MAXIMUM CAPACITIES OF BEAM PUMPING EQUIPMENT AND HIGH STRENGTH STEEL SUCKER RODS

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In the Sucker Rod Handbook No. 489 published by Bethlehem Steel Company in 1958, four total fluid produced from varying depths are shown. Curve A was presented by Bruce Robinson in 1935 in "Economics of Pumping" and was published in API Drilling and Production Practices in 1935. He assumed the maximum allowable stress was 27,000 psi. The curve is a straight line and shows that 800 BFPD could be produced from 2,000 feet and that over 200 BFPD could be produced from 7,000 feet.

Curve B limited rod stress to 30,000 psi and limited stroke length to 74 inches. This allowed 1,000 BFPD to be lifted from 3,000 feet and over 200 BFPD to be produced from 7500 feet.

Curve C showed the fluid that could be produced with longer strokes and a maximum allowable stress of 35,000 psi. This allowed 900 BFPD to be produced from 5,000 feet and 200 BFPD from 10,000 feet.

Curve D is from "Some Limitations of Rod Pumping" by Kenneth T. McCamman, presented at the API Division of Production, Pacific Coast District meeting in May 1948. This curve indicates the theoretical limitation if maximum loading could be 40,000 psi. Curve D indicates that 1200 BFPD could be produced from 5,000 feet and over 200 BFPD could be produced from 11,000 feet.

Present day technology allows maximum sucker rod loading to be 50,000 psi, and air balance pumping units are available with stroke lengths of 240 inches, beam capacities of 47,000 pounds and gear reducers that have a torque capacity of 2,560,000 inch-pounds. Sucker rods with a diameter of 1.125 inches are available. A.P.I. RP 11L supplies data on 1.25 inch rods, but these are not manufactured at this time.

Each manufacturer of subsurface sucker rod pumps calculates allowable setting depth differently. The API committee on standardization of production equipment has appointed a task group to come up with API recommended pump setting depths. These should be available in one to two years. The pump setting depths that I will use in this study were supplied by Harbison-Fischer Manufacturing Campany, and they assume that the yield strength of the pump barrel material is 75,000 psi and that the fluid being pumped has a specific gravity of 1.0.

Whenever the engineer and operator are designing a new beam pumping installation, they should assume that the well will make slightly more or slightly less than present data indicates. Once the well stabalizes, the pump displacement can be increased by increasing the size of the sheave on the primemover. Capacity can be decreased by decreasing the pitch diameter of this sheave, if the v-belt drive has been properly designed.

Thirteen generalized design rules-of-thumb follow:

1. Maximum recommended pumping speed, N = 0.35x1.125x245,000/ pump depth, feet.

2. Minimum recommended pumping speed, N = 0.20x1.125x245,000/ pump depth, feet.

3. Maximum recommended design stroke length, inches = 0.30x 70500/(maximum recommended pumping speed,SPM)squared.

4. Maximum allowable setting depth of sucker rod pumps.

TABLE 1

pump plunger diameter,in.	wall thickness,in.	maximum allowable setting depth,ft.
a. Bottom holddown, heavy wall barrels:		
1.0	0.125	11,538
1.06	0.125	10,992
1.25	0.188	13,346
1.50	0.188	11,569
1.75	0.25	11,962
2.0	0.156	7,785
2.25	0.25	10,485
b. Bottom holddown, thin wall barrels:		
2.0	0.125	6,408
2.50	0.125	5,238
c. Tubing pumps:		
1.75	0.25	9,619
2.25	0.25	7,870
2.75	0.25	6,657
d. Casing and oversized tubing pumps:		
2.75	0.25	6,657
3.25	0.25	5,773
3.75	0.25	5,092
4.75	0.25	4,122

Assume top holddown pumps can be run two-thirds as deep as bottom holddown pumps.

5. From API RP 11BR, Section 4, we find that maximum allowable peak stress, S_a, for API grade C and grade D sucker rods = 0.25 x minimum tensile strength, psi + 0.5625 x minimum stress, psi. Assume minimum tensile strength for grade C rods is 90,000 psi and minimum tensile for grade D rods is 115,000 psi.

   Assume minimum allowable peak stress for National-Oilwell EL rods is 50,000 psi regardless of minimum stress.

   Maximum calculated stress when unseating the pump will not exceed 80 percent of the minimum yield strength for API rods or 90 percent of the minimum yield strength when utilizing EL or equivalent rods.

TABLE 2

API sucker rod slim-hole coupling derating factors from S.P.E. Petroleum Engineering Handbook, page 9-8:

API rod size, in.	K	API grade C	D
5/8		0.97	0.77
3/4			0.86
7/8	0.93	0.88	0.69
1			0.89

The use of slim-hole-couplings cannot be recommended with National-Oilwell EL rods, or equivalent rods.

6. The tubing will be anchored no more than 200 feet above the seating nipple if the casing is good and if the well does not make sand.

7. The pump intake should be located at least 15 feet below the producing zone if at all practical. The liquid capacity of the natural gas anchor will be about = area of casing-tubing annulus, square inches x 0.5 feet per second/9702 cubic inches per barrel/(12 inches per foot x 86400 seconds per day) = area of annulus, in.^{2}/0.0187153.

   The gas capacity, standard ft.^{3}/day, of this natural gas anchor will be about equal to the area of the annulus, in.^{2} x 7000 ft.^{3}/in.^{2}.

If the pump displacement is greater than the gas anchor liquid capacity, pump volumetric efficiency will be decreased.

If gas production is greater than the gas separating capacity of the gas anchor, pump volumetric efficiency will be decreased.

If the pump intake is above the producing zone, a natural gas anchor cannot be utilized and the liquid and gas capacity will be decreased.

8. Assume that liquid will have to be lifted from the seating nipple when designing beam pumping installations.

9. Assume the specific gravity of the liquid will be equal to the specific gravity of the formation water.

10. If the prime mover is an electric motor, the unit should be equipped with a pump-off control.

11. The unit should be set so that the polished rod is in the center of the pumping tee throughout the pumping cycle.

12. Assume that the pump will operate at 70 percent volumetric efficiency. When the pump is new, if the pump intake piping is properly designed and if the fluid does not foam, volumetric efficiency will be higher and the unit will have to be shut-in for part of each demand period.

13. Recommended maximum pumping speed and stroke length versus pump setting depth.

pump setting depth, ft.	recommended maximum pumping speed, SPM*	recommended maximum stroke length, in.**	polished rod travel, ft./min.
4000	24.1	36	145
6000	16.1	82	220
8000	12.1	145	292
10000	9.6	227	363
12000	8.0	327	436
14000	6.9	445	512

*N, SPM = $0.35 \times 1.125 \times 245{,}000/L = 96{,}468.75/L$
** S = $0.30 \times 70500/N^2$

If desired production cannot be secured with these recommended combinations because the optimum pump size cannot be run, the stroke lenth will have to be increased and the pumping speed will have to be decreased. In shallow wells, casing smaller than optimum will require longer strokes than optimum.

If you need to increase the pump displacement but the present pumping speed is resulting in a dynamometer card that indicates that an increase in pumping speed will cause the load range to increase enough to overload the gear reducer, what can you do? If the present pumping speed is resulting in the minimum load either going to, or approaching zero, on the downstroke, what can you do? Maybe you cannot do anything, but consider the following:

1. If the well does not make gas, you can increase the allowable downstroke velocity by moving the traveling valve to the top of the plunger.

2. You can also increase the downstroke velocity by running sinker bars above the pump handling pony rod and a full bore centralizer.

3. A tight polished rod stuffing box can decrease the minimum polished rod load, as can a polished rod not centralized in the middle of the pumping tee throughout the pumping cycle.

4. If the subsurface hole contains doglegs that result in excessive sucker rod coupling wear, the rods in these sections should be equipped with cast on plastic centralizers. Centralizers that contain kevlar, the material that they make bullet proof vests out of, are available.

5. Small tubing and small flowlines in high volume wells can increase the upstroke loads and decrease the downstroke loads.

6. If you run tubing pumps in high volume wells, have the top of the plunger on 2.375x1.75 in. tubing pumps equipped with a 0.625 in. sucker rod pin. Attach the plunger to the rod string with a 0.625 in. slimhole coupling and a 0.625 in. pony rod longer than the maximum polished rod stroke length. Attach the pony rod to the bottom sucker rod with a 0.625 in. slimhole coupling. If a 2.875x2.25 in. tubing pump is run utilize 0.75 in. slimhole couplings.

Using rule-of-thumb 7, casing design curves and casing and tubing capacity tables, the liquid and gas capacity of different $5\frac{1}{2}$ in. and 7 in. casing-tubing annulus were calculated. These are in table 3.

TABLE 3

Liquid and gas capacity of natural gas anchors

casing I.D.,in.	interval covered,ft.	area in.^{2}	liquid capacity, BFPD	gas capacity, MFPD	natural gas anchor size
4.95	0-6800	14.82	792	104	5½x2
		12.76	682	89	5½x2½
		9.62	514	67	5½x3½
4.892	6800-10600	14.37	768	101	5½x2
		12.30	657	86	5½x2½
		9.17	490	64	5½x3½
4.778	10600-13800	13.49	721	94	5½x2
		11.43	611	80	5½x2½
		8.31	444	58	5½x3½
6.456	3500-4500	28.31	1531	198	7x2
		26.24	1402	184	7x2½
		23.11	1273	162	7x3½
6.366	4500-5800	27.4	1464	192	7x2
		25.34	1396	177	7x2½
		22.20	1223	155	7x3½
6.276	5800-9400	26.51	1417	186	7x2
		24.44	1306	171	7x2½
		21.31	1139	149	7x3½
6.184	9400-11600	25.60	1368	179	7x2
		23.54	1258	165	7x2½
		20.42	1091	143	7x3½
6.094	11600-13700	24.74	1322	173	7x2
		22.68	1212	159	7x2½
		19.54	1044	137	7x3½

Utilizing API RP 11L calculated pump displacement from 4,000 to 14,000 feet, in 2500 foot steps were made. Result of these calculations are shown in table 4. The pump displacements at 100 percent volumetric efficiency versus depth are also shown on curve 1.

TABLE 4

Item					
pump setting depth, ft.	4000	6500	9000	11500	14000
pump plunger diameter, in.	3.75	2.75	1.75	1.50	1.25
rod string	98	97	96	96	86
stroke length, in.	200	200	240	240	240
strokes/min.	10.3	10.3	9.4	8.7	7.1
net plunger travel,in.	176	164	211.2	204	204
pump displacement,BPD	2972	1490	709	466	264
pprl,lbs.	42883	45006	41492	44850	39760
mprl,lbs	2433	5856	10029	15838	18566
peak torque,in.-lb.	2198323	2079814	2063480	1620097	1098820
prhp	111.3	89.3	77.9	69.7	41.9
load range,lb.	40450	39150	31463	29012	21194
lrxs/4,in.-lb.	2022490	1957489	1887780	1620097	1271659
rods stress,psi.	43142	39150	41742	45121	50624
c r	0.30	0.30	0.30	0.258	0.172
allowable pump depth,ft.	5092	6657	11962	11569	13346
hydraulic horsepower	90.2	73.5	48.4	40.7	28.0
counter balance,lbs.	22548	27003	26708	31376	30691
pump unseating stress,psi				55788	55046

I want to give credit to my wife and friend, Dorothy Lee Gipson, for editing and typing this paper.

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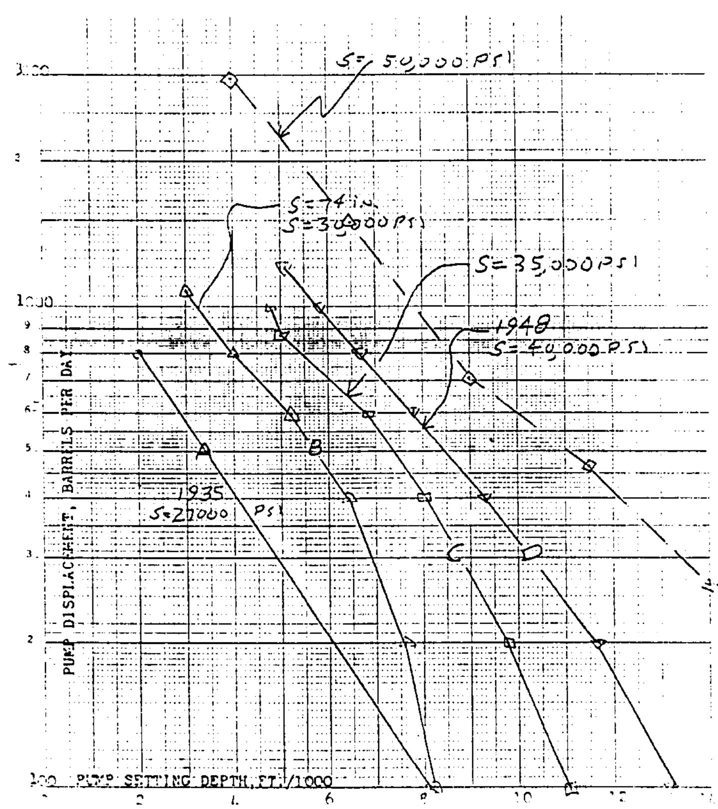

CHART 1