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MIST UNOERGROUND STORAGE SITE CERTIFICATE APPLICATION

Oregon Natural Gas Development Corporation

February 5, 1981

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Introduction

Oregon Natural Gas Development Corporation, a wholly-owned subsidiary of Northwest Natural Gas Company, in this application to the Oregon Energy Facility Siting Council, is proposing to convert the Mist gas field to an underground reservoir by constructing some additions to the existing production facilities.

Background of Northwest Natural Gas Company

On January 7, 1859, Portland Gas Light Company, the earliest predecessor of Northwest Natural Gas Company, was granted a perpetual franchise by Oregon's last territorial legislature. Five weeks later, on February 14, 1859, Oregon was admitted into the Union as the nation's 33rd state.

The corporate successors of Oregon's first major utility have continuously served this area without pause for 120 years. In 1979, Northwest Natural Gas Company distributed gas to 237,822 residential, commercial, and industrial customers in western Oregon and southwestern Washington. This includes more than 29% of the residences, 50% of the commercial firms and more than 90% of the major industries with process heat requirements in the areas served.

The Company's exclusive service area, which covers approximately 15,000 square miles, with an estimated population of 2,100,000, includes 77% of the population of Oregon. Approximately 90% of the Company's sales are made in Oregon. A service area map is included with this section.

Natural gas contributes about one-third of all energy consumed in Oregon for non-transportation uses. The Company supplies 84% of the gas sold in the state.

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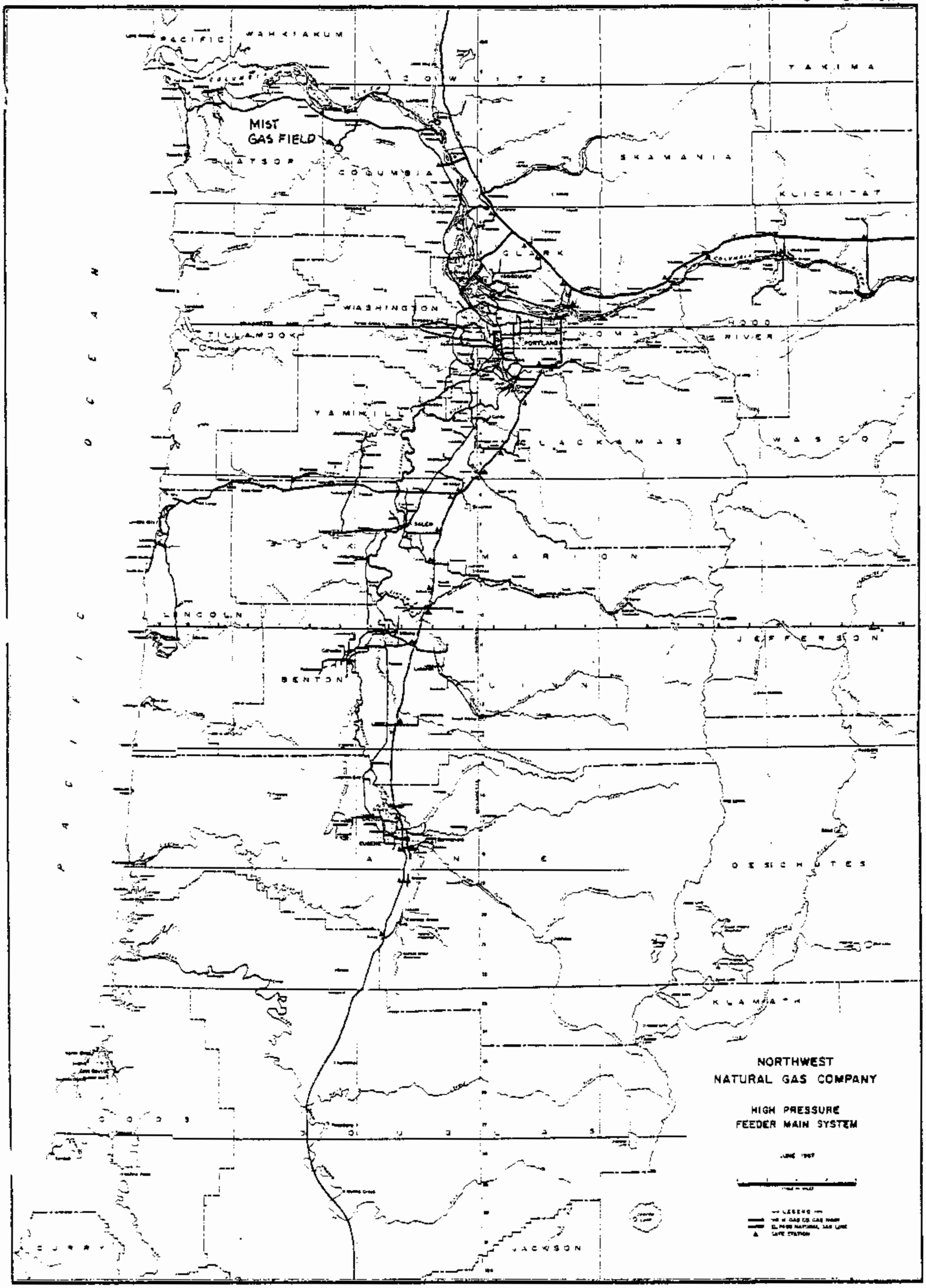
SERVICE AREA MAP



Oregon Natural Gas Development Corporation

In March 1979, in an effort to augment its pipeline supply with a reliable domestic source of natural gas for the future, Northwest Natural Gas Company entered into an operating agreement with Reichhold Energy Corporation and Diamond Shamrock Corporation for the drilling of two gas exploration wells near Mist in northwestern Oregon. Later, during May 1979, the joint venture parties announced the completion of the first gas well with commercial production quantities of natural gas in Oregon.

In July 1979, Northwest Natural Gas Company formed Oregon Natural Gas Development Corporation (Oregon Natural), a wholly-owned subsidiary, to which it assigned its interests in the Mist exploration and development operations. Oregon Natural was charged with the responsibility of developing additional energy supplies for the benefit of the customers of Northwest Natural, more specifically:

(1) To investigate, explore, drill for, find, develop and produce natural gas, oil, coal, and other hydrocarbon and mineral resources, used or useful in the production of energy and for other purposes, on public and private lands, both within and without the State of Oregon;

(2) To gather, market, sell and deliver natural gas, oil, coal and other hydrocarbon and mineral resources in commercial volumes in whatever form for the use and benefit of consumers both within and without

the State of Oregon; and to construct, operate and maintain on public and private lands all facilities necessary or convenient therefore;

(3) To investigate, explore, find and develop underground reservoirs for the injection, storage, operation and delivery of natural gas for the use and benefit of consumers, both within and without the State of Oregon, during periods of peak demand and interruptions in the normal flow of natural gas supplies; and

(4) To cooperate with federal, state and municipal agencies and other persons, corporations, associations and entities, individually and jointly as a partner, associate or otherwise, in the achievement of any and all of the foregoing purposes as a means of supplementing supplies of energy within the State of Oregon and the United States in order to reduce their dependency on the importation of foreign energy in any and all forms.

Oregon Natural Gas Development Corporation, Reichhold Energy and Diamond Shamrock have a joint venture agreement which distributes the gas production in one-third portions. Oregon Natural sells its one-third portion to the parent company, Northwest Natural Gas Company. Diamond-Shamrock is selling its share to Northwest Natural. Reichhold pays Northwest Natural to transport its one-third share to the Reichhold Chemical Corporation's Deer Island fertilizer plant.

At the Mist gas field Oregon Natural is producing all the natural gas. The gas is processed in Northwest Natural's Miller Station and distributed through the Northwest Natural pipeline system.

Mist Natural Gas Production

The field, at a depth of 2500 feet below the surface, is considered to be of shallow depth and production is from marine sediments. The gas at Mist is not oil-associated, it has no condensible components (butane, propane, or heavier hydrocarbons), has trace amounts of sulfur and little associated water. Production processing from wellhead to customer requires only removal of water vapor from the gas stream. The production of natural gas energy, in comparison with electric power generation, is quite simple.

The Mist gas field was discovered in April, 1979, and has been developed with additional wildcat and stepout wells since that time. Gas production was established late in December of the same year when the first volumes of natural gas were transported to existing Northwest Natural Gas Company pipelines through a new 12-inch pipeline. Since then, five producing wells of the seven commercial discoveries have been tied with gathering lines to the gas-processing equipment in Miller Station. Daily production is presently supplying about five percent of the daily supply to Northwest Natural.

At each wellhead, the produced gas has small quantities of water removed in a conventional separator vessel, is measured in an orifice meter and sent to Miller Station through 4, 6, or 8-inch diameter buried gathering lines. Natural reservoir pressure, initially about 950 psig, is sufficient to send the gas to Miller Station and the distribution system of Northwest Natural. In the future, when the natural reservoir pressure drops below normal system operation pressures of 300-500 psig due to the effects of production it will be necessary to augment the flow with small natural gas engine-driven compressors located at Miller Station.

At the receiving point of Miller Station, the gas passes through a second liquid separation vessel and a pressure control system.

The combined gas stream in Miller Station is sent through a triethylene glycol dehydration unit which reduces water levels to about 5 pounds per million cubic feet of throughput gas. After dehydration the gas is odorized with mercaptain odorant, measured and released in the 12-inch transmission line.

The Mist field was developed and is operated in accordance with comprehensive regulations and rules administered by the Oregon Department of Geology and Mineral Industries. It acts as agent for the Department of Environmental Quality, State Fish & Game, Water Resources and other state and federal agencies under a memorandum of understanding between the agencies.

Pipelines and related components of Miller Station were constructed and are operated under safety-oriented codes administered by the Public Utility Commissioner of Oregon as agent for the Federal Office of Pipeline Safety. Pressure vessels were constructed and are operated under the A.S.M.E. Pressure Vessel Code which is administered by the State Boiler Board. Other portions of the project were developed in compliance with the Uniform Building Code as permitted and inspected by Columbia County. Planning and zoning considerations were also administered at the county level. Copies of some of these regulations and codes are set forth in Appendix B hereto.

A number of support systems in Miller Station assist the plant personnel who monitor operations on a 24-hour a day basis. These include: systems for emergency shutdown; compressed air; electronic and pneumatic control; gas quality; potable water; fire protection; radio, and microwave communications; and emergency power. Many of these systems are located in a central operating building. Six plant operators, who work in shifts, control the field production at Mist.

Underground Storage at Mist

A gas utility delivers energy to thousands of customers whose energy needs change significantly on a seasonal basis from factors such as spaceheating requirement, harvest processing, annual production cycles and others. For example, in 1980 the highest daily sendout by Northwest Natural to its customers was 370,672,000 standard cubic feet (scf) on February 15, 1980, compared to the lowest of 92,834,000 scf on July 5, 1980.

Underground gas storage provides the most efficient means of balancing relatively constant pipeline gas supplies with widely fluctuating seasonal, daily and hourly market requirements. Gas is injected into storage during off-peak periods when market requirements are less than supply availability, and is withdrawn from storage when market demand exceeds available supplies from other sources. Storage reservoirs are usually replenished during the April through September period and drawn down between October and March.

Underground reservoir storage requires suitable underground geological conditions in a specific geographic area. These conditions occur in depleted oil or gas fields. The importance of underground storage in the U.S. is shown in a 1979 American Gas Association statistical summary which lists 399 separate underground storage pools in operation in the U.S. These storage fields during 1979 stored an amount equal to a fourth of the annual gas consumption in this country. A copy of these industry statistics on underground storage is included in Appendix C. A comparison of the Mist Project with the national average and total volumes is shown in Table 1.

An understanding of the underground storage of natural gas requires the use of some technical terms:

Cushion Gas: The total volume of gas which will maintain the required rate of delivery during an output cycle. For Mist this rate will be 100 MMcfd.

Working Gas: The total volume of gas in a storage reservoir which is in excess of the cushion gas. Also known as Current Gas in the industry. Working gas volume for the Mist Project will be half of the total volume, 10 billion cubic feet (Bcf).

Native Gas: The total volume of gas indigenous to the storage reservoir at the time gas storage started.

Storage Reservoir: That part of the storage zone having a defined limit of porosity and/or permeability which can effectively accept, retain and deliver gas.

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TABLE I

UNDERGROUND STORAGE IN THE U.S.

	Mist	U.S. Average	Total in U.S.
Underground storage pools	2	1.4	399
Number of active wells	5(later up to 9)	62	17,605
Number of compressor stations	1	1	283
Total installed compressor power	4,000	6,376	1,804,552
Native cushion gas, Billion cubic feet (Bcf)	-	3.69	1,045.6
Injected cushion gas, Bcf	-	8.06	2,280.8
Total cushion gas, Bcf	-	11.75	3,326.4
Working gas, Bcf	10.00	9.77	2,766.1
Ultimate reservoir capacity, Bcf	20.004	26.28	7,436.8
Totals for year ending December 31,1979			
Native gas, Bcf	-	3.73	1,056.0
Stored gas, Bcf	-	17.80	5,036.6
Maximum stored gas, Bcf	-	19.29	5,459.5
Input to storage during year, Bcf	-	8.07	2,285.0
Removed from storage during year, Bcf	-	7.27	2,057.0
Maximum day output Million cubic feet (MMcfd)	100 (design)	94.10	37,555.0

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Storage Well: A cased bore hole, extending from the surface into the storage reservoir, which is used primarily for gas input and/or output purposes. Depending on storage well performance, the Mist project will use two to four storage wells.

Ultimate Reservoir Capacity: The total estimated volume of gas that could be contained in an underground storage reservoir when it is developed to the maximum design pressure.

Nature picked the location of the proposed Mist underground gas storage project. Millions of years ago the present gas producing sands were laid under salt water at a depth of about 1000 feet. Years later, mud settled over the sand. Geologic activity and time turned these zones into harder layers of sandstone and mudstone. Concurrently with this rock formation activity, organic decomposition processes deep in the earth were forming natural gas. Large amounts of natural gas accumulated where gas could displace water between the grains of the sandstone rock. The silt and clay grains of the caprock, located above the sandstone, were packed so close together by natural forces that they formed an impassable barrier to the natural gas. This natural feature allows gas bearing sand zones to be sealed off under the overburden of impervious caprock. The stable nature of these stored gas zones is attested to by extinct underground faults which have been inactive for 10 to 20 million years.

The trapped gas was first discovered in April 1979 on the Bruer Pool when the Columbia County No. 1 well was completed. That year saw the discovery of two more commercially productive wells, Columbia County No. 3 and Columbia County No. 6, on the Bruer Pool and the Columbia

County No. 10 well on the Flora Pool. A fifth well, Columbia County 33-3, was discovered on the Flora Pool in 1980, the following year. Two other commercial grade wells were discovered in the Mist area but will not be included in the storage project.

In the late Summer of 1979 construction was started on the buried gathering pipelines which connect the production wells with Miller Station. Miller Station, which occupies part of an eleven acre piece of property, is the central gathering point for gas production. The gas is collected, measured, treated and odorized in Miller Station before being sent through a 12-inch diameter transmission pipeline to a point where it joins the Northwest Natural Gas pipeline system about 9 miles away, near Clatskanie. The first well production was initiated December 30, 1979, and the last well was brought on line late in 1980. The highest daily production rate of the five wells was prior to April 1981 when 21 MMcfd were produced.

During the latter half of 1981 enough gas will have been produced so the pressure underground will be below the operating pressure of the adjacent Northwest Natural pipelines near Clatskanie. Gas production will continue through pressure augmentation by two production compressors on the Miller Station property. Gas production can continue until the cost of compression is equal to the value of the gas produced. This economic limit allows a gas field operator to recover about 91% of the total underground volume. At Mist, when the abandonment point is reached, the underground gas pressure will be 50 p.s.i.g.

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An underground reservoir, reduced to simplest terms, is little more than a gas production field with some means to inject gas back into the ground. Knowledge of this fact allowed engineers of Northwest Natural to incorporate certain features into the original design. Related mostly to equipment sizing, station layout and design codes, these features allow for eventual use of the Mist Project as an underground storage facility after the shorter-term natural gas production phase is completed.

The principal differences between a natural gas production field and an underground storage reservoir occur in the way that each is operated. It is useful to relate these differences as they occur in the Mist Project.

The gas wells in a production field are spaced at distances prescribed by state regulation. At Mist this allows one well per quarter section or 160 acres. This is done to prevent waste of the underground gas pressure. Closer well spacing could deplete the pressure before the maximum amount, about 91%, of the gas is producted. This production rate limitation means that about 5 years will be needed to produce the maximum recoverable amount of gas from the two gas pools at Mist. The highest production rate at Mist was between September 1980 and April 1981 when a production rate of 21 MMcfd was sustained. As the field pressure is reduced by continued production, the daily production rate declines.

A different operating concept applies for a storage reservoir. Instead of producing the major portion of the underground gas by careful management of field pressures and auxiliary compression over a period of years the goal changes to that of an annual fill and empty cycle. Because the Mist Storage Project design withdrawal rate is 100 MMcfd, a more closely spaced well pattern will be used. Large compressors, used for gas injection, allow the storage pressure to be restored during a six month period as the field is refilled. To increase the present maximum daily flow rate from the present 21 MMcfd to 100 MMcfd the number of storage wells will be increased.

During the Summer of 1981 a deep well will be sunk through the Bruer Pool as a 7500 ft. wildcat to search for gas at deeper horizons. Naturally, there are hopes that natural gas will be discovered beneath the present production levels. If the well is dry, which is more probable than success, it will be plugged for 5000 ft. back up to the depth of the producing sands in the Bruer Pool. The top portion of the well will be completed with 8 inch production casing and 4 inch production tubing. Details of these wells will be found in Exhibit C, Appendix A. One or two wells of this size on each of the two pools, in addition to the five existing wells, will be sufficient to increase the total reservoir withdrawal rate to the design rate. Working gas volume of the proposed storage reservoir is about half of the ultimate storage volume of 20 Bcf. Cushion gas, once it is injected, will be retained in the reservoir as long as it is used for storage.

The storage compressors will be installed on the Miller Station property in the same soundproofed building as the production compressors. Because the injection compressors transfer larger volumes of gas at higher pressures than the production compressors a total of 4000 horspower will be required. Sound control measures will also be applied to engine exhausts and cooling systems.

Each additional storage well must have a buried pipeline connection to Miller Station for transferring the gas in and out of the reservoir. Routes of these underground pipelines will follow existing logging roads to minimize interference with forest reproduction practices. Each of the existing and proposed storage wells each occupy far less than an acre of ground surface. This illustrates an interesting paradox concerning storage reservoir projects. Most of the facility is below ground. The Mist Storage Project, at the time of ultimate development, will occupy less than 20 acres of land on the surface. To allow for a separation zone around the two gas pools, about 1600 acres of land below the surface will be leased from the surface owners.

The foregoing discussion describes the major changes that are required to alter the Mist Gas Field from its present production role to an underground gas storage reservoir. The improvements would be added in yearly stages until the full capability of the total project volume of 20 Bcf is in use. Design filling rates of 50 MMcfd and withdrawal rates of 100 MMcfd will be achieved when the project is complete in 1984.

An underground gas storage reservoir is unique among all of the energy facilities subject to the jurisdiction of the council. The facility itself is entirely natural. In the case of the Mist field, the integrity of the reservoir is proven by the fact that it has been holding native gas for eons. Most of the man-made facilities necessary to utilize the natural reservoir already have been installed and operated in compliance with comprehensive safety codes for primary gas production.

Under these circumstances, it seems appropriate to, and the Applicant does cordially, invite the members of the council, staff personnel, and representatives of interested parties to tour the Mist field facilities for an explanation and demonstration of operations by the applicant.

Required information keyed to Oregon Administrative Rule sections, together with exhibits which are incorporated by reference, follow this introductory section of the application.

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STANDARDS FOR THE SITING OF UNDERGROUND RESERVOIRS

Rule 345-100-010 Purpose:

The purpose of these rules is to establish standards that applicants for site certificates for natural gas underground reservoirs must meet. The Council will apply these standards in reaching a decision for or against issuance of a site certificate for the construction and operation of a natural gas storage reservoir and its "related and supporting facilities", as defined in ORS 469.300. When the Council deems appropriate, it will adopt additional standards. Any additional standards will be adopted sufficiently in advance of the close of testimony at a hearing on a site certificate to allow parties to address the standard, or if after the close of testimony, in sufficient time to allow the parties an opportunity to supplement their testimony to offer evidence relating to the new standard. These standards as well as other statutory and regulatory requirements of the EFSC and federal, state and local agencies may also be utilized in formulating site certificate conditions required by ORS 469.400(3).

Rule 345-100-011 - Mandatory site Certificate Conditions:

In addition to any other site certificate conditions which may be imposed by the Council pursuant to ORS 469.400(3), the Council shall impose site certificate conditions which shall require an applicant to commit to design, build, and operate a facility in accordance with the design standards contained in OAR 345-100-036(1)-(4), (6) and (7); 040(1) and (6) and in accordance with any representations made in satisfaction of OAR 345-100-040(2), (4), (8), and 050.

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Rule 345-100-012 Applicability:

These specific standards are applicable to site certificate applications for all underground reservoirs for the purpose of storage of natural gas.

Rule 345-100-015 Interpretation:

These standards are authorized under ORS 469.470(3) and shall be interpreted so as to carry out the purposes of ORS 469.300 through 469.570, 469.990 and 469.992 governing energy facility siting in Oregon. The fundamental policy of that law is set out in ORS 469.310.

Rule 345-100-025 Definitions:

1. The definitions set out in ORS 469.300 are hereby incorporated as the definitions to be used in interpreting these specific standards, unless the context requires otherwise or a term is specifically defined within these specific standards.

2. Underground reservoir means any subsurface sand, strata, formation, aquifer, cavern or void whether natural or artificially created, suitable for the injection and storage of natural gas therein and the withdrawal of natural gas therefrom, but excluding a "pool".

3. Underground storage means the process of injecting and storing natural gas within and withdrawing natural gas from an underground reservoir.

4. Natural gas means all gas and all other fluid hydrocarbons not defined as oil in ORS 520.005(6), including condensate originally in the gaseous phase in the reservoir.

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5. Pool shall mean an underground reservoir containing a common accumulation of oil and natural gas. A zone of a structure which is completely separated from any other zone in the same structure is a pool.

6. Well log shall mean the written record progressively describing the strata, water, oil or gas encountered in drilling a well with such additional information as to give volumes, pressure, rate of fill-up, water depths, caving strata, casing record, etc., as is usually recorded in normal procedure of drilling, also to include electrical survey or logging.

7. "Related or supporting facilities" means structures or equipment adjacent to and associated with an underground reservoir and shall include but is not limited to:

a. Major facilities such as compressor stations, stripping plants and main line dehydration stations,
b. Minor facilities such as wellhead equipment including separators, pressure reducers, pressurizing equipment and dehydrating equipment, and compressors rated less than 1000 horsepower, and
c. Pipelines, such as gathering lines and liquid collection lines,
d. Roads and road maintenance equipment housing at the reservoir site.

8. Facility means an underground reservoir and related supporting structures.

9. Injection well means a well drilled in a known reservoir which is proposed to be used for injecting and withdrawing natural gas as required in normal operation of the storage field.

Rule 345-100-036 <u>Standards Relating to Public Health and Safety:</u>
In order to issue a site certificate for a facility the Council must find that:

1. The following supporting facilities can be located at distances in accordance with the schedule below from any existing permanent habitable dwelling:

   a. major facilities . . . 220 meters

   b. minor facilities, excluding compressors . . . 15 meters

   c. compressors rated less than 1000 horsepower . . . 100 meters

   d. roads and road maintenance equipment housing . . . 15 meters

<u>Applicant Response</u>

The closest existing permanent habitable dwelling to the compressor building will be about 7000 feet. The nearest minor facility to the same dwelling will be about 2000 feet.

Rule 345-100-036 (continued)

2. Pipelines can be constructed in accordance with the requirements of the U.S. Department of Transportation as set forth in Title 49, Code of Federal Regulations, Part 192 Subpart C, in effect on the date of these rules.

<u>Applicant Response</u>

Pipelines for the proposed project can be constructed in accordance with the U.S. Department of Transportation requirements 49 CFR Part 192, Subpart C-Pipe Design. The Oregon Public Utility Commissioner administers this requirement on pipelines constructed by Northwest Natural. All of the existing pipelines which will be used were also constructed in accordance with this design code. A copy of the code is included in Appendix B.

3. Compressor stations and related facilities can be designed so as not to violate noise standards specified by the Oregon Department of Environmental Quality in OAR 340-35-035, Noise Control Regulations for Industry and Commerce.

Applicant Response

The noise regulations in OAR 340-35-035 require noise sources to meet specified noise levels at the nearest noise sensitive property. Noise sensitive property is defined in the regulations as real property normally used for sleeping, or normally used for schools, churches, hospitals or public libraries.

The proposed underground reservoir will have two potential noise sources requiring analyses to control noise emissions: the injection-withdrawal wells and the compressor building. Noise sensitive properties are all south and southeast of the proposed underground reservoir. These would include homes, the Mist Store and the Mist Elementary School. The shortest distance between the proposed compressor building and the nearest noise sensitive property is about 6500 feet.

Sound from the noise sources can be controlled by design features in common use. Wellhead noises occur when gas flows at high velocity through valves and piping. The human ear perceives these noises as a faint rushing water sound on the existing Mist gas wells. When these noises can be detected by the specified measurement standards, controls can be successfully applied. These noise controls can be achieved with a type of weatherproof enclosure which is lined with a sound absorbent material.

The compressor building has the potential for excessive noise emanating from the large internal combustion engines that drive large reciprocating compressors. These machines are normal production equipment items which are produced by a few U.S. based manufacturers. These suppliers have noise emission information about any of their equipment manufactured today and can furnish noise control devices as part of the original purchase. The Department of Environmental Quality and the applicant have knowledge of several qualified noise control consultants in Oregon who can provide technical knowledge to meet the noise standard requirements should such assistance be necessary.

Rule 345-100-036 (continued)

4. Abandoned wells within the area affected by the project can be capped and sealed, using the best available technology, so as to prevent leakage.

5. The proposed underground reservoir has a geologic structure such that it is capable of being sealed, in the event of leakage, in a manner that can prevent toxic or flammable levels to exist at the surface.

6. The related and supporting facilities of the proposed facility will use the technologically best available surface and subsurface safety devices and testing procedures which can prevent leakage which could change the quality or quantity of adjacent oil, gas or water resources or endanger the health and safety of the citizens of Oregon.

7. A program can be developed using the best available technology to monitor the facility, to ensure the public health and safety.

8. In support of assessments required in this specific standard, the applicant shall submit:

a. An engineering study, including but not limited to:

i. Characteristics of the cap rock, such as areal extent, average thickness, and threshold pressure.

ii. Oil and gas reserves of storage zones prior to start of injection including calculations,

iii. Casing diagrams, including cement plugs, and actual or calculated cement fill behind casing, of all idle, abandoned, or deeper zone producing wells within the area affected by the project.

b. At least one geologic cross section through at least one injection well in the project area;

c. List of all observation wells used to monitor the project, indicating what parameter each well is monitoring (i.e. pressure, temperature, etc.)

Applicant's Response

Abandoned Wells

Abandoned wells can be readily capped and sealed to prevent leakage. Underground sediments in Oregon are geologically analogous to many oil and gas producing sediments in California. In developing the Mist field the applicant employed California-based petroleum engineers and geologists who are acquainted with and employ the best available technology as developed for the Pacific states. Well service companies from California were employed to apply this technology. In some cases, these same service companies originated the best available technology. An example is the Halliburton Company who specializes in well cementing and abandonment techniques. Halliburton has developed many of the best techniques in present use and has a wide range of knowledge to draw upon.

All abandoned wells in the Mist Field were plugged and abandoned in accordance with Department of Geology and Mineral Industries Rule 632-10-198. Records of these wells, which are confidential under ORS 520.095, were made available to the Siting Council staff as Exhibits G1 through G14.

Reservoir Seal

Geologic conditions encountered at the Mist gas field indicate that the gas has been contained since at least the Pliocene era (10 million years). The gas is trapped by a complex of structural and stratigraphic elements. These consist of a northwest trending anticlinal fold, east-west normal faults, and underlying saline formation water. Drilling has also established that either an unconformity exists at the top of the producing sand or the sand facies changes to shale. In either case the sand is sealed at the top by about 2200 feet of shale and siltstone. Storage pressures will not exceed the initial pressures that were found in the reservoir rock.

Recently drilled wells are the only manmade penetrations of the reservoir pools at Mist. Without the long history of tight storage of natural gas that the reservoirs exhibit there is a possibility, however small, that the seals between the abandoned wells or the injection-withdrawal wells and the surrounding underground material could leak. This does happen once in a while for unforeseen reasons during oil and gas operations. In the event that the applicant has a damaged well seal which will compromise the reservoir sealing qualities many proven and effective sealing procedures can be quickly implemented. These remedies can be applied by a number of gas and oil industry well service companies under the supervision of an experienced petroleum engineer. These repairs can be satisfactorily completed, and in most cases, the same well can continue production.

Monitoring to Assure Public Health and Safety

The monitoring program, including periodic wellhead inspections, wellhead safety systems, leakage inspection of pipelines, and continuous pressure monitoring will be described next in the section on leakage prevention. In addition to those systems and procedures, there is an inline flow monitor which continuously calculates and records the flow parameters from or into each well. If the calculated flow is outside a specified operating range an alarm notifies the operators who adjust or shut off the flow. The system also has a chromatograph which samples each reservoir stream automatically, and detects any change in the composition of the gas which may indicate leakage from other reservoirs.

Other systems designed to prevent leakage, which could also endanger public health and safety, are described in the following section.

Reservoir Leakage Prevention

The ability to prevent reservoir leakage, as specified in OAR 345-100-036 Subpart 6, is dependent on the ability to detect leakage. Once leakage is detected on a pipeline equipment can stop gas flow to the pipeline by closing a valve or other sealing procedures.

Several leakage detection systems are in operation at the Mist Field. They are coordinated with a periodic downhole monitoring program to determine the condition of the wells. Each injection-withdrawal well is outfitted with a control system on the well christmas tree which will shut down the well for abnormal operating conditions which are: high pressure, low pressure, or sand production. In Miller Station there is a safety shutdown system for the station header, actuated manually or by heat sensing mechanisms, which will secure and isolate all flow. This system when activated will shut down the inlet and outlet of the station header and release the stored gas from the header.

The casing program for each well is designed in accordance with state regulation to meet the following requirements:

1. The surface casing is installed to a depth sufficient to prevent contamination of the local fresh water table and to provide an anchor for well control valves while drilling.
2. The production casing is designed with an extensive cement seal to prevent leakage of gas out of the producing reservoir and also prevent the flow of water into the casing from saturated zones.

A detail of each well casing program is provided in Exhibits G-1 through G-14 of Appendix A.

In addition to the installed safety and leakage detection systems, operating procedures and monitoring programs also ensure safety. The operating station at Mist is manned and certain plant data are under observation and are controllable via microwave telemeter at the

Northwest Natural Gas Company gas supervisor's office in Portland. Inspections of each wellhead are conducted by the plant operators, as well as periodic leakage surveys of underground piping by a trained inspection crew.

Flowing pressures at each wellhead meter are recorded continuously on a chart, and wellhead casing and tubing pressures are recorded. For any given well flow the pressure drop is known so pressure monitoring to observe sudden pressure changes is an effective way to avoid overpressurization of the reservoir. Twice a year each reservoir is shut-in for sufficient time to allow the pressure to stabilize and a pressure recording tool is lowered down the well to determine the static reservoir pressure. Monitor wells will be checked to observe change in reservoir state. These show up as a change in reservoir water level that isn't explainable by gas injection or withdrawal conditions. In this way the condition of the monitor wells can be related to the condition of the adjacent underground reservoir.

Applicant Engineering Study for Rule 345-100-036(8)

The Mist gas field is situated in the northwest corner of Oregon within the Western Tertiary Marine Basin. One deep test drilling, put down near the town of Mist by Texaco, Inc. in 1946, explored to a depth of 8500 feet. Mapping by the U.S. Geological Survey in 1946 identified marine sedimentary rocks in this area as Oligocene and Eocene in age. Volcanic rocks are interspersed with Eocene age sediments. The gas at Mist is trapped in sandstone of Eocene age which is referred to as the Cowlitz Formation and the reservoir sandstone named the Clark & Wilson Sand.

Stratigraphy

Three main rock types occur in the upper Nehalem basin: a lower sequence of basaltic submarine flows, an intermediate sedimentary section consisting of units ranging in age from upper Eocene through lower Miocene, and a capping series of Miocene basalt flows. Data obtained from two deep Texaco exploration holes drilled in Columbia County indicate that Tertiary sedimentary units probably extend to a depth of at least 10,000 feet in this area. Below a depth of 5000 feet, volcanic rocks are interbedded with sediments and become the predominant rock type at greater depth.

Exhibit D shows a generalized geologic column for the area. Sedimentary units are typically fine grained and argillaceous, with some interbeds of medium-grained, fairly clean sandstone.

Structure

The upper Nehalem basin is part of the lower Columbia River downwarp, which formed prior to extrusion of Miocene lavas. Uplift and arching of the northern Coast Range formed a northward plunging anticline which projects as a salient into this downwarp. Contacts of sedimentary units bend around the Coast Range cross-warp in the upper Nehalem Valley.

Originally this structure was interpreted as fairly gentle northwest trending enechelon folds but drilling in the Mist Field has shown that the structures are quite complex. The large folds are a complex of smaller folds cut by a system of northwest-southeast, east-west and northeast-southwest faults believed to be produced by a north-south stress field stress field compression of crusted rocks. Dips on fold limbs range from 10° to 20°. Vertical closure on the folds is on the order of 1000 to 1500 feet. Production quality reservoirs found to date at Mist are separated into four, fault-controlled reservoirs.

In the Mist area the producing sands are overlain by an average of 2200 feet of shale, mudstone, and siltstone of the Keasey and Cowlitz Formations (see Exhibits E & F). Fifty feet of this type of rock can provide an adequate seal against upward leakage of gas. The fact that the gas has been trapped in these structures for the last few million years is a good indication that leakage is not occurring. Tightly-packed fine sediments have so little pore space that they can seal in hydrocarbons at tremendous pressures. The nearest exposure of reservoir rock is at least 8 miles to the southwest of the Mist field. It is not exposed at the surface in any other direction.

Gas Reserves

Through downhole pressure testing of both reservoirs, estimates for original gas-in-place have been calculated. Industrial Gas Services, an independent consulting firm from Denver, has calculated the reserves as follows:

Reservoir		Original gas in place
Bruer Pool		11.253 BCF (billion cubic feet)
Flora Pool		8.751 BCF
	Total	20.004 BCF

Of the total 20 BCF capacity, the intention is to use one-half this for storage with the remaining half as cushion gas. The actual reserve of cushion gas at the start of injection will depend on how much gas remains in the ground at the time of an agreement with the applicant's production parties.

Casing Information

The casing information for all wells, including cement plugs, actual and calculated cement fill, and other pertinent well data will be found in Exhibits G-1 through G-14.

Geological Cross Sections

A geological cross section through all producing wells in the two reservoirs is provided as Exhibits E and F. These cross sections illustrate the relationship of the gas bearing sands to the surrounding underground sedimentary zones. Once storage operations commence, these wells will be utilized for injection-withdrawal along with some new high-capacity injection-withdrawal wells which have not yet been drilled. A cross section of the casing arrangement and gravel pack for an injection-withdrawal well like those planned for Mist is shown in Exhibit C.

Observation Wells

Due to the geological characteristics of the storage reservoirs, and the intention to operate the field only up to the original field discovery pressure, few monitoring wells will be required. In addition to the operating pressure monitoring of the injection-withdrawal wells previously described, two previously drilled wells have been selected for monitoring use. CC #5 and CC #32-3 will be redrilled and intrumented to monitor possible gas leakage at the down dip edge of each reservoir.

Rule 345-100-040 Standards Relating to Environmental Impact:

In order to issue a site certificate for a facility, the Council must find that:

1. The facility can be designed so that water quality can be maintained as follows:

   a. for groundwater which is potable, as defined by the Environmental Protection Agency in Federal Registers Vol 40, No. 28, December 24, 1975, and Vol 41, No. 133, July 9, 1976, paragraphs 141.11, 141.121, 141.15a and 141.16 - contaminants from the facility will not make the water non-potable.

   b. for surface waters which meet the requirements of Oregon River basins given in subsection (2) of OAR 340-42-205, 245, 285, 325, 365, 445, 485, 525, 565, 605, 645, 685, 725, 765, 805, 845, 885, 925 and 965 contaminants will not cause surface waters to exceed these levels. References to maximum permissable concentrations of radioactivity shall refer to paragraphs 141.15a and 141.16 in the Federal Register Vol 41, No. 133, July 9, 1976.

   c. for ground or surface waters which currently exceed the foregoing standards of (a) or (b) contaminants in water discharged from the facility, measured at the point of entrance to the ground or surface water, will not exceed the concentrations of the foregoing standards (a) or (b).

Applicant Response

Potable Groundwater Protection

Monitor wells, discussed previously on page 21, as an important means of preventing underground leakage into adjacent potable water aquifers. Cementing procedures and other controls used during well drilling and operation, under the public supervision of the Oregon Department of Geology and Mineral Industries, can prevent flow and contamination between different levels of ground water aquifers. These procedures and controls are described in the well histories listed in Exhibits G1 through G14.

Surface Water Protection

Contaminants released by any portion of the applicant's facility will not cause the surface waters to exceed requirements of OAR 340-41-205 North Coast-Lower Columbia Basin. Fluids and solids used to process the withdrawn gas, with the exception of the water associated with the withdrawn gas, are not presently released to the environment in an untreated manner nor will they be during future underground reservoir operations. Minor drips or spills of liquids during operation are routinely cleaned up now as they occur. Experience to date, during 10 months of gas production, indicates that gas-associated water produced from the gas pools is a small quantity, about 20 gallons per day. This water is collected in primary and secondary liquid separators, and is disposed of in accordance with DEQ regulations. A chemical analysis of this water is included as Exhibit I.

Rule 345-100-040 (continued)

2. The proposed site is not in one of the designated natural resource areas listed below and the proposed project is not likely to produce significant adverse impacts on any such area including:

a. National Parks, National Monuments and National Wildlife Refuges;

b. State of Oregon Parks, Waysides, Wildlife Refuges and Natural Preserves;

c. Wilderness areas as established under the Federal Wilderness Act (16 USC 1131 et seq.) and areas recommended for designation as wilderness areas pursuant to Section 603 of the Federal Land Policy and Management Act of 1976 (P.L. 94-579);

d. Scenic Waterways designated pursuant to ORS 390.825;

e. Federally-designated Wild and Scenic Rivers established pursuant to P.L. 90-452;

f. Experimental areas established by the Rangeland Resources Program, School of Agriculture, Oregon State University;

g. Areas having unique or significant wildlife, geologic, historic, botanical, research or recreational values as lawfully designated by the state agency having jurisdiction over such values.

3. Studies have been performed characterizing the relative abundance and diversity of the plant and animal species at the proposed site of the facility. (Shannon-Weaver index H shall be a satisfactory measure of diversity) and

4. The proposed project is not likely to jeopardize the continued use of deer, elk and antelope wintering ranges or migration routes.

5. The aboveground portions of the facility shall not be located on antelope fawning areas, sage grouse strutting or nesting grounds, raptor nesting areas, or waterfowl and waterbird nesting and rearing areas.

<u>Applicant Response</u>

<u>Designated Natural Resource Areas</u>

A review of literature supplemented by verbal communication with Mr. Jim Reher, the local Oregon Fish & Wildlife representative, indicates there is nothing existing or planned in the above categories. The land being considered by the applicant is private timber land that has produced more than one timber cut.

Study on Relative Abundance and Diversity of Plant and Animal Species

This study has not been completed for the Mist area in Columbia County. Facts will be furnished when they are available.

Continued Use of Ranges and Migration Routes

Five fenced wellheads will be added for the underground reservoir at Mist and are expected to have a modest effect on wildlife. Although each active wellhead will be within a small fenced area, these, by private timber company preference, are within areas previously cleared for logging operations. Noise levels of the passive wellhead equipment is low. No observable effects on wildlife have been yet found at Mist.

Miller Station was built along a ridge top. It was fenced previously for plant security. No new fencing is required for underground reservoir use.

All pipelines connecting wellhead facilities with Miller Station will be underground on routes approved by the surface owner. The backfilled pipeline ditches will be restored to the original soil contours.

These described features of the applicant's project appear to have the same potential to jeopardize large game migration or wintering habits in the future as they have in the past. Discussions with the Oregon Fish & Game supervisor disclosed no previous problems of this type.

Fawning Areas, Nesting and Rearing Areas

The land proposed for use in the storage field operation is private forest land in Western Oregon. The last old growth timber was cut out during the 1940's. Second growth timber naturally established since that time has largely been harvested in the area overlaying the two storage pools.

The applicant is in compliance with the Administrative Rule. According to Mr. Jim Reher of the Oregon Department of Fish & Wildlife antelope and sage grouse are not found this far west in Oregon. No raptor nesting areas exist to be disturbed during construction or operation of the proposed storage project. Last, because the project lands are upland timber areas, no waterfowl and waterbird nesting and rearing areas will be disturbed by the project.

Rule 345-100-040 (continued)

6. Areas within the project boundary with unstable or fragile soils have been satisfactorily identified and available construction techniques can be employed to reduce adverse impacts such as compaction and erosion.

Applicant Response

During construction of the gas production system at Mist Northwest Natural had to install everything with the cooperation of the private timber companies who own the land surface rights. Nothing was installed before the field operation supervisors approved. These foresters or engineers have years of experience in constructing logging roads, clearing and locating logging equipment which includes experience in working with these specific soils. In several cases they have helpfully tion rerouting or modifications in procedure that allowed drilling operations or pipeline installations to proceed in a manner more harmonious with the terrain.

Some success in soil erosion prevention must have been achieved in recent years because Adams Creek and Ford Creek which are fed from these timbered ridges continue to be maintained as spawning and rearing areas for salmon and trout species.

Any foundations, such as those in the Miller Station improvements will require a routine structural and soils design. Many engineering consultants can do this work.

Rule 345-100-040 (continued)

7. The bird species within the area affected by the facility have been identified and the facility is not likely to jeopardize the continued existence of local or migratory populations of such bird species.

8. Construction and operation of the facility is not likely to jeopardize the continued existence of any of the following species, or destroy habitat critical to continued existence of these species.

i. Wildlife

(A) Deer, Columbian white-tailed (Odocoileus virginianus luecurus),

(B) Wolf, Gray (Canus lupus),

(C) Eagle, Bald (Haliaeetus leucocephalus)

(D) Falcon, American peregrin (Falco peregrinus anatum),

(E) Falcon, Arctic peregrin (Falco peregrinus tundrius),

(F) Goose, Aleutian Canada (Branta canadensis leucopareia),

(G) Pelican, brown (Pelecanus occidentalis),

(H) Butterfly, Oregon silverspot (Speyeria zerene hippolyta),

ii. Plants - any of the fifty-one species proposed by the Fish and Wildlife Service as endangered in Oregon by publication in the Federal Register (41 FR 24524; June 16, 1976).

NOTE: The species identified in subsection (8) consist of endangered and threatened wildlife listed as of October 1, 1978, in 50 CFR Park 17 with a range which includes Oregon, and species in Oregon proposed by the Fish and Wildlife Service for addition to the list in 50 CFR Park 17 as published in the Federal Register.

Applicant Response

Local and Migratory Birds

Facts on the effects of the underground storage facility on local and migratory birds have not been determined at this time. They will be included in this section when available.

Endangered Species

Facts to determine whether or not any endangered or threatened species occur in the project area will be included here when they are available.

Rule 345-100-045 Standards Relating to Land Use

In order to issue a site certificate for a facility the Council must find that:

1. That the Land Conservation Development Commission has acknowledged pursuant to OAR 197.251 (1979 replacement part) the comprehensive land use plan(s) and implementing measures of the general purpose local

government(s) having land use planning jurisdiction over the site of the facility and that the facility has been determined by the local government(s) to be consistent with the plan(s) and measures;

2. That if the plan and implementing measures have not been acknowledged by the Land Conservation and Development Commission, the applicant has demonstrated to the Council that after providing notice and opportunity for public and other government agency review and comment, the statewide planning goals (OAR Chapter 660, Division 15) have been considered and applied by the local government(s) during a land use review of the facility, and such facility has been determined by the local government(s) to be consistent with applicable statewide planning goals and local land use plan and measures; or

3. If the local government(s) having land use planning jurisdiction over the site of the facility has not completed a land use review of the facility prior to approval of a site certificate as required by subsection (1) and (2) of this rule, or if such local government has denied that the facility is consistent with applicable statewide planning goals and land use plans and measures the council has determined that the application is consistent with the statewide planning goals and provided, however, that a site certificate authorizing the construction within the boundaries of an incorporated city shall be conditioned on compliance with city ordinances in effect on the date of the application of the site certificate as required by ORS 469.400(6) (1979 replacement part).

Applicant Response

Columbia County doesn't have an approved or acknowledged comprehensive land use plan so public review and county level review of the underground reservoir project will be required as described in the above paragraph (3). Two levels of review will be required for the unincorporated area being proposed by the applicant.

The first group is the Mist-Birkenfeld Community Planning Advisory Committee. A public notice must be sent out ten days prior to any meeting of the Mist-Berkenfeld CPAC. The Columbia County Planning Commission will determine if the project conforms to statewide guidelines. The Board of County Commissioners will rule on this determination.

Rule 345-100-050 Standards Relating to Socioeconomic Impacts:
In order to issue a site certificate the Council must find that:

1. The applicant has identified the major and reasonably foreseeable socioeconomic impacts on person and communities located in the vicinity of the facility resulting from construction and operation, including, but not limited to, anticipated need for increased governmental services or capital expenditures, and

2. The applicant and the affected local government can provide adequate resources to mitigate the impacts identified pursuant to (1), and

3. The applicant has an adequate process for periodically updating, during construction and operation, its assessment of anticipated impacts of the facility.

Applicant Response

Experience encountered during the previous construction at Mist showed a low sociological impact for this type of project. The work proposed in this application will not be greatly different from that of the previous development, but, in any event, the lists of impacts, necessary mitigation and required updating will be developed in cooperation with the Columbia County planning staff by the applicant. When they are completed this section will include those facts.

Rule 345-100-052 Standard Relating to Water Rights

In order for the Council to issue a site certificate for a facility the Council must find that the requirements for water used in construction and operation of the facility can be met without infringing upon the existing water rights of other persons.

Applicant Response

With the exception of the compressor building construction all of the proposed types of man-made improvements will repeat those done earlier during the gas field development period. Water requirements of the construction and well drilling operations were done, at that time, without infringement on the water rights of nearby persons. The compressor building construction will include concrete foundations, machinery placement, connecting piping and an encompassing building. None of these activities has a large consumptive water requirement.

During the underground reservoir operation no large consumptive uses will be taken from the local water resources. Large machinery will have recirculating cooling systems with no continuing water requirement. A slight amount of water will be produced as described in the Applicant Response for Rule 345-100-040 but any effect will not be noticed as an impact or infringement on the water rights of others.

Rule 345-100-053 <u>Organization, Managerial and Technical Expertise</u>

In order for the Council to issue a site certificate for a facility the Council must find that the applicant has the organization, managerial, and technical expertise to construct, operate, and retire the facility.

Rule 345-100-054 <u>Financial Assurance</u>

In order to issue a site certificate for a facility the Council must find that the applicant, together with all co-owners, possesses or has reasonable assurance of obtaining the funds necessary to cover estimated construction costs, operating costs for the design lifetime of the facility, and the estimated costs of retiring the facility.

Rule 345-100-055 <u>Applications</u>

1. The applicant shall submit an application which includes but is not limited to:

    a. a description of the facility;

    b. one or more maps, containing the following information for the general area between the terminal points of the proposed transmission line:

        (1) topography, including contour lines, and lakes, streams and rivers.

        (2) natural resource areas listed in OAR 345-100-040.

        (3) transmission lines, improved roads, railroads and pipelines.

(4) landownership by class federal, state, local government, and private.

(5) current and planned land uses including but not limited to forests, agriculture, range lands, population centers and airports.

(6) known habitats of threatened and endangered species as defined in 50 CFR part 17 as the effective date of these rules.

c. a description of the construction and operation of the facility to the extent practicable.

d. a description of proposed techniques for monitoring impacts.

e. the location of the injection well;

f. the location of all oil and gas wells, including abandoned and drilling wells and dry holes, which penetrate the underground reservoir proposed to be used for storage and the names of the owners of any interests in oil and gas within such underground reservoirs.

g. the formation from which wells are producing or have produced;

h. the name, description, and depth of the formation field, pools and sands to be injected.

i. the depths of each formation into which gas is to be injected.

j. the elevations of the top of the oil or gas bearing formation in the injection well and the wells producing from the same formation within one half mile of the intake well;

k. the log of the injection well, or such information as is available;

l. description of the injection well casing;

m. description of the gas, stating kind, where obtained, and estimated amounts to be injected daily;

n. the names and addresses of the operators.

o. a list of approvals required from governmental agencies.

2. At the time an application is filed, the applicant may indicate to the Council what information the applicant considers to be within the exemption to the public records law, ORS Chapter 192, provided by ORS 469.560. The Council shall treat all such information as confidential subject to a determination by the Council or the Attorney General pursuant to ORS 192.450 that the exemption is not applicable.

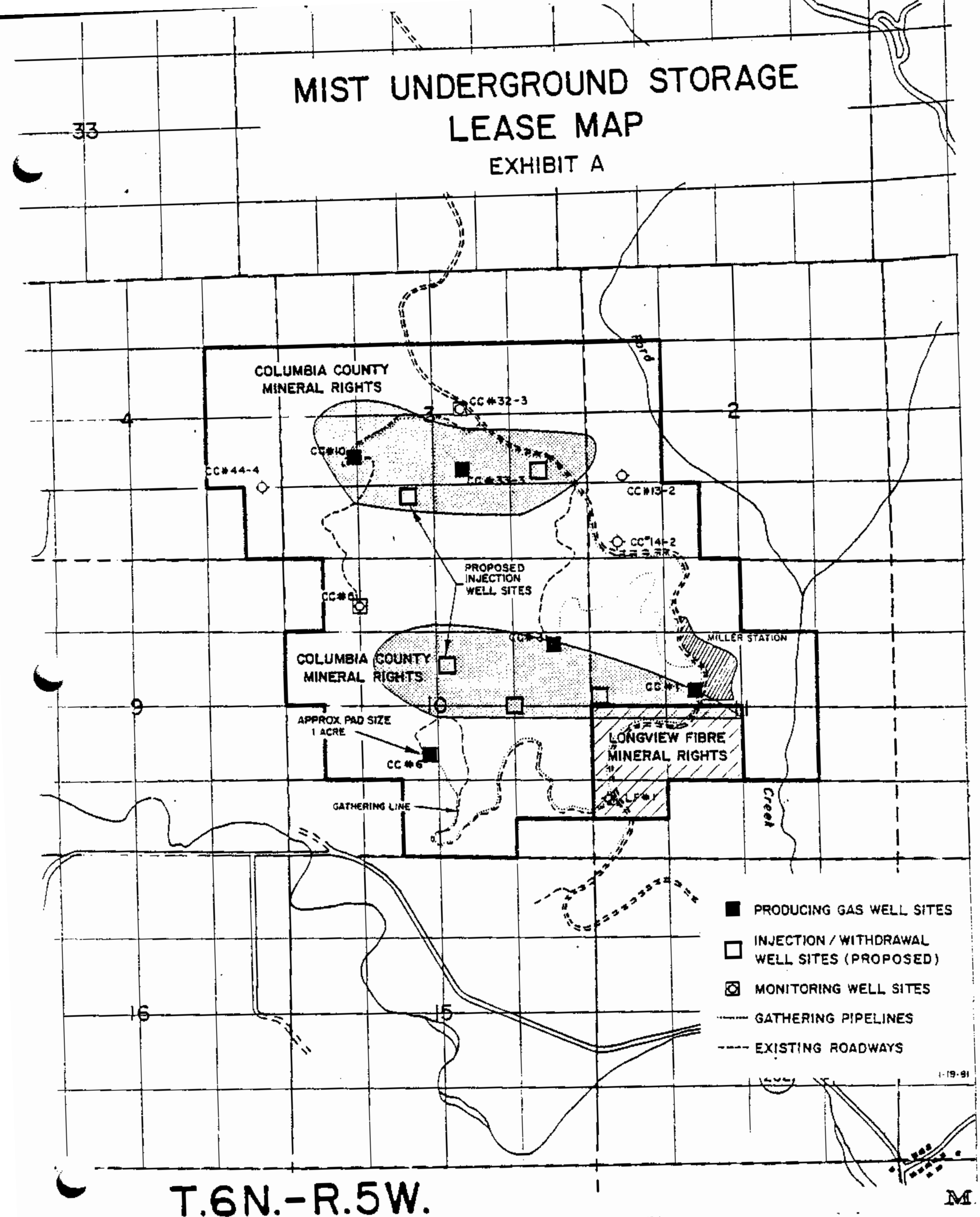
mSTAPPDoc1

APPENDIX A

TABLE OF CONTENTS

*This information is confidential under the provisions of ORS 520.095 and for that reason has been omitted from this copy.

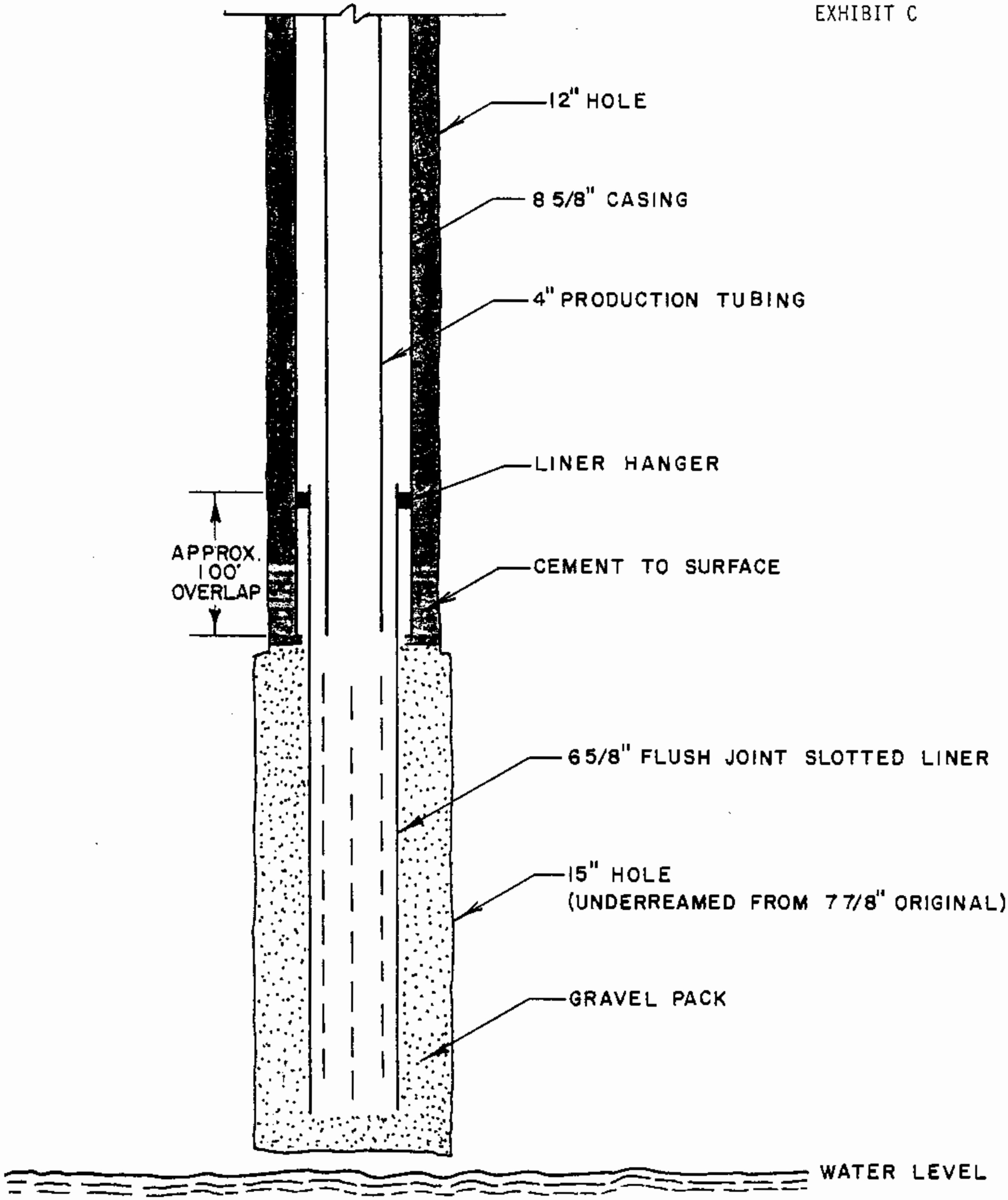
per.3-2



*This information is confidential under the provisions of ORS 520.095.

8096 NS

EXHIBIT C

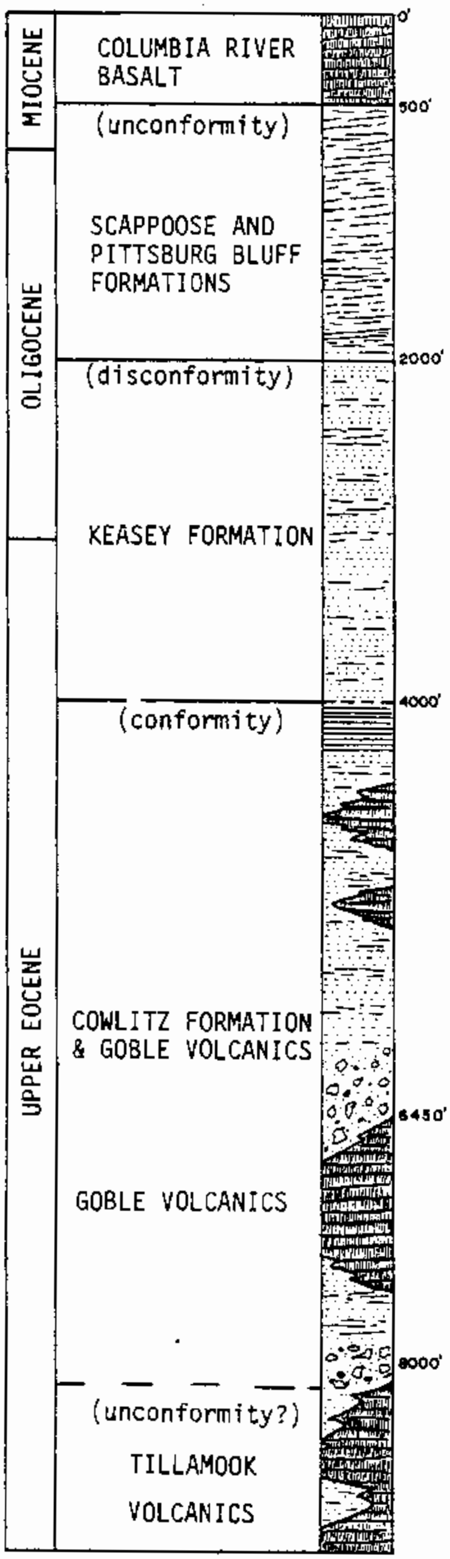


SYM	DR	APP	REVISIONS	DATE	SYM.	DR.	APP.	REVISIONS	DATE

CH. DATE	NORTHWEST NATURAL GAS COMPANY	DR A DATE 12-3-80
APP. DATE	85/8" INJECTION / WITHDRAWAL WELL	SCALE NONE
APP. CBB DATE 12/8/80		DWG. NO. Y-00-03-A

EXHIBIT D

UPPER NEHALEM RIVER BASIN



Basalt: *dark gray-black, fine-grained, columnar flows, some interbedded pyroclastics.*

Siltstone, argillaceous tuffaceous sandstone, some clean sandstone, some mudstone: *gray, weathers to yellowish color, fossiliferous, often spotted with pumiceous material, some medium-grained arkosic sandstone, carbonaceous material, some pebble bands, cross bedding, micaceous, some thin limestone beds, few thin coal seams.*

Tuffaceous sandstone, mudstone, and shale: *micaceous, argillaceous, fossiliferous, interbeds of light-colored tuff, dark greenish-gray, weathers to buff color, concretionary limestone beds, some limestone layers.*

Mudstone and siltstone: *micromicaceous, dark greenish-gray, weathers to buff color, some thinly bedded, concretionary limestone, fossiliferous, some glauconite layers.*

Shale: *dark gray, micaceous, fossiliferous, some fine-grained shaley sandstone, tuffaceous sandstone, and water-laid tuff. Interbedded basaltic flows and flow breccia. Goble equivalent.*
Sandstone: *gray, massive, fine to medium-grained, micaceous, some carbonaceous material, cross bedding.*

Volcanics: *basalt flows and breccias, calcite and zeolite veining, pillow structure.*

Claystone and siltstone: *dark gray, well stratified, fossiliferous, containing white, intercalated Goble basalt flows.*
Conglomerate: *rust stained, hard, pebble, cobble, and boulder basaltic, some fossils.*

Volcanics: *greenish-gray, pillow structure, zeolite and calcite veining; flow breccia and interbedded claystone, siltstone, and argillaceous sandstone, tuff.*
(Bottom not exposed in area)

Figure 4. Generalized geologic section in the upper Nehalem basin.

EXHIBIT G12-1

Form 4- 1/54

STATE OF OREGON
DEPARTMENT OF GEOLOGY AND MINERAL INDUSTRIES
1069 State Office Building, Portland 1, Oregon

WELL SUMMARY REPORT
(Submit in duplicate)

Operator Reichhold Energy Corporation Field Wildcat

Well No. Columbia County No. 1 Sec. 11, T 6N, R 5W, Columbia County W. B. & M.

Location 310' North & 812' West from Center of Section 11 Elevation above sea level 1021 feet

All depth measurements taken from top of KB, which is 10 feet above ground

In compliance with the rules and regulations pursuant to ORS 520 (Chapter 667 OL 1953) the information given herewith is a complete and correct record of the present condition of the well and all work done thereon, so far as can be determined from all available records.

Date September 8, 1977 Signed [signature]

W. G. Bruer ~~Engineer~~ Geologist — H. C. Patterson Superintendent — Title Engineer (President, Secretary or Agent)

Commenced drilling 8/29/77 Completed drilling 9/5/77 Drilling tools ~~Cable~~ Rotary

Total depth 3,111' Plugged depth 2,684'-2,240' GEOLOGICAL MARKERS DEPTH

Junk 409'- 279'

Commenced producing Suspended Flowing/gas lift/pumping
Date (cross out unnecessary words)

	Clean oil bbl. per day	Gravity Clean oil	Percent water including emulsion	Gas Mcf. per day	Tubing Pressure	Casing Pressure
Initial production	Never Produced -		Suspended			
Production after 30 days						

CASING RECORD (Present Hole)

Size of casing (A.P.I.)	Depth of shoe	Top of casing	Weight of casing	New or second hand	Seamless or Lapweld	Grade of casing	Size of hole drilled	No. of sacks of cement	Depth of cementing if through perforations
7"	359'	0	20#	N	S	K	9-7/8"	450	

PERFORATIONS

Size of casing	From	To	Size of perforations	Number of rows	Distance between centers	Method of perforations
None	ft.	ft.				
	ft.	ft.				
	ft.	ft.				
	ft.	ft.				
	ft.	ft.				

Electrical Log Depths 3,099' (Attach Copy of Log)

WELL HISTORY

Reichhold Energy Corporation
Well: COLUMBIA COUNTY NO. 1

API No. 36-009-00007
Section 11-6N-5W, W.B.& M.
Columbia County, Oregon

August, 1977

28 Paul Graham Drilling and Service Company moved in and rigged up Rig No. 1

29 Spudded in at 7:00 AM with 9-7/8" bit and drilled ahead.

214' Sand and gravel.

Lost and regained circulation. Drilled ahead.

364' Sand, clay, and shale.
Survey at 335' 0°-15'

Conditioned mud and hole.

30 Ran 9 joints of 7" 20# K casing equipped with a B&W guide shoe and cemented around shoe at 359' with 140 sacks of Class G cement treated with 2% $CaCl_2$. Lost returns while displacing cement. No cement returns at surface. Cement in place at 1:30 AM.

Ran 1" pipe to 150' in annulus and pumped in 100 sacks of cement premixed with 8% gel. Cement rose to surface then dropped in annulus. Cement in place at 11:30 AM.

Ran 1" pipe to top of cement at 90'. Pumped in 65 sacks of cement premixed with 8% gel and treated with 3% $CaCl_2$. Cement in place at 6:00 PM.

Ran 1" pipe to top of cement in annulus at 71'. Pumped in 75 sacks of cement premixed with 8% gel and treated with 3% $CaCl_2$. Cement in place at 8:15 PM.

31 Ran 1" pipe to top of cement in annulus at 40'. Pumped in 70 sacks of cement, filling annulus to surface.

Landed casing and installed 6" series 900 screw on casing head.

Installed BOP equipment.

Tested BOP equipment with 1000 psi.

Drilled out cement and shoe with 6-1/4" bit and drilled ahead.

1,240' Shale.

WELL HISTORY

Reichhold Energy Corporation
Well: COLUMBIA COUNTY NO. 1

API No. 36-009-00007
Section 11-6N-5W, W.B.& M.
Columbia County, Oregon

September, 1977

1	2,315'	Shale.		
		Survey at	1,326'	1°-15'
2	3,111'	Sand and shale.		
		Survey at	3,111'	2°- 0'

Conditioned hole for logs.

3 Welex ran Induction-electric log from 361' to 3,099'.

Welex ran Compensated Acoustic Velocity Log from 361' to 3,093'.

Welex ran Dipmeter from 675' to 3100'.

Welex took Sidewall samples. Descriptions attached.

Laid down drill collars.

Waited for cementers.

4 Plug No. 1. Hung drill pipe at 2,684' and pumped in 100 sacks of Class G cement. Calculated to fill to 2100'. Cement in place at 4:30 PM.

Located top of cement at 2,240' at 8:30 PM.

Plug No. 2. Hung drill pipe at 409' and pumped in and equalized 35 sacks of Class G cement treated with 2% $CaCl_2$. Cement in place at 9:00 PM.

5 Located top of plug at 279' at 3:00 AM.

Location and hardness of top of plug witnessed and approved by Mr. Vernon Newton of Division of Geology and Mineral Industries.

Capped top of surface casing.

Well suspended in this condition.

Form 4- 1/54

STATE OF OREGON
DEPARTMENT OF GEOLOGY AND MINERAL INDUSTRIES
1069 State Office Building, Portland 1, Oregon

WELL SUMMARY REPORT
(Submit in duplicate)

Operator Reichhold Energy Corporation Field Wildcat

Well No. DSC-LONGVIEW FIBRE NO. 1 Sec. 11 , T 6N , R 5W , Columbia County W. B. & M.

Location 1070' N & 304' E from SW Corner Of Section 11 Elevation above sea level 833.6 feet

All depth measurements taken from top of KB , which is 10 feet above ground

In compliance with the rules and regulations pursuant to ORS 520 (Chapter 667 OL 1953) the information given herewith is a complete and correct record of the present condition of the well and all work done thereon, so far as can be determined from all available records.

Date October 26, 1977 Signed [signature]

W. G. Bruer, ~~Engineer~~ Geologist — H. C. Patterson, Superintendent — Title Engineer (President, Secretary or Agent)

Commenced drilling October 8, 1977 Completed drilling October 18, 1977 Drilling tools Cable Rotary

Total depth 3,088' Plugged depth 2535'-2193'± GEOLOGICAL MARKERS DEPTH

Junk 466'- 275'

Commenced producing Suspended (Date) Flowing/gas lift/pumping (cross out unnecessary words)

	Clean oil bbl. per day	Gravity Clean oil	Percent water including emulsion	Gas Mcf. per day	Tubing Pressure	Casing Pressure
Initial production	Never produced.					
Production after 30 days						

CASING RECORD (Present Hole)

Size of casing (A.P.I.)	Depth of shoe	Top of casing	Weight of casing	New or second hand	Seamless or Lapweld	Grade of casing	Size of hole drilled	No. of sacks of cement	Depth of cementing if through perforations
7"	386'	0	23#	N	S	K	9-7/8"	140	

PERFORATIONS

Size of casing	From	To	Size of perforations	Number of rows	Distance between centers	Method of perforations
None	ft.	ft.				
	ft.	ft.				
	ft.	ft.				
	ft.	ft.				
	ft.	ft.				

Electrical Log Depths 3075' (Attach Copy of Log)

WELL HISTORY

Reichhold Energy Corporation
Well No.: DSC-LONGVIEW FIBRE NO. 1

Section 11-6N-5W, W.B.& M.
Columbia County, Oregon

October, 1977

8		Taylor Drilling Company moved in Rig No. U-34 and rigged up.
		Spudded in at 5:00 PM with 9-7/8" bit and drilled ahead.
	100'	Sand and clay.
9	420'	Clay.
		Ran 9 joints of 7" 23# K casing equpped with a guide shoe and cemented around shoe at 386' with 140 sacks of Class G cement. Had good cement returns at surface. Cement in place at 8:00 PM.
10		Landed casing and installed screw on 6" series 900 casing head.
		Installed and tested BOP equipment.
		Drilled out cement and shoe with 6-1/4" bit and drilled ahead.
	642'	Clay and shale.
11	1,663'	Clay and shale.
12	2,353'	Clay and shale.
13	3,002'	Sand and shale.
14	3,088'	Sand and shale.
		Ran Welex Induction-electric log, Compensated Acoustic Velocity Log, and Dipmeter.
		Waiting for cementing equipment.
15		Waiting for cementing equipment.
		Ran open end drill pipe to 2535' and circulated.
16		Plug No. 1. Hung drill pipe at 2535' and pumped in and equalized 40 sacks of cement. Cement in place at 10:30 AM.
		Located top of plug at 2330' at 4:00 PM.

WELL HISTORY

Reichhold Energy Corporation
Well No.: DSC-LONGVIEW FIBRE NO. 1

Section 11-6N-5W, W.B.& M.
Columbia County, Oregon

October, 1977

16 Cleaned out cement to 2382'.

Circulated and conditioned mud.

DST NO. 1. Ran Halliburton tester with no cushion and set packers at 2345' and 2350' with tail to 2382'. Opened tool at 1:01 PM. Had immediate strong blow through bubble hose. Turned to sump through 3/4" bean at 1:03 PM. Blow gradually decreased. Gas to surface at 1:12PM. Very weak blow, rate too low to measure. Closed tool for ISIP at 1:31 PM. Opened for flow at 2:14 PM. Immediate moderate bubble hose blow decreasing rapidly to very weak blow. Nearly dead at 2:24 PM. Closed for FSIP at 2:44 PM. Pulled tool loose at 3:14 PM.

Recovered a rise of 2200' as follows:

Top	120'	Mud
	120'	Watery mud
	1,960'	Gassy salt water, Salinity 15,000 ppm

PRESSURES	TOP	BOTTOM
IHP	1,249	1,269
IFP	612	864
ISIP	986	1,006
FFP	988	1,006
FSIP	988	1,006
FHP	1,196	1,215

Plug No. 2. Hung drill pipe at 2380' and pumped in and equalized 35 sacks of cement. Calculated to fill to 2193'.

18 Plug No. 3. Hung drill pipe at 466' and pumped in and equalized 40 sacks of cement.

Located top of Plug No. 3. at 275'.

Capped 7" surface casing at surface.

Hole suspended in this condtion.

LAND OWNERSHIP CLASS

and

ACCESS MAP

EXHIBIT H

This map is enclosed in the pocket on the inside front cover of the application binder.

EXHIBIT I

CHEMICAL ANALYSIS OF PRODUCED WATER

CONFIDENTIAL

THE MOGUL CORPORATION

Enviroservice Programs

ANALYTICAL REPORT

TOTAL WATER MOGUL MANAGEMENT

Company: Northwest Natural Gas Co.

Address: 122 N. W. Flanders

City, State and Zip: Portland, OR 97209

Attention: Tom Amies

Laboratory Reference Number: A 8891

Date Collected: 12/15/80

Date Received: 12/15/80

Date Analyzed:

SAMPLE NO.	SAMPLE TAKEN FROM	DATE	TIME	SAMPLE NO.	SAMPLE TAKEN FROM	DATE	TIME
1	Well # 1	12/15	12:00	3			
2				4			

CHEMICAL	NO. 1	NO. 2	NO. 3	NO. 4		NO. 1	NO. 2	NO. 3	NO. 4
Acidity as $CaCO_3$					Nitrogen, Organic as N				
Alkalinity as $CaCO_3$	122				Oil & Grease Freon				
Aluminum					Oil & Grease (Soxhlet)				
Antimony					pH S.U.	7.0			
Arsenic	<0.001				Phenols				
Barium	2.1				Phosphorous, Total as P				
Beryllium					Phosphorous Ortho as P				
BOD (5 - day)					Potassium				
Cadmium	0.005				Selenium	<0.001			
Calcium	6				Silicon as SiO_2	6			
Carbon, Total Organic					Silver	0.002			
COD					Sodium	109			
Chloride	247				Solids, Dissolved				
Chlorine					Solids, Settleable				
Chlorine Demand					Solids, Suspended				
Chromium Hexavalent					Solids, Total Dried at 180°C	541			
Chromium Total	<0.005				Solids, Total Volatile	60			
Cobalt					Solids, Volatile Dissolved				
Color (APHA)	400				Solids, Volatile Suspended				
Conduct. mmhos@25°C					Sulfate	6			
Copper	0.006				Sulfide	2.92			
Cyanide					Tin				
Cyanide (Amen. to Chlor.)					Titanium				
Fluorides (Distillation)	~~XXXX~~				Turbidity, NTU				
Fluorides (Direct)	0.135				Zinc	0.025			
Hardness, Total as $CaCO_3$	32								
Iron	15.8								
Lead	0.09								
Magnesium	0.54								
Manganese	0.37				**BIOLOGICAL (Bacteria)**				
Mercury	0.0017				Coliforms, Total *				
Molybdenum					Coliforms, Fecal *				
Nickel					Strepococci, Fecal				
Nitrate as N	<0.005				Standard Plate Count**				
Nitrite as N	0.01								
Nitrogen, Amm.Distill. as N									
Nitrogen, Kjeldahl as N									

NOTE: UNITS EXPRESSED IN MG/LITER UNLESS SPECIFIED OTHERWISE.

* indicates colonies/100 ml ** indicates colonies/ml

*This information is confidential under the provisions of ORS 520.095.

Jo Ann Bevans

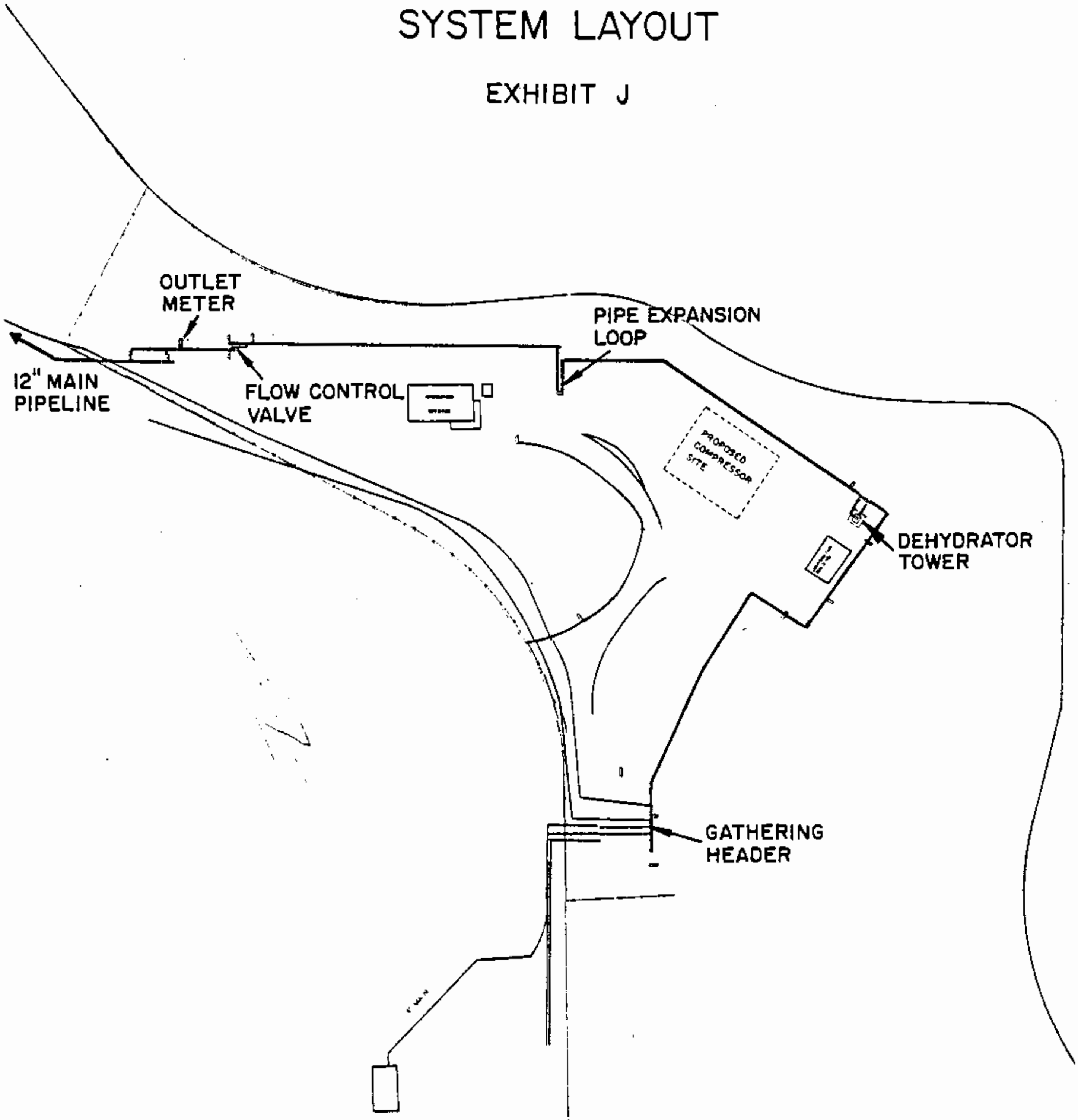
~~XXXXXXXXXXXXXXXX~~

Jo Ann Bevans/Laboratory Chemist

HH-3 WHITE — CUSTOMER CANARY — FILE PINK — MISCELLANEOUS Printed in the U.S.A.

MILLER STATION
SYSTEM LAYOUT

EXHIBIT J



MIST TOPOGRAPHIC MAP

EXHIBIT K

This map is enclosed in the pocket on the inside front cover of the application binder.

EXISTING PIPING, ROADS,

and

RIGHT-OF-WAYS

EXHIBIT L

This map is enclosed in the pocket on the inside front cover of the application binder.

REGULATIONS FOR THE TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE

PARTS 191 AND 192, TITLE 49 OF THE CODE OF FEDERAL REGULATIONS

REVISED AS OF OCTOBER 1, 1979

* NOTE: INCLUDING AMENDMENTS THROUGH JUNE 1, 1980

DEPARTMENT OF TRANSPORTATION

TABLE OF CONTENTS

PREFACE

These regulations, published by the Office of Operations and Enforcement, Materials Transportation Bureau, Research and Special Programs Administration, U. S. Department of Transportation are a reproduction of the Federal Gas Pipeline Safety Regulations, Parts 191 and 192 as they appear in Title 49, Code of Federal Regulations, Parts 100-199, revised as of October 1, 1979.

The Code of Federal Regulations is a codification of the general and permanent rules published in the Federal Register by departments and agencies of the Federal Government.

These regulations were current as of October 1, 1979. Since published, there have been changes made by amendments to these regulations published in the Federal Register. All amendments published between October 1, 1979 and June 1, 1980, have been noted and attached to this publication.

The following amendments to Part 192 were issued subsequent to October 1, 1979, and are set forth in this publication.

1. Amdt. 192-27B; Docket OPS-30
2. Amdt. 192-34A; Docket PS-54
3. Amdt. 192-35; Docket PS-52
4. Amdt. 192-35A; Docket PS-52

Note: Amendments to the regulations are identified by a vertical bar on the left.

The effective dates of amendments are usually not the same as the dates they are published in the Federal Register. Thus, care must be exercised by the user of these regulations to determine the actual effective date.

A note showing the effective date is included in the preamble of each amendment and in the text of the regulations if an amendmen becomes effective after it is published in the Code of Federal Requaltions.

Inquiries concerning technical or legal aspects of these regulations may be addressed to the Director, Office of Pipeline Safety Regulation, Department of Transportation, 400 Seventh Street S.W., Washington, D. C. 20590

SUBCHAPTER D—PIPELINE SAFETY

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; REPORTS OF LEAKS

AUTHORITY: 49 U.S.C. 1671 et seq.; 49 CFR Part 1; 33 FR 16468, unless otherwise noted.

SOURCE: 35 FR 320, Jan. 8, 1970, unless otherwise noted.

§ 191.1 Scope.

(a) This Part prescribes requirements for the reporting of gas leaks that are not intended by the operator and that require immediate or scheduled repair and of test failures, by persons engaged in the transportation of gas. However, it does not apply to leaks and test failures that occur in the gathering of gas outside of the following areas:

(1) An area within the limits of any incorporated or unincorporated city, town, or village; or

(2) Any designated residential or commercial area such as a subdivision, business or shopping center, or community development.

(b) The reporting requirements in this part supersede any accident or leak reporting requirements that were incorporated by reference in the Interim Minimum Federal Safety Standards in Part 190 of this chapter.

§ 191.3 Definitions.

As used in this Part and in the DOT Forms referenced in this Part—

"Gas" means natural gas, flammable gas, or gas which is toxic or corrosive;

"Municipality" means a city, county, or any other political subdivision of a State;

"Operator" means a person who engages in the transportation of gas;

"Person" means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof;

"Pipeline facilities" includes, without limitation, new and existing pipe, right-of-way, and any equipment facility, or building used in the transportation of gas or the treatment of gas during the course of transportation;

"Secretary" means the Secretary of Transportation or any person to whom he has delegated authority in the matter concerned;

"State" includes each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico;

"System" means all pipeline facilities used by a particular operator in the transportation of gas, including but not limited to, line pipe, valves and other appurtenances connected to line pipe, compressor units, fabricated assemblies associated with compressor units, metering (including customers' meters) and delivery stations, and fabricated assemblies in metering and delivery stations;

"Test failure" means a break or rupture that occurs during strength-proof testing of transmission or gathering lines that is of such magnitude as to require repair before continuation of the test;

"Transportation of gas" means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas in or affecting interstate or foreign commerce.

§ 191.5 Telephonic notice of certain leaks.

(a) At the earliest practicable moment following discovery, each operator shall give notice in accordance with paragraph (b) of this section of any leak that—

(1) Caused a death or a personal injury requiring hospitalization;

(2) Required the taking of any segment of transmission pipeline out of service;

(3) Resulted in gas igniting;

(4) Caused estimated damage to the property of the operator, or others, or both, of a total of $5,000 or more; or

(5) In the judgment of the operator, was significant even though it did not meet the criteria of paragraphs (a)(1), (2), (3), or (4) of this section.

An operator need not give notice of a leak that met only the criteria of paragraph (a) (2) or (3) of this paragraph, if it occurred solely as a result of, or in connection with, planned or routine maintenance or construction.

(b) Each notice required by paragraph (a) of this section shall be made by telephone to Area Code (202) 426-0700 and shall include the following information.

(1) The location of the leak.

(2) The time of the leak.

(3) The fatalities and personal injuries, if any.

(4) All other significant facts that are known by the operator that are relevant to the cause of the leak or extent of the damages.

(35 FR 320, Jan. 8, 1970, as amended by Amdt. 191-1, 36 FR 7507, Apr. 2, 1971)

§ 191.7 Addressee for written reports.

Each written report required by this part must be made to the Director, Office of Pipeline Safety, Department of Transportation, Washington, D.C. 20590. However, reports for intrastate facilities subject to the jurisdiction of a State agency pursuant to certification under section 5(a) of the Natural Gas Pipeline Safety Act; may be submitted in duplicate to the State agency if the regulations of that agency require submission of these reports and provide for further transmittal of one copy, within 10 days of receipt for leak reports and not later than February 15 for annual reports, to the Director, Office of Pipeline Safety.

§ 191.9 Distribution system: Leak report.

(a) Each operator of a distribution system serving more than 100,000 customers shall, as soon as practicable but not more than 20 days after detection, report the following on Department of Transportation Form DOT-F-7100.2:

(1) A leak that required notice by telephone under § 191.5.

(2) A leak that, because of its location, required immediate repair and other emergency action to protect the public such as evacuation of a building, blocking off an area, or rerouting of traffic.

(b) Where additional related information is obtained after a report is submitted under paragraph (a) of this section, the operator shall make a supplemental report as soon as practicable with a clear reference by date and subject to the original report.

§ 191.11 Distribution system: Annual report.

(a) Except as provided in paragraph (b) of this section, each operator of a distribution system shall submit an annual report on Department of Transportation Form DOT F 7100.1-1. This report must be submitted not later than February 15 for the preceding calendar year.

(b) The annual report required by paragraph (a) of this section need not be submitted with respect to petroleum gas systems which serve less than 100 customers from a single source.

(Amdt. 191-2, 37 FR 1173, Jan. 28, 1972)

§ 191.13 Distribution system: Certain facilities reported as a transmission system.

Each operator of a distribution system shall, for pipeline facilities that operate at 20 percent or more of specified minimum yield strength, or that are used to convey gas into or out of storage, submit reports for those facilities under § 191.15 and § 191.17.

§ 191.15 Transmission and gathering systems: Leak report.

(a) Each operator of a transmission system or a gathering system shall as soon as practicable but not more than 20 days after detection, report the following on Department of Transportation Form DOT-F-7100.2:

(1) A leak that required notice by telephone under § 191.5.

(2) A leak in a transmission line that required immediate repair.

(3) A test failure that occurred while testing either with gas or another test medium.

(b) Where additional related information is obtained after a report is submitted under paragraph (a) of this section, the operator shall make a supplemental report as soon as practicable with a clear reference by date and subject to the original report.

§ 191.17 Transmission and gathering systems: Annual report.

Each operator of a transmission system or a gathering system shall submit an annual report on Department of Transportation Form DOT-F-7100.2-1. This report must be submitted for the preceding calendar year not later than February 15, 1971, and not later than February 15 of each year thereafter.

§ 191.19 Report forms.

Copies of the prescribed report forms are available without charge upon request from the Office of Pipeline Safety. Additional copies in this prescribed format may be reproduced and used if in the same size and kind of paper. In addition, the information required by these forms may be submitted by any other means that is acceptable to the Secretary.

NOTE: The recordkeeping and reporting requirements of this regulation have been approved by the Office of Management and Budget in accordance with the Federal Reports Act of 1942.

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

AUTHORITY: Sec. 3, Pub. L. 90-481, 82 Stat. 721 (49 U.S.C. 1672); sections applicable to offshore gathering lines also issued under Sec. 105, Pub. L. 93-633, 88 Stat. 2157 (49 U.S.C. 1804); 40 FR 43901, 49 CFR 1.53; unless otherwise noted.

SOURCE: 35 FR 13257, Aug. 19, 1970, unless otherwise noted.

Subpart A—General

§ 192.1 Scope of part.

(a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to—

(1) Offshore gathering of gas upstream from the outlet flange of each facility on the outer continental shelf where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream; and

(2) Onshore gathering of gas outside of the following areas:

(i) An area within the limits of any incorporated or unincorporated city, town, or village.

(ii) Any designated residential or commercial area such as a subdivision, business or shopping center, or community development.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976]

§ 192.3 Definitions.

As used in this part—

"Distribution Line" means a pipeline other than a gathering or transmission line.

"Gas" means natural gas, flammable gas, or gas which is toxic or corrosive.

"Gathering Line" means a pipeline that transports gas from a current production facility to a transmission line or main.

"High pressure distribution system" means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

"Listed specification" means a specification listed in section I of Appendix B of this part.

"Low-pressure distribution system" means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

"Main" means a distribution line that serves as a common source of supply for more than one service line.

"Maximum actual operating pressure" means the maximum pressure that occurs during normal operations over a period of 1 year.

"Maximum allowable operating pressure" means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

"Municipality" means a city, county, or any other political subdivision of a State.

"Offshore" means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

"Operator" means a person who engages in the transportation of gas.

"Person" means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.

"Pipe" means any pipe or tubing used in the transportation of gas, including pipe-type holders.

"Pipeline" means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

"Pipeline facility" means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

"Secretary" means the Secretary of Transportation or any person to whom he has delegated authority in the matter concerned.

"Service line" means a distribution line that transports gas from a common source of supply to (a) a customer meter or the connection to a customer's piping, whichever is farther downstream, or (b) the connection to a customer's piping if there is no customer meter. A customer meter is the meter that measures the transfer of gas from an operator to a consumer.

"SMYS" means specified minimum yield strength is—

(a) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

(b) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with § 192.107(b).

"State" means each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico.

"Transmission line" means a pipeline, other than a gathering line, that—

(a) Transports gas from a gathering line or storage facility to a distribution center or storage facility;

(b) Operates at a hoop stress of 20 percent or more of SMYS; or

(c) Transports gas within a storage field.

"Transportation of gas" means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

[Amdt. 192-13, 38 FR 9084, Apr. 10, 1973, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976]

§ 192.5 Class locations.

(a) Offshore is Class 1 location. The Class location onshore is determined by applying the criteria set forth in this section: The class location unit is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. Except as provided in paragraphs (d)(2) and (f) of this section, the class location is determined by the buildings in the class location unit. For the purposes of this section, each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(b) A Class 1 location is any class location unit that has 10 or less buildings intended for human occupancy.

(c) A Class 2 location is any class location unit that has more than 10 but less than 46 buildings intended for human occupancy.

(d) A Class 3 location is—

(1) Any class location unit that has 46 or more buildings intended for human occupancy; or

(2) An area where the pipeline lies within 100 yards of any of the following:

(i) A building that is occupied by 20 or more persons during normal use.

(ii) A small, well-defined outside area that is occupied by 20 or more persons during normal use, such as a playground, recreation area, outdoor theater, or other place of public assembly.

(e) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

(f) The boundaries of the class locations determined in accordance with paragraphs (a) through (e) of this section may be adjusted as follows:

(1) A Class 4 location ends 220 yards from the nearest building with four or more stories above ground.

(2) When a cluster of buildings intended for human occupancy requires a Class 3 location, the Class 3 location ends 220 yards from the nearest building in the cluster.

(3) When a cluster of buildings intended for human occupancy requires a Class 2 location, the Class 2 location ends 220 yards from the nearest building in the cluster.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976]

§ 192.7 Incorporation by reference.

(a) Any documents or parts thereof incorporated by reference in this part are a part of this regulation as though set out in full.

(b) All incorporated documents are available for inspection in the Office of Pipeline Safety, Room 107, 400 Sixth Street SW., Washington, D.C. In addition, the documents are available at the addresses provided in Appendix A to this part.

(c) The full titles for the publications incorporated by reference in this part are provided in Appendix A to this part.

§ 192.9 Gathering lines.

Each gathering line must comply with the requirements of this part applicable to transmission lines.

§ 192.11 Petroleum gas systems.

(a) No operator may transport petroleum gas in a system that serves 10 or more customers, or in a system, any portion of which is located in a public place (such as a highway), unless that system meets the requirements of this part and of NFPA Standards No. 58 and No. 59. In the event of a conflict, the requirements of this part prevail.

(b) Each petroleum gas system covered by paragraph (a) of this section must comply with the following:

(1) Aboveground structures must have open vents near the floor level.

(2) Belowground structures must have forced ventilation that will prevent any accumulation of gas.

(3) Relief valve discharge vents must be located so as to prevent any accumulation of gas at or below ground level.

(4) Special precautions must be taken to provide adequate ventilation where excavations are made to repair an underground system.

(c) For the purpose of this section, petroleum gas means propane, butane, or mixtures of these gases, other than a gas air mixture that is used to supplement supplies in a natural gas distribution system.

§ 192.12 Liquefied natural gas facilities.

(a) Except for a pipeline facility in operation or under construction before January 1, 1973, no operator may store, treat, or transfer liquefied natural gas in a pipeline facility unless that pipeline facility meets the applicable requirements of this part and of NFPA Standard No. 59A.

(b) No operator may store, treat, or transfer liquefied natural gas in a pipeline facility in operation or under construction before January 1, 1973, unless—

(1) The facility is operated in accordance with the applicable operating requirements of this part and of NFPA Standard 59A; and

(2) Each modification or repair made to the facility after December 31, 1972, conforms to the applicable requirements of this part and NFPA Standard 59A, insofar as is practicable.

[Amdt. 192-10, 37 FR 21839, Oct. 13, 1972]

§ 192.13 General.

(a) No person may operate a segment of pipeline that is readied for service after March 12, 1971, or in the case of an offshore gathering line, after July 31, 1977, unless—

(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or

(2) The pipeline qualifies for use under this part in accordance with § 192.14.

(b) No person may operate a segment of pipeline that is replaced, relocated, or otherwise changed after November 12, 1970, or in the case of an offshore gathering line, after July 31, 1977, unless that replacement, relocation, or change has been made in accordance with this part.

(c) Each operator shall maintain, modify as appropriate, and follow plans, procedures, and programs that it is required to establish under this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-30, 42 FR 60148, Nov. 25, 1977]

§ 192.14 Conversion to service subject to this part.

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:

(1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation.

(2) The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.

(3) All known unsafe defects and conditions must be corrected in accordance with this part.

(4) The pipeline must be tested in accordance with Subpart J of this part to substantiate the maximum allowable operating pressure permitted by Subpart L of this part.

(b) Each operator must keep for the life of the pipeline a record of the investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (a) of this section.

[Amdt. 192-30, 42 FR 60148, Nov. 25, 1977]

§ 192.15 Rules of regulatory construction.

(a) As used in this Part—

"Includes" means including but not limited to.

"May" means "is permitted to" or "is authorized to".

"May not" means "is not permitted to" or "is not authorized to".

"Shall" is used in the mandatory and imperative sense.

(b) In this Part—

(1) Words importing the singular include the plural;

(2) Words importing the plural include the singular; and

(3) Words importing the masculine gender include the feminine.

§ 192.17 Filing of inspection and maintenance plans.

(a) Except as provided in paragraph (b) of this section, each operator shall file with the Secretary not later than February 1, 1971, a plan for inspection and maintenance of each pipeline facility which he owns or operates. In addition, each change to an inspection and maintenance plan must be filed with the Secretary within 20 days after the change is made.

(b) The provisions of paragraph (a) of this section do not apply to pipeline facilities—

(1) That are subject to the jurisdiction of a State agency that has submitted a certification or agreement with respect to those facilities under section 5 of the Natural Gas Pipeline Safety Act (49 U.S.C. 1675); and

(2) For which an inspection and maintenance plan is required to be filed with that State agency.

(c) Plans filed with the Secretary must be sent to the office of Pipeline Safety, Department of Transportation, Washington, D.C. 20590.

(Sec. 11, Natural Gas Pipeline Safety Act of 1968, 49 U.S.C. sec. 1671, et seq.; Part 1, Regulations of Office of the Secretary of Transportation, 49 CFR Part 1; delegation of authority to Director, Office of Pipeline Safety, dated Nov. 6, 1968, 33 FR 16468)

[35 FR 16405, Oct. 21, 1970]

Subpart B—Materials

§ 192.51 Scope.

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

§ 192.53 General.

Materials for pipe and components must be—

(a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

(b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and

(c) Qualified in accordance with the applicable requirements of this subpart.

§ 192.55 Steel pipe.

(a) New steel pipe is qualified for use under this part if—

(1) It was manufactured in accordance with a listed specification;

(2) It meets the requirements of—

(i) Section II of Appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of Appendix B to this part; or

(3) It is used in accordance with paragraph (c) or (d) of this section.

(b) Used steel pipe is qualified for use under this part if—

(1) It was manufactured in accordance with a listed specification and it meets the requirements of paragraph II-C of Appendix B to this part;

(2) It meets the requirements of—

(i) Section II of Appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of Appendix B to this part;

(3) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of Appendix B to this part; or

(4) It is used in accordance with paragraph (c) of this section.

(c) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 p.s.i. where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in paragraph II-B of Appendix B to this part.

(d) Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.

(e) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Standard 5LX.

(Sec. 3, Natural Gas Pipeline Safety Act of 1968, 49 U.S.C. 1672; sec. 1.58(d), regulations of the Office of the Secretary of Transportation, 49 CFR 1.58(d); the redelegation of authority to the Director, Office of Pipeline Safety, set forth in Appendix A to Part 1 of the regulations of the Office of the Secretary of Transportation, 49 CFR Part 1)

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 191-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-12, 38 FR 4761, Feb. 22, 1973]

§ 192.57 Cast iron or ductile iron pipe.

(a) New cast iron or new ductile iron pipe is qualified for use under this part if it has been manufactured in accordance with a listed specification.

(b) Used cast iron or used ductile iron pipe is qualified for use under this part if inspection shows that the pipe is sound and allows the makeup of tight joints and—

(1) It has been removed from an existing pipeline that operated at the same or higher pressure; or

(2) It was manufactured in accordance with a listed specification.

§ 192.59 Plastic pipe.

(a) New plastic pipe is qualified for use under this part if—

(1) When the pipe is manufactured, it is manufactured in accordance with the latest listed edition of a listed specification, except that before March 21, 1975, it may be manufactured in accordance with any listed edition of a listed specification; and

(2) It is resistant to chemicals with which contact may be anticipated.

(b) Used plastic pipe is qualified for use under this part if—

(1) When the pipe was manufactured, it was manufactured in accordance with the latest listed edition of a listed specification, except that pipe manufactured before March 21, 1975, need only have met the requirements of any listed edition of a listed specification;

(2) It is resistant to chemicals with which contact may be anticipated;

(3) It has been used only in natural gas service;

(4) Its dimensions are still within the tolerances of the specification to which it was manufactured; and

(5) It is free of visible defects.

(c) For the purpose of paragraphs (a)(1) and (b)(1) of this section, where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it—

(1) Meets the strength and design criteria required of pipe included in that listed specification; and

(2) Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-19, 40 FR 10472, Mar. 6, 1975]

§ 192.61 Copper pipe.

Copper pipe is qualified for use under this part if it has been manufactured in accordance with a listed specification.

§ 192.63 Marking of materials.

(a) Except as provided in paragraph (e) of this section, each valve, fitting, length of pipe, and other component must be marked as prescribed in—

(1) The specification or standard to which it was manufactured; or

(2) MSS Standard Practice, SP-25.

(b) In addition to the requirements in paragraph (a) of this section, thermoplastic pipe manufactured in accordance with the 1974a or earlier listed edition of ASTM D2513 must be marked as required by section 9.2 of ASTM D2513 (1975b edition) unless the pipe was manufactured before May 18, 1978, and is installed where operating temperatures are not above 38° C (100° F).

(c) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(d) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

(e) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:

(1) The item is identifiable as to type, manufacturer, and model.

(2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

(49 U.S.C. 1672; 49 U.S.C. 1804; App. A of Part 1 and App. A of Part 102 of 49 CFR)

[Amdt. 192-1, 35 FR 17660, Nov. 17, 1970, as amended by Amdt. 192-31, 43 FR 13883, Apr. 3, 1978]

§ 192.65 Transportation of pipe.

In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by railroad unless—

(a) The transportation is performed in accordance with the 1972 edition of API RP5L1, except that before February 25, 1975, the transportation may be performed in accordance with the 1967 edition of API RP5L1.

(b) In the case of pipe transported before November 12, 1970, the pipe is tested in accordance with Subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under Subpart J of this part, the test pressure must be maintained for at least 8 hours.

(Sec. 3, Natural Gas Pipeline Safety Act of 1968, 49 U.S.C. 1672; sec. 1.58(d), regulations of the Office of the Secretary of Transportation, 49 CFR 1.58(d); the redelegation of authority to the Director, Office of Pipeline Safety, set forth in Appendix A to Part 1 of the regulations of the Office of the Secretary of Transportation, 49 CFR Part 1)

[Amdt. 192-12, 38 FR 4761, Feb. 22, 1973, as amended by Amdt. 192-17, 40 FR 6346, Feb. 11, 1975]

Subpart C—Pipe Design

§ 192.101 Scope.

This subpart prescribes the minimum requirements for the design of pipe.

§ 192.103 General.

Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

§ 192.105 Design formula for steel pipe.

(a) The design pressure for steel pipe is determined in accordance with the following formula:

$$P=(2\,St/D)\times F\times E\times T$$

P = Design pressure in pounds per square inch gauge.

S = Yield strength in pounds per square inch determined in accordance with § 192.107.

D = Nominal outside diameter of the pipe in inches.

t = Nominal wall thickness of the pipe in inches. If this is unknown, it is determined in accordance with § 192.109. Additional wall thickness required for concurrent external loads in accordance with § 192.103 may not be included in computing design pressure.

F = Design factor determined in accordance with § 192.111.

E = Longitudinal joint factor determined in accordance with § 192.113.

T = Temperature derating factor determined in accordance with § 192.115.

(b) If steel pipe that has been cold worked to meet the SMYS is heated, other than by welding, to 600° F. or more, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section.

§ 192.107 Yield strength (S) for steel pipe.

(a) For pipe that is manufactured in accordance with a specification listed in section I of Appendix B of this part, the yield strength to be used in the design formula in § 192.105 is the SMYS stated in the listed specification, if that value is known.

(b) For pipe that is manufactured in accordance with a specification not listed in section I of Appendix B to this part or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in § 192.105 is one of the following:

(1) If the pipe is tensile tested in accordance with section II-D of Appendix B to this part, the lower of the following:

(i) 80 percent of the average yield strength determined by the tensile tests.

(ii) The lowest yield strength determined by the tensile tests, but not more than 52,000 p.s.i.

(2) If the pipe is not tensile tested as provided in paragraph (b)(1) of this section 24,000 p.s.i.

§ 192.109 Nominal wall thickness (t) for steel pipe.

(a) If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

(b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in § 192.105 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches or more in outside diameter.

§ 192.111 Design factor (F) for steel pipe.

(a) Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in § 192.105 is determined in accordance with the following table:

Class location	Design factor (F)
1	0.72
2	0.60
3	0.50
4	0.40

(b) A design factor of 0.60 or less must be used in the design formula in § 192.105 for steel pipe in Class 1 locations that:

(1) Crosses the right-of-way of an unimproved public road, without a casing;

(2) Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;

(3) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or

(4) Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

(c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in § 192.105 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

(d) For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in § 192.105 for—

(1) Steel pipe in a compressor station, regulating station, or measuring station; and

(2) Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976]

§ 192.113 Longitudinal joint factor (E) for steel pipe.

The longitudinal joint factor to be used in the design formula in § 192.105 is determined in accordance with the following table:

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.60
ASTM A 106	Seamless	1.00
ASTM A 134	Electric fusion arc welded	.80
ASTM A 135	Electric resistance welded	1.00
ASTM A 139	Electric fusion welded	.80
ASTM A 155	Electric fusion arc welded	1.00
ASTM A 211	Spiral welded steel pipe	.80
ASTM A 333	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
API 5 L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	.60
	Furnace lap-welded	.80
API 5 LX	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
API 5 LS	Electric resistance welded	1.00
	Submerged arc welded	1.00
Other	Pipe over 4 inches	.80
Other	Pipe 4 inches or less	.60

If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other".

§ 192.115 Temperature derating factor (T) for steel pipe.

The temperature derating factor to be used in the design formula in § 192.105 is determined as follows:

Gas temperature in degrees Fahrenheit	Temperature derating factor (T)
250 or less	1.000
300	0.967
350	0.933
400	0.900
450	0.867

For intermediate gas temperatures, the derating factor is determined by interpolation.

§ 192.117 Design of cast iron pipe.

Cast iron pipe must be designed in accordance with ANSI A 21.1 using the following values for S (bursting tensile strength) and R (modulus of rupture) in the design equations:

Specification	Type of pipe	S	R
		psi	psi
ANSI A 21.3	Pit cast	11,000	31,000
ANSI A 21.7	Centrifugal (metal mold)	18,000	40,000
ANSI A 21.9	Centrifugal (sand-lined mold)	18,000	40,000

§ 192.119 Design of ductile iron pipe.

(a) Ductile iron pipe must be designed in accordance with ANSI A21.50 using the following values in the design equations:

s (design hoop stress) = 16,800 p.s.i.
f (design bending stress) = 36,000 p.s.i.

(b) Ductile iron pipe must be grade (60-42-10) and must conform to the requirements of ANSI A21.52.

§ 192.121 Design of plastic pipe.

The design pressure for plastic pipe is determined in accordance with the following formula, subject to the limitations of § 192.123:

$$P = 2S \frac{t}{(D-t)} \times 0.32$$

P = Design pressure, gage, kPa (psi).

S = For thermoplastic pipe the long-term hydrostatic strength determined in accordance with the listed specification at a temperature equal to 23° C (73° F), 38° C (100° F), 49° C (120° F), or 60° C (140° F); for reinforced thermosetting plastic pipe, 75,800 kPa (11,000 psi).

t = Specified wall thickness, mm (in.).

D = Specified outside diameter, mm (in.)

(49 U.S.C. 1672; 49 U.S.C. 1804, App. A of part 1, 49 CFR)

[Amdt. 192-31, 43 FR 13883, Apr. 3, 1978; 43 FR 43308, Sept. 25, 1978]

§ 192.123 Design limitations for plastic pipe.

(a) The design pressure may not exceed a gauge pressure of 689 kPa (100 psig) for plastic pipe used in—

(1) Distribution systems; or

(2) Classes 3 and 4 locations.

(b) Plastic pipe may not be used where operating temperatures of the pipe will be—

(1) Below minus 29° C (−20° F); or

(2) In the case of thermoplastic pipe, above the temperature at which the long-term hydrostatic strength used in the design formula under § 192.121 is determined, except that pipe manufactured before May 18, 1978, may be used at temperatures up to 38° C (100° F); or in the case of reinforced thermosetting plastic pipe, above 66° C (150° F).

(c) The wall thickness for thermoplastic pipe may not be less than 1.57 millimeters (0.062 in.).

(d) The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

Nominal size in inches	Minimum wall thickness in millimeters (inches)
2	1.52 (0.060)
3	1.52 (0.060)
4	1.78 (0.070)
6	2.54 (0.100)

(49 U.S.C. 1672; 49 U.S.C. 1804, App. A of Part 1, 49 CFR)

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-31, 43 FR 13883, Apr. 3, 1978]

§ 192.125 Design of copper pipe.

(a) Copper pipe used in mains must have a minimum wall thickness of 0.065 inches and must be hard drawn.

(b) Copper pipe used in service lines must have a minimum wall thickness as specified for type "L" pipe in ASTM B 88.

(c) Copper pipe used in mains and service lines may not be used at pressures in excess of 100 p.s.i.g.

(d) Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains per 100 standard cubic feet of gas.

Subpart D—Design of Pipeline Components

§ 192.141 Scope.

This subpart prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

§ 192.143 General requirements.

Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service.

§ 192.145 Valves.

(a) Each valve must meet the minimum requirements, or the equivalent, of API 6A, API 6D, MSS SP-70, MSS SP-71, or MSS SP-78, except that a valve designed before July 1, 1978, may meet the minimum requirements of MSS SP-52. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those standards.

(b) Each valve must be able to meet the anticipated operating conditions.

(c) No valve having shell components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if—

(1) The temperature-adjusted service pressure does not exceed 1,000 p.s.i.g.; and

(2) Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

(d) No value having pressure containing parts made of ductile iron may be used in the gas pipe components of compressor stations.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-22, 41 FR 13590, Mar. 31, 1978]

§ 192.147 Flanges and flange accessories.

(a) *General requirements.* Each flange or flange accessory must meet the minimum requirements of ANSI B16.5, MSS SP-44, or ANSI B16.24, or the equivalent.

(b) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

§ 192.149 Standard fittings.

(a) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this part, or their equivalent.

(b) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

§ 192.151 Tapping.

(a) Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.

(b) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

(c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that.

(1) Existing taps may be used for replacement service, if they are free of cracks and have good threads; and

(2) A 1¼-inch tap may be made in a 4-inch cast iron or ductile iron pipe, without reinforcement.

However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6-inch or larger pipe.

§ 192.153 Components fabricated by welding.

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of section VIII of the ASME Boiler and Pressure Vessel Code.

(b) Each prefabricated unit that uses plate and longitudinal seams must be designated, constructed, and tested in accordance with the ASME Boiler and Pressure Vessel Code, except for the following:

(1) Regularly manufactured butt-welding fittings.

(2) Pipe that has been produced and tested under a specification listed in Appendix B to this part.

(3) Partial assemblies such as split rings or collars.

(4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i.g., or more, or is more than 3 inches nominal diameter.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§ 192.155 Welded branch connections.

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

§ 192.157 Extruded outlets.

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

§ 192.159 Flexibility.

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

§ 192.161 Supports and anchors.

(a) Each pipeline and its associated equipment must have enough anchors or supports to—

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

(1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.

(2) Provision must be made for the service conditions involved.

(3) Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

(1) A structural support may not be welded directly to the pipe.

(2) The support must be provided by a member that completely encircles the pipe.

(3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

(e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

(f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent lateral and vertical movement.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976]

§ 192.163 Compressor stations: design and construction.

(a) *Location of compressor building.* Except for a compressor building on a platform located offshore or in inland navigable waters, each main compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of fire-fighting equipment.

(b) *Building construction.* Each building on a compressor station site must be made of noncombustible materials if it contains either—

(1) Pipe more than 2 inches in diameter that is carrying gas under pressure; or

(2) Gas handling equipment other than gas utilization equipment used for domestic purposes.

(c) *Exits.* Each operating floor of a main compressor building must have at least two separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be of a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.

(d) *Fenced areas.* Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety, or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.

(e) *Electrical facilities.* Electrical equipment and wiring installed in compressor stations must conform to the National Electrical Code, ANSI Standard C1, so far as that code is applicable.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976]

§ 192.165 Compressor stations: liquid removal.

(a) Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.

(b) Each liquid separator used to remove entrained liquids at a compressor station must—

(1) Have a manually operable means of removing these liquids.

(2) Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and

(3) Be manufactured in accordance with section VIII of the ASME Boiler and Pressure Vessel Code, except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.

§ 192.167 Compressor stations: emergency shutdown.

(a) Except for unattended field compressor stations of 1,000 horsepower or less, each compressor station must have an emergency shutdown system that meets the following:

(1) It must be able to block gas out of the station and blow down the station piping.

(2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.

(3) It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except, that—

(i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and

(ii) Electrical circuits needed to protect equipment from damage may remain energized.

(4) It must be operable from at least two locations, each of which is—

(i) Outside the gas area of the station;

(ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and

(iii) Not more than 500 feet from the limits of the station.

(b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

(c) On a platform located offshore or in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:

(1) In the case of an unattended compressor station—

(i) When the gas pressure equals the maximum allowable operating pressure plus 15 percent; or

(ii) When an uncontrolled fire occurs on the platform; and

(2) In the case of a compressor station in a building—

(i) When an uncontrolled fire occurs in the building; or

(ii) When the concentration of gas in air reaches 50 percent or more of the lower explosive limit in a building which has a source of ignition.

For the purpose of paragraph (c)(2)(ii) of this section, an electrical facility which conforms to Class 1, Group D of the National Electrical Code is not a source of ignition.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976]

§ 192.169 Compressor stations: pressure limiting devices.

(a) Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent.

(b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

§ 192.171 Compressor stations: additional safety equipment.

(a) Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.

(b) Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

(c) Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

(d) Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

(e) Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

§ 192.173 Compressor stations: ventilation.

Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

§ 192.175 Pipe-type and bottle-type holders.

(a) Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the holder, in connecting pipe, or in auxiliary equipment, that might cause corrosion or interfere with the safe operation of the holder.

(b) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:

$$C=(3D\times P\times F)/1{,}000$$

in which:

C = Minimum clearance between pipe containers or bottles in inches.

D = Outside diameter of pipe containers or bottles in inches.

P = Maximum allowable operating pressure, p.s.i.g.

F = Design factor as set forth in § 192.111 of this part.

§ 192.177 Additional provisions for bottle-type holders.

(a) Each bottle-type holder must be—

(1) Located on a storage site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum allowable operating pressure	Minimum clearance (feet)
Less than 1,000 p.s.i.g.	25
1,000 p.s.i.g. or more	100

(2) Designed using the design factors set forth in § 192.111; and

(3) Buried with a minimum cover in accordance with § 192.327.

(b) Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:

(1) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in either API Standard 5A or ASTM A 372.

(2) The actual yield-tensile ratio of the steel may not exceed 0.85.

(3) Welding may not be performed on the holder after it has been heat treated or stress relieved, except that copper wires may be attached to the small diameter portion of the bottle end closure for cathodic protection if a localized thermit welding process is used.

(4) The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85 percent of the SMYS.

(5) The holder, connection pipe, and components must be leak tested after installation as required by Subpart J of this part.

§ 192.179 Transmission line valves.

(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows:

(1) Each point on the pipeline in a Class 4 location must be within 2½ miles of a valve.

(2) Each point on the pipeline in a Class 3 location must be within 4 miles of a valve.

(3) Each point on the pipeline in a Class 2 location must be within 7½ miles of a valve.

(4) Each point on the pipeline in a Class 1 location must be within 10 miles of a valve.

(b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:

(1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

(2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blow-down valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

(d) Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow of gas to an offshore platform in an emergency.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976]

§ 192.181 Distribution line valves.

(a) Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

(b) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

(c) Each valve on a main installed for operating or emergency purposes must comply with the following:

(1) The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.

(2) The operating stem or mechanism must be readily accessible.

(3) If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

§ 192.183 Vaults: Structural design requirements.

(a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.

(b) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.

(c) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inches, and less, except that control and gage piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gasses or liquids through the opening and to avert strains in the pipe.

§ 192.185 Vaults: accessibility.

Each vault must be located in an accessible location and, so far as practical, away from—

(a) Street intersections or points where traffic is heavy or dense;

(b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and

(c) Water, electric, steam, or other facilities.

§ 192.187 Vaults: sealing, venting, and ventilation.

Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated, as follows:

(a) When the internal volume exceeds 200 cubic feet—

(1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches in diameter;

(2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and

(3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.

(b) When the internal volume is more than 75 cubic feet but less than 200 cubic feet—

(1) If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;

(2) If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or

(3) If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.

(c) If a vault or pit covered by paragraph (b) of this section is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.

§ 192.189 Vaults: drainage and waterproofing.

(a) Each vault must be designed so as to minimize the entrance of water.

(b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

(c) All electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, ANSI Standard C1.

§ 192.191 Design pressure of plastic fittings.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517.

(b) The design pressure of acrylonitrile-butadiene-styrene (ABS) and polyvinyl chloride (PVC) Schedule 40 and 80 thermoplastic fittings must be obtained from the following table:

DESIGN PRESSURE OF THERMOPLASTIC FITTINGS, P.S.I.G. OF VARIOUS STRENGTHS, MATERIALS AND CLASS LOCATIONS

Size inches	Schedule	ABS Type I and PVC Type II class location			PVC Type I class location		
		1	2 and 3	4	1	2 and 3	4
½	40	100	100	100	100	100	100
	80	100	100	100	100	100	100
¾	40	100	100	96	100	100	100
	80	100	100	100	100	100	100
1	40	100	100	90	100	100	100
	80	100	100	100	100	100	100
1¼	40	100	92	74	100	100	100
	80	100	100	100	100	100	100
1½	40	100	83	68	100	100	100
	80	100	100	94	100	100	100
2	40	89	69	55	100	100	100
	80	100	100	91	100	100	100
2½	40	98	76	61	100	100	100
	80	100	100	85	100	100	100
3	40	94	56	53	100	100	100
	80	100	94	75	100	100	100
3½	40	77	60	48	100	100	96
	80	100	96	69	100	100	100

DESIGN PRESSURE OF THERMOPLASTIC FITTINGS, P.S.I.G. OF VARIOUS STRENGTHS, MATERIALS AND CLASS LOCATIONS—Continued

Size inches	Schedule	ABS Type I and PVC Type II class location			PVC Type I class location		
		1	2 and 3	4	1	2 and 3	4
4	40	71	58	44	100	100	99
	80	100	81	65	100	100	100
5	40	62	49	39	100	97	78
	80	93	72	58	100	100	100
6	40	58	44	35	100	88	71
	80	89	70	56	100	100	100

NOTE: These pressure ratings are the same value as the design pressure of the corresponding pipe size and schedule in the same class location, as determined by the formula given in § 192.121 and the limitations in § 192.123 of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§ 192.193 Valve installation in plastic pipe.

Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

§ 192.195 Protection against accidental overpressuring.

(a) *General requirements.* Except as provided in §192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of §§ 192.199 and 192.201.

(b) *Additional requirements for distribution systems.* Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must—

(1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

(2) Be designed so as to prevent accidental overpressuring.

§ 192.197 Control of the pressure of gas delivered from high-pressure distribution systems.

(a) If the maximum actual operating pressure of the distribution system is under 60 p.s.i.g. and a service regulator having the following characteristics is used, no other pressure limiting device is required:

(1) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.

(2) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.

(3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.

(4) Pipe connections to the regulator not exceeding 2 inches in diameter.

(5) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(6) A self-contained service regulator with no external static or control lines.

(b) If the maximum actual operating pressure of the distribution system is 60 p.s.i.g., or less, and a service regulator that does not have all of the characteristics listed in paragraph (a) of this section is used, or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

(c) If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i.g., one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

(1) A service regulator having the characteristics listed in paragraph (a) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i.g. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 p.s.i.g. or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, if the pressure on the inlet of the service regulator exceeds the set pressure (60 p.s.i.g. or less), and remains closed until manually reset.

(2) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

(3) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 p.s.i.g. For higher inlet pressures, the methods in paragraph (c) (1) or (2) of this section must be used.

(4) A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 7, 1970]

§ 192.199 Requirements for design of pressure relief and limiting devices.

Except for rupture discs, each pressure relief or pressure limiting device must—

(a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;

(b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

(c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;

(d) Have support made of noncombustible material;

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

(f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

(g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and

(h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§ 192.201 Required capacity of pressure relieving and limiting stations.

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system—

(i) If the maximum allowable operating pressure is 60 p.s.i.g. or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

(ii) If the maximum allowable operating pressure is 12 p.s.i.g. or more, but less than 60 p.s.i.g., the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i.g.; or

(iii) If the maximum allowable operating pressure is less than 12 p.s.i.g., the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

(b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

(c) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-9, 37 FR 20827, Oct. 4, 1972]

§ 192.203 Instrument, control, and sampling pipe and components.

(a) *Applicability.* This section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

(b) *Materials and design.* All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

(1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.

(2) A shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.

(3) Brass or copper material may not be used for metal temperatures greater than 400° F.

(4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.

(5) Pipe or components in which liquids may accumulate must have drains or drips.

(6) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

(7) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.

(8) Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself.

(9) Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

Subpart E—Welding of Steel in Pipelines

§ 192.221 Scope.

(a) This subpart prescribes minimum requirements for welding steel materials in pipelines.

(b) This subpart does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

§ 192.223 General.

(a) Welding must be performed in accordance with established written welding procedures that have been qualified under § 192.225 to produce sound, ductile welds.

(b) Welding must be performed by welders who are qualified under §§ 192.227 and 192.229 for the welding procedure to be used.

§ 192.225 Qualification of welding procedures.

(a) Each welding procedure must be qualified under Section IX of the 1974 edition of the ASME Boiler and Pressure Vessel Code or Section 2 of the 1973 edition of API Standard 1104, whichever is appropriate to the function of the weld, except that a welding procedure qualified under Section IX of the 1968 edition of the ASME Boiler and Pressure Vessel Code before July 1, 1976, or Section 2 of the 1968 edition of API Standard 1104 before March 20, 1975, may continue to be used but may not be requalified under that edition.

(b) When a welding procedure is being qualified under section IX of the ASME Boiler and Pressure Vessel Code, the following steels are considered to fall within the P-Number 1 grouping for the purpose of the essential variables and do not require separate qualification of welding procedures:

(1) Carbon steels that have a carbon content of 0.32 percent (ladle analysis) or less.

(2) Carbon steels that have a carbon equivalent (C + ¼ Mn) of 0.65 percent (ladle analysis) or less.

(3) Alloy steels with weldability characteristics that have been shown to be similar to the carbon steels listed in paragraphs (b) (1) and (2) of this section.

Alloy steels and carbon steels that are not covered by paragraph (b) (1), (2), or (3) of this section require separate qualification of procedures for each individual pipe specification in accordance with sections VIII and IX of the ASME Boiler and Pressure Vessel Code.

(c) Each welding procedure must be recorded in detail during the qualifying tests. This record must be retained and followed whenever the procedure is used.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-22, 41 FR 13591, Mar. 31, 1976]

§ 192.227 Qualification of welders.

(a) Except as provided in paragraph (c) of this section, each welder must be qualified in accordance with one of the following:

(1) Section IX of the 1974 edition of the ASME Boiler and Pressure Vessel Code or, if qualified before July 1, 1976, the 1968 edition, except that a welder may not requalify under the 1968 edition.

(2) The following editions of section 3 of API Standard 1104:

(i) The 1973 edition, except that a welder may be qualified by radiography under subsection 3.51 without regard for the standards in subsection 6.9 for depth of undercutting adjacent to the root bead unless that depth is visually determined by use of a depth measuring device on all undercutting along the entire circumference of the weld; or

(ii) If a welder is qualified before March 20, 1975, the 1968 edition, except that a welder may not requalify under the 1968 edition.

(b) When a welder is being qualified under section IX of the ASME Boiler and Pressure Vessel Code, the following steels are considered to fall within the P-Number 1 grouping for the purpose of the essential variables and do not require separate qualification:

(1) Carbon steels that have a carbon content of 0.32 percent (ladle analysis) or less.

(2) Carbon steels that have a carbon equivalent (C + ¼ Mn) of 0.65 percent (ladle analysis) or less.

(3) Alloy steels with weldability characteristics that have been shown to be similar to the carbon steels listed in paragraphs (b) (1) and (2) of this section.

Alloy steels and carbon steels that are not covered by paragraph (b) (1), (2), or (3) of this section require separate qualification of welders for each individual pipe specification in accordance with sections VIII and IX of the ASME Boiler and Pressure Vessel Code.

(c) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C to this part. A welder who makes welded service line connections to mains must also perform an acceptable test weld under section II of Appendix C to this part as a part of his qualifying test. After initial qualification, a welder may not perform welding unless—

(1) Within the preceding 12 calendar months, he has requalified; or

(2) Within the preceding 6 calendar months he has had—

(i) A production weld cut out, tested and found acceptable in accordance with the qualifying test; or

(ii) For welders who work only on service lines 2 inches or smaller in diameter, two sample welds tested and found acceptable in accordance with the test in section III of Appendix C to this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-18, 40 FR 10182, Mar. 5, 1975; Amdt. 192-18A, 40 FR 27222, June 27, 1975; Amdt. 192-22, 41 FR 13591, Mar. 31, 1976]

§ 192.229 Limitations on welders.

(a) No welder whose qualification is based on nondestructive testing may weld compressor station pipe and components.

(b) No welder may weld with a particular welding process unless, within the preceding 6 calendar months, he has engaged in welding with that process.

(c) A welder qualified under § 192.227(a) may not weld unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under—

(1) Section 3 or 6 of the 1973 edition of API Standard 1104, except for the standards in subsection 6.9 for depth of undercutting adjacent to the root bead unless that depth is visually determined by use of a depth measuring device on all undercutting along the entire circumference of the weld; or

(2) In the case of tests conducted before March 20, 1975, section 3 or 6 of the 1968 edition of API Standard 1104.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-18, 40 FR 10182, Mar. 5, 1975; Amdt. 192-18A, 40 FR 27223, June 27, 1975]

§ 192.231 Protection from weather.

The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

§ 192.233 Miter joints.

(a) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3°.

(b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than 12½° and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

(c) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90°.

§ 192.235 Preparation for welding.

Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

§ 192.237 Preheating.

(a) Carbon steel that has a carbon content in excess of 0.32 percent (ladle analysis) or a carbon equivalent (C + ¼ Mn) in excess of 0.65 percent (ladle analysis) must be preheated for welding.

(b) Carbon steel that has a lower carbon content or carbon equivalent than the steels covered by paragraph (a) of this section must be preheated for welding when preheating will alleviate existing conditions that would limit the welding technique or tend to adversely affect the quality of the weld.

(c) When steel materials with different preheat temperatures are being preheated for welding, the higher temperature must be used.

(d) Preheat temperature must be monitored to ensure that the required preheat temperature is reached before, and maintained during, the welding operation.

§ 192.239 Stress relieving.

(a) Except as provided in paragraph (f) of this section, each weld on carbon steel that has a carbon content in excess of 0.32 percent (ladle analysis) or a carbon equivalent (C + ¼ Mn) in excess of 0.65 percent (ladle analysis) must be stress relieved as prescribed in section VIII of the ASME Boiler and Pressure Vessel Code.

(b) Except as provided in paragraph (f) of this section, each weld on carbon steel that has a carbon content of less than 0.32 percent (ladle analysis) or a carbon equivalent (C + ¼ Mn) of less than 0.65 percent (ladle analysis) must be thermally stress relieved when conditions exist which cool the weld at a rate detrimental to the quality of the weld.

(c) Except as provided in paragraph (f) of this section, each weld on carbon steel pipe with a wall thickness of more than 1¼ inches must be stress relieved.

(d) When a weld connects pipe or components that are of different thickness, the wall thickness to be used in determining whether stress relieving is required under this section is—

(1) In the case of pipe connections, the thicker of the two pipes joined; or

(2) In the case of branch connections, slip-on flanges, or socket weld fittings, the thickness of the pipe run or header.

(e) Each weld of different materials must be stress relieved, if either material requires stress relieving under this section.

(f) Notwithstanding paragraphs (a), (b), and (c) of this section, stress relieving is not required for the following:

(1) A fillet or groove weld one-half inch, or less, in size (leg) that attaches a connection 2 inches, or less, in diameter; or

(2) A fillet or groove weld three-eighths inch, or less, in groove size that attaches a supporting member or other nonpressure attachment.

(g) Stress relieving required by this section must be performed at a temperature of at least 1,100° F. for carbon steels and at least 1,200° F. for ferritic alloy steels. When stress relieving a weld between steel materials with different stress relieving temperatures, the higher temperature must be used.

(h) When stress relieving, the temperature must be monitored to ensure that a uniform temperature is maintained and that the proper stress relieving cycle is accomplished.

§ 192.241 Inspection and test of welds.

(a) Visual inspection of welding must be conducted to insure that—

(1) The welding is performed in accordance with the welding procedure; and

(2) The weld is acceptable under paragraph (c) of this section.

(b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with § 192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if—

(1) The pipe has a nominal diameter of less than 6 inches; or

(2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 6 of the 1973 edition of API Standard 1104. However, the standards in subsection 6.9 for depth of undercutting adjacent to the root bead apply only if—

(1) That depth is visually determined by use of a depth measuring device on all undercutting along the entire circumference of the weld; and

(2) Visual determination of internal undercutting is made in all pipe of the

(c) When steel materials with different preheat temperatures are being preheated for welding, the higher temperature must be used.

(d) Preheat temperature must be monitored to ensure that the required preheat temperature is reached before, and maintained during, the welding operation.

§ 192.239 Stress relieving.

(a) Except as provided in paragraph (f) of this section, each weld on carbon steel that has a carbon content in excess of 0.32 percent (ladle analysis) or a carbon equivalent (C + ¼ Mn) in excess of 0.65 percent (ladle analysis) must be stress relieved as prescribed in section VIII of the ASME Boiler and Pressure Vessel Code.

(b) Except as provided in paragraph (f) of this section, each weld on carbon steel that has a carbon content of less than 0.32 percent (ladle analysis) or a carbon equivalent (C + ¼ Mn) of less than 0.65 percent (ladle analysis) must be thermally stress relieved when conditions exist which cool the weld at a rate detrimental to the quality of the weld.

(c) Except as provided in paragraph (f) of this section, each weld on carbon steel pipe with a wall thickness of more than 1¼ inches must be stress relieved.

(d) When a weld connects pipe or components that are of different thickness, the wall thickness to be used in determining whether stress relieving is required under this section is—

(1) In the case of pipe connections, the thicker of the two pipes joined; or

(2) In the case of branch connections, slip-on flanges, or socket weld fittings, the thickness of the pipe run or header.

(e) Each weld of different materials must be stress relieved, if either material requires stress relieving under this section.

(f) Notwithstanding paragraphs (a), (b), and (c) of this section, stress relieving is not required for the following:

(1) A fillet or groove weld one-half inch, or less, in size (leg) that attaches a connection 2 inches, or less, in diameter; or

(2) A fillet or groove weld three-eighths inch, or less, in groove size that attaches a supporting member or other nonpressure attachment.

(g) Stress relieving required by this section must be performed at a temperature of at least 1,100° F. for carbon steels and at least 1,200° F. for ferritic alloy steels. When stress relieving a weld between steel materials with different stress relieving temperatures, the higher temperature must be used.

(h) When stress relieving, the temperature must be monitored to ensure that a uniform temperature is maintained and that the proper stress relieving cycle is accomplished.

§ 192.241 Inspection and test of welds.

(a) Visual inspection of welding must be conducted to insure that—

(1) The welding is performed in accordance with the welding procedure; and

(2) The weld is acceptable under paragraph (c) of this section.

(b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with § 192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if—

(1) The pipe has a nominal diameter of less than 6 inches; or

(2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 6 of the 1973 edition of API Standard 1104. However, the standards in subsection 6.9 for depth of undercutting adjacent to the root bead apply only if—

(1) That depth is visually determined by use of a depth measuring device on all undercutting along the entire circumference of the weld; and

(2) Visual determination of internal undercutting is made in all pipe of the same diameter in a pipeline, except where impractical at tie-in welds.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-18A, 40 FR 27223, June 27, 1975]

§ 192.243 Nondestructive testing.

(a) Nondestructive testing of welds must be performed by any process other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.

(b) Nondestructive testing of welds must be performed—

(1) In accordance with written procedures; and

(2) By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.

(c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under § 192.241(c).

(d) When nondestructive testing is required under § 192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:

(1) In Class 1 locations, except offshore, at least 10 percent.

(2) In Class 2 locations, at least 15 percent.

(3) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, and offshore, 100 percent if practicable, but not less than 90 percent.

(4) Within railroad or public highway rights-of-way, including tunnels, bridges and overhead road crossings, and at pipeline tie-ins, 100 percent.

(e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under § 192.241(b).

(f) When nondestructive testing is required under § 192.241(b), each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976]

§ 192.245 Repair or removal of defects.

(a) Each weld that is unacceptable under § 192.241(c) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipelay vessel, a weld must be removed if it has a crack that is more than 2 inches long or that penetrates either the root or second bead.

(b) Each weld that is repaired must have the defect removed down to clean metal and the segment to be repaired must be preheated. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability. If the repair is not acceptable, the weld must be removed, except that additional repairs made in accordance with written welding procedures qualified under § 192.225 are permitted for welds on an offshore pipeline being installed from a pipelay vessel.

[Amdt. 192-27, 41 FR 34606, Aug. 16, 1976]

Subpart F—Joining of Materials Other Than by Welding

§ 192.271 Scope.

(a) This subpart prescribes minimum requirements for joining materials in pipelines, other than by welding.

(b) This subpart does not apply to joining during the manufacture of pipe or pipeline components.

§ 192.273 General.

(a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

(b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

(c) Each joint must be inspected to insure compliance with this subpart.

§ 192.275 Cast iron pipe.

(a) Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.

(b) Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.

(c) Cast iron pipe may not be joined by threaded joints.

(d) Cast iron pipe may not be joined by brazing.

(e) Each flange on a flanged joint in cast iron pipe must conform in dimensions and drilling to ANSI Standard B16.1 and be cast integrally with the pipe, valve, or fitting.

§ 192.277 Ductile iron pipe.

(a) Each mechanical joint in ductile iron pipe must conform to ANSI Standard A21.52 and ANSI Standard A21.11.

(b) Ductile iron pipe may not be joined by threaded joints.

(c) Ductile iron pipe may not be joined by brazing.

§ 192.279 Copper pipe.

Copper pipe may not be threaded, except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of standard wall pipe, as defined in ANSI Standard B36.10.

§ 192.281 Plastic pipe.

(a) *General.* A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Solvent cement joints.* Each solvent cement joint on plastic pipe must comply with the following:

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be deterimental to the joint.

(2) The solvent cement must conform to ASTM Specification D 2513.

(3) The safety requirements of Appendix A of ASTM Specification D 2513 must be met.

(4) The joint may not be heated to accelerate the setting of the cement.

(c) *Heat-fusion joints.* Each heat-fusion joint on plastic pipe must comply with the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the pastic hardens.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

(3) Heat may not be applied with a torch or other open flame.

(d) *Adhesive joints.* Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM Specification D 2517.

(2) The materials and adhesive must be compatible with each other.

(e) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffner, must be used in conjection with the coupling.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR 1.53 and App. A to Part 1)

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-34, 44 FR 42973, July 23, 1979]

EFFECTIVE DATE NOTE: At 44 FR 42973, July 23, 1979, the first sentence of paragraph (a) was removed, effective January 1, 1980. For the convenience of the user, the first sentence is set forth below.

§ 192.281 Plastic pipe.

(a) * * * Each plastic pipe joint must be made in accordance with written procedures that have been proven by destructive burst test to produce joints at least as strong as the pipe being joined.

* * * * *

§ 192.283 Plastic pipe: qualifying joining procedures.

(a) *Heat Fusion, Solvent Cement, and Adhesive Joints.* Before any written procedure established under § 192.273(b) can be used for making joints in plastic pipe by a heat fusion, solvent cement, or adhesive method, it must be qualified by—

(1) Meeting the burst test requirements of Paragraph 8.6 (Sustained Pressure Test) of Paragraph 8.7 (Minimum Hydrostatic Burst Pressure) of ASTM D2513; and

(2) Meeting the tensile test requirements of ASTM D638 or, in the case of a procedure for making lateral connections to pipelines, by subjecting a specimen made from pipe sections joined at right angles according to the procedures to an impact force on the lateral pipe parallel to the axis of the pipe to which the lateral connection is made until failure occurs in the specimen. In this latter test, if failure occurs outside the joint area, the procedure qualifies for use.

(b) *Mechanical Joints.* Except for a procedure applicable to joints that will not be subjected to the design pullout or thrust forces addressed in § 192.273(a), before any written procedure established under § 192.273(b) can be used for making joints in plastic pipelines by a mechanical method, it must be qualified in accordance with the following test for determining short-term pullout resistance:

(1) The apparatus and conditioning for the testing shall be as specified in ASTM D638-77a.

(2) The speed of the testing shall be 5.0 mm (0.20 inches) per minute, plus or minus 25 percent.

(3) Five specimen joints shall be prepared following the procedure being qualified. Length of the specimen shall be such that the distance between the grips of the apparatus and the end of the stiffener is at least five times the nominal outside diameter of the pipe size being tested.

(4) Pipe specimen less than 4 inches in diameter shall be pulled until the tubing yields to an elongation of 25 percent or is pulled from the fitting. Length of yield is to be ascertained over a 50 mm (2 inch) span.

(5) Pipe specimen 4 inches and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100° F (55.6° C).

(6) Specimen that fails at the grips shall be retested using new pipe or tubing.

(7) If the pipe or tubing pulls from the fitting, the lowest of the five values shall be used in the design calculations for stress.

(8) Results obtained pertain only to the specific outside diameter, wall thickness, and material of the pipe or tubing tested.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints at the site where joining is accomplished.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR 1.53 and App. A of Part 1)

[Amdt. 192-34, 44 FR 42973, July 23, 1979]

EFFECTIVE DATE NOTE: At 44 FR 42973, July 23, 1979, § 192.283 was added, effective January 1, 1980.

§ 192.285 Plastic pipe: qualifying persons to make joints.

(a) No person may make a joint in a plastic pipe unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure: and

(2) Making a specimen joint from pipe sections joined according to the procedure, that is—

(i) Visually examined and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(ii) In the case of a heat fusion, solvent cement, or adhesive joint, cut into at least 3 longitudinal straps, each of which is—

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Destructively tested and found not to have failed in the joint area.

(b) No person determined to have made three or more unacceptable joints under an applicable joining procedure within any 12-month period may be considered qualified under that procedure in accordance with Paragraph (a) of this section until that person has been requalified under Paragraph (a)(2) of this section.

(c) Each operator shall establish a method to determine that each person making joints in plastic pipelines in his system is qualified in accordance with this section.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR 1.53 and App. A to Part 1)

[Amdt. 192-34, 44 FR 42973, July 23, 1979]

EFFECTIVE DATE NOTE: At 44 FR 42973, July 23, 1979, § 192.285 was added, effective January 1, 1980.

§ 192.287 Plastic pipe: inspection of joints.

No person may carry out the inspection of joints in plastic pipes required by §§ 192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR 1.53 and App. A to Part 1)

[Amdt. 192-34, 44 FR 42974, July 23, 1979]

EFFECTIVE DATE NOTE: At 44 FR 42974, July 23, 1979, § 192.287 was added, effective January 1, 1980.

Subpart G—General Construction Requirements for Transmission Lines and Mains

§ 192.301 Scope.

This subpart prescribes minimum requirements for constructing transmission lines and mains.

§ 192.303 Compliance with specifications or standards.

Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this part.

§ 192.305 Inspection: general.

Each transmission line or main must be inspected to ensure that it is constructed in accordance with this part.

§ 192.307 Inspection of materials.

Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

§ 192.309 Repair of steel pipe.

(a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:

(1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS:

(1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.

(2) A dent that affects the longitudinal weld or a circumferential weld.

(3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of—

(i) More than one-quarter inch in pipe 12¾ inches or less in outer diameter; or

(ii) More than 2 percent of the nominal pipe diameter in pipe over 12¾ inches in outer diameter.

For the purpose of this section a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

(c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:

(1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.

(e) Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

(35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§ 192.311 Repair of plastic pipe.

Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired by a patching saddle or removed.

§ 192.313 Bends and elbows.

(a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with § 192.315, must comply with the following:

(1) A bend must not impair the serviceability of the pipe.

(2) For pipe more than 4 inches in nominal diameter, the difference between the maximum and minimum diameter at a bend must not be more than 2½ percent of the nominal diameter.

(3) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

(4) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless—

(i) The bend is made with an internal bending mandrel; or

(ii) The pipe is 12 inches or less in outside diameter or has a diameter to wall thickness ratio less than 70.

(b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.

(c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch.

(Amdt. No. 192-26, 41 FR 26018, June 24, 1976, as amended by Amdt. 192-29, 42 FR 42866, Aug. 25, 1977; Amdt. 192-29, 42 FR 60148, Nov. 25, 1977]

§ 192.315 Wrinkle bends in steel pipe.

(a) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS.

(b) Each wrinkle bend on steel pipe must comply with the following:

(1) The bend must not have any sharp kinks.

(2) When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter.

(3) On pipe 16 inches or larger in diameter, the bend may not have a deflection of more than 1½° for each wrinkle.

(4) On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

§ 192.317 Protection from hazards.

(a) Each transmission line or main must be protected from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, offshore pipelines must be protected from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

[Amdt. 192-27, 41 FR 34606, Aug. 16, 1976]

§ 192.319 Installation of pipe in a ditch.

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that—

(1) Provides firm support under the pipe; and

(2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(c) All offshore pipe in water at least 12 feet deep but not more than 200 feet deep, as measured from the mean low tide, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976]

§ 192.321 Installation of plastic pipe.

(a) Plastic pipe must be installed below ground level.

(b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

(c) Plastic pipe must be installed so as to minimize shear or tensile stresses.

(d) Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inches, except that pipe with an outside diameter of 0.875 inches or less may have a minimum wall thickness of 0.062 inches.

(e) Plastic pipe that is not encased must have an electrically conductive wire or other means of locating the pipe while it is underground.

(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

§ 192.323 Casing.

Each casing used on a transmission line or main under a railroad or highway must comply with the following:

(a) The casing must be designed to withstand the superimposed loads.

(b) If there is a possibility of water entering the casing, the ends must be sealed.

(c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.

(d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

§ 192.325 Underground clearance.

(a) Each transmission line must be installed with at least 12 inches of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

(b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

(c) In addition to meeting the requirements of paragraph (a) or (b) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in § 192.175(b).

§ 192.327 Cover.

(a) Except as provided in paragraphs (c) and (e) of this section, each buried transmission line must be installed with a minimum cover as follows:

Location	Normal soil	Consolidated rock
	Inches	*Inches*
Class 1 locations	30	18
Class 2, 3, and 4 locations	36	24
Drainage ditch of public roads and railroad crossings	36	24

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches of cover.

(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) A main may be installed with less than 24 inches of cover if the law of the State or municipality—

(1) Establishes a minimum cover of less than 24 inches;

(2) Requires that mains be installed in a common trench with other utility lines; and

(3) Provides adequately for prevention of damage to the pipe by external forces.

(e) All pipe which is installed in a navigable river, stream, or harbor must have a minimum cover of 48 inches in soil or 24 inches in consolidated rock, and all pipe installed in any offshore location under water less than 12 feet deep, as measured from mean low tide, must have a minimum cover of 36 inches in soil or 18 inches in consolidated rock, between the top of the pipe and the natural bottom. However, less than the minimum cover is permitted in accordance with paragraph (c) of this section.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976]

Subpart H—Customer Meters, Service Regulators, and Service Lines

§ 192.351 Scope.

This subpart prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

§ 192.353 Customer meters and regulators: location.

(a) Each meter and service regulator, whether inside or outside of a building, must be installed in a readily accessible location and be protected from corrosion and other damage. However, the upstream regulator in a series may be buried.

(b) Each service regulator installed within a building must be located as near as practical to the point of service line entrance.

(c) Each meter installed within a building must be located in a ventilated place and not less than 3 feet from any source of ignition or any source of heat which might damage the meter.

(d) Where feasible, the upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building.

§ 192.355 Customer meters and regulators: protection from damage.

(a) *Protection from vacuum or back pressure.* If the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system.

(b) *Service regulator vents and relief vents.* The outside terminal of each service regulator vent and relief vent must—

(1) Be rain and insect resistant;

(2) Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and

(3) Be protected from damage caused by submergence in areas where flooding may occur.

(c) *Pits and vaults.* Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated, must be able to support that traffic.

§ 192.357 Customer meters and regulators: installation.

(a) Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

(b) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this part.

(c) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.

(d) Each regulator that might release gas in its operation must be vented to the outside atmosphere.

§ 192.359 Customer meter installations: operating pressure.

(a) A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure.

(b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 p.s.i.g.

(c) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§ 192.361 Service lines: installation.

(a) *Depth.* Each buried service line must be installed with at least 12 inches of cover in private property and at least 18 inches of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

(b) *Support and backfill.* Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

(c) *Grading for drainage.* Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

(d) *Protection against piping strain and external loading.* Each service line must be installed so as to minimize anticipated piping strain and external loading.

(e) *Installation of service lines into buildings.* Each underground service line installed below grade through the outer foundation wall of a building must—

(1) In the case of a metal service line, be protected against corrosion;

(2) In the case of a plastic service line, be protected from shearing action and backfill settlement; and

(3) Be sealed at the foundation wall to prevent leakage into the building.

(f) *Installation of service lines under buildings.* Where an underground service line is installed under a building—

(1) It must be encased in a gas-tight conduit;

(2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and

(3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

§ 192.363 Service lines: valve requirements.

(a) Each service line must have a service-line valve that meets the applicable requirements of Subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.

(b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

(c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

§ 192.365 Service lines: location of valves.

(a) *Relation to regulator or meter.* Each service-line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

(b) *Outside valves.* Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.

(c) *Underground valves.* Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

§ 192.367 Service lines: general requirements for connections to main piping.

(a) *Location.* Each service-line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

(b) *Compression-type connection to main.* Each compression-type service line to main connection must—

(1) Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and

(2) If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system.

§ 192.369 Service lines: connections to cast iron or ductile iron mains.

(a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of § 192.273.

(b) If a threaded tap is being inserted, the requirements of § 192.151 (b) and (c) must also be met.

§ 192.371 Service lines: steel.

Each steel service line to be operated at less than 100 p.s.i.g. must be constructed of pipe designed for a minimum of 100 p.s.i.g.

[Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§ 192.373 Service lines: cast iron and ductile iron.

(a) Cast or ductile iron pipe less than 6 inches in diameter may not be installed for service lines.

(b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

(c) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

§ 192.375 Service lines: plastic.

(a) Each plastic service line outside a building must be installed below ground level, except that it may terminate above ground and outside the building, if—

(1) The above ground part of the plastic service line is protected against deterioration and external damage; and

(2) The plastic service line is not used to support external loads.

(b) Each plastic service line inside a building must be protected against external damage.

§ 192.377 Service lines: copper.

Each copper service line installed within a building must be protected against external damage.

[Amdt. 192-3, 37 FR 20694, Oct. 3, 1972]

§ 192.379 New service lines not in use.

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:

(a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

Subpart I—Requirements for Corrosion Control

AUTHORITY: Natural Gas Pipeline Act of 1968 (49 U.S.C. sec. 1671 et seq.). Part I regulations of Office of the Secretary of Transportation, 49 CFR Part I, and delegation of authority to Director, Office of Pipeline Safety, 33 FR 16468, unless otherwise noted.

SOURCE: Amdt. 192-4, 36 FR 12302, June 30, 1971, unless otherwise noted.

§ 192.451 Scope.

(a) This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR App. A of Part 1)

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]

§ 192.452 Applicability to converted pipelines.

Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with § 192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR 1.53(a))

[Amdt. 192-30, 42 FR 60148, Nov. 25, 1977]

§ 192.453 General.

Each operator shall establish procedures to implement the requirements of this subpart. These procedures, including those for the design, installation, operation and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified by experience and training in pipeline corrosion control methods.

§ 192.455 External corrosion control: buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

(1) It must have an external protective coating meeting the requirements of § 192.461.

(2) It must have a cathodic protection system designed to protect the pipeline in its entirety in accordance with this subpart, installed and placed in operation within one year after completion of construction.

(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet, and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a)(2) of this section.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that—

(1) For a copper pipeline, a corrosive environment does not exist; or

(2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

(d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a)(2) of this section.

(e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.

(f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines if—

(1) For the size fitting to be used, an operator can show by tests, investigation, or experience in the area of application that adequate corrosion control is provided by alloyage;

(2) The fitting is designed to prevent leakage caused by localized corrosion pitting; and

(3) A means is provided for identifying the location of the fitting.

(49 USC 1672; 49 CFR 1.53(a))

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended at Amdt. 192-28, 42 FR 35654, July 11, 1977]

§ 192.457 External corrosion control: buried or submerged pipelines installed before August 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

(b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found:

(1) Bare or ineffectively coated transmission lines.

(2) Bare or coated pipes at compressor, regulator, and measuring stations.

(3) Bare or coated distribution lines. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

(c) For the purpose of this subpart, active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.459 External corrosion control; examination of buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion is found, remedial action must be taken to the extent required by § 192.483 and the applicable paragraphs of §§ 192.485, 192.487, or 192.489.

§ 192.461 External corrosion control: protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must—

(1) Be applied on a properly prepared surface;

(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling and soil stress; and

(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.

(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

§ 192.463 External corrosion control: cathodic protection.

(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in Appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

(b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential—

(1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

(2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of Appendix D of this part for amphoteric metals.

(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

§ 192.465 External corrosion control: monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463. However, if tests at those intervals are impractical for separately protected service lines or short sections of protected mains, not in excess of 100 feet, these service lines and mains may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system, must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2½ months, to insure that it is operating.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

(e) After the initial evaluation required by paragraphs (b) and (c) of § 192.455 and paragraph (b) of § 192.457, each operator shall, at intervals not exceeding 3 years, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR App. A to Part 1)

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.467 External corrosion control: electrical isolation.

(a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

(b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

(e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR App. A of Part 1.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.469 External corrosion control: test stations.

Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

[Amdt. 192-27, 41 FR 34606, Aug. 16, 1976]

§ 192.471 External corrosion control: test leads.

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

§ 192.473 External corrosion control: interference currents.

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR App. A of Part 1)

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.475 Internal corrosion control: general.

(a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found—

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of § 192.485, § 192.487, or § 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.1 grain of hydrogen sulfide per 100 standard cubic feet may not be stored in pipe-type or bottle-type holders.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR App. A of Part 1)

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.477 Internal corrosion control: monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7½ months.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR App. A of Part 1)

[Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.479 Atmospheric corrosion control: general.

(a) *Pipelines installed after July 31, 1971.* Each aboveground pipeline or portion of a pipeline installed after July 31, 1971 that is exposed to the atmosphere must be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion. An operator need not comply with this paragraph, if the operator can demonstrate by test, investigation, or experience in the area of application, that a corrosive atmosphere does not exist.

(b) *Pipelines installed before August 1, 1971.* Each operator having an above-ground pipeline or portion of a pipeline installed before August 1, 1971 that is exposed to the atmosphere, shall—

(1) Determine the areas of atmospheric corrosion on the pipeline;

(2) If atmospheric corrosion is found, take remedial measures to the extent required by the applicable paragraphs of §§ 192.485, 192.487, or 192.489; and

(3) Clean and either coat or jacket the areas of atmospheric corrosion on the pipeline with a material suitable for the prevention of atmospheric corrosion.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR App. A of Part 1)

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.481 Atmospheric corrosion control: monitoring.

After meeting the requirements of 192.479 (a) and (b), each operator shall, at intervals not exceeding 3 years for onshore pipelines and at least once each calendar year, but with intervals not exceeding 15 months, for offshore pipelines, reevaluate each pipeline that is exposed to the atmosphere and take remedial action whenever necessary to maintain protection against atmospheric corrosion.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR App. A of Part 1)

[Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.483 Remedial measures: general.

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of § 192.461.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.

(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

§ 192.485 Remedial measures: transmission lines.

(a) *General corrosion.* Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR App. A of Part 1)

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.487 Remedial measures: distribution lines other than cast iron or ductile iron lines.

(a) *General corrosion.* Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

§ 192.489 Remedial measures: cast iron and ductile iron pipelines.

(a) *General graphitization.* Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result, must be replaced.

(b) *Localized graphitization.* Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result, must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

§ 192.491 Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, other than unrecorded galvanic anodes installed before August 1, 1971, and neighboring structures bonded to the cathodic protection system.

(b) Each of the following records must be retained for as long as the pipeline remains in service:

(1) Each record or map required by paragraph (a) of this section.

(2) Records of each test, survey, or inspection required by this subpart, in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist.

(49 U.S.C. 1672; 49 U.S.C. 1804; 49 CFR App. A of Part 1)

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

Subpart J—Test Requirements

§ 192.501 Scope.

This subpart prescribes minimum leak-test and strength-test requirements for pipelines.

§ 192.503 General requirements.

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—

(1) It has been tested in accordance with this subpart to substantiate the proposed maximum allowable operating pressure; and

(2) Each potentially hazardous leak has been located and eliminated.

(b) The test medium must be liquid, air, natural gas, or inert gas that is—

(1) Compatible with the material of which the pipeline is constructed;

(2) Relatively free of sedimentary materials; and

(3) Except for natural gas, nonflammable.

(c) Except as provided in § 192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1	80	80
2	30	75
3	30	50
4	30	40

(d) Each weld used to tie-in a test segment of pipeline is excepted from the test requirements of this subpart.

§ 192.505 Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS.

(a) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet of such a building, but in no event may the test section be less than 600 feet unless the length of the newly installed or relocated pipe is less than 600 feet. However, if the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium.

(b) In a Class 1 or Class 2 location, each compressor station, regulator station, and measuring station must be tested to at least Class 3 location test requirements.

(c) Except as provided in paragraph (e) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.

(d) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that—

(1) The component was tested to at least the pressure required for the pipeline to which it is being added: or

(2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added.

(e) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

§ 192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and above 100 p.s.i.g.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and above 100 p.s.i.g. must be tested in accordance with the following:

(a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium—

(1) A leak test must be made at a pressure between 100 p.s.i.g. and the pressure required to produce a hoop stress of 20 percent of SMYS: or

(2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.

(c) The pressure must be maintained at or above the test pressure for at least 1 hour.

§ 192.509 Test requirements for pipelines to operate at or below 100 p.s.i.g.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at or below 100 p.s.i.g. must be leak tested in accordance with the following:

(a) The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) Each main that is to be operated at less than 1 p.s.i.g. must be tested to at least 10 p.s.i.g. and each main to be operated at or above 1 p.s.i.g. must be tested to at least 90 p.s.i.g.

§ 192.511 Test requirements for service lines.

(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service-line connection to the main must be included in the test: if not feasible, it must be given a leakage test at the operating pressure when placed in service.

(b) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i.g. but not more than 40 p.s.i.g. must be given a leak test at a pressure of not less than 50 p.s.i.g.

(c) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i.g. must be tested to at least 90 p.s.i.g., except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with § 192.507 of this subpart.

§ 192.513 Test requirements for plastic pipelines.

(a) Each segment of a plastic pipeline must be tested in accordance with this section.

(b) The test procedure must ensure discovery of all potentially hazardous leaks in the segment being tested.

(c) The test pressure must be at least 150 percent of the maximum operating pressure or 50 p.s.i.g., whichever is greater. However, the maximum test pressure may not be more than three times the design pressure of the pipe.

(d) The temperature of thermoplastic material must not be more than 100° F. during the test.

§ 192.515 Environmental protection and safety requirements.

(a) In conducting tests under this subpart, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

(b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

§ 192.517 Records.

Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505 and 192.507. The record must contain at least the following information:

(a) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.

(b) Test medium used.

(c) Test pressure.

(d) Test duration.

(e) Pressure recording charts, or other record of pressure readings.

(f) Elevation variations, whenever significant for the particular test.

(g) Leaks and failures noted and their disposition.

Subpart K—Uprating

§ 192.551 Scope.

This subpart prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

§ 192.553 General requirements.

(a) *Pressure increases.* Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:

(1) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.

(2) Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.

(b) *Records.* Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this subpart, of all work performed, and of each pressure test conducted, in connection with the uprating.

(c) *Written plan.* Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this subpart is complied with.

(d) *Limitation on increase in maximum allowable operating pressure.* Except as provided in § 192.555(c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under this part for a new segment of pipeline constructed of the same materials in the same location.

§ 192.555 Uprating to a pressure that will produce a hoop stress of 30 percent or more of SMYS in steel pipelines.

(a) Unless the requirements of this section have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of 30 percent or more of SMYS and that is above the established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure the operator shall—

(1) Review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this part; and

(2) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.

(c) After complying with paragraph (b) of this section, an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under § 192.619, using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

(d) After complying with paragraph (b) of this section, an operator that does not qualify under paragraph (c) of this section may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met:

(1) The segment of pipeline is successfully tested in accordance with the requirements of this part for a new line of the same material in the same location.

(2) An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if—

(i) It is impractical to test it in accordance with the requirements of this part;

(ii) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and

(iii) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this part.

(e) Where a segment of pipeline is uprated in accordance with paragraph (c) or (d)(2) of this section, the increase in pressure must be made in increments that are equal to—

(1) 10 percent of the pressure before the uprating; or

(2) 25 percent of the total pressure increase,

whichever produces the fewer number of increments.

§ 192.557 Uprating: Steel pipelines to a pressure that will produce a hoop stress less than 30 percent of SMYS: plastic, cast iron, and ductile iron pipelines.

(a) Unless the requirements of this section have been met, no person may subject—

(1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or

(2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall—

(1) Review the design, operating, and maintenance history of the segment of pipeline;

(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous;

(3) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;

(4) Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an excavation;

(5) Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and

(6) If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.

(c) After complying with paragraph (b) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 p.s.i.g. or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b)(6) of this section apply, there must be at least two approximately equal incremental increases.

(d) If records for cast iron or ductile iron pipeline facilities are not complete enough to ascertain compliance with § 192.117 or § 192.119, as applicable, the following procedures must be followed:

(1) If the original laying conditions cannot be ascertained, the operator shall assume, when applying the design formulas of ANSI A21.1, that cast iron pipe was supported on blocks with tamped backfill and, when applying the design formulas of ANSI A21.50, that ductile iron pipe was laid without blocks with tamped backfill.

(2) Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three places where the cover is most likely to be greatest and shall use the greatest cover measured.

(3) Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table:

Pipe size (inches)	Allowance (inches)		
	Cast iron pipe		Ductile iron pipe
	Pit cast pipe	Centrifugally cast pipe	
3–8	0.075	0.065	0.065
10–12	0.08	0.07	0.07
14–24	0.08	0.08	0.075
30–42	0.08	0.09	0.075
48	0.09	0.09	0.08
54–60	0.09		

NOTE.—The nominal wall thickness of the cast iron is the standard thickness listed in table 10 or table 11, as applicable, of ANSI A21.1 nearest the value obtained under this subparagraph. The nominal wall thickness of ductile iron pipe is the standard thickness listed in table 6 of ANSI A21.50 nearest the value obtained under this subparagraph.

(4) For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of 11,000 p.s.i. and a modulus of rupture of 31,000 p.s.i.

Subpart L—Operations

§ 192.601 Scope.

This subpart prescribes minimum requirements for the operation of pipeline facilities.

§ 192.603 General provisions.

(a) No person may operate a segment of pipeline unless it is operated in accordance with this subpart.

(b) Each operator shall establish a written operating and maintenance plan meeting the requirements of this part and keep records necessary to administer the plan.

§ 192.605 Essentials of operating and maintenance plan.

Each operator shall include the following in its operating and maintenance plan:

(a) Instructions for employees covering operating and maintenance procedures during normal operations and repairs.

(b) Items required to be included by the provisions of Subpart M of this part.

(c) Specific programs relating to facilities presenting the greatest hazard to public safety either in an emergency or because of extraordinary construction or maintenance requirements.

(d) A program for conversion procedures, if conversion of a low-pressure distribution system to a higher pressure is contemplated.

(e) Provision for periodic inspections to ensure that operating pressures are appropriate for the class location.

§ 192.607 Initial determination of class location and confirmation or establishment of maximum allowable operating pressure.

(a) Before April 15, 1971, each operator shall complete a study to determine for each segment of pipeline with a maximum allowable operating pressure that will produce a hoop stress that is more than 40 percent of SMYS—

(1) The present class location of all such pipeline in its system; and

(2) Whether the hoop stress corresponding to the maximum allowable operating pressure for each segment of pipeline is commensurate with the present class location.

(b) Each segment of pipeline that has been determined under paragraph (a) of this section to have an established maximum allowable operating pressure producing a hoop stress that is not commensurate with the class location of the segment of pipeline and that is found to be in satisfactory condition, must have the maximum allowable operating pressure confirmed or revised in accordance with § 192.611. The confirmation or revision must be completed not later than December 31, 1974.

(c) Each operator required to confirm or revise an established maximum allowable operating pressure under paragraph (b) of this section shall, not later than December 31, 1971, prepare a comprehensive plan, including a schedule, for carrying out the confirmations or revisions. The comprehensive plan must also provide for confirmations or revisions determined to be necessary under § 192.609, to the extent that they are caused by changes in class locations taking place before July 1, 1973.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-53, 36 FR 18194, Sept. 10, 1971]

§ 192.609 Change in class location: required study.

Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine—

(a) The present class location for the segment involved.

(b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part.

(c) The physical condition of the segment to the extent it can be ascertained from available records;

(d) The operating and maintenance history of the segment;

(e) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

(f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

§ 192.611 Change in class location: confirmation or revision of maximum allowable operating pressure.

If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised as follows:

(a) If the segment involved has been previously tested in place to at least 90 percent of its SMYS for a period of not less than 8 hours, the maximum allowable operating pressure must be confirmed or reduced so that the corresponding hoop stress will not exceed 72 percent of SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(b) If the segment involved has not been previously tested in place as described in paragraph (a) of this section, the maximum allowable operating pressure must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(c) If the segment of pipeline involved has not been qualified for operation under paragraph (a) or (b) of this section, it must be tested in accordance with the applicable requirements of Subpart J of this part, and its maximum allowable operating pressure must then be established so as to be equal to or less than the following:

(1) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(2) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.

(3) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of the SMYS in Class 4 locations.

(d) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§ 192.553 and 192.555.

(e) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under § 192.609 must be completed as follows:

(1) Confirmation or revision due to changes in class location that occur before July 1, 1973, must be completed not later than December 31, 1974.

(2) Confirmation or revision due to changes in class location that occur on or after July 1, 1973, must be completed within 18 months of the change in class location.

(Natural Gas Pipeline Safety Act of 1968, 49 U.S.C. Sec. 1671 et seq.; Part 1, Regulations of the Office of the Secretary of Transportation, 49 CFR Part 1, delegation of authority to the Director, Office of Pipeline Safety, November 6, 1968 (33 FR 16468))

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-5, 36 FR 18195, Sept. 10, 1971]

§ 192.613 Continuing surveillance.

(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with § 192.619 (a) and (b).

§ 192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

(3) Prompt and effective response to a notice of each type of emergency, including the following:

(i) Gas detected inside or near a building.

(ii) Fire located near or directly involving a pipeline facility.

(iii) Explosion occurring near or directly involving a pipeline facility.

(iv) Natural disaster.

(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

(5) Actions directed toward protecting people first and then property.

(6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property.

(7) Making safe any actual or potential hazard to life or property.

(8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency.

(9) Safely restoring any service outage.

(10) Beginning action under § 192.617, if applicable, as soon after the end of the emergency as possible.

(b) Each operator shall—

(1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures.

(2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.

(3) Review employee activities to determine whether the procedures were effectively followed in each emergency.

(c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to—

(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

(4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

(d) Each operator shall establish a continuing educational program to enable customers, the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a gas pipeline emergency for the purpose of reporting it to the operator or the appropriate public officials. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

[Amdt. 192-24, 41 FR 13587, Mar. 31, 1976]

§ 192.617 Investigation of failures.

Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

§ 192.619 Maximum allowable operating pressure: steel or plastic pipelines.

(a) Except as provided in paragraph (c) of this section, no person may operate a segment of steel or plastic pipeline at a pressure that exceeds the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part.

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i.g. or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors [1], segment— Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under § 192.14
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

[1] For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970 (or in the case of offshore gathering lines, July 1, 1976), unless the segment was tested in accordance with paragraph (a)(2) of this section after July 1, 1965 (or in the case of offshore gathering lines, July 1, 1971), or the segment was uprated in accordance with Subpart K of this part.

(4) For furnace butt welded steel pipe, a pressure equal to 60 percent of the mill test pressure to which the pipe was subjected.

(5) For steel pipe other than furnace butt welded pipe, a pressure equal to 85 percent of the highest test pressure to which the pipe has been subjected, whether by mill test or by the post installation test.

(6) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(6) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.

(c) Notwithstanding the other requirements of this section, an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970, or in the case of offshore gathering lines, July 1, 1976, subject to the requirements of § 192.611.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-27A, 41 FR 47253, Oct. 28, 1976; Amdt. 192-30, 42 FR 60148, Nov. 25, 1977]

§ 192.621 Maximum allowable operating pressure: high-pressure distribution systems.

(a) No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

(1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part.

(2) 60 p.s.i.g., for a segment of a distribution system otherwise designed to operate at over 60 p.s.i.g., unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of § 192.197(c).

(3) 25 p.s.i.g. in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

(4) The pressure limits to which a joint could be subjected without the possibility of its parting.

(5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

(b) No person may operate a segment of pipeline to which paragraph (a)(5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.

§ 192.623 Maximum and minimum allowable operating pressure: low-pressure distribution systems.

(a) No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.

(b) No person may operate a low pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

§ 192.625 Odorization of gas.

(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

(b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless—

(1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

(2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;

(i) An underground storage field;

(ii) A gas processing plant;

(iii) A gas dehydration plant; or

(iv) An industrial plant using gas in a process where the presence of an odorant—

(A) Makes the end product unfit for the purpose for which it is intended;

(B) Reduces the activity of a catalyst; or

(C) Reduces the percentage completion of a chemical reaction; or

(3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location.

(c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

(1) The odorant may not be deleterious to persons, materials, or pipe.

(2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.

(d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

(e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

(f) Each operator shall conduct periodic sampling of combustible gases to assure the proper concentration of odorant in accordance with this section.

(g) The odorization requirements of Part 190 of this chapter, as in effect on August 12, 1970, must be complied with, in each State in which odorization of gas in transmission lines is required by that part, until the earlier of the following dates:

(1) January 1, 1977; or

(2) The date upon which the distribution companies in that State are odorizing gas in accordance with paragraphs (a) through (f) of this section.

(35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17335, Nov. 11, 1970]

NOTE: For amendments to § 192.625 see the List of CFR Sections Affected appearing in the Finding Aids section of this volume.

§ 192.627 Tapping pipelines under pressure.

Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

§ 192.629 Purging of pipelines.

(a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

(b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

Subpart M—Maintenance

§ 192.701 Scope.

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

§ 192.703 General.

(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.

(b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

(c) Hazardous leaks must be repaired promptly.

§ 192.705 Transmission lines: Patrolling.

(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and oper[illegible]

(b) The frequency of patrols is de[illegible]mined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

Class location of line	Maximum interval between patrols: At highway and railroad crossings	Maximum interval between patrols: At all other places
1, 2	6 months	1 year.
3	3 months	6 months.
4	do	3 months.

[Amdt. 192-21, 40 FR 20283, May 9, 1975]

§ 192.706 Transmission lines: Leakage surveys.

(a) Each operator of a transmission line shall provide for periodic leakage surveys of the line in its operating and maintenance plan.

(b) Leakage surveys of a transmission line must be conducted at intervals not exceeding 1 year. However, in the case of a transmission line which transports gas in conformity with § 192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted—

(1) In Class 3 locations, at inte[illegible] not exceeding 6 months; and

(2) In Class 4 locations, at intervals not exceeding 3 months.

[Amdt. 192-21, 40 FR 20283, May 9, 1975]

§ 192.707 Line markers for mains and transmission lines.

(a) *Buried pipelines.* Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line—

(1) At each crossing of a public road, railroad, and navigable waterway; and

(2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

However, until January 1, 1978, paragraphs (a)(1) and (2) of this section do not apply to mains installed before April 21, 1975, and until January 1, 1978, paragraph (a)(1) of this section does not apply to transmission lines installed before April 21, 1975.

(b) *Exceptions for buried pipelines.* Line markers are not required for buried mains and transmission lines—

(1) Located offshore or under inland navigable waters;

(2) In Class 3 or Class 4 locations—

(i) Where placement of a marker [illegible] impractical; or

(ii) Where a program for prevent[illegible] interference with underground pipelines is established by law; or

(3) In the case of navigable waterway crossings, within 100 feet of a line marker placed and maintained at that

waterway in accordance with this section.

(c) *Pipelines aboveground.* Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

(d) *Markers other than at navigable waterways.* The following must be written legibly on a background of sharply contrasting color on each line marker not placed at a navigable waterway:

(1) The word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least one inch high with one-quarter inch stroke.

(2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

(e) *Markers at navigable waterways.* Each line marker at a navigable waterway must have the following characteristics:

(1) A sign, rectangular in shape, with a narrow strip along each edge colored international orange and the area between lettering on the sign and boundary strips colored white.

(2) Written on the sign in block style, black letters—

(i) The word "Warning," "Caution," or "Danger," followed by the words "Do Not Anchor or Dredge" and the words "Gas (or name of gas transported) Pipeline Crossing"; and

(ii) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

(3) In overcast daylight, the sign is visible and the writing required by paragraph (e)(2)(i) of this section is legible, from approaching or passing vessels that may damage or interfere with the pipeline.

(f) *Existing markers.* Line markers installed before April 21, 1975, which do not comply with paragraph (d) or (e) of this section may be used until January 1, 1980.

(Sec. 3, Pub. L. 90-481, 82 Stat. 721, Natural Gas Pipeline Safety Act of 1968 (49 U.S.C. 1672); sec. 1.58(d) of the regulations of the Office of the Secretary of Transportation (49 CFR 1.58(d)), and the redelegation of authority to the Director, Office of Pipeline Safety, set forth in Appendix A to Part 1 of the regulations of the Office of the Secretary of Transportation (49 CFR Part 1), 1.53(a))

[Amdt. 192-20, 40 FR 13505, Mar. 27, 1975, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; 41 FR 39752, Sept. 16, 1976; Amdt. 192-20A, 41 FR 56808, Dec. 30, 1976]

§ 192.709 Transmission lines: record keeping.

Each operator shall keep records covering each leak discovered, repair made, transmission line break, leakage survey, line patrol, and inspection, for as long as the segment of transmission line involved remains in service.

§ 192.711 Transmission lines: general requirements for repair procedures.

(a) Each operator shall take immediate temporary measures to protect the public whenever—

(1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and

(2) It is not feasible to make a permanent repair at the time of discovery.

As soon as feasible, the operator shall make permanent repairs.

(b) Except as provided in § 192.717(c), no operator may use a welded patch as a means of repair.

§ 192.713 Transmission lines: permanent field repair of imperfections and damages.

(a) Except as provided in paragraph (b) of this section, each imperfection or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40 percent of SMYS must be repaired as follows:

(1) If it is feasible to take the segment out of service, the imperfection or damage must be removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.

(2) If it is not feasible to take the segment out of service, a full encirclement welded split sleeve of appropriate design must be applied over the imperfection or damage.

(3) If the segment is not taken out of service, the operating pressure must be reduced to a safe level during the repair operations.

(b) Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the imperfection or damage.

[Amdt. 192-27, 41 FR 34607, Aug. 16, 1976]

§ 192.715 Transmission lines: permanent field repair of welds.

Each weld that is unacceptable under § 192.241(c) must be repaired as follows:

(a) If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of § 192.245.

(b) A weld may be repaired in accordance with § 192.245 while the segment of transmission line is in service if—

(1) The weld is not leaking;

(2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and

(3) Grinding of the defective area can be limited so that at least ⅛-inch thickness in the pipe weld remains.

(c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design.

§ 192.717 Transmission lines: permanent field repair of leaks.

(a) Except as provided in paragraph (b) of this section, each permanent field repair of a leak on a transmission line must be made as follows:

(1) If feasible, the segment of transmission line must be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.

(2) If it is not feasible to take the segment of transmission line out of service, repairs must be made by installing a full encirclement welded split sleeve of appropriate design, unless the transmission line—

(i) Is joined by mechanical couplings; and

(ii) Operates at less than 40 percent of SMYS.

(3) If the leak is due to a corrosion pit, the repair may be made by installing a properly designed bolt-on-leak clamp; or, if the leak is due to a corrosion pit and on pipe of not more than 40,000 psi SMYS, the repair may be made by fillet welding over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.

(b) Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the leak.

[Amdt. 192-27, 41 FR 34607, Aug. 16, 1976]

§ 192.719 Transmission lines: testing of repairs.

(a) *Testing of replacement pipe.* (1) If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location.

(2) The test required by paragraph (1) of this paragraph (a) may be made on the pipe before it is installed, but all field girth butt welds that are not strength tested must be tested after installation by nondestructive tests meeting the requirements of § 192.243.

(b) *Testing of repairs made by welding.* Each repair made by welding in accordance with §§ 192.713, 192.715, and 192.717 must be examined in accordance with § 192.241.

§ 192.721 Distribution systems: patrolling.

(a) The frequency of patrolling

mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.

(b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled at intervals not exceeding 3 months.

§ 192.723 Distribution systems: leakage surveys and procedures.

(a) Each operator of a distribution system shall provide for periodic leakage surveys in its operating and maintenance plan.

(b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements:

(1) A gas detector survey must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 1 year.

(2) Leakage surveys of the distribution system outside of the principal business areas must be made as frequently as necessary, but at intervals not exceeding 5 years.

§ 192.725 Test requirements for reinstating service lines.

(a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.

(b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

§ 192.727 Abandonment or inactivation of facilities.

(a) Each operator shall provide in its operating and maintenance plan for abandonment or deactivation of pipelines, including provisions for meeting each of the requirements of this section.

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(d) Whenever service to a customer is discontinued, one of the following must be complied with:

(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the value by persons other than those authorized by the operator.

(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

(e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging.

(f) Each abandoned vault must be filled with a suitable compacted material.

[Amdt. 192-8, 37 FR 20695, Oct. 3, 1972, as amended by Amdt. 192-27, 41 FR 34607, Aug. 16, 1976]

§ 192.729 Compressor stations: procedures for gas compressor units.

Each operator shall establish starting, operating, and shutdown procedures for gas compressor units.

§ 192.731 Compressor stations: inspection and testing of relief devices.

(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §§ 192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found must be promptly repaired or replaced.

(c) Each remote control shutdown device must be inspected and tested, at intervals not to exceed 1 year, to determine that it functions properly.

§ 192.733 Compressor stations: isolation of equipment for maintenance or alterations.

Each operator shall establish procedures for maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.

§ 192.735 Compressor stations: storage of combustible materials.

(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

(b) Aboveground oil or gasoline storage tanks must be protected in accordance with National Fire Protection Association Standard No. 30.

§ 192.737 Pipe-type and bottle-type holders: plan for inspection and testing.

Each operator having a pipe-t[illegible] or bottle-type holder shall establi[illegible] a plan for the systematic, routine inspection and testing of these facilities, including the following:

(a) Provision must be made for detecting external corrosion before the strength of the container has been impaired.

(b) Periodic sampling and testing of gas in storage must be made to determine the dew point of vapors contained in the stored gas, that if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant.

(c) The pressure control and pressure limiting equipment must be inspected and tested periodically to determine that it is in a safe operating condition and has adequate capacity.

§ 192.739 Pressure limiting and regulating stations: inspection and testing.

Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected, at intervals not exceeding 1 year, to inspections and tests to determine that it is—

(a) In good mechanical condition;

(b) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(c) Set to function at the c[illegible] pressure; and

(d) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

§ 192.741 Pressure limiting and regulating stations: telemetering or recording gages.

(a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gages to indicate the gas pressure in the district.

(b) On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gages in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

(c) If there are indications of abnormally high- or low-pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

§ 192.743 Pressure limiting and regulating stations: testing of relief devices.

(a) If feasible, pressure relie[illegible] de[illegible] (except rupture discs) must be t[illegible] in place, at intervals not exceedi[illegible] year, to determine that they have enough capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure.

(b) If a test is not feasible, review and calculation of the required capacity of the relieving device at each station must be made, at intervals not exceeding one year, and these required capacities compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works.

(c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required.

§ 192.745 **Valve maintenance: transmission lines.**

Each transmission line valve that might be required during any emergency must be inspected and partially operated, at intervals not exceeding 1 year.

§ 192.747 **Valve maintenance: distribution systems.**

Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced, at intervals not exceeding 1 year.

§ 192.749 **Vault maintenance.**

(a) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet or more, must be inspected, at intervals not exceeding 1 year, to determine that it is in good physical condition and adequately ventilated.

(b) If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

(c) The ventilating equipment must also be inspected to determine that it is functioning properly.

(d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.

§ 192.751 **Prevention of accidental ignition.**

Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

(a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.

(b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

(c) Post warning signs, where appropriate.

§ 192.753 **Caulked bell and spigot joints.**

(a) Each cast-iron caulked bell and spigot joint that is subject to pressures of 25 p.s.i.g. or more must be sealed with:

(1) A mechanical leak clamp; or

(2) A material or device which—

(i) Does not reduce the flexibility of the joint;

(ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

(iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of §§ 192.53 (a) and (b) and 192.143.

(b) Each cast iron caulked bell and spigot joint that is subject to pressures of less than 25 p.s.i.g. and is exposed for any reason, must be sealed by a means other than caulking.

(Sec. 3, Pub. L. 90-481, 82 Stat. 721, 49 U.S.C. 1672; 40 FR 43901, 49 CFR 1.53)

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-25, 41 FR 23680, June 11, 1976]

§ 192.755 **Protecting cast-iron pipelines.**

When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

(1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

(2) Impact forces by vehicles;

(3) Earth movement;

(4) Apparent future excavations near the pipeline; or

(5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of §§ 192.317(a), 192.319, and 192.361(b)-(d).

[Amdt. 192-23, 41 FR 13589, Mar. 31, 1976]

APPENDIX A—INCORPORATED BY REFERENCE

I. List of organizations and addresses.

A. American National Standards Institute (ANSI), 1430 Broadway, New York, N.Y. 10018 (formerly the United States of American Standards Institute (USASI)). All current standards issued by USASI and ASA have been redesignated as American National Standards and continued in effect.

B. American Petroleum Institute (API), 1801 K Street NW., Washington, DC 20006, or 300 Corrigan Tower Building, Dallas, Tex. 75201.

C. The American Society of Mechanical Engineers (ASME) United Engineering Center, 345 East 47th Street, New York, N.Y. 10017.

D. American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, Pa. 19103.

E. Manufacturers Standardization Society of the Valve and Fittings Industry (MSS), 1815 North Fort Myer Drive, Room 913, Arlington, Va. 22209.

F. National Fire Protection Association (NFPA), 470 Atlantic Avenue, Boston, Massachusetts 02110.

II. Documents incorporated by reference. Numbers in parentheses indicate applicable editions. Only the latest listed edition applies except that an earlier listed edition may be followed with respect to pipe or components which are manufactured, designed, or installed in accordance with the earlier edition before the latest edition is adopted, unless otherwise provided in this part.

A. American Petroleum Institute:

(1) API Standard 5A "API Specification for Casing, Tubing, and Drill Pipe" (1968, 1971, 1973 plus Supp. 1).

(2) API Standard 6A "API Specification for Wellhead Equipment" (1968, 1974).

(3) API Standard 6D "API Specification for Pipeline Valves" (1968, 1974).

(4) API Standard 5L "API Specification for Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

(5) API Standard 5LS "API Specification for Spiral-Weld Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1, and 1977).

(6) API Standard 5LX "API Specification for High-Test Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1, and 1977).

(7) API Recommended Practice 5L1 "API Recommended Practice for Railroad Transportation of Line Pipe" (1967, 1972).

(8) API Standard 1104 "Standard for Welding Pipe Lines and Related Facilities" (1968, 1973).

B. The American Society for Testing and Materials:

(1) ASTM Specification A53 "Standard Specification for Welded and Seamless Steel Pipe" (A53-65, A53-68, A53-73).

(2) ASTM Specification A72 "Standard Specification for Welded Wrought-Iron Pipe" (A72-64T, A72-68).

(3) ASTM Specification A106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (A106-66, A106-68, A106-72a).

(4) ASTM Specification A134 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Plate Pipe, Sizes 16 in. and over" (A134-64, A134-68, A134-73).

(5) ASTM Specification A135 "Standard Specification for Electric-Resistance-Welded Steel Pipe" (A135-63T, A135-68, A135-73a).

(6) ASTM Specification A139 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Pipe (Sizes 4 in. and over)" (A139-64, A139-68, A139-73).

(7) ASTM Specification A155 "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service" (A155-65, A155-68, A155-72a).

(8) ASTM Specification A211 "Standard Specification for Spiral-Welded Steel or Iron Pipe" (A211-63, A211-68, A211-73).

(9) ASTM Specification A333 "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (A333-64, A333-67, A333-73).

(10) ASTM Specification A372 "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessel" (A372-67, A372-71).

(11) ASTM Specification A377 "Standard Specifications for Cast Iron and Ductile Iron Pressure Pipe" (A377-66, A377-73).

(12) ASTM Specification A381 "Standard Specification for Metal-Arc-Welded Steel Pipe for High-Pressure Transmission Systems" (A381-66, A381-68, A381-73).

(13) ASTM Specification A539 "Standard Specification for Electric Resistance-Welded Coiled Steel Tubing for Gas and Fuel Oil Lines" (A539-65, A539-73).

(14) ASTM Specification B42 "Standard Specification for Seamless Copper Pipe, Standard Sizes" (B42-62, B42-66, B42-72).

(15) ASTM Specification B68 "Standard Specification for Seamless Copper Tube, Bright Annealed" (B68-65, B68-68, B68-73).

(16) ASTM Specification B75 "Standard Specification for Seamless Copper Tube" (B75-65, B75-68, B75-73).

(17) ASTM Specification B88 "Standard Specification for Seamless Copper Water Tube" (B88-66, B88-72).

(18) ASTM Specification B251 "Standard Specification for General Requirements for Wrought Seamless Copper and Copper-Alloy Tube" (B251-66, B251-68, B251-72).

(19) ASTM Specification D638 "Standard Test Method for Tensile Properties of Plastic" (D638-77a).

(20) ASTM Specification D2513 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (D2513-66T, D2513-68, D2513-70, D2513-71, D2513-73, D2513-74a).

(21) ASTM Specification D2517 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (D2517-66T, D2517-67, D2517-73).

C. The American National Standards Institute, Inc.:

(1) ANSI A21.1 "Thickness Design of Cast-Iron Pipe" (A21.1-1967 A21.1-1972).

(2) ANSI A21.3 "Specifications for Cast Iron Pit Cast Pipe for Gas" (A21.3-1953).

(3) ANSI A21.7 "Cast-Iron Pipe Centrifugally Cast in Metal Molds for Gas" (A21.7-1962).

(4) ANSI A21.9 "Cast-Iron Pipe Centrifugally Cast in Sand-Lined Molds for Gas" (A21.9-1962).

(5) ANSI A21.11 "Rubber-Gasket Joints for Cast-Iron and Ductile-Iron Pressure Pipe and Fittings" (A21.11-1964, A21.11-1972).

(6) ANSI A21.50 "Thickness Design of Ductile-Iron Pipe" (A21.50-1965, A21.50-1971).

(7) ANSI A21.52 "Ductile-Iron Pipe, Centrifugally Cast, in Metal Molds or Sand-Lined Molds for Gas" (A21.52-1965, A21.52-1971).

(8) ANSI B16.1 "Cast Iron Pipe Flanges and Flanged Fittings" (B16.1-1967).

(9) ANSI B16.5 "Steel Pipe Flanges, Flanged Valves and Fittings" (B16.5-1968, B16.5-1973).

(10) ANSI B16.24 "Bronze Flanges and Flanged Fittings" (B16.24-1962, B16.10-1971).

(11) ANSI B36.10 "Wrought Steel and Wrought Iron Pipe" (B36.10-1959, B36.10-1970).

(12) ANSI C1 "National Electrical Code" (C1-1968, C1-1975).

D. The American Society of Mechanical Engineers:

(1) ASME Boiler and Pressure Vessel Code, Section VIII "Pressure Vessels, Division 1" (1968, 1974).

(2) ASME Boiler and Pressure Vessel Code, Section IX "Welding Qualifications" (1968, 1974).

E. Manufacturer's Standardization Society of the Valve and Fittings Industry:

(1) MSP-25 "Standard Marking System for Valves, Fittings, Flanges, and Union" (1964).

(2) MSS SP-44 "Steel Pipe Line Flanges" (1955, 1972, 1975).

(3) MSS SP-52 "Cast Iron Pipe Line Valves" (1957).

(4) MSS SP-70 "Cast Iron Gate Valves, Flanged and Threaded Ends" (1970).

(5) MSS SP-71 "Cast Iron Swing Check Valves, Flanged and Threaded Ends" (1970).

(6) MSS SP-78 "Cast Iron Plug Valves" (1972).

F. National Fire Protection Association:

(1) NFPA Standard 30 "Flammable and Combustible Liquids Code" (1969, 1973).

(2) NFPA Standard 58 "Standard for the Storage and Handling of Liquefied Petroleum Gases" (1969, 1972).

(3) NFPA Standard 59 "Standard for the Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants" (1968).

(4) NFPA Standard 59A "Storage and Handling Liquefied Natural Gas" (1971, 1972).

(Sec. 3, Pub. L. 90-481, 82 Stat. 721, (49 U.S.C. 1672); for offshore gathering lines, sec. 105, Pub. L. 93-633, 88 Stat. 2157, (49 U.S.C. 1804); 49 CFR 1.53 and App. A to Part 1)

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

NOTE: For amendments to Appendix A of Part 192 see the List of CFR Sections Affected appearing in the Finding Aids section of this volume.

APPENDIX B—QUALIFICATION OF PIPE

I. *Listed Pipe Specifications.* Numbers in parentheses indicate applicable editions. Only the latest listed edition applies except that an earlier listed edition may be followed with respect to pipe or components which are manufactured, designed, or installed in accordance with the earlier edition before the latest edition is adopted, unless otherwise provided in this part.

API 5L—Steel and iron pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

API 5LS, Steel pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1, and 1977).

API 5LX, Steel pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1, and 1977).

ASTM A53—Steel pipe (1965, 1968, 1973).

ASTM A72—Wrought Iron Pipe (1964T, 1968).

ASTM A106—Steel pipe (1966, 1968, 1972a).

ASTM A134—Steel pipe (1964, 1968, 1973).

ASTM A135—Steel pipe (1963T, 1968, 1973a).

ASTM A139—Steel pipe (1964, 1968, 1973).

ASTM A155—Steel pipe (1965, 1968, 1972a).

ASTM A211—Steel and iron pipe (1963, 1968, 1973).

ASTM A333—Steel pipe (1964, 1967, 1973).

ASTM A377—Cast iron pipe (1966, 1973).

ASTM A381—Steel pipe (1966, 1968, 1973).

ASTM A539—Steel tubing (1965, 1973).

ASTM B42—Copper pipe (1962, 1966, 1972).

ASTM B68—Copper tubing (1965, 1968, 1973).

ASTM B75—Copper tubing (1965, 1968, 1973).

ASTM B88—Copper tubing (1966, 1972).

ASTM B251—Copper pipe and tubing (1966, 1968, 1972).

ASTM D2513—Thermoplastic pipe and tubing (1966T, 1968, 1970, 1971, 1973, 1974a).

ASTM D2517—Thermosetting plastic pipe and tubing (1966T, 1967, 1973).

ANSI A21.3—Cast iron pipe (1953).

ANSI A21.7—Cast iron pipe (1962).

ANSI A21.9—Cast iron pipe (1962).

ANSI A21.52—Ductile iron pipe (1965, 1971).

ASTM A72—Wrought iron pipe (1964T, 1968).

ASTM B42—Copper pipe (1962, 1966).

ASTM B68—Copper tubing (1965, 1968).

ASTM B75—Copper tubing (1965, 1968).

ASTM B88—Copper tubing (1966).

ASTM B251—Copper pipe and tubing (1966, 1968).

ASTM D2513—Thermoplastic pipe and tubing (1966T, 1968, 1970, 1971).

ASTM D2517—Thermosetting plastic pipe and tubing (1966T, 1967).

II. *Steel pipe of unknown or unlisted specification.*

A. *Bending Properties.* For pipe 2 inche[illegible] or less in diameter, a length of pipe must b[illegible] cold bent through at least 90 degree[illegible] around a cylindrical mandrel that has a di[illegible]ameter 12 times the diameter of the pipe without developing cracks at any [illegible] and without opening the longitudinal [illegible]eld.

For pipe more than 2 inches in diameter the pipe must meet the requirements of the flattening tests set forth in ASTM A53 except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.

B. *Weldability.* A girth weld must be made in the pipe by a welder who is qualified under Subpart E of this part. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104. If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code. The same number of chemical tests must be made as are required for testing a girth weld.

C. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. *Tensile Properties.* If the tensile properties of the pipe are not known, the minimum yield strength may be taken as [illegible]0 p.s.i.g. or less, or the tensile properties [illegible] be established by performing tensile tests as set forth in API Standard 5LX. All test specimens shall be selected at random and the following number of tests must be performed:

NUMBER OF TENSILE TESTS—ALL SIZES

10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in § 192.55(c).

III. *Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.* Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this appendix, is qualified for use under this part if the following requirements are met:

A. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. *Similarity of specification requirements.* The edition of the listed specification under which the pipe was manufactured must have substantially the sa[illegible] requirements with respect to the foll[illegible] properties as a later edition of that sp[illegible]cation listed in section I of this appendix:

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.

(2) Chemical properties of pipe and testing requirements to verify those properties.

C. *Inspection or test of welded pipe.* On pipe with welded seams, one of the following requirements must be met:

(1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this appendix.

(2) The pipe must be tested in accordance with Subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under Subpart J of this part, the test pressure must be maintained for at least 8 hours.

(Sec. 3, Pub. L. 90-481, 82 Stat. 721, (49 U.S.C. 1672); for offshore gathering lines, sec. 105, Pub. L. 93-633, 88 Stat. 2157, (49 U.S.C. 1804); 49 CFR 1.53 and App. A to Part 1)

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17661, Nov. 11, 1970]

NOTE: For amendments to Appendix B of Part 192 see the List of CFR Sections Affected appearing in the Finding Aids section of this volume.

APPENDIX C—QUALIFICATION OF WELDERS FOR LOW STRESS LEVEL PIPE

I. *Basic test.* The test is made on pipe 12 inches or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than ⅛-inch long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered.

II. *Additional tests for welders of service line connections to mains.* A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. *Periodic tests for welders of small service lines.* Two samples of the welder's work, each about 8 inches long with the weld located approximately in the center, are cut from steel service line and tested as follows:

(1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 2 inches on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.

(2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in subparagraph (1) of this paragraph.

APPENDIX D—CRITERIA FOR CATHODIC PROTECTION AND DETERMINATION OF MEASUREMENTS

I. *Criteria for cathodic protection*—A. *Steel, cast iron, and ductile iron structures.* (1) A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made with the protective current applied, and in accordance with sections II and IV of this appendix.

(2) A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied, and in accordance with sections II and IV of this appendix. This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.

(3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.

(5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. *Aluminum structures.* (1) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) voltage shift of 150 millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with sections II and IV of this appendix.

(2) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(3) Notwithstanding the alternative minimum criteria in paragraphs (1) and (2) of this paragraph, aluminum, if cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate half cell, in accordance with section IV of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(4) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. *Copper structures.* A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. *Metals of different anodic potentials.* A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. *Interpretation of voltage measurement.* Voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement in paragraphs A(1) and (2) and paragraph B(1) of section I of this appendix.

III. *Determination of polarization voltage shift.* The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(3), B(2), and C of section I of this appendix.

IV. *Reference half cells.* A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated copper-copper sulfate half cell. Two commonly used reference half cells are listed below along with their voltage equivalent to −0.85 volt as referred to a saturated copper-copper sulfate half cell:

(1) Saturated KCl calomel half cell: −0.78 volt.

(2) Silver-silver chloride half cell used in sea water: −0.80 volt.

C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.

[Amdt. 192-4, 36 FR 12108, June 30, 1971]

DEPARTMENT OF TRANSPORTATION

Materials Transportation Bureau

Research and Special Programs Administration, Transportation Department

49 CFR Part 192

[Amdt. 192-27B; Docket OPS-30]

Transportation of Natural and Other Gas by Pipeline; Repair of Transmission Lines

AGENCY: Materials Transportation Bureau, DOT.

ACTION: Final rule.

SUMMARY: This document amends Material Transportation Bureau's regulation on general requirements for repair procedures of gas-pipelines (49 CFR 192.711) by correcting a reference to another section which has been redesigngated.

EFFECTIVE DATE: This amendment becomes effective January 17, 1980.

FOR FURTHER INFORMATION CONTACT: Ralph T. Simmons, 202-426-2394.

SUPPLEMENTARY INFORMATION: Section 192.711(b) refers to § 192.717(c). This referenced section was redesignated as § 192.717(a)(3) in Amendment 192-27 (41 FR 34598), but the reference in § 192.711(b) was not changed accordingly.

Since this amendment is an editorial change and does not make a substantive change to the regulations, public participation in this rulemaking is unnecessary.

In consideration of the foregoing, § 192.711(b) is amended by deleting the reference to "§ 192.717(c)" and inserting in lieu thereof "§ 192.717(a)(3)."

(49 U.S.C. 1672; U.S.C. 1804; 49 CFR 1.53, Appendix A of Part 1 and Appendix A of Part 106.)

Issued in Washington, D.C. on January 9, 1980.

L. D. Santman,
Director, Materials Transportation Bureau.

[FR Doc. 80-1400 Filed 1-16-80; 8:45 am]
BILLING CODE 4910-60-M

3272 Federal Register / Vol. 45, No. 12 / Thursday, January 17, 1980 / Rules and Regulations

Research and Special Programs Administration

49 CFR Part 192

[Amdt. 192-34A, Docket PS-54]

Transportation of Natural and Other Gas by Pipeline; Joining of Plastic Pipe

February 11, 1980.

AGENCY: Materials Transportation Bureau.

ACTION: Final rule.

SUMMARY: A final rule was published July 23, 1979, (Amdt. 192-34; 44 FR 42068), establishing tests for qualifying procedures and personnel to make all types of joints in plastic pipeline used in the transportation of natural and other gas by pipeline. The docket was held

open until September 30, 1979, for further comments.

In response to comments, MTB has made certain changes to that final rule. The most significant changes: (1) permit the use of any force on a specimen lateral joint that initiates failure; (2) permit tensile testing at ambient temperature and humidity; (3) more clearly define the criteria for test specimen acceptance or failure; (4) permit joining of pipe and fittings manufactured before July 1, 1980, in accordance with existing procedures without requalifying those procedures; (5) permit alternative test methods for qualifying persons to make heat fusion, solvent cement, or adhesive joints; and (6) redefine and limit the conditions under which a person must requalify to make plastic pipe joints.

EFFECTIVE DATE: July 1, 1980.

FOR FURTHER INFORMATION CONTACT: Paul J. Cory, (202) 426-2392.

SUPPLEMENTARY INFORMATION: Final rules (Amendment 192-34) were published (44 FR 42968, July 23, 1979) establishing tests for qualifying procedures and personnel to make all types of joints in pipelines used in the transportation of natural and other gas.

In the preamble of the final rules, MTB invited further comments concerning the effect upon safety of three amendments: (1) The addition of new § 192.283(a)(1), which established alternative burst tests for qualifying plastic pipe joining procedures (Paragraphs 8.6 or 8.7 of ASTM D2513); (2) repeal of the existing requirement in § 192.281(e) for qualifying mechanical joining procedures by burst testing specimen joints; and (3) the use of an impact-type test under new § 192.283(a)(2) to qualify the tensile strength of lateral connections. In addition to the specific comments requested on these three amendments, many other comments were submitted on the final rule. Most of these additional comments have been treated by MTB as petitions for reconsideration, and are being considered in this document. Several of the additional comments are not being treated as petitions for reconsideration because the comments requested action that would go beyond the scope of the notice or proposed rulemaking (NPRM) (43 FR 49334). In view of the extended comment period and MTB's reconsideration of the final rule in this document, the docket will not remain open for 30 days following publication of this document in the Federal Register for receipt of petitions for reconsideration under 49 CFR 106.35. Instead, any further comments or petitions received in Docket PS-54 will be treated as petitions for rulemaking.

In response to the request for comments to the final rule, 43 persons submitted comments. Although most commenters represented themselves or their companies, at least five commenters were representing industry groups that included the American Gas Association, the New England Gas Association, the Pennsylvania Gas Association, the Plastic Pipe Institute, and the Texas Gas Association. The disposition of comments, including those treated as petitions for reconsideration, together with the reasons for accepting or rejecting these comments follow:

Who Can Qualify Joining Procedures

Seven commenters argued that the regulations should state that operators may qualify their own joining procedures by performing the required tests or basing the qualification on testing done by others, such as the manufacturers of the pipe or fittings involved, other operators, or other qualified persons. MTB wishes to emphasize that for compliance with the new §§ 192.283 and 192.285, just as for compliance with other testing requirements of Part 192, it does not matter who does the qualification testing, either the operator or someone else, but the operator is bound to assure that proper testing is done. If the operator adopts a procedure that was improperly qualified by himself or others, it is still the operator who is responsible for compliance on his pipeline. Because the ultimate duty of compliance with the testing requirements lies with the operator, the regulations do not state who may do the required testing, but only establish that such testing be performed.

Qualifying Procedures To Make Joints

Burst Tests. There were eight commenters who recommended that under § 192.283(a)(1), the burst testing of heat fusion, solvent cement, or adhesive joints be limited to the sustained pressure test (ASTM D1598) as modified by Paragraph 8.6 of ASTM D2513. If adopted, this recommendation would eliminate the use of the minimum hydrostatic burst pressure test (ASTM D1599) as modified by Paragraph 8.7 of ASTM D2513 that was originally proposed in the NPRM and included in the final rule. These commenters state that the sustained pressure test is a much more severe test that would detect flaws that would not be detected by the minimum hydrostatic burst pressure test. Although MTB agrees with this latter statement, we also believe that the minimum hydrostatic burst pressure test in combination with the required tensile testing will detect the flaws that would cause failure under service conditions. At least three commenters concurred with MTB in the use of this test, citing their own successful experience. One commenter also recommended eliminating all burst tests as ineffective. Because of conflicting opinions and lack of solid data to support use of only the more stringent test, MTB is retaining the burst test requirements as issued.

Lateral Connections. With one exception, all those who commented on the use of the impact test for qualifying procedures for making joints on lateral connections agreed that it was a valid test. Of those commenters agreeing with the use of the impact test, there were five who suggested methods other than impact for deforming the test specimen (such as by torsion, bending, and pinching or combinations of these). Since failure of the specimen rather than the means of failure is the critical aspect of the test, MTB believes the suggested alternative test methods would be equally as effective as the impact test. The one commenter who disagreed with the use of an impact force to test lateral connections stated that it would be ineffective on service tees and may lead to dangerous practices. He offered no viable alternative other than visual inspections as are required under § 192.285(a)(2)(i) during qualification of persons to make joints. Because of the above, MTB has amended § 192.283(a)(2) in a manner to permit the use of a force of any kind in testing the strength of lateral connections rather than only permitting an impact force.

Two commenters considered that in § 192.283(a)(2), the phrase "pipe sections joined at right angles" implied the use of miter type joints. MTB does not agree with this since miter joints are clearly prohibited on plastic pipe in gas service by § 192.281(a). Thus, preparing a specimen lateral connection for testing in accordance with § 192.283(a)(2) would involve some type of fitting between pipe sections.

Criteria for Force Tests. At least two commenters suggested that the criterion for judging the failure of all types of specimen joints during testing should be clarified by indicating that the important point is where the failure initiates. MTB had intended this in the original wording and as a result has changed the phrase "failure occurs outside the joint area" to read "failure initiates outside the joint area" where appropriate in the final rule.

Tensile Tests. Three commenters objected to incorporation by reference of ASTM D638 as the tensile test for heat fusion, solvent cement, or adhesive joints. One stated that the D638 requirements for specimen configurations were too exotic for practical use. A second suggested deleting D638 and specifying tensile requirements in the regulations. A third stated that a tensile test will not necessarily detect faulty butt-fusion joints. None of these commenters presented any data in support of their statements or recommended viable alternatives. Therefore, MTB is not convinced that it is inappropriate to incorporate by reference D638, the most widely recognized industry standard MTB is aware of that is intended to test the tensile strength of plastic pipe materials (which include a joint segment).

Several commenters pointed out that specifying particular temperature and humidity conditions for tensile pull testing will not effect improved test precision and does not simulate field use conditions, but adds to the cost of compliance. MTB agrees with this assessment in that the testing is intended to show whether joints meet the "go/no-go" criterion with the specific materials involved rather than to evaluate material properties. As a result, MTB has amended § 192.283(b)(1) to permit testing done under ASTM D638 to be performed at ambient temperature and humidity.

One commenter pointed out that in testing large diameter mechanical joints, the requirement for 5 pipe diameters between the joint and pulling machine grips in § 192.283(b)(3) would require massive tensile testing machines that are not available. In reviewing this problem, MTB recognizes that the intent of this requirement is to preclude any effect on the strength of the joint by attachment of the test sample to the testing apparatus. By changing to performance language, other means of eliminating this effect may be utilized. As a result, MTB has eliminated the requirement for 5 pipe diameters in favor of the performance requirement that the distance between the grips of the apparatus and the end stiffener may not affect the joint strength. This requirement has been relocated in § 192.283(b)(2).

Two commenters pointed out that ASTM D638 does not contain criteria for a "go/no-go" determination on joints being tested. Three commenters suggested the criteria should be failure of the specimen initiating outside the joint area or no less than 25% elongation of the specimen without failure. Based on similar criterion established for mechanical joints, MTB believes 25% elongation is an adequate indication of joint strength. The criterion of specimen failure is also valid because it relates joint strength to pipe strength and includes the important point that failure may not initiate in the joint area. As a result, the requirements of § 192.283(a)(2) for testing heat fusion, solvent cement, and adhesive joints have been amended to include these criteria. Similarly, for mechanical joints, failure of the specimen has been added as a test criterion to § 192.283(b) in addition to the 25% elongation standard that was included in the final rule.

Five commenters pointed out in regard to tensile tests for mechanical joints, that for larger pipe such as 16 inch diameter SDR 11 polyethylene pipe, the theoretical force resulting from a temperature change of 55.6° C (100° F) would be 90,000 pounds or greater. There are no mechanical fittings available that would withstand such tensile forces. MTB agrees with a suggested solution to this problem that would permit mechanical joining procedures on larger pipe to be qualified on the basis of actual resistance to tensile pull determined by the required testing, as long as the determined tensile strength of the joint does not exceed the manufacturer's rating. Because of this, MTB has amended the wording of § 192.283(b)(5) to permit such a practice.

One commenter stated that the regulations in § 192.283(b) for testing mechanical joints should recognize that there are mechanical fittings made to provide a gas seal only and others designed for both seal and longitudinal restraint. This commenter further argued that "seal only" mechanical joints should not be permitted to be used under conditions for which they were not designed by the manufacturer. In other words, operators should not be permitted to qualify these types of joints for use where longitudinal restraint is needed. The lead-in exception clause in § 192.283(b) was intended to exclude the "seal only" type joints from testing, but this point has been clarified in the final rules by limiting the applicability of § 192.283(b) to mechanical joints that are designed to withstand tensile forces, and for pipe 4 inches and larger where the specimen joint is permitted to be qualified at tensile strengths less than that of the pipe, the tensile stress permitted in the design calculation may in no case be more than the manufacturer's rating.

One commenter pointed out that in performing tensile testing of mechanical joints, the present wording of § 192.283(b)(8) would require excessive testing, since each pipe size for each wall thickness must be tested. This commenter argued that any joint that would qualify with heavy walled pipe would also qualify with lighter walled pipe. MTB has considered this point and believes there is no safety advantage to requiring each wall thickness of a particular size and material to be tested. Because of this, MTB is changing the newly designated requirement of § 192.283(b)(7) to permit testing of a heavier wall pipe joint to qualify joints made from pipe of the same material but with a lesser wall thickness.

One commenter stated that in testing mechanical joints, there seems to be confusion between qualifying a particular fitting and qualifying a procedure to properly install that fitting. He further stated that basing a plastic joining procedure upon destructively testing an entire test specimen has no more merit than destructively testing an entire welded assembly in qualifying a weld procedure. MTB does not agree with this because the final rule does not require the qualification of fittings but rather the qualification of joining procedures and persons who make joints with fittings. In § 192.283(b), we are also dealing with mechanical joints that have no similarity to welded joints. In addition, these tests are designed to compare joint strength to a stress level related to pipe strength. Thus, testing an assembly or joint specimen is considered appropriate.

At least nine commenters agreed with MTB that a burst test for mechanical joints is meaningless. There were no adverse comments.

Regarding § 192.283(c), seven commenters agreed that joining procedures needed to be available to inspectors and persons making joints, but not necessarily available at the job site as required by § 192.283(c). One commenter stated that if operators or inspectors need copies of each written procedure at the work site, they probably are not well qualified and should not be making joints. After reconsideration of this, MTB agrees that qualified persons joining and inspecting joints should know the applicable joining procedure thoroughly and as a result has deleted from § 192.283(c) the phrase "at the site where joining is accomplished." Under the final rule, copies would still have to be available to personnel.

One commenter pointed out that the wording of Amdt. 192-34 would preclude the use of considerable quantities of previously manufactured pipe and fittings now in warehouse stocks, the joining of which has been qualified by tests similar to those being required by this rulemaking, unless some provision is made to "grandfather" the continued use of these materials. MTB agrees that such an economic loss would be unwarranted provided the joint produced by such materials using previously qualified procedures would be as strong as the pipe. As a result, MTB has added a new § 192.283(d) to permit the joining of material made before July 1, 1980, in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

Qualifying Persons To Make Joints

Six commenters pointed out that in qualifying persons to make joints under § 192.285(a)(2)(i), mechanical joints could not be judged solely on the appearance of the completed joint. MTB did not intend this result because on mechanical joints the required inspection must be made during assembly to assure that the proper procedure is followed. Photographs showing each step of the assembly procedure on a qualified specimen joint are effective in providing a standard for comparison. In view of this comment however, MTB has inserted the phrase, "during and after assembly or joining," in the requirement which is relocated in § 192.285(b)(i) to make it clear that this visual examination must be performed at each step of the joining process.

Seven commenters proposed that test methods, in addition to destructively testing straps from a specimen joint, be permitted for qualifying persons to make heat fusion, solvent cement, or adhesive joints under § 192.285(a)(2)(ii). Convincing arguments were presented for using as a qualifying test any of the test methods permitted under § 192.283(a) for qualifying joining procedures as well as ultrasonic inspection. In addition, most of these comments emphasized that the term "destructively tested" requires a fracture of some part of the specimen, although this is often inappropriate because deformation of the joint area without fracture would detect flaws in the specimen by producing a failure or visible cracks. If a test shows no failure of the specimen under deformation or no visible cracks, a good joint is produced. In addition, some of these commenters argued in favor of allowing bending, torque, or impact forces to produce this deformation. After a thorough evaluation of these comments, the MTB is convinced that all of these methods will adequately detect significant flaws in joints being inspected and has amended the requirement which is relocated in § 192.285(b)(2) to permit, as personnel qualifying tests, for heat fusion, solvent cement, or adhesive joints, tests under §192.283(a) or examination by ultrasonic inspection showing no flaws that could cause failure. In addition, the existing test regarding the use of at least 3 longitudinal straps is changed by amending the words "destructively tested" to read "deformed by bending, torque, or impact."

One commenter recommended that in § 192.285(a)(2)(ii)(A) between the words "discontinuities" and "on" the phrase "greater than two millimeters average diameter" be added because heat fusion joints of 3 inches and larger diameter sometimes have small shrinkage voids that do not interfere with safe operation of the pipeline. MTB did not adopt this comment since no data was found to support the proposition that some voids can be identified as acceptable.

Four commenters stated that under § 192.285(a)(2)(ii), the longitudinal straps should be required to be taken 120° apart and not required at all on pipe less than 2 inches in diameter. MTB does not agree with this recommendation. We believe that specification of strap location would serve no useful purpose and that regardless of the pipe diameter, the straps provide a good means to visually inspect the cross section of the joint area as well as providing a manageable size specimen for additional testing. This requirement has been relocated in § 192.285(b)(iii).

Requalification of Persons to Make Joints. Nine commenters stated that in establishing a requirement for requalification of a person to make joints under § 192.285(b) that is based upon faulty joints, only joints left in the pipeline as satisfactory and later detected to be faulty by pressure testing or operation of the pipeline should be considered. These same commenters pointed out, however, that to determine who had made each joint that failed during operation of the pipeline would require excessive recordkeeping that would not be cost effective. While MTB agrees that only faulty joints left in the pipeline affect safety and that recordkeeping required to determine who made a joint that fails during pipeline operation would be excessively costly, the underlying intent of this final rule is to preclude the existence of faulty joints before a pipeline goes into operation. The required pressure test under § 192.513 serves this intent by subjecting joints to at least 150 percent of the maximum allowable operating pressure which should detect faulty joints. For this reason, MTB has amended this requirement which is relocated in § 192.285(c)(2) to limit the joints considered in applying the requalification requirements to those found by pressure testing under § 192.513.

One commenter stated that requiring requalification on the basis of making 3 bad joints a year does not recognize that some persons may make only a few joints per year while others may make many times that in just one day. This commenter further pointed out that field conditions such as rain, snow, blowing dirt, trench cave-ins, equipment malfunctions, and material flaws would affect the joining process without reflecting a lack of skill or proper training. He suggested that for those persons making large numbers of joints, it would be more equitable to require requalification if 3 percent or more of the production joints left in the line by the person making joints were found unacceptable. MTB agrees with this because limiting the threshold for requalification to only 3 faulty joints per year could cause the most highly qualified persons to be disqualified as a result of the large number of joints that are made that may involve conditions beyond the joiner's control. Because of this, MTB has amended the requirement which is relocated in § 192.285(c)(2) to require a person to be requalified under the applicable procedure if 3 joints or 3 percent of the joints made, whichever is greater, are found unacceptable by the required pressure test under § 192.513.

Two commenters argued that requalification should be required for persons who during the preceding 12 months have not been tested under the applicable procedure or made acceptable production joints. Both of these commenters and a third commenter also recommended requiring an annual requalification. MTB proposed an annual requalification in the NPRM, but it was not adopted in the final rules in favor of a less stringent and less costly requirement. MTB does, however, agree that a person who has not made acceptable production joints in the preceding 12 months should be required to be requalified because it is likely that some details of the procedure would be forgotten. Thus, MTB has amended the requirement which is relocated in § 192.285(c)(1) to require requalification in a procedure when no joints are made under the procedure during a 12-month period.

Inspection of Joints

There were eleven commenters who stated that MTB's interpretation in the preamble of the final rules of § 192.273, indicating that an adequate inspection of a production joint cannot be performed by the person who makes the joint, is unrealistic, excessively expensive, and does not assure safety.

Comments indicated that in most cases the inspection requirement of § 192.273(c) is met by the person making the joint, but some operators do spot check joining performance by their personnel. One commenter stated that imposition of a second qualified joiner on every company crew for the purpose of inspection will not improve the joint quality or improve the safety of plastic pipe construction, but will increase the cost of construction substantially. Another commenter stated that during 1978, approximately 720,000 heat fusion joints were installed in his system (one of the largest in the U.S.) and the cost of having a second person inspect each of these would have been substantial. As a result of these comments and after reviewing the history and purpose of § 192.273(c), MTB is persuaded that interpreting § 192.273(c) to require a second person to inspect each joint is not cost effective and not consistent with the intent of the rule as originally written. Therefore, the inspection of joints in plastic pipe required under § 192.273(c) may be performed by the person making joints, provided that person also is qualified under § 192.287 as required by the new § 192.285.

In consideration of the foregoing, Part 192 of Title 49 of the Code of Federal Regulations is amended as follows:

1. By revising § 192.283 to read as follows:

§ 192.283 Plastic pipe; qualifying joining procedures.

(a) *Heat Fusion, Solvent Cement, and Adhesive Joints.* Before any written procedure established under § 192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of Paragraph 8.6 (Sustained Pressure Test) or Paragraph 8.7 (Minimum Hydrostatic Burst Pressure) of ASTM D 2513.

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

(3) For procedures intended for nonlateral pipe connections, follow the tensile test requirements of ASTM D638, except that the test may be conducted at ambient temperature and humidity. If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical Joints.* Before any written procedure established under § 192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D638–77a (except for conditioning).

(2) the specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

(3) The speed of testing is 5.0 mm (0.20 in) per minute, plus or minus 25 percent.

(4) Pipe specimens less than 102 mm (4 in) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

(5) Pipe specimens 102 mm (4 in) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 55.6° C (100° F) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

(d) Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

2. By revising § 192.285 to read as follows:

§ 192.285 Plastic pipe; qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by—

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be—

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) tested under § 192.283;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is—

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be requalified under an applicable procedure, if during any 12-month period that person—

(1) Does not make any joints under that procedure; or

(2) Has 3 joints or 3 percent of the joints made, whichever, is greater, under that procedure that are found unacceptable by testing under § 192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in his system is qualified in accordance with this section.

(49 U.S.C. 1672; 49 U.S.C. 1804 with regard to offshore gathering lines; 49 CFR 1.53 and Appendix A of Part 1)

Issued in Washington, D.C., on February 11, 1980.

L. D. Santman,

Director, Materials Transportation Bureau.

[FR Doc. [illegible] Filed 2-13-80; [illegible]]

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DEPARTMENT OF TRANSPORTATION

Materials Transportation Bureau

49 CFR Part 192

[Amdt. 192-35; Docket No. PS-52]

Transportation of Natural and Other Gas by Pipeline; Cathodically Protected Transmission Lines

AGENCY: Materials Transportation Bureau (MTB).

ACTION: Final Rule.

SUMMARY: This amendment establishes the monitoring requirements for testing short sections of transmission pipelines on a sampling basis to determine the effectiveness of cathodic protection in controlling corrosion.

EFFECTIVE DATE: December 20, 1979.

FOR FURTHER INFORMATION CONTACT: George L. Mocharko, (202) 426-2392.

SUPPLEMENTARY INFORMATION: On August 28, 1978, MTB issued a notice of proposed rulemaking to amend the requirements contained in § 192.465 to permit the monitoring of short sections of transmission lines on a sampling basis (43 FR 39401, September 5, 1978). The deadline for comments was October 15, 1978.

Justification for this Rulemaking: Beyond the support cited in the original notice, 14 commenters responded to the notice. In summary: All commenters agreed with MTB's proposal and stated that it reflected good technical judgement since the present more stringent annual monitoring requirement for short sections of transmission lines is not warranted on a public safety basis. They also believe that the economic burden upon industry would be reduced without reducing safety.

Other significant comments and their disposition: Based on one commenter's experience of monitoring short sections of distribution pipelines, it was suggested that the monitoring frequency should be once every 10 years or one-half of the design life of the cathodic protection system, whichever is more frequent. MTB believes that the proposed sampling procedure adequately covers such cases since the preponderance of gas operators use a 20-year design life for cathodic protection systems. Furthermore, MTB believes that use of a sliding scale for monitoring based on design life would increase operator's costs relative to monitoring and create compliance and recordkeeping problems resulting from subjective personal opinions of the operators and enforcement officials as to what data tests must be made. MTB wished to emphasize, however, that if the sampling method is used, the operator must assure that the design life of the cathodic protection system is not less than the period of sampling.

One commenter stated that MTB's proposed wording does not make it clear that "short sections" would include "hot spot" protection on bare transmission lines. The final regulation applies to pipelines that are separately protected by the "hot spot" method.

Beyond the scope of the notice: One commenter proposed wording that would permit service lines of any length to be monitored on a sampling basis.

One commenter proposed that for transmission lines, MTB should define short sections as 500 feet in Class 1 and 2 locations.

No further Technical Pipeline Safety Standards Committee (TPSSC) consideration is needed, since the TPSSC recommended that the Office of Pipeline Safety Regulation institute rulemaking action concerning this specific amendment at its January 1978 meeting.

MTB has determined that this amendment would not result in a major economic impact ($100 million or greater) under the terms of Executive Order 12044 and DOT implementing procedures (44 FR 11034). Also, MTB has determined that this amendment does not require a full Final Regulatory Evaluation under those procedures because the amendment establishes an equivalent safety requirement and imposes no added compliance burdens and, therefore, has a minimal cost impact upon the industry. In fact, it could result in an estimated cost savings of $1 million per year to the industry.

MTB has made the effective date immediate upon publication so that operators can take advantage of the economic relief provided by the amendment.

Based on the foregoing, Part 192 of Title 49 of the Code of Federal Regulations is amended as follows:

By revising § 192.465(a) to read:

§ 192.465 External corrosion control: Monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463. However, if tests at those intervals are impractical for separately protected sections of pipeline not in excess of 100 feet, these pipeline sections may be surveyed on a sampling basis. At least 10 percent of these separately protected sections, distributed over the entire system, must be surveyed each calendar year with a different 10 percent checked each subsequent year, so that all separately protected pipeline sections are tested in each 10-year period.

(49 U.S.C. 1672; 18 U.S.C. 1804 for offshore gathering lines; 49 CFR 1.53, Appendix A of Part 1)

Issued in Washington, D.C., on December 13, 1979.

L. D. Santman,

Director, Materials Transportation Bureau.

[FR Doc. 79-38872 Filed 12-18-79; 8:45 am]

BILLING CODE 4910-60-M

Research and Special Programs Administration

49 CFR Part 192

[Amdt. 192-35A; Docket No. PS-52]

Transportation of Natural and Other Gas by Pipeline; Separately Protected Service Lines

AGENCY: Materials Transportation Bureau (MTB), DOT.

ACTION: Final rule.

SUMMARY: A final rule was published (Amdt. 192-35; 44 FR 75384 December 20, 1979) establishing requirements for testing, on a sampling basis, cathodic protection on short sections of transmission lines. That final rule unintentionally altered the requirement for testing cathodic protection on separately protected service lines. This amendment reinstates the original requirement, which allowed separately protected service lines, regardless of their length, to be tested on a sampling basis if annual tests are impractical.

EFFECTIVE DATE: April 7, 1980.

FOR FURTHER INFORMATION CONTACT: L. M. Furrow on (202) 426-2392.

SUPPLEMENTARY INFORMATION: On August 29, 1978, MTB issued a notice of proposed rulemaking to amend the cathodic protection monitoring requirements of § 192.465(a) (43 FR 39401, September 5, 1978). The purpose of the notice was to invite comments on a proposal to allow transmission line sections that are impractical to monitor annually to be monitored by the sampling procedure applicable to service lines and mains.

The language of the proposal read: "However, if tests at those intervals are impractical for separately protected service lines or short sections of protected mains and transmission lines, not in excess of 100 feet, these pipelines may be surveyed on a sampling basis." (The proposal merely would have added the words "and transmission lines," immediately after the word "mains" in the original rule.) In Amendment 192-35, this proposed language was changed to read: "However, if tests at those intervals are impractical for separately protected sections of pipeline not in excess of 100 feet, these pipeline sections may be surveyed on a sampling basis." This language change was intended merely to clarify that the phrase "not in excess of 100 feet" in the original rule applied to service lines as well as mains. The change appeared justified by the plain meaning of the original rule, and it did not appear that any contrary interpretation had been made.

Following adoption of Amendment 192-35, MTB has received letters and petitions from several interested persons pointing out that ever since the issuance of section 192.465(a) (Docket No. OPS-5, 36 FR 12302, June 30, 1971), the gas industry has been permitted to monitor separately protected service lines that are impractical to monitor annually, on a sampling basis, regardless of their length. Various arguments (technical, legal, and cost/benefit) have been advanced to support the position that the 100-foot limitation in the original rule was intended only to define "short sections of protected mains" and not to modify the term "service lines."

MTB has evaluated these arguments by checking the record of Docket No. OPS-5 and consulting knowledgeable field enforcement personnel. Both the record and enforcement practices are consistent with the view that until issuance of Amendment 192-35, separately protected service lines have been eligible for monitoring on a sampling basis, regardless of length. It also appears that Departmental training material provided to industry participants indicates that separately protected service lines were not considered subject to the 100-foot limitation. As a result, because Amendment 192-35 was not intended to modify the existing rule with regard to service lines, MTB is hereby amending section 192.465(a) as set forth below to eliminate any further misunderstanding about application of the 100-foot limitation to separately protected service lines.

In consideration of the foregoing, section 192.465(a) is revised to read as follows:

§ 192.465 External corrosion control: monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of section 192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet, or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

* * * * *

(49 U.S.C. 1672; 49 CFR 1.53 and Appendix A of Part 1)

Issued in Washington, D.C. on April 1, 1980.

L. D. Santman,

Director, Materials Transportation Bureau.

[FR Doc. 80-[illegible] Filed 4-4-80; 8:45 am]

BILLING CODE 4910-60-M

☆ U.S. GOVERNMENT PRINTING OFFICE: 1980 O— [illegible] REGION [illegible]

Oregon Department of Environmental Quality

Noise Control Regulations

Contents

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DEPARTMENT OF ENVIRONMENTAL QUALITY

CHAPTER 340, OREGON ADMINISTRATIVE RULES

DIVISION 35

NOISE CONTROL REGULATIONS

Amended November 1980

General

Policy

340-35-005 In the interest of public health and welfare, and in accordance with ORS 467.010, it is declared to be the public policy of the State of Oregon:

(1) To provide a coordinated state-wide program of noise control to protect the health, safety, and welfare of Oregon citizens from the hazards and deterioration of the quality of life imposed by excessive noise emissions;

(2) To facilitate cooperation among units of state and local governments in establishing and supporting noise control programs consistent with the State program and to encourage the enforcement of viable local noise control regulations by the appropriate local jurisdiction;

(3) To develop a program for the control of excessive noise sources which shall be undertaken in a progressive manner, and each of its objectives shall be accomplished by cooperation among all parties concerned.

Exceptions

340-35-010 Upon written request from the owner or controller of a noise source, the Department may authorize exceptions as specifically listed in these rules.

In establishing exceptions, the Department shall consider the protection of health, safety, and welfare of Oregon citizens as well as the feasibility and cost of noise abatement; the past, present, and future patterns of land use; the relative timing of land use changes and other legal constraints. For those exceptions which it authorizes, the Department shall specify the times during which the noise rules can be exceeded and the quantity and quality of the noise generated, and when appropriate shall specify the increments of progress of the noise source toward meeting the noise rules.

Definitions

340-35-015 As used in this division:

(1) "Air Carrier Airport" means any airport that serves air carriers holding Certificates of Public Convenience and Necessity issued by the Civil Aeronautic Board.

(2) "Airport Master Plan" means any long-term development plan for the airport established by the airport proprietor.

(3) "Airport Noise Abatement Program" means a Commission-approved program designed to achieve noise compatibility between an airport and its environs.

(4) "Airport Proprietor" means the person who holds title to an airport.

(5) "Ambient Noise" means the all-encompassing noise associated with a given environment, being usually a composite of sounds from any sources near and far.

(6) "Annual Average Day-Night Airport Noise Level" means the average, on an energy basis, of the daily Day-Night Airport Noise Level of a 12-month period.

(7) "Any one hour" means any period of 60 consecutive minutes during the 24-hour day.

(8) "Closed Course Motorcycle Racing Vehicle" means any motorcycle racing vehicle that is operated in competition or practice session on a closed course motor sports facility, i.e. where public access is restricted and admission is generally charged.

(9) "Commission" means the Environmental Quality Commission.

(10) "Construction" shall mean building or demolition work and shall include all activities thereto such as clearing of land, earthmoving, and landscaping, but shall not include the production of construction materials.

(11) "Day-Night Airport Noise Level (Ldn)" means the Equivalent Noise Level produced by airport/aircraft operations during a 24-hour time period, with a 10 decibel penalty applied to the level measured during the nighttime hours of 10 pm to 7 am.

(12) "Department" means the Department of Environmental Quality.

(13) "Director" means the Director of the Department.

(14) "Drag Racing Vehicle" means any racing vehicle used to compete in any acceleration competition initiated from a standing start and continued over a straight line course.

(15) "Emergency Equipment" means noise emitting devices required to avoid or reduce severity of accidents. Such equipment includes, but is not limited to, safety valves and other pressure relief devices.

(16) "Equivalent Noise Level (Leq)" means the equivalent steady state sound level in A-weighted decibels for a stated period of time which contains the same acoustic energy as the actual time-varying sound level for the same period of time.

(17) "Existing Industrial or Commercial Noise Source" means any Industrial or Commercial Noise Source for which installation or construction was commenced prior to January 1, 1975.

(18) "Farm Tractor" means any Motor Vehicle designed primarily for use in agricultural operations for drawing or operating plows, mowing machines, or other implements of husbandry.

(19) "Four Wheel Drive Racing Vehicle" means any four-wheeled racing vehicle with at least one wheel on the front and rear axle driven by the engine or any racing vehicle participating in an event with predominantly four wheel drive racing vehicles.

(20) "Go-Kart Racing Vehicle" means a light-weight four-wheeled racing vehicle of the type commonly known as a go-kart.

(21) "Impulse Sound" means either a single pressure peak or single burst (multiple pressure peaks) for a duration of less than one second as measured on a peak unweighted sound pressure measuring instrument.

(22) "In-Use Motor Vehicle" means any Motor Vehicle which is not a New Motor Vehicle.

(23) "Industrial or Commercial Noise Source" means that source of noise which generates Industrial or Commercial Noise Levels.

(24) "Industrial or Commercial Noise Levels" means those noises generated by a combination of equipment, facilities, operations, or activities employed in the production, storage, handling, sale, purchase, exchange, or maintenance of a product, commodity, or service and those noise levels generated in the storage or disposal of waste products.

(25) "Motorboat" as used in OAR 340-35-025 means a water craft propelled by an internal combustion engine but does not include a boat powered by an outboard motor designed to exhaust beneath the surface of the water.

(26) "Motorcycle" means any Motor Vehicle, except Farm Tractors, designed to travel on not more than three wheels which are in contact with the ground.

(27) "Motor Sports Advisory Committee" means a committee appointed by the Director, from among the nominees, for the purpose of technical advice on racing activities and to recommend Exceptions to these rules as specified in OAR 340-35-040(12). This Committee shall consist of:

(a) One permanent public member nominated by a noise impacted group or association; and

(b) One representative of each of the racing vehicle types identified in OAR 340-35-040(2) as nominated by the respective sanctioning bodies; and

(c) The program manager of the Department's noise pollution control section who shall also serve as the departmental staff liaison to this body.

(28) "Motor Sports Facility" means any facility, track or course upon which racing events are conducted.

(29) "Motor Sports Facility Noise Impact Boundaries" means the daily 55 dBA day-night (Ldn) noise contours around the motor sports facility representing events that may occur on the day of maximum projected use.

(30) "Motor Sports Facility Owner" means the owner or operator of a motor sports facility or an agent or designee of the owner or operator. When a Racing Event is held on public

land, the event organizer (i.e., promoter) shall be considered the motor sports facility owner for the purposes of these rules.

(31) "Motor Vehicle" means any vehicle which is, or is designed to be self-propelled or is designed or used for transporting persons or property. This definition excludes airplanes, but includes watercraft.

(32) "New Airport" means any airport for which installation, construction, or expansion of a runway commenced after January 1, 1980.

(33) "New Industrial or Commerical Noise Source" means any Industrial or Commercial Noise Source for which installation or construction was commenced after January 1, 1975 on a site not previously occupied by the industrial or commercial noise source in question.

(34) "New Motor Sports Facility" is any permanent motor sports facility for which construction or installation was commenced after the effective date of these rules. Any recreational park or similar facility which initiates sanctioned racing after the effective date of these rules shall be considered a new motor sports facility.

(35) "New Motor Vehicle" means a Motor Vehicle whose equitable or legal title has never been transferred to a Person who in good faith purchases the New Motor Vehicle for purposes other than resale. The model year of such vehicle shall be the year so specified by the manufacturer, or if not so specified, the calendar year in which the new motor vehicle was manufactured.

(36) "Noise Impact Boundary" means a contour around the airport, any point on which is equal to the airport noise criterion.

(37) "Noise Level" means weighted Sound Pressure Level measured by use of a metering characteristic with an "A" frequency weighting network and reported as dBA.

(38) "Noise Sensitive Property" means real property normally used for sleeping, or normally used as schools, churches, hospitals or public libraries. Property used in industrial or agricultural activities is not Noise Sensitive Property unless it meets the above criteria in more than an incidental manner.

(39) "Octave Band Sound Pressure Level" means the sound pressure level for the sound being measured within the specified octave band. The reference pressure is 20 micropascals (20 micronewtons per square meter).

(40) "Off-Road Recreational Vehicle" means any Motor Vehicle, including watercraft, used off Public Roads for recreational purposes. When a Road Vehicle is operated off-road, the vehicle shall be considered an Off-Road Recreational Vehicle if it is being operated for recreational purposes.

(41) "One-Third Octave Band Sound Pressure Level" means the sound pressure level for the sound being measured within the specified one-third octave band at the Preferred

Frequencies. The reference pressure is 20 micropascals (20 micronewtons per square meter).

(42) "Open Course Motorcycle Racing Vehicle" means any motorcycle racing vehicle that is operated in competition on an open course motor sports facility, i.e. where public access is not generally restricted. This definition is intended to include the several types of motorcycles such as "enduro" and "cross country" that are used in events held in trail or other off-road environments.

(43) "Oval Course Racing Vehicle" means any racing vehicle, not a motorcycle and not a sports car, which is operated upon a closed, oval-type motor sports facility.

(44) "Person" means the United States Government and agencies thereof, any state, individual, public or private corporation, political subdivision, governmental agency, municipality, industry, co-partnership, association, firm, trust, estate, or any other legal entity whatever.

(45) "Practice Sessions" means any period of time during which racing vehicles are operated at a motor sports facility, other than during racing events. Driver training sessions or similar activities which are not held in anticipation of a subsequent racing event, and which include only vehicles with a stock exhaust system, shall not be considered practice sessions.

(46) "Preferred Frequencies" means those mean frequencies in Hertz preferred for acoustical measurements which for this purpose shall consist of the following set of values: 20, 25, 31.5, 40, 50, 63, 80, 100, 125, 160, 200, 250, 315, 400, 500, 630, 800, 1000, 1250, 1600, 2000, 2500, 3150, 4000, 5000, 6300, 8000, 10,000, 12,500.

(47) "Previously Unused Industrial or Commercial Site" means property which has not been used by any industrial or commercial noise source during the 20 years immediately preceding commencement of construction of a new industrial or commercial source on that property. Agricultural activities and silvicultural activities of an incidental nature shall not be considered as industrial or commercial operations for the purposes of this definition.

(48) "Propulsion Noise" means that noise created in the propulsion of a Motor Vehicle. This includes, but is not limited to exhaust system noise, induction system noise, tire noise, cooling system noise, aerodynamic noise and where appropriate in the test procedure, braking system noise. This does not include noise created by Road Vehicle Auxiliary Equipment such as power take-offs and compressors.

(49) "Public Roads" means any street, alley, road, highway, freeway, thoroughfare, or section thereof in this state used by the public or dedicated or appropriated to public use.

(50) "Quiet Area" means any land or facility designated by the Commission as an appropriate area where the qualities of serenity, tranquility, and quiet are of extraordinary significance and serve an important public need, such as, without

being limited to, a wilderness area, national park, state park, game reserve, wildlife breeding area or amphitheater. The Department shall submit areas suggested by the public as Quiet Areas, to the Commission, with the Department's recommendation.

(51) "Racing Event" means any time, speed or distance competition using motor vehicles conducted under a permit issued by the governmental authority having jurisdiction, or under the auspices of a recognized sanctioning body. This definition includes, but is not limited to, events on the surface of land and water. Any motor sports event not meeting this definition shall be subject to the ambient noise limits of OAR 340-35-030(1)(d).

(52) "Racing Vehicle" means any Motor Vehicle that is designed to be used exclusively in Racing Events or any vehicle participating in or practicing for a Racing Event.

(53) "Recreational Park" means a facility open to the public for the operation of off-road recreational vehicles.

(54) "Road Vehicle" means any Motor Vehicle registered for use on Public Roads, including any attached trailing vehicles.

(55) "Road Vehicle Auxiliary Equipment" means those mechanical devices which are built in or attached to a Road Vehicle and are used primarily for the handling or storage of products in that Motor Vehicle. This includes, but is not limited to, refrigeration units, compressors, compactors, chippers, power lifts, mixers, pumps, blowers, and other mechanical devices.

(56) "Sound Pressure Level (SPL)" means 20 times the logarithm to the base 10 of the ratio of the root-mean-square pressure of the sound to the reference pressure. SPL is given in decibels (dB). The reference pressure is 20 micropascals (20 micronewtons per square meter).

(57) "Special Motor Racing Event" means any racing event in which a substantial or significant number of out-of-state racing vehicles are competing and which has been recommended as a special motor racing event by the motor sports advisory committee and approved by the Department.

(58) "Sports Car Racing Vehicle" means any racing vehicle which meets the requirements and specifications of the competition rules of any sports car organization.

(59) "Statistical Noise Level" means the Noise Level which is equalled or exceeded a stated percentage of the time. An L_{10} = 65 dBA implies that in any hour of the day 65 dBA can be equalled or exceeded only 10 percent of the time, or for six minutes.

(60) "Stock Exhaust System" means an original equipment manufacturer exhaust system or a replacement for original equipment for a street legal vehicle whose noise emissions do not exceed those of the original equipment.

(61) "Temporary Autocross or Solo Course" means any area upon which a paved course motor sports facility is temporarily established. Typically such courses are placed on parking lots, or other large paved areas, for periods of one or two days.

(62) "Top Fuel-Burning Drag Racing Vehicle" means a drag racing vehicle that operates using principally alcohol (more than 50 percent) or utilizes nitromethane as a component of its operating fuel and commonly known as top fuel and funny cars.

(63) "Trackside" means a sound measuring point of 50 feet from the racing vehicle and specified in Motor Race Vehicle and Facility Sound Measurement and Procedure Manual, NPCS-35.

(64) "Warning Device" means any device which signals an unsafe or potentially dangerous situation.

(65) "Watercraft Racing Vehicle" means any racing vehicle which is operated upon or immediately above the surface of water.

(66) "Well Maintained Muffler" means a device or combination of devices which effectively decreases the sound energy of internal combustion engine exhaust without a muffler by a minimum of 5 dBA at trackside. A well maintained muffler shall be free of defects or modifications that reduce its sound reduction capabilities. Each outlet of a multiple exhaust system shall comply with the requirements of this subsection, notwithstanding the total engine displacement versus muffler length requirements. Such a muffler shall be a:

(a) Reverse gas flow device incorporating a multitube and baffle design; or a

(b) Perforated straight core device, fully surrounded from beginning to end with a sound absorbing medium, not installed on a rotary engine, and:

(i) at least 20 inches in inner core length when installed on any engine exceeding 1600 cc (96.7 cubic inches) displacement; or

(ii) at least 12 inches in inner core length when installed on any non-motorcycle engine equal to or less than 1600 cc (96.7 cubic inches) displacement; or

(iii) at least 6 inches in inner core length and installed at the outlet end of any four-cycle motorcycle engine; or

(iv) at least 8 inches in inner core length when installed on any two-cycle motorcycle engine; or an

(c) Annular swirl flow (auger-type) device of:

(i) at least 16 inches in swirl chamber length when installed on any engine exceeding 1600 cc (96.7 cubic inches) displacement; or

(ii) at least 10 inches in swirl chamber length when installed on any engine equal to or less than 1600 cc (96.7 cubic inches) displacement; or a

(d) Stacked 360° diffusor disc device; or a

(e) Turbocharger; or a

(f) Go-Kart muffler as defined by the International Karting Federation as specified in Motor Race Vehicle and Facility Sound Measurement and Procedure Manual, NPCS-35; or an

(g) Original equipment manufacturer motorcycle muffler when installed on a motorcycle model such muffler was designated for by the manufacturer; or

(h) Outboard boat motor whose exhaust exits beneath the water surface during operation; or

(i) Any other device demonstrated effective and approved by the motor sports advisory committee and the Department.

Noise Control Regulations for the Sale of New Motor Vehicles

340-35-025 (1) Standards and Regulations:

(a) No person shall sell or offer for sale any new motor vehicle designated in this section which produces a propulsion noise exceeding the noise limits specified in Table 1, except as otherwise provided in these rules.

(b) Subsequent to the adoption of a Federal Environmental Protection Agency procedure to determine sound levels of passenger cars and light trucks, or a nationally accepted procedure for these vehicles not similar to those specified and approved under subsection (2)(a), the Department shall conduct an evaluation under such new procedure.

(c) After an appropriate evaluation of noise emission data measured under the procedure specified under subsection (1)(b), the Department shall make recommendations to the Commission on the adequacy of the procedure and the necessity of amendments to this rule for incorporation of the procedure and associated standards.

(d) Notwithstanding the provisions of the subsections (1)(b) and (1)(c) the Department shall present a progress and status report on passenger car and light truck noise emission controls to the Commission no later than July 1, 1982.

(2) Measurement:

(a) Sound measurements shall conform to test procedures adopted by the Commission in Motor Vehicle Sound Measurement Procedures Manual (NPCS-21), or to standard methods approved in writing by the Department. These measurements will generally be carried out by the motor vehicle manufacturer on a sample of either prototype or production vehicles. A certification program shall be devised by the manufacturer and submitted to the Department for approval within 60 days after the adoption of this rule.

(b) Nothing in this section shall preclude the Department from conducting separate or additional noise level tests and measurements on new motor vehicles being offered for sale. Therefore, when requested by the Department, a new motor vehicle dealer or manufacturer shall cooperate in reasonable noise testing of a specific class of motor vehicle being offered for sale.

(3) Manufacturer's Certification:

(a) Prior to the sale or offer for sale of any new motor vehicle designated in Table 1, the manufacturer or a designated representative shall certify in writing to the Department that vehicles listed in Table 1 made by that manufacturer and offered for sale in the State of Oregon meet applicable noise limits. Such certification will include a statement by the manufacturer that:

(A) The manufacturer has tested sample or prototype vehicles.

(B) That such samples or prototypes met applicable noise limits when tested in accordance with the procedures specified.

(C) That vehicles offered for sale in Oregon are substantially identical in construction to such samples or prototypes.

(b) Nothing in this section shall preclude the Department from obtaining specific noise measurement data gathered by the manufacturer on prototype or production vehicles for a class of vehicles for which the Department has reasonable grounds to believe is not in conformity with the applicable noise limits.

(4) Exceptions. Upon prior written request from the manufacturer or designated representative, the Department may authorize an exception to this noise rule for a class of motor vehicles, if it can be demonstrated to the Department that for that specific class a vehicle manufacturer has not had adequate lead-time or does not have the technical capability to either bring the motor vehicle noise into compliance or to conduct new motor vehicle noise tests.

(5) Exemptions:

(a) All racing vehicles, except racing motorcycles, and racing motorboats, shall be exempt from the requirements of this section provided that such vehicles are operated only at facilities used for sanctioned racing events.

(b) Racing motorcycles and racing motorboats shall be exempt from the requirements of this section provided that racing motorcycles are operated only at facilities used for sanctioned racing events, racing motorboats are operated only at areas designated by the State Marine Board for testing or at an approved racing event, and the following conditions are complied with:

(A) Prior to the sale of a racing motorcycle or racing motorboat, the prospective purchaser shall file a notarized affidavit with the Department , on a Departmentally approved form, stating that it is the intention of such prospective purchaser to operate the vehicle only at facilities used for sanctioned racing events; and

(B) No racing vehicle shall be displayed for sale in the State of Oregon without notice prominently affixed thereto:

(i) That such vehicle will be exempt from the requirements of this section only upon demonstration to the Department that the vehicle will be operated only at facilities used for sanctioned racing events; and

(ii) That a notarized affidavit will be required of the prospective purchaser stating that it is the intention of such prospective purchaser to operate the vehicle only at facilities used for sanctioned racing events; and

(C) No racing vehicle shall be locally advertised in the State of Oregon as being for sale without notice included:

(i) which is substantially similar to that required in (B)(i) and (B)(ii) above, and

(ii) Which is unambiguous as to which vehicle such notice applies.

Noise Control Regulations for <u>In-Use Motor Vehicles</u>

340-35-030 (1) Standards and Regulations:

(a) Road Vehicles

(A) No person shall operate any road vehicle which exceeds the noise level limits specified in Table 2 or 3, except as otherwise provided in these rules.

(B) No person shall operate a road vehicle with any of the following defects:

(i) No muffler

(ii) Leaks in the exhaust system

(iii) Pinched outlet pipe

(C) Non-conforming "classic" and other "special interest" vehicles may be granted an exception to this rule, pursuant to Rule 340-35-010, for the purpose of maintaining authentic equipment.

(b) Off-Road Recreational Vehicles.

(A) No person shall operate any off-road recreational vehicle which exceeds the noise level limits specified in Table 4.

(B) No person shall operate an off-road recreational vehicle with any of the following defects:

(i) No muffler

(ii) Leaks in the exhaust system

(iii) Pinched outlet pipe

(c) Trucks Engaged in Interstate Commerce. Motor vehicles with a GVWR or GCWR in excess of 10,000 pounds which are engaged in interstate commerce by trucking and are regulated by Part 202 of Title 40 of the Code of Federal Regulations, promulgated Stat. 1248, Pub. L. 92-574, shall be:

(A) Free from defects which adversely affect sound reduction;

(B) Equipped with a muffler or other noise dissipative device;

(C) Not equipped with any "cut-out" devices, "by-pass" devices, or any other similar devices; and

(D) Not equipped with any tire which as originally manufactured or newly retreaded having a tread pattern composed primarily of cavities in the tread, excluding sipes and local chunking, not vented by grooves to the tire shoulder or vented circumferentially to each other around the tire.

(d) Ambient Noise Limits.

(A) No person shall cause, allow, permit, or fail to control the operation of motor vehicles, including motorcycles, on property which he owns or controls, nor shall any person operate any such motor vehicle if the operation thereof increases the ambient noise level such that the appropriate noise level specified in Table 5 is exceeded as measured from either of the following points, if located within 1000 feet (305 meters) of the motor vehicle:

(i) Noise sensitive property, or

(ii) The boundary of a quiet area.

(B) Exempt from the requirements of this subsection shall be:

(i) Motor vehicles operating in racing events;

(ii) Motor vehicles initially entering or leaving property which is more than 1000 feet (305 meters) from the nearest noise sensitive property or boundary of a quiet area;

(iii) Motor vehicles operating on public roads; and

(iv) Motor vehicles operating off-road for non-recreational purposes.

(e) Auxiliary Equipment Noise Limits.

(A) No person shall operate any road vehicle auxiliary equipment powered by the road vehicle's primary power source which exceeds the noise limits specified in Table 6, except as otherwise provided in these rules.

(B) As of June 1974, the Department does not have sufficient information to determine the maximum noise levels for road vehicle auxiliary equipment powered by a secondary source. Research on this noise source will be carried out with the goal of setting noise level limits by January 1, 1975.

(2) Measurement. Sound measurement shall conform to test procedures adopted by the Commission in Sound Measurement Procedures Manual (NPCS-1) and Motor Vehicle Sound Measurement Procedures Manual (NPCS-21) or to standard methods approved in writing by the Department.

(3) Exemptions:

(a) Motor Vehicles registered as antique or historical motor vehicles licensed in accordance with ORS 481.205(4) are exempt from these regulations.

(b) Motor vehicle warning devices are exempt from these regulations.

(c) Vehicles equipped with at least two snowtread tires are exempt from the noise limits of Table 3.

(d) Motor vehicles described in subsection (1)(c), which are demonstrated by the operator to be in compliance with the noise levels in Table 3, for operation greater than 35 mph, are exempt from these regulations.

(4) Equivalency:

(a) The in-use motor vehicle standards specified in Table 2 have been determined by the Department to be substantially equivalent to the 25 foot stationary test standards set forth in 1977 Oregon Laws Chapter 273 (ORS 483.449).

(b) Tests shall be conducted according to the procedures in Motor Vehicle Sound Measurement Procedures Manual (NPCS-21) or to standard methods approved in writing by the Department.

Noise Control Regulations <u>for Industry and Commerce</u>

340-35-035 (1) Standards and Regulations:

(a) Existing Noise Sources. No person owning or controlling an existing industrial or commercial noise source shall cause or permit the operation of that noise source if the statistical noise levels generated by that source and measured at an appropriate measurement point, specified in subsection (3)(b) of this section, exceed the levels specified in Table 7, except as otherwise provided in these rules.

(b) New Noise Sources.

(A) New Sources Located on Previously Used Sites. No person owning or controlling a new industrial or commercial noise source located on a previously used industrial or commercial site shall cause or permit the operation of that noise source if the statistical noise levels generated by that new source and measured at an appropriate measurement point, specified in subsection (3)(b) of this section, exceed the levels specified in <u>Table 8,</u> except as otherwise provided in these rules.

(B) New Sources Located on Previously Unused Site.

(i) No person owning or controlling a new industrial or commercial noise source located on a previously unused industrial or commercial site shall cause or permit the operation of that noise source if the noise levels generated or indirectly caused by that noise source <u>increase the ambient statistical noise levels L_{10} or L_{50}, by more than 10 dBA in any one hour, or exceed the levels specified in Table 8</u>, as measured at an appropriate measurement point, as specified in subsection (3)(b) of this rule.

(ii) The ambient statistical noise level of a new industrial or commercial noise source on a previously unused industrial or commercial site shall include all noises generated or indirectly caused by or attributable to that source, including all of its related activities. Sources exempted from the requirements of section (1) of this rule, which are identified in subsection <u>(5)(b), (5)(c), (5)(d), (5)(e), (5)(f), (5)(j), (5)(k) and (5)(l)</u> of this rule, <u>shall not be excluded from this ambient measurement.</u>

(c) Modified Noise Sources. After January 1, 1975 and before January 1, 1978, no person owning or controlling an existing industrial or commercial noise source shall modify that noise source so as to violate the following rules:

(A) If prior to modification an industrial or commercial noise source does not exceed the noise levels in Table 8, the modified industrial or commercial noise source shall not exceed the noise levels in Table 8, except as otherwise provided in these rules.

(B) If prior to modification an existing industrial or commercial noise source exceeds the noise levels in Table 8, but does not exceed the noise levels in Table 7, then the modification shall not cause an increase in the existing statistical noise levels, except as otherewise provided in these rules.

(d) Quiet Areas. No person owning or controlling an industrial or commercial noise source located either within the boundaries of a Quiet Area or outside its boundaries shall cause or permit the operation of that noise source if the statistical noise levels generated by that source exceed the levels specified in Table 9 as measured within the Quiet Area and not less than 400 feet (122 meters) from the noise source.

(e) Impulse Sound. Notwithstanding the noise rules in Tables 7 through 9, no person owning or controlling an industrial or commercial noise source shall cause or permit the operation of that noise source if an impulsive sound is emitted in air by that source which exceeds the peak sound pressure levels specified below, as measured at an appropriate measurement point, as specified in subsection (3)(b) of this rule: 100 dB during the hours 7 am to 10 pm and 80 dB between the hours of 10 pm and 7 am.

(f) Octave Bands and Audible Discrete Tones. When the Director has reasonable cause to believe that the requirements of subsections (1)(a), (1)(b), (1)(c) or (1)(d) of this rule do not adequately protect the health, safety or welfare of the public as provided for in ORS Chapter 467, the Department may require the noise source to meet the following rules:

(A) Octave Bands. No person owning or controlling an industrial or commercial noise source shall cause or permit the operation of that noise source if such operation generates a median octave band sound pressure level which, as measured at an appropriate measurement point, specified in subsection (3)(b) of this rule, exceeds applicable levels specified in Table 10.

(B) One-third Octave Bands. No person owning or controlling an industrial or commercial noise source shall cause or permit the operation of that noise source if such operation generates a median one-third octave band sound pressure level which, as measured at an appropriate measurement point, specified in subsection (3)(b) of this rule, and in a one-third octave band at a preferred frequency, exceeds the arithmetic average of the median sound pressure levels of the two adjacent one-third octave bands by:

(i) 5 dB for such one-third octave band with a center frequency from 500 Hertz to 10,000 Hertz, inclusive. Provided: such one-third octave band sound pressure level exceeds the sound pressure level of each adjacent one-third octave band, or;

(ii) 8 dB for such one-third octave band with a center frequency from 160 Hertz to 400 Hertz, inclusive. Provided: such one-third octave band sound pressure level exceeds the sound pressure level of each adjacent one-third octave band, or;

(iii) 15 dB for such one-third octave band with a center frequency from 25 Hertz to 125 Hertz, inclusive. Provided: such one-third octave band sound pressure level exceeds the sound pressure level of each adjacent one-third octave band.

This rule shall not apply to audible discrete tones having a one-third octave band sound pressure level 10 dB or more below the allowable sound pressure levels specified in Table 10 for the octave band which contains such one-third octave band.

(2) Compliance. Upon written notification from the Director, the owner or controller of an industrial or commercial noise source operating in violation of the adopted rules shall submit a compliance schedule acceptable to the Department. The

schedule will set forth the dates, terms, and conditions by which the person responsible for the noise source shall comply with the adopted rules.

(3) Measurement:

(a) Sound measurement procedures shall conform to those procedures which are adopted by the Commission and set forth in Sound Measurement Procedures Manual (NPCS-1) or to such other procedures as are approved in writing by the Department.

(b) Unless otherwise specified the appropriate measurement point shall be that point on the noise sensitive property, described below, which is further from the noise source:

(A) 25 feet (7.6 meters) toward the noise source from that point on the noise sensitive building nearest the noise source,

(B) That point on the noise sensitive property line nearest the noise source.

(4) Monitoring and Reporting:

(a) Upon written notification from the Department, persons owning or controlling an industrial or commercial noise source shall monitor and record the statistical noise levels and operating times of equipment, facilities, operations, and activities, and shall submit such data to the Department in the form and on the schedule requested by the Department. Procedures for such measurements shall conform to those procedures which are adopted by the Commission and set forth in Sound Measurement Procedures Manual (NPCS-1).

(b) Nothing in this section shall preclude the Department from conducting separate or additional noise tests and measurements. Therefore, when requested by the Department, the owner or operator of an industrial or commercial noise source shall provide the following:

(A) Access to the site,

(B) Reasonable facilities, where available, including but not limited to electric power and ladders adequate to perform the testing,

(C) Cooperation in the reasonable operation, manipulation, or shutdown of various equipment or operations as needed to ascertain the source of sound and measure its emission.

(5) Exemptions. Except as otherwise provided in subsection (1)(b)(B)(ii), the rules in section 340-35-035(1) shall not apply to:

(a) Emergency equipment not operated on a regular or scheduled basis.

(b) Warning devices not operating continuously for more than 5 minutes.

(c) Sounds created by the tires or motor used to propel any road vehicle complying with the noise standards for road vehicles.

(d) Sounds resulting from the operation of any equipment or facility of a surface carrier engaged in interstate commerce by railroad only to the extent that such equipment or facility is regulated by preemptive federal regulations as set forth in Part 201 of Title 40 of the Code of Federal Regulations, promulgated pursuant to section 17 of the Noise Control Act of 1972, 86 Stat. 1248, Pub. L. 92-576; but this exemption does not apply to any standard, control, license, regulation, or restriction necessitated by special local conditions which is approved by the Administrator of the EPA after consultation with the Secretary of Transportation pursuant to procedures set forth in section 17(c)(2) of the Act.

(e) Sounds created by bells, chimes, or carillons.

(f) Sounds not electronically amplified which are created by or generated at sporting, amusement, and entertainment events, except those sounds which are regulated under other noise standards. An event is a noteworthy happening and does not include informal, frequent or ongoing activities such as, but not limited to, those which normally occur at bowling alleys or amusement parks operating in one location for a significant period of time.

(g) Sounds that originate on construction sites.

(h) Sounds created in construction or maintenance of capital equipment.

(i) Sounds created by lawn care maintenance and snow removal equipment.

(j) Sounds generated by the operation of aircraft and subject to preemptive federal regulation. This exception does not apply to aircraft engine testing, activity conducted at the airport that is not directly related to flight operations, and any other activity not preemptively regulated by the federal government.

(k) Sounds created by the operation of road vehicle auxiliary equipment complying with the noise rules for such equipment.

(l) Sounds created by agricultural activities.

(m) Sounds created by activities related to the growing or harvesting of forest tree species on forest land as defined in subsection (1) of ORS 526.324.

(6) Exceptions: Upon written request from the owner or controller of an industrial or commercial noise source, the Department may authorize exceptions to section 340-35-035(1), pursuant to rule 340-35-010, for:

(a) Unusual and/or infrequent events.

(b) Industrial or commercial facilities previously established in areas of new development of noise sensitive property.

(c) Those industrial or commercial noise sources whose statistical noise levels at the appropriate measurement point are exceeded by any noise source external to the industrial or commercial noise source in question.

(d) Noise sensitive property owned or controlled by the person who controls or owns the noise source or noise sensitive property located on land zoned exclusively for industrial or commercial use.

Noise Control Regulations for Motor Sports Vehicles and Facilities

340-35-040 (1) Statement of Purpose. The Commission finds that the periodic noise pollution caused by Oregon motor sports activities threatens the environment of citizens residing in the vicinity of motor sports facilities. To mitigate motor sports noise impacts, a coordinated statewide program is desirable to ensure that effective noise abatement programs are developed and implemented where needed. This abatement program includes measures to limit the creation of new noise impacts and the reduction of existing noise impacts to the extent necessary and practicable.

Since the Commission also recognizes the need of Oregon's citizens to participate in recreational activities of their choice, these rules balance those citizen needs which may conflict when motor sports facilities are in operation. Therefore, a policy of continuing participation in standards development through the active cooperation of interested parties is adopted. The choice of these parties is to limit the noise emission levels of racing and recreational vehicles, to designate equipment requirements, and to establish appropriate hours of operation. It is anticipated that safety factors, limited technology, special circumstances, and special events may require exceptions to these rules in some instances; therefore, a mechanism to accommodate this necessity is included in this rule.

This rule is designed to encourage the motor sports facility owner, the vehicle operator, and government to cooperate to limit and diminish noise and its impacts. These ends can be accomplished by encouraging compatible land uses and controlling and reducing the racing vehicle noise impacts on communities in the vicinity of motor sports facilities to acceptable levels.

This rule is enforceable by the Department and civil penalties ranging from a minimum of $25 to a maximum of $500 may be assessed for each violation. The motor sports facility owner, the racing vehicle owner and the racing vehicle driver are held responsible for compliance with provisions of this rule. A schedule of civil penalties for noise control may be found under OAR 340-12-052.

(2) Standards:

(a) Drag Racing Vehicle. No motor sports facility owner and no person owning or controlling a drag racing vehicle shall cause or permit its operation at any motor sports facility unless the vehicle is equipped with a properly installed and well maintained muffler.

(b) Oval Course Racing Vehicle. No motor sports facility owner and no person owning or controlling an oval course racing vehicle shall cause or permit its operation at any motor sports facility unless the vehicle is equipped with a properly installed and well maintained muffler and noise emissions from its operation do not exceed 105 dBA at trackside.

(c) Sports Car Racing Vehicle. No motor sports facility owner and no person owning or controlling a sports car racing vehicle shall cause or permit its operation at any motor sports facility unless the vehicle is equipped with a properly installed and well maintained muffler and noise emissions from its operation do not exceed 105 dBA at trackside.

(d) Closed Course Motorcycle Racing Vehicle. No motor sports facility owner and no person owning or controlling a closed course motorcycle racing vehicle shall cause or permit its operation at any motor sports facility unless the vehicle is equipped with a properly installed and well maintained muffler and noise emissions from its operation do not exceed 105 dBA at trackside or 105 dBA at 20 inches (.5 meter) from the exhaust outlet during the stationary measurement procedure.

(e) Open Course Motorcycle Racing Vehicle. No motor sports facility owner and no person owning or controlling an open course motorcycle racing vehicle shall cause or permit its operation at any motor sports facility unless the vehicle is equipped with a properly installed and well maintained muffler and noise emissions do not exceed 105 dBA at 20 inches (.5 meter) from the exhaust outlet during the stationary measurement procedure.

(f) Four Wheel Drive Racing Vehicles. No motor sports facility owner and no person owning or controlling a four wheel drive racing vehicle shall cause or permit its operation at any motor sports facility unless the vehicle is equipped with a properly installed and well maintained muffler and noise emissions from its operation do not exceed 105 dBA at trackside.

(g) Watercraft Racing Vehicle. No motor sports facility owner and no person owning or controlling a watercraft racing vehicle shall cause or permit its operation at any motor sports facility unless the vehicle is equipped with a properly installed and well maintained muffler and noise emissions from its operation do not exceed 105 dBA at trackside.

(h) Autocross or Solo Racing Vehicle. No motor sports facility owner and no person owning or controlling an autocross or solo racing vehicle shall cause or permit its operation on any temporary autocross or solo course unless the vehicle is equipped with a properly installed and well maintained muffler and noise emissions from its operation do not exceed 90 dBA at trackside. Autocross and solo events conducted on a permanent motor sports facility, such as a sports car or go kart course, shall comply with the requirements for sports car racing vehicles specified in subsection (2)(c) of this section.

(i) Go Kart Racing Vehicle. No motor sports facility owner and no person owning or controlling a go kart racing vehicle shall cause or permit its operation at any motor sports facility unless the vehicle is equipped with a properly installed and well maintained muffler and noise emissions from its operation do not exceed 105 dBA at trackside.

(3) New Motor Sports Facilities. Prior to the construction or operation of any permanent new motor sports facility, the facility owner shall submit for Department approval the projected motor sports facility noise impact boundaries. The data and analysis used to determine the boundary shall also be submitted to

the Department for evaluation. Upon approval of the boundaries, this information shall be submitted to the appropriate local planning unit and the Department of Land Conservation and Development for their review and appropriate action.

(4) Practice Sessions. Notwithstanding subsection (2) of this section, all racing vehicles in order to operate in practice sessions, shall comply with a noise mitigation plan which shall have been submitted to and approved by the motor sports advisory committee and the Director. Such plans may be developed and submitted prior to each racing season. An approved plan may be varied with prior written approval of the Department.

(5) Recreational Park. When a motor sports facility is used as a recreational park for the operation of off-road recreational vehicles, the ambient noise limits of OAR 340-35-030(1)(d) shall apply.

(6) Operations:

(a) General. No motor sports facility owner and no person owning or controlling a racing vehicle shall permit its use or operation at any time other than the following:

(A) Sunday through Thursday during the hours 8 a.m. to 10 p.m. local time; and

(B) Friday through Saturday, state and national holidays and the day preceding, not to exceed three consecutive days, during the hours 8 a.m. to 11 p.m. local time.

(b) Overruns. Each motor sports facility may overrun the specified curfew times, not to exceed 30 minutes, no more than six (6) days per year due to conditions beyond the control of the owner. Each overrun shall be documented to the Department within 10 days of the occurrence.

(c) Special Events. Any approved special motor racing event may also be authorized to exceed this curfew pursuant to subsection (12)(a) of this section.

(7) Measurement and Procedures. All instruments, procedures and personnel involved in performing sound level measurements shall conform to the requirements specified in Motor Race Vehicle and Facility Sound Measurement and Procedure Manual, NPCS-35, or to standard methods approved in writing by the Department.

(8) Monitoring and Reporting:

(a) It shall be the responsibility of the motor sports facility owner to measure and record the required noise level data as specified under subsection (2) of this section and the Motor Race Vehicle and Facility Sound Measurement and Procedure Manual, NPCS-35. The owner shall either keep such recorded noise data available for a period of at least one calendar year or submit such data to the Department for storage. Upon request the owner shall make such recorded noise data available to the Department.

(b) When requested by the Department, any motor sports facility owner shall provide the following:

(A) Free access to the facility

(B) Free observation of noise level monitoring

(C) Cooperation and assistance in obtaining the reasonable operation of any Racing Vehicle using the facility as needed to ascertain its noise emission level.

(9) Vehicle Standards. No motor sports facility owner and no person owning or controlling a racing vehicle shall cause or permit a racing event or practice session unless the vehicle is equipped and operated in accordance with these rules.

(10) Vehicle Testing. Nothing in this section shall preclude the motor sports facility owner from testing or barring the participation of any racing vehicle for non-compliance with these rules.

(11) Exemptions:

(a) Any motor sports facility whose racing surface is located more than 2 miles from the nearest noise sensitive property shall be exempt from this rule.

(b) Any top fuel-burning drag racing vehicle shall be exempt from the requirements of subsection (2)(a) of this section. No later than January 31, 1985 the Department shall report to the Commission on progress toward muffler technology development for this vehicle class and propose any necessary recommendations to amend this exemption.

(12) Exceptions. The Department shall consider the majority and minority recommendations of the motor sports advisory committee prior to the approval or denial of any exception to these rules. Exceptions may be authorized by the Department for the following pursuant to OAR 340-35-010:

(a) Special motor racing events.

(b) Race vehicle or class of vehicles whose design or mode of operation makes operation with a muffler inherently unsafe or technically unfeasible.

(c) Motor sports facilities previously established in areas of new development of noise sensitive property.

(d) Noise sensitive property owned or controlled by a motor sports facility owner.

(e) Noise sensitive property located on land zoned exclusively for industrial or commercial use.

(f) Any motor sports facility owner or race sanctioning body that proposes a racing vehicle noise control program that accomplishes the intended results of the standards of subsection (2), the measurement and procedures of subsection (7), the monitoring and the reporting of subsection (8), of this section.

(g) Any motor sports facility demonstrating that noise sensitive properties do not fall within the motor sports facility noise impact boundaries may be exempt from the curfew limits of subsection (6) and the monitoring and reporting requirements of subsection (8) of this section.

(13) Motor Sports Advisory Committee Actions. The committee shall serve at the call of the chairman who shall be elected by the members in accordance with the rules adopted by the committee for its official action.

(14) Effective Date. These rules shall be effective January 1, 1982.

Noise Control Regulations for Airports

340-35-045 (1) Statement of Purpose. The Commission finds that noise pollution caused by Oregon airports threatens the public health and welfare of citizens residing in the vicinity of airports. To mitigate airport noise impacts a coordinated statewide program is desirable to ensure that effective Airport Noise Abatement Programs are developed and implemented where needed. An abatement program includes measures to prevent the creation of new noise impacts or the expansion of existing noise impacts to the extent necessary and practicable. Each abatement program will primarily focus on airport operational measures to prevent increased, and to lessen existing, noise levels. The program will also analyze the effects of airport noise emission regulations and land use controls.

The principal goal of an airport proprietor who may be required to develop an Airport Noise Abatement program under this rule should be to reduce noise impacts caused by aircraft operations, and to address in an appropriate manner the conflicts which occur within the higher noise contours.

The Airport Noise Criterion is established to define a perimeter for study and for noise sensitive use planning purposes. It is recognized that some or many means of addressing aircraft/airport noise at the Airport Noise Criterion Level may be beyond the control of the airport proprietor. It is therefore necessary that abatement programs be developed, whenever possible, with the cooperation of federal, state and local governments to ensure that all potential noise abatement measures are fully evaluated.

This rule is designed to encourage the airport proprietor, aircraft operator, and government at all levels to cooperate to prevent and diminish noise and its impacts. These ends may he accomplished by encouraging compatible land uses and controlling and reducing the airport/aircraft noise impacts on communities in the vicinity of airports to acceptable levels.

(2) Airport Noise Criterion. The criterion for airport noise is an Annual Average Day-Night Airport Noise Level of 55 dBA. The Airport Noise Criterion is not designed to be a standard for imposing liability or any other legal obligation except as specifically designated within this Section.

(3) Airport Noise Impact Boundary:

(a) Existing Air Carrier Airports. Within twelve months of the adoption of this rule, the proprietor of any existing Air Carrier Airport shall submit for Department approval, the existing airport Noise Impact Boundary. The data and analysis used to determine the boundary and the field verification shall also be submitted to the Department for evaluation.

(b) Existing Non-Air Carrier Airports. After an unsuccessful effort to resolve a noise problem pursuant to subsection (5), the Director may require the proprietor of any existing non-air carrier airport to submit for Department approval, all information reasonably necessary for the calculation of the existing airport Noise Impact Boundary. This information is specified in the Department's Airport Noise Control Procedure Manual (NPCS-37), as approved by the Commission. The proprietor shall submit the required information within twelve months of receipt of the Director's written notification.

(c) New Airports. Prior to the construction or operation of any New Airport, the proprietor shall submit for Department approval the projected airport Noise Impact Boundary for the first full calendar year of operation. The data and analysis used to determine the boundary shall also be submitted to the Department for evaluation.

(d) Airport Master Planning. Any airport proprietor who obtains funding to develop an Airport Master Plan shall submit for Department approval an existing noise impact boundary and projected noise impact boundaries at five, ten, and twenty years into the future. The data and analysis used to determine the boundaries and the field verification shall also be submitted to the Department for evaluation.

(e) Impact Boundary Approval. Within 60 days of the receipt of a completed airport noise impact boundary, the Department shall either consider the boundary approved or provide written notification to the airport proprietor of deficiencies in the analysis.

(4) Airport Noise Abatement Program and Methodology:

(a) Abatement Program. The proprietor of an existing or new airport whose airport Noise Impact Boundary includes Noise Sensitive Property, or may include Noise Sensitive Property, shall submit a proposed Airport Noise Abatement Program for Commission approval within 12 months of notification, in writing, by the Director. The Director shall give such notification when the Commission has reasonable cause to believe that an abatement program is necessary to protect the health, safety or welfare of the public following a public informational hearing on the question of such necessity. Reasonable cause shall be based upon a determination that: 1) Present or planned airport operations cause or may cause noise impacts that interfere with noise sensitive use activities such as communication and sleep to the extent that the public health, safety or welfare is threatened; 2) These noise impacts will occur on property presently used for noise sensitive purposes, or where noise sensitive use is permitted by zone or comprehensive plan; and 3) It appears likely that a feasible noise abatement program may be developed.

(b) Program Elements. An Airport Noise Abatement Program shall consist of all of the following elements, but if it is determined by the Department that any element will not aid the development of the program, it may be excluded.

(A) Maps of the airport and its environs, and supplemental information, providing:

(i) Projected airport noise contours from the Noise Impact Boundary to the airport property line in 5 dBA increments under current year of operations and at periods of five, ten, and twenty years into the future with proposed operational noise control measures designated in subsection (4)(b)(B);

(ii) All existing Noise Sensitive Property within the airport Noise Impact Boundary;

(iii) Present zoning and comprehensive land use plan permitted uses and related policies;

(iv) Physical layout of the airport including the size and location of the runways, taxiways, maintenance and parking areas;

(v) Location of present and proposed future flight tracks;

(vi) Number of aircraft flight operations used in the calculation of the airport noise levels. This information shall be characterized by flight track, aircraft type, flight operation, number of daytime and nighttime operations, and takeoff weight of commercial jet transports.

(B) An airport operational plan designed to reduce airport noise impacts at Noise Sensitive Property to the Airport Noise Criterion to the greatest extent practicable. The plan shall include an evaluation of the appropriateness and effectiveness of the following noise abatement operations by estimating potential reductions in the airport Noise Impact Boundary and numbers of Noise Sensitive Properties impacted within the boundary, incorporating such options to the fullest extent practicable into any proposed Airport Noise Abatement Program:

(i) Takeoff and landing noise abatement procedures such as thrust reduction or maximum climb on takeoff;

(ii) Preferential and priority runway use systems;

(iii) Modification in approach and departure flight tracks;

(iv) Rotational runway use systems;

(v) Higher glide slope angles and glide slope intercept altitudes on approach;

(vi) Dispaced runway thresholds;

(vii) Limitations on the operation of a particular type or class of aircraft, based upon aircraft noise emission characteristics;

(viii) Limitations on operations at certain hours of the day;

(ix) Limitations of the number of operations per day or year;

(x) Establishment of landing fees based on aircraft noise emission characteristics or time of day;

(xi) Rescheduling of operations by aircraft type or time of day;

(xii) Shifting operations to neighboring airports;

(xiii) Location of engine run-up areas;

(xiv) Times when engine run-up for maintenance can be done;

(xv) Acquisition of noise suppressing equipment and construction of physical barriers for the purpose of reducing aircraft noise impact;

(xvi) Development of new runways or extended runways that would shift noise away from populated areas or reduce the noise impact within the Airport Noise Impact Boundary.

(C) A proposed land use and development control plan, and evidence of good faith efforts by the proprietor to obtain its approval, to protect the area within the airport Noise Impact

Boundary from encroachment by non-compatible noise sensitive uses and to resolve conflicts with existing unprotected noise sensitive uses within the boundary. The Plan is not intended to be a community-wide comprehensive plan; it should be airport-specific, and should be of a scope appropriate to the size of the airport facility and the nature of the land uses in the immediate area. Affected local governments shall have an opportunity to participate in the development of the plan, and any written comments offered by an affected local government shall be made available to the Commission. The Department shall review the comprehensive land use plan of the affected local governments to ensure that reasonable policies have been adopted recognizing the local government's responsibility to support the proprietor's efforts to protect the public from excessive airport noise. The plan may include, but not be limited to, the following actions within the specified noise impact zones:

(i) Changes in land use through non-noise sensitive zoning and revision of comprehensive plans, within the Noise Impact Boundary (55 dBA);

(ii) Influencing land use through the programming of public improvement projects within the Noise Impact Boundary (55 dBA);

(iii) Purchase assurance programs within the 65 dBA boundary;

(iv) Voluntary relocation programs within the 65 dBA boundary;

(v) Soundproofing programs within the 65 dBA boundary, or within the Noise Impact Boundary (55 dBA) if the governmental entity with land use planning responsibility desires, and will play a major role in implementation.

(vi) Purchase of land for airport use within the 65 dBA boundary;

(vii) Purchase of land for airport related uses within the 65 dBA boundary;

(viii) Purchase of land for non-noise sensitive public use within the Noise Impact Boundary (55 dBA);

(ix) Purchase of land for resale for airport noise compatible purposes within the 65 dBA boundary;

(x) Noise impact disclosure to purchaser within the Noise Impact Boundary (55 dBA);

(xi) Modifications to Uniform State Building Code for areas of airport noise impact within the Noise Impact Boundary (55 dBA).

(c) Federal Aviation Administration Concurrence. The proprietor shall use good faith efforts to obtain concurrence or approval for any portions of the proposed Airport Noise Abatement Program for which the airport proprietor believes that Federal Aviation Administration concurrence or approval is required. Documentation of each such effort and a written statement from FAA containing its response shall be made available to the Commission.

(d) Commission Approval. Not later than twelve months after notification by the Director pursuant to subsection (4)(a), the proprietor shall submit a proposed Airport Noise Abatement

Program to the Commission for approval. Upon approval, the abatement program shall have the force and effect of an order of the Commission. The Commission may direct the Department to undertake such monitoring or compliance assurance work as the Commission deems necessary to ensure compliance with the terms of its order. The Commission shall base its approval or disapproval of a proposed Noise Abatement Program upon:

(A) The completeness of the information provided;

(B) The comprehensiveness and reasonableness of the proprietor's evaluation of the operational plan elements listed under subsection (4)(b)(B);

(C) The presence of an implementation scheme for the operational plan elements, to the extent feasible;

(D) The comprehensiveness and reasonableness of the proprietor's evaluation of land use and development plan elements listed under subsection (4)(b)(C);

(E) Evidence of good faith efforts to adopt the land use and development plan, or obtain its adoption by the responsible governmental body, to the extent feasible;

(F) The nature and magnitude of existing and potential noise impacts;

(G) Testimony of interested and affected persons; and

(H) Any other relevant factors.

(e) Program Renewal. No later than six (6) months prior to the end of a five year period following the Commission's approval, each current airport Noise Abatement Program shall be reviewed and revised by the proprietor, as necessary, and submitted to the Commission for consideration for renewal.

(f) Program Revisions. If the Director determines that circumstances warrant a program revision prior to the scheduled five (5) year review, the Airport Proprietor shall submit to the Commission a revised program within twelve (12) months of written notification by the Director. The Director shall make such determination based upon an expansion of airport capacity, increase in use, change in the types or mix of various aircraft utilizing the airport, or changes in land use and development in the impact areas that were unforeseen in earlier abatement plans. Any program revision is subject to all requirements of this rule.

(5) Consultation. The Director shall consult with the airport proprietor, members of the public, the Oregon Departments of Transportation, Land Conservation and Development and any affected local government in an effort to resolve informally a noise problem prior to issuing a notification under subsection (3)(b), (4)(a), and (4)(f) of this section.

(6) Noise Sensitive Use Deviations. The airport noise criterion is designed to provide adequate protection of noise sensitive uses based on out-of-doors airport noise levels. Certain noise sensitive use classes may be acceptable within the airport Noise Impact Boundary if all measures necessary to protect interior activities area taken.

(7) Airport Noise Monitoring. The Department may request certification of the airport noise impact boundary by actual

noise monitoring, where it is deemed necessary to approve the boundary pursuant to subsection (3)(e).

(8) Exceptions. Upon written request from the Airport Proprietor, the Department may authorize exceptions to this section, pursuant to rule 340-35-010, for:

(a) Unusual or infrequent events;

(b) Noise sensitive property owned or controlled by the airport;

(c) Noise sensitive property located on land zoned exclusively for industrial or commercial use.

Variances

340-35-100 (1) Conditions for Granting. The Commission may grant specific variances from the particular requirements of any rule, regulation, or order to such specific persons or class of persons or such specific noise source upon such conditions as it may deem necessary to protect the public health and welfare, if it finds that strict compliance with such rule, regulation, or order is inappropriate because of conditions beyond the control of the persons granted such variance or because of special circumstances which would render strict compliance unreasonable or impractical due to special physical conditions or cause, or because strict compliance would result in substantial curtailment of closing down of a business, plant, or operation, or because no other alternative facility or method of handling is yet available. Such variances may be limited in time.

(2) Procedure for Requesting. Any person requesting a variance shall make his request in writing to the Department for consideration by the Commission and shall state in a concise manner the facts to show cause why such variance should be granted.

(3) Revocation or Modification. A variance granted may be revoked or modified by the Commission after a public hearing held upon not less than 20 days notice. Such notice shall be served upon the holder of the variance by certified mail and all persons who have filed with the Commission a written request for such notification.

TABLE 1

(340-035-025)

New Motor Vehicle Standards

Moving Test at 50 Feet (15.2 Meters)

Vehicle Type	Effective For	Maximum Noise Level, dBA
Motorcycles	1975 Model	86
	1976 Model	83
	1977-1982 Models	81
	1983-1987 Models	78
	Models after 1987	75
Snowmobiles as defined in ORS 481.048	1975 Model	82
	Models after 1975	78
Trucks in excess of 10,000 pounds (4536 kg) GVWR	1975 Model	86
	1976-1981 Models or Models manufactured after January 1, 1982	83
	Models manufactured after January 1, 1982, and before January 1, 1985	80
	Models manufactured after January 1, 1985	(Reserved)
Automobiles, Light Trucks, and All Other Road Vehicles	1975 Model	83
	Models after 1975	80
Buses as defined under ORS 481.030	1975 Model	86
	1976-1978 Models	83
	Models after 1978	80
Motorboats	Models offered for sale after June 30, 1980	82

TABLE 2

(340-35-030)

In-Use Road Vehicle Standards

Stationary Test

Vehicle Type	Model Year	Maximum Noise Level, dBA	Minimum Distance from Vehicle to Measurement Point
All vehicles described in ORS 481.205(2)(a)	Before 1976	94	25 feet (7.6 meters)
	1976 and After	91	25 feet (7.6 meters)
All other trucks in excess of 8,000 pounds (3629 kg) GVWR	Before 1976	94	25 feet (7.6 meters)
	1976-1981	91	25 feet (7.6 meters)
	After 1981	88	25 feet (7.6 meters)
Motorcycles	1975 and Before	102	20 inches (1/2 meter)
	After 1975	99	20 inches (1/2 meter)
Front-engine automobiles, light trucks and all other front-engine road vehicles	All	95	20 inches (1/2 meter)
Rear-engine automobiles and light trucks and mid-engine automobiles and light trucks	All	97	20 inches (1/2 meter)
Buses as defined under ORS 481.030	Before 1976	94	25 feet (7.6 meters)
	1976 and After	91	25 feet (7.6 meters)

TABLE 3

(340-35-030)

In-Use Road Vehicle Standards

Moving Test at 50 Feet (15.2 meters) or Greater at Vehicle Speed

Vehicle Type	Model Year	Maximum Noise Level, dBA: 35 mph (56 kph) or less	Maximum Noise Level, dBA: Greater than 35 mph (56 kph)
Vehicles in excess of 10,000 pounds (4536 kg) GVWR or GCWR engaged in interstate commerce as permitted by Title 40, Code of Federal Regulations, Part 202, Environmental Protection Agency (Noise Emission Standards-Motor Carriers Engaged in Interstate Commerce)	All	86	90
All Other Trucks in excess of 10,000 pounds (4536kg) GVWR	Before 1976	86	90
	1976-1981	85	87
	After 1981	82	84
Motorcycles	Before 1976	84	88
	1976	81	85
	1977-1982	79	83
	1983-1987	76	80
	After 1987	73	77
Automobiles, Light Trucks and All Other Road Vehicles	Before 1976	81	85
	1976-1980	78	82
	After 1980	73	77
Buses as defined under ORS 481.030	Before 1976	86	90
	1976-1978	85	87
	After 1978	82	84

TABLE 4

(340-35-030)

Off-Road Recreational Vehicle Standards

Allowable Noise Limits

Vehicle Type	Model Year	Maximum Noise Level (dBA) and Distance from Vehicle to Measurement Point	
		Stationary Test 20 Inches (1/2 Meter)	Moving Test at 50 Feet (15.2 Meters)
Motorcycles	1975 and Before	102	
	After 1975	99	
Snowmobiles	1971 and Before		86
	1972-1975		84
	1976-1978		80
	After 1978		77
Boats			
Underwater exhaust	All		84
Atmosphere exhaust	All	100	84
All Others			
Front engine	All	95	
Mid and rear engines	All	97	

TABLE 5

(340-35-030)

Ambient Standards for Vehicles Operated Near Noise Sensitive Property

Allowable Noise Limits

Time	Maximum Noise Level, dBA
7 a.m. - 10 p.m.	60
10 p.m. - 7 a.m.	55

TABLE 6

(340-35-030)

Auxiliary Equipment Driven by Primary Engine Noise Standards

Stationary Test at 50 Feet (15.2 Meters) or Greater

Model Year	Maximum Noise Level, dBA
Before 1976	88
1976 - 1978	85
After 1978	82

TABLE 7

(340-35-035)

Existing Industrial and Commercial Noise Source Standards

Allowable Statistical Noise Levels in Any One Hour

Pre-1978		Post-1977	
7 a.m.-10 p.m.	10 p.m.-7 a.m.	7 a.m.-10 p.m.	10 p.m.-7 a.m.
L_{50} - 60 dBA	L_{50} - 55 dBA	L_{50} - 55 dBA	L_{50} - 50 dBA
L_{10} - 65 dBA	L_{10} - 60 dBA	L_{10} - 60 dBA	L_{10} - 55 dBA
L_1 - 80 dBA	L_1 - 65 dBA	L_1 - 75 dBA	L_1 - 60 dBA

TABLE 8

(340-35-035)

New Industrial and Commercial Noise Source Standards

Allowable Statistical Noise Levels in Any One Hour

7 a.m. - 10 p.m.	10 p.m. - 7 a.m.
L_{50} - 55 dBA	L_{50} - 50 dBA
L_{10} - 60 dBA	L_{10} - 55 dBA
L_1 - 75 dBA	L_1 - 60 dBA

TABLE 9

(340-35-035)

Industrial and Commercial Noise Source Standards for Quiet Areas

Allowable Statistical Noise Levels in Any One Hour

7 a.m. - 10 p.m.	10 p.m. - 7 a.m.
L_{50} - 50 dBA	L_{50} - 45 dBA
L_{10} - 55 dBA	L_{10} - 50 dBA
L_1 - 60 dBA	L_1 - 55 dBA

TABLE 10

(340-35-035)

Median Octave Band Standards for
Industrial and Commercial Noise Sources

Allowable Octave Band Sound Pressure Levels

Octave Band Center Frequency, Hz	7 a.m. - 10 p.m.	10 p.m. - 7 a.m.
31.5	68	65
63	65	62
125	61	56
250	55	50
500	52	46
1000	49	43
2000	46	40
4000	43	37
8000	40	34

STATE OF OREGON
DEPARTMENT OF GEOLOGY AND MINERAL INDUSTRIES
1069 State Office Building
Portland, Oregon 97201

LAWS AND ADMINISTRATIVE RULES RELATING TO OIL AND GAS EXPLORATION AND DEVELOPMENT IN OREGON

MISCELLANEOUS PAPER NO. 4

PART 1

Revised 1980

Chapter 520

1979 REPLACEMENT PART

Conservation of Gas and Oil

CROSS REFERENCES

County oil and gas leases, 275.294 to 275.300
Mineral leases on state lands, 273.551
State Department of Geology and Mineral Industries, Ch. 516
Submerged lands, oil and gas leases, 274.705 to 274.860

DEFINITIONS

520.005 Definitions. As used in this chapter, unless the context requires otherwise:

(1) "And" includes "or" and "or" includes "and."

(2) "Board" means the governing board of the State Department of Geology and Mineral Industries.

(3) "Condensate" means liquid hydrocarbons that were originally in the gaseous phase in the reservoir.

(4) "Field" means the general area underlaid by one or more pools.

(5) "Gas" means all natural gas and all other fluid hydrocarbons not defined as oil in subsection (6) of this section, including condensate originally in the gaseous phase in the reservoir.

(6) "Oil" means crude petroleum oil and all other hydrocarbons, regardless of gravity, which are produced in liquid form by ordinary production methods, but does not include liquid hydrocarbons that were originally in a gaseous phase in the reservoir.

(7) "Person" means any natural person, partnership, corporation, association, receiver, trustee, guardian, fiduciary, executor, administrator, representative of any kind, or the State of Oregon and any of its political subdivisions, boards, agencies or commissions.

(8) "Pool" means an underground reservoir containing a common accumulation of oil and natural gas. A zone of a structure which is completely separated from any other zone in the same structure is a pool.

(9) "Owner" means a person who has the right to drill into and to produce from any pool and to appropriate the oil or gas he produces therefrom either for others, for himself or for himself and others.

(10) "Producer" means the owner of one or more wells capable of producing oil or gas or both.

(11) "Protect correlative rights" means that the action or regulation by the board affords a reasonable opportunity to each person entitled thereto to recover or receive the oil or gas in his tract or tracts or the equivalent thereof, without being required to drill unnecessary wells or to incur other unnecessary expense to recover or receive such oil or gas or its equivalent.

(12) "Unit area" means one or more pools or parts thereof under unit operation pursuant to ORS 520.260 to 520.330 and subsection (2) of 520.230.

(13) "Well" means a well drilled in search of oil or gas, but shall not include core test wells, stratigraphic test wells, seismic test wells or wells drilled for information purposes only as distinguished from wells drilled for the purpose of producing oil or gas if found.

(14) "Underground reservoir" means any subsurface sand, strata, formation, aquifer, cavern or void whether natural or artificially created, suitable for the injection and storage of natural gas therein and the withdrawal of natural gas therefrom, but excluding a "pool."

(15) "Underground storage" means the process of injecting and storing natural gas within and withdrawing natural gas from an underground reservoir.
[1953 c.667 §1; 1961 c.671 §15; 1973 c.276 §1; 1977 c.296 §1]

520.010 [Repealed by 1953 c.667 §21]

520.015 "Waste" defined. "Waste" in addition to its ordinary meaning, means "physical waste" as that term is generally understood in the petroleum industry. If includes:

(1) Underground waste and the inefficient, excessive or improper use or dissipation of reservoir energy, including gas energy and water drive, of any pool; and the locating, spacing, drilling, equipping, operating or producing of any oil well or gas well in a manner which results or tends to result in reducing the quantity of oil or gas ultimately recoverable from any pool;

(2) Surface waste and the inefficient storing of oil and the locating, spacing, drilling, equipping, operating or producing of oil wells or gas wells in a manner causing or tending to cause unnecessary or excessive surface loss or destruction of oil or gas.
[1953 c.667 §2]

520.020 [Repealed by 1953 c.667 §21]

GENERALLY

520.025 Permit for drilling oil or gas well or using well for gas storage; application form; grounds for granting or denying permit; disposition of fees. (1) No person proposing to drill any well for oil or gas or proposing to drill or use any well for underground storage of gas in an underground reservoir shall commence the drilling or use until he has applied to the State Geologist upon a form prescribed by the State Geologist for a permit to operate the well, paid to the board a fee of $100 for each such well, posted any bond that may be required pursuant to subsection (1) of ORS 520.095 and obtained the permit to drill the well pursuant to subsection (3) of this section.

(2) The State Geologist shall require that the form indicate:

(a) The exact location of the well.

(b) The name and address of the owner, operator, contractor, driller and any other person responsible for the conduct of the drilling operations.

(c) The elevation of the well above sea level.

(d) Such information as is necessary to determine whether the method of drilling and equipment to be used in drilling the well comply with applicable laws and rules.

(e) Such other relevant information as the State Geologist deems reasonably necessary to effectuate the purpose of this chapter.

(3) (a) If upon receipt of the application the State Geologist determines that the method and equipment to be used by the applicant in drilling or using the well comply with applicable laws and rules, the State Geologist shall issue the permit.

(b) The State Geologist may refuse to issue a permit or revoke a permit issued pursuant to this subsection if he determines that methods or equipment to be used or being used in drilling or using the well do not comply with applicable laws or rules.

(4) All moneys paid to the board under this section shall be deposited by the board with the State Treasurer for credit to and the benefit of the Department of Geology and Mineral Industries.
[1953 c.667 §5; 1973 c.276 §2; 1977 c.296 §3]

520.030 [Repealed by 1953 c.667 §21]

520.035 Waste of oil and gas prohibited. The waste of oil and gas, as defined in ORS 520.015, hereby is prohibited.
[1953 c.667 §3]

520.040 [Repealed by 1953 c.667 §21]

520.045 Determination of waste of oil or gas. The board shall make such inquiries as it may think proper to determine whether or not waste over which it has jurisdiction exists or is imminent. In the exercise of such power the board may:

(1) Collect data.

(2) Make investigations and inspections.

(3) Examine properties, leases, papers, books and records, including drilling records and logs.

(4) Examine, check, test and gauge oil and gas wells and tanks.

(5) Hold hearings.

(6) Provide for the keeping of records and the making of reports.

(7) Take such action as may be reasonably necessary to enforce this chapter.
[1953 c.667 §6]

520.050 [Repealed by 1953 c.667 §21]

520.055 General jurisdiction and authority of board; tidal lands. (1) The board has jurisdiction and authority over all persons and property necessary to enforce effectively this chapter and all other laws relating to the conservation of oil and gas.

(2) In addition to and not in lieu of any other powers granted under this chapter, the Department of Geology and Mineral Industries and its governing board may in compliance with ORS 520.105 promulgate reasonable rules, regulations and orders necessary to regulate geological, geophysical and seismic surveys on, and operations to remove oil, gas and sulphur from the tidal submerged and submersible lands of this state under ORS 274.705 to 274.860.
[1953 c.667 §4; subsection (2) enacted as 1961 c.619 §40; 1969 c.594 §57]

520.060 [Repealed by 1953 c.667 §21]

520.065 [1953 c.667 §8; renumbered 520.210]

520.070 [Repealed by 1953 c.667 §21]

520.075 [1953 c.667 §9; 1961 c.671 §16; renumbered 520.220]

520.080 [Repealed by 1953 c.667 §21]

520.085 [1953 c.667 §10; 1961 c.671 §17; renumbered 520.230]

520.090 [Repealed by 1953 c.667 §21]

520.095 Rules and orders; notice and hearing. The board may make, in compliance with ORS chapter 183, such reasonable rules and orders as may be necessary in the proper administration and enforcement of this chapter, including rules and orders for the following purposes:

(1) To require the drilling, casing and plugging of wells to be done in such a manner as to prevent the escape of oil or gas out of one stratum to another; to prevent the intrusion of water into oil or gas strata; to prevent the pollution of fresh water supplies by oil, gas or salt water; and to require reasonable bond

conditioned upon compliance with applicable laws and rules and upon the performance of the duty to plug each dry or abandoned well.

(2) To compel the filing of logs, including electrical logs, if any are taken, drilling records, typical drill cuttings or cores, if cores are taken, in the office of the State Geologist within 20 days from the date of completion or abandonment of any well. For a period of two years from the date of abandonment or completion, such logs or other records or drill cuttings or cores shall be kept confidential and shall not be accessible to public inspection.

(3) To prevent wells from being drilled, operated and produced in such a manner as to cause injury to neighboring leases or property.

(4) To prevent the drowning by water of any stratum or part thereof capable of producing oil or gas in paying quantities, and to prevent the premature and irregular encroachment of water which reduces, or tends to reduce, the total ultimate recovery of oil or gas from any pool.

(5) To require the operation of wells with efficient gas-oil ratios, and to fix ratios.

(6) To prevent blowouts, caving and seepage in the same sense that conditions indicated by such terms are generally understood in the oil and gas business.

(7) To prevent fires.

(8) To identify the ownership of all oil and gas wells, producing leases, tanks, plants, structures and all storage equipment and facilities.

(9) To regulate the "shooting" and chemical treatment of wells.

(10) To regulate secondary recovery methods, including the introduction of gas, air, water or other substance into producing formations.

(11) To regulate the spacing of wells.

(12) To require the filing currently of information as to the volume of oil and gas, or either of them, produced and saved from the respective properties.

(13) To require the filing with the State Geologist of a notice of intention to drill stratigraphic test wells, core test wells, seismic test wells or wells drilled only for information purposes, giving the location thereof, and to require the filing with the State Geologist of a plugging report within 60 days after completion of such well. No fee shall be required in connection with the filing of such notices and reports.

(14) To require the disposal of salt water and oil field waste so as not to damage land or property unnecessarily.

(15) To require that wells drilled for oil or gas be logged adequately enough to identify the geologic formations penetrated by the wells.

(16) To regulate the underground storage of natural gas and the drilling and operation of any wells required therefor.
[1953 c.667 §7; 1961 c.671 §18; 1973 c.276 §3; 1977 c.296 §2]

520.100 [Repealed by 1953 c.667 §21]

520.105 Administrative procedure. (1) The board shall, in accordance with ORS chapter 183, from time to time prescribe reasonable rules governing practice and procedure before it.

(2) No rule, regulation or order, except in emergency, shall be made by the board without a prior public hearing upon at least 10 days' notice. Such public hearings shall be held at such times and places as may be designated by the board. However, in respect to matters of local interest such hearings shall be held at the county seat of the county wherein the greater part of real or personal property affected is situated. Any interested person shall be entitled to be heard at such hearings.

(3) When an emergency requiring immediate action is found to exist, the board may in compliance with ORS chapter 183 issue an emergency order without notice or hearing, effective upon promulgation. However, no emergency order shall remain effective for more than 15 days.

(4) Notice as required by this chapter shall be given in compliance with ORS chapter 183, except as follows:

(a) In respect to matters of statewide interest, by publication in a newspaper of general circulation in Multnomah, Harney, Jackson and Marion Counties.

(b) In respect to metters of local interest, by publication in a newspaper of general circulation in the county or counties wherein the affected lands are located.

(c) In respect to proceedings before the board where persons are named therein, by personal service upon such persons thereto. Personal service may be made by any agent of the board or by any officer authorized by law to serve process and shall be made in the manner provided by law for the service of summons in civil actions in the courts of this state. Proof of service by an agent of the board shall be made by such person's affidavit and by an officer authorized by law to serve process by his lawful certificate.

(5) Notice shall issue in the name of the state and shall be signed by the chairman or secretary of the board. It shall specify the style and number of the proceeding, the time and place of hearing and the purpose of the proceeding.
[1953 c.667 §11; 1961 c.671 §19]

520.110 [Repealed by 1953 c.667 §21]

520.115 Board may act on own motion; filing petition with board; notice; hearing; orders. The board may act upon its own motion or upon the verified written petition of any interested person. Upon the filing with the board of such a petition, which shall state in substance the matter involved, the reasons for and the nature of the relief requested, concerning any matter within its jurisdiction, the board shall promptly fix a date for a hearing thereon, and shall cause due notice thereof to be given as prescribed by ORS 520.105. Such hearing shall be held without undue delay and the board shall enter its order within 30 days thereafter.
[1953 c.667 §12]

520.120 [Repealed by 1953 c.667 §21]

520.125 Authority of board to compel the giving of testimony and the production of evidence. (1) The board may summon witnesses, administer oaths and require the production of records, books and documents for examination at any hearing or investigation conducted before it. No person shall be excused from attending and testifying or from producing books, papers and records before the board or a court or from obedience to the subpena of the board or a court on the grounds that such testimony or evidence required of him may tend to incriminate him or subject him to any penalty or forfeiture; provided, however, that nothing contained in this section shall be construed as requiring any person to produce any books, papers or records or to testify in response to any inquiry not pertinent to some question lawfully before such board or court for determination. No natural person shall be subjected to criminal prosecution or to any penalty or forfeiture for or on account of any transaction, matter or thing concerning which, in spite of his objection, he may be required to testify or produce evidence before the board or a court; provided, however, no person so testifying shall be exempted from prosecution and punishment for perjury in so testifying.

(2) In case of failure or refusal on the part of any person to comply with the subpena issued by the board or in the case of the refusal of any witness to testify as to any matter regarding which he may lawfully be interrogated it shall be the duty of the circuit court of any county or any judge thereof, upon application of the board, to issue an order to show cause why such person should not be held for contempt as in the case of disobedience of the requirements of a subpena issued from such court or a refusal to testify therein.

(3) The board or any party may, in any matter before the board, cause the depositions of witnesses residing within or without the state to be taken in the manner prescribed by law for like depositions in civil suits in the circuit courts of this state.
[1953 c.667 §13]

520.130 [Repealed by 1953 c.667 §21]

520.135 Application for rehearing by person adversely affected by order of board. Any person adversely affected by any rule, regulation or order of the board may within 30 days after its entry apply to the board for a rehearing. Such application shall be acted upon by the board within 30 days from its filing date and if granted such rehearing shall be held without undue delay.
[1953 c.667 §14]

520.145 Judicial review of board actions. (1) Any person adversely affected by any rule, regulation or an order entered by the board may obtain judicial review thereof pursuant to ORS chapter 183.

(2) The circuit court having jurisdiction shall, in so far as is practicable, give precedence to proceedings for judicial review under this chapter.

(3) Either party may appeal to the Supreme Court of the State of Oregon in the same manner as provided by the laws for appeals from the circuit court in suits in equity.
[1953 c.667 §15; 1961 c.671 §20]

520.155 Records, accounts, reports and writings not to be falsified, altered, destroyed or removed from state. No person shall, for the purpose of evading the provisions of this chapter or any rule, regulation or order of the board, make or cause to be made any false entry or statement in a report

required by this chapter or by any rule, regulation or order of the board or make or cause to be made any false entry in any record, account or other writing required by this chapter or by any rule, regulation or order of the board or omit or cause to be omitted from any such record, account or writing, full, true and correct entries as required by this chapter or any rule, regulation or order of the board or remove from this state, or destroy, mutilate, alter or falsify any such record, account or writing.
[1953 c.667 §16]

520.165 Aiding or abetting in a violation of chapter prohibited. No person shall knowingly aid or abet any other person in the violation of any provision of this chapter or of any rule, regulation or order of the board.
[1953 c.667 §17]

520.175 Injunctions to restrain violation or threatened violation of chapter. (1) Whenever it appears that any person is violating or threatening to violate any provision of this chapter or any rule, regulation or order of the board, the board shall bring suit against such person in the circuit court of any county where the violation occurs or is threatened, to restrain such person from continuing such violation. Upon the filing of any such suit, summons issued to such person may be directed to the sheriff of any county of this state for service by such sheriff upon such person. In any such suit, the court shall have jurisdiction to grant to the board, without bond or other undertaking, such temporary restraining orders or final prohibitory and mandatory injunctions as the facts may warrant, including any such orders restraining the movement or disposition of oil or gas.

(2) If the board fails to bring suit to enjoin a violation or threatened violation of any provision of this chapter or of any rule, regulation or order of the board, within 15 days after receipt of a written request to do so by any person who is or will be adversely affected by such violation, then the person making such request may bring suit in his own behalf to restrain such violation or threatened violation in any court in which the board might have brought such suit. The board shall be made a party defendant in such suit in addition to the person or persons aforesaid and the action shall proceed and injunctive relief may be granted without bond in the same manner as if suit had been brought by the board.
[1953 c.667 §18]

SPACING UNITS

520.210 Establishment of spacing units for a pool; purpose; scope; effect. (1) When necessary to prevent waste, avoid the drilling of unnecessary wells or protect correlative rights the board shall establish spacing units for a pool. Spacing units when established shall be of uniform size and shape for the entire pool except that when found to be necessary for any of the above purposes the board is authorized to divide any pool into zones and establish spacing units for each zone, which units may differ in size and shape from those established in any other zone.

(2) The size and shape of spacing units shall be such as will result in efficient and economical development of the pool as a whole and the size thereof shall not be smaller than the maximum area that can be efficiently drained by one well.

(3) An order establishing spacing units for a pool shall specify the size and shape of each unit and the location of the permitted well thereon in accordance with a reasonably uniform spacing plan. Upon application and after hearing if the board finds that a well drilled at the prescribed location would not produce in paying quantities or that surface conditions would substantially add to the burden or hazard of drilling such well, then the board is authorized to enter an order permitting the well to be drilled at a location other than that prescribed by such spacing order; provided, however, the board shall include in the order suitable provisions to prevent the production from the spacing unit of more than its just and equitable share of the oil and gas in the pool.

(4) An order establishing units for a pool shall cover all lands determined or believed to be underlaid by such pool and may be modified by the board from time to time to include additional areas determined to be underlaid by such pool. When found necessary for the prevention of waste or to protect correlative rights an order establishing spacing units in a pool may be modified by the board to increase the size of spacing units in a pool or any zone thereof or to permit the drilling of additional wells on a reasonably uniform plan in such pool or zone.
[Formerly 520.065]

520.220 Integrating interests or tracts within spacing unit; compulsory unitization. (1) When two or more separately owned tracts are embraced within a spacing unit or when there are separately owned interests in all or a part of such spacing unit, then the interested persons may integrate their tracts or interests for the development and operation of the spacing unit.

(2) In the absence of voluntary integration, the board, upon the application of any interested person, shall make an order integrating all tracts or interests in the spacing unit for the development and operation thereof and for the sharing of production therefrom. The board, as a part of the order establishing one or more spacing units, may prescribe the terms and conditions upon which the royalty interests in the units shall, in the absence of voluntary agreement, be deemed to be integrated without the necessity of a subsequent order integrating royalty interests. Each such integration order shall be upon terms and conditions that are just and reasonable.
[Formerly 520.075]

520.230 Approved agreement for cooperative or unit development of pool not to be construed as violating certain regulatory laws. (1) An agreement for the unit or cooperative development and operation of a field or pool in connection with the conduct of repressuring or pressure maintenance operations, cycling or recycling operations, including the extraction and separation of liquid hydrocarbons from natural gas in connection therewith, or any other method of operation, including water floods, is authorized and may be performed and shall not be held or construed to violate ORS chapter 59 or any of the statutes of this state relative to trusts, monopolies or contracts and combinations in restraint of trade, if such agreement is approved by the board as being in the public interest, for the protection of correlative rights and reasonably necessary to increase ultimate recovery or prevent waste of oil or gas. The failure to submit such an agreement to the board for approval does not, for that reason, imply or constitute evidence that the agreement or operations conducted pursuant thereto violate ORS chapter 59 or any statute of this state now or hereafter in effect relating to trusts and monopolies.

(2) An agreement for the unit or cooperative development or operation of a field, pool or part thereof may be submitted to the board for approval as being in the public interest or reasonably necessary to prevent waste or protect correlative rights. Approval by the board constitutes a complete defense to any proceeding charging violation of ORS chapter 59 or of any statute of this state now or hereafter in effect relating to trusts and monopolies on account thereof or on account of operations conducted pursuant thereto. The failure to submit such an agreement to the board for approval does not, for that reason, imply or constitute evidence that the agreement or operations conducted pursuant thereto violate ORS chapter 59 or any statute of this state now or hereafter in effect relating to trusts and monopolies.
[Formerly 520.085; subsection (2) enacted as 1961 c.671 §13; 1963 c.69 §1]

520.240 Voluntary unitization of operations by lessees of tidal or submersible lands; Division of State Lands' function. (1) For the purpose of properly conserving the natural resources of any single oil or gas pool or field, lessees under ORS 274.705 to 274.860 and their representatives may unite with each other jointly or separately, or jointly or separately with others owning or operating lands not belonging to the state, in collectively adopting and operating under a cooperative or unit plan of development or operation of the pool or field, whenever it is determined by the Division of State Lands to be necessary or advisable in the public interest.

(2) The Division of State Lands may, with the consent of the holders of the leases involved, establish, alter, change and revoke any drilling and production requirements of such leases, and make such regulations with reference to such leases, with like consent on the part of the lessees, in connection with the institution and operation of any such cooperative or unit plan, as the Division of State Lands deems necessary or proper to secure the proper protection of the interests of the state.
[1961 c.619 §33]

520.260 Hearing to determine need for unitization of operations; required findings; order. (1) The board as defined in ORS 520.005, upon its own motion may, and upon the application of any interested person shall, hold a hearing to consider the need for the operation as a unit of one or more pools or parts thereof in a field.

(2) The board shall make an order providing for the unit operation of a pool or part thereof if it finds that:

(a) Unit operation is reasonably necessary to effectively carry on pressure control, pressure maintenance or repressuring operations, cycling operations, water flooding operations, injection operations, or any combination thereof, or any other method of recovery designed to substantially increase the ultimate recovery of oil from the pool or pools; and

(b) The value of the estimated additional recovery of oil or gas exceeds the estimated additional cost incident to conducting unit operations.
[1961 c.671 §2]

UNIT OPERATIONS

520.270 Plan for unit operations. An order issued pursuant to ORS 520.260 shall be upon terms and conditions that are just and reasonable, and shall prescribe a plan for unit operations that includes the following:

(1) A description of the pool or pools or parts thereof to be so operated.

(2) A statement of the nature of the operations contemplated.

(3) An allocation to the separately owned tracts in the unit area of all tha oil and gas that is produced from tha unit area and is saved, being the production that is not used in the conduct of operations on the unit area or not unavoidably lost.

(4) A provision for the credits and charges to be made in the adjustment among the owners in the unit area for their respective investments in wells, tanks, pumps, machinery, materials and equipment contributed to the unit operations.

(5) A provision stating how the costs of unit operations, including capital investments, shall be determined and charged to the separately owned tracts and how these costs shall be paid, including a provision stating when, how and by whom the unit production allocated to an owner who does not pay the share of the cost of unit operations charged to such owner, or the interest of such owner, may be sold and the proceeds applied to the payment of such costs.

(6) A provision, if necessary, for carrying or otherwise financing any person who elects to be carried or otherwise financed, allowing a reasonable interest charge for such service payable out of that person's share of the production.

(7) A provision for the supervision and conduct of the unit operations, in respect to which each person shall have a vote with a value corresponding to tha percentage of the costs of unit operations chargeable against the interest of that person.

(8) The time when the unit operations shall commence, and the manner in which, and the circumstances under which, the unit operations shall terminate.

(9) Additional provisions that are found appropriate for carrying on the unit operations, and for the protection of correlative rights.
[1961 c.671 §3]

520.280 Allocation of production under plan; ownership. (1) The allocation described in subsection (3) of ORS 520.270 shall be in accord with the agreement, if any, of the interested parties. If there is no such agreement, the board shall determine the relative value, from evidence introduced at the hearing, of the separately owned tracts in the unit area, exclusive of physical equipment, for development of oil and gas by unit operations. The production allocated to each tract shall be the proportion that the relative value of each tract so determined bears to the relative value of all tracts in the unit area.

(2) That portion of the unit production allocated to any tract, and the proceeds from the sale thereof, are the property and income of the several persons to whom, or to whose credit, they are allocated or payable under the order providing for unit operations.
[1961 c.671 §§4, 10]

520.290 When unitization order to become effective; supplemental hearings. (1) No order of the board providing for unit operations is effective until:

(a) The plan for unit operations prescribed by the board under ORS 520.270 has been approved in writing by (A) those owners who, under the board's order, will be required to pay at least 75 percent of the costs of the unit operation, and (B) those persons who, at the time of the order of the board, owned of record legal title to 75 percent of royalty and overriding royalty payable with respect to oil and gas produced from the pool or part thereof over the entire unit area; and

(b) The board has made a finding, either in the order providing for unit operations or in a supplemental order, that the plan for unit operations has been so approved.

(2) If the plan for unit operations has not been approved pursuant to subsection (1) of this section at the time the order providing for unit operations is made, the board shall upon application and notice hold such supplemental hearings as are required to determine if and when the plan for unit operations has been approved. If the persons owning the percent-

age of interest in the unit area required by subsection (1) of this section do not approve the plan for unit operations within a period of six months after the date on which the order providing for unit operations is made, the order is ineffective and shall be revoked by the board unless the board, for good cause shown, extends the time for approval.
[1961 c.671 §5]

520.300 Amending unitization order. An order providing for unit operations may be amended by an order made by the board, as defined in ORS 520.005, in the same manner and subject to the same conditions as an original order providing for unit operations. However:

(1) If the amendment affects only the rights and interests of the owners, the approval of the amendment by the royalty owners is not required.

(2) The order of amendment may not change the percentage for the allocation of:

(a) Oil and gas as established for any separately owned tract by the original order, except with the consent of all persons owning oil and gas rights in the tract; or

(b) Cost as established for any separately owned tract by the original order, except with the consent of all owners in the tract.
[1961 c.671 §6]

520.310 Unitization of area including area previously unitized; partial unitization of pool. (1) The board, as defined in ORS 520.005, by order may provide for the unit operation of a pool or pools or parts thereof that embrace a unit area established by a previous order of the board. The order, in providing for the allocation of unit production, shall first treat as a single tract the unit area previously established, and the portion of the unit production so allocated thereto shall then be allocated among the separately owned tracts included in the previously established unit area in the same proportions as those specified in the previous order.

(2) An order may provide for unit operations on less than the whole of a pool where the unit area is of such size and shape as may reasonably be required for that purpose, and the conduct thereof will have no adverse effect upon other portions of the pool.
[1961 c.671 §§7, 8]

520.320 Unitization order does not terminate prior agreements or affect oil and gas rights; acquisition of property during unit operations. (1) No division order or other contract relating to the sale or purchase of production from a separately owned tract may be terminated by the order providing for unit operations, but remains in force and applies to oil and gas allocated to that tract until terminated in accordance with the provisions thereof.

(2) Except to the extent that the parties affected so agree, no order providing for unit operations results in a transfer of all or any part of the title of any person to the oil and gas rights in any tract in the unit area.

(3) All property, whether real or personal, that may be acquired in the conduct of unit operations under ORS 520.260 to 520.330 and subsection (2) of 520.230 shall be acquired for the account of the owners within the unit area, and is the property of such owners in the proportion that the expenses of unit operations are charged.
[1961 c.671 §§11, 12]

520.330 Effect of operations in unit area. All operations, including but not limited to the commencement, drilling or operation of a well, upon any portion of the unit area, are considered for all purposes the conduct of such operations upon each separately owned tract in the unit area by the several owners thereof. The portion of the unit production allocated to a separately owned tract in a unit area, when produced, is considered for all purposes to have been actually produced from that tract by a well drilled thereon. Operations conducted pursuant to an order of the board, as defined in ORS 520.005, providing for unit operations constitute a fulfillment of all the express or implied obligations of each lease or contract covering lands in the unit area to the extent that compliance with such obligations cannot be had because of the order of the board.
[1961 c.671 §9]

UNDERGROUND RESERVOIRS

520.340 Legislative findings. The underground storage of natural gas in Oregon is found by the Legislative Assembly to be in the public interest in thet the establishment of underground reservoirs of natural gas will help insure the continued, uninterrupted availability of natural gas supplies to residential, commercial and industrial consumers in Oregon during periods of peak demand and

during interruptions in the normal flow of natural gas supplies.
[1977 c.296 §5]

520.350 Property rights in underground reservoirs for natural gas storage. (1) All natural gas in an underground reservoir utilized for underground storage, whether acquired by eminent domain or otherwise, shall at all times be the property of the natural gas company utilizing said underground storage, its heirs, successors, or assigns. In no event shall such gas be subject to the rights of the owner of the surface of the land under which said underground reservoir lies or of the owner of any mineral interest therein or of any person other than said natural gas company, its heirs, successors and assigns to release, produce, take, reduce to possessions, or otherwise interfere with or exercise any control thereof.

(2) Any right of condemnation granted for the purposes of ORS 520.340, 772.610 to 772.625 and this section shall be without prejudice to the rights of the owner of the condemned lands or of the rights and interest therein to drill or bore through the underground reservoir in such a manner as shall protect the underground reservoir against pollution and against the escape of natural gas in a manner which complies with the orders and rules of the State Department of Geology and Mineral Industries. Such condemnation shall be without prejudice to the owners of such lands or other rights or interests therein as to all other uses thereof. The additional costs of complying with rules or orders to protect the underground shall be paid by the condemnor.
[1977 c.296 §6]

PENALTIES

520.990 [Repealed by 1953 c.667 §21]

520.991 Penalties. Violation of any provision of this chapter or any rule, regulation or order of the board is punishable, upon conviction, by a fine not exceeding $2,500 or imprisonment in the county jail for a term not exceeding six months, or both.
[1953 c.667 §19]

CERTIFICATE OF LEGISLATIVE COUNSEL

Pursuant to ORS 173.170, I, Thomas G. Clifford, Legislative Counsel, do hereby certify that I have compared each section printed in this chapter with the original section in the enrolled bill, and that the sections in this chapter are correct copies of the enrolled sections, with the exception of the changes in form permitted by ORS 173.160 and other changes specifically authorized by law.

Done at Salem, Oregon,
October 1, 1977.

Thomas G. Clifford
Legislative Counsel

CHAPTER 521

[Reserved for expansion]

OREGON ADMINISTRATIVE RULES

DEPARTMENT OF GEOLOGY AND MINERAL INDUSTRIES

CHAPTER 632

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GENERAL

General Rules

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Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

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632-10-004 Special rules will be issued when required and shall prevail as against general rules if in conflict therewith.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Secretary to the Board

632-10-006 The director of the State Department of Geology and Mineral Industries shall act as secretary to the Board.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Definitions

632-10-008 As used in rules 632-10-010 to 632-10-200, unless otherwise required by context:

(1) "Allowable" shall mean the quantity of natural gas or oil allowed by order of the Board to be produced within a stated period.

(2) "Atmospheric Pressure" shall mean the pressure of air at sea level, equivalent to about 14.73 pounds per square inch absolute.

(3) "Barometric Pressure" shall mean the pressure or weight of air determined by the use of a barometer at a given point.

(4) "Barrel" shall mean 42 U.S. gallons of oil at a temperature of 15.55 degrees Centigrade (60 degrees Fahrenheit), with deductions for the full percent of basic sediment, water and other impurities present, ascertained by centrifugal or other recognized and customary test.

(5) "Blow-Out" shall mean an uncontrolled escape of oil, natural gas, or saltwater as a flow of oil, or natural gas or saltwater from a well.

(6) "Blow-Out Preventer" shall mean a heavy casing-head control of special gates or rams which will seal the annular space between drill pipe or tubing and casing or which completely closes off the top of the inner casing string.

(7) "Bottom Hole Pressure" shall mean the pressure in pounds per square inch at or near the bottom of an oil or gas well determined at the face of the producing horizon by means of a pressure recording instrument, adopted and recognized by the oil and gas industry, and corrected to the sea level elevation.

(8) "Casing Pressure" shall mean the pressure built up between the casing and tubing when the casing and tubing are packed off at the top of the well and measured at the surface.

(9) "Casing-Head Gas" shall mean any gas or vapor, or both gas and vapor, indigenous to an oil stratum and produced from such stratum with oil.

(10) "Combination Well" shall mean well productive of both oil and gas in commercial quantities from the same common source of supply and which has sufficient natural pressure to cause gas to enter a pipe line carrying more than atmospheric pressure.

(11) "Common Source of Supply" is synonymous with pool.

(12) "Condensate" shall mean hydrocarbons existing in the gaseous state in the reservoir, by condensing to a liquid at pressures or temperatures below those of the reservoir. For the purpose of brevity, the use herein of the word "oil" shall include condensate as defined herein, unless otherwise provided. For instance, oil well shall mean not only an oil well but also a condensate well.

(13) "Connate Water" shall mean the water which was present with the deposition of solid sediments in an oil or gas reservoir and which has not, during the oil accumulation, been displaced.

(14) "Correlative Rights" as used in these rules shall mean that each owner or producer in a pool is privileged to produce therefrom only in such manner or amount as not to injure the reservoir to the detriment of others or to take an undue proportion of the oil or gas obtainable therefrom, or to cause net drainage between developed units.

(15) "Cubic Foot of Gas" shall mean the volume of gas expressed in cubic feet computed at standard pressure base of 14.73 pounds per square inch absolute and a standard temperature base of 60 degrees F.

(16) "Day" shall mean a period of twenty-four consecutive hours from 7 a.m. one day to 7 a.m. the following day.

(17) "Development" shall mean any work which actively looks toward bringing in production, such as erecting rigs, building tanks, drilling wells, etc.

(18) "Developed Area or Developed Unit" shall mean a proration unit having a well completed thereon which is capable of producing oil or gas in paying quantities; however, in the event it be shown, and the Board finds, that a part of any unit is nonproductive, then the developed area of the unit shall include only that part so found to be productive.

(19) "Differential Pressure" shall mean in the case of wellhead measurement, the difference between the tubing pressure and the casing pressure; in the case of an orifice meter, the pressure difference between the up-stream and the down-stream sides of the orifice, a pressure difference measured with a differential gauge or with a manometer (U tube).

(20) "State Geologist" shall mean the chief administrator for the State Department of Geology and Mineral Industries.

(21) "Edge Water" shall mean water that holds the oil or gas, or both oil and gas, in a higher structural position usually encroaching on a pool as the oil or gas is recovered.

(22) "Field" shall mean the general area underlaid by one or more pools.

(23) "Gas" shall mean all natural gas, including casing-head gas and other hydrocarbons not defined as oil in section (5) of this rule.

(24) "Gas Allowable" shall mean the amount of natural gas authorized to be produced by order of the Board.

(25) "Gas-Oil Ratio" shall mean the relation of the gas in cubic feet to the production of oil in barrels as accepted by pipe lines.

(26) "Gas Repressuring" shall mean the introduction of gaseous substances into a pool by artificial means in order to replenish, replace, or increase the reservoir energy.

(27) "Gas, Sour" shall mean gas which contains hydrogen-sulphide, sulphur, or other deleterious substances, in sufficient quantities to render it unfit for domestic light and fuel.

(28) "Gas Well" shall mean:

(a) A well which produces natural gas only;

(b) That part of a well where the gas producing stratum has been successfully cased off from the oil, the gas and oil being produced through separate casing or tubing;

(c) Any well capable of producing gas in commercial quantities; or

(d) A well producing from a reservoir containing no liquid hydrocarbons.

(29) "Illegal Gas" shall mean gas which has been produced within the state from any well or wells in excess of the amount allowed by any rule, regulation, or order of the Board, as distinguished from gas produced within the state not in excess of the amount of allowed production by any such rule, regulation, or order which is legal gas.

(30) "Illegal Oil" shall mean oil which has been produced within the state from any well or wells in excess of the amount allowed by any rule, regulation, or order of the Board, as distinguished from oil produced within the state not in excess of the amount so allowed by any such rule, regulation, or order which is legal oil.

(31) "Illegal Product" shall mean any product of oil or gas, any part of which was processed or derived, in whole or in part, from illegal oil or illegal gas or from any product thereof, as distinguished from legal product, which is a product processed or derived to no extent from illegal gas or illegal oil.

(32) "Indices of Productive Value" shall mean the factors to be considered in ascertaining the productivity of all property in a pool for the purpose of fixing the allowable production. These indices can mean, at the discretion of the Board, potential acreage, gas-oil ratios, static reservoir pressures, flowing pressures, fluid level draw-downs, the well or wells, or any other pertinent factors.

(33) "Mud-Laden Fluid" shall mean any approved mixture of fluid and clay or other material as the term is commonly used in the industry which will effectively seal the formation to which it is applied.

(34) "Net Drainage" shall mean the drainage or migration of oil or gas within the reservoir which is not equalized by counter-drainage.

(35) "Nomination" shall mean the statement made by a purchaser as to the amount of oil or gas he is willing to purchase for a given period.

(36) "Oil" shall mean crude petroleum oil and any other hydrocarbons, regardless of gravity, which are produced at the well head in liquid form and from gas by ordinary production methods.

(37) "Oil Allowable" shall mean the amount of oil authorized to be produced by order of the Board.

(38) "Oil Well" for the purpose of the rules, shall mean any well not a gas well capable of producing oil or condensate in paying quantities.

(39) "Operator" shall mean any person who, duly authorized, is in charge of the development of a lease or the operation of a producing well.

(40) "Overage, Overproduction" shall mean the oil or gas produced in excess of the allowable fixed by the Board.

(41) "Owner" shall mean the person who has the right to drill into and produce from a field or pool, or to appropriate the production therefrom, or both, either for himself or for himself and others.

(42) "Period Allowable" shall mean the period as designated in which an allowable may be produced.

(43) "Person" shall mean any natural person, partnership, corporation, association, receiver, trustee, guardian, fiduciary, executor, administrator, representative of any kind, or the State of Oregon and its political subdivisions.

(44) "Pipe Line Oil" shall mean oil free from water and basic sediment to the degree that it is acceptable for pipe line transportation and refinery use.

(45) "Pool" shall mean an underground reservoir containing or appearing to contain a common accumulation of oil and natural gas. A zone of a structure which is completely separated from any other zone in the same structure is a pool.

(46) "Potential" shall mean the computed daily ability of a well to produce oil as determined by a test made in conformity with rules prescribed by the Board.

(47) "Pressure Maintenance" shall mean:

(a) The re-introduction (in the early stages of field development) of gas or fluid produced from an oil or gas well to maintain the pressure of the reservoir;

(b) The introduction of gas or fluid for the same purpose but obtained from an outside source.

(48) "Producer" or "owner" shall mean a person who has the right to drill into and to produce from any pool and to appropriate the oil or gas he produces therefrom either for others, for himself, or for himself and others.

(49) "Product" shall mean any commodity made from oil or gas, and shall include refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, fuel oil, treated crude oil, residuum, gas oil, casing-head gasoline, natural gas, gasoline, kerosene, benzene, wash oil, waste oil, blended gasoline, lubricating oil, blends or mixtures of oil with one or more liquid products or by-products derived from oil or gas, and blends or mixtures of two or more liquid products or by-products from oil or gas.

(50) "Proved Oil or Gas Land" shall mean the area which has been shown by development or geological information to be such that additional wells drilled thereon are reasonably certain to be commercially productive of oil or gas, or both.

(51) "Purchaser" shall mean any person who directly or indirectly purchases, transports, takes, or otherwise removes production to his account from a well, wells, or pool.

(52) "Recycle" — See Pressure Maintenance (section (47)).

(53) "Repressure" — See Pressure Maintenance (section (47)).

(54) "Run" shall mean oil or gas piped from one place to another.

(55) "Separator" shall mean an apparatus for separating oil, gas, water, etc., with efficiency as it is produced.

(56) "Share, Fair" shall mean that part of the authorized production for the pool which is substantially in the proportion that the quantity of recoverable oil and gas in the developed area of a tract in the pool bears to the recoverable oil and gas in the total developed area of the pool, insofar as these amounts can be practically ascertained.

(57) "Shortage of Underage" shall mean the amount of production less than the allowable.

(58) "Spacing Unit" shall mean the maximum area in a pool which may be efficiently and economically drained by one well.

(59) "Storage" shall mean produced oil, gas, or both confined in tanks, reservoirs, or containers.

(60) "Storage, Underground" shall mean underground cavities either natural or artificial or both which are suitable for storage of natural gas, produced petroleum, and petroleum products. The term may also mean the produced petroleum and petroleum products confined in underground cavities.

(61) "Survey" shall mean all tests made for the purpose of obtaining information concerning the productive possibility of any geological formation and shall include electrical and directional surveys.

(62) "Waste" in addition to its ordinary meaning, shall mean "physical waste" as that term is generally understood in the petroleum industry. It includes:

(a) Underground waste and the inefficient, excessive, or improper use or dissipation of reservoir energy, including gas energy and water drive, of any pool; and the locating, spacing, drilling, equipping, operating, or producing of any oil well or gas well in a manner which results or tends to result in reducing the quantity of oil or gas ultimately recoverable from any pool;

(b) Surface waste and the inefficient storing of oil and the locating, spacing, drilling, equipping, operating, or producing of oil wells or gas wells in a manner causing or tending to cause unnecessary or excessive surface loss or destruction of oil or gas.

(63) "Well" shall mean a well drilled in search of oil or gas, but shall not include core test wells, stratigraphic test wells or wells drilled for information purposes only as distinguished from wells drilled for the purpose of producing oil or gas if found.

(64) "Well Log" shall mean the written record progressively describing the strata, water, oil or gas encountered in drilling a well with such additional information as to give volumes, pressure, rate of fill-up, water depths, caving strata, casing record, etc., as is usually recorded in normal procedure of drilling, also to include electrical survey or logging.

(65) "Wildcat Well" shall mean a drilling or producing well in an unproved area.

(66) Additional definitions may be found in ORS 520.005 and 520.015.

(67) "Abandonment" shall mean that a well is to be considered abandoned when it has been properly plugged and sealed off and requirements under the regulations have been fulfilled to the satisfaction of the Board.

(68) "Completion" shall mean, for the purposes only of filing well records that a well is considered completed:

(a) When it is capable of producing oil and/or gas;

(b) When it has been properly plugged and abandoned.

When operations to accomplish subsections (a) or (b) of this section have been suspended for a period of thirty (30) consecutive days or more. In such instances any required supplemental data shall be furnished the State Geologist upon the occurrence of either subsections (a) or (b) of this section.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 2, f. 6-20-55; GMI 1-1979, f. & ef. 1-25-79

Application and Permit to Drill, Deepen, or Rework

632-10-010 (1) No person proposing to drill, deepen, or rework any well for oil or gas shall commence the drilling, deepening, or reworking until he has applied to the State Geologist upon a form prescribed by the State Geologist for a permit to operate the well, paid to the Board a fee of $100 for each such well, posted a $10,000 bond required pursuant to rule 632-10-205 and obtained the permit to drill, deepen, or rework the well pursuant to section (3) of this rule.

(2) The State Geologist shall require that the application indicate:

(a) The location of the well;

(b) The name and address of the owner, operator, and any other person responsible for the conduct of the drilling operations;

(c) The elevation of the well above the sea level;

(d) Casing and cementing programs giving details of casing sizes, casing grade, hole diameters, and volume of cement to be used;

(e) Eologic objectives for holes drilled in known producing areas, proposed depth in all cases.

(3) The State Geologist shall circulate the application for technical review to appropriate state natural resource agencies and the governing body of the county or city in which the well will be located. The agencies have 20 days from the date of application in which to comment.

(4) If upon receipt of the application the State Geologist or his agent determines that the method of drilling and equipment to be used by the applicant in drilling the well comply with applicable laws and rules, the State Geologist shall issue the permit within 30 days. The State Geologist may refuse to issue a permit if he determines that the methods of drilling or equipment to be used or being used in drilling the well do not comply with the applicable laws or rules. If the State Geologist refuses to issue a permit; he shall notify the applicant in writing within 30 days from the date of application the reasons for denying the permit. Any person adversely affected by a ruling of the State Geologist may within 30 days of such ruling apply to the Board for a rehearing.

(5) When issuing the permit, the State Geologist shall inform the applicant that:

(a) Issuance of the permit is not a finding of compliance with the Statewide Planning Goals (ORS 197.225) or the acknowledged comprehensive plan; and

(b) The applicant must receive a land use approval from the affected local government. The approval may include a determination that the proposed action is in compliance with the Statewide Planning Goals.

(6) The State Geologist may revoke a permit for noncompliance with rules of this chapter after first giving the permitee written notice and after such notice the permittee fails to correct the violation within 30 days from receipt of the notice. A person receiving a permit to drill, deepen, or rework any well shall commence such drilling, deepening, or reworking within 180 days from issuance of the permit, otherwise the permit will become invalid. The permit may be extended by the Board upon receipt of written notice from the permittee giving reasons for not beginning drilling, deepening, or reworking within the 180-day period.

Stat. Auth.: ORS Ch. 520
Hist: GMI 2, f. 6-20-55; GMI 1-1978(Temp), f. 5-26-78, ef. 7-1-78; GMI 1-1979, f. & ef. 1-25-79; GMI 3-1980, f. 2-29-80, ef. 3-1-80

[ED. NOTE: The text of Temporary Rules is not printed in the Oregon Administrative Rules Compilation. Copies may be obtained from the adopting agency or the Secretary of State.]

Changes of Location or Ownership

632-10-012 (1) If, prior to the drilling of a well, the person to whom the permit was issued desires to change the location, he shall submit a letter so stating and another application properly filled out showing the new location. No additional fee is necessary, but drilling shall not be started until the transfer has been approved and the new permit posted at the new location.

(2) If, while a well is drilling or after it has been completed, the person to whom the permit was issued disposes of his interest in the well, he shall submit a written statement to the director setting forth the facts.

(3) Before the transfer of any well, the person who is to acquire it must obtain a permit and post a bond as required by rule 632-10-010.

Stat. Auth.: ORS Ch. 520
Hist: GMI 2, f. 6-20-55

Drilling Practices

632-10-014 (1) Pits for Drill Cuttings: There shall be provided at every well before the actual drilling has been started, one or more pits of adequate and approved size for holding the drill cuttings removed from such well.

(2) Casing and Sealing Off Formations: The State Geologist shall determine that surface casing used in all wells shall be of suitable grade and wall thickness. In all wells drilled in areas where pressure and formation are unknown, sufficient surface casing shall be run to reach a depth below known potable fresh water levels. Surface casing shall be cemented by the pump and plug or displacement method with sufficient cement to circulate to the top of the hole.

(a) Each fluid bearing zone above the producing horizon in oil and gas wells shall be cased and sealed off to prevent effectively the migration of formation fluids to other areas. Such casing and sealing off shall be effected and tested in such manner and by such methods and means as may be prescribed by the State Geologist or his representative.

(b) In wells drilled in areas where subsurface conditions have been established by drilling experience, surface casing size at the operator's option shall be set and cemented to the surface by the pump and plug or displacement method at a depth sufficent to protect all potable fresh water.

(c) Cement shall be allowed to set a minimum of twelve (12) hours under pressure before drilling the plug.

(3) Mud-Laden Fluid to be Applied: No rock formation containing natural gas shall be drilled or be permanently left open without the application of mud-laden fluid to prevent the escape of gas during further drilling in or through such gas bearing formations.

(4) Well-Head Equipment: In all proven areas, the use of blow-out shall equipment shall be in accordance with established practice in the area.

In unproven areas, (wildcat wells) all drilling wells shall be equipped with a full closure gate, or its equivalent, an adequate blow-out preventer, together with a flow line valve of the proper size and working pressure. The entire control equipment shall be in good working condition at all times.

(5) Well Records (Logs): During the drilling, deepening or reworking of every well, except seismic, core, or other shallow wells drilled solely for geoloqlical data, the owner, operator, contractor, driller, or other person responsible for the conduct of drilling operations, shall keep at the well a detailed and accurate record of the well, reduced to writing from day to day, which shall be accessible to the State Geologist and his agents at all reasonable times. A copy of the records shall be furnished to the State Geologist upon a form prescribed by the State Geologist within twenty (20) days after the completion or abandonment of any well which ever date comes first:

(a) Any logging including, but not limited to, electrical logging or bore hole surveying of the well shall also be recorded and copy furnished the Board within twenty (20) days after completion or abandonment which ever date comes first. Upon request by the State Geologist, a complete set of cuttings or samples of cores, if taken, correctly labeled and identified as to depth, shall be filed with the Supervisor within 20 days after completion or abandonment of every such well.

(b) Well logs, electrical logs, cuttings, and cores shall be kept confidential for a period of two years from the required filing date. The well record shall describe progressively the strata, water, oil, or gas encountered in drilling a well with such additional information as to gas volumes, pressures, rate of fill-up, water depths, caving strata, casing record, shooting, perforating, chemical treatment, etc., as are usually recorded in the normal procedure of drilling.

(6) Deepening: Every person, owner, or producer who desires to deepen a well to a depth below that to which it was originally drilled shall file a written notice of intention to deepen. The notice shall set forth in detail the new proposed total depth, the plan for sealing off any oil, gas, brine, or fresh-water strata to be found or expected to be found in the deepening. If the method set forth is satisfactory and the person, owner, or producer is not in violation of the law or the rules of the Board, the director shall issue a deepening permit. The actual deepening shall not be started until the deepening permit has been posted at the well location.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 1-1979, f. & ef. 1-25-79

Identification of Wells

632-10-016 Hereafter, every person drilling for oil or gas or operating, owning, or controlling or in possession of any well drilled for oil or gas, shall paint or stencil and post and keep posted in a conspicuous place near the well, the name of the person drilling, operating, owning, or controlling the well, the name of the lease, the number of the well, and the number of the permit for the well, together with the Section, Township, and Range.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Organization Reports

632-10-018 Every person acting as principal or agent for another or independently engaged in drilling for oil or gas or in the production, storage, reclaiming, treating, or processing of crude oil or natural gas produced in Oregon shall immediately file with the Board in the form of an affidavit: the name under which such business is being conducted or operated; the name and postoffice address of such person, the business or businesses in which he is engaged; the plan of organization and, in case of a corporation, the law under which it is chartered and the name and postoffice address of any person acting as a trustee, together with the name of the manager, agent, attorney-in-fact, or principal executive thereof, and the name and postoffice address of each officer thereof. In each case where such business is conducted under an assumed name, such report shall show the names and postoffice addresses of all owners in addition to the other information required and also the name of the county in which the certificate of assumed name is filed. Immediately after any change occurs as to the facts stated in the report filed, a supplementary report under oath shall be immediately filed with the Board with respect to such change.

Stat. Auth.: ORS Ch.
Hist: GMI 2, f. 6-20-55

Surface Equipment

632-10-020 Meter fittings of adequate size to measure the gas efficiency for the purpose of obtaining gas-oil ratios shall be installed on the gas vent-line of every separator. Well-head equipment shall be installed and maintained in first-class condition so that static bottom hole pressure may be obtained at any time by the duly authorized agents of the Board or the director. Valves shall be installed so that pressures can be readily obtained on both casing and tubing.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Blow-Out Prevention

632-10-122 In drilling in areas where high pressures are likely to exist, all proper and necessary precautions shall be taken for keeping the well under control, including the use of blow-out preventers and high-pressure fittings attached to casing strings properly anchored and cemented.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Drilling Fluid

632-10-124 At any time of drilling any well by rotary method, the operator shall continuously maintain in the hole, from top to bottom, good mud-laden fluid in accordance with recognized safe practice.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Cleaning Wells

632-10-126 All wells shall be cleaned into a pit not less than one hundred fifty (150) feet from the derrick floor and one hundred fifty (150) feet from any fire hazard.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Boiler or Light Plant

632-10-128 No boiler or electric lighting generator shall be placed nearer than 100 feet to any producing well or oil tank.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Rubbish or Debris

632-10-130 Any rubbish or debris that might constitute a fire hazard shall be removed to a distance of at least 150 feet from the vicinity of wells, tanks, and pump stations. All waste shall be burned or disposed of in such manner as to avoid creating a fire hazard or polluting streams and fresh-water strata.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Tubing

632-10-132 All wells shall be equipped with, and produced through tubing. The bottom of tubing on flowing wells shall not be higher than 100 feet above the top of the producing horizon or as otherwise approved by the State Geologist.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 1-1979, f. & ef. 1-25-79

Chokes

632-10-134 All flowing wells shall be equipped with chokes or beans adequate to control the flow thereof.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Separators

632-10-136 All flowing wells must be produced through an approved oil and gas separator.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Fire Walls

632-10-138 Every permanent oil tank, or battery of tanks, must be surrounded by a dike or fire wall with a capacity of one and one-half times that of the tank or battery of tanks.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Slush Pits Or Sumps

632-10-140 Materials and fluids or any fluid necessary to the drilling, production, or other operations by the permittee shall be discharged or placed in pits and sumps approved by the State Geologist and the State Department of Environmental Quality. The operator shall provide pits, sumps, or tanks of adequate capacity and design to retain all materials. In no event shall the contents of a pit or sump be allowed to:

(1) Contaminate streams, artificial canals or waterways, groundwaters, lakes, or rivers.

(2) Adversely affect the environment, persons, plants, fish, and wildlife and their population.

(3) When no longer needed, pits and sumps are to be filled and covered and the premises restored to a near natural state so as not to damage the aesthetic values of the property or adjacent properties.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 1-1979, f. & ef. 1-25-79

Directional Drilling

632-10-142 (1) Any well which is drilled or deepened shall be surveyed at reasonably frequent intervals to determine the deviation from the vertical. Deviation from the vertical is permitted without special permission for short distances, to straighten the holes, sidetract junk, or correct other mechanical difficulties. For the purposes of this rule an affected operator is an owner in a lease directly or diagonally offsetting any lease upon which the operation is proposed to be conducted.

(2) Except for the purposes of straightening the hole, sidetracking junk, or correcting mechanical difficulties as provided in this rule, no well shall be intentionally deviated from the vertical unless the operator thereof shall first file application and obtain a permit from the State Geologist. If drilling is in progress, the operator must notify the State Geologist immediately of the deviation of the hole or his intention to deviate the hole. When an operator follows this procedure, he must file an application as soon as practicable and obtain a permit as prescribed in subsection (a) of this rule:

(a) The application shall be made in such form as provided below and shall include or have attached to it:

(A) Surface and proposed producing interval locations in terms of distances from lease and section boundaries.

(B) Reason for deviation.

(C) List of affected operators and a showing that each has been furnished a copy of the application by registered mail, or a showing that the applicant is the only affected operator.

(D) Neat and accurate plat of the lease and of all affected leases showing the names of all affected operators and the surface and proposed producing interval locations of the well. The plat shall be drawn to a scale which will permit easy observation of all pertinent data.

(b) Paragraphs (C) and (D) of this subsection shall not be applicable to any well drilled on lands subject to an approved unit unless the proposed subsurface location of such well shall be nearer to any exterior boundary of such unit or to the subsurface location or proposed subsurface location of any producing or drilling well not subject to such unit then the applicable distances required as to oil and gas wells, respectively.

(c) If the applicant is the only affected operator and the State Geologist does not object to the application, the State Geologist may approved it immediately. If there are other affected operators, the State Geologist will hold the application for 30 days unless a letter of non-objection from each affected operator has been filed with the State Geologist. If objection from an operator to the proposed intentional deviation is received within the 30-day period, the application shall be subject to public hearing. If no objection from the affected operators is interposed within the 30-day period, the application shall be approved and permit issued by the State Geologist.

(3) Upon completion a complete directional survey of the well obtained by approved well surveying methods shall be filed with the State Geologist together with other regularly required reports.

(4) If the proposed or final location of the producing interval of the directionally deviated well is not in compliance with the spacing or other rules applicable to the reservoir, proper application shall be made to obtain approval of exceptions to such rules. Such approval shall be granted or denied at the discretion of the State Geologist and shall be accorded the same consideration and treatment as if the well had been drilled vertically to the producing interval.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 1-1979, f. & ef. 1-25-79; GMI 3-1980, f. 2-29-80, ef. 3-1-80

Report of Result of Shooting, Perforating, or Treating of Well

632-10-144 Within 60 days after either the shooting or chemical treatment of a well, a report shall be filed with the State Geologist by the owner, giving the condition of the well after shooting and other pertinent data.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 1-1979, f. & ef. 1-25-79

Vacuum Pumps Prohibited

632-10-146 The use of vacuum pumps or other devises for the purpose of putting a vacuum on any gas or oil-bearing stratum is prohibited, unless, upon application and hearing, and for good cause shown, the Board shall permit the use of vacuum pumps.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Production Practice

632-10-148 Naturally flowing wells shall be produced at a continuous uniform rate as far as is practical, in keeping with the current allowable, unless the Board specifically permits stop-cocking to reduce the gas-oil ratio.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Removal Of Casings

632-10-150 No person shall remove a casing, or any portion thereof, from any well without first giving advance notice and obtaining approval in writing from the State Geologist or his deputy.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 1-1979, f. & ef. 1-25-79

Notification of Fire, Breaks, Leaks, or Blow-Outs

632-10-151 (1) All persons controlling or operating any oil and gas wells, or receiving tanks, storage tanks, or receiving and storage receptacles into which crude oil is produced, received, or stored, shall immediately notify the Board by letter giving full details concerning all fires which occur at such oil or gas wells or tanks or receptacles on their property, and all such persons shall immediately report all tanks or receptacles struck by lightning and any other fire which destroys oil or gas, and shall immediately report any breaks in or from tanks or receptacles and pipe lines from which oil or gas is escaping or has escaped.

In all such reports of fires, breaks, leaks, or escapes, or other accidents of this nature, the location of the well, tank receptacle, or line break shall be given by Section, Township, Range, and property so that the exact location thereof can be readily located on the ground. Such report shall likewise specify what steps have been taken or are in progress to remedy the situation reported and shall detail the quantity of oil or gas lost, destroyed, or permitted to escape.

In case any tank or receptacle is permitted to run over, the escape thus occurring shall be reported as in the case of a leak. The report hereby required as to oil losses shall be necessary only in case such oil loss exceeds five barrels in the aggregate.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Multiple Completion of Wells

632-10-152 No well shall be permitted to produce either oil or gas from different strata through the same tubing without approval of the State Geologist. The approval of the State Geologist will require evidence of adequate and complete separation as ascertained by pressure or circulated tests conducted at the time the packers are set. Subsequently, if packer leakage is suspected the State Geologist may request the operator to provide proof of adequate and complete separation of the pools involved in the completions or make a packer leakage test. Notification shall be given so that the State Geologist or his agent may witness the actual operation of multiple completion of a well or witnessing any packer leakage test.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 1-1979, f. & ef. 1-25-79

Determining and Naming Pools

632-10-154 Wells shall be classified as to the pool from which they produce and pools shall be determined and named by the director, provided, that in the event any person is dissatisfied with any such classification, an application may be made to the Board for such classification as the applicant deems proper, and the Board will hear and determine the same.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Spacing Units

632-10-156 Immediately upon the discovery of any pool or at any time after the effective date of this rule, the Board may prescribe spacing units for each pool and specify the size, shape, and location thereof.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Location and Spacing of Wells

632-10-158 (1) Spacing Plan:

(a) The minimum spacing for oil wells shall be 40 acres, and the minimum spacing for gas wells shall be 160 acres when the producing zone is less than 7000 feet in depth. The minimum spacing for oil wells shall be 160 acres and the minimum spacing for gas wells shall be 640 acres when the producing zone is equal to or greater than 7000 feet in depth.

(b) In portions of the state covered by federal land survey grid, the spacing for oil wells shall consist of a governmental quarter or quarter quarter section and the spacing for gas wells shall consist of a governmental section or quarter section. In portions of the state not covered by federal land survey grid, the spacing units shall be square in shape and of an area prescribed in subsection (a) for oil and gas wells.

(c) Any existing dry holes shall not affect the spacing for producing wells.

(2) Location of Well: The completion location of each well permitted to be drilled on any spacing unit shall be the location of the well at the top of the producing horizon. For oil wells the completion location of the well shall not be located nearer than 250 feet from the unit boundary, and 500 feet from the nearest producing well from the same pool. For gas wells the completion location of the well shall not be located nearer than 500 feet from the unit boundary, and 1000 feet from the nearest producing well from the same pool. Exceptions may be recognized by the Board after a hearing when reasonably necessary on the basis of geology, productivity, topography, enhancement requirements, or environmental protection.

(3) Exceptions: Whenever a uniform spacing plan has been prescribed for any pool exceptions thereto may be permitted if the Board finds, after notice and hearing, that conditions within such pool are such that reasonably uniform spacing would be impracticable.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 3-1980, f. 2-29-80, ef. 3-1-80

Underground Reservoirs for Natural Gas Storage

632-10-159 Rules providing for well spacing and proration of gas shall not apply to gas storage wells, injection wells or monitor wells.

Stat. Auth.: ORS Ch. 520
Hist: GMI 3-1980, f. 2-29-80, ef. 3-1-80

Pooling of Small Tracts

632-10-160 When two or more separately owned tracts of land are embraced within a spacing unit which has been established by the Board, the owners thereof may pool their interests and develop their lands as a unit. Where, however, such owners have not agreed to pool their interests, the Board, for the prevention of waste or to protect correlative rights, may limit the allowable of each such owner to his reasonable prorata share of production from such spacing unit.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Illegal Production

632-10-162 No purchaser, producer, operator, or any other person shall produce any crude oil, natural gas, or waste oil from any spacing unit or pool in this state except in accordance with the rules, regulations, and orders of the Board: Provided that tank splitting shall not be required.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Limitation of Production

632-10-163 In the absence of unitization, whenever the Board, after notice and hearing, finds that waste as defined in the Act, is occurring or is imminent in any oil or gas field or pool and that the production of oil or gas from such field or pool should be limited to prevent waste, then the Board shall issue an order limiting production from such field or pool and specify rules applicable thereto for the allocation or distribution of allowable production therefrom as provided for in ORS 520.005(11) and 520.015.

Stat. Auth.: ORS Ch. 520
Hist: GMI 3-1980, f. 2-29-80, ef. 3-1-80

Commingling of Production Prohibited

632-10-164 The production from one pool shall not be commingled with that from another pool in the same field before delivery to a purchaser, unless otherwise ordered by the Board.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Allocation of Gas Pursuant to Special Pool Rules

632-10-165 Whenever the full production from any pool producing natural gas is in excess of the market demand for gas from that pool, any operator or interest owner in accordance with ORS 520.115 may petition the agency for a hearing and an order establishing a method of determining the market demeand from the pool and of distributing that demand among the wells producing therefrom.

Stat. Auth.: ORS Ch. 520
Hist: GMI 3-1980, f. 2-29-80, ef. 3-1-80

Reports by Purchasers and Producers

632-10-166 (1) Purchasers: Each purchaser or taker of any oil or gas from any well, lease, or pool shall on or before the 25th day of each month succeeding the month in which the purchasing or taking occurs, file with the director on a form furnished by the Board, a verified statement of all oil or gas purchased, or taken from any such well, lease, or pool during the preceding month.

(2) Producers: The producer or operator of each and every well or spacing unit in prorated pools shall each month submit to the director a sworn statement showing the amount of production made by each well and by each such spacing unit upon forms furnished therefor.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Maximum Efficient Rate Hearings

632-10-167 The Board on its own motion may, or at the request of any interested party shall, call hearings to determine the maximum efficient rate at which any pool in the state can produce oil and gas without waste.

Stat. Auth.: ORS Ch. 520
Hist: GMI 3-1980, f. 2-29-80, ef. 3-1-80

Use of Earthen Reservoirs

632-10-168 Oil shall not be stored or retained in earthen reservoirs or in open receptacles.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Natural Gas Policy Act Determination Procedures

632-10-169 (1) All category determinations under that Natural Gas Policy Act of 1978 will be initiated by the operator by filing with the State Geologist single legible copies of the documentation described below. A co-lessee may make application if the operator refuses to take such action upon written request.

(a) For new onshore reservoirs, an application under section 102(c)(1)(C) will be accompanied by:

(A) Federal Energy Regulatory Commission Form 121.

(B) Application for permit to drill.

(C) Geological information sufficient to support a determination that the reservoir is a new onshore reservoir including all well logs, results of well potential tests, geologic maps and cross-sections showing the extent of the reservoir as known at the time of application, gas analyses, well completion reports, and directional drilling surveys if performed.

(D) Well summary report (completion report).

(E) Monthly production reports, if there has been production.

(F) A statement by the Operator under oath:

(i) that he has made, or has caused to be made pursuant to his instructions, a diligent search of all records (including but not limited to production, State severance tax, and royalty payment records) which are reasonably available and contain information relevant to the determination of eligibility describing the search made, the records reviewed, the location of such records, and a description of any records which he believes may contain information relevant to the determination but which he has determined are not reasonably available to him;

(ii) that on the basis of the results of this search and examination, he has concluded that to the best of his information, knowledge, and belief, the natural gas to be produced and for which he seeks determination is from a new onshore reservoir.

(iii) that he has no knowledge of any other information not described in the application which is inconsistent with his conclusion; and

(b) the applicant, in his statement under oath, shall also answer, to the best of his information, knowledge and belief, and on the basis of the results of his search and examination, the following questions:

(A) Was natural gas produced in commercial quantities fromthe reservoir prior to April 20, 1977?

(B) Was the reservoir penetrated before April 20, 1977, by an old well from which natural gas or crude oil was produced in commercial quanitities from any reservoir?

(C) If the Question in clause (B) is answered in the affirmative, could natural gas have been produced in commercial quantities from the reservoir before April 20, 1977?

(D) If the natural gas is to be produced through an old well, were suitable facilities for the production and delivery to a pipeline of such natural gas in existence on April 20, 1977?

(c) For new natural gas, an application under section 102(c)(1)(B) will be accompanied by:

(A) Federal Energy Regulatory Commission Form 121.

(B) Application for permit to drill.

(C) A plat map showing the location of all oil and gas wells within 2.5 miles of the subject well at a scale of 1:48,000 or larger.

(D) Well summary reports (completion reports) and logs on the subject well and directional drilling surveys, if performed.

(E) A description of any wells shown in (b)(C) which had production between January 1, 1970, and April 20, 1977.

(F) Monthly production reports, if there has been production.

(G) A statement by the applicant, under oath:

(i) that he has made or has caused to be pursuant to his instructions, a diligent search of all records (including but not limited to production, State severance tax, and royalty payment records) which are reasonably available and contain information relevant to the determination of eligibility; describing the search made, the records reviewed, the location of such records, and a description of any records which he believes may contain information relevant to the determination but which he has determined are not reasonably available to him;

(ii) that on the basis of the results of this search and examination, he has concluded that to the best of his information, knowledge and belief, there is no marker well within 2.5 miles of the well for which he seeks a determination which has a completion location less than 1,000 feet above the completion location of the new well; and

(iii) that he has no knowledge of any other information not described in the application which is inconsistent with his conclusion.

(d) For new onshore production wells an application under section 103 will be accompanied by Federal Energy Regulatory Commission Form 121.

(A) Application for permit to drill.

(B) A plat map showing the location of the subject well. If the subject well is within a spacing unit, the map shall also show the boundaries of the unit and any existing wells in the unit.

(C) Well summary report (completion report) and logs on the subject well and directional surveys, if performed.

(D) A statement by the applicant, under oath:

(i) that the surface drilling of the well for which he seeks a determination was begun on or after February 19, 1977;

(ii) that the well satisfies any applicable federal or state well spacing requirements;

(iii) that, except as provided in paragraph (D) of this section, the well is not within a spacing unit:

(I) Which was in existence at the time the surface drilling of the well began;

(II) What was applicable to the reservoir from which such natural gas is produced; and

(III) Which was applied to any other well which either produced natural gas in commercial quantities or the surface drilling of which was begun before February 19, 1977, and was thereafter capable of producing natural gas in commercial quantities;

(iv) that on the basis of the documents submitted in the application, the applicant has concluded that to the best of his information, knowledge, and belief, the natural gas for which he seeks a determination is produced from a new onshore production well; and

(v) that the applicant has no knowledge of any other information not described in the application which is inconsistent with his conclusion.

(e) If the applicant is seeking a determination with respect to a new well to be drilled into an existing spacing unit, the applicant must file all items required in paragraphs (A) through (D) of this section, except for the portion of the oath statement described in paragraph (D)(iii) and demonstrate by appropriate geological evidence that the new well is necessary to effectively and efficiently drain a portion of the reservoir covered by the spacing unit which cannot be effectively and efficiently drained by any existing well within the spacing unit.

(f) For stripper wells an application under section 108 will be accompanied by:

(A) Federal Energy Regulatory Commission Form 121.

(B) Application for permit to drill.

(C) A plat map showing the location of the subject well.

(D) Well summary report (completion report).

(E) Monthly production reports.

(F) Copies of all lithologic, electric, gamma, and other logs, drill test results and directional surveys, if performed.

(G) Name and address of operator and parties to purchase contracts.

(H) For cases of increased production resulting from enhanced recovery techniques, a description of the processes and equipment used for such recovery and the dates such processes or equipment were installed and used.

(I) For cases of seasonally affected production, a description of the nature of the fluctuations and the data used to determine the seasonal variation.

(J) A statement by the applicant, under oath, that to the best of his information, knowledge and belief, the information supplied and conclusions drawn are true and that the operator has no knowledge of any information not contained or described in the application which is inconsistent with any of his conclusions.

(2) The applicant shall, at the time of filing for a category determination, notify, by certified mail the purchasers and all working interest owners of such filing, and mail a list of the parties as notified to the Board. If more than one category determination is being requested as to a single well, separate applications for each determination must be filed. The application, upon filing, shall be given a filing number and date.

(3) Applications containing logs which are confidential under the provisions of ORS 520.095(2) shall be kept confidential by the State Geologist.

(4) The Board will review uncontested applications at its regularly scheduled meetings.

(5) Any person desiring to protest the granting of a determination shall send, within 15 days after receiving notification from the applicant, a written protest to the Board and applicant by certified mail. The protest must be supported by documentation in the same manner as the documentation submitted by the applicant. Contested applications will be referred to public hearings. The Board will review the record of the hearing and issue a category determination at its regularly scheduled meeting.

(6) The Board shall give written notice of its category determination to the Federal Energy Regulatory Commission, the applicant, parties to the purchase contract, working interest owners and any protestant within 15 days after the meeting date.

Stat. Auth.: ORS Ch. 520
Hist: GMI 3-1980, f. 2-29-80, ef. 3-1-80

Reservoir Surveys

632-10-170 By special order of the Board, periodic surveys may be made of the reservoirs in this state containing oil and gas. These surveys will be thorough and complete and shall be made under the supervision of the petroleum and natural gas engineers of the Board. The condition of the reservoirs containing oil and gas and the practices and methods employed by the operators shall be investigated. The volume and source of crude oil and natural gas; the reservoir pressure of the reservoir as an average; the areas of regional or differential pressure; stabilized gas-oil ratios; and the producing characteristics of the field as a whole and the individual wells within the field shall be specifically included.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Operators to Assist in Reservoir Surveys

632-10-172 All operators of oil wells are required to permit and assist the agents of the Board and the director in making any and all tests including bottom hole pressure and gas-oil ratio determinations that may be required by the Board or director on any or all of their wells.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Measurement of Potential Open-Flow of Gas Wells

632-10-174 The potential open-flow of a gas well may be ascertained by U.S. Bureau of Mines back pressure method, or by other approved methods.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Supervison of Open-Flow and Pressure Tests

632-10-176 All tests made in determining the potential flow and shut-in well-head or bottom hole pressure of a gas well and used in calculating the allowable of the spacing unit which the well is located shall be made under the supervision of representatives of the Board.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Duration of Tests

632-10-178 The tests for open-flow and pressure of completed gas wells shall be made at such intervals and shall continue for such time as may be necessary to effect accurate determination.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 1-1979, f. & ef. 1-25-79

Notice of Tests

632-10-180 Open-flow and pressure tests of gas wells may be witnessed or observed by a representative of any producer in the field, and the owners of the adjoining or offset leases must be notified by the owner of the well on which the test is to be taken, stating the time when such test will commence.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Gas to be Metered

632-10-182 (1) Meters: All gas when produced or sold shall be metered with an approved meter of sufficient capacity, provided that gas may be metered from a lease or unitized property as a whole if it is shown that ratable taking can be maintained; provided that meters shall not be required for gas produced and used on the lease for development purposes and lease operations.

(2) Meter Charts and Records: Purchasers shall keep meter charts and records on gas purchased in a permanent file, for a period of at least two years, and such information shall be made available to the Board and director.

(3) By-Passes: By-passes shall not be connected around meters in such manner as to permit the improper taking of gas.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Direct Well Pressure

632-10-184 The use of direct well pressure to operate any machinery is hereby prohibited.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Gas-Oil Ratio

632-10-186 No well shall be permitted to produce gas in excess of the maximum ratio determined for a pool unless all gas produced in excess thereof is returned to the pool from which it was produced.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Gas-Oil Ratio Surveys and Reports

632-10-188 Gas-oil ratios and surveys shall be taken in the manner prescribed by the Board for individual fields where upon gas-oil ratio limits have been fixed and in accordance with the rules prescribed for each individual pool:

(1) Flowing Wells Intermittently (Stop-Cocked) Produced: In computing the operating gas-oil ratio, the total volume of gas and the total barrels of oil that are produced in order to obtain the daily oil allowable must be used regardless of the flowing time in the 24-hour period.

(2) Gas Lift or Jet Wells: The total volume of gas to be used in computing the operating gas-oil ratio is the total out-put volume minus the total input volume.

(3) Pumping Wells: Should gas be withdrawn from the casing in an attempt to maintain a fluid seal, or for any other reason, this volume of gas must be added to the gas produced through tubing in computing the gas-oil ratio.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Gas Utilization

632-10-190 (1) No gas shall be permitted to escape to the atmosphere except for short periods during testing authorized by the State Geologist or his representative.

(2) Flaring of produced gas shall not be permitted except by special order of the Board.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 1-1979, f. & ef. 1-25-79

Disposal of Brine or Salt Water

632-10-192 In addition to the requirement of the Act to prevent the escape of oil or gas out of one stratum to another and to prevent the pollution of fresh water supplies by oil, gas, or salt water, and in addition to any regulations of the State Department of Environmental Quality and the State Water Resources Department, the following conditions shall control the disposal of brine or salt water liquids, and any other means or methods of disposal which may be permitted.

(1) Disposal in Pits:

(a) Brine or salt water may be disposed of by evaporation when impounded in excavated earthen pits, which may be used for such purpose only when the pit is lined with impervious material and a Water Pollution Control Facilities permit has been issued by the Department of Environmental Quality.

(b) Impounding of brine or salt water in earthen pits that are porous is hereby prohibited. Earthen pits used for impounding brine or salt water shall be so constructed and maintained as to prevent the escape of fluid.

(c) The State Geologist shall have authority to condemn any pit which does not properly impound such water and order the disposal of such water into an underground formation, or by other authorized method.

(d) The level of brine or salt water in earthen pits shall at no time be permitted to rise above the lowest point of the ground surface level. All pits shall have a continuous embankment surrounding them sufficiently above the level of the surface to prevent surface water from running into the pit. Such embankment shall not be used to impound brine or salt water.

(e) At no time shall brine or salt water impounded in earthen pits be allowed to escape over adjacent land or into streams.

(2) Disposal by Injection: Salt water may also be disposed of by injection into the strata from which produced or into other proved salt water bearing strata.

(3) Ocean discharge of salt water may be permitted if water quality is acceptable and if such discharge is approved by the State Department of Environmental Quality through issuance of an National Pollutant Discharge Elimination System waste discharge permit.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 1-1979, f. & ef. 1-25-79

Water Injection and Water Flooding of Oil and Gas Properties

632-10-194 (1) Application and Approval: The owner or operator of any well may inject water under pressure into the formation containing oil or gas for the purpose of obtaining oil or gas from the reservoir, upon application to and approval by the Board.

(2) Casing and Cement: Wells used for the injection of water into the producing formation or repressuring wells shall be cased with sound casing so as not to permit leakage and the casing cemented in such manner that damage will not be caused to oil, gas, or fresh water resources.

(3) Application, Contents, Notice, Objection, Hearing, and Approval:

(a) No water injection or water flooding program shall be instituted until it has been regularly authorized by the Board.

(b) The application therefor shall be verified and filed with the Board, showing:

(A) The location of the intake well.

(B) The location of all oil and gas wells, including abandoned and drilling wells and dry holes, and the name of landowners and lessees within one-half mile of the intake well.

(C) The formations from which wells are producing or have produced.

(D) The name, description, and depth of the formations to be flooded.

(E) The depths of each formation into which water is to injected.

(F) The elevations of the top of the oil or gas bearing formation in the intake well and the wells producing from the same formation within one-half mile radius of the intake well.

(G) Log of the intake well or similar information as is available.

(H) Description of the intake well casing.

(I) Description of the liquid, stating the kind, where obtained, and the estimated amounts to be injected daily.

(J) The names and addresses of the operators.

(K) Such other information as the Board may require to ascertain whether the flooding may be safely and legally made.

(c) Applications may be made to include the use of more than one intake well on the same lease, or on more than one lease.

(d) Applications shall be executed by all operators who are to participate in the proposed water injection or water flooding plan.

(e) No order approving water injection or water flooding of oil properties shall be issued until after notice has been given by the Board to each operator in such pool, and hearing has been had before the Board.

(4) Notice of Commencement and Discontinuance of Water Injection or Water Flooding Operations:

(a) Immediately upon the commencement of water injection or water flooding operations, the applicant shall notify the Board stating the date of commencement.

(b) Within 10 days after the discontinuance of water injection or water flooding operations, the applicant or the one in charge thereof shall notify the Board of the date of such discontinuance and the reasons therefor.

(c) Before any intake well shall be abandoned, notice shall be served on the Board, and the same procedure shall be followed in the plugging of such well as provided for the plugging of oil and gas wells.

(5) Records: The owner or operator of an intake well shall keep an accurate record of:

(a) The amount of water injected into the intake wells,

(b) The total amount of water produced, and

(c) The total amount of oil produced from the area flooded.

Such information shall be made available to the Board or its agents.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Gas Injection of Oil and Gas Properties

632-10-196 (1) Application and Approval: The owner or operator of any well may inject gas under pressure into the formation containing oil or gas for the purpose of increasing production of oil or gas from the reservoir or for storing pipeline natural gas upon application to and approval by the Board.

(2) Casing and Cement: Wells used for the injection of gas into the producing formation shall be cased with sound casing so as not to permit leakage and the casing cemented in a manner that damage will not be caused to oil, gas, or fresh water resources. All injection of gas shall be through tubing with a casing packer set at the lower end above the zone of injection and the annular space between tubing and casing shall be monitored to be sure the packer is holding.

(3) Application, Contents, Notice, Objection, Hearing, and Approval:

(a) No gas shall be injected into a well for gas injection purposes until approved by the Board pursuant to application and notice as herein required.

(b) The application shall be verified and filed with the Board showing:

(A) The location of the intake well.

(B) The location and depth of all oil and gas wells, including abandoned and drilling wells and dry holes, and the name of landowners and lessees within a two and one-half mile radius of the injection well.

(C) The formations from which wells are producing or have produced.

(D) The name, description, and depth of the formations to be injected.

(E) The depths of each formation into which gas is to be injected.

(F) The elevations of the top of the oil or gas bearing formation in the injection well and the well producing from the same formation within one-half mile of the intake well.

(G) The log of the injection well, or similar information as is available.

(H) Description of the injection well casing.

(I) Description and chemical analysis of the gas, stating the kind, where obtained, and the estimated amounts to be injected daily.

(J) The names and addresses of the operators.

(K) Such other information as the Board may require to ascertain whether the gas injection plan meets the requirements of law and safety.

(c) Applications may be made to include the use of more than one intake well on the same lease or on more than one lease.

(d) Applications shall be executed by all operators who are to participate in the proposed gas injection plan.

(4) Notice of Commencement and Discontinuance of Gas Injection:

(a) Immediately upon commencement of gas injection operations, the applicant shall notify the State Geologist stating the date of commencement.

(b) Within 10 days after the discontinuance of gas injection operations, the applicant or the one in charge of the operations shall notify the Board of the date of discontinuance and the reasons therefor.

(c) Before any injection well shall be abandoned, notice shall be served on the State Geologist and the same procedure shall be followed in the plugging of such well as provided for the plugging of oil and gas wells.

(d) The above notification requirements shall not apply to a gas storage facility except for the initial injection and filling of the reservoir or for the abandonment of the storage reservoir.

(5) Records: The owner or operator of the gas injection project shall keep an accurate record of:

(a) The amount of gas injected into the injection wells;

(b) The amount of gas produced; and

(c) The amount of oil produced from leases affected by the gas injection;

(d) The well-head injection pressures.

Such information shall be made available to the State Geologist or his agents.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 1-1979, f. & ef. 1-25-79

Abandonment, Unlawful Abandonment, Suspension, Well Plugging

632-10-198 (1) Oil, Gas, and Water to be Protected: Before any well or any producing horizon encountered therein shall be abandoned, the owner or operator shall use such means, methods, and procedure as may be necessary to prevent water from entering any oil or gas-bearing formation, and to protect any underground or surface water that is suitable for domestic or irrigation purposes from waste, downward drainage, harmful infiltration and addition of deleterious substances.

The operator of any hole drilled for oil and gas which penetrates a usable fresh-water horizon, except those drilled for the purposes of seismic prospecting, shall be required to set casing through this formation and cement such casing from top to bottom, unless special exception is granted by the Board.

(2) Suspension: Removal of Equipment: Application: Extension: The Board may authorize a permittee to suspend operations or remove equipment from a well for the period stated in the Board's written authorization, given upon written application of the permittee and his or its affidavit showing good cause. The period of suspension may be extended by the Board, upon written application made before expiration of the previously authorized suspension, accompanied by affidavit of the permittee showing good cause for the granting of such extension.

(3) Abandonment: Notice of Intention: Presumptions:

(a) Before any work is commenced to abandon any well drilled for oil or gas, the permittee shall give written notice to the Board of his intention to abandon such well. The notice shall be upon forms supplied by the Board and shall contain the permit number of the well and such other information as reasonably may be required by the Board.

(b) After operations on or at a well have been suspended with the approval of the Board pursuant to section (2) of this rule, if operations are not resumed within six months from the date specified in such approval of suspension, an intention to abandon and unlawful abandonment shall be presumed unless the permittee has obtained from the Board an extension of time of such suspension, upon his or its written application and affidavit showing good cause for the granting of such extension.

(c) Whenever operations on or at any well shall have been suspended for a period of six months without compliance with these regulations, the well shall be presumed unlawfully abandoned.

(d) A well shall be deemed unlawfully abandoned if, without notice given to the Board as required by these rules, any drilling or producing equipment is removed.

(e) Any unlawful abandonment under these regulations shall be declared by the Board and such declaration of abandonment shall be entered in the Board minutes and written notice thereof mailed by registered mail both to such permittee at his last known post office address as disclosed by the records of the Board and to the permittee's surety; and the Board may thereafter proceed against the permittee and his or its surety.

(f) All wells abandoned or declared abandoned as herein provided shall be plugged as required by law and by these regulations.

(g) The bond furnished by permittee shall not be released until all procedures required by these regulations shall have been completed and the Board in writing shall have authorized such release.

(4) Plugging Methods and Procedure: The methods and procedure for plugging a well shall be as follows:

(a) The bottom of the hole shall be filled to the top of each producing formation, or a bridge shall be placed at the top of each producing formation, and in either event a cement plug not less than 15 feet in length shall be placed immediately above each producing formation whenever possible.

(b) A cement plug not less than 15 feet in length shall be placed approximately 50 feet below all freshwater bearing strata.

(c) A plug shall be placed at the surface of the ground in each hole plugged in such manner as not to interfere with soil cultivation.

(d) the interval between plugs shall be filled with an approved heavy mud-laden fluid.

(e) The operator shall have the option as to the method of placing cement in the hole by:

(A) Dump bailer;

(B) Pumping through tubing;

(C) Pump and plug; or

(D) Other method approved by the Board.

(5) Affidavit on Completion: Copies: Within 20 days after the plugging of any well has been accomplished, the owner or operator thereof shall file an affidavit with the director setting forth in detail the method used in plugging the well. Such affidavit shall be made on a form supplied by the Board. Copies of well-plugging records and affidavits filed, except those relating to core drilling and seismic or other wells drilled for geological data, will be furnished to anyone requesting them on payment of 50 cents per copy.

(6) Seismic Core and Other Exploratory Holes to be Plugged: Methods: Affidavit: Before abandoning any hole

drilled for seismic, core, or other exploratory purposes, which hole penetrates a usable fresh-water horizon, it shall be the duty of the owner or driller of such hole to plug the same in such manner as to protect properly all water-bearing formations; and within 60 days after the plugging, an affidavit shall be filed with the Director by the owner or driller, setting forth the location of the holes and the method used in plugging the same to protect water-bearing formations.

(7) Wells Used for Fresh Water:

(a) When the drilled well to be plugged may safely be used as a fresh-water well and such use is desired by the land owner, the well need not be filled above the required sealing plug set below fresh water; provided, however, authorization for use of any such well shall be obtained from the State Engineer, in conformance with Chapter 708, Oregon Laws 1955.

(b) Application for leaving the well partially unplugged as a fresh-water well may be made to the Board by the land owner, accompanied by his affidavit as to his need of water and the intended use of the well, together with certified copy of the State Engineer's order or permit, or that officer's statement that no permit is required.

(c) The operator shall leave the fresh-water well in a condition approved by the Board.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54; GMI 3, f. 4-3-56

Confidential Information

632-10-200 No information herein required to be furnished to the Board shall be disclosed by any employee of the Board except as expressly authorized by the Board.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1, f. 1-27-54

Drilling Bond

632-10-205 (1) Every person who engages in the drilling, deepening, or reworking of any well shall file with the State Geologist on a form provided by the State Geologist a surety bond in the sum of $10,000 for each well drilled, reworked, or deepened, or a $50,000 blanket bond for the drilling, deepening, or reworking of one or more wells being conducted at any time. The bond shall be filed with the State Geologist at the time of the filing of the notice of intention to drill, deepen, or rework as required in rule 632-10-010. The bond shall be executed by such person, as principal, and by a surety company authorized to do business in the State of Oregon, as surety, conditioned upon the faithful compliance by the principal with the rules, regulations, and orders of the Department of Geology and Mineral Industries.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1-1979, f. & ef. 1-25-79

Disposal of Solid and Liquid Wastes

632-10-210 (1) Stipulations approved by the State Department of Environmental Quality regarding disposal of solid and liquid wastes generated by drilling, deepening, or reworking operations shall be made a part of every permit issued under rule 632-10-010.

(2) Once field development is initiated a separate permit is required from the State Department of Environmental Quality for disposal of liquid and solid wastes.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1-1979, f. & ef. 1-25-79

Underground Storage Of Natural Gas

632-10-215 Wells drilled for the purpose of storing natural gas in an underground reservoir shall be drilled in such manner as shall protect the underground reservoir against pollution and against escape of natural gas in a manner which complies with the orders and rules of this chapter.

Stat. Auth.: ORS Ch. 520
Hist: GMI 1-1979, f. & ef. 1-25-79

Measurement of Oil

632-10-220 The volume of production of oil shall be computed in terms of barrels of clean oil on the basis of properly calibrated meter measurements or tank measurement of oil level differences made and recorded to the nearest quarter inch, using 100 percent tank capacity tables, subject to the following corrections:

(1) Correction for Impurities: The percentage of impurities (water, sand, and other foreign substances not constituting a natural component part of oil) shall be determined to the satisfaction of the State Geologist, and the observed gross volume of oil shall be corrected to exclude the entire volume of such impurities.

(2) Temperature Correction: The observed volume of oil corrected for impurities shall be further corrected to the standard volume at 60°F. in accordance with A.S.T.M. Standards or any revisions thereof approved by the State Geologist.

(3) Gravity Determination: The gravity of oil at 60°F. shall be determined in accordance with A.S.T.M. Standards or any revisions thereof and any supplements thereto or any close approximation thereof approved by the State Geologist.

Stat. Auth.: ORS Ch. 520
Hist:
GMI 1-1979, f. & ef. 1-25-79

Special Rules, Mist Gas Field

Spacing Plan

632-10-225 The minimum spacing for gas wells in the Mist Field shall be 160 acres when the top of the producing zone is less than 7,000 feet in vertical depth.

Stat. Auth.: ORS Ch. 520
Hist: GMI 2-1980, f. 2-29-80, ef. 3-1-80

Location of Well

632-10-230 The completion location of each well permitted to be drilled on any spacing unit shall be the location of the well at the top of the producing horizon. For gas wells the completion location of the well shall not be located nearer than 250 feet from the unit boundary and 500 feet from the nearest producing well from the same pool.

Stat. Auth.: ORS Ch. 520
Hist: GMI 2-1980, f. 2-29-80, ef. 3-1-80

Exceptions

632-10-235 (1) The Board may grant exceptions to the above field rules after holding a hearing when necessary on the basis of geology, productivity, topography, enhancement requirements, or environmental protection.

(2) Exceptions granted by the Board to Reichhold and partners:

(a) Variance for the location of Reichhold's Columbia County No. 1 Redrill at the south line of the producing unit defined by boundaries of the NW1/4 of section 11, T. 6N., R. 5W.

(b) Variance for the location of Reichhold's Columbia County No. 6 Redrill No. 2 located in the extreme southwest portion of the producing unit defined by the NE1/4 of section 10, T. 6 N., R. 5W.

(c) Variance for the producing unit defined by the NE1/4 of section 10, T. 6 N., R. 5W., to contain wells Reichhold's

Columbia County No. 3 Redrill and Reichhold's Columbia County No. 6 Redrill No. 2.

(d) Variance for the location of Reichhold's Columbia County No. 12 to be closer to the section boundary than 250 feet.

Stat. Auth.: ORS Ch. 520
Hist: GMI 2-1980, f. 2-29-80, ef. 3-1-80

WATER POLLUTION

DIVISION 41

STATE-WIDE WATER QUALITY MANAGEMENT PLAN; BENEFICIAL USES, POLICIES, STANDARDS, AND TREATMENT CRITERIA FOR OREGON

[ED. NOTE: The Tables and Figures referred to within the text of this division may be found at the end of this division.]

Preface

340-41-001 The rules which follow, together with the applicable laws of the State of Oregon and the applicable regulations of the Environmental Quality Commission, set forth Oregon's plans for management of the quality of public waters within the State of Oregon.

Under this plan, the Department of Environmental Quality will continue to manage water quality by evaluating each discharge and activity, whether existing or a new proposal, on a case-by-case basis, based on best information currently available and within the limiting framework of minimum standards, treatment criteria, and policies which are set forth in the plan.

The EQC recognizes that the deadlines for adoption of this plan prevented thorough involvement by local government in the development and review of the plan. Accordingly, the Department will review the contents of this plan with affected local governments and will use their comments and suggestions in preparing amendments for consideration by the EQC not later than December, 1977. At a minimum, the processes of coordination with local governments will consist of the following elements:

(1) Work with county coordinators to set up meetings to explain the plan to groups of local governments and solicit their comments.

(2) Provide copies of the plan and supporting documents to any affected local governments who have not already received them.

(3) Seek input from councils of governments.

(4) Upon request, visit local level governments to discuss the plan.

(5) Work with statewide associations of local governments and others to inform local governments of the plan.

Stat. Auth.: ORS Ch. 468
Hist: DEQ 128, f. & ef. 1-21-77,

Definitions

340-41-005 [SA 26, f. 6-1-67;
Repealed by DEQ 128, f. & ef. 1-21-77]

Definitions

340-41-006 Definitions applicable to all basins unless context requires otherwise:

(1) "BOD" means 5-day 20° C. Biochemical Oxygen Demand.

(2) "DEQ" or "Department" means the Oregon State Department of Environmental Quality.

(3) "DO" means dissolved oxygen.

(4) "EQC" means the Oregon State Environmental Quality Commission.

(5) "Estuarine waters" means all mixed fresh and oceanic waters in estuaries or bays from the point of oceanic water intrusion inland to a line connecting the outermost points of the headlands or protective jetties.

(6) "Industrial waste" means any liquid, gaseous, radioactive, or solid waste substance or a combination thereof resulting from any process of industry, manufacturing, trade, or business, or from the development or recovery of any natural resources.

(7) "Marine waters" means all oceanic, offshore waters outside of estuaries or bays and within the territorial limits of the State of Oregon.

(8) "mg/l" means milligrams per liter.

(9) "Pollution" means such contamination or other alteration of the physical, chemical, or biological properties of any waters of the state, including change in temperature, taste, color, turbidity, silt, or odor of the waters, or such radioactive or other substance into any waters of the state which either by itself or in connection with any other substance present, will or can reasonably be expected to create a public nuisance or render such waters harmful, detrimental, or injurious to public health, safety, or welfare, or to domestic, commercial, industrial, agricultural, recreational, or other legitimate beneficial uses or to livestock, wildlife, fish or other aquatic life, or the habitat thereof.

(10) "Public water" means the same as "waters of the state".

(11) "Sewage" means the water-carried human or animal waste from residences, buildings, industrial establishments, or other places together with such groundwater infiltration and surface water as may be present. The admixture with sewage as herein defined of industrial wastes or wastes, as defined in sections (6) and (13) of this rule, shall also be considered "sewage" within the meaning of this division.

(12) "SS" means suspended solids.

(13) "Wastes" means sewage, industrial wastes, and all other liquid, gaseous, solid, radioactive, or other substances which will or may cause pollution or tend to cause pollution of any water of the state.

(14) "Waters of the state" include lakes, bays, ponds, impounding reservoirs, springs, wells, rivers, streams, creeks, estuaries, marshes, inlets, canals, the Pacific Ocean within the territorial limits of the State of Oregon, and all other bodies of surface or underground waters, natural or artificial, inland or coastal, fresh or salt, public or private (except those private waters which do not combine or effect a junction with natural surface or underground waters), which are wholly or partially within or bordering the state or within its jurisdiction.

(15) "Low flow period" means the flows in a stream resulting from primarily groundwater discharge or baseflows augmented from lakes and storage projects during the driest period of the year. The dry weather period varies across the state according to climate and topography. Wherever the low flow period is indicated in the Water Quality Management Plans, this period has been approximated by the inclusive months. Where applicable in a waste discharge permit, the low flow period may be further defined.

(16) "Secondary treatment" as the following context may require for:

(a) "Sewage wastes" means the minimum level of treatment mandated by EPA regulations pursuant to Public Law 92-500.

(b) "Industrial and other waste sources" imply control equivalent to best practicable treatment (BPT).

Stat. Auth.: ORS Ch. 468
Hist: DEQ 128, f. & ef. 1-21-77

Highest and Best Practicable Treatment and Control Required

340-41-010 [SA 26, f. 6-1-67;
Repealed by DEQ 128, f. & ef. 1-21-77]

Restriction on the Discharge of Sewage and Industrial Wastes and Human Activities Which Affect Water Quality in the Waters of the State

340-41-015 [SA 26, f. 6-1-67;
Repealed by DEQ 128, f. & ef. 1-21-77]

Maintenance of Standards of Quality

340-41-020 [SA 26, f. 6-1-67;
DEQ 28, f. 5-24-71, ef. 6-25-71;
Repealed by DEQ 128, f. & ef. 1-21-77]

Implementation of Treatment Requirements and Water Quality Standards

340-41-022 [DEQ 28, f. 5-24-71, ef. 6-25-71;
DEQ 46, f. 6-15-72, ef. 7-1-72;
Repealed by DEQ 128, f. & ef. 1-21-77]

Mixing Zones

340-41-023 [DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

Testing Methods

340-41-024 [DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

General Water Quality Standards

340-41-025 [SA 26, f. 6-1-67;
DEQ 39, f. 4-5-72, ef. 4-15-72;
DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

Policies and Guidelines Generally Applicable to All Basins

340-41-026 (1)(a) Existing high quality waters which exceed those levels necessary to support propagation of fish, shellfish, and wildlife and recreation in and on the water shall be maintained and protected unless the Environmental Quality Commission chooses, after full satisfaction of the intergovernmental coordination and public participation provisions of the continuing planning process, to lower water quality for necessary and justifiable economic or social development. The Director or his designee may allow lower water quality on a short-term basis in order to respond to emergencies or to otherwise protect public health and welfare. In no event, however, may degradation of water quality interfere with or become injurious to the beneficial uses of water within surface waters of the following areas:

(A) National Parks;

(B) National Wild and Scenic Rivers;

(C) National Wildlife Refuges;

(D) State Parks.

(b) Point source discharges shall follow policies and guidelines (2), (3), and (4), and nonpoint source activities shall follow guidelines (5), (6), (7), (8), and (9).

(2) In order to maintain the quality of waters in the State of Oregon, it is the policy of the EQC to require that growth and development be accommodated by increased efficiency and effectiveness of waste treatment and control such that measurable future discharged waste loads from existing sources do not exceed presently allowed discharged loads unless otherwise specifically approved by the EQC.

(3) For any new waste sources, alternatives which utilize reuse or disposal with no discharge to public waters shall be given highest priority for use wherever practicable. New source discharges may be approved by the Department if no measurable adverse impact on water quality or beneficial uses will occur. Significant or large new sources must be approved by the Environmental Quality Commission.

(4) No discharges of wastes to lakes or reservoirs shall be allowed without specific approval of the EQC.

(5) Log handling in public waters shall conform to current EQC policies and guidelines.

(6) Sand and gravel removal operations shall be conducted pursuant to a permit from the Division of State Lands and separated from the active flowing stream by a water-tight berm wherever physically practicable. Recirculation and reuse of process water shall be required wherever practicable. Discharges, when allowed, or seepage or leakage losses to public waters shall not cause a violation of water quality standards or adversely affect legitimate beneficial uses.

(7) Logging and forest management activities shall be conducted in accordance with the Oregon Forest Practices Act so as to minimize adverse effects on water quality.

(8) Road building and maintenance activities shall be conducted in a manner so as to keep waste materials out of public waters and minimize erosion of cut banks, fills, and road surfaces.

(9) In order to improve controls over nonpoint sources of pollution, federal, state, and local resource management agencies will be encouraged and assisted to coordinate planning and implementation of programs to regulate or control runoff, erosion, turbidity, stream temperature, stream flow, and the withdrawal and use of irrigation water on a basin-wide approach so as to protect the quality and beneficial uses of water and related resources. Such programs may include, but not be limited to, the following:

(a) Development of projects for storage and release of suitable quality waters to augment low stream flow.

(b) Urban runoff control to reduce erosion.

(c) Possible modification of irrigation practices to reduce or minimize adverse impacts from irrigation return flows.

(d) Stream bank erosion reduction projects.

Stat. Auth.: ORS Ch. 468
Hist: DEQ 128, f. & ef. 1-21-77; DEQ 1-1980, f. & ef. 1-9-80

Beneficial Uses of Waters to be Protected by Special Water Quality Standards

340-41-030 [SA 26, f. 6-1-67;
Repealed by DEQ 128, f. & ef. 1-21-77]

Special Water Quality Standards For Public Waters of Goose Lake in Lake County

340-41-035 [SA 26, f. 6-1-67;
Repealed by DEQ 128, f. & ef. 1-21-77]

Special Water Quality Standards For Public Waters of the Main Stem Klamath River

340-41-040 [SA 26, f. 6-1-67;
DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

Special Water Quality Standards For the Public Waters of Multnomah Channel and the Main Stem Willamette River

340-41-045 [SA 26, f. 6-1-67;
DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

Special Water Quality Standards For the Public Waters of the Main Stem of the Columbia River From the Eastern Oregon-Washington Border Westward to the Pacific Ocean

340-41-050 [SA 26, f. 6-1-67;
DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

Special Water Quality Standards For the Public Waters of the Main Stem of the Grande Ronde River

340-41-055 [SA 26, f. 6-1-67;
DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

Water Quality Standards For the Public Waters of the Main Stem of the Walla Walla River

340-41-060 [SA 26, f. 6-1-67;
DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

Water Quality Standards For the Main Stem of the Snake River in and Adjacent to Oregon

340-41-065 [SA 26, f. 6-1-67;
DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

Water Quality Standards For the Marine and Estuarine Waters of Oregon

340-41-070 [SA 26, f. 6-1-67;
Repealed by DEQ 128, f. & ef. 1-21-77]

Implementation and Enforcement Plan

340-41-075 [SA 27, f. 6-19-67;
DEQ 38, f. 4-5-72, ef. 4-15-72;
Repealed by DEQ 128, f. & ef. 1-21-77]

Special Water Quality and Waste Treatment Standards For the Rogue River Basin

340-41-080 [SA 94, f. 10-29-69;
DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77

Special Water Quality and Waste Treatment Standards For the Umpqua River Basin

340-41-085 [SA 50, f. 10-29-69;
DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

Special Water Quality and Waste Treatment Standards For the Clackamas River Basin, Molalla River Basin, and Sandy River Basin

340-41-090 [SA 51, f. 10-29-69;
DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

Special Water Quality and Waste Treatment Standards For the Tualatin River Basin

340-41-095 [DEQ 2, f. 3-3-70, ef. 3-25-70;
DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

Special Water Quality and Waste Treatment Standards For the McKenzie River Basin and the Santiam River Basin

340-41-100 [DEQ 3, f. 3-3-70, ef. 3-25-70;
DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

Special Water Quality and Waste Treatment Standards For the Deschutes River Basin

340-41-105 [DEQ 4, f. 3-3-70, ef. 3-25-70;
DEQ 55, f. 7-2-73, ef. 7-15-73;
Repealed by DEQ 128, f. & ef. 1-21-77]

Implementation Program Applicable to All Basins

340-41-120 (1) No waste treatment and disposal facilities shall be constructed or operated and no wastes shall be discharged to public waters without obtaining a permit from the Department as required by ORS 468.740.

(2) Plans for all sewage and industrial waste treatment, control, and disposal facilities shall be submitted to the Department for review and approval prior to construction as required by ORS 468.742.

(3) Minimum design criteria for waste treatment and control facilities prescribed under this plan and such other waste treatment and controls as may be necessary to insure compliance with the water quality standards contained in this plan shall be provided in accordance with specific permit conditions for those sources or activities for which permits are required and the following implementation program:

(a) For new or expanded waste loads or activities, fully approved treatment or control facilities, or both shall be provided prior to discharge of any wastes from the new or expanded facility or conduct of the new or expanded activity.

(b) For existing waste loads or activities, additional treatment or control facilities necessary to correct specific unacceptable water quality conditions shall be provided in accordance with a specific program and timetable incorporated into the waste discharge permit for the individual discharger or activity. In developing treatment requirements and implementation schedules for existing installations or activities, consideration shall be given to the impact upon the overall environmental quality including air, water, land use, and aesthetics.

(c) Wherever minimum design criteria for waste treatment and control facilities set forth in this plan are more stringent than applicable federal standards and treatment levels currently being provided, upgrading to the more stringent requirements will be deferred until it is necessary to expand or otherwise modify or replace the existing treatment facilities. Such deferral will be acknowledged in the permit for the source.

(d) Where planning or design or construction of new or modified waste treatment and controls to meet prior applicable state or federal requirements is underway at the time this plan is adopted, such plans, design, or construction may be completed under the requirements in effect when the project was initiated. Timing for upgrading to meet more stringent future requirements will be as provided in section (3) above.

(4) Confined animal feeding operations shall be regulated pursuant to rules 340-51-005 through 340-51-080 in order to minimize potential adverse effect on water quality.

(5) Programs for control of pollution from non-point sources when developed by the Department, or by other agencies pursuant to Section 208 of Public Law 92-500 and approved by the Department, shall as applicable, be incorporated into this plan by amendment via the same process used to adopt the plan unless other procedures are established by law.

(6) Where minimum requirements of federal law or enforceable regulations are more stringent than specific provisions of this plan, the federal requirements shall prevail.

(7) Within a framework of state-wide priority and available resources, the Department will monitor water quality within the basin for the purposes of evaluating conformance with the plan and developing information for future additions or updating.

(8) The EQC recognizes that the potential exists for conflicts between water quality management plans and the land use plans and resource management plans which local governments and other agencies must develop pursuant to law. In the event any such conflicts develop, it is the intent of the Department to meet with the local government or responsible agency to formulate proposed revisions to one or both so as to resolve the conflict. Revisions will be presented for adoption

via the same process used to adopt the plan unless other specific procedures are established by law.

Stat. Auth.: ORS Ch. 468
Hist: DEQ 128, f. & ef. 1-21-77

North Coast-Lower Columbia Basin

Beneficial Water Uses to be Protected

340-41-202 Water quality in the North Coast-Lower Columbia River Basin (see Figures 1 and 2) shall be managed to protect the recognized beneficial uses as indicated in Table 1.

Stat. Auth.: ORS Ch. 468
Hist: DEQ 128, f. & ef. 1-21-77

Water Quality Standards Not to be Exceeded (To be adopted pursuant to ORS 468.735 and enforceable pursuant to ORS 468.720, 468.990, and 468.992.)

340-41-205 (1) Notwithstanding the water quality standards contained below, the highest and best practicable treatment and/or control of wastes, activities, and flows shall in every case be provided so as to maintain dissolved oxygen and overall water quality at the highest possible levels and water temperatures, coliform bacteria concentrations, dissolved chemical substances, toxic materials, radioactivity, turbidities, color, odor, and other deleterious factors at the lowest possible levels.

(2) No wastes shall be discharged and no activities shall be conducted which either alone or in combination with other wastes or activities will cause violation of the following standards in the waters of the North Coast — Lower Columbia River Basin:

(a) Dissolved oxygen (DO):

(A) Fresh waters: DO concentrations shall not be less than percent of saturation at the seasonal low, or less than 95 percent of saturation in spawning areas during spawning, incubation, hatching, and fry stages of salmonid fishes.

(B) Marine and estuarine waters (outside of zones of upwelled marine waters naturally deficient in DO): DO concentrations shall not be less than 6 mg/l for estuarine waters, or less than saturation concentrations for marine waters.

(C) Columbia River: DO concentrations shall not be less than 90 percent of saturation.

(b) Temperature:

(A) Columbia River: No measurable increases shall be allowed outside of the assigned mixing zone, as measured relative to a control point immediately upstream from a discharge when stream temperatures are 68° F. or greater; or more than 0.5° F. increase due to a single-source discharge when receiving water temperatures are 67.5° F. or less; or more than 2° F. increase due to all sources combined when stream temperatures are 66° F. or less, except for specifically limited duration activities which may be authorized by DEQ under such conditions as DEQ and the Department of Fish and Wildlife may prescribe and which are necessary to accommodate legitimate uses or activities where temperatures in excess of this standard are unavoidable and all practical preventive techniques have been applied to minimize temperature rises. The Director shall hold a public hearing when a request for an exception to the temperature standard for a planned activity or discharge will in all probability adversely affect the beneficial uses.

(B) All other freshwater streams and tributaries thereto: No measurable increases shall be allowed outside of the assigned mixing zone, as measured relative to a control point immediately upstream from a discharge when stream temperatures are 58° F. or greater; or more than 0.5° F. increase due to single-source discharge when receiving water temperatures are 57.5° F. or less; or more than 2° F. increase due to all sources combined when stream temperatures are 56° F. or less, except for specifically limited duration activities which may be authorized by DEQ under such conditions as DEQ and the Department of Fish and Wildlife may prescribe and which are necessary to accommodate legitimate uses or activities where temperatures in excess of this standard are unavoidable and all practical preventive techniques have been applied to minimize temperature rises. The Director shall hold a public hearing when a request for an exception to the temperature standard for a planned activity or discharge will in all probability adversely affect the beneficial uses.

(C) Marine and estuarine waters: No significant increase above natural background temperatures shall be allowed, and water temperatures shall not be altered to a degree which creates or can reasonably be expected to create an adverse effect on fish or other aquatic life.

(c) Turbidity (Jackson Turbidity Units, JTU): No more than a 10 percent cumulative increase in natural stream turbidities shall be allowed, as measured relative to a control point immediately upstream of the turbidity causing activity. However, limited duration activities necessary to address an emergency or to accommodate essential dredging, construction or other legitimate activities and which cause the standard to be exceeded may be authorized provided all practicable turbidity control techniques have been applied and one of the following has been granted:

(A) Emergency activities: Approval coordinated by DEQ with the Department of Fish and Wildlife under conditions they may prescribe to accommodate response to emergencies or to protect public health and welfare.

(B) Dredging, Construction or other Legitimate Activities: Permit or certification authorized under terms of Section 401 or 404 (Permits and Licenses, Federal Water Pollution Control Act) or OAR 141-85-100 et seq. (Removal and Fill Permits, Division of State Lands), with limitations and conditions governing the activity set forth in the permit or certificate.

(d) pH (hydrogen ion concentration): pH values shall not fall outside the following ranges:

(A) Marine waters: 7.0 — 8.5.

(B) Estuarine and fresh waters: 6.5 — 8.5.

(e) Organisms of the coliform group where associated with fecal sources (MPN or equivalent MF using a representative number of samples):

(A) Columbia River from the Highway 5 bridge between Vancouver and Portland to the mouth: A log mean of 200 fecal coliform per 100 milliliters based on a minimum of 5 samples in a 30-day period with no more than 10 percent of the samples in the 30-day period exceeding 400 per 100 ml.

(B) Marine waters and estuarine shellfish growing waters: A fecal coliform median concentration of 14 organisms per 100 milliliters, with not more than 10 percent of the samples exceeding 43 organisms per 100 ml.

(C) Estuarine waters other than shellfish growing waters: A log mean of 200 fecal coliform per 100 milliliters based on a minimum of 5 samples in a 30-day period with no more than 10 percent of the samples in the 30-day period exceeding 400 per 100 ml.

(f) Bacterial pollution or other conditions deleterious to waters used for domestic purposes, livestock watering, irrigation, bathing, or shellfish propagation, or otherwise injurious to public health shall not be allowed.

(g) The liberation of dissolved gases, such as carbon-dioxide, hydrogen sulfide, or other gases, in sufficient quantities to cause objectionable odors or to be deleterious to fish or other aquatic life, navigation, recreation, or other reasonable uses made of such waters shall not be allowed.

(h) The development of fungi or other growths having a deleterious effect on stream bottoms, fish or other aquatic life,

or which are injurious to health, recreation, or industry shall not be allowed.

(i) The creation of tastes or odors or toxic or other conditions that are deleterious to fish or other aquatic life or affect the potability of drinking water or the palatability of fish or shellfish shall not be allowed.

(j) The formation of appreciable bottom or sludge deposits or the formation of any organic or inorganic deposits deleterious to fish or other aquatic life or injurious to public health, recreation, or industry shall not be allowed.

(k) Objectionable discoloration, scum, oily sleek, or floating solids, or coating of aquatic life with oil film shall not be allowed.

(l) Aesthetic conditions offensive to the human senses of sight, taste, smell, or touch shall not be allowed.

(m) Radioisotope concentrations shall not exceed maximum permissible concentrations (MCP's) in drinking water, edible fishes or shellfishes, wildlife, irrigated crops, livestock and dairy products, or pose an external radiation hazard.

(n) The concentration of total dissolved gas relative to atmospheric pressure at the point of sample collection shall not exceed one hundred and ten percent (110%) of saturation, except when stream flow exceeds the 10-year, 7-day average flood. However, for Hatchery receiving waters and waters of less than 2 feet in depth, the concentration of total dissolved gas relative to atmospheric pressure at the point of sample collection shall not exceed one hundred and five percent (105%) of saturation.

(o) Dissolved chemical substances: Guide concentrations listed below shall not be exceeded unless otherwise specifically authorized by DEQ upon such conditions as it may deem necessary to carry out the general intent of this plan and to protect the beneficial uses set forth in rule 340-41-202:(mg/l)

Arsenic (As) ——— 0.01
Barium (Ba) ——— 1.0
Boron (Bo) ——— 0.5
Cadmium (Cd) ——— 0.003
Chromium (Cr) ——— 0.02
Copper (Cu) ——— 0.005
Cyanide (Cn) ——— 0.005
Fluoride (F) ——— 1.0
Iron (Fe) ——— 0.1
Lead (Pb) ——— 0.05
Manganese (Mn) ——— 0.05
Phenols (totals) ——— 0.001
Total dissolved solids —
Columbia River ——— 500.0
Total dissolved solids-all other fresh water streams and tributaries thereto ——— 100.0
Zinc (Zn) ——— 0.01

(p) Pesticides and other Organic Toxic Substances shall not exceed those criteria contained in the 1976 edition of the EPA publication "Quality Criteria for Water". These criteria shall apply unless supporting data show conclusively that beneficial uses will not be adversely affected by exceeding a criterion by a specific amount or that a more stringent criterion is warranted to protect beneficial uses.

(3) Where the natural quality parameters of waters of the North Coast — Lower Columbia River Basin are outside the numerical limits of the above assigned water quality standards, the natural water quality shall be the standard.

(4) Mixing zones:

(a) The Department may suspend the applicability of all or part of the water quality standards set forth in this rule, except those standards relating to aesthetic conditions, within a defined immediate mixing zone of specified and appropriately limited size adjacent to or surrounding the point of waste water discharge.

(b) The sole method of establishing such mixing zone shall be by the Department defining same in a waste discharge permit.

(c) In establishing a mixing zone in a waste discharge permit, the Department:

(A) May define the limits of the mixing zone in terms of distance from the point of the waste water discharge or the area or volume of the receiving water or any combination thereof;

(B) May set other less restrictive water quality standards to be applicable in the mixing zone in lieu of the suspended standards; and

(C) Shall limit the mixing zone to that which in all probability, will:

(i) Not interfere with any biological community or population of any important species to a degree which is damaging to the ecosystem; and

(ii) Not adversely affect any other beneficial use disproportionately.

(5) Testing methods: The analytical testing methods for determining compliance with the water quality standards contained in this rule shall be in accordance with the most recent edition of **Standard Methods for the Examination of Water and Waste Water published jointly by the American Public Health Association, American Water Works Association, and Water Pollution Control Federation**, unless the Department has published an applicable susperseding method, in which case testing shall be in accordance with the superseding method; provided, however, that testing in accordance with an alternative method shall comply with this rule if the Department has published the method or has approved the method in writing.

[**Publications:** The publication(s) referred to or incorporated by reference in this rule are available from the office of the Department of Environmental Quality.]

Stat. Auth.: ORS Ch. 468
Hist: DEQ 128, f. & ef. 1-21-77; DEQ 1-1980, f. & ef. 1-9-80

Minimum Design Criteria for Treatment and Control of Wastes

340-41-215 Subject to the implementation program set forth in rule 340-41-120, prior to discharge of any wastes from any new or modified facility to any waters of the North Coast — Lower Columbia River Basin, such wastes shall be treated and controlled in facilities designed in accordance with the following minimum criteria (In designing treatment facilities, average conditions and a normal range of variability are generally used in establishing design criteria. A facility once completed and placed in operation should operate at or near the design limit most of the time but may operate below the design criteria limit at times due to variables which are unpredictable or uncontrollable. This is particularly true for biological treatment facilities. The actual operating limits are intended to be established by permit pursuant to ORS 468.740 and recognize that the actual performance level may at times be less than the design criteria.):

(1) Sewage wastes:

(a) During periods of low stream flows (approximately May 1 to October 31): Treatment resulting in monthly average effluent concentrations not to exceed 20 mg/l of BOD and 20 mg/l of SS or equivalent control.

(b) During the period of high stream flows (approximately November 1 to April 30) and for direct ocean discharges: A minimum of secondary treatment or equivalent control and unless otherwise specifically authorized by the Department, operation of all waste treatment and control facilities at maximum practicable efficiency and effectiveness so as to minimize waste discharges to public waters.

(c) Effluent BOD concentrations in mg/l, divided by the dilution factor (ratio of receiving stream flow to effluent flow) shall not exceed one (1) unless otherwise approved by the EQC.

(d) Sewage wastes shall be disinfected, after treatment, equivalent to thorough mixing with sufficient chlorine to provide a residual of at least 1 part per million after 60 minutes of contact time unless otherwise specifically authorized by permit.

(e) Positive protection shall be provided to prevent bypassing raw or inadequately treated sewage to public waters unless otherwise approved by the Department where elimination of inflow and infiltration would be necessary but not presently practicable.

(f) More stringent waste treatment and control requirements may be imposed where special conditions may require.

(2) Industrial wastes:

(a) After maximum practicable inplant control, a minimum of secondary treatment or equivalent control (reduction of suspended solids and organic material where present in significant quantities, effective disinfection where bacterial organisms of public health significance are present, and control of toxic or other deleterious substances).

(b) Specific industrial waste treatment requirements shall be determined on an individual basis in accordance with the provisions of this plan, applicable federal requirements, and the following:

(A) The uses which are or may likely be made of the receiving stream;

(B) The size and nature of flow of the receiving stream;

(C) The quantity and quality of wastes to be treated; and

(D) The presence or absence of other sources of pollution on the same watershed.

(c) Where industrial, commercial, or agricultural effluents contain significant quantities of potentially toxic elements, treatment requirements shall be determined utilizing appropriate bioassays.

(d) Industrial cooling waters containing significant heat loads shall be subjected to offstream cooling or heat recovery prior to discharge to public waters.

(e) Positive protection shall be provided to prevent bypassing of raw or inadequately treated industrial wastes to any public waters.

(f) Facilities shall be provided to prevent and contain spills of potentially toxic or hazardous materials and a positive program for containment and cleanup of such spills should they occur shall be developed and maintained.

Stat. Auth.: ORS Ch. 468
Hist: DEQ 128, f. & ef. 1-21-77

Mid Coast Basin

Beneficial Water Uses to be Protected

340-41-242 Water quality in the Mid Coast Basin (see Figures 1 and 3) shall be managed to protect the recognized beneficial uses as indicated in Table 2.

Stat. Auth.: ORS Ch. 468
Hist: DEQ 128, f. & ef. 1-21-77

Water Quality Standards Not to be Exceeded (To be adopted pursuant to ORS 468.735 and enforceable pursuant to ORS 468.720, 468.990, and 468.992.)

340-41-245 (1) Notwithstanding the water quality standards contained below, the highest and best practicable treatment and/or control of wastes, activities, and flows shall in every case be provided so as to maintain dissolved oxygen and overall water quality at the highest possible levels and water temperatures, coliform bacteria concentrations, dissolved chemical substances, toxic materials, radioactivity, turbidities, color, odor, and other deleterious factors at the lowest possible levels.

(2) No wastes shall be discharged and no activities shall be conducted which either alone or in combination with other wastes or activities will cause violation of the following standards in the waters of the Mid Coast Basin:

(a) Dissolved oxygen (DO):

(A) Fresh waters: DO concentrations shall not be less than 90 percent of saturation at the seasonal low, or less than 95 percent of saturation in spawning areas during spawning, incubation, hatching, and fry stages of salmonid fishes.

(B) Marine and estuarine waters (outside of zones of upwelled marine waters naturally deficient in DO): DO concentrations shall not be less than 6 mg/l for estuarine waters, or less than saturation concentrations for marine waters.

(b) Temperature:

(A) Fresh waters: No measurable increases shall be allowed outside of the assigned mixing zone, as measured relative to a control point immediately upstream from a discharge when stream temperatures are 64° F. or greater; or more than 0.5° F. increase due to a single-source discharge when receiving water temperatures are 63.5° F. or less; or more than 2° F. increase due to all sources combined when stream temperatures are 62° F. or less, except for specifically limited duration activities which may be authorized by DEQ under such conditions as DEQ and the Department of Fish and Wildlife may prescribe and which are necessary to accommodate legitimate uses or activities where temperatures in excess of this standard are unavoidable and all practical preventive techniques have been applied to minimize temperature rises. The Director shall hold a public hearing when a request for an exception to the temperature standard for a planned activity or discharge will in all probability adversely affect the beneficial uses.

(B) Marine and estuarine waters: No significant increase above natural background temperatures shall be allowed, and water temperatures shall not be altered to a degree which creates or can reasonably be expected to create an adverse effect on fish or other aquatic life.

(c) Turbidity (Jackson Turbidity Units, JTU): No more than a 10 percent cumulative increase in natural stream turbidities shall be allowed, as measured relative to a control point immediately upstream of the turbidity causing activity. However, limited duration activities necessary to address an emergency or to accommodate essential dredging, construction or other legitimate activities and which cause the standard to be exceeded may be authorized provided all practicable turbidity control techniques have been applied and one of the following has been granted:

(A) Emergency activities: Approval coordinated by DEQ with the Department of Fish and Wildlife under conditions they may prescribe to accommodate response to emergencies or to protect public health and welfare.

(B) Dredging, Construction or other Legitimate Activities: Permit or certification authorized under terms of Section 401 or 404 (Permits and Licenses, Federal Water Pollution Control Act) or OAR 141-85-100 et seq. (Removal and Fill Permits, Division of State Lands), with limitations and conditions governing the activity set forth in the permit or certificate.

(d) pH (hydrogen ion concentration): pH values shall not fall outside the following ranges:

(A) Marine waters: 7.0 — 8.5.

(B) Estuarine and fresh waters: 6.5 — 8.5.

(e) Organisms of the coliform group where associated with fecal sources (MPN or equivalent MF using a representative number of samples):

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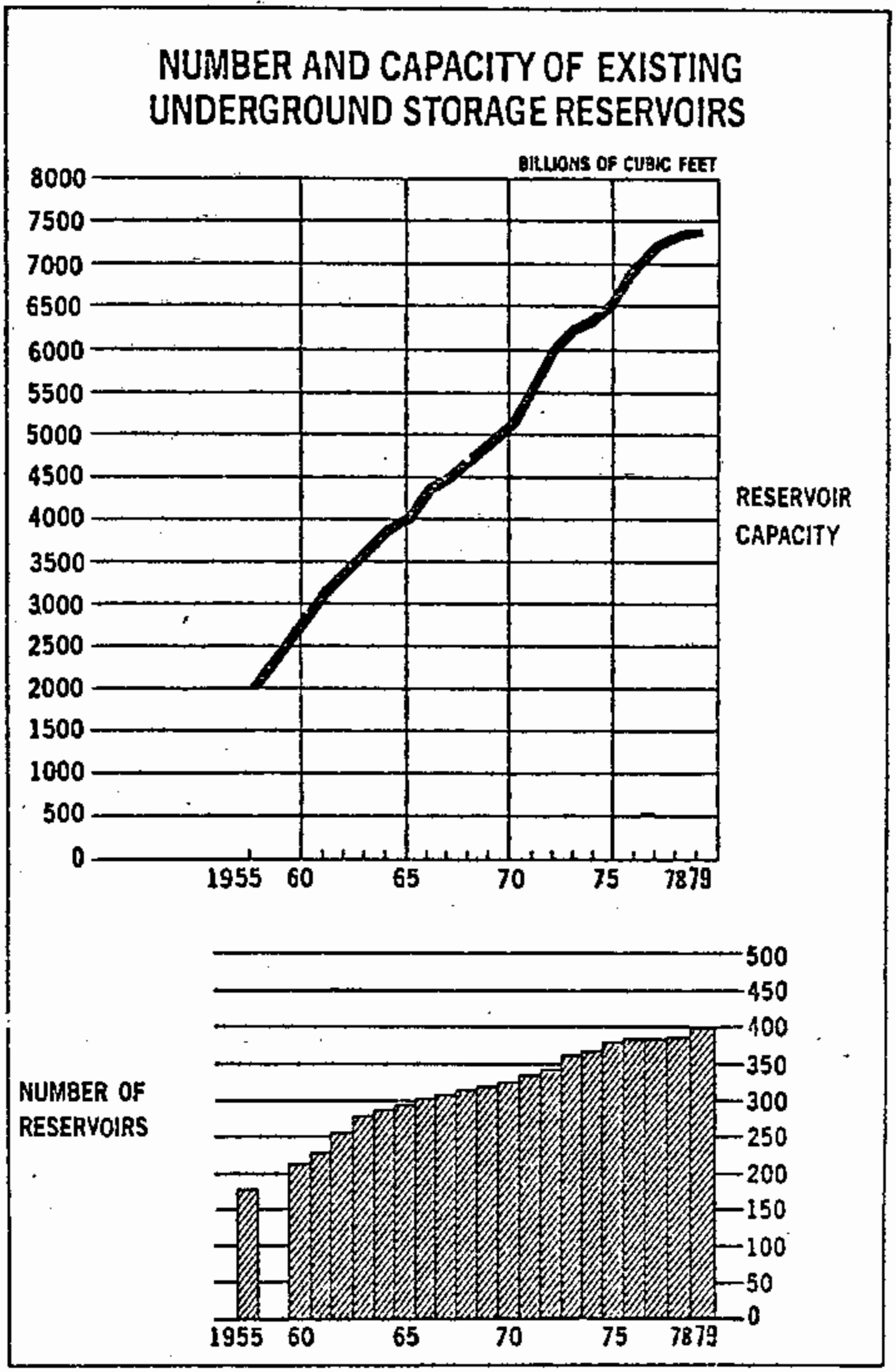
CHART 9



REFERENCE: TABLE 37

UNDERGROUND STORAGE

TABLE 40
INPUTS, OUTPUTS, AND GAS IN UNDERGROUND STORAGE, BY STATE, 1979
(Millions of cubic feet—14.73 psia at 60°F.)

Division and State	Input to Storage	Output from Storage	Native Gas	Stored Gas	Maximum Stored Gas	Maximum Day Output
	Year Ending December 31, 1979					
United States	2,285,016	2,057,019	1,055,966	5,036,559	5,459,523	37,555
New England	0	0	0	0	0	0
Connecticut	0	0	0	0	0	0
Maine	0	0	0	0	0	0
Massachusetts	0	0	0	0	0	0
New Hampshire	0	0	0	0	0	0
Rhode Island	0	0	0	0	0	0
Vermont	0	0	0	0	0	0
Middle Atlantic	403,673	373,294	44,177	756,125	806,054	6,130
New Jersey	0	0	0	0	0	0
New York	46,439	40,110	15,524	115,436	119,341	715
Pennsylvania	357,234	333,184	28,653	640,689	686,713	5,415
East North Central	897,924	777,967	375,461	1,887,641	2,036,266	12,955
Illinois	253,320	209,924	11,508	829,864	849,053	4,376
Indiana	27,177	23,709	20,622	92,302	94,026	489
Michigan	424,176	364,649	257,989	566,159	648,145	5,190
Ohio	193,251	179,685	85,342	399,316	445,042	2,900
Wisconsin	0	0	0	0	0	0
West North Central	150,025	124,348	42,976	427,534	453,276	1,826
Iowa	70,967	61,018	0	231,989	245,494	803
Kansas	59,148	52,028	19,984	110,396	122,276	851
Minnesota	987	668	0	4,601	4,687	43
Missouri	8,836	7,583	0	29,354	29,354	—
Nebraska	10,087	3,051	22,992	51,194	51,465	129
North Dakota	0	0	0	0	0	0
South Dakota	0	0	0	0	0	0
South Atlantic	192,775	178,767	65,868	447,622	464,956	3,620
Delaware	0	0	0	0	0	0
Dist. of Columbia	0	0	0	0	0	0
Florida	0	0	0	0	0	0
Georgia	0	0	0	0	0	0
Maryland	19,715	19,448	32,456	27,671	29,522	1,017
North Carolina	0	0	0	0	0	0
South Carolina	0	0	0	0	0	0
Virginia	0	0	0	0	0	0
West Virginia	173,060	159,319	33,412	419,951	435,434	2,603
East South Central	129,558	130,428	105,552	188,396	279,415	2,406
Alabama	0	0	0	0	0	0
Kentucky	68,961	63,328	78,229	117,854	197,703	1,174
Mississippi	60,597	67,100	27,323	70,542	81,712	1,232
Tennessee	0	0	0	0	0	0
West South Central	335,193	317,081	180,625	802,344	865,216	4,827
Arkansas	2,081	2,693	23,674	12,653	12,853	70
Louisiana	140,433	141,487	58,199	303,174	331,698	2,105
Oklahoma	110,354	103,983	25,662	266,951	289,280	1,726
Texas	82,325	68,918	73,090	219,566	231,385	926
Mountain	61,013	53,806	88,213	228,317	235,199	1,012
Arizona	0	0	0	0	0	0
Colorado	25,334	21,193	16,008	30,722	34,489	533
Idaho	0	0	0	0	0	0
Montana	23,254	15,497	46,938	128,225	129,109	187
Nevada	0	0	0	0	0	0
New Mexico	39	7,687	11,700	13,763	21,439	84
Utah	1,193	966	0	4,510	4,664	20
Wyoming	11,193	8,465	13,567	43,077	45,498	188
Pacific	114,854	101,329	153,093	306,577	319,143	4,780
Alaska	0	0	0	0	0	0
California	100,522	88,924	153,093	276,689	286,936	4,492
Hawaii	0	0	0	0	0	0
Oregon	0	0	0	0	0	0
Washington	14,332	12,405	0	29,888	32,207	288

Source: Same as Table 37.

TABLE 41
NUMBER OF POOLS, WELLS, COMPRESSOR STATIONS, AND HORSEPOWER IN UNDERGROUND STORAGE FIELDS, BY STATE, 1977-1979

	Number of Pools			Number of Active Wells		
Divison and State	1977	1978	1979	1977	1978	1979
(1) United States	385	388	399	16,928	17,297	17,605
(2) New England	0	0	0	0	0	0
(3) Middle Atlantic	86	86	95	2,855	2,821	3,012
(4) New Jersey	0	0	0	0	0	0
(5) New York	19	19	20	763	762	928
(6) Pennsylvania	67	67	75	2,092	2,059	2,084
(7) East North Central	126	127	128	8,437	8,640	8,725
(8) Illinois	31	31	33	1,669	1,717	1,724
(9) Indiana	27	28	30	902	928	951
(10) Michigan	45	45	42	2,731	2,830	2,867
(11) Ohio	23	23	23	3,135	3,165	3,183
(12) Wisconsin	0	0	0	0	0	0
(13) West North Central	29	29	31	1,368	1,387	1,386
(14) Iowa	8	8	9	414	424	424
(15) Kansas	17	17	18	780	780	772
(16) Minnesota	1	1	1	46	55	61
(17) Missouri	1	1	1	82	82	82
(18) Nebraska	2	2	2	46	46	47
(19) North Dakota	0	0	0	0	0	0
(20) South Dakota	0	0	0	0	0	0
(21) South Atlantic	39	39	38	1,573	1,594	1,595
(22) Delaware	0	0	0	0	0	0
(23) District of Columbia	0	0	0	0	0	0
(24) Florida	0	0	0	0	0	0
(25) Georgia	0	0	0	0	0	0
(26) Maryland	1	1	1	74	77	79
(27) North Carolina	0	0	0	0	0	0
(28) South Carolina	0	0	0	0	0	0
(29) Virginia	0	0	0	0	0	0
(30) West Virginia	38	38	37	1,499	1,517	1,516
(31) East South Central	27	27	27	1,279	1,298	1,297
(32) Alabama	0	0	0	0	0	0
(33) Kentucky	23	23	23	1,185	1,201	1,197
(34) Mississippi	4	4	4	94	97	100
(35) Tennessee	0	0	0	0	0	0
(36) West South Central	41	43	43	649	751	750
(37) Arkansas	5	5	5	22	22	23
(38) Louisiana	6	6	6	142	193	191
(39) Oklahoma	12	13	14	252	281	281
(40) Texas	18	19	18	233	255	256
(41) Mountain	26	26	26	311	329	354
(42) Arizona	0	0	0	0	0	0
(43) Colorado	7	7	8	85	99	122
(44) Idaho	0	0	0	0	0	0
(45) Montana	5	5	5	134	137	137
(46) Nevada	0	0	0	0	0	0
(47) New Mexico	2	2	2	46	46	47
(48) Utah	2	2	2	15	15	15
(49) Wyoming	10	10	9	31	32	33
(50) Pacific	11	11	11	456	477	486
(51) Alaska	0	0	0	0	0	0
(52) California	9	9	9	380	400	409
(53) Hawaii	0	0	0	0	0	0
(54) Oregon	0	0	0	0	0	0
(55) Washington	2	2	2	76	77	77

Source: Same as Table 37.

TABLE 41 (Continued)
NUMBER OF POOLS, WELLS, COMPRESSOR STATIONS, AND HORSEPOWER
IN UNDERGROUND STORAGE FIELDS, BY STATE, 1977–1979

Number of Compressor Stations			Total HP Installed in Compressor Stations			
1977	1978	1979	1977	1978	1979	
263	278	283	1,374,141	1,495,712	1,604,552	(1)
0	0	0	0	0	0	(2)
58	59	62	222,470	222,410	256,670	(3)
0	0	0	0	0	0	(4)
12	12	13	27,050	27,050	30,450	(5)
46	47	49	195,420	195,360	226,220	(6)
80	82	86	592,370	616,071	883,261	(7)
28	27	27	203,425	217,435	217,795	(8)
12	15	19	18,210	18,901	19,651	(9)
22	22	22	291,960	300,960	566,480	(10)
18	18	18	78,775	78,775	79,335	(11)
0	0	0	0	0	0	(12)
16	16	18	80,820	83,136	81,810	(13)
4	4	4	39,000	43,000	41,680	(14)
8	8	10	21,620	19,930	19,930	(15)
1	1	1	2,400	2,400	2,400	(16)
1	1	1	8,850	8,850	8,850	(17)
2	2	2	8,950	8,950	8,950	(18)
0	0	0	0	0	0	(19)
0	0	0	0	0	0	(20)
20	20	22	88,760	88,760	92,760	(21)
0	0	0	0	0	0	(22)
0	0	0	0	0	0	(23)
0	0	0	0	0	0	(24)
0	0	0	0	0	0	(25)
1	1	1	11,000	11,000	11,000	(26)
0	0	0	0	0	0	(27)
0	0	0	0	0	0	(28)
0	0	0	0	0	0	(29)
19	19	21	77,760	77,760	81,760	(30)
20	20	20	71,910	72,010	72,010	(31)
0	0	0	0	0	0	(32)
16	17	17	36,110	36,210	36,210	(33)
4	3	3	35,850	35,800	35,800	(34)
0	0	0	0	0	0	(35)
36	39	41	159,174	227,184	227,944	(36)
5	5	5	1,470	1,470	1,470	(37)
6	6	6	64,400	94,200	93,640	(38)
9	10	10	51,019	71,469	73,219	(39)
16	18	20	42,285	60,045	59,615	(40)
22	23	23	61,437	58,937	62,867	(41)
0	0	0	0	0	0	(42)
6	6	7	23,995	25,095	29,025	(43)
0	0	0	0	0	0	(44)
5	5	5	22,340	23,150	23,150	(45)
0	0	0	0	0	0	(46)
2	2	1	5,200	800	800	(47)
1	2	2	1,200	1,200	1,200	(48)
8	8	8	8,692	8,692	8,692	(49)
11	11	11	97,210	127,210	127,230	(50)
0	0	0	0	0	0	(51)
10	10	10	85,410	115,410	115,430	(52)
0	0	0	0	0	0	(53)
0	0	0	0	0	0	(54)
1	1	1	11,800	11,800	11,800	(55)

TABLE 42
ULTIMATE CAPACITY OF EXISTING RESERVOIRS, BY STATE, 1979*

(Millions of cubic feet—14.73 psia at 60°F.)

Division and State	Cushion Gas			Working Gas	Ultimate Reservoir Capacity
	Native	Injected	Total		
United States	1,045,594	2,280,806	3,326,400	2,766,124	7,436,818
New England	0	0	0	0	0
Connecticut	0	0	0	0	0
Maine	0	0	0	0	0
Massachusetts	0	0	0	0	0
New Hampshire	0	0	0	0	0
Rhode Island	0	0	0	0	0
Vermont	0	0	0	0	0
Middle Atlantic	44,177	371,685	415,863	384,441	908,749
New Jersey	0	0	0	0	0
New York	15,524	62,946	78,470	52,491	151,139
Pennsylvania	28,653	308,739	337,393	331,950	757,610
East North Central	367,149	983,869	1,351,019	912,084	2,837,018
Illinois	11,369	516,015	527,384	313,988	1,098,037
Indiana	20,622	56,353	76,975	35,949	172,784
Michigan	249,816	155,076	404,893	419,256	946,234
Ohio	85,342	256,425	341,767	142,891	619,963
Wisconsin	0	0	0	0	0
West North Central	42,976	209,741	252,716	217,793	666,838
Iowa	0	117,751	117,751	114,238	354,500
Kansas	19,984	73,711	93,694	36,685	154,225
Minnesota	0	3,000	3,000	1,601	20,000
Missouri	0	11,759	11,759	17,595	45,000
Nebraska	22,992	3,520	26,512	47,674	93,113
North Dakota	0	0	0	0	0
South Dakota	0	0	0	0	0
South Atlantic	65,868	241,085	306,954	206,537	573,871
Delaware	0	0	0	0	0
Dist. of Col.	0	0	0	0	0
Florida	0	0	0	0	0
Georgia	0	0	0	0	0
Maryland	32,456	12,438	44,893	15,233	64,770
North Carolina	0	0	0	0	0
South Carolina	0	0	0	0	0
Virginia	0	0	0	0	0
West Virginia	33,412	228,647	262,059	191,304	509,101
East South Central	104,550	47,104	151,654	142,294	315,366
Alabama	0	0	0	0	0
Kentucky	77,227	28,337	105,564	90,519	206,003
Mississippi	27,323	18,767	46,090	51,775	109,363
Tennessee	0	0	0	0	0
West South Central	179,638	298,392	478,030	504,938	1,193,399
Arkansas	23,674	0	23,674	12,653	42,145
Louisiana	58,199	160,131	218,330	143,043	420,814
Oklahoma	25,662	121,378	147,040	145,573	375,471
Texas	72,103	16,883	88,986	203,669	354,969
Mountain	88,213	38,011	126,224	183,306	409,911
Arizona	0	0	0	0	0
Colorado	16,008	10,588	26,596	20,134	56,420
Idaho	0	0	0	0	0
Montana	46,938	15,200	62,138	113,025	219,612
Nevada	0	0	0	0	0
New Mexico	11,700	6,543	18,243	7,240	34,577
Utah	0	2,740	2,740	1,770	4,914
Wyoming	13,567	2,940	16,507	40,137	94,388
Pacific	153,022	90,918	243,940	215,730	531,665
Alaska	0	0	0	0	0
California	153,022	70,518	223,540	206,242	499,458
Hawaii	0	0	0	0	0
Oregon	0	0	0	0	0
Washington	0	20,400	20,400	9,488	32,207

*In some states or regions, the difference between the sum of the components and Ultimate Reservoir Capacity represents presently unused capacity.

Source: Same as Table 37.