

IX. DRILLING PHASE: DRILLING, CASING AND COMPLETION OPERATIONS

A. INTRODUCTION

After the well and access road have been sited and constructed, as described in the previous chapter, the operator moves in a rig and starts the drilling phase of operations.

Prior to the commencement of drilling operations, a person who has been issued a drilling permit must notify by certified mail any local government and any landowner whose surface rights will be affected by drilling operations [ECL 23.0305-13]. This notification is required to those whose property may be potentially affected by drilling activity and so that local jurisdictions are aware of activity taking place in their areas. **This notification should be required at least five business days prior to the beginning of drilling operations and local jurisdictions should be notified through the clerk of the county, city or town, and village whose land will be physically affected.**

DEC must be notified in writing or by telegram prior to starting actual drilling operations under the current regulatory program [6NYCRR Part 554.2]. This provision is necessary so that the Department is aware of, and can monitor activity provided for in the permit as necessary. **It is recommended that these regulations be revised so that notification take place a minimum of 24 hours in advance by telephone.**

The permit must be prominently posted at the drill site and the permit expires if drilling operations do not begin within 180 days [6NYCRR Part 552.3(c)]. **It is recommended that this regulation be revised so the 180 day time period can be extended to 12 months.** An effective time period for each permit is needed. If too much time elapses before drilling begins, the environmental conditions under which the permit was granted may change; however, 180 days is not sufficient in some cases for industry coordination and scheduling.

1. Drilling Rigs

The majority of wells in New York State are drilled with rotary rigs. (Figure 9.1). The rig gets its name from the rotational motion of the drilling bit which grinds through rock. Cable tool rigs are an older, less common type of rig that chip rock to a powder by raising and dropping a heavy bit in the bore hole. (Figure 9.2).

Rotary rigs are larger and faster than cable tool rigs and can also drill to greater depths, yield a smoother well bore, and diminish the time water sands are exposed to the drilling process. Cable tool rigs are sometimes favored when there are no pressing time constraints and the operator wishes to save money. Their use, however, is restricted to relatively shallow wells (generally less than 2,000').

The remainder of this chapter focuses on rotary rig operations. However, additional information on cable tool rigs is given when significantly different procedures are involved and/or different regulations apply. Special permit conditions for wells drilled through primary aquifers or in the Bass Island trend are also explained.

2. Drilling Fluids

Drilling fluids must be used when drilling wells with a rotary rig. The fluids are pumped down the drill string, out through holes (jets) in the drill bit and up the wellbore. The moving fluid cools and lubricates the bit and removes the rock cuttings that would otherwise collect at the bottom of the wellbore.

There are four basic types of drilling fluids used in New York State: air, freshwater, brine and mud. Operators select a drilling fluid based on: 1) its compatibility with the rock formations being drilled through, 2) need to control downhole pressures and 3) cost. Air is the most frequently used drilling fluid in New York State. It is fast and economical, but cannot be

FIGURE 9.1 **TRUCK MOUNTED ROTARY**
DRILLING RIG

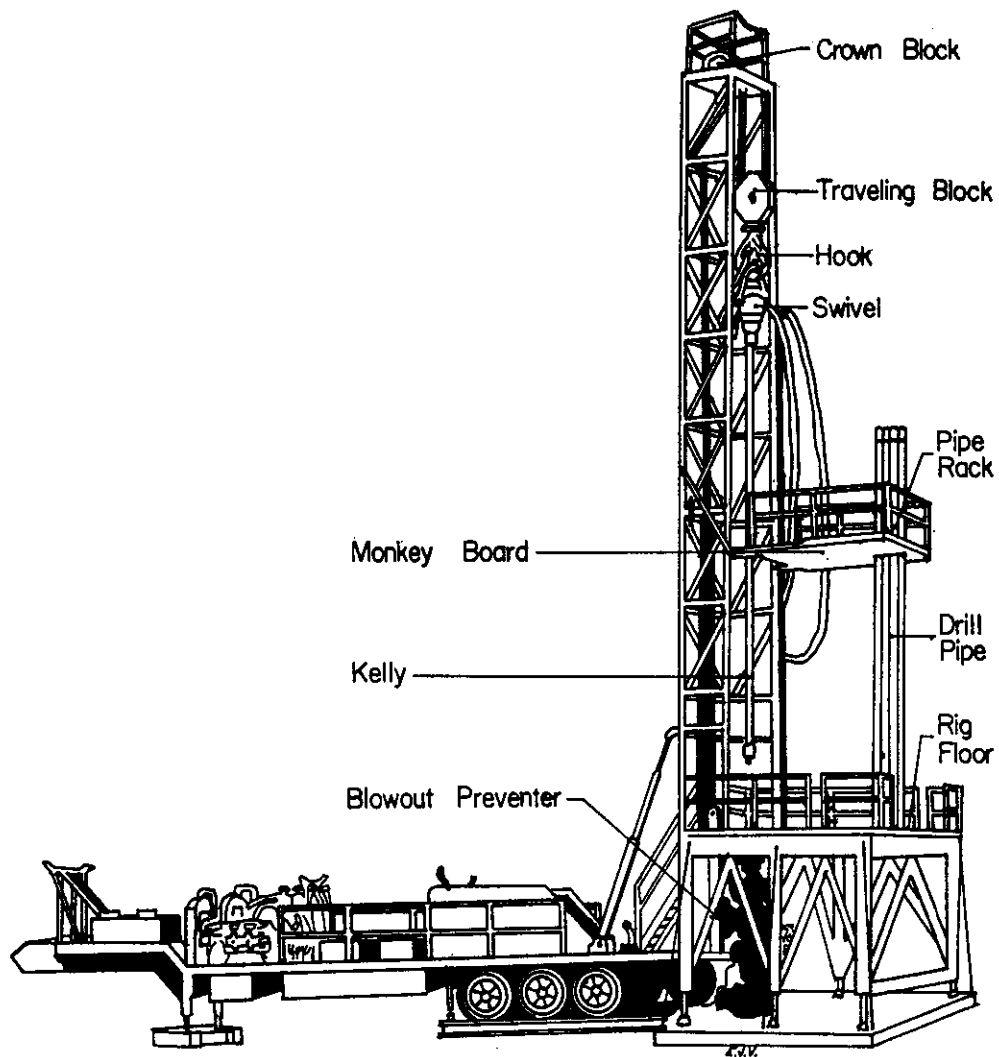


FIGURE 9.1

FIGURE 9.2 CABLE TOOL RIG

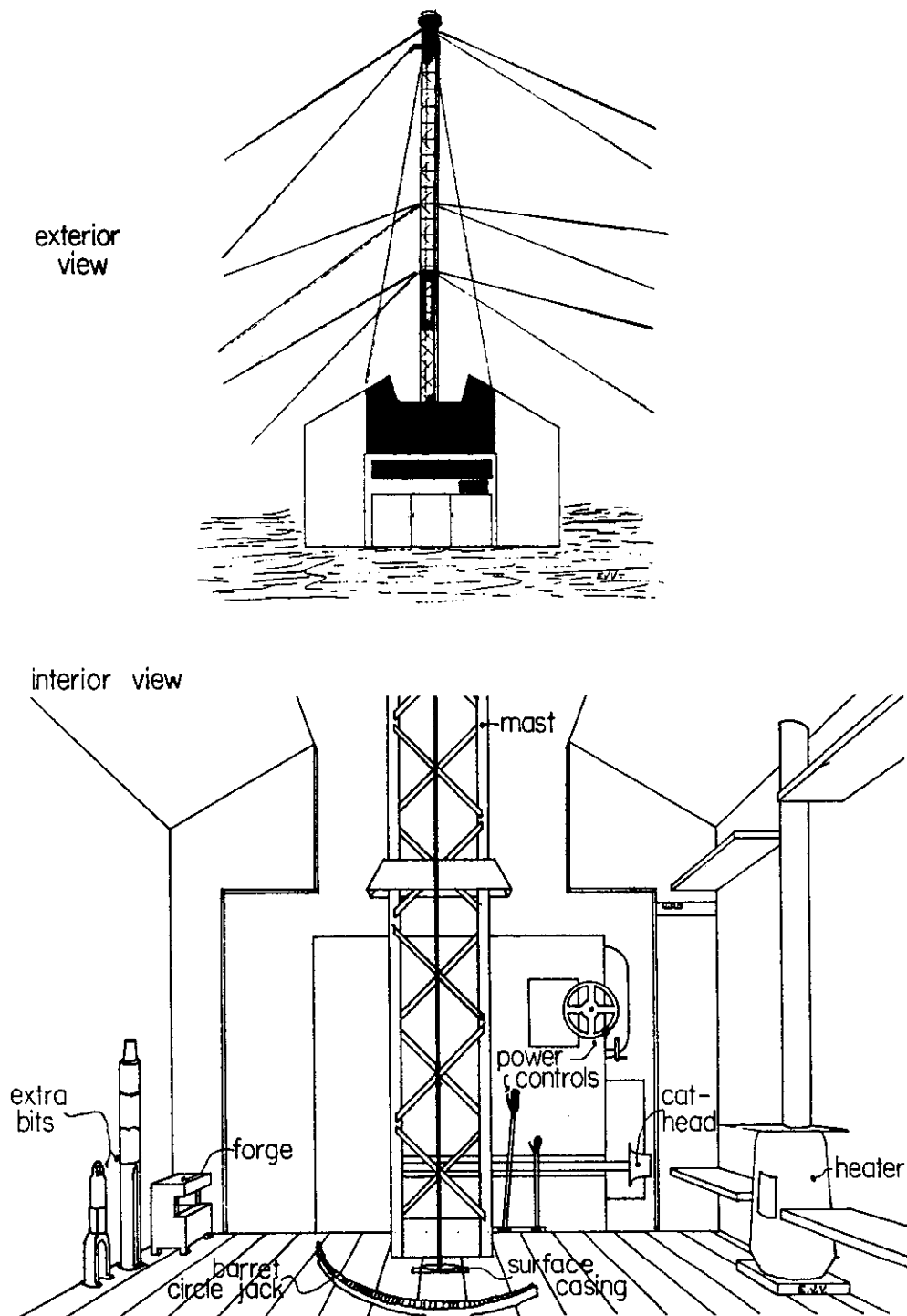


FIGURE 9.2

used when excessive pressures or amounts of water are encountered. Freshwater may be selected when air cannot provide sufficient pressure to control the well. Air or fresh water based drilling fluid is required by the Department when drilling through freshwater aquifers.

Brine (salt water) is sometimes employed as a drilling fluid because of the physical and chemical characteristics of the rocks that are being drilled through. For example, a fully saturated brine must be used when drilling through rock salt to prevent the rock from dissolving and rapidly enlarging the borehole.

Though drilling mud is the most common drilling fluid in the country, it is used infrequently in New York State because it is not needed due to low subsurface pressures. Mud ingredients are expensive and the use of mud slows the drilling rate thereby increasing drilling cost. Mud is sometimes also difficult to dispose of properly. In New York State, mud is generally used only in specific instances such as spudding (starting) wells or drilling the surface casing hole through thick shallow gravel deposits. It may also be needed and used when unusually high formation pressures or volumes are encountered.

The changing conditions encountered as the well gets deeper frequently require changes in the properties of the drilling fluid. The fluid can be altered as needed by the addition of special chemicals. These chemicals include such things as surfactants, foaming agents, corrosion inhibitors, weighting materials, fluid loss control additives, and bactericides.

3. Casing and Cementing

A good casing and cementing program is essential to protect groundwater quality and provide well control. From the operator's viewpoint it is also essential to the future production potential of the well.

Casing is heavy metal pipe that is used to prevent the borehole from caving in. Once the casing is cemented into place it also plays an important role in preventing fluid migration and protecting freshwater aquifers. Three strings of casing are normally set in New York State wells. A short conductor casing at the top of the well keeps soil, sand and gravel from sloughing into the borehole and filling in the well. A small diameter surface casing is set inside the conductor casing and extends beneath the deepest freshwater zone to protect it from contamination. In some instances, an additional casing string, called an intermediate string, is necessary because of a lost circulation zone or other hole problems. The last string, known as "production casing" extends the full length of the well and is used to carry hydrocarbons from the producing horizon to the surface.

4. Drilling Safety Considerations

Injuries to oil and gas field service employees occur at about twice the rate as for general industry employees and, of this group, oil and gas drilling workers are exposed to even greater dangers due to the nature of this type of work (U.S. Dept. of Health and Human Services, 1983). The Federal Occupational Safety and Health Administration (OSHA) has proposed rig safety regulations for drilling operations, but as yet, it does not have requirements for routine drilling operations. Therefore, it is important for drilling operators, in the absence of strict guidelines, to ensure that drilling activities are conducted in a safe manner. A sound safety program helps guard against drilling accidents which could cause environmental damage as well as injure employees. A good safety program also has the added benefits of lower insurance rates, lower maintenance costs, fewer employee benefits claims, less lost production or productivity, and fewer legal fees and settlements.

Some of the most common accidents associated with drilling have to do with working the slips, tongs, catlines, and elevators which are used to

handle the drill pipe, and other heavy drilling equipment. Slippery rig floors and cable breaks also contribute to accidents. Injuries to the derrickman are common either from falling or being hit by swinging objects. Uncommon accidents include catastrophic events such as blowouts or the collapse of the derrick or mast.

Employee training programs are an important component of accident prevention. Accidents are also reduced when employees are trained properly, well oriented, motivated and retained to become career oil field staff. Training of staff should include information about basic principles of a well drilling operation: 1) the safe work operations and hazards associated with the job, 2) purpose and operation of drilling equipment, 3) Hydrogen sulfide detection and safety equipment as well as emergency procedures, 4) fire protection and control, 5) emergency escape procedures for employees working on the derrick mast or in confined spaces, and 6) information about personal protective equipment.

Many drilling sites are located in rural areas of New York. Therefore, it is advisable to post first aid and emergency procedure information in a conspicuous place should these be needed in the case of an accident. First aid equipment, appropriate telephone and/or radio numbers, an arm and leg splint, a heavy blanket and a stretcher are recommended to be on hand in case of an emergency.

Employee clothing should be well fitted (not loose) and include long sleeves and pant legs. It is also advisable that employees not wear jewelry, that hair be short or tied-back, and safety shoes, hard hats, goggles, face shields for welding, safety glasses and/or hearing protection be worn as needed. Employee protection against falls also needs attention. Measures such as safety belts, lifelines and lanyards of suitable strength, safety nets for

work areas more than 25' off the ground and ladders in place of "riding" climbing devices should be installed to safeguard workers in the event of a fall.

Precautionary measures for the drill site would include proper lighting for working at night, and the prohibition of flame heaters in doghouses or outbuildings. Drill sites need to have no-smoking area designations and fire and explosion protection equipment. Firefighting equipment needs to be on hand. DEC currently requires a blowout prevention plan from all operators in the Bass Island trend. Responsibilities of individual employees in such an event are to be posted in the doghouse. In addition, the local fire department must be called in the event of a blowout. It is also recommended that operators make regular operating tests of blowout preventers and conduct kick response training in order to be prepared in the case of an accident. Where blowout preventers are required, they should be actuated and tested with rig air or another approved method before drilling out the shoe of the surface casing.

Other precautionary measures to guard against fires or other accidents include proper grounding of derricks or masts, electric cords and receptacles from lightning and static electricity, use of appropriate containers and portable tanks for handling combustible liquids, use of cleaning materials that have a flash point greater than 100°F, and locating fuel storage tanks some distance, such as 50' to 75', from a wellbore.

Routine inspections, testing and maintenance of rig components also help avoid accidents from drilling operations. Daily inspections should include all functional operating mechanisms, the drill string weight indicator, air or hydraulic system parts for deterioration or leakage, bending of hooks, hoist or load attachment chains, rope slings, and rope reeving. Periodic inspections should also be conducted of bails, elevator links, upper side hook

saddles, A-leg pins, housing, and hoisting mechanisms. Drilling equipment tests might include load tests of repaired or altered rigs, and operating tests of new and/or altered hoisting equipment. Adjustments and repairs should be done promptly and equipment maintained to the manufacturer's specifications.

The Department's regulatory program addresses some safety concerns. These are primarily oriented towards oil wells and operations. The existing regulations require the following:

- a. The operation of any well, lease or unit shall be such as to keep each well location and unit installation free of rubbish, debris, dead grass, brush, weeds, and other flammable material. In addition, all waste oil shall be disposed of in a manner which will not create a fire hazard [6NYCRR Part 556.4(b)].
- b. At the Department's requirement when it deems it necessary to protect life, health, or property, the owner or operator must construct around any storage tank or other tank an earthen dike having a capacity of at least one and one-half times the capacity of the tank it surrounds. This dike must be continuously maintained; and the reservoir it creates must be kept free of vegetation and water [Part 556.4(c)].
- c. At any time when oil or gas is lost from wells or pipelines, receiving tanks, storage tanks or receiving and storage receptacles and creates a fire or pollution hazard or exceeds 100 barrels of oil in aggregate, or 3 million cubic feet of gas in aggregate, the DEC regional headquarters must be notified within five days after the event. A report of remedial measures being taken to correct the situation must also be given to DEC [6NYCRR Part 556.4(d)].

New regulations require that any loss or spill of oil or gas from pipelines and gathering lines, receiving tanks, storage tanks or receiving or storage receptacles must be reported to the DEC's Division of Water, Bureau of Spill Prevention and Response. Their Hot Line phone number is 1-800-457-7362. The Division of Mineral Resources will retain jurisdiction over spills and leaks at the wellhead. The appropriate Regional Minerals office should be notified immediately of any wellhead leak of more than one barrel of oil. It is also recommended that the Department's regulations reinforce further the need to conduct safe operations by stating that the owner or operator must perform all operations in a safe and workmanlike manner and must maintain all equipment in a safe condition for the health and safety of all persons and for the protection of the well, lease, or unit and associated facilities. Additional language for the regulations should direct the owner or operator to immediately take all necessary precautions to control, remove or otherwise correct any health, safety, environmental, or fire hazard and only personnel who are trained and competent to drill and operate wells be used in well drilling operations. Oil and gas well drillers must be registered in New York State.

B. CONDUCTOR CASING

Conductor casing is the short string of casing (20' to 40') set at the very top of the well to keep surficial sediments (soil, sand, gravel, etc.) from filling the wellbore. In locations where the sediments are unusually soft, the conductor casing can also support some of the wellhead load.

When the hole for the conductor casing is drilled, a lightweight mud is generally used as the drilling fluid to help hold the wellbore open. In most cases because of the difficulty of drilling in loose surficial deposits, the conductor casing is simply driven into the ground. The conductor casing has normally been cemented only when the conductor hole was drilled or cementing

was required as a permit condition. The general practice of driving casing into the ground leaves little clearance for cement between the pipe and the material it penetrates. Since February 6, 1985, however, operators using a conductor string in primary aquifers, have been required to cement the conductor casing to prevent the possible downward flow of pollutants, along the outside of the casing to freshwater zones.

If the conductor casing is set in a drilled hole, it must be cemented in place before drilling can continue. The operator must calculate the amount of cement needed to fill the space between the conductor casing and borehole wall and use at least that amount in the cementing job. For wells drilled in principal and primary aquifers, operators are required to use a calculated 50 percent excess in cementing the conductor casing. If circulation to the surface is not achieved, even with the excess cement, then the operator must grout cement down from the surface to achieve a complete cement bond. Grouting is done by inserting a thin piece of tubing known as the macaroni or spaghetti string between the borehole and the outside of the conductor casing. Cement is pumped through the string until the space is filled with cement.

When the conductor casing is driven and there is no clearance around the outside of the pipe, the operator must grout from the top of the casing to form a protective cement pad around the conductor if this casing string is not recovered when surface pipe is run. The pad must have a minimum diameter of three feet, minimum thickness of six inches at the casing and a minimum thickness of four inches at the outer radius. The pad must also slope away from the casing in all directions to further ensure that surface pollutants do not enter the subsurface at the top of the conductor casing.

Drilling of the well below the conductor casing cannot resume until the cement has been allowed to set. Operators usually wait 8 to 10 hours for the

cement to harden, though the process can be accelerated with special additives. Depending on weather conditions, 8 to 10 hours may be insufficient to harden. Failure to wait until the cement is dry can disrupt the bond between the cement and the casing and provide a conduit for pollutants.

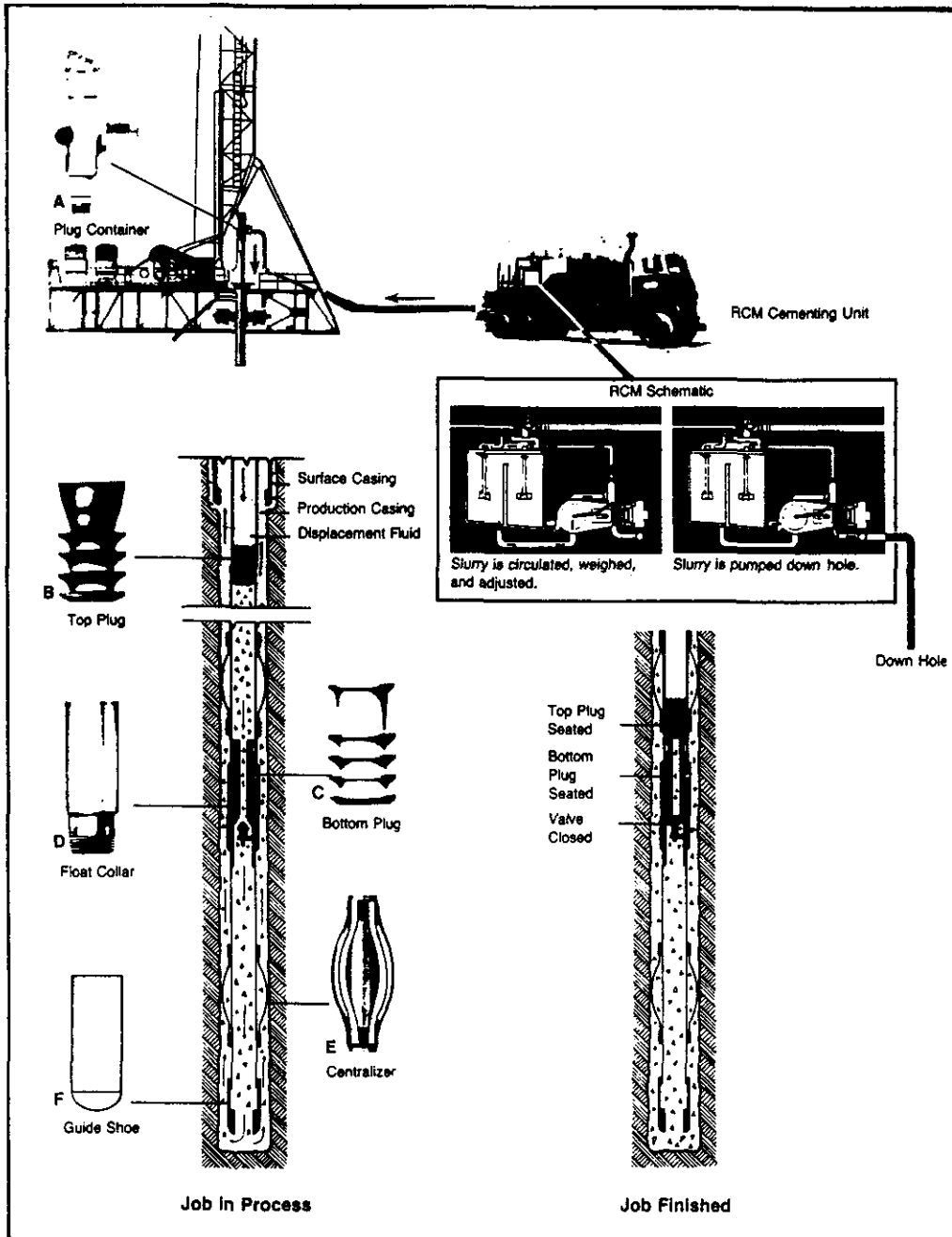
C. SURFACE CASING

The primary functions of the surface casing are to provide an anchor for well control equipment, prevent water zones from flooding the wellbore and protect freshwater zones from contamination by gas, oil, brine, drilling fluid or any other substances that may be present in the wellbore (Figure 9.3). Operators must cement enough surface casing to contain any pressure on the blowout prevention equipment that may be encountered further downhole. This requires that the surface casing be set into competent bedrock. Existing statewide casing regulations adopted in 1966 require that casing be set below the deepest potable freshwater level [6NYCRR 554.4(b)]. The length of the surface casing is generally between 300' and 500', though a survey of Well Completion Reports shows individual instances of shorter as well as longer casing lengths.

Cement in the annular space around the surface casing restricts the movement of fluids between formations as well as between formations and the surface. In terms of protecting groundwater resources, adequate annular cement jobs help prevent the contamination of fresh groundwaters.

Most operators run surface casing in their wells. However, current regulations allow them to eliminate the surface casing if the production casing is cemented from total depth to the top of the well in areas where the pressure characteristics of the subsurface formations have been reasonably well established by prior drilling experience [6NYCRR 554.4(a)]. With the exception of the Bass Island trend, which wasn't discovered until 1981, the producing formations in New York State are generally well known and have low

FIGURE 9.3 PRIMARY CEMENTING PROCEDURES



Cementing a well helps accomplish the following:

- o Bonds and supports the casing.
- o Restricts fluid movement between formations, e.g., to prevent contamination of fresh water zones by hydrocarbons or salt water.
- o Seals lost circulation or thief zones.
- o Protects casing from corrosion due to subsurface mineral waters and electrolysis from the outside.
- o Protects casing from shock loads when drilling deeper.

*figure taken from paper by Charles George, Ronald Paul, Halliburton Services, Duncan, Oklahoma - Cementing Techniques for Solution Mining Wells and Salt Storage Domes: The State-of-the Art - Symposium Proceedings Salts and Brines '85.

FIGURE 9.3
9-10a

formation pressures. Therefore, surface casing can be omitted from many wells under the existing regulations. However, as a practical matter this is rarely done because the surface casing is required for freshwater protection and well control. **It is recommended this practice be restricted to areas where it has been proven no subsurface pressures or freshwaters exist.**

When surface casing is utilized, existing regulations require that it be cemented from below the deepest potable freshwater zone to the top of the well. The drilling of the well cannot resume until the cement has been allowed to set in accordance with prudent current industry practice. Operators usually wait 8 to 10 hours or longer for the cement to set or harden, though the process can be accelerated with special additives.

Inadequate cement jobs can result from the industry's tendency to rely on a standard "recipe" of cement weights and additives. This is a particular problem when shallow shale gas is encountered behind the surface pipe. The gas "cuts" the wet cement, creating micro-annular channels that allow surface leakage of gas behind the casing. In addition, many New York operators do not follow the general industry practice of reciprocating (rotating or moving) the pipe during cementing operations which, though not as important for air drilled holes as it is for holes drilled with mud, provides for a more even distribution of the cement. Pipe cannot be reciprocated if cement baskets are used. Many operators also feel centralizers interfere with or are damaged by reciprocation, however, use of more substantial centralizers could avoid that problem.

During the waiting-on-cement (WOC) time, there should be no activity on the rig, such as installing the blowout preventer and picking up or laying down drill pipe and collars. Any jostling can disturb the cement.

If there is any question about the adequacy of the cement job, the

operator may be required to run a temperature and/or cement bond log and/or do expensive remedial work. The order to run the log may be given by the State Inspector present during the cementing operations or during a routine well drilling site inspection. Site inspections are conducted at least once during the drilling of every well to determine if all the conditions of the permit are being followed. The inspections usually occur after the surface casing is set but before the production string is cemented except in primary or principal aquifers where inspectors are required to be on location during the cementing job on the surface casing. Inspection staff pay particular attention to the depth of the surface pipe and whether cement circulation was achieved. They also check the wellbore diameters listed on the driller's records. This information will be required for every well when a new version of the Completion Report Form is issued in the near future. It is needed to compare the size of the annular space against the number of sacks of cement used to seal it off.

Since November, 1982, operators drilling in primary aquifers have had to comply with detailed surface casing requirements. An 8 5/8" freshwater string (surface casing) had to be set a minimum of 450', or 100' into bedrock, whichever was greater. The cement for the surface casing had to be circulated back to the surface using a calculated 50 percent excess and the casing had to have a minimum bursting pressure of 1,800 psi. A State Inspector had to be present during the surface casing cementing operation and the cement had to contain lost circulation material to help ensure adequate cementing results. A minimum of two cement baskets and centralizers had to be run at appropriate intervals during the surface casing cement jobs to help guarantee a sound cement job. Centralizers center the casing in the wellbore and cement baskets are used where the weight of the cement column might break-down the formation. The Bass Island permit conditions also require cement baskets and centralizers

for cementing the surface casing but specify only that an "appropriate" number of them be used.

In the event cement circulation is not achieved, cement has to be grouted down from the surface (or squeezed) to form a complete cement bond around the casing.

1. Recent Revisions

As a result of public comments made at a hearing on December 19, 1984, the casing and cementing requirements in the aquifer permit conditions were revised in February, 1985. The changes will remain in effect until the final Generic Environmental Impact Statement (GEIS) on Oil, Gas and Solution Mining is published. After the EIS has been reviewed and comments have been received, the Department will decide whether the revisions should be retained as is or whether other aquifer permit conditions are needed.

As of February, 1985, the 450' specification on the permit conditions has been dropped and all surface casing in primary and principal aquifers must be set a minimum of 100' into bedrock unless shallow gas is present. The pipe used for the surface casing must be either new API graded pipe with a minimum burst pressure of 1,800 psi or reconditioned pipe that has been tested to 2,700 psi. If reconditioned pipe is used, an affidavit that the pipe has been tested must be submitted to the State Inspector before the pipe is run. The length of the advance notice given the Department prior to cementing the surface casing has been increased from 4 to 8 hours and the permit condition has been reworded to stress that the cementing may not commence until a State Inspector is present.

2. Further Revisions

The Department has significantly strengthened its regulatory requirements for oil and gas wells drilled in primary and principal aquifers, but potable

groundwater, outside of the major aquifers, is found throughout the State.

Over two million people in upstate New York are served by private water wells and many of these wells are in small isolated or bedrock aquifers (NYS DEC Division of Water, 1985). Because of numerous complaints involving oil and gas in water wells in these areas, the Department has made an extensive review of existing cementing and casing practices for both oil and gas wells.

In the review on drilling and completion practices for oil and gas wells, the Department found some drilling and completion practices deficient with respect to long-term protection of groundwater with a high degree of certainty.

The revised casing and cementing guidelines are designed to mitigate and alleviate the following problems:

1. potential gas and fluid migration into groundwater;
2. gas channeling through cemented annuli;
3. migration of fluids from one stratum to another;
4. repressurization of old oil field areas by natural gas wells drilled to deeper horizons; and
5. ensuring the long-term integrity of oil and injection well completions to preclude future problems.

The new cementing guidelines were implemented April 1, 1986.

SURFACE CASING

1. The diameter of the drilled surface hole shall be large enough to allow running of centralizers in recommended hole sizes.
2. Surface casing shall extend at least 75 feet beyond the deepest fresh water zone encountered or 75 feet into competent rock (bedrock), whichever is deeper. However, the surface pipe must be set deeply enough to allow the BOP stack to contain any formation pressures that may be encountered before the next casing is run.
3. Surface casing shall not extend into zones known to contain measurable quantities of shallow gas. In the event that such a zone is encountered before the fresh water is cased off, the operator shall notify the

Department and, with the Department's approval, take whatever actions are necessary to protect the fresh water zone(s).

4. All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi). Used casing may be approved for use, but must be pressure tested before drilling out the casing shoe or, if there is no casing shoe, before drilling out the cement in the bottom joint of casing. If plain end pipe is welded together for use, it too must be pressure tested. The minimum pressure for testing used casing or casing joined together by welding, shall be determined by the Department at the time of permit application. The appropriate Regional Mineral Resources office staff will be notified six hours prior to making the test. The results will be entered on the drilling log.

5. At least two centralizers shall be run on surface casing. The minimum spacing requirement is one per one hundred-twenty feet. Cement baskets shall be installed appropriately above major lost circulation zones.

6. Prior to cementing any casing strings, all gas flows shall be killed and the operator shall attempt to establish circulation by pumping the calculated volume necessary to circulate. If the hole is dry, the calculated volume would include the pipe volume and 125% of the annular volume. Circulation is deemed to have been established once fluid reaches the surface. A flush, spacer or extra cement shall be used to separate the cement from the borehole fluids to prevent dilution. If cement returns are not present at the surface, the operator may be required to run a log to determine the top of the cement.

7. The pump and plug method shall be used to cement surface casing. The amount of cement will be determined on a site specific basis and a minimum of 25% excess cement shall be used, with appropriate lost circulation materials, unless additional excesses are specified by the Department.

8. The operator shall test or require the cementing contractor to test the mixing water for ph and temperature prior to mixing the cement and to record the results on the cementing ticket.

9. The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.

10. After the cement is placed and the cementing equipment is disconnected, the operator shall wait until the cement achieves a calculated compressive strength of 500 psi before the casing is disturbed in any way. The WOC time shall be recorded on the drilling log.

11. When drive pipe (conductor casing) is left in the ground, a pad of cement shall be placed around the wellbore to block the downward migration of surface pollutants. The pad shall be three feet square or, if circular, 3 feet in diameter and shall be crowned up to the drive pipe (conductor casing).

WHEN REQUESTED BY THE DEPARTMENT IN WRITING, EACH OPERATOR MUST SUBMIT CEMENT TICKETS AND/OR OTHER DOCUMENTS THAT INDICATE THE ABOVE SPECIFICATIONS HAVE BEEN FOLLOWED.

THE CASING AND CEMENTING PRACTICES ABOVE ARE DESIGNED FOR TYPICAL SURFACE CASING CEMENTINGS. THE DEPARTMENT WILL REQUIRE ADDITIONAL MEASURES FOR WELLS DRILLED IN ENVIRONMENTALLY OR TECHNICALLY SENSITIVE AREAS (I.E. PRIMARY OR PRINCIPAL AQUIFERS).

THE DEPARTMENT RECOGNIZES THAT VARIATIONS TO THE ABOVE PROCEDURES MAY BE INDICATED IN SITE SPECIFIC INSTANCES. SUCH VARIATIONS WILL REQUIRE THE PRIOR APPROVAL OF THE REGIONAL MINERAL RESOURCES OFFICE STAFF.

INTERMEDIATE CASING

Intermediate casing string(s) and the cementing requirements for that casing string(s) will be reviewed and approved by Regional Mineral Resources office staff on an individual well basis.

PRODUCTION CASING

12. The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.

13. Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval. A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.

14. The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the lowest (deepest) full joint of casing.

15. The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.

16. Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way. The operator shall test or require the cementing contractor to test the mixing water for ph and temperature prior to mixing the cement and to record the results on the cementing ticket and/or the drilling log. WOC time shall be adjusted based on the results of the test.

17. The annular space between the surface casing and the production string shall be vented at all times. If the annular gas is to be produced, a pressure relief valve shall be installed in an appropriate manner and set at a pressure approved by Regional Mineral Resources office staff.

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RECOMMENDED CENTRALIZER-HOLE SIZE COMBINATIONS

Centralizer Size Inches	Minimum Hole Size Inches	Minimum Clearance Inches
4 1/2	6 1/8	1 5/8
5 1/2	7 3/8	1 7/8
6 5/8	8 1/2	1 7/8
7	8 3/4	1 3/4
8 5/8	10 5/8	2
9 5/8	12 1/4	2 5/8
13 3/8	17 1/2	4 1/8

Note: (1) If a manufacturer's specifications call for a larger hole size than indicated in the above table, then the manufacturers specs take precedence.

(2) Check with appropriate regional office for sizes not listed above.

When a well has surface casing that is set at the proper depth and the above guidelines are followed, the only impacts that might occur from drilling in very close proximity to a waterwell are turbidity and temporary loss of the supply. Turbidity and water supply disruption can occur while drilling the surface hole before the protective surface casing is set. When an aquifer is penetrated, the disturbance allows unconsolidated sediments to enter a water supply and create offset turbidity, but only if a subsurface channel of

sufficient porosity and permeability in close proximity is present.

If the surface hole is drilled with the proper drilling fluid, a filtercake will develop and isolate the wellbore. With a filtercake, only minor turbidity a maximum of few feet into a permeable aquifer could occur from the infiltration of the drilling fluid. Cement can also filtrate into permeable aquifer zones if adequate lost circulation material is not used during cementing operations. The majority of these situations are temporary, and ususally correct themselves in a short time. In isolated cases, uncased water wells can cave-in or permeable water channels can be intercepted and re-routed, adversely affecting a water well's quality and quantity of water. In rare cases, the drilling of a new water well may be required.

D. WELL CONTROL

A blowout is an uncontrolled intrusion of fluid (oil, gas, water) under high pressure into the wellbore. The ability of casing to withstand pressure is affected by the grade of steel, thickness of the casing and the setting depth. The casing must be able to withstand unexpected high pressure formations or a pressure kick and the high pressure surges encountered when a well is shut-in to control a threatened well blowout.

1. Blowout Preventers

Blowout preventers (BOP's) have been required since September 1982 on all wells drilled in New York State. Exceptions are granted only if the operator submits a written request for a waiver showing that: 1) the well is not a rank wildcat, 2) the well is neither in or near the Bass Island trend, 3) there has been no prior history of blowouts within a one mile radius, 4) some sort of pressure diverting device will be used on the well to control high pressures. A waiver is never given to wells drilled under aquifer permit conditions.

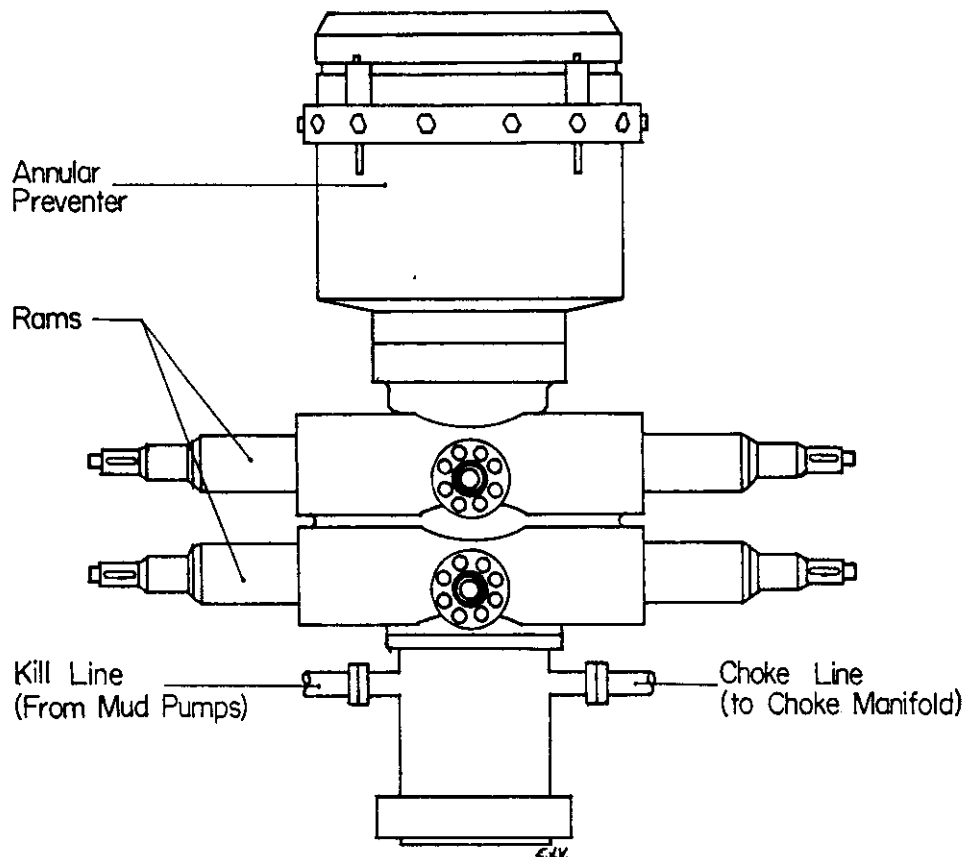
Blowout preventers are manually or hydraulically operated devices installed at the top of the surface casing to seal off fluids coming up the wellbore. (See Figure 9.4). Within the blowout preventer there may be a combination of different types of sealing devices. Pipe rams contain two metal blocks with semi-circular notches that fit together around the outside of the drill pipe when it is in the hole. Blind rams contain two rubberfaced metal blocks that can completely seal off the hole when there is no drill pipe in it. Annular or "bag" blowout preventers contain a resilient packing element which expands inward to seal off the hole with or without drill pipe. Each BOP assembly must contain 1) both blind and pipe rams or 2) a bag or annular preventer, so it can function effectively with or without drill pipe in the hole.

The BOP is flanged and bolted to the spool which is flanged and bolted to the casinghead. The casinghead is welded to the top of the surface casing. If this weld or any other connections in the BOP stack are not sound, the BOP system can fail, resulting in loss of well control, possible damage to the rig, fire and/or loss of life.

To ensure that the BOP will be ready in any emergency, the Bass Island permit conditions stipulate that the BOP cannot be dependent on rig hydraulics for its actuation energy source. If the rig power system fails or the rig area is too dangerous to enter, the BOP can then be operated from a separate power source a safe distance away.

In the Bass Island trend all of the control lines connected to the BOP must be made of high pressure tubular steel with flanged connections. All BOPs have both a choke line and a kill line. The choke line goes to the choke manifold which is an assembly of high pressure flanged pipe fittings with several lateral outlets controlled by manual and/or automatic valves. When activated, the choke manifold assists in maintaining sufficient back pressure

FIGURE 9.4 BLOWOUT PREVENTION EQUIPMENT



Blowout prevention equipment is placed at the top of the well casing and includes one or more devices for closing off the well. Typical examples are:

Annular preventers - equipment containing a packing element which, when activated, will extend into the well-bore and around the drillpipe to form a pressure-tight seal. These are usually used when pipe is in the hole.

Blind rams - a closure mechanism containing two metal blocks which can be closed together hydraulically to seal off the hole. These are usually used when no pipe is in the hole. Blind rams can seal with pipe in the hole by crushing the pipe.

Pipe rams - are similar to blind rams except the metal blocks contain semi-circular notches on the closing edges so that, when the rams are drawn together, they fit around the drillpipe to seal off the well. Pipe rams are used when pipe is left in the hole.

FIGURE 9.4

in the wellbore to prevent any further formation fluid intrusion. The well fluid can then be diverted from the BOP stack to the reserve pit or the mud conditioning area thus relieving wellbore pressure. This allows the operator to pump kill fluid (heavy fluid to hold the well pressure) into the wellbore. The line that diverts fluids to the pit is known as the flow or "blooie" line. In the Bass Island trend, the blooie line must be constructed of T + C (thread and collar) tubular goods with a working pressure of at least 1,500 psi. In addition, the choke line connection to the wellhead must be flanged for extra strength. The Bass Island conditions were placed in final regulations May, 1986.

During the well drilling site inspections conducted on every well, DEC staff routinely check whether a blowout preventer is in place if required. They also check to make sure the flow or blooie line is secured to keep it from whipping around or dismantling in the event of a kick (pressure surge). On Bass Island wells all the pipes and lines must be staked and chained down because of the high pressures or volumes that could be encountered in drilling.

The choke manifold assembly on wells in the Bass Island trend must be flanged and installed no less than 25 feet from the wellhead. The setback is required to allow the crew to continue to use the manifold when the rig area itself is not safe. To help safely control the kick or blowout, the choke manifold assembly cannot contain elbows or T's in its lines, either at the wellhead, or before the choke. The choke line must also be welded from the flange spool to the choke assembly. Certain threaded, flanged and bolted connections are also allowed but the Department will not accept dresser sleeves.

The kill line extends from the mud pumps to the BOP stack and is usually attached to the BOP directly opposite the choke line. In the event of a kick

or blowout, drilling fluid adequate to control flow can be pumped directly through the kill line into the wellbore to overcome the intruding fluids. While drilling in the Bass Island trend, at least 300 barrels of kill fluid must be on site and ready for use if needed. Additionally, appropriate amounts of weighting material and lost circulation material must be on site to aid in well control. To pump the kill fluid in case of emergency, operators must have redundant mud pumping equipment connected to the well in the form of a stand-by service company pump truck or a secondary mud pump.

Almost all operators test their blowout preventers for leaks after installation. Usually the test pressures are only 300 or 400 psi. In the Bass Island Trend and other sensitive areas, however, the Department requires the BOP to be tested to a minimum of 1,000 psi before the surface casing cement can be drilled out. The test pressure is applied to the wellbore through the kill line or the kelly. The pressure is stabilized and the rams, lines, valves, etc., in the BOP are individually tested for leaks by watching for pressure changes at the choke manifold gauge. DEC must be notified eight hours prior to the test so a State Inspector can be present. If the Inspector is not on location at the agreed to time, then the test may continue with the witness' name and the results of the test being noted on the drillers log.

During the BOP test the surface casing is also pressure tested to 1,000 psi. Although the surface casing must be able to withstand 1,800 psi, pressure testing of casing prior to installation is not a requirement. The Completion Report, Notice of Intention to Plug and Abandon, and the Plugging Report that operators submit to the Department should contain information on the casing's grade and weight which directly affect its pressure rating. **Inclusion of such information on drilling permit applications forms which are being revised, will allow Division of Mineral Resources (DMR) staff to review the adequacy of the casing program ahead of**

time and require changes if needed.

E. PRODUCTION CASING

A third string of casing is often set in the well for gas or oil to flow through. It is generally about 4 1/2" in diameter and 1,000' to 4,500' long, depending on the depth of the well. The production hole is usually drilled on air instead of water. Air drilling is generally preferred by operators because it is faster, cheaper and produces smaller quantities of waste. In addition, some oil and gas formations are water sensitive and their producing capabilities can be damaged by contact with water.

While drilling the production hole in Bass Island wells, operators are required to take a number of special precautions because of the potential for relatively high pressures and volumes that have caused a number of blowouts in the past. Most productive areas and formations in New York State have lower than normal (defined as hydrostatic) subsurface pressures. The operator must provide the drilling company with a well prognosis indicating where problem formations such as the high pressure Onondaga may occur, with appropriate warning comments and a listing of emergency duties. Prior to penetrating the Onondaga and associated fractured and faulted formations, the driller must install a new air head rubber in the rotating head. The air head rubber is a device that seals the wellhead at the spool. The rubber, which prevents leakage of gas up the casing, can wear out as the well is drilled. Prior to penetrating the Onondaga, the local fire department must also be notified of the well's location and the potential hazards involved. This requirement can be waived if the company has its own DEC approved firefighting equipment and personnel on standby. To help decrease chances for accidents, every effort must be made to penetrate the Onondaga during daylight hours. In addition, the operator or his designated representative must be on site during the

penetration of the Onondaga to handle any problems that may arise.

Operators are required to cement the production casing in all wells to a sufficient height above the production zone to prevent any movement of oil, gas or other fluids around the exterior of the casing [6NYCRR Part 554.4(d)]. Compliance with this regulation is generally achieved by cementing the casing from the bottom to 100' above the production zone, though exceptions to this are known. Some operators cement the production string from top to bottom as a standard practice.

Wells drilled in the Bass Island trend that are completed in the Medina instead of the Onondaga formation (several hundred feet above the Medina) also have more of their production casing cemented. If there are no hydrocarbon shows in or above the Onondaga and its associated fault zones, the production casing must be cemented back a minimum of 100' above the Onondaga. However, if hydrocarbon shows are encountered, this minimum is increased to 300'.

1. Annular Pressure

Because of high annular pressures exhibited by many wells drilled in the Jamestown Aquifer area and the difficulty of monitoring annular pressures, it is proposed that all future oil and gas wells in primary and principal aquifers be cemented from total depth to the surface. In special cases where extensive surface or intermediate casing is set below the required depth, permission may be granted to cement the production casing 50 feet into the surface casing or intermediate string instead of to the surface. Division personnel have had several meetings with service companies, operators, and the Oil, Gas and Solution Advisory Mining Board to formulate cementing procedures and guidelines that will mitigate this problem. It is now required that all existing aquifer wells be vented or produced with limited back pressure so as to not break down the formation at the shoe of the surface (freshwater protection) casing. The Department may approve in some areas annular

production of shale gases with an annular pressure relief valve set below hydrostatic pressure.

2. Completion and Testing

After the casing is set, the well must be completed. Prior to completion the well may be stimulated and production tested.

Generally some kind of production test is made to determine the productivity of a well. There are various kinds of tests made such as drill-stem tests, bottom-hole pressure tests, potential tests and productivity tests. For a drill-stem test, special tools are run into the well on the drill pipe. Packers isolate the zone to be tested and fluids from the zone flow through the testing (recording) tools into the drill pipe where they are trapped by a system of valves. The fluid sample and recording devices are then withdrawn from the well for examination. The bottom-hole pressure test measures the pressure in the production zone when a specially designed pressure gauge is lowered into the well. A potential test is a measurement of the oil, water and/or gas a well will produce in a 24 hour period under fixed conditions. A productivity test determines the effects of different flow rates on the flowing bottom-hole pressure. The well is produced at several rates and at each rate the bottom-hole pressure is measured.

Sometimes an extensive testing program is conducted prior to completing a well to production. This is especially true for wildcat wells. As many as 20 or 30 zone tests may be conducted on a wildcat well. The testing and evaluation time may take several months and may involve alternate stimulation and testing. Flaring may also be allowed upon approval of the Regional Minerals Manager. **It is recommended that notification of the Regional DMN manager be required prior to any significant changes or time extensions of the originally proposed well testing program, and approval of revisions to the permanent wellbore configuration (casing and cement) proposed in the drilling**

permit application is required.

Open hole completions are the simplest. Instead of running the full length of the wellbore, the production casing is set just above the producing formation. Open hole completions cost less but can present problems. The production interval is much more difficult to selectively stimulate, excessive gas or water production can be difficult to control, and the well may require more frequent clean-outs.

In most new wells in New York State the casing extends the full length of the well and the casing is perforated across the producing zone(s). The holes in the production casing are made with a perforating "gun" that is lowered down the well to the producing zone. The gun pierces the casing with bullets or special shaped explosive charges. The cost of perforating long production zone intervals in this manner may be expensive. Good log interpretations are also critical in determining the correct intervals to perforate. Gas and water zones can be eliminated by selectively perforating and perforated casing completions give operators much better control over stimulation operations. Since most wells in New York State must be stimulated to produce, perforating is the preferred completion method.

F. STIMULATION

Permeability is the ability of a fluid to flow through a porous medium or formation and it is measured in Darcys. All other characteristics being equal, the higher the permeability, the higher the flow rate of gas or oil from the formation into the wellbore. Most of New York State's oil and gas bearing rocks are noted for their unusually low permeability and must be "stimulated", usually by acidizing and/or hydraulic fracturing, before wells drilled into them can produce.

Wells in New York State are usually stimulated in one or two stages. The first stage involves pumping 7 to 15 percent inhibited hydrochloric acid into

the producing formation. The acid will dissolve and enlarge the pore spaces in carbonate bearing rocks and increase the rocks' permeability. Full acid matrix treatment is restricted predominantly to Bass Island wells. However, a light acid treatment is usually given to every Medina well before it is stimulated to clean the carbonate based cement out of the perforations in the production casing. After being spent, the 250 to 500 gallons of acid that were injected at the perforations are returned to the surface with the other waste fluids when the frac job is completed.

1. Water-Gel Fracs

Water-gel fracs are the most common stimulation technique. Twenty to eighty thousand gallons of fluid are injected into the producing formation under high pressure. Approximately 20 pounds of gel are added to every thousand gallons of water. The gel increases the water's viscosity allowing it to carry from 40,000 to 100,000 pounds of sand down the well. Surfactants are also used at the rate of one gallon per 1,000 gallons of water to reduce surface tension. In shallow oil wells, these stimulation operations usually use less than 5,000 gallons of water and only 4 - 6,000 pounds of sand per stage.

Hydraulic fracturing is accomplished by pumping the frac fluid into the formation under high pressure and at a rate faster than the fluid can leak off into the rock. The fluid pressure must build up sufficiently to overcome the rock's compressive strength and the overburden and hydrostatic pressures. In New York the pressure required is usually 2,000 to 3,500 psi. The rock then fractures along a plane perpendicular to the minimum compressive stress. In most areas the minimum stress is horizontal and a vertical fracture results. As injection continues, the fracture grows in width as fluid pressure works against the elasticity of the formation. Once sufficient frac fluid has been injected to open the fracture wide enough, a proppant such as sand is added to

the fluid and carried into the fracture to hold it open after pumping ceases. The word fracture evokes an image like a shattered piece of glass. This is not correct for sedimentary rocks which are elastic in their behavior at depth. The hydraulically induced fracture would close back up without a trace unless propped open by sand. The size of the fracture is also self limiting because the rate of fluid and pressure leak off grows exponentially as the surface area of the fracture increases.

Often the well clean-up after a hydraulic fracturing job must be assisted with coiled tubing and nitrogen. When the frac fluid flows back or is pumped back out of the well, the sand remains behind to "prop" the fractures open. The propped fractures create higher permeability avenues for movement of gas or oil from the formation to the wellbore.

To help maintain the producing formation's permeability, small amounts of chemicals are typically added to the frac fluid. Bactericides are sometimes utilized to prevent the growth of sulfate reducing bacteria that could clog the rock's pore spaces. Additives are also used to prevent clay particles or iron precipitates from plugging off the formation.

2. Foam Fracs

Foam fracs were gaining in popularity a few years ago, but have fallen into some disfavor. The foam contains nitrogen, and pipeline companies in some areas of New York have asked operators to cease using the foam when too much nitrogen, which has no heating value, started appearing in their gas pipelines.

Because of the nitrogen, foam fracturing systems contain only 20 to 40 percent liquid. The low water content makes foam useful for treating clay bearing formations. Hydration or swelling of the clays on contact with the water can plug off production. Foam systems also have a higher viscosity than water-gel systems and therefore can transport larger amounts of sand. Foam

systems are also lighter than water-gel systems and the reduced hydrostatic head enhances well clean-up after stimulation. In addition, foam systems produce considerably less waste fluid because of the lower proportion of water used.

3. Flowback

After the stimulation fluids are pumped underground, the well may be shut-in for one to two hours. Some of the inhibitors, stabilizers and other chemicals added to the stimulation fluid require a period of contact with the formation to perform their functions. When the stimulation fluid is allowed to flowback out of the well, it can occur in one of three ways. Usually a valve on the production string is opened and the stimulation fluid travels from the flow line to a pit. Sometimes this method provides insufficient control over the operation and a large volume of the pressurized stimulation fluid by-passes the pit and sprays into the surrounding areas. Wastes from water-gel fracs can cover the ground and vegetation. Surfactants, foaming agents and gels in both the foam and water-gel wastes can cause moderate to high Biochemical Oxygen Demand (BOD) problems if they enter surface waters (Moody & Associates, 1982-83). The breakdown of these chemicals can remove oxygen from the water to the point where fish and other aquatic organisms are killed. If breaker compounds are added to the initial frac fluid makeup, the problem is lessened. Uncontrolled, high pressure frac fluid returns containing sand, can rip through vegetation, abrade paint off cars, and cause erosion.

The flowback of wastes from rock matrix acid treatments presents different types of problems. The volume of acid used should be carefully calculated so that the carbonate in the producing formation will neutralize the acid as it dissolves. Because of the difficulty in calculating the

correct acid volume and other technical problems, the acid waste returned to the surface may not be completely "spent". Fortunately, acid wastes from perforation cleanup operations are generally too diluted by the volume of the frac fluid to be a concern.

The second flowback method involves installation of a choke on the wellhead. The choke reduces the flow to a manageable degree and allows the returned stimulation fluid to be efficiently directed to the pit. Although this method is generally better, internal sand erosion and failure of the choke can and occasionally does occur. In such instances, a controlled flowback can suddenly become unmanageable resulting in erosion of the pit, discharge of the stimulation fluid onto the ground and other potential problems.

The third flowback method involves the return of the fluid to a tank. Tanks have been steadily increasing in use and are now employed in about 50 percent of the flowback operations. This technique captures practically all of the spent stimulation fluid and enables the operator to determine the volume of fluid that has been returned to the surface. Some operators are reluctant, however, to flowback into tanks for safety reasons. The high pressure of the fluids and abrading action of the sand can eat through metal and cause mechanical failures. Cleaning sand out of the bottom of the tank can also be a time consuming chore.

DEC's existing policies do not specify any one of the three flowback methods. However, a site where stimulation fluids are improperly contained is subject to enforcement action and penalties.

G. COMPLETION REPORTS AND WELL LOGS

Within 30 days after the completion of a well, the operator must file a Well Drilling and Completion Report. The report shows: 1) the size and depth of the casing set, 2) casing grade and weight, 3) the number of sacks of

cement used on each string of casing, 4) the method used for cementing and 5) the estimated top of the cement. In addition, details are given on the type of logs run, the position and number of perforated zones, the type of well stimulation performed, and the results of the initial flow test. The report must also be accompanied by well logs and any other information the Department may require.

A major part of the form is the "Record of the Formations Penetrated". It shows the name and depth of the rock formations encountered in drilling the well. If the exact formation names are not known, rock descriptions are given. Room is also included on the form for reporting: 1) the depths at which any shows of oil or gas were encountered, 2) any measurements or estimates of their volume, 3) the depths at which any quantities of fresh, salt water or sulphur water were found and 4) if possible, an estimate of the producing capacity of these zones. This information has been so rarely included on the Completion Form, that DEC is considering additional regulations to ensure compliance. **As part of the aquifer permit conditions, the operator must keep a record of all water producing zones and report them on the Completion Form. This information is now required throughout the State.** The information is needed to make sure freshwater producing zones have been adequately protected and it may also be helpful in solving any future problems that might develop with the well.

Because of non-compliance by oil and gas operators in furnishing all the information requested in the Well Drilling and Completion Report (form 85-15-7), it is suggested that enforcement action be taken not only for submission of a fraudulent or false report but also for the repeated submission of an incomplete report which does not have all the information requested. Completion Reports are now being returned for missing information.

H. WASTE HANDLING AND DISPOSAL

1. On Site Waste Handling

Proper handling of wastes generated during drilling is one of the most important steps in preventing pollution of land and water resources. With the exception of the rock cuttings from the wellbore, most of the wastes generated are in liquid form and must be stored on site in pits or tanks.

2. Pit Construction

At least one pit must be present at each drilling site to hold waste fluids unless one or more large tanks have been installed. The size of the pit varies with the depth of the well, type of drilling fluid, amount of formation water likely to be encountered, site logistics and the type of rig used. Pits must be constructed with sufficient room to hold any precipitation. Small pits, which are more common with cable tool rig operations, can be as little as 8' wide by 20' long. Most pits have dimensions of approximately 25' x 50' though they can be larger. Pit depths range between 3' and 10'.

A bulldozer is generally used to excavate the pit below ground level and to build compacted earthen embankments around the perimeter of the pit. The presence of large rocks, vegetation or other debris in the earthen dikes can interfere with soil compaction and make the dike more likely to fail. The slopes of both the inside and outside faces of the embankment can also affect the stability of embankments and the use of slopes that are too steep will make them more susceptible to slumping and erosion.

The best type of pit construction will vary with well location. For example, pits are required to be at grade when located on floodplains or in wetlands but an excavated pit is most stable in bedrock areas. The condition of the pit is always checked during site inspections and repairs are ordered for breaches in pit integrity. Operators may be fined if the repairs are

inadequate or if they do not proceed with requested repairs in a timely manner.

It is recommended that a condition be added to drilling permits limiting the angle of the drilling blow-back pit walls to less than 45° when appropriate as determined from the pre-drilling site inspection. This requirement would greatly decrease the chances for pit wall collapse except in areas where pits are excavated in unconsolidated sediments. Once a pit wall collapses it is usually impossible to repair the liner. There can be disadvantages to beveled pits, however. A pit with slanted walls needs a larger area than one with vertical walls and this will necessitate a larger drilling pit and site. In addition, the increased ease of fitting a liner to the slanted surfaces may be offset by the difficulties in handling a larger liner. Availability of a large one piece liner may also be a problem. (See 9.H.3).

3. Pit Liners

Although the existing regulations do mention clay and hardpan as options in pit construction, the Department has consistently required that all earthen temporary drilling pits be lined with sheets of plastic before they can be used. Clay and hardpan are both low in permeability, but they are not watertight. They are also subject to chemical reaction with some drilling and completion fluids. In addition, the time constraints on drilling operations do not allow adequate time for the percolation tests which should be performed to check the permeability of a clay lined pit. Liners for large pits are usually made from several sheets of plastic which should be factory seamed. Careful attention to sealing the seams is extremely important in preventing groundwater contamination.

Waste fluids are often discharged under pressure and the impact can

dislodge or rip the liner. Such problems can be lessened if the operator submerges the flow or discharge line below the surface of the pit fluids. However, if frac fluids under high pressure are discharged to a pit, a submerged discharge line may tear or dislodge the liner. Additionally, many drilling contractors monitor the wells drilling progress by observing flow line returns. **Orienting the pit longitudinally to the flow line or installing a flow line baffle or placing heavy canvas or a plywood sheet at the point of impact can significantly reduce damage.** Tanks or beveled pits may be required to contain frac blow-back. It is recommended that one or more of these actions be taken. Liners can also be punctured by trash and debris thrown into the pit. If Department staff notice trash in a pit during a site inspection, they require the operator to remove it.

Although it is not currently regulated by the Department, liner thickness is one of the major factors in whether it becomes torn during use. Ideally, all liners should be made of Hypalon, PVC or an equivalent plastic and meet certain minimum thickness and strength criteria. Liners currently used in New York State are as thin as 6 mil, but liner thickness is only one criteria of overall strength. See Table 9.1 for a comparison between New York State's proposed standards and the standards specified in other States. **The Department suggests that these minimum standards for pit liners be required by regulation.** Pit standards, like all other proposed standards, can and will be changed with evolving technology.

Several factors were taken into consideration when these pit liner standards were formulated. They include the relatively short time period that New York pits are in use, approximately one week of drilling plus 45 days, and the financial burden on operators. Liner installation practices should include proper preparation of the pit's bottom surface, handling of the liners, and leaving slack in the liner to lessen strain at critical points.

TABLE 9.1

PIT LINER SPECIFICATIONS

L I N E R P R O P E R T I E S	M I C H I G A N ¹	L O U I S I A N A	N E W Y O R K P R O P O S A L
Thickness	20 mil ²	10 mil average	10 mil. minimum
Specific Gravity	1.20	--	--
Minimum Tensile Properties (each direction):			
a. Breaking Factor	46 lb./in. width or 2,300 lb./sq. in.	90 lbs. (Grab Method)	65 lbs. (Grab Method)
b. Elongation at Break	300 percent	--	--
c. Modulus (force) at 100 percent Elongation	18 lb./in. width or 900 lb./sq. in.	--	--
Low Temperature Cold Crack	-15°F	--	-15°F
Dimensional Stability (each direction, percent max. change)	5 percent	--	--
Resistance to Soil Burial (120 day soil burial, percent max. change)		--	--
a. Breaking Factor	5 percent		
b. Elongation at Break	20 percent		
c. Modulus at 100 percent	20 percent		
Seam Strength	80% of Original Material ³ (Breaking Factor)	50 lbs.	80% of original material ³ (Breaking Factor)
Maximum Number of Pinholes	1 pinhole/10 sq. yd.	--	--
Volatile Loss (percent loss max.)	0.9 percent	--	--
Maximum Water Extraction	35 percent	--	--
Tearing Strength	--	25 lb.	50 lb. (Graves Tear)
Bursting Strength	--	140 lb./sq. in.	--

¹Michigan Standards taken from Standard No. 54, Unsupported Flexible Membrane Liners, National Sanitation Foundation.

²Liner does not have to be 20 mil thick if it meets or exceeds all the other specification for virgin 20 mil polyvinylchloride (PVC) as shown in the table. Use of liners other than 20 mil virgin PVC requires written approval by the Supervisor prior to use.

³Seams must be factory installed.

Liner manufacturers have stressed that even their better liners can be adversely affected by poor installation practices. A properly installed thinner liner can often outperform a thicker, more costly liner which has been improperly installed.

Liner seams should be factory installed to insure integrity. It is also very important that the edges of liners be firmly anchored in place. Liner slippage is one of the most common reasons for pit leakage and also one of the most easily corrected. Liners can be anchored simply by mounding dirt over the edges of the plastic. Beveling pit walls to less than a 45° angle can also greatly decrease the chances of liner slippage.

In areas with significant fluctuations in groundwater levels, liner slippage can be more of a problem. If the water table rises above the bottom of the pit, the groundwater may float the liner out from under its anchoring. This is more likely to be a problem in low lying areas such as floodplains. Siting of pits is not specifically addressed in the oil and gas regulations. However, pits in or near freshwater wetlands and floodplains need other DEC permits where pit location can be specified as a permit condition. In addition, DEC staff can restrict the location of pits under general oil and gas regulations prohibiting pollution.

4. Pitless Drilling

Recent research on pitless drilling in the Allegany National Forest indicates this technique may be desirable for shallow, air drilled, Devonian wells in heavily forested areas. In pitless drilling, the drill cuttings, dust and associated brine are discharged directly to the land surface adjacent to the rig. However, the low quantity of brine typically associated with shallow Devonian wells kills fewer trees than clearcutting an area for a drilling pit. In addition, the calcium and magnesium from the drill cuttings

reduces the pH of the forest floor. Regrowth and flora diversity in drill cuttings discharge areas were found to be greater than that of the surrounding forest, one to two years later (Auchmoody, 1986 and Yarosz, 1986).

5. Tanks

Tanks may be temporarily installed on site to hold waste fluids generated during drilling, stimulation or completion. Tanks can completely replace pits, though they are most often used in conjunction with pits to keep brine separated from other waste fluids that cannot be disposed of by roadspreading. For example, in the past operators have elected to store spent stimulation fluids in the tank and the briny wastes produced during drilling in the pit.

Leaks from tanks can cause severe problems depending upon their location, capacity and contents. The most frequently used safety precaution is the construction of an earthen dike around the base of a tank to contain any accidental spills. Under existing regulations, operators are required to surround all permanent oil storage tanks with an earthen dike capable of holding one and one-half times the tanks' capacity where there is a chance an oil spill would result in contamination of surface or groundwaters [6NYCRR Part 556.4(c)]. The space within the dike must be kept free of vegetation, water or oil and the earthen embankment may have to be lined to maintain slope stability and integrity of the earthen embankment in loose unconsolidated soil areas.

Waste storage tanks in floodplains are a special concern. Floodwaters can move a tank off its foundations, and break the tank or the flow lines connected to it, resulting in a spill. A state or local Floodplain Permit is required to install a tank and any other well site facilities in a floodplain. As part of the permit, the operator may be required to anchor the tank to prevent problems.

6. Waste Fluids

Environmental impacts from leakage of tanks or pits can vary considerably. Any of the following combination of waste fluids may be involved, depending on the stage of drilling operations at the time of the accident.

a. Brine or Freshwater Drilling Fluid - Most wells in New York State are drilled on compressed air. If formation water does not occur naturally in the well, a small amount of fresh water is sometimes added at the blooie line to control dust. Surfactants and small quantities of additives are also regularly added to the well during drilling. Soaps are also sometimes added to maintain circulation when water intrusion becomes a problem.

The components of greatest environmental concern in the waste fluids from drilling are the chlorides (salt), trace metals and surfactants.

b. Drilling Mud - Drilling mud may be a simple clay in water suspension or it may also contain special additives to control its viscosity, pH, and other properties. Although it is not commonly used in New York State except when drilling the surface hole, most wells in the United States are drilled with fresh water or brine based drilling mud or fluid.

Used drilling mud is not as likely to be sent to the pit as other waste fluids. It is often reconditioned and employed again on another well to save money. When used drilling mud is present in waste fluids, the mud components of greatest environmental concern that might be present are chromium and sodium chloride.

c. Completion Fluid - A completion fluid is any air, brine, fresh water or mud drilling fluid that has been specifically selected for drilling or completing the target formation. The selection of a chemically incompatible completion fluid can seriously damage the target formation and

prevent it from producing oil or gas. As with all other drilling fluids, the chlorides, heavy metals and surfactants are the major concerns in completion fluid wastes.

d. Acid - If the target formation is a carbonate rock, such as limestone, it may be treated with acid (usually 15 percent hydrochloric) to increase production. The acid dissolves some of the carbonate cement in the rock, thereby increasing the spaces for the oil and gas to flow through. During the process the acid is "spent" or neutralized. The waste fluid, however, can still be slightly acidic when it enters the pit.

Small amounts of acid (250 to 500 gallons) are used in all Medina wells to clean up calcareous cement around the perforations. The spent acid remains in the well during the fracing procedure and is brought to the surface in greatly diluted form with the stimulation wastes.

e. Frac Fluid - Most wells in New York need to be fraced (pronounced fracked) before then can produce economic quantities of oil or gas. The frac fluid base may be brine, freshwater or oil.

Gelling agents are often added to the frac fluid to make it viscous enough to carry sand or some other proppant into the producing formation. Other chemicals similar to those used in drilling fluids are also added. The components of greatest environmental concern in the spent frac fluid are the gelling agents, surfactants, and chlorides. Spent acid will also be in frac fluid if the operator elected to combine acidizing and fracing into one operation. Frac fluids are often stored in a separate tank instead of the pit to simplify later waste disposal procedures.

f. Formation Water/Production Fluid - Most sedimentary rocks are formed by the deposition of sand and other sediments in water bodies, such as the ocean. During rock formation, some water (connate water) is trapped

inside the rock's pore spaces. When a well is later drilled into the rock, some formation water may be released and mix with the drilling fluid present in the wellbore. It is usually the largest component of pit waste fluids. The volume of formation water a particular well produces will depend on the rock characteristics and the operator's drilling practices. High chloride levels (150,000 to 250,000 mg/l Cl) and heavy metal concentrations are the major concern in these wastes.

Produced fluids from the shallow Devonian shales have barium levels from 620 to 786 mg/l and strontium levels from 1,030 to 5,330 mg/l (Moody and Associates, 1982-83). The produced fluids from the Medina sand have concentrations of barium, which range from .40 to 9.65 mg/l, strontium levels from 1,074 to 1,640 mg/l and lead concentrations from 2.8 to 6.0 mg/l (Moody and Associates, 1982-83). Trace amounts of copper (.48 mg/l), zinc (1.08 mg/l), nickel (2.2 mg/l), boron (14.8 mg/l), cadmium (.44 mg/l) and chromium (.41 mg/l) have also been detected in Medina produced waters (Moody and Associates, 1982-83).

Formation water is also pumped from the well during the production stage. Pits must be closed within 45 days after the cessation of drilling operations. However, if production starts within those 45 days, some of the produced fluids may be deposited in the pit. In addition to chloride and low concentrations heavy metals, the production fluid may also contain small amounts of corrosion inhibitors, bactericides and other additives used.

g. Precipitation - Depending upon the season of the year, the pit may contain a large amount of rainwater, which will dilute the concentration of chlorides and other elements in the waste fluids.

7. Environmental Impacts

As mentioned previously, it is extremely difficult to predict the exact composition of the wastes that might be involved in accidental leakage or

overflow of pits or tanks. However, certain components in the wastes that could pose environmental problems have been identified. For the most part, the environmental presence and impacts of these wastes are short term and local. The extent of the impacts in a specific instance will depend on the composition of the waste, the volume spilled, the natural attenuating capabilities of the soil, proximity of sensitive resources, and the success of cleanup operations.

a. Chlorides - Few tests on chloride levels in oil and gas drilling pit wastes in New York State are available. However, chloride analyses were published on 73 pits in Pennsylvania's northwestern gas fields, which are geologically similar to New York's. The chloride concentrations in the pits containing mixed waste fluids (drilling fluid, formation water, stimulation fluid and precipitation) ranged from a low of 5.0 mg/l to a high of 37,500 mg/l. The average chloride concentration was 3,551.8 mg/l. (Moody and Associates, 1982-83). (mg/l and ppm are equivalent measurements of concentration).

Although these figures are useful, they should not be relied on completely for predicting chloride associated environmental impacts of pit or tank leakage. The tests were conducted after the wells had been stimulated and precipitation had fallen. Chloride levels of 100,000 mg/l and higher have been found in drilling pits.

In almost all cases, a single accidental leak from a pit or tank will not pose a threat to ground or surface drinking water quality because of dilution by purer water. However, it has been documented that chloride levels in both ground and surface waters will increase in areas subjected to frequent and prolonged additions of chloride, whether it be from road salting or chronic contamination by chloride bearing wastes. There are no economical treatment

methods presently available for removal of large scale chloride contamination. Citizens are encouraged to report any leaks, so the Department can order timely repairs.

New York State's public drinking water standard for chloride is 250 mg/l which is the salt taste threshold of sodium chloride in water for some people. If the cations are calcium or magnesium, chloride levels as high as 1,000 mg/l may not be detectable from taste. However, the sodium found in combination with chlorides at concentrations below the taste threshold can be a serious problem for individuals with high blood pressure or heart problems.

For additional information on the potential impacts of sodium chloride on plants and soils, see page 9-41 in section 9.H.7.d.

b. Surfactants - Surfactants are surface active substances that are commonly used during both drilling and stimulation procedures. Depending upon the type and amount used, surfactants can control the emulsification, aggregation, dispersion, interfacial tension, foaming, defoaming, wetting, etc., of drilling or stimulation fluids. The composition of surfactants varies greatly, but they all have a base such as methyl alcohol, isopropanol, ethylene glycol or isobutanol, as well as other organic compounds common to detergents.

The major problem associated with waste fluids containing surfactants is their moderately high Biochemical Oxygen Demand (BOD) (Moody and Associates, 1982-83). Aerobic bacteria that feed on the organic compounds in surfactants break them down to simpler more environmentally acceptable compounds such as carbon dioxide and water. During the process, however, the bacteria lower the level of dissolved oxygen in the water. Therefore, the accidental contamination of surface waters with wastes containing surfactants can place oxygen stress on aquatic life and cause fish kills. The degree of the impact will be partly dependent on the age of the wastes at the time of the accident.

If the surfactant breakdown process has already had time to occur in the pit, accidental leakage of the wastes into surface water will not cause a serious problem.

c. Gelling Agents - Gelling agents added to frac fluid thicken it so it can carry sand or other proppants into the target formation. A common natural gelling agent is guar gum. Guar is a leguminous plant whose ground endosperm swells and disperses in water. Both guar gum and other gelling agents, such as carbohydrate polymers, give frac waste fluids a high BOD. Some gelling agents have enzymes or other compounds added that speed up their breakdown and help alleviate BOD problems (Moody and Associates, 1982-83).

d. Heavy Metals and Other Drilling Pit Components - Heavy metals are present in natural hydrocarbons and associated waters in small but measurable quantities because ancient and modern aquatic (usually marine) plants and animals from which petroleum is ultimately derived, selectively uptake and concentrate these metals from seawater. The chemical composition of waste fluids from drilling, stimulation and production of deep gas wells in northwestern Pennsylvania given in Table 15.2 should also be representative of the waste fluids from the geologically similar gas wells operating in New York State. The wastes have measurable amounts of many heavy metals such as strontium (Sr), barium (Ba), lead (Pb), magnesium (Mg), manganese (Mn), copper (Cu), zinc (Zn), aluminum (Al), iron (Fe), nickel (Ni), cadmium (Cd), boron (B), chromium (Cr), and cobalt (Co) (Moody and Associates, 1982-83). Most of these substances can pose an environmental threat to drinking water, aquatic life and/or vegetation if they are added to an area in sufficient quantity over a long period of time.

Over 2 million of the state's citizens are served by small private water wells which draw from low-yielding till and bedrock (NYS DEC Division of

**TABLE 9.2 - QUALITY STANDARDS & GUIDELINES FOR
COMMONLY FOUND INORGANIC CHEMICALS**

All units in mg/l(milligrams per liter) = ppm(parts per million)

CONTAMINANT	(a)* NPDWR	(b)* NYSDOH PART 5	(c)* NYSDOH GUIDELINES	(d)* NYSDOH PART 170	(e)* NYSDEC PART 703
<u>METALS</u>					
Arsenic	0.05	0.05	---	0.05	0.025
Barium	1	1	---	1	1
Cadmium	0.01	0.01	---	0.01	0.01
Chromium (Cr ⁺⁶)	0.05	0.05	---	0.05	0.05
Copper	1	1	---	0.2	1
Iron	0.3	0.3 ¹	---	---	0.3 ¹
Lead	0.05	0.05	---	0.05	0.025
Manganese	0.3	0.3 ¹	---	---	0.3 ¹
Mercury	0.002	0.002	---	0.005	0.002
Selenium	0.01	0.01	---	0.01	0.02
Silver	0.05	0.5	---	0.05	0.05
Sodium	---	---	---	20	---
Zinc	5	5	---	0.3	5
<u>NON-METALS</u>					
Chloride	250	250	---	250	250
Flouride	2.2	2.2	---	1.5	1.5
Nitrate	10	10	---	10	10
Sulfate	250	250	---	250	250

¹ Combined concentration of Iron and Manganese shall not exceed 0.5 mg/l.

*** Sources**

(a) USEPA, National Interim Primary Drinking Water Regulations, 40 CFR Part 141.

(b) NYSDOH, 10 NYCRR Part 5, Public Water Supplies, 6/30/81.

(c) NYSDOH, Guidelines for Organics in Drinking Water.

(d) NYSDOH, 10 NYCRR Part 170, Sources of Water Supply, 8/16/71.

(e) NYSDEC, Ground Water Classifications, Quality Standards, and Effluent Standards and/or Limitations, 6 NYCRR Part 703, 9/1/78.

Adapted from Table II-6, Draft Upstate Groundwater Management Plan, New York State Department of Environmental Conservation, Division of Water, January, 1985.

Water, 1985). Unrelated to oil and gas development, many of the bedrock water wells in some areas of southwestern New York are also high in some of the metallic cations identified above. Citizens with shallow bedrock water wells are advised to have analysis done on their water. Most of these metallic cations can be readily removed by a water softener.

Many of the water complaints received by the Department and thought to be related to oil and gas operations are found unrelated to these activities. The typical contamination sources in rural areas are usually localized and are best controlled and prevented when individuals understand how groundwater works, what potential sources of contamination might threaten their own or neighboring wells, and what to do to prevent contamination. Citizens who are interested in further information on groundwater protection and the health effects of substances in their drinking water are referred to the National Academy of Sciences study, Drinking Water and Health, Vol. I-VI, 1977-1984 and DEC's Draft Upstate New York Groundwater Management Program. Water Quality Standards and Guidelines are given in Table 9.2. These guidelines have safety factors of a hundred to a thousand incorporated.

Predicting the environmental impacts of heavy metals is difficult because of their complex interactions with soils and water. As soil pH decreases, heavy metal mobility increases, which in turn affects the likelihood of ground water contamination and uptake of the metals by plants (NYS DEC Division of Solid Waste, 1982). In research on heavy metals in sewage sludge it was found that landspreading could safely be accomplished if the soil's pH was maintained above 6.5 (NYS DEC Division of Solid Waste, 1982). In portions of New York State, however, soil can have a pH of 5 or lower (NYS Department of Agriculture and Markets, 1958). Ion mobility can also be affected by alkalinity, soil cation exchange capacity, level of organic matter, soil water saturation and other chemicals present (Miller, 1978). Sodium, boron,

cadmium, copper and nickel are the metals that could pose the most serious threats to plant life (Winkler, 1985, personal communication #72). Plants require several micronutrient elements for their normal growth. For example zinc, copper and iron act as fertilizers when present in small amounts (Winkler, 1983, personal communication #72). However, excessive amounts of zinc or copper can reduce plant yields or cause their death (NYS DEC Division of Solid Waste, 1982).

The high sodium chloride levels present in the production brine wastes (31,100 to 417, 000 mg/l) are the most serious threat to plant life. Such excessive concentrations of sodium chloride osmotically inhibit the ability of plants to absorb water (Miller, 1978). Therefore, spillage of brine or other waste fluids high in sodium chloride almost always kills vegetation and sterilizes the soil. However, recent research indicates the soil's plant toxicity is short lived due to the northeast's high rainfall and rapid leaching of the sodium and chloride salts. In addition, the brine has high concentrations of calcium and magnesium which have the beneficial effect of increasing the soil pH. Increase in soil pH helps combat the effects of acid rain and increase plant species diversity in the Northeast (Auchmoody, 1986).

Plant uptake is also a concern because it is the metal's primary route into animal and human food chains. Cadmium is the most likely metal to pose a threat to human health through plant accumulation (NYS DEC Division of Solid Waste, 1982). It is particularly dangerous because of its severe effect on the kidneys. However, experimental data indicate that zinc, which is also present in the waste fluids, may compete with cadmium in plant uptake. In addition, the zinc-cadmium ratio in body organs may deter cadmium's poisonous effects on the human body (National Academy of Sciences, 1977).

The high (250,000 mg/l) total dissolved solids (TDS) level of the pit

wastes could pose a major threat to aquatic life if they spilled into a stream. The combined effect of the TDS levels from the dissolved sodium, calcium, magnesium and chloride alone, could result in fish-kills, deformation of fish larvae and fry and other problems (Newell, 1985, personal communication #49). For this reason, the Department checks not only well setbacks, but pit setbacks from streams and lakes.

8. Waste Disposal

Waste fluids cannot be stored at the drilling site indefinitely. Within 45 days after the cessation of drilling operations, waste fluids must be removed from the pits and tanks and disposed of in an environmentally acceptable manner [6NYCRR Part 554.1(c)(3)]. Under no circumstances may operators fill in a pit before removing waste fluids. The Department occasionally grants extensions to the 45 day limit based on circumstances beyond the operator's control. The most common reasons for extensions are winter weather and the seasonal road weight limits imposed by local governments that prohibit passage of heavy brine hauling trucks during the spring thaw.

Injection wells are the most environmentally acceptable disposal option under DMN regulatory authority. Currently there are three permitted brine disposal wells located in New York. A proposed Memorandum of Understanding (MOU) between DMN and DEC's Division of Water specifically prohibits an operator from injecting waste fluids in, above or immediately below a primary ground water aquifer, such as the Jamestown Aquifer. Although none exist at the moment, a commercial "deep well" disposal unit could be safely built in an aquifer area provided it met stringent requirements. The well would have to be constructed to the standards of both DEC and the U.S. Environmental Protection Agency's Underground Injection Control (UIC) Program. A geological and engineering report would have to be approved by DEC's Bureau of Water Facilities Design in the Division of Water. A SPDES permit from the Division

of Water would also be required which would spell out the strict conditions under which the well would have to operate. The general State brine disposal well permitting guidelines are detailed in Appendix 7. In addition, a federal permit would be required under the UIC program.

Most of the brine wastes produced during drilling and production operations are disposed of by spreading on dirt roads for dust control or on highways for deicing. Brine spreaders must have a Solid Waste Haulers Permit pursuant to 6 NYCRR Part 364 from DEC's Division of Solid Waste. They must also have permission from the local government(s) where the brine waste spreading is to occur and limits are set by local governments on how much and how often brine can be spread.

The concentrated brine which is most useful for road spreading is produced by deep gas and Bass Island wells. The chemical composition of this brine is detailed in Table 15.3. Except for higher concentrations of some metallic cations, the produced brine is similar in chemical composition to commercial road salt and has similar deicing and dust suppression properties (Moody and Associates, 1984). New York State is one of the largest users of road salt. If produced brine, which is less expensive for local governments, were not used, more commercial road salt would be used. According to the Draft Upstate New York Groundwater Management Program, "deicing salt can be a potential threat to groundwater but it should not be considered a "hazardous material" in the Class of petroleum and industrial chemicals. The threat to groundwater quality in Upstate New York from the use of deicing compounds on highway surfaces is considered to be measurable but much less significant than the threat posed by improper storage. The threat to public health and the environment must also be carefully weighed against the safety of highway users" (NYS DEC Division of Water, 1985a). However, the spreading of brine and road salt can cause groundwater quality problems in some local situations.

Specifically, chloride contamination of private drinking water wells has occurred in locations where wells are located close to highways. Where problems have been found, the shallow depth of the wells, poor siting and construction (e.g. relatively direct surface drainage into the immediate vicinity of the well) are usually contributing factors. Therefore, local governments should take special care when spreading road salt or brine in such areas.

The remainder of the wastes produced during drilling operations are disposed of at special, industrial treatment plants in Pennsylvania and Ohio or other out-of-state disposal facilities. On occasion, a local sewage treatment plant may elect to accept drilling wastes if they will not upset the plant's operations. In fact, some sewage treatment facilities need a certain amount of brine for their operations. Should oil and gas development continue in New York State, more local brine disposal wells and industrial waste treatment plants will be necessary because of the very high transportation costs to out-of-state disposal facilities.