3.5" SLIMHOLE PLUNGER LIFT SYSTEM USED IN THE WAMSUTTER DEVELOPMENT ASSET IN GREATER GREEN RIVER BASIN, WYOMING

Bruce Gerrard, BP America
Bill Hearn, Weatherford Artificial Lift Systems

ABSTRACT

In order to keep capital cost down in tight gas fields, the slimhole 3%" wellbore was developed. Due to the large pipe diameter, high line pressure and low rock permeability, liquid loading becomes an issue early on a wells life cycle and, in most cases, liquid loading is immediate upon first delivery.

3%" plungers have proven to be an effective method for deliquification of the slim hole wellbore utilizing the larger-cross sectional area to effectively push the plunger and accumulated liquids up the wellbore. In comparison, using the Foss & Gaul Calculation, the 3%" plunger can operates with a lower differential pressure across it than smaller tubing sizes.

The 3%" slimhole plunger has been successful in restoring production to the original decline curve or eliminating the hyperbolic decline recognized when liquid loading occurs. 3½" plungers are currently pushing the existing fluid lifting limits and new 3%" plunger technologies such as freecycle plunger lift systems are under evaluation.

In this paper the authors will describe the process of evaluation that was used and provide details of the operational problems that were encountered and how they were handled. They will go on to provide production data for several case study wells that illustrate the effectiveness of the plunger lift system and its close adherence to the performance predicted in the evaluation process.

INTRODUCTION

BP's Wamsutter Asset resides in the Green River Basin in Southern Wyoming (see Fig 1 in the attached list of illustrations) and comprises a total of some 650 wells from which gross production is currently approximately 204 MMCFD. The vast majority of the wells are drilled as slimholes that are completed with 3-1/2" tubing as production casing. Production is from the Almond and Lewis formations that exist at depths ranging from 7000' to 10,500'. The gross production interval ranges from 350' – 1000' and the tight gas formation is characterized by porosity in the range 8-14% and permeability from as low as 0.001 md up to 1 md. The gas production rates vary from 30 MCFD to as high as 3 MMCFD with accompanying liquid rates ranging from 10-150 bbls/MMCFD. The gas rate differences are due in part to the relatively high line pressures at each well, which can fluctuate from 325-550 psi. This situation has a major effect on the production characteristics of each well and on the artificial lifting required to remove fluid build up in the production casing.

HANDLING THE LIQUID LOADING

The Wamsutter project presented some unique challenges and required a defined strategy for decline and depletion in order to maximize production while handling the increasing liquid outflow. Several different solutions to the problems associated with liquid loading were considered, as follows:

- Installation of 1-1/4" coiled tubing to increase the gas velocity above the critical flow rate either up the annulus or up the coiled tubing
- The use of tubing flow controllers designed to keep wells flowing above the critical velocity of the coiled tubing while allowing excess gas to flow up the annulus
- The use of soap to foam the liquid, break down its surface tension and increase fluid height while lowering the density to reduce the gas required for fluid displacement to the surface
- Employing shut-in cycles
- Venting wells
- Installation of 2-1/16" tubing to increase the gas velocity and to add annular capacity that will help future plunger operations
- The use of 3-1/2" plunger lifts, which uses the near wellbore area as a capacitor to help lift the plunger and associated fluids

Previous deliquification practices were limited to 1-1/4" coiled tubing installations, with soap injection, venting and coiled tubing flow as the only options available to lift the liquids. The problem with 1-1/4" coiled tubing flow is that most wells are restricted to a maximum flow of 500 MCFD mainly due to the small tubing I.D. Larger coiled tubing sizes were tried, but due to the higher critical rate required for continuous liquid removal, these strings needed to be replaced with smaller coiled tubing. Operationally, coiled tubing sizes smaller than 1-1/4" were found to form hydrate easily and severely restrict the flowrate. The best overall coiled tubing size was found to be 1-1/4" with an upper limit at 500 MCFD and a liquid loading point of 230 MCFD.

Therefore, with 1-1/4" coiled tubing inside of 3-1/2" casing, a well will initially liquid load at 1600 MCFD. However, flowing the well up the coiled tubing will restrict the wells capability to 500 MCFD. This results in a liquid loading gap anywhere between 750-1100 MCFD. This liquid loading gap is illustrated in Fig ***2*** in the attached list of illustrations.

EVALUATION METHODS

Foss & Gaul

The characteristic which has the biggest effect on the efficiency of any method of lifting the liquids produced, is the fluid column weight for any given production rate, as this will influence the number of lifting cycles required to remove the liquids. The pressure required to lift a barrel of fluid is directly proportional to the cross sectional area of the tubing and, with the restrictions placed on production by the high line pressures, this is a critical factor. This is best illustrated by considering the Foss and Gaul equation for minimum plunger cycling pressure (see Reference 1):

$$Pcmin = [\{ Pp + Plp + (Plw + Plf) \times L\} \times \{1 + (D/K)\}]$$

Where:

Pcmin = Minimum pressure necessary to cycle the plunger.
Pp = Pressure to lift the weight of the plunger.
Plp = Flow line pressure.
Plw = Pressure to lift the weight of fluid per barrel.
Plf = Liquid frictional pressure loss per barrel.
L = Load size in barrels
D = Depth of tubing in feet.
K = Constant to show the relationship between tubing size and pressure losses due to friction.

The value of Pp is similar for all sizes and for evaluation purposes, a constant. Plp must be used for all sizes of tubing. The value of Plw is smaller for larger pipe due to the reduced hydrostatic head, similarly Plf is lower in larger pipe due to the tubing restriction. The value of K is much higher in larger pipe due to the reduced final pressure losses per foot of pipe. As a result the final term (minimal pressure below plunger) is lower in larger pipe. It can be concluded that it will require less pressure below the plunger to move the same amount of fluid in the largest pipe available.

The Six Point Evaluation

A 6-point evaluation was also developed (See Fig. 4 and *5)* for current and future conditions for the three well completion scenarios (3-1/2", 2-1/16" and 1-1/4"). It became necessary to develop a proper evaluation method in order to account for both the current and future well conditions as the well pressure declined. Evaluation in tight gas is very difficult as the inflow performance curves do not follow typical IPR rules and thus dependable IPR's in Wamsutter have been difficult to develop. Developing these IPR's required getting a realistic shut in bottomhole pressure as well as finding appropriate gradients to match the wells production to a proper curve. At this point, it was necessary to start from scratch to acquire the data needed to develop an accurate IPR could be developed for the current conditions. After developing this IPR, the future conditions were predicted assuming a certain amount of depletion. With the current and future condition IPR curves completed, the evaluation for all available types of completion and artificial lift were evaluated. Estimated production and well conditions were computed and a reference to the critical velocity as well as the flowing bottom hole pressure was made.

From this data the 6 point evaluation was born (figure 4), resulting in 6 important data points:

CURRENT RESERVOIR CONDITION

1) The well flowing up the 3.5” casing (preferably above critical rate for increased accuracy)
2) The well after 2 1/16” tubing was added to the well
3) The well after the addition of 1 ¼” coil tubing

FUTURE RESERVOIR CONDITION (DEPLETION OF BOTTOM HOLE PRESSURE)

4) The well flowing up the 3.5” casing. (Most likely assisted by 3.5” plunger lift).
5) The well flowing up 2-1/16” tubing (usually trying to make this point around the loading point.)
6) The well flowing up the 1-¼” coil tubing.

With each of these points, there is an associated flowing bottom hole pressure, a flow rate (both gas and fluid), a reference to critical velocity, an estimate of the Foss and Gaul minimal pressure necessary for plunger lift (if well was below critical) and an estimate of the cost to get to this point. All of this data was then used to establish the economic viability of the project.

This data was then compared to the decline curve to get an idea how long a time frame we were looking at until the future conditions would exist and we could ultimately make an estimate on incremental and payout period. The ultimate goal of the 6-point evaluation was to develop “intervention guidelines” which would separate each well into a group and make production optimization decisions easier. These “intervention guidelines” continue to be developed as plunger lift capabilities are explored

The evaluation results showed that the lowest bottom hole pressure is obtained by using a 3-1/2” plunger. This 6-point evaluation gave strong indications that the 3-1/2” plunger approach would be the most economic and yield the best results. Using this evaluation method and other tools such as IPR (see Fig. 6), VLP curves, daily production and well test data, a case was built for the use of 3-1/2” plunger lift.

PREVIOUS PERIENC

Another major contributing factor was the previous field experience that BP had in the Wapiti Field in Alberta, Canada where well characteristics were very similar. Many wells had 3-1/2” tubing and a packer set at similar depths to the Wamsutter wells and some 20 wells had been successfully produced with 3-1/2 conventional plungers.

Based on these evaluation results and the previous positive field experience, the decision was made to install 3-1/2” tubing plunger lift systems in those types of well in which its application was considered to be most suitable.

CASE STUDIES

There are three ideal well candidates for 3-1/2” plunger lift installations:

- High liquid rates (+50 bbls/MMCFD) combined with low daily gas rate (<500MCFD)
  - Unable to move this much fluid up coiled tubing due to hydrostatic pressure and friction
- Low liquid rates (<25bbls/MMCFD) combined with high gas rates (500-1800 MCFD)
  - No tubing restriction after plunger arrival. This falls into the liquid loading gap described earlier
- Low liquid rates (<25bbls/MMCFD) combined with low bottomhole pressure (<800 psi pressure buildup at the wellhead)
  - The pressure needed is unavailable to move fluid and overcome friction up coiled tubing. These wells sometime fall into the liquid loading gap

For evaluation purposes, to verify theoretically which of the possible lift installations would be the most effective, three wells were chosen to exemplify the three categories mentioned above:

- Wild Rose 13-3 with production rates of 70bbls/MCFD liquid and 350MCFD gas fitted the high liquid / low gas rate category
- Champlin 261 B-3 with rates of 19bbls/MMCFD liquid and 1.5 MMCFD gas the low liquids / high gas category
- Champlin 278 A-6 with rates of 30 bbls/MMCFD, 300 MMCFD gas and a 2 day shut-in bottomhole pressure of 800 psi, the low liquids / low BHP category

For each well production vs. time charts were constructed and the predicted depletion curve and the corresponding curve developed for the intervention with 3-1/2’ plunger lift were added to them. For Champlin 261 B-3, IPR curves were constructed, and an analysis of wellhead pressure swings and their affect on liquid loading with respect to critical velocity are visible (See Fig. 3). As can be seen in Figure 3, this particular well crosses the critical rate constantly as the pressure swings between 350 & 400 psi. Therefore the plunger cycles at 400 psi (below critical rate) and it rests in the lubricator at 350 psi (above critical rate).

For each of the three wells chosen above the production vs. time charts built up in the evaluation stages were continued after the intervention to install plunger lift. As can be seen in Fig.7, 8 and 9, the predicted path obtained in the evaluation process and the actual path resulting from the intervention showed close similarities, verifying that the evaluation techniques were valid. In each case the well intervention paid out in a period of 2-3 months as detailed in the same figures.

OPERATIONAL PROBLEMS

The plungers that were used were conventional brush type plungers which produce a "turbulent" seal, as opposed to conventional casing plungers which generally use a rubber sealing material which would not stand up to the high pressures inherent in the Wamsutter wells. Several operational problems were encountered as follows:

- Sand production causing the plungers to become stuck in the tubing. To counter this conventional brush plungers were used initially and replaced with "quick-trip''models when the sand cleaned up. It was important to avoid more than two non-arrivals in a row and to monitor this a SCADA system installation was made to track arrivals and signal or provide for shut down if two non-arrivals occurred consecutively. When plungers did become stuck, proper fishing techniques were defined and implemented.
- High liquid/gas ratios – it was important to avoid much after-flow below the critical velocity, again the SCADA system installation helped to avoid this and missed arrivals which were avoided by overcompensating initially during the clean up period.
- Problems were experienced with sweeping the wellhead gas dehydrators due to the high tubing over line pressure that was necessary to move large amounts of liquids. This was addressed by the use of automated chokes to hold flow to an acceptable maximum and then open up as the pressure bled down.
- A critical issue was controlling the wells so that the plunger lift system operated at an optimum level. This was addressed by the SCADA system, by the installation of plunger optimization software and the detailed training of BP engineers and field personnel.
- The absence of an annulus provided some difficulties in monitoring and control. This was countered by building additional pressure to hold the Foss and Gaul minimum pressure and using the near wellbore storage area for volume. In addition it was found to be advantageous to avoid logging off by running the wells in the "safe zone" until well characteristics were fully understood and the initial clean up completed.

CONCLUSIONS

The 3-1/2" slimhole plunger has been extremely successful, with none of the 40+ installations being removed for being unable to flow back against line pressure. **A** 100% increase has been seen with some wells gaining more than 800 MCFD over what was predicted without plunger lift. The average incremental gas gained has been around 250 MCFD/installation, with most wells paying out in less than 3 months. The maximum fluid lifted is over 120 bbls/MMCFD at an average daily rate of 200 MCFD, as is seen in the Monument 29-2. In some cases, the oil and water recovery has increased as much as 30%, recovering liquids left behind while producing below the critical rate. The 3-1/2" plunger is substantially cheaper to install over 2-1/16" tubing. The 3-1/2" plunger is far less restrictive and lifts more fluid than 1-1/4" coiled tubing and 2-1/16" tubing. Also, after the plunger is lined out, there is less operator time involved in operating the well.

The evaluations made in the early processes of deciding on the type of artificial lift and flow control best suited to the Wamsutter project wells, were borne out by the field results obtained. The application of 3-1/2" plunger lift will be continued accordingly, employing the established techniques of evaluation and the lessons learned to date.

ACKNOWLEDGEMENTS

The authors wish to thank BP America for permission to publish this paper.

REFERENCES

D.L. Foss and R.B Gaul; *Plunger Lift Performance Criteria with Operating Experience – Ventura Avenue Field*, API Drilling and Production Practice, 1966.

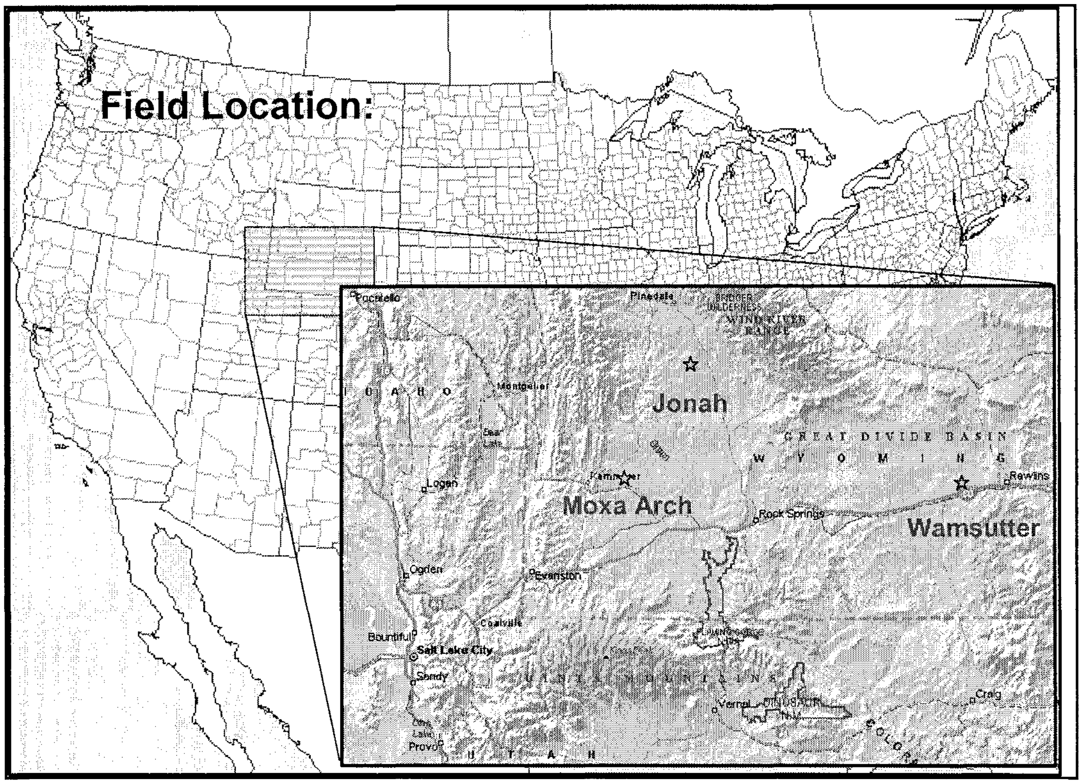

Figure 1 - Wamsutter Map

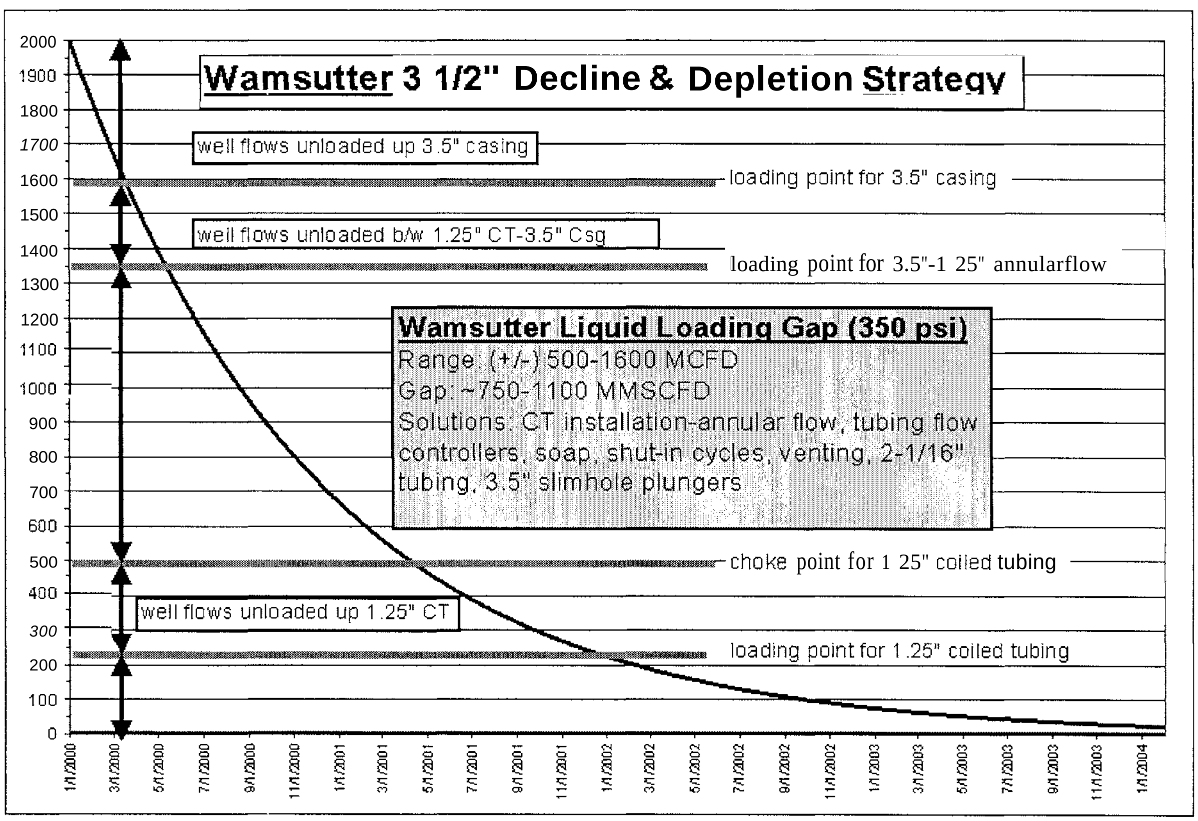

Figure 2 - Wamsutter 3-1/2” Decline and Depletion Strategy

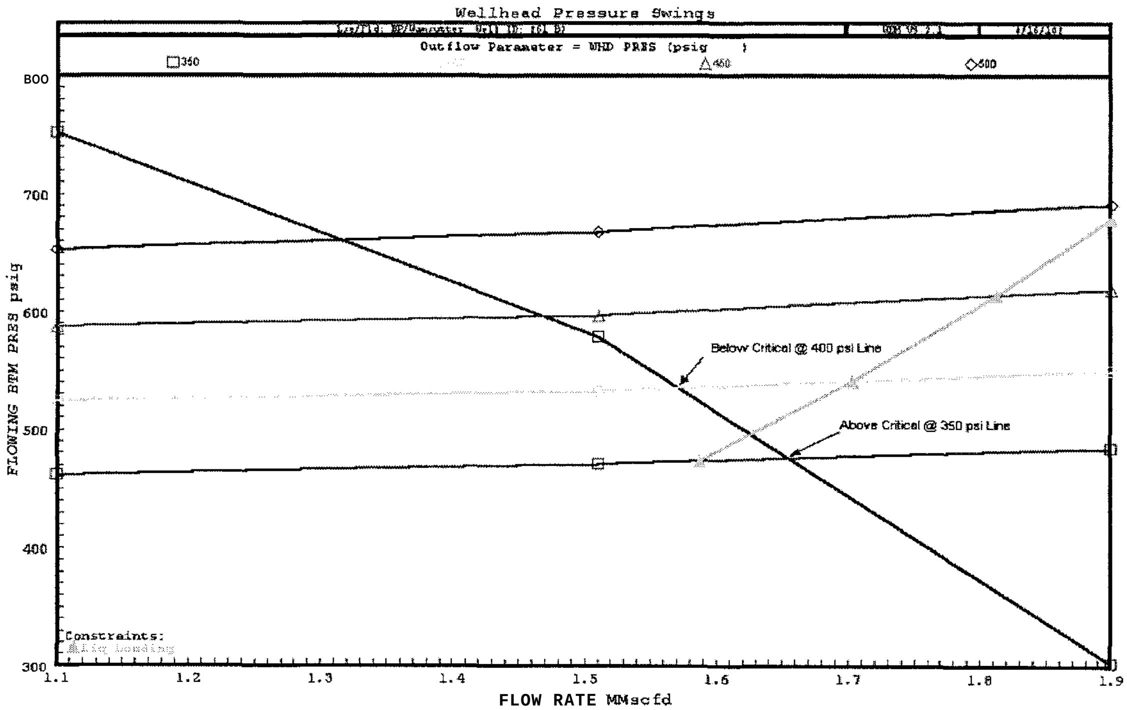

Figure 3 - Champlin 261 B-3 Wellhead Pressure Swings

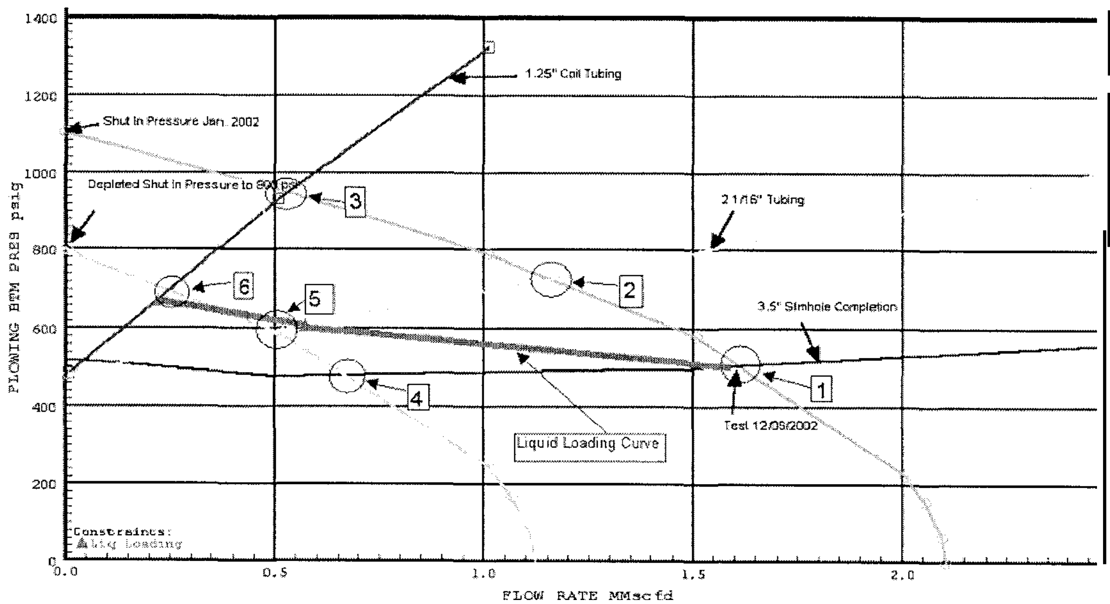

Figure 4 - 6 Point Evaluation

Current Conditons	3.5" Slimhole	2 1/16" Tubing	1.25" Coil Tubing
Reference on Graph	1	2	3
Shut In BHP (psi)	1100	1100	1100
Flowing BHP (psi)	505	728	956
Flow Rate (MCFD)	1649	1158	531
Liquid Rates (BBLS)	26	18.5	8.49
Reference to Critical Velocity	Falls Below on Line Pressure Swings	Above	Above
Foss and Gaul Calculations	693 psi to lift 3.7 bbls per cycle, 7 time/day	N/A	N/A
Pressure Availiable	Yes	N/A	N/A
Gas Necessary Availiable	Yes	N/A	N/A
Cost	$25,000	$105,000	$25,000

Future Conditions	3.5" Slimhole	2 1/16" Tubing	1.25" Coil Tubing
Reference on Graph	4	5	6
Shut In BHP (psi)	8M	800	800
Flowing BHP (psi)	482	589	701
Flow Rate (MCFD)	663	503	251
Liquid Rates (BBLS)	10.6	8	4
Reference to Critical Velocity	Below	Below	Above
Foss and Gaul Calculations	534 psi to lift 1.5 bbls per cycle 7 times/day	600 psi to lift 0.4 bbls per cycle 20 times/day	N/A
Pressure Availiable	Yes	Yes	N/A
Gas Necessar Availiable	Yes	Yes	N/A
Cost	$25,000	$105,000	$25,000

Figure 5 - 6 Point Evaluation

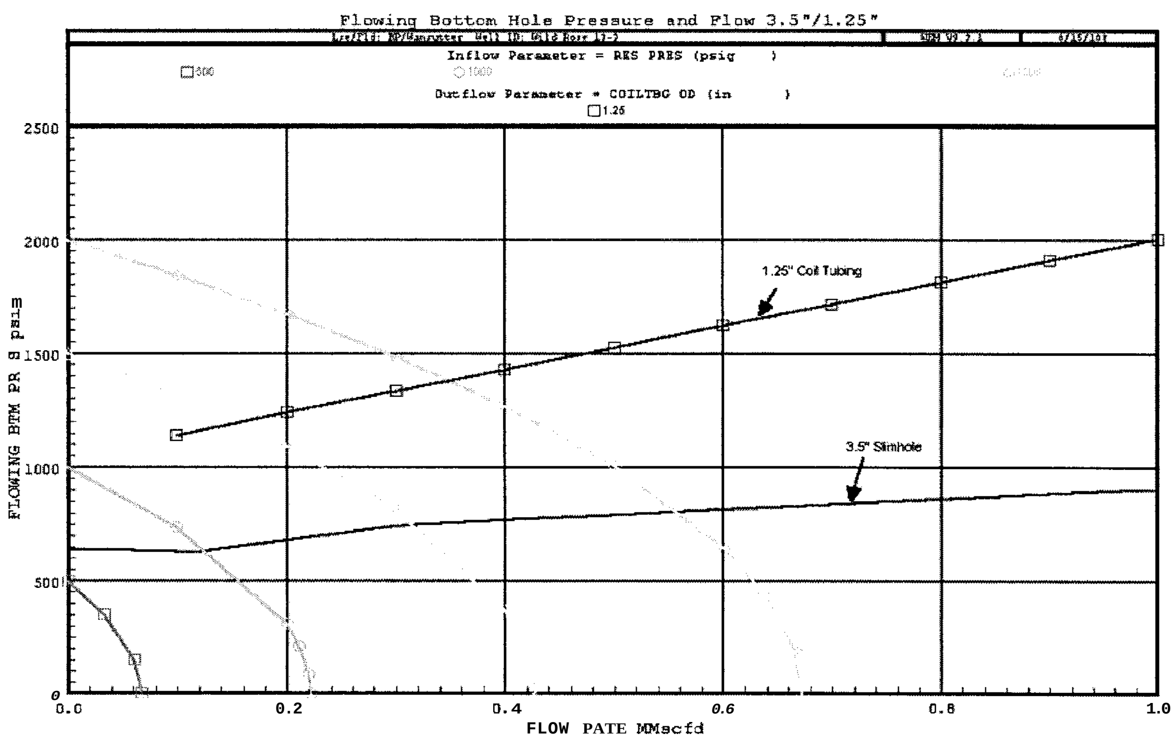

Figure 6 - Wild Rose 13-3

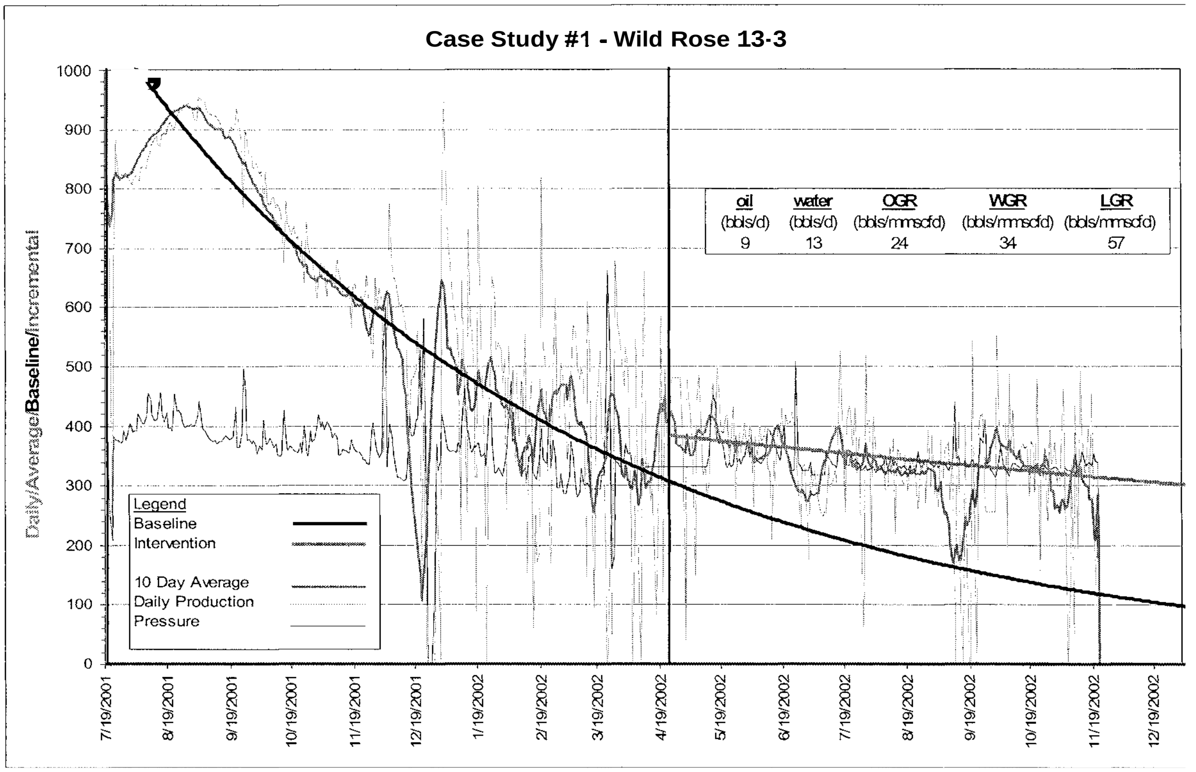

Figure 7 - Wild Rose 13-3 Production Plots

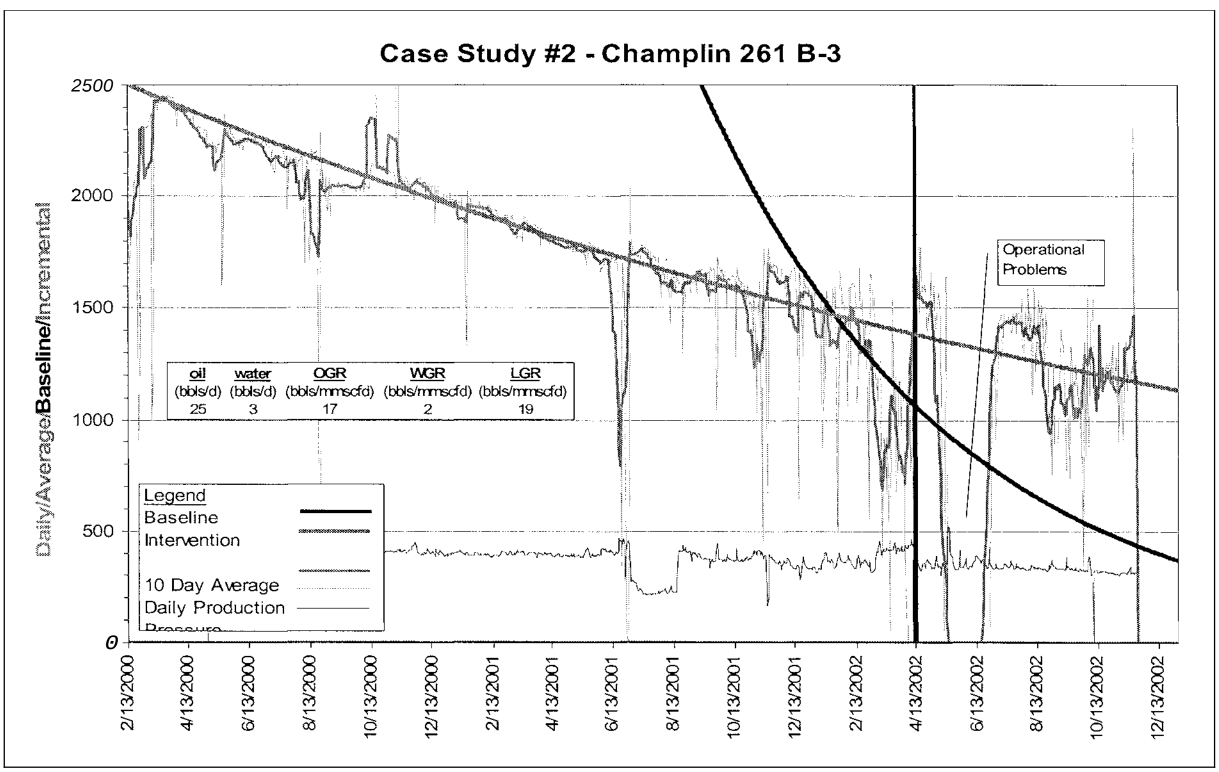

Figure 8 - Champlin 261 B-3 Production Data

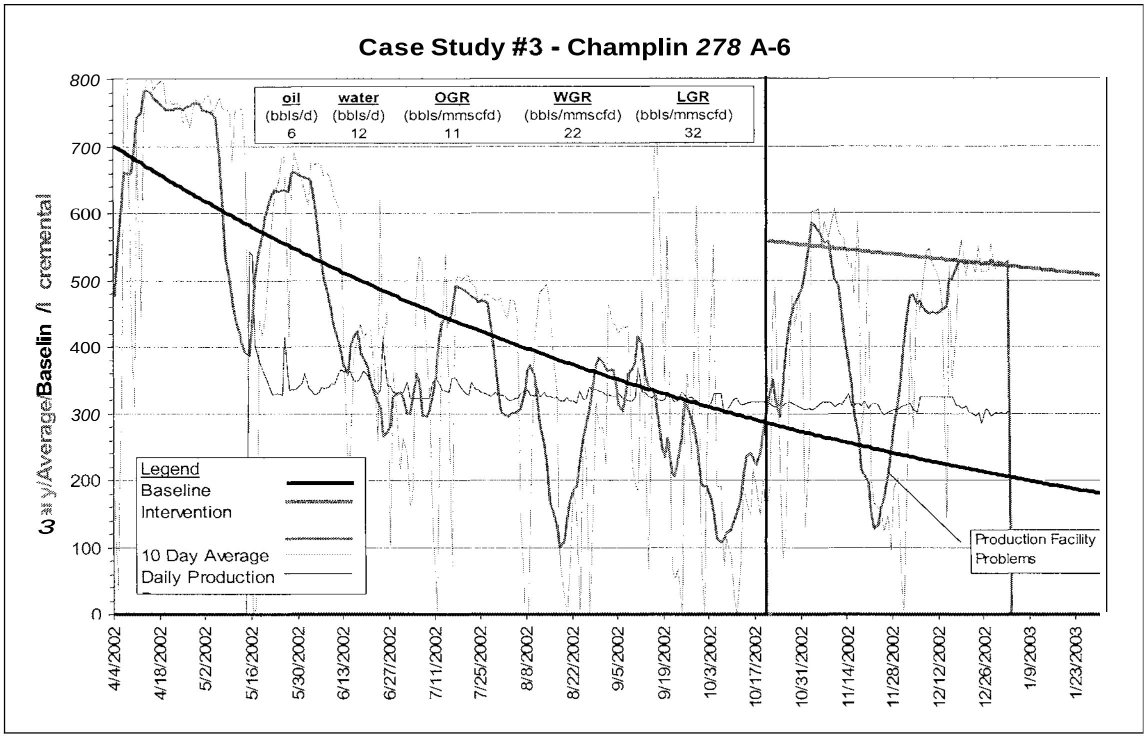

Figure 9 - Champlin 278 A-6 Production Data

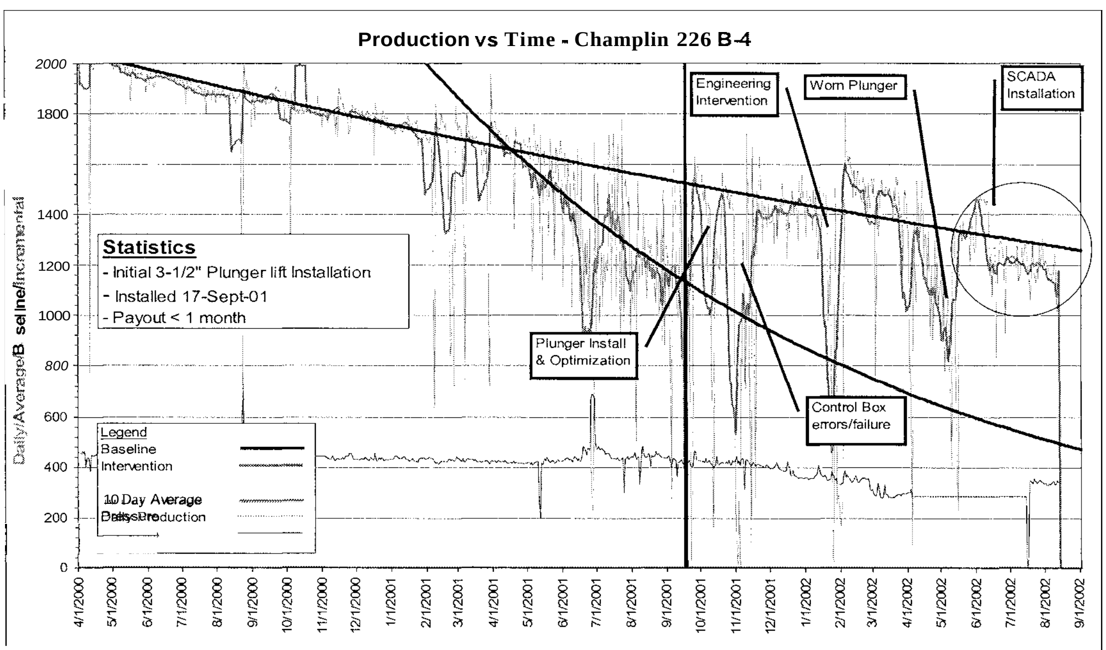

Figure 10 - Champlin 226 **B-4** Production Data