

Gas Operated Automatic Lift [G.O.A.L.] PetroPump Demonstration in New York Gas Wells

Final Report

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Notice

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Abstract

The G.O.A.L. PetroPump is a free floating in well device, which operates within the well casing using natural gas pressure to automatically remove fluids from oil and or gas wells. The tool is configured with a unique on tool pressure activated self-closing and self opening valve that allows the tool to operate 'smart' on both down hole and up hole transit. The G.O.A.L. PetroPump automatically descends down hole to obtain a predetermined volume of fluid which also seals the on tool valve and then returns that volume fluid, utilizing below tool formation pressure to deliver it to the process unit for sales. The G.O.A.L. PetroPump upon delivering fluid to the process unit awaits decreased down hole pressure/ around tool pressure before automatically descending for another load of fluids.

The objectives of this study were to evaluate the G.O.A.L. PetroPump to determine its ability to improve productivity and extend economic life of oil and gas stripper wells in the state of New York.

This Paper investigates the operation of four G.O.A.L. PetroPumps in three wells in Chatauqua County, New York. A case study is presented illustrating the operation of the tools in these three wells. The operation of the G.O.A.L. PetroPump is analyzed to show operational and cost benefits and additional applications. Results of testing have shown 1.5 to 2.3 multiple improved gas yield on average using the G.O.A.L. PetroPump over other casing plunger type tools.

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Table of Contents

Section	Page
Summary	S - 1
1 Description of Project	1 - 1
Background	1 - 1
Well Details	1 - 2
Well LRI # 52	1 - 2
Well LRI # 54	1 - 2
Well LRI # 332	1 - 3
2 Work Program	2 - 1
Tool Preparation	2 - 2
Well Preparation	2 - 2
Tool Installation	2 - 3
3 Analysis of Tool Operation	3 - 1
3.1 Analysis of Well LRI # 52 [1996/1997test]	3 - 1
Analysis of Well LRI # 54 [1996/1997 test]	3 - 3
3.2 Analysis of Well LRI # 52 [2001/2002 test]	3 - 4
Analysis of Well LRI # 332 [2001/ 2002 test]	3 - 5
4 Production Analysis	4 - 1
Cost/ Benefit	4 - 1
Comparison Cost to Other Alternatives	4 - 3

5	Findings and Recommendations	5 - 1
	Findings	5 - 1
	Recommendations	5 - 1
6	Appendix/ Figures	6 - 1
	Figure # 1 Tool and Lubricator Schematic	6 - 2
	Figure # 2 Production Chart for Oct. 96 LRI # 52	6 - 3
	Figure # 3 Production Chart for Oct. 96 LRI # 54	6 - 4
	Figure # 4 Production Chart for Jan. 2001 LRI # 52 [Pre GOAL PetroPump Tool]	6 - 5
	Figure # 5 Production Chart for Jan 2002 LRI # 52 [With GOAL PetroPump Tool]	6 - 6
	Figure # 6 Production Chart for Jan. 2001 LRI # 332 [Pre GOAL PetroPump Tool]	6 - 7
	Figure # 7 Production Chart for Jan 2002 LRI # 332 [With GOAL PetroPump Tool]	6 - 8
7	Overview of Common Stripper Well Production Techniques Used in New York State	7 - 1

TABLES

Table No.	Page No.
1 - 1 Well Details LRI # 52	1 - 2
1 - 2 Well Details LRI # 54	1 - 2
1 - 3 Well Details LRI # 332	1 - 3
3 - 1 Production Summary for Well LRI # 52 for 1996/ 1997 Test	3 - 2
3 - 2 Production Summary for Well LRI # 54 for 1996/ 1997 Test	3 - 3
3 - 3 Production Summary for Well LRI # 52 for 2001/ 2002 Test	3 - 5
3 - 4 Production Summary for Well LRI # 332 for 2001/ 2002 Test	3 - 5
4 - 1 Estimated Payback from Production LRI # 52 for 2001/2002 test	4 - 2
4 - 2 Estimated Payback from Production LRI # 332 for 2001/2002 test	4 - 3

FIGURES

Figure No.	Page No.
1 Schematic of G.O.A.L. PetroPump	6 - 2
2 Production Chart for LRI # 52 for 10-08-96	6 - 3
3 Production Chart for LRI # 54 for 10-22-96	6 - 4
4 Production Chart for LRI # 52 in Jan 2001 Pre GOAL Tool Test	6 - 5
5 Production Chart for LRI # 52 in Jan 2002 With GOAL Tool	6 - 6
6 Production Chart for LRI # 332 in Jan 2001 Pre GOAL Tool Test	6 - 7
7 Production Chart for LRI # 332 in Jan 2002 With GOAL Tool	6 - 8

SUMMARY

Brandywine Energy and Development Company Inc. hereafter referred to as BEDCO in conjunction with the New York State Energy and Research and Development Authority first conducted a production test on two- [2] gas wells in Chatauqua County, New York using a version of the G.O.A.L. PetroPump, hereafter referred to as the "Tool", in 1996/ 1997. The first test was conducted from September of 1996 until May of 1997, a period of 8 months. The purpose of the test was to evaluate performance of the "Tool" in its ability to improve production and extend the life of stripper oil and gas wells. The wells used for the tests were owned and operated by Lenape Resources Inc, hereafter referred to as LRI. All wells tested had production zones in the Medina Formation. The two wells initially used were more than a decade old and had previously used tubing to produce gas and fluids. This method of using a tubing string employs the use of a 1.5" tubing set down hole near the top of the well perforations to lessen the water pressure that gas must overcome to reach the surface process unit and accelerate gas velocity to aid in carrying the fluid to the surface. Post this test the two wells were equipped with a commercial casing plunger [ConCoyle] here after referenced as 'casing plunger' which operated with improved yield versus tubing until August of 2001. The second test conducted by BEDCO took place in the period of November of 2001 until April of 2002. This test was conducted using one of the original two test wells LRI # 52 and an additional well also producing gas from the Medina Fm., LRI # 332. The second test was conducted using an operationally-different [new-designed] tool developed from the knowledge gained from the 1996/ 1997 testing. [Note: Section # 7 provides an overview of common used stripper well production techniques in New York state.]

This G.O.A.L. PetroPump/ the Tool as designed and built for the 2001 and 2002 testing is a "unique" free traveling in well Tool which automatically uses on Tool pressure controls to remove fluids from wells and improve yield and operational efficiency. The Tool employs an on tool self-actuating pressure regulated valve to self-close and self-open at predetermined pressure [fluid load] limits. The Tool operates 'smart' in both down well and up well transit. The G.O.A.L. PetroPump descends down hole to obtain a predetermined volume of fluid which seals the on Tool valve which in

conjunction with surround Tool cups creates a complete seal with the well casing. The Tool with its fluid load returns to the surface process unit using below tool in well formation pressure to automatically lift Tool and the load of fluid. The G.O.A.L. PetroPump post delivery of its fluid load to the process unit awaits decreased down Hole and surround Tool pressure before automatically descending for another load of fluids.

Upon completion of preparation of the two wells, wells # 52 and # 54 for the 1996/ 1997 test and wells # 52 and # 332 in the test of 2001/ 2002, the Tools were deployed. The Tools were assembled and calibrated to make the unassisted 6000 foot plus round trip travel distance and remove one [1] to two [2] barrels of brine in the 96/97 test and 0.33 to 0.55 barrels of brine in the 2001/2002 test. In both test periods a well service company was contracted to collect test data including the monitoring of pressures and fluid removal rates from each well on a periodic basis.

The production test for the wells with the Tool [s] is divided into three periods. Two periods for the 1996/97 test and 1 period for the 2002/2002 test are evaluated.

For the first seven weeks of the 96/97 testing well # 52 showed a 2.2 multiple increase in average gas flow over the 1995 tubing average. For the second period the well produced 1% less gas than the 1995 average. The contrast between the two periods can be shown in the water production. First period produced 23 barrels in 7 weeks, while the second period of 24 weeks produced only 34 barrels of fluid.

Operations for well # 54 showed a 1.2 multiple on the first period of 1996 production increase over 1995. The second 20-week period showed a -37% decline in production over the 1995 period. Water production appears the strongest correlation for decline in yield during the second period. For the first 7 week period 8.5 barrels of water were produced and during the second 20 week period less than 20 barrels of fluid were produced.

Production test for 2001/ 2002 using the new/ re-designed Tool showed a marked difference in

performance through out the test period. Well # 52 showed up to an 80 % [1.8multiple] improved gas yield compared to the previously operating casing plunger with the Tool average increase of 1.6 multiple over the casing plunger. It should be noted that the 2001/ 2002 new designed G.O.A.L. PetroPump improved performance versus the 1995 average production from tubing was an approximate multiple of 4 times. Production testing of the G.O.A.L. PetroPump in well # 332 for the test period of Nov. 2001 through March of 2002 was as much as 3.0 multiple versus the previous installed and operated casing plunger and averaged a 2.3 multiple over the casing plunger for the period of testing. Similarly the G.O.A.L. PetroPump performance in the well versus the 1995 tubing production technique was an approximate 6 multiple in production.

Description of Project

Section 1

Sponsored with partial funding from the New York State Research and Development Authority, Brandywine Energy and Development Company Inc., investigated the effectiveness of its unique Tool the G.O.A.L. PetroPump in New York state gas wells. The project consisted of constructing two [2] sets of two [2] Tools for installation, operation and monitoring in 3 different gas wells in New York state. Upon completion of the two different phases of testing the effectiveness of the G.O.A.L. PetroPump performance was analyzed.

Background

The G.O.A.L. PetroPump is a unique free traveling tool, which operates inside a well casing to automatically remove fluids using in well natural formation pressure while improving well yield and efficiency of operation. The Tool as designed, deployed and successfully operated during the 2001/ 2002 test period is a free standing and operating in well tool of 51" in length and 54 pounds of weight. The Tool has a unique internal pressure activated automated self closing and opening valve assembly which allows for rhythmic, regular and automatic removal of in well fluids. The Tool is smart in both down well and up well transit. The Tool is pre set to descend into a fixed volume of fluid; use the combined pressure around the Tool at that point to close its on board valve and make a seal in the well casing in concert with external tool sealing cups. Formation pressure below the Tool lifts the Tool and fluid to the well head process unit where at such time as pressure around and below the Tool drops to preset limits the Tool automatically descends into the well for another load of fluid. A schematic of the G.O.A.L. PetroPump 2001/2002 is shown as Figure # 1 in the Appendix.

Well Details

The three wells tested are operated by Lenape Resources Inc. of Alexander New York. The wells are located in Chataqua County New York near the town of Villanova. The designations for the wells are LRI # 52, LRI # 54, and LRI # 332. The following are summaries of the technical information available prior to test [s] initiation.

Table 1 - 1 Well # 52

Test Period	1996/1997	2001/2002
Completion date	11-1-83	11-1-83
Formation	Medina [Grimsby/ Whirlpool]	Medina [Grimsby/ Whirlpool]
Geology	Sandstone [tight]	Sandstone [tight]
Total Depth	3,343 feet	3,343 feet
Perforations	3,127 – 3,229 feet	3,127 – 3,229 feet
Casing size	4.5"	4.5"
Production prior to test	3 mcf/d via tubing	8mcf/d w/ casing plngr. tool
Well head pressure	320 c/ 60 t psig	180 psig
Line pressure [sales]	60 psig	55 psig
Bottom Hole Temperature	97 deg. F	----

Table 1 - 2 Well # 54

Test Period	1996/1997	-----
Completion Date	02-14-84	-----
Formation	Medina [Grimsby/ Whirlpool]	-----
Geology	Sandstone [tight]	-----
Total Depth	3,373 feet	-----
Perforations	3,134 to 3,250 feet	-----
Casing Size	4.5"	-----
Production prior to test	4 mcf/d via tubing	-----
Well Head Pressure	210 c/ 65 t psig	-----
Line pressure [sales]	65 psig	-----
Bottom Hole Temp.	94 deg. F	-----

Notes: c = Casing Pressure

 t = Tubing Pressure

 mcf/d = 1000 cubic feet per day

Table 1 – 3 Well # 332

Test Period	-----	2001/ 2002
Completion Date	-----	1986
Formation	-----	Medina
Geology	-----	Sandstone [tight]
Total depth	-----	3425 feet
Perforations	-----	3399 – 3425 feet
Casing size	-----	4.5"
Production prior to test	-----	6 mcf/d [w/ csg. plngr. tool]
Well head pressure	-----	220 psig
Line Pressure	-----	55 psig

Work Program

Section 2

The following section outlines the work program completed for the G.O.A.L. PetroPump demonstration in New York state. This section of the document discusses Tool preparation, well preparation and Tool installation. This program was initiated in two phases, the first phase and testing was implemented in mid Sept. 1996 and the second phase was initiated between November and December of 2001.

Tool Preparation

The Tools used during the two tests in the Chataqua LRI wells were prepared and bench tested at a BEDCO facility in Chester Co., Pennsylvania. All components were fit tested and the actuator valve was pressurized and assembled to simulate anticipated well field conditions.

At such time that it was determined that components and Tools were in working order, final assembly and packaging for field transport was made. The Tools were physically re-inspected in the field prior to deployment in target gas wells.

Well Preparation

The target wells LRI # 52 and # 54 in the Phase I testing of 1996/ 1997 and LRI # 52 and # 332 in 2001/ 2002 were made ready for Tool deployment. The general preparation techniques included scraping the inside of the casing for removal of solids build up, sizing the casing to assure integrity and swabbing of fluids and solids when and where needed. Total depth of hole and perforation locations were confirmed. Finally a safety stand to prevent Tool travel below the perforations was installed in a joint collar above the top perforations.

“Tool” Installation/ Deployment

As part of Tool installation and deployment the well heads at each location were modified to

create a lubricator and catcher for the tool. The well head lubricator is comprised of certain 4" and 2" isolation valves and piping. This well head configuration allows flexibility in producing the well and accommodates catching or retrieval of the Tool to perform maintenance if and as necessary. Figure # 1 also provides a schematic of the lubricator design for the 2001/ 2002-test period on wells # 332 and # 52. The Tools, upon completion of the well head plumbing modifications, were placed in the lubricator and subsequently dropped down hole to initiate testing.

Analysis of "Tool" Operations

Section 3

Section 3 analyses the operation and production of the wells during the two phases [time periods] of testing. Subsection 3.1 addresses the 1996 and 1997 period of testing of the original Tool design. Further subsection 3.2 addresses the period of 2001/ 2002 test period and the new Tool design, derived from the 96/97, testing. Analysis of Tool and well performance during those periods of testing is evaluated and presented herein.

Section 3.1

Analysis of Well LRI # 52 for the 1996/1997 Test Period

An overview of the Tool deployed in well # 52 for the 8-month test period showed it to be in operation for the entire period. The Tool made multiple trips with in the well and produced tens of barrels of fluid [brine] to the process unit at the well surface. The Tool required no physical retrieval nor were mechanical problems encountered with the Tool workings. The Tool operated well in a mechanical sense and proved durable of construction. Over time the Tool appeared to lose pressure equilibrium in its ability to adjust to fluid production from the well. This is a matter correctable with adjusting the tool for variations in fluid production and down hole pressure conditions for any well.

Over the entire period of testing the production for well # 52 [versus previous production from tubing] was increased by a 1.6multiple. A more detailed analysis of the Tool operations is afforded by segmenting the testing into two periods of testing. The first 7-week period from 16 September to 7 November of 1996 was a period of active attention to the Tools and wells and resulted in marked improved yield and fluid production. Figures # 2 and # 3 are production charts for

maintenance or physical retrieval from the well. The Tool operated mechanically as expected.

The Tool did however go out of pressure equilibrium with the well brine production resulting in irregular production of fluids and less than optimum production of gas.

Over the entire period of testing production from the well averaged 24% less than the previous period using tubing to lift fluids from the well. Production from the well LRI # 54 as with # 52 was improved slightly during the first 7 week period [16 September 1996 to 7 November 1996] of testing and active testing at 1.1 to 1.25 multiple of production. The second segment [November 1996 to April 1997] of more passive testing of the well resulted in lesser than the previous years average of gas production. This appears due in chief to infrequency of runs of the tool and fluid production.

During this second segment the average production dropped as much as 37% from the previous year. Water/ brine production, total quantity and frequency of production appear the major restriction to improved production from this well. Under more uniform water production and operation of the tool this well appeared capable of producing in excess of 150-mcf/ month of gas

Table 3 – 2

BEDCO Production Summary Well # 54 for the period September 1996 to April 1997

Month Prod. Test	Total Prod. For Month	Multiple over Previous Yr.	Water Production	Tool Trips	Notes
Sept. 96	152 mcf	1.1 X	2 Bbls	1	Well swabbed
Oct. 96	173 mcf	1.25 X	6 Bbls	15	----
Nov. 96	82 mcf	0.4 X	2.5 Bbls	4	----
Dec. 96	122 mcf	0.9 X	3 Bbls	3	----
Jan. 97	138 mcf	1 X	8 Bbls	8	Induced water prod.
Feb. 97	84 mcf	0.6 X	4 Bbls	2	SI for 6 days
Mar. 97	14 mcf	0.1 X	4 Bbls	2	SI for 12 days
April	72 mcf	0.5 X	4 Bbls	3	Well Swabbed
Total	837 mcf	0.76 X	33.5 Bbls	38	

Notes: SI = Shut in
 mcf = 1000 cubic feet
 Bbls = Barrels

Comparison of Operational Data for the initial Test period of September 1996 to April 1997

The "Tools" deployed during this initial test period show the ability to operate in an unattended fashion and improve production by up to 1.25 multiple for well # 54 and by up to a 2.2 multiple for well # 52. Maintenance of the improved performance over the entire period of testing was not achieved as the Tools went out of equilibrium with the wells brine production and over all performance albeit positive was less than desired. The automated unattended operational aspects of the Tool performance were most promising and are/ were used as backdrop for additional and on going research and development targeted to improve tool operational performance.

Section 3.2

Analysis of Well # 52 for the second test period of November 1, 2001 to April 1, 2002

An overview of the new designed Tool/ well performance for well LRI # 52 for the period shows the Tool to have made multiple, regular, rhythmic, Tool runs in a totally unassisted manner. The Tool produces tens of barrels of brine and improved gas production by an average of 1.5 multiple over the previous year's operation using a casing plunger. Further, gas production was improved by approximately 4 fold in comparison to 1995 tubing only production from this well.

The G.O.A.L. PetroPump proved to be capable of making 15 to 20 unassisted/ automatic runs per month compared to 5 to 8 man-assisted casing plunger runs per month. The G.O.A.L. PetroPump proved to average 381 mcf for the 5 months of testing as compared to a 252 mcf average for the casing plunger over a comparable previous period. Figures # 4 and # 5 respectively provide pre GOAL Tool production data and with GOAL Tool Production [Note: the 1995 tubing production from this well was approximately 98 mcf/m] The tool averaged brine production at 9.5 barrels/ months for the period. In its best monthly period of testing the well produced 1.8 multiple of gas production versus a comparable period of mechanical casing plunger operation in this well.

Table 3 – 3

BEDCO Production Summary Well LRI # 52 [1 Nov. 2001 to 1 April 2002]

Well # 52	Pre GOAL ave. gas prod. w/ csg. plngr.	Pre GOAL 'casing plunger' runs	GOAL tool test ave. gas prod. 5 months	GOAL tool ave. "Tool" runs/ mo.	GOAL tool test ave. fluid prod. 5 months	Multiple of previous yield	Value ++ equivalent/ Yr. @ \$3.00 mcf
	252 mcf/@ 6 mo. ave.	5 – 8 runs/ mo.	381 mcf/@ 5 mo. Ave.	15/20 "Tool" run	9.5 Bbls/ mo.	1.5	\$4644/ Yr

Analysis of Well # 332 for the test Period of December 1, 2001 to April 1, 2002

An overview of the Tool/ well performance for well # 332 for the period shows the tool to have made multiple, regular, rhythmic, Tool runs in a totally unassisted manner. The Tool produces tens of barrels of brine and improved gas production by an average of 2.33 multiple over the previous year's operation using a casing plunger. Further, gas production was improved by approximately 5.0 fold in comparison to 1995 tubing-only production from this well.

The G.O.A.L. PetroPump proved to be capable of making 15 to 20 unassisted/ automatic runs per month compared to 5 to 8 man-assisted casing plunger runs per month. The G.O.A.L. Pump proved to average 473 mcf for the 4 months of testing as compared to a 203 mcf average for the casing plunger over a comparable previous period. See Figures # 6 and # 7 in the Appendix respectively for pre tool production data and with GOAL PetroPump Tool production data [Note: the 1993 tubing production from this well was < 100 mcf/m] The tool average brine production at approximately 9.5 barrels/ months for the period. In its best monthly period of testing the well produced a 3 multiple on gas production versus a comparable period of mechanical casing plunger operation in this well.

Table 3 - 4

BEDCO Production Summary Well LRI # 332 [1 December 2001 to 1 April 2002]

Well # 332	Pre GOAL ave. gas prod. w/ 'csg. plngr.'	Pre GOAL 'casing plunger' tool runs	GOAL tool test ave. gas prod. 4 months	GOAL tool ave. "Tool" runs/ mo.	GOAL tool test ave. fluid prod. 4 months	Multiple of previous yield	Value ++ equivalent/ Yr. @ \$3.00 mcf
	203 mcf/@ 10 mo.ave.	5 – 8 tool runs/ mo.	473 mcf/@ 4 mo. Ave.	15/20 "Tool" run	9.5 Bbls/ mo.	2.33	\$9,720/ Yr

Comparison of Operational Data for the Period of November 2001 to April 2002

The G.O.A.L. PetroPump tool[s] operation and attendant production improvement in these two wells tested, # 332 and # 52 was most notable and in direct response to tool design changes resultant from data and knowledge gathered from previous Tool testing in this well field in 1996/1997. Both Tools performed as designed, without manpower or outside well mechanical and or electrical assistance. The Tool designed as a free traveling; self- closing and self- opening automated tool for removal of fluids and enhanced production proved most effective. The Tool made regular unassisted 6000 plus foot round trips in the well producing an average of 0.33 to 0.55 Barrels of brine per cycle. The Tool further automatically adjusted to changes in well system operating pressures and performance with out need for adjustment during the test period. The average improved gas production was a 1.5 multiple for well # 52 over the previous installed and operating casing plunger and a 4 multiple over the historical tubing production from this well. The improved production for well # 332 was greater than a 2.3 fold increase over previous production from the casing plunger and more than 5 times the production of this well from tubing.

Production Analysis

Section 4

The following section analyses the economic use of the tool. This section also provides potential cost benefits for tool use.

Cost Vs Benefit

The cost of the G.O.A.L. PetroPump under current manufacturing conditions is approximately \$ 8000, the associated piping and well head changes with valves to accept the tool can add up to another \$950. A total Tool cost for economic analysis is estimated at \$8950.00. Table 4 – 1 shows potential economic pay back based upon the results from the two wells tested in November 2001 through April 2002. As can be seen from these data the increased production of the G.O.A.L. PetroPump Vs the casing plunger previous in place in these two wells is approximately 2 years for well # 52 and 1 year for well # 332. If one compares the G.O.A.L. performance to previous production history via tubing from these wells, well # 52 would yield a 10-month pay back with the G.O.A.L. Tool. Well # 332 would produce a payback in 7 months time. A point that is most interesting to consider is that the G.O.A.L. PetroPump produced these increased results to the former tubing and casing plunger production after 5 additional years of production/ depletion on these wells. A 1.5 to 2.33 multiple of improved production rate over the casing plunger and 4 to 5 fold improvement over their historic tubing production for wells # 52 and # 332 respectively was achieved during the 2001/ 2002 test period.

Table 4 – 1

Estimates of Payback from Production

Assumptions: * “Tool” Cost and Well Modifications @ \$8950.00
 * LRI # 52 Monthly Average Production with Tubing @ 98 mcf
 * LRI # 52 Monthly Average Production with ‘casing plunger’ @ 252 mcf
 * Value of gas @ \$3.00 mcf

Ave. Prod. using GOAL Pump	Ave. Prod. using tubing in 1995	Average Prod. Using ‘casing plunger’	Payback @ \$3 mcf vs tubing production	Payback @ \$3 mcf vs ‘casing plunger’ production
381 mcf	98 mcf	252 mcf	~10 months	~25 months

Table 4 –2

Estimates of Payback from Production

Assumptions: * “Tool” Cost and Well Modifications @ \$8950.00
 * LRI # 332 Monthly production with tubing @ ~100 mcf/ month
 * LRI # 332 Monthly production with concocyle casing plunger @ 203 mcf
 * Value of gas @ \$3.00 mcf

Ave. Prod. using GOAL Pump	Ave. Prod. using tubing in 1992	Average Prod. Using ‘casing plunger’	Payback @ \$3 mcf vs tubing production	Payback @ \$3 mcf vs ‘casing plunger’ production
473 mcf	~ 100 mcf	203 mcf	~ 7 months	~11 months

It must be noted that the yields of the wells tested are very small [~3 mcf/day of gas via tubing at initiation of test] in comparison to the average gas stripper well in the US @ 15 mcf/ day. These wells, even with the improvements yielded by the G.O.A.L Petropump are at or below the average US gas stripper well production. Application of the Tool in wells with greater production potential [i.e. the average stripper well] which have need for regular automatic brine removal should yield better results and quicker payback on capital invested in the tool. The current cost of the Tool at approximately \$9000 complete with well head modifications for installation is elevated. This is due to proprietary construction materials and techniques. Production of Tool in a commercial manner should reduce cost and payback on capital investment for the Tool user. Finally the uniqueness of the G.O.A.L PetroPump and its on Tool self-actuating controls to regulated frequency and volume of fluid removal from

wells differs greatly from casing plungers producing superior results in these test and has its own unique market niche.

Cost Comparisons to Other Alternatives

Cost comparison of the G.O.A.L. PetroPump to the common used equipment for fluid removal from gas wells in the depth range of 3000' to 6000' would include:

- Pump Jack/ Beam Lift, associated sucker rod, tubing and down hole pump can have capital cost in the range of \$10,000 - \$40,000. Operating cost for pump jacks range from \$2000 to \$10,000/ year depending on volume and type of fluids produced, maintenance, replacement parts and service required.
- Tubing string production could have \$8,500 to \$15,000 capital cost dependant on tubing diameter and operating cost ranging in the \$1500- \$3000/ year for man-power & surfactants.
- Casing plungers capital cost with the necessary well head modifications to receive the unit are in the range of \$3500 to \$5000 capital. Additional capital cost for well head controllers for any attempt at automation of casing plungers is also needed [as opposed to man assisted runs], at \$1000 to \$5000. Operating cost would include manpower at a minimum of \$500 to \$1000/ year to \$2000- \$3000/ year on manual run tools. Work over cost to retrieve drowned and or stuck tools are not herein quantified but typical rig/ day cost are \$750-\$1000.
- Tubing plungers [Rabbits] base requirements include the installation of a tubing string at \$8,500 to \$15,000 as noted above plus the capital cost of a Tubing plunger at \$2000 without any automation to \$6000 with automation [semi] controls. Operating cost are not dissimilar to casing plungers noted above at \$1000 to \$3000.

Further with respect to casing plungers and tubing plungers, they do not operate in the same or similar fashion to the G.O.A.L. PetroPump with on Tool controls and down hole/ up hole *smart* Tool technology.

In terms of applicability of this G.O.A.L. Tool to wells in the test area. It was determined that

approximately 3,523 gas wells and approximately 529 active oil wells exist in Chataqua County. Based upon our exposure to the wells in the area it is likely that 50% or more of these wells will have fluid production related problems in the life of the wells. It is further likely they will require some form of tool related technology to produce gas and or oil. Assuming the G.O.A.L. PetroPump Tool would serve 1/3 of the wells in need of tools for enhanced production some 500 to 600 wells would be candidates for the GOAL tool in Chataqua County. Projecting those numbers to the entire state of New York production could mean more than 1500 tools for state of New York wells.

Assuming only an 8 mcf/d increase per well [in range of test increases] at \$3/ mcf could yield \$13,000,000 in gas value and a pay back on 1500 tools at \$9000/ tool in a one year time period

Findings and Recommendations

Section 5

Section 5 discusses the findings of the report and also provides recommendations for further work, research and field testing. The findings include a summary of production data and cost analysis. The recommendation section provides suggestions of additional work that could be undertaken to improve the "Tool" and production from the wells.

Findings

The following is a summary of the findings from the production testing of wells # 52 and #332 for the period of November 2002 to April 2002:

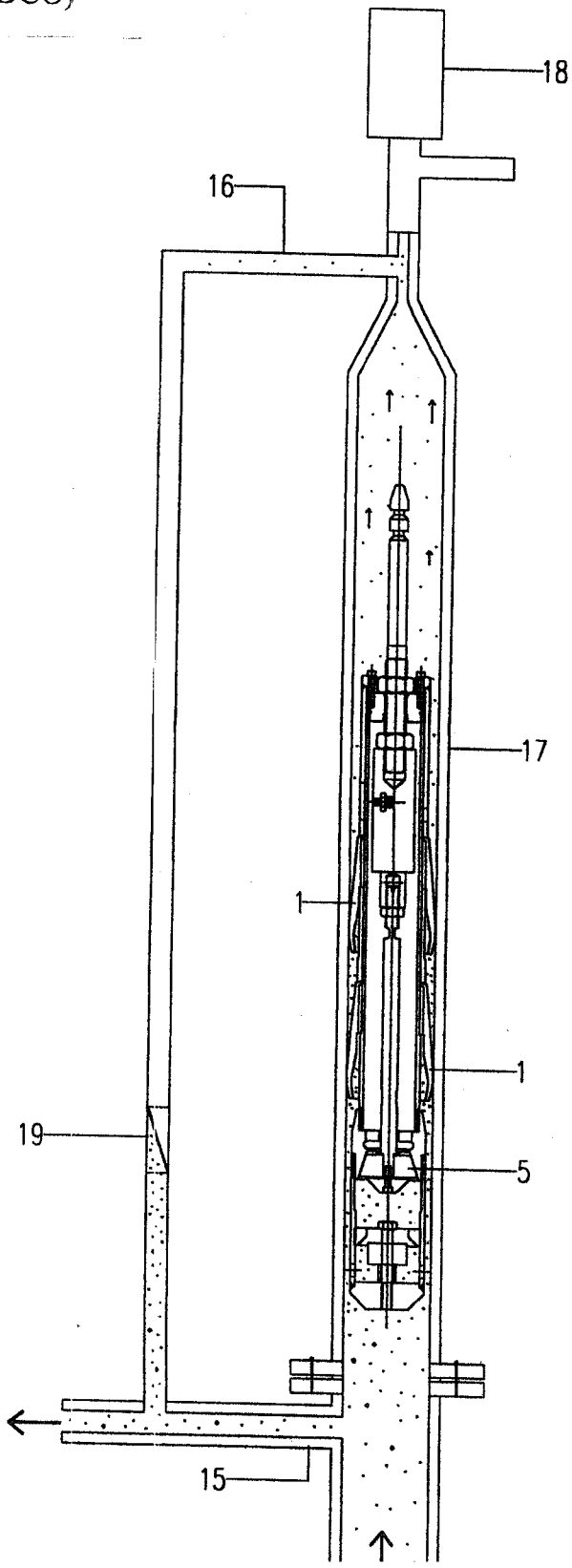
- **Wells # 332 and # 52 during the production testing period were capable of producing Approximately 9.5 barrels of fluid per month. Monthly deviations from the average were observed to be associated with variable back pressure conditions on sales line pressure.**
- **Well # 332 is currently capable of producing and average of up to 500 MCF/ Month of Gas with the aide of the GOAL Pump**
- **Well # 52 is currently capable of producing an average of up to 400 MCF/ Month of Gas with the aide of the GOAL Pump**
- **Well # 52 improved Gas yield versus the previous applied casing plunger technology was 1.5 multiple and a 4 multiple to the historic used tubing technology.**
- **Well # 332 improved Gas yield versus the previously applied casing plunger technology was a 2.33 multiple and 6multiple versus the historically used tubing technology.**
- **Payback on the current cost of the GOAL Tool at approximately \$9000 versus the improved production from these two targeted wells is 12 to 24 months as compared to the previous applied casing plunger technology. Pay back versus the wells historic use of tubing technology is 7 to 10 months**
- **Tool cost reduction is achievable with manufacturing in volume.**

Recommendations

The following is a list of recommendations considered applicable for additional demonstration testing of the G.O.A.L. PetroPump:

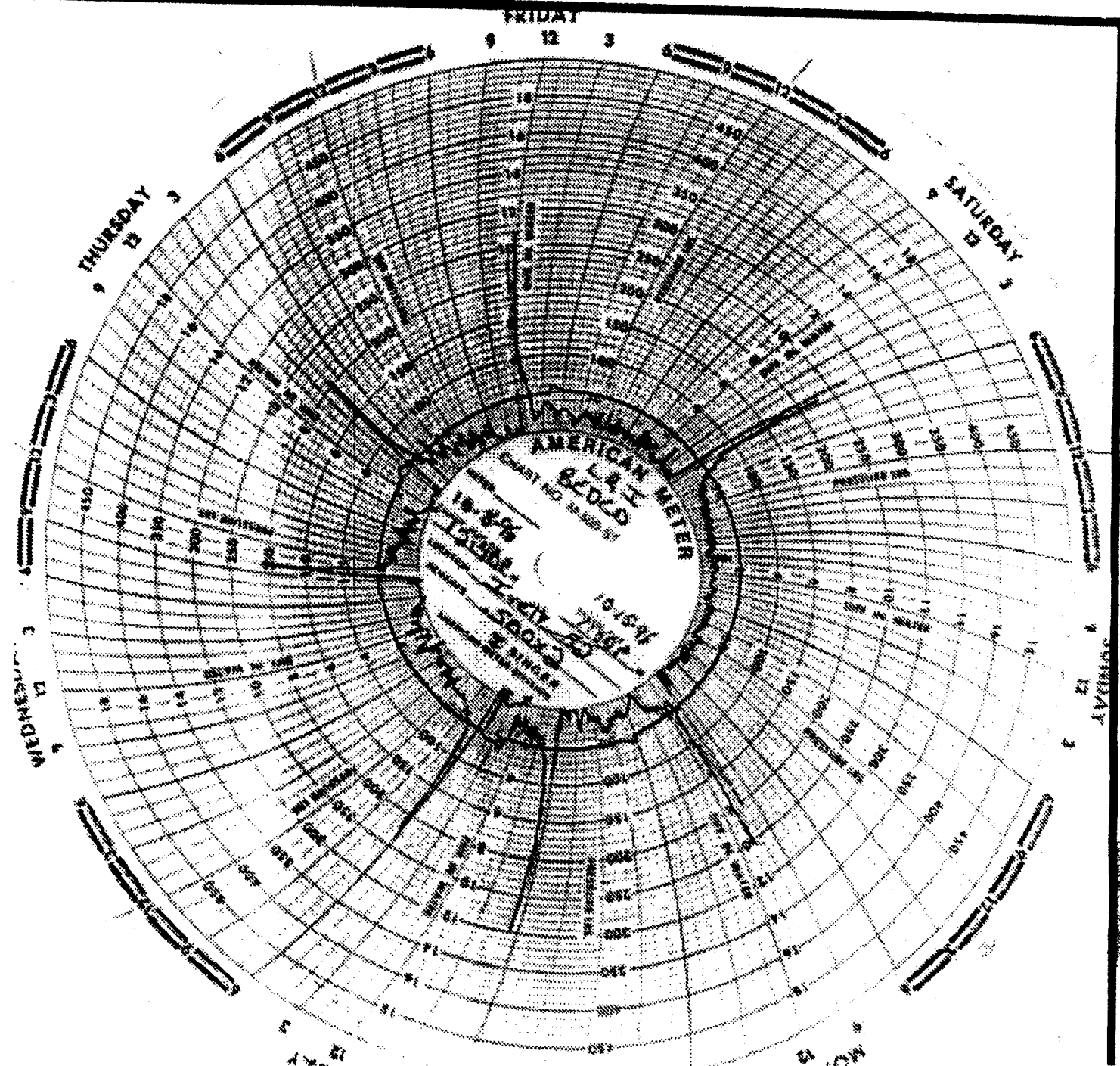
- **The “Tool” should be tested in higher volume wells and wells with greater fluid production. Applicable targets would be considered to be wells with fluid production of up to 10 barrels/ day and current gas flows of 20 or more mcf/Day.**
- **“Tool” cup research, development and testing to address variability of commonly used casing dimensions is needed to increase durability and life of Tool cups as well as decrease potential for cataclysmic cup and hence Tool failure.**
- **Research and development of a small diameter Tool of 2.5” or less is for producers using siphon tubing with 2.5” or less internal diameter should be considered.**
- **Research and development of a small diameter “Tool” of 2.5” or less and use of continuous non ferrous tubing or less is warranted for rejuvenating open hole production wells with declining production associated with fluid accumulation in New York state**
- **Integrating wellhead data recorders and cellular communication data transfer systems should also be considered for developing as a feature of the GOAL Tool system which can add value to well production techniques.**

Appendix/ Figures

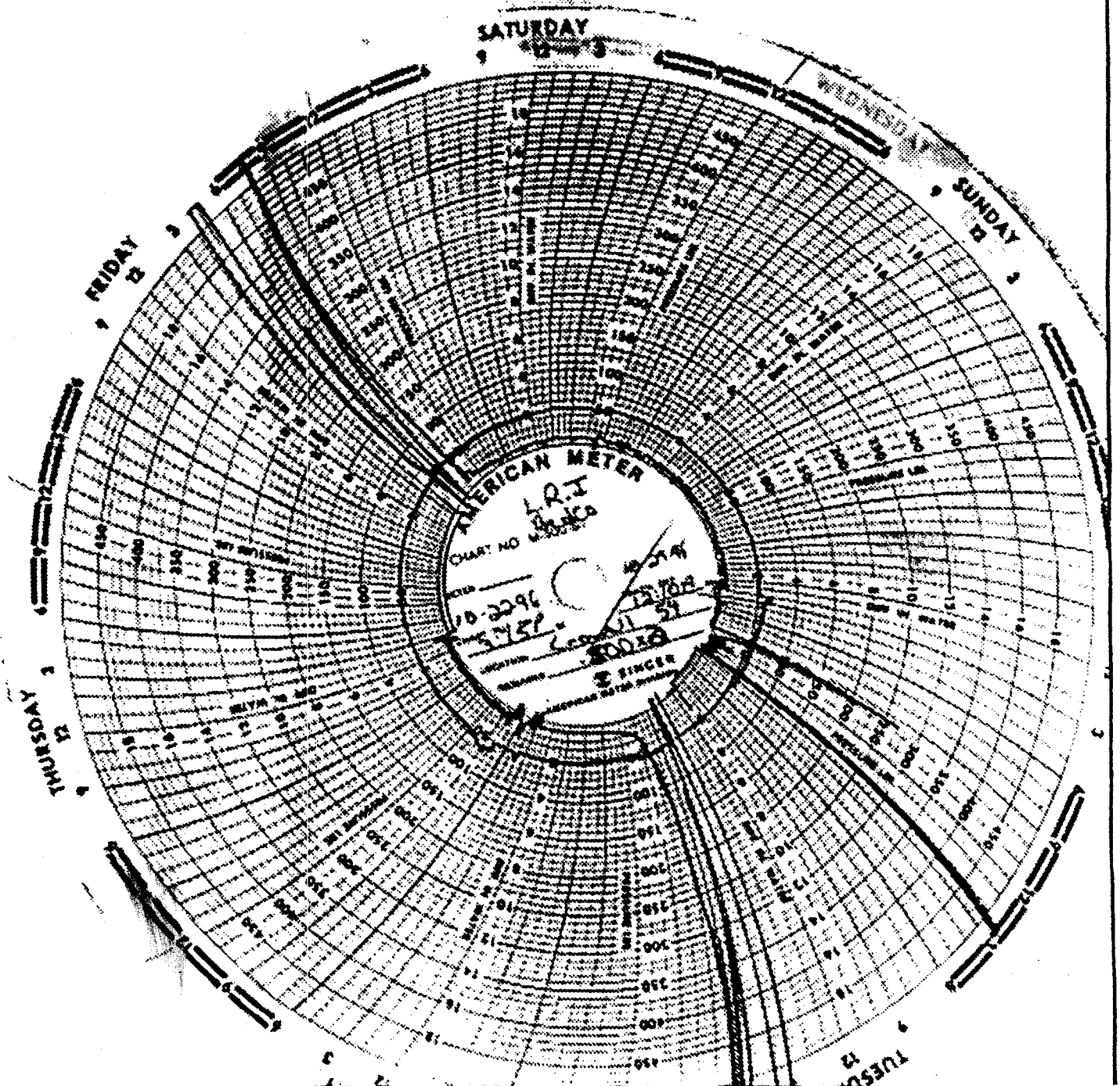


Schematic of GOAL Tool in Well Head Lubricator

Figure # 1

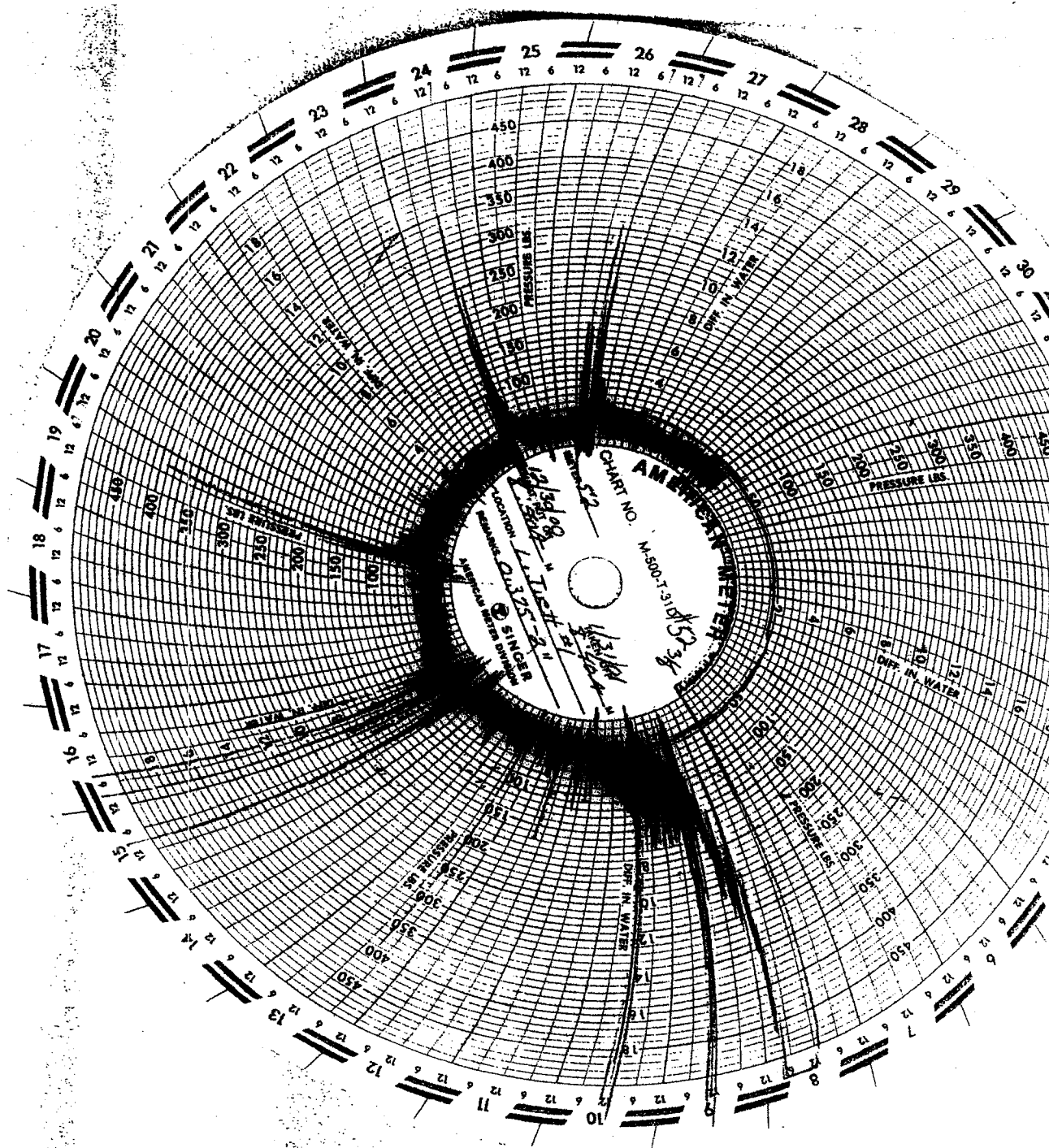


Well # 52 Production Chart for October 8-15, 1996



Well # 54 Production Chart for October 22-29, 1996

Production Chart of Well # 52 for January 2001

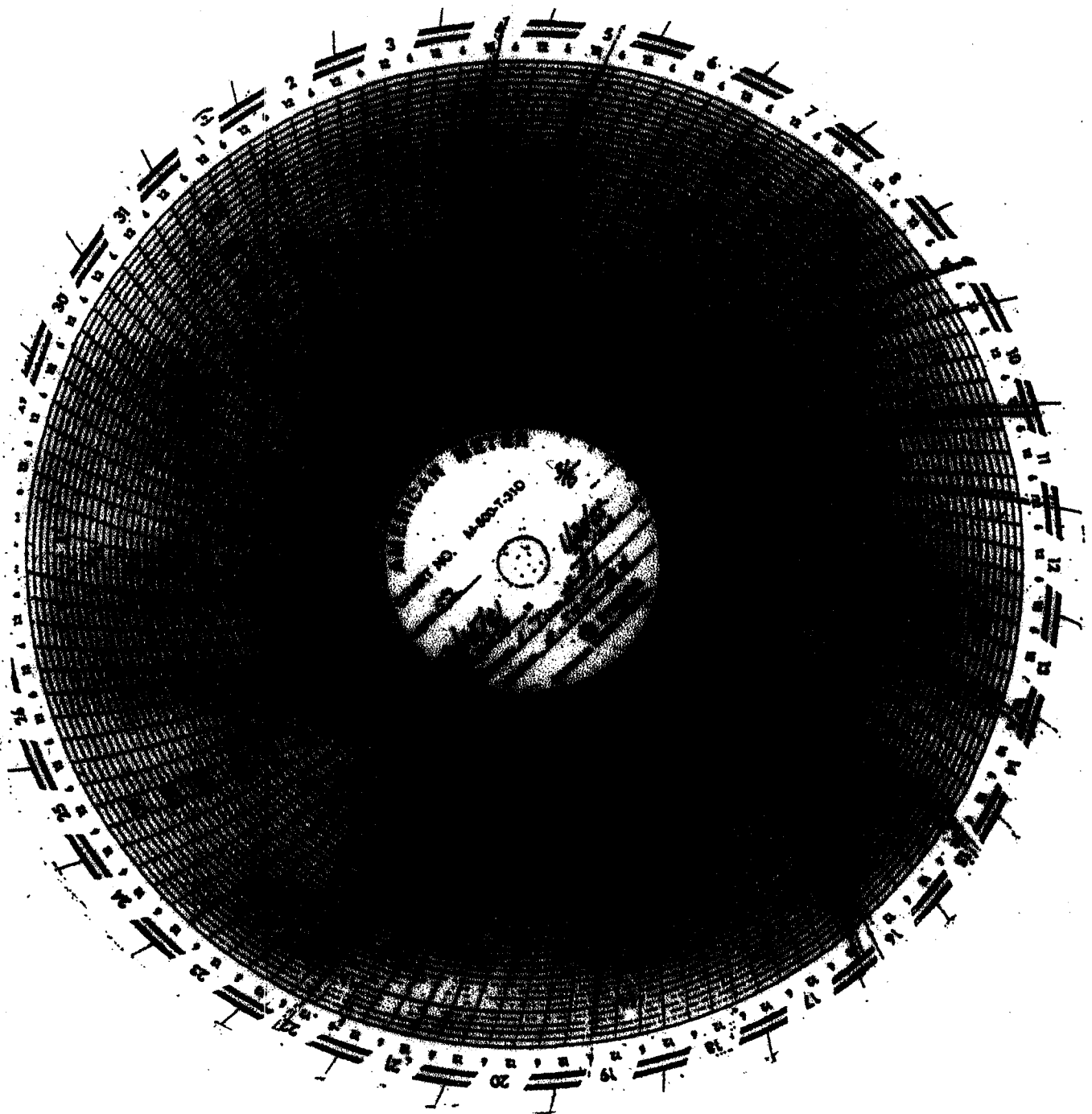


January 2001

Well # 52

212 MCF/M

7.06 MCF/D



JANUARY 2002

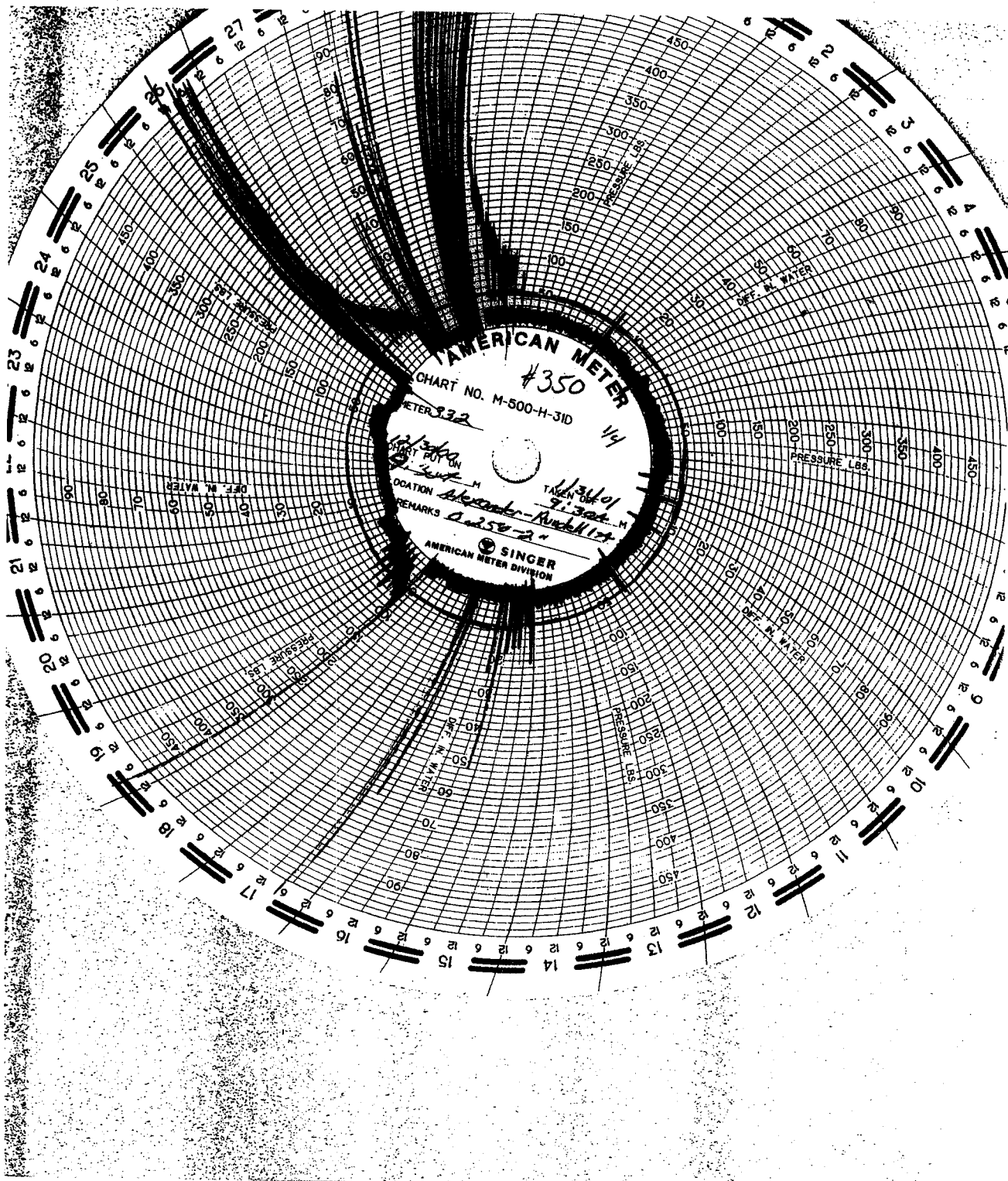
WELL #52

457 MCF/M

13.62 MCF/D

805 HRS/M

Figure # 5



Production Chart of Well # 332 for January 2001

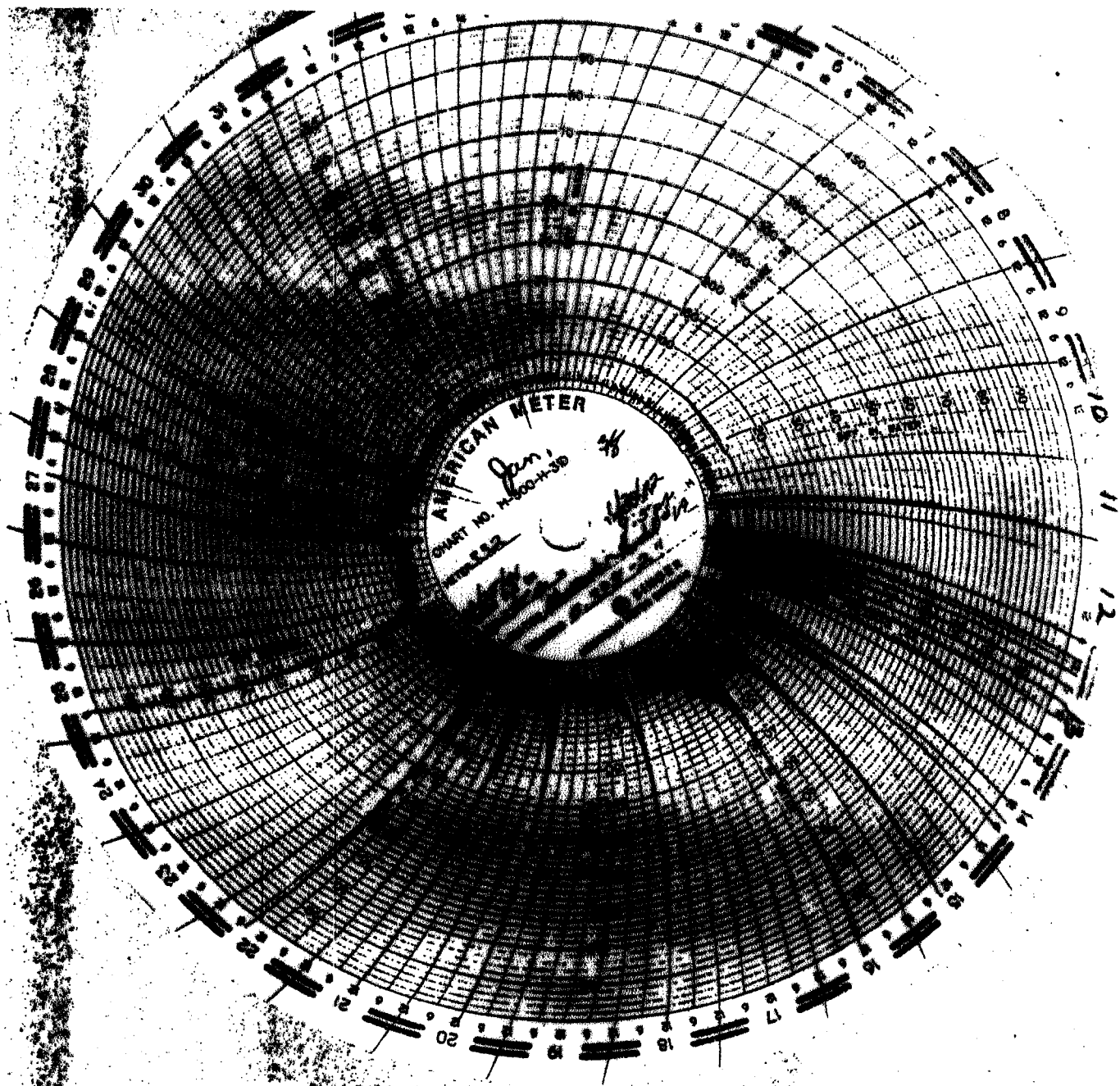
January 2001

173 MCF/M

Well # 332

5.76 MCF/D

Figure # 6



Production Chart of Well # 332 for January 2002

January 2002

Well # 332

613 MCF/M

20.0 MCF/D

SECTION 7

Overview of Common Fluid Production Techniques used in New York State Stripper Wells.

Pump Jack/ Beam Lift Pump The Beam Lift pump is comprised of well head motor/ engine, walking beam, gear box, rod, tubing and down hole pump. The use of a Pump Jack and associated in well hardware is one of the oldest and most long-lived techniques for removal of fluid build up in wells. The methodology employs a rod driven in tubing down hole reciprocating pump and foot valve operated by a walking well head beam, commonly driven by an electric motor or drive shaft of an internal combustion engine. The benefits of such tried and true technology are their significant lift height and volume capabilities.

The limitations are high capital cost, energy cost and consumption and operating and replacement cost of the many wear intensive mechanical components of the system. The many components which wear and which are in need of regular service, repair and or replacement include but are not limited to:

- drive belts,
- filters and lubes for motors and engines and or their replacement,
- gear box and bridle connection maintenance/ repair/ replacement ,
- stuffing box seals replacement- polish rod replacement,
- rod and tubing in well wear/ breakage/ leaks/repair/ replacement,
- pump components wear and failure and foot value plugging, failure/repair and or replacement

The limitations of use of this time- honored system for stripper wells is its maintenance of mechanical needs above and the need for both a mechanic and well tender to service the well to produce product for sale resulting in significant cost.

Tubing String. The use of a tubing string or velocity string to produce fluid from wells is based upon the simple fact that given a certain down hole or in Formation pressure and flow rate, a small diameter pipe can raise fluid higher in the well and allow the gas driving the fluid to flow faster than it would in the nominal 4 to 6" well casing or bore. In fact given a small enough tube and or high enough pressure and velocity [flow] a quantity of fluid can be pushed/ possibly lifted to the well head process units. Normally 2.5" or smaller pipe is installed inside the typical 4" to 6" well and casing. The small diameter tubing string is normally set at or near the top of the well perforation/ production zone to achieve optimum results. Over time decreasing Formation pressure and declining velocity of gas production [flow], as with many New York wells, results

in inability of the tubing string [velocity string] to continuously lift fluid with the gas. Production correspondingly declines then ceases. The typical response by operators to such conditions is the periodic operation of the well. The operator first shuts in the well to produce a pressure build up. The shut in period may build for a day or more followed by a deliberate manual opening of the well and rapid release of pressure and flow of gas/ fluid, to the process unit and fluid storage tank, to attempt to purge the well of its accumulated fluid. The well post this trap and purge episode is then returned to gas production until fluid again reduces and or eliminates flow. Some of the limitations, of such production techniques, are:

- long periods of well down/ shut in time with no gas production
- accumulation of undesirable quantities of fluid in the well bore which actually hold back gas production and cause the Formation to become water wet and transmit less gas
- loss of gas to the atmosphere during purge cycles
- increased production cost associated with manpower and additives needed to service the well.

Variations on the shut in and release technique include the addition of surfactants which can improve capillary rise of the fluid in the tubing, reduce friction and reduce pressure gradient to ease lift requirements.

Tubing Plungers. Tubing plungers or Rabbits as they are often referred are small diameter plugs or pigs which fit inside the tubing in a well and are used to push the fluid level accumulated in the tubing to the surface for processing. The energy to push/ lift the tubing plunger and the fluid to the surface is derived from the stored gas in the annulus of the well between tubing and casing. The limitations of tubing plungers is the inability to produce the well down [close to] to the sales line pressure. Typical tubing plunger operations require a significant pressure differential between the sales line pressure and the pressure in the well annulus. The average pressure differential to lift a barrel of fluid in 2.5" tubing is on the order of 100+ psi. Other limitations include short cycle times on certain more aged well which result in a production chart that is not easily read and or integrated. This can result in off chart spikes and uncompensated for yet produced gas.

Casing Plungers The typical casing plunger is configured as a hollow steel tube with a pair of external cup shaped flexible seals surrounding the steel cylinder and an external activated strike plate/ trigger connected

to and operating/ closing an internal valve. Use of a standard casing plunger requires certain well head modification including the installation on the well of a full port 4" ball valve and lubricator/ catcher assembly. Semi-automation of the system requires the installation of additional pressure and or electronic activated controllers to catch and release the mechanism at some desired programming frequency and or pressure. Use further requires the installation of a down hole stand/ valve set mechanism located just above the production zone to close the casing plunger valve and allow for the lift of fluid and tool. The principal benefit of the standard casing plunger over the other mechanisms noted above is it ability to use Formation pressure to lift itself and an accumulated column of fluid to the surface. The casing plungers can theoretically work with slightly more than 30 psi of pressure differential between Formation and the sales line to lift 1 barrel of fluid plus the casing plunger. Typical targeted lift volumes are 1 to 3 barrels of fluid per casing plunger cycle. In order to lift a 3 barrel slug of fluid a pressure differential of approximately 90 psi over sales line pressure is required. In their deployment casing plungers have in general proved less costly than Beam Lift pumps and more productive than Tubing Strings and Tubing Plungers. A principal limitation of the casing plunger is its need to travel to the down hole safety stand/ stop to set the valve, with the commensurate requirement that it subsequently lift all the accumulated fluid atop the casing plunger at that point to the surface. Unless the well is regularly attended in the manual operation mode and or the tool dropped regularly in the semi-auto mode, stalling and sitcking of the casing plunger due to excessive fluid load down hole versus available lift pressure, volume and velocity is an unfortunate too common problem. Casing plunger retrieval once drowned by too much fluid versus Formation pressure differential to the sales line or even differential to the atmosphere usually will require a work-over or wire line rig to retrieve the tool.

G.O.A.L. PetroPump The G.O.A.L. PetroPump is a unique free traveling tool, which operates inside a well casing to automatically remove fluids using in well natural Formation pressure while improving well yield and efficiency of operation. The Tool is designed around an on tool pressure activated [self opening and closing] valve assembly. The tool is 51" in length and weighs 54 pounds and designed to operate in 4", 5" and 6" casings. The Tool has two flexible seal cups attached to the Tool cylindrical body which create a

seal between tool and well casing. The Tool's unique internal, in well, activated, automated, self closing and opening valve assembly allows for rhythmic, regular and automatic removal of in well fluids. The Tool is smart in both down well and up well transit. The Tool is pre set to descend into a fixed volume or column of fluid; use the combined pressure around the Tool at that point to close its on board valve and make a seal in the well casing in concert with external tool sealing cups. Formation pressure below the Tool lifts the Tool and fluid to the well head process unit where at such time as pressure around and below the Tool drops to preset limits the Tool automatically descends into the well for another load of fluid. No external controls or down hole triggers are necessary to set /close and or open the valve. All operating and automating components are contained within the Tool. The on tool self actuating valve can be preset to retrieve as little as 0.1 barrel of fluid and or greater than 6 barrels of fluid. The Tool fluid retrieval setting can be set to match well characteristics of pressure, flow of gas, volume of fluid production and operating back-pressure of the sales system. Setting the tool to make frequent, small volume, runs produces a minimum hydrostatic head versus the formation pressure, thereby creating optimum conditions for Formation to in well pressure differential and gas and oil production. The tool lifting characteristics require approximately 10 psi of pressure differential between formation and the sales line to move the Tool in a 4" well. Further, Tool operational character is such that once released from its lubricator/ catcher it can levitate/ float in the well ,allowing gas flow through the tool, until such time as in well conditions of fluid build up dictate it close its internal valve and travel to the surface to deliver the fluid load. Similarly the tool will adjust to variable back pressure of sales line by levitating during periods of increased back-pressure while allowing flow of gas through the tool and descending down hole to capture more fluid during periods of decreased back pressure on the sales line.