent)
- Must be netted or have other approved means of protecting migratory birds

Liners

- Primary (upper) liner made of synthetic material
- Secondary (lower) liner can be synthetic or other material approved by regulators
- Upper and lower liners must be separated by at least 2 ft of compacted soil with leak detection equipment between the liners and under lower liner
- Shall meet:
  - At least 30 mils (0.030 inches) thick
  - Impervious to hydrocarbons, salts, acidic and alkaline solutions
  - Resistant to UV light
- At any point where fluid enters pit, liner must be protected from fluid force and mechanical damage

$F = 1.0 - 1.7 \times 10^{-5} * z$

Pond Size

- Start with the PenPan equation to get evaporation rate

$$E_0 = \left(0.015 - 0.00042T_m + z * 10^{-6}\right)\left(0.8 * R_s - 40\right) + 2.5 * F * u\left(T_m - T_D\right)$$

- The terms of this equation are:
  - E_0 = Evaporation rate (mm/day)
  - F = A factor that accounts for the change in air density with changes in elevation $F = 1.0 - 1.7 \times 10^{-5} * z$
  - R_s = Solar irradiance (W/m^2) $R_s = 10.8 * T_m + 153$
  - T_D = Mean dew point temperature (°C)
  - T_m = Mean daily temperature (°C)
  - u = Wind velocity at 2 meters above surface (m/s)
  - z = Elevation above sea level (m)

Pond Size

- Go to NOAA and get climatological data
  - It includes average temp, rainfall, dew points, etc. for every month
  - It also includes minimums and maximums for each term
- With NOAA data and the PenPan equation you can estimate
  - average net evaporation (i.e., evaporation minus precipitation),
  - evaporation in the worst year (min temps and max precipitation)
  - evaporation in the best year (max temp, min precipitation)
- Determine the pond size needed for the expected inflow during the worst months of the worst year
- Add a safety factor for a worst of the worst year

Page 1 of NOAA Data

NORMALS, MEANS, AND EXTREMES

GRAND JUNCTION, CO (GJT)

LATITUDE: 39° 08' 03" N LONGITUDE: 108° 32' 15" W ELEVATION (FT): GRND: 4823 BARO: 4826 TIME ZONE: MOUNTAIN (UTC + 7) WBAN: 23066

	ELEMENT	POR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
TEMPERATURE °F	NORMAL DAILY MAXIMUM	30	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	MEAN DAILY MAXIMUM	56	36.6	44.8	54.8	65.1	75.9	87.4	93.3	89.9	81.0	67.8	50.5	39.2	65.5
	HIGHEST DAILY MAXIMUM	57	60	68	81	89	101	105	105	103	100	88	75	64	105
	YEAR OF OCCURRENCE		1971	1986	1971	1992	2000	1990	2003	2000	1995	2003	1977	1980	JUL 2003
	MEAN OF EXTREME MAXS.	56	49.4	58.4	70.7	80.5	89.7	98.5	101.0	98.3	92.6	81.6	64.9	52.6	78.2
	NORMAL DAILY MINIMUM	30	15.6	22.7	31.0	37.5	46.4	55.3	61.4	59.7	50.4	38.6	26.3	17.5	38.5
	MEAN DAILY MINIMUM	56	16.5	23.2	30.8	38.7	48.0	57.0	63.9	61.8	52.8	41.1	28.5	19.1	40.1
	LOWEST DAILY MINIMUM	57	-23	-18	5	11	26	34	44	43	29	18	-2	-17	-23
	YEAR OF OCCURRENCE		1963	1989	1948	1975	2002	1976	1993	1968	1978	1993	1976	1990	JAN 1963
	MEAN OF EXTREME MINS.	56	1.8	9.0	17.5	25.5	34.5	44.5	55.6	53.2	40.2	28.2	15.1	5.5	27.5
	NORMAL DRY BULB	30	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	MEAN DRY BULB	56	26.6	33.9	42.7	51.9	61.8	72.3	78.6	75.8	67.0	54.4	39.6	29.0	52.8
	MEAN WET BULB	20	24.3	29.9	36.2	41.2	48.0	53.3	58.7	58.7	51.4	42.7	32.8	25.4	41.9
	MEAN DEW POINT	20	18.4	22.2	24.9	27.6	32.7	35.0	43.6	45.8	37.8	30.0	24.3	19.1	30.1
	NORMAL NO. DAYS WITH:														
	MAXIMUM ≥ 90°	30	0.0	0.0	0.0	0.0	1.1	13.4	24.0	19.8	4.3	0.0	0.0	0.0	64.4
	MAXIMUM ≤ 32°	30	10.0	2.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	6.0	19.2
	MINIMUM ≤ 32°	30	30.1	24.4	15.7	6.1	0.4	0.0	0.0	0.0	0.2	3.5	21.9	29.8	132.1
	MINIMUM ≤ 0°	30	3.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*	1.0	4.7
H/C	NORMAL HEATING DEG. DAYS	30	1194	860	656	409	178	33	12	3	73	367	792	1125	5700
	NORMAL COOLING DEG. DAYS	30	0	0	0	2	44	232	394	318	100	1	0	0	1091
RH	NORMAL (PERCENT)	30	72	64	52	44	40	30	34	38	40	47	60	69	49
	HOUR 05 LST	30	79	74	65	59	58	44	49	55	54	60	71	78	62
	HOUR 11 LST	30	65	55	43	36	32	24	29	32	34	39	51	61	42
	HOUR 17 LST	30	63	49	36	29	26	19	22	24	27	33	48	59	36
	HOUR 23 LST	30	77	69	58	49	44	32	37	41	43	52	66	74	54
S	PERCENT POSSIBLE SUNSHINE	34	61	65	65	70	73	81	79	77	78	74	65	61	71
W/O	MEAN NO. DAYS WITH:														
	HEAVY FOG(VISBY≤1/4 MI)	58	2.7	1.8	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.2	0.8	2.0	8.2
	THUNDERSTORMS	58	0.1	0.3	0.8	2.1	4.7	4.8	7.4	8.2	5.3	1.5	0.4	0.1	35.7
CLOUDINESS	MEAN:														
	SUNRISE-SUNSET (OKTAS)	50	4.9	5.0	5.0	4.8	4.4	3.2	3.3	3.4	2.9	3.4	4.2	4.5	4.1
	MIDNIGHT-MIDNIGHT (OKTAS)	32	4.6	4.4	4.6	4.3	4.0	3.0	3.2	3.3	2.7	3.2	4.0	4.3	3.8
	MEAN NO. DAYS WITH:														
	CLEAR	51	9.1	7.6	8.0	7.9	9.6	14.9	13.7	13.3	16.0	14.7	10.4	9.6	134.6
	PARTLY CLOUDY	51	7.0	7.4	8.6	9.4	10.7	9.4	11.2	11.3	8.1	7.6	7.4	7.6	105.6
	CLOUDY	51	14.8	13.3	14.4	12.7	10.7	5.7	5.5	6.3	5.3	8.0	11.6	13.1	121.2
PR	MEAN STATION PRESSURE(IN)	30	25.20	25.19	25.10	25.10	25.10	25.10	25.20	25.20	25.20	25.20	25.21	25.30	25.17
	MEAN SEA-LEVEL PRES. (IN)	19	30.23	30.10	29.97	29.89	29.83	29.81	29.87	29.92	29.94	30.03	30.13	30.22	29.99
WINDS	MEAN SPEED (MPH)	57	5.8	6.7	8.4	9.4	9.6	9.8	9.6	9.3	9.2	8.1	6.9	6.1	8.2
	PREVAIL.DIR(TENS OF DEGS)														
	MAXIMUM 2-MINUTE:														
	SPEED (MPH)	7	36	41	53	49	45	48	45	45	40	44	37	35	53
	DIR. (TENS OF DEGS)		25	20	34	27	20	30	35	33	04	21	13	31	34
	YEAR OF OCCURRENCE		1999	1998	2001	2000	2002	1999	2002	2002	2002	1997	1997	2000	MAR 2001
	MAXIMUM 5-SECOND:														
	SPEED (MPH)	7	45	55	60	60	59	55	68	64	48	54	45	43	68
	DIR. (TENS OF DEGS)		23	19	34	16	19	31	36	26	30	22	25	31	36
	YEAR OF OCCURRENCE		1999	1998	2001	2003	2002	1999	2002	1995	2002	1997	2003	2000	JUL 2002
PRECIPITATION	NORMAL (IN)	30	0.60	0.50	1.00	0.86	0.98	0.41	0.66	0.84	0.81	1.00	0.71	0.52	8.99
	MAXIMUM MONTHLY (IN)	57	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	YEAR OF OCCURRENCE		1957	1948	1979	1997	1995	1969	1983	1957	1997	1972	1983	1951	AUG 1957
	MINIMUM MONTHLY (IN)	57	T	T	0.02	0.06	T	T	0.01	0.04		0.00		0.01	0.00
	YEAR OF OCCURRENCE		1961	1972	1972	1958	1970	1980	1994	1956		1952		1976	OCT 1952
	MAXIMUM IN 24 HOURS (IN)	57	0.72	0.88	1.85	1.33	1.13	1.57	1.42	1.68	1.35	1.24	0.83	1.16	1.68
	YEAR OF OCCURRENCE		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	NORMAL NO. DAYS WITH:														
	PRECIPITATION ≥ 0.01	30	6.6	5.4	7.8	7.1	7.1	4.0	5.5	6.3	6.5	6.2	6.0	5.6	74.1
	PRECIPITATION ≥ 1.00	30	0.0	0.0	*	0.0	0.0	0.0	*	0.1	0.0	0.0	0.0	0.0	0.1
SNOWFALL	NORMAL (IN)	30	6.0	3.2	2.8	1.5	0.2	0.0	0.0	0.0	0.0	0.7	2.3	4.8	21.5
	MAXIMUM MONTHLY (IN)	57	33.7	18.4	14.9	14.3	5.0	T	T	T	3.1	6.1	12.1	19.0	33.7
	YEAR OF OCCURRENCE		1957	1948	1948	1975	1979	1997	2001	1993	1965	1975	1964	1983	JAN 1957
	MAXIMUM IN 24 HOURS (IN)	57	9.1	9.0	6.1	8.9	5.0	T	T	T	3.1	6.1	8.4	6.3	9.1
	YEAR OF OCCURRENCE		1957	1989	1948	1975	1979	1997	2001	1993	1965	1975	1954	1998	JAN 1957
	MAXIMUM SNOW DEPTH (IN)	55	16	12	8	7	1	0	0	0	2	5	8	11	16
	YEAR OF OCCURRENCE		1957	1957	1960	1975	1979				1965	1975	1954	1983	JAN 1957
	NORMAL NO. DAYS WITH:														
	SNOWFALL ≥ 1.0	30	2.2	1.0	0.9	0.5	0.1	0.0	0.0	0.0	0.0	0.2	0.8	1.8	7.5

published by: NCDC Asheville, NC 3

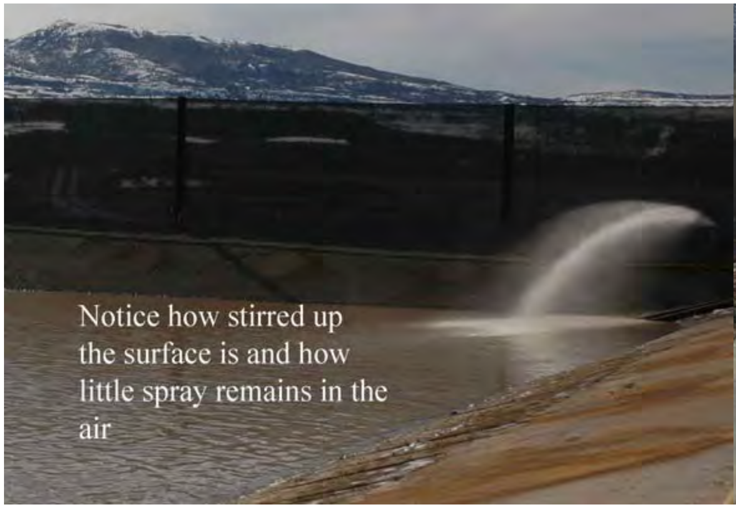
Extra Considerations

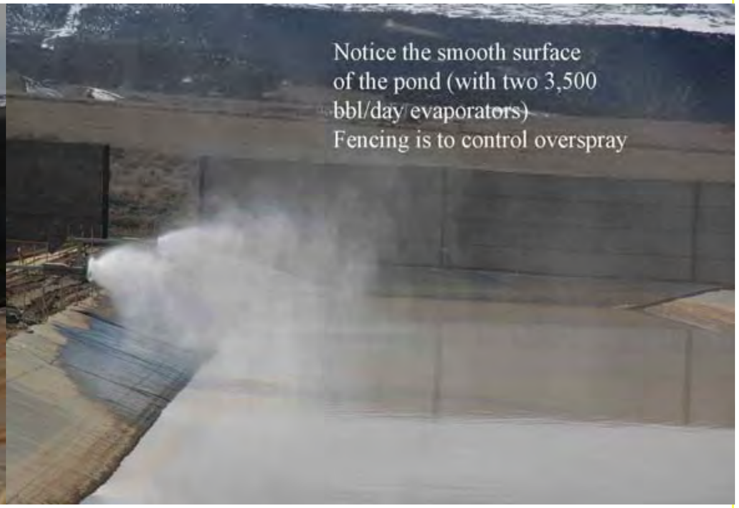
- For 10,000 TDS water
  - Every barrel evaporated will leave 3.5 lb (0.03 ft^3) of solids in the pond
  - When the pond fills up with solids it will have to be drained to muck out
- Bird netting will reduce evaporation rate
- Properly designed spray heads will improve evaporation rate
- My preference is to design two ponds, each sized for full expected inflow and average conditions
  - Flow into one pond
  - Suck out of inflow pond and spray over other pond
  - When pond fills with solids, turn sprayer over inflow pond and muck out other pond
- Aeration equipment may be needed to control odors

Spray Heads

- The best information on evaporation from sprayers comes from people doing irrigation
  - They avoid sprayers that break water drops up very small
  - They use sprayers that put out large drops
  - With large drops, evaporation is a surface function
  - With small drops, evaporation is a volume function
- For evaporation ponds it is good to use spray heads that cut the drops to less than 50 microns
  - Increases buoyancy so drops stay in the air longer
  - Allows bulk temperature to participate in evaporation
  - Overspray becomes a larger issue

Spray Options





- Drop diameter about 200 microns

- Drop diameter about 25 microns

Bottom Line on Pond Size

- Bird Netting cuts evaporation
- Wind fencing cuts evaporation
- Aerators increase evaporation at moderate and high ambient temperatures
- Well-designed spray heads significantly increase evaporation in all temperatures
- The net result is probably close to natural evaporation from an uncovered pond in an "average" year

Pond Sizing Example

- Pond in Farmington, expected inflow 750 bbl/day
- Net evaporation rates:
  - 0.31 inches/day minimum
  - 2.01 inches/day average
  - 4.85 inches/day maximum
- Expected inflow divided by average evaporation = 0.58 acres
- Design settled on two ponds each 224 ft X 112 ft (total 1.16 acres) with two 1,000 bbl/day spray heads that can be rotated between ponds
- Depth 8 ft (for 4.6 acre-ft per pond, 9.2 acre-ft total)
  - 3 ft of freeboard (minimum allowed in many jurisdictions)
  - 2 ft of reserve room (9,000 bbl in each pond)
  - 3 ft for solids accumulation (3 years at 15,000 mg/L TDS)

Beneficial Use Challenges

In many Western states water rights law can be extremely complicated and contentious. Operators may be reluctant to pursue beneficial uses because once they have made the investment to clean and use the water, their rights may be challenged.

Even if the challenge is unsuccessful, the cost and uncertainty associated with litigation may make the pursuit of beneficial produced-water use unattractive. Another legal concern is the potential for unknown future liability. While there are no known problems with using treated produced water, the specter of liability issues arising in the future still looms. Other industries have faced huge liabilities from products once thought to be benign. In addition, the possibility exists for lawsuits to be filed alleging problems where none exist. Whether these fears are founded or not, these are very real concerns that limit the beneficial uses of produced water.

National Energy Technology Laboratory, Program Facts

Beneficial Use Risk Example

- Lawsuit *Vance v. State of Colorado*
- Plaintiff sued the State claiming:
  - In situ water must be removed from well before CBM can be produced
  - Therefore, all CBM water production is “beneficial use” instead of a waste product
  - Plaintiff won
- Therefore:
  - CBM wells in Colorado now must be permitted as both gas wells and water wells
  - CBM operators are required to acquire (purchase) water rights
  - It is unclear whether this will extend to requiring royalty payments on produced water or not, but additional lawsuits are expected

Beneficial Use

- Reuse
- Treatment
- Surface Discharge to rivers
- Irrigation
- Stock/wildlife watering
- New uses

Reuse

- Produced water can be used in Operations
  - Drilling fluids
  - Frac water
  - Hydrotest water
  - Dust control on roads
- Often permits are required before you can reuse produced water (and it can sometimes be difficult to find who to ask)

Treatment

- Most CBM and Shale Gas water must be treated before it is useable for most beneficial use options
- Reverse Osmosis (RO) is the most common treatment method used in other industries
  - Can concentrate solids into 30-40% of volume (i.e., 100 bbl of 10,000 TDS water can become 70 bbl of 200 TDS water and 30 bbl of 32,800 TDS concentrate
  - The concentrate is typically disposed of in a Class II well, but an evaporation pond can be used
  - Has failed repeatedly in Oil & Gas due to complex filtering requirements

Treatment

- Distilling
  - Water is boiled and the steam is condensed
  - Can concentrate further than RO
  - It takes a lot of energy, manpower, and capital
  - It only makes economic sense if the steam can be used to do useful work
- Manmade Wetlands
  - Can be an effective way to purify a large volume of water
  - Be sure you understand all of the ramifications prior to starting
  - Can create an obligation to maintain the wetlands in perpetuity

Treatment
Freeze/Thaw Evaporation

- “Purer” water will freeze before less pure water
- Over time the ice on a pond will be nearly pure
- The rub is how to remove the ice to someplace where it won’t recontaminate
- Amoco did a study on this in 1996-97 and it works well in the San Juan Basin in winter (8,000 bbl of 12,800 TDS yielded 6,400 bbl of 1,000 TDS and 1,600 bbl of 44,900 TDS in 60 days of operation)

Surface Discharge

- The Clean Water Act requires any discharge that can reach surface waters to have an NPDES permit
  - Permits are either issued by EPA or by the state at the state's election
  - EPA promulgated Effluent Limitation Guidelines for certain categories of discharge, but not for CBM.
- Treated water may still kill fish/vegetation because it has no oxygen or aerobic bacteria and is at a different temperature than the river
- Additional tests such as "fish kill" may be required on water that otherwise meets guidelines
- This is often an expensive option, but in some locations it is very reasonable due to water quality
- RO and surface discharge can cost $3-5/bbl

Irrigation

TDS	Irrigation Comments
<400	No restrictions to crop growth
400-1,900	Slight restrictions to crop growth
>1,900	Severe restrictions to crop growth

- Example water quality:
  - Barnett Shale – 150,000 mg/L
  - San Juan Basin Fruitland – 10,000 mg/L
  - Powder River Coal - 1,000 mg/L
  - Antrim Shale – 1,200 mg/L

Irrigation

- Sodium Absorption Ratio (SAR) is defined as:

$$SAR = \frac{\left[Na^{+}\right]}{\sqrt{\frac{1}{2}\left(\left[Ca^{2+}\right]+\left[Mg^{2+}\right]\right)}}$$

SAR	Irrigation Comments
<3	No restrictions to crop growth
3-12	Some crops can tolerate the sodium well, some will be stressed and reduce output, some will die
>12	Serious effects on soils and vegetation

- San Juan Fruitland water tends to be around 28

Livestock/Wildlife Watering

TDS (mg/L)	Stock Watering Comments
<1,000	Excellent for all stock
1,000-2,999	Very Satisfactory, may cause mild diarrhea in animals until acclimated
3,000-4,999	Satisfactory, may be refused by animals not used to it
5,000-6,999	Avoid use for pregnant or lactating animals
7,000-10,000	Avoid use with very young or very old stock
>10,000	Unsatisfactory for all classes of animal

New Uses

- Large-scale industrial cooling
- Small-scale industrial cooling
  - Swamp cooler
  - Water cooled equipment
- Marginal crop irrigation

Power Plant Cooling

- A San Juan County power plant evaporates 500,000 bbl/day (64 acre-ft/day or 15,000 gpm) of river water in cooling towers
- They have conducted feasibility studies of replacing 50,000 bbl/day with produced water.
- The project is still under consideration, but some enthusiasm was dampened when the 7 year drought ended

Small Scale Cooling

- Swamp coolers have proven very effective in arid regions
- A swamp cooler for a compressor has real potential
  - Air is cooled to about 20°F below ambient
  - Air is saturated with water vapor (further increasing heat transfer)
  - Can add significant hp for compression
- Biggest concern is that solids might get onto cooling surfaces and foul them
- Mist pads do clog quickly, but choice of pads may help that

Water Cooling

- Replacing the standard air cooler on a compressor with a plate and tube heat exchanger can transfer a large quantity of heat into an evaporation pond
- This heat transfer will improve the performance of the compressor
- The heat in the pond will accelerate evaporation
- This will work,
  - There are many thousands of water-cooled compressors in other places
  - The idea is foreign to Oil & Gas and is meeting a lot of resistance

Irrigation of Marginal Crops

- One operator found a tree (Chinchilla Eucalyptus) that can tolerate high TDS water
- Irrigating 1.2 million trees uses 80,000 bbl/day (about 3 gal/day/tree)
- Trees mature into a commercial hardwood in 12 years
- As the field-development proceeds, additional plots can be planted to handle that water

Produced Water Conclusions

- Produced water is a large and growing problem
- All solutions are expensive and all have drawbacks:
  - Deep-well injection requires considerable manpower and wells don't have a predictable life
  - Evaporation ponds require a lot of space and overspray of concentrated solids can be a problem
  - Beneficial use options can have unintended consequences
- Any option should be reviewed by an environmental/ regulatory specialist early in the process—the rules, laws, and regulations are very complex and often contradictory.

Thank you for your attention.
Additional information can be found at
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1. ASME—American Society of Mechanical Engineers.
2. atm—Atmosphere. This pressure unit is a multiple of atmospheric pressure, but since atmospheric pressure varies with altitude, typically "atm" is used interchangeably with "bar" or 14.5 psia.
3. Autoignition Temperature—the temperature where a flammable mixture will spontaneously ignite (also called "Dieseling"). For methane at atmospheric pressure Autoignition temperature is around 1,000°F (538C), values for elevated pressure are not standardized and researchers seem to agree that this value drops rapidly at elevated pressure but consistent values for the magnitude of the change are non-existent.
4. bbl—U.S. Oil Field Barrel (42 U.S. Gallons or 0.1589 m^3)
5. BHP—bottom hole pressure
6. BHT—bottom hole temperature
7. BTU—British Thermal Units. In the U.S. BTU is defined as the amount of heat required to raise the temperature of 1 lbm of water from 59°F to 60°F. One U.S. BTU is equivalent to about 1054.7 Joule. The exact value depends on the temperature range where the experiment started. The Canadian standard is to start at 60°F and that results in 1054.8 Joule. If you start at 39°F then one BTU is 1059.67 Joule. If you average the heat content from the freezing point of water to the boiling point of water you get 1055.87 Joule. It is often convenient to define "thousands of BTU" as "MBTU" and "millions of BTU" as "MMBTU".
8. CBM—CoalBed Methane.
9. CSG—CoalSeam Gas (used interchangeably with CBM)
10. Cum—cumulative production.
11. dP—Differential Pressure.
12. EFM or EGM—Electronic Flow Measurement or Electronic Gas Measurement. EFM or EGM refers to replacing an analog pressure signal that is fed into a pen-and-ink chart with pressure transducers feeding electronic recording devices.
13. ESP—Electric Submersible Pump.
14. FBHP—Flowing Bottom Hole Pressure.
15. FRC—Fire Resistant Clothing. This used to stand for "Fire Retardant Clothing" but evolution in the language (along with litigation) has changed most manufacturers to "resistant" instead of "retardant".
16. FWP—Flowing Wellhead Pressure.
17. GIP—Gas in Place. Original Gas In Place (see OGIP) less cumulative production.
18. GPS—Global Positioning System.
19. HDPE—High Density Polyethylene. Material used in low pressure pipelines.
20. hp—Horsepower. One hp is equivalent to 0.7457 kW
21. ID—Inside Diameter.
22. ISO—International Organization for Standardization
23. lbf—Pounds force. This term has replaced the "Slug" in the conversion from mass to weight or other force. On earth 1 lbm weighs 1 lbf. It is currently popular to define a metric force term used in place of the "Newton" of kgf which is 2.2 lbf.
24. lbm—Pounds mass (2.2 lbm is the same mass as a metric kg)
25. LEL or LFL—Lower Explosive Limit or Lower Flammable Limit. The minimum concentration of a flammable gas in air that will burn. LEL for methane in air is 5% at

STP (see "STP" in this glossary, higher pressures or higher temperatures decrease this value).

26. LOE—Lease Operating Expense
27. Mach—a dimensionless parameter that expresses speed in terms of a multiple of the speed of sound. Occasionally it is abbreviated as "M", but this causes confusion in Oil & Gas where "M" is the Roman numeral for "1,000" in traditional oil field units and "million" in metric units.
28. MAWP or MAOP—Maximum Allowable Working Pressure or Maximum Allowable Operating Pressure. The pressure of a pressure-containing system that the designer selected as the maximum pressure that the system has been designed to withstand.
29. mg/L—milligram per liter, a measure of liquid contamination. This value also works out to ppm so a 10,000 mg/L TDS value is also a 10,000 ppm TDS value
30. MIC—Microbiologically Influenced Corrosion. This is a kind of corrosion caused by the biological activity of microbes.
31. NPSH—Net Positive Suction Head.
32. NPV—Net Present Value, an economic term that brings all future costs back to time zero at a specified interest rate to allow projects to be compared on a consistent basis.
33. OCD—New Mexico *Oil Conservation Division* responsible for regulating Oil & Gas operations within the state.
34. OD—Outside Diameter.
35. OGIP—Original Gas in Place. The total gas that can be contacted by a wellbore over infinite time.
36. OSHA—U.S. *Occupational Safety and Health Administration*. OSHA is responsible for promulgating regulations to protect health and safety of industrial workers and for enforcing those regulations. Roughly equivalent to the *Health and Safety Executive* in the U.K, *Occupational Health and Safety* (OH&S) in Canada, India, and Australia.
37. P&A—Plug and Abandon (used for Oil & Gas wells)
38. PCP—Progressing Cavity Pump. A downhole positive displacement pump.
39. Permeability—A measure of the ability of a porous material to transmit fluids. Common oil field units are "Darcy", mili Darcy (Darcy/1000, symbol mD), micro Darcy (mD/1000, symbol μD), nano Darcy (μD/1000), or pico Darcy (μD/1000000).
40. pH—a measure of a substance's free hydrogen. pH is a log scale with 7.0 being neutral. Values less than 7.0 are acidic (i.e. a pH of 6.0 is 10 times more acidic than 7.0). Values greater than 7.0 are basic or alkaline (i.e., pH of 9.0 is 100 times more alkaline than 7.0)
41. POD—Plan of Depletion. This term is used anytime you develop a systematic methodology to develop (or deplete) an oil or gas field. In this class, "The POD" is a project described in SPE 84509.
42. ppb—Parts per billion
43. ppm—Parts per million
44. Pressure—A thermodynamic parameter representing a force applied over an area
    - Atmospheric pressure—the pressure applied locally by the atmospheric overburden. Values range from around 14.73 psia (101.6 kPa(a), or 1.016 bar(a)) at sea level to values around 10.76 psia at 8,500 ft elevation (74.2 kPA(a) or 0.742 bar(a))
    - psig—Pounds (force) per square inch gauge. The pressure above atmospheric that reads on a pressure gauge. Units are psig, kPa, or bar(g). Gauge pressure is never used for scientific calculations, but many industries (such as "Pressure Vessel" and

"Pressure Safety Valves") have developed empirical equations that use gauge pressures. Using gauge pressure for the empirical equations in these industries is accepted practice and yields results that are compatible with others doing the same calculations.

- psia—Pounds (force) per square inch absolute—the sum of the local atmospheric pressure and the indicated gauge pressure. Absolute pressure is used in all scientific calculations and most engineering calculations except as noted above.
- psid—Pounds (force) per square inch differential. The pressure difference between two points. This is referred to as "psid" or "dP"

45. PSV or PRV—Pressure Safety Valve or Pressure Relief Valve
46. QA/QC—Quality Assurance/Quality Control. This term is used all over the world, but is rarely defined and it means whatever the speaker wants it to mean.
47. Reynolds Number—a dimensionless parameter that relates friction forces to momentum forces.
48. Reservoir Parameters—in "The POD" case study, the undefined parameters are:
    - A Drainage Area (ft^2)
    - b Langmuir shape factor (1/psi)
    - ϕ_0 Reservoir porosity at time zero (void fraction of total volume)
    - k Permeability (mili Darcy or mD)
    - h Pay Thickness (ft)
    - V_m Gas Content (SCF/ton, see "SCF" under "Volume" below)
49. RH—Relative Humidity. Expressed as a percentage, this is the amount of water vapor in a gas stream divided by the theoretical maximum water vapor that the gas can hold.
50. ROW—Right Of Way. A fiscal right to access physical property. ROW is generally purchased from the property owner.
51. San Juan Basin (SJB) CBM Types—the San Juan Basin has three distinctly different types of CBM production
    - Type I—also known as "Fairway", this is source of the lion's share of CBM production from the San Juan Basin. It is represented by about 550 wells in the center of the field, these wells make very large gas rates, fairly small water rates, and significant CO_2 production.
    - Type II—also known as "Colorado Type", this area is north of the Fairway and is represented by an increasing number of wells (currently over 3,000); these wells make fairly large gas rates, very high water rates, much less CO_2 than Fairway wells.
    - Type III—this area is south of the Fairway and is represented by a slowly increasing number of wells (currently over 1,000); these wells make very small gas rates, tend to make very little water, and nearly zero CO_2. There is development activity in the Type III, but it is fairly slow.
52. SDR—Standard Dimension Ratio. HDPE is sold by "SDR" number, you can purchase SDR-13.5, SDR-11, SDR-7, etc. The number after the SDR is the ratio of the pipe Outside Diameter (OD) to the wall thickness. HDPE comes in OD's that are the same as steel (i.e., 8-inch pipe has an OD of 8.625 inches). Using these relationships, 8-inch SDR-7 would have a wall thickness of 1.232 inches (8.625/7). The Inside Diameter (ID) of that pipe would be OD-2*(OD/SDR) or OD*(1-2/SDR)=6.161 inches for the example.
53. SG—Specific Gravity. This is the ratio of the density of a fluid to a reference fluid. For gases the reference fluid is air at STP and for liquids it is water at 60°F.

54. SI—le Système international d'unitès or the "International System of Units" also called colloquially "The Metric System".
55. SMYS—Specified Minimum Yield Stress. The manufacturer's guaranteed minimum stress that a material can withstand before it will begin to yield (i.e., mechanically deform under stress). This number is always well under the actual yield point (generally material will begin to yield around 125% of SMYS), but the safety factor is unreliable and SMYS must be used in any stress calculations. Companies and regulators have their own ideas about SMYS and often allowable stresses will be capped at 20-40% of SMYS by fiat.
56. STP—Standard Temperature and Pressure. There is not really a standard, and the most common "standard" pressures referenced in U.S. regulations and contracts are 14.73 psia, 14.696 psia, or 15.025 psia. STP in the SI unit system is also subject to regulatory and contractual manipulation, but the most common value is 101.6 kPa. Temperature in U.S. customary units is most often given as 60°F. In SI, the most common values I see are 0C and 15C, but there are others used.
57. TDS—Total Dissolved Solids
58. UEL or UFL—Upper Explosive Limit or Upper Flammable Limit. The maximum concentration of a flammable gas in air that will burn (adding more of the flammable gas will make the mixture "too rich to burn"). UEL for methane in air is 15% at STP (higher pressures or higher temperatures increase this value).
59. UIC—Underground Injection Control. A well that is intended for water injection.
60. VI—Volume Index. This is a design parameter of a screw compressor and it is the ratio of the inlet volume to the outlet volume. VI can be used to determine the optimum compressor discharge pressure for a given suction pressure by: $P_{disch}=P_{suct}VI^k$ where "k" is the ratio of specific heat at constant pressure over specific heat at constant volume and is usually a number between 1.28 (generic natural gas) and 1.43 (CO_2). Methane is 1.310 and air is 1.299. Pressures are in absolute units. For a common VI of 3.0, a suction pressure of 10 psig at 8,500 ft (10.76 psia) in natural gas would give you an optimum discharge pressure of $20.76*3^{1.28}$=84.76 psia=74.0 psig. Other discharge pressures are achievable, but at the cost of overall system efficiency (and fuel consumption)
61. Volume Units (in traditional oil field units the value "M" stands for the Roman Numeral "Thousand", and "MM" is "Thousand Thousand" or Million)
    - Energy Conversion—often, attempts will be made to add volumes from different fields by assuming that the specific energy is 1,000 BTU/ft^3. This allows the (incorrect, but often close enough) approximation of 1 MCF ≈ 1MMBTU. Some countries assume the energy content is 37.259 kJ/m^3 which conveniently ties an approximate energy content to a standard oil field unit.
    - SCF—Standard Cubic Feet or ft^3. Approximately 1.0 kJ (kilo Joule)
    - MCF—Thousands of Standard Cubic Feet (SCF, see STP) or ft^3 * 1000. Approximately 1.0 MJ (mega Joule)
    - MMCF—Millions of SCF or MCF * 1000. Approximately 1.0 GJ (giga Joule)
    - BCF—Billions of SCF or MMCF * 1000. Approximately 1.0 TJ (tera Joule)
    - TCF—Trillions of SCF or BCF * 1000. Approximately 1.0 PJ (peta Joule)
62. WI—Working Interest. The ownership share that is obligated to participate in expenses and capital expenditure.