

Beam Pumping to Dewater Horizontal Gas Wells

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INTRODUCTION

With the advent of Shale gas, fractured horizontal gas wells are the preferred method of well construction. **Figure 1** illustrates production from Shale Gas. The well construction of horizontal wells can take on many forms. **Figure 2** shows that horizontal wells can be drilled up from the kick off point, approximately horizontally from the kick off point and downward from the kick off point. The wells can be more complex than shown in **Figure 2** and of different depths than illustrated. However for horizontal wells, when using pumps, the pumps cannot be set below the perforations as they sometimes can be for gas separation in near vertical wells, so this advantage is lost. This is one reason that many horizontal gas wells are dewatering using gas lift. However there are advantages to using beam pumps that still can be considered.

PUMPS FOR DEWATERING

When using pumps for dewatering, the gas flows up the annulus and the liquid are pumped up the tubing. As shown in **Figure 3**, if the casing pressure is low (i.e. from compression) then the gas can flow against little pressure, if also the pumps can lower the fluid level near or even below the perforations in a near vertical well. This is shown in **Figure 3**. However as mentioned above in a horizontal well the pump cannot be set below the perforations so methods of gas separation must be considered when using a beam pump or other pump (that is depth rated for the job) to dewater a gas well.

Beam pumps are used for shallow viscous thermally steamed wells, and for relatively shallow CBM wells to lift water off of coal. Other pumps are used as well for CBM including PCP's and ESP's. For cold viscous production PCP's can be used instead of beam pumps but when steamed, wells are usually converted to beam pump. This may change for shallow wells as the there are new metal to metal PCP's being introduced for hot wells. Beam pumps are also used to lift deep horizontal oil wells and also shale gas wells which are horizontal wells. Beam lift can achieve good drawdown if gas separation can be achieved. Gas lift does not achieve as good of drawdown, especially when the liquid rates are higher. Also beam lift can be more energy efficient and is the most widely used form of lift, at least from the well count perspective. Beam lift wells are not hindered by higher bottom hole temperatures as are ESP's or PCP's (with rubber stators). Hydraulic reciprocating pumps could be considered but many do not work well with solids. Hydraulic jet pumps can handle some solids and gas but, like gaslift, may not achieve the desired drawdown and are energy inefficient, if that is a concern.

For this presentation the following classifications of the pump setting location will be used.

Possible pump locations:

1. Locate in straight section
2. Locate in curved section
3. Locate in Horizontal

SETTING IN THE "NEAR" STRAIGHT SECTION

In the near straight section, life should be same as for pump in similar well with vertical bore, but for problems cause by poor gas separation since the intake cannot sit below perforations. **Figure 4** shows a pump set in the near vertical section of a horizontal well. Reference 2 discusses using beam pumps in horizontal wells including in the near vertical section. The disadvantages of setting in the near vertical section are that slugging of liquids may be present in the near vertical section, the pump may not be low enough to achieve the lowest possible drawdown and the gas separation requirement is present.

Gas separation in the near vertical section can be from use of gas segregation or use of poor boy separators. **Figure 5** is a general figure showing the down hole gravity type of gas separator. **Figure 6** shows a useful rule that for each one sq in of down liquid flow area between the outside diameter of the dip tube and the inside diameter of the separator outer barrel, 50 bpd per square inch of separator flow area can be pumped and still the downflow velocity is less than ½ ft/sec rise velocity of a gas bubble. **Figure 7** shows some practical constructions of gravity segregation separators using the 50 bpd rule. Reference 3 shows separator performance can be a continuous function of pressure, GOR, fluid properties, and downflow area but the best separator performance is still with the downflow velocity of the liquids in the separator below ½ ft/sec. For instance this reference shows that the gas into the pump can be given by Ffgo in scf/bbl:

$$Ffgo = Kga p^{2/3} Vsl^{1/2} Bo 5.614 /Bg < GOR - Rs$$

Where:

Kga is separator performance coefficient, .01-.05 for poor boy separators

Bo is the oil formation volume factor, bbl/stk – bbl

Bg is the gas formation volume factor cu ft/scf

GOR is the well gas/oil ratio, scf/stk bbl oil

Rs is the solution volume factor, scf/stk bbl oil

Vsl is the superficial downflow velocity of the liquid in the gas separator, ft/sec

P is pressure, psia

However **Figure 7** shows limitations exist when the casing is smaller or the desired liquid rate to be pumped is higher. In these cases, the gravity segregation separator may be insufficiently sized to separate gas. Gas often gets pulled into the pump, because field construction practices do not consider the required 1 inch of flow area per 50 BPD requirement when assembling the poor boy gas separator using standard size perforated tubing sub and dip tube. Due to too small flow area inside the poor boy gas separator for liquid flow, the pump capacity exceeds the liquid separation capacity and gas is pulled into the pump.

Another type of separator is the casing packer separator. A conventional packer gas separator is shown in **Figure 9**. The gas and liquids come up a tube and the fluids fall back on the packer above the pump intake. With the casing packer separator high gas flow rates can result in gas interference occurring inside the pump.

An improved packer separator that is being used in the vertical section of horizontal wells for gas separation is shown in **Figure 10**. Their tubing anchor is mated with the anchor and allows the packer rubber and the anchor to be set by rotation. It is ideal for easy setting and retrieval just above the kickoff point in a deep horizontal well.

Baker Hughes Centrilift has used successfully (especially for severe slugging) and upturned shroud. This is shown conceptually in **Figure 11**. The upturned shroud collects fluids to provide continuous fluids to the pump. This concept was used in Reference 4 with beam pumps (although at lower rates) with some success.

Also in the curved section some bottom feeder or weighted intakes may work for gas separation if the curved section is closer to horizontal. A possibility of this kind of separator is shown in the following section where the pump is set in the horizontal.

SETTING IN THE CURVED SECTION

Some operators may want to set in the curved section. According to HF Pumps the pump life can be 30 % of setting in the near vertical.

- According to HF, a Two Stage Hollow Valve Rod Pump (2SHVR) with a Flexite™ Plunger is best.
- Flexite rings contact the barrel
- If not thinner wall box end plunger is more flexible than pin end
- Set in straight but inclined section if possible

For gas separation a “poor boy” separator or a packer separator may still be effective in the curved section if the inclination is still not too great. The greater the inclination angle the less gravity separation can separate gas due to the effects of gravity, resulting in these types separators perform poorly. The upturned shroud idea is possible as long as there is a good component of vertical to horizontal in the deviation of the curved section.

Again according to HF pumps problems setting in the curved section may include:

- Broken valve rod
- Broken upper plunger pin
- Worn valve rod or pull tube
- Worn valve rod or pull tube guide

SETTING IN THE HORIZONTAL

If the pump and rods can be run in the horizontal, then according to HF pumps:

- The pump itself may last 60% compared to setting in the vertical
- Standard valves still open/close
- Guided/lined cages extend life

HF recommends:

- 10-12 molded on guides/rod in curved/horizontal sections
- Use rod rotator
- Use pump guide collar on top of the pump to centralize smaller pump in tubing.
 - Example: for 2 3/8's x 1-1/4" RWBC pump in 2 7/8's; leave off guide collar in curved section
- Pumps have been run through 20-24 deg/100

Since most studies show that flow in the horizontal section is stratified, then taking fluids off the bottom of the casing in the horizontal can work to separate gas for a beam pump. This type of bottom feeder gas separator has been used with some success in applications for use with ESP's. **Figure 12** shows a gas separator that has a weighted intake for a beam pump designed to take the intake off the bottom of the casing. While made in Canada, there are good reports from this application.

ROD PROTECTION

Rod protection may include conventional factory (preferred) or field applied guides or the wheeled rod guides such as from Oil Field Improvements if the side loads are not predicted as too high. See **Figure 13**.

PREDICTIONS FOR RODS IN HORIZONTAL WELLS

Reference 5 overviews rod pumping in horizontal wells and deviated wells and also overviews some of the analysis methods used in industry. Reference 6 overviews design of rod strings in deviated wells. Reference 7 focuses on diagnosis of a rod string operating in a deviated or horizontal well.

Figure 14 displays a measured surface dynamometer card acquired on a conventional beam pumped well with the sucker rod pump set 800 feet into the horizontal section of the well. The red dot on the generalized deviation survey show the general location of the pump is set in the horizontal section of the well. When dynamometer data is acquired on sucker rod pumps set in the horizontal, the pump cards often do not show excessive friction. The 1.5 inch diameter pump is a standard API pump and the pump card shows normal pump action with unanchored tubing. The rod loading were modified to only include the vertical rod weight in determining the pump card loads. Damping factors for this dynamometer analysis are double what they would normally be for a vertical well at this depth. The practice of setting the pump in the horizontal section is a common practice. Even though the pump card does not display unusual appearance or excessive loadings; the more common practice is to set the pump in the vertical section of the well to avoid excessive down hole failure rates.

HORIZONTAL WELL CONTROL

Reference 8 discusses drilling of the well and how true to horizontal the length actually is has a big effect on the fluids that enter flows to the well. **Figure 15** show results comparing wells drilled with good control (L10) versus poor control (L5). These “sumps” or undulations in L5 provided slugging when the well was flowing. When tighter control of the undulations was accomplished in L10, then there were no slugging problems.

These slugging problems would occur and may be much worse if the L5 well had any type of lift pump installed since when the final slug of liquid hit the pump, and this was produced, then all the pump would see would be gas. Unless the pump was specifically built to handle gas, then the pump would become “gas locked” or gas blocked until there was sufficient liquid produced along the horizontal length to provide the pressure necessary to break the gas problem in the pump.

SUMMARY

Dewatering horizontal gas wells is discussed. Some recent methods of gas separation are presented. Other factors such as where to land the pump, gas separation, rod protection, analysis of the rod string, and horizontal well drilling control are discussed.

ACKNOWLEDGEMENTS:

The authors appreciate their management for allowing them to present this paper.

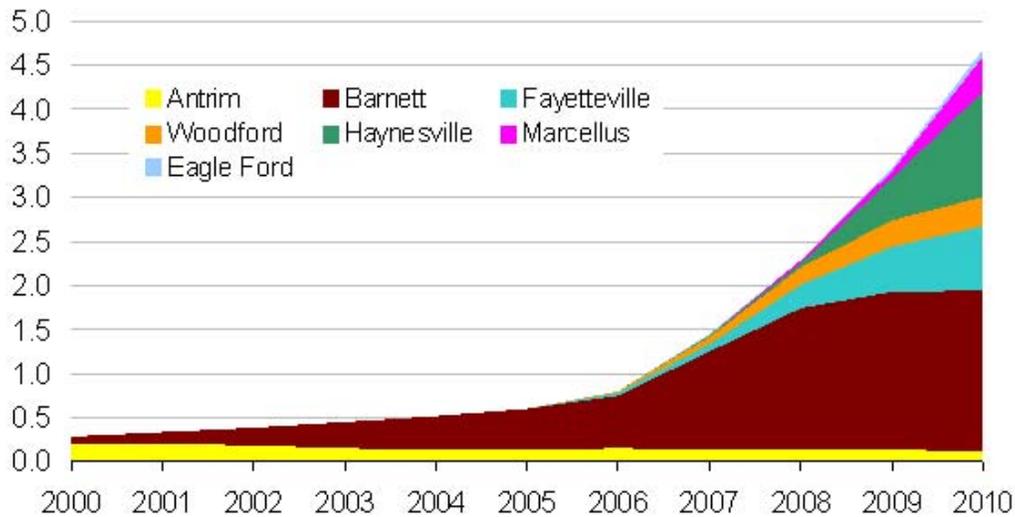
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U.S. shale gas production has increased 14-fold in 10 years

annual shale gas production
trillion cubic feet



Source: EIA, Lippman Consulting (2010 estimated)



Howard Gruenspecht, U.S. – Canada ECM, Dec 2 2010

Figure 1: Gas production from Shale Plays. Ref. 1

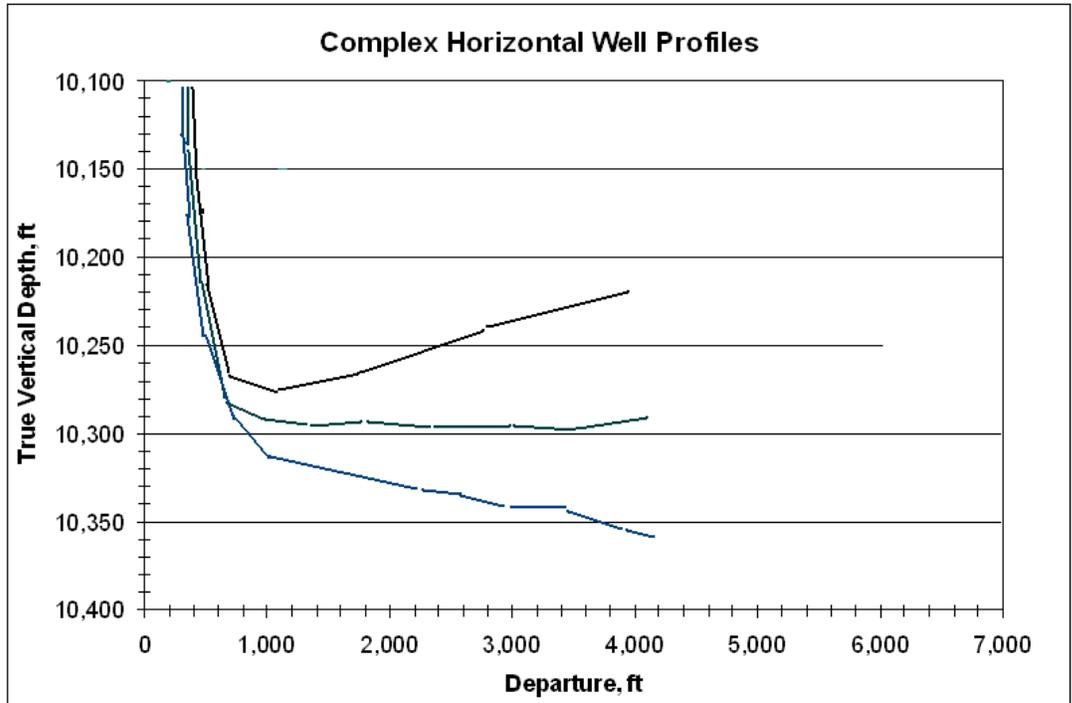
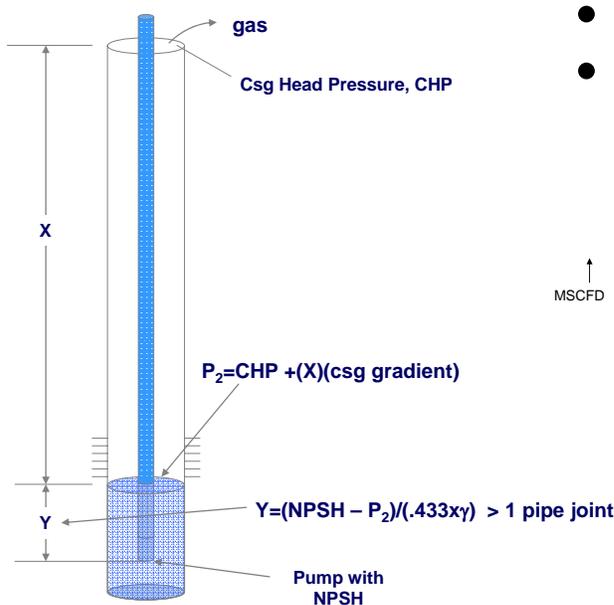
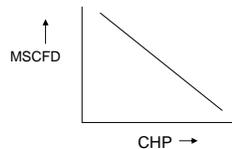


Figure 2. Horizontal Wells can be in many complex profiles.

Pump with CHP Compression: Best System for Drawdown?



- Lower csg level with pump
- If CHP compressed to low pressure, then very low PBHP's will be obtained



***BUT for horizontals, cannot sit below perforations... gas separation more difficult**

Figure 3. How pumps dewater in a near vertical well.

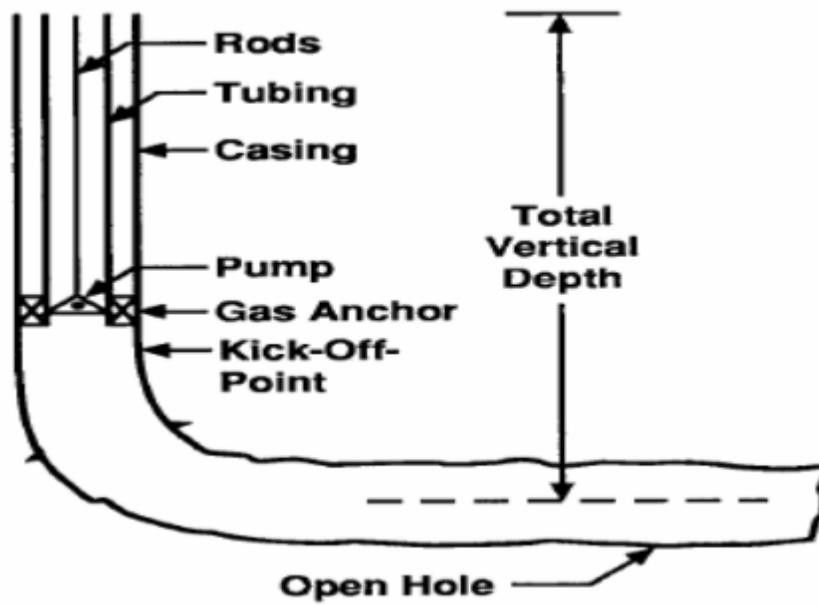


Figure 4: Showing pump can be set in the near vertical section of a horizontal well.

- Downhole separators must be efficient, low cost, trouble free, long lasting.
- Gravity separation is the governing principle for plunger pump installations.
- Many designs have been proposed (over 75 US patents) but only those that satisfy the above conditions are used in practice.

Basic Principles of Downhole Separator System

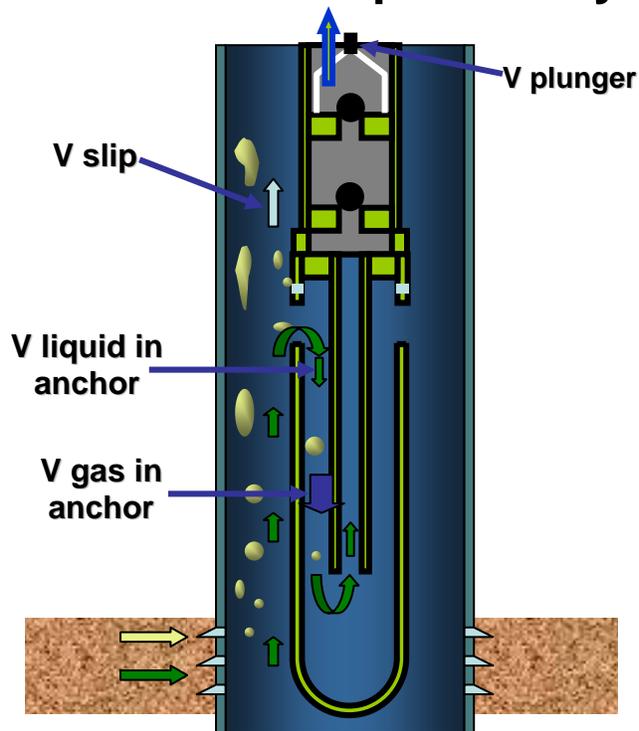
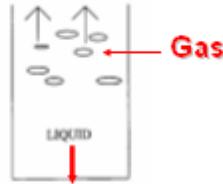


Figure 5: Review of what gravity segregation gas separator or “poor boy” gas separator is. From Echometer.

Liquid Should NOT Flow Too Fast into Gas Separator

GAS SEPARATOR LIQUID CAPACITY IS BASED ON THE FOLLOWING PRINCIPLE:



1 sq inch =
6.54 cm

GAS BUBBLES FLOW UPWARD IN OIL OR WATER AT A RATE OF APPROXIMATELY 6 INCHES PER SECOND. THUS, GAS BUBBLES WILL BE RELEASED FROM A LIQUID COLUMN IF THE **DOWNWARD LIQUID VELOCITY IS LESS THAN 6 INCHES PER SECOND**. A LIQUID COLUMN HAVING AN AREA OF 1 SQUARE INCH TRAVELLING AT A RATE OF 6 INCHES PER SECOND IS A RATE OF APPROXIMATELY **50** BPD.

Courtesy: [Echometer](#)

Figure 6: For each sq in of separator downflow area, 50 bpd can be pumped with downflow velocity still below 1/2 ft/sec. Figure 7 shows some practical separator constructions utilizing this rule.

Poor Boy Separator Liquid Capacity

GAS SEPARATOR CAPACITY TABLE SEPARATOR ABOVE FLUID ENTRY ZONE

OUTER BARREL DESCRIPTION AND SIZE, INCH	DIP TUBE SIZE INCH	ANNULUS* AREA SQ INCH	LIQUID CAPACITY BPD
3 1/2 PERFORATED TUBING SUB	1 1/4	4.9	240
2 7/8 PERFORATED TUBING SUB	1 1/4	2.7	135
2 7/8 PERFORATED TUBING SUB	1	3.9	195
2 3/8 PERFORATED TUBING SUB	1 1/4	1.0	50
2 3/8 PERFORATED TUBING SUB	1	2.1	105
2 3/8 PERFORATED TUBING SUB	3/4	2.3	115

Courtesy: [Echometer](#)

Figure 7: Some limitations on “poor boy” type separators with size of tubulars used.

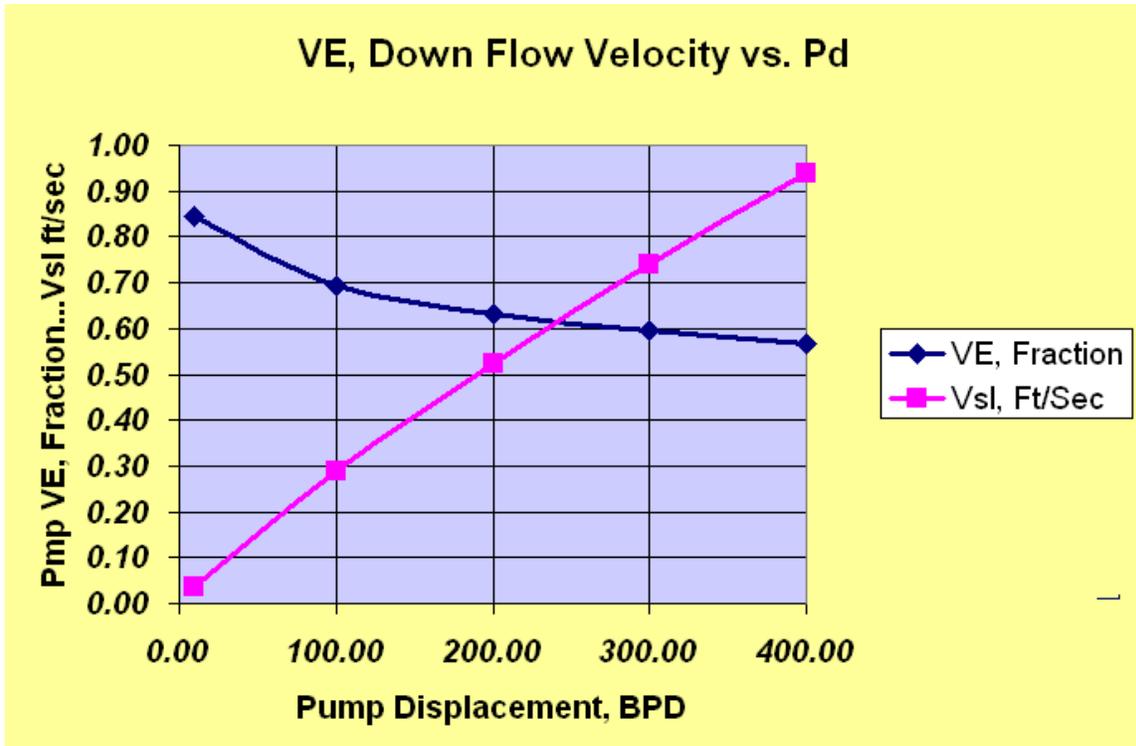


Figure 8: Showing separator performance can be continuous relationship that is function of GOR, pressure, downflow area and fluid properties. However the best performance will still be with the downflow velocity below 1/2 ft/sec.

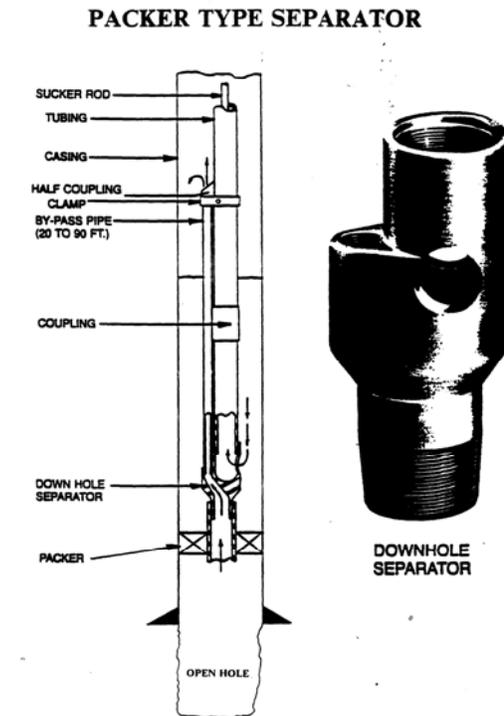


Figure 9: Packer type gas separator for Beam Pump.

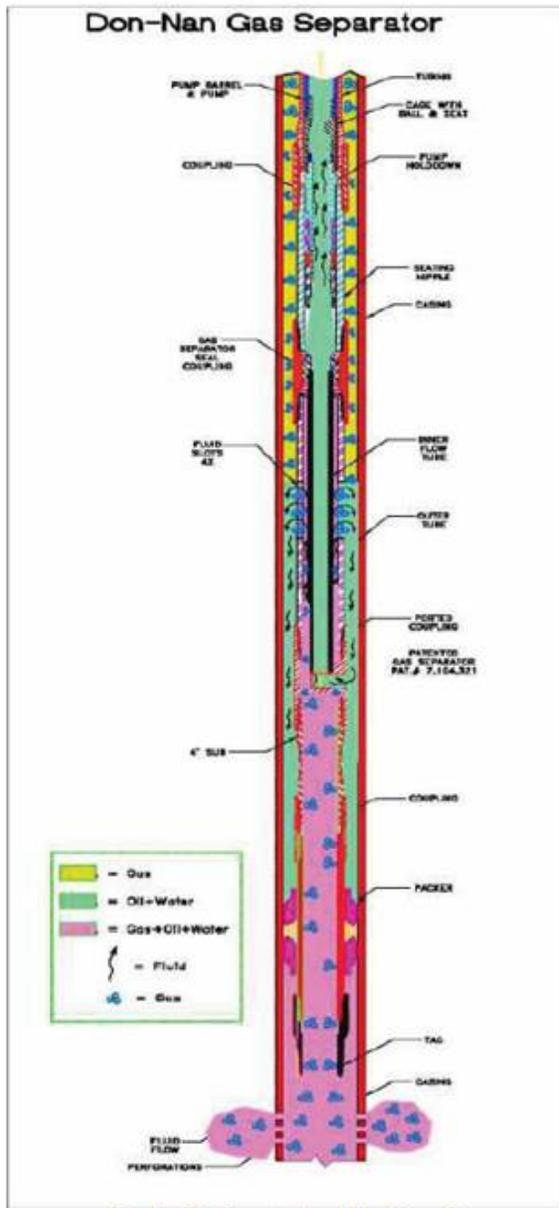


Figure 10: Improved packer separator with increased radial symmetry and other features.

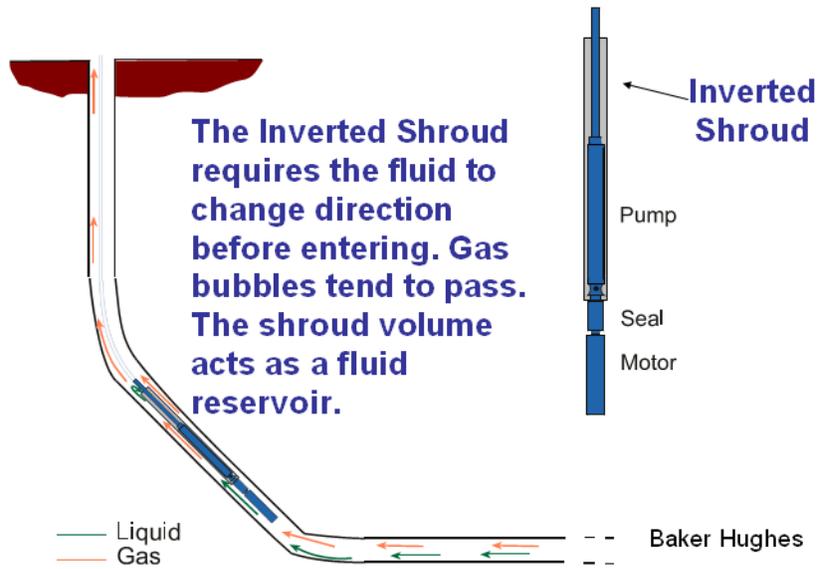


Figure 11: Concept of upturned shroud applied to an ESP. From Centrilift.

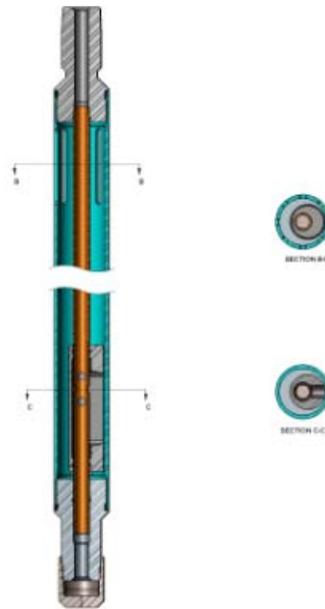
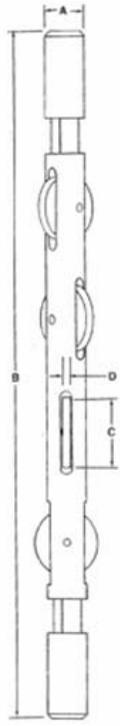


Figure 12: Bottom feeder or weighted intake for beam pumps in horizontal section of horizontal wells. Contact: John Haverko General Manager Premium ALS Main: (403) 723-3008 email: jhaverko@premiumals.com



Applications and Dimensions Model No and application 1	Max Rod Load 2	Dimensions			Weight
		A"	B"	C"	
2058P 5/8" Rod / 2 3/8" Tubing	19,600	1.50	27	1.80	10lbs
2034P 3/4" Rod / 2 3/8" Tubing	19,660	1.50	27	1.80	10lbs
2558P 5/8" Rod / 2 7/8" Tubing	19,600	1.50	27	2.25	10lbs 2oz
2534P 3/4" Rod / 2 7/8" Tubing	19,600	1.50	27	2.25	10lbs
2578P 7/8" Rod / 2 7/8" Tubing	22,400	1.625	27	2.25	11lbs 5oz
3034P 3/4" Rod / 3 1/2" Tubing	19,600	1.50	29	2.75	12lbs 6oz
3078P 7/8" Rod / 3 1/2" Tubing	22,400	1.75	29	2.75	15lbs
3010P 1" Rod / 3 1/2" Tubing	35,000	2.0	29	2.75	19lbs

Figure 13: Wheeled rod guides for rod protection in deviated wells.

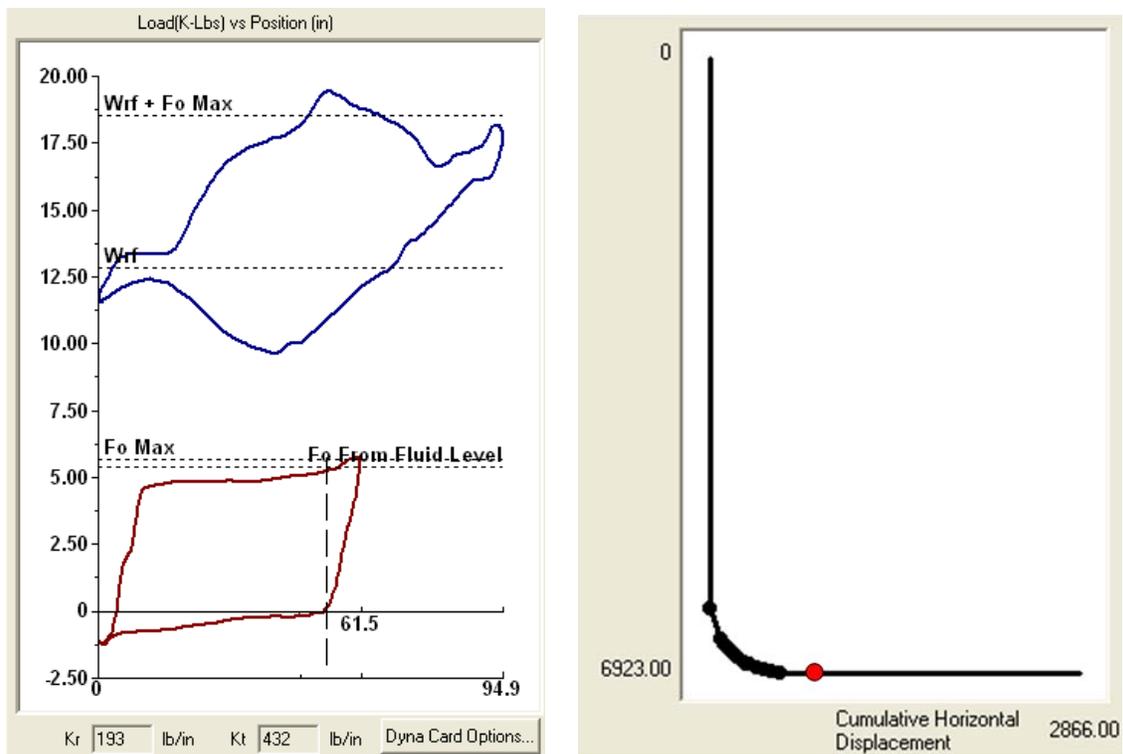


Figure 14: Measured Surface Dynamometer Card and Horizontal Well Profile.

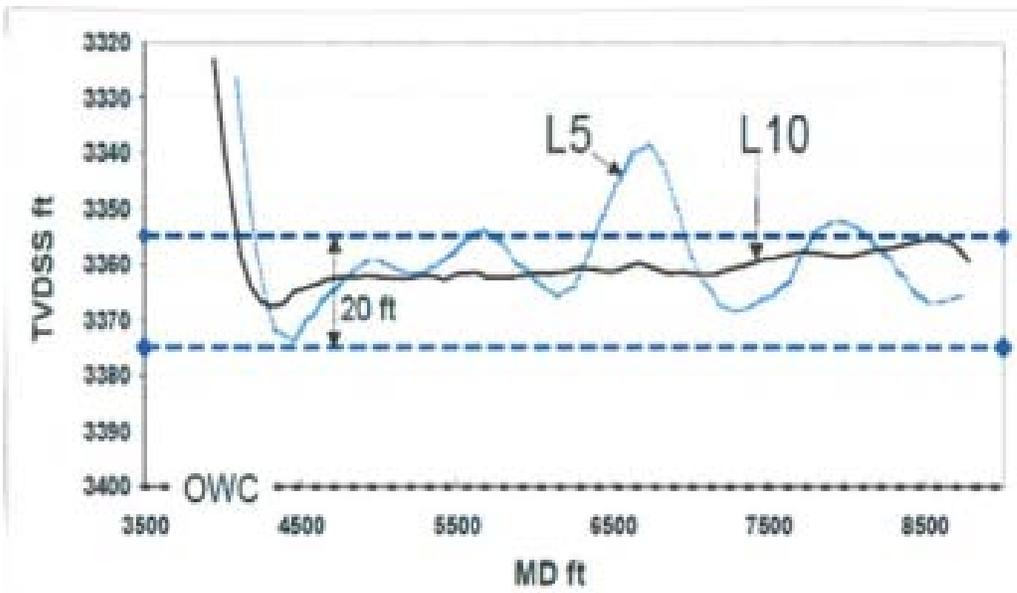


Figure 15. Horizontal well L5 with poor control of deviations along the length resulting in many “sumps” or undulations vs. controlling deviations in L10. Ref. 8.