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Cyclic Steam Injection Pilot, Yacimiento Los Perales

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Abstract

This paper describes the studies, implementation and results of the first cyclic steam pilot project in the Los Perales Field located in the San Jorge Basin, in the province of Santa Cruz, Argentina. The presentation also includes a brief description of the usual steam injection methods; these methods are widely used in the on-going thermal operations around the world.

Preliminary studies showed the feasibility of injecting steam in intervals with heavy oil located in the Bajo Barreal formation at a depth of 3300 ft.

Some reservoir characteristics are:

1. Fluvial systems with multi-layer reservoirs mainly conformed by packages of four layers and three packages by well on average. The distance between these packages can vary from 262 to 328 ft.
2. Viscosity ranges from 300 to 10000 cp, which varies from well to well and layer to layer.

The pilot project consists of four new wells that were designed and drilled specifically for steam injection. After injecting the pilot wells we decided to stimulate an old reconditioned well with the intention of evaluating the possibility of stimulating this type of wells.

The surface equipment includes a 25 MMBTU/h steam generator at a pressure of 2500 psi.

The steam injection started at the beginning of 1999 in well 804, with the following characteristics:

1. Injection periods: 18 days with flow rate and pressure of 820 bbl/d (cold water equivalent, CWE) and 1800 psi (wellhead pressure, WHP). Steam temperature of 625 deg-F (wellhead temperature) and a steam quality of 65-70% at the sandface.
2. Soak Period: after the injection period, the well was shut-in for 1 week.
3. Peak oil and water production rates occurred within 1-3 weeks, being the initial response three times the primary production with a maximum rate of 27 m3/day in the well 804. The well produced almost a year before it reached the forecasted primary oil production. The history match had a good fit with the Gontijo & Aziz [1] analytical stimulation model that was prepared by the people of Repsol YPF.
4. The well is being prepared for the second cycle.

Throughout 1999, the rest of the wells were steamed, the individual characteristics are being analyzed in detail.

Introduction

When analyzing the secondary recovery process, the primary individual parameter to take into consideration is the mobility (permeability/viscosity) ratio. This serves to measure the ratio between the mobility of the displacing fluid (water) and the mobility of the displaced fluid (oil). For heavy oils, the mobility ratio values are so high that these projects are rendered antieconomic primarily because significantly higher volumes of water must be injected if results matching those from light crude oils are to be expected. It is therefore reasonable that for these crude oils any successful recovery technique must reduce crude oil viscosity in order to increase crude oil mobility. Heat application is the easiest method for reducing viscosities considering that the higher the viscosity the greater the relative viscosity reduction for a given increase in temperature.

Prior to presenting the steam injection pilot in Los Perales field, we will review the basic concepts involved in the two injection methods currently applied, i.e., cyclic steam injection (or more colloquially “huff and puff”) and continuos injection or Steam Drive.

A third steam injection method, i.e. downhole steam generation, has been studied and implemented in pilots since 1973. Attempts to implement this method on a commercial basis are still in progress.

Mechanism for oil recovery under cyclic steam injection

A typical “huff and puff” cyclic steam stimulation consists of three periods, i.e., injection period, soak period, and production period. During the injection period, the well is steamed at the highest possible injection rate (in order to reduce heat losses) for a time which, in the case of a pilot implemented in a new area as is the case with Los Perales, will provide an estimation of formation injectivity and injectivity variation with time (which depends on reservoir conditions). Steam injection rates usually match water injection rates though at lower differential pressures. Injected steam heats the rock and fluids around the well. It is channelized into the formation due to gravity segregation, preferential injection into high-permeability strata, and adverse viscosity ratios. Once the desired steam volume is injected, the well is shut-in for a given time. The duration of the shut-in or soak period depends on the amount of steam injected. This period is aimed at attaining partial steam condensation to heat the rock and fluids and bringing about a more uniform injected heat distribution.

During the injection and soak periods, there is a significant reduction in the original oil viscosity down to perhaps a few centipoises across the steam zone. Oil and water undergo a thermal expansion process, which is higher for the former, and due to sand pressurization free gas, if any, is forced to dissolve. Immediately before the well is brought on production, the steam-heated sand contains high-mobility oil, steam, and water. As pressure in the sand interface is lowered as a result of fluid production, several driving forces act to expel oil and other fluids towards the well, which may be pumped. If reservoir pressure is sufficiently high, the flow rate will be substantially higher than the original rate (cold production) just as a result of the increased oil mobility.

If the formation is considerably thick and involves a relatively few horizontal barriers, hot oil flowing to the well is dominated by gravity. As oil is lifted from the hot zone, it is partially replaced by oil flowing from the adjacent cold zone in the formation.

Mechanism for oil recovery under continuous steam injection

Continuous steam injection, steamflooding or steam drive, is an important oil recovery method which has proved effective even with light oils.

Continuous steam injection is analogous to water injection in that steam is injected into patterns.

In order to understand the mechanism for oil recovery during continuous steam injection, we will consider an inverted five spot flooding system consisting of four producers located in the corners and one injector placed in the central part. As steam is injected into the central well, an expanding steam zone is formed the extent of which can be determined by an analytical model. Hot condensate leaving the steam zone creates a hot waterflood effect ahead of the steam zone. Finally, while the condensation cools down to formation temperature (at least during the early stages of continuous steam flow) a cold waterflood takes place. Thus, the process consists of a steam zone, a hot water drive zone, and a cold water drive in the remaining pattern volume. Oil recovery is the result of the effective mechanism in each of these zones. Displaced oil forms an "oil bank" ahead of the steam-condensation zone. Prior to steam invasion, a given portion of sand has already been swept by cold water and then by hot water. These flows increase oil recovery. Residual saturation after steam sand sweep is highly dependent on the temperature reached by the zone and also varies with oil viscosity. This fact has been shown in laboratory models.

Cyclic Steam Injection Pilot - Los Perales Field

Outline of previous studies

Phase I

Involved an initial geological evaluation which included a report and structure maps.

Phase II

During phase II, simulations based on assumed petrophysical parameters and fluid properties yielded economically advantageous results.

Execution of an additional data acquisition program and implementation of a pilot aimed at increasing confidence in and improving the steam injection method are recommended.

Phase III

The first pilot well , i.e. 801, is drilled and well data are analyzed.

Then, the remaining pilot wells, i.e. 802, 803, and 804, are drilled.

Cores were taken from these wells and well data indicated that oil saturation, permeabilities and thicknesses were lower than assumed in Phase II. Well data also showed higher heterogeneity.

Final report

Production forecasts were made on the basis of core and drilled well data. Economic evaluations showed results lower than previously estimated during Phase II.

Steam Plant - General Characteristics

The general characteristics of the steam generator plant can be summarized as follows:

Water supply: Water from the Senguer River

River water salinity: 42 mg/l

Breather tank

The breather tank is used to provide a stable inlet water flow for the pump feeding the water treatment plant and prevent potential cavity.

Water treatment plant

The plant produces water suitable to feed the boiler. Sand filters are used to remove suspended solids larger than 5 microns. Afterwards, the water is circulated through ion exchange resins softening tanks where calcium and magnesium solids are removed. Water is then treated with caustic soda to set the pH to 7 and a O_2 scavenger for storage and subsequent feeding to the boiler.

Storage tank

Capacity: 500 m3

Boiler

Boiler capacity 25 MM BTU/h at 175 kg/cm2 (maximum working pressure)
Rated working pressure: 130 kg/cm2
Steam temperature at maximum pressure: 343º C
Steam quality: 80%. The reason for using wet steam is the high cost of removal of all solids in the water treatment plant to inject 100% steam. Therefore, we have to work with wet steam capable of carrying suspended solids.
At present, two procedures are used to determine steam titer. One, using enthalpy tables, and the other using boiler feeding water data, fuel heat value, generator discharge pressure, etc. Values are compared during injection.

Cost of generated steam

In order to determine the steam cost the following items shall be taken into consideration: electric power, gas, additives used in the water treatment plant, and their costs. In Los Perales, the cost of steam is 1.5 $/m3 (as CWE).

Characteristics of the reservoirs selected for injection

The pilot was designed to start using cyclic injection that could be changed to continuous sweep according to the response obtained.
The main reservoir characteristics are:
Pattern: irregular. Reservoir area: 6.3 ha
Well spacing: 280 m (average)
Formation: Bajo Barreal
Range of heavy oil depths: 1000 – 700 m (below ground level) made up of packages of 4 layers each (3 packets per well on average).
Average depth of better developed formations: 950 m (below ground level)
Average initial reservoir pressure at 900 m (RFT data): 85 kg/cm2
Average layer thickness: 4 m
Porosity: 28%
Permeability: 500 md
Viscosity: variable between 300 to more than 10,000 cp (to be determined) for live oil at reservoir conditions (results obtained from deep sample analysis).
Oil gravity: <10 to 17º API
Open layer test: variable from water with traces, 90 l/h to 500 l/h oil, with water cuts ranging from 10 to 30%. Non-mobile petroleum under reservoir conditions was also reported.

Pilot implementation
Well completion conditions

The 4 wells were drilled to be cased using 7” and 23 lb/ft N-80 casing. Drilling conditions did not greatly differ from the normal conditions prevailing in Los Perales. On the other hand, the completion program required variations specially in reference to cement composition. The silica percentage adopted was 36% with 24% of another additive such as Litefil being aimed at increasing cement compression resistance. Wells were cemented from bottomhole to wellhead. Deep wells as those drilled for the pilot require an excellent cement quality to secure normal injection and production operations. Successive cycles of heating and cooling subject the casing to stresses that only good quality cements can withstand.

Injection column

Fig. 1 shows the typical injection assembly used in the pilot wells. A thermal packer and a expansion joint were used. The thermal packer is used to isolate the annulus and therefore reduce the heat transfer to the casing. The expansion joint is used to allow longitudinal expansion of the tubing string during injection. Calculation for a packer set at a depth of 870 m with a steam temperature of 320º C, for example, shows a 3.4 m elongation while the maximum elongation allowed by the joint is 5.2 m
Insulated tubing was used, the O.D. is 4.5” and the I.D. is 2 3/8”. The annulus between them was filled with inert gas having a thermal conductivity lower than molecular nitrogen.
The object of using this expensive type of string is to reduce the heat transfer to the casing and therefore prevent the development of tensional stresses (if bare 2 7/8” tubing would have been used) that could exceed the casing yield point at pilot depths and given the viscosity of stimulated crude.
The cement quality logs run after injection showed that the thermal tools used preserved the proper cement condition. The useful life of the thermal tools could be evaluated after a longer number of cycles are completed.

The use of highly reliable elements to reduce the heat transfer permitted the conditioning of and successful injection into an old well.

Viscosity tests

Samples were taken at depth in three pilot wells. Samples were sent to the laboratory for analysis. One sample showing 37% water emulsion was rejected. It is considered that under those conditions the test results are masked giving a viscosity higher than actual.
Results show changes in viscosity from one layer to another layer and from one well to another. Viscosity vs. temperature curves were plotted.
Two types of determinations were made:
1. Sample at atmospheric pressure without gas: Haake Viscosimeter.
2. Sample at reservoir pressure with gas (practically negligible due to the fact that measured GORs were about 2 m3/m3). Ruska Viscosimeter.

In both cases, the data fit equation was used to determine the most appropriate viscosity value to be shown by crude at temperatures between 150 and 300º C. This was necessary because the maximum viscosimeter working temperature did not reach the minimum oil range temperature.
The test values obtained using both types of equipment for the same crude differ at low temperatures and are closer at higher temperatures. This is due to the fact that below reservoir temperature, fluids exhibit non-Newtonian behavior. In all cases viscosity diminishes with the increase in temperature until a value of a few centipoises is reached at 300º C. Fig. 2 shows the viscosity vs. temperature curve for a layer in well 801.

Well 804. Response to injection

This well is located in the pilot area where reservoir characteristics and layer thickness and continuity are more favorable. It began to produce from layer C-210, at 889 – 994 m, at the beginning of 1997. It was in production for a year and a half with continuos interruptions due to high crude viscosity. The net flow rate was below 1 m3/day. In July 1998 the remaining three layers making up the packet to be steam-stimulated were opened. The net thickness is 18 m with clay intercalations being 5m-thick on average. Primary production (cold production) was 8 m3/day for 5 months and then the well was converted into an injection well.
Steam injection in well 804 started at the beginning of 1999 with the following characteristics:
1. Injection period: 18 days with a 130 m3/day steam rate (CWE) at 125 kg/m2 wellhead pressure (WHP). Cumulative injection production was 2500 m3 (CWE). Injection was interrupted due to problems in surface facilities.
2. Soak period: After injection was completed the well was shut-in for one week.
3. Production period (Fig. 3): Initial response was 27 m3/d, three times as much the primary production. The well produced during one year until production rates were lowered back to cold production rates. Well cumulative production and production decline at the cold production time are in close agreement with the forecast method used and developed by Repsol-YPF.

The incremental accumulated oil was 3287 m3.

Produced oil/injected steam ratio

This is a very important thermal method indicator. It is identified with the letter m and relates the incremental oil produced in one cycle with the steam injected as cold water equivalent (CWE).
The range of m in successful thermal projects is between 0.5 and 5 (average of successive cycles).
The first cycle value for well 804 was 1.33.

Actual – forecasted production match
Gontijo & Aziz Analytical Model

Production performance of cyclically steam-stimulated wells can be derived by means of empiric correlations, simple analytical models, or numeric simulators. Empiric correlations can be extremely useful to correlate data and, within the same field, they can forecast injection responses. Nevertheless, if these correlations are used in situations fairly different from those in which they were obtained, large forecast errors will result. In the case of thermal simulation, it is based on the use of energy conservation laws, and the fluid flow is related to the pressure gradient through the empiric concept of relative permeability.

In addition, thermal simulation models are highly sensitive to rock properties, fluid properties, and geologic characteristics. As a great part of this information is often unknown, simulation is not a suitable tool to predict the response to cyclic steam stimulation in these cases.
Economic analyses during the Los Perales pilot study stage were based on the results of numerical simulations. As mentioned above, a lot of reliable information should be available so that predictions can be made by use of these methods. In the pilot case, for example, crude oil viscosities at reservoir conditions were 2000 cp and sometimes actual values were shown to be significantly higher.
Considering this, it can be pointed out that production forecasts for lower sands (as those flooded in well 804) proved highly optimistic - net initial rates were on the order of 90 m3/day with cumulative production in excess of 8000 m3 for the first one-year cycle.

As a result of the foregoing, we decided to prepare a simple analytical model to predict the response to cyclic injection. Several models have been proposed assuming, for instance, steam distribution in the reservoir, drainage mechanisms, whether hot zones are combined with cold zones before a new cycle begins, etc. Such models have proven effective in predicting the response to injection in certain reservoirs but have not worked in others. Boberg and Lantz, for instance, provides a good match in the fields where it was originally applied but does not work well in the heavy oilfields of California. Furthermore, all of them use scale factors by which the forecasted production is divided to match field data.

For the Los Perales pilot, it was decided to prepare the Gontijo & Aziz model. This model works well with dynamic reservoir conditions where such parameters as viscosity, density, transferred heat, etc. vary with time as the well continues to produce. Therefore, heat is transferred by fluid flow.

Fig. 4 shows the actual-predicted match. In addition to rock characteristics, fluids, steam injection pressure, injection days, the program also requires a temperature-viscosity curve which best matches the produced fluid.

According to several authors, analytical models do not seem to work properly but for a few cycles. This may be due to the complexity of the processes involved in cyclic steam injection. That is, sharp fluid flow and reversed heat, sensitivity of temperature to permeability, multiple and changing reservoir mechanisms which, coupled with the multi-layer nature of the Los Perales pilot, suggest the need for adjustment of existing models and even development of new models for successive cycles.

Results and discussion

The results obtained in this well during the first cycle are very encouraging and can be summarized as follows:

1. The response to stimulation is acceleration with a decline typical of cyclic steam injection, which allows to match field results with the available analytical model.
2. m falls within the range over which thermal methods prove economically successful.
3. According to forecasts, the second cycle must be lower than the first cycle. However, as reservoirs are depleted steam sweep efficiency must increase. Thus, several cases have been reported where the second cycle is higher than the first cycle. Another consequence of the foregoing is that injecting at lower pressure will result in a lower working temperature, which will in turn lead to improved wellbore conditions.
4. The forecast resulting from the model for four cycles, which is an average value in several thermal projects, is 11000 m3.

Performance of the remaining pilot wells

Wells 802 and 803

These wells were analyzed together because they share two characteristics in common, i.e., 4 injected layers and a high water cut as an initial response to stimulation. Taken on an individual basis, the parameters were as follows:

Well 802

1. Mean perforation depth: 980 m (below ground level)
2. Injection period: 18 days, with a flow rate and pressure of 125 m3/d (CWE) and 121 kg/cm2 (WHP), respectively. Injection is interrupted as the packer is found to be released.
3. Soak period: 16 days.
4. Production period (Fig. 5): Three months to date, with a maximum rate of 18 m3/day. As the water cut continues to be high, it is decided to enter the well for well intervention aimed at isolating water.
5. A layer is cemented and the well is put on production again. The well has been producing for 6 months reaching a peak at 29 m3/day. Then, production rate rapidly declines to a settled rate of 7 m3/day.
6. Well intervention operations are again carried out for well injection.

Well 803

1. Mean perforation depth: 885 m (below ground level)
2. Injection period: 30 days, with a flow rate and pressure of 125 m3/day (CWE) and 97 kg/cm2 (WHP), respectively. Cumulative injection production: 3600 m3.
3. Soak period: 20 days.
4. Production period: Three months to date, with a settled rate of 4 m3/day. As the water cut continues to be high, it is decided to enter the well for well intervention for the purpose of isolating water.
5. A layer is cemented and the well is put on production again. The well has been producing for 3 months to date. The water cut decreases from 80% to less than 10%. Net production rate settles at 5.5 m3/day.

Results and discussion

The experience gained with these two wells highlights the importance of knowing the reservoirs to be injected, particularly multi-layer reservoirs in which steam will tend to enter such areas providing more favorable conditions (high water saturation, low viscosity as compared with adjacent formations). Where layers are highly heterogeneous, specially as regards fluids, steam will not be uniformly distributed which will result in reduced reservoir heating efficiency. This, in turn, will lead to unnecessary injection costs, loss of time to complete well cycles and, most important, loss of production.

Well 801

Four layers in this well were injected for four days. Injection had to be interrupted due to low leak-off. It was known, prior to well injection, that the well was located very near a fault. According to logs, porosity was lower and the net pay was less developed than in other pilot wells. At the time of injection, there were problems with BOPs. All in all, it was decided to stop the injection operation. Now the well is on primary production (with production being frequently interrupted due to high viscosity problems) to reduce formation pressure and thus increase formation leak-off.

Injection parameters were as follows:

1. Mean perforation depth: 975 m
2. Injection period: 4 days with a 80 m3/day rate (CWE) at 140 kg/cm2 wellhead pressure (WHP). Cumulative injection production was 320 m3 (CWE). Injection was interrupted due to low leak-off.

Results and discussion

Low leak-off seems to be due to poorer formation development and low porosity rather than to reservoir pressure and fluid viscosity (deep samples yielded the lightest oil of the pilot). Injection in the remaining wells showed that field operations could be made more flexible in order to improve the injectivity. This would allow us to make a new attempt with the expectation to increase steam entrance.

Pilot extension. Injection into well 115

One of the most interesting expectations in the Los Perales field is stimulating old wells, that is, wells which were not drilled or completed for steam injection. To that end, a well located near the Steam Generation Plant was reconditioned. The primary requirement was cementing the zones underlying and overlying the only 10 m thick-layer which we planned to stimulate. When opened, the layer tested oil which could not be swabbed. This type of crude is known as Tar Sand in the literature (see Farouq here), that is, non-mobile oil at reservoir conditions (°API < 10 and Viscosity > 10000cp). In this case, the well was injected through partial steam venting so that fracture pressure was not exceeded throughout the early stages of the operation. Steam titer was slightly lowered in view of the excessive pressure build-up resulting from wellbore resistance, so that hydrostatic pressure could be developed and wellhead pressure could be relieved. After pressurizing the formation for several days, thus increasing the formation gradient [2], injection pressure was increased above fracture pressure and venting was almost eliminated (Fig. 6).

Injection characteristics were as follows:

1. Depth to perforation top: 700 m (below ground level)
2. Injection period: 18 days with a 96 m3/d rate (CWE) at 141 kg/cm2 wellhead pressure (WHP). Cumulative injection production was 1700 m3 (CWE). Injection was interrupted in an attempt to preserve casing condition.
3. Soak period: 20 days.
4. Production period: (Fig. 7). Two months to date. The initial rate was 14 m3/day of oil and the average water cut was 50%.

Results and discussion

Well reconditioning proved difficult due to the fact that auxiliary cementing was affected by casing condition, particularly the annular casing-formation condition. Furthermore, cement should not exist below and above the layer to be injected. In this case, thermal tools must work on a fail-safe basis. If thermal packer is released, for instance, injection must be immediately interrupted as the temperature rise which casing must withstand (J-55, K-55, N-80) exceeds casing yield point.

Based on the experience gained from an old well, developed zones can be assessed where the thermal project is likely to involve stimulating combined new and old wells.

Conclusions

Analyzing whether it is advisable to address cyclic steam injection projects in deep wells on a commercial basis calls for consideration of a number of factors. However, only those regarding quality of the reservoirs to be stimulated, lateral continuity, and oil saturation, will provide the final response as to the advantages or disadvantages of addressing such projects. The Los Perales case is further complicated as it is a multi-layer reservoir. In addition, it should be borne in mind here that each cycle involves pulling out the injection assembly and running in the production assembly. Obviously, such project indicators as development cost and lifting cost will rise considerably due to the high cost of drilling deep wells. For this reason, well spacing is wide and it is necessary to have a good lateral formation development. In addition, experience in Los Perales shows that deep geologic knowledge of the area is essential. Notwithstanding the foregoing, the risk that steam may not be uniformly distributed throughout the layers is high. Today, due to the availability of thermal tools, injecting deep wells such as our pilot well poses no major difficulty if wells are new. As shown by our experience, however, old wells must meet some essential requirements. As for production forecasting, numerical simulation is the ideal method. However, data acquisition is very expensive and complex particularly during the early stages of development. Field data from successive cycles will result in better-adjusted and improved models. A large-scale development will provide information for numerical simulators.

The extent of evaluating heavy oil volume in the pilot area as well as in other areas of the Los Perales field (at shallower depths, in some cases) is such that the feasibility to implement commercial scale projects should be established.

Acknowledgments

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SI Metric conversion

bbl x 1.5899	E-01 = m^3
psi x 6.8947	E+00 = kPa
ft x 3.048	E-01 = m
in x 2.54	E-02 = m
°F (°F-32/1.8)	E+00= °C

STEAM INJECTION COMPLETION

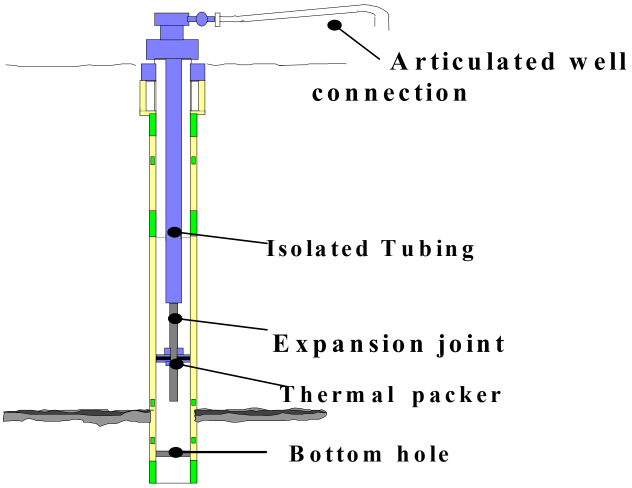


Figure 1

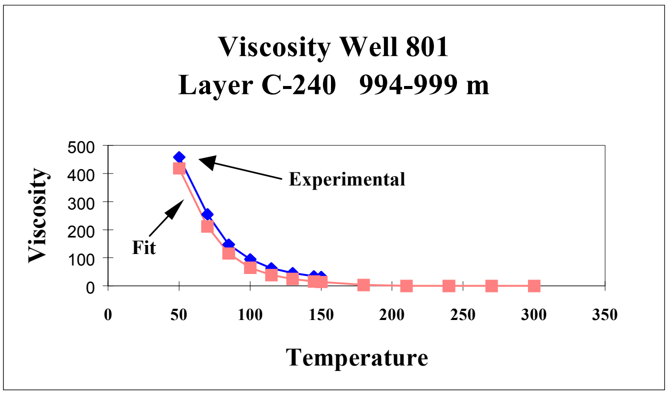
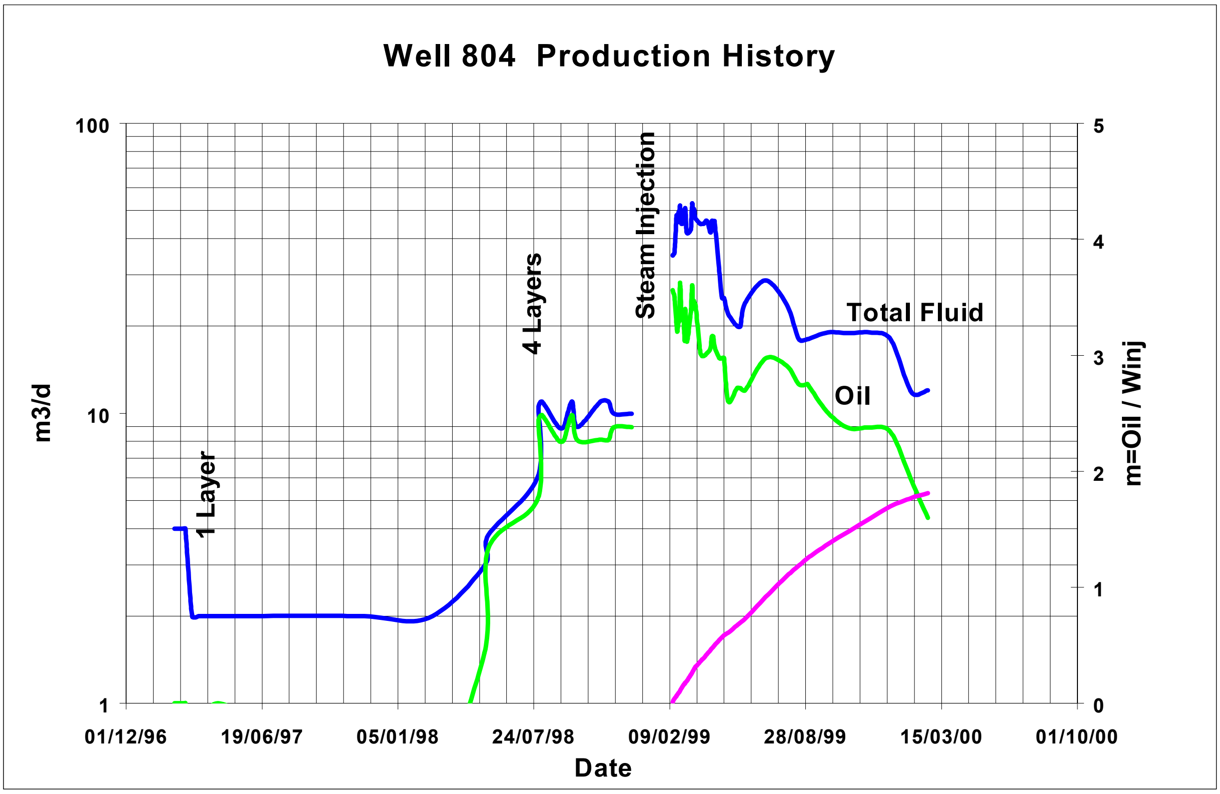


Figure 2



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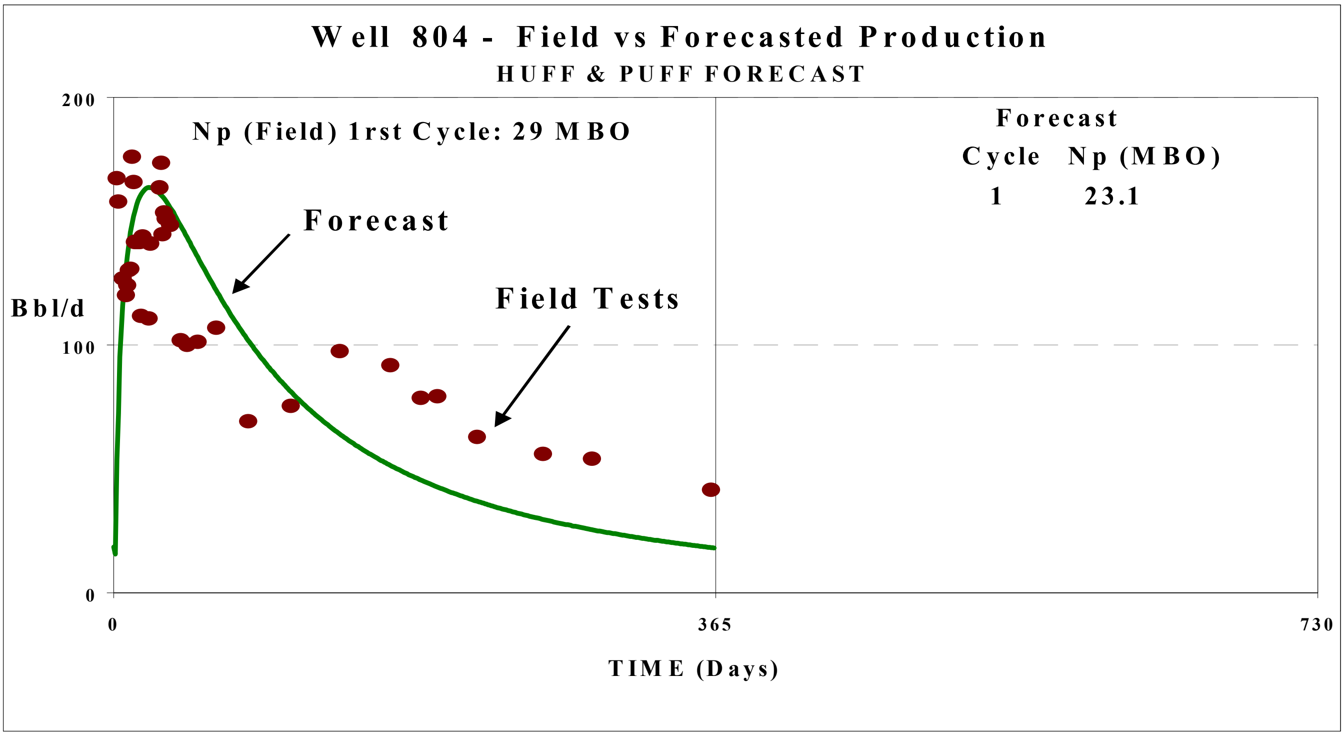

Figure 4

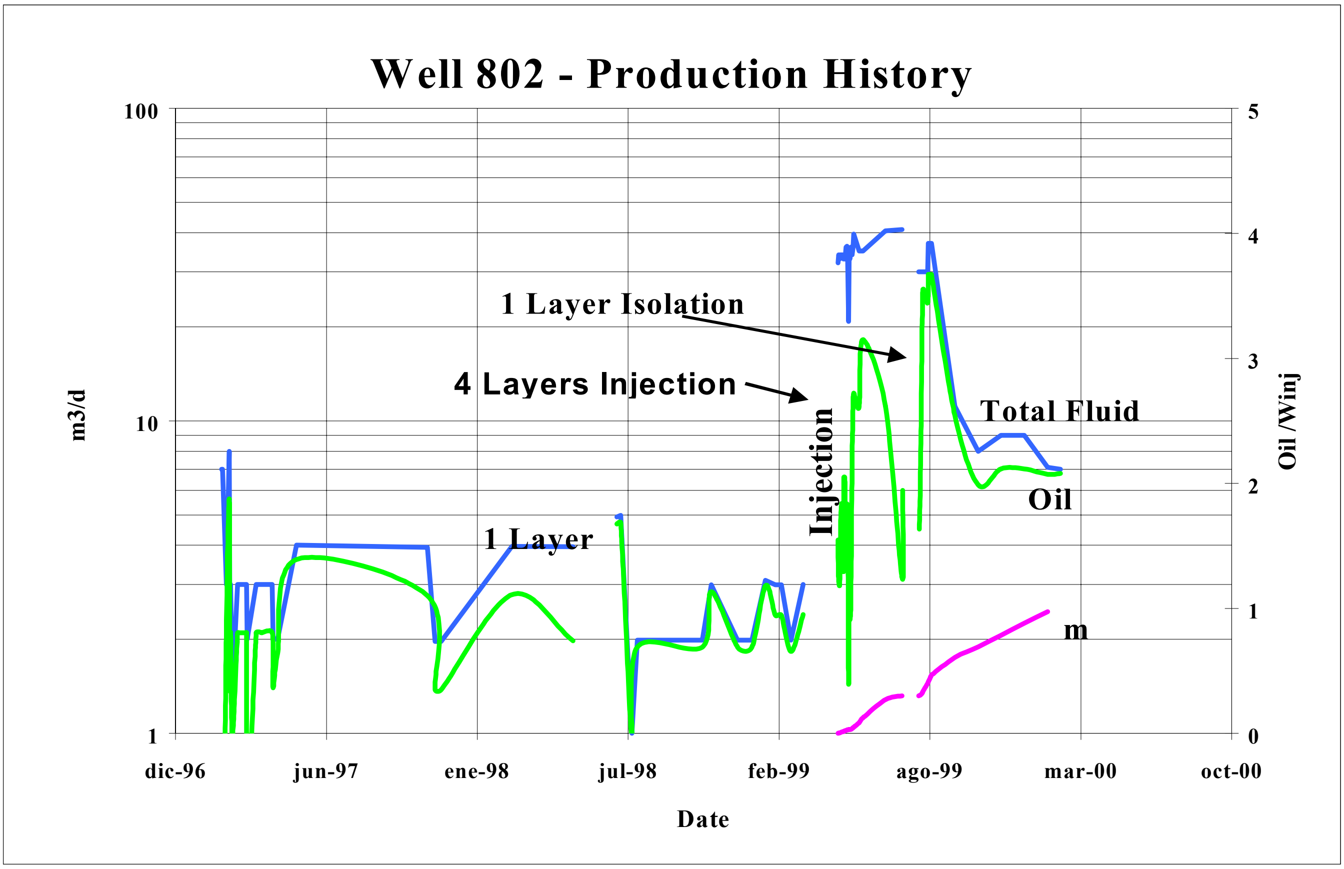

Figure 5

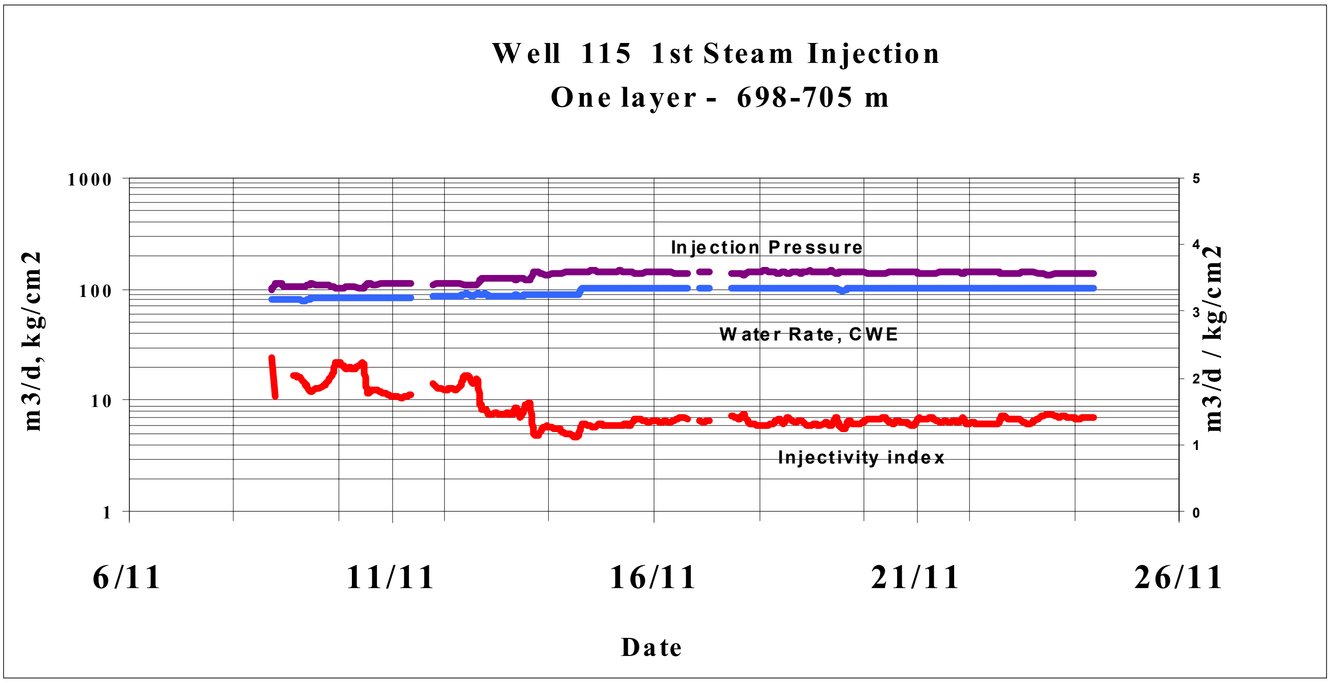

Figure 6

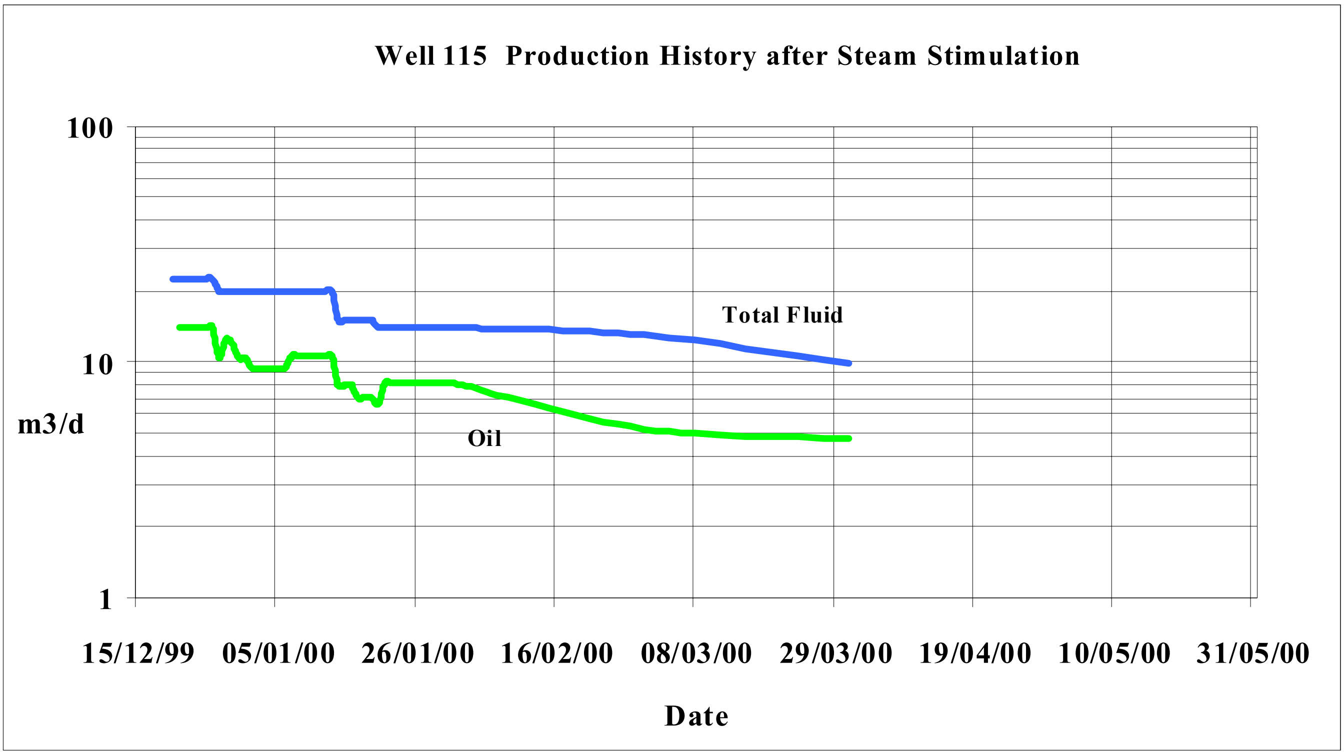

Figure 7