SPE 27932

An Economic Assessment of Artificial Lift in Low-Pressure, Tight Gas Sands in Ochiltree County, Texas

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SPE Members

Abstract

A review of 289 completions in Ochiltree County, Texas, shows 137 classified gas completions currently produce with the aid of artificial lift. Two methods of artificial lift, beam pumping units and plunger lift, were identified in the review. The study revealed that 130 gas wells produce with the aid of a plunger lift, while only 7 gas wells produce with the aid of a beam pumping unit. This paper reports on historical results obtained from using plunger lift systems. The historical results are compared to published methods for predicting liquid loading and plunger lift production responses. An evaluation of the historical plunger lift production responses and installation workover costs show that an impressive 32 BCF of reserves were added at a cost of less than $0.06/MCF.

Introduction

Artificial lift is a requirement in gas wells when velocities in the production string drop below a critical rate. Below the critical rate, liquids migrate down the tubing and collect at the bottom of the completion. This liquid build-up condition effectively increases the bottom hole flowing pressure and in many cases results in killing the well. The most obvious surface condition of this phenomena is “heading” on the gas sales chart.

With the ongoing emphasis on optimizing production while lowering lifting costs, many operators are evaluating methods of artificial lift in tight gas sands.[1] Techniques to remove wellbore liquids from gas wells have become increasingly more sophisticated.[2] Experience has shown that continuous removal of wellbore liquids can significantly increase gas production.[3] The plunger provides a mechanical interface between wellbore liquids and produced gas. Liquids are brought to the surface by the movement of the plunger traveling from the bottom of the well to the surface. This interface eliminates liquid fall-back, increasing the efficiency of the gas to lift liquid and remove liquids from the wellbore. The increased efficiency results in lower flowing bottom hole pressures. Gas stored in the tubing/casing annulus provides the energy to lift the plunger and the wellbore liquids to surface.

In this study, conventional tubing plunger lift systems are evaluated. The typical well configuration consists of a bottom-hole spring located at depth inside the tubing. On the surface, a lubricator and catcher are mounted above the master valve. The plungers use high efficiency steel pad-type seals. Plungers travel freely through the entire length of the tubing, from the spring at the bottom to the lubricator on the surface. Intermittent opening and closing of a motor valve at surface controls the flow of the well and the travel of the plunger.

Plunger lift production cycles from wells in this study area have been controlled by time only, and a combination of time and pressure. With the advent of microprocessors other methods of control are now available.[4] This study did not include using the automatic, self-adjusting controllers that operate based on plunger velocity. A follow-up study is planned.

Geology of Study Area

Ochiltree County is located in the Texas Panhandle along the Texas-Oklahoma border, as shown in Figure No. 1. In the study area, plunger lift systems have been successfully employed in three producing horizons. These are the Mississippian, Morrowan and Cleveland Formation.

Positioned in the Texas Anadarko Shelf, Ochiltree County is part of the Mid-Continent region. The Mid-Continent region is one of the oldest and most important oil and non associated gas provinces in the United States. Natural gas production in Ochiltree County is found in geologic ages ranging from Ordovician to Upper Pennsylvanian. A columnar section showing the geologic groups in the study area is provided on Figure No. 2.

During early and middle Mississippian time the entire Mid-Continent was covered by seas which deposited carbonates and shales. During late Mississippian time there was a major withdrawal of seas from the Mid-Continent. Porosity development in the Mississippian is varied and reservoir thicknesses are erratic. The leached Mississippian limestones produce from structural reservoir traps.[5] Plunger lifts have successfully enhanced production in Mississippian wells producing from depths of 9,800’.

Marine transgression into the Mid-Continent region during Pennsylvanian Morrowan was interspersed with stillstands and regressions. The Basal Morrow sands are a result of sand lenses accumulating along and near shorelines under high-energy conditions. In the Texas Anadarko Basin, the Lower Morrow is distinguished from the Upper Morrow by a middle unit of calcareous sandstone commonly referred to as the Squaw Belly. Lower Morrowan sandstones are more predictable in occurrence than the fluvially dominated Upper Morrowan sandstones. However, the Upper Morrow beds are generally more porous with higher permeability, resulting in higher production rates and reserves.[6] Plunger lifts have proven successful in Morrowan depths ranging from 10,500’ to 8,200’.

The Cleveland Formation is readily correlated over a wide area in the Texas Anadarko Basin. Within the study area, the Cleveland Formation is comprised mostly of stacked, progradational marine successions containing deltaic facies. Cleveland gas is found primarily in proximal delta front sandstones, fluvial channel fills and delta-distributary channel fills. Although permeability is generally below 0.10 md, the Cleveland Formation is a major gas-producing reservoir in the Texas Anadarko Basin.[7] Plunger lifts have proven successful in the Cleveland depths ranging from 7,200' to 6,700'.

Prediction of Liquid Loading

The challenge to engineers evaluating depleted Mississippian and Pennsylvanian gas reservoirs is to be able to identify successful artificial lift candidates. It is apparent that engineering derived criteria can be established to identify liquid loaded wells. Artificial lift systems can then be analyzed to determine maximum gas production rates while minimizing lifting costs.

Turner et al[8] compared two physical models for predicting the minimum flow rates required to continually remove liquids from gas wells. Turner concluded in his paper that the drop removal model provided a more clear distinction between adequate and inadequate flow rates, as related to liquid removal, than the film movement model. The data published by Turner examined unloading gas wells producing at rates generally exceeding 1 MMCFPD and at wellhead pressures generally exceeding 1000 psia.

Turner concluded that the empirical equation derived to calculate minimum gas velocities must be adjusted upward by 20 percent to insure removal of all drops. Turner also concluded that the gas : liquid ratio does not influence the minimum lift velocity up to 130 bbl/MMCF, and that if water and condensate liquids are both present in the wellbore, the higher density fluid should be used in the equation.

The minimum gas velocity in the drop removal model is based on density differences between the liquid and gas phases. Bizanti et al[9] evaluated the various parameters affecting liquids removal using the drop removal model. Bizanti presented the drop removal model with variable temperature and gas specific gravity inputs:

$$V_g = \frac{C\,(P_1 - P_g)^{0.25}}{P_g^{0.5}}, \ldots\ldots\ldots\ldots (1)$$

In the case where water is present in the wellbore:

$$V_g = \frac{5.62\,(67 - P_g)^{0.25}}{P_g^{0.5}}, \ldots\ldots\ldots\ldots (2)$$

Where:

$$P_g = \frac{2.7\ P\ SG}{Z\ (T + 460)}, \ldots\ldots\ldots\ldots (3)$$

A minimum gas flow rate is then calculated as:

$$Q_{min} = \frac{3.06\ P\ V_g\ (0.25 D_{it}^2 \pi)}{Z\ (T + 460)}, \ldots\ldots (4)$$

Figure No. 3 graphically illustrates the results for determining minimum gas flow rates using the drop removal model for the Mississippian, Morrowan, and Cleveland Formations. As noted by Turner, the relative impact of absolute temperature and gas gravity have very small effects, when compared to pressure and flow area, on the calculation of minimum velocity.

Prediction of Plunger Lift Production Response

There have been several methods published discussing pressure requirements for lifting liquids from gas wells.[10,11] James F. Lea presented a method of analysis based on Newton's Law of motion.[12] Lea analyzed the motion of the plunger as the sum of forces equated to the mass of the plunger plus the slug multiplied by acceleration:

$$\Sigma F = A_t (p_f - p_b) - w_t - \tau L_{st} \pi D_{it} = w_t/g\ a, \quad (5)$$

solving for the plunger acceleration at any time during the plunger rise, the velocity, v, and the distance traveled by the plunger L, can be found by integration with respect to time, t.

$$V = \int_0^t a\ dt + v_i \ ,\ldots\ldots\ldots\ldots\ldots\ldots..(6)$$

and

$$L = \int_0^t v\ dt + L_i \ ,\ldots\ldots\ldots\ldots\ldots\ldots..(7)$$

where the initial velocity, v_i, and the initial distance traveled, L_i are zero at the bottom of the tubing. The Dynamic Model presented by Lea eliminates the need to specify the velocity of rise as required by other methods.

Figure No. 4 shows the results from applying the Dynamic Model to calculate plunger velocity as a function of plunger travel distance for typical Mississippian, Morrowan, and Cleveland wells.

Plunger lift wells can be divided into four specific periods. These periods are:

1. Gas and liquids production during plunger rise.
2. Gas production as casing blows down after plunger surfaces.
3. Gas production as a result of reservoir response and corresponding wellbore liquid build-up.
4. Gas andliquid build-up in tubing and casing during shut-in.

Assuming no slippage of gas during the plunger rise, the gas production rates during period 1 are calculated as:

$$Q_g = L\ \pi\ D_{it}\, 2/4\ B_g \ ,\ldots\ldots\ldots\ldots\ldots..(8)$$

Assuming stored casing gas is produced preferentially to the reservoir, the volume of casing and tubing gas produced during period 2 is determined using a mass balance:

$$Vcg = (MASS_i - MASS_f) / P_{sc},\ldots\ldots\ldots(9)$$

$$MASS_i = \pi(D_c^2 - D_{ot}^2)/4 * DEPTH * P_i \ ,...(10)$$

$$MASS_f = VOLUME * DEPTH * P_f,\ldots...(11)$$

$$VOLUME = \pi(D_c^2 - D_{ot}^2 + D_{it}^2)/4,\ldots\ldots(12)$$

$$P = \frac{2.7\ P\ SG}{Z\,(T + 460)} \ ,\ldots\ldots\ldots\ldots\ldots\ldots(13)$$

After the casing and tubing have blown down to a pressure sufficient for the reservoir to respond, the familiar back pressure equation can be used to determine gas flow rates as a function of flowing bottom hole pressure. The flowing bottom hole pressure increases as liquid build-up occurs in the wellbore. The height of accumulated liquids is determined from the natural gas-liquid ratio of the well on plunger lift:

$$Q_g = C\,(P_R^2 - P_{wf}^2)^n \;,\ldots\ldots\ldots(14)$$

where:

$$P_{wf} = P_f + Y_1 h_1 \;,\ldots\ldots\ldots(15)$$

and M_1 is calculated from:

$$\frac{dh_1}{dt} = \frac{C\,(5.61)\,P_R^2}{F_{gl}\;A_t} \times \{1 - D\},\ldots(16)$$

$$D = \frac{(Pf + Y_1 h_1)^2}{P_R^2},\;\ldots\ldots\ldots(17)$$

when h_1 has reached an accumulated height, yielding a value for the maximum liquids mass determined from the Dynamic Model, the well is shut-in. The casing/tubing pressure builds to the required pressure determined from the Dynamic Model to lift the liquid slug from the well. As gas from the reservoir flows into the shut-in well, the liquid height continues to build. The incremental fluid height after shut-in, h_2, is assumed to increase equally in the tubing and casing-tubing annulus. The shut-in time requirement to build to the necessary casing pressure is found using a mass balance:

$$Q_{AF} = C\,(P_R^2 - P_{wf}^2)^n \;,\ldots\ldots\ldots(18)$$

$$Q_l = Q_{AF} / F_{gl} \;,\ldots\ldots\ldots(19)$$

$$h_2 = \frac{Q_l\;(5.615)}{(A_t + A_a)} \;,\ldots\ldots\ldots(20)$$

$$MASS_{AF} = \frac{Q_{AF}\,2.7\,P_{sc}\,SG}{Z\,(T_{sc} + 460)} + MASS_r\ldots(21)$$

where:

$$MASS_r = VOL_r * \frac{2.7\,P_{avg}\;SG}{Z\;(T + 460)},\;\ldots\ldots(22)$$

$$VOL_r = A_a\,(DEPTH) + A_t\,(DEPTH - h_1)\;,..(23)$$

with the casing pressure calculated from the mass flow into the well:

$$P_c = \frac{MASS_{AF}\,Z\,(T + 460)}{2.7\,SG\;\;VOL_{AF}}\;,\ldots\ldots\ldots(24)$$

$$VOL_{AF} = \frac{Aa\,(DEPTH - h2) + At\,(DEPTH - h1 - h2)}{144},(25)$$

Figure No. 5 shows predicted plunger cycle results for typical Mississippian, Morrowan, and Cleveland wells using the Dynamic Model in conjunction with the 4 flow periods developed above. Each beginning casing pressure was established so as to provide an average rate of rose for the plunger of 1000 ft/min. Each graph represents one plunger cycle, plotting the predicted flow rates and casing pressures as functions of cycle time.

Evaluation Method of Historical Results

A commercial production database was employed to download production, field and reservoir data for all gas wells operated by one specific operator in

Ochiltree County, Texas. The operator provided information concerning the method of production for each of their operated gas wells. Railroad Commission well numbers were used as the common identifier between the two data sources. Spreadsheets and QMF routines were used to merge data from the commercial production data base with operator provided information for each subject well. Finally, the integrated data base was loaded into a graphical PC software package for production decline analysis.

Capabilities of the PC software package included sorting routines by key word identifiers. These sort functions allowed categorization of wells by method of production, reservoir and field. Each well on artificial lift was then evaluated using decline curve analysis to obtain gross ultimate recoverable reserves. Each wells' production curve was analyzed prior to and following artificial lift installation. The difference between the two reserve determinations was defined as those reserves attributable to the artificial lift installation.

Of the 130 plunger lift wells, 17 wells had plungers installed upon well completion or after September, 1993. These wells were not used to evaluate plunger lift costs or reserve increases. Example production curves for Mississippian, Morrowan and Cleveland wells are provided in Figure 6.

The operator provided the actual workover costs incurred to install plungers on 113 gas wells. These costs included all costs associated with the plunger lift installation workover. In many cases dropping the plunger and installing the necessary surface equipment was all that was required. While in the extreme cases, packers were milled, tubing was replaced, and casing leaks were repaired, resulting in significant workover cost increases.

Historical Study Results

Plunger lift systems have successfully increases gas production from Mississippian, Morrowan, and Cleveland wells. Table No. 1 enumerates the number of wells on plunger lift evaluated in this study, by geologic horizon.

A statistical illustration of pre-plunger production rates are the average daily production volumes obtained over a 3-month period immediately prior to plunger lift installation. Figure No. 7 shows the total number of wells, or frequency, that produce in a specified rate interval. Increments of 50 MCFPD are used for each rate interval increase. A tabulation of the data is provided.

The average 3-month well production rate for each geologic horizon, prior to plunger lift installation, is compared to the minimum unloading rates in Table No. 1. Turner's drop removal model is used to calculate the minimum unloading production rates, as illustrated in Figure No. 3. The pressure ranges used in Figure No. 3 are representative of operating flowing tubing pressures prior to plunger lift installation. Based on the Turner model, liquid loading is occurring under the average condition.

A statistical illustration of post-plunger production rates is provided in Figure No. 8 for the 113 study wells, organized by geologic horizon. The post-plunger production rates are the average daily production volumes obtained over a 3-month period immediately after plunger lift installation. Figure No. 8 shows the total number of wells, or frequency, that produce in a specified rate interval. Increments of 50 MCFPD are used for each rate interval increase. A tabulation of the data is provided.

The average three month well production rate for each geologic horizon, following plunger lift installation, is compared to the predicted plunger lift production response in Table No. 1. The predicted production responses are calculated using Lea's Dynamic Model and the four specified plunger lift periods. Predicted gas volumes in Table No. 1 were calculated from a 24-hour period for the plunger cycles developed in Figure No. 5.

A statistical illustration of results from the pre-plunger reserve evaluation is provided in Figure No. 9 for the 113 study wells, organized by geologic horizon. Figure No. 9 shows the total number of wells, or frequency, with reserves in a specified reserve interval. Increments of 500 MMCF are used for each reserve interval increase. A tabulation of the data is provided.

A statistical illustration of results from the post-plunger reserve evaluation is provided in Figure No. 10 for the 113 study wells, organized by geologic horizon. Figure No. 10 shows the total number of wells, or frequency, with reserves in a specified reserve interval. Increments of 500 MMCF are used for each reserve interval increase. A tabulation of the data is provided.

The average reserve and production rate increases for the Mississippian, Morrowan, and Cleveland producing wells is provided in Figure No. 11.

The plunger lift installation costs for each well were grouped by geologic formation and averaged. The resulting per well costs to implement plunger lift operations for the Mississippian, Morrowan, and Cleveland formations is shown in Figure No. 12. The cost for incremental reserves recovered using plunger lift operations is also shown in Figure No. 12.

The evaluation of investment costs versus incremental reserves added shows the plunger to be an economically efficient lift system in low pressure gas wells. Incremental gas recoveries attributed to the plunger lift in this study area exceed 32 BCF. The investment costs totaled $1,879,613 to install plunger lift systems on 113 subject wells.

Conclusions

1. Minimum predicted flow rates from Turner's drop removal model shows liquid loading conditions will likely exist in wells producing less than 500 MCFPD at 200 psia flowing tubing pressure.

2. Applying Lea's method for calculating plunger rise velocity reasonably predicts the operating conditions and production responses from plunger lift wells in the study area.

3. A significant increase in production rate and reserves have occurred from all geologic horizons in this study area, as a result of plunger lift installations.

4. The operator in this study area has invested $1,879,613 in workover operations to install plunger lift.

5. The total daily production rate increase attributed to plunger lift installations in the study area is 7,883 MCFPD, or nearly 70 MCFPD per well.

6. An incremental 32 BCF of gross gas reserves are directly attributable to plunger lift installation in the study area.

7. Average workover cost to install plunger lift is $16,793 per well and resulted in additional reserves of 283 MMCF per well.

8. Plunger lifts have added reserved in this study area at a cost of less than $0.06/MCF.

Acknowledgments

The authors would like to thank Maxus Exploration Company for permission to publish this paper. A special note of appreciation is given to Georgia McLain for her expert assistance.

Nomenclature

a = acceleration of the plunger plus the liquid slug at any point in the tubing ft/sec^2.
A_a = cross-sectional area annulus, sq ft.
A_t = tubing cross-sectional area, sq ft.
Bg = gas formation volume factor.
C = constant, SCF/D/(psi)^2.
Dc = inside casing diameter, ft.
Dit = inside tubing diameter, ft.
Dot = outside tubing diameter, ft.
F_{gl} = natural GLR of the well on plunger lift, scf/bbl.
f_s = friction force between the liquid slug and the walls of the tubing, lbf.
g = gravitational constant.
h_1 = height of wellbore fluids accumulated in tubing, ft.
h_2 = height of fluids accumulated during the shut-in in tubing and casing, ft.
L = plunger travel distance, ft.
Lst = total slug length, ft.
P = pressure, psia.
P_{avg} = average wellbore pressure, psia.
P_{wf} = flowing bottomhole pressure, psia.
P_f = flowing surface pressure corrected for gas column weight and gas friction to the top of the slug, psia.
P_1 = casing pressure corrected for gas column weight and friction to the bottom of the plunger, psia.
P_R = average reservoir pressure, psia.
Q_g = gas volume, SCF.
Q_{AF} = afterflow of gas into wellbore after shut-in, SCF.
Q_1 = afterflow of liquid into wellbore after shut-in, bbl.
Q_{min} = minimum gas flowrate, MMCFD.
SG = gas specific gravity.
T = temperature, °F.
V_g = gas velocity, ft/sec.
v = plunger rise velocity, ft/sec.
Vol = wellbore gas volume, cu ft.
w_t = total weight of the plunger and slug, lbf.
Z = gas compressibility factor.
L = plunger travel distance, ft.
P = gas density, lbm/cu ft.
P_g = gas phase density, lbm/cu ft.
P_l = liquid phase density, lbm/cu ft.
τ = shear stress, lbf/sq ft.
γ_1 = liquid density gradient, psi/ft.

Subscripts

AF = afterflow
avg = average
f = final
i = initial
min = minimum
r = remaining
sc = standard conditions

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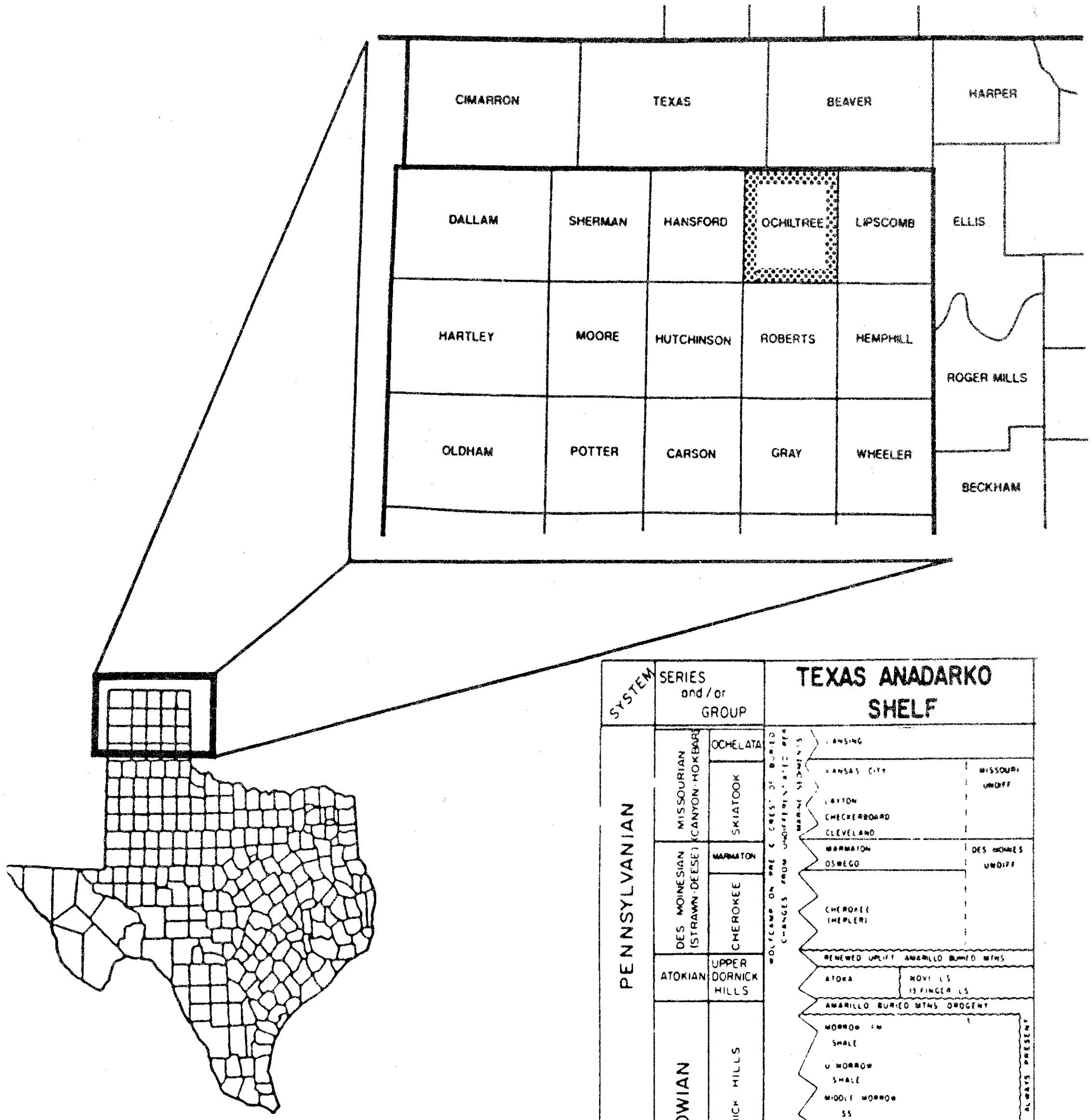


Figure No. 1 - Study Area Outline

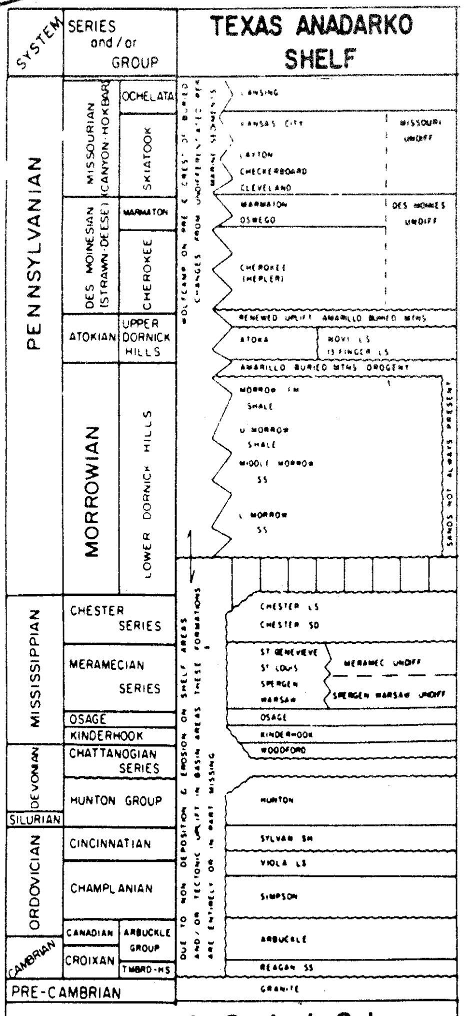
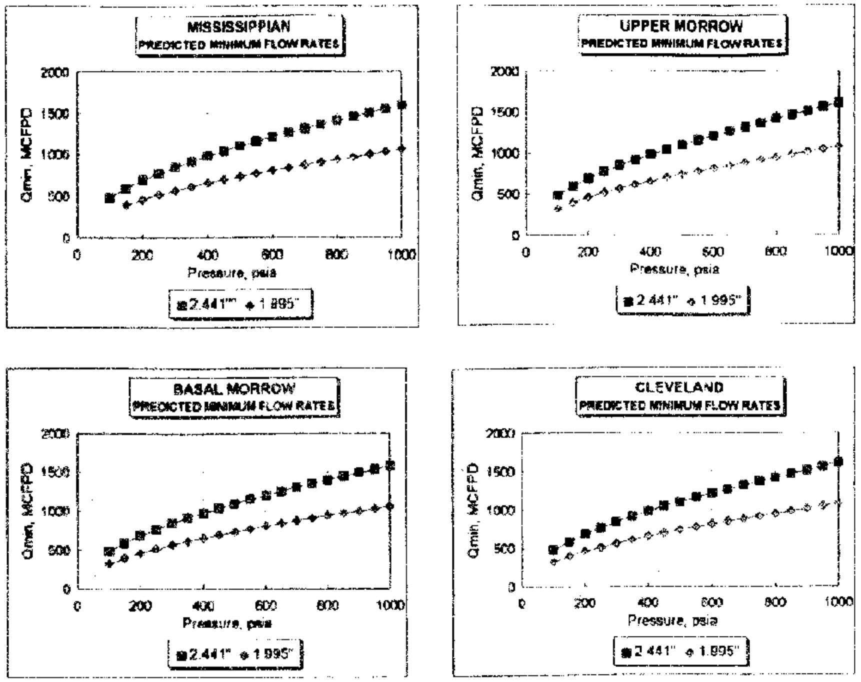
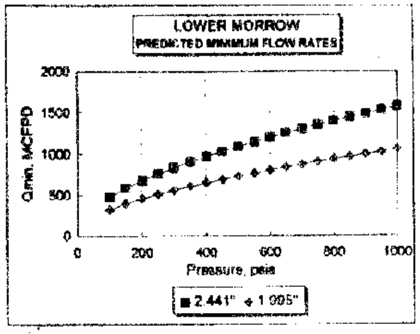


Figure No. 2 - Geologic Column

Table 1 - Historical and Predicted Rates for Study Area Plunger Lift Wells

GEOLOGIC HORIZON	NO. WELLS ON PLUNGER LIFT	AVERAGE PRE-PLUNGER RATE (MCFPD)	LIQUID LOADED RATE (MCFPD) @ 200 psia
MISSISSIPPIAN	4	125	461
BASAL MORROW	4	256	456
LOWER MORROW	10	108	453
UPPER MORROW	19	107	458
CLEVELAND	76	104	456
GEOLOGIC HORIZON	AVERAGE POST-PLUNGER RATE (MCFPD)	CALCULATED PLUNGER CYCLES PER DAY	PREDICTED PLUNGER RESPONSE RATE (MCFPD)
MISSISSIPPIAN	255	5	246
BASAL MORROW	265	4	217
LOWER MORROW	189	5	156
UPPER MORROW	150	6	165
CLEVELAND	179	7	167

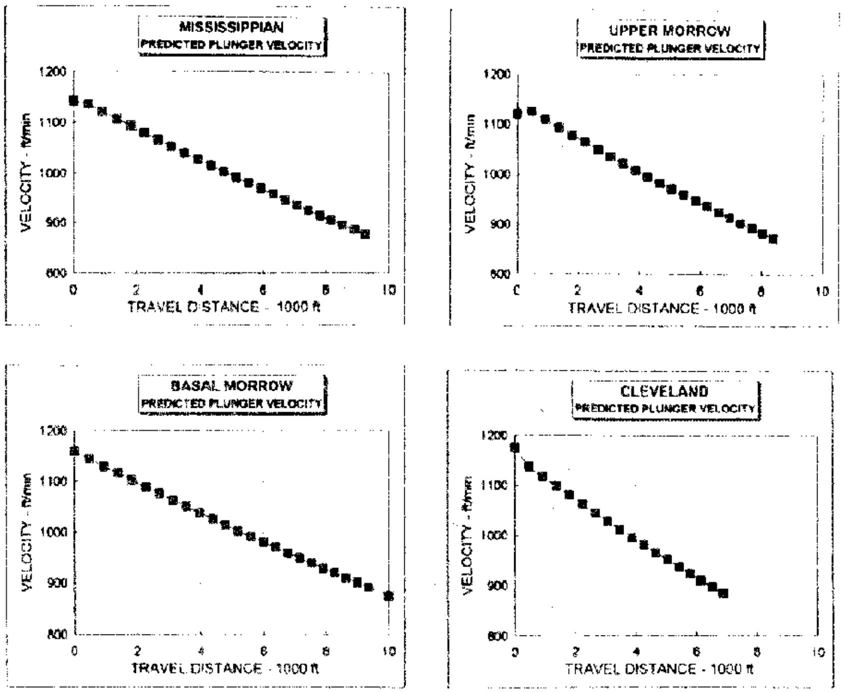


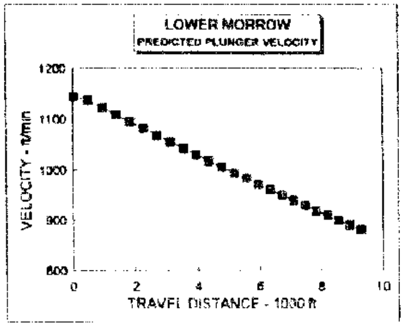


TABULATED MINIMUM FLOW RATES - MCFPD

2 7/8" TUBING	600 psia	400 psia	200 psia
MISSISSIPPIAN	1216	1048	689
BASAL MORROW	1202	972	681
LOWER MORROW	1198	967	676
UPPER MORROW	1213	978	684
CLEVELAND	1213	977	681
2 3/8" TUBING			
MISSISSIPPIAN	815	650	461
BASAL MORROW	805	651	456
LOWER MORROW	802	648	453
UPPER MORROW	812	655	458
CLEVELAND	812	654	456

Fig. 3 - Predicted Minimum Gas Flow Rates, Liquid Drop Removal Model

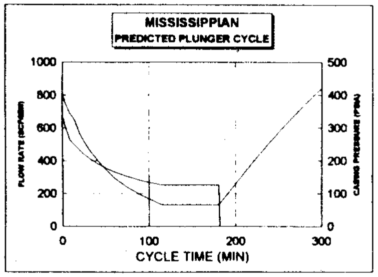


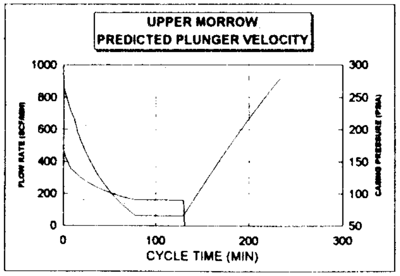


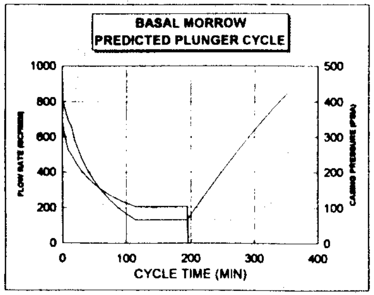
TABULATED PLUNGER VELOCITY - ft /min

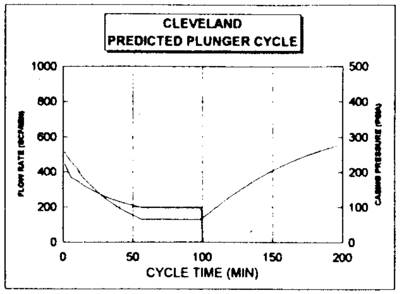
DEPTH	INITIAL	AVERAGE	SURFACE
MISSISSIPPIAN	1142	1003	878
BASAL MORROW	1161	1010	877
LOWER MORROW	1144	1005	880
UPPER MORROW	1120	995	873
CLEVELAND	1175	1011	883

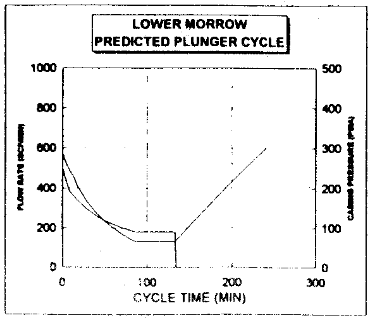
Fig. 4 - Predicted Plunger Velocity, Dynamic Model







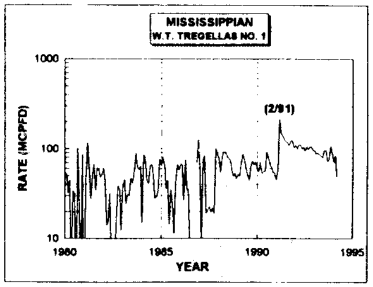


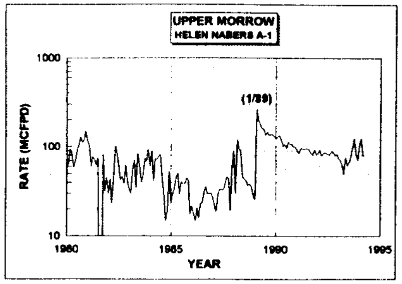


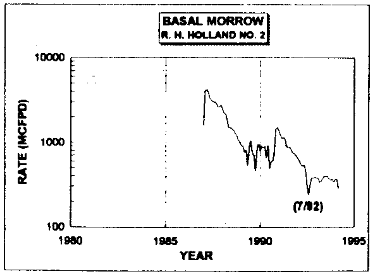
TABULATED PLUNGER PERIOD CYCLE DATA

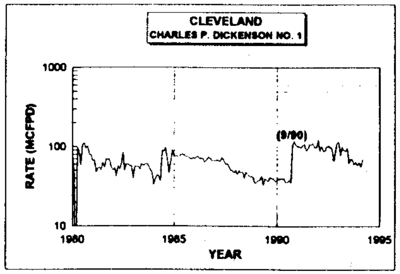
ENDING Pc	PERIOD 1	PERIOD 2	PERIOD 3	PERIOD 4
MISSISSIPPIAN	342	66	66	422
BASAL MORROW	350	67	67	425
LOWER MORROW	244	67	67	300
UPPER MORROW	228	66	66	280
CLEVELAND	227	65	65	275
CYCLE VOLUME (SCF)				
MISSISSIPPIAN	5,280	27,213	16,762	0
BASAL MORROW	5,350	32,347	16,669	0
LOWER MORROW	3,906	18,928	8,749	0
UPPER MORROW	3,425	11,502	12,597	0
CLEVELAND	2,436	11,272	10,115	0

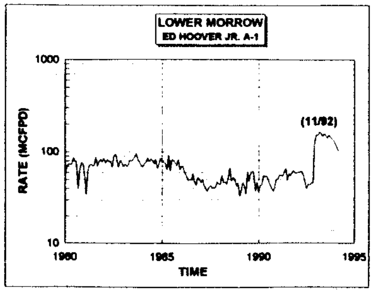
Fig. 5 - Predicted Plunger Cycle Responses







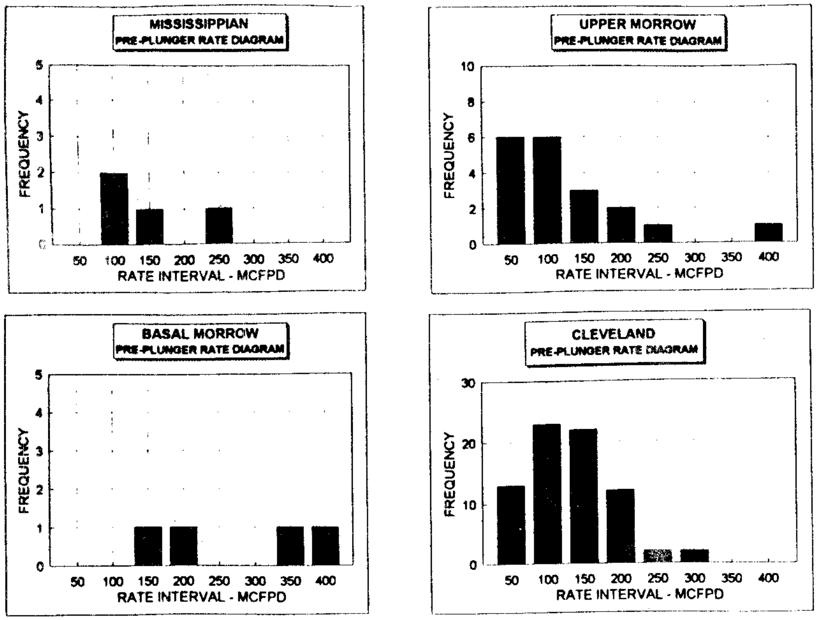


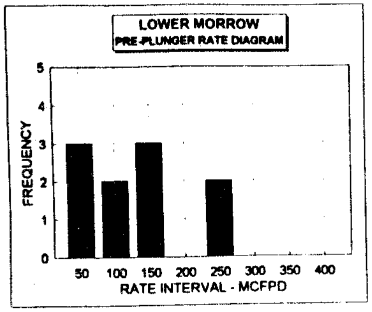


TABULATED PLUNGER PRODUCTION RESPONSES

	PRE-PLUNGER		POST-PLUNGER	
Example	RATE M/D	GUR (M/B)	RATE M/D	GUR (M/B)
MISSISSIPPIAN	60	1837	142	2003
BASAL MORROW	320	2675	345	2957
LOWER MORROW	44	1091	155	1341
UPPER MORROW	63	1790	201	2068
CLEVELAND	36	412	102	560

Fig. 6 - Plunger Lift Production Responses, Examples

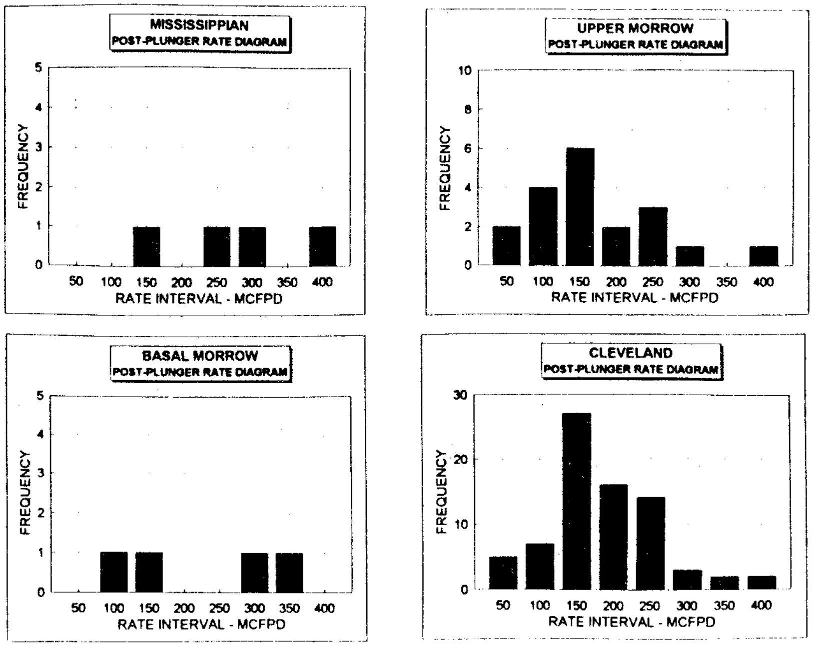


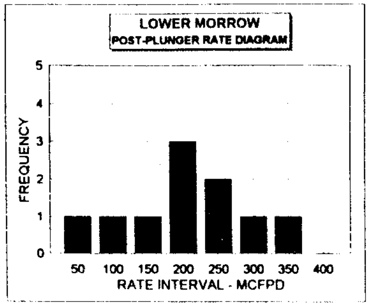


FREQUENCY vs RATE INTERVALS (MCFPD)

	0 - 50	- 100	- 150	- 200	- 250	- 300	- 350	- 400+
MISSISSIPPIAN	0	2	1	0	1	0	0	0
BASAL MORROW	0	0	1	1	0	0	1	1
LOWER MORROW	3	2	3	0	2	0	0	0
UPPER MORROW	6	6	3	2	1	0	0	1
CLEVELAND	13	24	23	12	2	2	0	0

Fig. 7 - Pre-Plunger Lift Installation Rate Diagram

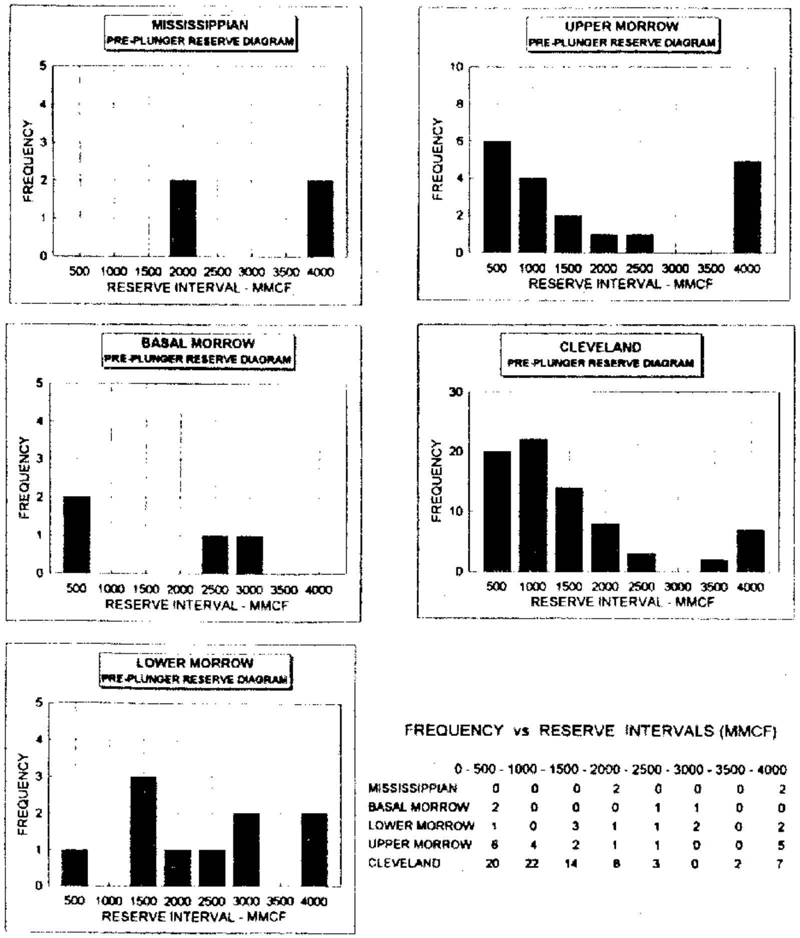




FREQUENCY vs RATE INTERVALS (MCFPD)

	0 - 50	- 100	- 150	- 200	- 250	- 300	- 350	- 400+
MISSISSIPPIAN	0	0	1	0	1	1	0	1
BASAL MORROW	0	1	1	0	0	1	1	0
LOWER MORROW	1	1	1	3	2	1	1	0
UPPER MORROW	2	4	6	2	3	1	0	1
CLEVELAND	5	7	27	16	14	3	2	2

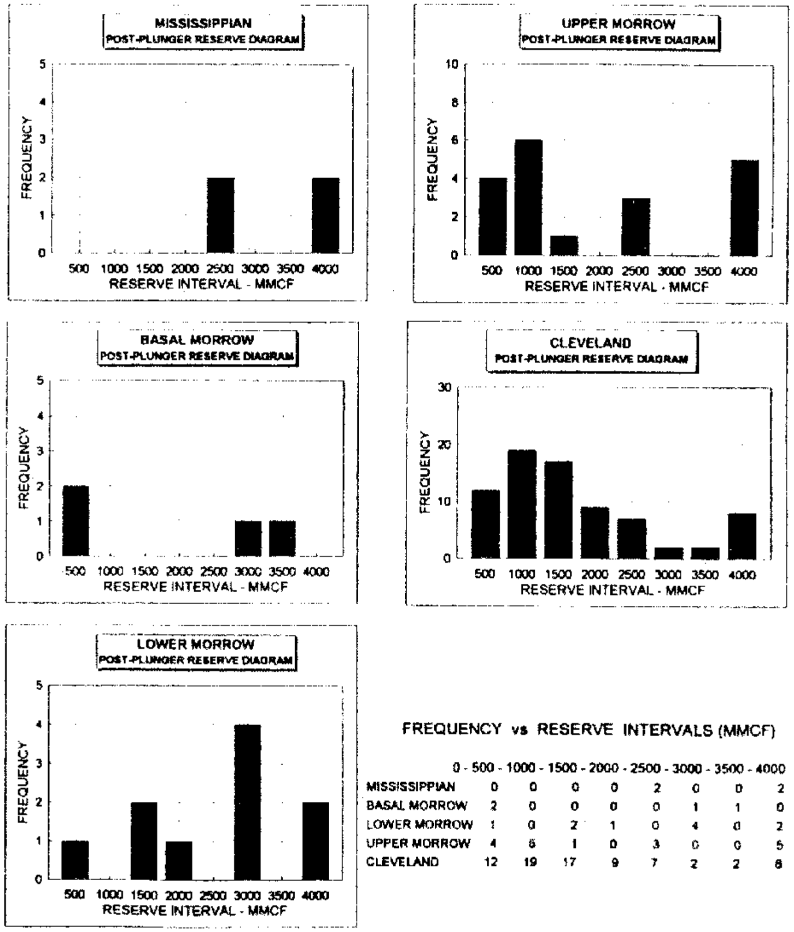
Fig. 8 - Post-Plunger Lift Installation Rate Diagram



FREQUENCY vs RESERVE INTERVALS (MMCF)

	0 - 500	- 1000	- 1500	- 2000	- 2500	- 3000	- 3500	- 4000
MISSISSIPPIAN	0	0	0	2	0	0	0	2
BASAL MORROW	2	0	0	0	1	1	0	0
LOWER MORROW	1	0	3	1	1	2	0	2
UPPER MORROW	6	4	2	1	1	0	0	5
CLEVELAND	20	22	14	8	3	0	2	7

Fig. 9 - Pre-Plunger Lift Installation Reserve Diagram



FREQUENCY vs RESERVE INTERVALS (MMCF)

	0 - 500	- 1000	- 1500	- 2000	- 2500	- 3000	- 3500	- 4000
MISSISSIPPIAN	0	0	0	0	2	0	0	2
BASAL MORROW	2	0	0	0	0	1	1	0
LOWER MORROW	1	0	2	1	0	4	0	2
UPPER MORROW	4	6	1	0	3	0	0	5
CLEVELAND	12	19	17	9	7	2	2	8

Fig. 10 - Post-Plunger Lift Installation Reserve Diagram

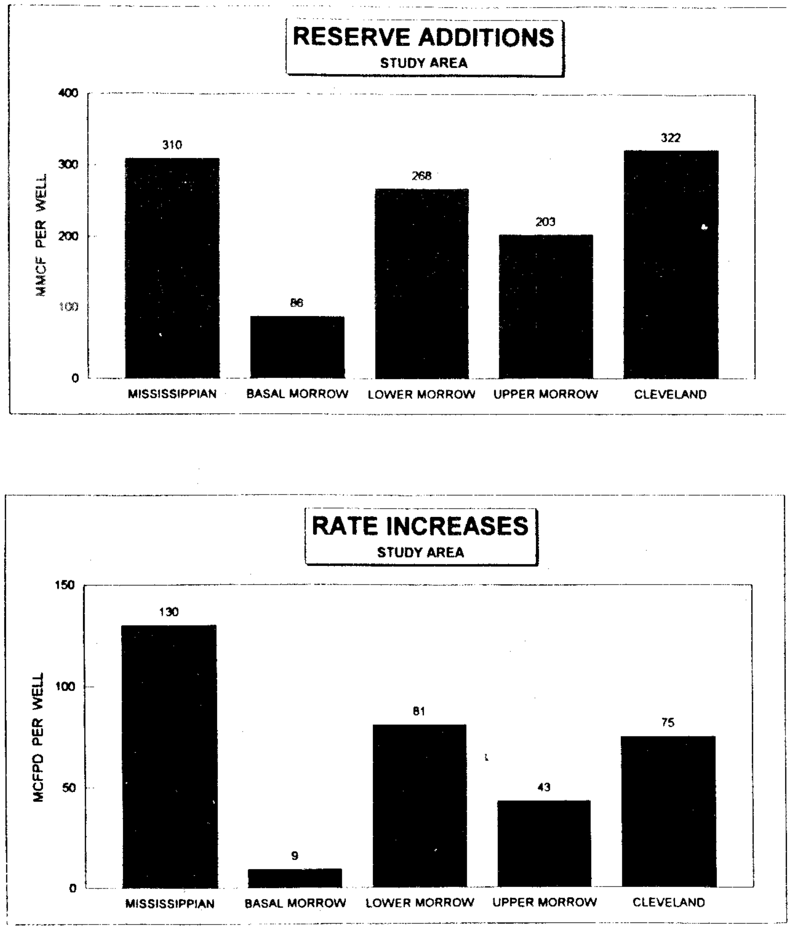


Fig. 11 - Plunger Lift Response Summary

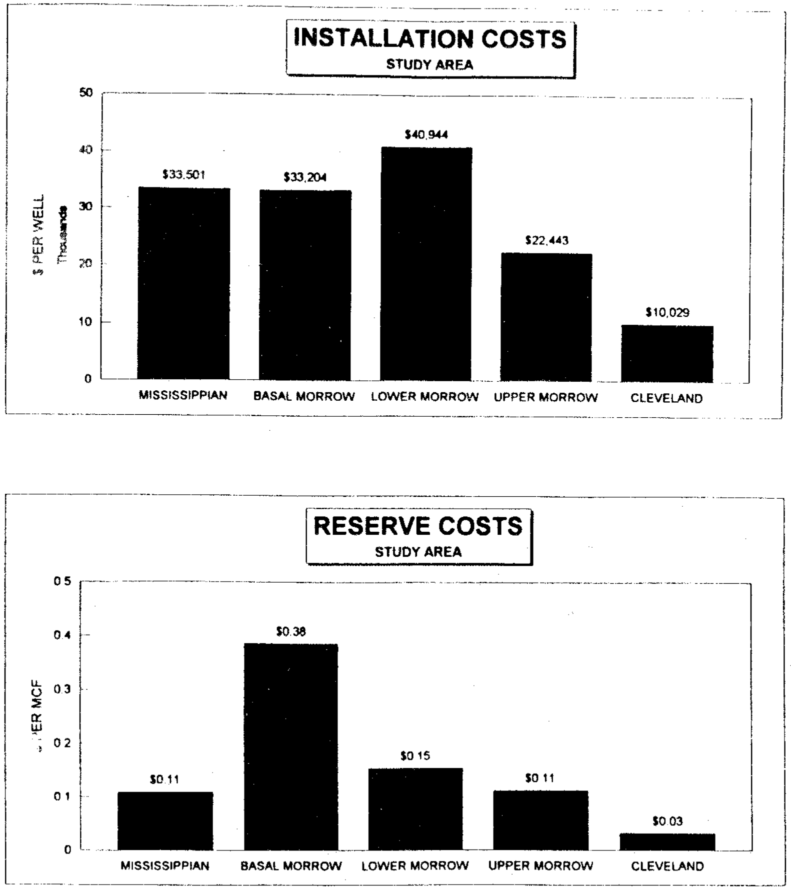


Fig. 12 - Plunger Lift Economic Summary