MERISOL GREENS BAYOU PLANT

2000 EPA PETITION REISSUANCE

SECTION 4.0 – SITE GEOLOGY

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4.0 SITE GEOLOGY

4.1 INTRODUCTION

The geologic suitability of a specific stratigraphic interval for the injection and confinement of hazardous wastes is determined primarily by consideration of the following criteria:

- Lateral extent, thickness, porosity, and permeability of the injection reservoir;
- Lateral extent, thickness, porosity, and permeability of the overlying aquicludes and confining zone;
- Mineralogical composition of the injection reservoir, overlying aquicludes, and confining zone;
- Hydrogeologic compatibility of the injected waste stream with formation materials and formation brines;
- Faulting or fracturing of injection reservoir, overlying aquicludes, or confining zone; and
- Seismic risk.

These criteria are determined by the regional and local depositional and structural histories of the geologic section.

Basal sandstones of the Oligocene Frio Formation provide effective injection reservoirs in terms of their petrophysical characteristics, mineralogical composition, and areal extent. They have sufficient porosity, permeability, thickness, and lateral continuity to readily accept and contain injected fluids. The overlying aquiclude layers of the Frio Formation and the overlying Anahuac Formation confining zone are free of transecting, vertically transmissive faults and fractures, and are sufficiently thick, impermeable and laterally continuous to confine the waste.

In the following sections, the depositional and structural framework of the sedimentary column (Figure 4-1) currently being utilized for the injection and confinement of hazardous wastes at the Merisol Greens Bayou Plant are outlined. Also included is a hydrogeological discussion of the

reservoirs in which the usable and potentially usable ground-water resources occur.

4.2 REGIONAL GEOLOGY

The earliest record of sedimentation in the Gulf of Mexico Basin occurred during the Late Triassic to Early Jurassic when the early phases of continental rifting resulted in the deposition of non-marine redbed and deltaic sediments (shales, siltstones, sandstones, and conglomerates) of the Eagle Mills Formation in a series of restricted, graben fault-block basins (Figure 4-2). These sediments were overlain by a thick sequence of anhydrite and salt beds (Werner Anhydrite and Louann Salt) deposited during Middle Jurassic time. The deposition of the Louann Salt beds was localized within major basins that were defined by the major structural elements in the Gulf Coast Basin. The clastic Norphlet Formation (sandstones and conglomerates) overlies the Louann Salt and is more than 1,000 feet thick in Mississippi, but thins westward to a sandstone and siltstone in Texas. Norphlet conglomerates were deposited in coalescing alluvial fans near Appalachian sources and grade downdip into dune and interdune sandstones deposited on a broad desert plain (Mancini et al., 1985). Although the Norphlet Formation is unfossiliferous, based on dating of the overlying and underlying sequences, the Norphlet Formation is probably late Middle Jurassic (Callovian) in age (Todd and Mitchum, 1977).

Shallow-water carbonate and clastic rocks of the Smackover, Buckner, and Haynesville Formations and Cotton Valley Group were deposited over the Norphlet Formation from the Late Jurassic into the Late Cretaceous. Jurassic, nonskeletal, carbonate sands and muds accumulated on a ramp-type shelf with reefal build-ups developed on subtle topographic highs (Baria et al., 1982). A high terrigenous clastic influx in eastern Louisiana and Mississippi occurred during deposition of the Haynesville, and diminished westward where the Haynesville Formation grades into the Gilmer Limestone in East Texas. The top of the Jurassic occurs within the Cotton Valley Group, with the Knowles Limestone dated as Early Cretaceous (Berrasian) in age (Todd and Mitchum, 1977). The middle Cretaceous was a period of particular stability, permitting the development of extensive, shelf-edge reef complexes (Baria et al, 1982). Tectonism in the western United States and northern Mexico (Laramide Orogeny) in the Late Cretaceous resulted in a large influx of terrigenous sands and muds (Washita-Fredericksburg and Tuscaloosa Formations) into the Gulf Coast Basin. This effectively shut off the production of carbonates, except in the Florida and Yucatan regions. The rate of terrigenous sediment influx has been

greater than the rate of basin subsidence, resulting in significant progradation of the continental shelf margin since the Cretaceous (Figure 4-3).

The geometry of Cenozoic deposition in the Gulf Coast Basin was primarily controlled by the interaction of the following factors:

1) Changes in the location and rates of sediment input, resulting in major shifts in the location of areas of maximum sedimentation;

2) Changes in the relative position of sea level, resulting in the development of a series of large-scale depositional cycles throughout Cenozoic time;

3) Diapiric intrusion of salt and shale in response to sediment loading; and

4) Flexures and growth faults due to sediment loading and gravitational instability.

Early Tertiary sediments are thickest in the Rio Grande Embayment of Texas, reflecting the role of the ancestral Rio Grande and Nueces Rivers as sediment sources to the Gulf of Mexico. By Oligocene time, deposition had increased to the northeast, suggesting that the ancestral Colorado, Brazos, Sabine, and Mississippi Rivers were increasing in importance. Miocene time is marked by an abrupt decrease in the amount of sediment entering the Rio Grande Embayment, with a coincident increase in the rate of sediment supply in southeast Texas, Louisiana, and Mississippi. Throughout the Pliocene and Pleistocene Epochs, maximum depocenters of sedimentation were controlled by the Mississippi River and are located in the offshore of Louisiana and Texas.

Tertiary sediments accumulated to great thicknesses where the continental platform began to build toward the Gulf of Mexico, beyond the underlying Mesozoic shelf margin and onto transitional oceanic crust. Rapid loading of sand on water-saturated prodelta and continental slope muds resulted in contemporaneous growth faulting (Loucks et al., 1986). The effect of this syndepositional faulting was a significant expansion of the sedimentary section on the downthrown side of the faults. Sediment loading also led to salt diapirism, with its associated faulting and formation of large salt withdrawal basins (Galloway et al., 1982).

Sediments of the Tertiary progradational wedges were deposited in continental, marginal marine, nearshore marine, shelf, and basinal environments and present a complex depositional system

along the Texas Gulf Coast.

Overlying the Tertiary progradational wedges along the Texas Gulf Coast are the Pleistocene and Holocene sediments of the Quaternary Period. Pleistocene sedimentation occurred during a period of complex glacial activity and corresponding sea level changes. As the glaciers made their final retreat, Holocene sediments were being deposited under the influence of an irregular, but rising sea level. Quaternary sedimentation along the Texas Gulf Coast occurred in fluvial, marginal marine, and marine environments.

4.2.1 Structure

The sediments of the Cenozoic were deposited along the margin of the Gulf Coast basin, an extracratonic basin characterized by rapid subsidence in areas of sediment loading. Three major areas characterized by unique structural styles have been defined along the Texas Gulf Coast, based on the syndepositional province and the type of diapiric sediment involved in deformational processes. They are the Houston Embayment of Southeast Texas, the San Marcos Platform of South-central Texas, and the Rio Grande Embayment of South Texas. The Merisol Greens Bayou Plant is located in the broadly defined Houston Embayment of Southeast Texas. This structural province is characterized by salt diapirism, with its associated faulting and large unfaulted salt withdrawal sub-basins (Bebout et al., 1978) (Figure 4-4). As the Oligocene-Holocene section thickens basinward, major fault and diapiric displacement extends upward through the unit, and deformation becomes increasingly complex (Galloway et al., 1982).

4.2.2 Seismicity

The Texas Gulf Coast is historically an area of low seismicity with naturally occurring earthquakes being rare and of low magnitude. In fact, the Merisol Greens Bayou Plant is located in one of the areas recognized as having the lowest level of seismic risk in the continental United States (Figure 4-5). Rare instances of fluid injection-induced and fluid withdrawal-induced earthquakes from oil field operations have been documented along the Texas Gulf Coast. However, fluid injection-induced earthquakes are associated with much higher injection pressures and volumes than encountered in Class I waste injection operations, while fluid withdrawal-induced earthquakes are associated with large-scale oil and gas production of greater magnitude than any past or present production in the Merisol Greens Bayou Plant area.

4.2.2.1 Induced Seismicity

The increased pore pressure most likely causes fluid injection-induced earthquakes from injection operations, which have reduced frictional resistance to failure. This mechanism has been used to explain the best known case of injection-induced seismicity, which occurred at the Rocky Mountain Arsenal near Denver, Colorado. In Texas, there are at least two known examples of previously seismically inactive areas becoming seismically active after major injection programs began. These are in the Central Basin Platform, near Kermit, and in the Midland Basin, near Snyder. In both cases, large-scale, high pressure, oil field related, waterflooding projects were under way, and subsequent earthquakes were recorded. No induced earthquakes have been known, or are postulated to have been caused in Texas by the relatively low-volume, low-pressure Class I injection operations, such as at the Merisol Greens Bayou Plant (Davis et al., 1987).

The potential for induced seismicity at the Merisol Greens Bayou Plant site can be evaluated using the very conservative "zero-cohesion Mohr-Coulomb failure criterion," recommended by the U.S. Geological Survey (Wesson and Nicholson, 1987). This method is based on the following equation:

$$P_{crit}=\frac{S_v(3\alpha-1)}{2} \quad (1)$$

where:

P_{crit} = the critical injection zone fluid pressure required to initiate slippage along faults and fractures

S_v = the total overburden stress (which represents the maximum principal stress in the Gulf Coast region)

α = the ratio of the minimum principal stress (horizontal in the Gulf Coast region) to the maximum principal stress (overburden stress)

Inherent in Equation (1) are a number of conservative assumptions, guaranteed to produce a worst-case lower bound to the critical fluid pressure for inducing seismicity. These are:

1) It neglects the cohesive strength of the sediments;

2) It assumes that a fault or fracture is oriented at the worst possible angle; and

3) It assumes a worst-case value of 0.6 for the coefficient of friction of the rock (see Figure 4 of Wesson and Nicholson, 1987).

For present purposes, Equation (1) can be expressed in a more convenient form by introducing the so-called matrix stress ratio (Ki) (Matthews and Kelly, 1967; Eaton, 1969), which is defined as the ratio of the minimum to the maximum "effective" principal stresses. Effective principal stress is equal to actual principal stress minus fluid pore pressure (p_o). Thus:

$$K_i = \frac{\alpha S_v - p_o}{S_v - p_o} \quad (2)$$

Substituting Equation (2) into Equation (1) yields:

$$\Delta P_{crit} = \frac{(3K_i - 1)}{2}(S_v - p_o) \quad (3)$$

where ΔP_{crit} is the critical injection zone pressure build-up required to induce seismicity, with:

$$P_{crit} = p_o + \Delta P_{crit} \quad (4)$$

Equation (3) will be used to evaluate induced seismicity at Merisol.

Section 3.0 indicates that, at the injection depths, the initial pore pressure (p_o) is approximately 0.432 psi per foot of depth. Eaton (1969) provides a plot of the effective overburden stress (S_v) as a function of depth for locations along the Gulf Coast. According to this plot, at depths greater than 6,500 feet, S_v exceeds 0.92 psi per foot of depth. Matthews and Kelly (1967) provides a plot of the matrix stress ratio (K_i) for tectonically relaxed reservoir sediments along the Louisiana and Texas Gulf Coast. This plot indicates that, at all depths greater than 6,500 feet, K_i exceeds a value of 0.60. Substituting these values for p_o, S_v, and K_i into Equation (3), yields a ΔP_{crit} greater than 0.195 psi per foot of depth, or 195 psi per 1,000 feet of depth at the Greens Bayou Plant site.

The observed and calculated injection zone pressure increases at the Greens Bayou Plant (see Table 4-15) are much lower than this very conservative value (1,269 psi) required to induce seismicity, even directly at the injection well at the maximum injection rate. Therefore, induced seismicity will not be a problem at the Merisol site.

4.2.2.2 Seismic Risk

Faulting in the Gulf Coast Basin is predominantly of two types: listric normal growth faulting; and faulting associated with shale or salt piercement structures (diapirism). Growth faults form contemporaneously with sedimentation so that their throw increases with depth, and strata on the downthrown side are thicker than the correlative strata on the upthrown side of the fault (Figure 4-6). The faults form in clastic sequences that build out into unconfined depositional sites that have prograded to the edge of the continental margin, resulting in contemporaneous failure of the prograding sediments (Jackson and Galloway, 1984). The buoyant rise of shale or salt through brittle geologic sections to produce diapirs and ridges can result in radial fault patterns (Figure 4-7). The Louann Salt has been shown to have moved as recently as the Pleistocene in some locations, and earthquakes have been located on or near these salt features.

The nearest reported naturally occurring earthquake to the Merisol Greens Bayou Plant occurred approximately 70 miles to the northwest, near Hempstead, Texas, and had a magnitude of 3.6 on the Richter Scale. Approximately 135 miles to the north, a series of eleven earthquakes occurred in the Hemphill area in April through June of 1964, with magnitudes of 3.0 to 4.4. Approximately 100 miles to the east, an earthquake of magnitude 3.8 was reported near Orange, Texas, in 1925. While these particular earthquake occurrences have not been studied in detail, they are believed to be due to regional sediment loading and/or salt tectonics.

At the Merisol Greens Bayou Plant, the likelihood of an earthquake is considered extremely remote, based on historical data, whether caused by natural forces or fluid injection. All the earthquakes recorded within 150 miles of the site have been of a magnitude of 4.4 or less, which, by definition, would do no noticeable damage to man-made structures. Therefore, the probability of an earthquake of sufficient magnitude to damage the injection system, injection well, or the confining layer is very low.

4.2.3 Stratigraphy

4.2.3.1 Frio Formation

Deposition of the progradational Frio wedge was initiated by a major global fall in sea level, with subsequent Frio sediments being deposited under the influence of a slowly rising sea (Galloway et al., 1982). On a regional scale, the Frio and Catahoula Formations can be divided into a number of distinct depositional systems that are related spatially and in time. Two major progradational delta complexes, designated the Houston and Norias delta systems, identified by Galloway et. al., (1982), were centered in the Houston and Rio Grande Embayments, respectively (Figure 4-8). Separating the two delta complexes was a broad barrier island/strandplain system (Greta/Carancahua) along the South-central Texas coast. A similar but smaller barrier island/strandplain system (Buna) was deposited by longshore currents off the eastern flank of the Houston Delta System (Galloway et al., 1982). Two Catahoula Formation fluvial systems, the Chita/Corrigan and the Gueydan, respectively, supplied sediment to the delta complexes. Frio sandstones of the Upper Texas Gulf Coast contain a higher percent of quartz, less feldspar, and less volcanic rock fragments (quartzose feldspathic volcanic litharenite), than Frio sandstones (feldspathic litharenite) of the Lower Texas Gulf Coast (Figure 4-9) (Bebout et al., 1978).

The Houston Delta System of East Texas underlies parts of nine counties centered in southern Harris County. The system is composed of several minor, laterally coalescent, and frequently shifting delta lobes (Galloway et al., 1982). Streams of the Chita/Corrigan fluvial system of the Catahoula Formation supplied sediment. Updip deltas exhibited wave-dominated, arcuate geometries; whereas, lobate delta geometries characterized episodes of maximum progradation, or an area where high subsidence rates were associated with salt withdrawal basins (Galloway et al., 1982). Due to constant switching of delta lobes, the rate of coastal progradation was slow for the Houston Delta System (Galloway et al., 1982).

The Norias delta system constitutes the main depocenter for Frio sediments in South Texas. Deposition of the Norias system resulted in the progradation of the continental margin more than 60 miles basinward (Galloway et al., 1982). The lateral boundaries of the delta system remained fairly fixed through time, centered in Kenedy County, Texas. Streams of the Gueydan fluvial

system of the Catahoula Formation supplied sediment to the system. Individual deltas of the Norias system exhibited wave-modified, lobate geometries to wave-dominated, cuspate geometries (Galloway et al., 1982).

Along the South-central Texas Coast, flanking the two Frio delta systems, was a broad, strike-parallel, barrier island/strandplain system. The Greta/Carancahua barrier/strandplain system comprises a linear sandstone belt separating marine from brackish-water (back-barrier lagoon) shales. Shoreline conditions remained fairly constant during Frio deposition. This, coupled with aggredational processes, resulted in the development of a thick, narrow, homogenous sand section (Galloway et al., 1982). Strike-parallel growth faults accentuated the coast-parallel geometry of the Greta/Carancahua barrier island/strandplain system.

4.2.3.2 Catahoula Formation

Updip to the Oligocene Frio Formation, the time-equivalent Catahoula Formation accumulated on the progradational continental platform inherited from Yegua, Jackson, and Vicksburg deposition (Galloway et al., 1982). The two Catahoula fluvial systems, the Gueydan and the Chita/Corrigan, supplied terrigenous clastic sediment to the Norias delta system and the Houston delta system, respectively. The Choke Canyon/Flatonia coastal lake/streamplain system drained the South-central Texas Coast behind the Greta/Carancahua barrier island/strandplain system.

The Gueydan fluvial system records the entry of a major river into the Gulf Coast Basin (Figure 4-7) (Galloway et al., 1977). The system is characterized by the development of multilateral sand belts several miles wide, composed of coarse-grained, bed-load, and mixed-load fluvial channel fill deposits encased in floodplain mudstones (Galloway et al., 1982). The Chita/Corrigan fluvial system in the Houston Embayment constitutes a broad sand belt with at least three main drainage axes (Figure 4-10).

Sandstone composition in the Catahoula Formation reflects the nature of transport of volcanic debris and distance from the volcanic source. Typical Catahoula Formation sandstone composition variations are shown in Figure 4-11. East Texas samples have heavy mineral assemblages containing ultra-stable, polycyclic, metamorphic, and igneous minerals such as rounded zircon, sphene, tourmaline, staurolite, kyanite, apatite, rutile, sillmanite, and garnet

(Ledger et al., 1984). South Texas samples contain abundant hornblend, zircon, apatite, and biotite (Ledger et al., 1984). The Trans-Pecos volcanic area is the probable source for the volcaniclastic material found in the Catahoula Formation (Ledger et al., 1984).

4.2.3.3 Anahuac Formation

As sea level continued to rise during the late Oligocene, the underlying Frio progradational platform was flooded. Wave reworking of sediment along the encroaching shoreline produced thick, time-transgressive blanket sands at the top of the Frio Formation and base of the Anahuac Formation (Marg-Frio) section. The transgressive Anahuac marine shale was deposited conformably on top of the blanket sands throughout the Texas and Louisiana coastal region. The Anahuac shale was deposited in an open-shelf environment and is typically composed of calcareous, marine shales with localized, lenticular, micritic limestone units. The Anahuac shale is regional in extent, thickening from its inshore margin to nearly 2,000 feet offshore in the Gulf of Mexico (Galloway et al., 1982).

4.2.3.4 Fleming Group

The Oakville Formation and the Lagarto Formation form the units of the thick Miocene Fleming Group that was deposited throughout the Gulf Coast. Deposition of the Fleming Group occurred in relatively shallow water across the broad, submerged, shelf platform constructed during Frio and Anahuac deposition. Three major depositional regimes characterize the Fleming Group. Figure 4-12 shows the distribution of the lower Miocene depositional systems across the Texas Coastal Plain.

A major fluvial system (Santa Cruz fluvial system) extended across South Texas and supplied sediment to the North Padre delta system (Figure 4-12). The Hebronville and George West fluvial axes are interpreted as two principal depositional loci of a single major river that shifted southward through Miocene time (Galloway et al, 1982). The high sand content and internal structures of the fluvial system indicate low-sinuosity, braided, bed-load channel deposition (Galloway et al, 1982). The Santa Cruz fluvial system grades basinward into delta-plain deposits of the North Padre delta system. The delta system is generally coincident in geographic distribution with the underlying Oligocene Norias delta system of the Frio Formation. The North Padre delta system is characterized by sand-rich, strike-parallel, delta-margin, facies tracts

typical of coastal-barrier and beach-ridge facies, characteristic of highly-destructive, wave-dominated deltas (Galloway, 1985).

Along the northeastern boundary of Texas, the Newton fluvial system supplied sediment to the Calcasieu delta system of Southeast Texas and Southwest Louisiana (Figure 4-12). Sands of the Newton fluvial system are fine- to medium-grained, with thick, vertically and laterally amalgamated sand lithosome geometries typical of meanderbelt fluvial systems (Galloway, 1985). Depositional patterns within the Oakville Formation (lower Fleming) of Southeast Texas show facies assemblages typical of a delta-fringing strandplain system (Galloway, 1985). The Calcasieu delta system is best developed in Southeast Texas in the Lagarto Formation of the upper Fleming. The delta system consists of stacked delta-front, coastal-barrier, and interbedded delta-destructional shoreline sandstones that compose the main body of the delta system, with interbedded prodelta mudstones and progradational sandy sequences deposited along the distal margin of the delta (Galloway, 1985).

Along the South-central Texas Coast, flanking the two Miocene delta systems, was a broad, strike-parallel barrier island/strandplain system. The Matagorda barrier/strandplain system is cored by a prominent strike-parallel belt of sandstone, bounded both updip and downdip by mud-rich bays and lagoons, and marine shales, respectively (Galloway, 1985). The shore-zone complex has been interpreted by Galloway (1985) and Galloway et al., (1986) to consist of a mix of microtidal barrier-island and sand-rich strandplain deposits. Where streams of the Moulton/Point Blank streamplain infilled the back-barrier bays and lagoons, fluvial channel deposits merge directly with shore-zone sands (Galloway, 1985).

4.2.3.5 Pliocene

Conformably overlying the Miocene marine units are the Pliocene-aged sediments of the Goliad Formation. The Goliad sedimentary sequence is similar in character to the underlying Miocene unit, having been deposited in fluvial, deltaic and marginal marine environments. The section thickens in a dip direction (toward the present day coast line) and has a variable thickness along strike. In the Merisol Greens Bayou Plant area the unit reaches a thickness of approximately 900 feet and is composed of interbedded, fluvial and deltaic sandstones with minor conglomerates.

Sandstones of the Goliad Formation are the lowermost units containing fresh to slightly saline water and form the Upper Evangeline aquifer in Harris County (Aronow and Wesselman, 1971).

4.2.3.6 Pleistocene

Lying conformably above the Goliad are the Pleistocene-aged sediments of the Willis, Lissie, and Beaumont Formations that were deposited under the influence of the complex glacial and interglacial climatic sea level changes of the Pleistocene. The Willis Formation was deposited in both fluvial and deltaic environments, and thickens in a dip direction as well as along strike toward the southwest. Immediately overlying the Willis Formation is the Lissie Formation, which throughout Southeast Texas is subdivided into the Bentley and Montgomery members. Both the Lissie Formation and the overlying Beaumont Formation were deposited in fluvial environments and are composed of interbedded channel sandstones, crevasse splays, gravels and flanking meander belt deposits in the area. Pleistocene sediments thicken along the Texas-Louisiana border and in a dip direction where there was significant deposition along growth faults during Pleistocene sea level lowstands (Aronow and Wesselman, 1971). The combined thickness of the Pleistocene formations is approximately 600 feet in the vicinity of the Greens Bayou Plant. The Pleistocene sediments grade conformably into the overlying Holocene depositional units that contain the Chicot aquifer.

4.2.3.7 Holocene

With the retreat of the Pleistocene glaciers, sea level began a final irregular rise to its present day level. As sea level rose, the lower reaches of the San Jacinto river valley slowly filled with brackish-to-marine water and subsequently began filling with fluvial sediments. In the area, Holocene sediments were deposited in river valley meander belts and are primarily composed of point bar sandstones with interbedded, finer-grained overbank deposits. The most extensive Holocene sedimentation occurred in coastal marsh, mud flat, and beach environments located along the southern coastal margin of Harris County (Aronow and Wesselman, 1971).

The slow rise of the Holocene sea level marked the beginning of the recent geologic processes that have created the present Texas coastal zone. During recent times, sediment compaction, slow basin subsidence, and minor glacial fluctuations have resulted in insignificant, relative sea level changes. The coastal zone in Southeast Texas has evolved to its present condition through

the continuing processes of erosion, deposition, compaction, and subsidence period. Recent alluvial deposition in the area is restricted to the geomorphic floodplain of the present day San Jacinto River system and to the entrenched valleys of the ancestral San Jacinto River system, which had downcut into the underlying Pleistocene deposits during sea level lowstands (Aronow and Wesselman, 1971).

4.3 LOCAL GEOLOGY

A structural and stratigraphic picture of the geology beneath the Merisol Greens Bayou Plant was developed from a series of structure and stratigraphic maps and cross sections prepared from the available well control in the area (including offset Class I Injection Wells and oil and gas exploration/production wells). Artificial Penetration numbers for wells within the 2.5-mile radius Area of Review are included on the maps, for ease of cross-reference with the logs included in Appendix 3-2. The structure and stratigraphy in the local area are detailed in the following sections. Wells for which no logs are available (logs could not be obtained or have not been released) are labeled "NL" on the maps. Wells that are not drilled to sufficient depth to penetrate a relevant marker or stratigraphic interval are labeled "NDE" on the maps. In cases of deviated wells, where deviation surveys are available, depths and thicknesses have been converted to true vertical depths and thicknesses. Note that due to the concentration of wells on Clinton Dome, only wells on the periphery of the structure are labeled.

Correlations of the major Lower Frio structure markers and stratigraphic intervals from the Merisol Greens Bayou Plant to the Clinton Dome wells is detailed in Appendix 4-8. Cross Section A-C runs approximately counter clock-wise from the L. Bowling, T. Mulligan No. 1 well (located immediately northeast of the 2.5-mile radius Area of Review) to the Roberts-Whitson Oil & Gas Corp., M.O. Furr No. 1 well, located upstructure from the Merisol injection wells. Note that this section "ties" to the Southwest-Northeast Structural Cross Section (Figure 4-19) at the Humble Oil & Refining Co., M.O. Furr No. 1 well, and to the Northwest-Southeast Structural Cross Section (Figure 4-18) at the Roberts-Whitson Oil & Gas Corp., M.O. Furr No. 1 well. Well logs used for this section are also included in Appendix 4-8.

4.3.1 Structure

The Merisol Greens Bayou Plant is located within the Houston Embayment of the Texas Gulf Coast. Three structure maps were constructed to illustrate the subsurface structure in the vicinity of the 2.5-mile radius Area of Review (key geology well logs are contained in Appendix 4-2). Additionally, a regional structure map obtained from Cambe Geological Services is included in Appendix 4-5. A structure map on the Anahuac Marker, a local resistivity marker that can be correlated in the area, is located approximately 377 feet above the top of the injection zone,

shows that the plant site sits on the western flank of the Lynchburg Field structure, near the south-southwest plunging saddle separating the Clinton Dome (located approximately five miles to the northwest) from the Renee-Lynchburg Field structure (located approximately 2.5 miles to the east) (Figure 4-13). A structure map on the deeper Vicksburg Marker, a local resistivity marker that can be correlated in the area, located approximately 700 feet below the base of the Frio E&F Sand, shows similar structuring (Figure 4-14), as does a structure map on the top of the Frio E&F Sand (Figure 4-15). The rate of dip away from the plant site of the south-southwest plunging saddle is approximately 130 feet/mile at the Vicksburg Marker level. The Renee-Lynchburg Field structure is transected by three main southwest-to-northeast trending down-to-the-basin normal faults (labeled Fault A, Fault B, and Fault C). Based on fault cuts in the field wells and contouring, the three main faults that cross-cut Lynchburg Field have throws of 100 - 200 feet at the Frio E&F Sand level. These main faults are detailed below:

Fault A – This fault is primarily defined by log cuts on its eastern segment. The westernmost fault cut is found in the Mitchell Energy, Houston Port Authority #1 well located 3,700 feet east of the Merisol Plant Well 1 (WDW-147). A 150 foot displacement fault is observed at –5,850 feet subsea. Further fault cuts are observed to the east of the Mitchell Energy well: in the Amerada Hess, Destec "A" #2 well, the series of Inexco and Kelly Brock, Kelly Brock Fee wells, the Gulf Coast, Houston Ship Channel #1, and the Gulf Corp., Wilburn #1 well. Measured displacements range from 100 to 180 feet along the trace of this fault. Fault A separates the high-side structural closure at Renee Field (northeast corner of the Richard & Robert Vince A-76 survey) from the down-thrown four-way closure to the south-southeast.

Fault B – This fault is defined by log cuts on its southern and eastern segments. The southernmost fault cut is found in the Traders, Houston Deepwater Land Co. #1 well located just south of the 2.5-mile radius Area of Review, with an 80 foot displacement fault observed at –6,660 feet subsea. Further fault cuts are observed to the northeast of the Traders well: in the Frazier, T, Jones #1 well, the Ethyl, Ethyl Fee #1 well, and the Frazier Brooks #2 well. On its eastern segment, a fault cut of 90 feet displacement is observed at a subsea depth of –7,830 feet in the Inexco, Kelly-Brock #1 well. Measured displacements along the trace of Fault B range from 100 to 180 feet along the trace of this fault. Fault B separates the down-thrown four-way Renee Field closure from the down-thrown four-way Lynchburg Field closure to the south-southeast.

Fault C – This fault is defined by the structural elevation separation between Lynchburg Field from the four-way closure to the southeast. This fault separates the three top of Frio gas production wells and the other Class I injection wells from Lynchburg Field. Contoured displacement along the trace of Fault C is in excess of 100 feet along the trace of this fault.

Additionally, a small displacement splinter fault (Fault A') occurs trending to the northeast of Fault A. This fault is defined by cuts in the Mitchell Energy, Houston Port Authority #1 well (50 foot displacement fault is observed at –6,820 feet subsea) and the L. Bowling, Bynum et al. #1 well (Vicksburg marker faulted-out by a 60 foot fault), located in the Peter J. Duncan A-232 Survey. The splinter fault is not believed to carry much further northeast of the L. Bowling, Bynum et al. #1 (see Figure 2-13 – Flow and Containment Modeling Section 2.0), as no faults are found in either the Humble Furr # 1 well and the Frazier, Kalb et al. #1 well, or the wells located near the Lyondell Chemical Company, Plant Well No. 1 (WDW-148) and Plant Well No. 2 (WDW-162) injection wells.

Radial faulting patterns characterize the structuring at the three nearby salt domes: 1) Clinton, 2) South Houston (located eight miles to the southwest), and 3) Clear Lake (located 9.5 miles to the southeast). The mapped faults shown on Figures 4-13 through 4-15 are supported by missing geologic sections in geophysical well logs (fault cuts) and Texas Railroad Commission field maps.

The Anahuac Marker, Top of Frio E&F Sand, and Vicksburg Marker structures at Clinton Dome, located approximately five miles to the northwest of the plant, were prepared based on fault cuts in the field wells, supported by missing geologic sections, and Texas Railroad Commission field maps for the Miocene 3,800' Sand (Appendix 4-6). The main fault transecting Clinton Field is northwest-southeast oriented, down-to-the-northeast, normal fault that sets up the production in the Miocene 3,800' Sand as a high-side fault closure. Orientation of the fault was determined by tracing the trend of the fault-cut arcs in the well logs obtained for this study and the Texas Railroad Commission field maps for the Miocene 3,800' Sand (Appendix 4-6). The fault has 300 to 350 feet of throw through the main portion of the field. The main fault is approximately paralleled by a down-to-the-southwest, antithetic fault of smaller throw, resulting in a central graben area that is open towards the southeast. Structural dip on the southeast flank of this

central graben area is more similar to the dip found to the north-northeast of the dome, than the steeper dip found on the southern and southwestern flank of the dome. This is expected, since the central graben area compensates between the structure exhibited on the southern and southwestern flank, which is the high point of the field, and the lower angle dip exhibited on the north-northeast flank of the dome. The dip rate of the bedding in the central graben area and southeastern flank of the Clinton Dome structure was determined at the Anahuac Marker level by the difference in depth between several of the field wells in the graben and control at and near the plant site (Plant Well 1 (WDW-147) and the Frazier Brooks #1 well). Additionally, structural depths from wells in the adjacent fault blocks on the dome and the known displacement exhibited across the faulting was also used as point of control for the Anahuac Marker, Top of Frio E&F Sand, and Vicksburg Marker maps.

The transmissivity of fluids across a fault must be considered with respect to both lateral (horizontal) and vertical components, requiring an assessment of the likelihood of a sealing surface (top seal and/or lateral seal) being present. Faults, in and of themselves, do not seal (Downey, 1984). However, faults can place porous intervals against seals and form non-transmissive barriers (traps). In a sand-shale geologic sequence, faulting will result in the juxtaposition of like and/or unlike lithologies across the fault plane in three manners: a) sand-to-sand, b) sand-to-shale, and c) shale-to-shale. Fault planes are normally inconsequential to migrating fluids, and generally are of significance as sealing surfaces only because they may juxtapose rocks of differing capillary properties and fluid pressures (Downey, 1984, Smith, 1966). Each fault case, based on the juxtaposition of lithologies across the fault, must be considered during an assessment for both lateral and vertical transmissivity.

Because the shales beneath the Greens Bayou Plant are ductile at the depths of interest, the juxtaposition of shale beds or sand-to-shale beds across a fault will form a vertical barrier (seal) to fluid flow, due to their very low vertical permeability. This property of viscoelastic deformation behavior will cause any fractures and/or faults to close very rapidly under the action of the in-situ compressive stresses. This well known ductile (or plastic) behavior of the geologically young Gulf Coast shales is amply demonstrated by the presence of shale diapir structures and the natural closure of uncased boreholes with time (Jophnston and Greene, 1979, Gray et al., 1980, Davis, 1986, Clark et al., 1987, Warner and Syed, 1986, and Warner, 1988).

Jones and Haimson (1986) have found that, due to the very plastic nature of the Gulf Coast shales, faults will seal across shale-to-shale contacts, allowing no vertical fluid movement vertically along the fault plane. E. I. du Pont de Nemours and Company conducted a borehole closure test at the Orangefield Dome, which demonstrates the plastic nature of the Gulf Coast shales and the rapidity of shale movement to seal off open areas in the subsurface. The test conclusively demonstrated that the young Miocene shales of the Gulf Coast will flow and seal off an open area in the subsurface in a very short time period (test duration was approximately one week) (Clark et al., 1991).

The potential for fault-plane sand smear material to provide a vertical avenue for fluid movement through shale-to-shale juxtaposed lithologies is minimal in the Greens Bayou Plant area. This is due, not only to the ability of the shale layers to deform and close off any open areas in the subsurface, but also due to the fact that it can be shown through stratigraphic and structural analysis that many of the containment interval shale beds have not been faulted through sand beds. Therefore, there is no mechanism to get sand grains into the fault plane.

The vertical sealing nature of the faults can be demonstrated by looking at the original formation pressure gradients for sands in the lower Miocene and the sands in the lower Frio. Original formation pressure measurements for the injection interval sands beneath the DuPont La Porte Plant, located approximately nine miles south-southeast of the Merisol Greens Bayou Plant show pressure gradients in the range of 0.455 psi/ft to 0.460 psi/ft. These gradients are substantially higher than the pressure gradients measured in the lower Frio, which are on the order of 0.432 psi/ft (see Section 3.0). If the nearby faults were vertically transmissive, formation pressure gradients in the Miocene and Frio would be expected to be more similar. Additional evidence of the sealing property of shale-to-shale juxtaposed lithologies can be seen in the numerous oil and gas fields that have fault traps in the Gulf Coast, where both the top seal and the lateral seal are provided by shale beds. Specifically, the shallower Miocene and deeper Vicksburg and Yegua oil and gas accumulations near the plant site provide site specific evidence of vertical seal. The hydrocarbon accumulations would not have occurred if the faults are vertically transmissive.

Smith (1980) presents a mechanism whereby shale may be emplaced along the fault plane to provide an effective seal against vertical fluid movement. Shale can be deformed much more

readily prior to failure than sandstone can in a sand-shale sequence. Continued deformation will eventually fault the shales; however, a zone of deformed shale may become greatly attenuated and trapped along the plane of the fault, resulting in a vertical seal.

Therefore, the only mechanism for vertical movement up a fault is through "stair-stepping", whereby the fluid potentially moves laterally across juxtaposed sand-to-sand beds. However, beneath the Greens Bayou Plant, the preponderance of shale within the containment interval above the injection interval sand will quickly restrict this type of movement, due to the presence of juxtaposed shale-to-shale or sand-to-shale beds. Therefore, criteria can be developed to determine which faults in the vicinity of the Greens Bayou Plant are vertically transmissive or form top seals based on the juxtaposition of lithologies across the fault.

1) Juxtaposed shales present in the geologic section have a ductile nature and are likely to have squeezed in from both sides of the fault plane, sealing the fault to fluid movement. The juxtaposition of shale across from a sand bed would also seal the fault to fluid movement. This characteristic of Gulf Coast shales to seal open spaces in the subsurface is a well known and documented phenomena.

2) Where the geologic section is predominately sand, upward fluid movement may take place and would be expected to dissipate through "stair-stepping" into the overlying, juxtaposed sand units, similar to the oil migration in the Niger Delta (Weber and Daukoru, 1975). Were the waste to migrate up through the injection interval and cross the fault, the waste would still be in the injection zone on the other side of the fault.

The overlying geologic section of predominately shales (present in the section between the top of the Frio Formation and the injection interval), which provide extensive shale-to-shale contacts along the fault plane, will prevent waste migration out of the injection zone.

Conclusions from faulting case histories indicate that lateral transmissivity is primarily dependent upon the sand-shale ratio of the displaced section and the permeability of the juxtaposed sections (Smith, 1980). In addition, where faults vary in throw along the fault strike, faulting may be transmissive in one area of the fault plane and non-transmissive in another. Therefore, lateral transmissibility across a fault must be addressed, based on the local

juxtaposition of lithologies across that fault. Case studies show, only in special, rare cases where thick, undercompacted shales are interspersed between reservoirs, can clay smears be emplaced along a fault plane between offset sand beds. The case studies of Gulf Coast reservoirs show where parts of the same sandstone body are juxtaposed across a fault (30 - 300 feet of throw), the faults are laterally transmissive (Smith, 1980). Even in cases where "fault gouge" material was present, the faults were laterally transmissive when the same sandstone body was juxtaposed across the fault (Handlin, 1963). Weber and Daukoru (1975) determined from field evidence that in a young, growth-faulted basin similar to the Texas Gulf Coast, laterally non-transmissive faults are only likely when a given sand body on the high side (hanging wall) of the fault is passed by a sedimentary sequence on the down-thrown side (foot wall) that contains more than 25 percent shale beds (excluding the thin shale beds in the sandstone body).

Therefore, criteria can be developed from these case studies to determine which faults in the vicinity of the Greens Bayou Plant are laterally transmissive or form lateral seals:

1) Where the sand-shale ratio of the faulted geologic section indicates a substantial amount of impermeable shale (25 percent or greater in shale beds) is present, this shale could be expected to be smeared out along the fault plane during the growth of the fault. This clay smear would impede fluid movement laterally to a juxtaposed sand, resulting in a laterally non-transmissive fault.

2) A fault is laterally sealing where the entire injection interval sand is juxtaposed with a low permeability layer, such as clay or shale.

3) A fault is laterally non-sealing where parts of the same sandstone body (excluding shale beds within a sandstone body) are juxtaposed (Smith1966, Smith, 1980).

Detailed review of the cross sections (Figure 4-18 and 4-19) were conducted to determine the lateral transmissivity of the Frio sands based upon the juxtaposed geologic section, following the above outlined criteria.

Lateral transmissivity across the faults located to the east of the Greens Bayou Plant is an important consideration for the modeling of fluid flow in the injection zone. A site-specific

determination of the lateral transmissivity of faulting, based on the previously described criteria, is as follows:

Fault "A' "

Frio E&F Sand is laterally transmissive across this fault due to the small amount of fault throw (50 - 60 feet) as compared to the sand thickness (200+ feet). The injection interval sand is juxtaposed against the same stratigraphic sand body across the fault. The sand has been passed by continuous sand on the downthrown side of the fault. The above outlined criteria show that this fault is laterally transmissive.

Frio A&B Sand is laterally transmissive across this fault due to the small amount of fault throw (50 - 60 feet) as compared to the gross sand thickness (140+ feet). The injection interval sand is juxtaposed against the same stratigraphic sand body across the fault. The sand has been passed by continuous sand on the downthrown side of the fault. The above outlined criteria show that this fault is laterally transmissive.

Frio C sand is laterally transmissive across this fault due to the small amount of fault throw (50 - 60 feet) as compared to the gross sand thickness (190+ feet). The injection interval sand is juxtaposed against the same stratigraphic sand body across the fault. The sand has been passed by continuous sand on the downthrown side of the fault. The above outlined criteria show that this fault is laterally transmissive.

Fault "A"

Frio E&F Sand is laterally transmissive with the potential exception of a short segment (<3,000 feet long) of the fault adjacent to the intersection of Fault A' with Fault A located southeast of the plant, and a 10,000 foot segment located at the crest of the Lynchburg Field Structure located east of the plant. Along these segments, displacement along the fault approximates the sand thickness, juxtaposing the injection interval sand against shale. Along the remainder of the fault, the Frio E&F Sand is juxtaposed against the same stratigraphic sand body across the fault. The sand has been passed by continuous sand on the downthrown side of the fault. The above outlined criteria show that this fault is laterally transmissive through most of its length.

Frio A&B Sand is laterally transmissive. Along the fault, the Frio A&B Sand is

juxtaposed against either the same stratigraphic sand body or the Frio E&F Sand across the fault. The sand has been passed by fairly continuous sand on the downthrown side of the fault. The above outlined criteria show that this fault is laterally transmissive.

Frio C sand is laterally transmissive. Along the fault, the Frio C sand is juxtaposed against either the same stratigraphic sand body or the Frio A&B Sand across the fault. The sand has been passed by fairly continuous sand on the downthrown side of the fault when offset against itself. The above outlined criteria show that this fault is laterally transmissive.

Fault "B' "

Frio E&F Sand is laterally transmissive across this fault due to the small amount of fault throw (50 - 100 feet) as compared to the sand thickness (200 - 300 feet). The injection interval sand is juxtaposed against the same stratigraphic sand body across the fault. The sand has been passed by continuous sand on the downthrown side of the fault. The above outlined criteria show that this fault is laterally transmissive.

Frio A&B Sand is laterally transmissive. Along the fault, the Frio A&B Sand is juxtaposed against either the same stratigraphic sand body or the Frio E&F Sand across the fault. The sand has been passed by fairly continuous sand on the downthrown side of the fault. The above outlined criteria show that this fault is laterally transmissive.

Frio C sand is laterally transmissive. Along the fault, the Frio C sand is juxtaposed against the same stratigraphic sand body across the fault. The sand has been passed by fairly continuous sand on the downthrown side of the fault when offset against itself. The above outlined criteria show that this fault is laterally transmissive.

Fault "B"

Frio E&F Sand is laterally transmissive across this fault due to the amount of fault throw (100 - 200 feet) as compared to the sand thickness (280 - 300+ feet). The Frio E&F Sand is juxtaposed against the same stratigraphic sand body across the fault. The sand has been passed by continuous sand on the downthrown side of the fault. The above outlined criteria show that this fault is laterally transmissive through most

of its length.

Frio A&B Sand is laterally transmissive. Along the fault, the Frio A&B Sand is juxtaposed against either the same stratigraphic sand body or the Frio E&F Sand across the fault. The sand has been passed by fairly continuous sand on the downthrown side of the fault. The above outlined criteria show that this fault is laterally transmissive.

Frio C sand is most likely sealed along this fault. This is mainly due to the stratigraphic thinning of the sand body in the southeasterly direction. Although the Frio C sand would be in juxtaposition with the thick Frio A&B Sand on the downthrown side of the fault, the shale percentage in the Frio C sand interval is greater than 25 percent on the upthrown side. The above outlined criteria show that this fault is laterally non-transmissive through most of its length.

Fault "C"

Frio E&F Sand is laterally transmissive across this fault due to the amount of fault throw (100+ feet) as compared to the sand thickness (280 - 300+ feet). The Frio E&F Sand is juxtaposed against the same stratigraphic sand body across the fault. The sand has been passed by continuous sand on the downthrown side of the fault. The above outlined criteria show that this fault is laterally transmissive through most of its length.

Frio A&B Sand is laterally transmissive. Along the fault, the Frio A&B Sand is juxtaposed against either the same stratigraphic sand body or the Frio E&F Sand across the fault. The sand has been passed by fairly continuous sand on the downthrown side of the fault. The above outlined criteria show that this fault is laterally transmissive.

Frio C sand is most likely sealed along this fault. This is mainly due to the stratigraphic thinning of the sand body in the southeasterly direction. The Frio C sand would be in juxtaposition with itself on the downthrown side of the fault. The shale percentage in the Frio C sand interval is greater than 25 percent on both the upthrown side and downthrown side. The above outlined criteria show that this fault is laterally non-transmissive through most of its length.

The well test data from injectivity/falloff pressure tests (see Section 3.0) were reviewed to see if boundaries could be identified from the existing data. Unfortunately, due to the short duration of the falloff period, it was determined that the faults are located outside of the radius of investigation of the tests.

The land surface of the Houston area has been offset by over 160 surface faults (Verbeek and Clanton, 1981). Figure 4-16 shows the surface faulting pattern in the Houston area. Strong evidence indicates that the surface faulting has been accelerated or reinitiated along pre-existing faults that cut the deeper Tertiary geologic section, and is primarily due to the withdrawal of ground water from the subsurface (Verbeek and Clanton, 1981). Verbeek (1979) has stated that correlations between surface and subsurface faults are not conclusive because of the large distances involved in making the correlations. As subsurface fluids are extracted, pore pressure decline in the aquifer (reservoir) causes a higher overburden pressure to be supported by the sediment framework grains. Since the shallow subsurface sediments are loosely consolidated, the grains are forced closer together due to compaction, leading to land surface subsidence. A surface geologic investigation during the original permitting of Plant Well 1 (WDW-147) located a possible surface fault approximately 800 feet northwest of the plant site. Since the withdrawal of ground water in the area surrounding the Merisol Greens Bayou Plant is generally from less than 1,500 feet in depth, movement on the surface fault due to compaction should have no effect on the integrity of the injection and confining zones.

4.3.2 Stratigraphy of Injection and Confining Layers

4.3.2.1 Frio Formation – Injection Zone

Basal sands of the Frio Formation (approximately 6,560 feet to 7,290 feet referenced to Plant Well 1 (WDW-147)) serve as the injection intervals for process waste from the Merisol Greens Bayou Plant (Figure 4-17). These sands are identified as the Frio E&F Sand (Frio E&F Sand completion interval for Plant Well 1 (WDW-147)), and the Frio A&B Sand and the Frio C Sand (Commingled Frio A/B/C Sand completion interval for Plant Well 2 (WDW-319)) in this petition reissuance. Two structural-stratigraphic cross sections, approximately perpendicular to each other, were constructed to show the broad lateral continuity of the sand injection intervals

and shale (aquiclude) containment layers within the Frio Formation injection zone (Figures 4-18 and 4-19).

The structural-stratigraphic sections show the correlation and continuity of stratigraphic units in the subsurface. Note that the stratigraphic interval between the Anahuac Marker and the Vicksburg marker thickens towards the southeast (Figure 4-18), towards the depositional basin. Additionally, on the downthrown side (southeast side) of Fault C, a sand (termed the "Lower A&B Sand") is developed in the shale interval between the Frio A&B Sand and the Frio C Sand. Several of the Houston Ship Channel area Class I injection site wells (Shell and Hampshire) have had completions that spanned this sand (see Section 2.0).

A series of three detailed stratigraphic cross sections were prepared in the 2.5-mile radius Area of Review (Appendix 4-9). The sections use the top of the Frio A&B Sand. These sections generally run northeast, east, and southeast from the Merisol injection wells and show the geometry and continuity of the injection interval sands and confining shales in the Lower Frio.

Frio E&F Sand

The Frio E&F Sand is defined as the interval located at a log depth between 6,564 feet and 6,816 feet in Plant Well 1 (WDW-147). This designation includes a lower sand lobe, not previously included in the Frio E&F Sand, located at a log depth between 6,800 feet and 6,816 feet in Plant Well 1 (WDW-147). The series of three detailed stratigraphic cross sections in the 2.5-mile radius Area of Review (Appendix 4-9) show that the shale interval located between the thick upper portion of the Frio E&F Sand and this lower Frio E&F Sand lobe thins towards the Mitchell Energy Corp., Houston Port Authority No. 1 well (AP No. 16) and is absent on the downthrown side (southeast side) of fault A-A'. Therefore, this sand lobe is properly placed, from a stratigraphic standpoint, in the Frio E&F Sand injection interval. Note that neither injection well is currently completed in this lower Frio E&F Sand lobe interval.

In order to gain a more detailed understanding of the sand body geometry of the Frio E&F Sand, a gross sand isopach map was constructed from the available geophysical well log data (Figure 4-20). The gross sand isopach shows a broadly lobate, strike-oriented geometry near the plant site, thickening from northwest to southeast across the Area of Review (Figure 4-20). The sand

body geometry of the Frio E&F Sand is consistent with the overall deltaic depositional patterns exhibited during Frio time in the Houston Embayment. The Frio E&F Sand has a gross thickness of approximately 225 feet at the plant and ranges in thickness from +150 feet to +300 feet across the Area of Review. The Frio E&F Sand is generally "blocky" in the Area of Review, with thin shales being more prevalent towards the east-southeast (see Appendix 4-9).

To the northwest of the Area of Review, detailed recorrelation of new well logs recently available shows that the Frio C sand **is** present across the crest of Clinton Dome (Appendix 4-8). This result is different than previously depicted in the approved 1995 HWDIR Exemption Petition, which indicated that the Frio C sand was absent across the crestal portion of the field. Correlations across shorter lateral areas with the new logs show that a "miscorrelation" of the Frio A&B Sand east of the dome was made to the Frio C Sand at the dome. This resulted in an "apparent situation" where the Frio C Sand was thought to be shaled out in the original interpretation. Therefore, recorrelation of the Frio E&F Sand is made across the Clinton Dome area. The revised interpretation is illustrated on both the Northwest-Southeast Structural Cross Section (Figure 4-18) and the Gross Sand Isopach Map: Frio E&F Sand (Figure 4-20). The correlation of the E&F Sand to Clinton Dome is also shown in Appendix 4-8. Note that the upper portion of the Frio E&F Sand interval is very shaly northeast of the Clinton Done structure (see MaGuire Oil Co., Hahn No. 2 and Eddy Refining Co., Hunt No. 1 wells in Appendix 4-8). Although it is likely that the dome was a positive feature during Frio time (300 - 400 feet of thinning of the geologic section between the Anahuac and Vicksburg Marker Structure Points), presence of the lower Frio sands across the dome do not appear to be impacted.

Petrographic analysis of sidewall core samples from Plant Well 1 (WDW-147) for the Frio E&F Sand shows the sand to be a very fine- to medium-grained, silty to clean sand with porosities ranging from 27.6 percent to 34.0 percent, and permeabilities (to air) ranging from 41 millidarcies to 3,000 millidarcies (Pennington, 1979). A conventional rubber sleeve core was retrieved from the upper 20 feet of the Frio E&F Sand during drilling of Plant Well 1 (WDW-147). The core was sampled for porosity and permeability (to air) at one foot intervals. Porosities of the analyzed samples ranged from 23.6 percent to 34.3 percent, and permeabilities of the samples ranged from 5.8 millidarcies to 4,410 millidarcies (Pennington, 1979). Porosities determined from geophysical well log analysis of the Compensated Formation Density Log™

run during the drilling and completion of Plant Well 1 (WDW-147) are in good agreement with the whole core and the sidewall core porosity data. Data from recently drilled Plant Well 2 (WDW-319) are in good agreement with the Plant Well 1 (WDW-147) data.

From 1990 through 2001, annual injection/falloff testing has been performed on the Frio E&F Sand in Plant Well 1 (WDW-147). These tests have been evaluated as a consolidated interpretation for this 2000 HWDIR Exemption Petition Reissuance request following procedures outlined in the *EPA's Pressure Falloff Testing Guideline - Second Revision* (January 22, 1998). The consolidated analysis was performed by Reservoir Description Services, and the interpretation is contained in Appendix 2-6, Volume 2. The average test transmissibility is approximately 682,000 md-ft/cp, for an average permeability of 1,700 millidarcies. The data generally fall between a transmissibility of 576,800 md-ft/cp (1,476 md) and 870,400 md-ft/cp (2,227 md).

Petrographic and x-ray diffraction analysis of conventional and sidewall core samples from Merisol Plant Well 2 (WDW-319) showed a bi-modally sorted sandstone, with quartz being the dominant framework grain (potassium feldspar, plagioclase, rock fragments, and chert are the other framework grains). The sample is described as friable and only slightly compacted. X-ray diffraction of four samples indicate total clay of 4 to 7 percent, with kaolinite and illite/smectite being the dominant types.

A conventional core sample from the lower Frio Formation taken in the Lyondell Chemical Company, Plant Well 2 (WDW-162), located approximately 28,500 feet northeast of the Greens Bayou Plant site, showed a clean, well sorted, medium feldspathic litharenite (ARCO, 1990). The sample was composed of 85 percent quartz, 12 percent feldspar, and minor amounts of chert and clay minerals (Table 4-1). The individual grains were angular to subangular and equant (ARCO, 1990). The quartz grains were generally monocrystalline, free of inclusions, and showed optically continuous overgrowths at grain boundaries (ARCO, 1990). Orthoclase was the most common feldspar, but plagioclase and microcline were also present (ARCO, 1990). The sample was essentially devoid of matrix material, with the quartz overgrowths acting as a weak, patchy cementing agent (ARCO, 1990).

The original formation pressure of the Frio E&F Sand is estimated from the collective historic

static formation pressures (see Section 2.4.7). The original formation pressure is estimated to be 2875.8 psi at 6,650 feet. Bottom-hole temperature measured in Plant Well 1 (WDW-147) during open-hole logging was 156°F at a datum of 7,336 feet. Table 4-2 shows the chemical analysis of the native formation fluid obtained from Plant Well 1 (WDW-147), and analyses of native formation fluids from the nearby Class I well operators that also inject into the lower Frio Sands.

Frio A&B Sand

The Frio A&B Sand is defined as the interval located at a log depth between 6,826 feet and 6,980 feet in Plant Well 1 (WDW-147). The gross sand isopach for the Frio A&B Sand shows a broadly lobate, wedge geometry, with thickening from west to east across the study area (Figure 4-21). The gross sand isopach shows a broadly lobate, dip- to strike-oriented geometry near the plant site, and thickening from northwest to southeast across the Area of Review (Figure 4-21). The sand body geometry of the Frio A&B Sand is consistent with the overall deltaic depositional patterns exhibited during Frio time in the Houston Embayment. The Frio A&B Sand has a gross thickness of approximately 135 feet at the plant and ranges in thickness from ±80 feet to ±200 feet across the Area of Review. Thin shale breaks are present in the Merisol injection wells; however, the sand becomes more blocky towards the east-southeast (Appendix 4-9).

To the northwest of the Area of Review, detailed recorrelation of new well logs recently available shows that the Frio C sand **is** present across the crest of Clinton Dome (Appendix 4-8). This result is different than previously depicted in the approved 1995 HWDIR Exemption Petition, which indicated that the Frio C sand was absent across the crestal portion of the field. Correlations across shorter lateral areas with the new logs shows that a "miscorrelation" of the Frio A&B Sand east of the dome was made to the Frio C Sand at the dome. This resulted in the apparent situation where the Frio C Sand was thought to be shaled out in the original interpretation. Therefore, recorrelation of the Frio A&B Sand is made across the Clinton Dome area. The revised interpretation is illustrated on both the Northwest-Southeast Structural Cross Section (Figure 4-18) and the Gross Sand Isopach Map: Frio A&B Sand (Figure 4-21). Although it is likely that the dome was a positive feature during Frio time (300 - 400 feet of

thinning of the geologic section between the Anahuac and Vicksburg Marker Structure Points), presence of the lower Frio sands across the dome do not appear to be impacted.

Petrographic and x-ray diffraction analyses of conventional and sidewall core samples (see Appendix 2-6, Volume 2) from Merisol Plant Well 2 (WDW-319) showed a bi-modally sorted sandstone, with quartz being the dominant framework grain (potassium feldspar, plagioclase, rock fragments and chert are the other framework grains) in the Frio A&B Sand. The sample is described as friable and only slightly compacted. X-ray diffraction of four samples indicate total clay of 2 to 6 percent, with kaolinite and illite/smectite being the dominant types. Porosities of the Frio A&B Sand, from whole core and sidewall core samples range from 27.1 percent to 33.8 percent. These values are consistent with geophysical well log analysis of the Compensated Formation Density Log™ run during the drilling and completion of Plant Well 1 (WDW-147) and the Compensated Z-Densilog™ and Compensated Neutron Log™ run during the drilling and completion of Plant Well 2 (WDW-319).

An injection/falloff test was run on Plant Well 2 (WDW-319) on September 26 and 27, 2000. This well is completed in both the Frio A&B Sand and the Frio C Sand. Test derived transmissibility is 472,547 md-ft/cp in the commingled unit, for an average effective permeability of 1,022 millidarcies, if all of the 245 feet of completion interval is contributing to the falloff (assumes a fluid viscosity of 0.53 centipoise representative of the native formation fluid). A second high-quality injection/falloff test was run on Plant Well 2 (WDW-319) on March 7 and 8, 2002. Test derived transmissibility is 372,018 md-ft/cp in the commingled unit, for an average effective permeability of 1,245 millidarcies, if all of the 245 feet of completion interval is contributing to the falloff (assumes a fluid viscosity of 0.82 centipoise representative of the wastewater fluid). An interpretation of these falloff tests is also contained in Appendix 2-6, Volume 2.

Frio C Sand

The Frio C Sand is defined as the interval located at a log depth between 7,097 feet and 7,286 feet in Plant Well 1 (WDW-147). The gross sand isopach shows a broadly lobate, strike-oriented geometry near the plant, with a regional thick oriented from north to south across the Area of Review (Figure 4-22). The sand thins to the east-southeast, pinching-out into Frio shales

approximately six miles southeast of the plant. This pinch-out is oriented southwest-northeast and can be traced towards Clear Lake Field and Friendswood Field, approximately 10 miles southeast from the plant.

To the northwest of the Area of Review, detailed recorrelation of new well logs recently available shows that the Frio C sand **is** present across the crest of Clinton Dome (Appendix 4-8). This result is different than previously depicted in the approved 1995 HWDIR Exemption Petition, which indicated that the Frio C sand was absent across the crestal portion of the field. Correlations across shorter lateral areas with the new logs shows that a "miscorrelation" of the Frio A&B Sand east of the dome was made to the Frio C Sand at the dome. This resulted in the apparent situation where the Frio C Sand was thought to be shaled out in the original interpretation. The revised interpretation is illustrated on both the Northwest-Southeast Structural Cross Section (Figure 4-18) and the Gross Sand Isopach Map: Frio C Sand (Figure 4-22). Although it is likely that the dome was a positive feature during Frio time (300 - 400 feet of thinning of the geologic section between the Anahuac and Vicksburg Marker Structure Points), presence of the lower Frio sands across the dome do not appear to be impacted.

The sand body geometry of the Frio C sand is consistent with the overall deltaic depositional patterns exhibited during Frio time in the Houston Embayment. The Frio C sand has a gross thickness of approximately 155 feet at the plant and ranges in thickness from ±50 feet to ±155 feet across the Area of Review (a sand thick is developed at the plant). In the Merisol injection wells, the Frio C Sand occurs as two blocky lobes separated by a prominent shale unit in the middle portion of the sand. Across Clinton Dome (northwest of the Merisol wells), the Frio C Sand occurs as a blocky sand unit, without the prominent shale unit. However, thin shale breaks occur in the unit spanning the Frio C Sand interval across Clinton Dome. South and southeast of the Merisol injection wells, the Frio C retains its two blocky lobes separated by a prominent shale unit in the middle portion of the sand. The lowermost lobe shales out into the Lower Frio/Upper Vicksburg shale in the vicinity of Fault B-B'. The upper lobe of the Frio C Sand continues to thin further to the southeast, shaling out into the Lower Frio/Upper Vicksburg shale in the vicinity of Fault C', near the Houston Ship Channel Class I injection well sites (see Figure 4-22).

Porosities of the Frio C Sand, from whole core and sidewall core samples, range from 27.2 percent to 34.6 percent. These values are consistent with geophysical well log analysis of the Compensated Formation Density Log™ run during the drilling and completion of Plant Well 1 (WDW-147) and the Compensated Z-Densilog™ and Compensated Neutron Log™ run during the drilling and completion of Plant Well 2 (WDW-319).

Petrographic and x-ray diffraction analysis of conventional and sidewall core samples from Merisol Plant Well 2 (WDW-319) showed a bi-modally sorted sandstone, with quartz being the dominant framework grain (potassium feldspar, plagioclase, rock fragments and chert are the other framework grains) in the Frio C Sand. The sample is described as friable and only slightly compacted. X-ray diffraction of four samples indicate total clay of 4 to 7 percent, with kaolinite and illite/smectite being the dominant types.

An injection/falloff test was run on Plant Well 2 (WDW-319) on September 26 and 27, 2000. This well is completed in both the Frio C Sand and the Frio A&B Sand (commingled completion). Test derived transmissibility is 472,547 md-ft/cp in the commingled unit, for an average effective permeability of 1,022 millidarcies, if all of the 245 feet of completion interval is contributing to the falloff (assumes a fluid viscosity of 0.53 centipoise representative of the native formation fluid). A second high-quality injection/falloff test was run on Plant Well 2 (WDW-319) on March 7 and 8, 2002. Test derived transmissibility is 372,018 md-ft/cp in the commingled unit, for an average effective permeability of 1,245 millidarcies, if all of the 245 feet of completion interval is contributing to the falloff (assumes a fluid viscosity of 082 centipoise representative of the wastewater fluid). An interpretation of these falloff tests is also contained in Appendix 2-6, Volume 2.

Lower Frio Injection Interval Shale Between the Frio E&F Sand and the Frio A&B Sand

The shales that separate the Lower Frio Injection Interval Sands are generally continuous within the 2.5-mile radius Area of Review and the surrounding area. These shales form effective barriers to vertical fluid movement. In general, shales are alumino-silicates, composed primarily of clays and quartz (SiO_2), with smaller amounts of feldspar, carbonates, and miscellaneous oxides. The composition of a typical sedimentary shale is shown in Table 4-3.

The thickness of shale present between the base of the Frio E&F Sand and the top of the Frio A&B Sand is approximately 18 feet, in the Merisol injection wells. The shale thins towards the east (to less than 10 feet), but is present in all the wells that penetrate the top of the Frio A&B Sand (Appendix 4-10). The shale thickens to the north and northwest and is in excess of 50 feet thick in several of the Clinton Dome wells (Appendix 4-10). Confinement and isolation between the Frio E&F Sand and the Frio A&B Sand is demonstrated in the vicinity of the Merisol injection wells, since no injectate was observed in the Frio A&B Sand during drilling of Plant Well 2 (WDW-319). The High Definition Induction Log from Plant Well 2 (WDW-319) clearly shows that injecate from Plant Well 1 (WDW-147) is confined to the Frio E&F Sand (see Figure 2-3). Since the injectate, on average, is more dense than the native formation brine, the tendency would be for the injectate to move downward from the Frio E&F Sand into the Frio A&B Sand, if the units were in communication.

Upper and Middle Frio Shales

Shales within the Frio Formation injection zone form effective barriers to vertical fluid movement. Net shale, as measured from well logs in the interval between the top of the Frio E&F Sand and the top of the Frio Injection Zone (Frio Containment Interval), shows that there is a minimum of 400 feet of net shale in the Frio Containment Interval in the area surrounding the plant site. This shale thickness is more than adequate to contain the conservatively estimated vertical waste extent over the 10,000-year time frame (Section 2.0). In general, shales are alumino-silicates, composed primarily of clays and quartz (SiO_2), with smaller amounts of feldspar, carbonates, and miscellaneous oxides. The composition of a typical sedimentary shale is shown in Table 4-3.

Based on age and depth of burial, shales in the Frio Formation are expected to be of a similar composition as the "typical shale" shown above (Potter et al., 1980). Thin section and scanning electron microscope analysis of a shale sample at 6,428.7 feet in Plant Well 2 (WDW-319) showed a very argillaceous siltstone. X-ray diffraction of four samples showed 28 to 39 percent total clays, with illite/smectitie being the dominate clay mineral. Based on the data contained in Appendix 2-6, the total porosity of the shales in the Frio Containment Interval are expected to range between 20 - 23 percent (confirmed by Plant Well 2 (WDW-19) samples), and the

permeabilities of the shales are conservatively expected to range between 1.6×10^{-6} darcies and 8.2×10^{-7} darcies.

4.3.2.2 Anahuac Formation

Shales of the Anahuac Formation serve as the confining zone for the underlying Frio Formation injection zone. The Anahuac Formation is predominantly shale, deposited during a major rise in sea level, and is broadly regional in extent across the Gulf Coast Basin. The two structural cross sections show the lateral continuity of the Anahuac Formation across the Area of Review. The Anahuac Formation is approximately 380 feet thick at the Greens Bayou Plant. In order to gain a more detailed understanding of the geometry of the Anahuac shale, an interval isopach map was constructed (Figure 4-23). The Anahuac thickens in a broad wedge geometry, from 300 feet at the northwest corner of the Area of Review, to over 500 feet at the southeast corner of the Area of Review. Across the study area, the Anahuac Formation thickens from 200 feet, northwest of the plant, to over 900 feet, south-southeast of the plant (Figure 4-23).

Thin section and scanning electron microscope analysis of a shale sample at 5,007.3 feet in Plant Well 2 (WDW-319) showed an argillaceous calcareous siltstone, with quartz and calcite skeletal grains being the dominant framework component. X-ray diffraction of four samples showed 28 to 48 percent total clays, with illite/smectitie being the dominate clay mineral.

A conventional core, taken in the Anahuac Formation, was obtained during drilling of the DuPont Beaumont Works Plant Well 3 (WDW-188). Petrophysical and mineralogical analysis of samples from the core showed the composition to be approximately 61 percent total clay (predominantly mixed layer illite/smectite, with minor amounts of kaolinite and chlorite) and 30 percent quartz, with minor amounts of calcite, feldspar, and pyrite (DuPont 1990). These values are in the range expected for a typical Tertiary sedimentary shale (see Table 4-3). Vertical permeabilities (to brine) measured from two conventional core samples from the Anahuac Formation were 1.8×10^{-9} darcies and 5.9×10^{-9} darcies, respectively (see Appendix 2-6). Porosities for the Anahuac shales are expected to be approximately 23 percent (Appendix 2-6).

4.4 HYDROGEOLOGY

4.4.1 Regional Hydrogeology

The Miocene and younger formations containing usable quality water (<3000 mg/l TDS) and potentially usable quality water (<10,000 mg/l TDS) (base of lowermost USDW) can be divided into four major hydrogeologic units along the Texas Gulf Coast. These are, from oldest to youngest, the Miocene-aged Jasper aquifer and the Burkville confining system, the Miocene-Pliocene-aged Evangeline aquifer, and the Pleistocene-Holocene-aged Chicot aquifer (Baker, 1979). Freshwater recharge to the aquifer system is primarily from rainfall on the outcrop areas and from rainfall on the surficial aquifer system, which in turn recharge the underlying aquifers.

Most of the ground water in Harris County is supplied by the Evangeline and Chicot aquifers. Large ground-water withdrawals for municipal, industrial, and agricultural uses from the Evangeline and Chicot aquifers began in the 1930s (Gabrysch, 1980). Pumpage of ground water in the Houston area averaged 500 million gallons per day during the early 1970s (Gabrysch, 1980). These large amounts of ground-water withdrawal, in excess of rates of natural recharge, have resulted in water-level declines in both the Chicot aquifer and the Evangeline aquifer in Harris County. Figures 4-24 and 4-25 show potentiometric surface maps for the two aquifers in 1989. Ground-water withdrawals from the Chicot and Evangeline aquifers are not expected to have an effect on either the safety of the site (non-endangerment of USDWs) or injection operations. Based on the detailed geologic study, no natural conduits (vertically transmissive faults or fractures) exist between the injection sand and the fresh water aquifers. The safety of the man-made conduits within the Area of Review and the 10,000-year plume path (active and abandoned oil and gas wells) by either casing, cement, or mud plugs is demonstrated in Section 5.0. The Frio E&F Sand is separated by over 3,460 feet of geologic section (>1,800 feet net impermeable shale) from the shallow, fresh water aquifers (<10,000 mg/l TDS). Therefore, continued ground-water withdrawals from the Chicot or Evangeline aquifers will not have an effect on either non-endangerment or waste containment.

In the general area of the Greens Bayou Plant, sands containing usable quality water (<3,000 ppm TDS), the Chicot and Evangeline aquifers, occur to a subsea depth of –2,400 feet,

and those sands containing potentially usable water (<10,000 ppm TDS), the Jasper aquifer, occur to a subsea depth of –3,070 feet (base of lowermost USDW). Figure 4-26 is structure map on the base of lowermost USDW in the vicinity of the Merisol Greens Bayou Plant. The base of the lowermost USDW (<10,000 mg/l TDS) was determined by detailed log analysis of the ARCO Chemical Company, Plant Well No. 1 (WDW-148), located approximately 28,500 feet northeast of the Greens Bayou Plant (Appendix 4-3). Based on the analysis presented in Appendix 4-3, a formation resistivity (r_t) of 3.0 ohm-m on the long-spaced resistivity tool was determined to be a conservative cut-off in identifying the base of the lowermost USDW. Figure 4-27 shows the variation in total dissolved solids content as a function of depth for those geologic units between the lowermost USDW and the base of the Frio Formation. The figure is based on detailed log analysis of the Merisol Plant Well 1 (WDW-147), using the methodology outlined in Appendix 4-3.

4.4.2 Hydrogeologic Compatibility

Compatibility testing predicts whether individual waste streams will effect either the confining zone, injection reservoirs, or aquicludes within the injection zone. The two sections in hydrogeologic compatibility are:

a) Compatibility of the waste stream with the geologic formations; and

b) Compatibility of the waste stream with formation brine.

Compatibility tests between the waste stream and formation brine were conducted to determine whether the injected waste stream at the Merisol Greens Bayou Plant would form any precipitates. The formation of precipitates downhole could cause a continual decrease in reservoir performance with time, by clogging the throats between pore spaces. The resulting decrease in the effective permeability of the injection reservoir near the injection well would have to be compensated for by increasing the pressure of injection.

Based on the results of the hydrogeologic compatibility tests (summarized below), a buffering program was developed prior to waste injection into Plant Well 1 (WDW-147) (Section 4). The

buffering program consisted of injecting a low calcium brine with a clay stabilizer prior to putting the well on line.

4.4.2.1 Waste Stream - Frio Formation Brine Compatibility

Fluid compatibility tests between the original caustic waste stream and Frio Formation brines were conducted in 1977, as part of the pre-permitting of Plant Well 1 (WDW-147). The fluid compatibility test results indicated that injection of the waste stream into Frio Formation brines may cause the formation of precipitates (1.1-3.0% wt./vol.) (Flynn and Pierce, 1977). The precipitates formed due to the high concentration of calcium, magnesium, and barium in the synthetic Frio brine, which reacted to form insoluble carbonates and hydroxides on contact with the alkaline waste stream. The formation of precipitates in the near-wellbore region may lead to a loss of injectivity if the particulates are large enough to cause plugging of the perforations and formation pore throats. Reduced injectivity is only a concern, as it results in higher injection pressures at the well head and does not effect the integrity of the injection zone or the confining zone. Periodic well cleanouts, which increase injectivity, have enabled the plant to inject the waste at pressures well below the 950 psi permitted injection pressure.

4.4.2.2 Waste Stream - Formation Compatibility

Results of the modeling (Section 2.0) shows that the wastes are contained by the shale layers in the injection zone and never approach the confining zone. Shales of the aquiclude layers within the injection zone or the confining zone are primarily alumino-silicates, with quartz and minor amounts of feldspar, carbonates, and miscellaneous oxides. Although studies of clays in high-pH environments indicate that chemical reactions may take place between alkaline waste and clay (such as by cation exchange, clay dissolution, and new mineral formation (zeolites)) (Mohnot et al. 1984), such reactions are probably not significant to the integrity of the shale layers in the injection zone or the confining zone, due to their very low rates of reaction (kinetics) (DuPont 1990b). The primary neutralization reaction for alkaline wastes in subsurface environments is between the waste and Si-OH groups on the surface of the quartz grains, which is followed by sand dissolution. Chemical fate studies show that even highly alkaline wastes (pH >12.5) will be rapidly neutralized to a pH of 10 or less in a time period of years to decades (DuPont, 1990b). Since native brines in carbonate-shale sequences often have a pH of +10, once the injected waste

approached this pH value, such a liquid would no longer be expected to react with shales in the injection zone or confining zone. Other formation materials, due to the highly plastic nature of the sediments, would quickly fill any voids created by sand grain dissolution in either the injection sand or the containment interval shales.

Waste stream-formation solubility testing was conducted using core material obtained from Plant Well 2 (WDW-319). Formation solubility to the wastewater for five samples between 6,500 feet and 7,133 feet ranged from 0.4 percent to 1.86 percent, indicating that the waste stream is only weakly reactive with the formation material in the Frio.

4.5 SUMMARY

From the analysis of both the regional and local geology near the Merisol Greens Bayou Plant, it has been demonstrated that the plant is well sited for waste injection. The massive fluvial-deltaic sandstones of the Oligocene Frio Formation provide effective injection reservoirs in terms of their lateral extent, mineralogical composition and petrophysical characteristics. The reservoirs into which wastes are injected have the permeability, porosity, thickness, and lateral continuity to accept and contain injected fluids. The overlying aquiclude layers in the Frio Formation are sufficiently thick, impermeable, and laterally continuous to confine the injected fluids to the injection zone. Shales of the overlying Anahuac Formation possess the necessary confining zone criteria to be effective barriers to upward movement. The Anahuac shales exhibit good lateral extent on a regional scale, thickness, and are well over 1,000 times less permeable than the underlying injection reservoirs. The existence of multiple sand/shale layers between the top of the injection zone and the base of the lowermost USDW offers additional protection from contamination of a USDW.