

Case Study of Plunger-Lift Installation in the San Juan Basin



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Abstract

An analysis and economic evaluation of over 150 plunger installations in the San Juan Basin (SJB) has been made. The case study reviews performance and results of all installations, and clearly shows that plunger-lift has significantly increased volumes and reserves. Best practices, screening criteria and design considerations are presented. Individual well results are presented in tabular form showing before and after rates. Economic analysis indicates plunger-lift on these SJB wells is extremely attractive with average payout of installations in two months.

Introduction

The San Juan Basin consists of over 20,000 wells (mostly gas). The wells produce principally from four main Cretaceous reservoirs. These reservoirs are the Fruitland Coal, Pictured Cliffs, Mesaverde, and the Dakota. Most of the reservoirs are volumetric with minimal water and oil production. As these reservoirs have depleted and flow rates have dropped, the ability of a well to maintain the gas velocity necessary to keep the well free of liquids has decreased. Keeping these gas wells unloaded is a critical success factor for all operators in the San Juan Basin. Development is on 320 or 160 acre spacing units and locations are often remote and electricity is usually not available or expensive to install. These conditions make plunger-lift an excellent artificial lift method for SJB wells.

This paper was initially an in-house look back study to determine the profitability of Conoco's use of plunger-lift in the San Juan Basin. The main objective was to determine if plunger-lift had been economically successful and document the results. The secondary objective of the look back was to determine if additional plunger-lift systems should be installed and what screening criteria/best practices should be followed to evaluate subsequent plunger-lift installations. Conclusions of this study and recommendations for proceeding forward with plunger-lift installations follow. Over 150 installations are included in this study. Wells that had compressions installed at or near the time plunger-lift was installed have not been included in this study to eliminate volume increases due to compression rather than plunger-lift. Also, only gas production increases have been included. This

is because SJB oil/condensate production is normally very small (<5 BOPD) and difficult to track on a daily basis; however, any increases in oil production would improve the economics.

Discussion

Plunger-lift might be best described as a more efficient form of gas lift. It differs in that it usually uses well shut-in pressure and a plunger or piston to lift fluids from the well bore and not artificially imposed pressure. The greatest advantage over gas lift is that it limits fluid slippage or fallback. The plunger is essentially an efficient swab cup sweeping well bore fluids out of the tubing.

A detailed discussion of the fundamentals of plunger-lift operation will not be discussed in this paper. However, plunger-lift control on these installations is by programmable controllers. These controllers or "Smartboxes" are a critical success factor and part of the operating philosophy. Once the plunger-lift system is installed and operating, it allows lease operators to spend less time at each well. The operators do not have to manually vent or unload wells. This can increase the number of wells operated per lease operator.

There are 154 plunger-lift installations in the attached spreadsheet. There are 128 Dakota (DK) installations, 19 Mesaverde (MV) installations, and 7 Fruitland Coal (FC) installations. A typical 7,000' Dakota well will produce 100 MCFPD, 1 BCPD and 1 BWPD. A typical 4,500' Mesaverde well will produce about 250 MCFD, 1 BOPD and 1 BWPD.

The spreadsheet shows well, formation, pre-installation rate, post-installation rate, date installed, and payout days. The rates are monthly sales volume average before installation. The post-rate is monthly sales volume average 3-6 months after installation. Therefore, this rate is conservative, since immediately after installation, rates are almost always greater than the later monthly average. The payout calculation is based on a \$5,000 installation cost, a gas price of \$1.50/MCF and NRI of 0.76.

Economics

The spreadsheet shows that the average installation paid out in 66 days and also increased production by 66 MCFPD. Sixty wells paid out in less than 2 months. Forty-four wells paid out in 2-4 months and 17 wells paid out in 4-6 months. Sixteen wells had payouts longer than a year and 14 wells showed no



payout (no production increase or decrease). Although some of the wells did not show a payout, there was still some benefit to these installations. Eleven of these installations eliminated venting, either manual or by stop clocking. This reduces operator time, eliminates air emissions, and prevents waste. Nine of the “failure” installations did not improve production due to high line pressure.

In addition to this simple payout method of analysis, a total project economic evaluation was done. To do this, a question needed to be answered: What portion of these production increases are reserve additions and/or reserves acceleration? Since some of the wells were either shut-in or near the economic limit, production increases on these wells are obviously reserve additions. Production increases on economic wells also allow a well to produce longer before it reaches the economic limit, thus increasing reserves.

After much discussion, it was decided to do the analysis under the assumption that the production increases were 100 percent reserve acceleration. This methodology would give a bottom line conservative value of the plunger-lift installations. Inputs and results of the analysis are shown below:

Investment:	\$775,000
Net Present Value:	\$8,234,000
Profitability Index	11.6
Internal ROR	>200%
Project life:	20 years
Discounted Payback	0.35 years
Operating Cost:	\$100,000/year

These economics are very competitive with other investment opportunities and validate the simple payout calculations.

Conclusions-Operating Parameters

1. Lease Operator knowledge of plunger-lift mechanics, trouble shooting, and optimizations is critical to efficient plunger-lift operations.
2. Programmable controllers can reduce the amount of time an operator spends at a location by automatically adjusting to changing line pressures and fluid volumes. This will reduce operating costs and help achieve higher well counts per operator while maintaining maximum production.
3. Gas venting, either manual or by stop clocking, has greatly decreased on these SJB wells.
4. At current line pressures and rates, the majority of non compressed wells in the SJB do not have sufficient rate, to

remain unloaded, even with 1.66” tubing.

5. The majority of plunger-lift failures have been caused by mechanical problems with the wellhead or tubing string.
6. Based on field experience, 1.66” OD plungers break more frequently than larger size plungers.
7. Field experience shows that plunger trips can be timed to prevent compressor under load or competition between low and high rate wells.
8. Field experience indicates plungers are an effective mechanical method for controlling paraffin deposition in tubing strings.

General Conclusions

1. Plunger-lift systems are efficient in eliminating liquid loading problems on DK, MV, and FC SJB wells. The attached screening criteria can be used to minimize cost and increase overall success rate.
2. Lease operator training, buy in, and understanding are critical to the successful use of plunger-lift systems.
3. Mechanical failures are minimized by replacing tubing or wellheads.
4. Plunger-lift can be an effective alternative to pumping units.
5. Avoid the use of small, i.e. 1.66/ OD, tubing in plunger-lift installations. Small plungers break more frequently and the tubing is difficult to unload following a shut-in due to its small volume per linear foot.
6. Plunger-lift installations should be reviewed with lease operators and production technicians at least once a quarter to insure proper operation.

Plunger-lift Best Practices/screening Criteria

1. Gather and document line pressure, well shut-in pressure and tubing pressures to evaluate an installation.
2. Determine current and past GLR.
3. Document and evaluate size and mechanical condition of the tubing. Perform the necessary wireline work. Run tubing drift and broach if necessary. Run test plug and test tubing before installation. If a tubing restriction/hole or casing leak is found or suspected, pull the well and correct the problem before installing the plunger system. *
4. Check for packers, surface line constraints or pressure control valves. Check wellhead for plunger clearance problems.



5. Screen well for current operating problems including manual venting and/or stop clocking.
6. Gather and analyze production history and establish an accurate daily sales baseline volume.
7. Run computer design program to determine operating parameters.

*The importance of the wireline work cannot be overemphasized. Holes in the tubing or restrictions will hinder plunger operation and most plunger-lift installation failures can be attributed to mechanical problems.

Acknowledgments

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Exhibit – Spreadsheet

Well Name / Number	Zone Form.	Pre-Inst Rate MCFD	Post-Inst Rate MCFD	Incremental Production MCFD	Date Installed	Payout Days	Comments
100	DK	11	30	19	09/19/1995	231	TRANSFERRED FROM SO. AREA 11/95
126	DK	38	425	387	07/21/1995	11	
129	DK	37	140	103	07/25/1995	43	
129E	DK	59	87	28	08/01/1995	157	
132	DK	59	138	79	8/8/1999	56	
133	DK	53	142	89	5/22/1995	49	
136E	DK	83	125	42	07/13/1995	104	
152	DK	51	150	99	08/03/1995	44	
156	DK	104	200	96	06/15/1995	46	
158	DK	18	40	22	07/19/1995	199	MOVE SYSTEM TO 28-7 #95. 11/30/95
164E	DK	106	164	58	07/12/1995	76	
165E	DK	115	120	5	08/02/1995	877	
183	DK	88	225	137	07/20/1995	32	
187	DK	33	135	102	07/11/1995	43	
229	DK	35	110	75	08/15/1995	58	
233E	DK	62	110	48	07/13/1995	91	REQUIRES MULTI-FLEX PLUNGER
239	DK	154	198	44	06/30/1995	100	
239E	DK	56	110	54	06/21/1995	81	
241	DK	45	85	40	06/19/1995	110	
242	DK	37	75	38	06/23/1995	115	
242E	DK	85	123	38	07/10/1995	115	
243	DK	35	70	35	07/21/1995	125	
246	DK	56	100	44	06/23/1995	100	TIGHT TBG, REQUIRES TURNED DOWN FIBER-SEAL 1.450"
246E	DK	42	165	123	06/28/1995	36	
248	DK	149	260	111	06/20/1995	40	
248E	DK	131	242	111	07/07/1995	40	
252E	DK	33	20	-13	07/24/1995	-337	
256	DK	86	295	209	06/22/1995	21	
BABBITT #1	DK	30	65	35	05/28/1993	125	ELIMINATED MANUAL VENTING
BLOOMFIELD CANYON 1	DK	90	150	60	04/26/1993	73	ELIMINATED MANUAL VENTING
CHARLES HUTTON 1	DK	19	50	31	08/04/1995	141	STILL OPTIMIZING
COLKET 1 (NASSAU)	DK	69	140	71	8/95	62	
COLKET 1E (NASSAU)	DK	7	20	13	8/95	337	
DUMP MESA FED 1	DK	70	123	53	5/94	83	ELIMINATED INEFFECTIVE AUTO EQUALIZE SYSTEM
EDGAR FED #2	DK	T81	27	27	02/22/1993	162	
ERIN 1 (NASSAU)	DK	55	117	62	8/95	71	
ERIN 1E (NASSAU)	DK	119	87	-32	8/95	-137	DOWNTIME
FARMINGTON A COM 1	DK	50	51	1	5/93	4386	ELIM VENT, ADDED AMOCO WELLS
FARMINGTON B COM 1	DK	120	120	0	5/93	ERR	
FARMINGTON B COM 1E	DK	50	75	25	3/93	175	
FED 10E	DK	20	77	57	09/08/1995	77	TOO EARLY, 1 BWPD 1 BOPD
FEDERAL A #1	DK	86	106	20	7/94	219	ELIMINATED VENTING
FEDERAL G #1	DK	20	54	34	9/93	129	WAS IN RED FINANCIALLY STILL IS ? MAY NEED TO SELL OR P&A
FEDERAL #10	DK	120	83	-37	07/20/1993	-119	
FEDERAL #10E	DK	20	50	30	07/19/1993	146	
FEDERAL #5E	DK	75	84	9	1991	487	*ELIMINATED VENTING, ALREADY ON PL, JUST ADDED AUTOCYCLE CONTROLLER*
FEDERAL #9	DK	?	10	10	1991	439	HAD PROB, MUCH DT FOR PRESENT MCF-ALREADY ON PL, CAN DO BETTER
FEUILLE FED #1	DK	100	131	31	05/28/1993	141	ELIMINATED MANUAL VENTING
FEUILLE FED #3	DK	90	183	93	05/28/1993	47	
FOGELSON 10-1	DK	90	165	75	8/95	58	
HARRIS MESA FED 1	DK	0	88	88	N/A	50	

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SCHLOSSER FED #5E	DK	20	37	17	10/93	258	ELIM VENT, HIGH LINE PSI
SCHLOSSER FED #6	DK	85	110	25	10/27/1993	175	PROD. STABILIZED
SCHLOSSER FED #6E	DK	70	92	22	10/22/1993	199	PROD. STABILIZED
SCHLOSSER FED #7	DK	60	136	76	10/28/1993	58	PROD. STABILIZED
SCHLOSSER FED #7E	DK	42	233	191	05/20/1994	23	7/94 STABILIZED 250 MCF/D
SCHLOSSER FED #8	DK	45	55	10	4/94	439	ELIM VENT, HIGH LINE PSI
SCHLOSSER FED #8E	DK	17	29	12	5/94	365	ELIM VENT, HIGH LINE PSI
SO UTE 33-1	DK	400	600	200	07/14/1994	22	HAD TO VENT TWICE A WEEK
STANDARD 1	DK	20	105	85	6/94	52	WAS LOG'N OFF WITH COMP ONLY
STATE B COM #1E	DK	95	275	180	11/01/1993	24	PROD. STABILIZED
STATE COM AD #26	DK	175	178	3	7/94	1462	WAS LOG'N OFF WITH COMP ONLY
STATE COM AF #28	DK	75	110	35	03/29/1993	125	ELIMINATED MANUAL VENTING
STATE COM AI #33	DK	30	78	48	06/15/1993	91	ELIMINATED MANUAL VENTING
STATE COM AJ #34	DK	12	86	74	3/93	59	OP NEGLECT TO SURFACE EQUIP HAS CAUSED SOME DT
STATE COM AK #35	DK	78	78	1992		56	LOW PROD - AT PRESENT WAITING ON DUAL WORKOVER
STATE COM AL #36	DK	30	123	93	04/23/1993	47	
STATE COM AM #37	DK	20	100	80	05/28/1993	55	EXPECT MORE, NOT STABILIZED
STATE E COM #1	DK	80	238	158	06/03/1994	28	
STATE E COM #1E	DK	20	0	-20	11/02/1993	NA	PROD. NOT STABILIZED
STATE M1	DK	70	180	110	07/11/1995	40	
STATE M1E	DK	119	300	181	8/95	24	ELIMINATED AUTO VENT TO ATMOS
STATE #32	DK	60	70	10	05/29/1993	439	ELIMINATED MANUAL VENTING
TIDEWATER FED #1	DK	100	122	22	04/29/1994	199	ELIMINATED MANUAL VENTING
TIDEWATER FED #2	DK	200	105	-95	8/94	-46	
WALKER 1	DK	40	147	107	8/95	41	REPAIRED 1.666 TBG LEAK W/2.375
WALKER 1	DK	20	37	17	6/94	258	WAS LOG'N OFF WITH COMP ONLY. STILL OPTIMIZING-TRY W/O COMP
WOOD WN FED 1	DK	30	144	114	9/95	38	10/95 INT VOL WAS 85 MCFD
		8,236	15,646	7,410	128	76	
DAY B #14	FC	58	58	N	A	76	
FC BARNES COM1	FC	212	330	118	8/95	37	ELIMINATE LOGGED OFF DT
FC FED COM 10	FC	65	65	0	8/95	ERR	5 GAL WTR PER DAY AT THE MOST
FC ST COM #13	FC	75	273	198	7/94	22	
FC ST COM #24	FC	81	85	4	7/94	1096	ELIM PU AND GEN, ENABLED ADJ TO COMP, IMPROVED SC AH 30E PROD
FC ST COM #5	FC	155	474	319	12/02/1992	14	ELIMINATED P/U
ROELOFS A4	FC	32	50	18	07/01/1998	244	STILL OPTIMIZING, ELIM MAN VENT
		620	1,335	715	7	43	
135M	MV	170	228	58	06/28/1995	76	REQUIRES BAR STOCK. PARAFFIN CONTROL
85	MV	21	50	29	07/22/1995	151	
HAMMOND FED #8	MV	80	178	98	10/29/1993	45	4 BBL OIL/DAY PROD. NO COMPRESSOR
JOHNS 1A	MV	175	375	200	4/93	22	DID BETTER WHEN COMPRESSOR HAD TURBO CHARGER
JOHNS FED 1R	MV	250	430	180	07/12/1994	24	MUCH DT - LOGGING OFF
JOHNS FED 2	MV	200	430	230	7/94	19	MUCH DT - LOGGING OFF
SC AK 35	MV	107	225	118	03/30/1995	37	NO COST, USED DK EQUIP
SC F1A	MV	20	80	60	09/25/1995	73	8 BWP/D, .25 BOPD
STATE COM F #1X	MV	75	250	175	03/28/1994	25	GOOD OIL PROD NOW - 3 BBL/D ON COMPRESSION
STATE N1M	MV	66	145	79	07/17/1995	56	
SUTER 1A	MV	137	350	213	8/94	21	WAS LOG'N W/COM ONLY
SUTER 2A MV	MV	200	224	24	5/94	183	WAS LOG'N W/COM ONLY - BEFORE RATE WITH COMP RUNNING, MUCH DT
SUTER 3	MV	60	70	10	5/93	439	ELIM VENT, ADDED AMOCO WELLS, NO COMPRESSOR

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SUTER 3A	MV	190	225	35	8/95	125	ELIMINATE LOGGED OFF DT
SUTER 4	MV	300	335	35	8/95	125	ELIMINATE LOGGED OFF DT
SUTER 4A	MV	295	450	155	04/05/1995	28	ELIMINATE LOGGED OFF DT
THREE STATES LS 1	MV	40	70	30	8/95	146	ELIM MUCH AUTO VENTING
WALKER LS 2	MV	0	320	320	8/95	14	VERY CLOSE TO LINE PSI S/I PSI
WALKER LS 2A	MV	0	55	55	8/95	80	VERY CLOSE TO LINE PSI S/I PSI
TRIEB FED #2E	MV/DK	300	366	66	11/09/1993	66	40 BBLs H ₂ O/DAY ON COMPRESSION
		2,686	4,856	2,170	20	40	
Totals/Numbers		20,398	38,818	18,420	157	37	

Note: Payout calculation based on \$5,000/well and \$1.50/MCF gas price.