DESIGN YOUR ROD STRING TO UNSEAT THE PUMP – BUT NOT OVERLOAD THE SYSTEM

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ABSTRACT

The sucker rod string for rod pumped wells can be adequately designed from hand calculations using API RP 11L[1] or computer programs. While these methods will provide very good approximations of the loads and related stresses on the sucker rods and pumping system, they do not consider the loads the downhole equipment will be subjected to if a downhole pump is stuck and the rods are used to try to unseat the pump.

This paper will discuss the basic loads on the sucker rods when they are subjected to the fluid loads and forces when trying to unseat the pump. Additionally, results from testing downhole seating cups and mechanical bottom lock assemblies will be provided. Since the pulling unit weight indicator may not be accurate, the calculation converting unseating loads to maximum inches of pull or rod stretch will be provided. Recommended maximum pull weight on various grades of sucker rod diameters and grades will be provided from one sucker rod manufacturer. Finally, it is recommended that a check on the rig hoisting equipment (rod elevator and sucker rod hook) capacity is obtained to make sure the pulling system does not become overloaded when trying to unseat the pump.

INTRODUCTION

Typically, the sucker rod design calculation methods consider the loads and resulting stresses to select the smallest rod number and the appropriate sucker rod grade so that the rod string is not overloaded when lifting the peak polished rod load.[1] While new generation computer design programs may consider other loads or resulting stresses when the rod string is operating in a deviated well, neither the original API RP 11L or these newer programs consider checking to see if the selected rod string design and rod grade can unseat the downhole rod pump and retrieve it from the well. This normally is not a major consideration, since the forces or loads to pull the pump from the seating assembly are not very large. However, if there is sand, corrosion by-products, other solids, scale, etc. that prohibit the pump barrel movement relative to the seating nipple assembly. When this occurs, the resulting loads may be sufficiently high that the sucker rod string may be stressed greater than the yield strength for the rod grade used and the rods will be permanently, plastically deformed.

Some sucker rod manufacturers may provide their maximum recommended weight indicator pull force or load for their various rod diameters and rod grade to assist in checking the design versus the capacity to unseat the pump if it is suck. They also may even provide a derating or multiplying factor to consider using to accommodate the potential loss in diameter or cross sectional area due to wear and/or corrosion if the rods have been in the well operating for awhile. However, no manufacturer provides recommendations to check the rating capacity of the hoisting equipment to assure the workover rig equipment is not overloaded since some of the larger rod diameters and higher, special grade steels may have higher working load capacity than the hoisting equipment. This increased load capability may become more of a problem if the pump is stuck since the higher velocity, impact loads when trying to jar on a stuck pump (WHICH IS NOT RECOMMENDED) may damage or overload the hoisting equipment.

BACKGROUND

The relationship between the various sucker rod string design loads have been easier to understand when the "6 Basic Loads" building blocks depicted by Gipson and Swaim were developed.[2] An example of the building blocks are shown in Figure 1.

The idea of looking at the loads and resulting stresses on the rod string was previously used to develop the original analysis of the unseating the pump loads and design method developed by Conoco, Inc. in the 1980s. These calculations have been part of the internal Conoco sucker rod design program until it was no longer used in the late 2000s as more sophisticated, computer programs were being developed to consider deviated and horizontal wells. Figure 2 provides the procedure and design formulas originally developed N. W. Hein, Jr.

As shown in this figure, the resulting load on the top rod of the bottom section ($Load_{TRBS}$) may cause this rod to be overloaded due to the unseating the pump from the seating nipple and pull it up versus the column of liquid in the tubing resisting this load. If this occurs then produced water, which is compatible with the well and producing zones, could be pumped down the annulus (loading the annulus) to provide added buoyancy or lift force to help reduce the loads on the top rod of the bottom section. The calculation for the minimum amount of liquid height in the annulus, or E_L, also is provided in Figure 2.

The consideration and related formulas for determining the allowable stretch or inches of pull necessary to not permanently deform the rod string when unseating the pump versus using the weight indicator of the rig are considered in this analysis. These formulas and design procedures also developed by N. W. Hein, Jr. for the internal Conoco, Inc. sucker rod design program are presented in Figure 3. The resulting differential load can then be used to determine the maximum height or length of rods that can safety be pulled the required distance without causing the rod string to yield. These analyses considered new sucker rods and the full cross sectional area from having the full rod diameter. If, however, the rods have been in service and the diameter or area have been decreased due to wear or corrosion pitting, then an appropriate derating factor should be applied to accommodate the reduced rod capacity.

UNSEATING THE PUMP LOAD TESTS

A major downhole sucker rod pump manufacturer has recently conducted tests on the normal or typical loads or forces needed for a downhole pump to become unseated. These tests were conducted in a modified honing machine that allowed the pull forces to be measured when various types of pumps and pump plunger diameters were pulled out of the various seating assemblies (seating cups or mechanical hold downs). Figure 4 shows the testing machine used to conduct these tests. Figures 5 and 6 show the testing procedure when the first cup and all the cups have been pulled from a seating nipple pump hold down assembly. These tests also were conducted if top or bottom seating nipples or mechanical hold downs assemblies were used.

Tables I and II provide the test results showing the typical load or force that should be needed to pull the pump from its downhole assembly. Table I provide the results if cup type hold down or seating assemblies were used. Table II provide the force results if mechanical type seating assemblies were used for the various types of pumps, with varying plunger sizes and top or bottom hold downs used.

Now that these data are available, the original design calculation formulas can be adjusted to add these added forces to provide a more complete analysis and resulting load calculation for the rod string design.

NEW FORMULAS

The new calculations when the hold down forces are included in these unseating the pump forces and allowable stretch procedures are shown in Figure 7. Example multiplying safety factors of 0.8 or 0.9 are shown as a reference. The use of these factors should be included if the rod condition are no longer considered new. Additionally, typical manufacturers' yield strengths are shown. These could be used if the manufacturer has not provided the actual yield strength for the grade of rods used.

ALLOWABLE SUCKER ROD INDICATOR PULL

Sucker rod manufacturers may have provided assistance to the workover rig crew to tell them the maximum allowable weight indicator pull. At least one of these manufacturers have considered that a minimum safety factor of 0.9 should be considered since the rods most likely will not be used. Table III provide the data from one major sucker rod manufacturer. These loads should be compared to the resulting calculation of unseating the pump loads to make sure the rods may not be overloaded using the manufacturer's recommendations. However, with the development of larger diameter sucker rods and higher strength, specialty rods becoming more commonly used as deeper wells and/or increased fluid volumes are being produced, there may be a situation where the rods are now stronger than the rig hoisting equipment.

Sucker rod elevators normally have two different load capacities. The regular elevator normally has 15 tons or 30,000 lbf capacity, while the deep well elevator may have 25 ton or 50,000 lbf capacity. Sucker rod hooks normally are 25 ton, or 50,000 lbf capacity or some are available at up to 40 ton or 80,000 lbf capacity.

Comparing these hoisting equipment capacities to the allowable weight indicator pull provided from one rod manufacturer shows that there a many examples where the normal and even the deeper well/higher capacity hooks may be overloaded. If this could occur, then there needs to be a limit on the pull force the rig crew can pull on the rod string to try to get it unseated based on the hoisting equipment capacity. If this situation occurs on a well, then the rig crew could try loading the back side or they will have to pull a wet tubing string. The environmental concerns to the rig personnel and the well area land will now have to be considered, especially to try to capture any produced fluids and to try to prevent these from reaching in ground. The other thing that could be considered, if a well is known to have frequent stuck pump problems, is to run a downhole tubing drain. An example of one and the explanation of this equipment is shown in Figure 8.

EXAMPLE CALCULATIONS

Table IV provides an example calculation using the new formulas and hold down unseating force included for unseating the pump. Using the same well conditions, then the allowable stretch or inches of pull to consider since there is concern that the workover rig weight indicator is not accurate or working properly, is shown in Table V.

CONCLUSIONS

1. A "new" method has been developed to calculate the load/stress necessary to unseat a downhole sucker rod pump.
2. This method was modified based on recent testing done to determine the load or force typically required to pull the pump from its seating assembly based on pump plunger diameter, type of pump, and type of seating assembly.
3. A "new" method has been developed to calculate the amount of allowable stretch necessary to unseat the sucker rod pump without overloading the rod string when compared to the sucker rod manufacturers' yield strength for the grade of rod and the recommended maximum allowable weight indicator pull data.
4. A calculation has been developed to provide the minimum required fluid level that the annulus should be filled to provide additional force on the back side to assist in unseating the pump if the unseating force or stress is greater than the allowable.

RECOMMENDATIONS

1. If a well has sticking pump problems, then a tubing drain or similar type device should be considered to be installed to prevent pulling a wet tubing string.
2. While the allowable load and stretch to unseat the pump can be calculated and compared to the manufacturers' recommendations in order to select the correct rod grade and diameter, a check needs to be made of the

hoisting equipment (sucker rod elevator and sucker rod hook) rated capacities to prevent overload this equipment.

3. These calculations for allowable load/stress and allowable stretch should be incorporated into industry rod string design programs.

REFERENCES

1. API RP 11L, "Recommended Practice for Design Calculations for Sucker Rod Pumping Systems (Conventional Units)," API, Washington, D.C., 1988.
2. Gipson, F.W. and Swaim, H. S.; "Beam Pump Design Chain," SouthWestern Petroleum Short Course, Lubbock, 1985.

ACKNOWLEDGEMENTS

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NOMENCLATURE

W = Weight of the rod string in air
B_e = Buoyancy effect of the rod string
F_0 = Fluid load on cross sectional area of the rods
F_1 = Dynamic loads on the upstroke
F_2 = Dynamic loads on the downstroke
PPRL = Peak Polished Rod Load
TV = Traveling Valve Load
CBE = Counter Balance Effect
SV = Standing Valve Load
MPRL = Minimum Polished Rod Load
G = Mixed specific gravity of the fluids
L = Seating nipple depth
A_{RBS} = Cross sectional area of the rods in the bottom section

W_{RBS} = Weight of the rods in the bottom section
B_R = Buoyancy of the rods in the bottom section
B_{eR} = Buoyancy effect of the rods in the bottom section
F_{oSN} = Fluid load over the seating nipple cross sectional area
D_{SN} = Diameter of the seating nipple
E_L = Effective Lift from pump submergence
HD_{UF} = Pump hold down unseating force

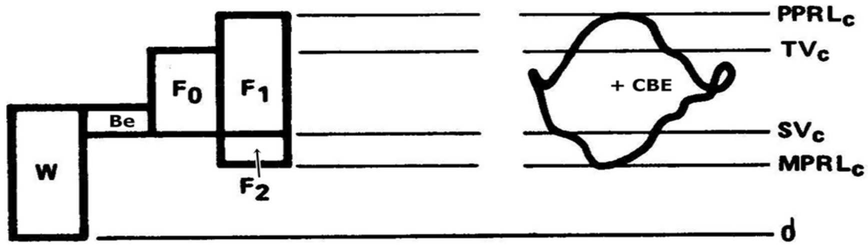

Figure 1 - 6 Basic loads for sucker rod string design interrelationships. (Ref. 2).

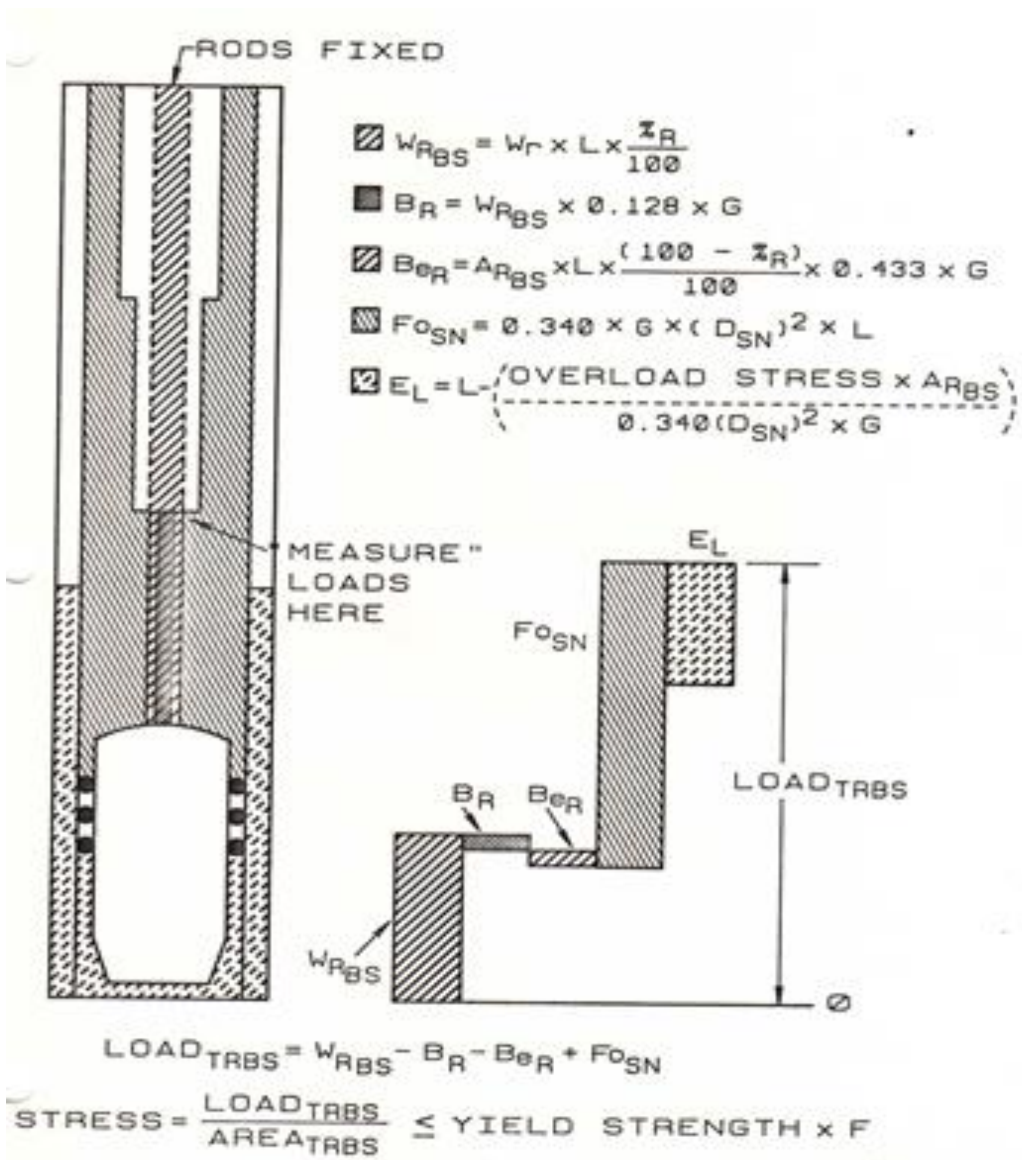

Figure 2 - Original design considerations and formulas for unseating the pump developed by N. W. Hein, Jr. for the internal Conoco rod string design computer program.

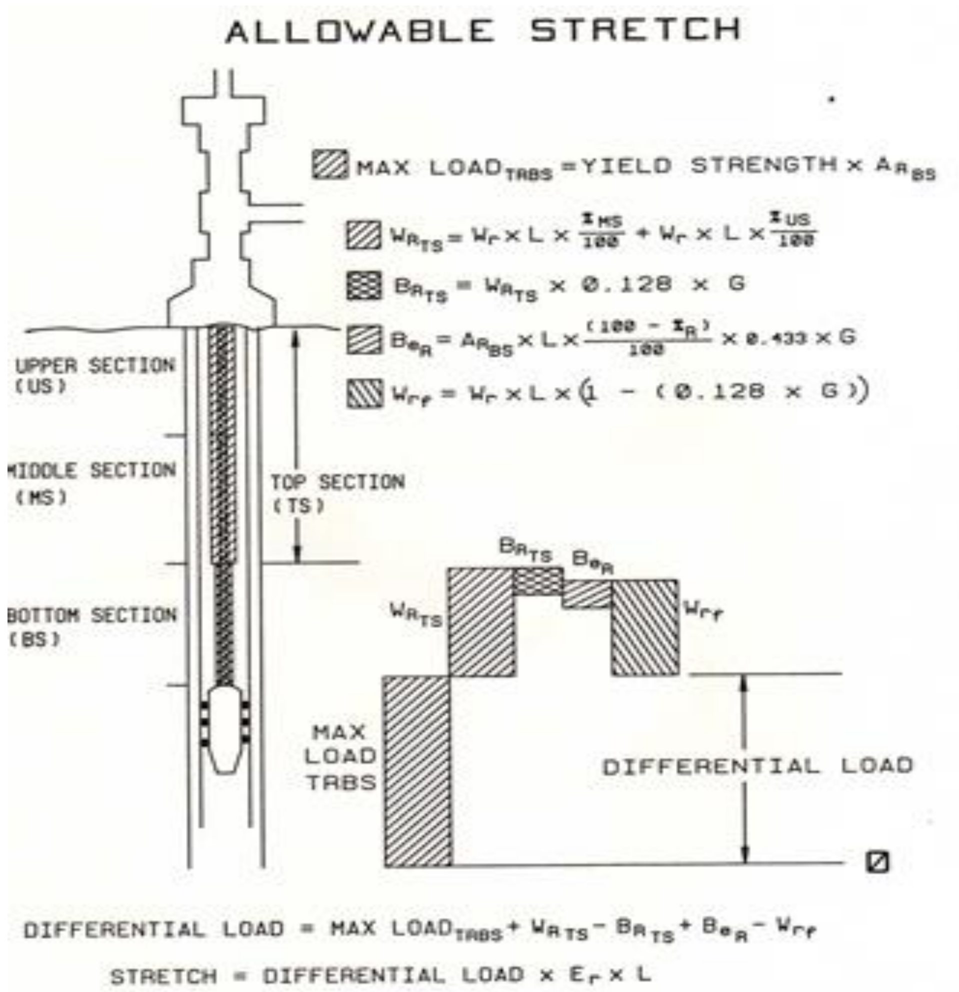

Figure 3 - Original design and calculations developed by N. W. Hein, Jr. for determining the allowable stretch and differential load necessary to prevent permanent deformation to the sucker rod string versus using the workover rig weight indicator.

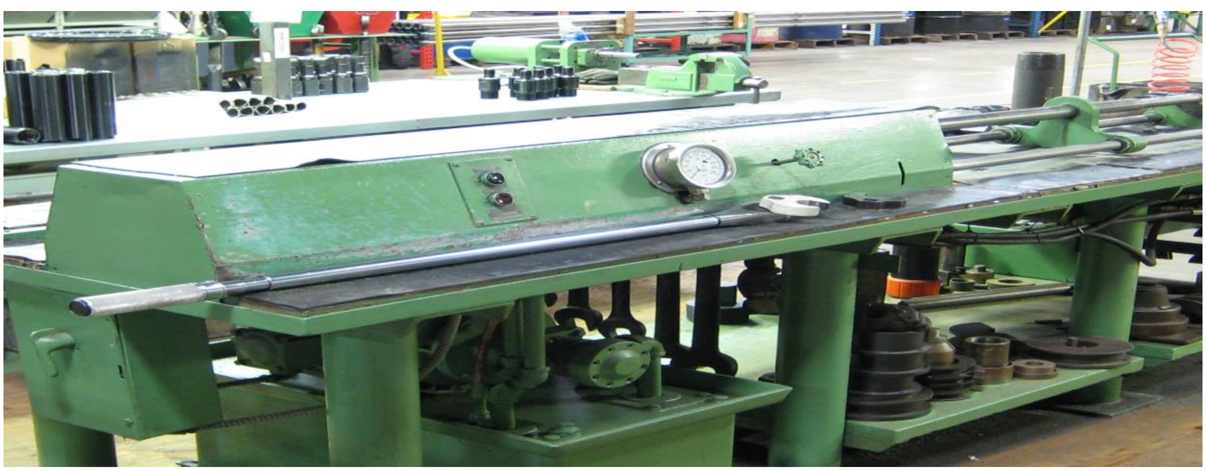

Figure 4 - Test machine used to measure required forces to pull downhole pumps from various seating assemblies.

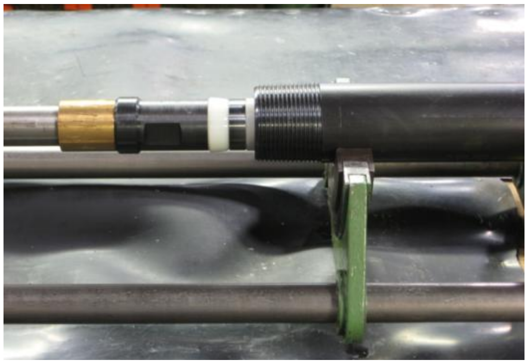

Figure 5 - Example test where the first ring or cup is being pulled from the seating nipple assembly.

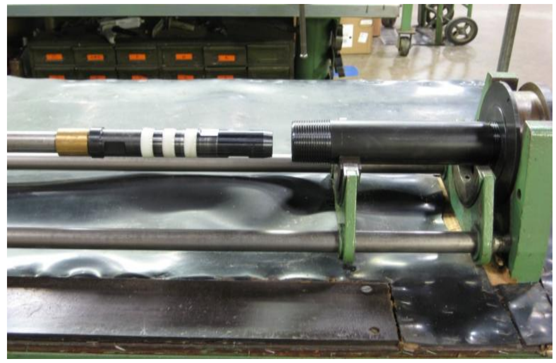

Figure 6 - Results showing all three cups pulled from seating nipple.

Table I
Force necessary to pull the insert pump, with top or bottom cup type hold downs, and tubing pumps of various plunger diameter sizes.

API Seating Nipple Designation	Force to Unseat w/o pressure (lbf)
Insert Pump (top or bottom HD)	
N11-15	**425**
N11-20	**500**
N11-25	**650**
N11-30	**740**
Tubing Pump	
N13-20	**500**
N13-25	**650**
N13-30	**740**

Table II

Forces necessary to pull the various insert or tubing pumps with bottom hold down or insert pump with top hold down using mechanical seating assembly.

API Seating Nipple Designation	Force to Unseat w/o pressure (lbf)
Insert or Tubing Pump – Bottom HD	
N12-15	1,100
N12-20	1,100
N12-25	2,000
N12-30	1,250
Insert Pump – Top HD	
N14-20	1,000
N14-25	1,200
N14-30	2,500

$$Load_{TRBS} = WRBS - BR - BeR + FoSN + HD\ Unseating\ Force$$

$$Allowable\ Stress = (Load_{TRBS}/Area_{TRBS}) \leq Yield\ Strength * F$$

Where F is safety factor; typically 0.8 or 0.9 Min.

Rod Grade:	**Yield Strength*:**
API C & K	60,000 psi
API D	85,00 psi
Grade EL	60,000 psi
Special Grade	115,000 psi

***check w/ rod manufacturer**

Figure 7 - Resulting "new" calculations and forces to be considered to unseat a pump when the hold down unseating forces have been included.

Table III
. Example maximum recommended weight indicator pull force or load (assuming F = 0.9) for various diameters and grades of rods.

Rod size (in)	Load for Grade C & K	Load for Grade D (54)	Load for Grade D (75, 78, & 90)	Load for Special Grade (96 & 97)
5/8	16,560	23,450	24,850	31,750
3/4	23,850	33,750	35,780	45,725
7/8	32,475	46,000	48,700	62,200
1	42,400	60,000	63,625	81,250
1-1/8	53,675		80,500	102,880
1-1/4				127,000

We are now offering a tubing drain that is integrated into a bottom hold-down insert pump. A bushing similar to our 80 series has a small rupture disc installed on the OD. The tubing drain bushing is used between the hold-down and the standing valve. This product is specifically targeted towards wells that produce a lot of particulates that could cause problems when pulling the pump. If the pump sticks, bursting the rupture disc may wash away some of the particulates allowing the pump to be pulled without having to pull tubing. Since the rupture disc is on the pump it can be replaced without pulling the tubing. It also allows a tubing drain to be added without having to pull tubing.

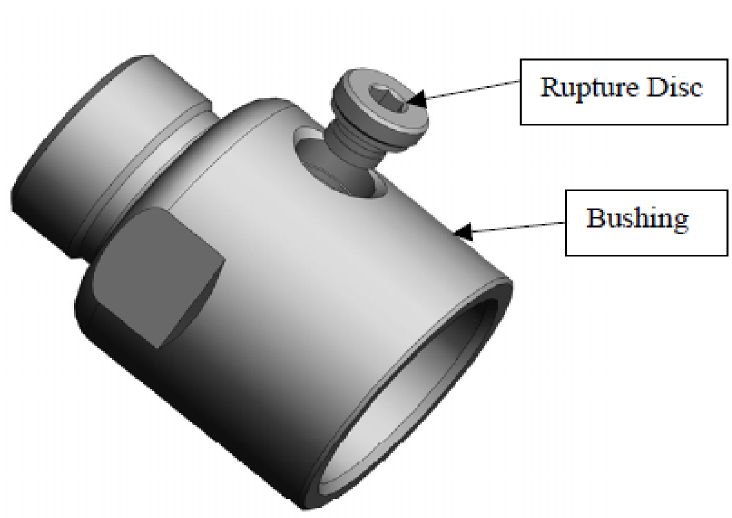

Figure 8 - A sketch and explanation of a typical downhole tubing drain that should be considered if a pump normally sticks or the pulling forces are high due to well conditions to prevent the need to pull a wet tubing string.

Table IV
Example calculation of unseating the pump forces or stresses

- **Given: 1.25” plunger, set at 11,000 ft, API 86 D grade rod string, 2.5” tubing, G_{mix} = 1.05**
- **Find: Stress to unseat pump**
- **Solution:**
- **1. 86 rod string w/1.25” plunger: 24.3% 1”, 24.5% 7/8”, 51.2% 3/4”; seating nipple ID = 2.280”**
- **Wrbs = Wr * L * %R/100 = 1.634 * 11,000* 0.512 = 9202.7 lb**
- **Br = Wrbs * 0.128 * G =9202.7 * 0.128 * 1.05 = 1236.8 lb**
- **Ber = Arbs * L * (100-%R)/100 * 0.433 * G =**
  0.422*11,000*0.488*0.433*1.05 = 1078.7 lb
- **FoSN = 0.340 * G * $(D_{SN})^2$ *L =**
  0.340 * 1.05 * $(2.28)^2$ * 11000 = 20,414.1 lb
- **HD unseating = 650 lb**
- **$LOAD_{TRBS}$ = Wrbs – Br – BeR + FoSN + HD**
- **= 9202.7-1236.8-1078.7+20414.1+650 = 27,951.3 lb**
- **Stress = $LOAD_{TRBS}$ / $Area_{TRBS}$ = 27951.3/0.442=63,238.2 psi**
- **Is stress < YS * F?**
  If F = 0.8; YS * 0.8 = 85,000 * 0.8 = 68,000 psi
  If F = 0.9; YS * 0.9 = 85,000 * 0.9 = 76,500 psi

Table V

Example calculation of allowable stretch or maximum inches of pull that the rod string can be pulled from the well once the plunger had hit the top of the pump downhole and a weight or resistance force is felt.

- **Given: Same**
- **Find: Allowable Stretch**
- **Max Load$_{TRBS}$ = YS * Area rbs = 85000 * 0.442 = 37,570 lb**
- **Wrts = Wr * L * % US/100 + Wr * L * %MS/100 =**

2.9 * 11000 * 0.243 + 2.2 * 11000 * 0.245 = 7751.7 + 13734.6 = 21,486.3 lb

- **Brts = Wrts *0.128*G = 21486.3 * 0.128 *1.05 = 2,887.8 lb**
- **Ber = Arbs* L * (100-%R)/100 * 0.433 * G = 0.442*11000*0.488*0.433*1.05 = 1078.7 lb**
- **Total Allowable Load =Max LoadTRBS + Wrts – Brts + Ber**
- **= 44200.0+21486.3-2887.8+1078.7 = 63,877.2 lb**

- **Wrf =Wrbs * L * (1-0.128 * G)=2.087*11000*0.866=19,880.8 lb**
- **Differential Load = Total Allowable Load – Wrf =**

  63,877.2-19880.8 = 43,996.4 lb

- **Allowable Stretch (once all stretch taken out by pulling up to standing valve load) = Differential Load * Er*L =**

  43,996.4 * 0.732 x10^{-6} * 11000 = 354.3 inches = 29.5 feet