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USE OF DATA OBTAINED FROM CORE TESTS IN THE
DESIGN AND OPERATION OF SPENT BRINE INJECTION
WELLS IN GEOPRESSURED OR GEOTHERMAL SYSTEMS

ROBERT M. JORDA

COMPLETION TECHNOLOGY COMPANY

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The Use of Data Obtained From Core Tests in the Design and Operation of Spent Brine Injection Wells in Geopressured or Geothermal Systems

Abstract

Extremely large volumes of water will have to be reinjected in conjunction with large-scale, future geopressured or geothermal projects. However, cost of drilling and operating injection wells is totally parasitic, in that no income is produced directly by these wells, and some of the energy produced by power plants must be used for injection power. Thus accurately engineered reinjection systems are critically needed to make proposed geopressured and geothermal developments economically viable.

This report is a review of the effects of formation characteristics on injection well performance. Use of data acquired from cores taken from injection horizons to predict injectivity is described. And methods for utilizing data from bench scale testing of brine and core samples to optimize injection well design are presented.

Currently available methods and equipment provide data which enable the optimum design of injection wells through analysis of cores taken from injection zones. These methods also provide a means of identifying and correcting well injection problems. Methods described in this report are:

1. Bulk density measurement
2. Porosity measurement
3. Pore size distribution analysis

4. Permeability measurement
5. Formation grain size distribution analysis
6. Core description (lithology) and composition
7. Amount, type and distribution of clays and shales
8. Connate water analysis
9. Consolidatability of friable reservoir rocks
10. Grain and pore characterization by scanning electron microscopy
11. Grain and pore characterization by thin section analysis
12. Permeability damage and enhancement tests
13. Distribution of water-borne particles in porous media
14. Reservoir matrix acidizing effectiveness

The injection well and the surface treating system design can be optimized in advance of system construction and operation if core samples and representative spent brine samples are tested using bench-size equipment. Existing field test reports indicate that serious and costly problems can be avoided or minimized if adequate core and core flow tests are performed early in the system planning stage.^{24, 26, 38, 53}

Although not discussed in this study, the reported data from Strategic Petroleum Reserve brine injection system tests underscores this philosophy.³⁴

The precise methods of obtaining the information in (1-14) above are described in this report, and their use in the engineering of injection wells is illustrated by examples, where applicable.

Areas where additional work is recommended are:

- (1) The effects on injection zone permeability caused by injection

of high-temperature spent brines ($t \approx 200^{\circ}\text{F}$) into shallow, lower temperature reservoirs. This problem is specifically addressed in the report.

(2) What may be a more definitive method of examining the distribution of water-borne particles in porous media has been described in SPE 8120.¹¹ Because of the potential direct utility of this technology, it is recommended that further testing of the method be undertaken using data and samples from existing injection systems.

(3) A number of examples of the application of core test data appear in this report, each of which was calculated on a case-by-case basis. It was not possible to provide sufficiently broad decision-making capability or sensitivity analyses for each case and keep expenditures within the amount funded for this report. But the desirability of broader analyses made itself evident in each example presented. It can be concluded that an injection system simulator, parallel in purpose to the drilling well simulator recently developed by Sandia Laboratories,⁴⁸ will provide needed analytical capabilities, and the development of such a simulator by Sandia Laboratories is recommended.

(4) Core availability from injection reservoirs is limited at this time. The funding and establishment of a "core bank" for injectivity studies is recommended.

(5) Commercial laboratory services can provide all of the core tests included in this report. However, non-routine core flow tests often require special coordination, logistics, attention and procedures which, though available, cause scheduling problems and long delays in commercially available laboratories. Many of the special tests are required to insure proper well

completions. It is recommended that Sandia Laboratories' Drilling Technology Division provide core flow test equipment at their laboratory. Properly designed, a core flow tester would also be of use in other Drilling Technology Division studies, such as those involving drilling and completion fluids, and lost circulation materials.

Purpose and Scope

Spent water reinjection is a requirement in most power generating plants where energy is extracted from fluids produced from geothermal or geopressured wells. ReInjection is also a requirement for geopressured systems designed to recover methane from deep aquifers which contain small amounts of C_1^+ hydrocarbons in solution.

Spent water reinjection has been carried out in many projects to date without full utilization of the technical guidance available through core analysis. The results have been mixed - - both unexpectedly high and unacceptably low specific injectivities have been encountered.

When low injectivities occur in a project, the drilling of additional reinjection wells is usually required. Sometimes these additional wells are proven to have been unnecessary, when data acquired later in the program development indicate that low injectivities resulted from a mismatch of water quality or chemistry with the injection zone.

Very few cores have been acquired from geothermal reinjection wells. Had more cores been available, there is evidence to support the belief that some reinjection problems could have been avoided or more quickly defined by the proper use of core tests.

Also, most systems which have been operated in the United States to date have been experimental or demonstrational in character. When commercial liquid dominated systems are proposed, a more accurate assessment of reinjection capacity must be in hand for proper planning, drilling, and cost analysis.

Core tests will not always provide a complete answer to reinjection

well design or operation. But a more precise assessment of the entire reinjection segment of a project can be obtained with information which core tests can provide.

This report describes types of tests which can be performed on core samples, and (where applicable) the report illustrates how data obtained from core tests can be directly applied to reinjection system engineering.

Coring Requirements in the Injection Interval

When a geothermal project is explored and developed, geologic and geophysical data are often used to delineate the subsurface targets. These data can and should be used to locate potential reinjection zones. Structure maps are often constructed using a well-defined geologic marker. Figure 1 is an example structure map contoured on the top of the Strawn Reef (Texas). The deeper zones of interest might not be as well defined, especially in areas such as the Imperial Valley (Calif.) KGRA sites. Referring to Figure 1, an injection zone (for example) may have been defined from geophysical data as having the zone top 4,000 feet below the T/Strawn Reef, plus or minus 200 feet, and the zone bottom at 4,600 feet below the T/Strawn Reef, plus or minus 180 feet. Such information is not adequate for precise completion specifications, and coring/logging would be used to locate the zone more accurately. Logging after drilling would help define the zone boundaries, and logs can be analyzed to yield net sand footage. However, all of the data required to assess injectivity would not be provided by electric logs alone. Even a SARABAND analysis of an electric log (Figure 2) cannot always provide such necessary information as porosity and permeability within the accuracy limits often necessary for

SEC. 1, BLK. B, HE & WT RR CO. SURVEY

A STRUCTURE MAP OF THE E (CANEY REEF) FIELD, TEXAS, CONTOURED ON THE TOP OF THE STRAWN REEF. (REDRAWN FROM PETROLEUM INFORMATION SERVICES).

Figure 1

AN EXAMPLE SARABAND LOG OF SHALLOW SEDIMENTARY DEPOSITS IN THE IMPERIAL VALLEY (CA) NEAR THE NILAND KGRA.

Figure 2

engineering reinjection wells. Because SARABAND and CORABAND techniques rely heavily on the extensive use of statistical methods and cross-plots, resolution of the data can be less than adequate. The SARABAND analysis of one injection well in the Imperial Valley KGRA (Figure 2) indicated permeabilities which are about 50 percent higher than those actually measured later with other techniques.²⁶ This is within the claimed accuracy of SARABAND analysis, and while this degree of accuracy may be adequate for many oil or gas wells, it does not always satisfy the needs for shallow reinjection wells. Thus, cores of the injection zone may be required to provide data when the sand development in the injection zone is not well defined.

Conventional Coring Methods

Taking a core is indicated when examination of drill cuttings at the surface shows that the interval just above the zone to be cored is being penetrated. An open-centered bit (Figure 3) is attached to a core barrel (Figure 4) which contains a cylindrical core sleeve ranging in length from 10 feet to 30 feet. For friable sections, a rubber core sleeve is commonly used. When water-bearing reservoirs are cored, water-base muds are recommended. Oil base or inverted oil emulsion muds may alter the rock properties by changing the naturally water-wet core material to an oil wet condition. During coring, mud filtrate invades the core and can flush out some connate fluids. Coring rates of penetration are usually lower than the rate of penetration while drilling, and the total mud filtrate volume per foot of hole drilled increases. Many operators specify a 3cc water loss mud as a target while coring to minimize damage by mud filtrate and to lower the risk of sticking the core barrel in the hole because low penetration rates cause thicker mud cakes to be built up on

CORE BITS WHICH USE DIAMOND INSERTS FOR ROCK CUTTING, (UPPER PHOTO COURTESY CHRISTENSEN DIAMOND PRODUCTS, LOWER COURTESY DIAMONT BOART, BELGIUM).

Figure 3

COMPLETE BARREL

1 SAFETY JOINT ASSEMBLY

- A SAFETY JOINT PIN
- B SPRING (3 REQUIRED)
- C PLUNGER (3 REQUIRED)
- D FRICTION RING
- E "O" RING
- F SAFETY JOINT BOX
- G "O" RING

2 SWIVEL ASSEMBLY

- A CARTRIDGE CAP
- B SHIMS
- C BEARING RETAINER
- D THRUST BEARING
- E CARTRIDGE PLUG
- F INNER TUBE PLUG
- G 1" STEEL BALL
- H PRESSURE RELIEF PLUG

3 OUTER TUBE SUB

4 OUTER TUBE

5 THREAD PROTECTOR (UPPER)

6 THREAD PROTECTOR (LOWER)

7 INNER TUBE

8 THREAD PROTECTOR (UPPER)

9 THREAD PROTECTOR (LOWER)

10 INNER TUBE SHOE

11 CORE CATCHER

A SECTIONED VIEW OF CONVENTIONAL CORE BARREL ASSEMBLY (REDRAWN FROM CHRISTENSEN DIAMOND PRODUCTS).

Figure 4

the wellbore. However, achieving a 3cc mud may not be practical, especially in shallow wells where mud conditioning time is limited.

Cores several inches in diameter and up to the entire height of the injection interval can be obtained from cemented and other competent formations. In friable and unconsolidated formations, core recovery may be as little as 10-15 percent of the cored section. Continuous coring (i.e., coring the entire section) is not a routine procedure in oil and gas wells, unless practically no other means of obtaining data can be used. Coring is expensive because of slow penetration rates, tool rental, mud preparation, and the added costs of special handling and analysis. Also, some desired information may take weeks to obtain (such as permeability and porosity). However, in experimental projects such as first attempts at water flooding, polymer flooding, and in-situ combustion, the expense and delay were deemed necessary by many operators venturing into relatively unexplored technical areas.

Wireline Coring Methods

Where operators have highly skilled petrophysical talent available, wireline coring after electric logging may be used in lieu of conventional coring.⁵⁴ This technique uses a wireline operated percussion device which selectively fires up to 72 hollow projectiles into the wellbore wall at depths selected from electric log analysis. The projectiles are retrieved on flexible cables attached to the projectiles and the tool body (Figure 5). These cores, often called "side wall samples", range 0.75 to 1.125 inches in diameter and 1.125 to 2.125 inches in length.

Some alteration of the rock sample takes place because of crushing and

A SCHEMATIC OF A PORTION OF A WIRE LINE CORE TOOL, OFTEN CALLED A "SIDE WALL SAMPLER". UP TO 72 CHARGES, INDIVIDUALLY CONTROLLED, CAN BE RUN IN A SINGLE TOOL.

Figure 5

compaction, but the basic features of the reservoir rock are retained.⁴⁷

Side wall sampling is most effective in consolidated soft and medium hardness formations. Sidewall sample tools are presently limited to 300°F environments (conventional guns) but can be used with special powders up to 400°F with reduced projectile penetration.⁵⁴

Although side wall coring has the advantage of selectivity not inherent in conventional coring, the small size of the sample precludes widespread use of the technique when relatively unknown projects are to be investigated. Filtrate invasion may reduce the useful length of a recovered sample by 0.5 inches or more. This minimizes the useful data which core flow tests can provide from side wall cores. However, the small sample size does not adversely affect the determination of the porosity, grain size distribution and similar tests which do not involve flowing fluids through a core plug.

Core Handling and Preservation

When a core is removed from a reservoir and brought to the surface, the temperature and pressure are reduced from the reservoir values to ambient values. In oil reservoirs, this presents problems not found in water reservoirs. Loss of volatile hydrocarbons from oil bearing cores requires special handling and preservation techniques.¹⁰

Usually, the problems associated with pressure and the temperature changes in cores recovered from water-filled sands involve the possibility of precipitation of scales such as calcium carbonate, calcium sulfate, and the like. Calcium carbonate may precipitate if the core pressure falls below about 900 psi, the reaction being:

Calcium sulfate and other scales may precipitate if sufficient water evaporates from the core to bring about aqueous phase supersaturation. For reasons such as this, quick-freezing of cores is recommended. Other methods for minimizing water evaporation include sealing core sections in sealed jars or cans, plastic containers, and heavy walled, capped rubber containers. Before preserving the sample, the core should be wiped to remove drilling mud. Water washing a core should not be used to remove mud or dirt. Color photographs taken after the core is wiped are widely employed, and a core description should be completed before the cores are stored.

A record of the core should include depth, type of coring fluid, mud filtrate loss, and a complete description of the amount and type of special mud additives used during coring. Listing additives is sometimes omitted, and perplexing problems can arise later because of this omission. Many special additives are surfactants, and can alter rock wettability with the result that misleading information is generated, through no fault of the core testing laboratory.³¹

Finally, cores should not be discarded after testing. If serious injection problems develop later in a project's life, the availability of preserved cores may provide the only effective means of identifying the problem. Otherwise, drilling another expensive well to obtain cores may be required.

Core Description and Compositional Analysis

When a core is recovered, the first analysis usually available is an on-site lithologic log. This is obtained through careful examination of the core by a skilled geologist. Instruments used by geologists include a microscope, a strong magnifying glass, sieves, tweezers, small scoops and

picks, bottles of acid, other simple reagents, which are used to provide an accurate mineral and structural description of the core.

Usually, the mineral description includes the presence of shales, schists, chinks, quartzite, limestone, dolomite, siltstones, claystones, sandstones, conglomerates, and a number of igneous rocks. Structural description includes color, hardness, competence, grain sorting, grain size, lamination, mineral inclusions and bands. An example of a lithologic log of an East Mesa (CA) core appears in Figure 6. The core analysis was provided by Terra Tek.

The target formations for water reinjection are permeable sands and fractured (or fracturable) dense rocks such as limestones. Referring to Figure 6, a sequence of sedimentary layers has been identified. Because claystones and siltstones are not very permeable, the only sedimentary deposit useful for water injection in Figure 6 is the medium grain sandstone. The sand grain size is described as "very well sorted", and the subrounded to round grain geometry indicated good fluid transmissability properties for this sandstone.

Estimating Well Injectivity from Core Description Information

In order to illustrate the value of this core description, a simulated electric log of the well is shown in Figure 7. The actual log is proprietary and differs from the simulated log in Figure 7.

If no other information other than the core description and electric log were available, a reasonably valid assessment of the ideal injection capacity of the hypothetical well can be made. The log, Figure 7, indicates that the gray sandstone appears in four other layers, separated by silt or shale layers. Net sand can be estimated to be 40 feet from the electric log.

LITHOLOGIC LOG
EAST MESA WELL #58-30

■ INDICATES ZONES OF BADLY BROKEN CORE

THE CORE DESCRIPTION PROVIDED BY TERRA TEK FOR SHALLOW SEDIMENTARY DEPOSITS IN THE EAST MESA (CA) KGRA, IMPERIAL VALLEY.

Figure 6

THE SELF POTENTIAL - RESISTIVITY LOG (SIMULATED) SHOWING LAYERED SANDS AND SHALES IN THE EXAMPLE WELL IN THE TEXT.

Figure 7

From this information, an injection well schematic, Figure 8, can be constructed.

The sands are described as "very fine grained" and reasonably well rounded. The description "very fine grained", plus the very well sorted grain geometry allows maximum theoretical permeabilities to be estimated (order of magnitude) using the expression:

$$k = \frac{d^2}{14.44}$$

Where: k = permeability, millidarcies

d = grain diameter, microns

"Very fine grained" is defined to include sands larger than 0.0625 mm and smaller than 0.125 mm in diameter. Using the above equation, the permeability of well sorted, very fine sands ranges from about 270 to 1,080 millidarcies. Poorly sorted sands and sands less rounded (more angular, rugose) would exhibit lower permeabilities, and simple expressions cannot be used to estimate permeability accurately - - but upper limits of permeability would most likely be those values calculated in this example.

Assuming average overburden, hydrostatic and geothermal gradients for the East Mesa area, and calculating maximum sub-fracture injectivity using the methods in reference 28, the range of injection rates for the example well are about 5,700 barrels per day if $k = 270$ md, and 23,000 barrels per day at $k = 1,080$ md. Surface injection pressure would be about 600 psi. If the mean grain diameter, 0.09375 mm is used, permeability is 609 md. With this value, injection would be about 13,000 barrels per day, and this would be a logical value to use for first approximation design purposes.

THE CASING AND LINER ARRANGEMENT FOR THE EXAMPLE WELL USED TO ILLUSTRATE HOW INJECTION CAPACITY CAN BE ESTIMATED FROM CORE DESCRIPTION.

Figure 8

From values obtained in this manner, reasonably acceptable well costs and parasitic injection power costs can be estimated.

But it must be kept in mind that these calculations assume ideal conditions - - no impairment by particles in the water, no poor completion practices, no scale precipitation, no adverse reaction between the injected water and the connate water and sands. Injectivity estimates would not be realistic unless it were fairly certain that very low turbidity, non-scaling, compatible waters were to be used, and that impairment - free completions would be specified. If these requirements could be satisfied, it would be safe to assume that injection could approach the calculated rate, possibly reaching 80 or 90 percent of this value. The approach followed in this example is not a substitute for more complete testing, but it can provide an early assessment of the well's injection capacity.

The remaining analysis includes mineral description of the core and chloride content of the connate water. The percent and identification of minerals and cementing materials, and textural properties of the core materials are obtained using optical techniques, most commonly requiring the use of a petrographic microscope for examination of thin section samples. More will be said about microscopic examination of thin sections later in this report. Some geothermal operators have found additional analysis, i.e., complete spectrographic analysis of the core material, to be of value. In a few barefoot injection wells, sidewall samples recovered after sustained injection have been analyzed spectrographically to define the character and amount of impairment. With a sample taken in-situ, determination of both the impairment mechanism and the most effective means of restoring

full injectivity are considerably simplified.

If reservoir fluids cannot be recovered through drill stem, bailer, or other methods, a section of a core can be crushed, leached with water, and a chloride or total dissolved solids determination can be made. Chloride content is usually obtained by titrating with silver nitrate, and either conductrimetric or pycnometric analysis can be employed to obtain total dissolved solids.

Measurement of Porosity from Core Samples

To measure effective porosity in the laboratory it is necessary to determine bulk volume, and grain volume and/or void (pore) volume. A portion of a core is first extracted to remove interstitial connate fluids and mud filtrate (if present). Extraction can be accomplished using several techniques.⁴⁷ One method uses a Soxhlet apparatus (Figure 9). Samples of the rock are placed in a glass container, above which is a water cooled reflux condenser. A boiling flask with vapor line and trapped liquid return line heats solvent, such as benzene, toluene, or light gasoline. The solvent, entering the sample container as a nearly pure vapor, is condensed. The condensate flushes through the core samples and condensate and extracted fluids return to the boiling flask. This process is carried out for several hours, after which samples are removed and heated to 100° - 105°C to remove the solvent. Drying should not be severe enough to dehydrate any clays.

Nonflammable solvents, such as chloroform and carbon tetrachloride are not recommended because they can form acids which are capable of altering the rock sample. For water sands, mutual solvents (alcohols, glycol ethers) may be used.

After extraction and drying, the sample is weighed and immersed in a bulk volume cell filled with a non-wetting liquid, usually mercury. Mercury will not enter even large pores because of its high contact angle with most rock surfaces, unless pressure of few psi is applied. The example bulk volume cell shown in Figure 10 indicates volume of mercury displaced by the sample.

Bulk volume of weak, loosely cemented samples may also be obtained by saturating samples with a rock-wetting liquid and obtaining displacement in a bulk volume cell containing the same liquid.

Saturation is accomplished by placing the samples in a vacuum flask which also allows valve-controlled entry of the saturating liquid into the flask. The flask is evacuated, then partially filled with saturating liquid to the top of the rock samples, after which container pressure is returned to atmospheric. The saturating liquid should have a low viscosity and surface tension at ambient temperatures, and should wet rock surfaces. Often, kerosene is used.

Effective porosity then can be calculated if either grain volume, or volume of fluid required to resaturate extracted samples is determined. In the wetting fluid method described above, the sample is weighed when dry, and again after saturation. Porosity is the ratio of

A SCHEMATIC OF THE SOXHLET EXTRACTION APPARATUS DESCRIBED IN THE TEXT.

Figure 9

weight of saturating fluid divided by weight of similar fluid displaced by the bulk volume, multiplied by 100. (See additional discussion, page 46).

Other methods are used depending on sample strength and size and general magnitude of porosity. Using Boyle's Law, Ruska or Washburn-Bunting type porosimeters, the volume of air required to fill the evacuated sample is measured. For low porosity samples, a high-pressure Ruska porosimeter injects mercury into sample pore space. (See discussion and illustration, page 50).

Estimating Porosity from Bulk Density Data

A rock property which provides a means to determine absolute porosity in situ is bulk density. If this property is known, and the fraction and type of matrix rock and corresponding densities are known, absolute porosity, the percentage of total void space, can be calculated. Effective porosity (interconnected voids) is a better indicator of fluid conductivity that can only be measured from core samples, as previously described.

Wireline logs are used to measure bulk density over sections too long to be cored economically, or which are not suitable for coring. Like other wireline logs, readings are subject to errors from mud cakes, mud filtrate invasion, and log interpretation; they are most effective when interpretation can be correlated with laboratory measurements of core or sidewall samples.

Once bulk density has been measured the core descriptions and compositional analyses can be used in the porosity calculation.

A SCHEMATIC OF THE BULK VOLUME CELL DESCRIBED IN THE TEXT.

Figure 10

Porosity is calculated:

$$\phi = \frac{\rho_m - \rho_b}{\rho_m - \rho_f}$$

Where: ϕ = absolute porosity, decimal

ρ_m = matrix rock density, g/cc

ρ_b = bulk density, g/cc

ρ_f = interstitial reservoir fluid density, g/cc

Useful values of densities of matrix rocks are:

<u>Mineral</u>	<u>Matrix density, g/cc</u>
Quartz	2.65
Calcite	2.71
Dolomite	2.8 to 2.9
Anhydrite	2.9 to 2.99
Shale	2.7 (Louisiana Gulf Coast)

Values of bulk densities are often available in petrophysical literature. One such example, bulk densities in the Texas Gulf Coast, is shown in Figure 11.

Estimating Required Well Spacing from Bulk Density Data

If the well in Figure 8 is used as an example, a water injection front advance rate can be calculated once porosity is known. Assuming that $\rho_b = 2.2$ from Figure 11, and that $\rho_f = 1.02$, then;

$$\phi = \frac{2.65 - 2.2}{2.65 - 1.02}$$

$$\phi = 0.276 = 27.6\%$$

AN EXAMPLE PLOT OF FORMATION BULK DENSITY AT DEPTHS TO 8,000 FEET
IN THE TEXAS GULF COAST.

Figure 11

The injection front position at any time provides information used in interference calculations and to estimate pressure increase caused by reservoir fill up, etc. Assuming that uniform injection takes place, the injection front radius can be calculated as:

$$r_i = \left(\frac{650.42 \times q \times t}{\phi \times s \times h} \right)^{\frac{1}{2}}$$

Where: r_i = injection front radius, feet
 q = water injection rate, barrels per day
 t = cumulative injection time, years
 ϕ = porosity, decimal
 s = flow saturation factor (*), decimal
 h = injection height, net interval, feet

At an injection rate of 13,000 b/d, the injection front can be calculated for $t = 1$ year.

$$r_i = \left(\frac{650.42 \times 13,000 \times 1}{0.276 \times 1.0 \times 40} \right)^{\frac{1}{2}}$$

$$r_i = 875 \text{ feet}$$

At $t = 5$ years, $r_i = 1,957$ feet, and:

At $t = 10$ years, $r_i = 2,767$ feet, and so on.

* The decimal fraction of interconnected pore space through which the fluid flows, usually 1.0 for water injection into water reservoirs.

These data are useful in determining well spacing to avoid interference, and to make proper analyses of reservoir behavior. For example, at $t = 10$ years in the preceding example, the spacing, acres per well, is calculated:

$$\begin{aligned}\text{Spacing} &= \frac{\pi r_i^2}{43560 \text{ sq. ft./acre}} \\ &= \frac{\pi \times (2,767)^2}{43,560} \\ &= 552 \text{ acres per well}\end{aligned}$$

If the project life for the example were 10 years, a group of injection wells would require a spacing equal to or greater than one well per 552 acres to prevent undue injection pressure buildup through interference in the reservoir. Also, if the spent brines were to be injected into the geothermal or geopressured producing horizon, proper spacing to avoid source well quenching would be required.

As will be demonstrated later, porosity is useful in engineering well stimulation treatments and other required operations, because it can be used to measure the depth to which an injected fluid penetrates the reservoir.

The Concept of Porosity

Porosity is defined as the void volume in a rock matrix expressed as a decimal fraction of the bulk volume of the rock. Porosity alone does not provide total insight to the rock productivity or injectivity, because the porosity value does not contain information relative to the variation in pore size within the rock.

A first approach to the understanding of the porosity can be illustrated by modelling a porous network of cubic packed spheres of uniform size

(Figure 12). In this geometry, porosity is exactly 0.4764 and porosity is independent of sphere diameter.

Figure 13 shows sections of spheres in both cubic and hexagonal packing. The hexagonal packing provides the lowest value of porosity, 0.2595, when uniform sized spheres are considered.

In either the cubic or hexagonal packs, porosity can be decreased by placing small particles in the pore spaces formed by the spheres. This serves to illustrate the well-known geological observation that the porosity of rocks decreases as the particle size of the rock minerals becomes less uniform.

In oil field geology, porosities have been observed to range from 0.50 (Kansas Sandstones) to as low as 0.015 (fractured limestones, Foothills belt of Canada). Both the Kansas Sandstone and the Foothills limestone have been highly productive, which illustrates another geological observation, porosity is not considered to be a sole criterion for fluid productivity or injectivity. But because fluid flow occurs through a network of interconnected pores, the amount, type and size distribution of the pore network is important; this concept will be developed in a later section of this study.

Some Geologic Factors Which Affect Porosity

When the thickness of a rock, the areal extent of the rock, and the porosity of the rock are known, the fluid storage capacity of the rock can be calculated. Only interconnected pores are considered in the calculation.

Pore networks are formed by voids which exist between rock particles and fragments after their sedimentary deposition is completed. Additional, or secondary porosity can develop if leaching, fracturing, or fissuring takes

$$V_b = L^3$$

$$n = \text{number of spheres} \\ = (L/d)^3$$

$$V_{ms} = n(\pi d^3/6)$$

$$\phi = \frac{L^3 - (L/d)^3 (\pi d^3/6)}{L^3}$$

$$= \frac{L^3 - L^3 (\pi d^3/6 d^3)}{L^3}$$

$$= 1 - (\pi/6)$$

$$= 0.4764$$

CALCULATING THE POROSITY OF CUBIC - PACKED SPHERES

Figure 12

PORE GEOMETRY OF HEXAGONAL PACKED SPHERES (UPPER) AND CUBIC PACKED SPHERES (LOWER)

Figure 13

place after the sediments have lithified. Migration of waters through the sediments at a later date can cause pore size reduction through cementation of the rock particles. Well sorted sediments (i.e. approaching uniform particle size) produce porosities of 0.3 to 0.4 after packing, whereas poorly sorted sediments (large variation in particle size) result in porosities in the range 0.2 to 0.3 after packing.

In carbonate rocks (limestone, dolomite) primary pores are the result of voids between clastic grains, voids along cleavage planes, skeletal voids, and voids caused by solution of joints and bedding planes. This usually results in porosities one order of magnitude less than sedimentary porosity. Natural or induced fracturing can increase carbonate porosity substantially. Further, matrix acidizing of carbonates is routinely used to increase the natural porosity of carbonates where fracturing is not applicable.

Figure 14 compares a sandstone and a limestone pore network (redrawn from thin section photomicrographs).⁴⁷

Direct Measurement of Effective Porosity in the Laboratory

Unless otherwise specified, porosity values refer to effective porosity, or the porosity of the interconnected pore network. Discontinuous voids, such as vugs, are not included in the measurement of effective porosity. Common practice currently dictates that the term "absolute porosity" be used when referring to total (continuous and discontinuous) porosity, and that "porosity" be used when effective porosity is intended to be discussed.

Porosity is generally measured by one of three methods:

- 1) The dry, extracted rock is weighed, saturated with a wetting liquid, the exterior surface is damp dried, and the sample is weighed again.

REPRESENTATION OF STEVENS (CA) OIL SAND PORE STRUCTURE (UPPER) AND CARBONATE POROSITY FROM SOLUTION OF JOINTS AND BEDDING PLANES (LOWER). AFTER P.D. KRYNINE, MODIFIED.

Figure 14

The pore volume is calculated using the weight increase and the liquid density. This works well with friable or loosely consolidated samples where crushing might otherwise take place. Bulk volume must be known to use this method. Usually, kerosene is the favored saturating liquid.

2) Hydrostatic weighing is a variation of (1) and is more accurate than (1) because errors caused by damp-drying are eliminated. With this method, the weight of the dry sample is compared with the submerged weight of the saturated sample immersed in the saturation liquid. Like (1), bulk volume is required for this method.

3) Gas displacement in a dried sample is used to measure porosity in relatively complicated equipment such as the "Boyle's Law Porisometer".^{4,7} Because special equipment and empirical corrections are required, this method requires careful application. Gas expansion comparisons between a dummy sample (about the same size and shape as the rock sample, but nearly impermeable) and the rock sample provide the means of measuring porosity. This process is subject to some error due to gas adsorption on the pore walls, and to temperature fluctuations.

Generally, direct measurement of porosity is preferred over the method which converts bulk density to porosity using matrix density data.

When absolute porosity is required, the sample is crushed, washed with acetone, dried, weighed, and volume of the dried grains is obtained using a pycnometer or a Russell volumeter. Most sandstone data and a sizeable amount of carbonate sample data indicate that discontinuous porosity can usually be neglected in reservoir calculations.

Estimating Reservoir Storage Capacity Using Porosity Data

An example of the application of porosity data has been developed in the preceding section, "Estimating Reservoir Well Spacing from Bulk Density Data". Another example, calculating reservoir storage capacity for water injection, provides insight to problems currently encountered in spent brine reinjection.

Assume that a bounded cylindrical aquifer about 36 miles in diameter (about 1,000 square miles in areal extent) has a porosity $\phi = 0.35$ and that the injection sand thickness averages 100 feet. Because the aquifer is bounded, injection storage capacity is limited to water compressibility. If the net bottom hole injection pressure is 1,000 psi (69 megabars) above static reservoir pressure, the water compressibility is 45×10^{-6} per megabar.

One acre-foot has a volume of 7,758 barrels (1 barrel = 42 U.S. gallons) Then: areal extent of reservoir = 1,000 sq. miles x 640 acres/sq. mile = 640,000 acres.

$$\begin{aligned}\text{Total pore capacity} &= 6.4 \times 10^5 \times 7,758 \times 100 \times 0.35 \\ &= 1.738 \times 10^{11} \text{ barrels}\end{aligned}$$

$$\begin{aligned}\text{Then, total injection capacity from compressibility} &= 1.738 \times 10^{11} \times 69 \times 45 \times 10^{-6} \\ &= 5.4 \times 10^8 \text{ Barrels}\end{aligned}$$

This type of analysis on an expanded time-step basis can provide important insight to long-term injection power demands when combined with appropriate pressure increases caused by laminar flow of injected fluids through porous media.

Measuring Pore Size Distribution

In 1944, W.L. Horner devised a system for measuring very low porosity

rocks by forcing a noncompressible liquid into the sample under very high pressure (U. S. Patent No. 2345535)²⁰ The porosity is obtained by measuring the bulk volume of the rock sample at atmospheric pressure using mercury in a high-pressure pycnometer. Then mercury is forced into the pore spaces at pressures up to 1,000 psig while measuring the displacement of the piston driving the mercury by means of a micrometer drive wheel. Mercury displacement is measured to 0.01 cubic centimeters, and instruments such as the Ruska high pressure device automatically correct for any air trapped in the system and for elastic changes in the pump at high pressures. Figure 15 schematically illustrates a high-pressure mercury pycnometric porisometer.

In 1948, W.R. Purcell published the results of his studies which pioneered the use of mercury injection to determine pore size distribution.⁴⁹ Purcell's research showed that the non-wetting mercury required higher pressures for injection as pore size decreased. By recording mercury injection pressures as a function of cumulative injection volume, correlations were developed which made pore size determination possible.

Basically, Purcell was able to demonstrate that:

$$r_i = f \left(\gamma, \cos \theta, \frac{1}{P_c} \right)$$

Where:

r_i = pore radius

γ = mercury-water interfacial tension

θ = mercury-rock contact angle

P_c = mercury capillary pressure

Specific equations and distribution functions appear in Purcell's work, and in subsequent studies by other investigators³⁰ which describe the pore size distribution calculation procedure. This procedure was widely accepted and used by reservoir engineers and petrophysicists, but over a decade passed before the utility of pore size distribution was recognized by engineers

SCHEMATIC DRAWING OF A HIGH PRESSURE MERCURY POROSIMETER

Figure 15

working on water injection. Even today, many injection projects are designed and built without taking advantage of pore size distribution data. This is the case mainly because of a philosophy which has somehow become part and parcel to injection - - that is, water injection is an expense item, and does not directly produce income, is often regarded as a costly nuisance, and is not worthy of any but the most meager development costs or effort. The fact that injection is a necessary utility to income generating systems is often overlooked.

Pore size distribution plots appear in Figures 16 and 17. Figure 16 illustrates well sorted pores, that is, pore sizes vary by a factor of four or five. Figure 17 illustrates a poorly sorted pore geometry, with pore sizes varying over sixty fold.

Pore size distributions are also plotted using cumulative volume percent of pores related to pore diameter. Other plot parameters are occasionally seen in the literature, but the two cited are most often chosen.

Relating Pore Size Distribution to Water Quality

Because pore size distribution has not been widely used in water injection, most injection well performance prediction techniques, such as the Barkman-Davidson (SPE 3543), assume very well sorted pores, if not uniform pore size.¹³ This assumption either limits the use of predictive techniques to disposal zones where pore size is nearly uniform, or it compels the user to apply the predictive method "at his own risk".

If pore size distribution is determined and the size distribution of particles in the injection water is accurately measured using a Coulter counter or a device of equivalent capability, a reasonably accurate prediction of at

AN EXAMPLE OF WELL SORTED PORE DISTRIBUTION. 95% OF THE PORES ARE LESS THAN 15 MICRONS, 50% ARE LESS THAN 5 MICRONS, AND 10% ARE LESS THAN 3.5 MICRONS IN SIZE.

Figure 16

AN EXAMPLE OF POORLY SORTED PORE SIZE DISTRIBUTION. 95% OF THE PORES ARE LESS THAN 22 MICRONS, 80% ARE LESS THAN 7 MICRONS, 50% ARE LESS THAN 1.6 MICRONS, AND 10% ARE LESS THAN 0.26 MICRONS IN SIZE.

Figure 17

least a partial distribution of the water-borne particles in the injection well is possible.¹ It is important to know (1) whether all particles will bridge on the wellbore rock face or (2) whether invasion of all the particles will take place, or (3) whether both types of particle distribution will be the case (mixed distribution).⁶ Experience has shown that mixed distribution tends to cause more severe injectivity declines than wells in which either all surface filtration or all formation invasion occurs.⁸ Surface filtration localizes all particles where backflow can aid their removal. If invasion is known to occur, high unit injection rates are specified to sweep the particles as deep as possible into the formation to avoid the high pressure drop which shallow invasion causes.¹² When mixed distribution occurs, it is often impossible to achieve the high injection rates necessary to avoid shallow invasion, and severe impairment often results.¹⁷

It is generally acknowledged that the ratio of pore size to particle size necessary to cause surface filtration lies between pore-to-particle size ratios of 10:1 to 3:1 (often called the "bridging ratio").⁵⁰ Unfortunately, this range of bridging ratios is not sufficiently narrow to provide the geothermal operator with the specific information needed to minimize parasitic injection horsepower requirements by totally optimizing injection well design. Hopefully, some sector of the geothermal community will undertake the studies necessary to provide the technology needed to refine the pore-particle size ratios, using cores recovered from geothermal sites and particles which represent the "real" geothermal system.

Thomeer and Abrams have proposed the following guideline, based on well-sorted, rounded to sub rounded sand grains and particulates of a similar

geometry:⁵⁹

1. If pore throat diameter is less than three times particle size, the solids bridge on the rock face.
2. If pore throats are larger than three times particle diameter, and less than ten times the particle diameter, shallow invasion of solids will take place and damaging internal filter cake will form.
3. If the particle diameter is less than one-tenth the pore diameter, deep invasion of solids will take place, and a non-damaging condition exists.

These observations reflect the results of careful laboratory studies. But the shortcoming lies in the fact that few injection systems have the specified sand grain and water-borne particle geometries specified by Thomeer and Abrams.

Figure 18 illustrates at least a part of the ratio problem. This illustration shows a cross-section of three spherical grains of different size, with a spherical particle which just fits into the pore throat. A mercury pore size test might indicate a pore almost as large as the dashed circle in Figure 18. The bridging ratio in this geometry would then be about 3.5:1. However, three particles, each one-third the size of the single particle, arriving at the pore throat simultaneously could form a stable bridge at the pore throat. In this case, the bridging ratio would be about 10:1.

Figure 19 illustrates pore and particle size distributions where pore size is well sorted and the particles are poorly sorted. If a 4:1 bridging ratio is assumed, ten percent of the particles (those above 6 microns in size) would bridge over all of the pores. Further, thirty percent of the

A THREE - GRAIN SAND AND PORE ARRANGEMENT DESCRIBED IN THE TEXT TO ILLUSTRATE PORE SIZE/PARTICLE SIZE RATIOS AS THEY AFFECT PLUGGING OF PORES.

Figure 18

THIRTY PERCENT OF THE PARTICLES ARE LARGER THAN 2 MICRONS SIZE (OPEN SQUARE) AND WILL PLUG OVER FIFTY PERCENT OF THE PORES. TEN PERCENT OF THE PARTICLES ARE LARGER THAN 6 MICRONS (OPEN CIRCLE) AND WILL PLUG ALL OF THE PORES. IF PARTICLES WERE SIZED AT 1 MICRON (OPEN TRIANGLE) PLUGGING WOULD NOT OCCUR IN ANY OF THE PORES. THIS ASSUMES THAT PLUGGING TAKES PLACE WHEN THE PORE/PARTICLE RATIO IS 4:1.

Figure 19

particles are larger than 2 microns, and will bridge more than half of all the pores. Some of the particles smaller than 2 microns would invade the formation until a continuous bridge layer of 6 micron particles was in place. This type of mixed distribution would be capable of causing severe impairment if suspended solids in the water exceeded only a few ppm, and removal of the particles would probably be difficult.

For dependable, long-term, trouble free injection in the system shown in Figure 19, it would be advisable to filter the water to remove all particles larger than 0.5 microns, (achieve a 10:1 ratio, based on the smallest pore size) and maintain a high unit injection rate (50 or 100 barrels per day per net foot of sand thickness) to minimize impairment,

This specification may appear to impose severe constraints on the system, but unless better technical capabilities are acquired, it may be necessary to use this method where systems like this are encountered, in spite of the expense of the required filtration.

The example shown represents a condition to be avoided unless particles are miniscule in relation to pore sizes - - that is, poorly sorted particulates create problems not encountered when particulates are well sorted. Filtration through mixed media filters or diatomaceous earth filters produce filtrates containing well sorted particles. Often, even coarse filtration, that is, filtration to a filtrate suspended solids content of 10 or 20 parts per million is advantageous in that particle size in the filtrate is sufficiently well sorted to avoid the problem of the Figure 19 system.

Further references to topics of particle and pore size relationships appear later in this study.

Permeability - Definition and Application

Permeability of a rock is defined as the ability of the rock to conduct fluid through an interconnected pore network. Permeability, like porosity, is governed by grain size (or pore size in a carbonate), grain angularity and rugosity, grain size distribution, grain packing geometry and the amount of cementation in the grain matrix. The most widely used unit of measurement for permeability is the Darcy, named for M. Henry Darcy, Inspector General of Bridges and Roads in the mid 1800's for the town of Dijon. In 1856, Darcy reported the results of experiments involving fluid flow through sand packs (filters) and defined a unit of permeability in algebraic terms. This established Darcy's Law, an algebraic expression describing laminar, viscous, linear flow of fluids through porous media.

Referring to Figure 20, Darcy's equation states:

$$k = \frac{q \mu L}{A \Delta P}$$

Where: k = permeability, Darcys (or Darcies)

q = fluid flow rate, cubic centimeters per second

μ = fluid viscosity, centipoise

ΔP = pressure differential causing flow, atmospheres

L = distance over which fluid flows, centimeters

A = cross sectional area through which fluid flows, square centimeters

When $q = 1$ cc/sec, $\mu = 1$ cp., $\Delta P = 1$ atm., $L = 1$ cm, and $A = 1$ sq. cm, then $k = 1$ Darcy.

Usually permeability is expressed in units of millidarcies (md),

THE MODEL USED TO CALCULATE PERMEABILITY IN THE LAMINAR, VISCOUS LINEAR FLOW OF FLUIDS THROUGH POROUS MEDIA. LABORATORY EQUIPMENT USED TO MEASURE PERMEABILITY IS CONSTRUCTED TO FOLLOW THIS GEOMETRY.

Figure 20

where $1 \text{ md} = 10^{-3}$ Darcies. In oil and gas reservoirs, measured permeabilities are found to range from $< 0.1 \text{ md}$ ("tight" limestones and dense sandstones) to the tens of Darcies (shallow water sands).

In sedimentary sands, permeability parallel to the bedding plane is usually higher than the permeability normal to the bedding plane. This directional anisotropy results because oblate grains tend to fall with their greatest cross-sectional area in the horizontal plane during sedimentation. Further, they tend to become oriented with their longest axis parallel to water currents prior to lithification.

To evaluate the productivity or injectivity of a well, a radial flow expression is used (sometimes called "Darcy's radial flow equation").

$$q = \frac{2 \pi k h (P_s - P_f)}{\mu \ln(r_e/r_w)}$$

Where: q = well fluid flow rate, cc/sec.

k = linear reservoir rock permeability measured parallel to direction of well fluid flow, Darcies

h = vertical thickness of reservoir rock open to the well, cm.

μ = fluid viscosity at reservoir temperature, cp.*

r_e = well drainage/interference radius (function of well spacing), cm.

r_w = wellbore radius, cm.

P_s = reservoir static pressure, atm.

P_f = steady state flowing (or injecting) wellbore pressure, atm.

* for injection wells, average temperature of the mobile water mass must be estimated and the corresponding viscosity determined⁴⁵

In "practical" units, the expression for radial flow can be written:

$$q = \frac{0.007087 \cdot k \cdot h \cdot (P_s - P_f)}{\mu \ln(r_e/r_w)}$$

- Where:
- q = liquid production or injection rate, barrels per day
 - k = linear reservoir rock permeability measured parallel to the direction of liquid flow, millidarcies
 - h = vertical thickness of reservoir rock open to the well, feet
 - μ = fluid viscosity at reservoir temperature, centipoise*
 - r_e = well drainage/interference radius, feet
 - r_w = wellbore radius, feet
 - P_s = reservoir static pressure, psi
 - P_f = steady-state flowing (or injecting) wellbore pressure, psi

Permeability is widely used to predict well performance. Actual well flow is compared with predicted well flow to see if damage exists. Well stimulation treatments are often examined to see if in-situ permeability increases have occurred. And when the radial flow equation is applied to multicylinder models, information otherwise not easily obtained becomes available.^{24, 25} Without permeability measurements, vital reservoir and well flow information would probably be available only as "after the fact" knowledge.

Measuring Permeability in the Laboratory

In the laboratory, permeability measurement requires the following equipment.

1. A holder for the core sample
2. Means of measuring inlet and outlet pressures

3. Control of flow, either by constant inlet pressure or constant fluid flow rate
4. A means of measuring incremental fluid flow as a function of time
5. Temperature measurement equipment.

Usually, a cylindrical plug is drilled or punched from the core sample. Areas of mud invasion must be removed, and the porosity needs to be known. Porosity is usually obtained using a sample taken earlier from a section of the core close to the sample to be tested. If mud damage is severe and deep, the core may be extracted several times and then resaturated with the reservoir fluids.

The core plug may be mounted in epoxy, or held in a Hassler sleeve. The latter is preferred, because confining pressures can be applied to the Hassler device to simulate overburden pressures. Figure 21 shows a Hassler core holder. The core is contained in an elastomer sleeve which is positioned in a metal cylinder with seals and removable end caps. Pressure can be applied to the core by connecting a hydraulic press so that the sleeve/cylinder annulus is pressured with liquid.

The core holder assembly is then ready for testing. An example complete test hook-up is shown in Figure 22. This system provides the means of measuring permeability either at a constant flow rate or at a constant upstream pressure.

The system shown is an all-liquid one, and proper operation of this type of apparatus requires highly skilled personnel to avoid unacceptable data scatter.

A HASSLER - TYPE CORE HOLDER USED TO TEST CORES. CONFINING PRESSURE IS APPLIED TO THE CORE PLUG TO SIMULATE OVERBURDEN PRESSURES.

Figure 21

1. PRESSURE BOTTLE AND REGULATOR
2. INJECTION WATER SAMPLE CONTAINER
3. FILTER
4. PROPORTIONING FLUID PD PUMP
5. PUMP BYPASS
6. CORE HOLDER
7. CORE INFLOW PRESSURE GAUGE
8. CORE OUTFLOW PRESSURE GAUGE
9. FLOW CONTROLLER WITH BYPASS
10. GRADUATED CYLINDER FOR VOLUMETRIC MEASUREMENT

CORE FLOW TEST APPARATUS ARRANGED TO PROVIDE EITHER CONSTANT UPSTREAM PRESSURE TESTS OR TESTS AT A CONSTANT FLOW RATE. NOT SHOWN IS EQUIPMENT WHICH PROVIDES CONSTANT TEMPERATURE CONTROL, USUALLY EITHER HEATER STRIPS OR IMMERSION SYSTEMS.

Figure 22

Data scatter can be reduced by measuring permeability using air flow instead of liquid flow. At air pressures in excess of 300-400 psig, air permeability and liquid permeability measurements can agree within one-percent or so. However, it is more convenient and considerably less expensive to use low pressure air, but the resulting air permeabilities may differ by a factor of 4 or 5 fold from permeabilities measured under liquid flow. Nonetheless, many laboratories use the low pressure air system, measure air permeability, and then apply the Klinkenberg correction to obtain final values.³²

It will be demonstrated throughout this study that for geothermal or geopressure studies, the liquid type permeability equipment is preferred over the air permeability equipment. The liquid system can be modified easily to satisfy the requirements for many other special core tests, but the air-type equipment is relatively inflexible.³⁰

Permeability Data Analysis and Verification Procedures

Figure 23 illustrates the results of a permeability test on a Miocene core plug. The section tested is a sample of the Frio sand composed primarily of silica sand grains interspersed with clays. Filtered Frio formation water was used in the test. The test was conducted with extreme care, and was supervised by experienced personnel. Individual permeability readings varied from about 1,600 md to 1,040 md. The mean value of all data is 1,165 md, and the median is 1,098 md. The standard deviation of the recorded data is 146.

The test did not produce stable permeability readings until a liquid throughput of over 20 pore volumes was reached (the effective porosity of the sample was measured to be 38 percent).

Initially, permeability reduction was observed in the test. When

DATA RECORDED DURING A PERMEABILITY MEASUREMENT TEST PERFORMED UNDER CLOSELY CONTROLLED CONDITIONS ON A MIOCENE CORE PLUG. THIS ILLUSTRATES THE DATA SPREAD OFTEN ENCOUNTERED IN TESTS OF THIS TYPE. THE STANDARD DEVIATION OF THE DATA IS 146. THE TEST RESULTS SUGGEST THAT A PERMEABILITY VALUE OF ABOUT 1100 MILLIDARCIES SHOULD BE USED FOR RESERVOIR CALCULATIONS IN THE SECTION OF THE MIOCENE FROM WHICH THIS CORE WAS RECOVERED. (DATA FROM TEXAS DEPARTMENT OF WATER RESOURCES PUBLIC RECORDS).

Figure 23

this occurs, the test is stopped and the core is reversed in the test apparatus. A sharp increase in the permeability during reversed flow would indicate that the permeability reduction was caused by fines migration.⁸¹ This was not observed during the test of the Frio core, and indicates that the initial reduction in permeability can be attributed to some clay swelling as the argillaceous materials in the core hydrated to equilibrium size.⁵¹ The core had been extracted, and some clay shrinkage can be expected as a result of the extraction.

In applying the data from a core test such as this, the core permeability would be described as having a permeability "in the range of one thousand millidarcies". Permeability data should be regarded as an order of magnitude number. Whether the permeability of the Frio section was 800 or 1,200 md is insignificant - - but it is important to know that the permeability in this case is about 1,000 md, and not 100 or 10,000 md. Some reservoir engineers just want to be certain that the measured permeability is within the right log cycle! This philosophy is valid, at least in part, because sand permeability variations within a given section can vary as much as 5:1 or 10:1 where poor grain size sorting is encountered. Also, it must be kept in mind that any analytical core work involves attempting to characterize a large rock mass by determining specific properties of a very small sample.

Verifying permeability values when unacceptable data scattering occurs may also require checking to see if gas bubbles are trapped in the core prior to the start of the test. Gas bubbles trapped in the core will produce very erratic permeability measurements, and resaturation of the core is usually recommended to see if the problems are due to gas entrapment (the Jamin effect).

Further, poor or no temperature control can produce erratic test results. Permeability is directly proportional to fluid viscosity. For fresh water, viscosity relates to temperature:⁴⁶

<u>TEMP, °C</u>	<u>VISCOSITY, cp</u>
20	1.0050
30	0.8007
40	0.6560
50	0.5494
60	0.4688
70	0.4061
80	0.3565
100	0.3165

Misleading information has resulted from temperature induced changes in viscosity caused by heat of reaction in acidizing studies, further illustrating the need for utmost care in permeability measurement tests.

Generally permeability tests should provide reproducible data. When such is not the case, a careful analysis of the test apparatus and procedures is in order.

One Effect of Elevated Liquid Temperatures on Permeability

Often, if not most of the time, a reinjected spent brine is disposed of into a formation other than that from which it was produced. Also, many spent brine temperatures are close to 200°F, which may be 30-80°F (or so) higher than the temperature of shallow disposal zones. Thus, two conditions are set (1) the waste brine may be slightly chemically reactive toward the reservoir rock, since the waste liquid probably differs in composition from the disposal zone connate waters which have been equilibrated with the rock over geologic time, and (2) rock stresses may be increased when waters at a temperature above

the static reservoir value are injected.

References dealing with the effects of these two conditions are sparse. A research project reported by C.E. Cooke, Jr.¹⁰ provides some insight into the possible consequences of these two variables in geothermal brine disposal.

Cooke's research was concerned with fluid conductivity of fracture proppants, and a special linear flow model was used to measure permeability of packed proppants at elevated temperatures and stresses. When clean, well sorted sands were tested, a significant decrease in permeability resulted from temperature elevation. One set of data using a mixture of 8 mesh sands (0.093" diameter) to 12 mesh sands (0.055" diameter) appears in Figure 24. The reduction in permeability as stress increases is not unusual because this behavior results from expected changes in grain packing and some crushing of the grains, accompanied by the release of small grain fragments into the pore network. However, the reduction of permeability when the test temperature was increased from 150°F to 250°F was not necessarily expected (oil at 250°F produced data which overlay the data for water at 150°F). Cooke's study shows that the hot water may have induced widespread stress corrosion cracking of the sands initiated by solubilization of microscopic rock matrix components. This could be especially prevalent if "new" hot waters contacted reservoir sands.⁶²

Cooke also demonstrated that exposure time at elevated temperatures of the order of days are required to assess the influence of temperature on permeability properly.

THE EFFECT OF BRINE TEMPERATURE ON SAMPLE PERMEABILITY - SAMPLE IS A MIXTURE OF SANDS 8 TO 12 MESH. (REDRAWN FROM REFERENCE 62).

Figure 24.

What Cooke's work suggests is that more research is required to define the behavior of geopressured and geothermal reinjection zones under elevated stresses and temperatures. It may well turn out that longer-than-customary pre-flow saturation times (usually 16 hours) will be required when testing cores for permeability in geothermal and geopressure projects. At this writing, it is not known whether such a study has been considered for funding, but it appears that at least some exploratory test work would be of value to the overall geopressure and geothermal program.

Porosity-Permeability Correlations

Because porosity can be measured more easily and quickly than permeability, many attempts have been made over several decades to develop rigorous porosity-permeability correlations which would be valid over a wide range of values.^{41,47} However, the results over the years demonstrate that most correlations are restricted to the zone for which the correlation was made. No data from past or current studies indicate that a generalized correlation will be developed.

An example of the site-specificity of porosity-permeability correlations appears in Figure 25. In this illustration, porosity-permeability correlations are shown for two "similar" sections of the Andrews-South Devonian limestone (West Texas). At any given porosity, permeabilities differ by a factor of at least 10:1 within the limits of the plotted data. The differences increase as porosity values increase in Figure 25. Since the values of permeability for a given porosity in this correlation are not "in the same log cycles", (limits of acceptability by some reservoir engineers, cited earlier

ONE CORRELATION OF PERMEABILITY AND POROSITY FOR THE ANDREWS SOUTH DEVONIAN FORMATION, WEST TEXAS. THIS ILLUSTRATES THE UNCERTAINTIES INVOLVED WHEN ATTEMPTING TO OBTAIN PERMEABILITY WHEN ONLY POROSITY IS KNOWN.

Figure 25

in this text) the lack of transferability of data from the Encrinite zone to the Calcarenite zone in Figure 25 is self-evident.

Figure 26 shows another correlation, often seen in various writings, but of unknown origin. It is said of this correlation that it is acceptable for sands which are well sorted and well rounded, but no technical basis for this statement has been encountered. It is usually (and perhaps properly) used as a "last resort" approximation when dealing with a reservoir where almost no petrographic or geologic information exists, other than porosity.

It is unlikely that rigorous, general correlations enabling permeability determination from porosity data will emerge in the foreseeable future.

Grain Size-Permeability Correlations

In an effort to acquire permeability data by a method other than direct measurement, considerable work has been directed toward finding a means of accurately determining permeability through grain size correlation^{7,33,41}

Grain size is measured by dry sieving a crushed sandstone core; the procedure is quick and inexpensive, and lends itself to the use of portable equipment with rig-site measurement capability.

Kozeny³³ is credited with the development of a fundamental (and somewhat remarkable) relationship of grain geometry and permeability. Kozeny's equation states:

$$k = \frac{C \phi^3}{S_v^2 (1-\phi)^2}$$

Where: k = permeability

C = unit conversion constant

A PERMEABILITY - POROSITY CURVE WHICH SHOULD BE USED WITH CAUTION WHEN ABSOLUTELY NO OTHER INFORMATION IS AVAILABLE. (A LAST RESORT).

Figure 26

S_v = grain surface area per unit volume

ϕ = porosity of a pack of grain

In order to use this, S_v must be measured. Because measuring S_v requires rather sophisticated equipment, direct measurement of permeability is preferred over Kozeny's method for everyday use.

But a reasonable approximation has been developed based on Kozeny's equation which usually results in the calculation of a permeability which is "within the right log cycle". For spherical grains, the surface per unit volume increases as the inverse of the grain diameter. Thus, for uniform spherical grains in a packed system,

$$k = Cd^2 \frac{\phi^3}{(1-\phi)^2}$$

Where: k = permeability

C = unit conversion constant

d = grain diameter

ϕ = porosity

Applying this to a practical end use, the expression can be written:

$$k = \frac{d^2 \phi^3}{(1-\phi)^2}$$

Where: k = permeability, millidarcies

d = median grain diameter, microns

ϕ = porosity, decimal fraction

Further, engineers using this method have estimated that average sandstone porosities are such that they can set the expression to an equation which may be familiar to many readers:

$$k \approx \frac{d^2}{14.44} \quad (\text{units as above})$$

Many engineers feel that this will provide good order of magnitude permeability when the median grain diameter is known. The expression immediately above has, indeed, provided a measure of information which is at least several steps ahead of a wild guess toward reality.^{3,24,26,27} And the expression has been used to estimate the median particle size of water-borne particulates when particle cake permeability has been calculated using the Barkman-Davidson method.^{3,24,26}

Nonetheless, Kozeny's modified equation is not intended to be a substitute for actual permeability measurement. Nor should it be used as an accurate substitute for a Coulter counter when water-borne particle measurement is needed. Generally, its use is best confined to field tests, where an immediate assessment of the order of magnitude of permeability or particle size is required. It may also, by default, be the only means available at times when the cost of better test methods deters their use.

Application of Permeability Data to ReInjection Wells

Once the permeability of an injection zone is established, the application of the data to injection well performance may be carried out. The objective of an injection performance analysis is the development of the relationship between surface injection pressure and liquid injection rates. The explicit methodology for such an analysis is contained in studies funded by the Department of Energy through Sandia Laboratories^{28,29} and will not be repeated here.

Surface injection pressure can be expressed by the following summation:

Surface pressure = static reservoir pressure + pressure
resistance to radial flow + tubing friction pressure -
tubing column hydrostatic pressure.

Reservoir permeability affects only the pressure resistance to
radial flow. As well depth increases, permeability becomes less dominant in
the system.

To illustrate the influence of permeability in a medium depth
injection well, the following system parameters will be used:

well depth = 6,000 feet

static reservoir temperature = 180°F

reservoir static pressure = 2,600 psia

fracture gradient = 0.65 psi/ft.

wellbore radius = 5 inches

hydrostatic fluid gradient = 0.466 psi/ft at $T = 70^{\circ}\text{F}$

hydrostatic fluid gradient = 0.463 psi/ft at $T = 200^{\circ}\text{F}$

well spacing = 480 acres/well

reservoir interference radius = 2,580 feet

desired injection rate = 40,000 b/d

average formation permeability = 140 md

net vertical sand thickness = 180 feet

wellhead water temperature = 200°F

calculated water mass temperature²⁴ = 198°F

effective water viscosity in the injected water mass = 0.15 cp

Using the methods in references 28, 29 an injection well performance analysis (IWPA) can be constructed (Figure 27). Three flow strings are used, (1) 4-1/2" tubing, (2) 5-1/2" tubing, and (3) a 7" tieback string.

Surface pressures of about 1,200-1,500 psi would result in formation fracturing; thus, the smallest usable size flow string is 5-1/2" at an injection rate of 40,000 b/d. Using a 7" tieback string would reduce injection horsepower by about 60 percent.

If, after the well was completed, the results of pressure build-up or fall-off tests³⁷ showed that the actual permeability of the injection interval averaged 70 md, (50 percent of the expected value) the resulting well performance would be that shown in Figure 28. At $q = 40,000$ b/d, the surface pressure using a 5-1/2" flow string would be close enough to fracture pressures to require a small reduction in the injection rate. Otherwise stated, a 50 percent reduction in permeability did not result in a 50 percent reduction in well capacity.

If actual permeability were 50 percent higher than the expected permeability, or 210 md, the well performance shown in Figure 29 would result, and a modest reduction in surface pressures would be achieved.

Finally, if the actual permeability were one log cycle lower than expected and had a value of 14 md, then a drastic reduction in well capacity would result (Figure 30). At maximum sub-fracture surface pressures, well injectivity would be about 20,000 b/d.

These examples illustrate the sensitivity of permeability variations on one well of fixed dimensions. A wide-range sensitivity analysis model, such as the one developed by Sandia Laboratories for well drilling studies,⁴⁸ would be

INJECTION WELL PERFORMANCE FOR THE EXAMPLE WELL IN THE TEXT WHEN THE FORMATION PERMEABILITY IS EQUAL TO 140 MILLIDARCIES.

Figure 27

THE DASHED LINES INDICATE THE INJECTION WELL PERFORMANCE OF THE WELL IN FIGURE 27 WHEN THE FORMATION PERMEABILITY IS EQUAL TO 70 MILLIDARCIES.

Figure 28

THE DASHED LINES INDICATE THE INJECTION WELL PERFORMANCE OF THE WELL IN FIGURE 27 WHEN THE FORMATION PERMEABILITY IS EQUAL TO 210 MILLI-DARCIES.

Figure 29

IF THE PERMEABILITY OF THE WELL IN FIGURE 27 IS REDUCED ONE ORDER OF MAGNITUDE FROM 140 MILLIDARCIES TO 14 MILLIDARCIES, THE CHANGE IN WELL SURFACE PRESSURES IS SIGNIFICANT (ONLY THE 7" TUBING CURVE IS SHOWN).

Figure 30

valuable in providing rapid sensitivity analyses for injection systems, the value of which is illustrated in part in the example just presented. The implementation of such a model is beyond the scope of this report, but if serious consideration of spent brine reinjection costs is a genuine concern to the geothermal community, the model should be developed and made available at an early date.

Much, if not most of the technology required to construct the model is available, and includes:

1. Linear fluid flow equations
2. Single and multicylinder radial fluid flow equations
3. Fluid compressibility calculations
4. Interference and well spacing equations
5. Methods for evaluating clay swelling as an injection-reducing mechanism
6. Several methods which define the effects of water-borne particulates on injectivity
7. Methods to evaluate completion damage, and removal thereof
8. Methods to evaluate the effects of sand control by gravel packing or consolidation on injectivity
9. Scale and corrosion evaluation programs (EQUILIB)
10. Multiple well reservoir performance programs.

The suggested model would include, but not be limited to these items.

Sand Grain Size Distribution

When unconsolidated sands are encountered in injection reservoirs, core samples are a necessity for grain size distribution analysis if proper sand control measures are to be included in the well completion. Also, if grain-to-grain cementation in consolidated sands can be destroyed by acidizing or other chemical solubilization, or by mechanical failure due to thermal or other stresses, core samples are required for grain size distribution data.

The necessity for core samples exists because effective sand control, i.e., prevention of well impairment by partial or total fill of the wellbore by inflow of formation sand, requires a precise knowledge of the range of sand grain sizes in the disposal reservoir.^{9,57} A widely used method of sand control is called "gravel packing". Other methods are described in available literature,⁵⁷ and specific applications to geothermal and geopressure systems appear in publications funded by the Department of Energy through Sandia Laboratories.^{26,27}

One example of a gravel packed completion, the "open hole pack", is shown in Figure 31. Gravel (actually, carefully sorted sands of specified size) is pumped or circulated between the formation to be contained and a screen through which the gravel cannot pass.

The gravel is sized to block flow of formation particulates without unduly restricting fluid flow, and the retaining screen is sized to block the passage of any of the gravel. Because gravel size is uniform, there is no problem in selecting a wire-wrapped screen opening to assure retention of the gravel in the screen-wellbore annulus. However, formation sands range from very well sorted to very poorly sorted, and the selection of gravel to formation

AN OPEN-HOLE GRAVEL PACK IN AN UNDERREAMED WELL BORE, OFTEN USED IN POORLY CEMENTED SANDS. WHEN PROPERLY ENGINEERED AND INSTALLED, THE PRESSURE DROP CAUSED BY FLUID FLOW IS MINIMAL.

Figure 31

size ratio to control sand without undue restrictions to flow is more difficult, especially where sands are not well sorted.

Grain size distribution is measured by sieving dry sand from a core sample through a series of stacked sieves of specified meshes, with mesh openings decreasing in size from the top to the bottom of the stack of sieves. The sand retained on each screen is weighed, and the cumulative weight percent is tabulated against sieve size, and plotted on a sieve analysis graph.⁴⁷

Figure 32 is an example of a graph used to plot sand grain size distribution. Superposed on the graph are the boundaries of grain size descriptions from pea gravel to silt. Note that the grain diameter sizes increase in value from right to left on the abscissa. Grain size classification (U.S. standard method) is:

Classification	Size, mm.	Proximate Size, inches
Pea Gravel	2-4	0.08-0.16
Fine Gravel	1-2	0.04-0.08
Coarse Sand	0.5-1.0	0.02-0.04
Medium Sand	0.25-0.5	0.01-0.02
Fine Sand	0.125-0.25	0.005-0.01
Very Fine Sand	0.0625-0.125	0.0025-0.005
Silt	0.032-.0625	0.0012-.0025

Figure 33 shows a detailed sieve (or screen) analysis form of the type commonly used by commercial laboratories. To facilitate gravel pack size selection (discussed later) several standard U.S. Mesh sizes are identified on the abscissa of the graph in Figure 33.

To illustrate the wide range of sand grain size and sorting, three sieve analyses from different sedimentary oil reservoirs are shown in Figure 34.⁹ The Midway-Sunset (CA) sand grains are very poorly sorted, unconsolidated,

THE BASIC GRAPH USED FOR PLOTTING GRAIN SIZE DISTRIBUTION SHOWING SIZE RANGES FOR SILT THROUGH PEA GRAVEL. NOTE THAT THE ABSCISSA INCREASES IN NUMERICAL VALUE FROM RIGHT TO LEFT.

Figure 32

SIEVE ANALYSIS PLOTS FOR VERY POORLY SORTED SANDS (MIDWAY-SUNSET), POORLY SORTED (KETTLEMAN HILLS), AND WELL SORTED (LA GULF COAST) SANDS. (REDRAWN FROM COBERLY⁹).

Figure 34

with extreme grain sizes ranging from less than 0.01" to almost one-half inch in size. These sands are thick, and oil is produced from depths as shallow as about one thousand feet.

The Kettleman Hills (CA) sand grains are very fine to coarse, poorly sorted and poorly consolidated, and lie some 2,000-5,000 feet subsurface in the San Joaquin Valley (CA) about fifty miles north of the Midway-Sunset area.

The Gulf Coast (LA) sands shown in Figure 34 are well sorted, mostly very fine unconsolidated to poorly consolidated, and are very successfully controlled by gravel packs because they are well sorted. These sands vary in depth from about 6,000 feet to 8,000 feet in the offshore Louisiana area.

Most reliable grain size data are obtained from samples taken by conventional coring. However, where the need is the greatest, (unconsolidated sands) conventional core recovery may be the poorest. This has presented problems which have necessitated alternate, but less precise sand grain size distribution data gathering techniques to be developed.

Sand Grain Size Distribution Using Side Wall Samples

Because of the relatively poor recovery when conventional core barrels are run in unconsolidated sands, side wall samples are often used to obtain sand grain size data.⁵⁷

As stated previously in this report, side wall samples cause sample crushing and some sand grain fracturing. Figure 35 shows typical data scatter obtained when correlating whole core median grain size and side wall sample median grain size for Louisiana Gulf Coast Sands. Most data points would be

CORRELATING SIDEWALL SAMPLE AND CONVENTIONAL CORE MEDIAN GRAIN SIZE MEASUREMENTS GENERALLY PRODUCES DATA WHICH REFLECTS GRAIN SIZE REDUCTION CAUSED BY IMPACT OF THE SIDEWALL SHOT.

Figure 35

found to lie below the 45° line of agreement, indicating that crushing of the samples occurs in the side wall cores. A linear regression analysis of the data shown indicates that Pearson's coefficient (R) is too low in value for a reliable least squares correlation. Perhaps the significant conclusion from this type of data is that it is not difficult to demonstrate the results of side wall sample crushing, but it is difficult to quantify the effect, other than to make a correction in the proper direction when selecting gravel size from side wall sample data. If no correction is made, gravel sizing will be somewhat conservative.

Sand Grain Size Distribution from Bailer and Surface Samples

Another method upon which some Gulf Coast oil and gas operators rely for grain size data when whole cores are unavailable is noteworthy. Although the technique to be described has not been subjected to rigorous technical scrutiny, operators who use it claim that it is successful.

The method involves bailing samples from sanded-up wells where no sand control exists, and sieving the bailer samples. Also, samples are removed from surface equipment (tanks, meters, etc) and sieved. The operator then "eyeballs" a line from the upper tip of the fine sand sieve plot (surface samples) to the lower tip of the coarse sands sieve plot (bailer samples), and sizes gravel packs using the resulting curve (Figure 36). The logic which supports this is that the bailer samples are too large to be carried to the surface, but when "blended" (on the sieve plots) with the smaller sands which are produced to the surface, the results are satisfactory. For reasons not stated, the operators who use this method feel that this gives better results than

AN ILLUSTRATION OF THE BAILED SAND-SURFACE SAND DATA "BLENDING" TECHNIQUE USED BY SOME OPERATORS TO PROVIDE GRAIN SIZE DISTRIBUTION ANALYSIS.

Figure 36

mixing and sieving combined bailer and surface sand samples. This method is presented to illustrate a technique which might be worthy of consideration if no other data are available.

Application of Grain Size Distribution Data

Until the early 1970's, most methods for sizing sand control gravel packs were similar to the technique developed by C.J. Coberly in 1937.⁹ Because Coberly's work related principally to the control of sand produced from poorly sorted formations, Coberly's methods tended to oversize gravel pack grain size in fine, well-sorted sands.^{50, 57} Oversized gravel affords poor sand control, especially where formation sands are well sorted. The research necessary to modify Coberly's data to provide effective sand control in the Texas and Louisiana Gulf Coast (and other well-sorted sandstones) was undertaken by, and published by R. J. Saucier.⁵⁰ The landmark SPE paper by Saucier has provided the oil industry with a gravel sizing specification which works equally well in well or poorly sorted sandstone reservoirs.

Saucier developed mathematical models and constructed radial and linear flow physical models which, after several years' of effort, demonstrated that (1) gravel-to-sand ratios should be established using median gravel and median sand grain size values, and (2) effective, non-impaired sand control is best accomplished when the gravel median grain size is 4 to 6 times formation sand median grain size.

Figure 37 illustrates the composite findings of Saucier's physical model experiments. Of special importance are:

(1) Effective sand control is achieved when the median gravel size is 4 to 6 times the median formation grain size.

SAUCIER'S DATA WHICH INDICATE THAT A MEDIAN GRAVEL/SAND SIZE RATIO OF 6:1 SHOULD NOT BE EXCEEDED TO INSURE UNIMPAIRED GRAVEL PACKS (REDRAWN FROM REFERENCE 60).

Figure 37

(2) If this ratio is reduced, sand control is effective but resistance to fluid flow increases because the gravel pack permeability is reduced.

(3) If the gravel/sand ratio is larger than six but smaller than about 14, sand control will be achieved, but a high pressure drop will occur across the gravel pack because of deep invasion of sand into the gravel pack and the resulting impairment of the gravel pack.

(4) If the gravel/sand ratio exceeds about 14, no sand control takes place; neither does gravel pack impairment occur because of unrestricted and complete passage of the sand grains through the gravel pack.

This information provides reliable guidance for gravel packing wells. In North America, most operators use a U.S. Mesh-sized gravel. Representative data for this sizing standard are:

U.S. MESH	DIAMETER RANGE, INCHES	MEDIAN DIAMETER, INCHES
40/100	0.006-0.017	0.012
40/70	0.008-0.017	0.013
40/60	0.010-0.017	0.014
20/40	0.017-0.033	0.025
16/30	0.023-0.047	0.035
12/20	0.033-0.066	0.050

Figure 38 shows an example formation sieve analysis and a 20/40 U.S. Mesh commercial oil well gravel sieve analysis which comply with Saucier's sizing ratio. When using this method, exact "fits" are not always possible; then the general rule is to go to the next smaller gravel size.

When poorly sorted sands are encountered, the method of Saucier (or Coberly) results in some pass through of fines until a bridge layer of larger sand grains is established, after which total sand exclusion takes

AN EXAMPLE OF THE METHOD FOR SELECTING GRAVEL SIZE FOR SAND CONTROL USING SAUCIER'S SIZING RATIO.

Figure 38

place by trapping the fines on the bridge grain layer.⁵⁰ Under this type of operation, intermittent flowing of a producing well necessitates the re-establishment of a bridge layer each time the well is returned to production, and continuous well operation is set as a goal to eliminate the intermittent production of small amounts of reservoir fines.

With injection wells, problems arise with gravel packs which are not encountered in producing wells. Although proper gravel/grain sizing is successful in maintaining sand control, the gravel pack is subject to impairment by particulates entrained in the injected fluids. Particles which pass through the gravel pack, if they bridge out on the surface of the formation face, will back-build through the gravel pack and cause high resistance to fluid flow. For optimum long-term injection well operation, particles entrained in the injectant should be sized so that they pass through the gravel pack and then enter the formation in the deep invasion mode.²⁸ However, this may not be the most cost-effective method of operation, and the development of an injection well simulator (see earlier section, "Application of Permeability Data to ReInjection Wells") may be required to evaluate this problem.

Until such a simulator becomes available to provide a broad sensitivity analysis capability, one example of the effects of gravel pack impairment in a reinjection well can be developed to illustrate the value of such analysis. For this example, the well parameters will be those specified in the section "Application of Permeability Data to ReInjection Wells" which appears earlier in this study.

Using Darcy's radial flow equation, the injection rate (at $k =$

140 md) can be calculated to be about 54,500 b/d when the bottom hole injection pressure is 3,000 psia, assuming a 10 inch diameter wellbore. If the hole is underreamed to a 20 inch diameter and open-hole gravel packed with 20/40 U.S. Mesh gravel, injection increases to about 60,000 b/d. This can be calculated using the two cylinder, bounded, radial viscous laminar flow equations developed previously for Sandia Laboratories in reference 28 (the permeability of the gravel pack is about 100 Darcy units).⁵⁷

If the gravel is oversized and is impaired by formation sands, pack permeability will be reduced to about thirty percent of its original value (Figure 37). The effect on injectivity is trivial, and amounts to a decrease in flow rate of a fraction of one percent as long as laminar flow is maintained through the gravel pack.

However, if solids in the injection water bridge on the formation face and back-fill into the gravel pack, the effective permeability of the impaired pack can be reduced to a value of 20 or 30 md. Then, injection rates will decrease to about 40,000 b/d; then, this type of pack impairment causes injectivity decreases which are significant.

Neither of these permeability reductions are as severe as would be encountered by sand fill in a well of the geometry specified in the example. This effect is illustrated in a recent field test of an East Mesa (CA) injection system, conducted for Sandia Laboratories. The test results contain specific information describing the effects of wellbore fill on injection capacity.²⁶

Also, Suman⁵⁷ reports that in gravel packs through cemented and perforated casing, impairment of oversized gravel by formation sands can

produce unacceptably high pressure drops when flow rates through impaired, gravel-filled perforation tunnels are in a turbulent flow regime. Observations such as these reinforce the need for an injection well performance simulator.

Permeability Reduction Caused by Hydration or Dispersion of Clays and Shales

Clays are broadly defined as earth materials which become plastic when they are wet, and which consist (essentially) of hydrated aluminum silicates or aluminometallic silicates. Shales are consolidated clays in a fissile structure. Fully developed shales do not soften when immersed in water. The clays most frequently found in sedimentary deposits are montmorillonite (bentonite), illite (including glauconite and mica), kaolinite (hydrated aluminum disilicate) and chlorite (ferromagnesiumaluminum silicate).

In the Texas and Louisiana Gulf Coast, where geopressured wells are being drilled and evaluated, montmorillonite prevails to depths of about 7,000 feet, and diminishes in quantity to depths near 17,000 feet. The montmorillonite is present both as shales and as discrete, lesser constituents of sedimentary sandstone sections.⁶¹

Montmorillonite appears widely in sedimentary sandstones, world-wide. This is significant because of the clays - - montmorillonite, illite, kaolinite and chlorite - - only montmorillonite swells substantially by absorbing ordered water layers in its structure (although some clay mineralogists assign a slight degree of hydrolysis to illite).¹⁶

All clays, when contacted by a foreign water, will undergo some amount of dispersion. This liberates otherwise undetached clay particles which migrate in flowing fluids and are capable of plugging pores and pore throats.

In addition to the dispersion phenomenon, montmorillonite can swell to several times its volume (unconfined) when fresh, brackish, low ionic strength or alkaline waters are absorbed in this clay.

Permeability reduction of clay-bearing sandstones occurs because of clay dispersion, montmorillonite swelling, or both. X-ray diffraction analysis can indicate the types and approximate concentrations of clays in a core sample, but X-ray diffraction does not provide any information about the location of the clays in the rock matrix. Usually, the position of the clays in the rock is determined by the use of selective dyes and specific chromophores combined with microscopic examination.¹⁸ Thin section microscopy, discussed later in this report, is also used to ascertain the distribution of clays in a rock matrix.

Clay swelling is generally reversible; the clays will slowly return to their original equilibrium size if a water of pH and ionic strength equal to the original connate water's pH and ionic strength displaces and replaces the foreign water which caused the swelling. Also, strong acids, alcohols, and some ketones are capable of removing the effects of clay swelling very quickly (within a few hours).

Measuring the Effects of Clay Dispersion and Swelling

Two basic laboratory tests are generally used to study the effects of foreign waters on clays; measured are (1) the degree of clay swelling, and (2) permeability reduction due to the combined effects of dispersion and swelling.

The degree of clay swelling is measured by first drying and crushing two core samples of about 100 grams weight each. One sample is placed in a

graduated glass (such as a centrifuge vial) containing connate water. The second sample is placed in an identical vial filled with the foreign water. Both samples are stirred with a glass or plastic rod and allowed to stand for one or two days. The volumes after standing are compared, and the clay swelling is reported as a percent increase in volume of the sample exposed to foreign water over the volume of the sample exposed to connate water. This test is a "yes-no" type test, and only establishes the presence or absence of clay swelling. The value of the number describing clay swelling cannot be used to predict well behavior.

If clay swelling is observed, the second test usually follows. This test uses the conventional core flow apparatus, described in the earlier section "Measuring Permeability in the Laboratory" (Figure 39) and the test is structured to compare the permeability of a core established by flowing connate water to the permeability of a similar core while flowing foreign water. This test produces values which can be entered into radial flow well simulation models which predict injection capacity. Also, unlike the swelling test, the core flow test can differentiate between permeability reduction caused by dispersed clay particles and clay swelling using the core flow direction reversal procedure, described in "Measuring Permeability in the Laboratory".

The "foreign" waters reported in most of the literature are mud filtrates, completion fluids, fluid loss from cement slurries, gravel pack slurry water, frac water, and other fluids which may contact the formation.^{18,30,40,42,56,60}

Also, most of the problems which have been investigated are related to producing oil and gas wells, and much of the literature presents solutions to correct damage in zones which are localized near the wellbore. While this

1. PRESSURE BOTTLE AND REGULATOR
2. INJECTION WATER SAMPLE CONTAINER
3. FILTER
4. PROPORTIONING FLUID PD PUMP
5. PUMP BYPASS
6. CORE HOLDER
7. CORE INFLOW PRESSURE GAUGE
8. CORE OUTFLOW PRESSURE GAUGE
9. FLOW CONTROLLER WITH BYPASS
10. GRADUATED CYLINDER FOR VOLUMETRIC MEASUREMENT

CORE FLOW TEST APPARATUS ARRANGED TO PROVIDE EITHER CONSTANT UPSTREAM PRESSURE TESTS OR TESTS AT A CONSTANT FLOW RATE. NOT SHOWN IS EQUIPMENT WHICH PROVIDES CONSTANT TEMPERATURE CONTROL, USUALLY EITHER HEATER STRIPS OR IMMERSION SYSTEMS

Figure 39

is important to injection well completions, it does not provide the user with the effects of massive permeability reduction in the reservoir caused by sustained injection of waters which swell or disperse clays.

Clay problems are numerous and diverse in nature; no single approach of the problem can correct all conditions encountered in practice. One example of the magnitude of clay swelling is illustrated in Figure 40. This presents core flow test data relating swelling-induced reduction in permeability of very fine sand in East Bay, offshore Louisiana,⁵⁷ to water salinity. These East Bay sands contain up to 20 percent clays, predominantly sodium montmorillonite. This type of information has dictated that aqueous workover fluids be treated to have a minimum salinity of at least 50,000 ppm in East Bay.

Figure 41 shows permeability reduction of a Frio (Miocene) sandstone, containing some 8 to 10 percent montmorillonite, when connate waters (total dissolved solids about 120,000 ppm) are displaced with a weaker brine (tds about 50,000 ppm). Reverse flow confirmed that the permeability reduction was caused by clay swelling, not clay dispersion. (This information was obtained from public records, the Texas Department of Water Resources, Austin, Texas).

In core flow tests such as this, the effects of the reversal of clay swelling can be studied. Also, chemicals which can adsorb on clay surfaces to prevent clay swelling (such as the widely used hydroxy aluminum series of retardants) are often evaluated in core flow tests after preliminary screening with the two-vial swelling test.

FRESH WATER DAMAGE TO EAST BAY SANDS (OFFSHORE LOUISIANA) PERMEABILITY. (REDRAWN FROM REFERENCE 57).

Figure 40

AN EXAMPLE OF PERMEABILITY REDUCTION IN A MIOCENE SAND OBSERVED WHEN WATER HAVING AN IONIC STRENGTH OF ABOUT 40 PERCENT OF THE CONNATE WATER'S IONIC STRENGTH CAUSED CLAY SWELLING. (DATA FROM TDWR PUBLIC RECORDS).

Figure 41

Evaluating the Effects of Massive Reservoir Permeability Reduction Caused by Alteration of Clay Structure

When injected waters swell or disperse clays, these phenomena occur throughout the portion of the reservoir where the injected water flows. In laminar reservoir flow, an almost complete displacement of connate water by injected water takes place. Dispersed clay particles are carried away from the wellbore, and because available pore space increases as the square of the distance from the wellbore, the severe impairment by dispersed clay particles, so often observed in radially inflowing producing wells, does not always occur. However, clay swelling which causes permeability reduction can be expected to occur uniformly throughout the portion of the reservoir swept by the injected water.

In order to examine the influence of reservoir permeability reduction caused by clay swelling, the example well described in the section of this report "Application of Permeability Data to Injection Wells", can serve as a basis for predicting injection performance. Using the two cylinder model (Reference 28) which simulates laminar radial, viscous fluid flow through concentric cylinders of different permeabilities, and assuming that the volume of the reservoir contacted by injected water reduces the formation permeability uniformly from 140 to 70 md, these data are calculated for an injection rate of 50,000 b/d:

Total Injection Time, Years	Injection Front Radius, feet	Bottom Hole Pressure Required to Inject at 50,000 b/d, psia
0	0	2,979
1	776	3,400
5	1,735	3,432
10	2,053	3,442
20	3,470	3,444

The difference between the calculated initial and final surface injection pressures is 465 psi, most of which occurs in the first year of operation. The result of the clay swelling is that an additional 380 $\pm$ hydraulic horsepower would be required for each well for most of the 20 year project life.

If horsepower were fixed, the injection rate would decline as the injection front advanced. Using the same well specifications, and fixing available bottom hole pressure at about 3,000 psia, the injection rate would decline to about 60 percent of the desired rate of 50,000 b/d in one or two years.

Thus, if the surface injection pressures were fixed by statute or permit, additional injection wells would be required unless clay swelling could be economically controlled by treating the water with chemical inhibitors which could prevent or reduce clay swelling.

Injection well behavior often requires case-by-case evaluating, and it is generally agreed that the effects of clay alteration requires careful attention with emphasis on the acquisition of reliable core flow test data, supported by techniques such as scanning electron microscopy and thin section petrography. Special attention is directed to reference (42) which contains in-depth studies of special interest to operators and engineers working with injection of spent brines into sandstones which contain clays or shales.

The Role of the Scanning Electron Microscope in Water Injection

The scanning electron microscope (SEM) functions by projecting an electron beam at a target through a series of magnetic focusing lenses and recording the pattern of secondary electrons which the primary beam excites. The secondary emission provides a topograph of the specimen. High topography, i.e., sections of the target close to the primary beam, emit a larger number of secondary electrons than points which are topographically low. This provides image contrast and resolution. Unlike optical microscopes, bottom illumination of thin specimens is not possible with the SEM, nor is it possible to distinguish colors with the SEM. The SEM provides only the surface morphology of rocks. However, the extraordinary surface detail provided by the SEM offsets the apparent disadvantages of lack of color identification or bottom illumination.⁴² The resolution, depth of focus, rock texture and porosity detail obtained with the SEM surpasses results provided by optical microscopes.

The SEM analysis can be performed on small rock fragments, chips, drill cuttings, cores and thin sections. Because clays have distinctive shapes and sizes, clay distribution and morphology can be better defined. The SEM provides data on rock microporosity, that is, porosity less than 1 or 2 microns, which may not be visible under ordinary microscopic examination.

Usually, the exposed surfaces of the rock sample are coated with a 50 to 100 Angstrom Unit (Å) thickness of carbon or a palladium-gold alloy for SEM analysis. Another popular alloy coating consists of 90 percent

platinum and 10 percent paladium; this alloy can provide coatings of thicknesses up to 500 Å. The purpose of coating samples is to suppress space charge buildup which would cause unwanted diffusion of the image. Recent studies have shown that some rocks with high innate electric conductivity can be used for SEM analysis without surface coatings.⁴²

Plate 1, Page 113, illustrates photomicrographs of sand with clay fractions. The sand has been characterized through the combined use of the SEM and the EDS (energy dispersive system) attached to the scanning electron microscope. The EDS enables spot analysis and identification of crystal components of the rock sample.

For injection systems, the value of having SEM photomicrographs of the injection zone rock prior to exposure to injection waters should be apparent, both for bench-scale core flow tests prior to an injection system's actual operation, and for trouble shooting after injection begins. Discrete particle deposition by injection water contaminants can be observed, and acidizing or hydrodynamic removal of particles can be studied. The occurrence and magnitude of pore size alteration by dispersed clays or by scale precipitation can be examined carefully. Flow-reducing phenomena such as pore lining or pore bridging can be unmistakably recognized.¹⁷ Development of a secondary microporosity through partial solubilization of rock constituents by injected waters can be identified.⁴⁵

Combined with core flow tests, the potential effectiveness and utility of the SEM is thought to be substantial.

At this writing, the reported use of the SEM in geothermal (and

Scanning Electron Microscope (SEM) photomicrographs of sandstone sample showing details of diagenetic montmorillonite clay coating sand grains and "bridging" across intergranular pores to restrict fluid flow (i.e., low permeability). Note leached grain (center of D) and resultant secondary porosity. The "smooth" pore-filling material in upper right of photo D is interpreted to be in part amorphous silica (glass?). $\Phi = 21.7\%$, $k_a = 1.9$ md.

(SEM photos and geological interpretation provided by Reservoirs, Inc. of Houston, Texas)

other) water injection well analysis is very sparse. But where SEM has been used, such as in Lawrence Livermore Laboratory's study of Imperial Magma's injection system at the Niland (CA) KGRA,⁴⁵ the data obtained provided insight to injectivity problems not otherwise accessible. Lack of core availability, a fundamental deficiency in much of the geothermal work to date, has been a deterrent to the use of SEM technology in reinjection systems.

Also contributing to the sparse use of SEM for injection systems is the popular belief that the SEM is primarily a geological or reservoir evaluation tool. This is the same type of thinking which delayed the use of pore size distribution measurements in water injection systems engineering (mentioned earlier in this report); perhaps demonstrated utility of SEM in water injection systems will alter this.

One purpose for preparing this report is to encourage geothermal operators to recover more cores and to use the techniques herein, where applicable, to reduce the total cost of spent brine injection; hopefully, the use of SEM will expand and provide useful information to the geothermal community.

The Preparation and Use of Thin Section Rock Specimens

The "thin section" has been mentioned several times in earlier sections of this text. Thin section microscopy is a technique whereby a rock sample from a drill cutting, sidewall sample, or a whole core is rendered uniformly 30 to 60 microns thick, so that the finished sample can be microscopically examined and photographed with bottom or top illumination.

The main objectives of thin section analysis (TSA) in water injection wells are (1) characterization of the rock, (2) determination of pore morphology, (3) distribution and position of clay minerals relative to the pore space, (4) distribution and position of water-borne particulates, and (5) occurrence and characterization of mineral scales precipitated within the rock matrix:^{1,18,61}

Thin section preparation varies somewhat among laboratories but basically the preparation is as follows:

- (1) Cut a section of the rock sample to about 0.25 inch thickness, with the cut oriented in a direction transverse or axial to plumb, as desired.
- (2) Impregnate the cut section with a colored, plastic (blue is often used) to enable visual identification of the effective pore network. (Note: This is an optional step, depending on the requirements to be met. Often, the plastic used is an amine-cured epoxy).
- (3) Lap either cut face on successively finer grades of carborundum, finishing with very fine grade.
- (4) Cement the lapped face to a glass slide. Amine or polyamide-cured epoxy is often used for cementing. The cement must be transparent after drying.
- (5) After the cement hardens, saw the sample to a thickness of about 1 mm, with the saw cut parallel to the glass mounting.
- (6) Grind the exposed face of the sample against a diamond lap wheel to a thickness of 30 or 40 microns. Automated, vacuum-chuck grinders are often used for this.
- (7) Hand-finish the surface of the rock against plate glass.

The resulting specimen is ready for microscopic examination and TSA. Generally, the thin section can provide information which compliments the observations from SEM-EDS analysis. Solubility of foreign matter in the thin section by acidization can be at least qualitatively determined by using very small syringe needles dipped in acid to probe the specimen while observing the process through a microscope. TSA specialists using syringe needles can dislodge foreign particles for further analysis. Comparisons of thin section taken before and after injection, or before and after simulated well stimulation are capable of providing valuable insight to injection problems and proposed solutions to problems. The expense involved is a fraction of the cost of experimenting with the injection well, and bad choices for remedial measures damage only rock samples in the laboratory, not the well.

Plate II, Page 117, illustrates thin section photomicrographs (original photographs are in color). Sands and argillaceous materials are characterized, and effective pore space (light blue) is easily recognized. The sandstone illustrated is characteristic of several Gulf Coast Miocene sands, such as might be used for geopressured methane-recovery project disposal systems. The sands shown have not been subject to any contamination from water injection, and it is apparent that the occurrence of mineral scales or plugging by water-borne particles would be easily detected.

Thin section photomicrograph of sandstone sample showing well developed, intergranular pore space (blue areas) and sand grains containing grain-coating clays (brown rims). Porosity = 21.7%; Air Permeability = 87 md. Plane light; 128X.

Thin section photomicrograph of central portion of sandstone area shown above. Note sand grains with grain-coating, brownish clay rims and associated intergranular pore space. Rectangular grain at right portion of photo is feldspar. Plane light; 512X.

Testing Unconsolidated Cores for Application and Durability of Plastic Consolidation

One alternate to gravel packing for sand control is to consolidate the sand around the well. In principle and practice, this is attractive because part of the formation which would cause sand problems is transformed into an immobilized yet permeable cylinder around the wellbore.

Most sand-consolidating processes currently in use employ high-purity epoxy, phenolic, or furan resins with acceptable resistance to oil, water, and most well treating chemicals. The resin is injected into the unconsolidated sand as a solution, from which a limited amount of solidified resin is caused to remain at the sand grain-to-grain contact points at the end of the consolidation process (Figures 42,43).

Sand consolidation processes have been designed for use in oil or gas condensate wells, where the solidified resin is wetted with crude oil or gas condensate during the useful life of the well. An unplanned result of sand consolidation chemistry is that designing resins for hydrocarbon exposure produced resin systems which deteriorate to varying degrees when exposed to water. Methods for testing deterioration of consolidated sands have not been standardized, so comparisons of suppliers' data may be misleading. Nonetheless, systems are available which provide sufficient compressive strength for use in most water-wetted environments to temperatures of about 200⁰F (epoxies) to 350⁰F (phenolics and furans).

The ability to produce a satisfactory sand consolidation also depends on the amount of clay materials present in the formation. G.O. Suman has prepared tabular information which specifies limits of applicability, such

A SCHEMATIC OF THE RESIN SYSTEM FOR CONSOLIDATING SANDS. MULTIPLE PREFLUSHES ARE OFTEN REQUIRED.

Figure 42

THE OBJECTIVE OF SAND CONSOLIDATION IS TO CEMENT SAND GRAINS (HATCHED) AT GRAIN CONTACT POINTS WITH A RESIN (BLACK) LEAVING ADEQUATE EFFECTIVE POROSITY (WHITE).

Figure 43

as clay content and useful temperature range; the interested reader is directed to reference (57) for these and other data on sand consolidation chemistry and application.

Essential to effective sand consolidation is even distribution of the resin solution over the whole section to be consolidated. Depths of consolidation range from two to four feet from the well center. Also, the final resin distribution should be such that the permeability retained after consolidation exceeds about 50 percent of the sand's original permeability, with higher values preferred.

Initial compressive strengths after consolidation in the low thousands of pounds per square inch range are normally achieved. Compressive strengths needed to prevent failure of consolidated sands due to formation stress and fluid flow have not been determined, and it appears sufficient to use the stated initial compressive strengths to allow for a large margin of deterioration.

Plastic consolidation systems developed in the late 1950's and early 1960's suffered significant long-term deterioration when exposed to water. This was found to be caused by water being drawn between the resin and the sand by capillary forces. Coupling agents, such as silanes, were added to the resin solutions to create a chemical bond between the resin and the sand, and couplers are now in widespread use, and are generally very successful.

Sand consolidation technology is in hand, and the question of the applicability of sand consolidation to spent brine injection wells has been posed.

Current literature indicates that sufficient test data have been

provided to state.*

(1) Prolonged exposure of consolidated sands to hydrocarbon systems causes little decrease in the compressive strength of the sand.

(2) Prolonged exposure of consolidated sands to brines and fresh water causes significant decreases in the compressive strength of the sand, but coupling agents provide consolidation with an acceptable (but low) compressive strength.

(3) Sands with clay contents up to 20 or 30 percent can be consolidated.

(4) Epoxy resins and furan resins work up to temperature of 200°F and 350°F, respectively.

(5) Brief exposure (24 hours or less) of consolidated sands to HF acid causes serious strength degradation of consolidated sands. Most operators avoid using HF in consolidated wells.

(6) Prolonged exposure (6 months) of consolidated sands to HCl is required to degrade the strength of consolidated sands to an unacceptable level.

The question which remains concerns the effects of long term exposure of resin consolidated sands to spent geothermal/geopressured brines. No work on this specific subject has been found in literature. However, a review of the types of waters tested to date suggests that no special problems should arise. But other experiments with geothermal brines have produced unexpected results, and it would be considered prudent to undertake a few exploratory

* Reference (57), and literature cited therein.

experiments with core and water samples gathered from existing geothermal/geopressured spent water injection systems. Tests no more complicated than measuring compressive strength changes at prolonged brine exposure times should provide insight to whether geothermal brines present any special problems in sand consolidation. Oil field well treating companies such as B.J., Dowell, and Halliburton have the equipment necessary for this testing, and one of these companies has expressed an interest in carrying out initial exploratory tests, on a funded basis.

Until the basic question has been answered, justification for other studies does not appear to be warranted.

The Effect of Sand Consolidation on Injectivity

Sand consolidation reduces permeability around the wellbore in an irregular cylinder averaging about six feet in diameter. As stated earlier, permeability reductions as much as 50 percent have been measured in resin consolidated sands. The minimum permeability reduction experienced is about 10 percent. These effects are easily evaluated using the two-cylinder radial flow model referenced earlier.

Using the same well contained in the section of this report "Evaluating the Effects of Massive Reservoir Permeability Reductions Caused by Alteration of Clay Structure", the effects of sand consolidation on injection rates can be assessed.

The basic well specifications are repeated for clarity:

well depth = 6,000 feet
reservoir static pressure = 2,600 psi
wellbore radius = 5 inches
hydrostatic fluid gradient = 0.466 psi/ ft at T = 70°F

well spacing = 480 acres/well
desired injection rate = 50,000 b/d
net vertical sand thickness = 180 feet
formation permeability = 140 md
effective water viscosity = 0.15 cp

then, the following are specified:

radial depth of sand consolidation = 3 feet from well center
permeability of consolidated sands = 70 md

With these specifications, the added wellbore injection pressure (also surface pressure) due to the sand consolidation required to maintain injection at 50,000 b/d is about 90 psi. This is caused by the reduction in permeability of 50 percent in the consolidated collar around the well. The 90 psi pressure increase requires about 77 hydraulic horsepower over the pump horsepower required without consolidating the sands. Otherwise, injection rate would be reduced to about 41,000 b/d without the added pump power.

If the permeability of the consolidated sands were only reduced by 10 percent of the original permeability, then an additional 10 psi pumping pressure, or about 8 hydraulic horsepower would be required to maintain an injection rate of 50,000 b/d. Without this added pump pressure, the injection rate would be reduced to about 48,800 b/d.

Since permeability reductions caused by sand consolidation are more likely to be near the 10 percent value than the 50 percent value, the magnitude of the additional horsepower requirement does not appear to be excessive.

Evaluating Formation Damage Using Core Flow Tests

In the oil and gas industry, new drilling muds, completion fluids, frac fluids, corrosion and scale inhibitors, injected waters, and almost every other fluid system to which the formation would be exposed are examined for their effects on reservoir permeability and porosity changes.* These tests are lumped together in the industry as "damage tests". Most damage tests are conducted using linear flow through cylindrical core plugs, usually about 1 inch in diameter and 2 to 4 inches in length using the now familiar core flow test apparatus. On occasion, radial flow physical models are used,^{1,50} but their expense and the time-consuming complexity of their operation precludes their widespread use.

It is customary to flow several hundred pore volumes through the core, simulating operational velocities, temperatures and pressures. Permeabilities are measured throughout the test, and when indicated reverse flow to remove damage is attempted and evaluated.

Total agreement on interpretation and application of linear flow damage tests does not exist. Generally, most experimenters concur that the core damage tests provide at least a ranking of damage by the various fluids tested, and it is also generally accepted that examining the damaged core provides reliable information regarding clay swelling, distribution of foreign particles, and degree of permeability reduction. And, properly applied, this information has consistently provided effective guidelines for avoiding moderate to catastrophic well damage.

* References, 1, 2, 10, 11, 16, 17, 18, 30, 31, 38, 39,40,42, 45, 51,56 and 60

The interpretation and application of the data poses a problem because producing or injection wells are cylindrical radial flow systems, but most core damage tests are linear flow systems. To illustrate the problem of direct application of core flow data, consider the well which has been used as an example in the sections preceding this portion of this study. This example well has a 10 inch diameter wellbore, a net injection interval thickness of 180 feet, and a porosity in the range of thirty percent. At the end of one day's injection at 50,000 b/d, the injected water front has advanced to a position about forty feet from the wellbore center. After injecting 50,000 barrels of water, the flow through the first 3 inches of formation adjacent to the wellbore exceeds 6,000 pore volumes. At a distance of one foot from the well center line, about 3,000 pore volumes have been injected in the same time period through a 3 inch flow path.

At a distance of five feet into the formation, the pore volumes swept through 3 inches is about 600, decreasing to a value under 200 at a distance 15 feet from the well center. This introduces a dissimilarity between flow in the well and in the damage test. The pore volume in the water flow path increases as the distance from the point of water entry into the well increases, but remains constant in the linear core flow test. Accordingly, superficial water velocity in the well decreases as distance from the well center increases, but water velocity is constant in the core test.

These facts are well known to those involved with core flow damage tests (bear in mind, these shortcomings do not prohibit direct application of permeability, porosity, pore size distribution, bulk density, grain size distribution, clay swelling, or consolidation data). To avoid misapplication of data

gathered from core flow damage tests, core plugs have been deliberately sized to a length of about three inches. Figure 44 illustrates the comparative geometries of a section of a core cut to represent a one inch thick slab of the reservoir (measured perpendicular to the bedding plane) with three inches of penetration into the formation when the wellbore diameter is ten inches, and a "conventional" one-inch diameter cylindrical core plug three inches long. The ratio of the downstream to inlet areas of the "pie cut" slab is about 1.56:1, and pore volumes at these faces would be proportioned according to this ratio. With the cylindrical plug, of course, the pore volume is consistent throughout a uniform core plug. Most experimenters feel that the effect of a 1.56:1 (or so) pore volume change in a three-inch flow path in the actual well is small enough so that effects of damage very close to the wellbore face can be simulated with tests using the cylindrical core plug. The same experimenters would question the direct application of data using linear flow through cores three or four feet in length, such as might be used to study deep invasion of water-borne solids into reservoir rock. As will be discussed later, phenomena such as invasion of particulates is more often examined through mathematical models or by the application of empirical correction factors to transfer linear flow data to radial flow geometry.

The logic which supports the direct use of short cylindrical core plugs for shallow damage tests is based, in part, on the observations over the years that depth of damage is inversely proportional to severity of the damage. Otherwise stated, damage which would seal off a rock face with a flow of six or eight pore volumes would restrict or shut off flow, thus confining the damage to thin penetration into the core. And whatever would flow through the core

THE COMPARATIVE GEOMETRY OF A RADIAL FLOW CORE SECTION (UPPER AND MIDDLE) AND A "CONVENTIONAL" CYLINDRICAL CORE PLUG. THE RADIAL FLOW CORE IS DRAWN TO THE DIMENSIONS OF THREE INCHES OF PENETRATION INTO A FIVE INCH RADIUS WELL, CUT TO A ONE INCH (VERTICAL) FORMATION THICKNESS.

Figure 44

for hundreds of pore volumes with modest permeability reduction would probably cause lesser damage deep in the formation where larger amounts of pore space are available for the flowing fluid.

Application of Core Flow Damage Test Data

Most core damage tests are structured to meet specific requirements and a review of the large suite of test data in the literature is beyond the scope of this report. But to illustrate the flexibility and value of core damage tests, three tests based on work by J.H. Barkman et.al⁶⁰ will be discussed.

Figure 45 illustrates the data taken from a series simple flow tests through a sandstone core where permeability changes with pore volumes of flow are measured using East Bay (LA) "brown water" containing various amounts of bay water particulates. The solids in the bay water in the brown water region are silts, decaying marine matter and marine macroorganisms. Collectively, they appear as a lightly flocced solids system. The bay water, untreated, was being mixed with gravel and circulated to the wellbore to position gravel packs. Pack impairment resulted, and Barkman's tests served to provide filtration guidelines for the use of water nearly free of suspended solids. Pack impairment decreased markedly where the filtered water was used to place gravel packs in subsequent operations.

Although not reported by Barkman, the damage to the cores tested in this series of experiments was easily removed by unrestricted reverse flow through the core. The flocced character of the solids caused surface filtration to take place on the core face, with a well-defined layer of solids deposited on the core inlet surface. However, when reverse flow was restricted by gravel, the impairment was not reversible.

MEASURED PERMEABILITIES OF A CYPRESS SANDSTONE CORE PLUG PLOTTED AGAINST PORE VOLUMES OF WATER THROUGHPUT FOR EAST BAY (LA) WATERS OF VARYING SUSPENDED SOLID CONTENT (SHOWN IN PARENTHESES). UNDAMAGED CYPRESS SANDSTONE PERMEABILITY IS 450 MILLIDARCIES (REDRAWN FROM REFERENCE 60).

Figure 45

Figure 46 illustrates the results of flow tests in which an aqueous hydroxy ethyl cellulose (HEC) completion fluid was flowed through a sandstone core.⁶⁰ The HEC-water system is designed to provide reversible wellbore sealing during completion. As figure 46 shows, excellent sealing of the rock takes place, and reverse flow restores the rock permeability to about forty percent of its original value. Later tests demonstrated that acidizing the core with 15% HCl restored the permeability of the sandstone to its original value.

Figure 47 shows the results of a guar gum - water completion fluid tested in a sandstone. Guar gum is a copolymer of mannose and galactose sugars, and is manufactured by grinding beans harvested from the guar bush. Although the rock was sealed easily, restoration of permeability by reverse flow was about twenty percent effective. Of greater importance is the fact that subsequent acidizing with 15% HCl did not restore the permeability as in the HEC-water system.

The results of these tests caused a decreased use of guar gum in unfractured sandstones and an increase in the use of HEC systems with an overall benefit to the users of polymer-water completion fluids.

The two cylinder radial flow model cited earlier in this report²⁸ can be used to construct a series of curves which define the effect of permeability damage (reduction) near the wellbore. Figure 48 shows a family of such curves for specified wellbore size and well spacing. Damage ratios in Figure 48 range from fifty percent to ninety-eight percent. As shown, a fifty percent reduction in permeability to a depth of thirty-six inches produces only twenty percent reduction in well capacity. But as damage increases, very

PERMEABILITY LOSS IN A CYPRESS SANDSTONE CORE CAUSED BY A LIGHT AQUEOUS GEL OF HYDROXY ETHYL CELLULOSE (HEC). REVERSE FLOW DID NOT RESTORE THE PERMEABILITY TO ITS ORIGINAL VALUE BECAUSE SOME COLLOIDAL HEC INVADDED THE ROCK. (REDRAWN FROM REFERENCE 60).

Figure 46

PERMEABILITY LOSS IN A CYPRESS SANDSTONE CORE CAUSED BY A LIGHT GEL OF GUAR GUM IN WATER. COLLOID INVASION WAS ALSO OBSERVED IN THIS TEST. (REDRAWN FROM REFERENCE 60).

Figure 47

THE EFFECTS OF PERMEABILITY DAMAGE NEAR THE WELLBORE ON WELL CAPACITY FOR VARIOUS DEGREES OF PERMEABILITY LOSS AND DEPTH OF DAMAGE. THE CURVES SHOWN ARE THOSE FOR A TEN-INCH DIAMETER WELL SPACED AT 280 ACRES PER WELL.

Figure 48

shallow damage produces severe restrictions to flow.

The curves in Figure 48 are independent of original rock permeability, but changes in wellbore diameter and spacing will alter them. The direct transfer of damage values obtained from linear flow cores in the range 2 to 4 inches in length to Figure 48 will usually provide acceptable predictions of well performance, but the direct transfer of data obtained using linear flow cores of much greater length is not considered to be valid.

The Use of Cores to Study Particle Transport Through Porous Media

One phenomenon observed in water injection which has been difficult to assess quantitatively has been the distribution of water-borne particles within the injection well and the adjoining formation. The Barkman-Davidson membrane filter test³ provides a measurement of the permeability of a filter cake and thus indirectly provides a qualitative location of the particles - on a wellbore face, in an invasion mode, or in a pass through mode (Figure 49). Many studies, using both mathematical and physical models, have provided insight to particle distribution within injection and producing wells.* At least one field test, funded by the Department of Energy through Sandia Laboratories produced data which suggested that deep invasion of particles was occurring in a manner where well longevity was favorable in spite of the high suspended solid loading of the injection water.²⁷

Abrams and Thomeer^{1,59} have published papers which contain useful parameters related to particle transport in porous media, and Mitchell³⁹ has recently reported good correlation between membrane filter and core tests in the North Sea's Forties reservoir.

* References 1,8,11,12,15,17,24,25,28,31,34,35,36,39,45,55,58,59

A MAP WHICH PROVIDES APPROXIMATE DISTRIBUTION OF WATER-BORNE PARTICLES FLOWING THROUGH A POROUS MEDIUM WHEN FORMATION PERMEABILITY AND PARTICLE CAKE PERMEABILITY ARE KNOWN.

Figure 49

Historically, particle transport tests have, like most core tests, used linear flow systems and cores a few inches in length. Radial flow test apparatus, scaled to provide water flow paths of several feet in length, seem to be all but nonexistent. As stated earlier in this report, the expense and time involved in radial flow test apparatus dissuades most funding sectors from supporting such experiments.

• Recently, D.H. Davidson published information on particle transport and distribution in porous media which was directed exclusively toward the injection well.¹¹ Davidson's paper is somewhat unique in that it contains finite specifications for constant pressure or constant flow rate linear core flow tests and equations which provide both direct and indirect means of calculating (1) minimum unit injection rates to cause deep invasion of solids, (2) depth of invasion of solids, and (3) injection well half-life. Davidson's findings have a potential value such that efforts to apply his work to actual systems should be encouraged. The user-oriented approach of his work adds to the need for field corroboration of the methods set forth.

One report which contains enough data to demonstrate the potential utility of the referenced work is the Sandia sponsored study of an injection system in the Niland (CA) KGRA.²⁴ Data from this study can be entered into the formulas contained in Davidson's writing.¹¹

First, reference 11 contains:

$$Q_c = 3.6 \times \left(\frac{\Delta p}{\rho} \right)^{1/2} \times \left(\frac{d}{a^2} \right)$$

Where:

Q_c = minimum b/d per foot to cause deep invasion

$\Delta \rho$ = solids density - fluid density, g/cc

ρ = fluid density, g/cc

d_o = initial pore diameter, microns

a = particle diameter, microns

From reference 24, values of the four known variables are:

$\Delta \rho \approx 2$ g/cc (solids density ≈ 3 g/cc)

$d_o \approx 10\mu$

$a \approx 2\mu$

$\rho \approx 1$ g/cc

Using these values, Q_c is calculated to have a value of 36 b/d per foot of sand. The Niland injection well specific injection rate is about 100 b/d per foot of sand. Thus the probability of deep invasion of solids in the Niland system is less speculative than at the time of writing reference 24.

Second, reference 11 contains:

$$\bar{r}_a = \frac{(\bar{K}_f)^{0.75}}{(\bar{d}_B)^3}$$

$\bar{r}_a$ = radial distance of particle invasion, in multiples of wellbore radius

$\bar{K}_f$ = the value of the asymptotic impairment, md

$\bar{d}_B = 3 a/d_o$

From reference 24, the values provided are:

$K_f \approx 30$ md

$3 a/d_o \approx 0.6$

Then, $\bar{r}_a$ equals 60 wellbore radii, or about twenty-five feet. This is consistent with findings in reference 24.

Third, reference 11 contains:

$$t_{1/2} = b/d \text{ per ft.} \times \frac{3.6 \times \rho_s}{\Delta \rho \times w \times a}$$

Where:

$t_{1/2}$ = time in years to attain an overall 50 percent reduction in effective formation permeability in the region where solids accumulate

w = concentration of suspended solids in water, ppm

ρ_s , $\Delta \rho$ and a are as defined above.

From reference 24, the values for this equation are:

$$b/d \text{ per ft.} \approx 100$$

$$\rho_s \approx 3 \text{ g/cc}$$

$$\Delta \rho \approx 2 \text{ g/cc}$$

$$w \approx 100 \text{ ppm}$$

$$a \approx 2\mu$$

From these input data, $t_{1/2} = 2.7$ years. This appears consistent with observed well behavior, but is not in agreement with $t_{1/2}$ values of well under 0.1 year calculated using the membrane filter correlation.^{24, 45} According to reference 11, deep invasion can cause asymptotic declines in the affected area of the reservoir, thus producing longer half lives than those predicted using the Barkman-Davidson membrane method.

Because none of the three values obtained using the equations in reference 11 are contradictory to observed behavior in the Niland system, it

appears that at least order of magnitude answers (or better) to important injection well performance questions might be available. However additional field tests are required to confirm this opinion.

The ultimate need for long flow path, radial flow physical models cannot be rejected because of Davidson's findings. But the need for such a model will depend, in part, on results obtained in field tests. Also, the work in reference 11 does not necessarily account for, or predict well performance if supersaturated waters cause significant in-situ precipitation of mineral scales. Nor does it directly provide a means of assessing the development of secondary porosity through the solubilization of formation components by injected waters (thought to be occurring at Niland based on SEM studies by L.L.L.). But reference 11 does provide a firm basis for analysis of a problem of long standing in subsurface water injection.

Core Tests for Matrix Acidizing as a Stimulation Technique for Undamaged Injection Wells

The previous section described core flow tests which illustrated the damage removal capability of acids. In addition to removal of localized permeability damage, acidizing is widely used to increase well flow, both for production and injection, by increasing the effective porosity of the rock matrix. The porosity increase, caused by solubilization of a finite thickness of the pore walls, increases the permeability of the acidized section of rock. Often, radial depths of acid penetration and pore enlargement are of the order of 8 or 10 feet in low porosity reservoirs ($\phi \approx 0.05$) and 3 or 4 feet where porosities are in the range $\phi \approx 0.3$ or more. This method of well improvement is called "matrix acidizing".

The benefits of matrix acidizing are illustrated in Figure 50, which shows injectivity improvement for several permeability enhancement ratios for radial penetrations up to forty feet. As an example, if acidizing increases the permeability of a rock by ten fold for a penetration of four feet, injectivity improves to 1.3 x the original rate for the well and reservoir geometry shown in Figure 50. The curves in Figure 50 were generated using the two-cylinder radial flow model.²⁸ A graph which complements Figure 50 is shown in Figure 51. This provides the amount of acid to achieve a desired radius of penetration for matrix acidizing for various formation porosities. If, in the example just cited, the original reservoir porosity is 25 percent, then just over 100 gallons of acid per foot of formation thickness would be required to obtain a radial penetration of four feet.

The information which appears in Figures 50 and 51 is based on

THEORETICAL RESPONSE OF A 10 INCH BORE WELL IN 280 ACRE SPACING TO MATRIX ACIDIZATION.

Figure 50

THE AMOUNT OF ACID REQUIRED FOR A SPECIFIC RADIAL ACID PENETRATION
IN MATRIX ACIDIZING FOR VARIOUS RESERVOIR ROCK POROSITIES.

Figure 51

explicit geometric and algebraic formulae. However, in order to apply this information, it is necessary to ascertain the permeability improvement of different reservoir rocks as related to various pore volumes throughput of different acids of varying molar concentration. The core flow test is almost universally used to obtain this information, with careful attention directed toward test temperature, pressure, and flow rate per unit cross section area of the rock. Attempts to substitute other tests, such as rate of solubilization of reservoir chips in a stirred beaker, have been generally incapable of providing usable data. Mathematical models have been used successfully when simulating pore enlargement in pure limestone reservoirs, but they have not provided satisfactory information when applied to acidization of sandstones.

Figure 52 illustrates the type of information which can be generated using a mathematical model to predict permeability enhancement of low porosity limestone ($\phi \approx 0.05$) using hydrochloric acid. One gallon of 4.4 molar HCl (15 weight percent) will dissolve 1.84 pounds of calcium carbonate, in the reaction:

Assuming uniform pore enlargement, and specifying a range of pore sizes, the type of information in Figure 52 is easily generated.

Several noteworthy statements can be made regarding Figure 52:

(1) Experimental data from limestone acidizing core tests provide values which are close to those determined mathematically.

(2) The indication that one pore volume of 4.4 molar HCl enhances limestone permeability by at least 10 fold is widely accepted by oil and gas operators. Many operators no longer use core tests, but simply use the

THE THEORETICAL INCREASE IN LIMESTONE PERMEABILITY RELATED TO PORE VOLUMES OF ACID INJECTED FOR THREE DIFFERENT ACID STRENGTHS.

Figure 52

"15% -10X" rule for matrix acidizing design in limestones.

(3) Where satisfactory inhibition against acid attack of tubulars permits (i.e., temperatures are below about 150°F), 8.77 molar (28 weight percent) HCl is used for matrix acidizing limestone reservoirs to get a 100 fold permeability increase. However, Figure 50 illustrates that the larger gain in permeability results in only a modest gain in fluid flow, so a "no-risk" condition is stipulated when the stronger acid is used.

(4) Weak acids will provide permeability gains equal to those of strong acids, but require greater total volumes of injection. Total volume required to achieve a given permeability increase is roughly proportional to the ratio of strong acid molarity to weak acid molarity.

Sandstone acidizing has posed problems which have been more difficult to evaluate than those encountered in limestones. Sandstones are composed of silica, and the clays found in sandstones are silicates. Only hydrofluoric acid is capable of dissolving these materials. For the sandstones, the reaction is:

When silicates are exposed to HF, the product is usually clay fragments and SiF_4 . The reactions are complex, are dependent on the clay type, and cannot be written as a simple reaction.

Core flow tests using HF and nearly pure silica cores have provided information which has been somewhat misleading. Figure 53 shows results of an HF-sandstone core flow test which is characteristic of the type of data made available in recent years. The first fifty or so pore volumes of HF

THE PERMEABILITY CHANGES LIKELY TO BE ENCOUNTERED WHEN ACIDIZING A SANDSTONE WITH DIFFERENT AMOUNTS OF 2-4 WT. PERCENT HYDROFLUORIC ACID.

Figure 53

produces impairment caused by the copious generation of rock fragments. Then, the permeability shows what appears to be an improvement of 2.5 fold after 1,000 pore volumes of flow. What actually occurs is the reduction of the core to an unconsolidated rubble. As a result, matrix acidizing of sandstones with HF has generally been unsuccessful. Acidizing with the HF to remove well damage at and very close to the wellbore has been a very satisfactory practice, and should not be viewed in the context of matrix acidizing.

In the last four or five years, HF matrix acidizing of sandstones has been used more effectively due to the development of self-generating, low strength HF acids. The acknowledged damage to sandstones caused by the flow of hundreds of pore volumes of HF led to the use of fluids which were inert to the sandstones during placement in the formation, but which would react by solvolysis or nucleophilic substitution to generate weak HF acid in situ. Then the HF, produced in-place after injecting the reagent liquids, effectively dissolved small fines which would otherwise be free to move during well flow and cause pore blockage.

The underlying chemistry for such systems can be illustrated by using allyl fluoride (3-fluoro propene) and water in a mutual solvent such as isopropyl alcohol (2-propanol). The reaction is:

This reaction is time, temperature, and concentration dependent, and the reaction time in wells of varying bottom hole temperature can be accurately controlled. The self-generating HF acid systems currently in use provide reagents less noxious than allyl fluoride, and all major oil field acidizing companies supply the self-generating acids.

Core tests for matrix acidizing can provide the data required to predict well improvement, but the direct application of the permeability improvement data should be used with caution. In order to achieve predicted well improvement, live acid must be placed in the formation to the desired radius of penetration. Generally, the fastest rate at which the acid can be pumped without fracturing the reservoir rock is the rate used. Very slow acid injection rates cause the acid to spend near the wellbore, and often a slow acid placement results in an enlarged wellbore, not a matrix improvement. The success of a matrix acidization also depends on the uniform distribution of the acid over the entire injection interval. Often, fluid diverting agents are required to achieve the desired distribution. Other requirements must be met, and specific recommendations are usually available on a no-charge basis from the major oil field acidizing organizations.

Special problems are expected to be encountered in acidizing geopressured or geothermal producing wells, but this is beyond the scope of this report. A major contract to explore specific objectives in this area has been awarded to Republic Geothermal by the Department of Energy, and it is anticipated that information of value to thermal energy operators will be developed in that study.

Meanwhile the availability and testing of cores may increase, and at least some site-specific information on matrix acidizing and the many other types of information available through core tests will become available.

APPENDIX I

Laboratories Engaged in Core Analysis

Three types of laboratories which provide core analysis tests are described in this appendix to the report. These are:

1. Core Laboratories, Inc., also called Core Labs, a major commercial laboratory, world wide in coverage. General offices are located at 7501 North Stemmons Freeway, Dallas, Texas, 75247, phone (214) 631-8270.

2. Dowell Technical Services Laboratory, a customer service and research/development facility. Located at 1150 N. Utica, Tulsa, Oklahoma, 74102, phone (918) 582-0101.

3. Reservoirs, Inc., a specialty commercial laboratory, located at 1151-C Brittmore Road, Houston, Texas, 77043, phone (713) 932-7183.

Many other laboratories for both commercial and customer service testing may be found in petroleum service directories. There is no endorsement, implied or otherwise, intended in the selection of the three named facilities, and it should be understood that their selection was random, and that the services which they provide are generally available elsewhere.

Table I lists the availability of the 21 tests described in the body of this report for each named laboratory.

Core Labs

Core Laboratories, Inc., was founded in 1936 to provide oil field core analysis on a commercial basis. In addition to core analyses, hydrocarbon well logging and source bed evaluation capabilities are available. Portable and mobile field laboratories for rig-site analyses are also included

in Core Lab's services. A Special Core Analysis Laboratory (SCAL) section has been implemented within Core Labs to provide tests such as thermal, miscible, polymer and micellar drive studies. Also, SCAL will examine uncommon fluids for subsurface disposal by special arrangement.

Fee schedules are available by writing Core Labs.

Dowell Technical Services Laboratory

Dowell, a Division of Dow Chemical, U.S.A., is one of the major oil field service companies which provide acidizing, fracturing, cementing and other services for oil or gas producing wells and water injection wells. Their technical services laboratory provides core and other analyses for customers who do not have in-house or otherwise available laboratory services, usually in conjunction with operations where a well workover will involve the use of Dowell products and equipment. Limited funded research is conducted in the Dowell facility, such as the cement development study recently authorized by the Department of Energy.

Reservoirs, Inc.

Reservoirs, Inc., is staffed and equipped to provide rapid and practical interpretations of reservoir rock properties, and the influence of rock properties on the fluid transport capability of the rock. The principle thrust of this company's efforts is directed toward the description, interpretation and evaluation of hydrocarbon-bearing sandstone and carbonate reservoirs. In conjunction with these efforts, conventional core analyses and complete geological capabilities are available. Fee schedules are available on request.

TABLE I - Capabilities of Three
Laboratory Groups for Core Analyses Shown (X = available)

CORE TEST	CORE LAB	DOWELL	RESERVOIRS, INC.
Core description	X	X	X
Core composition	X	X	X
Bulk density	X		X
Effective porosity	X	X	X
Absolute porosity	X		
Pore size distribution	X		
Pore fluid analysis	X	X	X
Permeability	X	X	X
Sand grain size distribution	X	X	X
Clay mineralogy	X	X	X
Clay distribution	X	X	X
Clay swelling	X	X	
Clay dispersion	X	X	
Clay control agents	X	X	
Scanning electron microscopy	X	X	X
Thin section analysis	X	X	X
Consolidation capability	X	X	
Consolidation durability	X	X	
Core flow damage tests	X	X	
Particle transport analysis	X	X	
Matrix acid improvement ratios	X	X	

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