CHEMOURS DELISLE PLANT

2017 HWDIR EXEMPTION PETITION REISSUANCE APPLICATION

SECTION 5.0 - WELL CONSTRUCTION

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5.0 WELL CONSTRUCTION

This section contains the surface and subsurface well construction information and detailed discussion of materials of construction used for the four Chemours DeLisle injection wells (Well Nos. 2, 3, 4, and 5) and Monitor Well No. 1. Figure 5-1 shows the location of the injection wells and the monitoring well. This application is seeking approval to convert Monitor Well No. 1 to an injection well as originally intended, and this section provides diagrams and procedures for two drilling options for this conversion. This section also includes proposed well construction materials for Wells No. 6 and No. 7 and a step-by-step procedure for installation of this well. Finally, well abandonment procedures and post-closure care plans are also presented. This application is also seeking approval to complete all wells into the Tuscaloosa Massive sand if necessary.

5.1 MONITORING WELL NO. 1

Monitoring Well No. 1 was drilled in 1974, as a test well for injection operations prior to full construction of the Chemours (then DuPont) DeLisle Plant. When drilled and logged, the well was called the "No. 1 Lester Earnest" and is often referred to as such in early correspondence. It was originally intended to be used as an injection well. However, the location of the manufacturing processes within the DeLisle Plant were moved, which rendered Monitoring Well No. 1 ineffective as an injection well due to its distance from the process areas. In 1978, this well was converted to a monitoring well, with the designation "Monitoring Well No. 1" (Egler, 1978). Section 5.1 and associated subsections discuss all aspects of the surface and subsurface construction of Monitoring Well No. 1. Figure 5-2 contains a current downhole well schematic of Monitoring Well No. 1. Figure 5-2a contains a current schematic of the wellhead on Monitor Well No.1.

5.1.1 Purpose of Monitoring Well

Preserving the purity of underground sources of drinking water (USDW) is of primary concern when injecting waste into the subsurface. In order to be prudent and follow this course, Monitoring Well No. 1 was completed as a pressure monitoring well to track significant changes within the Washita-Fredericksburg injection interval sand during disposal operations.

5.1.2 Monitoring Program at DeLisle

Monitoring underground waste injection operations at the DeLisle Plant is accomplished by using Monitoring Well No. 1, in addition to the actual injection wells themselves. The injection wells are monitored by continuous pressure recorders. Anomalies in the injection operation are immediately investigated, with injection operations shut down, if necessary.

5.1.3 Drilling, Original Design/Construction and Original Completion

5.1.3.1 Drilling

Monitoring Well No. 1 was spudded on January 9, 1974, and drilled to a total depth (TD) of 10,030 feet into the Washita-Fredericksburg sandstone (DuPont, 1974a). A 15-inch diameter bit was used to drill a surface hole to a depth of 3,460 feet and surface casing was set. A 10-5/8-inch hole was then drilled to TD. Drilling was completed on March 23, 1974 (DuPont, 1974b). Results of the borehole deviation survey are shown in Table 5-1.

Conventional cores and sidewall core samples were taken during drilling operations and were analyzed by Location Sample Service, Inc. for reservoir porosity and permeability (see Appendix 2-22 of Section 2.0 - Geology for copies of core analyses). Drill stem tests were run at various depths with formation fluid recovery providing the following chloride concentration results (DuPont, 1974a). The results of the drill stem tests conducted are shown in Table 5-2.

The chloride values recorded at approximately 3,900 feet (53,500 ppm Cl) and at approximately 9,900 feet (102,500 ppm Cl) are generally consistent with the known chloride concentrations of Gulf Coast saline formation waters. Caliper, induction/electric, and nuclear porosity logs were run to evaluate formation characteristics and calculated the hole volume for cementing operations.

5.1.3.2 Original Well Design/Construction

Steel surface casing (11-3/4-inch) was set to 3,459 feet. See Table 5-3 for summary of casing and tubing data (DuPont, 1974b). The surface casing was cemented back to the surface with 3,700 sacks (sx) of Halliburton Light Weight cement and 300 sx of Class H (with Tuf-fiber) cement and 100 sx of common cement (two % $CaCl_2$), effectively sealing off the near-surface formations from the wellbore; see Table 5-4 for summary of cementing (DuPont, 1974a). The cement was circulated through a float shoe on the bottom of the casing and good returns were noted at the surface.

The surface casing and cement are compatible with native formation fluids (brine). The types of materials used are similar to those used by most petroleum exploration wells drilled in the area.

Carbon steel protective casing (8-5/8-inch) was set to 10,015 feet (DuPont, 1974b). See Table 5-3 for a summary of casing and tubing data. The protective casing was cemented in two stages to the surface through a float shoe on the bottom of the casing string and through a diversion (DV) tool set at 5,568 feet. The first slurry contained 1,200 sx of Halliburton Light Weight cement (4.0 % gel, 0.5 % Halad 9, 2.61 lbs salt, 1/4 lb Flocele, and 0.25 % HR-4), and 300 sx of Class H (7.8 lbs salt, CFR-2 at 75 % and 0.3 % HR-4), and 1,000 sx of Halliburton Light Weight cement (4.0 % gel, 0.5 % Halad 9, 2.61 lbs salt, and 1/4 lb Flocele) was used as the tail cement. The wellbore was sealed off from the borehole formations and a double seal was also provided between the wellbore and USDWs. Twenty-one centralizers were used to enable the cement to circulate around the casing, and cement returns were noted at the surface (DuPont, 1974a, b).

Caliper and electric logs were run in the open hole prior to running casing to determine formation characteristics and to determine hole volume ahead of running the protection casing string. A cement bond log was run after setting casing in the well to evaluate cement integrity.

5.1.3.3 Original Completion

Monitoring Well No. 1 was originally completed on March 23, 1974, with perforations set from 9,775 to 9,974 feet (four holes per foot) into the Washita-Fredericksburg sandstone (DuPont, 1974a), which is the sand used for fluid injection in the DeLisle Plant wells; see Table 5-5 for summary of perforations.

5.1.4 Current Completion

The current completion is the same as the original completion described in Section 5.1.3. However, the wellhead was modified by installing a pressure gauge with a 0 to 160 psi range. Figure 5-2a shows a schematic of the current wellhead. An annotated electric log for Monitoring

Well No. 1 is included as Figure 5-3, with the injection zone, injection interval, and formation tops labeled.

5.1.5 Monitoring Washita-Fredericksburg sandstone Pressure

Monitoring Well No. 1 monitors the formation pressure of the injection interval through perforations into the Washita-Fredericksburg sandstone. Currently, the well is filled with brine and No. 2 diesel oil (pers. com. Linda K. Bernard, DuPont to John Johnston, EPA Region 4 on 8/13/2004) to a surface pressure of approximately 150 psig and sealed. The diesel provides a positive buoyant force at the surface and will not mix with formation brine water. This also allows for a pressure pulse to propagate through this homogenous fluid medium. Permit regulations require that the wellhead pressure be maintained and monitored. Thus, the measured wellhead pressure reflects the increase over original formation pressure for the active injection interval. Pressure at the wellhead gauge is read once a week and recorded. A maximum and minimum pressure range for each month is reported quarterly to the MDEQ as an ambient monitoring parameter. A graph of the historical pressures is included as Figure 5-4. It indicates when each injection well was placed online and shows when the monitoring well was opened for logging and maintenance in August 1992, May 2012, and April 2016. The surface pressure gauge was replaced in December 1992, following extensive reservoir tests of the injection wells at the site. The current pressure gauge has a range from 0 to 160 psig. The level of diesel was located at approximately 1,820 feet in April of 2016.

5.1.6 Well History - Monitoring Well No. 1

Monitoring Well No. 1 was completed March 23, 1974, in the Washita-Fredericksburg sandstone. An 11-3/4-inch surface casing string was set to 3,459 feet in a 15-inch borehole. Surface casing was cemented to the surface with 4,100 sx of cement. The 8-5/8-inch protective casing was set to 10,015 feet in a 10-5/8-inch borehole. The protective casing was cemented in two stages. The first stage of 1,200 sx was pumped through the float shoe and the second stage of 1,300 sx was pumped through a cement DV tool and circulated to the surface (DuPont, 1974a).

Original completion of Monitoring Well No. 1 consisted of acidizing the perforated interval (see Table 5-5 for perforations) with 15 % HCl. The lower perforations from 9,854 to 9,974 feet were acidized with 3,700 gallons of 15 % HCl pumped at an average rate of 2.7 barrels per minute (bbl/min) and an average surface injection pressure of 1,300 psi. The rate and pressure range used was 0.5 bbl/min to 6.0 bbl/min and 900 to 2,300 psi. A second acidization was performed on the upper perforations (9,775 to 9,874 feet). This acidization consisted of 2,500 gallons of 15 % HCl pumped at averages of 2.8 bbl/min and 1,000 psi (DuPont, 1974a).

The acidization was followed by an injection test. A total volume of 13,310 gallons of 9.3 ppg brine was injected at rates from 300 gal/min to 700 gal/min and surface injection pressures ranging from 1,200 to 3,100 psi (DuPont, 1974a). The rates and pressures are shown in Table 5-6.

A frac test was also performed on Monitoring Well No. 1. It involved pumping 9.3 ppg brine water into the well under pressure in an attempt to break down the perforated intervals. During the test, 11,120 gallons were pumped into the hole at various rates and pressures shown in Table 5-7.

The pressures listed are recorded surface pumping readings. Halliburton's analysis of the data indicates that the frac test did not cause a breakdown in the formation (DuPont, 1974a).

After this well was drilled, the footprint of the site for plant was moved, which resulted in Monitoring Well No. 1 being unsuitable for injection due to its distant location. The well was converted to an observation well (DuPont, 1974a) and officially designated as Monitor Well No. 1 in May 1978.

No physical changes were made to the well until 1992, when a 5-1/2-inch swedge with a four-inch ball valve and a one-inch gate valve was placed on the top of the blind flange to monitor pressures within the casing using a 0 to 100 psi gauge (Egler, 1978) (see Section 5.1.4). Pressure readings are taken weekly. No workovers or stimulations have been required on the well. The pressure gauge was changed again in March 2005, to a 0 to 160 psig gauge. The level of diesel was located at approximately 1,820 feet in April of 2016.

December 2, 1991 – Reservoir Test

Starting December 2, 1991, Monitoring Well No. 1 was used for site-wide reservoir testing in Well Nos. 2, 3, and 4, and recorded a measured surface pressure of 56.5 psi. A vacuum truck was used to place approximately 1,400 gallons of No. 2 diesel into the wellhead head space to top off the well. A set of bottom-hole pressure tools (Panex surface readout probe and Panex memory gauge) were then run inside the 8-5/8 inch casing. Pressure gradient stops were made at various intervals on the way down to the logging/recording level. The tools were placed at a depth of 9,850 feet for the duration of the extended reservoir testing operations. The recorded bottom-hole pressure value at 9,850 feet was 4,578 psia.

August 31 to September 4, 1992 – Mechanical Integrity Evaluation

On August 31, 1992, Monitor Well No. 1 was entered to conduct cased hole wireline logging operations to determine the condition of the casing and evaluate the bottomhole pressure. The measured surface pressure was 40 psi before the wellhead was initially opened. A vacuum truck was used to bleed ±1,200 gallons of kerosene from the well. A wireline sampler was then used to retrieve fluid samples at 26 feet (kerosene), 5,000 feet (pH = 7.3), 9,982 feet (pH = 6.1), and 9,982 feet (pH = 6.0). Wedge Wireline Services ran a differential temperature log from surface to total depth and recorded a maximum down-hole temperature of 262° F at 9,965 feet. After the temperature log was completed, a Gamma Ray-Neutron-CBL log was then run from 9,962 feet to surface to evaluate condition of the casing.

Following this testing, bottom-hole pressure tools were set at 9,775 feet, with initial readings of 4,994 psi and 244° F. The well was shut-in overnight. The final pressure recorded the next morning was 4,594 psi. As the gauges were pulled from the well, 20-minute fluid gradient stops were made. A multi-arm caliper and magnetic thickness tool were then run from 9,962 feet to surface and the casing was found to be in satisfactory condition. The well was re-filled with 1,386 gallons (33 bbl) of No. 2 diesel (pumped into the well), yielding a final wellhead pressure of 55 psi. The well was then returned to monitoring service.

December 1992 – Reservoir Test

The purpose of the test was to obtain adequate information by way of interference testing to determine which of the 4 wells are completed in the same formation and are in communication. The interference test was performed by placing quartz electronic gauges in Monitoring Well No. 1 and Injection Well Nos. 2, 3, and 4 at the corresponding depths of 9,760 feet, 9,272 feet, 9,238 feet, and 9,207 feet, respectively. The gauge in Injection Well No. 3 was pulled and positioned at a depth of 5,000 feet during the second phase of the test. The gauges in each particular well were only used when acting as a monitor well during the injection period. Therefore, Monitoring Well No. 1 was evaluated for interference during injection periods in Injection Well Nos. 2, 3, and 4. Injection Well No. 2 was evaluated for interference during injection periods in Injection Well Nos. 3 and 4. Well No. 3 was evaluated for interference during injection periods in Injection Well Nos. 2 and 4. Finally, Injection Well No. 4 was evaluated for interference during injection periods in Injection Well Nos. 2 and 3. For Monitoring Well No. 1, the BHP at 9,850 feet was 4,577 psi at 226°F on December 3, 1992.

The conclusions of the interference test showed that the interference at Monitoring Well No. 1 from injection Well No. 2 was visible by significant pressure increases and decreases during the two injection periods for Injection Well No. 2. The pressure change at Monitoring Well No. 1 during the injection periods at Injection Well Nos. 3 and 4 was not conclusive. However, the pressure at Injection Well No. 4 with injection at Injection Well Nos. 2 and 3 showed significant pressure changes. Therefore, the graphical results suggest that all four wells are in communication. However, further investigation by geographical and analytical methods is suggested to verify these results (Rosenberg, 1993).

On December 18, 1992, the well was entered for comprehensive site reservoir testing work within the Washita-Fredericksburg Injection Interval. Approximately 1,134 gallons (27 bbl) of No. 2 Diesel were pumped into the well to top it off, resulting in a measured shut-in surface pressure of 40 psi.

January 1996 to July 1997 - Injection Evaluation

Over this 18 month period, a trend of increasing surface pressures was noted in Monitor Well No. 1. An analysis of facility operating data indicated that the cause of increasing pressure corresponded to an increase in fluid injection volumes and higher associated waste densities being injected into Well Nos. 2 and 4, both of which had been recompleted via sidetrack into the Washita-Fredericksburg sand.

Tubing Failure July 2004

On July 29, 2004, a leak of No. 2 diesel oil was discovered in the tubing between the wellhead and the pressure gauge. The amount of oil released was approximately 526 gallons. The amount of diesel required to restore positive pressure to the well was added as required by the MDEQ UIC permit (*pers. comm.*, Linda. K. Bernard, DuPont to Jon Johnston, EPA Region 4 on 8/13/2004).

August 2005 to March 2006 – Period of No Injection (Hurricane Katrina)

Hurricane Katrina made landfall along the Mississippi Gulf Coast on August 29, 2005, and inflicted severe damage to the DeLisle facility. Plant operations were down for several months. During this time period, Monitoring Well No. 1 recorded decreasing pressures as no injection wells were operating. Pressure decayed and dissipated in the Washita-Fredericksburg sand, stabilizing at approximately 20-30 psig. This 20-30 psig pressure reading at the wellhead, with the current amount of diesel oil in the well, represents the pressure in the injection interval with the interval completely relaxed due to a long period of no injection.

May 2012 – Mechanical Integrity Evaluation

On May 14, 2012, a differential temperature survey was performed on Monitor Well No. 1 from surface to total depth. A maximum downhole temperature of 248°F was recorded at a depth of 10,015 feet. The temperature log showed no anomalies or deviations in the temperature survey that could be attributed to fluid moving upward out of the permitted injection interval.

Following this testing, bottomhole pressure tools were set at 9,850 feet and recorded a 15-minute static pressure of 4,696 psia. The tool was then pulled up to 9,000 feet and recorded a 5-minute static pressure of 4,287 psia, and then removed from the well. A wireline sampler was then used to retrieve two fluid samples at 9,850 feet.

April 2016 – Well Sampling and Pressure Monitoring

On April 7, a differential temperature survey was performed on Monitor Well No. 1 from surface to total depth. A maximum downhole temperature of 243.5°F was recorded at a depth of 9,985 feet. The temperature log showed no anomalies or deviations in the temperature survey that could be attributed to fluid moving upward out of the permitted injection interval.

Following this testing, bottomhole pressure tools were used to take static gradient stops while retrieving the tools from the well. Refer to Table 3-4 for the results. A wireline sampler was then used to retrieve a 600 mL fluid sample at 9,850 feet for analysis. Table 3-11 contains the results from the analysis of the bottomhole fluid sample.

In conjunction with a scheduled shut-in of the four injection wells, a high-resolution gauge was installed on the wellhead of Monitor Well No. 1. Wellhead pressures and temperatures were monitored for a 600-hour duration, extending from April 8, 2016 to May 3, 2016. A multi-well simulation was then used to iteratively model the pressure response at Monitor Well No. 1 from the rate histories in each of the injection wells and input well and reservoir properties. The rate changes from the injection wells have an influence on the resulting Monitor Well No. 1 surface pressures, demonstrating interwell communication.

5.1.7 Conversion of Monitoring Well No. 1 to an Injection Well

Monitor Well No. 1 was originally intended to be an injection well. However, sometime between 1974 and 1978 the location of the process areas was moved further inland and away from Well No. 1. At that time, Well No. 1 was considered to be too far from the process area and it was decided to use Well No. 1 as a deep monitor well. If, at this time, the plant were to convert the well from monitoring status to injection, the two options for converting the well are: 1) milling out the existing completion casing and replacing the casing and cement, or 2) plug the wellbore in the injection interval and side-track the well back to the injection interval and complete with new casing and cement.

Conversion by Milling the Existing Completion

In order to convert Monitor Well No. 1 to an injection well by milling the existing completion, the current casing will be section milled from the top of the Washita-Fredericksburg injection interval, and down. Acid resistant cement will be placed at the top of the injection interval to prevent upward migration. A 5-1/2-inch liner consisting of titanium and carbon steel will be installed and cemented in place with acid resistant cement. A titanium packer, with a slotted fiberglass liner below it, will be installed at the top of the Washita-Fredericksburg injection interval, in the 5-1/2-inch titanium casing. The existing casing below the titanium components is expected to corrode away once injection is initiated. A tapered injection string consisting of 5-1/2-inch by 3-1/2-inch fiberglass will be installed. In the event that the well is needed as an injection well, the well will be completed in accordance with the regulations and detailed procedures and a completion schedule will be submitted for approval prior to any work to be performed. Figure 5-2a shows a completion schematic for the proposed section milling option.

Conversion by Sidetracking the Well

In order to convert Monitor Well No. 1 to an injection well by sidetracking, the current completion will be plugged in a similar manner as the previous sidetracks. The existing casing will be milled, along with the cement behind the casing, and acid resistant cement will be placed at the top of the injection interval to prevent upward migration. The well will then be sidetracked and a 5-1/2-inch liner consisting of titanium and carbon steel will be installed and cemented in place with acid resistant cement. A titanium packer, with a slotted fiberglass liner below it, will be installed at the top of the Washita-Fredericksburg injection interval, in the 5-1/2-inch titanium casing. A tapered injection string consisting of 5-1/2-inch by 3-1/2-inch fiberglass will be installed. In the event that the well is needed as an injection well, the well will be completed in accordance with the regulations and detailed procedures and a completion schedule will be submitted for approval prior to any work to be performed. Figure 5-2b shows a completion schematic for proposed sidetracking option.

5.2 DELISLE PLANT WELL NO. 2 (MSI1001)

5.2.1 Drilling, Original Design/Construction, and Original Completion

5.2.1.1 Drilling

DeLisle Plant Well No. 2 (MSI1001) was permitted by the state of Mississippi under the National Pollutant Discharge Elimination System (NPDES) on May 19, 1978 (DuPont, 1985a). The well was spudded on May 19, 1978, and was drilled to a total depth (TD) of 10,062 feet into the Washita-Fredericksburg sandstone. A 17-1/2-inch hole was drilled to 3,721 feet and a 13-3/8-inch surface casing string was set at 3,702 feet and cemented to surface. A 12-1/4-inch hole was drilled to 9,863 feet, and 9-5/8-inch protective casing was set at 9,824 feet and cemented to surface. Finally, an 8-3/4-inch hole was drilled to 10,062 feet TD. Drilling was completed on October 11, 1979 (DuPont, 1979). Results of the borehole deviation survey in the well is shown in Table 5-8. Figure 5-5 is a current downhole well schematic.

Conventional cores and sidewall core samples were taken during drilling operations and analyzed for reservoir porosity and permeability (see Appendix 2-22 in Section 2.0 - Geology for full core report). Caliper, induction/electric, and nuclear porosity logs were run to evaluate formation characteristics and determine the hole volume for cementing operations (DuPont, 1985a).

5.2.1.2 Original Design/Construction

Surface casing (13-3/8-inch, 68 lb/ft, K-55, carbon steel) was set to 3,702 feet; see Table 5-9 for summary of casing and tubing data (DuPont, 1979). This casing has a burst pressure of 3,450 psi, a collapse pressure of 1,950 psi, and a tensile strength of 1,069,000 lbs. The surface casing was cemented to the surface with 2,280 sx of Pozmix/HLC cement (0.25 lb/sx Flocele) and 275 sx of Class H cement (5.0 % salt, 0.35 % $CaCl_2$), effectively sealing off the shallow formations from the wellbore (see Table 5-10 for summary of cementing). The cement was circulated through a float shoe on the bottom of the casing and good returns were noted at the surface (DuPont, 1985a).

The surface casing and cement are compatible with the native formation fluids (brine). The type of tubular materials used is similar to those used by petroleum exploration wells drilled in the area.

A 12-1/4-inch hole was then drilled to 4,660 feet. The hole was obstructed, and it was found that the bottom joint of the 13-3/8-inch casing had parted or separated from the main surface casing string. Cement bond logs were run, and the surface casing was perforated and squeezed with cement from 3,410 to 3,412 feet. After milling the separated casing to 3,795 feet, the hole was plugged back to 3,500 feet and sidetracked at a depth of 3,635 feet. A 12-1/4-inch sidetrack hole was drilled to a depth of 9,863 feet. The 9-5/8-inch protection casing was set to 9,829 feet and cemented in three stages through cement DV tools. Protective casing (9-5/8-inch, 40 lb/ft, and 47 lb/ft, N-80) was set to 9,726 feet and titanium casing (9-5/8-inch, 1/2-inch wall thickness) was set from 9,726 to 9,824 feet (DuPont, 1985a, b). These casings have respective burst pressures of 5,750 psi and 3,636 psi; respective collapse pressures of 3,090 psi and 2,520 psi; and a tensile strength of 916,000 lbs (DuPont, 1985c).

The protective casing was cemented in three stages to the surface using DV tools located at 4,856 feet and 9,116 feet, and a float shoe located on the bottom of the casing string (DuPont, 1985a, b). Cementing was conducted using 3,780 gallons of *Epseal®* in the first stage, 2,050 sx of Halliburton Light cement (0.3 % HR4, 0.8 % Halad 22A) in the second stage, and 1,150 sx of Halliburton Light cement in the third stage, the wellbore was sealed off from the native formations, and a double seal provided between the wellbore and the USDW (DuPont, 1985b). Cement returns were noted to the surface (DuPont, 1979).

Caliper and electric logs were run in the open hole prior to completion to evaluate formation characteristics and to determine hole volume for cementing operations. A cement bond log was run in the well to evaluate cement integrity.

An 8-3/8-inch hole was then drilled to 10,062 feet. This hole was under-reamed to 16 inches from 9,842 to 10,028 feet. While washing out the 8-3/8-inch pilot hole, the bottom-hole assembly (BHA) became stuck. Fishing operations were successful in recovering only part of the BHA, resulting in the plugging back of the open hole to 10,027 feet (DuPont, 1979). The well was completed with a 5-1/2-inch titanium screen set in an 8- to 12-mesh gravel pack from 9,788 to 10,027 feet. The screen was attached to a packer with a polished bore receptacle (PBR), which allows the 4-1/2-inch fiberglass injection tubing to sting in to the packer (DuPont, 1979). During

July 1979, the well was acidized with 450,000 gallons of 10 % HCl as an initial stimulation (Envirocorp, 1989).

5.2.1.3 Original Completion

DeLisle Plant Well No. 2 was originally completed on October 11, 1979, with a screen and gravel pack into the Washita-Fredericksburg sandstone from a depth of 9,766 to 10,021 feet (DuPont, 1985a). This well was intentionally drilled with an 8.3% deviation from vertical starting at 4,700 feet due to an obstruction in the well. The well was originally permitted for injection by the Mississippi Natural Resources Board, Underground Injection Control (UIC), on July 1, 1986 (State of Mississippi, 1986).

5.2.2 Well History -- DeLisle Plant Well No. 2

January 1980 - Workover

The well was consuming large quantities of brine to maintain annular pressure differential; therefore, DeLisle Plant Well No. 2 was shut down for a workover. The tubing was purged with 240,000 gallons of NaCl brine, pulled, and inspected. Casing inspection and caliper logs also indicated no abnormalities in the protection casing. A retrievable, test, treat, and squeeze (RTTS) packer was used to locate a casing leak at 9,715 feet (11 feet above the top of the titanium casing). The casing was pressure tested above the leak to 125 % of the maximum operating pressure using 1.2 specific gravity (SG) brine, and found to be secure. The Texas Iron Works (TIW) J & G Supply (JGS) titanium packer was removed, and 20/40 sand was used to cover the 9-5/8-inch titanium casing and disposal zone. Four perforations were made at the level of the leak to establish an acceptable flow rate for squeezing cement. The leak area was squeezed with 225 sx of Class H cement, containing 35 % silica flour, 159 lbs of CFR-2, 84 lbs of Halad 22-A, and 42 lbs HR-5. A RTTS packer was used to establish cement displacement. The cement was drilled out and successfully pressure tested to 2,000 psi using 1.2 SG brine. The sand bridge was then cleaned out. Because the TIW JGS packer was damaged during removal, it was temporarily replaced with a Lynes titanium inflatable packer. The injection tubing string was replaced and tested as it was run in the well. The annulus was refilled with $CaCl_2$ brine and the packer was inflated. The annulus seal was successfully tested and the well was returned to service (DuPont, 1985a).

April 1980 – Repair to Packer

The Lynes inflatable packer failed in service due to sudden shut down of the well from an accidental well interlock. The well was purged with 325,000 gallons of brine, tubing was removed, and the Lynes packer was pulled. Temperature and gamma ray logs were run to check the cement placement from the January workover. A TIW JGS titanium packer was set and successfully tested. Tubing was rerun into the well and reset. The casing annulus was successfully tested to 125% of maximum operating pressure. The casing annulus was filled with $CaCl_2$ and the well was returned to service. The computer logic was redesigned to prevent operational problems resulting from incorrect operation (DuPont, 1985a).

January 1986 – Casing Test

On January 16, 1986, DeLisle Plant Well No. 2 suddenly lost annular pressure and gained tubing pressure momentarily, an indication of failure in the injection tubing (data from plant computer output). The plant purged the annular area with water to regain annulus pressure immediately after the failure was detected. The injection tubing was removed from the well. It was found that the tubing had parted at a depth of 9,575 feet, leaving 225 feet of tubing in the well. Analysis of the recovered injection tubing indicated it to be in good condition, despite being in service for six years. The tubing failure occurred in the bottom section of the tubing where the tubing was under maximum stress during well operation. The FRP injection tubing was inserted back into the well with the bottom 2,100 feet of the injection tubing consisting of a new heavy wall fiberglass and the remaining tubing consisting of the inspected tubing pulled from the well. The two pressure tests for casing and tubing were successful (Decker, 1986). The well was returned to service on January 29, 1986.

November 1991 to April 1992 - Workover

A workover began on November 15, 1991, to address the excess consumption of brine needed to maintain the required annulus pressure differential. The brine consumption rate had incrementally increased over several years leading up to the workover. The 4-1/2-inch fiberglass tubing, the TIW packer, and the PBR were all removed from the well. An electromagnetic casing caliper inspection survey was run in the 9-5/8-inch protection casing and showed internal and external degradation of the carbon steel at the titanium/carbon steel interface area. A multifinger casing caliper survey was run in the casing and found metal loss in the same area. A cement bond log and a radioactive tracer survey (RTS) were conducted to evaluate the existing condition of the cement behind the 9-5/8-inch casing. These surveys did not show cement deterioration or fluid movement behind pipe. The existing 5-1/2-inch titanium slotted liner was removed from the open hole section of the well, and the 8/12-mesh sand was washed from around the slotted liner.

A 7-inch protective casing liner was set from 8,547 to 9,788 feet and cemented in place with 1,176 gallons (28 bbl) of *Epseal®* LC epoxy cement. A 4-1/2-inch fiberglass slotted liner with 24 slots per foot (0.02-inch width by 2-inch long) was set below a Groundwater Protection Services (GPS) Model 12 (Grade 7 titanium) disposal packer at 9,766 feet. A 20-foot PBR was latched into the top of the packer. A tapered injection string consisting of 96 joints of 4-1/2-inch internal upset (IUE) Red Box 2500 and 230 joints of 5-1/2-inch Red Box 2500 were installed. A successful annular pressure test confirmed the mechanical integrity of the 9-5/8-inch casing, the 7-inch liner, the injection packer, and the fiberglass injection string. A RTS verified that the injected fluids were exiting the wellbore in the permitted interval.

September 1995 – Sidetrack No. 1 DeLisle Plant Well No. 2

The lower section of the original wellbore was plugged and the well was sidetracked above the plugged interval. This sidetrack well was recompleted in the Washita-Fredericksburg Injection Interval. Field activities began in September 1995, with mobilization of a rig and removal of the completion equipment. The wellbore was pressure tested, and a casing leak confirmed. The workover rig was moved off, and a second rig was moved in to perform plugging operations in the 7-inch liner. A whipstock was set at 7,803 feet and used to sidetrack through the 9-5/8-inch casing at that point. A directional hole was drilled adjacent to the original wellbore to 10,060 feet (measured depth). A 7-inch liner was set and cemented from 7,573 to 9,743 feet. The well was completed as an openhole completion, with a slotted fiberglass injection screen installed below a Titanium Grade 7 packer. A tapered string of 4-1/2-inch and 5-1/2-inch FRP tubing was stung in the packer to complete the well.

An MIT was performed to demonstrate integrity of the well. The APT confirmed soundness of the casing, tubing, wellhead, and injection packer. The RTS verified that flow of injected fluids was confined to the Washita-Fredericksburg Injection Interval. Field operations were concluded in late February 1996, and the well was returned to the plant for service.

December 18-20, 1996 - Interference Test – Well Nos. 2, 4, and 5

A 30-hour interference test was conducted between DeLisle Plant Well Nos. 2, 4, and 5 after a bottomhole pressure falloff test was conducted on DeLisle Plant Well No. 4. This test proved that all wells are in communication within the Washita-Fredericksburg Injection Interval.

August 15-17, 1997 – Well Nos. 2, 4, & 5 Interference Test

This interference test consisted of injection and pressure monitoring operations in DeLisle Plant Well No. 5 and injection operations in offset DeLisle Plant Well Nos. 2 and 4. A summary of the test and interpreted results is provided in the Well History for DeLisle Plant Well No. 5 (Section 5.5.2).

August 2005 to March 2006 – Period of No Injection (Hurricane Katrina)

Hurricane Katrina made landfall on the Mississippi Gulf Coast on August 29, 2005, and inflicted severe damage to the DeLisle facility operations. The plant was down for several months. During this period DeLisle Plant Well No. 2 did not operate.

April 2014 – Injection Screen Perforations

To improve injectivity, the injection screen on DeLisle Plant Well No. 2 was perforated a week after conducting the BHP falloff test. Approximately 50 feet of perforations were completed in the Upper and Middle Sand lobes of the Washita-Fredericksburg sand.

July – October 2014 – Workover/Completion Equipment Replacement

DeLisle Plant Well No. 2 was reworked to replace completion equipment because the injection string had been in operation since the 1995 sidetrack. The injection interval, below 9,779 feet, was isolated from the wellbore to facilitate removal of completion equipment. The FRP injection tubing string and seal assembly were pulled out of the well. A 16-inch underreamer and 6-1/8-inch rock bit were used to enlarge the open hole from 8-1/2-inches to 16-inches; the open hole section was opened up from 9,775 feet to 10,088 feet.

A new Delta P, Inc. (DPI) Model 12 packer, with titanium Grade 7 wetted parts, was inserted into the well. A new PBR was then placed in the well. After installing and successfully pressure testing all of the new equipment, the seal assembly and FRP injection tubing were run into the well. After landing the injection tubing and assembling the wellhead equipment, the tubing-casing annulus was successfully pressure tested for a one-hour period. The test confirmed the integrity of the injection tubing, casing, PBR, seal assembly, and injection packer. The well was returned to the plant for injection service. (Sandia Technologies, LLC, 2014).

February 2017 to Present

Daily annulus brine consumption was first noticed to be elevated on February 21, 2017. At no time was the applicable annulus brine use limit of 500 gallons in any 24-hour period (MDEQ Permit MSI1001 Part I Section B.3.d) exceeded. Injection into this well was immediately stopped. The root cause has been identified, and well repairs are currently in progress with expected completion towards the end of August 2017. The workover report will contain a detailed history of the investigation and a description of the repairs. Pursuant to MDEQ Permit MSI1001 Part I Section D.2, the workover report will be submitted within 45 days of the completion of the workover.

5.2.3 Current Well Design and Completion

The wellhead currently in use at DeLisle Plant Well No. 2 is shown in Figure 5-6. The wellhead does not come in direct contact with the waste stream. It has a 13-5/8-inch x 11-inch carbon steel casing spool. A full ported ball valve on top of the wellhead allows the use of workover tools and test equipment. The wellhead and gate valves are rated to 3,000 psi maximum service pressure. Pressure gauges continuously read and record the injection tubing and annulus wellhead pressures (other surface control systems are identified in Table 5-11).

The current completion (Figure 5-5) consists of 252 joints 6-5/8-inch FRP injection tubing (10 feet to 7,430 feet), one cross-over joint (7,430 feet to 7,459 feet), 75 joints of 4-1/2-inch FRP tubing (7,459 feet to 9,675 feet) and a 4-1/2 inch Titanium Grade 7 DPI Seal assembly with locator collar and extension from 9,675 feet to 9,695 feet. The injection packer is a DPI Model 12, 7-inch x 4-1/2-inch Titanium Grade 7 set from 9,700 feet to 9,705 feet. The burst pressure of the tubing is

2,500 psi; the collapse pressure is 3,300 psi; and the tensile strengths of the tubing are 47,800 lbs and 54,500 lbs, respectively. Volumes are calculated in Table 5-12 and calculated tubular stresses (Table 5-13) are less than manufacturer-rated stresses.

The injection screen assembly is made of 4-1/2-inch BB 2,500 psig FRP tubing consisting of 2 joints of blank tubing (9,705 feet to 9,764 feet), and eight joints of slotted fiberglass screen (9,764 feet to 9,999 feet). The slotted joints have 33 slots per foot; each slot is 3 inches long and 0.15-inch wide. The current wellbore schematic is presented in Figure 5-5.

The open hole was originally an 8-1/2-inch diameter hole. It was underreamed to a 16-inch diameter hole in September 2014.

The annular fluid used is corrosion inhibited brine with a specific gravity of 1.25. DeLisle Plant Well No. 2 currently maintains a permitted pressure differential on the annulus of at least 25 psig.

A type log (annotated electric log) of DeLisle Plant Well No. 2 is included as Figure 5-7. The injection zone, injection interval, and formation tops are labeled on the log.

5.3 DELISLE PLANT WELL NO. 3 (MSI1001)

5.3.1 Drilling, Original Design/Construction, and Original Completion

5.3.1.1 Drilling

DeLisle Plant Well No. 3 (MSI1001) was originally permitted by the state of Mississippi under the NPDES on April 25, 1978. The well was spudded on December 9, 1978, and was drilled to a TD of 10,057 feet into the Washita-Fredericksburg sandstone. A 17-1/2-inch bit was used to drill a hole to 3,628 feet and surface casing was set. A 12-1/4-inch hole was then drilled to TD. Drilling was completed on December 21, 1979 (DuPont, 1986a). Results of the deviation survey from the well are shown in Table 5-14. Figure 5-8 is a current downhole well schematic.

Caliper, induction/electric, and nuclear porosity logs were run to evaluate formation characteristics and to determine the hole volume for cementing operations.

5.3.1.2 Original Design/Construction

Surface casing (13-3/8-inch, 68 lb/ft, K-55, carbon steel) was set to 3,614 feet (see Table 5-15 for summary of casing and tubing data) (DuPont, 1986a). This casing has a burst pressure of 3,450 psi, a collapse pressure of 1,950 psi, and a tensile strength of 1,069,000 lbs.

The surface casing was cemented to the surface with 2,280 sx of Pozmix/HLC (0.25 lb/sack Flocele) and 275 sx of Class H (5.0 % salt, 0.35 % $CaCl_2$) cement, effectively sealing off the formation from the wellbore (see Table 5-16 for summary of cementing). The cement was circulated through a float shoe on the bottom of the casing and good returns were noted at the surface.

The surface casing and cement are compatible with formation fluids (brine). The type of tubular materials used is similar to those used in petroleum exploration wells drilled in the area.

The original protective casing (9-5/8-inch by 40 lb/ft and 47 lb/ft, N-80 carbon steel) was set from surface to 9,738 feet, and 9,818 to 9,831 feet, with 9-5/8-inch titanium set from 9,738 to 9,818 feet (DuPont, 1986a).

The original protective casing was cemented in three stages to the surface through a float shoe on the bottom of the casing string, and through DV tools set at 4,842 and 9,127 feet. The first stage used 4,116 gallons of *Epseal®* cement, the second stage used 2,200 sx of Pozmix cement, and the third and final stage used 1,200 sx of Halliburton Light cement. Fluid returns were noted at the surface during the first two stages, but were lost during cementing of the third stage. A cement bond log was run and indicated the top of the cement was located at approximately 3,680 feet. A "bradenhead" squeeze was performed by pumping 1,800 sx of Halliburton Light cement down the 9-5/8-inch annulus. During the final pumping of the slurry, pressure was observed at the surface, and pressure was maintained during the squeeze job. The cement bond log was rerun and indicated a successful squeeze job (DuPont, 1978). The 7-inch liner annulus was cemented with 5,838 gallons (139 bbl) of Class H cement with 35 % silica flour. Caliper and electric logs were run in the open hole prior to completion to evaluate formation characteristics and to determine hole volume.

The well was initially underreamed with a hydrojet from 10,018 to 10,040 feet. Following the hydrojetting, the hole was mechanically underreamed to 12-1/4-inch from 9,827 to 10,040 feet. A second mechanical underreaming was performed to open the hole to 15 inches from 9,930 to 10,035 feet. A titanium screen was set from 9,788 to 10,025 feet and gravel-packed. The well was acidized with 4,500 gallons of HCl and 500 gallons of HF pumped at 800 psi. An injectivity test was run using 9.8 ppg brine. A total of 52,000 gallons were injected at a maximum rate of 400 gallons per minute (gal/min) at a surface pressure of 1,200 psi. An unsuccessful attempt was made to install the packer and PBR, resulting in slight damage to the titanium packer. While the packer was being repaired, the DV tools were milled to eliminate the slight decrease in the internal diameter of the casing. The packer and PBR were then successfully installed. The 4-1/2-inch fiberglass tubing was tested to 500 psi and installed in the well. The annulus was successfully tested to 1,000 psi for 30 minutes, and the well was placed on standby. The well was completed on December 21, 1979.

The DeLisle Plant Well No. 3 (Figure 5-9) wellhead was made by Gray Tool Company. It has a 12-11/16-inch bore casing head and a 9-inch bore tubing head, both made of carbon steel as the waste stream does not come in direct contact with the wellhead. A tee with a full opening gate valve on top of the wellhead allows the use of workover tools and test equipment. The wellhead and gate valves are rated to 3,000 psi maximum service pressure. Pressure gauges continuously read and record the injection tubing and annulus wellhead pressures (other surface control systems are identified in Table 5-17).

5.3.1.3 Original Completion

DeLisle Plant Well No. 3 was originally completed on December 21, 1979, with a screened interval from 9,788 to 10,025 feet into the Washita-Fredericksburg sandstone. This well was intentionally drilled with an 8.3° deviation from vertical starting at a kickoff point of 4,700 feet. The original permitted injection interval was located from 9,799 to 10,043 feet (DuPont, 1986a); however, on January 28, 1992, the permit was modified, and the new injection interval was designated between depths of 9,799 to 10,035 feet.

5.3.2 Well History -- DeLisle Plant Well No. 3

July to September 1979 - Workover

The workover was performed to repair a leak discovered when pumping an HCl buffer consisting of 450,000 gallons of 10 % acid. While picking up the injection string from the wellhead to pull it, the fiberglass tubing parted four feet below the titanium landing joint at a depth of approximately 20 feet. The tubing string was fished out and removed from the well. The leak appeared to be from damaged seals on the stinger assembly, which seats into the PBR and packer. The stinger was repaired and the tubing tested as it was run back into the well. The stinger was seated into the PBR and the annulus filled with $CaCl_2$ brine. Pressure testing of the annulus was problematic due to thermal imbalances in the wellbore. The well was returned to standby status awaiting plant start-up (DuPont, 1985b).

October 1979 – Workover

Repair procedures were initiated due to an excessive use of brine to maintain required annular pressure differential. The well was shut-in and purged with 250,000 gallons of NaCl brine. Following removal of the injection tubing, a casing caliper log was run and indicated a hole in the casing at a depth of 9,712 feet. A RTTS packer was set above the indicated leak, and the casing above the tool was successfully tested (no test conditions were recorded). The titanium packer was removed and the screen bridged with sand. The hole was sealed by squeezing 35 sx of Class H cement with 35 % silica flour, 0.75 % CFR-2, 0.4 % Halad 22-A, and 12 gallons of HAl-75. The sand was washed out using nitrogen-lift, and then the packer and tubing were reinstalled. The annulus was filled with $CaCl_2$ brine and successfully tested to 125 % of maximum operating pressure. The well was returned to service (DuPont, 1985b).

November 1980 to February 1981 - Workover

A workover was undertaken to remedy a loss in annular differential pressure. The injection tubing was purged with 400,000 gallons of NaCl brine, and then the tubing was removed from the well. A RTTS tool was used in conjunction with a RTS to locate the leak at a casing collar 9,450 feet from surface. While attempting to recover the RTTS tool, 19 joints of work string were lost in the hole. Following partial recovery of the fish and milling of the remainder of the fish, a casing profile log indicated that a 300-foot section of casing (9,430 to 9,730 feet) was severely corroded, with two sections missing (9,695 to 9,690 feet and 9,730 to 9,724 feet). The casing was found to be bridged with sand up to 9,700 feet. The casing was perforated at a depth of 9,436 feet and 2,268 gallons (54 bbl) of Class H cement, containing 35 % silica flour, 2.0 % HR12, and 0.4 % Halid 22A, were used to squeeze and plug back the hole. The cement was milled out. Tubing was pressure tested as it was run in the well and the annulus filled with $CaCl_2$. The annulus was successfully tested (no test conditions available), and the well was returned to service (DuPont, 1985b).

April 1981 – Leak Repair

A high rate of brine consumption indicated that a leak had developed in the well. With the assistance of Halliburton, a gelled $CaCl_2$ solution with silica flour was developed and successfully pumped down the annulus to plug the leak. The well was returned to service (DuPont, 1985b).

December 1983 to May 1984 - Workover

In December 1983, DeLisle Plant Well No. 3 was shut down because of the inability to maintain a pressure differential between the casing annulus and injection tubing. The well was purged with freshwater and brine. The tubing was pulled except for 13 joints and the titanium stinger. An additional 12 joints were recovered from the well, and the remaining joint of tubing was drilled out. Due to debris falling in from up-hole, the stinger could not be recovered. The well was squeeze-cemented from above the stinger. While drilling out the cemented section, the hole caved in, sticking the drill string. Several squeeze cementing jobs were necessary to inhibit caving of the hole. The well was then drilled to the former total depth. Before suspending operations at the end of May 1984, 20/40 mesh sand was placed across the disposal interval, and a bridge plug was set above the sand while waiting on delivery of a liner (Morgenthaler, 1986b).

January 1985 – Workover – Sidetrack No. 1

Workover operations were resumed in January 1985, after the delivery of a combination fiberglass covered steel and titanium liner (Morgenthaler, 1986b). To remedy caving, the hole was then cemented to 9,600 feet and sidetracked at 9,738 feet. The well was re-drilled to a total depth of 10,030 feet. The 7-inch titanium liner was landed at 9,787 feet and cemented with Halliburton *Epseal*® Epoxy Resin. Following cementing, a leak was discovered in the casing between depths of 7,926 and 7,957 feet. The interval between 7,920 and 7,960 feet was repaired and pressure tested, which indicated that the total casing system had integrity.

Drill-out operations within the liner were resumed. A casing caliper log indicated a damaged section of titanium near where the bottom titanium section connected to the steel casing. Approximately 19 feet of steel casing was missing. The liner repair was unsuccessful, and it was decided to remove the entire liner and replace it. The workover was suspended to wait for the casing liner (Morgenthaler, 1986b).

July to September 1986 – Liner Replacement

After an extended period of time, due to washing and milling operations of the original 7-inch liner, the new liner was installed on July 16, 1986. The liner placed from 7,457 to 9,769 feet, consisted of: carbon steel N-80 casing from 7,457 to 8,671 feet, fiberglass wrapped carbon steel N-80 casing from 8,671 to 9,648 feet, and titanium casing from 9,648 to 9,769 feet. The liner was cemented with Class H cement containing 35 % silica flour and additives. Schlumberger temperature and RTS logs, run on September 3, 1986, indicated no upward migration of material and showed that fluid was entering formations below a depth of 9,800 feet. Successful pressure tests were run on September 12, 1986, following installation of 4-1/2-inch fiberglass injection tubing. Inhibited $CaCl_2$ brine was placed in the annulus, and the wellhead was reinstalled on September 12, 1986.

October 1986 – Pressure Testing

On October 22, 1986, two pressure tests were run. During the first test, the pressure dropped 80 psi, from 750 to 670 psig using a panel pressure gauge. The computer showed a loss of 73 psi, from 700 to 627 psig. The tubing was then flushed with about 6,000 gallons of brine, and the test was repeated. The gauge pressure dropped 80 psi, from 720 to 640 psig. The computer showed a pressure loss of 82 psi, from 717 to 635 psig (Ruff, 1986a). The well was retested on October 27, 1986, (a successful pressure test) and returned to service (Ruff, 1986b).

August 1988 to July 1990 - Workover

The injectivity of DeLisle Plant Well No. 3 dropped to an unacceptable level. Wireline investigation indicated fill in the base of the 7-inch liner. DeLisle Plant Well No. 3 was shut in and purged with 415,000 gallons of brine. The injection tubing parted during removal. The remaining tubing, packer, and screen were fished from the well.

Cleaning out of the open hole was complicated due to continuous sloughing of material into the wellbore. Geophysical logs revealed the source of the sloughing to be a cavern behind the 7-inch liner. The cavern was successfully cemented. Additional rubble was cleaned out of the well by stabilizing the rubble with cement, which was spotted in the open hole section. In an open hole section which has experienced severe sloughing and hole enlargement, normal circulation is not adequate to clean the hole. Hydrostatic bailing was not effective, probably due to the low ratio of volume recovered in each run to the total volume of rubble in the hole. A skirted bit was successfully used to prevent plugging of the tubing and clean out of the open hole. The well was cleaned out to a depth of 10,045 feet.

Fiberglass tubing was used as a liner in the open hole as the titanium pipe was found to be defective. The lead time for fabricating new pipe was nine months, which was unacceptable from a timing standpoint. A slotted liner, made of 4-1/2-inch fiberglass tubing with 24 slots per foot (2-inch x 0.032-inch), was run and set below a permanent packer on December 19, 1988 (Envirocorp, 1990). The top of the packer was set at 9,738 feet.

The diagnostic testing of DeLisle Plant Well No. 3 was prompted by the inability to maintain a positive pressure on a 750 psi annulus and open tubing. The test showed a 700 psi loss of pressure over a 12-hour period. The diagnostic testing conditions were designed to pinpoint the location of the leak (Commiskey, 1989). Multiple tests were conducted and determined that there was brine infiltration from the annulus to the tubing below a depth of 7,000 feet (highest inflow was found between 9,300 to 9,710 feet) when pressure was applied to the annulus. Tubing was cut at 9,606 feet and removed from the well. A test was conducted at simulated downhole conditions on fiberglass tubing connections. The preliminary test indicated that a 20 mil *Teflon*® shrink wrap over connections would seal them. The shrink wrap and sealant were tested by running a few connections into the well and pressuring the annulus. A slight leak was still present. It was determined that additional testing of the connection makeup and thread dope was required.

DuPont attempted to use a different thread dope (Dow-Corning RTV 736 silicone sealant) and *Teflon*® shrink wrap (60 mil thickness) combination. A few made-up joints were run into the well, but the same slight leak was present. Tubing and wireline tools were fished and pulled from the well.

The casing and packer were successfully re-tested. Less than 0.25 psi/hr of pressure bleed-off was noted. Five joints of fiberglass tubing with secondary protection seal ring and thread lubricant were run into the wellbore and successfully tested. New tubing with secondary containment seal (SCS) connections was ordered and installed. The annulus was filled with brine. The annulus was pressure tested, and it lost pressure due to the collapse of joint No. 39. The tubing was pulled from the well, and the casing and packer were tested again.

The 4-1/2-inch fiberglass injection tubing was reinstalled using 96 joints of previously used Red Box 2500 with SCS connections. An additional 16 joints of new fiberglass with SCS connections were purchased to complete the injection string. The tubing string was landed with 213 joints of Red Box 2000. The annulus was filled with $CaCl_2$ brine and left overnight. An attempt to refill the annulus the next morning with 40 bbls of $CaCl_2$ brine were unsuccessful. A spinner survey indicated a tubing leak at approximately 8,796 feet. The tubing was cut at 9,600 feet and pulled from the well. The remaining fiberglass and the titanium seal assembly were fished from the well.

It was decided to run a PBR, rather than a fixed packer seal, and attach it to the packer as this assembly had worked previously.

The PBR was installed in the packer at 9,738 feet. Fiberglass tubing was run, but it failed to maintain pressure integrity. A MicroResistivity log was conducted inside the tubing and indicated numerous tubing leaks. The fiberglass tubing was pulled from the well. The high bottomhole temperature (230ºF) in DeLisle Plant Well No. 3, along with collapse and compressional forces, were determined to be contributing factors in the fiberglass tubing leaks. The well was left idle while new fiberglass tubing was being made.

June to July 1990 – Tubing Pressure Test

Twenty joints of 4-1/2-inch internal upset end (IUE) FRP were run on the bottom of the work string, which was stung into the PBR at 9,717 feet. The tubing annulus was successfully pressure tested to 763 psi. The assembly was pulled from the wellbore. A seal assembly was run on the work string and stung into the packer. The injection liner was backwashed with nitrogen from 9,750 to 9,934 feet using coiled tubing. Electromagnetic Casing Caliper Inspection Logs were run on the 7-inch liner and 9-5/8-inch casing. A RTS was run with no evidence of upward migration of injectate. The work string was pulled from the hole, and the FRP injection tubing was picked up. Coiled tubing clean out was used to remove solids from the wellbore prior to installing the fiberglass tubing and starting injection. A full string of fiberglass tubing, consisting of 2,400 feet of 4-1/2-inch Red Box 2500 with a 2-foot long internal upset pin end (3.5-inch I.D. and 4-inch I.D. in tube) and 7,400 feet of 5-1/2-inch Red Box 2,500, was run in the wellbore. The well annulus was successfully tested to 753 psi and the well was returned to service.

December 1990 – Improvement of Injectivity

Injectivity of DeLisle Plant Well No. 3 did not meet acceptable operating criteria (injectivity) for the plant. A sample was collected with a wireline bailer, which indicated excess thread compound present in the tubing, slotted liner, and possibly the receiving interval. The affected areas were treated with the Gold Flush II, utilizing coiled tubing and nitrogen. This procedure did remove the excess thread compound, but did not alleviate the injectivity problems.

A spinner survey indicated that the injected fluid was exiting throughout the slotted interval. The well was treated with 50,000 gallons of 15% HCl. The maximum injection rate was 399 gpm with 1,181 psi surface injection pressure, and the BHP estimated to be 5,490 psi. However, the acid treatment did not significantly improve the injectivity of the well.

The slotted liner was perforated in three 40-foot sections (9,835 to 9,875 feet, 9,925 to 9,966 feet, and 9,988 to 10,028 feet), but the injectivity of the well still did not improve.

The disposal zone was treated with a total of 210,000 gallons of 3% brine water, of which the first 105,000 gallons contained a surfactant. An analysis of this data revealed a significant well skin effect (damaged zone) was present near the wellbore. Improvements to operating injection pressure from this treatment were minimal.

The upper area of the disposal zone was perforated at 9,777 to 9,797 feet and 9,800 to 9,820 feet; the well injectivity did not improve.

The well was backwashed utilizing coiled tubing and nitrogen, and solids were recovered through the perforations of the slotted liner. The well was purged with 8,000 gallons of 3-4% HCl. The injectivity of the well improved to a rate of 284 gpm at a surface injection pressure of 355 psi surface injection pressure (Envirocorp, 1990).

December 1992 – Interference Test

The observations from Continuous Flowmeter Surveys run during the testing showed that DeLisle Plant Well No. 3 was injecting an even distribution of fluid into the Middle and Lower sand lobes. However, there was no evidence of injection into the Upper sand lobe. The observations from the injectivity and falloff testing data showed that DeLisle Plant Well Nos. 2 and 3 were in communication through the top of the Middle Sand, based on observed pressures responses and Continuous Flowmeter Survey analysis (Rosenberg, 1993). The smallest pressure changes were observed in DeLisle Plant Well No. 3 (Rosenberg, 1993).

December 1996 - Plug-back and Temporary Abandonment

DeLisle Plant Well No. 3 was plugged back from the Washita-Fredericksburg sandstone in December 1996, and temporarily abandoned until preparation for a future sidetrack. Multiple cement plugs were set in the 7-inch titanium liner and carbon steel protection casing section up to a depth of 7,130 feet. The well was placed in a temporarily abandoned status.

December 1998 – April 1999 - DeLisle Plant Well No. 3--Sidetrack No. 1

The drilling of Sidetrack No. 1 began on December 14, 1998, with the final MIT performed on April 14, 1999. On December 14, 1998, a Grey Wolf Drilling Company rig was mobilized and set up. Sidetrack drilling operations began on January 1, 1999, with the running of a whipstock tool that was used to assist in the milling of a window in the existing 9-5/8-inch protective casing. From the window at a depth of 7,103 ft, a 9-7/8-inch hole was drilled using a bi-center bit on a downhole motor and directional drilling assembly to a total measured depth of 10,112 feet.

After drilling of the new hole was completed, openhole logs were run and rotary sidewall cores and formation fluid samples were collected. A 7-inch casing/liner was run into the well and cemented in place with epoxy resin cement. The 7-inch casing was set from a depth of 6,808 feet to 9,735 feet. The 7-inch liner was made up of Grade 7 titanium and carbon steel materials, with a single joint of fiberglass-reinforced plastic (FRP) casing placed between the two sections to prevent galvanic corrosion.

The well was completed in the Washita-Fredericksburg sandstone with a slotted FRP pipe placed across this openhole interval. A Grade 7 titanium packer was set in the 7-inch liner. The injection tubing consists of a 6-5/8-inch and 4-1/2-inch FRP tubing, with a Grade 7 titanium seal assembly. $CaCl_2$ brine, with corrosion inhibiting materials, was placed in the tubing-casing annulus, prior to landing the tubing with seals in the polished bore receptacle. A titanium landing joint was used in the wellhead. The well was then stimulated to remove formation damaging/plugging materials remaining from the sidetrack drilling fluid. Fifty thousand gallons of HCl acid and additive were used to stimulate the well.

The rig was moved off the site following the running of the FRP injection tubing. After the well had been stable for several days, an MIT was performed per MDEQ UIC Permit No. MSI1001 and U.S. EPA regulations. On April 12, 1999, the well's mechanical integrity was verified by wireline logging operations and pressure tests. A differential temperature survey, an APT, and RTS were performed. A BHP Falloff Test was performed April 13-14, 1999, following completion of MIT operations. The test was performed to quantify the well's reservoir characteristics and to verify communication with the other plant injection wells. Following completion of the BHP Falloff Test, the well was returned to the Plant for installation of surface injection and monitoring equipment.

September 1999 to December 1999 – Leak Repair and Acid Stimulation

Due to high injection pressures and low injection rates, DeLisle Plant Well No. 3 was taken out of service. Initial remedial operations included an acid stimulation treatment to improve the injection performance of the well. A total of 37,800 gallons (900 bbls) of 22% HCl were mixed with additives to obtain a blend of inhibited acid designed to dissolve particulates adjacent to the wellbore that were plugging the injection interval. The first joint of FRP tubing, a 6-5/8-inch by 4-1/2-inch crossover joint failed during the acid treatment.

This was confirmed during a video camera survey, which was run into the well. A new landing joint and wellhead equipment was designed and built. The new landing joint and wellhead eliminated the need for the crossover joint. Repairs were completed without a problem. A carbon steel work string was run inside the FRP injection tubing, and several additional acid stimulation procedures were performed. This acid stimulation was not effective in improving injection characteristics of the well. Plans were made to backwash the well, but before the start of those operations, the well lost integrity. Diagnostic tests indicated that a tubing, packer, or seal assembly-PBR leak had occurred. The MDEQ was notified, and plans were made to work over the well.

December 1999 – March 2000 – Workover

The FRP injection tubing and seal assembly was pulled from the well. Severe corrosion was noted on the titanium Grade-7 seal assembly. The polished bore receptacle, the packer, and the FRP slotted screen were all removed from the well. Severe corrosion was observed on all of the Titanium Grade-7 equipment. The loss in mechanical integrity was a result of this corrosion.

Operations were suspended and new equipment was ordered for the well. A new slotted screen, packer, polished bore receptacle, seal assembly, and FRP injection tubing string were ordered. After delivery of the new equipment, workover operations resumed. The open hole section was cleaned with a rotary hydro jetting tool, in conjunction with surface solids removal equipment. The fluid used to clean the injection interval was discarded to ensure that all fine size particles were removed and to ensure that the injection interval was as clean as possible.

The new screen and packer were placed in the well. A short seal assembly was run into the well on the work string and the well was stimulated with 224 bbls (9,400 gallons [gals]) of 10% hydrochloric acid, pumped down through the work string. The acid treatment improved the flow from +/-250 gallons per minute (gpm) with +/-700 pounds per square inch-gauge (psig) to 378 gpm with 750 psig.

The work string and short seal assembly was pulled out of the well. The polished bore receptacle was run into the well on the work string and set in the packer. The work string was then laid down. The seal assembly and FRP injection tubing was run into the well, with external pressure tests performed on each connection.

An MIT, including an APT, RTS, and differential temperature survey, were performed. All of the tests successfully demonstrated the structural integrity of the individual well casings, injection tubing string, and the wellhead. The RTS showed that the injected fluid was entering and remaining in the approved injection interval. (Sandia Technologies, LLC, 2000)

September-November 2003 – Workover

In February 2003, DeLisle Plant Well No. 3 was tested for mechanical integrity. The RTS and APT demonstrated that the well had mechanical integrity. However, during the injection-falloff test, the annulus pressure in the well suddenly fell to zero. The injection falloff test was completed without incident. The well was taken out of service, pending evaluation and repair.

In late February 2003, a multi-arm Sondex caliper log was run in the well to determine the location of the seal assembly in reference to the polished bore receptacle. The seal assembly was found to be in the correct position. A fluid resistivity log was run in the well to determine if fluid was entering the injection tubing from the annulus; however, fluid was not found to be entering the tubing from the annulus.

In late March 2003, differential temperature and audio (noise) logs were run in the well. These logs indicated problems in the area of the FRP transition joint in the liner. A procedure was prepared and equipment ordered to repair a suspected hole in the 7-inch liner.

In September 2003, a Moncla Well Service rig was mobilized and positioned over DeLisle Plant Well No. 3. The FRP injection tubing and seal assembly were pulled from the well. The polished bore receptacle (PBR) was removed from the well. When the PBR was retrieved, corrosion on the latch area was observed. This corrosion most likely occurred while the well was out of service. The existing injection packer was left in the well.

The FRP transition joint in the 7-inch liner was isolated with retrievable packers and pressure tested. The pressure testing confirmed that the loss in annulus pressure resulted from a loss in integrity in the FRP transition joint. A new injection packer was set immediately above the existing injection packer. A straddle packer assembly, with a latch mechanism, was attached to the new injection packer and packers set to isolate the FRP transition joint. A new PBR was then run and set in the top of the straddle packer assembly. A new seal assembly and FRP injection tubing string were placed in the well.

MIT tests, including an APT and a RTS, were performed. All of the tests successfully demonstrated the structural integrity of the casing, injection tubing, and the wellhead. The RTS also showed that the injected fluid was entering and remaining in the approved injection interval. The well was returned to service (Sandia Technologies, LLC, 2004).

August 2005 to March 2006 – Period of No Injection (Hurricane Katrina)

Hurricane Katrina made landfall on the Mississippi Gulf Coast and inflicted severe damage to the DeLisle facility operations. The plant was down for several months. During this period DeLisle

Plant Well No. 3 did not operate. The well was returned to injection service and has operated normally since January 2006, when the plant was restarted.

March to November 2018

DeLisle Plant Well No. 3 was reworked to replace completion equipment after the failed mechanical integrity test. The injection interval, below 9,750 feet, was isolated from the wellbore above to facilitate removal of completion equipment. A Reliable Production Services rig was mobilized and positioned over Well No. 3. All of the Fiberglass Reinforced Plastic (FRP) tubing and dynamic seal assembly, the polished bore receptacle (PBR), the upper straddle packer, the lower straddle packer with 75 feet of extension pipe, expansion joint, upper injection packer and lower injection packer were retrieved from the well after multiple fishing attempts.

After attempting to underream the open hole section, the interval was perforated in an attempt to open the formation and remove any near wellbore damage (skin). A new upper and lower Delta P Completions (DPC) Model 12 injection packer, with titanium Grade 7 wetted parts, was inserted into the well. A new straddle packer assembly to cover a damaged section of the protection casing was installed. A new PBR and dynamic seal assembly was installed. After installing and successfully pressure testing all of the new equipment, the seal assembly and FRP injection tubing were run into the well. After landing the injection tubing and assembling the wellhead equipment, the tubing-casing annulus was successfully pressure tested for a 30-minute period. On November 13, 2018, the official Annulus Pressure Test (APT) and a Radioactive Tracer Survey (RTS) were performed as part of the required mechanical integrity testing. All of the tests successfully demonstrated the structural integrity of the well's casing, injection tubing string, and wellhead, and confirmed that the injected fluid was entering and remaining in the approved injection interval. Mr. Jimmy Sparks of the MDEQ witnessed all of the testing and agreed that the tests had demonstrated the mechanical integrity of Well No. 3. The well was returned to the plant for injection service.

5.3.3 Current Well Design and Completion

The current completion (Figure 5-8) consists of a tapered string (5-1/2-inch, FRP fiberglass to 6,689 feet and 4-1/2-inch, FRP fiberglass from 6,689 to 9,738 feet) set into a GPS Model 12 packer. A GPS floating seal assembly is set on the end of the injection tubing string at approximately 9,762 feet. The burst pressure of the tubing is 2,500 psi; the collapse pressure is 3,300 psi; and the respective tensile strengths of the tubing are 54,500 and 47,800 lbs. Volumes are calculated in Table 5-18 and calculated tubular stresses (Table 5-19) are less than manufacturer-rated stresses.

The annular fluid is corrosion-inhibited $CaCl_2$ brine solution (1.25 SG). The permitted annulus pressure differential is at least 25 psig. A type log of DeLisle Plant Well No. 3 is included as Figure 5-10. The injection zone, injection interval, and formation tops are labeled on the log.

5.4 DELISLE PLANT WELL NO. 4 (MSI1001)

5.4.1 Drilling, Original Design/Construction, and Original Completion

5.4.1.1 Drilling

DeLisle Plant Well No. 4 (MSI1001) was originally permitted by the state of Mississippi under the NPDES on August 4, 1981, and the permit was modified by MDEQ on January 23, 1992. The well was spudded on June 21, 1982 and drilled to a TD of 10,045 feet into the Washita-Fredericksburg sandstone (DuPont, 1985a). A 20-inch hole was drilled to 3,750 feet and surface casing was set to 3,745 feet. A 14-3/4-inch hole was then drilled to TD. Protection casing was set to 9,772 feet. The string includes: 9-5/8-inch pipe from surface to 9,738 feet, 8-5/8-inch pipe from 9,738 to 9,746 feet, and 7-inch casing from 9.746 to 9,772 feet. Drilling was completed on October 18, 1982. Results of the borehole deviation survey are shown in Table 5-20. Figure 5-11 is a current well schematic.

Sidewall core samples were taken during drilling operations and were analyzed for porosity and permeability (see Appendix 2-22 in Section 2.0 - Geology).

Caliper, induction/electric, and nuclear porosity logs were run to evaluate formation characteristics and to determine the hole volume for cementing operations.

5.4.1.2 Original Design/Construction

Surface casing (16-inch, 84 lb/ft, K-55, carbon steel) was set to 3,705 feet (see Table 5-21 for casing and tubing summary) (DuPont, 1985a). This casing has a burst pressure of 2,980 psi, a collapse pressure of 1,410 psi, and a tensile strength of 1,326,000 lbs.

The surface casing was cemented to the surface with 6,969 sx of Pozmix/HLC (1.25 lb/sack Flocele) and 600 sx of Class H cement (3.0 % salt, 0.35 % $CaCl_2$), effectively sealing off the formation from the wellbore (see Table 5-22 for cementing summary). The cement was circulated through a float shoe on the bottom of the casing and good returns were noted at the surface.

The surface casing and cement are compatible with native formation fluids (brine). The type of tubular materials used is similar to those used in most petroleum exploration wells drilled in the area.

Protective casing (9-5/8-inch by 53.5 lb/ft, N-80) was set from 0 to 9,320 feet; 9-5/8-inch by 1/2-inch wall titanium casing from 9,320 to 9,359 feet; 9-5/8-inch 53.5 lb/ft N-80 casing with external Fibercast epoxy from 9,359 to 9,641 feet; 9-5/8-inch by 1/2-inch wall titanium casing from 9,641 to 9,738 feet; 8-5/8-inch titanium set from 9,738 to 9,746 feet; 7-inch titanium set from 9,746 to 9,754 feet; and 7-inch steel casing with float collars and float shoe from 9,754 to 9,772 feet. These casings have respective burst pressures of 7,930 and 3,636 psi and respective collapse pressures of 6,620 and 2,520 psi. The tensile strength of the casing is 1,244,000 lbs.

The protective casing was cemented in three stages to the surface through a float shoe on the bottom of the string and through DV tools set at 3,705 and 8,300 feet. A total of 19,744 gallons (470 bbl) of *Epseal*® LC (with WAC-9 additive) were used in the first stage of cementing. This cement was not circulated because the cement flash set before the DV tool could be opened. The top of the cement was established at 8,340 feet by a temperature log, and the casing was perforated at 8,300 feet for second stage cementing. The second stage consisted of 5,710 sx of Class H cement (35 % SSA-1, 0.4 % Halad 22-A, and 0.5 % CFR-2) followed by 100 sx of Class H with 3.0 % salt. The upper DV tool was opened, and 1,850 sx of Pozmix/HLC (0.2 % Halad 4) cement were circulated to seal off the wellbore from the injection formations and to provide a double seal between the wellbore and the formations. Centralizers were used to enable the cement to circulate around the casing with cement returns noted at the surface (DuPont, 1985a).

Caliper and electric logs were run in the open hole prior to completion to evaluate formation characteristics and to determine hole volume for cementing operations. A cement bond log was also run in the well to determine cement integrity.

5.4.1.3 Original Completion

DeLisle Plant Well No. 4 was originally completed on October 18, 1982, as an open hole completion into the Washita-Fredericksburg sand from 9,772 to 9,985 feet (DuPont, 1986a, b). This well was drilled vertically with less than 2.0° deviation.

5.4.2 Well History DeLisle Plant Well No. 4

November 1982 – Acidization

A total of 450,000 gallons of 10% HCl and 2% iron chloride aqueous solution was injected into the well. This solution would react all the calcium carbonate ($CaCO_3$) present in the Washita-Fredericksburg sand within a 15 foot radius of the borehole, with the pores in that radius filled with the solution of 10% HCl concentration (Spitler, 1982). The iron chloride portion of the solution was used to prevent damage to the downhole titanium tubulars. During the treatment, annulus brine consumption was slightly above normal, which was attributed to wellbore stabilization. After several weeks of operation, brine consumption rose to the 40-50 gallons per hour (gph) range, and a decision was made to rework the well (McDonnell, 1983).

December 1982 – Workover – Tubing Leak Repair

During the workover, several tubing leaks were indicated by brine crystal deposits located at the joint connections on the tubing string (McDonnell, 1983). A leak was found at the joint between the top of the stinger seal nipple and the fiberglass tubing. The female threads in the seal nipple were found to not be the required long thread design. The female connection was rethreaded for long threads and cemented with a male fiberglass long thread connection. The new connection was reinstalled with a spare injection string and the workover was completed with a successful pressure test performed on December 21, 1982 (McDonnell, 1983).

January 1985 – Leak Repair and Well Test

A 9-5/8-inch casing leak was repaired in January 1985. On January 18, the casing was tested for its mechanical integrity, using the normal 4-1/2-inch fiberglass injection tubing. The well was pressured to 1,567 psi with 1.086 SG fluid. At the end of a 30 minute test period, the annulus had lost a total of 142 psi. The slope of the pressure decline curve at the end of the test was at a zero derivative. Compressibility of the fiberglass tubing string, when subjected to outside pressure, was the suspected reason for the pressure loss noted during testing. The examination of the pressure decline curve during testing showed this compressibility factor. The test was considered to be successful (Decker, 1986).

May 1986 – Brine Leakage

Due to a high rate of brine usage (~80 gph) experienced during well operations in early April, the well was tested. The analysis of data from the testing showed: first, a nominal 10 gph brine leak located most likely in the casing at the site of the cement repair; and second, a major portion of the leak was due to the position of stinger chevrons within the polished bore receptacle. The leak did not exceed 60 gph (versus 80 gph previously) during the well testing. A pressure test of the annulus showed no indication of tubing or casing leakage. On well restart, brine usage was 9-12 gph. The variation in brine usage was attributed to a change in the position of the stinger. DeLisle Plant Well No. 4 was left in service as a viable backup (40 gph brine loss versus 80-100 gph) for DeLisle Plant Well No. 2 (Commiskey, 1986).

August 1985 – Tubing Failure

Analysis of geophysical logs run in the well by Schlumberger Well Surveys indicated that the casing suffered some damage in the lower limits of the well as a result of a tubing failure. These damaged areas in the casing were subsequently repaired by squeeze cementing. The tubing string was rerun and was successfully tested up to levels exceeding 125% of normal operating pressures used during system operations (DuPont, 1986).

February 1992 – Workover – Tubing Replacement

The well experienced a loss of differential annulus pressure. To establish a pressure differential of 25 psi, a total of 18,000 gallons of 1.25 SG $CaCl_2$ brine was pumped into the injection tubing and 8,200 gallons was pumped into the annulus. Injection tubing joint number 32 parted while the tubing string was being pulled from the well. The remainder of the tubing was fished out of the well and inspected before it was rerun back in the well. The top 34 joints of tubing were replaced (Jackson, 1992).

March 1992 – Workover – Tubing Leak Repair

Due to excessive brine consumption, approximately 817 gallons used in 24 hours (permit limit 550 gallons per 24 hours), the well was purged with 8,000 gallons of brine. The annulus was pressure tested, and failed. Schlumberger's Micro Resistivity Log indicated leaks in the tubing at depths of 1,500 feet, 2,050 feet, and 2,560 feet. While removing the injection tubing, the tubing parted and the remaining 147 joints and seal assembly had to be fished out of the well. A casing caliper log was run in the 7-inch and 9-5/8-inch casing and the casing was pressure tested with a test packer, showing no leaks in the casing. A total of 325 joints of tubing were run in the well and a successful annulus pressure test provided was performed on the well (Envirocorp, 1992a).

July to August 1992 – Workover – Tubing Leak Repair

Due to an excessive loss of annular fluid in the well, a total of eight pressure tests were performed after purging the injection tubing with 15,000 gallons of brine water. A Micro-Resistivity/Temperature Survey was conducted to determine the location of the leak. The survey reflected the intrusion of annular brine water into the injection tubing in the area of 8,680 feet. The fiberglass injection tubing was removed from the well. The injection string, consisting of 100 joints (2,974 feet) of 4-1/2-inch IUE Red Box 2500 and 225 joints (6,692 feet) of 5-1/2-inch Red Box 2500, was rerun in the well. All of the fiberglass connections were installed utilizing the controlled torque method. An external hydrostatic pressure test was used to test the sealing properties of each tubing connection. A successful annular pressure test confirmed the mechanical integrity of the 9-5/8-inch protection casing, the 7-inch liner, the packer, and the fiberglass injection tubing (Envirocorp, 1992b).

December 1992 – Interference Test

The observations from the Continuous Flowmeter Surveys showed that DeLisle Plant Well No. 4 was injecting into the upper, middle, and lower portions of the Washita-Fredericksburg Sand. Approximately 50% of the fluid was observed going into the upper and middle sands. The observations from the injectivity and falloff testing data showed that DeLisle Plant Well No. 2 is communicating with DeLisle Plant Well No. 4, primarily through the upper sand, with a minor amount of communication through the top of the middle sand (Rosenberg, 1993). The largest overall pressure change, 80 psi, was observed in DeLisle Plant Well No. 4 while DeLisle Plant Well No. 2 was injecting (Rosenberg, 1993). More details of the interference test are presented under Monitor Well No. 1- Interference Test of this report (Section 5.1.4).

May-August 1995 – Sidetrack No. 1 DeLisle Plant Well No. 4

The lower section of the original wellbore was plugged and the well was sidetracked above the plugged interval. The well was recompleted into the Washita-Fredericksburg Injection Interval. Field activities began in May 1995 with mobilization of the drilling rig. Existing completion equipment was removed from the well and the wellbore was plugged to the top of the original 7-inch liner. A whipstock was set at 7,483 feet and used to sidetrack from the 9-5/8-inch casing at that point. A directional hole was drilled adjacent to the original wellbore to a depth of 10,040 feet (measured depth), and a 7-inch liner was set and cemented from 7,254 to 9,738 feet. The well was completed as an openhole completion, with a slotted fiberglass injection screen installed below a titanium Grade 7 packer. A tapered string of 4-1/2-inch and 5-1/2-inch FRP tubing was stung in the packer to complete the well.

An MIT was performed to demonstrate well competency. The APT confirmed soundness of the casing, tubing, wellhead, and injection packer. A RTS verified that flow of injected fluids was confined to the Washita-Fredericksburg Injection Interval. Field operations were concluded in late August 1995, and the well was returned to the plant for normal service.

December 1996 - Acid Stimulation Treatment

DeLisle Plant Well No. 4 was stimulated with a 50,000 gallon (1,190 bbl) 10% hydrochloric acid buffer treatment containing chemical corrosion inhibitor, surfactant, and clay stabilizer additives. The acid was pumped in five stages of 9,600 gallons each. Between each stage, 500 gallons of diverting agent (benzoic acid flakes) were pumped as part of the stimulation treatment. After the last stage of acid, 10,000 gallons of 2% potassium chloride brine, with methanol, was pumped as the final part of the treatment. The methanol solution speeds the degradation of the benzoic acid flakes. The entire treatment was displaced with 9.0 ppg sodium chloride brine. The well was shut-in after the brine displacement and left in this condition until the 1996 pressure falloff test was conducted (see discussion below). An evaluation of injection parameters following the acid treatment indicated this stimulation procedure only provided marginal well improvement.

December 17-18, 1996 - Bottomhole Pressure Falloff Test

DeLisle Plant Well No. 4 was selected for testing in 1996 because it was stimulated with acid prior to the falloff test. For the bottomhole pressure falloff test, flowing pressures were monitored for 4-hour duration immediately prior to shutting the well in at surface. The well was shut-in for an 18 hour fall-off period, with the gauge placed at a depth of 9,750 feet. The final injection rate prior to shut-in was 8,640 bbl/day. Based on the test interpretation, radial flow occurred after 6 hours into the fall-off period.

December 18-20, 1996 - Interference Test -- Well Nos. 2, 4, and 5

After completing the annual bottomhole pressure falloff test on DeLisle Plant Well No. 4, a 30-hour interference test was conducted between Well Nos. 2, 4, and 5. The bottomhole pressure falloff test concluded at 5:15 p.m. on December 18th, and the interference test was initiated. Injection into DeLisle Plant Well No. 2 was ceased at 7:10 p.m., with the recorded final injection rate at 11,590 bbl/day. Shut-in bottomhole pressures in DeLisle Plant Well No. 4 continued to be recorded as the influence of the injection effects from DeLisle Plant Well No. 2 were observed. At 11:15 p.m., the plant began injection into DeLisle Plant Well No. 5. Shut-in bottomhole pressures in DeLisle Plant Well No. 4 continued to be recorded as the influence of DeLisle Plant Well No. 5 injection was observed. Recorded pressures in DeLisle Plant Well No. 4 were influenced both by the injection startup of DeLisle Plant Well No. 5 and the previous shut-in of DeLisle Plant Well No. 2.

DeLisle Plant Well No. 5 was operated at an injection rate of ± 475 gpm rate for approximately 24 hours. At 11:07 p.m. on December 19, 1996, injection in DeLisle Plant Well No. 5 was stopped while down-hole pressure continued to be collected at DeLisle Well No. 4. After several hours of shut-in, the influence of pressure transient from DeLisle Plant Well No. 5 was observed at DeLisle Plant Well No. 4. Due to high fluid levels in the injection well storage vaults (tanks), injection was resumed into the other injection wells, concluding the test at 2:00 a.m. on December 20, 1996.

August 15-17, 1997 - Interference Test -- Well Nos. 2, 4, & 5

This interference test consisted of injection and pressure monitoring operations in DeLisle Plant Well No. 5 and injection operations in offset Well Nos. 2 and 4. A summary of the test is provided in Section 5.5 - Well History – DeLisle Plant Well No. 5.

August 2005 to March 2006 – Period of No Injection (Hurricane Katrina)

Hurricane Katrina made landfall on the Mississippi Gulf Coast and inflicted severe damage to the DeLisle facility operations. The plant was down for several months. During this period DeLisle Plant Well No. 4 did not operate.

February – September 2013 – Workover – Tubing Leak Repair

Due to loss in annulus pressure, DeLisle Plant Well No. 4 was taken out of service for testing and repair. An injection tubing leak at approximately 250 feet was determined to be the cause of the annulus pressure loss. The FRP injection tubing string and seal assembly were pulled and fished out of the well. A 12-inch underreamer and 6-1/8-inch rock bit were used to enlarge the open hole from an initial diameter of 8-1/2-inches to a final diameter of 12-inches, with the open hole section being opened up from a depth of 9,750 feet to a depth of 10,040 feet. A new DPI Model 12 Packer, with Titanium Grade 7 wetted parts, was inserted into the well. A new PBR was then placed in the well. After installing and successfully pressure testing the new equipment, a seal assembly and FRP injection tubing were run into the well. All of the mechanical tests successfully demonstrated the structural integrity of the well's casing, injection tubing string, and wellhead, and confirmed that the injected fluid was entering and remaining in the approved injection interval. The well was returned to the plant for injection service (Sandia Technologies, LLC, 2013).

5.4.3 Current Design and Completion

The current open hole completion (Figure 5-11) is in the Washita-Fredericksburg Sand from a depth of 9,738 to a depth of 10,040 feet. The injection tubing consists of 83 joints of 4-1/2-inch EUE Red Box 2500 tubular fiberglass, one 4-1/2-inch to 6-5/8-inch EUE Red Box 2500 crossover joint, and 244 joints of 6-5/8-inch EUE Red Box 2500 tubular fiberglass. The DPI seal assembly is set at a depth of 9,662 feet. The DPI Model 12 polished bore receptacle is set from 9,662 feet to 9,683 feet in the well and the 7-inch Titanium Grade 7 injection packer (DPI Model 12) is set from 9,683 feet to 9,688 feet (mid element set at 9,686 feet).

The injection screen consists of 2 joints of 4-1/2-inch Red Box 2500 tubing, set from 9,688 feet to 9,747 feet and 9 joints of slotted 4-1/2-inch Red Box 2500 tubing set from 9,747 feet to 10,013 feet (266 feet of slotted tubing screen). A bull plug is set on the bottom of the slotted tubing screen at a depth of 10,014 feet. The slotted tubing liner has 132 slots per foot, with individual slots being 3 inches long and 0.04 inches wide.

The annular fluid is corrosion-inhibited 10.5 ppg $CaCl_2$ (at SG of 1.25). The MDEQ permit requires a pressure differential in the annulus of at least 25 psig. A type log of DeLisle Plant Well No. 4 is included as Figure 5-13. The injection zone, injection interval, and formation tops are labeled on the log.

The wellhead for DeLisle Plant Well No. 4 (Figure 5-12) was replaced during the 2013 workover. The existing casing spool was removed from the wellhead and replaced with a new 16-3/4-inch, 3,000 psi x 11-inch, 5,000 psi casing spool. The existing casing spool showed no signs of corrosion, but was replaced due to age and lack of a replacement tubing hanger. A tee with a full opening gate valve on top of the well head will allow the use of workover tools and test equipment to access the wellbore. The wellhead and gate valves are rated to 3,000 psi maximum service pressure. Pressure gauges continuously read the injection tubing and annulus well head pressures (other surface control systems are identified in Table 5-23).

Volumes are calculated in Table 5-24 and calculated tubular stresses (Table 5-25) are less than manufacturer-rated stresses.

5.5 DELISLE PLANT WELL NO. 5 (MSI1001)

5.5.1 Drilling, Original Design/Construction and Original Completion

5.5.1.1 Drilling

DeLisle Plant Well No. 5 (MSI1001) was originally permitted by the state of Mississippi under the NPDES program on October 13, 1992, and spudded on December 11, 1992. The well was drilled to a TD of 10,050 feet into the Washita-Fredericksburg sand (DuPont, 1993). Twenty-inch conductor pipe was driven and set at a depth of 406 feet. A 17-1/2-inch hole was drilled to 3,506 feet and 13-3/8-inch surface casing was set at a depth of 3,444 feet. A 12-1/4-inch hole was then drilled to a TD of 10,050 feet. Protective casing includes: 9-5/8-inch carbon steel set at a depth of 8,550 feet and fiberglass (FRP) wrapped casing from 8,550 to 9,586 feet. A 10-3/4-inch (FRP) transition joint was set from 9,586 to 9,611 feet, and 9-5/8-inch Titanium Grade 7 casing was set from 9,611 to 9,765 feet. Drilling was completed on January 27, 1993. Results of the borehole deviation survey are shown in Table 5-26. Figure 5-14 is a current downhole well schematic (Envirocorp, 1994).

Ten sets of conventional core samples were taken during drilling operations and were analyzed by for porosity and permeability (see Appendix 2-22 in Section 2.0 Geology).

Caliper, induction/electric, and nuclear porosity logs were run to evaluate formation characteristics and to determine the hole volume for cementing operations.

5.5.1.2 Original Design/Construction

The conductor pipe (20-inch) was set at 406 feet. Six hundred sx of Class A cement were pumped around the conductor pipe for extra stability. Surface casing (13-3/8-inch, 68 lb/ft, N-80, carbon steel) was set to 3,444 feet (see Table 5-27 for summary of casing and tubing). This casing has a burst pressure of 5,020 psi, a collapse pressure of 2,260 psi, and a tensile strength of 1,300,000 lbs. The surface casing was cemented in two stages, with a DV tool located at a depth of 1,700 feet. The first stage consisted of 3,125 sx of 12.4 pound per gallon (ppg) Halliburton Light Cement (HLC) and 1,763 sx of Class A mixed at 16.4 ppg, which was circulated through a float shoe on the bottom of the casing. The DV tool was opened and an additional 3,256 sx of HLC were pumped. A temperature tool was run into the well and found that the cement top was located at a depth of 240 feet from the surface. One-inch pipe was lowered down the surface casing annulus, and 150 sx of Class A were pumped, which effectively sealed the wellbore (see Table 5-28 for summary of cementing).

The surface casing and cement are compatible with native formation fluids (brine). The type of tubular materials used is similar to those used in most petroleum exploration wells drilled in the area.

Protective casing (9-5/8-inch by 43.5 lb/ft, N-80) was set from 0 to 8,550 feet, and 9-5/8-inch FRP wrapped casing from 8,550 to 9,586 feet. A 10-3/4-inch FRP Transition Joint was set from 9,586 to 9,611 feet, and 9-5/8-inch by 1/2-inch wall titanium Grade 7 casing was set from 9,611 to 9,765 feet (Envirocorp, 1994). The 9-5/8-inch N-80 casing has a burst pressure of 6,630 psi and a collapse pressure of 3,810 psi. The tensile strength of the casing is 737,000 lbs.

The protective casing was cemented in four stages. The first stage consisted of 3,318 gallons (79 bbl) of *Epseal*® epoxy resin cement. After displacing the *Epseal*®, the FRO cement tool was opened at 8,969 feet, and 2,818 sx of premium cement with 0.6 % Halad-322 and 0.5 % Lap-1 were pumped. A temperature log was run and the top of cement was found at approximately 6,450 feet. The casing was perforated above the top of cement, and the annulus was circulated with mud. An EZSV cement retainer was set at 6,325 feet, and cement was circulated up the annulus. This cement consisted of 767 sx of HLC, with 0.2 % CFR-3 and 0.2 % Halad 322, followed by 180 sx of premium cement containing latex. The FRO cement tool at 3,801 feet was then opened and 1,100 sx of HLC, with 0.2 % CFR-3 and 0.2 % Halad-322, were pumped, effectively sealing the annulus.

Caliper and electric logs were run in the open hole prior to completion to evaluate formation characteristics and determine hole volume. A cement bond log was also run in the well to determine cement integrity.

The wellhead at DeLisle Plant Well No. 5 (Figure 5-15) consists of a 12-11/16-inch bore casing head and an 11-inch bore tubing head, both made of carbon steel (the waste stream does not come in contact with the wellhead). The wellhead is rated to 3,000 psi maximum service pressure.

Pressure gauges continuously read and record the injection tubing and annulus wellhead pressures (other surface control systems are identified in Table 5-29).

5.5.1.3 Original Completion

DeLisle Plant Well No. 5 was originally completed on June 1, 1994, with a screened interval from 9,765 to 10,050 feet into the Washita-Fredericksburg sandstone (Envirocorp, 1994). The well was drilled vertically with a maximum deviation of 1.75° of the wellbore.

5.5.2 Well History -- DeLisle Plant Well No. 5

June 1994 – Acid Stimulation

An acid stimulation was performed due to poor initial well injection performance. The well was purged with filtered brine and a stimulation treatment was performed using 53,400 gallons (1,271 bbl) of 10 % HCl, with additives. Injectivity increased from 130.2 gpm (3.1 bpm) at 600 psi (pre-job) to 294 gpm (7.0 bpm) at 600 psi (post-job). A temperature survey, RTS, and bottom-hole pressure fall-off test were conducted following the acid job (Conoco, 1994).

August 1994 – Initial Injection

The first injection of waste occurred into DeLisle Plant Well No. 5, following a buffer injection of 250,000 gallons (5,952 bbl) of HCl acid. The HCl acts as a buffer fluid to pretreat the Washita-Fredericksburg sand.

September 15-26, 1995 - Permit Revision -– Startup Flow Rates

On September 15, 1995, a request was submitted to the MDEQ to raise the maximum permitted startup injection rate on DeLisle Plant Well No. 5. This increase was for startup purposes only, limited to the first eight hours of operation, with the allowable injection rate not exceeding 1,000 gpm. The increased rate was necessary due to the high completion efficiency of the well as compared to the other three injection wells. On September 26, 1995 the MDEQ permit was revised to include a 2,200 gpm site limit.

August 15-17, 1997 - Bottomhole Pressure Falloff Test -Interference Test - Well Nos. 2, 4, & 5

The annual bottomhole pressure fall-off test was performed on DeLisle Plant Well No. 5 and interference from a second well. The requirement for testing two wells per year was in effect until DuPont could collect several years of bottomhole pressure falloff data from DeLisle Plant Well No. 5 and demonstrated that all of the injection wells were in direct pressure communication.

Analysis of the data demonstrates that the Washita-Fredericksburg sand in DeLisle Plant Well No. 5 is in direct pressure communication with the other plant injection wells. Although this test proved interwell communication, it did not allow for detailed analysis of the interwell reservoir properties, since the length of each injection pulse or interference period was limited due to plant operating constraints.

February 2004 – Leak Repair

Diagnostic wireline logs were run in DeLisle Plant Well No. 5 in an attempt to locate the cause of increased annulus fluid usage. A differential temperature survey, an audio survey, and a fluid resistivity log were run, all with limited success in identifying the cause of annulus fluid losses. The annulus pressure loss was less than the 5 % pressure loss allowed by MDEQ guidelines, however, because the loss rate was higher than previous tests, the MDEQ requested that the well be taken out of routine service until a workover could be performed on the well.

June 2004 to February 2005 - Workover

A workover to restore mechanical integrity to DeLisle Plant Well No. 5 was performed during the period from June 11, 2004, to February 10, 2005 (Sandia Technologies, LLC, 2005). The workover identified a separation in the injection tubing and a potentially leaky multi-stage cementing tool. A new injection packer was placed directly above the old packer, due to concerns about the condition of the old packer. The old straddle packer assembly was removed and replaced with a new straddle packer assembly to isolate a leak located in the FRP transition joint. The PBR was refurbished and an extension added below the PBR. The seal assembly was refurbished and a new string of FRP injection tubing was placed in the well.

DeLisle Plant Well No. 5 underwent the required post-workover MIT on February 9 – 10, 2005. The MIT consisted of a differential temperature survey, an APT, and a RTS. The APT and DTS were both conducted on February 9, and the RTS was conducted on February 10. All tests met regulatory criteria for a successful test and the well was returned to injection service.

August 2005 to March 2006 – Period of No Injection (Hurricane Katrina)

Hurricane Katrina made landfall on the Mississippi Gulf Coast and inflicted severe damage to the DeLisle facility operations. The plant was down for several months. During this period DeLisle Plant Well No. 5 did not operate.

April to September 2015 – Workover – Completion Equipment Replacement

All of the FRP tubing and seal assembly, the PBR with 4-1/2-inch titanium extension pipe, the upper straddle packer with 86 feet of extension pipe, the lower straddle packer, and injection packer were retrieved from the well. The lower injection packer was retrieved after multiple fishing attempts. The open hole section was opened to a 16-inch diameter from a depth of 9,768 feet to 10,000 feet. A new upper and lower DPI Model 12 injection packer, with Titanium Grade 7 wetted parts, was inserted into the well. A new straddle packer assembly to cover a damaged section of the protection casing was installed. The new PBR, with 4-1/2-inch titanium extension pipe and anchor seal assembly, was installed. After installing and successfully pressure testing all of the new downhole equipment, the seal assembly and FRP injection tubing were run into the well. All of the mechanical tests successfully demonstrated the integrity of the well before it was returned to the plant for injection service (Sandia Technologies, LLC, 2015).

5.5.3 Current Well Design and Completion

The current open hole completion (Figure 5-14) is in the Washita-Fredericksburg sand from a depth of 9,765 to 10,058 feet. The injection tubing consists of a 6-5/8-inch Titanium Grade 2 landing joint located 25.5 to 33 feet; 195 joints of 6-5/8-inch BB-2500 NU from 33 to 5,724 feet; and 127 joints of 6-5/8-inch BB-2500 IUE from 5,724 to 9,460 feet. The DPI Titanium Grade 7 seal assembly is located from 9,460 to 9,483 feet. One Titanium Grade 7 6-5/8-inch by 4-1/2-inch crossover joint and the PBR are located from 9,466 to 9,489 feet is followed by 11 joints of 4-1/2-inch Titanium Grade 7 located from 9,489 feet to 9,691 feet. The Titanium Grade 7 anchor seal assembly is located at a depth of 9,694 feet. The burst pressure of the tubing is 2,500 psi, and the collapse pressure is 3,300 psi. The tensile strength of the 4-1/2-inch tubing is 47,800 lbs, and the tensile strength of the 6-5/8-inch tubing is 73,600 lbs. Volumes are calculated in Table 5-30 and calculated tubular stresses (Table 5-31) are less than manufacturer-rated stresses.

As shown in Figure 5-14, DeLisle Plant Well No. 5 utilizes a retrievable liner to straddle the transition between the top of the protection casing (made of carbon steel) to the bottom section (made of Titanium Grade 7). The retrievable liner is located from a depth of 9,507 feet to 9,686 feet. Above the upper packer of the retrievable liner is a seal assembly made of carbon steel and is located from 9,679 to 9,682 feet. The upper packer is a Delta P, Incorporated (DPI) Model 12 9-5/8-inch by 7-5/8-inch carbon steel located from 9,507 feet to 9,513 ft, with a minimum internal diameter (ID) of 5.75 inches. The liner is made of 7-5/8-inch 29.7 ppf L-80 collared. It is located between 9,513 feet and 9,679 ft, with a minimum ID of 6.876 inches. The lower packer of the retrievable liner is a DPI Model 12 9-5/8-inch carbon steel packer, with a minimum ID of 5.75 inches. The lower packer is located from 9,680 feet to 9,686 feet.

Well 5 also uses two injection packers. The upper injection packer is a DPI Model 12 9-5/8-inch by 4-1/2-inch Titanium Grade 7 packer set at 9,692 feet to 9,699 feet. Elements are located at 9,696 ft; the alignment extension is inside the lower injection packer to 9,699 feet. The upper packer has a minimum ID of 4.75 inches. The lower injection packer has a DPI Model 12 9-5/8-inch by 6-5/8-inch Titanium Grade 7 packer set at 9,697 feet to 9,703 feet with a minimum ID of 4.75 inches.

The injection screen assembly consists of 1 blank joint of 6-5/8-inch BB-2500 FRP tubing from 9,703 to 9,733 feet. This is followed by 10 joints of slotted fiberglass screen from 9,733 to 10,028 feet. The screen has 46 slots per foot. The slots are 3 inches long and 0.15 inches wide. A bull plug is set at a depth of 10,028 feet at the base of the slotted FRP.

The open hole from 9,765 to 10,058 feet was drilled to a 12-1/4-inch diameter and was underreamed to a 16-inch diameter from 9,765 to 10,000 feet.

The annular fluid is brine (at SG 1.25) with an oxygen scavenger. The permit-required annulus pressure differential is at least 25 psig. A type log of DeLisle Plant Well No. 5 is included as Figure 5-16. The injection zone, injection interval, and formation tops are labeled on the log.

5.6 PROPOSED DELISLE PLANT WELLS NOS. 6 AND 7

Proposed DeLisle Plant Wells Nos. 6 and 7 are intended to handle site expansion and serve as a back-up well for Well Nos. 2, 3, 4, and 5. DeLisle Plant Well No. 6 was approved within the 2000 EPA Petition Exemption, and the DeLisle Plant's MDEQ injection well permit, MSI1001. Proposed Well No. 7 will be included in the MDEQ permit in 2027. Proposed DeLisle Plant Wells Nos. 6 and 7 will be completed either into the Washita-Fredericksburg sand or into the Massive Tuscaloosa Sand.

5.6.1 Location and General Information

Proposed DeLisle Plant Wells Nos. 6 and 7 will be located in the northern section of the DeLisle Plant to minimize pressure interference from the existing injection wells. Refer to Section 1 for approximate location coordinates. The estimated ground level elevation in this area of the plant is approximately 25-30 feet above sea level.

5.6.2 Summary of Drilling Program and Design

Proposed DeLisle Plant Wells Nos. 6 and 7 are planned to be drilled to an approximate total depth (TD) of 10,100 feet and completed into the Washita-Fredericksburg sand as an open hole completion. Best engineering practices will be followed during installation of the new well. Drilling, logging, and cementing practices for proposed DeLisle Plant Wells No. 6 and/or Well No. 7 will utilize similar construction techniques employed for installation of DeLisle Plant Well No. 5, except that the well design and completion will differ. A downhole well schematic of the proposed construction design for Plant Well No. 6 is included as Figure 5-17 and Well No. 7 as Figure 5-19. These figures show details of proposed tubular components, cement, packer, and well completion equipment.

A summary of the proposed casing program design detailing the tubing completion program for DeLisle Plant Wells Nos. 6 and 7 is given in the following sections.

5.6.3 Detailed Well Construction and Design

Proposed DeLisle Plant Wells Nos. 6 and 7 are designed for injection into the Washita-

Fredericksburg sand or the Tuscaloosa Massive sand as replacement wells and/or business expansion well for the existing injection well field at the DeLisle Plant.

5.6.3.1 Description

Proposed DeLisle Plant Wells Nos. 6 and 7 will be vertical injection wells with an open hole completion in the Washita-Fredericksburg sand or in the Massive Tuscaloosa sand. The subsurface depth of the Washita-Fredericksburg sand injection interval is expected to be at a depth of ± 9,700 to 10,100 feet. The subsurface depth of the Tuscaloosa Massive sand injection interval is expected to be at a depth of 9,300 to 9,600 feet.

Conductor casing (20-inch O.D.) will be set to approximately 500 feet. Surface casing (13-3/8-inch O.D.) will be set and cemented below the lowermost USDW, at a depth of approximately 2,700 feet. During drilling operations in the protection hole, from a depth of 2,700 feet to total depth, formation cores are proposed to be taken in the confining shale, injection zone, and injection interval. A 9-5/8-inch O.D. protection casing string, consisting of carbon steel, transition joint(s) from carbon steel to corrosion-resistant alloy, and corrosion-resistant alloy tubulars will be set to the top of the Washita-Fredericksburg sand. The well will be completed as an open-hole completion in the Washita-Fredericksburg sand. The completion will be tied to the surface using a 6-5/8-inch fiberglass tubing string set in a pressurized annulus. Figures 5-17 and 5-19 are downhole well schematics of the planned well design and Figures 5-18 and 5-20 depict the proposed wellhead assemblies.

5.6.3.2 Drilling Program

<u>DRILLING PROCEDURE</u>

Conductor Hole

1. Prepare surface location and mobilize drilling rig.
2. Drill conductor casing hole to approximately 500 feet KB.
3. Cement the conductor pipe in place using standard cement plus any required additives.

Surface Hole

1. Drill surface casing hole to approximately 3,450 feet KB. Take deviation surveys every 500 feet. Maximum deviation from vertical will be no more than 3°, and maximum deviation between surveys will be no more than 1°.
2. Run open hole electric logs as listed in the Formation Evaluation section of this plan.
3. Run 13-3/8 inch surface casing to approximately 3,450 feet. (Refer to the Casing and Tubing Program section of the well plan for a detailed description of the casing.)
4. Cement surface casing in place in two stages, using a stage-cementing tool placed at approximately 1,700 feet. The stages will consist of light weight and standard cement plus additives. (Refer to the Cementing Program section for details.)
5. If no cement returns are observed at surface, run a temperature survey to determine the top of the cement. Grout the un-cemented annular space to fill the open space to surface.
6. Allow cement to set for a minimum of 12 hours, cut off the surface casing and conductor pipe. Install a 13-3/8 inch X 3,000 psi casing head and pressure test the head.
7. Install well control equipment and auxiliary equipment.
8. Pick up a drilling assembly and lower into the well. Pressure the surface casing to 1,000 psi and record the pressure for 30 minutes.
9. Lower the drilling assembly into the well and drill the cement and float equipment to within 10 feet of the casing shoe.
10. Run a temperature survey and cement bond log over surface pipe. If cement bond is unacceptable, a remedial cementing plan will be developed and implemented.

12-1/4-inch Protection Hole

1. Drill the protection hole from surface casing point to approximately 10,100 feet. The actual total depth of the well will be contingent on correlation of the subsurface formations as well as the thickness of the Washita-Fredericksburg sand. Take inclination surveys every 500 feet to monitor the well path. Conventional cores will be taken at selected geologic intervals.
    a. NOTE: Depths for completion into the Tuscaloosa Massive sand will be approximately 400 feet shallower.
2. Upon reaching total depth, run a multi-shot borehole survey over the entire well.
3. Run open hole electric wireline logs, collect formation fluid samples, and collect sidewall core samples

as necessary (see Formation Evaluation section of this plan).

4. Place a balanced cement plug at the top of the Washita-Fredericksburg sand to isolate the injection/completion interval from the remaining open hole.
5. Run 9-5/8 inch casing to the planned casing point (+/- 9,750 feet). (Refer to the Casing and Tubing Program in this section of the well plan for a detailed description of the casing grades and sizes.)
6. The protection casing will be cemented in place in three stages, using two stage-cementing tools placed at approximately 3,800 and 8,950 feet. The first stage cement will be epoxy resin, and the second and third stage cements will consist of premium and standard cements plus additives. (Refer to the Cementing Program section for details.)
7. If cement returns are lost during any of the cementing stages, a temperature or similar diagnostic survey will be run to determine the top of cement. After the cement top is located, a revised cementing procedure will be developed.
8. After completion of cementing procedures, hang the 9-5/8 inch casing in the casing head and remove the well control equipment.
9. Install the casing/tubing spool and perform a pressure test on the spool seals.

5.6.3.3 Completion Program

<u>COMPLETION PROCEDURE</u>

1. Drill out the cement and cementing equipment to within 15 feet of the casing shoe. Scrape the inside of the casing.
2. Run a temperature survey from surface to the top of cement. Run cement bond logs from top of the cement inside the 9-5/8-inch casing, back to surface.
3. Apply 1,500 psi to the 9-5/8-inch casing string and monitor/record the pressure for a minimum of 30 minutes.
4. Drill out the remaining cement from the 9-5/8-inch casing. Drill the cement plug from the open hole and clean the open hole section to total depth (+/-10,100 feet).
5. Run approximately 500 feet of 6-5/8-inch slotted and un-slotted fiberglass screen. Attach the screen to the injection packer and lower the assembly into the well.

6. Set the injection packer in the corrosion-resistant casing.
7. Run 6-5/8 inch fiberglass injection tubing and fill annulus with inhibited packer fluid. (Refer to the Casing and Tubing Program of this well plan for details.)
8. Perform required MIT program.

General Notes: *All depths referenced are approximate and are based on the expected log depth. Actual depths may vary, depending on actual geology.*

5.6.3.4 Well Fluids Program

Conductor Hole:

- Lost circulation material (LCM) will be on location to treat for fluid losses in upper shallow sands. The fluid system will be pre-treated with LCM before encountering any known or suspected loss zones.
- High-viscosity sweeps will be used regularly to assist hole cleaning.
- Refer to Table 5-29 for the Conductor Hole Fluids Program.

Surface Hole:

- Lost circulation material (LCM) will be on location to treat for fluid losses in upper shallow sands. The fluid system will be pre-treated with LCM before encountering any known or suspected loss zones.
- High-viscosity sweeps will be used regularly to assist hole cleaning.
- Refer to Table 5-30 for the Surface Hole Well Fluids Program.

Protection Hole:

- High-viscosity sweeps will be used periodically as needed to assist hole cleaning.
- Refer to Table 5-31 for the Protection Hole Well Fluids Program.

Completion Annular Fluid

The annular fluid for this well is inhibited calcium chloride brine.

5.6.3.5 Formation Evaluation Program

Surface Hole:

Refer to Table 5-32 for the surface hole formation evaluation program.

Protection Hole:

Refer to Table 5-33 for the protection hole formation evaluation program.

5.6.3.6 Casing and Tubing Program

Refer to Table 5-34 for the casing and tubing program.

5.6.3.7 Cementing Program

Conductor Casing

- 30 inch to 125 feet driven to refusal and 20 inch in 24 inch hole at 500 feet
- Cement from total depth to surface
- Estimated 100% excess over bit size
- Standard Cement blends
- Refer to Table 5-35 for the conductor hole cementing program

Surface Casing

- 13-3/8 inch in 17-1/2 inch hole at 3450 feet
- Cement stage tool at approximately 1,700 feet
- Cement from total depth to surface
- Estimated 100% excess over bit size
- Actual volume to be calculated from caliper log plus 20% excess
- Standard and Premium (Class H) cement blends
- Refer to Table 5-36 for the surface hole cementing program

Protection Casing

- 9-5/8 inch in 12-1/4 inch hole at +/- 6200 feet
- Cement stage tools at approximately 8,950 and 3,800 feet
- Cement from total depth to surface
- Estimated 50% excess over bit size
- Actual volume to be calculated from caliper log plus 20% excess
- Epoxy resin, Standard, and Premium (Class H) cement blends
- Refer to Table 5-36 for the protection hole cementing program.

Table 5-37 shows the casing and tubing program for proposed DeLisle Plant Well Nos. 6 and 7.
Table 5-38 shows the conductor hole cementing program for proposed DeLisle Plant Well Nos. 6 and 7.
Table 5-39 shows the surface hole cementing program for proposed DeLisle Plant Well Nos. 6 and 7.
Table 5-40 shows the protection hole cementing program for proposed DeLisle Plant Well Nos. 6 and 7.

5.7 INJECTION WELL CLOSURE

Chemours maintains financial assurance, meeting the compliance requirement in 40 CFR Part 144, Subpart F, to demonstrate adequate financial responsibility and resources to close, plug, and abandon the permitted well(s). Refer to Appendix 5-1 of this section for a copy of the relevant financial responsibility documents executed by Chemours and MDEQ.

Plugging and abandonment of all permitted DeLisle wells will be performed in accordance with Part I, Section F of the MDEQ Permit MSI1001 and 40 CFR 146.71(d). Before the decision is made to plug any of the well(s), the DeLisle Plant will notify the MDEQ and U.S. EPA at least 60 days before intended closure of a well or wells (note a shorter notice period may be required if an emergency situation is present). A closure plan will be provided to MDEQ in advance of the start of plugging operations. After plugging is complete, DeLisle Plant will submit the completed field work report, a certification of well plugging, and a post-closure care plan to the MDEQ.

5.7.1 Plugging and Abandonment Plan

Chemours has prepared, maintained and complied with regulatory requirements of 40 CFR 146.71 by providing a plan for closure of all wells. Refer to Appendix 5-2 of this section for a copy of the plan. Prior to closing a well, Chemours will observe and record the pressure decay in the injection interval and report the data to the MDEQ and U.S. EPA. The MDEQ can analyze the pressure decay and the transient pressure observations required under Part I, Section C, item 7, and determine whether the injection activity has conformed to predicted values. In addition, recorded wellhead data from Monitor Well No. 1 will be provided to determine pressure effects on the formation before any well closure.

5.7.2 Plugging and Abandonment Report

Chemours will submit a closure report to the MDEQ and U.S. EPA within 60 days after closure, or at the time of the next quarterly report (whichever is less). If the quarterly report is due less than 15 days after completion of closure, then the report will be submitted within 60 days after well closure. The closure report will be certified as accurate by Chemours and persons who performed the closure operation (if other than the permittee), and consist of either of the following:

(a) A statement that a well was closed in accordance with the closure plan previously submitted and approved by the MDEQ; or

(b) Where actual closure differed from the previously submitted plan, a written statement specifying the differences between the previous plan and the actual closure.

5.7.3 Post-Closure Care

Chemours will submit a post-closure care plan to the MDEQ and U.S. EPA that complies with the regulatory requirements of 40 CFR 146.72. Chemours understands that the obligation to implement a post-closure plan survives the termination of this permit or the cessation of injection activities, and that the requirement to maintain an approved plan is directly enforceable, regardless of whether the requirement is a condition of any petition or permit.

5.8 CUMULATIVE WASTE VOLUMES

Table 5-41 contains the historical waste injection from the four active disposal wells at the DeLisle Plant, with the values reported in millions of gallons. The total cumulative injectate through December 31, 2015 is 8.05 billion gallons of waste fluid disposed of and contained in the Washita-Fredericksburg sand.

5.9 SURFACE FACILITIES

The underground injection feed system for Well Nos. 2, 3, 4, and 5 consists of a waste storage tank which contains the process waste. The waste is pumped via transfer pump to each well's injection pumps. The injection pumps feed the waste into each well's injection tubing and injection formation. Supporting facilities include the ability to pump dilute HCl and sodium chloride brine into the injection interval. The well facilities also include separate storage tanks for sodium chloride brine, corrosion-inhibited calcium chloride brine, and dilute aqueous HCl. In addition, there is an annulus pressure control system consisting of a tank and annulus pumps to maintain an adequate level of corrosion–inhibited chloride brine in the annulus of each injection well. Gauges and meters monitor injection pressure, temperature, specific gravity, annulus pressure, and injection rate.

The waste to Proposed Well 6 will come through the existing waste storage tank; however, Proposed Well 6 will have dedicated transfer pumps, injection pumps, annulus pressure control system, and storage tanks for sodium chloride brine, corrosion-inhibited calcium chloride brine, and dilute aqueous HCl. All surface equipment is constructed to materials compatible with the process streams handled. In addition, adequate measures are taken to control leaks and prevent groundwater contamination. (See Figure 5-21.)

The iron chloride waste sent to Proposed Well No. 7 and to Well No. 1 (after it is converted to an injection well) will come from the existing surface facilities used for Well Nos. 2, 3, 4 and 5.

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TABLES

Table 5-1
DeLisle Plant
Monitoring Well No. 1 - Borehole Deviation Survey

Surface Location: 1,346 feet FSL and 1,842 feet FWL of Section 4; T8S, R13W

Depth (feet)	Deviation (degrees)	Depth (feet)	Deviation (degrees)
307	0	5,422	1/4
571	1/2	5,919	1/2
1,504	1/4	6,410	1/4
1,812	1/2	6,473	1/2
2,165	1/2	7,472	1/4
2,439	1/2	8,040	1
2,750	1/2	8,119	1/2
3,103	1/2	8,229	3/4
3,372	1/4	8,628	1/2
4,265	1	8,952	0
4,927	3/4	9,458	1/2

Reference: DuPont, 1974c.

Table 5-2
DeLisle Plant
Monitoring Well No. 1 – Drill Stem Tests

Drill Stem Test No.	Depth Interval Tested (ft)	Chlorides Analysis (ppm)
1	3,831 - 3,992	53,500
2	4,288 - 4,340	No recovery -mis-run
3	4,920 - 4,340	No recovery - mis-run
4	4,490 - 4,540	Recovered only 140 ft drilling mud
5	9,405 - 9,460	No recovery - no data
6	9,831 - 9,917	102,500

Table 5-3
DeLisle Plant
Monitoring Well No. 1 - Casing and Tubing Data

Casing Type	Size/Weight/Grade	Depth (feet)	Burst-Collapse* (psi)	Tensile Strength* (lbs)
Conductor	18" steel	89	N/A	N/A
Surface Casing	11 3/4" OD steel			
	N-80, 60 lb/ft	331	5,830 - 3,180	1,384,000
	K-55, 60 lb/ft	331 - 1,289	4,010 - 2,660	952,000
	K-55, 54 lb/ft	1,289 - 1,657	3,560 - 2,070	850,000
	K-55, 47 lb/ft	1,657 - 3,459	3,070 - 1,510	737,000
Protective Casing	8 5/8" OD steel			
	36 lb/ft	0 - 2,328	4,460 - 3,450	568,000
	40 lb/ft	2,328 - 4,109	6,850 - 5,350	867,000
	32 lb/ft	4,109 - 6,672	2,860 - 2,210	366,000
	36 lb/ft	6,672 - 6,864	4,460 - 3,450	568,000
	40 lb/ft	6,864 - 6,990	6,850 - 5,350	867,000
	36 lb/ft	6,990 - 8,102	4,460 - 3,450	568,000
	32 lb/ft	8,102 - 10,015	2,860 - 2,210	366,000

* Data obtained from API bulletins 5C2 and 5C3 and ASTM Standards A312

Table 5-4
DeLisle Plant
Monitoring Well No. 1 - Cementing Data Summary

Casing Type	Cement Type/Class	Slurry Additives	Volume (gals)	
			Annular*	Pumped
Surface Casing	3700 sx Halliburton	Light Weight		50,925
	300 sx Class H	Tuf-fiber		2,424
	100 sx Common	2% $CaCl_2$		883
	Volume Totals		19,484	54,232
Protective Casing	1000 sx Halliburton	4% gel, 0.5% Halad 9,		
	Light Cement	2.61 lb salt, 1/4 lb Flocele		10,771
	1200 sx HLC	4% gel, 0.5% Halad 9,		
		2.61 lb salt, 1/4 lb Flocele		
		0.25% HR-4		12,929
	300 sx Class H	7.8 lb salt, CFR-2 at		
		75%, 0.3% HR-4		2,738
	Volume Totals		22,141	26,435

* Annular volumes calculated with 1 in. over bit size to allow for borehole irregularities.

Centralizers: Eight centralizers were used with the surface casing and 13 centralizers were used with the protective casing enabling the cement to freely circulate around the casings and returns were noted at the surface (Du Pont, 1974b).

Table 5-5
DeLisle Plant
Monitoring Well No. 1 - Perforation Summary

Depth (feet)	Formation Name	Number of Perforations
9,775 - 9,801	Washita-Fredericksburg Shale	4 holes per ft
9,812 - 9,844	Washita-Fredericksburg Sandstone	4 holes per ft
9,850 - 9,874	Washita-Fredericksburg Sandstone	4 holes per ft
9,874 - 9,894	Washita-Fredericksburg Sandstone	4 holes per ft
9,894 - 9,914	Washita-Fredericksburg Sandstone	4 holes per ft
9,934 - 9,954	Washita-Fredericksburg Sandstone	4 holes per ft
9,954 - 9,974	Washita-Fredericksburg Sandstone	4 holes per ft

Table 5-6
DeLisle Plant
Monitoring Well No. 1, 1974 Injection Test

Time	Injection Rate (gpm)	Cumulative Volume (gal)	Surface Pressure (psi)
05:51	300	300	1,200
05:52	520	820	2,200
05:53	950	1,470	2,800
05:54	670	2,140	2,400
05:55	660	2,800	2,800
05:56	630	3,430	2,700
05:57	650	4,080	2,800
05:58	680	4,760	3,100
05:59	700	5,460	3,000
06:00	690	6,150	3,100
06:01	690	6,840	3,100
06:02	690	7,530	3,100
06:03	690	8,220	3,100
06:04	690	8,910	3,000
06:05	700	9,610	2,900
06:06	690	10,300	2,900
06:07	690	10,990	2,900
06:08	700	11,690	2,800
06:09	700	12,390	2,800
06:10	690	13,080	2,800
06:10	690	13,310	2,800

Table 5-7
DeLisle Plant
Monitoring Well No. 1, 1974 Frac Test

Time	Injection Rate (gpm)	Cumulative Volume (gal)	Surface Pressure (psi)
19:00	530	530	2,800
19:01	720	1,250	3,100
19:02	740	1,990	3,150
19:03	740	2,730	3,100
19:04	750	3,480	3,150
19:05	730	4,210	3,150
19:06	740	4,950	3,150
19:07	730	5,680	3,150
19:08	740	6,420	3,150
19:09	740	7,160	3,150
19:10	740	7,900	3,175
19:11	740	8,640	3,175
19:12	740	9,380	3,175
19:13	740	10,120	3,175
19:14	740	10,860	3,175
19:14	740	11,120	3,175

Table 5-8
DeLisle Plant
Well No. 2 - Borehole Deviation Survey
Surface Location: 1,448 ft FNL and 924 ft FEL of Section 5, T8S, R13W

Depth (feet)	Deviation (degrees)	Hole Direction	Depth (feet)	Deviation (degrees)	Hole Direction
503	1/4		6,577	8-1/4	N 80 E
1,006	1/4		6,705	8-1/4	N 79 E
1,537	1		6,863	8-1/4	N 78 E
2,568	1/4		7,019	8	N 78 E
3,068	1		7,174	7-3/4	N 78 E
3,900	1		7,269	7-3/4	N 77 E
4,071	1	S 50 W	7,393	8	N 78 E
4,226	1/4	S 75 W	7,518	7-3/4	N 78 E
4,381	1/4	S	7,610	7-1/4	N 78 E
4,660	3/4	N 10 E	7,736	7-1/2	N 77 E
4,855	1-1/4	N 73 E	7,859	8	N 77 E
5,022	2-1/4	N 75 E	7,984	8-1/2	N 76 E
5,270	5-3/4	N 48 E	8,139	8-3/4	N 76 E
5,463	8	N 79 E	8,295	8-1/2	N 76 E
5,511	8	N 81 E	8,454	8	N 77 E
5,731	8	N 80 E	8,610	8	N 76 E
5,857	8-1/2	N 82 E	8,767	8	N 77 E
6,045	8-1/4	N 81 E	8,953	7-1/4	N 77 E
6,139	8-1/4	N 78 E	9,109	7-1/2	N 76 E
6,264	8-1/4	N 80 E	9,423	7-3/4	N 76 E
6,390	8-1/4	N 80 E	9,612	8	N 76 E
6,453	8-1/4	N 80 E			

Table 5-9
DeLisle Plant
Well No. 2 - Casing and Tubing Data

Casing Type	Size/Weight/Grade	Depth (feet)	Burst-Collapse* (psi)	Tensile Strength* (lbs)
Conductor	20" carbon steel	0 - 97	N/A	N/A
Surface Casing	13-3/8", 68 lb/ft,	0 - 3,658	3,450 - 1,950	1,069,000
	K-55			
Protective Casing	9-5/8" 40 and 47 lb/ft	0 - 6,041	5,750 - 3,090	916,000
	N-80			
	9-5/8" 47 lb/ft	6,041 - 9,766	9,440 - 5,300	1,493,000
	P-110			
	1/2" wall titanium	9,766 - 9,845	3,636 - 2,520	75,000
	9-5/8" 53.5 lb/ft	9,845 - 9,855	7,930 - 6,620	1,244,000
	N-80			
Liner	7" 26 lb/ft	7,573 - 9,536	7,240 - 5,410	604,000
	7-5/8" Fiberglass	9,536 - 9,563	N/A	N/A
	7" Titanium	9,563 - 9,743	N/A	N/A
Injection Tubing	6-5/8" Fiberglass	0 - 7,459	2,500 - 2,900	72,500
	4-1/2" Fiberglass	7,459 - 9,675	2,500 - 2,900	46,500

* Data obtained from API bulletins 5C2 and 5C3, ASTM Standards A312, and Tubular Fiberglas Products, fiberglass tubing.

Table 5-10
DeLisle Plant
Well No. 2 - Cementing Data Summary

Casing Type	Cement Type/Class	Slurry Additives	Volume (gals)**	
			Annular*	Pumped
Conductor Casing	200 sx, Neat		N/A	N/A
Surface Casing	2280 sx, HLC	0.25 lb/sk Flocele		28,824
	275 sx, Class H	0.35% $CaCl_2$		2,201
	Volume Totals		24,674	31,025
Protective Casing	2050 sx, HLC	0.3% HR4, 0.8% Halad 22A		28,063
	1150 sx, Class H			13,334
	Epseal®			3,780
	Volume Totals		30,000	45,177
Liner	28 barrels *Epseal*®		1,449	1,176***

* Annular volumes calculated with 1-inch over bit size to allow for borehole irregularities.

** Volume calculations are located in Table 5-9.

*** Top of *Epseal*® epoxy cement is located above the corroded area in the 9-5/8" casing.

Centralizers: Centralizers were used to enable the cement to completely circulate around the casing.

Table 5-11
DeLisle Plant
Well No. 2 - Surface Control Systems

Instrumentation	Location	Name and Model
Injection Pressure Gauge	Injection Pumps	USG-Solfrunt Ashcroft-PSI
Injection Pressure Recorder	Control Room	Fisher TL 101
Annulus Pressure Recorder	Control Room	Fisher Tl 132, TL 101
Injection Rate Meter	Surge Tank Discharge	Fisher TL 101
Temperature Gauge	Control Room	Thermo-Electrical Type K
Annulus Pump	Brine Feed Tank	Bran and Lubbe
Injection Pump(s)	Centrifugal	Gould Titanium, 2 at 400 gpm each

Sampling Procedures: Waste parameters are sampled continuously by plant process computers.

Table 5-12
DeLisle Plant
Well No. 2 - Volume Calculations

SURFACE CASING ANNULAR VOLUME

$$(D^2 - d^2) \times L \times 0.0408 = \text{Volume (gals)}$$

D	=	Hole Diameter (in)	d = Casing OD (in)
L	=	Setting Depth (ft)	0.0408 = Conversion Factor (gal/ft-in^2)

$(18.5^2 - 13.375^2) \times 3,702 \times 0.0408 = 24,674$ gals

PROTECTIVE CASING ANNULAR VOLUME

$$[(D^2 - d^2) \times (L-L_{sc}) \times 0.0408] + [(D^2_{sc} - d^2) \times [L_{sc} \times 0.0408] = \text{Volume (gals)}$$

D = Hole Diameter (in)
L = Setting Depth (ft)
D_{sc} = Surface Casing ID (in)
d = Casing OD (in)
L_{sc} = Surface Casing Setting Depth (ft)
0.0408 = Conversion Factor (gal/ft-in^2)

$[(13.25^2 - 9.625^2) \times (9,824 - 3,702) \times 0.0408] + [(12.415^2 - 9.625^2) \times 3,702 \times 0.0408] = 30,000$ gals

LINER ANNULAR VOLUME

$$[(D^2 - d^2) \times L \times 0.0408 = \text{Volume (gals)}$$

D = Casing ID (in)
L = Liner Length (ft)
d = Liner OD (in)
0.0408 = Conversion Factor (gal/ft-in^2)

$(8.835^2 - 7^2) \times 1,222 \times 0.0408 = 1,449$ gals

CEMENT VOLUME

V_{SL} x # of sacks x 7.48052 = Volume (gals)

V_{SL} = Slurry Volume (ft^3/sack)
7.48052 = Conversion Factor (gal/ft^3)

SURFACE CASING

1.69 x 2,280 x 7.48052 = 28,824 gals
1.07 x 275 x 7.48052 = 2201 gals
Total Volume = 31,025 gals

PROTECTIVE CASING

1.83 x 2,050 x 7.48052	=	28,063 gals
1.55 x 1,150 x 7.48052	=	13,334 gals
Epseal®	=	3,780 gals
Total Volume	=	45,177 gals

Liner 28 barrels *Epseal®* = 1,176 gals

Table 5-13
DeLisle Plant
Well No. 2 - Tubular Stress Calculations

BURST PRESSURE:

$$P_{max} = P_{max\ inj} + (0.433 \text{ x } SG_{injfl} \text{ x } D) - (0.433 \text{ x } SG_{afl} \text{ x } D)$$

Where:

P_{max}	=	maximum pressure (psi)
0.433	=	pressure gradient (psi/ft)
Sg_{injfl}	=	maximum specific gravity of injection fluid
SG_{afl}	=	specific gravity of the annular fluid
D	=	depth of tubing (ft)
$P_{max\ inj}$	=	maximum injection pressure (psi)
P_{max}	=	600 + (0.433 x 1.35 x 9,762) - (0.433 x 1.25 x 9,762) = 1,023 psi

COLLAPSE PRESSURE:

$$P_{max} = P_{maxan} + (0.433 \text{ x } SG_{afl} \text{ x } D) - (0.433 \text{ x } SG_{injfl} \text{ x } D)$$

Where:

P_{max}	=	maximum pressure (psi)
0.433	=	pressure gradient (psi/ft)
SG_{injfl}	=	maximum specific gravity of the injected fluid
SG_{afl}	=	specific gravity of the annular fluid
D	=	depth of tubing (ft)
P_{maxan}	=	maximum annular pressure
P_{max}	=	700 + (0.433 x 1.25 x 9,762) - (0.433 x 1.35 x 9,762) = 277 psi

TENSILE STRENGTH:

$$W_{max} = (W_{ta} \text{ x } D) + (W_{ta} \text{ x } D)$$

Where:

W_{max}	=	maximum tensile weight (lbs)
W_{ta}	=	weight of tubing in air (lb/ft)
D	=	depth of tubing (ft)
W_{max}	=	(10.1 x 7,459) + (5.2 x 2,236) = 86,859 lbs

This demonstration need not be performed for surface and protective casing because the maximum stresses are induced during cementing of the casing strings. Since this well has been completed with no problems, the casings will be strong enough to endure the maximum burst and collapse pressures and axial loading for the design life of the well.

a. Assume injection of maximum specific gravity fluid at maximum pressure with no annular pressure other than hydrostatic for burst calculations.

b. Assume maximum annular pressure and maximum specific gravity injection fluid under hydrostatic pressure for collapse calculations.

c. Assume no buoyancy effect on tubing for tensile strength calculations.

Table 5-14
DeLisle Plant
Well No. 3 - Borehole Deviation Survey

Surface Location: 1,464.93 feet FNL and 1,083.12 feet FEL of Section 5, T8S, R13W

Measured Depth (feet)	True Vertical Depth (feet)	Drift Angle (degrees)	Drift Direction (degrees)	Degrees per 100 feet	Measured Depth (feet)	True Vertical Depth (feet)	Drift Angle (degrees)	Drift Direction (degrees)	Degrees per 100 feet
111	110.99	1 15	N 43 W	1.126	4,743	4,742.80	2 50	N 77 W	2.218
205	204.98	0 15	N 18 W	1.096	4,780	4,779.76	3 00	N 79 W	2.042
299	298.98	0 15	N 38 W	0.092	4812	4,811.72	3 00	N 75 W	0.654
393	392.98	0 30	N 22 W	0.286	4,843	4,842.67	3 15	N 77 W	0.880
487	486.98	0 00	0	0.532	4,873	4,872.62	3 15	N 72 W	0.945
581	580.98	0 15	N 80 W	0.266	4,967	4,966.43	4 00	N 90 W	1.440
675	674.98	0 15	N 54 W	0.120	5,029	5,028.25	4 45	N 84 W	1.416
770	769.98	0 15	S 7 E	0.483	5,092	5,091.01	5 15	N 78 W	1.147
864	863.97	0 15	S 73 W	0.342	5,154	5,152.73	5 45	N 72 W	1.228
958	957.97	0 15	S 38 W	0.160	5,341	5,338.57	7 00	S 86 W	1.455
1,052	1,051.97	0 15	N 17 W	0.472	5,403	5,400.09	7 15	S 87 W	0.450
1,146	1,145.97	0 15	N 67 W	0.225	5,496	5,492.29	7 45	N 82 W	1.632
1,240	1,239.97	0 00	0	0.266	5,595	5,590.36	8 00	S 81 W	2.358
1,334	1,333.97	0 00	0	0	5,700	5,694.27	8 30	S 78 W	0.628
1,429	1,428.97	0 15	S 77 W	0.263	5,793	5,786.25	8 30	S 80 W	0.318
1,523	1522.97	0 30	S 57 W	0.296	5,916	5,907.82	9 00	S 82 W	.0476
1,617	1,616.97	0 30	S 56 W	0.009	6,072	6,061.79	9 30	S 83 W	0.337
1,711	1,710.96	0 30	S 53 W	0.028	6,167	6,155.42	10 00	S 83 W	0.526
1,805	1,804.96	0 30	S 46 W	0.065	6,261	6,247.99	10 00	S 83 W	0
1,899	1,898.96	0 30	S 40 W	0.056	6,385	6,370.10	10 00	S 82 W	0.140
1,993	1,992.95	0 15	S 24 W	0.286	6,542	6,524.72	10 00	S 80 W	0.221
2,088	2,087.95	0 15	N 77 W	0.335	6,698	6,678.35	10 00	S 79 W	0.111
2182	2,181.95	0 30	S 89 W	0.281	6,793	6,771.91	10 00	S 78 W	0.183
2,276	2,275.95	0 15	S 87 W	0.266	6,927	6,903.97	9 30	S 78 W	0.373
2,370	2,369.95	0 15	S 64 W	0.106	7,053	7,028.29	9 15	S 78 W	0.198
2,464	2,463.95	0 15	S 46 W	0.083	7,210	7,183.19	9 30	S 78 W	0.159
2,558	2,557.94	0 30	S 9 W	0.357	7,365	7,336.06	9 30	S 78 W	0.005
2,653	2,652.94	0 45	S 2 W	0.275	7,522	7,491.02	9 00	S 78 W	0.318
2,747	2,746.93	0 30	S 5 W	0.268	7,653	7,620.45	8 45	S 78 W	0.191
2,841	2,840.93	0 45	S 17 W	0.229	7,809	7,774.64	8 45	S 78 W	0.003
2,935	2,934.92	1 00	S 39 W	0.441	7,966	7,929.86	8 30	S 78 W	0.159
3,029	3,028.90	1 15	S 47 W	0.314	8,091	8,053.53	8 15	S 78 W	0.200
3,123	3,122.88	1 00	S 54 W	0.303	8,249	8,209.99	7 45	S 78 W	0.316
3217	3,216.87	0 30	S 62 W	0.542	8,375	8,334.84	7 45	S 79 W	0.107
3,312	3,311.87	0 30	S 72 W	0.092	8,530	8,488.47	7 30	S 80 W	0.183
3,406	3,405.86	0 30	S 66 W	0.381	8,619	8,576.76	7 00	S 80 W	0.562
3,500	3,499.86	0 30	S 78 W	0.329	8,804	8,760.28	7 30	S 85 W	0.435
3,594	3,593.86	0 15	S 43 W	0.349	8,960	8,914.85	8 00	S 85 W	0.321
3620	3,619.86	0 15	S 43 W	0.019	9,135	9,087.98	8 45	S 86 W	0.437
3,820	3,819.86	0 50	N 5 E	0.236	9,223	9,174.96	8 45	S 88 W	0.346
3,990	3,989.86	0 00	0	0.147	9,380	9,330.08	9 00	S 88 W	0.159
4,178	4,177.85	0 00	S 70 W	0.266	9,558	9,505.83	9 15	N 90 W	0.227
4366	4,365.85	0 00	S 71 W	0.005	9,658	9,604.63	8 30	N 90 W	0.750
4,553	4,552.83	0 50	S 72 W	0.134	9,802	9,747.23	7 30	N 89 W	0.701
4,675	4,674.82	0 50	N 84 W	0.256	9,858	9,802.75	7 30	N 89 W	0.012

Table 5-15
DeLisle Plant
Well No. 3 - Casing and Tubing Data

Casing Type	Size/Weight/Grade	Depth (feet)	Burst-Collapse* (psi)	Tensile Strength (lbs)
Conductor	20", carbon steel	0 - 101	N/A	N/A
Surface Casing	13-3/8", 68 lb/ft,	0 - 3,613	3,450 - 1,950	1,069,000
	K-55			
Protective Casing	9-5/8",40 lb/ft	0 - 4,853	5,750 - 3,090	916,000
	N-80			
	9-5/8",47 lb/ft	4,853 - 5,590	6,870 - 4,760	1,086,000
	N-80			
	9-5/8",47 lb/ft	5,590 - 9,610	9,440 - 5,300	1,493,000
	P-110			
Liner	7", 26 lb/ft, L-80	6,808 - 8,757	7,420 - 5,410	604,000
	FRP coated steel	8,757 - 9,531	7,240 - 5,410	604,000
	7-5/8” Fiberglass	9,531 - 9,561	2,900 - 2,500	107,500
	7" Titanium	9,561 - 9,735	N/A	N/A
Injection Tubing	6-5/8" Fiberglass	0 - 6,620	2,900 - 2,500	72,500
	4-1/2" Fiberglass	6,620 - 9,492	2,900 - 2,500	46,500

* Data obtained from API bulletins 5C2 and 5C3, ASTM Standards A312 and Tubular Fiberglas Products, fiberglass tubing.

Table 5-16
DeLisle Plant
Well No. 3 - Cementing Data Summary

Casing Type	Cement Type/Class	Slurry Additives	Volume ** (gals)	
			Annular*	Pumped
Conductor Casing	200 sx, Neat		N/A	N/A
Surface Casing	2280 sx, Pozmix/HLC	0.25 lb/sk Flocele		28,824
	275 sx, Class H	5% salt, 0.35% $CaCl_2$		2,201
	Volume Totals		24,081	31,025
Protective Casing	2200 sx, Pozmix/HLC	0.8% Halad 22A, 5% HR-4		27,812
	3000 sx, Light	2% $CaCl_2$		23,788
	Epseal®	Silica flour		4,116
7-inch Liner	520 sx Class H	35% Silica Flour		5,873
	Volume Totals		29,354	61,589

* Annular volumes calculated with 1-inch over bit size to allow for borehole irregularities.

** Volume calculations are located in Table 5-15.

Centralizers: Centralizers were used to enable the cement to completely circulate around the casing.

Table 5-17
DeLisle Plant
Well No. 3 - Surface Control Systems

Instrumentation	Location	Name And Model
Injection Pressure Gauge	Injection Pumps	USG-Solfrunt Ashcroft-PSI
Gauge		
Injection Pressure Recorder	Control Room	Fisher TL 101
Recorder		
Annulus Pressure Recorder	Control Room	Fisher Tl 132, TL 101
Recorder		
Injection Rate Meter	Surge Tank Discharge	Fisher TL 101
Temperature Gauge	Control Room	Thermo-Electrical Type K
Annulus Pump	Brine Feed Tank	Durco
Injection Pump	Centrifugal	Gould Titanium, two at 400 gpm each

Sampling Procedures: Daily sampling of waste on scheduled basis with laboratory testing to assure water quality. Water levels in ponds are measured continuously on the plant process computer, as is a calculated bottom hole pressure of well (Du Pont, 1986a).

Table 5-18
DeLisle Plant
Well No. 3 - Volume Calculations

SURFACE CASING ANNULAR VOLUME

$$(D^2 - d^2) \times L \times 0.0408 = Volume\ (gals)$$

D	=	Hole Diameter (in)
d	=	Casing OD (in)
L	=	Setting Depth (ft)
0.0408	=	Conversion Factor (gal/ft-in^2)

$(18.5^2 - 13.375^2) \times 3{,}613 \times 0.0408 = 24{,}081$ gals

PROTECTIVE CASING ANNULAR VOLUME

$$[(D^2 - d^2) \times (L - L_{sc}) \times 0.0408] + [(D^2_{sc} - d^2) \times [L_{sc} \times 0.0408] = Volume\ (gals)$$

D	=	Hole Diameter (in)
d	=	Casing OD (in)
L	=	Setting Depth (ft)
L_{sc}	=	Surface Casing Setting Depth (ft)
D_{sc}	=	Surface Casing ID (in)
0.0408	=	Conversion Factor (gal/ft-in^2)

$[(13.25^2 - 9.625^2) \times (9{,}610 - 3{,}613) \times 0.0408] + [(12.415^2 - 9.625^2) \times 3{,}613 \times 0.0408] = 29{,}354$ gals

CEMENT VOLUME

$$V_{SL} \times no.\ of\ sacks \times 7.48052 = Volume\ (gals)$$

V_{SL}	=	Slurry Volume (ft^3/sack)
7.48052	=	Conversion Factor (gal/ft^3)

Surface Casing

1.69 x 2,280 x 7.48052 = 28,824 gals
1.07 x 275 x 7.48052 = 2201 gals

Total Volume = 31,025 gals

Protective Casing

	1.69 x 2,200 x 7.48052	=	27,812 gals
	1.06 x 3,000 x 7.48052	=	23,788 gals
	Epseal®	=	4,116 gals
7" liner	1.51 x 520 x 7.48052	=	5,873 gals
	Total Volume	=	61,589 gals

Table 5-19
DeLisle Plant
Well No. 3 - Tubular Stress Calculations

BURST PRESSURE:

$$P_{max} = P_{max\ inj} + (0.433 \times SG_{injfl} \times D) - (0.433 \times SG_{afl} \times D)$$

Where:

P_{max}	=	maximum pressure (psi)
0.433	=	pressure gradient (psi/ft)
SG_{injfl}	=	maximum specific gravity of injection fluid
SG_{afl}	=	specific gravity of the annular fluid
D	=	depth of tubing (ft)
$P_{max\ inj}$	=	maximum injection pressure (psi)

P_{max} = 600 + (0.433 x 1.35 x 9,738) - (0.433 x 1.25 x 9,738) = 1,022 psi

COLLAPSE PRESSURE:

$$P_{max} = P_{maxan} + (0.433 \times SG_{afl} \times D) - (0.433 \times SG_{injfl} \times D)$$

Where:

P_{max}	=	maximum pressure (psi)
0.433	=	pressure gradient (psi/ft)
SG_{injfl}	=	maximum specific gravity of the injected fluid
SG_{afl}	=	specific gravity of the annular fluid
D	=	depth of tubing (ft)
P_{maxan}	=	maximum annular pressure

P_{max} = 600 + (0.433 x 1.25 x 9,738) - (0.433 x 1.35 x 9,738) = 178 psi

TENSILE STRENGTH:

$$W_{max} = (W_{ta} \times D) + (W_{ta} \times D)$$

Where:

W_{max}	=	maximum tensile weight (lbs)
W_{ta}	=	weight of tubing in air (lb/ft)
D	=	depth of tubing (ft)

W_{max} = (10.1 x 6,620) + (5.2 x 2,872) = 81,796 lbs

This demonstration need not be performed for surface and protective casing because the maximum stresses are induced during cementing of the casing strings. Since this well has been completed with no problems, the casings will be strong enough to endure the maximum burst and collapse pressures and axial loading for the design life of the well.

a. Assume injection of maximum specific gravity fluid at maximum pressure with no annular pressure other than hydrostatic for burst calculations.
b. Assume maximum annular pressure and maximum specific gravity injection fluid under hydrostatic pressure for collapse calculations.
c. Assume no buoyancy effect on tubing for tensile strength calculations.

Table 5-20
DeLisle Plant
Well No. 4 - Borehole Deviation Survey

Surface Location: 1,809 feet FNL and 1,086 feet FEL of Section 5, T8S, R13W

Depth (feet)	Deviation (degrees)	Depth (feet)	Deviation (degrees)
553	1/4	7,129	1/2
1,081	1/2	7,370	1-3/4
1,585	1/4	7,401	1-3/4
2,243	1	7,503	1
2,873	1-1/2	7,716	1
3,740	1/4	7,809	1
4,365	1	8,095	1
4,620	1/4	8,343	1-1/2
5,014	3/4	8,507	1
5,295	3/4	8,700	1
5,516	3/4	8,889	1/2
5,737	1/4	9,097	1-1/4*
6,024	1/4	9,378	1-1/2
6,302	0	9,566	3/4
6,522	1/4	10,003	1/4
6,678	3/4		

* One drift indicator inoperative; replaced both instruments

Reference: Pritchard Engineering & Operating, Inc., 1982.

Table 5-21
DeLisle Plant
Well No. 4 - Casing and Tubing Data

Casing Type	Size/Weight/Grade	Depth (feet)	Burst Collapse (psi)	Tensile Strength (lbs)
Conductor	24" carbon steel	0 - 88	N/A	N/A
Surface Casing	16", 84 lb/ft, K-55	0 - 3,705	2,980 - 1,410	1,326,000
Protective Casing	9 5/8", 53.5 lb/ft, N-80	0 - 7,254		
Liner	7", 26 lb/ft, L-80	7,254 - 8,678	7,240 - 5,410	519,000
	7" 26 lb/ft L-80 Resin Coated	8,678 - 9,515	7,240 - 5,410	519,000
	7-5/8" fiberglass	9,515 - 9,561	N/A	N/A
	7" titanium	9,561 - 9,738	N/A	N/A
Injection Tubing	5 1/2" fiberglass	0 - 6,700	2,500 - 3,300	54,500
	4-1/2" fiberglass	6,700 - 9,662	2,500 - 3,300	47,800

* Data obtained from API bulletins 5C2 and 5C3, ASTM Standards A312, and Tubular Fiberglas Products, Fiberglass Tubing

Table 5-22
DeLisle Plant
Well No. 4 - Cementing Data Summary

Casing Type	Cement Type/Class	Slurry Additives	Volume** (gals)	
			Annular*	Pumped
Conductor Casing	400 sx, neat	NA	N/A	N/A
Surface Casing	6969 sx, HLC	1.25 lb/sk Flocele		88,103
	600 sx, Class H	3% salt, 0.35% $CaCl_2$		4,758
	Volume Totals		27,965	92,861
Protective Casing	1850 sx, Pozmix/HLC	0.2% Halad 4		23,388
	5710 sx, Class H	35% SSA-1, 0.4% Halad 22-A, 0.5% CFR-2		45,277
	Epseal®			19,740
	Volume Totals		57,356	88,405
Protective Casing Liner***	*Epseal*® Resin Cement	NA		1,764

* Annular volumes calculated with 1-inch over bit size to allow for borehole irregularities.

** Volume calculations are located in Table 5-21.

*** Liner set inside Protective Casing from 9,735 to 7,742 feet.

Centralizers: Centralizers were used to enable the cement to completely circulate around the casing.

Table 5-23
DeLisle Plant
Well No. 4 - Surface Control Systems

Instrumentation	Location	Name And Model
Injection Pressure Gauge	Injection Pumps	USG-Solfrunt Ashcroft-PSI
Injection Pressure Recorder	Control Room	Fisher TL 101
Annulus Pressure Recorder	Control Room	Fisher Tl 132, TL 101
Injection Rate Meter	Surge Tank Discharge	Fisher TL 101
Temperature Gauge	Control Room	Thermo-Electrical Type K
Annulus Pump	Brine Feed Tank	Durco
Injection Pump	Centrifugal	Gould Titanium, 2 at 400 gpm each

Sampling Procedures: Waste is sampled continuously by the plant process computers.

Table 5-24
DeLisle Plant
Well No. 4 - Volume Calculations

SURFACE CASING ANNULAR VOLUME

$$(D^2 - d^2) \times L \times 0.0408 = Volume\ (gals)$$

D	=	Hole Diameter (in)
d	=	Casing OD (in)
L	=	Setting Depth (ft)
0.0408	=	Conversion Factor (gal/ft-in^2)

$(21^2 - 16^2) \times 3{,}705 \times 0.0408 = 27{,}965$ gals

PROTECTIVE CASING ANNULAR VOLUME

$$[(D^2 - d^2) \times (L-L_{sc}) \times 0.0408] + [(D^2_{sc} - d^2) \times [L_{sc} \times 0.0408] = Volume\ (gals)$$

D	=	Hole Diameter (in)
d	=	Casing OD (in)
L	=	Setting Depth (ft)
L_{sc}	=	Surface Casing Setting Depth (ft)
D_{sc}	=	Surface Casing ID (in)
0.0408	=	Conversion Factor (gal/ft-in^2)

$[(15.75^2 - 9.625^2) \times (9{,}772 - 3{,}705 \times 0.0408] + [(14.75^2 - 9.625^2) \times 3{,}705 \times 0.0408] = 57{,}356$ gals

CEMENT VOLUME

$$V_{SL} \times no.\ of\ sacks \times 7.48052 = Volume\ (gals)$$

V_{SL}	=	Slurry Volume (ft^3/sack)
7.48052	=	Conversion Factor (gal/ft^3)

Surface Casing

1.69 x 6,969 x 7.48052	=	88,103 gals
1.06 x 600 x 7.48052	=	4,758 gals
Total Volume	=	92,861 gals

Protective Casing

1.69 x 1,850 x 7.48052	=	23,388 gals
1.06 x 5,710 x 7.48052	=	45,277 gals
Epseal®	=	19,740 gals
Total Volume	=	88,405 gals

Table 5-25
DeLisle Plant
Well No. 4 - Tubular Stress Calculations

BURST PRESSURE:

$$P_{max} = P_{max\ inj} + (0.433 \times SG_{injfl} \times D) - (0.433 \times SG_{afl} \times D)$$

Where:

P_{max}	=	maximum pressure (psi)
0.433	=	pressure gradient (psi/ft)
SG_{injfl}	=	maximum specific gravity of injection fluid
SG_{afl}	=	specific gravity of the annular fluid
D	=	depth of tubing (ft)
$P_{max\ inj}$	=	maximum injection pressure (psi)

P_{max} = 600 + (0.433 x 1.35 x 9,526) - (0.433 x 1.25 x 9,526) = 1,012 psi

COLLAPSE PRESSURE:

$$P_{max} = P_{maxan} + (0.433 \times SG_{afl} \times D) - (0.433 \times SG_{injfl} \times D)$$

Where:

P_{max}	=	maximum pressure (psi)
0.433	=	pressure gradient (psi/ft)
SG_{injfl}	=	maximum specific gravity of the injected fluid
SG_{afl}	=	specific gravity of the annular fluid
D	=	depth of tubing (ft)
P_{maxan}	=	maximum annular pressure

P_{max} = 600 + (0.433 x 1.25 x 9,526) - (0.433 x 1.35 x 9,526) = 188 psi

TENSILE STRENGTH:

$$W_{max} = (W_{ta} \times D) + (W_{ta} \times D)$$

Where:

W_{max}	=	maximum tensile weight (lbs)
W_{ta}	=	weight of tubing in air (lb/ft)
D	=	depth of tubing (ft)

W_{max} = (6.5 x 6700) + (5.2 x 2962) = 58,952 lbs

This demonstration need not be performed for surface and protective casing because the maximum stresses are induced during cementing of the casing strings. Since this well has been completed with no problems, the casings will be strong enough to endure the maximum burst and collapse pressures and axial loading for the design life of the well.

a. Assume injection of maximum specific gravity fluid at maximum pressure with no annular pressure other than hydrostatic for burst calculations.
b. Assume maximum annular pressure and maximum specific gravity injection fluid under hydrostatic pressure for collapse calculations.
c. Assume no buoyancy effect on tubing for tensile strength calculations.

Table 5-26
DeLisle Plant
Well No. 5 - Borehole Deviation Survey

Surface Location: 1,330 feet N and 450 feet W of Well No. 3

Depth (feet)	Deviation (degrees)	Depth (feet)	Deviation (degrees)
0	0	5,000	0
250	1/2	5,250	1/4
500	1/4	5,500	1/4
750	1/2	5,750	0
1,000	1/4	6,000	1/4
1,250	1/2	6,250	1/2
1,500	1/2	6,500	3/4
1,750	1/4	6,750	1/4
2,000	1/2	7,000	1/2
2,250	3/4	7,250	1/4
2,500	1	7,500	1/4
2,750	1 3/4	7,750	1/2
3,000	1 1/2	8,000	1/2
3,250	1 1/2	8,250	1/2
3,500	1 1/2	8,500	1/2
3,750	1 1/4	8,750	1/2
4,000	1	9,000	1
4,250	1/2	9,250	1/2
4,500	3/4	9,500	1/2
4,750	1/4	9,750	3/4

Table 5-27
DeLisle Plant
Well No. 5 - Casing and Tubing Data

Casing Type	Size/Weight/Grade	Depth (feet)	Burst Collapse (psi)	Tensile Strength (lbs)
Conductor	20" carbon steel	0 - 406	N/A	N/A
Surface Casing	13 3/8", 68 lb/ft, N-80	0 - 3,440	5,020 - 2,260	1,300,000
Protective Casing	9 5/8", 53.5 lb/ft, N-80	0 - 8,550	6,330 - 3,810	825,000
	9 5/8", 43.5 lb/ft, N-80 FRP	8,550 - 9,586	6,330 - 3,810	825,000
	10 3/4" Fiberglass Joint	9,586 - 9,611	3,000 - 2,500	N/A
	8-5/8" titanium	9,611 - 9,765	N/A	N/A
Injection Tubing	6-5/8" FRP, NU Red Box 2500	0 - 5,724	2,500 - 3,000	73,600
	6-5/8" FRP, IUE, Red Box 2500	5,724 - 9,460	2,500 - 3,000	73,600

* Data obtained from API bulletins 5C2 and 5C3, ASTM Standards A312, and Tubular Fiberglas Products, Fiberglass Tubing

Table 5-28
DeLisle Plant
Well No. 5 - Cementing Data Summary

Casing Type	Cement Type/Class	Slurry Additives	Volume** (gals) Annular*	Volume** (gals) Pumped
Conductor Casing	600 sx Class A	N/A	N/A	N/A
Surface Casing	6381 sx Light Cmt.	35% Fly ash + 8% gel		99,821
	1913 sx Class A			15,455
	Volume Totals		22,928	115,276
Protective Casing	*Epseal®*			3,318
	2998 sx Premium	0.6% Halad-322		23,772
	1867 sx HLC	0.2% CFR-3 + 0.2% Halad-344		25,628
	Volume Totals		30,009	52,718

* Annular volumes calculated with 1 in. over bit size to allow for borehole irregularities.

** Volume calculations are located in Table 5-27.

Centralizers: Centralizers were used to enable the cement to completely circulate around the casing.

Table 5-29
DeLisle Plant
Well No. 5 - Surface Control Systems

Instrumentation	Location	Name and Model
Injection Pressure Gauge	Injection Pumps	USG-Solfrunt Ashcroft-PSI
Injection Pressure Recorder	Control Room	Fisher TL 101
Annulus Pressure Recorder	Control Room	Fisher Tl 132, TL 101
Injection Rate Meter	Surge Tank Discharge	Fisher TL 101
Temperature Gauge	Control Room	Thermo-Electrical Type K
Annulus Pump	Brine Feed Tank	Durco
Injection Pump	Centrifugal	Gould Titanium, 2 at 400 gpm each

Sampling Procedures: Waste is sampled continuously by the plant process computers.

Table 5-30
DeLisle Plant
Well No. 5 - Volume Calculations

SURFACE CASING ANNULAR VOLUME

$$(D^2 - d^2) \times L \times 0.0408 = \text{Volume (gals)}$$

D	=	Hole Diameter (in)
d	=	Casing OD (in)
L	=	Setting Depth (ft)
0.0408	=	Conversion Factor (gal/ft-in^2)

$(18.5^2 - 13.375^2) \times 3{,}440 \times 0.0408 = 22{,}928$ gals

PROTECTIVE CASING ANNULAR VOLUME

$$[(D^2 - d^2) \times (L-Lsc) \times 0.0408] + [(D^2sc - d^2) \times [Lsc \times 0.0408] = \text{Volume (gals)}$$

D	=	Hole Diameter (in)
d	=	Casing OD (in)
L	=	Setting Depth (ft)
L_{sc}	=	Surface Casing Setting Depth (ft)
D_{sc}	=	Surface Casing ID (in)
0.0408	=	Conversion Factor (gal/ft-in^2)

$[(13.25^2 - 9.625^2) \times (9{,}759 - 3{,}440) \times 0.0408] + [(12.415^2 - 9.625^2) \times 3{,}440 \times 0.0408] = 30{,}009$ gals

CEMENT VOLUME

$$V_{SL} \times \text{no. of sacks} \times 7.48052 = \text{Volume (gals)}$$

V_{SL}	=	Slurry Volume (ft^3/sack)
7.48052	=	Conversion Factor (gal/ft^3)

Surface Casing

2.02 x 6381 x 7.48052	=	96,421 gals
1.08 x 1913 x 7.48052	=	15,455 gals
Total Volume	=	111,876 gals

Protective Casing

1.06 x 2998 x 7.48052	=	23,772 gals
1.835 x 1867 x 7.48052	=	25,628 gals
Epseal®	=	3,318 gals
Total Volume	=	52,718 gals

Table 5-31
DeLisle Plant
Well No. 5 - Tubular Stress Calculations

BURST PRESSURE:

$$P_{max} = P_{max\ inj} + (0.433 \times SG_{injfl} \times D) - (0.433 \times SG_{afl} \times D)$$

Where:

P_{max}	=	maximum pressure (psi)
0.433	=	pressure gradient (psi/ft)
SG_{injfl}	=	maximum specific gravity of injection fluid
SG_{afl}	=	specific gravity of the annular fluid
D	=	depth of tubing (ft)
$P_{max\ inj}$	=	maximum injection pressure (psi)
P_{max}	=	600 + (0.433 x 1.35 x 9,691) - (0.433 x 1.25 x 9,691) = 1,020 psi

COLLAPSE PRESSURE:

$$P_{max} = P_{maxan} + (0.433 \times SG_{afl} \times D) - (0.433 \times SG_{injfl} \times D)$$

Where:

P_{max}	=	maximum pressure (psi)
0.433	=	pressure gradient (psi/ft)
SG_{injfl}	=	maximum specific gravity of the injected fluid
SG_{afl}	=	specific gravity of the annular fluid
D	=	depth of tubing (ft)
P_{maxan}	=	maximum annular pressure

P_{max} = 750 + (0.433 x 1.25 x 9,691) - (0.433 x 1.35 x 9,691) = 330 psi

TENSILE STRENGTH:

$$W_{max} = W_{ta} \times D) + (W_{ta} \times D)$$

Where:

W_{max}	=	maximum tensile weight (lbs)
W_{ta}	=	weight of tubing in air (lb/ft)
D	=	depth of tubing (ft)

W_{max} = 10.1 x 9,460 = 95,546 lbs

This demonstration need not be performed for surface and protective casing because the maximum stresses are induced during cementing of the casing strings. Since this well has been completed with no problems, the casings will be strong enough to endure the maximum burst and collapse pressures and axial loading for the design life of the well.

a. Assume injection of maximum specific gravity fluid at maximum pressure with no annular pressure other than hydrostatic for burst calculations.
b. Assume maximum annular pressure and maximum specific gravity injection fluid under hydrostatic pressure for collapse calculations.
c. Assume no buoyancy effect on tubing for tensile strength calculations.

Table 5-32
Proposed DeLisle Plant
Well Nos. 6 and 7 – Conductor Hole Well Fluids Program

Depth (feet)	**Mud Type**	**Weight** (lb/gal)	**Viscosity**	**Fluid Loss** (cc/30 min)
0 – 500	Freshwater Gel	8.5 - 8.8	40 - 50	No control

Table 5-33
Proposed DeLisle Plant
Well Nos. 6 and 7 – Surface Hole Well Fluids Program

Depth (feet)	**Mud Type**	**Weight** (lb/gal)	**Viscosity**	**Fluid Loss** (cc/30 min)
0 – 3,450	Freshwater Gel	8.5 - 8.8	40 - 50	No control

Table 5-34
Proposed DeLisle Plant
Well Nos. 6 and 7 – Protection Hole Well Fluids Program

Depth (feet)	**Mud Type**	**Weight** (lb/gal)	**Viscosity**	**Fluid Loss** (cc/30 min)
3,450 – 10,100*	Salt	8.8 - 10.2	35 - 50	6 - 10

* Depth will be approximately 400 feet shallower if the well is completed into the Tuscaloosa Massive sand.

Table 5-35
Proposed DeLisle Plant
Well Nos. 6 and 7 – Surface Hole Formation Evaluation Program

Open-hole Logs	**Cased-Hole Logs**
• Spontaneous Potential/Resistivity • Natural Gamma • Neutron-Density • Open Hole Caliper	• Cement Bond with Variable Density Log • Temperature

Table 5-36
Proposed DeLisle Plant
Well Nos. 6 and 7 – Protection Hole Formation Evaluation Program

Open-hole Logs	Cased-Hole Logs
• Spontaneous Potential/Resistivity	• Cement bond with Variable Density Log
• Natural Gamma Ray	• Temperature
• Neutron-Density (Porosity)	
• Sonic (Porosity)	• Casing Inspection
• Fracture Finder/Dipmeter	
• Combinable Magnetic Resonance	
• Dipole Shear Sonic	• Inclination Survey
• Open Hole Caliper	• Bottom-hole Pressure – static and fall-off pressure determination
• Bottom-hole Temperature	• Differential Temperature Survey
• Whole Cores	• Radioactive Tracer Survey
• Sidewall Cores--Rotary & Percussion	
• Formation Fluid Samples	

Table 5-37
Proposed DeLisle Plant
Well Nos. 6 and 7 – Casing and Tubing Program

Tubular	Depth (feet)	Size (in)	Weight (lb/ft)	Grade Thread	Collapse/ Burst (psi)	Body/Joint Tensile (x 1000 lbs)
CONDUCTOR	0 - 125	30	--	--	--	--
CONDUCTOR	0 - 500	20	94	J-55 STC	520 / 2110	1,480 / 784
SURFACE CASING	0 – 3,450	13-3/8	68	N-80 Buttress	2260 / 5020	1,556 / 1,545
PROTECTION** CASING	0 – 9,550 (carbon steel)	9-5/8	43.5	N-80 LTC & ST-L*	3810 / 6330	1005 / 825 / 669
PROTECTION** CASING	9,550 – 9,580 (transition joint)	9-5/8	55.4	C276 ST-L*	4385 / 5036	794 / 782
PROTECTION** CASING	9,580 – 9,750 (corrosion-resistant)	9-5/8	+/- 36	CRA	3000 / 5000	500
INJECTION** TUBING	0 – 9,700	6-5/8	9.6	Red Box 2500 FRP	2500 - 2500	72.5

*or equivalent flush, integral joint connection

** depths will be about 400 feet shallower if these wells are completed into the Tuscaloosa Massive sand

Table 5-38
Proposed DeLisle Plant
Well Nos. 6 and 7 – Conductor Hole Cementing Program

Cement:	Coverage (feet)	Weight (ppg)	Yield (feet^3/sx)	Water (gal/sx)	Volume (sx)*	Notes:
Lead Cement	300	13.6	1.73	9.07	335	Standard Cement + 3% salt + 1/4 lb/sx cellophane flakes + retarder + extender
Tail Cement	200	15.6	1.18	5.2	325	Standard cement + 2% $CaCl_2$

*sx = cement sack of 94 lb.

Table 5-39
Proposed DeLisle Plant
Well Nos. 6 and 7 – Surface Hole Cementing Program

FIRST STAGE

Cement:	**Coverage** (feet)	**Weight** (ppg)	**Yield** (feet^3/sx)	**Water** (gal/sx)	**Volume** (sx)	**Notes:**
Lead Cement	1250	13.6	1.73	9.07	1005	Standard Cement + 3% salt + 1/4 lb/sx cellophane flakes + retarder + extender
Tail Cement	500	16.4	1.06	4.33	650	Premium cement

SECOND STAGE

Cement:	**Coverage** (feet)	**Weight** (ppg)	**Yield** (feet^3/sx)	**Water** (gal/sx)	**Volume** (sx)	**Notes:**
Lead Cement	1200	13.6	1.73	9.07	1005	Standard Cement + 3% salt + 1/4 lb/sx cellophane flakes + retarder + extender
Tail Cement	500	15.6	1.18	5.2	585	Standard cement

Table 5-40
Proposed DeLisle Plant
Well Nos. 6 and 7 – Protection Hole Cementing Program

FIRST STAGE

Cement:	Coverage (feet)	Weight (ppg)	Yield ($feet^3/sx$)	Water (gal/sx)	Volume (bbl)	Notes:
Lead Cement	800	13.0	N/A	N/A	45	Epoxy Resin Cement

SECOND STAGE

Cement:	Coverage (feet)	Weight (ppg)	Yield ($feet^3/sx$)	Water (gal/sx)	Volume (sx)	Notes:
Lead Cement	3650	13.6	1.73	9.07	990	Standard Cement + 3% salt + 1/4 lb/sx cellophane flakes + retarder + extender
Tail Cement	1500	16.4	1.06	4.33	665	Premium cement

THIRD STAGE

Cement:	Coverage (feet)	Weight (ppg)	Yield ($feet^3/sx$)	Water (gal/sx)	Volume (sx)	Notes:
Lead Cement	3000	12.5	2.07	11.41	1215	Standard Cement + 3% salt + 1/4 lb/sx cellophane flakes + retarder + extender

Table 5-41
DeLisle Plant
Injection Volume through Year End 2015

DeLisle Plant Injected Volume through Year End 2015	
Well	**Injected Volume (Million Gallons)**
Well 2	2,748
Well 3	1,643
Well 4	1,557
Well 5	2,102
Plant Total	8,050

FIGURES

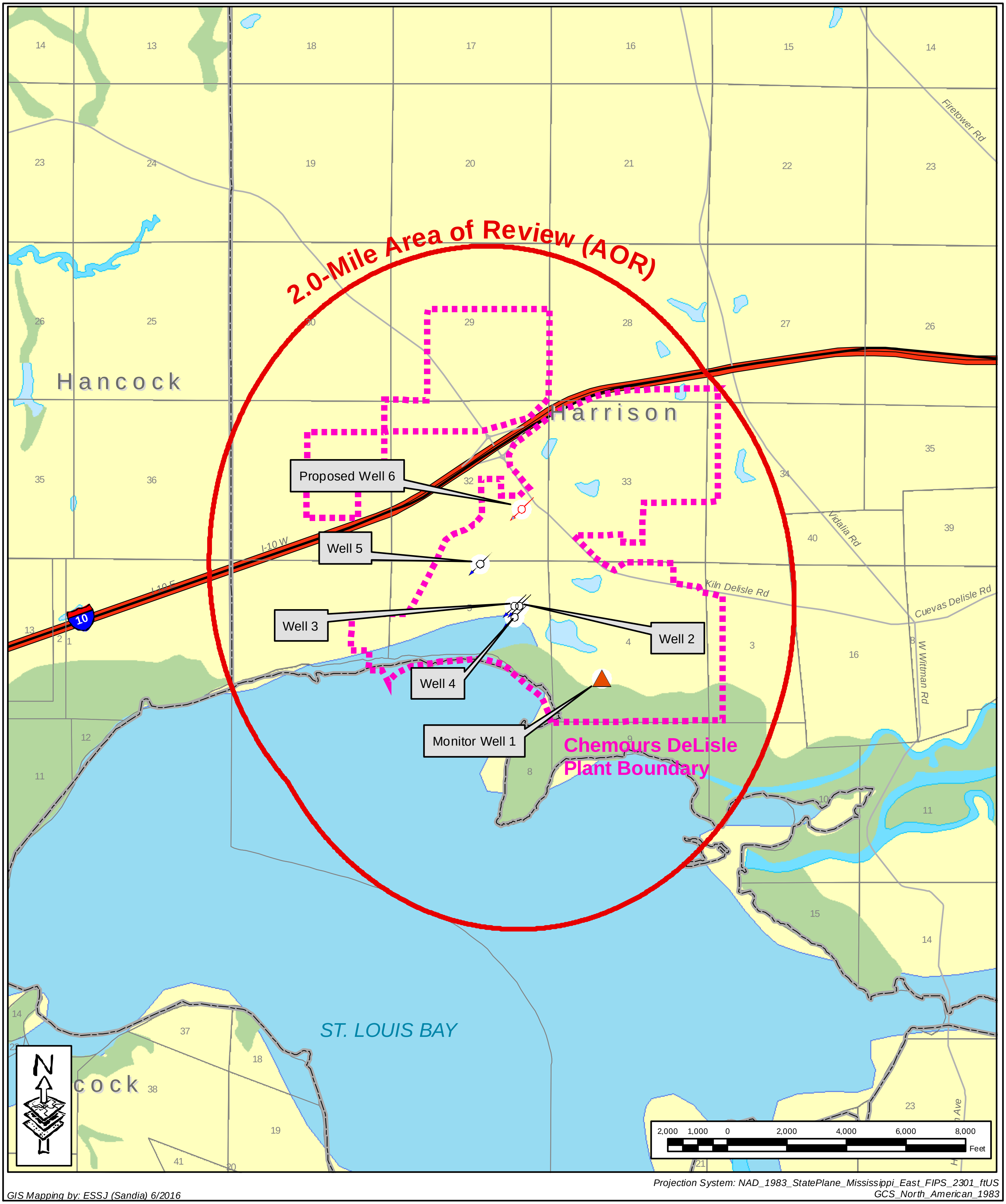
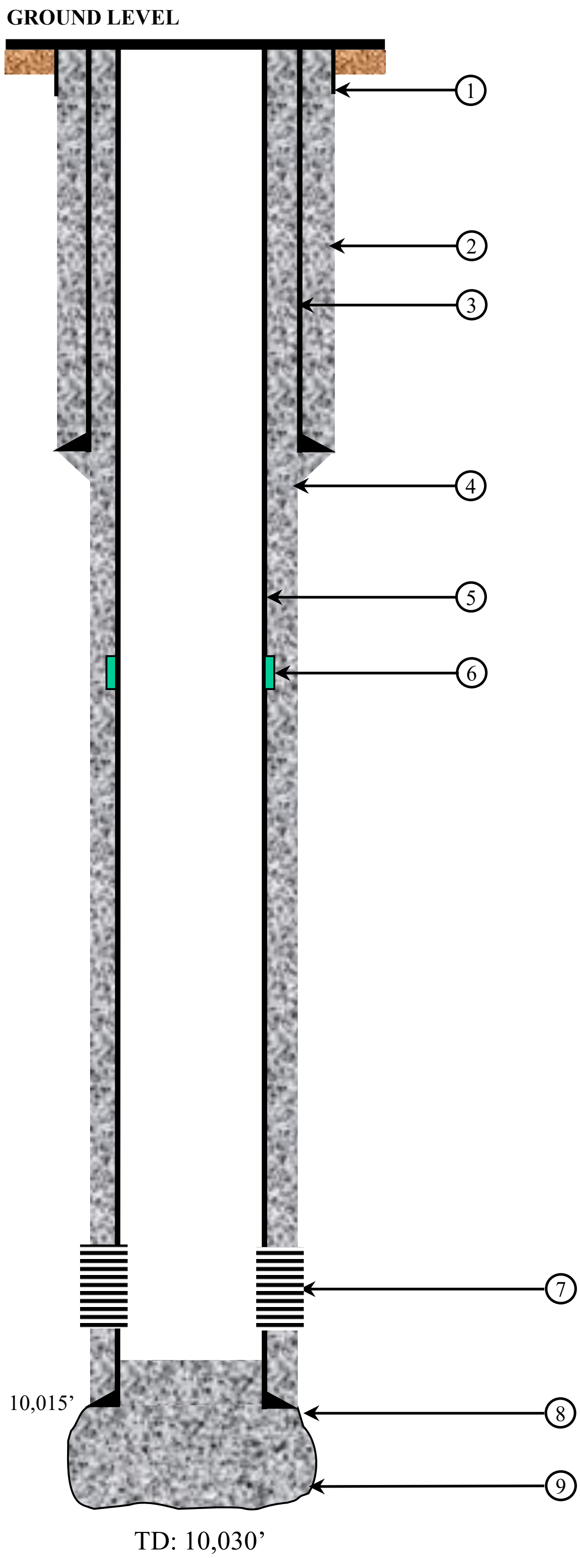


Figure 5-1 Well Location Map

Chemours Company, FC, LLC,
Titanium Technologies

DeLisle Plant Monitor Well No. 1
Well Schematic
Status: Active

GL = 3.6' MSL
KB = 16'
All depths RKB



COMPLETION DETAIL

1. **Conductor Pipe**: 18" O.D., driven to 99'
2. 15" Borehole
3. **Surface Casing**: 11-3/4" O.D., 60.0 lb/ft., of N-80 set to 331'; 958' of 60.0 lb/ft., K-55 set to 1,289'; 368' of 54 lb/ft., K-55 set to 1,657'; 1,802' of 47 lb/ft., K-55 set to 3,459': cemented with 3700 sx of Halliburton lt., 300 sx Class H with Tuf-fiber, and 100 sx common with 2% CaCl
4. 10-5/8" Borehole
5. **Protection Casing**: 8-5/8" O.D. CS 36 lb/ft., to 2,328', 1,781' of 40 lb/ft. to 4,109', 2,563' of 32 lb/ft. to 6,672', 192' of 36 lb/ft. to 6,864', 126' of 40 lb/ft. to 6,990', 1,112' of 36 lb/ft. to 8,102, 1,919' of 32 lb/ft. to 6,672', 192' of 36 lb/ft. to 6,864', 126' of 40 lb/ft. to 6,990', 1,112' of 36 lb/ft. to 8,102, 1,919' of 32 lb/ft. to 10,015'; cemented in two stages: 1,200 sx of Halliburton lt. (4% gel, .5% Halad 9, 2.61 lbs. salt, ¼ lb. Flocele, & .25% Hr-4) & 300 sx Class H (7.8 lbs. salt, CFR-2 @ 75% & 0.3% HR-4) as first slurry, & 1000 sx Halliburton lt. (4% gel, .5% Halad 9, 2.61 lbs. salt & ¼ lb. Flocele) as a tail cement
6. DV tool set @ 5,568'
7. **Perforations**: 9,775' to 9,801 with 4 SPF, 9,812' to 9,844' with 4 SPF, 9,850' to 9,914' with 4 SPF, 9,934' to 9,974' with 4 SPF
8. Underreamed
9. Plugged back to 9,991' with cement

GEOSTOCK SANDIA
ENTREPOSE

8860 Fallbrook Drive Houston, TX 77064 USA
Tel: (346) 314-4347 Fax: (832) 478-5172

Drawn by: ESSJ	Date: 02/01/2007	*Drawing not to scale*

Figure 5-2 Monitor Well No. 1 Well Schematic

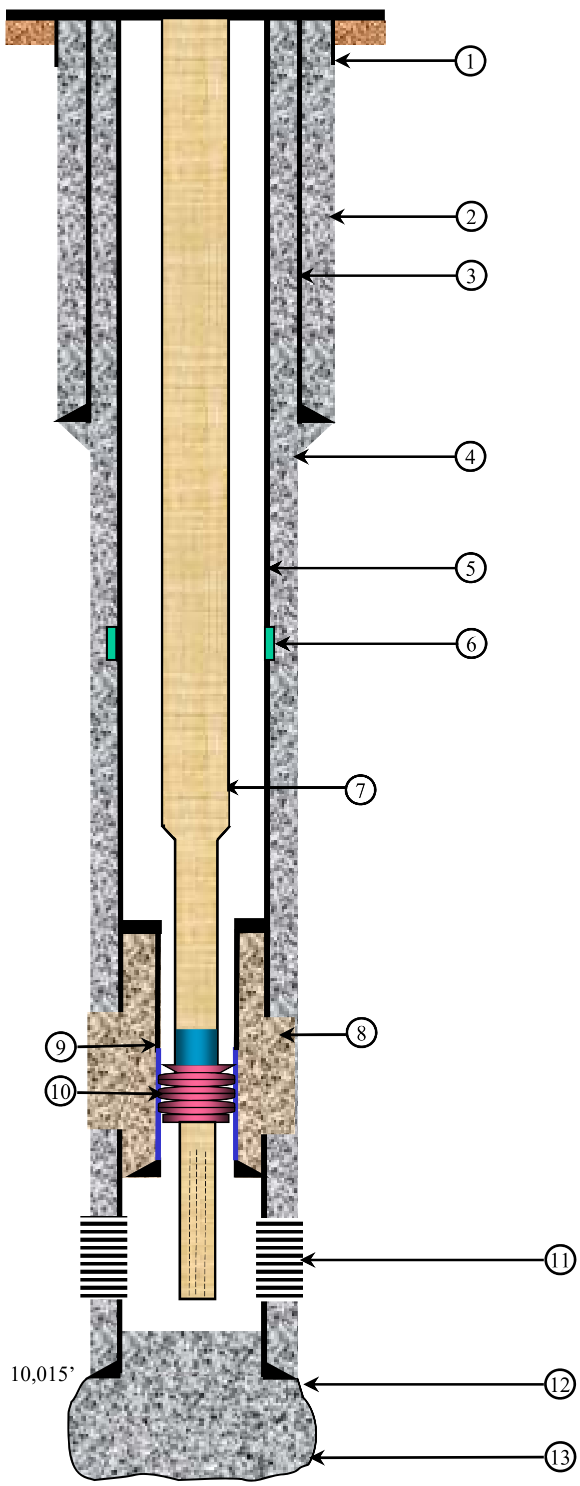
Chemours

Chemours Company, FC, LLC, Titanium Technologies

DeLisle Plant Monitor Well No. 1
Well Schematic

Status: Proposed Completion

GL = 3.6' MSL
KB = 16'
All depths RKB



COMPLETION DETAIL

1. **Conductor Pipe**: 18" O.D., driven to 99'
2. 15" Borehole
3. **Surface Casing**: 11-3/4" O.D., 60.0 lb/ft., of N-80 set to 331'; 958' of 60.0 lb/ft., K-55 set to 1,289'; 368' of 54 lb/ft., K-55 set to 1,657'; 1,802' of 47 lb/ft., K-55 set to 3,459': cemented with 3700 sx of Halliburton lt., 300 sx Class H with Tuf-fiber, and 100 sx common with 2% CaCl
4. 10-5/8" Borehole
5. **Protection Casing**: 8-5/8" O.D. CS 36 lb/ft., to 2,328', 1,781' of 40 lb/ft. to 4,109', 2,563' of 32 lb/ft. to 6,672', 192' of 36 lb/ft. to 6,864', 126' of 40 lb/ft. to 6,990', 1,112' of 36 lb/ft. to 8,102, and 1,919' of 32 lb/ft. to 10,015'; cemented in two stages: 1,200 sx of Halliburton lt. (4% gel, .5% Halad 9, 2.61 lbs. salt, ¼ lb. Flocele, & .25% Hr-4) & 300 sx Class H (7.8 lbs. salt, CFR-2 @ 75% & 0.3% HR-4) as first slurry, & 1000 sx Halliburton lt. (4% gel, .5% Halad 9, 2.61 lbs. salt & ¼ lb. Flocele) as a tail cement
6. DV tool set @ 5,568'
7. **Injection string**: A proposed tapered string of 5-1/2-inch x 3-1/2-inch fiberglass tubing with titanium seal assembly
8. **Acid resistant cement**: Placed at the top of the injection interval by section milling the casing
9. **Liner**: 5-1/2-inch carbon steel and titanium liner
10. **Completion Equipment**: The proposed completion will consist of a slotted fiberglass liner, titanium packer, and titanium polished bore receptacle (PBR) in accordance with the approved and actively in service completions at Injection Well Nos. 2, 3, 4, and 5.
11. **Perforations**: 9,775' to 9,801 with 4 SPF, 9,812' to 9,844' with 4 SPF, 9,850' to 9,914' with 4 SPF, 9,934' to 9,974' with 4 SPF
12. Underreamed
13. Plugged back to 9,991' with cement

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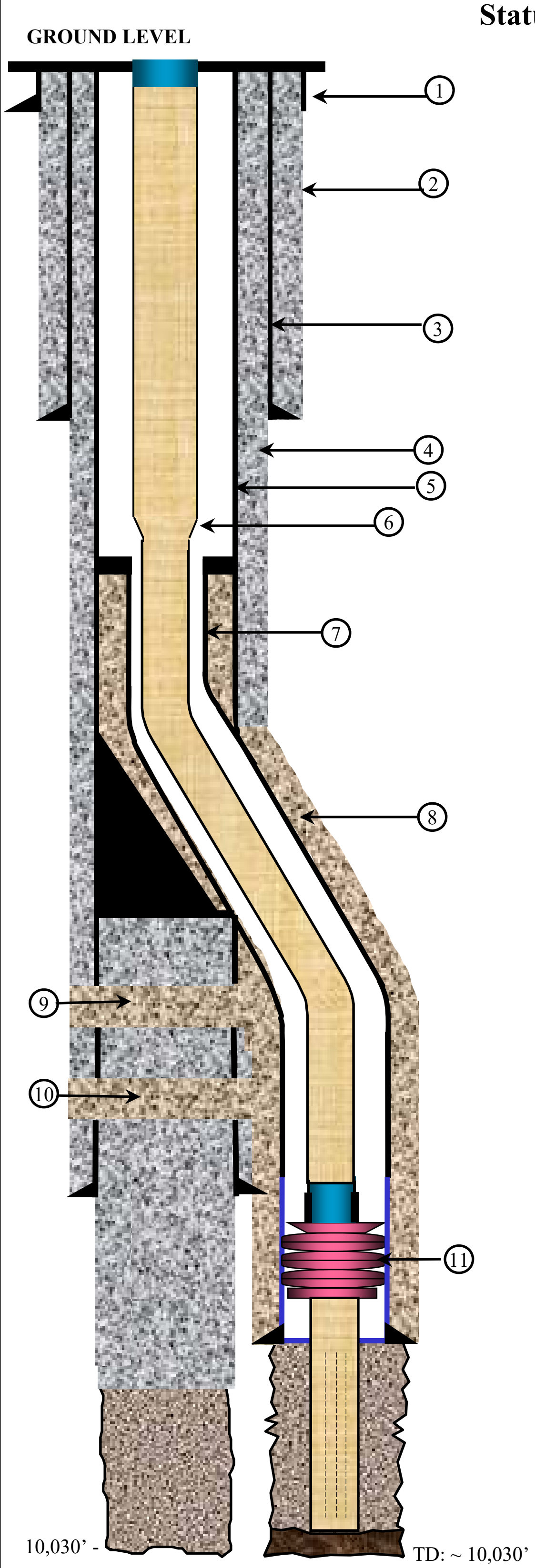
Drawn by: GCH	Date: 7/31/2017	*Drawing not to scale*

Figure 5-2a Monitor Well No. 1 Well Schematic – Proposed section milling option

Chemours Company, FC, LLC, Titanium Technologies

DeLisle Plant Monitor Well No. 1
Well Schematic
Status: Proposed Completion

GL = 3.6' MSL
KB = 16'
All depths RKB



COMPLETION DETAIL

1. **Conductor Pipe**: 18" O.D., driven to 99'
2. 15" Borehole
3. **Surface Casing**: 11-3/4" O.D., 60.0 lb/ft., of N-80 set to 331'; 958' of 60.0 lb/ft., K-55 set to 1,289'; 368' of 54 lb/ft., K-55 set to 1,657'; 1,802' of 47 lb/ft., K-55 set to 3,459': cemented with 3700 sx of Halliburton lt., 300 sx Class H with Tuf-fiber, and 100 sx common with 2% CaCl
4. 10-5/8" Borehole
5. **Protection Casing**: 8-5/8" O.D. CS 36 lb/ft., to 2,328', 1,781' of 40 lb/ft. to 4,109', 2,563' of 32 lb/ft. to 6,672', 192' of 36 lb/ft. to 6,864', 126' of 40 lb/ft. to 6,990', 1,112' of 36 lb/ft. to 8,102, and 1,919' of 32 lb/ft. to 10,015'; cemented in two stages: 1,200 sx of Halliburton lt. (4% gel, .5% Halad 9, 2.61 lbs. salt, ¼ lb. Flocele, & .25% Hr-4) & 300 sx Class H (7.8 lbs. salt, CFR-2 @ 75% & 0.3% HR-4) as first slurry, & 1000 sx Halliburton lt. (4% gel, .5% Halad 9, 2.61 lbs. salt & ¼ lb. Flocele) as a tail cement
6. **Injection string**: A proposed tapered string of 5-1/2-inch x 3-1/2-inch fiberglass tubing with titanium seal assembly
7. **Liner**: 5-1/2-inch carbon steel and titanium liner
8. **Acid resistant cement**: Cementing the liner in place
9. **Plug:** Placed at the top of the Tuscaloosa Massive by section milling the casing
10. **Plug:** Placed at the top of the Washita Fredericksburg by section milling the casing
11. **Completion Equipment**: The proposed completion will consist of a slotted fiberglass liner, titanium packer, and titanium polished bore receptacle (PBR) in accordance with the approved and actively in service completions at Injection Well Nos. 2, 3, 4, and 5.

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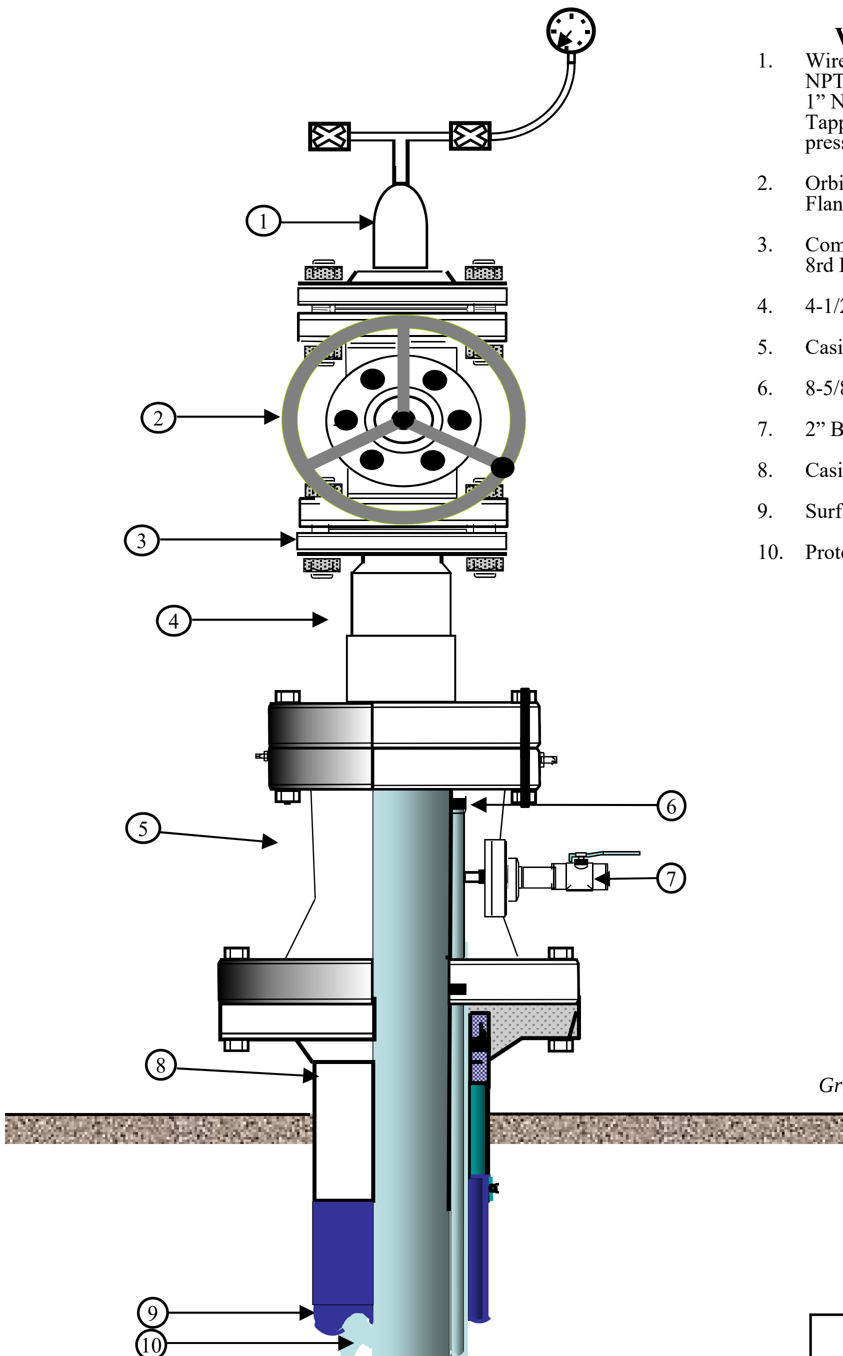
Drawn by: GCD	Date: 7/31/2017	*Drawing not to scale*

Figure 5-2b Monitor Well No. 1 Well Schematic – Proposed sidetracking option

Chemours Company, FC, LLC,
Titanium Technologies
DeLisle Plant Monitor Well #1
Wellhead Schematic
Status: Active



WELLHEAD ASSEMBLY DETAIL

1. Wire Line Access: Bull Plug, Tapped, 4-1/2" EUE 8rd X ½" NPT; Flow Tee, 1/2" EUE 8rd top & bottom with 2" NPT and 1" NPT side outlets. Companion Flange 7-1/16" 3M API. Tapped Bull Plug supports local and remote injection tubing pressure functions with a 0-160 psig Pressure Gauge.
2. Orbit Gate Valve: Full Opening 4", 600-Series, ANSI-RF, Flanged.
3. Companion Flange: 4", 600-Series, ANSI-RF, tapped 4-1/2" 8rd LTC.
4. 4-1/2" 8rd Pin x 5-1/2" LTC Pin Adapter Swage
5. Casing Spool: 11", 3M x 13-5/8", 3M
6. 8-5/8" Casing Hanger
7. 2" Ball Valve
8. Casing Head: 13-5/8", 3M, SOW
9. Surface Casing: 11-3/4", N-80 & K-55
10. Protective Casing: 8-5/8", K-55 & S-95

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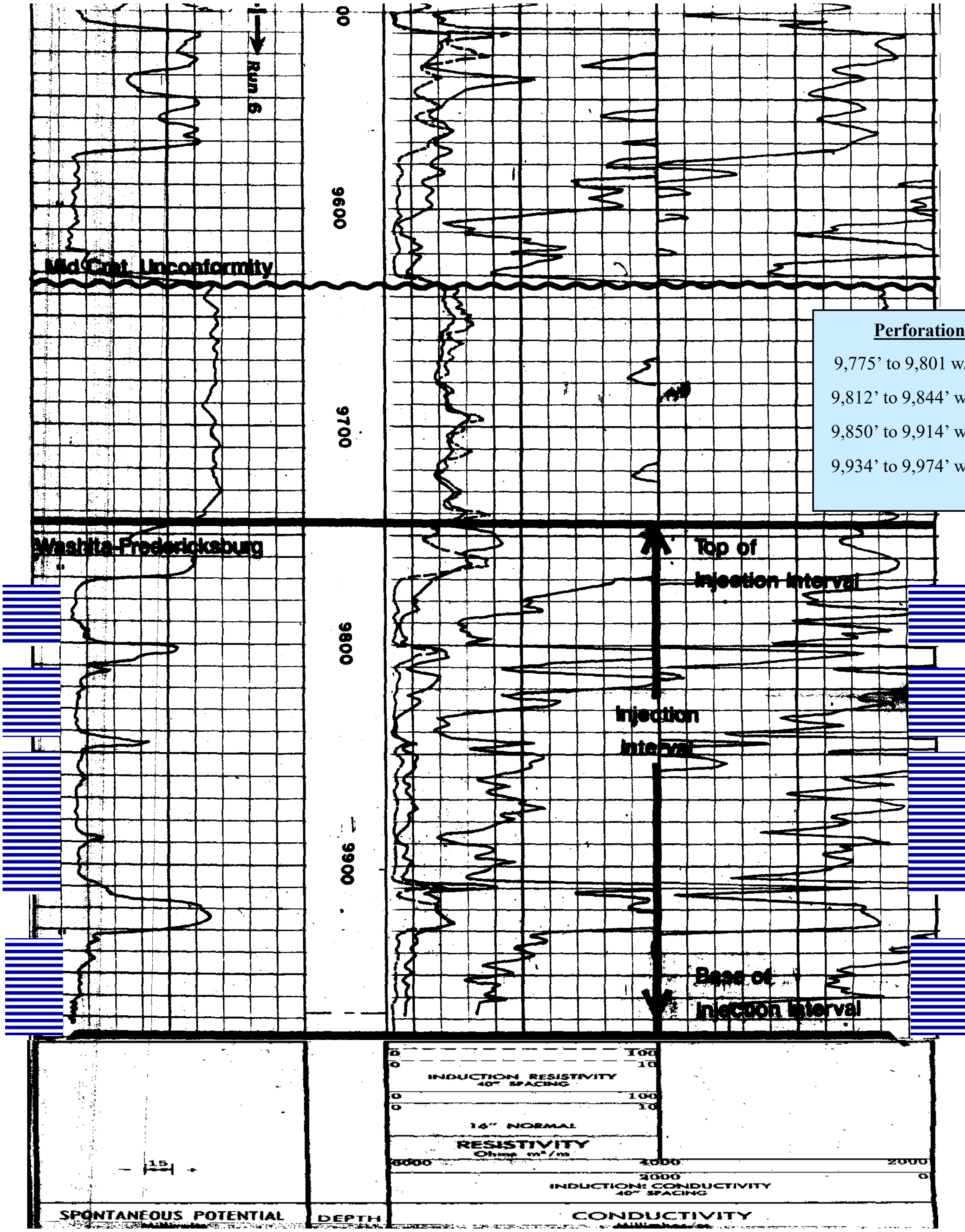
Drawn by: JOC	Date: 3/21/2016	*Drawing not to scale*

Figure 5-2c Monitor Well No. 1 Wellhead Schematic

Chemours Company, FC, LLC,
Titanium Technologies

DeLisle Plant Monitor Well No. 1
Annotated Openhole Log with Completion

Status: Active



Perforations:

9,775' to 9,801 w/ 4 SPF

9,812' to 9,844' w/ 4 SPF

9,850' to 9,914' w/ 4 SPF

9,934' to 9,974' w/ 4 SPF

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Drawn by: ESSJ	Date: 02/01/2007	*Drawing not to scale*

Figure 5-3 Monitor Well No. 1 Electric Log (annotated)

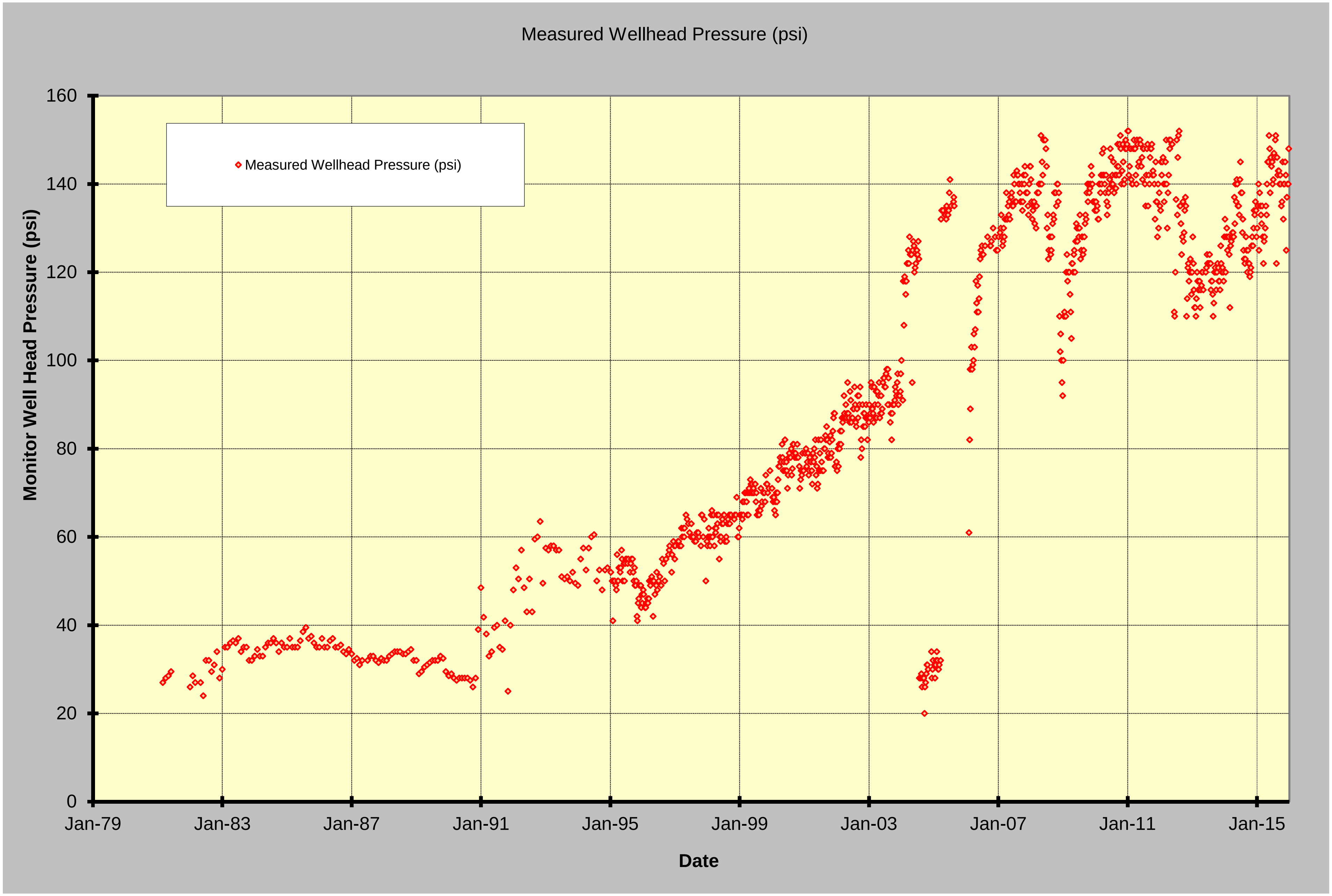


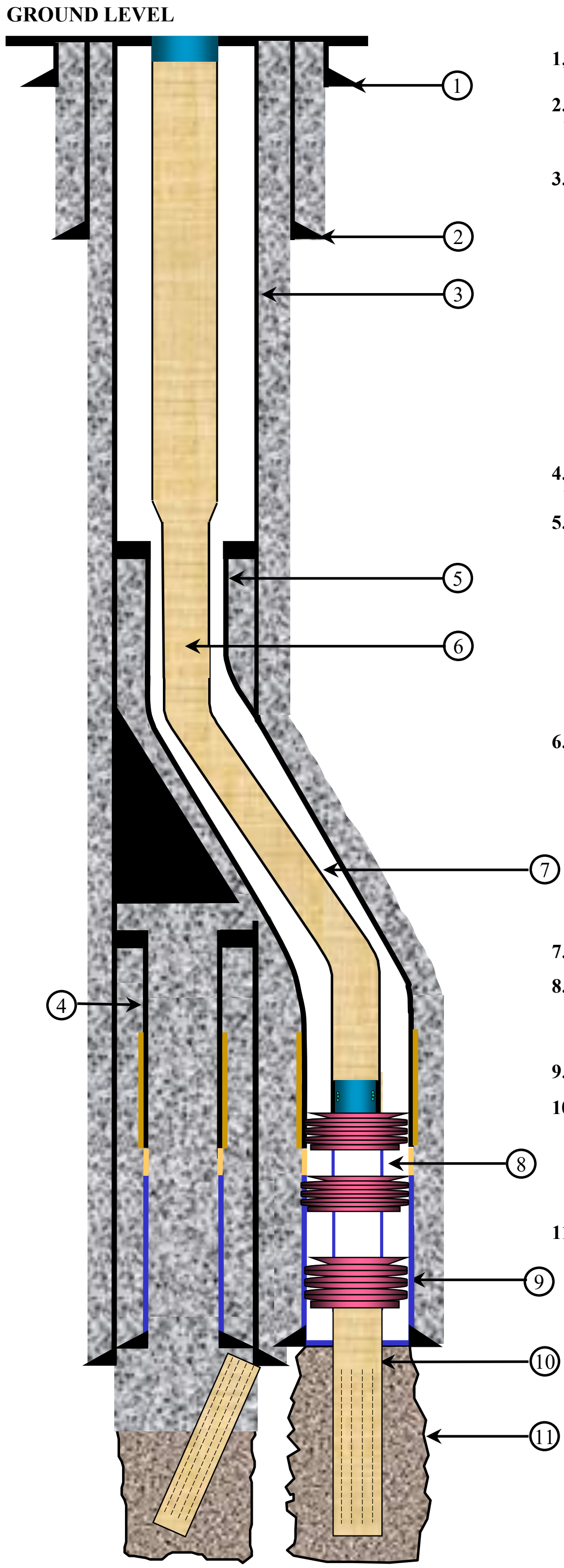
Figure 5-4 Monitoring Well No. 1 Historical Pressure Responses

Chemours™

Chemours Company, FC, LLC, Titanium Technologies

DeLisle Plant Well No. 2
Sidetrack No. 1
Well Schematic

GL = 16.58' MSL
KB = 29.58' LMF
All depths RKB



COMPLETION DETAIL

1. **Conductor Pipe**: 20", Surface to 101'. Set in 26" hole & cemented to surface with 200 sx Neat cement.

2. **Surface Casing**: 13-3/8", 68 ppf, K-55, Surface to 3,658'. Set in 17-1/2" hole and cemented to surface with 2,280 sx of Halliburton Light (0.25#/sx Flocele) and 275 sx Class H (35% $CaCl_2$).

3. **Protection Casing**: 9-5/8", Surface to 9,855' in 12-1/4" hole:
   - •Surface to 40', 53.5-ppf, N-80, LT&C.
   - •40' to 5510', 40-ppf, N-80, LT&C.
   - •5510' to 6000', 47-ppf, N-80, LTC
   - •6000' to 6041', Cross-Over, 47-ppf, N80, LT&C X Buttress
   - •6041' to 9766', 47-ppf, P-110, Buttress
   - •9766' to 9845', Titanium, ½" wall
   - •9845' to 9855', 53.5-ppf, N-80
   - •Halliburton Stage tools (DV) with string at 4885' and 9160'. Protective casing was cemented in 3 stages: Lower stage was 98 bbls of Epseal®, lower stage consisted of 2047.5 sxs., Upper stage consisted of 1150 sxs and cement was circulated to surface.
   - •Weatherford Bottom Trip Whipstock set 7,803' to 7,822' with window milled from 7,800' to 7,815''.

4. **Original Protection Liner** (plugged and abandoned, November, 1995): 7" OD from 8,551' to 9,792'.

5. **Protection Liner**: 7" OD from set in a 9-7/8" hole, from 7,573' to 9,743':
   - •Baker CMC Liner Hanger from 7,573' to 7,591'.
   - •25 Joints, 26 ppf, L-80, Hydril SLX, from 7,591' to 8,677'.
   - •1 Joint, 26 ppf, L-80, Hydril SLX, 8,677'-8,697' (marker, short joint).
   - •20 Joints, 26 ppf L-80, Hydril SLX, over-wrapped w/fiberglass from 8,697' to 9,536'.
   - •1 Joint, 7-5/8" Tubular Fiberglass RB-2500, LT&C from 9,536' to 9,563'.
   - •9 Joints, 0.375" wall (6.151 drift) Gr. 7 Titanium, AB ST-L, from 9,563' to 9,743'.

   Cemented with 225 bbl Epseal® LC Epoxy Resin. Set December, 1995.

6. **Injection Tubing**: Tapered string of 6-5/8" X 4-1/2" FRP, from Surface to 9,517':
   - •6-5/8" Titanium Grade 2 landing joint from Surface to 4'.
   - •6-5/8" BB-2500 (257 jts and 2 pup joints) from 4' to 7,516'.
   - •6-5/8" X 4-1/2" crossover joint from 7,516' to 7,545'.
   - •4-1/2" BB-2500 (66 jts) from 7,545' to 9,496'.
   - •4-1/2" Titanium Grade 7 Delta P, Inc (DPI) Seal assembly with locator collar and extension (L = 20.72 ft) from 9,496' to 9,517'.
   - •DPI Latch-in Polished Bore Receptacle from 9,499' to 9,519'

7. **Annulus Fluid**: Calcium Chloride Brine at 10.7 ppg with Tetra Technologies inhibitors.

8. **Straddle Packer Assembly**: Set from 9,519' to 9,696'. Upper Straddle Packer at 9,519' (element at 9,524'), Lower Straddle Packer at 9,579 feet (element at 9,575'), 11 joints of 4-1/2-inch titanium spacer pipe with latch-in seal assembly

9. **Injection Packer**: DPI Model 12, 7" X 4-1/2", Titanium Grade 7, set at 9,696' to 9,701'.

10. **Injection Screen Assembly**: 4-1/2" BB 2500 FRP Tubing.
    - •Blank tubing (2 jts) from 9,701' to 9,764'.
    - •Slotted Fiberglass screen (8 jts) from 9,764' to 9,999'.
    - •Bull plug bottom at 10,000'
    - •33 slots per foot, 3" penetration per slot, and 0.15 thickness per slot.

11. **Open Hole**: TD = 9,743' to 10,060', Drilled 8-1/2". Under reamed to 16" in September 2014.

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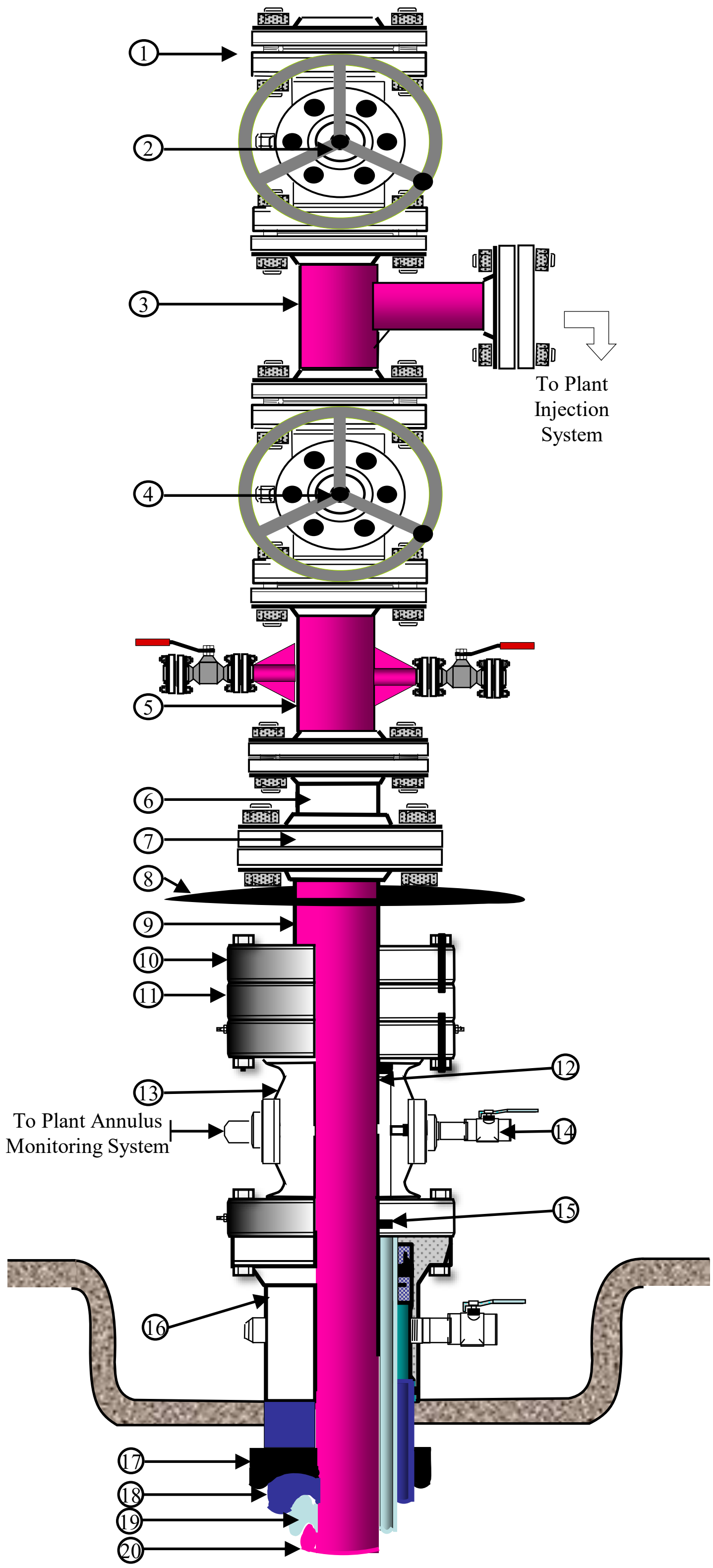
Drawn by: GCH	Date: 9/6/2017	*Drawing not to scale*

Figure 5-5 DeLisle Plant Well No. 2 Wellbore Schematic

Chemours

Chemours Company, FC, LLC, Titanium Technologies

DeLisle Plant Well #2
Sidetrack #1
Wellhead Schematic
Status: Active



WELLHEAD ASSEMBLY DETAIL

1. Wire Line Access: 4”, 300-Series, Titanium, ANSI-RF Blank Flange (plant has 4”, 300-Series carbon steel, ANSI-RF by 2-7/8” EUE 8rd pin adapter)
2. Valve: Full Opening 4”, 300-Series, Titanium, ANSI-RF
3. Flow Tee: 4”, 300-Series, Titanium, ANSI-RF
4. Valve: Full Opening 4”, 300-Series, Titanium, ANSI-RF
5. Instrumentation/Gauge access spool, 4” 300-Series, Titanium, ANSI-RF
6. Spool: 4”, 300 series x 6”, 300 Series Titanium, ANSI-RF
7. Flange: 6-5/8” 10rd straight with seal ring x 6”, 300 series Titanium, ANSI-RF x6-5/8” Adapter Swage
8. Rubber Drip Guard, 6-5/8” ID (snug fit) x 28” OD, to be slipped over 6-5/8” OD Casing to protect Wellhead from product dripping down from above. ½” Thick Material.
9. Landing Joint: 6-5/8” Titanium
10. 11” Nominal Quicklock Hold-Down Retainer w/ 6-5/8” Slips & O-Ring Seal (B&B)
11. Double Studded Packoff: 11” 5M BB-22-L. (B&B)
12. Tubing Hangers, With 2 O-Ring Seals 11” x 6-5/8” BB-22
13. Casing Spool: 13-5/8”, 3M
14. Valve
15. Secondary Seal: 9-5/8”, P-Seal
16. Casing Head: 16-3/4”, 3M
17. Conductor Pipe: 20”
18. Surface Casing: 16”, 84 ppf, K-55
19. Protective Casing: 9-5/8”, 53.5ppf, N-80
20. Landing Joint: 6-5/8” Titanium

Note: All Studs & Nuts to be Teflon Coated.

Ground Level

GEOSTOCK SANDIA ENTREPOSE

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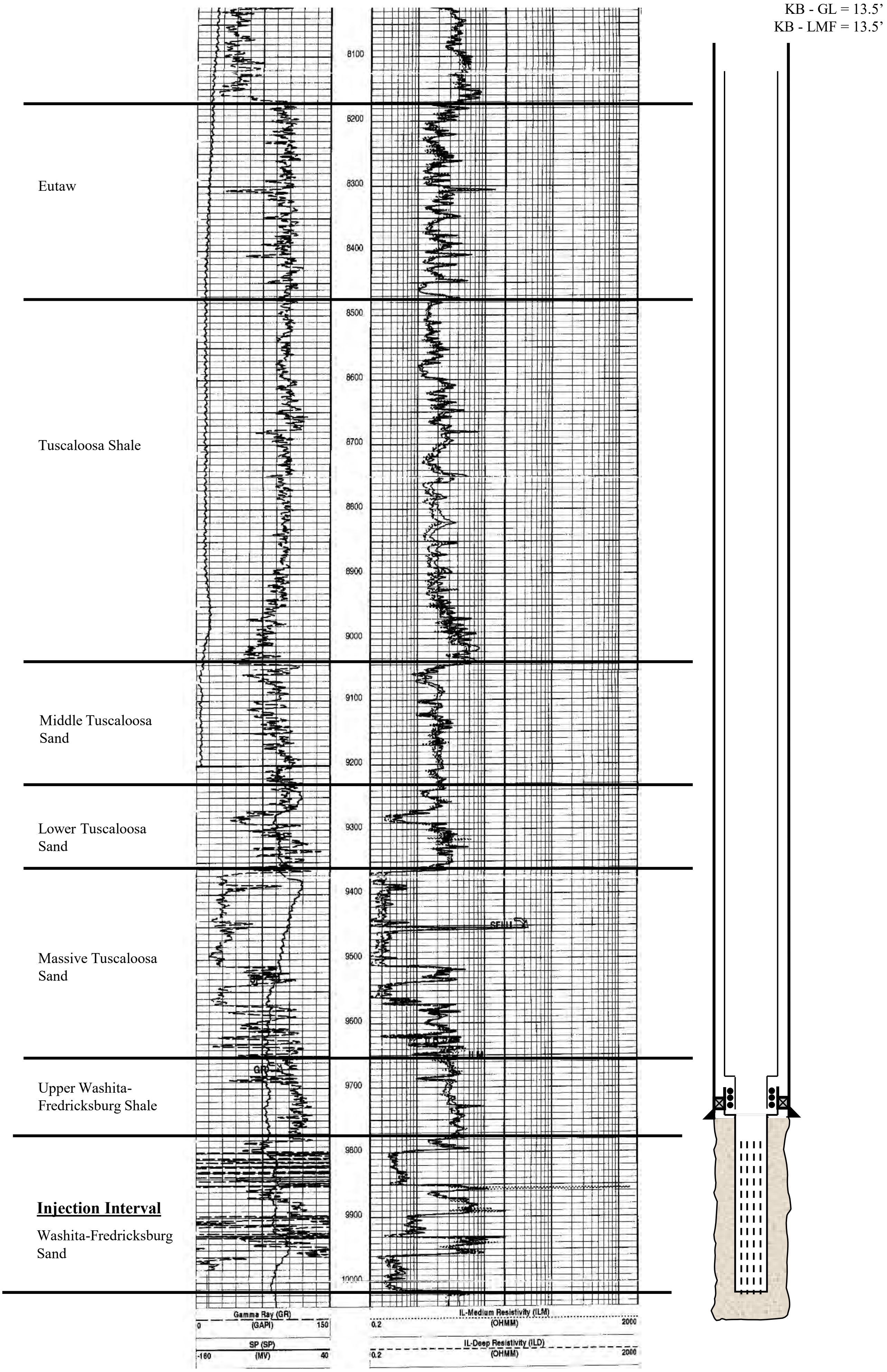
Drawn by: KDS	Date: 2/9/2015	*Drawing not to scale*

Figure 5-6 DeLisle Plant Well No. 2 Wellhead Schematic

Chemours

Chemours Company, FC, LLC
Titanium Technologies.

DeLisle Plant Well No. 2
Sidetrack No. 1
Annotated Openhole Log with Completion



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Drawn by: ESSJ	Date: 04/03/2003	*Drawing not to scale*

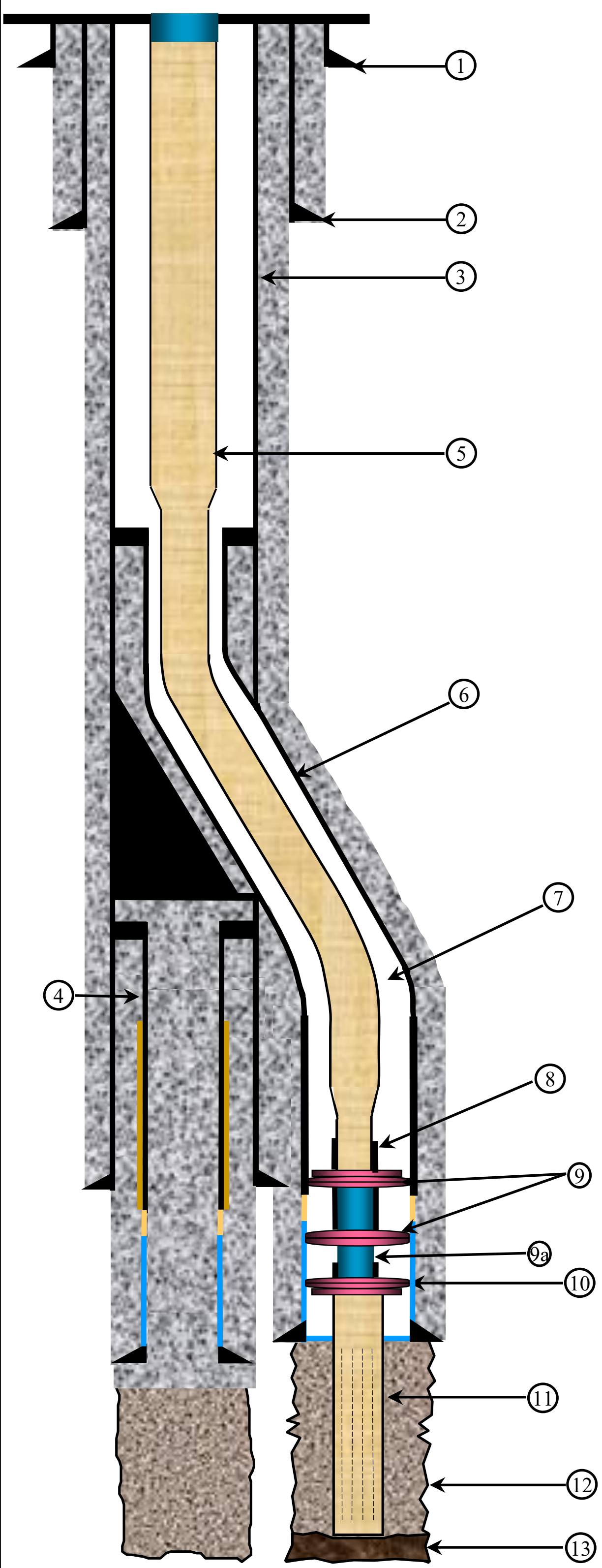
Figure 5-7 DeLisle Well No. 2 Electric Log (annotated)

Chemours Company, FC, LLC,
Titanium Technologies

DeLisle Plant Well No. 3
Sidetrack No. 1
Wellbore Schematic

GL = 16.58' MSL
KB = 23.5' GL
KB-LMF = 24.5'
All depths are KB

GROUND LEVEL



COMPLETION DETAIL

1. **Conductor Pipe**: 20", 58 ppf., Surface to 101'. Set in 26" hole & cemented to surface with 225 sx.
2. **Surface Casing**: 13-3/8", 68 ppf., K-55, LT&C, Surface to 3,613'. Set in 17-1/2" hole and cemented to surface with 2,280 sx of Pozmix/Halliburton Light and 275 sx of Class H
3. **Protection Casing**: 9-5/8", Surface to 9610' in 12-1/4" hole:
   - 40 ppf, N-80, LT&C from Surface to 4,853'
   - 47 ppf, N-80, LT&C from 4,853' to 5,590'
   - 47 ppf, P-110, LT&C from 5,590' to 9,610'

   Cemented in three stages through DV tools at 9,127' & 4,842':
   - Stage 1: 98 bbl Epseal® Epoxy Resin
   - Stage 2: 2,200 sx Halliburton Pozmix®
   - Stage 3: 3,000 sx Halliburton Lite®
4. **Original Protection Liner** (plugged and abandoned December, 1996): 7" OD from 7,457' to 9,970'
5. **Injection Tubing**: Tapered string of 6-5/8" X 4-1/2" FRP:
   - 6-5/8" Titanium Grade 2 landing joint from Surface to 56"
   - 6-5/8" BB-2500 IUE (222 jts & 3 pup jts 22.93') from 56" to 6,581'
   - 6-5/8" X 4-1/2" IUE crossover joint from 6,581' to 6,611'
   - 4-1/2" BB-2500 IUE(97 jts) from 6,611' to 9,483'
   - 4-1/2" Titanium Grade 7 Delta P Dynamic Seal assembly (L = 21.71 ft) from 9,483' - 19' in PBR. Minimum Seal Assembly I.D. is 3.50". Seal Assembly O.D. is 4.50". Set November 2018
6. **Protection Liner**: 7" OD from 6,808' to 9,735':
   - 26 ppf L-80 Hydril SLX from 6,808' to 8,757'
   - 26 ppf L-80 Hydril SLX over-wrapped w/fiberglass from 8,757' to 9,531'
   - 7-5/8" Tubular Fiberglass RB-2500 from 9,531' to 9,561'
   - 0.375" wall Gr. 7 Titanium (6.151 drift) AB ST-L from 9,561' to 9,735'

   Cemented with 200 bbl Epseal® LC Epoxy Resin; Liner top squeezed with 200 sx Premium Cement at 16.4 ppg. Set February 1999
7. **Annulus Fluid:** Inhibited Calcium Chloride Brine at 10.6 ppg.
8. **DPC**: Delta P Model 12 Polished Bore receptacle set at 9,485' - 9,505'
9. **DPC**: Delta P Model BJ Straddle Packer Assembly: Packer at 9,506'- 9,511' & 9,571' - 9,574'

9a. **DPC**: Spacer pipe & expansion joint at 9,573' – 9,621'

10. **Injection Packer**: Delta P Model 12, 7" X 4-1/2", set at 9,621' to 9,626'. Minimum I.D. through packer is 3.25". Set October 2018
11. **Injection Screen Assembly**: 4-1/2" BB 2250 EUE FRP Tubing.
    - Blank tubing (4 jts) from 9,626' to 9,744'
    - Slotted Fiberglass screen (10 jts) from 9,744' to 10,040'
    - Bull plug bottom at 10,041'
12. **Open Hole**: TD = 10,103' (10,054' TVD); Drilled 6-1/8" and perforated from
13. **Wellbore Fill** to 10,042'

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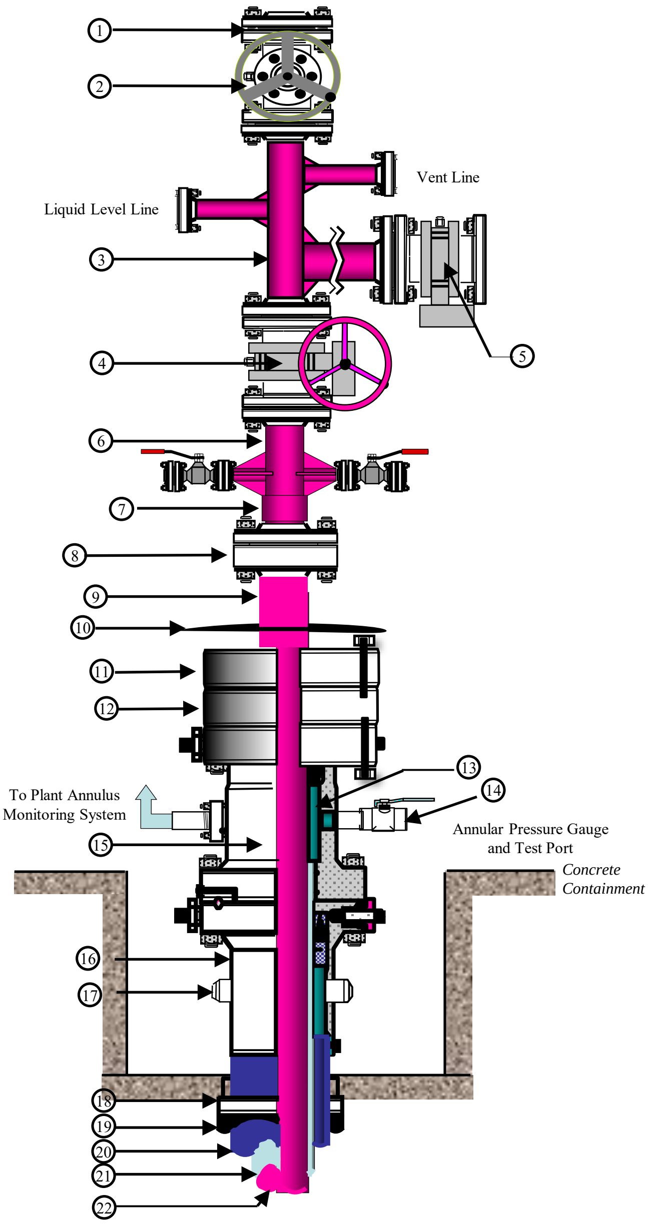
Drawn by: SCH	Date: 11/04/2018	*Drawing not to scale*

Figure 5-8 : DeLisle Plant Well No. 3 Wellbore Schematic

Chemours Company, FC, LLC,
Titanium Technologies

DeLisle Plant Well #3
Sidetrack #1
Well Head Schematic
Status Active



WELLHEAD ASSEMBLY DETAIL

1. Wire Line Access: Blind Flange, 4", 300-Series, Titanium ANSI-RF.
2. Valve: Full Opening 4", 300-Series, Titanium, ANSI-RF.
3. Production Tee: Riser is 4-1/2" O.D. Titanium, top and bottom flanges are 4", 300-Series, Van Stone flanges, ANSI RF. Side outlets, upper two outlets are 2", 300-Series, Van Stone flanges, ANSI RF. The lower outlet is 4", 300-Series, Van Stone flange, ANSI RF. The 2" outlets are used for vent and liquid level control devices.
4. Valve: Full Ported 4", 300-Series, Titanium, ANSI-RF.
5. Valve: Automatic, Open/close valve, Remote, Air Operated, 4", 300-Series, Titanium, ANSI-RF. Note: Valve is located approximately 10-feet from well head.
6. Well Monitor Sub: Riser is 4-1/2" O.D. Titanium, top and bottom flanges are 4", 300-Series, Van Stone flanges, ANSI RF. Side outlets (2) are 1", 300-Series, Van Stone flanges, ANSI RF. Side outlets have four gussets per outlet for vibration control. Each side outlet has a 1" Titanium Ball valve and is used for pressure monitoring equipment.
7. Combination Cross-Over, 6-5/8" LT&C, AB Modified, box X 4-1/2" EUE Long Casing Thread, pin, Titanium, Grade 2, 3.5"ID.
8. Flange: 6-5/8", 300-Series (Special, XH), Titanium, ANSI-RF, with 4-1/2", 8rd, AB Modified, LT&C internal thread.
9. Injection Tubing Landing Joint: 6-5/8" O.D. Titanium, Grade 2, Schedule 80, 8rd, LT&C threads.
10. Rubber drip guard, 6-5/8" I.D. (snug fit) X 28" O.D., ½" thick
11. 11" Nominal Quicklock Hold-Down Retainer w/ 6-5/8" Slips & O-Ring Seal (B&B)
12. Double Studded Packoff: 11" 5M BB-22-L. (B&B)
13. Tubing Hangers, With 2 O-Ring Seals 11" x 6-5/8" BB-22
14. Valve
15. Casing Spool: 13-5/8", 3M Model B22-L
16. Casing Head: Cameron, Type WF, SOW, 13-5/8" 3M, dressed for 13-3/8", casing w/2 F-NPT, XXH Bull Plugs
17. Plug: 2" NPT, XXH Bull Plug.
18. Plate: Welded to 13-3/8" Surface Casing and 20" Conductor Pipe.
19. Conductor Pipe: 20".
20. Surface Casing: 13-3/8", 87.5 ppf, K-55.
21. Protective Casing: 9-5/8", 40 ppf, N-80.
22. Injection Tubing, 6-5/8", Titanium Landing Joint.

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Drawn by: SCH	Date: 11/04/2018	*Drawing not to scale*

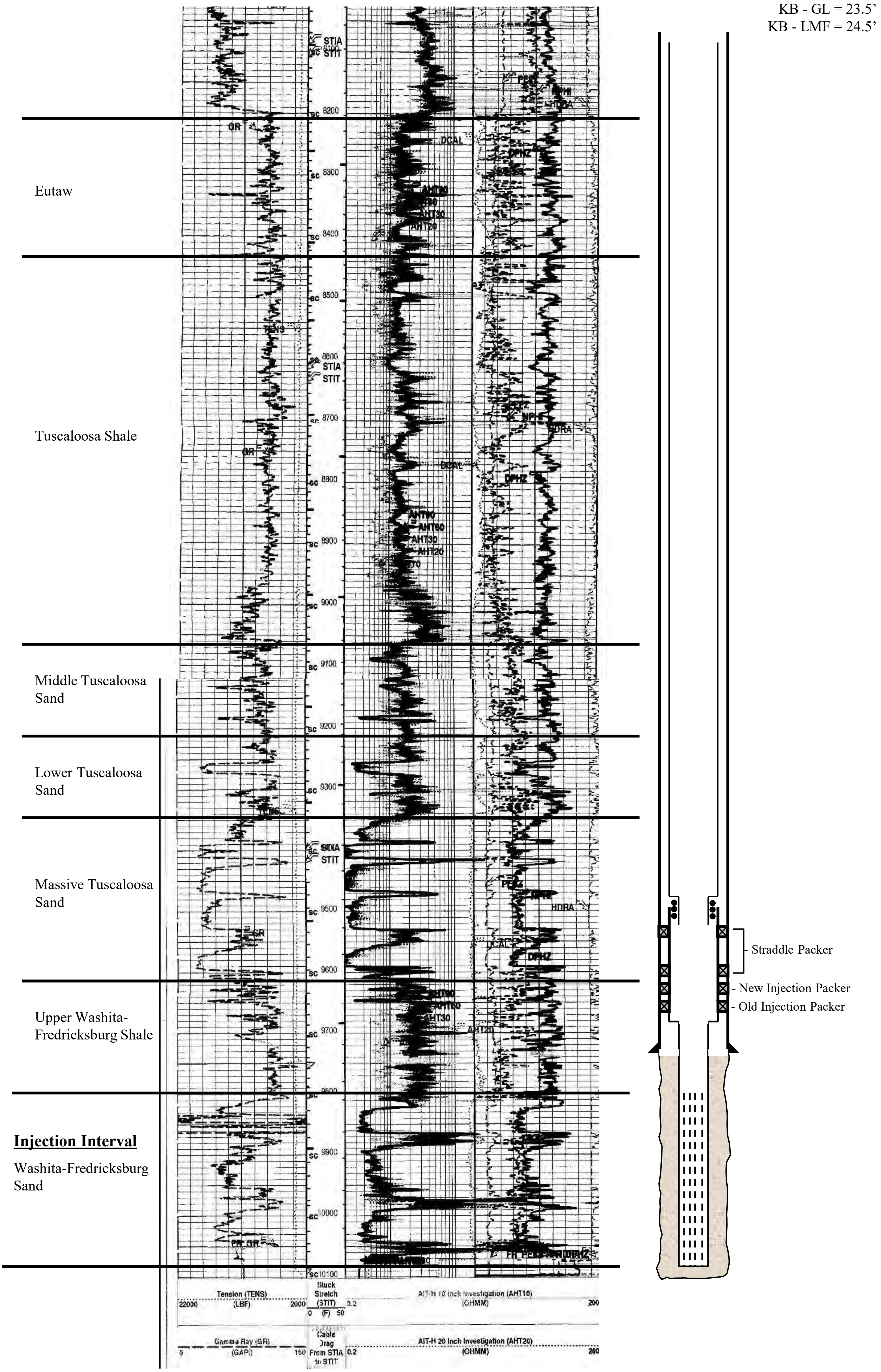
Figure 5-9 DeLisle Plant Well No. 3 Wellhead Schematic

Chemours™

Chemours Company, FC, LLC
Titanium Technologies

DeLisle Plant Well No. 3
Sidetrack No. 1
Annotated Openhole Log with Completion

GL = 16.58’
KB - GL = 23.5’
KB - LMF = 24.5’



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Drawn by: ESSJ	Date: 01/19/04	*Drawing not to scale*

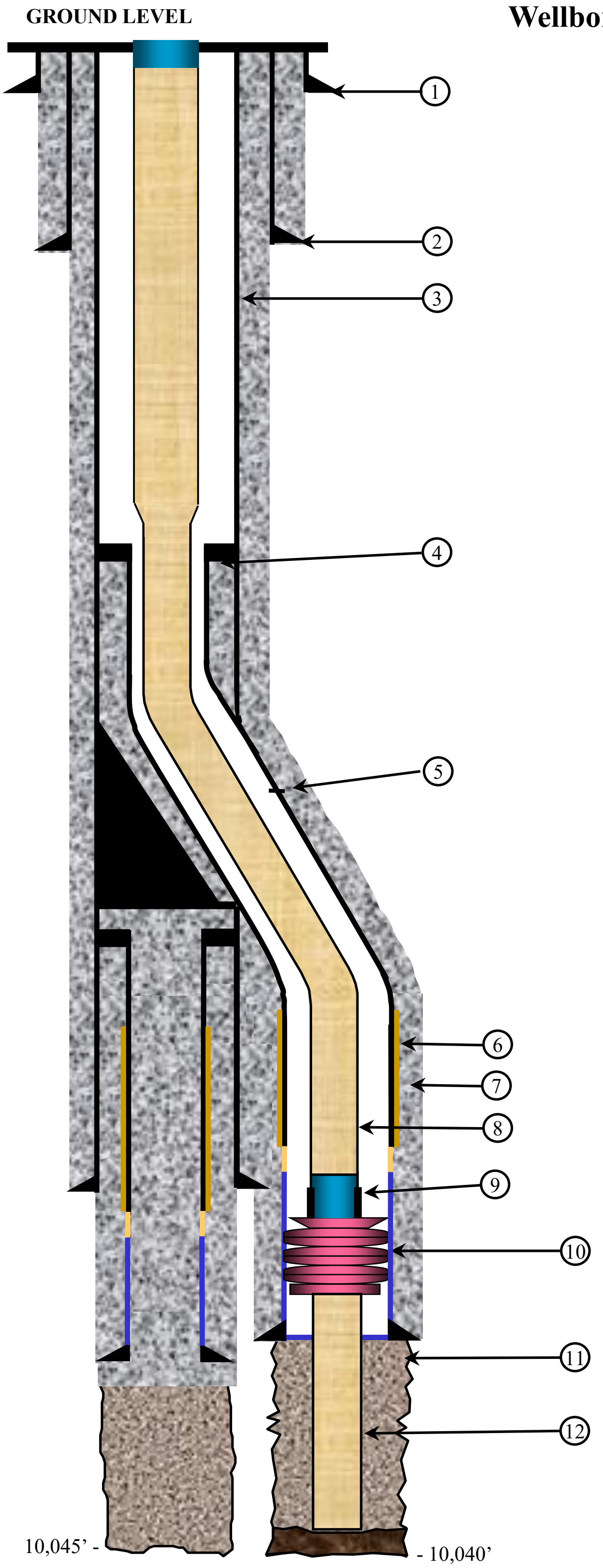
Figure 5-10 DeLisle Well No. 3 Electric Log (annotated)

Chemours Company, FC, LLC
Titanium Technologies

DeLisle Plant Well No. 4
Sidetrack No. 1

Wellbore Schematic

GL = 12.3' MSL
KB = 25.8' GL
KB-LMF = 24.5'
All depths RKB



COMPLETION DETAIL

1. **Conductor Pipe**: 24" O.D. set @ 105' with 110 barrels Class H Cement with 2% $CaCl_2$ to surface.
2. **Surface Casing**: 16" O.D., 84#, K-55 set @ 3745' cemented with 6969 sx HLC with 3% salt (1.25#/sx Flocele) and 600 sx Class H cement. Cement circulated.
3. **Protection Casing**: 9-5/8", 53.5#, N-80 set from 0'-9320'
4. **Liner:** TIW "DTM" liner hanger and "S-6" packer from 7254'-7276'; 32 joints of 7", 26#, L-80, LT & C from 7276'-8699', 19 joints of 7", 26#, L-80 LT & C fiberglass overwrapped from 8699'-9561', 1 joint of 7 5/8" Red Box 2500 fiberglass casing from 9561'-9592'; 6 joints of 7" O.D. Titanum Grade 7, 6.25" I.D. from 9592'-9738'.
5. Perfs from 7618'-7620', 200 sx of Class H cement weighing 16.2 ppg circulated through perfs to top of liner. Perfs squeezed with 200 sx Class H and 100 sx Class H with 7% salt.
6. Perfs from 8825'-8827', 575 sx of Class H cement weighing 16.2 ppg circulated through perfs to 7630'.
7. Liner cemented from 8900' - 9738' with 65 bbl of 14.0 ppg Epseal containing silica flour.
8. **Injection Tubing**: Tapered string of 83 joints Tubular Fiberglass, 4 1/2" EUE Red Box 2500, 1 4 1/2" to 6 5/8" EUE Red Box 2500 crossover joint, and 245 joints of 6 5/8" EUE Red Box 2500, DPI seal assembly set @ 9662'.
9. DPI Model 12 Polished bore receptacle set from 9662'-9683'.
10. 7" O.D. Titanium Grade 7 Injection Packer, DPI Model 12; set from 9683'-9688' (mid-element at 9686').
11. Open Hole Underreamed to 12" in August 2013
12. **Fiberglass injection screen:** 2 joints of 4 1/2" Red Box 2500 tubing from 9688'-9747'; 9 joints of slotted 4 1/2" Red Box 2500 tubing from 9747'-10,013'; 1 bull plug at 10,014'.

FRP Slotted Liner Detail:
132 slots per foot
Slots 3" long by 0.04" wide; resin coated
266 total slotted feet

- All depths referenced to original Kelly Bushing Measurement 25.8' above ground level.

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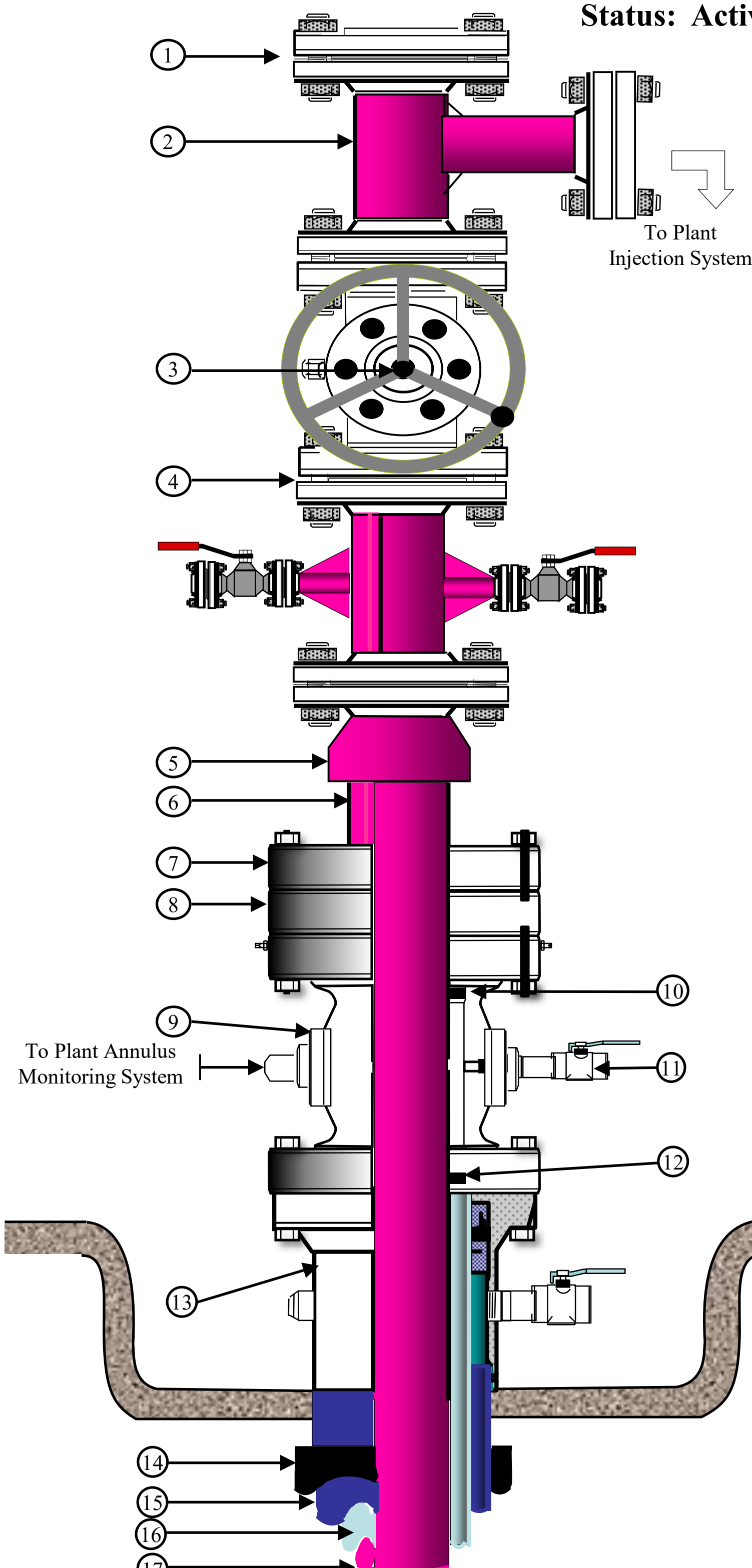
Drawn by: GCD	Date: 10/08/2013	*Drawing not to scale*

Figure 5-11 DeLisle Well No. 4 Well Schematic

Chemours™

Chemours Company, FC, LLC, Titanium Technologies

DeLisle Plant Well #4
Sidetrack #1
Wellhead Schematic
Status: Active



WELLHEAD ASSEMBLY DETAIL

1. Wire Line Access: 4", 300-Series, Titanium, ANSI-RF Blank Flange (plant has 4", 300-Series carbon steel, ANSI-RF by 2-7/8" EUE 8rd pin adapter)
2. Flow Tee: 4", 300-Series, Titanium, ANSI-RF
3. Valve: Full Opening 4", 300-Series, Titanium, ANSI-RF
4. Flange: 4", 300 Series, Titanium, ANSI-RF Screw-on (4-1/2" 8rd Casing Thread)
5. 4-1/2" 8rd LTC AB mod. x 6-5/8" Adapter Swage
6. Landing Joint: 6-5/8" Titanium
7. 11" Nominal Quicklock Retainer w/ 6-5/8" Slips & O-Ring Seal
8. Double Studded Packoff: 11" 5M Btm x 11" Nom.
9. Casing Spool: 16-3/4", 3M x 11" 5M
10. Quicklock Top, 2 O-Ring Seals 11" x 6-5/8" BB-22
11. Valve
12. Secondary Seal: 9-5/8", 16-3/4" 3M
13. Casing Head: 16-3/4", 3M
14. Conductor Pipe: 20"
15. Surface Casing: 16", 84 ppf, K-55
16. Protective Casing: 9-5/8", 53.5ppf, N-80
17. Landing Joint: 6-5/8" Titanium

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Drawn by: KDS	Date: 10/07/2013	*Drawing not to scale*

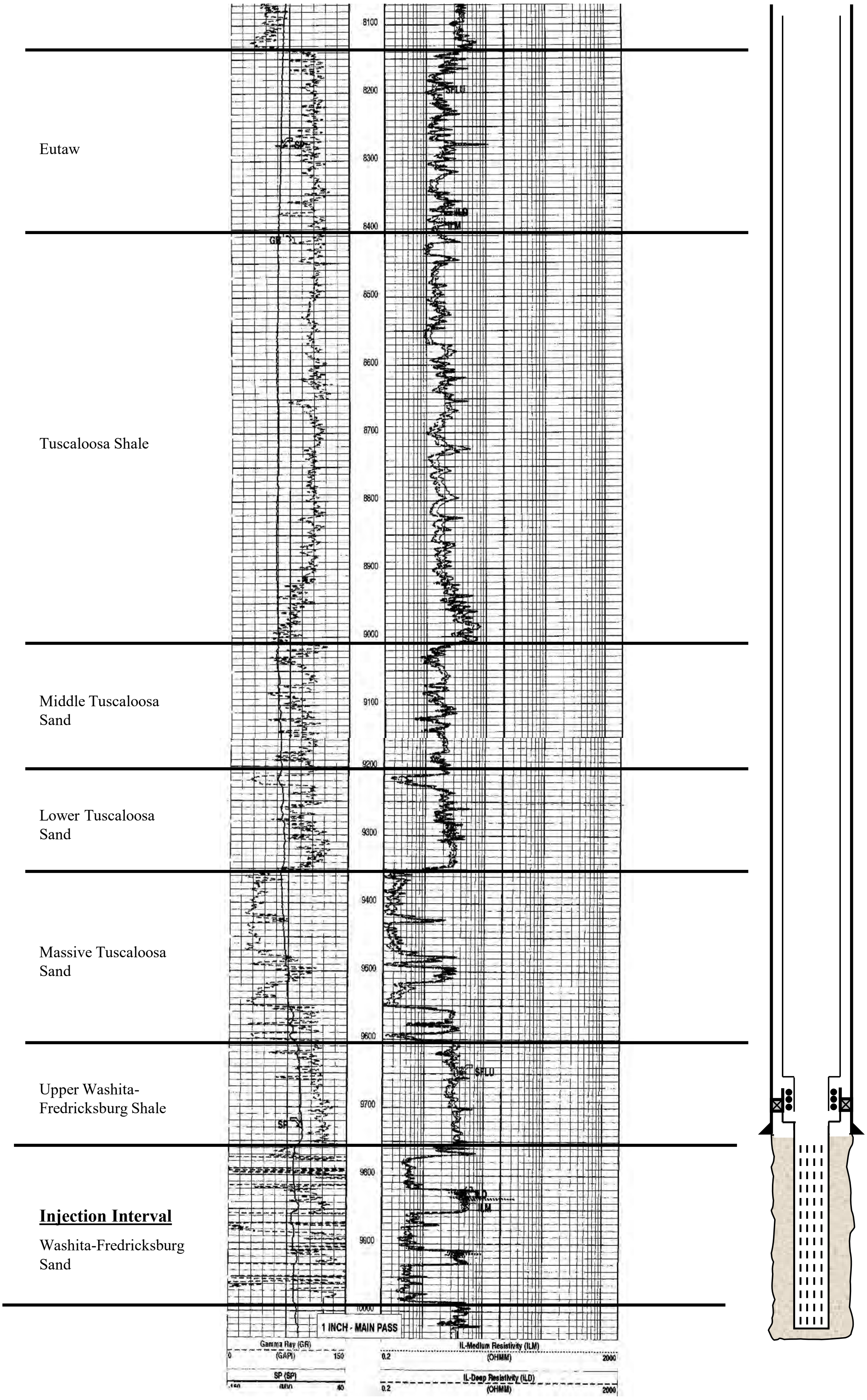
Figure 5-12 DeLisle Plant Well No. 4 Wellhead Schematic

Chemours™

Chemours Company, FC, LLC, Titanium Technologies

DeLisle Plant Well No. 4
Sidetrack No. 1
Annotated Openhole Log with Completion

GL = 12.3’
KB - GL = 13.5’
KB - LMF = 13.5’



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Drawn by: ESSJ	Date: 04/03/2003	*Drawing not to scale*

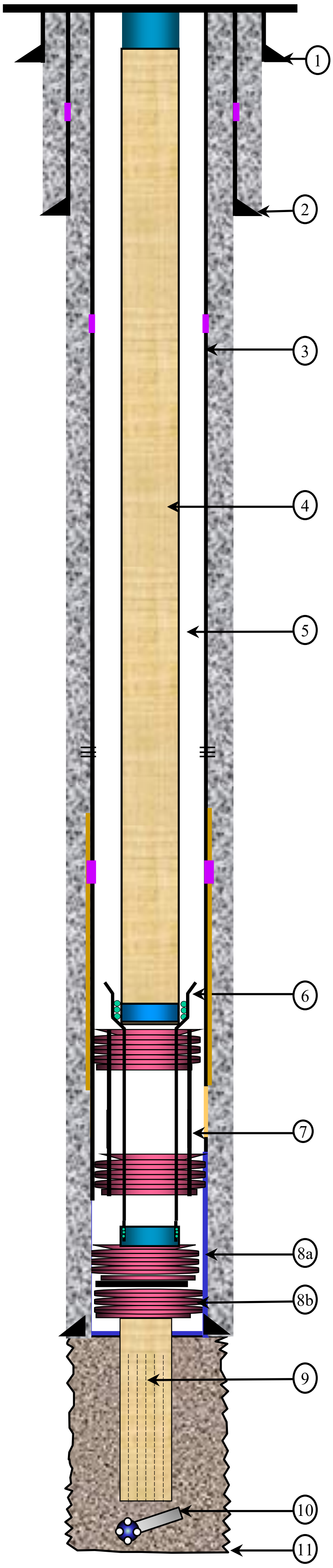
Figure 5-13 DeLisle Well No. 4 Electric Log (amnnotated)

Chemours™

Chemours Company, FC, LLC, Titanium Technologies

DeLisle Plant Well No. 5
Wellbore Schematic

COMPLETION DETAILS



Original Drilling Rig RKB = 31' from GL
GL = 33' MSL KB = 64'MSL
All depths RKB

1. **Conductor Pipe**: 20", Driven, surface to 406' (welded).
2. **Surface Casing:** 13-3/8", Surface to 3,440', in 17-1/2" hole
- 68 ppf, N-80, buttress, Surface to 3,440';
- Stage cement tool at 1,742';
- Cemented in two stages:
  Stage 1: 3,125 sx of lightweight, followed with 1,763 sx of Class A.
  Stage 2: 3,256 sx of lightweight cement
- Top out cement with tremie string: 200 sx of Class A.

3. **Protection Casing**: 9-5/8", Surface to 9,765', with cement stage tools at 3,799' and 8,969' in 12-1/4" hole:
- 53.5 ppf, N-80, LT&C, Surface to 8,550' (279 joints);
- 43.5 ppf, N-80, AB-FL-4S over-wrapped w/fiberglass, 8,550' to 9,586' (30 joints)
- 10-3/8" Tubular Fiberglass RB-2500, LT&C, 9,586' to 9,611' (1 joint);
- Titanium, Grade 7, ½" wall, 9,611' to 9,765' (5 joints);
- Stage cement tools at 3,799' and 8,969', & perforations at 6,350' to 6,351'
- Cemented in four stages:
  Epseal® LC Epoxy Resin, 79 bbls, 9,765' to 8,969';
  Class H w/35% Silica Flour, 3,080 sx, 8,969' to 6,350';
  1,550 cu. ft. of Lite Wate, tailed with 212 cu.ft. of Class H w/Latex;
  Lite Wate, 1650 sx, 3,799' to surface.

4. **Injection Tubing:**
- 6-5/8" Titanium Grade 2 landing joint (7.10'), 25.5'to 33';
- 6-5/8" BB-2500, NU, (195 jts – 5,691'), +/-33' to 5,724';
- 6-5/8" BB-2500, IUE, (127 jts – 3,736'), +/-5,724' to 9,460';
- DPI Titanium Grade 7 seal assembly (22.65'), 9,460' to 9,483'

5. **Annulus Fluid**: Calcium Chloride Brine at 10.4 ppg with Tetra inhibitor (CORSAF SF)
6. **PBR & Extension**:
- Titanium Grade 7 Anchor Seal Assembly @ 9,694';
- 4-1/2" Titanium Grade 7 (11 joints), 9,489' to 9,691';
- Titanium Grade 7 Crossover and PBR, 9,466' to 9,489'.

7. **Retrievable Liner**: Straddle packer assembly, set from 9,507' to 9,686'.
- Upper Liner Packer, Delta P, Inc (DPI) Model 12, 9-5/8" X 7-5/8" carbon steel, 9,507' to 9,513', min. I.D. is 5.75";
- Liner extension:
- 7-5/8", 29.7 ppf, L-80, collared, 9,513' to 9,679'; min. I.D. is 6.875";
  Seal Assembly, carbon steel, 9,679' to 9,682';
  Lower Liner Packer, DPI Model 12, 9-5/8" carbon steel, 9,680' to 9,686', min. I.D. is 5.75".

8a. **Upper Injection Packer**: DPI Model 12, 9-5/8" X 4-1/2", Titanium Grade 7, set at 9,692' to 9,699', elements at 9,696', the alignment extension is inside lower injection packer to 9,699', Min. I.D. through packer is 4.75". Set July 2015.

8b. **Lower Injection Packer**: DPI Model 12, 9-5/8" X 6-5/8", Titanium Grade 7, set at 9,697' to 9,703'. Min. I.D. through packer is 4.75". Set July 2015.

9. **Injection Screen Assembly**: 6-5/8" BB 2500 FRP Tubing
- Blank tubing (1 jt.), 9,703' to 9,733';
- Slotted Fiberglass screen (10 jts), 9,733' to 10,028'; 46 slots per foot, 0.15" Width x 3" Length
- Bull plug bottom at 10,028'

10. **Abandoned Underreamer Blade:** Rock cone blade left at 10,058', July 2015
11. **Open Hole**: 9,765' to 10,058', Drilled 12-1/4". Under reamed to 16" in June 2015.

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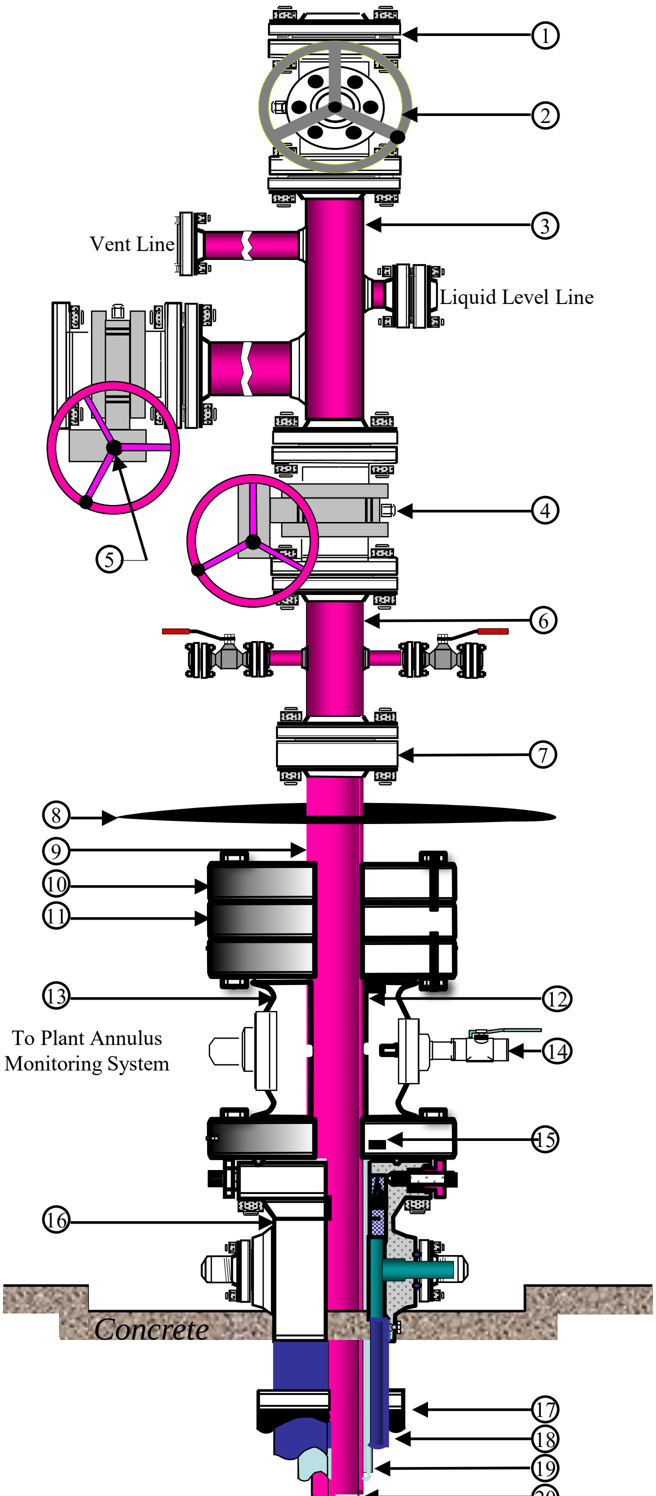
Figure 5-14 DeLisle Plant Well No. 5 Well Schematic

Chemours Company, FC, LLC
Titanium Technologies

DeLisle Plant Well No. 5
Wellhead Schematic
Status: Active



WELLHEAD ASSEMBLY DETAIL

1. Wire Line Access: Blind Flange, 6”, 300-Series, Titanium ANSI-RF.
2. Valve: Full Opening 6”, 300-Series, Titanium, ANSI-RF.
3. Production Tee: Riser is 6” O.D. Titanium, top and bottom flanges are 6”, 300-Series, Van Stone flanges, ANSI RF. Side outlets, upper two outlets are 3”, 300-Series, Van Stone flanges, ANSI RF, located above ground level in access tray. The lower outlet is 6”, 300-Series, Van Stone flange, ANSI RF. The 3” outlets are used for vent and liquid level control devices. The 6” outlet is used for waste inlet.
4. Valve: Full Opening 6”, 300-Series, Titanium, ANSI-RF.
5. Valve: Wing, Motor Valve, Remote, Air Operated, 6”, 300-Series, Titanium, ANSI-RF. Note: Valve is located approximately 12-feet from well head, just above ground level in access tray.
6. Monitor Sub: Riser is 6” O.D. Titanium, top and bottom flanges are 6”, 300-Series, Van Stone ANSI RF flanges. Side outlets (2) are 1”, 300-Series, weld-neck ANSI RF flanges. Each side outlet has a 1” Titanium Ball valve and are used for pressure monitoring equipment.
7. Flange: 6”, 300-Series (Special, XH), Titanium, Grade 7, ANSI-RF, with 6-5/8”, 8 rd, LT&C internal thread.
8. Rubber Drip Guard, 6-5/8” ID (snug fit) x 28” OD, to be slipped over 6-5/8” OD Casing to protect Wellhead from product dripping down from above. ½” Thick Material.
9. Landing Joint: 6-5/8” Titanium
10. 11” Nominal Quicklock Retainer w/ 6-5/8” Slips & O-Ring Seal (B&B)
11. Double Studded Packoff: 11” 5M BB-22-L. (B&B)
12. Tubing Hangers, With 2 O-Ring Seals 11” x 6-5/8” BB-22
13. Casing Spool: 13-5/8”, 3M
14. 2-1/16” 5M ¼ Turn Ball Valve
15. Secondary Seal: 9-5/8”, “PE”-Seal
16. Casing Head: SOW, 13-5/8”, 3M, dressed for 13-3/8”, casing w/2, 2-1/16”, 3M, API flanged with 2” NPT-F outlets, bull-plugged.
17. Conductor Pipe: 20”.
18. Surface Casing: 13-3/8”, 87.5 ppf, K-55.
19. Protective Casing: 9-5/8”, 60 ppf, N-80.
20. Injection Tubing, 6-5/8”O.D., Titanium Landing Joint.

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Drawn by: KDS	Date: 09/18/2015	*Drawing not to scale*

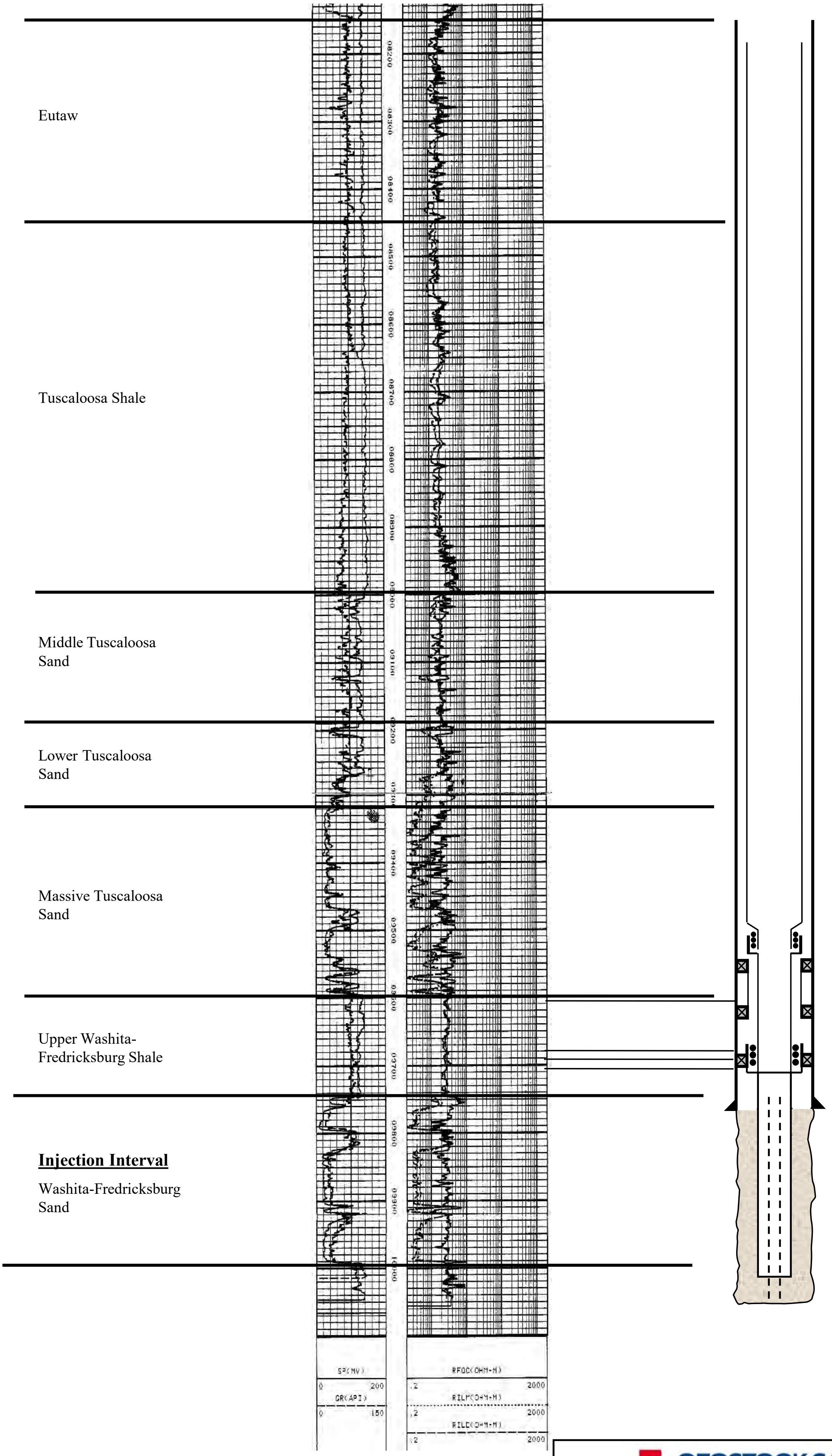
Figure 5-15 DeLisle Plant Well No. 5 Wellhead Schematic

Chemours™

Chemours Company, FC, LLC,
Titanium Technologies

DeLisle Plant Well No. 5
Annotated Openhole Log with Completion

GL = 33.0’
KB - GL = 31.0’
KB - LMF = 31.0’



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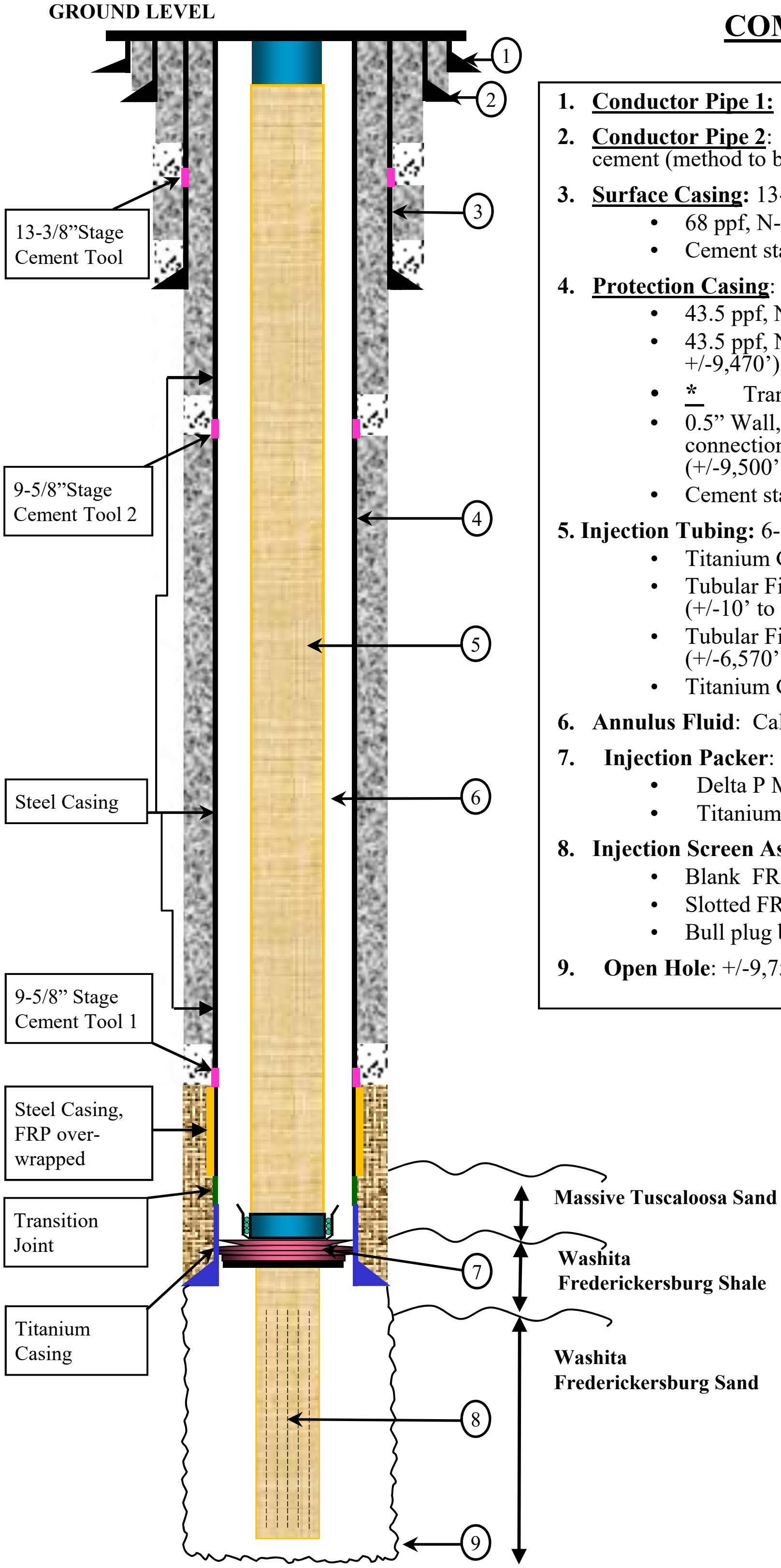
Drawn by: ESSJ	Date: 04/03/2003	*Drawing not to scale*

Figure 5-16 DeLisle Plant Well No. 5 Electric Log (annotated)

Chemours

Chemours Company, FC, LLC, Titanium Technologies

DeLisle Plant Well No. 6
Proposed Wellbore Schematic
(Washita Fredericksburg Completion)



COMPLETION DETAILS

All depths are approximate

1. **Conductor Pipe 1:** 30”, Surface to +/125’, driven to refusal
2. **Conductor Pipe 2**: 20”, Surface to +/-500’, set in drilled hole with cement (method to be determined):
3. **Surface Casing:** 13-3/8”; Surface to +/-3,750’; in 17-1/2” hole:
   - 68 ppf, N-80, Buttress thread connection;
   - Cement stage tools at +/-1,700’.
4. **Protection Casing**: 9-5/8”, Surface to +/-9,750’, in 12-1/4” hole:
   - 43.5 ppf, N-80, LTC thread connection (0 to +/-8,670’);
   - 43.5 ppf, N-80, flush, integral joint connection (+/-8,670’ to +/-9,470’), with FRP overwrap;
   - * Transition joint (+/-9,470’ to +/-9,500’) (see below);
   - 0.5” Wall, Titanium Gr 7 (or Gr 16), flush, integral joint connection (+/-9,500’ to +/-9,750’);
   - Cement stage tools at +/-4,000’ and +/-8,670’.
5. **Injection Tubing:** 6-5/8”, Surface to +/- 9,700’:
   - Titanium Grade 2, 0.375” wall landing joint @ surface;
   - Tubular Fiberglass Blue Box-2500, non-upset (+/-10’ to +/-6570’);
   - Tubular Fiberglass, Blue Box-2500, internal upset end (+/-6,570’ to +/-9,700’;
   - Titanium Grade 7 seal assembly @ +/-9,700’.
6. **Annulus Fluid**: Calcium Chloride Brine at 10.4 ppg:
7. **Injection Packer**: 9-5/8” X 5-3/4”, at +/-9,700’:
   - Delta P Model 12;
   - Titanium Grade 7.
8. **Injection Screen Assembly**: 6-5/8”, +/-9,700’ to +/-10,200’:
   - Blank FRP tubing +/-9,700’ to +/-9,760’;
   - Slotted FRP screen +/-9,760’ to +/-10,200’;
   - Bull plug bottom at +/-10,200’.
9. **Open Hole**: +/-9,750’ to +/-10, 200’, Drilled 8-1/2”:

Notes / Definitions:

* Transition Joint Material Alternatives:
  -Hastelloy C276
- ppf - pound per foot
- LTC- long thread and collar
- FRP- fiberglass reinforced pipe

- Low density cement
- Standard cement
- Epoxy cement

Figure 5-17 DeLisle Plant Well No. 6 Well Schematic

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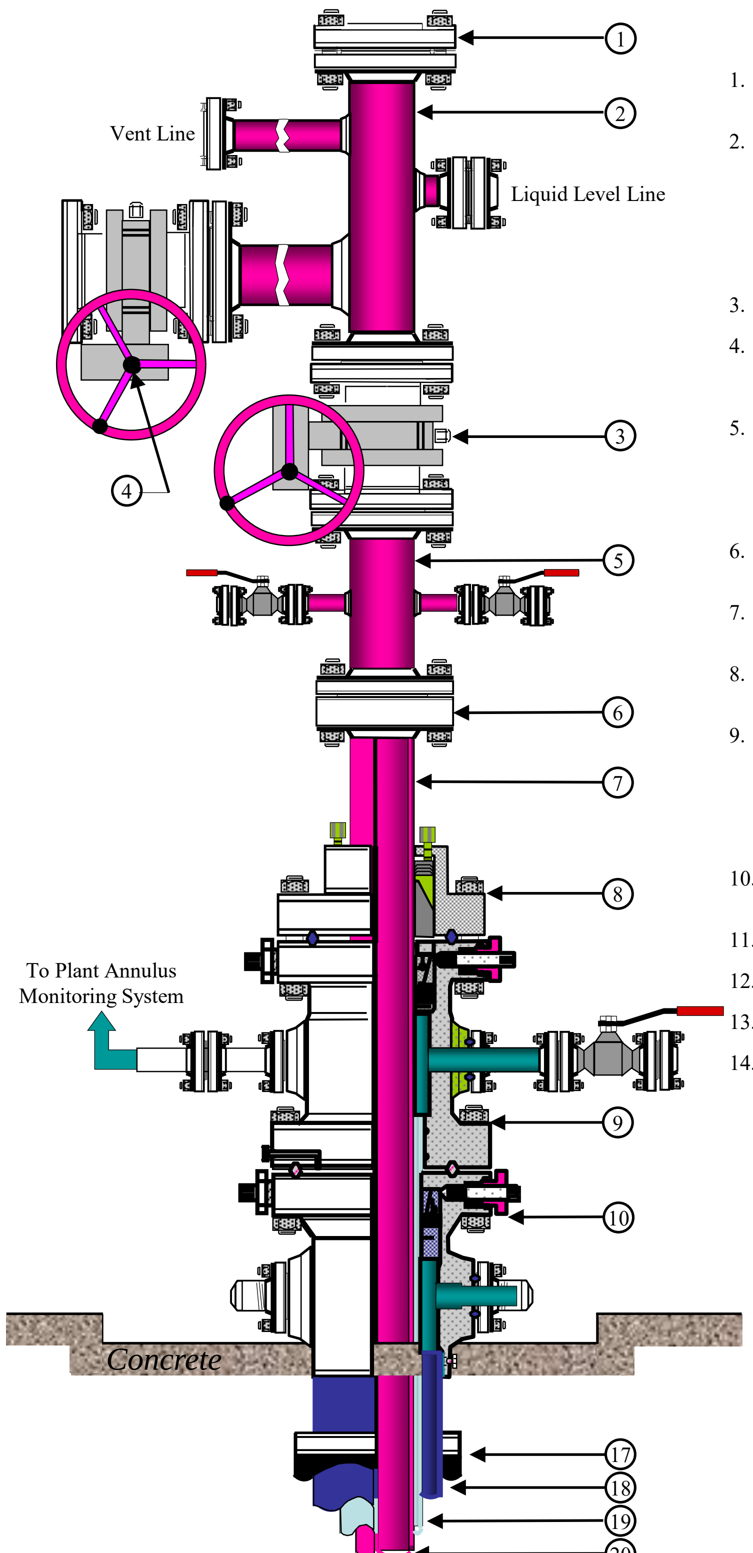
Drawn by: DES	Date: 8/1/17	*Drawing not to scale*

Chemours Company, FC, LLC,
Titanium Technologies

DeLisle Plant Well No. 6
Proposed Wellhead Schematic
Status: Proposed



WELLHEAD ASSEMBLY DETAIL

1. Wire Line Access: Blind Flange, 6", 300-Series, Titanium ANSI-RF.
2. Production Tee: Riser is 6" O.D. Titanium, top and bottom flanges are 6", 300-Series, Van Stone flanges, ANSI RF. Side outlets, upper two outlets are 3", 300-Series, Van Stone flanges, ANSI RF, located above ground level in access tray. The lower outlet is 6", 300-Series, Van Stone flange, ANSI RF. The 3" outlets are used for vent and liquid level control devices. The 6" outlet is used for waste inlet.
3. Valve, Master: Full Opening 6", 300-Series, Titanium, ANSI-RF.
4. Valve: Wing, Motor Valve, Remote, Air Operated, 6", 300-Series, Titanium, ANSI-RF. Note: Valve is located approximately 12-feet from well head, just above ground level in access tray.
5. Monitor Sub: Riser is 6" O.D. Titanium, top and bottom flanges are 6", 300-Series, Van Stone ANSI RF flanges. Side outlets (2) are 1", 300-Series, weld-neck ANSI RF flanges. Each side outlet has a 1" Titanium Ball valve and are used for pressure monitoring equipment.
6. Flange: 6", 300-Series (Special, XH), Titanium, Grade 7, ANSI-RF, with 6-5/8", 8 rd, LT&C internal thread.
7. Injection Tubing Landing Joint: 6-5/8" O.D. Titanium, Grade 7, 8rd, LT&C threads.
8. Adapter, Tubing Head: Gray, 6-5/8"O.D.(top) X 11", 3M API flange (bottom), with internal hold down slips and seals.
9. Tubing Hanger Spool: Gray, 13-5/8" (bottom) X 11" (top), 3M, API flanges, w/two, 2-1/16", 3M, API flanged outlets. Upper bowl contains wrap-around slips and seals for 6-5/8" O.D. injection tubing. Lower flange contains secondary seals and test ports. Two flanged 2-1/16" 3M outlets are utilized for annulus monitoring, control, and well service.
10. Casing Head: SOW, 13-5/8", 3M, dressed for 13-3/8", casing w/2, 2-1/16", 3M, API flanged with 2" NPT-F outlets, bull-plugged.
11. Conductor Pipe: 20".
12. Surface Casing: 13-3/8", 87.5 ppf, K-55.
13. Protective Casing: 9-3/8", 60 ppf, N-80.
14. Injection Tubing, 6-5/8"O.D., Titanium Landing Joint.

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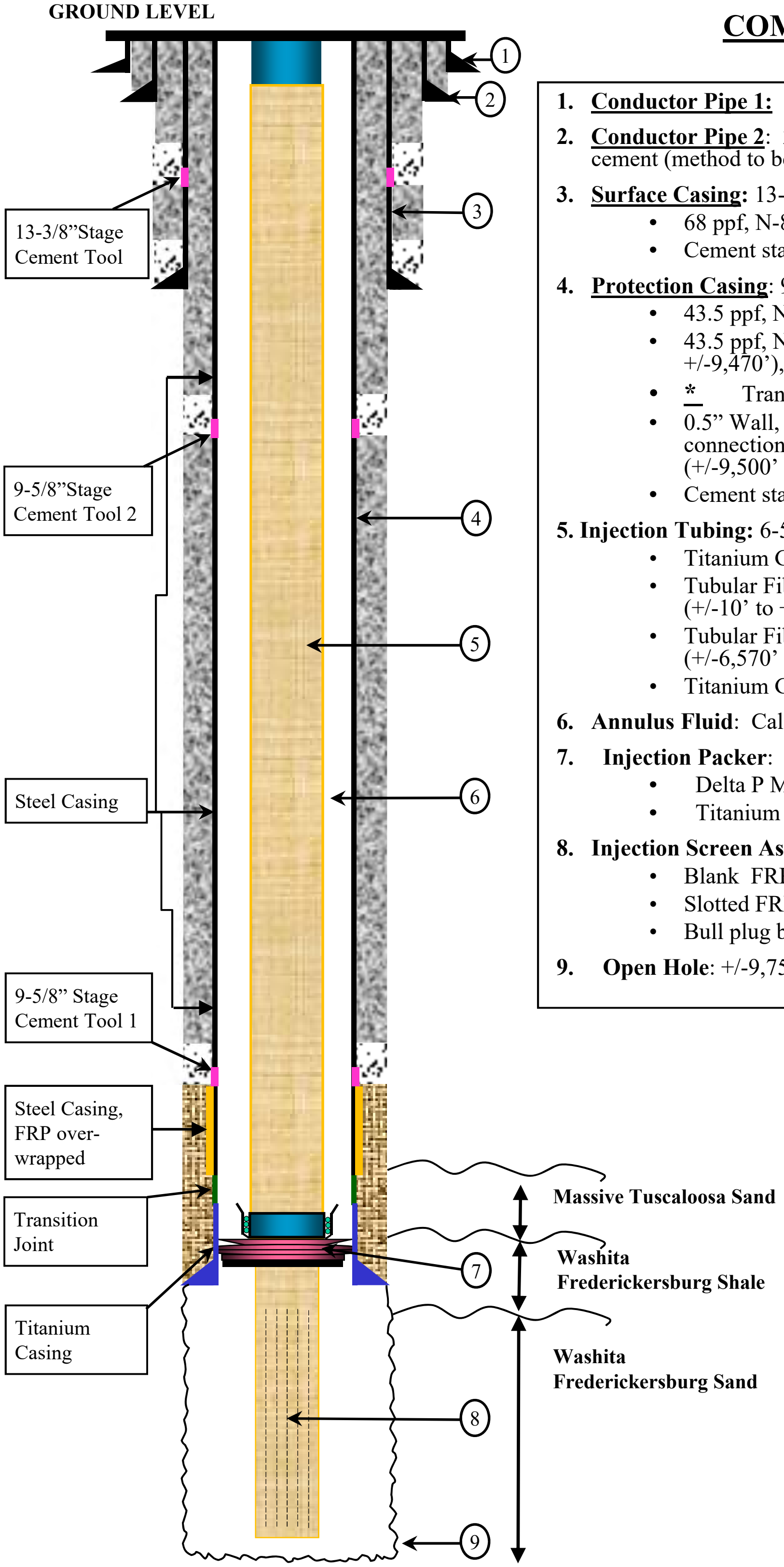
Drawn by: EAM, ESSJ	Date: 02/01/2007	*Drawing not to scale*

Figure 5-18 DeLisle Plant Well No. 6 Wellhead Schematic

Chemours Company, FC, LLC,
Titanium Technologies

DeLisle Plant Well No. 7
Proposed Wellbore Schematic
(Washita Fredericksburg Completion)



COMPLETION DETAILS

All depths are approximate

1. **Conductor Pipe 1:** 30", Surface to +/125', driven to refusal
2. **Conductor Pipe 2**: 20", Surface to +/-500', set in drilled hole with cement (method to be determined):
3. **Surface Casing:** 13-3/8"; Surface to +/-3,750'; in 17-1/2" hole:
   - 68 ppf, N-80, Buttress thread connection;
   - Cement stage tools at +/-1,700'.
4. **Protection Casing**: 9-5/8", Surface to +/-9,750', in 12-1/4" hole:
   - 43.5 ppf, N-80, LTC thread connection (0 to +/-8,670');
   - 43.5 ppf, N-80, flush, integral joint connection (+/-8,670' to +/-9,470'), with FRP overwrap;
   - * Transition joint (+/-9,470' to +/-9,500') (see below);
   - 0.5" Wall, Titanium Gr 7 (or Gr 16), flush, integral joint connection (+/-9,500' to +/-9,750');
   - Cement stage tools at +/-4,000' and +/-8,670'.
5. **Injection Tubing:** 6-5/8", Surface to +/- 9,700':
   - Titanium Grade 2, 0.375" wall landing joint @ surface;
   - Tubular Fiberglass Blue Box-2500, non-upset (+/-10' to +/-6570');
   - Tubular Fiberglass, Blue Box-2500, internal upset end (+/-6,570' to +/-9,700';
   - Titanium Grade 7 seal assembly @ +/-9,700'.
6. **Annulus Fluid**: Calcium Chloride Brine at 10.4 ppg:
7. **Injection Packer**: 9-5/8" X 5-3/4", at +/-9,700':
   - Delta P Model 12;
   - Titanium Grade 7.
8. **Injection Screen Assembly**: 6-5/8", +/-9,700' to +/-10,200':
   - Blank FRP tubing +/-9,700' to +/-9,760';
   - Slotted FRP screen +/-9,760' to +/-10,200';
   - Bull plug bottom at +/-10,200'.
9. **Open Hole**: +/-9,750' to +/-10, 200', Drilled 8-1/2":

Notes / Definitions:

* Transition Joint Material Alternatives:
-Hastelloy C276
- ppf - pound per foot
- LTC- long thread and collar
- FRP- fiberglass reinforced pipe

- Low density cement
- Standard cement
- Epoxy cement

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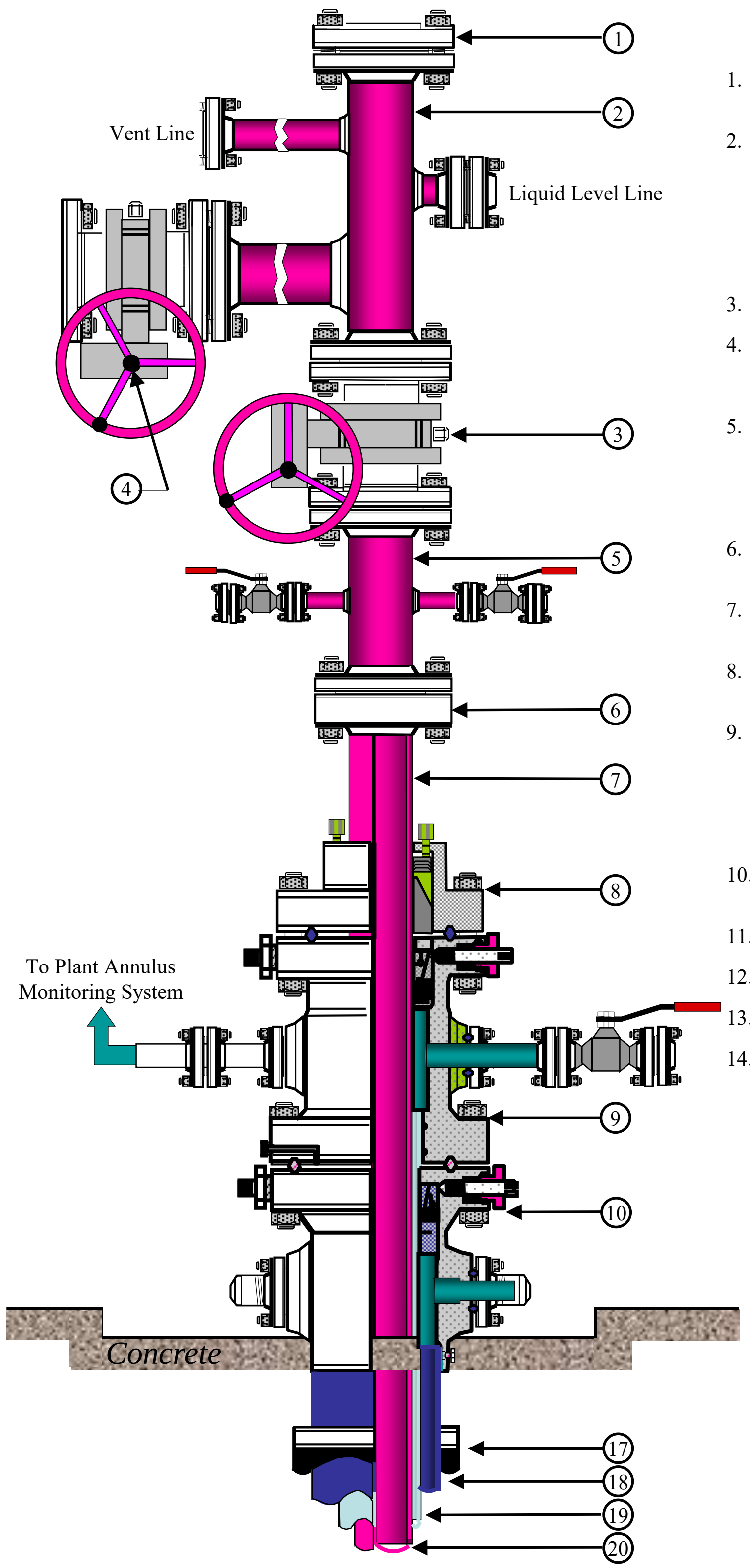
Drawn by: DES	Date: 8/1/17	*Drawing not to scale*

Figure 5-19 DeLisle Plant Well No. 7 Well Schematic

Chemours Company, FC, LLC,
Titanium Technologies

DeLisle Plant Well No. 7
Proposed Wellhead Schematic
Status: Proposed



WELLHEAD ASSEMBLY DETAIL

1. Wire Line Access: Blind Flange, 6", 300-Series, Titanium ANSI-RF.
2. Production Tee: Riser is 6" O.D. Titanium, top and bottom flanges are 6", 300-Series, Van Stone flanges, ANSI RF. Side outlets, upper two outlets are 3", 300-Series, Van Stone flanges, ANSI RF, located above ground level in access tray. The lower outlet is 6", 300-Series, Van Stone flange, ANSI RF. The 3" outlets are used for vent and liquid level control devices. The 6" outlet is used for waste inlet.
3. Valve, Master: Full Opening 6", 300-Series, Titanium, ANSI-RF.
4. Valve: Wing, Motor Valve, Remote, Air Operated, 6", 300-Series, Titanium, ANSI-RF. Note: Valve is located approximately 12-feet from well head, just above ground level in access tray.
5. Monitor Sub: Riser is 6" O.D. Titanium, top and bottom flanges are 6", 300-Series, Van Stone ANSI RF flanges. Side outlets (2) are 1", 300-Series, weld-neck ANSI RF flanges. Each side outlet has a 1" Titanium Ball valve and are used for pressure monitoring equipment.
6. Flange: 6", 300-Series (Special, XH), Titanium, Grade 7, ANSI-RF, with 6-5/8", 8 rd, LT&C internal thread.
7. Injection Tubing Landing Joint: 6-5/8" O.D. Titanium, Grade 7, 8rd, LT&C threads.
8. Adapter, Tubing Head: Gray, 6-5/8"O.D.(top) X 11", 3M API flange (bottom), with internal hold down slips and seals.
9. Tubing Hanger Spool: Gray, 13-5/8" (bottom) X 11" (top), 3M, API flanges, w/two, 2-1/16", 3M, API flanged outlets. Upper bowl contains wrap-around slips and seals for 6-5/8" O.D. injection tubing. Lower flange contains secondary seals and test ports. Two flanged 2-1/16" 3M outlets are utilized for annulus monitoring, control, and well service.
10. Casing Head: SOW, 13-5/8", 3M, dressed for 13-3/8", casing w/2, 2-1/16", 3M, API flanged with 2" NPT-F outlets, bull-plugged.
11. Conductor Pipe: 20".
12. Surface Casing: 13-3/8", 87.5 ppf, K-55.
13. Protective Casing: 9-3/8", 60 ppf, N-80.
14. Injection Tubing, 6-5/8"O.D., Titanium Landing Joint.

GEOSTOCK SANDIA
ENTREPOSE

8860 Fallbrook Drive Houston, TX 77064 USA
Tel: (346) 314-4347 Fax: (832) 478-5172

Drawn by: EAM, ESSJ	Date: June 2017	*Drawing not to scale*

Figure 5-20 DeLisle Plant Well No. 7 Wellhead Schematic

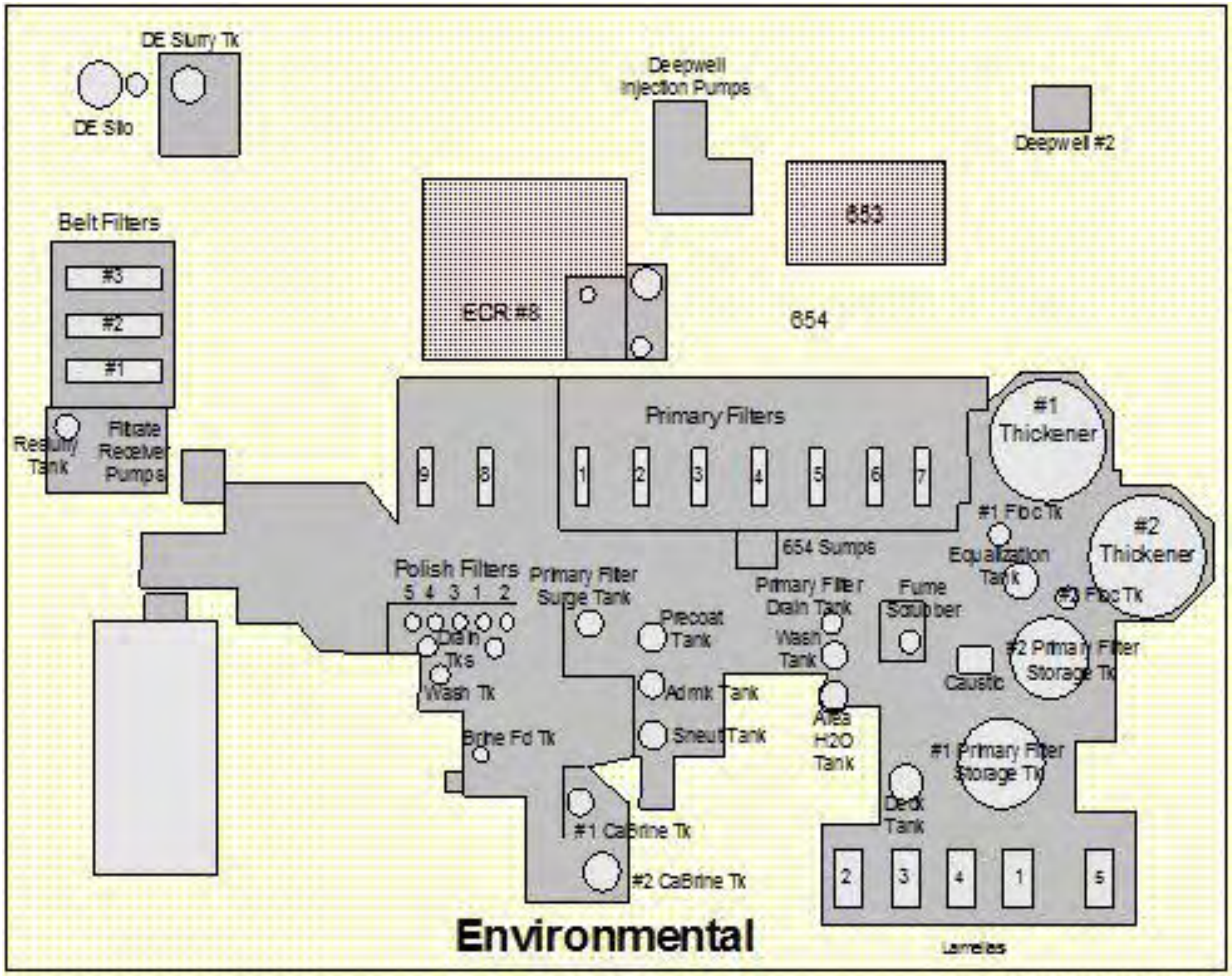


Figure 5-21 - DeLisle Plant Surface Facilities

APPENDICES

APPENDIX 5-1
DETERMINATION OF FINANCIAL RESPONSIBILITY

Chemours™

Bernard J. Reilly
Corporate Counsel
The Chemours Company
1007 Market Street, 9098-1
Wilmington, DE 19899
(302) 773-0061
bernard.j.reilly@chemours.com

March 30, 2018

SENT VIA CERTIFIED MAIL

Mississippi Department of Environmental Quality
RCRA Program Manager
Environmental Permits Division
P.O. Box 2261
Jackson, Mississippi 39225

Re: **Chemours DeLisle Plant and Pascagoula First Chemical Plant**
Corporate Guarantee for RCRA Closure Post Closure and UIC Closure

Dear Sir or Madam:

Guarantee made this date of March 30, 2018, by The Chemours Company, a business corporation organized under the laws of the State of Delaware, herein referred to as guarantor. This guarantee is made on behalf of The Chemours Company FC, LLC of 1007 Market Street, Wilmington, DE 19899, which is a subsidiary.

Recitals

1. Guarantor meets or exceeds the financial test criteria and agrees to comply with the reporting requirements for guarantors as specified in 40 CFR264.143(f), 264.145(f), 265.143(e), and 265.145(e).

2. The Chemours Company FC, LLC owns and operates the following hazardous waste management facilities covered by this guarantee: the Chemours DeLisle Plant, 7686 Kiln DeLisle Road, Pass Christian, MS 39571 and Pascagoula First Chemical Plant, 1001 Industrial Road, Pascagoula, MS 39581. This guarantee covers the costs of plugging and abandoning the UIC well at the DeLisle Plant in the amount $12,468,659 and closure/post-closure of the RCRA units at the Pascagoula Plant in the amount $386,900 for closure and $3,432,964 for post-closure.

3. "Closure plans" and "post-closure plans" as used below refer to the plans maintained as required by subpart G of 40 CFR parts 264 and 265 for the closure and post-closure care of facilities as identified above.

4. For value received from The Chemours Company FC, LLC guarantor guarantees to EPA that in the event that The Chemours Company FC, LLC fails to perform corrective action at the above facilities in accordance with the closure or post-closure plans and other permit or interim status requirements whenever required to do so, the guarantor shall do so or establish a trust fund as specified in subpart H of 40 CFR part 264 or 265, as applicable, in the name of The Chemours Company FC, LLC in the amount of the current corrective action estimate shown in attachment A.

5. Guarantor agrees that if, at the end of any fiscal year before termination of this guarantee, the guarantor fails to meet the financial test criteria, guarantor shall send within 90 days, by certified mail, notice to the Administrator for EPA Region 4, the Executive Director of MDEQ and to The Chemours Company FC, LLC that he intends to provide alternate financial assurance as specified in subpart H of 40 CFR part 264 or 265, as applicable, in the name of The Chemours Company FC, LLC. Within 120 days after the end of such fiscal year, the guarantor shall establish such financial assurance unless The Chemours Company FC, LLC has done so.

6. The guarantor agrees to notify the EPA Regional Administrator and Executive Director MDEQ by certified mail, of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming guarantor as debtor, within 10 days after commencement of the proceeding.

7. Guarantor agrees that within 30 days after being notified by an EPA Regional Administrator or the Executive Director MDEQ of a determination that guarantor no longer meets the financial test criteria or that he is disallowed from continuing as a guarantor of closure or post-closure care, he shall establish alternate financial assurance as specified in subpart H of 40 CFR part 264 or 265, as applicable, in the name of The Chemours Company FC, LLC unless The Chemours Company FC, LLC has done so.

8. Guarantor agrees to remain bound under this guarantee notwithstanding any or all of the following: amendment or modification of the closure or post-closure plans, amendment or modification of the permit, the extension or reduction of the time of performance of closure or post-closure, or any other modification or alteration of an obligation of the owner or operator pursuant to 40 CFR part 264 or 265.

9. Guarantor agrees to remain bound under this guarantee for as long as The Chemours Company FC, LLC must comply with the applicable financial assurance requirements of subpart H of 40 CFR parts 264 and 265 for the above-listed facility, except as provided in paragraph 10 of this agreement.

10. Guarantor may terminate this guarantee by sending notice by certified mail to the EPA Regional Administrators for the Regions in which the facilities are located, the Executive Director MDEQ and to The Chemours Company FC, LLC provided that this guarantee may not be terminated unless and until the Chemours Company FC, LLC obtains and the EPA Regional Administrators and Executive Director MDEQ approve, alternate corrective action coverage complying with 40 CFR 264.143,264.145, 265.143, and/or 265.145.

11. Guarantor agrees that if The Chemours Company FC, LLC fails to provide alternate financial assurance as specified in subpart H of 40 CFR part 264 or 265, as applicable, and obtain written approval of such assurance from the EPA Regional Administrator and the Executive Director MDEQ within 90 days after a notice of cancellation by the guarantor is received by the EPA Regional Administrator and the Executive Director MDEQ from guarantor, guarantor shall provide such alternate financial assurance in the name of The Chemours Company FC, LLC.

12. Guarantor expressly waives notice of acceptance of this guarantee by the EPA, MDEQ or by The Chemours Company FC, LLC. Guarantor also expressly waives notice of amendments or modifications of the closure and/or post-closure plans and of amendments or modifications of the facility permit(s).

I hereby certify that the wording of this guarantee is identical to the wording specified in 40 CFR 264.151(h) as such regulations were constituted on the date first above written.

Effective date: March 30, 2018

The Chemours Company, Guarantor

Bernard J Reilly

Bernard J Reilly
Corporate Counsel

Kelly K Burns

Signature of witness or notary:

pwc

Report of Independent Accountants

To The Chemours Company:

We have performed the procedures enumerated below, which were agreed to by the Company aud Mississippi Department of Environmental Quality, solely to assist you in evaluating the selected financial data of The Chemours Company ("The Company") as contained in the accompanying letter dated March 29, 2018 from Mark E. Newman to the Mississippi Department of Environmental Quality. These procedures were performed solely to assist the specified parties in confirming selected financial data disclosed by the Company in the accompanying letter to comply with the financial test to demonstrate financial assurance for closure and/or post-closure costs, as specified in Subpart H of 40 CFR 264.151 (f) as adopted by reference in Title 11 Part 3 Chapter 1 Rule 1.7. Management is responsible for the Company's compliance with those requirements. The sufficiency of these procedures is solely the responsibility of the parties specified in this report. Consequently, we make no representation regarding the sufficiency of the procedures enumerated below either for the purpose for which this report has been requested or for any other purpose.

The procedures performed and results thereof are as follows:

1. We confirm that we have audited the consolidated financial statements of the Company as of and for the year ended December 31, 2017. Our report dated February 16, 2018, with respect thereto, is included in the Company's 2017 Annual Report on Form 10-K.

2. We compared the amount entitled "Total Liabilities" in the accompanying letter to the Company's calculation of total liabilities, derived from the Company's December 31, 2017 consolidated financial statements and/or underlying accounting records which support the consolidated financial statements and found such amouut to be in agreement.

3. We compared the amount entitled "Tangible Net Worth" in the accompauying letter to the Company's calculation of tangible net worth, derived from the Company's December 31, 2017 consolidated financial statements and/or underlying accounting records which support the consolidated financial statements and found such amount to be in agreement.

4. We compared the amount entitled "Net Worth" in the accompanying letter to the Company's calculation of total net worth, derived from the Company's December 31, 2017 consolidated financial statements and/or underlying accountiug records which support the consolidated fiuancial statements and found such amouut to be iu agreement.

5. We compared the amount eutitled "Current Assets" in the accompanying letter to the Company's calculation of current assets derived from the Compauy's December 31, 2017 consolidated financial statements and/or underlying accountiug records which support the Company's December 31, 2017 consolidated financial statements and found such amount to be in agreement.

6. We compared the amount entitled "Current Liabilities" in the accompanying letter to the Company's calculation of current liabilities derived from the Company's December 31, 2017 consolidated financial statements aud/or underlying accounting records which support the

Company's December 31, 2017 consolidated financial statements and found such amount to be iu agreement.

7. We compared the amount entitled "Net Income Plus Depreciation, Depletion, and Amortization" in the accompanying letter to the Compauy's calculation of net income plus depreciation, depletion, and amortization derived from the Company's December 31, 2017 consolidated fiuancial statements and/or underlying accounting records which support the Company's December 31, 2017 consolidated fiuancial statements and found such amouut to be in agreement.

8. We compared the amount entitled "Total Assets in U.S." in the accompanying letter to the Company's calculation of total assets in U.S. derived from the Company's December 31, 2017 consolidated financial statements and/or underlying accounting records which support the Company's December 31, 2017 consolidated financial statements and found such amount to be in agreement.

9. We recomputed the ratio of the Company's total assets in the U.S. to the Company's total consolidated assets, derived from the Company's December 31, 2017 consolidated financial statements aud/or underlying accounting records, to note that the Company's conclusion that total assets in the U.S. is less than 90% of the Company's consolidated total assets is correct.

This agreed-upon procedures engagement was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. We were not engaged to and did not conduct an examination or review, the objective of which would be the expression of an opinion or conclusion, respectively, on financial compliance. Accordingly, we do not express such an opinion or conclusion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you.

This report relates only to the data specified in the steps above, and accordingly, we do not express an opinion or any form of assurance on any other data appearing in the Company's letter.

This report is intended solely for the information and use of you and the Mississippi Department of Environmental Quality, and is not intended to be, and should not be, used by anyone other than the specified parties.

PricewaterhouseCoopers LLP

March 29, 2018

The Chemours Company
1007 Market Street
PO Box 2047
Wilmington, DE 19899

302-773-1000 t
chemours.com

MARCH 29, 2018

MISSISSIPPI DEPARTMENT OF ENVIRONMENTAL QUALITY
RCRA PROGRAM MANAGER
ENVIRONMENTAL PERMITS DIVISION
P.O. BOX 2261
JACKSON, MS 39225

LETTER FROM CHIEF FINANCIAL OFFICER

I am the chief financial officer of The Chemours Company. This letter is in support of this firm's use of the financial test to demonstrate financial assurance for closure and/or post-closure costs, as specified in subpart H of 40 CFR parts 264 and 265.

1. This firm is the owner or operator of the following facilities for which financial assurance for closure or post-closure care is demonstrated through the financial test specified in subpart H of 40 CFR parts 264 and 265. The current closure and/or post-closure cost estimates covered by the test are shown for each facility: None.

2. This firm guarantees, through the guarantee specified in subpart H of 40 CFR parts 264 and 265, the closure or post-closure care, of the following facilities owned or operated by the guaranteed party. The current cost estimates for the closure or post-closure care responsibility so guaranteed are shown for each facility: See Attachment. The firm identified above is the direct or higher-tier parent corporation of the owner or operator.

3. In States where EPA is not administering the financial requirements of subpart H of 40 CFR part 264 or 265, this firm, as owner or operator or guarantor, is demonstrating financial assurance for the closure or post-closure care, of the following facilities through the use of a test equivalent or substantially equivalent to the financial test specified in subpart H of 40 CFR parts 264 and 265. The current closure and/or post-closure cost estimates covered by such a test are shown for each facility: See Attachment.

4. This firm is the owner or operator of the following hazardous waste management facilities for which financial assurance for closure or, if a disposal facility, post-closure care, is not demonstrated either to EPA or a State through the financial test or any other financial assurance mechanism specified in subpart H of 40 CFR parts 264 and 265 or equivalent or substantially equivalent State mechanisms. The current closure and/or post-closure cost estimates not covered by such financial assurance are shown for each facility: None.

5. This firm is the owner or operator of the following UIC facilities for which financial assurance for plugging and abandonment is required under part 144. The current closure cost estimates as required by 40 CFR 144.62 are shown for each facility: See Attachment

This firm is required to file a Form 10K with the Securities and Exchange Commission (SEC) for the latest fiscal year.

The fiscal year of this firm ends on December 31, 2017. The figures for the following items marked with an asterisk are derived from this firm's independently audited, year-end financial statements for the latest completed fiscal year, ended 2017.

ALTERNATIVE I

1. Sum of current closure and post-closure cost estimate [total of all cost estimates shown in the five paragraphs above] $106.5 million

*2. Total liabilities [if any portion of the closure or post-closure cost estimates is included in total liabilities, you may deduct the amount of that portion from this line and add that amount to lines 3 and 4] $6,428.0 million

*3. Tangible net worth $699.0 million

*4. Net worth $865.0 million

*5. Current assets $3,493.0 million

*6. Current liabilities $1,648.0 million

7. Net working capital [line 5 minus line 6] $1,845.0 million

*8. The sum of net income plus depreciation, depletion, and amortization $1,019.0 million

*9. Total assets in U.S. (required only if less than 90% of firm's assets are located in the U.S.) $3,808.0 million

10. Is line 3 at least $10 million? (Yes/No) Y

11. Is line 3 at least 6 times line 1? (Yes/No) Y

12. Is line 7 at least 6 times line 1? (Yes/No) Y

*13. Are at least 90% of firm's assets located in the U.S.? If not, complete line 14 (Yes/No) N

14. Is line 9 at least 6 times line 1? (Yes/No) Y

15. Is line 2 divided by line 4 less than 2.0? (Yes/No) N

16. Is line 8 divided by line 2 greater than 0.1? (Yes/No) Y

17. Is line 5 divided by line 6 greater than 1.5? (Yes/No) Y

ALTERNATIVE II (NOT USED)

1. Sum of current closure and post-closure cost estimates [total of all cost estimates shown in the five paragraphs above]

2. Current bond rating of most recent issuance of this firm and name of rating service ____

3. Date of issuance of bond ____

4. Date of maturity of bond ____

*5. Tangible net worth [if any portion of the closure and post-closure cost estimates is included in "total liabilities" on your firm's financial statements, you may add the amount of that portion to this line]

*6. Total assets in U.S. (required only if less than 90% of firm's assets are located in the U.S.)

7. Is line 5 at least $10 million ? (Yes/No)

8. Is line 5 at least 6 times line 1? (Yes/No)

*9. Are at least 90% of firm's assets located in the U.S.? If not, complete line 10 (Yes/No)

10. Is line 6 at least 6 times line 1? (Yes/No)

I hereby certify that the wording of this letter is identical to the wording specified in 40 CFR 264.151(f) as such regulations were constituted on the date shown immediately below.

Mark E. Newman
Senior Vice President and Chief Financial Officer
The Chemours Company
1007 Market Street
Wilmington, DE 19899

March 28, 2018

Date

2018 Chemours Financial Assurance

SITE	AGENCY	EPA ID#	CORRECTIVE ACTION (RCRA)	CLOSURE	POST CLOSURE	UIC	GRAND TOTAL
Chambers Works - Shell Road, Route 130, Deepwater, NJ 08023	EPA2	EPA ID # NJD 002385730	$ 11,616,000.00				
DeLisle - 7685 Kiln-DeLisle Road, Pass Christian, MS 39571	MDEQ	EPA ID # MSD096046792	$ 4,535,403.60			$ 12,468,659.14	
Florida Plant - Highland Site 274 NE CR 125, Lawtey, FL 32091; Maxville Mine Site Highway 302/CR 218, Maxville, FL 32234; Trail Ridge Site SR 230, Starke, FL 32091	FLDEP	EPA ID # FLD0040529200		$ 13,718,382.35			
Johnsonville Plant - DuPont Road, New Johnsonville, TN 37134	TNDEC	EPA ID # TND 004044491		$ 7,186,064.79	$ 12,375,186.80		
Martin Aaron Superfund - 1542 South Broadway, Camden, NJ 08104	EPA2	EPA ID # NJD 014623854	$ 4,004,456.90				
Necco Park - 56th & Pine, Niagara Falls, NY 14304	EPA2	EPA ID # NYD 980532162	$ 4,809,000.00				
Newport Superfund Site - James and Waters Streets, Newport, DE 19804	EPA3	EPA ID # DED 984066696	$ 7,326,987.00				
Pascagoula First Chemical - 1001 Industrial Road, Pascagoula, MS 39581	EPA4 and MDEQ	EPA ID # MSD 033417031	$ 3,712,839.08	$ 386,900.61	$ 3,432,964.15		
Pompton Lakes - 2000 Cannonball Road, Pompton Lakes, NJ 07442	EPA2	EPA ID # NJD 002173946	$ 18,980,929.00				
Washington Works - 8480 DuPont Road, Washington, WV 26181	EPA 3	EPA ID # WVD 045875291	$ 1,975,000.00				
Current Closure, Post-Closure, and CERCLA Cost Estimates for Chemours Sites using the Corporate Guarantee Financial Assurance Mechanism			$ 56,960,615.58	$ 21,291,347.75	$ 15,808,150.95	$ 12,468,659.14	$106,528,773.42

7014 3490 0001 8506 2802

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Street & Apt. No., or PO Box No. P.O Box 2261

City, State, ZIP+4 Jackson, MS 39225

PS Form 3800, July 2014 — See Reverse for Instructions

RCRA Program Manager
Environmental Permits Division
P.O. Box 2261
Jackson, Mississippi 39225

Chemours™
The Chemours Company
1007 Market Street
Wilmington, DE 19899

SENDER: *COMPLETE THIS SECTION*

- **Complete items 1, 2, and 3.**
- **Print your name and address on the reverse so that we can return the card to you.**

MS Department of Environmental Quality
RCRA Program Manager
Environmental Permits Division
P.O. Box 2261
Jackson, Mississippi 39225

9590 9402 2119 6132 1545 28

2. Article Number *(Transfer from service label)*

7014 3490 0001 8506 2802

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X ☐ Agent ☐ Addressee

B. Received by *(Printed Name)* C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
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- ☐ Adult Signature Restricted Delivery
- ☒ Certified Mail®
- ☐ Certified Mail Restricted Delivery
- ☐ Collect on Delivery
- ☐ Collect on Delivery Restricted Delivery
- ☐ Insured Mail
- ☐ Insured Mail Restricted Delivery (over $500)
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- ☐ Registered Mail Restricted Delivery
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- ☐ Signature Confirmation Restricted Delivery

PS Form 3811, July 2015 PSN 7530-02-000-9053 — Domestic Return Receipt

APPENDIX 5-2
PLUGGING AND ABANDONMENT PLAN AND JUSTIFICATION FOR INCREASING DEEPWELL FINANCIAL ASSURANCE SET ASIDE

Appendix 5-2

Plug and Abandonment Plan
Application to Reissue MDEQ UIC Permit MSI1001

This plugging and abandonment plan will be used to plug Well Nos. 2, 3, 4, 5, proposed Well No. 6 and Monitoring Well No. 1,and will be implemented when a decision has been made to plug a well. The following procedure is a general guide; the final plugging procedure will be submitted to MDEQ for review and approval prior to being implemented on any of the wells:

Well Nos. 2, 3, 4, 5 and Proposed Well No. 6

1. Displace any waste in the injection tubing with brine, flushing the well with two to three tubing volumes of sodium chloride brine.
2. Pull and remove injection tubing and packer; wash and scrape the casing.
3. Run a radioactive tracer survey to demonstrate injected fluid remains in the permitted injection interval.
4. Run a temperature survey, after the well has been static for a minimum of 36 hours to demonstrate that no flow is occurring between formations (intervals).

Well Nos. 2, 3, 4, 5, Proposed Well No. 6, and Monitor Well No. 1

5. Run casing inspection log(s) to demonstrate integrity of the casing.
6. Run a cement bond log to demonstrate cement isolation of the casing-formation annulus.
7. Run a bottom-hole pressure gauge to obtain a static reservoir pressure.
8. Evaluate all data and logs to determine if remedial cement squeezing is required.
9. Place an acid-resistant epoxy-resin cement or resin (Halliburton Epseal or WellLock® or similar) plug in the open hole at the top of the Washita Fredericksburg injection interval. After the plug hardens, tag the plug to demonstrate the material has set and document the exact depth of the plug.
10. Perforate the protective casing and class H cement at the top of the Massive Tuscaloosa Sand and bottom of the confining shale, and squeeze epoxy-resin cement (Halliburton Epseal or

Appendix 5-2

Plug and Abandonment Plan
Application to Reissue MDEQ UIC Permit MSI1001

WellLock® or similar) to protect the class H cement and carbon steel protective casing from potential acid attack in case that a future injection well were to be completed in the Massive Tuscaloosa. This step would give the plant the ability to complete a future injection well in the Massive Tuscaloosa Sand.

Alternatively:
Section mill the casing and cement from 10 feet below the top of the Massive Tuscaloosa Sand to 50 feet above the top of the Massive Tuscaloosa Sand, into the confining shale. Place and epoxy-resin cement (Halliburton Epseal or WellLock® or similar) to protect the class H cement and carbon steel protective casing from potential acid attack in case that a future injection well were to be completed in the Massive Tuscaloosa. This step would give the plant the ability to complete a future injection well in the Massive Tuscaloosa Sand.

11. Place an acid-resistant epoxy-resin cement or resin (Halliburton Epseal or WellLock® or similar) plug overlying the plug installed in Step 9 to the top of the Injection Zone (Top of Eutaw Formation). After the material hardens, tag the plug to demonstrate it has set and document the exact location of the plug.
12. If the cement bond log indicates questionable cement bonding at the top of the injection interval, the casing may be milled and the hole underreamed out to a size larger than the original drill bit size. This operation will insure that an adequate seal exists immediately above the injection interval. The underreamed hole would then be filled with acid-resistant epoxyresin cement or resin (Halliburton Epseal or WellLock®) from bottom to the top of the Washita Fredricksburg injection interval.
13. Fill the remaining portion of the wellbore with a Class H cement blend, using multiple plugs.
14. Cut off casing below ground; weld steel plate to the top of the casing.

Appendix 5-2

Plug and Abandonment Plan
Application to Reissue MDEQ UIC Permit MSI1001

Estimated costs for well plugging will include consultant fees, logging, workover rig costs, mud, welder, bridge plugs, and cement. Due to escalating petroleum industry service company prices and historically high oil and gas prices, activity and competition in services has increased, therefore, a contingency of 20 percent is warranted for use in any well plugging cost estimate.

Since, the specific cost of plugging the wells will increase with time, due to materials and personnel increase, financial assurance is provided for by Chemours per requirements of the MDEQ UIC Permit (MSI1001) and regulation. An estimate of plugging and abandonment costs will be updated periodically to ensure the amount of the bond used to meet financial assurance requirements is adequate to cover all five wells. If proposed Well No. 6 is drilled, the amount of financial assurance will be increase to cover plugging and abandoning that well also.

We do not need to do anything. Guy Johnson will take care of any increase in financial assurance levels. EC 12-GZ

DeLisle Well-Plugging Cost Estimate

Ed G Ramos to: Guy V Johnson, Barbara Wallace 01/16/2013 02:12 PM

Cc: William C Collins, Suzanne Gibson, Alice L Andrepont, James E Clark, Lisa M Wisniewski, Tim J Becnel, Daniel Telford Douty

TCEQ requested well operators in Texas to update their closure set-asides in a similar fashion. to update estimates for closure.

We need to increase the closure set-asides for the 5 delisle wells per the attached estimate from Donald Stehle.

The current set aside of $4,078 million total for the 5 wells is clearly insufficient. At $2.352 million per well * 5 wells, the set-aside needs to be $11.760 million\ starting calendar 2013.

This misalignment has been accumulated over the last 20 some years. Clearly the assumption from the Office of the Chief Economist to apply an increase of about 3% per year is not accurate.

I would recommend that we refresh the estimate every 5 years or so.

Call me if you have any questions.

Ed Ramos
Office (228) 255-4931
Cell (228) 323-0765

----- Forwarded by Ed G Ramos/HO/DuPont on 01/16/2013 01:56 PM -----

From:	"Donald E. Stehle" <donald.stehle@sandiatech.com>
To:	Ed G Ramos/HO/DuPont@DuPont
Date:	12/19/2012 02:03 PM
Subject:	Plugging Cost Estimate

Ed,

I finally had time to complete the cost estimate for plugging a well at DeLisle. The cost estimate and schedule estimate are attached.

I used the procedure from the August 2012 Petition document, pages 4-10 to 4-11, to develop schedule and estimate. I did not include any cost for repair of casing leaks, should those exist. Step 8 of the procedure states, "Evaluate all data and logs to determine if remedial cement squeezing is required." I would guess that any cement squeeze would cost $100,000 to $250,000 to place cement, drill out, and evaluate results of squeeze. Hopefully squeezing will not be needed.

Epseal (WellLOCK, new name) costs came from recent estimate from Halliburton. I adjusted quantities to reflect plugging volumes.

Estimate includes a 15% contingency ($307,000) and total estimated plugging cost, per well is $2.35 million.

I am guessing this is more than what is in bond. Call me to discuss.

Donald E. Stehle, PE
Sandia Technologies, LLC 6731 Theall Road Houston, TX 77066
Office: (832) 286-0471 Cell: (713) 882-0141 Fax: (832) 286-0477
Email: donald.stehle@sandiatech.com

Sandia Technologies, LLC

Plugging Cost Estimate.pdf Plugging Estimated Day Schedule.pdf

SANDIA TECHNOLOGIES, LLC
FIELD, ENGINEERING & THIRD PARTY COST ESTIMATE SUMMARY

Project:	**DuPont DeLisle Well Plugging**		**Page 1 of 8**
Company:	E. I. du Pont de Nemours	Date:	December 15, 2012
Location:	Pass Christian, MS	Well No.:	2
County/Parish:	Harrison	Sandia Proj.	none
Contract/PO:	Eduardo Ramos	Prepared by:	Donald E. Stehle

FIELD & OFFICE ENGINEERING PERSONNEL HOURS:

Field Activity/Description									TOT	COST
Principal Site Supervisor (day)	21								21	33,600
Senior Site Supervisor (day)	21								21	25,200
SUB-TOTAL DAYS	42								42	$58,800
Office Activity/Description	**SP**	**SM**	**SR**	**P**	**S**	**D**	**TA**	**A**	**TOT**	**COST**
Job Organization & Setup	40		40					20	100	11,740
Office Engr. & Geo.Support										
Report Preparation & Review	20		20				16	8	64	6,736
Falloff Analysis and Report										
Travel Time										
Miscellaneous										
SUB-TOTAL HOURS	60		60				16	28	164	$18,476

FIELD & OFFICE ENGINEERING COSTS:

Principal Site Supervisor (day)	21 day(s)	@ $	1600	/day	33,600.00
Senior Site Supervisor (day)	21 day(s)	@ $	1200	/day	25,200.00
Air Travel Expenses	4 trip(s)	@ $	500	/trip	2,000.00
Lodging, Meals & Other Travel Expenses	50 day(s)	@ $	250	/person	12,500.00
Auto Mileage Expense	400 miles	@ $	1.00	/mile	400.00
Senior Principal (SP)	60 hrs	@ $	160.00	/hr	9,600.00
Principal (SM)	hrs	@ $	130.00	/hr	
Senior (SR)	60 hrs	@ $	110.00	/hr	6,600.00
Project (P)	hrs	@ $	98.00	/hr	
Staff (S)	hrs	@ $	83.00	/hr	
Drafting, Geological (D)	hrs	@ $	65.00	/hr	
Technical Assistant (TA)	16 hrs	@ $	60.00	/hr	960.00
Administrative (A)	28 hrs	@ $	47.00	/hr	1,316.00
Pressure transducer/flow meter	10 day(s)	@ $	300.	day	3,000.00
	Contractor Expenses				**$95,176.00**

THIRD PARTY COSTS:

- Third Party Costs (from page 2)		$1,789,307.55
- Third Party handling Fees @	9%	$161,037.68
	Sub-Total Estimated Project Costs	**$2,045,521.23**
- Total Contingencies @ Other Misc. Exps.	15%	$306,828.18
	TOTAL ESTIMATED PROJECT COSTS	**$2,352,349.41**

SANDIA TECHNOLOGIES, LLC
THIRD PARTY COST ESTIMATE SUMMARY

Project:	**DuPont DeLisle Well Plugging**		
Company:	E. I. du Pont de Nemours	Date:	December 15, 2012
Location:	Pass Christian, MS	Well No:	2
County/Parish:	Harrison	Prepared by:	Donald E. Stehle

THIRD PARTY COST ESTIMATES:

	DESCRIPTION OF SERVICES	VENDOR NAME	COST
1	Workover rig	Not specified	$132,600.00
2	FRP Tubing Tongs	Not specified	$32,150.00
3	Brines / fluids	Not specified	$15,000.00
4	Wireline	Not specified	$35,475.00
5	Packer services	Delta P	$11,400.00
6	Cementing	Halliburton	$1,381,615.00
7	Welder	Not specified	$4,200.00
8	Frac Tanks	Not specified	$10,000.00
9	Rental Tools	Not specified	$30,500.00
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
36	Estimated Sales Taxes	8.25%	$136,367.55

TOTAL THIRD PARTY COSTS **$1,789,307.55**

E. I. duPont - DeLisle Plant

Plug & Abondon Project Schedule - Estimate

	Activity Description	Days	Vendor	Depth	Project Days	Project Hours
					0.0	0
1	Temperature survey & BHP	1	Sandia, Wireline		1.0	10
2	APT & RTS (BHP if necessary)	1	Sandia, Wireline, Plant		2.0	20
3	Displace waste from inject tubing	1	Plant		3.0	30
4	Remove surface lines	1	Plant		4.0	40
5	MIRU rig / Vent annulus / RU BOP	1	Sandia, Workover rig		5.0	50
6	Pull & lay down FRP injection tubing	3	Sandia, Workover rig, Tongs, Brine		8.0	80
7	Pull PBR & Packer	2	Sandia, Workover rig, Brine		10.0	100
8	Run wireline casing inspection logs	1	Sandia, Workover rig, Wireline		11.0	110
9	Run cement bond logs	1	Sandia, Workover rig, Wireline		12.0	120
10	Place Epoxy Resin cement plug 1	2	Sandia, Workover rig, Cementing		14.0	140
11	Place Epoxy Resin cement plug 2	2	Sandia, Workover rig, Cementing		16.0	160
12	Place Standard Cement plugs	3	Sandia, Workover rig, Cementing		19.0	190
13	Cut casing, Weld plate	1	Sandia, Workover rig, Welder		20.0	200
14	Rig down rig and equipment	1	Sandia, Workover rig		21.0	210
15					21.0	210

DeLisle UIC financial Assurance
Barbara Wallace to: Ed G Ramos 11/19/2012 02:16 PM

Ed,

Attached is the Financial Assurance Financial Guarantee Bond to MDEQ for the UIC wells and the transmittal letter to MDEQ.

Thank you,

Barbara

Barbara S. Wallace, AACP, RP, DCP
Corporate Paralegal
Antitrust Compliance
RCRA - Financial Assurance
DuPont Legal
(302) 892-8715
(302) 355-0886 FAX

2012 DeLisle UIC Bond.pdf

2012 DeLisle MDEQ UIC transmittal.pdf

DUPONT
The miracles of science™

Barbara S. Wallace,
AACP, RP, DCP
Corporate Paralegal
Legal Department
BMP 25-2260
4417 Lancaster Pike
Wilmington, DE
19805
Phone: 302-892-8715
Fax: 302-992-2105

November 19, 2012

James O. Sparks
MDEQ ECED UIC Coordinator
P.O. Box 2261
Jackson, MS 39225

Re: DuPont DeLisle MSD 096046792
UIC Financial Assurance

Mr. Sparks,

Enclosed please find the Financial Guarantee Bond to meet the financial assurance obligation on the above referenced site.

Thank you for your consideration.

Sincerely,

Barbara S. Wallace

Barbara S. Wallace AACP,RP, DCP
Corporate Paralegal
Environment Group

Enclosure
C: Ed Ramos

FINANCIAL GUARANTEE BOND

Date bond executed: November 9, 2012
Effective date: April 01, 2012

Principal: E. I. du Pont de Nemours and Company
1007 Market Street, Wilmington, DE 19898
Type of Organization: Corporation
State of incorporation: Delaware

Surety(ies): Arch Insurance Company
300 Plaza Three
Jersey City, NJ 07311

EPA Identification Number, name, address and closure and/or post-closure amount(s) for each facility guaranteed by this bond:

- Identification Number: MSD096046792, De Lisle, 7685 Kiln-DeLisle Road, PO Box 430, Pass Christian, MS 39571-9423, UIC: $4,078,000.00

Total penal sum of bond: $4,078,000.00
Surety's bond number: SU1112841

Know All Persons By These Presents, That we, the Principal and Surety(ies) hereto are firmly bound to the Mississippi Department of Environmental Quality (MDEQ), in the above penal sum for the payment of which we bind ourselves, our heirs, executors, administrators, successors, and assigns jointly and severally; provided that, where the Surety(ies) are corporations acting as co-sureties, we, the Sureties, bind ourselves in such sum "jointly and severally" only for the purpose of allowing a joint action or actions against any or all of us, and for all other purposes each Surety binds itself, jointly and severally with the Principal, for the payment of such sum only as is set forth opposite the name of such Surety, but if no limit of liability is indicated, the limit of liability shall be the full amount of the penal sum.

Whereas said Principal is required, under the Resource Conservation and Recovery Act as amended (RCRA), to have a permit or interim status in order to own or operate each hazardous waste management facility identified above, and

Whereas said Principal is required to provide financial assurance for closure, or closure and post-closure care, as a condition of the permit or interim status, and

Whereas said Principal shall establish a standby trust fund as is required when a surety bond is used to provide such financial assurance;

Now, Therefore, the conditions of the obligation are such that if the Principal shall faithfully, before the beginning of final closure of each facility identified above, fund the standby trust fund in the amount(s) identified above for the facility,

Or, if the Principal shall fund the standby trust fund in such amount(s) within 15 days after a final order to begin closure is issued by an The Mississippi Department of Environmental Quality – Executive Director or a U.S. district court or other court of competent jurisdiction,

Or, if the Principal shall provide alternate financial assurance, as specified in subpart H of 40 CFR part 264 or 265, as applicable, and obtain the Mississippi Department of Environmental Quality – Executive Director's written approval of such assurance, within 90 days after the date notice of cancellation is received by both the Principal and the The Mississippi Department of Environmental Quality – Executive Director from the Surety(ies), then this obligation shall be null and void; otherwise it is to remain in full force and effect.

The Surety(ies) shall become liable on this bond obligation only when the Principal has failed to fulfill the conditions described above. Upon notification by the Mississippi Department of Environmental Quality – Executive Director that the Principal has failed to perform as guaranteed by this bond, the Surety(ies) shall place funds in the amount guaranteed for the facility(ies) into the standby trust fund as directed by the Mississippi Department of Environmental Quality – Executive Director.

The liability of the Surety(ies) shall not be discharged by any payment or succession of payments hereunder, unless and until such payment or payments shall amount in the aggregate to the penal sum of the bond, but in no event shall the obligation of the Surety(ies) hereunder exceed the amount of said penal sum.

The Surety(ies) may cancel the bond by sending notice of cancellation by certified mail to the Principal and to the Mississippi Department of Environmental Quality – Executive Director, provided, however, that cancellation shall not occur during the 120 days beginning on the date of receipt of the notice of cancellation by both the Principal and the Mississippi Department of Environmental Quality – Executive Director, as evidenced by the return receipts.

The Principal may terminate this bond by sending written notice to the Surety(ies), provided, however, that no such notice shall become effective until the Surety(ies) receive(s) written authorization for termination of the bond by the Mississippi Department of Environmental Quality – Executive Director.

Principal and Surety(ies) hereby agree to adjust the penal sum of the bond yearly so that it guarantees a new closure and/or post-closure amount, provided that the penal sum does not increase by more than 20 percent in any one year, and no decrease in the penal sum takes place without the written permission of the Mississippi Department of Environmental Quality – Executive Director.

In Witness Whereof, the Principal and Surety(ies) have executed this Financial Guarantee Bond and have affixed their seals on the date set forth above.

The persons whose signatures appear below hereby certify that they are authorized to execute this surety bond on behalf of the Principal and Surety(ies) and that the wording of this surety bond is identical to the wording specified in 40 CFR 264.151(b) as such regulations were constituted on the date this bond was executed.

Principal:
E.I. du Pont de Nemours and Company

Signature
Alicia A. Grivas
Name
Treasury Manager
Title

CORPORATE SEAL

Attest:

Corporate Surety:
Arch Insurance Company
300 Plaza Three
Jersey City, NJ 07311

State of Incorporation: Missouri
Liability Limit: $4,078,000.00

Signature
Kathleen K. Freund, Attorney-in-Fact

CORPORATE SEAL

Bond Premium: $10,195.00

AIC 0000007563

THIS POWER OF ATTORNEY IS NOT VALID UNLESS IT IS PRINTED ON BLUE BACKGROUND.

This Power of Attorney limits the acts of those named herein, and they have no authority to bind the Company except in the manner and to the extent herein stated. Not valid for Mortgage, Note, Loan, Letter of Credit, Bank Deposit, Currency Rate, Interest Rate or Residential Value Guarantees.

POWER OF ATTORNEY

Know All Persons By These Presents:

That the Arch Insurance Company, a corporation organized and existing under the laws of the State of Missouri, having its principal administrative office in Jersey City, New Jersey (hereinafter referred to as the "Company") does hereby appoint:

Joseph R. Poplawski, Kathleen K. Freund, Margarita Holguin and Stacy Killebrew of Denver, CO (EACH)

its true and lawful Attorney(s)in-Fact, to make, execute, seal, and deliver from the date of issuance of this power for and on its behalf as surety, and as its act and deed:

Any and all bonds, undertakings, recognizances and other surety obligations, in the penal sum not exceeding Ninety Million Dollars ($90,000,000.00).

This authority does not permit the same obligation to be split into two or more bonds in order to bring each such bond within the dollar limit of authority as set forth herein.

The execution of such bonds, undertakings, recognizances and other surety obligations in pursuance of these presents shall be as binding upon the said Company as fully and amply to all intents and purposes, as if the same had been duly executed and acknowledged by its regularly elected officers at its principal administrative office in Jersey City, New Jersey.

This Power of Attorney is executed by authority of resolutions adopted by unanimous consent of the Board of Directors of the Company on September 15, 2011, true and accurate copies of which are hereinafter set forth and are hereby certified to by the undersigned Secretary as being in full force and effect:

"VOTED, That the Chairman of the Board, the President, or the Executive Vice President, or any Senior Vice President, of the Surety Business Division, or their appointees designated in writing and filed with the Secretary, or the Secretary shall have the power and authority to appoint agents and attorneys-in-fact, and to authorize them subject to the limitations set forth in their respective powers of attorney, to execute on behalf of the Company, and attach the seal of the Company thereto, bonds, undertakings, recognizances and other surety obligations obligatory in the nature thereof, and any such officers of the Company may appoint agents for acceptance of process."

This Power of Attorney is signed, sealed and certified by facsimile under and by authority of the following resolution adopted by the unanimous consent of the Board of Directors of the Company on September 15, 2011:

VOTED, That the signature of the Chairman of the Board, the President, or the Executive Vice President, or any Senior Vice President, of the Surety Business Division, or their appointees designated in writing and filed with the Secretary, and the signature of the Secretary, the seal of the Company, and certifications by the Secretary, may be affixed by facsimile on any power of attorney or bond executed pursuant to the resolution adopted by the Board of Directors on September 15, 2011, and any such power so executed, sealed and certified with respect to any bond or undertaking to which it is attached, shall continue to be valid and binding upon the Company.

In Testimony Whereof, the Company has caused this Instrument to be signed and its corporate seal to be affixed by their authorized officers, this 17th day of November, 2011.

Attested and Certified

Arch Insurance Company

Martin J. Nilsen, Secretary

CORPORATE SEAL 1971 Arch Insurance Company Missouri

David M. Finkelstein, Executive Vice President

STATE OF PENNSYLVANIA SS

COUNTY OF PHILADELPHIA SS

I, Kathleen Marcinkus, a Notary Public, do hereby certify that Martin J. Nilsen and David M. Finkelstein personally known to me to be the same persons whose names are respectively as Secretary and Executive Vice President of the Arch Insurance Company, a Corporation organized and existing under the laws of the State of Missouri, subscribed to the foregoing instrument, appeared before me this day in person and severally acknowledged that they being thereunto duly authorized signed, sealed with the corporate seal and delivered the said instrument as the free and voluntary act of said corporation and as their own free and voluntary acts for the uses and purposes therein set forth.

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
KATHLEEN MARCINKUS, Notary Public
City of Philadelphia, Phila. County
My Commission Expires March 14, 2014

Kathleen Marcinkus

Kathleen Marcinkus, Notary Public
My commission expires 03/14/2014

CERTIFICATION

I, Martin J. Nilsen, Secretary of the Arch Insurance Company, do hereby certify that the attached Power of Attorney dated November 17, 2011 on behalf of the person(s) as listed above is a true and correct copy and that the same has been in full force and effect since the date thereof and is in full force and effect on the date of this certificate; and I do further certify that the said David M. Finkelstein, who executed the Power of Attorney as Executive Vice President, was on the date of execution of the attached Power of Attorney the duly elected Executive Vice President of the Arch Insurance Company.

IN TESTIMONY WHEREOF, I have hereunto subscribed my name and affixed the corporate seal of the Arch Insurance Company on this 9th day of November, 2012.

Martin J. Nilsen, Secretary

This Power of Attorney limits the acts of those named therein to the bonds and undertakings specifically named therein and they have no authority to bind the Company except in the manner and to the extent herein stated.

PLEASE SEND ALL CLAIM INQUIRIES RELATING TO THIS BOND TO THE FOLLOWING ADDRESS:

Arch Insurance – Surety Division
3 Parkway, Suite 1500
Philadelphia, PA 19102

CORPORATE SEAL 1971 Arch Insurance Company Missouri

E. I. DU PONT DE NEMOURS AND COMPANY
ASSISTANT SECRETARY'S CERTIFICATE

In my capacity as an Assistant Secretary of E. I. du Pont de Nemours and Company, a Delaware Corporation, (the "Company"), I hereby certify that:

1. Set forth below is a true copy of action duly taken by the Board of Directors of the Company on October 17, 1949, as last amended by the Office of the Chief Executive on February 14, 1996, and same is still in full force and effect:

   RESOLVED, that any member of the Office of the Chief Executive or any Vice President of DuPont Finance, together with the Secretary or any Assistant Secretary, of this Company, hereby are authorized to sign and execute on behalf of the Company any and all proposals, contracts and/or indemnity, surety or guaranty bonds or agreements necessary in connection with its business with national, state or local governments, corporations, partnerships or individuals, whether in the United States or foreign countries;

2. Set forth below is a true copy of a delegation of authority adopted by the Vice President and Treasurer of the Company effective October 19, 2012 and same is still in full force and effect:

   I, D. H. Grier, Vice President and Treasurer of E. I. du Pont de Nemours and Company, (the "Company") hereby delegate to each of the Manager, Global Treasury Operations, and the Treasury Supervisor, the authority to sign and execute, together with the Secretary or any Assistant Secretary, on behalf of the Company, any and all surety or guaranty bonds or agreements necessary in connection with the Company's business with national, state or local governments, corporations, partnerships or individuals, whether in the United states or foreign countries.

3. Alicia A. Grivas is the Manager, Global Treasury Operations and Eugene Slesicki is the Treasury Supervisor.

IN WITNESS WHEREOF, I have set my hand and affixed the seal of this Corporation this 12th day of November, 2012

Assistant Secretary

(SEAL)

AIC 0000007563

In Testimony Whereof, the Company has caused this instrument to be signed and its corporate seal to be affixed by their authorized officers, this 17th day of November, 2011.

Attested and Certified

Arch Insurance Company

Arch Insurance Company CORPORATE SEAL 1971 Missouri

Martin J. Nilsen, Secretary

David M. Finkelstein, Executive Vice President

STATE OF PENNSYLVANIA SS

COUNTY OF PHILADELPHIA SS

I, Kathleen Marcinkus, a Notary Public, do hereby certify that Martin J. Nilsen and David M. Finkelstein personally known to me to be the same persons whose names are respectively as Secretary and Executive Vice President of the Arch Insurance Company, a Corporation organized and existing under the laws of the State of Missouri, subscribed to the foregoing instrument, appeared before me this day in person and severally acknowledged that they being thereunto duly authorized signed, sealed with the corporate seal and delivered the said instrument as the free and voluntary act of said corporation and as their own free and voluntary acts for the uses and purposes therein set forth.

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
KATHLEEN MARCINKUS, Notary Public
City of Philadelphia, Phila. County
My Commission Expires March 14, 2014

Kathleen Marcinkus, Notary Public
My commission expires 03/14/2014

CERTIFICATION

I, Martin J. Nilsen, Secretary of the Arch Insurance Company, do hereby certify that the attached Power of Attorney dated November 17, 2011 on behalf of the person(s) as listed above is a true and correct copy and that the same has been in full force and effect since the date thereof and is in full force and effect on the date of this certificate; and I do further certify that the said David M. Finkelstein, who executed the Power of Attorney as Executive Vice President, was on the date of execution of the attached Power of Attorney the duly elected Executive Vice President of the Arch Insurance Company.

IN TESTIMONY WHEREOF, I have hereunto subscribed my name and affixed the corporate seal of the Arch Insurance Company on this 9th day of November, 2012.

Martin J. Nilsen, Secretary

This Power of Attorney limits the acts of those named therein to the bonds and undertakings specifically named therein and they have no authority to bind the Company except in the manner and to the extent herein stated.

PLEASE SEND ALL CLAIM INQUIRIES RELATING TO THIS BOND TO THE FOLLOWING ADDRESS:

Arch Insurance – Surety Division
3 Parkway, Suite 1500
Philadelphia, PA 19102

Arch Insurance Company CORPORATE SEAL 1971 Missouri

Re: DELISLE - UNDERGROUND INJECTION FACILITIES - FINANCIAL ASSURANCE

Guy V Johnson to: Ed G Ramos 10/17/2012 09:04 PM

Cc: Barbara Wallace, Lisa M Wisniewski, Suzanne Gibson, William C Collins, Guy V Johnson

ED:

Based on the fact MDEQ is the permitting authority for DeLisle's deepwells, the UIC financial assurance requirements need to be demonstrated to MDEQ. We initially understood that EPA was the permitting authority, but they clarified that MDEQ was - thus the genesis of my e-mail below.

Barbara Wallace can clarify - but my belief is that we did send the package originally sent to EPA to MDEQ with modified language to satisfy the Mississippi's requirements.

Barb - please clarify that we submitted a 2012 financial assurance package to MDEQ for the DeLisle deepwells. Thx

Guy

Ed G Ramos Sorry for the late response to your e-mail from la... 10/16/2012 05:28:45 PM

From: Ed G Ramos/HO/DuPont
To: Guy V Johnson/AE/DuPont@DuPont
Cc: Barbara Wallace/AE/DuPont@DuPont, William C Collins/AE/DuPont@DuPont, Lisa M Wisniewski/HO/DuPont@DuPont, Suzanne Gibson/AE/DuPont@DuPont
Date: 10/16/2012 05:28 PM
Subject: Re: DELISLE - UNDERGROUND INJECTION FACILITIES - FINANCIAL ASSURANCE

Sorry for the late response to your e-mail from last May. However, this subject has become an item of interest at DeLisle recently.

Who we send this update on closure cost to was set up more than 14 years ago when I took over the deepwell regulatory job at DeLisle. Linda Bernard used to send this annual update to Nancy every year.

EPA has never said anything questioning why we send the information to them before. The language of the no-migration petition approval does not say anything about financial responsibility.

However, the MDEQ UIC permit has the following. I gather then that MDEQ is the agency to which we should address this notification. However, I don't recall that DeLisle has updated its demonstration of financial responsibility since I took over this job in 1998. Please advise if we have to.

The contact at MDEQ is the following. However, I will need to let him know a notification is coming so that he'll know what's it all about.

James O. Sparks

MDEQ ECED UIC Coordinator
P. O. Box 2261
Jackson, MS 39225

Part II Section B - Financial Responsibility page 18 of 19

SECTION B. FINANCIAL RESPONSIBILITY

1. The permittee shall maintain continuous compliance with the requirement to demonstrate adequate financial responsibility and resources to close, plug, and abandon the permitted injection well, as required in Subpart F of 40 CFR Part 144.

2. The permittee shall not substitute an alternative demonstration of financial responsibility from that which was initially submitted, unless he has previously submitted evidence of that alternative demonstration to the Office of Pollution Control and the Office notifies him that the alternative demonstration of financial responsibility is acceptable.

No Migration Exemption 5-5-00.pdf

Ed Ramos
Office (228) 255-4931
Cell (228) 323-0765

Guy V Johnson	ED: Our files indicate that the permitting authori...	05/17/2012 02:00:36 PM

Re: MSI1001 Land Ban Exemption Petition Modification
Fred McManus to: Ed G Ramos 09/17/2012 07:43 AM

Thanks Ed! Got your voice mail too!

Hope you are doing well.

Fred

Ed G Ramos ---09/14/2012 02:55:42 PM---Fred, I have received your letter of September 12. The submission you received

From: Ed G Ramos <Ed.G.Ramos@usa.dupont.com>
To: Fred McManus/R4/USEPA/US@EPA, Lee Thomas/R4/USEPA/US@EPA
Date: 09/14/2012 02:55 PM
Subject: MSI1001 Land Ban Exemption Petition Modification

Fred,

I have received your letter of September 12. The submission you received on August 16, 2012 (FedEx tracking # 875589630854) is the final document . No further revisions are anticipated.

We are available to respond to your questions at your earliest convenience. The modeling results in the submission should be identical to those we discussed on May 17.

Thanks for your comments and suggestions.

Ed Ramos
Office (228) 255-4931
Cell (228) 323-0765