UNDERGROUND INJECTION CONTROL PROGRAM
WATER QUALITY DIVISION
WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY

GUIDANCE DOCUMENT NUMBER 1

PERMITTING OF CLASS I INJECTION WELLS

May 11, 1994

THIS GUIDANCE DOCUMENT WAS PREPARED BY THE WATER QUALITY DIVISION OF THE WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY TO PROVIDE GUIDANCE IN THE PREPARATION OF PERMIT APPLICATIONS FOR CLASS I INJECTION WELLS. THIS DOCUMENT IS MEANT TO EXPLAIN THE TECHNICAL ASPECTS OF THE PERMITTING PROCESS BUT THIS DOCUMENT SHOULD NOT BE QUOTED IN APPLICATIONS. IF THERE ARE ANY CONFLICTS BETWEEN THIS DOCUMENT AND THE REGULATIONS, THE REGULATIONS WILL PREVAIL.

Section 1.0 The Area Of Review Calculation

Chapter XIII, Section 5(b)(iv) states that:

"(b) A complete application for a Class I well shall include:

> (iv) A calculation of the area of review, which requires the calculation of the cone of influence and the area of the ultimate limit of emplaced waste."

Determining the area of review is important and should be done as soon as information can be gathered about the site of the injection. It is recommended that this calculation be done before land work is done and before extensive effort is made to accumulate information about adjacent wells. The area of review will determine how much work is required in both of these areas.

1.1 The Cone of Influence.

There are three separate calculations required. The first of these calculations is called the cone of influence. Section 5(b)(iv)(A) states that the cone of influence is calculated as:

> "(A) The formula for determining the cone of influence is:

$$r = \left(\frac{2.25\ KHt}{S10^{x}}\right)^{\frac{1}{2}} \qquad \text{(EQUATION 1)}$$

$$\text{where: } x = \left(\frac{W}{G} - B\right)\left(\frac{4\pi KH}{2.3Q}\right) \qquad \text{(EQUATION 2)}$$

r = Radius of the cone of influence of an injection well (feet)
K = Hydraulic conductivity of the injection zone (feet/day)
H = Thickness of the injection zone (feet)
t = Time of injection (days)
S = Storage coefficient (dimensionless)
Q = Injection rate (cubic feet/day)
B = Original hydrostatic head of injection zone (feet) measured from the base of the injection zone
W = Hydrostatic head of underground source of drinking water (feet) measured from the base of the injection zone
G = Specific gravity of fluid in the injection zone (dimensionless)
π = 3.142 (dimensionless)"

The above calculation would be easily done, except that most of the information available is likely to be in different units. The first conversion that usually has to be done is to convert intrinsic permeability in millidarcies to the permeability in ft/day which is required by the above formula. The formula for this conversion is as follows:

$$K = K_i\ (\rho g/\mu) \qquad \text{(EQUATION 3)}$$

where: K = Permeability in cm/sec
K_i = Intrinsic Permeability in millidarcies
ρ = .999099 gm/cm^3 - the density of water
g = 980 cm/sec^2 - the acceleration of gravity
μ = .011404 gm/(sec cm)

and: there are 9.87×10^{-9} cm^2/darcy
and: there are 2835 ft/day per cm/sec

EXAMPLE: An applicant finds that the receiver has a reported intrinsic permeability of 107 millidarcies.

$$K_i = 107 \text{ millidarcies} = .107 \text{ darcies}$$

$$K_i = (.107 \text{ darcies})(9.87 \text{ X } 10^{-9} \text{ cm}^2/\text{darcy})$$

$$K_i = 1.056 \text{ X } 10^{-9} \text{ cm}^2$$

$$K = \frac{(1.056 \text{ X } 10^{-9} \text{ cm}^2)(.999099 \text{ gm/cm}^3)(980 \text{ cm/sec}^2)}{.011404 \text{ gm/(sec cm)}}$$

$$K = 90.665 \text{ X } 10^{-6} \text{ cm/sec}$$

$$K = (90.665 \text{ X } 10^{-6} \text{ cm/sec})(2835 \text{ ft/day / cm/sec})$$

$$K = .2570 \text{ ft/day}$$

The thickness of the injection zone is the entire thickness of the zone being injected into which is hydrologically continuous. This is regardless of the interval actually perforated.

EXAMPLE: An applicant wishes to inject into the Minnelusa Formation at a depth of 8596 feet. The perforated interval is 8586 to 8596. The Minnelusa Formation itself extends from 8586 to 8603. The thickness of the injection zone is therefore, 8603 - 8586 = 17 feet.

The pumping time is the duration of the permit being sought, usually 10 years or 3650 days. This value is entered in days. The pumping time used should be the total planned duration of the project. If you intend to inject for 25 years, then that should be what is used. The permit itself must be reissued every 10 years, but the duration used should be the project duration, not the permit duration. These permits allow for injection continuously, there is no provision for limiting injection to working days. For this reason, the pumping time should be based on 365 day years.

> EXAMPLE: The applicant wishes to inject for only 10 years and then plans to shut in the well. 10 years X 365 days = 3650 days.

The Coefficient of Storage is the thickness of the injection zone multiplied by 10^{-6}/ft. This is per the EPA Guidance Document on Area of Review calculations on page V-14. The coefficient of storage is a dimensionless number.

> EXAMPLE: The Minnelusa Formation is 17 feet thick at this location. The coefficient of storage is therefore 17 X 10^{-6}.

There are two terms in equation 1 which now must be determined. B, the original hydrostatic head of injection zone (feet), and W, the hydrostatic head of underground source of drinking water (USDW) (feet). The important point in determining these values is that they must both be measured from the same datum. In the regulations, it states that they should both be measured from the base of the injection zone. By measuring them from the base of the injection zone, one is always subtracting one positive number from another positive number. The most troublesome number to determine may be the static head in the overlying USDW. Some assumption is usually necessary. The applicant can look to USGS water supply papers, for estimates of water levels in wells, or one can make the assumption that the USDW is under artesian head at the location, or one can make the assumption that the deepest USDW is a water table aquifer with no artesian head. The most conservative assumption that can be made is to assume that the head on the USDW exactly equals the head in the receiver. If this assumption is made, the entire equation reduces to the radius within which there will be any increase in reservoir pressure.

> EXAMPLE: The reservoir pressure in the Minnelusa Formation at this location is 2000 psi. Converting this to a static pressure will yield a pressure in feet of water as measured from the base of the injection zone.
> 2000 psi / .433 psi/ft = 4615 feet

The pressure in the overlying USDW in this case has been approximated by the land surface. At this location, well within the boundaries of the Powder River Basin, most aquifers are under artesian head, but not a great deal of artesian head. Assuming that the head is just great enough to bring the water to the surface from the deepest USDW means that the depth to the base of the receiver becomes the head in the USDW. In this example the head is 8603 feet.

$$W - B = 8603 - 4615 = 3988 \text{ feet}$$

The next step in the example is to convert the Q or discharge rate into the units required by the equation. If you are using barrels per day (bbl/day) or gallons per day (gal/day), which are the normal units, you must convert to cubic feet per day. There are 42 gallons per barrel and 7.48 gallons per cubic foot.

EXAMPLE: The applicant wishes to inject 2000 bbl/day.
$Q = 2000 \text{ bbl/day} = (2000 \text{ bbl/day})(42 \text{ gal/bbl})/7.48 \text{ gal/ft}^3$
$Q = 11{,}229$ cubic feet per day

The next step is to determine the specific gravity of the fluid in the injection zone. Fresh water has a specific gravity of 1.00. The most concentrated brine, with a TDS of 280,000 mg/l has a specific gravity of 1.1. It may be possible to find measured specific gravity numbers. The so called API standard water analyses for produced water many times has the specific gravity determined. If these numbers are not available, one can assume a straight line relationship exists between specific gravity and TDS. The following example shows how this calculation would be done.

EXAMPLE: The fluid in the injection zone has been shown to contain 200,000 mg/l in Total Dissolved Solids.

$$\frac{G - 1}{200{,}000} = \frac{1.1 - 1}{280{,}000} \qquad \text{(EQUATION 4)}$$

$$G - 1 = .0714$$

$$G = 1.0714$$

At this point in the example, we are ready to calculate the exponential term (EQUATION 2) which goes in the denominator under the radical. The equation is, in itself, quite complex. The equation is:

$$x = \left(\frac{W}{G} - B \right) \left(\frac{4\pi KH}{2.3Q} \right) \qquad \text{(EQUATION 2)}$$

EXAMPLE:

$$x = \left(\frac{8603 \text{ ft}}{1.0714} - 4615 \text{ ft} \right) \left(\frac{4(3.14)(.257\text{ft/day})(17 \text{ ft})}{(2.3)(11{,}229 \text{ ft}^3\text{/day})} \right)$$

$$x = (3414)(.0021) = 7.2589$$

The final calculation is then made into equation 1 as follows:

$$r = \left(\frac{2.25 \text{ KHt}}{S10^x} \right)^{1/2} \qquad \text{(EQUATION 1)}$$

$$r = \left(\frac{(2.25)(.257\text{ft/day})(17\text{ft})(3650 \text{ days})}{(17 \times 10^{-6})(10^{7.2589})} \right)^{1/2}$$

$$r = 32 \text{ feet}$$

The above equation will generally yield a larger number as the difference between W and B becomes smaller. For example, in the above calculation, if the difference had been 2500 feet instead of the 3,414 which was calculated, then r would have been 78 feet instead of 32 feet. This should not be surprising. From an environmental point of view, the best receiver will be one which has a very low initial reservoir pressure, especially compared to any overlying USDW. Applicants will find that played out oil producing zones, particularly those zones which have had large volumes of fluid removed and not replaced.

The regulations do not preclude injecting into a zone which may be overpressurized prior to injection. However, this department will look at these applications very carefully in terms of plugging of existing wells, and the quality of construction. In the event that the zone to be injected into is already at a pressure higher than the USDW, the above equation would yield infinity. Applicants should use the assumption that the pressure in the USDW exactly equals the pressure in the receiver. This will yield the total radius of any increased pressure in the receiver as a result of the injection. This assumption is likely to yield an area of review of several miles.

1.2 The area of the ultimate limit of emplaced waste.

A calculation of the area of emplaced waste (volumetric fillup calculation) is required by Chapter XIII, Section 5(b)(iv)(B), which states:

> "(B) A volume calculation to determine the maximum area that the injected waste could occupy shall be submitted on all new Class I wells. This calculation determines the total amount of void space around the well and assumes that the injected fluid completely displaces the formation water."

The following formula may be used for this calculation:

$$R = (Qt/\pi Hp)^{1/2} \qquad \text{(EQUATION 5)}$$

Where:
- R =Radius of volumetric fillup (feet)
- H =Thickness of the injection zone (feet)
- t =Time of injection (days)
- Q =Injection rate (feet /day)
- π =3.14
- p =porosity expressed as a pure decimal

EXAMPLE: For the example above, everything has already been determined except the porosity. The applicant was able to find a reservoir study in the area which indicated that the porosity of the formation was 15%. Other sources include porosity logs, measurements from core, and pressure falloff curves generated in nearby fields. For the same example used in calculating EQUATION 1, the following substitutions would be made:

$$R = ((11{,}229\ ft^3/day)(3650\ days)/(3.14)(17ft)(.15))^{1/2}$$

$$R = 2{,}261\ feet$$

The above example is quite typical. The waste will completely fill an area much larger than the area over which increased pressure is sufficient to drive the waste into a USDW.

1.3 The minimum area of review

Chapter XIII, Section 5(b)(iv)(C) and (D), impose certain minimum areas of review. This section states:

> "(C) A Class I non-hazardous waste well's area of review shall never be less than one-quarter (1/4) mile, the cone of influence, or the area of emplaced waste, whichever is greatest.
>
> (D) A Class I hazardous waste well's area of review shall never be less than two (2) miles, the cone of influence, or the area of emplaced waste, whichever is greatest."

EXAMPLE: In our example, the applicant wishes to inject only non-hazardous industrial waste. The applicant must use the greatest number of the following:

$r = 32$ feet

$R = 2{,}261$ feet

or

$r = 5280/4$ feet $= 1{,}320$ feet

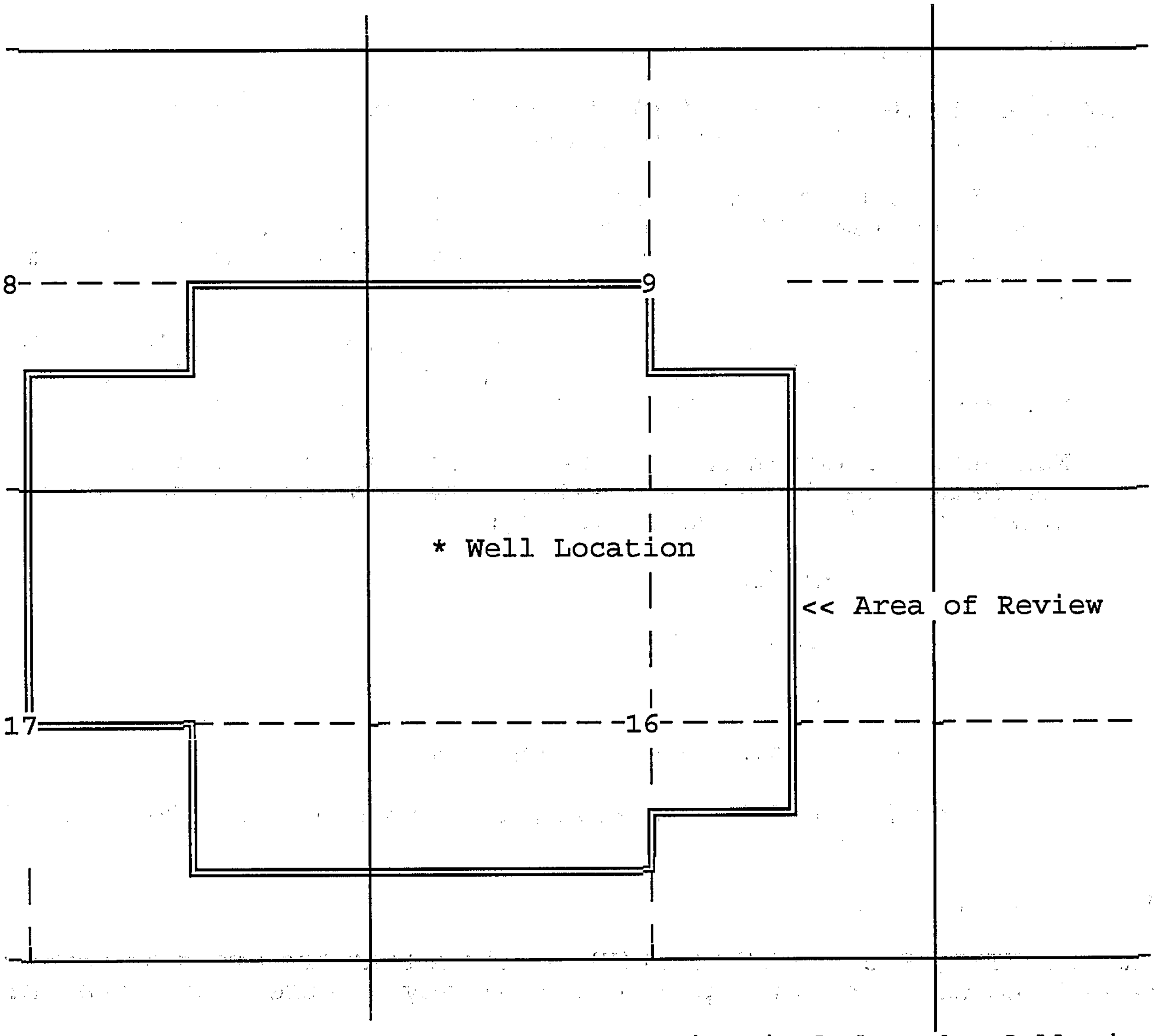
The area of review will have a radius therefore of 2,261 feet based on the area of emplaced waste.

1.4 Final area of review

Chapter XIII, Section 5(b)(iv)(E) requires that the areas of review be made to conform to the public land survey. Subsection E states:

> "(E) All Areas of Review shall be legally described by Township, Range and Section to the nearest 1/4 1/4 of a section."

In this example, the well is located in the center of the NW quarter of the NW quarter of Section 16, TXXN, RYYW, Sixth Principal Meridian. (The entire State of Wyoming is covered by the Sixth Principal Meridian except for the area around Riverton which is covered by the Wind River Meridian.) In this example, the well is 660 FNL and 660 FWL of Section 16. Therefore, the area of review includes 1601 feet west into section 17 and 1601 feet north into section 9. The well location would map as follows:



In this example then, the area of review includes the following legally described lands:

<u>Township XX North, Range YY West, Sixth P.M.</u>

Section 8:	S1/2SE1/4, NE1/4SE1/4
Section 9:	SW1/4, SW1/4SE1/4
Section 16:	NW1/4, W1/2NE1/4, N1/2SW1/4, NW1/4SE1/4
Section 17:	NE1/4, NE1/4SE1/4

Section 2.0 Specific Industrial Waste Characterization (SIC CODES)

The EPA requires all UIC permits to include the SIC codes for the various industries which may use an injection well. Include up to 4 SIC Codes with the most prevalent industry listed first in the application. SIC Codes are included here for your convenience:

01 - Agricultural Production - Crops
02 - Agricultural Production - Livestock
03 - Metal Mining
101 - Mining of Iron Ores
102 - Mining of Copper Ores
103 - Mining of Lead and Zinc Ores
104 - Mining of Gold and Silver Ores
105 - Mining of Bauxite and Other Aluminum Ores
106 - Mining of Ferroalloy Ores
109 - Mining of Miscellaneous Metal Ores
11 - Anthracite Coal Mining
12 - Bituminous Coal Mining
13 - Oil and Gas Extraction
14 - Mining of Non Metallic Minerals
16 - Heavy Construction
20 - Food and Kindred Products
22 - Textile Mill Products
24 - Lumber and Wood Products
26 - Paper and Allied Products
28 - Chemicals and Allied Products
287 - Agricultural Chemicals
29 - Petroleum Refining
30 - Rubber and Misc Plastic Products
31 - Leather and Leather Products
32 - Stone, Clay, Glass and Concrete Products
33 - Primary Metal Industries
331 - Blast Furnaces, Steel Works, and Rolling and Finishing Mills
332 - Iron and Steel Foundries
333 - Primary Smelting and Refining of Nonferrous Metals
34 - Fabricated Metal Products, Except Machinery and Transportation Equipment
35 - Machinery, Except Electrical
36 - Electrical and Electronic Machinery, Equipment and Supplies
37 - Transportation Equipment
49 - Electric, Gas and Sanitary Services
491 - Electric Services
492 - Gas Production and Distribution
494 - Water Supply
495 - Sanitary Services

Section 3.0 Fracture Pressure Calculation

Chapter XIII, Section 9(d)(ii) requires that the applicant document the fracture pressure of the receiver and that this be confirmed by a fracture pressure test of the receiver. Section 9(d)(ii) states:

> "(d) All permits issued under this chapter shall contain the following conditions:
>
> (ii) A requirement that the injection pressure shall be limited to the fracture pressure of the receiver, except as necessary during well stimulation, and, within one (1) year of the issuance of the permit, the operator shall conduct a step-rate injection test to determine the actual fracture pressure of the receiver."

3.1 Determining fracture pressure from fracture gradient

During the permitting process, it will probably not be possible to obtain a fracture pressure for the well itself. In most cases, abandoned oil and gas wells will not have been tested for this parameter. In the case where a new well is to be installed, there is no direct way to determine this number directly. The calculation which is required can be made as follows:

Fracture pressure of receiver:

$$P = (F)(D) \qquad \text{(EQUATION 6)}$$

Where:
- P = Fracture pressure of the receiver measured at the bottom of the receiver
- F = Fracture gradient in psi/ft of depth
- D = Depth to the bottom of the receiver

The fracture gradient may be obtained from step injection tests made in the general area of the well being permitted. The step injection test used should be for the same formation. Fracture pressure will vary greatly between different formations depending on their bulk strength, initial pressure, and any existing fracturing. There are many more complex methods of obtaining fracture gradient directly from the physical properties of the formation itself. This guidance document will deal only with the simplest methods. The simplest methods generally yield the most understandable results and appear to be as accurate as any of the methods available to the applicant.

Fracture gradients obtained from stimulation operations are usually inaccurate. This is because there is usually available to the stimulation operator, much more hydraulic horsepower than is necessary to fracture the formation. When a large excess in hydraulic horsepower is applied, the formation breaks so suddenly that observations of the fracture pressure are impossible or nearly so.

Once the fracture pressure has been obtained for the bottom of the receiver, this number is converted to the maximum allowable surface pressure as follows:

First the hydrostatic head of the column of water in the tubing is obtained. The Specific Gravity used should be the fluid to be injected which is highest in density if fluid will change over time. If fluids are co-mingled prior to injection so that the average composition is similar over time, then the average specific gravity should be used.

$$h = (G)(D)(.433 \text{ psi/ft}) \qquad \text{(EQUATION 7)}$$

Where:
- h = Hydrostatic head at the bottom of the receiver
- G = Specific Gravity of the injection fluid
- D = Depth to the bottom of the receiver

There are several additional parameters which must then be determined. Tubing pressure loss (T) is obtained from charts, tables or fluid dynamic calculation. There are several excellent references, Halliburton, Western, and Dow Schlumberger all publish references which contain nomographs and charts for the determination of tubing pressure loss. Perforation pressure loss (L) is generally quite small and is obtained from the same references as tubing pressure loss. The applicant is free to ignore either of these loses since they lead to higher pressures on the surface. The limiting surface injection pressure is then calculated as follows:

$$L = (P - h + T + L)(.90) \text{ psi} \qquad \text{(EQUATION 8)}$$

where L is the limiting surface pressure

Because of the difficulty in obtaining accurate fracture gradient numbers, all applicants will be required to run a step test within the first one year of operation. After running this test, the injection pressure will be limited as a matter of policy to 90% of the fracture pressure or 200 psi less than the fracture pressure determined by test, whichever is greater. In order to illustrate the use of the charts found in the various references, the following example is provided:

EXAMPLE: The applicant for our example well which will inject into the Minnelusa at 8603 feet has obtained a step injection test from a well in the Minnelusa which is 12 miles west of his proposed operation. That step rate test indicated a fracture gradient of .65 psi/ft on a well that was 9300 feet deep. The applicant must first calculate the bottom hole pressure at which the formation fractures:

$$P = (F)(D) \qquad \text{(EQUATION 6)}$$
$$P = .65 \text{ psi/ft} \times 8603 \text{ ft}$$
$$P = 5591 \text{ psi}$$

The applicant then calculates the pressure on the surface at which the formation will fracture. In this case, the applicant will inject the heaviest salt water with a density of 1.1:

$$h = (G)(D)(.433\text{psi/ft}) \qquad \text{(EQUATION 7)}$$
$$h = (1.1)(8603 \text{ ft})(.433\text{psi/ft})$$
$$h = 4097 \text{ psi}$$

The applicant then calculates the available surface pressure. The applicant has used tables supplied by one of the well stimulation service companies to determine the tubing pressure loss and the perforation pressure loss. The applicant will inject 2000 bbl/day or 1.389 bbl/min (2000bbl/day/1440min/day). The injection tubing in the well will be 2-7/8" 6.5 lb tubing. Using the 9 pound brine chart found on page 5 of that document, the applicant has determined that the tubing pressure loss will be only 14 psi/1000 feet of tubing. At 8600 feet, this adds up to 120 psi of tubing pressure loss. The perforation loses are ignored because they are small in any case.

The limiting surface injection pressure is then calculated as follows:

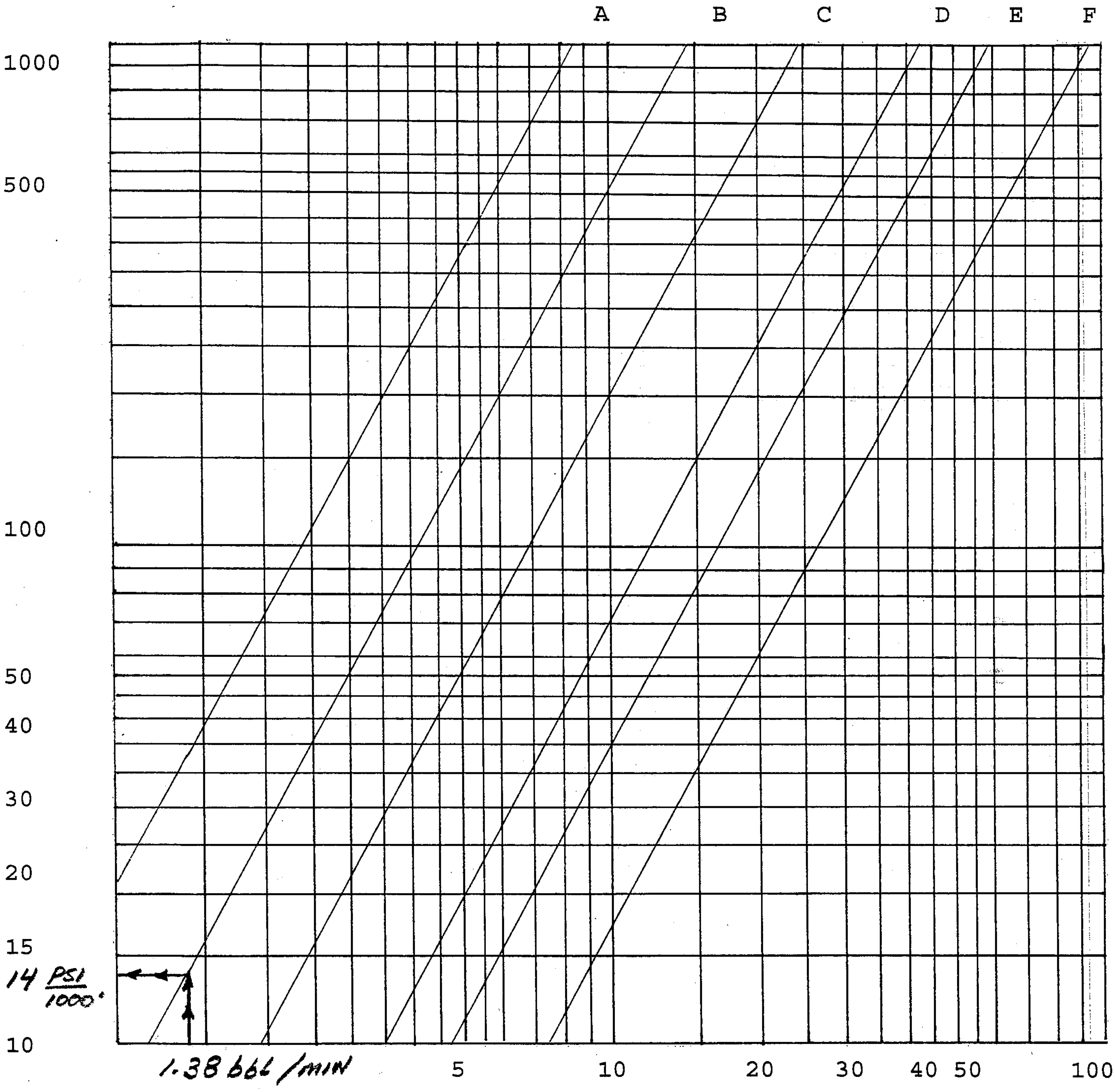
$$L = (P - h + T + L)(.90) \text{ psi} \qquad \text{(EQUATION 8)}$$

$$L = (5591 - 4097 + 120)(.90) \text{ psi}$$

$$L = 1452 \text{ psi}$$

The chart on the following page illustrates the use of the charts found in many of the common reference materials:

Tubing Friction Losses for 9 Lb Brine



A - 2-3/8", 4.7 lb tubing
B - 2-7/8", 6.5 lb tubing
C - 3-1/2", 9.3 lb tubing
D - 4", 11 lb tubing
E - 4-1/2", 9.5 lb casing
F - 5-1/2", 15.5 lb casing

In using the above graph, locate the maximum permitted injection rate on the bottom axis, draw a line as shown up to the appropriate line for the type of tubing which will be used in the well. From that intersection draw a line over to the y-axis and read off the tubing friction loss per 1000 feet of tubing in psi.

3.2 A general guide to fracture pressure.

In May of 1983, the Society of Petroleum Engineers held a seminar on Fracture Gradient. The information published serves mainly to illustrate how variable the fracture gradient can be for the same formation in the same basin. The following values are quoted from this seminar:

FORMATION	FORMATION LITHOLOGY	FRAC GRADIENT PSI/FT
Powder River Basin		
Dakota	Sandstone	.60 - .90
Ferguson	Sandstone	.50 - .60
Frontier - Wall Creek	Sandstone	.50 - .80
Lakota	Sandstone	.70 - .85
Lance	Sandstone	.55 - .85
Leo	Sandstone	.58 - .75
Minnelusa	Sandstone	.55 - .75
Muddy - Newcastle	Sandstone	.63 - .85
Niobrara	Sandstone/Dolomite/ Limestone	.70 - .80
Parkman	Sandstone	.50 - .65
Shannon	Sandstone	.60 - .80
Sundance	Sandstone	.75 - .80
Sussex	Sandstone	.50 - .72
Teapot	Sandstone	.55 - .72
Tekla	Sandstone	.53 - .75
Turner	Sandstone	.44 - .80
D-J Basin		
Codell	Sandstone/Mudstone	.70 - .85
"D" Sand	Sandstone	.69 - .89

FORMATION	FORMATION LITHOLOGY	FRAC GRADIENT PSI/FT
"J" Sand	Sandstone	.60 - .86
Lakota - Dakota	Sandstone	.71 - .90
Lyons	Sandstone	.60 - .82
Muddy	Sandstone	.68 - .92
Niobrara	Sandstone/Limestone	.61 - .84
Shannon	Sandstone	.60 - .70
Sussex	Sandstone	.58 - .79

The above table shows how variable that fracture gradients can be. If the above table is useful at all in the permitting process, it might be to allow an estimate to be made of the maximum permitted injection pressures. One could use the values above to calculate the lowest and highest maximum injection pressure which might result from a step rate test. Of course the above table does not provide any information about how much fluid could be injected at any given pressure.

3.3 Determining fracture pressure from step rate tests

Once the permit is issued, the applicant is required, by section 9(d)(ii) of Chapter XIII, to perform a step injection test during the first year of operation. The following example is from an actual step injection test conducted on a class I well in Wyoming. In this example, the well was completed with a mixed string of tubing including 2935.9 feet of 2-7/8" above 5587 feet of 2-3/8".

Rate (BPM)	Surface Pressure	Static Water Pressure	Loss in 2935.9' 2-7/8" Tubing		Loss in 5587' 2-3/8" Tubing		Total Friction Loss
			psi/1000'	psi	psi/1000'	psi	
1/4	1600	4284	5	14.7	5	27.9	42.6
1/2	1800	4284	5	14.7	5	27.9	42.6
1	2200	4284	10	29.3	25	139.7	169.0
1-1/2	2450	4284	20	58.7	50	279.7	338.1
2	2800	4284	33	96.8	90	502.8	599.1
3	3550	4284	70	205.4	180	1005.6	1211

The Static water pressure in the above table is calculated by multiplying the depth of this well, 8596 feet, by .433 psi/ft. The calculations of the tubing pressure loss have already been covered in section 3.1. The above numbers are then used to calculate the bottom hole pressure for each injection rate. The formula for determining bottom hole pressure is:

$$BHP = S + S_t - F$$

where:

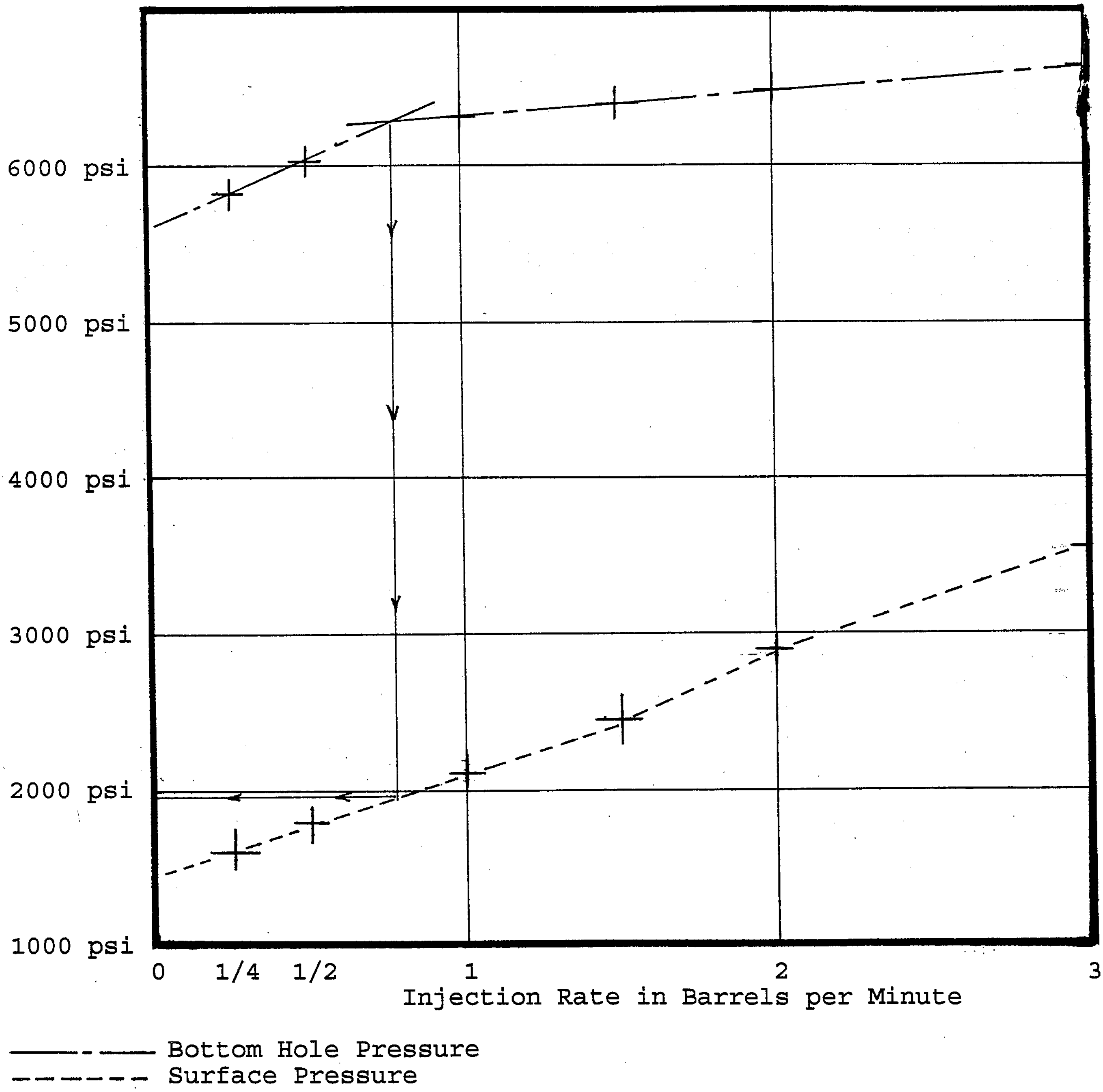
BHP = Bottom Hole Pressure
S = Surface Pressure
S_t = Static Water Pressure
F = Total Friction Losses

The following table illustrates these calculations:

Rate (BPM)	Surface Pressure (psi)	Static Water Pressure (psi)	Total Friction Loss (psi)	Bottom Hole Pressure (psi)
1/4	1600	4284	43	5841
1/2	1800	4284	43	6041
1	2200	4284	169	6315
1-1/2	2450	4284	338	6396
2	2800	4284	600	6484
3	3550	4284	1211	6623

After the bottom hole pressure has been calculated for each step in the step rate test, these pressures are then graphed as shown on the next page. The fracture pressure is the point where the line above the fracture pressure intersects the line below the fracture pressure.

Step Rate Injection Test



The surface pressure at the point when the formation fractures is found by following the solid line down from the bottom hole pressure, intersecting the surface pressure graph and then reading the pressure at that point. In this case the formation fractures at 2,000 psig as measured at the wellhead. The fracture gradient works out to be .73 psi/ft (6,300 psi bottom hole/8596 ft). This well is completed in the Minnelusa Formation. The above fracture gradient is near the top of the range of values reported by the Society of Petroleum Engineers and quoted in section 3.2 above. One important point concerning step rate tests: The individual steps should all be of the same time duration.

THIS GUIDANCE DOCUMENT WILL BE REVISED AND EXPANDED FROM TIME TO TIME AS EXPERIENCE SHOWS THAT POTENTIAL PERMITTEES REQUIRE GUIDANCE IN OTHER AREAS. AT THIS TIME, THE ABOVE ARE THE ONLY AREAS IN WHICH POTENTIAL PERMITTEES HAVE REQUIRED TECHNICAL ASSISTANCE.