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High Performance Brine Drilling Fluid Proves Cost Effective in Eagle Ford Shale

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Abstract

In many areas of the Eagle Ford shale, lost circulation is a common cause of lost time and increased well cost. The preferred well design utilizes multi-well pads and relies on surface casing to protect fresh water reservoirs. Once surface casing is set, the production hole is drilled including all directionally drilled sections. This is typically called a "two string" design and can result in the lowest well costs when compared to other well designs with surface and intermediate casing (i.e. "three string" well plans).

In areas where production has occurred, depleted zones are commonly encountered in the Austin Chalk above the Eagle Ford where lost circulation of the drilling fluid results in excessive cost and considerable non-productive time (NPT).

A high performance brine drilling fluid (HPBDF) was developed as an alternative to conventional diesel oil based fluid (DOBF). The HPBDF has reduced NPT and drilling fluids costs in the Austin Chalk when lost circulation occurs. A successful system provides rates of penetration (ROP) and wellbore stabilities equivalent to or better than DOBF. Shale stability is a concern as the prolonged exposure of the Midway shale has proven to be problematic with water-based fluids. Detailed results from HPBDF wells in Gonzales and Fayette counties provide examples of the performance of the brine system. By using this system, losses of over 15,000 bbl of DOBF have been avoided on a single multi-well pad.

Introduction

A discussion on the shale formations encountered in this region will be followed by a description of a brine water based fluid that provides an economical solution to operator's lost circulation problems that are prevalent in this area. Compared to offset DOBF wells, considerable cost savings and time reductions are achieved.

Eagle Ford & Midway Shales

The Eagle Ford formation is described as a thin calcareous shale lying below the Austin Chalk and above the Buda limestone[1,2]. It is categorized in the Upper Cretaceous system and represents a major oil and gas unconventional resource. The formation is variable in composition but can generally be described as consisting of quartz, calcite and clays[2]. Geographically the area is best described as beginning in the northern portion of the south Texas plains and stretching north eastward into the north central plains running parallel to the coastal plains as shown in Figure 1[3].

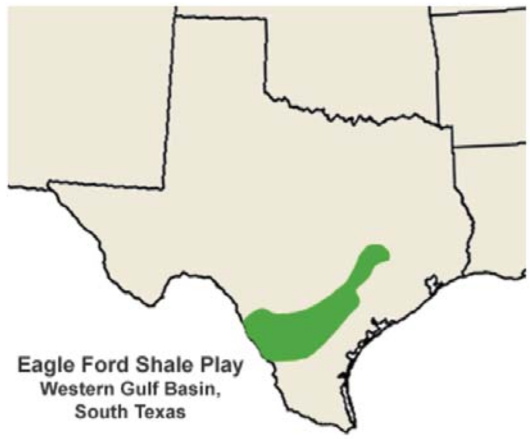

Figure 1: Eagle Ford Shale Region (adapted from reference 3)

Not fully accepted as a producing rock until 2008 it is known as a source rock for the Austin Chalk[3]. Due to horizontal drilling and hydraulic fracturing the low permeability Eagle Ford formation has been found to be accessible as a producing horizon. The formation is currently one of the leading producing provinces in the United States.

The Austin Chalk has historically produced from naturally occurring fractures. Most production occurs from single and dual lateral wells drilled to intersect these fractures. Long term production creates depletion zones where lost circulation occurs on subsequent drilling[4]. These depletion zones consist of the drained natural fractures. In addition to these depleted natural fractures, it is not unusual to encounter undrained fractures that contain oil and natural gas.

More problematic and therefore worthy of mention is the Midway shale. This formation marks the beginning of the Cenozoic era (61.5-59.1 Ma) and is therefore above the Eagle Ford formation (approx. 98-89 Ma), this is illustrated in figure 2[5] (see next page). The Midway shale has been reported to consist of sand and clays that contain calcareous materials[6]. When drilling, the shale is experienced as dispersible and sloughing and therefore is difficult to stabilize the formation that increases the clay and low gravity content of the drilling fluid. This can result in increased drilling fluid density and viscosity as the Midway section is drilled. Mud density requirements for wellbore stability tend to increase in the Midway. It is not unusual for mud densities as high as 10.5 lb/gal to be required to prevent the Midway from becoming destabilized due to pore pressure and wellbore stresses.

Figure 2: Stratigraphic Chart (adapted from ref 5)

Shale Analysis

Proper design of the fluid requires knowledge of the shale formations to be drilled. The two formations of interest will be discussed one at a time.

Eagle Ford shale composition: Samples received at the laboratory confirmed high levels of calcite present. Other minerals seen were quartz and clays. The clays appear to be mainly illite and kaolinite. The Cation Exchange Capacities (CEC) measured indicated that these samples were slightly reactive with minimal swelling potential. The clay species and its relative amounts verify these findings. In the area discussed in this paper, it has been noticed that when the calcite content of the Eagle Ford is 15 wt% or more, lower mud densities in the range of 11.0 to 12.0 lb/gal are indicated for wellbore stability. If the calcite is less than 15 wt%, higher mud densities in the range of 12.0 to 13.5 lb/gal may be needed to ensure a stable wellbore.

Midway shale composition: Samples of Midway appear to be mainly clay and quartz. The clays were measured to be kaolinite, illite and mixed layer. Generally, Midway can be distinguished from Eagle Ford due to its higher (CEC) which is best described as somewhat reactive. It also has higher clay content. An example from each formation is compared in Table 1.

These analyses and previous field experience indicate that a sodium chloride (NaCl) brine based system will be effective at preventing wellbore instability in this area.

Table 1: Comparison of Typical Shale Mineralogy

	Eagle Ford		**Midway**	
CEC	11.4		24.1	
Main Components, % by Weight	Calcite	45	Total Clay+Mica	70
	Total Clay	32	Quartz	22
	Quartz	10	Feldspar	4
Main Clay, % by Weight	Illite	39	Kaolinite	43
	Kaolinite	36	Illite	29

Well Casing and Design

There are two typical well designs used in the Eagle Ford area. The first, commonly known as the two string well design begins with placing a surface casing at or below approximately 2,500-5,500’ measured depth (MD). This is to meet state and local requirements for protection of potable water. The fracture gradient of 11.5 to 12.5 lb/gal realized will be sufficient to drill to total depth in the Eagle Ford in most cases. From this point, the well may be drilled utilizing a 8-1/2” to 9-7/8” hole size to the bottom of the curve with an angle of 70-90°. The larger hole size of 9-7/8” is used when there is a possibility of requiring intermediate casing. With the two string design, intermediate casing is not set and the well is drilled to total depth in the lateral with a 8-1/2” to 8-3/4” hole size. The well true vertical depth (TVD) is roughly 9,000-9,500’ down to total measured depth of 15,000-18,000’ depending on lateral length in the area discussed in this paper.

The second well design, known as the three string well design consists of a similar surface casing depth, followed by an intermediate string of casing cemented after drilling all or a significant portion of the curve to an inclination of 80 - 90°. This can be performed to cover up the Austin chalk fractures that cause the high fluid losses experienced in this region. It also may be required if a mud density greater than the fracture gradient in the Wilcox formations below surface casing is required. The lateral can then be drilled with a 6-1/8” to 6-3/4” bit to a depth of 15,000-18,000’ MD.

Offset Review

The area where the wells discussed in this paper are located is west of Flatonia, TX in northern Gonzales County and southwestern Fayette County. When wells are drilled that do not closely offset Austin Chalk production, well designs with DOBF drilling fluids out from under surface casing are the preferred choice.

Where Austin Chalk production is closely offset, operators have used oil mud and conventional brine fluids. As mentioned previously the issues associated with the DOBF include costs associated with lost mud and NPT due to dealing with losses. The issues associated with a conventional brine fluid include reduced lateral length due to torque and drag and lower ROPs.

Originally permitted for 5 wells, the Newtonville unit was planned on three different pads. The first well drilled in the unit, the 3H, lost returns while drilling the curve and ultimately lost a total of 4,000 bbl of DOBF with a mud cost of over $800K. The time on the well was 35 days total, spud to TD. The 4H was then drilled with conventional brine base fluids. High torque and low rates of penetration were problems with the well. Drilling fluid costs were reduced compared to the DOBF at about $350K. At this time, the need for an alternative to these two fluids was identified. After review of the available fluid, the brine base HPBDF was identified as a candidate drilling fluid.

Drilling Fluid Formulation

Using an innovative performance enhancer, conditioning agent and filtrate control product as the key ingredients a fluid could be constructed using sodium chloride brine[7]. The HPBDF was formulated to achieve similar performance to a DOBF but was also economical to replace if lost down-hole. Chlorides can be maintained sufficient to provide the needed inhibition in the Midway. After application in a number of areas, this fluid was proposed as an alternate if lost circulation occurred that could not be easily remedied. A typical formulation for the fluid is listed in table 2.

Table 2: Typical HPBDF Formulation

Additive	Function	Approximate Concentration
Fluid Stabilizer	Stabilizes natural polymers	0.75 - 1.5 lb/bbl
Xanthan Gum	Rheology	0.5 - 1 lb/bbl
CM Starch	Fluid loss and supplemental viscosity	2 - 3 lb/bbl
Low Viscosity PAC	Filtration control	0.75 - 1.5 lb/bbl
Fluid Conditioner	Conditioner	0.25 - 0.75 lb/bbl
Performance Enhancer	Friction Control	1 - 3 vol%
Chlorides (from NaCl)	Inhibition and density	100K - 180K ppm

The fluid property objectives for drilling to the Austin Chalk are given in Table 3. Keeping the density lower is important to maximize rate of penetration and avoid thick filter cake across the Wilcox section. Table 4 lists the typical properties used in building the curve and drilling the lateral. A benefit of the brine is that at 10 lb/gal, it is near the density required for this area. It is also easily diluted without the risk associated with weighting material settling. Also volume can be built rapidly mixing minimal amounts of products.

Table 3: Intermediate Fluid Parameters

Parameter	Specification
Hole Size (in)	9 7/8”
TVD (ft)	3,400’—9,400’
Mud Weight (lb/gal)	9.5—10
Plastic Viscosity (cp)	8—18
Yield Point (lb/100ft^2)	8—16
API Fluid Loss (mL/30 min)	6-8
Water Salinity (ppm)	70,000-80,000
pH	8-9.0
Total Solids (%)	<8
Coefficient of friction	0.08 - 0.15

Table 4: Production Fluid Parameters

Parameter	Specification
Hole Size (in)	8 3/4”
Measured Depth (ft)	9,600’—16,500’
Mud Weight (lb/gal)	10.8—11.0
Plastic Viscosity (cp)	15—35
Yield Point (lb/100ft^2)	14-20
API Fluid Loss (mL/30 min)	<6
Water Salinity (ppm)	150,000-170,000
pH	9.0 to 9.5
Total Solids (%)	< 8
Coefficient of friction	0.05 - 0.10

Newtonville North 5H

The first well drilled after returning to the area, the Newtonville North 5H was planned as a two string well with DOBF. While building the curve at 9,030’ MD in 8-3/4” hole, a kick was taken and the DOBF was weighted up to 11.0 lb/gal and drilling continued after killing the well. While continuing to drill the curve at 9,446’, total returns were lost.

After attempting to regain circulation, the drill string was tripped out and an open bit and collars tripped in to treat the losses. After spotting an 80 lb/bbl lost circulation material (LCM) pill and chasing it with 10 lb/gal NaCl brine, weak returns were achieved. The hole was filled with brine and weak flow was observed. The brine was circulated and treated to increase the density to 10.8 lb/gal. After spotting another 80 lb/bbl LCM pill and circulating the well, tripping out was attempted. When the well did not appear to be completely controlled, the brine mud was weighted to 10.9 lb/gal and a 15.0 lb/gal pill with 35 lb/bbl of LCM was spotted. A directional assembly was picked up and after cleaning out the hole, the curve was built to 9,789’ MD without further incident and minimal losses using 10.5 lb/gal brine fluid. A total of 2,722 bbl of fluid was lost in correcting this lost circulation incident over 3 days. A 7” intermediate casing was set at total depth and cemented with returns.

Drilling proceeded to a total depth of 14,952’ MD/9,336’ TVD using the HPBDF. The performance enhancer additive concentration was increased to approximately 2 vol% through pumping sweeps while sliding. A 5-1/2”production casing was ran to total depth and cemented with full returns. The mud cost for the well was $656K and included 2,000 bbl of lost oil mud.

Newtonville North 6H and 7H

The next two wells were drilled using the HPBDF from under surface casing. The fluid from the previous well was reused to minimize cost and reduce disposal expense.

The 6H set 9-5/8-in surface casing at 3,367’ MD. An 8-3/4-in hole was drilled to a total depth of 15,773’ MD/9,334’TVD. A total of 795 bbl of mud was lost while drilling. Total returns were lost in the Austin Chalk, but after spotting an LCM pill through the directional tools and allowing the hole to heal, drilling proceeded to land the curve and drill the lateral section. Pumping LCM sweeps mitigated any losses to seepage. Production casing (5-1/2”) was ran to total depth and cemented with full returns.

The 7H set 9-5/8”surface casing at 3,358’ MD. An 8-3/4” hole was drilled to a total depth of 15,850’MD/9,383’TVD. A total of 1,250 bbl of mud was lost while drilling. Lost returns in the Austin Chalk on this well were handled by pumping LCM pills through the directional tools with losses of 20-30 bbl/hr, drilling proceeded to land the curve and drill the lateral section. While drilling the lateral, pumping LCM sweeps mitigated any losses to seepage. Production casing (5-1/2”) was ran to 14,926’ MD and cemented with full returns.

Newtonville East 1H

The 1H set 9-5/8” surface casing at 3,374’ MD. An 8-3/4” hole was drilled to a total depth of 16,555’MD/9,991’TVD in 21 days. After several days of rig repair, a reamer assembly was lost in the hole on a clean out trip. Due to unsuccessful fishing efforts, the well was sidetracked at 8,452’ MD and drilled to 16,430’ MD/9,978’ TVD in 10 days, the current record curve and lateral time for the field. A 5-1/2” production string was ran to 16,310’ MD and cemented with full returns. Downhole losses were minimal in this well with a total of 750 bbl lost due to seepage. This was the result of a proactive program of pumping LCM sweeps to quickly seal any losses before they became severe. On this well the upper hole section, including the Midway shale, remained open and exposed for over 20 days during the fishing and sidetrack operations with no issues associated with wellbore instability. This long term exposure without any lost time or wellbore problems proved that the NaCl brine HPBDF was providing wellbore stability for almost any conceivable circumstances.

Newtonville North 8H, 4H, 3H, and 2H

These wells were planned differently than the previous Newtonville North wells. Instead of 9-5/8” surface casing, 10-3/4” surface casing was utilized to allow drilling 9-7/8” hole. This allowed intermediate casing if needed due to losses in the Austin Chalk. Previous attempts to build curves with a 9-7/8” bit had required much more time than the 8-3/4” curves, but advances in bit and bottom hole assembly (BHA) design had advanced to allow 9-7/8” curves to be built quickly. After building the curve with a 9-7/8” bit, it was planned to drill the laterals with an 8-1/2” or 8-3/4” assembly.

The 8H set 10-3/4” surface casing at 3,422’ MD. A 9-7/8” hole was drilled to the base of the curve at 9,571’ MD. An 8-3/4” lateral assembly was utilized to drill to total depth of 16,120’ MD/9257’ TVD in 17 days. A total of 1,586 bbl of mud was lost while drilling. As in the previous wells, LCM sweeps were used to cure losses while drilling. This prevented NPT while treating lost circulation. Production casing (5-1/2”) was ran to total depth and cemented with full returns.

The 4H set 10-3/4” surface casing at 3,395’ MD. A 9-7/8” hole was drilled to the base of the curve at 9,812’ MD. An 8-1/2” lateral assembly was utilized to drill to total depth of 15,986’ MD/9212’ TVD in 14 days. Minimal amounts of mud were lost while drilling. Production casing (5-1/2”) was ran to total depth and cemented with full returns.

The 3H set 10-3/4” surface casing at 3,422’ MD. A 9-7/8” hole was drilled to the base of the curve at 9,905’ MD. An 8-1/2” lateral assembly was utilized to drill to total depth of 16,255’ MD/9203’ TVD in 20 days. Large amounts of mud were lost while drilling for a total of 6,949 bbl losses. During most of the losses, drilling was able to proceed. One occasion required pulling above the losses and rebuilding volumes. Production casing (5-1/2”) was ran to total depth and cemented with partial returns.

The 2H set 10-3/4” surface casing at 3,408’ MD. A 9-7/8” hole was drilled to the base of the curve at 9,812’ MD. An 8-1/2” lateral assembly was utilized to drill to total depth of 15,975’ MD/9191’ TVD in 12 days. Minimal amounts of mud were lost while drilling. Production casing (5-1/2”) was ran to total depth and cemented with full returns.

Newtonville North 1H

The final well drilled in this area was the one that experienced the most lost circulation. With surface casing at 3,401’ MD, drilling proceeded with 9-7/8” vertical and build similar to the previous wells to 9,638’ MD. The 8-1/2” section proceeded according to plan until a fault was drilled into at 13,747’ MD and total returns were lost. After incurring losses of over 16,380 bbl, the well was plugged back and sidetracked to 13,600’ MD/9240’ TVD where 5-1/2” production casing was ran. After all the losses, the mud cost was $462K for the well. The lost return circumstances for this well were different than those experienced in previous wells as the losses occurred from drilling into a fracture zone associated with a fault system. Previous lost circulation events were associated with drilling in the curve and early stages of the lateral. Dealing with these losses proved to be a much greater challenge than experienced previously. The fluid provided excellent wellbore stability throughout the lost circulation event and the sidetrack, with the hole open through the Midway shale for over 30 days. In this situation, the properly formulated brine HPBDF was used successfully in the Eagle Ford.

Summary of Newtonville HPBDF Wells

The HPBDF provided clear benefits to reduce cost and NPT in this area with a high potential for lost circulation. For these wells, over 30,000 bbl of drilling fluid was lost. Based on actual materials mixed, the cost of the HPBDF fluid on average was 61% less than the cost of an equivalent DOBF for the Newtonville wells.

A major concern with the use of water mud in many areas is the rate of penetration[8]. The drilling curves for the 9 wells are shown in Figure 3 (page 6). The wells drilled with very similar rates of penetration to oil mud in that area. Figure 4 (page 6) gives a comparison of the drilling times of the Newtonville wells with those of nearby units using oil mud without severe losses. As can be seen, the Newtonville North wells drilled with similar days to depth as nearby units with DOBF.

In only one case were the downhole losses so severe that the well could not be drilled to the planned total depth. A solution for a similar situation has been designed and is ready to be implemented on future wells if it occurs.

Conclusions

Based on the experience obtained on these wells it can be concluded that a high performance brine drilling fluid can be used to successfully and economically drill Eagle Ford wells. Its use is especially beneficial in lost circulation prone areas like those associated with depleted fractures in the Austin Chalk.

Applying a simple sodium chloride brine base fluid using high performance additives that delivers high rates of penetration and reduced torque and drag is possible with the right combination of personnel, products and procedures. It also requires an operating organization that can respond quickly to changing well conditions

Lessons Learned and Best Practices

When facing predictable fluid losses it is important to preplan. The following is a list of lessons learned from this project:

1. Optimize performance enhancing additive based on lubricity measurements and well conditions rather than concentration
2. Chlorides need to be high enough to provide adequate inhibition and corrosion prevention
3. When required to build mud rapidly, select additives that can be mixed quickly
4. Solids control management is also key in controlling fluid properties and reducing costs

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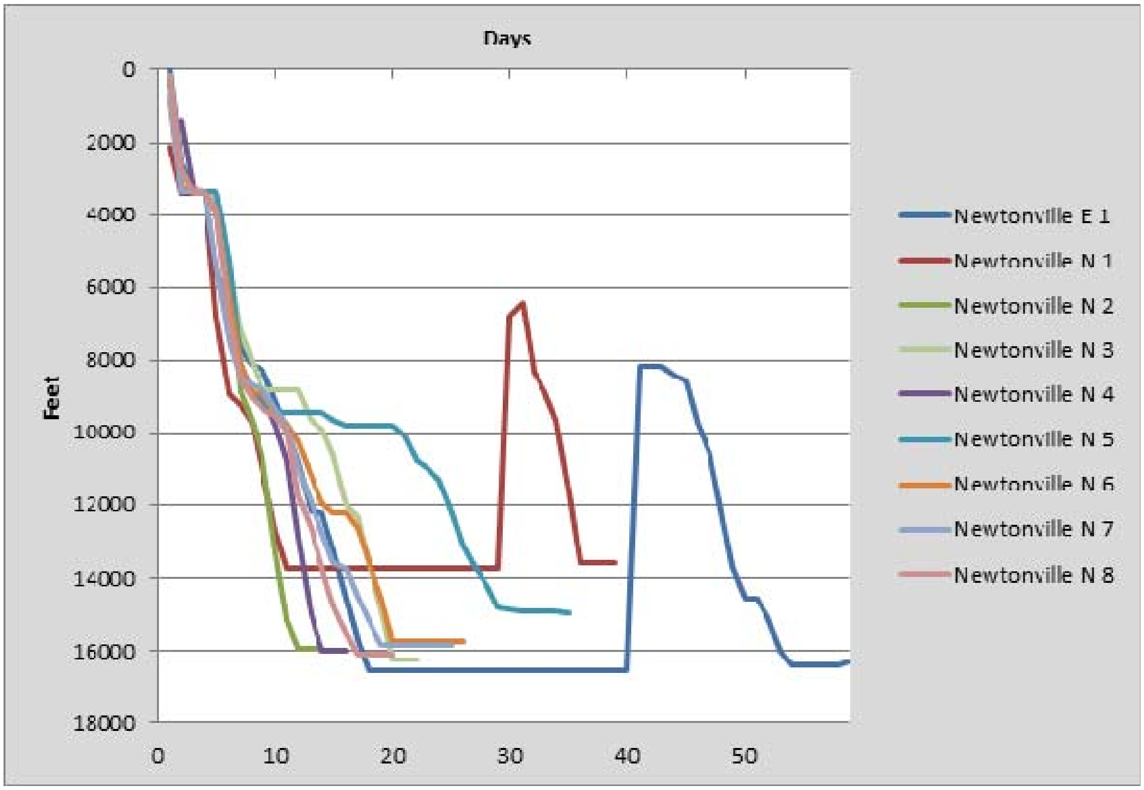

Figure 3: Days vs. Depth for Newtonville Wells

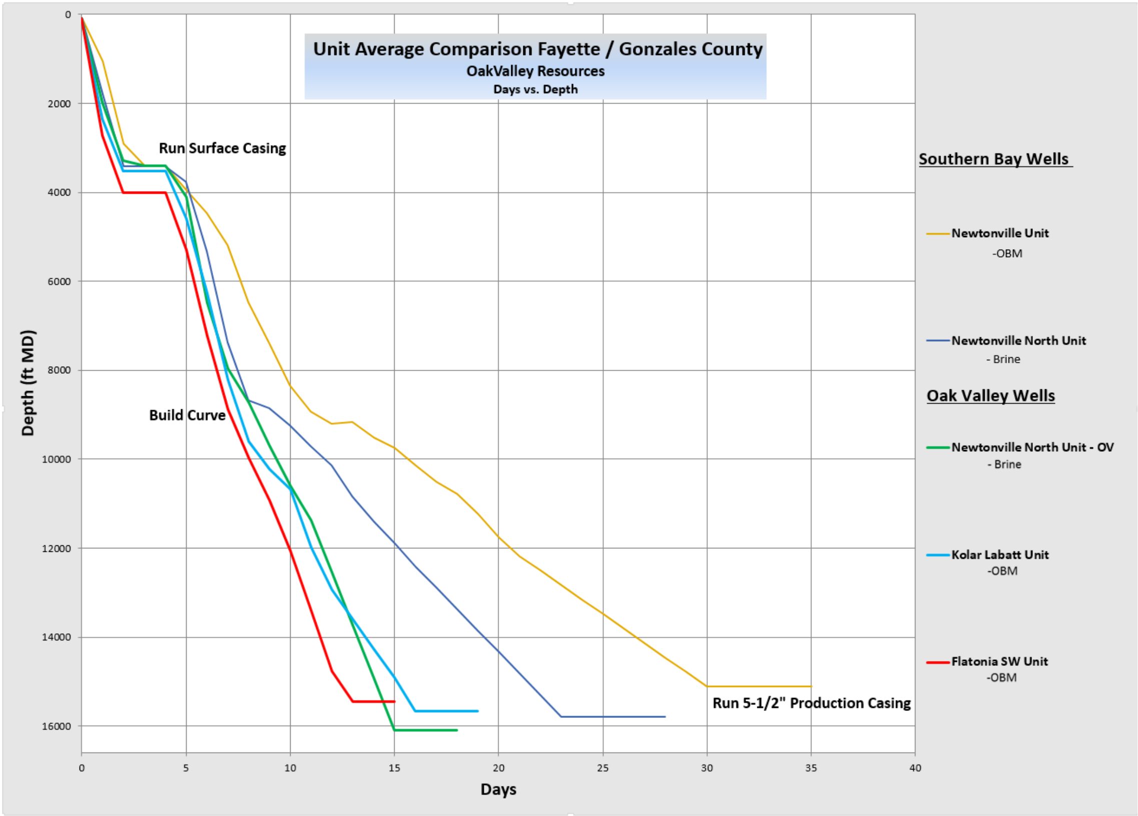

Figure 4: Days vs. Depth comparison of Newtonville to nearby unit