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Using Horizontal Well Technology for Enhanced Recovery in Very Mature, Depletion Drive Gas Reservoirs - Pirkle #2 Well, A Case History, Carthage (Lower Pettit) Field, Panola County, Texas

A.W. McCoy, SPE, F.A. Davis, SPE, J.P. Elrod, SPE, S.L. Rhodes Jr., SPE, S.P. Singh, SPE, OXY USA Inc.

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Abstract

Horizontal well technology has been successfully applied to exploit reservoirs involving thin beds, low permeability zones, naturally fractured reservoirs, high-cost areas, and zones of water coning. The Pirkle #2 well represents the first use of horizontal technology to enhance ultimate gas recovery in a very mature, low pressure zone in the Lower Pettit horizon at Carthage Field, Panola County, Texas.

The Pirkle #2 well was drilled to test the concept that a horizontal well could enhance ultimate recovery by lowering the final abandonment pressure in a very mature, depletion drive gas reservoir. However, numerous technical obstacles existed to the successful drilling and completion of an economic well in a 0.0308 psi/ft pressure gradient environment. This paper outlines the steps taken by OXY team members in planning and executing the project, as well as the results achieved from the Pirkle #2 well. Information gained from this project will help others to define appropriate screening criteria and provide guidance for planning/application of horizontal technology to other mature gas reservoirs worldwide.

Introduction

Carthage Field is located in Panola County, Texas as shown in figure 1. The field encompasses over 300,000 productive acres and produces from seven different formations, three of which, the Upper Pettit, Lower Pettit and Cotton Valley have produced 2.1, 3.8 and 2.0 TCF, respectively [1].

The productive intervals of the Lower Pettit member in Carthage generally consist of a series of porous and permeable, linear-trending, northwest-southeast oölitic beds [2]. The Lower Pettit pay zones, first discovered in 1936, occur between the depths of 5,900 and 6,100 feet, and originally contained 4 TCF of gas in place. The Lower Pettit reservoirs at Carthage cover over 267,000 acres, an area approximately 48 miles long by 24 miles wide, and have been produced by over 470 wells. A map of the net porous limestone thickness and the productive area limit is shown in figure 2. As of January 1996, there were 199 wells producing with a total average daily production of 34 MMCFD from the Lower Pettit [3].

Many of the older Lower Pettit wells have been abandoned due to low production rates (less than 60 MCFD). These wells were generally located in thinner pay intervals within the field. Due to the drilling of wells to the deeper Cotton Valley sands within the last 20 years, new log information has been obtained over the Pettit zone which has significantly increased our understanding of this formation. In OXY's portion of the field, several recent replacement wells drilled in thicker pay sections have resulted in substantial improvement in well deliverabilities over the older wells. It was this discovery that lead to the idea of drilling a horizontal well to improve ultimate gas recovery.

Reservoir Description

The Lower Pettit pay is described as an ooid coated-bioclast grainstone having variable intergranular primary and intra-granular secondary porosity. Variations in porosity are illustrated in a thin section photograph of the Lower Pettit as shown in figure 3. These dramatic variations in porosity and permeability are common throughout the Pettit pays at Carthage and they are important factors to consider in determination of well location.

A typical well log across the Pettit formation is shown in figure 4. The Lower Pettit member on OXY's acreage is divided into two main pay zones, whose in-house names are Frost "A" and Pirkle A-2. The Frost "A" is the major producing zone in the area around the Pirkle #2 well. General reservoir characteristics for the Lower Pettit are listed in Table 1.

In OXY's portion of the field, the Frost "A" pay zone is essentially a large depletion drive reservoir. Early in the field life a few gas wells along the southwestern edge watered out during the late 1950's and early 1960's. However, the aquifer ceased to encroach during the mid 1960's and this zone has basically behaved as a depletion drive since that time. Typical daily production for wells completed in this zone range from 200 to 450 MCFD.

Horizontal Well Design Considerations

General factors. There were several general reservoir characteristics important in the selection process for the Pirkle #2 well. These were:

1. *Sufficient reservoir volume* was needed to get enough incremental reserves to justify project economics.
2. C*ompetent rock* was required for air drilling and subsequent open hole completion.
3. *A moderate depth* (about 6,000 feet) was preferred due to fewer drilling complications and lower associated costs.
4. *Effectiveness of stimulation on the formation* was a major concern if needed to remedy any skin damage associated with drilling and prevent further damage during completion.
5. *Homogeneity of rock* having little or no imbedded shales and good lateral continuity of porous zones was critical.
6. *Good vertical permeability* (high K_v/K_h) was necessary for sufficient rates and ultimate recoveries.
7. *Medium range permeabilities* were essential to allow a good chance for a successful zone completion. Low permeability zones at low pressures might not be able to flow naturally given drilling skin damage, while in high permeability zones, vertical wells would drawdown the reservoir to similar abandonment pressures as with horizontal wells.

Other factors which were specific to the Frost "A" zone and favored selection of this project where:

8. *Large pore throat* sizes, some ranging from ⅛ to ¾ mm in diameter helped in the ability of natural flowback and cleanup of lateral section.
9. *The absence of faulting and good subsurface well control* was helpful during drilling operations by reducing the amount of steering required within the pay zone.

Major project obstacles. Negative aspects of drilling the Pirkle #2 well included:

1. *Extreme low pressure of reservoir*, estimated at 210 psia, caused serious doubts as to whether an economic horizontal well could be successfully drilled.
2. *Water disposal zones* located at 2,600, 2,900, and 5,200 feet complicated the drilling program and raised overall well cost.
3. *A low pressured gas pay zone above the objective* in the Upper Pettit located at 5,830 feet (150 feet above Frost "A" pay) posed potential differential pipe sticking problems.

Location selection. There were two important criteria in site selection; a thick reservoir net pay area and reservoir rock having high porosities. The locations spotted on the Frost "A" net pay isopach map shown in figure 5 met both criteria. The oölitic bars are oriented in a northwest-southeast direction. The north-south lateral orientation was preferred since it was felt there was greater chance to encounter higher porosity/permeability rock in this direction. The log of the adjacent Seagull Williamson #1 (Cotton Valley) well in figure 4 has 53 feet of net Frost "A" pay with uncorrected density porosities as high as 29%. The original plan called for the lateral to begin in top of the Frost "A" pay (as shown at 5,990 feet in the Williamson #1 log) and drill horizontally towards the bottom of the pay zone. Due to field well spacing restrictions, the final lateral location was oriented from west to east as shown in figure 5.

Incremental recovery calculations. The general idea for this project was a horizontal well would be able to draw the reservoir down to a lower abandonment pressure than the existing vertical wells for any given economic gas rate. The lower abandonment pressure would result in incremental reserves recovered over the existing wells. The puesdo steady state equation for a vertical gas well (in low pressures) in a circular reservoir [5] is given by:

$$q = \frac{0.0007027\ k\ h\ (\overline{P^2} - P_{wf}^2)}{T\ Z\ \mu\ [\ln\ (R_e/R_w) - .75 + S]}$$

The corresponding puesdo steady state equation for a horizontal gas well [6] is given by:

$$q = \frac{0.0007027\ k\ \ h\ (\overline{P^2} - P_{wf}^2)}{T\ Z\ \mu\ [\ln(R_e/R_w) - .75 + S + S_m + S_{CA} - C' + D_q]}$$

Due to its extended contact within the reservoir, the pressure drawdown between the reservoir and the wellbore is much lower in a horizontal than a vertical well. Under the assumption the final bottom hole flowing pressure is equal in the two wells, the horizontal wellbore will achieve a lower reservoir abandonment pressure for the same surface flow rate. Given the specific numbers applicable to our situation for the Pirkle #2 well as listed in table 2, and rearranging the equation above and solving for $\overline{P}$ the horizontal well abandonment pressure was calculated at 58 psia. Similar calculations for the existing vertical unit well revealed an abandonment pressure of 111 psia.

Initial Well Performance. Based upon the factors listed above and the estimated bottom hole pressure of 210 psia, several sensitivity cases were analyzed to determine minimum criteria needed for economic success. Initial gas flow rates versus several different effective lateral lengths were calculated and are shown in figure 6. An initial flow rate of 750 MCFD was considered the minimum benchmark for a successful project. Calculations indicated an effective lateral length of 500 feet would achieve this rate even with significant skin damage, assuming the well would clean up enough to achieve a sustained flow rate. If the well was to recover incremental reserves, the drawdown between the reservoir and bottom hole flowing pressure should be approximately 10 psi. This is in contrast to a 30 to 50 psi pressure drop observed in typical vertical wells in the field.

Drilling system options. The Pettit formation at Carthage has been traditionally drilled with a fresh water mud. Completion involves perforating with a casing gun with pre-stimulation skin damage in the range of +1 to +5. Foam acid jobs stimulate wells resulting in -1 to -2 skin factors after treatments.

The Pirkle #2 would be drilled with a traditional mud system through the straight hole section and angle build section to 90° in the zone of interest where casing would be set. The lateral would be drilled and left open hole. Four different types of drilling systems were considered for the open hole section of the lateral. The systems evaluated for the well were:

1. *Traditional mud system:* The lateral section could be drilled with a conventional mud. Removal of skin damage would be accomplished by foam acid treatment.

Benefits of this method included lower drilling costs due to a single mud system and the use of MWD/LWD tools that would help stay within the high porosity zones. Disadvantages included differential pipe sticking, significant formation skin damage and stimulation costs. It was felt the amount of damage from filtrate seepage and wall cake would be too great to overcome with stimulation at these low pressures.

2. *Calcium Carbonate system:* Sized calcium-carbonate, often used as a lost circulation material, was a viable alternative to conventional mud. The particular system considered had the ability to seal off the wellbore while allowing a very small amount of leakoff.

Benefits include a highly lubricious filter cake that is very thin and can be flowed back and removed with foam acid treatment if necessary. Concerns included fluid loss to the formation resulting in skin damage and water block and the difficulties associated with stimulation if required to produce the well in the event it did not flow back as intended. It was also a very expensive system.

3. *Foam system:* The lateral section could be drilled using a foam system. Foam acid treatment would be required in order to cleanup the lateral section.

Again, the chief concern was fluid loss and subsequent water block. In addition, there were only minor cost savings associated with a foam versus an air system or the calcium carbonate system.

4. *Air system*: Under this method, the lateral section would be drilled using air. This would result in the lowest fluid loss and skin damage to the formation of all the systems considered.

Advantages were a minimal overbalance due to air pressure rather than fluid hydrostatics, no fluid invasion and faster drilling rates. If needed, spotting foam acid could be done on a selective basis to remove any skin damage. Concerns included wellbore collapse, particle plugging (dust/mud into the pore throats), downhole fire, hitting a higher pressure isolated lens and higher cost associated with changing over to an air system. Steering tools would be required because conventional MWD and LWD systems would not function in this medium. The team felt the overall benefits from this design outweighed its disadvantages, and this system was chosen for the Pirkle #2 well.

Well Plan. The drilling plan called for drilling a 13½ inch hole to 2,000 feet where 10¾ inch surface casing would be set. A 9⅞ inch hole would be drilled to a depth of 5,428 feet. The well would be logged and a directional BHA would be run to drill the curve section at 10° per 100 feet to 90° at the top of the Frost "A" (6,000 feet TVD). At this point, 7 inch casing would be set to protect the Frost "A" formation from the zones above and facilitate drilling with a low hydrostatic in the lateral section. After cementing and drilling out of the float equipment, the mud would be displaced with water which in turn would be displaced by air. The planned lateral length would be a 6 ¼ inch hole drilled out to 2,000 feet with the possibility of extending out to 3,000 feet.

Drilling the Pettit with air would require equipment to handle under-balanced drilling such as a rotating head and blooey line. The lateral would initially be dry drilled with a 97% nitrogen mixture to eliminate the possibility of down hole fires. Nitrogen generating membrane units, capable of separating nitrogen from the air, would be used to achieve the mixture. Due to concerns about cuttings removal and particle plugging, the rig would be able to mist with foam additives to aid in cuttings removal if needed.

The completion would be relatively straight forward and would be done with the drilling rig. The lateral would be completed open hole. A 2⅞ inch tubing string would be run under pressure for a packerless completion. If needed, the well could be stimulated with foam acid, or unloaded using coiled tubing.

Actual Well Results

Drilling. The well was drilled to a total depth of 7,687 feet (6,015 feet TVD) with a 1,432 foot open hole lateral section. Surface casing (10 ¾ inch) was set at 1,985 feet MD. A 9⅞ inch hole was drilled down to the kick off point of 5,436 feet to start the medium radius build section. Initial mud weight was 8.9 ppg but increased to 11.4 ppg to accommodate salt water disposal zones.

The curve was initiated utilizing a down hole motor and MWD/LWD tools with an average build rate of 10.34° per 100 feet. The build section was completed at 6,252 feet MD (5,984 feet TVD) and 7 inch casing was run and cemented. After the casing string was set, handling tools were changed out to handle the 3½ inch drill pipe, and blooey lines were installed from the rotating head above the BOP stack. When the surface rig up was completed, the float equipment was drilled out using mud and then circulated out with fresh water. The water was displaced with air in stages, eventually drying the hole.

Due to the slow progress encountered while drilling the curve, the 9⅞ inch build section was ended at 6,252 feet MD at an angle of 84°, about 16 feet higher TVD than originally planned. Once on air, the build section was continued in the 6¼ inch hole until an angle of 89.4° was reached in the high porosity zone. In 8.5 hours, drilling progressed to a depth of 7,002 feet MD (750 feet of lateral) where air returns were lost. After attempts to regain circulation failed, the drill pipe was pulled out of the hole. As the drilling assembly neared the surface, cuttings were found caked around the drill pipe, and the well began flowing at an estimated gas rate between 1,500 and 2,500 MCFD. Surface shut in pressure was 160 psig. To continue drilling, 35 BBLS of stiff foam was pumped to kill the well and the drill string was run back into the hole. The foam was displaced out every 1,000 feet as the drill string was lowered to help unload the well and to resume drilling.

To prevent balling of cuttings around the drill pipe, foam mist was added to the air/nitrogen mixture. Drilling resumed, but at a slower rate, due to longer circulating time, misting, and jetting of the bit. After making 1,432 feet of lateral at a depth of 7,687 feet MD, wireline problems were encountered by the steering tool. Due to indications that additional lateral footage was only adding minor contribution to overall well productivity, the team members decided to stop drilling and complete the well. The drill pipe was laid down and the BOP rams were changed out to run tubing for completion. Figure 7 shows the final orientation of the lateral with respect to the high porosity zones in the Frost "A" zone. It is estimated that 1,200 feet were drilled in high porosity rock, considered pay.

A comparison between the estimated and actual drilling days per well segment is shown in Table 3. The estimated days to convert to an air/nitrogen system, to drill the lateral section and to complete the well were very close to actual results. The slow drilling of the straight hole and medium radius sections were attributed to high mud weights, oriented drilling assembly, hole drag and wall sticking.

Completion. Utilizing the drilling rig, the 2⅞ inch tubing string was run through the rotating head while the well was flaring. The final well completion schematic is shown in Figure 8. Two profiles were placed in the tubing so the well could be pulled without killing the well. Initially, a pump out plug was run on the bottom of the 'XN' nipple to prevent gas from entering the tubing string. This plug sheared after 15 joints were run. Utilizing slickline, a 'PXN' plug was set in the 'XN' nipple until the 'X' nipple had been run. Once the 'X' nipple was in place, the 'PXN' plug was pulled and a plug was set in the 'X' nipple. Tubing was run to a depth of 6,248 and hung off. The rig installed a recompletion spool and screw on flange with one tree valve. After the rig was removed and the surface equipment was installed, the 'PX' plug was pulled and the well was put on line.

Production. The well is currently producing at the rate of 1,260 MCF, 19 BBLS of condensate, and 8 BBLS water per day at a FTP of 25 psig. A daily production plot is shown in figure 9. Cumulative production has been 165 MMCF gas and 2,575 BBLS condensate in 150 days.

Utilizing Nodal analysis programs, it was determined the well would flow up the annulus (7 inch casing by 2⅞ inch tubing) at a surface flowing pressure of 50 psig or less. Since the gathering system pressure was 110 psig, a compressor was set to handle the volumes that were expected. If annular flow was possible, rates of 2,000 to 2,500 MCFD would be expected. With the compressor in place, several attempts were made to produce the well up the annulus. However, due to the high volumes of gas and liquids, large friction losses in surface equipment and high discharge pressures into the gathering system, the well tended to load up after a couple of days. Contrary to annular flow, the tubing was able to stay unloaded.

A flowing bottom hole pressure was taken after 97 days of production. Two pressure gauges were run in tandem to 6,050 feet MD (5,930 feet TVD). A flowing pressure of 143 psig was measured and the well was shut in to conduct a build up test. After one hour, pressure built up to 147 psig. At the end of three days, maximum record pressure was 152 psig with a build rate of 0.03 psig per hour. Results indicated that flowing pressure drawdown from the reservoir into the lateral was less than 10 psi. This pressure drop was in agreement with initial estimates and it appears the Pirkle #2 well will be successful in producing incremental reserves and should extend reservoir life by 12 to 15 years.

Conclusions

The Pirkle #2 well demonstrates that economic horizontal wells can be drilled in very mature gas reservoirs. Careful planning of reservoir and zone selection is critical for success. Preliminary post audit economics indicate the project is successful with a development cost of approximately $0.72 per MCF. Although existing vertical wells will recover approximately 50% of remaining gas-in-place, the Pirkle #2 well should increase this recovery factor to 75%.

Several modifications will be considered for future wells, such as configuration changes in rig and service equipment (bits, motors, etc.) to improve penetration rate and reduce drilling time. Well design options under investigation are smaller hole configuration, short radius designs and utilization of existing vertical wellbores. Other items being studied are use of coiled tubing for drill string and alternative mud systems for drilling the lateral section.

Even though the Pirkle #2 was a success, there are some aspects that warrant additional investigation. The first is the relationship between skin damage and increasing lateral length. The second is the effect that drilling medium selection has on wellbore damage and cleanup. Finally, more studies are needed to define what lower limits of permeabilities and pressures can be successfully drilled (horizontally) in extreme low-pressure gas reservoirs.

Table 1. General characteristics of Lower Pettit [2,4]

	Average	Range
Pay Thickness	15 feet	5 to 55 feet
Pay Porosity	18%	7 to 30%
Permeability	35 md	.6 to > 1,000 md
Water Saturation	17%	12 to 25%
Original Pressure	3280 psia	
Current Pressure	200 psia	150 to 250 psia
Condensate Yield	10 BBL/MMCF	8 to 20 BBL/MMCF

Table 2. Parameters used in horizontal flow equation.

q = 75 MCFD (economic limit)	μ = .0128 cp
T = 206°F = 666° R	Z = .996
R_w = 3 inches = .25 ft	k = 32 md
R_e = 2978 ft (640 acres)	h = 34 ft
L = 1000 ft (effective length)	$K_v/K_h = 1$
S = -6.908 (calculated)	$S_{CA} = 1.69$
C′ = 1.386 (defined)	$S_m = .5$
$Dq = 1.335 \times 10^{-5}$	P_{wf} = 35 psia

Table 3. Estimated versus Actual Rig Time (in days)

	Prognosis	Actual
Straight hole section	7	14
Medium Radius section	4	15
Air system conversion	4	5
Lateral section	5	6
Well Completion	2	2.5
Total	22	41.5

Nomenclature

- S = equivalent negative skin factor due to either well stimulation or due to horizontal well
- S_m = mechanical skin damage, dimensionless
- S_{CA} = shape related skin factor, dimensionless
- C′ = shape related conversion constant, dimensionless
- k = permeability, md
- h = reservoir height, feet
- $\overline{P}$ = average reservoir pressure, psia
- p_{wf} = well flowing pressure, psia
- q = gas rate, Mscfd
- T = reservoir temperature, °R
- μ = gas viscosity evaluated at some average pressure between Pbar and P_{wf}, cp
- Z = gas compressibility factor evaluated at some average pressure between Pbar and P_{wf}
- R_e = effective drainage radius, feet
- R_w = wellbore radius, feet
- Dq = gas turbulence factor, dimensionless

Acknowledgments

We thank Kirk Sparkman and Christopher Whitten, the geologists responsible choosing and guiding the azimuth direction and TVD location for lateral. Special thanks to our management for their support to this project.

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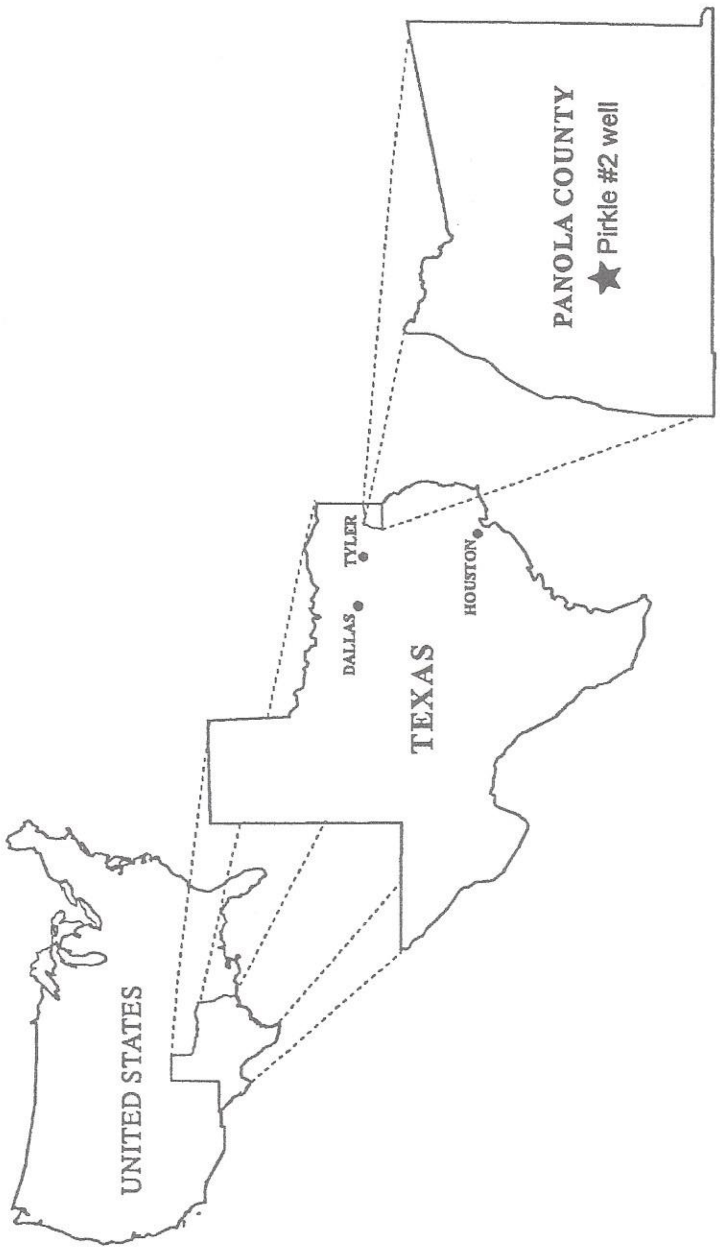


Figure 1. Orientation map showing location of Panola County, Texas

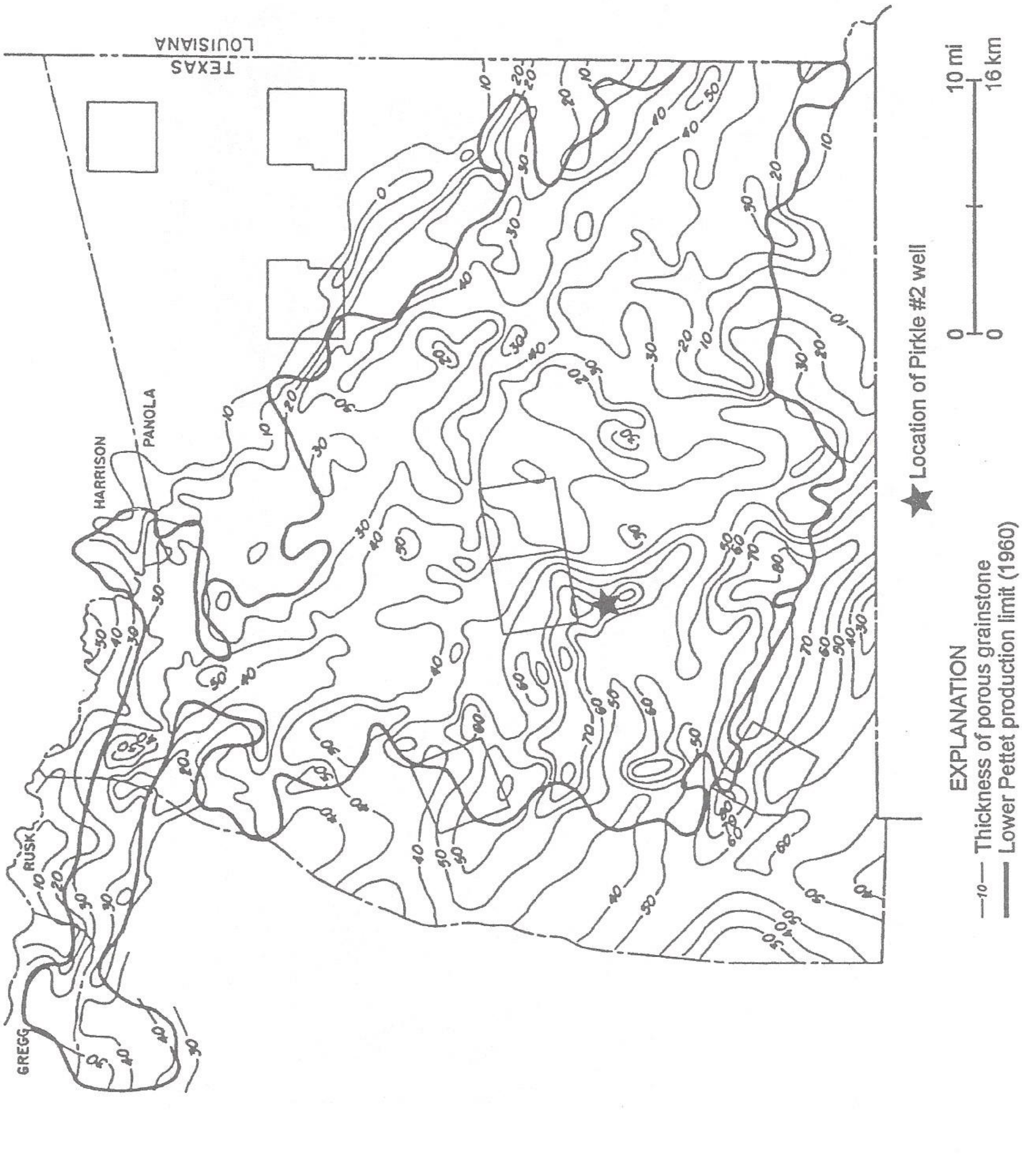


Figure 2. Isopachous map of lower Pettet porous limestone. Taken from Rogers (1968).

Figure 3. Thin section of lower Pettet (Frost "A") depicting intergranular and intragranular porosity.

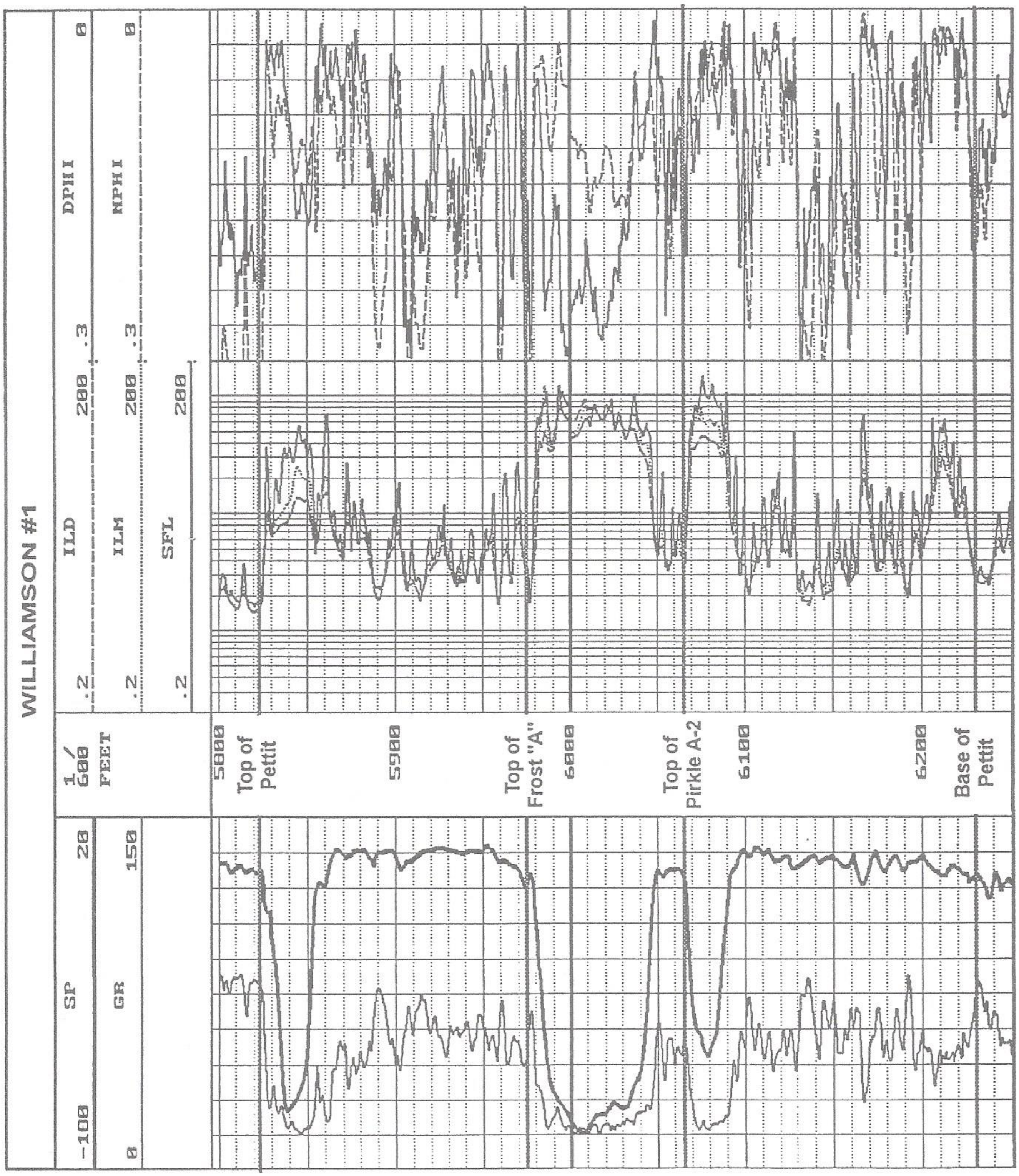


Figure 4. Log of Pettit section in Seagull Williamson #1 well.

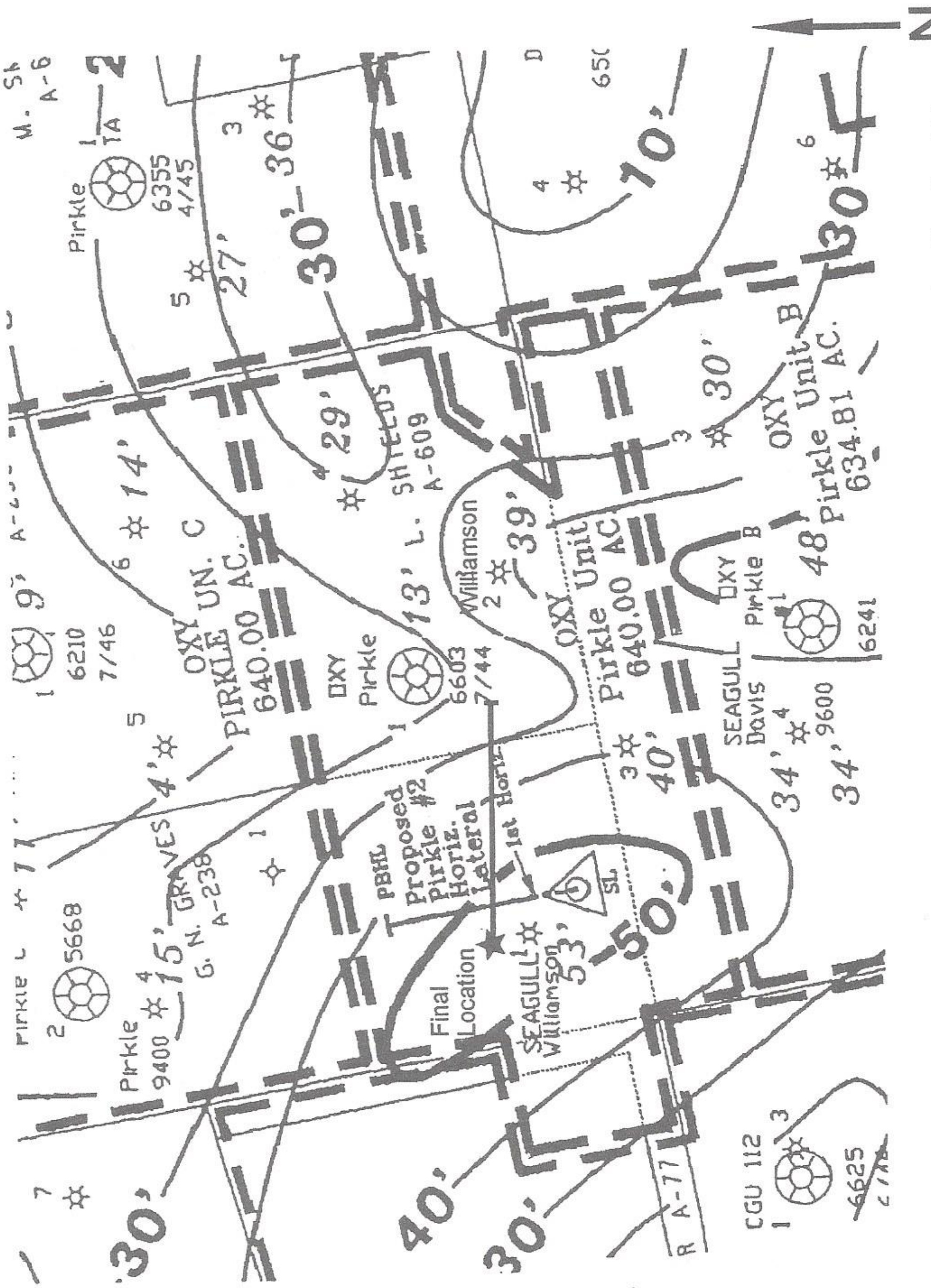


Figure 5. Net pay isopach of Frost "A" zone. Original planned location (Δ) and actual well location (★).

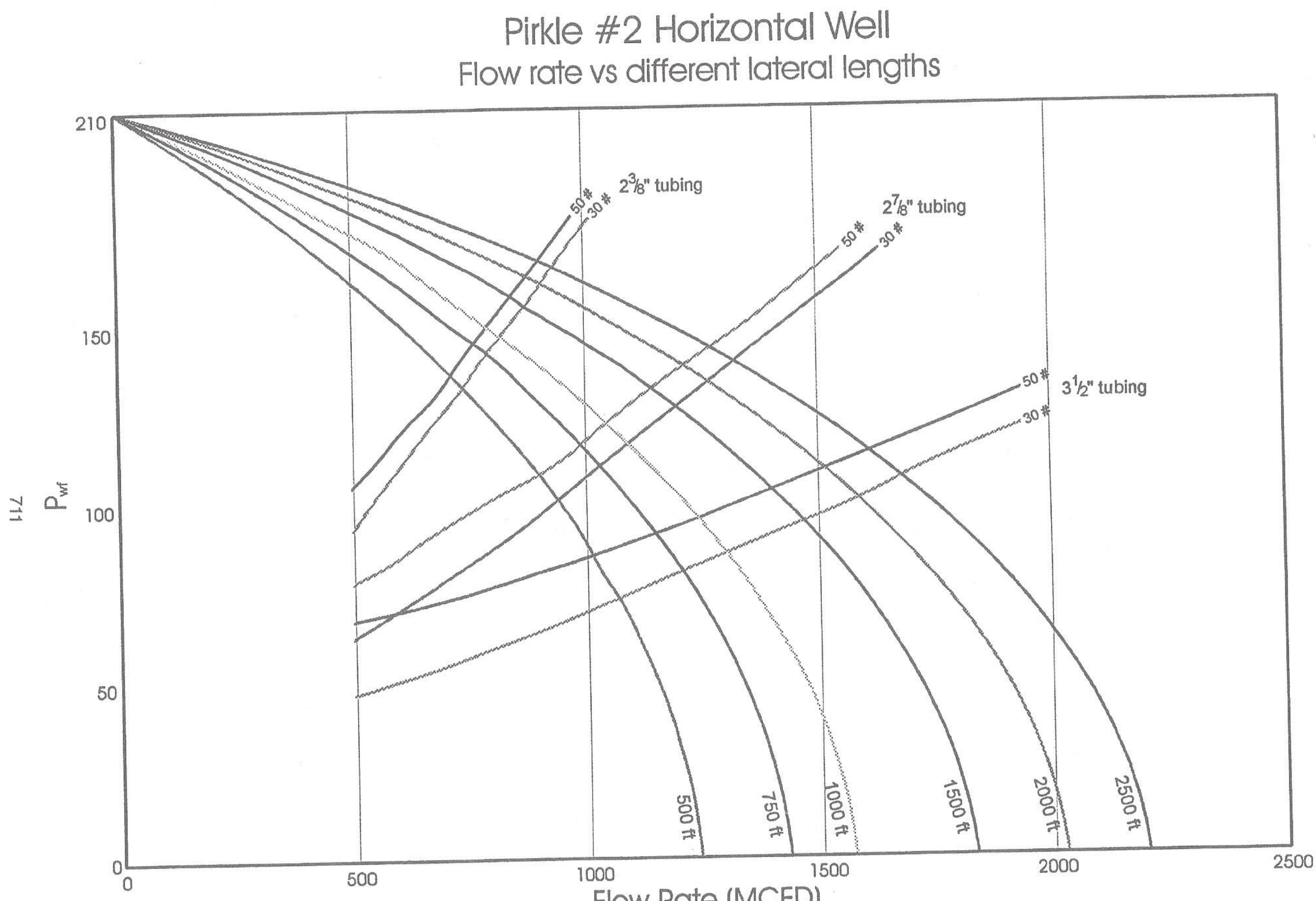


Figure 6. Estimated initial gas rates for different lateral lengths and tubing sizes using S_m=.5 and K_v/K_h=1.

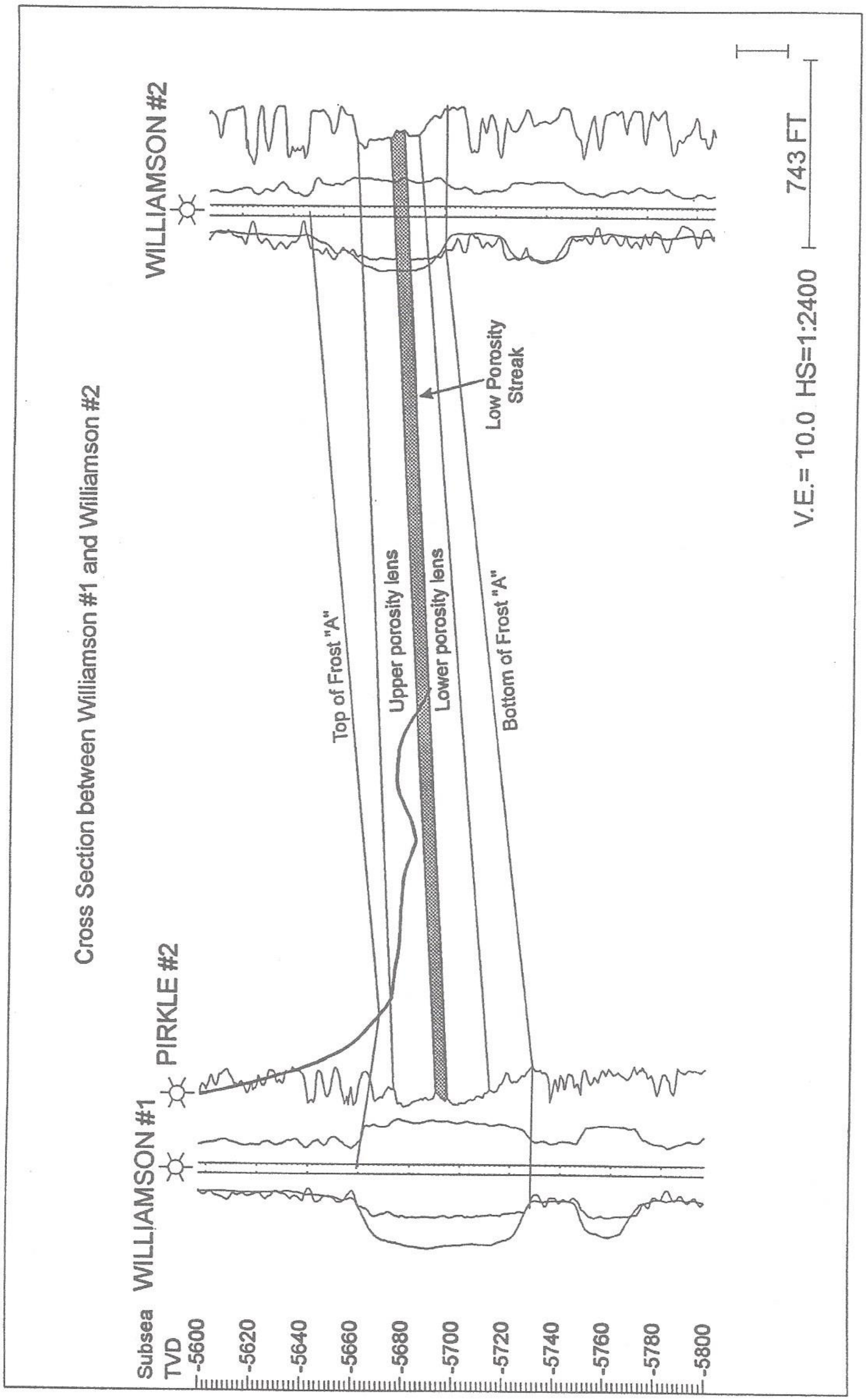
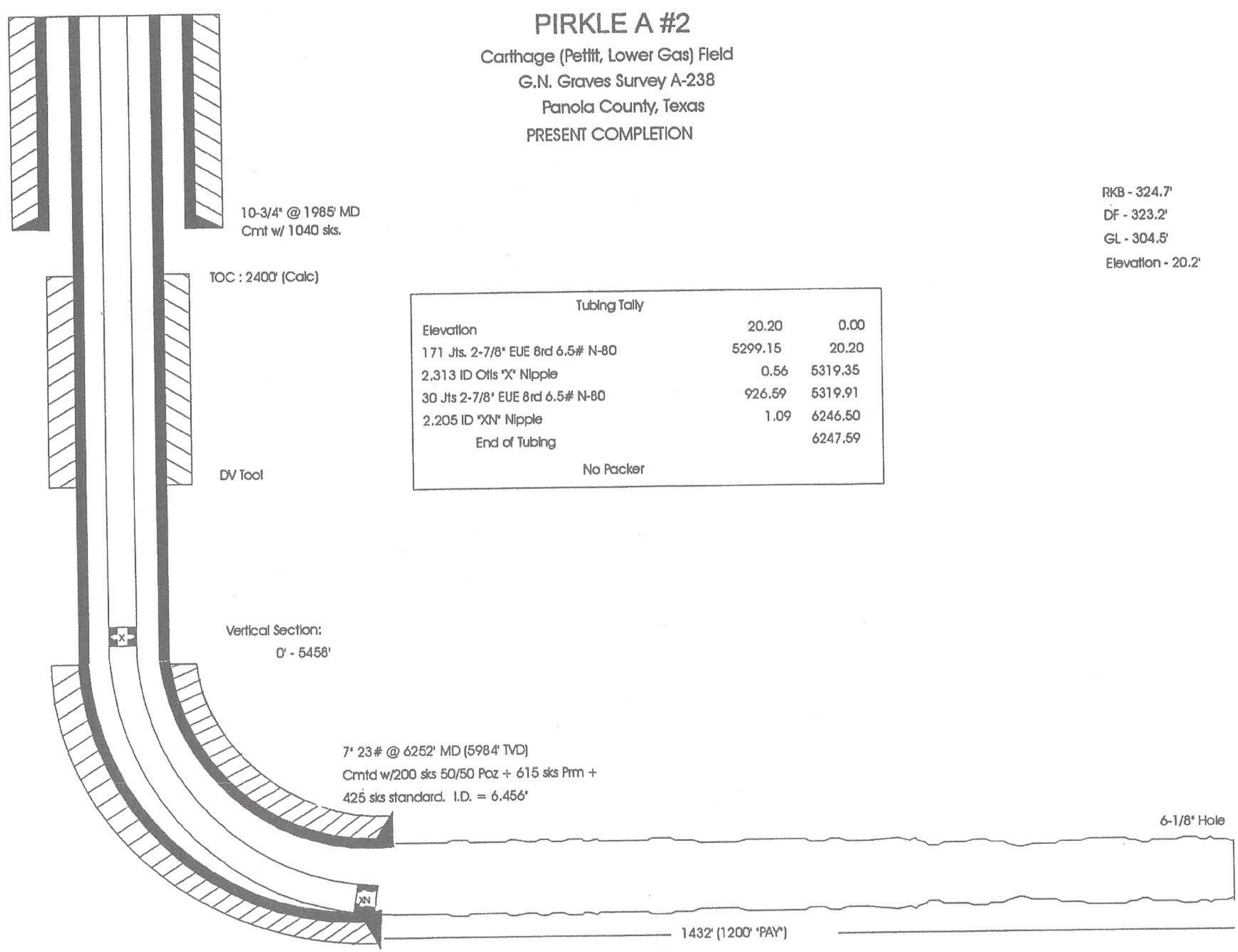


Figure 7. Cross section showing Pirkle #2 lateral location within Frost "A" pay zone.



Tubing Tally

Elevation	20.20	0.00
171 Jts. 2-7/8" EUE 8rd 6.5# N-80	5299.15	20.20
2.313 ID Otis "X" Nipple	0.56	5319.35
30 Jts 2-7/8" EUE 8rd 6.5# N-80	926.59	5319.91
2.205 ID "XN" Nipple	1.09	6246.50
End of Tubing		6247.59

No Packer

Firgure 8. Pirkle #2 well completion schematic.

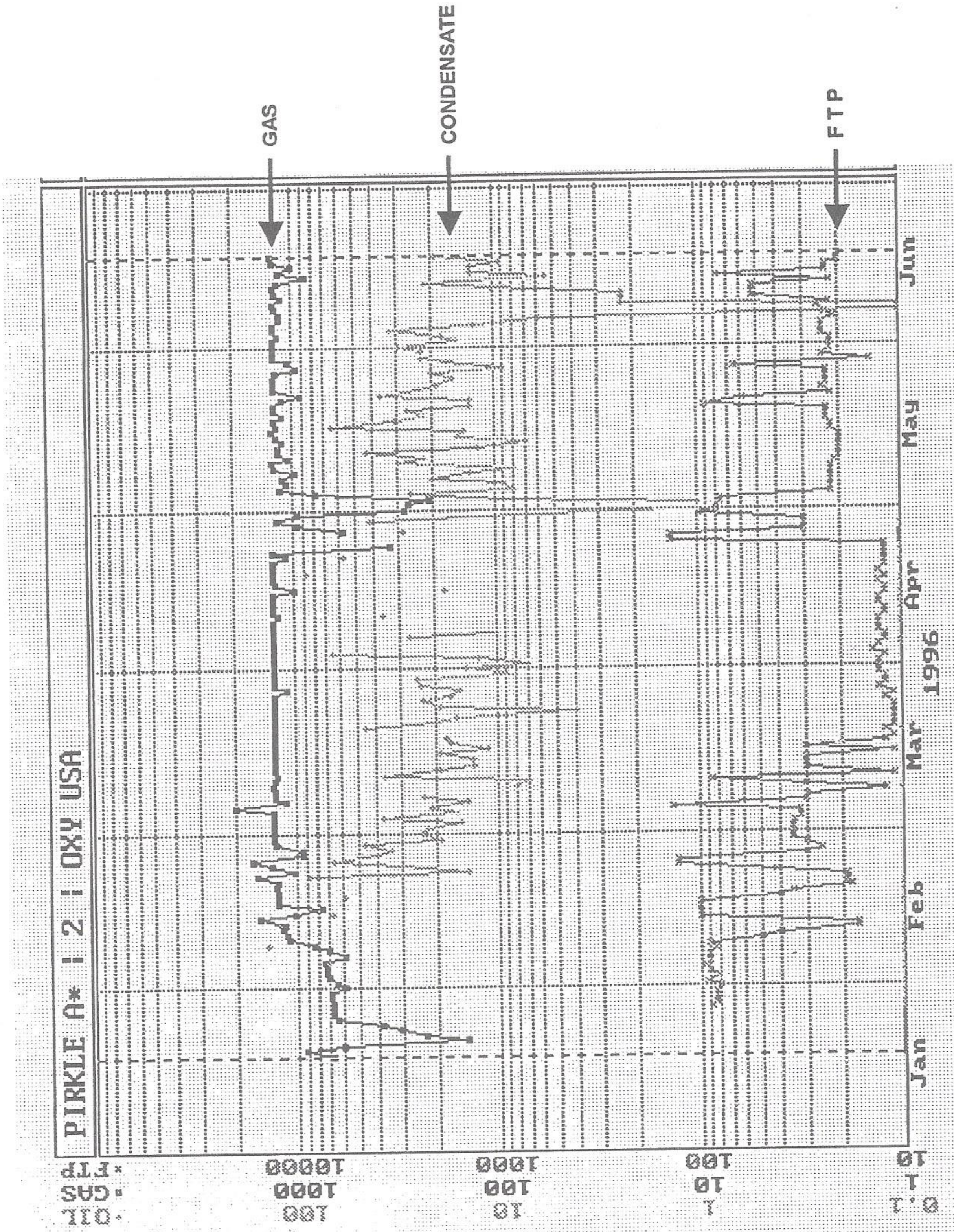


Figure 9. Daily production graph of Pirkle #2 well.