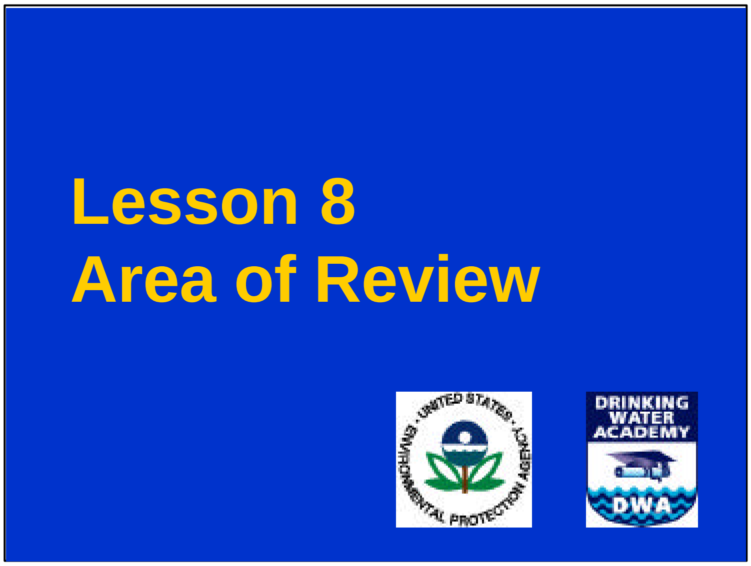
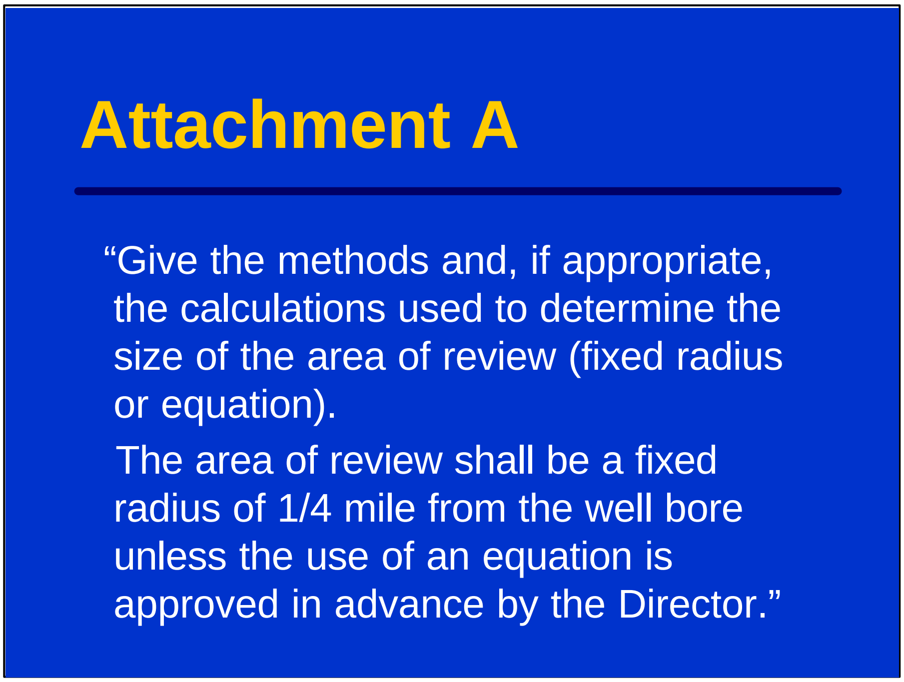


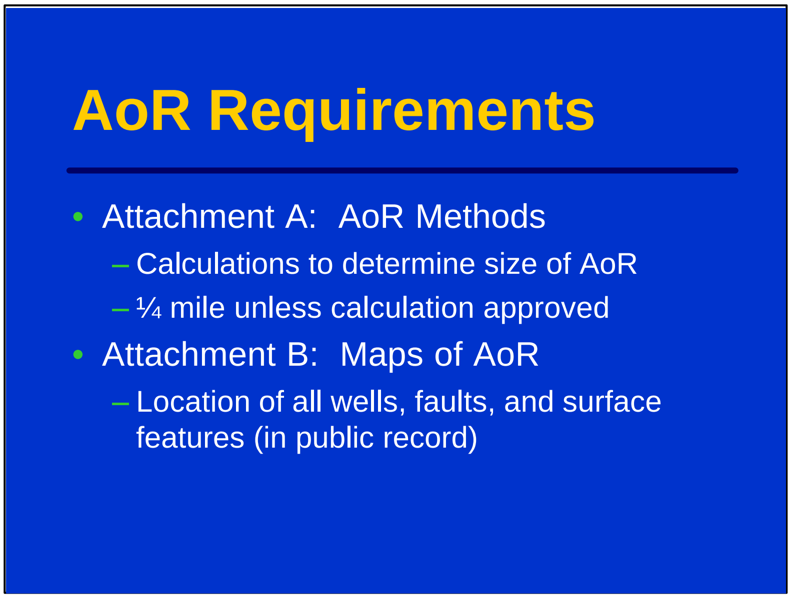
- The Area of Review of a well may be considered the "Area of Most Detailed Study," or the "Area of Greatest Concern" regarding a UIC permit.
- A primary concern of the UIC program is the potential for waste excursion from the confining zone due to the presence of conduits. Conduits may be natural or man-made. Natural conduits include transmissible faults or fractures that penetrate the confining zone, whereas man-made conduits are wells or shafts. These wells may be abandoned wells that were poorly plugged (or not plugged at all), or active wells that were not properly cemented. The pressure increase in the injection interval can force waste (or saline formation fluids) up these conduits and into USDWs. Several high-profile examples of this phenomenon caused Congress to specifically include AoR issues in SDWA.
- The original 1981 UIC regulations, as well as the current regulations, provide for analysis of the area of review (AoR) as a permit requirement for all well classes. The radius of the area of review may be a fixed radius, or it may be calculated using well-specific data. Most States use a fixed radius for most well classes, ranging from ¼ mile for Class II to 2 ½ miles for Class I Hazardous. Even if a fixed radius is mandated, however, it is very important that an analysis be undertaken to determine the suitability of the fixed radius to the injection operation in question.
- The basic principle of a calculated AoR is that of ***endangerment***. Endangerment occurs when the pressure increase due to injection has the potential to cause a column of formation fluid in a conduit to extend above the level of the base of a USDW. Imagine a glass U-tube half-full of water. If one blew on one end (adding injection pressure), the water level in the opposite side of the U-tube would rise. If the level rose high enough to overflow the open end, you would have "endangerment" on the laboratory floor, or, in the subsurface, the potential for movement of saline or waste fluids into USDWs.
- There is no standardization of AoR techniques among the different Regions and States, so each may use a slightly different method. Nevertheless, this discussion will identify the key parameters necessary for any AoR analysis, and will provide the math and details in these notes, so that you can try a method if you choose. We will also go over a typical AoR attachment later in the program.
- You may also want to refer to the UIC Technical Work Group's paper summarizing approaches to the AoR analysis (A UIC Program Summary of Regional and State Implementation of the Area of Review, March 17, 1998. **http://www.epa.gov/r5water/uic/aorsum.pdf**

Section Outline

- AoR requirements
- Mechanics of subsurface injection
- Components of injection pressure
- Fracturing and fracture gradient
- Endangerment
- AoR calculations
- Exercise: Graphical method
- Discussion: AoR issues



- Here are the instructions for Attachment A, The Area of Review:
- “Give the methods and, if appropriate, the calculations used to determine the size of the area of review (fixed radius or equation). The area of review shall be a fixed radius of 1/4 mile from the well bore unless the use of an equation is approved in advance by the Director.”



- Attachment A describes Area of Review methods. The applicant must give the methods and, if appropriate, the calculations used to determine the size of the area of review (fixed radius or equation). The area of review is a fixed radius of 1/4 mile from the well bore unless the use of an equation is approved in advance by the Director.
- Regarding the choice of a fixed radius, 40 CFR 146.6 also says:
  - For applications for well permits under § 122.38 a fixed radius around the well of not less than 1/4 mile may be used;
  - For applications for area permits under § 122.39 a fixed width of not less than 1/4 mile for the circumscribing area may be used. In determining the fixed radius, the following factors must be taken into consideration: chemistry of injected and formation fluids; hydrogeology; population and ground-water use and dependence; and historical practices in the area.
- Attachment B contains maps of the well, area, and area of review. The applicant must submit a topographic map, extending one mile beyond the property boundaries, showing the injection wells or project area for which a permit is sought and the applicable area of review. The map must show all intake and discharge structures and all hazardous waste treatment, storage, or disposal facilities. If the application is for an area permit, the map should show the distribution manifold (if applicable) applying injection fluid to all wells in the area, including all system monitoring points. Within the area of review, the map must show the following:
  - **Class I -** The number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and faults, if known or suspected. In addition, the map must identify those wells, springs, other surface water bodies, and drinking water wells located within one quarter mile of the facility property boundary. Only information of public record is required to be included in this map;
  - **Class II -** In addition to the requirements for Class I, the applicant must include pertinent information known to the applicant. This requirement does not apply to existing Class II wells; and
  - **Class III -** In addition to requirements for Class I, the applicant must include public water systems and pertinent information known to the applicant.

AoR Requirements

40 CFR 144.55

- Construction details for all wells in AoR that penetrate the injection zone

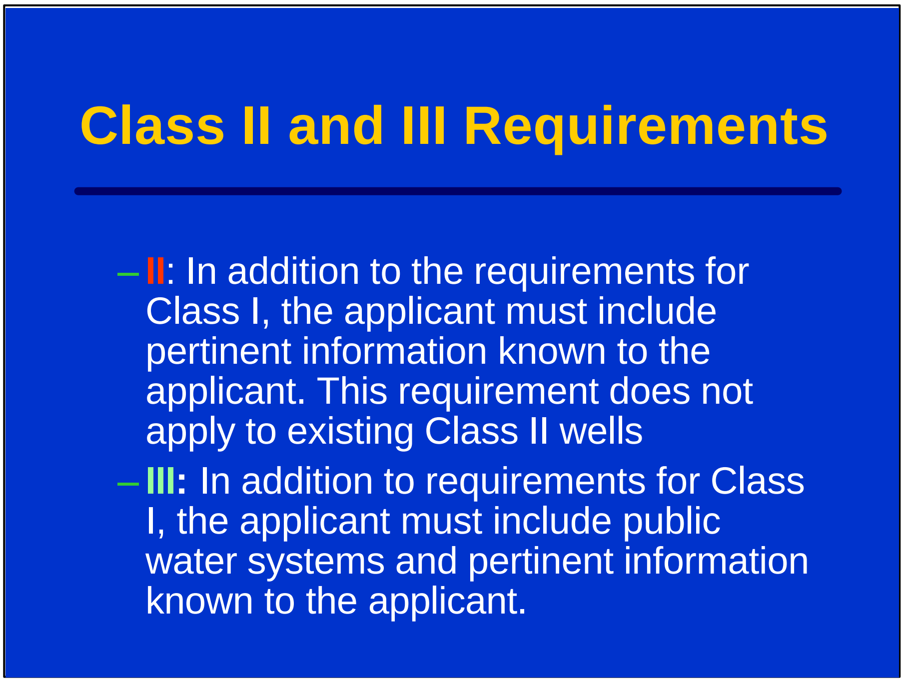
40 CFR 146.14(a)(3)

- Description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require.

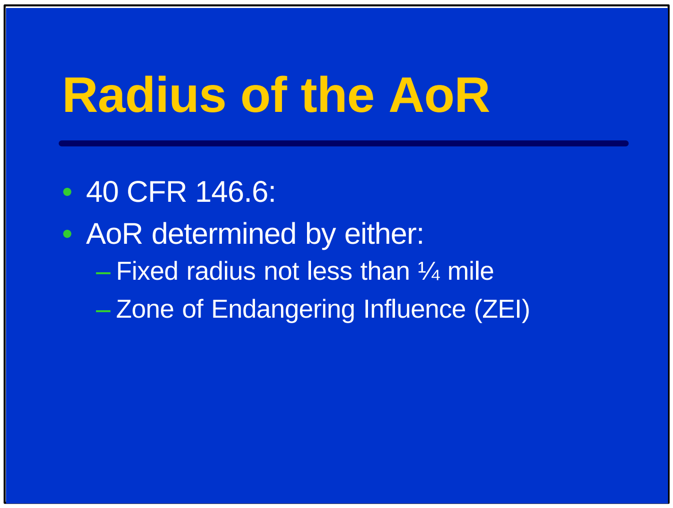
- Applicants for Class I, II (other than existing), or III injection well permits must identify the location of all known wells within the injection well's area of review that penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the injection formation, all known wells within the area of review penetrating formations affected by the increase in pressure.
- 40 CFR 146.14(a)(3) requires that the applicant provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require.
- For wells that are improperly sealed, completed, or abandoned, the applicant must also submit a plan to prevent movement of fluid into underground sources of drinking water (corrective action). We will discuss corrective action in detail later in the day.

Class I requirements

- The number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface and subsurface), quarries, and other pertinent surface features, including residences and roads, and faults, if known or suspected. In addition, the map must identify those wells, springs, other surface water bodies, and drinking water wells located within one quarter mile of the facility property boundary. Only information of public record …



- Class II: In addition to the requirements for Class I, the applicant must include pertinent information known to the applicant. This requirement does not apply to existing Class II wells; and
- Class III**:** In addition to requirements for Class I, the applicant must include public water systems and pertinent information known to the applicant.



- The area of review for an injection well must be determined according to either:
  - *Fixed radius* around the well of not less than 1/4 mile; or
  - *Zone of endangering influence*, within which the pressures in the injection zone may cause the migration of the injection and/or formation fluid into an underground source of drinking water.
- With a fixed radius the Director may specify an area between ¼ mile (common in Class II permits) and the 2 ½ miles used for most Class I-Hazardous wells. The "Zone of Endangering Influence" concept, however, is based on the actual geologic and hydraulic properties of a specific injection zone and the proposed operating characteristics of the injection well. A prudent permit writer will always consider the AoR from both perspectives.
- The Zone, or ZEI as some call it, is an analysis of the pressure effects of injection compared to the hydrogeologic environment of the site. Up until now, we have discussed the macro aspects of underground injection: wells and confining zones and so on. This section will consider the role of the micro aspects of injection, that is, the dynamics of adding injection volume to a system that is already full, in that it is saturated with other fluids. We can describe deep underground injection as emplacement of fluids into a closed, or at least partially-closed, infinite acting system. The dynamics of adding injected volume to a closed hydraulic system that is already "full" creates an increase in pressure within the system, just like blowing more air into a balloon. In an injection zone that is effectively confined, this increase in pressure is not usually harmful unless the balloon pops, that is, unless the pressure exceeds the rupture limits of the confining zone. But in the case where the balloon has a leak, or an injection zone has a potential upward conduit like an abandoned well, the injected fluid can escape, possibly into a USDW. So, in a nutshell, the ZEI analysis estimates the amount of pressure we will be putting into the balloon, and the AoR analysis looks for the leaks.
- Our discussion, while based on theoretical concepts, is grounded in the practical role that injection dynamics plays in the UIC permitting process. An understanding of the basics of injection supports the entire area of review process, as well as a permit writer's analyses to develop permit limitations for injection rate and volume and potential for hydraulic fracturing. There are complex equations presented on a few of the following slides. They present the basic steps and detailed math for these analyses, however, so that you can use these as reference materials in the event you have to perform the steps yourself.

Components of Injection Pressure

- Existing lithostatic and hydrostatic pressure
- Darcy friction losses
- Displacement resistance

- In order to understand the principles and practices involved in permitting and area of review analysis, we must first examine the mechanics of subsurface injection. Injection implies the introduction of fluids into the porous network of a rock or sediment layer. Fluid injected into a subsurface reservoir does not flow into empty voids; the injection process must displace the fluids that are already there, usually saline water. The pressure necessary to effect this displacement consists of three components: the existing formation pressure; the Darcian head loss that must be overcome when pushing fluid into a porous, granular medium; and the resistance to displacement.
- Existing formation pressure can be caused by a combination of rock overburden, the weight of the saturated fluid-column (hydrostatic pressure), the temperature at depth, the presence of gas, and chemical reactions within the system. While the existing subsurface pressure varies considerably among geologic environments, almost all injection reservoirs approach nominal lithostatic conditions, that is, containing less than 1 psi per foot of depth.
- The friction losses that must be overcome are a function of permeability, and are described by Darcy's Law. In its simplest form, Darcy's Law shows that injection pressure is a function of injection rate and formation transmissivity (i.e., thickness times permeability). For a given injection rate, a highly transmissive formation will present lower friction losses than will a less-transmissive formation. That is, the lower the transmissivity the higher the injection pressure required for emplacement at a given rate. The effective *porosity* of the rock affects the *amount* of fluid that can be emplaced, whereas the effective *permeability* of the rock affects the *rate* at which fluids may be emplaced.

Fluid Injection

- Fluid is injected into saturated pores
  - Native water is displaced
  - or
  - Native water is compressed and system expands
- Injection reservoirs should be infinite-acting systems

- The resistance to displacement is, in a Newtonian sense, the reservoir pushing back. We mentioned that subsurface injection takes place into a "full" reservoir, that is, the pores are already saturated with native saline water. During injection, space is created for the injection fluid by two possible mechanisms:
  - o The receiving formation is part of an open system, and native water is displaced elsewhere; or
  - o The reservoir is a closed system, and space is created by compressing the native water and aquifer skeleton.
- All injection reservoirs are (or should be) closed systems. This does not mean that the reservoir cannot outcrop, but rather that displacement of native liquids cannot approach the outcrop. Neither should the pressure effects reach the limits of the reservoir. This situation is referred to as "infinite acting". Although water is generally considered a non-compressible fluid, some slight compression does occur (3.1 x 10^{-6} lb/in^2 at subsurface temperature). Similarly, the "elasticity" of the rocks allows very slight compression of the reservoir rock skeleton and/or expansion of the system, on the order of 3.2 x 10^{-6} lb/in^2 for typical sand injection reservoirs featuring 30 percent porosity. In simple terms, every psi of injection pressure (in excess of existing formation pressure) creates 0.0000065 cubic inch of space for injectate. This may be a very small amount, but when applied to the immense volume and area of a reservoir system, large volumes of fluid storage may be created by injection pressure.
- Oilfield applications refer to this phenomenon as the "compressibility factor," whereas in ground water usage it is called the "storage coefficient."

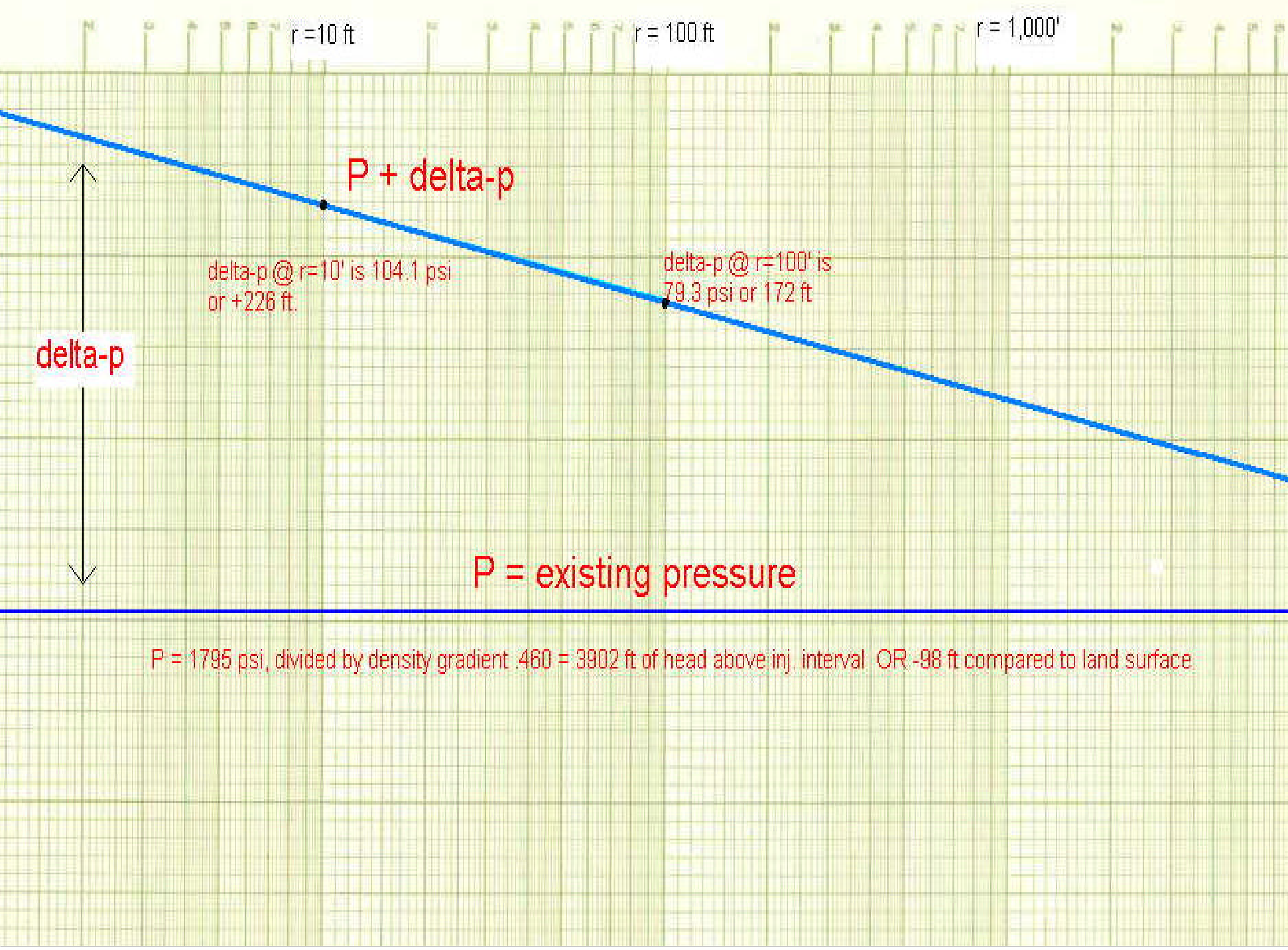
Delta p (? p)

- Matthews and Russell (1967) show that pressure increase is greatest at the well, but decreases dramatically (log) with distance

$$? p = 162.6 \; \frac{Q \mu}{k \, b} \; [\log \frac{k \, t}{F \; \mu C r^2} - 3.23]$$

- The injection of fluid into a subsurface reservoir is accomplished by increasing pressure within the system. The pressure increase is greatest at the wellbore and decreases away from the wellbore (i.e., into the injection formation). The effect is the mathematical opposite of the cone of depression in a pumping well. The cone of impression created by an injection well reflects highest pressure at the well, decreasing logarithmically with distance from the well. The amount of injection pressure required for emplacement and the distance to which it extends into the formation depends on the properties of the injection fluid and the formation, the rate of fluid injection, and the length of time the injection has been going on.
- The most common mathematical expression for a single well injecting to an infinite, homogenous and isotropic, non-leaking aquifer was developed by Matthews and Russell (1967).
- delta p (the increase in pressure) = 162.6 Q (μ) / k b * [(log k t / $\phi \mu$C r^2) – 3.23], where:
  - ? p = pressure change (psi) at radius r and time t
  - Q = injection rate (bbl/day)
  - μ = injectate viscosity (centipoise)
  - k = average reservoir permeability (millidarcies)
  - b = reservoir thickness (ft)
  - t = time since injection began (hrs)
  - C = compressibility or storage coefficient (sum of water/aquifer compressibility and reservoir expansion) (psi^{-1})
  - r = radial distance from wellbore to point of investigation (ft)
  - ? = average reservoir porosity (decimal)
- It's interesting to see what REALLY matters in this analysis. In the second half of the equation, kt over $\phi \mu C r^2$ is usually a big number over a decimal, and the log result is usually a number between 6 and 25. Conversely, injection rate (Q) and transmissivity (Kb) are the major factors in delta-p. Similarly, as k decreases over time (due to precipitates and solids), then delta-p will increase (or Q will have to decrease).

? p and Semi-Log Plot



- Matthews and Russell's equation shows that delta-p declines logarithmically with distance from the wellbore. If we assume homogeneous and isotropic conditions in the injection interval, the pressure surface will describe a straight line on semi-log graph paper. We only need to solve for two values of "r" using Matthews and Russell, plot these points on semi-log paper (vertical axis is arithmetic depth and horizontal is log distance "r"), and connect the dots to describe the pressure increase "delta-p" at any distance from the well.
- Using r=10 and r=100 feet, we calculate corresponding delta-p as 104.1 psi (r=10) and 79.3 psi (r=100). These values represent the pressure increase (over existing formation pressure) due to injection of 50 gpm for 20 years. When plotted on semi-log paper, these values describe a straight line. Because delta-p values at any point "r" are additive, we can add the delta p values to the existing formation pressure, shown here as "P". Note that substitution of different values for injection rate (Q) or aquifer transmissivity (k or b) will provide lines of differing *slope* on the semi-log graph, whereas different "t" values will result in a family of lines of parallel slope.

Analysis of Formations

- Formation pressure eventually equalizes when injection stops and pressure dissipates
- Pressure buildup and equalization are unique in each formation, allowing for analysis of formation properties

- When injection ceases, the pressure begins to dissipate to lower-pressure areas of the system (i.e., the cone begins to flatten). Eventually, at a rate proportional to buildup, the formation pressure will equalize to a higher, post-injection formation pressure.
- As we have seen, injection into a formation produces a pressure buildup and equalization that are unique to that formation's geological properties. Conversely, that phenomenon is also the basis of pressure transient analysis: the analysis of pressure buildup or dissipation in a well allows us to solve for the unique properties of the formation.
- The most common uses of the equation of Matthews and Russell are to determine the allowable injection pressure of a well and to assess the radius of endangerment for area of review studies.

Bottom Hole Pressure

- Bottom-hole pressure during injection (BHPI) consists of
  - – ? p (injection pressure at some Q) plus
  - – Weight of the fluid column
    - Height of fluid x density, e.g.,
      4000 ft @ .4416 psi/ft = 1766 psi
- BHPI also expressed as gradient (psi/ft)
    - E.g., 1940 psi ÷ 4000 ft. = 485 psi/ft

- We have previously considered the minimum pressure necessary for emplacement of fluids into the reservoir. It is also important to consider this pressure as the bottom hole pressure, or BHP, which also includes the weight of the fluid column. The components of BHPI include delta-p (the injection pressure), the weight of the fluid column in the tubing, and certain friction losses at the injection face that we call "skin" losses. Unless you have a documented test of skin losses, it's best to ignore them for most BHPI calculations.
- The weight of the fluid column equals the height of the fluid column times the density gradient of the fluid. Charts and conversion tables allow you to convert units to density gradient as psi per foot using traditional measurements such as grams per cc, pounds per gallon, specific gravity, or even TDS concentration.
- Most analysts also express BHPI is as a *BHPI gradient*, which is BHPI divided by the depth of the injection zone. The BHPI gradient for this example would be 1940 psi divided by 4000 feet, or 0.485 *psi per foot*.
- BHP can be estimated as we have done, or directly measured in the field using a pressure sensor. You could also work at this 'backwards' in the field if you needed to, by observing the operating well-head pressure. The problem with this method is that WHIP (well-head injection pressure, also called SIP for surface injection pressure) also includes friction losses in the tubing and skin losses downhole. In some Class I wells, these losses can total hundreds of psi, because of pore-plugging by chemical waste reactions.

Fracture Gradient

- Injection pressure can not exceed the fracture pressure
  - Of the injection zone (Class I), or
  - Of the confining zone (Class II)
- Fracture pressure is unique for every formation and time

- One of the primary objectives of an AoR review is to assess the potential for hydro-fracturing of the injection and confining zones. Hydro-fracturing occurs when injection pressure (BHPI) exceeds the lithostatic and hydrostatic forces that confine the pore spaces. When this pressure is exceeded, the pores are forced apart hydraulically, just like your car is forced apart from the garage floor by the action of a hydraulic jack when fluid pressure overcomes the downward force of gravity. In extreme cases, hydro-fractures can cause breaches of the confining zone, and allow wastes to escape and endanger USDWs. UIC regulations (40 CFR 146.13(a)(1)) prohibit Class I wells from exceeding the frac pressure of the rocks of the *injection* zone (except during stimulation), whereas Class II wells must not exceed the frac pressure of the *confining* zone (40 CFR 146.23 (a)(1)). Many Class II wells are purposely fractured to enhance injection or production permeability in the injection zone, but fractures are prohibited from penetrating the confining zone. We will talk more later about well stimulation.
- Hydro-fracture pressure is unique for every formation, and is related to the formation's depth, elastic modulus, overburden and fluid pressure, geologic age, and the sand/shale ratio. The fracture pressure can change with increasing (or decreasing) formation pressure, due to injection or production. In other words, a fracture pressure measured early in the life of a well may not be valid after continuous injection for a number of years. Hydro-fracture pressure information for a given area can be found in the literature, measured directly by a drill-stem or step test, or estimated using several possible methods.
- Fracture pressure is usually expressed as the fracture gradient, in psi per foot, by dividing the fracture pressure by the well depth. This allows test results or regulatory standards to be applied to different wells. Frac gradients can vary from 0.65 psi per foot for poorly-consolidated sand zones, to over 1 psi per foot in the hard rocks of the Mid-continent and Appalachian regions.

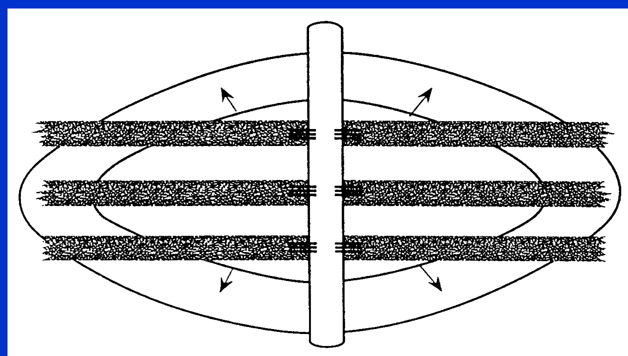
Fracture Pressure

- Finding fracture pressure
  - Published data (oil and gas industry)
  - Measured downhole using injection test
  - Estimated

- When considering published data from the oil and gas industry or the scientific literature, it is important to remember that injection wells usually operate in an environment markedly different from the oil wells that are the usual subjects of published research. Injection well use is typically at shallower depth (less than 7000 feet), in normally pressured, water-saturated formations of high permeability and porosity, in areas free of active faulting and tectonic activity. Published values for oilfield fracture gradients are usually derived from deep production zones and overstate the true fracture gradient in shallower formations.
- Fracture gradients can also be measured, using either a specific test in the subject well, or using industry or published data derived from fracturing procedures.

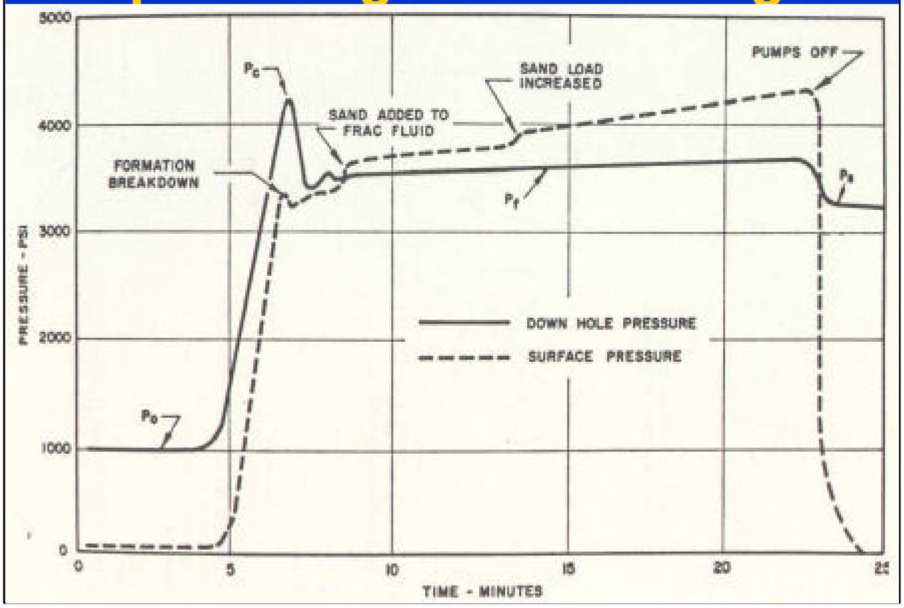
Hydraulic Fractures

- Planar, two lobes centered on wellbore

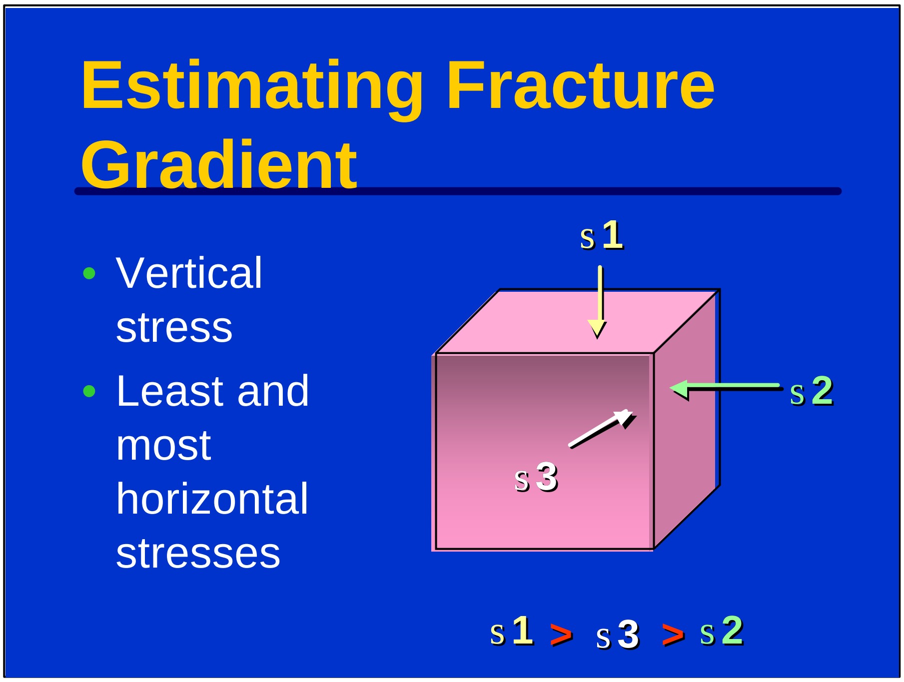


- Most hydraulic fractures are planar, like a sheet of paper. The fracture grows from a tiny crack that occurs when rock grains are forced apart by hydraulic pressure. Fractures grow in opposite directions away from the wellbore, oriented to the direction of earth stresses. Hydraulic fractures prefer to grow upward first, because the overburden stress is less and because delta-p is highest near the wellbore. When the fracture has grown as high as it can vertically, it turns and grows in the horizontal plane. Fractures grow, or propagate from one pore to another, but, in the process, hydraulic energy is leaked-off in directions away from the direction of propagation, and less hydraulic energy is available to fracture the next pore in line. The amount of leak-off is a function of permeability; so for equal pressure, fractures can grow farther in less-permeable formations.
- Commercial fractures are made by using a gelled fluid that can't leak off, which tends to focus the hydraulic power into propagating the fracture. To the contrary, in an underground injection environment, the clear fluids injected are very poor at propagating fractures, and unless the injection pressure is extreme (or the injection zone is very impermeable), it's not likely that the fracture will grow very high or far.
- The fracture will continue to grow until the hydraulic energy is insufficient to fracture the next pore in line (in the case of a homogeneous medium) or until it reaches a rock layer which exhibits higher elastic properties, such as a shale. The hydraulic energy necessary to fracture a shale confining zone is extreme, and is probably not even possible using the typical pumping capacity available at most UIC sites.

Step Testing and Frac Logs



- In a step test, injection pressure is increased until the formation breaks down. These tests are usually required for a Class I Hazardous permit application, especially in Region 5. For other wells, the most common information available is from a nearby hydraulic fracturing procedure. Data from these procedures is usually available from service companies who perform the procedures (such as Halliburton) or from State agencies (given to operators to allow planning for blowouts). In either case, a step test and fracture log provide the same information, and the terms and solutions are the same. This example is a log of a fracture procedure. Ignore the dotted line, but concentrate your attention on the down-hole pressure.
- P-zero is the initial hydrostatic pressure in the formation plus the weight of the fluid column (BHP). Injection pressure is increased until breakover is observed, labeled “P_c” on most logs. Once the fracture pressure has been exceeded and a flowpath is created, continued injection into the fracture is easier as the fracture is being extended. This phenomenon is labeled “P_f” and is known as flowing pressure. P_f is especially significant, in that once injection pressure has exceeded a threshold fracture-pressure value, subsequent injection into the fracture requires significantly lower pressure. Depending on the elastic properties of the formation, the initial fractures may never heal, and the effective fracture gradient is now lowered. In semi-consolidated formations, however, fractures can heal, and the original breakdown pressure must again be exceeded for subsequent fractures.
- When pumping is stopped, the well stabilizes at a value known as the “instantaneous shut-in pressure,” or ISIP, labeled P_s on this slide. This pressure is considered by most researchers to be equal to the least principal earth stress in the vicinity of the well.
- Many frac logs are recorded as surface pressure (always check the log header or P-zero first). For surface-recorded logs, we would need to add the weight of the injection fluid column to ISIP to get the true ‘Fracture pressure’ for the new injection well. This log is recorded as ‘down-hole pressure’, but many fracture jobs use light fluids (such as methanol) or the fluid level is not to surface when P-zero is measured. So for bottom-hole frac logs, subtract P-zero from log-ISIP for a true ISIP pressure, and then add the weight of the proposed injection fluid column.
- Because of the “P_f” phenomenon and the fact that some fractures never heal completely, many regulators avoid fracture-testing every well, and for setting permit limitations rely instead on tests of similar wells or on estimates of the fracture gradient.



- Hydro-fracture pressure for a given formation can be measured directly by a fracture log or step test, or can be estimated using several methods. Most estimation methods require specialized tests of rock properties (such as Young's Modulus), or may be valid only for certain depths or geologic provinces. It is possible, however, to develop a simple estimation logic using published data and the method of Hubbert and Willis.
- There are two principal stresses acting at any point in the earth's crust: vertical overburden stress, and horizontal tensile or compressive stresses. A practical way to express that relationship is to measure their effects at any point in the subsurface: we can define vertical stress as the rock overburden pushing down, and describe the relationship of tensile or compressive forces as the two, perpendicular directions of ***least*** and ***most*** horizontal stress.

Hubbert and Willis (1972)

- Fracture orientation perpendicular to least principal stress
- Fracture gradient is usually from 0.64 to 0.73 psi/ft in typical oil sands
- More for shale-rich, hard rock, or thrust areas (up to 1.0 psi/ft)

- Hubbert and Willis (1972) are most famous for proving that fracture orientation is perpendicular to least principal stress. (Remember that hydraulic fractures are planar and are oriented in a particular direction). When the least principal stress is vertical, that is, the overburden is small, then fracture orientation will be horizontal. That is the usual case for shallow wells, usually less than 1,000 feet in depth. When the least principal stress is horizontal, fracture orientation will be vertical. That is generally the case for deeper wells.
- The method of Hubbert and Willis also postulates that the fracture pressure gradient is dependent on the overburden, the pore-pressure gradient, and the rock frame stress. In typical oil-exploration basins that feature normal faulting, they found that the least stress is probably horizontal and from 1/2 to 2/3 the effective pressure of the overburden. Using these assumptions and data for overburden in many regions, Hubbert and Willis found that the fracture pressure gradient probably ranges from 0.64 to 0.73 psi per foot. Published data from other literature sources generally agree with the postulate of Hubbert and Willis (if we consider the geologic conditions typical of injection wells). Test data in the field, however, has shown frac gradients approaching 0.85 psi/ft for shale-rich sections, and in hard-rock environments that feature thrust faulting, gradients can approach 1.0.

Area of Review Calculations

- Endangerment
  - Pressure increase has the potential to cause a column of formation fluid in a conduit to extend above the level of the base of a USDW
- Suggested method in 40 CFR 146.6

- Even if a fixed radius is used for the Area of Review, a prudent permit writer should always require some analysis of endangerment. One method for calculating the Zone of Endangerment is contained in the regulations at 40 CFR 146.6.
- Remember that almost every calculation and estimation method in hydrogeology or petroleum engineering is subject to the DePuit assumptions that make hydrologic calculations possible. These assumptions include fully-penetrating wells, homogeneous and isotropic reservoir properties, and constant values at every distance and in every direction, as well as many others. These simplifications will work in almost every case, but if you suspect a highly compartmentalized or fractured reservoir, the only alternative to estimation is problem-specific downhole testing and a healthy degree of caution.

40 CFR 146.6

$$r = \frac{(2.25\ KHt)^{1/2}}{S10^{x}}$$

where

$$X = \frac{4\pi KH\ (h_w - h_{bo} \times S_p G_b)}{2.3Q}$$

Where:

- r=Radius of endangering influence from injection well (length)
- k=Hydraulic conductivity of the injection zone (length/time)
- H=Thickness of the injection zone (length)
- t=Time of injection (time)
- S=Storage coefficient (dimensionless)
- Q=Injection rate (volume/time)
- h_{bo}=Observed original hydrostatic head of injection zone (length) measured from the base of the lowermost underground source of drinking water
- h_w=Hydrostatic head of underground source of drinking water (length) measured from the base of the lowest underground source of drinking water
- S_p G_b=Specific gravity of fluid in the injection zone (dimensionless)
- p=3.142 (dimensionless) The above equation is based on the following assumptions:
  - The injection zone is homogenous and isotropic;
  - The injection zone has infinite area extent;
  - The injection well penetrates the entire thickness of the injection zone;
  - The well diameter is infinitesimal compared to "r" when injection time is longer than a few minutes; and
  - The emplacement of fluid into the injection zone creates instantaneous increase in pressure.
- 40 CFR 146.6 (c) states that, "If the area of review is determined by a mathematical model pursuant to paragraph (a) of this section, the permissible radius is the result of such calculation even if it is less than one-fourth (1/4) mile."
- Note that these are ground water-type units.

Area of Review Calculations

- $?p = 162.6 \frac{Q\,\mu}{k\,b} \left[\log \frac{k\,t}{F\ \mu C r^2} - 3.23 \right]$
- ?p declines logarithmically with distance; straight line on semi-log plot

- The primary villain in our endangerment analysis is the quantity we discussed earlier, delta-p. Remember that delta-p is shorthand for the pressure increase in the injection zone at radius “r” due to injection of volume “Q” for time “t.” The Matthews and Russell equation is formatted for oil-field units, and forms the basis for several types of ZEI analyses.
- The most important thing to remember is that delta-p declines logarithmically with distance from the wellbore – note that “r” in the equation is a log function. This means that delta-p, and the associated potential for USDW contamination, would be highest nearer the wellbore.
- Another interesting use of the log relationship is that we can make plots of delta-p with distance, and the points describe a straight line on log paper.

Example: Injection Pressure

- Well depth: 4000 feet
- Thickness of interval (b): 50 feet
- Porosity (?): 30 percent
- Permeability (k): 400 md
- Injection rate (Q) = 1700 bbl/day
- Viscosity (µ) = 0.90 centipoise
- Duration of injection (t) =10 yr=87,600 hours
- Effective well radius (r) = .292 ft
- System compressibility(C) = 6.5 x 10^{-6} psi^{-1}
- Well tubing = 2.375"
- Injectate specific gravity = 1.02

- Consider this example: use Matthews and Russell to determine delta-p for the following well.
- Depth to injection interval: -4000 feet
  - Thickness of interval (b): 50 feet (measured or estimated from logs)
  - Porosity (ϕ): 30 percent (measured or estimated from logs)
  - Permeability (k): 400 md (measured or estimated from logs)
  - Injection rate (Q) = 1700 bbl/day
  - Viscosity (mu) = 0.90 centipoise @ 100º (measured or estimated from chart)
  - Duration of injection (t) = 10 years = 87,600 hours (life of permit)
  - Effective well radius (r) = .292 ft (casing diameter is 7 inches)
  - Reservoir compressibility or "storage" (C) = 6.5 x 10^{-6} psi^{-1} (estimated from chart)
  - Well tubing = 2.375" steel
  - Injectate specific gravity = 1.02 (.44 psi/ft, from conversion chart)
  - Existing formation pressure: 1795 psig @ 4000 feet (measured)

Example: Injection Pressure

? p = $\dfrac{(162.6)\ (1700)\ (.90)}{(400)\ (50)}$ x

[log $\dfrac{(400)\ (87600)}{(.30)\ (.90)\ (.0000065)\ (.292)^2}$ - 3.23]

? p = 138.6 psi at the injection face (10 yrs)
= 142.3 psi (20 years = 175,200 hours)

- **Refer to Handout #8-1**

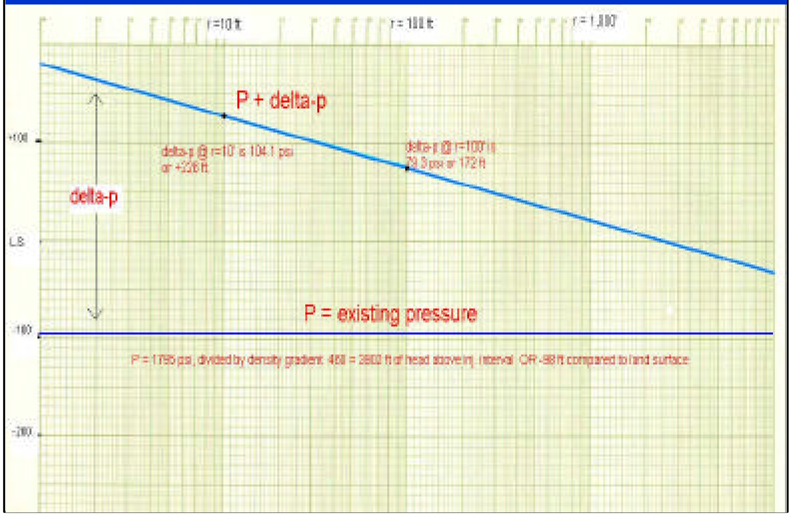
- At the injection face (r = casing radius) and considering the lifetime of the well (20 years), we can calculate the necessary injection pressure:

Delta-p (psi) = $\dfrac{(162.6)\ (1700)\ (.90)}{(400)\ (50)}$ x [log $\dfrac{(400)\ (87600)}{(.30)\ (.90)\ (.0000065)\ (.292)^2}$ - 3.23]

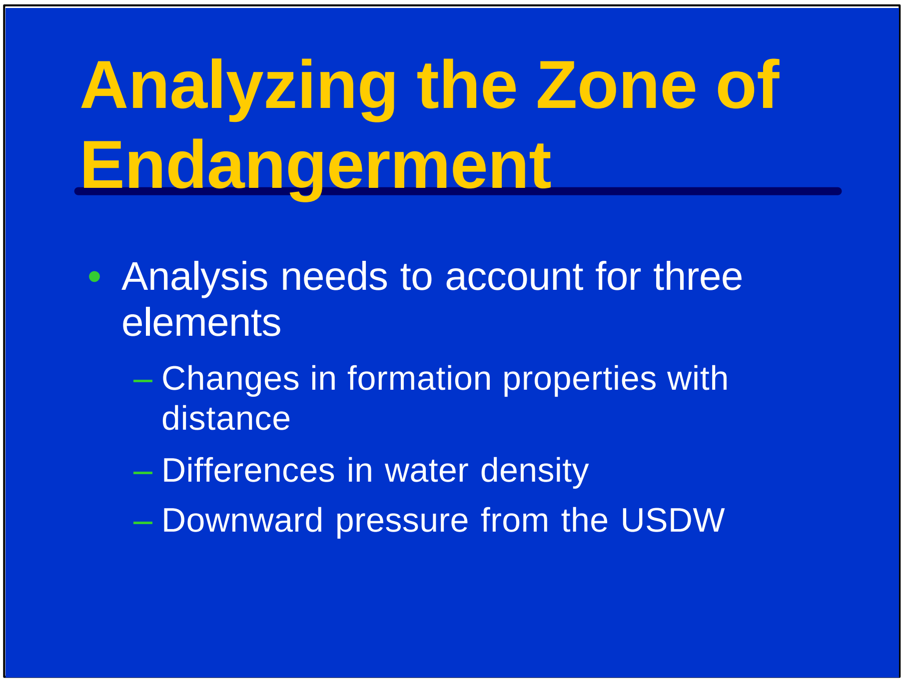
- Delta-p = 138.6 psi at the face of the injection interval

- This is the injection pressure at the formation face required after 10 years' service that is necessary to emplace 1700 bbl per day (about 50 gpm) into the example formation.
- If we perform the calculation for a 20-year well lifetime (175,200 hours), we would find that delta-p equals 142.3 psi. It's interesting to see that the primary pressure increase occurs in the early phase of injection, whereas the pressure increase is less during later phases. The reason for this phenomenon is that in later phases the 'compressibility factor' is being applied to a larger-and-larger area of the reservoir, and the pressure increase at the well is proportionally less.

? p and Semi-Log Plot



- In the previous example, we considered increases in delta-p at the formation face, i.e., “r” = casing radius. It is also possible, however, to specify any other distance “r” from the wellbore, and consider delta-p buildup at distances outside the wellbore.
- Matthews and Russell’s equation shows that delta-p declines logarithmically with distance from the wellbore. If we assume homogeneous and isotropic conditions in the injection interval, the pressure surface will describe a straight line on semi-log graph paper. We only need to solve for two values of “r” using Matthews and Russell, plot these points on semi-log paper (vertical axis is arithmetic depth and horizontal is log distance “r”), and connect the dots to describe the pressure increase “delta-p” at any distance from the well. Don't use a wellbore calculation as one of the points on this analysis – without a skin test you may not be able to estimate the effective well radius (**Refer to Handout #8-2**).
- Assuming the 20-year lifetime of the well and using r=10 and r=100 feet, we calc ulate corresponding ? p as 104.1 psi (r=10) and 79.3 psi (r=100). These values represent the pressure increase (over existing formation pressure) due to injection of 50 gpm for 20 years. When plotted on semi-log paper, these values describe a straight line. Because delta-p values at any point “r” are additive, we can add the delta p values to the existing formation pressure, shown here as “P”. Note that substitution of different values for injection rate (Q) or aquifer transmissivity (k or b) will provide lines of differing *slope* on the semi-log graph, whereas different “t” values will result in a family of lines of parallel slope.
- This method can also account for injection conditions that are NOT homogeneous and isotropic. Here is how we can adjust the key elements of the equation.
  - o Variable injection rate: define average injection rate using volume-to-date divided by time period.
  - o Two or more injection wells: if nearby, treat as one well with combined injection rate; if not, delta- p for each well is additive at a particular location (e.g., site of potential conduit, different “r” for each well).
  - o Presence of a pumping well: solve for a negative delta-p at the pumping well and subtract from delta-p at radius r.
  - o Change in reservoir properties with distance (k, b, ϕ): Solve for straight line solution for nearest properties; at distance of change, solve for two new delta-p data points, with both r greater than change distance; plot as straight line intersecting first line; each line has different slope.



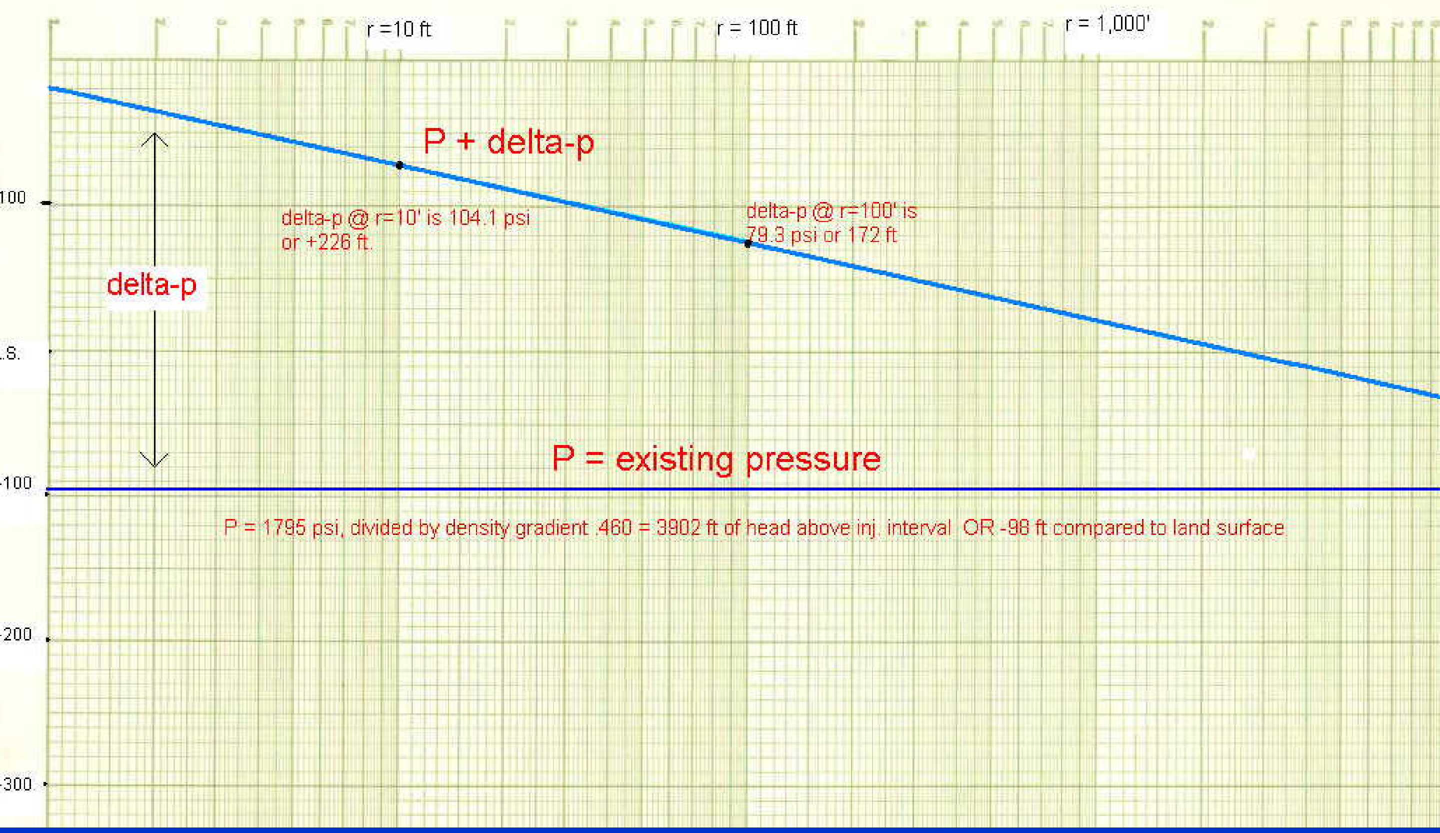
- There are several methods proposed for calculating the zone of endangerment, including the equation first presented in the 1981 UIC regulations (40 CFR 146.6(a)(2)). Most calculation methods usually neglect three critical elements, however: changes in formation properties with distance, differences in water density, and the counter-endangerment, downward pressure exerted by the USDW.
- Consider an example:
  - Pressure increase due to injection causes a column of water to rise in an open hole to a level equivalent to 10 feet of head above the base of a USDW. Considered at the USDW base, the formation fluid is exerting an upward potential equal to 10 feet of hydrostatic head, relative to brine density.
  - However, if the USDW is 200 feet in saturated thickness, the USDW, at its base, is exerting simultaneously a downward potential equal to 200 feet of hydrostatic head, relative to freshwater density.
  - Any movement of fluid is in response to gradient or potential, and the gradient in this case is downward. The USDW water will move (or attempt to move) downward into the injection interval.
  - Only when injection pressure can overcome this downward gradient can there be the potential for upward movement, or endangerment.
- One easy method for analysis of the zone of endangerment is the graphical method used by Region 6 (Browning, 1978).

Graphical Method

- Step 1: Plot "cone of impression" in space
- Solve ? p for two "r" values Add ?p to existing formation pressure
  - (A) Convert "psi" to "feet of head" using gradient
  - (B) Add "feet of head" to (-) depth, and plot on semi-log graph

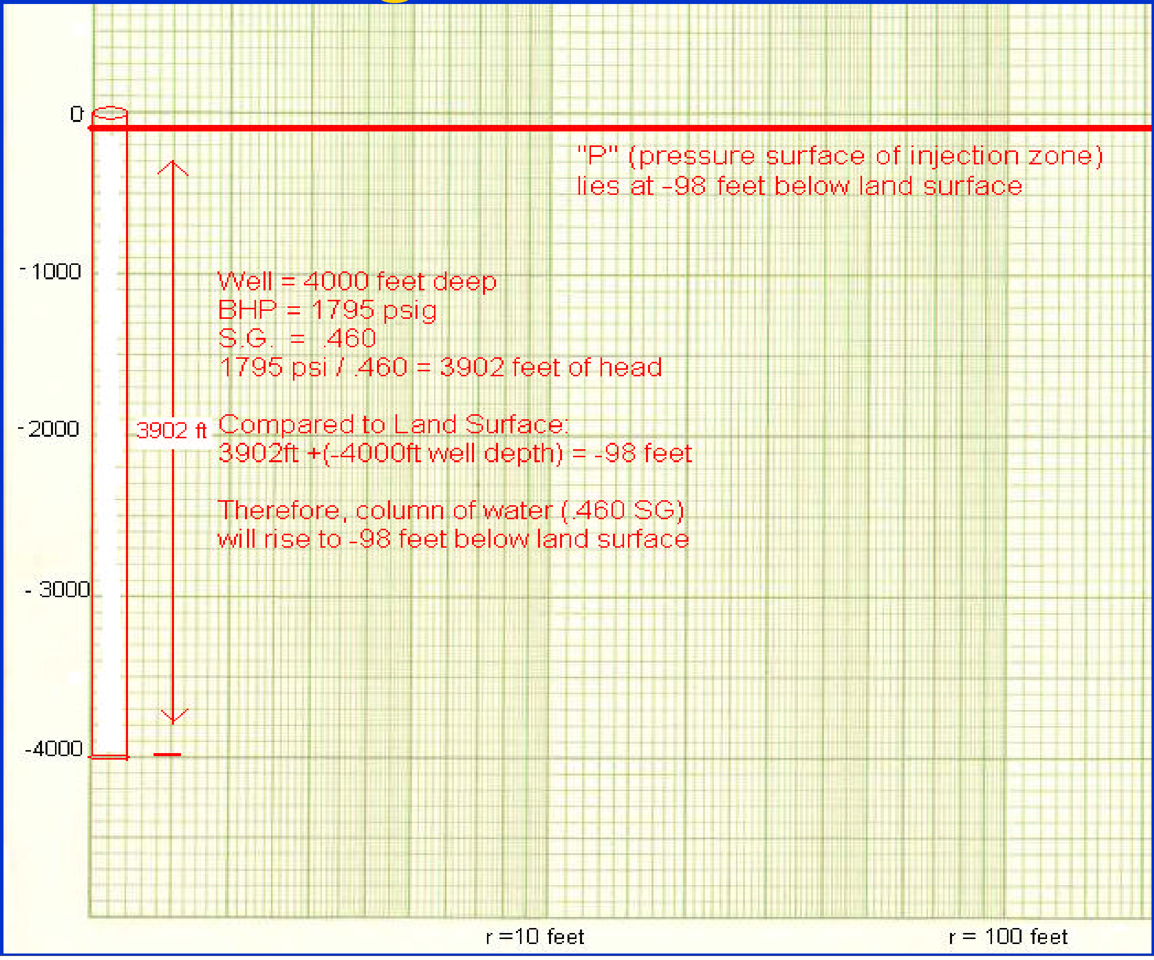
- **Step 1: Plot cone of impression in space.** The pressure change in the injection interval at any distance from the well may be calculated using the Matthews and Russell equation. Correct the analysis for changes in reservoir properties with distance or the presence of an offset injection or production well, if necessary.
- Delta-p is additive to the existing formation pressure before injection commenced (P). Add P and Δ p (psi), and convert to feet of head by dividing each by the density gradient of the formation fluid (psi/ft).
  - **(A)** (previous slide) For our example well, we found that P + delta-p = 1795psi + 104.1 psi for r=10 feet, and 79.3 psi for r=100 feet. The specific gravity of the formation fluid is 1.07, or 0.46 psi/ft gradient (from conversion chart). Convert (P + delta-p) to feet of head of formation brine: 1899.1 psi / .460 = 4128.5 ft of head @ r=10 feet, and 1874.3 psi / .460 = 4074.6 feet of head @ r=100 feet.
  - **(B1)** Consider the height of the fluid column by adding these values to the (negative) depth of the injection interval. Relate to the injection interval depth by adding to the (negative) depth value: -4000 ft of depth + 4128.5 ft of head = +128.5, or a column 128.5 feet above land surface, at r=10 feet. For r=100 feet, -4000 + 4074.6 = +74.6.
  - **(B2)** Plot these values as a straight line on the semi-log plot discussed earlier, substituting "feet (head or depth)" for "psi" on the vertical (arithmetic) axis.
- This plot shows the pressure surface within the injection interval as it exists in space, measured as feet of head of formation brine above the top of the injection interval.

Example Graph



- This is the graph of the example well that we showed earlier.
  - Note that P, the existing pressure in the injection interval, is converted from “psi” to “feet of head of formation brine” by dividing by the density gradient of the brine, .460 psi per foot.
  - The pressure increase due to injection after 20 years (delta-p) was solved for two points (r=10 and r=100) and plotted as a straight line on the semi-log plot.
  - Delta-p is additive to the existing formation pressure, and is also converted to “feet of head of formation brine.”
- Remember that these values can be adjusted for changes with distance from the wellbore.
  - For example, a second injection well located at r=1000 could be solved for a delta-p curve and plotted (a pumping well would use a negative delta-p).
  - The delta-p values are additive at all r’s, and a new cone, characterized by distinct, intersecting slopes, is created.
  - Similarly, if P was found to decrease due to formation “dip” into the subsurface, then P would describe a line of decreasing slope, and delta-p would be additive to that.

Calculating Pressure Surfaces



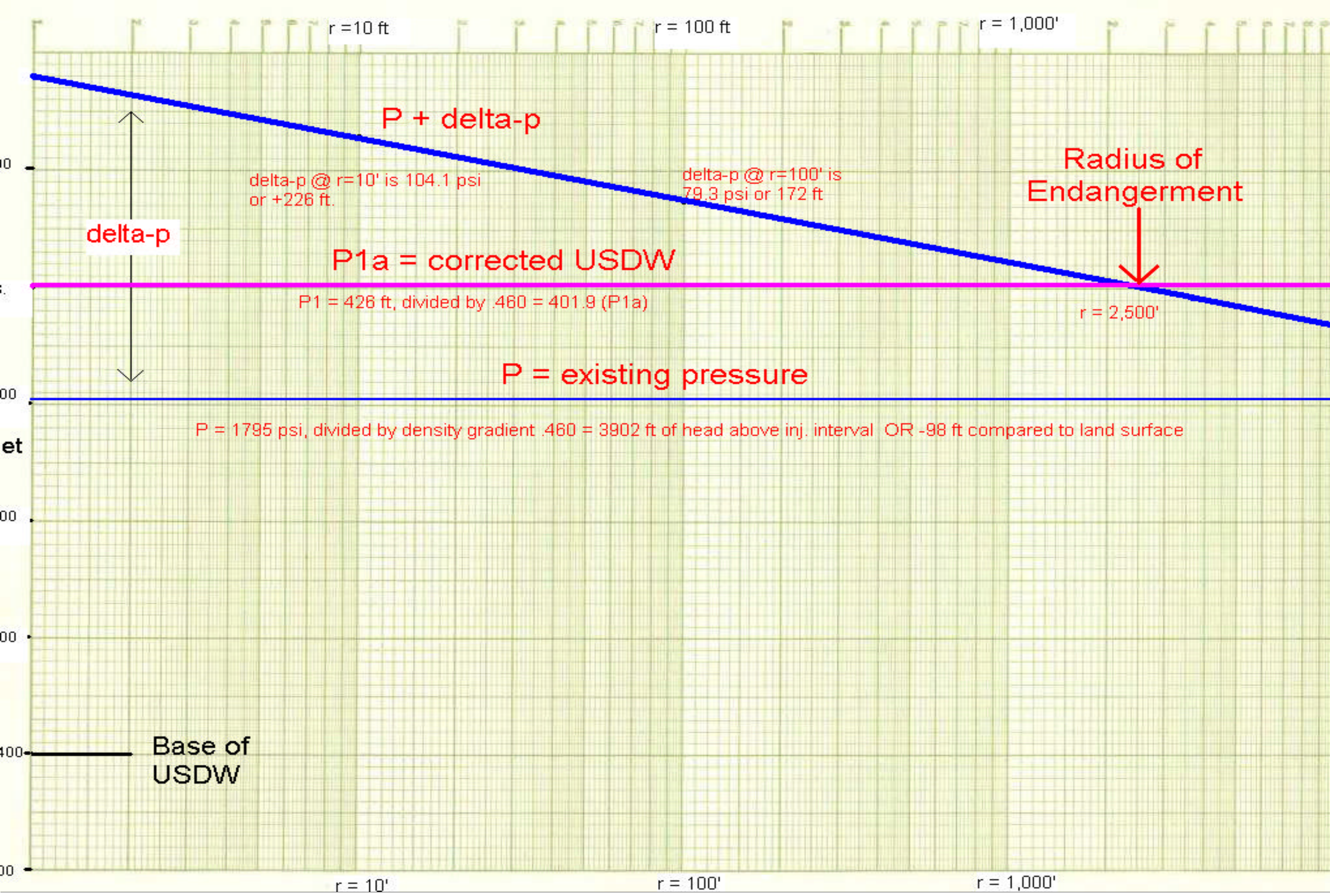
- We are plotting a pressure surface in space. In this case, we used land surface as a datum reference, which is the way most AoR analyses are done. If we have a 4000-foot well, and we have measured the bottom hole pressure as 1795 psi, then we can convert that pressure into feet of head. We must know or estimate the specific gravity of the water in the zone, in this case, .460 at 4000 feet. To convert to feet of head, we divide 1795 psi by .460, and get 3,902 feet of head, as .460 brine.
- The next step is to calculate the position of the pressure surface in space. We add 3902 feet of head to the well depth of minus-4000 feet, and get –98 feet. A column of water in a well that penetrates the injection zone will rise 3902 feet, to 98 feet below land surface.
- If we calculate the value of delta-p at any radius (usually 10 and 100 feet), and add that value to P, the injection zone pressure surface. The result, P plus delta-p, is the pressure surface that exists in the injection zone at radius “r” after time “t.”

Graphical Method

- Step 2: Compare P + ? p to P1a, the density-adjusted pressure surface of the USDW
  - (A) Calculate the height of the USDW water column (P1)
  - (B) Adjust density (USDW / formation gradient)
  - (C) Add to (-) depth of USDW base and plot
- Intersection is radius of endangerment

- Similarly, some pressure (P1) exists at the base of the lowermost USDW, which corresponds to the weight of a column of water in a well that fully penetrates the USDW. Therefore, the second step of the method involves plotting the pressure surface of the USDW in space, and comparing it to that of the injection interval at a point of reference.
- Step 2:
  - **(A)** Calculate the height of a column of water that would exist in a well fully penetrating the USDW section (P1). In most cases, data is available (or can be estimated) concerning the depth to water (for unconfined aquifers) or surface pressure (for artesian aquifers). Consider the height of the column as measured from the base of the lowermost USDW.
  - **(B)** Convert that value into "feet of head of formation brine" by multiplying the height of the USDW column (P1) by the additional density gradient of the formation fluid you used in Step 1B, compared to the density gradient of fresh water (.434).
  - **(C)** For example, consider that a USDW exists from the surface to a depth of 400 feet. The lowermost USDW is a confined, artesian aquifer, and the water level measures 26 feet above surface. Therefore, P1 equals about 426 feet. Using the density gradient of the formation fluid (.460) compared to that of the fresh water column (.434), we find that, as feet of head of formation brine, P1a equals 426 x .434/.460 = 401.9 feet.

Completed Graph



- The pressure surface of the USDW is measured or estimated as the height of a column of water in a fully penetrating well. In this case, we specified a confined, artesian aquifer with a water column equivalent to 126 feet above land surface, or 426 feet. To use this value on the same graph as the other values, we must convert this value to "feet of head of formation brine." To convert from psi, divide by the density gradient of the brine, in this case .460. To convert directly from "feet of USDW head," multiply by the ratio of density gradients: .434 (fresh water) over .460 (brine). Add this value to the (negative) depth value of the USDW base, and plot this value that we call P1a, or P1, adjusted. The intersection of the ? p and P1a lines denotes the radius of the zone of endangerment.
- Remember, if there were a pumping well in the USDW at distance r=1000, we could perform a "negative Q" solution for the Matthews and Russell equation, and plot as "negative delta- p" or cone of *de*pression, that is, subtract the negative values from the P1a of the USDW injector. Note that the P1a line would change to a downward slope, and the radius of endangerment would be much larger.
- We have performed an analysis of hydraulic potential considered at the base of the USDW. This analysis of flow/no flow could also be performed using another depth reference, such as the base of surface casing, depth of a cement plug, etc.
- We used an example which features a measurable radius of the zone of endangerment (i.e., intersection of the pressure surfaces on the graph). There may also be cases in which there is *no* zone of endangerment (i.e., the P1a surface is higher/greater than that of the injection interval) or cases where the zone of endangerment is *infinite* (P+ delta-p is greater than P1a at all values of r).

Short Method

- Use as a check for ¼-mile radius

1) BHP+?p (@1320ft.) \ density gradient
   - 1795+51 / .460 = 4014 feet of head

2) Subtract (well depth – depth to USDW)
   - 4014 – (4000 – 400) = 414 feet of head @usdw

3) USDW saturated thickness x density ratio
   - 400 feet x .433/.460 = 377 feet of head @usdw

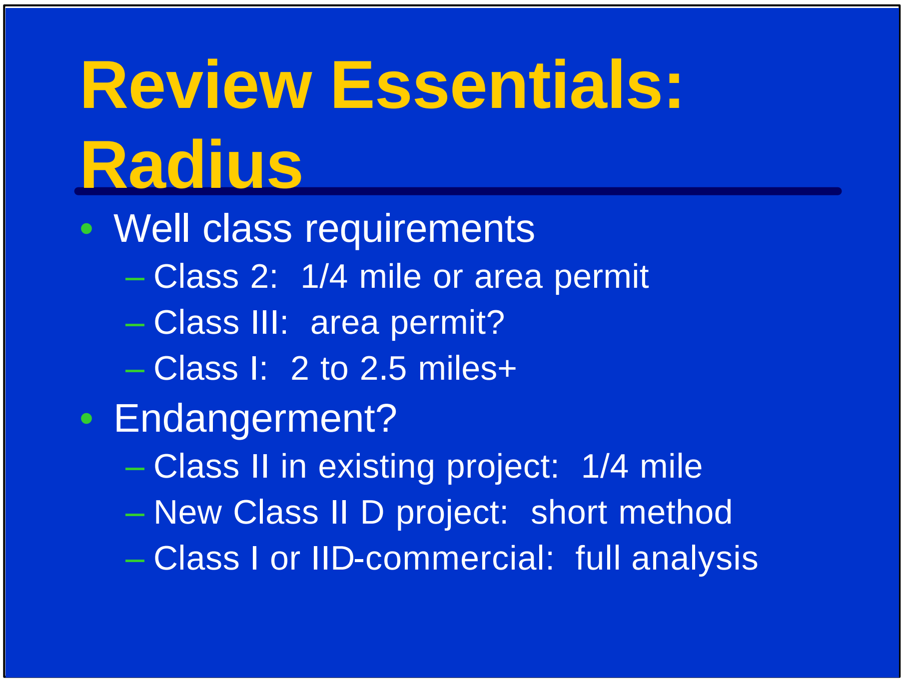
4) Compare 2 and 3
   - If 2>3, ¼-mile AoR radius too small
   - If 2<3, AoR OK
   - 414>377: 1/4–mile AoR not enough

- You can use a short method to check for the applicability of a particular AoR radius, usually the ¼ mile default radius. Use a measured or estimated BHP, and solve delta-p for a radius of 1320 feet (1/4 mile). In the example case, the value is 51 psi. Add BHP and delta-p, and divide by the density gradient, in this case, .460 psi per foot. That gives us an upward gradient of 4014 feet of head.
- We must consider endangerment at the base of the lowermost USDW, although you could also use any other point of reference, such as the top of cement of an offset well. From the value in step 1, subtract the depth to the base of the USDW from the well depth, in this case, 3600 feet. The result is the upward gradient considered at the base of the USDW, or 414 feet of UPWARD head.
- For step 3, adjust the saturated thickness of the usdw by the ratios of density-gradient, in this case, 400 feet times .433 divided by .460. The answer is the downward gradient at the base of the usdw, or 377 feet.
- Now compare 2 and 3. If the upward gradient is larger than the downward gradient, endangerment is indicated and your ¼-mile AoR radius is too small. If 2 is less than 3, ¼ mile is sufficient. In this case, the upward gradient (414 feet) is greater than the downward gradient (377), which indicates that the default radius is not appropriate for this example. If you want to know how big the endangerment radius is, you have to do the extended analysis.

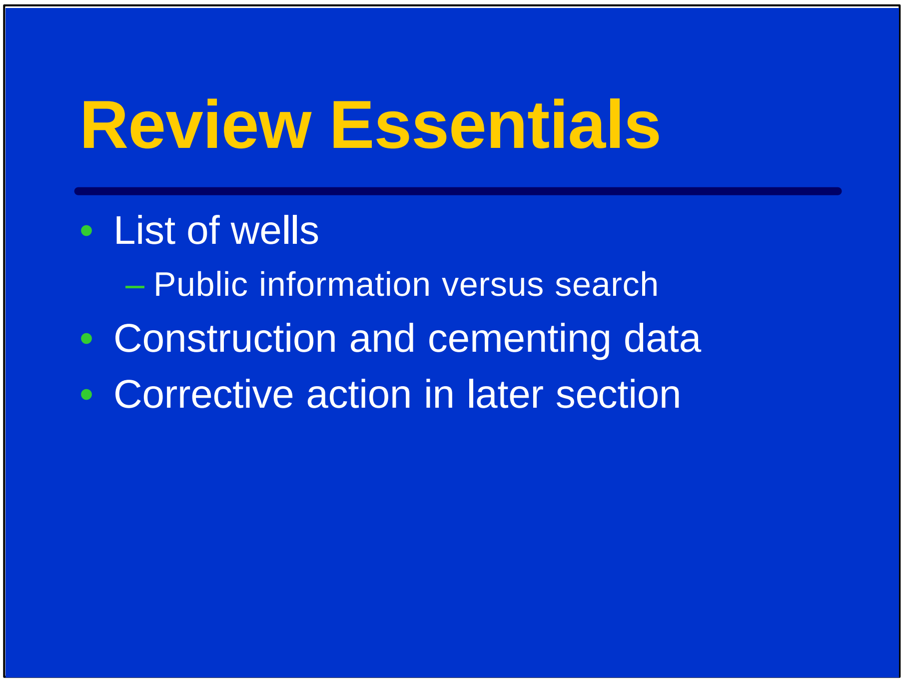
AoR Issues

- Some States use “mud gradient” calculations
  - Piston-displacement of .8 psi/ft mud column
  - Grossly understates radius of endangerment
- Most oil wells and Class II wells feature minimum long-string cement, and short surface casing
  - If injection interval offset, pathway to USDW

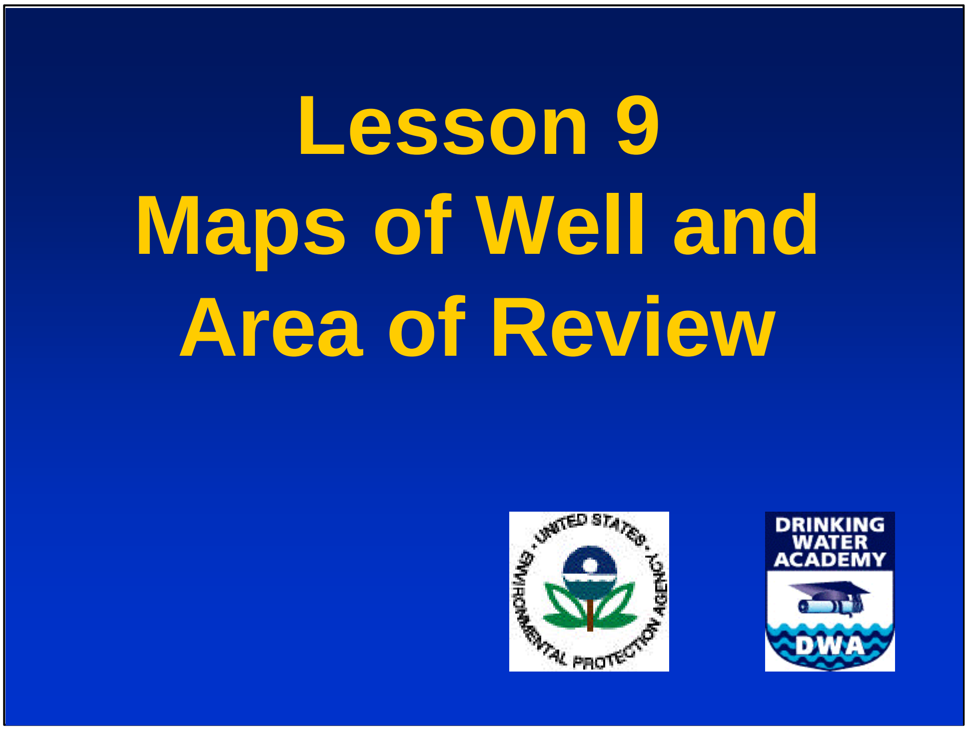
- Remember that any analysis for endangerment assumes a worst case scenario: instantaneous communication between the injection interval and the USDW through an open hole. This is unlikely for two reasons: 1) unless the abandoned wellbore is cased, pressure will leak off into intervening permeable layers, and 2) the presence of mud or other fluids in the abandoned wellbore will delay or prevent communication. Some State agencies use a calculation that incorporates a “mud gradient” of up to .8 psi/ft, that is, includes the weight (or gradient) of a column of mud in the abandoned hole. Unfortunately, these calculations imply that a mud column must be literally increased to the level of the USDW before flow will take place. This piston-like displacement of the mud column is highly unlikely, and laboratory studies show that flow in mud occurs through wormholes (wet mud) and shrinkage discontinuities (drier mud), and along the borehole boundary. The use of the mud gradient equation unfortunately results in grossly understated zones of endangerment.
- A common scenario in Class I and II involves the presence of active or plugged production wells that were not fully cemented. Almost all production wells and the vast majority of Class II wells do not feature complete cement of the long-string casing, but rather feature cement that extends as little as 100 feet above the top of the injection interval. The balance of the long-string/borehole annulus is filled with diluted drilling mud, or whatever fluid was in the borehole at the time of cementing. If this uncemented casing is opposite the injection interval, flow can occur along the *outside* of the uncemented long-string casing. Note also that all production wells (and most Class II injection wells) feature surface casing that does not extend to the base of USDWs. This situation provides a pathway directly from the injection interval into USDWs.



- Here is a partial list of the steps to take to review an AoR attachment for a permit application.
- First, what class of well are we dealing with? Most UIC programs will automatically specify the ¼ mile fixed radius for Class II wells, with the notable exception of Class II-D commercial. Furthermore, many Class II wells may be part of an existing area permit, and no further analysis is necessary (assuming the well meets the conditions of the previous area permit). Most programs also use area permits for Class III wells. If you are reviewing a new area permit, remember that the AoR analysis extends 1/4 mile from the project boundary. The minimum federal requirement for all but Class I hazardous waste disposal wells is 1/4 mile. However, Class I wells and Class II-D commercial wells may be required to review an AoR as large as a 2 or 2.5 mile radius, due to the type and volume of fluids to be injected. Class I hazardous wells are required to use at least a 2-mile radius (40 CRF 146.63).
- Regardless of fixed radii or the usual practices or policies in your program, you have to ask yourself: does this well pose a threat of endangerment? If you have even a suspicion, perform an analysis like the one shown here, or some other method. It is not likely that a Class II well in an existing field is really going to endanger anything that wasn't already endangered in the past; you can usually feel safe in allowing the ¼ mile radius. But for new Class II projects or II-D wells in a new disposal zone, at least consider the short endangerment analysis. For Class I wells and II D commercial wells, apply some analysis as a rule. In fact, you should never permit ANY Class I well without a complete endangerment analysis.



- Once you have answered the questions of endangerment and established an appropriate radius, these are the next things to look for.
- The operator will provide a list of wells that penetrate the injection zone. For Classes II and III, the operator can use "information from the public record." For Class I wells, however, the operator should look outside the typical API and "Oil Scout" reports, but check directly with the State oil and gas agency, county records, etc. In cases of known endangerment, some programs have required operators to conduct landowner interviews or geophysical investigations.
- Regardless of whether or not you have defined endangerment, make a graph of the depths of wells that the operator has identified in the AoR. Better yet, instruct the applicant to provide you with a graph as a visual aid in your analysis. Better still, if you have done the graphical analysis we did as an exercise, you can plot the well depths and construction right on the graph.
    - Make a depth versus distance plot and lay out the injection and confining zones and the base of USDWs. On that graph, plot the wells in the AoR, using distance from the injection well and depth. Note any important construction details on the plot, like top of cement or location of plugs.
    - Corrective action may be necessary to deal with wells in the AoR that might serve as conduits. We will cover corrective action in another section.



- All Class I, II and III well permit applications are required to have an Attachment B. This attachment is a topographic map that extends one mile beyond the property boundaries of the injection well facility. It is up to the EPA to decide if this map will be required for a Class V injection well permit. Certainly, deeper, more high tech Class V wells that inject under pressure should be required to submit this information. For Class V wells that are gravity fed, the necessity and appropriateness of submission of this map should be based on site-specific data that indicates the likelihood of the injection well having an impact for any distance away from the well itself. For instance, even a gravity fed well that receives a relatively constant flow of one-half to one GPM can impact a highly permeable aquifer for some distance.
- The following things must be illustrated on the map *for the facility*, according to 40 CFR 144.31(e)(7). Again, the extent of requirements for a Class V well permit will be site-specific and this list may be altered for this well class only.
  - Injection wells or project area (for area permit);
  - All intake and discharge structures;
  - All hazardous waste treatment, storage or disposal facilities (TSDFs); and
  - For area permits, the Attachment B instructions require the operator to illustrate the distribution manifold for the wells and all system monitoring points.

Purpose of Attachment B

- Visual depiction of potential migration conduits
- Identify other operations and land uses that may affect or be affected by the UIC facility

- The purpose of the map for the AOR is to provide a visual depiction of the facility and potential conduits for upward migration of injection fluids.
- It also provides a visual depiction of nearby land uses and operations that could be impacted by, or could cause impact to, the UIC facility. This information will not necessarily cause the UIC program to refuse to issue the permit, since proximity of homes, schools, and other land uses are not considered in the UIC statutes and regulations. However, if multiple receptors are located close to the facility, this may cause you to add conditions to the permit, especially if there are drinking water wells nearby.
- Also, the information about nearby land use is helpful so you can anticipate public concerns. If the well is in a very rural area, it is less likely to prompt significant public concern compared to a UIC well being permitted in or very near a residential area, for instance.

Information in the AOR

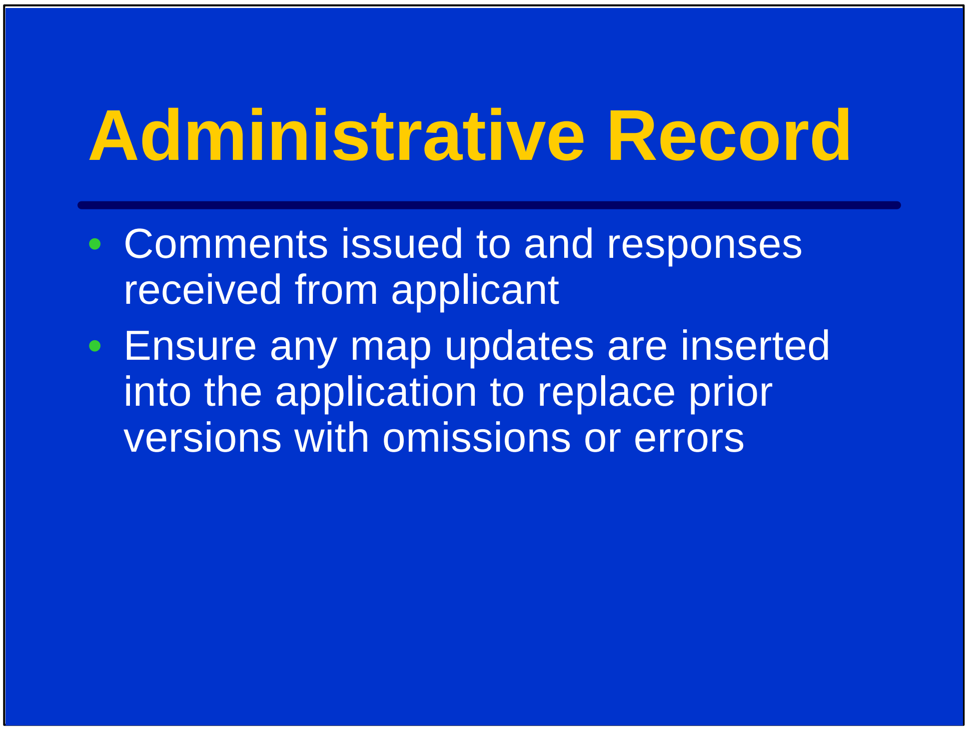
- Producing, injection and abandoned wells
- Dry holes
- Surface water bodies
- Mines and quarries
- Residences and roads
- Known or suspected faults

- From here it gets a little more complicated. The entire list of items required is on page 4 of the permit application. Essentially, all types of wells, all mines and quarries, and all surface structures *within the AOR* (e.g., houses, roads, faults that extend to the surface, manufacturing facilities,) must be identified.
- *Within 1/4 mile of the facility boundary*, all wells, springs, surface water bodies and drinking water wells must be specifically identified.
- The specific requirements of the application form are different among the three well classes, so refer to the directions for Attachment B when reviewing the application.
- For facilities in populated areas, a significant amount of information may be included in the list above. The good news for the applicant is that the requirement is limited to publicly available information, so no field verification is required.

Frequent Omissions

- Map doesn’t extend one mile from property boundaries of the source
- Facility features are out of date
- Locations of drinking water supplies not consistent with PWSS program records
- Map scale is not meaningful

- When reviewing the map, you should be aware that it is not uncommon for this seemingly simple requirement to be a stumbling block to some operators.
- The map may not be prepared for a wide enough area. For a larger project, the applicant may be concerned that extending one mile beyond the boundary of the project is onerous. But it is the regulatory requirement, so that is the size map that must be submitted.
- The facility details may not be up to date, so review those and discuss questions with the applicant.
- Check with your PWSS counterpart to see if all public water supplies have been identified in the appropriate area.
- While a large enough map may be submitted, is it at a scale that is meaningful and legible? If not, request that it be resubmitted so that you can use it for your review.



- As with all portions of the permit, any comments issued by EPA to the applicant, and any responses received from the applicant, regarding changes to application pieces such as the AOR map, must be placed in the administrative record.
- Also, make sure that any updated maps or data supporting the map are inserted into the application. It is not uncommon for replacement maps to be set aside, and issues one thought were resolved crop back up again. Paper and data management is critical to having a complete and accurate administrative record.

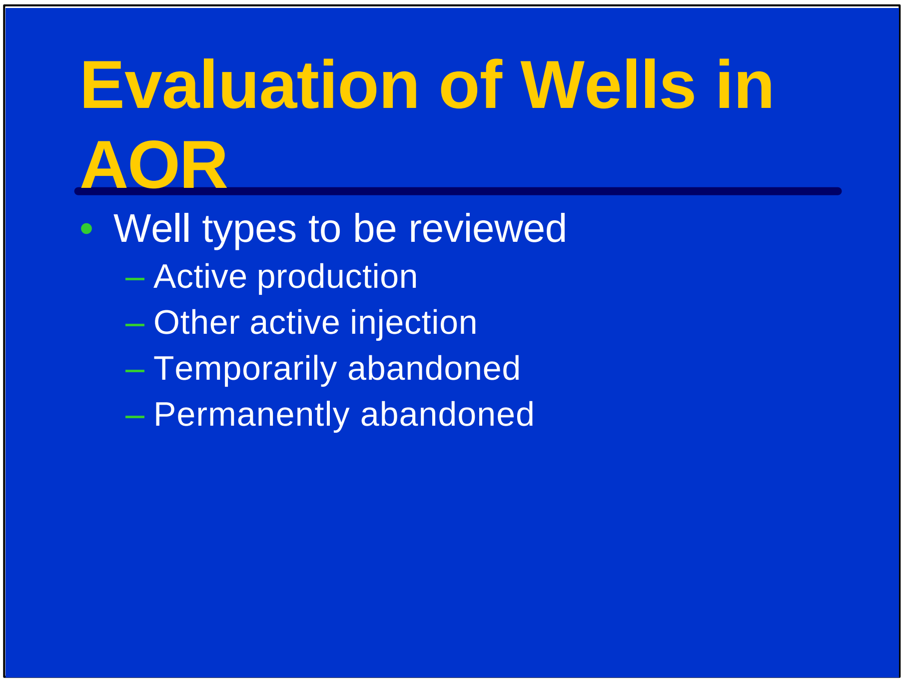
Lesson 10
Corrective Action Plan and Well Data

- We have talked about the AOR and defined it. However, a complete AOR analysis considers the relationship between pressure surfaces that co-exist in time and three-dimensional space. That is why a well owner or operator has to look for potential natural or man-made conduits in the area of review. This information must be submitted in Attachment C of a UIC Permit Application.
- In this section, we will talk about what the regulations require for the analysis, what information needs to be evaluated, steps that an owner or operator can take, and how the permit writer evaluates a plan for dealing with potential conduits within the AOR.
- Please be aware that Corrective Action (CA) is defined differently in the hazardous waste regulations under RCRA compared to what we will discuss in this section. Additional CA requirements may apply to a Class IH site as imposed by a RCRA permit. This section of the course deals strictly with CA requirements of the UIC rules. The UIC Program Guidance #45, entitled Interim Guidance Concerning Corrective Action for Prior and Continuing Releases, April 9, 1985, describes how EPA implements CA requirements of RCRA for injection wells. The overlap between SDWA and RCRA CA can be complicated. If you become involved in evaluating a Class IH permit application, you should discuss this issue with a permit writer who understands the limits of the UIC requirements and the overlap with the RCRA requirements.

Purpose of Requirement

- Integrity of UIC system is dependent on proper containment
- Wells needing CA are likely vertical migration conduits, causing contamination
- Must identify conduits and ensure proposed measures are adequate to protect USDWs

- We have discussed previously how important the concept of USDW protection is to the UIC Program. Conduits that can allow fluids to migrate upward into a USDW include naturally occurring faults, natural or induced fractures, shafts from mining or other operations, and other wells. The corrective action plan requirements of the UIC regulations focus on other wells that exist in the AOR. Siting requirements are intended to address the other types of conduits.
- The integrity of the whole UIC well system concept is based on the absence of vertical conduits to USDWs. Proper containment will not exist if unidentified conduits exist within the area where changes in pressure will drive fluids upward into USDWs.
- EPA needs to be aware of any identified conduits, have the authority to review data on the conduits, and ensure that all have been properly identified and addressed.



- Wells that need to be evaluated may be abandoned wells that were poorly plugged (or not plugged at all), active wells that were not properly cemented, or temporarily abandoned wells that could pose a risk due procedures used. The pressure increase in the injection interval can force waste (or saline formation fluids) up these conduits and into USDWs. Several high-profile examples of this phenomenon caused Congress to include UIC issues in their consideration of SDWA.
- Depending upon the depth of the injection well being permitted, types of wells may include oil or natural gas production, water producing wells, or other injection wells of any Class.
- The corrective action rules are located in 40 CFR 144.55, 146.7, and 146.64 (for Class IH wells). The requirements for Class II wells are a little different from those for Classes I and II, but the essential concept is the same.
- The search is limited to reasonably available data, as stated on the instructions for the Federal UIC Permit Application. In some unusual circumstances, field work may come into play. However, the review generally is based on records available to the public.

What is the Requirement?

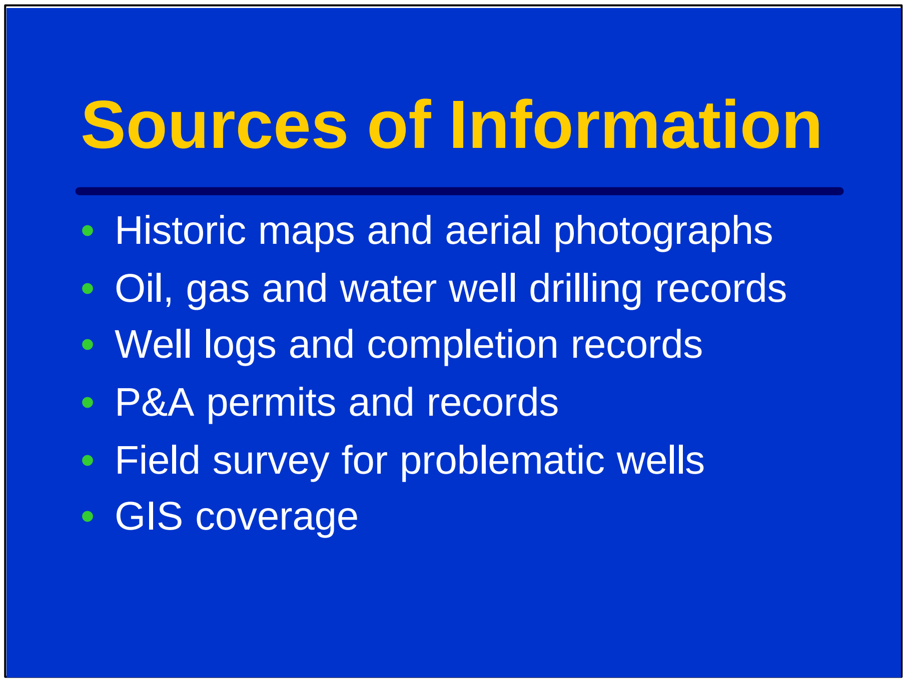
- UIC regulations require three steps
  - Identification of certain wells in AOR
  - Determining which of the wells need corrective action
  - Developing and submitting a plan for the action

- First, wells that may allow migration of fluids into USDWs must be identified. For Class I and Class III wells, all known wells in the AOR that are completed into the injection zone of the well being permitted must be identified. This requirement also applies to Class II wells that were drilled after April 1983 (when the rule was first effective). Permit applications for Class II wells that are operating over the injection formation fracture pressure must identify all known wells within the AOR that penetrate formations affected by the increase in pressure. Some of the wells may be identified on the map of the AOR, but maps are not always current. Because of this, a search needs to be conducted beyond the information presented on the topographic map. In addition to a map, the applicant must provide tabulated details of all the wells that lie within the AOR or zone of endangering influence and penetrate the injection zone.
- For each well that is identified as being completed at the depths listed above, the applicant then has to review the well records to evaluate how the well was constructed and, if it is abandoned, how it was plugged. Construction and/or plugging records need to show that the well is not a potential conduit. This means the cement or well log records need to show that cement is present in sufficient amounts and with proper placement behind pipe to prevent upward fluid movement. For plugged wells, a sufficient number of plugs at appropriate depths need to be in place to prevent fluid migrating upward to a USDW.
- If the applicant discovers that some wells exist that have not been properly plugged, or perhaps never were plugged, that temporary abandonment procedures are not adequate, or that construction records indicate that cement placement is not adequate to protect USDWs, the applicant has to submit a CA plan to deal with these wells.
- The CA plan is reviewed by EPA and must be determined to be "adequate."

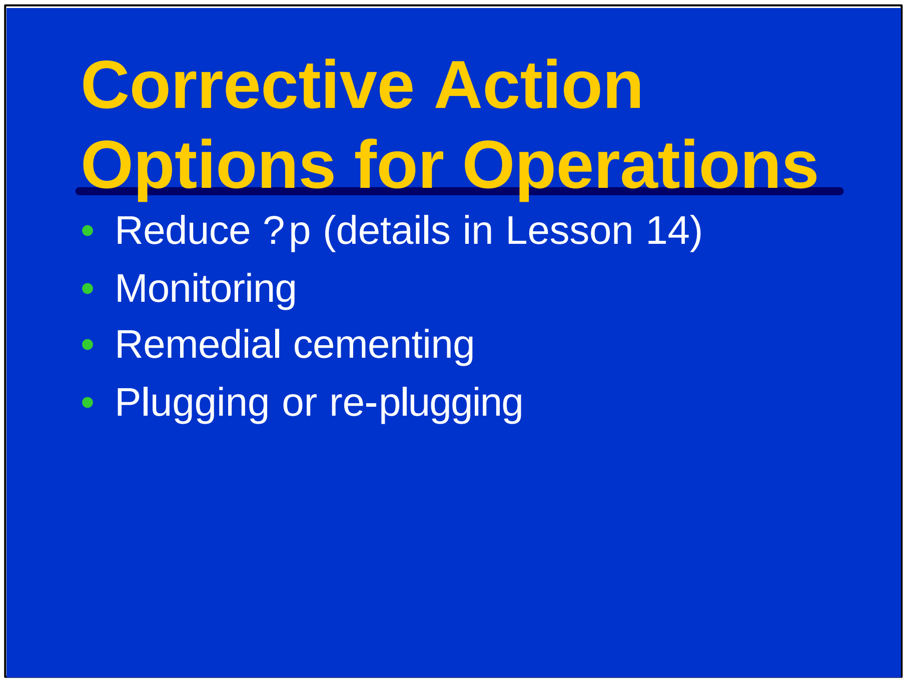
CA Plan Evaluation

- What is being injected and how much
- Native fluids and injection by-products
- Potentially affected population
- Geology and hydrology
- Injection history
- P&A records and procedures
- Hydraulic connections with USDWs

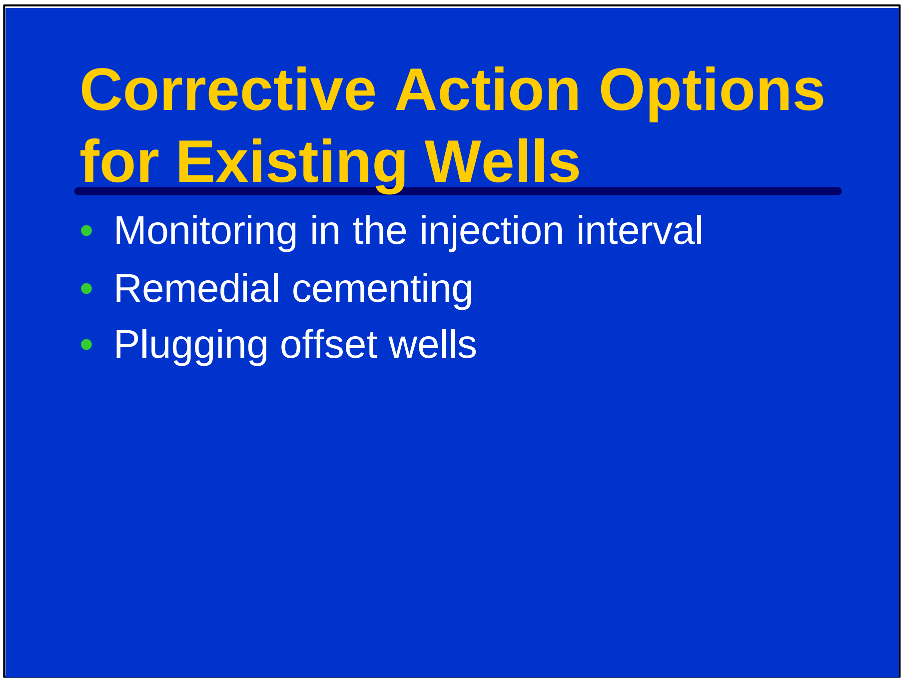
- The regulations list nine factors that need to be considered when determining if a CA plan is "adequate." The list is found at 40 CFR 146.7. Additional items must be considered for a Class IH CA plan, as listed in 40 CFR 146.64. We will focus on the basic requirements in this course. You should review 40 CFR 146.64 if you are involved with a Class I H well.
- First, you need to consider the character and quantity of the fluid being injected. Generally speaking, larger volumes injected 24 hours a day will pose greater risk than a small stream injected intermittently, since the larger volume will cause larger subsurface pressure increases. However, we reiterate that a site-specific analysis needs to be completed, as geologic conditions can change significantly from site to site, affecting the Δp that determines whether endangerment will occur. Also, different fluids pose varying risks to USDWs, so fluid composition needs to be considered.
- The nature of the native fluids or by-products of injection need to be evaluated. Not only injected fluids, but native formation fluids and those substances created by interaction of the injectate and native formation fluids may migrate through an artificial conduit.
- The potentially affected population is evaluated to see if sensitive populations exist, and how many people may be affected if a conduit is present.
- Geology and hydrology must be evaluated, since the characteristics of the injection formations, confining layers and USDWs vary so greatly from one site to another.
- The history of the injection operation must be examined. If the well subject to permitting has been operating for a significant amount of time and the applicant can show that no migration has occurred, this needs to be considered. Also, the historic operating pressures of the operation need to be considered.
- Well completion and plugging records help the Agency evaluate what is present in the subsurface.
- An evaluation of procedures that were used when an existing well was plugged helps you decide whether you can have confidence in the plugging job that is in place.
- Hydraulic connections with USDWs are critical, for obvious reasons.



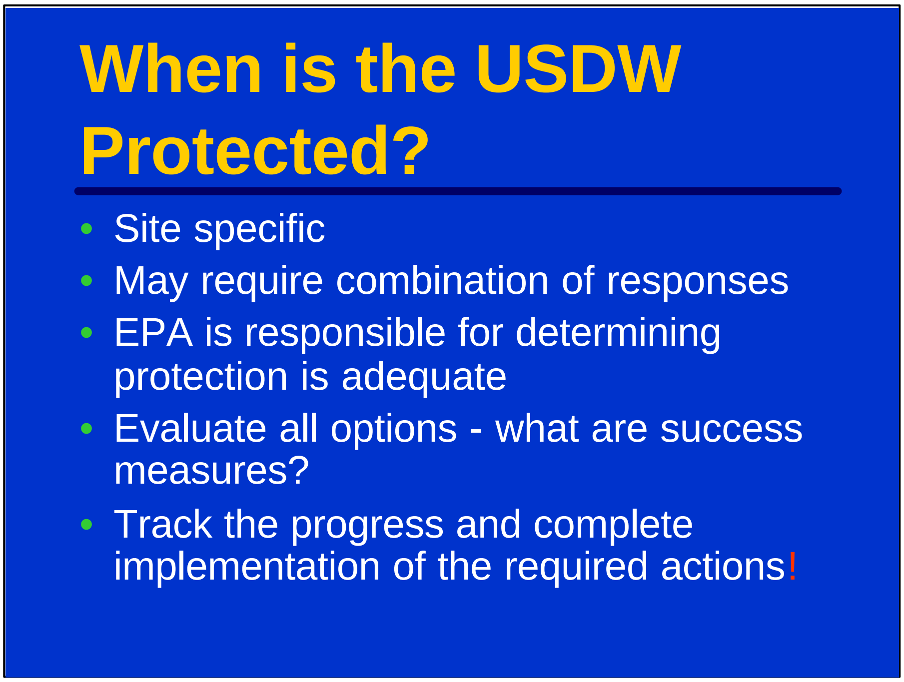
- Where can the applicant or the permit reviewer find the information needed? The State historical society or other repositories of historical information may be able to provide information on historic drilling practices in a given county or township. Historic maps, aerial photographs, and other publications often are available from this source as well.
- The State Geological Survey usually retains records of well drilling activities, including well logs and completion records from across the State. The records may be available in any number of record formats, from electronic access to plain old-fashioned paper.
- Historic procedures used in plugging and abandoning wells may be available from agencies that issued permits or approvals for closing a well. Permits and records of well closures are available from the agencies that regulate the various well types, State Geological Survey, and/or the State historical society.
- With the tremendous advancements in GIS technology and its availability, many States and Regions now can generate plots of the AOR to assist both the permit applicant and the regulator in determining if problematic wells may exist. Where very old wells exist, however, historic records still should be searched, even with the best of GIS coverage. Frequently, extremely old well records will not have been incorporated into a GIS database.
- Occasionally, one or two wells may turn up that are problematic, where their status is uncertain. A field survey can be conducted to locate and evaluate these wells if necessary. Generally, this will not be necessary.
- Let's assume that the publicly accessible information has been located and reviewed, and these data indicate that one or more wells exist that pose a risk to USDWs. Perhaps a well was not plugged prior to abandonment. This means there may be a way for fluids to move upward into a USDW as a result of the injection operation being considered in the permit application.



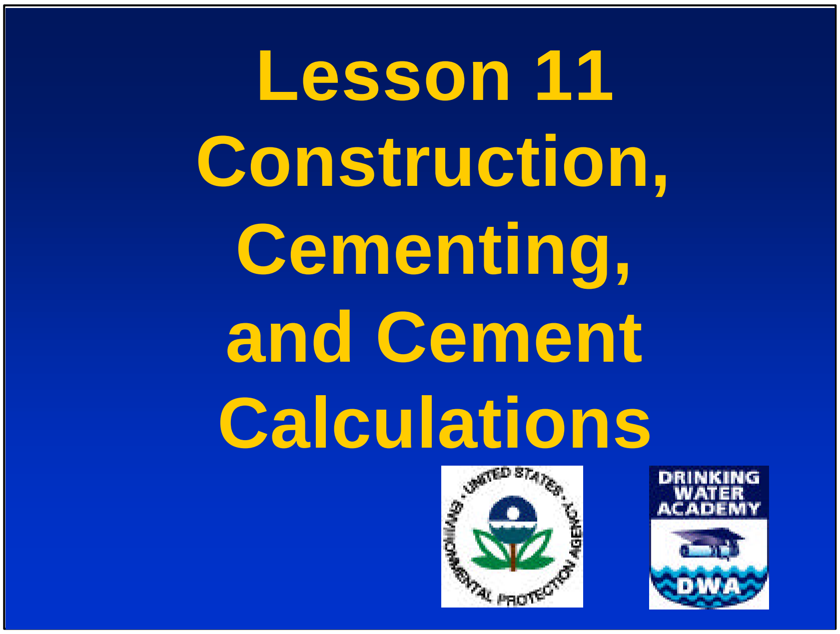
- What now? It is best to work with the operator and guide his response regarding what can and can not be done to mitigate or eliminate the endangerment, especially if the operator is not experienced in dealing with these issues.
- As we have shown previously, the driving force of endangerment is Δ p. If the operator can reduce the effective Δ p in the injection interval, the operator may be able to operate without restrictions. Remember the analysis for WHIP and the elements of the delta-p equation. The methods include:
    - Lowering the injection rate;
    - Reducing the viscosity and/or specific gravity of the waste; or
    - Increasing the thickness of the injection interval by perforating more of the section.
- In most cases, one or more of these modifications will mitigate endangerment. Of course, any of these modifications or limitations need to be addressed in the permit language.
- In many process operations, however, modifications to the injection scheme are not possible, and further corrective action is needed.



- If the endangerment involves an unplugged well or point source, a common form of corrective action is the use of a monitoring well completed in the injection interval. The well should be located between the injection well and the unplugged well, nearer to the latter. The permit would establish an action level Δ p value for the monitoring well, or sampling for the arrival of the waste front. In either case, the action level standards can not be exceeded, and signal the closure of the well. Although monitoring wells are effective, make sure that the well is also capable of internal and external MI testing.
- Other forms of monitoring may be implemented as well, such as visual observations. UIC Program Guidance #23, Corrective Action Requirements, July 27, 1981, provides EPA policy on specifying monitoring requirements under the CA rules for UIC wells.
- Remedial cementing is a common method of corrective action, especially for Class II projects. In many cases, a relatively shallow disposal zone in a field featuring a deep production zone will expose the uncemented portion of partially-cemented long-string casings of the producing wells. In this case, if Δ p remedies are not available, operators will squeeze-cement all producing wells along the interval exposed to Class II injection. This is common in many fields, where only shallow zones offer the permeability to accept the volume of produced water. Squeeze-cementing is not a cure-all for repairing a poorly cemented well, but it is usually effective in preventing upward migration along uncemented casing.
- Plugging offset wells is an effective method of corrective action. Casing must be pulled from the wells, however, so that a wall-to-wall plug can prevent upward migration outside the casing. Re-entering poorly plugged wells can be a technical challenge and immensely expensive. It is very difficult to measure the effectiveness of these procedures, because deviated boreholes and other problems can cause more trouble than the original unplugged well would have. Use this option very sparingly, as there are no guarantees or measurements of success.



- As you can see, the decision about what level of CA is needed is definitely site-specific. The actions taken for a given permitting project may require anything from no action at all to multiple CA steps.
- The regulations allow EPA to decide what is adequate, given the variety of factors that are listed in the rules that must be considered for CA. It is important to evaluate all options, and ensure that you have a means of measuring the success of the selected options. Otherwise, you cannot know if the USDW is being protected or not.
- For a permit renewal application, it is important to ensure that the applicant has contacted appropriate agencies and updated recent drilling and other information so that EPA can have confidence that no new conduits are present.
- As with all portions of the application review, document your decisions in the administrative record, and make sure that any updated plan submissions are inserted into the application.
- Beyond this basic paperwork, it is also extremely important to track the progress of the required corrective action and verify all necessary steps have been completed. You may require the applicant to file periodic reports on CA progress; inspect the site to verify completion of certain steps; or use other means to accomplish the necessary tracking. Just remember that if you do not track the CA, it may not be completed or may be only partially implemented on an on-going basis. Without this key step, you do not know if the necessary protective measures are truly in place.

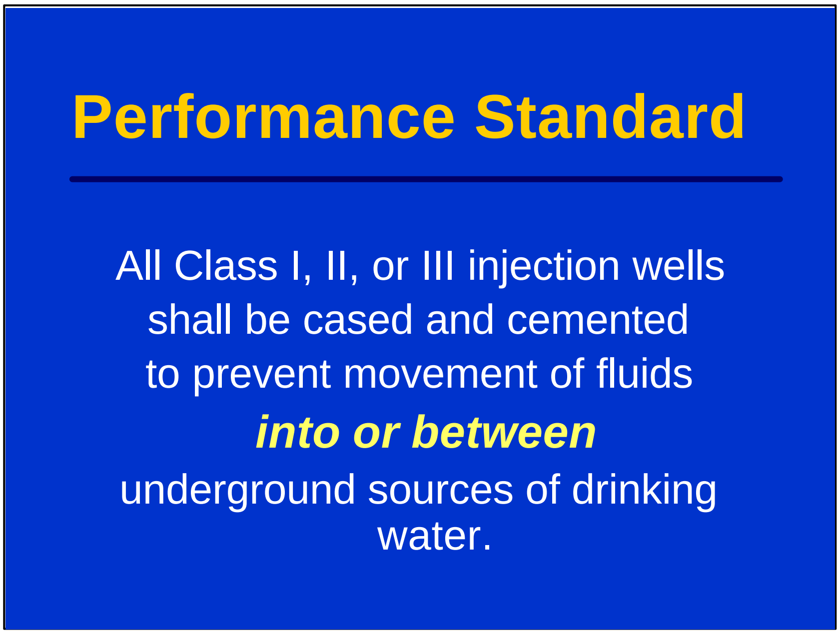


- This section discusses the processes of well construction and cementing, as they apply to permit analysis.
- Construction and cementing standards and oversight form the basis for injection well regulation under the UIC program. Most of the immediate threats to USDWs originate with poor construction and cementing practices. Regions and States witness some of the construction and cementing procedures for many Class I wells, but few Class II and III procedures are witnessed. In most cases, the operator proposes a well design and reports the results of construction to the UIC primacy agency. Permit standards and conditions that are technically correct and appropriate for each well class and geologic environment ensure that USDWs are protected.
- In this section, we will consider the technical aspects of reviewing a construction program. Later today, we will also review an actual construction program, step by step.
- You may also want to refer to two papers by the UIC Technical Work Group:
  - o Use of Annulus Additives to Address Leaks in Deep Injection Wells (http://www.epa.gov/r5water/uic/issue5.htm); and
  - o Cementing Requirements in Direct Implementation Programs to Achieve Part II of Mechanical Integrity in Class II Injection Wells (http://www.epa.gov/r5water/uic/cement.pdf).

Attachments L and M

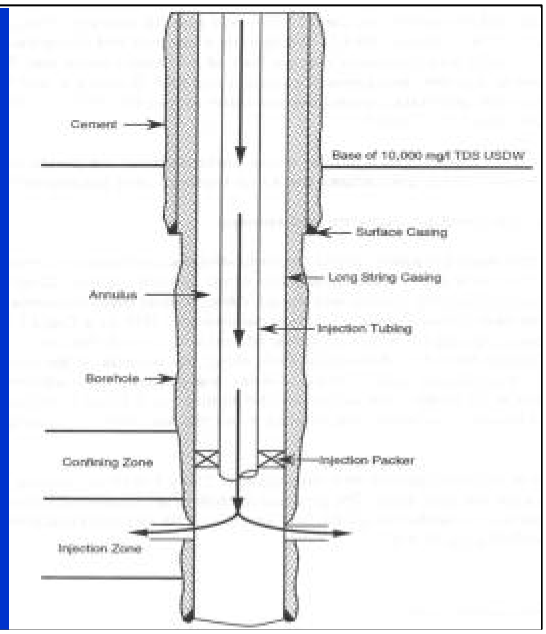
- Attachment L: Construction procedures
- Attachment M: Construction details

- Construction standards are contained in 40 CFR 146.12 for Class I, 40 CFR 146.22 for Class II, and 40 CFR 146.32 for Class III.
- These standards are addressed in a permit application in Attachments L and M.
- Attachment L requires the applicant to discuss the construction procedures to be utilized. This should include details of the casing and cementing program, logging procedures, deviation checks, and the driving, testing and coring program, and proposed annulus fluid. The permit applicant must submit justifying data if requesting to use an alternative to packer for Class I.
- Attachment M requires the applicant to submit schematic or other appropriate drawings of the surface and subsurface construction details of the well.

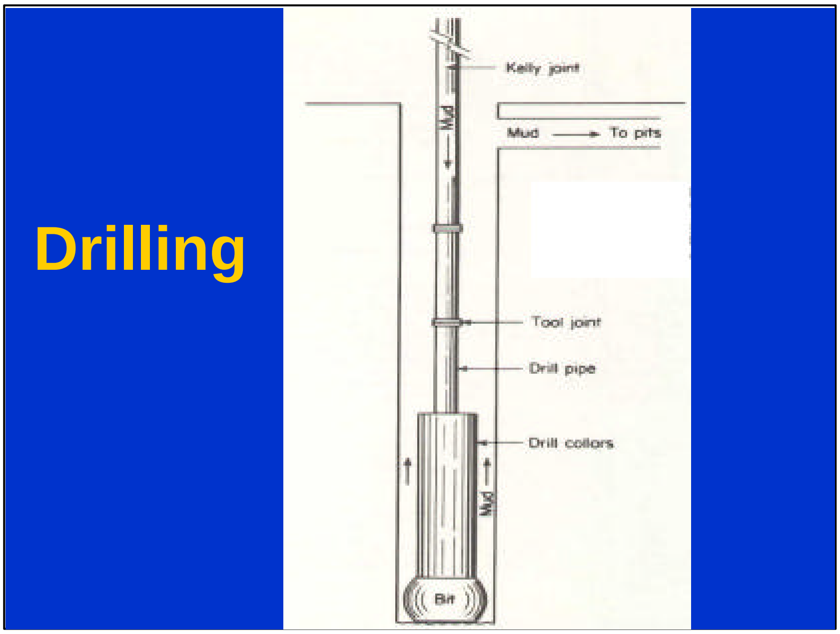


- The absolute goal of the UIC program is to prevent injection from putting anything whatsoever into a USDW. It is easy to find agreement that fluid should not move "into" a USDW. But the regulations have always specified that movement is also prohibited "between" USDWs; for example, 7,000 TDS waters flowing into 1,000 TDS waters.
- The only problem with "between" is that it requires 100 percent cementing of the casing. The vast majority of Class II wells do not feature complete cementing, and many State programs do not always require complete adherence to the principle of "between." Keep this in mind when reviewing permits issued by many State agencies.

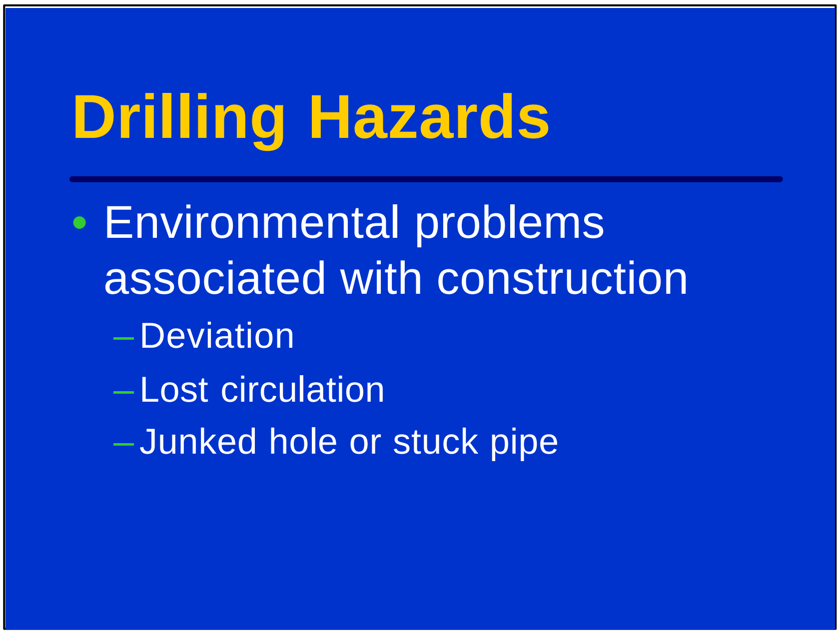
Injection Well Components



- A typical injection well is composed of several key components, and best fits the description of a pipe-within-a-pipe-within-a-pipe.
- Surface casing extends from the surface to the base of the lowermost USDW. For Class II wells in some States, the depth of surface casing may be prescribed according to a different standard, for example, to the base of 3,000 mg/l TDS rather than 10,000 (e.g., Texas), or as 10 percent of the total well depth (e.g., California and Arkansas). Surface casing represents the outermost string of pipe, and its purposes are to protect USDWs from the effects of the drilling process, and to furnish a redundant layer of protection for USDWs. Surface casing sizes range from 6½ to 15 inches in typical wells, or up to 60 inches in municipal wells. Surface casing is almost always fully cemented into the borehole.
- Intermediate or long-string casing extends from the surface to or through the injection zone. Typically from 4½ to 10 inches in diameter, long-string casing is the primary layer of protection for the well. The casing is cemented into the borehole to prevent fluid movement outside the pipe along casing. For Class II wells, the long-string may be only partially cemented, and cement typically extends 100 feet above the confining zone.
- Tubing carries the waste from the surface to the injection interval. Typically from 2½ to 7 inches in diameter, it is hung from the wellhead and set on a packer. The wellhead and packer seal the annulus and provide a method of pressure testing for leaks. In Class I wells, the annulus is maintained at a constant pressure, for continuous monitoring of annulus integrity. Class I NH wells are allowed to request an exemption from using a packer. A prudent permit writer would have to have a ***very*** persuasive reason to exempt the packer. The packer-wellhead annulus forms the first line of defense in the UIC program, in that it allows the well to be self-monitoring. Packerless wells generally do not provide the same level of protection.
- The injectate enters the injection interval through a well screen and gravel pack or through a series of perforations of the long-string casing.
- This diagram features typical Class I construction. The differences between Class I and other classes involves the extent of long-string cement (Class II), the amount or presence of surface casing (Classes II and III), and the presence of tubing and/or packer (Class IM, IIH, and III).



- Almost all injection wells are drilled using rotary methods. Rotary drilling is boring a hole by using a rotating bit to which downward force is applied. The bit is attached to and rotated by a drill pipe, which extends from the drill face to the turntable on the rig floor. Drilling fluid, usually mud, is circulated down the drill pipe, past the bit, and upward between the drill pipe and the hole. The drilling fluid carries the rock chips and cuttings up the hole. The cuttings are separated from the mud for analysis of the drilling progress, and the mud is reconditioned and continually reused.
- The rig turntable uses a Kelly bushing, which is a joint of square tubing that fits in the square hole in the turntable, to turn the drill pipe. Mud is pumped down the tubing and back up the hole. When 20 or 30 feet of hole is made, another joint of drill pipe is screwed on and drilling continues. When casing is run, special tools are used to screw it together. We'll cover cementing in another section.
- When the hole has been drilled and the casing set and cemented, the well is completed. Either bullets are fired through the casing (known as "perforating") or a special tool is used to ream the injection zone wider than the bottom of the casing. A slotted screen is installed and pea-gravel circulated around it. This method is called a "gravel-pack" completion, and has much higher hydraulic efficiency. If the well is completed in consolidated rock that will not be subject to collapse, an "open hole" completion can be made without perforations or a gravel-pack. The bare rock face that has been drilled through is left intact, thus the name open hole.
- Tubing is run in the hole, and the size is chosen based on what will fit and provide the best trade-off between minimizing frictional losses and reducing cost. A packer is set to seal the tubing-casing annulus. Packers can be simple, cast-iron designs costing $400, or complex, 60-feet-long, multiple-element, polished bore receptacle (PBR)-type designs that use exotic metals and cost $1.2 million.



- There may be environmental hazards associated with the drilling process.
    - Deviation occurs when the well tilts from the true vertical condition and another hole is created. When the drillbit enters a hard zone from a soft zone, the bit can "walk" and re-start the wellbore at an angle. Sometimes, the drill-string will straighten itself, causing a "dogleg," or kink in the middle of the well. This is bad for tool entry and maintenance, but the worst part is that you are guaranteed a poor cement job as the casing will lie to one side of the hole and/or restrict cement circulation. In a worst case scenario, the driller realizes he is off-track, and will pull up and try to straighten the hole by up-and-down motion of the drillstring. What usually happens is that the bit will head off in another direction entirely, and there will be a "phantom" well bore that parallels the first. That is also a sure way to get poor cementing and, in extreme cases where it involves penetration of the confining zone, the deviation can present an avenue for migration.
    - Lost circulation is when a porous and permeable zone steals a large proportion of the mud. The drill string usually sticks at that point, and the efforts to free it will, at the least, create an oval hole, which can be bad for cementing. At worst, the pipe remains stuck and the hole is worthless. If the hole is deep enough, it could act as a conduit to shallower zones.
    - Several other problems can ruin a hole or stick the drill pipe, such as junk in the hole, sloughing or heaving formations, or differential-pressure sticking. "Blowouts" could also be included in any list of drilling hazards, but drilling injection wells does not involve the conditions in which blowouts occur: deep, high-pressure zones; gas; and wildcat drilling.

Data Obtained During Drilling and Completion

- Numerous opportunities to obtain site-specific data
- Data used to predict performance
- Test types
  - Rock and fluid sampling
  - Geophysical logging
  - Pressure and transient testing

- During drilling and completion, there are numerous opportunities to obtain site-specific data concerning the geology, hydrology, and engineering properties of the injection zone, confining and containment zones, and USDWs. Many of these types of data are essential to predicting the performance and acceptability of the injection operation over time, and provide a sound foundation for permitting decisions.
- The types of tests and sampling methods can be classified as rock and fluid sampling, geophysical logging, and pressure transient testing. We will discuss the logging phase of construction here, but we will discuss the formation testing program separately after this section.
- Remember that most UIC construction is not witnessed. The permit writer's only connection to the construction process is the operator's submission of the completion report. Make sure that you specify in advance the standards and types of logs and samples that you require.

§146.12 "Considered…"

- Resistivity, SP, gamma, caliper logs
- Cement bond, temperature, or density log
- Fracture finder logs
- Fluid pressure, temperature, fracture pressure
- Physical and chemical characteristics of the injection matrix and formation fluids

- The UIC regulations specify a suite of logs and tests necessary to support a permit application. The types of information shown here "shall be considered" for open-hole, after the casing is cemented, and for testing the injection and confining zones. Consider this the minimum of information.
- In Class II and III applications, most of what you will see is data developed when the field was first drilled. For Class I, although the regulations allow "similar, available" data in the application, you should insist on verification logs and tests performed directly in the well in question.

Open-Hole Well Logs - Electrical

Method	Property	Application
• Spontaneous potential (SP)	• Electrochemical and electrokinetic potentials	• Formation water resistivity (Rw); shales and nonshales; bed thickness; shaliness
• Nonfocused electric log	• Resistivity	1. Water and gas/oil saturation 2. Porosity of water zones 3. Rw in zones of known porosity 4. True resistivity of formation (Rw) 5. Resistivity of invaded zone
• Focused conductivity log	• Resistivity	• 1-4; very good for estimating R† in fresh water or oil base mud
• Focused resistivity logs	• Resistivity	• 1-4; especially good in determining R† of thin beds • Depth of invasion
• Focused and nonfocused microresistivity logs	• Resistivity	• Resistivity of the flushed zone (Rxo) for calculating porosity • Bed thickness

Open-Hole Well Logs – Elastic Wave Propagation

Method	Property	Application
• Transmission	• Compressional and shear wave velocities • Compressional and wave attenuations	• Porosity; lithology; elastic properties, bulk and pore compressibilities • Location of fractures; cement bond quality
• Reflection	• Amplitude of reflected waves	• Location of vugs, fractures; orientation of fractures and bed boundaries; casing inspection

Open-Hole Well Logs - Radiation

Method	Property	Application
Gamma ray	Natural radioactivity	Shales and nonshales; shaliness
Spectral gamma ray	Natural radioactivity	Lithologic identification
Gamma-Gamma	Bulk density	Porosity, lithology
Neutron-Gamma	Hydrogen content	Porosity
Neutron-Thermal Neutron	Hydrogen content	Porosity; gas from liquid
Neutron-Epithermal Neutron	Hydrogen content	Porosity; gas from liquid
Pulsed neutron capture	Decay rate of thermal neutrons	Water and gas/oil saturations; reevaluations of old wells
Spectral neutron	Induced gamma ray spectra	Location of hydrocarbons; lithology

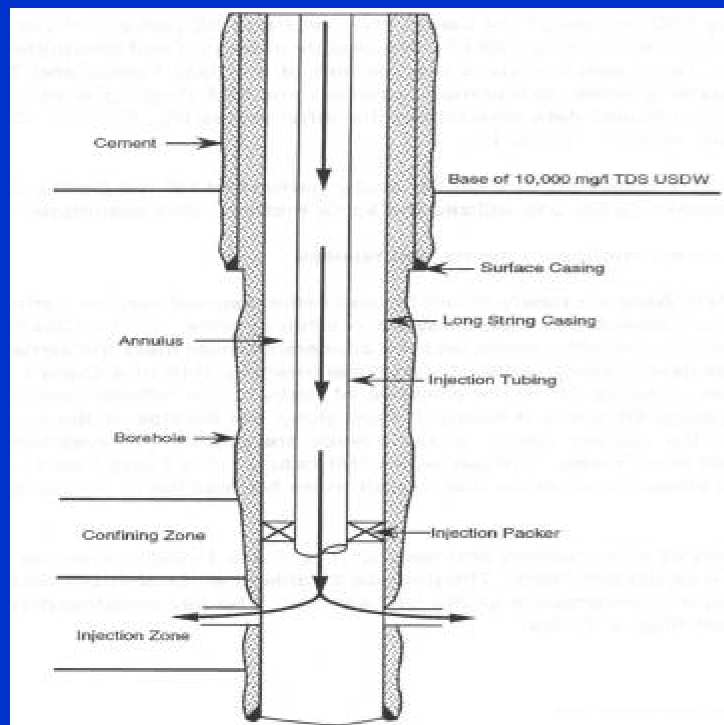
Open-Hole Well Logs - Other

Method	Property	Application
• Gravity meter	• Density	• Formation density
• Ultra-long spaced electric log	• Resistivity	• Salt flank location
• Nuclear magnetism	• Amount of free hydrogen; relaxation rate of hydrogen	• Effective porosity and permeability of sands; porosity for carbonates
• Temperature log	• Temperature	• Formation temperature

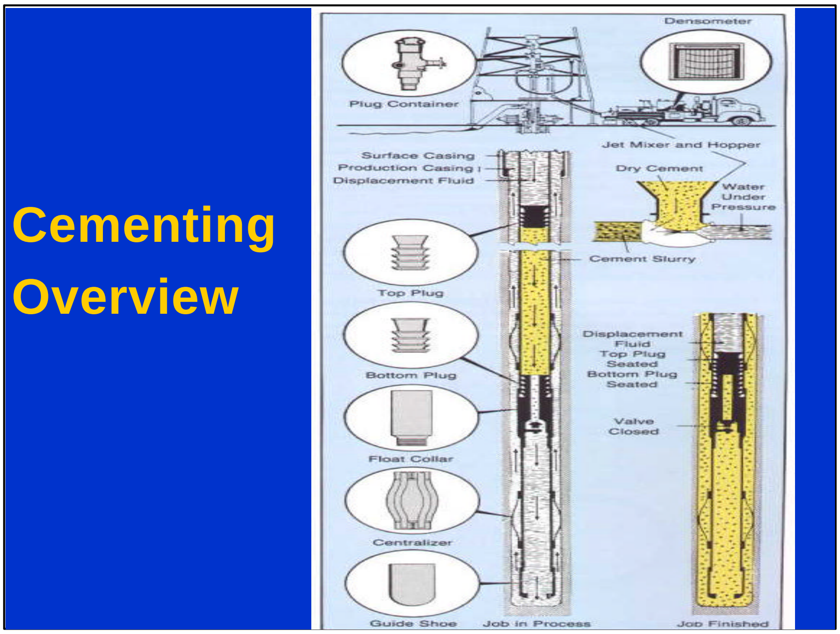
Cased Hole Logs

Log	Function
• Cement bond	• Determine extent and effectiveness of casing cementing
• Gamma ray	• Determine lithology and presence of radioactive tracers through casing
• Neutron	• Determine lithology and porosity through casing
• Borehole televiewer	• Provide an image of casing wall or well bore
• Casing inspection	• Locate corrosion or other casing damage
• Flow meter	• Locate zones of fluid entry or discharge and measure contribution of each zone to total injection or production
• High resolution thermometer	• Locate zones of fluid entry including zones behind casing
• Radioactive tracer	• Determine travel paths of injected fluids including behind casing
• Fluid sampler	• Recover a sample of well bore fluids
• Casing collar	• Locate casing collars for accurate reference
• Fluid pressure	• Determine fluid pressure in borehole at any depth
• Casing caliper	• Locate casing damage

Cement and Cementing

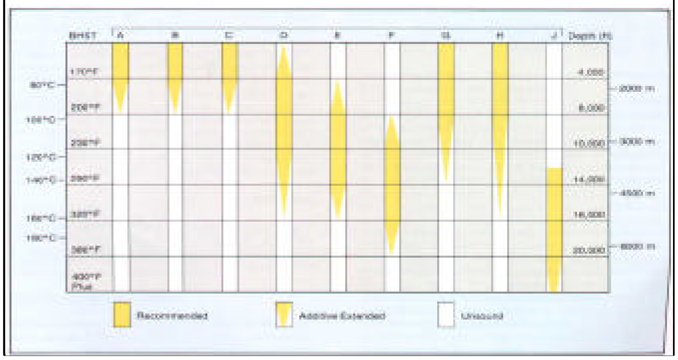


- After casing is installed in the well, cement is circulated to seal the casing into the borehole. Cement is required on long string casing to prevent fluid and waste movement out of the injection zone and to protect casing from corrosion. Class I wells usually require complete cement to the surface, whereas most Class II wells feature only partial cement, usually a hundred feet above the top of the confining zone.
- The tubing, casing, and packer can be directly tested for integrity by means of an MI pressure test and, in Class I, continuous monitoring of the annulus pressure. Cement, however, can not be directly tested, but its presence and competence may be indirectly measured by means of wireline logs.



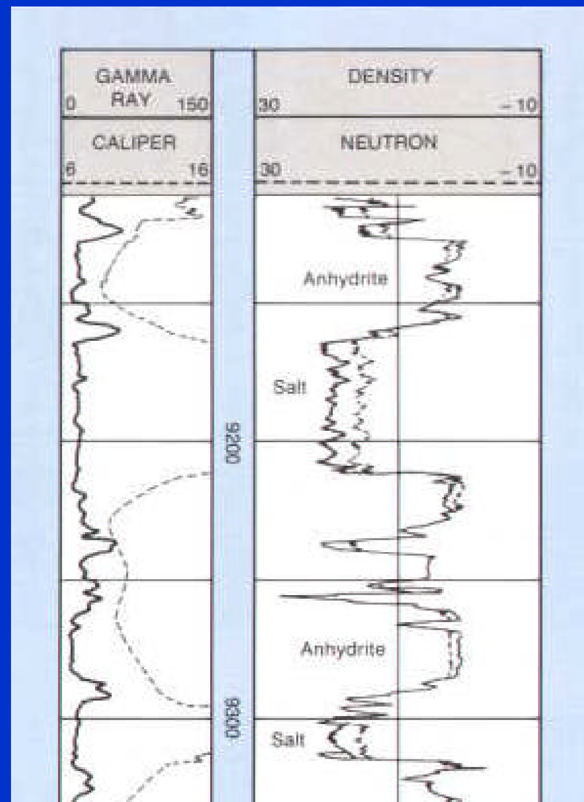
- After casing is set in the well, a cement slurry is pumped downhole through the casing, and back up the annular space between the pipe and formation. The technology supporting modern well cementing is a complex science of cement properties and mechanical devices, used to achieve good cement coverage downhole.
- A schematic of a typical cementing job is shown here. As the casing is run in the hole, the string is assembled to include a “guide shoe” at the bottom and a “float collar,” which acts as a check valve to prevent cement from flowing back into the casing after it has been pumped down. “Centralizers” are run at intervals to ensure the casing is centered in the hole, so that the cement slurry can flow evenly up the hole and provide uniform coverage. Cement is mixed at the surface prior to being pumped downhole as a slurry.
- The cementing operation begins when the “bottom plug” is released down the wellbore, immediately followed by the cement slurry. When the hollow bottom plug lands or “bumps” into the float collar during pumping, the increase in pressure causes a rubber membrane in the plug to rupture. The cement then passes through the bottom plug and begins moving up the casing-borehole annulus. When a sufficient volume of slurry has been pumped, an upper or top plug is introduced to the wellbore. The top plug separates the cement slurry from the displacement fluid that follows.
- When the top plug lands on the bottom plug in the float collar, the slurry has been displaced from the inside of the casing and a dramatic pressure increase is seen at the surface. This signals that the cement job is complete. The cement then cures to its final hardness over a period of 8 to 30 hours, depending on slurry composition and downhole temperature.
- In deeper wells, the length of casing to be cemented may present the risk that the weight of the cement column might exceed fracture pressure. Cement fracs occur when fracture pressure is exceeded and the cement level falls as slurry enters a hydraulic fracture until hydraulic equilibrium is re-established. This is prevented by cementing the well in stages using the same methods.
- In Class I wells, the volume of cement slurry is designed to allow circulation of slurry to the surface before the top plug lands. In most Class II wells, however, the volume is designed to extend only a few hundred feet above the injection zone, primarily for reasons of economy.

Cement Classes and Additives



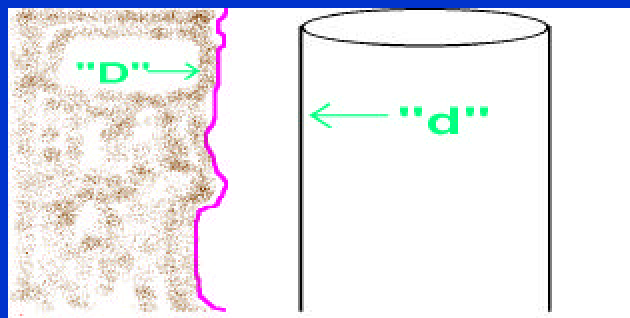
- Cements are manufactured according to standards developed by the American Petroleum Institute (API). The API classifies cements based primarily on temperature rating, using a letter rating from Class A to Class J. API class "G" cement is the most commonly used in EPA Region 6, where most Class I and II wells are located.
- Cement cures through a process of crystal growth. Once the cement is in place around the casing, it is important that the crystallization process proceed quickly so that water from permeable formations does not dilute the slurry and prevent crystallization.
- Cement is broadly classified as "neat" or "tailored." Neat "Portland" cements are finely ground mixtures of calcium compounds, usually ground-up limestone. Iron and aluminum oxides are added, and the material is subjected to intense heat in a rotary kiln. After heating, gypsum is added to form the completed cement.
- Tailored cements contain additives to modify the slurry properties for a particular downhole condition. Additives may be used for a variety of reasons: to raise or lower slurry density, to increase compressive strength, and to accelerate or retard the setting time. The most common types of additives are:
  - ***Accelerators and retarders***: to speed up or slow down the early stages of curing, depending on downhole temperature. Calcium chloride is the most common accelerator, used at 2 to 4 percent by volume in shallower, low temperature wells. Lignosulfates are the most common retarders.
  - ***Extenders***: to reduce slurry density to prevent cement fractures. Bentonite, sodium silicate, and Pozzolans (from volcanic ash) are the most common extenders. High-strength foam cements may also be used to cement long stages.
  - ***Lost circulation agents***: additives to prevent losses to vugular or weak zones, from corn cobs and walnut shells to engineered gel agents.
  - ***Fluid-loss agents***: control water loss from the slurry into permeable formations. Bentonite, polymers, and cellulose derivatives are most common.
  - ***Weighting agents***: increase slurry density to prevent blowouts in high pressure zones. Lead ores are most common.
  - ***High temperature additives***: Portland cement becomes unstable above 750º F. Geothermal wells and some deep gas wells require the use of calcium aluminate or calcium silicate cements.

Cement Volume Calculations



- As part of the open-hole logging process, the operator will run an open-hole caliper log. This log provides a three-dimensional measurement of the diameter of the hole, and indicates the location and magnitude of intervals that are "out of gauge," due to washouts, sloughing, etc. This slide shows an extreme example, the washouts created due to drilling through salt with water-based muds. The primary purpose of the open-hole caliper log is to calculate cement volume.
- Modern computerized wireline trucks will provide not only the log, but the calculated volume of the hole. If the operator specified the size and grade of casing to be used, the program will also provide an accurate cement volume calculation and a 3-D color illustration of hole conditions. In most cases, however, the operator will not share these data with the permit writer who must make an independent estimate of the cement volume. This is especially true for wells that were drilled at an earlier date, and only a cement volume is known. The permit writer's review must determine whether there was sufficient cement volume to provide an effective cement seal in the well.

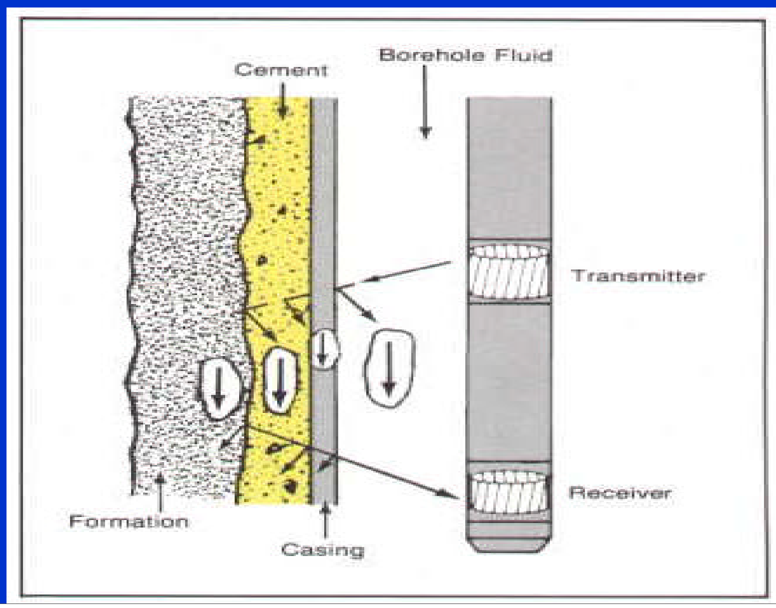
Cement Calculations



$$(D^2 - d^2)\ 0.0009714 = \text{bbl/foot}$$

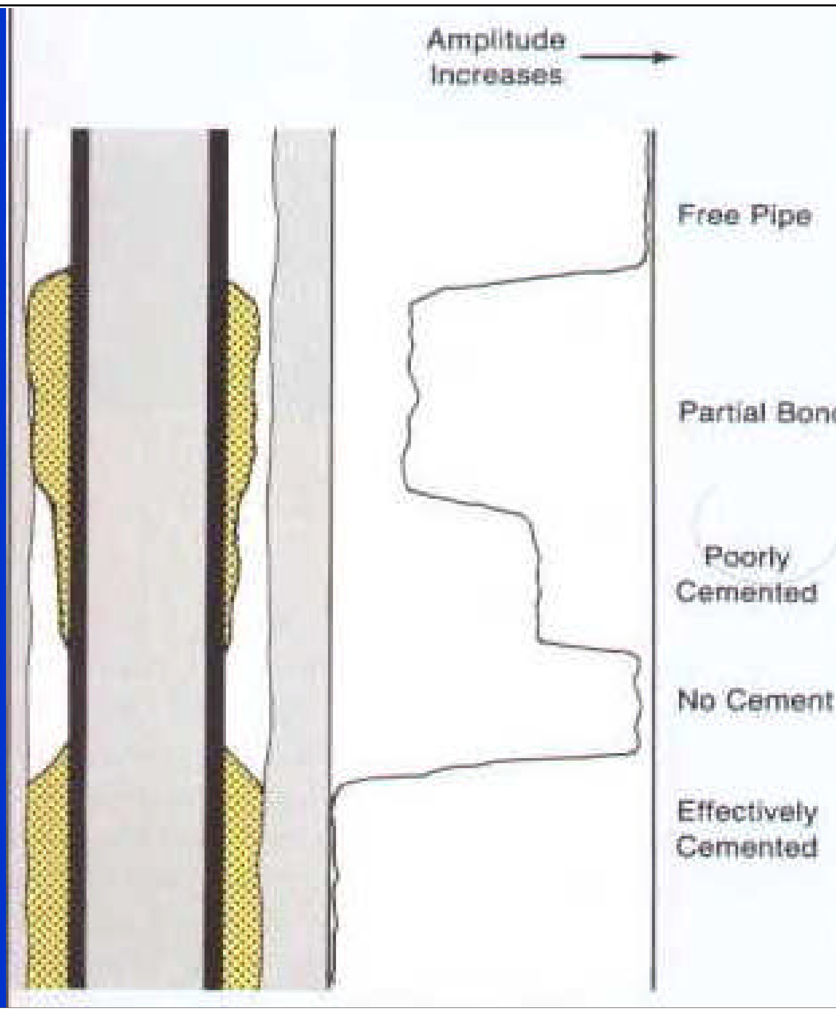
- The first-cut analysis involves simple geometry. What is the volume of the hole, minus the volume of the casing that is in the hole? Most manuals provide a table of values for different borehole/casing combinations. For example, the Halliburton handbook specifies that the volume between 7-inch casing and a borehole of 8.5 inches is 0.0226 barrels per linear foot of depth. There is a formula available also: $(D^2 - d^2)$ x .0009714 for barrels per foot and .005454 for cubic feet per foot, where capital-D is the hole diameter and little-d is the outside diameter of the casing.
- If the attachment includes a design cement volume, you can perform a rough comparison of cement volumes. Subtract the outside diameter of the casing from the bit size, and multiply by the depth cemented and you have a rough idea of the ***minimum*** cement volume necessary to provide the appropriate cement coverage. Conversely, you could use the known cement volume and divide by the "barrels per foot" value to get the ***maximum*** number of feet cemented.
- After the completion report has been submitted, use the caliper log to perform this calculation. Mark the intervals where the hole is in or out of gauge. Most people disregard excursions of less than an inch, unless it occurs over more than a hundred feet. For those excursions of the borehole diameter that are over one inch and/or 100 feet, you can do the same calculation in a micro scale. Use "hole diameter plus 1" for big D, and the gauge hole diameter for little-d.
- Most engineers use a safety factor when calculating cement volume. Most in the oilfield use 15 percent excess, but many Class I programs use up to 40-percent excess. Most Class I operators would rather pay for discarded cement, than see a cement column come up short.

Principles of Cement Logs



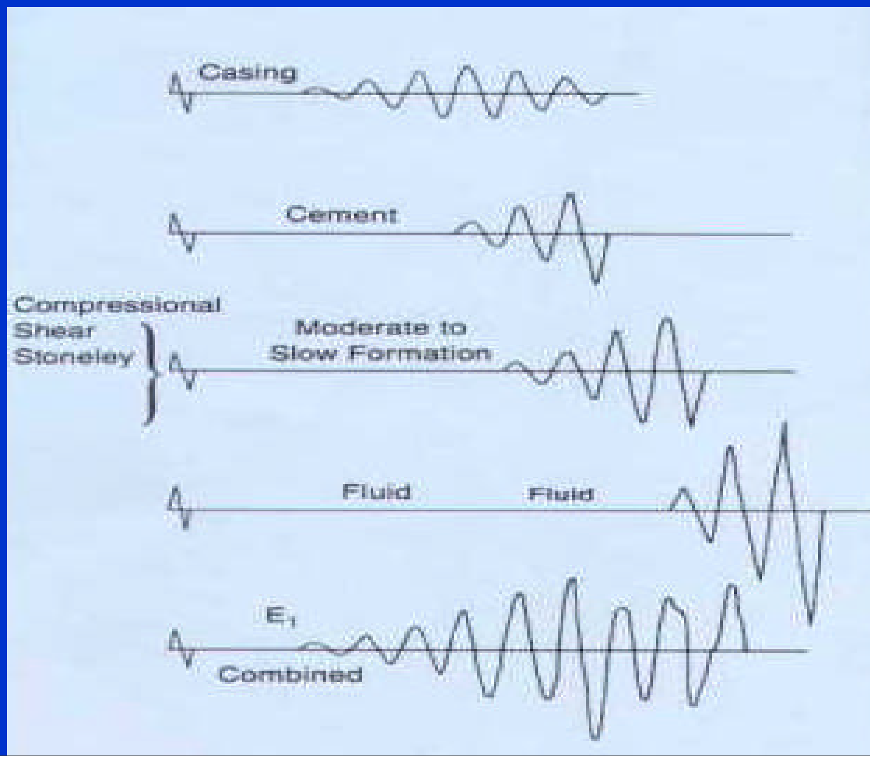
- Hang a length of pipe from a string and hit it with a hammer. The pipe will ring loudly, like a wind chime. Now, hold it in your hand and hit it; the sound is only a thud. The basic principle of cement logging is that cement muffles the sound of casing. Unsupported casing, if hit by a hammer or other acoustic source, will ring loudly. The amount of sound produced is called the "amplitude." Cement around the casing will drastically reduce, or attenuate, the sound.
- The amplitude produced by an acoustic signal in pipe is highest when unsupported and lowest when a sheath of hard cement is bonded to the entire casing periphery. Lab and field experiments have found that a linear relationship exists between increasing amplitude and the portion of the casing periphery that is not supported by cement.
- Cement logging tools utilize an acoustic transmitter and one or more receivers. The transmitter emits a timed, 20 kHz signal, which transmits elastic compressional waves traveling vertically and horizontally in the borehole fluid. Of primary interest is the wavefront moving horizontally, directly toward the casing wall. As the wavefront impinges on the casing, some energy is reflected, while the balance is transferred into the steel, the cement sheath, and the formation. At each interface, some energy will be reflected, and some will be transferred into the adjoining medium.

Amplitude: How Loud?



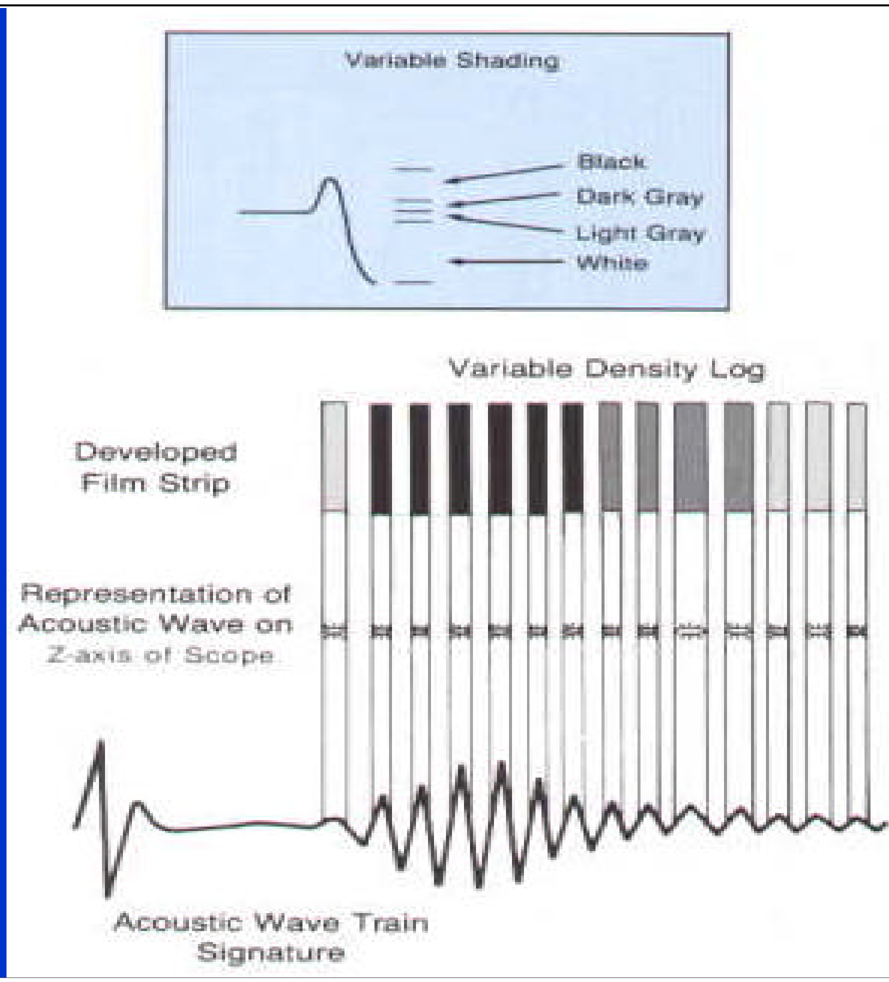
- When acoustic energy is transmitted into the borehole fluid, the nearest reflective component is the well casing. The reflection of that energy from the casing wall to the receiver is called the "first arrival." The amplitude of that reflected signal is directly related to the thickness of the casing, and to the presence and amount of cement that supports the casing.
- A high amplitude indicates casing that is free to vibrate, and is poorly or incompletely supported by cement.
- A low amplitude indicates the casing is supported by cement, which causes adsorption and transmission of the wave energy to the surrounding media.
- Amplitude measurements between maximum and minimum values are a function of the percentage of casing bond.
- The primary component of a cement log is the amplitude measurement.

Energy Reflections: When and How Much?



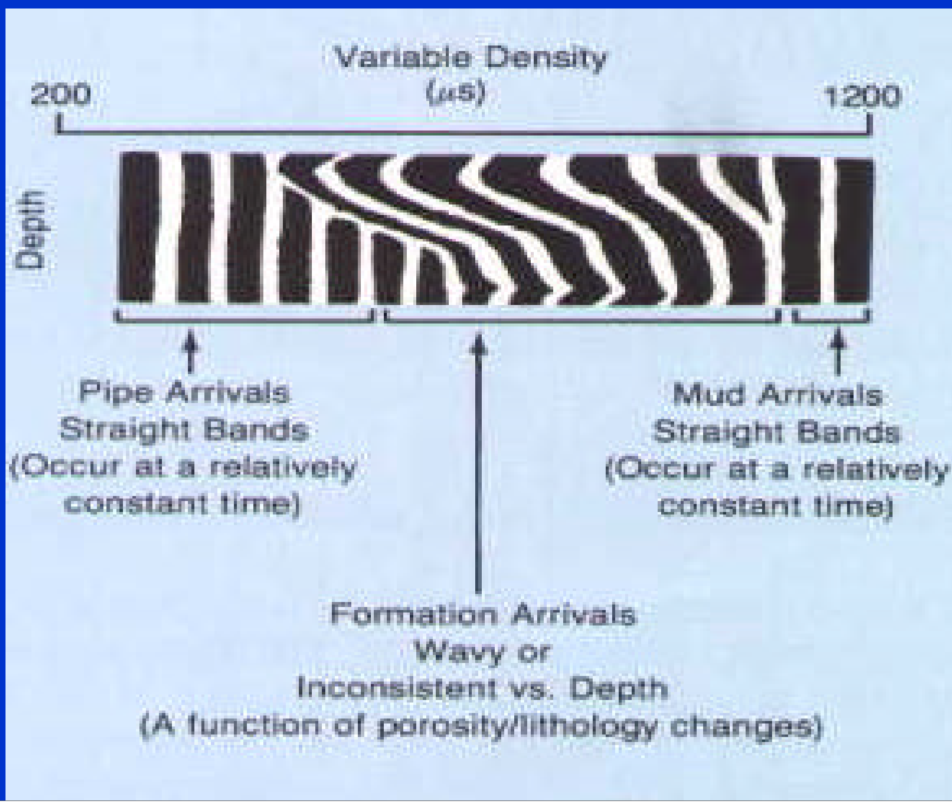
- The first arrival is the reflection of energy from the casing wall. We can also measure the reflection of energy from other components of the well system.
- Compression waves from the transmitter pass through the borehole fluid, the casing, the cement, and the formation, and return to the receiver. Passage through these media alters the character of the compressional wave. Each material exhibits its own characteristics that influence wave velocity, amplitude and frequency.
- The wave train above is a representation of the time of arrival and character of the compressional wave reflected by each component of the well system. The first arrival represents reflections from the casing, then the cement, then the formation, and finally the mud wave traveling vertically down the wellbore.

Louder Equals Darker



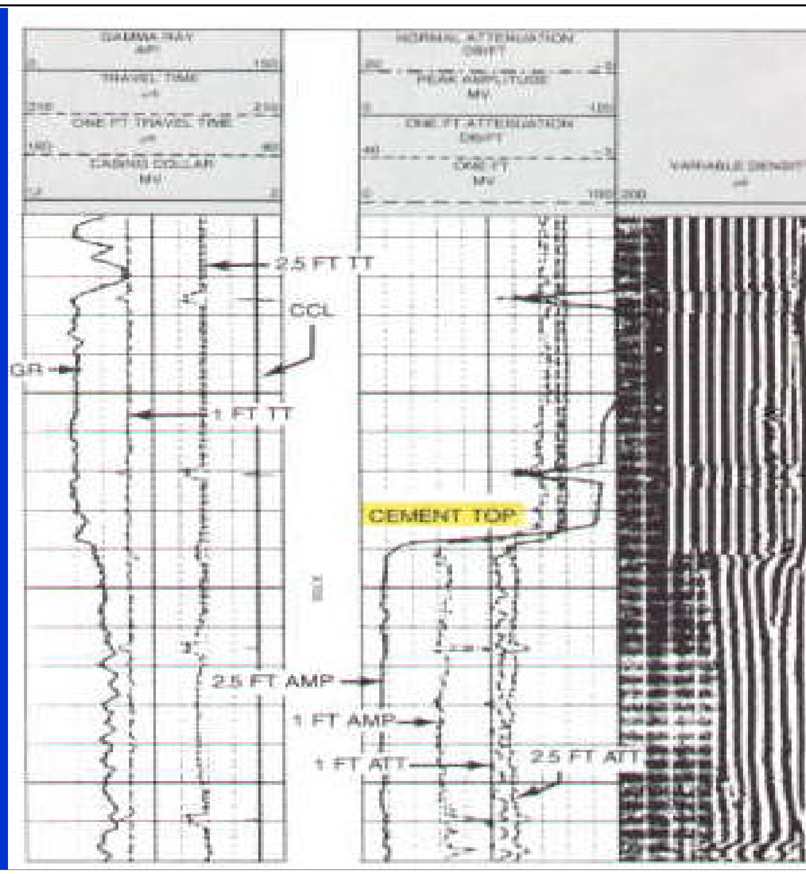
- The frequency and amplitude of the wave components can be shown graphically in what is known as a "variable density display."
    - o The spacing of the bars represents the frequency of the wave components, and the shading of the bands represents the amplitude.
    - o The horizontal scale is time of arrival, in microseconds: casing first, followed by cement, formation, and so on.

Variable Density Log



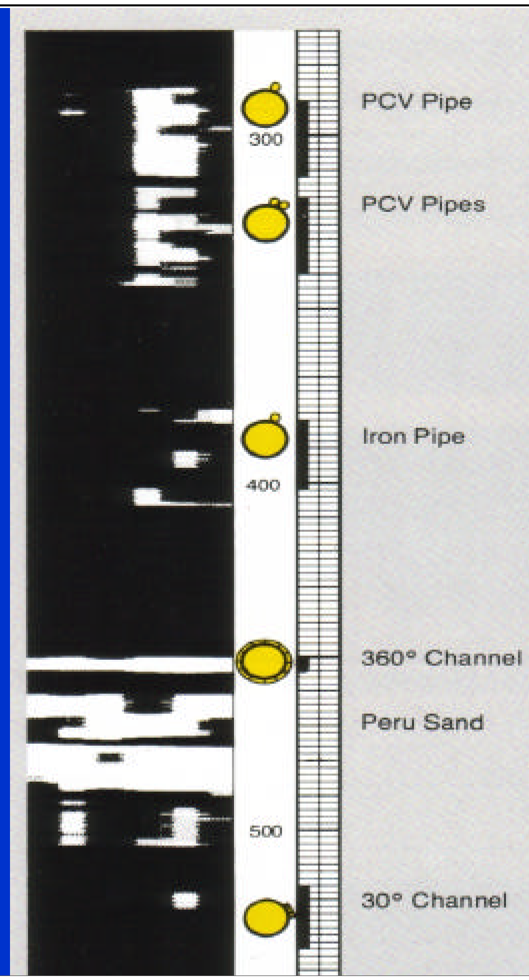
- The variable density display is labeled in microseconds. The display features the equivalent of a wave graph for every foot of depth. The time of arrival of casing reflections is constant, and is determined by the size and weight of casing. If formation arrivals are shown, the presence of cement is inferred.

Typical CBL Cement Log (Faked?)

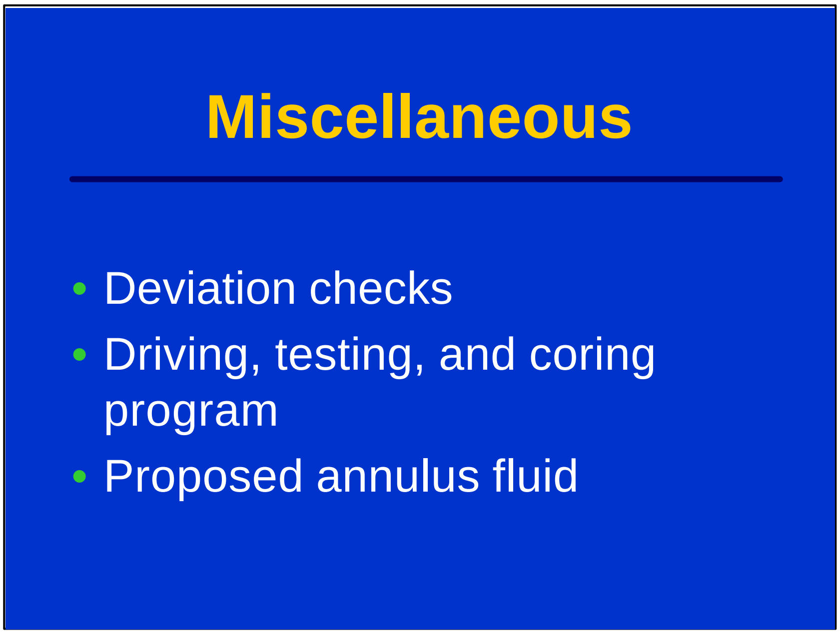


- This is a typical CBL log. The combination of amplitude and wave analysis provides a tool for interpreting the presence and condition of cement. Many Class II wells will utilize older, less expensive technology such as this CBL.
- These logs feature a lot of information at first glance. Remember that amplitude, or loudness, is the primary measurement. It is located on the center track, and may be called different things by different companies, but it is always scaled in millivolts, or MV. There are usually two presentations: a simple scale and an amplified scale for when the amplitude is really low due to perfect cement. On the right is the variable density waveform display.
- It's been said that interpreting a CBL is more art than science. Be aware, however, that many, if not most, of these logs are "faked" to some degree.
- The primary method of accuracy and calibration of the tool is a single knob. The logging engineer must set the equivalent of a volume control in the logging truck (the amplitude gain and/or gate), and an improper setting of this control can result in an over- or under-optimistic log presentation. For an semi-accurate calibration, the logging engineer must find a zone of "no cement" in the well, and "zero" the tool. If there is no zone which he knows is free of cement (i.e., a Class I well), then he is guessing at the calibration. Turning up the gain will essentially move the amplitude or Bond Index lines several gradations to the left or right (giving an over-optimistic diagnosis, unless you are an ace at interpreting the VDL). Furthermore, in a study of over 200 Class I wells that had CBL logs, 70 percent of the wells had more than one cement log run by different companies. The one log they submitted for the permit was the most optimistic, usually run by a less-qualified company. In at least 15 cases, the logs were so optimistic they were worthless, and in a few cases there was a clear case of fraud. Unless you know how to check the calibration of a CBL, never accept one as the single basis for any important permitting decision. You may also want to specify allowable gain in the permit to drill, to minimize potential for these issues.

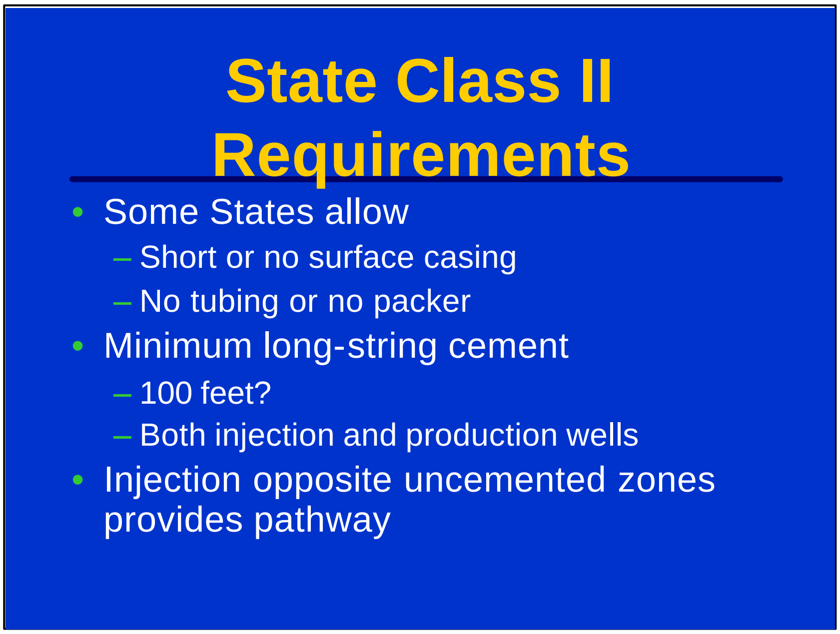
Typical 3rd Generation Cement Log



- There are plenty of CBL-type logs still used for Class II wells, but this is an example of the so-called "third generation" of logging tools used for most Class I wells. This log was run in Jerry Thornhill's Ada cement-test well. These tools use several, directional transmitter-receiver pairs in a single tool, and utilize computerized signal discrimination and analysis for interpretation and presentation. Examples of these logs include Dresser-Halliburton's SBT and Schlumberger's CET tools.
- Computerization allows for a pretty easy interpretation: black is good (i.e., competent cement), white is bad (poor or no cement), and gray is something in between.
- However, these logs can be faked as in the case of the old CBLs. The key is to note on the log header an input value called something like "input compressive strength" or "screening value strength." This value is the equivalent of the old Gain knob on CBLs, as it sets the maximum value the log will look for, as compressive strength (in psi). Another way of saying this is that the input compressive strength value is how strong the cement has to be to read as full-black on the log presentation. NEVER accept a log that has an input value lower than 1000 psi compressive strength, but 1500 psi is much more realistic. By setting this value to 300 or so, ***mud*** will look black on the log. Beware: many Class I wells were given permits based on black logs. Know what the compressive strength input of the log is before you make any determination!



- Attachment L also requires information concerning these aspects of construction.
- We discussed deviation under drilling hazards. Deviation occurs when the drillbit walks offline and the hole starts off at a diverging angle. When the operator discovers his error and pulls up to straighten the hole, he can leave another hole next to the wellbore. If this occurs near the confining zone, a conduit can be inadvertently created. Deviation used to be more of a problem in the past, but most modern rigs allow a continuous measure of angle. In cases where continuous measurement is not feasible, operators stop the drilling process periodically to run a wireline measurement in drill pipe.
- Most rotary rigs use a casing hammer to drive conductor pipe a few feet when beginning the well, but this has no environmental implications.
- Formation testing will be discussed in the next section. Coring is a method of retrieving 20-foot long, bit-diameter samples of formations. For Class I hazardous wells, these may be necessary for lab testing of waste reactions and permeability, but coring is very expensive and rarely done for other wells.
- If the well has an annulus, the operator will fill it with something. Air or other gases are too compressible and do not provide accurate MITs, and do not provide differential support for the tubing. Annulus fluids must be corrosion-resistant, so most operators use brine with an additive. A few Class II operators use diesel fuel, and in permafrost environments most operators use glycol.



- Presented on the following slides are a few scenarios to look for when you review a construction program. In many Regions, EPA may have permitting responsibility for Class I wells, which can exist side by side with Class II wells permitted by a State agency that uses different construction standards. For example:
  - ***Short or no surface casing***: Most Class II injection wells feature surface casing that does not extend to the base of USDWs. Rather than depth to the lowermost USDW, Arkansas, California and a few other States require surface casing as a percentage of depth, usually 10 percent. In several other States that do use a water quality standard, surface casing depth is set according to local practice, usually related to drinkable quality or 3,000 mg/l TDS.
  - ***No tubing***: In Texas, for example, any well of less than 1,000 feet is not required to use tubing (or surface casing) (Rule 13). Similar standards are used in Kansas, Indiana, and several other States.
- Almost all production wells and the vast majority of Class II wells do not feature complete cement of the long-string casing, but rather feature cement that extends as little as 100 feet above the top of the injection interval. The balance of the long-string/borehole annulus is filled with diluted drilling mud, or whatever fluid was in the borehole at the time of cementing.
- If this uncemented casing is opposite the proposed injection interval, upward flow can occur along the outside of the uncemented long-string casing. If the well in question ALSO features short surface casing, this situation provides a pathway directly from the injection interval into USDWs.

State Class II Requirements

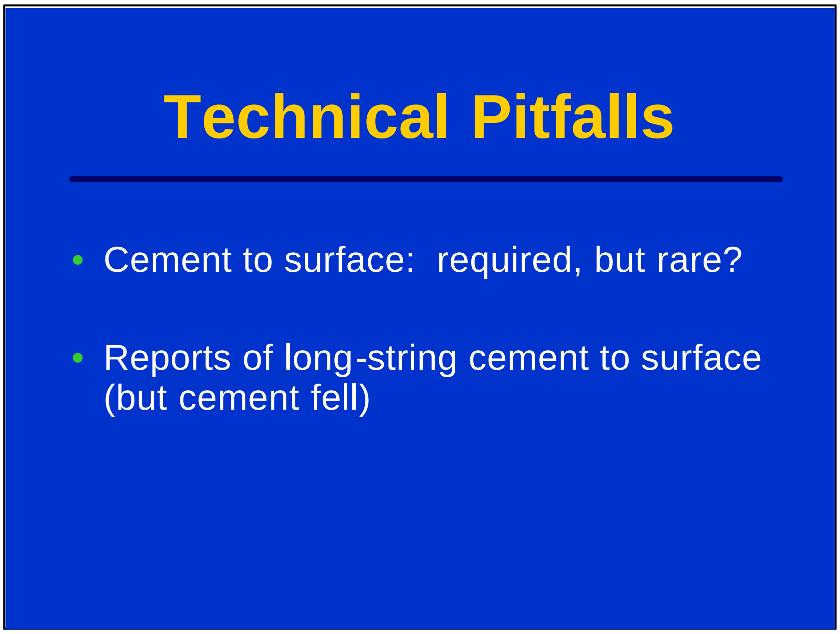
- 146.22 (c) field rules

  The [construction] requirements … need not apply if:

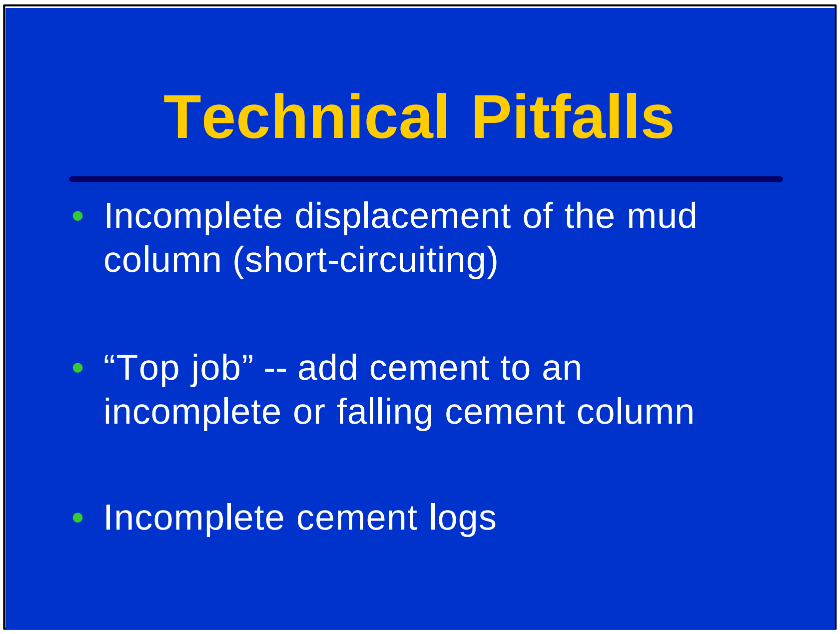
  (i) Regulatory controls for casing and cementing existed at the time of drilling of the well and the well is in compliance with those controls; and

  (ii) Well injection will not result in the movement of fluids into an underground source of drinking water **so as to create a significant risk to the health of persons**.

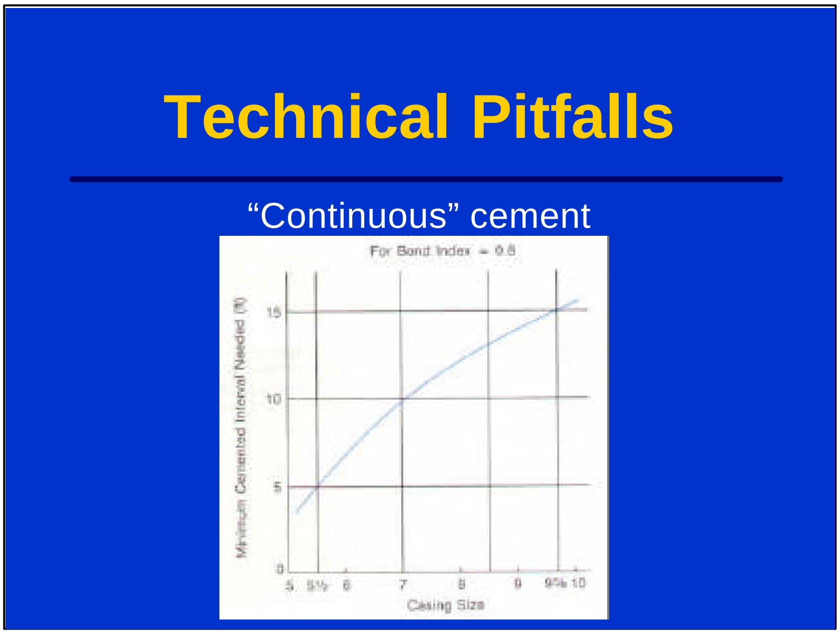
- Be aware that the so-called "field rules" in many States allow operators to utilize construction methods that would otherwise be considered sub-standard. EPA struggled with this concept for several years during development of the regulations, but decided that if all the other existing wells in the field were allowing migration due to substandard construction, the operator did not need to spend extra money for the one well in the field that was not. If a zone were already contaminated, a few non-polluting ***new*** wells would do no good. Note that this idea cut the Class II regulatory impacts by over 50 percent.
- You should also note that in the second paragraph, the construction standard is not the same as the rest of the UIC program ("… movement into or between USDWs"), but specifies that the well not create a human health risk.
- Bottom line: construction standards in existing fields tend to stay the way they always have been. You need a lot of evidence to change them.
- Be sure you are clear, however - this standard is limited to existing Class II fields and does not apply to wells drilled outside of existing fields.



- A study of cement issues in a large southwestern State found that almost all of the well schematics and/or permit narratives indicated long string cement to surface. However, almost 90 percent of wells with logs show top of cement (TOC) at least 400 feet lower, and 30 percent have TOC below the surface casing shoe.
- Of the wells where a cement log was available to allow the interpretation, only a handful of wells were found that truly had cement to surface. Thirty-three of 37 had TOC at least 400 feet below surface, and for most it was more than 1,000 feet. Eleven wells (30 percent) were found to have TOC below the surface casing shoe, with 6 wells having TOC several hundreds or thousands of feet below the shoe.
- A few of these wells experienced mechanical failures during primary cementing. However, the study found two mechanisms whereby an operator (or agency witness) could report cement to surface, but actually have TOC far down the hole.
- It found several instances in drilling logs where operators reported long string cement to surface (sometimes witnessed by inspectors), but who found that the cement column then fell, either immediately or up to two hours later.
  - o This condition is common in cases where operators attempt to cement long intervals of casing, and the weight of the cement column causes the cement to fracture the formation.
  - o The cement runs into the fracture until hydraulic equilibrium is re-established, sometimes after hundreds or thousands of linear feet of cement have "gone south," as it is called in the oil field.
- The study also found many instances in the file reviews where the installed cement volume grossly exceeded the annular volume of the hole, but the TOC was still hundreds of feet down the hole, and massive cement fracs were indicated.



- A second mechanism would involve incomplete displacement of the mud column, or “short-circuiting.” In this case, cement could arrive at the surface having bypassed a significant volume of the casing/hole annulus. In other cases, drillers may report returns of what is actually gray water, rather than cement. Whatever the mechanism, the study found that the vast majority of the active Class I HW wells with cement bond logs (CBLs) do not have cement to the surface.
- The study found several instances of operators attempting to “top” long string cement jobs, sometimes after reporting returns to the surface. A “top job” is a procedure in which an operator attempts to add cement to an incomplete or falling cement column by adding it from the surface through 1-inch tubing in the annulus or bullheading into the bradenhead. Some operators will even specify this method as a contingency.
- This procedure is rarely successful and, if the cement volume calculations were originally correct, implies a cement fracture at the shoe. If you see this procedure in a construction program, be sure to remind the operator that top jobs imply problems and require extra diagnosis. If ever you see any mention in a Class I completion report about “topping out,” suspect cement problems and immediately order the best cement log the operator can run.
- Production well long-strings are cemented only to keep the water out, and to save money most operators will log only the cement immediately above the production zone. Most Class II wells feature only partial cement on the long string, and many operators will do the same thing. Be sure to specify that all cement in the well be logged. If you are specifying that the entire long string be cemented, make sure that you get 100 percent of the well logged, top to bottom.

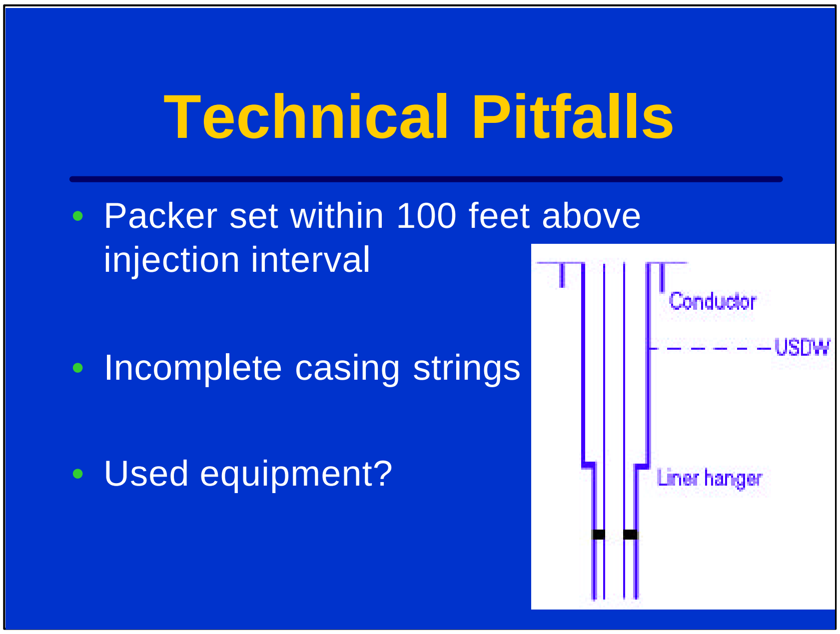


- The big Southwestern State study found that about half of the wells had major cement problems over substantial intervals of the long string. Some of the wells had sufficient bonding in the lowest interval above the injection interval to rate a fair-to-good rating overall, but a few wells appear to have absent to poor cement bond overall.
- The question is now being discussed in UIC forums: **How much** of **what quality** cement is good enough for Class I service? What is the performance standard supporting UIC hydraulic isolation requirements? The basis for an answer lies with standard oil industry practice. "Hydraulic isolation" is defined by the oil and wireline logging industries as the number of feet of continuous cement bond, of greater than 80 percent quality, that will reasonably assure isolation of adjacent, normally pressured, permeable zones. Eighty percent bond is the condition in which 80 percent of the circumference of the casing is supported by cement. The number of feet of 80 percent bond necessary to achieve hydraulic isolation is a function of casing size. For example, the interval requirement ranges from 5 feet for 5-½ inch casing, to 15 feet for 9-5/8 in casing.
- The question becomes: how many intervals of hydraulic isolation are necessary in the well? At a minimum, each of three intervals would need at least one zone of hydraulic isolation: near the base of surface casing (for both surface and long string casing); within the confining zone; and between the top of the confining zone and the base of USDWs.

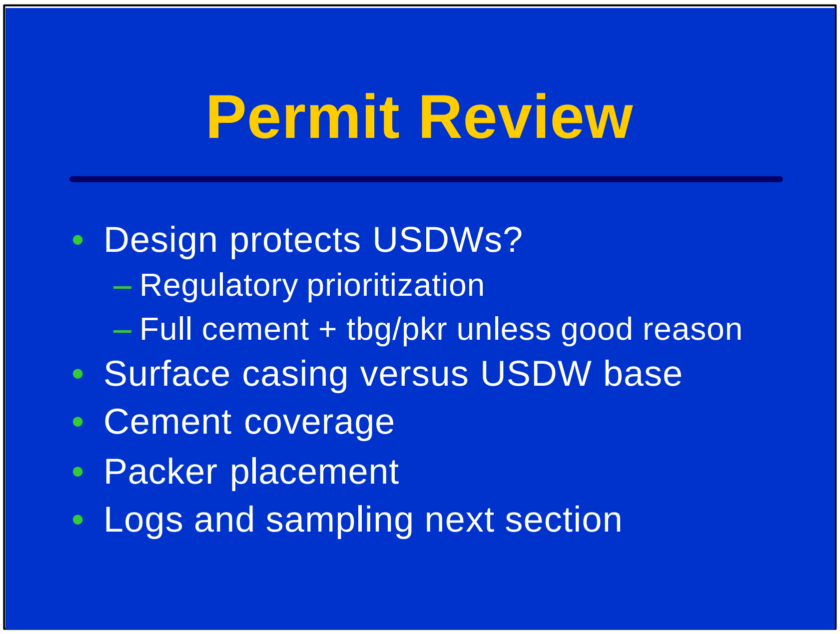
Technical Pitfalls

- Remedial “squeeze” cementing
  - Often tried but not always successful due to restrictions behind casing
  - Applicable for uncemented casing

- Remedial cementing is a common method of corrective action, especially for Class II projects. Squeezing involves perforating the casing, setting bridge plugs or packers above and below the perforations, and pumping cement into the voids behind the casing.
- In a poorly-cemented well, most squeeze jobs are not successful because circulation behind the casing is very limited. In a zone that has not been cemented or that is entirely devoid of cement, circulation can be established and hydraulic isolation can usually be achieved.
- Squeeze-cementing is not a cure-all for repairing a poorly cemented well, but it is usually effective in preventing upward migration along uncemented casing.



- A common pitfall in many permit applications is a well schematic that provides for packer setting somewhere up the hole. This is convenient for operators, since there is less annulus to monitor and a cost savings due to fewer joints of tubing used in the well. The drawbacks for a permit writer are that a greater amount of casing is exposed to the injection stream, and the entire well is not subject to internal MIT. Always check, and insist that the packer be set within 100 feet of the current injection interval unless the operator has a very convincing reason as to why this is not essential. This can be specified as a permit condition to ensure it is enforceable.
- Occasionally you will see a well design in which the operator will propose a liner hanger and an incomplete casing string. This is used a lot for production wells, and may show up as a Class II design. Technically, the surface casing isn't there, or you could say the upper part of the long string serves double-duty. In most areas, if this design featured complete cement it might be acceptable. Most likely, however, the cement will cover approximately the bottom hundred feet of each casing string (and that's not enough).
- As mentioned, there is usually a lot of used tubing and casing lying around most big-company equipment yards. There is nothing specific in the regulations about the use of used equipment, provided it can pass an MIT. But, given a five-year MIT interval, at least disposal wells should feature new tubular goods. If you think the use of new components is an issue, make it a permit condition or at least mention it somewhere.



- Many reviewers get concerned with trivia like the grades of casing and the cement additives. The operator probably knows what works in that field, and what sizes, grades, and additives will give him mechanical integrity. Instead, focus on these issues, the essential items to look for in reviewing the construction attachments of a permit application.
  - Does the design protect USDWs? For Class I or commercial Class II-D, that usually means cement to the surface and tubing and packer. For Class II, however, you may that find partial cement and a packer exemption meet the regulatory standards. For Class II, consider the proximity of USDWs and threat posed by the injectate. You should specify cement to the surface casing shoe and tubing and packer for any design or well class, unless there is a good reason to accept less. Remember, cost can be a good reason.
  - Where is the base of the 10,000 tds USDW? You may not know, because the State uses a different standard of 3,000 tds for production wells. It doesn't make much sense to demand 2000 feet of surface casing when every other well in the field has 1,200.
  - Verify the cement coverage by asking for details rather than just accepting the shading on a schematic drawing. Remember the between standard if surface casing does not cover all the USDWs.
  - Specify as a permit condition that the packer must be set within 100 feet of the ***current*** injection interval, not just 100 feet above the injection zone.
- We will cover the logging and sampling program in a later section.

Discussion

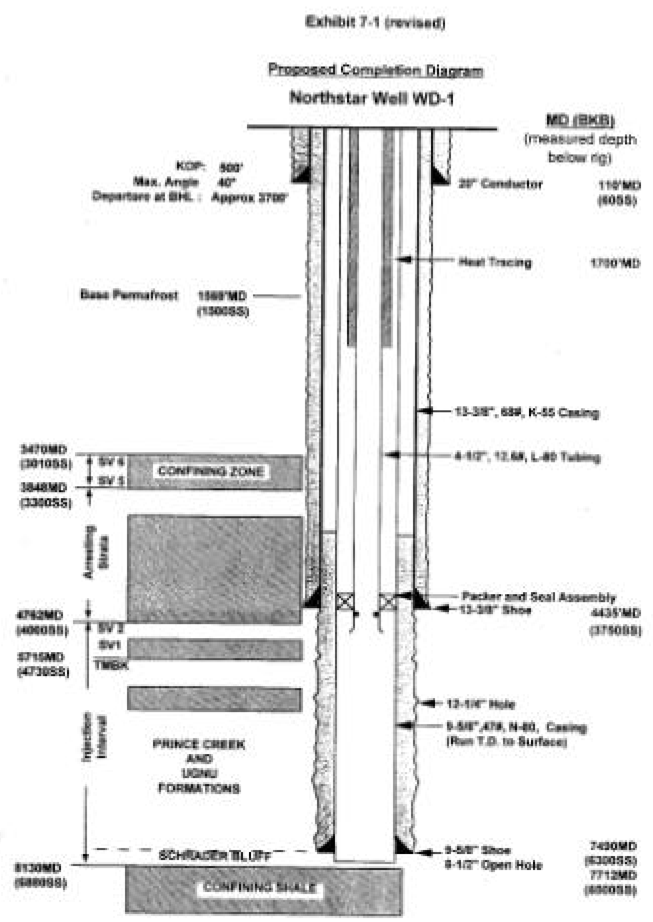


Exhibit 7-1 (revised)
Proposed Completion Diagram
Northstar Well WD-1
MD (RKB)
(measured depth
below rig)
KOP: 500'
Max. Angle 40°
Departure at BHL : Approx 3700'
20" Conductor
Heat Tracing
1700'MD
Base Permafrost
13-3/8", 68#, K-55 Casing
4-1/2", 12.6#, L-80 Tubing
3470MD
(3010SS)
SV 4
SV 5
CONFINING ZONE
3848MD
(3300SS)
Packer and Seal Assembly
13-3/8" Shoe
4762MD
(4060SS)
SV 3
SV1
TMBK
12-1/4" Hole
9-5/8", 47#, N-80, Casing
(Run T.D. to Surface)
PRINCE CREEK
AND
UGNU
FORMATIONS
SCHRADER BLUFF
9-5/8" Shoe
8-1/2" Open Hole
CONFINING SHALE

Exercise

ATTACHMENT "L" (Continued)

Excess Cement Volume for Surface Casing

The 9 5/8" surface casing was cemented to surface with 350 sxs of regular Class A cement. This volume is 40.5% in excess of the required annular volume as shown below:

$$\text{Vol. Req.} = \frac{HD^2 - PD^2}{183.33} \quad (L)$$

Where: Vol. Req. is the cement slurry volume required (ft^3)
HD is the hole diameter (in)
PD is the pipe diameter (in)
L is the desired length of the cement column (ft)

HD = 12.250 in
PD = 9.675 in
L = 937 ft

$$\text{Vol. Req.} = \frac{12.25^2 - 9.625^2}{183.3} \quad (937)$$

Vol. Req. = 293.48 ft^3

Vol. used = (sx)(yield)

Where: Vol. used is cement slurry volume used (ft^3)
Sx is the number of sacks of cement used (sx)
Yield is the slurry yield per sack of cement (ft^3)

Sx = 350 Sx
Yield = 1.18 ft/sx

Vol. used = (350) (1.18) = 413 ft^3

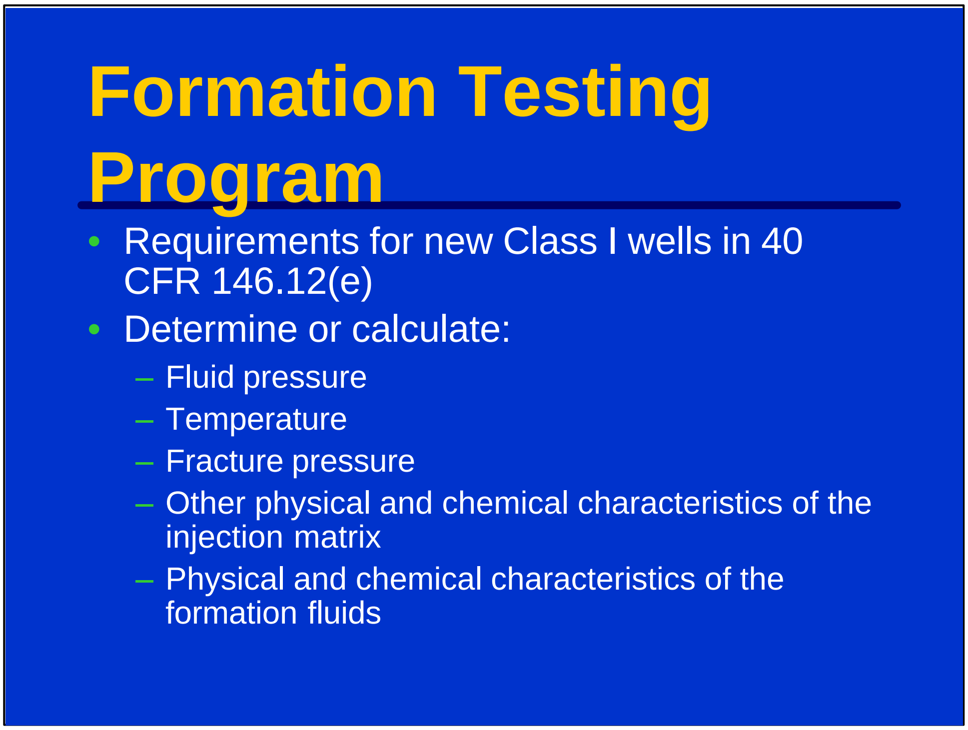
$$\text{\% Excess} = \frac{\text{Vol. used} - \text{Vol. req.}}{\text{Vol. req.}} \quad (100)$$

Vol. used = 413 ft^3
Vol. req. = 294 ft^3

$$\text{\% Excess} = \frac{413 - 294}{294} \quad (100) = 40.5\%$$

Lesson 12
Formation Testing Program

- Attachment I concerns the formation testing program. Testing of the formation rocks and fluids takes place during completion activities, and may involve sampling, pressure testing, and chemical and physical analysis, for USDWs or for the injection and confining zones. The purposes of formation testing can involve almost any aspect of the UIC program, such as:
  - Verifying the lowermost USDW;
  - Logging to determine permitted intervals;
  - Sampling, testing, and logging in support of model validation; or
  - Collecting in-situ samples to simulate down-hole chemical reactions and products.
- The instructions for Attachment I suggest the scope of testing necessary to support different permit levels.



- 40 CFR 146.12(3) requires the permit applicant to determine or calculate:
  - Fluid pressure;
  - Temperature;
  - Fracture pressure;
  - Other physical and chemical characteristics of the injection matrix; and
  - Physical and chemical characteristics of the formation fluids.
- Be sure that the applicant includes radiological characteristics in its analyses.
- Note also that the formation testing requirements for Classes I, II, and III apply only to new wells.

Formation Testing Program

- Requirements for new Class II wells or projects in 40 CFR 146.22(g)
- Determine or calculate
  - Fluid pressure
  - Estimated fracture pressure
  - Physical and chemical characteristics of the injection zone

- For new Class II wells or projects, the permit applicant must determine or calculate:
  - Fluid pressure;
  - Estimated fracture pressure; and
  - Physical and chemical characteristics of the injection zone.

Formation Testing Program

- Requirements for new Class III wells at 40 CFR 146.32(c) apply to injection zones that are naturally water-bearing
  - Fluid pressure
  - Fracture pressure
  - Physical and chemical characteristics of the formation fluids
- If the formation is not water-bearing, 40 CFR 146.32(d) requires only fracture pressure

- We discussed fluid pressure in a previous section. It's another way of saying static bottom-hole pressure; that is, the weight of the fluid column as defined by fluid density and column height.
- We also covered fracture pressure in a previous section, which can be measured in a step-test, estimated using State or service-company fracture logs, or estimated using the method of Hubbert and Willis.
- Determining the physical and chemical characteristics of the formation usually involves mineralogical analysis and shale identification, porosity measurement, and permeability tests. Some fracture-related properties such as Young's Modulus of Elasticity can only be measured using specialized down-hole samples.
- Determining the physical and chemical characteristics of the fluids usually involves physical and chemical analysis, but in Class I wells that feature corrosive or reactive wastes, testing for down-hole compatibilities can involve many other types of additional analyses.

Use of "Similar Data"

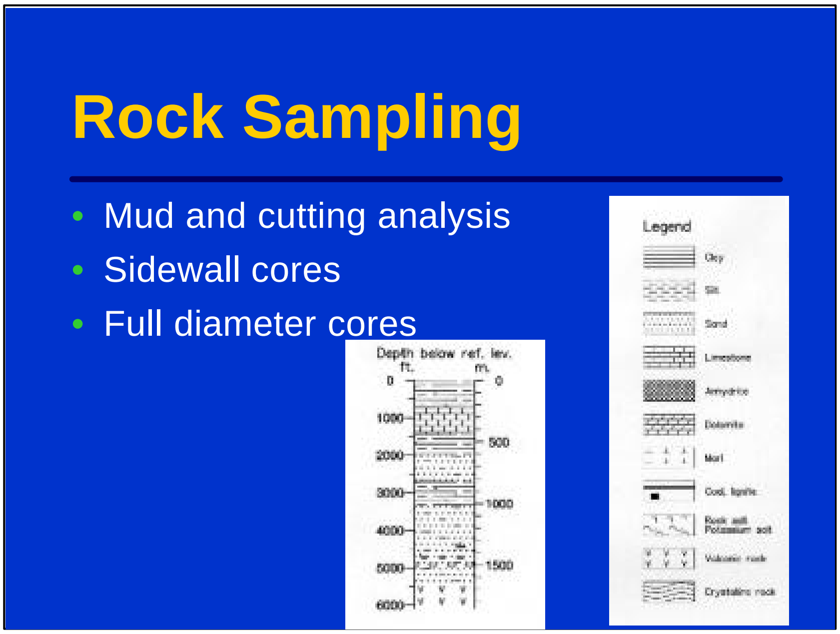
- In determining tests and logs to be conducted, may consider ". . .availability of similar data in the area of the drilling site. . ."
  - 40 CFR 146.12(d)(2), Class I
  - 40 CFR 146.22(f)(2), Class II
  - 40 CFR 146.32(b), Class III
  - 40 CFR 146.66, Class IH

- The regulations allow operators to submit non-original data to satisfy formation testing requirements.
- For Class I wells, however, you should require basic correlation logging, porosity and mineralogy samples, and a cursory drill-stem test for the specific well.
- In Class II and III applications, however (unless the application is for a municipal well), much of what you will see is data developed when the project was first drilled. It is not usually necessary to require much beyond a correlation log, but most operators would run those logs anyway, to assist cementing design.
- Class IH wells have their own requirements in 40 CFR 146.66. The more detailed Class IH requirements are not covered in detail in this course, but are mentioned here ony so the permit writer is aware that these wells are subject to different standards and requirements.
- One issue that isn't discussed very much is that a permit writer can exempt operators from extensive formation testing if there is no USDW within ¼ mile of the wellbore.

Data Obtained During Drilling and Completion

- Several opportunities to obtain site-specific data
- Data used to predict performance
- Test types
  - Rock and fluid sampling
  - Geophysical logging
  - Pressure and transient testing

- During drilling and completion, there are several opportunities to obtain site-specific data concerning the geology, hydrology, and engineering properties of the injection zone, confining and containment zones, and USDWs. Many of these types of data are essential to predicting the performance and acceptability of the injection operation over time, and provide a sound foundation for permitting decisions.
- The types of tests and sampling methods can be classified as rock and fluid sampling, geophysical logging, and pressure transient testing.
- Most UIC construction is not witnessed. The permit writer's only connection to the construction process is the operator's submission of the Completion Report. Make sure that you specify in advance the standards and types of sampling that you require.



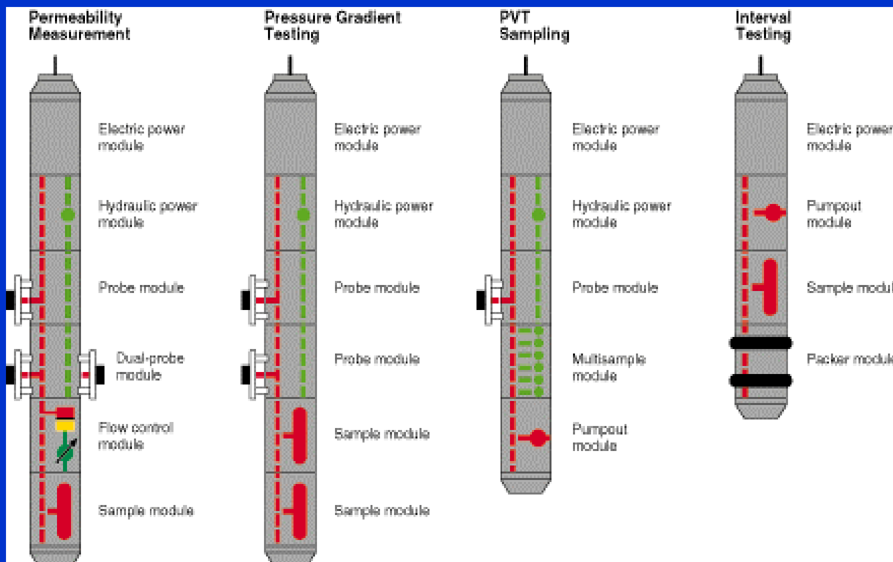
- Almost every Class I and II injection well utilizes rotary drilling methods. As the bit advances by grinding the penetrated rock into small chips, the mud system carries these chips to the surface. Shakers and other filtration equipment separate the rock cuttings from the mud, prior to its recirculation into the hole. Periodically, the collected chips are washed and examined under a microscope. Careful analysis of the drill cuttings will yield an accurate depiction of the stratigraphic column. Soft shales and unconsolidated sands will not yield useful samples, however.
- Sidewall cores can be taken by a wireline tool that carries hollow, cylindrical bullets from 7/8 to 1 ¾ inches diameter. When the sidewall sampler is in position opposite a formation of interest, a hollow bullet is fired into the borehole wall. The bullet and sample are retrieved by means of a cable attached to the tool. Sidewall cores are very useful for lithologic analysis and for basic measurements of in-situ permeability and porosity.
- Full diameter cores are taken in 20-foot sections using a hollow coring bit, either drilled or pushed. In contrast to sidewall cores, full cores provide a continuous sample of the borehole and provide better samples for testing. These samples range from 1 to 5 inches in diameter and from 20 to 60 feet in length, depending on the tool configuration. In addition to lithology and permeability information, full diameter cores exhibit important geologic features such as fractures, bedding planes, solution cavities, and other macro-scopic characteristics. More importantly, full diameter cores can be used for "core-flood" studies, in which the intended waste is injected through the core in a dynamic process that includes the downhole aspects of temperature and pressure. The downside is that full diameter coring is a very expensive process, and core recovery in poorly consolidated formations can be problematic.

Fluid Sampling

- Drill-stem testing
- Nitrogen lift and swabbing
- Downhole formation sampler

- Samples of fluid from the injection zone or a USDW provide important information in the permitting process. Samples of injection zone fluid allow testing for corrosion or injectate reactions. Sampling USDWs in the borehole provides salinity data, and when USDWs prove to be more saline than expected, might serve to support exemptions from other UIC drilling and testing requirements.
- Drill-stem testing is a technique in which a zone in an open borehole is isolated by a temporary packer, and fluid from the zone is allowed to flow through a bottom-hole valve and into the drill pipe. Fluid may flow to the surface, or be trapped within the drill pipe until it is pulled and the contents of the pipe sampled. We will discuss pressure transient testing with a drill-stem test in a subsequent slide.
- Swabbing is a method of fluid recovery that uses a collapsible element within the drill pipe. The element collapses on the down stroke through the drill pipe, but opens on the up stroke, rests against the inner pipe wall, and pulls a volume of fluid to the surface. The advantage to swabbing is that a large volume of fluid can be produced, until the flow stream is representative of the true formation water chemistry. A similar method uses nitrogen injected down the drill pipe to lift the fluids contained in the pipe. The lifting mechanism, however, can change the fluid chemistry of samples by driving off volatiles, creating precipitates due to the lowered temperature, and introducing water from other zones.
- Downhole formation testers are somewhat similar to sidewall coring devices. A tool is run into the well on wireline and positioned opposite a permeable formation. A suction-cup element is forced against the borehole wall and the tool is opened, allowing formation fluid to be collected. The tool can be configured with many small chambers for sampling several intervals, or as one sample of about 7 gallons. The testing protocol allows detection of leakage to the borehole environment and indicates contaminated samples. The primary drawback of this method is that the sample may consist partly of mud filtrate that has invaded the formation during drilling. When sampling is planned for some zones, the mud system is changed out for a polymer system to allow representative sampling.

New MFT Tool



- Schlumbeger's new modular formation tester (MFT) tool takes over where the old repeat formation tester left off. It can take multiple fluid samples, up to 15 gallons each, from multiple zones. Samples are suitable even for gas analysis, in that a series of packers and sealing devices allow a probe to be inserted into the borehole wall up to 20 inches deep in sandy formations. This allows virgin water samples, free of contamination from completion fluids or mud filtrate; preserves dissolved gases; and prevents precipitation of key solutes. What's more exciting, the tool also can be configured to contain sensors and instruments, so that the sample event can be interpreted in the logging truck as a transient test and generate accurate measurements of in situ permeability. For ***multiple*** zones in a single wireline trip!
- The tool can be configured for many purposes, but for in-situ fluid sampling from multiple zones it opens unique opportunities for the UIC permit process. Imagine a valid water sample and in-situ permeability measurement for every USDW in the surface casing section.

Open-Hole Well Logs - Electrical

Method	Property	Application
• Spontaneous potential (SP)	• Electrochemical and electrokinetic potentials	• Formation water resistivity (Rw); shales and nonshales; bed thickness; shaliness
• Nonfocused electric log	• Resistivity	1. Water and gas/oil saturation 2. Porosity of water zones 3. Rw in zones of known porosity 4. True resistivity of formation (Rw) 5. Resistivity of invaded zone
• Focused conductivity log	• Resistivity	• 1-4; very good for estimating R† in fresh water or oil base mud
• Focused resistivity logs	• Resistivity	• 1-4; especiallly good in determining R† of thin beds • Depth of invasion
• Focused and nonfocused microresistivity logs	• Resistivity	• Resistivity of the flushed zone (Rxo) for calculating porosity • Bed thickness

- Most of you are familiar with these types of logs, but logging companies now digitize the data and presentations, and can present amazing cross-plots and solutions that used to take three hours each.

Open-Hole Well Logs – Elastic Wave Propagation

Method	Property	Application
• Transmission	• Compressional and shear wave velocities • Compressional and wave attenuations	• Porosity; lithology; elastic properties, bulk and pore compressibilities • Location of fractures; cemend bond quality
• Reflection	• Amplitude of reflected waves	• Location of vugs, fractures; orientation of fractures and bed boundaries; casing inspection

Open-Hole Well Logs - Radiation

Method	Property	Application
• Gamma ray	• Natural radioactivity	• Shales and nonshales; shaliness
• Spectral gamma ray	• Natural radioactivity	• Lithologic identification
• Gamma-Gamma	• Bulk density	• Porosity, lithology
• Neutron-Gamma	• Hydrogen content	• Porosity
• Neutron-Thermal Neutron	• Hydrogen content	• Porosity; gas from liquid
• Neutron-Epithermal Neutron	• Hydrogen content	• Porosity; gas from liquid
• Pulsed neutron capture	• Decay rate of thermal neutrons	• Water and gas/oil saturations; reevaluations of old wells
• Spectral neutron	• Induced gamma ray spectra	• Location of hydrocarbons; lithology

Open-Hole Well Logs - Other

Method	Property	Application
Gravity meter	Density	Formation density
Ultra-long spaced electric log	Resistivity	Salt flank location
Nuclear magnetism	Amount of free hydrogen; relaxation rate of hydrogen	Effective porosity and permeability of sands; porsity for carbonates
Temperature log	Temperature	Formation temperature

Pressure-Transient Testing

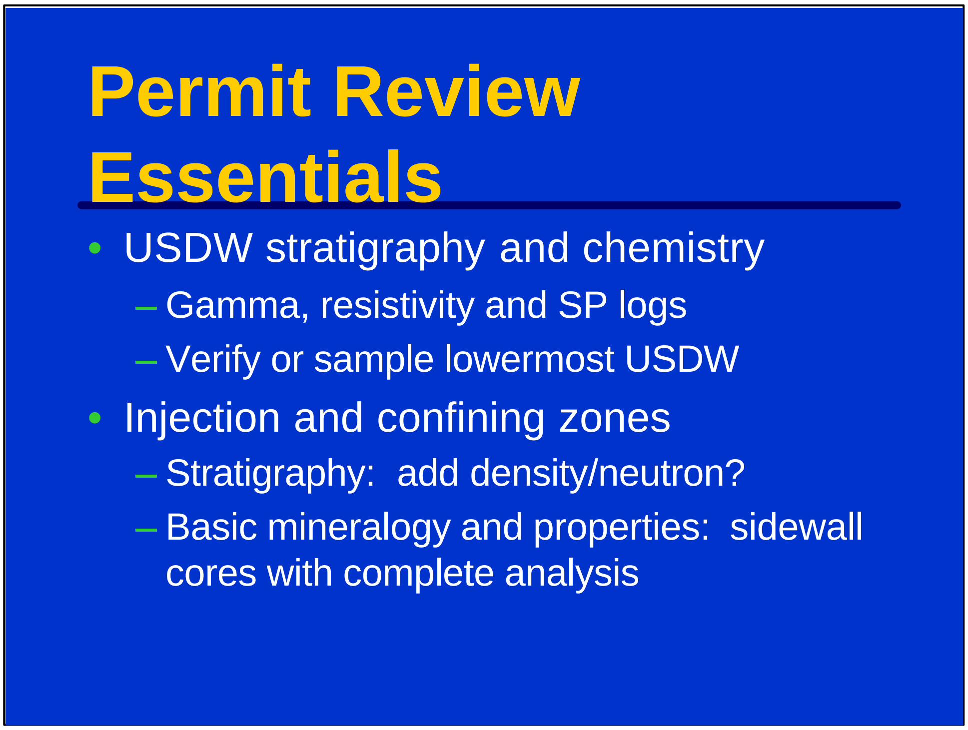
- Provides averaged data for larger portion of reservoir
  - Build-up or draw-down
- Types of tests
  - Drill-stem test
  - Injectivity
  - Specialized (e.g., straddle-packer)

- Well logs and all the other tests we have discussed provide data that is relevant only for the near-borehole environment. Pressure transient testing allows information to be gathered concerning the formation properties outside the wellbore, and provides averaged, effective data for the entire reservoir, rather than from a small sample. These tests provide the optimum basis for predicting the long-term behavior of the well, detecting changes in well performance or reservoir conditions during operation, and analyzing the well effects during post-closure.
- Transient testing involves recording and interpreting changes in reservoir pressure induced by pumping or injection. Typical tests record pressure build-up and falloff, or draw-down and recovery. For interpretation, transient test analysis uses the known quantities in the Matthews and Russell equation we discussed earlier to solve for formation variables such as formation pressure, effective average permeability, skin, and many other injection variables. Another objective would be to determine if significant fractures are present that could provide non-radial injection.
- The area of investigation of a single-well test is primarily a function of test duration. During the drilling process, a drill-stem test may be performed to evaluate potential injection or confining intervals. These tests are run for a few minutes, and provide average effective permeability data for a radius of investigation of only a few feet away from the borehole.
- Injectivity testing is performed after the well is completed. Tests are run for a few hours (or days, for large radii of investigation), and provide data concerning formation damage and skin factor, permeability, storage, and compressibility, averaged over a radius of investigation of hundreds of feet. Longer tests can evaluate the presence of flow boundaries, changes in reservoir thickness or permeability, and other information, over a radius of thousands of feet from the wellbore.
- Specialized tests involving dual packers are used to evaluate the leakage potential of a confining zone.

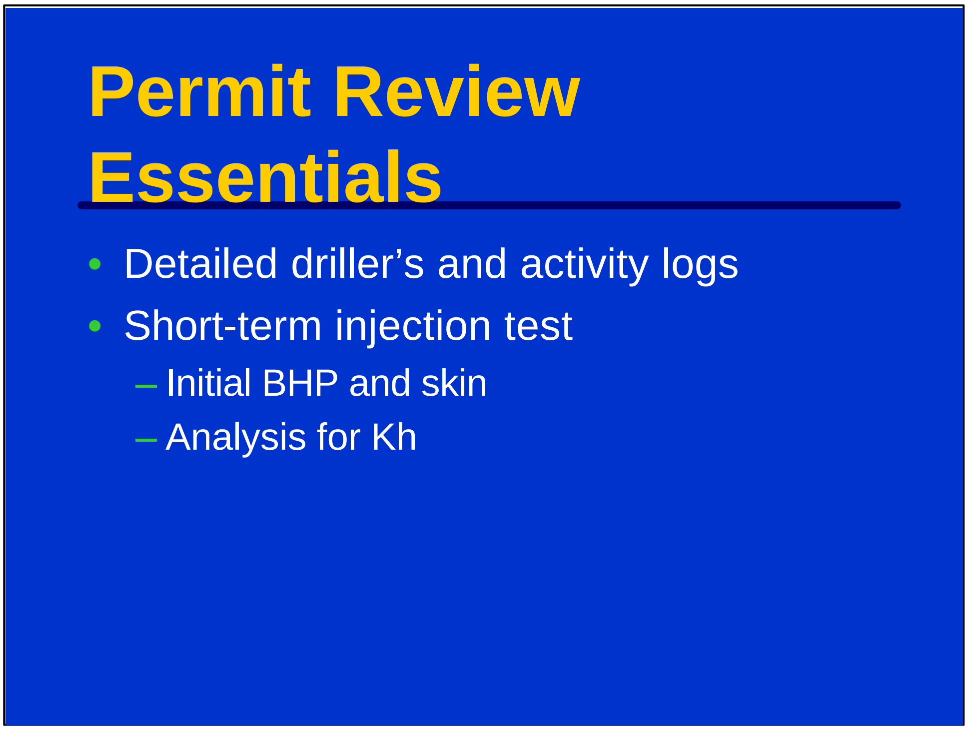
Objectives of Formation Testing

- Consider how much you need to know before asking for expensive tests
- Focus on real concerns
  - USDW, confining zone, and AoR
  - Cement
  - Detailed mineralogy and water chemistry
  - Fracturing or step test

- Every well is different, but every formation testing program shares a common set of questions to answer. Obviously, for Class-I Hazardous wells there is a high data hurdle for the operator to leap. But aside from that, the most important question is: how much do I need to know? Some permit writers will ask for the same extensive tests and information for every well, just because it's allowed in the regs (to be "considered," remember) or it's in the sample permit. But rig-time, sampling, and analysis are very expensive, and you should focus an operator's time, money, and attention into areas where you have real concerns. The price of coring will buy a lot of extra cement or MITs!
- In that sense, how much about the lithology do you really need to know? If logs from the area indicate the presence of a substantial confining zone, the injectivity and mineralogy of the injection zone are the operator's problem.
- What will a 4-day pressure transient test tell you that you didn't already know at 4 hours?
- Some permit writers like to see lots of fracturing tests. But before asking, consider, for example, how an applicant can generate a significant frac with 85-horse pumps and clear fluid.
- Before requesting 150-species mass-spec analyses of the formation fluids, consider that if the well plugs due to reaction products, it is entirely the permittee's problem, and not related to the environment unless he willfully exceeds his maximum injection pressure (but that's a different issue).
- Focus on the things that concern you, and spare no expense there, but be more judicious about requesting "technical window-dressing."



- Keep in mind that the permit writer does not initiate the formation testing program – the operator submits it with the permit application. However, if extensive testing is not required for the particular site, you might consider trading off some of the tests that are not required for better cement logs and more frequent MIT.
- Consider these the minimums, but remember that for Class II and II you will probably see data from other wells in the project. A prudent permit writer should want to know the following from a formation testing program:
    - Detailed stratigraphy of the USDW section. Gamma, resistivity and SP are sufficient in most cases, unless limestone is present (in which case, you should add a neutron log). Given the MFT tool and other new technologies, require proof of the lowermost USDW ***and*** a sample from the uppermost non-USDW aquifer. (It is usually not that expensive because the applicant must clean up the surface casing hole prior to cementing.) The surface casing should be set at least 50 feet below 10,000 TDS (100 feet is used in most States for Class I wells).
    - Detailed stratigraphy of the confining and injection zones. You can use the same logs as surface casing, but add a density/neutron combination to allow cross-plots. The applicant should provide representative sidewall cores of both zones (NTE 40), with mineralogical analysis, porosity measurement, and permeability estimate for water.



- ***Detailed*** driller's log and log of all rig activities, signed by the engineer in charge and by the operator.
- Short-term injection test (with bhp and skin) to confirm allowable injection pressure.
- If the operator submits (or you require) these basics, you can perform an accurate review on any well except I-H. In the case of Class II or III, you can use representative data from nearby wells, but for Class I or Class II-D commercial use original data.

Lesson 13
Stimulation Program

- Attachment J concerns the proposed well stimulation program. Stimulation of a well involves improving injectivity by either chemical or physical means.

Chemical Stimulation

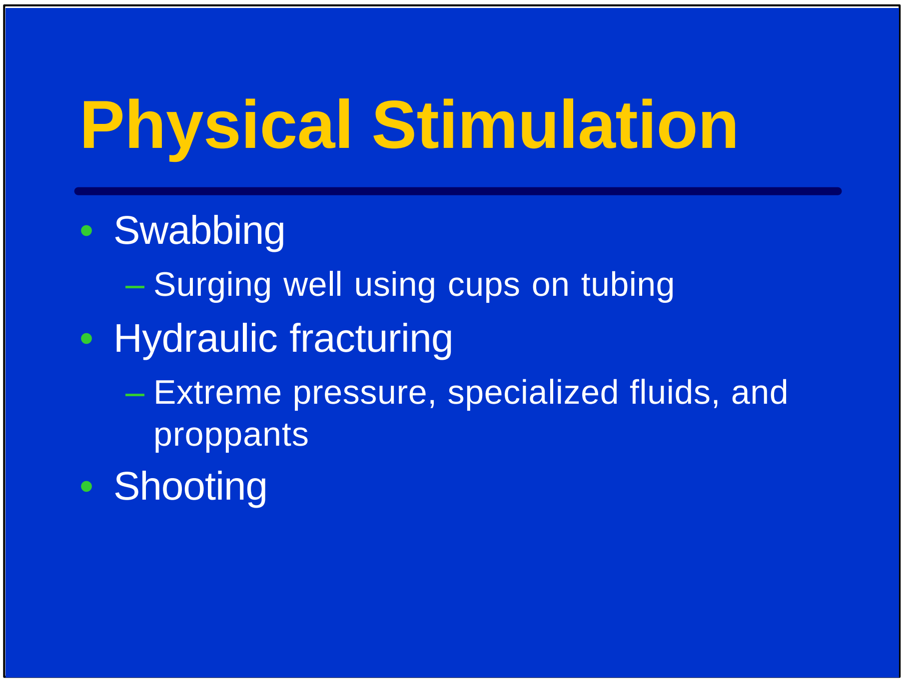
- Salts
  - Potassium chloride (KCl)
- Acid
  - Hydrochloric (HCl)
  - Hydrofluoric (HF)
- Organic solvents
  - Methanol or detergents

- One widespread method of stimulation utilizes potassium or ammonium chloride (KCl) brines. KCl has been found to stabilize some types of clay particles by saturating their ion exchange sites. Although this technique does not immediately improve permeability, the stabilized clays will shed fewer fine particles that tend to migrate and plug pore throats, which reduces permeability.
- Chemical stimulation usually involves the injection of chemicals that will dissolve either formation minerals or waste reaction products in an effort to improve permeability. The most common stimulation fluid is 15 percent hydrochloric acid (HCl), which dissolves carbonate cements and precipitates. Another common acid agent is hydrofluoric acid (HF), which dissolves most types of clay particles. Sometimes these acids are used in combination. In either case, the enhancement of permeability can approach 100 percent in a virgin injection zone or over 500 percent in a zone that has been partially plugged by precipitates.
- A less-common stimulation chemical involves organic solvents such as methanol. These chemicals are used mostly in Class II wells to flush away a partial oil saturation in the pores, but are also used in Class I wells to dissolve or mobilize organic polymers that form as reaction products with organic wastes.

Design Criteria

- Prevent corrosion
  - Inhibitors reduce steel corrosion (but not cement)
- Reduce harmful side-effects
  - Iron precipitates, clay disaggregation
- Depth of beneficial effects
  - Sizing and staging of treatment chemicals
  - Maximum injection pressure limitations not applicable

- The primary design criterion of chemical stimulation is to dissolve the bad things without dissolving the ***good*** things. For example, although HCl will readily dissolve carbonate cements and precipitates, it will also dissolve tubing, packer, and most types of cement. To prevent corrosion of tubular goods, acids used for downhole stimulation are almost always treated with inhibitors. These chemicals inhibit (but do not eliminate) corrosion of the steel components of the well. Inhibitors do not prevent corrosion of the cement, however.
- In addition to inhibitors, other components of the acid program might include surfactants to mobilize oil, chelation agents to prevent iron precipitation, and polymers to prevent clay disaggregation.
- A small-volume treatment might only improve injectivity in the skin area of the wellbore, which extends only a few inches into the injection zone. These treatments typically utilize up to 50 barrels of acid to remove residual drilling mud and improve skin efficiency. Conversely, many Class I wells utilize complex, multi-stage acid treatment that are intended to penetrate hundreds of feet into the injection zone. These treatments typically utilize up to 15,000 barrels of acid, and alternate injection with other acids and treatment chemicals. For example, a recent large-scale acid treatment was designed to utilize six alternating stages of 1500 barrels of HF acid, followed by 5,000 barrels of HCl and 3,000 barrels of KCl.
- Maximum injection pressure limitations do not apply to well stimulations, due to the specific "except during stimulation" language that is included in the regulatory requirements at 40 CFR 146.13(a)(1) and 146.67(a). However, a permit condition can be developed to require the well operator to submit a plan for any chemical or physical stimulation program to EPA for review and approval prior to implementation. EPA also can require that the well operator provide assurance of the proper design and implementation of any well stimulation through post-stimulation well tests, if deemed necessary. These requirements would have to be written into the permit to drill and permit to operate, however, since the regulations provide no authority to EPA to obstruct or limit well stimulations. 40 CFR 144.52(a)(9) and (b)(1) provide EPA the authority to impose additional conditions in a permit to protect USDWs and ensure compliance with the SDWA. This is one situation where an additional requirement is justified and defensible in the case of an appeal.
- An additional consideration for operating wells is the frequency of chemical stimulations. If the well needs to be stimulated with high frequency (multiple times per year), you would wonder whether the well filtration system and other related components are functioning properly. You may need to ask the operator some questions about the need for frequent stimulations.



- Physical stimulation utilizes mechanical methods to improve injectivity. The most common method is “swabbing,” where injectivity is improved by moving the fluid column up and down by means of a series of cups mounted on tubing. This provides a surging action that dislodges fine particles and mud which can plug pore throats at the injection face.
- Another common method involves hydraulic fracturing, used primarily in Class II wells. In a previous section, we discussed hydraulic fracture gradient and the properties of fractures. Hydraulic fracturing for well stimulation involves thousands of barrels (or hundreds of thousands barrels!) of specialized fracturing fluids, injected at high rates and extreme pressure using specialized treatment units, and creates fractures that may be hundreds of feet both in length and/or height above the perforations. When the fracturing pressure is released, the fracture will close. To provide a permeable pathway within the fracture, proppants (glass or plastic beads) are emplaced in the fracture to keep it open.
- Hydraulic fracturing of Class I wells has been debated through the years, and generally is discouraged. 40 CFR 146.13(a) requires that Class I well operating requirements in permits include that “***Except during stimulation*** injection pressure at the wellhead shall not exceed a maximum. . .to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures. ***In no case*** shall injection pressure initiate fractures in the confining zone or cause the movement of . . . fluids into an underground source of drinking water.” So the prohibition that is in the regulations stimulation that could cause the confining zone to be fractured or that could cause fluid movement into a USDW. As we mentioned already, limits on well stimulations can and should be included in Class I permits under the authority of 40 CFR 144.52(a)(9) and (b)(1).
- A less-common method of wellbore stimulation involves shooting the well using explosives, or, most recently, surplus Russian and American solid-fuel rocket motors. Explosives can cause catastrophic well failures and this method is seldom used anymore, but was once popular before hydraulic fracturing became more economical. The disarmament treaties of the last 15 years have made available thousands of solid-fuel rocket motors. This method provides a slower, controlled, burn that can create horizontal fractures over 100 feet from the wellbore.

Fracturing Design Criteria

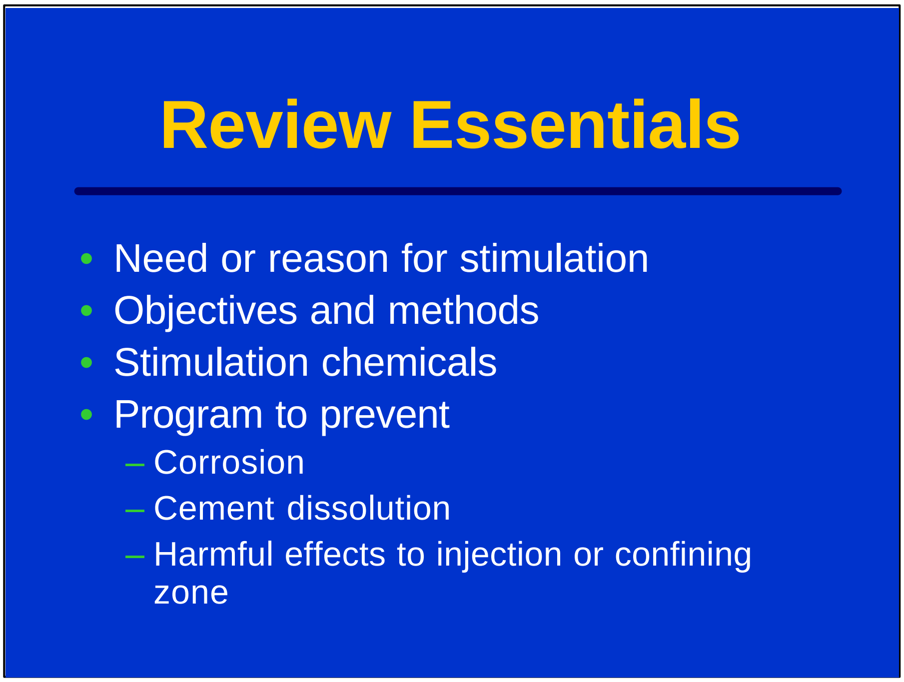
- Require detailed fracture design
- Ensure confining zone integrity
  - Observe fracture limit for confining zone
- Ensure USDW integrity

- Swabbing is a routine drilling practice and not usually specified as a stimulation treatment in Attachment J. Shooting can cause damage to the cement, and should not be allowed for an injection well under any circumstances. The only mechanical stimulation method we are concerned with is hydraulic fracturing. UIC regs usually prohibit fracturing the injection zone, so this practice is usually limited to Class II wells.
- The fracture treatment is designed by the service company that will perform the treatment. The fracture program may have been designed using typical oil production criteria, rather than UIC regulatory criteria and specific permit limitations. Be sure to look for a detailed fracture design in the permit application. Always ask for a detailed job design, and caution the operator about the prohibition against fracturing the confining zone (Class II).
- The primary design objective of a fracture treatment is to ensure that the fracture will not break out of the target zone by breaching the confining zone. Preventing break-out is achieved by having knowledge of the fracture gradient of the confining zone rocks, and limiting the injection pressure during fracturing to respect that gradient. This knowledge could be obtained by the service company in other frac jobs, or testing or sampling performed in the subject well. Other than pressure limitations, there are no other methods to prevent fracturing the confining zone or to detect breaching after the fracture treatment.
- However, you should recognize that under normal stimulation conditions, it is highly unlikely that a properly designed fracture treatment would fully penetrate a clay confining zone of any thickness over a few feet.
- A recent EPA study indicates that the highest hydraulic fracture ever created using non-slurry fluids reached only 600 feet above the perforations. Unless your USDW is located within 600 vertical feet of the injection zone, this indicates that direct or secondary effects are unlikely. In shallow injection zones (or production zones such as for coal-bed methane), you should be aware that fracturing fluids can contaminate USDWs and that the connection between the injection zone and USDW can provide a direct pathway for contamination. The smaller the distance to the USDW, the greater caution necessary and appropriate in permitting the well.
- The secondary design objective is to ensure that injectivity improvements actually support a proposed maximum injection pressure limitation. Make sure that a short injectivity test is also included to document the improved injection rate (or lower injection pressure for the old rate).

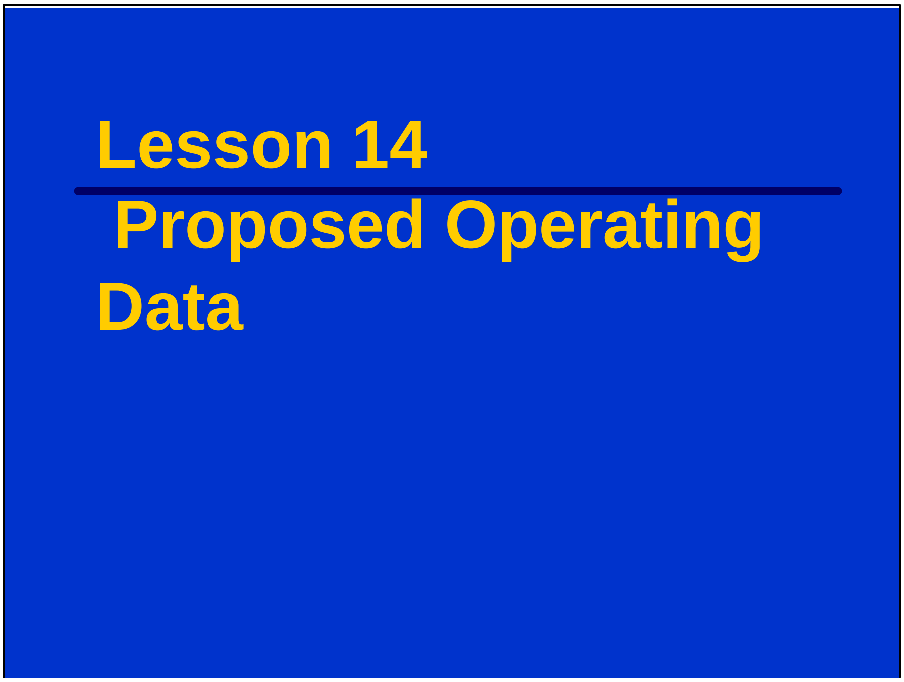
Too Much Stimulation?

- Post-construction acid jobs improve injectivity
  - Dissolve precipitates and solids
- Acid jobs can also:
  - Dissolve cement in AoR
  - Create channels along borehole
  - Cause harmful reactions
  - Dissolve confining zone

- We can all use a little stimulation! But just like the human kind, too much stimulation of an injection well can be a bad thing. Most wells are stimulated during construction, but stimulation can also be performed to remedy injectivity problems during operation. There are permit records for Class I wells where the operator has stimulated his well twice a month for the life of the well, due to the formation of precipitates. Acid jobs are no substitute for proper preventive measures to assure compatibility between wastes and formation fluids.
- First, most acid programs will readily attack some types of cements, both in the injection well and for offset wells in the AoR. Second, the repeated use of acid can create solution channels in the interface between the cement sheath and borehole, not all of which can be seen by a RAT. Third, unspent acid may cause harmful reactions with formation rocks, such as when excess gas is created (which can migrate to the wellbore when the well is shut in for workovers) or when organic wastes in contact with acids form permanent polymers in the pores. Most important, the formation of new, high-permeability flow channels is not a homogeneous process, and channels can grow vertically as well as horizontally. Acids can be delivered to and also dissolve the materials of the confining zone.
- In reviewing a permit application, make clear to an operator that post-construction stimulation jobs must be approved in advance, and for Class I and other well classes where there are concerns about the potential to violate a performance standard, be sure to ask for detailed program specifications. Remember that you may need to add a permit condition for submission of stimulation plans in advance for EPA approval, since the regulations do not call for this as a standard condition.



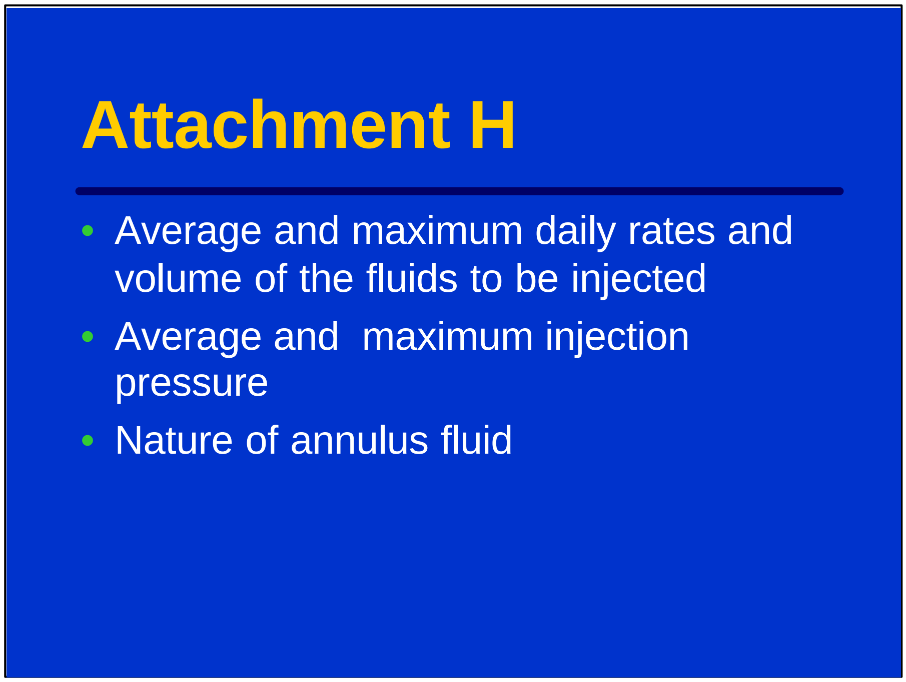
- Basically, the operator should present the reason for stimulation, the objectives and methods he proposes, and the chemicals to be employed. The operator will propose the program he thinks he needs, but you should require that he justify the need for stimulation and that he define the steps he will take to prevent well damage or harmful effects.
- You may also want to add a permit condition that he notify you prior to performing stimulation during operation, or submit a plan for your approval if this heavy of a condition is warranted based on well siting and the other factors we have discussed.



- Attachment H of the permit application provides information on the permit applicant's proposed operating data.

Section Outline

- Regulatory requirements
- Performance standard
- Components of injection pressure
- Exercise: calculate permit injection pressure
- Shorthand method
- Calculate permit injection rate and volume
- Monitoring injected waste



- The instructions for Attachment H require that supporting data for the following values be included in the permit application:
  - Average and maximum daily rates and volume of the fluids to be injected;
  - Average and maximum injection pressure; and
  - Nature of annulus fluid.
- The key relationship to injection rate and volume is the radius of the Area of Review (AoR). That is, for any given injection zone, higher rate (and therefore, higher pressure and volume) will increase the radius of the AoR. As we will see in a later section, the primary method of corrective action is a restriction of injection rate and pressure, which can reduce the radius of the AoR to accommodate a problem well, for example.

Attachment H

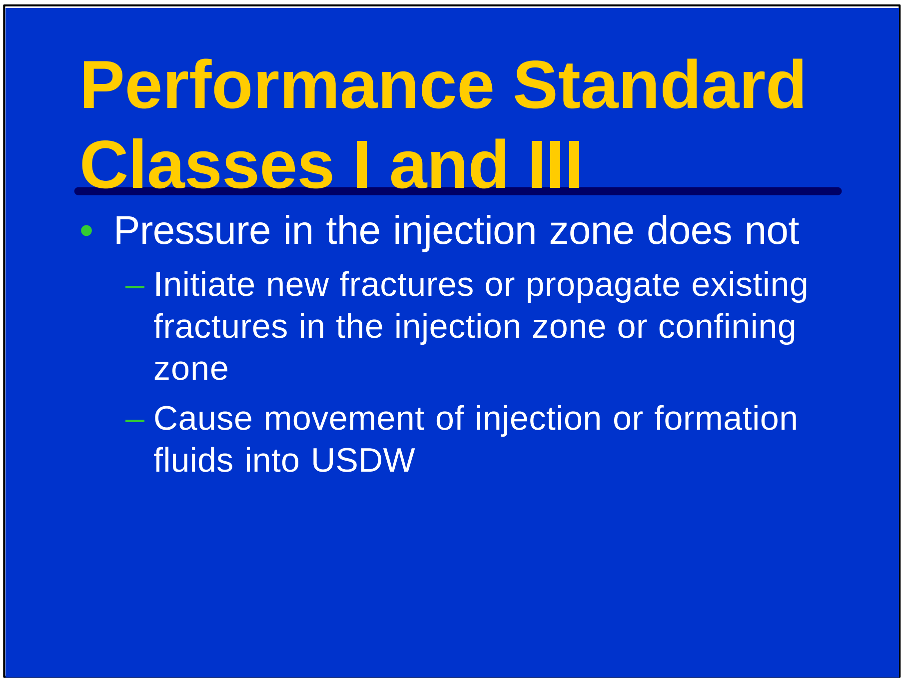
- Class I wells
  - Source of injection fluids
  - Analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness
- Class II wells
  - Source of the injection fluid
  - Analysis of the physical and chemical characteristics

- Attachment H also should contain data concerning the nature and source of the injectate. These requirements vary by well class.
- For Class I wells, the permit application should identify the source of injection fluids and provide the results of an analysis of the chemical, physical, radiological and biological characteristics, including density and corrosiveness.
- For Class II wells, the applicant should identify the source of injection fluids and provide the results of an analysis of the physical and chemical characteristics of the injection fluid.

Attachment H

- Class III wells
  - Qualitative analysis and ranges in concentrations of all constituents
  - If the information is proprietary, maximum concentrations only may be submitted, but all records must be retained

- For Class III wells, the owner/operator should provide a qualitative analysis and ranges in concentrations of all constituents of injected fluids. If the information is proprietary, maximum concentrations only may be submitted, but all records must be retained.

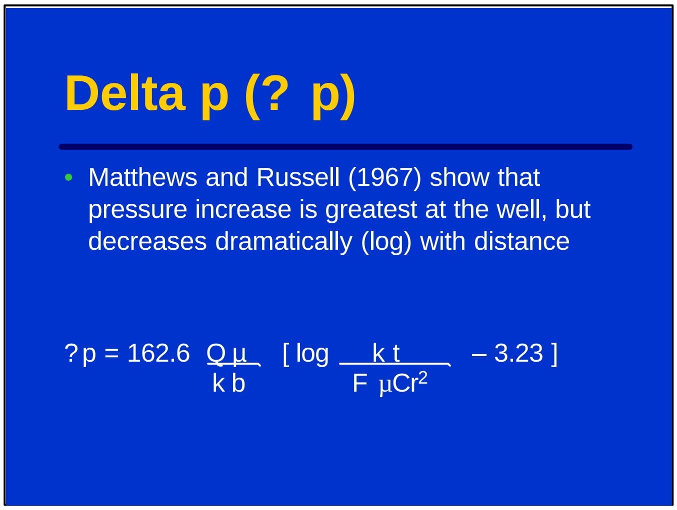


- The overriding performance standards for injection pressure are contained in 40 CFR 146.13 (for Class I) and 146.33 (for Class III).
- For Classes I and III, the standard requires that except during stimulation, pressure in the injection zone does not initiate new fractures or propagate existing fractures in the injection zone or confining zones ***or*** cause movement of injection or formation fluids into USDW. As we discussed in the AoR section, the pathways for communication with USDWs are natural faults and fractures, induced hydraulic fractures, and incomplete or faulty construction, cementing, or plugging of offset wells.
- Note carefully that the regulations include the harmful effects to USDWs not only of wastes, but also the native formation fluids (which are usually high-TDS brines).

Performance Standard Class II

- Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs.

- The standard for Class II wells is not nearly as clear. The regulation at 40 CFR 146.23 reads: “Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs.”
- First, 40 CFR 146.23 specifies “injection pressure at the wellhead,” rather than the “pressure in the injection zone” used for Class I. This usually limits measurements to less meaningful wellhead gauge pressure rather than bottom-hole pressure or injectivity tests. Gauge pressure neglects the considerable effects of fluid density and skin.
- Second, “calculations” are specified. Pressure calculations without the benefit of injectivity-derived transmissivity are almost meaningless. However, as we have discussed elsewhere, the Director can require acquisition of site-specific data if it is necessary.
- Third, and most important, the Class II standard locates the no-fracture prohibition at the last confining zone before the USDW, rather than the zone immediately above the injection zone. In a typical Class II well of over 2,500 feet depth (and assuming at least 500 feet to the base of the USDW), it is highly unlikely that fracture technology in a well stimulation could vertically fracture that much intervening rock, let alone injection pressure.
- There are some geographic locations where Class II pressure or volume limitations may not truly need to be specified in the permit, unless there are serious AoR issues like faulty plugging or cementing. However, in other parts of the country, pressure limitations may be necessary due to the geology and proximity of the receiving formation to USDWs. Nevertheless, the regulations ((40 CFR 146.23) requires that permits specify a maximum operating pressure for all Class II wells. The permit writer should be aware, however, that the issue of whether the performance standard will realistically be violated varies based on all the factors discussed above.
- However, in the case of AoR issues, the regulations also add the standard fluid-movement prohibition: “In no case shall injection pressure cause the movement of injection or formation fluids into an underground source of drinking water.” The bottom line is that the permit writer should conduct a thorough review of the operating and geologic



- We talked about fluid injection, its components and the Matthews and Russell equation in Section 8. To briefly review:

Delta p (the increase in pressure) = 162.6 Q (µ) / k b * [(log k t / F µ-C r^2) – 3.23],

where

  - ? p = pressure change (psi) at radius r and time t
  - Q = injection rate (bbl/day)
  - µ = injectate viscosity (centipoise)
  - k = average reservoir permeability (millidarcies)
  - b = reservoir thickness (ft)
  - t = time since injection began (hrs)
  - C = compressibility or storage coefficient (sum of water/aquifer compressibility and reservoir expansion) (psi-1)
  - r = radial distance from wellbore to point of investigation (ft)
  - ? = average reservoir porosity (decimal)

- We talked about the fact that kt over F µ-C r^2 is usually a big number over a decimal, and the log result is usually a number between 6 and 25. Conversely, injection rate (Q) and transmissivity (kb) are the major factors in delta-p. Similarly, as K decreases over time (due to precipitates and solids), then delta-p will increase (or Q will have to decrease).
- When injection ceases, the pressure begins to dissipate to lower-pressure areas of the system (i.e., the cone begins to flatten). Eventually, at a rate proportional to buildup, the formation pressure will generally equalize to a higher, post-injection formation pressure. In many circumstances, the formation will return to very near original pressures, because the formation is infinite acting.
- Remember that injection should be occurring in an infinite acting system. It is also important to recall that the lower the transmissivity of the receiving formation(s), the higher the injection pressure required for emplacement at a given rate. The effective ***porosity*** of the rock affects the ***amount*** of fluid that can be emplaced, whereas the effective ***permeability*** of the rock affects the ***rate*** at which fluids may be emplaced.
- The most common uses of the equation of Matthews and Russell are to determine the allowable injection pressure of a well and to assess the radius of endangerment for area of review studies.

Bottom Hole Pressure

- Bottom-hole pressure during injection (BHPI) consists of
  - ? p (injection pressure at some Q) plus
  - Weight of the fluid column
    - Height of fluid x density, e.g.,
      4000 ft @ .4416 psi/ft = 1766 psi
- BHPI also expressed as gradient (psi/ft)
    - E.g., 1940 psi ÷ 4000 ft. = 0.485 psi/ft

- We have previously considered the minimum pressure necessary for emplacement of fluids into the reservoir. Let's review what we talked about in Section 8, regarding bottom hole pressure. This review is important, because BHP is a significant factor in setting operating conditions for an injection well.
- You recall that BHP includes the weight of the fluid column in the well. The components of BHPI include delta-p (the injection pressure), the weight of the fluid column in the tubing, and certain friction losses at the injection face that we call "skin" losses. Unless you have a documented test of skin losses, it's best to ignore them for most BHPI calculations.
- The weight of the fluid column equals the height of the fluid column times the density gradient of the fluid. Charts and conversion tables allow you to convert units to density gradient as psi per foot using traditional measurements such as grams per cc, pounds per gallon, specific gravity, or even TDS concentration.
- Most analysts also express BHPI as a *BHPI gradient*, which is BHPI divided by the depth of the injection zone. The BHPI gradient for this example would be 1940 psi divided by 4000 feet, or 0.485 *psi per foot*.
- BHP can be estimated as we have done, or directly measured in the field using a pressure sensor. You could also work at this backwards in the field if you needed to, by observing the operating well-head pressure. The problem with this method is that WHIP (well-head injection pressure, also called SIP for surface injection pressure) also includes friction losses in the tubing and skin losses downhole. In some Class I wells, these losses can total hundreds of psi, because of pore-plugging by chemical waste reactions.

Example: Allowable Injection Pressure

- Well depth: 4000 feet
- Thickness of interval (b): 50 feet
- Porosity (F): 30 percent
- Permeability (k): 400 md
- Injection rate (Q) = 1700 bbl/day
- Viscosity (µ) = 0.90 centipoise
- Duration of injection (t) = 87,600 hours
- Effective well radius (r) = .292 ft
- Reservoir storage (C) = 6.5 x 10^{-6} psi^{-1}
- Well tubing = 2.375"
- Injectate specific gravity = 1.02

- We're going to consider two methods of calculating allowable injection pressure. The first method considers every possible variable so that you can see how it all fits together, and so you can use all or parts of it in the future. For now, however, we will just skim over it and concentrate here on a shorthand version.
- Allowable injection pressure for a well is considered at the surface. An analysis of wellhead injection pressure (WHIP) must consider not only the injection pressure at the formation face (Matthews and Russell), but also friction loss in the tubulars of the well and the weight of the fluid column in the tubing.
- Consider this problem: determine the allowable injection pressure for the following well.
- Depth to injection interval: -4000 feet
  - Thickness of interval (b): 50 feet (measured or estimated from logs)
  - Porosity (F): 30 percent (measured or estimated from logs)
  - Permeability (k): 400 md (measured or estimated from logs)
  - Injection rate (Q) = 1700 bbl/day
  - Viscosity (µ) = 0.90 centipoise @ 100º (measured or estimated from chart)
  - Duration of injection (t) = 10 years = 87,600 hours (life of permit)
  - Effective well radius (r) = .292 ft (casing diameter is 7 inches)
  - Reservoir compressibility or "storage" (C) = 6.5 x 10^{-6} psi^{-1} (estimated from chart)
  - Well tubing = 2.375" steel
  - Injectate specific gravity = 1.02 (.44 psi/ft, from conversion chart)
  - Existing formation pressure: 1795 psig @ 4000 feet (measured)

Step 1: Injection Pressure

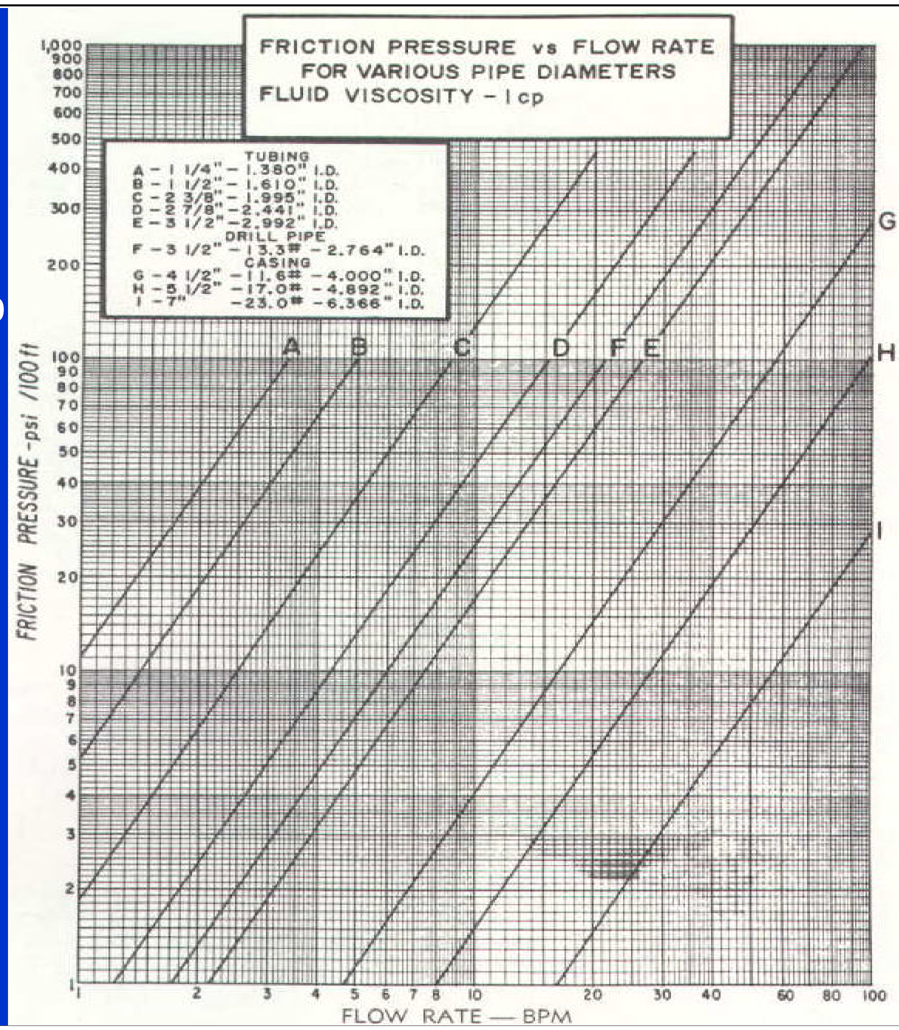
? $p = \frac{(162.6)\,(1700)\,(.90)}{(400)\,(50)} \times \left[\log \frac{(400)\,(87600)}{(.30)\,(.90)\,(.0000065)\,(.292)^2} - 3.23 \right]$

? p = 138.6 psi at the injection face

- At the injection face (r = casing radius) and considering the lifetime of the well (10 years), we can calculate the necessary injection pressure:
- ? $p\ (\text{psi}) = \frac{(162.6)\,(1700)\,(.90)}{(400)\,(50)} \times \left[\log \frac{(400)\,(87600)}{(.30)\,(.90)\,(.0000065)\,(.292)^2} - 3.23 \right]$
- ? p = 138.6 psi at the face of the injection interval
- This is the injection pressure required after 10 years' service that is necessary to emplace 1700 bbl per day (about 50 gpm) into the example formation.

Step 2: Friction Loss

Additional pumping pressure is needed to overcome frictional losses in the tubing (34 psi)

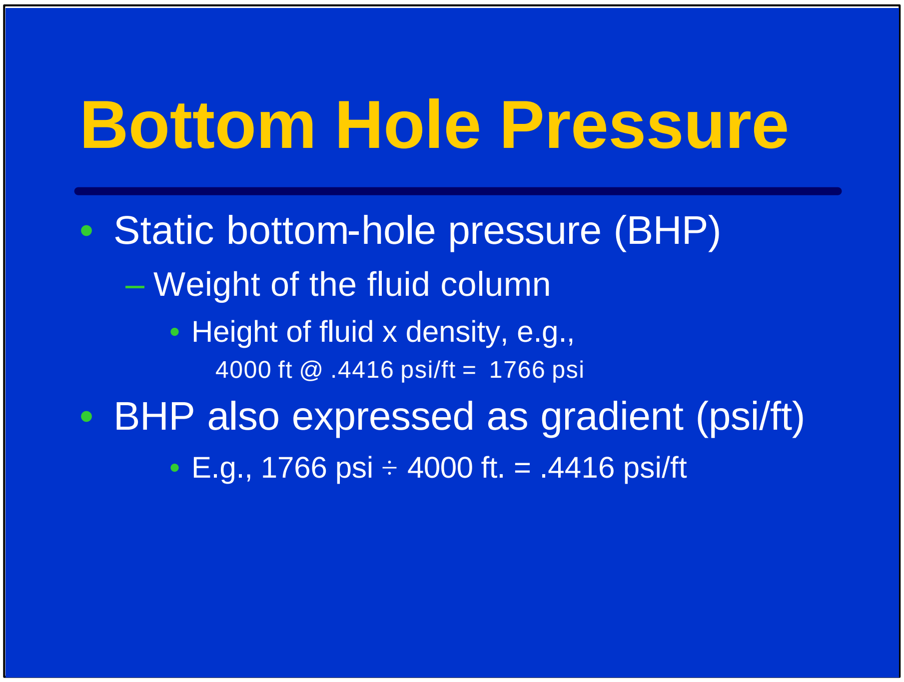


- To the injection pressure we must add friction losses that are encountered in the well tubulars and at the entry to the injection formation.
- Friction losses are a function of tubing size and length, flow rate, injectate viscosity, and the smoothness of the interior of the tubing. Friction losses are usually provided by the manufacturer of the tubulars, or can be calculated or estimated from a standard chart. The friction losses of the specified 2-3/8 inch tubing are 0.00839 psi/ft, at 50 gpm, as estimated from this standard chart. The additional WHIP that accounts for friction in tubing is about 34 psi.
- Now, that's not very much pressure, and may not even seem worth the effort. However, there is lots of used 2-3/8 inch tubing lying around most oil leases, and a lot of operators will use it by default. In other words, a higher-rated pump head is a lot cheaper than a new 3-1/2 inch tubing string, and the friction losses in many Class II wells can be 150 psig or more.

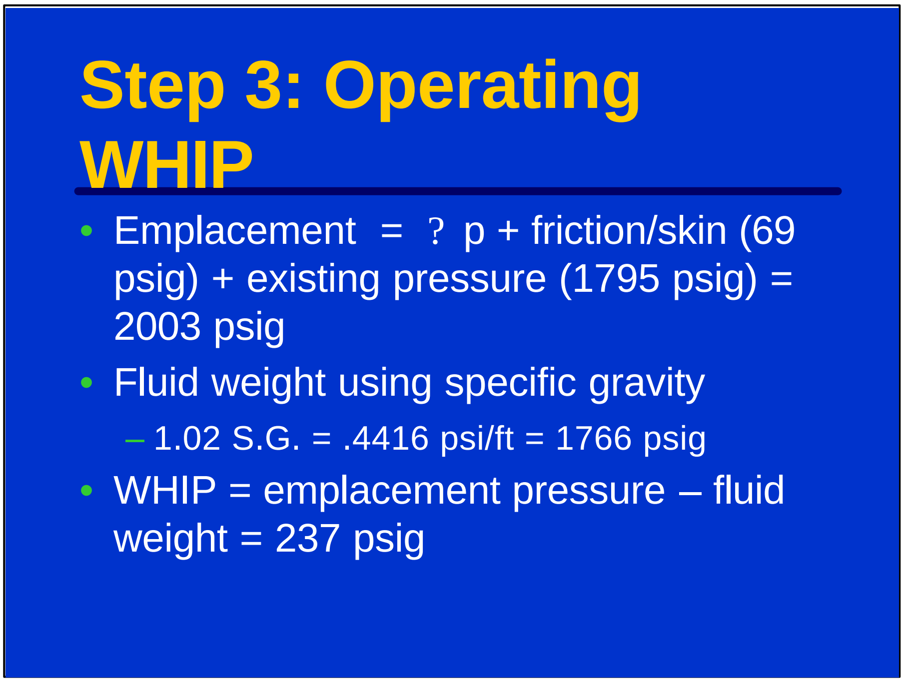
Friction Loss at Formation Face

- Friction losses also at the formation face (“skin”) (35psi)
- ?p + friction + skin = 207.6 psig @ wellhead (+ formation pressure)

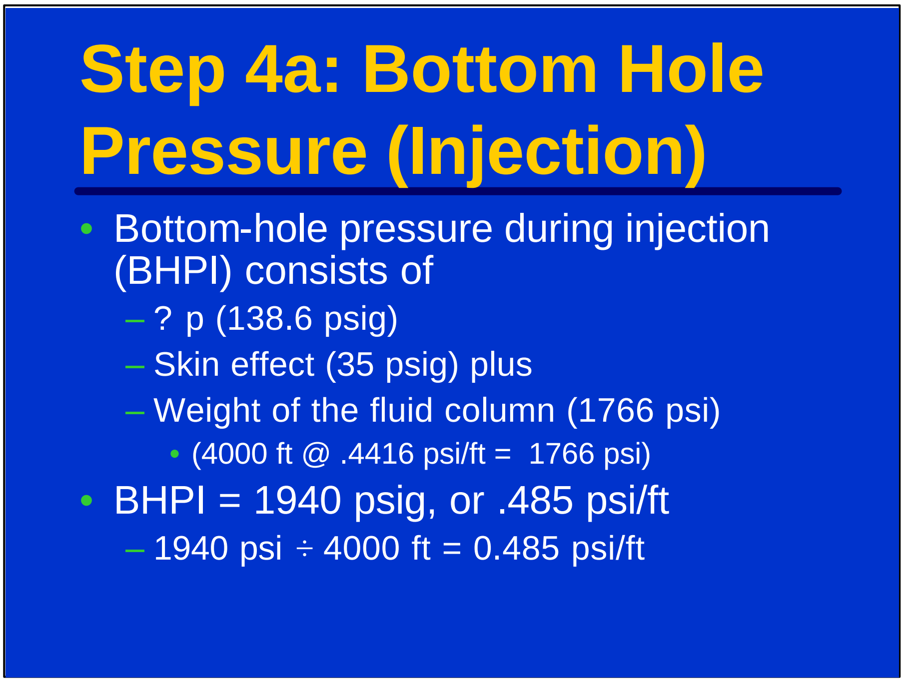
- Friction losses at the formation face are due to perforation restrictions and permeability reductions from plugging from drilling mud, chemical precipitates, or unfiltered solids in the waste stream. This phenomenon is known as skin, skin damage, or skin effect in the oil industry and as well losses in the water well industry. Whatever you call it, it covers a wide range of processes that can reduce effective permeability near the wellbore. In extreme cases, the formation permeability can be severely reduced, sometimes permanently, by plugging from precipitates or solids. Skin effect is tested and measured by a variety of methods that involve an injection test and some form of ? p analysis.
- The net effect of skin is to reduce well efficiency and increase pumping pressure. We can express skin as a percentage increase in ? p. Completions using perforations commonly exhibit skin on the order of 15 to 35 percent, whereas gravel pack completions are more efficient and feature skin as low as 2 percent. The perforated completion in the example features 25 percent skin effect, so an additional 35 psig is required for emplacement (138.6 x .25).
- In the subject well, a total of 207.6 psig WHIP is necessary to emplace 50 gpm of injectate into the subject formation (? p + friction). Note that this value is ***in addition*** to the existing formation pressure in the injection interval (specified as 1795 psig). For the example well, 2003 psig will be necessary to emplace the design injection rate of 50 gpm; that is, the combination of ? p (138.6) and friction losses (34 + 35 psig) added to the existing formation pressure of 1795 psig.
- Not all of the 2003 psig necessary for injection must come from surface pumps; the weight of the fluid column in tubing supplies kinetic energy at the formation face. By calculating this kinetic energy, we can determine the actual operating pressure at the wellhead (WHIP).



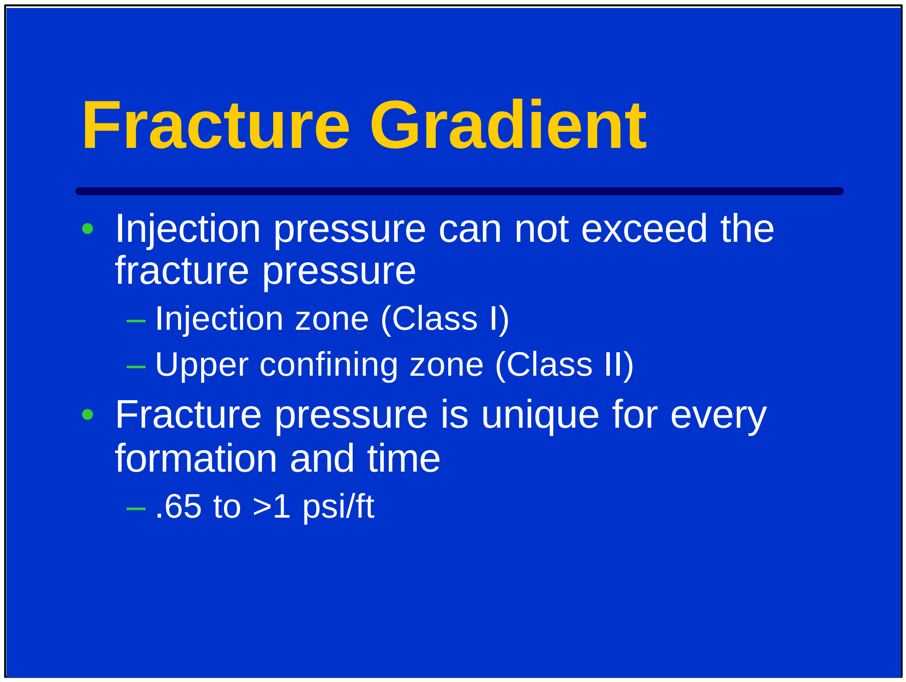
- The weight of the fluid column in tubing is a function of injectate density, usually expressed as grams per cc. Injectate density is either directly measured in the field or laboratory, or estimated using total dissolved solids (TDS) data. Density is usually reported as "specific gravity" (SG), a comparison to the density of distilled water at room temperature. The specific gravity of the example injectate was measured as 1.02, which corresponds to a weight of 0.4416 psi per foot (multiply 1.02 x .433, the weight gradient of distilled water). The weight of the fluid column in the example well would be 1766 psi (4000 ft @ .4416 psi/ft).
- Most analysts also express BHPI as a BHPI gradient, which is BHP divided by the depth of the injection zone. The BHP gradient for this example would be 1766 psi divided by 4000 feet, or 0.4416 psi per foot.
- BHP can be estimated as we have done, or directly measured in the field using a pressure sensor. You could also work at this backwards in the field if you needed to, by observing the operating well-head pressure. The problem with this method is that WHIP (well-head injection pressure, also called SIP for surface injection pressure) also includes friction losses in the tubing and skin losses downhole. Remember that in some Class I and II wells, these losses can total hundreds of psi.



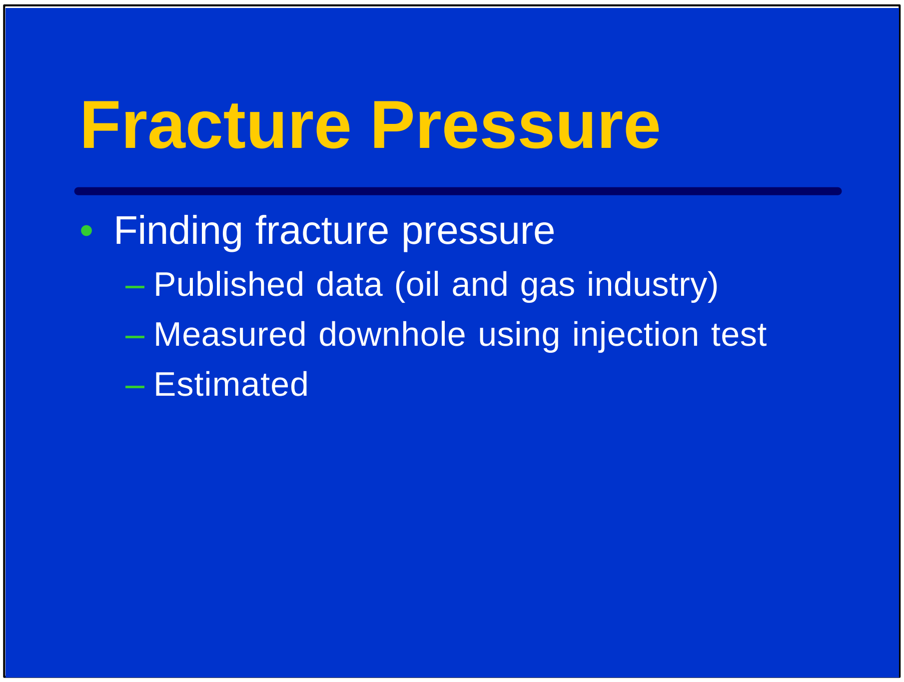
- The actual operating wellhead injection pressure would be the emplacement pressure (2003 psig) minus the kinetic energy of the fluid column (1766 psig), or 237 psig WHIP. This isn't the maximum allowable WHIP, but rather the gauge pressure the operator will experience at his requested injection rate.
- Note that if the skin damage increases, for a given injection rate the WHIP will increase. If the specific gravity of the waste stream increases (more saline wastes, for example), the WHIP will decrease.



- Here in another way of looking at BHP. This step involves analysis of the operating bottom-hole pressure (BHPI). The components of BHPI include ? p, skin losses, and the weight of the fluid column in the tubing. Note that friction losses in the tubing are expended in travel downhole, and should not be included in BHPI calculations. During operation, the BHPI of the example well would be 1940 psig (including fluid column weight, ? p, and skin). Another way to express BHPI is as a BHPI gradient, which is BHPI divided by the depth of the injection zone. The BHPI gradient for the well would be 1940 psi divided by 4000 feet, or 0.485 psi per foot.

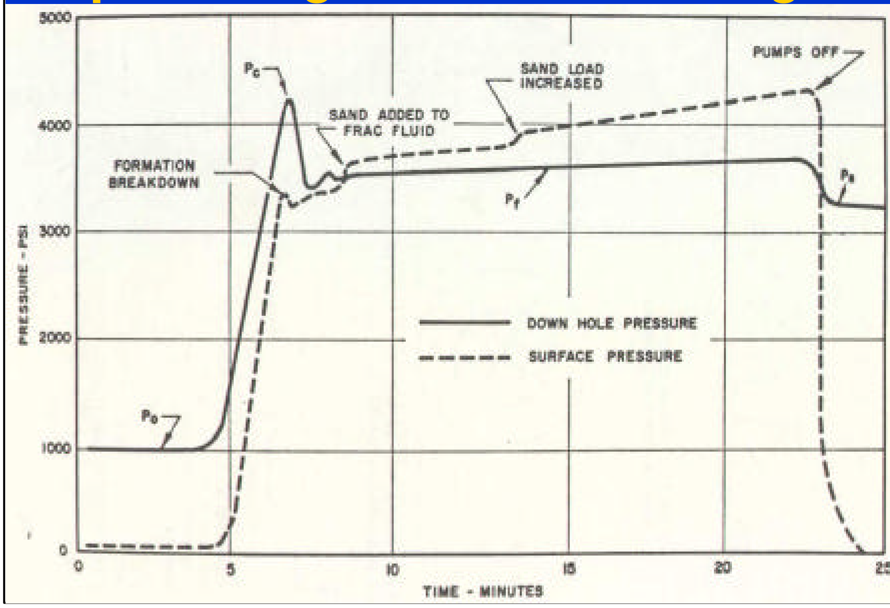


- The ultimate limit for allowable injection pressure in Class I and III wells is the fracturing pressure. UIC regulations prohibit Class I wells from exceeding the fracture pressure of the rocks of the injection zone (except during well stimulation), whereas Class II wells must not exceed the fracture pressure of the uppermost confining zone.
- Hydro-fracture pressure is unique for every formation, and is related to the formation's depth, elastic modulus, overburden and fluid pressure, geologic age, and the sand/shale ratio. The fracture pressure can change with increasing (or decreasing) formation pressure, due to injection or production. In other words, a fracture pressure measured early in the life of a well may not be valid after continuous injection for a number of years. Hydro-fracture pressure information for a given area can be found in the literature, measured directly by a drill-stem or step test, or estimated using several possible methods.
- Fracture pressure is usually expressed as the fracture gradient, in psi per foot, by dividing the fracture pressure by the well depth. This allows test results or regulatory standards to be applied to different wells. Fracture gradients can vary from 0.65 psi per foot for poorly-consolidated sand zones, to over 1 psi per foot in the hard rocks of the midcontinent and Appalachian regions.

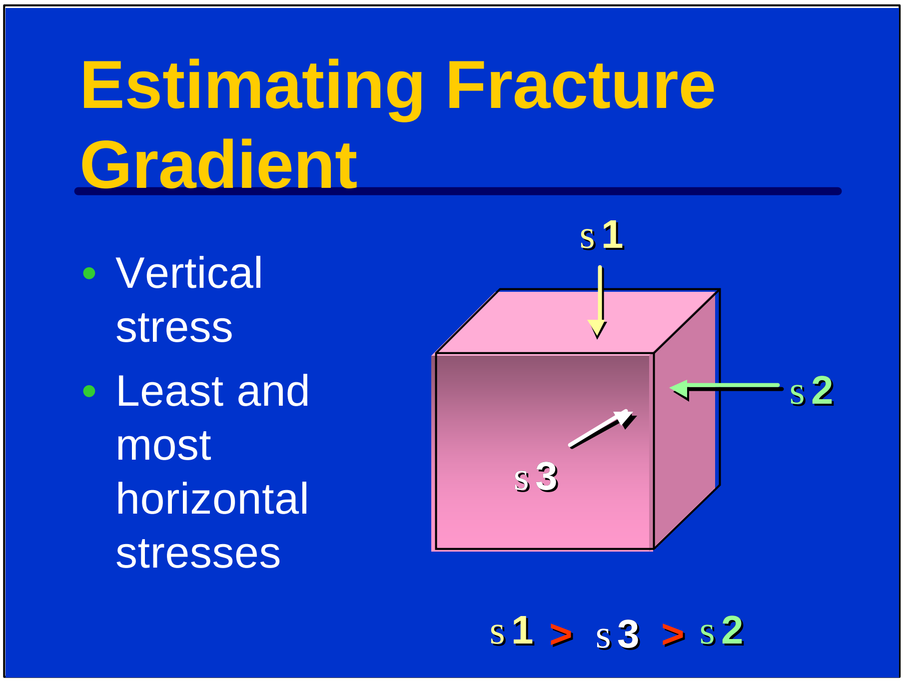


- Fracture pressure information can be found in oil and gas industry publications or the scientific literature. When considering published data, it is important to remember that injection wells usually operate in an environment markedly different from the oil wells that are the usual subjects of published research. Injection well use is typically at shallower depth (less than 7000 feet), in normally pressured, water-saturated formations of high permeability and porosity, in areas free of active faulting and tectonic activity. Published values for oilfield fracture gradients are usually derived from deep production zones and overstate the true fracture gradient in shallower formations.
- Fracture gradients can also be measured, using either a specific test in the subject well, or using industry or published data derived from fracturing procedures.

Step Testing and Fracture Logs



- In a step test, injection pressure is increased until the formation breaks down. These tests are usually required for a Class I Hazardous permit application, especially in Region 5. For other wells, the most common information available is from a nearby hydraulic fracturing procedure. Data from these procedures is usually available from service companies who perform the procedures (such as Halliburton) or from State agencies (given to operators to allow planning for blowouts). In either case, a step test and fracture log provide the same information, and the terms and solutions are the same. This example is a log of a fracture procedure. Ignore the dotted line, but concentrate your attention on the down-hole pressure.
- P-zero is the initial hydrostatic pressure in the formation plus the weight of the fluid column (BHP). Injection pressure is increased until "breakover" is observed, labeled "P_c" on most logs. Once the fracture pressure has been exceeded and a flowpath is created, continued injection into the fracture is easier as the fracture is being extended. This phenomenon is labeled "P_f," and is known as flowing pressure. P_f is especially significant, in that once injection pressure has exceeded a threshold fracture-pressure value, subsequent injection into the fracture requires significantly lower pressure. Depending on the elastic properties of the formation, the initial fractures may never heal, and the effective fracture gradient is now lowered. In semi-consolidated formations, however, fractures can heal, and the original breakdown pressure must again be exceeded for subsequent fractures.
- When pumping is stopped, the well stabilizes at a value known as the "instantaneous shut-in pressure," or ISIP, labeled P_s on this slide. This pressure is considered by most researchers to be equal to the least principal earth stress in the vicinity of the well.
- Many fracture logs are recorded as surface pressure (always check the log header or P-zero first). For surface-recorded logs, we would need to add the weight of the injection fluid column to ISIP to get the true fracture pressure for the new injection well. This log is recorded as down-hole pressure, but many fracture jobs use light fluids (such as methanol) or the fluid level is not to surface when P-zero is measured. So for bottom-hole fracture logs, subtract P-zero from log-ISIP for a true ISIP pressure, and then add the weight of the proposed injection fluid column.
- Because of the P_f phenomenon and the fact that some fractures never heal completely, many regulators avoid fracture testing every well, and for setting permit limitations rely instead on tests of similar wells or on estimates of the fracture gradient.



- Hydro-fracture pressure for a given formation can be measured directly by a fracture log or step test, or can be estimated using several methods. Most estimation methods require specialized tests of rock properties (such as Young's Modulus), or may be valid only for certain depths or geologic provinces. It is possible, however, to develop a simple estimation logic using published data and the method of Hubbert and Willis.
- There are two principal stresses acting at any point in the earth's crust: vertical overburden stress, and horizontal tensile or compressive stresses. A practical way to express that relationship is to measure their effects at any point in the subsurface: we can define vertical stress as the rock overburden pushing down, and describe the relationship of tensile or compressive forces as the two, perpendicular directions of ***least*** and ***most*** horizontal stress.

Hubbert and Willis (1972)

- Fracture orientation perpendicular to least principal stress
- Fracture gradient is usually from 0.64 to 0.73 psi/ft in typical oil sands
- More for shale-rich, hard rock, or thrust areas (up to 1.0 psi/ft)

- Hubbert and Willis (1972) are most famous for proving that fracture orientation is perpendicular to least principal stress. (Remember that hydraulic fractures are planar and are oriented in a particular direction.) When the least principal stress is vertical, that is, the overburden is small, then fracture orientation will be horizontal. That is the usual case for shallow wells, usually less than 1,000 feet in depth. When the least principal stress is horizontal, fracture orientation will be vertical. That is the case for deeper wells.
- The method of Hubbert and Willis also postulates that the fracture pressure gradient is dependent on the overburden, the pore-pressure gradient, and the rock frame stress. In typical oil-exploration basins that feature normal faulting, they found that the least stress is probably horizontal and from 1/2 to 2/3 the effective pressure of the overburden. Using these assumptions and data for overburden in many regions, Hubbert and Willis found that the fracture pressure gradient probably ranges from 0.64 to 0.73 psi per foot. Published data from other literature sources generally agree with the postulate of Hubbert and Willis (if we consider the geologic conditions typical of injection wells). Test data in the field, however, has shown fracture gradients approaching 0.85 psi/ft for shale-rich sections, and in hard-rock environments that feature thrust faulting, gradients can approach 1.0.

Step 4b: Calculate Permit WHIP

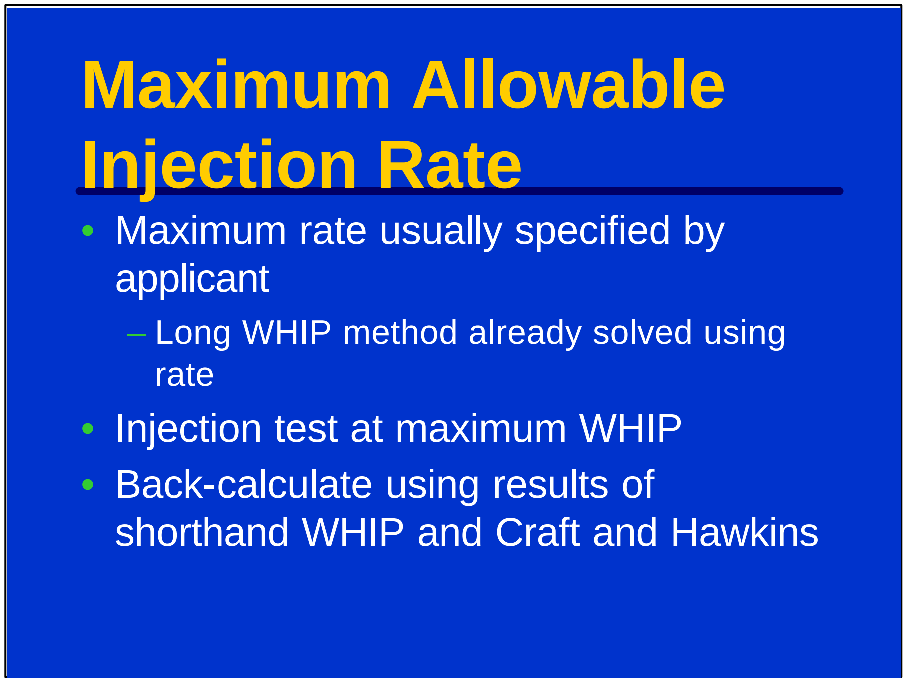
- Operating WHIP = 237 psi
- Allowable WHIP (for 1.02 S.G.) = 654 psig
  - Fracture pressure (2560 psi using .64 psi/ft gradient @ 4,000 feet)
  - Minus BHPI (1940 psi)
  - Plus tubing friction (34 psi)

- The WHIP the operator will experience at his requested injection rate of 1700 bbl/day is 237 psig. Most Regions and States calculate the maximum allowable WHIP using the fracture gradient as an upper limit.
- Now that we have researched, measured, or estimated the fracture gradient, we can calculate the allowable injection pressure as a permit limitation. Calculating the allowable injection pressure for the example well involves considering the range between the operating WHIP (237 psig, the minimum WHIP necessary for injection) and a WHIP related to the estimated fracture gradient. Using the Hubbert and Willis method, the BHP fracture pressure may be estimated as from 2560 psi (.64) to 2920 psi (.73), or more in some areas. If specific test data are not available, using the 0.64 psi/ft gradient provides a margin of safety when considering allowable pressure. Some States and Regions may use a different standard.
- Regardless of whether the fracture gradient is measured or estimated, EPA permits injection pressure limitations as surface injection pressure (WHIP). To calculate maximum allowable WHIP, multiply the fracture gradient by depth (fracture pressure), subtract operating BHP, and add tubing friction loss. For the example well: .64 psi/ft x 4000 ft = 2560 psi, minus 1940 psi (BHP), plus 34 psi (friction in tubing) = 654 psi maximum WHIP.
- Remember that this WHIP calculation is only valid for the specified 1.02 specific gravity. Most permit limitations also specify an allowable range for the gravity of the injectate.

Shorthand Version

- Maximum WHIP = fracture pressure – BHP
  - Injection rate not considered
- For example:
  - .64 x 4000 = 2560 fracture pressure
  - .4416 x 4000 = 1766 BHP
  - 2560 – 1766 = 794 psig maximum WHIP

- Now that you understand how it all fits together, here is a shorthand method of determining allowable WHIP.
- First, measure, estimate, or find an applicable fracture gradient from State or industry data, and multiply by the well depth. Many DI and State programs (especially Class II) use a separate test of the injection zone to establish the maximum injection pressure. In this case, we estimated the fracture gradient in this sandy zone as .64 psi per foot. Multiplied by depth we get .64 times 4000 or 2560 psi fracture initiation pressure.
- Second, estimate static BHP by multiplying depth by fluid gradient. Remember, you can use specific gravity of the injectate times .433. In this case the SG was 1.02, or .4416 psi/ft, times 4000 equals 1766 psi BHP. If you subtract the two, you have a rough idea of allowable injection pressure. In this case, 2560 – 1766 equals 794 psi WHIP. In essence, we are using the friction losses in the tubing and at the injection face as our safety factor.
- Recall that using the long method calculates a maximum WHIP as 654 psi. The primary difference is that in the long method, we are specifying the maximum WHIP in relation to the permit applicant's requested maximum injection rate. In the short version, the injection rate is not considered.



- The maximum allowable injection rate is a function of the maximum allowable injection pressure. If you figured maximum WHIP using the applicant's proposed maximum rate and the long method using Matthews and Russell, you are already done.
- You could also require that the applicant perform an injection test, and observe the maximum injection rate achieved at the maximum WHIP you already calculated using either the long or short methods.
- But if you used the shorthand method based on fracture gradient and the operator can't perform an injection test (typical for a Class II application), you must back-calculate the maximum rate that corresponds to the shorthand maximum pressure.
- Many permit writers conclude that the maximum rate is far less important than maximum WHIP, and do not specify a maximum rate at all, providing that the maximum WHIP limitation is observed. It is probably advisable to give operators some sort of maximum rate limitation, just to give them another point of reference.

Matthews and Russell

$$Q = \frac{?p\ kb}{162.6\ \mu} \quad \frac{1}{\left[\log \dfrac{k\,t}{F\ \mu C r^2} - 3.23\right]}$$

$$Q = \frac{(794)(400)(50)}{(162.6)(0.9)} \quad \frac{1}{\left[\log \dfrac{(400)\,(87600)}{(.30)\,(.90)\,(.0000065)\,(.292)^2} - 3.23\right]}$$

Q = 9740 BPD @ 794 psi maximum WHIP

- If you want to calculate the maximum injection rate that corresponds to the shorthand injection pressure, you have to plug everything back into Matthews and Russell.
- This is Matthews and Russell transposed to solve for "Q." Just remember that ? p here is the maximum WHIP you calculated using the shortcut method, and "r" is the effective well radius.

Maximum Injection Volume

- Specified by applicant?
- Estimated from maximum rate
  - Use 24- or 10-hour days, 5 or 7-day weeks

- The last permit limitation you must specify is maximum allowable injected volume.
- Almost all applicants will specify the maximum volume they expect to inject over the life of the well. If not, you can estimate it using the maximum rate we calculated earlier. Simply multiply maximum rate times the days and years the well is expected to operate.
- Some permit writers use a 24-hour day and a 7-day week, whereas others use a 10-hour day or 5-day week as a safety factor. If you are using the long method of the previous slide, substitute a 10-hour day or 7-day week when calculating the "t = hours" component of Matthews and Russell.
- Actually, except for unusual Class I-H situations, maximum volume is much less important than setting valid limitations for maximum pressure and rate.

Issue: Limiting WHIP for Corrective Action

Consider unplugged well at r = 300 feet

1) BHP divided by density gradient
   - 1795 / .460 = 3902 feet of head

2) Subtract (well depth – depth to USDW)
   - 3902 – (4000 – 400) = +302 feet of head @ usdw base
   - Convert to psi: 302 x .460 = 138.9 psi

3) USDW head (or sat. thickness) x density ratio
   - 426 feet x (.433+.460/2) = 190.2 psi @usdw base

4) Compare 2 and 3
   - 138.9 psi upward versus 190.2 downward
   - 51.3 psi downward *before injection begins*

- Remember that corrective action is the response to a problem identified by the Area of Review study. One of the most common methods of corrective action involves limiting the WHIP. Let's say that the problem is an unplugged well located 300 feet from the injection well. Unless subjected to corrective action, that well could serve as a conduit for injection fluids from the injection zone to the base of the lowermost USDW. We will use the example well we've been talking about all along. It is a real Class I well on the Gulf Coast, by the way.
- First, you need a measured or estimated BHP for the injection zone. In this case, we have a measured vale of 1795 psi and .460 density gradient. The column of water in the unplugged well would therefore rise 3,902 feet, that is, 1795 psi divided by .460 psi per ft. Remember that the well is 4,000 feet deep. If we consider the situation at the base of the USDW at –400 feet, then there is an ***upward*** gradient of 302 feet at the base of the USDW; that is, 3,902 ft of head + [-4,000ft –(-400ft)] = +302 feet of head when considered at –400 feet. If the answer had been negative (e.g., -302 feet), then the water column would be 302 feet below the USDW. 302 feet of .460 psi/ft water would equal an upward gradient of 138.9 psi (i.e., 302 x .460).
- The water level in the (artesian) USDW is measured as +426 feet. If you didn't have a water-level measurement, you can use the USDW depth. Normally, 426 feet of fresh (.433) water would give us a downward gradient at the base of the USDW of (426 x .433) = 184.5 psi. The problem is, with an upward gradient from the injection zone and a known or suspected conduit, there is probably a mixture of USDW and injection zone water in the wellbore. Use an average of the two densities to calculate the downward potential in the USDW, i.e., 426 ft x (.433 + .460/2) = 190.2 psi at the base of the USDW.
- 138.9 psi ***upward*** versus 190.2 psi ***downward*** equals a 51.3psi ***downward*** gradient ***before injection starts***. Stated another way, we need to limit the delta-p due to injection to 51.3 psi or less, at 300 feet and t=10 years.

? p @ r=300ft, t=10yrs < 51.3 psi

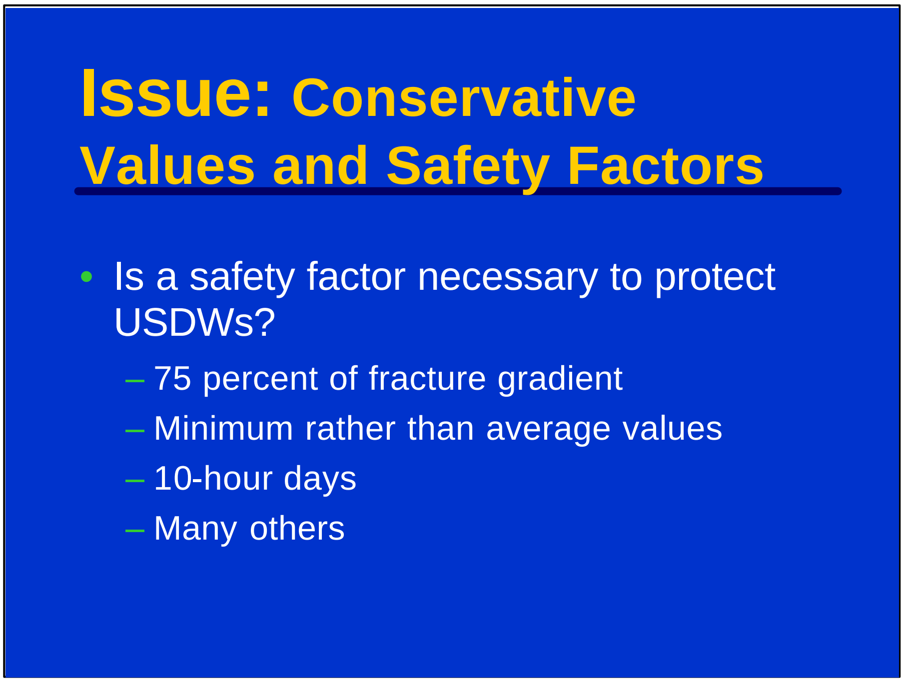
$$Q = \frac{?p\ kb}{162.6\ \mu} \quad \frac{1}{[\log \frac{k\,t}{F\ \mu C r^2} - 3.23\,]}$$

$$Q = \frac{(51.3)(400)(50)}{(162.6)(0.9)} \quad \frac{1}{[\ \log \frac{(400)\,(87600)}{(.30)\,(.90)\,(.0000065)\,(300)^2} - 3.23\,]}$$

Q = 1370 BPD limit to achieve 51.3 psi @300 feet

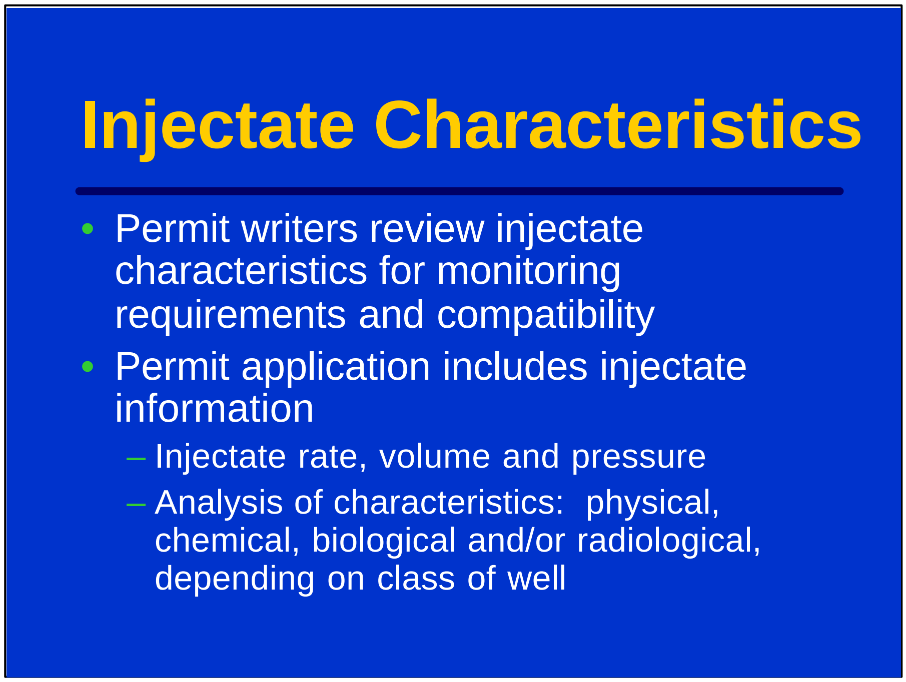
- or limit BHP in injector or monitoring well

- We decided that any ? p that exceeded 51.3 psi at 300 feet after 10 years injection, would cause migration into the USDW.
- This is Matthews and Russell transposed to solve for "Q." Just remember that ? p here is the threshold of migration we calculated in the last slide. We also must plug in 300 fee' for r, the distance to the unplugged well. The answer is that we must limit the injection rate to 1,370 barrels per day to prevent upward migration in the unplugged well. Remember, this assumes 24-hour per day injection, which is true of many Class I operations. If you knew that the operator was only planning to inject 10 hours per day, use that number in the "t" value (87,600 here).
- Recall that the operator was asking for 1,700 bpd. It's better in these cases to limit the maximum injection rate, rather than the WHIP pressure, because a number of factors can affect the wellhead pressure. If you wanted to know the likely WHIP that 1370 BPD would give, use the complete method presented earlier in this section, using pipe and formation friction losses, etc.
- You could also limit the operator to the corresponding *bottom-hole* pressure at the injection well. In this case, the BHP after 10 years injection of 1370 BPD would be 1795 psi (original, pre-injection BHP) plus ? p @ r= .292 feet (casing radius) and t=10 years. Solve Craft and Hawkins for ? p and get 111.7 psi, or 1906.7 psi. That's a bit riskier, because if the operator did not inject continuously, the BHP will decline during down periods. Furthermore, you need to know the ***exact*** Kh value between the injector and the unplugged well (using a very long injectivity test).
- Best of all would be for the operator to monitor the pressure or water level in the unplugged well or a well nearby, because the pressure drop-off away from the injector would be much smaller and much less important. Calculate the ? p at the location of the monitoring well, and base his permit on that. There are two Class I-H wells in Texas whose permits are limited to reaching a certain pressure in an offset well.



- Some permit writers believe that a safety factor is necessary in all of the previous calculations in order to protect USDWs from excessive injection pressure, rate, and volume. These safety factors may be applied at various points in the calculation exercises, such as using only 75 percent of ISIP or estimated fracture gradient, 10-hour days, least values for porosity rather than averages, et cetera. Different Regions and permit writers maintain different standards and methods for safety factors.
- Safety factors aren't recommended except in cases of corrective action, for two reasons:
  - You may have to justify them to the applicant, and there is usually no technical explanation for them; and
  - When multiple reviewers start plugging in their own safety factors, the analysis soon becomes invalid.

Monitoring Injected Waste



- A second aspect of operating data is a review of the injectate characteristics. The purpose of this review is two-fold: To determine appropriate monitoring requirements; and to determine whether there are any compatibility issues with respect to the injection zone.
- The permit application must contain information on the injectate. The requirements vary depending on the class of well.
  - o Class I NH (40 CFR 146.14(a)(7) and (8))
    - – Average and maximum rate, volume and injection pressure
    - – Source and an analysis of the chemical, physical, radiological and biological characteristics
    - – Proposed program to analyze the chemical, physical and radiological characteristics of the injection formation and the confining zone
  - o Class II (40 CFR 146.24(a)(4))
    - – Average and maximum rate, volume and injection pressure
    - – Source and an analysis of the physical and chemical characteristics
  - o Class III (40 CFR 146.34(a)(7) and (8))
    - – Average and maximum rate, volume and injection pressure
    - – Quantitative analysis and ranges in concentrations of all constituents of injected fluids or maximum concentrations not to be exceeded
    - – Proposed formation testing program to obtain fluid and fracture pressures and physical and chemical characteristics of the formation fluids
  - o Class I H (40 CFR 146.70 (a)(8) and (9))
    - – Average and maximum rate, volume and injection pressure
    - – Proposed program to analyze the chemical, physical and radiological characteristics of the injection formation and the confining zone

Monitoring Injectate and Injection Parameters

- All injected fluids must be monitored
- Monitoring requirements vary by well type
- Monitoring parameters
  - Injection rate
  - Injection pressure
  - Monthly and cumulative injected volume
  - Annulus pressure and volume
  - Waste characteristics such as density, pH, and other parameters

- In addition to mechanical integrity, measuring and reporting these characteristics are the fundamental factors in permit compliance. For every type of injection well, State and Federal UIC regulations specify the type of tests necessary, the frequency of testing, and the method of recording the results for each parameter, depending on the toxicity of the injectate and the perceived threat to USDWs.
- For Class I NH, II and III injection wells, the fluids injected into a permitted well are required to be monitored to provide "representative data of their characteristics." This minimum requirement is located in the following rules for the different well classes:
  - Class I wells: 40 CFR 146.13(b)(1);
  - Class II wells: 40 CFR 146.23(b)(1); and
  - Class III wells: 40 CFR 146.33(b)(1).
- Class V wells are subject to different standards, since many are not subject to permitting. Under 40 CFR 144.88 (64 FR 68545, December 7, 1999), however, permitted Class V motor vehicle waste disposal wells are required to demonstrate that injected fluids meet MCLs and other health based standards at the point of injection. Additional details on this topic (including the *Federal Register* notice and several new guidance documents) can be found on the Web at **www.epa.gov/safewater/uic/c5imp.html**.
- Class I hazardous injection wells have more stringent requirements for monitoring, found at 40 CFR 146.68(a). A written waste analysis plan must be developed and followed for these wells.

Injectate Monitoring

Measurement	Monitoring Methods	Comments
• pH	• Grab sample	• Measure in the field; influences corrosivity and well construction materials
• TDS	• Grab sample	• Compatibility with injection zone
• Chemical content	• Generator knowledge; field sampling	• Representativeness; potential to be hazardous waste
• Temperature	• Grab sample	• Field measurement; formation and well construction issues
• Compatibility and reactivity	• Grab or composite, depending on waste stream	• Formation and construction component influences

- Monitoring requirements for injected wastes are defined in the permit itself. The permit writer needs to evaluate what will be injected and how the fluid may affect the well construction components as well as the receiving formations.
- Many injected fluids are required to be evaluated for pH, total dissolved solids (TDS), and temperature. Chemical content must be evaluated based on site-specific information. The range of constituents evaluated should be based on the known composition of the waste stream as well as variability in the waste stream. For instance, the waste generated from production of natural gas is well defined and should be consistent. However, for a commercial hazardous waste disposal facility, the wastes received vary from hour to hour and day to day. Also, the potential risk to USDWs from hazardous waste injection is greater, given the characteristics of the various contaminants in the waste.
- The permit writer also must consider potential compatibility and reactivity issues regarding the injected waste. Injectate may react with the injection zone formation or formation fluids. The wastes may be incompatible with the well construction materials as well, causing degradation of the injection tubing, packer or other materials.
- When you anticipate injection near the maximum permitted pressure and varying injectate characteristics, specific gravity may be added to the list above.
- Whatever parameters are determined to be appropriate, characterization of the waste stream and its ability to compromise the well integrity and risk to USDWs are the issues at hand. As a permit writer, you should be able to relate these monitoring requirements back to protection of USDWs; if you cannot, rethink the reason that you are requiring the operator to monitor for that particular parameter.
- The applicant also may be required to develop and submit a waste analysis plan that specifies how sampling and analysis will be conducted. This is common for Class I wells, but not routinely required for other well classes.

Monitoring Waste Parameters

- Many Class I wells operate under permit limitations for waste density, waste pH and temperature, or specific chemical parameters. Before the digital age, these parameters involved a chemist analyzing periodic samples of the waste. Now, however, the use of digital probes and transmitters makes this type of permit limitation more practical.
- Density and pH transmitters are now available for less than $300, and their interface with PC-based recording systems makes collecting and reporting these permit data incrementally very inexpensive. Due to the lower cost and ease of data collection, constant density monitoring should be considered as a part of any permit that poses a risk of hydraulic fracturing, as well as pH monitoring for any site that handles acid or caustic wastes.
- Notice that we specify reasons a pH or density monitoring system should be considered. While the instrumentation itself may be inexpensive, the permit writer again has the responsibility of weighing whether the data are scientifically useful and needed to assure USDW protection. For instance, a site that has variable pH due to the process probably should be required to use the digital probe and transmitter so compliance with pH limits and potential risks to well integrity can be evaluated. On the other hand, if a facility injects a waste stream that is known to be extremely acidic, the well is designed to handle that waste, and the permit addresses the hazardous issues regarding the waste, will a constant measurement that tells you what you already know (the pH is REALLY low!!) be anything other than an unnecessary cost to the operator? Weigh your permit requirements to maximize protective measures rather than merely maximizing numbers of data points.
- Another question that arises from this equipment is, “What is continuous, or constant, monitoring?” And a good question it is! Some States or Regions have defined what those terms mean, but the Federal regulations do not define them.
    - First, realize that the frequency of sampling versus recording with an electronic system can be very different. You may determine that significant injectate variability necessitates certain parameters (such as pH) be measured every 30 seconds, but need only be recorded (and thus reported) every several minutes. An electronic alarm system could be set to respond to the 30 second reading.
    - Second, be sure you know what the real concern is, and whether high frequency monitoring and recording will resolve the issue.
    - Third, make sure you spell out your expectations clearly to the well operator, and share the regulatory concerns so the basis for the requirement is understood. And last, ensure the permit provides an unambiguous definition of terms if extremely high frequency data point capture is being required by the permit to be considered “continuous.”

Subsurface Waste Interactions

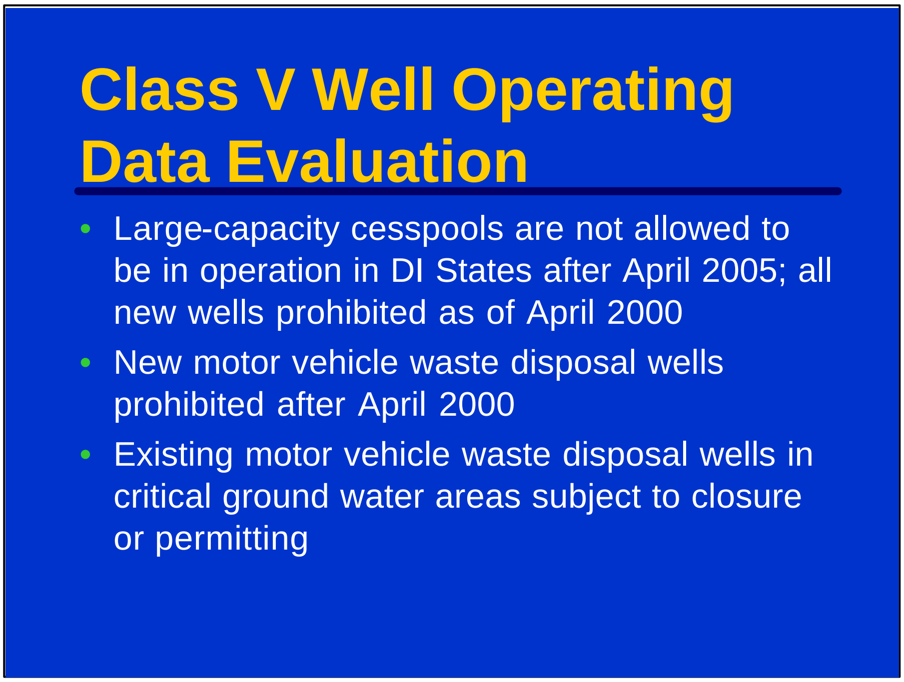
- Permeability reduction
  - Precipitates or polymers
  - Clay swelling
- Permeability increase: Dissolution of matrix minerals
- Gas generation
  - Reduce permeability
  - Blowouts
- Adsorption or desorption: Immobilize, exchange, retard solutes

- Potential reactions may occur between injected waste and the rocks and fluids of the injection zone. The primary types of reactions are:
  - o Permeability reduction: chemical precipitates form and block the pore throats; sensitive clay minerals may swell or disaggregate; or complex organic polymers may form. Some precipitate damage is reversible, but many types cause permanent formation damage and loss of injectivity;
  - o Permeability increase: low pH wastes can dissolve matrix minerals of the injection and confining zones;
  - o Gas generation: dissolution of matrix minerals and some waste-fluid reactions can generate gaseous reaction products. In small quantities, effective permeability may be reduced. In large quantities, explosive blowouts have occurred during workovers; and
  - o Adsorption and desorption: most of the minerals in a sand reservoir are capable of a wide range of selective adsorption and desorption reactions. Many of these reactions are non-reversible, and hold the potential for immobilizing enormous quantities of hazardous substances in typical injection zones, at volumes up to 60 percent by weight. This complex system of reactions, cross-reactions, and inter-reactions is impossible to predict or quantify at the surface, but undoubtedly occurs in all types of well and waste scenarios.
- Some of these subsurface reactions may sound beneficial, such as adsorption removing large volumes of hazardous constituents. Almost all of the reactions are unpredictable, however, concerning rate and duration and reaction products, because of variations or uncertainties regarding flow dynamics and chemical stochiometry.
- All of these reactions are taking place, to some degree, in every Class I injection well.

Changes in Fluid (Class III)

- Attachment N provides expected changes in fluid
  - Pressure
  - Native fluid displacement
  - Direction of movement of injection fluid

- Another aspect of injection fluid is presented in Attachment N. This attachment is oriented primarily to Class III, but be aware of other fluid change issues for other well classes.
- Class I wells, especially commercial wells, may apply for a permit for a wide range of injectates to facilitate blending or changes in treatment processes.
- In Class II, it is common practice that EOR wells change fluids during the course of the project, as different polymers are used to effect changes in injection or sweep profile. Class II-H wells in salt domes routinely alternate between brine injection for production and product injection for emplacement.
- For Class III wells, changes in injected fluid are commonplace during mining, and Attachment N is where the applicant will spell out the details of his proposed process.
  - Class III mining projects commonly change injection fluids and orates, depending on the process involved. In many Class III methods, the injection well periodically reverts to a production well, in order to recover the injected mining fluid and the dissolved or mobilized minerals.
  - In these types of projects, it is very tough (if not impossible) to specify an accurate permit limitation for volume and to predict the pressure effects on the injection zone. In most cases, the applicant will spell out the details of his process in Attachment N, especially the fluids he proposes to use. This data may also include detailed modeling for ground water effects, and some processes will specify a remediation plan to recover mining fluids and restore the injection zone to its pre-mining condition.
  - One option you may decide to use is to require that the operator notify you in writing whenever the process changes or fluids are changed over.
- Whatever class of wells you are dealing with, make sure that the applicant clearly specifies the details of his injection program if changes in fluid are indicated. You may also decide to require written or verbal notification when the fluid program changes over. Also remember that if an operator decides to change to a fluid that he is not permitted for, a permit amendment is required.



- A few types of Class V wells have specific limitations on operations that need to be mentioned. First, all large capacity cesspools (capable of serving 20 or more persons per day) were banned as of April 2000 in DI States. For primacy States, the ban date will be based on the date on which their updated State regulations became effective. You will need to review primacy State regulations on a State-by-State basis to determine the date.
- All existing large-capacity cesspools are to be closed, under an EPA reviewed closure plan, by April 2005.
- No new motor vehicle waste disposal wells were authorized to be constructed or operated after April 2000 in DI States. Again, the effective date of this prohibition will vary in primacy states, depending on the date of their rule update adoption.
- Existing motor vehicle waste disposal wells in critical ground water areas are banned as well. However, the owner/operator may request a waiver from the ban and apply for a permit to operate. The permit to operate must include some specific operating limitations.

Motor Vehicle Waste Disposal Well Limitations

- If allowed to continue to operate in critical ground water area, must be permitted
- Operations limited:
  - Meet MCLs and other health based standards at point of injection
  - Monitor injectate and sludge
  - Implement best management practices (BMPs)

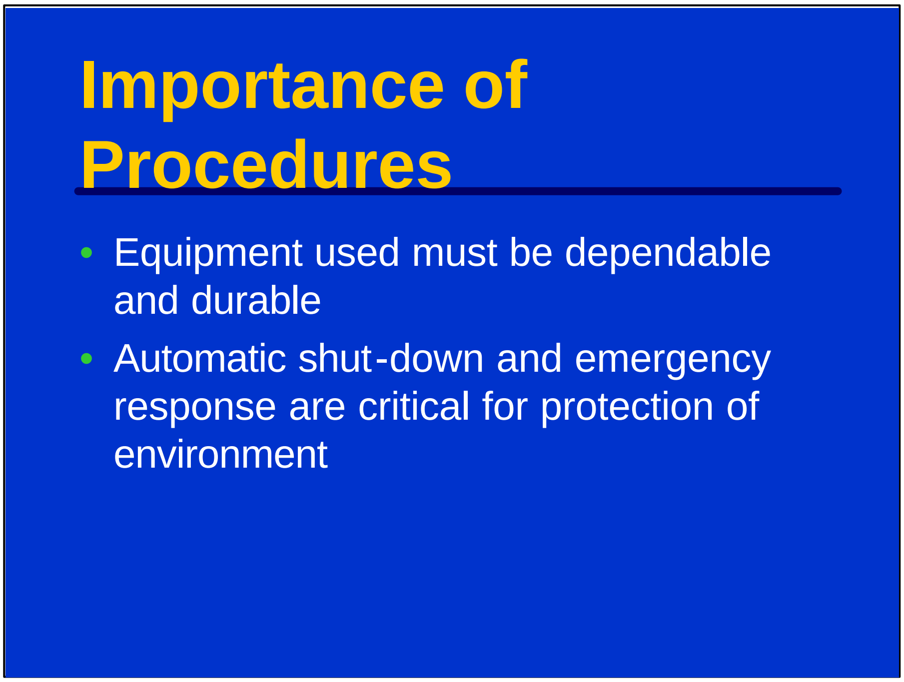
- The motor vehicle waste disposal wells that are subject to the ban and waiver or permit option are those located in a critical ground water area. There are two possible types of areas in which these Class V wells may be located. They may be in a delineated source water protection area or in an "other sensitive ground water area" as defined by the Region or State. Additional information regarding other sensitive ground water areas is available in the Class V Rule, signed December 7, 1999, and in guidance developed by Headquarters. You can access this information on the Web at:
  - **www.epa.gov/safewater/uic/c5imp.html**
- If the motor vehicle waste disposal well owner/operator desires to continue to operate his well in a critical ground water area, he may apply for the waiver from the ban and submit a permit application. A permit issued for these wells or any other Class V well must include the minimum permitting requirements applicable to Class V wells (or "all wells") in 40 CFR 144.31 and 144.51. The permit conditions of 40 CFR 144.52 must be considered and applied as EPA deems appropriate. In addition, permit applications for all motor vehicle waste disposal wells must describe and the permit must list:
  - A requirement that MCLs and other health based standards will be met at the point of injection. The application should discuss how the applicant proposes to meet this requirement on an on-going basis;
  - A requirement to monitor the quality of the injectate and sludge. Again, the application should describe how this will be accomplished and the permit must specify the conditions (we will discuss this more when we discuss injectate monitoring); and
  - A requirement that best management practices (BMPs) be implemented at the facility to protect the well from releases at the facility.
- Other Class V wells may be required to be permitted, based on where and what is injected. There is no simple way to state what operating conditions should be imposed on any Class V well, given the large universe. However, at a minimum, you should consider the limitations placed on motor vehicle waste disposal wells as a relevant standard, then determine what different conditions may be appropriate given site-specific data.

Lesson 15
Proposed Injection Procedures

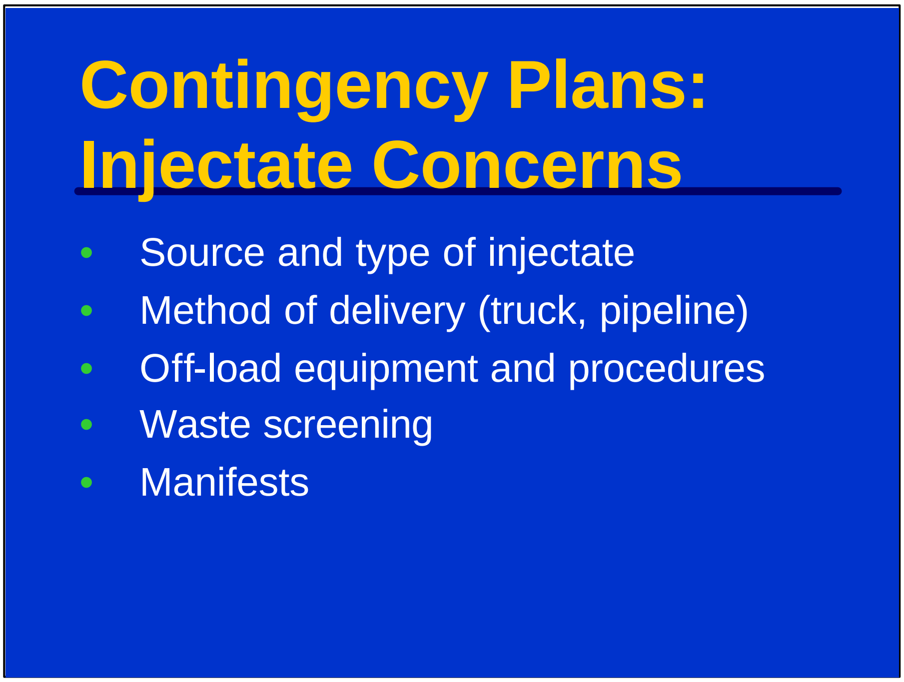
Injection Procedures

- Describe the proposed injection procedures, including pump, surge tank, etc.
- Include operating procedures and contingency plans

- In the permit instructions, injection procedures are specified as hardware, to include "pump, surge tank, etc." An effective permit application, however, should also include a complete overview of operating methods and procedures, and plans to address surface-related emergencies.
- The class of the well and nature of the injectate should guide the level of detail necessary. For example, a Class II application might include a process diagram and three paragraphs for operational methods, whereas a Class I application might run for several pages.



- The equipment chosen for use in emergencies must be dependable and durable. While one can more easily inspect and replace surface equipment compared to downhole devices, alarm systems and other emergency response equipment are critical for protection of the environment.
- A properly functioning automatic alarm and shut-down system is a critical part of the multi-barrier protection system in place for UIC wells. Until you can investigate the reason for a well's pressure anomaly, you cannot be certain what has happened. Rapid response of the well system is necessary to shut off the flow of waste to best protect the USDWs at the site.

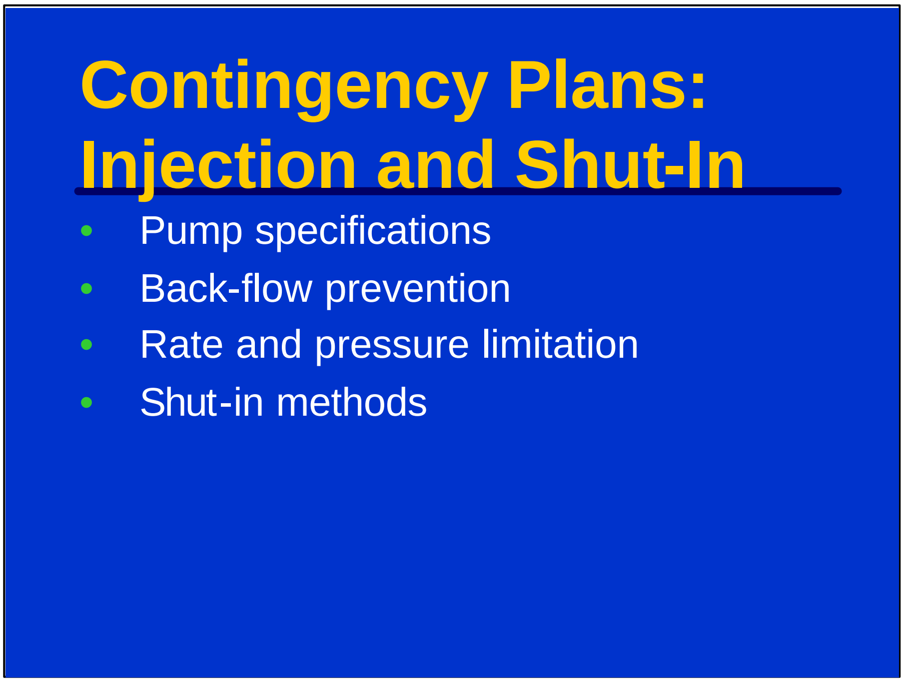


- In addition to a site schematic diagram, you may decide to require specific information concerning several areas of concern that are common to all injection well operations. The discussion of surface equipment and procedures might entail different degrees of detail, but all applications should include contingency plans that address these common areas and issues.
- Incoming injectate issues include:
  - Source and type of injectate, to include special handling characteristics such as corrosive, explosive, etc.;
  - Methods of delivery to the site, such as by barge, truck, or pipeline (whether on- or off-lease);
  - Off-loading equipment and procedures;
  - Waste screening, which might range from a simple pH check for Class II waste to elaborate laboratory testing for Class I waste; and
  - Manifests, which may be required for Class I wastes or for Class II commercial salt water wells.

Contingency Plans: Processing and Pre-Treatment

- Oil-water separation
- Filtration
- Storage
- Treatment equipment and methods
  - RCRA §3004(m) treatment
  - Reagent storage
  - Sludge handling and disposal
  - Air emissions

- Processing and treatment processes may include:
  - o Oil-water separation;
  - o Filtration, whether simple settling or pressure filtration;
  - o Long or short-term storage; and
  - o Treatment equipment and methods. Treatment procedures may range from the simple addition of a biocide or oxygen scavenger to sophisticated chemical reactions such as pH adjustment or toxic neutralization. Since the advent of the Class I-Industrial (that is, non-hazardous) well category, many industrial operators pre-treat their waste under RCRA §3004 (m) (land disposal restrictions) to remove hazardous constituents or characteristics in order to avoid regulation as I-H. The applicant should explain the process and how he will guarantee the effectiveness of the process and procedures on a day-to-day basis.
- Of course, any pre-treatment process opens the door to many other related issues, such as reagent storage, handling and disposal of sludges or other reaction products, and a wide range of other air or water issues. These pre-treatment processes may be subject to permitting under other programs (either Federal, State or local). Be sure you are coordinating with those authorities.



- Injection and shut-in equipment and procedures should be covered in some degree of detail, no matter what class of well is involved. A discussion of injection equipment should include not only pump specifications and back-flow prevention, but also the specific equipment and procedures that will be used to limit injection pressure, rate, and volume as prescribed in the permit. Inspectors have encountered several sites whose method of limiting injection pressure was a red Magic Marker line on the wellhead pressure gauge. Especially for Class I wells, demand to know about specific procedures and equipment!
- Shut-in of a well is an important step. As you know, abrupt shut-in during operation causes pressure spikes that can damage downhole components, similar to water hammer in your home. In many Class I wells, shut-in can also involve switching to injection of a clean stream in order to protect tubulars from corrosion or to provide a buffer between incompatible waste streams. Written procedures for routine shut-in should have already been developed for operator training, and also should be submitted as part of any Class I permit application.

Contingency Plans: Emergency Procedures

- Spill prevention and containment
- Loss of mechanical integrity
- Exceed maximum rate or pressure
- Auto alarm and/or shutdown
- Emergency contacts

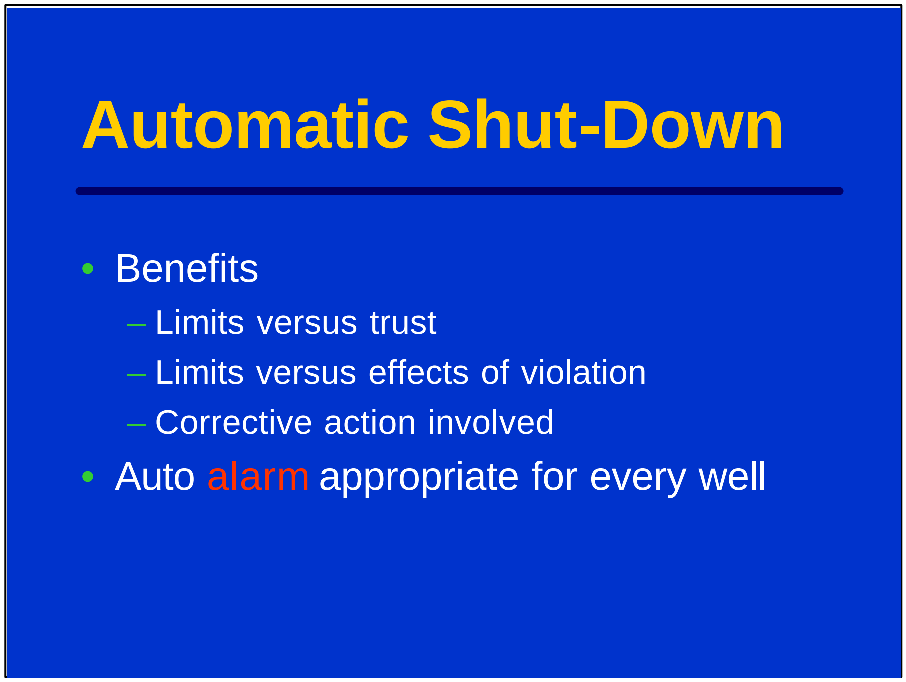
- Emergency procedures should be written (and practiced!) in any class of facility.
  - o Spill Prevention, Control, and Countermeasures (SPCC) plans should be prepared for every facility that features tanks, and may be submitted as part of the UIC permit application. Reviewing SPCC plans is a complex subject; permit writers should forward the plans to the appropriate expert reviewer for separate comments, especially for Class I permits. If you need additional information about whether a facioity may be regulated under SPCC requirements or need to find an appropriate SPCC contact, go to **http://www.epa.gov/oilspill/index.htm** for the information.
  - o In addition, require written procedures that prescribe actions to be taken when a permit limitation is exceeded or MI is lost, for any class of well. If the well also features continuous annulus monitoring (Class I-Industrial), require automatic **alarms** under any and all circumstances. An automatic shutdown system can be complex and expensive, but if you think that the circumstances justify the expense, do not hesitate to require one.
- Emergency contact numbers are an important part of a contingency plan. Every application and permit should prominently feature the telephone numbers that the operator would use to notify site and corporate management in the case of a well failure or other emergency, and which a UIC official can use to contact the site directly.

Automatic Shut-Down

- Typically monitor rate, pressure, or MI
  - Requires continuous monitoring, usually of electronic devices
- Limitations
  - Complex shutdowns
  - Expensive

- As we have discussed, typical permit limits for an injection well usually involve restrictions to injection pressure, rate, and volume, as well as maintenance of MI. An injection well operating outside specified permit limits is a matter of grave concern. In order to prevent these violations, automatic shut-down systems can be used. Automatic shutdowns can be harmful to a well, however, and a prudent permit writer should consider both the benefits and the limitations of these systems.
- First, automatic systems are applicable only to wells that feature continuous monitoring of the permit parameter.
- Except for simple mechanical pressure-actuated switches and valves (flow regulation applicable only to centrifugal pumps with a bypass system), most automatic systems require monitoring of **electronic** devices. Most Class II and III wells feature only periodic monitoring of analog devices, so do not qualify for most automatic systems.
- Automatic shut-down of a well entails a lot more than closing a valve. First, the valve actuation rate must be carefully controlled, and is a function of injection rate and pressure. Second, most 440-and higher voltage pumps must be shut down using several steps, rather than all at once. For fuel-powered pumps (gasoline, natural gas), shutdown is even more complex in that the fuel pressure and flow must also be bled down or diverted. Third, shutdown at the wellhead must also entail closing valves at tanks and lines, and recirculating line contents back to the tanks. Fourth, most Class I shutdown procedures involve switching to a brine stream so that waste is not left in tubing or surface piping.
- Automatic shut-down systems are expensive, and may cost from $75,000 to almost $1 million for a system on a slurry injector on the North Slope. There is also a significant expense related to maintenance of these systems, because an unintentional automatic shut-down disrupts surface processes, and may in fact cause a coincident shutdown of an entire chemical plant.

- Here is an example of part of a simple, mechanically actuated, automatic shut-down system. A drop in annulus pressure triggers a valve actuator. Abrupt shut-down of most injection wells would cause downhole damage to tubulars or might allow sand to surge into the wellbore of perforated completions. Therefore, most automatic shutdown systems switch to a noncorrosive injection stream and reduce the pump rate until the tubing has been displaced, in order to protect the tubulars from corrosion due to waste standing in the wellbore. Waste standing in tubing would also provide a hazard to a workover crew in the event of well repair.



- The primary potential benefit of an automatic shut-down is that permit limitations will be observed. You must also consider, however, that an operator who would consciously operate outside permit limits or ignore an alarm would also be capable of disabling the automatic shut-down system, as well. An automatic system is no substitute for trust.
- If rate or pressure has been limited for corrective action, there may be situations where a system more compelling than an alarm is necessary.
- Loss of internal MI in the tubing or packer is a more serious reason for automatic shut-down, but unless the waste is very corrosive (or otherwise harmful to the casing), it may still not be necessary. Indeed, if the MI loss were in the casing, the only thing exiting the annulus is annular fluid, not waste.
- Permit writers would be wise to require in every case an automatic **alarm** appropriate to the monitoring system, but save the automatic shut-downs for extreme circumstances.

Emergency Shut-Down

- Notification of excursion or MI loss
- Specific response procedures
- Response time
- Procedures to secure waste
- Subject to inspection and rehearsal

- It may not be appropriate to require an *automatic* shut-down system for every well, but you should certainly know the details of the operator's procedure for **emergency** shut-down.
  - o How does the operator propose that the site respond to excursions from any permit limitation, or to a loss of MI?
  - o How will he find out that the parameter has been exceeded or MI lost?
  - o How will he shut down the surface and downhole operations, or regulate the rate or pressure?
  - o How long will the process take?
  - o How will he secure the waste in piping and tanks in the event of a downhole or pump failure, or for a spill?
- Make sure that the procedures are in writing and are specific. Verify the procedures during inspections and require rehearsals, at least when the well is shut in for MIT.

Documentation

- Accurate diagrams of system
- Complete description of alarm system; know "internal" from "permit" alarms
- Response procedures and proper notification when shut-down occurs
- Schedule for testing system and calibration of components as appropriate

- The permit itself, as well as the administrative record, should document a variety of issues that arise out of this section. First, an accurate diagram of the well system should be included in the permit or referenced clearly and retained in the application. This diagram is especially important if an auto-alarm and shut-down system is required. The diagram should be referenced or included so inspectors can appropriately inspect the well system during site visits.
- Any required alarm system should be clearly presented in the permit. You should be able to recognize and understand the difference between alarms that may be in place at a facility for internal reasons (for parameters not regulated in the permit; early warning alarms for pressures, etc.) compared to those that are in place explicitly to meet permit requirements. The facility need not report every alarm that sounds - only those that are in place to address a specific permit requirement.
- Be sure to evaluate the proposed response procedures when an emergency occurs. Any loss of MI should be reported to the regulatory agency, and the permit should require this reporting within a specific time frame. 40 CFR 144.51(k)(6) specifies conditions that are required to be reported within 24 hours. The 24 hour reporting requirement has generally been interpreted to included losses and apparent losses of MI. Within five days, a written report must be submitted; this requirement must be in the permit as well. Guidance 21 for the UIC Program provides some interpretation of what is required in the verbal vs. written report.
- The auto warning and shut-down system, if required, should be tested to demonstrate its effectiveness, and EPA should have the right to witness testing. You should ensure this is in the permit as well. Some system components may require periodic calibration; if appropriate, require the calibration through the permit.

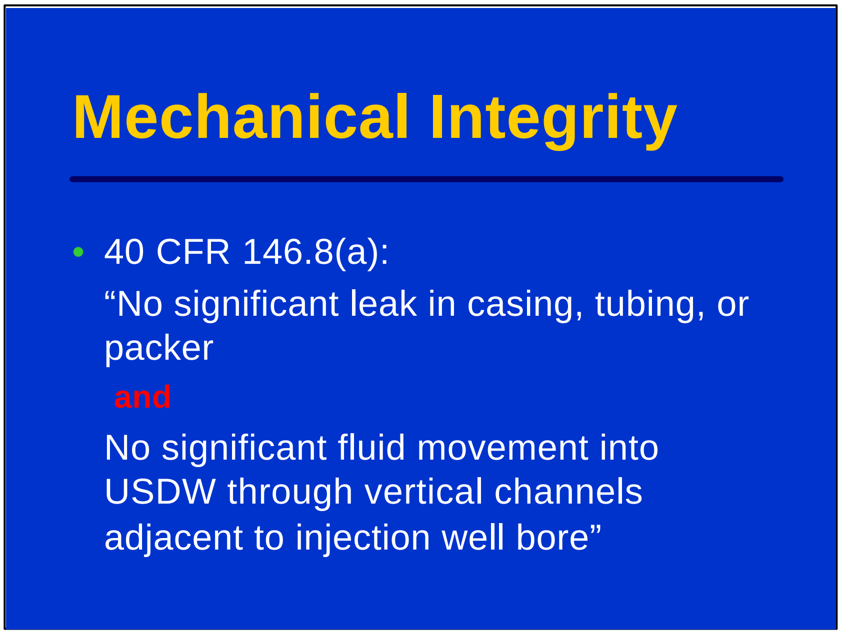
Lesson 16
Plans for Well Failures

- We ended the previous section (Injection Procedures) with a discussion of the operator’s responses to process-related emergencies: exceeding permit limitations such as injection rate, pressure, or volume; or receiving indications from the monitoring system that mechanical integrity has been lost.
- In this section, we will present a detailed analysis of **downhole** problems and failures, as well as the methods the operator will use to test for, respond to, and, hopefully, **prevent** well failures.

Attachment O Instructions

- Contingency plans (proposed plans, if any, for Class II) to prevent migration of fluids into any USDW
  - Shut ins
  - Well failures
- Provides assurance of existing and future well integrity

- In the last section, we covered how contingency plans spell out what to do in the event of a well failure related to injection procedures.
- Attachment O is really misnamed; the primary emphasis of this attachment is the operator’s plan to **prevent** well failures, which should include plans for testing and monitoring the downhole integrity of the injection well.



- An operator is required to maintain the mechanical integrity of his well at all times. First, we need to define mechanical integrity as used in the UIC program.
- Mechanical integrity (MI) of a well is defined in 40 CFR 146.8(a). The regulation states:

“An injection well has mechanical integrity if:

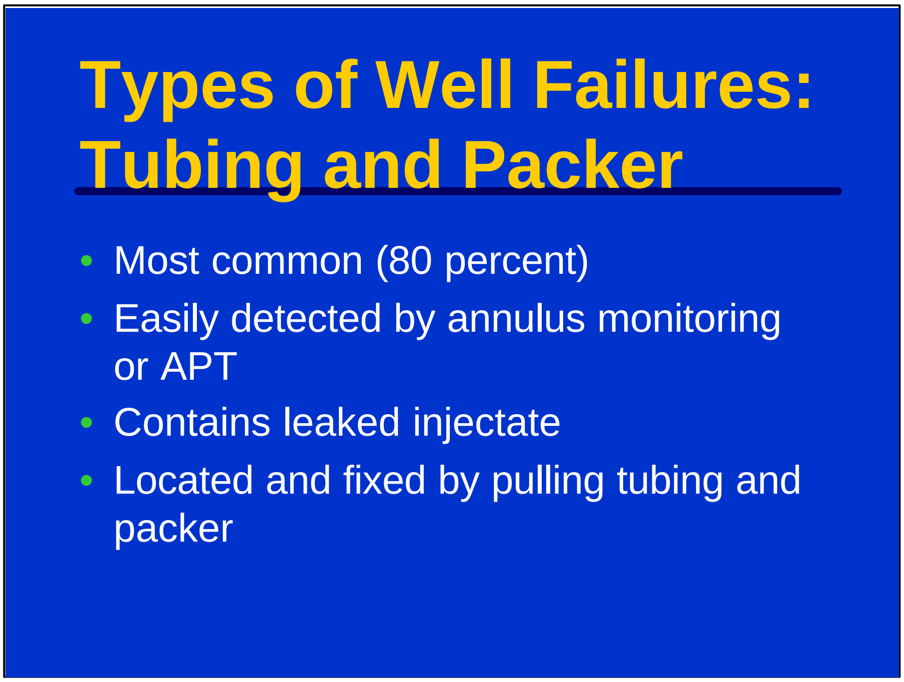
  - o There is no significant leak in the casing, tubing or packer; and
  - o There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.”

- These two provisions are typically called “Part 1” or “internal” and “Part 2” or “external” MI.

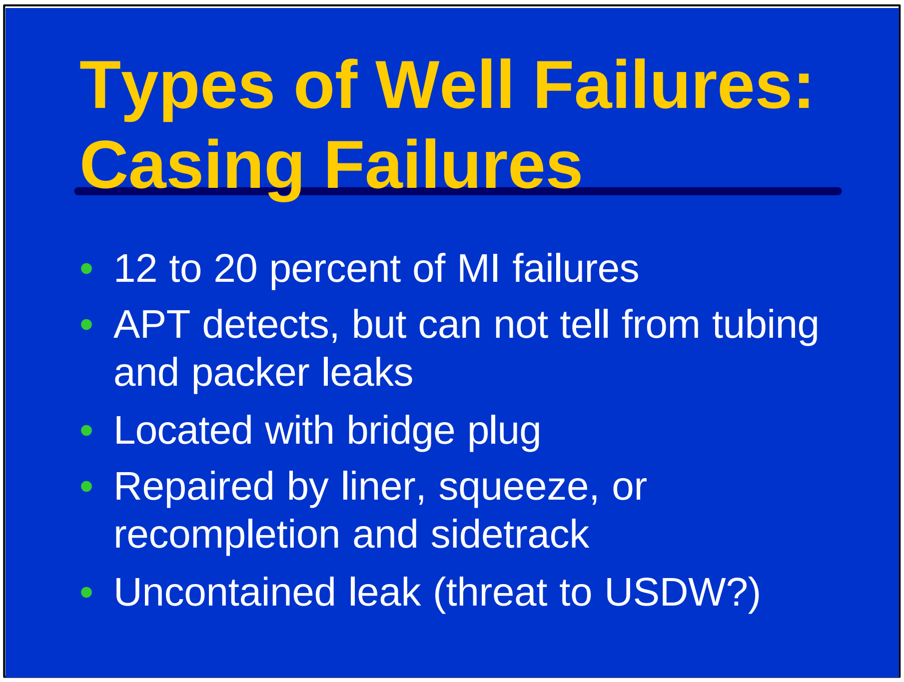
What is Required?

- All wells are required to demonstrate external and internal MI on a regular basis
- Frequency and acceptable tests vary among well classifications

- The regulations for Class I, II and III injection wells have specific schedules for demonstrating mechanical integrity.
  - o Class I nonhazardous wells: Part 1 and 2 MI at least once every five years (40 CFR 146.13(b)(3));
  - o Class I hazardous wells: Part 1 annually, Part 2 every five years (40 CFR 146.68(d);
  - o Class II: Part 1 and 2 MI at least once every five years (40 CFR 146.23(b)(3)); and
  - o Class III: Part 1 and 2 MI at least once every five years for salt solution mining (40 CFR 146.33(b)(3)).
- Class V wells typically do not have MI requirements, unless they are unusually deep or sophisticated.
- You may also consider more or less frequent MIT when writing permit conditions, depending on circumstances. Many wells with poor mechanical histories are subjected to more frequent MIT, as are wells in sensitive locations, such as low fracture gradient or deep USDWs. Less frequent MIT may be allowed for wells that inject hazardous and non-hazardous waste on a long-term periodic basis; such as injecting hazardous waste at plant changeover for two months every five years and non-hazardous waste the rest of the time. However, unless unusual circumstances like this exist, the permit writer must require at least the minimum frequency of testing listed in the regulations.



- In the previous section, "Injection Procedures," we discussed the types of things that can go wrong with the surface processes of injection. This section will discuss the types of things that can go wrong with the subsurface aspects of injection. We will deal primarily with things related to the mechanical aspects of the well. You will recall that we covered external subsurface problems in our section dealing with corrective action.
- Four nationwide studies of MI failures showed that tubing leaks were the most common form of MI loss, by a four-to-one margin over packer and casing leaks, combined. Packer leaks are the second-most common, and will be tough to discern from a tubing leak in an annulus pressure test (APT). Continuous annulus monitoring or a traditional annulus pressure test will detect these leaks 100 percent of the time. The only way to find the leak is to perform pressure tests on segments of the tubing using a bridge plug, or to pull the tubing and test at the surface. Because you have to pull the tubing to fix it, most use the latter method.
- Most regulators regard tubing and packer failures as less threatening than other failures, because as long as the well is shut down, there is nowhere for the leaked injectate to go but downward to the injection zone (or it is contained in the annulus). Oilfield operators will even argue that tubing is an expendable maintenance item, and many Class II wells are constructed with used tubing. Unless the waste is highly corrosive, or other components are also leaking, this type of leak can be considered contained.
- Always keep in mind that a well can have MI but fail an MIT. For instance, if a well has not adequately thermally stabilized after a well workover, the well may not pass the standard set by the regulatory authority (such as less than 3 percent pressure change in 30 minutes). However, after thermal stabilization, the well will pass the test with flying colors. Make sure you are aware of factors such as these that can affect the apparent well test results. ***Any*** MIT must be examined along with a host of other well data so the interpretation of the test result is thorough and accurate.

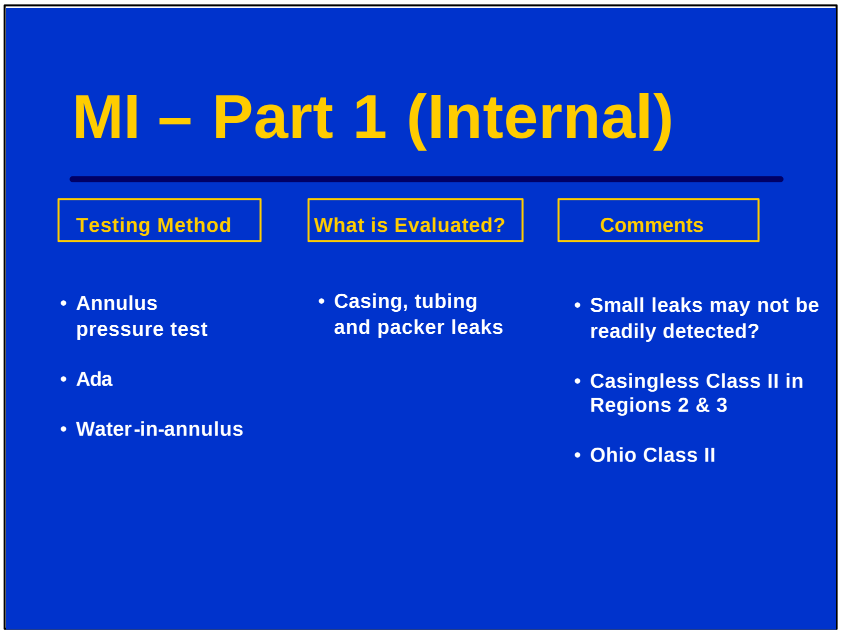


- The second major category of MI failures are casing failures. About 12 to 20 percent of MI failures involve casing, with frequency depending on well class (Class IIs have more because they are not usually fully cemented). A traditional APT or annulus monitoring will find a casing leak, but can not discern the difference between tubing and packer leaks and casing leaks. About 30 percent of the time, however, a distinct pressure differential between annulus and tubing can indicate the difference.
- The only way to find the actual location of a casing leak is to perform segment tests using a bridge plug. Casing can be repaired by running a liner (another string of casing set or cemented inside the first), squeeze-cementing, or plugging back and recompleting in a higher zone. A few Class I wells may sidetrack (i.e., directionally drill a new lower wellbore) if a higher zone is not available.
- Casing leaks may present a severe threat to USDWs, depending on the vertical location of the leak, that is, ranging from within the permitted injection zone to opposite a USDW.

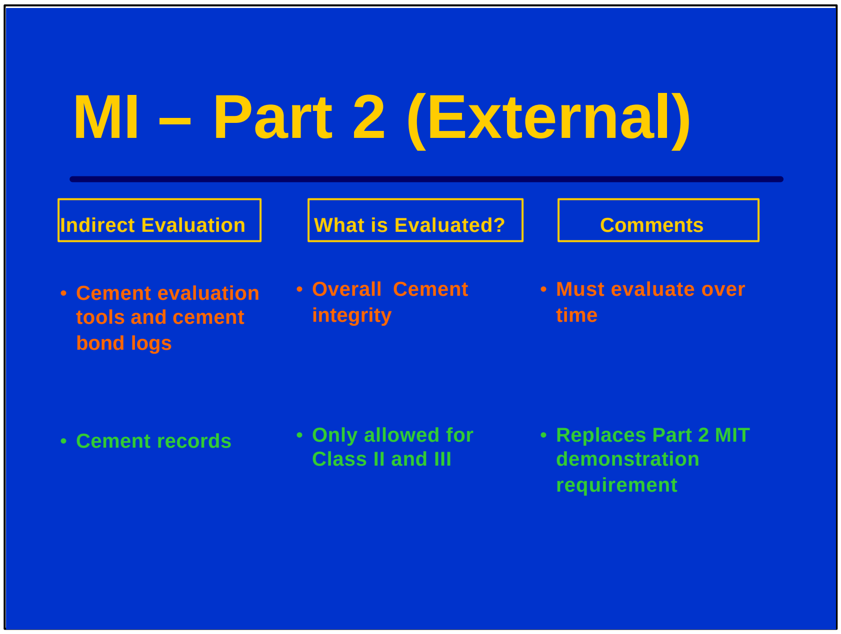
Types of Well Failures: Cement Failure

- Migration captured
  - Indirect connection to USDW through conduit in capture zone?
- Direct connection to USDW through uncemented or poorly cemented casing
- Detect with RAT or other external MIT (Class I)
  - Prevented with cement logs or records during permitting
- Repaired by squeeze or recompletion

- The scariest kind of MI failure involves failure of the cement seal. An external MI failure can allow waste to migrate out of the injection zone. If the waste escapes the confining zone (a bad thing), it will probably be captured in the first permeable zone above the confining zone (a good thing). That could present an indirect threat to USDWs, however, if that zone has a conduit to a USDW, such as a poorly constructed or abandoned well, as we discussed in the corrective action section.
- If, however, the well features a segment of uncemented casing above the confining zone (typical of Class II) or the overall cement job is poor to begin with, there is a distinct possibility that the injection zone could communicate directly with the USDW. Experience and studies show that:
  - The most difficult thing to do in constructing a well is to get a good cement job;
  - Cement failures in wells with good cement seals are rare to non-existent; and
  - Lots and lots of injection wells have substandard cement jobs, including Class I-H.
- Unfortunately, the only way to detect a cement failure is with a radioactive tracer test (RAT) or other approved test. These tests are run every five years on most Class I wells, and but are not run at all on Class II wells. Therefore, the primary way to prevent cement failures is to give permits only to wells with decent cement jobs. As we discussed, that would involve cement logging for Class I wells, and careful scrutiny of cement records for Class II and III wells.
- Cement failures are repaired by squeeze-cementing or, more commonly, by abandoning the zone and recompleting by plugback or sidetrack. There are three ways you can deal with a migration incident caused by cement failure, that does not involve a USDW:
  - Attempt to recover or remediate (very infrequent);
  - Take no action (usually used when zone is saline); or
  - In Texas, repermit the injection zone to include the migration.



- The UIC regulations denote a few acceptable MITs, but the program also has the authority to evaluate and approve additional, or alternative, tests for both internal and external MI. Although this list may not be complete, because there are a few tests approved in some Regions for unconventional well types, these are the basic MITs you will see in the majority of cases.
- An ***annulus pressure test (APT)*** is a test in which the annular space between the injection tubing and well casing is pressurized. The pressure is monitored for a preestablished time period (based on the regulatory agency's requirements). If the pressure changes more than a certain percentage of the starting pressure (often three percent), the test is determined to have failed and the agency may require a retest or further investigation of the well prior to allowing injection to resume. Some States require that test pressure equal injection pressure; others specify one test standard, such as 1500 psi for 30 minutes, plus or minus 10 percent; while others require that the test pressure exceed routine injection pressures.
- Other approved internal MITs are the Ada and water-in-annulus tests. These tests also evaluate the pressure characteristics of tubulars, but use a dynamic fluid level as the pressure source.
- The permit should specify that internal tests are performed at the casing head, not at a remote fitting. The annulus should be full of liquid (not compressed air or nitrogen) , and that liquid used for the test. Also, for traditional APTs, most inspectors know to check for the volume of "returns," the flow-back from the pressure test. If you put a thousand psi on a 5,000 foot annulus, fluid compression may total five gallons. When you release the pressure on a liquid-full annulus, the casing head will "return" the five gallons it took to attain 1,000 psi. If it doesn't, the packer is not set accurately.
- Recording methods should also be specified in the permit. Digital recording devices are available for rent in almost all areas, and the output from a certified device is almost 100 percent valid. At the least, the permit writer may accept a circular chart recorder, but should require the circular charts from two simultaneous recording devices, both signed by the operator.
- For Ada-type tests in other well classes, it may be prudent to require that any time the tubing is pulled, a packer-type test be performed on the well.



- External MITs look for flow channels behind casing.
- ***Cement evaluation tools and cement bond logs*** evaluate the integrity of the cement behind the casing. They look for annuli between the casing and the cement, or the formation wall and the cement. Just as with the casing inspection tools, it is important not to assume a cement area that is thin or a possible annulus is a huge issue and has been formed by injectate leakage. The problem may have been there from the initial emplacement of the cement and may not pose a risk to the well's integrity.
- ***Cement records*** may be used only for Class II and III wells, replacing the Part 2 MIT requirement. For Class II wells, the cementing records must demonstrate the presence of adequate cement to prevent behind-pipe migration. For Class III wells, the records can only be used when the nature of the casing precludes using Part 2 MI tools downhole.

MI – Part 2 (External)

Testing Method	What is Evaluated?	Comments
• Radioactive tracer test	• Internal leaks, behind pipe flow	• Very useful tool
• Temperature	• Behind pipe flow	• Temperature contrast between injected test fluid and formation fluid required for conclusive results

- A ***radioactive tracer test (RAT)*** is a logging technique in which a radioactive tracer is ejected from portals in a tool. The movement of the tracer is observed to ensure that the tracer material does not exit the tubing prior to the packer, does not move back up behind the packer into the annular space, and does not move upward in fractures behind the well casing ("behind-pipe flow"). The pumping rate of the fluid and methods used by the logger can affect the results observed, and close examination of the results compared to historical results and the permitted injection interval are critical.
- The RAT is the most commonly used (by far), but the regulations also allow for these alternatives. Remember that the RAT can only detect injection-related flow at the bottom of casing.
- ***Temperature logs*** can be conducted two ways. One method involves injecting fluid at a different temperature from the downhole temperature, with observation over time to evaluate whether the fluid has moved behind the pipe and is changing the temperature of the formation (cooling or heating it). The second method involves static logging over time to observe the way the formations downhole cool (or heat) when the well is shut in. If a particular zone does not cool or heat according to what is expected, the anomaly may be caused by upward migration of fluid behind the casing through microannuli or formation fractures. It is not advisable to accept a noise or temperature log as the sole method of proving MIT. These tests require a larger amount of flow than a RAT test or oxygen activation, and, in many cases, the interpretation is somewhat subjective.

MI – Part 2 (External)

Testing Method	What is Evaluated?	Comments
• Noise	• Behind pipe flow	• Very limited due to small zone heard by tool
• Oxygen activation	• Behind pipe flow	• Calibration crucial

- ***Noise logs*** essentially involve placing a microphone downhole to listen. Upward flow of fluids behind the pipe will be heard. This log is not as widely used as the temperature and oxygen activation logs. Noise logs are 1950s technology, and are useful only in gas environments or for larger flow. These days, noise logs are not used at all in industry except in offshore gas wells.
- ***Oxygen activation (OA)*** logs use excitement of oxygen atoms to monitor flow behind the casing, and is the only tool capable of directly monitoring flow above the bottom of the casing (noise and temperature logs use indirect indicators of flow). It used to be more expensive than other MI-related logs, but has become much cheaper with increased usage by the oil industry.
- Oxygen activation logs got a bad reputation when they came out, because the Class I Hazardous industry lobbied aggressively against them when EPA was considering a requirement for them. A major oil company and the American Petroleum Institute also lobbied against them, so that EPA would not think about extending the requirement to Class II.

Know What You Are Seeing!

- MITs are crucial to ensuring on-going well component safety *but* they only see within inches of the wellbore
- MITs do not replace siting criteria
- Failure can occur beyond the wellbore environment that can contaminate USDWs
- MITs are one part of an injection well's multiple barrier set to protect USDWs
- All MIT results evaluated in conjunction with other well data

- It is crucial that the permit writer and other UIC staff understand exactly what the tools "see" in the well, and what the various tests are able to tell you. MITs provide valuable information about the wells. Most tools used for MITs only reveal what is happening within inches (a few feet at best) outside the well casing. A RAT can **only** provide information about injection-related flow at the casing shoe.
- Thus, a permit writer needs to understand that the siting criteria for a well, and associated verification of the local and regional geologic settings, are still very important even when all MITs are passed with flying colors.
- MITs can indicate that a well has a problem before there is an actual failure of MI. Obviously, the goal is to prevent significant flow from the well and injection interval that will put USDWs at risk. So even if an annulus pressure test (APT) indicates a fairly small leak, don't wait until it's really big, call it "significant" and then require repairs!
- MITs are one part of a multiple-barrier system designed to protect USDWs from contamination.
- When evaluating MIT results, ***do*** make sure that you are reviewing and considering all the other well data at the same time. Well construction information, previous logs, other logs run simultaneously with the MIT, wellbore geology, and other factors can significantly affect what you see in MIT results. Any time you review an MIT in a data vacuum, you are significantly at risk for misinterpreting the results – either to the detriment of USDWs or your professional reputation, or both!

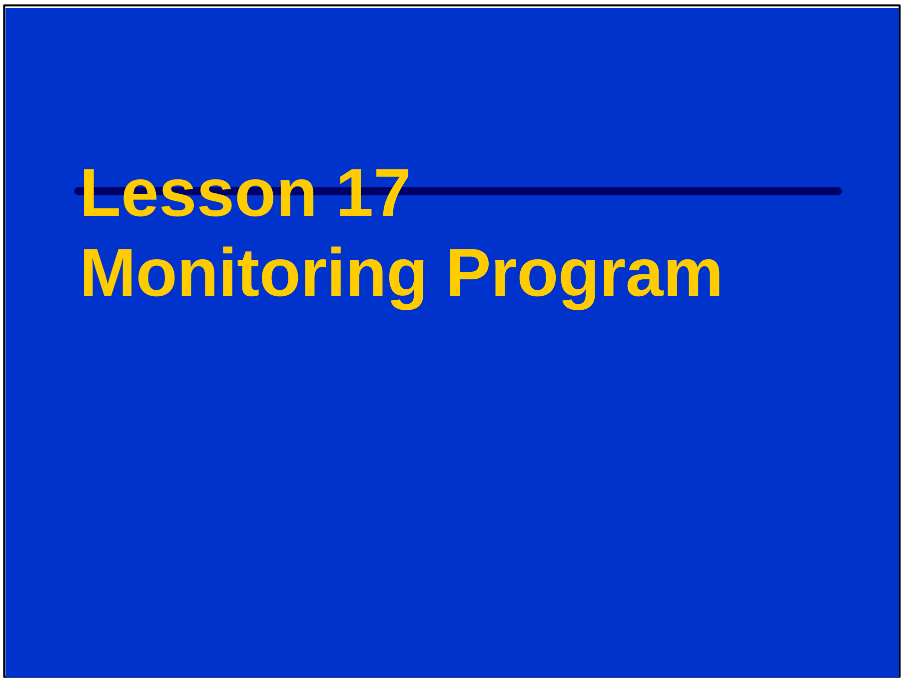
Annulus Monitoring

- Class I is unique in that continuous annulus monitoring is required for all non-municipal wells (40 CFR 146.13(b)(2)). Continuous annulus monitoring usually provides instant warning of mechanical integrity failures that involve the tubing, casing, or packer.
- Most States require that annulus pressure be maintained at a level greater than tubing pressure. This provides improved identification of minor tubing leaks that occur during operation, and ensures that leakage will involve annulus fluid leaking into tubing, rather than waste leaking into the casing annulus.
- Some operators monitor a closed, pressured annulus, but operating temperature and expansion effects can cause significant pressure fluctuations in the annulus. Most operators utilize an expansion tank as part of the annulus monitoring system, and also monitor changes in fluid level in the expansion tank. This is an extreme example of annulus expansion-tank monitoring; this is the Class I well at the Badami site on the North Slope. The waste-to-annulus fluid temperature differential can be 180 degrees F in winter and fluid volume can change 20 percent. Most wells use an expansion tank on the order of 5 to 20 gallons.
- Most Class I wells are required to use alarm systems to alert operators that a monitoring parameter has been violated. Alarms are required not only within operating spaces, but in central offices or control rooms.
- Almost all Class I monitoring and recording devices are digital, and use a PC to collect and simultaneously analyze the monitoring data. By assigning pre-set operating ranges for all parameters, operators can use a PC to trigger alarms or automatic shut-down systems. Make sure that the operator demonstrates his system during inspections.

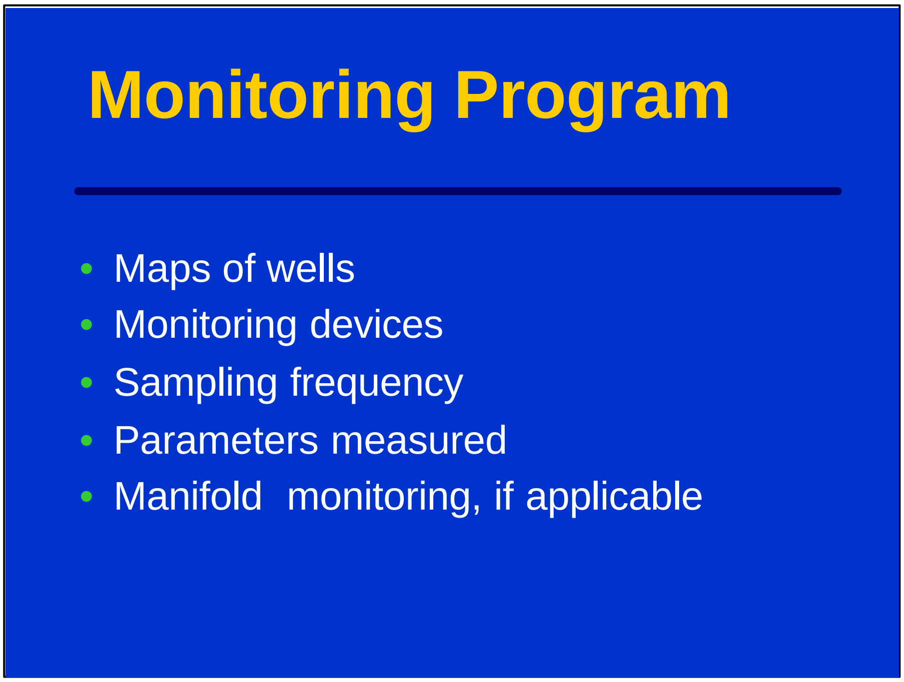
MIT Guidance

- Many procedural differences among States and Regions, well classes
- Annulus pressure test
  - Test pressure, duration, and variance
- Radioactive tracer test
  - Moving versus stationary, stations, flow

- States and Regions have unique specifications and procedures for MITs. In addition, most specify different procedures for different well classes.
- For APTs, the areas of difference usually involve test pressure, duration, and allowed variance. For RATs, the differences usually involve moving versus stationary tests, the number and location of stations, and flow conditions. Many Regions use a variation on the excellent RAT procedural guidance developed by Region 5.
- Most permit writers include the type and interval of MITs in permits. Include a reference to and attach the applicable guidance or procedures. Also include a requirement for timely notification, such as seven days rather than the 48 hours most permits specify, to allow you to witness a test now and then.



- An essential part of the permitting strategy for Class I wells involves careful consideration of applicable and appropriate methods of monitoring and establishing mechanical integrity. Monitoring should include periodic or continuous measurement and recording of operational parameters and waste characteristics, using tests and test frequencies sufficient to establish that the well is operating in compliance with permit conditions. This information will be included in Attachment P of the application. This type of information may also be necessary for Class II, III and V wells. Mechanical integrity testing is usually not necessary in Class V wells unless they are deeper wells than average.
- MIT should include internal pressure testing, radioactive tracer testing or fluid-flow logging, and casing inspections on a sufficient basis to establish the long-term acceptability of the well.
- This section will discuss not only the methods of monitoring and recording, but also the guidelines by which permit writers may decide the appropriate level of requirements for a particular well.



- The instructions for the permit application read as follows:

  Discuss the planned monitoring program. This should be thorough, including maps showing the number and location of monitoring wells as appropriate and discussion of monitoring devices, sampling frequency, and parameters measured. If a manifold monitoring program is utilized, pursuant to §146.23(b)(5), describe the program and compare it to individual well monitoring.

Monitoring Requirements: Class I (40 CFR 146.13)

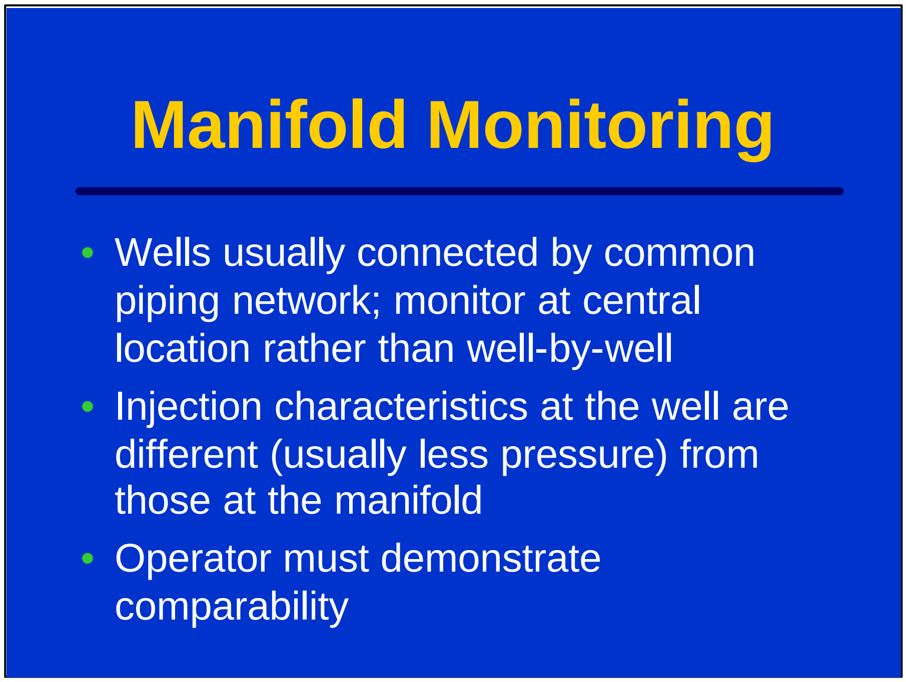
- Analyze injectate (at unspecified frequency) for representative data
- Use continuous recording devices
  - WHIP, rate, volume, annulus
- Conduct MITs every 5 years
- Put monitoring wells in USDWs?
- Report quarterly

- 40 CFR 146.13 (b) states that *monitoring requirements for Class I* wells must, at a minimum, include:
  - The analysis of the injected fluids with sufficient frequency to yield representative data of their characteristics;
  - Installation and use of continuous recording devices to monitor injection pressure, flow rate and volume, and the pressure on the annulus between the tubing and the long string of casing;
  - A demonstration of mechanical integrity pursuant to §146.8 at least once every five years during the life of the well; and
  - The type, number and location of wells within the area of review to be used to monitor any migration of fluids into and pressure in the underground sources of drinking water, the parameters to be measured and the frequency of monitoring.

Monitoring Requirements: Class II (40 CFR 146.23)

- Monitor nature of injectate (at unspecified frequency) for representative data
- Observe WHIP, rate, volume
  - Monthly for II-R
  - Weekly for II-D
  - Daily for II-H and cyclic steam
- Conduct MIT (APT) every 5 years
- May use manifold monitoring for II-R and II-H
- Report annually

- 40 CFR 146.23(b) states that *monitoring requirements for Class II* wells must, at a minimum, include:
  - o Monitoring of the nature of injected fluids at time intervals sufficiently frequent to yield data representative of their characteristics;
  - o Observation of injection pressure, flow rate, and cumulative volume at least with the following frequencies:
    - Weekly for produced fluid disposal operations;
    - Monthly for enhanced recovery operations; and
    - Daily during the injection of liquid hydrocarbons and injection for withdrawal of stored hydrocarbons during the injection phase of cyclic steam operations;
  - o Recording one observation of injection pressure, flow rate and cumulative volume at reasonable intervals no greater than 30 days;
  - o A demonstration of mechanical integrity pursuant to §146.8 at least once every five years during the life of the injection well; and
  - o Maintenance of the results of all monitoring until the next permit review (see 40 CFR 144.52(a)(5)).
- Hydrocarbon storage and enhanced recovery may be monitored on a field or project basis rather than on an individual well basis by manifold monitoring. Manifold monitoring may be used in cases of facilities consisting of more than one injection well, operating with a common manifold. Separate monitoring systems for each well are not required provided the owner/operator demonstrates that manifold monitoring is comparable to individual well monitoring.



- In Classes II and III, the regulations provide for manifold monitoring. This concept reduces the monitoring burden on operators by allowing them the option of monitoring rate, pressure, and volume in a common manifold or piping network, rather than at each individual wellhead.
- In enhanced recovery and hydrocarbon storage projects (Class II), and in almost all Class III projects, it would be prohibitively expensive and impractical for the operator to install a dedicated pump for every well. Instead, the operator installs a bank of pumps at a central location and runs a piping network to each wellhead. The regulations allow him to monitor the entire project from a central location, i.e., the manifold, rather than installing measuring devices and driving around to every well in the pattern.
- There are two things to remember:
  - The calculations in this course for allowable rate and pressure can not be used when an operator uses manifold monitoring. Every well in the pattern is injecting at a different pressure and rate (sometimes ***very*** different), depending on the distance and gradient of the piping to each well. If you specify the maximums as measured in the manifold, it is unlikely that any well would have ***more*** rate or pressure at the wellhead.
  - Second, the regulations provide that the operator must demonstrate that manifold-monitoring is “comparable to individual well monitoring.”

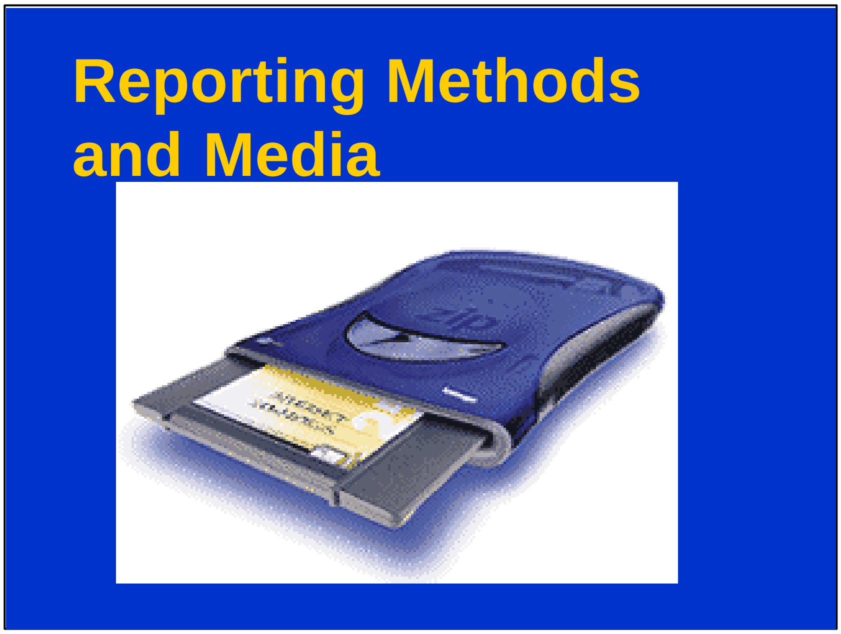
Monitoring Requirements: Class III (40 CFR 146.33)

- Monitor nature of injectate (at unspecified frequency) for representative data
- Monitor WHIP and rate or volume every 2 weeks **OR** meter and daily record injection and production volumes
- MIT every 5 years for salt solution mining only
- Fluid level and water quality every 2 weeks
  - Quarterly for collapse in USDW (146.32.g)
- May use manifold monitoring
- Report quarterly

- 40 CFR 146.33(b) states that *monitoring requirements for Class III* wells must, at a minimum, specify:
  - Monitoring of the nature of injected fluids with sufficient frequency to yield representative data on its characteristics. Whenever the injection fluid is modified to the extent that the analysis required by §146.34(a)(7)(iii) is incorrect or incomplete, a new analysis as required by §146.34(a)(7)(iii) shall be provided to the Director;
  - Monitoring of injection pressure and either flow rate or volume semimonthly, or metering and daily recording of injected and produced fluid volumes as appropriate;
  - Demonstration of mechanical integrity pursuant to §146.08 at least once every five years during the life of the well for salt solution mining;
  - Monitoring of the fluid level in the injection zone semimonthly, where appropriate and monitoring of the parameters chosen to measure water quality in the monitoring wells required by §146.32(e), semimonthly;
  - Quarterly monitoring of wells required by §146.32(g); and
  - All Class III wells may be monitored on a field or project basis rather than an individual well basis by manifold monitoring. Manifold monitoring may be used in cases of facilities consisting of more than one injection well, operating with a common manifold. Separate monitoring systems for each well are not required provided the owner/operator demonstrates that manifold monitoring is comparable to individual well monitoring.
- There is also a requirement (§146.32(e)) for Class III solution mining projects to monitor the injection zone (unless >10,000 TDS), the first permeable zone above or beneath the mining zone, and within the USDW at the periphery of the project.

Digital Monitoring

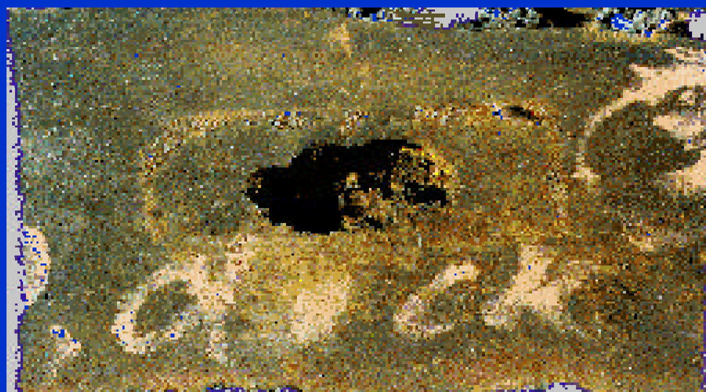
- In Class I, operators of non-municipal wells are required to constantly measure and record the injection parameters (40 CFR 146.13(b)). Most Class I measuring devices are digital, although a few operations continue to use circular charts and/or pump-stroke totalizers. Most Class I systems also use digital ***recording*** equipment. These systems easily manage alarms and automatic shutdowns.
- In Class II and III, however, pressure monitoring usually consists of an operator checking a gauge on the pump manifold at the end of every day or shift. Monitoring for volume probably consists of checking a rack of pump stroke totalizers and marking a clipboard list.



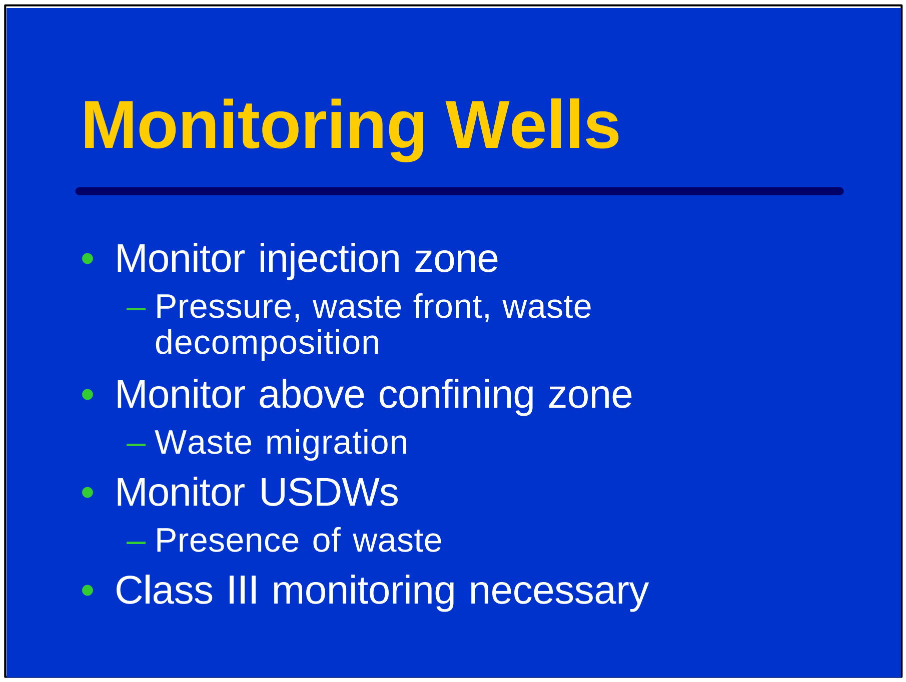
- Reporting for Class I wells is performed on a quarterly basis (40 CFR 146.13(c) and 146.69) at a minimum (some state regulations require more frequent reporting). Although a few operators still use paper circular charts, the preferred format for monitoring data is becoming PC "Zip" discs or CD-recordable media. The rules, however, do not specify electronic submissions though, so the permit writer should not require a system change unless it can be justified under the regulatory standards. For Class II and III, expect to get daily or monthly summary information for the project or field.
- If electronic deliverables are submitted by the permittee, the regulator may require that a signature letter accompany the disk to certify the report in accordance with 40 CFR 144.32(d).
- Monitoring reports should not be strictly a "data dump," but should provide a few basic analyses in addition to the raw data.
  - o The permit should specify that all types of data be graphed, both for the current reporting period and to date;
  - o In addition, the report should identify, for each parameter, the maximum, minimum, and average values for the quarter and explain any deviations from permit limitations; and
  - o The report should also discuss any maintenance activities, MITs, or other significant events that took place during the reporting period.

- As we discussed earlier, Class I is unique in that continuous annulus monitoring is required for all non-municipal wells (40 CFR 146.13(b)(2)). Continuous annulus monitoring usually provides instant warning of mechanical integrity failures that involve the tubing, casing, or packer.
- Most States require that annulus pressure be maintained at a level greater than tubing pressure. This provides improved identification of minor tubing leaks that occur during operation, and ensures that leakage will involve annulus fluid leaking into tubing, rather than waste leaking into the casing annulus.

Corrosion Monitoring



- The corrosion rate of tubing and packers may be monitored by means of corrosion coupons inserted in the waste stream. Corrosion coupons are specimens of the same material as the well components. The samples are periodically removed from the flow line, and carefully cleaned and weighed. The weight is compared to previous values, and divided by the surface area and time of exposure, which, for metals, provides a corrosion rate in terms of mils per year.
- Most corrosion samples are metal, but it is also possible to estimate the corrosion potential for cement samples and fiberglass. Most corrosion samples are located at the surface, so it is important to remember that downhole temperatures will accelerate corrosion. Many corrosion sample holders are heated to approximate subsurface conditions.
- Another method of corrosion monitoring uses wireline enhanced caliper or imaging logs to inspect casing. These logs are required by some states on a 5-year interval, and involve pulling the tubing from the well. Most casing inspection logs are helpful, but seldom provide definitive data ***before*** the well starts leaking.
- This photo is of casing from a prominent Class I-H well, a week after it "passed" an MIT. That's a two-finger-sized hole in the foreground, and a fist-sized hole in the upper background.

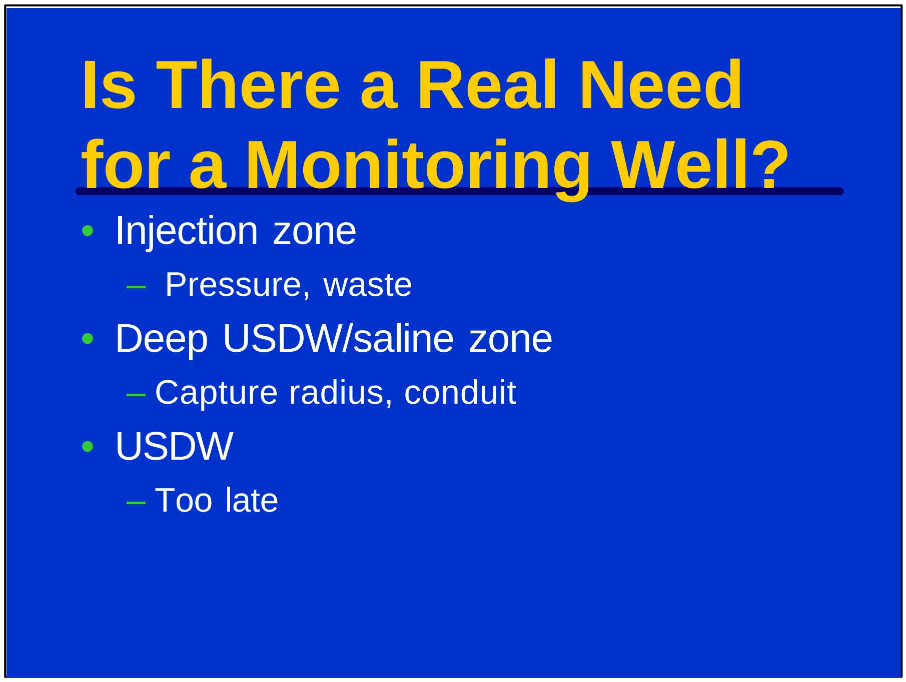


- Some States and Regions routinely require some sort of monitoring well, whereas in others the practice is entirely unknown.
- There are three types of monitoring wells:
    - o Wells in the injection zone, used to monitor pressure and the position and chemistry of the waste;
    - o Wells in the first permeable zone above the confining zone, used to act as sentry for waste migration; and
    - o Wells in the lowermost or other USDWs, used as confirmation that waste is not present.
- Class III solution mining wells are fairly shallow and inexpensive, and because most mining takes place within or near USDWs, monitoring is a necessity in most cases. The following discussion is limited to deep wells.

Monitoring Wells: Problems and Limitations

- Expensive (approach cost of injector)
- Small capture radius unless continuous pumping (water disposal)
- Path for migration

- There are some pretty significant problems and limitations connected with the use of monitoring wells.
- First, they are expensive, and costs for the two deep methods range from about 60 to 80 percent of the cost of the injection well itself. This could range from $150,000 to $1 million for a Class I or II well.
- Second, the capture radius of wells outside the injection zone is pretty small, unless the well is continuously pumped. A typical sampling event, even one with a lot of pumping, will give you an effective sampling radius of a few feet, especially in typically thick aquifers. Because the potential problem area around an injection well is defined by the area of review, you would need literally hundreds of monitoring wells to sample that area. Continuous pumping sounds feasible, but if that well is monitoring a saline aquifer above the confining zone (or even a 10,000 TDS USDW), water-disposal costs can be very substantial.
- In the case of deeper methods, a monitoring well can create its own migration pathway. In a 1999 study of Class I MI failures, Florida reported that 4 of 16 Class I waste migration incidents were caused by the ***monitoring well*** the State had required for each project (and they were looking into others). These were both internal and external MI failures of the monitoring wells. To safeguard this eventuality, require the operator to run internal and external MITs, which also means bigger casing and tubing and packer. This may result in a price similar to the cost of the injection well, and still have no guarantee that the well won't allow flow above the casing shoe.



- A monitoring well in the injection zone can monitor injection pressure, but so can the injection well itself. If you are looking for presence of the waste front, once it arrives at the well, there is no further use for the well (but it still can act as a migration pathway).
- Monitoring waste decomposition is probably not necessary from an operational standpoint, except for a Class I H well with a no-migration petition (although with a 10,000-year timeframe only the foolhardy would drill a monitoring well). The effectiveness of the confining zone is your primary line of defense.
- A well monitoring the deepest USDW or a zone above the confining zone sounds more effective, but you still have that tiny capture radius in relation to the size of the AoR. More importantly, any migration that would make it all the way to a USDW is not due to wholesale upward migration, but to the presence of a conduit like an abandoned well. It's highly unlikely that the monitoring well would detect the real mechanisms that threaten USDWs.
- A well monitoring a USDW has the same small capture radius, and if you did find evidence of waste migration, given transit times in ground water, the damage is already done.

Uses of Monitoring Wells

- RCRA monitoring in upper USDW
- Corrective action
- Known migration
  - Use other drilling on site for monitoring
- Florida
  - Poor confinement versus need for injection
- Concessions?

- If the operator also has a RCRA permit for his surface facility, that program will usually require him to install monitoring wells in the uppermost USDW. You can specify in the permit that those sampling results be shared with you.
- The primary use of monitoring wells involves corrective action. It can often be necessary to monitor pressure in the injection zone, and there are at least two facilities that monitor pressure in the injection zone using existing wells in the AoR.
- In a few cases, wells monitor waste migration that was found in an unpermitted saline zone above the confining zone. In the two cases mentioned above, the migration was discovered during the drilling of another well on the site. There is also a lesson here: if another well is drilling on a site, ask (or require) the operator to sample a few key zones above the confining zone. Sampling can be done as a drill-stem test or by monitoring the mud returns for indicator chemicals in the waste.
- In Florida, the poor confinement offered by fractured dolomites is offset by the perceived need for injection as a disposal method for municipal wastes. In many projects, deep and shallow monitoring wells are required by the State UIC agency. As we discussed earlier, many of the monitoring wells have themselves been responsible for contamination of USDWs.
- The words “deep monitoring well” will strike terror into most operators, due to the cost involved and the potential for ambiguous (read expensive) results. Most operators would do more frequent MITs or allow other concessions in order to avoid having to install a monitoring well.

Review Essentials

- Monitoring and reporting versus regs
  - Specific to well class
- Details of annulus system
- Reporting format (specify!)
- Special conditions
  - pH, corrosion, density
  - More MITs!

- Review of this attachment is pretty straightforward – the regulations are very specific as to the parameters to be monitored, how often sampled, and when reported. You should compare the proposed program to the regulations as presented earlier in this section.
- You also want to know all the details of the annulus monitoring system, if appropriate. Avoid systems that do not allow for overflow or surge tanks and volume monitoring. Also avoid any methods that utilize air or other gases, both in the annulus or for testing.
- Specify the reporting format as we discussed, for Class I wells that tend to be more sophisticated.
- If you have concerns, specify additional permit conditions for extra parameters to be monitored or for additional frequency. For example, you might require some form of pH and simple corrosion monitoring for any low or high-pH waste. If the maximum allowable injection pressure is an issue, require continuous waste density monitoring. With the low cost of the new generation of digital monitoring, you are not out of line in asking for things unheard-of in the past, if you can justify the need as related to USDW protection.
- Also seriously consider additional MITs for any Class I-NH industrial well beyond the 5-year minimum federal standard. It may not be reasonable to use the same 5-year interval for MITs as used for Class II. An annual internal MIT is ***always*** advisable. If you have concerns about the waste or cement, add a condition for an annual or 2-year RAT. There aren't many things we can control in UIC once the well is drilled. The MIT is our first line of defense.

Injectate Monitoring: Exercise

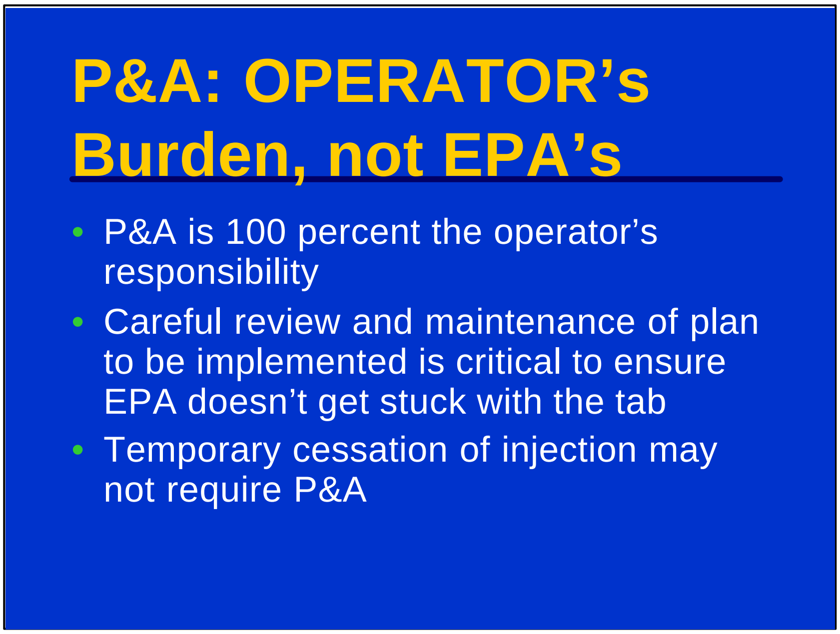
- Class I-H commercial disposal well
- High waste acid content
- Injection into dolomite cemented sandstone, through fiberglass injection tubing with standard steel casing
- What would you require the operator to evaluate regarding injectate content? How often?

- ***Consider the following scenario and decide what kind of waste monitoring you think would need to be conducted, and how often, to ensure the waste (injectate) characteristics and potential impacts are adequately defined. Think back to everything we've discussed about delta p, geology, hydrogeology, siting, construction and other elements of the permitting process. Explain the rationale behind each of the parameters you define for monitoring.***

- SCENARIO: A facility operator has one Class I hazardous waste injection well as part of the facility. The facility receives waste fluids from off-site generators, including a large quantity of waste acids. The injection interval consists of a dolomite-cemented sandstone. The injection tubing is fiberglass, and the well casing is standard steel casing. Averaged over the last five years, the well is operated approximately 250 days per year, with a flow rate of up to 100 GPM.

Lesson 18
Plugging and Abandonment Plan

- All UIC wells are required to be properly plugged prior to being abandoned.
- Abandoned wells can become conduits to USDWs, allowing injected fluids or native brines to migrate vertically into them. Uncemented annular space and open casing can both provide these vertical conduits.
- In this section, we will discuss the requirements of the plugging and abandonment (P&A) plan that must be submitted for Class I, II and III wells as part of the permit application. We also will discuss requirements for Class V wells, and ideas of what to require for P&A in the permit.



- While it may seem strange to think about how one should plug and abandon a well before it even is drilled, the review and approval of this plan, and ensuring money is in place to implement it, is critical. Historically, many operators have walked away from "temporarily abandoned" wells and left the state or Region with inadequate funds to properly plug the wells. The Agency's already stretched budget then must cover costs that truly are an operator burden.
- Be certain that the permit very clearly specifies the responsibility to properly close the well, regardless of well class. While a Class I vs. Class V closure plan may be very different, the regulatory agency should not bear the cost of closing even a shallow Class V well.
- Temporary or intermittent cessation of injection is not "abandonment" for purposes of deciding when plugging and abandonment is required. However, if well operations cease for two years, the owner or operator is required to plug the well in accordance with the approved plan. This two-year time frame is in effect unless the owner/operator notified EPA and describes actions or procedures that are satisfactory to the Agency, demonstrating that the well will not endanger USDWs during this temporary abandonment period (40 CFR 144.52(a)(6)). This requirement regarding the two-year cessation of operations, with the option to continue to leave the well temporarily inactive with Agency approval, should be included in the terms of the permit.

Requirement for P&A

- Plugging must occur in a way that will not allow movement of fluids into or between USDWs
- Must use cement
  - Class III wells may use other plugging materials with EPA approval
- Temporary cessation of injection may not require P&A

- As with all UIC activities, plugging and abandonment must be conducted in a manner that is protective of USDWs. 40 CFR 146.10 requires that Class I, II and III UIC wells be plugged with cement "in a manner which will not allow the movement of fluids either into or between underground sources of drinking water."
- EPA may allow plugging material other than cement if the owner/operator demonstrates to EPA's satisfaction that the proposed materials will prevent movement of fluids into or between USDWs.
- The reader should refer to the section on cementing in this training course to gain insight into appropriate types of cement, methods of cementing and other technical information regarding cement.

Plugging Methods

- Cement plugs emplaced in the well by:
  - Balance method
  - Dump bailer method
  - Two-plug method
  - Alternative approved method

- Specific means of plugging the well are listed in 40 CFR 146.10:
  - o Balance method;
  - o Dump bailer method;
  - o Two-plug method; or
  - o Alternative approved method that will reliably provide a comparable level of protection to USDWs.
- Briefly, we will define what these methods are. Additional resources, such as Region 5's Guidance #4 on Plugging and Abandoning Injection Wells, may be reviewed for more detailed information on this and other plugging and abandonment topics.
- ***Balance method***: This technique involves setting a viscous mud pill or mechanical plug at a required (predetermined) depth. The necessary quantity of cement is pumped down the drill pipe or tubing and displaced until the level of cement is the same both inside and outside the pipe. The pipe or tubing is then pulled slowly from the cement slurry, leaving the plug in place. Cement volume and heights of fluid need to be determined beforehand to ensure an adequate and successful plug is set.
- ***Dump bailer method***: A cement basket, bridge plug or gravel pack is placed below the desired plugging location. A dump bailer containing a measured amount of cement is lowered on a wire line , then dumped and raised to place a cement plug on top of the plug or basket.
- ***Two-plug method***: This method, used in open holes, uses a plug catcher into which two separate plugs are injected. The bottom cementing plug is set first. As cement continues to flow out of the string at the plugging depth, the annulus is filled. The top plug is introduced into the cementing string. When it is caught by the plug catcher, a sharp rise in cement pressure occurs at the surface, illustrating that the plug catcher has been closed off.

Other Conditions

- Well must be in static equilibrium
- Class I, II and III permit must include P&A conditions, with a plan submitted by applicant. May include in Class V permit
- Plan must be submitted to EPA 30 days prior to closure for large capacity cesspool and motor vehicle waste disposal Class V wells

- The well to be plugged is required to be in a state of static equilibrium, with the mud weight equalized top to bottom. This can be accomplished by circulating the mud in the well prior to placing the plug(s). This requirement also is part of the P&A requirements of 40 CFR 146.10.
- 40 CFR 144.51(o) requires that Class I, II or III permits include conditions that meet the plugging and abandonment requirements of 40 CFR 146.10. Class V well permits may also include these requirements if EPA decides that it is appropriate. A plan must be submitted for all large capacity cesspools and motor vehicle waste disposal wells being closed, at least 30 days prior to scheduled closure. This gives EPA an opportunity to review it and determine if the steps planned for closure of the Class V well are considered adequate, given the hydrogeology of the site, wastes disposed and other information. Keep in mind that techniques used for a deeper Class I, II or III well may not be necessary to impose on an operator of a Class V well. Very simple cementing may be allowed, but other issues, such as related piping being cleaned and removed, may need to be addressed.
- A plan is required to be submitted by the well owner/operator, addressing the requirements of procedures for plugging the well. EPA reviews the plugging and abandonment plan for adequacy.
- State regulatory agencies in Direct Implementation states may have well plugging requirements that are more stringent than EPA's UIC requirements. It is important that the EPA's DI Program personnel coordinate with state personnel to ensure the plan complies with all applicable regulations.

Plan Content

- Provide details of proposed plugging method
- Demonstrate movement of fluids into or between USDWs will not occur after plugging
- For Class V wells, sampling and analysis may be necessary prior to closure

- The P&A plan must discuss the methods that will be used in the plugging and abandonment procedures to protect USDWs. It must demonstrate that the proposed procedures will prevent any migration into USDWs. In addition to discussing the specific method of plugging that will be used, other information that should be discussed includes:
  - Prior notification to EPA of intent to plug the well;
  - Pulling free casing, as applicable;
  - Proposed depths of plugs (or discussion of cementing to surface as applicable);
  - Proposed cement type and quantity;
  - Testing or logging that may need to be conducted prior to plugging (such as part II MIT testing);
  - Surface restoration; and
  - Reporting of P&A activities to EPA.
- The prior notification and subsequent report are required by 40 CFR 144.51, and need to be addressed in the plan. Often, EPA will want to have a technical person present to witness the plugging activities.
- At least 30 days prior notice must be provided to EPA for closure of Class V large capacity cesspools and motor vehicle waste disposal wells.
- Free (uncemented) casing usually will need to be cut and pulled from cased wells. Otherwise, the annular space between the wellbore face and the casing will provide a potential migration conduit to USDWs. In deciding what portions of free casing should be pulled, the protection of USDWs needs to be the focal point. Consultation with other UIC personnel experienced in dealing with this issue will be highly beneficial to the reviewer of the plan if this issue arises.
- If the submitted plan meets the requirements of 146.10, it is incorporated into the permit. If not, the permit writer should require the applicant to revise the plan, prescribe conditions meeting the requirements, or deny the permit.

- The P&A plan ties directly into the section we discussed previously regarding financial responsibility (Section 19.0). 40 CFR 144.52(a)(7) requires that the permittee demonstrate and maintain financial responsibility and resources to close, plug and abandon the UIC well until the well has been plugged and abandoned in a way prescribed in the approved P&A plan and an abandonment report (required by 144.51(p)) has been submitted.
- It is important that the P&A plan provide adequate information on volume of cement, equipment, testing, and other equipment and materials proposed for closure of the well. The permit reviewer can then acquire information on current market costs of these materials and equipment, as well as labor, to determine if the cost estimate used for financial responsibility documentation is adequate and realistic.
- Some well operators will provide "in-house" labor and/or equipment costs in their closure cost estimate. It is wise to require that only third-party costs be included in this estimate. If EPA has to perform well closure, the facility's in-house personnel and equipment will no longer be available, and the cost of closure will be higher than the estimate provided. Use of third-party costs insures that EPA does not get stuck paying for well closure costs.

Additional Class IH Requirements

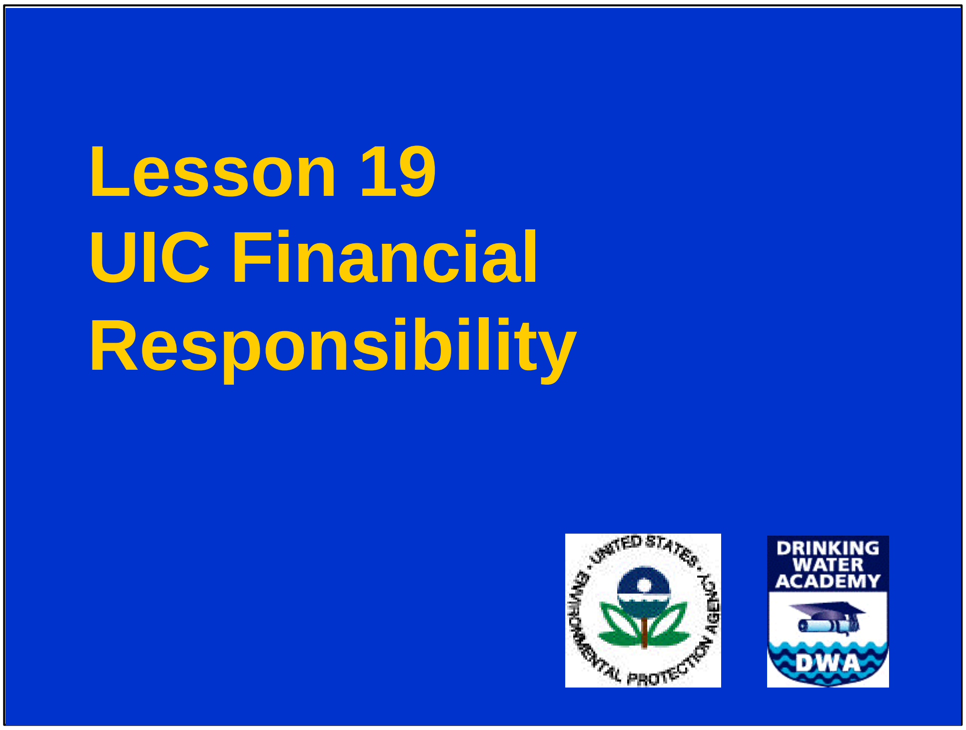
- Class IH wells have additional requirements for well closure
- 40 CFR 146.71 lists the requirements for closure
- Post-closure plan also required for Class IH wells as part of the permit application (see 40 CFR 146.72)

- Class I hazardous waste disposal wells are subject to slightly different requirements. The basic concepts regarding the P&A plan are included in 40 CFR 146.71, which spells out the requirements for a closure plan for these wells. In addition, a few other requirements are included in this rule. If you are working on a Class IH permit, you should review these requirements ***instead of*** the P&A requirements of 40 CFR 146.10.
- Also, Class IH wells are required to have post-closure plans submitted with the permit application. The post-closure care plan deals with pressure changes in the injection zone, waste front position at closure, status of any required corrective action, financial assurance issues, as well as recordkeeping and notification to appropriate authorities and deed notations to record information on the hazardous waste managed and injected at the site.
- The post-closure care plan is separate from the closure plan. 40 CFR 146.72 should be closely reviewed when evaluating the adequacy of these plans.

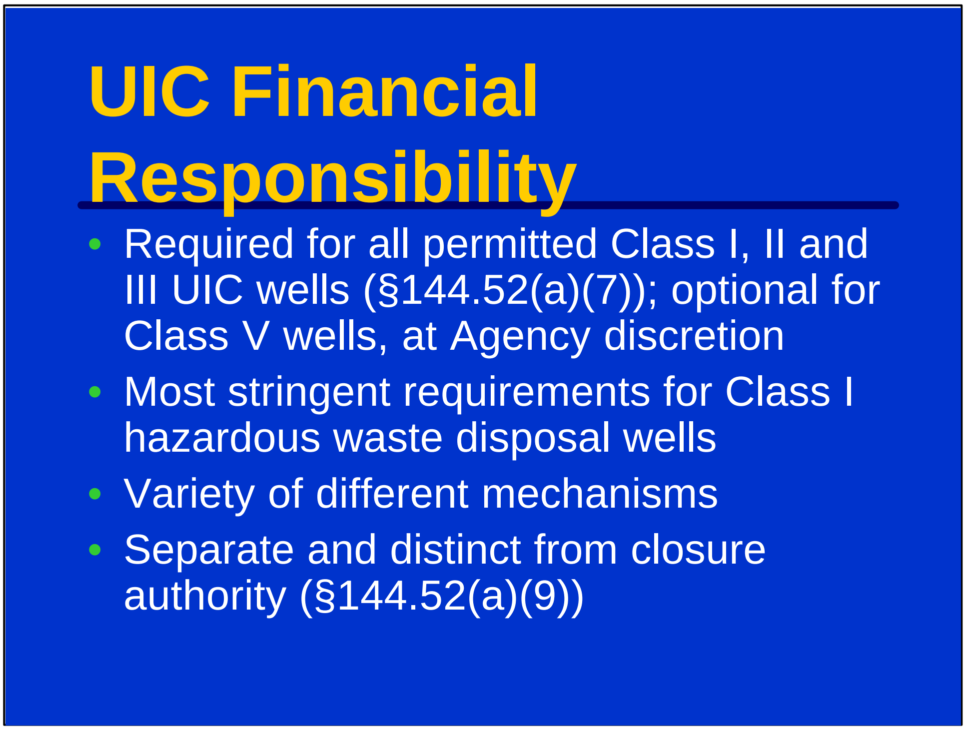
Get It into the Administrative Record

- Documentation of verification of cement quantity
- Comments and responses
- Updated plans submitted during permitting process

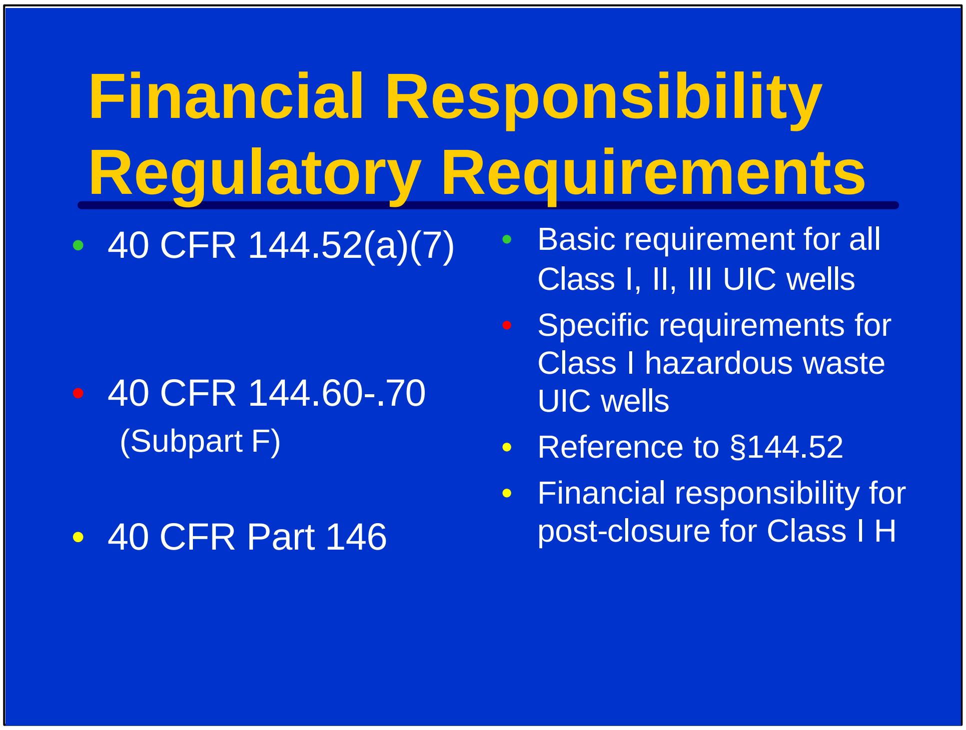
- It is a good idea to document in the administrative record that you verified the calculations for adequate cement quantity, as well as any other calculations and verifications conducted.
- Along with all other plans that are part of the application, if you comment on them and a new plan is submitted as a replacement, make sure you update the application and the record demonstrates when the new version was submitted.



- Owning and operating a UIC well is a costly venture that requires financial stability from the beginning of the permitting process through closure of the well and post-closure care, if applicable. An owner/operator must demonstrate that funds will be available to properly close the facility and provide post-closure care.
- In order to demonstrate that he has the financial resources to operate a UIC well, the owner/operator must use one or more of the financial assurance mechanisms designed by EPA or the primacy State.
- The topic of financial assurance documentation can become quite tedious, and all aspects of each instrument will not be covered in this training course. However, additional supporting information is available in the regulations, EPA guidance and other materials available for reference.
- In this section of the training we will discuss:
  - Why financial assurance is required;
  - What financial responsibility requirements apply to the different UIC well classes;
  - The different mechanisms that may be acceptable; and
  - The UIC permit writer's responsibilities for reviewing the mechanism and instrument submitted by the owner or operator.



- Financial assurance for UIC wells is required only for permitted wells in order to cover the costs of closing, plugging and abandoning a well. No documentation regarding the owner's or operator's ability to cover these costs is required for wells authorized by rule. This should not, however, be confused with the regulatory agency's ability to require closure of any rule-authorized well. At the expense of the owner or operator, the regulatory agency ***has the authority*** to require closure of any well if it determines that the well poses an endangerment to USDWs (see 40 CFR 144.12).
- Financial assurance is a demonstration on the part of the owner or operator of a well that when closure is necessary, funds will be available to permanently close the well in a way that is protective of USDWs. Closure of the well may be necessary due to closure of a facility, implementation of other disposal means, the well's useful life being reached, or problems with the well.
  - For deeper wells and for wells that have been used for disposal of hazardous waste, the cost of closure is relatively high due to the volume of cement and the equipment necessary to implement closure, as well as testing that may be required just before closure.
  - Closure requirements vary by well type, and closure requirements in the regulations directly affect the cost. For example, shallow Class V wells may be able to be closed quite simply, by backfilling from the surface with cement. Deeper, more "high-tech" Class V wells may need more complicated closure and thus should be required to demonstrate financial responsibility. Also, even shallow wells that inject wastes that, if system failure occurred may cause significant contamination, should be required to implement these requirements.
- Post-closure requirements, including financial assurance, apply to all Class I hazardous waste disposal wells, and may be applied to other wells if deemed necessary to protect USDWs.



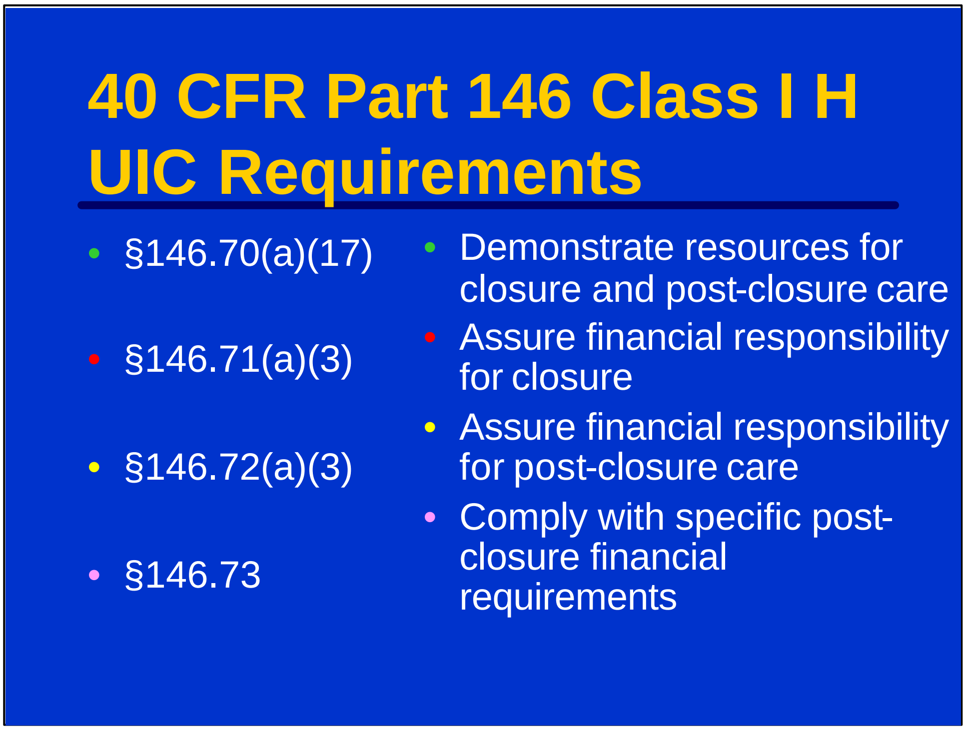
- 40 CFR 144.52(a)(7) provides the basic requirement regarding financial responsibility:
  - "The permittee, including the transferor of a permit, is required to demonstrate and maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director [i.e., EPA Regional Administrator or primacy agency Director]. . .The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance, such as a financial statement or other materials acceptable to the Director."
- 40 CFR Part 144, Subpart F (§§144.60-.70), establishes very specific financial responsibility requirements that apply to Class I hazardous waste injection wells.
- 40 CFR Part 146, Subparts B, C and D, each has a requirement included in "Information to be considered by the Director" regarding financial assurance. These regulations state that prior to issuance of a permit to operate, construct or convert a well to a Class I, II or III injection well, the Director must review and consider a certificate that the applicant has assured (through a performance bond or other appropriate means) the resources necessary to close, plug and abandon the well.
- 40 CFR Part 146, Subpart G, imposes requirements for post-closure financial responsibility for Class I hazardous waste injection wells. Note that the financial responsibility requirements for these wells are consistent with the financial responsibility requirements under the Resource Conservation and Recovery Act (RCRA) for hazardous waste disposal facilities.

Financial Responsibility Requirements

- Class II oil- and gas-related injection wells
  - Acceptable options for Class II wells
  - Specific information on each acceptable type
  - Available on-line at: **http://www.epa.gov/r5water/uic/r5_02.htm**

- Specific information about financial assurance mechanisms that are acceptable for Class II wells is provided in EPA's guidance entitled *Federal Financial Responsibility Demonstrations for Owners and Operators of Class II Oil- and Gas-Related Injection Wells*, dated May 1990 (Publication EPA 570/9-90-003).
- This guidance is also available on Region 5's Web site at:

  http://www.epa.gov/r5water/uic/ffrdooc2.htm
- Financial instruments (surety bonds, letters of credit, and trust funds) and financial statements are discussed as options for fulfilling the requirement for demonstration of financial assurance for these well types.
- Full coverage or blanket coverage may be options for Class II well operators as well.
- **Full coverage** is an option in which the chosen instrument guarantees that enough money will be available to close, plug and abandon each injection well owned or operated. The amount of the instrument meets or exceeds the total cost per well.
- For **blanket coverage**, the amount of the instrument is sufficient to plug an appropriate number and acceptable proportion of the total number of injection wells owned or operated in a project or by a company. The decision to allow blanket coverage is at EPA's discretion, and the owner/operator needs to meet certain criteria outlined in the guidance to qualify for this type of mechanism. Just a reminder – we talked about third party vresus in-house costs in Lesson 18. Be certain that ony third party costs have been used in deriving the financial assurance requirements.



- 40 CFR 146.70(a)(17) requires that the well owner or operator demonstrate to the Director, as part of a permit application, that resources needed for closure, plugging and abandonment, and post-closure care are available. The rule cross-references Part 144, Subpart F.
- Closure requirements for Class I hazardous waste injection wells are provided at §146.71. The closure plan for Class I hazardous wells is required by this section of the regulations. The plan must include financial assurance, and the estimated cost of well closure.
- Post-closure care is required for Class I hazardous wells also, as established by §146.72. This section requires that a post-closure care plan be submitted by the well owner/operator. Assurance of financial responsibility and a cost estimate for post-closure care are required to be included in the post-closure plan. 40 CFR 146.73 requires that post-closure care financial responsibility demonstrations meet all the standards established for closure in 40 CFR Part 144, Subpart F. Based on this, all the standards for closure financial responsibility also apply to post-closure financial responsibility.
- Though financial assurance is specifically required independent of the closure and post-closure regulations (§146.71 and §146.72), it is tied closely to the closure and post-closure plans. Cost estimates are part of the plans, and the mechanisms established to fulfill the regulatory requirements for financial responsibility must cover all the costs provided in these cost estimates. Further, the closure and post-closure plans, as well as financial responsibility demonstrations, must be "acceptable" to the Director, and thus are subject to review and approval by regulators.
- The requirements to provide for closure and post-closure care survives the term of the permit or cessation of injection and are enforceable regardless of whether the requirements are conditions of permits (40 CFR 146.71(a) and 146.73).

Permit Writer's Responsibilities

- Determine that the amount of assurance is adequate
- Determine that the type of mechanism is appropriate
- Determine that the wording of the instrument complies with the regulations
- Determine that all parts of the instrument are in place
- Decide if a permitted Class V well needs to have financial assurance in place

- Permit writers may be tempted to downplay this element of the permitting process to some degree, as most permit writers are scientists and engineers, not accountants. It may seem relatively unimportant, especially if the well owner/operator is a large corporation that would appear to have plenty of money to close a well. However, it is important that attention be paid to the mechanism to ensure that when the time comes to close a well, the regulatory agency is not stuck paying for it!
- Permit writers have a responsibility to review four aspects of an applicant's financial assurance submission:
  - The amount of assurance;
  - The type of mechanism used;
  - The specific wording of the instrument;
  - The completeness of the mechanism, especially when the selected mechanism requires that a standby trust accompany it.
- For Class V well permits, it is likely that if a permit is necessary, some type of closure and financial assurance requirements may be appropriate to protect the agency. The permit writer should consider the well depth and construction, type of fluids injected, and other site-specific factors to make this evaluation.
- Though permit writers may be somewhat intimidated initially by reviewing these documents, staff in other programs (such as RCRA) with experience in reviewing such documents may be able to provide some assistance.

Closure Plans and Cost Estimates

- Financial responsibility amounts are directly related to cost estimates in the closure and post-closure care plans
- A variety of factors influence costs
  - Inflation
  - Well design changes (drilling out to increase depth)
  - Equipment costs
  - Site-specific well issues

- The basis for the financial assurance is the cost estimate, which is, in turn, based on the closure (and post-closure) plan.
- A number of factors can influence the validity of the cost estimate for closure and post-closure, and thus the amount of the financial assurance mechanism. Inflation is one such factor. 40 CFR 144.62(b) requires that these cost estimates be adjusted every year, on a very specific schedule.
- Due to well performance, well design changes may be made over time that will influence the cost of closure. For instance, a well may be drilled out to increase the injection interval thickness, deepening the well. If the change is significant enough, it will increase the cost of well closure.
- The cost of materials and equipment needed for closure may vary over time. The cement, frac tanks, rigs and other equipment, as well as personnel required to oversee the closure activities, may change from the time a cost estimate is prepared. Though these costs generally will not change very much from one year to the next, they may change significantly over the life of the well.
- Site specific circumstances influence the costs of closure and post-closure more than anything else! The well depth, internal diameter, number of UIC monitoring wells on-site, pressure in the well, and many other factors will determine how simple or complicated the closure and post-closure will be, and will determine the cost of performing the required activities.
- Since well permits are issued for anywhere from a few years to the life of the well (for some Class II wells), costs of closure may change over time, based on the cost of materials, labor, equipment, and other factors.
- As cost estimates for closure and post-closure are updated, the financial assurance mechanism needs to be reviewed to see if the amount of the mechanism is adequate to cover the total costs anticipated.

Reviewing the Cost Estimate

- Review the cost estimate to determine whether the amount of the financial assurance is adequate
- Ensure that all activities in the plan are covered in the cost estimate
- Ensure that costs are reasonable and valid

- The permit writer must review the cost estimate in conjunction with the closure (and post-closure care) plan to ensure that all activities in the plan are covered by the cost estimate.
- It is also important to review the cost estimates to see if they are reasonable. If two Class I nonhazardous well owners or operators for similar wells both submit estimates at the same time, and closure costs are estimated by one at $15,000 and by the other at $5,000, the regulator must determine whether these estimates are "reasonable." He or she may need to request a breakout of costs, showing estimated labor, equipment, materials, etc., to determine if the costs make sense.
- Some operators may overestimate the cost so they do not have to keep updating the estimate every time it rises. Similarly, the financial assurance instruments submitted are often developed for costs that exceed the truly anticipated closure and post-closure costs, to avoid reissuance of the instrument over time. Each reissuance may cost the owner or operator additional money, so an inflated cost estimate may be used to provide a long life to the instrument chosen.
- Conversely, there may also be incentives to underestimate the costs in order to reduce the owner/operator's financial requirements while the facility is operating.

What Mechanisms Are Allowed for Hazardous Waste Wells?

- Trust fund
- Surety bond with standby trust
- Letter of credit with standby trust
- Insurance
- Corporate guarantee
- Financial test

- There is no guessing about what is acceptable to satisfy financial assurance requirements for Class I hazardous waste disposal wells! The regulations are extremely specific regarding the wording, timing, and means to implement the various mechanisms listed in Subpart F of 40 CFR Part 144.
- Significant details regarding language, methods for cancellation, schedules of submission, and additional information specific to each mechanism are included in the regulations. It is important that you reference the regulations and review these details when you review an instrument submitted by an owner/operator.
- Remember that Subpart F requirements apply to financial assurance for **both** closure and post-closure care for Class I hazardous waste disposal wells.

What Mechanisms Are Allowed for Class II Injection Wells?

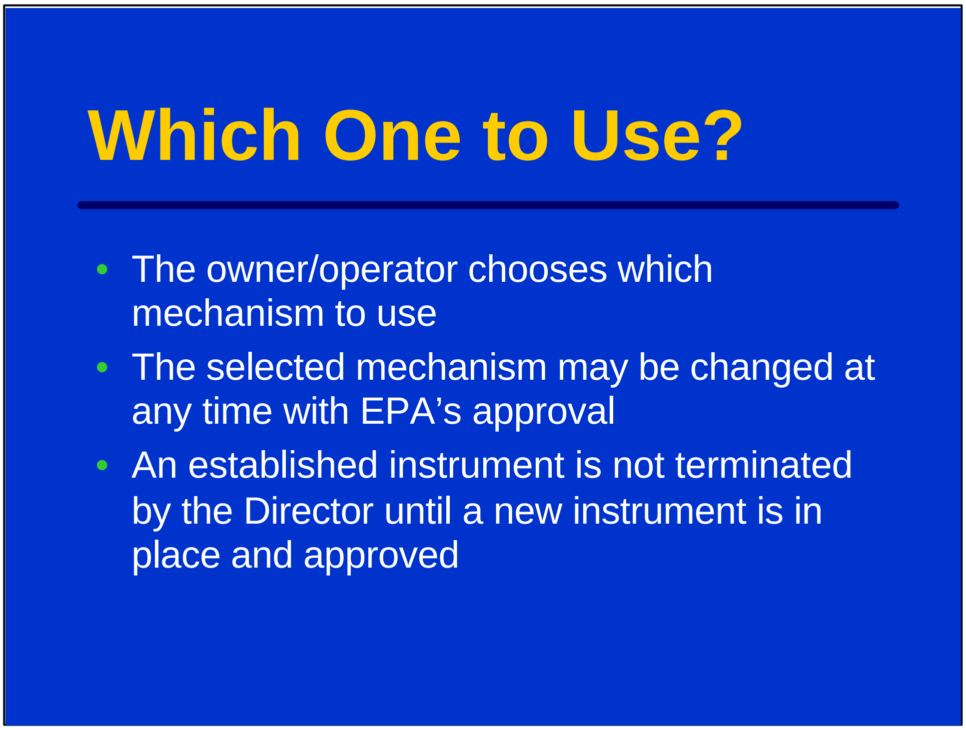
- Surety bond with standby trust
- Financial guarantee bond
- Performance bond
- Letter of credit with standby trust
- Irrevocable trust
- Financial statement

- Each instrument that is acceptable for Class II wells is discussed in the EPA publication *Federal Financial Responsibility Demonstrations for Owners and Operators of Class II Oil- and Gas-Related Injection Wells*.
- The mechanisms that may be acceptable for Class II wells are:
  - Surety bond with standby trust fund;
  - Financial guarantee bond with standby trust fund;
  - Letter of credit with standby trust;
  - Irrevocable trust fund; and
  - Financial statement (financial test).
- It is important to realize that the use of a bond or letter of credit always requires a standby trust fund to be in place.
- It is important for a Class II UIC well owner/operator to know whether full or blanket coverage can be used for his or her wells. EPA must be consulted to determine this, since allowing blanket coverage is discretionary. Use of the Federal guidance document will assist both permit writers and owners/operators to decide what options exist for the wells in question, based on the pointers laid out in the guidance document.

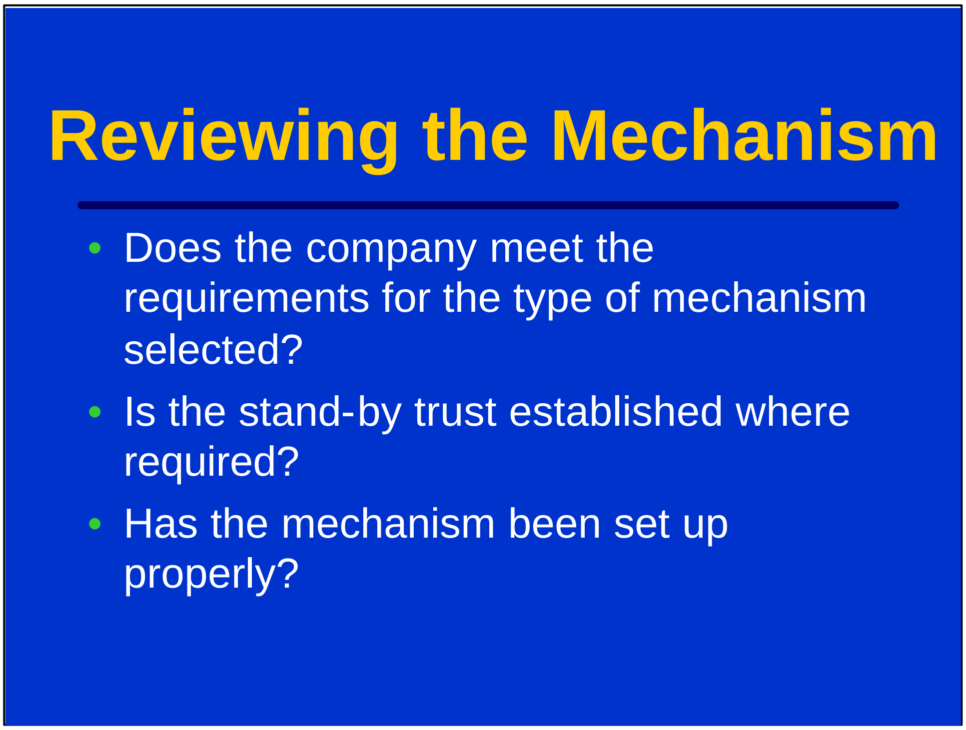
What Mechanisms Are Allowed for Other Injection Wells?

- Surety bond
- Other adequate assurance
  - Financial statement
  - Other materials

- As touched on previously, the minimum financial assurance requirements of the Federal regulations for UIC wells other than Class IH and Class II do not specify a list of instruments that would be "acceptable to the Director."
- A surety bond or a financial statement are the only two items specifically listed. Thus, for other permitted injection wells, the Director has a great deal of latitude regarding what is permissible. As noted before, however, most permit writers are not experts in this area, and thus may not be comfortable deciding what is "acceptable."
- Since the regulations for Class I hazardous waste injection wells and guidance for Class II wells are very specific regarding what is deemed acceptable, they can be used as models for other well types if the permit writer so chooses. The language may need to be modified somewhat, for instance to eliminate references to hazardous waste as stated in the Class IH regulations. Otherwise, the basic elements are established and available for use.
- This does not prevent the use of other means of establishing financial assurance, however, if the owner or operator is able to satisfy the regulatory agency that its submission guarantees that money will be available to cover closure costs on closing the well.



- The owner or operator of the well will submit the financial assurance instrument as part of a permit application. The instrument is reviewed and determined to be adequate or inadequate by the regulatory agency. If it is found to be inadequate in language, the Agency will issue comments to indicate this. However, in some instances the owner or operator may not be able to meet the criteria required by rule for certain mechanisms. In this case, the choice of that mechanism is eliminated and the regulatory agency will have to tell the owner or operator that the chosen mechanism cannot be used.
- The owner or operator may chose a different mechanism at any time with the Director's permission, based on the company's business structure, costs of the mechanism, or other factors that may not be revealed to the reviewer. As long as the standards of the rule are met, any of the mechanisms listed may be used. The existing instrument is not terminated, however, until a new instrument that has been deemed acceptable by the regulatory agency is in place. The means of terminating an existing instrument and circumstances under which the termination is allowed are listed at the end of the discussion of each mechanism in §144.63.
- If EPA has reason to believe that the instrument in place is no longer adequate to cover the cost of closing, plugging and abandoning the well, 40 CFR 144.28(c)(3) provides the authority for the Agency to require a revised demonstration be submitted.



- The permit writer needs to review the mechanism to ensure that it is appropriate for the company and that it has been set up correctly.
- For example, a company must meet certain financial requirements in order to use the financial test or to provide a corporate guarantee. Certain mechanisms require the owner/operator to establish a stand-by trust fund.
- Permit writers should consult guidance, more experienced permit writers (including those in other programs), or Regional Counsel to help with the complicated technical or legal aspects of reviewing the financial mechanisms. The guidance documents listed below may be helpful in reviewing these documents.
  - Federal Financial Responsibility Demonstrations for Owners and Operators of Class II Oil- and Gas-Related Injection Wells, May 1990.
  - Guidance for Financial Responsibility in Federally-Administered UIC Class II Programs, March 29, 1989.
  - Guidance for Financial Assurance for Federally-Administered UIC Programs, May 29, 1985.

Wording of Instruments

- 40 CFR 144.70 provides the **EXACT** wording for Class I H instruments
- Applies to instruments for closure and post-closure care
- Wording, including punctuation, must be in compliance
- Wording may be used as a guide for instruments for other well classes

- We have mentioned before, but need to stress again, that the wording of the instruments is critical. Because these are detailed, legally binding documents, the **exact** wording of the regulatory language in 40 CFR 144.70 must be used. This is true for both closure and post-closure financial assurance instruments.
- 40 CFR 146.73 requires that post-closure care financial assurance meet the specifications for the mechanisms and instruments in 40 CFR Part 144, Subpart F. The wording merely needs to be revised to cover post-closure care as well as closure.
- A word-for-word comparison should be made for each instrument against the wording in the regulations.
- To ensure that nonhazardous waste wells have acceptable financial assurance, you may want to use the language of these instruments as a basis for the financial assurance for nonhazardous waste UIC well owners or operators.

Release from Financial Assurance

- Completion of closure (or post-closure) according to the approved plan must be certified by an independent professional engineer prior to the release
- The obligation to maintain financial assurance survives the permit termination and cessation of injection

- Based on 40 CFR 144.63(i), a well owner/operator may only be released from the requirement to maintain financial assurance by the Director. An official notification must be sent releasing the owner/operator from the requirement, once the Director is satisfied that the closure and post-closure plan have been complied with fully. The completion of required closure and post-closure activities must be certified by an independent professional engineer.
- The Federal guidance on Class II financial assurance states that financial assurance mechanisms may only be canceled with the written consent of the EPA Regional Administrator or the UIC Program Director.
- Neither the completion of closure, the cessation of injection into a well, nor the termination of a permit release the owner or operator of a hazardous waste disposal well from maintaining financial assurance. Only the regulatory agency may release the owner/operator from the requirement to fulfill this regulatory obligation.

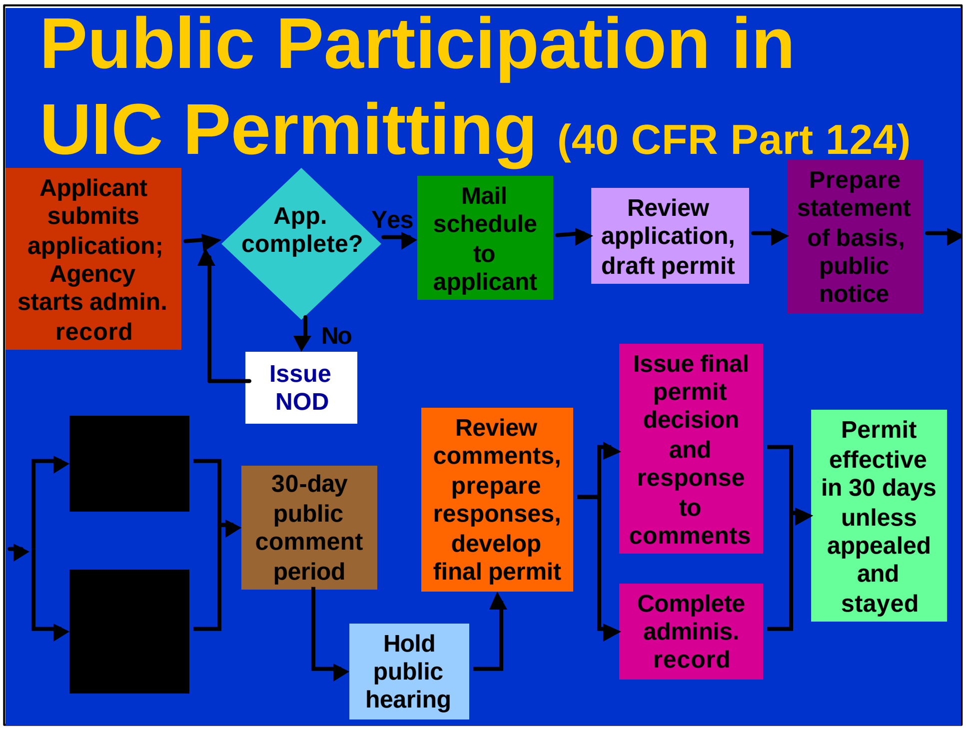
Administrative Record

- Final approved financial assurance mechanism
- Documentation illustrating how review determined submission meets requirements

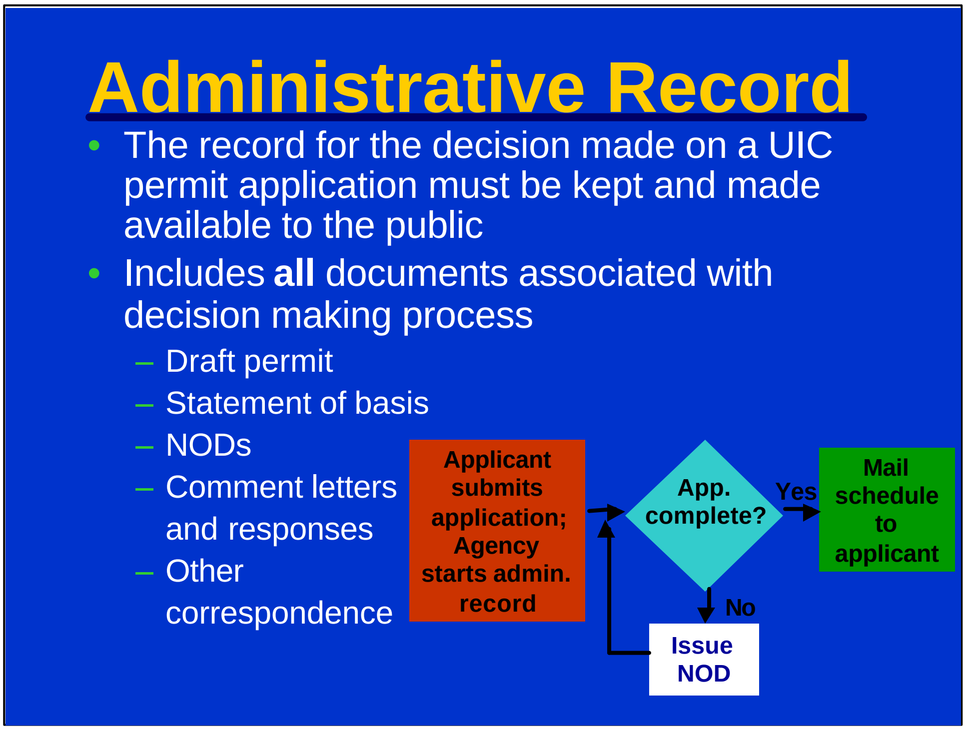
- The final approved financial assurance mechanism should be documented in the administrative record of the permitting action. The original document may need to be stored elsewhere, based on Regional policy, but a copy may be inserted in its place.
- Evidence of the Agency's review and determination that the mechanism is adequate should also be placed in the record.
- You may want to avoid specifically listing the approved mechanism in the permit itself. If the operator changes mechanisms during the term of the permit, you may need to conduct a permit modification. Leaving the specific mechanism out of the permit keeps you from creating that additional work for yourself and the applicant. The permit definitely should, however, indicate the requirement to maintain an approved mechanism for closure of the well.

Lesson 20
Public Participation in the Permitting Process

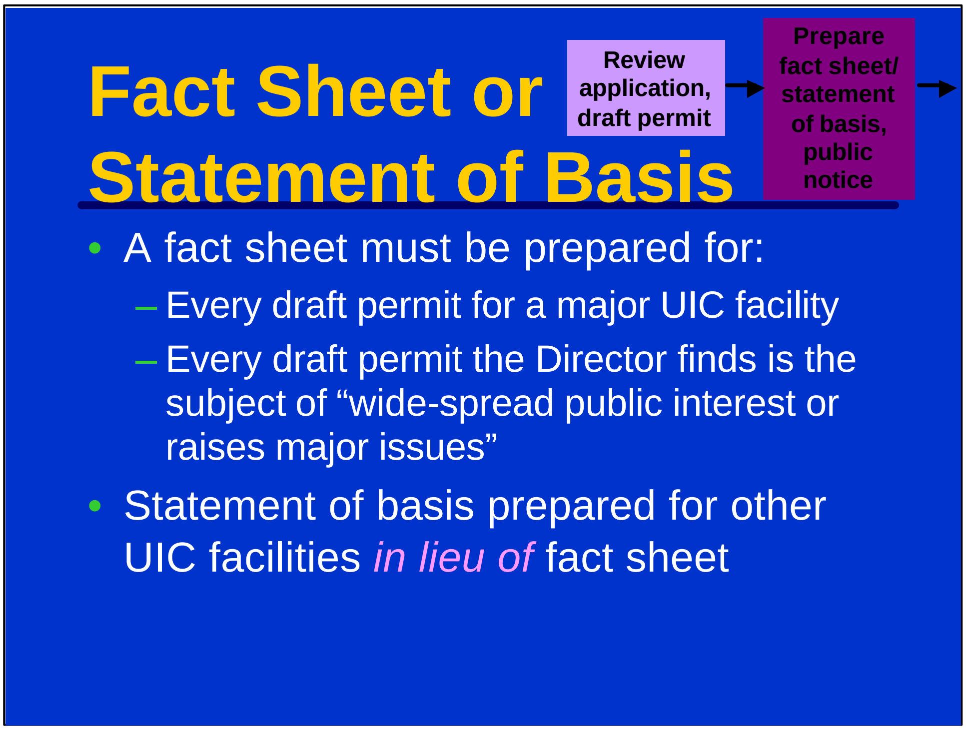
- 40 CFR 144.1(f)(3) requires that UIC permits be issued following the procedures in 40 CFR Part 124, which provides the procedural rules for EPA's UIC, RCRA, NPDES and other permitting programs.
- It is important to follow the public participation procedures carefully. EPA's policy is to inform the public and maintain open communication channels on issues of concern. Also, if these procedures are not followed, they may become an issue in a contested permit. States follow an issuance process very similar to the Federal process described here.
- Many Regions have guidance or other helpful documents that walk you step-by-step through the public participation process for permit issuance or reissuance. You should refer to these documents as you develop a permit or permit renewal. It hurts the Agency's credibility and wastes resources if a permit has to go through the public participation process more than once because proper procedures were not followed.
- Always feel free to have an experienced permit writer double-check your steps as you prepare all the documentation and work through the steps described here. The public desires and has a right to timely, accurate information about UIC facilities. An experienced permit writer can help make sure that little steps that mean a great deal to the public are not overlooked.
- Please note that the process for issuing an emergency permit is different from that described in this section. If you must issue an emergency permit, you should work closely with other experienced UIC staff, and refer to 40 CFR 144.34 for rule requirements. The requirements here apply to new and reissued permits, as well as major modifications to permits.



- Only minor modifications of permits, as defined in 40 CFR 144.41 are exempt from the public participation requirements of 40 CFR Part 124.
- Please keep in mind that the "public" in the regulations includes not only people in the community around the UIC facility, but any other interested party and the permit applicant as well. Anyone and everyone is able to have a say in the permitting decision. However, the ultimate decision must be based on the regulations applicable to the particular UIC well, not on well-intentioned public sentiment or corporate interests that are not based on protection of USDWs and public health.
- The first step in the permit application review is ensuring that the application is complete. This means it includes all the elements required (the basic application plus all attachments) completed. **"Complete"** is defined in 40 CFR 144.31(d). If the application is incomplete, the reviewer develops and sends a Notice of Deficiency (NOD) and the applicant must respond. Generally, there is a difference between a complete application versus one that is completely adequate technically. All the parts may be there, but additional detail may be required even once the application is "complete." The reviewer needs to make sure that the applicant did not make a claim of confidentiality for all or part of the application. If this claim is made, it must be done according to the requirements of 40 CFR 144.5, and EPA cannot release the confidential information to the public.
- Let's assume that no part of the application is claimed as confidential and that the application submitted is "complete" as defined in the rules. We will now walk through the steps that must be completed to act on the application by issuing a permit.



- The administrative record is started on receipt of the applicant's permit application. The administrative record is an extremely important document. If the permit is contested, the agency is allowed only to use documentation in the administrative record to justify its permit decisions. The permit writer needs to carefully document the entire permitting process to ensure that the record is thorough and complete.
- The administrative record for a draft permit includes documents listed in 40 CFR 124.9, including the permit application and any supporting data the applicant submitted, the draft permit, the statement of basis or fact sheet, and any other documents that are cited in the statement of basis or fact sheet or used in support of permit development (such as maps or geologic articles).
- The administrative record is required to be maintained by the regulatory agency. It must be made available for public comment when the draft permit is issued (40 CFR 124.6(e)) and for public review when the final permit decision is made (40 CFR 124.(8)).
- After receipt of an application from a major new UIC well, the "Director" must mail the applicant a project decision schedule that includes target dates for major permit milestones (40 CFR 124.3(g)). ("Director" means the State UIC program director for a UIC primacy State or the EPA Regional Administrator for a Direct Implementation State.)



- To help inform the public of the UIC activities at a facility, a fact sheet is prepared by the regulatory agency and distributed to the public. 40 CFR 124.8 requires that a fact sheet be developed by the regulatory agency for every draft permit for a major facility, and for every draft permit which the Director finds is the subject of widespread public interest, or which raises major issues. What do "widespread" and "major" mean? Work closely with your supervisor to help you determine what sites and issues merit use of these terms.
- The fact sheets are required to contain certain information listed in 40 CFR 124.8, such as a description of the facility, type and quantity of fluids to be injected, a summary of the basis for the permit conditions included in the draft, procedures that will be used to make a final decision, and information on the public comment period and hearing.
- A statement of basis must be prepared for every draft permit for which a fact sheet is not prepared. The statement of basis contains a brief description of the facility, the permit conditions and how they were derived (§124.7).
- Some Regions may use the statement of basis in place of a fact sheet. The title is not what matters nearly as much as the content of the document, which is intended to educate the public about the injection facility.
- The fact sheet or statement of basis is mailed to the applicant and, on request, to any other person. It may also be distributed at a public information meeting or may receive a wider distribution through the mailing list that is maintained by the regulatory agency. The primary goal is to *reach as many people as possible* through this and all other notices sent to the public.

Draft Permit Issuance

- Draft permits must be announced through a public notice
- Opportunity for a public hearing must be provided
- A final permit decision must be accompanied by a response to any comments submitted on the draft permit

- Since the application has been deemed complete, the agency prepares a draft permit or a notice of intent to deny the permit. For procedural purposes, a notice of intent to deny is considered a form of draft permit and the same administrative requirements apply. We will assume that a draft permit is being issued.
- The draft permit includes permit conditions applicable to all permits (40 CFR 144.51 and .52); compliance schedules, as necessary (40 CFR 144.53); recordkeeping, reporting and monitoring requirements (40 CFR 144.54); and other requirements and limitations as established in 40 CFR Parts 144 and 146. Additional details about draft permits are provided in 40 CFR 124.6.
- Most Regions have boilerplate permits for each well class that you can use as a starting point in developing the draft permit. Language is modified to be site-specific, and any special conditions that are necessary based on site conditions and the need for protection of USDWs are inserted as well.

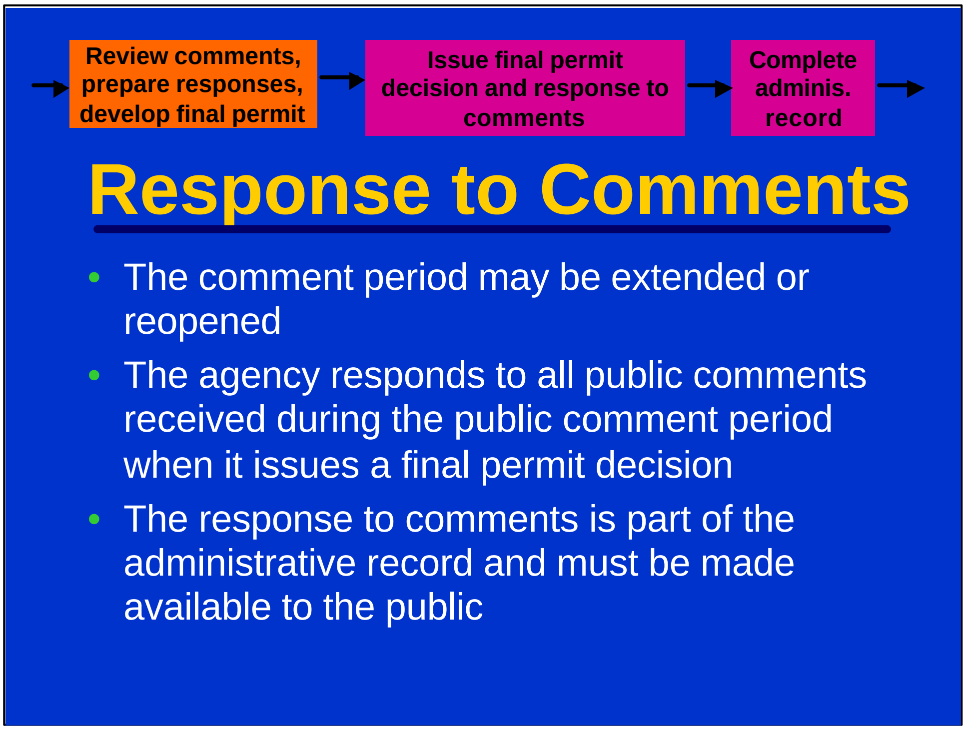
Public Notice

30-day public comment period

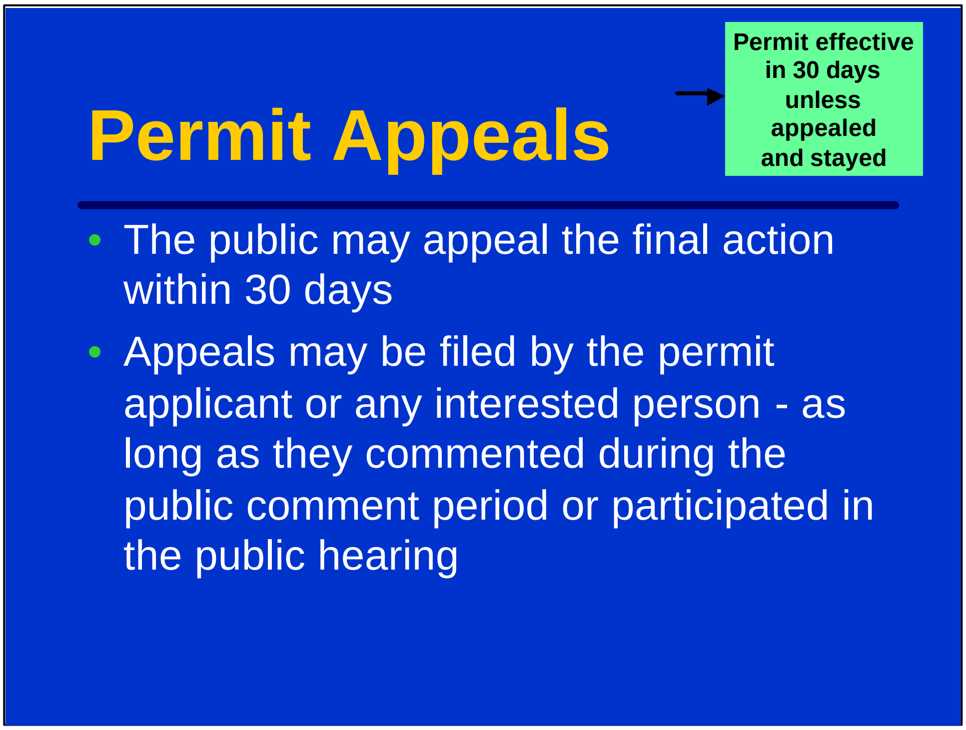
- Public notice prepared and published. Must allow at least 30 days for public comment once draft decision has been made on the permit application
- Describes draft action, where draft can be reviewed, invites comment
- The notice may include details of a public hearing, if one has been scheduled

- Decisions to deny a permit, issue a draft permit, grant an appeal, and schedule a public hearing are required to be published in a public notice. 40 CFR 124.10 lists the requirements for public notice and a public comment period.
- For our draft permit example, a public notice is issued, usually through the Branch Chief. This announcement provides the public an opportunity to be aware of the action, review the draft permit and supporting documents, and provide comments on the draft.
  - o Any interested individual may submit written comments on the draft permit. These comments may support the permit action as prepared, or may object to various conditions or language in the draft permit.
  - o The Director responds to any comments prior to issuing a final permit action.
- The public notice is actually prepared as part of the Statement of Basis in some cases. It must allow at least 30 days for public comment on the action described. Also, public notice of a public hearing is required to be given at least 30 days before the hearing. Public notice of the draft permit and of a public hearing may be combined in one notice. If a hearing is scheduled later due to public interest, another 30 day prior notice must be issued.
- Mailing the notice to persons on a mailing list, the permit applicant, various agencies, and local governing bodies, as well as publication in a newspaper, are methods used to circulate the public notice.
- Given the timing of the public notice requirements and preparation of the various documents for public review, good planning and careful timing are

- We have mentioned a public hearing several times. The hearing provides an opportunity for interested persons to submit comments for the administrative record either verbally or in writing. Written comments may be submitted by mail using the procedures noted in the public notice of the draft permit action. However, an individual or group of individuals may wish to speak to EPA representatives about the action and request a public hearing.
- The Director is required to hold a hearing if "a significant degree of public interest" is generated regarding the draft permit. This may be just one individual requesting the meeting, or a larger number of requests may be required at the Director's discretion - the decision to hold or not hold the hearing is up to the Region, but must be defensible given the procedural regulations. EPA wants to seek out and be sensitive to public concerns. Each Region has its own method of addressing the term "significant," so work closely with your supervisor to determine whether a hearing is needed. The Director may also schedule a hearing without a request from the public if he or she believes the hearing will clarify the permit action.
- You should note that EPA does not respond to questions or comments during a public hearing. It is a formal session with designated roles for individuals to preside over it. A transcript is made of all comments.
  - EPA responds to questions and comments from interested parties at a public information meeting (information session).
  - Records from a public hearing are maintained for the permit administrative record. No such records are included for a public information session.



- The applicant and all other individuals who believe any permit condition is inappropriate are obligated to raise issues and submit arguments in support of their position ***during the public comment period*** (see 40 CFR 124.13). Depending on what issues arise, it may be necessary to extend the comment period beyond 30 days, or reopen the public comment period. Specific procedures for reopening the public comment period are provided in 40 CFR 124.10.
- After all comments have been received and evaluated, the Agency makes a final permit decision. At the time that the final decision is issued, a response to comments must be prepared and distributed according to the procedures listed in 40 CFR 124.17.
- All changes made from the draft permit compared to the final permit must be explained in the response to comments. Also, a brief description of significant comments received during the public comment period and a response to those comments must be included. The response to comments is part of the administrative record for the final permit and must be made available to the public. Often, the Agency sends the response to comments by mail to the list of attendees of the public hearing and other commentors.
- The administrative record for the final permit (§124.18) must include the draft permit, all comments received during the public comment period, the tape or transcript of any hearing held, any written material submitted at a hearing, the response to comments, any other documents that support the permit (such as correspondence or data submittals), and the final permit.



- Briefly, to review, the public is notified of a draft action, can comment during the published public comment period, can testify at a public hearing, and can review all the materials in the administrative record of the permit. There is still one more way the public can participate and affect the action, even after a final action has been issued -- by appealing the decision.
- The final permit decision is effective 30 days after issuance unless a later date is specified or review is requested (an appeal) under §124.19. The permit may also be immediately effective if no commenters requested changes from the draft permit. Any appeal must be made within 30 days of the notice of the Director's final action issuing the permit (or denial).
- If a request for review is granted, the effect of the contested conditions is "stayed" – that is, put on hold – pending final agency action. If the permit is for a new facility, it cannot commence operation pending final agency action. Only the contested conditions of the permit are stayed; all others must be complied with on the effective date of the permit.
- We often think of the permittee as being the one who would appeal a permit decision, filing a complaint that certain conditions are unreasonable or beyond the agency's bounds of authority. But anyone who participated in the public hearing or commented during the public comment period can appeal a permit. They are limited, however, to appealing the issues they raised in their comments. For instance, a person who commented only on the operating pressure of the well cannot then appeal the waste stream constituents allowed by the permit. Also, any changes that were made from the draft to the final permit can be appealed by anyone.

Unpleasant Surprises

- Other issues that can arise
  - Highly political sites
  - New information at the last minute
  - Public claiming lack of information
- Anticipating issues and planning well can alleviate many of the problems and headaches!

- There are many headaches and problems that can arise from the time a draft permit is issued until it is final and the appeals deadline is passed. It is not uncommon for EPA to be in a position where it cannot satisfy both the regulated entity and the interested public at large. Some UIC permits, like any other Agency action, become embroiled in political arguments or other scenarios that can difficult to manage.
- This is why it is so important to anticipate the issues that are likely to arise and plan for them. For an existing site, have there been recent or historical controversial issues that keep coming up? Be ready for them by preparing a scientifically and regulatorily sound response, even if the issue is not really about the UIC well permit. Check and double check that you have covered all the bases required in preparing the statement of basis or fact sheet, properly public noticing the action, and mailing the notice to all the interested parties on the mailing list. Verify that the newspaper did in fact publish the public notice – sometimes they do not, or it is published late. If your schedule is tight, this can disrupt the process by causing you to have to change the date of the public hearing and end of the public comment period.
- There are many other details about how the newspaper ad is placed, who maintains a mailing list, how you should format the statement of basis and public notice, and so forth. Be certain to coordinate with your supervisor and experienced permit writers and you can follow the right procedures. This helps maintain your own and your Branch's credibility!

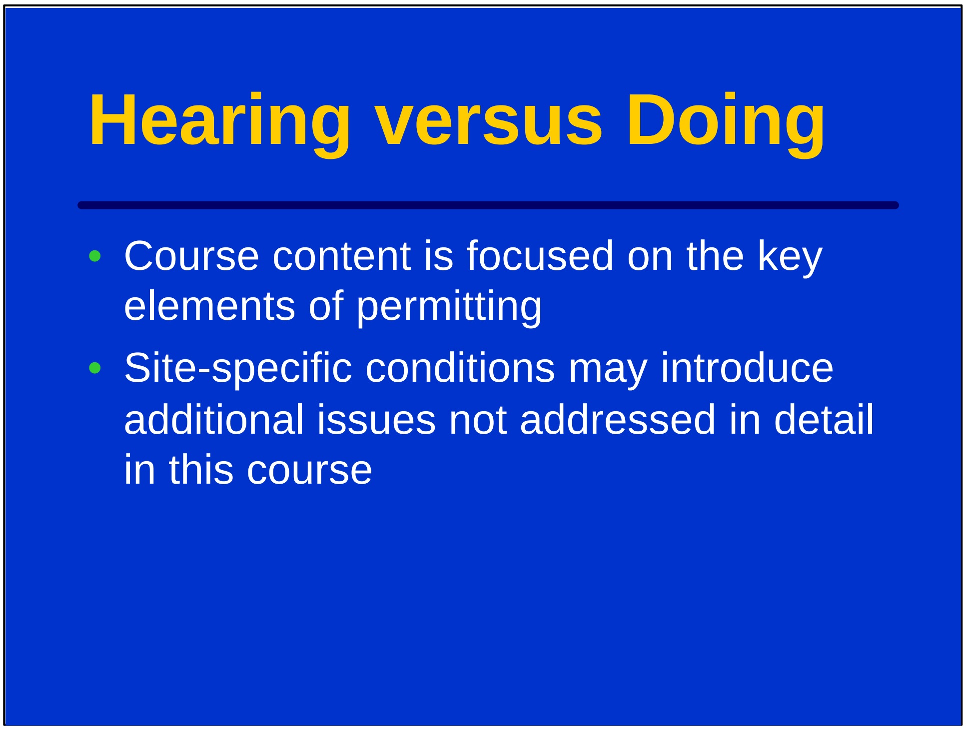
Lesson 21
Summary and Conclusions

- We have covered a tremendous amount of material in this course. We have a few more points, then we will review some applications and permits and discuss further the ways you can implement what we have covered.

Additional Conditions

- Additional conditions may be established on a case-by-case basis
  - To prevent migration of fluids into USDWs
  - To assure compliance with all applicable requirements of SDWA and the UIC regulations

- In addition to all the things that have been covered in the last 21 sections of this course, there is one final permitting point we need to cover. It is a bit of a "catch-all" - the Director has the authority to impose additional conditions through a permit on a case-by-case basis.
- The authority for these additional conditions is found in 40 CFR 144.52(a)(9).
- Conditions may be added "as necessary to prevent the migration of fluids" into USDWs, and to "provide for and assure compliance with all applicable requirements of the SDWA and [40 CFR] parts 144, 145, 146 and 124."
- The rule also defines what an "applicable requirement" is, for both EPA DI programs and primacy State programs.
- This authority provides the permit writer with one final opportunity to insert permit conditions as necessary where all the other conditions may not be specific or stringent enough. For instance, if ground water monitoring is determined to be essential at a site to ensure USDWs are protected, it can be required under this authority.
- It is important to exercise this option with care, however, as requirements not specifically spelled out in the regulations are often appealed by the permittee. As with any other permitting decision, make sure you have a strong technical justification for any conditions developed under this authority.



- The content of this course was based on the key elements that are required to be addressed in a permit application for a Class I, II or III well. Many of the topics are also applicable to Class V wells that are required to be permitted.
- However, site-specific conditions will often arise that are not addressed in detail in the course materials provided in these slides and notes.
- Additional reference materials are provided in the appendices to this manual. You should familiarize yourself with them, so you can reference them later as the need arises.
- EPA has produced a large number of guidance documents that will be valuable references when dealing with permitting issues. You can view a list of all available guidance documents on the Web at:
  - **www.epa.gov/OGWDW/uic/uicguid.html**
  - If the guidance document you need is not available through a link, check with others in your Region to see if they have copies.
- We have noted repeatedly that experienced co-workers are a great resource for information. Members of the national UIC Technical Workgroup can also be contacted for a variety of questions. Your Region has a member on the Workgroup who can answer your question or put you in touch with other members across the country with diverse areas of expertise.

Conclusions

- Consult other technical resources (see appendices to this training manual)
- Ask questions of the owner/operator
- Use a team approach to deal with areas that are new to you

- A variety of other technical resources are listed in the appendices to this training course. Many of the topics we covered are highly technical, and additional training in some of these areas (either formal or informal) may be necessary.
- The owner/operator submitting the application should be able to answer many questions regarding the specifics of the proposed well and operations. Definitely ask for additional information where the application is not clear or does not provide enough specific detail. The permit needs to be as clear as possible about how the well will be constructed, operated, maintained and monitored.
- Use a team approach by utilizing the experience of others, not only in UIC but also in other programmatic areas that are relevant, to deal with permitting issues that are not familiar to you.
- It is to everyone's advantage to have a clear and strongly enforceable permit. The owner/operator needs to know what is and is not allowed, and the conditions of the permit need to ensure that USDWs are protected. Refer often to resources such as this training manual and your co-workers, and you should be able to master the art of effective permitting!