A REPORT DETAILING TEST DATA COMPARING STANDARD VS VORTEX PUMPS

By

M. A. Obrigewitsch, Data Analyst, CCA, Baker Mt.

Vortex Style Pump Tests

In these times of low oil prices and increasing operating costs, we at Shell NorthStar in Baker, MT, have been searching for ways to reduce costs and at the same time reduce failures. We have been successful in failure reduction caused by corrosion. But now, we needed a way of reducing rod loads to reduce rod failures and still pump the necessary amounts of fluid to maintain production. Our pump depths range from 8200' in the Little Beaver field to 9100' in the Pine unit; average production is 40 BOPD and 250 BWPD. Gas interference had not been a problem until we started drilling horizontal wells. This problem was addressed with the use of a ring valve assembly.

After discussions with Rod Johnson (Rig Management Team leader), Doug Kaufman (Dresser Oil Tools™ District manger), the RCFA team and several people in Altura field in West Texas, we came up with several ideas. We could run a shorter plunger, run a loose fit plunger (.007 clearance instead of .003) or take a closer look at a "vortex" standing valve we learned of at a recent school.

Action Items

1. We ran several short plungers (3' or 4') instead of a 5' plunger; we noticed little or no improvement with this idea. It was shortly discarded.

2. The next idea was to run the "loose fit" plunger, a 4' plunger with a change in clearance from .003 to .007. Currently, we have about 7 of these pumps in operation. The downside is keeping track of these wells, of insuring that a similar pump is used when the equipment is changed out and the amount of slippage that is noted on dynamometer cards. The upside is these wells appear to be pumping as much fluid as a conventional pump due to an increase in the unit speed possibly because of less drag. We are also seeing an increase in the minimum loads and a significant decrease in the negative rod loads, resulting in a drop in the number of failures. Ex: Cabin Creek 23x20R had a failure rate of 3.2 per year with a fluid level of 2200 FAP before this pump was run. After 13 months of running, this well had a 3/4 pin failure; we then pulled the pump to check for problems. None were found when the pump was broken down. The fluid level has dropped to 800 FAP, the lowest level recorded for this well. This is attributed to the long run between failures.

3. At the 1996 Southwestern Petroleum Short Course in Lubbock Texas, we learned about a standing valve discussed in the World Oil magazine. A valve developed by HIVAV Company Ltd. Of Calgary, Alberta, Canada was designed to allow more fluid to pass through and enable the producer to pump more fluid and gas with a smaller bore pump. This valve should allow us to reduce rod loads, thereby reducing rod failures, and still pump the same or more fluid from the wells. These valves were advertised as being better in reducing gas breakout. Doug Kaufman of Dresser Oil Tools™ of Glendive, MT, agreed to supply several large bore standing valves and to assist us in obtaining several valves from other manufacturers to test in the Cedar Creek Anticline.

These valves were vortex designed valves. They are 2.25" cages with a spiral turn used on pumps ranging from 1.5" to 2" in a 2-7/8" tubing string. Initial costs were acceptable, about $400. The metallurgy was Monel, a very important factor in our wells with H2S gas. Stainless steel tends to harden in a H2S environment and break; we haven't had similar problems with Monel products.

Test results:

#1 ND # 70 Little Beaver Field – New horizontal well

Our first test well was nothing to brag about, We ran a 1.5" x 222" standard pump (25–150-rhbm–20-5-5) with a ring valve assembly and a 2.25 vortex standing valve. We ran this pump in 6-97 at North Dakota well # 70, a new horizontal well. The pump was set at 8600'. The next day the well had stopped pumping; and, we were unable to get it to pump. The pump was pulled; it was full of fluid and pumped on surface. We next ran a standard 1.5" pump with a ring valve assembly. This pump is still in operation. Later information indicated that the pump might not have been at fault; it may have done what we expected, that is, to pump the well off. Tests showed that this well was only producing 100 BBLS fluid and is now producing 20 oil and 15 water. Is it possible this pump gas locked when we severely pumped it off with a Lufkin Mark II 912 unit running 8.8 SPM and a 1.5" vortex valve pump?

#2 43-20 Cabin Creek

This is the same type of pump (vortex valve) we tested in ND # 70 Beaver with a different result: *IT WORKS*! We lowered the pump 2000' to 8660 in 7-97; to gain back the fluid lost when the pump shoe was raised in 1996. Prior to raising the pump shoe 2000', this well had a failure rate of 5.5 per year. Since we lowered the pump and ran a "spiral" pump, there have been only 2 failures in 16 months. This 1.75 "spiral" pump is producing 502 BBLS daily, about the same as we could pump using a standard 2" pump under the same conditions (*see table 1a*). The production tests as of 10-97 show 34 BOPD, 474 BWPD and 4 MCFS gas. The well is still producing 28 BOPD and 416 BWPD with a run time of 22 hrs. The rod loads were 65 to 70% with a 2" pump set at 6800', the same as with a 1.75" pump set at 8800'. The max and min loads remained close: 31,000# and 7700# with both pumps.

On June 1st, we had a 1" pin failure; we fished the rods, and put the well back to production. Shortly after the rig finished, we noticed the pump was not working. While attempting to change the pump, the rig crew found a partial pump. The vortex valve had broken in the weld joining the two pieces together. This is no longer a problem since the valve is now a single piece assembly.

 # 3 42-09H Pennel – recent re-entry well

On this, the latest re-entry horizontal well, we ran a vortex valve on a 1.5" pump after the re-entry work was finished. Initial tests showed 400 BOPD and 17 BWPD at 9.1 SPM with a fluid level of 1300' from surface. Ten days later the test showed 330 BOPD, 12 BWPD and a fluid level of 2000' from surface. The October test was 313 BOPD, 4 BWPD and 33 MCFS gas; the well is running 24 hrs with a fluid level of 2250 FAP.

In 9-97 we upsized the pump with a 1.75" ring valve and a vortex valve. This well is currently at pumpoff, runs 21 hours, and is producing 200 BOPD. We are allowing this well tag slightly to keep from gas locking and losing production.

One thing we noticed is the larger standing valves (vortex valves) don't handle gassy horizontal wells very well. On vertical wells, this style of pump results in more production than expected from the 25-175-RHBM-20-5-5 pump. On horizontal wells, we get the additional fluid but have to work hard to prevent gas locking. The Shell NorthStar pumping philosophy on horizontal wells is to set the pump shoe at the top of the kickoff point, thereby setting the pump above the "perforated or horizontal" zone. All gas, free and breakout, must travel through the pump rather than break out above the pump intake, which would permits better gas handling.

 # 4 13-30 EH Pine – New horizontal well

We ran a 1.75" pump with a vortex valve on this well. It produced initially 40 BOPD and 513 BWPD with a fluid level of 2000 ft from surface. The pumped off test was 101 BOPD, 221 BWPD and 40 MCFS gas with an 18 hour runtime. The well is still producing 85 BOPD, 200 BWPD with 40 MCFS gas.

In 9/97, the well stopped producing; the pump shoe was washed. We replaced the pump with a 1.75" ring valve pump with a standard standing valve assembly. The well is pumped off. On this well, we noticed the same problem, as on 42-09 Pennel re-entry well. These vortex type standing valves don't work as well on gassy horizontal wells.

#5 11-19BH Pennel – New horizontal well

This is another new horizontal well with a vortex type pump. This well is pumped off; the tests are 142 BOPD, 4 BWPD and 66 MCFS of gas as of 10/97. The tests during the month of December indicate the production is 225 oil and 5 water. We are pumping this well off; but, as with other horizontal wells with vortex valves, we are seeing gas interference.

In Sept 1998, we replace the pump with a 1.50 ring valve pump. The well is now pumping off with little gas interference.

#6 Pine 41-23A

We downsized from a 2" to a 1.5" pump with a vortex valve in 8/97. The tests are the same. *(Table 1b)* Rod loads dropped from 67% with the 2" pump to 55% using a 1.5" pump. The unit load dropped from 84% loaded to 59% loaded and the well is pumped off. (*Table1c*) This well is pumping under a packer.

The downhole stroke increased 18" when we changed pump sizes, not necessarily because of the spiral valve pump.

#7 Pine 21-23A

We ran a 1.5" vortex type pump replacing the 2" pump in this wellbore in 10/97. It took three months to return to the original test rate. At that, time the chemical pump stopped and the well failed. Since it took so long using a 1.50 pump to get the normal production back, we upsized to a 1.75" large bore standing valve type pump. The rods parted while running in the hole; we pulled all the equipment, laid down the bent rods and replaced the pump with a 1.75" vortex type pump. After having the pump shop inspect the pump with the large bore standing valve pump, it was put back on the rack (waiting for a new home). Currently the well is producing the same amount of oil and water with the 1.75" as it did with a 2" pump.

On this well we noticed an increase of 8"-10" of downhole stroke compared to the standard 1.75 pump we were running in 10-96.

#8 Pine 42-22A:

We ran a vortex type 1.75" pump on 10/97; this replaced a 2" pump. I found this well tagging bottom very hard three days after the rig left; the rods were raised 12" and the well was returned to production. One month later this well had a 2000 ft fluid level and the production was down 10 oil and 50 water daily.

In May, we pulled the well equipment for a water shutoff. The pump was taken back to the shop where it was discovered that the traveling valve cage was cracked, possibly from tagging bottom 6 months earlier. After the shutoff, we ran a 1.5" vortex pump; the well is pumped off making 55 BOPD and 129 BWPD.

#9 Cabin 44x-17H

We ran a 1.75" vortex pump, replacing a 2" pump, on 10/97. Currently the fluid level is 300 FAP and the tests show the same oil and a small drop in the water production, possibly due to the well being pumped off. We did not see any gas interference on this well possibly because the well is only producing 1 MCF of gas.

#10 Pennel 33-23R

We replaced a 2" pump with 1.75" vortex pump in 10/97. The well is nearly pumped off and the tests show the production is the same as with the 2" pump.

(*Table 1d*)

#11 11-36 RR Pennel:

The latest test pump ran in this well was a 1.75" large bore standing valve; it replaced a standard 2" pump. The gearbox loads, formerly 102%, have now dropped to 74%. The rod loads were 85 - 95% loaded, and are now 74% loaded. The maximum loads dropped 4000#, from 36,500 to 32,500 and the downhole stroke increased from 134" to 164". We are now capable of pumping more fluid with the 1.75" pump than we were with the 2" standard based on the downhole stroke. But, the tests indicated that we are pumping less. The prior tests showed 560 BBLS total fluid; we are now producing about 500 BBLS total fluid. After 2 months, this pump was pulled and we ran a vortex style pump. Initial tests indicate we are still short production, The oil production dropped to 85 bbls from 115 bbls.

On August 14^{th}, we replaced this pump with a standard 2"; the production is back to normal. The October test showed 112 oil and 440 water.

#12 ND 6 Well

We pulled the pump in 12/97 and replaced it with a "loose fit plunger" type in an attempt to increase the total production from this well. The well stopped pumping; the pump was stuck. We discovered a joint of tubing crimped above the pump; pinching the rods and pump.

We replaced the pump with the large bore standing valve pump. The tests indicate that we were getting more fluid than with a standard pump, less oil and more water. Prior tests showed an average of 34 oil and 560 water, as of 3/98 we produced 25 oil and 580 water. Delta cards indicate a significant standing valve leak. Is it due to the large bore valve or something else?

Recent tests indicate oil production is back to 37 oil and 550 water; the well is at pumpoff. We are still seeing a large standing valve leak.

This well had a pump failure on 7/98; we replaced the large bore standing valve with a vortex standing valve. The large bore standing valve was broken and this was what caused the standing valve leak.

Summary:

This report was not written from an engineering standpoint but as an actual field study. We are not attempting to offer answers to any questions that we raised but relaying data from our tests. If anyone would like more detail about the vortex valves, both traveling and standing, contact P.O.S.S.I. at 1-281-373-1128. They will be very helpful as they were with us.

This style of pump, with a vortex standing valve has performed as reported in the documents from Flowmore™ systems Inc. We have seen a substantial increase in the amount of fluid lifted with a smaller bore pump; fitted with the vortex style standing valve. The tables below prove that we are able to produce as much fluid with 1.75" bore pump, as we were able to with a 2" standard pump. In isolated cases we have seen this also using a 1.5" pump. These pumps helped reduce the rod loads and we believe reduced rod failures. Eight of the well listed in this paper were pumping prior to the use of a vortex pump. They had a total of 56 failures between 1995 and mid 1997, since then there have been 8 failures. *(Table 1e)*

On the downside, we experienced a lot of gas interference in the horizontal wells when the pump shoe was placed above the kickoff point. This could be minimized by placing the pump in the horizontal curve or by adding a Sidekicker ™ valve to alleviate the gas problem.

At this time, there is no question that the "modified standing valve" pump is capable of producing more fluid with less size. There appears to be a difference between the large bore standing valve and the vortex standing valve; the vortex is clearly the better choice for our use. We haven't attempted any comparison tests with other style vortex valves. Overall, we are currently running 25 or more pumps with this "modified" standing valve and feel that it is a critical part of our business.

Vortex Traveling Valve Test Data:

24-19C Pennel:

The well has the first pump with a 1.75" vortex traveling valve. The well was shut in on June 13 for flowline replacement. It was returned to production on July 30 and ran until August 17 when the rods parted. The new pump was installed on August 24; and, we began to monitor the well.

It is normally a 23-24 hour well with a 168" surface stroke, a 126" downhole stroke and a 1.75" pump. Production is approximately 40 oil/237 water/5 MCF gas. Rod loads are about 72%; the rods are N97's; the 1" rods were run in June of 1996 and the 7/8" and 3/4" in September of 1994.

Twenty-four hours after 24-19C was returned to production, the fluid level was 2300 fap; the rod loads were about 68%. The surface stroke was 168" with a 142" downhole stroke.

Pennel 24-19C ran for nine days and then pumped off. During this time, tests were 64 oil/285 water/7 MCF gas. After the well pumped off, the tests returned to 40 oil/ 202 water/6 MCF gas. Today, the well has a surface stroke of 168" and a downhole stroke of 133". Run time is 19-20 hours, a decrease of 4 hours from what it had pumped with the standard pump. The rod loads show 60% loaded, a drop of 12%, possibly due to more gas produced and lighter loads.

This well parted the rods on 11-4-98. We fished and hung the well back on Nov. 15th, two days later the dynamometer cards showed pump failure. We pulled the pump and found the traveling valve was busted. We replaced it with another vortex traveling valve.

Two weeks later we had a tubing leak, we pulled the pump and again it was worn and wallowed out again. We ran a vortex standing valve pump this time. I ran a delta the day the rig finished, the 4th of December. At this time the well had 2600 feet of fluid. The downhole stroke was 145" and a surface stroke of 168".

On 12-7-98 I reshot the fluid level, it was 1000 fap and the well was running smoothly. The current test showed 49 oil and 304 water, total fluid was comparable to the vortex traveling valve production. This well pumped off on the 9th of December and is running 19 hrs daily.

12X-36 Pennel

This is the second pump we installed with a vortex traveling valve. Pennel 12X-36 produces 22 oil/270 water/4 to 5 MCF gas. Previously, run time was 24 hours with an average fluid level of 1200 fap. The Mark II 640 is in the 144" stroke length, running 9.2 SPM with a 1.75 x 222" pump. At that time, the well had an 87 rod design with the 1" and 7/8" rods loaded to 64%. The surface stroke was 144" with a 116" downhole stroke.

On September 28, we ran the 1.75" pump with the vortex traveling valve and changed the rod design to an 86 style. A delta run on October 1 showed the fluid level was 6700 fap. (The well had been down for two weeks with a tubing leak.) The rod loads went from 52% loaded on the 1" rods to 42% on the 3/4" rods. The downhole stroke length was 140" and the surface was 144". A test taken on October 2 was 0 oil/360 water/1 MCF gas. On October 6, this well produced 32 oil/300 water/4 MCF gas, an increase of 40 BBLS total fluid over what the conventional pump had pumped.

A follow-up delta performed on October 7 showed the fluid level had dropped 5900 feet to 800 fap; rod loads were 69% and the downhole stroke was 111".

The data analyst reported the pump had failed according to the SPOC system we are using. I ran a delta and confirmed his findings. The pump was 68 days old and had broken into several pieces. We replaced it with a vortex standing valve pump on 12-8-98. This well has a fluid level of 4200 fap.

On 12-11, I ran a delta and shot the fluid level, the well is pumped off. The rod loads and max and min loads were equal to the traveling valve. The downhole stroke was 111" and the production is the same as with the traveling valve. The run time is 23 hrs, compared to the 24 hr runtime and a fluid level of 1200 fap we used to have with a conventional pump.

More data about the vortex traveling valve...

14-33U Pine

We ran a vortex traveling and standing valve pump in this well on 11-6-98.The well checker reported 14-33U would not pressure test on the 23rd. We sent a rig to pull the production equipment and check the pump. There was a split JT of tubing. We replaced the pump with a vortex standing valve pump. The traveling valve on the pump we pulled was worn and cracked after 17 days.

Summary on the vortex traveling valve

These valves did not stand up in actual field usage. They were able to produce as much as a vortex standing valve pump but the standing valve appears to be the better choice.

References:

1. World Oil, March 1997, page 69. "(What's New in Artificial Lift)". By James Lea, Amoco Research and Herald W. Winkler, Texas Tech University.

2. Southwestern Petroleum Short course, April 1998, pages 133-136. "(Production optimization by vortexing in sucker rod pumps)". By A.A. Pennington, Possi

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Table 1A - 43-20 Cabin Creek Test Records

Date	oil	water	gas	test hrs	
07-98	36	406	9	24 hrs	
05-98	26	399	3	24 hrs	
03-98	39	459	3	23 hrs	
02-98	39	450	5	24 hrs	
10-97	32	467	8	23 hrs	
09-97	39	483	3	23 hrs	ran spiral & lowered shoe.
02-97	22	372	3	24 hrs	
10-96	23	412	5	24 hrs	
03-96	29	377	0	24 hrs	
08-95	21	401	6	24 hrs	after pump shoe raised.
05-95	42	414	19	24 hrs	
09-94	32	534	16	22 hrs	

Table 1B - 41-23A South Pine Test Records

Date	oil	water	gas	test hrs	
06-98	13	234	9	22 hrs	
05-98	14	228	4	23 hrs	
10-97	15	224	2	21 hrs	
10-97	15	241	3	21 hrs	1.50 " spiral pump
08-97	14	245	6	16 hrs	
05-97	18	249	5	17 hrs	standard 2" pump

Table 1C - 41-23A South Pine Delta Records

This was a Mark 912 with a 2" pump; beam load of 84% & GB loaded 87%.

Rods	GRD	#	Min	Max	% loaded
1"	EL	88	13505#	40680#	66%
7/8	EL	98	8810#	39715#	68%
¾"	EL	144	3226#	38174#	69%
1"	EL	20	-2732#	11200#	23%

This is the same unit with a 1.5" pump, beam loaded 59% & GB loaded 76%

Rods	GRD	#	Min	Max	% loaded
1"	EL	93	13328#	27935#	57%
7/8	EL	98	8801#	33222#	56%
¾"	EL	164	3432#	28728#	51%

Table 1D - 33-23R Pennel Well Test Records

Date	oil	water	gas	test hrs	
07-98	38	369	13	24 hrs	
06-98	47	360	13	24 hrs	
06-98	44	372	14	24 hrs	
05-98	41	358	14	24 hrs	
04-98	45	352	13	24 hrs	
01-98	41	373	10	24 hrs	
11-97	41	366	10	24 hrs	Ran 1.75" spiral pump
08-97	38	367	10	24 hrs	
05-97	33	351	7	24 hrs	
01-97	36	346	4	24 hrs	
11-96	33	298	7	24 hrs	
09-96	32	324	11	24 hrs	
07-96	48	367	13	24 hrs	Standard 2" pump

Table 1E - Failure Statistics from 1995 thru 10-98

Well #	Before vortex	After vortex
12x-26	5	0
24-19C	7	0
ND# 6	10	0
11x-36	7	2
33-23R	5	1
21-23A	9	3
41-23A	8	0
43-20	5	2