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Will Jones,

Here is a copy of the ED report, I promised concerning the Monument SWD we are working on.

I have readvertised and have sent out notices to landowner & Amerada as directed, when I get certified notice back I will send them to you. The ~~[illegible]~~ well owner is out of town, but will file bond next week.

I appreciate your help.

Thanks

Eddie Seay

NOV 1997

New Mexico Environment Department
Ground Water Protection and Remediation Bureau
Ground Water Discharge Permit Application
Class I - Nonhazardous Injection Well
DLD Resources Inc., Monument, NM

NAME OF FACILITY: DLD RESOURCES, INC.

LEGALLY RESPONSIBLE PERSON:

DARRELL BEARDEN, PRESIDENT
P.O. DRAWER A, MONUMENT, NM 88265

OWNER OF FACILITY: DLD RESOURCES, INC.

OWNER'S ADDRESS: P.O. DRAWER A, MONUMENT, NM 88265

CONTACT PERSON: JOHN C. GOOD, ENVIRONMENTAL MANAGER
P.O. DRAWER A, MONUMENT, NM 88265
(505) 397-1927, FAX (505) 393-9913

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INTRODUCTION

DLD Resources, Inc. submits this Application for a Class I Non-Hazardous Injection well permit following the New Mexico Water Quality Control Commission Regulations, Subpart V, amended through December 1, 1995. The injection well was previously installed by Climax Chemical Company on their property located approximately 3-½ miles west of Monument, New Mexico. Climax Chemical's consulting engineer on the project was Ken E. Davis & Associates, Houston, Texas.

The well was constructed in 1985 and permitting of the well was nearly complete at the time of Climax Chemical's bankruptcy and closure in September 1992. The well has remained unused and an annulus pressure of approximately 100-psi has been maintained (nitrogen gas) since that time. Most of Climax Chemical's facilities and real property, including the injection well, were purchased by DLD Resources, Inc. in 1996.

The injection well is located on DLD Resources' property located at 8205 South Highway 322, approximately 3 ½ miles west of Monument, NM. The well is approximately 1000 feet north of DLD's manufacturing plant. The injection well was installed under the supervision of Ken E. Davis Associates of Houston, TX in 1985. The well was installed to 5000-ft. depth to attain discharge in the San Andres zone, a limestone formation. A diagram of the well as constructed is contained in this application.

The original permit application was submitted by Ken E. Davis & Associates (KEDA) in August 1983 with subsequent revisions and additions as the project progressed. The KEDA materials are the definitive source of information regarding this injection well. Much of this permit application is taken directly from the KEDA documentation, or direct reference to the KEDA materials is made.

TYPE OF FACILITY or OPERATION

DLD Resources, Inc. manufactures hydrochloric acid (HCl) and sodium sulfate (Na_2SO_4). The hydrochloric acid varies in concentration from 31% to 35%. The sodium sulfate is approximately 99% pure.

The hydrochloric acid is utilized primarily in the production aspects of the petroleum industry, and the sodium sulfate is used in the manufacture of paper and detergents.

METHOD OF TREATMENT AND DISPOSAL OF EFFLUENT

The injection well will be utilized for subsurface injection of neutralized process effluent into the San Andres limestone formation (4350-5000 ft. depth from surface). The discharge from the facility is a brine solution.

The effluent consists primarily of (1) process water from the wet venturi scrubber used to meet air quality standards, (2) quench tank purge solution, and (3) wash water used for cleanup of the plant area. Prior to being discharged from the plant, the effluent is treated in an Elementary Neutralization Unit (ENU) with soda ash (Na_2CO_3) to maintain the pH above 3.0.

DISCHARGE CHARACTERISTICS

QUANTITY:

Design discharge rate (gpd):

When in full operation, the plant can produce effluent at an approximate maximum rate of 100-gpm (144,000-gpd). This maximum rate would be achieved under full operation of plant with a large quantity of water going into the sump pumps to wash down operations or heavy local precipitation.

Gallons per day computed on annual basis:

The flow characteristics of the system are based on the data obtained from several years of operation of the circular irrigation discharge system (previously DP-426, presently DP-1129).

The system discharge rate will vary from 50-gpm (72,000-gpd to 90-gpm (129,600 gpd), depending on the rate of production of the plant. We are estimating the systems average discharge rate to be around 72-gpm (103,680-gpd). The overall actual average for years 1991, 1990, and 1989 was 60.4-gpm (86,976-gpd).

Table 1 - Average Effluent Flow (GPM) for Calendar Years 1989 – 1991

1989 Discharge Rates Month	Avg. GPM	1990 Discharge Rates Month	Avg. GPM	1991 Discharge Rates Month	Avg. GPM
January	47	January	60	January	92
February	25	February	48	February	70
March	24	March	56	March	68
April	48	April	56	April	69
May	44	May	49	May	63
June	63	June	50	June	79
July	66	July	51	July	67
August	70	August	57	August	66
September	56	September	55	September	63
October	65	October	48	October	63
November	82	November	72	November	62
December	69	December	83	December	69
Tot. Avg. GPM	55	Tot. Avg. GPM	57	Tot. Avg. GPM	69

Number of days per year facility will be discharging

300-320 days per year. The plant is often shut down 1-2 days per week for maintenance work. During shut down periods, there is little or no effluent flow.

Design waste injection rate

The well, as installed by KEDA, was designed to receive a maximum injection rate of 200-gpm, with a projected average injection rate of 160-gpm. Actual step rate testing of the well after fracturing of the injection formation indicates that the well will take 160-gpm with gravity flow.

METHOD USED TO METER OR CALCULATE THE DISCHARGE RATE:

The effluent will be metered using a flow meter with a totalizer indication of gallons discharged. Totalizer readings will be logged daily.

FLOW CHARACTERISTICS

Daily or seasonal:

The plant will be operating 5 - 6 days per week, depending on maintenance needs and inventory capacities.

Continuous or intermittent:

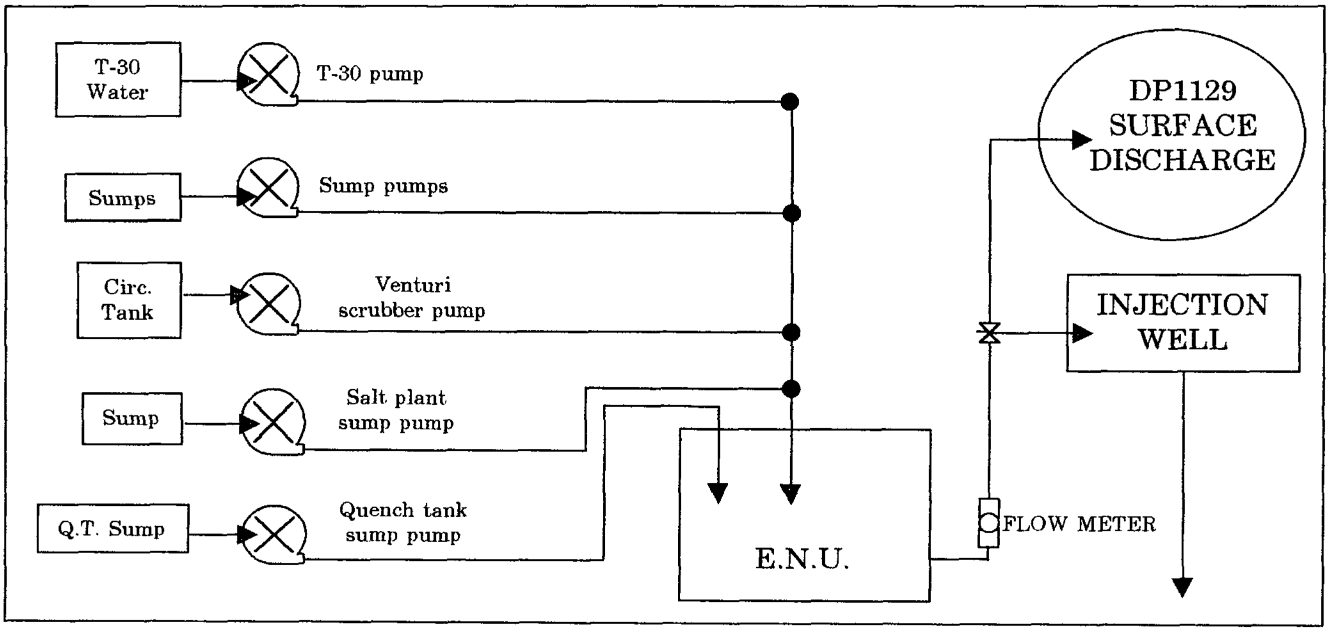
Discharge of wastewater will be continuous on the days of operation of the facility.

DISCHARGE QUALITY

Waste Composition

The effluent produced by the facility originates from five plant sources as depicted in Figure 1. The effluent is a brine solution with a pH less than 2.0 prior to neutralization in the Elementary Neutralization Unit (ENU). Ions contained in the un-neutralized effluent solution are H^+, Na^+, $SO_4^=$, and Cl^-. The neutralization reaction with soda ash (Na_2CO_3) in the ENU produces a brine mixture containing **$NaCl$ and Na_2SO_4 in ionic states. CO_2 and H_2O are also produced in the reaction.**

Figure 1 – Plant Effluent Sources



Section 3103 Contaminants

The Section 3103 contaminants contained in the neutralized effluent to be injected are:

pH – range 4.0 to 6.5

Total Dissolved Solids (TDS) – 30,000-60,000 mg/l

Waste Compatibility and Stability

The formation (lower San Andres) fluid was sampled on 5-31-85 and analyzed by Unichem of Hobbs, NM. The results of the analyses are contained in Table IV, Vol. II, KEDA Project No. 10-0509, received by NMED 6-21-85.

The KEDA permit application discusses waste compatibility at length because it was the original intent to inject $<$ 2.0-pH effluent into the well. It was concluded by KEDA that there would have been no problem with the injection of $<$ 2.0-pH effluent into the formation. (See KEDA, Vol. I., pp. 63-74; and, KEDA Project No. 20-0581, page 7, received by NMED 7-30-85.) Since DLD's waste stream will be neutralized to $>$ 2.0-pH, CO_2 generation and pressure build up in the injection zone should not be a factor in the operation of the well.

LOCATION INFORMATION

LOCATION OF DISCHARGE SITE:

The proposed injection well is located on DLD's property, approximately 3-½ miles east of Monument, Lea County, New Mexico. (Township 19S, Range 36E, Section 35; Latitude: 32°37'05", Longitude: 103°19'26"). See Figures 2, 3.

2 ½ MILE RADIUS ARTIFICIAL PENETRATION SURVEY

The KEDA artificial penetration survey was done in 1984 utilizing private and public sources of information. The KEDA survey indicates approximately 420 penetrations (oil wells, gas wells, oil & gas wells, salt water injection, LPG storage, SWD, and plugged or temporary abandoned.) The KEDA survey does not indicate water wells.

This application incorporates an updated survey utilizing NM Oil Conservation Division records for oil, gas, LPG storage, SWD, and injection wells; and NM State Engineer records for water wells. Section maps with all oil, gas, injection, and water wells within the 2 ½ mile radius of the proposed waste injection well are contained in Appendix A of this application. A summary of this survey, completed in February 1997, is as follows:

- 299 oil wells
- 134 gas wells
- 70 salt water injection wells
- 2 LPG storage wells
- 3 drilled and abandoned (dry holes)
  Total = 508 (approximately 88 more than the 1984 survey)
- 76 water wells (all types, producing or abandoned)

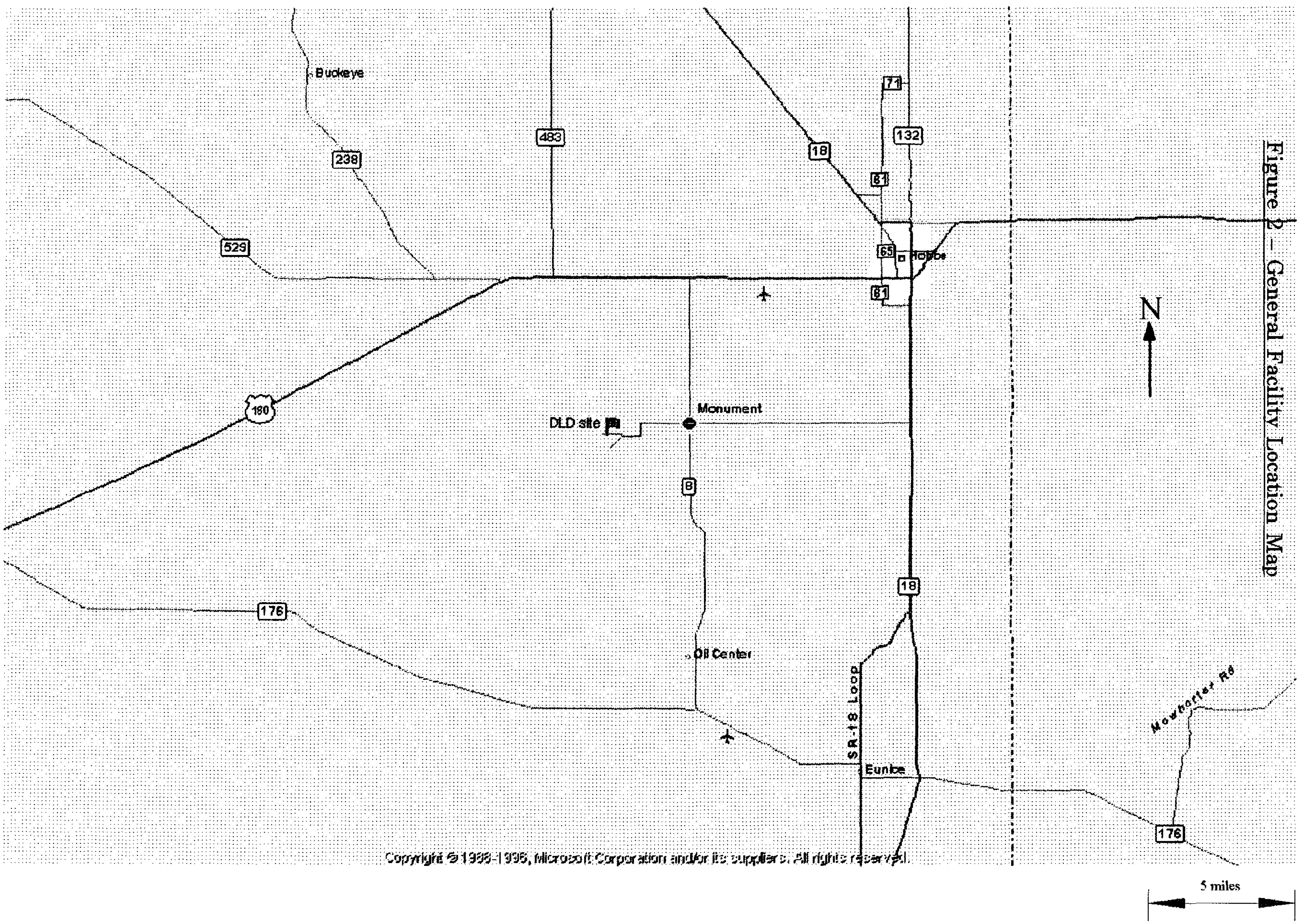


Figure 2 - General Location Map

Figure 3 – Detailed Facility Location Map

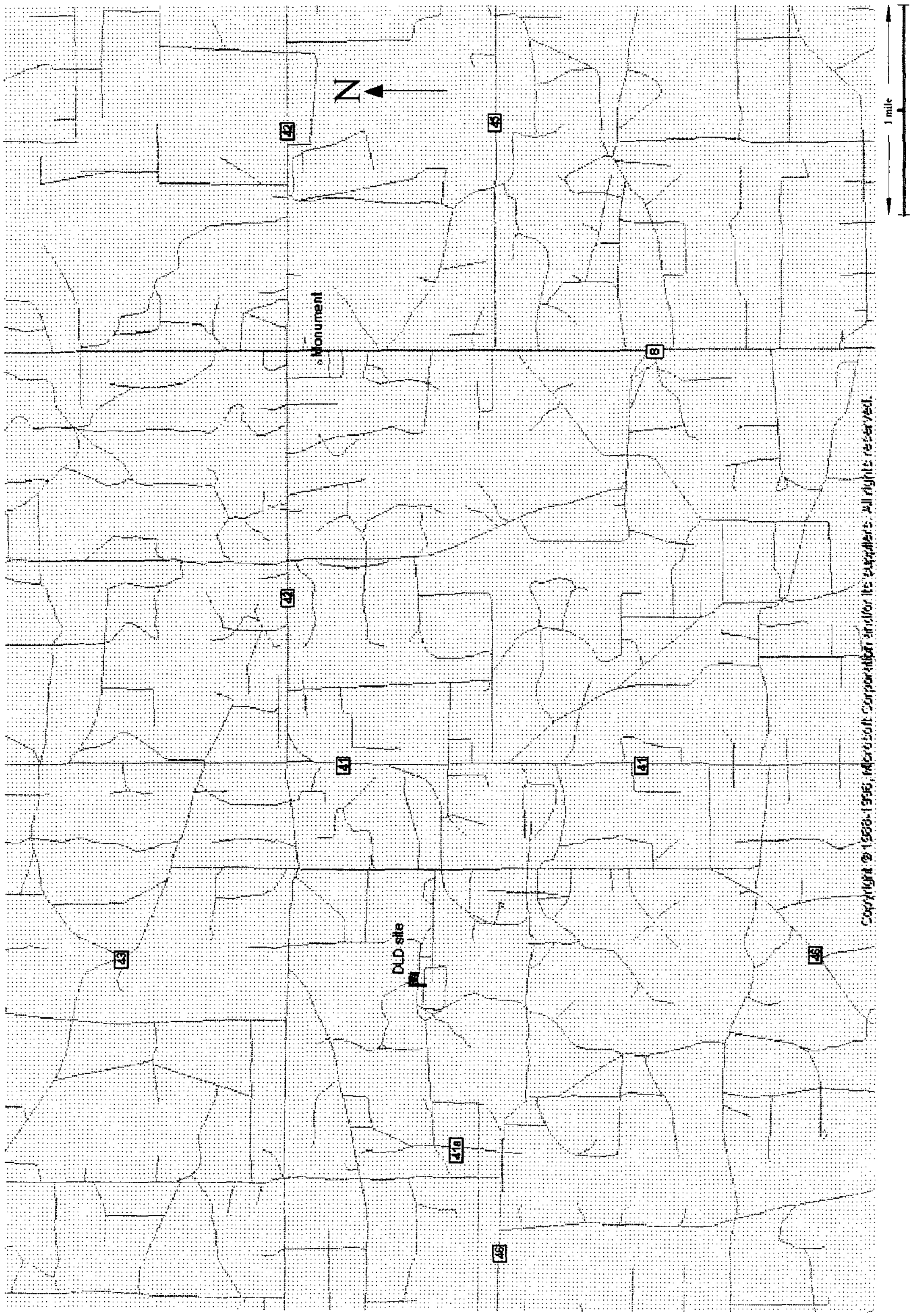


Figure 3 - Detailed Location Map

LOCATION OF GROUND WATER MONITORING WELLS

Figure 4 indicates the locations of all ground water monitoring wells within the confines of the DLD facilities.

HYDROLOGY OF DISCHARGE SITE

GROUND WATER

Ground water in the Monument area is derived from three geologic units; the Dockum Group, the Ogallala Formation and the Quaternary Alluvium. Beneath the Dockum Group, the undifferentiated redbeds are thought to act as an aquiclude between the evaporite bearing rocks of the Permian and the sandstone aquifers in the overlying Dockum. Because the redbeds are difficult to differentiate, the top of the underlying Rustler Formation (anhydrite) is considered the base of useable ground water since waters beneath this zone are highly mineralized[1].

Although several wells do produce water from the Dockum Group, they generally have low yields. The majority of ground water is withdrawn from the Ogallala Formation and Quaternary alluvium, which are more permeable and yield water of better chemical quality.

Southern Lea County is an important recharge area for the shallow aquifers: primarily by infiltration from playa lakes common to the area. The deeper aquifers are thought to receive recharge from downward leakage and from other parts of the county where they crop out.

A regional ground water map of southern Lea County prepared by Nicholson and Clebsch (1961) is presented in Figure 5. Although this map is based on mid-1950 data, studies done in the 1980's by Geohydrology Associates, Inc for Climax Chemical Company indicated that there was very little change in the water table in the area of concern since the earlier work was completed.

In addition to domestic, livestock, and industrial supply wells in the area, oil industry wells have been drilled in the area as temporary water supply wells for drilling operations. These wells are typically shallow and are plugged and abandoned upon completion of the production well. No fresh water wells are known to have been completed deeper than 180' within 2 ½ miles of the injection site. Deeper saline water wells used by the oil industry to provide a flooding medium for secondary recovery operations are treated in Section ?x.

Dockum Group Aquifers

In Lea County, water is obtained from both the Santa Rosa and Chinle Formations. In the western third of the county, the Santa Rosa is the principal aquifer. Throughout the county, aquifers are recharged by precipitation on sand dunes; by precipitation and runoff directly on the outcrops; and from the overlying Ogallala Formation and the alluvium.

1 Nicholson, A. Jr. and Clebsch, A. Jr., 1961, Geology and Ground Water Conditions in Southern Lea County, New Mexico: New Mexico Bureau of Mines and Mineral Resources, Ground Water Report 6.

Figure 4 – Ground Water Monitoring Wells

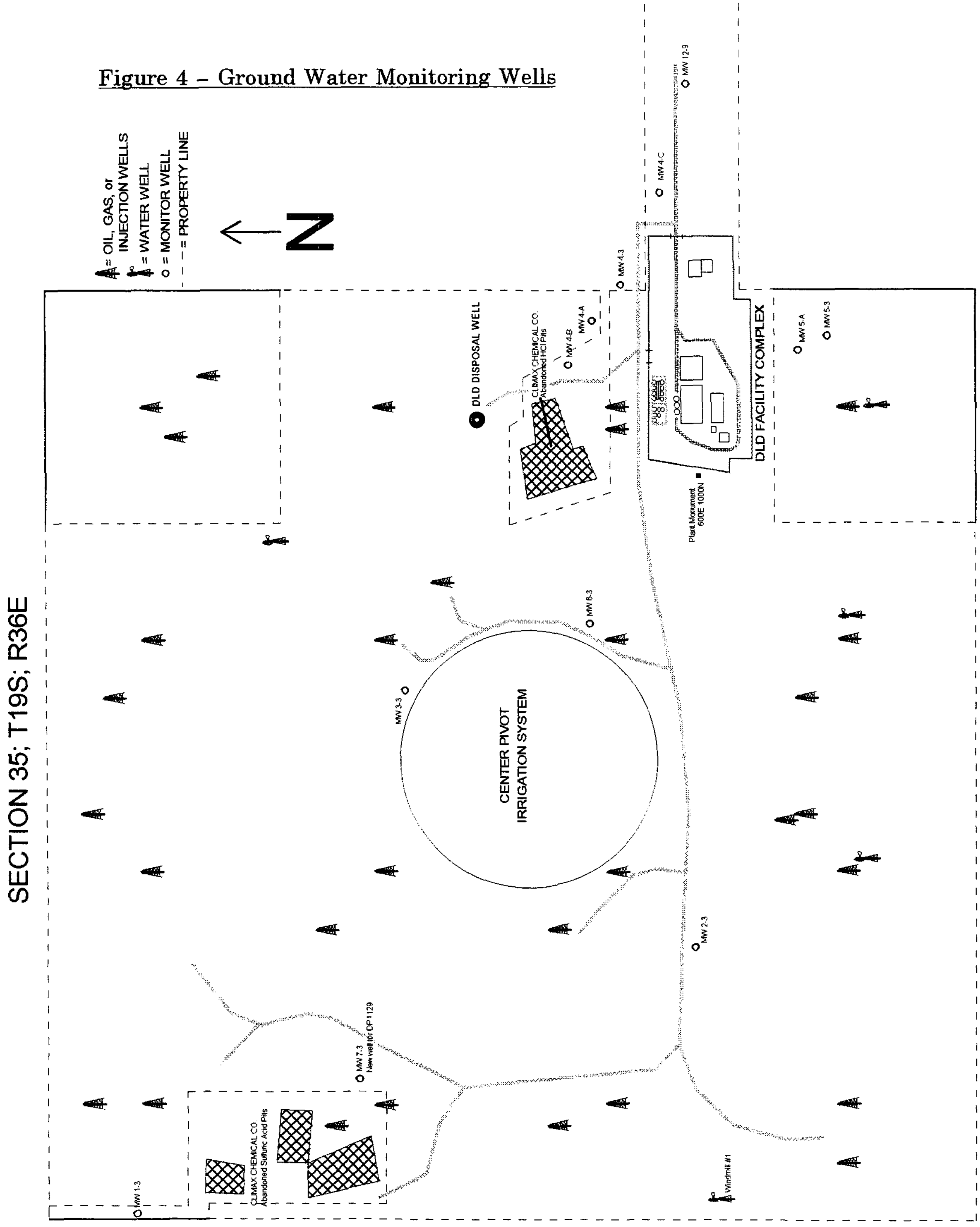


FIGURE 4

Due to the low permeability of the Santa Rosa and the Chinle, wells in the aquifers generally have very low yields. Pumping tests indicated that wells completed in this aquifer have specific capacities of less than 0.2 gallons per minute per foot of drawdown.[1]

Ogallala and Quaternary Aquifers

The Ogallala Formation covers the High Plains north of the Monument area where it is between 100' to 250' thick. Because of the underlying Triassic erosional surface, the saturated thickness of the aquifer ranges between 25' to 175'. Recharge to the Ogallala on the High Plains is entirely due to precipitation. Due to the southeastward slope of the Triassic redbeds surface, movement of the ground water beneath the High Plains is generally towards the southeast. From End Point to the Monument area, ground water generally leaves the Ogallala and flows into the Quaternary alluvium of the Laguna Valley and the Eunice Plain. In these areas, the Ogallala Formation is saturated only in valleys or isolated depressions formed in the erosional surface of the underlying redbeds.

The saturated thickness of the Quaternary alluvium in the Monument area is 15' to 30' thick and ground water movement is towards the southeast. In the Laguna Valley area, the water table is intersected by an impermeable barrier, formed by a rise in the redbeds, causing water to be diverted eastward towards Monument Draw. From the north end of Monument Draw, ground water again moves southward through both the Quaternary alluvium and the Ogallala where the two units are considered as one aquifer having a saturated thickness of approximately 30'. In the vicinity of the injection site, the saturated thickness ranges from 5' to 35'.[1]

Pumping tests conducted in wells completed in the alluvial aquifer indicated transmissivities on the order of 20,000 gpd/ft in the South Plains area. These tests, however, were made in wells that penetrated approximately 340' of saturated sediments.[2] Tests conducted near the injection site resulted in transmissivity values ranging from approximately 7 gpd/ft to 800 gpd/ft, reflecting the heterogeneity of the alluvium.[1]

SURFACE WATER

There are no surface water bodies in the Monument area. The only major drainage feature is Monument Draw (see Figure 6). Generally, the course of Monument Draw is almost perpendicular to regional topography and drainage cuts across normal drainage patterns. Monument Draw is described as being a well defined, sharply incised cut about 30' deep and 1800' to 2000' wide. There is no thoroughgoing drainage course and the draw is partly filled with dune sand, alluvium and vegetative overgrowth.

GRADIENT AND DIRECTION OF GROUND WATER FLOW

The direction of ground water flow in the near vicinity of the injection site is to the south and then east along the axis of a trough which acts as an impermeable barrier causing this diversion in the area of the DLD facility. This trough or ridge is due to a "redbed"

1 Geohydrology Associates, Inc. (1982)

2 Nicholson and Clebsch, 1961

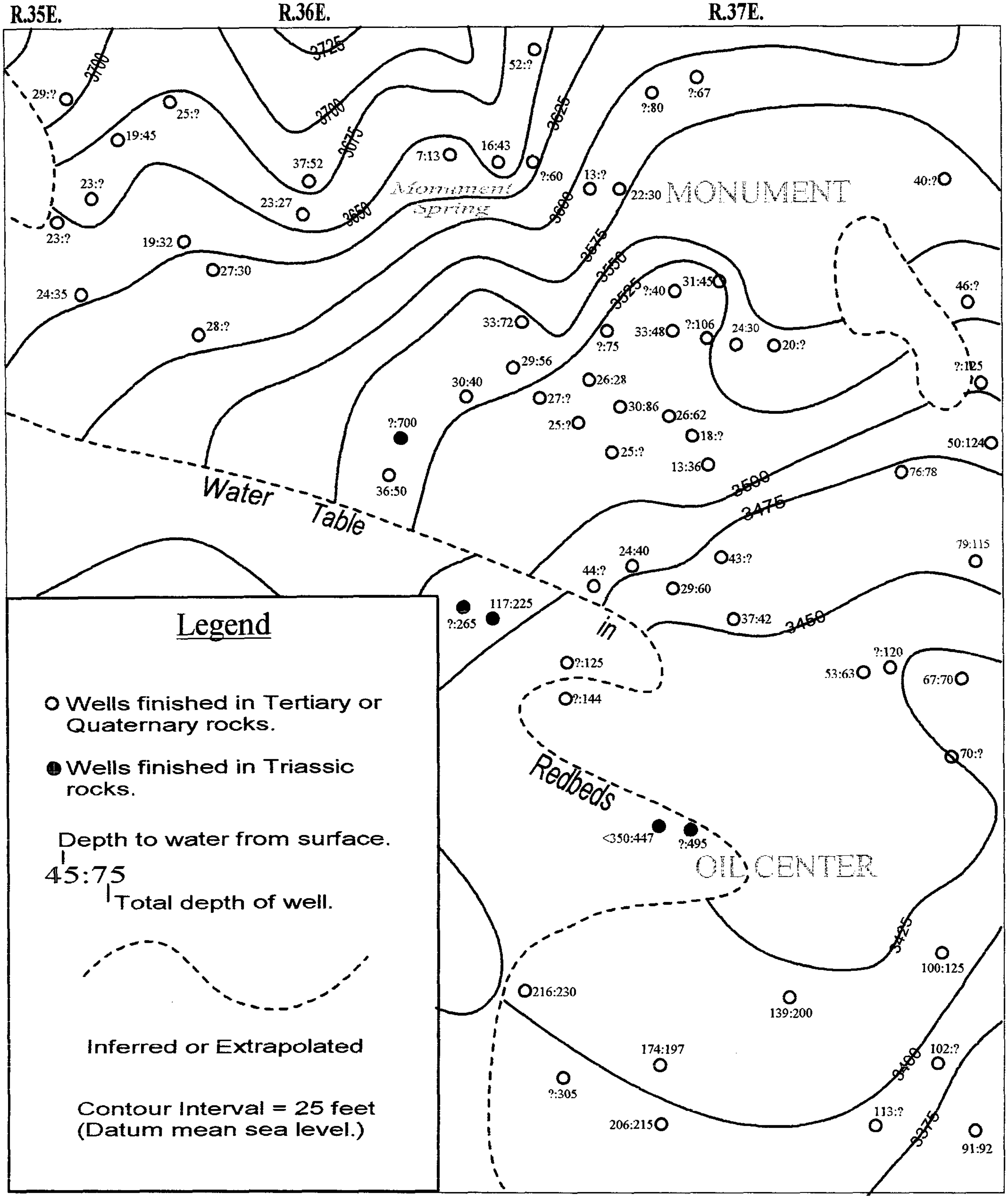


Figure 5 - Regional Water Table Contour Map
(Nicholson & Clebsch, 1961)

high" that exists northwest of the plant facility. This ridge acts as a ground water divide between the flow in Monument Draw and the water present beneath the DLD facility.

The regional water table contour map (Figure 5) shows that the water table surface, in the vicinity, slopes toward the southeast regionally. The average gradient is approximately 35 feet per mile.

A cross-section of the water table and underlying redbed formation immediately down-gradient to the injection well can be obtained by comparing surveyed and measured data from wells 4-A, 4-B, 4-C, 4-3, 12-9, and 10-10. The following table contains the data for this analysis:

Table 2 – Monitor Well Elevation Data

Well #	Surface Elevation	Water Elevation	Redbed Elevation	Surface to Water (ft)	Thickness of Aquifer (ft)
4-B	3592.02	3565.58	3560.18	26.44	5.4
4-A	3590.47	3564.58	3559.68	25.89	4.9
4-3	3589.18	3564.03	3559.18	25.15	4.85
4-C	3587.79	3559.99	3555.91	27.8	4.08
12-9 *	3587.63	3556.43	3552.63	31.2	3.8
10-10	3584.78	3551.21	3544.78	33.57	6.43

The straight-line distance between Well 4-B and Well 10-10 is 1735 ft. The gradient of the water table derived from the above measurements is 14.37 vertical ft. per 1735 linear ft., or a southeasterly slope of 43.73 ft/mile. The gradient in this immediate area is probably higher than the 35'/mile average noted by Nicholson and Clebsch (1961) due to the dome of waste water present in the immediate plant area as a result of Climax Chemical's disposal practices prior to 1986.

** Monitor well #12-9 has been infiltrated by crude oil. The thickness of the oil layer has not been determined. The water elevation for this well is actually the elevation of the top of the oil layer.*

WATER QUALITY

Southern Lea County

The chemical quality of ground water is determined largely by the lithologic characteristics of the aquifer and the source areas. Other factors that influence water chemistry are permeability, hydraulic gradient, distance from the recharge area, and chemical character of the rainfall.

In the area of investigation, the Ogallala Formation and alluvium derived from the Ogallala result in water of similar chemical quality. The Triassic aquifers and the alluvial aquifers derived from the weathering of Triassic rocks have distinctively different characteristics. Although a wide range of chemical constituents are found in all the aquifers, the apparent distinctions are as follows:[1]

- The Quaternary alluvium yields water of moderately high dissolved solids and is generally high in silica, moderately high in calcium and magnesium, low in sodium and potassium, and moderately low in sulfate and magnesium.
- The Ogallala aquifer water is typically high in silica, contains moderate concentrations of calcium and magnesium, is low in sodium and chloride, very low in sulfate, and the typical TDS is <1000 ppm.
- The Triassic aquifers have TDS levels that are generally higher than in the water derived from the overlying aquifers. They are low in silica, show a wide range in calcium and magnesium, are high in sodium, moderately high in sulfate, and moderately low in chloride.

Contamination of the potable aquifer from brine water produced during oil production has historically occurred. Typically, brine water was disposed of in unlined evaporation ponds and leakage from the ponds caused localized contamination. Disposal of brine by deep-well injection into the native formation or other brine aquifers has reduced the danger of contamination.

Immediate Vicinity

The TDS varies widely in the immediate area from 950 mg/l from Well 2-3 near the proposed discharge site to 49,000 mg/l in Well 4-3 east of the abandoned HCl surface impoundments.

The TDS of the ground water in the immediate area of the discharge location is indicative of the past activities of Climax Chemical Co. TDS can be measured directly by evaporation at 180°C, or can be closely approximated by multiplying the Specific Conductance of a sample (μmohs) by a factor of 0.65. The most recent actual or approximate TDS and Chloride values for the Monitor Wells utilized for Climax Chemical's RCRA Assessment Program are summarized in the following table (* - denotes calculated from Spec. Conductance):

Table 3 - TDS and Chloride sampling data from DLD Monitoring Wells:

Well	Location to Discharge Site	Sample Date	TDS (mg/l)	Cl (mg/l)
Windmill #1	Up-gradient, SW	8-3-90	1003*	270
MW 1-3	Up-gradient, NW	5-29-97	1280	324
MW 2-3	Side-gradient, SSW	5-29-97	1070	220
MW 4-3	Down-gradient, SE	5-29-97	66140	20493
MW 5-3	Down-gradient, SSE	5-29-97	25320	7598
MW 6-3	Up-gradient, W	5-29-97	59500	14595
MW 12-9	Down-gradient, SE	12-13-90	37774*	19147
MW 10-10	Down-gradient, SE	5-29-97	21360	8297

[1] Nicholson and Clebsch, 1961.

Water from Injection Zone

Water quality data was gathered from wells producing for the San Andres formation within the area of review. As expected, water quality is poor and TDS values are >10000 ppm. All information gathered indicates that water quality at and below 3600' has TDS >10000 ppm. (Tables showing sample locations, depths, dates, and TDS values are contained in the KEDA Application, Vol. I, pages 33-33.2, and the control points are plotted on a review area map in Figure 4.1, page 34.) (The water from the injection zone was collected at the time of well drilling and analyzed by Unichem International, Hobbs. Results of the formation fluid analysis by Unichem are contained in the KEDA Application, Vol. II, Table IV.)

FLOODING

Flooding Potential of the Site

There are no flood plain maps available for the area. The only maps available for the area are within the city limits of Hobbs, NM, which is 16 miles distant. The area generally is gradually sloped (0% - 2%) to the southeast. Flooding would be due to Hortonian Overland Flow. This type of flow occurs when the rainfall rate exceeds the soil's capacity to absorb water and is most common in arid or semi-arid climates where the hydraulic conductivity of the soil is low.

Flood Control Measures

The acid storage facility of the plant is entirely contained within a 2-½ ft. earthen berm. In addition, the entire plant area is protected by a 2-½ ft. berm on the north and west boundaries. Flood protection at the well head, other than proper construction of the surface structures, should not be necessary.

GEOLOGY OF DISCHARGE SITE

PHYSIOGRAPHY

The DLD Resources, Inc. plant is located 3-½ miles west of Monument, Lea County, New Mexico, approximately 20 miles west of the Texas-New Mexico border (Figures 2 & 3). The nearest population center is Hobbs, approximately 10 miles northeast of Monument. The climate of the area ranges from dry sub-humid to arid, and is characterized by low annual precipitation, low humidity and high annual average temperature. Mean annual precipitation ranges from 15.68" to 12.63" and the mean annual temperature is approximately 62°F.[1]

Lea County is divided into two physiographic subdivisions of the Great Plains physiographic province, the Pecos Valley section and the High Plains section. As illustrated in Figure 6, the well location is in the Pecos Valley section that is divided into the Querecho Plains, Laguna Valley, Grama Ridge Area, Eunice Plains, San Simon Swale, Antelope Ridge Area and the South Plain.[1]

1 Nicholson & Clebsch, 1961.

Figure 6 – Physiographic Map of Southern Lea County[1]

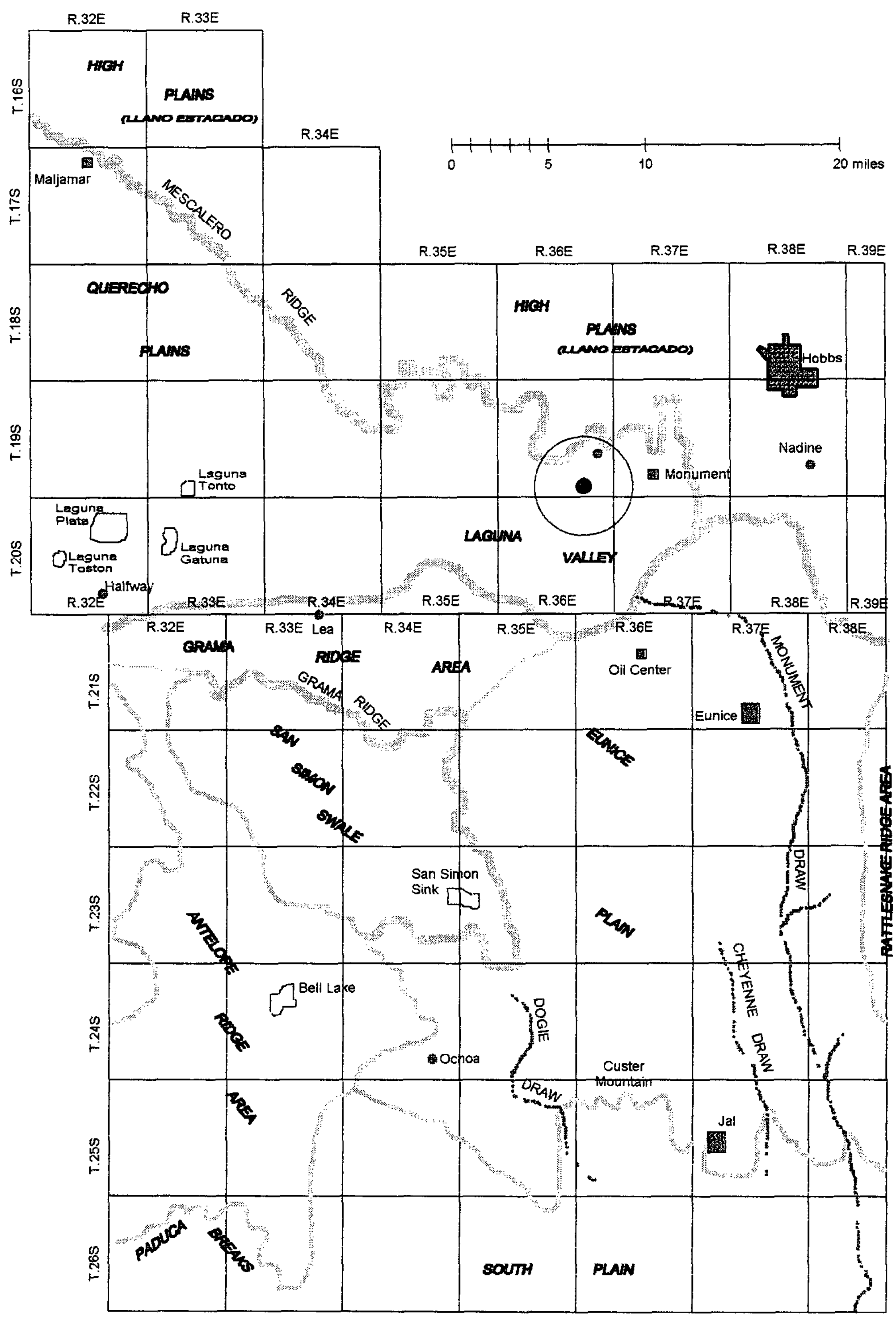


Figure 6 - Physiographic Map of Southern Lea County, NM

[1] Physiographic Subdivisions of Southern Lea County after Ground Water Report 6, State Bureau of Mines and Mineral Resources. (Modified from Long, 1953.)

To the north of DLD Resources, the southern extent of the High Plains section is marked by the Mescalero Ridge of the Llano Estacado. An abrupt change in topography is the primary contrast between the Llano Estacado and the Pecos Valley. The Llano Estacado is an almost uniform depositional surface of low relief sloping to the southeast. In contrast, the Pecos Valley is a very irregular erosional surface sloping to the west toward the Pecos River. Total relief of the area is about 1300', having altitudes ranging from 4000' mean sea level (MSL) to 2900' MSL. The physiographic subdivisions of southern Lea County are described as follows:

Mescalero Ridge and High Plains

The Mescalero Ridge is the most prominent topographic feature in southern Lea County and marks the southern limit of the High Plains section. The ridge is a nearly perpendicular cliff capped by a thick layer of resistant caliche, locally called caprock.

The High Plains is a uniformly flat surface with a southeast slope of about 17' per mile. The only significant relief features are small sand dunes and shallow playa lakes called "buffalo wallows." These depressions range in size from a few feet to more than a quarter of a mile and can be up to 20' deep. These playa lakes collect rainfall and contain it until removed by evaporation or seepage.

Querecho Plains and Laguna Valley

Immediately southwest and south of the Mescalero Ridge is a vast sand dune area of approximately 400 square miles. It is called Querecho Plains (to the west) and Laguna Valley (to the east). As shown in Figure 6, the DLD Resources facility is located in the Laguna Valley. The Querecho Plains-Laguna Valley area is almost entirely covered by dune sand which is stable or semi-stable over most or the area. The sand is generally underlain by recent alluvium and may be underlain by caliche in places. Drilling logs indicate surface sand underlain by caliche is found to depths of about 35'.

The most significant feature of the area is a group of four playa lakes. These playas are irregularly shaped, flat-bottomed, and are underlain by fine sediments with some pebble gravel and precipitated salt and gypsum.

Grama Ridge Area

The Grama Ridge Area is directly south of the Querecho Plains-Laguna Valley area and is topographically higher, indicating it may be a detached portion of the High Plains. It is characterized by a hard caliche surface with a texture and composition indicating it was once part of the Llano Estacado. The surface of the Grama Ridge Area has many shallow depressions that do not have integrated drainage.

Eunice Plain

The area east of Laguna Valley and Grama Ridge is referred to as the Eunice Plain. It is bounded on the north by the Llano Estacado and on the southwest by the San Simon Ridge and the Antelope Ridge. The westward extension of the Eunice Plain is the Grama Ridge area. Dune sands almost entirely cover the Eunice Plain and it is usually underlain by a hard caliche surface. In some places, however, it is underlain by alluvial sediments. A sand cover is generally 2' to 5' thick, but may be 20' to 30' thick locally.

Rattlesnake Ridge

Toward the east, the Eunice Plain rises into a north-trending topographic high called Rattlesnake Ridge. It parallels the Texas-New Mexico border for most of its length. It is regarded as the drainage divide between the Pecos Basin and the Colorado River Basin, Texas.

San Simon Swale

To the west of the Eunice Plain is the San Simon Swale, a large depression covering approximately 100 square miles. Most of the San Simon Swale is covered by stabilized dune sand and it shows no apparent drainage pattern. The deepest point of the swale is San Simon Sink, being 100' deep and ½ mile across. Calcareous silt and fine sand are the predominant fill material in the sink.

Antelope Ridge Area

The area to the west and southwest of Antelope Ridge has been called the Antelope Ridge Area, located in southwestern Lea County. The area is a relatively flat, sand-covered surface similar to the Eunice Plain and it is also partially underlain by caliche. Towards the south, the area appears to be underlain by Quaternary fill and loamy soil similar to the San Simon Swale. Because the Antelope Ridge is an anomalous geographic feature similar to the High Plains, it is thought to be an outlying remnant of the High Plains.

HISTORICAL GEOLOGY

The Precambrian history of Southern Lea County is a complex history of mountain building, metamorphism and erosion. Active deposition was taking place in the area during most of the Paleozoic Era. In later Paleozoic time, the south-central United States was a region of crustal unrest with the most significant activity in the West Texas-New Mexico area taking place during the Pennsylvanian Period. During this time and earlier in the Paleozoic, a geosyncline (the Llanoria geosyncline) formed across West Texas and adjacent states. (A geosyncline is a linear trough that has subsided through time and has accumulated large volumes of clastic sediment). Strong compression forces from the southeast caused the geosynclinal area to be raised into mountain ranges which some refer to as the Marathon folded belt. Although much of the folded belt was eroded, it remained high during most of the Permian Period. During the Pennsylvanian Period, what is now the Central Basin Platform was emergent in the form of mountain ranges and the area was subject to erosion.

At the close of the Pennsylvanian Period, the major features of the Permian Basin formed as the entire area subsided. The Central Basin Platform subsided more slowly than the Delaware and Midland Basins and received less sediment under different depositional conditions. The basins were areas of accumulation of large amounts of sediment. Limestone tended to form in higher areas, such as the Central Basin Platform, while the formation of evaporites took place at the fringes of the sea. At the very edge of the seas, redbeds were formed by the deposition of sediments from nearby landmasses.

During Wolfcamp time, the early Permian, seas spread over the region. Later the seas became restricted causing deposition of evaporites and limestones. The final event of the Permian was the retreat of evaporite-depositing waters from the West Texas region which caused the deposition of a thin layer of redbeds known as the Ochoan Series.

The end of the Permian, and therefore the end of the Paleozoic Era, marks a major time break in the geologic column. During most of the Triassic (except late Triassic) and Jurassic, most of southern Lea County was emergent and undergoing erosion.

During early to middle Cretaceous time, southeastern New Mexico was covered by a large shallow sea, which deposited a thick sequence of Cretaceous rocks. In the late Cretaceous, during the uplift of the Rocky Mountains, seas retreated from the Lea County area and intense erosion took place removing almost all Cretaceous rocks.

In the Pliocene Age, the Ogallala Formation was evenly deposited across the High Plains area, effectively removing the irregular surface formed by previous episodes of erosion. A cycle of erosion began again during the Quaternary, removing much of the Ogallala Formation and eroding Triassic rocks for the third time at some locations. Accordingly, erosion by the major rivers of New Mexico and Texas caused the isolation of a large remnant of the Ogallala Formation, the Llano Estacado. The climate of the region became more arid in the late Quaternary, and detrital material was reworked by wind creating the large sand dune deposits in the area.

STRATIGRAPHY

The DLD Resources, Inc. plant is located in the Central Basin Platform of the Permian Basin. Approximately 8000' of geologic strata overlie the Precambrian basement rocks in the Central Basin Platform.[1] Only strata of middle Permian age and younger are pertinent to this application. Figure 7 is a generalized stratigraphic column for Southeastern New Mexico[2]. In addition, colored stratigraphic columns based on drilling logs near the site are depicted in Figures 8 and 9[3]. Following in ascending order is a description of the stratigraphy beneath the well site.

Guadalupian Series (Middle Permian)

The Guadalupian Series in the Central Basin Platform consists of the San Andres Formation and the Whitehorse Group. The Whitehorse Group consists of a fine-grained sandstone with thin layers of black shale and argillaceous limestone and can also be referred to as the Artesia or Chalk Bluff Group.[4] The Whitehorse Group of the Central Basin Platform is correlative to the Delaware Mountain Group of the Delaware Basin. In the Monument are, it is a sequence of evaporites, redbeds, dolomitic limestone and sandstone ranging from 1000' to more than 2000' thick. The Whitehorse Group can be subdivided, in descending order into the Tansill, Yates, Seven Rivers, Queen and Grayburg. These formation tops in the site area are at estimated depths of 2360', 2480', 2760', 3280', and 3650' respectively. The Queen and Yates Formations are chiefly sandstone while the others are dolomitic limestone and anhydrite.

Beneath the Whitehorse Group is the San Andres Formation, the injection zone for this well. The top of the San Andres is an erosional unconformity and consists of dolomite beds with subordinate limestone members. It is divided into an upper, light-colored, non-

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[1] Nicholson and Clebsch, 1961.

[2] NM Oil Conservation Division

[3] KEDA, Vol. I.

[4] King, Phillip B., 1942, *Permian of West Texas and Southeastern New Mexico*, AARG, pp. 533-763

cherty member and a lower, dark, cherty member. The San Andres thins out north and northeast of the Central Basin Platform and is replaced by gypsum and redbed members. The San Andres is approximately 1460' thick in Lea County. Beneath the DLD Resources plant site, the top of the San Andres occurs at about 3880' and appears to be about 1300' thick. In the Monument area, the top of the San Andres is encountered at from 4000' to 4500', depending on structure. The first 75' to 100' is generally a dense dolomite with anhydrite plugging the pore spaces. The San Andres in the Monument area ranges in thickness from 500' to 900'.

After penetrating the hard, dense upper San Andres, porosity zones occur at irregular intervals. These zones do not occur with regularity and they can be correlated only short distances. When porosity does occur, it ranges from 10% to 20% with generally good permeability. Where no oil is present, these zones make good disposal intervals.

Beneath the San Andres is the Glorieta sandstone. It consists of about 130' of white, gray and buff medium to coarse-grained sandstone. The Glorieta thins to the southwest and may be only 10' thick in the Monument area, with the top at approximately 5100' below surface.[1]

Ochoan Series (Upper Permian)

The lowermost formation of the Ochoan Series is the "Salt" Formation, consisting of anhydrite and some halite. It rests unconformably on the Whitehorse Group in the Central Basin Platform but does not extend beyond the basin margins. Total thickness of the anhydrite and halite at the plant site is approximately 1200'. Halite was mined by Climax Chemical Company in the subsurface interval between 1400' to 2616'. Three brine wells previously used to leach salt were plugged and abandoned by Climax Chemical Company. The base of mineable salt was found to be at a depth of approximately 2610'.

The "Salt" Formation is unconformable in places with the overlying Rustler Formation. The top of the Rustler is considered to be the top of the first continuous anhydrite bed penetrated by oil and gas wells in southeastern New Mexico and occurs at a depth of 1008' in the DLD Resources area. The Rustler is characterized as dolomitic limestone with some sandstone and chert pebble conglomerates at the base. Eastward, in the Monument area, the limestone is overlain by anhydrite, redbeds, and halite, which is considered an upper member. In Lea County, the Rustler is between 90' to 360' thick and appears to 100'+ thick at the well site.

The "Salt" Formation and Rustler Formation together compose the Salado Group or Ochoan Series as shown in Figures 7 and 9.

Upper Permian or Triassic

Above the Rustler formation are the undifferentiated redbeds of Permian or Triassic age. They consist of micaceous red siltstone, sandstone, shale, and are cemented with gypsum. They are thought to retard the movement of water between the rocks of the Permian and the overlying aquifers.[2] The Middle and Upper Triassic consists of a sequence of redbeds,

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[1] Kinney, Edward E., 1969, *The San Andres Formation in New Mexico.*, Symposium of the New Mexico Geological Society Special Publication No. 3, pp. 3-4.

[2] Nicholson and Clebsch, 1961.

the Dockum Group, which rest unconformably on the lower undifferentiated redbeds. The Dockum can usually be differentiated into the Santa Rosa Formation and the uppermost Chinle Formation. The Santa Rosa is a fine-to-coarse-grained sandstone containing minor shale layers and ranging in thickness from 140' to 300'. The Santa Rosa and the Chinle are similar lithologically and in some places have been mapped as the Dockum Group, undifferentiated.

The Chinle Formation consists of red and green claystone that is interbedded with fine-grained sandstone and siltstone. The Chinle has been eroded in the west, however, it reaches a thickness of 1270' in the Monument area. About 2 miles southeast of Monument, the Chinle grades into a micaceous red clay.[2]

Both the Dockum Group and the undifferentiated redbeds are estimated to 888' thick at the well site with the top at approximately 120' below the surface.

Cretaceous

The rocks of Cretaceous age, although once present in Lea County, have been almost entirely removed by erosion. The only known exposure of Cretaceous rocks in Lea County are found in a gravel pit about seven miles south of Hobbs. At the site, the limestone is white, light gray, or buff, and is highly fossiliferous. There are no known deposits of Jurassic rocks in Lea County.

Tertiary

Beneath the surface deposits, at the well location, are rocks of the Tertiary System represented by the Ogallala Formation of Pliocene age. It is a heterogeneous complex of terrestrial sediments, consisting chiefly of calcareous, unconsolidated sand containing clay, silt, and gravel. Conditions of deposition varied rapidly during Ogallala time causing well-sorted sediments to be interbedded with poorly sorted sediments. The Ogallala Formation ranges form a few feet to as much as 300' thick and is major aquifer where it has sufficient thickness.

Quaternary System

In the Monument area, sediments of the Quaternary System exist in the form of alluvial deposits of Pleistocene and Recent age and dune sands of Recent age. The older alluvium is exposed locally in small duneless patches or in pits and it underlies the areas of Querecho Plans, Laguna Valley, San Simon Swale and several small areas. The alluvium ranges from a few inches to more than 400' thick in San Simon Sink.

The most extensive Quaternary unit is the cover of red dune sand called the Mescalero Sands. This fine-to-medium grained, reddish-brown sand covers 80% of Lea County, parts of Eddy County, and West Texas. It was probably derived from the Permian and Triassic rocks of the Pecos Valley. Near DLD's facility, the alluvial deposits consist of unconsolidated fine to coarse sand and gravel with stringers of silt and clay. Eaolian sands cover the surface.[1]

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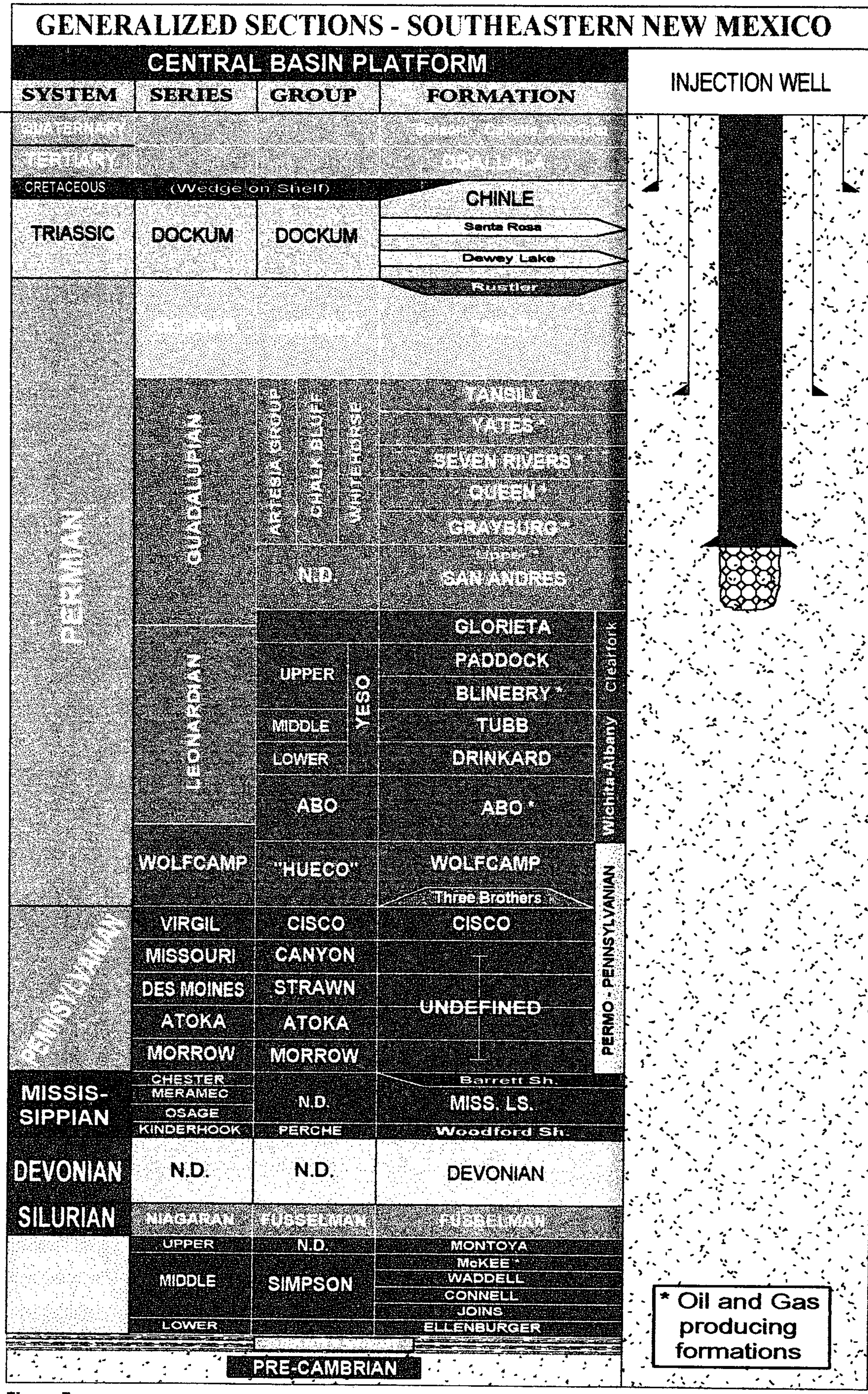
[1] Geohydrology Associates, 1982.

Table 4 – Geologic Cross Section at DLD Resources Plant Site[1]

From – To	Thickness (ft)	Formation	TDS (mg/l)
0 – 2	2	Soil	
2 – 22	20	Caliche	
22 – 45	23	Ogallala	600 - >3250
45 – 1008	963	Redbeds	
Top of anhydrite (1008)			
1008 – 1160	152	Dockum Group	
1160 – 2303	1143	Salt	
2303 – 2423	120	Tansill	
2423 – 2853	430	Yates	
2853 – 3225	372	7-Rivers	
3225 – 3570	345	Queen	
Top of Penrose (3380)			13 - 19000
3570 – 3800	230	Grayburg	15 - 34000
3800 – 5150	1350	San Andres	>15000
Top of Oil-Water Contact (3995)	Disposal Zone (4300-5150)		
5150 – 5244	94	Glorieta	
5244 – 5695	451	Paddock	~26000 – ~87000
5695 – 6316	621	Blinebry	~74000
6316 – 6334	18	Tubb	
6334 – 7075	741	Drinkard	
7075 – 7843	768	Abo	~78000
7843 – 8120	277	Wolfcamp	
8120 – 8362	242	Pennsylvanian	
8362 – 9207	845	Devonian-Silurian	
9207 – 9875	668	Montoya	
9875 – 10147	272	Simpson Group	
10147 – 10216	69	Ellenburger	
10216 ----		Granite	

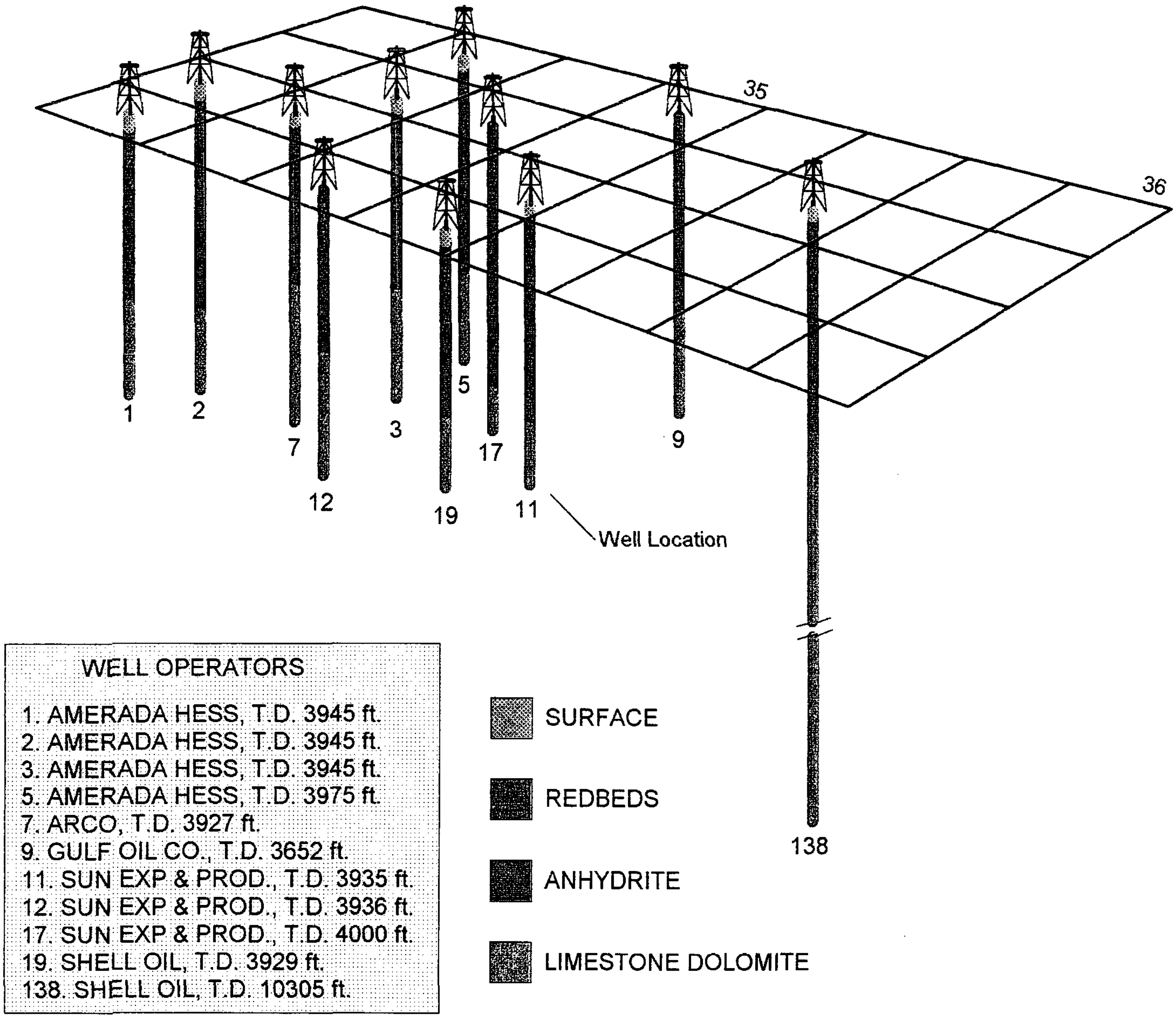
[1] KEDA, Vol. I., Table 3.1, p. 12.2, 12.3.



GENERALIZED SECTIONS - SOUTHEASTERN NEW MEXICO
CENTRAL BASIN PLATFORM
INJECTION WELL
SYSTEM
SERIES
GROUP
FORMATION
QUATERNARY
TERTIARY
OGALLALA
CRETACEOUS
(Wedge on Shelf)
CHINLE
TRIASSIC
DOCKUM
DOCKUM
Santa Rosa
Dewey Lake
Rustler
PERMIAN
GUADALUPIAN
ARTESIA GROUP
CHALK BLUFF
WHITEHORSE
TANSILL
YATES *
SEVEN RIVERS *
QUEEN *
GRAYBURG *
N.D.
Upper *
SAN ANDRES
LEONARDIAN
GLORIETA
UPPER
MIDDLE
LOWER
YESO
PADDOCK
BLINEBRY *
TUBB
DRINKARD
ABO
ABO *
Clearfork
Wichita-Albany
WOLFCAMP
"HUECO"
WOLFCAMP
Three Brothers
PENNSYLVANIAN
VIRGIL
CISCO
CISCO
MISSOURI
CANYON
DES MOINES
STRAWN
UNDEFINED
ATOKA
ATOKA
MORROW
MORROW
PERMO - PENNSYLVANIAN
MISSIS-SIPPIAN
CHESTER
MERAMEC
OSAGE
KINDERHOOK
N.D.
PERCHE
Barrett Sh.
MISS. LS.
Woodford Sh.
DEVONIAN
N.D.
N.D.
DEVONIAN
SILURIAN
NIAGARAN
FUSSELMAN
FUSSELMAN
UPPER
N.D.
MONTOYA
MIDDLE
SIMPSON
McKEE *
WADDELL
CONNELL
JOINS
LOWER
ELLENBURGER
PRE-CAMBRIAN
* Oil and Gas producing formations

Figure 7

Figure 8 – Stratigraphic Column #1



STRATIGRAPHY TAKEN FROM DRILLERS LOGS

FIGURE 8

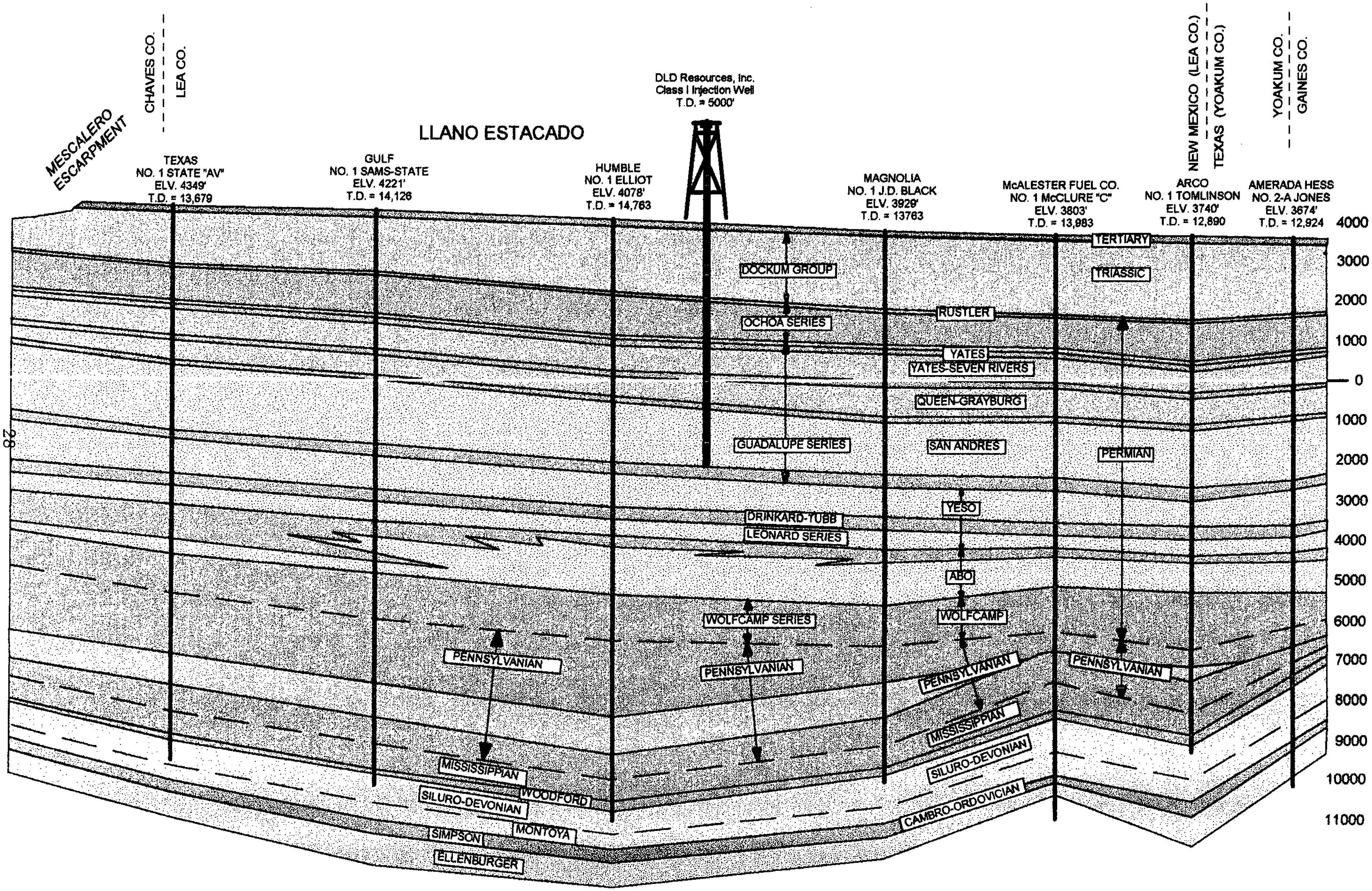


Figure 9 - Stratigraphic Column #2

STRUCTURAL GEOLOGY

Regional Structure

West Texas and half of southern New Mexico is part of a large subsurface structural feature known as the Permian Basin, which is subdivided into several smaller areas. DLD Resources is located on the Central Basin Platform (see Figure 10). The Central Basin Platform is bounded by the Northwestern Shelf on the north, the Delaware Basin on the west, the Sheffield Channel and Southern Shelf on the south, and the Midland Basin on the east.[1] Basins are depressed areas varying in size and shape and are formed by subsidence of an area and/or uplift of the surrounding regions. In most cases, basins probably result from both subsidence and uplift.[2]

Within the Permian Basin are several basins, however, the most important to the Monument area are the Delaware Basin, the Central Basin Platform, and the Midland Basin. Also present are shelf, platform, and uplift areas. The basins were dominantly negative features, which are believed to be 100 miles or more across.[3] Due to subsidence, the basins received larger amounts of sediments than the surrounding areas. Strata in the basins are found at greater depths than the equivalent beds on the shelves and platforms. The platforms and shelves were positive areas that rose as narrow, elongated masses between the basins.

During Permian time, the basin areas were covered by deeper water than the shelf and platform areas accounting for the contrast in facies. These contrasts suggest that sedimentation was not keeping pace with subsidence and the two processes were independent of each other. Shallow water over the shelves and platforms is indicated by the presence of evaporites and carbonate deposits.

These Permian Basin structures are reflected indirectly in Mesozoic and Cenozoic rocks since there has been no major tectonic movement within the basin since the end of Permian time.

Local Structure

A structural contour map has been constructed for the top of the San Andres Formation using electric logs.[4] This map indicates that a general westward dip occurs with a more pronounced dip to the southwest and the northwest. A structural high is exhibited to the east, which is concurrent with the trapping of hydrocarbons in the Monument Field. The interval (1380') between the top of the Glorieta Formation and the top of the San Andres Formation was contoured using isopack values computed from the inspection of the available electric log control.[5]

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[1] Jones, T. S., 1953, *Stratigraphy of the Permian Basin of West Texas,* West Texas Geological Society, p. 3.

[2] Huffington, Roy, 1951, *Introduction to the Petroleum Geology of the Permian Basin of West Texas and Southeastern New Mexico,* p. 51.

[3] King, Phillip B., 1942

[4] KEDA, Vol. I., Plate 4

[5] KEDA, Vol. I, 1984, p. 23 and Plate 5.

Figure 10 – Permian Basin Structure

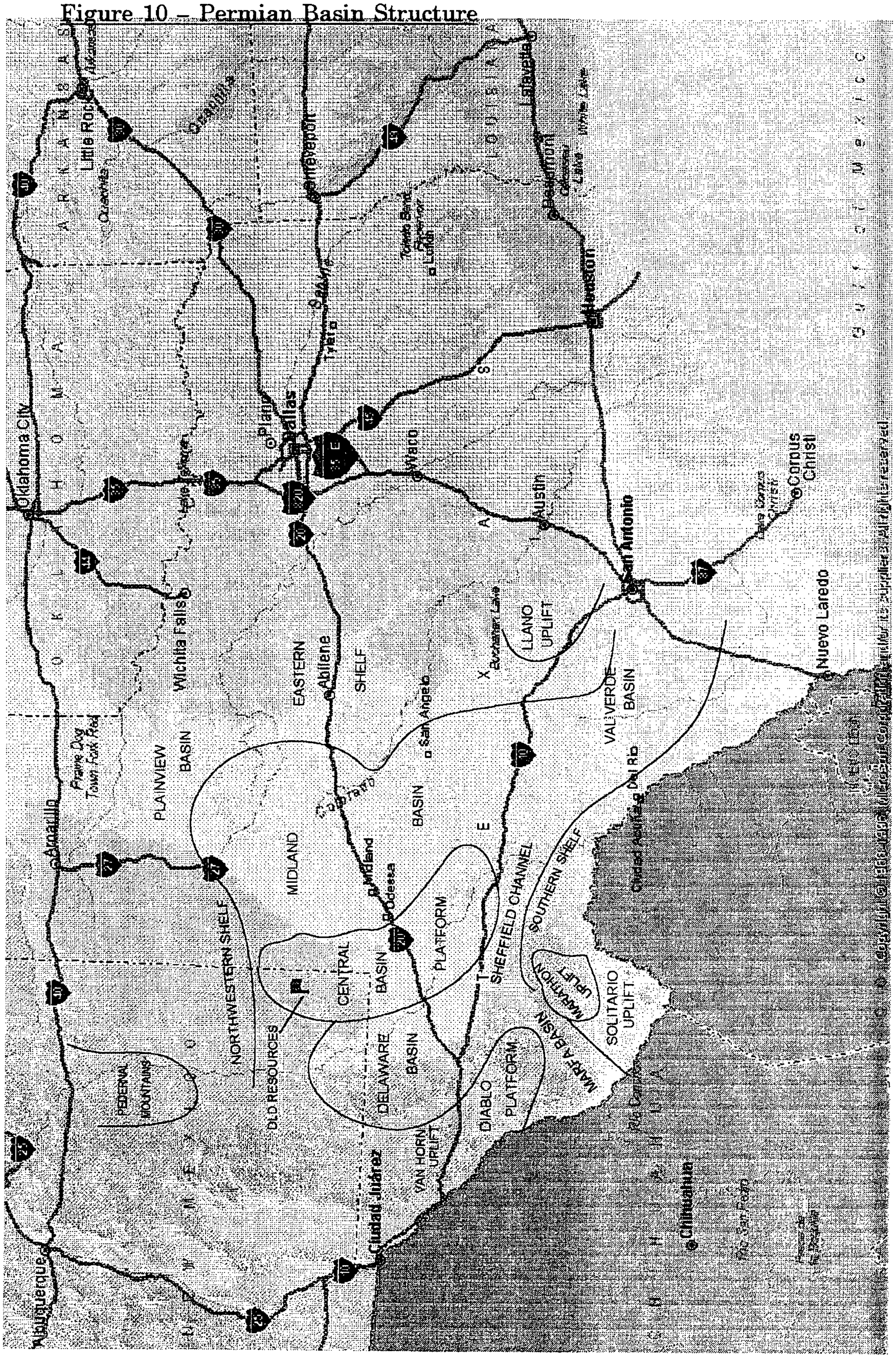

Figure 10 - Permian Basin Structure

To further exhibit the structure of the area, north-south and east-west cross sections were drafted and depicted in KEDA, Vol. I. as Plates 6 and 7. Analysis of the logs was limited to the picking of certain formation tops. Information regarding confining zones is best depicted on a porosity type log. A detailed analysis of the sonic log of the Amerada State "V" #5 was provided by KEDA to address the confining intervals. This log is of good quality and is typical of the project area. An index map illustrating locations of all the cross sections is contained in KEDA, Vol. I., as Figure 3.6, page 24.

Besides the Delaware Basin and the Central Basin Platform, other structural features in southern Lea County are unconformities. As defined, an unconformity is an erosional surface separating younger strata form older strata. They are indicative of an area which was emergent and undergoing erosion that later became submergent and an area of renewed deposition.

Contact between the Permian and Triassic is represented by an erosional unconformity sloping to the southeast. This unconformity represents the lower limit of potable and industrial ground water. In areas underlain by redbeds, this lower boundary is indefinite and in general, the top of the underlying Rustler Formation is used as the lower limits of ground water.[1]

The surface of the undifferentiated redbeds associated with the unconformity was formed in part by features referred to as closed depressions. These features probably formed when overlying Triassic rocks collapsed into cavities in the underlying Permian salt beds. Gradual subsidence due to removal of salt by the ground water may also have been a contributing factor to the formation of closed depressions.

An erosional unconformity is also present between rocks of Triassic and Tertiary age. The surface is high irregular with moderate relief and has undergone tow or three episodes of erosion truncating the southeastward dipping formations. Triassic rocks beneath the unconformity thicken southeastward.

Seismic History

DLD Resources is located in a seismically stable area of the United States. The Monument area is considered to be in Zone 1 of seismic risk (see Figure 11).[2]

SURFACE SOIL TYPES:

The following soil types are associated with DLD's property: KO (Kimbrough gravelly loam, 0-3% slope); TF (Tonuco loamy fine sand); BE (Berino-Cacique loamy fine sands association); BF (Berino-Cacique fine sandy loams association).[3]

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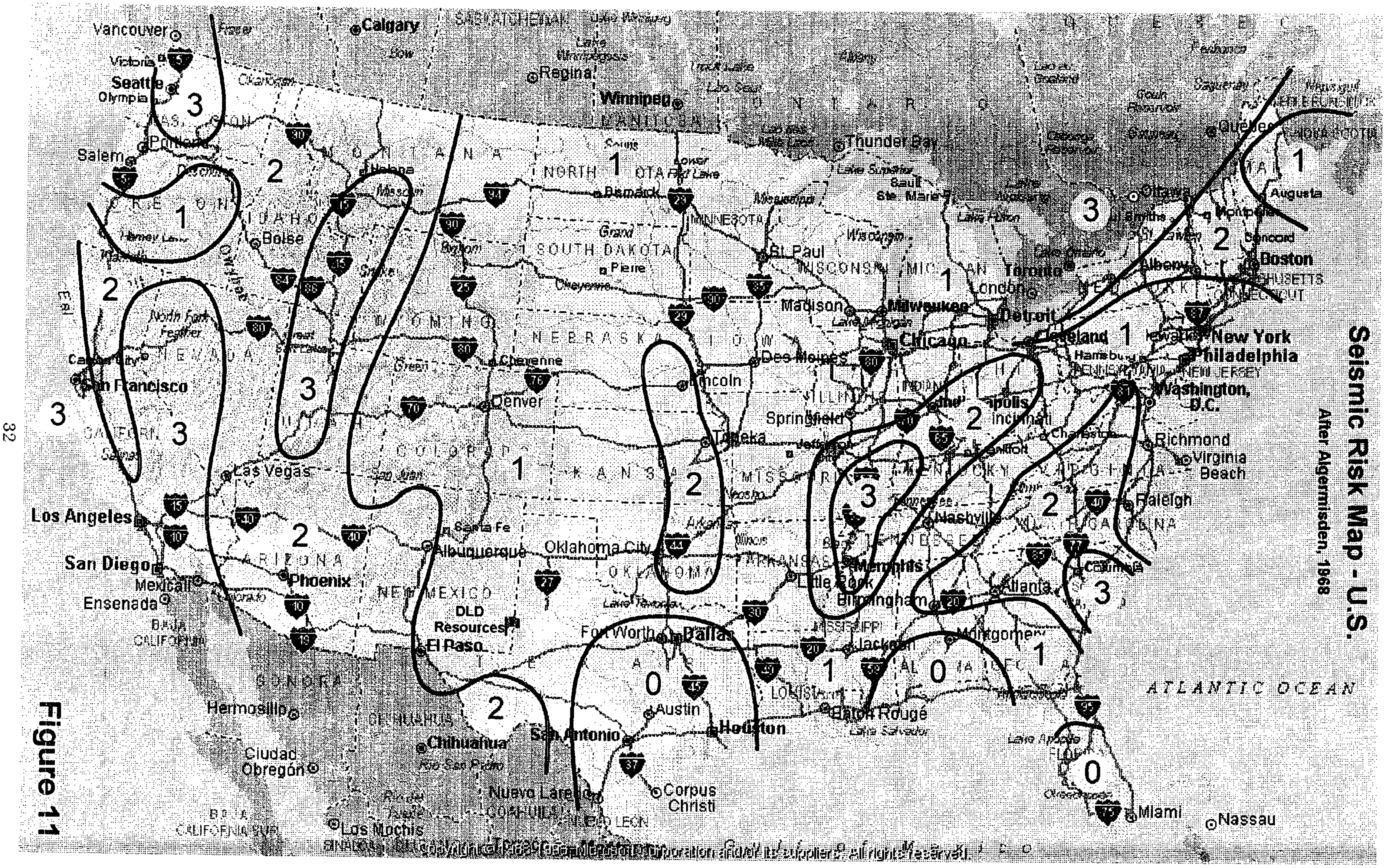
[1] Nicholson and Clebsch, 1961.

[2] Algermissen, S.T., 1969, *Seismic Risk Studies in the United States*, Reprint from Proceeding of the Fourth World Conference on Earthquake Engineering, Chilean Association for Seismology and Earthquake Engineering, Santiago, Chile, 20 p.

[3] Information taken from Soil Survey, Lea County New Mexico, United States Department of Agriculture, Soil Conservation Service, in cooperation with New Mexico Agricultural Experiment Station, issued January 1974. (DLD location shown on pages 124-125.)



0 No Damage 1 Minor Damage 2 Moderate Damage 3 Heavy Damage

Figure 11

Kimbrough Series

The Kimbrough series consists of well-drained loams, gravelly loams, or gravelly fine sandy loams overlying indurated caliche at a depth of 6 - 20 inches. These soils formed in wind-deposited and water-deposited sediments on uplands in the northern half of Lea County. Slopes are 0 - 3%. The vegetation consists of short and mid grasses and shrubs. The average annual precipitation is 12 - 15 inches, the average annual air temperature is 58° to 60° F., and the frost-free season is 195 to 205 days. Elevations range from 3,600 to 4,200 feet. Kimbrough soils are associated with Lea, Stegall, Portales, and Arvana soils.

Typically, the surface layer is dark grayish-brown gravelly loam about 6 inches thick. In places it is loam. The substratum is white indurated caliche.

Kimbrough soils are used for range, wildlife, and limited irrigated farming. They are a source of crushed caliche for use in construction.

Kimbrough gravelly loam, 0 to 3 percent slopes (KO): This soil is on low ridges in the northern part of Lea County. Included in mapping are areas of Lea, Sharvana, Stegall, and Slaughter soils.

A representative profile of Kimbrough gravelly loam, on the north edge of a caliche pit, SW ¼ NE ¼ sec. 16, T. 17 S., R. 37 E.:

A11 - 0 to 2 inches, dark grayish-brown (10YR 4/2) gravelly loam, very dark grayish-brown (10YR 3/2) when moist; moderate, thin, platy structure; slightly hard, friable when moist, sticky and slightly plastic when wet; few caliche fragments on the surface and intermixed; mildly alkaline (pH 7.8), slightly calcareous; abrupt boundary. 2 to 6 inches thick.

A12 - 2 to 6 inches, dark grayish-brown (10YR 4/2) gravelly loam, very dark grayish-brown (10YR 3/2) when moist; moderate, medium, subangular blocky structure; slightly hard, very friable when moist, sticky and slightly plastic when wet; many, sharp-angled, hard caliche fragments intermixed; mildly alkaline (pH 7.8), strongly calcareous; abrupt boundary. 4 to 10 inches thick.

Ccam - 6 inches, white (10YR 8/1), indurated caliche, fragmental and indurated to a depth of about 30 inches, graded to weakly cemented, white caliche below. Several feet to many feet thick.

The "A" horizon ranges from gravelly loam to gravelly fine sandy loam in texture and from 7.5YR to 10YR in hue. It is dark grayish-brown when dry and very dark grayish-brown when moist. In areas where this horizon is gravelly, the depth to indurated caliche is 6 - 16 inches. The caliche is either fragmentary or massive.

This soil is moderately permeable. Runoff is slow to medium. Water intake is moderate, and the available water holding capacity is 1 to 2 inches. Roots penetrate to a depth of 6 to 16 inches. Erosion is a slight hazard.

This soil is too shallow to be suitable for crops. It is used for range and wildlife. It is also a source of crushed caliche for use in construction.

Tonuco Series

The Tonuco series consists of excessively drained loamy fine sands 10 to 20 inches thick over indurated caliche. The surface layer is loamy fine sand to fine sand and is underlain by loamy fine sand. These non-calcareous, coarse textured soils formed in wind-deposited sands over thick sloping ridges throughout the shallow sand country in the southern part of Lea County. Slopes are 0 to 3 percent. The vegetation consists of mid-grasses, forbs, and shrubs. The annual precipitation is 10 to 13 inches, the annual average air temperature is 59° - 62° F., and the frost-free season is 190 to 205 days. Elevations range from 3,200 to 3,900 feet. These soils are associated with Palomas, Cacique, and Simona soils.

Typically, the surface layer is yellowish-red loamy sand about 12 inches thick. In places it is fine sand. The next layer is yellowish-red loamy sand about 5 inches thick. The substratum is indurated caliche.

Tonuco soils are used as range, wildlife habitat, and recreational areas. Indian artifacts can be found in some areas.

Tonuco loamy fine sand, 0 - 3% slopes (TF): This gently undulating soil is on uplands, ridges, and level prairies. Included in mapping are areas of Simona, Berino, and Cacique soils.

A representative profile of Tonuco loamy fine sand, about 0.2 mile west of the entrance road to gas plant in the southeastern part of Eunice, about half a mile west of the southeast corner of sec. 34, T. 21 S., R. 37 E.:

A1 - 0 to 12 inches, yellowish-red (5YR 5/6) loamy fine sand, yellowish red (5YR 4/6) when moist; very weak, medium, subangular blocky and weak, fine, granular structure; soft, very friable when moist, nonsticky and nonplastic when wet; few small pockets of lighter colored sand intermixed; many fine roots; few organic stains; neutral (pH 7.1), noncalcareous; clear boundary. 8 to 12 inches thick.

AC - 12 to 17 inches, yellowish-red (5YR 5/6) loamy sand, yellowish-red (5YR 4/6) when moist; weak, medium, subangular blocky and weak, coarse, prismatic structure; soft, very friable when moist, nonsticky and nonplastic when wet; many fine roots; common organic stains; neutral (pH 7.3), noncalcareous; abrupt boundary. 4 to 8 inches thick.

IICcam - 17 inches, white (5YR 8/1), indurated caliche, fractured in places.

The soil ranges from 10 - 20 inches in thickness. The "A" horizon ranges from 5YR to 7.5YR in hue, and the AC horizon from 2.5YR to 7.5YR. Typically, the soil is neutral, but ranges from neutral to mildly alkaline. There are a few segregated lime films on some peds. In places quartzose gravel and caliche fragments occur above the indurated caliche.

Permeability is very rapid. Runoff is very slow, and water intake is rapid. The available water holding capacity is 1 to 2 inches. The effective rooting depth is 10 to 20 inches. Soil blowing is a severe hazard.

The soil is used as range, wildlife habitat, and recreational areas.

Berino Series

The Berino series consists of well-drained soils that have a light sandy clay loam subsoil. These are undulating to hummocky soils on upland plains in the "deep sand country" in the southern part of Lea County. They formed in wind-worked sands of mixed origin overlying alluvial, sandy, calcareous sediments. Slopes are 0 to 3 percent. The vegetation consists of mid and tall grasses and shrubs. The average annual precipitation is 10 to 13 inches, the average annual air temperature is 60° to 62°F., and the frost-free season is 195 to 205 days. Elevations range from 3,000 to 3,400 feet above sea level. These soils are closely associated with Maljamar, Palomas, and Cacique soils.

Typically, the surface layer is reddish-brown loamy fine sand about 6 inches thick. The subsoil is red light sandy clay loam about 42 inches thick. The substratum, to of depth of 60 inches and more, is pink light sandy clay loam that has a high lime content.

Berino soils are used as wildlife habitat, range, and recreational areas. Indian artifacts can be found in some areas.

Berino-Cacique loamy fine sands association, 0 - 3% slopes (BE): About 50 percent of this association is Berino soils and about 40 percent is Cacique soils. The rest is Maljamar, Palomas, and Tonuco soils. This association is mostly in the southern part of Lea County.

A representative profile of Berino loamy fine sand in an area of Berino-Cacique loamy fine sand association, northeast quarter of sec. 16, T24S, R34E, about ¾ mile north of highway:

A1 - 0 to 6 inches, reddish-brown (5YR 4/4 loamy fine sand, dark reddish brown (5YR ¾) when moist; weak, fine, granular structure; soft, friable when moist, non-sticky and non-plastic when wet; many fine roots; neutral (pH 7.0), non-calcareous; smooth, abrupt boundary. 4 to 10 inches thick.

B1 - 6 to 16 inches, red (2.5YR 4/6) light sandy clay loam, dark red (2.5YR 4/6) when moist; moderate, medium sub-angular blocky structure; soft, friable when moist, non-sticky and non-plastic when wet; many medium roots; neutral (pH 7.0), non-calcareous; smooth, clear boundary. 4 to 12 inches thick.

B2t - 16 to 30 inches, red (2.5YR 5/6) light sandy clay loam, red (2.5YR 4/6) when moist; strong, medium, sub-angular blocky structure; slightly hard, friable when moist, sticky and slightly plastic when wet; common medium and fine roots; moderately thick clay films; neutral (pH 7.1), non-calcareous; gradual boundary. 12 to 20 inches thick.

B3 - 30 to 48 inches, red (2.5YR 5/6) light sandy clay loam, red (2.5YR 5/8) when moist; weak, coarse, prismatic and weak, fine, granular structure; slightly hard, friable when moist, sticky and slightly plastic when wet; few fine roots; neutral (pH 7.3), non-calcareous; clear boundary. 7 to 20 inches thick.

Cca - 48 to 60 inches, pink (7.5YR 7/4) light sandy clay loam, light brown (7.5YR 6/4) when moist; massive; soft, friable when moist, slightly sticky and slightly plastic when wet; moderately alkaline (pH 8.4), strongly calcareous.

The "A" horizon ranges from brown to reddish brown. It is loamy sand to loamy fine sand and in places has a thin layer of fine sand on the surface. Reaction of the "A" horizon is neutral to mildly alkaline. The "B" horizon ranges from reddish brown to yellowish red or red. It is heavy fine sandy loam to sandy clay loam. The clay content is 18 to 30 percent. The B2t horizon is generally neutral but in places is mildly alkaline in the lower part. The Cca horizon is commonly at a depth of 29 to 60 inches, and lime content ranges from moderate to high. The Cca horizon is soft or strongly cemented caliche in some areas where Berino soils are associated with Cacique soils.

The Berino soil is moderately permeable. Runoff is very slow. Water intake is rapid. Available water holding capacity is 7 to 10 inches. Roots penetrate to a depth of 60 inches or more. Soil blowing is a severe hazard.

The Cacique soil is moderately permeable. Runoff is very slow. Water intake is rapid, and the available water holding capacity is 3 to 6 inches. Root penetration is restricted by the indurated caliche at a depth of 20 to 34 inches. Soil blowing is a severe hazard.

The soils in this association are used as range, wildlife habitat, and recreational areas.

Berino-Cacique fine sandy loams association, 0 - 3% slope (BF): This mapping unit is about 50% Berino fine sandy loam, 40% Cacique fine sandy loam, and 10% Pyote, Kermit, and Wink soils.

The Berino soil is similar to Berino loamy fine sand, but is surface layer is fine sandy loam about 8 inches thick. The Cacique soil is similar to Cacique loamy fine sand, but is surface layer is fine sandy loam about 8 inches thick.

Runoff is slow. Water intake is moderate. Soil blowing is a moderate hazard.

These soils are used as range, wildlife habitat, and recreational areas.

MONITOR WELL LITHOLOGICAL DATA

Lithologic Log 1 - Monitor Well #2-3 (drilled 3/4/81); T19S, R36E, Sec. 35.323

Thickness (feet)	Description
0 - 5	sand and soil; buff in color, unconsolidated; medium-coarse grained
5 - 10	sand; light-brown, medium-fine grained
10 - 15	caliche; some sand; light brown to gray; calcium carbonate cement; dry
15 - 20	sand; light brown, fine grained, calcium carbonate cement; caliche or limey sand fragments; dry
20 - 25	sand and caliche; brown, poorly cemented caliche fragments; calcium carbonate cement
25 - 30	sand; brown, very poorly cemented, caliche fragments; calcium carbonate cement; dry
30 - 35	same as above; dry
35 - 40	sand; light brown, fine grained; dry
40 - 45	sand, light brown to buff; some clay present, medium to fine grained, with caliche fragments; dry
45 - 50	sand and caliche; light brown, mostly sand; medium grained, with caliche fragments; dry
50 - 52	red bed; dry; sandy mudstone with larger quartz inclusions; mostly clay
52 - 55	same as above
55 - 58	moist, mudstone, red, gypsum and caliche fragments; mostly clay
58 - 60	mudstone; dark red to brown; sandy, moist; gypsum and caliche fragments present
60 - 65	shaley mudstone, slightly moist, deep red to brown, sandy; mostly clay
65	TOTAL DEPTH

Lithologic Log 2 - Monitor Well #3-3 (drilled 3/4/81); T19S, R36E, Sec. 35.234

Thickness (feet)	Description
0 - 5	soil, very sandy; red grained, poorly cemented; clay abundant; light brown; caliche fragments
5 - 10	sand; buff in color; fine grained gypsum and caliche fragments, some clay
10 - 15	sand and caliche; light brown to buff
15 - 20	sand and caliche; light brown, calcium carbonate cement
20 - 30	same as above
30 - 35	red siltstone and mudstone, dry, mostly silt
35 - 39	red siltstone, dry; no calcium carbonate at all
39	TOTAL DEPTH

Lithologic Log 3 - Monitor Well #4-3 (drilled 3/4/81); T19S, R36E, Sec. 35.442

Thickness (feet)	Description
0 - 5	soil, brown, sandy with a lot of clay
5 - 10	sand and caliche; brown, abundant clay
10 - 15	same as above except moist
15 - 20	same as above
20 - 25	soil and caliche; light brown; saturated
25 - 30	sand and caliche with gypsum fragments, brown, very coarse grained; saturated
30 - 35	mudstone and shale, brown red, large caliche fragments; saturated
35 - 39	mudstone and shale; abundant clay, deep red, caliche fragments; saturated
39	TOTAL DEPTH

Lithologic Log 4 - Monitor Well #5-3 (drilled 3/4/81); T19S, R36E, Sec. 36.313

Thickness (feet)	Description
0 - 5	caliche with some sand, light brown
5 - 10	same as above
10 - 15	sand with caliche fragments, some gypsum fragments, light brown, calcium carbonate cement
15 - 20	same as above; slightly moist
20 - 25	caliche rock and sand; some gypsum fragments, light brown; saturated
25 - 30	same as above
30 - 35	same as above
35 - 39	red beds, shale and mudstone, caliche fragments, saturated
39	TOTAL DEPTH

Note: The wells were drilled using an air rotary drilling rig, making approximately a 5-7/8" hole. Prior to inserting the 4" PVC casing, the bottom was perforated with twelve 6" X 1/8" slots. After placing the casing into the hole, soil was packed around the annular space between the hole and the casing.

RESERVOIR ANALYSIS

RESERVOIR DESCRIPTION

Scope

It is requested that the injection well should be capable of handling an injection volume of 84 million gallons per year (160 gpm average flow) and a maximum instantaneous injection rate of 200 gpm. In view of this requirement, reservoir pressure analysis and process design aspects are presented to cover the flow range of 160 – 200 gpm.

The summary data on maximum allowable surface injection pressures as related to well design and flow rates are presented in Table 5.1 (KEDA, Vol. I, p. 36). The well was constructed utilizing 3 ½ inch injection tubing, thus KEDA's projections indicate that the maximum allowable surface injection pressure should be 1010 psi.

Proposed Formation

It is important to define the injection reservoir in order to model its pressure behavior. Table 5 presents the thickness data on the injection interval and confining strata. According to electric logs from Artificial Penetration #125, about 71.6% of the San Andres Formation between 4340' ± and 4920' ± is permeable and porous.[1]

Permeability cannot be estimated from the log. This determination has been done based on an injectivity fall-off test reported for a Browning-Ferris Industry disposal well located at Odessa, Texas. This well has been completed into the San Andres.

The porosity of the San Andres Formation (10% - 12%) is well known from several density logs in the study area. Therefore, the net useable thickness for all pressure estimates is projected to be 415 feet.

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[1] KEDA, Vol. I, Table 5.2; Plate 10, p. 37.

Table 5 – Correlative Injection Zone Thickness[1]

STRATA	DEPTH, FT.	THICKNESS, FT.
a) Overlying strata with low porosity	4105 – 4340	235
b) Proposed injection interval	4340 – 4920	580
c) Underlying strata with low porosity	4920 – 5850	930
d) Total depth	5000	

Electric logs of the overlying strata (235 feet) indicate very low porosity. These strata should act as a barrier between upper aquifers and the injection interval. The strata underlying the injection interval are about 930 feet thick. It also appears to be non-porous. Published data of confining zones immediately above and below the disposal zone and log interpretation indicates adequate confinement to prevent vertical fluid movement.

Confining zones are typically evaluated based on porosity and permeability of the reservoir rock. KEDA's approach in the original study was to evaluate the porosity of the confining intervals from geophysical logs and to correlate the porosity to permeability values from generic curves.

As an example, an analysis is presented of the log from the Amerada Hess State "V" #5 (KEDA control #120), located in Sec. 36, T-19S, R-36E, 2800'+ from the well site. The objective of this log was to determine porosity of the reservoir rock. (A copy of the log is contained in KEDA, Vol. I, Appendix H).

The top of the San Andres is indicated from the gamma ray portion of the log to be at 3910'. The oil-water contact in this area is known to occur at 400' below mean sea level.[2] Since the surface elevation of this well is 3592', all San Andres production must occur above 3992'.

The interval from 3992' to 4110' is represented by erratic shifts in the transit time curve of the sonic log indicating scattered porosity.

The interval from 4110' to 4225' is of primary interest as a confining unit. This interval is 116' thick and falls between the oil/water contact and the top of the disposal zone at 4335'. In the confining interval, the sonic transit time ranges between 43 and 50± microseconds per foot. This corresponds to a porosity in limestone reservoirs of 0-4% (KEDA, Vol. I, Figure 5.0A, p. 38.4).

The petrophysical relationship between permeability and porosity in several formations is shown in Figure 5.0B, KEDA, Vol. I, p. 38.5). At a porosity value of 4%, the permeability in the confining interval is close to zero.

[1] Schlumberger Data Induction Waterlog, Amerada Hess – State "V", Monument-McKee, sec. 36, 19S, 36E.

[2] Babcock, C.V., 1956, Symposium of Oil and Gas Fields of Southeast New Mexico, Roswell Geological Society, p. 164-165.

A similar analysis was applied to the remainder of the San Andres to identify receptive disposal intervals and interbedded confining units. This data is summarized in Table 6.[1] As indicated in Table 6, a 260' confining barrier is located beneath the disposal zone.

It is notable on the log that the evaporite section from the top of the Rustler formation (1040') to the top of the Yates formation (2440') provides a massive confining unit between the disposal zone and the Ogallala water bearing formation above.

Table 6 – San Andres Formation Porosity Data

Interval Ft.	Thickness Ft.	Porosity %	Comments
3939 – 4160	250	4 - 16%, avg. 12%	Top of San Andres at 3910'; Potential oil production above 4000'
4160 – 4276	116	Less than 4%	Barrier zone; Permeability probably less than .02md
4276 – 4335	59	4 – 12%	Top of disposal zone
4335 – 4370	35	16 – 18%	Primary Receptor Interval
4370 – 4620	250	Scattered, avg. 12%	
4620 – 4640	20	Less than 4%	
4640 – 4720	80	12 – 16%	Primary Receptor Interval
4720 – 4850	210	4 – 12%	
4850 – 4910	60	12 – 16%	Primary Receptor Interval
4910 – 5170	260	Less than 4%	Barrier Zone; Top of Glorieta 5130'

Formation Properties and Operating Parameters

The reservoir calculations performed by KEDA in the original study incorporated the reference data given in Tables 7 and 8.[2]

Liquid Permeability (K): An average liquid permeability of the San Andres formation was estimated to be 30 millidarcies. Two wells of Rice Engineering Co. in the same injection zone indicated permeability from 50 – 70 millidarcies after acid stimulation.

Porosity (0): The best estimate from electric logs of offset wells shows San Andres porosity to be about 10%. (Actual core porosity average was 9%).

Compressibility [c]: The total compressibility of the formation and connate fluid was estimated to be 3 X 10^{-6} psi^{-1}, for the carbonate rock at a depth of 4340'.

Reservoir Hydrostatic Gradient: Two wells in the study area were examined to estimate the hydrostatic gradient. Rice Engineering Well #5 indicated a gradient of 0.32 psi/ft and another well in Odessa, TX indicated a gradient of 0.4 psi/ft. As a conservative estimate, a gradient of 0.4 psi/ft was considered reasonable. The bottom-hole pressure at the Odessa

[1] KEDA, Vol. I, p. 38.3.

[2] KEDA, Vol. I, Tables 5.3A & 5.3B, p. 40-41

well was reported to be 2150-psi @ 5380'. (Actual hydrostatic gradient of the completed well was 0.413-psi/ft).

Reservoir Temperature: Electric log data indicated the bottom-hole temperature to be 107°F. at 4340'.

Flow Rate: The average flow rate was estimated to be 160 gpm while the maximum flow rate was not to exceed 200 gpm.

Viscosity: Viscosity was assumed to be that of water.

Specific Gravity: Estimated to be 1.05 (saline solution)

Table 7 – Formation Properties Used For Calculations

Description	Typical	Range
Liquid Permeability, millidarcy	30	20 – 50
Proposed Formation, ft.	4350 to 4950	N/A
Well Completion Thickness, ft.	580 (open hole)	200 – 600
Net Useable Thickness, %	71.6	50 – 80
Net Useable Thickness, ft.	415	100 – 600
Porosity, %	10	10 – 15
Compressibility, l/psi	3.0 X 10^{-6}	10-6±
Distance/Radius, ft.	0.33	0.3±
Skin Factor, dimensionless	0	0 – 20
Hydrostatic gradient, psi/ft	0.4	N/A
Specific Gravity	1.02	N/A
Bottom-Hole Temp, °F.	107	N/A

Table 8 – Operating Parameters Used For Calculations

Description	Data
Average Flow rate, gpm	106
Viscosity @ 72oF, cp water	1
Viscosity @ Bottom-Hole, cp	0.7
Injection time, yr.	20
Specific Gravity of Material	1.05

BOTTOM HOLE PRESSURE INCREASE

Reservoir Mechanics

In order to model the hydrodynamics of the underground injection of fluids, it was necessary to make four assumptions.

The first assumption is that the injection reservoir is a horizontally layered homogeneous, porous and permeable aquifer with low porosity and low permeability layers located above and below the injection zone. Historically, the San Andres formation has been used for deep well disposal, and it conforms to the above criteria.

The second assumption is that the physical properties of the injected fluids at reservoir temperatures and pressures do not differ significantly from the connate waters.

The third assumption is that the injection fluids can move out uniformly and radially in all directions and that, the relative thickness of the disposal reservoir remains constant.

The fourth assumption is that overlying and underlying layers remain constant over similar distances.

Most reservoirs are layered because of stratification; therefore, overlying and underlying strata are layers having transmissivity and porosity lower than the zone of interest.

This concept in KEDA's modeling of the reservoir was based on the cross-sectional mapping and the logs from the nearest wells to the site. In KEDA's estimation, cross-flow between these layers should be negligible. It was pointed out that the underlying and overlying layers are not shale strata, but rather dense carbonate layers. On the basis that cross-flow does not take place, KEDA made the basic assumption that the injection zone was homogeneous for estimating pressure buildup in the reservoir. Furthermore, KEDA assumed a net effective injection interval of 415 ft out of an available 580 ft based on this formula:

$$\lambda = \frac{\Sigma K_i \bullet h_i}{\Sigma h_i}$$

where λ = effective (or equivalent) permeability of the total interval estimated to be 32 millidarcies.

K = permeability of the i^{th} interval

h_i = height of the i^{th} interval

To describe the mechanics of waste fluid injection it is necessary to visualize the disposal reservoir before injection begins. The injection reservoir is primarily composed of calcium carbonate with 10% porosity and 30 millidarcy permeability values. The pore spaces are completely saturated with native brine. Storage of wastes in the injection reservoir is not available except by displacement of the native fluid. In subsurface saline aquifers, storage is obtained by compression of the reservoir and native fluid. Most injection wells require sufficient surface injection pressures to displace the native fluid outward in a radial flow pattern.

As soon as injection begins, a cone of pressure elevation develops immediately with its apex at the wellbore. The amount of pressure build-up is determined by the injection flowrate and reservoir properties. The long-term effects are transmitted to the hydrologic boundaries of the disposal reservoir. In this case, the pressure effects are spread over a very large area. The area of investigation (2-½ mile radius) is so large that when waste fluid injection stops, the disposal reservoir comes to equilibrium with very small residual pressure effects.

RESERVOIR PRESSURE BUILD-UP MODEL

Matthews and Russel Equation

KEDA calculated the projected pressure increase in the injection zone for the DLD well using an equation developed by Matthews and Russel, (1967)[1]. KEDA, Vol. I, page 46 presents the Matthews and Russel equation and is reproduced as follows:

$$\Delta p = \frac{70.6\, q\mu}{kh}\left[1n \left(\frac{kt \quad 2}{70.4\, \mu\, \phi\, cr} \right) + 2S \right]$$

Where:

Δ p = bottom hole pressure increase, psi
q = injection rate, bbl/day
Φ = viscosity, cp
r = radius, ft.
t = time, days
k = permeability, md
h = net reservoir thickness, ft.
Φ = porosity, fraction
c = total compressibility, psi-1
S = skin factor

(note: this equation and symbol definitions were taken exactly as presented in KEDA, Vol. I, pg 46.

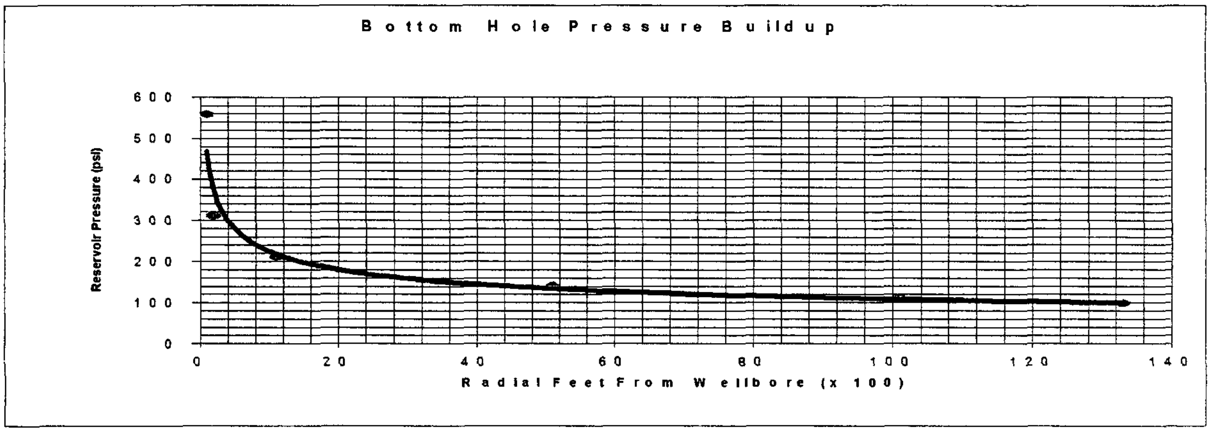
Single Injector, Bottom Hole Pressure Build-Up

Considering the injection and operating variables (Tables 7 and 8), the projected bottom hole pressure increase would be about 558 psi in 20 years. If operating conditions differed from the assumed conditions, the bottom hole pressure could increase in the range 176 psi to 1160 psi. The calculated changes in bottom hole pressure as a function of skin factor, net useable disposal zone thickness, and formation permeability are presented in Table 5.5 of KEDA, Vol. I., page 48.

[1] Matthews, C. S., and Russel, D. G., 1967, Pressure Buildup and Flow Tests in Wells Monograph Series, Society of Petroleum Engineers or AIME, Dallas, TX.

The amount of bottom hole pressure build-up due to proposed injection would be greatest at the borehole and would fall off significantly as the radial distance from the borehole increased. KEDA projected that the pressure build-up at the 2-½ mile radius would be 97 psi after 20 years of operation @ an average injection rate of 160 gpm. These figures are presented in Table 5.6 of KEDA, Vol. I., page 49, and graphically as Figure 12 of this application.

<u>Figure 12 - Artificial Penetrations and Multiple Well Pressures</u>



By using the principle of super-imposing pressures, it is possible to estimate the pressure at a point due to the influence of multiple wells. KEDA considered three models in their study:

- Pressure imposed by the DLD well on those injection wells that are completed in the injection zone.
- Pressure imposed by the DLD well on those wells that penetrate the strata overlying the injection zone. (The purpose of this model is to illustrate that the overlying strata will act as a barrier to vertical movement of the injected fluid).
- Pressures at the well and probable operating wellhead pressures.

Table 5.7, KEDA, Vol. I., page 51, presents the projected pressures exerted by the DLD well on surrounding penetrations. In the case of the two injection wells operated by Rice Engineering in the same injection zone, a bottom hole pressure increase of 100 – 125 psi over a 20-year period would not adversely affect these wells. It is common that several permits are granted for injection into the same reservoir. For example, the Miocene Sands near Texas City, Texas are permitted for more than 10 Class I injection wells.

It was KEDA's judgement that the San Andres reservoir has the capacity for additional users in the study area. The KEDA study concluded that the DLD well will not over-pressurize the reservoir. The bottom hole pressure increase of approximately 120 psi indicates that the rise in the reservoir pressure gradient would be in the order of 0.025 psi/ft in 20 years.

During the original permitting process for the well in the late 1980's, no objections were raised by Rice Engineering.

Table 5.4A (KEDA, Vol. I., pages 43, 43A, 43B) contains a 1984 list of artificial penetrations within the 2-½ mile radius. These penetrations either were completed below the injection zone or were completed within the overlying strata of the injection zone (4100' – 4340'). From this table, it may be noted that several wells are plugged and abandoned. All of the operating wells in the overlying strata that are listed are approximately 2 miles from the DLD well. The closest well listed is an injection well at a distance of 9387', operated by Gulf Oil Co.

The injection interval in the San Andres Formation, 4150' – 5000', is assumed to be homogenous (wastewater movement is not restricted in this section). The overlying strata (4150' – 4340') are assumed a barrier for vertical movement. If this barrier is confining, a reservoir pressure increase will not be transferred to the other side of the barrier.

A problem or questionable well is one that is abandoned without any cement plugs or for which no records are available to substantiate plugging. The following is a determination of whether the hydrostatic pressure of the fluid in such a well bore is sufficient to overbalance reservoir pressure increases in the study area.

KEDA Control Well #399, belonging to Conoco, is the only improperly abandoned well in the study area. For calculating purposes, it is assumed that the pressure increase due to the DLD's injection operation would be realized at this well since it penetrates through the injection zone although the well is greater than 2 ½ miles away. The fluid or drilling mud in this well will oppose vertical migration because the hydrostatic pressure of the mud exceeds the reservoir pressure. The NM Oil Conservation Division requires a salt gel mud consisting of 10 lb/gal brine mixed with 25 pounds of gel per barrel in all plugging and abandonment programs. For this well, a mud weight of only 9.5 lb/gal is assumed. The pressure overbalance due to the mud is estimated to be 414 psi, as shown in Table 9.

It can be concluded that the DLD well will exert negligible pressure on the Conoco well. In addition, it should be noted that the waste front radius at 200 gpm would be only 2179' (dispersion effect included) in 20 years, whereas, the Conoco well is at a distance of 13,000'+ from the DLD well.

Table 9 – Pressure Overbalance at Conoco Abandoned Injection Well (KEDA #399)

1. Reference Depth*, ft.	4,340
Total Depth, ft	8,656
Distance from DLD Well, ft	13,322
Mud Weight, lb/gal	9.5
2. Mud Pressure, psi (0.494 psi/ft)	2,143
3. Reservoir Pressure	
3.1 Hydrostatic Pressure @ 0.4 psi/ft	1,736
3.2 Bottom Hole Pressure Increase	54
(Darcy's radial pressure, psi)	
3.3 Radial Pressure on the unplugged hole	0
Total Reservoir Pressure, psi, (3.1+3.2+3.3)	1,790
4. Pressure overbalance, psi	353
(Mud pressure – Reservoir pressure)	
5. Shear strength of mud**, psi	61
6. Pressure overbalance w/gel strength, psi	414
* top of proposed injection zone	
** additional safety factor	

Operating Wellhead Pressures:

The foregoing bottom hole pressures calculated by using Darcy's Law, act upon the area covered by the thickness of the injection zone in all directions. In order to determine the wellhead pressures at the DLD location it is important to superimpose the bottom-hole pressure increases caused by the Rice Engineering wells. An analysis of the operating wellhead injection pressures for 3 ½ inch injection tubing is presented as Table 5.8B, KEDA, Vol. I, page 54.

The wellhead pressure is dependent on three differential pressures (1) bottom hole pressure increase, (2) static head difference between the weight of the fluid column inside the injection pipe and the hydrostatic weight of the formation fluids and, (3) frictional losses due to flow through the injection pipe. These differential pressures are algebraically added to estimate the wellhead pressures for various flow rates. On the basis of information available to KEDA at the time of the original study, it was concluded that there was a high probability that the well would take the average waste stream on a vacuum. Subsequent development and testing of the well confirmed that the well will take 160 gpm on a vacuum (gravity flow)

WASTE FRONT RADIUS

A good estimate of the minimum distance of waste front travel in an injection well can be made by assuming that the wastewater will uniformly occupy an expanding cylinder with the well at the center. Based in this concept, KEDA calculated the waste front radius as a function of time (Table 5.9, KEDA, Vol I, page 56). By factoring in dispersion, density segregation, and channeling, KEDA concluded that the 20-year waste front radius would be between 1313 ft. - 1985 ft. (from the well bore), with a average 160 gpm flowrate.

MAXIUMUM ALLOWABLE SURFACE INJECTION PRESSURE

The following discussion is presented to determine the maximum allowable surface injection pressure which can be sustained without initiating fractures of the disposal zone or extending any natural joints or fractures that may have been present prior to drilling of the well. The requested maximum surface injection pressure based on a measured reservoir pressure of 1929 psi at 4675 ft, and a 200 gpm flowrate through 3 ½ inch tubing, is 1050 psi.

Determining Fracture Treatment Gradient

Hubbert and Willis (1957)[1] published a paper that included the development of an equation used to predict the fracture-treating gradient. The fracture-treating gradient is the pressure required to maintain and extend fractures and not the pressure required to break down the formation. In the San Andres Formation near Odessa, Texas, the break down pressure is much greater than the pressure required to extend fractures. Results from a formation test performed on the El Paso Products Mize Number 4 show that the break

[1] Hubbert, M. King and Willis, D. G. 1957, Mechanics of Hydraulic Fracturing, Trans., AIME 210 pp. 153-166.

down pressure was 659 psi higher than the fracture treating, or "pump in", pressure at a depth of approximately 4750 ft.[1]

The equation developed by Hubbert and Willis is widely used to determine the limiting pressure on waste injection wells because of the above inherent safety factor. Injection treating gradient (P_t) is a function of the overburden stress gradient (P_{ob}), reservoir pressure gradient (P_r), and Poisson's ratio for rocks (υ). The equation is expressed as follows:

$$P_t = \left(P_{ob} - P_r\right) \frac{\upsilon}{1 - \upsilon} + P_r$$

Substituting the following typical values for the San Andres Formation in Lea County:

P_{ob} = 1.0 psi/ft (Lea County Density Log)

P_r = 0.4 psi/ft (estimated)

υ = .284 (Halliburton fracture treatment data)

The fracture treating gradient for the proposed well at initial reservoir conditions is calculated to be 0.637 psi/ft.

The equation indicates that the fracture treating pressure changes under different reservoir pressure conditions. Table 10 predicts the fracture treating pressure for the San Andres at various reservoir pressures.

Table 10 – Bottom Hole Fracture Treating Pressure in Relation to Reservoir Pressure

Depth = 4675' (middle of disposal interval)

P_{ob} = 1.0 psi/ft

υ = .284

Reservoir Pressure, P_r psi (psi/ft)	Bottom Hole Fracture Gradient, P_t, psi/ft	Bottom Hole Fracture Pressure, psi
1496 (.32)	.589	2754
1590 (.34)	.601	2810
1683 (.36)	.613	2866
1777 (.38)	.625	2922
1870 (.40)	.637	2978
1964 (.42)	.649	3034
2057 (.44)	.661	3090
2151 (.46)	.673	3146

[1] Jones, T. A., 1980, Fracture Gradient Determination for Amendment to Permit WDW-146, Browning-Ferris Industrial Chaparral Project; TDWR Disposal Well File WDW-146, BFI.

Surface Injection Pressure Limitations

The surface injection limitation widely used for waste disposal well is the surface pressure expression of the bottom hole fracture pressure. The surface injection pressure is defined as the sum of the bottom hole pressure (P_t), tubing pressure loss (P_f), and pressure loss due to skin damage (P_S), less fluid head (P_h), and a safety factor (P_{SF}).

Surface Injection Pressure = $(P_t) + (P_f) + (P_S) - (P_h) - (P_{SF})$

The pressure loss due to skin damage is usually offset by the safety factor so these terms cancel each other. The tubing friction loss is usually calculated at the lower value for new pipe (to introduce an additional safety factor). The above equation thus reduces to:

Surface Injection Pressure = $(P_t) + (P_f) - (P_h)$

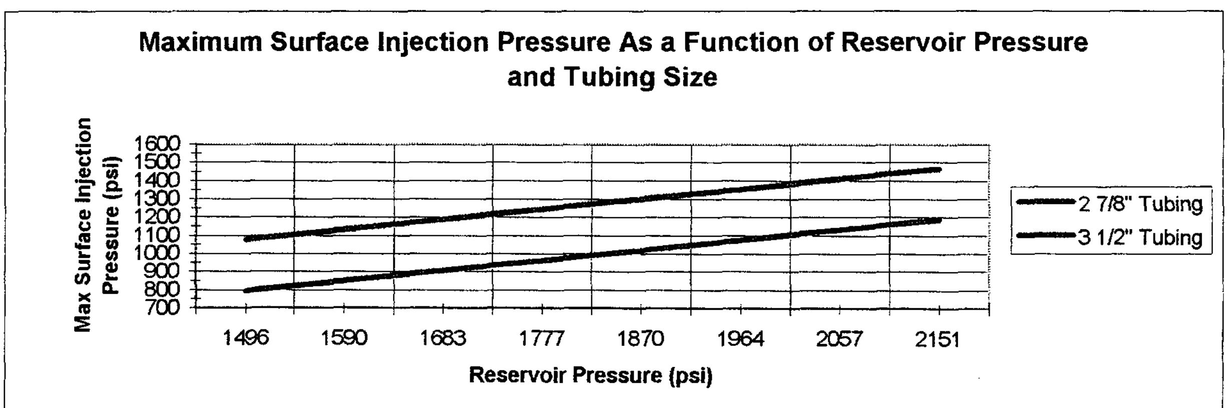
Fracture Treating Pressure (P_t) – as calculated in Table 10 the fracture treating pressure varies with the injection history of the well. As reservoir pressure increases, the fracture treating pressure increases proportionately.

Friction Loss in Tubing (P_f) – the friction loss for 3-½ inch injection tubing at 4670' is 107-psi @ 160-gpm and 173-psi @ 200-gpm.

Hydrostatic Head (P_h) – the hydrostatic head varies with the density of the fluid column. The DLD effluent will have a specific gravity of approximately 1.05 (8.8 lbs/gal) which corresponds to a hydrostatic gradient of .4571 psi/ft. At a vertical depth of 4675' the hydrostatic pressure exerted by the fluid weight will be 2137 psi (assuming that the tubing is completely full).

Figure 13 gives the wellhead pressure limit as a function of the reservoir pressure and tubing size at a maximum injection rate of 200-gpm. A maximum surface injection pressure of 1050 psi corresponds to the measured reservoir pressure of 1929 psi at 4675' depth for 3-½ inch injection tubing.

Figure 13 – Maximum Surface Injection Pressure as a Function of Reservoir Pressure and Tubing Size



EFFLUENT AND FORMATION MATRIX REACTION

The DLD effluent to be injected into the well will be acidic with an average pH of 3.5. It is well known that hydrochloric acid reacts readily with limestone or dolomite zones such as the San Andres Formation according to the following:

$$CaCO_3 + 2HCl \rightarrow H_2O + CO_2 + CaCl_2$$

The above chemical equation shows calcium carbonate reacting with hydrochloric acid to yield carbon dioxide, calcium chloride, and water.

The slightly acidic effluent injected into the disposal zone will move through the carbonate and encounter enough rock to spend itself. Two consequences of this reaction are 1) the dissolution of the rock matrix and 2) the evolution of carbon dioxide gas. The consequences of the reaction will be discussed with respect to the DLD injection well in the following sections.

Cavity Development for the Injection Well

Cavity development is not expected to be a problem with the DLD injection well because of the low concentration of acid in the waste stream and the density of the reservoir material. Some bore hole enlargement may occur over time. The KEDA study, Vol. I, pages 64-68 goes into detail describing four case studies of cavity development in injection wells located in other areas of the country. In all four cases, acidic wastewater was injected into limestone formations.

Cavity Growth for the DLD Injection Well

Considering the dimensions of DLD's well and the properties of the carbonate rock it is possible to estimate the order of magnitude of the eventual cavity. In the present application, a reservoir model can be described as follows:

A carbonate rock cylinder having a useable thickness of 415' receives wastewater at an average rate of 160-gpm. The weight rate (lb./min) of hydrochloric acid injected into the formation at a given flow rate depends on the concentration of acid in the wastewater. Part of this acid contributes to the enlargement of the well bore and the formation of a cavity. The remainder of the acid is flushed away from the well bore.

According to the chemical reaction (stoichiometry) of hydrochloric acid with calcium carbonate, 1.36 lbs. of calcium carbonate rock would be dissolved per pound of acid injected. Knowing the bulk density of the rock, the weight of the reacted carbonate can be converted to volumetric units. The amount of rock reacting at the well bore with hydrochloric acid will depend on several parameters. In effect, radial growth of the cavity is mainly the function of flow rate, acid concentration, and years of injection.

The radial cavity growth as a function of time may be visualized from the data presented in Table 11. On the basis of the cavity growth model presented by Shannon and Wilson[12], it appears reasonable to project that large portions of the injection acid will be reacting within the formation and away from the well bore. This assumption will be discussed in detail below. Based on this assumption, the well bore radius is calculated to be an average of 4.5 feet in 20 years assuming a 0.2 percent concentration (2000-ppm) of hydrochloric

[1] Shannon and Wilson, Inc. 1976, Evaluation of Cavity Development and Stability, Disposal Well No. 1, Mulberry, Florida: Consultant's Report for Kaiser Aluminum and Chemical Corporation.

[2] Shannon and Wilson, Inc. 1980, Evaluation of Cavity Development and Stability, Injection Wells A and B, Pensacola, Florida: Consultant's Report for Monsanto Company, p. 70

acid in the wastewater. The order of magnitude of this growth is not sufficient to cause casing damage, formation collapse or vertical migration of wastewater.

Table 11 – Cavity Growth Data for the DLD Injection Well

Model Parameters:

Carbonate rock shape: cylindrical
Net thickness: 415 feet
Radius: changing proportional to flow rate
Flow Rate: 160-gpm (avg)
Injection Rate: lb/min dependent on acid concentration
Rock Bulk Density: 156-lb/ft^3

Injection Time (Years)	0.05% (500 ppm) acid Cavity radius (ft)	0.2% (2000 ppm) acid Cavity radius (ft)
One year	0.5	1.0
Ten years	1.6	3.2
Twenty years	2.2	4.5
Avg. growth, ft^3/yr	315	1260

The increase in porosity caused by rock dissolution will be negligible due to the relative volumes of acid and carbonate rock in the formation. The existing rock is in excess of the stoichiometric requirement by a factor of 2000. The acid may form channels and vugs. If this occurs, the transmissivity of the injection well will be improved.

It was assumed that only a portion of the injected acid could contribute to enlarge the well bore radius. The radius of wastewater neutralization was not predicted. This prediction is complex, especially in the absence of reaction kinetics data. The reaction rates in turn depend on matrix properties. It is necessary to characterize the pore structure and determine the change in this structure as acid reaction proceeds. In projecting the acid neutralization radius, on page 71 of Volume I, KEDA referred to a monograph on "Acidizing Fundamentals" by B.B. Williams, J.L. Gidley and R.S. Schechler, SPE, Dallas 1979, which was submitted as Appendix G of the original KEDA study.

Referencing this monograph, it was noted that acid penetration distances are reported in the range of a few feet to a few hundred feet depending upon the controlling variables, especially the number of enlarged flow channels (worm holes) that occur.

In order to estimate the radius of neutralization, a simple model is considered:

Step 1 – Estimate the average velocity of the wastewater near the well bore area (ft/day).

Step 2 – From the laminar flow heterogeneous reaction model (page 23 of the referenced monograph) estimate the reaction time to neutralize acid form pH 1.0 to pH 7.0.

Step 3 – Assume that wastewater would be neutralized when the waste front travel time is equal to the time calculated per Step 2.

Table 12 presents the application of the above model to the DLD well. It may be noted that the assumed values concerning carbonate and HCl reactions are typical and the estimate is conservative. The radius of neutralization, estimated according to the above methodology, is approximately 41 feet. This distance corresponds to worm holes growing in radial directions, i.e. possible changes occurring in porosity and permeability of the reservoir.

Table 12 – Approximate Radius of Neutralization

1. Predict the average velocity of wastewater:

Basis:	Use expanding cylinder model
Flow:	160 gpm
Formation thickness:	415 feet
Porosity:	10%

   Using the above data the waste front radius will be 15.37 feet after 24 hours. This figure (15.37 ft/day) is used as the average velocity of the wastewater near the well bore.

2. Predict the reaction time for the acid to reach a neutral pH (7.0):

   A correlation table contained on page 26 of the referenced monograph (Appendix G of the original KEDA submittal) was used to estimate the reaction time for hydrochloric acid to change from pH 1.0 to pH 7.0. The time of reaction for pH 2.0 acid was estimated to be 63.75 hours. (Note: it was the original intention of Climax Chemical to inject un-neutralized, < 2.0 pH, effluent into the injection well).

3. Calculate the approximate radius of neutralization:

   Radius = 15.37 ft/day X 63.75 hours X 24 hours/day = 41 feet

Table 12 above reflects an estimate of a neutralization radius for un-neutralized effluent injected into the formation. DLD intends to partially neutralize the wastewater with soda ash to bring the pH up to a 3.5 – 4.0 range. This would have to reduce the neutralization radius significantly below the Table 12 estimate of 41 feet.

Conclusion: With an estimated neutralization radius of less than 41 feet, the possibility of DLD's acidic waste reaching and affecting the cementing and casing of artificial penetrations completed within the same formation is negligible.

Carbon Dioxide Generation

A primary concern when injecting acids into any carbonate reservoir is the potential buildup of pressure due to the release of carbon dioxide during the reaction with the formation matrix.

As shown in Figure 14 carbon dioxide can exist in three physical states depending on temperature and pressure. The critical temperature for carbon dioxide is about 85°F. The equilibrium curve indicates that CO_2 can be liquefied by increasing the pressure if the temperature is below 85°F. Above this temperature, CO_2 cannot be liquefied by increasing pressure. Since the bottom-hole temperature will be around 107°F, carbon dioxide will be in the gaseous state when it exceeds the solubility limit in the wastewater, or the naturally occurring formation fluids.

Figure 15 shows the solubility of carbon dioxide in water at various temperatures and pressures. The solubility of carbon dioxide in the DLD wastewater should be nearly equal to that of fresh water. With a bottom-hole temperature of 107oF and pressure approximately 3000-psi, water can dissolve 184-scf/bbl (4.38-scf/gal). This value is approximately 6.2% CO_2 by weight in water. As long as CO_2 generation does not exceed this solubility, gaseous CO_2 will not exist.

At the anticipate bottom-hole conditions of the DLD injection well, it appears that the dissolution of limestone bearing rock will not generate carbon dioxide in quantities that will exert abnormal back pressures. It is anticipated that the safe limit of injectable hydrochloric acid concentration is 5% by weight. DLD's effluent is approximately 1.5% HCl by weight prior to any neutralization. When the pH is raised to 3.5 – 4.0 prior to injection, the concentration will be less than 0.2%.

REGIONAL FLOW OF SAN ANDRES FORMATION WATER

Orr and Dutton (1983) developed a geostatistical model to map the potentiometric surface for the San Andres Formation in west Texas and southeast New Mexico.[1] KEDA, Vol. I, page 75B reproduces two figures (5.5A and 5.5B). Figure 5.5A is a hydraulic head map for the San Andres Formation in west Texas and southeast New Mexico which was generated using geostatistical data. Figure 5.5B is a hydraulic head map for the same area utilizing 342 actual data points to generate the map.

Figure 5.5A indicates that the regional ground water flow is in a southeast direction. The hydraulic gradient in east central Lea County is relatively flat with a 500-foot change in head over approximately 40 miles.

Considerable variance in the hydraulic head of wells in the project area is actually reported, thus, Figure 5.5B was generated using 342 actual data points. Part of the variance in head reflects the regional differences in reservoir development. This transient state caused by oil and gas production could remain for thousands of years.

Given the formation properties reported in Table 7 and considering the regional hydraulic gradient (Figure 5.5A, KEDA, Vol. I., page 75B), the velocity of the water due to the differential head of potentiometric surfaces is estimated to be in the order of 0.6 feet/year in a southeast direction. This regional velocity is of such a low order of magnitude that for all practical purposes the San Andres Formation water may be assumed stagnant. This reinforces the concept that the mechanism of reservoir storage is by compression of the connate fluids.

[1] Orr, Elizabeth D. and Alan R. Dutton, 1983. An Application of Geostatistics to Determine Regional Ground Water Flow in the San Andres Formation, Texas and New Mexico. Ground Water, vol 21, no. 5, pp. 619-624.

Figure 14 – Carbon Dioxide Equilibrium Curve[1]

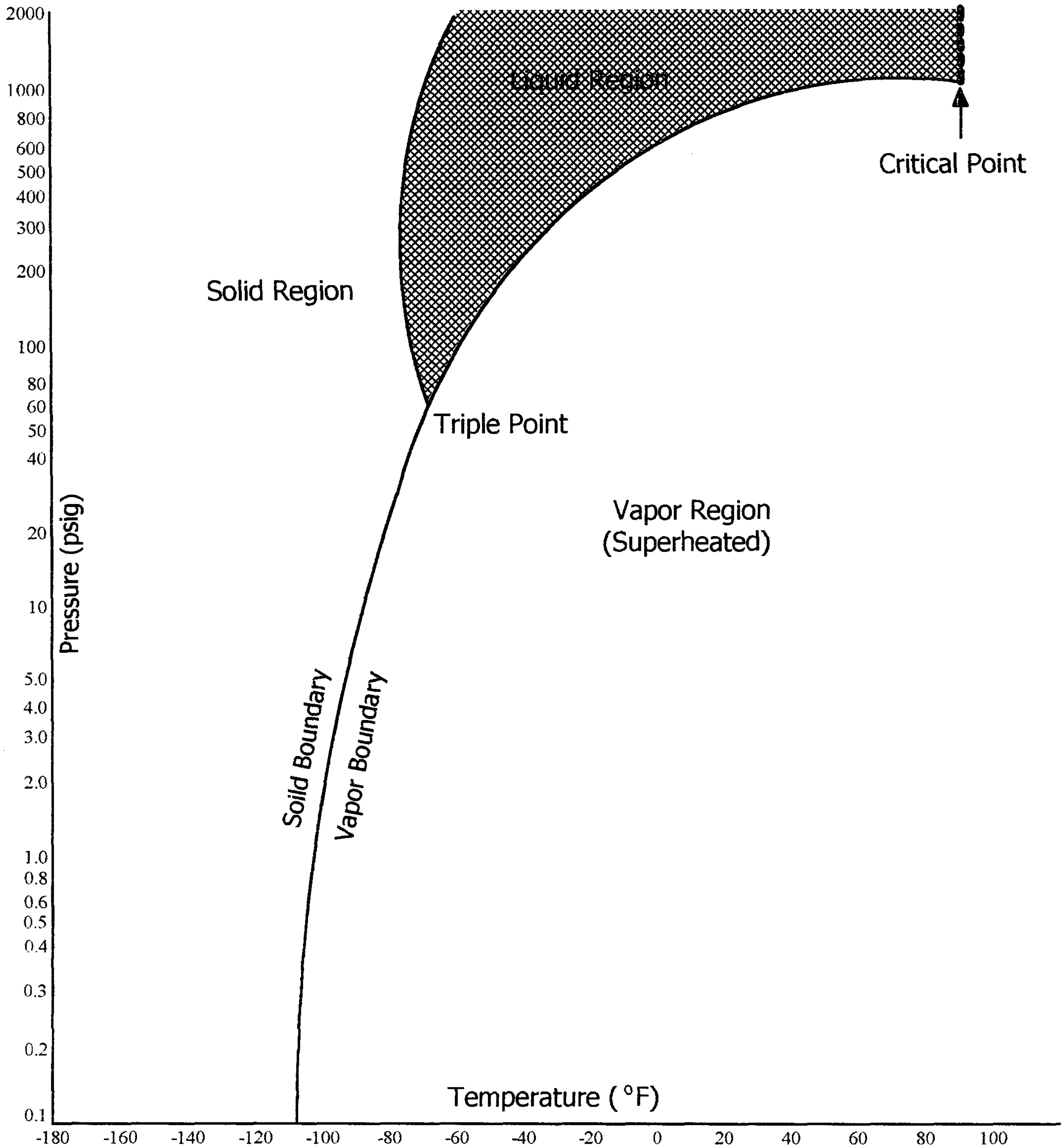
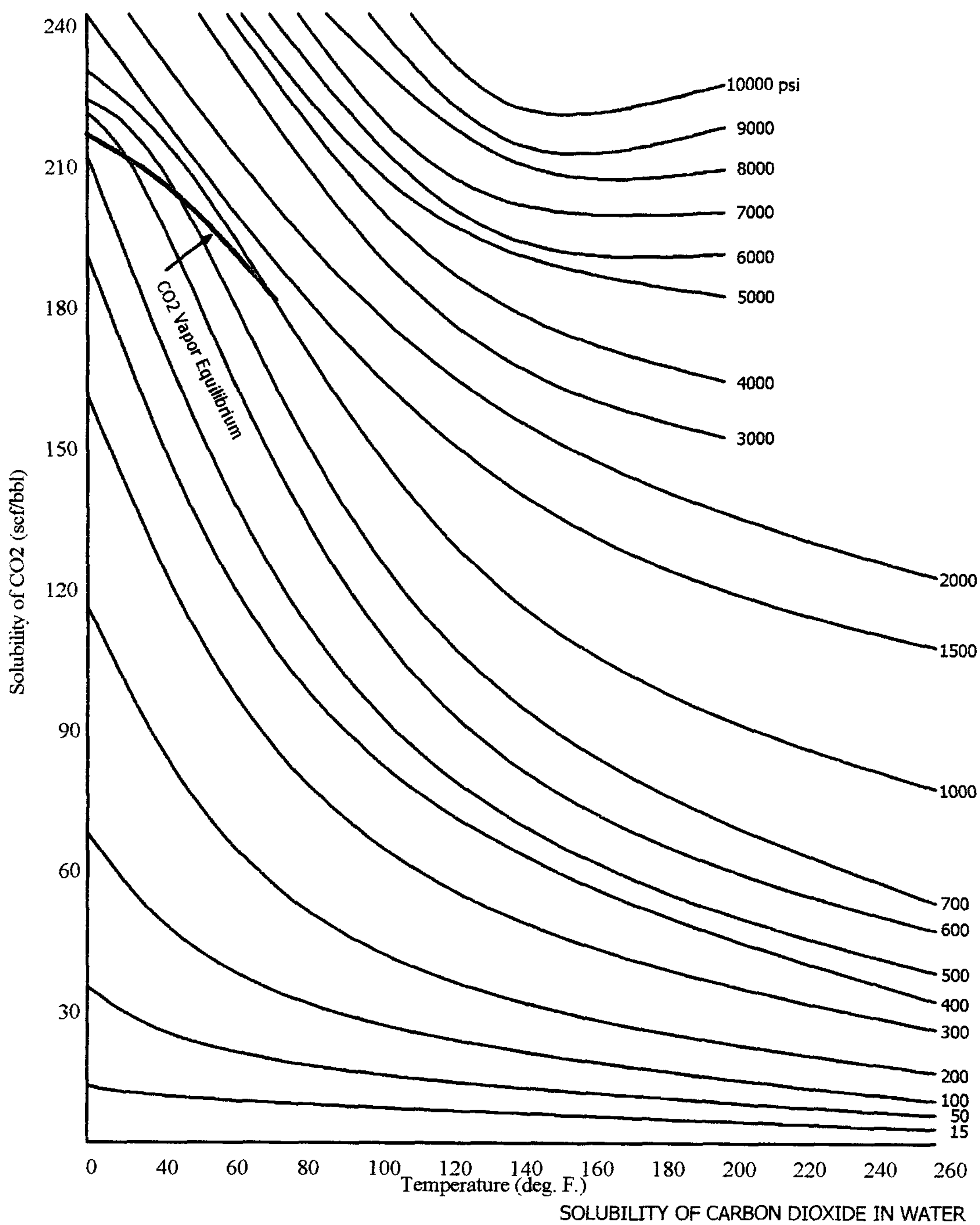


FIGURE 14 - CARBON DIOXIDE EQUILIBRIUM CURVE

[1] KEDA, Vol. I, Figure 5.3, p. 74

Figure 15 – Solubility of Carbon Dioxide in Water[1]



[1] KEDA, Vol. I, Figure 5.4, p. 75 (Taken from Oil Field Carbon Dioxide Services Handbook, Halliburton Company, 1980, page I-11

WELL DESIGN AND CONSTRUCTION

GENERAL

The DLD Resources, Inc. Class I injection well is located on DLD's property, approximately 1000 feet north of the manufacturing plant. This well was originally installed by Climax Chemical Company to conform with state specifications as presented in the original permit application for a new well, and subsequently approved by the New Mexico Environment Department. The installation was performed by Ken E. Davis Associates under Project No. 10-509. The well is designed and installed for injection of a low pH waste stream into the lower San Andres Formation.

WELL DRILLING

The well was successfully drilled to a total depth of 5,000 feet by Cactus Drilling Company, Rig No. 63. Drilling began on April 15, 1985 and was completed on June 3, 1985. Deviation surveys were run every 500 feet and are shown in Table 13[1].

Table 13 – Record of Inclination (Garlin Taylor, Drilling Technician, Cactus Drilling Co.,

Measured Depth (feet)	Course Length (ft. X 100)	Angle of Inclination (degrees)	Displacement per 100 ft (Sine of Angle X 100)	Course Displacement (feet	Accumulative Displacement (feet)
367	367	0.50	0.87	3.1929	3.1929
844	477	0.50	0.87	4.1499	7.3428
1062	218	0.75	1.31	2.8558	10.1986
1563	501	0.75	1.31	6.5631	16.7617
2064	501	1.00	1.75	8.7675	25.5292
2450	386	1.25	2.18	8.4148	33.9440
2810	360	1.75	3.05	10.9800	44.9240
3287	477	1.50	2.62	12.4974	57.4214
3760	473	1.50	2.62	12.3926	69.8140
4140	380	1.25	2.18	8.2840	78.0980
4638	498	1.00	1.75	8.7150	86.8130
5000	362	1.00	1.75	6.3350	93.1480

Climax Chemical Company prepared the location and rat hole, mouse hole and conductor hole were drilled prior to moving in the rig. A 17 ½ inch hole was drilled to 365' and 13 3/8" casing was run to 365', and cemented to the surface with Class "C" cement. The casing was tested to 1,000-psi with no loss of pressure.

A 12 ¼" hole was drilled to 2,810' with a saturated salt gel mud system. A Dual Guard – Micro Guard with Gamma Ray and Compensated Density-Dual Spaced Neutron logs were run from 2,810 to the surface. After completing the logging, the 9 5/8" casing was run to 2,809'

[1] KEDA, (1985), Rework Report, Table I

and cemented to the surface with Class "C" cement. The 9 5/8" casing was tested to 1,000 psi for one hour with no loss of pressure.

The 9 5/8" casing was drilled out and a 8 ¾" was drilled to 4,170'. At this point a full hole core was taken from 4170' to 4,186'. The core hole was then drilled out and drilling continued to 4,677' at which point Core No. 2 was cut from 4,677' to 4,707'. The core recovery was 100%.

The 8-¾" hole was drilled with 9.0-ppg mud with 40,000-ppm chloride. No loss of circulation was observed while drilling to 4,707'. Welex performed the log Run No. 2 at this depth, which consisted of the same type logs run at 2,810'.

The core analyses of the San Andres Formation compared favorably with calculated log porosity. The porosity ranged from 5% to 11% and the permeability averaged 0.8 millidarcy. Core analyses and field porosity calculations are provided in the Appendix section.

The hole was filled with 12-20-mesh sand from 4,350' to 5,000' to prevent cement damage and plugging of the injection zone after confirming the top of the sand at the proper depth.

The 7" casing was then run with one joint of 5-½" Hastelloy C-276 at the bottom (4,319' to 4,349'). The physical properties and characteristics of Hastelloy C-276 are contained in the Appendix section. The cementing was performed using a inner string method. This was accomplished by running a tubing string inside the casing and stringing into the inner string baffle collar on the bottom of the 5-½" Hastelloy casing. Howco Lite cement was mixed and pumped until cement returns were observed at the surface. After getting cement to the surface, 100 sacks of Class "C" cement was pumped and followed by 840 gallons of Howco Epseal (acid resistant cement). The Epseal was placed across the hole to the casing annulus from 4,140' to 4,351'. There was no evidence of loss of circulation while cementing. The drilling rig was released. Table 14 presents the casing tallies and details for thirteen (13) 3/8", 9-5/8" and 7" casings.

Table 14 – Tubular Tallies and Casing Details

105 joints, 7", 20#, J-55, LT & C	4,122.34'
4 joints, 7", 23#, J-55, LT & C	157.80'
1 7" Howco innerstring, baffle collar with insert float	1.25'
1 joint, 7", 23#, J-55, LT & C	29.19'
1 7" collar, 7" X 5 ½" swage, 5 ½" collar	1.95'
1 5-½" 0.250" wall Hastelloy tube (4.812 I.D. drift)	29.40'
1 5-½" collar and all thread nipple carbon steel	.80'
1 5-½" float shoe, carbon steel	1.75
TOTAL STRING	4,354.48'
ABOVE K.B.	3.48'
LANDED DEPTH	4,351'
5-½" Hastelloy C-276 liner from 4,319' to 4,349'.	

WELL CONSTRUCTION

Detailed cross-sectional well schematics are presented as Figures 16 and 17.[1] The wellhead schematic is presented as Figure 18.[2] The drawing of the surface facilities (Figure 19) is a new drawing not contained in the KEDA materials. Figure 20 is detailed drawing of the Louisiana Oil Tools Model 12 packer.

WELL COMPLETION

A DA&S Service Co. work-over rig was moved in and the 7" casing was pressure tested to 1,000 psi for one hour with no loss of pressure. The cement was drilled to 4,340' (10' above shoe) and re-tested to 1,150 psi with loss of 5 psi in one hour.[3] The balance of Epseal was drilled and sand was circulated out of the hole to a depth of 5,000' by reverse circulation. A Welex bond log was then run which indicated adequate bonding of the Epseal cement at the confining zone. Lite water bonding results were typical.

WELL TESTING AND EVALUATION

The well was jetted with nitrogen and coil tubing through a packer on a 2-7/8" workstring. The well produced an estimated three barrels per hour after jetting to 5,000'. A sample of the formation fluid was collected and analyzed by Unichem International. The analysis results are included as Table 15.[4] The formation was cleaned with 2,500 gallons of 15% hydrochloric acid and an additional 10,000 gallons of 15% hydrochloric acid were used in five stages to treat the formation. This was performed through a tubing with 3,200 psi at 10 barrels per minute using a total of 3,250 pounds of rock salt as diverting agent.

To evaluate the effect of acid treatment a series of step-rate injection tests were conducted by John West Engineering Company, Hobbs. After each test the well was acidized to improve its receptivity. All test data are presented in Appendix C.

Step-Rate Test #1 was conducted on May 11, 1985 with an injection rate of 160-gpm at 1,433-psi injection pressure, which included approximately 295-psi friction loss inside the 2-7/8" tubing. Since injectivity was unsatisfactory, the formation was re-acidized with 2,500 gallons of 28% HCl to alleviate any possible skin damage. The excess acid was swabbed out of the hole and Step-Rate Test #2 was performed on May 15, 1985. The test showed a slight reduction of injection pressure to 1,300-psi for an injection rate of 160-gpm. For further improvement of injectivity, the well was swabbed for five days in a clean-up effort. The injection test tubing was placed 570' deeper, which increased the friction loss, by an additional 38-psi. Step-Rate Test #3 conducted on May 23, 1985 showed 1,447-psi injection pressure for an injection rate of 160-gpm. These efforts did not result in improved injectivity.

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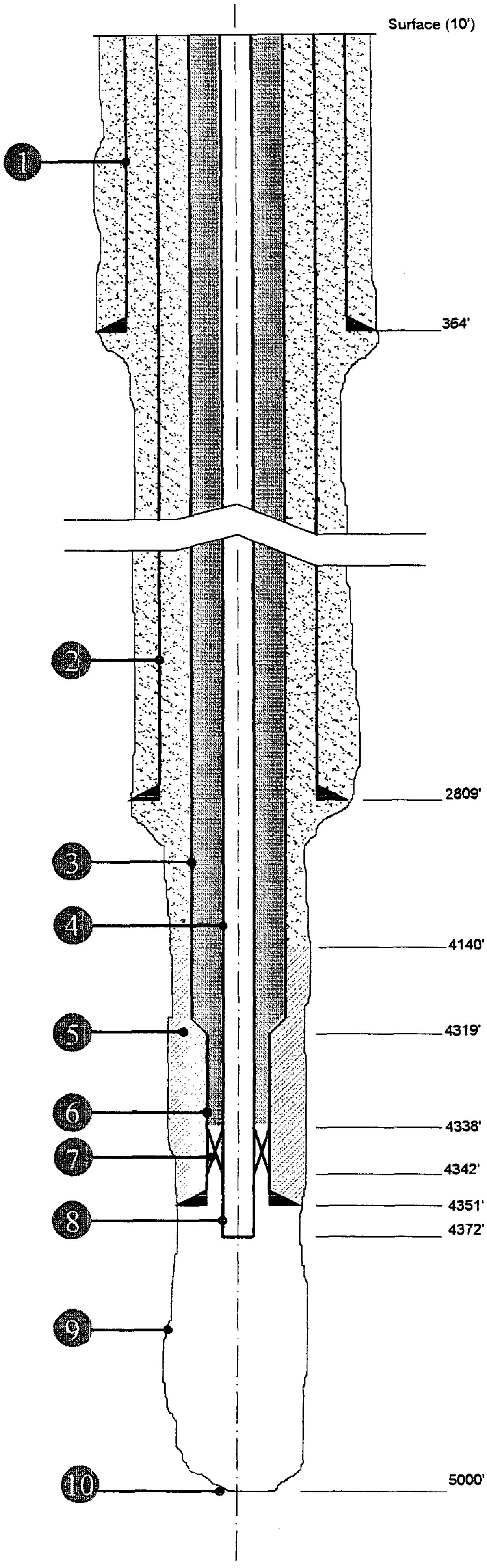
[1] KEDA, (1985) Rework Report, Figures 1, 3

[2] KEDA, (1985) Rework Report, Figure 2

[3] KEDA, (1985) Rework Report, Table III

[4] KEDA, (1985) Rework Report, Table IV



1. Surface Casing: 13-3/8" O.D., 54.5#/ft, J-55, ST & C set to 364' in 17-1/2" hole. Cemented to surface with 350 sacks of Class "C" cement with 2% calcium chloride and 1/4#/sack Flocele.
2. Intermediate casing: 9-5/8" O.D. 36#/ft, K-55, ST & C set to 2809' in 12-1/4" hole. Cemented to surface with a lead slurry of 2050 sacks of light cement with 15# salt plus 1/4#/sack Flocele plus 5#/sack Gilsonite and tail-in slurry of 150 sacks Class "C" cement plus 2% calcium chloride. Cement top side annulus with 50 sacks of Class "C" cement.
3. Protection casing: combination string consisting of 4317', 7" O.D., 20# and 23#/ft, J-55, ST & C and 30', 5-1/2" O.D. 250" W.T. Hastelloy C-276 threaded 8rd ST & C set to 4351' in 8-3/4" hole, cemented as follows: 750 sacks of Howco lite cement with 1/4#/sack Flocele and 100 sacks of Class "C" cement (4140' to surface) followed by 840 gallons of Howco Epseal acid resistant cement from 4351' to 4140'.
4. Injection tubing: 3-1/2" Texas Fiberglass Products, 2100-L premium set to 4338'.
5. Howco Epseal cement 4351' to 4140'
6. Casing: 5-1/2", .250" wall, Hastelloy C-276 from 4319' to 4349'.
7. Packer: 5-1/2" X 3-1/2" Louisiana Oil Tools Model 12 w/Hastelloy wetted parts set from 4338' to 4342'.
8. Tail Pipe: 3-1/2" Texas Fiberglass Products tubing, 4342' to 4372'.
9. Disposal Interval: open hole 8-3/4", 4351' to 5000' (basal San Andres).
10. Total Depth: 5000'

Note: All measurements are in reference to the Kelly Bushing (10' above ground).

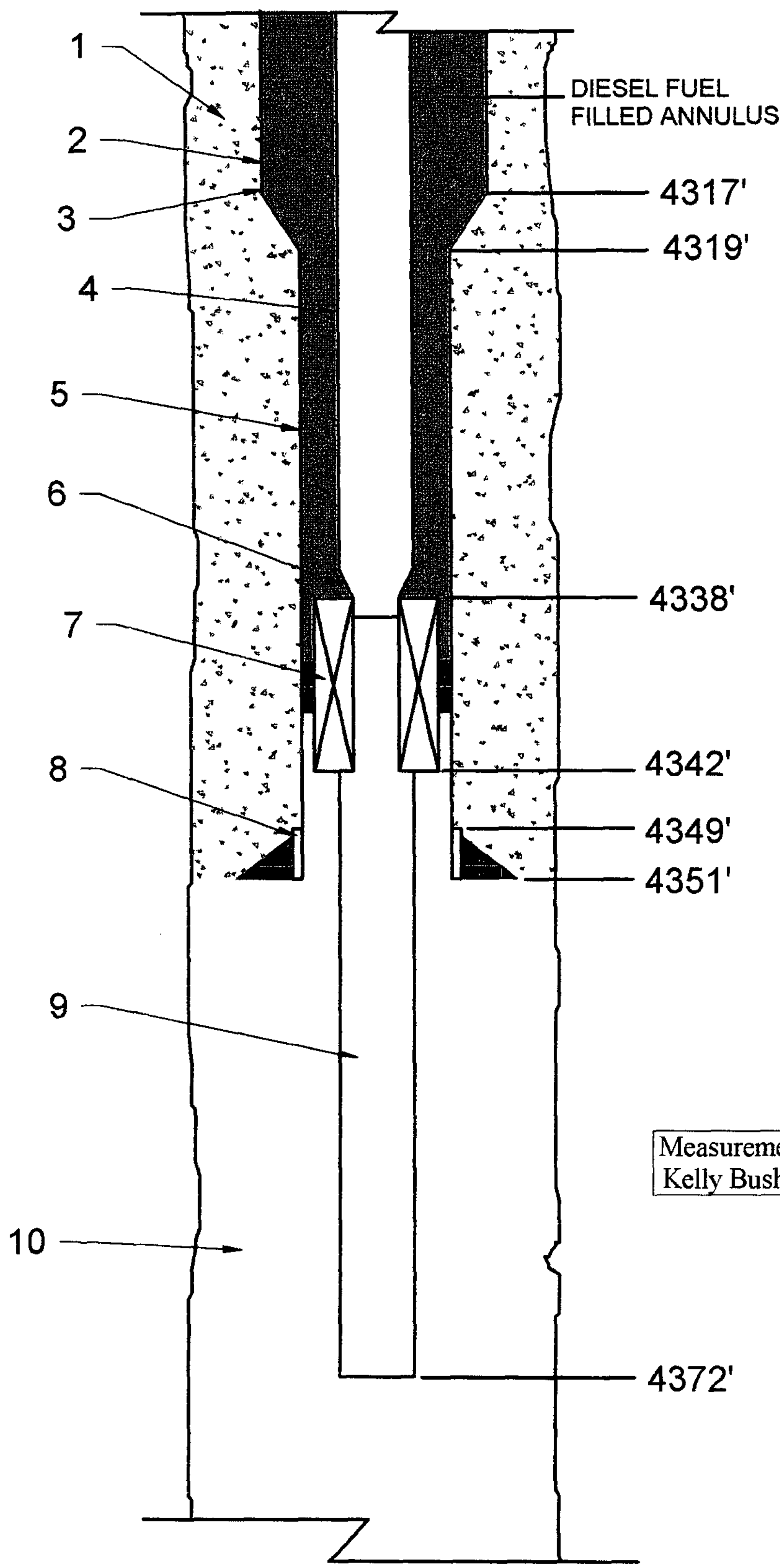
DLD RESOURCES, INC.

MONUMENT, NEW MEXICO

CLASS I INJECTION WELL

SCHEMATIC

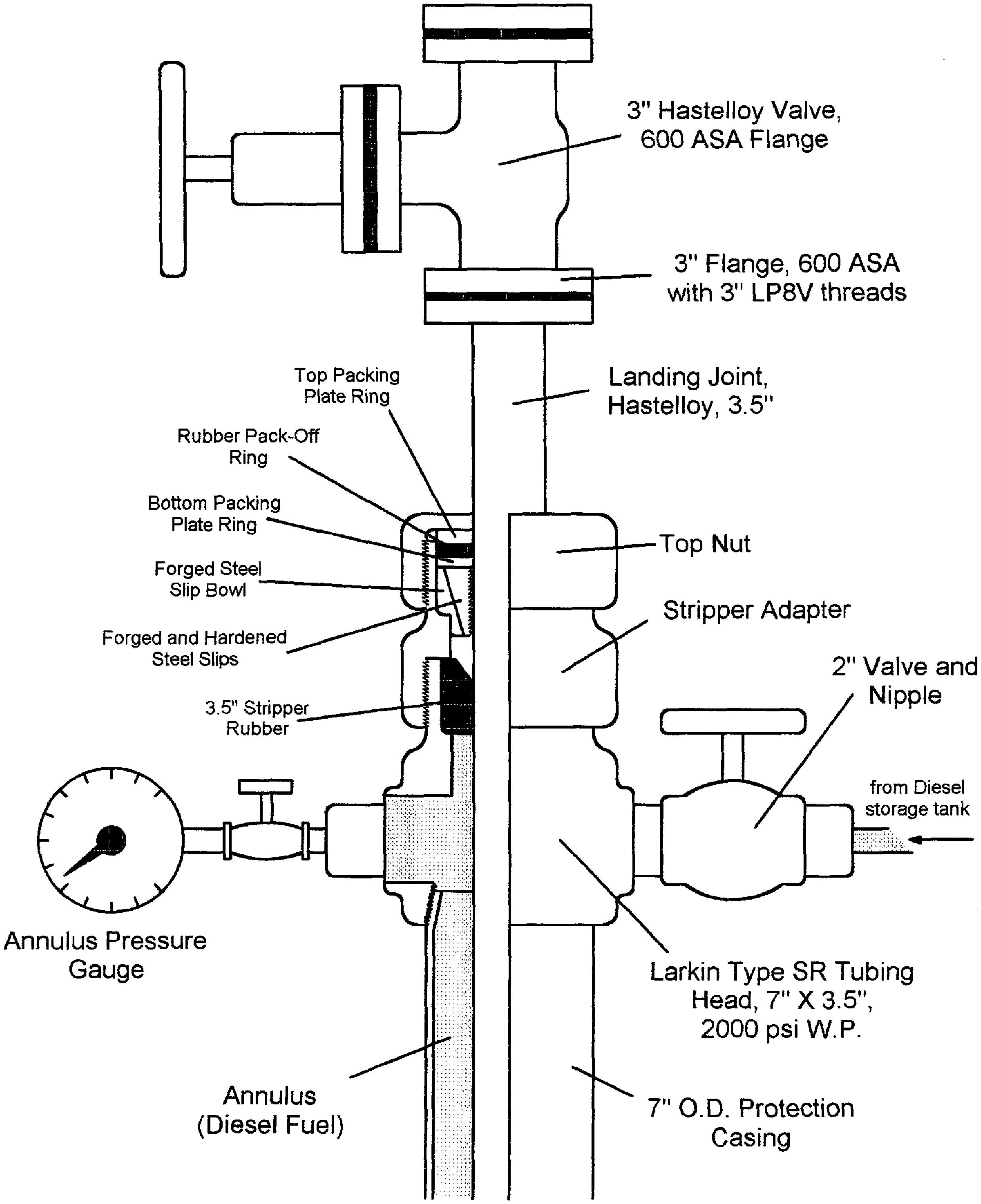
Figure 16



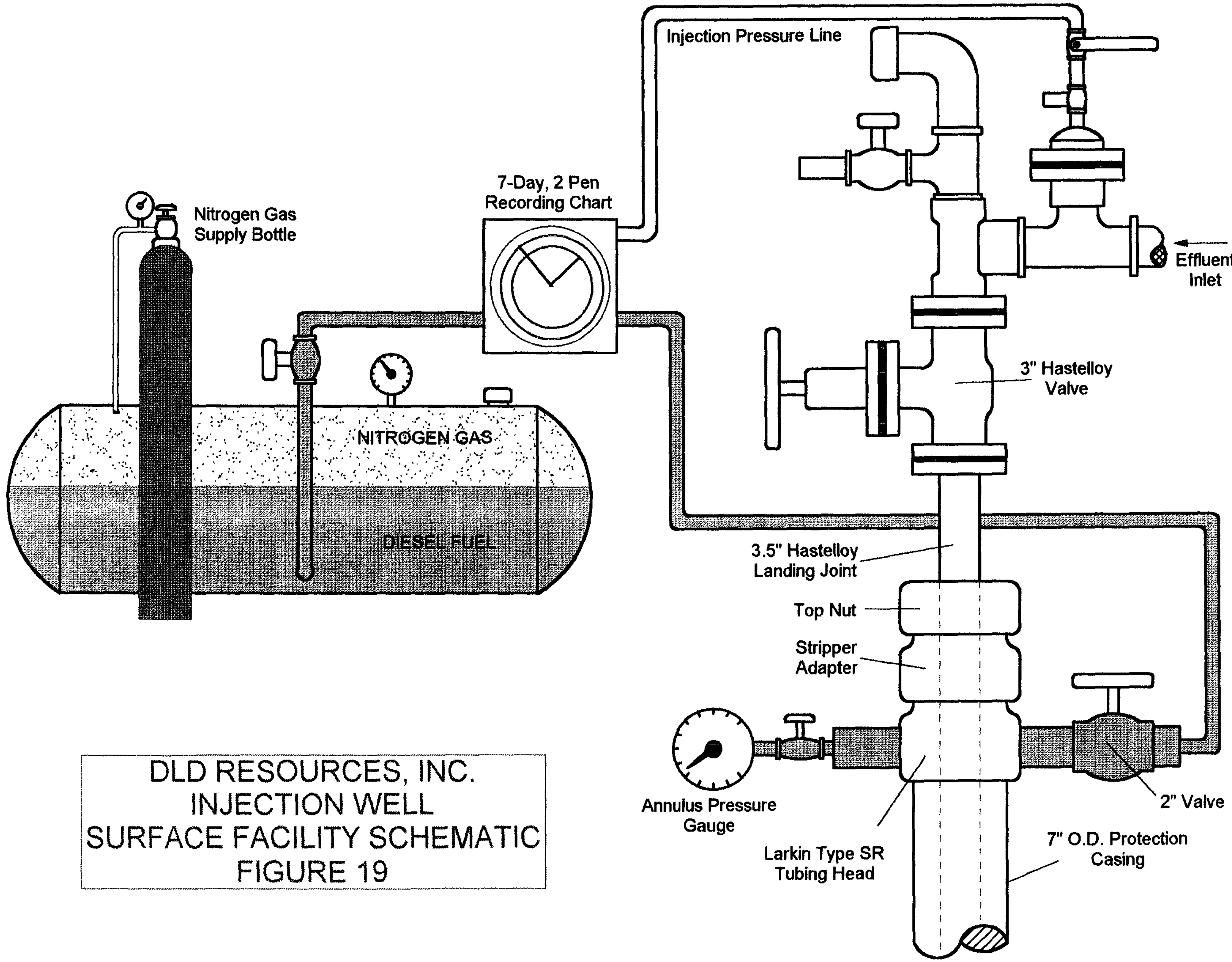
1. Cement, Howco Epseal
2. Protection Casing: 7" O.D., 20# and 23#/ft., J-55, ST & C
3. 7" collar, 7" X 5.5" swage, 5.5" collar
4. Injection Tubing, 3.5" Texas Fiberglass Products, premium 2100-L, resin rich lining
5. Casing 5.5" Hastelloy, C-276, .250" wall
6. Seal assembly, 3.5" EUE, 8rd, Louisiana Oil Tool latch in
7. Packer, Louisiana Oil Tool, Model 12, Hastelloy wet parts and teflon-viton seals
8. Collar carbon steel nipple and float shoe
9. One 3.5" TFP joint of tubing on bottom of packer
10. Open hole to ~5000'

Measurements are in relation to the Kelly Bushing (10' above ground).

DLD RESOURCES, INC.
INJECTION WELL
PACKER SECTION DETAIL
FIGURE 17



DLD RESOURCES, INC.
INJECTION WELL
WELLHEAD ASSEMBLY DETAILS
FIGURE 18



DLD RESOURCES, INC.
INJECTION WELL
SURFACE FACILITY SCHEMATIC
FIGURE 19

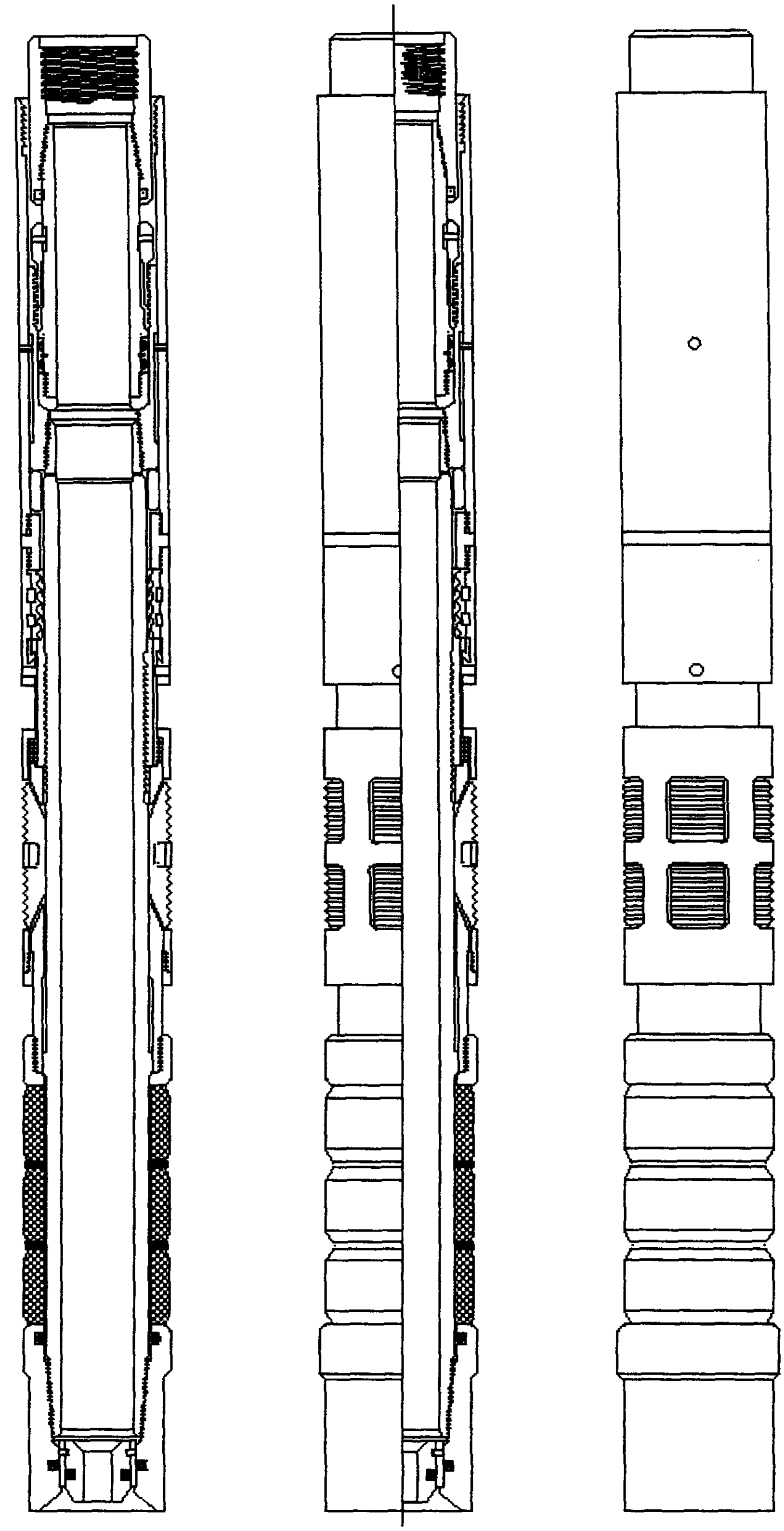


Figure 20 - Louisiana Oil Tools Packer

The open hole interval 4,351' to 5,000' was fracture treated with a Howco 100,000 gallon Mighty Acid – Alpha Phase type treatment. Appendix C contains this treatment report. Maximum pressure was 1,650-psi. Average treatment was at 1,500-psi and a 59-barrel per minute injection rate.

Treatment Sequence:
20,000 gallon gel water
20,000 gallon gel 28% HCl acid
20,000 gallon gel water
20,000 gallon gel 28% HCl acid
20,000 gallon slick flush

Instant Shut-in Pressure -	1,200-psi	180 minutes -	1,110-psi
10 minutes -	1,150-psi	300 minutes -	1,050-psi
30 minutes -	1,140-psi	1,260 minutes -	600-psi

After bleeding off the pressure, the tubing was run to 5,000' and then reversed out to 4,970'. The spent acid was recovered with some formation fine particles. Step-Rate Test #4 was performed on May 30, 1985. Injection pressure was measured at 1,100-psi with a rate of 160-gpm. Tubing pressure was acceptable at 1,435-psi.

A Welex tracer survey was performed by first recording a base gamma ray log prior to injecting radioactive material at 4,200' (base of casing 4,351'). Increments of water were injected and subsequent log runs were recorded. The material passed the shoe of the casing going down with no evidence of upward vertical migration. The survey indicated that a large percentage of the fluid exits the borehole near 4,450' with only a small portion travelling as low as 4,600'. No fluid movement at or below 4,700' was observed. (See Appendix C)

The packer (Louisiana Oil Tool, Model 12) was set at 4,338'-4,342' (Figure 16). A description of this packer is included as Appendix F. The packer was tested to 1,300-psi without any loss. After removing the workstring and BOP, the Louisiana Oil Tool Latch-in-Seal assembly and 28 joints of 3-1/2" Texas Fiberglass Products (TFP) 2100L premium resin-rich lined tubing were installed. Prior to setting the packer the annulus was displaced with a packer fluid of water containing 55 gallons of Champion Chemical Control R-2264 (a 3 in 1, bactericide, corrosion inhibitor, and oxygen scavenger). All tubing joints were internally tested to 1,700-psi. 145 joints of 3-1/2" TFP tubing plus 2 subs and Hastelloy landing joints were latched into the packer with 8,000 pounds of tension. The specifications of the TFP fiberglass tubing are presented as Appendix G. The wellhead was assembled. The casing and the annulus was pressure tested successfully to 1,300-psi.[1]

The annulus fluid was displaced with air to 15' and then filled with diesel fuel. The valves were installed. A bottom hole pressure test was run by John West Engineering Company. The test indicated 1,929-psi at 4,675'.[2]

The well was ready for service and returned to Climax Chemical Company.

Appendix H provides the rig inventory of the Cactus Drilling Rig No. 63.

[1] KEDA (1985), Rework Report, Table III – Test No. 2.)

[2] KEDA (1985), Rework Report, Table VII

KEDA CONCLUSIONS AND RECOMMENDATIONS (MAY 1985)

The San Andres formation encountered in this well is very dense dolomitic limestone with anhydrite deposited in the pore spaces. Permeability is reduced to a low range not capable of accepting fluid at required rates without pressure. Injection tests indicate that the pressure required to inject at a rate of 160-gpm will be at least 1,200-psi (Howco instant shut-in) plus 105-psi friction pressure in the 3-1/2" tubing. The tracer survey showed no upward vertical migration and the survey was performed after the fracture treatment. The logic here is that if a rate of 59 barrels per minute was contained in the zone, then a rate of 4 barrels per minute should certainly follow the same path as the fracture treatment.

KEDA recommended "that the waste stream be filtered and pumped in the well a pressures less than the fracture pressures exerted by Howco (max 1,650-psi) during the fracture treatment. Tracer surveys can be performed to ensure against vertical migration. Annular pressure (3-1/2" X 7") should be monitored to detect tubing leaks. Continuous recording of tubing and annulus pressure should be performed. Monthly review of operating data should be performed to detect irregularities. Wastewater should be monitored daily for volume, temperature, pH, specific gravity, and suspended solids".

OPERATIONAL PLAN

A series of sumps collect runoff from the plant process area. These, along with process effluent discharges from the venturi scrubber system, are pumped to an Elementary Neutralization Unit (ENU) where soda ash (Na_2CO_3) is added to neutralize the acidic waste stream. Refer to Figures 21, 22, and 23.

The chemical reaction in the neutralization unit is as follows:

- Sodium Carbonate (Na_2CO_3) goes into solution with water in the slurry tank at a ratio of approximately 1 part soda ash to 3.5 parts water (1:3.5). The slurry is then added to the neutralization tank where the following reaction takes place:

$$Na_2CO_3 + 2HCl \rightarrow 2NaCl + CO_2 + H_2O$$

In case of an ENU failure, DLD has three optional operational responses.

- The first response would be to simply shut the plant down and stop the flow of effluent.
- The second option is manual neutralization of the waste stream to maintain the pH above 4.0. This will be accomplished by plant personnel by the manual addition of soda ash into a number of vessels such as T-11, the neutralization tank, scrubber tank, or the sumps. The small quench tank neutralization vessel can also be used to mix the slurry, which could then be gradually fed into the neutralization system via the salt plant sump.
- The third option is to pump the un-neutralized effluent to tank T-11. This tank as a capacity of 50,000 gallons which would be sufficient to store process effluent for 8-12 hours, depending on the rate of plant operation (100-gpm = 8.3 hours; 72-gpm = 11.5 hours).

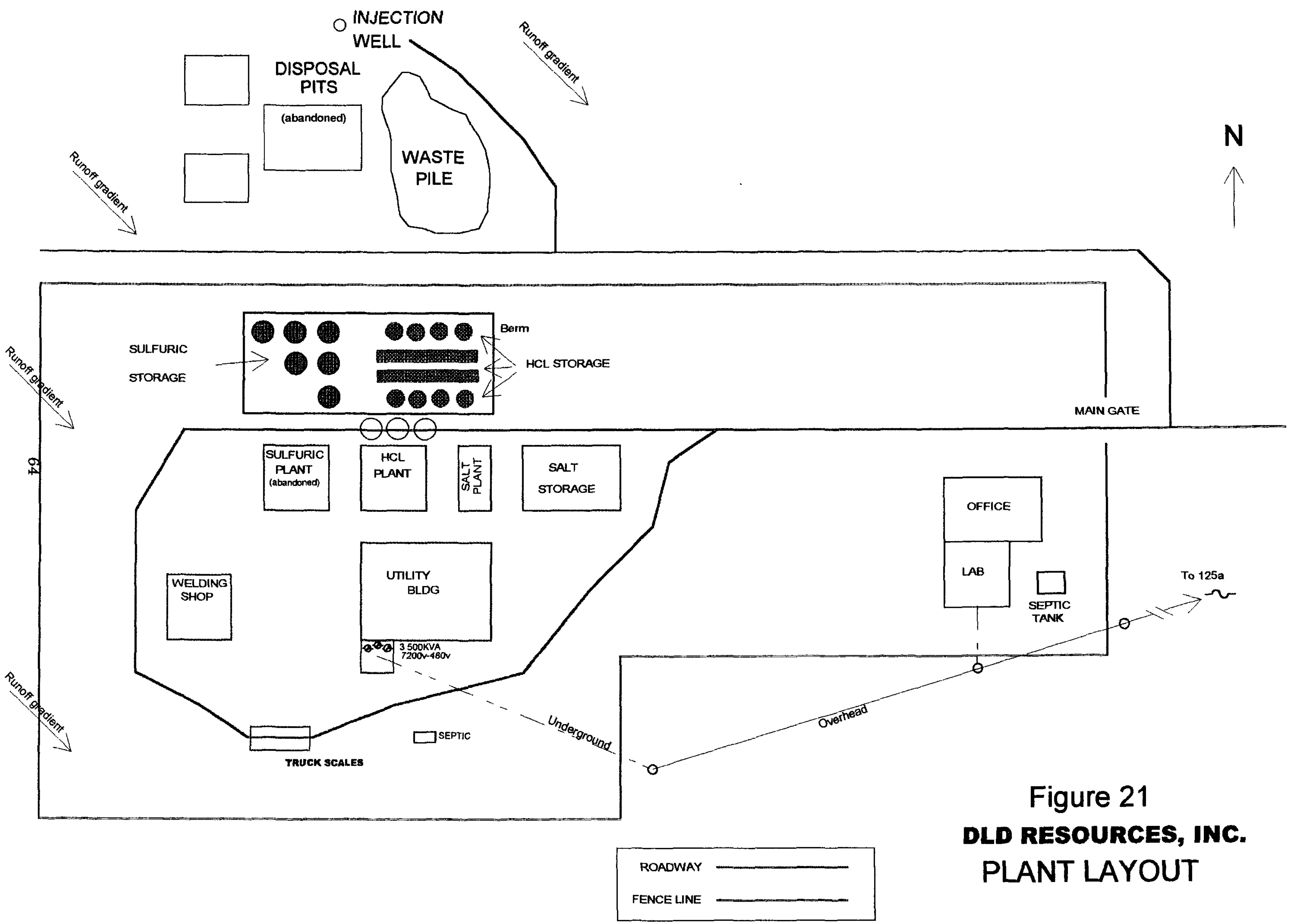
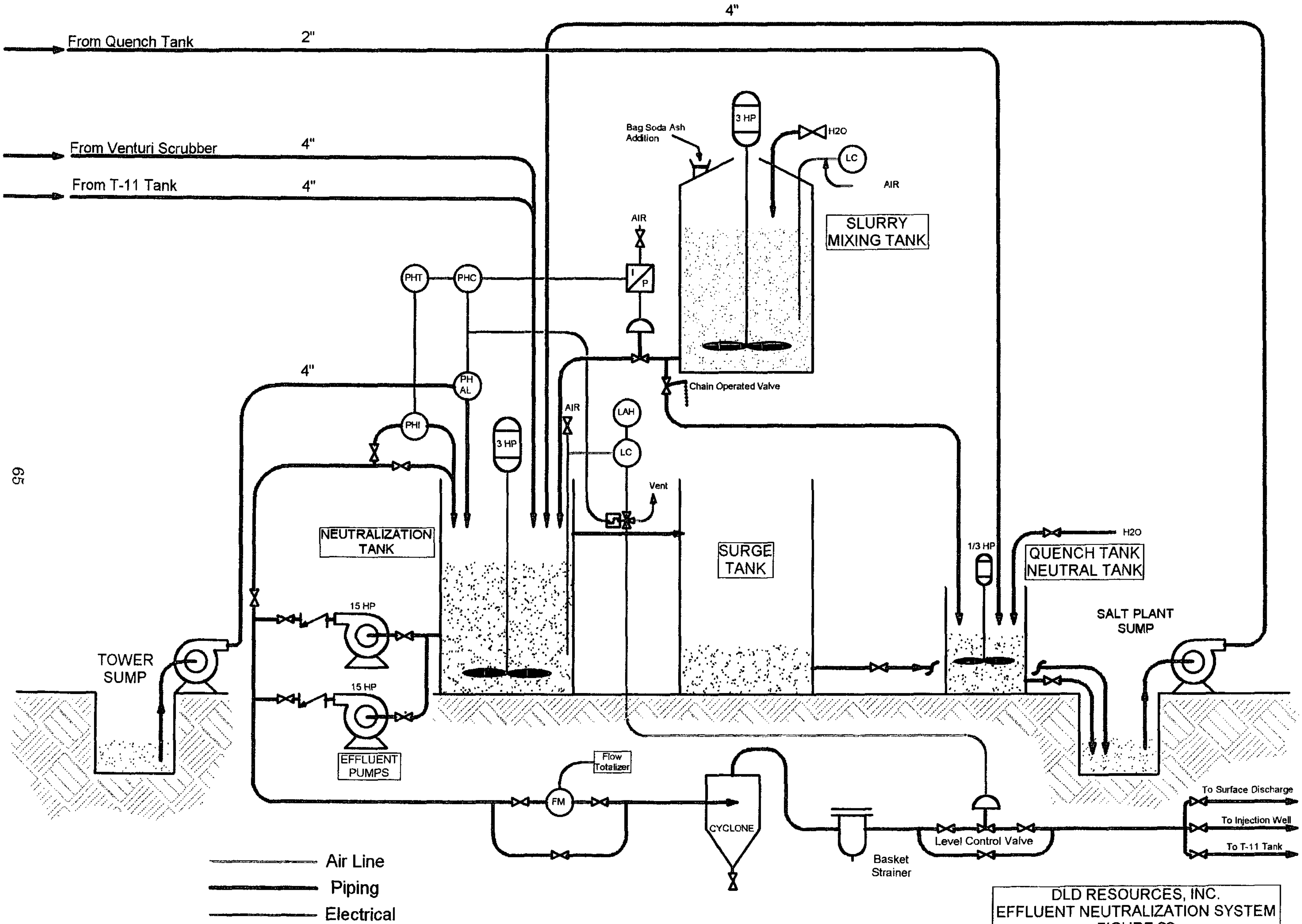
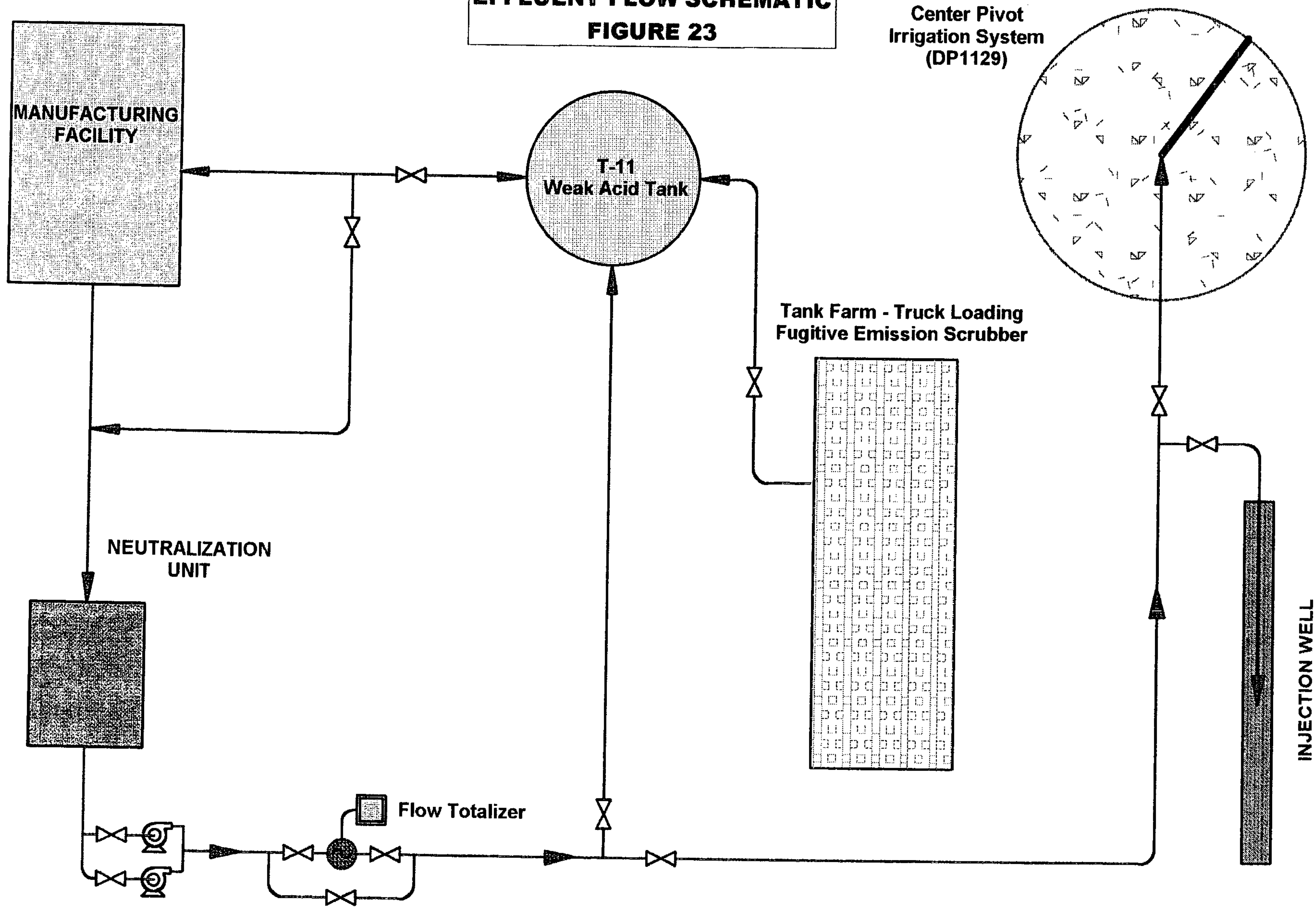


Figure 21
DLD RESOURCES, INC.
PLANT LAYOUT



DLD RESOURCES, INC.
EFFLUENT NEUTRALIZATION SYSTEM
FIGURE 22

DLD RESOURCES, INC.
EFFLUENT FLOW SCHEMATIC
FIGURE 23



Extended shutdown of the neutralization system is unlikely because of the redundancy built into the system and because of the spare parts inventory kept on hand. Equipment critical to the ENU operation includes the neutralization tank agitator, effluent discharge pump, and pH instrumentation.

In the case of the agitator, DLD maintains one operational spare motor and the manufacturer's recommended spare parts for the gearbox. The entire soda ash tank agitator is a duplicate of the neutralization tank agitator, excepting the PVC coated agitator. In a crisis, the soda ash tank agitator could be removed and installed in the neutralization tank if needed. In this event, the slurry suspension would be maintained using air lances.

A stand-by effluent pump is included in the neutralization system (see Figure 22). Either pump is capable of handling the plant's effluent flow. The spare parts inventory for both pumps is maintained onsite.

Under this Discharge Permit, pH 3.5+ effluent from the ENU will be discharged to the Class I injection well for disposal into the San Andres Formation injection zone (4,350' – 5,000').

CONTINGENCY PLAN

The facility contingency plan is submitted in this permit application as Appendix J.

As regards alternate disposal options, the following options will be available:

ENU FAILURE:

- Shut the plant down and block effluent flow; or
- Accomplish adequate neutralization of effluent with manual procedures; or
- Divert low pH effluent to weak acid tank T-11 (50,000 gallon capacity, 8-12 hours depending on operating rate). Divert back through the ENU once repairs have been facilitated.

ENU PRIMARY PUMP FAILURE:

- Switch to secondary ENU inline pump.

INJECTION WELL NON-OPERATIONAL:

- Shut the plant down and block effluent flow; or
- Divert neutralized effluent to weak acid tank T-11; or
- Increase neutralization of effluent to >6.0 and divert to land application system (DP1129)

MONITORING AND SAMPLING PLAN

EFFLUENT CHEMISTRY

Effluent will be sampled and logged by DLD personnel once daily and analyzed for pH and Specific Conductance. Effluent pH is also monitored within the ENU system and a continuous chart is generated in the plant control room.

Effluent will be sampled quarterly and analyzed by an independent laboratory for pH, TDS @ 180°F, Chloride, and Sulfate.

EFFLUENT VOLUME

Effluent flow will be through a magnetic flow totalizer. Readings will be logged daily.

INJECTION WELL PRESSURES

Injection well annulus and tubing head pressures are constantly monitored at the wellhead. Readouts are recorded on a double-pen, 7-day circular chart.

REPORTING

Quarterly reports will be submitted to NMED. Reports shall include: daily pH, daily Specific Conductance, daily volumes, quarterly lab analysis of effluent, and photocopies of pressure charts.

MECHANICAL INTEGRITY TESTING

Class I injection wells are required by Federal and New Mexico regulations to have Mechanical Integrity Tests (MIT) performed on them at a minimum interval of five years. The MIT requirement is implemented to ensure that there is no vertical migration of injected fluids along the cement-wellbore seal or the cement-casing seal.

TESTING METHODS

Mechanical integrity testing is routinely done on oil and gas producing wells. Several major oil field service companies specialize in this type of service. The most commonly used methods are:

Acoustic Cement Bond Log

This method utilizes an acoustic emitter and sensor combination to test the integrity of the cement bonding along the entire length of the well casing. This method requires that the injection tubing be removed from the well. The packer is then plugged and the entire well casing is filled with water. Due to the necessity to pull the injection tubing, this method is very expensive and time consuming.

Radioactive Tracer

This method utilizes the injection of a radioactive isotope (generally Iodine-131) into the injection zone. A sensor is then moved within the injection tubing to detect the presence of radioactivity along the cement bonds. The presence of radioactivity above the open borehole indicates vertical migration of injected fluids.

Due to the severe environmental and safety concerns inherent with the handling of radioisotopes, companies generally have ceased the performance of this test.

Water Flow Log (Activated Oxygen)

This method utilizes the fact that when an oxygen atom absorbs a neutron it will emit gamma radiation in the process (see Appendix K). The test involves the placement of a neutron emitter and a gamma radiation detector inside the injection tubing. Water is then injected into the well and the neutron emitter is activated. If gamma radiation is detected, vertical migration is occurring.

PRIOR TESTING ON THE WELL

Climax Chemical Company performed two MITs on this well. The first was in 1985 upon completion of well construction. The second was in 1990.

1985 - Welex

Welex (now Halliburton Logging Services) performed five surveys on the injection well upon its completion in 1985. These five surveys were:

- Dual Guard Micro Guard Log; (4-22 to 4-30-85)
- Compensated Density Dual Spaced Neutron Log; (4-22 to 4-30-85)
- Micro-Seismogram Log Cased Hole; (4-22 to 4-30-85)
- Acoustic Cement Bond Log; (5-7-85)
- Radioactive Tracer Survey (5-31-85)

None of these tests indicated any anomalies in the well construction.[1]

1990 – Halliburton Energy Services

On October 11, 1990, Halliburton Logging Services performed an Acoustic Cement Bond Log on the well. One anomaly was noted at around 200 feet below surface level. It is not known if there is a degeneration of the cement at this location, or if there was interference with the instrumentation due to a constituent of the cement. Regardless of the cause, this anomaly will not have any effect on the integrity of the well since it is extremely confined in size and over 4,000 feet above the injection zone of the well (See Appendix L).

PROPOSED MECHANICAL INTEGRITY TESTING

DLD Resources proposes to perform a Water Flow Log (Appendix K) on the well to prove mechanical integrity and lack of vertical migration. This survey will be performed prior to approval of this permit by NMED. The survey will be run by Schlumberger Well Services with the crew and equipment coming out of Midland, Texas.

CLOSURE PLAN

SURFACE EQUIPMENT

See Figure 19 for a schematic diagram of the injection well surface facilities. The only system components that will be discontinued during the term of the permit are those components that

[1] KEDA, Rework Report, 1985, Exhibit B

would have to be replaced for maintenance reasons. Since the nature of the effluent is non-hazardous or non-toxic, no special treatment of hardware will be necessary.

PLUGGING AND ABANDONMENT

In the event that DLD Resources decides to permanently discontinue use of the injection well, the well will plugged and abandoned as described in the Halliburton Services Cost Estimate for Plugging and Abandonment (Appendix M).

FINANCIAL ASSURANCE

DLD Resources shall establish a Plugging and Abandonment Trust Agreement with Western Commerce Bank, Hobbs, NM (see Appendix N). The Trust shall be initially funded in the amount $14,000 to cover the cost of the well P&A and two years of ground water monitoring of wells associated with DP-1129 (surface discharge system). The sole beneficiary of the Trust shall be NMED. The instrument for funding of the Trust shall be 5-year Certificates of Deposit.

PROPERTY AND MINERAL OWNERS

The list of property and mineral owners within the 2-½ mile radius area of review is included as Appendix O. A copy of the letter of notification is also included.

CERTIFICATIONS

I certify that I have the authority to sign this document as an Officer/Director for DLD Resources, Inc., the legal owner of the property in which all discharges will occur.

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Signature of authorized person	Title	Date

I certify that I am familiar with the information contained in the application and that to the best of my knowledge and belief such information is true, complete and accurate.

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Signature of person legally responsible for the discharge	Title	Date

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