API Gas Lift Design

- API RP 11V6: Recommended Practice for Design of Continuous Flow Gas Lift Installations — Using Injection Pressure Operated Valves

- By Sid Smith
INTRODUCTIONS

PLEASE TELL US THE FOLLOWING INFORMATION ABOUT YOURSELF:

Name
Work Location
Job (role)
Number of Years Experience
Gas Lift Background
  - hands on
  - previous training
Design Outline

- Introduction (20)
- General Design (20)
- Inflow & Outflow & ……Tubing (45)
- Facilities (15)

- Gas Inj. Pressure (15)
- Mandrels & Valves (30)
- Temperature (15)
- Gas Passage (15)

- Design Methods:
  - Constant Rate (30)
  - Variable Rate (30)
  - Intermittent (15)
  - Equilibrium Curve (45)

- API Example # 1 (45)
- API Example # 2 (45)
- API Example # 3 (45)

- Summary (15)
0. Introduction : API RP 11L6

• RP to provide guidelines, procedures and recommendations. See other API RP’s. (Also ISO documents)
• 1 Scope: Guidelines for continuous flow using injection pressure valves
• 2 Intent: Maximize production and Minimize costs
• 3 Definitions
• 4 General Design Considerations
Continuous Intermittent

S.V.
Typical continuous flow gas lift installation

Injection gas into wing valve and then down the casing-tubing annulus.

Well equipped with tubing, side pocket mandrels, wireline retrievable gas lift valves and a single production packer located just above the producing zone.

Note: Upper gas lift valves closed and gas enters gas lift valve near bottom.
4.1 General

• Complete system!
• Combination of concepts and experience
• Continuous flow gas lift has advantages and limitations.
Continuous GL Strengths

- Flexible lift capacity
- Handles sand OK
- Deviated holes OK
- Permits wire line op
- Tubing fully open
- High GLR beneficial
- Low well R&M
- Low surface profile
- Compatible /SSSV’s
- Permits sounding
- Easy BHP surveys
- Permits PL surveys
- Dual lift feasible
- Tolerates bad design
Continuous GL Weakness

- High back pressure imposed
- Needs uninterrupted high pressure gas
- Compressor expenses often high
- Heading problem with low rates
- Potential gas freezing & hydrate problem
- Increased friction w/low gravity crude
- Valve interference & high inj. point
- Corrosion, Scale, & paraffin
- Efficient dual lift difficult
- Requires excellent data for good design
GL Design Guidelines

- Inject gas as deep as feasible
- Conserve injection pressure
- Ensure upper valves stay closed
- Be able to work down to bottom
- Check for ample gas passage
- Plan for changes in rate
- Avoid heading conditions
- Minimize costs & Maximize rates
Types of Installations

- Conventional (Tubing): Inject gas down annulus & produce up tubing.
- Annulus: Inject gas down tubing & produce up annulus
- Special: Slim-hole, Dual, Concentric, etc
- Open installation: No packer or SV
- Semi-closed: Packer but no SV
How do we inject gas into a well in the first place?

This process of replacing the completion brine with injection gas is called *unloading* and it is done only once after the initial completion and after any well servicing where the casing to tubing annulus is filled with liquid.
IPV UNLOADING

Gas is injected into the casing - tubing annulus and the pressure pushes the brine through each of the gas lift valves which are wide open. This is a particularly dangerous time for the valves. If the differential is too high the liquid velocity can be enough to cut the valve seat. Then, the valve will not be able to close and the design will not work.
IPV UNLOADING

Operators must allow sufficient time for unloading. The rule from API RP 11V5 is to take 10 minutes for each 50 psi increase in casing pressure up to 400 psig. After that point a 100 psi increase every 10 minutes is acceptable until gas injects into the tubing. To get up to 1000 psig should require at least 2 hr, 20 min. A good practice is to assign an operator to the well for the duration of this operation.

Brine may go out the tubing or into the reservoir.
IPV UNLOADING

Once the brine level is below the top valve, gas will enter the tubing and begin lifting the well. If the tubing pressure is less than the SBHP the reservoir will begin to contribute. The first production from the reservoir is normally recovered completion brine.
IPV UNLOADING

When the second valve is uncovered, gas will begin to enter the tubing at the second valve.
In the case of IP valves, the injection gas rate into the well at the surface must be regulated to control the gas entry to approximately the design rate of one valve. Since two valves are passing injection gas, the pressure in the casing annulus will fall.

With more gas leaving casing than entering, the injection pressure must fall.
IPV UNLOADING

When the casing pressure falls enough, the top valve will close based on valve mechanics in a good design.
IPV UNLOADING

Since there is still more casing pressure than tubing pressure at the bottom valve and the bottom valve is still open, the injection gas will continue to displace the brine in the annulus until the third valve is uncovered.
IPV UNLOADING

Once again with more gas leaving the casing through two valves, the casing pressure will fall until the second valve closes. Obviously if there were more valves deeper the unloading process would continue.

What would happen if the third valve injected too much gas?
IPV UNLOADING

Valve 1 injecting
Valve 2 injecting, 1 closes
Valve 3 injecting, 2 closes
Valve 4 (orifice) injecting, 3 closes
Start gas to well

Time
4.2 Well Performance (Inflow and Outflow)

Well Productivity: A well’s ability to produce fluids related to a reduction in bottom hole pressure
Inflow: Pseudo-Steady-State-Radial

(After Darcy)

- \( Q_o = C \times k \times h \times (P_r - P_{wf}) \)
- \( Bo \times \mu \times [\ln(Re/Rw) - 0.75 + S + Dq] \)
- \( Q_o = J \times (P_r - P_{wf}) \) or \( J = Q_o / (P_r - P_{wf}) \)
- Where \( J = PI = Productivity Index \)
- Specific \( PI = J / h \)
- \( C = 0.00708 \) bpd \( \) Oilfield Units
- \( 1/C = 141 \)
**Inflow:**
Flow into Well from the Reservoir

- **PI = Productivity Index = J** (in bfpd/psi)
- **Note:** PI for single phase flow
- **PI = Change in Rate / Change in Pressure**
- **PI = Rate / (Pr - Pwf)** in bfpd/psi
- **Rate in bfpd = QI = PI * (Pr - Pwf)**
- **Drawdown = ΔP = (Pr - Pwf) = Rate / PI**
PI Problem # 1B

- **Given:**  
  - $Pr = 2500$ psig (172.4 bar) = $Pb$
  - $Pwf = 1750$ psig (120.7 bar)
  - $Ql = 1500$ BPD (238.5 m$^3$)

- **Find:**  
  - $PI$, $Qmax$, and $Ql$ at 500 psig (34.5 bar) and $Pwf$ if $Ql = 3000$ BPD (476.9 m$^3$)
PI Problem # 1B when Pb= 0

PI = 1500/(2500-1750) = 2 bpd/psi
It is more accurate to describe Well Productivity in terms of:

Multi-phase, radial-flow

This means it handles flow of both liquids AND gas, which changes the curve

This method is called:

Inflow Performance Relationship or IPR
Vogel IPR

Vogel IPR equation:

\[ Q = 1 - 0.2(P_{wf}/P_r) - 0.8(P_{wf}/P_r)^2 \]

Initial slope = -1.8
Inflow: Vogel IPR

- \( \frac{Q_l}{Q_{\text{max}}} = 1 - 0.2 \left( \frac{P_{wf}}{P_r} \right) - 0.8 \left( \frac{P_{wf}}{P_r} \right)^2 \)
- \( \frac{Q_l}{Q_{\text{max}}} = 1 - v \left( \frac{P_{wf}}{P_r} \right) - (1 - v) \left( \frac{P_{wf}}{P_r} \right)^2 \)
- For multiphase flow
- Need well test rate (Ql), Pr & Pwf
- Find pressure ratio: \( \frac{P_{wf}}{P_r} \)
- Find production ratio: \( \frac{Q_l}{Q_{\text{max}}} = (x1) \) from graph
- Calculate Qmax: \( Q_{\text{max}} = \frac{Q_l}{(x1)} \)
- Once Qmax known, find other rates
**IPR Fetkovich:** $Q_o/Q_m = [1 - P_{wf}^2 /P_r^2]^n$

- **n = 1**
- **n > 0.5**
- **n ≤ 1**
- Typically $N = 0.8$

**Initial Slope = -2.0**

**Ratio 1/1000**

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Combination PI & IPR Problem

- **Given:**
  - $P_r = 2800$ psi ; $P_b = 1800$ psi
  - $P_{wf} = 2300$ psi ; $Q_{l1} = 500$ bpd
- **Find:** $Q_b$, $Q_a$, $Q_{max}$ & $Q_{l2} @ P_{wf} = 900$ psig
- **Solution:** Just divide into a PI + IPR problem
For $Pr > Pb$)

$Pr = 2800$, $PI = 1.0$

$Pwf = 2300$

$Pb = 1800$, $Slope = -1.8$

$Q_b$, $Q_a$, $Q_{max}$

$PI + IPR$ Vogel
Now you know how to find the well’s inflow

Use PI for single-phase flow
Use IPR for multi-phase flow
Outflow Introduction

- Flow from perforations to storage tanks
- Requires a good vertical flow correlation
- Also a horizontal flowline correlation
- Learn to use pressure-depth (gradient) curves
- Draw tbg outflow performance curves
Inflow & Outflow Analysis

Flowline: Gradient Curves

Tubing Performance: Gradient Curves

PI or IPR Inflow

Gas Sales

Oil

Tank

STB

Pwf

Pwh

Psep

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Outflow: Multiphase Vertical Flow

- **Empirical Models**
  - Gilbert (CA oil wells)-developed 1940 to 1950 but published in 1954
  - Poettmann & Carpenter (no slip) - 1952
  - Baxendell & Thomas (high rate extension of P&C)-1961
  - Duns & Ros (lab data)-1961
  - Ros & Gray (improved D&R)-1964
  - Hagedorn & Brown (most used--slip?)-1964
  - Orkiszewski (Exxon composite)-1967
  - Beggs & Brill (incline flow)--1973
  - MMSM (Moreland-Mobil-Shell-Method)-1976
- **Mechanistic Models**
  - Aziz, Grover & Fogarasi-1972
  - OLGA –Norwegian- 1986
  - Ansari. Et al. – 1990
  - Choksi, Schmidt & Doty-1996
  - Brill, et al-ongoing
AGL_GRAD: GAS LIFT GRADIENT CURVES

DEPTH (ft) or (meters)

PRESSURE (psi) or (bar)

GLR=250(44.5) 500(89) 750(134) 1000(178) 1250(223) 1500(267)

0 GLR

50% cut

g = 0.42

GLR=250(44.5) → 500(89) → 750(134) → 1000(178) → 1250(223) → 1500(267)
Flow Regimes

Mist

Annular

Slug or Churn (Surface)

Plug or Piston

Bubble(y)

Single Phase Flow

Gas with oil droplets

Oil up tubing wall with gas at higher velocity up center

Bubbles connect and expand

Bubbles grow

Slightly below BP

Above Bubble Point

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Water Cut Effect on Gradient

As per ROS with Shell

\[ \gamma_o \] (per ROS with Shell)

\[ \gamma_w \] (0.46±)

Gradient
psi/ft

0.42 psi/ft

(Lab tests)

Water Cut (%)

0 35 65 95 100

Gradient
psi/ft

0 35 65 95 100

Water Cut (%)

0 35 65 95 100

(0.38±)

\[ \gamma_o \]
Outflow: Find Pwf: Case 1

- Given: Tubing ID = 1.995 inches, Rate = 800+ bpd
- Cut = 50%+, GOR = 1200, GLR = 600
- Pwh=440 psig, Flow Surf. Temp =100 ‘F
- Well Depth = 5100’,
- BH Temp = 180 ‘F, Water SG = 1.074
- Oil Gravity = 35 ‘API, Gas SG = 0.65
- Static BHP = 2060 psig
- Find Pwf & PI (Find the correct chart)
Gradient = 0.42 psi/ft
Outflow Example

• Case 1: Find $P_{wf} = 1560$ psig from 800 BPD graph

• Calculate $PI = \text{Prod}/\text{Drawdown}$
  
  $$PI = \frac{800}{(2060-1560)} = 1.6 \text{ BPD/psi}$$

• Problem B: Find $P_{wh}$ for a $P_{wf}$ of 1200 psig?
OIL WELL INFLOW & OUTFLOW PERFORMANCE

A 6000 ft flowing well with GLR = 500 and 10% WOR

Production Rate in BPD

Thousands

Pwf

Production Rate in BPD

1.995” 2.441” 2.992”

IPR TBG-1 TBG-2 TBG-3
Outflow: Summary

- Essential to have a good multiphase flow program or gradient charts
- Use well test data & correlation to find Pwf
- Calculate PI or IPR for each well
- Construct tbg perf curves
- Select most profitable tbg size
- Size flowline (Typically same as tubing)
- Minimize Back-pressure and Maximize Rate
Tubing Size Guideline

• In both flowing & gas lift wells, the size of tubing is critical.
• Too large a size results in heading, loading up, and unstable flow.
• Too small a size results in excessive friction and loss of production.
• For best results, use the following:
  1.995” ID-- 200 to 1000 bfpd
  2.441” ID-- 500 to 1500 bfpd
  2.992” ID-- 1000 to 3000 bfpd
  3.958” ID-- > 3000 bfpd
Typical Tubing Curves

Pwh = 100 psig

Rate in 1000 BFPD

TUBING PERFORMANCE (OUTFLOW) CURVES
FOR 10,000 FT WELL W/ 1000 GLR & 50% CUT
4.4 Facilities

• John Martinez
GL Surface Equipment

Testing
Treating
Compression
Dehydration
Distribution
Metering
Miscellaneous

API Manual Chapter 4
API RP 11V7

XX
A Typical Gas Lift System
GL Surface Gas Facilities (49)

• GL is a system type AL; thus, all components must operate efficiently
• Freezing often a problem requiring dehydration, heaters, or methanol injection
• Most important & expensive are the compressors.
• Proper piping & good meters are essential for accurate gas measurement
• Manifolds to distribute the gas & adequate separation/treating are also important
• Plus controls--all are some of our favorite things
GAS LIFT

Simple System
GL Compression

- Reciprocating & Centrifugal
- One -- economical but all eggs in one basket
  Two - most practical; Three -- allows better maintenance; >3 -- too expensive
- Need high reliability (>96 %) [< 1 day/month]
- Low suction Pressure (< 100 psia)
- Adequate discharge pressure!
- Adequate cooling System
- Good maintenance important
Piping, Distribution, Metering

• Provide good operating and maintenance plus minimize investment
• Keep back-pressure low!
• Adequate separation & scrubbing
• Follow good piping practices
• Provide for pigging and traps
• Install gas meters properly (GPSA)
Choke-Regulation Control for Gas Lift Well

Choke

Regulator

Meter Run
4.5 Gas Injection Pressure

- Has a large effect on efficiency and operation of continuous flow GL wells
- Too high a pressure results in needless investment of compressors & lines
- Need enough pressure to inject near bottom (100 ft above perforations) at the planned rate.
- Request suction pressure < 100 psig
- See paper by J.R. Blann, JPT Aug. 84
Benefit from Higher Gas Injection Pressure

Gas Injection Pressures, psig

Depth, (ft)

Pressure (psig)

Equilibrium Curve

x 200 bpd

x 400 bpd

x 500 bpd

x 600 bpd

x 700 bpd

0

Dw

600 1000 1400
Gas Injection Pressure

• For the system, select an injection gas pressure that will permit well gas injection just above the producing zone.
• Install pressure recorder at well and record pressure for a minimum of 24 hours. The pressure variation should be less than 100 psi.
• Use average gas injection pressure recorded at the well for gas lift design. No safety factor should be necessary.
Kick-Off Injection Gas Pressure

• If available, allows deeper lift.
• Normally not practicable in multi-well installations.
References/Bibliography

• Clegg, JD; S.M. Bucaram; N.W. Hein Jr.: Recommendations and Comparisons for Selecting Artificial-Lift Methods,” JPT Dec 93
• Neely, Clegg, Wilson, & Capps: “Selection of Artificial Lift Methods: A Panel Discussion,” SPE 56th Annual Fall Meeting Oct 81
• Winkler & Smith: Camco Gas Lift Manual 1962
• Brown: “The Technology of Artificial Lift Methods”
• API Recommended Practices 11V8
API Mandrel
See API 11V1
And ISO 17078-1

Figure 10—With Guard/Deflector with Orienting Sleeve
API Mandrel Selection Guideline

External Test
Pressure (See Table 9)

Internal Test
Pressure (See Table 9)

S—Fluid Passage from Casing at Undercut. See Fig. 11.
E—Fluid Passage from Casing at Undercut. Exit thru Snorkel. See Fig. 12.
C—Fluid Passage from Tubing at Undercut. Exit thru Snorkel. See Fig. 13.
W—Fluid Passage from Top of Pocket. Exit thru Snorkel. See Fig. 14.

Mandrel Drift Prior to Coating. See Table 8.

Wireline Configuration:
A—Without Guard or Orienting Sleeve. See Fig. 7.
B—Without Guard, with Orienting Sleeve. See Fig. 8.
C—With Guard, without Orienting Sleeve. See Fig. 9.
D—With Guard and Orienting Sleeve. See Fig. 10.

1-1" [2.54 cm] Valve Receptacle
2-1½" [3.81 cm] Valve Receptacle

Material. See Table 7.

Tubing Connection Size. See Table 6.
Gas Lift Mandrels

- **Conventional--Tubing Retrievable**
- **Side-pocket--Wireline Retrievable (Oval or Round)**
- Connections same as tubing (avoid crossovers)
- Material normally 4130
- Valve Receptacle 1” or 1.5”
- With Guard and Orienting Sleeve
- Drift to tbg size; Fluid Passage (S)
- Internal test pressure-to tbg rating
- External test pressure to max collapse case
- Check clearance; Min spacing 90 ft
- Plastic coating (optional--Drift check after coating)
4.7 Gas Lift Valves

- **Conventional (Tubing Retrievable)**
- **Wireline Retrievable** *
- **Valve size**: 0.625”, 1.0” & 1.5” *
- **Closing Force**: Gas Charged*, Spring Loaded; Combination Spring-Gas
- **Valve Type**: Injection Pressure Operated*; Dummy; ...Production Pressure Operated; Pilot; Orifice; Other
- **Flow Configuration**: Type 1*, 2, 3, or 4
- **Service Class**: Standard *; SCC
- **Reference API Spec 11V1 & ISO 17078-2**
Reverse flow valve

Type 1

Type 2

Type 3

Type 4

Gas flow
Typical Gas Lift Valves

BK-1
BK
R20
API 11V1 VALVE DESIGNATION

<table>
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<td>1 — Standard Service.</td>
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<td>See Table 2.</td>
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<tr>
<td>2 — Stress Corrosion Cracking.</td>
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<td>Flow Configuration</td>
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<td>1 — See Figure 3.</td>
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<td>3 — See Figure 3.</td>
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<td>4 — See Figure 3.</td>
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<tr>
<td>Valve Type</td>
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<td>P — Injection Pressure Operated.</td>
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<td>F — Production Pressure Operated.</td>
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<td>X — Pilot Operated.</td>
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<td>Z — Other.</td>
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<tr>
<td>D — Dummy.</td>
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<td>O — Orifice.</td>
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<td>Closing Force</td>
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<td>G — Gas Charge.</td>
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<td>S — Spring Loaded.</td>
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<tr>
<td>C — Combination Spring and Gas Charge.</td>
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<tr>
<td>N — None.</td>
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<tr>
<td>Z — Other.</td>
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<tr>
<td>Valve Retrieval Method.</td>
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<td>W — Wireline Retrievable.</td>
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<td>T — Tubing Retrievable.</td>
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<td>Z — Other Retrieval Method.</td>
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<tr>
<td>Valve Size</td>
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<td>062-0.625 inches [15.9 mm] OD</td>
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<td>100-1.000 inches [25.4 mm] OD</td>
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<td>150-1.500 inches [38.1 mm] OD</td>
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Gas Lift Valves Guidelines

- Use a 3-ply bellows-- single-element, unbalanced valve w/ a nitrogen charged dome and/or a spring
- Choice between: Injection Pressure* or Production Pressure (Fluid) Operated.
- Use reverse flow (check) valve in each
- Age valve and shelf test
- Standard Monel Seats or Solid Carbide
- Use Orifice Valve w/ check on bottom
- Dummy all unused mandrels
- Consider combination Gas-charged & Spring- loaded for set pressures > 1500 psi (Field Experience)
- Use screened orifice/nozzle-Venturi on bottom
Gas Lift Mandrel & Valve Summary

- Purchase mandrels as per:  
  ......................API Spec 11V1 or ISO 17078-1
- Purchase valves as per:  
  API Spec 11V1 or ISO 17078-2
- Follow proposed ISO 17078-3 for running, pulling, and kick-over tools, and latches
- Select suitable type valves
- Check on shop to observe practices
- Keep good records of performance
In an IPO valve, high pressure nitrogen in the dome exerts pressure on the inside of the bellows. This causes the bellows to extend down and pushes the ball on the seat.
Gas from the casing tries to get into the valve. The pressure acts on the outside of the bellows, trying to compress the bellows.
Fluid from the production tubing tries to force the stem off the seat.
When the valve opens, gas moves through the valve and out the nose.
The valve is in the closed position now.

What it take to get this valve open?

Let’s look first at the forces trying to close the valve.

Closing force = \( P_b \times (A_b) \)

where:

\( P_b = \) nitrogen pressure

\( A_b = \) area of the bellows
Now the opening forces:


where:

Ppd = tubing pressure

Piod = casing pressure

Ap = port area

Ab = bellows area

The casing pressure only acts on this area when the valve is closed.
The solution

The valve begins to come open when the opening and closing forces are equal.

\[ \text{Pb (Ab)} = \text{Ppd (Ap)} + \text{Piod(Ab - Ap)} \]

For a given Pb we could solve for Piod the pressure at which the valve should open.

Or for a design case of Piod and Ppd, we could solve for the correct Pb.
Test Rack
Set Pressure

GAS LIFT VALVE

Pvo

SUPPLY LINE

DONUT TESTER

BLEED

Ppd=0

Figure 15—Typical Sleeve Tester

Unbalanced pressure charged valve

Fig. 5-11
Test Rack Set Pressures, Pvo

• Simple Injection Pressure Operated Valve where well forces ready to open valve:
  (1) \( P_b \times Ab = P_{iod} \times (Ab-Ap) + P_{pd} \times Ap \)

• For Test rack conditions where \( P_{pd} = 0 \):
  (2) \( P_b \times Ab = P_{vo} \times (Ab-Ap) \)

• Then by substitution:
  (3) \( P_{vo} \times (Ab-Ap) = P_{iod} \times (Ab-Ap) + P_{pd} \times Ap \)

• Or: (4) \( P_{vo} = P_{iod} + P_{pd} \times Ap/(Ab-Ap) \) and by definition \( Ap/(Ab-Ap)=Ap/Ab/(1-Ap/Ab) = PPEF \)

Correct for Shop temperature for bellows charged valve
\( P_{vo} = [P_{pd} \times PPEF + P_{iod}] \times Ct \)
<table>
<thead>
<tr>
<th>PORT SIZE (IN)</th>
<th>OILFIELD UNITS</th>
<th>VALVE OD (IN)</th>
<th>BELLOWS SIZE (IN^2)</th>
<th>Ap/Ab (1/64”)</th>
<th>Mfg (MONEL)</th>
</tr>
</thead>
<tbody>
<tr>
<td>12</td>
<td>0.77</td>
<td>0.1875</td>
<td>0.0380</td>
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<td>0.1480</td>
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<td>0.3750</td>
<td>0.3650</td>
<td>0.5748</td>
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</table>
Test Rack Set Pressure: Example

• Given: XXXXX 1-inch BK valve w/ 3/16” port w/monel seat. Find PPEF = 0.1038 (mfg. data)
• $P_{io} = \text{Csg pressure @ valve depth}=1060 \text{ psig}$
• $P_{pd} = \text{Tbg pressure @ depth}=420 \text{ psig}$
• $T_v = \text{Valve Temp @ depth}=121 \text{ 'F}$
• $T_{shop} = 60 \text{ 'F}$ (Valve temp in shop)
• Find from Table 4-1 that $C_t = 0.88$
• Thus: $P_{vo} = [PPEF*P_{pd}+P_{io}]*C_t$
• $P_{vo} = [0.1038*420+1060]*0.880= 971 \text{ psig}$
**API Gas Lift Manual**

Table 4.1

Temperature Correction for Nitrogen Charged Bellows

1000 psia & 60 °F
### Table 4-1  Page 40  (Program CT_TEMP)

Temperature Correction Factors for Nitrogen

- Based of 60 F’ and Pbv = 1000 psig
- F  Ct
- 121  .880
- **Where:** Ct = \(1/[1.0 + (Tv(n) - 60) \times M/Pbv]\)
  - For Pbv<1238 psia : 
    \[M=3.054xPbv^2/10000000+1.934xPbv/1000-2.26/1000\]
  - For Pbv> 1238 psia : 
    \[M=1.804xPbv^2/10000000+2.298xPbv/1000-2.67/10\]
Calculate Valve Set Pressures

Graph showing depth in feet and pressure in psi or bar. The graph includes lines for different valve spacing angles (121°, 135°, 145°, 150°) with corresponding pressures at various depths.

- Gg = 0.03
- Gf = 0.15

Pressures at specific depths:
- 420 psi at 121°
- 1060 psi at 135°
- 420 psi at 145°
- 150°

Legend:
- INJ GAS
- TBP
- Temp
- VALVESPACING

Example points and lines indicate how valve set pressures vary with depth and angle.
## Test Rack Pressure Calculation Sheet

<table>
<thead>
<tr>
<th>Valve No.</th>
<th>Depth (ft)</th>
<th>(T_v) (°F)</th>
<th>(P_{PEF}) (psig)</th>
<th>(P_{pd}) (psig)</th>
<th>(P_{iod}) (psig)</th>
<th>(C_T)</th>
<th>(P_{wo}) (psig)</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td></td>
<td></td>
<td>(\times)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
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<tr>
<td>2</td>
<td></td>
<td></td>
<td>(\times)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
</tr>
<tr>
<td>3</td>
<td></td>
<td></td>
<td>(\times)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
</tr>
<tr>
<td>4</td>
<td></td>
<td></td>
<td>(\times)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
</tr>
<tr>
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<td></td>
<td></td>
<td>(\times)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
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<td>6</td>
<td></td>
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<td>(\times)</td>
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<td>(_)</td>
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<td>7</td>
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<td>(\times)</td>
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<td></td>
<td></td>
<td>(\times)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
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<tr>
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<td></td>
<td></td>
<td>(\times)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
</tr>
<tr>
<td>11</td>
<td></td>
<td></td>
<td>(\times)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
</tr>
<tr>
<td>12</td>
<td></td>
<td></td>
<td>(\times)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
</tr>
<tr>
<td>13</td>
<td></td>
<td></td>
<td>(\times)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
</tr>
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<td>14</td>
<td></td>
<td></td>
<td>(\times)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
</tr>
<tr>
<td>15</td>
<td></td>
<td></td>
<td>(\times)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
<td>(_)</td>
</tr>
</tbody>
</table>

Remarks:

\[ P_{wo} = (P_{PEF} \times P_{pd} + P_{iod}) \times C_T \]

\[ C_T = \frac{1}{(T_v - 60) \times 0.00215 + 1.0)} \]

Designer: ___________________________ Date: ___________________________
4.10 Temperature

- Determine Surface Static and Reservoir Static Temperatures
- Calculate Static Gradient
- Measure Flowing Temperature for different rates
- Never use static for design basis
- Design on estimated production rate
AGL_TEMP: FLOWING TEMPERATURE PROFILE

DEPTH (ft) or (meters)

TEMPERATURE ('F) or ('C)

STATIC TEMP

FLOW TEMP

Flowing

Static
Temperature

- The surface and bottom hole temperatures are relatively constant in a given field but change throughout the world.
- The field static temperature gradient should be known or measured as well as the reservoir temperature from well logs.
- Field data when available is best but the flowing temperature can be calculated.
- Normally a linear temperature increase approach with depth is adequate.
Isothermal Gradient Map

Contour values are in degrees per 100 feet.
Mean surface temp. = 74°F.

- Isothermal Gradient Map
Kirkpatrick Correlation

- Example: \( Q_I = 2250 \text{ bpd} \) through 3.5” Tbg
- Well Depth = 5500’, BHT = 180 ‘F
- Geothermal Gradient = 
  \[
  \frac{(180-75)}{(5500/100)} = 1.9 \text{ ‘F/100’}
  \]
- Solution: intersection of \( 2250/1.5 = 1500 \text{ bpd} \) & 1.9 GG find flow GG = 1.0 ‘F/100’
- Flowing Surf Temperature = 
  \[
  180 - 1.0 \times \frac{5500}{100} = 125 \text{ ‘F}
  \]
Fig 6-9 Kirkpatrick
Chart to be used directly for 2.5” tubing
For 2” tubing, multiply rate by 2
For 3” tubing, divide by 1.5
Temp Computer Program Solution

• “Predicting Temperature Profiles in a Flowing Well,” by Sagar, Doty & Schmidt

• Also for gas lift wells

• For multi-phase flow: Regression analysis---many assumptions

• Check against real field data
**PREDICTING TEMPERATURE PROFILES**

**Flowing Temperature Example**

---INPUT DATA---

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<tr>
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<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Pwh: Wellhead Pressure</td>
<td>100 psi</td>
</tr>
<tr>
<td>2</td>
<td>Ts: Temp.Surf.Static</td>
<td>75 'F</td>
</tr>
<tr>
<td>3</td>
<td>Tf: Temp of Formation</td>
<td>180 'F</td>
</tr>
<tr>
<td>4</td>
<td>Qo: Oil Rate</td>
<td>2000 bopd</td>
</tr>
<tr>
<td>5</td>
<td>Qw: Water Rate</td>
<td>250 bwpd</td>
</tr>
<tr>
<td>6</td>
<td>Qg: Form. Gas Rate</td>
<td>750 mcfd</td>
</tr>
<tr>
<td>7</td>
<td>API: Oil Weight</td>
<td>40.0 'API</td>
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<tr>
<td>8</td>
<td>SGw: SG. Water</td>
<td>1.060 sp.gr.</td>
</tr>
<tr>
<td>9</td>
<td>SGi: SG Gas (Air = 1)</td>
<td>0.700 air=1</td>
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<tr>
<td>10</td>
<td>OD: Tubing OD</td>
<td>3.500 in</td>
</tr>
<tr>
<td>11</td>
<td>CSG: Casing OD</td>
<td>7.000 in</td>
</tr>
<tr>
<td>12</td>
<td>Dw: Total Well Depth</td>
<td>5,500 ft</td>
</tr>
<tr>
<td>13</td>
<td>Di: Depth of Gas Inj.*</td>
<td>0 ft*</td>
</tr>
<tr>
<td>14</td>
<td>Qi: Gas Lift Inj. Rate</td>
<td>0 mcfd</td>
</tr>
<tr>
<td>15</td>
<td>Unit Selection</td>
<td>E E or M (OILFIELD = E; METRIC = M)</td>
</tr>
</tbody>
</table>

---CALCULATIONS---

<p>| | | |</p>
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<thead>
<tr>
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<th></th>
<th></th>
</tr>
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<tbody>
<tr>
<td>1</td>
<td>Tg: TEMP GRAD</td>
<td>1.909 'F/100'</td>
</tr>
<tr>
<td>2</td>
<td>Cpl: SPEC. HEAT</td>
<td>0.542 BTU/lbm</td>
</tr>
<tr>
<td>3</td>
<td>f: DIM. TIME</td>
<td>2.306 't</td>
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<tr>
<td>4</td>
<td>SGo: OIL wt.</td>
<td>0.825 sp.gr.</td>
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<td>5</td>
<td>Wt1: MASS FLOW</td>
<td>8.23 lbm/sec</td>
</tr>
<tr>
<td>6</td>
<td>Wt2: MASS FLOW</td>
<td>8.23 lbm/sec</td>
</tr>
<tr>
<td>7</td>
<td>U1: HEAT t.c.</td>
<td>121.22</td>
</tr>
<tr>
<td>8</td>
<td>U2: HEAT t.c.</td>
<td>#N/A</td>
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<td>A1: COEF.</td>
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<td>A2: COEf.</td>
<td>1.00E-04</td>
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<td>11</td>
<td>SGM1: CORRECTION</td>
<td>-0.0043</td>
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<tr>
<td>12</td>
<td>SGM2: CORRECTION</td>
<td>-0.0043</td>
</tr>
<tr>
<td>13</td>
<td>Flowing Twh =</td>
<td>125 'F</td>
</tr>
</tbody>
</table>
Temperature data

- API Gas Lift Manual & API RP11V6
- C.V. Kirkpatrick “The Power of Gas”
- K.E. Brown “The Technology of Artificial Lift Methods,” Volume 2a
- Sagar, Doty & Schmidt, “Flowing Temperature Profiles in a Flowing Well”
- Winkler & Eads, “Algorithm for more accurately predicting nitrogen-charged gas lift valve operations at high pressures and temperatures”
4.12 Gas Passage

• Use the minimum size port (choke) that will pass the desired rate of gas!
• Check Valve Port size for amount of gas passage that is possible
• Use Thornhill-Craver Equation/Chart
• Make Gas Gravity & Temp Correction
• Predict on high side
• Use next higher standard port/orifice
Upstream: Piod

PRODUCTION

GAS INJ.

square-edge orifice

SGg =

Tv =

Ppd

1 CHOOSE

port
Thornhill-Craver Chart: Example

• Find corrected gas throughput (Qgi)
• Given: Upstream Pressure (Piod)=1000 psig
• Downstream Pressure (Ppd)= 790 psig
• Orifice Size (Valve Port) = 12/64”
• Temperature of valve = 160 ‘F
• Gas SG = 0.75
• Find from chart : Qgi = 660 MCFD
• From Correction Chart find: Cc = 1.17
• Actual Qgi = 660/1.17 = 564 MCFD
**Basis:**

Correction Factor = 0.0544 \( \sqrt{GT} \)

Where: 
- \( G \) = Gas Gravity (Air = 1.0)
- \( T \) = Temperature, °R.

---

Correlation Factor

- Gas Gravity: 0.80, 0.75, 0.70, 0.60, 0.50, 0.40, 0.30, 0.20, 0.10, 0.05
- Temperature: 40, 60, 80, 100, 120, 140, 160, 180, 200, 220, 240, 260, 280, 300

---

**Cc=**

2007 Workshop Clegg & Smith
Orifice/Choke Problems

• Orifice/Choke Problem # 1
• Upstream Pressure = 1250 psig
• Downstream Pressure = 1150 psig
• Valve Port Size = 8/64 inch
• GG = 0.7 & Temp @ Depth = 180 ‘F
• How much gas can be Injected?
• What size orifice for Injection GAS Volume of 850 MCFD?
Constant Injection Pressure Test of Gas Lift Valve

See API RP 11V2
Fig. 1

Typical VPC Gas-Lift Valve Performance Plot

(after Decker & Dunham)

- Camco BK with 12/64ths VPC
  \[ P_{voT} = 964 \text{ Pcf} = 920 \text{ Temp} = 150 \]
- Camco BK with 16/64ths VPC
  \[ P_{voT} = 964 \text{ Pcf} = 920 \text{ Temp} = 150 \]
- Camco BK with 20/64ths VPC
  \[ P_{voT} = 964 \text{ Pcf} = 920 \text{ Temp} = 150 \]
Comparison of Gas-Lift Valve Performance Based on VPC Model
Vs. Performance Based on Thornhill-Craver Model

Camco BK with 12/64ths VPC
PvoT= 964 Pcf= 920 Temp=150

Camco BK with 12/64ths Thornhill
PvoT= 964 Pcf= 920 Temp=150

API
Pvo(n) = Test rack opening pressure for nth valve
Pcf = Injection gas pressure
Nozzle-Venturi Gas Lift Valve

- Inlet Ports
- Converging Section
- Throat (Orifice)
- Diverging Section
- Packing
- Check Valve
- Outlet Ports
Gas Injection Rate vs. Production Pressure

- Critical Flow
- Conventional Orifice Valve
- New Nozzle-Venturi Valve
- Subcritical Flow

Points A and B indicate different flow regimes.
Pressures Acting on an Unchoked Valve

The gas injection rate through the valve is reduced as the valve throttles closed.

Injection Pressure. This pressure is greater than the pressure downstream of the ball.

The pressure downstream of ball is nearly equal to the tubing (production) pressure.

Production Pressure

Large pressure drop, large suction force on ball, small gap between ball and seat.
The gas injection rate through the valve is higher because the valve ball is held off of the seat by the higher pressure beneath the ball.

Injection Pressure

The pressure down-stream of the ball is held higher by the choke.

Choke

P ~ Tubing Pressure

Small pressure drop, small suction force on ball, more gap between ball and seat

Large pressure drop

Pressures Acting on a Choked Valve
Comparison Between Choked and Unchoked Valves

(After Dunham, Decker, & Waring)

Plot of Injection Rate vs. Pressure
Unloading Gas-Lift Valve with Choke vs. Valve with no Choke
Using Gas-Lift Valve/Choke Model

Note that choked valve remains open over entire range and actually transmits much more gas. It "snaps" closed when closing pressure is reached.
4.9 Design Methods

- Need to space mandrel/valves to permit working to the lowest possible depth
- Find the location of the first valve
- Injection Pressure Operated Valves
- (1) Constant Rate Design
- (2) Variable Rate Design
- (3) Intermittent Design*
- (4) Equilibrium Curve
Graphical Solution--
Gas Lift Spacing

- Need to space mandrel/valves to permit working to the lowest possible depth
- You will learn to space using different techniques--depending on type valve
- Find the location of the first valve
- Injection Pressure Operated Valves
  - (1) Constant Rate Design*
  - (2) Variable Rate Design
  - (3) Intermittent Design: Other Designs
1st Mandrel/Valve

- Depth of 1st Valve is the same for most designs
- Strictly a U-tube case where the outlet and inlet pressures are nearly balanced
- Outlet Po. = Pwh+Depth(1)*[Liquid Grad (Gs)]
  Inlet Pi. = Pg + Gg * Depth(1) -Psf
- Example: Pwh = 100 psig, Gs= .465 psi/ft, Pg = 1000 psig,
  Gg = .03 psi/ft, Psf = 20 psi or about 50’(min)
- 100+D(1)*.465=1000+.03*D(1)-20
- D(1) = [1000-100-20]/[.465-.03] = 2023 ft
Injection Gas Gradient

For $T_s = 75^\circ F \& T_f = 175^\circ F$

$P_{gd} = P_g \times e^{(0.1875GxD/(TaxZ)}$

API GL Manual
Page 44  Fig. 4.7
AGL_SPAC: GAS LIFT SPACING

Gs = 0.465
Gg = 0.03
Gf = 0.1

DEPTH (ft) or (meters)

GAS INJ  TBG  SPACING

2007 Workshop Clegg & Smith
Exception to depth of 1st Valve

- In most cases the depth of the 1st valve is as outlined.
- But for relatively deep, high PI wells with low injection pressures, the depth of first valve can be placed at the static fluid level. After any workover where the well is loaded with SW, it may be necessary to swab the fluid level to the normal fluid level.
Injection Pressure Valve Worksheet
Constant Rate Design:
for Injection Pressure Operated Valve with good well data

- Draw Gas Injection Pressure Line (Pgd) & Grad.
- Find location of 1st Valve
- Select desired rate
- Select two points (Dw1 & Dw2) from gradient curve for desired rate. Plot gradient curve for desired rate on graph paper.
- Use unloading gradient to find intersection with Pgd. Move back up-hole to achieve necessary PD.
- This is depth of 2nd Valve.
- Repeat until Dw is reached or min space
Constant Rate Design Problem

- $P_g = 1200$ psig; $SG_g = .65$; $G_g = 0.033$ psi/ft
- $Gs = 0.465$ psi/ft; $P_{wh} = 100$ psig; $P_{sep} = 50$ psi; $D_w=8000'$
- Max rate = 600 bpd; Cut 50 %; 35 API;
- $T_{gs} = 75$ ‘F; $T_{wh} = 100$ ‘F; $T_f = 180$ ‘F       (650 psi @ 4000’)
- $T_{bg} = 1.995$” ID; $GLR = 1000$;                   (1300 psi @ 8000’)
- Min Space = 500’; PD = 20 psi
- Solution: Use program or gradient curves to find pressures @ depth for desired rate. Draw $P_{pd}(1)$…$P_{pd}(n)$
- Find 1st Valve @ about 2600’ w/ $P_{pd}(1) = 445$ psig
- Extend .465 psi/ft gradient to $P_{gd}$. Move back up-hole until a 20 psi PD results. $D(2) = about 4450’$
- Continue until 500’ min spacing reached.
- Find operating valve
Constant Rate Design

Pressures vs. Depth for different scenarios:
- GAS INJ
- TBG
- SPACING

Depth (ft or meters) vs. Pressure (psi) graph.

1464
1200
## WELL NAME: W S-Space for Constant Rate

<table>
<thead>
<tr>
<th>DEPTH (ft)</th>
<th>Ppd(n) psi</th>
<th>Pio(n) psi</th>
<th>Piod(n) psi</th>
<th>Tv °F</th>
<th>CT</th>
<th>Pvo(n) psi</th>
<th>Qgi mscfd</th>
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<td>1200</td>
<td>1200</td>
<td>100</td>
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<td>-</td>
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</table>

¼” S.O. Dummy
A. Mandrel Spacing: Constant Rate for injection pressure valves

- Given: $P_{wh} = P_{sep} = 100$ psig; $P_g = 1400$ psig
- $G_s = 0.465$ psi/ft; $T_{wh} = 120$ F'; $T_f = 200$ ‘F
- $S_{Gi} = 0.7$; $D_w = 10000$’; $D_{min} = 500$’
- $P_D = 25$ psi; Tubing = 3.5” OD
- Max rate = 2000 bpd @ max depth
- Total Rgl = 1000 CF/B
- Space mandrels & find max injection depth
GAS LIFT GRADIENT CURVES FOR 2.992" ID TUBING & 1000 GLR

- Flowing TBG Pressure (PSIG)
- Gradient = 0.465 psi/ft
- Depth (Feet)

Flow rates: 3000 bpd, 2500 bpd, 2000 bpd, 1500 bpd, 1000 bpd, 500 bpd

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<table>
<thead>
<tr>
<th>WELL NAME</th>
<th>Constant Rate Problem A</th>
</tr>
</thead>
<tbody>
<tr>
<td>D(n)</td>
<td>Ppd(n)</td>
</tr>
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<td>NO. DEPTH</td>
<td>TBG PRES</td>
</tr>
<tr>
<td>(ft)</td>
<td>(psi)</td>
</tr>
<tr>
<td>(INPUT)</td>
<td>------</td>
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<td>11</td>
<td>#N/A</td>
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<tr>
<td>12</td>
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</tr>
</tbody>
</table>

Dw | 10000 | 1840 | 0.0 | #N/A | 200 | 0.000 | 0 |
Variable Gradient Design for limited data

- Draw Gas Injection Pressure Line (Pgd)
- Draw Upper Design Line (UDL) \{Pgd-Pwh\}
- Find location of 1st valve @ D(1). (Same approach)
- Calculate Pseudo Tbg Pressure@ surface:
  \[ Ps = Pwh + 0.2 \times (Pg-Pwh) \]
- Find Ppd(n) at total depth or total injection depth:
  Note: (Ppd(n) < Pgd-200 psi)
- Connect these two points: Lower Design Line (LDL)
- Find intersection of LDL @ D(1): Extend using unloading gradient to intersection w/ Pig (UDL). No pressure adjustment necessary. Locate D(2)
- Continue spacing until Dw reached or Min Space
Variable Rate Design Problem

- \( P_g = 1200 \ \text{psig}; \ \text{SG}_g = .65; \ \text{G}_g = 0.033 \ \text{psi/ft} \)
- \( \text{G}_s = 0.465 \ \text{psi/ft}; \ \text{P}_{\text{wh}} = 100 \ \text{psig}; \ \text{P}_{\text{sep}} = 50 \ \text{psi}; \text{D}_w=8000' \)
- \( \text{Rate} = 200-600 \ \text{bpd}; \ \text{Cut} 50 \%; \ 35 \text{ 'API} \)
- \( \text{T}_{\text{gs}} = 75 \text{ 'F}; \ \text{T}_{\text{wh}} = 100 \text{ 'F}; \ \text{T}_f = 180 \text{ 'F} \)
- \( \text{T}_{\text{bg}} = 1.995'' \text{ ID}; \ \text{GLR} = 1000; \)
- \( \text{Min Space} = 500' \)
- Calculate Pseudo \( \text{T}_{\text{bg}} \) Pressure@ surface:
  \[ Ps = \text{P}_{\text{wh}} + 0.2 * (P_g-\text{P}_{\text{wh}}) = 100 + 0.2 \ (1200-100) = 320 \ \text{psig} \]
- Find \( \text{Ppd}(n) \) at total depth or total injection depth:
  \[ \text{Ppd}(n) = 1200 + .033\times8000 -200 =1264 \ \text{psig @ 8000'} \text{ [max]} \]
- Connect these two points: Lower Design Line (LDL)
- Find \( \text{D}(1) \)  {Same approach as before}
- Find intersection of LDL...\( \text{Ppd}(1) @ \text{D}(1) \): Extend using unloading gradient to intersection w/ Pig (UDL). Locate \( \text{D}(2), \text{D}(3)....\text{D}(n) \)
- Continue spacing until \( \text{D}_w \) reached or Min Space
AGL_SPAC: GAS LIFT SPACING

Bellows Injection Pressure Operated Valves

Variable Rate Injection Pressure Valves

DEPTH (ft)

PRESSURE (psi)

GAS INJ  TBG  SPACING

1264

320
AGL_SPAC: GAS LIFT SPACING

Spring Production Pressure Operated Valves

DEPTH (ft) or (meters)

PRESSURE (psi)

- GAS INJ
- TBG
- SPACING
Intermittent Design

- Draw Gas Injection Pressure Line, Pgd:UDL
- Find location of 1st Valve.
- Select design rate -Use small ported unloading valves
- Find Int. Spacing Factor (Fs):
  API GLM - Page 106, Fig 8-4
- \( P_{dp(n)} = F_s \times D_w + P_{wh} \); Connect Pwh & Pdp(n): LDL
- From intersection of LDL & D(1) extend unloading gradient (Sg) to UDL. Move back up-hole until the PD is reached. This is location of D(2). Find D(3)...
- Continue same procedure until Dw reached.
- Select large ported or pilot operating valve
Intermittent Spacing Example

- Well Depth = 8000’
- Pressure of injection Gas = 1000 psig
- Injection Gas Gravity = 0.60
- Sep. pres =50 psig & Flow TP=100 psig
- Planned Production Rate = 400 BPD
- Kill Fluid Gradient = 0.465 psi/ft
- Tubing OD = 2 3/8” & Casing OD = 7”
- Valve DP = 20 psig: Space Valves
Intermittent Gas Lift

Spacing Factors

Fig. 8.4

Rate in BPD

Spacing Factor (SF) in psi/ft

1.61"ID
1.995"ID
2.441"ID
2.992"ID
Intermittent Lift Spacing

AGL_SPAC: GAS LIFT SPACING

Spacing Factor = .1

DEPTH (ft) or (meters)

GAS INJ    TBG    SPACING
Mandrel Spacing Summary

• You have learned methods for spacing valves:
  • (2) Constant Rate for Injection Pressure Valves;
  • (3) Variable Gradient for Inj. & Prod. Pressure Valves;
  • (4) Intermittent design for Inj. Pressure Valves.

• Good spacing is essential for good operation & being able to work down to the lowest possible valve

• Plan ahead for changing conditions.
B. Mandrel Spacing: Variable
Gradient for injection pressure operated Valves

- Given: \( P_{sep} = 100 \) psig; \( P_g = 1400 \) psig
- \( G_s = 0.465 \) psi/ft; \( T_{wh} = 100 \) ‘F; \( T_f = 160 \) ‘F
- \( S_{Gi} = 0.65; \ D_w = 7000’; \ D_{min} = 500’ \)
- \( P_D = 25 \) psi; Tubing = 3.5” OD
- Rate \( ? = 1500\pm \) bpd from 7000’+
- Total Rgl = 750 CF/B
- Calculate Pseudo Tubing Pressure
- Space mandrels & find max injection depth
C. Mandrel Spacing: Intermittent Gas Lift for injection pressure valves

- Given: $P_{sep} = 50$ psig; $P_{wh} = 50$ psig; $P_g = 800$ psig
- $G_s = 0.465$ psi/ft; $T_{gs} = 75^\circ F$; $T_{wh} = 100^\circ F$; $T_f = 150^\circ F$
- $S_{Gi} = 0.70$; $D_w = 7,000'$; $G_g = 0.024$ psi/ft
- $P_{D} = 25$ psi; Tubing = 2.875” OD
- Rate = 200 bpd from 7,000’
- Use intermittent lift spacing factors for LDL (.055)
- Space mandrels
Equilibrium Curve

• Definition: A curve that connects the intersection of the natural flowing gradients with the gas lift producing gradients.

• Draw graph of Pressure Vs Depths. Plot upper flowing gradient curves for selected rates for GL conditions.

• Find from PI or IPR various Pwf’s for different rates at total depth.

• Draw the lower gradient curves and find the intersection with the appropriate upper gradient curve

• Maximum production rate will be about 200 psi less than the gas injection pressure.
### TABLE 6-1
CONTINUOUS FLOW GAS LIFT DESIGN CONDITIONS

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
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</thead>
<tbody>
<tr>
<td>Production Desired - q</td>
<td>Maximum</td>
</tr>
<tr>
<td>Well Depth - D_w</td>
<td>10,000'</td>
</tr>
<tr>
<td>Static BHP - P_ws</td>
<td>3,600 psig</td>
</tr>
<tr>
<td>Productivity Index - J</td>
<td></td>
</tr>
<tr>
<td>(Gross Fluid)</td>
<td>0.4 BLPD/psi</td>
</tr>
<tr>
<td>Formation R_{go}</td>
<td>300 CF/B</td>
</tr>
<tr>
<td>Water Cut - F_w</td>
<td>65%</td>
</tr>
<tr>
<td>Oil Gravity</td>
<td>35° API</td>
</tr>
<tr>
<td>Water Gravity - S_{G_w}</td>
<td>1.05</td>
</tr>
<tr>
<td>Gas Gravity - S_{G_g}</td>
<td>0.6</td>
</tr>
<tr>
<td>Casing Size</td>
<td>5(\frac{1}{2}) in. OD</td>
</tr>
<tr>
<td>Tubing Size</td>
<td>2(\frac{3}{8}) in. OD</td>
</tr>
<tr>
<td>Surface Wellhead Pressure - P_{wh}</td>
<td>100 psig</td>
</tr>
<tr>
<td>Available Gas Pressure - P_g</td>
<td>1200 psig</td>
</tr>
<tr>
<td>Gas Injection Rate - q_i</td>
<td>500 MCF/D</td>
</tr>
<tr>
<td>Static Fluid Gradient* - g_s</td>
<td>0.465 psi/ft</td>
</tr>
<tr>
<td>Bottom Hole</td>
<td></td>
</tr>
<tr>
<td>Temperature - T_f</td>
<td>190°F</td>
</tr>
<tr>
<td>Flowing Temperature - T_{wh}</td>
<td>Fig. 6-9 120°F</td>
</tr>
<tr>
<td>Type Reservoir</td>
<td>Waterdrive</td>
</tr>
</tbody>
</table>

*Static Fluid Gradient is the gradient of the fluid expected in the tubing and annulus at the time unloading starts.*
Fig. 6-4 — Graphical solution for design based on conditions of Table 6-1

Lower Gradient Curves (0.42 psi/ft above BP)

E.C.
Fig. 6-5 — Graphical solution for design based on conditions of Table 6-1 (continued)

After Jack Blann
Equilibrium Curve Problem

- Find the rate and the lift depth for the following planned gas lift well:
- Well Depth = 10,000’; Tubing size = 3.5” OD
- Gas Injection Pressure = 1400 psig; Pwh = 100 psig
- Temp @ Surface = 75 F’; BH Temp = 200 F’
- Pr = 3000 psig; Pb = 500 psig
- PI = 2.0
- Lower flowing gradient = 0.42 psi/ft (if Pwf > Pb)
- Planned GLR = 1000 during gas lift
5. Continuous Flow Problems
API RP 11V6

• 5.1 Example Problem No. 1
• 5.2 Example Problem No. 2
• 5.3 Example Problem No. 3
5. API RP 11V6: Injection Pressure Operated Valves: Example Problem No. 1: Typical Well with Good Data

- $P_{wh} = 100$ psig
- $P_g = 1250-1200$ psig
- $T_s = 78$ ‘F
- $T_{wh} = 108$ ‘F
- $T_f = 178$ ‘F
- $G_s = 0.465$ psi/ft
- $D_w = 8000$ ft.
- $P_{gd}$ at $D_w = 1440$ psig
- Water Cut 50%
- $P_r = P_B^* = 2125$ psig
- $R_{go} = 700$ & $R_{gl} = 350$
- $P_{sp} = 75$ psig
- $S_{gi} = 0.6$ (.65)
- $P_{l1} = 400$ psig @ 2500’
- $P_{l2} = 880$ psig @ 6000’
- $P_D = 25$ psig
- $D_{min} = 250’$
- $T_{bg} = 2.441$” ID
- Valve = 1” w/3/16” port
- Rate = 200 BPD @ 1941 psig
API RP 11V6: Example # 1

PI = 1000/1000 = 1.0

Pr = 2125 psig

1941 psig

Qmax = 1325 BPD

1125 psi
## AGL_DSN: EQUILIBRIUM PROGRAM

<table>
<thead>
<tr>
<th>RATE (bfpd)</th>
<th>Pwf (psi)</th>
<th>LEVEL (ft)</th>
<th>GFA (psi/ft)</th>
<th>DEPTH (ft)</th>
<th>PRES. (psi)</th>
<th>Pgd (psi)</th>
<th>OK</th>
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<td>0</td>
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<td>0.080</td>
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<td>100</td>
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<td>100</td>
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<td>3155</td>
<td>0.087</td>
<td>4273</td>
<td>470</td>
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<td>200</td>
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<td>4997</td>
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<td>7634</td>
<td>1108</td>
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</table>

### Diagram

**PRES. (psi) or (bar)**

**DEPTH (ft) or (meters)**

- **NEEDED INJ PRESSURE**
- **GAS INJ PRESSURE**
- **INJ GAS-SF**
Optimum Injection Gas

- Use the available injection gas to make the most **oil** production and greatest profit
- Split the gas between wells to achieve such results
- **However; installation of additional compressors to achieve max rate seldom justified!** {Parkinson’s Gas Law}
- **Experience: Maximum profit @ about 50% of max injection to achieve max rate**
Gas Lift Performance
For 2.992” Tbg & 2000 BPD

Pt: Tubing Pressure @ 5000 ft in PSIG

- Insufficient Gas
- Typical
- Optimum Gas
- Max Rate
- Excessive Gas
- @ 5000’

Total Gas (Formation + Injection)

MMCFD
AGL_GRAD: GAS LIFT GRADIENT CURVES

EXAMPLE FOR 1000 BPD UP 2.875" OD TUBING

DEPTH (ft) or (meters)

PRESSURE (psi) or (bar)

- GLR=250 (44.5)
- 500 (89)
- 750 (134)
- 1000 (178)
- 1250 (223)
- 1500 (267)
TYPICAL CASE

Max Oil Rate

Max OCI

Max Profit

BOPD

Gas Injection Rate in MCFD
Plot IPR and Selected GLR Outflow Curves

Figure 4—Oil IPR Graph

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5.1.6 Injection Gas Required @ Depth

- For a production rate of 800 BFPD

  For a Rgl of:  (Correction Factor @ 178 °F & Gg of .65 = 1.11)

  1500:  \( \frac{1500 \times 800 - 350 \times 800}{1000} = 920 \times 1.11 = 1021 \text{ MCFD} \)

  1200:  \( \frac{1200 \times 800 - 350 \times 800}{1000} = 680 \times 1.11 = 755 \text{ MCFD} \)

  1000:  \( \frac{1000 \times 800 - 350 \times 800}{1000} = 520 \times 1.11 = 577 \text{ MCFD} \)

  800:  \( \frac{800 \times 800 - 350 \times 800}{1000} = 360 \times 1.11 = 400 \text{ MCFD} \)
5.1.7 Temperature

- $T_f = 178 \, ^\circ F$
- $T_s = 78 \, ^\circ F$
- $T_{wh} = 108 \, ^\circ F$

AGL_TEMP: FLOWING TEMPERATURE PROFILE

DEPTH (ft) or (meters)

STATIC TEMP
FLOW TEMP
5.1.8 Gas Gradient

Gas Gradient, psi/ft

Gas Gradient = \( P_{gd} = P_g \times e^{(0.1875 \times G \times D / (T_X Z))} \)

For \( T_s = 75 \, ^\circ F \) & \( T_f = 175 \, ^\circ F \)

**Figure 4.7**
5.1.10 Valve Setting Depths

• First Valve Setting Depth
• Tubing pressure = casing pressure − Psf
• Max unloading flowing pressure = gas injection pressure − Psf
• \( P_{wh} + g_s \times D(1) = P_g + g_g \times D(1) − Psf \)
• \( 100 + 0.465 \times D(1) = 1200 + 0.03 \times D(1) - 20 \)
• \( 0.465 - 0.03 \times D(1) = 1200 - 100 - 20 = 1080 \)
• \( D(1) = \frac{1080}{0.435} = 2483 \text{ ft} \)
• Adjusted \( D(1) = 2475 \text{ ft} \) (close as you can read chart)
Figure 6—Gas Lift Design
5.1.12 Subsequent Valve Setting Depths

- \( Ppd(n) + gsxDbv = (pg-nxPD) + ggx(D(n)+Dbv-Psf) \)
- For valve(2)
- \( 400 + 0.465xDbv = (Pg-25) + 0.03x(2483+Dvb)-20 \)
- \( Dbv = 1907 \text{ ft} \)
- \( D(2) = 2483 + 1907 = 4390 \text{ ft} \) about 4375 ft
- \( D(3) = 5797 \) about 5800 ft (as close as can read chart)
- \( D(4) = 6783 \) about 6775 ft
- \( D(5) = 7434 \) about 7425 ft
- \( D(6) = 7820 \) Adjustment to 7690 ft (half-way between D(5) & D(7))
- \( D(7) = 8000+ \) Adjustment to 7940 ft (30 ft above packer)
API RP 11V6: Example # 1

AGL_SPAC: GAS LIFT SPACING

DEPTH (ft) or (meters)

GAS INJ  TBG  SPACING

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5.1.14 Valve Selection

• In this case, one-inch, unbalanced, nitrogen-charged bellows valves without a spring was selected. (A common practice in some areas.)

Port Size = ?

PPEF = ?
<table>
<thead>
<tr>
<th>Valve No.</th>
<th>Depth (ft)</th>
<th>$T_v$ (°F)</th>
<th>$P_{PEF}$</th>
<th>$P_{pd}$ (psig)</th>
<th>$P_{ind}$ (psig)</th>
<th>$C_T$</th>
<th>$P_{vo}$ (psig)</th>
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### Summary: Table 2 – Test Rack Pressure Calculation--Modified

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<th>NO. DEPTH (ft)</th>
<th>TBG PRES psi</th>
<th>D(n)</th>
<th>Ppd(n) psi</th>
<th>Pio(n) psi</th>
<th>Piod(n) psi</th>
<th>Tv 'F</th>
<th>CT</th>
<th>Pvo(n) psi</th>
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<tr>
<td>3 5800</td>
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<td>1145</td>
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<tr>
<td>4 6775</td>
<td>996</td>
<td>1125</td>
<td>1315</td>
<td>167</td>
<td>0.803</td>
<td>1138</td>
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<tr>
<td>5 7425</td>
<td>1095</td>
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<td>1304</td>
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<td>0.792</td>
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<tr>
<td>7 7940</td>
<td>1176</td>
<td>1050</td>
<td>1258</td>
<td>177</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

14/64” SO
5.1.16 Summary for Example Problem No. 1

- Predicted rate of about 800 BFPD
- Lift from Screened Orifice near bottom
- Gas injection rate of about 680(755) MCFD
- Flowing surface temperature of about 108 °F
- Anticipated operating surface gas injection of 1075 psig
- After installation, production tests should be run to optimize production and injection gas rates.
A. Well Completion Data

- Field name: Canyonfield
- Lease name and well no: Smith #1
- Lithology: [Blank]
- casing: 2 7/8 in. OD, 26 #/ft; Grade; ; ft
- liner: 2 7/8 in. OD; #/ft; Grade; ; ft
- Open hole: yes/no; ; Gravel pack: yes/no; 
- Well reference depth (D1/D2): ; Straight hole; 
- Per. Interval (D1/D2): 7000 - 15
- Pack.: ; fi
- TRG LCT: 7050 ft. OD; 2 7/8 in.; WT: 4.7 #/ft, Grade: N-80HD Bl
- SSSV: type; Depth; ; ft; Bore; ; in.
- Wellhead bore (ID): 2" ; in.; WP
- Choke (type): None; Size max. ID; ; in.; Length: 1500 ft
- Well profile: ; Straight hole; 

B. Reservoir, Test and Production Data

- Test date: ; None (q)
- Water cut (qw): ;
- Flowing WHP (Pwf): 160 ; Oil gravity: deg APL; Water SG (SGw): ;
- Static BHP (Psb); ; psig @ ft
- Static fluid level; None; ft & Psh; ; psig & g; ; psi/ft
- Flow BHP (Pfb); ; psig @ ft & qf; ; BLPD
- *max=7100x.465=3300 psig
- Oil gravity: deg APL; Water SG (SGw): ;
- Formation gas SG (SGg): 0.65; BH temp (Tb): 173 °F @ 7100 ft
- Static surf. temp (Tsw): ; °F
- Bubble point (Pbp): ; psig; Pd (Ji): ; BPD/psi; Flow eff:
- Sand: yes/no; ; Paraffin (yes/no): ; Scale (yes/no): ;
- H2S (yes/no): ; CO2 (yes/no): ; Unknown Emulsion (yes/no): ;
- Other unusual lift problems:

C. Design Information

- Tubing/Annulus flow; Taking; Space/setrun WL valves; Space clx
- Production rate (q): max; 800 ; design: Multirate BPO
- Max water cut (qw); ; Max lift depth: 7050 ; Min BHP; ;
- Well inj. pres. (Pinf): 960 ; Operating pressure (Pinf); 900 ; psig
- Compressor discharge pressure; 960 ; °F ; Inj gas SG (SGi): 0.65
- Inj gas volume: max/unloading/design; ; Rgi/MCFD
- Load fluid grad (g;): ; psi/ft; Lower grad (g;); ; psi/ft
- Min spacing of valves; ; Min pressure drop (PDr); ; psi
- Design flow pres (Pd); 160 ; psig; Design flow temp (Tinf); 115 °F
- Gas lift mandrel; ; Gas lift valve (ngl & type): ;
- Gas lift valve description; ;
- Other value type: PPFP; 1/2B; Bellows area;

Remarks: 

Note: 2 3/8 inch tbg

**Pi from 0.1 to 1.0 bpd/psi
Min PI = 0.1
Av. PI = 0.4
Max PI = 1.0

By: ; Date: 3-1-98

*Indicates data that must be supplied for good design.

Figure 17—Data Sheet Example 2A
## API Example 2: Assume PI = 0.1 bpd/psi

<table>
<thead>
<tr>
<th>FLUID</th>
<th>INJ.</th>
<th>TBG</th>
<th>CSG</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>RATE</td>
<td>Pwf</td>
<td>LEVEL</td>
<td>GFA</td>
<td>DEPTH</td>
</tr>
<tr>
<td>bfpd</td>
<td>psi</td>
<td>ft</td>
<td>psi/ft</td>
<td>ft</td>
</tr>
<tr>
<td>------</td>
<td>------</td>
<td>------</td>
<td>-------</td>
<td>-------</td>
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<tr>
<td>2</td>
<td>150</td>
<td>1800</td>
<td>2814</td>
<td>0.088</td>
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<td>4</td>
<td>250</td>
<td>778</td>
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<td>0.100</td>
</tr>
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</table>
API Example 2: Assume $PI = \frac{200}{500} = 0.4 \text{ bpd/psi}$ & $Pr = 3300 \text{ psi}$

<table>
<thead>
<tr>
<th>RATE (bfpd)</th>
<th>Pwf (psi)</th>
<th>LEVEL (ft)</th>
<th>GFA (psi/ft)</th>
<th>DEPTH (ft)</th>
<th>PRES. (psi)</th>
<th>Pgd (psi)</th>
<th>OK</th>
<th>Remark</th>
</tr>
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<tbody>
<tr>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.070</td>
<td>0</td>
<td>80</td>
<td>900</td>
<td></td>
<td>or NO</td>
</tr>
<tr>
<td>1</td>
<td>200</td>
<td>2800</td>
<td>433</td>
<td>0.094</td>
<td>804</td>
<td>156</td>
<td>919</td>
<td>OK</td>
</tr>
<tr>
<td>2</td>
<td>300</td>
<td>2550</td>
<td>1029</td>
<td>0.106</td>
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<td>253</td>
<td>939</td>
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<tr>
<td>3</td>
<td>400</td>
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<td>1624</td>
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<td>378</td>
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<td>OK</td>
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<tr>
<td>4</td>
<td>500</td>
<td>2050</td>
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<td>0.130</td>
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<tr>
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<td>1800</td>
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<td>3410</td>
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<td>955</td>
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<td>800</td>
<td>1300</td>
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<td>6937</td>
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</table>
### API Example 2: PI = 1 bpd/psi

<table>
<thead>
<tr>
<th>RATE (bpd)</th>
<th>Pwf (psi)</th>
<th>LEVEL (ft)</th>
<th>GFA (psi/ft)</th>
<th>DEPTH (ft)</th>
<th>PRES. (psi)</th>
<th>Pgd</th>
<th>OK</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.070</td>
<td>0</td>
<td>80</td>
<td></td>
<td>900</td>
<td>or NO</td>
</tr>
<tr>
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<td>300</td>
<td>3000</td>
<td>0</td>
<td>0.106</td>
<td>197</td>
<td>101</td>
<td>905</td>
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</tr>
<tr>
<td>2</td>
<td>400</td>
<td>2900</td>
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<td>0.118</td>
<td>536</td>
<td>143</td>
<td>913</td>
<td>OK</td>
</tr>
<tr>
<td>3</td>
<td>500</td>
<td>2800</td>
<td>433</td>
<td>0.130</td>
<td>903</td>
<td>197</td>
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<td>OK</td>
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<td>2500</td>
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<td>447</td>
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</tr>
<tr>
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<td>8</td>
<td>1000</td>
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<td>994</td>
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<td></td>
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<td>1068</td>
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</tr>
</tbody>
</table>
API Example 2: Variable Gradient Design

AGL_SPAC: GAS LIFT SPACING

Pw_h' = 160 + 0.2 \times (900 - 160) = 308 \text{ psi}

P_g = 900 \text{ psi}
<table>
<thead>
<tr>
<th>WELL NAME:</th>
<th>Example #2</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 Psep: Min. Surface Pres.</td>
<td>80 psi</td>
</tr>
<tr>
<td>2 Pwh: Well Head Pres.</td>
<td>308 psi</td>
</tr>
<tr>
<td>3 Pg: Inj. Gas Pres.</td>
<td>900 psi</td>
</tr>
<tr>
<td>4 Gs: Fluid Gradient</td>
<td>0.465 psi/ft</td>
</tr>
<tr>
<td>5 Ts: Temp. Surf. Static</td>
<td>74 °F</td>
</tr>
<tr>
<td>6 Twh: TEMP. Surf. Flow</td>
<td>115 °F</td>
</tr>
<tr>
<td>7 Tf: Temp. Form.</td>
<td>173 °F</td>
</tr>
<tr>
<td>8 SGi: SG. Inj. Gas</td>
<td>0.650 air=1</td>
</tr>
<tr>
<td>9 DI1: Lift Depth 1</td>
<td>1000 ft</td>
</tr>
<tr>
<td>10 PI1: Lift Pres. 2</td>
<td>400 psi</td>
</tr>
<tr>
<td>11 DI2: Lift Depth 2</td>
<td>7000 ft</td>
</tr>
<tr>
<td>12 PI2: Lift Pres. 2</td>
<td>860 psi</td>
</tr>
<tr>
<td>13 Dv: Max Val. Depth: TVD</td>
<td>7000 ft</td>
</tr>
<tr>
<td>14 PORT or CHOKE: (1/64&quot;)</td>
<td>12 no.</td>
</tr>
<tr>
<td>15 Av/Ab: VALVE: (P/B) Ratio*</td>
<td>0.038</td>
</tr>
<tr>
<td>16 PD: Pressure Drop</td>
<td>20.0 psi</td>
</tr>
<tr>
<td>17 Unit Selection</td>
<td>E or M (OILFIELD = E; METRIC = M)</td>
</tr>
</tbody>
</table>

**--PROGRAM TO SET INJECTION PRESSURE GAS LIFT VALVES--**

- **Pwh** = \(0.2 \times (900 - 160) + 160\)
- **Min. Spacing** = 200 ft
- **--CALCULATIONS--**
  - **GAS Gradient** = 0.0237 psi/ft
  - **GL VALVE PPEF** = 0.0395 psi
  - **INJ PRES @ TD** = 1060 psi

*PRESS [Ctrl] [A] FOR TYPICAL GAS LIFT VALVE MFG DATA*
<table>
<thead>
<tr>
<th>DEPTH (ft)</th>
<th>D(n)</th>
<th>Ppd(n)</th>
<th>Pio(n)</th>
<th>Piod(n)</th>
<th>Tv</th>
<th>CT</th>
<th>Pvo(n)</th>
<th>Qgi</th>
<th>Pvc(n)</th>
<th>Surf close</th>
<th>@ depth</th>
<th>Pvcd(n)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>115</td>
<td>------</td>
<td>------</td>
<td>------</td>
<td>----</td>
<td>----</td>
<td>--------</td>
<td>-----</td>
<td>--------</td>
<td>------------</td>
<td>----------</td>
<td>---------</td>
</tr>
<tr>
<td>1753</td>
<td>308</td>
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<tr>
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<td>940</td>
<td>138</td>
<td>0.853</td>
<td>821</td>
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<tr>
<td>3599</td>
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</tbody>
</table>

Example #2

WELL NAME: Dummy

1/4” s. orifice

D(n) s. orifice

Psd(n) dummy

Pio(n) dummy

Piod(n) dummy

Tv dummy

CT dummy

Pvo(n) dummy

Qgi dummy

Pvc(n) dummy

surf close dummy

@ depth dummy

Pvcd(n) dummy

2007 Workshop Clegg & Smith
Pr = 3300 psi
A. Summary: Problem # 2

- The design results are for Injection Pressure Operated Valves.
- This spacing is too wide for Production Pressure Operated (PPO) Valves.
- For PPO Valves, the top of the design line should be based on 30 or 40% of the difference between Pio1 and Pwh.
- The resulting closer spacing permits the uppermost PPO Valves to close as unloading progresses deeper in the well.
B. Summary: Problem # 2

• Original mandrel spacing for new wells must be carefully thought out.
• When little or no well productivity info is available, mandrel spacing should be closer, mainly in the upper part of the string.
• Mandrel spacing must be sufficient to last for the lifetime of the completion.
C. Summary: Problem # 2

• Flexible design from 250 to 1100 BFPD
• Minimum of 10 mandrels
• “Valve” to lift from near total depth
• Drop injection pressure 20 psi on each lower valve to deter multi-point injection
• Use ¼-inch screened orifice on bottom
API RP 11V6: 5.3 Example No. 3 - Fixed Mandrel
Using Injection Pressure Operated Valves

- Pr = Pws = 3350 psig
- Pb = 1500; (Standing)
- Test Rate = 200 BFPD
- Pwh = 120 psig
- API Oil = 35°; GOR = 400
- Cut = 50 %:Water SG=1.074
- Tbg = 1.995” ID
- Dw=8000’TVD/9936’MD
- Pwf = 2550 psig (Fig 21)
- Ts = 74 ‘F
- Tf = 180 ‘F
- Gs = 0.465 psi/ft
- Pg = 1150 to 1250 psig
- Sgi = 0.7
- Mandrel = Oval Side Pocket
- Min Spacing = 500’
- PD= 20 psig
- GL Valve = 1” w/ 3/16” port
- Casing = &’ OD
- Directional Well
- Gg = 0.032
- Twh = Measured: 100 ‘F
- Use all known information

2007 Workshop Clegg & Smith
5.3.2 Well Data

- $P_r = P_{ws} = gs \times (\text{Depth}-\text{SFL}) + P_{wh}$
- $P_{ws} = 0.465 \times (8000 - 900^*) + 50 = 3350$ psig
  .....from sonic fluid level measurement
- $P_{wf} = 2550$ psig from Fig. 21

- $P_b = \text{Bubble Point Using Standing’s} = 1500$ psia

- $G_g = 0.032$ psi/ft Fig. 5

- Temp. gradient $= 100 \times (180-100)/8000= 1 \text{ ‘F/100’}$
API RP 11V6
Example # 3

Figure 21—Vertical Flowing Pressure Gradient Curve
Bubble Point

GOR = 400
SGg = 0.85
Oil Gr. = 35
Ff = 180

BP = 1500 psia

FIG. 2-10—Bubble-point pressure by Standing’s correlation. Permission to publish by SPE.
5.3 API Example Problem No. 3

Pws = 3350 psig

Pwf = 2550 psig

PI = 200/(3350-2550) = .25 bpd/psi

Qmax = 670 bpd
### API 11V6 Example # 3: Equilibrium Curve Data

<table>
<thead>
<tr>
<th>RATE (bfpd)</th>
<th>Pwf (psi)</th>
<th>LEVEL (ft)</th>
<th>GFA (psi/ft)</th>
<th>DEPTH (ft)</th>
<th>PRES. (psi)</th>
<th>Pgd</th>
<th>Remarks</th>
</tr>
</thead>
</table>
| 0           | 0         | 0          | 0.070        | 0          | 120         | 1200|     \*
| 1           | 100       | 2950       | 976          | 0.082      | 1568        | 249 | 1259    | OK   |
| 2           | 200       | 2550       | 1929         | 0.094      | 2853        | 388 | 1307    | OK   |
| 3           | 300       | 2150       | 2881         | 0.106      | 4236        | 569 | 1359    | OK   |
| 4           | 400       | 1750       | 3833         | 0.118      | 5728        | 796 | 1415    | OK   |
| 5           | 500       | 1343       | 4803         | 0.130      | 7370        | 1078| 1477    | OK   |
| 6           | 600       | 808        | 6076         | 0.142      | #N/A        | #N/A| #N/A    | #N/A |

Maximum Production Rate of 500+ bfpd from 7370 ft
Well Data: Mandrel Spacing:
Well straight to 1500’ then Directional

<table>
<thead>
<tr>
<th>No.</th>
<th>Dtv</th>
<th>Dm</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0’</td>
<td>0’</td>
</tr>
<tr>
<td>1</td>
<td>2350’</td>
<td>2450’</td>
</tr>
<tr>
<td>2</td>
<td>3460’</td>
<td>3921’</td>
</tr>
<tr>
<td>3</td>
<td>4345’</td>
<td>5094’</td>
</tr>
<tr>
<td>4</td>
<td>5000’</td>
<td>5962’</td>
</tr>
<tr>
<td>5</td>
<td>5500’</td>
<td>6624’</td>
</tr>
<tr>
<td>6</td>
<td>6000’</td>
<td>7287’</td>
</tr>
<tr>
<td>7</td>
<td>6500’</td>
<td>7949’</td>
</tr>
<tr>
<td>8</td>
<td>7000’</td>
<td>8612’</td>
</tr>
<tr>
<td>9</td>
<td>7500’</td>
<td>9274’</td>
</tr>
<tr>
<td>10</td>
<td>7900’</td>
<td>9804’</td>
</tr>
</tbody>
</table>

41+ degree angle from 2450’ to total depth
### Table 5—Summary of Rate vs. Gas Injection

<table>
<thead>
<tr>
<th>$RG$ (SCF/bbl)</th>
<th>$P_{wf}$ (psig)</th>
<th>Rate $^*$ (BPD)</th>
<th>Injection Gas $^a$ (MCFD)</th>
<th>Change in Oil Rate $\Delta$(BPD)</th>
<th>Change in Injection Gas $\Delta$(MCFD)</th>
<th>Change in Oil Rate $\Delta$(BOPD)/(MCFD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>600</td>
<td>1550</td>
<td>449</td>
<td>179.6 (Base Case)</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>800</td>
<td>1430</td>
<td>478</td>
<td>286.8</td>
<td>14.5</td>
<td>107.2</td>
<td>0.135</td>
</tr>
<tr>
<td>1000</td>
<td>1370</td>
<td>494</td>
<td>395.2</td>
<td>8.0</td>
<td>108.4</td>
<td>0.074</td>
</tr>
<tr>
<td>1200</td>
<td>1335</td>
<td>502</td>
<td>502.0</td>
<td>4.0</td>
<td>106.8</td>
<td>0.037</td>
</tr>
<tr>
<td>2000</td>
<td>1275</td>
<td>514</td>
<td>926.2</td>
<td>6.0</td>
<td>424.2</td>
<td>0.014</td>
</tr>
</tbody>
</table>

$^a$Injection gas required $= \text{Rate} \times (R_{gl} - 200)$.

* Fluid rate---50% cut
Gas Passage Chart

Note: Gas flow capacities (0 – 4000 MCF/D) for known upstream pressure, downstream pressure, and orifice size. Courtesy F.T. Focht.

Figure 25—Gas Passage Chart for Various Orifice Sizes
Table 6—Summary of Gas Flow Using $\frac{3}{16}$-in. Port/Orifice

<table>
<thead>
<tr>
<th>Upstream Pressure (psig)</th>
<th>Downstream Pressure (psig)</th>
<th>Uncorrected Gas Rate (MCFD)</th>
<th>Correction Factor$^a$</th>
<th>Corrected Gas Rate (MCFD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1200</td>
<td>1100</td>
<td>550</td>
<td>1/1.15</td>
<td>478</td>
</tr>
<tr>
<td>1200</td>
<td>1000</td>
<td>720</td>
<td>1/1.15</td>
<td>626</td>
</tr>
<tr>
<td>1200</td>
<td>900</td>
<td>830</td>
<td>1/1.15</td>
<td>722</td>
</tr>
<tr>
<td>1200</td>
<td>800</td>
<td>880</td>
<td>1/1.15</td>
<td>765</td>
</tr>
<tr>
<td>1200</td>
<td>700 (critical)</td>
<td>920</td>
<td>1/1.15</td>
<td>800</td>
</tr>
</tbody>
</table>

Gravity = 0.70 and Temperature = 180°F (see API Gas Lift, Figure 4.9). Results indicate that a $\frac{3}{16}$-in. ported valve when fully open should allow sufficient gas injection during unloading.

Some designers recommend using smaller ported valves or installing $\frac{10}{64}$-in. chokes in the upper unloading valves. This practice will likely aid in unloading, but may cause multi-pointing.

PPEF = 0.104
API RP 11V6 Example # 3

Figure 26—Pressure-Depth Gas Lift Space Graph for: API
API RP 11V6: Example # 3- Ideal spacing

AGL_SPAC: GAS LIFT SPACING

Requires pulling tubing to re-space

500 bfpd

DEPTH (ft) or (meters)

GAS INJ  TBG  SPACING
AGL_SET:INJECTION PRESSURE VALVE DESIGN

Example

Valve installed in each mandrel

![Graph showing pressure vs. depth with lines for INJ GAS, TBG, Temp, and VALVE SPACING]
API RP 11V6 Example Problem No. 3

Figure 28—Pressure-Depth Gas Lift Program
## Test Rack Pressure Calculation Sheet

<table>
<thead>
<tr>
<th>Well</th>
<th>Valve</th>
<th>Qg</th>
<th>MCFD</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Valve No.</th>
<th>Depth ft</th>
<th>TV °F</th>
<th>PPEF psig</th>
<th>Ppd psig</th>
<th>Piod psig</th>
<th>CT</th>
<th>Pvo psig</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td></td>
<td></td>
<td>x</td>
<td></td>
<td>+</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td></td>
<td></td>
<td>x</td>
<td></td>
<td>+</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td></td>
<td></td>
<td>x</td>
<td></td>
<td>+</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td></td>
<td></td>
<td>x</td>
<td></td>
<td>+</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td></td>
<td></td>
<td>x</td>
<td></td>
<td>+</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td></td>
<td></td>
<td>x</td>
<td></td>
<td>+</td>
<td>x</td>
<td></td>
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<tr>
<td>7</td>
<td></td>
<td></td>
<td>x</td>
<td></td>
<td>+</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>8</td>
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<td>x</td>
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<td>+</td>
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<td>+</td>
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<td></td>
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<td>+</td>
<td>x</td>
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<tr>
<td>15</td>
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<td></td>
<td>x</td>
<td></td>
<td>+</td>
<td>x</td>
<td></td>
</tr>
</tbody>
</table>
### Table 7—Mandrel/Valve Summary

<table>
<thead>
<tr>
<th>Mandrel</th>
<th>Valve No.</th>
<th>Depth (ft)</th>
<th>Valve/Dummy</th>
<th>$P_{io}$ (psig)</th>
<th>$P_{iod}$ (psig)</th>
<th>Ppd (psig)</th>
<th>PPEF</th>
<th>$T_y$ (°F)</th>
<th>CT</th>
<th>$P_{vo}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>2350</td>
<td>V</td>
<td>1200</td>
<td>1275</td>
<td>430</td>
<td>.104</td>
<td>123.5</td>
<td>.88</td>
<td>1161</td>
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<td>2</td>
<td>3460</td>
<td>V</td>
<td>1180</td>
<td>1290</td>
<td>570</td>
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<td>134.6</td>
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<td>4345</td>
<td>D</td>
<td>—</td>
<td>—</td>
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<td></td>
<td></td>
<td></td>
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<tr>
<td>4</td>
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<td>D</td>
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<td>7000</td>
<td>V</td>
<td>1100</td>
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<td>170</td>
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<td>1167</td>
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<tr>
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<td>7</td>
<td>7500</td>
<td>O</td>
<td>1080</td>
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<td>1240</td>
<td></td>
<td>175</td>
<td></td>
<td>—</td>
</tr>
<tr>
<td>10</td>
<td>—</td>
<td>7900</td>
<td>D</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td></td>
<td></td>
<td></td>
<td>—</td>
</tr>
</tbody>
</table>

**PPEF = 0.104**

**$P_{vo} = (PPEF \times Ppd + Piod) \times CT$**
### WELL NAME: API RP 11V6: Fixed Mandrels-Example # 3

<table>
<thead>
<tr>
<th>NO.</th>
<th>DEPTH (ft)</th>
<th>TBG PRES (psi)</th>
<th>D(n)</th>
<th>Ppd(n)</th>
<th>Pio(n)</th>
<th>Piod(n)</th>
<th>Tv</th>
<th>CT</th>
<th>Pvo(n)</th>
<th>Qgi</th>
<th>INJ GAS</th>
</tr>
</thead>
<tbody>
<tr>
<td>INPUT</td>
<td></td>
<td></td>
<td>----</td>
<td>-------</td>
<td>-------</td>
<td>---------</td>
<td>----</td>
<td>----</td>
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<td>-----</td>
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<td>1200</td>
<td>100</td>
<td>-</td>
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<tr>
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<td>2350</td>
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<td>0.873</td>
<td>1150</td>
<td>917</td>
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<td>0.854</td>
<td>1151</td>
<td>918</td>
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</tr>
<tr>
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<td>4345</td>
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<td>1159</td>
<td>918</td>
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<tr>
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<td>5500 D</td>
<td>968</td>
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<td>1140</td>
<td>1323</td>
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<td>0.813</td>
<td>1158</td>
<td>848</td>
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<td>6000</td>
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<td>1120</td>
<td>1315</td>
<td>165</td>
<td>0.806</td>
<td>1148</td>
<td>761</td>
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<tr>
<td>6</td>
<td>6500</td>
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<td></td>
<td>1100</td>
<td>1307</td>
<td>170</td>
<td>0.799</td>
<td>1139</td>
<td>626</td>
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<tr>
<td>7</td>
<td>7000</td>
<td>1240</td>
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<td>1080</td>
<td>1298</td>
<td>175</td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>8</td>
<td>7900 D</td>
<td>1317</td>
<td></td>
<td>1060</td>
<td>1286</td>
<td>179</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1/4” SO Dummy
Summary Example Problem No. 3

- Calculated a PI = 0.25 bfpd
- Used Equilibrium Curve to predict a rate of 500+ bfpd from about 7500 ft.
- Spaced valves using TVD
- Recommended valves @ 2350, 3460, 5000, 6000, 6500 & 7000 ft with dummies @ 4345, 5500 & 7900 ft plus a 14/64 inch screened orifice @ 7500 ft to pass 500 MCFD
Summary for Design

• The better the data, the more specific the design.
• The poorer the data, the more flexible the design.
• If feasible, design to lift from near bottom.
• Carefully select the tubing size.
• For better valve performance, use 1 ½-inch valves. Select the smallest port that will pass the required injection gas.
• For most wells, use a screened orifice as the bottom injection “valve.”
Impact of Significant Variables

- **INJECTION PRESSURE**: The higher the injection gas pressure, the wider the mandrel spacing and the deeper the maximum lift depth can be.
- **FLOWING WELLHEAD TUBINE PRESSURE**: The higher the pressure, the lower the maximum producing rate and the higher the injection gas requirement will be.
- **TUBING SIZE**: Larger tubing sizes permit higher producing rates and wider mandrel spacing.
- **UNLOADING GRADIENTS**: Higher gradients mean closer mandrel spacing and shallower maximum lift depths.
- **INJECTION GAS GRAVITY**: Higher gas gravity means wider mandrel spacing and higher test rack opening pressures for gas lift valves.
- **CLOSER MANDREL SPACING**: Permits near optimum gas lift performance and unloading the well with less injection gas volume.
DESIGN PRINCIPLES

• CLOSER MANDREL SPACING IS PREFERRED.

• HIGHER PRODUCTIVITY WELLS REQUIRE CLOSER MANDREL SPACING NEAR TOP OF WELL.

• MANDREL SPACING SHOULD BE BASED ON WELL LIFE CYCLE ESPECIALLY OFFSHORE.
GOOD GAS-LIFT PRACTICES

• Streamlined Wellhead
• Flowline Size
• Separator Pressure
• Well Conditioning f/Unloading
• Unloading Precautions
UNLOADING PRECAUTIONS

• Don’t Cut Out the Valves!
• Buildup Injection Pressure Slowly
• 5 psi/min. to 400 psi
• 10 psi/min. Until Gas Production
• Then increase Gas Injection Rate to the Desired Value
Preferences

- SINGLE COMPLETIONS PREFERRED OVER DUALS.

- LARGER OD (1.5") GAS LIFT VALVES PERMIT SMALLER INJECTION PRESSURE DROPS FOR CONTINUOUS FLOW IN SMALLER PORT SIZES.

- MANDRELS W/ORIENTING SLEEVES BETTER FOR HIGHLY DEVIATED WELLS.

- RuleOfThumb: FLOWLINE SIZE SHOULD BE ONE STANDARD SIZE LARGER THAN TUBING SIZE.

- STREAMLINING WELLHEADS REDUCES FLOWING WELLHEAD BACKPRESSURE & INJECTION GAS REQUIREMENT.
Summary

• You have learned to do a complete gas lift design using an equilibrium curve to determine the max rate, various graphical methods for spacing, and how to calculate the test rack pressures for injection pressure operated valves.

• You how know more than most people about gas lift---hopefully!
This is to certify that

__________________________

Completed the

API Gas-Lift
Design Course

Sid Smith