SYSTEMATIC EVALUATION AND APPLICATION OF CAPILLARY STRING/FOAMER APPLICATIONS FOR INCREASED NATURAL GAS PRODUCTION

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ABSTRACT

Although the utilization of foaming surfactants (foamers) through down-hole capillary tubing has been used by the industry for a number of years to unload liquids from natural gas wells, there has been marked increase in the application in the past year. This marked increase has resulted, in part, due to improved gas economics, continuing liquid-loading problems with onshore gas wells, and improvements in capillary-string installation and foamer technologies. A systematic approach to the evaluation of wells for potential application has been used to improve its success. This evaluation includes the use of a down-hole computer model in conjunction with field and laboratory tests. This paper discusses the approach involved in the evaluation, case studies that demonstrate the success of the evaluation process for the unloading of liquids from gas wells and the treatment of gas wells for salt plugging, and the economic results of the applications.

INTRODUCTION

Gas well loading has and continues to be a primary cause for the loss of gas volumes and revenue from older or low-producing gas wells. As the production continues to decrease during the life-cycle of a producing gas well, the gas velocity decreases to a critical point in which liquid (water and/or gas-condensate) begins to accumulate in the well bore. This accumulation increases the hydrostatic pressure on the reservoir and eventually changes the flow regime in the well bore to slug flow. Once in slug flow, more water and/or condensate will accumulate until the hydrostatic pressure exceeds the reservoir pressure and the well will not produce under natural conditions. Once this occurs, alternative methods for the removal of the fluids are necessary for the production of the well to be continued.

The liquid loading in a gas well can be eliminated or delayed by various approaches. Depending on the depletion stage of the well, these methods include but are not limited to:

- the use of smaller tubing or siphon strings to increase the gas velocity,
- the use of lower pressure systems to reduce well head pressures,
- the use of mechanical methods to lift the fluids (intermittent rod pump, intermittent gas lift, plunger lift, etc.),
- intermittent production,
- the use of surfactants (foamers).

Although each of these lift methods have application and advantages depending on the life-cycle of the well, the use of surfactants (foamers) injected down hole using capillary tubing has increased markedly during the past year. This increase has resulted, in part, due to improved gas prices, advances in capillary-string installation methods. and foamer technologies.

This paper presents a systematic method for the evaluation of wells for foamer/capillary tubing application. This evaluation includes the use of a down-hole computer model in conjunction with field and laboratory tests.

RESULTS AND DISCUSSION

Model Theory

A number of approaches have been used in an attempt to accurately predict loading in gas wells. The approach developed by Turner et al has probably been the commonly used method.[1] Turner et al developed two physical models for the removal of liquids from gas wells. These are commonly referred to as the liquid film and the liquid droplet models. Based on field data, it was determined that the liquid droplet model could be used to accurately predict the onset of loading with an empirical 20% upward adjustment of the equation. The necessity of the 20% modification in the liquid drop equation was questioned by Coleman et al based on their field studies.[2] Nosseir et al recently reevaluated the liquid drop equation as developed by Turner and developed a set of equations that eliminate the need for the empirical adjustment and matches both the data sets of Turner and Coleman.[3] Nosseir et al determined that the wide range of pressures, temperatures, and flow rates encountered in gas wells result in different flow regimes that are not necessarily confined to the range assumed by Turner. In Turner's model, he assumed a turbulent flow regime with a Reynold's number (N_{Re}) range of $10^4<N_{Re}<2x10^5$ and a corresponding drag coefficient of 0.44. Nosseir et al showed that most of the wells in Turner's data set were in highly turbulent flow ($2x10^5<N_{Re}<10^6$). In this case, the drag coefficient is 0.2. Correction for the drag coefficient corresponds to a change in the original liquid drop model by 21.2% which is very close to the empirical adjustment made by Turner. With regard to Coleman's data, Nosseir et al showed that these wells were in turbulent flow and that the assumptions made initially by Turner were valid for their data set.

As a first approximation for foamer/capillary string evaluations, we have chosen to use the original Turner et al liquid drop equation without the empirical correction. In general, the wells that we have evaluated match the flow regime assumed by Turner ($10^4<N_{Re}<2x10^5$) quite well. This equation (Equation 1) as expressed in the units by Coleman et al is given below.

$$V_t = \frac{1.593 \{ \sigma^{1/4} (\rho_l - \rho_g)^{1/4} \}}{\rho_g^{1/2}} \qquad (1)$$

Assuming, the interfacial tension of water and condensate to be 60 and 45 dynes/cm, respectively, the terminal velocity of water (Equation 2) and condensate (Equation 3) can expressed as a function of the gas phase density. **As** in the case of Turner et al, the equations are simplified by using an average gas gravity of 0.6 and a gas temperature of 120°F.

$$V_g\,(\text{water}) = \frac{4.43 \{ (SG_w)(62.4283) - 0.0031p)^{1/4} \}}{(0.0031p)^{1/2}} \qquad (2)$$

$$V_g\,(\text{cond}). = \frac{3.37 \{ (SG)(62.4283) - 0.0031p)^{1/4} \}}{(6.0031p)^{1/2}} \qquad (3)$$

As shown in equations 1, 2, and 3, the terminal velocity for a column of foam as a function of gas phase density can be estimated from the same relationships if the interfacial tension and foam phase density of the foam can be determined. Although these values can be estimated in the laboratory, it is quite difficult to translate these values to a well bore due to issues with foam stability, compressibility, and other factors. However, as a first approximate we have chosen to take these values (s_f and r_f) as determined in the laboratory and apply them as a tool for screening wells for potential application to foamer technology. Consequently, an analogous equation can be expressed for a column of foam (Equation 4).

$$V_g\,(\text{foam}) = \frac{1.593 \{ \sigma_f^{1/4} (\rho_f - 0.0031p)^{1/4} \}}{(0.0031p)^{1/2}} \qquad (4)$$

The critical gas production for unloading fluids from a well can be expressed as a function of the minimum flow rates for either water, condensate, or a column of foam by the following equation (Equation 5) as developed by Turner et al.

$$Q_g\,(\text{MMCF/D}) = \frac{3.06\,P\,V_g\,A}{T\,Z} \qquad (5)$$

Application of Model

As shown in the previous equations, to effectively unload fluid from a well without the use of a foamer, the superficial gas velocity (V_g) must be greater than the terminal velocity for the water or condensate that is loading the well. If the gas velocity is greater than these critical fluid velocities (V_g water or V_g condensate), the well will be in annular flow and the fluids will be produced with the gas. Conversely, if the superficial velocity is less than the liquid terminal velocity, the well will be in slug flow and will potentially continue to load up until the well dies.

The applicability of a capillary string and a foamer depends on a number of issues. The first of these is the relationship between the superficial gas velocity and the critical foam velocity. If the critical foam velocity is less than the superficial velocity, then a capillary string/foamer application may work if the correct foam can be determined for the application.

The effectiveness of a foamer is a function of a number of parameters. These include but are not limited to the bottom hole temperature, the salinity of the brine, the relative concentration of condensate and water as a function of depth in the well bore, and the location of liquid phase water in the well bore. To accurately determine the superficial gas and terminal foam velocities as a function of depth, the relative concentrations of condensate and water with depth, and the location of liquid phase water in a well bore, a multiphase-flow simulator program is used. A number of commercial simulator programs are available. Although our initial evaluations were performed with the University of Louisiana at Lafayette (ULL) gas well corrosion model, other multiphase-flow simulators have also been effectively used. Although the input requirements vary from model to model, the following information is typically necessary.

Gas Analyses
Well Schematic (tubing size, casing size, packer location, perforated interval, etc.)
Daily Production Data
Gas (MMSCF/D)
Water (BPD)
Condensate (BPD)
Well head and Bottom Hole Temperatures
Well head Pressure

Unlike a number of multiphase-flow simulator programs, the ULL model does not calculate the flowing-bottom-hole pressure (FBHP) but requires it as an input parameter. If this model is used, the FBHP must be estimated from either a dry-gas friction model or other simulator program. For the results presented in this paper, a dry-gas friction model was used to estimate the FBHP. For high-liquid producing wells, the dry gas model may under estimate the FBHP and overestimate the superficial gas velocity and should not be used.

Interpretation of Foamer Model

To demonstrate the model, a gas well with the following conditions was modeled. The model utilizes the ULL gas well corrosion model in conjunction with equations 2-5. Champion Technologies refers to this as the Perfoam ^{tm} model.

Production: 450 mcfd gas
21 bpd condensate
13 bpd water

Operating Parameters:
Well Head Pressure - 300 psi
Well Head Temperature - 90 F
Bottom Hole Temperature - 250 F
Flowing Bottom Hole Pressure - 383 psi

Well Completion:
Tubing - 2 3/8"
Casing - 5.5"
Packer - 9920'

Perforations - 64'; 9930- 9992'

From the tables and figures, the applicability of a capillary string/foamer can be determined. As shown in Table 2, based on Turner's equation, the well is loaded under these production conditions. The critical gas production (Qg water) for the removal of the fluids is 530 mcfd, whereas, this well currently is making only 450 mcfd. Graphically this is shown in Figure 1. This figure shows that above approximately 8500 feet, the critical water production (Qg water) is greater than the current production.

From Table 1 and Figure 2, the model indicates that the fluids are at the bottom of the wellbore. This is critical for a successful capillary string application. In some wells with low fluid production and high bottom-hole-temperatures, the loading up of the well does not occur at the perforations but in the tubing itself. In cases like this, if a capillary string is set at the bottom of the tubing or at the perforations, there will be no fluid to form the foam and the well will not unload. This is one advantage of using the ULL model as a multiphase-flow model. Since this model was developed for down-hole corrosion estimation, it accurately predicts where liquid is in the wellbore.

It is important to note that this well produces a relative large amount of condensate. Condensate can break the foam in a well and prevent the well from unloading. This is where product selection becomes critical. In our approach, we have incorporated both laboratory and field tests of the foamers prior to capillary string installation. This has assisted in the evaluation of wells for applicability.

Table *2* and Figure 3 present the critical velocities for the well. As noted in the table, the superficial gas velocity for the well (Vsg) is slightly greater than the critical water velocity (Vc water) at the bottom of the well (9890') but becomes less than Vc (water) at approximately 7500'. This again indicates that the well is loaded with fluid. In other words, the minimum velocity to unload water from the well is greater than the superficial gas velocity.

However, as shown in the table and figure, the critical velocity required to remove the water with a foamer (Vc foam) is less than Vsg through out the well bore. This indicates that although the well is currently loaded with fluid, the well does have sufficient velocity to unload if a foamer is used. Table 2 and Figure 1 indicate the amount of gas necessary to unload the well with a foamer. In the case presented, the amount of gas required to foam the well is 300 mcfd. With the current production of 450 mcfd, there is sufficient gas for the foam to unload the well.

In summary, based on the model, this well would be a good candidate for a capillary string/foamer application. It is important to note that the superficial gas velocity below the tubing/packer will be significantly less than what the model shows in the tubing. The ULL model does not allow for the velocity to be modeled below the tubing although most of the other multiphase fluid flow models will allow for multiple-string modeling. In terms of application, if the distance from the tubing to the perforations is significant, the capillary string/foamer application may not work due to this low velocity. As a "rule of thumb" based on field studies, if the distance between the tubing and perforations is greater than 200 to 250', field tests are needed before a final decision for application can be made.

Standard Procedure for Well Evaluation

As noted above, the model alone, in some cases, is not definitive and additional testing should be conducted before installation of a capillary string. We have developed a 4-step process for the evaluation of wells. This approach involves modeling and laboratory and field tests. The steps are listed below.

Collect data for down-hole modeling and model well.

Evaluate the well fluids for the best foamer.

Based on model and well completion data, conduct a batch treatment with foamer of choice on the well.

Based on model and batch treatment results, formulate a plan to unload the well.

The above process is conducted in every new field or wells that are producing from different reservoirs in a common field. In cases where capillary string applications have been implemented in a field, some of these steps are obviously not necessary.
As noted above, we have found in some cases that the choice of foamer is critical for the success of the application.

Although a laboratory evaluation provides good information, we have found in many cases, an actual field test of the product is necessary.

Although this paper is primarily concerned with the applicability of capillary string/foam applications, it is important to note that once the data are reviewed that a plan to unload the well is formulated. This plan may or may not utilize a capillary string and foamer. Depending on the where the well is in its life-cycle or potential problems with a capillary string application, alternative methods for unloading the well may be chosen. As an example, depending on the tubing in the well or the depth from the tubing to the perforations, the evaluation may indicate that a coiled tubing string may provide adequate velocity to unload the well without a foamer. If this is the case then the coiled tubing string would be recommended and foamer could be incorporated at a later stage of the life-cycle for the well.

Case Histories and Capillary String/Foamer Applications

To date, capillary strings for foam application have been installed in approximately 40 Kerr-McGee wells in numerous fields. Using the approach described above, the success of the applications has been approximately 90%. Of those wells that have been unsuccessful, they were either not loading up as believed, the fluids were in the tubing and not at the perforations, or the completion of the well was an issue (i.e. distance from tubing to perforations, multiple completions, sliding sleeves, etc.). The following examples present the results of some of the installations. These examples show various applications of the technology and the results that we have seen.

<u>Case History #1 - Production Increase</u>. This well in South Texas produces from the Lower Vicksburg formation at approximately 10,400' through 2.875" tubing. Prior to the capillary string installation the well made approximately 600 mcfd gas, 35 BCPD, and 25 BWPD. The well was having some problems with loading and evaluation of the production curve suggested that some additional production could be realized if the well could be unloaded. Figure 4 shows the production curve prior to and after installation of the capillary string. Based on a run length of 379 days, the well has averaged an additional 104 mcfd based on the initial decline curve and generated a cumulative increase of approximately 39 MMcf of gas.

<u>Case History #2 - Stabilized Production</u>. This well also in South Texas produces from the Vicksburg formation at approximately 8,000' through 2.875" tubing. As shown in Figure 5, soap sticks were used to keep this well unloaded. Since an automatic soap launcher was not on the well, the production was quite erratic and ranged from 50-450 mcfd (average production of approximately 220 mcfd). The well made 3-4 BWPD and 1 BCPD. As noted in the figure, the capillary string/foamer application stabilized the production at approximately 240 mcfd and eliminated the operational issues associated with the soap sticks. A modest increase of approximately 20 mcfd in production was also realized.

<u>Case History #3 - Elimination of Artificial Lift</u>. This well in South Texas produces from the San Miguel formation at approximately 5300' through 2.375" tubing. To produce the well, the well was rod pumped under a packer. Using the rod pump, the well made approximately 190 mcfd of gas and 1-2 BWPD. The production curve for this well in shown in Figure 6. As noted in the figure, the rod string parted in this well and without removal of the fluids, the production dropped to approximately 60 mcfd. Due to repeated failures on this well, the capillary string was installed. As noted in the figure, the production was stabilized back to approximately 190 mcfd and the well service cost and down time for this multiple-failure well were eliminated.

<u>Case History #4 - Elimination of Compressor</u>. This remote well in South Texas produces from the Nowacek formation. Prior to the capillary string application, the well produced approximately 170 mcfd and 1-2 BWPD through 2.375" using a rental compressor. Without the compressor, the well would not produce due to the low bottom-hole pressure. Production from the well was used as fuel gas for the compression. The capillary string was installed due to the cost of the compressor and the fuel gas usage. Figure 7 shows the production curve for the well before and after installation of the capillary string. As noted in the figure, although the production from the well is less with the capillary string (125-135 mcfd), the removal of the well from compression has more than offset this decrease in production and increased revenue from the well. In addition, since the well was at a remote location, there has been a significant reduction in operational expense that was required to maintain the compressor.

<u>Case History #5 - Control of Salt Formation/Production Increase</u>. This well is in Northern Louisiana and produces from the Gray Sand formation at approximately 11,250' through 2.375" tubing. Prior to the installa

tion, the well produced approximately 280 mcfd gas, 4 BWPD, and 1 BCPD. Due to the brine salinity and bottom-hole temperature in this well, it was treated with fresh water once a week to remove salt. The production curve for the well is shown in Figure 8. To reduce the down time for the well and to increase production, the capillary string was installed and the well treated with 8 barrels of fresh water a day containing 1% foamer. Since the capillary string was installed the production has increased to an average of 470 mcfd and the well has only been shut in twice for salt treatment in the past 6 months.

Economics of Capillary String/Foamer Applications

As noted above, it is somewhat difficult to evaluate the economics of the capillary string/foamer applications due to the various reasons for the applications and the intangible benefits that are realized (minimization of manpower, rental compressors, fuel, etc.). In an attempt to evaluate the economics, we have looked at 30 capillary string installations in South Texas. Of these 30 installations, 4 capillary strings were removed due to lack of response and moved to other wells. Of the remaining 26 strings, 5 were installed to stabilize production and to reduce manpower required to produce the wells. The remaining 21 wells have a current average production of 168 mcfd. Capillary strings have been installed in these 21 wells for an average of 283 days and have resulted in cumulative production increase of 244 MMcf of gas or approximately 865 mcfd (41 mcfd per well).

The cost of the capillary string, chemical, water, and chemical pumps for these 21 wells over the 283 days is approximately $20,900 per well or a total expenditure of $438,900.

The length of time to pay out the investment of the capillary strings, equipment, and chemical is obviously a function of natural gas prices. All of this work in South Texas was done when natural gas was approximately $6.50/mcf or greater. Assuming an average gas price of $5.00/mcf over this time period, the capillary strings on these 21 wells generated approximately $1.22 MM in increased gas revenue and the pay out for the strings and chemical is approximately 100 days. Even at $3.00/mcf, the pay out is less than 6 months.

NOMENCLATURE

A = flow area of tubing, sq ft
p = pressure, lb. force/ sq in
Q_g = gas flow rate, MMcf/D
SG_c = specific gravity of condensate
SG_w = specific gravity of water
T = temperature, °R
V_g = gas velocity, ft/sec
V_t = terminal velocity of free falling particle, ft/sec
z = gas deviation factor
r_f = foam phase density, lb mass/cu ft
r_g = gas phase density, lb mass/cu ft
r_l = liquid phase density, lb mass/cu ft
s = interfacial tension, dynes/cm

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1) Turner, R. G., Hubbard, M., and Dukler A., "Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells", J. Pet. Tech. November 1969) 1475; Trans., AIME, 246.
2) Coleman, **S.** B., Clay, H. B., McCurdy, D .G., and Norris, H. L., "A New Look at Predicting Gas Well Load-Up", J. Pet. Tech. (March 1991), 329; Trans., AIME, **291.**
3) Nosseir, M. A, Darwich, T. A., Sayyouh, M.H., and El Sallaly, M., SPE Prod. & Facilities, **15** (4), 241-246 (2000). Tables 1 and 2 and Figures 1-3 present the output file from the model based on the ULL corrosion model and equations 2-5.

Table 1
Perfoam tm Model Output

Depth	Temp (OF)	FP (psig)	Gas (mmscf/d)	Water (bwpd)	Cond (bopd)	Total Liq. (bfpd)
0	90	300	0.44	13.4	22.0	35.4
500	98	304	0.45	13.4	22.0	35.4
1500	114	313	0.45	13.4	22.0	35.3
2500	130	321	0.45	13.3	22.0	35.2
3500	147	329	0.45	13.1	22.0	35.1
4500	163	338	0.45	12.9	22.0	34.9
5500	179	346	0.45	12.6	21.9	34.5
6500	195	355	0.46	12.1	21.9	34.0
7500	211	363	0.46	11.5	21.8	33.3
8500	228	371	0.47	10.6	21.6	32.2
9445	243	379	0.48	9.5	21.3	30.8
9890	250	383	0.48	8.9	21.1	30.0

Table 2
Continuation of Output from Perfoam tm Model

from USL V_{mix} (ft/s)	V_L (ft/s)	V_{sg} (ft/s)	Vc Water	Vc Cand	Vc Foam	Water Qg(mmscf)	Foam Qg(mmscf)
11.22	0.08	10.99	12.90	9.19	7.15	0.529	0.300
11.26	0.08	11.01	12.81	9.12	7.10	0.525	0.297
11.36	0.08	11.05	12.63	9.00	7.00	0.517	0.293
11.45	0.08	11.09	12.46	8.88	6.90	0.509	0.288
11.56	0.08	11.15	12.30	8.76	6.81	0.502	0.284
11.67	0.08	11.21	12.15	8.65	6.72	0.494	0.280
11.80	0.08	11.30	12.00	8.54	6.63	0.488	0.276
11.95	0.08	11.41	11.85	8.44	6.55	0.481	0.272
12.13	0.08	11.55	11.72	8.34	6.47	0.475	0.268
12.35	0.08	11.74	11.58	8.25	6.39	0.469	0.265
12.61	0.07	11.96	11.46	8.16	6.32	0.463	0.261
12.75	0.07	12.08	11.40	8.12	6.29	0.461	0.260

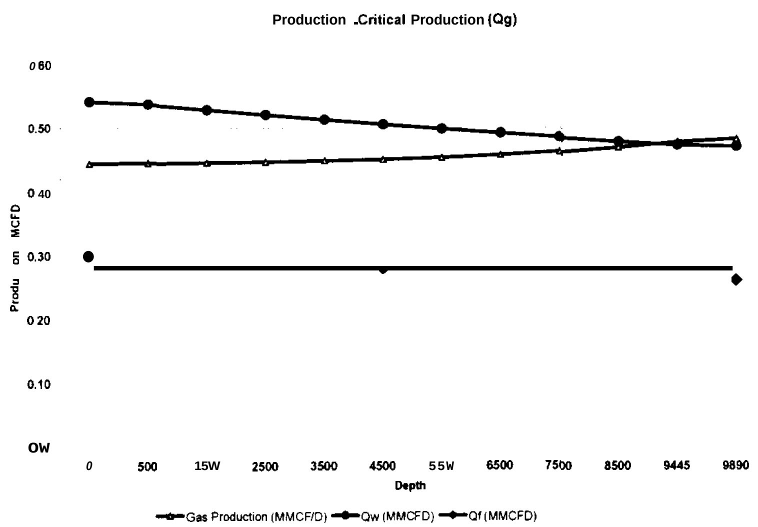

Figure 1 - Critical Production Data from Perfoam tm Model

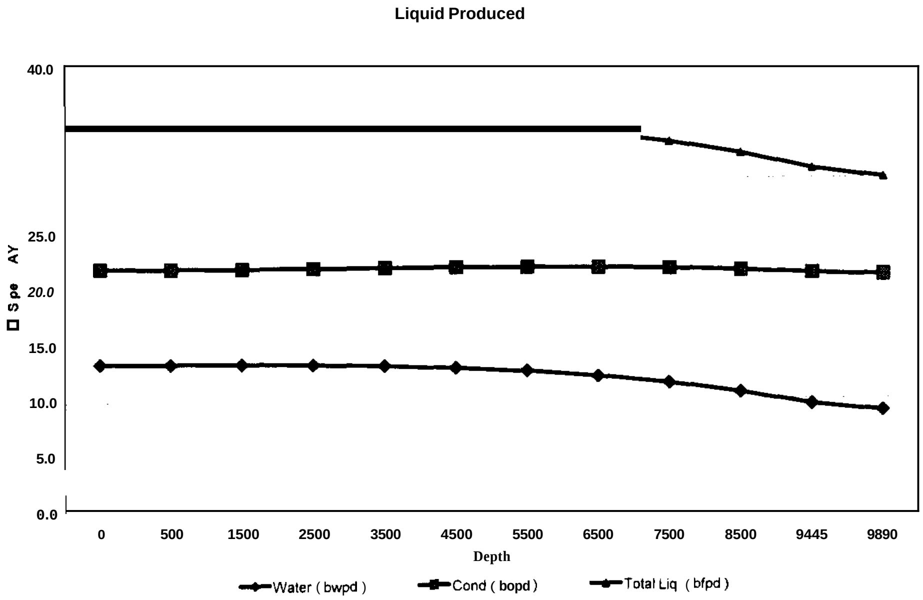

Figure 2 - Liquid Production from Perfoam tm Model

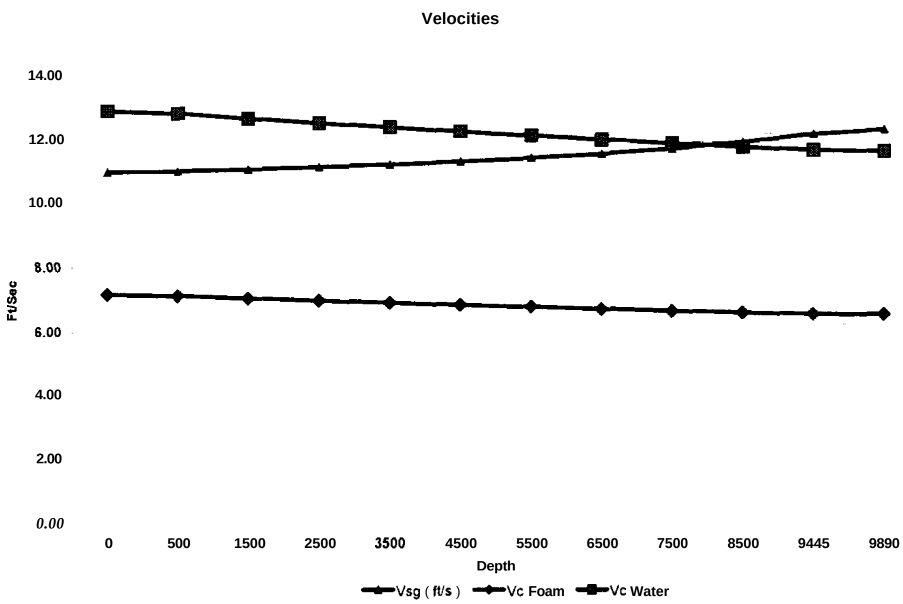

Figure 3 - Velocity Distributions from Perfoam tm Model

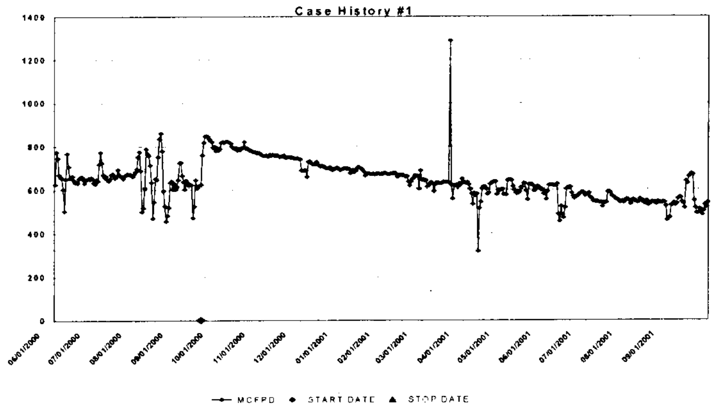

Figure 4 - Capillary Installation to Increase Production

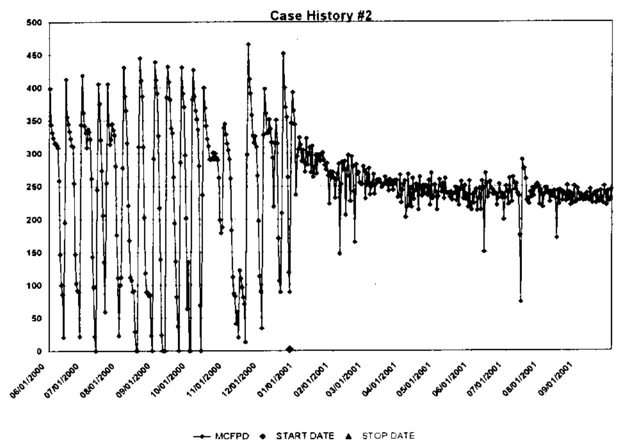

Figure 5 - Capillary Installation to Stabilize Production

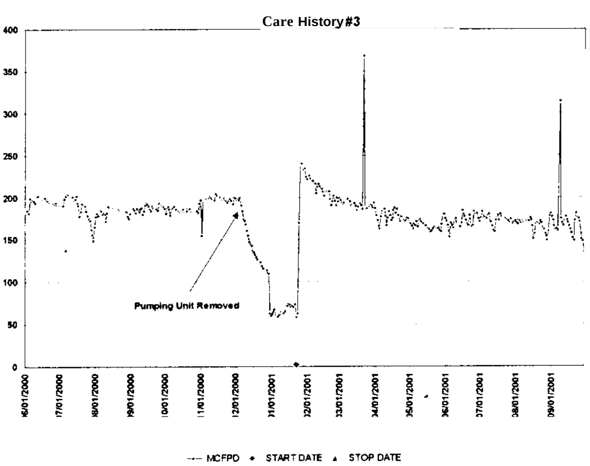

Figure 6 - Installation of Capillary String to Replace Rod Pump

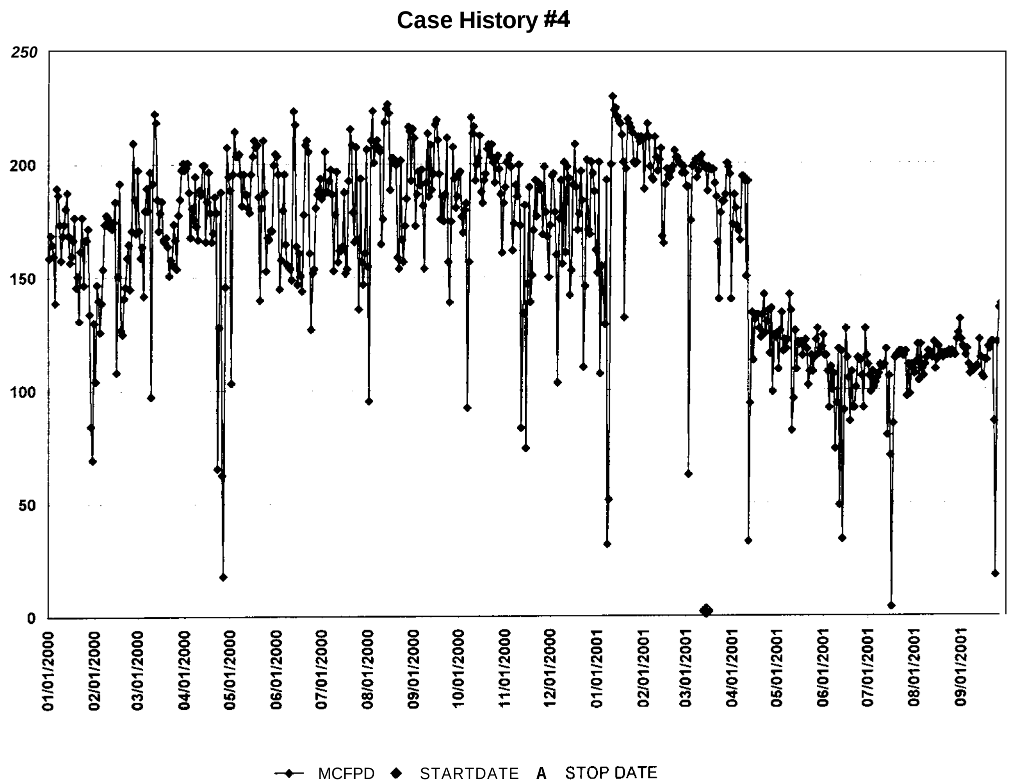

Figure 7 - Capillary String Installation to Repalce Compression

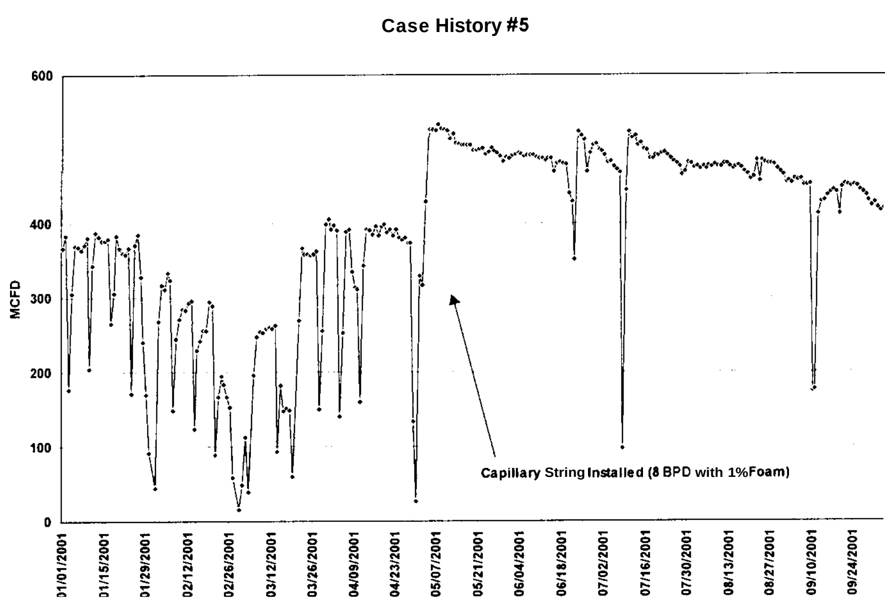

Figure 8 - Capillary String Remove Salt Deposition