UIC - I - 8-1, 2 & 3

WDWs-1, 2 & 3 PERMITS, RENEWALS, & MODS (11 of 18)

2017

APPENDIX 2.7-1

CHRONOLOGY OF FIELD ACTIVITIES

__Monday, July 6, 1998__
Brian Rogers traveled to Artesia, New Mexico. Met with the drilling contractor during move-in and rig-up. L&M's Rig No. 1 was moved in and rigged up the steel mud pits, pumps, and substructure.

Tom Ball traveled to Artesia, New Mexico. Rigged up L&M's Rig No. 1.

__Tuesday, July 7, 1998__
Tom Ball arrived on site. Continued to rig up. Nippled up the blowout preventer and flow line. The location had been prepared for the selected rig. A divided reserve pit, lined with a 6-mil plastic and fenced, was complete. An extension was welded onto the 9-5/8 inch surface casing with a rental 9-5/8" sow x 11" 3000 flange to the blowout preventer. A cellar was completed with a rathole and mousehole.

Brian Rogers arrived on site. Continued nippling up the blowout preventer and flow line. Went in the hole with Kelly to 40 feet. Did not tag cement. Filled the hole with water. Picked up a Smith 8-3/4 inch FDSH+ (Journal Bearing bit with gauge protection) dressed with 13-13-13-blank (Serial No. LS0625). Went in the hole. Attempted to test the hydril. Test failed. Pulled out of the hole with the bit and drill collar. Closed blind rams and attempted to test. Test failed. Ordered out a replacement hydril. Nippled down the flow line and blowout preventers.

__Wednesday, July 8, 1998__
Tom Ball arrived on site. Replaced the ring gasket on the flange. Received the replacement Hydril. Nippled up same. Tested casing to 1000 psi for 30 minutes. Test okay. Started at 1600 hours. Picked up the bit and 13 drill collars. Tagged top plug at 374 feet. Washed the cement from 374 feet to 445 feet.

Brian Rogers arrived on site. Went in the hole with 13 drill collars. Worked through the cement plug at 445 feet. Tallied 4-1/2 inch drillpipe and went in the hole to 1620 feet. 0115 hours, closed the pipe rams and pressured up the well system to 750 psi at the standpipe. 0115 hours, Test No. 1 at 750 psi. 0145 hours, Test No. 1 ended at 690 psi. Pressure loss was -60 psi per 30 minutes. 0150 hours, Test No. 2 started at 900 psi. 0220 hours, Test No. 2 ended at 865 psi. Pressure loss was -35 psi per 30 minutes (-3.89%).

Continued in the hole with the 4-1/2 inch drillpipe. Tagged the top of plug at 2188 feet with 10 feet out on Joint No. 72 and no kelly. Picked up kelly and drilled cement plug to 2301 feet. 0700 hours, changed shifts.

Thursday, July 9, 1998

Tom Ball arrived on site. Drilled the cement to 2465 feet. Washed to 2521 feet. Ran mud sweep. Totco survey was 1° at 2481 feet. Washed to 3543 feet. Survey at 3441 feet was 1-1/4°. Drilled 3543 feet to 3573 feet. Went in the hole to 4200 feet. Washed down the bridges to 4440 feet.

Brian Rogers arrived on site. 1900 hours to 2200 hours, drilled to 4479 feet. Survey at 4432 feet was 1-3/4°. 2200 hours to 2400 hours, went in the hole. Tagged to the top of the cement at 5092 feet. Drilled cement from 5092 feet to 5220 feet (128 feet). Washed to 5296 feet. Swept the hole clean and surveyed at 5277 feet, 4-1/4°. 0130 hours to 0300 hours, washed in the hole 5317 feet to 5785 feet. Tagged. Circulated hole for one hour while moving the drill collar and drillpipe on the rack. 0400 hours to 0430 hours, drilled cement from 5785 feet to 5840 feet (55 feet). Felt spotty. 0430 hours to 0530 hours, went in the hole with the pipe to 6265 feet. Tagged hard. Picked up to circulate with the kelly. The pipe stuck at 6240 feet. Rigged up the kelly. Circulated with full returns. Worked the pipe. Mixed gelled pill for the sweep.

Friday, July 10, 1998

Tom Ball arrived on site. Pumped sweep while working the pipe 140,000 lbs down to 40,000 pounds (pipe weight 115,000 pounds). Circulated heavy concentration of drilling detergent around the drill collars. Did not free pipe. Pipe was stuck near the bit from stretch calculations. Spotted 50 barrels of oil with 30 barrels around the drill collars. Worked the pipe and moved 2 barrels oil each hour.

Brian Rogers arrived on site. 1900 hours, pumped two barrels (20 strokes) and worked pipe, 40,000 pounds to 190,000 pounds. 1930 hours, the pipe was free. Circulated and rotated the kelly down. Continued washing in the hole. 2015 hours, tagged hard cement at 6395 feet. Drilled cement with ±15,000 pounds WOB, 52 strokes per minute, 900 psi, 8.6 ppg, 45-second viscosity, 10.5 pH. Drilled to 6475 feet. Washed from 6475 feet to 6635 feet. Tagged hard cement at 6635 feet. Drilled to 6650 feet. Washed in the hole to 6745 feet. Spotted the gelled pill and swept the hole. Attempted to survey at 6705 feet. Failed twice. Mud was too thick and would not allow the tool to be lowered into the well before setting. Continued washing in the hole to 6808 feet. Mud was extremely thick. Jet mud to reserve pit and added fresh water to dilute. Rotated and worked the pipe while conditioning the mud. Surveyed at 6768 feet, 3-1/2°.

Saturday, July 11, 1998

Tom Ball arrived on site. Continued to wash in the hole. Circulated and conditioned the mud as the pipe was worked downhole. Washed to 7274 feet and circulated to thin the mud. 1545 hours, tagged the cement at 7613 feet. 1545 hours to 1725 hours, short tripped 16 stands. No bridges or tight spots. 1725 hours to 1830 hours, surveyed at 7571 feet, 1-3/4°. 1830 hours to 1900 hours, drilled the cement at 7613 feet.

Brian Rogers arrived on site. 1900 hours, drilled the cement at 7613 feet. 2115 hours, broke out of the cement at 7726 feet (113 feet). Continued washing in the hole. Mud weight was 8.7 pounds per gallon (ppg), viscosity was 34 seconds, pH was 12, string weight was 130,000 pounds. 0200 hours, washed in the hole to tag cement at 8293 feet. 0200 hours to 0320 hours, drilled cement at 8293 feet to 8385 feet (92 feet). Conditioned mud with SAPP and Desco, as needed. Added premix at suction while drilling. Set marker in the pit. Did not observe loss of circulation or pit gain while washing to 8635 feet. Slowly regained full returns. Circulated the hole clean. Spotted a 25-barrel (42 viscosity) gelled pill for sweep. Mud weight was 8.9 ppg, 37 viscosity. Survey at 8604 feet was 1-1/4°.

Sunday, July 12, 1998

Tom Ball arrived on site. Installed an overflow for the reserve pit. Lined over flow with 6-mil plastic. Circulated the well clean. 1930 hours to 1330 hours, washed in the hole at 8635 feet to 9160 feet. 1330 hours, attained total depth of 9160.95 feet. 1330 hours to 1700 hours, circulated and swept the hole clean. 1700 hours to 1900 hours, short tripped 20 stands. No fill, bridges, or tight spots observed. 1900 hours, changed shift.

Brian Rogers arrived on site. 1900 hours to 2100 hours, circulated well and tallied seven inch casing. 2100 hours to 2115 hours, spotted a gelled pill. 2115 hours to 2130 hours, pumped gelled pill out of the drillpipe and into the bottom of the hole. 2200 hours, started pulling drillpipe out of the hole. Strapped the pipe as it was pulled from the well. Survey at 9160 feet was 1°. 2400 hours, moved in and rigged up Schlumberger. 0300 hours, pulled out of the hole. Went in the hole with 9-5/8 inch casing cement bond log, gamma ray, and casing collar locator logging tool to log 2548 feet to 400 feet. Correlated depths to the gamma ray curve/casing setting depth on the Halliburton spectral density, dual-spaced neutron log, dated September 8, 1993.

Monday, July 13, 1998

Tom Ball arrived on site. Performed a fracture identification survey with gamma ray from 9144 feet to 4000 feet. Integrated the four-arm caliper survey from 9144 feet to 2555 feet. Calculated the cement volume from the log and added 20% excess cement. Went in the hole with drillpipe and broke circulation at 5000 feet and 7000 feet. Continued in the hole. Good returns with no lost circulation.

Brian Rogers arrived on site. Set bit at 9115 feet and circulated the hole. Monitored returns. Swept the hole with 100 barrels, 40-second viscosity gelled pill. Monitored returns. Spotted a viscous gel pill at 9105 feet. Rigged up a lay-down machine. Pulled out of the hole. Laid down drillpipe and drill collars.

Tuesday, July 14, 1998

Tom Ball arrived on site. Rigged up Bull Rogers' casing crews. Picked up a seven inch packoff float shoe, Baker weld to the Bottom Joint No. 1. Ran two joints, float collar at 9007 feet and differential valve (DV) tool at 5498 feet. All equipment was Baker welded to the pipe. Ran Joint Nos. 1-50, 29 lb/ft N-80; Joint Nos. 51-84, 29 lb/ft, P-110; Joint Nos. 85-259, 26 lb/ft, P110. Torque turned and monitored each connection. 1550 hours, positioned float shoe at 9094 feet. Circulated well and reciprocated pipe for one seven inch casing volume. 1615 hours, dropped the ball and set a packoff float shoe at 9094 feet. Moved in and rigged up Halliburton. Cemented 7 inch casing with 20 barrels of fresh water, 12 barrels of mud flush, 20 barrels of fresh water, 12 barrels of Super Flush, 20 barrels of fresh water, and 600 sacks (171 barrels) modified Class H + 0.4% CFR-3 plus five pounds per sack (lb/sx) Gilsonite +0.5% Halad-344, + one lb/sx of salt mixed at 13.0 ppg (yield at 1.66 ft^3 per sack). Displaced with 150 barrels of fresh water and 194 barrels of mud. Did not bump plug. Floats were holding. Dropped dart and opened the DV tool at 824 psi. Circulated well with good returns throughout.

Brian Rogers arrived on site. Circulated through the DV tool for eight hours. Observed 42 barrels (142 sacks) of cement circulated to the surface. 0310 hours, pumped 20 barrels of fresh water, 12 barrels of super flush, 20 barrels of fresh water, Mixed (103 barrels) 220 sacks interfill C (lead slurry) at 11.7 ppg, followed by 163 barrels (550 sacks) Modified Class H + 0.5% Halad-344 + 0.1% HR7 + 0.4% CFR-3, + 5 lb/sx Gilsonite + one lb/sx salt at 13.0 ppg. Released the closing plug and displaced with 210 barrels of fresh water. Landed the plug and closed the DV tool with 3000 psi. Checked flowback. Okay. Tool closed. Circulated 35 barrels (75 sacks) to the surface. Picked up 1 inch tremie line and lowered to 20 feet (could not work past 7 inch collar) and cemented the 9-5/8" x 7" annulus with 20 sacks of premium cement containing 3% calcium chloride. Waited on cement. Cleaned the mud pits.

<u>Wednesday, July 15, 1998</u>

Brian Rogers arrived on site. Waited on cement. Mud pits were clean. 1215 hours, slacked off on casing and cut to remove the blowout preventers. 1500 hours, released the drilling rig. Installed the seven inch Larkin Type R tubinghead. Returned the surplus mud inventory and inspected 13 drill collars. Rigged down the drilling rig.

<u>Thursday, July 16, 1998</u>

Brian Rogers arrived on site. Rigged down, moved out the drilling rig. Installed anchors and stabilized the seven inch casing with cement and filled in the rathole and mousehole. Delivered two 6-1/8 inch bits an coordinated completion operations.

<u>Monday, July 20, 1998</u>

Brian Rogers arrived on site. Moved in and rigged up Real Well Service's completion rig; Star Tool Company's pump, tank, pipe racks, catwalk, power swivel, and tools; and Knight Oil Tools' 2-7/8 inch, 6.50 lb/ft, N-80 work string. Purchased wellhead valves and fittings. Picked up the 6-1/8 inch bit, sub, six drill collars, and x-over (BHA at 183.80 feet) on the 2-7/8 inch work string. Went in the hole to tag soft bottom at 5455 feet. Picked up and pressure tested the well system above the DV tool at 5498 feet as shown below in Test Nos. 1 and 2:

Pressure Test No. 1 above DV tool at 5498 feet. Bottom of work string at 5450 feet:

Time (hours)	Pressure (psig)	Δ P (psi)
1441	1580	--
1446	1574	-6
1451	1571	-3
1456	1568	-3
1501	1565	-3
1506	1563	-2
1511	1561	-2
	TOTAL	-19 psi/ 30 minutes

Pressure Test No. 2 above DV tool at 5498 feet. Bottom of work string at 5450 feet:

Time (hours)	Pressure (psig)	ΔP (psi)
1516	1559	--
1521	1558	-1
1526	1556	-2
1531	1555	-1
1536	1555	0
1541	1554	-1
1546	1553	-1
	TOTAL	-6 psi/ 30 minutes

Washed in the hole to tag the top of the DV at 5498 feet. Drilled out the DV tool part way, circulated the tubing clean, and installed the TIW valve. 1900 hours, shut down for the night.

Note: Monitored the well system pressures using an Adalet digital pressure gauge (Catalog No. XIHFGCXZ-54967) with an Iniex Certificate Rating No. EX88B103703U. Pressure range was 0 to 2000 psig.

Tuesday, July 21, 1998

Brian Rogers arrived on site. 0700 hours, finished drilling out the DV tool. Went into the hole to tag soft bottom at 8896 feet. Drilled and washed in the hole to 9004 feet. Circulated the well clean. Picked up and pressure tested the well system above the top of the float collar, as shown below in Test Nos. 3 and 4.

Pressure Test No. 3 above the float collar at 9007 feet. Bottom of the work string at 8972 feet.

Time (hours)	Pressure (psig)	ΔP (psi)
1405	1600	--
1410	1592	-8
1415	1588	-4
1420	1584	-4
1425	1580	-4
1430	1577	-3
1435	1575	-2
	TOTAL	-25 psi/ 30 minutes

Pressure Test No. 4 above the float collar at 9007 feet. Bottom of the work string at 8972 feet:

Time (hours)	Pressure (psig)	ΔP (psi)
1440	1573	--
1445	1571	-2
1450	1569	-2
1455	1568	-1
1500	1567	-1
1505	1566	-1
1510	1565	-1
	TOTAL	-8 psi/ 30 minutes

Monitored the well system pressures using an Adalet digital pressure gauge (Catalog No. XIHFGCXZ-54967) with an Iniex Certificate Rating No. EX88B103703U. Pressure range was 0 to 2000 psig.

Pulled out of the hole. Laid down the drill collars. Cleaned out the rig tank and filled it with clean fresh water.

Wednesday, July 22, 1998

Brian Rogers arrived on site. 0700 hours, went in the hole with a bit and scraper to 8823 feet. Reverse circulated bottoms up. Pickled the wellbore with six barrels 15% HCl (inhibited) pumped down the tubing and up the casing. Displaced the well with an 8.7 ppg brine water. Laid down 11 joints and tripped out of the hole. Secured the well for the night. Loaded the storage tank with 500 barrels of 8.7 ppg brine.

Thursday, July 23, 1998

Brian Rogers arrived on site. 0600 hours, moved in and rigged up Wedge Wireline. Performed a differential temperature survey from the surface to total depth. Performed a cement bond log from 8997 feet to 135 feet. Cement bond log performed with 1000 psi applied to the well system. Conducted a casing inspection survey from 8997 feet to the surface.

Friday, July 24, 1998

Brian Rogers arrived on site. Moved in and rigged up Wedge Wireline with eight 4 inch retrievable cased-hole perforating guns. Perforated selected intervals at two jet shots per foot as follows:

Run No.	Feet
1	8470 to 8476
	8460 to 8464
2	8430 to 8446
3	8419 to 8423
	8400 to 8410

Run No.	Feet
4	8360 to 8366
	8370 to 8378
5	8280 to 8302
6	8260 to 8270
7 & 8	8220 to 8254

All shots were fired. Fluid level dropped from the surface to ±1380 feet. Bottom-hole pressure at 8220 feet was measured at 3176 psia. A static gradient survey was performed as the tool was pulled out of the well. Static stays were conducted at 6000 feet, 3000 feet, 1500 feet, and at the surface. The well was secured for the night.

Saturday, July 25, 1998

Brian Rogers arrived on site. 0700 hours, strapped in the hole with nine joints 2-7/8" work string (287.56 feet), Arrow X-1 packer (6.25 feet), seating nipple (one foot), and 133 joints 2-7/8 inch work string (8178.32 feet) to set the end of the tubing below the bottom perforation (8476 feet) at 8479 feet. Packer element was at 8189 feet. Rigged up swab line and went into the hole to tag the fluid level at 1700 feet. Swab tested the perforated interval and recovered two tubing volumes of fluid. Strong hydrogen sulfide smell was observed while swabbing. Retained samples of the formation water for analysis. A total of 139 barrels of fluid was recovered. Secured the well for the night.

Sunday, July 26, 1998

Brian Rogers arrived on site. 0700 hours, set end of tubing at 8158 feet (top perforation was 8220 feet). Moved in and rigged up Dowell Schlumberger and performed step rate test using 8.7 ppg brine water. Results of Step Rate Test No. 1 (before acid) are as follows:

Rate (bpm)	Volume Pumped (barrels)	Pressure (psig)	Friction Pressure (psig)	Pump-in Pressure (psig)
2	50	560	285	+ 275
4	35	2020	734	+1286
4.85	35	2673	1020	+1653
5	3	+2850	1020	+1830

Maximum allowable pump-in = 8220 ft x 0.2 psi/ft = 1644 psig.

Acidized perforations 8220 feet to 8476 feet in four stages as follows:

Spotted acid (9.5 barrels) across perforations and pulled out of the hole to set end of the tubing at 8158 feet. Stage 1: 27 barrels of 15% HCl + 20 barrels of gelled salt for block at 800 pounds; Stage 2: 27 barrels of 15% HCl + 26 barrels of 8.7 brine pad + 21 barrels of gelled salt for block at 800 pounds; Stage 3: 27 barrels of 15% HCl + 26 barrels of 8.7 brine pad + 20 barrels of gelled salt for block at 800 pounds; Stage 4: 27 barrels of 15% HCl + 65 barrels of 8.7 brine for displacement at 10 bpm and 2450 psi. Allowed acid to soak for two hours and performed Step Rate Test No. 2. Results of Step Rate Test No. 2 are:

Rate (bpm)	Volume Pumped (Barrels)	Pressure (psig)	Friction Pressure (psig)	Pump-in Pressure (psig)
4	20	86	734	-648
7	130	1085	1632	-547
10	35	2674	2774	-100
12	50	3948	3875	+ 73

Well went on a vacuum following both tests.

Laid down nine joints and pulled out of the hole with the tubing and the packer.

Monday, July 27, 1998

Brian Rogers arrived on site. Moved in and rigged up Wedge Wireline with eight 4 inch retrievable cased-hole perforating guns. Perforated selected intervals at two jet shots per foot as follows: 8170 feet to 8188 feet, 8160 feet to 8164 feet, 8118 feet to 8127 feet, 8132 feet to 8140 feet, 8066 feet to 8080 feet, 8050 feet to 8056 feet, 7974 feet to 8030 feet, and 7924 feet to 7942 feet. Started loading the tanks with an 8.7 ppg brine water. Secured the well and shut down for the night.

Tuesday, July 28, 1998

Brian Rogers arrived on site. Went into the hole with an Arrow retrievable bridge plug and packer on the work string. Tool hung up at 4830 feet. Pulled out of the hole. Lower slip cage on the plug was broken. Called for a replacement. Went into the hole with a 6-1/8 inch bit on the work string. Did not encounter any obstructions. Pulled out of the hole. Went into the hole with a replacement retrievable bridge plug and packer on 88 stands. Had mechanical failure on rig. Shut down. Secured the well for the night.

Wednesday, July 29, 1998

Brian Rogers arrived on site. Went into the hole with an Arrow retrievable bridge plug and packer. Set the retrievable bridge plug at 8214 feet. Set the packer at 8193 feet. Pressure tested between the packers at 500 psi. Tested okay. Pulled up the hole. Set the packer at 7852 feet. Swab tested the perforated interval and recovered 112 barrels (more than two tubing volumes). Moved in and rigged up Dowell Schlumberger to perform Step Rate Test No. 1 using an 8.7 ppg brine water. Acidized perforations 7924 feet to 8188 feet in four stages as follows: (1) 30 barrels 15% HCl + 10 barrels of gelled salt at 500 pounds; (2) 30 barrels 15% HCl + 20 barrels 8.7 brine pad + 16 barrels of gelled salt for block at 800 pounds; (3) 30 barrels 15% HCl + 20 barrels 8.7 brine pad + 21 barrels of gelled salt for block at 1000 pounds; and (4) 30 barrels 15% HCl + 60 barrels 8.7 brine for displacement at 6.5 bpm and 1050 psi.

Allowed acid to soak for one hour and performed Step Rate Test No. 2. Lowered the retrieving head onto the retrievable bridge plug. Unset the retrievable bridge plug and pulled out of the hole with the tools. Laid down the retrievable bridge plug and the packer. Secured the well for the night.

All storage tanks were loaded with an 8.7 ppg brine, totaling 7840 barrels.

Results of Step Rate Test No. 1 (before acid):

Rate (bpm)	Volume Pumped (barrels)	Pressure (psig)	Friction Pressure (psig)	Pump-in Pressure (psig)
2	47	400	275	125
4	15	1780	706	1074
4.36	2	2416	706	1710

Maximum allowable pump-in = 7924 ft x 0.2 psi/ft = 1585 psig.

Step Rate Test No. 2 (after 5000 gallons 15% HCl acid):

Rate (bpm)	Volume Pumped (Barrels)	Pressure (psig)	Friction Pressure (psig)	Pump-in Pressure (psig)
4	25	7	706	-700
7	25	1070	1570	-500

Well went on a vacuum following both tests.

<u>Thursday, July 30, 1998</u>

Brian Rogers arrived on site. 0600 hours, moved in and rigged up Wedge Dia-Log with a digital quartz surface readout gauge, Eccosse Tex, Serial No. 009, 0 psia to 5000 psia and a Z.I. Probe memory recorder, Serial No. P59, 0 psia to 5000 psia with a casing collar locator for depth control. 0700 hours, went into the hole and correlated logging depths to the July 23, 1998, cement bond log. Set the surface readout gauge at 7924 feet (top perforation). 0830 hours, bottom-hole pressure was 2928.16 psia at 125.41°F. Moved in and rigged up Halliburton's pump truck and booster pump. 0920 hours, started pumping 8.7 ppg brine at 10 bpm. Well on vacuum at surface. 2153 hours, final bottom-hole pressure injection pressure at 7924 feet was 3071.85 psia at 90.80°F. Shut down injection. Pumped a total of 7490 barrels of 8.7 ppg brine while monitoring the bottom-hole pressure. Monitored the pressure falloff.

Friday, July 31, 1998

Brian Rogers arrived on site. 0700 hours, discontinued the pressure falloff test. Pulled out of the hole making static gradient stops at 6000 feet, 3000 feet, 1700 feet and at the surface. Rigged up a differential temperature tool and casing collar locator and conducted a survey from the surface to wireline total depth at 8997 feet. Pulled out of the hole and laid down the temperature tool. Picked up a dual detector gamma ray tool configured with an upper detector, ejector, casing collar locator, and lower detector. Went into the hole. Performed a pre-survey baseline 7800 feet to wireline total depth at 8997 feet. Conducted a five-minute statistical survey at 7904 feet. Performed two injection profile surveys at 1 bpm. Conducted two stationary surveys at 7904 feet, pumping at 10 bpm. No upward migration was observed behind the casing. Performed a post-survey baseline. Rigged down and moved out wireline and pump equipment. Note: Released all 16 frac tanks at 0900 hours.

Saturday, August 1, 1998

Brian Rogers arrived on site. Laid down the 2-7/8 inch work string and returned to Knight Oil Tools. Delivered 197 joints, new 4-1/2 inch, 11.60 lb/ft, N-80, SMLS, R3, LT&C injection tubing.

Sunday, August 2, 1998

Brian Rogers arrived on site. Picked up an Arrow Model X-1 (7" x 3.5") retrievable packer (minimum ID = 3.0 inches) with a wireline reentry guide on bottom and a X/O 3.5 EUE 8rd pin x 4-1/2" LTC box on top. Total length was 9.01 feet. Made up and went in the hole with 193 joints, 4-1/2 inch, 11.60 lb/ft, N-80, SMLS, R3, LT&C injection tubing. Set the packer at 7879 feet and loaded the annulus with 8.7 ppg corrosion inhibited brine water. Slacked off 15,000-pound compression on the packer. Pressure tested the annulus at 600 psi. Lost 90 psi/30 minutes. Repressurized the annulus and lost 20 psi/30 minutes. Released the pump truck and left the annulus open during stabilization. Shut down for the night.

Monday, August 3, 1998

Brian Rogers arrived on site. Pressurized the annulus to 700 psi and monitored overnight. Notified the New Mexico Oil Conservation Division (OCD) of the test to begin at 0700 hours on Tuesday, August 4, 1998. Returned the rental tools and moved out the tanks.

Tuesday, August 4, 1998

Brian Rogers arrived on site. Continued monitoring the annulus pressure. 0700 hours, annulus pressure was 702 psig. 0900 hours, the OCD representatives witnessed the annulus pressure test. Mr. E. L. Gonzales and Gerry Williams represented the OCD. 0900 hours, started the annulus pressure test at 704 psig. 0930 hours, ended the annulus pressure test at 705 psig. Pressure change was +1 psi/30-minute period (0.14%), which is within the regulatory guidelines.

Rigged down and released the completion unit and all ancillary equipment.

APPENDIX 4.1-1

BOTTOM-HOLE PRESSURE FIELD DATA RECORDED DURING THE INJECTIVITY/FALLOFF TEST FOR WDW-1

APPENDIX 4.1-1
Navajo Refining Company
Pressure Falloff Data

Well Name : WDW-1
Started on : 07/30/1998
Ended on : 07/31/1998

Time	Pressure (Psia)	Temperature (°F)
0.0000	2927.912	123.434
0.0003	2927.912	123.439
0.0006	2927.904	123.444
0.0008	2927.904	123.444
0.0011	2927.903	123.459
0.0014	2927.899	123.457
0.0017	2927.899	123.467
0.0019	2927.877	123.462
0.0022	2927.894	123.474
0.0025	2927.886	123.485
0.0028	2927.889	123.487
0.0031	2927.892	123.500
0.0033	2927.881	123.497
0.0200	2927.845	123.822
0.0367	2927.879	124.129
0.0533	2927.914	124.377
0.0700	2927.958	124.595
0.0867	2928.012	124.782
0.1033	2928.041	124.924
0.1200	2928.073	125.036
0.1367	2928.096	125.124
0.1533	2928.120	125.208
0.1700	2928.117	125.256
0.1867	2928.131	125.299
0.2033	2928.158	125.352
0.2200	2928.158	125.379
0.2367	2928.162	125.410
0.2533	2928.178	125.438
0.2700	2928.169	125.448
0.2867	2928.184	125.470
0.3033	2928.195	125.483
0.3200	2928.211	125.501
0.3367	2928.202	125.506
0.3533	2928.191	125.508
0.3700	2928.208	125.521
0.3867	2928.207	125.526
0.4033	2928.193	125.521
0.4200	2928.203	125.534
0.4367	2928.205	125.541
0.4533	2928.190	125.546
0.4700	2928.199	125.559
0.4867	2928.220	125.574
0.5033	2928.196	125.556
0.5200	2928.189	125.556
0.5367	2928.209	125.572
0.5481	2928.219	125.584
0.5647	2928.232	125.594
0.5814	2928.215	125.582
0.5981	2928.202	125.572
0.6147	2928.205	125.574
0.6314	2928.212	125.579
0.6481	2928.219	125.584
0.6647	2928.218	125.594
0.6650	2928.214	125.587
0.6653	2928.214	125.587
0.6656	2928.208	125.577
0.6658	2928.218	125.594
0.6661	2928.221	125.592
0.6664	2928.218	125.589
0.6667	2928.201	125.577
0.6669	2928.218	125.594
0.6672	2928.221	125.592
0.6675	2928.214	125.587
0.6678	2928.214	125.587
0.6681	2928.211	125.584
0.6683	2928.211	125.589
0.6686	2928.214	125.587
0.6689	2928.238	125.604
0.6692	2928.183	125.569
0.6694	2928.231	125.599
0.6697	2928.208	125.582
0.6700	2928.221	125.597
0.6703	2928.208	125.582
0.6706	2928.225	125.594
0.6708	2928.214	125.592
0.6711	2928.214	125.587
0.6714	2928.214	125.587
0.6717	2928.207	125.587
0.6719	2928.225	125.594
0.6722	2928.207	125.587
0.6725	2928.236	125.597
0.6728	2928.194	125.577
0.6731	2928.235	125.602
0.6733	2928.211	125.584
0.6736	2928.221	125.592
0.6739	2928.204	125.584
0.6742	2928.232	125.594
0.6744	2928.214	125.592
0.6747	2928.221	125.592
0.6750	2928.218	125.589
0.6753	2928.214	125.587
0.6756	2928.221	125.592
0.6758	2928.207	125.587
0.6761	2928.228	125.597
0.6764	2928.214	125.592
0.6767	2928.207	125.587
0.6769	2928.228	125.597
0.6772	2928.204	125.584
0.6775	2928.221	125.597
0.6778	2928.207	125.587
0.6781	2928.228	125.597
0.6783	2928.214	125.592
0.6786	2928.211	125.589
0.6789	2928.214	125.592
0.6792	2928.218	125.594
0.6794	2928.214	125.592
0.6797	2928.218	125.589
0.6800	2928.210	125.594
0.6803	2928.214	125.587
0.6806	2928.224	125.599
0.6808	2928.214	125.592
0.6811	2928.214	125.592
0.6814	2928.214	125.592
0.6817	2928.221	125.597
0.6819	2928.203	125.589
0.6822	2928.218	125.594
0.6825	2928.221	125.597
0.6828	2928.200	125.587
0.6831	2928.228	125.602
0.6833	2928.204	125.584
0.6836	2928.217	125.599
0.6839	2928.211	125.589
0.6842	2928.235	125.607
0.6844	2928.196	125.584
0.6847	2928.211	125.589
0.6850	2928.207	125.592
0.6853	2928.231	125.604
0.6856	2928.207	125.592
0.6858	2928.218	125.594
0.6861	2928.203	125.589
0.6864	2928.218	125.594
0.6867	2928.210	125.594
0.6869	2928.231	125.604
0.6872	2928.200	125.587
0.6875	2928.214	125.592
0.6878	2928.224	125.599
0.6881	2928.210	125.594
0.6883	2928.207	125.592
0.6886	2928.211	125.589
0.6889	2928.224	125.604
0.6892	2928.214	125.592
0.6894	2928.218	125.594
0.6897	2928.199	125.592
0.6900	2928.214	125.592
0.6903	2928.220	125.602
0.6906	2928.218	125.594
0.6908	2928.207	125.592
0.6911	2928.210	125.594
0.6914	2928.224	125.599
0.6917	2928.213	125.597
0.6919	2928.203	125.589
0.6922	2928.218	125.594
0.6925	2928.213	125.597
0.6928	2928.220	125.602
0.6931	2928.221	125.597
0.6933	2928.203	125.589
0.6936	2928.213	125.597
0.6939	2928.224	125.599
0.6942	2928.217	125.599
0.6944	2928.207	125.592
0.6947	2928.218	125.594
0.6950	2928.217	125.599
0.6953	2928.210	125.594
0.6956	2928.227	125.607
0.6958	2928.218	125.594
0.6961	2928.203	125.589
0.6964	2928.224	125.604
0.6967	2928.213	125.597
0.6969	2928.224	125.599
0.6972	2928.200	125.587
0.6975	2928.220	125.602
0.6978	2928.217	125.599
0.6981	2928.210	125.594
0.6983	2928.220	125.602
0.6986	2928.207	125.592
0.6989	2928.224	125.604
0.6992	2928.210	125.594
0.6994	2928.224	125.599
0.6997	2928.196	125.589
0.7000	2928.234	125.612
0.7003	2928.213	125.597
0.7006	2928.213	125.597
0.7008	2928.210	125.594

Time	Pressure (Psia)	Temperature (°F)
0.7011	2928.217	125.599
0.7014	2928.220	125.602
0.7017	2928.220	125.602
0.7019	2928.210	125.594
0.7022	2928.207	125.592
0.7025	2928.230	125.610
0.7028	2928.209	125.599
0.7031	2928.220	125.602
0.7033	2928.210	125.594
0.7036	2928.217	125.599
0.7039	2928.213	125.602
0.7042	2928.217	125.599
0.7044	2928.217	125.599
0.7047	2928.213	125.597
0.7050	2928.220	125.602
0.7053	2928.224	125.604
0.7056	2928.217	125.599
0.7058	2928.202	125.594
0.7061	2928.224	125.604
0.7064	2928.220	125.602
0.7067	2928.220	125.602
0.7069	2928.202	125.594
0.7072	2928.213	125.597
0.7075	2928.224	125.604
0.7078	2928.217	125.599
0.7081	2928.209	125.599
0.7083	2928.217	125.599
0.7086	2928.209	125.599
0.7089	2928.228	125.602
0.7092	2928.213	125.602
0.7094	2928.209	125.599
0.7097	2928.224	125.604
0.7100	2928.217	125.599
0.7103	2928.217	125.599
0.7106	2928.209	125.599
0.7108	2928.220	125.602
0.7111	2928.213	125.597
0.7114	2928.227	125.607
0.7117	2928.210	125.594
0.7119	2928.235	125.607
0.7122	2928.218	125.594
0.7125	2928.238	125.610
0.7128	2928.228	125.597
0.7131	2928.235	125.602
0.7133	2928.231	125.599
0.7136	2928.260	125.610
0.7139	2928.236	125.597
0.7142	2928.250	125.597
0.7144	2928.261	125.604
0.7147	2928.262	125.599
0.7150	2928.279	125.607
0.7153	2928.280	125.602
0.7156	2928.298	125.604
0.7158	2928.292	125.594
0.7161	2928.313	125.610
0.7164	2928.332	125.607
0.7167	2928.275	125.554
0.7169	2928.406	125.640
0.7172	2928.380	125.610
0.7175	2928.381	125.599
0.7178	2928.410	125.604
0.7181	2928.412	125.594
0.7183	2928.469	125.615
0.7186	2928.464	125.594
0.7189	2928.514	125.615
0.7192	2928.527	125.597
0.7194	2928.560	125.604
0.7197	2928.594	125.602
0.7200	2928.634	125.610
0.7203	2928.657	125.599
0.7206	2928.716	125.610
0.7208	2928.736	125.597
0.7211	2928.783	125.610
0.7214	2928.822	125.599
0.7217	2928.884	125.607
0.7219	2928.915	125.602
0.7222	2928.981	125.607
0.7225	2929.026	125.607
0.7228	2929.083	125.599
0.7231	2929.138	125.607
0.7233	2929.192	125.597
0.7236	2929.276	125.615
0.7239	2929.315	125.599
0.7242	2929.375	125.599
0.7244	2929.449	125.599
0.7247	2929.526	125.612
0.7250	2929.580	125.602
0.7253	2929.672	125.615
0.7256	2929.719	125.594
0.7258	2929.803	125.607
0.7261	2929.867	125.604
0.7264	2929.938	125.602
0.7267	2930.021	125.597
0.7269	2930.105	125.610
0.7272	2930.187	125.610
0.7275	2930.252	125.602
0.7278	2930.335	125.597
0.7281	2930.427	125.604
0.7283	2930.517	125.604
0.7286	2930.602	125.612
0.7289	2930.693	125.597
0.7292	2930.771	125.599
0.7294	2930.876	125.599
0.7297	2930.986	125.615
0.7300	2931.084	125.604
0.7303	2931.164	125.592
0.7306	2931.282	125.602
0.7308	2931.387	125.602
0.7311	2931.502	125.610
0.7314	2931.596	125.607
0.7317	2931.684	125.589
0.7319	2931.802	125.599
0.7322	2931.902	125.602
0.7325	2931.999	125.607
0.7328	2932.064	125.589
0.7331	2932.160	125.604
0.7333	2932.232	125.597
0.7336	2932.313	125.607
0.7339	2932.345	125.587
0.7342	2932.398	125.582
0.7344	2932.513	125.617
0.7347	2932.568	125.602
0.7350	2932.628	125.592
0.7353	2932.710	125.597
0.7356	2932.789	125.594
0.7358	2932.859	125.597
0.7361	2932.930	125.594
0.7364	2933.021	125.594
0.7367	2933.082	125.584
0.7369	2933.191	125.599
0.7372	2933.271	125.592
0.7375	2933.372	125.594
0.7378	2933.469	125.584
0.7381	2933.596	125.589
0.7383	2933.711	125.592
0.7386	2933.853	125.592
0.7389	2933.992	125.584
0.7392	2934.154	125.582
0.7394	2934.347	125.587
0.7397	2934.537	125.589
0.7400	2934.721	125.582
0.7403	2934.927	125.579
0.7406	2935.135	125.584
0.7408	2935.341	125.582
0.7411	2935.516	125.584
0.7414	2935.723	125.572
0.7417	2935.905	125.579
0.7419	2936.066	125.577
0.7422	2936.261	125.577
0.7425	2936.384	125.574
0.7428	2936.534	125.574
0.7431	2936.687	125.572
0.7433	2936.808	125.584
0.7436	2936.935	125.562
0.7439	2937.105	125.572
0.7442	2937.249	125.562
0.7444	2937.452	125.574
0.7447	2937.648	125.564
0.7450	2937.816	125.562
0.7453	2938.067	125.559
0.7456	2938.285	125.572
0.7458	2938.499	125.564
0.7461	2938.740	125.549
0.7464	2938.964	125.554
0.7467	2939.239	125.559
0.7469	2939.503	125.567
0.7472	2939.693	125.541
0.7475	2940.009	125.554
0.7478	2940.275	125.546
0.7481	2940.555	125.554
0.7483	2940.929	125.549
0.7486	2941.198	125.539
0.7489	2941.552	125.546
0.7492	2941.918	125.546
0.7494	2942.199	125.539
0.7497	2942.610	125.539
0.7500	2942.928	125.536
0.7503	2943.233	125.541
0.7506	2943.578	125.531
0.7508	2943.777	125.529
0.7511	2944.113	125.529
0.7514	2944.344	125.534
0.7517	2944.557	125.526
0.7519	2944.823	125.519
0.7522	2944.906	125.513
0.7525	2945.171	125.544
0.7528	2945.240	125.501
0.7531	2945.321	125.506
0.7533	2945.559	125.521
0.7536	2945.596	125.526
0.7539	2945.647	125.498
0.7542	2945.746	125.516
0.7544	2945.845	125.496
0.7547	2945.852	125.506
0.7550	2945.953	125.503
0.7553	2945.980	125.496
0.7556	2945.995	125.496
0.7558	2946.076	125.501
0.7561	2946.059	125.488
0.7564	2946.064	125.481
0.7567	2946.118	125.498
0.7569	2946.123	125.486
0.7583	2946.342	125.470
0.7597	2946.994	125.450
0.7611	2947.771	125.445
0.7625	2948.461	125.420
0.7639	2948.858	125.415
0.7653	2948.980	125.385
0.7667	2949.150	125.372
0.7681	2949.417	125.321
0.7694	2949.969	125.326
0.7708	2950.390	125.296
0.7722	2950.584	125.268
0.7736	2950.593	125.258
0.7750	2950.695	125.213
0.7764	2950.717	125.190
0.7778	2951.029	125.167
0.7792	2951.606	125.142
0.7806	2952.135	125.124
0.7819	2952.151	125.081
0.7833	2952.090	125.053
0.7847	2952.004	125.023
0.7861	2952.313	124.987
0.7875	2952.483	124.937
0.7889	2952.800	124.912

Time	Pressure (Psia)	Temperature (°F)
0.7903	2952.953	124.876
0.7917	2953.042	124.838
0.7931	2953.086	124.805
0.7944	2953.169	124.767
0.7958	2953.278	124.722
0.7972	2953.527	124.696
0.7986	2953.581	124.643
0.8000	2953.920	124.613
0.8014	2954.069	124.575
0.8028	2954.117	124.534
0.8042	2954.151	124.494
0.8056	2954.156	124.443
0.8069	2954.193	124.405
0.8083	2954.189	124.370
0.8097	2954.570	124.316
0.8111	2954.921	124.278
0.8125	2955.347	124.235
0.8139	2955.368	124.169
0.8153	2955.231	124.152
0.8167	2954.919	124.093
0.8181	2955.019	124.053
0.8194	2955.359	123.997
0.8208	2955.763	123.954
0.8222	2955.726	123.901
0.8236	2955.528	123.855
0.8250	2955.282	123.797
0.8264	2955.435	123.761
0.8278	2955.962	123.700
0.8292	2956.361	123.660
0.8306	2956.432	123.604
0.8319	2956.200	123.566
0.8333	2955.780	123.500
0.8347	2955.514	123.459
0.8361	2955.708	123.406
0.8375	2956.395	123.342
0.8389	2956.842	123.304
0.8403	2957.140	123.251
0.8417	2956.879	123.198
0.8431	2956.312	123.144
0.8444	2956.119	123.076
0.8458	2956.432	123.027
0.8472	2957.045	122.997
0.8486	2957.226	122.903
0.8500	2957.202	122.875
0.8514	2956.952	122.814
0.8528	2956.556	122.761
0.8542	2956.357	122.715
0.8556	2957.170	122.651
0.8569	2957.904	122.611
0.8583	2958.026	122.544
0.8597	2957.821	122.483
0.8611	2957.392	122.422
0.8625	2956.841	122.382
0.8639	2956.793	122.305
0.8653	2956.997	122.265
0.8667	2957.455	122.198
0.8681	2957.569	122.132
0.8694	2957.542	122.081
0.8708	2957.231	122.020
0.8722	2957.063	121.959
0.8736	2957.150	121.916
0.8750	2957.417	121.852
0.8764	2957.461	121.788
0.8778	2957.437	121.725
0.8792	2957.331	121.681
0.8806	2957.143	121.613
0.8819	2957.406	121.557
0.8833	2957.795	121.501
0.8847	2957.838	121.442
0.8861	2957.710	121.383
0.8875	2957.324	121.322
0.8889	2957.073	121.256
0.8903	2957.414	121.192
0.8917	2957.747	121.138
0.8931	2957.890	121.072
0.8944	2957.880	121.019
0.8958	2957.673	120.957
0.8972	2957.375	120.911
0.8986	2957.168	120.830
0.9000	2957.337	120.771
0.9014	2957.499	120.723
0.9028	2957.574	120.656
0.9042	2957.307	120.595
0.9056	2956.637	120.528
0.9069	2955.792	120.460
0.9083	2955.081	120.411
0.9097	2954.180	120.355
0.9111	2953.331	120.288
0.9125	2952.516	120.219
0.9139	2951.436	120.143
0.9153	2950.818	120.112
0.9167	2950.159	120.028
0.9181	2950.051	119.984
0.9194	2950.249	119.915
0.9208	2950.860	119.869
0.9222	2951.833	119.800
0.9236	2952.802	119.754
0.9250	2953.647	119.649
0.9264	2954.265	119.613
0.9278	2955.349	119.565
0.9292	2956.813	119.501
0.9306	2958.861	119.439
0.9319	2960.637	119.391
0.9333	2961.325	119.311
0.9347	2961.391	119.255
0.9361	2960.984	119.186
0.9375	2960.515	119.150
0.9389	2959.948	119.083
0.9403	2959.645	119.019
0.9417	2959.294	118.973
0.9431	2958.920	118.901
0.9444	2958.670	118.832
0.9458	2958.468	118.791
0.9472	2958.429	118.740
0.9486	2958.353	118.668
0.9500	2958.032	118.627
0.9514	2957.896	118.545
0.9528	2957.842	118.463
0.9542	2958.121	118.440
0.9556	2958.234	118.381
0.9569	2958.132	118.312
0.9583	2957.911	118.268
0.9597	2957.622	118.204
0.9611	2957.602	118.140
0.9625	2957.599	118.073
0.9639	2957.851	118.027
0.9653	2957.711	117.963
0.9667	2957.627	117.927
0.9681	2957.565	117.850
0.9694	2957.845	117.783
0.9708	2958.126	117.737
0.9722	2958.239	117.678
0.9736	2958.267	117.631
0.9750	2958.097	117.572
0.9764	2957.674	117.513
0.9778	2957.626	117.457
0.9792	2958.149	117.403
0.9806	2958.800	117.325
0.9819	2959.014	117.290
0.9833	2958.896	117.225
0.9847	2958.507	117.179
0.9861	2958.154	117.127
0.9875	2957.775	117.063
0.9889	2957.828	117.019
0.9903	2958.438	116.955
0.9917	2958.908	116.906
0.9931	2958.983	116.852
0.9944	2958.689	116.796
0.9958	2958.214	116.747
0.9972	2957.764	116.690
0.9986	2957.772	116.631
1.0000	2958.427	116.577
1.0014	2959.110	116.551
1.0028	2959.156	116.469
1.0042	2958.985	116.389
1.0056	2958.925	116.345
1.0069	2960.832	116.339
1.0083	2962.101	116.333
1.0097	2964.754	116.327
1.0111	2966.967	116.255
1.0125	2968.985	116.211
1.0139	2970.896	116.180
1.0153	2972.739	116.137
1.0167	2974.210	116.095
1.0181	2976.977	116.049
1.0194	2978.117	115.998
1.0208	2980.255	115.952
1.0222	2982.153	115.911
1.0236	2984.456	115.832
1.0250	2986.898	115.721
1.0264	2988.887	115.525
1.0278	2993.896	115.296
1.0292	2995.964	115.027
1.0306	2997.171	114.998
1.0319	2999.813	114.735
1.0333	3001.492	115.290
1.0347	3011.142	115.320
1.0361	3015.741	115.377
1.0375	3007.901	116.068
1.0389	3018.019	116.347
1.0403	3018.755	117.125
1.0417	3018.801	117.119
1.0431	3017.091	117.473
1.0444	3017.476	117.980
1.0458	3017.145	117.703
1.0472	3017.984	117.881
1.0486	3012.824	117.259
1.0500	3012.926	117.698
1.0514	3013.444	117.466
1.0528	3013.021	117.467
1.0542	3015.803	117.279
1.0556	3018.625	117.169
1.0569	3014.113	117.325
1.0583	3018.374	116.198
1.0597	3017.375	116.322
1.0611	3016.556	116.394
1.0625	3018.841	116.978
1.0639	3013.757	116.861
1.0653	3017.574	117.857
1.0667	3016.946	117.635
1.0681	3017.526	117.771
1.0694	3018.244	117.516
1.0708	3019.199	116.794
1.0722	3019.124	116.383
1.0736	3019.331	116.438
1.0742	3019.550	116.744
1.0783	3018.981	116.123
1.0825	3016.417	115.808
1.0867	3020.184	115.714
1.0908	3020.730	115.556
1.0950	3018.411	111.400
1.0992	3021.348	111.126
1.1033	3018.552	111.506
1.1075	3019.752	111.173
1.1117	3019.509	111.124
1.1158	3018.809	110.957
1.1200	3021.578	110.478
1.1242	3020.136	109.912
1.1283	3020.964	109.987
1.1325	3021.163	109.687
1.1367	3020.681	109.491
1.1408	3021.506	108.302
1.1450	3024.089	107.316
1.1492	3023.971	105.586
1.1533	3023.281	105.557

Time	Pressure (Psia)	Temperature (°F)
1.1575	3023.140	106.178
1.1617	3023.929	107.811
1.1658	3024.548	107.693
1.1700	3023.795	107.720
1.1742	3023.765	107.105
1.1783	3023.355	106.822
1.1825	3024.549	106.277
1.1867	3025.226	105.650
1.1908	3026.732	105.276
1.1950	3024.874	105.712
1.1992	3027.866	105.525
1.2033	3025.389	105.162
1.2075	3025.660	104.956
1.2117	3025.544	104.650
1.2158	3025.892	104.426
1.2200	3026.531	104.151
1.2242	3024.534	103.890
1.2283	3025.066	103.615
1.2325	3025.537	103.493
1.2367	3025.488	103.102
1.2408	3026.308	102.850
1.2450	3025.981	102.585
1.2492	3025.807	102.578
1.2533	3026.400	102.114
1.2575	3026.094	101.867
1.2617	3025.542	101.700
1.2658	3028.294	101.440
1.2700	3026.430	101.187
1.2742	3028.150	100.922
1.2783	3028.556	100.696
1.2825	3028.904	100.483
1.2867	3027.725	100.185
1.2908	3027.367	99.996
1.2950	3027.972	99.941
1.2992	3029.438	99.524
1.3033	3029.510	99..570
1.3075	3029.722	99.386
1.3117	3030.407	98.881
1.3158	3027.983	98.609
1.3200	3027.677	98.406
1.3242	3028.238	98.230
1.3283	3028.190	98.080
1.3325	3029.915	97.797
1.3367	3030.180	97.633
1.3408	3030.952	97.616
1.3450	3031.439	97.160
1.3492	3029.839	96.921
1.3533	3029.834	96.720
1.3575	3032.410	96.490
1.3617	3030.239	96.299
1.3658	3032.472	96.084
1.3700	3034.314	95.870
1.3742	3032.960	95.671
1.3783	3031.984	95.469
1.3825	3033.338	95.335
1.3867	3034.104	94.999
1.3908	3032.794	94.889
1.3950	3033.671	94.765
1.3992	3033.674	94.320
1.4033	3033.823	94.326
1.4058	3035.134	94.186
1.4142	3033.250	93.776
1.4225	3035.015	93.296
1.4308	3034.955	93.005
1.4392	3035.091	92.594
1.4475	3037.052	92.270
1.4514	3035.447	92.118
1.4597	3037.855	91.782
1.4681	3035.232	91.517
1.4764	3035.322	91.674
1.4847	3036.387	90.845
1.4931	3038.930	90.623
1.5014	3037.500	90.405
1.5097	3037.682	90.215
1.5181	3038.093	89.995

Time	Pressure (Psia)	Temperature (°F)
1.5264	3038.751	89.824
1.5347	3038.824	89.686
1.5431	3036.912	89.571
1.5514	3036.623	89.490
1.5597	3037.738	89.373
1.5681	3036.297	89.286
1.5764	3037.434	89.394
1.5847	3035.125	89.082
1.5931	3035.666	89.038
1.6014	3037.004	89.003
1.6097	3035.659	88.916
1.6181	3038.110	88.829
1.6264	3039.499	88.961
1.6347	3037.330	88.752
1.6431	3037.409	88.583
1.6514	3040.908	88.510
1.6597	3038.173	88.412
1.6681	3037.366	88.284
1.6764	3038.583	88.232
1.6847	3038.404	88.090
1.6931	3039.049	87.850
1.7014	3039.678	87.796
1.7097	3039.370	87.637
1.7181	3040.737	87.512
1.7264	3039.796	87.373
1.7347	3038.973	87.184
1.7431	3040.045	87.017
1.7514	3039.806	86.903
1.7597	3039.804	86.766
1.7681	3040.195	86.673
1.7764	3039.878	86.473
1.7847	3038.912	86.356
1.7931	3038.322	86.328
1.8014	3039.569	86.241
1.8097	3038.612	86.090
1.8181	3038.244	85.907
1.8264	3038.553	85.855
1.8347	3038.958	85.721
1.8431	3039.434	85.630
1.8514	3039.398	85.526
1.8597	3040.171	85.441
1.8681	3041.009	85.359
1.8764	3041.993	85.318
1.8847	3037.846	85.175
1.8931	3036.729	85.327
1.9014	3034.890	85.085
1.9097	3035.590	84.925
1.9181	3036.662	84.873
1.9264	3036.072	84.020
1.9347	3037.825	84.785
1.9431	3038.485	84.799
1.9514	3038.499	84.684
1.9597	3038.805	84.645
1.9681	3041.017	84.591
1.9764	3039.103	84.544
1.9847	3040.425	84.522
1.9931	3042.733	84.500
2.0014	3043.406	84.407
2.0097	3040.577	84.398
2.0181	3045.565	84.913
2.0264	3042.995	84.321
2.0347	3043.057	84.723
2.0431	3044.380	84.231
2.0514	3042.977	84.102
2.0597	3045.221	84.192
2.0681	3044.350	84.168
2.0764	3045.273	84.137
2.0847	3045.161	84.099
2.0931	3041.219	84.030
2.1014	3042.338	84.113
2.1097	3042.890	84.014
2.1181	3043.374	83.994
2.1264	3042.878	83.978
2.1347	3041.991	83.975
2.1431	3039.606	83.382

Time	Pressure (Psia)	Temperature (°F)
2.1514	3041.945	83.582
2.1597	3043.861	83.937
2.1681	3041.760	83.981
2.1764	3043.330	83.917
2.1847	3042.952	83.956
2.1931	3043.226	83.538
2.2014	3042.726	83.909
2.2097	3043.066	83.917
2.2181	3043.071	83.162
2.2264	3043.461	83.417
2.2347	3043.209	83.699
2.2431	3043.886	83.931
2.2514	3042.495	83.926
2.2597	3044.604	83.989
2.2681	3044.086	83.950
2.2764	3043.688	83.753
2.2847	3042.371	83.989
2.2931	3043.476	83.994
2.3014	3045.483	83.948
2.3097	3045.507	84.000
2.3181	3044.056	84.005
2.3264	3045.295	84.137
2.3347	3044.419	84.033
2.3431	3045.022	84.000
2.3514	3044.383	84.258
2.3597	3043.324	84.077
2.3681	3042.898	84.077
2.3764	3041.400	84.195
2.3847	3041.271	84.397
2.3931	3042.685	84.484
2.4014	3043.691	84.191
2.4097	3043.496	84.297
2.4181	3042.208	84.228
2.4264	3041.602	84.297
2.4347	3041.343	84.310
2.4431	3041.845	84.360
2.4514	3042.751	84.228
2.4597	3041.123	84.277
2.4681	3043.033	84.255
2.4764	3042.552	84.165
2.4847	3041.961	84.449
2.4931	3043.229	84.121
2.5014	3042.517	84.066
2.5097	3042.448	84.091
2.5181	3041.935	83.992
2.5264	3042.856	83.945
2.5347	3043.422	83.901
2.5431	3041.623	83.857
2.5514	3044.156	83.761
2.5597	3044.138	83.711
2.5681	3043.213	83.667
2.5764	3043.504	83.585
2.5847	3044.707	83.576
2.5931	3044.258	83.447
2.6014	3043.549	83.464
2.6097	3044.815	83.414
2.6181	3045.537	83.312
2.6264	3046.855	83.296
2.6347	3043.623	83.221
2.6431	3043.977	83.656
2.6514	3043.534	83.133
2.6597	3042.998	83.100
2.6681	3044.393	83.056
2.6764	3043.873	83.252
2.6847	3042.308	83.252
2.6931	3043.370	83.131
2.7014	3042.106	83.147
2.7097	3042.819	82.861
2.7181	3045.122	82.852
2.7264	3043.116	82.167
2.7347	3044.347	82.862
2.7431	3044.093	82.811
2.7514	3043.776	82.657
2.7597	3043.144	82.615
2.7681	3042.837	82.778

Time	Pressure (Psia)	Temperature (°F)
2.7764	3044.088	82.728
2.7847	3043.743	82.972
2.7931	3043.438	82.000
2.8014	3041.471	82.624
2.8097	3042.180	82.739
2.8181	3043.030	82.329
2.8264	3043.897	82.025
2.8347	3043.851	82.665
2.8431	3043.827	82.646
2.8514	3043.657	82.704
2.8597	3042.292	82.759
2.8681	3043.461	82.720
2.8764	3042.224	82.772
2.8847	3044.702	82.912
2.8931	3042.674	82.748
2.9014	3042.667	82.726
2.9097	3042.508	82.753
2.9181	3043.637	82.511
2.9264	3041.833	82.753
2.9347	3042.665	82.411
2.9431	3041.757	82.814
2.9514	3042.854	82.593
2.9597	3042.363	82.717
2.9681	3044.638	82.830
2.9764	3044.493	82.087
2.9847	3043.438	82.367
2.9931	3043.282	82.872
3.0014	3041.746	82.186
3.0097	3040.899	82.833
3.0181	3041.585	82.951
3.0264	3042.053	82.954
3.0347	3040.582	82.913
3.0431	3041.713	83.034
3.0514	3041.299	83.062
3.0597	3042.729	83.064
3.0644	3042.914	83.380
3.0811	3043.342	83.180
3.0978	3042.185	83.252
3.1144	3043.144	83.610
3.1311	3044.276	83.758
3.1478	3044.367	83.788
3.1644	3045.007	83.810
3.1811	3045.209	83.214
3.1978	3046.833	83.656
3.2144	3049.644	83.964
3.2311	3046.539	84.394
3.2478	3050.614	84.244
3.2644	3049.021	84.151
3.2811	3048.756	84.574
3.2978	3047.335	84.750
3.3133	3049.331	84.997
3.3300	3048.990	84.873
3.3467	3049.280	85.038
3.3633	3047.765	84.871
3.3800	3048.272	85.008
3.3967	3049.124	85.019
3.4133	3049.177	85.038
3.4300	3049.410	85.052
3.4467	3049.138	85.052
3.4633	3049.792	85.158
3.4800	3049.545	86.048
3.4967	3049.490	85.952
3.5133	3049.762	85.723
3.5300	3049.841	85.308
3.5467	3048.697	85.074
3.5633	3049.177	85.368
3.5800	3047.381	85.378
3.5967	3049.007	85.019
3.6133	3049.731	85.180
3.6300	3049.625	85.661
3.6467	3050.298	85.159
3.6633	3049.042	85.148
3.6800	3048.232	85.139
3.6967	3049.957	85.183
3.7133	3049.163	85.268

Time	Pressure (Psia)	Temperature (°F)
3.7300	3052.430	85.282
3.7467	3051.838	85.257
3.7633	3051.778	85.216
3.7800	3050.998	85.282
3.7967	3050.755	85.608
3.8133	3054.032	85.397
3.8300	3053.021	85.414
3.8467	3052.927	85.739
3.8633	3053.045	85.504
3.8800	3051.540	85.564
3.8967	3054.196	85.685
3.9133	3052.310	85.723
3.9300	3053.646	85.479
3.9467	3052.703	86.174
3.9633	3051.997	86.008
3.9800	3052.528	86.454
3.9967	3053.634	86.317
4.0133	3052.678	86.224
4.0300	3051.165	86.153
4.0467	3051.147	87.085
4.0633	3050.755	87.012
4.0800	3050.658	87.173
4.0967	3051.353	87.378
4.1133	3053.614	87.392
4.1300	3055.224	87.463
4.1467	3050.471	87.386
4.1633	3052.273	87.446
4.1800	3051.510	87.304
4.1967	3050.180	87.405
4.2133	3049.304	87.045
4.2300	3051.355	86.864
4.2467	3050.774	86.673
4.2633	3050.729	86.534
4.2800	3051.275	86.348
4.2967	3052.208	86.194
4.3133	3053.225	86.049
4.3300	3054.157	85.896
4.3467	3052.284	85.729
4.3633	3051.154	85.767
4.3800	3049.935	85.611
4.3967	3049.195	85.493
4.4133	3049.593	85.430
4.4300	3051.028	85.375
4.4467	3049.987	85.403
4.4633	3049.325	85.246
4.4800	3048.921	85.183
4.4803	3050.515	85.268
4.4969	3049.733	85.252
4.5136	3048.830	85.145
4.5303	3048.368	85.175
4.5469	3049.562	85.244
4.5636	3051.426	85.194
4.5803	3050.590	85.213
4.5969	3049.895	85.271
4.6136	3053.192	85.255
4.6303	3052.078	85.312
4.6469	3052.681	85.353
4.6636	3051.436	85.463
4.6803	3048.765	85.562
4.6969	3050.467	85.564
4.7136	3050.647	85.737
4.7303	3051.339	85.838
4.7469	3051.653	86.057
4.7636	3050.594	86.181
4.7803	3051.686	86.298
4.7969	3051.355	86.440
4.8136	3050.615	86.539
4.8303	3047.648	86.605
4.8469	3047.671	86.695
4.8636	3049.646	86.709
4.8803	3050.338	86.758
4.8969	3051.481	86.752
4.9136	3051.716	86.763
4.9303	3053.402	86.791
4.9469	3051.347	86.725

Time	Pressure (Psia)	Temperature (°F)
4.9636	3050.159	86.700
4.9803	3046.631	86.689
4.9969	3045.079	86.670
5.0136	3045.848	86.624
5.0303	3048.133	86.646
5.0469	3048.508	86.575
5.0636	3048.016	86.564
5.0803	3049.940	86.577
5.0969	3050.082	86.605
5.1136	3050.649	86.553
5.1303	3051.024	86.512
5.1469	3049.343	86.479
5.1636	3050.472	86.523
5.1803	3049.409	86.509
5.1969	3051.556	86.539
5.2136	3049.948	86.536
5.2303	3050.280	86.575
5.2469	3049.901	86.580
5.2636	3051.438	86.640
5.2803	3053.698	86.657
5.2969	3052.255	86.719
5.3136	3052.829	86.780
5.3303	3052.729	86.867
5.3469	3052.330	86.930
5.3636	3051.326	86.985
5.3803	3049.407	87.105
5.3969	3051.986	87.247
5.4136	3053.035	87.310
5.4303	3052.592	87.531
5.4469	3055.729	87.752
5.4636	3054.580	87.313
5.4803	3055.518	88.338
5.4969	3056.766	88.281
5.5136	3058.369	88.515
5.5303	3056.976	88.624
5.5469	3054.276	88.712
5.5636	3055.348	88.657
5.5803	3057.091	88.600
5.5969	3057.154	88.420
5.6136	3057.515	88.235
5.6303	3056.112	88.066
5.6469	3056.574	87.823
5.6636	3057.765	87.615
5.6803	3056.989	87.463
5.6969	3059.323	87.250
5.7136	3052.330	87.080
5.7303	3055.072	86.930
5.7469	3054.807	86.799
5.7636	3056.186	86.621
5.7803	3056.285	86.525
5.7969	3059.622	86.312
5.8136	3059.826	86.457
5.8303	3059.311	86.233
5.8389	3058.792	86.167
5.8556	3057.597	86.142
5.8722	3056.813	86.098
5.8889	3059.578	86.044
5.9056	3057.426	85.970
5.9222	3058.054	85.923
5.9389	3056.522	85.940
5.9556	3057.658	85.923
5.9722	3056.761	85.882
5.9889	3055.153	85.920
6.0056	3055.280	85.940
6.0222	3057.643	85.923
6.0389	3060.250	85.978
6.0556	3054.375	86.033
6.0722	3055.430	86.098
6.0889	3055.999	86.208
6.1056	3057.295	86.276
6.1222	3059.083	86.438
6.1389	3057.820	86.558
6.1556	3057.509	86.763
6.1722	3057.783	86.933
6.1889	3058.601	87.151

Time	Pressure (Psia)	Temperature (°F)
6.2056	3058.084	87.394
6.2222	3058.719	87.637
6.2389	3057.404	87.894
6.2556	3058.265	88.197
6.2722	3057.987	88.398
6.2889	3058.386	88.551
6.3056	3057.976	88.703
6.3222	3060.124	88.684
6.3389	3060.048	88.793
6.3556	3060.656	88.758
6.3722	3060.785	88.638
6.3889	3058.583	88.592
6.4056	3056.252	88.475
6.4222	3060.231	88.379
6.4389	3058.454	88.267
6.4556	3058.410	88.180
6.4722	3057.377	88.047
6.4889	3057.845	87.992
6.5056	3059.517	87.899
6.5222	3061.076	87.831
6.5389	3059.939	87.738
6.5556	3059.673	87.651
6.5722	3061.874	87.667
6.5889	3060.659	87.561
6.6056	3060.060	87.525
6.6222	3057.875	87.457
6.6389	3059.385	87.435
6.6556	3060.672	87.424
6.6722	3059.781	87.337
6.6889	3061.686	87.345
6.7056	3061.056	87.433
6.7222	3060.234	87.400
6.7389	3062.373	87.482
6.7556	3061.115	87.452
6.7722	3060.753	87.515
6.7889	3059.322	87.539
6.8056	3059.726	87.599
6.8222	3061.977	87.678
6.8389	3060.193	87.763
6.8556	3060.230	87.842
6.8722	3059.938	87.976
6.8889	3057.843	88.142
6.9056	3060.619	88.284
6.9222	3062.188	88.436
6.9389	3059.951	88.660
6.9556	3057.811	88.842
6.9722	3058.086	88.973
6.9889	3060.646	89.125
7.0056	3055.850	89.229
7.0222	3056.868	89.272
7.0389	3057.698	89.332
7.0556	3059.821	89.376
7.0722	3061.181	89.406
7.0889	3059.448	89.362
7.1056	3060.363	89.435
7.1075	3058.949	89.446
7.1242	3059.304	89.425
7.1408	3060.328	89.433
7.1575	3061.714	89.571
7.1742	3062.085	89.493
7.1908	3061.729	89.529
7.2075	3061.807	89.877
7.2242	3062.704	89.520
7.2408	3061.664	89.230
7.2575	3061.543	89.152
7.2742	3061.263	89.040
7.2908	3063.188	89.672
7.3075	3061.533	89.691
7.3242	3062.009	89.740
7.3408	3062.764	89.735
7.3575	3065.635	89.941
7.3742	3063.368	89.941
7.3908	3060.067	90.012
7.4075	3060.302	90.115
7.4242	3060.878	90.215

Time	Pressure (Psia)	Temperature (°F)
7.4408	3060.812	90.308
7.4575	3060.811	90.615
7.4742	3060.176	90.617
7.4908	3059.929	90.631
7.5075	3057.564	90.861
7.5242	3061.129	91.062
7.5408	3061.180	91.208
7.5575	3060.650	91.909
7.5742	3060.746	91.975
7.5908	3060.177	91.590
7.6075	3060.307	91.674
7.6242	3062.727	91.723
7.6408	3059.009	91.739
7.6575	3058.792	91.726
7.6742	3058.808	91.769
7.6908	3060.375	91.780
7.7075	3056.728	91.799
7.7242	3059.133	91.777
7.7408	3056.258	91.834
7.7575	3058.459	91.799
7.7742	3056.764	91.476
7.7908	3056.631	91.077
7.8075	3058.991	91.842
7.8242	3059.292	91.869
7.8408	3058.386	91.985
7.8575	3058.021	91.991
7.8742	3058.444	91.512
7.8908	3058.608	92.021
7.9075	3058.002	92.067
7.9242	3057.604	92.280
7.9408	3057.931	92.215
7.9575	3057.931	92.251
7.9742	3060.932	92.318
7.9908	3058.629	92.903
8.0075	3057.258	92.475
8.0242	3060.492	92.440
8.0408	3060.750	92.616
8.0575	3059.308	92.718
8.0742	3059.817	92.824
8.0908	3057.458	92.894
8.1075	3057.320	92.219
8.1242	3057.928	92.345
8.1408	3058.671	92.994
8.1575	3058.861	93.283
8.1742	3058.028	93.648
8.1908	3058.168	93.585
8.2075	3058.067	93.771
8.2242	3059.409	93.916
8.2408	3059.373	94.035
8.2575	3063.637	94.226
8.2742	3063.749	94.927
8.2908	3064.091	94.898
8.3075	3063.377	95.155
8.3242	3063.190	95.155
8.3408	3062.925	95.381
8.3575	3063.098	95.970
8.3742	3062.569	95.714
8.3908	3059.613	95.348
8.4075	3060.685	95.940
8.4242	3061.353	95.756
8.4408	3061.834	95.534
8.4575	3062.265	95.347
8.4742	3061.771	94.751
8.4908	3062.548	94.690
8.5075	3062.693	94.443
8.5242	3062.338	93.930
8.5408	3063.956	93.556
8.5575	3063.528	93.194
8.5742	3063.386	92.725
8.5908	3062.462	92.656
8.6075	3065.505	92.418
8.6242	3063.634	92.686
8.6408	3061.454	92.053
8.6575	3059.610	91.977
8.6742	3055.146	91.574

Time	Pressure (Psia)	Temperature (°F)
8.6908	3057.271	91.495
8.7075	3055.253	91.352
8.7242	3057.361	91.295
8.7408	3057.642	91.195
8.7575	3058.939	91.075
8.7742	3061.209	91.000
8.7908	3059.166	91.013
8.8075	3058.057	90.964
8.8242	3058.193	90.812
8.8408	3056.277	90.823
8.8575	3056.803	90.900
8.8742	3058.675	90.062
8.8908	3060.719	90.766
8.9075	3061.221	90.810
8.9242	3061.086	90.850
8.9408	3060.782	90.403
8.9575	3061.430	90.703
8.9742	3059.534	91.021
8.9908	3062.381	91.162
9.0075	3061.406	91.238
9.0242	3060.401	91.387
9.0408	3061.894	91.571
9.0575	3062.645	91.815
9.0742	3063.075	92.026
9.0908	3063.479	92.286
9.1075	3065.755	92.613
9.1242	3066.590	92.918
9.1408	3063.935	93.261
9.1575	3065.623	93.650
9.1742	3067.499	93.946
9.1908	3068.557	94.216
9.2075	3068.100	94.436
9.2242	3067.748	94.485
9.2408	3067.413	94.480
9.2575	3065.157	94.412
9.2742	3066.536	94.318
9.2908	3067.631	94.170
9.3075	3065.674	93.968
9.3242	3069.410	93.747
9.3408	3067.098	93.528
9.3575	3066.980	93.364
9.3742	3068.198	93.126
9.3908	3066.476	92.940
9.4075	3068.926	92.778
9.4242	3067.596	92.553
9.4408	3065.438	92.410
9.4575	3066.773	92.213
9.4742	3066.150	92.156
9.4908	3062.874	92.091
9.5075	3066.233	91.939
9.5242	3065.744	91.969
9.5408	3066.357	91.904
9.5575	3065.514	91.845
9.5742	3066.710	91.788
9.5908	3068.191	91.761
9.6075	3066.280	91.728
9.6242	3066.925	91.777
9.6408	3068.180	91.755
9.6575	3067.760	91.774
9.6742	3068.075	91.758
9.6908	3067.114	91.717
9.7075	3066.758	91.810
9.7242	3068.269	91.926
9.7408	3067.216	91.926
9.7575	3068.622	91.945
9.7742	3068.853	92.013
9.7908	3064.671	91.967
9.8075	3064.622	92.159
9.8242	3066.186	92.459
9.8408	3066.512	92.261
9.8575	3065.120	92.386
9.8742	3066.778	92.562
9.8908	3067.148	92.586
9.9075	3066.679	92.645
9.9242	3067.773	92.834

Time	Pressure (Psia)	Temperature (°F)
9.9408	3067.109	92.897
9.9575	3067.073	93.202
9.9742	3066.307	93.315
9.9908	3066.481	93.404
10.0075	3068.025	93.590
10.0242	3068.577	94.022
10.0408	3066.137	93.935
10.0575	3066.909	94.178
10.0742	3065.875	94.315
10.0908	3068.625	94.375
10.1075	3068.123	94.528
10.1242	3067.381	94.407
10.1408	3067.812	94.275
10.1575	3068.601	94.224
10.1742	3066.908	94.059
10.1908	3067.231	93.854
10.2075	3067.318	93.650
10.2242	3064.288	93.539
10.2408	3064.215	93.339
10.2575	3063.793	93.194
10.2742	3064.216	93.372
10.2908	3065.438	92.807
10.3075	3069.127	92.713
10.3242	3067.208	92.345
10.3408	3070.536	92.383
10.3575	3067.712	92.253
10.3742	3068.163	92.029
10.3908	3067.055	92.004
10.4075	3069.578	92.099
10.4242	3068.679	91.785
10.4408	3071.913	91.820
10.4575	3073.201	91.677
10.4742	3072.445	91.647
10.4908	3072.565	91.878
10.5075	3073.824	91.711
10.5242	3074.177	91.590
10.5408	3071.608	91.471
10.5575	3070.959	91.509
10.5742	3070.764	91.531
10.5908	3073.096	91.506
10.6075	3071.159	91.653
10.6242	3072.777	91.682
10.6408	3071.086	91.746
10.6575	3070.939	91.948
10.6742	3070.328	92.056
10.6908	3071.822	92.307
10.7075	3072.232	92.656
10.7242	3069.797	92.678
10.7408	3071.714	93.072
10.7575	3071.573	93.196
10.7742	3068.343	93.391
10.7908	3069.877	93.493
10.8075	3067.356	93.520
10.8242	3068.069	93.582
10.8408	3069.349	93.428
10.8575	3067.341	93.516
10.8742	3065.518	93.053
10.8908	3066.575	92.848
10.9075	3065.131	92.540
10.9242	3065.492	92.310
10.9408	3066.298	91.905
10.9575	3068.507	91.923
10.9742	3067.556	91.617
10.9908	3066.910	91.425
11.0075	3070.101	91.214
11.0242	3072.009	90.964
11.0408	3071.600	90.897
11.0575	3068.523	90.739
11.0742	3068.605	90.571
11.0908	3068.361	90.452
11.1075	3069.621	90.376
11.1242	3068.267	90.245
11.1408	3070.100	90.142
11.1575	3068.823	90.090
11.1742	3067.900	90.001
11.1908	3068.090	89.974
11.2075	3069.125	89.968
11.2242	3068.899	89.947
11.2408	3068.394	89.933
11.2575	3066.408	89.903
11.2742	3068.777	89.952
11.2908	3069.252	89.985
11.3075	3067.561	90.020
11.3242	3066.398	90.066
11.3408	3067.536	90.126
11.3575	3066.323	90.237
11.3742	3067.538	90.226
11.3908	3065.623	90.367
11.4075	3069.189	90.419
11.4242	3067.737	90.571
11.4408	3069.502	90.758
11.4575	3068.592	90.910
11.4742	3068.419	91.162
11.4908	3067.618	91.206
11.5075	3068.415	91.422
11.5242	3069.106	91.615
11.5408	3069.803	92.031
11.5575	3070.423	92.315
11.5742	3072.575	92.456
11.5908	3070.472	92.664
11.6075	3069.708	92.156
11.6242	3070.427	92.691
11.6408	3071.865	92.575
11.6575	3071.152	92.191
11.6742	3067.785	91.985
11.6908	3069.490	91.685
11.7075	3070.776	91.390
11.7242	3070.897	91.272
11.7408	3071.436	90.538
11.7575	3072.568	90.139
11.7742	3072.516	89.773
11.7908	3068.239	89.318
11.8075	3068.467	89.226
11.8242	3068.557	88.613
11.8408	3068.895	88.352
11.8575	3068.670	88.082
11.8742	3069.740	87.831
11.8908	3069.286	87.689
11.9075	3070.070	87.444
11.9242	3070.297	87.244
11.9408	3070.239	87.072
11.9575	3070.832	86.884
11.9742	3070.095	86.025
11.9908	3070.566	86.692
12.0075	3070.772	86.446
12.0242	3069.519	86.389
12.0408	3070.886	86.265
12.0575	3071.867	86.230
12.0742	3073.390	86.186
12.0908	3073.844	86.096
12.1075	3072.016	86.030
12.1242	3073.813	86.014
12.1408	3073.938	85.953
12.1575	3073.434	85.948
12.1742	3072.785	85.899
12.1908	3074.881	85.929
12.2075	3075.575	85.893
12.2242	3074.177	85.948
12.2408	3074.501	85.915
12.2575	3072.843	85.983
12.2742	3074.960	86.087
12.2908	3074.526	86.559
12.3075	3074.018	86.202
12.3242	3074.554	86.265
12.3408	3073.849	86.337
12.3575	3074.641	86.391
12.3742	3074.731	86.482
12.3908	3075.619	86.575
12.4075	3073.700	86.462
12.4242	3074.443	86.781
12.4408	3075.559	86.577
12.4575	3074.530	86.618
12.4742	3074.979	86.607
12.4908	3074.833	86.575
12.5075	3076.600	86.643
12.5242	3075.087	86.498
12.5408	3075.438	86.064
12.5575	3075.022	86.465
12.5742	3075.219	86.446
12.5908	3075.122	86.367
12.6075	3074.793	86.353
12.6242	3046.591	86.339
12.6408	3011.372	86.287
12.6433	3015.056	86.427
12.6436	3015.329	86.175
12.6439	3016.249	86.435
12.6442	3017.002	86.369
12.6444	3017.489	86.167
12.6447	3017.918	86.735
12.6450	3019.651	86.525
12.6453	3020.694	86.317
12.6456	3021.832	86.484
12.6458	3022.917	86.424
12.6461	3023.740	86.304
12.6464	3024.128	86.296
12.6467	3025.468	86.375
12.6469	3026.277	86.263
12.6472	3026.679	86.337
12.6475	3027.435	86.317
12.6478	3028.048	86.334
12.6481	3028.619	86.328
12.6483	3029.769	86.274
12.6486	3030.742	86.399
12.6489	3030.997	86.293
12.6492	3032.000	86.298
12.6494	3032.051	86.298
12.6497	3032.223	86.326
12.6500	3034.044	86.378
12.6503	3034.468	86.320
12.6506	3035.256	86.309
12.6508	3035.795	86.306
12.6511	3035.959	86.383
12.6514	3035.105	86.304
12.6517	3035.654	86.287
12.6519	3036.930	86.353
12.6522	3037.325	86.304
12.6525	3038.330	86.246
12.6528	3037.590	86.405
12.6531	3037.941	86.326
12.6533	3038.054	86.334
12.6536	3037.840	86.334
12.6539	3040.107	86.290
12.6542	3040.824	86.555
12.6544	3041.117	86.408
12.6547	3041.216	86.290
12.6550	3039.648	86.315
12.6553	3039.240	86.279
12.6556	3041.112	86.304
12.6558	3041.673	86.380
12.6561	3042.608	86.298
12.6564	3042.223	86.331
12.6567	3040.360	86.153
12.6569	3041.516	86.383
12.6572	3044.474	86.410
12.6575	3044.411	86.356
12.6578	3043.845	86.304
12.6581	3043.241	86.317
12.6583	3043.338	86.315
12.6586	3043.965	86.372
12.6589	3044.060	86.282
12.6592	3045.908	86.339
12.6594	3046.452	86.268
12.6597	3045.627	86.421
12.6600	3043.927	86.233
12.6603	3044.240	86.430

Time	Pressure (Psia)	Temperature (°F)
12.6606	3045.188	86.246
12.6608	3047.291	86.276
12.6611	3045.929	86.350
12.6614	3044.858	86.378
12.6617	3046.621	86.328
12.6619	3047.507	86.263
12.6622	3048.854	86.402
12.6625	3047.634	86.290
12.6628	3046.591	86.309
12.6631	3047.244	86.331
12.6633	3049.520	86.213
12.6636	3050.042	86.416
12.6639	3048.207	86.372
12.6642	3046.919	86.323
12.6644	3047.677	86.241
12.6647	3048.662	86.342
12.6650	3049.281	86.380
12.6653	3048.211	86.265
12.6656	3048.174	86.337
12.6658	3049.965	86.309
12.6661	3050.420	86.361
12.6664	3049.830	86.323
12.6667	3049.143	86.317
12.6669	3049.823	86.293
12.6672	3051.353	86.271
12.6675	3051.499	86.424
12.6678	3051.413	86.339
12.6681	3051.346	86.290
12.6683	3049.452	86.265
12.6686	3050.276	86.378
12.6689	3051.744	86.391
12.6692	3050.750	86.260
12.6694	3050.261	86.326
12.6697	3051.317	86.361
12.6700	3051.896	86.312
12.6703	3051.111	86.331
12.6706	3050.756	86.293
12.6708	3052.371	86.378
12.6711	3052.109	86.282
12.6714	3053.111	86.279
12.6717	3053.347	86.369
12.6719	3053.159	86.345
12.6722	3053.638	86.394
12.6725	3053.599	86.224
12.6728	3053.090	86.298
12.6731	3052.095	86.372
12.6733	3052.649	86.358
12.6736	3052.337	86.282
12.6739	3051.995	86.317
12.6742	3052.445	86.408
12.6744	3052.358	86.375
12.6747	3052.650	86.265
12.6750	3053.396	86.342
12.6753	3054.092	86.285
12.6756	3053.952	86.254
12.6758	3055.238	86.367
12.6761	3055.096	86.369
12.6764	3054.914	86.378
12.6819	3057.137	86.364
12.6875	3058.577	86.345
12.6931	3062.026	86.342
12.6986	3064.924	86.287
12.7042	3063.784	86.361
12.7097	3065.968	86.369
12.7153	3068.587	86.315
12.7208	3069.581	86.293
12.7264	3070.134	86.413
12.7319	3068.316	86.345
12.7375	3069.079	86.389
12.7431	3069.067	86.405
12.7486	3068.654	86.304
12.7539	3069.175	86.181
12.7706	3070.451	86.391
12.7872	3072.322	86.479
12.8039	3073.071	86.740

Time	Pressure (Psia)	Temperature (°F)
12.8206	3074.289	86.451
12.8372	3072.556	86.479
12.8539	3072.593	86.050
12.8706	3072.926	86.183
12.8872	3073.772	86.629
12.9039	3073.265	86.304
12.9206	3072.788	86.047
12.9372	3072.335	86.156
12.9539	3072.764	86.065
12.9706	3073.509	86.843
12.9872	3073.217	87.037
13.0039	3073.426	87.863
13.0206	3074.675	87.411
13.0372	3074.774	87.626
13.0539	3073.653	87.801
13.0706	3072.921	88.210
13.0872	3072.715	88.682
13.1039	3072.923	88.464
13.1206	3072.149	88.611
13.1372	3071.611	88.580
13.1539	3070.229	89.085
13.1706	3070.311	89.748
13.1872	3070.243	89.762
13.2039	3072.074	89.868
13.2206	3071.697	90.058
13.2372	3072.195	90.240
13.2539	3071.670	90.270
13.2706	3070.499	90.384
13.2808	3070.002	90.443
13.2811	3069.367	90.538
13.2814	3070.407	90.706
13.2817	3070.317	90.639
13.2819	3069.654	90.492
13.2822	3069.954	90.495
13.2825	3069.402	90.457
13.2828	3070.206	90.465
13.2831	3071.059	90.503
13.2833	3071.066	90.121
13.2836	3070.441	90.075
13.2839	3070.478	90.484
13.2842	3069.869	90.378
13.2844	3069.871	90.563
13.2847	3070.993	90.484
13.2850	3070.322	90.541
13.2853	3068.969	90.400
13.2856	3069.504	90.560
13.2858	3069.268	90.441
13.2861	3070.569	90.509
13.2864	3069.676	90.427
13.2867	3069.070	90.606
13.2869	3069.522	90.473
13.2872	3069.510	90.479
13.2875	3068.922	90.479
13.2878	3069.363	90.525
13.2881	3068.579	90.557
13.2883	3067.832	90.433
13.2886	3067.821	90.492
13.2889	3068.227	90.776
13.2892	3068.537	90.536
13.2894	3068.986	90.435
13.2897	3069.264	90.557
13.2900	3068.574	90.471
13.2903	3068.401	90.522
13.2906	3068.964	90.509
13.2908	3069.057	90.503
13.2911	3068.759	90.544
13.2914	3069.484	90.400
13.2917	3069.204	90.595
13.2919	3068.122	90.465
13.2922	3069.531	90.620
13.2925	3069.530	90.500
13.2928	3069.532	90.498
13.2931	3069.757	90.538
13.2933	3068.249	90.593
13.2936	3069.409	90.457

Time	Pressure (Psia)	Temperature (°F)
13.2939	3069.575	90.528
13.2942	3069.670	90.519
13.2944	3069.802	94.049
13.2947	3069.184	90.259
13.2950	3070.109	90.587
13.2953	3069.957	90.454
13.2956	3069.531	90.536
13.2958	3069.372	90.598
13.2961	3068.524	90.525
13.2964	3068.657	90.487
13.2967	3069.673	90.598
13.2969	3069.434	90.741
13.2972	3069.800	90.568
13.2975	3069.961	90.449
13.2978	3069.702	90.682
13.2981	3070.522	90.465
13.2983	3069.889	90.576
13.2986	3070.079	90.522
13.2989	3070.661	90.568
13.2992	3069.390	90.566
13.2994	3069.108	90.568
13.2997	3070.416	90.460
13.3000	3070.476	90.617
13.3003	3069.779	90.473
13.3006	3069.455	90.650
13.3008	3070.208	90.574
13.3011	3070.461	90.506
13.3014	3070.071	90.736
13.3017	3070.646	90.430
13.3019	3070.682	90.571
13.3022	3070.068	90.528
13.3025	3070.764	90.541
13.3028	3070.467	90.655
13.3031	3070.667	90.533
13.3033	3070.667	90.625
13.3036	3069.729	90.509
13.3039	3070.599	90.536
13.3042	3070.308	90.642
13.3044	3070.141	90.528
13.3047	3069.710	90.579
13.3050	3069.780	90.547
13.3053	3068.718	90.568
13.3056	3068.103	90.666
13.3058	3068.517	90.506
13.3061	3068.611	90.582
13.3064	3068.005	90.604
13.3067	3069.465	90.536
13.3069	3069.089	90.666
13.3072	3068.582	90.471
13.3075	3068.493	90.008
13.3078	3069.941	90.511
13.3081	3070.290	90.609
13.3083	3071.036	90.495
13.3086	3069.990	90.560
13.3089	3070.781	90.650
13.3092	3071.708	90.623
13.3094	3070.735	90.595
13.3097	3071.178	90.492
13.3100	3071.630	90.701
13.3103	3070.523	90.650
13.3106	3070.687	90.555
13.3108	3071.382	90.606
13.3111	3071.364	90.593
13.3114	3071.017	90.639
13.3117	3071.611	90.549
13.3119	3071.335	90.582
13.3122	3070.794	90.633
13.3125	3071.451	90.585
13.3128	3072.054	90.669
13.3131	3071.106	90.547
13.3133	3071.513	90.663
13.3136	3071.556	90.647
13.3139	3071.853	90.579
13.3142	3072.236	90.606
13.3144	3071.521	90.552

Time	Pressure (Psia)	Temperature (°F)
13.3147	3071.910	90.655
13.3150	3071.950	90.614
13.3153	3071.626	90.614
13.3156	3071.582	90.642
13.3158	3071.233	90.617
13.3161	3071.527	90.628
13.3164	3072.310	90.633
13.3167	3072.359	90.806
13.3169	3072.615	90.666
13.3172	3073.032	90.726
13.3175	3072.551	90.525
13.3178	3071.914	90.623
13.3181	3071.242	90.865
13.3183	3071.472	90.669
13.3186	3070.440	90.587
13.3189	3071.830	90.644
13.3192	3070.719	90.606
13.3194	3072.298	90.723
13.3197	3071.280	90.614
13.3200	3070.990	90.571
13.3203	3071.301	90.717
13.3206	3072.342	90.492
13.3208	3072.041	90.723
13.3211	3072.632	90.701
13.3214	3072.503	90.623
13.3217	3072.404	90.617
13.3219	3072.592	90.623
13.3222	3071.956	90.652
13.3225	3072.437	90.631
13.3228	3072.603	90.914
13.3231	3072.569	90.828
13.3233	3072.177	90.755
13.3236	3070.609	90.652
13.3239	3071.866	90.590
13.3242	3070.756	90.717
13.3244	3070.059	90.631
13.3247	3071.240	90.582
13.3250	3070.960	90.720
13.3253	3072.051	90.644
13.3256	3072.136	90.696
13.3258	3071.254	90.536
13.3261	3072.923	90.761
13.3264	3071.907	90.631
13.3267	3071.183	90.644
13.3269	3072.694	90.623
13.3272	3073.576	90.764
13.3275	3071.804	90.669
13.3278	3072.288	90.541
13.3281	3072.269	90.731
13.3283	3072.280	90.717
13.3286	3072.791	90.658
13.3289	3073.411	90.647
13.3292	3072.596	90.671
13.3294	3072.946	90.704
13.3297	3072.418	90.563
13.3300	3073.240	90.723
13.3303	3073.102	90.647
13.3306	3072.812	90.780
13.3308	3072.222	90.487
13.3311	3072.007	90.254
13.3314	3072.266	90.745
13.3317	3071.675	90.701
13.3319	3071.292	90.636
13.3322	3071.146	90.957
13.3325	3071.188	90.628
13.3328	3071.021	90.617
13.3331	3070.834	90.739
13.3333	3071.907	90.677
13.3336	3071.655	90.680
13.3339	3072.379	90.992
13.3342	3072.880	90.612
13.3344	3072.479	90.791
13.3347	3072.470	90.506
13.3350	3073.574	90.812
13.3353	3072.510	90.642

Time	Pressure (Psia)	Temperature (°F)
13.3356	3073.063	90.723
13.3358	3072.561	90.726
13.3361	3072.314	90.685
13.3364	3072.953	90.704
13.3367	3073.070	90.696
13.3369	3072.678	90.652
13.3372	3073.070	90.742
13.3375	3073.074	90.709
13.3378	3072.919	90.682
13.3381	3073.368	90.655
13.3383	3072.508	90.736
13.3386	3072.826	90.745
13.3389	3071.836	90.938
13.3392	3071.487	90.734
13.3394	3071.719	90.636
13.3397	3071.895	90.693
13.3400	3070.984	90.717
13.3403	3072.567	90.717
13.3406	3072.669	90.709
13.3408	3071.512	90.693
13.3411	3072.524	90.680
13.3414	3073.234	90.758
13.3417	3072.316	90.709
13.3419	3073.399	90.717
13.3422	3072.999	90.693
13.3425	3072.632	90.793
13.3428	3072.188	90.685
13.3431	3072.635	90.734
13.3433	3072.490	90.685
13.3436	3073.628	90.745
13.3439	3072.609	90.693
13.3442	3072.521	90.987
13.3444	3073.098	90.699
13.3447	3072.117	90.952
13.3450	3072.268	90.769
13.3453	3072.299	90.666
13.3456	3072.048	90.777
13.3458	3071.503	90.685
13.3461	3073.305	90.753
13.3464	3072.059	90.690
13.3467	3072.586	90.731
13.3469	3071.616	90.051
13.3472	3071.948	90.663
13.3475	3072.968	90.769
13.3478	3073.152	90.769
13.3481	3072.666	90.650
13.3483	3072.729	90.005
13.3486	3072.888	90.712
13.3489	3071.948	90.821
13.3492	3072.975	90.761
13.3494	3071.426	90.579
13.3497	3072.203	90.804
13.3500	3072.961	90.981
13.3503	3072.862	90.829
13.3506	3072.838	90.701
13.3508	3072.983	90.685
13.3511	3073.257	90.804
13.3514	3072.966	90.726
13.3517	3073.173	90.761
13.3519	3072.042	90.720
13.3522	3074.347	90.766
13.3525	3073.709	90.726
13.3528	3072.673	90.742
13.3531	3073.166	90.761
13.3533	3073.366	90.769
13.3536	3073.170	90.682
13.3539	3073.973	90.875
13.3542	3073.092	90.576
13.3544	3073.581	90.878
13.3547	3073.711	90.807
13.3550	3072.915	90.707
13.3553	3073.027	90.769
13.3556	3073.229	90.747
13.3558	3073.411	90.758
13.3561	3072.304	90.761

Time	Pressure (Psia)	Temperature (°F)
13.3564	3072.208	90.734
13.3567	3072.393	90.807
13.3569	3071.941	90.736
13.3572	3072.363	90.807
13.3575	3072.122	90.712
13.3578	3071.525	90.723
13.3581	3071.989	90.769
13.3583	3071.733	90.859
13.3586	3072.027	90.766
13.3589	3073.179	90.726
13.3592	3071.512	90.785
13.3594	3073.951	90.755
13.3597	3071.780	90.717
13.3600	3071.980	90.826
13.3603	3073.267	90.745
13.3606	3073.303	90.810
13.3608	3073.177	90.747
13.3611	3073.146	90.804
13.3614	3072.789	90.799
13.3617	3072.714	90.783
13.3619	3071.960	90.750
13.3622	3071.389	90.764
13.3625	3071.282	90.769
13.3628	3071.109	90.902
13.3631	3070.774	90.696
13.3633	3070.261	90.774
13.3636	3070.659	90.728
13.3639	3071.628	90.861
13.3642	3071.328	90.766
13.3644	3071.444	90.769
13.3647	3070.918	90.736
13.3650	3071.435	90.945
13.3653	3072.828	90.704
13.3656	3072.598	90.845
13.3658	3071.085	90.701
13.3661	3072.975	90.880
13.3664	3071.448	90.717
13.3667	3070.678	90.769
13.3669	3072.225	90.842
13.3672	3071.919	90.810
13.3675	3070.810	90.761
13.3678	3071.555	90.804
13.3681	3071.622	90.785
13.3683	3071.564	90.812
13.3686	3071.424	90.008
13.3689	3071.700	90.826
13.3692	3071.726	90.831
13.3694	3070.622	90.747
13.3697	3071.402	90.766
13.3700	3070.584	90.878
13.3703	3070.550	90.745
13.3706	3071.424	90.793
13.3708	3070.618	90.853
13.3711	3070.915	90.796
13.3714	3071.677	90.864
13.3717	3070.410	90.745
13.3719	3071.514	90.736
13.3722	3071.595	90.929
13.3725	3070.450	90.796
13.3728	3070.915	90.804
13.3731	3070.496	90.878
13.3733	3070.295	90.723
13.3736	3070.061	90.850
13.3739	3069.498	90.818
13.3742	3069.464	90.823
13.3744	3068.753	90.856
13.3747	3068.567	90.766
13.3750	3069.693	90.878
13.3753	3069.207	90.777
13.3756	3070.271	90.818
13.3758	3070.700	90.861
13.3761	3070.093	90.755
13.3764	3070.892	90.861
13.3767	3070.747	90.793
13.3769	3069.943	90.869

Time	Pressure (Psia)	Temperature (°F)
13.3772	3070.879	90.747
13.3775	3071.741	90.840
13.3778	3070.426	90.772
13.3781	3070.447	90.727
13.3783	3070.613	90.490
13.3786	3071.313	90.812
13.3789	3070.718	90.821
13.3792	3070.975	90.859
13.3794	3071.262	90.840
13.3797	3070.486	90.834
13.3800	3071.297	90.796
13.3803	3071.384	90.826
13.3806	3070.873	90.848
13.3808	3070.546	90.842
13.3811	3071.594	90.840
13.3814	3070.604	90.780
13.3817	3071.435	90.918
13.3819	3071.062	90.823
13.3822	3071.571	90.859
13.3825	3071.262	90.812
13.3828	3070.750	90.707
13.3831	3070.846	90.964
13.3833	3071.309	90.864
13.3836	3070.924	90.886
13.3839	3071.764	90.783
13.3842	3071.922	90.861
13.3844	3071.323	90.883
13.3847	3071.607	90.804
13.3850	3070.648	90.880
13.3853	3070.995	90.823
13.3856	3070.919	90.845
13.3858	3069.965	90.878
13.3861	3070.609	90.902
13.3864	3071.626	90.826
13.3867	3071.226	90.867
13.3869	3070.879	90.812
13.3872	3071.850	90.869
13.3875	3071.864	90.842
13.3878	3071.812	90.880
13.3881	3071.630	90.812
13.3883	3071.161	90.883
13.3886	3071.898	90.856
13.3889	3071.538	90.872
13.3892	3071.067	90.872
13.3894	3071.090	90.853
13.3897	3070.029	90.872
13.3900	3068.561	90.848
13.3903	3068.290	90.883
13.3906	3066.185	90.845
13.3908	3065.160	90.875
13.3911	3063.679	90.867
13.3914	3062.587	90.869
13.3917	3061.271	90.867
13.3919	3059.736	90.872
13.3922	3058.903	90.872
13.3925	3057.352	90.869
13.3928	3055.996	90.880
13.3931	3055.061	90.861
13.3933	3053.468	90.875
13.3936	3052.206	90.878
13.3939	3051.227	90.878
13.3942	3049.744	90.872
13.3944	3048.665	90.886
13.3947	3047.397	90.869
13.3950	3046.087	90.878
13.3953	3044.987	90.872
13.3956	3043.783	90.886
13.3958	3042.563	90.875
13.3961	3041.499	90.888
13.3964	3040.290	90.880
13.3967	3039.149	90.880
13.3969	3038.077	90.886
13.3972	3036.920	90.886
13.3975	3035.850	90.880
13.3978	3034.775	90.888

Time	Pressure (Psia)	Temperature (°F)
13.3981	3033.661	90.883
13.3983	3032.650	90.886
13.3986	3031.605	90.894
13.3989	3030.531	90.883
13.3992	3029.541	90.897
13.3994	3028.481	90.878
13.3997	3027.510	90.894
13.4000	3026.536	90.897
13.4003	3025.527	90.897
13.4006	3024.527	90.878
13.4008	3023.626	90.907
13.4011	3022.622	90.883
13.4014	3021.716	90.902
13.4017	3020.773	90.894
13.4019	3019.857	90.905
13.4022	3018.929	90.897
13.4025	3018.019	90.894
13.4028	3017.140	90.897
13.4031	3016.289	90.910
13.4033	3015.372	90.888
13.4036	3014.528	90.902
13.4039	3013.694	90.905
13.4042	3012.827	90.902
13.4044	3012.013	90.907
13.4047	3011.157	90.891
13.4050	3010.393	90.915
13.4053	3009.568	90.907
13.4056	3008.742	90.899
13.4058	3007.959	90.902
13.4061	3007.222	90.921
13.4064	3006.424	90.915
13.4067	3005.640	90.902
13.4069	3004.879	90.905
13.4072	3004.163	90.915
13.4075	3003.410	90.918
13.4078	3002.660	90.907
13.4081	3001.946	90.915
13.4083	3001.205	90.913
13.4086	3000.505	90.921
13.4089	2999.763	90.902
13.4092	2999.085	90.921
13.4094	2998.377	90.921
13.4097	2997.673	90.918
13.4100	2996.990	90.915
13.4103	2996.326	90.926
13.4106	2995.643	90.924
13.4108	2994.960	90.913
13.4111	2994.327	90.929
13.4114	2993.680	90.929
13.4117	2992.993	90.913
13.4119	2992.371	90.926
13.4122	2991.738	90.926
13.4125	2991.114	90.932
13.4128	2990.475	90.921
13.4131	2989.851	90.918
13.4133	2989.271	90.934
13.4136	2988.654	90.924
13.4139	2988.091	90.945
13.4142	2987.448	90.913
13.4144	2986.904	90.937
13.4147	2986.342	90.940
13.4150	2985.760	90.940
13.4153	2985.143	90.913
13.4156	2984.662	90.951
13.4158	2984.069	90.937
13.4161	2983.524	90.937
13.4164	2982.951	90.918
13.4167	2982.467	90.951
13.4169	2981.926	90.945
13.4172	2981.393	90.940
13.4175	2980.867	90.934
13.4178	2980.367	90.943
13.4181	2979.861	90.948
13.4183	2979.341	90.937
13.4186	2978.853	90.948

Time	Pressure (Psia)	Temperature (°F)
13.4189	2978.349	90.943
13.4192	2977.880	90.948
13.4194	2977.377	90.943
13.4197	2976.900	90.940
13.4200	2976.460	90.964
13.4203	2975.983	90.953
13.4206	2975.476	90.934
13.4208	2975.065	90.959
13.4211	2974.611	90.956
13.4214	2974.144	90.951
13.4217	2973.687	90.943
13.4219	2973.285	90.956
13.4222	2972.864	90.967
13.4225	2972.401	90.948
13.4228	2972.004	90.964
13.4231	2971.576	90.956
13.4233	2971.155	90.959
13.4236	2970.767	90.964
13.4239	2970.341	90.953
13.4242	2969.931	90.951
13.4244	2969.589	90.981
13.4247	2969.171	90.962
13.4250	2968.763	90.956
13.4253	2968.385	90.959
13.4256	2968.047	90.975
13.4258	2967.659	90.972
13.4261	2967.243	90.951
13.4264	2966.917	90.970
13.4267	2966.577	90.981
13.4269	2966.213	90.975
13.4272	2965.832	90.964
13.4275	2965.496	90.970
13.4278	2965.155	90.972
13.4281	2964.834	90.986
13.4283	2964.470	90.964
13.4286	2964.146	90.972
13.4289	2963.825	90.978
13.4292	2963.521	90.989
13.4294	2963.160	90.962
13.4297	2962.855	90.975
13.4300	2962.583	90.991
13.4303	2962.263	90.986
13.4306	2961.953	90.978
13.4308	2961.632	90.975
13.4311	2961.380	90.994
13.4314	2961.083	90.989
13.4317	2960.775	90.978
13.4319	2960.496	90.986
13.4322	2960.221	90.989
13.4325	2959.956	90.997
13.4328	2959.653	90.981
13.4331	2959.386	90.983
13.4333	2959.151	91.000
13.4336	2958.871	90.991
13.4339	2958.621	91.000
13.4342	2958.334	90.981
13.4344	2958.097	90.991
13.4347	2957.872	91.005
13.4350	2957.629	91.005
13.4353	2957.345	90.983
13.4356	2957.145	91.002
13.4358	2956.913	91.008
13.4361	2956.667	91.002
13.4364	2956.420	90.989
13.4367	2956.215	91.005
13.4369	2955.984	91.000
13.4372	2955.781	91.013
13.4375	2955.557	91.008
13.4378	2955.316	90.997
13.4381	2955.128	91.010
13.4383	2954.931	91.016
13.4386	2954.705	91.005
13.4389	2954.509	91.010
13.4392	2954.301	91.013
13.4394	2954.116	91.013

Time	Pressure (Psia)	Temperature (°F)
13.4397	2953.925	91.021
13.4400	2953.693	91.000
13.4403	2953.527	91.013
13.4406	2953.336	91.013
13.4408	2953.205	91.046
13.4411	2952.921	90.989
13.4414	2952.818	91.032
13.4417	2952.609	91.019
13.4419	2952.427	91.016
13.4422	2952.268	91.021
13.4425	2952.075	91.013
13.4428	2951.954	91.035
13.4431	2951.755	91.027
13.4433	2951.618	91.032
13.4436	2951.400	91.010
13.4439	2951.276	91.027
13.4442	2951.147	91.040
13.4444	2950.964	91.029
13.4447	2950.807	91.024
13.4450	2950.645	91.024
13.4453	2950.543	91.048
13.4456	2950.361	91.029
13.4458	2950.216	91.035
13.4461	2950.098	91.043
13.4464	2949.914	91.027
13.4467	2949.801	91.037
13.4469	2949.664	91.043
13.4472	2949.511	91.032
13.4475	2949.404	91.054
13.4478	2949.246	91.032
13.4481	2949.139	91.054
13.4483	2948.978	91.035
13.4486	2948.861	91.043
13.4489	2948.734	91.046
13.4492	2948.630	91.054
13.4494	2948.483	91.046
13.4497	2948.360	91.043
13.4500	2948.238	91.048
13.4503	2948.142	91.056
13.4506	2948.017	91.056
13.4508	2947.879	91.046
13.4511	2947.771	91.051
13.4514	2947.666	91.054
13.4517	2947.568	91.065
13.4519	2947.450	91.065
13.4522	2947.312	91.046
13.4525	2947.231	91.062
13.4528	2947.119	91.065
13.4531	2946.995	91.054
13.4533	2946.895	91.059
13.4536	2946.797	91.062
13.4539	2946.709	91.070
13.4542	2946.599	91.070
13.4544	2946.498	91.067
13.4547	2946.365	91.051
13.4550	2946.307	91.075
13.4553	2946.183	91.065
13.4556	2946.128	91.086
13.4558	2945.977	91.056
13.4561	2945.931	91.084
13.4564	2945.783	91.059
13.4567	2945.750	91.089
13.4569	2945.601	91.065
13.4572	2945.546	91.078
13.4575	2945.438	91.075
13.4578	2945.349	91.075
13.4581	2945.286	91.089
13.4583	2945.160	91.073
13.4586	2945.099	91.084
13.4589	2945.003	91.084
13.4592	2944.918	91.089
13.4594	2944.856	91.092
13.4597	2944.723	91.075
13.4600	2944.662	91.086
13.4603	2944.579	91.089
13.4606	2944.488	91.084
13.4608	2944.435	91.103
13.4611	2944.295	91.067
13.4614	2944.273	91.103
13.4617	2944.176	91.094
13.4619	2944.123	91.105
13.4622	2944.010	91.092
13.4625	2943.936	91.092
13.4628	2943.870	91.100
13.4631	2943.814	91.113
13.4633	2943.720	91.103
13.4636	2943.598	91.073
13.4639	2943.579	91.113
13.4642	2943.479	91.092
13.4644	2943.481	91.132
13.4647	2943.292	91.078
13.4650	2943.298	91.113
13.4653	2943.220	91.111
13.4656	2943.098	91.089
13.4658	2943.110	91.127
13.4661	2942.991	91.103
13.4664	2942.912	91.100
13.4667	2942.904	91.127
13.4669	2942.785	91.103
13.4672	2942.749	91.119
13.4675	2942.677	91.116
13.4678	2942.604	91.108
13.4681	2942.572	91.127
13.4683	2942.478	91.116
13.4686	2942.462	91.135
13.4689	2942.361	91.116
13.4692	2942.279	91.108
13.4694	2942.233	91.119
13.4697	2942.227	91.143
13.4700	2942.133	91.124
13.4703	2942.066	91.124
13.4706	2941.977	91.108
13.4708	2941.956	91.124
13.4711	2941.922	91.138
13.4714	2941.868	91.141
13.4717	2941.776	91.119
13.4719	2941.753	91.138
13.4722	2941.696	91.135
13.4725	2941.632	91.132
13.4728	2941.588	91.132
13.4731	2941.549	91.143
13.4733	2941.472	91.130
13.4736	2941.413	91.130
13.4739	2941.415	91.154
13.4742	2941.330	91.141
13.4744	2941.301	91.149
13.4747	2941.219	91.132
13.4750	2941.178	91.138
13.4753	2941.149	91.146
13.4756	2941.100	91.151
13.4758	2941.079	91.159
13.4761	2940.981	91.135
13.4764	2940.920	91.130
13.4767	2940.949	91.165
13.4769	2940.870	91.154
13.4772	2940.853	91.165
13.4775	2940.761	91.143
13.4778	2940.706	91.138
13.4781	2940.700	91.162
13.4783	2940.664	91.162
13.4786	2940.620	91.162
13.4789	2940.558	91.157
13.4792	2940.485	91.138
13.4794	2940.502	91.170
13.4797	2940.453	91.168
13.4800	2940.396	91.165
13.4803	2940.374	91.173
13.4806	2940.285	91.149
13.4808	2940.263	91.157
13.4811	2940.259	91.178
13.4814	2940.177	91.162
13.4817	2940.168	91.173
13.4819	2940.129	91.176
13.4822	2940.060	91.162
13.4825	2940.053	91.178
13.4828	2939.999	91.173
13.4831	2939.982	91.184
13.4833	2939.945	91.184
13.4836	2939.835	91.149
13.4839	2939.847	91.178
13.4842	2939.823	91.181
13.4844	2939.788	91.187
13.4847	2939.744	91.187
13.4850	2939.695	91.176
13.4853	2939.652	91.173
13.4856	2939.628	91.184
13.4858	2939.609	91.189
13.4861	2939.575	91.195
13.4864	2939.496	91.176
13.4867	2939.479	91.178
13.4869	2939.465	91.195
13.4872	2939.425	91.189
13.4875	2939.411	91.206
13.4878	2939.366	91.197
13.4881	2939.299	91.181
13.4883	2939.250	91.178
13.4886	2939.293	91.214
13.4889	2939.189	91.181
13.4892	2939.225	91.216
13.4894	2939.153	91.197
13.4897	2939.104	91.187
13.4900	2939.086	91.197
13.4903	2939.055	91.200
13.4906	2939.058	91.214
13.4908	2938.988	91.200
13.4911	2938.976	91.206
13.4914	2938.935	91.203
13.4917	2938.893	91.200
13.4919	2938.898	91.219
13.4922	2938.836	91.206
13.4925	2938.842	91.216
13.4928	2938.772	91.203
13.4931	2938.753	91.208
13.4933	2938.734	91.214
13.4936	2938.692	91.211
13.4939	2938.713	91.230
13.4942	2938.638	91.214
13.4944	2938.605	91.208
13.4947	2938.554	91.200
13.4950	2938.587	91.230
13.4953	2938.550	91.230
13.4956	2938.518	91.225
13.4958	2938.473	91.216
13.4961	2938.449	91.219
13.4964	2938.410	91.214
13.4967	2938.406	91.227
13.4969	2938.409	91.241
13.4972	2938.346	91.227
13.4975	2938.329	91.230
13.4978	2938.280	91.219
13.4981	2938.261	91.225
13.4983	2938.258	91.235
13.4986	2938.240	91.241
13.4989	2938.192	91.235
13.4992	2938.175	91.238
13.4994	2938.113	91.216
13.4997	2938.113	91.233
13.5000	2938.116	91.246
13.5003	2938.117	91.262
13.5006	2938.037	91.235
13.5008	2938.008	91.235
13.5011	2937.980	91.233
13.5014	2937.958	91.233
13.5017	2937.954	91.246
13.5019	2937.930	91.249

Time	Pressure (Psia)	Temperature (°F)
13.5022	2937.928	91.260
13.5025	2937.879	91.249
13.5028	2937.852	91.246
13.5031	2937.797	91.233
13.5033	2937.812	91.249
13.5036	2937.801	91.262
13.5039	2937.763	91.254
13.5042	2937.767	91.268
13.5044	2937.664	91.225
13.5047	2937.695	91.257
13.5050	2937.673	91.257
13.5053	2937.656	91.260
13.5056	2937.646	91.271
13.5058	2937.619	91.268
13.5061	2937.547	91.241
13.5064	2937.549	91.254
13.5067	2937.538	91.260
13.5069	2937.515	91.260
13.5072	2937.516	91.276
13.5075	2937.489	91.273
13.5078	2937.469	91.271
13.5081	2937.410	91.254
13.5083	2937.405	91.260
13.5086	2937.406	91.276
13.5089	2937.376	91.268
13.5092	2937.392	91.292
13.5094	2937.316	91.260
13.5097	2937.317	91.276
13.5100	2937.280	91.268
13.5103	2937.275	91.273
13.5106	2937.264	91.279
13.5108	2937.257	91.287
13.5111	2937.235	91.287
13.5114	2937.187	91.273
13.5117	2937.180	91.281
13.5119	2937.150	91.273
13.5122	2937.143	91.281
13.5125	2937.137	91.290
13.5128	2937.122	91.298
13.5131	2937.089	91.284
13.5133	2937.062	91.281
13.5136	2937.016	91.276
13.5139	2937.026	91.281
13.5142	2937.031	91.300
13.5144	2936.979	91.284
13.5147	2937.009	91.309
13.5150	2936.962	91.295
13.5153	2936.920	91.284
13.5156	2936.926	91.295
13.5158	2936.881	91.287
13.5172	2936.817	91.300
13.5186	2936.735	91.311
13.5200	2936.641	91.309
13.5214	2936.558	91.311
13.5228	2936.462	91.311
13.5242	2936.409	91.330
13.5256	2936.333	91.333
13.5269	2936.247	91.330
13.5283	2936.176	91.336
13.5297	2936.128	91.349
13.5311	2936.051	91.352
13.5325	2935.985	91.360
13.5339	2935.927	91.368
13.5353	2935.838	91.360
13.5367	2935.785	91.371
13.5381	2935.689	91.363
13.5394	2935.672	91.390
13.5408	2935.604	91.393
13.5422	2935.553	91.401
13.5436	2935.489	91.398
13.5450	2935.443	91.409
13.5464	2935.407	91.425
13.5478	2935.315	91.411
13.5492	2935.302	91.436
13.5506	2935.232	91.430

Time	Pressure (Psia)	Temperature (°F)
13.5519	2935.153	91.420
13.5533	2935.137	91.447
13.5547	2935.086	91.447
13.5561	2935.052	91.460
13.5575	2934.968	91.447
13.5589	2934.949	91.460
13.5603	2934.890	91.460
13.5617	2934.883	91.485
13.5631	2934.802	91.468
13.5644	2934.785	91.487
13.5658	2934.691	91.468
13.5672	2934.677	91.485
13.5686	2934.636	91.490
13.5700	2934.581	91.485
13.5714	2934.565	91.504
13.5728	2934.541	91.514
13.5742	2934.479	91.509
13.5756	2934.448	91.520
13.5769	2934.416	91.523
13.5783	2934.375	91.528
13.5797	2934.346	91.536
13.5811	2934.329	91.547
13.5825	2934.302	91.552
13.5839	2934.273	91.560
13.5853	2934.216	91.558
13.5867	2934.194	91.566
13.5881	2934.180	91.574
13.5894	2934.133	91.577
13.5908	2934.094	91.579
13.5922	2934.060	91.585
13.5936	2934.003	91.574
13.5950	2934.012	91.598
13.5964	2933.959	91.590
13.5978	2933.943	91.601
13.5992	2933.931	91.615
13.6006	2933.867	91.596
13.6019	2933.883	91.628
13.6033	2933.836	91.623
13.6047	2933.809	91.628
13.6061	2933.809	91.644
13.6075	2933.775	91.650
13.6089	2933.740	91.647
13.6103	2933.714	91.653
13.6117	2933.687	91.658
13.6131	2933.668	91.663
13.6144	2933.641	91.669
13.6158	2933.632	91.680
13.6172	2933.605	91.685
13.6186	2933.575	91.685
13.6200	2933.556	91.690
13.6214	2933.540	91.701
13.6228	2933.510	91.701
13.6242	2933.490	91.707
13.6256	2933.483	91.715
13.6269	2933.466	91.726
13.6278	2933.442	91.720
13.6319	2933.394	91.742
13.6361	2933.330	91.755
13.6403	2933.254	91.758
13.6444	2933.246	91.801
13.6486	2933.187	91.810
13.6528	2933.129	91.818
13.6569	2933.048	91.818
13.6611	2932.994	91.828
13.6653	2932.968	91.850
13.6694	2932.946	91.875
13.6736	2932.871	91.877
13.6778	2932.844	91.891
13.6819	2932.782	91.893
13.6861	2932.774	91.921
13.6903	2932.753	91.945
13.6944	2932.689	91.942
13.6986	2932.677	91.964
13.7028	2932.638	91.975
13.7069	2932.566	91.964

Time	Pressure (Psia)	Temperature (°F)
13.7111	2932.555	91.994
13.7153	2932.523	92.004
13.7194	2932.497	92.010
13.7236	2932.450	92.013
13.7278	2932.426	92.031
13.7319	2932.377	92.029
13.7361	2932.343	92.034
13.7403	2932.334	92.053
13.7444	2932.282	92.053
13.7486	2932.270	92.067
13.7528	2932.236	92.072
13.7569	2932.192	92.072
13.7611	2932.190	92.091
13.7653	2932.151	92.094
13.7694	2932.131	92.099
13.7736	2932.090	92.096
13.7778	2932.080	92.115
13.7819	2932.058	92.123
13.7861	2932.051	92.140
13.7903	2932.037	92.148
13.7944	2932.023	92.156
13.7986	2931.978	92.156
13.8028	2931.969	92.167
13.8069	2931.949	92.172
13.8111	2931.917	92.175
13.8153	2931.878	92.178
13.8194	2931.851	92.175
13.8236	2931.817	92.180
13.8278	2931.797	92.186
13.8319	2931.790	92.202
13.8361	2931.778	92.207
13.8403	2931.772	92.224
13.8444	2931.732	92.218
13.8486	2931.727	92.232
13.8528	2931.716	92.245
13.8569	2931.684	92.240
13.8611	2931.692	92.264
13.8653	2931.662	92.264
13.8694	2931.632	92.264
13.8736	2931.591	92.261
13.8778	2931.609	92.283
13.8819	2931.554	92.270
13.8861	2931.565	92.291
13.8903	2931.573	92.307
13.8944	2931.533	92.302
13.8986	2931.544	92.324
13.9028	2931.486	92.305
13.9069	2931.512	92.334
13.9111	2931.463	92.324
13.9153	2931.456	92.332
13.9181	2931.440	92.332
13.9264	2931.421	92.345
13.9347	2931.395	92.359
13.9431	2931.338	92.356
13.9514	2931.346	92.388
13.9597	2931.290	92.378
13.9681	2931.258	92.388
13.9764	2931.256	92.416
13.9825	2931.199	92.397
13.9908	2931.185	92.413
13.9992	2931.188	92.434
14.0075	2931.141	92.437
14.0158	2931.110	92.440
14.0242	2931.103	92.464
14.0325	2931.100	92.483
14.0408	2931.051	92.472
14.0492	2931.049	92.491
14.0575	2930.987	92.478
14.0658	2930.986	92.497
14.0742	2930.973	92.510
14.0825	2930.919	92.505
14.0908	2930.909	92.516
14.0992	2930.913	92.537
14.1075	2930.854	92.529
14.1158	2930.846	92.545

Time	Pressure (Psia)	Temperature (°F)
14.1242	2930.802	92.537
14.1325	2930.815	92.564
14.1408	2930.778	92.564
14.1492	2930.758	92.570
14.1575	2930.752	92.586
14.1658	2930.754	92.599
14.1742	2930.720	92.597
14.1825	2930.678	92.594
14.1908	2930.706	92.621
14.1992	2930.649	92.610
14.2075	2930.634	92.618
14.2158	2930.588	92.613
14.2242	2930.580	92.621
14.2325	2930.566	92.629
14.2408	2930.531	92.626
14.2492	2930.534	92.648
14.2575	2930.549	92.672
14.2658	2930.552	92.686
14.2742	2930.483	92.672
14.2825	2930.439	92.664
14.2908	2930.474	92.699
14.2992	2930.477	92.721
14.3075	2930.462	92.729
14.3158	2930.475	92.764
14.3242	2930.411	92.745
14.3325	2930.367	92.745
14.3408	2930.360	92.761
14.3492	2930.395	92.797
14.3575	2930.341	92.783
14.3658	2930.323	92.786
14.3742	2930.336	92.805
14.3825	2930.259	92.783
14.3908	2930.297	92.824
14.3992	2930.265	92.818
14.4075	2930.236	92.818
14.4158	2930.273	92.851
14.4242	2930.249	92.853
14.4325	2930.224	92.856
14.4408	2930.209	92.864
14.4492	2930.185	92.875
14.4575	2930.190	92.894
14.4658	2930.158	92.888
14.4742	2930.181	92.913
14.4825	2930.119	92.899
14.4908	2930.127	92.915
14.4992	2930.114	92.921
14.5075	2930.105	92.932
14.5158	2930.118	92.951
14.5242	2930.059	92.934
14.5325	2930.058	92.942
14.5408	2930.047	92.956
14.5492	2930.049	92.969
14.5575	2930.030	92.975
14.5658	2930.012	92.978
14.5742	2930.037	93.007
14.5825	2930.015	93.007
14.5908	2929.976	93.002
14.5992	2930.008	93.032
14.6075	2929.967	93.021
14.6158	2929.974	93.045
14.6242	2929.967	93.053
14.6325	2929.907	93.037
14.6408	2929.888	93.034
14.6492	2929.865	93.042
14.6575	2929.874	93.067
14.6658	2929.898	93.096
14.6742	2929.926	93.131
14.6825	2929.857	93.110
14.6908	2929.869	93.137
14.6992	2929.835	93.134
14.7075	2929.848	93.161
14.7158	2929.870	93.185
14.7242	2929.863	93.202
14.7325	2929.816	93.196
14.7408	2929.780	93.188
14.7492	2929.787	93.212
14.7575	2929.802	93.237
14.7658	2929.794	93.245
14.7742	2929.795	93.261
14.7825	2929.776	93.266
14.7908	2929.739	93.258
14.7992	2929.711	93.264
14.8075	2929.741	93.288
14.8158	2929.734	93.296
14.8242	2929.744	93.318
14.8325	2929.737	93.326
14.8408	2929.690	93.320
14.8492	2929.702	93.339
14.8575	2929.710	93.355
14.8658	2929.690	93.361
14.8742	2929.683	93.369
14.8825	2929.671	93.374
14.8908	2929.671	93.391
14.8992	2929.651	93.396
14.9075	2929.659	93.412
14.9158	2929.624	93.409
14.9242	2929.632	93.426
14.9325	2929.646	93.450
14.9408	2929.625	93.450
14.9492	2929.622	93.461
14.9533	2929.590	93.447
14.9700	2929.652	93.517
14.9867	2929.605	93.520
15.0033	2929.588	93.539
15.0200	2929.598	93.569
15.0264	2929.524	93.544
15.0431	2929.535	93.582
15.0597	2929.495	93.593
15.0764	2929.495	93.633
15.0931	2929.500	93.668
15.1097	2929.498	93.703
15.1264	2929.466	93.714
15.1431	2929.496	93.771
15.1597	2929.459	93.795
15.1764	2929.422	93.811
15.1931	2929.412	93.838
15.2097	2929.402	93.873
15.2264	2929.400	93.908
15.2431	2929.410	93.954
15.2597	2929.397	94.000
15.2764	2929.371	94.022
15.2931	2929.380	94.076
15.3097	2929.357	94.108
15.3264	2929.362	94.159
15.3431	2929.318	94.183
15.3597	2929.330	94.243
15.3764	2929.346	94.305
15.3931	2929.352	94.356
15.4097	2929.300	94.380
15.4264	2929.284	94.428
15.4431	2929.310	94.488
15.4597	2929.266	94.504
15.4764	2929.263	94.539
15.4931	2929.292	94.587
15.5097	2929.250	94.617
15.5264	2929.249	94.649
15.5431	2929.249	94.681
15.5597	2929.266	94.743
15.5764	2929.230	94.781
15.5931	2929.244	94.846
15.6097	2929.214	94.886
15.6264	2929.204	94.921
15.6431	2929.203	94.945
15.6597	2929.222	94.964
15.6764	2929.198	94.967
15.6931	2929.197	94.991
15.7097	2929.192	95.012
15.7264	2929.169	95.029
15.7431	2929.178	95.058
15.7597	2929.173	95.080
15.7764	2929.175	95.101
15.7931	2929.149	95.160
15.8097	2929.159	95.252
15.8264	2929.128	95.332
15.8431	2929.106	95.402
15.8597	2929.083	95.459
15.8764	2929.095	95.531
15.8931	2929.101	95.580
15.9097	2929.110	95.625
15.9264	2929.104	95.663
15.9431	2929.112	95.709
15.9597	2929.154	95.773
15.9764	2929.106	95.808
15.9931	2929.051	95.851
16.0097	2929.066	95.913
16.0264	2929.008	95.942
16.0431	2928.961	96.015
16.0597	2928.970	96.168
16.0764	2928.959	96.302
16.0931	2928.970	96.398
16.1097	2928.983	96.468
16.1264	2929.030	96.535
16.1431	2929.050	96.575
16.1597	2929.071	96.600
16.1764	2929.063	96.600
16.1931	2929.006	96.567
16.2097	2929.017	96.648
16.2264	2928.983	96.720
16.2431	2928.968	96.790
16.2597	2929.011	96.851
16.2764	2929.035	96.881
16.2931	2929.026	96.905
16.3097	2929.044	96.932
16.3264	2929.015	96.916
16.3431	2929.023	96.916
16.3597	2928.985	96.894
16.3764	2929.009	96.908
16.3931	2929.040	96.913
16.4097	2929.016	96.892
16.4264	2929.015	96.841
16.4431	2928.954	96.774
16.4597	2929.056	96.843
16.4764	2928.976	96.827
16.4931	2928.930	96.843
16.5097	2928.960	96.897
16.5264	2928.909	96.926
16.5431	2928.883	97.036
16.5597	2928.848	97.170
16.5764	2928.859	97.310
16.5931	2928.814	97.409
16.6097	2928.822	97.529
16.6264	2928.850	97.612
16.6431	2928.871	97.636
16.6597	2928.902	97.657
16.6764	2928.897	97.647
16.6931	2928.889	97.625
16.7097	2928.845	97.639
16.7264	2928.887	97.724
16.7431	2928.841	97.786
16.7597	2928.819	97.853
16.7764	2928.828	97.895
16.7931	2928.825	97.936
16.8097	2928.823	97.930
16.8264	2928.859	97.909
16.8431	2928.886	97.845
16.8597	2928.908	97.778
16.8764	2928.874	97.692
16.8931	2928.862	97.660
16.9097	2928.803	97.660
16.9264	2928.821	97.708
16.9431	2928.798	97.732
16.9597	2928.779	97.751
16.9764	2928.808	97.797
16.9931	2928.766	97.831
17.0097	2928.750	97.914

Time	Pressure (Psia)	Temperature (°F)
17.0264	2928.783	97.970
17.0431	2928.787	98.010
17.0597	2928.756	98.064
17.0764	2928.758	98.166
17.0931	2928.716	98.267
17.1097	2928.730	98.371
17.1264	2928.758	98.425
17.1431	2928.803	98.446
17.1597	2928.802	98.417
17.1764	2928.798	98.414
17.1931	2928.799	98.406
17.2097	2928.779	98.411
17.2264	2928.802	98.417
17.2431	2928.824	98.395
17.2597	2928.790	98.393
17.2764	2928.757	98.433
17.2931	2928.722	98.497
17.3097	2928.739	98.540
17.3264	2928.768	98.540
17.3431	2928.785	98.516
17.3597	2928.759	98.438
17.3764	2928.758	98.358
17.3931	2928.744	98.313
17.4097	2928.746	98.296
17.4264	2928.741	98.264
17.4431	2928.722	98.232
17.4597	2928.731	98.200
17.4764	2928.700	98.166
17.4931	2928.681	98.184
17.5097	2928.693	98.187
17.5264	2928.704	98.168
17.5431	2928.701	98.171
17.5597	2928.731	98.141
17.5764	2928.716	98.149
17.5931	2928.694	98.208
17.6097	2928.674	98.243
17.6264	2928.642	98.305
17.6431	2928.663	98.379
17.6597	2928.676	98.403
17.6764	2928.659	98.398
17.6931	2928.637	98.435
17.7097	2928.644	98.494
17.7158	2928.624	98.521
17.7325	2928.663	98.585
17.7492	2928.646	98.588
17.7658	2928.680	98.561
17.7825	2928.680	98.532
17.7992	2928.676	98.529
17.8158	2928.624	98.588
17.8325	2928.615	98.692
17.8492	2928.629	98.759
17.8658	2928.640	98.799
17.8825	2928.608	98.801
17.8992	2928.614	98.788
17.9158	2928.652	98.772
17.9325	2928.652	98.743
17.9492	2928.660	98.764
17.9658	2928.586	98.823
17.9825	2928.595	98.916
17.9992	2928.609	98.953
18.0158	2928.621	98.927
18.0325	2928.662	98.908
18.0492	2928.644	98.889
18.0658	2928.653	98.903
18.0825	2928.664	98.884
18.0992	2928.668	98.873
18.1158	2928.638	98.852
18.1325	2928.611	98.871
18.1492	2928.529	98.879
18.1658	2928.617	98.916
18.1825	2928.625	98.879
18.1992	2928.596	98.849
18.2158	2928.587	98.865
18.2325	2928.577	98.868
18.2492	2928.622	98.868

Time	Pressure (Psia)	Temperature (°F)
18.2658	2928.583	98.825
18.2825	2928.605	98.855
18.2992	2928.583	98.884
18.3158	2928.583	98.913
18.3325	2928.571	98.940
18.3492	2928.536	98.967
18.3658	2928.542	98.991
18.3825	2928.542	98.991
18.3992	2928.576	99.007
18.4158	2928.563	98.999
18.4325	2928.530	98.980
18.4492	2928.552	99.039
18.4658	2928.537	99.089
18.4814	2928.558	99.097
18.4981	2928.573	99.097
18.5147	2928.564	99.084
18.5314	2928.527	99.063
18.5481	2928.540	99.087
18.5647	2928.574	99.119
18.5814	2928.529	99.119
18.5981	2928.562	99.167
18.6147	2928.544	99.177
18.6314	2928.563	99.188
18.6481	2928.540	99.167
18.6647	2928.582	99.170
18.6814	2928.507	99.177
18.6981	2928.538	99.255
18.7147	2928.538	99.263
18.7314	2928.493	99.271
18.7481	2928.530	99.300
18.7647	2928.557	99.316
18.7814	2928.522	99.322
18.7981	2928.509	99.407
18.8147	2928.497	99.497
18.8314	2928.498	99.540
18.8481	2928.498	99.612
18.8647	2928.536	99.676
18.8814	2928.524	99.695
18.8981	2928.521	99.676
18.9147	2928.508	99.681
18.9314	2928.452	99.721
18.9481	2928.487	99.852
18.9647	2928.488	99.937
18.9814	2928.476	99.985
18.9981	2928.509	99.996
19.0147	2928.472	99.932
19.0314	2928.487	99.966
19.0481	2928.492	99.948
19.0647	2928.508	99.961
19.0814	2928.517	100.009
19.0981	2928.456	100.004
19.1147	2928.473	100.030
19.1314	2928.490	100.006
19.1481	2928.499	99.977
19.1647	2928.518	99.937
19.1814	2928.510	99.852
19.1981	2928.522	99.804
19.2147	2928.575	99.796
19.2314	2928.477	99.719
19.2481	2928.515	99.711
19.2647	2928.521	99.727
19.2814	2928.517	99.716
19.2981	2928.479	99.724
19.3147	2928.487	99.716
19.3314	2928.454	99.684
19.3481	2928.501	99.703
19.3647	2928.452	99.679
19.3814	2928.506	99.727
19.3981	2928.454	99.684
19.4147	2928.463	99.711
19.4314	2928.492	99.761
19.4481	2928.458	99.801
19.4647	2928.420	99.817
19.4814	2928.429	99.823
19.4981	2928.441	99.897

Time	Pressure (Psia)	Temperature (°F)
19.5147	2928.435	99.932
19.5314	2928.454	99.934
19.5481	2928.407	99.916
19.5647	2928.425	99.927
19.5814	2928.479	99.910
19.5981	2928.476	99.892
19.6147	2928.462	99.913
19.6314	2928.445	99.929
19.6481	2928.432	99.934
19.6647	2928.484	99.956
19.6814	2928.513	99.977
19.6981	2928.432	99.956
19.7147	2928.460	99.993
19.7314	2928.490	99.993
19.7481	2928.478	100.004
19.7647	2928.386	100.036
19.7814	2928.400	100.129
19.7981	2928.448	100.246
19.8147	2928.387	100.283
19.8314	2928.404	100.331
19.8481	2928.464	100.374
19.8647	2928.409	100.411
19.8814	2928.403	100.509
19.8981	2928.447	100.595
19.9147	2928.392	100.605
19.9314	2928.428	100.712
19.9481	2928.442	100.754
19.9647	2928.437	100.738
19.9814	2928.480	100.746
19.9981	2928.508	100.741
20.0147	2928.440	100.693
20.0314	2928.427	100.733
20.0481	2928.433	100.770
20.0647	2928.419	100.783
20.0814	2928.447	100.813
20.0981	2928.467	100.794
20.1147	2928.446	100.743
20.1314	2928.470	100.693
20.1481	2928.481	100.661
20.1647	2928.492	100.629
20.1814	2928.464	100.571
20.1981	2928.486	100.557
20.2147	2928.460	100.525
20.2314	2928.478	100.536
20.2481	2928.480	100.563
20.2647	2928.459	100.597
20.2814	2928.385	100.597
20.2981	2928.428	100.648
20.3147	2928.419	100.664
20.3314	2928.400	100.696
20.3481	2928.443	100.767
20.3647	2928.448	100.762
20.3814	2928.372	100.786
20.3981	2928.386	100.884
20.4147	2928.427	100.951
20.4314	2928.425	100.932
20.4481	2928.445	100.906
20.4647	2928.447	100.890
20.4814	2928.455	100.868
20.4981	2928.458	100.866
20.5147	2928.423	100.948
20.5314	2928.378	101.047
20.5481	2928.387	101.150
20.5647	2928.411	101.190
20.5814	2928.412	101.225
20.5981	2928.430	101.227
20.6147	2928.453	101.227
20.6314	2928.445	101.193
20.6481	2928.455	101.155
20.6647	2928.474	101.145
20.6814	2928.451	101.089
20.6981	2928.469	101.031
20.7147	2928.479	101.028
20.7314	2928.442	101.070
20.7481	2928.409	101.094

Time	Pressure (Psia)	Temperature (°F)
20.7647	2928.421	101.166
20.7814	2928.409	101.206
20.7981	2928.396	101.211
20.8147	2928.423	101.248
20.8314	2928.436	101.264
20.8481	2928.411	101.267
20.8647	2928.445	101.339
20.8814	2928.432	101.365
20.8981	2928.431	101.331
20.9147	2928.475	101.317
20.9314	2928.462	101.344
20.9481	2928.406	101.410
20.9647	2928.394	101.541
20.9814	2928.377	101.618
20.9981	2928.382	101.620
21.0147	2928.434	101.607
21.0314	2928.464	101.599
21.0481	2928.405	101.633
21.0647	2928.406	101.716
21.0814	2928.413	101.750
21.0981	2928.408	101.769
21.1147	2928.407	101.846
21.1314	2928.456	101.883
21.1481	2928.432	101.947
21.1647	2928.410	101.994
21.1814	2928.412	102.047
21.1981	2928.428	102.066
21.2147	2928.430	102.045
21.2314	2928.479	102.013
21.2481	2928.459	101.976
21.2647	2928.455	101.952
21.2814	2928.440	101.939
21.2981	2928.431	101.933
21.3147	2928.433	101.952
21.3314	2928.447	101.973
21.3481	2928.403	101.973
21.3647	2928.380	102.016
21.3814	2928.395	102.098
21.3981	2928.385	102.148
21.4147	2928.388	102.172
21.4314	2928.418	102.220
21.4481	2928.425	102.241
21.4647	2928.452	102.222
21.4814	2928.446	102.201
21.4981	2928.476	102.193
21.5147	2928.366	102.233
21.5314	2928.406	102.381
21.5481	2928.385	102.456
21.5647	2928.377	102.538
21.5814	2928.384	102.585
21.5981	2928.454	102.596
21.6147	2928.431	102.570
21.6314	2928.407	102.577
21.6481	2928.463	102.628
21.6647	2928.431	102.609
21.6814	2928.415	102.577
21.6981	2928.430	102.617
21.7147	2928.393	102.652
21.7314	2928.393	102.699
21.7481	2928.421	102.816
21.7647	2928.403	102.927
21.7814	2928.376	103.033
21.7981	2928.347	103.186
21.8147	2928.350	103.345
21.8314	2928.334	103.432
21.8481	2928.428	103.501
21.8647	2928.449	103.496
21.8814	2928.434	103.469
21.8981	2928.433	103.451
21.9147	2928.445	103.406
21.9314	2928.454	103.358
21.9481	2928.450	103.361
21.9647	2928.449	103.395
21.9814	2928.397	103.430
21.9981	2928.426	103.504
22.0147	2928.415	103.541
22.0314	2928.435	103.536
22.0481	2928.441	103.530
22.0647	2928.461	103.485
22.0814	2928.449	103.443
22.0981	2928.446	103.419
22.1147	2928.447	103.525
22.1314	2928.375	103.610
22.1481	2928.393	103.673
22.1647	2928.393	103.734
22.1814	2928.421	103.795
22.1981	2928.425	103.758
22.2147	2928.440	103.744
22.2314	2928.438	103.713
22.2481	2928.442	103.702
22.2647	2928.470	103.697
22.2814	2928.416	103.660
22.2981	2928.415	103.747
22.3147	2928.374	103.784
22.3314	2928.364	103.840
22.3481	2928.420	103.921
22.3647	2928.430	103.932
22.3814	2928.391	103.948
22.3981	2928.397	104.035
22.4147	2928.374	104.122
22.4314	2928.354	104.212
22.4481	2928.354	104.304
22.4647	2928.411	104.326
22.4814	2928.453	104.289
22.4981	2928.419	104.194
22.5147	2928.449	104.141
22.5314	2928.446	104.091
22.5481	2928.409	104.104
22.5647	2928.360	104.101
22.5814	2928.426	104.101
22.5981	2928.395	104.056
22.6147	2909.964	104.386
22.6208	2889.494	104.885
22.7767	2051.202	105.796
22.7850	2051.117	105.415
22.7933	2051.041	105.040
22.8017	2050.997	104.721
22.8100	2050.933	104.415
22.8183	2050.896	104.159
22.8267	2050.861	103.927
22.8350	2050.813	103.697
22.8433	2050.780	103.506
22.8517	2050.720	103.313
22.8600	2050.720	103.171
22.8683	2050.680	103.020
22.8767	2050.665	102.893
22.8850	2050.661	102.792
22.8933	2050.630	102.670
22.8964	2050.609	102.628
23.1733	680.106	91.531
23.1817	680.042	91.124
23.1900	679.972	90.728
23.1983	679.937	90.408
23.2067	679.880	90.082
23.2150	679.814	89.786
23.2233	679.770	89.528
23.2317	679.731	89.291
23.2400	679.708	89.093
23.2483	679.678	88.902
23.2567	679.647	88.725
23.2650	679.740	88.570
23.2733	679.716	88.445
23.2817	679.704	88.316
23.2900	679.684	88.197
23.2983	679.667	88.093
23.3067	679.658	87.997
23.3150	679.623	87.886
23.3233	679.621	87.812
23.4244	85.500	85.570
23.4328	85.556	85.296
23.4411	85.526	85.027
23.4494	85.494	84.783
23.4578	85.449	84.560
23.4661	85.433	84.382
23.4744	85.419	84.217
23.4828	85.384	84.052
23.4911	85.372	83.906
23.4994	85.356	83.774
23.5078	85.333	83.651
23.5161	85.325	83.554
23.5244	85.316	83.458
23.5269	85.313	83.428
23.5283	85.301	83.398
23.5339	83.839	86.632
23.5353	82.457	86.807
23.5367	80.235	85.931
23.5381	79.278	86.640
23.5394	75.037	83.340
23.5408	73.573	83.398
23.5422	72.016	83.337
23.5436	70.467	83.296
23.5450	68.907	83.232
23.5464	67.458	83.307
23.5478	65.966	83.331
23.5492	64.377	83.243
23.5533	59.712	83.070
23.5561	56.716	83.097
23.5589	53.779	83.142
23.5603	52.276	83.144
23.5617	50.721	83.086
23.5644	47.538	82.902
23.5658	46.125	83.020
23.5672	44.639	83.053
23.5686	43.036	82.938
23.5756	35.452	82.935
23.5769	33.793	82.761
23.5797	30.942	82.979
23.5811	29.313	82.841
23.5825	27.830	82.885
23.5839	26.189	82.734
23.5853	24.766	82.841
23.5867	23.335	82.949
23.5881	21.688	82.789
23.5894	20.172	82.794
23.5908	18.675	82.814
23.5922	17.123	82.767
23.5936	15.603	82.759
23.5950	14.123	82.800
23.5964	14.123	82.808
23.5978	14.123	82.731
23.5992	14.123	82.819
23.5997	14.123.	82.818

APPENDIX 4.1.2-1

PANSYSTEM2 VERSION 2.5, WELL TEST ANALYSIS REPORT, WDW-1

ENVIROCORP® ENVIROCORP SERVICES AND TECHNOLOGY, INC. HOUSTON, TX. · SOUTH BEND, IN. BATON ROUGE, LA.	Envirocorp Services & Technology, Inc.	Report File:	WDW1.PAN
	PanSystem Version 2.5	Analysis Date:	9/15/1998
	Well Test Analysis Report		

Company	Navajo Refining Company
Location	Artesia, New Mexico
Well	WDW-1
Test Type	Injection/Falloff
Test Date	July 30 - 31, 1998
Gauge Type/Serial #	Eccossetex/009
Gauge Depth	7924 Feet
Injection Interval	7924 - 8115 Feet; 8220 - 8476 Feet
Completion Type	Perforated
Top of Fill	8997 Feet
Last Stabilization	New Completion
Analyst	LKM
Envirocorp Project No.	70A4614

ENVIROCORP ENVIROCORP SERVICES AND TECHNOLOGY, INC. HOUSTON, TX · SOUTH BEND, IN. BATON ROUGE, LA.	Envirocorp Services & Technology, Inc.	Report File:	WDW1.PAN
	PanSystem Version 2.5	Analysis Date:	9/22/1998
	Well Test Analysis Report		

Reservoir Description
Fluid type : Water
Well orientation : Vertical
Number of wells : 1
Number of layers : 1

Layer Parameters Data

	Layer 1
Formation thickness	253.00 ft
Average formation porosity	0.10
Water saturation	0.00
Gas saturation	0.00
Formation compressibility	0.0000 psi-1
Total system compressibility	8.4000e-6 psi-1
Layer pressure	2925.3599 psia
Temperature	0.0000 deg F

Well Parameters Data

	WDW-1
Well radius	0.3696 ft
Distance from observation to active well	0.0000 ft
Wellbore storage coefficient	0.1038 bbl/psi
Well offset - x direction	0.00 ft
Well offset - y direction	0.00 ft

Fluid Parameters Data

	Layer 1
Oil gravity	0.0000 API
Gas gravity	0.0000 sp grav
Gas-oil ratio (produced)	0.0000 scf/STB
Water cut	0.0000
Water salinity	0.0000 ppm
Check Pressure	0.0000 psia
Check Temperature	0.0000 deg F
Gas-oil ratio (solution)	0.0000 scf/STB
Bubble-point pressure	0.0000 psia
Oil density	0.000 lb/ft3
Oil viscosity	0.000 cp
Oil formation volume factor	0.000 RB/STB

Fluid Parameters Data (cont)

	Layer 1
Gas density	0.000 lb/ft3
Gas viscosity	0.0 cp
Gas formation volume factor	0.000 ft3/scf
Water density	0.000 lb/ft3
Water viscosity	0.530 cp
Water formation volume factor	1.000 RB/STB
Oil compressibility	0.0000 psi-1
Initial Gas compressibility	0.0000 psi-1
Water compressibility	0.0000 psi-1

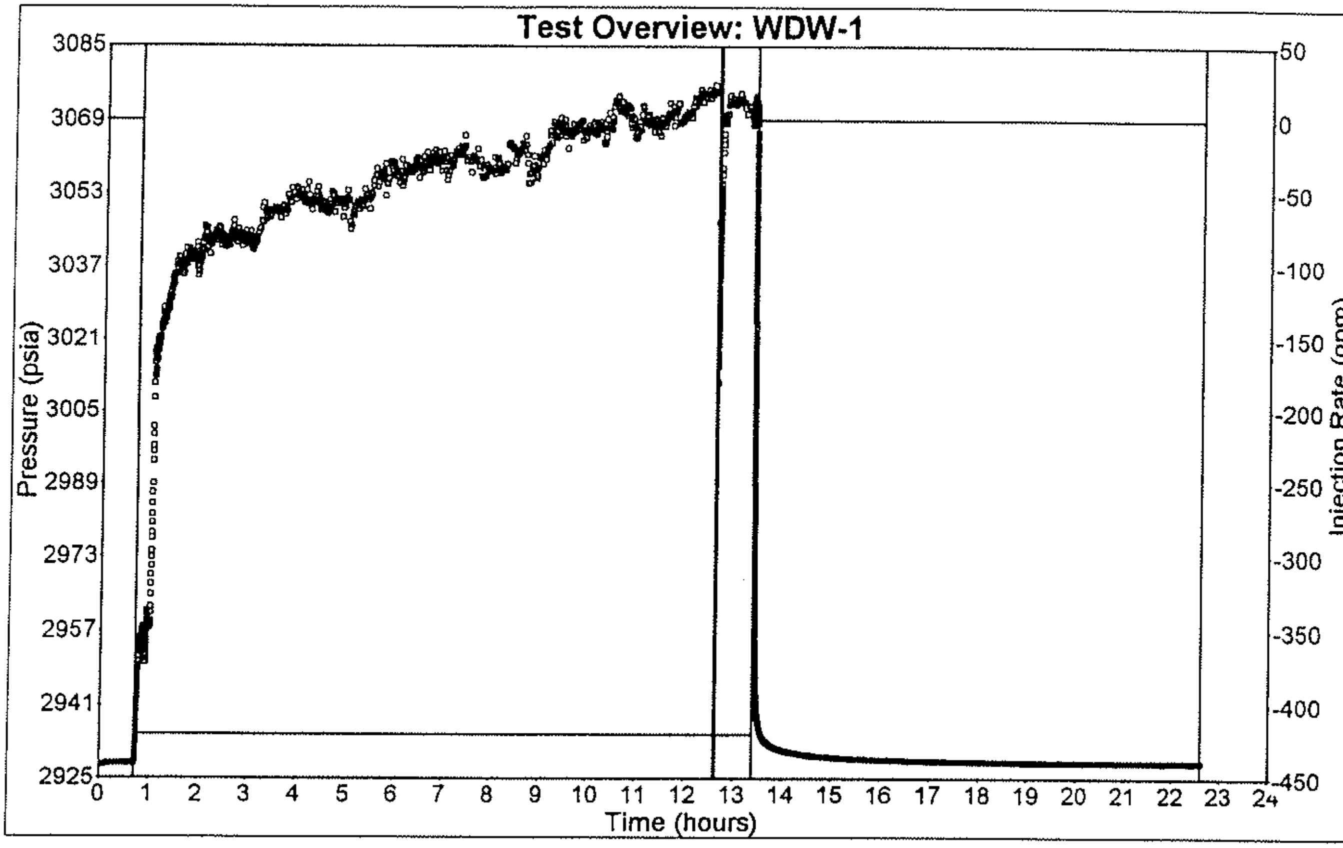
Layer 1 Correlations
Not Used

Layer 1 Model Data
Layer 1 Model Type : Radial homogeneous

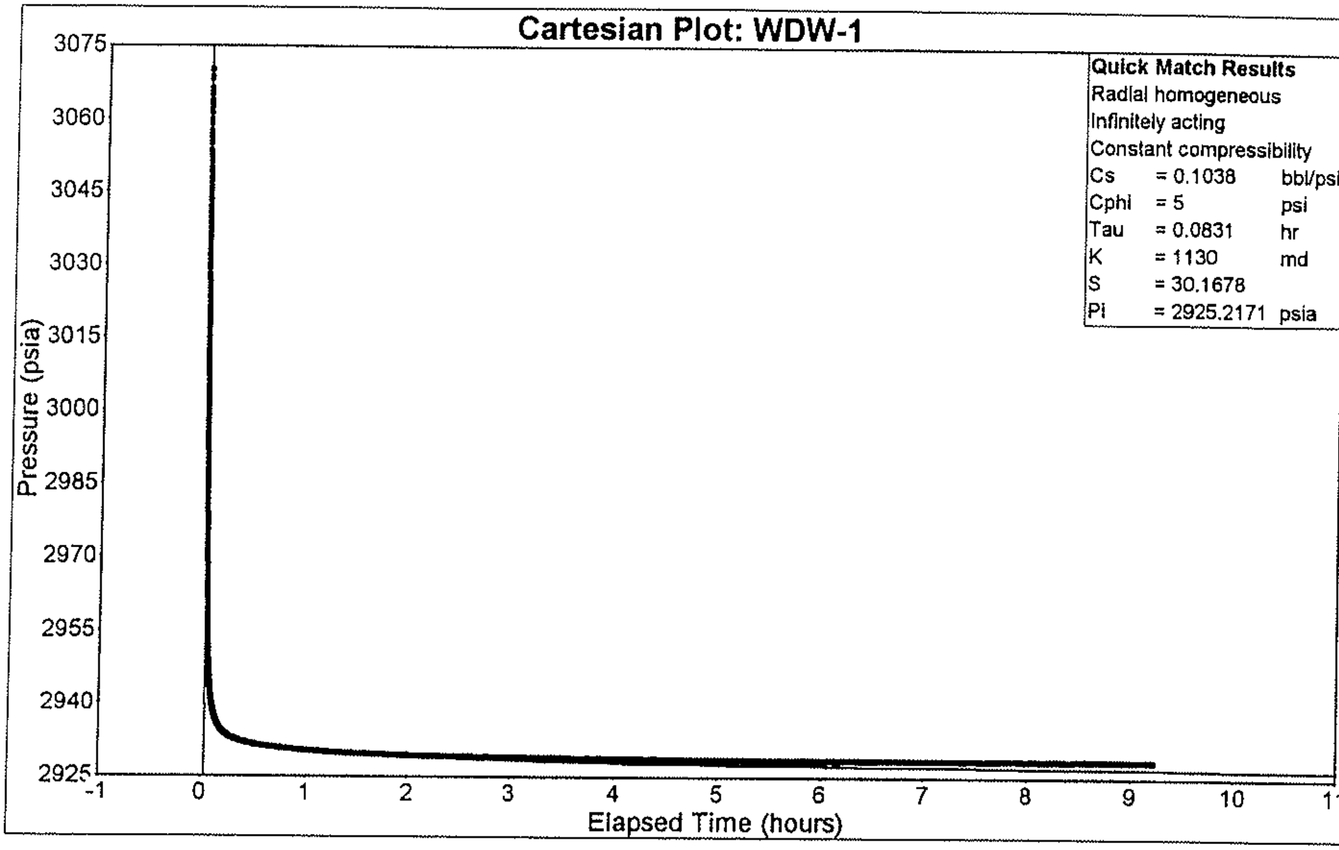
	Layer 1
Permeability	1130.00 md
Skin factor (Well 1)	30.1678

Rate Change Data

Time Hours	Pressure psia	Rate gpm
0.71330	2928.2310	0.0000
12.60750	3074.7930	-420.0000
12.64080	3011.3721	-200.0000
13.38939	3071.6079	-420.0000
22.59810	2928.3950	0.0000


Test Overview: WDW-1
Pressure (psia)
3085
3069
3053
3037
3021
3005
2989
2973
2957
2941
2925
Injection Rate (gpm)
50
0
-50
-100
-150
-200
-250
-300
-350
-400
-450
Time (hours)
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

ENVIROCORP	Envirocorp Services & Technology, Inc.	Report File:	WDW1.PAN
Envirocorp Services and Technology, Inc. Houston, TX · South Bend, IN Baton Rouge, LA	PanSystem Version 2.5	Analysis Date:	9/15/1998
	Well Test Analysis Report		



Cartesian Plot: WDW-1 Model Results

Radial homogeneous

Infinitely acting

	Value
Wellbore storage coefficient	0.1309 bbl/psi
Dimensionless wellbore storage	1035.9075

Cartesian Plot: WDW-1 Line Details

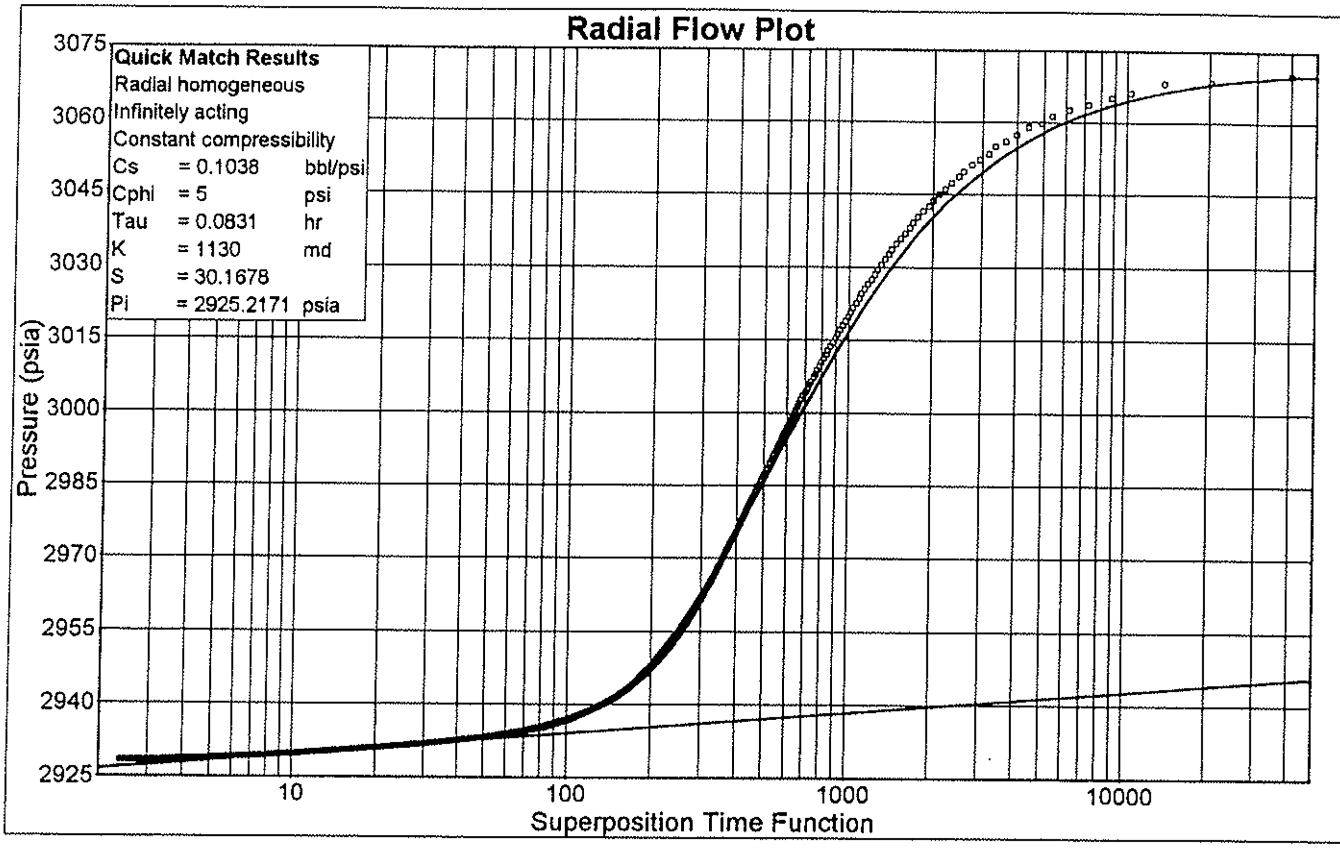
Line type : Wellbore storage

Slope : -4582.2

Intercept : 3071.68

Coefficient of Determination : 0.997527

Number of Intersections = 0



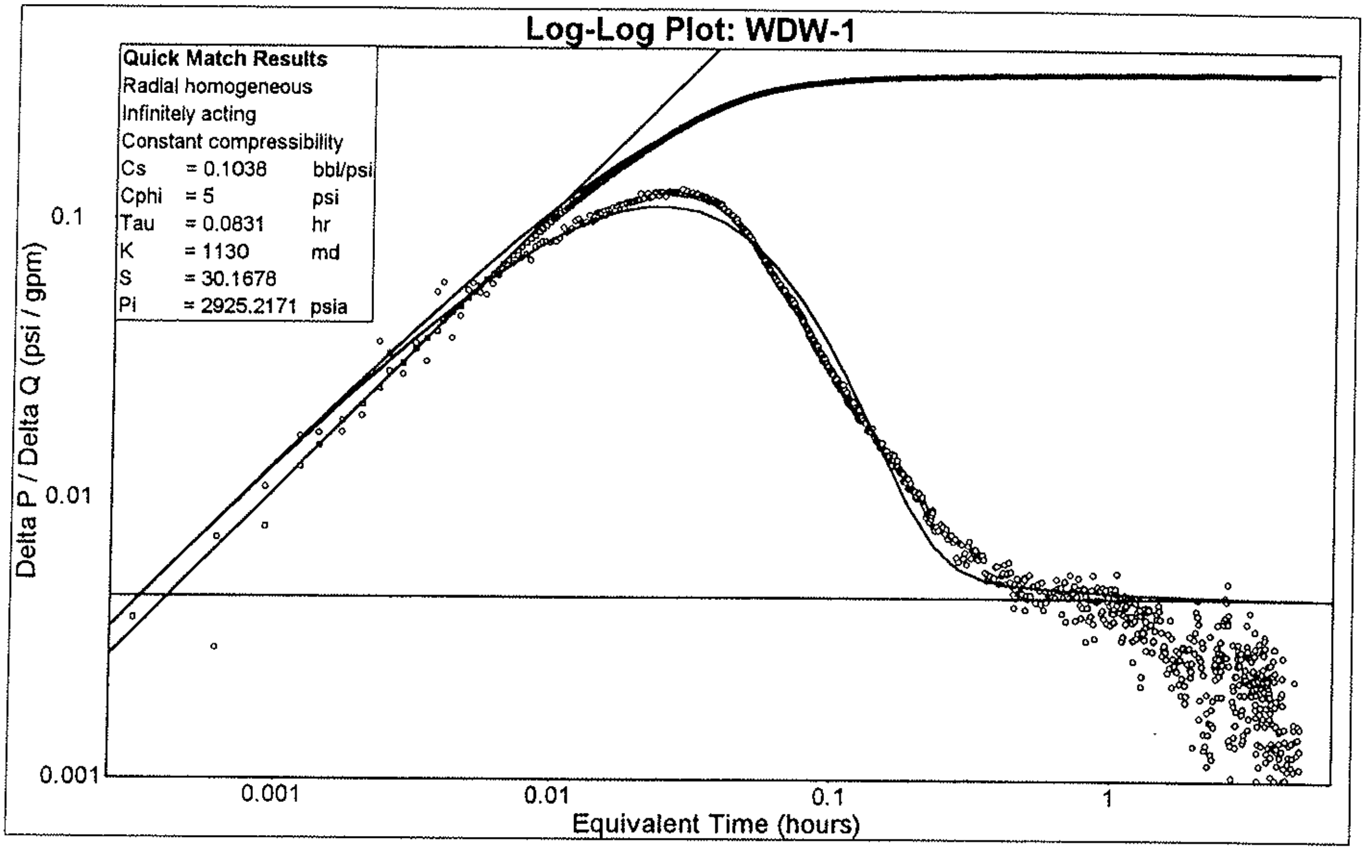
Radial Flow Plot Model Results
Radial homogeneous
Infinitely acting

	Value
Permeability	1125.5867 md
Permeability-thickness	2.8477e5 md.ft
Radius of investigation	4424.9595 ft
Flow efficiency	0.2247
dP skin (constant rate)	113.3868 psi
Skin factor	29.9633
Extrapolated pressure	2925.3599 psia

Radial Flow Plot Line Details
Line type : Radial flow
Slope : 4.35671
Intercept : 2925.36
Coefficient of Determination : 0.996956

	Radial flow
Extrapolated pressure	2925.3599 psia
Pressure at dt = 1 hour	2930.2690 psia

Number of Intersections = 0



Log-Log Plot: WDW-1 Model Results

Radial homogeneous

Infinitely acting

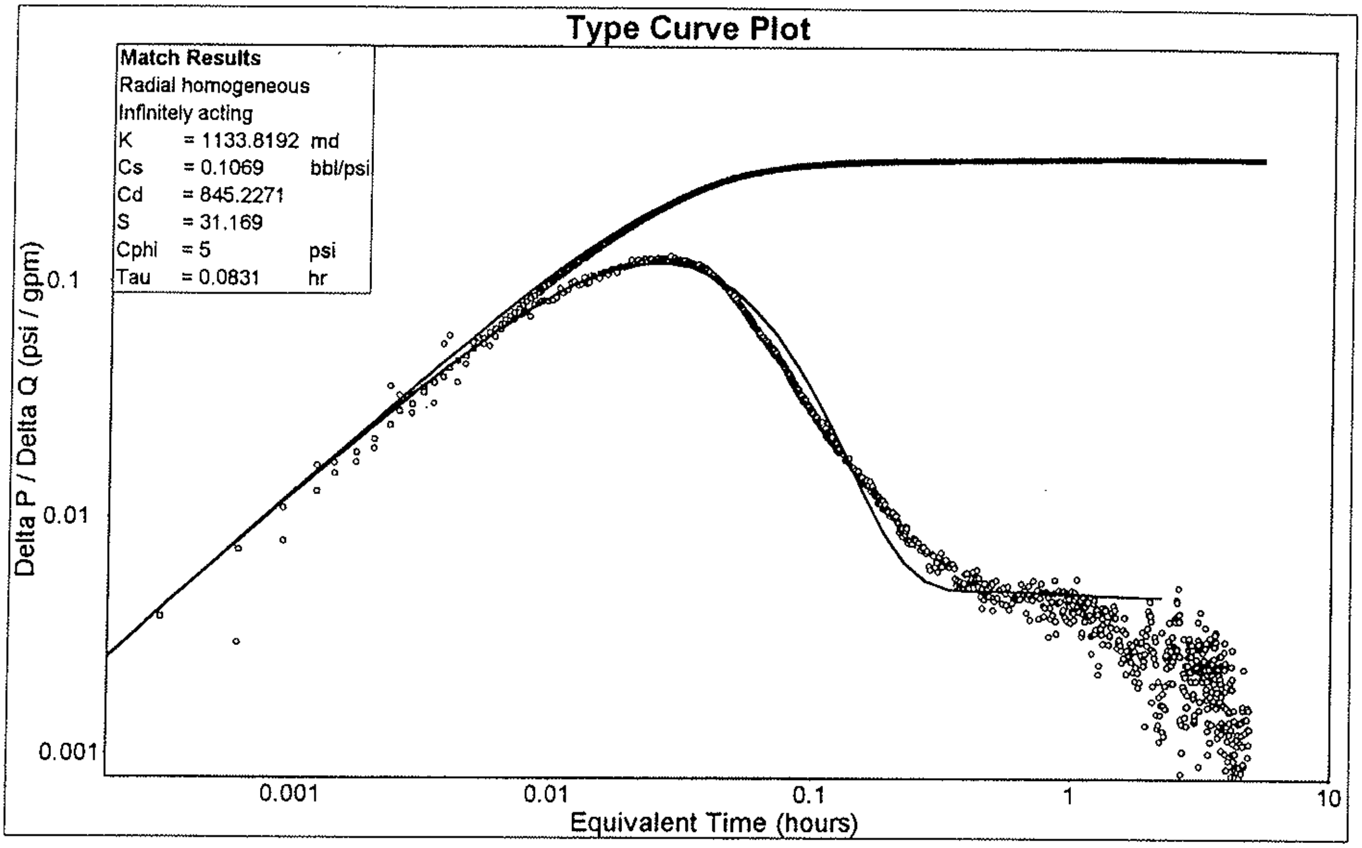
	Value
Wellbore storage coefficient	0.1305 bbl/psi
Dimensionless wellbore storage	1032.4241
Permeability	1130.6444 md
Permeability-thickness	2.8605e5 md.ft
Skin factor	30.1285

Log-Log Plot: WDW-1 Line Details

Line type : Radial flow
Slope : 0
Intercept : 0.00448484
Coefficient of Determination : Not Used

Line type : Wellbore storage
Slope : 1
Intercept : 10.9468
Coefficient of Determination : Not Used

Number of intersections = 0



Type Curve Plot Model Results
Radial homogeneous
Infinitely acting

	Value
Permeability	1133.8192 md
Wellbore storage coefficient	0.1069 bbl/psi
Dimensionless wellbore storage	845.2271
Skin factor	31.169

Type Curve Details
Stage 1 File Name : C:\pan25\typecurv\radhomog.tch
Axis Type : Td/Cd

	Stage 1
Match point - X	-3.1743
Match point - Y	3.5836
Curve Number	13.0000
Curve Value	1.0000e30

APPENDIX H

WDW-2 CONSTRUCTION INFORMATION

SUBSURFACE

REENTRY AND COMPLETION REPORT
WASTE DISPOSAL WELL NO. 2

NAVAJO REFINING COMPANY
ARTESIA, NEW MEXICO

Subsurface Project No. 70A4955

July 1999

Prepared By:

SUBSURFACE TECHNOLOGY, INC.
Houston, Texas

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLES

TABLE OF CONTENTS (Continued)

FIGURES

TABLE OF CONTENTS (Continued)

APPENDICES

EXHIBITS

TABLE OF CONTENTS (Continued)

EXECUTIVE SUMMARY

Navajo Refining Company (Navajo) contracted Subsurface Technology, Inc. (Subsurface), formerly Envirocorp Services & Technology, Inc., to prepare an application for permit to reenter a producing Class II well and conduct injection testing within the Wolfcamp, Cisco, and Canyon Formations. The Application for Permit to Drill or Deepen was submitted to the Department of the Interior, Bureau of Land Management (BLM), on April 13, 1999. A permit modification was submitted to the State of New Mexico Oil Conservation Commission (OCD) in April 1999.

The BLM granted approval for the reentry and testing by letter, dated April 27, 1999. The OCD granted approval for the reentry and testing on the wellbore by letter dated May 3, 1999. In April 1999, Navajo contracted Subsurface to prepare a detailed engineering plan to reenter, test and complete The Eastland Oil Company, Chukka Federal No. 2.

Under contract with Navajo, Subsurface commenced field operations on May 5, 1999. The existing location was cleared and a pad was constructed for the drilling and completion rigs. Initially a completion rig was moved in and rigged up. The existing well pumping equipment was removed and the perforations from 1446 feet to 1462 feet were squeezed with cement. A 7-7/8 inch bit was lowered into the wellbore to drill and wash to 1922 feet. The 8-5/8 inch surface casing was successfully pressure tested to 660 psi prior to drilling out the cement plug across the shoe. A cement bond log confirmed continuous cement with good bond behind the 8-5/8 inch surface casing. The completion rig was released and moved off site.

The top 10 feet of the 8-5/8 inch casing was replaced before the installation of the blowout preventer assembly. A lined reserve pit was constructed for the containment of drill cuttings and fluids. A rotary drilling rig was moved in and rigged up. The BLM and the OCD were notified, and verbally approved the commencement of reentry operations on May 13, 1999. A 7-7/8 inch bit was lowered into the wellbore to drill out cement plugs within the 8-5/8 inch surface casing.

The 7-7/8 inch bit was lowered into the open-hole portion of the wellbore and cement plugs were drilled out to a total reentry depth of 8992 feet. A fracture identification log, 4-arm caliper, and gamma-ray log were conducted within the open-hole portion of the wellbore.

The 5-1/2 inch protection casing was installed with cement circulated through the annular space from bottom to the surface using a two-stage pump and plug method on May 19, 1999. Good returns were observed at the surface while cementing. The rotary drilling equipment was released and moved off site.

A completion rig and blowout preventers were moved in and rigged up on May 24, 1999. A 4-3/4 inch bit was lowered into the wellbore to clean out and pressure test the 5-1/2 inch protection casing. On May 25, 1999, the 5-1/2 inch casing was successfully pressure tested to 1514 pounds per square inch gauge (psig) above the differential valve tool at 5785 feet. On May 26, 1999, the 5-1/2 inch casing was successfully pressure tested to 1504 psig from surface to the plugged-back total depth of 8770 feet.

The wellbore was displaced with a clean brine fluid and a baseline temperature and casing inspection surveys were performed. A cement bond log was performed over the length of the 5-1/2 inch protection casing. The injection interval (Cisco/Canyon Formations) was perforated from 7826 feet to 8399 feet at two jet shots per foot. A sample of the formation fluid was obtained for analysis and the lower injection interval was stimulated using 5000 gallons of 15% HCl acid and rock salt as a diverter.

The injection interval (L. Wolfcamp/Cisco Formations) was perforated from 7570 feet to 7736 feet at two jet shots per foot. A retrievable bridge plug and packer were set to isolate the newly perforated interval. A sample of the formation fluid was obtained for analysis and the perforations were stimulated using 5000 gallons of 15% HCl acid and rock salt as a diverter. The packer and bridge plug were removed from the wellbore in preparation for the pressure buildup portion of the falloff test.

On June 4, 1999 and June 5, 1999, an injection pressure buildup and falloff test was conducted. Upon completion of the falloff test a differential temperature log was conducted from surface to a total depth of 8736 feet. A radioactive tracer log was conducted and the results obtained from the survey confirmed external mechanical integrity of the wellbore.

A 3-1/2 inch outside diameter (OD) injection tubing and packer were installed in the well to 7528 feet. An extended annular pressure test was performed to confirm stabilization within the well system. On June 8, 1999, an annular pressure test was performed in accordance with the requirements of the OCD. The OCD witnessed the annular pressure test that successfully confirmed internal mechanical integrity at a pressure of 753 psig.

Upon conclusion of the annular pressure test, all equipment was rigged down and moved out.

1.0 INTRODUCTION

Navajo reentered, tested and completed The Eastland Oil Company, Chukka Federal No. 2 wellbore for injection of plant waste effluent. The name of the new waste disposal well will be designated as Navajo Refining Company Waste Disposal Well No. 2 (WDW-2). The wellbore is located in Section 12, T18S, R27E, Unit Letter E, approximately 11 miles east-southeast of Artesia, in Eddy County, New Mexico. A Well Location and Acreage Dedication Plat of the well location is shown on Figure 1.0-1. The construction and testing of this well were performed in compliance with the provisions of the New Mexico Water Quality Control Commission Regulations (NMWQCCR), dated November 15, 1996, Subpart V, Section Nos. 5204 and 5205, and the United States Environmental Protection Agency Code of Federal Regulations, 40 CFR 146.12, Subpart B.

Subsurface was contracted by Navajo to reenter and test WDW-2. The construction and testing of this Non-Commercial Class I Nonhazardous Waste Disposal Well were permitted by the Department of the Interior, Bureau of Land Management (BLM), and the New Mexico Energy, Minerals, and Natural Resources Department, OCD by letters dated May 3, 1999 (Appendix 1.0-1) and April 27, 1999 (Appendix 1.0-2). All work associated with WDW-2 was completed in accordance with the provisions specified in the permit approved by the BLM and OCD.

The work for WDW-2 was designated as Subsurface's Project No. 70A4955. This report summarizes all work performed on WDW-2 and includes the filing of the necessary documents.

2.0 SUMMARY OF DAILY OPERATIONS

The original wellbore was designated as the Amoco Production Company, Diamond Federal Gas Com. Well No. 1, installed July 18, 1973. The OCD Sundry Notices and Reports on Wells are presented in Appendix 2.0-1. The wellbore was constructed with a 13-3/8 inch OD conductor casing set at 40 feet and cemented to surface. An 11 inch hole was drilled to a depth of 1995 feet. Open-hole logs were conducted to include resistivity, spontaneous potential, porosity, and gamma ray, as presented in Exhibits 2.0-1 and 2.0-2. An 8-5/8 inch surface casing was set at 1995 feet and cemented to surface. A 7-7/8 inch hole was drilled to a depth of 10,372 feet to test potentially productive hydrocarbon zones. Subsequently, the wellbore was abandoned on August 31, 1973.

On August 29, 1985, Fred Pool Drilling Inc. submitted an Application for Permit to Drill or Deepen to the BLM. The wellbore was reentered to 1912 feet and completed as a producing oil well with perforations from 1446 feet to 1462 feet, as noted in the Sundry Notices and Reports on Wells (Appendix 2.0-2). The name of the wellbore was changed to the Chukka Federal Well No. 2. Figure 2.0-1 is the plugged-back wellbore schematic.

The Chukka Federal Well No. 2 continued to operate as a producing oil well from September 1985 to May 5, 1999. The Operator changed from Fred Pool Drilling, Inc. to The Eastland Oil Company prior to purchase by Navajo Refining Company in April 1999.

Navajo Refining Company submitted and received approval for the reentry, testing, and completion of the Chukka Federal Well No. 2 from the BLM on April 27, 1999.

On Monday, May 3, 1999, OCD approved the Application for Permit to Drill or Deepen Navajo Refining Company's (Navajo) WDW-2, formerly the Chukka Federal No. 2 operated by The Eastland Oil Company.

The reentry, testing, and completion operations for WDW-2 are presented in this section. Details of certain operations are referenced in the text and included as figures, exhibits, tables, and appendices.

Figure 2.0-2 is the current wellbore schematic for WDW-2. Table 2.0-I contains the detailed tubular program for WDW-2.

2.1 Cement Squeeze the Perforations

From May 5, 1999 to May 8, 1999, Navajo initiated field operations. The existing pumping equipment, rods, and tubing were removed from the wellbore. The perforations from 1446 feet to 1462 feet were squeezed using 100 sacks of Class 'H' cement. Approximately 50 sacks of cement were displaced into the perforated interval. The cement was allowed to cure and drilled out to a total depth of 1922 feet (1911 feet below ground level).

2.2 8-5/8 Inch Mechanical Integrity Testing

On Sunday, May 9, 1999, the 8-5/8 inch surface casing, set from 1955 feet (KB) to surface, was pressure tested for internal mechanical integrity between 1922 feet (KB) and 30 feet (KB) using a packer set at 30 feet. The 8-5/8 inch surface casing was pressure tested to 660 pounds per square inch (psi) and monitored at the surface for one hour. The fluid used for testing was a clean fresh water fluid. A pressure loss of 1 psi (0.15%) was observed during the first 30 minutes of the test. A pressure loss of 2 psi (0.30%) was observed during the last 30 minutes of the test. The results from the pressure test confirmed internal mechanical integrity of the 8-5/8 inch surface casing from 1922 feet (KB) to 30 feet (KB).

On Sunday, May 9, 1999, Halliburton Logging Services completed a Cement Bond Log and Microseismogram (same as a variable density log), CBL/MSG, survey within the 8-5/8 inch casing from a wireline total depth of 1919 feet (KB) to the surface (Exhibit 2.2-1). The results from the survey indicate a continuous column of cement from 1922 feet to surface with good bonding characteristics. The cement behind the 8-5/8 inch casing will provide an effective hydraulic seal to prevent the movement of groundwater fluids into the underground source of drinking water with a base at 473 feet.

The workover rig was rigged down. A letter requesting regulatory approval for the surface casing pressure test and CBL/MSG log was submitted to the OCD for review and approval (Exhibit 2.2-2).

From Monday, May 10, 1999 to Tuesday, May 11, 1999, the 8-5/8 inch riser was replaced and the reserve pit was excavated.

2.3 Preparation of the Drillsite

On May 12, 1999, a 6 millimeter, high density, polyethylene liner was installed in the reserve pit. The rathole and mouseholes were installed in accordance with Patterson Rig 47 specifications.

2.4 Mobilization of the Drilling Equipment

On May 13, 1999, Patterson moved in and rigged up the drilling rig. A rental wellhead was installed and the blowout prevention equipment was installed and tested in accordance with The United States Department of the Interior, Bureau of Land Management, Onshore Order No. 2 Specifications (Appendix 2.5-1).

2.5 Reentry Operations

On May 14, 1999, a 7-7/8 inch bit was lowered into the 8-5/8 inch casing to drill out the 100-foot cement plug from 1922 feet to 2093 feet. The drillpipe was washed into the wellbore to 2898 feet. A deviation survey at 2898 feet indicated ¼-degree inclination. The wellbore was washed out to 3830 feet. A deviation survey at 3838 feet indicated ¼-degree inclination. The wellbore was washed and reamed to 4783 feet. A deviation survey at 4783 feet indicated ½-degree inclination. The wellbore was washed and reamed to 5082 feet.

On May 15, 1999, the cement plug at 5450 feet was tagged. The blowout prevention equipment was successfully tested in accordance with Section III(A) of the Conditions for Approval attached to the Application for Permit to Drill or Deepen, approved April 27, 1999. The BLM was notified by letter of the blowout prevention equipment pressure test results on May 17, 1999 (Appendix 2.5-1). The wellbore was washed and reamed to 6106 feet. A deviation survey at 6106 feet indicated an inclination of 3/4 degree. The wellbore was washed and reamed to 6500 feet. The mud weight was increased to 8.7 pounds per gallon (ppg).

On May 16, 1999, the wellbore was washed and reamed to 6633 feet. A deviation survey at 6633 feet indicated an inclination of 1/2 degree. The wellbore was washed and reamed to 7269 feet and the mud weight was increased to 8.9 ppg. At 7500 feet, a small amount of gas was circulated out of the wellbore and the mud weight was increased to 9.1 ppg. The wellbore was washed reamed to 8100 feet. There was no indication of a cement plug from 7435 feet to 7534 feet.

On May 17, 1999, the wellbore was washed and reamed to total depth at 8992 feet. The wellbore was circulated clean and a short trip to 1900 feet did not indicate tight spots, bridges, or excessive drag on the drillpipe. The drillpipe, drill collars, and bit were removed from the hole.

On May 18, 1999, Halliburton Logging Services performed a 4-arm caliper survey from 8901 feet to 1800 feet (Exhibit 2.5-1), and a fracture identification survey from 8900 feet to 4000 feet (Exhibit 2.5-2). Cement volumes were calculated using the 4-arm caliper survey with 20% excess.

The bit, drill collars, and drillpipe were lowered into the hole to tag 30 feet of fill. The wellbore was circulated clean and the drillpipe was pulled out of the hole and laid down.

2.6 Installation of the Protection Casing

On May 19, 1999, 119 joints of 5-1/2 inch, 17 lb/ft, L-80, LTC, new, seamless, Range 3 protection casing were installed in WDW-2 (Table 2.6-I). The Mill Test Report from the manufacturer is included in Appendix 2.6-1. The packoff float shoe was set at 8869 feet, float collar at 8788 feet, and DV tool at 5792 feet. The

BLM was notified of the cementing operations. Halliburton cemented the first stage using 20 barrels of fresh water, 12 barrels of Super Flush, 20 barrels of water, and 575 sacks of modified Class 'H' cement (yield = 1.71 ft^3/sack at 13.0 ppg). The DV tool was opened and a total of 20 sacks of cement was displaced to the surface. A total of 18 hours was allotted to wait on cement to cure above 500 psi compressive strength.

On May 20, 1999, the second stage was successfully completed with 20 barrels of water, 12 barrels of Super Flush, 20 barrels of water, 300 sacks of Interfill 'C' (yield = 2.77 lb/sack at 11.7 ppg), and 695 sacks of modified 'H' cement (yield = 1.71 lb/sack at 13.0 ppg). The DV tool was closed with 3300 psi and a total of 150 sacks of cement was displaced to the reserve pit. Mr. J.D. Whitlock, representing the BLM, was on site and witnessed the second stage cementing operations. The cement was allowed to cure for 12 hours.

On May 21, 1999, the blowout preventers were removed and the rig was released. A Larkin Type 'R' 5-1/2 inch by 3-1/2 inch wellhead was installed. Ready-mix cement was used to stabilize the 5-1/2 inch casing and the location was cleaned up in preparation of completion operations.

From May 22, 1999 to May 23, 1999, preparations were performed prior to completion activities.

2.7 Testing and Completion Operations

On May 24, 1999, Key Energy Services, Inc. moved in and rigged up a completion rig, pump, tank, power swivel, and 2-7/8 inch EUE 8rd work string. A 6 inch manual blowout preventer was installed for pressure control. A piece of pipe was lost in the hole during rig-up operations.

On May 25, 1999, the lost piece of pipe was successfully washed over and retrieved from the wellbore. A 4-3/4 inch outside diameter rock bit and six 3-1/2 inch drill collars were lowered into the wellbore on the 2-7/8 inch work string. The well system was pressurized to 1514 psig and monitored for testing. A loss of 17 psi per 30 minutes was observed (-1.15%) during the pressure test. The DV tool was drilled out.

On May 26, 1999, the bit was lowered into the well to wash and drill to a total plugged-back depth of 8770 feet (Table 2.7-I). The wellbore was circulated clean, pressurized to 1584 psig, and monitored for testing. A loss of 16 psi per 30 minutes was observed (-1.01%) during the pressure test (Figure 2.7-1).

On May 27, 1999, a bit and scraper were lowered into the wellbore to 8569 feet. A total of 500 gallons of 15% HCl inhibited acid preceded displacement of 250 barrels of 8.7 ppg clean brine water. Fluid returns were circulated to the reserve pit.

On May 28, 1999, a differential temperature survey was conducted within the 5-1/2 inch protection casing from surface to 8769 feet. The well system was pressurized to 1000 psig and a cement bond survey, concurrent with a casing inspection survey, was conducted from 8769 feet to 100 feet.

2.8 Perforating and Testing the Cisco/Canyon Formations

On May 29, 1999, the wellbore was perforated within the injection interval at two jet shots per foot, 120 degree phasing, using retrievable casing guns. The selected intervals were determined from the Compensated Neutron-Formation Density Log, dated August 27, 1973, as follows: 7826-34 feet, 7858-80 feet, 7886-7904 feet, 7916-36 feet, 7944-64 feet, 7990-8042 feet, 8096-8116 feet, 8191-8201 feet, 8304-8319 feet, 8395-99 feet. This interval has been designated Zone 1. The wellbore fluid level dropped during the perforating operations.

On May 30, 1999, Zone 1 was swab tested and a formation fluid sample was retrieved for analysis. The results from the laboratory analysis on the Zone 1 formation fluid sample are presented in Appendix 2.8-1.

On May 31, 1999, the injection interval from 7820 feet to 8392 feet (Zone 1) was stimulated with 5000 gallons of inhibited 15% HCl acid. A total of 2300 pounds of salt was used as diverter during the stimulation operations. A final test rate indicated WDW-2 can accept an 8.7 ppg brine water at 7 bpm on a vacuum.

2.9 Perforating and Testing the L. Wolfcamp/Cisco Formations

On June 1, 1999, the wellbore was perforated within the injection interval at two jet shots per foot, 120-degree phasing, using retrievable casing guns. The selected intervals were determined from the Compensated Neutron-Formation Density Log, dated August 27, 1973, as follows: 7570 feet to 7620 feet and 7676 feet to 7736 feet. This interval has been designated Zone 2. The wellbore fluid level remained at approximately 1300 feet during the perforating operations. A complete record of the perforated intervals is presented in Table 2.9-I.

On June 2, 1999, Zone 2 was swab tested and a formation fluid sample was retrieved for analysis. The results from the laboratory analysis on the Zone 2 formation fluid sample are presented in Appendix 2.8-1.

On June 3, 1999, the injection interval from 7570 feet to 7736 feet (Zone 2) was stimulated with 5000 gallons of inhibited 15% HCl acid. A total of 2300 pounds of salt was used as a diverter during the stimulation operations. A final test rate indicated WDW-2 can accept an 8.7 ppg brine water at 7 barrels per minute (bpm) on a vacuum.

2.10 Injectivity Testing

On June 4, 1999, an electric wireline unit was moved in and rigged up with a digital quartz surface readout and memory backup pressure gauge. Both gauges were run into the well to a depth of 7570 feet. The initial bottom-hole pressure was 2843.86 pounds per square inch absolute (psia) at 124°F. Injection of an 8.7 ppg brine water was initiated at 10 bpm on a vacuum and continued for 12.75 hours. The final injection pressure was 2939 psia at 88°F. Injection of brine was discontinued and the bottom-hole pressure falloff was monitored at the surface.

On June 5, 1999, the pressure falloff was discontinued and the tools were removed from the wellbore while making gradient stops at 6000 feet, 4500 feet, 3000 feet, 1500 feet, and at the surface. A differential temperature survey was performed from the surface to a wireline total depth of 8736 feet (top of fill). A radioactive tracer survey confirmed external mechanical integrity of the 5-1/2 inch protection casing and provided an injection profile across the perforated intervals.

2.11 Installation of the Injection Tubing and Packer

On June 6,1999, a 5-1/2" x 3.5" Weatherford (Arrow) Model X-1 packer (Figure 2.11-1) was lowered into the wellbore on the 3-1/2 injection tubing (Table 2.11-I). The annulus was displaced with an 8.7 ppg corrosion inhibited brine water as packer fluid. The corrosion inhibitor was a Unichem TECHNI-HIB 370, as presented in the product information and Material Safety Data Sheets presented in Appendix 2.11-1. Mill test and inspection reports for the 3-1/2 inch injection tubing are presented in Appendix 2.11-2. The packer was set 7528 feet with 18,000 pounds of compression and the annulus was pressurized to 771 psig. The annular pressure was monitored for stabilization through June 7, 1999.

On June 8, 1999, an annulus pressure test was performed. The OCD elected to witness the test. The annulus was pressurized at 752 psig and monitored for 30 minutes. The final test pressure was 753 psig, an increase of 1 psi (0.13%), which is within the 10% allowed by the regulations. Upon the conclusion of the annulus pressure test the rig and ancillary equipment were rigged down and moved off site.

The installation of WDW-2 was completed on June 8, 1999. The wellhead was secured and the well remained shut in pending approval of the permit by the OCD.

2.12 Chronology of Field Activities

Appendix 2.12-1 is a Chronology of Field Activities from the Field Activity Reports.

3.0 MECHANICAL INTEGRITY TESTING

The demonstration of the mechanical integrity of WDW-2, required by NMWQCCR Subpart V, Section 5204(A) to (D) and Section 5205(A)(1)(a), included a casing inspection log of the 5-1/2 inch protection casing, pressure testing of the 5-1/2 inch protection casing, cement bond log of the 8-5/8 inch and 5-1/2 inch casings, a radioactive tracer survey, a differential temperature survey, and an annular pressure test. Results of these tests demonstrated that the well had internal and external mechanical integrity.

3.1 5-1/2 Inch Protection Casing Inspection Log

On May 28, 1999, Halliburton Logging Services conducted a casing inspection log from 8769 feet to the surface (Exhibit 3.1-1). A Circumferential Acoustic Scanning Tool was used to conduct the casing inspection survey. The data obtained from the survey may be used as a baseline for future comparison.

3.2 5-1/2 Inch Protection Casing Pressure Test

The protection casing was successfully pressure tested to 752 psig on June 8, 1999, for 30 minutes. A pressure gain of 1 psi was observed, as indicated on the pressure test chart shown on Figure 3.5-1.

3.3 Cement Bond Logging

A cement bond log was conducted within the 8-5/8 inch surface casing during the reentry operations from 1910 feet to the surface. Upon installation of the 5-1/2 inch protection casing, a cement bond log was conducted. A total of two strings of casing were successfully installed and cemented across the base of the underground source of drinking water (USDW).

3.3.1 8-5/8 inch Cement Bond Log

On May 9, 1999, a cement bond with variable density log was performed within the 9-5/8 protection casing from 1910 feet to the surface (Exhibit 2.2-1). The data obtained from the cement bond log confirmed a continuous column of cement with good bonding characteristics behind the 8-5/8 protection casing from 1910 feet to 116 feet. The hydraulic coupling was lost above 116 feet and the tool would not respond. A letter of interpretation of the surface casing cement bond/variable density log is presented as Exhibit 2.2-2.

3.3.2 5-1/2 Inch Cement Bond Log

A cement bond with variable density log was conducted on the 5-1/2 inch protection casing on May 28, 1999 (Exhibit 3.3.2-1). As indicated on the log, a continuous column of cement extends from the base of the protection casing from a plugged-back depth of 8769 feet to the surface. Cement bonding was indicated to be sufficient for completion of the well. A letter of interpretation of the protection casing cement bond/variable density log is presented as Exhibit 3.3.2-2.

The adequacy of the cement above the top of the perforations was successfully confirmed in the subsequent radioactive tracer survey discussed in Section 3.4 and differential temperature survey discussed in section 3.6.

The results obtained from the cement bond and variable density logs conducted on the surface casing and the protection casing established that a continuous column of cement, with good compressive strength and cement bond, existed behind both casings. The installation of two casing strings across the base of the USDW, both of which demonstrate a continuous column of cement from surface to bottom, assures protection of the USDW.

3.4 Radioactive Tracer Survey

A radioactive tracer survey for WDW-2 was performed on June 5, 1999, following the reservoir evaluation testing operations and prior to the installation of the injection packer. The radioactive tracer survey consisted of running statistical checks, two baseline gamma ray surveys, and ejecting four slugs of radioactive material. Two (2) of the slug tests were stationary time-drive surveys and two were moving surveys. The radioactive tracer log, conducted June 5, 1999, is presented as Exhibit 3.4-1. An injection profile analysis log is presented as Exhibit 3.4-2. All tests were conducted while injecting a nonhazardous brine water into the well.

The radioactive tracer tool was lowered into the well to tag the total depth at 8743 feet. A pre-survey baseline gamma ray log was conducted from 8743 feet to 7460 feet. A pre-survey statistical check was performed at 7550 feet (20 feet above the top perforation) for five minutes.

The moving surveys were conducted with the radioactive tracer tool initially positioned at 7460 feet (above the intended packer setting depth). The injection of a nonhazardous brine was initiated at a rate of 1/2 bpm. A slug of radioactive material was ejected and verified for intensity. The slug's downward movement was recorded by logging upward through the slug intermittently as it moved downward and dissipated into the perforated interval. This test was repeated at an injection rate of 1/2 bpm. The results obtained from the moving surveys determined that the ejected radioactive material was exiting into the permitted injection interval; therefore, mechanical integrity was confirmed between the intended packer setting depth and the top of the injection interval.

The injection of a nonhazardous brine was increased to 10 bpm. The radioactive tracer tool was positioned with the bottom detector at 7550 feet, which is 20 feet above the top of the top perforation, and a stationary time-drive survey was conducted. The tool remained stationary across the interval and the well was monitored for upward migration above 7550 feet for 15 minutes. This test was repeated and monitored for upward migration above 7550 feet for 15 minutes. No upward migration of radioactive material was observed during either survey.

A post-survey baseline gamma ray log was performed from 8727 feet to 7453 feet, with no residual radioactive material.

3.5 Annular Pressure Test

The official annular pressure test was conducted on June 8, 1999. The injection packer and tubing had been installed and the wellbore allowed to attain a thermal equilibrium.

A Barton circular chart recorder (Serial Number 0323), scaled from 0 psig to 1000 psig, was installed to monitor the annulus pressure. The OCD representative, Mr. Van Barton, was present to witness the annulus pressure test. At 0800 hours, the initial annulus pressure was 752 psig. At 0830 hours, the final annulus pressure was 753 psig. This represents a pressure gain of 1.00 psi in 30 minutes, which is within the limit of 10% in 15 minutes allowed by the OCD. An annulus pressure test chart is presented as Figure 3.5-1.

3.6 Differential Temperature Survey

A baseline differential temperature survey was performed on May 28, 1999 (Exhibit 3.6-1) following the cleanout of the 5-1/2 inch protection casing to 8770 feet. On June 5, 1999, a second differential temperature survey was performed following the reservoir evaluation testing, which included 12-hour injection of an 8.7 ppg brine water into the permitted injection interval (Exhibit 3.6-2).

As indicated on the May 28, 1999 baseline differential temperature log, the wellbore temperature increased steadily from 77.0 degrees at the surface to 154.0 degrees at 8769 feet. A temperature gradient of 0.01 degrees per foot was observed.

On June 5, 1999, a second differential temperature log was performed following the injection of brine water into the injection interval. A temperature gradient of .01 degrees per foot was observed from surface to the top perforation at 7570 feet. A significant cooling anomaly was observed within the perforated injection interval as temperatures cooled to 97.5 degrees. The data obtained from the differential temperature survey confirmed external mechanical integrity of the 5-1/2 inch protection casing and may be used for comparison during future surveys.

4.0 RESERVOIR EVALUATION

4.1 Bottom-Hole Pressure Testing

The bottom-hole pressure testing which was conducted on WDW-2, following the completion of the well, was designed to obtain the best estimate of permeability and transmissibility in the reservoir. The pressure testing on WDW-2 consisted of a static gradient survey and an injectivity/falloff test. Appendix 4.1-1 lists the time and pressure data recorded during the static gradient survey, injection period, and falloff period.

4.1.1 Static Gradient Survey and Bottom-Hole Pressure Analysis

On June 5, 1999, static gradient measurements were performed after conducting the injection/falloff test on WDW-2. Pressure data from the gradient stops made at the surface, 1500 feet, 3000 feet, 4500, 6000 feet, and 7570 feet are shown on Table 4.1.1-I. The gradient data are presented graphically as Figure 4.1.1-1. The static fluid gradient at 7570 feet was determined to be 0.429 psi per foot. The fluid level was at approximately 1292 feet.

4.1.2 Analysis of the Falloff Test

On June 4, 1999, a HP surface readout digital quartz pressure transducer with memory tool backup was positioned at 7570 feet in WDW-2 and allowed to stabilize for approximately 45 minutes. Injection into WDW-2 commenced at 0912 hours at an injection rate of 428.4 gallons per minute (gpm). WDW-2 was shut in at 2156 hours and the bottom-hole pressure and temperature were recorded for 7.2 hours.

The pressure data obtained during the falloff test were analyzed with the assistance of the commercially available pressure transient analysis software program "PanSystem2, Version 2.5". Appendix 4.1.2-1 contains the output from this software program. Figure 4.1.2-1 shows the pressure response recorded by the pressure tool from the time the tool was in place through the 7.2-hour shutin period. Figure 4.1.2-2 is a log-log diagnostic plot of the falloff data, showing change in pressure and pressure derivative versus equivalent shutin time. The radial flow period is denoted on Figure 4.1.2-2.

The reservoir permeability was determined from the radial flow region of the superposition Horner plot (Figure 4.1.2-3). The radial flow regime begins at a Horner time of 16.9 and continues to 8.6. Figure 4.1.2-4 shows an expanded view of the superposition Horner plot. The slope of the radial flow period was determined to be 1.563604 psi per cycle.

An estimate of mobility-thickness, kh/μ, for the reservoir was determined from the following equation:

$$\frac{k\ h}{\mu} = 162.6\ \frac{q\ B}{m}$$

where,

kh/μ	=	mobility-thickness, md-ft/cp
q	=	flow rate, barrels per day
μ	=	viscosity, centipoise
B	=	formation volume factor, reservoir vol/surface vol
m	=	slope of semi-log straight line, psi/cycle

Using an injection rate of 428.4 gpm (14,688 barrels per day) and the information previously mentioned results in a mobility-thickness of 1,527,413 md-ft/cp:

$$\frac{k\ h}{\mu} = 162.6\ \frac{(14{,}688)(1.0)}{1.563604}$$

$$= 1{,}527{,}413\ \text{md-ft/cp}$$

Multiplying this value by the viscosity, μ, results in transmissibility, kh:

$$k\ h = \left(\frac{k\ h}{\mu} \right) \mu$$

$$= (1{,}527{,}413)\ (0.53)$$

$$= 809{,}529 \quad md\text{-}ft$$

And finally, permeability is determined by dividing transmissibility by the formation thickness. The formation thickness is 299 feet, which results in a permeability of 2707 md.

$$k = \frac{(k\ h)}{h}$$

$$= \frac{809{,}529}{299}$$

$$= 2707 \quad md$$

The skin factor was determined from the following equation:

$$s = 1.151 \left[\frac{p_{wf} - p_{1\,hr}}{m_1} - \log \left(\frac{k_p}{\phi\ \mu\ c_t\ r_w^2} \right) + 3.23 \right]$$

where,

s	=	formation skin damage at open perforations, dimensionless
1.151	=	constant
p_{wf}	=	flowing pressure immediately prior to shutin, psi
$p_{1\,hr}$	=	pressure determined by extrapolating the first radial flow semi-log line to a Δt of one hour, psi
m_1	=	slope of the first radial flow semi-log line, psi/cycle
k_p	=	permeability of the formation opposite the open perforations, md
ϕ	=	porosity of the injection interval, fraction

μ = viscosity of the fluid the pressure transient is traveling through, centipoise

c_t = total compressibility of the formation plus fluid, psi^{-1}

r_w = radius of the wellbore, feet

3.23 = constant

The final flowing pressure, p_{wf}, was 2939.42 psia. The pressure determined by extrapolating the radial flow semi-log line to a Δt of one hour, $p_{1\,hr}$, was 2846.23 psi. The porosity of the injection interval, ϕ, is 0.10 and the total compressibility, c_t, is 8.4×10^{-6} psi^{-1}. The wellbore radius, r_w, is 0.3281 feet. Using these values in addition to the previously determined parameters, m and k, results in a skin of 59.9:

$$s = 1.151 \left[\frac{2939.42 - 2846.23}{1.563604} - \log\left(\frac{2707}{(0.10)(0.53)(8.4 \times 10^{-6})(0.3281)^2} \right) + 3.23 \right]$$

$$= 59.9$$

The "Auto-Match" feature of PanSystem2 was used to improve upon the reservoir parameters. The final results of the auto-match are shown on Figures 4.1.2-5 through 4.1.2-7. These figures show the falloff data in cartesian, superposition Horner, and log-log formats with the simulated pressures overlaid.

SUBSURFACE

RE-ENTRY AND COMPLETION REPORT
WASTE DISPOSAL WELL NO. 3

NAVAJO REFINING COMPANY
Artesia, New Mexico

SUBSURFACE PROJECT NO. 70F5826

December 2006

PREPARED BY

SUBSURFACE CONSTRUCTION CORP.
6925 Portwest Dr., Suite 110
Houston, Texas77024

SUBSURFACE

February 5, 2006

Mr. Darrell Moore
Navajo Refining Company
P.O. Box 159
Artesia, NM 88211

RE: Re-Entry and Completion Report Waste Disposal Well No. 3;
Subsurface Project No. 70F5826

Dear Darrell:

Enclosed are four (4) copies of the above-referenced report. Four copies have been included for your records and for the State of New Mexico Energy Minerals and Natural Resources Department, Oil Conservation Division.

If you should have any questions, please feel free to contact me at (713) 880-4640.

Very truly yours,

Rusty L. Smith
Project Engineer, EIT

RLS/bl

Enclosures

Moore1_Ltr

Subsurface Construction Corp.
6925 Portwest Drive Suite 110 Houston TX 77024
713/880-4640 Fax 713/880-3248 1-800-535-4105

TABLE OF CONTENTS

TABLES

FIGURES

APPENDICES

ATTACHMENTS

EXECUTIVE SUMMARY

Navajo Refining Company (Navajo) contracted Subsurface Technology, Inc. (Subsurface), to prepare an Application for Permit and to Re-enter a Plugged and Abandoned (P&A) Oil and Gas Well. The Application for Permit to Drill or Re-enter and the Sundry Notices and Reports on Wells was submitted to the Department of the Interior, Bureau of Land Management (BLM), on June 29, 2006, and approved. The Application for Permit to Drill, Re-enter, Deepen, Plug Back, or add a Zone was submitted to the State of New Mexico Oil Conservation Commission (OCD) on June 29, 2006, and approved.

Subsurface prepared an engineering plan to re-enter the P&A' oil and gas well formally owned by Mewbourne Oil Company. The original well name was Caulk Bluff Federal No. 1 (API number 30-015-26575), and a Change of Operator application was submitted to the OCD on December 5, 2000, and approved under the well name of WDW-3. Under contract to Navajo, Subsurface commenced field operations on September 25, 2006. The existing location was cleared and prepared for re-entry operations. An earthen lined reserve pit was dug to catch returns. All depths, unless stated, are referenced to workover rig floor at six feet to seven feet above ground level. The rig floor was moved from six feet to seven feet after drilling out the cast iron bridge plugs.

A workover rig and reverse unit was placed on location and the existing wellhead was removed. The first cast iron bridge plug (CIBP) at 7010 feet was drilled and the perforated interval from 7050 feet to 7102 feet was squeezed off with neat cement and successfully pressured tested to six hundred eighty pounds per square inch gauge pressure (680 psig). The second and third CIBP at 7190 feet and 7279 feet was drilled. There appeared to be ten feet of cement on top of the third CIBP. The perforated interval from 7262 feet to 7278 feet and from 7304 feet to 7314 feet was squeezed with neat cement. The squeezed interval was pressure tested to 920 psig and would not hold. A second cement squeeze was performed across the perforated interval from 7262 feet to 7278 feet and from 7304 feet to 7314. The interval was pressured tested to 630 psig and continued to lose pressure at a rate of two pounds per square inch every thirty minutes (2 psi/30 min). The fourth CIBP at 7595 feet was drilled and at 7838 feet a cement plug was encountered and drilled through. Cement was tagged twenty nine (29) feet above the top of the liner at 9022 feet. The hole was circulated clean and prepared for logging.

A Cement Bond Log (CBL), Variable Density Log (VDL), caliper log, and temperature survey were performed. The CBL/VDL showed that the top of the cement (TOC) behind the 7-inch casing was located 900 feet from the surface. The OCD was notified and approved the existing well condition. The casing was perforated from 7660 feet to 8450 feet and from 8540 feet to 8620 feet at 2-JSPF on sixty degree (60°) phasing.

A packer was set at 7546 feet with 2 7/8-inch PH-6 tubing, the well was swabbed back and samples of the formation fluid were recovered. It was estimated that two hundred twenty six barrels (226 bbls) of formation fluid was returned to the surface. A pressure test on the annulus between the 7-inch and 2-7/8-inch was performed at 660 psig with the annulus losing pressure at a rate of 8 psi/hr.

An injection test was performed on the well down the 2-7/8-inch tubing with the annulus open to the bottom of the well. The open annulus will allow for the calculation of the bottom hole pressure while pumping down the 2-7/8-inch tubing with out the influence of tubing friction pressure on the bottom hole calculations. The injection rates were from two barrels per minute (2 bpm) to ten barrels per minute (10 bpm). From the data collected during the injection test it appears that the well will be able to accept an injection rate up to 10 bpm at the permitted pressure of 1550 psig with 4-1/2-inch, 11.6 pound per foot (11.6 lb/ft) tubing in the wellbore.

At the request of the OCD, Subsurface went back into the wellbore with a retrievable bridge plug (RBP) to test the casing and isolate any leaks to within 1000 feet. The RBP was set at 7550 feet and the packer was set at 6985 feet to isolate the squeezed interval from 7050 feet to 7314 feet. The squeezed interval was pressure tested to 490 psig and the annulus to 632 psig. The squeezed interval was losing pressure at a rate of 6 psi/hr and the annulus was gaining pressure due to thermal affects. The RBP was moved up the wellbore to 1255 feet and casing pressure tested to 569 psig. The casing above 1255 feet was losing pressure at a rate of 2 psi/hr. The casing leaks were isolated to the squeezed interval from 7050 feet to 7314 feet and in the interval from surface to 1255 feet. The

OCD was called and approved the 300PSI sealing application to stop the casing leaks across the two intervals.

The 4-1/2-inch tubing was run into the wellbore and the Arrow X-1 packer was set at 7575.73 feet with 37,000 lbs of tension. Prior to running the 4-1/2-inch tubing a new Superior hanging spool was installed. Prior to setting the tubing packer, the annulus between the 4-1/2-inch tubing and the 7-inch casing was filled with inhibited brine, with the 300psi sealant across the squeezed perforations and across the upper section of the 7-inch casing. Once the packer was set and tubing hung off in the spool, a new Superior wellhead was installed and the P-seals were pressure tested to 3000 psig. After the wellhead was assembled the annulus was squeezed at 545 psig for four hours (4 hrs), as specified by the sealant manufacture representative on site. The annulus was then pressure tested to 480 psig overnight with no pressure loss. The workover rig was disassembled and moved off location with all associated equipment.

A 12-hr pump-in and falloff test was performed down the 4-1/2-inch tubing. To maintain a surface injection pressure that was below the permitted pressure of 1550 psi the injection rate was lowered to 9 bpm at the end of the pump-in procedure. The BHP gauge was placed at 8630 feet for 14 hrs to monitor BHP. When the gauge was pulled, five minute (5 min) gradient stops were made every 1000 feet with the first stop at 7000 feet. The equipment used to perform the falloff testing was moved off location to prepare for mechanical integrity testing (MIT).

The MIT consisted of an annulus pressure test and a radioactive tracer survey. The temperature survey was performed during the CBL/VDL logging event and will be used as a baseline for any future temperature surveys. The annulus pressure test was performed at 530 psia and lost 2.5 psi over a one-hour period, which was within the OCD requirements of five percent (5%) over a 30 minute time interval. The radioactive tracer survey showed no signs of fluid flow out of the permitted interval above 7650 feet. The OCD witnessed the annular pressure test and the first half of the radioactive tracer survey.

The annulus monitoring system will be installed and tested in March 2007. After the installation of the well annulus monitoring system, the well will be turned over to Navajo for injection.

1.0 INTRODUCTION

Navajo re-entered, tested, and completed WDW-3 for the injection of plant waste effluent. The well is located in Section 1, Township18 South, Range 27 East (S1-T18S-R27E) approximately 11.5 miles east-southeast of Artesia, New Mexico in Eddy County. A Well Location and Acreage Dedication plat of the well location is located in Appendix 2.0-2. The construction and testing of this well was performed in compliance with the provisions of the New Mexico Water Quality Control Commission Regulations (NMWOCCR) Subpart V, Section Nos. 5204 and 5205, New Mexico Oil Conservation Division Underground Injection Control (UIC) Program Manual, and the Environmental Protection Agency (EPA) Code of Federal Regulations 40 CFR 16.12, Subpart B.

Subsurface was contracted by Navajo to re-enter and test WDW-3. The construction and testing of this Non-Commercial Class I Nonhazardous Waste Disposal Well was permitted by the BLM and the OCD. All work associated with WDW-3 was completed in accordance with the provisions specified in the permit approved by the BLM and OCD.

The following report and contracted work on WDW-3 was designated as Subsurface Project No. 70F5826. The following report summarizes all work performed on the WDW-3 and includes the fillings of the necessary documents. The report is broken down into four parts Summary of Daily Activities, Mechanical Integrity Testing, Reservoir Evaluation, and Regulatory Compliance. For continuity this report is written in the same structure as the report completed on WDW-2. The well reentry procedure can be found in 1.0-1.

2.0 SUMMARY OF DAILY OPERATIONS

The reentry, testing, and completion operations for WDW-3 are presented in this section. Details of certain operations are referenced in the text and included as figures, exhibits, tables, and appendices. Appendix 2.0-1 contains a Chronology of Field Activities from the Field Activity Reports.

The original wellbore was designated as the Mewbourne Oil Company, Chalk Bluff Federal No. 1 (API No. 30-015-26575), installed March 7, 1991, as a producing oil & gas well. The wellbore was constructed with 13-3/8-inch, 54.5 lb/ft surface casing set to 400 feet in a 17-1/2-inch hole and was cemented to the surface. A 9-5/8-inch, 36 lb/ft intermediate casing was set at 2600 feet in a 12-1/4-inch hole and cemented to the surface. The 7-inch, 26 lb/ft and 29 lb/ft production casing was set at 9450 feet in an 8-3/4-inch hole and was cemented to 900 feet below ground level (GL). On March 7, 1991, the well was deepened to 10,119 feet and a 4-1/2-inch, 11.6 lb/ft liner was installed from 9051 feet to 10,119 feet and cemented in place with 175 sks of cement. The well was plugged and abandoned on August 14, 1995. The well was acquired by Navajo on November 27, 2000. The current well configuration is presented in Figure 2.0-1 and Table 2.0-1.

Navajo submitted the application to recomplete the well to both the BLM and the OCD on June 6, 2006, and received approval from the OCD on August 11, 2006, (Appendix 2.0-3 and Appendix 2.0-4). The Sundry Notices and Reports on New Wells notification was submitted to the BLM on June 6, 2006, (Appendix 2.0-5). The New Mexico Energy, Minerals and Natural Resources Department sent a letter of approval to discharge according to UIC-CLI-008-3 on June 23, 2004, which was later modified to raise the top of the injection interval from 7750 feet to 7650 feet (Appendix 2.0-6)

2.1 LOCATION CLEARING AND RIG MOBILIZATION

On September 27, 2006, Banta's roustabout crew arrived at the job site with two back holes and a three man crew. The location was cleared of all overgrowth and a thirty feet by thirty feet by five feet (30 ft x 30 ft x 5 ft) lined pit was dug to hold returns. An eight foot by seven foot by three foot (8 ft x 7 ft x 3 ft) cellar was dug around the wellhead in order to inspect the lower section of the wellhead for repairs. New valves and fittings were installed on the existing wellhead. Rig support equipment started to arrive at the job site.

On September 28, 2006, the roustabout crew framed in the cellar and the Basic workover rig arrived at the job site. The rig was spotted and the remaining support equipment arrived at the job site. The derrick was erected and the rig crew repaired the sand line break and replaced the drilling line. The 2-7/8-inch work string was tallied at 9413.59 feet with a bottom hole assembly of 126.45 feet (See Table 2.1-1).

On September 29, 2006, the wellhead was inspected by a Superior Wellhead technician and was found to be an eleven inch, three thousand pound, by seven inch, five thousand pound (11^3 x 7^5) Cameron type spool. The Cameron type spool attached to the wellhead had been discontinued and Superior suggested that the spool be replaced. The remaining support equipment arrived at the job site and was rigged up for drilling. The annular blow out preventer (BOP) was attached up to the wellhead and the rig crew went into the wellbore with 2-7/8-inch, 7.9 lb/ft, PH-6 tubing, four 4-3/4-inch drill collars, 46.67 lb/ft, and a 6-1/8-inch Baker Hughes Rock bit. The rig crew tagged bottom at 7001 feet.

2.2 DRILLING OF CAST IRON BRIDGE PLUGS AND CEMENT SQUEEZING OF THE PERFORATIONS

On September 30, 2006, the sand line brake on the rig would not hold and operations were shut down until the brake was repaired. On October 1, 2006, first CIBP was drilled out with no show of cement or drilling mud. The second CIBP was tagged at 7190 feet. The well was circulated clean with brine water and an injection test was performed. The rig crew tripped out of the hole (TOOH) with the work string and tripped into the hole (TIH) with the work string excluding the bit and drill collars (open ended) to spot cement for squeeze operations.

On October 2, 2006, the first cement squeeze was executed across the perforations from 7050 feet to 7102 feet. Halliburton spotted eighty sacks (80 sks) of Premium Plus neat 14.8 ppg cement across the perforations. The rig crew pulled nine stands to get out of the cement and circulated out any excessive that was trapped in the work string. Halliburton was able to pump four barrels (4 bbls) of cement into the formation before reaching a squeeze pressure of 2000 psig. The well was shut-in over night with 680 psig left on the wellhead.

On October 3, 2006, the rig crew tagged cement at 6873 feet assuming the hole was full of cement to the CIBP. At 7190 feet there were 12.1 bbls of cement left in the wellbore. The total amount of cement spotted in the wellbore was 18.7 bbls leaving 6.6 bbls of cement either place in the formation or circulated out of the wellbore. It was estimated that 3.5 bbls were circulated out of the tubing during the clean out, leaving 3.1 bbls placed into the formation (Halliburton Report Appendix 2.1-1). The cement in the wellbore was drilled out to the top of CIBP at 7190 feet and the well was pressure tested to 578 psig. The well lost 123 psi over a thirteen and half hour period at 9.1 psi/hr (1.58%).

On October 4, 2006, the second CIBP was drilled out and the third CIBP was tagged at 7278.96 feet. It was estimated that there was 9 feet of cement on top of the third CIBP. The third CIBP was drilled out and the formation started to take fluid at a rate of 1.0 bpm to 1.25 bpm. It was estimated that during circulation 180 bbls of 8.7 ppg brine was lost to the formation. The fourth CIBP was tagged at 7591 feet. The hole was circulated clean to prepare for the second cement squeeze operation. A pump-in test was performed and the well would take fluid at a rate of 4.5 bpm at 710 psig. The rig crew TOOH with collars and bit and TIH open ended to spot cement for squeeze operations.

On October 5, 2006, the bottom of the work string was placed at 7321 feet. Halliburton pumped 100 sks of 14.8 ppg Premium Plus neat cement across the perforations. The rig crew pulled ten stands and Halliburton started to squeeze into the formation using a hesitation squeeze method. The cement was squeezed into the formation in seven stages 10 minutes apart with 1.5 bbls of cement pumped between each stage. After the first stage the wellhead pressure was 78 psig and after the seventh stage the wellhead pressure was 1973 psig. The well was shut-in with 1970 psig for 2 hours and then was bled off and an additional eight stands were pulled and the tubing was circulated to clear the tubing of any excessive cement (see Halliburton Report Appendix 2.1-2). The well was shut-in over night with 930 psig on the wellhead.

On October 6, 2006, the rig crew drilled through soft cement and tagged bottom at 7554 feet, which was 37 feet above the previous spot at 7591 feet. The well would not hold pressure and squeeze perforation were taking fluid at 25 gpm with 920 psig on the wellhead. A second cement squeeze was required to seal off the perforations.

On October 7, 2006, Halliburton was not available to do the third squeeze job so Key Pumping Services was called and performed the third cement squeeze. Rig crew TOOH with collars and bit and TIH open ended (without collars and bit). The bottom of the work string was placed at 7290 feet. On October 8, 2006, Key Pumping Services placed 80 sks of 14.8 ppg Premium Plus neat cement across the perforations. The rig crew pulled eight stands of pipe and circulated the pipe free of excessive cement. Key Pumping Services pumped 6 bbls of cement into the formation at 750 psig. At a squeeze pressure of 1975 and additional 1.5 bbls was pumped into the formation. Key Pumping Service stopped pumping for 10 min to allow the pressure to fall then pumped another 1.5 bbls into the formation before the formation refused to take any addition fluid at 1940 psig (see Key's Report in Appendix 2.1-3). The well was shut-in for the night with 1830 psig on the wellhead.

On October 9, 2006, Rig crew tagged hard cement at 6981 feet and drilled hard cement to 7312 feet. The estimated amount of cement left in the pipe was 12.7 bbls out of a total of 18.8 bbls pumped with no sign of returned cement. The rig crew tagged bottom at 7559 feet and the wellbore was circulated clean. On October 10, 2006, the casing was pressure tested for twelve hours with a starting pressure 630 psig. At the end of the twelve hour period, the pressure was 568 psig. The wellhead pressure was recorded every thirty minutes and, after six hours the rate of pressure loss was maintaining 2 psi/ 30 minutes. The annulus valve between the 7-inch casing and the 9-5/8-inch casing was opened and contained pressure. A gauge was placed on the 7-inch by 9-5/8-inch annulus and monitored for 18 hours with no apparent increase in pressure (Table 2.1-2). The 7-inch by 9-5/8-inch annulus was initially bled off before the BOP was placed on the wellhead.

On October 11, 2006, rig crew drilled through the fourth CIBP at 7595 feet and while drilling though the plug the plug dropped to 7776 feet. At 7780 feet mud contaminated cement was encountered. At 7838 feet the rig crew had drilled though the cement plug and TIH to the top of the 4-1/2-inch liner (TOL). The rig crew tagged bottom at 9022 feet 28 feet above the TOL. It appears that there is a 28 foot cement plug across the top of the liner at 9051 feet. The wellbore was circulated clean from 9022 feet to surface. On October 12, 2006 the rig crew TIH with a casing scraper and circulated the hole to prepare for logging. Wood Group Logging Services arrived at the job site and spotted equipment.

2.3 LOGGING AND PERFORATING THE INJECTION INTERVAL

On October 13, 2006, Wood Group ran a CBL/VDL log, temperature survey, and a caliper log. The CBL/VDL log showed top of cement behind the 7-inch casing at 900 feet below the ground level (Appendix 2.3-1). The temperature log showed no major anomalies throughout the wellbore (Appendix 2.3-2). The caliper log showed some minor ware in the casing wall below the top of the injection interval (Appendix 2.3-3).

The CBL/VDL log was difficult to evaluate due to the fast formation responses. It appears that there is cement behind the 7-inch casing from the packer at 7575 feet up to 1500 feet with areas that appear to have a micro annulus. Isolation from 1500 feet to 1000 feet is spotty with little or no cement. From 900 feet to the surface, the CBL and VDL show no cement behind the casing.

The temperature survey showed no anomalies in the temperature curve. The fluid level in the well was found at 296 feet. The static bottom hole temperature (BHT) at 7575 feet was 126° F, at 8140 feet the BHT was 132.5° F, and at 9020 feet the BHT was 142.6° F.

The caliper log showed 7-inch, 29 lb/ft casing and 7-inch, 26 lb/ft casing mixed throughout the casing string. A bad spot in the 7-inch casing string was discovered at 7604 feet. There appears to be some additional corrosion from 8662 feet to 8705 feet.

From October 14, 2006 through October 15, 2006, Wood Group perforated the intervals from 7660 feet to 8450 feet and from 8540 feet to 8620 feet. Perforating was done using a 40 foot steel hollow carrier gun that produced a 0.5-inch hole at two shots per foot on 60° phasing. On the first day 12 perforating runs were made completing the interval from 8540 feet to 8620 feet and 400 feet of the interval from 8050 feet to 8450 feet. On the second day 10 perforating runs were made completing the interval from 7660 feet to 8050 feet. There were no misfires during both days and all perforating charges went off as planned.

2.4 FORMATION SAMPLE COLLECTION AND INJECTION TESTING OF THE WELL

On October 15, 2006, the well was swabbed back from 2400 feet to surface to collect formation samples. Four samples were collected at different volumes of returned fluid. The first sample was collected after twelve runs estimated volume at 151 bbls. The second sample was taken after fourteen runs estimated volume at 176 bbls. The third sample was taken after sixteen runs estimated volume at 201 bbls, and the fourth sample was taken after eighteen runs estimated volume of 226 bbls. Samples were delivered to the Navajo Refining Facility in Artesia, New Mexico. Between runs seven through nine hydrogen sulfide gas was encountered and all personnel not active in the swabbing process were moved off the location. The formation fluid sample lab results can be found in Appendix 2.4-1. A standard API water analysis of the formation water samples and brine water samples was completed by Texas Oil Tech Laboratories.

On October 18, 2006, Key Pumping services arrived at the job site to perform the injection test. Key Pumping services started the injection testing down 2-7/8-inch, PH-6 tubing. Key's pump truck broke down after pumping 80 bbls. Key Pumping services returned on October 19, 2006. The wellhead was shut-in with the bottom of the pipe left open ended. Pressure gauges were placed on the annulus and on the wellhead. Key Pumping services circulated the wellbore at 2 bpm and caught returns after 37 bbls. The test commenced starting at 2 bpm and increasing in 1 bpm increments to 10 bpm. Both the wellhead pressure and annulus pressure were monitored during the testing. The annulus pressure will allow for a calculation of the BHP with out the affect of the 2-7/8-inch pipe friction. The brine fluid weight that was pumped into the well was measured at 8.6 ppg.

Key pumping was able to reach 10 bpm for a short five minute period before the deck engine over heated and the pump shut down. The wellhead tubing pressure at 10 bpm was 5087 psig the annulus pressure was estimated at 660 psig. With a hydrostatic pressure of 3488.16 psi calculated to 7800 feet, the BHP is 4148 psi. The pressure gradient is 0.53 psi/ft, which is below the fracture gradient. According to the data collected from the annulus pressure gauge, it appears that it would be possible to pump into the well at 10 bpm and still stay below the fracture gradient and the permitted wellhead pressure of 1550 psig (Table 2.4-1).

2.5 FINDING AND REPAIRING CASING LEAKS

The State of New Mexico OCD requested that Navajo Refining try to find all the casing leaks to within 1000 feet. For two days from October 20, 2006 to October 22, 2006, a retrievable bridge plug (RBP) and packer were placed in the wellbore to isolate sections of the casing within 1000 foot intervals. The additional testing that was performed after each perforation cement squeeze revealed that there were two intervals that were suspect of casing leaks; the interval across the squeezed perforations and the interval from 1000 feet to surface.

The first suspected interval was across the squeezed perforations. The RBP was set at 7550 feet and the packer was set at 6985 feet. The isolated interval was pressure tested to 490 psig and the annulus between the 2-7/8-inch tubing to the packer was pressure tested to 632 psig. The pressure loss across the squeezed interval stabilized after two hours and was losing 6 psi/hr. The annulus gained pressure due to thermal affects and would not stabilize.

The next suspect interval in the casing was in the upper 1000 feet to surface interval. The RBP was set at 1255 feet and the entire casing interval form 1255 feet to surface was pressure tested to 570 psig. The pressure stabilized after two hours and maintained a pressure loss of 2 psi/hr over a twelve hour period. The two tested intervals accounted for the majority of the 7-inch casing leaks. The OCD was called and approved the pumping of a sealant treatment provided by 300 PSI, Inc. as a solution to sealing off the 7-inch casing leaks. The treatment would be pumped ahead of and be hind the inhibited packer fluid.

2.6 RUNNING THE 4 1/2-INCH 11.6 LB/FT TUBING AND SETTING THE PACKER

On October 23, 2006, Superior Wellhead replaced the existing Cameron spool with a new Superior Wellhead spool. The BOP was reseated and Allen's Casing Crews started into the hole with the Weatherford Arrow X-1 7-inch by 3-inch packer. The Packer would not go past 50 feet before getting hung up in the casing. The packer was pulled and examined, and it was discovered Weatherford had brought out the wrong packer. Kenco, out of Artesia, was called and they delivered a new Arrow X-1, 7-inch by 2-7/8-inch (Figure 2.6-1) packer to the location. The Weatherford packer was made with a 3-inch EUE thread and the Kenco packer had a 2-7/8-inch REG thread. As a result of the Weatherford cross over not threading up to Kenco's packer, Kenco had an integral cross over made and brought to the location.

On October 24, 2006, Allen's Casing crew started into the wellbore with 4-1/2-inch tubing and Arrow X-1 packer. The tubing was torqued to specifications at 1600 lbs. The bottom of the packer was set at 7575.73 feet with 37,000 lbs of tension on the packer. Before the packer was set the wellbore was circulated with approximately 240 bbls. 300PSI pumped 23.8 bbls of sealant followed by 95 bbls of 8.7 ppg inhibited brine (55 gals Baker Petrolite CRW 132 inhibitor fluid) and 14.29 bbls of sealant. At the end of the pumping the packer was set with 37,000 lbs of tension and the slips placed into the hanging spool. The BOP was removed and the wellhead installed.

2.7 INSTALLATION OF THE WELLHEAD

On October 25, 2006, the rig crew finished rigging up the wellhead. Superior arrived and pressure tested the P-seals to 3000 psig. The rig crew filled the annulus with 2.5 bbls of 8.7 ppg brine water and 300 psi applied 545 psig to the 4-1/2-inch by 7-inch annulus using nitrogen. The pressure was maintained for four hours. The pressure was bled off and the annulus was pressure tested to 490 psig with brine for one-hour and recorded on a circular chart (Appendix 2.7-1). The annulus was bled down and retested overnight to 480 psig with no pressure loss. From October 25, 2006 to October 28, 2006, the rig was demobilized and moved off location with all support equipment. Key Energy services started moving frac tanks onto the location for the pressure build up and falloff testing. The pipe tally for the 4-1/2-inch tubing can be found in Table 2.7-1. A schematic of the as-built wellhead can be located in Figure 2.7-1.

2.8 PRESSURE BUILD UP AND FALLOFF TESTING

On November 2, 2006, Key Energy services placed fourteen frac tanks on the location and were in the process of filling them. On November 3, 2006, Banta Roustabout service installed the pump-in flange on the wellhead. Six temperatures were taken at the mid-point in the frac tanks to determine the brine fluid temperature, so that the stress that would be applied to the packer, due to temperature changes in the wellbore could be calculated. The average water temperature of brine that would be used to perform the pump-in procedure portion of the pressure build up was 60.6° F. The shear pins in the packer were set at 80,000 lbs and the maximum amount of shear stress that would be applied to the packer was determined to be less than 60,000 lbs. All the brine located in the frac tanks were treated with biocide and the tanks were rolled with a Key vacuum truck.

On November 4, 2006, Petroplex Pumping service rigged up to the injection side of the wellhead and a Key Energy kill truck rigged up to the annulus side of the wellhead. The kill truck will maintain 700 psig on the annulus in order to help reduce tubing and packer stresses. Petroplex Pumping service started pumping at 3 bpm and after 28 bbls the well caught pressure at 162 psig. The rate was slowly increased to 10 bpm with a wellhead pressure of 1278 psig. The rate was maintained at 10 bpm until the wellhead pressure started to approach the 1400 psig mark and at that time the rate was decreased to 9 bpm at a wellhead pressure of 1170 psig. Based on strap measurements from the frac tanks it was estimated that 6700 bbls of 8.8 ppg brine were pumped into the well (Table 2.8-1 and Appendix 2.8-1).

Two hours prior to ending the pumping procedure, Schlumberger Slickline service lowered a bottom-hole pressure gauge into the well at 8630 feet. While lowering the tool, the rate was decreased to 5 bpm in order to get the tool passed through the upper section of the wellbore. At 9:00 PM pumping was stopped with the BHP tool at 8630 feet, and the well was closed in with 50 psig on the annulus and no pressure on the wellhead. On November 5, 2006, at 10:20 a.m. Schlumberger Slickline service started out of the hole, with the BHP gauge taking gradient stops every 1000 feet, starting at 7000 feet. Once the BHP tool was out of the wellbore the annulus was bled down and the well shut-in (Appendix 4.1-2). All but one frac tank were removed from the location.

2.9 LOCATION CLEANUP AND STATE REQUIRED TESTING

On November 13, 2006, Banta Roustabout service cleared the location of debris, hauled off trash, filled in cellar with pea gravel, removed diesel contaminated soil around the location, and leveled the location. The well cuttings and contaminated soils were placed in the reserve pit. The returned solids that remain in the reserve pit will have to be profiled prior to disposal and cannot be disposed of under the oil field exemption. The cuttings and returned solids that remain in the reserve pit will be hauled off once the profile of the material is complete.

On November 14, 2006, Wood Group was unable to rig up to the wellhead due to high winds and the OCD delayed testing until November 15, 2006.

On November 15, 2006, Wood Group logging services, Petroplex Pumping services, and OCD inspectors arrived at the job site. Wood Group Logging services performed an annulus pressure test, and radioactive tracer survey. Petroplex Pumping services provided pumps for the annulus pressure test and the chase down portion of the radioactive tracer survey.

The 4-1/2-inch by 7-inch annulus was pressure tested to 530 psia over a one-hour period and lost 1.99 psi. This represents a 0.37% pressure loss which is well within the OCD requirement of 5% for 30 minutes at a minimum pressure of 300 psig. The annulus pressure test was witnessed by the OCD representatives. The radioactive tracer test was run without any sign of radioactive material being pumped out of the injection interval. The first part of the radioactive tracer survey was witnessed by the OCD representatives (Appendix 2.8-1, Attachment 2.8-1, Table 2.8-1, Figure 2.8-1). At the end of the job the annulus was again pressure tested to 300 psig and held pressure for 1-1/2-hrs before being bled off.

3.0 MECHANICAL INTEGRITY TESTING

The demonstration of the mechanical integrity of WDW-3, required by New Mexico Water Quality Control Commission Regulations (NMWQCCR) Subpart V, Section 5204 (A) to (D) and Section 5205(A)(1)(a), included a casing caliper inspection on the 7-inch protective casing, pressure testing of the 7-inch protective casing, CBL/VDL of the 7-inch casing, a radioactive tracer survey, a differential temperature survey, and an annulus pressure test. Results of these tests demonstrated that the well had internal and external mechanical integrity.

3.1 CALIPER CASING INSPECTION LOG

On October 13, 2006, Wood Group Logging services ran a caliper log to determine the condition of the existing casing wall thickness and to check for anomalies (Appendix 2.2-3). Overall the 7-inch protective casing looked good. The caliper log revealed that there was 26 lb/ft and 29 lb/ft casing in the wellbore. There was one anomaly found that occurred at 7604 feet, which appeared to be a gouge in the casing wall. The upper section of the 7-inch casing string appeared to be in better condition than the lower section. There appeared to be some corrosion and scale build up in a section of the casing just above and below the 8700 feet. The data obtained from the caliper log may be used as a baseline for future comparisons.

3.2 CEMENT BOND LOGGING

On October 13, 2006, Wood Group Logging services ran a CBL/VDL log (Exhibit 2.2-1). The CBL/VDL revealed cement had not been circulated to the surface behind the 7-inch protective casing, as was indicated in the state records. The TOC behind the 7-inch protective casing was located at 900 feet and the cement bond quality was poor down to 1200 feet. There were indications on the log that a micro annulus may be present below the 1200 foot interval. The intervals above the injection interval from 2662 feet to 2160 feet, from 4876 feet to 5372 feet, and from 6750 feet to 7600 feet indicated that there was good bonding between the 7-inch casing and the cement to isolate the injection interval. The OCD was called and they approved the existing wellbore for injection and did not request that any additional cement be placed behind the 7-inch casing (Attachment 3.2-1).

3.3 CASING PRESSURE TESTING

After performing each perforation squeeze, the wellbore was drilled out and the casing was pressure tested. The casing pressure test that was performed across the squeezed interval from 7050 feet to 7102 feet had a loss rate of 9.1 psi/hr with a starting pressure of 580 psig. The pressure was run for 13.5 hours with the final reading at 455 psig.

The second perforation squeeze was over the perforated interval from 7262 feet to 7278 feet and 7304 feet to 7314 feet. The second cement squeeze would not hold pressure. A third cement squeeze was performed across the interval and the casing was pressure tested to 630 psig for a period of 12 hours. The final casing pressure was 568 psig with a average pressure loss of 2 psi/hr.

The OCD was notified of the pressure losses on the casing pressure test and requested that Navajo attempt to isolate the leakoff in the casing to within 500 feet to 1000 feet. A 2-7/8-inch by 7-inch packer and an RBP were run into the wellbore to isolate the squeezed interval. The RBP was set at 7550 feet and the packer was set at 6985 feet. The annulus between the 2-7/8-inch work string and the 7-inch protective casing was pressure tested to 632 psig and appeared to gain pressure due to a thermal heating effect in the wellbore. The tubing was pressure tested to 490 psig with a loss rate of 6 psi/hr down the 2-7/8-inch tubing.

The 7-inch protection casing interval from 900 feet to the surface did not appear to have cement behind it, therefore, it was necessary to determine if that interval mechanically sound. The RPB was set at the shallowest point possible at 1255 feet and the casing was pressure tested to 570 psig. Over a 13 hour period the wellhead pressure dropped to 540 psig with a loss rate of 2 psi/hr.

The request by the OCD was completed. The intervals across the squeezed perforations and the interval from 1255 feet to surface both showed signs of a casing leak. The leak-off rate across both intervals was small and within the regulator requirements of 5%. Again the OCD was contacted and they requested that Navajo attempt to seal off the leaks. A casing sealant was pumped with the inhibited brine down the 4-1/2-inch by 7-inch annulus before setting the 2-7/8-inch by 7-inch Arrow X-1 injection packer. The sealant treatment was performed by 300PSI Inc. and approved by the OCD (Attachment 3.2-1). The packer was set and the sealant was squeezed. An annulus pressure test was recorded with the initial annulus pressure at 490 psig, after one-hour the annulus pressure maintained 490 psig, there was no measurable loss over the one-hour period. A copy of the chart is in Appendix 2.7-1.

3.4 ANNULUS PRESSURE TEST

The State of New Mexico required an annulus pressure test which was performed on November 15, 2006, in conjunction with a radioactive survey. The well was allowed to sit idle for 10 days to attain a thermal equilibrium in the wellbore prior to running the annulus pressure test. Wood Group Logging service monitored the annulus pressure and Petroplex Pumping Service provided the pressure pumping equipment. The OCD representatives were present to witness the annular pressure test.

The annulus was pressurized using a high pressure, low volume triplex pump isolated from the pressure source. The official annular pressure test began at 11:32:30 AM at a pressure of 530.94 psia. The tubing pressure was 0 psi. After one-hour, the pressure decreased to 528.95 psia. This represents a loss of 1.99 psi, or 0.37%, which complies with the OCD allowable of 5% per 30-minute test period at a minimum test pressure of 300 psi. The annulus pressure test data are presented as Table 2.9-1. The pressure gauge calibration certificate is presented as Appendix 3.4-1.

3.5 RADIOACTIVE TRACER SURVEY

A radioactive tracer survey was performed on the WDW-3 on November 15, 2006, following the annulus pressure test. The first part of the radioactive tracer survey was witnessed by the OCD representatives. The radioactive tracer survey consisted of running two statistical checks, two baseline gamma ray surveys, and injecting four slugs of radioactive material. Two (2) of the slugs were injected during the time-drive surveys and two were injected during the moving surveys. All tests were conducted while injecting nonhazardous brine water into the well. Wood Group Logging service performed the logging services and Petroplex Pumping service provided the pumping equipment.

The radioactive tracer tool was lowered to a total depth of 9,020 feet and a pre-survey baseline log was then run from 9,020 feet to 7,350 feet. Five-minute statistical surveys were conducted at 7,550 feet and at 7,640 feet.

The injection rate was set at 102 gallons per minute (gpm) and a slug of radioactive iodine was ejected at 7,375 feet. A total of seven passes were made during the first moving survey, until the slug dissipated into the permitted injection interval from 7,650 feet to 8,830 feet.

The radioactive tracer tool was repositioned at 7,375 feet and a second slug of radioactive iodine was ejected. The injection rate was 102 gpm. A total of five passes were made during the second moving survey, until the slug dissipated into the permitted injection interval from 7,650 feet to 8,894 feet.

The first stationary time-drive survey was performed with the lower detector at 7,640 feet with an injection rate of 102 gpm. A slug of radioactive iodine was ejected and monitored on time drive for 15 minutes.

The second stationary time-drive survey was performed with the lower detector at 7,640 feet. The injection of brine water was maintained at 102 gpm. A 2-second slug of radioactive iodine was ejected and monitored on time-drive for 15 minutes.

No upward fluid movement was observed during the two chase downs or the two time-drive surveys. There does not appear to be any upward movement of fluid out of the injection interval from 7,650 feet to 8,884 feet.

Injection into WDW-3 was terminated and a post-survey gamma ray log was run from 9,016 to 7,342 feet. The initial and post-survey gamma ray logs were comparable.

The radioactive tracer log is presented as Appendix 2.9-1. The corresponding letter of interpretation of the radioactive tracer log, dated November 27, 2006, by Wood Group is presented as Appendix 3.5-1.

3.6 DIFFERENTIAL TEMPERATURE SURVEY

A baseline differential temperature survey was performed on October 13, 2006, (Exhibit 2.2-2) after the CBL/VDL logging run. The baseline differential temperature survey will be used to evaluate future temperature surveys to confirm mechanical integrity of the well. No anomalies were observed during the differential temperature survey.

The temperature log was run from 9020 feet to the surface. The fluid level in the wellbore was at 296 feet with 8.6 ppg brine water in the wellbore. The wellbore temperature at 560 feet was 68.1° F, at 1000 feet the wellbore was temperature 74.6° F, at 7650 feet the temperature was 127° F, at 8850 feet the temperature was 140.2 ° F, and at 9020 feet the temperature was 142.9° F. The gradient from 7650 feet to 9020 feet was 1.16° F / 100 ft.

4.0 RESERVOIR EVALUATION

The bottom-hole pressure testing, which was conducted on the WDW-3 following the completion of the well, was designed to obtain the best estimate of the permeability and mobility-thickness in the reservoir. The pressure testing consisted of an injection falloff test and a gradient survey. Petroplex Pumping Service provided the pumping equipment for the injection period of the testing and Schlumberger Slickline Services provided the BHP equipment.

The calculated value for the skin does not appear to correspond with the pump-in surface pressure values or the injection test valves. It is possible that the offset wells, WDW-1 and WDW-2, influenced the bottom hole pressure response of the bottom hole pressure gauge during the pressure falloff test. Historically, the calculation for the permeability appears to be in the range that was anticipated from previous falloff testing conducted on WDW-1 and WDW-2. WDW-1 and WDW-2 are completed in the same zone of interest.

Due to the proximity of WDW-3 to both the WDW-1 and the WDW-2 and the procedure used by Navajo for injecting into the wells, consideration needs to be given to monitoring the bottom hole pressure in the two offset wells while performing a fallout test the target well. This should allow for a better understanding of the pressure behavior in the reservoir.

4.1 PRESSURE FALLOFF TEST

Petroplex Pumping Services rigged up on WDW-3 on November 4, 2006. Injection into WDW-3 was initiated at 0919 hours at an injection rate of 126 gpm. The injection rate was gradually increased to 420 gpm. At 1800 hours, Schlumberger rigged up and the injection rate was decreased to 210 gpm in order to run the bottom-hole pressure gauges into the well. The tandem memory gauges were positioned at 8,630 feet below ground level and the injection rate was increased to 378 gpm.

At 2100 hours, the injection pumps began to lose suction and WDW-3 was subsequently shut in. The final injection rate was 189 gpm with a final injection pressure at 8,630 feet of 4,577.59 psia.

The pressure falloff test was terminated after 13.57 hours with a final shut-in pressure of 3,804.87 psia. Gradient stops were made at 1000-foot intervals while removing the pressure gauges from the well.

The pressure data obtained from the falloff test were analyzed with the assistance of the commercially available PanSystem pressure transient analysis software. The PanSystem output for the falloff analysis has been included as Appendix 4.1-1 and includes the input reservoir parameters used in the reservoir analysis. The pressure and temperature data recorded during the pressure falloff testing are included as Appendix 4.1-2.

Figure 4.1-1 shows the pressure response recorded by the bottom-hole pressure gauge from the time the tool was in place through the 13.57-hour shut in period. Figure 4.1-2 is a cartesian plot of the pressure falloff data. The superposition time function was used to account for the rate changes during the pressure build up portion of the testing. Figure 4.1-3 is a log-log diagnostic plot of the falloff data, showing change in pressure and pressure derivative versus equivalent shut in time.

The reservoir permeability was determined from the radial flow region of the superposition Horner plot, Figure 4.1-4. The radial flow regime occurs between Horner times of 486 and 196. Figure 4.1-5 shows an expanded view of the radial flow regime. The slope of the radial flow period was determined to be 0.473785 psi/cycle.

An estimate of mobility-thickness, kh/μ, for the reservoir was determined to be 2,223,895 md-ft/cp from the following equation:

$$\frac{kh}{\mu} = 162.6 \frac{qB}{m}$$

where,

kh/μ	=	formation mobility-thickness, millidarcy-feet/centipoise
q	=	rate prior to shut in (6,480 bbl/day)
B	=	formation volume factor (1.0 reservoir bbl/surface bbl)
m	=	slope of the infinite acting radial flow period (0.473785 psi/cycle)

Substituting,

$$\frac{kh}{\mu} = 162.6\,\frac{(6,480)(1.0)}{0.473785}$$
$$= 2,223,895 \text{ md–ft/cp}$$

The permeability-thickness, kh, was determined to be 1,601,204 md-ft by multiplying the mobility-thickness by 0.72 centipoise, the viscosity of the reservoir fluid (μ res).

$$kh = \left(\frac{kh}{\mu}\right)\mu_{res}$$
$$= (2,223,895)(0.72)$$
$$= 1,601,204 \text{ md–ft}$$

The average reservoir permeability was determined to be 1,840 md using the total perforated interval thickness of 870 feet:

$$k = \frac{(kh)}{h}$$
$$= \frac{1,601,204}{870}$$
$$= 1,840 \text{md}$$

4.2 STATIC GRADIENT SURVEY

On November 5, 2006, the pressure gauges were removed from WDW-3. Static gradient stops were made at 8,630 feet, 7,000 feet, 6,000 feet, 5,000 feet, 4,000 feet, 3,000 feet, 2,000 feet, 1,000 feet, and at the surface. The bottom-hole pressure and temperature after 13.57 hours of shut in at 8,630 feet were 3,804.87 psia and 135.88° F, respectively. The static fluid level was determined to be at 420 feet.

A summary of the static gradient survey results is provided in Table 4.2-1 and are graphically depicted in Figure 4.2-1.

5.0 Regulatory Compliance

The construction of WDW-3 was performed in accordance with the regulatory considerations and standards specified in the approved modification to the Discharge Plan UIC-CLI-008-3 Dated June 23, 2004; the OCD Permit, Dated June 29, 2006; the BLM Sundry Notices and Reports on Wells Dated June 29, 2006; NMWQCCR, Subpart V, Section Nos. 5204 and 5205; and the United States Environmental Protection Agency 40 CFR 146.12.

5.1 Siting

Navajo re-entered, tested, and completed a plugged and abandoned wellbore located in Section 1, T18S, R27E, Unit Letter N, approximately 11 miles east-southeast of Artesia, in Eddy County, New Mexico. The modification to Discharge Plan UIC-CLI-008-3 includes provisions for the location, depth of the injection interval, and specific reentry and completion requirements. The Navajo WDW-3 will inject plant effluent into a the Cisco and Brushy Canyon formations, which are beneath the lowermost formation contained within one quarter of a mile of the wellbore, with ground water having 10,000 mg/l total dissolved solids or less. A plat of the Navajo WDW-3 well location is shown in Appendix 2.0-2.

5.2 Casing Cementing

The existing casing and wellbore configuration was used and the only modifications to the wellbore were the removal of four existing CIBP's in the original wellbore configuration and the squeeze cementing of existing perforations. Table 2.0-1 and Figure 2.0-1 contain a detailed description of the current wellbore configuration.

5.3 Tubing and Packer

The Installation of the tubing and packer were in accordance with NMWQCCR Subpart V, Section 5205(B)(3).

The WDW-3 injection tubing is a 4-1/2-inch, 11.6 lb/ft, J-55, LTC 8rd connection, carbon steel pipe. The injection tubing was connected into the Arrow X-1, 2-7/8-inch by 7-inch packer via an integral 2-7/8-inch by 4-1/2-inch crossover. The packer was set with 37,000 lbs of tension in a competent area of the 7-inch casing with the bottom of the packer at 7575 feet, which is approximately 85 feet above the upper most perforation. The tubing was designed and selected based on its ability to withstand the chemical affect of the injectorate and its burst pressure, collapse pressure, and tensile stresses, which may be experienced during the operational life of the well. Table 2.0-1 is a detailed tubular list of the existing pipe and the installed pipe. Figure 5.3-1 is a schematic of the Kenco packer system, and Table 2.6-1 is an inspection tally of the tubing that was used. All the injection tubing that was placed in the well was inspected and threads cleaned prior to installation.

5.4 Directional Surveys

Deviation checks were obtained prior to re-entering WDW-3 and were based on prior deviation surveys obtained from state records, which were in accordance with NMWQCCR Subpart V, Section 5205 (A)(4)(a). Attachment 5.4-1 contains the deviation surveys that were obtained from the State of New Mexico record archives submitted to the OCD.

5.5 Logging Program

The logging program for WDW-3 was completed in accordance with the regulations specified in NMQCCR Subpart V, Section 5205(A)(4)(b).

Type of Log	Type of Hole Logged	Interval Logged (ft)	Document Reference
Dual Induction Laterolog	Open Hole	2595 – 9448	Appendix 5.5-1
Spectral Density Dual Spaced Neutron Log	Open Hole	0 – 9448	Appendix 5.5-2
Cement Bond Log (CBL/VDL)	Cased Hole	0 – 9020	Appendix 2.2-1
Temperature Log	Cased Hole	0 – 9020	Appendix 2.2-2
Casing Inspection Caliper Log	Cased Hole	0 – 9000	Appendix 2.2-3
Radioactive Tracer Survey	Cased Hole	7375 - 9008	Appendix 2.9-1

5.6 MECHANICAL INTEGRITY TESTING

The demonstration of the mechanical integrity of the WDW-3, required by NMWQCCR Subpart V, Section 5204 (A) to (D) and Section 5202 (A)(1)(a), is discussed in detail in Section 3.0 of this report. The associated logs and interpretation of the results obtained from the mechanical tests are also included in Section 3.0 of this report.

5.7 PHYSICAL AND CHEMICAL CHARACTERISTICS OF THE FORMATION FLUIDS

In accordance with NMWQCCR Subpart V, Section 5202(A)(3)(h), an analysis describing the physical and chemical characteristics of the formation fluids, extracted from the Cisco and Upper Canyon Formation, is presented as Appendix 2.3-1.

The well materials used to construct WDW-3 were compatible with fluids which the material may be expected to come into contact. Well material would be deemed to have compatibility as long as the materials used in the construction of the well meet or exceed standards developed for such materials by the American Petroleum

Institute (API), The American Society for Testing Materials (ASTM), or comparable standards acceptable to the NMWQCCR.

5.8 REGULATORY WITNESSING

In accordance with NMWQCCR Subpart V, Section 5205(A)(5), notification prior to commencement of the reentry, cementing and casing, well logging, and mechanical integrity testing was communicated with the BLM, Carlsbad, New Mexico and the OCD, Artesia, New Mexico offices. The BLM and the OCD had an opportunity to witness all installations, logging, and testing as required in the Application for Permit to Drill, Re-enter, Deepen, Plugback, or Add a Zone and in NMWQCCR Section 5205(A)(5).

6.0 FUTURE TEST RECOMMENDATIONS

As stated earlier, due to the proximity of WDW-3 to both the WDW-1 and the WDW-2 and the procedure used by Navajo for injecting into the wells, consideration needs to be given to monitoring the bottom hole pressure in the two offset wells while performing a fallout test in the target well (WDW-3). This should allow for a better understanding of the pressure behavior in the reservoir. This may further enhance reservoir pressure forecast and increase Navajo's ability to proactively respond to reservoir and wellbore conditions.

A proposed procedure for falloff testing on the three injection wells, consist of placing BHP gauges in each well prior to starting injection into WDW-3. The injection period would consist of maintaining a constant injection rate into WDW-3 for a period 24 hours. At the end of the 24-hour injection period, shut-in WDW-3 and shift the waste injection stream to WDW-1. This would be in line with the current Navajo injection procedures. Continue injection into WDW-1 for 12 hours, and then shift the injection stream to WDW-2 for a period of 12 hours. At the end of the 12 hour injection period in WDW-2 shut down injection operations and remove the BHP tools from each wellbore. Once the BHP gauges have been removed from the wells, return to normal injection operations.

APPENDIX 2.0-1

CHRONOLOGY OF FIELD ACTIVITIES

CHRONOLOGY OF FIELD ACTIVITIES

Tuesday, July 25, 2006

Rusty Smith, with Subsurface Construction, Inc. traveled to Artesia, New Mexico and met with David Alvarado, District Manager of Basic Energy, to inspect the two rigs that they will have available on August 7th. Only one rig was available; the other could not be released. The Cooper 500 with a 250K lb derrick was the rig that was inspected. The rig was well maintained, has no pipe racks, work string, and no power swivel. The rig is used mainly for workover operations. Inspected the well site where the workover rig unit will be located. Well site needs to be scraped clean and the barbed wire fence, which surrounds the area where the old tank used to be, needs to be removed. The wellhead needs some work. Pictures of the Basic rig and well location were taken.

Wednesday, July 26, 2006

Rusty Smith left Artesia, New Mexico and traveled to Farmington, New Mexico. The rig and well location inspection summary were completed and e-mailed to Subsurface personnel for review. Included in the inspection summary were photos of the rig and location.

Wednesday, August 30, 2006

Subsurface personnel traveled to Artesia, New Mexico to meet with David Alvarado, District Manager of Basic Energy, to develop a location layout for equipment and assist Joe Konicki. Talked with Julian Carrillo, the rig tool pusher, because David Alvarado was on vacation, and he informed Subsurface that the rig was no longer available because Yates Energy had changed its position and would not release it. Set up meetings with Darrel Moore and the new Project Engineer at the Navajo plant to discuss the current job situation and introduce Joe Konicki. Joe and I talked with Key Energy about the possibility of acquiring a rig.

Thursday, August 31, 2006

Rusty Smith measured the current WAMS units on Disposal Well No. 1 and Disposal Well No. 2 and acquired photos of Well No. 1 WAMS and the current well configuration. The well location inspection summary was completed. All photos, drawings, and the inspection summary were e-mailed to Subsurface personnel for review. Rusty Smith and Joe Konicki. left Artesia, New Mexico for Houston, Texas.

Monday, September 25, 2006

Rusty Smith traveled to Artesia, New Mexico to prepare the location for the reentry project on WDW–3, formally owned by Mewbourne Oil Company and known as Chalk Bluff Federal No. 1. The sundry notice to the BLM for the transfer of ownership was submitted on May 5, 2003. The OCD Change of Operator Notice was submitted on October 5, 2000.

Tuesday, September 26, 2006

Subsurface personnel called Knight Oil Tools & Rental and spoke with Francisco about work string and pipe. He wanted to know what type of crossovers, bit sub, safety clamp, and elevators would be needed. Spoke with Basic and they did not have any handling tools for the PH6 tubing and would need elevators and a safety valve. Knight said that they would provide elevators and a safety valve with the work string. Talked with Allen, of Key Fishing Tools, and he said that they would provide all the crossovers and bit subs. Basic was in agreement with the supplied tools.

Banta Oilfield Services will arrive tomorrow to clear the location and dig 30 foot x 30 foot x 3 foot pit. Key Energy Services will deliver tanks tomorrow and start filling them up. Portable toilets will arrive tomorrow from Sani-Tech Rentals. Young's Mobile Homes will deliver a small office trailer on Thursday. Knight Oil Tools will provide work string, elevators, and the safety valve to be delivered September 27, 2006. Key Fishing Tools and Rental will provide reverse unit, subs, collars, bit, BOP (Allen), which are scheduled to arrive on Thursday, after noon. The rig is also scheduled to arrive on Thursday. Steve L., with Halliburton, has been notified and will need 48 hours notice. Contacted Aztec Rental about a fork lift and they will send account information to the office to be filled out by Subsurface's accountant. Once the account is approved, they will deliver a fork lift on September 27, 2006.

Wednesday, September 27, 2006

Subsurface personnel arrived at the job site at 7:00 a.m. MST. Banta's roustabout crew called and said that were having problems finding the location. Therefore, I met them at the ATOKA compressor station and led them to the location. Banta arrived with two backhoes and proceeded to clear the location of over growth and remove all fencing. Key Energy arrived at the job site with three frac tanks, two sets of pipe racks, catwalk, and Knight Oil Tools arrived with 150 joints of 2-7/8-inch PH-6 tubing. Knight Oil Tools will not charge for the pipe until the remaining 148 joints pipe and tools are delivered. Aztec Rental arrived on the job site with an extended boom fork lift. Julian, with Basic, called and said that they should be able to move onto the location by noon tomorrow.

The roustabout crew dug a 30 feet x 30 feet x 5 feet lined pit, cleared the location of over growth, removed the barbed wire fence, and dug out cell. The roustabout crew will return tomorrow to frame in the cellar. Key will start filling the frac tanks tomorrow and Knight Oil Tools will deliver the remaining pipe and handling tools. Subsurface left the jobsite at 6:30 p.m.

Thursday, September 28, 2006

Subsurface personnel arrived at the location at 7:20 a.m. MST. The roustabout crew arrived at 8:00 a.m. The roustabout crew completed the cellar. The Basic rig crew arrived on the location at 12:30 p.m. with a mechanic to repair the sand line brake. The rig crew raised the derrick and replaced the drilling line. Rig mats had to be placed under the derrick for support. The rig mats were acquired from G&L Tools a division of Basic Energy Services. The rig crew completed repairs on the rig and left the location at 7:20 p.m. Key finished loading the frac tanks with water and brine. Key delivered the reverse unit and open top flow back tank, and the reverse unit operator will arrive tomorrow with BOP, collars, and handling tools.

Knight had problems getting the remaining work string delivered before nightfall. Knight will have the remaining pipe delivered in the morning. Young's delivered a 10 foot x 30 foot office trailer and Aztec delivered a light plant to the location. Superior Wellhead was notified and will have a man on the job site in the morning to inspect the hanger and wellhead before installing the BOP. The 150 joints of 2-7/8-inch PH-6 tubing were tallied at 4691.06 ft. Subsurface left the location at 7:45 p.m.

Friday, September 29, 2006

Subsurface personnel arrived on the jobsite at 6:45 a.m. MST. Basic rig crew arrived on location at 7:30 a.m. Subsurface and Basic crews spotted catwalk & pipe racks. The last load of pipe from Knight Tools arrived at the location with handling tools. The rig crew moved pipe and off-loaded pipe onto the pipe racks. The BOP from Key Energy arrived at the job site and was flanged up to the wellhead. The Superior wellhead technician arrived at the job and inspected the tubing hanger spool and found it to be 11_3 x 7_5 Cameron hanger and profile. The Superior wellhead technician suggested that the tubing hanger spool be replaced as the Cameron spool has been discontinued and is hard to find parts for. Key Energy's reverse unit operator arrived at the job site with 3-1/2-inch collars and handling tools.

The reverse unit (pump & tank) were rigged up to the wellhead. Portable toilets arrived at the job site. The rig crew tallied the top layer of PH-6 tubing, drill collars, bit, and started into the hole with the BHA at 1:30 p.m. The first plug was tagged at 7001 feet, at

7:10 p.m. The rig crew pulled a single joint of tubing from the wellbore, the well was shut in, and operations were shut down for the night.

Saturday, September 30, 2006

Subsurface personnel arrived on the jobsite at 7:20 a.m. MST. Basic rig crew arrived on location at 7:30 a.m. Basic rig crew and Key's reverse unit operator rigged up the swivel. At 10:30 a.m., Basic could not get the brake to hold on the sand line. Operations were shut down until Basic could repair the brake on the sand line and the reverse unit operator was put on stand by. Basic estimated that it will take all day to repair the brake. Basic finished repairing the brake at 7:00 p.m. Drilling operations will commence Sunday morning. Halliburton was notified to be ready to perform a perforation squeeze job on Monday. Pipe tally was checked and verified at 297 joints of 2-7/8-inch tubing for a total footage of 9413.59 feet, including the BHA at 126.45 feet. The well was shut in and operations were shut down for the night.

Sunday, October 1, 2006

Subsurface personnel arrived on the job site at 7:20 a.m. MST. Basic rig crew arrived on location at 7:30 a.m. At 8:00 a.m. Key's reverse unit operator started to drill out CIBP after circulating bottoms up (40 bbls) and there did not appear to be any cement on top of the plug. Current ROP is about 1 ft/hr while circulating returns to pit. The reverse unit operator will change over to tank once fluid cleans up. The returns appear to contain trace amounts of oil with no mud. RPM on the swivel is at 50 with a pump pressure between 250 psi to 300 psi with brine water. Drilled through plug at 9:45 a.m. and circulated hole clean. Rig crew started back into hole to tag second plug. Tagged second plug at 7190 feet, rig crew hooked up swivel to circulate hole and perform an injection test. The injection test revealed the following: 1 bpm at 300 psi, 1.5 bpm at 550 psi, and 2 bpm at 980 psi. After the pump-in test, the falloff went from ISIP of 950 psi to 200 psi in 22 minutes. Key Energy Service removed 250 bbls of water from earthen pit.

Rig crew tripped out of hole (TOOH) with pipe to prepare for cement squeeze job. Rig crew tripped in hole (TIH) open ended with tubing to spot cement for squeeze job, with bottom of the tubing at 7101.49 feet. Contacted Halliburton and ordered 80 sks of cement (cmt) for squeeze job into upper perforations.

Monday, October 2, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Halliburton was on the jobsite waiting on cement to arrive. Cement arrived at the location at 7:30 a.m. Halliburton rigged up their cement pump while waiting on a crossover for the PH-6 tubing. Halliburton did not bring a crossover to the PH-6 thread to 8rd, so Key Fishing Tools had one delivered.

Cement squeeze went well at 2000 psi squeeze pressure. Pressured up to 2001 psi. After 10 minutes, pressure fell to 1950 psi and re-pressured to 2007 psi. After one hour, pressure dropped to 1990 psi with 2.2 bbls, released pressure and recovered about 2 bbls. Re-pressured well to 2001 psi and held for 5 minutes at 1990 psi. The ring gasket began to leak around BOP. Halliburton released pressure and recovered 1.9 bbls. Halliburton rigged down and the rig crew TOOH with tubing. Hole remained full while tripping pipe. Rig crew tightened BOP flange head bolts. Key reverse unit operator pressured up well to 680 psi, with no apparent leaks, and the well was shut-in over night, while waiting on cement (WOC).

Tuesday, October 3, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. and TIH with the collars and bit. Rig crew tagged cement at 6873 feet on joint No. 215 plus 20 feet. Assuming hole is full of cement to CIBP at 7190 feet, there are 12.1 bbls of cement in the hole and 6.6 bbls of cement were circulated out and/or squeezed into the formation. It was estimated that 3.5 bbls were circulated out leaving 3.1 bbls of cement having been squeezed into the near wellbore. Rig crew drilled out cement and circulated hole clean at 4:00 p.m. The well was shut-in to prepare for a pressure test on the squeeze perforation for 12 hours at 500 psi.

Started 500 psi pressure test at 4:30 p.m. Pressured up well to 590 psi and after one hour pressure fell to 530 psi. Re-pressured well to 580 psi and after one hour pressure was at 578 psi. At 5:30 p.m. well was at 578 psi and holding. Shut down operations overnight.

Wednesday, October 4, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. At 7:00 a.m., the pressure on the well was 455 psi. The well lost 123 psi over 13.5 hour, for a 9.1 psi/hr (1.58%/hr) loss. Rig crew rigged up swivel and continued to drill out CIBPs at 7190 feet and (estimated third plug depth) at 7294 feet. While drilling through the second plug at 7190 feet metal cuttings were being retrieved across screen. Third CIBP was found at 7278.96 and it was estimated that there was 9 feet of cement on top of both plugs, which places the second plug at 7199 feet and third plug at 7287 feet. At 12:25 p.m., rig crew commenced drilling through third plug. At 3:00 p.m., driller punched through the third plug. The formation started taking fluid at a rate of 1.0 to 1.25 bpm while pumping, lost 180 bbls of 8.7 ppg brine water to the formation.

Rig crew TIH and tagged the forth CIBP at 7591 feet then pulled up 20 feet and reversed circulated the wellbore clean. The reverse unit operator completed the pump in test for the perforations from 7262 feet to 7278 feet and from 7304 feet to 7314 feet. The maximum rate was 4.5 bpm (max that the pump could deliver) at 710 psi with no pressure build up. The ISIP was about 580 psi and fell to 170 psi in 9 minutes. At 4:45 p.m., rig crew TOOH with collars and bit. Halliburton will be out tomorrow afternoon with 100 sks of Class C cement to squeeze off perforations. At 7:30 pm, the rig crew was out of the hole with the collars. The well was shutin and operations were shut down.

Thursday, October 5, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:20 a.m. and TIH open ended, placing the bottom of the work string at 7321 feet; 7 feet below the bottom perf at 7314 feet. Key filled fresh water and salt water tanks while we waited for a Halliburton pump truck to arrive. Halliburton arrived on the location at 11:30 a.m. At 12:44 p.m. Lines were pressure tested to 3000 psi. Halliburton broke circulation and caught returns with 6.3 bbls pumped. At 12:52 p.m., Halliburton started mixing cement and pumped 23.5 bbls of cement, followed by 35.5 bbls of fresh water. Rig crew pulled 10 stands (630 feet) and Halliburton started to squeeze the cement into the formation. The squeeze was performed in 7 stages, each 10 minutes apart, pumping approximately 1 to 1.5 bbls per stage.

After the first stage the wellhead pressure was 78 psi. After the 7th and last stage, the wellhead pressure had increased to 1973 psi. A total of 9 bbls were pumped during the squeeze job. The well was shut-in with 1970 psi on the wellhead. Subsurface allowed the well to remain shut-in for an additional 2 hours, after which the wellhead pressure was bled off and 8 stands (500 feet) of pipe were TOOH to insure that no cement remained around the pipe. The well was pressured up to 930 psi and shut-in overnight to WOC.

Friday, October 6, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. and TOOH with work string. The wellhead pressure this morning, after 14 hours, was 850 psi. With a loss of 80 psi over a 14-hour period after the squeeze or 5.7 psi/hr. At 10:00 a.m., rig crew TIH with work string, collars, and a new bit. At 12:30 p.m., rig crew tagged soft cement at 7052 feet and quickly drilled through the cement. At 7092 feet, hard cement was encountered. Rig crew drilled through cement to 7338 feet and tagged bottom at 7554 feet (previous tag 7591 feet). Well would not hold pressure during test and reverse unit operator was able to pump into the well at ~20 to 25 gpm at 920 psi. A second cement squeeze on the second set of perforations will be required. Well was shut in over night.

Saturday, October 7, 2006

Subsurface personnel arrived at the location at 7:20 a.m. MST. Rig crew arrived at 7:30 a.m. and TOOH with work string, collars, and bit. A new Key reverse unit operator arrived at the location. Halliburton was called to confirm a third cement squeeze job. Halliburton informed Subsurface that they would not have a pump truck available until Wednesday. Key Pumping service was contacted and retained to provide the service on Sunday afternoon. Due to unavailability of cement pumping services to do the third cement squeeze, the estimated schedule has been pushed back 2 days.

At 10:50 AM the rig crew had collars and bit out of the hole and TIH with open ended work string to just above the bottom set of perforations at 7314'. The open ended work string was placed at 7290 feet, 24 feet above the bottom set of perforations (1 bbl of casing volume). The well was shut-in while waiting on a cement pump truck to arrive.

Sunday, October 8, 2006

Subsurface personnel arrived at the location at 10:10 a.m. MST. Rig crew arrived at 10:20 a.m. Key Pressure Pumping Services arrived at the location at 10:30 a.m. Key pumping crew rigged up pump and bulk truck. The mix water for the cement squeeze in the frac tank was contaminated with brine water and a load of city water was called in for mix water. At 2:00 p.m., fresh mixed water arrived on location. Key pumping pressure tested lines to 2500 psi and then circulated 12 bbls to fill the wellbore with fluid. At 3:04 p.m., Key started mixing cement and pumped 10 bbls of FW ahead followed by 18.5 bbls of 14.8 ppg cement. The cement was displaced with 35.5 bbls of FW. Rig crew TOOH with 8 stands (500 feet) and the well was reversed circulated with 40 bbls of FW. At 4:03 p.m., Key pumping started to squeeze the well with an initial rate of 0.5 bpm at

750 psi. After 6 bbls the rate was decreased to 0.3 bpm at 1890 psi. After 7.5 bbls at 1975 psi pumping was stopped to allow the pressure to fall.

At the end of 10 minutes, the wellhead pressure had fallen to 1063 psi and pumping was resumed. An additional 1.5 bbls was pumped before the pressure reached 1940 psi. The wellhead pressure fell to 1914 psi after 20 minutes and did not appear to fall any further. The well was shut-in and Key rigged down their pumps. After one hour, the wellhead pressure had fallen to 1860 psi. At 6:00 p.m., the well was shut-in for the night with 1830 psi on the wellhead to WOC.

Monday, October 9, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. and TOOH with open ended work string. Rig crew TIH with work string, collars, and bit to drill out cement. The wellhead pressure this morning after the 80 sk cement squeeze job was 1825 psi. Reverse unit operator tagged cement at 6981 feet and found hard cement at about 7003 feet. At 4:43 p.m., driller broke through the cement at 7312 feet. The estimated cement plug length left in casing was 331 feet or 12.7 bbls out of 18.8 bbls of cement. Driller tagged bottom at 7559 feet, rig crew pulled up off bottom approximately 20 feet, and the reverse unit operator circulated the wellbore. The well was shut-in and pressure tested to 610 psi at 6:45 p.m. for a 12-hour test.

Tuesday, October 10, 2006

Subsurface arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. Wellhead pressure at the end of 13 hours was 480 psig, down from 610 psig; a pressure loss of 130 psi over the 13-hour period. The decision was made by Subsurface personnel to retest the casing after the squeeze for an additional 12 hours. At 8:03 a.m., the wellhead pressure was increased to 630 psig and monitored every thirty minutes. At 9:30 a.m., the 7-inch x 9-5/8-inch annulus valve was opened to see if it had any effect on the casing pressure. Casing pressure fell slightly faster from 2 psi/30 minutes to 5 psi/30 minutes. Once the annulus casing valve was closed, the pressure loss maintained a 2 psi/30 min loss.

When the casing valve was first opened it smelled like natural gas. The annulus casing valve was closed and a pressure gauge placed on the annulus and monitored. At 2:03 p.m., the wellhead pressure was falling at a rate of 2 psi/30 minutes with less than 5 psi on the casing annulus. At 5:03 p.m., wellhead pressure was maintaining a falloff rate of 2 psi/30 minutes. At 8:03 p.m., after 12 hours, the wellhead pressure was 568 psig.

Wednesday, October 11, 2006

Subsurface arrived at the location at 7:00 a.m. MST. The wellhead pressure was 523 psig. At 7:03 a.m., maintaining a 2 psi/30-minute pressure loss. Rig crew arrived at 7:30 a.m. and rigged up swivel and broke circulation. At 8:00 a.m., reverse unit operator tagged bottom and started to drill out plug at a circulation rate of 2 bpm, with 500 psi of pressure. At 9:30 a.m., reverse unit operator tagged the top of the plug at 7595 feet and started to drill through the plug. While drilling out the plug, the plug dropped to 7776 feet and, reverse unit operator continued to drill out the plug. Reverse unit operator drilled 2 feet through the plug and tagged mud contaminated cement at 7780 feet. Continued to drill through the cement.

At 2:00 p.m., reverse unit operator drilled through cement plug at 7838 feet, then circulated for 30 minutes before the rig crew TIH to tag the top of the liner (TOL). The well was taking fluid at a rate of about 1/2 bpm once the cement plug was drilled through. Rig crew tagged cement on TOL at 9022 feet and broke circulation. At 3:30 p.m., the reverse unit operator commenced circulating the hole clean to 9022 feet. Reverse unit operator circulated 347 bbls of 8.6 ppg brine water. At 5:30 p.m., the rig crew started TOOH with work string, bit, and collars. Tomorrow, the rig crew will TIH with casing scraper to prepare the well for logging operations.

Thursday, October 12, 2006

Subsurface arrived on location at 7:00 a.m. MST. Wood Group logging crew was at the job site spotting equipment. Rig crew arrived at the location at 7:30 a.m. and continued to TOOH with work string, collars, and bit. At 10:00 a.m., rig crew TIH with casing scraper to 9022 feet. At 12:30 p.m., rig crew TOOH with casing scraper. At 3:30 p.m., Wood Group Wireline Services rigged up to the wellhead to run the CBL/VDL into the wellbore. At 4:30 p.m., the well was shut-in for the night.

Friday, October 13, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Wood Group logging crew arrived at the job site at 7:10 a.m. Rig crew arrived at the location at 7:30 a.m. and Wood Group started into the wellbore with CBL/VDL logging tool. Fikes Truck Lines arrived at the location with 4-1/2-inch, 11.6 lb/ft, J-55, LTC tubing, from C&R Industries, and the rig crew unloaded 174 joints of tubing. Wood Group completed CBL/VDL logging and ran into the wellbore with the temperature logging tool. The temperature log was completed at 3:00 p.m. with no anomalies. At 3:15 p.m., Wood Group ran the caliper logging tool into the wellbore. The CBL/VDL log showed that the TOC was located at 900 feet with good to fair bonding to 9020 feet. The VDL indicated that cement was placed into the squeezed perforations.

At 6:40 p.m., Wood Group was out of the wellbore with the caliper log and there did not appear to be any major anomalies in the 7-inch casing from 9020 feet to surface. The well was shut-in for the night and Wood Group will be back tomorrow to perforate. The time needed to perforate well was estimated to be two days.

Saturday, October 14, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Wood Group logging crew arrived at the job site at 7:00 a.m. Rig crew arrived at the location at 7:30 a.m. and Wood Group started into the wellbore with a 40 foot perforating gun. Basic provided two men to assist Wood Group as needed with the rig. Wood Group made 12 perforating runs, completing the interval from 8540 feet to 8620 feet and 400 feet of the interval from 8050 feet to 8450 feet. Wood Group will complete the remaining 390 feet tomorrow from 7660 feet to 8050 feet. The well was shutin for the night.

Sunday, October 15, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Wood Group logging crew arrived at the job site at 7:00 a.m. Rig crew arrived at the location at 7:20 a.m. and Wood Group started into the wellbore with a 40 foot perforating gun. Basic provided two men to assist Wood Group as needed with the rig. Wood Group made 10 perforating runs, completing the interval from 7660 feet to 8050 feet. A total of 22 perforating runs were made and there were no misfires during any of the runs. All the retrieved hollow steel carrier guns shot 2-JSPF on a 60° phasing. The two man rig crew assisted Wood Group with rigging down the logging equipment. The well was shutin for the night.

Monday, October 16, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. and started to lay down collars. Kenco packer and operator arrived at the job site at 8:30 a.m.. Kenco did not have the proper x-over for the PH-6 to 8rd and had to wait for a cross-over before the rig crew could run the packer. Cross-over arrived at the location and the rig crew TIH with the 7-inch x 2-7/8-inch packer. Packer was set at 7546 feet and the rig crew started to swab back the well. The first formation fluid sample was taken after 12 runs to 2400 feet (estimated 151 bbls), the second sample was taken after 14 runs (estimated 176 bbls), the third sample taken after 16 runs (estimated 201 bbls), and fourth sample was taken after 18 runs (estimated 226 bbls). Had H_2S gas present between runs 7 through 9 (estimated at 88 and 113 bbls). Well was shutin over night.

Tuesday, October 17, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:20 a.m. Rig crew loaded collar and swivel onto Key's trailers. While waiting on Key's pump truck to arrive, reverse unit operator pressured up on 2.875-inch x 7-inch annulus with packer set at 7546 feet to perform an annulus pressure test. Initial pressure was 660 psi at 8:15 a.m. After 2 hours the pressure loss started to stabilize at about 4 psi/30 minutes. At 12:30 p.m., Key Pressure Pumping was called to verify that a pump truck was coming. Apparently there was a mix-up by the dispatcher and the pump was sent to another job. Key informed Subsurface that they will have a pump on the jobsite tomorrow afternoon.

At 1:30 p.m., the wind had picked up to a point that the rig crew could not TOOH with the packer and pipe. Therefore, the annulus pressure test will be continued for the remainder of the day. Rig crew worked on rig until 3:30 p.m. and then shut-in the well for the night. Subsurface monitored pressure until 6:30 p.m.

Wednesday, October 18, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:20 a.m.. Reverse unit operator arrived at 7:30 a.m. Subsurface delivered field copies of the logs to Navajo Refining and contacted Darrel Moore. Rusty Smith informed Darrel of the need to contact the State of New Mexico for approval to use the well, even though cement did not come all the way to the surface around the 7-inch x 9-5/8-inch casing annulus (900 feet from the surface). Darrel approved Subsurface's request to contact the appropriate state officials for approval and to take necessary steps as the State of New Mexico directs.

At 10:30 a.m., the reverse unit operator pressured up the annulus between the tubing and the 7-inch casing to 700 psig for the injection test and left the location. Key Pumping Service arrived at the job site at 3:30 p.m. and started pumping down the 2-7/8-inch tubing at 4:20 p.m. with produced water in the wellbore and 650 psi on the annulus. The initial rate was 2.2 bpm (inline flow meter) at 300 psig on the tubing. After 43 bbls the pressure stabilized at 150 psi, with a total of 50 bbls pumped. The rate was increased to 4.1 bpm with an initial pressure of 830 psi. After 20 bbls, the tubing pressure stabilized at 900 psi. The pump broke down with a total of 80 bbls pumped (tubing volume 43 bbls). The ISIP was about 630 psi. Rig crew shut-in the well for the night and Key Pumping will return tomorrow morning to complete the job. (Note: pump wire harness fell into the drive shaft ripping it apart along with some hydraulic hoses)

Thursday, October 19, 2006

Subsurface personnel arrived at the location at 7:30 a.m. MST. Rig crew arrived at 9:00 a.m. Reverse unit operator arrived at 8:00 a.m.. At 9:00 a.m., Key pumping supervisor called and said that they were 45 minutes out and were given directions to the location. Subsurface released the down hole packer and will monitor both the backside and tubing pressure during the pump-in testing.

Key Pumping circulated the wellbore at 2 bpm to fill the wellbore with fluid & caught returns after 37 bbls. At 2 bpm tubing pressure (Pt) was 183 psig and backside pressure (Pa) was 28 psig. At 3 bpm, Pt was 638 psig & Pa was 148 psig. At 4 bpm, Pt was 1132 psig & Pa was 250 psig. At 5 bpm, Pt was 1678 psig & Pa was 320 psig. At 6 bpm, Pt was 2343 psig & Pa was 408 psig. At 7bpm, Pt was 3108 psig & Pa was 518 psig. At 8 bpm, Pt was 3748 psig and Pa was 535 and at 9 bpm, Pt was 4522 psig Pa was 590 psig. Key was able to reach 10 bpm but the engine over heated and was shut down. The Pt was 5087 psig at shut down and no Pa was recorded but estimated at 660 psig. Well went on a vacuum once pumping had stopped. The best estimate for ISIP 230 psig total volume of brine water pumped was 280 bbls.

Rig crew started out of the wellbore with the packer and went back into the hole with RBP and packer to test casing below squeezed perforations. We first tested across squeezed perforations and then the annulus above the perforation. RBP was set at 7550 feet packer was set above the RBP and RBP was pressure tested for leaks and packer was released. At 6:00 p.m., 640 psig was left on the annulus with the well shut-in overnight.

Friday, October 20, 2006

Subsurface personnel arrived at the location at 6:45 a.m. MST. At 7:00 a.m., the wellhead had 770 psig from 640 psig over 13 hours, a net pressure build of 130 psi. Rig crew arrived at 7:20 a.m. Subsurface and Navajo Refining received approval from the State of New Mexico after they reviewed the revised procedure and CBL/VDL log to complete the well for injection without additional cementing. The State of New Mexico requested that we try to find the leak in the casing within 500 feet to 1000 feet of the leak. Rig crew pulled 8 stands and one joint of pipe and the packer was set at 6985 feet to isolate the cement squeezed perforated interval. The squeeze interval was initially pressure tested to 490 psig and the annulus was initially pressure tested to 632 psig. The pressure test ran for 5 hours and appeared to stabilize after 2 hours.

After 2 hours, the squeezed interval was losing 6 psi/hr while the annulus was gaining about 0.75 psi/hr due to thermal effects. The final pressure for the squeezed interval was 458 psig and the final pressure for the annulus was 640 psi. At 2:30 p.m., the rig crew picked up the RBP and TOOH to 1255 feet where the RBP was reset. At 5:30 p.m., the casing was pressure tested from surface to 1255 feet with an initial pressure of 570 psig. At 6:00 p.m., the well was shut-in over night with 569 psig on the casing.

Saturday, October 21, 2006

Subsurface personnel arrived at the location at 6:45 a.m. MST. At 7:00 a.m., the wellhead had 540 psig from 569 psig over a 13 hour period, a net pressure loss of 29 psi at a rate of 2 psi/hr with the RBP set at 1255 feet (48 bbl). Rig crew arrived at 7:30 a.m. Continued to monitor pressure to verify loss rate. At 7:30 a.m., pressure was 539 psig and at 8:00 a.m. pressure was 538 psi. Packer hand released RPB and rig crew TOOH with packer and RBP. Charlie's Services inspected the 4-1/2-inch tubing. Rig crew TIH and TOOH with work string and started laying down the work string as they came out of the hole. Charlie's inspection crew found two bad joints of 4-1/2-inch tubing as marked on their tally. Rig crew finished laying down the work string and loaded 4-1/2-inch tubing onto the pipe rack. Well was shut-in for the night.

Sunday, October 22, 2006

Pipe, location, and rig personnel are ready for casing crew. Wellhead, packer, and annulus fluid to arrive on Monday.

Monday, October 23, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. and replaced the old Cameron 7-1/16-inch 5M x 11-inch 3M spool with a new Superior 7-1/16-inch 5M x 11-inch 3M spool. P-seals were pressure tested for 15 minutes to 3000 psi with no leakoff. BOP was reseated on the new spool to run the casing into the wellbore. At 12:00 p.m., casing crew started into the wellbore with packer and 4-1/2-inch tubing. Packer would not go past the 50-foot mark therefore, packer was pulled out of the hole and inspected.

Weatherford had brought to location, a packer for 7", 24 lb/foot casing. The casing in the wellbore was 7 inches, 29 lb/ft casing. Weather had to go back to Hobbs, New Mexico to pick up the correct packer. Kenco was called, and they had an Arrow X-1 Packer in the shop. Kenco delivered a new 7-inch Arrow X-1 packer to the job site but brought out the wrong size cross-over. At 4:15 p.m., Weatherford brought out a rebuilt 29 lb/ft packer to replace the 24 lb/ft packer that was originally brought out to location. Kenco will have a cross-over on the job site in the morning and Weatherford was sent back to Hobbs. Kenco will install the packer. The well was shut in for the night.

Tuesday, October 24, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew and casing crew arrived at 7:30 a.m. The crews started running casing at 8:00 a.m. There were no problems getting Kenco's new Arrow Packer into the wellbore. Kenco also used an integral cross over rather than a sedge and casing collar for a cross. At 2:30 p.m., casing crew ran 7567 feet of casing into the hole and each joint was torqued to specifications at 1600 lbs. The wellbore was circulated full of fluid (240 bbls), then 300 PSI pumped 23.8 bbls of squeeze chemical. The reverse unit operator pumped 95 bbls of inhibited brine water followed by 14.29 bbls of squeeze chemical, leaving 7.23 bbls of brine in the bottom of the annulus. The weight of the brine circulated and the inhibited brine in the annulus was 8.7 ppg. The weight of the squeeze chemical was 10.2 ppg.

At 5:30 p.m., the bottom of the Arrow packer was set at 7575.73 feet with 37K lb in tension within 7 minutes after we stopped pumping with the well taking fluid at ~0.5 bpm. The length of the packer was 7.2 feet and the length of the cross over was 0.54 feet. Casing slips were set in the spool and the BOP was removed and a rough cut made on the casing. Once all equipment was removed from the area the 4-1/2-inch tubing was dressed off and the wellhead installed. At 7:00 p.m., the well was shut-in for the night.

Wednesday, October 25, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Superior Wellhead arrived at the job site at 7:20 a.m. and pressure tested the P-seals to 3000 psig. Rig crew and casing crew arrived at 7:30 a.m. Rig crew started mobilizing the rig. The reverse unit operator pumped the annulus full with 2.5 bbls. At 10:00 a.m. 300 PSI arrived at the job site and performed a 545 psi squeeze for 4 hours with no pressure loss. At 3:00 p.m., an annulus pressure test was performed and recorded for one hour by 300 PSI, at a pressure of 490 psig on the chart. At 4:00 p.m., the annulus pressure test showed no pressure loss over the hour. Left 480 psig on the annulus (at 4:30 p.m.) overnight to watch for pressure leaks. At 6:00 p.m., annulus was maintaining 480 psig. Well was shut-in for the night.

Thursday, October 26, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. At 7:00 a.m., EL Farmer trucking was at the job site waiting on someone to load the 2-7/8-inch, PH-6 tubing onto the truck. At 7:15 a.m., Subsurface started loading tubing onto the EL Farmer truck. At 7:30 a.m., Renco Equipment arrived at the job site with a fork lift and completed loading up truck. The first truck picked up slips, stabbing tool, safety valve, and 150 joints of pipe. At 8:00 a.m., annulus was maintaining 480 psig and showed no signs of pressure loss over the 14-hour period. The second truck arrived at 8:05 p.m. and was loaded with 147 joints of pipe. At 8:30 a.m., two Key Fishing Tool trucks arrived at the job site to pick up pump, open top tank, pipe racks, BOP, and catwalk. Key Energy delivered 4 frac tanks to the job site and started to fill the tanks with fresh water and brine. At 4:30 p.m., G&L Tool Rental picked up rig mat boards. At 5:30 p.m., annulus was maintaining 480 psig and showed no signs of pressure loss over the 23.5-hour period. Well was shut-in for the night.

Friday, October 27, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Key will not have all 14 frac tanks spotted and filled by this Saturday therefore the pressure build up/falloff test will have to be postponed until Saturday, November 4th, due to the availability of pump trucks to perform the pressure build up portion of the test.

Trailer and light plant will remain on the job site for another week, as we will need the light plant for the 12 hours of pumping. At 10:00 a.m., Medina's Hot Shot service arrived at the job site and delivered a flange, ring gasket, and bolts from Superior Wellhead to cover the injection line valve. At 3:00 p.m., Key delivered one frac tank to the job site and repaired a leak around the bottom valve on one of the tanks that was delivered yesterday.

Saturday, October 28, 2006

Rusty Smith traveled to Houston and will return on Thursday, November 2, 2006 to oversee the pressure build up and falloff test.

Thursday, November 2, 2006

Rusty Smith traveled to Artesia, New, Mexico and arrived at the jobsite at 2:30 p.m. MST. Key had 14 frac tanks on the site and should have them filled by tomorrow afternoon. Tried to find a 1-13/16-inch hammer wrench for flange bolts and could not find any in Artesia. Contacted Banta to install side flange for pump-in test, Banta will have hammer wrenches for flange. Subsurface acquired fuel containers for light plant. Key will roll frac tanks tomorrow.

Friday, November 3, 2006

Subsurface personnel arrived at the location at 7:30 a.m. MST. Banta Roustabout Service arrived at the location at 8:15 a.m. and installed the injection side flange. Six temperatures were taken at midpoint in the frac tanks to determine the current water temperatures. The shear pin in the packer was set at 80K lbs, which is well above the stress being applied due to temperature changes. Petroplex treated all tanks with biocide and Key came out and rolled the tanks with a vacuum truck.

Alex, with Schlumberger Slickline, was on notice for tomorrow at 3:00 p.m. MST. After rolling the tanks, the average water temperature in the tanks was 60.6° F. Key left the job site at 5:30 p.m.

Saturday, November 4, 2006

Subsurface personnel arrived at the location at 6:20 a.m. MST. Petroplex Pumping Service arrived at the location at 7:10 a.m. and started to rig up their pumps. Key's kill truck arrived at 7:12 a.m. and rigged up to the annulus to hold pressure on the annulus. At 9:15 a.m., treating lines were pressure tested to 4400 psi. Started pumping at 9:19 a.m. at 3 bpm to fill hole and after 28 bbls we caught pressure with 162 psig on the wellhead and 535 psig on the annulus. At 9:42 a.m., with 50 bbls into the well, the rate was increased to 5 bpm at 385 psig and 463 psig on the annulus. At 9:55 a.m., the rate was 5 bpm with 525 psig on the wellhead and 118 bbls pumped. At 10:00 a.m., the second pump was brought on line and the first pump was taken out of service due to a leaking hydraulic hole. At 10:10 a.m., the rate was 5 bpm at 531 psig and 493 psig on the annulus. At 10:15 a.m., the rate was increased to 6.8 bpm at 700 psig on the wellhead with 215 bbls pumped. At 10:45 a.m., the rate was increased to 10 bpm at 1200 psig and 542 psig on the annulus with 438 bbls pumped. At 10:55 a.m., the rate was 10 bpm at 1220 psig with 532 bbls pumped and 730 psig on the annulus. At 1105 a.m., the rate was being maintained at 10 bpm at 1278 psig with 673 bbls pumped.

Petroplex is sending out another pump to the location. The backup Petroplex pump arrived at 12:10 p.m. and the crew rigged up two additional pumps in the treating line for backup. At 1:00 p.m., the rate was 10 bpm at 1185 psig with 1785 bbls pumped, annulus pressure was 775 psig. At 2:30 p.m., the rate was 10 bpm at 1387 psig with 713 psig on the annulus, 2307 bbls pumped. At 3:30 p.m., the rate was lowered to 9 bpm at 1209 psig with 725 psig on the annulus, 3028 bbls pumped. At 5:30 p.m., the rate was 9 bpm at 1171 psig with 719 psig on the annulus. At 6:00 p.m., Schlumberger arrived at the job site and rigged up the slickline unit. At 7:17 p.m., the rate was lowered to 5 bpm to allow the BHP memory tool into the wellbore. At 7:30 a.m., the rate was increased to 5 bpm at

344 psig. At 7:41 p.m., the rate was increased to 9 bpm at 1104 psig. At 9:00 p.m., the pumps started to lose suction pressure and the pumping job was ended (est. 6700 bbls). Well was closed in with 50 psig on the annulus and no pressure on the wellhead. Petroplex rigged down and left location at 11:00 p.m.

Sunday, November 5, 2006

Subsurface personnel arrived at the location at 8:30 a.m. MST, with 800 psig on the annulus. Schlumberger slickline crew arrived at the location at 10:20 a.m. and started out of the hole with memory tool at 8630 feet (10:35 a.m.), taking gradient stops every 1000 feet for 5 minutes. The length of the tool was 27 feet with the top of the tool placed at 8630 feet. First stop was at 7000 feet at 10:40 a.m.. At 12:35 p.m., Schlumberger completed the rig down process and left location at 1:00 p.m. The office trailer was cleaned out and disconnected from the light plant. The light plant was rigged down and made ready for pickup. The well annulus was bled down and left open and the wellhead shut-in. Schlumberger left their 4-1/2-inch 8rd EUE x 2-7/8-inch female 8rd tubing swedge in the top of the wellhead.

Monday, November 6, 2006

Subsurface personnel traveled to Houston and will return on Monday, November 13, 2006, to oversee the temperature survey, radioactive tracer survey, and annulus pressure test. Called Young's to pickup office trailer, Sani-Tech to pick up portable toilets, and Aztec to pickup light plant. Larry at Key was notified to leave one frac tank on location and pickup the remaining frac tanks. Banta was notified for waste removal of pit and location cleanup for the week of November 13th.

Sunday, November 12, 2006

Rusty Smith traveled to Artesia, New Mexico, and arrived at the job site at 5:00 p.m. MST. Key Energy emptied the frac tank bottoms and the tanks are ready to be disconnected and picked up. Aztec and Sani-Tech still have not removed the equipment from the location. The equipment was taken off rental on November 6, 2006.

Monday, November 13, 2006

Subsurface arrived at the location at 7:30 a.m. MST. Banta roustabout service arrived at the job site at 8:15 a.m. to remove well cutting and clear location of debris, fill in cellar with gravel, and haul off trash. Navajo refining requires that that all produced cuttings and debris contained in the pit be profiled prior to disposal (cannot be disposed under oil field exemption). Key started to remove frac tanks from the location. The OCD pushed back the annulus pressure test, and radioactive tracer survey one day to November 15th. Wood Group Logging services will arrive tomorrow afternoon for testing on the 15th. Petroplex Pumping will provide a pump truck for the radioactive tracer test.

Tuesday, November 14, 2006

Subsurface personnel arrived at the location at 8:30 a.m. MST. Wayne, with the OCD, was emailed at 5:00 p.m. MST November 13, 2006, informing the OCD of the annulus pressure test and radioactive tracer survey set for November 15, 2006. Included in the email were directions to the well and a short testing procedure. Wood Group and Petroplex were contacted to verify the job for tomorrow. Key has filled one frac tank with one load of brine and three loads of fresh water to chase down the radioactive slug. Wind gusted up to 50 mph and Key could not haul any more frac tanks for the day, in accordance with DOT regulations. Because of the high wind speed Wood Group will rig up tomorrow. OCD called and said that they will arrive at 10:00 a.m. tomorrow morning.

Wednesday, November 15, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Petroplex was on location. At 7:50 a.m., Petroplex hooked up to the frac tank and started to circulate the tank and will circulate for +2 hours. Wood Group started to rig up at 8:30 a.m. and completed the rig up at 10:00 a.m. OCD representatives arrived at the location to witness the annulus pressure test. The annulus was pressure tested to 530 psia and over a one hour period and lost 2.5 psi. According to the OCD, the well passed the annulus pressure test.

The radioactive survey was started and during the 5-minute check, the upper gamma ray sensor malfunctioned and the sensor had to be pulled and replaced. Once the sensor was replaced, the remainder of the survey went as planned and there did not appear to be any radioactive material above the packer or being pumped out of the injection interval.

There were some undocumented perforations below 8600 feet that were taking fluid. During the first chase down, additional RA material was released as a result of the well being on a vacuum. At the end of the job the annulus was pressure tested to 300 psig and held pressure for 1.5 hours and was then bled off and left open. Wood Group rigged down at 8:30 p.m.

Thursday, November 16, 2006

Subsurface personnel called Key to release frac tank and went to location to check well and sign invoices from Basic and G&L Tools in Artesia, NM. Subsurface personnel travel to Houston, Texas.

Subsurface personnel will return to Artesia in ± one month to install WAMS. Subsurface is waiting on the unit to be built.

APPENDIX I
CALCULATION OF PERMEABILITY
FROM DST NO. 5
MEWBOURNE OIL COMPANY, CHALK BLUFF 31, STATE NO. 1

The permeability of the interval tested is calculated to be 597 md, as follows from test data in Attachment VIII-9:

$$k = 162 \frac{qB\mu}{mh}$$

where:

k	=	permeaibility, md
q	=	production rate (bbl/day)
B	=	formation volume factor, (reservoir bbl)/(stock tank bbl)
μ	=	viscosity, centipoise (cp)
m	=	slope of Horner plot, psi/cycle
h	=	reservoir thickness, feet

The production rate, q, is calculated from the total volume of fluid, 78.7 bbl, produced during DST No. 5, which lasted for 90 minutes (the sum of lengths of the first and second flow periods). Using these values, q is equal to 1259 bbl/day. The formation volume factor, B, is assumed to be 1. The viscosity, μ, of reservoir brine with 25,000 ppm chlorides (approximately 2% salinity) at a bottom-hole temperature of 130°F is 0.53 cp, taken from the charge in Attachment VI-7. The slope of the Horner plot, m, is taken form the Horner plot for the second flow period of DST no. 5, or 5.348 psi/cycle (page 22 of Attachment VIII-9). The reservoir thickness, h, is the thickness of the interval tested during DST No. 5, or 34 feet (7851 feet – 7817 feet). Substituting these values into the equation above gives:

$$k = 162 \frac{(1259)(1)(0.53)}{(34)(5.348)}$$

$$= 597 \text{ md}$$

INJECTED FLUID MONITORING PLAN

NAVAJO REFINING COMPANY, L.L.C.
ARTESIA, NEW MEXICO

SUBSURFACE PROJECT NO. 60A6781

SUBMITTED
JUNE 2012

SUBSURFACE TECHNOLOGY, INC.
HOUSTON, TEXAS

SUBSURFACE

TABLE OF CONTENTS

1.0 INTRODUCTION

This injected fluid monitoring plan (plan) has been prepared per the requirements of 20.6.2.5207B NMAC. This plan allows for consistent characterization of the injected fluids that are being injected into the three nonhazardous waste injection wells operated by Navajo Refining Company, L.L.C. (Navajo) at their refinery in Artesia, New Mexico. The plan shall be updated as necessary to remain accurate and the analysis remains representative of the fluids being injected into the three nonhazardous waste injection wells.

2.0 INJECTED FLUID DESCRIPTION

The fluid injected into all three Navajo injection wells is comprised of exempt and nonexempt nonhazardous oilfield waste that is generated in the refining process. Waste waters from process units, cooling towers, boilers, streams from water purification units, desalting units, recovered and treated ground water, and general waste waters, all waters will be blended to form the injected fluid into the injection wells.

3.0 INJECTED FLUID CHARACTERIZATION SAMPLING PROGRAM

The following sampling program shall be used to collect a representative sample of the injected fluid for chemical analysis to demonstrate the consistency of the fluid composition.

3.1 Sampling Frequency

The injected fluid shall be sampled on a quarterly basis unless a change in the injected fluid composition occurs as a result of operating changes at the Navajo refinery. If the injected fluid composition does change, a representative sample of the waste stream shall be collected at that time and reported to OCD.

3.2 Sampling Location

A representative sample of the injected fluid shall be obtained from the discharge side of the wastewater transfer pump that sends wastewater to the wellheads. The sample port is located at the refinery's wastewater treatment unit.

3.3 Sample Collection Equipment

The fluid samples shall be collected directly from the sample port on the wastewater transfer line into appropriately prepared sample containers required for specific analyses.

3.4 Sample Containers

The injected fluid sample shall be collected in new and previously unused sample containers as provided by the off-site commercial laboratory performing the analyses.

3.5 Sampling Methodology

The injected fluid sample shall be poured directly into the new and previously unused sample containers provided by the off-site commercial laboratory performing the analyses.

3.6 Sample Preservation

EPA and/or ASTM sampling protocols shall be used, including provisions for preserving samples when required. Sampling personnel shall verify that appropriate preservatives are present in sample containers if required by analytical protocol.

3.7 Field Measurements

Field measurements of pH, specific conductance, and temperature shall be recorded on a representative sample of the injected fluid during each quarterly monitoring event.

3.8 Sampling Personnel

Navajo environmental staff or qualified contractor sampling personnel shall be responsible for collecting the injected fluid samples in accordance with the procedures presented in this plan.

4.0 FIELD DOCUMENTATION

The following procedures shall be implemented to properly document each injected fluid characterization sampling event as described in Section 3.0.

4.1 Water Sampling Log

A water sampling log shall be completed at the time the sample is collected. The type of information to be recorded on the water sampling log includes, but is not limited to, the following:

- Date and time of sampling
- Weather conditions
- Sampling location
- Sampling method
- Sample identification
- Field measurements
- Laboratory analyses
- Sampling personnel

4.2 Sample Container Label

Each laboratory provided sample container shall have a label adhered to the outside of the container providing pertinent information identifying the sample, location and time the sample was collected, analytical parameters, preservatives, and sampler identification.

4.3 Chain-of-Custody Form

A chain-of-custody form shall be completed and accompany each shipment of samples to the off-site commercial laboratory. Each transfer of sample custody shall be signed by both parties on the chain-of-custody form.

4.4 Custody Seal

A custody seal shall be affixed over the opening of the ice chest used to store and transport samples to the receiving laboratory. The laboratory shall note in their Check-In Form that the seal is properly attached and has not been broken.

4.5 Field Equipment Calibration Log

Calibration and maintenance of field equipment (pH, specific conductance, turbidity, and temperature meters) shall be in compliance with the manufacturers' recommended calibration or maintenance procedures. Field logs shall be completed in the field to properly document all calibration and maintenance activities to field equipment.

5.0 QUALITY ASSURANCE/QUALITY CONTROL

A trip blank will be prepared during each waste stream characterization sampling event as described in Section 3.0.

6.0 SAMPLE CUSTODY AND TRANSPORT

Injected fluid characterization samples shall be maintained in the custody of the sampling personnel until the samples are transported to the laboratory or transferred to a representative of the receiving laboratory. Upon transfer of custody, the chain-of-custody record shall be completed and signed by the sampling personnel. The signed chain-of-custody record shall be placed in a plastic bag inside the shipment cooler containing the properly labeled injected fluid samples. A signed and dated custody seal shall be placed over the lid of the opening of the sample cooler to indicate if the cooler has been opened during delivery prior to receipt by the laboratory.

The chain-of-custody record shall be signed and returned by the laboratory no later than the date the analytical results are available. If the samples are delivered in person by the sampling personnel or picked up by a laboratory employee, the chain-of-custody record shall be signed by the laboratory representative immediately upon relinquishment of the samples by the sampling personnel. One of the copies shall be maintained by the sampling personnel and the remaining copies kept with the samples.

7.0 WASTE STREAM ANALYTICAL PROGRAM

The following describes the injected fluid characterization analytical program.

7.1 Laboratory Requirements

The laboratory performing the analytical services for this project shall be an accredited laboratory. The laboratory shall possess a quality control/ quality assurance (QA/QC) manual prepared in accordance with the requirements of the NELAC certification program. A current copy of the plan shall be sent by the laboratory to the project manager in charge. When the manual is updated by the laboratory the updated version of the manual shall be sent to the project manager. The previously issued copy of the manual must be archived by the project manager to insure traceability of the data generated using the applicable QA/QC manual.

Navajo is currently utilizing ALS Environmental, a commercial laboratory located in Houston, Texas. ALS is a NELAC accredited laboratory.

7.2 Analytical Parameters and Methods

The injected fluid samples are analyzed for the following listing of parameters that are representative of the injected fluid:

- VOC (EPA Method 8260)
- SVOC (EPA Method 8270)
- Total Metals (EPA Method 6020/7000)
- RCI
- Chloride
- Sulfate
- Alkalinity
- TDS
- pH
- Conductivity

The parameter listing shall be updated as necessary to remain accurate and the waste analysis remains representative of the injected fluid being injected.

8.0 REPORTING

The laboratory performing the injected fluid characterization analyses shall generate a report of the analytical results. These analytical results shall be compiled with the field measurement results and tabularized. The results of each waste stream characterization sampling event, including tabularization of analytical results, copies of laboratory reports, and copies of water sampling logs, shall be provided to OCD within 90 days following each sampling episode. The report shall document any obvious fluctuations in the injected fluid composition.

APPENDIX K

INJECTION WELL CLOSURE PLAN
HOLLYFRONTIER NAVAJO REFINING LLC
(WDW-1)

<u>Final Testing Program</u>

After ceasing injection in the well and prior to commencing physical closure procedures of the injection well, a pressure falloff test will be conducted in order to determine if the transient pressure data have conformed with predicted values within the injection interval. The brine injected for the falloff test will be nonhazardous and will also act as a buffer between the injectate and the well. Appropriate mechanical integrity testing shall also be conducted to ensure the integrity of the long casing string and cement that will remain in the ground after closure. Notify the OCD of mechanical integrity and pressure falloff testing procedures of the long casing string and cement that will remain.

<u>Mechanical Integrity Testing</u>

An annular pressure test and radioactive tracer survey will be conducted prior to removing the injection tubing and packer. Subsequent to tubing and packer removal, a casing inspection and a cement bond/variable density log will be conducted from total depth to the surface.

<u>Pressure Falloff Testing</u>

A wireline unit with pressure control equipment will be rigged up to run in the hole with a surface recording bottom-hole pressure transducer with temperature capabilities to position the transducer at the top of the injection interval. The transducer will be stabilized prior to injecting brine.

Two thousand barrels of brine will be injected at a constant rate. The brine will be compatible with the injection zone reservoir fluid as determined by compatibility testing. The pressure buildup will be recorded. After pumping is ceased, the pressure falloff will be recorded for a minimum of 24 hours after shut in. The pressure derivative curve to will be monitored confirm the test has investigated beyond the wellbore storage effect.

APPENDIX K (Continued)

Regulatory Notification

Navajo will notify OCD at least 60 days before commencing plugging and abandonment procedures on any waste disposal well.

Plug and Abandonment Procedures

The balance plug method will be employed to plug and abandon this well. This technique involves displacing the cement through a work string which has been run into the casing. The cement slurry is pumped down the work string and up the annulus to a calculated height which would balance the cement inside and outside the work string. The work string is then slowly pulled out of the cement leaving a solid, uniform plug.

Heavy drilling mud is placed between the cement plugs. This mud establishes a hydrostatic gradient that will exceed the static bottom-hole pressure at the time of plugging and any anticipated pressures which would result from future injection activity in these particular formations.

Finally, after all cement plugs are set, the well casings will be cut off 3 feet below grade and capped by welding a ½ inch steel plate to the outermost casing string.

The plugging and abandonment procedures for a typical well are described as follows:

1. Prepare the well and location for plugging. Remove the well monitoring equipment and wellhead injection piping.

2. Notify the OCD of the MIT schedule. Conduct an annulus pressure test and a radioactive tracer survey to satisfy OCD mechanical integrity requirements.

3. Move in and rig up the frac tanks and pump for the pressure falloff test. Fill frac tanks with 2,000 barrels of brine.

4. Rig up the wireline unit with pressure control equipment. Run into the hole with a surface recording bottom-hole pressure transducer with temperature capabilities and position the transducer at the top of the perforated injection interval. Allow the transducer to stabilize prior to injecting brine.

5. Commence injecting 2,000 barrels of brine at a constant rate. The brine will be compatible with the injection zone reservoir fluid, as determined by compatibility testing. Record the pressure buildup. Cease pumping and record the pressure

falloff. Measure the pressure falloff for a minimum of 24 hours after shut in. Monitor the pressure derivative curve to confirm the test has investigated beyond the wellbore storage effect.

6. Rig down the wireline unit.
7. Move in and rig up the well service unit with BOP equipment and a 2 7/8 inch work string.
8. Remove the wellhead and install the BOP equipment and stripper head.
9. Unseat the seal assembly from the packer and displace the annular fluid by flushing with 200 bbls of brine. Trip out of the hole laying down the 4 ½ -inch injection tubing.
10. Rig up the wireline unit and run a casing inspection log and a cement bond/variable density log from total depth to the surface. Pick up and run a wireline set cement retainer at 9,004 feet. Rig down the wireline unit.
11. Rig up cement service equipment. Cement shall be Class "A" (or comparable), weighing 15.6 pounds/gallon. Pressure test the surface lines as required.
12. Run in the well with the work string and sting into the cement retainer at 9,004 feet. Establish a pump-in rate into the injection perforations and pump 100 sx of Class “A” cement below the retainer. Pull out of the retainer and spot sufficient Class "A" (or comparable) cement slurry to develop a 100-foot plug above the cement retainer. Pull the tubing up above the top of cement and reverse out excess cement. Catch a sample of cement to check curing time and compressive strength. Allow the cement to set overnight (8-hour minimum) before tagging top of plug to confirm proper setup and location. Pressure test the plug to the pressure recommended by the OCD.
13. Set a balanced cement plug using Class “A” cement from the top of cement at approximately 9,004 feet to the surface.
14. Cut casing strings ±3 feet below ground level.

APPENDIX K (Continued)

15. Weld a ½ inch steel plate across the 13-3/8-inch casing. Inscribe on plate, in a permanent manner, the following information: (1) operator name, (2) closure date, and (3) UIC permit number.

16. Release all equipment and clean up the location.

17. Submit closure data to the OCD.

Once closure operations are complete and the well is officially plugged and abandoned, a closure report certifying that the well or wells were closed in accordance with applicable requirements, will be submitted to the OCD within 30 days. The report will include any newly constructed or discovered wells or information, including proposed well data, within the area of review. When plugging and abandonment is complete, Navajo will submit certification to the OCD that the injection well has been closed in accordance with applicable OCD regulations.

APPENDIX K

INJECTION WELL CLOSURE PLAN
HOLLYFRONTIER NAVAJO REFINING LLC
(WDW-2)

Final Testing Program

After ceasing injection in the well and prior to commencing physical closure procedures of the injection well, a pressure falloff test will be conducted in order to determine if the transient pressure data have conformed with predicted values within the injection interval. The brine injected for the falloff test will be nonhazardous and will also act as a buffer between the injectate and the well. Appropriate mechanical integrity testing shall also be conducted to ensure the integrity of the long casing string and cement that will remain in the ground after closure. Notify the OCD of mechanical integrity and pressure falloff testing procedures of the long casing string and cement that will remain.

Mechanical Integrity Testing

An annular pressure test and radioactive tracer survey will be conducted prior to removing the injection tubing and packer. Subsequent to tubing and packer removal, a casing inspection and a cement bond/variable density log will be conducted from total depth to the surface.

Pressure Falloff Testing

A wireline unit with pressure control equipment will be rigged up to run in the hole with a surface recording bottom-hole pressure transducer with temperature capabilities to position the transducer at the top of the injection interval. The transducer will be stabilized prior to injecting brine.

Two thousand barrels of brine will be injected at a constant rate. The brine will be compatible with the injection zone reservoir fluid as determined by compatibility testing. The pressure buildup will be recorded. After pumping is ceased, the pressure falloff will be recorded for a minimum of 24 hours after shut in. The pressure derivative curve to will be monitored confirm the test has investigated beyond the wellbore storage effect.

APPENDIX K (Continued)

Regulatory Notification

Navajo will notify OCD at least 60 days before commencing plugging and abandonment procedures on any waste disposal well.

Plug and Abandonment Procedures

The balance plug method will be employed to plug and abandon this well. This technique involves displacing the cement through a work string which has been run into the casing. The cement slurry is pumped down the work string and up the annulus to a calculated height which would balance the cement inside and outside the work string. The work string is then slowly pulled out of the cement leaving a solid, uniform plug.

Heavy drilling mud is placed between the cement plugs. This mud establishes a hydrostatic gradient that will exceed the static bottom-hole pressure at the time of plugging and any anticipated pressures which would result from future injection activity in these particular formations.

Finally, after all cement plugs are set, the well casings will be cut off 3 feet below grade and capped by welding a ½ inch steel plate to the outermost casing string.

The plugging and abandonment procedures for a typical well are described as follows:

1. Prepare the well and location for plugging. Remove the well monitoring equipment and wellhead injection piping.

2. Notify the OCD of the MIT schedule. Conduct an annulus pressure test and a radioactive tracer survey to satisfy OCD mechanical integrity requirements.

3. Move in and rig up the frac tanks and pump for the pressure falloff test. Fill frac tanks with 2,000 barrels of brine.

4. Rig up the wireline unit with pressure control equipment. Run into the hole with a surface recording bottom-hole pressure transducer with temperature capabilities and position the transducer at the top of the perforated injection interval. Allow the transducer to stabilize prior to injecting brine.

5. Commence injecting 2,000 barrels of brine at a constant rate. The brine will be compatible with the injection zone reservoir fluid, as determined by compatibility testing. Record the pressure buildup. Cease pumping and record the pressure

falloff. Measure the pressure falloff for a minimum of 24 hours after shut in. Monitor the pressure derivative curve to confirm the test has investigated beyond the wellbore storage effect.

6. Rig down the wireline unit.
7. Move in and rig up the well service unit with BOP equipment and a 2 7/8 inch work string.
8. Remove the wellhead and install the BOP equipment and stripper head.
9. Unseat the seal assembly from the packer and displace the annular fluid by flushing with 200 bbls of brine. Trip out of the hole laying down the 4 ½ -inch injection tubing.
10. Rig up the wireline unit and run a casing inspection log and a cement bond/variable density log from total depth to the surface. Pick up and run a wireline set cement retainer at 9,004 feet. Rig down the wireline unit.
11. Rig up cement service equipment. Cement shall be Class "A" (or comparable), weighing 15.6 pounds/gallon. Pressure test the surface lines as required.
12. Run in the well with the work string and sting into the cement retainer at 9,004 feet. Establish a pump-in rate into the injection perforations and pump 100 sx of Class “A” cement below the retainer. Pull out of the retainer and spot sufficient Class "A" (or comparable) cement slurry to develop a 100-foot plug above the cement retainer. Pull the tubing up above the top of cement and reverse out excess cement. Catch a sample of cement to check curing time and compressive strength. Allow the cement to set overnight (8-hour minimum) before tagging top of plug to confirm proper setup and location. Pressure test the plug to the pressure recommended by the OCD.
13. Set a balanced cement plug using Class “A” cement from the top of cement at approximately 9,004 feet to the surface.
14. Cut casing strings ±3 feet below ground level.

APPENDIX K (Continued)

15. Weld a ½ inch steel plate across the 13-3/8-inch casing. Inscribe on plate, in a permanent manner, the following information: (1) operator name, (2) closure date, and (3) UIC permit number.

16. Release all equipment and clean up the location.

17. Submit closure data to the OCD.

Once closure operations are complete and the well is officially plugged and abandoned, a closure report certifying that the well or wells were closed in accordance with applicable requirements, will be submitted to the OCD within 30 days. The report will include any newly constructed or discovered wells or information, including proposed well data, within the area of review. When plugging and abandonment is complete, Navajo will submit certification to the OCD that the injection well has been closed in accordance with applicable OCD regulations.

APPENDIX K

INJECTION WELL CLOSURE PLAN
HOLLYFRONTIER NAVAJO REFINING LLC
(WDW-3)

Final Testing Program

After ceasing injection in the well and prior to commencing physical closure procedures of the injection well, a pressure falloff test will be conducted in order to determine if the transient pressure data have conformed with predicted values within the injection interval. The brine injected for the falloff test will be nonhazardous and will also act as a buffer between the injectate and the well. Appropriate mechanical integrity testing shall also be conducted to ensure the integrity of the long casing string and cement that will remain in the ground after closure. Notify the OCD of mechanical integrity and pressure falloff testing procedures of the long casing string and cement that will remain.

Mechanical Integrity Testing

An annular pressure test and radioactive tracer survey will be conducted prior to removing the injection tubing and packer. Subsequent to tubing and packer removal, a casing inspection and a cement bond/variable density log will be conducted from total depth to the surface.

Pressure Falloff Testing

A wireline unit with pressure control equipment will be rigged up to run in the hole with a surface recording bottom-hole pressure transducer with temperature capabilities to position the transducer at the top of the injection interval. The transducer will be stabilized prior to injecting brine.

Two thousand barrels of brine will be injected at a constant rate. The brine will be compatible with the injection zone reservoir fluid as determined by compatibility testing. The pressure buildup will be recorded. After pumping is ceased, the pressure falloff will be recorded for a minimum of 24 hours after shut in. The pressure derivative curve to will be monitored confirm the test has investigated beyond the wellbore storage effect.

APPENDIX K (Continued)

Regulatory Notification

Navajo will notify OCD at least 60 days before commencing plugging and abandonment procedures on any waste disposal well.

Plug and Abandonment Procedures

The balance plug method will be employed to plug and abandon this well. This technique involves displacing the cement through a work string which has been run into the casing. The cement slurry is pumped down the work string and up the annulus to a calculated height which would balance the cement inside and outside the work string. The work string is then slowly pulled out of the cement leaving a solid, uniform plug.

Heavy drilling mud is placed between the cement plugs. This mud establishes a hydrostatic gradient that will exceed the static bottom-hole pressure at the time of plugging and any anticipated pressures which would result from future injection activity in these particular formations.

Finally, after all cement plugs are set, the well casings will be cut off 3 feet below grade and capped by welding a ½ inch steel plate to the outermost casing string.

The plugging and abandonment procedures for a typical well are described as follows:

1. Prepare the well and location for plugging. Remove the well monitoring equipment and wellhead injection piping.

2. Notify the OCD of the MIT schedule. Conduct an annulus pressure test and a radioactive tracer survey to satisfy OCD mechanical integrity requirements.

3. Move in and rig up the frac tanks and pump for the pressure falloff test. Fill frac tanks with 2,000 barrels of brine.

4. Rig up the wireline unit with pressure control equipment. Run into the hole with a surface recording bottom-hole pressure transducer with temperature capabilities and position the transducer at the top of the perforated injection interval. Allow the transducer to stabilize prior to injecting brine.

5. Commence injecting 2,000 barrels of brine at a constant rate. The brine will be compatible with the injection zone reservoir fluid, as determined by compatibility testing. Record the pressure buildup. Cease pumping and record the pressure

falloff. Measure the pressure falloff for a minimum of 24 hours after shut in. Monitor the pressure derivative curve to confirm the test has investigated beyond the wellbore storage effect.

6. Rig down the wireline unit.

7. Move in and rig up the well service unit with BOP equipment and a 2 7/8 inch work string.

8. Remove the wellhead and install the BOP equipment and stripper head.

9. Unseat the seal assembly from the packer and displace the annular fluid by flushing with 200 bbls of brine. Trip out of the hole laying down the 4 ½ -inch injection tubing.

10. Rig up the wireline unit and run a casing inspection log and a cement bond/variable density log from total depth to the surface. Pick up and run a wireline set cement retainer at 9,022 feet. Rig down the wireline unit.

11. Rig up cement service equipment. Cement shall be Class "A" (or comparable), weighing 15.6 pounds/gallon. Pressure test the surface lines as required.

12. Run in the well with the work string and sting into the cement retainer at 9,022 feet. Establish a pump-in rate into the injection perforations and pump 100 sx of Class “A” cement below the retainer. Pull out of the retainer and spot sufficient Class "A" (or comparable) cement slurry to develop a 100-foot plug above the cement retainer. Pull the tubing up above the top of cement and reverse out excess cement. Catch a sample of cement to check curing time and compressive strength. Allow the cement to set overnight (8-hour minimum) before tagging top of plug to confirm proper setup and location. Pressure test the plug to the pressure recommended by the OCD.

13. Set a balanced cement plug using Class “A” cement from the top of cement at approximately 9,022 feet to the surface.

14. Cut casing strings ±3 feet below ground level.

APPENDIX K (Continued)

15. Weld a ½ inch steel plate across the 13-3/8-inch casing. Inscribe on plate, in a permanent manner, the following information: (1) operator name, (2) closure date, and (3) UIC permit number.

16. Release all equipment and clean up the location.

17. Submit closure data to the TCEQ.

Once closure operations are complete and the well is officially plugged and abandoned, a closure report certifying that the well or wells were closed in accordance with applicable requirements, will be submitted to the OCD within 30 days. The report will include any newly constructed or discovered wells or information, including proposed well data, within the area of review. When plugging and abandonment is complete, Navajo will submit certification to the OCD that the injection well has been closed in accordance with applicable OCD regulations.

Form ___WQCC-1____
Adopted 5-24-2011

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION (OCD)
WATER QUALITY CONTROL COMMISSION (WQCC) OCD DISCHARGE PERMIT BOND

BOND NO.	**6186996**
OCD PERMIT	**UICI-008-1**
AMOUNT OF BOND	**$95,000.00**
COUNTY	**Eddy County**

File with the Oil Conservation Division, 1220 South St. Francis Drive, Santa Fe, NM 87505

KNOW ALL MEN BY THESE PRESENTS:

That Navajo Refining Company, (~~an individual~~ ~~**if dba must read Example: John Doe dba ABC Services)**~~ ~~(a general partnership)~~ (a corporation), (limited liability company) (limited partnership) organized in the State of New Mexico, and authorized to do business in the State of New Mexico, as PRINCIPAL, and Safeco Insurance Company of America, a corporation organized and existing under the laws of the State of Delaware and authorized to do business in the State of New Mexico, as SURETY, are firmly bound unto the State of New Mexico, for the use and benefit of the Oil Conservation Division of the Energy, Minerals and Natural Resources Department (or successor agency) (the DIVISION), pursuant to 20.6.2.5210.B(17) NMAC, 20.6.2.5006 NMAC, and 20.6.2.3107.A(11) NMAC, in the sum of $95,000.00, for the payment of which the PRINCIPAL and SURETY hereby bind themselves, their successors and assigns, jointly and severally, firmly by these presents.

The conditions of this obligation are such that:

WHEREAS, the PRINCIPAL does or may own or operate a "Facility" (identified by location only below) and/or one or more wells (identified by location(s) below) for the injection of fresh and non-fresh water, remediation fluids (i.e., Class I (NH) Disposal Well or Class V Pump & Treat Injection Well), oilfield exempt, non-exempt and/or geothermal produced fluid waste(s) into the subsurface for use in connection with oil, gas and/or geothermal activities, which well is classified as a Division Underground Injection Control Class I, III or V Injection Well pursuant to the 20.6.2.5002 et seq. NMAC, the identification and location(s) of said well(s) being:

______________WDW-1_____________________API No. 30-015-27592_, located___660___feet from the
(Name of Well)
____South________ (~~North~~/**South**) line and ______2,310______feet from the _____East___________ (**East**/~~West~~) line

of Section___31______ Township______17______ (~~North~~) (**South**), Range________28_________ (**East**) (~~West~~),

NMPM, and Latitude 32°47'6.77"N_ Longitude 104°12'50.22"W_ County _______Eddy_______, New Mexico.

NOW, THEREFORE, if the PRINCIPAL and SURETY or either of them, or their successors or assigns or any of them, shall: (a) cause said well(s) to be properly plugged and abandoned when no longer productive or useful for other beneficial purpose in accordance with the WQCC rules and/or orders of the DIVISION; and (b) take all measures necessary, as required by the DIVISION by OCD Permit No. UICI-008-1 pursuant to 20.6.2 and 20.6.4 NMAC, as such rules now exist or may hereafter be amended, to prevent contamination of ground water having 10,000 milligrams per liter (mg/l) or less concentration of total dissolved solids (TDS), including, but not limited to, surface and ground water restoration if applicable, and post-operational monitoring.

THEN AND IN THAT EVENT, this obligation shall be null and void; otherwise and in default of complete compliance with any and all of said obligations, the same shall remain in full force and effect.

______________________________	______________________________
PRINCIPAL	**SURETY**
______________________________	______________________________
Address	**Address**
By____________________________	______________________________
Signature	**Attorney-in-Fact**
______________________________	
Title	

If PRINCIPAL is a corporation, affix Corporate seal here

Corporate surety affix Corporate seal here

Form ___WQCC-1____
Adopted 5-24-2011

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION (OCD)
WATER QUALITY CONTROL COMMISSION (WQCC) OCD DISCHARGE PERMIT BOND

BOND NO.	**6187002**
OCD PERMIT	**UICI-008-2**
AMOUNT OF BOND	**$95,000.00**
COUNTY	**Eddy County**

File with the Oil Conservation Division, 1220 South St. Francis Drive, Santa Fe, NM 87505

KNOW ALL MEN BY THESE PRESENTS:

That Navajo Refining Company, ~~(an individual – **if dba must read – Example: John Doe dba ABC Services**) (a general partnership)~~ (a corporation), (limited liability company) (limited partnership) organized in the State of New Mexico, and authorized to do business in the State of New Mexico, as PRINCIPAL, and Safeco Insurance Company of America, a corporation organized and existing under the laws of the State of Delaware and authorized to do business in the State of New Mexico, as SURETY, are firmly bound unto the State of New Mexico, for the use and benefit of the Oil Conservation Division of the Energy, Minerals and Natural Resources Department (or successor agency) (the DIVISION), pursuant to 20.6.2.5210.B(17) NMAC, 20.6.2.5006 NMAC, and 20.6.2.3107.A(11) NMAC, in the sum of $95,000.00, for the payment of which the PRINCIPAL and SURETY hereby bind themselves, their successors and assigns, jointly and severally, firmly by these presents.

The conditions of this obligation are such that:

WHEREAS, the PRINCIPAL does or may own or operate a "Facility" (identified by location only below) and/or one or more wells (identified by location(s) below) for the injection of fresh and non-fresh water, remediation fluids (i.e., Class I (NH) Disposal Well or Class V Pump & Treat Injection Well), oilfield exempt, non-exempt and/or geothermal produced fluid waste(s) into the subsurface for use in connection with oil, gas and/or geothermal activities, which well is classified as a Division Underground Injection Control Class I, III or V Injection Well pursuant to the 20.6.2.5002 et seq. NMAC, the identification and location(s) of said well(s) being:

______________WDW-2_____________________API No. 30-015- 20894 , located___1980___feet from the
(Name of Well)
____North________ (**North**/~~South~~) line and ______660______feet from the _____West___________ (~~East~~/**West**) line

of Section___12______ Township______18______ (~~North~~) (**South**), Range_________27_________ (**East**) (~~West~~),

NMPM, and Latitude 32°45'49.32"N Longitude 104°14'18.59"W County _______Eddy_______, New Mexico.

NOW, THEREFORE, if the PRINCIPAL and SURETY or either of them, or their successors or assigns or any of them, shall: (a) cause said well(s) to be properly plugged and abandoned when no longer productive or useful for other beneficial purpose in accordance with the WQCC rules and/or orders of the DIVISION; and (b) take all measures necessary, as required by the DIVISION by OCD Permit No. UICI-008-2 pursuant to 20.6.2 and 20.6.4 NMAC, as such rules now exist or may hereafter be amended, to prevent contamination of ground water having 10,000 milligrams per liter (mg/l) or less concentration of total dissolved solids (TDS), including, but not limited to, surface and ground water restoration if applicable, and post-operational monitoring.

THEN AND IN THAT EVENT, this obligation shall be null and void; otherwise and in default of complete compliance with any and all of said obligations, the same shall remain in full force and effect.

________________________________ **PRINCIPAL**	________________________________ **SURETY**
________________________________ **Address**	________________________________ **Address**
By______________________________ **Signature**	________________________________ **Attorney-in-Fact**
________________________________ **Title**	
If PRINCIPAL is a corporation, affix Corporate seal here	**Corporate surety affix Corporate seal here**

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION (OCD)
WATER QUALITY CONTROL COMMISSION (WQCC) OCD DISCHARGE PERMIT BOND

BOND NO.	**6186995**
OCD PERMIT	**UICI-008-3**
AMOUNT OF BOND	**$95,000.00**
COUNTY	**Eddy County**

File with the Oil Conservation Division, 1220 South St. Francis Drive, Santa Fe, NM 87505

KNOW ALL MEN BY THESE PRESENTS:

That Navajo Refining Company, ~~(an individual – **if dba must read – Example: John Doe dba ABC Services)**~~ ~~(a general partnership)~~ (a corporation), (limited liability company) (limited partnership) organized in the State of New Mexico, and authorized to do business in the State of New Mexico, as PRINCIPAL, and Safeco Insurance Company of America, a corporation organized and existing under the laws of the State of Delaware and authorized to do business in the State of New Mexico, as SURETY, are firmly bound unto the State of New Mexico, for the use and benefit of the Oil Conservation Division of the Energy, Minerals and Natural Resources Department (or successor agency) (the DIVISION), pursuant to 20.6.2.5210.B(17) NMAC, 20.6.2.5006 NMAC, and 20.6.2.3107.A(11) NMAC, in the sum of $95,000.00, for the payment of which the PRINCIPAL and SURETY hereby bind themselves, their successors and assigns, jointly and severally, firmly by these presents.

The conditions of this obligation are such that:

WHEREAS, the PRINCIPAL does or may own or operate a "Facility" (identified by location only below) and/or one or more wells (identified by location(s) below) for the injection of fresh and non-fresh water, remediation fluids (i.e., Class I (NH) Disposal Well or Class V Pump & Treat Injection Well), oilfield exempt, non-exempt and/or geothermal produced fluid waste(s) into the subsurface for use in connection with oil, gas and/or geothermal activities, which well is classified as a Division Underground Injection Control Class I, III or V Injection Well pursuant to the 20.6.2.5002 et seq. NMAC, the identification and location(s) of said well(s) being:

_______________WDW-3______________________API No. 30-015- -26575_, located___790___feet from the
(Name of Well)
____South_________ (~~North~~/**South**) line and ______2250______feet from the _____West___________ (~~East~~/**West**) line

of Section___1______ Township______18______ (~~North~~) (**South**), Range_________27_________ (**East**) (~~West~~),

NMPM, and Latitude 32°46'16.51"N Longitude 104°13'59.80"W County _______Eddy_______, New Mexico.

NOW, THEREFORE, if the PRINCIPAL and SURETY or either of them, or their successors or assigns or any of them, shall: (a) cause said well(s) to be properly plugged and abandoned when no longer productive or useful for other beneficial purpose in accordance with the WQCC rules and/or orders of the DIVISION; and (b) take all measures necessary, as required by the DIVISION by OCD Permit No. UICI-008-3 pursuant to 20.6.2 and 20.6.4 NMAC, as such rules now exist or may hereafter be amended, to prevent contamination of ground water having 10,000 milligrams per liter (mg/l) or less concentration of total dissolved solids (TDS), including, but not limited to, surface and ground water restoration if applicable, and post-operational monitoring.

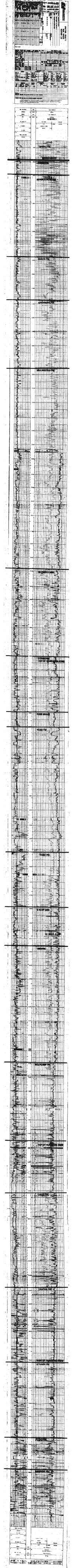
THEN AND IN THAT EVENT, this obligation shall be null and void; otherwise and in default of complete compliance with any and all of said obligations, the same shall remain in full force and effect.

______________________ **PRINCIPAL**	______________________ **SURETY**
______________________ **Address**	______________________ **Address**
By______________________ **Signature**	______________________ **Attorney-in-Fact**
______________________ **Title**	

If PRINCIPAL is a corporation, affix Corporate seal here

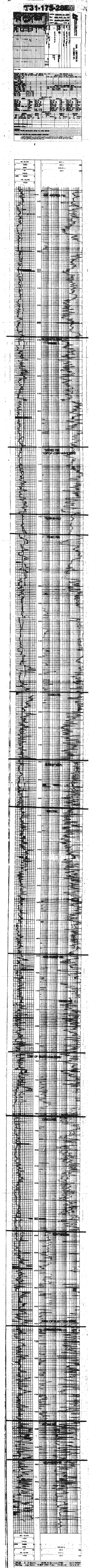
Corporate surety affix Corporate seal here

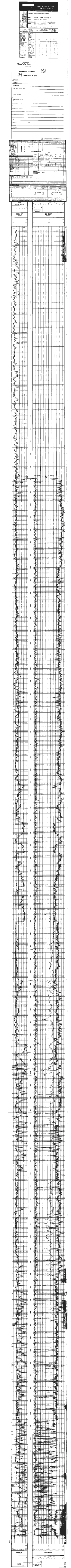
T31-17S-28E



A

APPENDIX A





HALLIBURTON LOGGING SERVICES, INC.

DUAL INDUCTION LATEROLOG

COMPANY

WELL

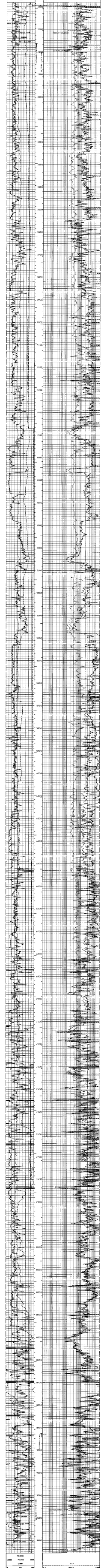
FIELD

COUNTY ST

Fold Here

TENSION		
2000	POUNDS	2000
GAMMA		
0	API	100
CALIPER		
6	INCHES	16
SP		
	-MV+	

DEEP		
0.2	OHM-M	2000
MEDIUM		
0.2	OHM-M	2000
LATEROLOG		
0.2	OHM-M	2000



TENSION		
2000	POUNDS	2000
GAMMA		
0	API	100
CALIPER		
6	INCHES	16
SP		
	-MV+	

DEEP		
0.2	OHM-M	2000
MEDIUM		
0.2	OHM-M	2000
LATEROLOG		
0.2	OHM-M	2000

SECTION # 6 Date: 1/22/91 Time:23:23 Version:2.50 E

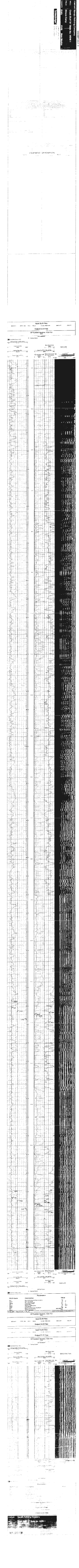


EXHIBIT 3.3.1-1
COMPANY Navajo Refining Company
WELL Chalk Bluff '31' State No. WDW-1
FIELD Illinois Camp
COUNTY Eddy
STATE New Mexico
Schlumberger
EQUIPMENT DESCRIPTION
Navajo Refining Company

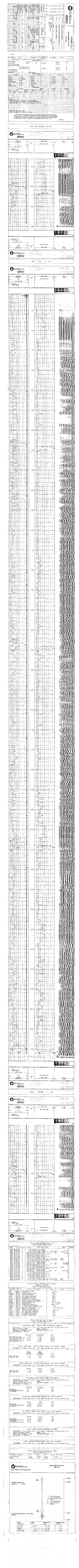
[illegible]

APPENDIX N

WDW-2 CASED-HOLE LOGS

[illegible]

[illegible]



APPENDIX O

DRAFT PUBLIC NOTICE

PUBLIC NOTICE

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

In accordance with 20.6.2.3108.F NMAC, Navajo Refining Company, L.L.C. hereby gives public notice of its application to renew the New Mexico Oil Conservation Division (OCD) discharge permit to inject treated non-hazardous waste water effluent from the Artesia Refinery's on-site wastewater system into a Class I (nonhazardous) injection well WDW-2 (API# 30-015-20894). The WDW-2 is located in the SW/4, NW/4 of Section 12, Township 18 South, Range 27 East, NMPM, Eddy County, New Mexico. The WDW-2 is location approximately 10 miles SE of the intersection of US-285 and Hwy 82 or approximately 3 miles South of the intersection of Hwy 82 and CR-204 (Hilltop Road). The Navajo Refinery is located at 501 E. Main Street, Artesia, New Mexico.

Waste water from the refinery is generated from the treatment of waters from the processing of crude oil, including the removal of water entrained in crude oil, the washing of crude oil to remove salts and sediment, water used for heating and cooling during refining, boiler blowdown, and stormwater collected from process portions of the refinery.

Underground injection at WDW-2 occurs within the Lower Wolfcamp, Cisco and Canyon Formations within the injection interval from 7,570 to 8,399 feet (log depth). The injection rate into WDW-2 will not exceed 500 gpm and the maximum allowable surface injection pressure is 1,514 psig. The injected refinery waste water quality is approximately 3,400 mg/L total dissolved solids (TDS). Formation fluid within the permitted injection interval exceeds 10,000 mg/L TDS. Groundwater is first encountered in the area of WDW-2 at a depth of approximately 50 to 150 feet below land surface. The groundwater quality ranges from about 1,500 to 2,200 mg/L TDS.

Persons interested in obtaining further information, submitting comments, or requesting to be on a facility-specific mailing list for future notices may contact the Environmental Bureau Chief of the New Mexico Oil Conservation Division.

Comments and inquiries on regulations should be directed to:

Director
Conservation Division
Energy Minerals and Natural Resources Department
1220 South St. Francis Drive
Santa Fe, New Mexico 87505
Telephone: (505) 476-3440

When corresponding, please reference the name of the applicant and the well name.

AVISO PUBLICO
ESTADO DE MEXICO
DEPARTMENTO DE ENERGIA, MINERALES Y RECURSO NATURALES
DIVISION DE CONSERVACION DE PETROLEO

Por medio de la presente La Navajo Company anuncia que de conformidad con los requisitos de las regulaciones de la Comisíon de Control de Calidad del Agua de Nuevo Mexico 20.6.2.3108.F NMAC, esta solicitando a la Division de Conservacíon del Petroleo de Nuevo Mexico (NMOCD) . Departamento del Medio Ambiente, un permiso de descarga para inyectar aguas residuales Artesia Refinery's hacia un pozo de inyección que se llama WDW-2 (API# 30-015-20894). El WDW-2 esta localizado en SW/4, NW/4 de Sección 12, Municipio 18 sur, 27 Este, Condado Eddy, Nuevo Mexico. El WDW-2 esta localizado aproximadamente 10 millas SE de la unidad de US-285 y Hwy 82 (Refineria Artesia) o aproximadamente 3 millas Sur de la unidad de Hwy. 82 y CR-204 (Hilltop Road). La Refineria Navajo se encuentra ubicada en 501 E. Main Street, Artesia, Nuevo Mexico.

La generacion de aguas residuals de la Refineria Artesia es el resultado del agua que se encuentran en al abastecimiento de crudo, el agua que se usa para el enfriamiento y calentamiento, el agua que se usa para retirar las sales del abastecimiento de crudo, y para purgar la caldera.

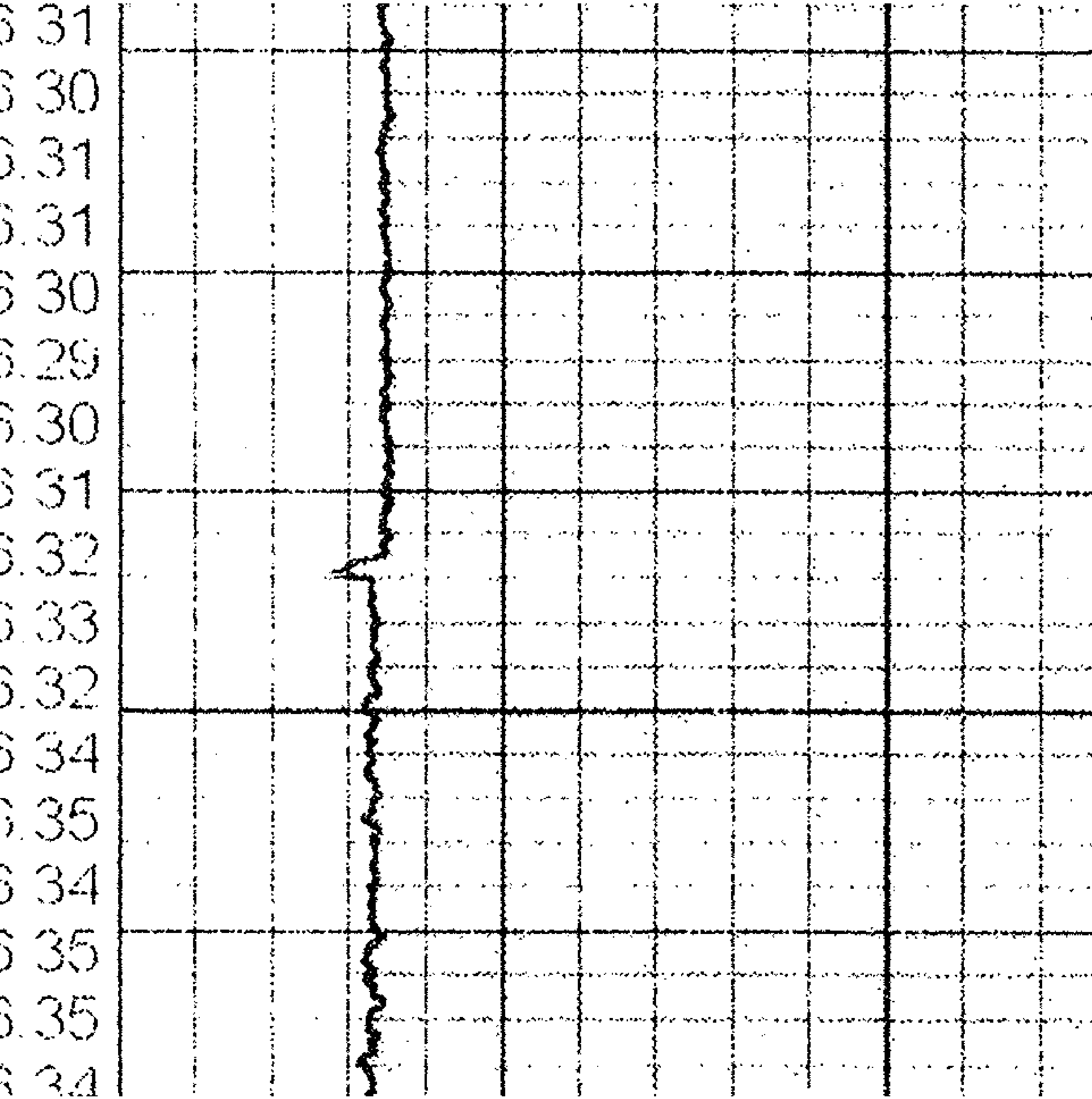
Las aguas residuals de WDW-2 se injectaran hacia las formaciones de Lower Wolfcamp, Cisco Y Canyon, ubicadas entre 7,570 y 8,399 pies (produndidad de registro). La tasa de inyeccion de WDW-2 no excedera los 500 gpm a una presion de inyeccion que no excedera los 1,514 psig. Estas aguas residuals tendran un contendido de total de solidos disueltos (TDS) de 3,400 partes por millón. Formacion de fluido dentro del interval permitido exceed 10,000 milligramos per litro (mg/L) TDS. En el area en donde se encuentran el pozo (WDW-2), el agua fresco se encuentra a una profundidad de 50 a 150 pies por debajo de la superficie de la tierra con un TDS de 1,500 a 2,200 partes por millón (ppm).

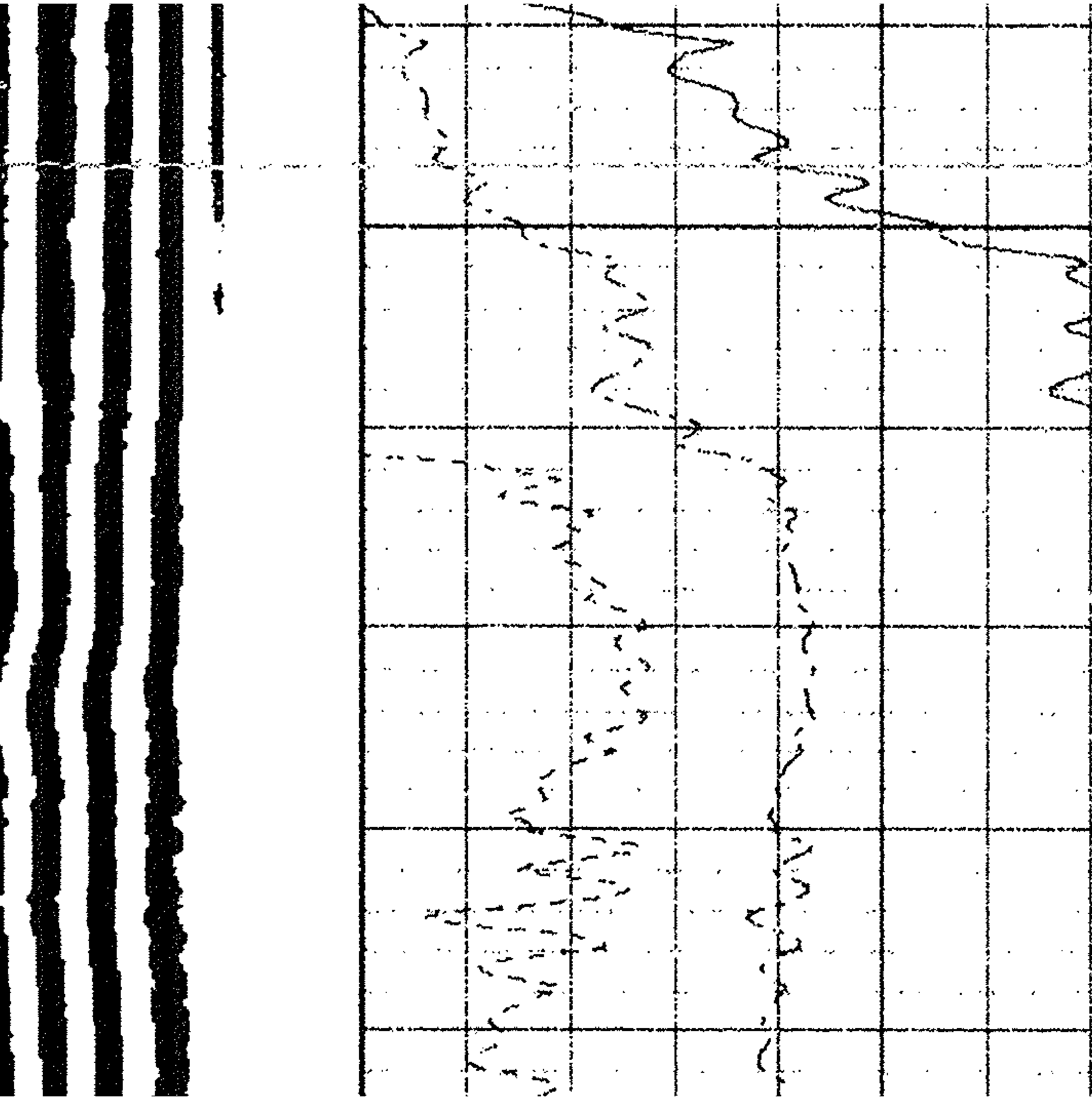
Personas interesadas en obtener mayores informes, presentar sus comentarios o solicitar que se les incluya en las listas de direcciones de una planta en especial para futuros avisos pueden ponerse en contacto con el Jefe del Departamento del Medio Ambiente de la División de Conservacíon de Petroleo de Nuevo Mexico.

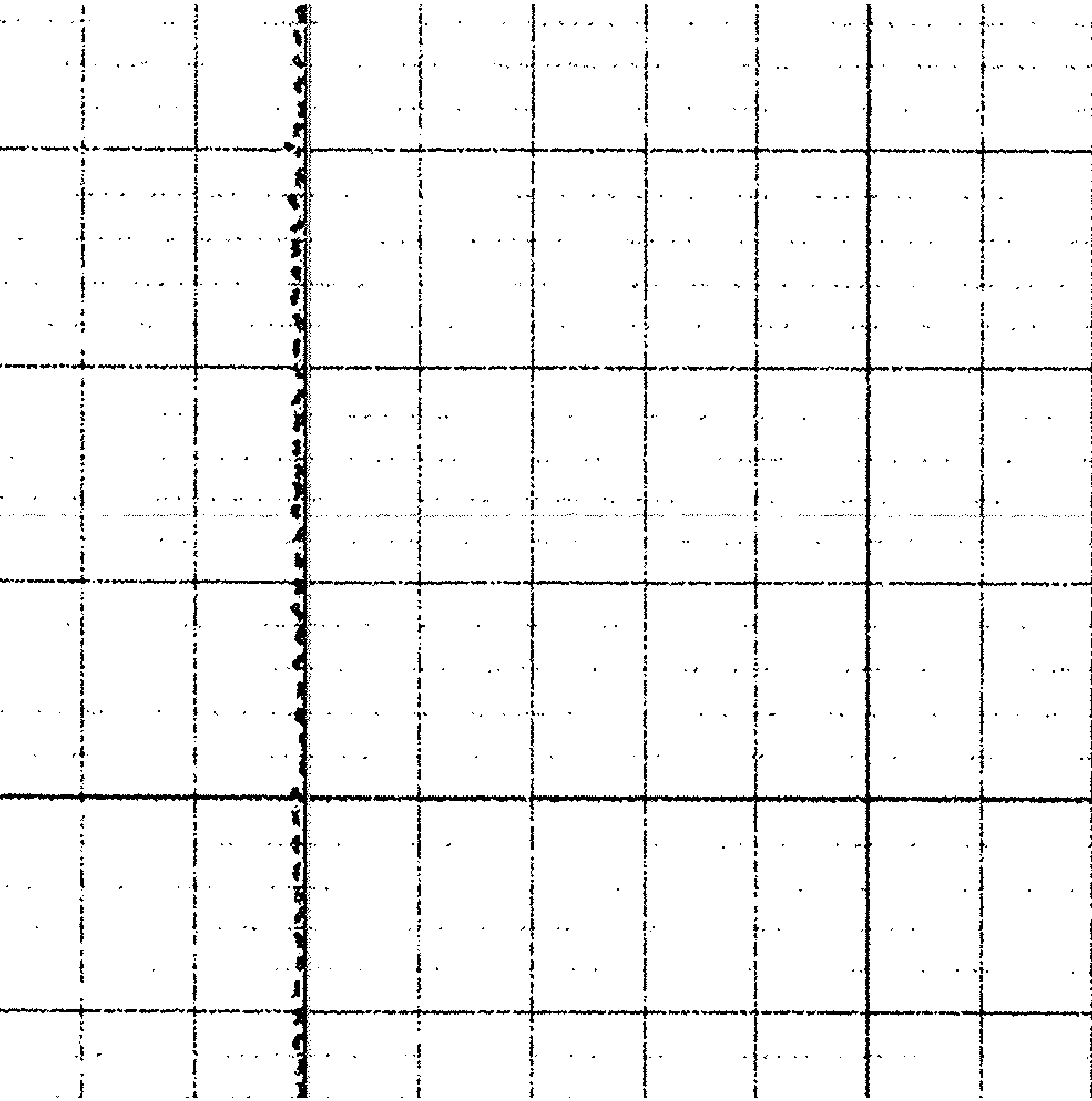
Por Favor envien los comentarios y las preguntas a:

Director
Oil Conservation Division
Energy, Minerals and Natural Resources Department
1220 South St. Francis Drive
Santa Fe, New Mexico 87505
Telefono: (505) 476-3440

Cuando escriban, por favor pongan de referencia el nombre del applicante y del pozo.


31
30
31
31
30
29
30
31
32
33
32
34
35
34
35
35
34





UIC - I - __8-2__

GENERAL CORRESPONDENCE (WDW-2)

2013 - Present

HOLLYFRONTIER
THE HOLLYFRONTIER COMPANIES

September 25, 2013

Scott Dawson
Deputy Director
Oil Conservation Division
Energy, Minerals and Natural Resources Department
1220 South St. Francis Drive
Santa Fe, New Mexico 87505

Certified Mail/Return Receipt
7011 3500 0001 4786 1558

RE: Navajo Refining Company Class I Injection Well Permit Renewals

Dear Mr. Dawson:

Navajo Refining Company LLC (Navajo) was issued a Final Discharge Permit for its Class I Non-Hazardous Injection Well, WDW-3 (API No. 30-015-26575), on December 18, 2012; expiring June 1, 2017. Navajo subsequently submitted Renewal Applications for Class I Non-Hazardous Wells WDW-1 (API No. 30-015-27592) and WDW-2 (API No. 30-015-20894) on March 14, 2013 and July 24, 2013, respectively. Navajo hereby respectfully requests that the New Mexico Oil Conservation Division (NM OCD) process the two pending applications for WDW-1 and WDW-2 as soon as possible. In addition, Navajo requests that the two pending applications be issued with the same expiration date as WDW-3, June 1, 2017.

If you have any questions, please do not hesitate to contact me at (575) 746-5487. We appreciate your assistance in this matter.

Sincerely,

Michael W. Holder
Environmental Manager
Navajo Refining Co. LLC

Elec. Cc: Glenn VonGonten, NM OCD
Carl Chavez, NM OCD

Env. Files: Injection Wells, Permit Renewal Request, WDW Class I, Subm'
2013-09-25 Permits. WDW-3.Gaines.Subm.UIC Permit Issuance

PUBLIC NOTICE

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT OIL CONSERVATION DIVISION

In accordance with 20.6.2.3108.F NMAC, Navajo Refining Company, L.L.C., located at 501 E. Main Street, Artesia, New Mexico, hereby gives public notice of its application to renew the New Mexico Oil Conservation Division (OCD) discharge permit to inject treated non-hazardous waste water effluent from the refinery's on-site wastewater treatment plant into three Class I (nonhazardous) injection wells listed below:

- WDW-1 (API# 30-015-27592). The WDW-1 is located in the SW/4, SE/4 of Section 31, Township 17 South, Range 28 East, NMPM, Eddy County, New Mexico. The WDW-1 is located approximately 11 miles SE of the intersection of I-285 and Hwy 82 or approximately 1 mile SW of the intersection of Hwy 82 and CR-206.

- WDW-2 (API# 30-015-20894). The WDW-2 is located in the SW/4, NW/4 of Section 12, Township 18 South, Range 27 East, NMPM, Eddy County, New Mexico. The WDW- 2 is located approximately 10 miles SE of the intersection of US-285 and Hwy 82 or approximately 3 miles South of the intersection of Hwy 82 and CR-204 (Hilltop Road).

- WDW-3 (API# 30-015-26575). The WDW-3 is located in the SE/4, SW/4 of Section 1, Township 18 South, Range 27 East, NMPM, Eddy County, New Mexico. The WDW-3 is located approximately 14 miles E-SE of the intersection of I-285 and Hwy 82 (Navajo Refinery) or approximately 2.75 miles S of Hwy 82 and CR-225.

Waste water from the refinery is generated from the treatment of waters from the processing of crude oil, including the removal of water entrained in crude oil, the washing of crude oil to remove salts and sediment, water used for heating and cooling during refining, boiler blowdown, and stormwater collected from process portions of the refinery. Underground injection for each of the wells occurs within the Lower Wolfcamp, Cisco and Canyon Formations.

- Underground injection at WDW-1 occurs within the injection interval from 7,924 to 8,476 feet (log depth). The injection rate into WDW-1 will not exceed 500 gpm and the maximum allowable surface injection pressure is 1,585 psig. The injected refinery waste water quality is approximately 3,400 mg/L total dissolved solids (TDS).

- Underground injection at WDW-2 occurs within the injection interval from 7,570 to 8,399 feet (log depth). The injection rate into WDW-2 will not exceed 500 gpm and the maximum allowable surface injection pressure is 1,514 psig. The injected refinery waste water quality is approximately 3,400 mg/L TDS.

- Underground injection at WDW-3 occurs within the injection interval from 7,660 to 8,620 feet (log depth). The injection rate into WDW-3 will not exceed 500 gpm and the maximum allowable surface injection pressure of 1530 psig.

The injected refinery waste water quality is approximately 3,400 mg/L TDS. Formation fluids within the permitted injection interval exceeds 10,000 mg/L TDS. Groundwater is first encountered in the area of the wells is at a depth range of approximately 50 to 150 feet below land surface. The groundwater quality ranges from about 1,500 to 2,200 mg/L TDS.

Persons interested in obtaining further information, submitting comments, or requesting to be on a facility-specific mailing list for future notices may contact the Environmental Bureau Chief of the New Mexico Oil Conservation Division.

Comments and inquiries on regulations should be directed to:

Director
New Mexico Oil Conservation Division
1220 South St. Francis Drive
Santa Fe, New Mexico 87505
Telephone: (505) 476-3440

When corresponding, please reference the name of the applicant and the well name.

AVISO PUBLICO
ESTADO DE MEXICO
DEPARTMENTO DE ENERGIA, MINERALES Y RECURSO NATURALES
DIVISION DE CONSERVACION DE PETROLEO

Por medio de la presente, la compania Navajo Refining Company, L.L.C., en 501 E. Main Street, Artesia, Nuevo Mexico, en conformidad con los requisitos de las regulaciones de la Comisíon de Control de Calidad del Agua de Nuevo Mexico 20.6.2.3108.F NMAC, esta solicitando a la Division de Conservacíon del Petroleo de Nuevo Mexico (NMOCD), anuncia al publico el permiso de descarga para inyectar aguas residuals, sin arriesgado, de la Refinería de Navajo:

- WDW-1 (API# 30-015-27592). El pozo WDW-1 esta localizado en SO/4, SE/4 de Sección 31, Municipio 17 Sur, Rango 28 Este, Condado Eddy, Nuevo Mexico. El WDW-1 2 esta localizado aproximadamente 11 millas SE de la unidad de I-285 y Hwy 82 o aproximadamente 1 milla SO de la unidad de Hwy 82 y CR-206.

- WDW-2 (API# 30-015-20894). El pozo WDW-2 esta localizado en SO/4, NO/4 de Sección 12, Municipio 18 Sur, Rango 27 Este, Condado Eddy, Nuevo Mexico. El WDW-2 esta localizado aproximadamente 10 millas SE de la unidad de US-285 y Hwy 82 (Refineria Artesia) o aproximadamente 3 millas Sur de la unidad de Hwy. 82 y CR-204 (Hilltop Road).

- WDW-3 (API# 30-015-26575). El pozo WDW-3 esta localizado en SE/4, SO/4 of Sección 1, Municipio 18 Sur, Rango 27 Este, Condado Eddy, Nuevo Mexico. El WDW-3 esta localizado aproximadamente 14 millas este-sur-este de la unidad de I-285 y Hwy 82 (Refinería de Navajo) or aproximadamente 2.75 millas Sur de Hwy 82 y CR-225.

La generacion de aguas residuals de la Refineria de Navajo es el resultado del agua que se encuentran en al abastecimiento de crudo, el agua que se usa para el enfriamiento y calentamiento, el agua que se usa para retirar las sales del abastecimiento de crudo, y para purgar la caldera. Las aguas residuals para se injectaran en cada pozo hacia las formaciones de Wolfcamp (bajo), Cisco, y Canyon,

- Injectaran en WDW-1 ubicada entre 7,924 y 8,496 pies (produndidad de registro). La tasa de injeccion de WDW-1 no excedera los 500 gpm a una presion de inyeccion que no excedera los 1,585 psig. Estas aguas residuals tendran un contendido de total de solidos disueltos (TDS) de 3,400 partes por millón (ppm).

- Injectaran en WDW-2 ubicada entre 7,570 y 8,399 pies (produndidad de registro). La tasa de injeccion de WDW-2 no excedera los 500 gpm a una presion de inyeccion que no excedera los 1,514 psig. Estas aguas residuals tendran un contendido de TDS de 3,400 ppm.

- Injectaran en WDW-3 ubicada entre 7,660 y 8,620 pies (produndidad de registro). La tasa de injeccion de WDW-1 no excedera los 500 gpm a una presion de inyeccion que no excedera los 1,530 psig. Estas aguas residuals tendran un contendido de total de solidos disueltos (TDS) de 3,400 ppm.

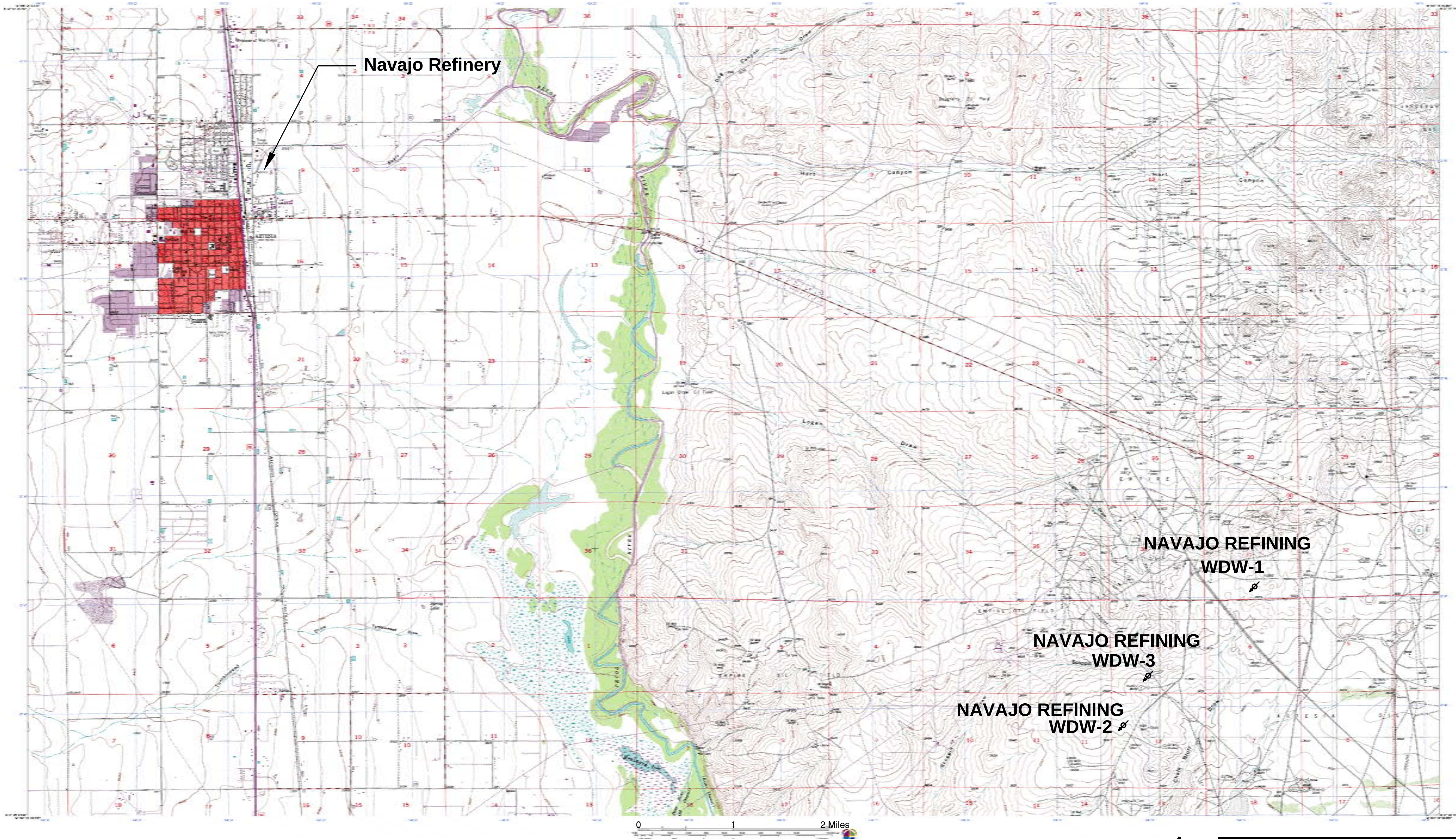
Formacion de fluido dentro del interval permitido exceed 10,000 milligramos per litro (mg/L) TDS. En el area en donde se encuentran el pozo, el agua fresco se encuentra a una profundidad de 50 a 150 pies por debajo de la superficie de la tierra con un TDS de 1,500 a 2,200 partes por millón (ppm).

Personas interesadas en obtener mayores informes, presentar sus comentarios o solicitar que se les incluya en las listas de direcciones de una planta en especial para futuros avisos pueden ponerse en contacto con el Jefe del Departamento del Medio Ambiente de la División de Conservacíon de Petroleo de Nuevo Mexico.

Por Favor envien los comentarios y las preguntas a:

Director
New Mexico Oil Conservation Division
1220 South St. Francis Drive
Santa Fe, New Mexico 87505
Telefono: (505) 476-3440

Cuando escriban, por favor pongan de referencia el nombre del applicante y del pozo.



Maps compiled from USGS Quads: Artesia, NM; Spring Lake, NM; Red Lake, NM; Illinois Camp, NM; Dayton, NM; Lake Mcmillan N, NM

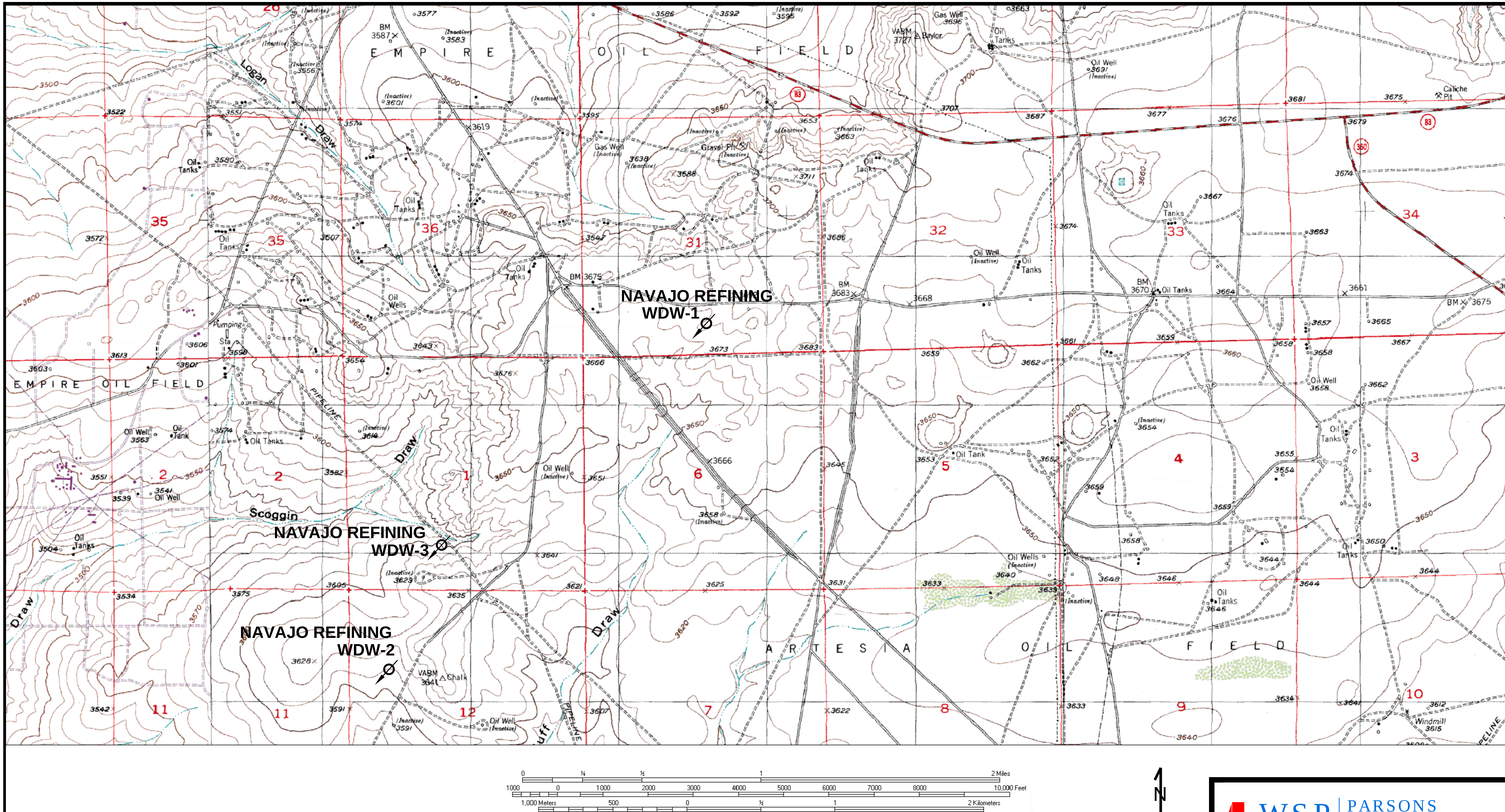
WSP | PARSONS BRINCKERHOFF

FIGURE 1

HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

SITE LOCATION MAP

DATE: 01/19/17	CHECKED BY:	JOB NO: 50904D
DRAWN BY: WDD	APPROVED BY:	DWG. NO:



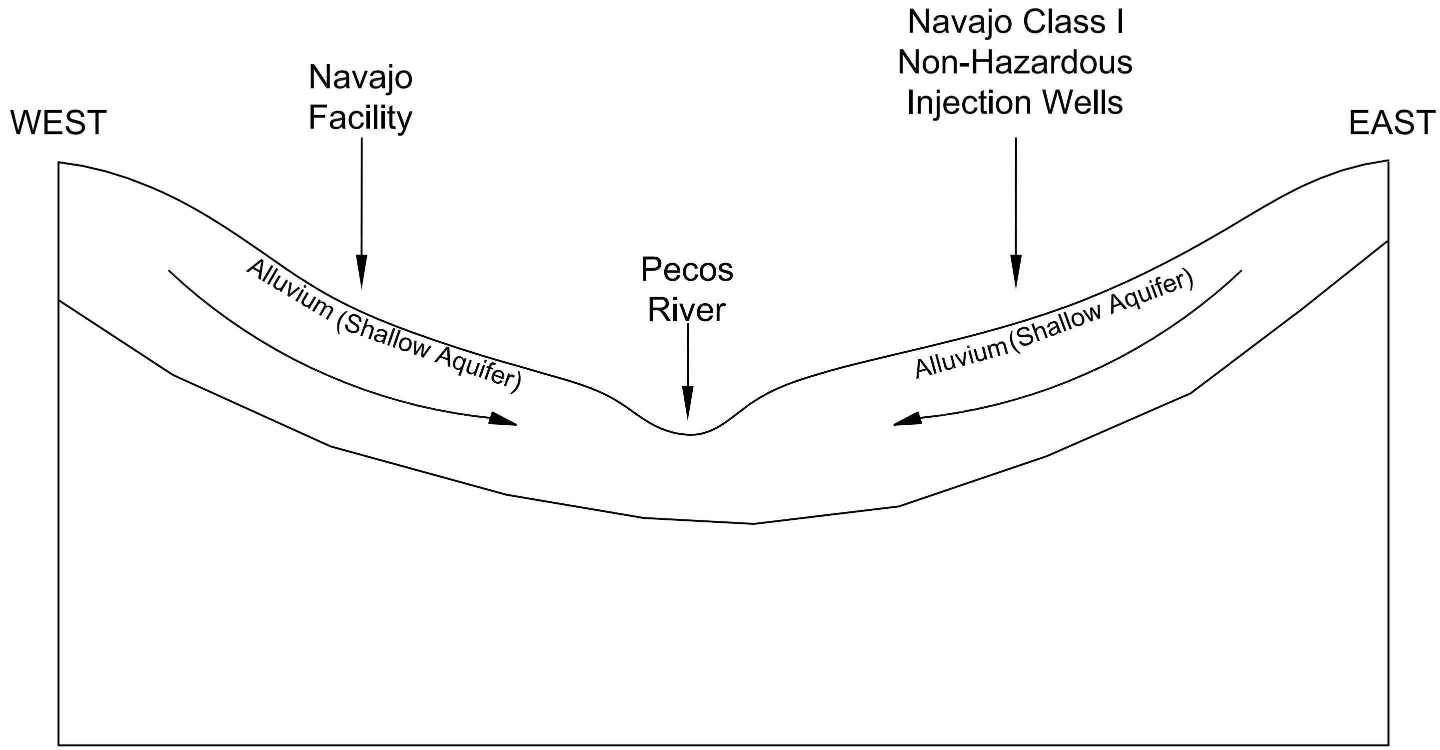
WSP | PARSONS BRINCKERHOFF

FIGURE 2

HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

SITE MAP

DATE: 01/19/17	CHECKED BY:	JOB NO: 50904D
DRAWN BY: WDD	APPROVED BY:	DWG. NO:



NOT TO SCALE

EXPLANATION

Direction of Groundwater Movement

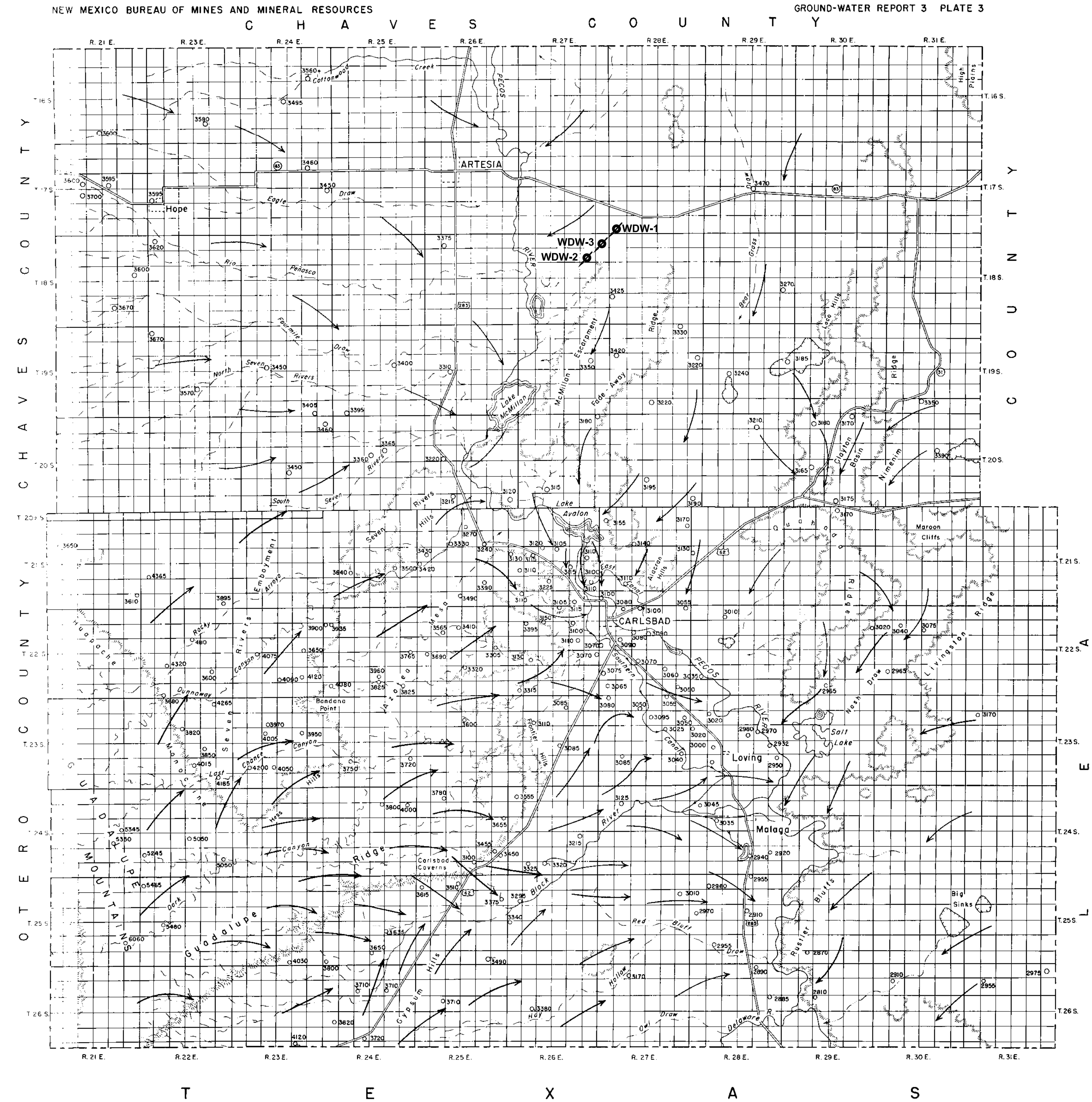
WSP | PARSONS BRINCKERHOFF

FIGURE 3

HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

GENERALIZED HYDROGEOLOGIC CROSS-SECTION

DATE: 01/26/17	CHECKED BY:	JOB NO: 60D6945
DRAWN BY: WDD	APPROVED BY:	DWG. NO:



GENERAL DIRECTION OF MOVEMENT OF GROUND WATER IN EDDY COUNTY, NEW MEXICO

SCALE

5 0 5 10 MILES

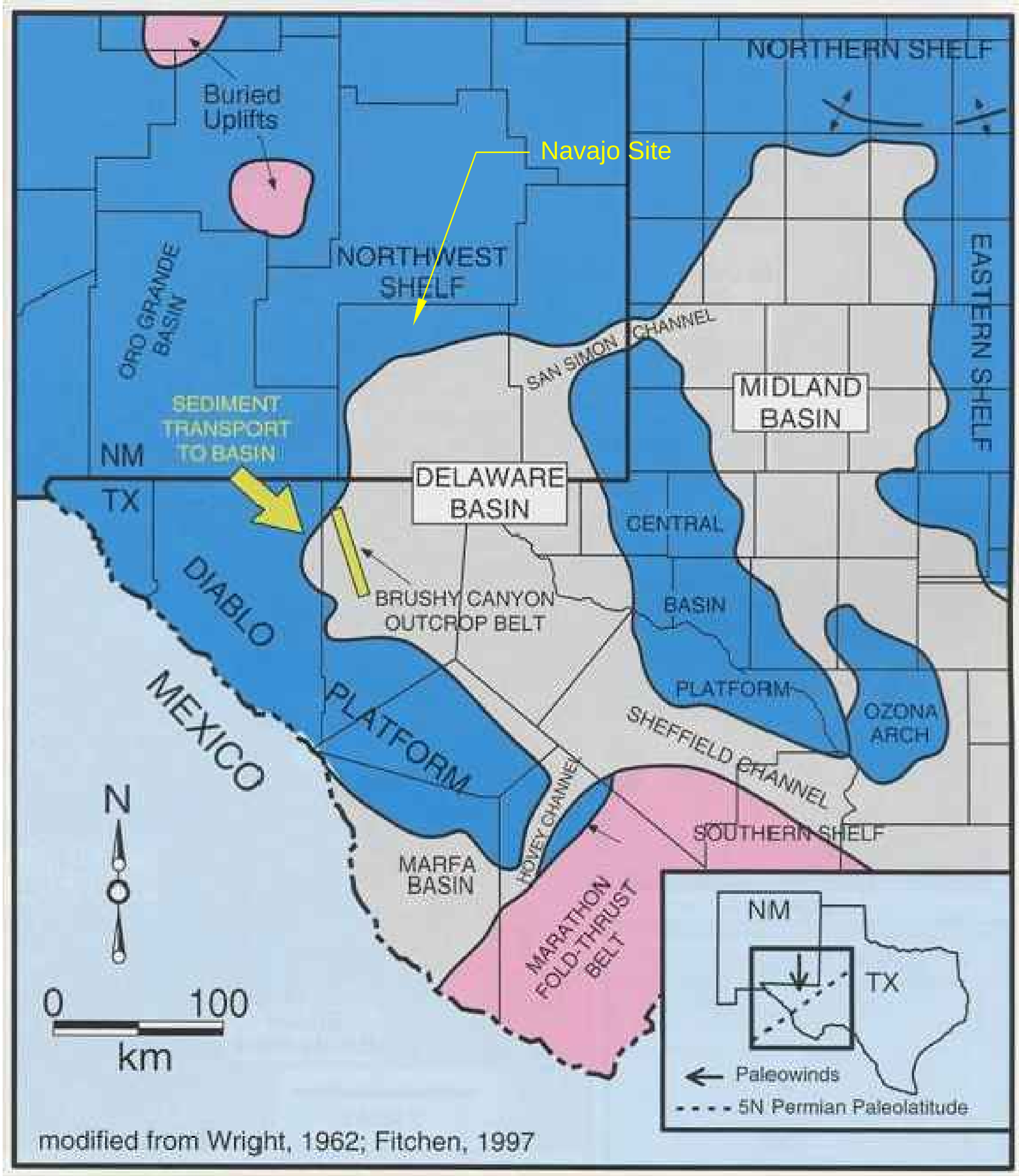
EXPLANATION

○ Well ⊙ Spring

↗ Direction of ground water movements

3380 Altitudes (feet above sea level) of ground water levels

FIGURE 4



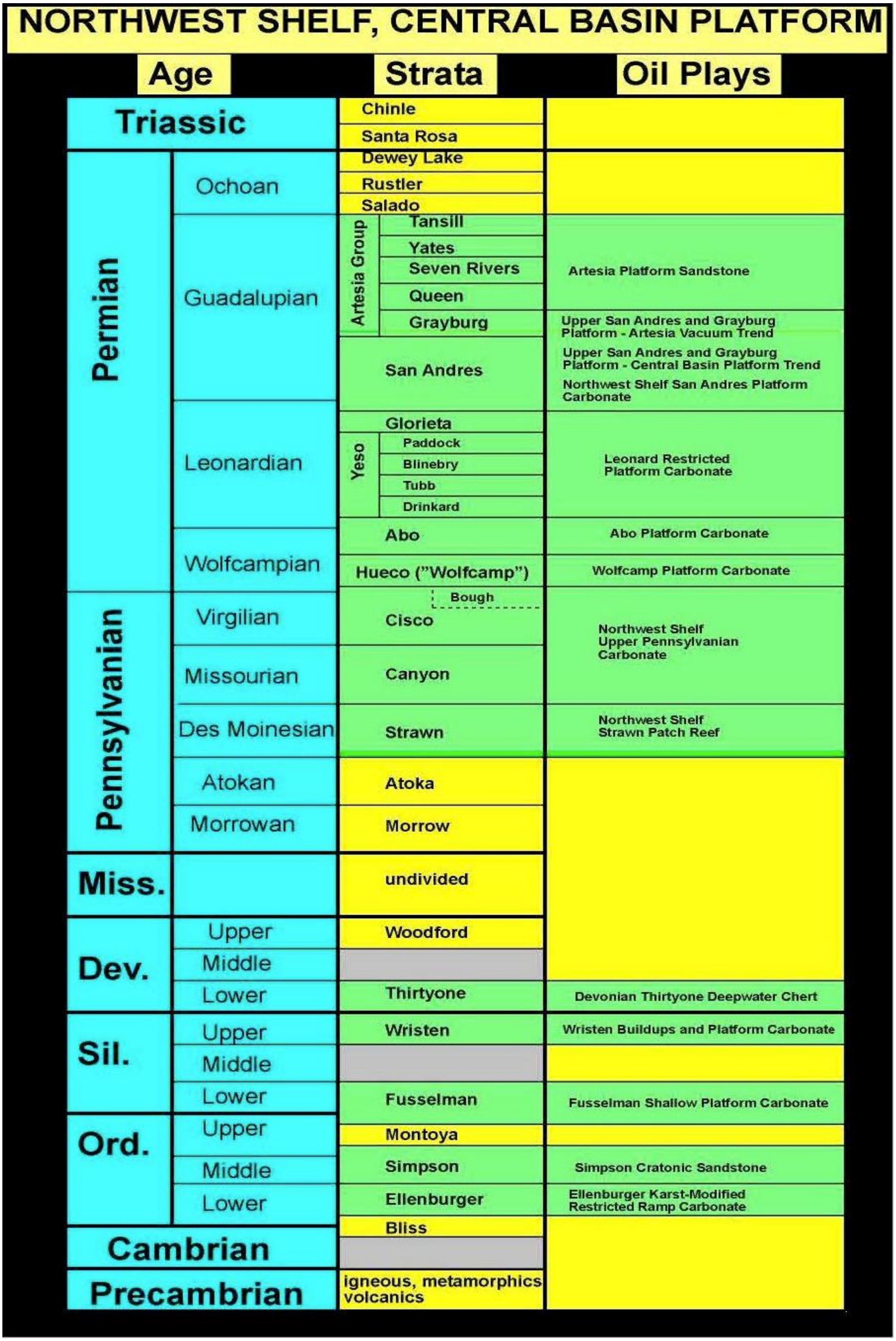
WSP | PARSONS BRINCKERHOFF

FIGURE 5

HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

PERMIAN BASIN MAP

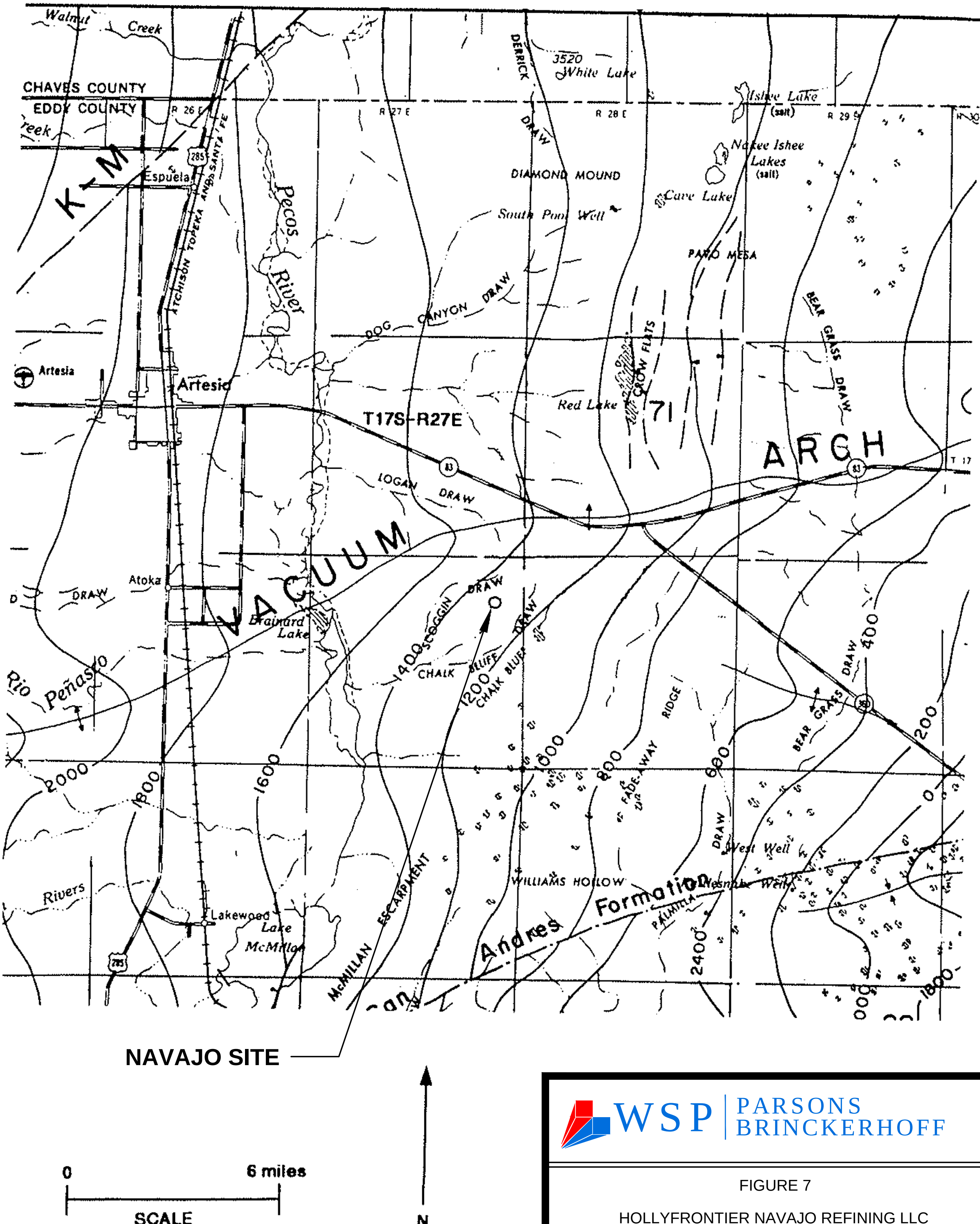
DATE: 01/19/20	CHECKED BY:	JOB NO: 60D6945
DRAWN BY: WDD	APPROVED BY:	DWG. NO:



STRATIGRAPHIC COLUMN

Source: Broadhead, et al., 2004. *Play Analysis of Major Oil Reservoirs in the New Mexico Part of the Permian Basin: Enhanced Production Through Advanced Technologies.* New Mexico Bureau of Geology and Mineral Resources. Open File Report 479.

FIGURE 6



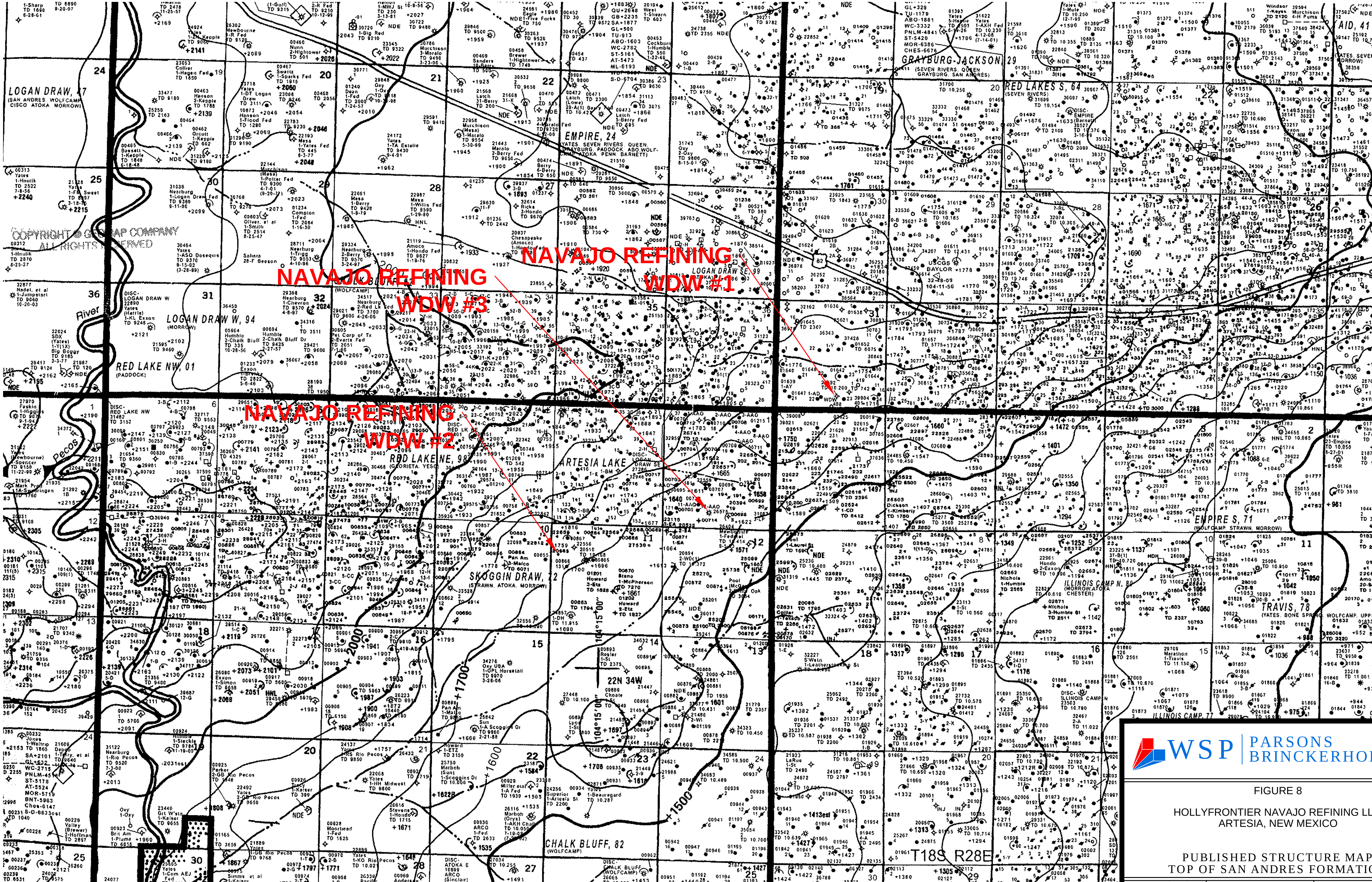
WSP | PARSONS BRINCKERHOFF

FIGURE 7

HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

REGIONAL GEOLOGIC FEATURES

DATE: 01/19/17	CHECKED BY:	JOB NO: 60D6945
DRAWN BY: WDD	APPROVED BY:	DWG. NO:



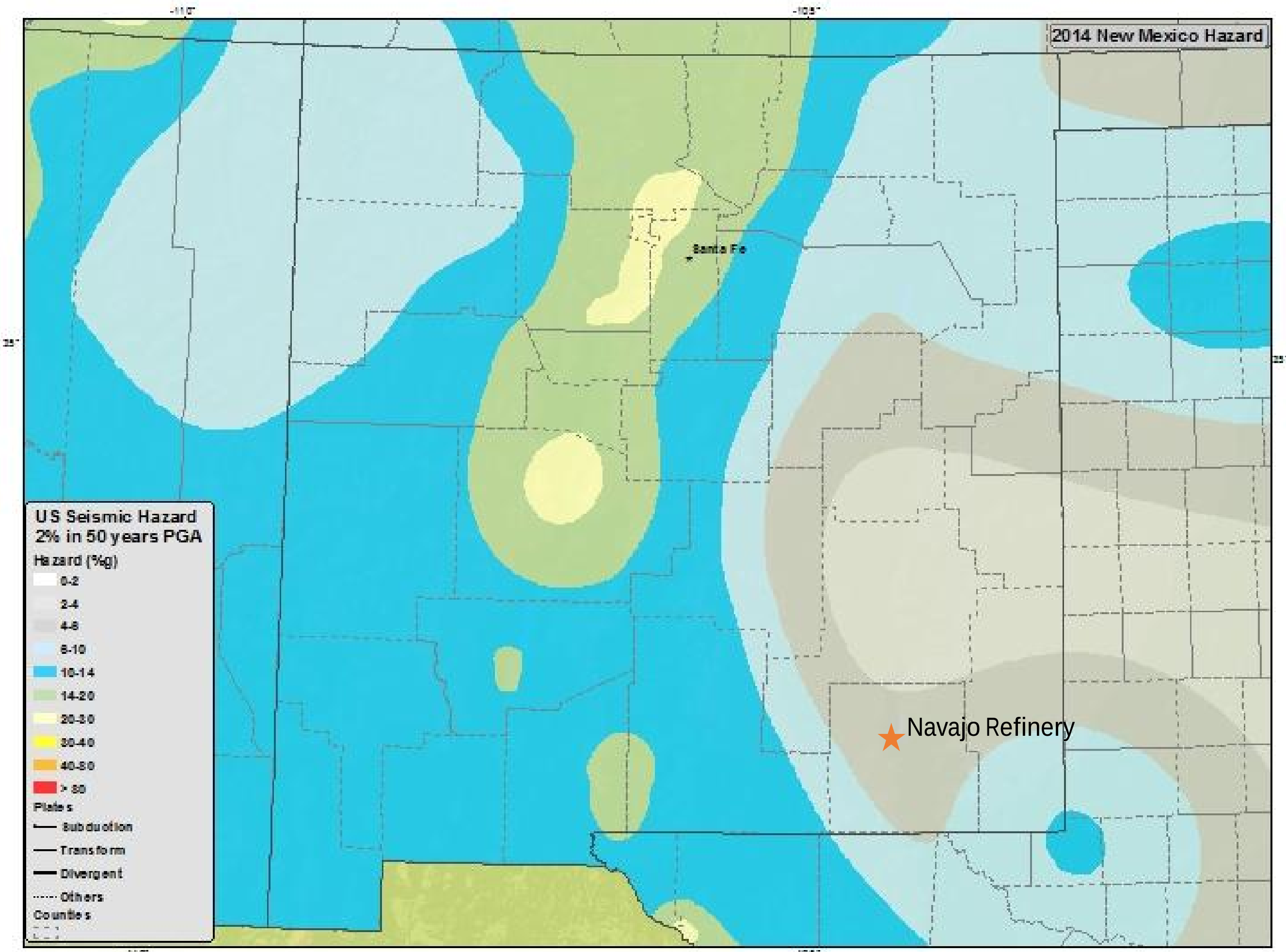
WSP | PARSONS BRINCKERHOFF

FIGURE 8

HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

PUBLISHED STRUCTURE MAP
TOP OF SAN ANDRES FORMATION

DATE: 01/26/17	CHECKED BY:	JOB NO: 60D6945
DRAWN BY: WDD	APPROVED BY:	DWG. NO:



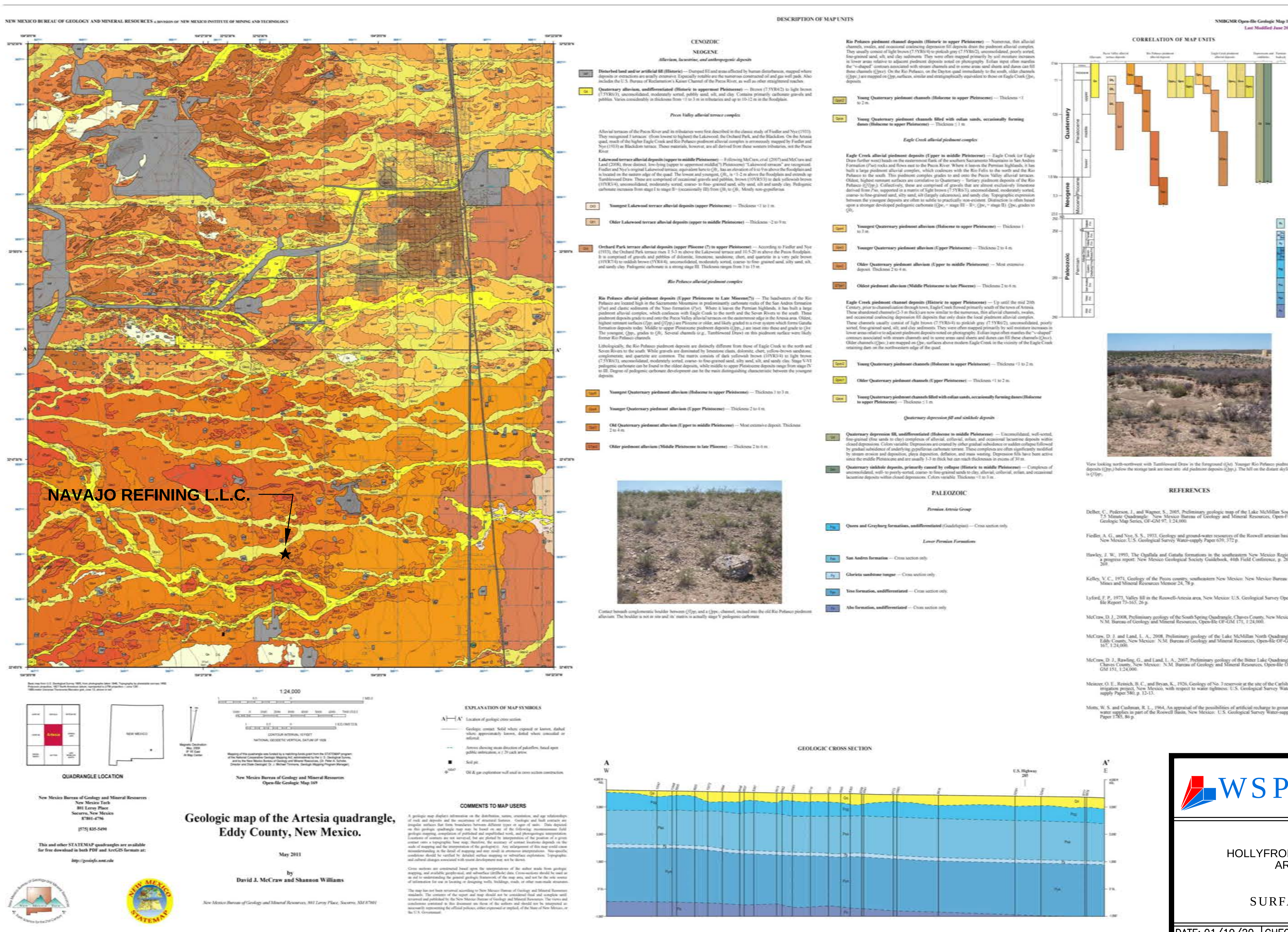
Source: USGS, 2017. *Information by Region – New Mexico; 2014 Seismic Hazard Map.* Earthquake Hazards Program. https://earthquake.usgs.gov/earthquakes/byregion/newmexico-haz.php

WSP | PARSONS BRINCKERHOFF

FIGURE 9
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

SEISMIC RISK MAP

DATED: 1/16/2017	APPROVED BY:	JOB NO. 50904D
DRAWN BY: GEM	CHECKED BY:	SCALE: N/A



WSP | PARSONS BRINCKERHOFF

FIGURE 10

HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

SURFACE GEOLOGIC MAP

DATE: 01/19/20	CHECKED BY:	JOB NO: 60D6945
DRAWN BY: WDD	APPROVED BY:	DWG. NO:

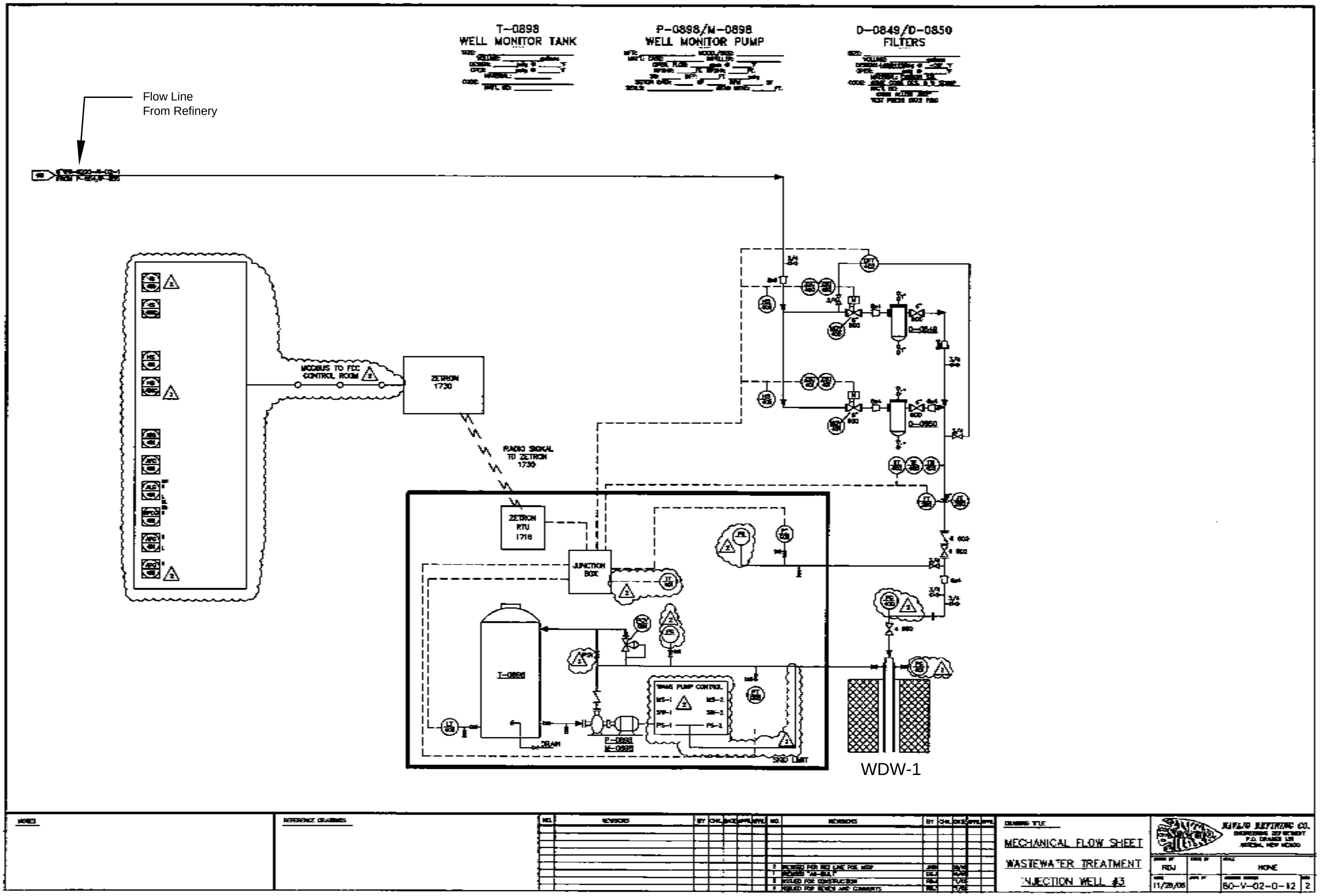


FIGURE 11a
PRE-INJECTION SURFACE FACILITIES
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

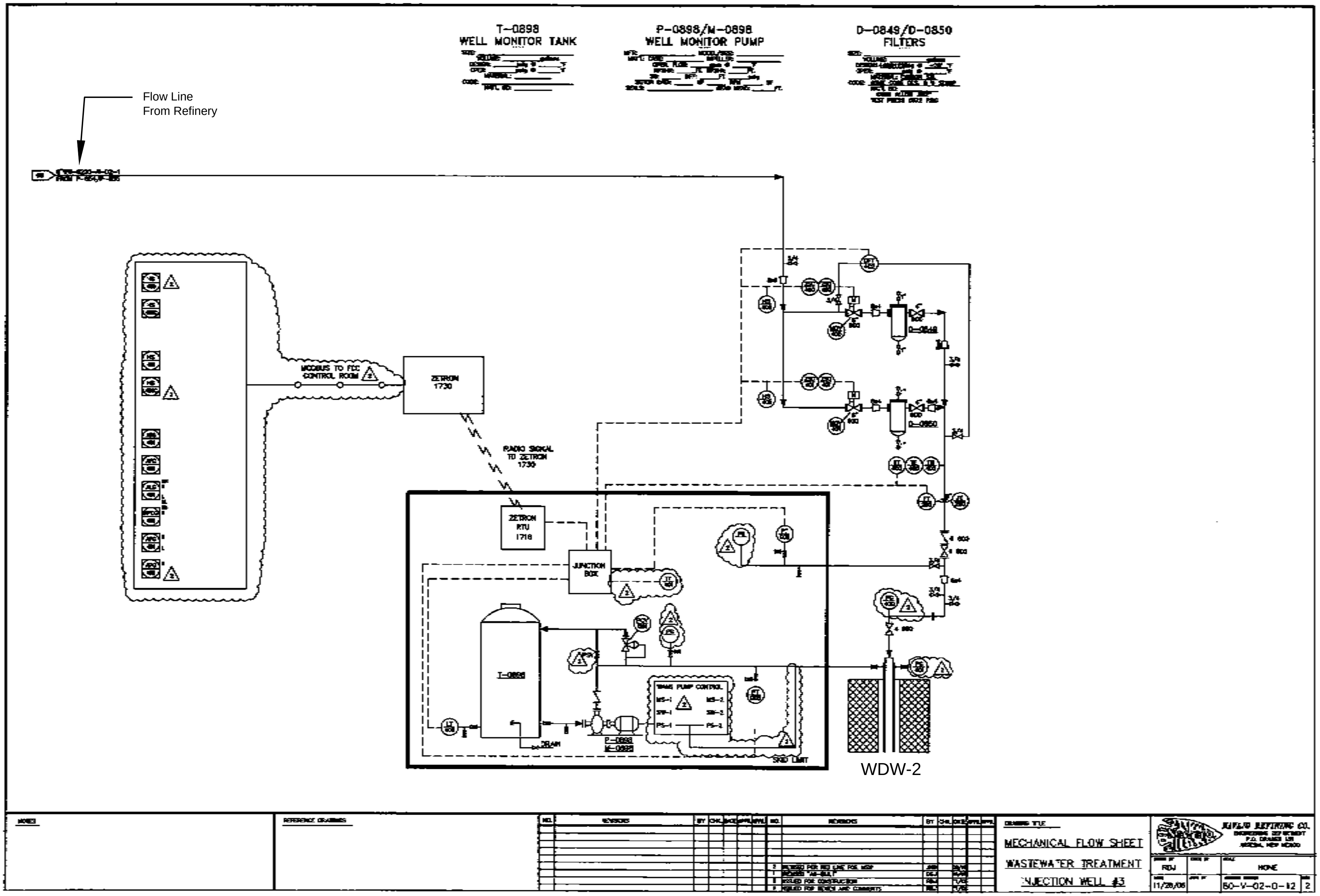


FIGURE 11b
PRE-INJECTION SURFACE FACILITIES
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

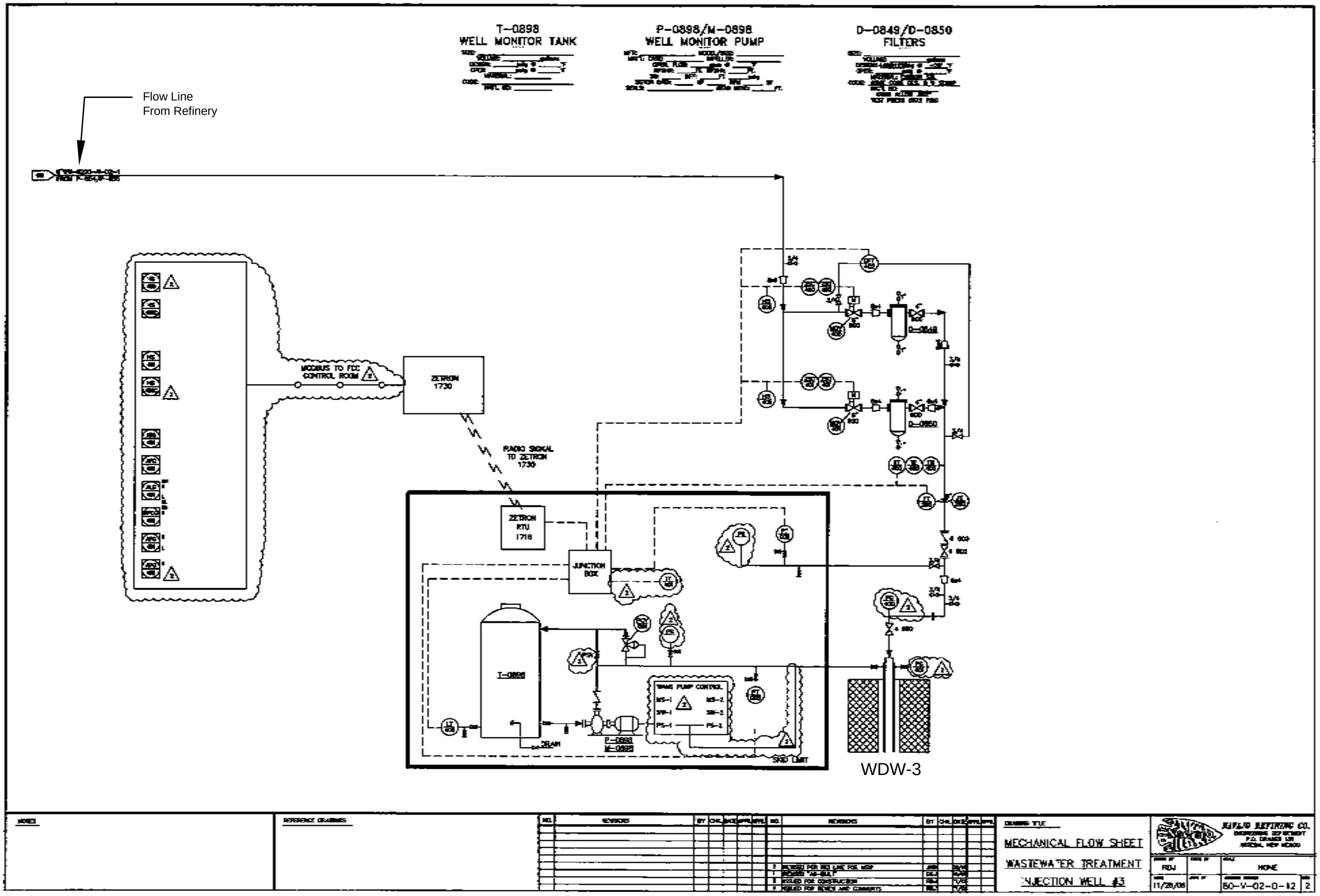
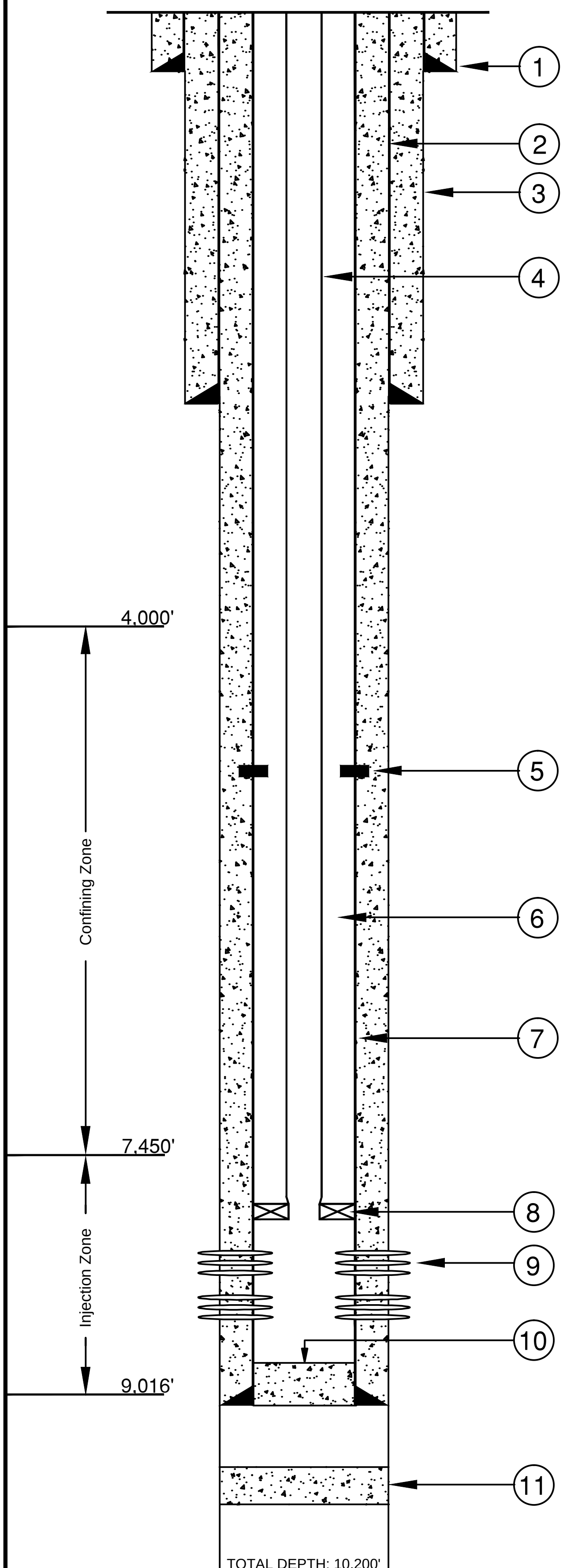


FIGURE 11c
PRE-INJECTION SURFACE FACILITIES
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO



Injection Interval: 7,924' - 8,476'

BELOW GROUND DETAILS

All depths are referenced to the Kelly bushing elevation of 12.5' above ground level. Ground level elevation is 3,678' above mean sea level.

1. Surface Casing: 13 $\frac{3}{8}$", 48 lb/ft, J-55, ST&C set at 390' in a 17 $\frac{1}{2}$" hole. Cemented with 150 sx Class C with 3% calcium chloride, 375 sx Class C Litewate w/3% calcium chloride and $\frac{1}{2}$ lb/sx flocele. Circulated 86 sx to surface.

2. Intermediate Casing: 9 $\frac{5}{8}$", 36 lb/ft, J-55, ST&C set at 2,555' in a 12 $\frac{1}{4}$" hole. Cemented w/800 sx of Class C Lite w/ $\frac{1}{2}$ lb/sx flocele and 2 lb/sx Gilsonite and 12% salt. Followed by 200 sx of Class C w/2% calcium chloride. Circulated 133 sx to surface.

3. Base of the USDW at 493'.

4. Injection Tubing: 4 $\frac{1}{2}$", 11.6 lb/ft, N-80, SMLS, R3, LT&C set at 7,879'.

5. DV Tool: at 5,498'.

6. Annulus Fluid: 8.7 lb/gal brine water mixed w/UniChem Techni-Hib 370 corrosion inhibitor.

7. Protection Casing: 7", 29 lb/ft, N-80, LT&C: 9094' to 7031'. 7", 29 lb/ft, P-110, LT&C: 7031' to 5845'. 7", 26 lb/ft, P-110, LT&C; 5,845' to surface. Casing set in 8 $\frac{3}{4}$" hole and cemented in two stages as follows:

   First Stage - 600 sx modified Class H w/0.4% CFR-3, 5 lb/sx Gilsonite, 0.5% Halad-344, and 1 lb/sx salt mixed at 13.0 ppg. Opened DV tool at 5,498' and circulated 142 sx to surface.

   Second Stage - Lead Slurry: 220 sx Interfill "C" (35:65:6) mixed at 11.7 ppg. Tail Slurry: 550 sx modified Class H w/0.4% CFR-3, 5 lb/sx, Gilsonite, 0.5% Halad-344, 0.1% HR-7, and 1 lb/sx mixed at 13.0 ppg. Circulated 75 sx to surface. Topped out w/20 sx premium plus 3% calcium chloride.

8. Packer: 7" x 3.5" EVI Oil Tools (Arrow), Model X-1 retrievable packer set at 7,879'. Minimum I.D. is 3.0". Wireline re-entry guide on bottom. To release: turn $\frac{1}{4}$ turn to the right and pick up.

9. Perforations (2 SPF):

   Upper Zone - 7,924 - 7,942', 7,974 - 8,030', 8,050 - 8,056', 8,066 - 8,080', 8,118 - 8,127', 8,132 - 8,140', 8,160 - 8,164', 8,170 - 8,188'.

   Lower Zone - 8,220 - 8,254', 8,260 - 8,270', 8,280 - 8,302', 8,360 - 8,366', 8,370 - 8,378', 8,400 - 8,410', 8,419 - 8,423', 8,430 - 8,446', 8,460 - 8,464', 8,470 - 8,476'.

10. PBTD: 9,004'.

11. Cement Plug: 45 sx Class H from 9624' to 9734'.

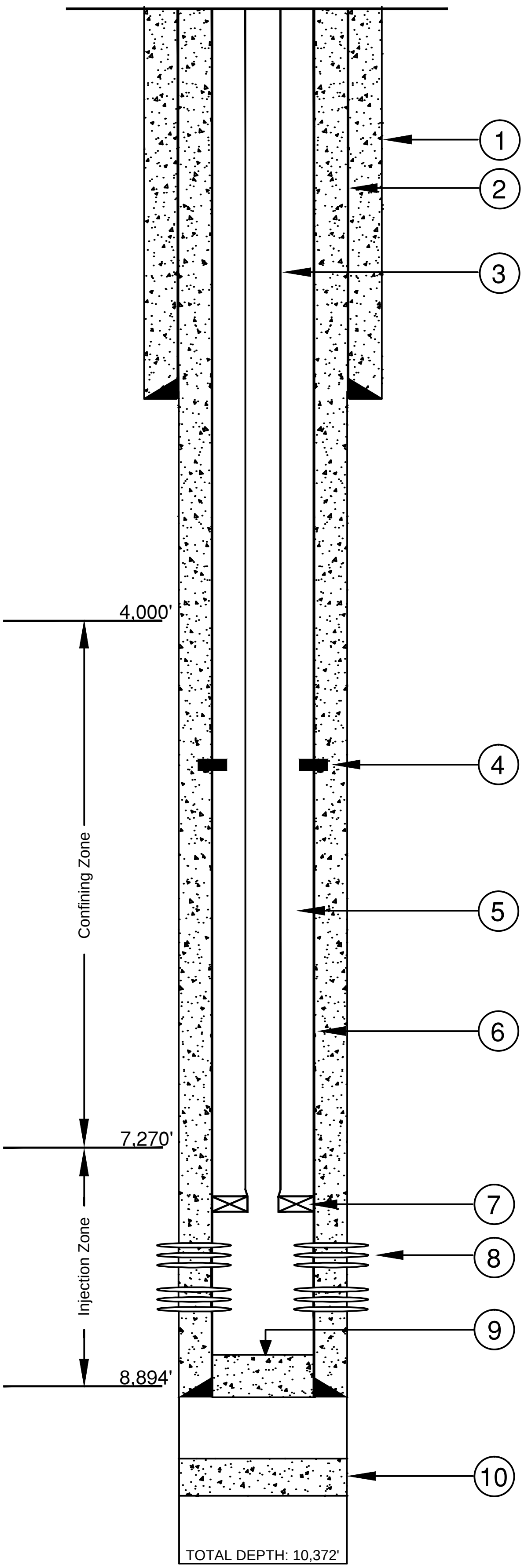
WSP | PARSONS BRINCKERHOFF

FIGURE 12a

HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

BELOW GROUND WELL SCHEMATIC
WASTE DISPOSAL WELL NO. 1

DATE: 01/19/17	CHECKED BY:	JOB NO: 50904D
DRAWN BY: WDD	APPROVED BY:	DWG. NO:



BELOW GROUND DETAILS

All depths are referenced to the Kelly bushing elevation of 13' above ground level. Ground level elevation is 3610' above mean sea level.

1. Base of the USDW at 473'.

2. Surface Casing: 8 5/8", 32 lb/ft, set at 1995' in an 11" hole. Cemented to surface with 800 sacks of cement.

3. Injection Tubing: 3 1/2", 9.2 lb/ft, J-55, smls, NUE 10rd set at 7,528'.

4. DV Tool: at 5,785'.

5. Annulus Fluid: 8.7 lb/gal brine water mixed w/UniChem Techni-Hib 370 corrosion inhibitor.

6. Protection Casing: 5 1/2", 17 lb/ft, L-80, LT&C: 8,869' to the surface and set in a 7 7/8" hole. Casing cemented in two stages as follows:

   First Stage - 575 sacks of modified Class "H" with 0.4% CFR-3, 5 lb/sk Gilsonite, 0.5% Halad-344, and 3 lb/sk salt. Mixed at 13.0 ppg. DV tool opened at 5,785 and 20 sacks circulated to surface.

   Second Stage - Lead Slurry: 300 sacks of Interfill "C" (35:65:6) mixed at 11.7 ppg. Tail slurry: 695 sacks modified Class "H" with 0.4% CFR-3, 5 lb/sk Gilsonite, 0.5% Halad-344 and 3 lb/sk salt mixed at 13.0 ppg. Circulated 150 sacks to surface. Topped out with 10 yards of Redi-mix.

7. Packer: 5 1/2" x 2 7/8" Weatherford Completion Tools (Arrow) Model X-1 retrievable packer set at 7,528'. Minimum ID is 2.4375". Wireline re-entry guide is on bottom. To release: turn 1/4 turn to the right and pick up.

8. Perforations (2 SPF):

   Zone 1: 7,570-7,620'; 7,676-7,736'

   Zone 2: 7,826-7,834'; 7,858-7,880'; 7,886-7,904'; 7,916-7,936'; 7,944-7,964'; 7,990-8,042'; 8,096-8,116'; 8,191-8,201'; 8,304-8,319'; 8,395-8,399'.

9. PBTD: 8,770'

10. Cement Plug: 45 sacks from 9,675' to 9,775'.

Injection Interval: 7,570' - 8,399'

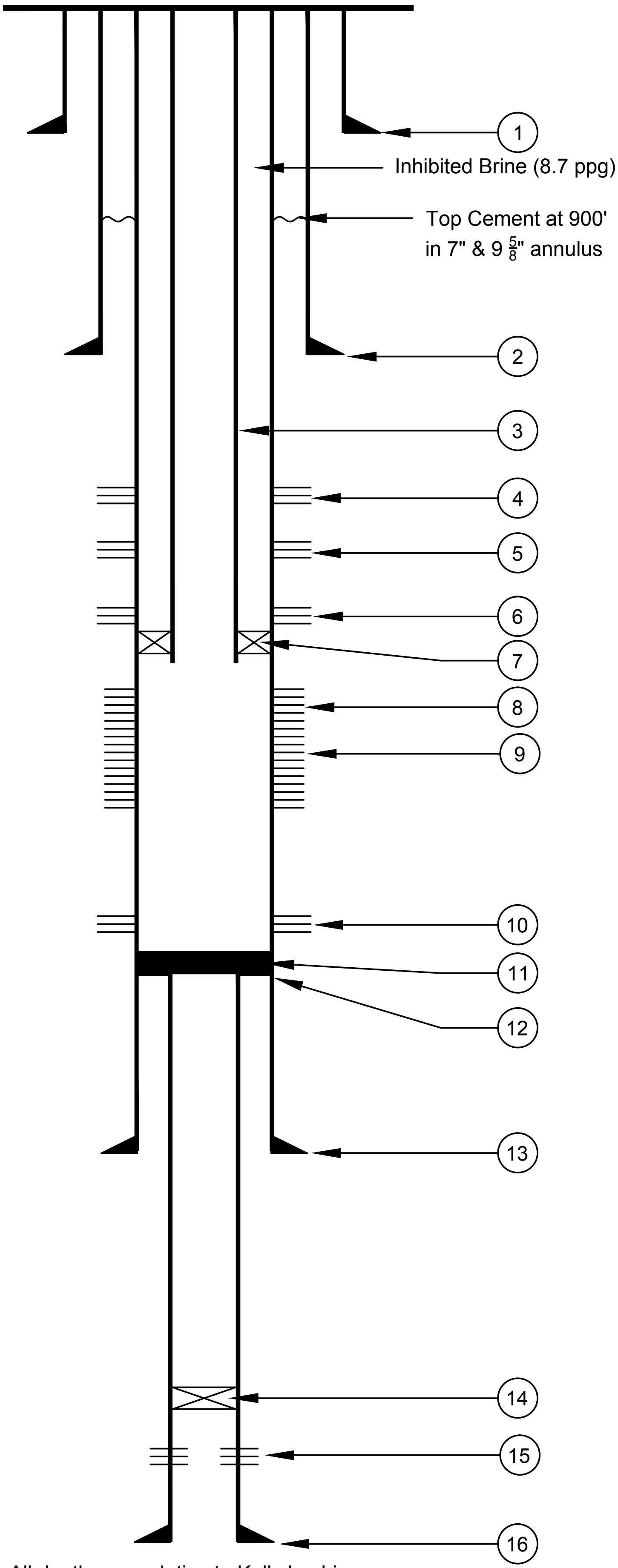
WSP | PARSONS BRINCKERHOFF

FIGURE 12b

HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

BELOW GROUND WELL SCHEMATIC
WASTE DISPOSAL WELL NO. 2

DATE: 01/19/17	CHECKED BY:	JOB NO: 50904D
DRAWN BY: WDD	APPROVED BY:	DWG. NO:



All depths are relative to Kelly bushing

BELOW GROUND DETAILS

1. Surface Casing: 13 $\frac{3}{8}$", 54 $\frac{1}{2}$" lb/ft, J-55 set in a 17 $\frac{1}{2}$" open hole at 400' and cemented to the surface with 425 sacks of Class C cement.

2. First Intermediate Casing: 9 $\frac{5}{8}$", 36 lb/ft, J-55 set in a 12 $\frac{1}{4}$" open hole at 2604' and cemented to the surface with 1025 sacks Class C cement.

3. Injection Tubing: 4 $\frac{1}{2}$", 11.6 lb/ft, J-55 LT&C set at 7568'.

4. Squeeze Perforations: 7050' - 7102' with 80 sacks.

5. Squeeze Perforations: 7262' - 7278' with 100 sacks.

6. Squeeze Perforations: 7304' - 7314' with 80 sacks.

7. Arrow X-1 Packer 7" x 2 $\frac{7}{8}$" set at 7575', 37K Tension, no nipples.

8. Old Open Perforations: 7676' - 7698'.

9. Perforations: 7660' - 8450', 2 JSPF, 60°, 0.5" 10/14/06.

10. Perforations: 8540' - 8620', 23 SPF, 60°, 0.5" 10/15/16.

11. Cement Plug: top tagged at 9022'.

12. Liner Top: 4 $\frac{1}{2}$" set at 9051'.

13. Second Intermediate Casing: 7", 29 lb/ft, N-80 and P-110 steel set in an 8 $\frac{3}{4}$" open hole at 9450' with 1350 sacks of Type H cement from 900' to 9450'.

14. Cast Iron Bridge Plug set at 9800' with 35' cement.

15. Old Perforations: 9861' - 9967'

16. Production Liner: 4 $\frac{1}{2}$", 17 lb/ft, J-55 set in a 6 $\frac{1}{4}$" open hole from 9051' to 10119' with 175 sacks Type H cement.

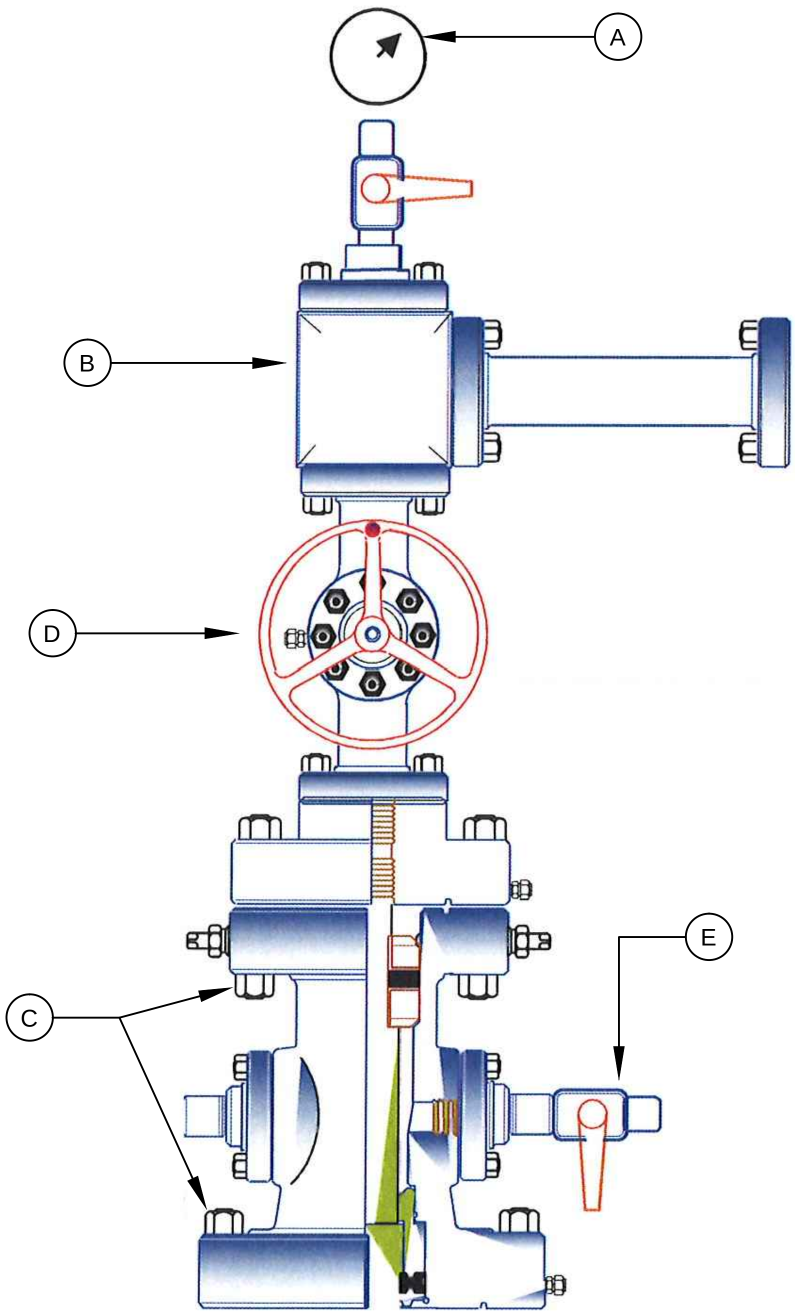
WSP | PARSONS BRINCKERHOFF

FIGURE 12c

HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

BELOW GROUND WELL SCHEMATIC
WASTE DISPOSAL WELL NO. 3

DATE: 01/19/17	CHECKED BY:	JOB NO: 50904D
DRAWN BY: WDD	APPROVED BY:	DWG. NO:



WELLHEAD DETAILS

A. Top Connection: 2 $\frac{3}{8}$" 8rd x 4 $\frac{1}{16}$" 3K 2" x 2 $\frac{3}{8}$" Ball Valve 2 $\frac{3}{8}$" Bull Plug $\frac{1}{2}$" NPT 5000 LB Pressure Gauge.

B. Upper Tree Assembly: A5PP, 4 $\frac{1}{2}$" 3K X 4 $\frac{1}{16}$" 3K

C. Flange: 7 $\frac{1}{16}$", 3 $\frac{1}{2}$" 3K X 4 $\frac{1}{16}$" UPTBG 3K

D. Tree Gate Valve: 4 $\frac{1}{16}$" 3K

E. Annulus Valve: 2" 3K Ball Valve

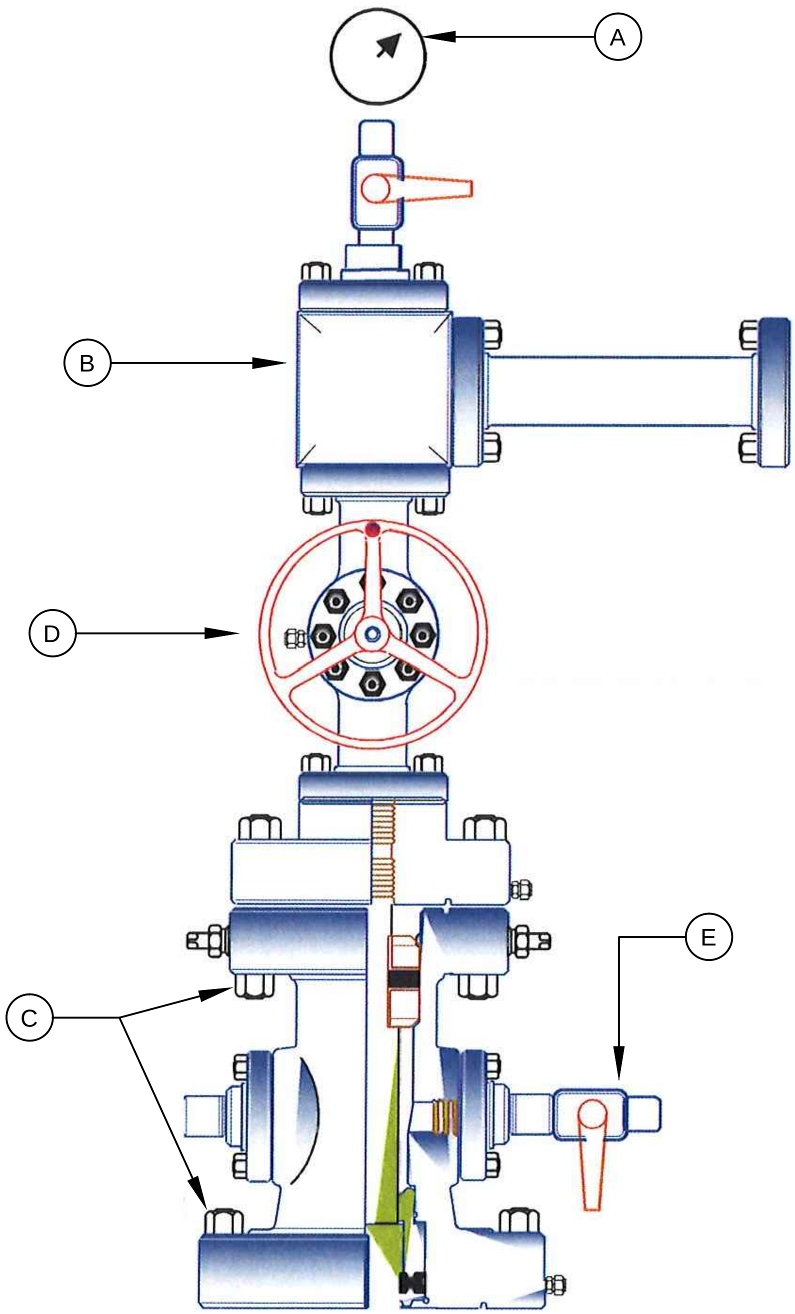
WSP | PARSONS BRINCKERHOFF

FIGURE 13a

HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

WELLHEAD SCHEMATIC
WASTE DISPOSAL WELL NO. 1

DATE: 01/26/17	CHECKED BY:	JOB NO: 50904D
DRAWN BY: WDD	APPROVED BY:	DWG. NO:



WELLHEAD DETAILS

A. Top Connection: $2\frac{3}{8}$" 8rd x $4\frac{1}{16}$" 3K, 2" x $2\frac{3}{8}$" Ball Valve, $2\frac{3}{8}$" Bull Plug $\frac{1}{2}$" NPT 5000 LB Pressure Gauge.

B. Upper Tree Assembly: A5PP, $4\frac{1}{2}$" 3K X $4\frac{1}{16}$" 3K

C. Flange: $7\frac{1}{16}$", $3\frac{1}{2}$" 3K X $4\frac{1}{16}$" UPTBG 3K

D. Tree Gate Valve: $4\frac{1}{16}$" 3K

E. Annulus Valve: 2" 3K Ball Valve

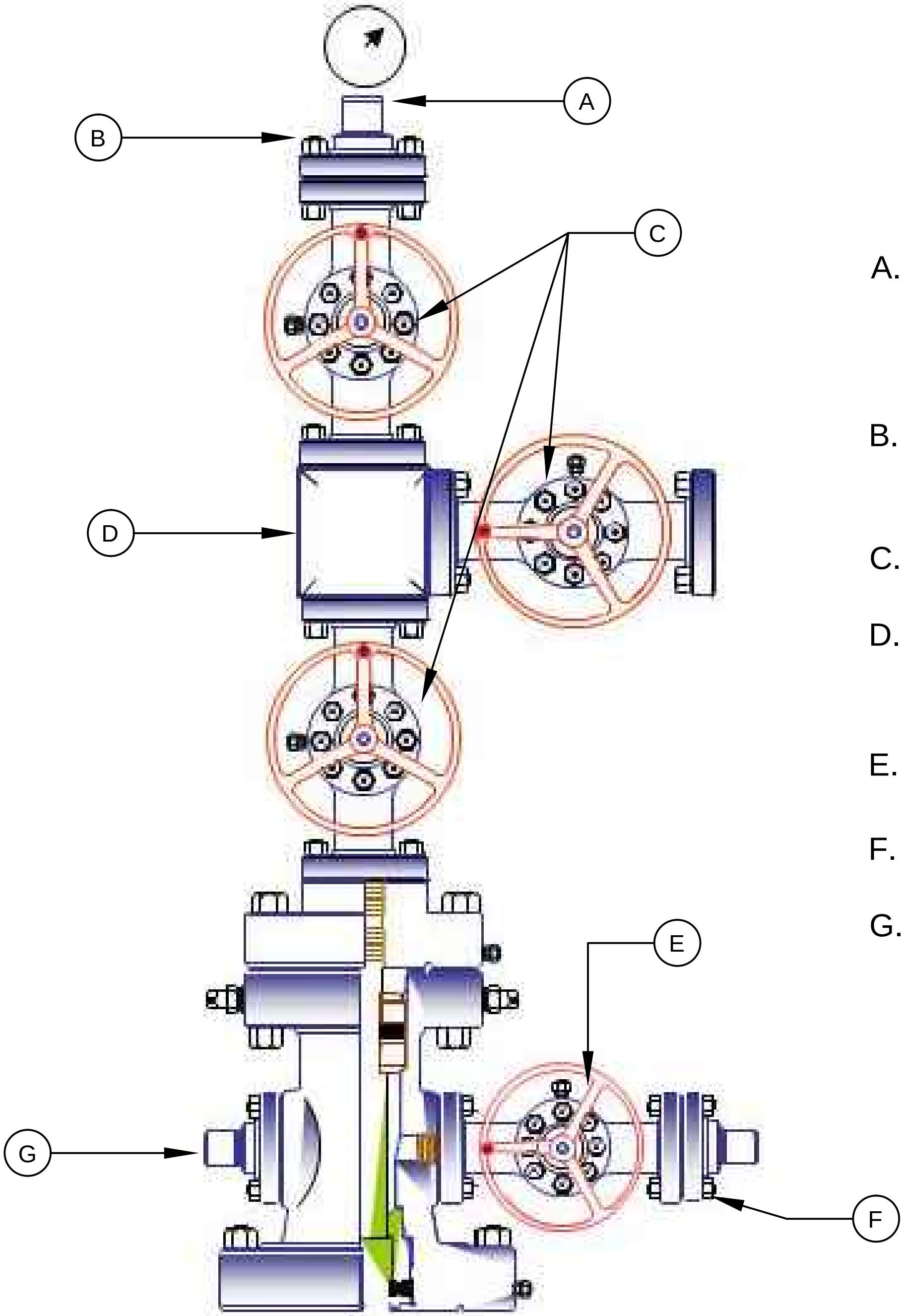
WSP | PARSONS BRINCKERHOFF

FIGURE 13b

HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

WELLHEAD SCHEMATIC
WASTE DISPOSAL WELL NO. 2

DATE: 01/26/17	CHECKED BY:	JOB NO: 50904D
DRAWN BY: WDD	APPROVED BY:	DWG. NO:



WELLHEAD DETAILS

A. Top Connection: $4\frac{1}{2}$" EUE, $2\frac{7}{8}$" 8rd, $2\frac{7}{8}$" bull plug, $\frac{1}{2}$" NPT 5000 lb gauge.

B. Flange: $4\frac{1}{16}$" 3K x $4\frac{1}{2}$" UPTBG 3K

C. Tree Gate Valves: $4\frac{1}{16}$" 3K

D. Upper Tree Assembly: A5PP, $4\frac{1}{2}$", $7\frac{1}{16}$" 3K x $4\frac{1}{16}$" 3K

E. Annulus Valve: $2\frac{1}{16}$" 5K

F. Flange: $2\frac{1}{16}$" 5K x 2" LP 5K

G. Annulus Valve: 2" ball valve 3K

WSP | PARSONS BRINCKERHOFF

FIGURE 13c

HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

WELLHEAD SCHEMATIC
WASTE DISPOSAL WELL NO. 3

DATE: 01/19/17	CHECKED BY:	JOB NO: 50904D
DRAWN BY: WDD	APPROVED BY:	DWG. NO:

INTRODUCTION

HollyFrontier Navajo Refining LLC (Navajo), located in Artesia, New Mexico, is applying to renew the discharge permits for Class I Non-hazardous Waste Disposal Well No. 1 (WDW-1), Waste Disposal Well No. 2 (WDW-2), and Waste Disposal Well No. 3 (WDW-3) which is located approximately ten (10) miles to the southeast of the refinery. WDW-1, WDW-2, and WDW-3 were initially permitted by the Oil Conservation Division (OCD) of the New Mexico Energy, Minerals and Natural Resources Department under the Water Quality Act in 1998 and have been operating under Permits UIC-CLI-008-1, UIC-CLI-008-2, and UIC-CLI-008-3.

The Navajo refinery is located at 501 East Main Street in Artesia, Eddy County, New Mexico. The three Class I nonhazardous waste injection wells operated by the refinery are designated WDW-1, WDW-2 and WDW-3. All three wells are permitted to inject nonhazardous waste water into a subsurface Injection Zone consisting of the lower portion of the Wolfcamp Formation and the underlying Cisco and Canyon Formations. The depth and thickness of the Injection Zone at the three Navajo refinery injection wells are as follows:

- WDW-1: 7,450 to 9,016 ft KB
- WDW-2: 7,270 to 8,894 ft KB
- WDW-3: 7,303 to 8,894 ft KB

Please note that the three Navajo injection wells were previously permitted separately coinciding with the life of the regulatory permit issued for each well. These Discharge Permits will expire on June 1, 2017. One technical report has been prepared along with three separate application forms for each of the wells.

Information concerning the locations of oil and gas wells and freshwater wells within the regulatory 1-mile radius area of review (AOR) surrounding the wells were obtained from OCD and New Mexico Water Rights Reporting System, respectively. No corrective action is needed for any of the artificial penetrations within the 1-mile radius AOR.

The regional and local geology have been evaluated, and no problems have been identified that will cause adverse effects as a result of the ongoing injection operations.

Reservoir characteristics of the Injection Zone indicate the reservoir has sufficient properties to accommodate the historical and planned future injection rate, volume and pressure from the three Navajo injection wells. Based on information gathered from the Navajo refinery injection well system, there are no adverse reactions identified with the waste stream and the well components of construction and the Injection Zone matrix and formation fluid.

WDW-1, WDW-2, and WDW-3 meet the construction and operating standards set forth in 20.6.2.5205 NMAC. A procedure to permanently plug and abandon the wells have been included per the requirements of 20.6.2.5209 NMAC.

TABLE 1A

NON-FRESHWATER (OIL AND GAS) ARTIFICIAL PENETRATIONS IN AREA OF REVIEW
WDW-1, WDW-2, AND WDW-3
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

ID NO	API	Sect	TWP	RNG	NS FTG	EW FTG	WELL NAME	WELL NUMBER	OPERATOR	TOTAL DEPTH (FT)	WELL TYPE	WELL STATUS	DRILLL DATE	PLUG DATE
1	30-015-01636	31	17S	28E	330	2310	Pre-Ongard Well #001		Pre-Ongard Well Operator	?	O	PA	1/1/1900	1/1/1900
2	30-015-01633	31	17S	28E	330	330	Aston & Fair A #001		George A Chase JV dba G&C Service	525	O	Active	12/28/1945	NA
3	30-015-01634	31	17S	28E	350	345	Pre-Ongard Well #001		Pre-Ongard Well Operator	?	O	PA	1/1/1900	1/1/1901
4	30-015-01645	31	17S	28E	990	990	Pre-Ongard Well #001		Pre-Ongard Well Operator	?	O	PA	1/1/1900	1/1/1900
5	30-015-32162	31	17S	28E	460	990	Enron State #4		LRE Operating, LLC	3460	O	Active	3/26/2003	NA
6	30-015-38512	31	17S	28E	990	940	Enron State #16		LRE Operating, LLC	3658	O	Active	8/11/2011	NA
7	30-015-33994	36	17S	27E	915	420	Red Lake 36 A State #002		Apache Corp	3650	O	Active	3/24/2005	NA
8	30-015-00646	36	17S	27E	990	330	Delhi #007		George A Chase JV dba G&C Service	540	O	Active	3/24/1950	NA
9	30-015-00689	36	17S	27E	1650	330	Gates State #001		George A Chase JV dba G&C Service	557	O	Active	7/22/1951	NA
10	30-015-36978	31	17S	28E	990	330	Enron State #015		LRE Operating, LLC	3700	O	Active	6/25/2009	11/1/2004
11	30-015-00647	36	17S	27E	1650	990	Gates State #002		Aspen Oil Inc.	9999	O	PA	10/3/1952	NA
12	30-015-31123	36	17S	27E	1980	760	No Bluff State Comm #002		LRE Operating, LLC	10050	G	Active	3/19/2001	NA
13	30-015-00669	36	17S	27E	2310	330	Homan #001		George A Chase JV dba G&C Service	1804	O	Active	5/21/1949	NA
14	30-015-31036	36	17S	27E	2310	990	Gates State #003		George A Chase JV dba G&C Service	614	O	Active	3/26/2000	NA
15	30-015-36116	36	17S	27E	2305	1650	South Red Lake 11 Unit #057		Legacy Reserves Operating LLC	2121	O	Active	4/14/2008	NA
16	30-015-00687	36	17S	27E	2310	990	Ramapo #002		Kersey & Co.	9999	G	PA	3/24/1948	6/14/1996
17	30-015-05934	36	17S	27E	1650	1650	Empire ABO Unit #019A		Apache Corp	5970	O	Active	NA	NA
18	30-015-39325	36	17S	27E	990	2210	Big Boy State #007		COG Operating LLC	5120	O	Active	1/6/2012	NA
19	30-015-00670	36	17S	27E	2970	330	Ramapo #003		Kersey & Co.	9999	O	PA	1/1/1990	6/17/1996
20	30-015-00688	36	17S	27E	2310	330	Ramapo #001		Kersey & Co.	590	O	PA	10/3/1941	6/18/1996
21	30-015-00685	36	17S	27E	1650	330	Pre-Ongard Well #020		Pre-Ongard Well Operator	?	O	PA	1/1/1900	1/1/1900
22	30-015-39401	36	17S	27E	1110	630	Empire ABO Unit #417		Apache Corp	6300	O	Active	1/9/2012	NA
23	30-015-39323	36	17S	27E	870	1560	Big Boy State #005		COG Operating LLC	4953	O	Active	4/21/2012	NA
24	30-015-01251	36	17S	27E	660	1980	Empire ABO Unit #019		BP America Production Co.	6200	O	Plugged, Site Released	1/1/1900	9/9/2009
25	30-015-39324	36	17S	27E	480	2210	Big Boy State #006		COG Operating LLC	5072	O	Active	12/18/2011	NA
26	30-015-39326	36	17S	27E	275	1560	Big Boy State #008		COG Operating LLC	NA	O	N	NA	NA
27	30-015-40410	36	17S	28E	615	10	Big Girl 31 State #011H		COG Operating LLC	NA	O	N	NA	NA
28	30-015-00677	36	17S	27E	330	990	Empire ABO Unit #020		BP America Production Co.	6013	O	PA	3/17/1960	9/9/2009
29	30-015-39021	6	18S	28E	40	145	Empire ABO Unit #411		Apache Corp	6312	O	T	10/31/2011	NA
30	30-015-32309	1	18S	27E	330	1690	AAO Federal #003		Apache Corp	4125	O	Active	3/13/2003	NA
31	30-015-00708	1	18S	27E	660	1980	Empire ABO Unit #019B		Apache Corp	6078	O	Plugged, Site Released	5/29/1959	5/22/2013
32	30-015-01215	1	18S	27E	667	666	Empire ABO Unit #020D		Apache Corp	6118	O	Active	9/23/1959	NA
33	30-015-32310	1	18S	27E	990	990	AAO Federal #004		Apache Corp	4110	O	Active	7/14/2003	NA
34	30-015-39898	1	18S	27E	1258	1005	Empire ABO Unit #412		Apache Corp	NA	O	Cancelled Apd	NA	NA
35	30-015-33784	1	18S	27E	1650	330	AAO Federal #008		Apache Corp	4310	O	Active	2/28/2005	NA
36	30-015-00711	1	18S	27E	1980	660	Empire ABO Unit #020C		Apache Corp	6218	O	Plugged, Site Released	9/1/1959	7/8/2013
37	30-015-22656	1	18S	27E	2400	700	Empire ABO Unit #203		Apache Corp	6225	O	Active	9/13/1978	NA
38	30-015-23116	6	18S	28E	2050	100	Empire ABO Unit #213		Apache Corp	6242	O	Active	3/1/1980	NA
39	30-015-22637	6	18S	28E	2450	400	Empire ABO Unit #212		Apache Corp	6267	O	Active	12/4/1978	NA
40	30-015-21553	1	18S	27E	2501	20	Empire ABO Unit #201		Apache Corp	6225	O	Active	6/28/1975	NA
41	30-015-02622	6	18S	28E	2219	660	Empire ABO Unit #21D		Apache Corp	6194	O	Active	12/27/1959	NA
42	30-015-02619	6	18S	28E	1990	660	Empire ABO Unit #021C		Apache Corp	6202	O	Active	10/8/1959	NA
43	30-015-02613	6	18S	28E	990	660	Empire ABO Unit #21B		Apache Corp	6119	O	Active	12/8/1959	NA
44	30-015-22012	6	18S	28E	1350	1572	Empire ABO Unit #222		Apache Corp	6303	O	Active	2/17/1977	NA
45	30-015-02626	6	18S	28E	1650	1650	Pre-Ongard Well #001		Pre-Ongard Well Operator	?	O	PA	1/1/1900	1/1/1900
46	30-015-10107	6	18S	28E	1874	1874	State FX #001		Pre-Ongard Well Operator	1985	O	Active	12/31/9999	NA
47	30-015-02620	6	18S	28E	1990	2082	Empire ABO Unit #22D		Alamo Permian Resources, LLC	6206	O	Active	12/31/9999	NA
48	30-015-02621	6	18S	28E	66	1980	Empire ABO Unit #22E		Apache Corp	6033	O	Active	12/31/9999	NA
49	30-015-02625	6	18S	28E	470	2170	Empire ABO Unit #23C		Apache Corp	6194	O	Active	12/31/9999	NA
50	30-015-02615	6	18S	28E	660	660	Empire ABO Unit #24B		Apache Corp	6241	O	Active	12/31/9999	NA
51	30-015-02614	6	18S	28E	1980	1980	Empire ABO Unit #23B		Apache Corp	6242	O	Active	12/31/9999	NA
52	30-015-02611	6	18S	28E	2310	2310	Pre-Ongard Well #001		Pre-Ongard Well Operator	?	O	PA	1/1/1900	1/1/1900
53	30-015-21395	6	18S	28E	2630	1300	Empire ABO Unit #211		Apache Corp	6200	O	Active	11/22/1974	NA
54	30-015-22527	6	18S	28E	2630	1930	Empire ABO Unit #223		Apache Corp	6250	O	Approved Temporary Abandonment	4/22/1978	NA
55	30-015-02623	6	18S	28E	2248	2075	Empire ABO Unit #022F		Apache Corp	6210	O	Active	1/28/1960	NA
56	30-015-23548	6	18S	28E	1950	1000	Empire ABO Unit #211A		Apache Corp	6311	O	Active	2/11/1981	NA
57	30-015-02628	6	18S	28E	2260	2270	Empire ABO Unit #023D		BP America Production Co.	6310	O	PA	4/3/1960	12/5/2008
58	30-015-02618	6	18S	28E	1647	2076	Pre-Ongard #001		Pre-Ongard Well Operator	?	G	PA	1/1/1900	1/1/1900
59	30-015-22491	6	18S	28E	1700	2350	Empire ABO Unit #231B		BP America Production Co.	6350	O	PA	12/31/9999	8/24/2009
60	30-015-02610	6	18S	28E	955	1750	Empire ABO Unit #022C		Apache Corp	6243	O	Active	7/20/1960	NA
61	30-015-02624	6	18S	28E	968	2270	Pre-Ongard #001		Pre-Ongard Well Operator	?	O	PA	1/1/1900	1/1/1900
62	30-015-02617	6	18S	28E	2310	990	Empire ABO Unit #024K		BP America Production Co.	6346	O	PA	12/31/9999	12/12/2002
63	30-015-22528	6	18S	28E	2300	1570	Empire ABO Unit #232A		BP America Production Co.	6350	O	PA	6/27/1978	10/9/2009
64	30-015-22490	6	18S	28E	2550	2050	Empire ABO Unit #233		BP America Production Co.	6300	O	PA	7/1/1978	10/9/2009
65	30-015-21746	6	18S	28E	2610	2713	Empire ABO Unit #221		Apache Corp	6305	O	Active	12/31/9999	NA
66	30-015-21737	6	18S	28E	2253	1576	Empire ABO Unit #232A		BP America Production Co.	6345	O	PA	12/31/9999	10/9/2009
67	30-015-23547	6	18S	28E	1950	660	Empire ABO Unit #241		BP America Production Co.	6386	O	PA	12/31/9999	12/23/2008
68	30-015-02616	6	18S	28E	1650	990	Empire ABO Unit #024C		Apache Corp	6253	O	Active	12/31/9999	NA
69	30-015-22913	6	18S	28E	1750	1600	Empire ABO Unit #235		Apache Corp	600	O	PA	12/31/9999	?
70	30-015-21542	6	18S	28E	1260	1580	Empire ABO Unit #231B		Apache Corp	6261	O	Active	12/31/9999	NA

TABLE 1A

NON-FRESHWATER (OIL AND GAS) ARTIFICIAL PENETRATIONS IN AREA OF REVIEW
WDW-1, WDW-2, AND WDW-3
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

ID NO	API	Sect	TWP	RNG	NS FTG	EW FTG	WELL NAME	WELL NUMBER	OPERATOR	TOTAL DEPTH (FT)	WELL TYPE	WELL STATUS	DRILLL DATE	PLUG DATE
71	30-015-21626	6	18S	28E	1361	2531	Empire ABO Unit #231A		Apache Corp	6390	O	Active	12/31/9999	NA
72	30-015-22593	6	18S	28E	1900	2441	Empire ABO Unit #234		BP America Production Co.	6260	O	PA	12/31/9999	12/25/2008
73	30-015-30785	6	18S	28E	430	330	NW State #015		LRE Operating, LLC	3225	O	Active	12/20/1999	NA
74	30-015-20019	6	18S	28E	330	330	NW Artesia Unit #016		LRE Operating, LLC	3273	O	Active	12/31/9999	NA
75	30-015-39008	6	18S	28E	160	1300	Empire ABO Unit #410		Apache Corp	?	O	N	12/31/9999	NA
76	30-015-25522	5	18S	28E	2240	400	Walter Solt State #001		Walter Solt LLC	8500	SWD	Active	12/31/9999	NA
77	30-015-10244	5	18S	28E	2310	330	State AG #001		Mack Energy Corp	6365	O	PA	12/31/9999	3/27/2001
78	30-015-24485	5	18S	28E	1980	990	Illinois Camp A Com #001		Conoco Phillips Co	10450	G	Active	5/28/1983	NA
79	30-015-31086	5	18S	28E	1650	990	LP State #001		Marbob Energy Corp	4503	O	PA	7/3/2000	3/11/2008
80	30-015-02602	5	18S	28E	1650	1650	Empire ABO Unit #026D		Apache Corp	6265	O	Active	11/28/1959	NA
81	30-015-22697	5	18S	28E	1080	1914	Empire ABO Unit #261A		BP America Production Co.	6350	O	PA	12/31/9999	6/15/2009
82	30-015-02607	5	18S	28E	660	660	Empire ABO Unit #25C		Apache Corp	6273	O	Plugged, Site Released	2/23/1960	6/25/2013
83	30-015-22750	5	18S	28E	660	150	Empire ABO Unit #251		Apache Corp	6250	O	Active	12/31/9999	NA
84	30-015-02605	5	18S	28E	330	2271	Empire ABO Unit #27E		BP America Production Co.	6261	O	PA	12/31/9999	6/16/2009
85	30-015-02606	5	18S	28E	330	1941	Empire ABO Unit #26E		Apache Corp	6254	O	Active	7/6/1960	NA
86	30-015-22009	32	17S	28E	330	2481	Empire ABO Unit #272		Apache Corp	6370	O	Active	2/8/1977	NA
87	30-015-21539	32	17S	28E	150	1400	Empire ABO Unit #261A		Apache Corp	6220	O	Active	12/31/9999	NA
88	30-015-39007	32	17S	28E	70	100	Empire ABO Unit #409		Apache Corp	6400	N	N	12/31/9999	NA
89	30-015-37058	32	17S	28E	330	330	NW State #32		LRE Operating, LLC	3425	O	Active	8/12/2009	NA
90	30-015-37057	32	17S	28E	330	1750	NW State #31		LRE Operating, LLC	3500	O	Active	7/21/2009	NA
91	30-015-01659	32	17S	28E	660	1980	Empire ABO Unit #26A		Apache Corp	6172	O	Active	12/31/9999	NA
92	30-015-01660	32	17S	28E	660	660	Empire ABO Unit #25		BP America Production Co.	6187	O	PA	12/31/9999	6/30/2009
93	30-015-30685	32	17S	28E	990	990	NW State #007		LRE Operating, LLC	3220	O	Active	8/30/1999	NA
94	30-015-10834	32	17S	28E	990	2030	NW Artesia Unit #13		SDX Resources, Inc.	2006	O	PA	12/31/9999	11/2/2006
95	30-015-30815	32	17S	28E	1090	2126	NW State #008		LRE Operating, LLC	3310	I	Active	11/18/1999	NA
96	30-015-20043	32	17S	28E	990	760	NW Artesia Unit #012		LRE Operating, LLC	1998	I	Active	12/31/9999	NA
97	30-015-01661	32	17S	28E	1650	2310	Empire ABO Unit #26B		Apache Corp	6083	O	Active	12/31/9999	NA
98	30-015-36989	32	17S	28E	1630	1710	NW State #30		LRE Operating, LLC	3405	O	Active	7/7/2009	NA
99	30-015-01662	32	17S	28E	1650	990	Empire ABO Unit #25A		Apache Corp	6123	O	Active	12/31/9999	NA
100	30-015-36554	32	17S	28E	1770	550	NW State #29		LRE Operating, LLC	3450	O	Active	1/21/2009	NA
101	30-015-39927	32	17S	28E	1750	1765	AA State #002		Apache Corp	5800	O	N	12/31/9999	NA
102	30-015-30781	32	17S	28E	1900	2146	NW State #005		LRE Operating, LLC	3190	I	Active	10/28/1999	NA
103	30-015-10818	32	17S	28E	2310	2105	NW Artesia #008		SDX Resources, Inc.	2003	O	PA	12/31/9999	11/6/2006
104	30-015-30777	32	17S	28E	2310	990	NW State #006		LRE Operating, LLC	3204	O	Active	10/19/1999	NA
105	30-015-10795	32	17S	28E	2310	66	NW Arteisa #009		Lime Rock Resources L.P.	1980	O	PA	12/31/9999	5/28/2008
106	30-015-01657	32	17S	28E	2280	1980	AA State #001		Apache Corp	6171	O	Active	7/30/1960	NA
107	30-015-01671	32	17S	28E	2280	978	Empire ABO Unit #25B		BP America Production Co.	6013	O	PA	12/31/9999	7/21/2008
108	30-015-31920	32	17S	28E	990	990	Enron State #002		LRE Operating, LLC	4030	O	Active	9/4/2001	NA
109	30-015-40339	32	17S	28E	99	330	Enron State #018		LRE Operating, LLC	4250	O	N	12/31/9999	NA
110	30-015-35050	32	17S	28E	330	500	Enron State #012		LRE Operating, LLC	3810	O	Active	11/20/2006	NA
111	30-015-01654	32	17S	28E	33	330	Pre-Ongard #001		Pre-Ongard Well Operator	651	O	PA	1/1/1900	1/1/1900
112	30-015-39638	30	17S	28E	412	679	Anthoney State #003		LRE Operating, LLC	5039	O	Active	2/21/2012	NA
113	30-015-38234	30	17S	28E	430	800	Anthoney State #002		LRE Operating, LLC	4823	O	Active	2/1/2011	NA
114	30-015-01616	30	17S	28E	330	990	Blake State #1		CFM Oil LLC	615	O	Active	12/31/9999	NA
115	30-015-36564	30	17S	28E	330	2210	Staley State #009		LRE Operating, LLC	4010	O	Active	12/15/2008	NA
116	30-015-40026	30	17S	28E	330	2410	Staley State #017		LRE Operating, LLC	5108	O	Active	3/15/2012	NA
117	30-015-37673	30	17S	28E	330	1650	Staley State #012		LRE Operating, LLC	4785	O	Active	5/24/2010	NA
118	30-015-38203	30	17S	28E	330	990	Maple State #008		COG Operating LLC	4750	O	N	12/31/9999	NA
119	30-015-21594	31	17S	28E	330	1650	Powco State #001		Finney Oil Co	650	O	Active	12/31/9999	NA
120	30-015-01638	31	17S	28E	330	990	Pre-Ongard #001		Pre-Ongard Well Operator	2003	O	PA	1/1/1990	1/1/1990
121	30-015-30784	31	17S	28E	330	480	NW State #002		LRE Operating, LLC	3300	O	Active	11/11/1999	NA
122	30-015-30893	31	17S	28E	973	959	NW State #028		LRE Operating, LLC	2808	O	Active	9/14/2000	NA
123	30-015-25621	31	17S	28E	980	1620	Powco State #002		Finney Oil Co	734	O	Active	12/31/9999	NA
124	30-015-30783	31	17S	28E	1650	330	NW State #11		LRE Operating, LLC	3205	O	Active	11/4/1999	NA
125	30-015-36343	31	17S	28E	1650	2310	Malco State #002		George A Chase JV dba G&C Service	633	O	Active	6/30/2008	NA
126	30-015-10537	31	17S	28E	2277	330	NW Artesia Unit #004		LRE Operating, LLC	6200	O	Active	3/3/1966	NA
127	30-015-01652	31	17S	28E	2288	1625	Boling #001		Kersey & Co.	1938	O	Active	12/14/1989	NA
128	30-015-37428	31	17S	28E	1980	1980	Malco State #003		George A Chase JV dba G&C Service	650	O	Active	12/20/2009	NA
129	30-015-01637	31	17S	28E	2310	2310	Malco State #001		George A Chase JV dba G&C Service	1852	O	Active	1/14/1953	NA
130	30-015-01635	31	17S	28E	2310	2310	Aston & Fair #001Y		George A Chase JV dba G&C Service	1926	O	Active	12/31/9999	NA
131	30-015-01643	31	17S	28E	2310	2360	Empire ABO Unit #22		BP America Production Co.	5971	O	PA	12/31/9999	7/10/2009
132	30-015-24887	31	17S	28E	2310	990	Hudson Saikin State #002		Alamo Permian Resources, LLC	1950	O	Active	12/31/9999	NA
133	30-015-02666	31	17S	28E	2310	330	Hudson Saikin State #001		Alamo Permian Resources, LLC	1860	O	Active	12/31/9999	NA
134	30-015-30849	31	17S	28E	2310	270	NW State #009		LRE Operating, LLC	3195	O	Active	12/14/1999	NA
135	30-015-10833	31	17S	28E	1980	660	NW Artesia Unit #010		LRE Operating, LLC	2000	O	Active	12/31/9999	NA
136	30-015-01644	31	17S	28E	1650	330	Empire ABO Unit #24A		BP America Production Co.	6106	O	PA	12/31/9999	6/15/2009
137	30-015-40409	31	17S	28E	1920	330	Big Girl 31 State #009H		COG Operating LLC	8447	O	N	12/31/9999	NA
138	30-015-01650	31	17S	28E	1650	1958	Empire ABO Unit #23A		BP America Production Co.	6094	O	PA	12/31/9999	9/17/2003
139	30-015-01642	31	17S	28E	1650	2310	State FW #001		Alamo Permian Resources, LLC	1937	O	Active	12/31/9999	NA
140	30-015-01651	31	17S	28E	1650	2387	Empire ABO Unit #22B		BP America Production Co.	6046	O	PA	12/31/9999	2/10/2010

TABLE 1A

NON-FRESHWATER (OIL AND GAS) ARTIFICIAL PENETRATIONS IN AREA OF REVIEW
WDW-1, WDW-2, AND WDW-3
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

ID NO	API	Sect	TWP	RNG	NS FTG	EW FTG	WELL NAME	WELL NUMBER	OPERATOR	TOTAL DEPTH (FT)	WELL TYPE	WELL STATUS	DRILLL DATE	PLUG DATE
141	30-015-01648	31	17S	28E	1651	1089	Empire ABO Unit #21A		BP America Production Co.	5971	O	PA	4/15/1960	8/24/2002
142	30-015-01640	31	17S	28E	2310	330	Rampo #002		Alamo Permian Resources, LLC	1996	O	Active	12/31/9999	NA
143	30-015-39011	31	17S	28E	1190	1320	Empire ABO Unit #419		Apache Corp	6310	O	Active	10/11/2011	NA
144	30-015-20042	31	17S	28E	990	660	NW Artesia Unit #011		LRE Operating, LLC	2012	O	Active	12/31/9999	NA
145	30-015-01653	31	17S	28E	990	1650	Pre-Ongard #001		Pre-Ongard Well Operator	742	O	PA	1/1/1900	1/1/1900
146	30-015-01639	31	17S	28E	990	330	Ramp #001		Alamo Permian Resources, LLC	1975	O	Active	12/31/9999	NA
147	30-015-30760	31	17S	28E	735	330	NW State #010		LRE Operating, LLC	3210	O	Active	10/12/1999	NA
148	30-015-01641	31	17S	28E	660	660	Empire ABO Unit #24		Apache Corp	6122	O	Active	12/31/9999	NA
149	30-015-39004	31	17S	28E	150	1300	Empire ABO Unit #401		Apache Corp	6400	O	N	12/31/9999	NA
150	30-015-01649	31	17S	28E	660	1939	Empire ABO Unit #23		BP America Production Co.	6094	O	PA	12/31/9999	1/14/2010
151	30-015-27592	31	17S	28E	660	2310	WDW #1		Navajo Refining Co.	10200	I	Active	8/4/1993	NA
152	30-015-10118	31	17S	28E	766	2188	State FV #001		Alamo Permian Resources, LLC	1957	O	Active	12/31/9999	NA
153	30-015-01646	31	17S	28E	660	2082	Empire ABO Unit #22A		BP America Production Co.	6050	O	PA	12/31/9999	8/20/2009
154	30-015-01647	31	17S	28E	660	660	Empire ABO Unit #21		BP America Production Co.	9999	O	PA	12/31/9999	7/23/2005
155	30-015-39020	31	17S	28E	140	2560	Empire ABO Unit #408		Apache Corp	6318	O	T	10/18/2011	NA
156	30-015-33473	1	18S	27E	1750	1650	AAO Federal #007		Apache Corp	4100	O	Active	10/22/2004	NA
157	30-015-25270	12	18S	27E	2310	2310	CHUKKA FEDERAL #001	#001	BILL L MILLER	1600	Oil	Active	4/23/1985	NA
158	30-015-26017	12	18S	27E	990	1650	COMSTOCK FEDERAL #010	#010	EASTLAND OIL CO	2040	Oil	Plugged, Site Released	12/22/1989	1/23/2003
159	30-015-25100	12	18S	27E	330	1650	COMSTOCK FEDERAL	#001	HARLOW ENTERPRISES LLC	2400	Oil	Active	12/10/1984	NA
160	30-015-25201	12	18S	27E	1650	1770	COMSTOCK FEDERAL #002	#002	HARLOW ENTERPRISES LLC	1600	Oil	Active	3/20/1985	NA
161	30-015-25545	12	18S	27E	990	990	COMSTOCK FEDERAL #003	#003	HARLOW ENTERPRISES LLC	1530	Oil	Active	5/19/1986	NA
162	30-015-25202	12	18S	27E	330	2310	COMSTOCK FEDERAL	#005	HARLOW ENTERPRISES LLC	NR	Oil	Active	4/19/1985	NA
163	30-015-25099	12	18S	27E	1809	990	COMSTOCK FEDERAL #006	#006	HARLOW ENTERPRISES LLC	1652	Oil	Active	8/18/1985	NA
164	30-015-00874	12	18S	27E	2310	2355	COMSTOCK FEDERAL #007	#007	HARLOW ENTERPRISES LLC	3664	Oil	Active	7/28/1948	NA
165	30-015-25738	12	18S	27E	2310	2310	COMSTOCK FEDERAL #009	#009	HARLOW ENTERPRISES LLC	1586	Oil	Active	4/25/1987	NA
166	30-015-26404	12	18S	27E	660	990	FEDERAL T SWD	#001	LIME ROCK RESOURCES II-A, L.P.	10,141	Salt Water Disposal	Active	6/28/1990	NA
167	30-015-20894	12	18S	27E	1980	660	WDW #002	#002	NAVAJO REFINING CO. PIPELINE DIVISION	10,372	Injection	Active	5/5/1999	NA
168	30-015-00872	12	18S	27E	310	990	PRE-ONGARD WELL #001	#001	PRE-ONGARD WELL OPERATOR	594	Oil	Plugged, Site Released	1/1/1900	1/1/1900
169	30-015-20535	12	18S	27E	330	455	PRE-ONGARD WELL #001	#002	PRE-ONGARD WELL OPERATOR	6295	Oil	Plugged, Site Released	1/1/1900	1/1/1900
170	30-015-06171	12	18S	27E	1069	251	PRE-ONGARD WELL	#003	PRE-ONGARD WELL OPERATOR	2200	Oil	Plugged, Site Released	1/1/1900	1/1/1900
171	30-015-23115	12	18S	27E	330	380	PRE-ONGARD WELL	#003	PRE-ONGARD WELL OPERATOR	6248	Oil	Plugged, Site Released	1/1/1900	1/1/1900
172	30-015-00873	12	18S	27E	330	330	PRE-ONGARD WELL	#004	PRE-ONGARD WELL OPERATOR	2510	Oil	Cancelled Apd	NA	NA
173	30-015-00875	12	18S	27E	330	330	PRE-ONGARD WELL	#004	PRE-ONGARD WELL OPERATOR	2000	Oil	Plugged, Site Released	1/1/1900	1/1/1900
174	30-015-00876	12	18S	27E	100	500	PRE-ONGARD WELL	#005	PRE-ONGARD WELL OPERATOR	1994	Oil	Plugged, Site Released	1/1/1900	1/1/1900
175	30-015-25649	12	18S	27E	1650	990	PRE-ONGARD WELL	#008	PRE-ONGARD WELL OPERATOR	2000	Oil	Plugged, Site Released	1/1/1900	1/1/1900
176	30-015-00871	12	18S	27E	330	330	FEDERAL EA #001	#001	RHONDA OPERATING CO	6253	Oil	Plugged, Site Released	7/3/1975	4/12/1994
177	30-015-22833	11	18S	27E	450	1175	EMPIRE ABO UNIT	#133B	APACHE CORP	6225	Oil	Active	5/23/1979	NA
178	30-015-22834	11	18S	27E	225	2280	EMPIRE ABO UNIT #141B	#141B	APACHE CORP	6225	Oil	Active	5/21/1979	NA
179	30-015-31319	7	18S	27E	2310	330	LAUREL STATE #003	003	BILL L. MILLER	1630	Oil	Active	10/2/2000	NA
180	30-015-06137	13	18S	27E	250	990	PRE-ONGARD WELL	002	PRE-ONGARD WELL OPERATOR	2696	Oil	Plugged, Site Released	1/1/1900	1/1/1901
181	30-015-24881	13	18S	27E	1880	1830	ANADARKO 13 FEDERAL	001	DAVID G. HAMMOND	3020	Oil	Plugged, Site Released	12/31/9999	7/17/2011
182	30-015-00888	13	18S	27E	1980	1650	PRE-ONGARD WELL	001	PRE-ONGARD WELL OPERATOR	2000	Oil	Plugged, Site Released	1/1/1900	1/1/1901
183	30-015-00880	13	18S	27E	1650	990	PRE-ONGARD WELL	001	PRE-ONGARD WELL OPERATOR	2353	Oil	Plugged, Site Released	1/1/1900	1/1/1900
184	30-015-00884	13	18S	27E	1650	990	PRE-ONGARD WELL	003	PRE-ONGARD WELL OPERATOR	2047	Oil	Plugged, Site Released	1/1/1900	1/1/1900
185	30-015-25394	13	18S	27E	2310	330	ARTESIA STATE	002	BILL L. MILLER	1613	Oil	Active	12/31/9999	NA
186	30-015-25241	13	18S	27E	330	1650	ARTESIA STATE	001	BILL L. MILLER	2300	Oil	Active	12/31/9999	NA
187	30-015-25370	13	18S	27E	480	940	ARTESIA STATE	802	ALAMO PERMIAN RESOURCES, LLC	1608	Oil	Active	8/27/1985	NA
188	30-015-00883	13	18S	27E	990	990	ARTESIA STATE	801	ALAMO PERMIAN RESOURCES, LLC	1650	Oil	Active	12/31/9999	NA
189	30-015-00895	14	18S	27E	1650	330	ARTESIA STATE	301	ALAMO PERMIAN RESOURCES, LLC	1888	Oil	Active	2/8/1945	NA
190	30-015-00891	14	18S	27E	990	330	PRE-ONGARD WELL	001	PRE-ONGARD WELL OPERATOR	2060	Oil	Plugged, Site Released	1/1/1900	1/1/1900
191	30-015-40187	14	18S	27E	660	990	VIOLET BIV STATE COM	001	YATES PETROLEUM CORP	10500	Gas	Cancelled Apd	4/18/2012	NA
192	30-015-36939	14	18S	27E	661	991	VIOLET BIV STATE COM	001C	YATES PETROLEUM CORP	10,500	Gas	Cancelled Apd	2/20/2009	NA
193	30-015-00870	14	18S	27E	1980	1980	PRE-ONGARD WELL	001	PRE-ONGARD WELL OPERATOR	7270	Oil	Plugged, Site Released	1/1/1900	1/1/1900
194	30-015-00866	14	18S	27E	1980	660	PRE-ONGARD WELL	131	PRE-ONGARD WELL OPERATOR	6120	Oil	Plugged, Site Released	1/1/1900	1/1/1900
195	30-015-00865	14	18S	27E	1650	1980	PRE-ONGARD WELL	014	PRE-ONGARD WELL OPERATOR	6208	Oil	Plugged, Site Released	1/1/1900	1/1/1900
196	30-015-20510	14	18S	27E	1650	1653	PRE-ONGARD WELL	001	PRE-ONGARD WELL OPERATOR	10168	Oil	Plugged, Site Released	1/1/1900	1/1/1900
197	30-015-22556	14	18S	27E	1100	1200	PRE-ONGARD WELL	131	PRE-ONGARD WELL OPERATOR	6325	Oil	Plugged, Site Released	1/1/1900	1/1/1900
198	30-015-00864	14	18S	27E	660	1980	PRE-ONGARD WELL	014	PRE-ONGARD WELL OPERATOR	6315	Oil	Plugged, Site Released	1/1/1900	1/1/1900
199	30-015-22569	14	18S	27E	560	2588	EMPIRE ABO UNIT #152B	152B	BP AMERICA PROD. CO.	6300	Oil	Plugged, Site Released	11/1/1978	10/2/2008
200	30-015-00868	14	18S	27E	660	1980	EMPIRE ABO UNIT #015C	015C	BP AMERICA PROD. CO.	6260	Oil	Plugged, Site Released	4/6/1958	7/16/2004
201	30-015-22568	14	18S	27E	400	1450	EMPIRE ABO UNIT #151B	151B	BP AMERICA PROD. CO.	6310	Oil	Plugged, Site Released	3/1/1979	8/16/2006
202	30-015-22838	14	18S	27E	200	1925	EMPIRE ABO UNIT	153B	BP AMERICA PROD. CO.	6225	Oil	Plugged, Site Released	5/6/1979	12/22/2008
203	30-015-00869	14	18S	27E	330	653	EMPIRE ABO UNIT #016C	016C	BP AMERICA PROD. CO.	6225	Oil	Plugged, Site Released	6/30/1959	1/24/2007
204	30-015-21807	2	18S	27E	275	1243	EMPIRE ABO UNIT	132	BP AMERICA PROD. CO.	6200	Oil	Plugged, Site Released	12/31/9999	6/22/2009
205	30-015-22608	2	18S	27E	100	1950	EMPIRE ABO UNIT #142	142	BP AMERICA PROD. CO.	6200	Oil	Plugged, Site Released	4/1/1979	9/9/2009
206	30-015-22013	2	18S	27E	90	1456	EMPIRE ABO UNIT #153	153	BP AMERICA PROD. CO.	6303	Oil	Plugged, Site Released	6/1/1977	10/30/2008
207	30-015-21825	2	18S	27E	320	2602	EMPIRE ABO UNIT #152	152	APACHE CORP	6335	Oil	Plugged, Site Released	7/1/1976	12/27/2011
208	30-015-22808	2	18S	27E	600	1330	EMPIRE ABO UNIT #156	156	BP AMERICA PROD. CO.	6225	Oil	Plugged, Site Released	5/1/1979	10/7/2009
209	30-015-00722	2	18S	27E	660	660	EMPIRE ABO UNIT	016A	BP AMERICA PROD. CO.	6114	Oil	Plugged, Site Released	12/12/1958	2/23/2009
210	30-015-00731	2	18S	27E	660	1980	EMPIRE ABO UNIT	015A	BP AMERICA PROD. CO.	6135	Oil	Plugged, Site Released	10/9/1958	2/12/2009

TABLE 1A

NON-FRESHWATER (OIL AND GAS) ARTIFICIAL PENETRATIONS IN AREA OF REVIEW
WDW-1, WDW-2, AND WDW-3
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

ID NO	API	Sect	TWP	RNG	NS FTG	EW FTG	WELL NAME	WELL NUMBER	OPERATOR	TOTAL DEPTH (FT)	WELL TYPE	WELL STATUS	DRILLL DATE	PLUG DATE
211	30-015-00730	2	18S	27E	660	1980	EMPIRE ABO UNIT	014	APACHE CORP	6152	Oil	Active	9/22/1958	NA
212	30-015-22669	2	18S	27E	800	2500	EMPIRE ABO UNIT #154	154	BP AMERICA PROD. CO.	6200	Oil	Plugged, Site Released	1/1/1979	6/30/2009
213	30-015-22885	2	18S	27E	1040	2025	EMPIRE ABO UNIT #155	155	APACHE CORP	6202	Oil	Plugged, Site Released	6/1/1979	1/3/2012
214	30-015-21544	2	18S	27E	1100	1322	EMPIRE ABO UNIT #151	151	APACHE CORP	6285	Oil	Plugged, Site Released	5/19/1975	1/6/2012
215	30-015-22914	2	18S	27E	1310	590	EMPIRE ABO UNIT #161	161	APACHE CORP	6225	Oil	Active	6/21/1979	NA
216	30-015-22051	2	18S	27E	1370	2445	EMPIRE ABO UNIT #141A	141A	APACHE CORP	6203	Oil	Plugged, Site Released	6/1/1977	12/21/2011
217	30-015-22609	2	18S	27E	1200	1900	EMPIRE ABO UNIT #212	143	APACHE CORP	6093	Oil	Active		NA
218	30-015-22896	2	18S	27E	1820	2550	EMPIRE ABO UNIT #143A	143A	APACHE CORP	6108	Oil	Active	4/16/1979	NA
219	30-015-00716	2	18S	27E	1980	1830	EMPIRE ABO UNIT #015	015	APACHE CORP	6100	Oil	Active	2/11/1959	NA
220	30-015-32946	2	18S	27E	2210	1650	SCBP STATE #1	001	APACHE CORP	3880	Oil	Active	3/14/2005	NA
221	30-015-35814	2	18S	27E	2063	441	STATE H NO 2	002	MACK ENERGY CORP	7545	Oil	Active	10/31/2007	NA
222	30-015-00704	1	18S	27E	1980	660	PRE-ONGARD WELL #017	017	PRE-ONGARD WELL OPERATOR	5960	Oil	Plugged, Site Released	1/1/1900	1/1/1900
223	30-015-00706	1	18S	27E	2310	1980	EMPIRE ABO UNIT #018A	018A	APACHE CORP	6087	Oil	Active	4/24/1959	NA
224	30-015-34071	1	18S	27E	2169	1963	AAO FEDERAL #006	006	APACHE CORP	3977	Oil	Active	7/6/2005	NA
225	30-015-21552	1	18S	27E	2500	2500	EMPIRE ABO UNIT #191	191	APACHE CORP	6259	Oil	Active	7/23/2013	9/1/1975
226	30-015-22657	1	18S	27E	2490	2200	EMPIRE ABO UNIT #193	193	APACHE CORP	6225	Oil	Active	9/29/1978	NA
227	30-015-36281	1	18S	27E	2193	1520	SUN DEVILS FEDERAL	001	MACK ENERGY CORP	6016	Oil	Cancelled Apd	NA	NA
228	30-015-22560	1	18S	27E	220	1390	EMPIRE ABO UNIT #192	192	APACHE CORP	6250	Oil	Active	5/30/1978	NA
229	30-015-00696	1	18S	27E	1980	1980	EMPIRE ABO UNIT #019Q	19Q	APACHE CORP	6,180	Oil	Plugged, Site Released	7/24/1959	7/12/2013
230	30-015-27163	1	18S	27E	1980	990	CHALK BLUFF FEDERAL #003	COM 003	MEWBOURNE OIL CO.	10,150	Gas	Active	5/10/1981	NA
231	30-015-21873	1	18S	27E	1526	1470	EMPIRE ABO UNIT #191A	191A	APACHE CORP	6350	Oil	Approved Temporary Abandonment	8/27/1976	NA
232	30-015-00699	1	18S	27E	940	330	EMPIRE ABO UNIT #020B	020B	APACHE CORP	6250	Oil	Active	11/16/1961	NA
233	30-015-22658	1	18S	27E	1500	2130	EMPIRE ABO UNIT #194	194	APACHE CORP	6325	Oil	Active	10/18/1978	NA
234	30-015-00717	2	18S	27E	1980	660	EMPIRE ABO UNIT #016	016	APACHE CORP	6100	Oil	Active	3/30/1959	NA
235	30-015-34576	1	18S	27E	2060	2160	AAO FEDERAL #010	010	APACHE CORP	4000	Oil	Active	6/2/2006	NA
236	30-015-22559	1	18S	27E	2290	2445	EMPIRE ABO UNIT #184	184	APACHE CORP	6200	Oil	Plugged, Site Released	2/1/1979	7/18/2013
237	30-015-20394	1	18S	27E	953	2197	Russell USA #045	019	PRE-ONGARD WELL OPERATOR	870	Oil	Plugged, Site Released	1/1/1900	8/12/2013
238	30-015-00698	1	18S	27E	660	1980	EMPIRE ABO UNIT	191	ARCO PERMIAN	6365	SWD	Plugged, Site Released	10/7/1959	12/8/1989
239	30-015-26575	1	18S	27E	790	2250	WDW #003	003	NAVAJO REFINING	10,119	Injection	Active	12/22/1990	NA
240	30-015-34998	1	18S	27E	890	1650	AAO FEDERAL #012	012	APACHE CORP	4075	Oil	Active	8/13/2006	NA
241	30-015-00713	1	18S	27E	995	1644	EMPIRE ABO UNIT #018D	018D	BP AMERICA PROD. CO.	6174	Oil	Plugged, Site Released	10/28/1959	9/27/2003
242	30-015-21792	1	18S	27E	1533	2370	EMPIRE ABO UNIT #182	182	APACHE CORP	6369	Oil	Active	5/6/1976	NA
243	30-015-00707	1	18S	27E	1980	1980	EMPIRE ABO UNIT #018B	018B	APACHE CORP	6163	Oil	Active	4/23/1959	NA
244	30-015-22096	1	18S	27E	2370	1510	EMPIRE ABO UNIT #183	183	APACHE CORP	6210	Oil	Active	6/23/1977	NA
245	30-015-21554	1	18S	27E	1367	1440	EMPIRE ABO UNIT #181	181	BP AMERICA PROD. CO.	6137	Oil	Plugged, Site Released	11/1/1975	4/17/2003
246	30-015-00703	1	18S	27E	1980	660	EMPIRE ABO UNIT #017A	017A	BP AMERICA PROD. CO.	7705	Oil	Plugged, Site Released	2/16/1959	3/19/2009
247	30-015-34387	1	18S	27E	1980	630	AAO FEDERAL #009	009	APACHE CORP	3950	Oil	Active	11/7/2005	NA
248	30-015-00695	1	18S	27E	1650	330	PRE-ONGARD WELL	001	PRE-ONGARD WELL OPERATOR	1763	Oil	Plugged, Site Released	1/1/1900	1/1/1901
249	30-015-00705	1	18S	27E	990	660	EMPIRE ABO UNIT #017B	017B	BP AMERICA PROD. CO.	6150	Oil	Plugged, Site Released	3/24/1959	7/21/2004
250	30-015-34555	1	18S	27E	890	660	AAO FEDERAL #011	011	APACHE CORP	4100	Oil	Active	2/15/2006	NA
251	30-015-22815	1	18S	27E	670	330	EMPIRE ABO UNIT #171	171	APACHE CORP	6300	Oil	Active	5/22/1979	NA
252	30-015-00745	2	18S	27E	1980	660	STATE H #001	001	MACK ENERGY CORP	5962	Oil	Plugged, Site Released	12/22/1958	3/7/2008
253	30-015-27538	11	18S	27E	990	660	PRE-ONGARD WELL	001	PRE-ONGARD WELL OPERATOR	NR	Oil	Cancelled Apd	12/31/9999	NA
254	30-015-00662	36	17S	27E	330S	330W	STATE NO. 2		ACREY, B L & F D	600	O	P&A	10/15/1942	10/15/1942
255	30-015-00676	36	17S	27E	330N	990W	EMPIRE ABO UNIT #017		LIME ROCK RESOURCES A, L.P.	5797	O	Active	?	NA
256	30-015-00697	1	18S	27E	1980S	660E	EMPIRE ABO UNIT #020K		BP AMERICA PRODUCTION COMPANY	6185	O	P&A	1/5/2003	1/5/2003
257	30-015-00709	1	18S	27E	1980N	1980E	EMPIRE ABO UNIT #019C		ALAMO PERMIAN RESOURCES, LLC	6205	O	Active	8/2/1959	NA
258	30-015-00710	1	18S	27E	660N	1980W	AAO FEDERAL No. 013		ALAMO PERMIAN RESOURCES, LLC	6200	O	Active	7/21/2004	NA
259	30-015-00712	1	18S	27E	647N	667W	EMPIRE ABO UNIT I NO. 17		ARCO OIL & GAS	5902	O	P&A	1/24/1987	1/24/1987
260	30-015-00715	1	18S	27E	330N	330W	SOUTH RED LAKE GRAYBURG UNIT #037		LEGACY RESERVES OPERATING LP	1820	I	Active	?	NA
261	30-015-00718	2	18S	27E	330S	610W	PRE-ONGARD WELL #2		PRE-ONGARD WELL OPERATOR	512	O	P&A	?	NA
262	30-015-00720	2	18S	27E	990N	1650E	RIVERWOLF UNIT #004		BP AMERICA PRODUCTION COMPANY	5881	O	P&A	10/21/1959	12/12/2008
263	30-015-00721	2	18S	27E	330N	990E	SOUTH RED LAKE GRAYBURG UNIT #036		FAIRWAY RESOURCES OPERATING LLC	1705	O	P&A	11/6/1947	NA
264	30-015-00724	2	18S	27E	990N	330E	EMPIRE ABO UNIT #016B		LIME ROCK RESOURCES A, L.P.	5920	O	Active	?	NA
265	30-015-00737	2	18S	27E	905N	1601E	SOUTH RED LAKE GRAYBURG UNIT #038		FAIRWAY RESOURCES OPERATING LLC	1685	O	Active	5/23/1948	NA
266	30-015-00740	2	18S	27E	1650N	2197E	SOUTH RED LAKE GRAYBURG UNIT #040		MCQUADRANGLE, LC	5884	I	P&A	7/10/2002	7/10/2002
267	30-015-00741	2	18S	27E	2310N	1980E	EMPIRE ABO UNIT #015B		APACHE CORPORATION	5884	O	Active	6/6/1959	NA
268	30-015-00742	2	18S	27E	1650N	990E	SOUTH RED LAKE GRAYBURG UNIT 39 WIW		S&J OPERATING COMPANY	1741	O	P&A	2/8/1991	2/8/1991
269	30-015-00744	2	18S	27E	2310S	1640E	STATE 1		COMPTON-SMITH	5962	O	P&A	?	NA
270	30-015-01218	36	17S	27E	330S	2310W	EMPIRE ABO UNIT #018		BP AMERICA PRODUCTION COMPANY	6849	O	P&A	3/11/2009	3/11/2009
271	30-015-02627	6	18S	28E	949S	990W	STATE M-AI #002		RUTH OIL CO, LLC	6225	O	Active	10/21/1960	NA
272	30-015-10184	36	17S	27E	330S	920W	STATE #006		ASPEN OIL INC	1343	O	Active	?	NA
273	30-015-21623	36	17S	27E	360S	455W	STATE #007		GEORGE A CHASE JR & C SERVICE	1366	O	Active	?	NA
274	30-015-21783	1	18S	27E	2490N	1299E	EMPIRE ABO UNIT #202		ALAMO PERMIAN RESOURCES, LLC	6296	O	Active	5/13/1976	NA
275	30-015-22816	1	18S	27E	1120S	1440E	EMPIRE ABO UNIT L #192		ARCO OIL & GAS	6350	O	ABANDONED	6/28/1980	6/23/1980
276	30-015-25675	7	18S	28E	940N	1757W	LAUREL STATE #002		EASTLAND OIL CO	1690	O	Active	11/10/1988	NA
277	30-015-25997	7	18S	28E	940N	1757W	LAUREL STATE #001		EASTLAND OIL CO	1690	O	Active	2/23/1987	NA
278	30-015-26741	1	18S	27E	1650N	1350W	CHALK BLUFF FEDERAL COM #002		MEWBOURNE OIL CO	10140	G	Active	8/24/1991	NA
279	30-015-26943	6	18S	28E	990S	730W	CHALK BLUFF 6 STATE #001		MEWBOURNE OIL CO	10200	G	Active	4/16/1992	NA
280	30-015-27286	36	17S	27E	660S	990W	CHALK BLUFF 36 STATE #001		MEWBOURNE OIL CO	10060	O	Active	3/30/1993	NA

TABLE 1A

NON-FRESHWATER (OIL AND GAS) ARTIFICIAL PENETRATIONS IN AREA OF REVIEW
WDW-1, WDW-2, AND WDW-3
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

ID NO	API	Sect	TWP	RNG	NS FTG	EW FTG	WELL NAME	WELL NUMBER	OPERATOR	TOTAL DEPTH (FT)	WELL TYPE	WELL STATUS	DRILLL DATE	PLUG DATE
281	30-015-31087	6	18S	28E	990S	330W	LP STATE #003		MARBOB ENERGY CORP	446	O	P&A	7/15/2000	3/17/2008
282	30-015-31592	36	17S	27E	330S	2310E	RAMAPO #007		ROJO GRANDE COMPANY LLC	612	O	P&A	12/21/2001	12/21/2001
283	30-015-32307	1	18S	27E	330N	990W	AAO FEDERAL #001		APACHE CORPORATION	3851	O	Active	12/10/2002	NA
284	30-015-32308	1	18S	27E	430N	2310W	AAO FEDERAL #002		APACHE CORPORATION	4150	O	Active	9/19/2002	NA
285	30-015-40429	36	17S	27E	492	806W	Big Boy State #004	4	COG Operating LLC	5015	O	Active	8/28/2014	NA
286	30-015-32959	1	18S	27E	1650N	875W	AAO FEDERAL #005		APACHE CORPORATION	3900	O	Active	10/12/2004	NA
287	30-015-39899	1	18S	27E	1305N	2535W	EMPIRE ABO UNIT #016		APACHE CORPORATION	6300	O	Cancelled Apd	NA	NA
288	30-015-39900	1	18S	27E	1120N	1205W	EMPIRE ABO UNIT #016		APACHE CORPORATION	6300	O	Cancelled Apd	NA	NA
289	30-015-00701	1	18S	27E	330N	330W	SOUTH RED LAKE GRAYBURG UNIT 37 WIW		FAIRWAY RESOURCES OPERATING LLC	NA	O	Plugged, Site Released	NA	NA
290	30-015-02608	5	18S	28E	1660N	330W	State E AI #001	1	Conoco Phillips Co	6265	O	Plugged, Site Released	3/1/1960	1/13/2006
291	30-015-40428	36	17S	27E	200S	485W	Big Boy State #002	2	COG Operating LLC	4990	O	Active	4/27/2013	NA
292	30-015-37045	32	17S	28E	1563S	2207E	Jeffers 32 State #002	2	Vanguard Operating, LLC	5130	O	Active	7/29/2010	NA
293	30-015-32028	2	22S	31E	990S	330W	Flora AKF State #004	4	EOG Y Resources, Inc.	8350	O	Active	11/20/2002	NA
294	30-015-34028	6	18S	28E	2285N	1366E	Slider 6 State #001	1	BP America Production Co	10374	O	Plugged, Site Released	6/19/2005	12/23/2008

(ft) - Feet
? - Data Not Available
Map ID No. - Refer to Drawing 2
N/A - Not Applicable
Well Type - O=Oil, I=Injection, G=Gas

TABLE 1B

NON-FRESHWATER (OIL AND GAS) WELLS IN AREA OF REVIEW PENETRATING TOP OF INJECTION ZONE
WDW-1, WDW-2, AND WDW-3
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

ID NO	API	Sect	TWP	RNG	NS FTG	EW FTG	WELL NAME	WELL NUMBER	OPERATOR	TOTAL DEPTH (FT)	WELL TYPE	WELL STATUS	DRILLL DATE	PLUG DATE
12	30-015-31123	36	17S	27E	1980	760	No Bluff State Comm #002	2	LRE Operating, LLC	10,050	G	Active	3/19/2001	NA
76	30-015-25522	5	18S	28E	2240	400	Walter Solt State #001	1	WALTER SOLT LLC	8,500	SWD	Active	1/9/1986	NA
78	30-015-24485	5	18S	28E	1980	990	Illinois Camp A Com #001	1	Conoco Phillips Co	10,450	G	Active	5/28/1983	NA
151	**30-015-27592**	**31**	**17S**	**28E**	**660**	**2310**	**WDW-1**	**1**	**NAVAJO REFINING**	**10,200**	**I**	**Active**	**34185**	**NA**
166	30-015-26404	12	18S	27E	660	990	FEDERAL T SWD	#001	LIME ROCK RESOURCES II-A, L.P.	10,141	Salt Water Disposal	Active	6/28/1990	NA
167	**30-015-20894**	**12**	**18S**	**27E**	**1980**	**660**	**WDW-2**	**2**	**NAVAJO REFINING CO. PIPELINE DIV**	**10,372**	**Injection**	**Active**	**5/5/1999**	**NA**
191	30-015-40187	14	18S	27E	660	990	VIOLET BIV STATE COM	001	YATES PETROLEUM CORP	10,500	Gas	Cancelled Apd	4/18/2012	NA
192	30-015-36939	14	18S	27E	661	991	VIOLET BIV STATE COM	001C	YATES PETROLEUM CORP	10,500	Gas	Cancelled Apd	2/20/2009	NA
193	30-015-00870	14	18S	27E	1980	1980	PRE-ONGARD WELL	001	PRE-ONGARD WELL OPERATOR	7,270	Oil	Plugged, Site Released	1/1/1900	1/1/1900
196	30-015-20510	14	18S	27E	1650	1653	PRE-ONGARD WELL	001	PRE-ONGARD WELL OPERATOR	10,168	Oil	Plugged, Site Released	1/1/1900	1/1/1900
221	30-015-35814	2	18S	27E	2063	441	STATE H NO 2	002	MACK ENERGY CORP	7,545	Oil	Active	10/31/2007	NA
230	30-015-27163	1	18S	27E	1980	990	CHALK BLUFF FEDERAL #003	COM 003	MEWBOURNE OIL CO.	10,150	Gas	Active	5/10/1981	NA
239	**30-015-26575**	**1**	**18S**	**27E**	**790**	**2250**	**WDW-3**	**3**	**NAVAJO REFINING**	**10,119**	**Injection**	**Active**	**5/5/1999**	**NA**
246	30-015-00703	1	18S	27E	1980	660	EMPIRE ABO UNIT #017A	017A	BP AMERICA PROD. CO.	7,705	Oil	Plugged, Site Released	2/16/1959	3/19/2009
278	30-015-26741	1	18S	27E	1650N	1350W	CHALK BLUFF FEDERAL COM #002	COM 002	MEWBOURNE OIL CO	10,140	G	Active	8/24/1991	NA
279	30-015-26943	6	18S	28E	990S	730W	CHALK BLUFF 6 STATE #001	1	MEWBOURNE OIL CO	10,200	G	Active	4/16/1992	NA
280	30-015-27286	36	17S	27E	660S	990W	CHALK BLUFF 36 STATE #001	1	MEWBOURNE OIL CO	10,060	O	Active	3/30/1993	NA

Map ID No. - Refer to Drawing 2
Well Type - O=Oil, I=Injection, G=Gas
(ft) - Feet
N/A - Not Applicable
? - Data Not Available

TABLE 2
INJECTION FLUID CHARACTERIZATION DATA
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

	Feb 2011	May 2011	Aug 2011	Nov 2011	Feb 2012	May 2012	Sept 2012	Nov 2012	Mar 2013
Metals									
Aluminum	6.0	0.438	0.625	0.752	1.87	0.394	1.11	4.04	1.34
Arsenic	0.0557	0.0198	0.0207	0.0365	0.141	0.0791	0.0468	0.070	0.0404
Barium	0.0590	0.0541	0.0796	0.0182	0.0282	0.0202	0.0182	0.0599	0.0860
Boron	0.216	0.353	0.276	0.243	0.335	0.238	0.253	0.286	0.722
Cadmium	<0.002	<0.002	<0.002	<0.002	<0.002	<0.002	<0.002	<0.004	<0.004
Chromium	0.00562	<0.005	<0.005	<0.005	0.00598	<0.005	<0.005	<0.010	<0.010
Copper	0.0265	0.00715	0.00709	<0.005	0.0117	<0.005	0.0108	0.018	<0.010
Lead	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.010	<0.010
Manganese	0.0940	0.0239	0.0559	0.0213	0.0555	0.0524	0.0329	0.0669	<0.832
Mercury	<0.0002	<0.0002	<0.0002	<0.0002	<0.0002	<0.0002	<0.002	<0.0002	<0.0002
Molybdenum	0.202	0.168	0.145	0.0443	0.0987	0.154	0.243	0.255	0.182
Nickel	0.0141	0.00605	0.00767	<0.005	0.106	0.0122	0.0112	0.0109	0.0153
Selenium	0.382	0.646	0.465	0.99	0.312	0.690	1.00	0.842	0.924
Silver	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.010	<0.010
Zinc	1.42	0.0884	0.0983	0.012	0.0746	0.0402	0.0560	0.0836	0.0737

All concentrations reported in milligrams per liter (mg/L).
< Less than.

TABLE 2
INJECTION FLUID CHARACTERIZATION DATA
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NM

	Feb 2011	May 2011	Aug 2011	Nov 2011	Feb 2012	May 2012	Sept 2012	Nov 2012	Mar 2013
Volatiles									
1,1,1-Trichloroethane	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005
1,1,2,2-Tetrachloroethane	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005
1,1,2-Trichloroethane	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005
1,1-Dichloroethane	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005
1,1-Dichloroethene	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005
1,2-Dichloroethane	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005
2-Butanone	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010	NA	<0.010	<0.010
2-Chloroethyl vinty ether	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010	NA	<0.010	<0.010
2-Hexanone	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010	NA	<0.010	<0.010
4-Methyl-2-pentanone	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010	NA	<0.010	<0.010
Acetone	0.025	<0.010	<0.010	0.200	0.120	<0.010	NA	<0.055	0.016
Benzene	<0.005	<0.005	<0.005	0.200	<0.005	<0.005	<0.005	<0.005	<0.005
Bromodichloromethane	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Bromoform	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Bromomethane	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Carbon disulfide	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010	NA	<0.010	<0.010
Carbon tetrachloride	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Chlorobenzene	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Chloroethane	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Chloroform	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005
Chloromethane	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	NA	<0.005	<0.005
cis-1,3-Dichloropropene	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Dibromochloromethane	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Ethylbenzene	<0.005	<0.005	<0.005	0.190	<0.005	<0.005	<0.005	<0.005	<0.005
m,p-Xylene	<0.010	<0.010	<0.010	0.360	<0.010	<0.010	NA	<0.010	<0.010
Methylene chloride	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010	<0.005	<0.010	<0.010
Styrene	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Tetrachloroethene	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005
Toluene	<0.005	<0.005	<0.005	0.510	<0.005	<0.005	<0.005	<0.005	<0.005
trans-1,3-Dichloropropene	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Trichloroethene	<0.005	<0.005	<0.005	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Vinyl acetate	<0.010	<0.010	<0.010	<0.010	<0.010	<0.010	NA	<0.010	<0.010
Vinyl chloride	<0.002	<0.002	<0.002	<0.002	<0.002	<0.002	<0.002	<0.002	<0.002
Xylenes, Total	<0.015	<0.015	<0.015	0.560	<0.015	<0.015	<0.015	<0.015	<0.015

All concentrations reported in milligrams per liter (mg/L).
< Less Than.
NA Not Analyzed.

TABLE 2
INJECTION FLUID CHARACTERIZATION DATA
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

	Feb 2011	May 2011	Aug 2011	Nov 2011	Feb 2012	May 2012	Sept 2012	Nov 2012	Mar 2013
Semivolatiles									
1,2,4-Trichlorobenzene	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
2,4,5-Trichlorophenol	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
2,4,6-Trichlorophenol	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
2,4-Dinitrotoluene	NA	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
2-Methylnaphthalene	<0.025	<0.005	<0.050	0.040	<0.005	<0.005	<0.0002	<0.005	<0.005
2-Methylphenol	<0.025	<0.005	<0.050	0.29	<0.005	<0.005	NA	<0.005	<0.005
2-Nitroaniline	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
3&4-Methylphenol	<0.025	<0.005	<0.050	0.52	<0.005	<0.005	NA	<0.005	<0.005
3-Nitroaniline	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
4-Nitroaniline	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
4-Nitrophenol	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Acenaphthene	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Acenaphthylene	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Aniline	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Anthracene	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Benz(a)anthracene	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	<0.0002	<0.005	<0.005
Benzidine	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Hexachlororthane	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Indeno(1,2,3-cd)pyrene	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Isophorone	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Naphthalene	<0.025	<0.005	<0.050	0.038	<0.005	<0.005	<0.0002	<0.005	<0.005
Nitrobenzene	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
N-Nitrosodimethylylamine	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
N-Nitosodi-n-propylamine	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
N-Nitrosodiphenylamine	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Pentachlorophenol	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Phenanthrene	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Phenol	<0.025	<0.005	<0.050	0.99	<0.005	<0.005	NA	0.013	0.013
Pyrene	<0.025	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005
Pyridine	NA	<0.005	<0.050	<0.005	<0.005	<0.005	NA	<0.005	<0.005

All concentrations reported in milligrams per liter.
< Less Than.
NA Not Analyzed.

TABLE 2
INJECTION FLUID CHARACTERIZATION DATA
HOLLYFRONTIER NAVAJO REFINING LLC
ARTESIA, NEW MEXICO

	Feb 2011	May 2011	Aug 2011	Nov 2011	Feb 2012	May 2012	Sept 2012	Nov 2012	Mar 2013
Miscellaneous									
Reactive Cyanide (mg/Kg)	<40.0	<40.0	<40.0	<40.0	<40.0	<40.0	<40.0	<40.0	<40.0
Reactive Sulfide (mg/Kg)	<40.0	<40.0	<40.0	<40.0	<40.0	<40.0	<40.0	<40.0	<40.0
Chloride (mg/L)	410	213	404	332	519	646	458	401	647
Sulfate (mg/L)	1,510	2,240	2,290	2,350	1,870	2,220	3,460	2,580	2,630
Alkalinity (Total) (mg/L)	441	243	302	217	466	175	284	239	366
Sp. Cond. (umhos/cm)	6,270	4,680	7,380	5,430	5,990	6,650	8,370	6,680	8,110
Ignitability (°F)	>212	>212	>212	>212	>212	>212	>212	>212	>212
pH (S.U.)	7.40	7.85	8.11	7.52	7.30	6.76	7.33	7.63	7.98
TDS (mg/L)	3,310	3,400	4,320	4,840	3,890	3,100(1)	6,140	4,780	5,500

mg/Kg	Milligrams per kilogram.
mg/L	Milligrams per liter.
umhos/cm	Micromhos per centimeter.
°F	Degrees Fahrenheit.
S.U.	Standard Units.
>	Greater than.
<	Less than.
(1)	TDS Sample collected in July 2012.

TABLE OF CONTENTS

TABLES

FIGURES

DRAWINGS

APPENDICES

INTRODUCTION

HollyFrontier Navajo Refining LLC (Navajo), located in Artesia, New Mexico, is applying to renew the discharge permits for Class I Non-hazardous Waste Disposal Well No. 1 (WDW-1), Waste Disposal Well No. 2 (WDW-2), and Waste Disposal Well No. 3 (WDW-3) which is located approximately ten (10) miles to the southeast of the refinery. WDW-1, WDW-2, and WDW-3 were initially permitted by the Oil Conservation Division (OCD) of the New Mexico Energy, Minerals and Natural Resources Department under the Water Quality Act in 1998 and have been operating under Permits UIC-CLI-008-1, UIC-CLI-008-2, and UIC-CLI-008-3.

The Navajo refinery is located at 501 East Main Street in Artesia, Eddy County, New Mexico. The three Class I nonhazardous waste injection wells operated by the refinery are designated WDW-1, WDW-2 and WDW-3. All three wells are permitted to inject nonhazardous waste water into a subsurface Injection Zone consisting of the lower portion of the Wolfcamp Formation and the underlying Cisco and Canyon Formations. The depth and thickness of the Injection Zone at the three Navajo refinery injection wells are as follows:

- WDW-1: 7,450 to 9,016 ft KB
- WDW-2: 7,270 to 8,894 ft KB
- WDW-3: 7,303 to 8,894 ft KB

Please note that the three Navajo injection wells were previously permitted separately coinciding with the life of the regulatory permit issued for each well. These Discharge Permits will expire on June 1, 2017. One technical report has been prepared along with three separate application forms for each of the wells.

Information concerning the locations of oil and gas wells and freshwater wells within the regulatory 1-mile radius area of review (AOR) surrounding the wells were obtained from OCD and New Mexico Water Rights Reporting System, respectively. No corrective action is needed for any of the artificial penetrations within the 1-mile radius AOR.

The regional and local geology have been evaluated, and no problems have been identified that will cause adverse effects as a result of the ongoing injection operations.

Reservoir characteristics of the Injection Zone indicate the reservoir has sufficient properties to accommodate the historical and planned future injection rate, volume and pressure from the three Navajo injection wells. Based on information gathered from the Navajo refinery injection well system, there are no adverse reactions identified with the waste stream and the well components of construction and the Injection Zone matrix and formation fluid.

WDW-1, WDW-2, and WDW-3 meet the construction and operating standards set forth in 20.6.2.5205 NMAC. A procedure to permanently plug and abandon the wells have been included per the requirements of 20.6.2.5209 NMAC.

1.0 Underground Injection Control Well Class

The Navajo refinery Waste Disposal Wells WDW-1, WDW-2, and WDW-3 are classified as Class I Non-Hazardous Waste Injection Wells.

2.0 Operator

The operator information for WDW-1, WDW-2, and WDW-3 is provided below:

Facility Address

HollyFrontier Navajo Refining LLC

501 East Main

Artesia, New Mexico 88210

(575) 748-3310

Contact Person

Randy Dade, Environmental Specialist

(575) 746-5281

Lewis.Dade@hollyfrontier.com

3.0 Location

WDW-1 (API No. 30-015-27592) is located 660 feet from the south line and 2,310 feet from the east line of SW/4, SE/4, Section 31, Township 17 South, Range 28 East, Latitude 32°47'6.77"N, Longitude 104°12'50.22"W, in Eddy County, New Mexico.

WDW-2 (API No. 30-015-20894) is located 1,980 feet from the north line and 660 feet from the west line of SW/4, NW/4, Section 12, Township 18 South, Range 27 East, Latitude 32°45'49.32"N, Longitude 104°14'18.59"W, in Eddy County, New Mexico.

WDW-3 is located 790 feet from the south line and 2,250 feet from the west line of SE/4, SW/4, Section 1, Township 18 South, Range 27 East, Latitude 32°46'16.51"N, Longitude 104°13'59.80"W, in Eddy County, New Mexico.

A topographic map showing the location of the Navajo refinery, WDW-1, WDW-2, and WDW-3 is provided as Figure 1. An enlarged version of the topographic map showing the locations of the wells is provided as Figure 2.

4.0 Landowner(s)

The parcel of land where WDW-1 is located is owned by the following:

HollyFrontier Navajo Refining LLC

501 E. Main Street

Artesia, New Mexico 88210

(575) 748-3311

The parcels of land where WDW-2 and WDW-3 are located are owned by the following:

U.S. Department of the Interior

Bureau of Land Management

620 Greene Street

Carlsbad, New Mexico 88220

(575) 887-6544

The parcels of land (Appendix A) where the wells are located are surrounded by state owned, privately owned, and Bureau of Land Management owned land.

5.0 Facility Description

The Class I non-hazardous injection wells WDW-1 and WDW-2 are located approximately 10 miles southeast of the Navajo refinery, and WDW-3 is located approximately 14 miles east of the Navajo refinery, the largest refinery in New Mexico. Drawing 1 presents an aerial photograph of the refinery's location with respect to the wellhead facilities, identifying pertinent features between the sites. The wellhead facilities are located within fenced areas that enclose the well, injection pumps, filters and piping, wellhead annulus monitoring systems (WAMS) on contained concrete pads, and power panels. The pumps and filters are located on a separate, contained concrete pad. No buildings or tanks, other than the 250 gallon glycol tank, are associated with the WAMS units.

6.0 Proposed Discharge Plan (see 20.6.2.3106C NMAC)

This permit renewal application is for three existing Class I Non-Hazardous waste injection wells. Those portions of 20.6.2.3106.C NMAC that are relevant to underground injection, especially 20.6.2.3103.C(8) NMAC, are addressed in Section 7.0 of this document.

- 6(a) is addressed in 7(f)
- 6(b) is addressed in 7(a)
- 6(c) is addressed in 7(d)
- 6(d) is addressed in 7(e)
- 6(e) measurement of flow is determined by a flow meter at each wellhead, with information transmitted electronically to the refinery control room
- 6(f) is addressed in 7(e)
- 6(g) is addressed in 7(e)

7.0 Information for Class I Non-Hazardous Waste Injection Wells and Class III Brine Wells (20.6.2.5210 NMAC)

The following sections present the information required in Subsection B of Section 20.6.2.5210 NMAC.

7 (a) Area of Review

The Area of Review (AOR) consists of a composite area within a 1-mile radius surrounding each well as shown on Drawing 2. Potential sources of information relevant to the locations of non-freshwater artificial penetrations of the injection zone and freshwater wells within the AOR were reviewed.

Non-Freshwater Artificial Penetrations in Area of Review

The locations of non-freshwater artificial penetrations (oil and gas wells, exploratory tests, disposal wells, etc.) within the composite 1-mile radius AOR surrounding WDW-1, WDW-2, and WDW-3 are identified in Drawing 2. A total of 294 non-freshwater artificial penetrations are present.

Each artificial penetration is identified by a Map ID number. Table 1A lists information about non-freshwater artificial penetrations in the AOR.

Of the 294 non-freshwater artificial penetrations identified within the composite AOR, a total of 17 wells were advanced to a depth to penetrate the top of the Injection Zone. Table 1B presents a listing of these wells. Appendix B contains NMOCD well records and constructions schematics for these non-freshwater artificial penetrations.

Freshwater Wells in Area of Review

Based upon information obtained from records maintained by the New Mexico Water Rights Reporting System, no freshwater wells exist within the AOR surrounding WDW-1, WDW-2, or WDW-3.

Drawing 3 presents a topographic map depicting the composite 1-mile radius AOR. The map illustrates surface bodies of water, mines (surface and subsurface), quarries, springs, and other surface features, including roads and residences. No subsurface faults in the AOR are known to have surface expression; therefore, no surface fault traces have been included on this map.

7 (b) Data Tabulation

Table 1A presents a tabulation of the non-freshwater artificial penetrations within the AOR. Table 1B presents a listing of wells that penetrate the Injection Zone. Appendix B contains well records and schematics for the non-freshwater artificial penetrations that penetrate the Injection Zone.

7 (c) Corrective Action

The available records for each of the artificial penetrations that penetrate the top of the Injection Zone within the AOR were evaluated to determine if corrective action would be required to prevent movement of fluids into or between Underground Sources of Drinking Water (USDW) that which could be caused by pressures in the Injection Zone. The USDWs are aquifers containing groundwater with total dissolved solids concentration of less than 10,000 milligrams per liter (mg/L). These records are contained in Appendix B.

No corrective actions are warranted because artificial penetration records reviewed for this permit indicate that the wells have been properly constructed, plugged and/or abandoned and they will prevent movement of fluids into or between USDWs, or they are still operating.

7 (d) Maps and Cross-Sections

Figure 3 presents a generalized hydrogeologic cross-section for the local area. Figure 4 presents a published map indicating the direction of shallow groundwater movement in the local area. The base of the USDW observed at each of the wells is shown in the table below.

	WDW-1 (KB = 3,693 ft MSL)		**WDW-2 (KB = 3,623 ft MSL)**		**WDW-3 (KB = 3,625 ft MSL)**	
	Depth KB (ft)	*Depth (ft MSL)*	*Depth KB (ft)*	*Depth (ft MSL)*	*Depth KB (ft)*	*Depth (ft MSL)*
Base of USDW	493	3,200	473	3,151	475	3,150

The top of the Injection Zone is separated from the base of the USDW by several thousand feet of low-permeability carbonates, siltstones, and shale as depicted on the geologic cross-sections presented on Drawings 5, 6 and 7. A map showing the locations of the cross-sections is presented as Drawing 4 (geologic cross-section index map).

7 (e) Geology

The Navajo refinery is located in Eddy County, New Mexico, on the Northwestern Shelf of the larger Permian Basin, as shown on Figure 5. Figure 6 is stratigraphic column presenting the geologic formations relevant to the underground injection operations at the injection well locations. The refinery is located on the southern flank of the Artesia-Vacuum anticline (also referred to as the Vacuum Arch), which trends east to west across the study area as shown Figure 7. Figure 8 is a published regional structural map of the San Andres Formation.

The hree geologic cross-sections presented on Drawings 5, 6, and 7, depict the subsurface geology in the area of the Navajo injection wells. Structural dip of all geologic formations is about 100 feet/mile to the southeast away from the Vacuum Arch depicted on Figure 7.

Injection Zone

The Injection Zone into which all three injection wells at the Navajo refinery are injecting is composed of the lower portion of the Wolfcamp Formation and the underlying Cisco and Canyon Formations. These formations occur in WDW-1, WDW-2, and WDW-3 at the depths shown in the table below.

Injection Zone Formations	**WDW-1 (KB = 3,693 ft MSL)**		**WDW-2 (KB = 3,623 ft MSL)**		**WDW-3 (KB = 3,625 ft MSL)**	
	Depth KB (ft)	*Depth (ft MSL)*	*Depth KB (ft)*	*Depth (ft MSL)*	*Depth KB (ft)*	*Depth (ft MSL)*
Lower Wolfcamp	7,450	3,757	7,270	3,647	7,303	3,678
Cisco	7,816	4,123	7,645	4,022	7,650	4,025
Canyon	8,475	4,782	8,390	4,767	8,390	4,765
Base of Injection Zone (base of Canyon)	9,016	5,323	8,894	5,271	8,894	5,269

The following are brief descriptions of the three geologic formations that form the Injection Zone.

Lower Portion of Wolfcamp Formation (Permian Age)

The lower portion of the Wolfcamp Formation is a light brown to tan, fine to medium grained, fossiliferous limestone with shale interbeds.

Cisco Formation (Pennsylvanian Age)

The Cisco Formation is a uniform, light-colored, chalky, fossiliferous limestone with shale interbeds.

Canyon Formation (Pennsylvanian Age)

The Canyon Formation is a white to tan to light brown fine grained, chalky, fossiliferous limestone with shale interbeds.

Drawing 8 presents a structure contour map of the Injection Zone and Drawing 9 presents an isopach map of the Injection Zone.

Confining Zone

The Confining Zone overlying the Injection Zone, in descending order, is composed of the Yeso Formation, Abo Formation, and the upper portion of the Wolfcamp Formation. The following are brief descriptions of the three geologic formations that form the Confining Zone.

Yeso Formation (Permian Age)

The Yeso Formation consists of orange shale, light gray to white dolostone, and bedded anhydrite.

Abo Formation (Permian Age)

The Abo Formation is a non-marine to marginal marine red shale and fine-grained sandstone interbedded sequence.

Upper Portion of Wolfcamp Formation (Permian Age)

The upper portion of the Wolfcamp Formation is a light brown to tan, fine to medium grained, fossiliferous limestone with shale interbeds.

Drawing 10 presents a structure contour map of the Confining Zone and Drawing 11 presents an isopach map of the Confining Zone.

Faulting

No evidence has been found of any subsurface faulting within or immediately surrounding the AOR that would provide hydraulic connection between the Injection Zone and the shallow USDW. The nearest documented subsurface fault is the “K-M” fault located approximately 17 miles to the northwest, well outside the geologic study area for the Navajo refinery injection wells.

Seismicity

The southeastern portion of New Mexico is historically an area of low seismicity with naturally occurring earthquakes being rare and of low magnitude. The Navajo refinery is located in one of the areas recognized as having the lowest level of seismic risk in the continental United States (Figure 9).

The potential for earthquakes to occur in the vicinity of the Navajo site are minimal. Appendix C presents a listing of all recorded seismic events within 200 miles of the Navajo refinery for the period from 1973 through 2012.

The injection operations at the Navajo refinery do not have the potential to cause any seismic activity which could alter the confining capability of the subsurface Injection Zone and overlying Confining Zone.

Surface Geology and Flooding Potential

The surface geology of the local area is shown on Figure 10. The Pecos River, located about three miles east of Artesia is the only surface water body in the area of the Navajo refinery. Local annual rainfall is approximately 13.5 inches. As indicated on the topographic map on Figure 1, the land surface elevation at the refinery is higher than that near the river; therefore, the potential for flooding at the Navajo refinery is minimal.

7 (f) Proposed Operating Parameters

Source and Description of Injection Fluid

The fluid injected into the Navajo injection wells is comprised of exempt and nonexempt non-hazardous oilfield waste that is generated in the refining process. Waste waters from process units, cooling towers, boilers, streams from water purification units, desalting units, recovered and treated ground water, and general waste waters will be blended to form the fluid to be injected into the injection wells. Table 2 and Appendix D present data characterizing the injection fluid.

Average and Maximum Daily Flow Rate and Volume

The maximum permitted composite injection rate into all three Navajo injection wells is 800 gallons per minute (gpm). This rate of injection is equal to 1,152,000 gallons per day or 420,480,000 gallons per year or 2,102,400,000 gallons into the injection zone over the upcoming 5-year permit time frame per well. The historical daily volumes of fluid injected into the three injection wells are summarized in Appendix E-1.

Average and Maximum Surface Injection Pressure

The average wellhead injection pressure is approximately 817 pounds per square inch gauge (psig) and an estimated bottom-hole pressure of 4,167 pounds per square inch absolute (psia). Appendix E-1 includes a tabulation of historical injection rates and associated surface injection pressures.

Maximum Allowable Surface Injection Pressure (MASIP) Calculation

As required by the New Mexico Oil Conservation Division (NMOCD) Proposed Rule 21.B(7), dated October 6, 1997, the maximum operating injection wellhead pressure (MASIP) will not exceed:

- 1,585 psi or 0.2 psi per foot of depth to the top of the injection zone at 7,924 feet in WDW-1; MASIP =7,924 feet x 0.2 psi/ft = 1,585 psi
- 1,514 psi or 0.2 psi per foot of depth to the top of the Injection Zone at 7,570 feet in WDW-2; MASIP =7,570 feet x 0.2 psi/ft = 1,514 psi
- 1,460 psi or 0.2 psi per foot of depth to the top of the injection zone at 7,303 feet in WDW-3; MASIP = 7,303 feet x 0.2 psi/ft = 1,460 psi

7 (g) Formation Testing Program

Formation testing was conducted during the initial construction of the Navajo refinery injection wells to obtain site-specific data relating to the chemical, physical and radiological characteristics of the injection zone.

The analysis of formation fluids can be found in Appendix F-1. The three wells were converted oil and gas wells and no cores were cut from the confining zone or injection intervals. Correlations were made using data from offset wells.

7 (h) Fluids and Pressure

The following are descriptions of the changes in reservoir conditions that have been observed to-date and the predicted changes over the upcoming 5-year permit time frame for WDW-1, WDW-2, and WDW-3. This information is based on the known historical rates and volumes that have been injected into the wells and the future 5-year emplacement of the permitted maximum volume at the maximum permitted injection rate between the three wells of 800 gpm.

The interface between injected waste and the formation brine (the waste front) expands radially from the wellbores in each well. As fluid is injected, the injection zone will continue to pressurize due to the resistance of fluid movement and the compression of the fluid and rock matrix.

Current Cone of Influence and Waste Plume Front

The maximum lateral spread of the waste front and the predicted pressure rise during the operational life of WDW-1, WDW-2, and WDW-3 to-date were initially calculated and included in the original permit application.

Calculated Cone of Influence (Current)

The current cone of influence within the injection zone is presented on Drawing 12. The current cone of influence is based on the injection operations through December 31, 2016.

Calculated Plume Front Migration (Current)

The radius of the current dispersed plume for the wells are:

- WDW-1: 4,274 feet
- WDW-2: 3,707 feet (WDW-2 is approximately 7,850 feet from WDW-1)
- WDW-3: 2,911 feet (WDW-3 is approximately 7,900 feet from WDW-1)

Future Cone of Influence and Waste Plume Front

The maximum predicted pressure rise during the upcoming 5-year permit time frame for WDW-1, WDW-2, and WDW-3 were calculated using the software program PredictW. The equations used in the program are presented in Appendix E-3.

The plume fronts for each well were calculated using the equations from Warner and Lehr (1977)

Calculated Cone of Influence (5 Years)

The predicted cone of influence can be found on Drawings 13 through 16. The following four analyses were performed for the cone of influence calculations:

1. Injection into WDW-1 and WDW-2 with no injection into WDW-3 (Drawing 13).
2. Injection into WDW-1 and WDW-3 with no injection into WDW-2 (Drawing 14).
3. Injection into WDW-2 and WDW-3 with no injection into WDW-1 (Drawing 15).
4. Injection into WDW-1, WDW-2 and WDW-3 (Drawing 16).

The cone of influence is defined as the area with increased injection zone pressures caused by injection of wastes which would be sufficient to cause vertical fluid movement through any wellbore or other conduits into a USDW. This demonstration shows that the conservative worst-case cone of influence of the injection operations is smaller than the regulatory 1-mile composite radius AOR in which artificial penetrations were investigated.

In the worst case, an undocumented abandoned well is imagined to be open to both the injection zone and the base of the USDW. In addition, the well is filled to within 100 feet of the ground surface with formation brine from the injection zone and fresh water from the base of the USDW. The cone of influence can be calculated by comparing the hydraulic heads of the injection zone and the lowermost USDW. It is only where the injection zone head is above the USDW head that fluid movement from the injection zone into the USDW could occur. This worst-case model of the potential effect of injection on the USDW is conservative. No wells within the 1-mile composite radius AOR surrounding the wells are open to both the injection zone and the USDW and they are filled with brine.

On July 25, 1998, formation fluid was swabbed from the perforations of the deeper Cisco interval between 8,220 feet and 8,476 feet in WDW-1. The total dissolved solids (TDS) concentration of the sample was 33,000 milligrams per liter (mg/L), and the specific gravity of the sample at room temperature was 1.034. On July 29, 1998, formation fluid was swabbed from the perforations of the shallower Cisco interval between 7,924 feet and 8,188 feet in WDW-1. The analysis of a sample of this fluid indicated that the TDS concentration of the sample was 18,000 mg/L, and the specific gravity at room temperature was 1.018. The chemical analysis of the formation fluid samples is included as Appendix F-1. These values compare favorably with information from the analysis of fluid retrieved during drill-stem test (DST) No. 5, which was conducted on August 26, 1993 in WDW-1 (Appendix F-1). The salinity of the formation fluid retrieved during DST No. 5 was reported as having a chlorides concentration of 25,000 mg/L. The formation fluid is therefore assumed to have a sodium chloride concentration of 25,000 mg/L. The specific gravity of the formation brine was approximately 1.02.

The pre-injection pressure of the injection interval was measured on July 30, 1998 in WDW-1 to be 2,928 psia at 7,911 feet below ground level (BGL). Using the reservoir brine with the lightest specific gravity (1.018) will yield a high initial pressure, P_i, which is conservative. The pre-injection pressure, P_i, at the top of the injection zone in WDW-1 at 7,924 feet BGL is 2,934 psia, and is calculated as follows:

$$
\begin{aligned}
P_i(7{,}924\text{ feet}) &= P_i(7{,}911\text{ feet}) + (7{,}924\text{ feet} - 7{,}911\text{ feet})\,(0.433\text{ psi/ft})\,(1.018) \\
&= 2{,}928\text{ psia} + 6\text{ psi} \\
&= 2{,}934\text{ psia}
\end{aligned}
$$

The hydraulic head of the lowermost USDW is estimated to be 100 feet BGL. This estimate is reasonably conservative, as it is based on a static water level measurement of 81 feet.

The critical pressure, P_c at 7,924 feet BGL that would be necessary to raise the hydrostatic head of the injection interval to the head of the lowermost USDW at 100 feet BGL is 3,446 psia, and is calculated as follows:

$$
\begin{aligned}
P_c &= \text{(Top of Injection Zone - Base of USDW) (0.433 psi/ft)(1.018)} \\
&\quad + \text{(Base of USDW - Head of USDW) (0.433 psi/ft)} \\
&= \text{(7,924 feet - 493 feet) (0.433 psi/ft) (1.018)} \\
&\quad + \text{(493 feet - 100 feet) (0.433 psi/ft)} \\
&= \text{3,446 psia}
\end{aligned}
$$

The critical increase in reservoir pressure, ΔP_c, above the native pressure that is necessary to raise the hydrostatic head of the injection zone to the head of the lowermost USDW is 512 psi, and is calculated as follows:

$$
\begin{aligned}
\Delta P_c &= P_c - P_i \\
&= \text{3,446 psia – 2,934 psia} \\
&= \text{512 psi}
\end{aligned}
$$

An increase in reservoir pressure greater than 512 psi would be sufficient to raise the head of the Injection zone above the head of the lowermost USDW. The cone of influence is the area around the injection wells within which the increase in reservoir pressure caused by injection is greater than 512 psi.

The gridded pressure increases created with PredictW were contoured using Surfer, a commercial contouring software package. Contour plots of the predicted pressure increase in the injection zone (Drawings 13 through 16) were generated using historical injection rates and volumes and the permitted maximum injection rate of 800 gpm over the upcoming 5-year permit time frame.

Conservative values for reservoir thickness and permeability were used to overestimate the predicted increase in reservoir pressure. The porosity was assumed to be 10 percent. The reservoir was assumed to have a thickness of 85 feet. The permeability of the reservoir was assumed to be 251 millidarcies (md). The modeled permeability-thickness, kh, of 21,335 millidarcy-ft (md-ft) (251 md x 85 feet), is approximately 18 percent of the kh, of 115,670 md-ft, that was determined from the pressure falloff test conducted in WDW-1 between September 21, 2012 and September 23, 2012 (Appendix G). Using a low kh yields a predicted pressure increase that is greater than expected and a cone of influence that is larger than expected.

The viscosity of the formation fluid with TDS concentration of 25,000 ppm at 130°F is 0.53 cp (Appendix E-3). The compressibility of the pore volume of the formation is c_r, is 5.5×10^{-6} psi^{-1}. The compressibility of the formation fluid is c_w, is 2.9 x 10^{-6} psi^{-1}. The total compressibility ($c_t = c_r + c_w$) is 8.4 x 10^{-6} psi^{-1} (Appendix E-4).

Historical injection data for WDW-1, WDW-2 and WDW-3 were used for the injection period from September 23, 1999 (initial injection at the site) through December 31, 2012. WDW-1, WDW-2 and WDW-3 were then modeled as injecting from January 1, 2013 through December 31, 2017 at a continuous rate of 800 gpm distributed among the three wells. The maximum modeled per-well injection rate for any one well is 400 gpm.

The 512-psi pressure-increase contour, which defines the outline of the worst-case cone of influence, is located less than one mile from WDW-1, WDW-2, and WDW-3, as shown on Drawing 16. An improperly abandoned wellbore or other conduit filled with formation fluid that is located farther than one mile from the proposed wells would not transmit sufficient pressure from the injection zone to move fluids into the USDW. Navajo researched public and private sources of information about wells within the 1-mile radius AOR. Information is presented in Section 7 (b) that demonstrates that each of the injection zone penetrations is properly constructed to prevent migration of fluids into the USDW. The output from PredictW is presented in Appendix E-5.

Modeled Plume Front Migration (to December 31, 2022)

The lithologic character of the injection zone, with the resulting hydrodynamic characteristics, is expected to be horizontally uniform. Given the anticipated homogeneity of the injection zone, plume geometry during the active injection phase is expected to be cylindrical.

More than 175 feet of formation is anticipated to exist in the injection zone at the locations of the three Navajo injection wells. Each well is completed in the same interval with 100 to 200 feet of perforations per well. For a conservative estimate of the injection plume size, the plume radius is calculated on the basis of all flow emplaced in an 85-foot thick interval. Based on historical injection data, the volume of fluid injected through January 1, 2017 are listed below. Assuming a continuous injection rate of 400 gpm over a 5-year injection period, the additional future volume which can be injected will be 1,051,200,000 gallons in any well. The following summarizes the plume radii for each well:

WDW-1

- Current plume radius (January 1, 2017): 4,274 feet
- Projected plume radius (January 1, 2022: 5,308 feet

WDW-2 (located approximately 7,850 feet from WDW-1)

- Current plume radius (January 1, 2017): 3,707 feet
- Projected plume radius (January 1, 2022: 4,886 feet

WDW-3 (located approximately 7,900 feet from WDW-1)

- Current plume radius (January 1, 2017): 2,911 feet
- Projected plume radius (January 1, 2022: 4,359 feet

Details of the plume radius calculations for WDW-1, WDW-2, and WDW-3 are presented in Appendix E-6.

7 (i) Stimulation Program

Historical Information

The only stimulation performed on the well has consisted of acid treatments of which the majority was performed through coil tubing pumped across the existing perforation. No fracturing of the injection interval has been performed.

Future Stimulation Programs and Procedures

Currently, no changes are planned in the way the wells are stimulated. Navajo reserves the right to fracture the injection interval with approval from NMOCD. Approximately once every two years an acid stimulation is performed on the wells. The stimulation procedure will consist of pumping 4,000 gallons to 8,000 gallons of 15 percent NEFE Hydrochloric acid through coil tubing at 1 bpm to 2 bpm across the perforations. The acid will be displaced into the formation down the tubing at the highest possible rate.

7 (j) Injection Procedure

Injection into all three Navajo injection wells is on a continuous basis. The injection fluid is routed from the refinery process areas via pipeline to each injection well. Figure 11a, 11b, and 11c present the pre-injection facilities for each well.

Historical Injection Rates and Volumes

The historical rates and volumes can be found in Appendix E-1.

Predicted Injection Rates and Volumes

The maximum permitted composite injection rate into all three Navajo injection wells is 800 gpm. This rate of injection is equal to 1,152,000 gallons per day or 420,480,000 gallons per year or 2,102,400,000 gallons into the injection zone over the upcoming 5-year permit time frame for WDW-1.

The maximum permitted composite injection rate into all three Navajo injection wells is 800 gpm. This rate of injection is equal to 1,152,000 gallons per day or 420,480,000 gallons per year or 2,102,400,000 gallons into the Injection Zone over the upcoming 5-year permit time frame for WDW-2.

The maximum permitted composite injection rate into all three Navajo injection wells is 800 gpm. This rate of injection is equal to 1,152,000 gallons per day or 420,480,000 gallons per year or 2,102,400,000 gallons into the Injection Zone over the upcoming 5-year permit time frame for WDW-3.

7 (k) Drawings

Figures 11a, 11b, and 11c present a schematic of the pre-injection surface facilities. Figures 12a, 12b, and 12c present as-built diagrams of the below-grade portions of the wells. Figure 13a, 13b, and 13c present as-built diagrams of the wellheads.

7 (I) Construction

WDW-1 was converted from the following oil and gas well originally drilled to a depth of 10,200 feet in 1993:

Mewbourne Oil Company

Chalk Bluff "31" State

Section 31, Township 17 South, Range 28 East

(API No. 30-015-27592)

The oil and gas well was re-entered in 1998 and converted to Injection Well WDW-1. Appendix H includes a copy of the report documenting the well conversion that provides relevant information about how the well was originally constructed and how it was converted to an injection well. Figure 12a presents an as-built diagram of the below-grade portions of WDW-1. Figure 13a presents an as-built diagram of the WDW-1 wellhead.

WDW-2 was converted from the following oil and gas well originally drilled to a depth of 10,200 feet in 1973:

The Eastland Oil Company

Chukka Federal No. 2

Section 12, Township 18 South, Range 27 East

(30-015-20894)

The oil and gas well was re-entered in 1999 and converted to Injection Well WDW-2. Appendix H includes excerpts from a report documenting the well conversion that provides relevant information about how the well was originally constructed and how it was converted to an injection well. Figure 12b presents an as-built diagram of the below-grade portions of WDW-2. Figure 13b presents an as-built diagram of the WDW-2 wellhead.

WDW-3 was converted from the following oil and gas well originally drilled to a depth of 9,450 feet in 1991:

Mewbourne Oil Company

Navajo Chalk Bluff Federal No. 1

Section 1, Township 18 South, Range 27 East

(API No. 30-015-26575)

The oil and gas well was converted to an injection well (WDW-3) in 2006. Appendix H includes excerpts from a report documenting the well conversion that provides relevant information about how the well was originally constructed and how it was converted to an injection well. Figure 12c presents an as-built diagram of the below-grade portions of WDW-3. Figure 13c presents an as-built diagram of the WDW-3 wellhead.

General Description of the WDW-1

Size, Type, and Depth of Injection Tubing: The information for the tubing string was obtained from NMOCD records on file with the state and geophysical logs.

- **Tubing**: 4 1/2-inch, 11.6 pound per foot, steel construction, API grade N-80, with long thread connections (LTC) set at 7,879.
- **Packer**: Arrow X-1, 7-inch by 3 1/2-inch set at 7,879 feet.

Size, Type, and Depth of Casing: There are three casing strings in the well. The information for these casing strings was obtained from NMOCD records on file with the state and geophysical logs.

- **13-3/8-inch**, 48.0 pound per foot, steel construction, API grade J-55, with short thread connections (STC), set at a depth of 390 feet back to surface. The casing was cemented to the surface with 525 sacks of cement. The casing was set in an open hole with a diameter of 17.5 inches. This information was obtained from NMOCD records.
- **9-5/8-inch**, 36.0 pound per foot, steel construction, API grade J-55, STC, set at a depth of 2,555 feet back to surface. The casing was cemented to the surface with 1,000 sacks of cement. The casing was set in an open hole with a diameter of 12.25 inches. This information was obtained from NMOCD records.
- **7-inch**, 29.0 pound per foot, steel construction, API grade N-80, with long thread connections (LTC), set at a depth of 9,094 feet to 7,031 feet; 29.0 pound per foot, steel construction, API grade P-110, LTC from 7,031 feet to 5,845 feet; and 26.0 pound per foot, P-110, LTC at 5,845 feet back to surface. The casing was cemented to the surface with 1,370 sacks of cement. The casing was set in an open hole with a diameter of 8.75 inches.

The original oil and gas well was drilled to a total depth of 10,200 feet. When the well was converted to an injection well in 1999, a cement plug was set from 9,624 to 9,734 feet and 7-inch protection casing was set at 9,094 feet. A bottom plug was installed into the base of the 7-inch casing with the top of the plug tagged at 9,004 feet. The 7-inch protection casing was perforated with a 0.5-inch diameter hole at 2 shots per foot on a 60° phasing. The perforations are located between 7,924 feet and 8,188 feet and from 8,220 feet to 8,476 feet as depicted on Figure 12a.

Current Loading on Pipe and Pipe Specifications for WDW-1

Pipe Size	Type	Weight	Depth Ref. to Kelly Bushing Level (12.5 ft above GL)		Hole Size	Cement Volume	Collapse	Yield
(in)		*(lb/ft)*	*Top*	*Bottom*	*(in)*	*(sks)*	*(psi)*	*(psi)*
13-3/8	Conductor Casing, J-55	48	Surface	390	17.5	525	1130	2730
9-5/8	Surface Casing	36	Surface	2555	12.25	1000	2020	3520
7	Protection, J-55 Casing, N-80, P-110	29 & 26	Surface	9094	8.75	1390	5410	7240
4-1/2	Injection Tubing, N-80	11.6	Surface	7879	6.184	N/A	4960	5350
7x 2-7/8	Arrow X-1 Packer	N/A	7871	7879	2.5	N/A	N/A	N/A

General Description of the WDW-2

Size, Type, and Depth of Injection Tubing: The information for the tubing string was obtained from NMOCD records on file with the state and geophysical logs.

- **Tubing**: 3 1/2-inch, 9.2 pound per foot, steel construction, API grade J-55, with long thread connections (LTC) set at 7,528.
- **Packer**: Arrow X-1, 5-1/2-inch by 2 7/8-inch set at 7,528 feet.

Size, Type, and Depth of Casing: There are three casing strings in the well. The information for these casing strings was obtained from NMOCD records on file with the state and geophysical logs.

- **8-5/8-inch**, 32.0 pound per foot, steel construction, API grade J-55, STC, set at a depth of 1,995 feet back to surface. The casing was cemented to the surface with 800 sacks of cement. The casing was set in an open hole with a diameter of 11.0 inches. This information was obtained from NMOCD records.
- **5-1/2-inch**, 17.0 pound per foot, steel construction, API grade L-80, with long thread connections (LTC), set at a depth of 8,869 feet. The casing was cemented to the surface in two stages using 1,570 sacks of cement. The casing was set in an open hole with a diameter of 7-7/8 inches.

The original oil and gas well was drilled to a total depth of 10,372 feet. When the well was converted to an injection well in 1999, a cement plug was set at 9,675 to 9,775 feet and 5-1/2-inch protection casing was set at 8,869 feet. A bottom plug was installed into the base of the 5-1/2-inch casing with the top of the plug tagged at 8,770 feet. The 5-1/2-inch protection casing was perforated with a 0.5-inch diameter hole at 2 shots per foot on a 60° phasing. The perforations are located between 7,570 feet and 7,736 feet and from 7,826 feet to 8,399 feet as depicted on Figure 12b.

Current Loading on Pipe and Pipe Specifications for WDW-2

Pipe Size	Type	Weight	Depth Ref. to Kelly Bushing Level (12.5 ft above GL)		Hole Size	Cement Volume	Collapse	Yield
(in)		*(lb/ft)*	*Top*	*Bottom*	*(in)*	*(sks)*	*(psi)*	*(psi)*
8 5/8	Surface Casing, J-55	32	Surface	1,995	11.0	800	2,530	3,930
5½	Protection Casing, L-80	17	Surface	8,869	7.875	1,570	6,280	7,740
3½	Injection Tubing, J-55	9.2	Surface	7,528	4.892	N/A	N/A	N/A
5½ x2 7/8	Arrow X-1Packer	N/A	7,526	7,528	4.892	N/A	N/A	N/A

<u>General Description of the WDW-3</u>

Size, Type, and Depth of Injection Tubing: The information for the tubing string was obtained from NMOCD records on file with the state and geophysical logs.

- **Tubing**: 4-1/2-inch, 11.6 pound per foot, steel construction, API grade J-55, with long thread connections (LTC).
- **Packer**: Arrow X-1, 7-inch by 2-7/8-inch set in tension (37,000 pounds) at 7,575 feet.
- **Tubing Length**: 7,568 feet with a 0.54-foot, 4-1/2-inch by 2-7/8-inch crossover in the top of the packer. There are no profile nipples in the tubing or the packer as this was not a requirement of the permit.

Size, Type, and Depth of Casing: There are four casing strings in the well and one below the injection interval. The information for these casing strings was obtained from NMOCD records on file with the state and geophysical logs.

- **13-3/8-inch**, 54.5 pound per foot, steel construction, API grade J-55, with short thread connections (STC), set at a depth of 400 feet. The casing was cemented to the surface with 425 sacks of cement. The casing was set in an open hole with a diameter of 17.5 inches. This information was obtained from NMOCD records.
- **9-5/8-inch**, 36 pound per foot, steel construction, API grade J-55, STC, set at a depth of 2,604 feet. The casing was cemented to the surface with 1,025 sacks of cement. The casing was set in an open hole with a diameter of 12.25 inches. This information was obtained from NMOCD records.

- **7-inch**, 26 pound per foot steel construction, API grade N-80 and P-110, STC, set at a depth of 9,450 feet. The casing was cemented with 1,350 sacks of cement to 900 feet from the surface. The casing was set in an open hole with a diameter of 8.75 inches. The top of cement and weight of the pipe was verified with a CBL and caliper log run on October 13, 2006. The remainder of the information was obtained from NMOCD records.

Below the cement plug at 9,022 feet is the top of a 4-1/2-inch liner. The liner is a string of 4-1/2-inch casing installed to a depth of 10,119 feet. There is a cast iron bridge plug set in the liner at 9,800 feet, which is above the original perforations between 9,861 feet and 9,967 feet. The current injection interval is above the plug at 9,022 feet. The cement plug also isolates the lower section of the original wellbore. This information was obtained from NMOCD records.

The top of cement was determined from a CBL that was run in the 7-inch casing string on October 13, 2006. The top of cement in the 7-inch casing was found at 900 feet below the surface. The top of cement in the 9-5/8-inch and 13-3/8-inch casing strings was verified through NMOCD records and volume calculations.

The 7-inch casing was perforated on October 14 and 15, 2006. The casing was perforated with a 0.5-inch diameter hole at 2 shots per foot on a 60° phasing. The perforations are located between 7,660 feet and 8,450 feet and from 8,540 feet to 8,620 feet as depicted on Figure 12c.

The total depth of the well is 10,119 feet with the plug back depth at 9,022 feet. On August 30, 2009, fill was tagged at 8,986 feet.

Current Loading on Pipe and Pipe Specifications for WDW-3

Pipe Size	**Type**	**Weight**	**Depth Ref. to Ground Level (ft)**		**Hole Size**	**Cement Volume**	**Collapse**	**Yield**
(in)		*(lb/ft)*	*Top*	*Bottom*	*(in)*	*(sks)*	*(psi)*	*(psi)*
13-3/8	Conductor Casing, J-55	54-1/2	Surface	400	17.5	425	1130	2730
9-5/8	Surface Casing	36	Surface	2604	12.25	1025	2020	3520
7	Protection, J-55 Casing, N-80, P-110	26 & 29	Surface	9450	8.75	1350	5410	7240
4-1/2	Injection Tubing, J-55	11.6	Surface	7561	6.184	N/A	4960	5350
7x 2-7/8	Arrow X-1 Packer	N/A	7561	7569	2.5	N/A	N/A	N/A
4-1/2	Liner, N-80	11.6	9051	10119	6.5	175	6350	7780

Depth to Injection Zone

The WDW-1 Injection Zone is 7,450 to 9,016 feet (MD below KB), and the Injection Interval (perforated interval) is 7,924 to 8,476 feet (MD below KB) as depicted on Figure 12a.

The WDW-2 Injection Zone is 7,270 to 8,894 feet (MD below KB). And the Injection Interval (perforated interval) is 7,570 to 8,399 feet (MD below KB) as depicted on Figure 12b.

The WDW-3 Injection Zone is 7,303 to 8,894 feet (MD below KB), and the Injection Interval (perforated interval) is 7,660 to 8,620 feet (MD below KB) as depicted on Figure 12c.

Pressures and Other Stresses That May Cause Well Failure

There are no known pressures or stresses that may cause failure in any of the wells.

Hole Size

The borehole advanced for the original oil and gas well that was later converted to WDW-1 was 12.25 inches in diameter.

The borehole advanced for the original oil and gas well that was later converted to WDW-2 was 11.0 inches in diameter.

The borehole advanced for the original oil and gas well that was later converted to WDW-3 was 12.25 inches in diameter.

Well Casing Information

Figures 12a, 12b, and 12c and Appendix H include information about the well casing for each of the wells. The preceding tables ("Current Loading on Pipe and Pie Specifications") provide overviews of the casing information.

Cement Information

Figure 12a, 12b, and 12c and Appendix H include information about the cement in each well.

Rate, Temperature and Volume of Injected Fluid

Average and Maximum Daily Flow Rate and Volume

The average injection rate for all three Navajo injection wells is approximately 400 gpm and the maximum permitted injection rate between the three wells is 800 gpm.

Temperature

The temperature of the injected fluid is within average ambient temperature ranges.

Volume of Injected Fluid

The maximum annual volume of injected fluid, based on a maximum composite injection rate of 800 gpm between the three injection wells is 420,480,000 gallons.

Chemical and Physical Characteristics of Injected Fluid

The fluid injected into the wells is comprised of exempt and nonexempt non-hazardous oilfield waste that is generated in the refining process. Waste waters from process units, cooling towers and boilers, streams from water purification units and desalting units, recovered and treated groundwater, and general wash waters are blended to form the fluid injected. Table 2 and Appendix D present data characterizing the injection fluid.

Chemical and Physical Characteristics of Formation Fluid

Formation testing was conducted during the initial construction of the Navajo refinery injection wells to obtain site-specific data relating to the chemical, physical and radiological characteristics of the Injection Zone. The formation fluid contained in the Injection Zone is compatible with the well construction components and the injected fluid.

Formation fluid information pertinent to the reservoir calculations is included in Appendix E.

Chemical and Physical Characteristics of the Receiving Formation

The Injection Zone is porous carbonates of the lower portion of the Wolfcamp Formation, the Cisco Formation, and the Canyon Formation.

The lower portion of the Wolfcamp Formation (Lower Wolfcamp) is the shallowest porous unit in the proposed injection interval. The Wolfcamp Formation (Permian-Wolf campaign age) consists of light brown to tan, fine to medium-grained, fossiliferous limestones with variegated shale interbeds (Meyer, 1966, page 69). The top of the Wolfcamp Formation was correlated for this study to be below the base of the massive, dense dolomites of the overlying Abo Formation. The base of the Wolfcamp coincides with the top of the Cisco Formation. The thickness of log porosity greater than 5 percent in the entire Wolfcamp Formation ranges from 0 feet to 295 feet in a band three miles wide that trends northeast-southwest across the study area.

The Cisco Formation (Pennsylvanian-Virgilian age) of the Northwest Shelf is described by Meyer (1966, page 59) as consisting of uniform, light colored, chalky, fossiliferous limestones interbedded with variegated shales. Meyer (1966, page 59) also describes the Cisco at the edge of the Permian basin as consisting of biothermal (mound) reefs composed of thick, porous, coarse-grained dolomites. Locally, the Cisco consists of porous dolomite that is 659 feet thick in WDW-1, 745 feet in WDW-2, and 720 feet in WDW-3. The total thickness of intervals with log porosity greater than 5 percent is approximately 310 feet in WDW-1, 580 feet in WDW-2, and 572 feet in WDW-3. The total thickness with log porosity greater than 10 percent is approximately 100 feet in WDW-1, 32 feet in WDW-2, and 65 feet in WDW-3. The thickness of the porous intervals in the Cisco ranges from 0 feet in the northwestern part of the study area to nearly 700 feet in a band three miles wide that trends northeast-southwest.

The Canyon Formation (Pennsylvanian-Missourian age) consists of white to tan to light brown fine grained, chalky, fossiliferous limestone with gray and red shale interbeds (Meyer, 1966, page 53). Locally, the Canyon occurs between the base of the Cisco dolomites and the top of the Strawn Formation (Pennsylvanian-Desmoinesian age). The total thickness of intervals with log porosity greater than 5 percent is 34 feet in WDW-1, 30 feet in WDW-2, and 10 feet in WDW-3. No intervals appear to have log porosity greater than 10 percent in any of the three injection wells.

Permeability measurements that range from less than 100 md to 2,733 md are available for the Lower Wolfcamp-Cisco-Canyon injection zone. Permeability measurements from hydrocarbon-producing intervals in the Wolfcamp, Cisco, and Canyon from Meyer (1966, Table) are summarized in Appendix I. Meyer reported permeabilities in the Cisco of up to 114 millidarcies (md), up to 38 md in the Canyon, and up to 200 md in the Wolfcamp.

Permeability was estimated to be 597 md from DST No. 5 conducted in WDW-1 on August 26, 1993. DST No. 5 was conducted near the top of the Cisco Formation from 7,817 feet to 7,851 feet (Appendix I).

Historical falloff data obtained during the life of the wells shows that the permeability ranges from 500 md to 1,000 md throughout the injection interval.

Chemical and Physical Characteristics of the Confining Zone

The Confining Zone extends from 4,000 feet to 7,450 feet in WDW-1, from 4,120 feet to 7,270 feet in WDW-2, and from 4,030 feet to 7,303 feet in WDW-3. The Confining Zone includes massive low-porosity carbonate beds and layers of shale in the Upper Wolfcamp, Abo, and Yeso Formations that will confine the injected fluids to the permitted Injection Zone (Lower Wolfcamp, Cisco, and Canyon Formations). The formations that comprise the Confining Zone are described below.

The Injection Zone is directly overlain by the confining layers of the upper portion of the Wolfcamp Formation. Three (3) DSTs were conducted in the upper portion of the Wolfcamp in WDW-1, in the interval from 7,016 feet to 7,413 feet, that indicate that the interval has low permeability and can confine injected fluids to the injection zone. An average permeability of 0.36 md was calculated from the data from DST No. 3, as follows:

$$k = 162.6 \frac{q \; B \; \mu}{mh}$$

$$= 162.6 \frac{(20 \text{ bbl}/ 89 \text{ min x } 1440 \text{ min/day})(1 \;)(0.53 \text{ cp})}{(570.883 \text{ psi/cycle}) \; (7382 \text{ feet} - 7230 \text{ feet})}$$

$$= 162.6 \frac{(323.6 \text{ bpd})(1)(0.\;53 \text{ cp})}{(570.883 \text{ psi/cycle}) \; (152 \text{ feet})}$$

$$= 0.36 \text{ md}$$

A permeability on the order of 0.1 md is at the low end of the permeability range for carbonates, and is at the high end of the permeability range for shales, according to Freeze and Cherry (1979, p. 29).

Therefore, the low-permeability carbonates of the upper Wolfcamp will provide the first level of confinement for the Injection Zone.

The Abo Formation overlies the Wolfcamp and extends from 5,400 feet to 6,890 feet in WDW-1, from 5,506 feet to 6,728 feet in WDW-2, and from 5,380 feet to 6,745 feet in WDW-3. Although the Abo is well known as a major oil producer in the AOR, the producing intervals lie in the upper Abo, whose equivalents are above 6,100 feet in WDW-1 and above 6,200 feet in WDW-2. The deepest Abo test well in the area is located 6,000 feet east (downdip) of WDW-3 and was drilled to 6,412 feet. No Abo production in the area has been established below 6,298 feet, the producing interval in Map ID No. 112, located 3,800 feet southeast (downdip) of WDW-1. The base of the producing interval within the Abo Formation in the AOR, therefore, is over 900 feet above the top of the injection zone. The lower 600 feet of the Abo Formation (below the deepest producing interval in the AOR), consisting primarily of dolomite with an average porosity less than 5 percent and interbedded shale, will serve as the secondary confining layer above the proposed injection zone.

The Yeso Formation, which will provide additional confining capabilities, directly overlies the Abo Formation. The top of the Yeso is not consistently identified in the AOR, according to well records submitted to the NMOCD and available scout tickets. However, the top of the Confining Zone can be considered to extend to the top of the low-porosity limestone interval below the higher-porosity dolomites below the Glorieta Member of the San Andres Formation (at 4,000 feet in WDW-1, 4,120 feet in WDW-2, and 4,030 feet in WDW-3). The Yeso consists of low-porosity carbonates and clastic beds. The Tubb shale, a shale interval that is up to 150 feet thick in some wells in the study area, also occurs in this interval. Although no faults are known to exist in the confining zone within the AOR, the Tubb shale will serve to prevent movement of fluids through a hypothetical unknown fault.

Depth, Thickness and Chemical Characteristics of Penetrated Formations Containing Ground Water

The base of the USDW, groundwater with total dissolved solids concentration with less than 10,000 milligrams per liter (mg/L), occurs at the base of the Tansill Formation. Figure 3 presents a hydrostratigraphic cross-section for the local area. Figure 4 presents a potentiometric surface map indicating the direction of groundwater movement in the freshwater aquifers.

The base of the USDW occurs at the following approximate depths in Navajo's three injection wells:

- WDW-1: approximately 493 feet KB (3,200 feet above mean sea level)
- WDW-2: approximately 473 feet KB (3,150 feet above mean sea level)
- WDW-3: approximately 420 feet KB (3,150 feet above mean sea level)

In the eastern part of the study area, at depth, the Tansill Formation is overlain by the Salado Formation (Permian - Ochoan age). The Salado consists of halite, polyhalite, anhydrite, and potassium salts, which are soluble. The Salado is overlain by the Rustler Formation (Permian - Ochoan age). In the AOR, which straddles the outcrop area of the Salado, and to the east, the Salado has been removed by solution by ground water flowing through the Rustler.

To the east, where the Rustler is present, the Rustler is the USDW. To the west, where the Rustler has been removed by erosion and the Salado has been removed by solution, the Tansill is the USDW. The Tansill Formation and the underlying Yates Formation comprise the Three Twins Member of the Chalk

Bluff Formation known in outcrops in the region (Hendrickson and Jones, 1952, page 20), and listed as a freshwater-producing interval.

The top of the Injection Zone (Lower Wolfcamp, Cisco, and Canyon Formations) is separated from the base of the USDW by several thousand feet of lower permeability carbonates, siltstones and shales as follows:

- WDW-1: 6957 feet (7,450 feet - 493 feet)
- WDW-2: 6,797 feet (7,270 feet - 473 feet).
- WDW-3: 6,883 feet (7,303 feet - 420 feet).

7 (m) Contingency Plans

The wells are equipped with a high-level shutoff switch to prevent operation of the injection pump at pressures greater than the designated MASIP. The wells are equipped with a low pressure shutoff switch that will deactivate the injection pump in the event of a surface leak. In addition, the wells are equipped with a high/low pressure shutdown switch with a pressure sensor on the tubing/casing annulus. This pressure switch is intended to stop the injection pump in the event of 1) a tubing leak, or 2) a casing, packer, or wellhead leak.

If an alarm or shutdown is triggered, the cause of the alarm or shutdown will be immediately investigated.

- Immediately cease injection operations;
- Take all necessary steps to determine the presence or absence of a leak; and
- Provide verbal notification to NMOCD within 24 hours.

If the alarm or shutdown is not related to mechanical integrity and the cause of the alarm or shutdown is corrected, injection operations will be resumed. If the mechanical integrity of the wells are in question, the well will remain out of service until the mechanical integrity of the well is restored to the satisfaction of NMOCD and the agency approves resumption of injection operations.

7 (n) MIT Monitoring Plans (20.6.2.5207 NMAC)

Navajo has an ongoing monitoring program that satisfies all applicable requirements of 20.6.2.5207.NMAC.

- The mechanical integrity of WDW-1, WDW-2, and WDW-3 are demonstrated on an annual basis.
- Continuous monitoring devices are used to provide a record of injection pressure, flow rate, flow volume, and annular pressure.

The results of these monitoring activities are reported to NMED as required by regulation.

7 (o) *Additional Monitoring Plans for Class I Non-Hazardous Waste Injection Wells (20.6.2.5207B NMAC)*

Appendix J includes an Injected Fluids Monitoring Plan that describes the procedures to be carried out on a quarterly basis to obtain a detailed chemical and physical analysis of a representative sample of the injected fluid, including the quality assurance procedures. The plan will be updated as necessary.

The plan includes the following elements:

- The parameters for which the injected fluid will be analyzed and the rationale for the selection of these parameters; The test methods that will be used to test for these parameters;
- The sampling method that will be used to obtain a representative sample of the injected fluid being analyzed;
- Field sampling documentation methodologies;
- The commercial laboratory who performs the analysis; and
- Method of reporting analytical results to NMOCD.

7 (p) *Additional Monitoring Plans for Class III Wells (20.6.2.5207C NMAC)*

This section is not applicable; WDW-1, WDW-2, and WDW-3 are not a Class III well.

7 (q) *Financial Assurance*

Appendix K includes a well closure plans for each well. The estimated plug and abandon cost per well is presented in the table below. This cost estimate has been prepared to reflect the estimated costs that would be incurred by Navajo to abandon the well in accordance with the procedures in Appendix K.

Description of Service	**Estimated Cost**
Wireline (BHP, RTS, PFOT, Perforate)	$20,000
Rental Tools	$5,000
Pumping Service	$10,000
Cementing Service	$20,000
Excavating and Welding	$2,500
Mud/Brine	$5,000
Frac Tanks	$2,500
Vacuum Trucks	$2,500
Miscellaneous	$2,500
SUBTOTAL	$70,000
Field Supervision, Project Management, Procurement	$25,000
Total Estimated Cost	**$95,000**

Appendix L includes a copy of the financial assurance instrument that Navajo has established to provide the appropriate monies for plugging and abandoning each well, any groundwater restoration that may be necessary, and any post-operational monitoring that may be required.

7 (r) Logging and Testing Data

Appendix M includes pertinent open-hole logs run on each of well:

- A copy of the original oil and gas well log that was drilled in 1993 and later converted to WDW-1.
- A copy of the original oil and gas well log that was drilled in 1973 and later converted to WDW-2.
- A copy of the original oil and gas well that was drilled in 1991 and later converted to WDW-3.

Appendix N includes copies of pertinent cased-hole logs that were run on each well:

- Logs run as WDW-1 was being converted to disposal services.
- Logs run as WDW-2 was being converted to disposal services.
- Logs run as WDW-3 was being converted to disposal services.

Copies of additional open-hole and cased-hole logs are contained in the following:

- WDW-1, report submitted to NMOCD in September 1998: *Reentry and Completion Report, Waste Disposal Well No. 1, Navajo Refining Company, Artesia, New Mexico* prepared by Envirocorp Well Services, Inc., Houston, Texas
- WDW-2, report submitted to NMOCD in July 1999: *Reentry and Completion Report, Waste Disposal Well No. 2*, Navajo Refining Company, Artesia, New Mexico prepared by Subsurface Technology, Inc., Houston, Texas

7 (s) Mechanical Integrity Data (20.6.2.5204 NMAC)

Mechanical Integrity Testing (MIT) is conducted on WDW-1, WDW-2, and WDW-3 in 2015 in accordance with NMOCD regulations. Appendix G includes the text portion of the 2015 MIT Report for WDW-1, WDW-2, and WDW-3. Copies of the full MIT report were submitted to NMOCD. Previous annual MIT reports are contained in NMOCD files. The MITs were successful for all three disposal wells.

In addition, Appendix G includes a copy of the text portion of the 2016 Annual Bottomhole Pressure Survey and Pressure Falloff Test for WDW-1.

7 (t) Maximum Pressure and Flow Rate

The maximum injection rate and the maximum surface injection pressure at each of the Class I non-hazardous injection wells (WDW-1, WDW-2, and WDW-3) are as follows:

- Maximum Injection Rate: 500 gpm
- Maximum Surface Injection Pressure: 1,585 psi

7 (u) Formation Testing Program Data

Appendix F-1 includes the results of formation testing that was performed on the well when it was originally drilled as an oil and gas exploratory well.

7 (v) Compatibility

Components of WDW-1, WDW-2, and WDW-3 that are in direct contact with the non-corrosive waste stream and formation fluids in the Injection Interval (e.g., wetted surfaces) are constructed of materials that are compatible with these fluids.

Compatibility tests for Navajo's waste stream were performed by analyzing the chemical reactions between different mixtures of the secondary reverse osmosis reject fluid and the waste water and flue gas scrubber mixture. All testing and analysis were performed by Intertek Group PLC (Intertek) who provide chemical testing and analyses to understand the composition of chemical substances and materials that are used in products, industrial processes and manufacturing (Appendix F-2).

7 (w) Area of Review Corrective Actions

No corrective action plan is required for any of the artificial penetrations identified in the AOR. Artificial penetration records reviewed show those identified within the AOR have been properly constructed, plugged and/or abandoned in order to prevent movement of fluids into or between USDWs which could be caused by pressures in the Injection Zone.

8.0 Modification(s)

A request was issued via correspondence to the NMOCD on September 25, 2013 to process the applications for WDW-1 and WDW-2 so that these permits would be issued with the same expiration date as the WDW-3 permit (June 1, 2017). The permits were processed and thusly issued with the same expiration date of June 1, 2017. Appendix O includes a copy of this correspondence.

There are no other modifications for the three wells or proposed modifications to existing discharge processes.

9.0 Inspection/Maintenance and Reporting

Navajo performs daily visual inspections of their three injection wells and the pipeline and performs required maintenance (PM) activities as scheduled to ensure safe operation of the wells.

Navajo performs routine reporting in accordance with the requirements of 20.6.2.5208.A NMAC for Class I Non-Hazardous waste injection wells.

10.0 Contingency Plans

Navajo Refinery has an Integrated Contingency Plan detailing responses to spills of all types, reporting spills/releases, mitigation and corrective actions, clean up and disposal as applicable. The remote wells (WDW-1, WDW-2, and WDW-3) are equipped with a high-pressure shutoff switch to prevent operation of the injection pump at pressures greater than the designated MASIP. The wells are equipped with a low pressure shutoff switch that will deactivate the injection pump in the event of a surface leak. In addition, the wells are equipped with a high/low pressure shutdown switch with a pressure sensor on the tubing/casing annulus. This pressure switch is intended to stop the injection pump in the event of 1) a tubing leak, or 2) a casing, packer, or wellhead leak.

If an alarm or shutdown is triggered at the wellhead, electronic signals are sent to the Control Room at the refinery notifying of the shutdown and the cause of the alarm or shutdown will be immediately investigated.

Operators will immediately cease injection operations at the wellhead and divert flow to another well; and notify Maintenance and Environmental to take all necessary steps to determine the presence or absence of a leak; and Environmental will provide verbal notification to NMOCD within 24 hours.

If the alarm or shutdown is not related to mechanical integrity and the cause of the alarm or shutdown is corrected, injection operations will be resumed. If the mechanical integrity of the well is in question, the well will remain out of service until the mechanical integrity of the well is restored to the satisfaction of NMOCD and the agency approves resumption of injection operations.

11.0 Other Information

No additional information is required to demonstrate that the discharge permit will not result in concentrations in excess of the standards of 20.6.2.3103 NMAC or the presence of any toxic pollutant at any place of withdrawal of water for present or reasonably foreseeable future use.

12.0 Filing Fee

A check in the amount of $300, made payable to Water Quality Management Fund, accompanies this permit renewal application document for Class I Injection wells WDW-1, WDW-2, and WDW-3.

13.0 Draft Public Notice

20.6.2.3108.C NMAC requires that Navajo provide notice in accordance with 20.6.2.3108.F NMAC within 30 days of NMOCD deeming the permit renewal application to be administratively complete. Appendix P includes a draft copy of the public notice that will be published following receipt of written notification from NMOCD that this discharge permit renewal application has been deemed administratively complete.

Navajo understands the requirement to submit to NMOCD within 15 days of completion of public notice requirements of 20.6.2.3108.C NMAC proof of notice, including an affidavit of mailing(s) and the list of property owner(s), proof of publication, and an affidavit of posting, as appropriate.

14.0 Certification

The required certification language is included at the end of the completed NMOCD Discharge Permit Application Form in the front of this permit renewal application document. The appropriate Navajo Refinery authority has signed the form.

TABLES

FIGURES

DRAWINGS

APPENDICES