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**TECHNICAL SUPPORT DOCUMENT FOR  
SECTION 194.32: FLUID INJECTION ANALYSIS**

**Volume 1 of 3**

**U. S. ENVIRONMENTAL PROTECTION AGENCY  
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## UNITS AND CONVERSION FACTORS

Area	square mile (mi <sup>2</sup> ) x 2.589988 = square kilometer (km <sup>2</sup> )
Area	acre x 4046.873 = meters (m <sup>2</sup> )
Permeability	millidarcy (md) x 9.869x10 <sup>-16</sup> = meter squared (m <sup>2</sup> )
Pressure	pound per square inch (psi) x 6.895x10 <sup>-3</sup> = mega pascal (MPa)
Volume	cubic foot (cf) x 0.02832 = cubic meter (m <sup>3</sup> )
Volume	barrel x 0.1589874 = cubic meter (m <sup>3</sup> )
Temperature	degree Fahrenheit (°F) -32.0/1.8 = degree Celsius (°C)
Temperature	degree Celsius ( C) +273.15 = degree Kelvin ( K)
Mass	pound (lb) x 0.3732 = kilogram (kg)
Density	pound/cubic foot (lb/ft <sup>3</sup> ) x 0.01602 = gram/cubic centimeter (g/cm <sup>3</sup> )
Density	pound/gallon (ppg) x 0.09977= gram/cubic centimeter (g/cm <sup>3</sup> )
Density	°API x 141.5/131/5+°API = gram/cubic centimeter (g/cm <sup>3</sup> )
Dip	foot/mile (ft/mi) x 0.1894 = meter/kilometer (m/km)
Length	foot (ft) x 0.3048 = meter (m)
Length	inch (in) x 2.54 = centimeter (cm)
Viscosity	centipoise (cp) x 1x10 <sup>-3</sup> = pascal-second (Pas)

Conversion references include (Bradley, 1989), (Eshbach, 1975) and (Perry, 1973).



## 1.0 INTRODUCTION

### 1.1 BACKGROUND

This report summarizes the U.S. Environmental Protection Agency's (EPA's) investigation of fluid injection practices in the vicinity of the Waste Isolation Pilot Plant (WIPP) in the Delaware Basin of southeastern New Mexico. Brine is being injected in the Delaware Basin into deep geologic strata for purposes of waste brine disposal, for secondary oil recovery by increasing declining oil reservoir pressures, and for secondary oil recovery by driving oil toward a production well in a waterflood operation. Of these, waste brine disposal is currently the most important fluid injection activity near WIPP. The potential for migration of brine into the WIPP repository as a result of fluid injection and the effects of such migration on the integrity of the repository have been identified by the U.S. Department of Energy (DOE), EPA, and in public comments as issues of concern. This report provides an overview of fluid injection practices and of the principal issues of concern. It summarizes the fluid injection studies that have been made by EPA and DOE, and presents EPA's conclusions regarding the potential effects of fluid injection practices on WIPP. Note that figures and tables are not referenced sequentially. Also, many figures and tables are not referenced in the text but are referenced in Appendices 1 and 20.

### 1.2 APPROACH

In evaluating the practices and potential impacts of current fluid injection practices on the WIPP repository, EPA evaluated the data provided by DOE in the October 1996 Compliance Certification Application (CCA; Docket A-93-02, II-G-01), supplemental materials provided by DOE at the Agency's request (Docket A-93-02, II-I-36, Attachments 1 and 2), and materials acquired from public and private sources relative to geologic conditions and oil and gas industry practices within the Delaware Basin in the vicinity of the WIPP (presented as appendices to this report). EPA's focused data collection was supplemented by the technical studies and reviews described in this document and by technical exchange meetings with Sandia National Laboratories (SNL) personnel.

The following approach was used for this study:

- ◆ Develop information about oil and gas activities that have occurred and are likely to occur in the general vicinity of WIPP. Specifically, this study characterized both the local geology and local oil and gas operations to determine the extent and nature of industry activity and fluid injection in the vicinity of WIPP.
- ◆ Use these data to evaluate the possible impact of oil and gas fluid injection activities on the WIPP disposal system.
- ◆ Review materials submitted by DOE to support its screening of the fluid injection scenario from performance assessment.

- ◆ Document EPA's conclusions regarding the potential impact of fluid injection practices on the WIPP disposal system.

This study focused on a 324 square mile (839.2 km<sup>2</sup>) area, comprised of 9 townships, centered on the WIPP Land Withdrawal Act (LWA) boundary. This area is denoted in discussion as the "study area" throughout the text of this document. The term "WIPP site" as used in this document refers to the 9 square mile area within the LWA boundary. Figure AX shows the study area and the WIPP site. As necessary, information from the surrounding area in southeastern New Mexico is also presented.

EPA reviewed information related to petroleum industry well penetrations in Lea and Eddy Counties, New Mexico, which was used to prepare a site specific database. Information was obtained from SNL on DOE's fluid injection screening, and additional literature was obtained from libraries and technical research outlets to complete the review. Comprehensive maps and listings of oil and gas well data are presented in the appendices. These appendices provide quick reference sources on the characteristics of well penetrations and injection operations in the study area. More comprehensive database information is provided on a CD-ROM (see Appendix 19) and a description of the data base development is presented in Appendix 20. Data sources are referenced in both the document text and attachments.

### 1.3 ORGANIZATION

This report is presented in 7 sections. Following the introduction, Section 2 presents an overview of EPA's regulations governing the future conditions to be assumed in assessing the performance of the WIPP disposal system over the 10,000-year regulatory time frame. Section 3 presents a review of fluid injection practices within the area of interest for this study. Section 4 provides a summary of fluid injection issues that have been raised, and Section 5 presents EPA's analysis of those issues. Fluid injection issues are summarized and EPA's conclusions are presented in Section 6. References are provided in Section 7.

## 2.0 REGULATORY SETTING

EPA required the DOE to project the performance of the WIPP repository over a 10,000-year time frame. The requirements imposed by EPA on the approach that DOE must use in preparing its projection provide the context within which all future activities, including fluid injection activities, must be addressed by DOE. These requirements, expressed in 40 CFR 194, imposed the following basic principles: with the exception of hydrogeologic, geologic and climatic conditions, future conditions are assumed to remain the same as current conditions (194.25(a)); performance assessments shall include activities that occur in the vicinity of the disposal system prior to disposal and are expected to occur in the vicinity of the disposal system soon after disposal (194.32(c)); performance assessment need not consider processes and events that have less than one chance in 10,000 of occurring over 10,000 years (194.32(d)); and future drilling practices and technology will remain consistent with practices in the Delaware Basin at the time

a compliance application is prepared (194.33(c)(1)).

The “current conditions” requirement of 194.25(a) is restated in 194.33(c)(1) with specific regard to drilling practices and technology because of the potential importance of drilling intrusions and drilling-related practices such as fluid injection on the integrity of the waste isolation system. When projecting repository performance over the 10,000-year regulatory time frame, EPA believes that the distant future is essentially unknowable, that current practices, activities, and technologies provide a basis for projecting future practices, activities, and technologies, and that the use of current conditions as a surrogate for future conditions avoids unnecessary and potentially unbounded speculation about future conditions. Because of this requirement, technologies that are not considered “current practice” in the Delaware Basin do not need to be considered by DOE in performance assessment. EPA intended this provision to refer to practices commonly used at the time DOE submitted its CCA or within several years before the submission of the CCA, rather than referring to every single practice used in the Delaware Basin. The Delaware Basin and the term “vicinity of the disposal system” were used in Sections 194.32(c) and 194.33(c)(1) of the Rule to define contiguous areas that had geologic properties that were similar to those at WIPP, and could therefore host current activities that should be considered in WIPP performance assessment. Activities outside these areas were considered to occur in different environments that were not directly applicable to conditions at WIPP and therefore did not need to be considered in WIPP performance assessment.

With the exception of drilling and mining practices (see 194.32(a)), EPA includes as “current conditions” the present legal prohibition on resource recovery activities within the 9 square mile Land Withdrawal Act (LWA) boundary of the WIPP site. This requirement means that activities such as fluid injection can be assumed in performance assessment to occur no closer than the edge of the LWA boundary, about 1.2 miles (about 2 km) from the WIPP repository. This requirement is consistent with EPA’s intent to avoid unbounded speculation about future events occurring at the repository site; however, the Agency specifically required DOE to include the effects of multiple direct drilling penetrations of the repository waste panels and considers these to be the most significant means by which releases could occur.

The requirement in 194.32(d) that performance assessments not address processes and events with less than one chance in 10,000 of occurring during the regulatory time frame is intended to allow DOE to eliminate very low probability events from consideration. Again, this requirement is intended to reduce unnecessary analysis of speculative and unlikely events.

### **3.0 FLUID INJECTION PRACTICES**

#### **3.1 OVERVIEW OF REGIONAL GEOLOGY**

The Delaware Basin is the western-most sub-basin of the Permian Basin. Straddling the border between southeastern New Mexico and west Texas, it covers an area approximately 100 miles wide (E-W) and 200 miles long (N-S). The northern and eastern boundaries of the Delaware Basin are defined by the Capitan Reef. The Delaware Basin is separated from the Midland Basin to the east by the Capitan Reef and the Central Basin Platform and from the Northwest Shelf by the Capitan Reef. The western and southwestern edges of the Delaware Basin in Texas are defined by the Pedernal Uplift and Diablo Platform.

There are widely varying rock sequences present within the Permian Basin. These variations are controlled by the presence of a shelf environment to the north, the basinal environment within the Delaware Basin itself, the Capitan Reef, and the significant erosion of pre-Pennsylvanian sediments on the Central Basin Platform. Although there has been significant exploitation and continues to be development potential associated with oil and gas resources within the Delaware Basin as discussed later in this document, the other portions of the Permian Basin including the Northwest Shelf, the Central Basin Platform, and the Midland Basin are more prolific producers of hydrocarbons and are more mature producing provinces than the Delaware Basin.

Within the Delaware Basin, the Cherry Canyon and Brushy Canyon Sandstones of the Permian Delaware Mountain Group are productive oil and gas zones. The uppermost formation in the group, the Bell Canyon Sandstone, is used extensively for waste brine disposal by fluid injection. The Delaware Mountain Group formations are not present outside the Delaware Basin. Deeper producing formations including the Permian Bone Spring and Pennsylvanian Strawn, Atoka, Morrow, and Wolfcamp are present on both the Northwest Shelf and in the Delaware Basin but not on the Central Basin Platform. Although there are isolated occurrences of Silurian and Devonian hydrocarbon production in all three areas, hydrocarbon production along the Capitan Reef, on the Northwestern Shelf, and on the Central Basin Platform is dominated by the Permian Yates, Seven Rivers, Queen, Grayburg, San Andres, Glorieta, Paddock, Yeso, Blinberry, Tubb, Drinkard, and Abo Formations which are not present within the Delaware Basin.

In addition to differences in the oil and gas reservoirs exploited in these parts of the Permian Basin, other significant differences exist between the depositional environments of the basinal, shelf, and platform settings. Formations within the basin were deposited in a fore-reef or basinal setting, while those outside the Delaware Basin were deposited in a back-reef shelf or platform setting. As will be discussed in this report, stratigraphic differences that are important to fluid injection scenarios exist between the geologic units in these two settings. Most notable of these differences is the rapid truncation or absence of pre-Permian and Permian rock on the shelf and platform, with rapid lateral facies changes in the Permian and Pennsylvanian age sections along the Delaware Basin margin. The Delaware Mountain Group sandstones are not present on the shelf or on the platform while the Capitan Reef abuts, but is not present within the Delaware Basin. The Permian age Salado evaporites thin appreciably moving out of the Delaware Basin

and the Castile Formation is generally absent on the shelf and platform (Figures CA, CB, and CC).

Figures C, D, AL, and W provide an overview of the geologic structure and stratigraphy in the area around the WIPP site, and detailed information on the geologic characteristics of the study area as relates to the hydrocarbon zones is presented in Appendix 1. The WIPP repository is located at a depth of 2150 feet (655 m) in the Salado Formation within the Delaware Basin. The WIPP is therefore located in a fore-reef or basinal setting. By comparison, sediments that were deposited behind the reef outside the Delaware Basin are located in a back-reef shelf or platform setting. As stated above, the stratigraphy is different in the two areas.

The Salado is younger and shallower than the oil and gas producing formations in the basin, and is therefore also shallower than the formations with potential for related fluid injection activities (see Table E). At the WIPP site the Salado is separated from the nearest fluid injection zone (the Bell Canyon Formation) by the Castile Formation which is locally a minimum of about 1050 feet (320 m) thick. The WIPP repository is located about 600 feet (183 m) above the top of the Castile and the minimum total thickness of evaporites between the repository and the nearest injection zone is about 1650 feet (503 m) (Figures J and K).

Laterally extensive interbeds of anhydrite and other minerals are present within the halites of the Salado and Castile at the WIPP site. Because these interbeds can be more permeable to fluid flow than the halites (see Section 4.1.2) they play a significant role in the postulated scenarios for fluid injection activities to impact the WIPP repository. The more dominant interbeds within the Salado have been used as marker beds for stratigraphic correlation across the region and have been sequentially numbered. Anhydrite Marker Beds 138 and 139 intersect the WIPP repository and are hypothesized as potential conduits for transmission of pressure transients and horizontal fluid movement between injection wells and the repository. Examples of marker beds in the Salado and the four thicker anhydrite interbeds in the Castile representative of conditions near the WIPP site are shown in the stratigraphic columns in Figures A and B.

### 3.2 OIL PRODUCTION POTENTIAL

The oil production potential of an area is important to fluid injection issues because of the requirement to dispose of large volumes of waste brine that are produced along with the oil, and the use of brine injection in secondary oil recovery operations. The WIPP site is located near the northern edge of the Delaware Basin (Figure AL). The Delaware Basin is the western-most sub-basin of the Permian Basin and has been a productive province for oil and gas operators since the early 1900s. As of 1996, the New Mexico portion of the Permian Basin had produced 4.3 billion barrels ( $6.9 \times 10^8 \text{ m}^3$ ) of oil and 19.7 trillion cubic feet ( $5.6 \times 10^{11} \text{ m}^3$ ) of natural gas from 1,164 oil fields and 1,853 gas fields (Broadhead, 1995). In the greater Permian Basin, more than 84,600 wells have been drilled related to hydrocarbon exploration and recovery. Based on well counts by Petroleum Information, Inc., there have been more than 10,000 wells drilled for hydrocarbon exploration and recovery purposes in the Delaware Basin. The database developed in this study indicates that there are currently 803 oil and gas boreholes in the nine township

study area surrounding the WIPP site.

Delaware Basin productivity is dominated by oil and associated gas found in Permian strata and gas condensate in Pennsylvanian strata (Tables A through E). Other formations produce minor amounts of oil and gas. Oil and gas production in the study area has primarily been from the Delaware Mountain Group sandstones at depths from the ground surface of approximately 6,000 to 8,000 feet (1,829 to 2,438 m), the Bone Spring sandstones and carbonates from approximately 8,000 to 10,000 feet (2,438 to 3,048 m), the Wolfcampian carbonates at a depth of approximately 12,000 feet (3,658 m), the Strawn carbonates at a depth of approximately 13,000 feet (3,962 m), and the Atoka and Morrow sandstones at depths of 13,000 to 14,000 feet (3,962 to 4,267 m). These formations and their elevations relative to the WIPP repository in the Salado Formation are shown in Figures J and K. These formations are continuous throughout the Delaware Basin and include productive fields near the WIPP site. Detailed geologic and production information on these reservoir formations is presented in Appendices 1 and 15.

A map of oil and gas wells near the WIPP site is shown in Figure AX, and selected petroleum production field trends that have been studied near WIPP are shown in Figure I. Reservoirs with petroleum production potential in the vicinity of the WIPP site include those listed in Tables A, B, C, and D, and geologic strata (zones) are ranked as to likelihood of petroleum production consistent with terms defined by the Potential Gas Committee (1992). Figure AY and Appendix 12 present cumulative injection volumes for all active injection wells within the study area. The data summarized in these figures were obtained from Lasser, Inc., Petroleum Information, Inc., and files from the State of New Mexico. Table D lists specific petroleum fields adjacent to the WIPP site and Figure I shows the locations of these fields.

Oil is the primary hydrocarbon produced near the WIPP site. The vicinity of WIPP was not a primary target for hydrocarbon exploration or development activities until the 1970s and few wells were drilled before that date. Successful exploration in the 1970s and 1980s clearly showed the presence of a significant hydrocarbon potential in the study area and the rate of drilling increased during that period. Most wells in this area have been permitted since the 1980s and development is clearly dominated by activity during the late 1980s and 1990s. Increases in activity can be attributed to improvements in technology, increases in operating efficiency, and greater flexibility in permitting by the State of New Mexico for well locations in previously restricted potash areas. Personal communications with operators in the area indicate that significant drilling programs are currently underway in the New Mexico portion of the Delaware Basin, particularly between Carlsbad and Hobbs, and will continue into the future. Reported increases in drilling activity have been substantiated by reductions in service company equipment availability and increases in drilling costs in the region due to increased activity. Appendix 8 presents recent scout tickets (well information summary information) obtained from Petroleum Information, Inc. As illustrated in Figures AZ and BA, drilling rates in the early 1990s have averaged approximately 75 wells per year in the study area. Many operators are currently active in the study area, ranging from small independents to large integrated major oil companies. Operators for each well are listed in the database included as Appendix 19 to this document.

A good potential exists for continued development of petroleum resources in the study area, and in the longer term, for the continued use of brine injection for disposal and secondary recovery. To date, the extent of oil fields near the WIPP site has generally not been defined by dry holes (non-productive wells that surround a producing area), thus operators continue to plan for future development drilling and secondary recovery activities following existing trends. Promising sandstone porosity and structural trends (see Figure AT) have been mapped according to the following listing:

Projected Near Future Oil Developments in the Vicinity of WIPP

Field:	Development Trend:
Livingston Ridge	Northward and southward within two miles of the eastern line of T22S R31E, into the eastern side of the LWA boundary (May 1995)
Cabin Lake	Southward into Sections 13 and 14 of T22S R30E, into the northwestern corner of the LWA boundary (Brown 1995)
Los Medanos and Sand Dunes	Northward and northeasterly through Sections 3, 4 and 5 of T23S R31E, into the southern part of the LWA boundary (Hoose and Dillman 1995)
Lost Tank	Southward into Sections 13, 24, and 25 of T21S R 31E, east of the LWA eastern boundary (May 1985)
Quahada Ridge	North or northeast into Sections 30 and 31 of T21S R 31E, into the southwest corner of the LWA boundary (possible)

### 3.3 CURRENT FLUID INJECTION ACTIVITIES

Fluid injection is a convenient and widely-used practice for disposal of waste brines produced as a by-product when pumping oil. Fluid injection is also used in secondary oil recovery for maintaining fluid pressure in the production zone to keep gasses in solution. A gas phase in the formation is undesirable because it reduces the flow of oil toward the production well. Fluid injection is also used in secondary oil recovery for waterflooding operations when primary recovery through natural reservoir drive mechanisms and direct gravity flow become uneconomical. Secondary recovery through waterflooding involves pumping brine into the producing formation through one or more injection wells and driving oil in the producing formation toward recovery wells (Bradley, 1989; Schumacher, 1978). The oil fields in the study area are relatively young and many are still under primary production. However, brine disposal and secondary recovery operations through fluid injection are occurring. Operators of permitted injection wells within the study area are listed in Appendix 10. Waste brine disposal and secondary recovery through waterflooding operations are common practices that can be expected to be used in many of the oil-producing zones in the study area. Fluid injection is therefore considered a “current practice” in the context of EPA’s Rule that can be expected to continue to occur near the WIPP site during the economic life of the petroleum production zones in that area.

Brine injection for disposal, pressure maintenance, and water flooding occur throughout the Delaware Basin and are currently underway in the vicinity of the WIPP site. For example, as shown in Appendix 7, there are more than 5,000 permitted injection wells in Lea County and 3,041 of these wells were active over the past 12 months. Wells in the area surrounding the WIPP site are included in these figures. Operators begin disposal of the brine accompanying oil immediately upon well completion and initiation of production. Water cuts (the percent of water or brine produced with the oil) for new oil production in the vicinity of WIPP range widely from 10% to 90% with the majority of water cuts in excess of 50% (Broadhead 1995). At this time, Class II Underground Injection Control (UIC) permits issued by the New Mexico Oil Conservation Division (NMOCD) authorize the injection of produced brine into the Bell Canyon and deeper formations in the vicinity of the WIPP site.

As shown in Appendix 9, the average age of injection wells in the study area is approximately five years. Although the oldest injectors in the area were completed in the late 1960s, most drilling and production activity in the area is relatively recent. Only two wells appear to have been active injection wells before 1989. By 1994 the number of active injection wells had risen to 16. During 1995 and 1996, 21 wells registered cumulative injection flows. The database query that summarizes all of these statistics for injection wells is presented as Appendix 14 of this document. The relatively young average age of the injection wells in the study area is consistent with the increased rates of drilling and completion over the past 5 years. Disposal via Class II injection in the vicinity of production operations is preferred over the generally less economical option of trucking brines significant distances for centralized treatment or other injection options.

Most injection in the study area involves disposal of waste brines into the Bell Canyon Formation of the Delaware Mountain Group below the Salado and Castile Formations (see Figures J and K, and Appendices 16, 17, and 18). Non-productive formations are often used for brine disposal operations. Most exploratory wells drilled before 1965 penetrated the Bell Canyon but typically did not produce petroleum with the exception of the Triste Draw location. Wells drilled prior to the acceleration in activity in the 1990s were focused on deeper natural gas plays (occurrences) in the Morrow and Atoka Formations.

As of September 1996, NMOCD information indicates that there were 23 active injectors within the nine township study area centered on the WIPP site. In addition, there were 3 completed and permitted injection wells that were not currently active and 10 permitted but not completed or converted wells, for a total of 36 permitted injectors within the study area. Figure BF shows the locations and relative rates of these active injectors. The additional permitted injection wells are typically active production wells that have been slated for conversion to injection at some time in the future. At any given time, it is likely that the number of active injection wells will change as oilfield activity continues. Some currently active injectors are likely to be plugged as other wells are put into active injection service. Information regarding locations, operators, leases, depths, disposal zones and other pertinent data for currently permitted injection wells is shown in Appendices 8 and 9. Files for individual injection wells within the study area as obtained from



Lasser, Inc., Petroleum Information, Inc., and NMOCD are included as Appendices 16, 17 and 18, respectively.

Injection wells in the study area are typically completed by perforation in the Delaware Mountain Group at depths ranging from 3,820 to 8,344 feet (1,164 to 2,543 m). As previously stated, injection for disposal typically takes place in the Bell Canyon Formation. This is the uppermost formation in the Delaware Mountain Group and it immediately underlies the Salado and Castile Formations in the salt section (Figures J and K). Injection rates in these wells vary widely depending on permit requirements and well conditions. Average injection rates of between 5 and 3,500 barrels of water per day (BWPD) (0.8 to 556 m<sup>3</sup>/day) have been reported, with most well rates in the range of 500 to 2,000 BWPD (80 to 318 m<sup>3</sup>/day). Appendix 14 provides injection information for each well in the study area and lists the injected volumes by year during the 1990s. Figure BF shows the locations of the currently active injection wells in the study area and also indicates the relative injection rates with larger symbols representing larger rates. Figure AY presents cumulative injection volumes for those wells.

Injection pressures are a primary concern to NMOCD regulators due to the widely recognized potential for high pressures to contribute to the migration of injected fluids into unpermitted zones (see NMOCD fluid injection regulations in 19 NMAC 15.I.700). Injection pressure is also critical for evaluating the potential impacts that injection activities could have on the WIPP repository. As shown in Appendix 10 and in Appendices 15, 16 and 17, which include individual well files, maximum permitted wellhead injection pressures range from 640 to 1,613 psi (4.4 to 11.1 MPa) in accordance with state regulations. Although the range of operating pressure varies widely, typical operating pressures appear to approach these maximums in many cases. The wide variation in permitted operating pressure is generally due to differences in well completions, historical operating rates, the nature of the injection interval, and in cases of pressure maintenance and waterflood projects, the rates of withdrawal of hydrocarbons from the injection reservoir.

### 3.4 FUTURE FLUID INJECTION POTENTIAL

Broadhead (1995) indicated that probable oil and gas condensate resources within the WIPP site are 12.3 million barrels (bbl; 1.96 x 10<sup>6</sup> m<sup>3</sup>) for primary production and an additional 6.4 million bbl (1.0 x 10<sup>6</sup> m<sup>3</sup>) through secondary recovery. Gas resources were estimated to be 186 billion cubic feet (BCF; 5.3 x 10<sup>9</sup> m<sup>3</sup>) with the majority of production coming from Pennsylvanian age formations (Morrow, Atoka, and Strawn). Approximately twice this amount of recovery was estimated to be probable if this area were increased to include all land within one mile of the LWA boundary. Oil fields in the vicinity of WIPP that are good candidates for near future secondary recovery operations by brine injection are presented in the following listing (Broadhead 1995):

#### FIELDS WITH SECONDARY RECOVERY POTENTIAL

Cumulative Production: January 1992

Zone:	Field:	Oil (million bbl)	Gas (billion cubic feet)
Delaware Mtn.	Paduca	14	16
Delaware Mtn.	Loving	5	19
Bone Spring	Scharb	14	13
Bone Spring	Avalon East	0.6	18
Wolfcamp	Denton	40	10
Wolfcamp	Kemnitz	16	69
Atoka	Antelope Ridge	2.1	84
Morrow	Quail Ridge	1.5	43
Morrow	Carlsbad South	0.07	238
Mississippian	Bronco	0.4	0.35
Mississippian	Austin	0.2	12
Ordovician	Brunson	28	19
Ordovician	Monument	0.6	63

Although estimates of the expected productive life of wells under primary recovery has ranged from months to as long as ten years before becoming marginally economic, wells in the area may remain productive for a much longer period of time using secondary recovery. Secondary recovery operations may use existing wells completed (equipped for use) in primary target formations, but brine disposal operations may also use secondary target formations by recompleting wells in zones that may not have been originally completed as production zones. As shown by a review of the information provided in Appendix 3 of this report, approximately 15% to 20% of the wells in the study area have been completed in more than one zone over the life of the well. For example, wells with original completions in the Morrow, Bone Spring, and Devonian zones have been recompleted in the Delaware Mountain Group. Wells producing from the Morrow zone have been plugged (casing filled with cement or other plugging material) back to the Atoka zone, recompleted again in the Bone Springs, and finally perforated (casing pierced) in the Delaware Mountain Group for completion as disposal wells.

Injection for the disposal of produced brines will be required over the lifetime of oil production in the area. More than half of the produced fluid brought to the surface will likely be reinjected into the subsurface for disposal or secondary recovery. As lands currently off limits to the oil industry due to potash mining claims become available for exploitation, it is likely that the cycle of drilling, production, and injection will continue around the WIPP site for some time.

Regardless of the specific nature of developments in the neighboring fields, economics will dictate that most fluid injection in the study area for the near future will be for purposes of waste brine disposal and relatively simple pressure maintenance operations. Waterflooding is also expected to occur, although improved profitability may be required before local fields could be subjected to the scale of waterflood operations present in other areas of the Delaware Basin.

Because most of the production and injection in the study area is modern and data has been collected over less than a decade, it is difficult to precisely project the scope and duration of

operations. Assuming that economic conditions remain similar to the present, it seems likely that the cycle of oil production activities will continue for a minimum of several decades. Primary recovery for more than ten years could be followed by well recompletion and another period of primary recovery. Conversion to waterflooding could then conceivably take place for a decade-long secondary recovery project. Alternatively, a single well may have a fifty year operational lifetime as a waste brine injector, disposing of brine from a number of production zones during its operational life. It is therefore reasonable to assume that injection activity in the study area will continue for a period of fifty years or more after a field begins production, and many promising locations exist that have not yet been drilled. In addition, oil and gas activities will be delayed in parts of the study area because of drilling restrictions due to potash mining activities. It is possible that mining for potash could continue for up to 100 years.

Production from the Brushy Canyon and shallower zones of the Delaware Mountain Group is often commingled (combined to be produced from the same well). In this way, reserves that might not be economical by themselves can be produced at a low rate incidental to more prolific production from other zones. Reductions in operating costs may extend the productive lives of these types of wells. After production is no longer practical, a number of such wells have been converted for brine disposal in other geologic formations such as the Bell Canyon. Such modifications are likely to continue as production in some fields matures and as the volume of brine accompanying the oil increases during primary or secondary production. A number of examples of twenty year old producers being converted into brine disposal wells in Eddy County during the 1990s are shown in the summaries of well history supplied in Appendices 16, 17 and 18.

In spite of limited economic incentives for development and production of hydrocarbons at the current time, extended primary recovery has occurred, pressure maintenance has been successful, and waterflooding which was originally dismissed as not applicable to the area in the 1950s, is now being used. A number of examples of waterflooding in the fore-reef environment on the Central Basin Platform are presented in Appendix 3. Pressure maintenance has had a beneficial impact on production in the Cabin Lake Field and Delaware Mountain Group sandstones are also likely to yield increased production due to water injection.

#### **4.0 FLUID INJECTION ISSUES**

Fluid injection practices in the vicinity of the WIPP site have been of concern because of the potential for the injected fluid to affect the ability of the WIPP repository to isolate waste materials. This concern was recognized by DOE early in the development of the performance assessment of WIPP and fluid injection practices were considered among other features, events, and processes for inclusion in performance assessment modeling. This concern has also been recognized by EPA and in public comments received by EPA. The primary means by which fluid injection could affect the repository is through the migration of the injected fluid from a failed injection well into the waste panels along higher permeability, fractured anhydrite interbeds present in the Salado Formation. Such migration could provide extra brine to the repository and

accelerate waste corrosion and pressure buildup in the repository, and the excess brine could provide a means for transporting waste materials to the ground surface through exploration boreholes. In this section the issues raised regarding injection well failure and migration in the anhydrite interbeds are discussed, and DOE's responses to those issues are presented. The results of EPA's analysis of the fluid injection issues are presented in Section 5 of this report.

#### 4.1 INJECTION WELL FAILURE

Fluid injection wells in the study area are designed to inject brine into specific geologic formations for either disposal, pressure maintenance, or waterflooding purposes. The closest fluid injection horizon is the Bell Canyon Formation, which is below both the Salado and Castile Formations and a minimum of 1,650 feet below the WIPP waste panels. The Salado and Castile Formations are together referred to as the "salt section" in the Delaware Basin. They are primarily composed of very low permeability halites, which preclude vertical fluid movement to or from the Bell Canyon. Therefore, only limited options remain for fluid injected into the Bell Canyon to reach the repository. One scenario is that the injection well casing fails such that the brine is injected at high pressure into an anhydrite interbed that also intersects the WIPP repository. Another is that the brine is injected into the intended zone but that it flows back up the injection well through leaks in the annular cement seal and thence through an anhydrite interbed to the repository (Figure BG). Public comments have suggested that a direct example of an injection well failure is provided by what has been called the *Hartman Case*, where significant brine inflows into an exploration well were found in a court of law to have been induced by fluid injection activities in a distant wellfield. Additional discussion of these failure issues is presented in the following paragraphs.

##### 4.1.1 Required Scenario Features

Several elements must be present to allow an oilfield injection operation to impact the WIPP repository. These include a system with sufficient energy to move significant fluid volumes into the repository, an appropriate communication pathway between the injection well and the repository, and a probability of occurrence that exceeds the regulatory threshold probability of 1 chance in 10,000 over the 10,000-year regulatory time frame (see Section 2). Each of these elements must be examined individually and collectively to develop reasonable potential scenarios. These scenario features are addressed below, and additional discussion of probability issues is presented in Section 5.

### *System Energy*

The first requirement for injected brine to impact the WIPP repository is the introduction of enough energy into the subsurface geologic system to move significant brine volumes into the repository against the resistance of the communication pathway. Energy is introduced into the system through the injection of fluids into the subsurface. Although oilfield operations including brine disposal, pressure maintenance, and waterflooding all may involve the displacement of fluid into the subsurface under pressure, the most volumetrically significant of these in the study area involves brine disposal.

Brine disposal operations are intended to manage waste fluids in the most cost-effective way. Except for environmental protection issues, NMOCD regulations tend to support making the process of brine disposal efficient and cost effective. According to Mr. David Catanach of the NMOCD Santa Fe office (Catanach, 1997), disposal wells tend to be operated at the highest rates and pressures allowed. Mr. Catanach stated that the maximum wellhead injection pressure allowed is 0.2 psi per foot of depth to the top of the injection zone unless other technical data is presented in support of a higher permit pressure. Based on a review of information from state files and industry experience, EPA believes that drilling additional wells only for injection purposes increases costs and operators have an incentive for centralizing disposal operations into a single existing injection well for a number of production wells. From the perspective of operating life-span, disposal wells tend to be used over a longer period of time than production wells because a number of consecutive production projects can make use of the same disposal well.

To optimize design and performance, pressure maintenance and secondary recovery operations tend to control pressure and water flood volumes more closely than disposal injection operations (Smith and Cobb, 1980). There is a financial incentive and often a regulatory requirement to proceed with pressure maintenance and secondary recovery injection in a manner that conserves the petroleum resource and optimizes oil recovery. Such goals do not typically coincide with operating solely at maximum rates and pressures. Pressures in secondary operations may also be lower due to the pressure drawdown caused by the production of fluids from the oil reservoir. Because secondary recovery operations may also have a shorter duration than brine disposal operations, consideration of brine disposal operations in this analysis presents a reasonable bounding case. Because most brine disposal within the study area occurs in the Bell Canyon Formation of the Delaware Group (Figures J and K), it is reasonable to evaluate disposal scenarios associated with the Bell Canyon.

### *Communication Pathway*

The second requirement for a potential impact to be caused by injection activities is the presence of a flow pathway that would allow brine intended for injection into the Bell Canyon to communicate with the WIPP repository. Because the repository is at a depth of approximately 2,150 feet (655 m), the injected brine would need to move a significant distance both vertically and horizontally from an injection operation in the Bell Canyon at the LWA boundary to have an effect on waste containment. This would require either a vertical pathway approximately 1,600 to 3,000 feet (579 to 914 m) in length that subsequently communicated with a horizontal

pathway of approximately 8,800 feet (2,682 m) to the repository, or a casing breach in the injection wellbore that allowed a shorter vertical pathway but would require an equally long horizontal pathway.

The most commonly considered hypothetical horizontal pathways are the naturally occurring anhydrite interbeds, and the most commonly considered hypothetical vertical pathways are associated with deep boreholes. Natural features that could result in high vertical permeabilities, such as natural fracturing, jointing, or fault planes that cross multiple formation layers, do not occur at WIPP because of the plastic nature of the thick halite beds that comprise the Salado and Castile Formations that lie between the Bell Canyon and the WIPP repository (CCA Vol. I, Section 2.2.1.3, Docket A-93-02, II-G-01). The more probable pathways are those associated with the injection well itself and are further discussed in the following paragraphs.

Vertical pathways that could reasonably be expected to be present are limited to deep boreholes that allow upward flow due to problems associated with an original well completion or from deterioration of the well seals over time. Vertical pathways connecting injection zones to the repository or to horizontal pathways within the Salado could consist of a poorly cased or cemented injection well annulus, a deteriorated casing or cement allowing leakage from an injector, a poorly plugged abandoned well neighboring an injector, and hydraulic fracturing up the annulus or vertically out of the permitted injection zone.

Figure BG illustrates the only two reasonable configurations that include the factors listed above and that could account for fluid movement from a permitted injector to the Salado interbeds. The right side of the figure illustrates a tubing or packer leak with flow through the annulus to a casing leak that allows communication to the interbeds. The complex chain of events necessary for this scenario to occur includes the failure of permit construction standards, the failure of injector monitoring procedures, and the unlikely event that such a flow path would not be discovered in a relatively prompt fashion and repaired. A catastrophic tubing or packer leak that would provide sufficient brine flow to affect the repository could be readily detected through pressure monitoring of the open annular space between the tubing and the casing, as required by NMOCD regulations (19 NMAC 15.I.704.B). Further, NMOCD regulations require dual casing strings and annular cement seals through the salt section for the specific purpose of minimizing casing breach failures (NMOCD Order R-111-P, Subpart D). The total operating period of an injection well will be on the order of 50 to 100 years before it is abandoned and plugged. Because wells have remained operational for durations within this time frame, EPA believes that this period of time is not sufficient for the casing and cement seals to completely degrade. EPA therefore concludes that injection well failure due to a catastrophic leak in a tubing or packer with subsequent flow through a major breach in the casing is improbable even if only the well construction standards required near the WIPP site were considered. However, because monitoring for such failures is easy to perform and is required by law, the possibility that a catastrophic tubing or packer leak (Figure BG, right side) could go undetected for years becomes so remote that EPA believes this failure scenario does not require further consideration.

The left-side of Figure BG illustrates a case where failure or degradation of the annular cement

or borehole plug has been assumed for the entire length of the long casing string (1650 to over 3000 feet) and brine flow up the annulus from the injection zone to the Salado interbeds that intersect the WIPP repository. For convenience, the Salado interbeds that intersect the WIPP repository (Salado Marker Beds 138 and 139) will be referred to in this report as the *WIPP interbeds*. The flow up the annulus would have to be sufficient that thief zones in the form of permeable stringers and interbeds between the Bell Canyon and the repository would be overcome, and sufficient pressure and flow rate would be available to reach the 2,150 foot level of the repository and begin migrating toward the repository. For injection-related flow to occur across the vertical and horizontal distances of this flowpath necessary to generate a significant impact on the WIPP repository, a well would need to leak undetected over a very long period while operating at a relatively high pressure and at a high injection rate into a high permeability annular pathway. All of these circumstances are unlikely due to the distances brine would have to flow and the effects of current injection monitoring regulations and present day well construction standards. Vertical migration of injected fluid from the injection zone to the interbeds would need to take place in close proximity to a well as a result of poor or fractured cement in the outer casing annulus. This pathway would then have to allow sufficient flow of high pressure fluids into the WIPP interbeds to cause hydraulic fracturing and a sufficient permeability increase to allow fluid flow and pressure transmittal through those interbeds to reach the WIPP repository. Brine injection would then have to continue under significantly high pressure and flow rate for a sufficient period of time to cause a significant impact on the disposal system. Deep borehole construction standards have been imposed by NMOCD for drilling in the vicinity of WIPP (NMOCD Order R-111-P, Subpart D) that are intended to preclude failure of the annular seal and boreholes constructed under these standards are considered by EPA to be “current practice” in the vicinity of WIPP. These standards are discussed in the following paragraph.

As discussed previously, few wells existed in the study area prior to the 1970s. Most of the drilling activity that has taken place has occurred over the past 10 years (1986 to 1996). Based on current drilling standards and field practices reviewed as shown in Appendices 16, 17, and 18, two main types of wells are now installed that differ primarily based on the intended drilling target depth. Wells that are designed to penetrate the deeper natural gas plays tend to start at surface with larger bits and conductor casings to allow completion with a long string of 4 ½ or 5 ½ inch diameter casing. In such wells, the exterior casing string present at the depth of the Bell Canyon and lower salt sections tends to be 8 5/8 inch, 9 5/8 inch, or larger. Wells intended for completion in the shallower Delaware Group are drilled with similar technology and mud systems through the salt sections. However, long string casing designs seem to vary widely. For active injection wells within the area of interest, long string casing present across the Bell Canyon varies from diameters of 4 ½ to 13 3/8 inches. These injectors are completed with 2 3/8 or 2 7/8 inch tubing strings inside the protective casing. Despite the differences in casing diameter, as required by state regulations both types of completions include dual cemented casing to protect the salt section (NMOCD Order R-111-P, Subpart D).

### *Vertical Pathway Permeability*

A required element of an injection well scenario that significantly impacts the WIPP repository is the presence of a high permeability vertical pathway connecting the injection zone with the WIPP interbeds. The presence of such a pathway is also one of the most unlikely elements of the scenario. The permeability of the vertical pathway must not only be high, but it must also be sufficiently high to provide a preferential pathway for brine and for transmission of pressure transients to the WIPP interbeds and through those interbeds to the repository. This complicated pathway must be permeable enough to minimize the potential dissipating effects of the anhydrite interbed “thief zones” that lie between the injection zone and the WIPP interbeds. Failure of the annular cement grout seal between the outer casing and the formation is generally hypothesized as the most likely vertical pathway; however, as discussed below, it is difficult to conceive of processes that could cause the permeability of this cement seal to increase by several orders of magnitude over the entire 1,650-foot minimum vertical distance between the injection zone and the marker beds within the approximately 50-year lifetime of most injection wells.

The key link in any hypothetical pathway necessary for a failed fluid injection well to have a potential impact on the WIPP repository is a high permeability, vertical flow conduit from the Bell Canyon injection zone to the WIPP interbeds. As shown by the injection well records presented in Appendices 16, 17, and 18, the minimum distance fluid would have to migrate upward to the WIPP interbeds in a wellbore annulus is approximately 1,650 feet (503 m). The average vertical distance to the interbeds at WIPP repository depth is greater than 1,900 feet (579 m), and the maximum distance is about 3,200 feet (975 m). As discussed below, in all but two of the injection wells in the study area, in accordance with state regulations a continuous cement seal is present behind the casing that extends upward from the permitted injection zone and across the WIPP interbeds (NMOCD Order R-111-P, Subpart D). Thus all but two of the wells in the study area have a concrete annular seal that creates a continuous, low-permeability barrier to the vertical migration of injected brine between the injection zone and the WIPP interbeds.

According to Petroleum Information Inc. records reviewed by EPA and presented in Appendix 17, the first of the two wells without a continuous cement seal across the WIPP interbeds is the Gilmore-Federal drilled in 1954 in T22S R32E S21. Injection well information collected by DOE (see Stoelzel and Swift 1997; WPO # 44158) indicates that the annulus of this well is cemented for a distance of 743 feet above the Bell Canyon. The second of these wells is the James-Federal drilled in 1992 in T23S R32E S29. It was found by DOE to have been cemented for a distance of 630 feet above the Bell Canyon. Even though these wells are not cemented through the elevation of the WIPP interbeds, as described below, several hundred foot-long cement seals and a remaining annulus filled with drilling mud are more than sufficient to create a vertical flowpath of sufficiently low average permeability that vertical migration of injected brine is not of concern.

The average permeability of materials in a linear series is calculated as the harmonic average (Craft and Hawkins 1959):

$$k_e = l_T \div \left[ \frac{l_1}{k_1} + \frac{l_2}{k_2} \right]$$



$$k_1 \quad k_2$$

where  $k$  is permeability,  $l$  is distance, and  $l_T$  is total distance. In a linear series, a short length of very low permeability material significantly weights the average effective permeability of the entire system to the low end. For example, for a 1,600 foot (488 m) long annulus with only 16 feet (5 m) of cement with a permeability of  $1 \times 10^{-5}$  md ( $9.9 \times 10^{-21}$  m<sup>2</sup>) and the remaining 1,584 feet (483 m) of annulus with a permeability of 320 md ( $3.2 \times 10^{-13}$  m<sup>2</sup>), the effective permeability of the entire annulus system would be  $1 \times 10^{-3}$  md ( $9.9 \times 10^{-19}$  m<sup>2</sup>). This means that even if most of the seal along the length of the borehole fails, only a short length of low permeability, intact seal will significantly reduce the effective average permeability of the entire borehole.

The permeability of borehole materials and drilling fluids in the petroleum industry was independently investigated by EPA. Literature values for the permeability of cement used in borehole applications can range from  $9 \times 10^{-21}$  to  $1 \times 10^{-16}$  m<sup>2</sup> ( $1 \times 10^{-5}$  to 0.1 md), which is similar to the ranges cited in several of the publications referenced in Section 5.1 of CCA Appendix DEL. Drilling muds have also been investigated. Filter cake and compacted clay-based drilling muds can yield permeabilities of less than  $1 \times 10^{-6}$  md ( $9.9 \times 10^{-22}$  m<sup>2</sup>) from field data for 11 ppg mud (Gray and Darley, 1980). Although drilling mud circulated in deep Delaware Basin boreholes during cementing may not have the degree of clay-based solids loading used in other areas but natural cuttings will contribute to reduce the effective annulus permeability in boreholes that do not have a continuous cement seal.

Because there is drilling mud in all casing annuli and cemented intervals of significant length (hundreds to thousands of feet) in all wells near the WIPP site, there is a low probability that the average annulus permeability over several hundred vertical feet of borehole would attain the relatively large permeabilities of 320 md to  $1 \times 10^{12}$  md ( $3.16 \times 10^{-13}$  to  $1.0 \times 10^{-3}$  m<sup>2</sup>) used to represent the leaky vertical pathways in the SNL modeling of fluid injection by Stoelzel and O'Brien (1996; WPO # 40837). Since the effective permeability of any given borehole will actually be defined by the series average of the permeabilities of all zones through which fluids must pass, the effective average permeability of any seal will be dominated by small sections of competent plug or other low permeability material such as the drilling mud discussed above. If even a short length of competent cement is present or if natural materials and mud provide any layers with sealing properties, the effective average annulus permeability over more than 1,000 feet (305 m) of borehole annulus is likely to remain in the low permeability range of  $9 \times 10^{-21}$  to  $1 \times 10^{-16}$  m<sup>2</sup> ( $9 \times 10^{-6}$  to 0.1 md) over a period of many years. There is no data available that indicates that any of the wells in the vicinity of WIPP have the potential for flow of injected fluids to occur through the casing annulus from the Bell Canyon to the WIPP interbeds in the Salado.

#### 4.1.2 Flow Through Anhydrite Interbeds

As previously discussed, oil and gas producing zones are found in the vicinity of WIPP at depths below the Salado-Castile evaporite sequence. All industry-related withdrawal and injection activities are anticipated at depths well below the base of the Castile, which occurs at a depth of approximately 3,800 feet (1,158 m) near the WIPP site. However, it is possible that the effects of petroleum industry activity may not be confined to these deeper units. The scenarios most likely to allow fluid injection activity outside the LWA boundary to potentially impact WIPP site containment include the flow of injected fluids into and through the WIPP interbeds in the Salado. For this reason, information regarding the characterization of these interbeds is discussed below.

The Salado-Castile salt section is more than 3,000 feet (914 m) thick in the Delaware Basin and generally ranges in depth from 500 to 3,800 feet (152 to 1,158 m). The salt section extends across the region (see structural cross-sections in Figures J and K). The WIPP site is located within the Salado evaporites at a depth of about 2150 feet (655 m), and is approximately 600 feet (183 m) above the top of the Castile Formation. The stratigraphic section in Figure A shows the WIPP site location relative to the underlying Castile and overlying Salado evaporites, McNutt Potash Zone, and Rustler Formation. The interbeds are layers of anhydrites found within both the Salado and Castile Formations and are shown in Figures A and B. The anhydrite interbeds are dominant features of the Castile Formation near the WIPP and aggregate to several hundred feet of thickness in four major units (see Figure B). Interbeds vary in thickness as well as occurrence within the Delaware Basin.

The correlation cross-section in Figure AU shows how interbeds are identified from a gamma log: on a scale of 0 to 100 API units, deflections greater than 20 API indicate strata containing more natural radioactivity, which are usually associated with non-evaporite beds. A high gamma-log response provided a method for identifying and mapping clastic interbed units in eleven selected oil and gas related wells examined at the margin of the WIPP site (see Figure AS). Interbed thickness was estimated from the portion of the gamma curve greater than 20 API units (refer to Tables F through P).

Neutron-log porosity adjacent to gamma signatures was estimated as a single maximum value representative of the interbed (see correlation cross-section in Figure AU). More than 45 interbeds can be distinguished on the geophysical well logs from these oil and gas wells by this method. However, it should be noted that neutron porosity is not an exact measure of permeable porosity. Bound water in interbedded clays can result in an anomalous high porosity reading. For example, no porosity was listed greater than 30%.

Tables F through P and Charts A through K present interbed correlation data for 11 wells around the perimeter of the WIPP site (see figure AS which is a key map for the wells evaluated). The tables list interbeds by number in each well. Same-numbered beds between wells do not necessarily correlate and only interbeds numbered Marker Bed 138 and 139 are assumed to correlate between wells. The list provides a basis for mapping correlations between ten interbeds

are shown on cross-section A-A' (Figure AU), though breaks in deposition in interbeds are possible between wells. Note that this log interpretation was not of sufficient detail to fully correlate all interbeds across the site, but was used to investigate the similarities in the wells and the similarity of the depositional sequence penetrated by the wells around the site.

Tables F through P show the depth to the top of the identified interbed (based on log data and elevations), estimated thickness of the interbed, and estimated maximum porosity. The vertical distance in the well-bore is calculated between the interbed and Marker Bed 139, and the lateral distance from the well-bore to the WIPP site is shown. The product of porosity times thickness is shown as Porosity\*Ft. This porosity thickness is calculated from log interpretations only and is intended for well comparison and correlation purposes. Since portions of this porosity may not be effective, the values should not be interpreted as a porosity thickness that would necessarily have meaning for flow calculations or modeling. At the bottom of each table is a statistical summary of data. Charts show the interbed thickness and neutron porosity by depth. Marker Bed 139 is indicated in the charts. These materials indicate the pervasive nature of interbedding around and through the WIPP LWA area and also demonstrate that significant porosity thickness is present within the Salado that will be available to arrest the upward migration of any fluid leaking up a hypothetical leaking borehole prior to intersecting Marker Beds 138 or 139 near the depth of the repository.

Marker Bed 139 is an anhydrite interbed located a few feet below the base of the WIPP repository. The marker beds are prominent interbeds and are used as markers for regional correlation (see cross section in Figure AU). The marker beds in the region have been numbered increasing with depth. The regional structural form of Marker Bed 139 is expected to be similar to that of Marker Bed 124 shown in Figure R. Because of rock strength differences between the bedded anhydrite and the surrounding halite, the anhydrite may include fractures in a variety of forms. Many naturally occurring fractures in Marker Bed 139 are filled with halite and other evaporites, reducing the fracture permeability that might otherwise be present.

Within the Salado Formation, the bedded halite has very low porosity (see neutron porosity log data in Figure AU). The halite also has a low permeability (see DOE/EIS-0026-FS, Vol. 1, p. 4-19; Docket A-93-02, II-G-01, Reference #177): "Using a Darcy flow model and assuming a porous and elastic medium, permeabilities of  $10^{-20}$  to  $10^{-21}$  m<sup>2</sup> (approximately equal to hydraulic conductivities of  $10^{-13}$  to  $10^{-15}$  m/sec) [are computed]" (Lappin et al., 1989; Saulnier and Avis, 1988; Tyler et al., 1988, Docket A-93-02, II-G-01, Reference #s 384, 574 and 637). Measured brine flow into the WIPP repository excavation supports the low permeability of the salt sequence. Flow to boreholes drilled from the WIPP repository excavation was measured at "a few thousandths" to a maximum of 0.5 liters per day (Lappin et al., 1989; Peterson et al., 1987; Saulnier and Avis, 1988; Tyler et al., 1988, Docket A-93-02, II-G-01, Reference #s 384, 574 and 637).

Fluid flow rates are higher through the interbeds than through the bedded halite because of the relatively higher interbed permeabilities. Tables 4.2 through 4.5 (in DOE/EIS-0026-FS, Vol. 1;

Docket A-93-02, II-G-01, Reference #177) present measured gas-flow permeabilities for boreholes drilled into anhydrite interbeds. Individual steady-state permeability measurements ranged from less than  $8.59 \times 10^{-20} \text{ m}^2$  to  $3.95 \times 10^{-12} \text{ m}^2$ , although these measurements were made in bore holes within the disturbed rock zone (DRZ) of the WIPP repository excavation. Because of the excavation disturbance, the in-situ measurements of marker bed permeability to gas may be anomalously high.

If significant thickness variations exist in the interbeds, such heterogeneity may limit the ability for fluid to flow through an interbed over distances of several thousand feet (>1,000 m) and could also serve to arrest hydrofracture development in any interbed that completely pinches out. With the exception of measurements made at the WIPP site in 1993, the permeabilities of the interbeds are not known. Based on tests at two different locations, Beauheim et al. (1993) estimated interbed permeabilities of  $1 \times 10^{-16} \text{ m}^2$  in one test hole and  $1 \times 10^{-20} \text{ m}^2$  in the other. Although these values are low relative to that of a typical aquifer, they are higher than that of the intact halite (generally less than  $1 \times 10^{-20} \text{ m}^2$  as cited above) and are therefore more likely to serve as conduits for horizontal fluid movement.

The interbed units within the Salado have different physical, chemical and mechanical properties than the surrounding halite. Some degree of natural and induced fracturing likely exists in these interbed intervals and these fractures have been shown to dilate when exposed to sufficient pressure (Beauheim et al., 1993). Induced pore pressure such as that coming from brine injection could serve to increase both the effective porosity and effective permeability of the interbed units if hydraulic communication with the injection zone occurs. If interbed fracture opening does occur at elevated pore pressures, it is probable that many of the interbed units throughout the Castile-Salado system would react in a similar fashion. This interbed dilation, which would probably consist of opening existing fractures as well as creating new fractures, is the only process by which injected brines can be hypothesized to migrate horizontally from the injection well toward the repository. Interbed dilation resulting from increased repository gas pressure is included in DOE's performance assessment modeling.

#### 4.2 FIELD ACCOUNTS OF INJECTION WELL FAILURES

The discussion in this section compares and contrasts key geological and technological oilfield conditions at WIPP with those at the Vacuum field and the Rhodes-Yates field where injection well failures have been reported (see, for example, Silva 1994, pp. 67-68). Both the Vacuum and Rhodes-Yates fields are outside the Delaware Basin in a stratigraphic setting that is different from that at the WIPP site (Figure CA). Principally in recognition of such differences, EPA only required DOE to consider drilling practices and technology in the Delaware Basin when preparing the WIPP performance assessment (194.33(c)(1)). The objective of this review is to assess the risk of catastrophic injection well failure and fluid migration into the Salado at WIPP compared with that in the Vacuum and Rhodes-Yates fields.

The most widely known field account of what may have been an injection well failure in the general area of WIPP was addressed in DOE's screening analyses (see CCA Vol. XVI,

Appendix SCR, Section SCR-3.3.1.3.1 (Docket A-92-03, II-G-01)) and in several public comments received by EPA, and has come to be known as the “Hartman Case.” In 1991, oil operator Doyle Hartman encountered a salt water blowout in the Bates #2 development well in the Rhodes-Yates field 40 miles (64.4 km) southeast of the WIPP site while drilling through the Salado Formation at a depth of 2,281 feet (695 m) (Figure CA, small map). In subsequent litigation (1997 case summary WL 203571, NM App.) the court found that the source of the water flow was injection water from a long-term waterflood located more than a mile away. The brine encountered at the Hartman well was believed to have flowed through one or more anhydrite interbeds within the Salado evaporite from the waterflood operation. A similar event is reported to have occurred at Vacuum field which is approximately 32 miles (51.5 km) northeast of the WIPP site (Silva 1994, pp. 67-68). The Vacuum and Rhodes-Yates fields are shown along with the WIPP location and the Delaware Basin, Capitan Reef, Northwestern Shelf, and Central Basin Platform geologic structures on Figure AW and Figure CA (small map).

The long-term injection of large volumes of brine at high pressures into deep geologic units surrounding the WIPP site will likely raise fluid pressures in those units. Events such as failure of well bore integrity, illegal operations, or inadvertent drilling through the WIPP repository may provide flow paths for injection fluids that may affect brine volumes and pressures in the WIPP repository. For the scenarios described, possible injection fluid pathways include well bores, salt interbeds, sub-salt flow units (Castile anhydrites and Delaware Group sandstones and limestones), and flow units above the Salado evaporite section. Fluid flow pathways could potentially transmit pressure and move fluids toward WIPP, or alternatively those pathways could disperse fluids and pressure from both injection wells and from the WIPP site. Some members of the public have indicated that they believe injected brines could adversely affect the WIPP site, possibly leading to significant releases of radiation.

In discussing the differences between the WIPP site and the Rhodes-Yates field site of the Hartman well blowout, it is important to note that the legal finding that the blowout was caused by a waterflooding operation is viewed by some as being based on relatively little direct technical evidence and that other reasonable explanations for the blowout exist, such as the inadvertent encounter of a pocket of pressurized brine. Additional discussions of these issues may be found in DOE’s letter to EPA of 24 February 1998 (Docket A-93-02, IV-G-34) responding to issues on WIPP that had been identified by the Environmental Evaluation Group (EEG).

#### 4.2.1 Technology Comparisons

An important difference between the WIPP and Rhodes-Yates areas is the greater age of hydrocarbon production in the Rhodes-Yates area and the relative lack of modern practices used to develop most of that field. As previously mentioned, widespread drilling and hydrocarbon production near the WIPP site began in the 1980s and 1990s. By comparison, the Rhodes-Yates field was discovered in 1927. Many wells were drilled in the 1920s and 1930s with cable tool rigs, were only cased to the top of the production zone (with an open hole in the production zone), and blasting with nitroglycerin was widely used in that era for stimulating the production

zone after the well casing was grouted (Tiratsoo, 1984). Because of the widespread use of these older technologies, the potential for damaging the grout seals during blasting, and the difficulty of quality control with these practices, the grout seals in many wells in that field have the potential to be either absent or ineffective. By comparison, as described above, the current well installation practice in the WIPP area uses continuously grouted, dual casing strings through the salt section and the production zone stimulation, when used, consists of hydrofracturing through pressurized fluid injection rather than by blasting (NMOCD Order R-111-P, Subpart D). EPA believes that the multiple grouted casing and tubing strings are much less likely to leak, the production zone stimulation methods are less violent and controlled such that they do not damage the well seals in the salt section, regulatory controls are more stringent, and construction controls are more refined allowing significantly improved quality. It is important to note that no parallels to the kind of injection well failure that may have occurred in the Hartman Case have been reported in oil fields that have been developed in the 1980s and 1990s.

#### 4.2.2 Stratigraphic Comparisons

WIPP is in a different regional geologic setting from the Vacuum and Rhodes-Yates fields (see Figures AW and W) . These fields are located landward from the Permian Capitan Reef in a back-reef shelf or platform setting, while WIPP is located in a fore-reef basinal setting (see CCA Vol. XVI, Appendix SCR, Section SCR3.3.1.3.1 (Docket A-93-02, II-G-01)). The principal difference between these settings as affects fluid injection issues is the thickness and composition of the Castile Formation that separates the Salado Formation (where the WIPP repository is located) from the brine injection horizons. The Castile Formation is almost exclusively confined to fore-reef area (the Delaware Basin) and is not present at either the Vacuum or the Rhodes-Yates fields (CCA Vol. XVI, Appendix SCR, p. SCR-119) (Docket A-93-02, II-G-01). The absence of the Castile significantly reduces the effective buffer zone for injection fluid leaks between the injection horizons and the Salado, and the lack of Castile anhydrite interbeds means that no thief zones are present to divert upward-migrating brine before it reaches the Salado. These differences are discussed in additional detail below. Generalized stratigraphic sections presented in Figures CA, CB, and CC for basinal versus shelf and platform show interbedded anhydrites in the Salado in both environments and the absence of the Castile on the shelf.

Figure CA presents stratigraphic sections from the WIPP area, the Vacuum field area, and the Rhodes-Yates field area. The Salado Formation is thickest in the WIPP area. The Salado exhibits thicknesses of 1,895, 1,015, and 1,490 feet (578, 309, and 454 m), respectively, in each area. Figure CA also shows the principal interbeds of the Salado. Interbeds in the upper Salado in the three areas were probably deposited contemporaneously; however, the interbed projections are not intended to show well-to-well correlations. The cross section presented in Figure CA illustrates that several of the interbeds in the Salado are thicker in the Vacuum and Rhodes-Yates than in the WIPP area. The reasons for this difference are probably related to differences in depositional environment. The thinner Salado interbeds in the WIPP area would result in less transmissivity to horizontal fluid flow and therefore lower lateral flow rates for any injected brine that did reach the Salado. Figure AU shows Salado interbeds in wells west and east of the

WIPP area.

Cross Section A-A' (Figure CA) shows the regional relationship of the Castile Formation evaporites, which underlie the Salado but are generally absent in the back reef areas. As shown in Figure B, the Castile Formation near WIPP contains four thick anhydrite horizons (from 110 to 375 feet (33 to 114 m) thick) and three intermediate, low permeability salt horizons. The anhydrite horizons in the Castile are considerably thicker than the anhydrite interbeds in the Salado that intersect the WIPP repository (the thickest such Salado interbed - Marker Bed 139 - is less than 3 feet (0.9 m) thick at the WIPP site) and their expected higher transmissivity would be capable of diverting a considerable amount of any brine that might migrate up a failed borehole seal. The Castile Formation at the Vacuum and Rhodes-Yates fields is missing and the buffer that the Castile halites offer at WIPP and anhydrite thief zones that could divert upward brine movement at WIPP are also missing. In addition to the aforementioned technology differences due to the ages of the oil fields, the lack of a Castile unit at the Vacuum and Rhodes-Yates fields could help to explain the possible injection well failures and encounter of brine flows in the Salado in those fields.

#### 4.2.3 Structural Comparisons

Structural deformation or stress field variations in the Salado and Castile evaporites would be expected to increase the degree of fracturing and potentially the permeability of the anhydrite interbeds in those units. The relative amount of deformation at WIPP and at the Vacuum and Rhodes-Yates fields can be estimated by comparing the extent of folding and faulting, the rates of dip, and the evaporite thickness changes in each area. Flow path permeability in the interbeds would be greatest through fractures because the matrix permeability of the anhydrite is low. Higher interbed permeabilities would tend to increase the likelihood of extensive lateral migration of injected brines that move up into the Salado.

Folds and dip rates at the base of evaporite sections in the immediate vicinity of the Rhodes-Yates and Vacuum fields are greater than at the WIPP site (100 to 300 feet/mile at the Rhodes-Yates and Vacuum fields versus less than 100 feet/mile at WIPP). A number of figures are presented in this report to illustrate the geologic structure of the evaporites. Figures O, R, S, and T from SNL work in 1978 show the structure at the top, middle, and base of the Salado (top of the Castile) and the top of the Delaware Group of clastics and limestones (base of the Castile) in the WIPP area. Structural cross sections presented in Figures J and K can be used to identify these structure contour surfaces.

Detailed information is available on the geologic structure near the WIPP site because of the extensive repository investigations. Figure O shows the structure at the top of the Salado in the WIPP area. There the dip of the Salado is northeasterly at 100 to 110 feet per mile (about 1°). An anticlinal fold in the Salado is located in Section 19, and a closed low feature with about 60 feet of relief is shown in the northeastern quarter of Section 16. Figure R shows the structure of Marker Bed 124 approximately in the middle of the Salado in the WIPP area. The dip there is easterly to northeasterly at approximately 70 to 100 feet per mile (3/4° to 1°) and is less than at

the top of the Salado. Marker Bed 124 is located approximately 505 feet above the WIPP repository.

Figure S shows the structure at the base of the Salado (top of the Castile) below the WIPP repository. The figure shows an 8-mile-long fault trending southeast through Sections 17 and 27 of the WIPP site area. Displacement is nearly 300 feet in Section 17, and less than 100 feet in Section 27. A southeast-trending anticlinal fold axis runs from the southwestern part of Section 16 of the WIPP area through the northeast corner of Section 27. The dip in the vicinity of the WIPP site is southwesterly at 100 feet per mile (about 1°). A southeast-trending synclinal fold axis runs from the east edge of Section 19 through the southeastern corner of Section 34. Figure T shows the structure at the top of the Delaware sandstone at the base of the Castile evaporites. The contour interval is 100 feet, and dip is approximately 100 feet per mile (about 1°) to the east and southeast. The figure shows a southeast trending anticlinal fold axis through Section 15 of the WIPP site and four faults from two to four miles in length with a displacement of 50 feet or less. Although structural features do exist near WIPP, the low dip rates indicate that structural trends are gentle and have not significantly disrupted the strata.

Structural information on the Vacuum and Rhodes-Yates field areas is older and a degree of detail similar to that at WIPP was not available for this study. Geologic structure in the Vacuum field area is shown on a 1956 map of the top of the San Andres Formation (see Figure CD). Although faults were not mapped, a dip of 100 to 300 feet per mile (1° to 3°) is associated with a doubly-plunging anticlinal feature. Geologic structure in the Rhodes-Yates field area is shown on a 1988 map of the top of the Yates Formation (see Figure CE). Although faults are again not mapped; dip of 150 to 200 feet per mile (1 1/2° to 2°) is associated with a south-plunging fold, with an axis through the west half of Section 10 in the Bates lease. Although no faults were interpreted from the data, dip rates up to three times that at WIPP indicate considerably greater deformation in the Vacuum and Rhodes-Yates areas. The greater deformation in the Vacuum and Rhodes-Yates areas as compared with that in the WIPP area could lead to anhydrite fracturing and greater fracture permeability in the Vacuum and Rhodes-Yates fields. This could potentially allow more substantial interbed brine flow from a leaky injection well in the Rhodes-Yates and Vacuum field areas than in the vicinity of WIPP.

#### 4.2.4 Chemical Comparisons

The salinity of water in the zones beneath the salt section at the Vacuum field is slightly less than that at the WIPP site and the salinity at the Rhodes-Yates field appears to be substantially lower. The salinity in the Livingston Ridge-Cherry Canyon zones beneath WIPP is about 190,000 ppm. The salinity in the Grayburg-San Andres zones at the Vacuum field is about 160,000 ppm and in the Yates Sandstone at the Rhodes-Yates field the salinity is only about 1,850 ppm. The relatively fresh waters at the Rhodes-Yates field would be more capable of creating high permeability flow paths by dissolution when migrating through the salt section and would therefore be more capable of migrating large distances both vertically and horizontally in the Salado Formation.



#### 4.2.5 Flow Path Comparisons

Interbeds are present in the lower Salado at both the Vacuum and Rhodes-Yates fields and the WIPP site but they are not laterally continuous between the WIPP site and these fields (see Figure CA). The source of brine flow encountered in Rhodes-Yates field by the aforementioned Hartman well could have been an anhydrite interbed in the lower third of the Salado Formation. EPA reviewed a summary of the Hartman Case (1997 case summary WL 203571 (N.M. App.)) to determine the nature of the court decision. Though a jury found the waterflood operator guilty of common law and statutory trespass in the Rhodes-Yates field, flow paths between the waterflood operation and Hartman's Bates #2 well were not identified with certainty.

The brine flow rate through a pathway in the Salado into Hartman's well was reported to be 32,000 barrels per day. A possible flow path from waterflood operations, as postulated on behalf of Hartman, involved brine movement up a wellbore in the waterflood area just a few hundred feet, then to fractured anhydrites in the lower third of the Salado, and then horizontally to the Hartman-operated Bates Lease. Hydraulic fracture initiation pressure within the Salado interbeds may have been exceeded by the waterflood injection pressure in the Rhodes-Yates field. Given the drilling technologies of the 1920s and 1930s and subsequent maintenance and plugging techniques that may have caused the grout seals in many wells in the Rhodes-Yates field to be either absent or ineffective, this flow path becomes plausible. However, similar flow paths in the WIPP area are much less likely because of the aforementioned differences in drilling technology and stratigraphy. With regard to flow paths, the principal effects of the technology differences are to make casing failures unlikely in the WIPP area because of the use of multiple, grouted casing through the salt section, and to make grouting failures unlikely because of the continuous, multigrouted annular space required by regulation, the quality control measures employed, and the use of hydrofracturing for production zone stimulation rather than blasting. The stratigraphic differences make vertical migration of injected brine less likely in the WIPP area because of the increased buffering effect of the thicker section of Castile Formation and the presence of additional anhydrite interbeds in the Castile that can act as thief zones that would divert upward moving brines before they reach the elevation of the repository.

#### 4.2.6 Summary of Comparisons

In summary, the stratigraphy and drilling technology in the vicinity of WIPP shows distinct differences from those at the Vacuum and Rhodes-Yates fields where injection well failures have been reported. The WIPP repository level in the Salado is separated from brine injection intervals in or beneath the Bell Canyon Formation by greater thicknesses of salt and anhydrite than in the other two fields. This greater thickness makes it more difficult for brine to penetrate vertically from the injection horizons to the repository horizon in the Salado. Anhydrite interbeds in the Salado at the repository level are more numerous but each individual interbed is likely to be thinner than in the vicinity of the Rhodes-Yates and Vacuum fields. This indicates the possibility of a decreased lateral continuity and a lower probability for contiguous lateral flow paths that could extend from the WIPP LWA boundary to the repository.

The salinity of water in the Yates Sandstone at the Rhodes-Yates field is substantially lower than in the Delaware Group in the vicinity of WIPP. Relatively fresh waters may have been a contributing factor to brine flow into the Hartman well because the lower salinity water could have more readily dissolved salt and created a higher permeability flowpath in the evaporites. The higher dip angles and greater structural deformation in the vicinity of the other two fields may contribute to increased anhydrite stress variations and fracturing as compared with anhydrite conditions in the vicinity of WIPP. In-situ stresses due to such deformation may be such that fractures are more likely to provide transmissive flow paths within the interbeds at the other two fields as compared with WIPP. Communication between an injection interval and the middle Salado appears less likely at WIPP due to the presence of additional thief zones that would tend to divert flow that is moving up a hypothetical vertical pathway away from the repository level. Based only on geologic information, horizontal flow toward the repository in an interbed interval may not be likely in the vicinity of WIPP, but it cannot be totally ruled out. However, differences in well history, construction standards, and operating practices are likely to reduce the potential for brine injection to impact the WIPP repository to a greater degree than will the geologic differences. Based on EPA's review of the WIPP, Vacuum, and Rhodes-Yates fields, the combination of the geologic differences and the well construction practices used in the WIPP vicinity make it unlikely for there to be a repeat of the Hartman Case at WIPP.

#### 4.3 DOE ANALYSIS OF INJECTION WELL SCENARIOS

Fluid injection as one of the features, events, and processes that was considered by DOE for inclusion in performance assessment of the WIPP. DOE's analyses and conclusions are summarized in CCA Vol. XVI, Appendix SCR, Section SCR.3.3.1.3 (Docket A-92-02, II-G-01). DOE studied the issues raised above in Section 4.2 including the differences in technology and geology between the WIPP site and the oilfields in which injection well failures are reported to have occurred. DOE notes in the aforementioned reference that "The WIPP is located in the Delaware Basin in a fore-reef environment, where a thick zone of anhydrite and halite (the Castile) exists [between the injection horizons and the Salado]. By contrast, the Castile is not present at either the Vacuum or the Rhodes-Yates Fields which lie outside the Delaware Basin." "Waterflooding at the Rhodes-Yates Field involves injection into a zone only 200 feet (60 meters) below the Salado. There are more potential thief zones below the Salado near the WIPP than at the Rhodes-Yates or Vacuum Fields; the Salado in the vicinity of the WIPP is therefore less likely to receive any fluid that leaks from an injection borehole." DOE also noted many of the technological differences identified in Section 4.2 between typical deep drilling practices in the WIPP area and those in the other two fields, as well as differences in injection pressure restrictions established by the NMOCD to reduce the possibility of injection wells leaking into the Salado in the potash enclave, which includes the WIPP site.

Although the aforementioned differences between drilling practices in the WIPP area and those in the Vacuum and Rhodes-Yates fields indicate that a blowout of the type encountered in the Hartman well would be highly unlikely near the WIPP, the DOE investigated this conclusion by simulating an injection well failure under WIPP geologic conditions of the type hypothesized

above for the Hartman Case. In the DOE modeling study (see Stoelzel and O'Brien 1996; WPO # 40837), the annular cement and borehole plugs were assumed to fail or degrade along the entire length of the 2,000 to 3,000 foot long casing strings of injection wells located at the LWA boundary both updip and downdip of the WIPP repository. Brine disposal was simulated into the Bell Canyon Formation in both wells with simultaneous leakage through the annulus of each well into an anhydrite interbed in the Salado that connected with the WIPP repository. A total of approximately  $7 \times 10^5 \text{ m}^3$  of brine was injected during a 50-year simulated disposal period. For the next 200 years the injection boreholes were assumed to be plugged with cement of permeability  $1 \times 10^{-17} \text{ m}^2$  at the injection zones and at the top of the Salado. Subsequently the plugs and borehole casing were assumed to have degraded and the borehole was assumed to be filled with a residual material with the permeability of silty sand. The simulation was continued until the end of the 10,000-year regulatory time frame and during the simulation period approximately  $400 \text{ m}^3$  of brine entered the waste disposal region of the repository from the anhydrite interbed. As further discussed below, this volume is small compared with the brine volumes of tens of thousands of cubic meters that are typically predicted in performance assessment to enter the repository from other sources. This result was considered by DOE to support its conclusion that a significant impact on the WIPP repository from an injection well failure was unlikely, and indicated that while under a series of conservative assumptions of degraded borehole casing and plugs some flow could reach the repository from fluid injection practices, the volume of that flow would not be sufficient to significantly impact repository performance. DOE therefore did not include fluid injection in WIPP performance assessment on the basis of low consequence (see CCA Vol. XVI, Appendix SCR, Section SCR 3.3.1.3; Docket A-93-02, II-G-01).

## **5.0 EPA ANALYSIS OF FLUID INJECTION ISSUES**

EPA reviewed conditions at the Vacuum and Rhodes-Yates fields where injection well failures have been reported (see Silva 1994 pp. 67-68). The Agency's comparison of geological conditions and typical well drilling practices in those fields with those at WIPP is summarized in Section 4.2 of this report. As stated in the conclusion to Section 4.2, EPA believes that while it is possible for injected fluid to enter the WIPP repository, differences in well history, construction standards, and operating practices between WIPP and the older fields are likely to reduce the potential for brine injection to impact the WIPP repository to a greater degree than will the geologic differences. Based on EPA's review of the WIPP, Vacuum, and Rhodes-Yates fields, the combination of the geologic differences and the current well construction practices in the WIPP vicinity make it unlikely for there to be a repeat of the Hartman scenario at WIPP.

EPA also believes that the steps taken by DOE to model an injection well failure in a WIPP setting has satisfactorily demonstrated that the Agency's qualitative conclusions based on the aforementioned differences in geology and construction practices were also quantitatively correct. DOE's analysis, reported by Stoelzel and O'Brien (1996; WPO # 40837), adequately demonstrated that if a catastrophic failure of the annular cement around an injection well is assumed in a WIPP setting, the consequences to WIPP would be small and would not significantly affect repository performance.

## 5.1 ANALYSIS OF DOE'S FLUID INJECTION MODELING

EPA conducted its review of DOE's fluid injection model through an evaluation of the modeling assumptions, a review of the parameter assignments, and an analysis of model implementation. SNL's BRAGFLO model data input and output files were reviewed by EPA to confirm that the parameters discussed by Stoelzel and O'Brien (1996; WPO # 40837) were appropriately used. The data files were found to be consistent with the descriptions in Stoelzel and O'Brien's report. Primary items of interest in the review of Stoelzel and O'Brien's simulation study included the extensive array of physical parameters assigned to the model, the scenarios evaluated, total flow rate assumptions, calculation of flow splits, temporal and spatial discretization effects, the description and representation of the assumed vertical leakage pathway, model grid conceptualization, the lumping of the disturbed zone into one block, and the description and representation of the assumed horizontal leakage pathways. Flow in the horizontal pathways was dominated by the fracture propagation model used in the BRAGFLO model for the anhydrite interbeds.

SNL's fluid injection modeling began with assignment of grid block parameters for a cross-section of the geologic column present in the vicinity of the repository. This was used to represent flow into the Bell Canyon injection zone, up the hypothetical annulus and into the WIPP interbeds. The flaring two-dimensional grid used was representative of a system that functions between radial flow and a wide channel oriented along the axis of the wells and repository, and the effects of this simplification are not likely to be detrimental to the validity of the model results. This is because all layers of the simulation are treated with the same flared grid and the simplification should not have any effect on the calculation of how the layers interact. A primary concern with the model grid was in the comparison of calculated flow rates from the model with actual field values. The flared grid, in combination with the assumption that the Bell Canyon injection interval was constrained with no-flow boundaries, would tend to result in a conservative over-estimate of flow leaving the Bell Canyon. This overestimation of brine flow into the Salado Formation occurred because all flow exiting the injection well was directed toward the repository.

In Stoelzel and O'Brien's modeling (1996; WPO # 40837), two hypothetical leaking injection wells were assumed to be present and located on opposite sides of the WIPP LWA boundary. These locations represent the closest that injection wells could be located to the WIPP repository under EPA's rule (see Section 2 of this report), and are considered appropriately conservative. As previously mentioned, additional conservatism is provided by DOE's assumption that the injection wells fail simultaneously and that the leakage continues undetected for the full lifetime of the simulation. Stoelzel and O'Brien indicate that temporal and spatial discretization effects were addressed by using the same convergence criteria utilized in the CCA performance assessment modeling.

Pressure sensitive permeability was assigned by DOE consistent with the CCA performance assessment modeling to represent the behavior of the interbeds at elevated pressures. Immediately upon the initiation of pressurization, pore space began to dilate and permeability

increased rapidly. EPA considers this representation of a fractured anhydrite interbed as a single porosity system with pressure sensitive flow parameters to be reasonable. No directional component was assigned to represent this fracture behavior.

A principle factor that influenced the results of the SNL fluid injection model was the assumption of a leaky vertical pathway at each of the active injection wells. In addition to the high permeability that was assigned to the borehole annulus at those wells, the simulations were conducted with the conservative assumption that the borehole could not transmit fluid vertically above the top of the Salado (base of the Rustler). This assumption is conservative because it further increases the flow rates that enter the anhydrite interbed layers by eliminating an avenue for fluid flow into other permeable zones closer to the surface. If a borehole annulus were open from the Bell Canyon to the top of the Salado, there is no technical reason why it would not be open to flow into shallower units as well.

EPA questioned the adequacy of SNL's representation of the disturbed rock zone (DRZ) as a single volume below the repository in Stoelzel and O'Brien's modeling (1996; WPO # 40837). In the CCA, the DRZ was modeled as separate zones above and below the repository waste panels and less than half of the DRZ volume was assumed to be present below the floor of the repository. Because brine volumes calculated in the SNL brine injection study are similar to the pore space volume associated with the DRZ, the lumping of the entire DRZ pore space below the waste may not be an appropriate simplification because it did not allow as much incoming brine to access and corrode the waste. This result was expected to occur because the decreased exposure of waste to brine would result in reduced waste corrosion rates, reduced gas generation rates, reduced repository gas pressures, and therefore reduced resistance to brine inflow.

EPA believes that the brine flows from the wellbore into various anhydrite interbed thief zones were calculated appropriately in the model. This is because, with the exception of a correction factor that was used to represent the leaky borehole gridblock permeabilities, the flow that is apportioned to each interbed is dominated by the permeability, cross-section area, and any previous pressurization of that particular interbed.

The questions that arose as a result of EPA's review of DOE's fluid injection modeling were documented by EPA in a March 19, 1997 letter from Ramona Trovato, EPA, to Al Alm, DOE, transmitting comments regarding completeness and technical sufficiency of DOE's Compliance Certification Application (Docket A-93-02, II-I-17). DOE's response was provided in a June 17, 1997 letter from George Dials, DOE, to Lawrence Weinstock, EPA (Docket A-93-02, II-I-36, Attachments 1 and 2), and included an additional evaluation of fluid injection and additional modeling to further study the impact of this activity on the repository. This additional modeling was described in a report by Stoelzel and Swift (1997; WPO # 44158). The issues addressed by DOE in this supplementary work include additional analysis of the nature of fluid injection activity in the vicinity of WIPP, injection well construction and the probability for failure in the vicinity of WIPP, operating pressures and rates for injection wells in the vicinity of WIPP, the duration of fluid injection activities, and the suitability of DOE's model grid configuration.

Based on the information reviewed during the course of EPA's injection well analysis, it is apparent that significant oil and gas activities currently surround the WIPP site and are likely to persist into the future. DOE has acknowledged this fact and provided a more detailed analysis of these activities in its supplemental evaluation. Data current to April 1997 for EPA's 9 township study area in the vicinity of WIPP was provided in DOE's supplemental report. These data were found to be consistent with the information collected in EPA's independent evaluation. One additional injection well was found by DOE to have become active in the previous 6 months, and a similar number of currently inactive but permitted wells were reported. Brine disposal was found to still be the predominant activity for injection wells in the area.

Based on data supplied in Attachment 1 of Stoelzel and Swift (1997; WPO # 44158), EPA believes that DOE is correct in asserting that the potential for brine disposal, waterflooding, or other oil industry related fluid injection activity to adversely impact the WIPP repository is highly dependant on the presence and characteristics of vertical and/or horizontal pathways for fluid migration. Such pathways must begin within the bore of an active injection well and allow communication to the Salado interbed layers present at the site boundary. DOE presented data regarding local well construction records, local regulatory testing requirements, historic wellbore failures in the vicinity of WIPP and in southeastern New Mexico, evaluation of possible vertical leakage pathways, and calculation of wellbore failure duration that justify both a short duration and low probability for communication between the Bell Canyon injection horizon and anhydrite interbeds at the depth of the WIPP repository.

Information supplied in Stoelzel and Swift (1997; WPO # 44158) also justified the parameters used to model the hypothetical leaking wellbore. The modeling uses a value of 10,133 md ( $1 \times 10^{11} \text{ m}^2$ ) to characterize the permeability of a fully degraded cement sheath. Although this is consistent with values reported and used in the CCA, it appears to be conservative with respect to the values shown by EPA in this report and by Stoelzel and Swift to be representative of probable annulus conditions through their review of available field data. Stoelzel and Swift indicate that no flow into the interbeds or into the repository would be possible if likely permeabilities of the failed annular seals were used in the modeling.

Operating pressures and rates for injection wells in the vicinity of the WIPP site are also addressed by Stoelzel and Swift (1997; WPO # 44158). They assumed injection under a borehole pressure gradient of up to 1 psi/ft of depth (22.6 Pa/m) in the supplemental modeling. This gradient results in a surface pressure that is substantially larger than the current maximum surface pressure permitted in the area of 1613 psi (11.1 Pa). By comparison, the maximum permitted surface pressure would be equivalent to a bottomhole injection pressure of 3,726 psi (25.7 MPa) at a depth of 4,000 feet (1,220 m) for 1.22 specific gravity fluid, resulting in a gradient of 0.93 psi/ft (21.1 Pa/m). This gradient of 0.93 psi/ft (21.1 Pa/m) is less than the assigned gradient of 1.0 psi/ft (22.6 Pa/m), indicating that the modeling assumption provides a conservative estimate of maximum possible injection pressure.

The duration of leaking wellbores and operational lifetimes for oil industry activities have been increased by Stoelzel and Swift (1997; WPO # 44158) to examine the effect of extended fluid injection on the system. As discussed in Sections 4.1.1 and 4.3 of Stoelzel and Swift, an operating period of 150 years with a variety of different scenarios for injection into different layers and different wells was used. These scenarios are conservative with respect to likely injection durations and provide for conservative calculations of the impact of fluid injection activities on the WIPP repository.

With respect to issues regarding model conceptualization and suitability, DOE made several alterations to address EPA's concerns. The DRZ was modeled with a volume assigned by using half the thickness of the previous SNL study. DOE also provided additional justification for the total interbed thickness that might be subject to flow from the hypothetical injection wellbore. These alterations are responsive to the concerns expressed in EPA's review of the Stoelzel and O'Brien model (1996; WPO # 40837). In addition, DOE used two types of models to investigate the effects of model gridding. A radial model as well as a cross-sectional model similar to that used in the original Stoelzel and O'Brien modeling were used. The model assumptions and approaches used in the supplemental evaluation are consistent with available data and were appropriate for use in the study.

In Stoelzel and Swift's (1997; WPO # 44158) supplemental evaluation, brine influx from the interbeds into the repository was calculated to be less than the values presented in the initial SNL fluid injection study by Stoelzel and O'Brien (1996; WPO # 40837). Based on these two analyses and the independent analyses performed by EPA, the Agency concludes that fluid injection scenarios have been appropriately screened out from consideration in the performance assessment of the WIPP repository due to a lack of consequence.

## 5.2 ANALYSIS OF THE PROBABILITY OF INJECTION WELL FAILURE

EPA prepared a rough assessment of the probability of an injection well failure and subsequent brine migration into the WIPP repository to provide insight into the relation of such an event relative to the probability limit of one chance in 10,000 expressed in 194.32(d) (see Section 2 of this report). Because this probability estimate relies heavily on judgement, the analysis was not intended to provide a basis for EPA's decision on whether fluid injection should be used in

performance assessment; rather, the intent was to further evaluate the Agency's aforementioned belief that failure of an injection well and the subsequent migration of significant volumes of brine into the WIPP repository is unlikely.

A scenario of injection well failure and the subsequent flow of injected brine across the vertical and horizontal distances necessary to generate an impact on the WIPP repository would have to consist of a chain of events that would occur in combination. An injection well would need to leak significant volumes of fluid in an undetected manner over a period of years while operating at a relatively high pressure and at a high injection rate. This combination of circumstances is unlikely because of the distances the brine would have to flow, the breakdowns that would have to occur in the requirements of current regulations, and failure that would have to be assumed in the effectiveness of current well construction standards. In addition, vertical migration of injected fluid from the injection zone to the WIPP interbeds would have to take place in close proximity to the injection well due either to poor cement in the outer casing annulus, hydraulic fracturing out of the injection zone, or other vertical communication pathways. Because of the rapid loss of pressure that occurs with distance away from an injection well in an injection zone, brine following vertical pathways that were distant from the injection well, such as an abandoned borehole with degraded casing and plugs, would not be under enough pressure to cause significant vertical flow. Even pathways near the injection well would have to have sufficiently high permeabilities that brine could migrate to the WIPP interbeds under a pressure and flow rate that were high enough to fracture the interbeds, causing their permeability to increase and allow significant fluid flow and pressure to be transmitted toward the WIPP repository. Flow would then have to continue for a sufficient period of time to propagate a pressure gradient through the interbeds to the repository more than 8,800 feet (2,683 m) away. In summary, the following combination of events would need to occur for the repository to be impacted.

- An injection well would have to be present near the WIPP LWA boundary;
- The injection well would have to leak;
- The leak would have to remain undetected;
- The leak would have to occur in or near the injection well annulus;
- Brine would have to migrate at a sufficient pressure and flow rate to vertically rise 1,900 feet passing intervening thief zones to reach a Salado interbed intersecting the WIPP repository;
- The brine pressure and flow rate at the Salado interbed would have to be high enough to initiate and propagate hydraulic fractures;
- The interbed permeability enhancement resulting from fluid injection would have to be oriented toward and communicate with the repository;
- The injection would have to continue for sufficient time to pressurize the interbed at the repository 8,800 feet away;
- The interbed pressure at the repository would have to be large enough to drive sufficient excess brine from the interbed into the repository to significantly affect waste containment.

The foregoing chain of events assumes that injection well failure occurs through vertical



migration of brine up the wellbore annulus between the outer casing and the formation through a failed cement grout seal. This is the type of failure postulated, for example, in the aforementioned Hartman Case. The alternative of failures in the injection tubing or packers and also in the casing wall of an injection well near an anhydrite interbed that intersects the WIPP repository was previously discussed in Section 4 and is so improbable that it is not further considered by EPA.

The probability of a chain of events occurring is equal to the product of the probabilities of each of the individual events occurring given that the previous events have occurred. These are called conditional probabilities, and the decision tree method used in this analysis is discussed by Davis (1986). The probability of occurrence for each event in the chain was estimated based on the professional judgement of EPA's contractors and staff. In each case, the probabilities represent expected upper bound values. These values were developed to provide an illustration of the maximum plausible value for the event to occur. The product of these values provides an estimate of the upper bound of the probability of a catastrophic injection well failure near the WIPP that could drive significant quantities of excess brine into the repository and impact waste containment.

The elements of the injection well failure event chain are discussed individually below, the estimated probability is identified, and the basis for that estimate is explained. In each case an estimated upper bound, maximum plausible value for the probability is presented. Both original and revised probability estimates are presented. Two of the original estimates made in the summer of 1997 were revised based on the aforementioned supplemental fluid injection information provided by DOE in response to EPA's letter of March 19, 1997 from Ramona Trovato, EPA, to Al Alm, DOE, transmitting comments regarding completeness and technical sufficiency of DOE's Compliance Certification Application (Docket A-93-02, II-I-17). In that supplemental information, fluid injection issues were principally addressed in a report by Stoelzel and Swift (1997, WPO # 44158). Estimated probabilities were assigned by EPA to the following elements of the event chain:

*An injection well would have to be present near the WIPP LWA boundary (Original Estimated Probability: 100%; Current Estimated Probability: 100%):* It is believed that oilfield injection activity will continue in the vicinity of the WIPP site and that injection wells located at or near the LWA boundary are plausible. This probability value was not changed.

*The injection well would have to leak (Original Estimated Probability: 10%; Current Estimated Probability: 25%):* Statistical information on historic injection well leaks for wells installed under the regulatory requirements applicable to the vicinity of the WIPP site was not reviewed at the time that the original estimate was made. The maximum plausible value for the estimated probability of a leak occurring was therefore based on professional judgement related to general oilfield experience for wells installed under the current regulatory environment in the WIPP study area. Subsequent analysis by DOE (Stoelzel and Swift, 1997; WPO # 44158) of actual injection well failure rates within the Delaware Basin in Lea and Eddy Counties, New Mexico,

indicated that 24 failures occurred in a total of 112 injection wells (21.4%). Within the 9 township study area surrounding the WIPP site, 3 failures were identified in a total of 24 injection wells (12.5%). The failure rate in the WIPP study area would be expected to be lower than for the basin as a whole because the WIPP area oilfields are younger, most wells were installed using more modern and effective practices, and the regulatory requirements are more stringent. Based on the specific injection well survey conducted by DOE, a probability of 25% was estimated as the maximum failure rate applicable to the WIPP area. This value is greater than was found by DOE in either the WIPP area or in the wider study area and is considered to account for leaks that occurred and were not detected as well as those that were detected. This probability is considered by EPA to be reasonable and adequately conservative.

*The leak would have to remain undetected (Original Estimated Probability: 25%; Current Estimated Probability: 25%):* This event relates to leaks that occur and remain undetected for decades. Estimates of the rates of undetected events are essentially unverifiable and must necessarily be based on judgement. Although the information reported by Stoelzel and Swift (1997; WPO # 44158) for the study area near WIPP indicates that all leaks are detected within less than one year and that the NMOCD regulatory requirements for leak detection and reporting are working (19 NMAC 15.I.704.B), the bounding probability of 25% that was originally estimated for this event has been retained unchanged. This value means that one in four leaks that occur in injection wells is assumed to not be detected. Higher non-detect rates would suggest that the NMOCD's Underground Injection Control (UIC) regulations that have been considered by industry professionals to have been effective since 1984 are, in fact, not effective and insufficient to meet the standard of protecting of human health and the environment. EPA believes that the UIC regulations are effective, and believes that the estimated probability value of 25% is reasonable and adequately conservative.

*The leak would have to occur in the injection well casing annulus (Original Estimated Probability: 50%; Current Estimated Probability: 50%):* The original estimated probability was based on professional judgement related to general oilfield experience for wells installed under the current regulatory environment in the vicinity of WIPP. Detected injection well leaks are generally in the tubing or packers inside the casing and little information is available on grout seal leaks outside the outer casing, probably because such leaks are hard to detect and are less frequent under modern drilling technology. According to the aforementioned DOE studies reported by Stoelzel and Swift (1997; WPO # 44158), of those leaks that did occur, 1 out of 3 in the study area and 8 out of 24 in Lea and Eddy Counties were casing-related leaks. Most of these were pinhole leaks from casing corrosion due to failure of the annular grout seal to adequately restrict fluid circulation outside the casing, the leaks occurred in isolated areas, and they were detected before they became significant. In fact, the data presented by DOE suggests that most of these casing leaks did not have the potential for injection fluid losses because the injection tubing was removed intact. Although the WIPP area sample is small, in both the study area around WIPP and in the greater region the casing and annulus leak rate was 33% of the total number of reported leaks. EPA considers these data to support the original estimate of 50% as a reasonable, bounding value and the original probability value was therefore not changed.

*Brine would have to migrate at a sufficient pressure and flow rate to vertically rise 1,900 feet (580 m) passing intervening thief zones to reach a Salado interbed intersecting the WIPP repository (Original Estimated Probability: 10%; Current Estimated Probability: 10%):* NMOCD well installation standards require a cement seal in the annular space between the casing and formation specifically to prevent vertical brine migration (NMOCD Order R-111-P, Subpart D). In addition, operating standards require the use of injection pressures that would not fracture or otherwise breach the annular cement seal, and construction standards require that the seal be in place and verified before the well can be used (19 NMAC 15.I.703 and 704). Verification of the seal integrity is performed by inspecting the cementing process, cement bond logging after the seal is emplaced, and pressure tests at the bottom of the casing string.

In addition to the NMOCD well standards, any fluids that could migrate vertically up the outer wellbore annulus would have to pass several anhydrite interbed thief zones in the Castile and lower Salado that would divert flow laterally because their higher permeability is higher than that of the surrounding halite. Flow would have to move a considerable distance in the annulus (more than 1,900 feet or about 580 m) before it could reach an interbed that intersected the repository, and even short lengths of lower permeability material in the annulus would significantly lower the effective average permeability of the system, significantly restricting flow. The alternating presence of cement, mud, and other natural low permeability materials in the annulus would be expected to significantly restrict flow.

There is no indication that any of the injection wells in the vicinity of WIPP have the potential for flow behind the long-string casing from the Bell Canyon to the Salado interbeds. Because of the construction, installation and operating standards for deep wells in the vicinity of WIPP, the significant resistance to vertical flow offered by a long, properly grouted wellbore annulus, and the influence of thief zones in diverting flow, EPA believes that the probability of fluids moving up the annulus of an injection well and reaching an interbed that intersects the WIPP repository is small. EPA has assigned a probability of 10% to this event, and believes that this probability is conservative. This probability value was not changed from the original estimate.

*The brine pressure at the Salado interbed would have to be high enough to initiate hydraulic fractures (Original Estimated Probability: 25%; Current Estimated Probability: 25%):* This event requires that in addition to brine migrating through the wellbore annulus and reaching a Salado interbed that intersected the WIPP repository, it would have to arrive at that interbed under sufficient pressure to initiate hydrofracturing. This event would require an even higher average permeability in the wellbore annulus than would be required for brine to reach the interbed, one that would allow the pressure transmission to overcome the bleed-off that would occur in the thief zones. EPA has estimated the conditional probability of this event to be higher than that estimated above for flow to reach the interbed, because if it is assumed that flow has indeed reached the interbed then it is acknowledged that something has already gone critically wrong with all of the construction, installation, and operation standards and monitoring requirements that are designed to prevent such an occurrence. EPA has therefore given this event a relatively high probability of 25%, indicating that if injected brine is capable of reaching the Salado interbed, there is as much as one chance in four that the brine will be under sufficient

pressure to initiate hydraulic fracturing. This probability value was not changed from the original estimate.

*The interbed permeability enhancement resulting from fluid injection would have to be oriented toward and communicate with the repository (Original Estimated Probability: 75%; Current Estimated Probability: 75%):* EPA does not believe that the stresses on the interbeds are sufficiently well known to be certain that interbed permeability enhancement propagating through hydraulic fracturing from an injection well over a mile away would necessarily intersect the WIPP repository. However, for conservatism EPA estimated a relatively high probability of 75% for this event because of the uncertainty associated with it. This probability was not changed from the original value.

*The injection would have to continue for sufficient time and at a sufficient rate to cause flow into the repository 8,800 feet away (Original Estimated Probability: 10%; Current Estimated Probability: 10%):* This event involves both the duration and rate of injection. Although some wells are older, a typical upper limit for the operating lifetime of an injection well is approximately 50 years. In DOE's modeling studies, injection well operating lifetimes of 50 to 150 years were used (Stoelzel and O'Brien 1996; WPO # 40837, and Stoelzel and Swift 1997; WPO # 44158). Both of these studies showed that under a sufficiently high wellbore annulus permeability, additional brine flow into the WIPP repository was observed. However, in their efforts to model such migration, Stoelzel and O'Brien found that they had to increase the wellbore annulus permeability to unrealistically high values on the order of  $1 \times 10^{-11} \text{ m}^2$  before detectable volumes of brine could reach the WIPP repository. This is equivalent to the highest end of the range of permeabilities for degraded borehole plugs used in the CCA and is two orders of magnitude higher than the expected permeability of the degraded plug (see CCA Vol. I, Section 6, Table 6-25; Docket A-93-02, II-G-01). From the same reference the permeability of an undegraded plug, for comparison, is  $5 \times 10^{-17} \text{ m}^2$ . Because complete plug degradation is expected by DOE to require about 200 years, EPA considers the assignment of a fully degraded borehole permeability to the annular seal of a borehole that will be typically used for only 50 years to be highly conservative and unlikely to occur. In addition, a more detailed analysis of the injection well leaks identified in DOE's survey (see Stoelzel and Swift, 1997; WPO # 44158) showed that they typically involved packer leaks, wellhead leaks, and tubing and casing leaks that were rapidly detected during operation. None of the leaks in either the Lea and Eddy County areas or the WIPP study area could have resulted in driving any excess brine into the repository. EPA therefore considered it unlikely that the brine flow rate up the annulus of an injection well would be sufficiently high and continue for a sufficient period of time to cause additional fluid to flow from the interbeds into the repository and assigned a probability of 10% to this event. This probability was not changed from the original value.

*The interbed pressure at the repository would have to be large enough to drive sufficient excess brine from the interbed into the repository to significantly affect waste containment (Original Estimated Probability: 75%; Current Estimated Probability: 10%):* The estimated probability for this event was reduced from 75% to 10% based on supplemental information provided by DOE (see Stoelzel and Swift, 1997; WPO # 44158) and on the Agency's evaluation of the

significance of the repository brine inflows estimated from those studies. After incorporating into their modeling unrealistically high injection well annulus permeabilities and high injection pressures, under WIPP geological conditions Stoelzel and O'Brien (1996; WPO # 40837) estimated cumulative excess brine flows into the WIPP repository ranging from about 250 to 1,050 m<sup>3</sup> over the 10,000-year regulatory time frame (1996, p. 34, Figure 8). With slightly different assumptions Stoelzel and Swift estimated cumulative excess brine inflows of less than 450 m<sup>3</sup> (1997, p. 52, Figure 23). DOE's Conceptual Models Peer Review Panel evaluated the issue of supplemental repository brine inflows resulting from processes that were not addressed by DOE in performance assessment, including brine inflows from fluid injection scenarios. The Panel concluded that the total cumulative brine flow into the waste area is typically about 40,000 m<sup>3</sup> following a borehole intrusion that intersects a Castile brine reservoir, and about 30,000 m<sup>3</sup> following a borehole intrusion that does not intersect a Castile brine reservoir. Given that about 6 borehole intrusions are expected to occur during the regulatory time frame, the total volume of brine potentially available to flow into the waste area could exceed 100,000 m<sup>3</sup>. The Panel concluded that "Although the actual volume of brine inflow will depend on the interrelationships among time of intrusion, repository creep closure, gas generation, repository pressure, and other factors, the modeling results indicate that sufficient brine is potentially available from other sources that an incremental supply of as much as 12,000 m<sup>3</sup> would have no consequential effect on performance assessment results." (see Docket A-93-02, II-G-12, Section 3.12.3.3).

EPA concurs with the Peer Panel's finding and believes that the conservatively estimated maximum supplemental brine inflow of about 1,000 m<sup>3</sup> calculated by DOE from fluid injection activities would have no consequential effect on performance assessment results. In view of these modeling results, EPA believes that the probability that supplemental brine inflows into the repository would exceed 12,000 m<sup>3</sup> is small, and has reassigned a probability of 10% to this event.

The probabilities associated with the foregoing chain of events are summarized on Table Q. The cumulative probability of all these events occurring together is equal to the product of the probabilities of the individual events. Based on the original probability values the cumulative probability is estimated as about one chance in 57,000. Based on the revised probability values the cumulative probability is reduced to about one chance in 171,000. EPA considers both cumulative probabilities resulting from this estimation process to be low and to illustrate the Agency's aforementioned belief that failure of an injection well and the subsequent migration of significant volumes of brine into the WIPP repository is unlikely.

**Table Q**  
 Illustration of Conditional Probability That An Injection Well  
 Will Leak and Impact the WIPP Repository

<b>What is the probability of ?</b>	<b>Original Value</b>	<b>Revised Value</b>
the presence of an injection well near the WIPP LWA boundary	100%	100%
the injection well leaking	10%	25%
the leaky well going undetected	25%	25%
the leak occurring in the injection well annulus	50%	50%
the upward brine migration reaching a Salado interbed 1,900 ft. away	10%	10%
the brine pressure and flow being sufficient to fracture the interbed	25%	25%
the interbed fracturing being oriented toward the repository and the interbed being continuous between the injection well and the repository	75%	75%
the injection continuing for sufficient time to pressurize the interbed at the repository 8,800 feet away	10%	10%
the interbed pressure at the repository being large enough to drive sufficient flow into the repository to significantly affect waste containment	75%	10%
the entire chain of events occurring	1 in 57,000	1 in 171,000

## 6.0 SUMMARY AND CONCLUSIONS

The purpose of this study was to evaluate the potential for fluid injection activities in the vicinity of the WIPP site to significantly affect the WIPP disposal system. In support of this objective, EPA reviewed and summarized the geology and the oil and gas operations around WIPP. In addition, EPA reviewed the documentation of DOE's fluid injection screening activities for performance assessment as well as supplemental information provided by DOE in response to questions raised by the Agency. EPA also developed estimates of the probability that a failed injection well could significantly impact WIPP repository performance. The most likely scenario for a failed injection well to impact the WIPP repository is for injected brine to migrate vertically upward from a deep injection zone through a faulty wellbore annulus seal to the elevation of an anhydrite interbed that intersects the WIPP repository, and then to migrate horizontally along that interbed causing a pressure transient that drives additional brine into the repository.

EPA found that fluid injection is a current practice in the vicinity of WIPP that can be expected to continue into the near future. Fluid injection is being conducted for purposes that can include brine disposal, oilfield pressure maintenance, and oilfield waterflooding. EPA has also

determined that the consequence of fluid injection on WIPP repository performance is likely to be low. This is because the geologic conditions and the well construction and operational standards in the vicinity of WIPP mitigate against both a catastrophic injection well failure and the movement of excess brine into the WIPP repository should such a failure occur.

The principal geologic considerations include the great vertical thickness (greater than 1,900 feet) of low permeability strata between the nearest injection zone and the WIPP repository in the Salado Formation, and the presence within those intervening strata of higher permeability, subhorizontal anhydrite interbeds that can serve as thief zones to divert upward migrating brines away from the repository. In areas such as the Rhodes-Yates oilfield where upward migration of significant volumes of brine may have occurred as a result of injection well failures, the thickness of geologic strata between the middle Salado and the nearest injection zone is as little as 200 feet, and there are no anhydrite thief zones in those strata.

The principal construction and operational considerations are the younger average age and consequently better construction practices for the wells in the vicinity of WIPP as compared with those in the Rhodes-Yates oilfield where injection well failures may have occurred. In addition, oilfield operations in the vicinity of WIPP are performed under comparatively stricter regulatory requirements by the New Mexico Oil Conservation Division than, for example, at the Rhodes-Yates field. The combination of improved oilfield drilling and operational technology and the stricter standards regulating use of that technology has resulted in safer drilling practices employing dual casing strings and continuous, dual annular seals through the salt section that are less likely to corrode or degrade during the well's operational life, improved well stimulation techniques through hydrofracturing that are less likely to damage the annular cement seals, improved controls on maximum allowed injection pressures to avoid seal damage, and improved monitoring of injection tubing leaks that could pressurize the interior of the well casing.

The consequences of a catastrophic injection well failure on the performance of the WIPP repository was modeled by DOE under WIPP site conditions. In performing that modeling, DOE found that it was necessary to assume unrealistically high permeabilities for a failed wellbore annular cement seal to allow brine to move vertically past the anhydrite thief zones to the elevation of the interbeds that intersect the WIPP repository. EPA found that the conceptual approach used in DOE's fluid injection modeling provided an acceptable realization that is consistent with available information regarding WIPP site conditions. EPA believes that the modeling was performed with sufficient conservatism that a more realistic representation of an injection scenario would probably reduce the flow that was calculated to enter the interbeds and the repository. Even when assuming conservatively high seal permeabilities, the volume of additional brine that was calculated by DOE to move into the repository was relatively small (typically less than 1,000 m<sup>3</sup>) as compared with the tens of thousands of cubic meters that are calculated to enter the repository from other sources.

Based on the foregoing, EPA believes that catastrophic injection well failures that could affect the WIPP repository are unlikely, but even if such failures did occur, the volume of additional

brine that would enter the repository would not be sufficient to affect repository performance. EPA therefore concludes that fluid injection was appropriately screened out of performance assessment by DOE.

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**Volume 2 of 3**

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**Table Q is located on Page 38 of the main text in Volume 1.**