Identification of Effective Fluid Removal Technologies for Stripper Wells

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By

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TITLE PAGE

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Abstract

Prior research for the Department of Energy identified the largest problem contributing to abnormal production decline in stripper gas wells was fluid accumulation in the wellbore. This study developed methodologies including decision trees and a procedure guide to economically identify the most effective fluid removal technology for specific stripper gas well characteristics. The application of systematic methodologies and techniques increases the efficiency of problem assessment and implementation of fluid removal solutions for stripper wells. Effective fluid removal from stripper wells benefits all producers by increasing production and ultimate recoveries since it corrects the most common production decline problem.

The fluid accumulation problem indicates many operators fail to recognize and evaluate the economics of the proper application of fluid removal methods over the entire life cycle of the stripper well. It is critical that changes in fluid removal techniques be effective over the life of the well. due to the limited net income from stripper wells. Therefore, the goal of this research program was to develop an application guide detailing cost effective fluid removal method evaluation and selection procedures.

Current study results indicate little work has been completed regarding fluid removal method selection for wells classified as stripper gas wells, that is, 60 mcfd or less. Further, the national stripper well average is only 15 mcfd while the Appalachian Basin well average is 11 mcfd with either representing a significantly lower volume than that established as stripper well production. To compound the limited production problem, stripper wells are also associated with multiple owners, aging production equipment, and mature, low permeability, low-pressure reservoirs.

The 448 well study group fluid removal method distribution was 289 tubing plungers, 115 pumping units, 26 casing plungers, and 18 swab wells. To complete the study, an existing well database was complemented through detailed wellfile review with producing well characteristics including historic fluid removal mechanisms, completion tubulars, producing and shut-in pressures, production cycles, and volumes per production cycle. In addition, a 40-year semi-log plot of historic monthly production versus time was reviewed for each well, analyzed for fluid removal method production performance, and then assigned a classification of "Good", "Fair", or "Poor".

The study identified 194 fluid removal method changes in 125 of 448 wells. The study found that tubing plunger wells with GLR's greater than 50 experience significantly better production performance than those with lower GLR's, while wells on pump are successful across all GLR's. Casing plunger wells are generally successful in high GLR limited completion interval wells, while successful swab wells have very high GLR's with very limited fluid production. Ultimately, the study resulted in a step-by-step methodology incorporated into a procedure guide to evaluate and select appropriate fluid removal methods for stripper gas wells.

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Introduction

This study was specifically developed for stripper well operators in a cost-sharing venture between James Engineering, Inc., the Stripper Well Consortium, the National Energy Technology Laboratory, and the New York State Energy Research and Development Authority.

The goal of this research program was to develop a procedure guide to identify cost-effective fluid removal technologies for stripper gas wells.

A study group of 448 wells provided the data to analyze the fluid removal technologies commonly utilized for stripper gas wells including tubing plungers, casing plungers, pumping units, and swabbing. An analysis of the fluid removal methods and their relative efficiencies indicated that wells produced with tubing plungers were 85% successful when the gas liquid ratio, GLR, was 50 mcf per barrel or greater. Data collection forms and decision trees were developed to review stripper gas wells, identify cost-effective fluid removal technologies, and suggest corrective action. The decision trees and data collection forms developed as a result of this research were incorporated into a procedure guide to provide operators with a methodology to evaluate and select appropriate fluid removal methods for stripper gas wells using commonly available data. The systematic methodologies and techniques developed increase the efficiency of problem well assessment and implementation of solutions for stripper gas wells.

This final technical report includes the procedure guide developed as a result of the study and summarizes the results of the specific steps for this study as follows:

- Perform a literature search of the appropriate application of fluid removal technologies for stripper wells
- Develop data collection forms
- Perform a field review of critical parameters affecting maximum flowrate
    - Reservoir pressure
    - Bottom hole flowing pressure
    - Line pressure
    - Gas production rates
    - Fluid production rates
    - Artificial lift mechanism
- Summarize the results of the field review of critical parameters
- Develop a decision tree to select the appropriate fluid removal technology
- Test the decision tree
- Prepare an application guide detailing cost effective fluid removal technologies
- Prepare technical paper and transfer the technology

Executive Summary

This study was specifically developed for stripper well operators in a cost-sharing venture between James Engineering, Inc., the Stripper Well Consortium, the National Energy Technology Laboratory, and the New York State Energy Research and Development Authority.

Prior research performed for the Department of Energy identified the largest problem contributing to abnormal production decline in stripper gas wells was due to fluid accumulation in the wellbore. This study was to develop methodologies including decision trees and procedure guides to economically identify the most effective fluid removal technology for specific stripper well characteristics. The application of systematic methodologies and techniques increases the efficiency of problem assessment and implementation of fluid removal solutions for stripper wells. Effective fluid removal from stripper wells benefits every producer by increasing production and ultimate recoveries since it is the most common production decline problem.

The liquid loading problem indicates that many operators fail to recognize and evaluate the economics of the proper application of fluid removal methods over the entire life cycle of the stripper well. Due to the limited net income from stripper wells, it is critical that changes in fluid removal techniques be effective over the life of the well. Therefore, it was the goal of this research program is to develop and deliver an application guide detailing cost effective fluid removal application selection procedures.

Based upon a 448 well review of critical pressure and production parameters, this study concluded the following:

- Most stripper wells require the application of a fluid removal method to maintain production.
- To optimize production, it is critical that the proper fluid removal method is systematically applied and the operating principals thoroughly understood.
- Further, optimized production to economic depletion is generally achieved when the flowing bottom hole pressure is kept reduced by a consistent removal of fluid.
- The fluid removal methods appropriate to produce stripper gas wells to economic depletion are tubing plungers, casing plungers, pumping units, and swabbing.
- Tubing plungers perform better on wells with high GLR's, greater than 50, and low fluid volumes, with few depth or completion restrictions.
- Casing plungers perform better on wells with high GLR's, limited perforation intervals, good mechanical integrity casing, and low fluid production.
- Pumping units are applicable to wells across a broad range of GLR's, long perforation intervals, and can sustain a lower flowing bottom hole pressure.
- Swabbing is applicable to wells with high GLR's, large pocket for fluid accumulation, and nominal fluid producing wells.

The procedure guide developed as a result of this study provides stripper well operators a methodology to select the most appropriate fluid removal method for stripper gas wells.

Experimental Apparatus and Operating Data

Operating data supplemented a preexisting well database from an extensive review of wellfiles, operating reports, and field data mainly from wells located in Ohio and New York.

Results and Discussion

This final technical report discusses a statement of the problem, and then summarizes the results of the following steps for this study:

- Perform a literature search of the appropriate application of fluid removal technologies for stripper wells
- Develop data collection forms
- Perform a field review of critical parameters affecting maximum flowrate
    - Reservoir pressure
    - Bottom hole flowing pressure
    - Line pressure
    - Gas production rate
    - Fluid production rate
    - Fluid removal method
- Summarize the results of the field review of critical parameters
- Develop a decision tree to select the appropriate fluid removal technology
- Test the decision tree
- Prepare an application guide detailing cost effective fluid removal technologies
- Prepare a technical paper and transfer the technology

I. A Statement of the Problem

Prior research for the Department of Energy found that 270 of 376 wells evaluated (>70%) exhibited some form of abnormal production decline during the past five years. Nearly 50% of the abnormal production declines were due to liquid loading resulting in decreased reserves and revenue. The frequency of the liquid loading problems represent a significant opportunity for improvement since in many cases liquid loading is a correctable problem through the evaluation and application of appropriate fluid removal technologies to stripper gas wells.

The liquid loading problem indicates that many operators fail to recognize and evaluate the economics of the proper application of fluid removal methods over the entire life cycle of the stripper well. Like hydraulic fracturing, developed to accelerate recovery from low permeability reservoirs, the proper application of fluid removal technologies to low-volume stripper wells should accelerate recovery of reserves. The misapplication of fluid removal methods appears related to temporary solutions for long-term problems.

The source of fluids that cause liquid loading problems are typically free liquids produced with the gas or condensed liquids in the gas, while other sources include inadequate cement bond, fracing or acidizing into water, poor perforation placement, and casing or packer leaks. However, high volumes of produced fluids are not typically associated with stripper gas wells.

The problems associated with stripper gas wells include mature (twenty years old or older), low permeability, low pressure reservoirs, owned by multiple operators, corroded surface facilities, with operators literally stripping the last 10 to 20% of wells' economic ultimate reserves. In addition, while stripper wells are defined as wells with production less than or equal to 60 mcfd or 10 bopd, the national average for stripper well production is only 15 mcfd and 2 bopd. The average Appalachian Basin stripper well only produces 11 mcfd and 0.4 bopd but represents 205,000 of the nation's 646,000 stripper wells. Therefore, by definition, even when stripper well production is maximized, the amount of capital available for repairs or enhancements is limited. Therefore, an absolute necessity in correcting problems with stripper wells is finding an economic solution and it is critical that the changes made in fluid removal techniques be effective for the life of the well.

The procedure guide developed as a result of this research provides methods for evaluating and selecting fluid removal methods for optimum fluid removal from stripper gas wells. A more detailed discussion on the statement of the problem is presented within the text of the procedure guide.

II. Literature Search of Appropriate Application of Fluid Removal Technologies for Stripper Wells

As per the original proposal:
"Search for previous studies and field results to incorporate all pertinent fluid removal technologies and research on the subject."

Data Reduction and Methodology
One hundred sixty-seven references were identified as pertinent to the research on fluid removal technologies for stripper wells and are included in this final report for future reference (Appendix 1). The searches were conducted on the SPE website, the Internet, the Marietta College Library, and the South West Petroleum Short Course 3-CD database. Key search words included liquid loading, artificial lift, fluid removal, gas well performance, and fluid production. Literature pertained to tubing plungers (34%), well performance (27%), general information (14%), pumping units (9%), foamers (5%), casing plungers (3%), progressive cavity pumps (3%), and swabbing (0%).

The literature review confirmed that little research has been completed for wells with production volumes classified as stripper wells and generally focused on the importance of well production performance as a function of the GLR, producing volumes and pressures, and fluid removal efficiency. The review further confirmed that sustained reductions of the flowing bottom hole pressure typically result in sustained production increases. Overall, the results of the literature search proved helpful throughout the study as references of previous work completed on fluid removal methods.

III. Develop Data Collection Forms

As per the original proposal:
"Develop data collection forms of pertinent information to analyze problem wells. Shut-in and producing pressuring information will be gathered to analyze bottom hole producing pressures. Fluid levels and other information will be collected to determine the effects of fluid on bottom hole pressure. Fluid production histories will be confirmed to determine the effect of gas to liquid ratios have on stripper well performance. Well equipment will be analyzed for mechanical failure."

Data Reduction and Methodology
Data collection forms were developed to provide a systematic methodology of gathering data for the analysis of the critical factors that affect the optimum performance of various fluid removal technologies. Experience indicates that through pressure and production decline curve analysis, an operator can typically estimate the productive potential of the producing reservoir and the efficiency of the production method. Ultimately, knowing the productive potential of the reservoir assists the operator in evaluating and selecting the proper fluid removal method.

Data collection forms were developed for the most common fluid removal methods; tubing plungers, casing plungers, beam pumps, and swabbing (Procedure Guide Appendices 3 – 6). While all the data collection forms were similar in design, specific data applicable to each fluid removal method was identified. Sections I, II, and III are for completion by field personnel, while sections IV, V, VI, VII, and VIII are for completion by the production manager. Stripper well operators rely heavily on well tenders to maintain optimum production and therefore completion of Sections I-III can often cue a well tender towards the proper corrective action without any additional action by the production manager required.

Field personnel Section I requests basic well information including producing formation, flowing tubing and casing pressures, domestic gas usage, and specific production cycle data. Section II requests current daily production rates and associated GLR, while Section III requests any comments the well tender might have regarding current operations or recommendations for production improvement.

Production manager Section IV requests analytical data including perforated intervals, casing and tubing sizes and depths, gas sales line size and length, and flowing and shut-in pressures. Section V requests a production performance estimate, Section VI forecasted rates of production, Section VII a description of recent well work, and Section VIII comments and recommendation based upon the analysis.

The data collection forms were utilized throughout the study to analyze fluid removal method performance and were included in the procedure guide with complete instructions to utilize the forms.

IV. Field Review of Critical Factors Affecting Maximum Flow Rate

As per the original proposal:
"James Engineering, Inc. has access to more than 500 stripper wells in Ohio and West Virginia. These wells are of various depths with a wide variety of producing mechanisms. Specific data will be collected and tests run to determine the critical factors affecting the optimum performance of various fluid removal technologies and the effectiveness in maximizing production. The critical factors to be evaluated will include but not be limited to reservoir pressure, bottom hole flowing pressure, line pressure, fluid production rates, gas production rates, artificial lift mechanisms, and surface production equipment."

Data Reduction and Methodology
Previous work for the DOE provided a database of information including lease name and well number, well identification number, well tender, API number, county, township, section, producing status, producing formation, operator, well type, well depth, and completion date. Supplemental information from company capital expenditure reports, detailed wellfile review, orifice chart integration reports, weekly well tender reports, current well tender information, production decline curve analysis, and cumulative production data were incorporated into the database.

From an initial database of 654 wells, a 448 well study group was established after wells that had been sold, plugged, shut-in, classified non-stripper, or outside operated were eliminated. The wells were then grouped according to their fluid removal method as tubing plungers (289, 65%), pumping wells (115, 25%), casing plungers (26, 6%), or swab wells (18, 4%).

Three hundred forty-seven capital expenditures from 1997 – 2001 were summarized by year, lease, well identification number, total cost, and description. Expenditures were further categorized as related to compression, fluid removal method, maintenance, mechanical, miscellaneous, pipeline, purchase, plug and abandon, re-completion, or unknown. Eighty-one (23%) expenditures related to fluid removal method were incorporated into the database.

An extensive wellfile research of all 448 wells identified fluid removal method changes, shut-in pressures, tubing and casing depths, perforation intervals, well tests, and any physical changes that impacted the performance of the fluid removal method. Physical changes included casing repairs, top tubing joint replacement, wellhead and pipeline repairs, well re-completions, and swabbing results. Orifice gas sales charts, chart integration statements, and weekly well tender sheets were reviewed to further identify production cycles, pressures, and well tender comments. All data was summarized and then entered into the database.

Current monthly and cumulative historic production volumes including oil, gas, and water volumes based upon state and in-house data were incorporated into the database and then the GLR's calculated based upon the current and historic volumes.

Historic monthly production decline curves were reviewed and compared to a type decline curve to provide a qualitative assessment of the current production method performance resulting in a classification of "Good", "Fair", or "Poor". The results of this review were then incorporated into the database.

Finally, summary sheets containing database performance information for each well were supplied to respective well tenders requesting current information or corrections including additional shut-in pressure information, beginning and ending cycle pressure, production cycle lengths, field gas and fluid volumes, and sales line pressures. Responses supplied by the well tenders were then incorporated into the database.

The resulting database of critical factors and general well information were analyzed to determine factors affecting the optimum performance of fluid removal technologies and the effectiveness in maximizing production as described in the next section.

V. Summarize Results of Field Review of Critical Parameters

As per the original proposal:
"The results of the field review study will be summarized and analyzed to determine the effects of the critical factors. An attempt will be made to determine when a particular method of fluid removal or artificial lift technology is both appropriate and cost-effective. We will also attempt to bracket at what pressures and fluid rates a particular method of fluid removal fails."

Data Reduction and Methodology

Database analysis revealed 194 fluid production method changes for 127 wells (28%) with some wells undergoing up to four fluid removal method changes. Further analysis indicated that 394 of the 448 wells (88%) were placed on tubing plunger wells at inception while 37 (8%) were placed on pump. The high percentage of wells on tubing plunger and pump at inception indicate that operators understood a fluid removal method would be required to maintain optimum production.

The following tables present some of the correlations regarding the factors affecting the performance of the fluid removal methods.

Table No. 1 shows the relative performance of each production method based upon historical production decline curve analysis. There was a general even percentage distribution of well performance ("Good", "Fair", and "Poor") for pumping wells and swab wells. However, tubing plungers did have a higher percentage of wells classified as "Good" while casing plungers had a higher percentage of wells performing "Poor".

Table No. 1				
Production Decline Curve Analysis to Determine Relative Well Performance				
		No. Of Wells (%)		
Production Method	**No. Wells**	**"Good"**	**"Fair"**	**"Poor"**
Tubing Plunger	289	121 (41)	97 (34)	71 (25)
Pumping Unit	115	43 (37)	40 (35)	32 (28)
Casing Plunger	26	7 (27)	7 (27)	12 (46)
Swab Well	18	5 (32)	7 (36)	6 (32)
Total Wells	**448**	**176 (40)**	**151 (34)**	**121 (27)**

Table No. 2 shows the distribution of each method based upon the historic GLR with the ranges of distribution selected arbitrarily. The distribution indicates a major distribution of high GLR wells associated with tubing plungers while pumping units showed a higher distribution in low GLR wells. Casing plungers and swab wells were almost exclusively high GLR wells.

Table No. 2					
GLR Analysis based upon Historic GLR, Mcf/bbl					
		No. Of Wells (%) by GLR			
Production Method	**No. Wells**	**<10**	**10 – 20**	**20 - 50**	**>50**
Tubing Plunger	289	10 (3)	12 (4)	46 (16)	221 (76)
Pumping Unit	115	39 (34)	21 (18)	29 (25)	26 (22)
Casing Plunger	26	0	0	3 (11)	23 (89)
Swab Well	18	0	0	1 (5)	18 (95)
Total Wells	**448**	**49 (11)**	**33 (7)**	**79 (18)**	**288 (64)**

Table No. 3 shows that 85% of the tubing plunger wells classified as "Good" also had GLR greater than 50 mcf per barrel. Also significant was that the casing plunger wells and the swab wells were also greater than 50 mcf per barrel.

Table No. 3					
GLR Analysis based upon Historic GLR, Mcf/bbl Group 1 or "Good" Wells					
		No. Of Wells (%) by GLR			
Production Method	**No. Wells**	**<10**	**10 – 20**	**20 - 50**	**>50**
Tubing Plunger	121 / 289	1 (0)	5 (4)	12 (11)	103 (85)
Pumping Unit	43 / 115	10 (23)	7 (16)	11 (25)	15 (35)
Casing Plunger	7 / 26	0	0	0	7 (100)
Swab Well	5 / 18	0	0	0	5 (100)
Total Wells	**176 / 448**	**11 (6)**	**12 (7)**	**23 (13)**	**130 (74)**

Table No. 4 provides average well characteristics for each of the four fluid removal methods. No meaningful cycle data was available for casing plunger wells. Limited swabbing information did not provide sufficient information for statistical analysis.

Table No. 4

Average Study Group Production Characteristics

Production Method	No. Wells	Depth Feet	Cycles per Month	MCF per Month	Bbl per Month	Bbl per Cycle	Sales Line Psi
Tubing Plunger	289	5,505	134	332	4.5	0.06	62
Pumping Unit	115	5,058	27	256	24.0	1.40	55
Casing Plunger	26	4,763	-	244	-	-	55
Swab Well	18	4,925	-	378	-	-	45
Total or Average	**448**	**5,062**	**-**	**303**	**-**	**-**	**54**

Table 5 provides a brief summary of the general guidelines for fluid removal method application including GLR, minimum flowing bottom hole pressure, ability to produce maximum fluid, good casing required, investment capital required (“1” = high, “4” = low), and operator training required.

Table No. 5

Stripper Gas Well Fluid Removal Method Application Guide

Production Method	High GLR	Low GLR	Min. Fbhp	Extensive Completion Interval	Bbls per Cycle	Good Prod Casing	Investment Capital $	Operator Training
Tubing Plunger	√			√	0.25 – 1.0		2	√
Pumping Unit	√	√	√	√	1.0 – 5.0		1	√
Casing Plunger	√				0.5 – 3.0	√	3	√
Swab Well	√		√	√	As swabbed		4	

The results of this analysis indicate that tubing plunger wells with GLR’s greater than 50 typically perform better than wells with lower GLR’s. Wells produced by pumping unit were effective regardless of GLR. Wells produced by casing plunger or swabbing, even with high GLR, were not effectively produced. Tubing plungers, casing plungers, and swab wells typically made less fluid monthly than pumping units that averaged significantly higher volumes. Note that the average well only produces 300 mcf per month (10 mcf per day). Final conclusions of the study are provided in the section titled “Conclusion”.

VI. Develop Decision Trees to Select Appropriate Fluid Removal Technologies

As per the original proposal:
"Develop decision trees to identify the problems causing the fluid accumulation and select the most appropriate solution. The decision tree will utilize pressure and rate information gathered on the data collection forms to direct the operator to the most effective fluid removal system."

Data Reduction and Methodology
The Decision Tree Form (Appendix 3) is a four-phase process to aid in fluid removal method analysis and selection. The decision tree provides a methodology to evaluate the most common fluid removal methods for stripper gas wells by dividing the analysis into four separate sections: Phase 1 - Identify the Problem, Phase 2 - Measure the Problem, Phase 3 - Solve the Problem, and Phase 4 – Monitor the Changes and Production.

The Decision Tree Form was designed to address the more common problems faced by operators first, then complete additional analysis by going forward to the next phase as required. This methodology can result in solving the fluid removal evaluation prior to any substantial investment. A Data Collection Form and the Alternate Fluid Removal Method Decision Form are incorporated into the Decision Tree Form. Complete descriptions on using all forms are included in the procedure guide.

VII. Test the Decision Tree

As per the original proposal:
"Run several wells with liquid loading problems through the process to be sure consistent results are achieved."

Data Reduction and Methodology
The decision tree methodology was applied to ten wells where recent well work had been performed to correct liquid loading problems to ensure that consistent results could be achieved. The decision tree form, appropriate data collection form, and alternate fluid removal decision form were completed for each well in the ten well test group. In general, the process for evaluating wells experiencing liquid loading problems utilizing the three forms proved effective. The testing not only refined the decision tree process but the decision tree and data collection forms as well.

The summary provides key indicators regarding the application of the fluid production method, including previous and current fluid removal method, completion date, cumulative gas and total fluids to date, historic GLR, Estimated net cost of fluid removal method change, estimated incremental stabilized production after fluid removal method change, and any specific comments regarding the analysis.

Table No. 6 Decision Tree Test Result Summary									
Lease	**Previous Fluid Removal Method**	**Current Fluid Removal Method**	**Comp. Date**	**Cumulative Mcf**	**Cumulative Bbls**	**Historic GLR**	**Est. Net Cost**	**Prod. After Change, Mcfm**	**Comment**
Aron Woodford #1	TPL	PJEM	11/14/74	155,530	1,280	120	$10,000	+100	Higher initial prod. predicted
OD Baker #1	SWB	TPL	07/01/77	178,930	510	3,500	$10,000	+200	Initially TPL. Swabbing not effective
John Bird #2	TPL	PJGE	08/20/73	97200	1,215	80	$10,000	+ 200	Significant fluid production - Combined production with #1
L. Derry #3	TPL	SWB	10/24/86	45,190	215	210	$0	+100	Combined production with #1
W. Fitzgerald #1	TPL	CPL	02/03/77	199,950	1,395	145	$5,000	+250	Recent 2002 conversion to CPL
Wm. Garris #2	SWB	TPL	09/01/85	50,970	55	930	$8,500	+0	Tubing test well, Initially TPL Combined production with #1
Hughes Stiles #1	TPL	PJEM	11/30/73	324,090	1,275	255	$10,000	+150	Higher initial prod. predicted
A. Larrick #2	CPL	PJGE	06/04/80	55,040	1,195	45	$10,000	+200	Incomplete prod. history: Offset well experienced better results.
Leachman #1	TPL	CPL	01/27/74	30,610	70	440	$0	+130	Incomplete production history
Ellis Miller #1	SWB	TPL	02/01/94	83,990	995	85	$8,500	+200	Initially TPL

Not all information requested in the data collection forms was available for analysis. A lack of information is consistent for stripper wells due to multiple owners and marginal economics. Particularly, flowing bottom hole pressures, shut-in pressures, and historic total monthly fluid volumes were generally unavailable. Therefore, some estimates may be required to provide a reasonable measure of potential production increases associated with a fluid removal method application.

Most stripper well operators have a good understanding of the day to day operating conditions for their wells, often being the well tender. Therefore, many of the questions or responses requested on the evaluation forms will be known without any wellfile research required. However, the questions and responses requested in the three forms were prepared to be as comprehensive as possible. The overall format of the forms provides a logical and useful tool for the evaluation and selection of fluid removal methods for stripper wells.

VIII. Prepare Application Guide Detailing Cost-Effective Fluid Removal Technologies

As per the original proposal:
"An application guide will be prepared to assist operators in determining appropriate fluid removal methods by evaluating the current producing characteristics of specific wells to maximize recovery of the remaining reserves."

Data Reduction and Methodology
The results of the study were incorporated into a procedure guide to assist operators in evaluating and selecting common fluid removal methods for stripper gas wells, which include tubing plungers, casing plungers, pumping units, and swabbing.

The procedure guide begins with an introduction and overall methodology to utilizing the guide followed by a complete description of the decision tree form. The guide then includes a description of the operation of each fluid removal method providing a typical application range based upon depth, GLR, and fluid production. The guide includes general operational guidelines for installation, the evaluation forms required, the advantages and disadvantages of each method, the identification of potential failure paths, and a listing of diagnostic tools.

IX. Prepare Technical Paper and Transfer the Technology

As per the original proposal:
"The summary report will be presented at either a PTTC conference and or through a SPE technical paper presented at a regional meeting. Additional presentations may be arranged as requested."

An SPE technical paper was presented in Lexington, Kentucky at the 2002 Eastern Regional Meeting. Two Stripper Well Consortium sessions were made in November 2002 in Oklahoma City and Pittsburgh. A presentation was also made to the Penn State petroleum engineering graduate students in November 2002. Additional presentations will be made locally as requested, possibly to the PTTC and the spring Marietta College SPE student chapter meeting, Marietta, Ohio.

The final report and procedure guide will be posted on the SWC website and provided to NYSERDA

X. Conclusion

- Most stripper gas wells require some application of a fluid removal method to maintain optimum production.
- It is important to production optimization that operating principals are thoroughly understood and proper fluid removal methods are systematically applied.
- Stripper well operators rely heavily upon field personnel to maintain optimum production that requires training in fluid removal methods and operating information understanding (location and pipeline maps, production decline curves, and wellbore schematics).
- Stripper well operators must provide well tenders the support and proper tools for production evaluation (Echometers or pressure recorders).
- Optimized production to economic depletion is achieved when the flowing bottom hole pressure is minimizes generally through the consistent removal of fluid.
- The fluid removal methods available to produce stripper gas wells to economic depletion are tubing plungers, casing plungers, pumping units, and swabbing.
- Tubing plungers perform better on wells with high GLR's, greater than 50, and low fluid volumes, with few depth or completion restrictions.
- Casing plungers perform better on wells with high GLR's, limited perforation intervals, good mechanical integrity casing, and low fluid production.
- Pumping units are applicable to wells across a broad range of GLR's, long perforation intervals, and can sustain a lower flowing bottom hole pressure than other methods.
- Swabbing is applicable to wells with very high GLR's, ideally a large pocket below the perforated interval for fluid accumulation, and limited fluid production.
- Additional work in the area of fluid removal method application could further the goal of production optimization.

References:

Appendix 1

Bibliography:

Turner, R.G. Hubbard, M.G., and Duckler, A.E.: “Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells”, Journal of Petroleum Technology, November, 1969

Hacksma, J.D., Shell Oil Company: “Users Guide to Predicting Plunger Lift Performance”

List of Acronyms and Abbreviations:

Not Applicable.

Appendix

1	Literature Search Results Summary
2	Procedure Guide

Appendix 1 – page 1
Literature Search Summary and References

Title	Author(s)	Source
1. Analyzing Well Performance XV	McCoy, Podio, Huddleston	SPE
2. Application of Nodal Analysis in Appalachian Gas Wells	Frear, Yu, Blair	SPE 17061
3. Inflow Performance Relationships for Solution Gas Drive Wells	Vogel	SPE 1476
4. Optimum Plunger Lift Operation	Baruzzi, Alhanati	SPE 29455
5. Plungerlift Benefits Bottom Line for a SE NM Operator	Schneider, Mackey	SPE 59705
6. Using Foaming Agents to Remove Liquids from Gas Wells	Dunning, Eakin, Walker	US Mn. 11
7. Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells	Turner, RG	JPT Nov 1969
8. A New Look at Predicting Gas Well Load Up	Coleman, SB	JPT Mar 1999
9. Gas Well Operation with Liquid Production	Lea, Tighe	SPE 11583
10. Introduction to Plunger Lift: Applications, Advantages, Limitations	Beauregard, Ferguson	SWPSC
11. Will Plunger Lift Work in My Well?	Beauregard, Ferguson	SWPSC
12. How to Optimize Production from Plunger Lift Systems I & II	Phillips, Listiak	
13. Plunger Lift Comes of Age	Christian, Lea, Bishop	World Oil 95
14. Predicting Plunger Lift Performance	Hacksma	Shell Oil
15. Plunger Lift Application in Wells with Set Packers or Permanent Tubing	Darden	SPE
16. Dynamic Analysis of Plunger Lift Operations	Lea, J.F.	
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18. Design Optimization of Plunger Lift Systems	Avery, Evans	SPE 17585
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Appendix 2
Procedure Guide

Identification of Effective Fluid Removal Technologies For Stripper Wells

Stripper Well Consortium
Subcontract No. 2042-JE-DOE-1025

Procedure Guide

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I. Introduction

This study was specifically developed for stripper well operators in a cost-sharing venture between James Engineering, Inc., the Stripper Well Consortium, the National Energy Technology Laboratory, the New York State Energy Research and Development Authority. The goal of this research was to develop a procedure guide detailing cost effective fluid removal method selection procedures for stripper gas wells.

SPE paper number 78707 and the final technical report for this research contain a complete description of the methodologies, results, and conclusions realized while developing this procedure guide.

Previous work completed by James Engineering, Inc. found that 270 of 376 wells evaluated (>70%) exhibited some form of abnormal production decline during the past five years. Nearly 50% of the abnormal production declines were due to liquid loading resulting in decreased reserves and revenue. The frequency of liquid loading problems represents a significant opportunity for improvement since in many cases liquid loading is a correctable problem through the systematic evaluation and application of appropriate fluid removal technologies to stripper gas wells.

Wellbore fluids that cause liquid loading problems are typically due to free liquids produced with the gas or condensed liquids in the gas. Additional sources of liquids may be attributable to inadequate cement bond, fracing or acidizing into water, poor perforation placement, or casing or packer leaks. However, high volumes of produced fluids are not typically associated with stripper gas wells.

The current study found that 125 (28%) of the 448 wells evaluated experienced at least one fluid removal method change during its production history. Of these 125 wells, 32 wells experienced multiple fluid removal changes for a total of 194 changes while 75 wells (60%) were ultimately put on pump as a fluid removal method. The multiple changes of fluid removal methods represent additional cost that reduce the already marginal economics of stripper gas well operations.

Stripper gas wells typically have poor reservoir quality and low reservoir pressure that compound the production problems resulting in operators literally stripping the last 10 to 20% of wells economic ultimate reserves. These wells are generally twenty years or older with multiple owners, and bring along with them a broad range of problems.

Experience indicates that twenty percent of the wells often represent a large portion of income producing assets. Therefore, stripper well operators need to able to identify and focus on those wells where a possible change in fluid removal method will make the greatest impact. Ultimately, stripper well operators must identify fluid removal methods that will not only carry a well to ultimate depletion but also where the additional capital cost can be recovered.

An absolute necessity in correcting problems with stripper wells is finding an economic solution. Stripper wells are defined as wells with production less than or equal to 60 mcfd or 10 bopd. However, the national average for stripper well production is 15 mcfd and 2 bopd or 30 mcfdeq (Appendix 1). The Appalachian Basin represents 205,000 of the nation's 646,000 stripper wells, but the average stripper well in the Appalachian Basin only produces 11 mcfd and 0.4 bopd or 14 mcfdeq. By definition, even when stripper well production is maximized, the amount of capital available for repairs or enhancements is limited. It is critical then that changes made in fluid removal techniques be effective for the life of the well. This procedure guide provides methods for evaluating and selecting fluid removal methods for optimum fluid removal from stripper gas wells.

When discussing options for fluid removal, it is recognized that stripper oil wells are typically on pump and only require efficient run times to optimize production. Conversely, most dry gas wells, those with no associated liquids, are only concerned with the minimum pressure afforded through compression. Stripper oil wells and dry gas wells do not lend themselves to fluid removal method selection but only how to optimize the flowing bottom hole pressure. Therefore, the options for fluid removal and specifically the timing of applications are normally associated with stripper gas wells. It is important for the stripper gas well operator to identify those areas where there are opportunities for economic production enhancement through the proper selection of fluid removal methods.

Upon initial completion a gas well generally has sufficient gas velocity to transport all fluids to the surface, while many oil wells require some form of fluid removal. As the gas flow rate and velocity decreases due to decreased reservoir pressure, the fluid suspended in the gas phase begins to drop out and accumulate at the bottom of the well. The well may then begin to slug fluid to the surface, until the fluid column pressure overcomes the reservoir pressure restricting or ceasing production altogether. Stripper gas wells are much more susceptible to this problem.

Liquid loading problems are identified at the surface by erratic gas and/or liquid production volumes, high differential pressure between the casing and the tubing, or additional swabbing or blow downs to maintain production. Erratic gas production is evidenced on gas production orifice meter charts, weekly readings from positive displacement meters, or monthly-integrated gas volume reports. Erratic liquid production is often noticed in weekly reported tank gages. Production problems are most evident on plots of historic monthly production decline curves. The regular plotting of all monthly produced volumes is one of the best methods of identifying liquid loading problems.

Liquid loading can be corrected by the installation of a fluid removal system, modifying tubing design or operating procedures, using foaming agents, installing compression, enhancing inflow performance, and water shut-off through remediation. This procedure guide focuses on the installation of relatively low cost fluid removal methods associated with fluid removal from stripper wells. These methods include casing plungers, tubing plungers, pumping units, swabbing, and compression.

Casing plungers, while not widely used, afford stripper well operators an option for fluid removal by utilizing a mandrel with rubber seals to provide an interface between the fluid and gas and then utilizing stored reservoir energy to remove the fluids. Casing plungers are an effective means of fluid removal but are limited to wells with high GLR, limited perforation intervals, and casing with good mechanical integrity. This method is typically not able to achieve the lowest bottom hole pressure for optimum reserve recovery. Low maintenance costs are typically associated with this method of liquid removal.

Tubing plungers are effective over a wide range of operating conditions but typically successful with wells with a high GLR. Tubing plungers effectively remove the majority of fluid accumulated in the tubing on a cyclic basis by providing an interface between the fluid and gas and then utilizing stored reservoir energy to remove the fluids. This method is typically not able to achieve the lowest bottom hole pressure for optimum reserve recovery. Low maintenance costs are typically associated with this method of liquid removal.

Pumping units have long been utilized for relieve liquid loading problems associated with stripper wells. This is typically the best method to lower the flowing bottom hole pressure and achieve maximum recovery of oil and gas reserves. However, the higher installation and associated maintenance costs normally encountered when compared with the previous methods of fluid removal can make this method too expensive for stripper well operators.

Swabbing, while long considered one of the most inexpensive forms of fluid removal should only be utilized for those wells with nominal fluid production and a large amount of pocket below the producing interval for fluid accumulation. Swabbing while seemingly inexpensive is often an inefficient fluid removal methods resulting in temporary increases in production after swabbing. Stripper well operators should carefully consider the cumulative annual costs associated with swabbing when compared to the benefits of some other fluid removal method.

Installing compression to lower the wellhead and flowing bottom hole pressure should always be considered as an option for stripper gas wells. This is especially true for mature reservoirs and where multiple wells can be gathered into one system. The application of compression typically results in long term benefits in those areas where high sales line pressure have restricted production. Operators should review their production systems for potential compressor installation applications but should be aware of the initial installation costs and annual operation and maintenance costs associated with any compressor installation. Compression installation by itself to reduce the flowing bottom hole pressure and increase the gas flowrate sufficiently for fluid removal is typically not a method applicable to the low production volumes associated with stripper wells. Furthermore, sizing the proper compressor installation for gas wells with intermittent flow can be difficult.

The following briefly reviews the other correction methods for liquid loading problems and the reasons why they may be inappropriate for stripper gas wells.

While modifying the tubing design (tubing diameter) is often successful in combination with a tubing plunger, by itself, it offers little relief for stripper gas wells. The critical gas flow rate to lift wellbore fluids through 1 ½" tubing or greater, as studied by Turner, Foss and Gaul and others, are in general greater than the flow rates for stripper wells (Appendix 2). For example, a 60 mcfd well with 1½"tubing would require a wellhead pressure of 10 psi while an average stripper well of 10 mcfd well at 10 psi would require ½" tubing. Generally, tubing smaller than 1½" is generally not practical for well servicing, tubing plungers, or beam pump using slim-hole rods. Therefore, modifying tubing design was not a consideration for stripper wells suffering from liquid loading.

Modifying the operating procedures to unload fluids involves periodically shutting in a well to build sufficient pressure to unload the well or by temporarily diverting production to a sales tank at a reduced wellhead pressure for increased gas velocity. Both methods are inefficient, wasting gas and reservoir energy and do not remove all fluids even when automated. The low implementation cost of these methods is attractive, but the additional shut-in time or diversions required result in loss production and revenue. These methods should be viewed as temporary solutions until a more appropriate fluid removal method is selected to increase and maintain production.

The application of foaming agents, soap, or surfactants to a well with liquid loading problems is a common and generally simple method of liquid removal. Studies as early as 1957 investigated the idea of using foaming agents to remove liquids from gas wells. The foaming agent can be introduced to the well in the form of a solid, liquid, gel, powder, or through capillary injection strings. Surfactants, or surface-active agents, act by reducing the surface tension of the water, lightening the column of fluid, thereby giving the reservoir pressure the ability to overcome the fluid column pressure. After a predetermined shut-in time, the liquid and foam are removed by diverting production to a sales tank at a reduced wellhead pressure. The highest cost associated with foamers is often the labor cost due to the hours spent soaping the well, shutting in the well, and then diverting production to the production tank. Automation has minimized the effects of liquid loading by optimizing the treatment program utilizing soap stick launchers and injection pumps, however, the shut-in period to build sufficient pressure to unload the well makes this method inefficient and ultimately another fluid removal method is required.

Enhancing inflow performance through re-stimulation and remedial water shut-off are beyond the scope of this study but should be considered when evaluating potential fluid sources and fluid elimination methods.

Stripper well operation requires the careful consideration of every investment due to the limited income associated with stripper wells where the economic line between success and failure is very thin. Timely and accurate decisions regarding liquid loading problems should be based upon data organized for quick review and not on unsubstantiated opinion. The fluid removal method selected should be effective for the remaining life of the well and based upon specific information. By better defining the source of the liquid loading problem, the better the solution or appropriate fluid removal method will be identified. Unfortunately, stripper well operators often do not track sufficient information to adequately identify the specific problem to implement an effective solution.

The minimum wellfile information should include drilling, cementing, completion, workover and repair reports, shut-in and producing pressure summary, and a wellbore schematic. All summaries prepared should be chronological order. In addition, monthly gas and fluid volumes as well as the GLR, should be plotted and summarized for easy reference and problem analysis.

Ultimately, the focus of every fluid removal method is the same, to maintain a reduced flowing bottom hole pressure to optimize production performance. Successful, economic stripper well production requires the cooperation of everyone involved. Additional training may be required to receive maximum benefit from the fluid removal method employed. Fluid removal equipment in the correct application is often only as effective as those operating it. It is important then to recognize that not all well tenders are equipped with the same set of skills, so where one well tender may succeed with producing a well, another may fail to achieve similar results.

This procedure guide provides the stripper well operator with general guidelines for the evaluation and selection of specific fluid removals methods typically associated with stripper gas wells and not intended as a comprehensive resource.

II. Methodology

A process can be defined as a systematic series of steps designed to result in a desired outcome. However, experience indicates that due to lack of a defined selection process, fluid removal methods are often randomly applied to stripper gas wells experiencing liquid loading problems often resulting in added expense with minimal production increases. This procedure guide provides an evaluation and selection process for the more common forms of fluid removal methods for stripper gas wells including casing plungers, tubing plungers, pumping wells, and swabbing.

Bucaram and Patterson in SPE 26212 entitled "Managing Artificial Lift" indicate that managing artificial lift generally requires information and experience necessary to select the optimum (ultimately the most economical) lift system and the optimum components for that lift system, a continuous production performance monitoring, a data collection system that allows efforts to be focused on problem wells, periodic meetings to discuss problem wells, a central contact that assists with the meetings and provides continuity, information, and contacts from inside the company and the industry, training for company personnel and for contractors, and finally continuous and repeated technology transfer. However, stripper well operators should recognize that the ultimate goal of production operations is to maximize profits and not to maximize production or to minimize equipment failures, since one may not equal the other.

Experience indicates that the process for the analysis of wells experiencing liquid loading problems should include an understanding of applicable fluid removal methods, a decision tree to evaluate other fluid removal methods, an estimate of the individual well ultimate reserves and the final reservoir pressure at economic depletion, a regular review of the complete production history (oil, gas, water, and GLR), a comparison of production history to a type decline curve for abnormal production decline, operating and shut-in pressure information, identification of potential sources of liquid loading, a wellbore schematic, a summary of equipment changes, workovers, and repairs, and a consideration for additional compression. The process should include an estimate of the maximum production performance for the particular fluid removal method, the basic installation procedure, identification of failure paths, a regular discussion of well performance and associated equipment with the well tender, and an estimate of the potential improvement through a fluid removal method change. The process should also include an evaluation of the production results from the implemented change for continued process improvement, and most importantly, the process should be easy to use or it will soon be abandoned.

Simply put, prior to any investment, stripper well operators must first optimize their production with the existing production equipment, and then based upon production, pressure, reserve, and economic analysis, decide if a change in the fluid removal method would optimize the production to the economic depletion of the well.

With regards to the fluid removal method selection process, any well that will still flow is typically non-stripper and any well that has associated liquid production typically has some form of fluid removal method already in place. In the study area, wells are generally on tubing plunger or pump when they reach stripper well production levels. The decision of which production method to utilize should previously have been based upon the GLR. In general, the GLR should be consistent over the life of the well, unless in special circumstances a water drive is present. When a baseline GLR has been established, continued monitoring on monthly basis can help ensure that the fluid removal method is performing as expected.

If a well is currently on pump, continued production by that method becomes a decision based upon past performance, current economics, future reserve recovery, and other opportunities to better utilize the equipment.

As part of this analysis, the operator needs to determine the productive potential of the well experiencing liquid loading problems. A previous study indicates that the productive potential of stripper wells can be estimated by utilizing production decline curves, pressure data, and inflow performance relationships. A full discussion on this method can be found in our previous study, see SPE 73259.

The stripper well operator should always identify those factors that would affect the bottom hole producing pressure when analyzing wells with abnormal production declines. Research indicates that many stripper wells experience abnormal production by failure to reduce the flowing bottom hole producing pressure sufficiently to maximize production. The inability to reduce the flowing bottom hole producing pressure is typically attributable to a misapplication of fluid removal method or a failure in mechanical integrity. Therefore, the operator should be aware of all changes in operating pressures, production volumes, production methods, and especially the producing cycles during the analysis.

The procedure guide is composed of three forms to guide the stripper well operator through liquid removal method selection; the Decision Tree Form, the Data Collection Form, and the Alternate Fluid Removal Method Decision Form. The Decision Tree Form provides a practical four-step process for the application of decision tree analysis to identify the most common causes of liquid loading. The Data Collection Form assists the stripper well operator to gather specific data required for analyzing common stripper well fluid removal methods. Finally, the Alternate Fluid Removal Method Decision Form guides the operator through an economic analysis to determine the most appropriate solution to correct the liquid loading problem.

In addition to the forms previously discussed, also included in the procedure guide Appendix are a swab well summary form, a casing plunger performance form, a shut-in pressure history summary form, three "investment vs. payout" nomagraphs to assist in stripper well decision making, a general wellbore schematic, and a Vogel inflow performance relationship curve.

III. General Steps for Fluid Removal Method Evaluation and Selection

1. **Identify** under performing wells based upon a review of the complete monthly production history plotted on forty-year semi-log paper, current production results, and a comparison to reservoir type curves.
2. **Review** procedure guide section on appropriate fluid removal method
   a. Swab or bailed wells
   b. Casing Plungers
   c. Tuning Plungers
   d. Pumping Wells
3. **Complete** Decision Tree Form
   a. Complete Appropriate Data Collection Form for fluid removal method
   b. Determine production cycles and producing pressures
   c. Estimate maximum production potential – Utilize Vogel's IPR
   d. Estimate remaining reserves (Decline Curve, P/Z, Volumetric Analysis)
   e. Complete Alternate Fluid Removal Method Decision Form
      i. Utilize information from Data Collection Form
      ii. Utilize economic nomagraphs
      iii. Determine appropriate fluid removal method
   f. Review results, re-evaluate as necessary

IV. Quick Reference Guidelines for Fluid Removal Method Selection

The general guidelines for fluid removal method selection are provided in Table 1 including GLR, minimum flowing bottom hole pressure, ability to produce maximum fluid, good casing required, investment capital required ("1" = high, "4" = low), and operator training required.

Table No. 1
Stripper Gas Well Fluid Removal Method Application Guide

Production Method	High GLR	Low GLR	Min. Fbhp	Extensive Completion Interval	Bbls per Cycle	Good Prod Casing	Investment Capital $	Operator Training
Tubing Plunger	√			√	0.25 – 1.0		2	√
Pumping Unit	√	√	√	√	1.0 – 5.0		1	√
Casing Plunger	√				0.25 – 3.0	√	3	√
Swab Well	√		√	√	As swabbed		4	

The following procedures provide the steps necessary to complete the forms and analyze stripper gas wells experiencing liquid loading problems to determine the appropriate fluid removal method.

V. Decision Tree Form Procedure

The Decision Tree Form (Appendix 3) provides a practical four-phase process to quickly and easily assess the application of the fluid removal method for stripper wells. The form provides a methodology for stripper well operators to evaluate the application of fluid removal methods for stripper gas wells by focusing on the GLR and the desired final bottom hole pressure. The Decision Tree Triage Form is divided into three sections, **Phase 1** – Identify the Problem, **Phase 2** – Measure the Problem, **Phase 3** – Solve the Problem, and **Phase 4** -Monitor the Changes and Production.

Phase 1 of the decision tree form, **Identify the Problem**, requests the operator to verify the production data, GLR, decline curve, and forecast to ensure correct data were used. Next the historic and current GLR are compared for significant differences. The entire production history, plotted on forty-year semi-log paper is compared to a reservoir type decline curve, then review for gas or fluid production change. A map of the gas gathering system and location of offset wells should be prepared and reviewed. Then, verify with pumper that the problem still exists to ensure the problem has not already been corrected. Finally, verify metering accuracy and gas gathering system integrity by ensuring charts were integrated correctly and that there are no gas gathering system leaks.

Phase 2 of the decision tree form, **Measure the Problem**, requests the operator to first complete the appropriate data collection form to analyze the liquid loading problem (Appendices 4 - 7) for the following fluid removal methods, Tubing Plunger, Casing Plunger, Pumping Unit, and Swab or Bailed wells. The forms were developed to assist the stripper well operator in evaluating the proper application of fluid removal methods. All of the forms are consistently divided into one section for field personnel to complete, Sections I-III, and one section for office personnel to complete, Sections IV - VII. Accurate data should be utilized to evaluate the fluid removal method, however, reasonable estimates can be utilized if necessary.

Phase 3 of the decision tree form, **Solve the Problem**, requests the operator to Complete the Alternative Production Method Decision Form (Appendix 8) and then determine to complete the recommended well work, review the well for shut-in, sale, or plug and abandon. If no further analysis is required, simply continue to produce any well that cannot be economically remediated. Quick reference nomagraphs are provided for the stripper well operator to determine the rate of return based upon the investment made compared to the production increase. The nomagraphs quickly indicate that very few dollars can be invested for 5 mcfd.

Finally, Phase 4 of the decision tree form, **Monitor the Changes and Production**, requests the operator to measure post change production rates and GLR and to determine if the production meets forecasted rates. If the current rate does not meet forecasted rates then the well should be reevaluated.

While specific failure paths for each fluid removal method are included in the guide, the general failure paths for stripper well operations include complacency, limited well tender training, ignoring well tender recommendations and individual well early production history, incomplete production histories of monthly oil, gas, and water volumes, incomplete pressure and workover summaries, not setting monthly production goals, never checking or changing production cycles, unnecessary gas gathering system restrictions, never comparing integrated produced volumes to sales volumes, and never estimating fluid removal performance.

Further, while specific evaluation tools for each fluid removal method are outlined in the guide, the general evaluation tools for a stripper well operator include production histories, wellfile information, brine hauling reports a wellbore schematic, the weekly well tender reports, swab reports, orifice meter gas sales charts, the well tender, a two pen recorder, an acoustic liquid level device, an amp meter. Special instrumentation like bottom hole pressure recorders and dynamometers are too expensive for most stripper well operators. Other technology is available to improve stripper well operations, but implementation may be cost prohibitive.

The success of a fluid removal method depends upon well tender knowledge and attitude, pipeline capacity, surface equipment surge capacity, and the downhole equipment condition. The chief obstacles faced by well tenders to achieving optimum production are lack of training, lack of information, too many wells, and complacency. It cannot be understated that a well tender's knowledge and acceptance of a production method is vital to stripper well operation. Well tenders need to be on guard that as well conditions change, production cycles need to be adjusted accordingly.

Summaries of artificial lift selection guides compiled by Brown, Clegg, and Weatherford have all included (Appendix 16-19) for reference even though their work exceeds the scope of this project.

A directory of fluid removal service companies and fluid removal equipment manufactures or suppliers, including product, mailing address, and phone number have been provide for easy reference (Appendix 20). A directory of stripper well associations is also included for future reference (Appendix 21).

Individual metering

While many wells are produced through a common sales meter or production facility, once a year tests should be scheduled to determine the production potential of each well, then documented to the wellfile.

Shut-in Pressures – Final word

It is important for the stripper well operator to document all shut-in pressures and to be complete regarding the parameters of the shut-in. While it is recognized that continuous production is important to stripper well profitability and contributes to the ease of operations, oftentimes wells are shut in due to pipeline restrictions, construction, or other events during the course of the year. However, in the event that no shut-in occurs, a planned time should be scheduled to retrieve the shut-in as well as the flowing bottom hole pressure.

VI. Fluid Removal Method Description
Swab or Bailed Wells

The removal of fluid accumulation by swabbing is one of the most basic forms of fluid removal and should only be considered for mature reservoirs with low-pressure that produce a very nominal amount of fluid. Ideally, a swab well should have sufficient pocket below the producing formation for fluid storage between swabbing operations.

Basic Operation

Swabbing or bailing removes fluids from the wellbore by lowering swab tools on steel line, usually inside of a lubricator, to the fluid level. Successive swabbing runs are made until all of the fluid has been removed from the well. Swabbing operations involve a portable swabbing unit or service rig equipped with a steel line, depth meter, swab tools and cups, a lubricator, a swabbing tee, a storage tank, and a one or two man crew. The swab tools can accommodate 1 ½” tubing to 5 ½” casing, although tubing is normally removed for more efficient operation.

Bailing is similar to swabbing but is normally reserved for open-hole completions or shot holes. A 10 to 20 gallon bailer is slowly lowered into the fluid, filled, pulled back to surface, and then emptied. This cycle is repeated until all fluid has been removed from the well. Wells that have been “shot” are generally low-pressure mature wells that require periodic removal of fluids. Swabbing or bailing is one of the earliest methods developed for fluid removal from stripper gas wells and is still utilized throughout the industry.

Cost Considerations

The cost of swabbing should be monitored carefully to ensure that annual expenses do not exceed the total investment of other fluid removal methods over time. The cost for each swabbing may range from $300 to $900 depending on the depth of the well, and the fluid recovered. Swabbing often results in temporary production increases that decline to previous production levels, requiring additional swabbing, the frequency of which is a function of the produced fluid volumes. The periodic removal of only a few barrels of fluid may not be an effective indicator that swabbing is the best method of fluid removal. A small recovery during swabbing is more indicative of low reservoir pressure than fluid production rate. The well may make a small amount of fluid but still load up quickly. A review of the decline curve may indicate that another fluid removal method could sustain production increases better because of a lower flowing bottom hole pressure maintained by continuous fluid removal.

Typical Stripper Well Application Range

- Depth 100 – 7,000’
- Gas Liquid Ratio High
- Fluid Production Nominal
- Large pocket below completion interval
- Established through production testing

General Operational Guidelines

1. Compile and review the complete production history, then compare to type production decline curve for abnormal production decline.
2. Estimate the historic gas to liquid ratio (mcf/barrel)
3. Review the well file for previous swabbing records or well work to identify the total depth, perforations, and any casing or tubing problems.
4. Move in the swabbing unit. Note and record the casing and sales line pressure, and the initial fluid level of the production tank.
5. Release the wellhead pressure to the production tank, and rig up with bare tools.
6. Verify the perforations or producing interval are clear of sand or sediment. Clean out hole to TD for additional storage capacity below the producing interval.
7. Swab the well to the top of the perforations. Note the initial fluid level in the daily report. Swab through the perforations to TD being careful not to get hung in the hole. Swab until hole is dry or note final fluid level.
8. Record the fluid type(s) and the volumes of fluids recovered.
9. Return the well to production and monitor production for effect of fluid influx.
10. If production declines substantially, move in a swab rig in two weeks to thirty days to check for additional fluid influx and swab as necessary.
11. Continue monitoring production and swab results to determine if swabbing is an economic application of fluid removal to optimize production.
12. Any change in fluid removal method to casing swab, tubing plunger, or pumping unit must be based upon GLR, depth, remaining reserves, and payout.
13. Maintain accurate swabbing record to monitor production and future swab volumes.

Evaluation Forms Required

• Decision Tree Form	Appendix 3
• Swab Well Data Collection Form	Appendix 7
• Alternative Fluid Removal Method Decision Form	Appendix 8
• Swabbing or bailing activity report form	Appendix 9
• Shut-in pressure summary form	Appendix 10
• General wellbore schematic	Appendix 11
• Vogel's Inflow Performance Relationship Curve	Appendix 12

Advantages

- Wells can often be produced to depletion
- Simple design and operation
- Annual cost could be relatively low
- Gas and liquids can be produced to sales line pressure if low enough.
- No capital requirement

Disadvantages

- Depending on fluid volumes or reservoir pressure, production increases immediately after swabbing may not be sustained.
- Accumulated annual expenditures may exceed the cost of other fluid removal methods that have higher initial costs.

- Timing of operations may require costs in total hours or dozer expense.
- Production may be delayed waiting on availability of swabbing rig.

Failure Paths

- Not identifying the true effects of fluid production on a well, that is, assuming the volume of fluid recovered during each operation represents the total fluid capability of the well if the bottom hole producing pressure was kept optimized.

- Not removing the tubing to minimize the effects of the hydrostatic pressure of the column of fluid and decreased swabbing efficiency.

- Not preparing a swabbing schedule based upon GLR to swab several wells once mobilized.

Diagnostic Tools

- Production decline curve
- Historic gas liquid ratio
- Well tender proprietary information
- Gas sales orifice meter chart
- Echometer or other sonic fluid level determination instrument
- Single or two-pen pressure recorder
- Swab reports: Fluid levels, fluid volumes, post production results
- BHP bomb – typically too expensive for extensive use on stripper wells.

Important Note –

In order to maintain a wellbore fluid level that would restrict production, the near well bore area is most likely water saturated. Extended swabbing may be required to effectively clean up a well that has been loaded up. The near wellbore storage restricts optimal gas production in three ways:

1. The hydrostatic column of the fluid
2. The fluid in the near well bore area to immediately replace the fluid being removed.
3. The reduction in relative permeability to gas by the presence of fluid.

Casing Plungers

Basic operation:

Casing plungers are designed to remove accumulated liquids from the production casing by isolating the fluids in the wellbore from the gas in the reservoir, and then utilizing reservoir energy to lift the plunger and the fluids above it to the surface. A casing plunger system is comprised of a casing plunger, lubricator or receiver, and a bottom hole stop. Additional surface equipment may include an electronic control box, motor control valve, sensor, drip pot, and gas regulator for pneumatic operation. The plunger is composed of a hollow steel mandrel, designed for 4 ½" casing, approximately 3 feet long, weighing 60 pounds, with multiple rubber sealing elements. Under normal operating conditions the casing plunger should lift 1 to 3 barrels of fluid per cycle. Depending on the volume of fluid produced, the minimum cycles for some wells may be as little as once per month while for other wells the tool may run continuous. There are several thousand casing plungers currently operating in various parts of the country.

A complete cycle for a casing plunger begins with the release of the casing plunger from the surface lubricator. The traveling valve is now in the open position allowing the plunger to free-fall to the bottom hole stop. Gas and fluids pass through the open traveling valve causing very limited interruption to gas production. The plunger's traveling valve closes upon contact with the bottom hole stop. Wellbore fluids that have accumulated above the bottom hole stop are effectively isolated from the gas in the reservoir by the rubber sealing elements. As gas enters the casing, the casing plunger and fluids are lifted to the surface, where production equipment separates the liquids from the gas. The casing plunger enters the surface lubricator, and is captured by a latching mechanism. The traveling valve opens as the latch is engaged allowing for production of the gas below the tool. Gas production continues until the plunger is released to begin another cycle. (After Jet Star sales brochure)

Successful operation of casing plungers can be sustained with regular maintenance, a pressure recorder, and a gas sales orifice meter chart. With this information, the cycle information in regards to the casing pressure, gas sales, and trip time can be documented. Produced fluid and gas volumes should be monitored to optimize plunger cycles. Cycles may be reduced after the well is eventually cleaned up.

Typical Stripper Well Application Range

- Depth 7,500'
- GLR 3 to 5 mcf per barrel minimum, 20 or higher recommended
- Fluid 0.25 to 3 barrels per cycle

General Installation and Operational Guidelines

1. Prior to moving in service rig, obtain a 72-hour shut-in pressure.
2. Move in service unit with lubricator for well cleanout and capacity for handling a tubing string. Record all pertinent information including the date, time, tubing, casing, and sales line pressure and the production tank fluid level prior to beginning installation.
3. Blow well down and remove the tubing and wellhead.
4. Check TD of the well and compare it to the original TD. Clean out 25' rat hole below the completion interval. Determine and record the initial fluid level.
5. Install safety nipple and a full opening ball valve on the production casing.
6. Clean production casing with a casing scraper or broach to TD. The walls of the casing must be clean for successful casing plunger operation.
7. Install the bottom hole stop. A casing stand that locks in a collar above the perforations or on a tubing stand that set on the bottom of hole are available. The stand must be set above the top perforation, ideally 10' to 20'.
8. Swab well to near bottom hole stop, and then close the production casing valve.
9. Install lubricator, insert casing plunger, then connect sales line to the lubricator.
10. Test and correct surface leaks by closing the sales line valve and slowly opening the master valve.
11. Open the master valve and the gas sales line valve.
12. Release the casing plunger from the lubricator. Verify the plunger left the lubricator, and then reset the latch mechanism.
13. Confirm gas sales and continue production.
14. After plunger has surfaced, measure and record the volume of fluid produced
15. Inspect gas sales chart to determine the elapsed time of the casing plunger cycle.
16. The plunger should initially be checked after every trip for the first 5 to 10 trips, then every 30 days or 30 cycles.

Evaluation Forms Required

• Decision Tree Form	Appendix 3
• Casing Plunger Data Collection Form	Appendix 5
• Alternate Production Method Decision Form	Appendix 8
• Shut-in pressure summary form	Appendix 10
• General wellbore schematic	Appendix 11
• Vogel's Inflow Performance Relationship Curve	Appendix 12

Advantages

- Wells can be produced to depletion
- Continuous gas sales, no shut-in time
- All gas produced through sales line and well can be produced at sales line pressure
- No external energy requirements
- Casing plungers can be repaired by one person in the field using common hand tools
- Few moving parts
- Plunger operation not affected by temporary increases in sales line pressure
- No tubulars, other than production casing, are required, except for tubing stop

Disadvantages

- Casing must be free of obstruction and generally free of defects
- Limited to 4 ½" and 5 ½" diameter production casing
- Applicable to limited completion interval spacing
- Manual release method relies on well tender for determining intermittent plunger cycles
- Service rig or swabbing unit required for removing stuck plungers
- Seals subject to deformation, stretching, swelling, tearing, and sticking under extreme conditions
- Not applicable to wells with significant deviation
- Not recommended for wells with unsettled sand or solids
- High-pressure wells can create very large forces across cross sectional area of tool

Cost

- Initial installation, $6,000
- Annual maintenance, $500

Failure Paths

- Insufficient or improper preparation of the casing
- Multiple weights of production casing
- Presence of scale or paraffin in the casing
- Low reservoir pressure
- Improper placement of the bottom hole stop
- Neglecting tool maintenance or periodic seal inspection
- Improper seal replacement

Diagnostic Tools

- Production decline curve
- Well tender proprietary information
- Pressure recorder
- Monthly or weekly orifice meter gas sales chart
- Swabbing reports
- Historic Gas/Liquid Ratio
- Echometer
- Weekly well tender reports
- Shut-in pressure
- Well records

Additional General Casing Plunger Operational Guidelines – Per Jet Star

Available Lift Pressure	Barrels per Cycle-4 ½"	Barrels per Cycle-5 ½"
50	1.5	2.3
100	2.9	4.6
150	3.3	7.0
200	4.7	9.3
250	6.1	11.6
300	7.5	13.9
350	8.9	16.2
400	9.3	18.6

Tubing Plungers

"JD Hacksma indicated that the compromise that yields the greatest production is found when cycling the plunger at the maximum frequency possible without killing the well. "

Basic Operation

A tubing plunger is designed to remove accumulated liquids from the production casing by providing an interface or seal (not 100%) between the liquid and gas in the tubing and the energy in the reservoir. After sufficient pressure has built up and a pneumatic valve activated, plunger and fluid are lifted to the surface. The tubing plunger system is comprised of a tubing plunger, a lubricator or receiver, and a bottom hole stop or bumper spring for the plunger set at the bottom of the tubing string. Additional surface equipment usually includes an electronic control box or timer to determine the production cycles, a pneumatically operated motor valve to open and close the production line, a sensor on the tubing to determine the arrival of the plunger, drip pot, and a pressure regulator to control the motor valve. The plunger is typically composed of a hollow steel mandrel, designed for various tubing diameters, approximately 1 to 2 feet long and weighing 5 – 8 pounds, with various sealing element configurations.

The hollow steel plunger mandrel has a fishing neck and is designed for 1 1/4" through 3 1/2" tubing. The five main types of plungers are solid, nylon brush, metal pad, wobble washer, and flexible. A solid plunger is solid steel with either a smooth surface or with concentric grooves over the entire length of the plunger. The brush plunger, good for wells with sand or tubing imperfections, has a brush segment over the length of the body to create the sealing mechanism. Metal pad plungers with spring-activated pads are available in various designs to provide the best mechanical seal against the tubing wall. Wobble washer plungers constructed of shifting steel rings are designed to enhance the liquid seal and to keep the tubing free of paraffin, salt, and scale. Flexible tubing plungers are available as articulated, cup, pad, or brush and are designed to run in tubing with bends or other imperfections.

A complete cycle occurs in three stages, shut-in, unloading, and afterflow. Specifically, the cycle for a tubing plunger consists of a release of the tubing plunger from the surface lubricator with the motor valve on the flow line closed. The plunger travels to bottom through the fluid in the tubing until it reaches the bumper spring. During the shut-in period, gas pressure begins to build in both the tubing and the casing-tubing annulus. The differential between the tubing and casing pressure indicates the approximate hydrostatic column of fluid. Based on time, pressure, differential pressure, or previous plunger velocity the motor valve at the surface opens and the head gas or gas in the tubing feeds into the flowline releasing tubing pressure. Gas accumulated in the casing tubing annulus and in the near wellbore area expands causing the plunger and liquid to travel to the surface. A lubricator - receiver with a spring-loaded cap stops the tubing plunger at the surface. The plunger stays in the lubricator until the after flow is complete and the downstream motor valve closes causing gas flow to cease. This allows the plunger to fall to bottom until activated for another cycle. The fluid recovered during the next cycle enters the tubing during the previous flow period.

Without a tubing plunger as an interface, approximately 75% of an initial slug can be lost from 10,000’. As liquid fall back continues to increase, additional pressure and gas volumes are required to lift subsequent slugs. This incomplete fluid removal increases the bottom hole producing pressure

Effective tubing plunger operation requires training and a clear understanding of inflow performance relationships, plunger efficiency, and system and data maintenance. The key to maximizing production, i.e. inflow performance, is to lower the flowing bottom hole pressure. This somewhat contradicts tubing plunger operation requiring shut-in or off time. JD Hacksma indicated that the compromise that yields the greatest production is found when cycling the plunger at the maximum frequency possible without killing the well. To restate this important principal, the most cycles with the smallest liquid loads equals the lowest bottom hole pressure required, the best inflow performance, and the best production.

Tubing plunger terminology includes off time, on time, and afterflow. Off time is the amount of shut-in time desired or required for the well to accumulate gas pressure. On time is the amount of time desired for the plunger to arrive at the surface and for the well to produce after arrival. Afterflow is the amount of time the well is allowed to produce after the fluid and plunger have surfaced.

Successful operation of tubing plungers can be optimized with the utilization of a pressure recorder, a gas sales orifice meter chart, and regular maintenance. A two-pen pressure recorder is required to monitor the casing and tubing pressures to determine the differential pressure and to maximize the effectiveness of tubing plunger cycles. However, orifice meter charts can yield the minimum and maximum sales line pressures during the cycles and performance throughout the cycle.

Typical Stripper Well Application Range
- Depth To 10,000’
- GLR 15 mcf per barrel minimum
- Fluid ¼ to 3 barrels per cycle

General Installation and Operational Guidelines
1. Prior to moving in service rig, obtain a 72-hour shut-in pressure
2. Move in a service unit with lubricator appropriate for well depth and handling of the tubing string, if necessary. Document the date and time, the tubing, casing, and sales line pressure, and the production tank fluid level prior to beginning well work.
3. Consider removing the tubing and wellhead equipment from the well to accurately access the downhole condition of the well.
4. Determine the TD of the well and compare it to the original TD. Clean out the well to 25’ below all completion intervals. Document the initial fluid level in the well in the daily rig report.
5. Inspect, tally, and run the tubing string with a seating nipple on bottom to the top of the perforations. Install a full opening master valve with the same internal diameter as the tubing.

6. Run a two-foot long gauge ring or broach, and drift the internal diameter of the tubing to TD. Micrometer the broach to ensure proper sizing. Compare the depth of the tubing with the tubing tally to confirm setting depth. Record the fluid level in the tubing.
7. Run a bumper spring assembly per the manufacturers specifications. Tag the bumper spring with a wireline to confirm depth of installation, swab as necessary.
8. Close the master valve, remove the wireline assembly, and install a tubing plunger lubricator, manual valves, flow tees, motor valves, supply gas, controller, and two-pen recorder for initial set up.
9. Slowly open the full opening master valve on production tubing allowing the pressure into the lubricator and repair any leaks. Install the plunger in the lubricator.
10. Slowly open the master valve to allow the plunger to fall from the lubricator.
11. Consider chasing the plunger to bottom with a blind box, being careful not to push the plunger.
12. Ensure that all manual valves are in a full open position.
13. Be prepared to cycle the plunger to the production tank for the first couple of cycles if cycling the well to the gas gathering system pressure results in a stalled plunger situation. The flow rate to the production tank should be controlled with a valve or choke to avoid damage by unrestricted travel of the plunger.
14. After the casing pressure and tubing pressure have stabilized, open the well to sales line pressure. The initial off time should be long enough to ensure that the plunger can reach bottom and that sufficient pressure has built to surface plunger with accumulated fluid.
15. Catch the plunger upon its first arrival at surface, close the master valve, bleed down the pressure on the lubricator, then remove and inspect the plunger for damage, paraffin, salt, or scale.
16. Repeat plunger cycles until the well cleans up. Record tubing and casing pressures before and after plunger runs to estimate fluid loads. A two-pen recorder will also record this information as well as the bleed off and build up pressure during cycles. Check tank gages regularly to confirm plunger performance.
17. Shut well in on plunger arrival for low GLR wells (no afterflow) and allow short afterflow for high GLR wells. Based on previous cycle, adjust the cycles as necessary by increasing the afterflow, increasing the number of cycles, or increasing the shut-in time. Some adjustment is always necessary initially, however, electronic pressure switches or sophisticated controllers are available to assist in adjusting the time required for shut-in to build pressure and afterflow to build differential.
18. Confirm plunger arrival and gas sales after turning the well into line and continue production.
19. The plunger should be checked after every trip for the first 5 to 10 trips and then every 7 days or 30 cycles.
20. Inspect the lubricator spring regularly and replace the plunger if worn or damaged.

Advantages

- No external energy requirements
- Can produce well to economic depletion
- Produced gas can go to the sales line if no venting is required.
- Liquid fall back associated with flowing wells is eliminated.

- Easily automated
- Replacement and maintenance by single person using common hand tools
- Low maintenance cost
- A slick line unit is often able to recover stuck or broken plungers
- Applicable to extensive completion intervals
- Good for deviated wells up to 60˚
- Reduced paraffin and scale buildup

Disadvantages

- Well shut-in time is required and gas sales are not continuous.
- Tubing must have consistent I.D. for plunger to work.
- Plunger performance can be affected by temporary increases in sales line pressure.
- Swabbing may be required periodically to assist in some applications.
- Wells with production packers or small casing tubing annulus must have higher GLR.

Evaluation Forms Required

• Decision Tree Form	Appendix 3
• Tubing Plunger Data Collection Form	Appendix 4
• Alternate Fluid Removal Method Decision Form	Appendix 8
• Shut-in Pressure Summary Form	Appendix 10
• General wellbore schematic	Appendix 11
• Vogel's Inflow Performance Relationship Curve	Appendix 12

Cost

- Initial Installation $9,000 including tubing
- Annual Maintenance $500

General Rules of Thumb to Operate a Tubing Plunger:

- Requires minimum 400 scf per barrel of fluid per 1000 feet, or for a 5000 ft. well, 2 mcf/bbl. Experience indicates much higher GLR required for stripper gas wells.
- Low GLR – short or no afterflow
- High GLR – long afterflow – If well slugging fluid evaluate afterflow time.
- The shut-in casing pressure is 1.5 times that of the sales line pressure. (CP-LP)/(CP-LP)
- A minimum of 115% of the tubing volume required for each production cycle.
- The average plunger velocity should be greater than 400 feet per minute.
- Optimum plunger efficiency is generally achieved with small loads and frequent cycles to minimize the flowing bottom hole pressure.
- Multiple wells with the same producing cycle in the same gas gathering system must be scheduled
- Limit the distance from the well to the separator to minimize the backpressure on the well during cycles
- Only requires 1.76 psi continuous differential across to lift a 5 lb 2 3/8" plunger to surface

Failure Paths:

- Lack of well operator training, understanding, or "buy-in"
- Domestic gas usage or production from casing-tubing annulus
- Use of completion packer – limits gas volume available for fluid removal
- Debris or obstructions in the tubing string: Broken or stuck plungers
- Low GLR for low gas volume producing wells
- High fluid production
- High gas sales line pressure
- Lack of production monitoring methods
- Mixed weight tubing string
- Different sized wellhead than tubing string
- Neglecting inspection of plunger diameter periodically after installation

Diagnostic Tools

- Production decline curve
- Historic GLR
- Well tender proprietary information
- Echometer or other sonic fluid level determination
- Two-pen pressure recorder
- Monthly or weekly orifice meter gas sales chart (fast/slow clocks)
- Weekly well tender sheet
- Shut-in pressure and pressure history
- Swabbing reports
- Wellfile
- Tank gages
- Echometer free well analysis software: http://www.echometer.com/software/index.thml
  Combines fluid level, pressure build up, and inflow performance analysis

Note: Consideration should also be given to the effects of annular area available for gas storage in various the tubing-casing combinations found in Table 6.

Table 6

Annular Volume in Cubic Feet as a Function of Tubing Size
5000' Depth

Tubing Size	# per Foot	1.500	2.375	2.785
1.500"	2.75	-	-	-
2.375"	4.70	-	-	-
2.875"	6.40	64	-	-
3.500"	9.20	146	-	-
4.500"	10.50	350	294	222
5.500"	15.50	570	515	427

Pumping Units – Electric, Gas, or Gasoline

Basic Operation

Pumping units are designed to remove accumulated liquids from the production casing by utilizing a downhole pump. The pumping unit system is comprised of a pumping unit, prime mover, bridal, polish rod, sucker rods, tubing, pump, gas anchor, and stuffing box. Additional surface equipment can include an electronic control box or timer to control the production cycles, or an "Autostart" to automatically start a gas engine.

A complete cycle for a pumping unit begins by energizing the pumping unit with electric, natural gas, or gasoline. The casing pressure is typically reduced to the gas gathering system pressure and gas produced twenty-four hours per day. As the pumping unit goes through its cycle, fluid enters the bottom hole pump through the standing valve, displaced through the traveling valve, then is forced to the surface through the continued action of the sucker rods. The well tender determines the number and length of production cycles based upon experience, gas sales chart analysis, or by the well pump off time.

Effective pumping unit operation requires training and a clear understanding of inflow performance relationships, and pump efficiency. However, the key to maximizing production or inflow performance is to maintain a reduced flowing bottom hole pressure. A pumping cycle results in a temporary production increases that declines to previous production levels, requiring periodic pumping, the frequency of which is a function of the produced fluid volumes. The timing of the production cycles is best achieved when electric is available and the well can be put on a timer to optimize the number and duration of the production cycle. Units are also available to automatically start natural gas engines at preset times to achieve similar results.

Various pump and pumping unit designs are available depending on the depth of application. While a significant initial investment is typically involved, the consistent production achieved and the ultimate salvage value of the equipment results in a satisfactory economic investment. One operator was known to have said, “I’ve never lost money on a pumping unit.”

The periodic removal of only a few barrels of fluid may not be an effective indicator that the pumping cycle has been effectively determined. A small recovery during a pumping cycle may indicate a low reservoir pressure rather than a low fluid production rate. The well may make a small amount of fluid but still load up quickly. A review of the gas sales chart and decline curve may indicate that further production cycle optimization could result in sustained production increases better because of a lower flowing bottom hole pressure maintained by continuous fluid removal.

Successful operation of pumping units can be sustained with the utilization of a pressure recorder, a gas sales orifice meter chart, an Echometer, and regular maintenance. While orifice meter charts can yield the cycle time and minimum and maximum sales line pressures, a separate two-pen recorder is required to monitor the casing and tubing differential for determining the effectiveness of day-to-day pumping unit operation.

General Installation Procedure

1. Shut-in the well before installation to establish a reservoir pressure.
2. Move in an appropriate service unit with lubricator for well cleanout and running a tubing string and rods. Record tubing, casing, and sales line pressure prior to beginning any well work.
3. Consider removing the tubing and wellhead equipment from the well to accurately determine the downhole condition of the well.
4. Determine the total depth of well, compare it to the original TD, and then clean out the well as necessary to obtain maximum pocket below the completion interval. Record the fluid level found in the casing in daily report.
5. Inspect, drift, tally, and run the tubing to below the bottom of the perforations with a seating nipple on bottom of sting. Consider a mud anchor or gas anchor.
6. Run appropriate rods and tubing to the seating nipple per the manufacturers specifications or experience.
7. Pump up the well with the rig to confirm pump movement.
8. Complete remainder of wellhead with stuffing box.
9. Hang bridal on horse's head and ensure unit is level.
10. Check all belts, energize the unit, and then recheck belts and stuffing box.
11. Ensure that all manual valves are in a full open position.
12. Begin with two cycles per day based upon previous fluid production volumes.
13. Confirm pumped off condition with an Echometer. Increase number and length of cycles to optimize fluid production and enhance gas production.
14. The results of the first few days will provide information on the performance of the pumping unit application.

Evaluation Forms Required

• Decision Tree Form	Appendix 3
• Pumping Well Data Collection Form	Appendix 6
• Shut-in Pressure Summary Form	Appendix 10
• General Wellbore Schematic	Appendix 11
• Vogel's Inflow Performance Relationship Curve	Appendix 12

Advantages

- Continuous production of gas to sales line – no venting
- Can be produced to economic depletion
- Eliminates liquid fall back associated with flowing wells
- Applicable to extensive completion intervals
- Typically 70 – 80% producing efficiency
- Reduced hydrostatic pressure against formation due to pump placement
- High salvage value

Disadvantages

- Initial investment is often high
- Requires outside energy source
- Many moving parts for potential repair: tubing leaks, rod parts, pump failures.

- Rig required for most servicing.
- Paraffin may create significant production problems.

Cost
- Initial installation - $18,000 including tubing
- Annual Maintenance - $3,000

Failure Paths
- Complete entire pumping cycle time required for entire day or week in one cycle.
- Over pump the well, that is, continue pumping in a pumped off condition.
- Never monitor the pump performance.
- Poor handling and makeup technique for rods
- Never service the unit
- Lack of training or understanding

Evaluation Tools
- Production Decline Curve
- Pressure History
- Well Diagnosis Software – often freeware available from suppliers
- Two-pen recorder information
- Tank gages
- Echometer or other sonic fluid level detection device
- Polish rod load cell – see below
- Beam transducer
- Gas sales chart
- Position devices
- Inclinometer
- Power measurement equipment
- Dynamometer - see below
- API Specification 11AX for Subsurface Sucker Rod Pumps and Fittings.

Dynamometer - Polish Rod Transducer Information

Well pumped off	Pump intake pressure
Pump fillage	Current pumping speed
Leaking traveling/standing valves	Maximum/ minimum rod limits
Polish rod and pump hp	Gearbox loaded – unit balanced
Downhole gas separator	

Important Note: Operating in a pumped off condition is expensive damaging equipment, unnecessary wear and tear, and wasting energy. The use of a time clock should always be considered to optimize production. There are now automatic staring gas engines for those locations where electricity is impractical. Consistent fluid removal is essential to stripper gas well production to optimize production.

VII. Appendix

No.

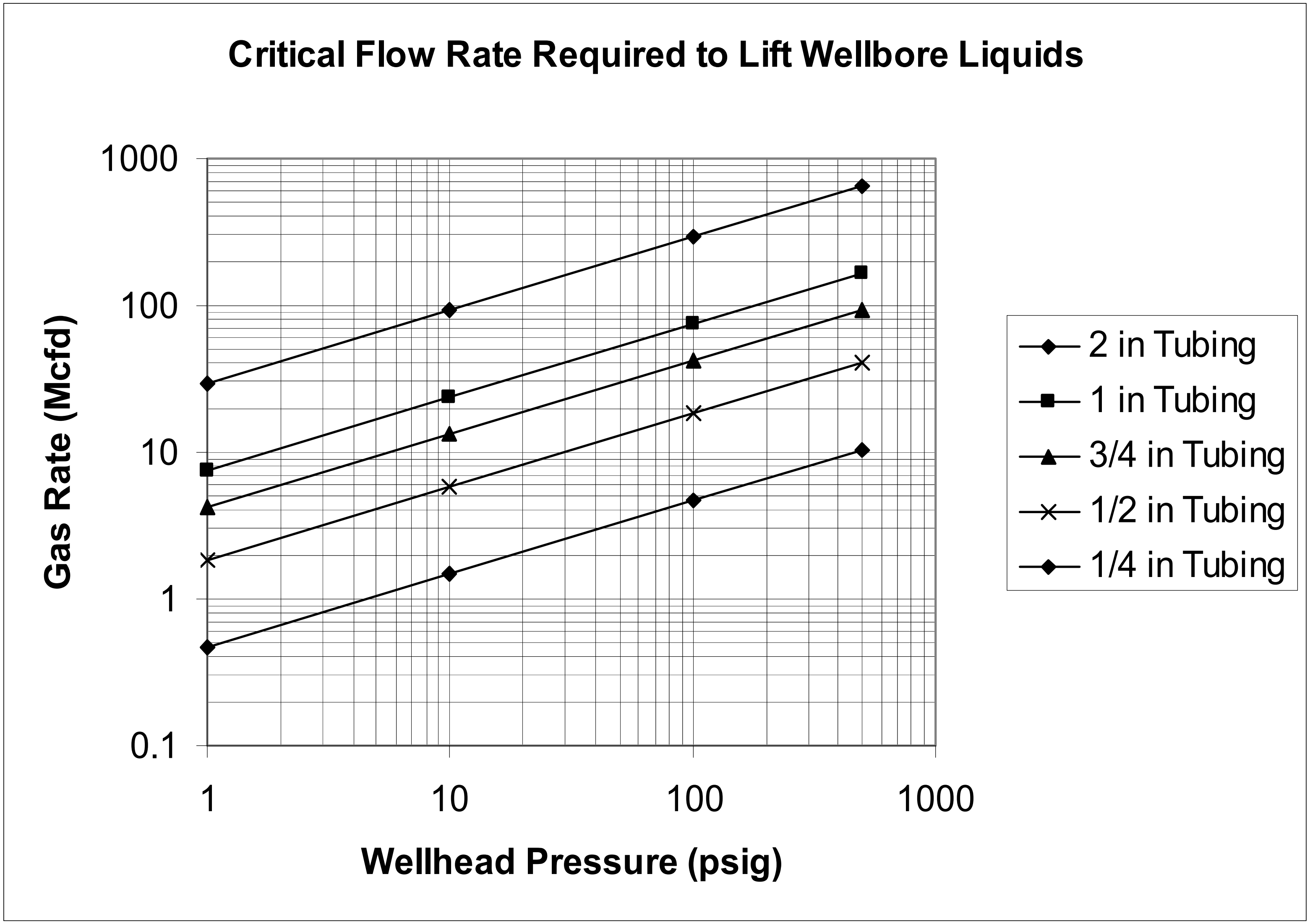
1. Stripper Well Comparison by State
2. Turner Liquid Unloading Curves: ¼" – 2" tubing
3. Decision Tree Form
4. Data Collection Form – Tubing Plunger
5. Data Collection Form – Casing Plunger
6. Data Collection Form – Pumping Well
7. Data Collection Form – Swab or Bailed Well
8. Alternative Fluid Removal Method Decision Form
9. Swabbing Record Summary Form
10. Shut-in Pressure Summary Form
11. General Wellbore Schematic
12. Vogel's Inflow Performance Relationship Curve
13. Investment Vs. Payout @ 20 MCFD Increase
14. Investment Vs. Payout @ 10 MCFD Increase
15. Investment Vs. Payout @ 5 MCFD Increase
16. Weatherford Artificial Lift Elimination Process
17. Relative advantages of artificial lift systems (from Brown, 1982)
18. Relative disadvantages of artificial lift systems (from Brown, 1982)
19. Artificial Lift Design Considerations and Overall Comparisons after Clegg, et al
20. Directory of Fluid Removal Service Companies or Equipment Mfg.
21. Directory of Stripper Well Associations

Appendix 1
National Stripper Well Comparison

State	Wells			Production per day per well		
	Gas	Oil	Total	Gas	Oil	Mcfeq
AL	1,416	627	2,043	27.8	4.99	62.73
AZ	5	20	25	21.8	2.88	41.96
AR	1,609	3,286	4,895	25.3	2.67	43.99
CA	369	22,244	22,613	21.0	3.87	48.09
CO	10,196	7,618	17,814	15.5	1.40	25.30
ILL	101	18,491	18,592	2.40	1.54	13.18
IN	1,502	5,049	6,551	1.50	1.11	9.27
KS	8,701	35,349	44,050	29.6	1.94	43.18
KY*	13,855	24,585	38,440	14.3	0.26	16.12
LA	9,645	21,091	30,736	7.60	1.98	21.46
MD*	7	0	7	13.2	0.00	13.12
MI	3,165	2,550	5,715	36.0	3.44	60.08
MS	449	376	825	10.1	4.19	39.43
MO	0	327	327	0.00	0.89	6.23
MT	3,752	2,476	6,228	28.1	2.25	43.85
NE	94	1,483	1,577	21.7	3.37	45.29
NM	8,534	12,642	21,186	24.9	2.77	44.29
NY*	5,446	2,638	8,084	5.60	0.19	6.93
ND	63	1,357	1,420	15.1	4.25	44.85
OH*	33,352	28,918	62,270	6.10	0.51	9.67
OK	11,554	60,120	71,674	28.4	2.28	44.36
PA*	35,337	15,170	50,507	9.70	0.40	12.50
SD	54	17	71	23.3	2.55	41.15
TN	191	301	492	15.3	1.72	27.34
TX	29,302	126,028	155,330	22.2	2.93	42.71
UT	626	943	1,569	26.2	4.11	54.97
VA*	133	15	148	42.2	0.84	48.28
WV*	36,816	8,450	45,266	16.3	0.42	19.24
WY	7,433	9,612	17,045	11.1	3.57	36.09
Total	**223,707**	**411,793**	**645,500**	**15.4**	**2.16**	**30.52**
App Basin*	**124,946**	**79,776**	**204,722**	**11.0**	**0.40**	**13.80**

506,397,202 mcf per year
11,458,862 bbl of oil per year

Appendix 2
Turner Critical Flowrate for Various Tubing Sizes



Appendix 3

Decision Tree Form
For
Fluid Removal Method Analysis

Lease Name and Well No. _________________________
Current Fluid Removal Method________
Date of Analysis________

Step **Phase I: Identify the Problem**

1. Review complete historic monthly production decline curve, and forecast _____________
2. Calculate and compare the historic and current gas liquid ratios, Mcf/bbl _____________
3. Compare monthly production history to reservoir type decline curve _____________
4. Check for gas and total fluid (oil and water) production changes _____________
5. Prepare and review map of gas gathering system and offset well location _____________
6. Check with well tender to verify problem still exists _____________
7. Check for gas metering or integration inaccuracy _____________
8. Check for integrity of gas gathering system _____________

Phase II: Measure the Problem

1. Complete the data **c**ollection form to evaluate current fluid removal method ________
2. Construct and review the wellbore schematic ________
3. Is problem due to fluid removal method, reservoir, or mechanical integrity? ________
4. Is current fluid removal method appropriate for well? Yes / No
5. Have offset wells experienced similar problems? Yes / No / Unknown
6. Can current fluid removal method be modified to produce well to economic limit? Yes / No
7. Check for reservoir depletion and shut-in pressure history _____________
8. What final bottom hole pressure is economically justified? __________Psi
9. Estimate remaining reserves to justify additional investment? _____________
   Utilize Vogel IPR__, P/Z__ , or production decline curve analysis___

Phase III: Solve the Problem

1. Can production cycles be modified to lower the flowing BHP Yes / No
2. Can the sales line pressure be reduced? (Current______,psi) Yes / No
3. Complete the alternative fluid removal method decision form _____________
4. Review the investment vs. payout nomagraphs _____________
5. Complete the proposed well work? (___________________________) Yes / No
6. Review to Shut-In, Sell, or Plug and Abandon _____________
7. No Further Analysis Required, Continue to Produce, _____________
   Well Cannot be Economically Remediated

Phase IV: Monitor the Changes and Production

1. Measure post change production rates and GLR _____________
2. Does the production meet forecasted rates? _____________
3. If production does not meet forecasted rates, re-evaluate _____________

Appendix 4

Stripper Gas Well
Data Collection Form for Fluid Removal Method Analysis
Production Method - Tubing Plunger

Lease Name and Well No: ______________________________
Date: __________________
Well Tender:___________________

Sections I-III for Field Completion

I. Well Information

Producing Formation(s) ______________
Tubing Pressure: Begin/End ______/_______Psi
Casing Pressure: Begin/End ______/_______Psi
Tubing Plunger System style ______________
Cycles per Day/Min On _______/______Min
Date Cycles Last Adjusted ______________
Previous Cycles per Day/ Min On _____/______Min
Domestic Gas Usage on Casing? Yes / No Move?
Gas Gathering System Operating Psi ______________ Psi
Additional Cycling in Gathering System Yes / No
Would cycle adjustment decrease the fbhp? Yes / No
Would compression assist production? Yes / No

II. Current Daily Production Rate

Oil, Bbl Oil per Day _____BOPD
Gas, Mcf per Day _____MCFD
Water, Bbl Water per Day _____BWPD
Total Fluid per day _____BFPD
Historic GLR_____ Current GLR_______ MCF/BBL
Has production or GLR changed?
MCF/Cycle_____ Bbl/Cycle__________

III. Comments and Recommendations

____
____

Sections IV-VIII for Office Completion

IV. Analytical Data

Perforated Interval(s) ________ - ________
Casing Size and Depth ______ In ________Ft
Tubing Size ________________ In
Tubing Depth ________________ Ft
Sales Line Size ________________ In
Sales Line Length ________________ Ft
Flowing Bottom Hole Pressure (FBHP)________________ Psi
Last Shut-in date and Pressure (SIBHP)________________ Psi

V. Vogel Inflow Performance Relationship Analysis*

Ratio of FBHP/SIBHP __________________
Estimated Maximum Production Rate ______BOPD_____MCFD
*(Or estimated by production decline curve analysis)

VI. Forecasted Rates of Production by Current Production Method

Oil, Bbl Oil per Day _____BOPD _____BFPD
Gas, Mcf per Day _____MCFD
Water, Bbl Water per Day _____BWPD
GLR _____ MCF/BBL

VII. Date and Description of Last Well Work

____
____

VIII. Comments and Recommendations

____
____

Appendix 5

Stripper Gas Well
Data Collection Form for Fluid Removal Method Analysis
Production Method - Casing Plunger

Lease Name and Well No: ______________________________
Date: _________________
Well Tender:__________________

Sections I-III for Field Completion

I. Well Information

Producing Formation(s)	______________	
Flowing Casing Pressure	______________	Psi
Casing Plunger Style	______________	
Trips per Week	______________	
Cycles per Day / Min On	______/_______	Min
Domestic Gas Usage	Yes / No	
Gas Gathering System Operating Psi	______________	Psi
Additional Cycling in Gathering System	Yes / No	
Last Fluid Level Shot: Date/Depth	________/______	Ft

II. Current Daily Production Rate

Oil, Bbl Oil per Day ______ BOPD
Gas, Mcf per Day ______MCFD
Water, Bbl Water per Day ______BWPD
Historic GLR________ Current GLR_______
Typical Bbl/Cycle__________

III. Comments and Recommendations

____
____
____
____

Sections IV-VIII for Office Completion

IV. Analytical Data

Perforated Interval(s)	_______ -________	
Casing Size and Depth	_____ In _______Ft	
Flow	Intermittent / Continuous	
Stand Depth	_______________	Ft
Sales Line Size	_______________	In
Sales Line Length	_______________	Ft
Flowing Bottom Hole Pressure (FBHP)	_______________	Psi
Last Shut-in Date and Pressure (SIBHP)	_______________	Psi

V. Vogel Inflow Performance Relationship Analysis*

Ratio of FBHP/SIBHP ________________
Estimated Maximum Production Rate _____ BOPD_____MCFD
*(Or estimated by production decline curve analysis

VI. Forecasted Rates of Production by Current Production Method

Oil, Bbl Oil per Day ______BOPD
Gas, Mcf per Day ______MCFD
Water, Bbl Water per Day ______BWPD
GLR _____ MCF/BBL

VII. Date and Description of Last Well Work

____
____

VIII. Comments and Recommendations

____
____
____
____

Appendix 6

Stripper Gas Well
Data Collection Form for Fluid Removal Method Analysis
Production Method - Pumping Unit Well

Lease Name and Well No: ______________________________
Date: _________________
Well Tender:__________________

Sections I-III for Field Completion

I. Well Information

Prime Mover * __________________
Producing Formation(s) __________________
Flowing Tubing Pressure __________________ Psi
Flowing Casing Pressure __________________ Psi
Pump Schedule __________________
Stroke Length __________________ In
Unit Speed __________________ SPM
Date Cycles Last Adjusted __________________
Previous Cycles __________________
Domestic Gas Usage Yes / No
Gas Gathering System Operating Psi _________________ Psi
Last Fluid Level Shot Date / Depth _________/_________Ft
*Electric-PJEM, Gas, Gasoline, or Propane-PJGE

II. Current Daily Production Rate

Oil, Bbl Oil per Day ______BOPD
Gas, Mcf per Day ______MCFD
Water, Bbl Water Day ______BWPD
Historic GLR_______ Current GLR_______

III. Comments and Recommendations

____
____
____

Sections IV-VIII for Office Completion

IV. Analytical Data

Perforated Interval(s) _______ - ________
Casing Size and Depth _____ In ________Ft
Tubing Size _______________ In
Depth of Tubing _______________ Ft
Rod Size _______________ In
Pump Description _______________
Sales Line Size _______________ Ft
Sales Line Length _______________ Ft
Flowing Bottom Hole Pressure (FBHP) _______________ Psi
Last Shut-in Pressure and Date (SIBHP) _______/________Psi

V. Vogel Inflow Performance Relationship Analysis*

Ratio of FBHP/SIBHP ________________
Estimated Maximum Production Rate _____ BOPD_____MCFD
*(Or estimated by production decline curve analysis

VI. Forecasted Rates of Production by Current Production Method

Oil, Bbl Oil per Day _____BOPD
Gas, Mcf per Day _____MCFD
Water, Bbl Water Day ______BWPD
GLR _____ MCF/BBL

VII. Date and Description of Last Well Work

____

VIII. Comments and Recommendations

____
____
____

Appendix 7

Stripper Gas Well
Data Collection Form for Fluid Removal Method Analysis
Production Method - Swab Well or Bailed Well

Lease Name and Well No: ______________________________
Date: _________________
Well Tender:__________________

Sections I-III for Field Completion

I. Well Information

Producing Formation(s) ______________
Flowing Tubing Pressure – Swab N/A ______________ Psi
Flowing Casing Pressure ______________ Psi
Date Last Swabbed ______________
Fluid Recovered ______________ Bbls
Domestic Gas Usage Yes / No
Gas Gathering System Operating Psi ______________ Psi
Last Fluid Level Shot Date / Depth _______/_______ Ft
Can gas gathering system pressure be reduced? Yes / No
Are there restrictions in the gas sales line? Yes / No
Review previous swabbing reports.

II. Current Daily Production Rate

Oil, Bbl Oil per Day _____ BOPD
Gas, Mcf per Day _____ MCFD
Water, Bbl Water Day _____ BWPD
Historic GLR ______ MCF/BBL
Current GLR _______MCF/BBL

III. Comments and Recommendations

____
____
____

Sections IV-VIII for Office Completion

IV. Analytical Data

Perforated Interval(s) ________ - _______
Casing Size and Depth _____ In ________Ft
Tubing Size – Swab N/A _______________ In
Depth of Tubing – Swab N/A _______________ Ft
Sales Line Size _______________ In
Sales Line Length _______________ Ft
Flowing Bottom Hole Pressure (FBHP) _______________ Psi
Last Shut-in Date and Pressure (SIBHP) _______________ Psi

V. Vogel Inflow Performance Relationship Analysis*

Ratio of FBHP/SIBHP ________________
Estimated Maximum Production Rate_____ BOPD_____ MCFD
*(Or estimated by production decline curve analysis)

VI. Forecasted Rates of Production by Current Production Method

Oil, Bbl Oil per Week / Day _____ BOPD
Gas, Mcf per Week / Day _____ MCFD
Water, Bbl Water Day _____ BWPD
GLR _____ MCF/BBL

VII. Date and Description of Last Well Work

Review swabbing history, sustained production, and associated costs.
Production immediately after last swab?_____MCFD
How long did production increase last?______Months/Weeks/Days

VIII. Comments and Recommendations

____
____
____

Appendix 8

Stripper Well
Alternative Fluid Removal Method Decision Form

Lease Name and Well Number ____________________________

I. Current Production Method ____________________________ **Current BOPD ____MCFD ____MCFEQ ____GLR_____**
Historic GLR______

II. Maximum Flow Rate Predicted by Vogel Inflow Performance Relationship Analysis and/or Production Decline Curve Analysis

Ratio of FBHP/SIBHP ____________________________

Estimated Maximum Production Rate ___ Bopd ___ Mcfd ___Mcfeq ____GLR Estimated Remaining Reserves________Mcf_______BO

Estimated Final BHP _____ Psi

III. Alternative Production Method**	**Forecasted Rates of Production by Production Method**	**Cost of Alternative Production Method**	**Economic Analysis M$/Mcfeqd**	**Payout, Months**	**NPV**
Swab or Flow Well	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______
Tubing Plunger	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______
Casing Plunger	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______
Pumping Unit	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______
Compression Installation	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______
Pipeline/Meter Installation	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______
Other _________________	____ Bopd ____ Mcfd ____Mcfeq	$_______________	______	______	______

****This comparison should determine which fluid removal method is the most economical to produce the well to depletion.**

IV. Comments and Recommendation

____

____

____

____

While M$ per mcfeqd and payout measured in months are good economic indicators to compare production method alternatives, the calculation of a Net Present Value (NPV) based upon future reserves and cash flow should be considered as the superior method for determining economic benefit.

Appendix 9

Lease Name and Well No: ______________________________
Date: _________________
Production Method – Swabbing Record Summary Form

Date / Cost	Last Shut-In Pressure, Psi	Initial Wellhead Pressure, Psi	Initial Swab Fluid Level, Feet	Final Swab Fluid Level, Feet	Total Depth, Feet	Volume, Barrels	Initial or Overnight Sales, mcf
_____/_____	________	________	__________	________	________	________	_________________
_____/_____	________	________	__________	________	________	________	_________________
_____/_____	________	________	__________	________	________	________	_________________
_____/_____	________	________	__________	________	________	________	_________________
_____/_____	________	________	__________	________	________	________	_________________
_____/_____	________	________	__________	________	________	________	_________________
_____/_____	________	________	__________	________	________	________	_________________
_____/_____	________	________	__________	________	________	________	_________________
_____/_____	________	________	__________	________	________	________	_________________

III. Comments and Recommendations____

____

Appendix 10

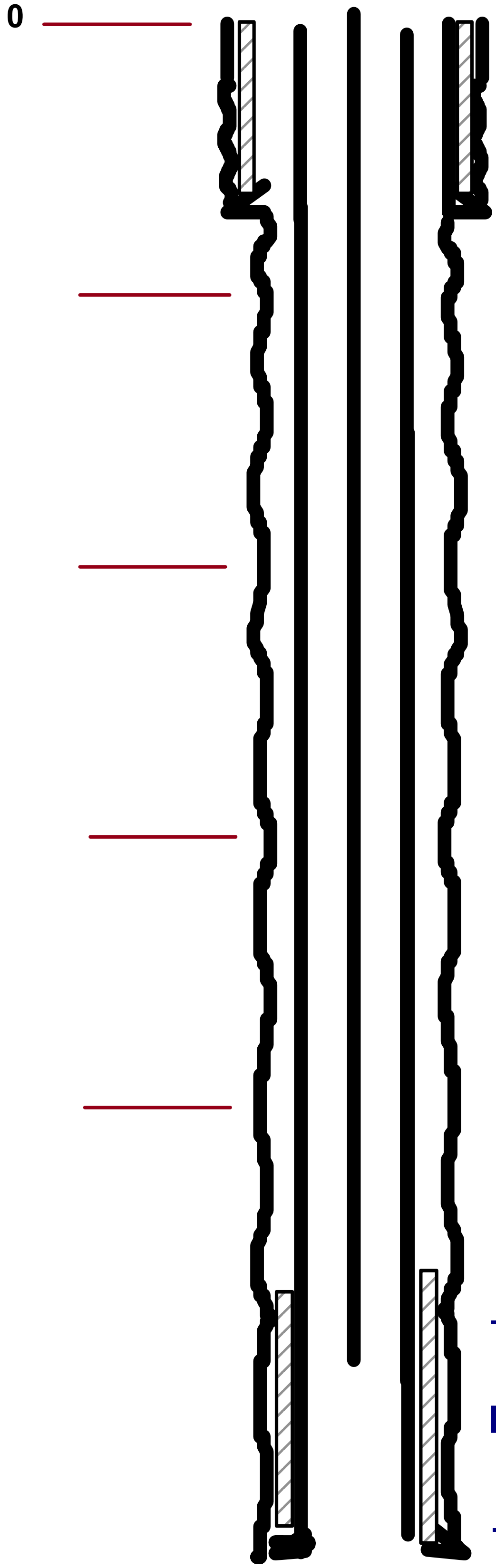
Lease Name and Well No: ______________________________

Shut-in Pressure Summary Form

Date	Starting Shut-In Pressure, Psi	Final Shut-In Pressure, Psi	Days, Hrs	Mcf, Gas To Date	Bbl, Water To Date	Bbl, Oil To Date	Total Fluid Barrels	GLR
______	________	__________	________	__________	___________	__________	__________	_____
______	________	__________	________	__________	___________	__________	__________	_____
______	________	__________	________	__________	___________	__________	__________	_____
______	________	__________	________	__________	___________	__________	__________	_____
______	________	__________	________	__________	___________	__________	__________	_____
______	________	__________	________	__________	___________	__________	__________	_____
______	________	__________	________	__________	___________	__________	__________	_____
______	________	__________	________	__________	___________	__________	__________	_____
______	________	__________	________	__________	___________	__________	__________	_____
______	________	__________	________	__________	___________	__________	__________	_____
______	________	__________	________	__________	___________	__________	__________	_____

This form provides an excellent summary for P/Z analysis.

General Wellbore Schematic



8-5/8" Surface Casing Set at ________'

____" Tubing Set at: _________SN ___________MA

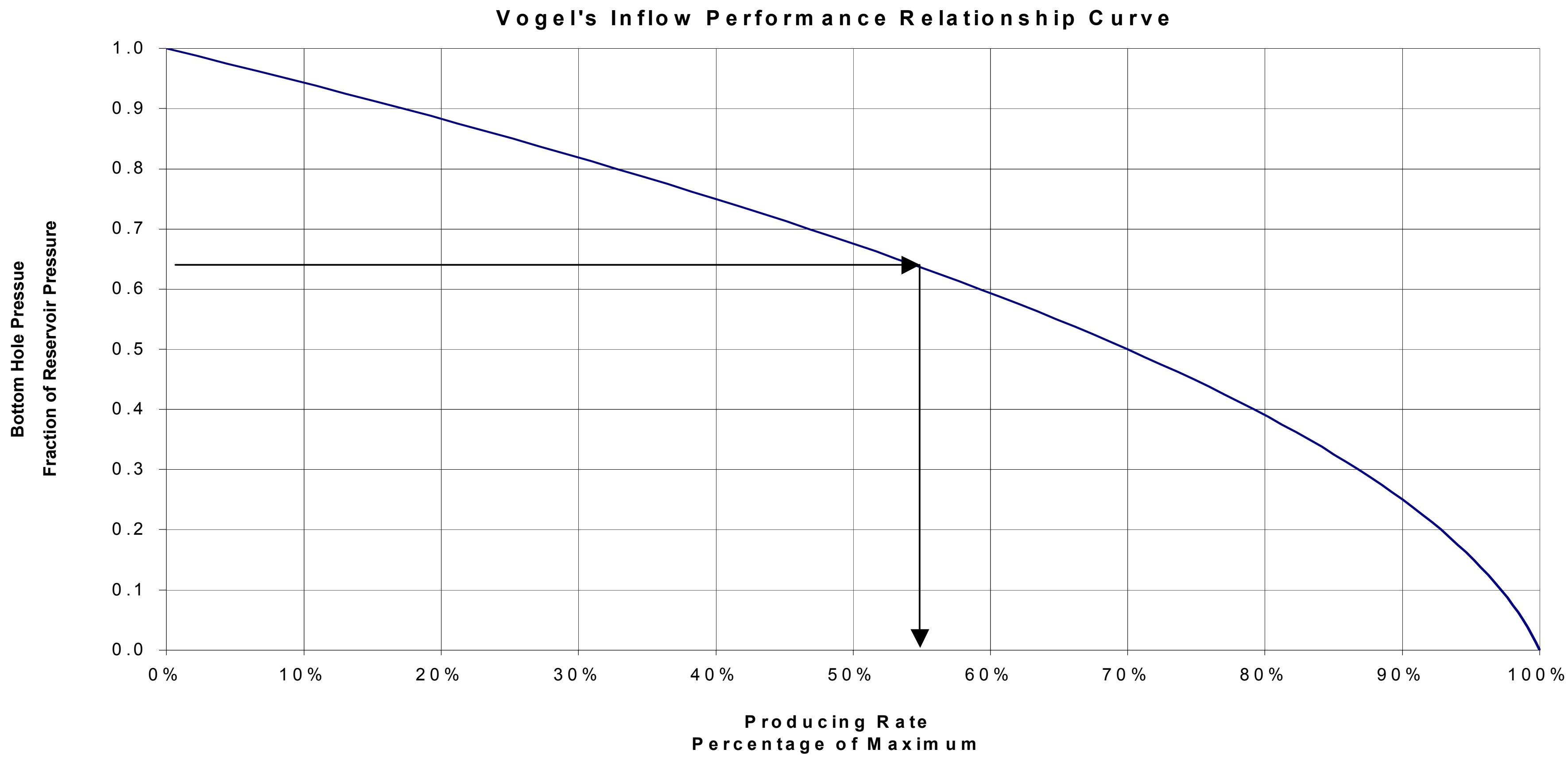
Perforations: _________ - ____________

____" Casing Set at: _________

Total Depth of Well:_________

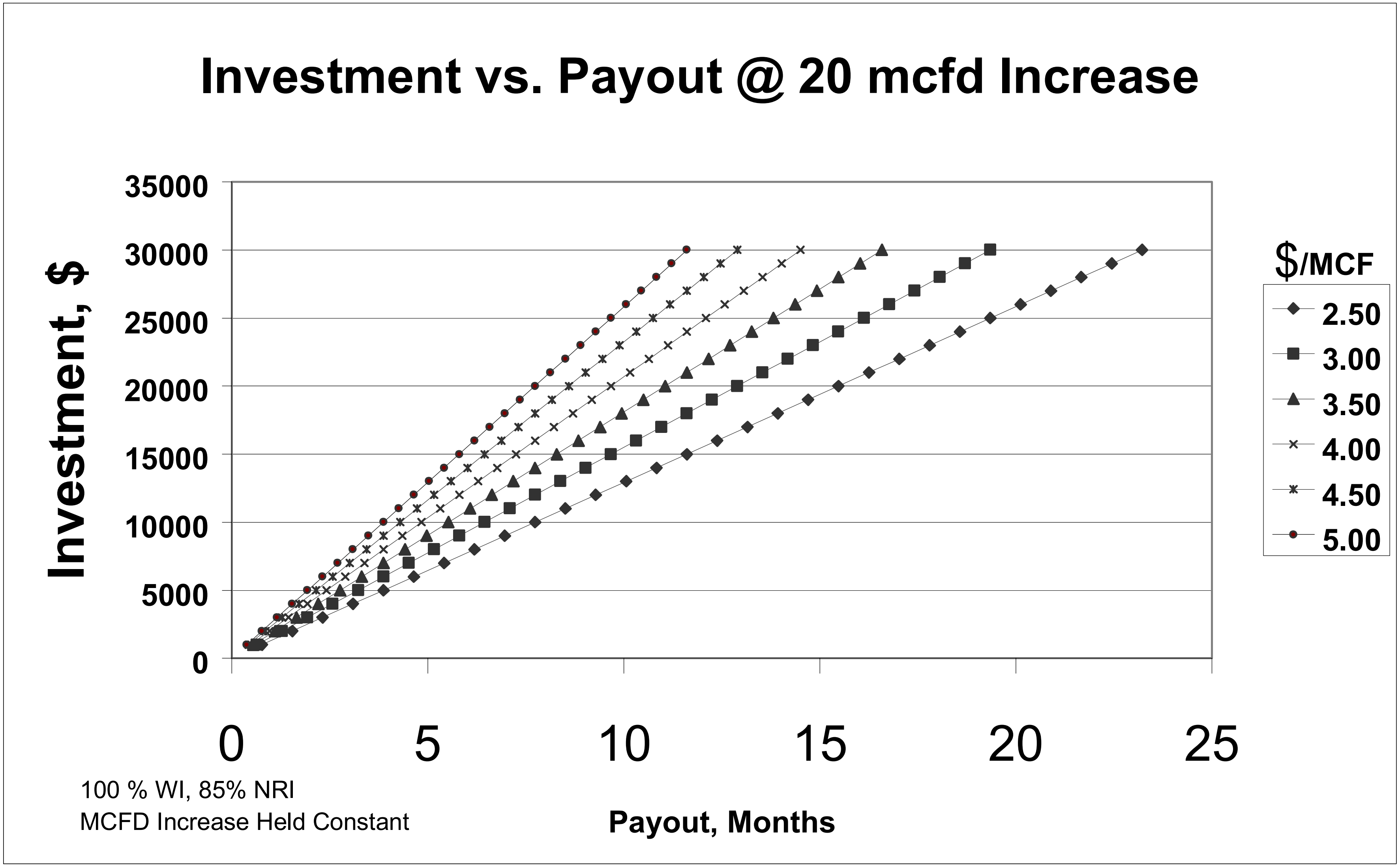
Lease Name and Well No. _____________________

Appendix 12

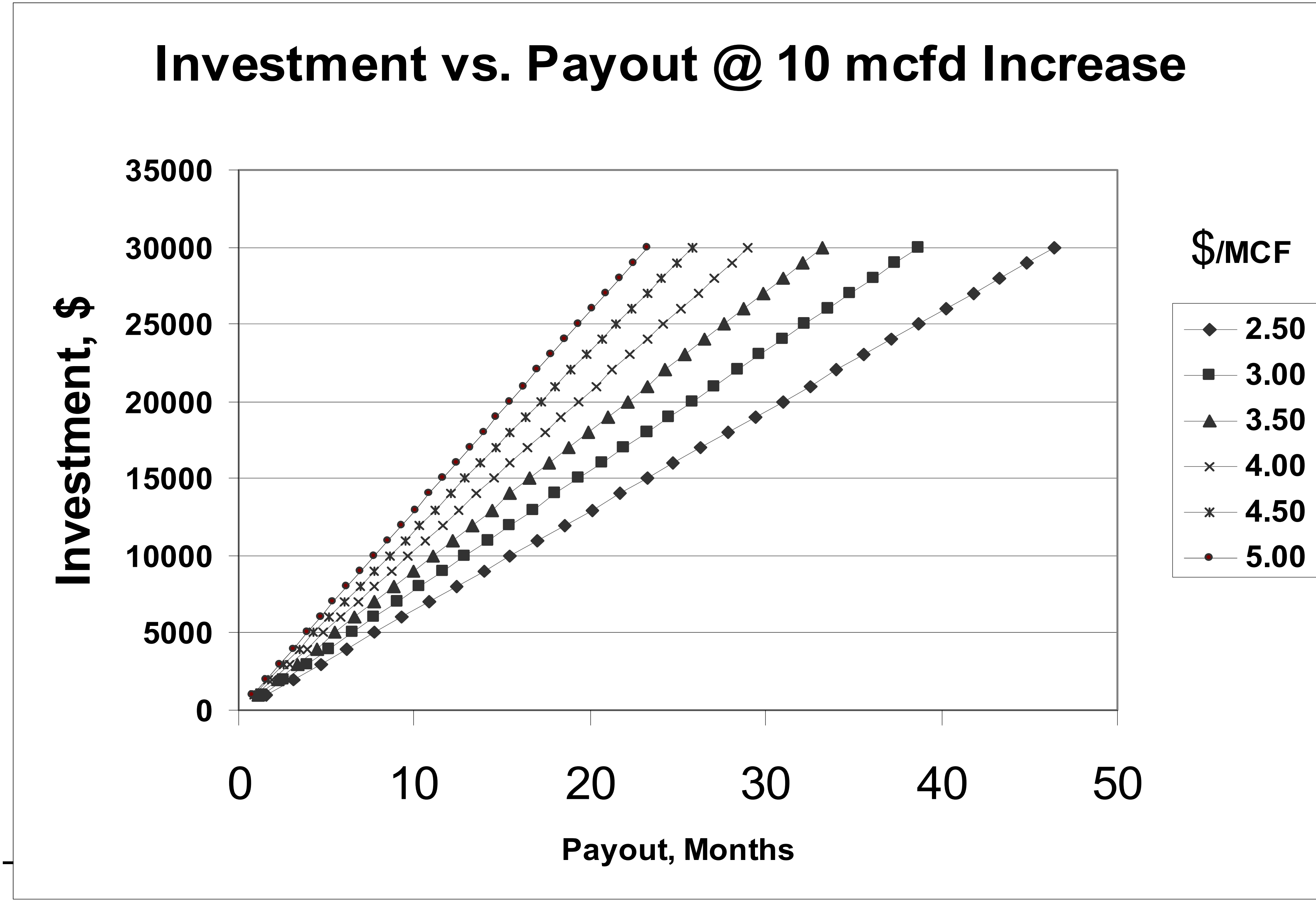


1. Divide the flowing bottom hole pressure by the shut-in bottom hole pressure, fbhp/sibhp.
2. Enter chart from left. Draw line to curve then drop down to determine percentage of maximum possible production being achieved.
3. Divide current production rate by percentage to determine maximum production rate possible.
4. For example: 195 psi / 300 psi = 0.65 ; 0.65 = 0.55% of Maximum Producing Rate ; 10 mcfd / 0.55 = 18 mcfd maximum production

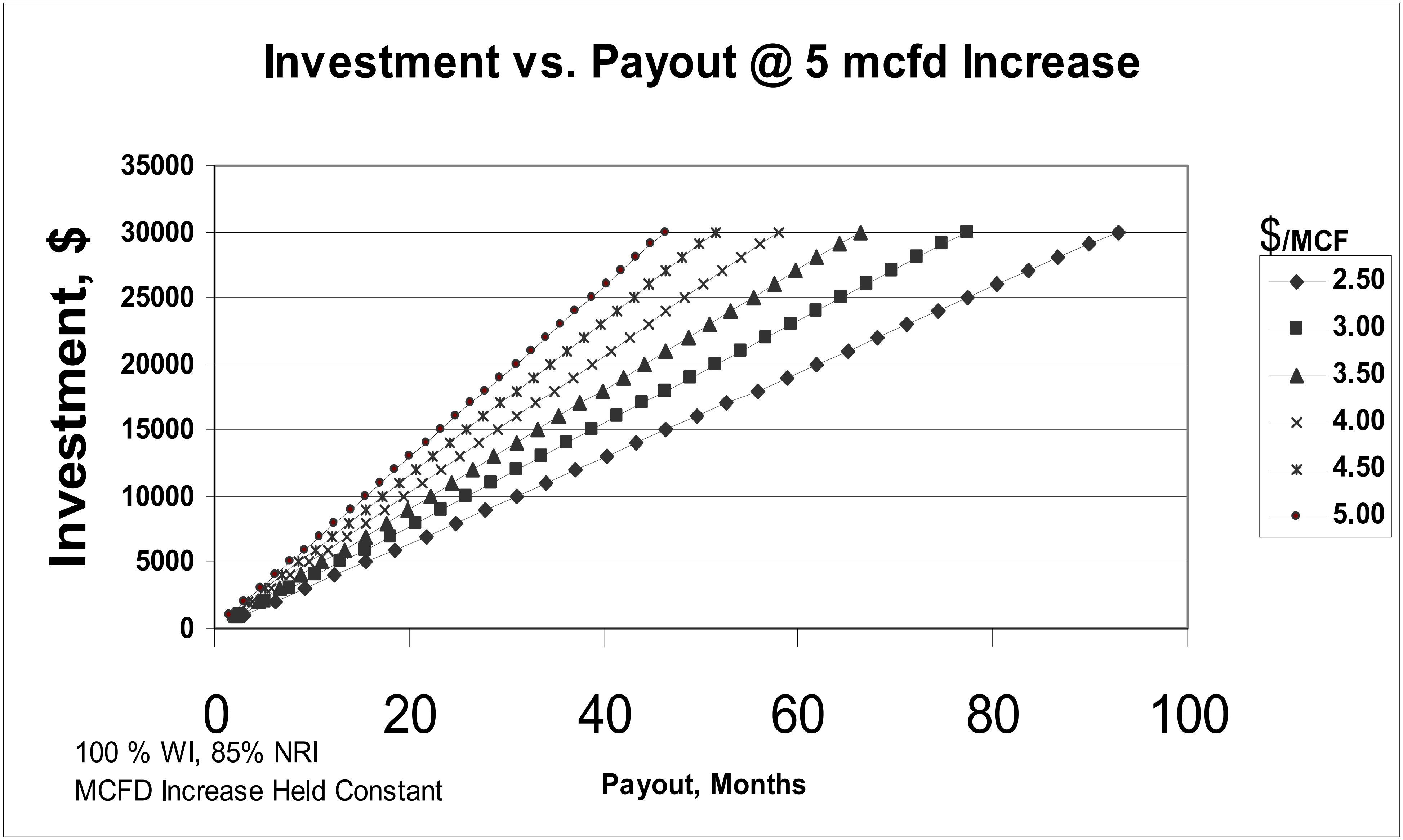
Appendix 13
Investment vs. Payout @ 20 MCFD Increase



Appendix 14
Investment vs. Payout @ 10 MCFD Increase



Appendix 15
Investment vs. Payout @ 5 MCFD Increase



Appendix 16
Weatherford Artificial Lift Elimination Process

Appendix 16 - Weatherford Artificial Lift Elimination Process

Criteria/Lift	Rod Lift	Progressive Cavity	Gas Lift	Plunger Lift	Hydraulic Piston Pump	Hydraulic Jet Lift	Electric Submersible
Operating Depth, Ft	100 –16,000	2,000 - 6,000	5,000 - 15,000	8,000 – 19,000	7,000 - 17,000	5,000 - 15,000	1,000 - 16,000
Operating Volume, Bbl per Day	5 – 6,000	5 – 4,500	100 – 30,000	1 – 200	50 – 8,000	300 – 15,000	200 to 40,000
Operating Temp, F	100 - 550	75 – 325	100 – 400	120 – 500	100 - 500	100 – 500	100 – 400
Corrosion Handling	Good to Excellent	Fair	Good to Excellent	Excellent	Good	Excellent	Good
Gas Handling	Fair to Good	Good	Excellent	Excellent	Fair	Good	Poor to Fair
Solids Handling	Fair to Good	Excellent	Good	Fair	Poor	Good	Poor to Fair
Fluid Gravity, API	>8	<35	>15	> 15	> 8	> 8	>10
Servicing	Workover or Pulling Rig	Workover or Pulling Rig	Wireline or Workover Rig	Wireline or Wellhead Catcher	Wireline or Hydraulic	Wireline or Hydraulic	Workover or Pulling Rig
Prime Mover	Gas or Electric	Gas or Electric	Compressor	Well’s Natural Energy	Multi-cylinder or Electric	Multi-cylinder or Electric	Electric
Overall System Efficiency	45 - 60	40 – 70	10 - 30	N/A	45 - 55	10 - 30	35 – 60

Appendix 17
Brown’s Relative Advantages of Artificial Lift Systems

Appendix 17 - Relative advantages of artificial lift systems (from Brown, 1982)

Rod Pumping	Hydraulic Piston Pumping	Electric Submersible Pump	Gas Lift	Hydraulic Jet Pump	Plunger Lift	Progressive Cavity Pump
Relatively simple system design	500 bpd from 15,000’ installed to 18,000’		Can handle large volume of solids	Has no moving parts	Very inexpensive installation	Moderate Cost
Units easily changed to other wells with minimum cost	Not so depth limited-can lift large volumes from great depths	Can handle volumes to 20,000 bpd	Can handle volumes to 50,000 bpd	Can handle volumes to 30,000 bpd		High electrical efficiency
Efficient, simple, and easy for field people to operate	Power source can be remotely located	Simple to operate	Power source can be remotely located	Power source can be remotely located		
Applicable to slim holes and multiple completions	Applicable to multiple completions	Lifting cost for high volumes generally very low	Lifting gassy wells is no problem		Applicable to high gas oil ratio wells	
Can pump down to very low pressure	Can pump down to fairly low pressure				Can be used to unload liquid from gas wells	
System usually vented for gas separation and fluid level soundings	Downhole pumps can be circulated out in free system		Sometimes serviceable with a wireline unit	Retrievable without pulling tubing	Retrievable without pulling tubing	Some types retrievable with rods
Flexible-can match displacement rate to well capability as well declines	Flexible-can match displacement rate to well capability as well declines		Fairly flexible-convertible from continuous to intermittent as well declines	Power fluid does not have to so clean as for hydraulic piston pumping	Automatically keeps tubing clean of paraffin and scale	
Analyzable	Analyzable	Easy to install downhole pressure sensor via cable	Easy to obtain downhole pressures and gradients			
Can lift high temperature and viscous oils	Crooked holes present minimal problems	Crooked holes present no problems	Crooked holes present no problems	Crooked holes present no problems	Can be used in conjunction with intermittent gas lift	
Can use gas or electricity as power source	Can use gas or electricity as power source			Can use water as a power source		Can use downhole motors that handle sand and viscous fluid

Appendix 17 - continued
Brown's Relative Advantages of Artificial Lift Systems

Rod Pumping	**Hydraulic Piston Pumping**	**Electric Submersible Pump**	**Gas Lift**	**Hydraulic Jet Pump**	**Plunger Lift**	**Progressive Cavity Pump**
Applicable to pump off control if electrified	Easy to pump in cycles by time clock					
Availability in different sizes	Adjustable gear box for triplex offers flexibility	Availability in different sizes				
Hollow sucker rods are available for slim hole completions and ease of inhibitor treatment	Unobtrusive in urban locations	Unobtrusive in urban locations	Unobtrusive in urban locations	Unobtrusive in urban locations		Low profile
Have pumps with double valving that pump on both upstroke and downstroke	Applicable offshore	Applicable offshore	Applicable offshore	Applicable offshore		

Appendix 18
Brown's Relative Disadvantages of Artificial Lift Systems

Rod Pumping	**Hydraulic Piston Pumping**	**Electric Submersible Pump**	**Gas Lift**	**Hydraulic Jet Pump**	**Plunger Lift**	**Progressive Cavity Pump**
Crooked holes present a friction problem	Power oil systems are a fire hazard	Not applicable to multiple completions	Lift gas is not always available	Relatively inefficient lift mechanism	May not take well to depletion, hence eventually requiring another lift mechanism	Elastomers in stator swell in some fluids
High solids production is troublesome	Large oil inventory required in power oil system which detracts from profitability	Only applicable with electric power	Not efficient in lifting small fields or one well leases	Requires at least 20% submergence to approach best lift efficiency	Good for low rate wells only normally less than 200 bpd	POC is difficult
Gassy wells usually lower volumetric efficiency	High solids production is troublesome	High voltage (1,000 V) are necessary	Difficult to lift emulsions and viscous crudes	Design of system is more complex	Requires more engineering supervision to adjust properly	Lose efficiency with depth
Is depth limited, primarily due to rod capability	Operating costs are sometimes higher	Impractical in shallow low volume wells	Not efficient for one well leases if compression equipment is required	Pump may cavitate under certain conditions	Danger exists in plunger reaching to high a velocity and causing surface damage	Rotating rods wear tubing: windup and afterspin of rods increase with depth
Obtrusive in urban locations	Usually susceptible to gas interference- usually not vented	Expensive to change equipment to match declining well capability	Gas freezing and hydrate problems	Very sensitive to any changes in back pressure	Communication between tubing and casing required for good operation unless used in conjunction with gas lift	
Tubing cannot be internally coated for corrosion	Vented installations are more expensive because of extra tubing required	Cable causes problems in handling tubulars	Problems with dirty surface lines	The producing of free gas through the pump causes reduction in ability		
H2S limits depth at which a large volume pump can be set	Treating for scale below packer is difficult	Cables deteriorate in high temperatures	Some difficulty in analyzing properly without engineering supervision	Power oil systems are fire hazard		
Limitations of downhole pump design in small diameter casing	Not easy for field personnel to troubleshoot	System is depth limited, 10,000, due to cable cost and inability to install enough power downhole	Cannot effectively produce deep wells to abandonment	High surface power fluid pressures are required.		
	Difficult to obtain valid well tests in low volume wells	Gas and solids production are troublesome	Requires makeup gas in rotative systems			
	Requires two strings of tubing for some installations	Not easily analyzable unless good engineering know how	Casing must withstand lift pressures			

Appendix 18 - continued
Brown's Relative Disadvantages of Artificial Lift Systems

Rod Pumping	Hydraulic Piston Pumping	Electric Submersible Pump	Gas Lift	Hydraulic Jet Pump	Plunger Lift	Progressive Cavity Pump
	Safety problem for high surface pressure power oil	Casing size limitation				
	Lost of power oil in surface equipment failure	Cannot be set below fluid entry without a shroud to route fluid by the motor				
		Shroud allows corrosion inhibitor to protect outside of motor				
		More downtime when problems are encountered due to entire unit being downhole				

Appendix 19
Clegg's Artificial Lift Design Consideration Comparison

(after Clegg, et al., 12/1993)

	Rod Pump	Progressive Cavity Pump	Electric Submersible Pump	Hydraulic Reciprocating	Hydraulic Jet	Gas Lift	Intermittent Gas Lift	Plunger Lift
Capital Cost Table 4A	Low to moderate	Low	Low with electric	Competitive to rod pump	Competitive to rod pump	Equipment low, compression high	Same as gas lift	Very low without compression
Downhole Equipment Table 4B	Reasonably good rod design and operating practices needed	Good design and operating practices needed	Requires proper cable installation, in addition to motor, pumps, seals, etc.	Proper pump sizing and operating practices essential.	Requires computer design programs for sizing.	Good valve design and spacing essential.	Unload to bottom with gas lift valves, cons. chamber for high PI low bhp wells	Operating practices have to be tailored to each well for optimization.
Efficiency(HHP/HP) Table 4C	Excellent	Excellent	Good	Fair to Good	Fair to poor	Fair	Poor	Excellent
Flexibility Table 4D	Excellent	Fair	Poor	Good to excellent	Good to excellent	Excellent	Good	Good
Miscellaneous Problems Table 4E	Stuffing box leakage	Limited service	Requires reliable electric	Power fluids solids control essential	More tolerant of power fluid solids	Highly reliable. Dehydrated gas required	Labor intensive	Sticking is major problem
Operating Costs Table 4F	Low	Potentially Low	Varies	Often higher than rod pump	Higher power costs	Well cost low	Well costs low	Very low
System reliability Table 4G	Excellent	Good	Varies	Good	Good	Excellent	Excellent	Good
Salvage Value Table 4H	Excellent	Fair to poor	Fair	Fair	Good	Fair	Fair	Fair
System Overall Table 4I	Straight forward	Simple to install and operate	Fairly simple to design but requires good rate data	Simple manual or computer design	Computer design well application	Adequate high pressure, dry, non-corrosive supply needed.	Adequate high pressure, dry, non-corrosive supply needed.	Simple to design, install, operate
Usage/Outlook Table 4J	Excellent	Limited to shallow	Excellent for high rates	Often default artificial lift	Good for higher volumes	Good, flexible, high rate	Often default artificial lift	Essentially low liquid, highGLR
Casing Size Limits Table 4K	Problems only in high rate wells	Normally no problem for 4 ½ and greater	Size will limit use of motors and pumps	Parallel free and closed systems – lg	Dual comp. Require larger casing	Sm <1000 bpd: Lg >5000 bpd	Small casing suitable for low volume	Small casing suitable for low volume
Depth Limits-Table 4L	11000' 16,000 max	5,000 6,000 max	10,000 15,000 max	10,000 20,000 max	10,000 15,000 max	10,000 15,000 max	10,000 10,000 max	8,000 19,000 max
Intake Capabilities Table 4M	Excellent	Good	Fair	Fair	Poor to fair	Poor	Fair	Good
Noise Levels Table 4N	Fair	Good	Excellent	Good	Good	Low Compressor?	Low Compressor?	Excellent

Appendix 19 - continued
Clegg's Artificial Lift Design Consideration Comparison

	Rod Pump	Progressive Cavity Pump	Electric Submersible Pump	Hydraulic Reciprocating	Hydraulic Jet	Gas Lift	Intermittent Gas Lift	Plunger Lift
Obtrusiveness-Table 4O	Poor to fair	Good	Good	Fair to good	Fair to good	Good	Good	Good
Prime Mover Flexibility Table 4P	Good	Good	Fair	Excellent	Excellent	Good	Good	Not applicable
Surveillance Table 4Q	Excellent	Fair	Fair	Good to fair	Good to fair	Good to excellent	Fair	Good
Relative Ease of Well Testing - Table 4R	Good	Good	Good	Fair	Fair	Fair	Poor	Good
Time Cycle and Pump off Controllers Table 4S	Excellent	Poor	Poor	Poor	Poor	Not applicable	Poor	Not applicable
Corrosion/Scale Handling Ability Table 4T	Good to excellent	Good	Fair	Good to excellent	Good to excellent	Good	Good	Fair
Crooked/Deviated Holes Table 4U	Fair	Poor to fair	Good	Excellent	Excellent	Excellent	Excellent	Excellent
Duals Application Table 4V	Fair	Unknown	Unknown	Fair	Fair	Fair	Fair	Unknown
Gas Handling Ability Table 4W	Good	Poor	Poor	Food to fair	Good to fair	Excellent	Excellent	Excellent
Offshore Application Table 4X	Poor	Poor	Good	Fair	Good	Excellent	Poor	Excellent
Paraffin Handling Capability - Table 4Y	Good to excellent	Fair	Fair	Good to excellent	Good to excellent	Good	Good	Excellent
Slim hole Completions Table 4Z	Feasible	Feasible	Unknown	Possible	Possible	Feasible	Feasible	Good
Solids/Sand Handling Ability Table 4AA	Fair	Excellent	Poor	Poor	Fair to good	Excellent	Fair	Poor
Temperature Limitation Table 4AB	Excellent 550	Fair 250	Fair 250 -400	Excellent 500	Excellent 600	Excellent 400	Excellent 400	Excellent
High Viscosity Fluid Handling Table 4AC	Good <200 cp	Excellent	Fair	Good	Good to excellent	Fair	Fair	Not applicable
High Volume Lift Capabilities-Table 4AD	Fair	Poor	Excellent	Good	Excellent	Excellent	Poor	Poor
Low Volume Lift Capabilities-Table 4AE	Excellent <100 bfpd	Excellent <100 bfpd	Poor <400 bfpd	Fair 100 – 300 bfpd	Fair 200 bpd @ 4000'	Fair 200 bpd 2"	Good ½ to 4 bbls per cycle	Excellent 1 to 2 bpd with high GLR

Appendix 20
Directory of Fluid Removal Service Companies
or Equipment Manufacturers

Company	Product	Address	City	State	Zip	Phone
American Int.	Pumping Units	905 South Grandview	Odessa	TX	79761	915-334-4500
Aquaclear	Foamers	608 Virginia Street	Charleston	WV	25301	304-343-4792
Baker Petrolite	Foamer	12645 W. Airport Rd	Sugar Land	TX	77478	800-231-3606
CFER Technologies	Production Enhancement	200 Karl Clark Rd.	Edmonton	CN	T6N1H2	780-450-8989
DIS	Chemical Injection		Houston	TX		800-817-7950
Echometer Co.	Diagnostic Equipment	5001 Ditto Lane	Wichita Falls	TX	76302	940-767-4334
EDI	Tubing Plungers	228 Pike Street	Marietta	OH	45750	740-374-4301
EP Solutions	Artificial Lift Systems	15995 N. Barkers	Houston	TX	77079	832-201-4200
Ferguson-Beauregard	Tubing Plungers	PO Box 130158	Tyler	TX	75713-0158	903-561-4851
Harbison-Fischer	Pumps	PO Box 2477	Ft. Worth	TX	76113	817-297-2211
Jensen	Pumping Units	PO Box 1509	Coffeyville	TX	67337	318-251-5700
Logic Plunger Lift	Tubing Plungers	4332 Tallmadge Rd.	Rootstown	OH	44272	330-325-1951
Lufkin	Pumping Units	601 S. Raguet	Lufkin	TX	75901	936-634-2211
Midway Supply	Jet Star Casing Plungers	291 Branstetter St.	Wooster	OH	44691	330-264-2131
Moyno	Progressive Cavity Pump	363 N. Sam Houston	Houston	TX	77060	281-445-1545
Multi Products	Tubing and Casing Plungers	PO Box 286	Millersburg	OH	44654	800-777-8617
National Oilwell	Pumps and Units	10000 Richmond	Houston	TX	77042	713-346-7561
Plungerlift Systems	Tubing Plungers	PO Box 9423	Midland	TX	79708	915-699-1200
Production Control	Production Enhancement	1762 Denver Ave.	Fort Lupton	CO	80621	303-659-9322
REDA	Electric Submersible	PO Box 1181	Bartlesville	OK	74005	918-661-2000
Sage Technologies	Fluid Level Equipment	PO Box 1466	Grapevine	TX	76099	877-488-2579
Skillman Pump Co.	Downhole Pumps	211 RR 620 South	Austin	TX	78734	888-826-4082
Weatherford	Most Artificial Lifts	1900 E. 25th Street	Oklahoma City	OK	73129	405-672-0003
Well Master	Plungerlift Systems	12860 W. Cedar Dr.	Lakewood	CO	80228	800-980-0254

Appendix 21
Directory of Stripper Well Resources

Company	Address	City	State	Zip	Phone
American Petroleum Institute	1220 L Street	Washington	DC	20005	202-682-8000
Artificial Lift Energy Optimization Consortium	Texas Tech University	Lubbock	TX	79409	806-842-1801
Artificial Lift R&D Council (ALRC)	2516 Timberline Drive	Austin	TX	78746	513-330-0671
Interstate Oil and Gas Compact Commission	PO Box 53127	Oklahoma City	OK	73152	405-525-3556
Marginal Oil and Gas Well Commission	1218B W. Rock Creek Rd.	Norman	OK	73069	405-366-8688
National Energy Technology Laboratory	PO Box 880	Morgantown	WV	26507	304-285-4589
National Petroleum Technology Organization	1 West 3rd Street	Tulsa	OK	74103	918-699-2076
National Stripper Well Association	10077 Grogan Mill Road	The Woodlands	TX	77380	281-364-7037
PERFORM Research Center	Colorado Sch. of Mines	Golden	CO	80401	303-273-3042
Petroleum Technology Transfer Council	PO Box 246	Tulsa	OK	74063	918-241-5801
Southwestern Petroleum Short Course	Texas Tech University	Lubbock	TX	79409	806-842-1801
Stripper Well Consortium	C-211 Coal Utilization Lab	University Park	PA	16802	814-865-4802
Texas Tech Univ. - PL-OPT/SWPSC	Box 43111	Lubbock	TX	79409	806-742-1727