**SUPPLEMENTARY INFORMATION:** A notice of proposed rulemaking concerning this amendment was published in the Federal Register on April 21, 1980 (45 FR 26722). Interested persons were invited to submit comments on the proposal by June 5, 1980. Two comments were received from sources outside of the Coast Guard. Both of these favored the proposal's adoption. The Coast Guard is issuing it as a final rule without change.

**Drafting Information**

The principal persons involved in drafting this amendment are Mr. Donald L. Ewing, Project Manager, Office of Merchant Marine Safety, and Mr. Coleman Sachs, Project Counsel, Office of the Chief Counsel.

This amendment has been reviewed and determined to be nonsignificant under the Department of Transportation's Regulatory Policies and Procedures published on February 26, 1979 (44 FR 11034). A final evaluation has been prepared and included in the public docket. This may be obtained from the Marine Safety Council (G-CMC/24), Coast Guard Headquarters, Washington, D.C. 20593, (202) 755-4901.

In consideration of the foregoing, Part 44 of Title 46, Code of Federal Regulations is amended as set forth below.

1. By revising § 44.01-12(b) (2) and (3) to read as follows:

**§ 44.01-12 Voyage limits; special service.**

* * * * *

(b) * * *

(2) Southeast Atlantic Coast—from Key West, Florida, to Jacksonville, Florida, except that the special service load line is not valid for manned vessels during the hurricane season, i.e., July 1st to November 15th, both dates inclusive, unless the vessel is operated in accordance with a Coast Guard approved heavy weather plan.

(3) Gulf of Mexico Coast—from the mouth of the Rio Grande River, Texas, to Key West, Florida, except that the special service load line is not valid for manned vessels during the hurricane season, i.e., July 1st to November 15th, both dates inclusive, unless the vessel is operated in accordance with a Coast Guard approved heavy weather plan.

* * * * *

2. By adding a new § 44.01-13 to read as follows:

**§ 44.01-13 Heavy weather plan.**

(a) Each heavy weather plan under § 44.01-12(b) must be prepared by the vessel owner or operator and approved by the cognizant Officer in Charge, Marine Inspection. Approval of a heavy weather plan is limited to the current hurricane season.

(b) The cognizant Officer in Charge, Marine Inspection, is—

(1) The Officer in Charge, Marine Inspection, within whose area the work site is located for a vessel that will be operating in a limited geographical area; or

(2) The Officer in Charge, Marine Inspection, within whose area the point of departure is located for a transiting vessel.

(c) The required content of the heavy weather plan is determined on a case-by-case basis by the cognizant Officer in Charge, Marine Inspection, based on knowledge of the local conditions. The heavy weather plan may contain weather radio frequencies and time schedules for seeking a harbor of safe refuge. A single heavy weather plan may be accepted for more than one vessel operating at a single work site or on a single route.

(d) The vessel owner or operator must place a copy of the heavy weather plan on each vessel to which it applies and ensure that it remains there throughout the hurricane season.

(46 U.S.C. 88a, 49 CFR 1.46(b))

Dated: August 20, 1980.

Henry H. Bell,

*Rear Admiral, U.S. Coast Guard, Chief, Office of Merchant Marine Safety.*

[FR Doc. 80-26421 Filed 8-27-80; 8:45 am]

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## Research and Special Programs Administration

## 49 CFR Part 193

**[Amdt. 193-1; Docket OPSO-46]**

## Liquefied Natural Gas Facilities; Reconsideration of Safety Standards for Siting, Design, and Construction

**AGENCY:** Materials Transportation Bureau (MTB), DOT.

**ACTION:** Final rule.

**SUMMARY:** Final rules were issued on the siting, design, and construction of Liquefied Natural Gas (LNG) facilities on January 30, 1980. In response to petitions for reconsideration, MTB is amending several sections of the final rules. These amendments are: (1) To clarify that any subsequent changes in "existing LNG facilities," as defined by the Pipeline Safety Act of 1979, including expansion of capacity, if made pursuant to an application for approval filed before March 1, 1978, would not be subject to Part 193 siting requirements; (2) to provide that the Director will respond within 90 days to a petition for finding or approval unless the petitioner is otherwise notified; (3) to exclude "pipeline facilities" of the operator from thermal radiation protection requirements; (4) to clarify the vaporization rate for a design spill from a transfer line that penetrates an LNG storage tank below its liquid level; (5) to require the Director's approval for siting LNG storage tanks in certain areas of high seismic activity; (6) to modify the criteria for identification of a high seismic area, where the Director's approval for siting an LNG storage tank is required; (7) to make only impounding systems for LNG storage tanks subject to requirements relating to penetration by wind borne missiles; (8) to establish a 200 mph wind speed as an upper limit in designing for wind forces; (9) to clarify that any ultraviolet decay of insulation must not be detrimental to the insulation; (10) to clarify that only valves for use in controllable emergencies must have powered local and remote operating capabilities; (11) to clarify the dimensions required for dikes; and (12) to provide that only LNG storage tanks must meet the protection requirements for shared impoundment. MTB has also amended the scope of Part 193 to be consistent with the siting provisions of the memorandum of understanding with the U.S. Coast Guard, amended the definition of "LNG facility" to be consistent with the definition of this term in the Pipeline Safety Act of 1979; and changed the title and scope of Subpart B to refer to "Siting Requirements."

**EFFECTIVE DATES:** Because this document clarifies or relaxes requirements currently in effect, it is advantageous for industry to begin compliance without delay. Therefore, the final rules are effective August 28, 1980. In addition, the recordkeeping requirements of §§ 193.2119 and 193.2329, and any recordkeeping requirements incorporated by reference in Part 193, adopted as final rules in 45 FR 9184, become effective September 29, 1980.

**FOR FURTHER INFORMATION CONTACT:** Walter Dennis, (202) 426-2392.

**SUPPLEMENTARY INFORMATION:** Final rules were published February 11, 1980, establishing standards for the siting, design, and construction of LNG facilities (45 FR 9184) in a new Part 193. These standards were issued under the Natural Gas Pipeline Safety Act of 1968, as amended by Title I of the Pipeline Safety Act of 1979 (49 U.S.C. 1671 et seq.)(the Act).

Earlier regulatory actions preceding issuance of the final rules were: (1) An advance notice of proposed rulemaking (ANPRM) (42 FR 20776, April 21, 1977), (2) A notice of proposed rulemaking (NPRM) (44 FR 8142, February 8, 1979), (3) A conference with Western LNG Terminal Associates (Western) *et al.*, held in Washington, DC, on April 24 and 25, 1979, and (4) a meeting of the Technical Pipeline Safety Standards Committee (TPSSC) held in Cambridge, Massachusetts, on June 12–15, 1979.

After the final rules were issued, the American Gas Association (AGA), Interstate Natural Gas Association of America (INGAA), and Western filed petitions for reconsideration of certain provisions in the new standards under 49 CFR Part 106. In aggregate, the petitions apply to 22 specific provisions, appearing in 16 separate sections of Part 193. Also, Western requests reconsideration of the final rules on the basis of several procedural issues.

Following receipt of the petitions for reconsideration, in accord with MTB procedures in 49 CFR 106.37, MTB sought comments on the petitions from several interested parties. Persons who commented on specific features of the petitions, either solicited or unsolicited, were:

Ted Stevens, U.S. Senator from Alaska (Stevens);
Harold T. Johnson, U.S. Representative from California (Johnson);
Robert B. Duncan, U.S. Representative from Oregon (Duncan);
The State of Alaska (Alaska);
Hollister Ranch Owners Association (Hollister);
Santa Barbara Citizens for Environmental Defense (Citizens);
Bixby Ranch (Bixby);
Sierra Club (Sierra);
James F. Devine, Acting Assistant Director of Engineering Geology, U.S. Geological Survey (Devine);
Federal Energy Regulatory Commission Staff (FERC); and Dr. Nathan M. Newmark, Consulting Engineering Services, (expert witness on seismic design for Western) (Newmark).

Except for FERC, which addressed all aspects of the petitions, the comments focused mainly on the prohibition under § 193.2061(f) against siting LNG facilities in certain areas of high seismic activity.

Both the petitioners and some commenters reference testimony given at the conference with Western *et al* in April, 1979, by expert witnesses, Newmark:

Dr. Robert D. Hanson, Chairman, Department of Civil Engineering, University of Michigan, (Hanson); and
Dr. Richard Jahns, Dean, School of Earth Sciences, Stanford University, (Jahns).

The disposition of the petitions together with the reasons for granting or denying aspects of the petitions or the basis for other decisions and the resulting amended rules follow:

General

In Part III of its petition (Parts I & II are discussed hereafter), Western asks that MTB reconsider several procedural issues and objections relating to this proceeding. While some of these matters have already been specifically answered by MTB, Western raises them to preserve its future rights in the event of court action. A brief response to each of these issues and objections follows.

*A. Analysis or Evaluation*

Western argues that a "Regulatory Analysis" instead of an "Evaluation" should have been prepared because the final rules will result in substantial compliance costs for the LNG industry and perhaps significantly impact consumer costs. Under the applicable Departmental procedures (43 FR 9582, March 8, 1978), a Regulatory Analysis is required for regulations that could result in a major effect on the general economy in terms of costs, consumer prices, or production, or could result in a major increase in costs or prices for individual industries, levels of government, or geographic regions. An Evaluation is required for all other regulations. Using figures from the Final Evaluation, the total annualized costs of the final rules to build from 6 to 64 facilities range from $8.4 million to $17.4 million yearly over a 20-year period. Even though Western characterizes these costs as "substantial," by any reasonable measure (there is none given in the procedures) they are not high enough to cause a "major effect" either on the general economy or the regulated LNG industry. Therefore, MTB's preparation of an Evaluation was proper under the Departmental procedures.

*B. Conclusions of the Evaluation*

The Final Evaluation concluded that eight sections in Part 193 have costs that exceed benefits. Western argues that adoption of these sections as final rules disregards the cost/benefit conclusions and makes the rules unreasonable and impracticable. This argument is equivalent to saying that MTB may not adopt a rule unless it is proven to be cost beneficial. Neither Executive Order 12044 nor the Departmental procedures support such a conclusion. There are many factors to be considered in deciding whether a rule should be adopted, of which compliance costs in comparison to quantifiable benefits is but one. Other factors include the need for the rule, the safety objectives to be attained, the effectiveness of the rule, the burdens it imposes, and its technical feasibility. Certainly no one of these factors should be determinative of reasonableness as Western suggests. Furthermore, MTB did not disregard the cost/benefit conclusions. A discussion of the need for the rules in light of the conclusions is included in the preamble to the final rules for each affected section.

*C. Sufficiency of Economic Data*

Western asserts that the data regarding the economic impacts of the final rules were insufficient for MTB to properly analyze the economic effects or consider alternatives. Although this assertion is made without foundation or examples of deficiencies, it is important to note that Departmental procedures do not require that any particular methodology be used in making an economic analysis. The use of a particular methodology, including the data for analysis, is left to the discretion of the agency concerned, subject, of course, to public scrutiny at the draft stage. MTB notes that Western did not raise this point when the Draft Evaluation was available for comment.

*D. Advisory Committee Review*

Western charges that MTB's handling of the advisory committee review of the proposed rules as required by section 4 of the Act was irregular in several respects: (1) The Committee lacked full membership, (2) The Committee's views were obtained, in part, by letter ballot rather than through direct discussion, and (3) MTB did not submit to the Committee for consideration proposed rules that, after their initial submission to the Committee, were later modified in a manner not approved by the Committee. MTB finds nothing in either section 4 of the Act or the Committee charter that would lend merit to any of Western's charges. The charter specifically authorizes Committee action by a majority of current members present and by letter ballot in lieu of discussion. The full intent of section 4 of the Act was met when MTB submitted all the proposed LNG rules to the Committee for review, and the Committee openly considered them at a 4-day meeting (June 12–15, 1979). Section 4 specifically permits MTB to make a final decision on proposed rules, after considering Committee views and explaining why any views are not adopted. After an initial review by the Committee, to return to the Committee for further comment in the mandatory sense suggested by Western would be equivalent to unlawfully relinquishing the final decisionmaking role to the Committee, since MTB could, under those conditions, never independently make a final rule.

*E. Statutory Decisionmaking Factors*

Western states that the final rules are defective because the record contains no evidence that MTB took into consideration in prescribing the rules the several factors listed in section 6(d) of the Act, particularly "the need to encourage remote siting." To the contrary, the final rules contain numerous specific provisions relating to the section 6(d) factors. For example, remote siting is an option available to operators in complying with the exclusion zones required by sections 193.2057 and 193.2059. Also, in this regard, the preamble to the April 21, 1977, advance notice discussed the need for safety standards based on different population densities, and the Evaluation analyzes the remote siting alternative. The safety advantages of "remote siting" are essentially obtained by compliance with the exclusion zone provisions, without incurring such potential drawbacks as poor positioning relative to existing pipelines, gas markets, or navigational needs.

*F. Advisory Committee Advice*

Under section 4 of the Act, MTB must give reasons for rejecting the views of the advisory committee upon a proposed rule. Western makes a general allegation that MTB has failed to meet this requirement with regard to proposed rules for which the Committee issued an unfavorable report. This is incorrect. For the most part, MTB adopted the views of the Committee in issuing the final rules and thus, there was no need to explain its position vis-a-vis that of the Committee. Where Committee views were not adopted, the reasons for rejection were given in the preamble to the final rules.

*Section 193.2005 Applicability.*

The purpose of this section is to distinguish between new and existing LNG facilities regarding the application of Part 193 standards affecting siting, design, or construction (including installation, initial inspection, or initial testing). In Part II of its petition, Western argues that in section 193.2005(b)(1), MTB has acted contrary to section 6(c)(1) of the Act by imposing new siting standards on existing LNG facilities.

Section 6(c)(1) of the Act forbids the application of new Federal LNG safety standards affecting design, location, installation, construction, initial inspection, or initial testing to an "existing LNG facility," although standards which do not affect location may under certain conditions (relating to compatibility or practicability) be applied to any "replacement component or part thereof" put in service after the standards are issued. The term "existing LNG facility" is defined by section 2(14) of the Act as any LNG facility for which an application for approval of the siting, construction, or operation was filed before March 1, 1978, with a particular Federal, State or local agency. Standards for the siting, design, and construction of any "new LNG facility" are authorized by section 6(a) of the Act; and a "new LNG facility" means any LNG facility other than an existing LNG facility.

Excepted from the meaning of "existing LNG facility" is any facility the construction of which begins on or after November 30, 1979, where the construction is pursuant to an approval initially applied for on or after March 1, 1978, in the form of an amendment to a pre-March 1, 1978, application. Under the Act, such a facility falls within the meaning of a "new LNG facility," and is therefore subject to siting, design, and construction standards for new LNG facilities authorized by section 6(a) of the Act. The intent of this exception can be illustrated using the applications filed with the Federal Energy Regulatory Commission (FERC) and its predecessor organization seeking approval for the construction and operation of an LNG facility on Staten Island, New York.

- November 1973—Application filed for a Certificate of Public Convenience and Necessity to construct and operate an LNG facility at Staten Island. Docketed as CP 74-122.
- March 1979—Amendment to CP 74-122 filed seeking authorization to operate the Staten Island facility as a peak shaving facility (using one of two 900,000 gallon storage tanks) and to construct and operate a liquefaction unit at the facility.
- February 1980—Amendment to CP 74-122 filed seeking authorization to use both of the facilities' 900,000 gallon storage tanks and existing vaporization and compressor equipment. Amendment also sought approval to construct and operate a liquefaction unit (twice the capacity of the unit filed for in the March 1979 amendment) and more vaporization units.

None of the above filings have yet been the subject of approval of FERC.

In applying the Act's definitions to the facilities subject to approval under CP-74-122, only those facilities for which approval of the siting, construction, or operation was applied for in the November 1973 filing would be considered "existing LNG facilities." In accordance with the Act's exception to the definition of "existing LNG facility," the facilities for which initial approval of the siting and construction was applied for in the March 1979 and February 1980 filed amendments would be considered "new LNG facilities," and therefore subject to the siting, design, and construction standards issued under section 6(a) of the Act.

Section 193.2005(b)(1) provides that if an existing LNG storage tank is relocated or its storage capacity is increased through replacement or significant alteration, the relocation tank, replacement tank, or significantly altered tank must meet the siting requirements of Part 193. Western argues that this provision is unauthorized because section 6(c)(1) of the Act forbids regulation of the siting of an existing LNG facility, including "any subsequent activity" that occurs with respect to the facility. Western supports this argument by referring to the plain meaning of section 6(c)(1) and its express prohibition against applying standards that affect location to any replacement of an existing facility, and by a somewhat liberal reading of the legislative history. From its reading of legislative history, Western infers that Congress did not intend to subject any reconstruction of an existing LNG facility to siting standards.

MTB does not dispute the basic premise of Western's argument, that nothing about an existing LNG facility may be regulated from a siting standpoint. In adopting this policy, Congress obviously recognized the virtual impracticability of retroactively applying new siting standards to facilities already built or under construction and, as indicated by the legislative history, the unfairness and delays that would result if siting standards were applied to facilities for which applications for approval had been pending since at least before March 1, 1978. Congress was also concerned that these existing facilities not be hindered from making needed replacements, but that the replacements be safe. Therefore, under section 6(c)(1)(B) Congress granted limited regulatory authority over the design and construction of replacements to existing LNG facilities, but specifically disallowed regulation of replacements to existing LNG facilities from a siting standpoint. We do believe, however, that Western has neglected to give recognition to the fact that the Act's definitions of "LNG facility," "existing LNG facility," and "new LNG facility" presuppose the possibility of a system of LNG facilities functioning as a unit, being composed of new and existing LNG facilities and also the possibility that certain relocation, reconstruction, or modification of an existing LNG facility makes the resulting facility a "new LNG facility."

For Western's argument to hold, relocated or enlarged facilities must be considered "existing LNG facilities" under section 6(c)(1). The relocated or enlarged facility would, under the statutory definition of "existing LNG facility," have to be one for which approval of the siting, construction, or operation was applied for before March 1, 1978. While we admit the possibility that a pre-March 1, 1978, application might have sought approval of subsequent relocation or enlargement activity, where it did not, such relocation or enlargement activity would need be the subject of an initial application for approval filed on or after March 1, 1978. As such, in applying the exception clause to the Act's definition of "existing LNG facility" (discussed earlier), the resulting relocated or enlarged facility would be a "new LNG facility" for which siting standards are authorized.

This reasoning, relied on in adopting § 193.2005(b)(1), is further supported by a statement from H. Rep. No. 96-201, Part 1, 96th Cong., 1st session (1979) at Page 24. At this point in its discussion of the authority to regulate existing LNG facilities, the House Committee on Interstate and foreign Commerce says:

> Standards for existing facilities are to be directed toward operational procedures only, including considerations such as the number of operators and security measures. They [standards for existing facilities] should not apply to any reconstruction or substantial modification of an existing LNG facility, which would result in a substantial increase in capacity. Such reconstruction or modification would render that facility subject to the rules promulgated for new LNG facilities, but only with respect to such reconstruction or modification. The original portion of the facility would remain "existing" but the reconstructed, modified or expanded portion would be "new".

This statement of the legislative history shows that any reconstruction activity that goes beyond mere replacement-in-kind of an existing facility to the extent that capacity is increased makes the resulting facility a new LNG facility. While the Committee continues its discussion by giving as an example of a new facility the construction of a third storage tank at a site where two had existed previously, it is important to note that the same result could be achieved (although impractically) by tearing down the original two tanks and rebuilding them to larger sizes.

Although we do not agree with Western that an existing facility remains an existing facility for purposes of section 6(c)(1) regardless of the changes it may undergo, we do concede that any subsequent construction for which approval was applied for before March 1, 1978, (even expansions of capacity) would fall within the meaning of "existing LNG facility." As currently drafted, § 193.2005(b)(1) does not reflect this distinction; and it is, therefore, changed to apply only to later modifications of existing LNG facilities that are not made pursuant to an original pre-March 1, 1978, application for approval. In addition, the term "replacement" is deleted to avoid the misunderstanding that its meaning includes reconstruction of a storage tank when storage capacity is increased, since such reconstruction would result in a new LNG facility.

*Section 193.2007 Definitions. "Fail-safe".*

AGA and INGAA petitioned to change the definition of "fail-safe" by deleting the word "component" and changing "control device" to "control signal." Thus for example, a "fail-safe" design of a shut-off valve would relate only to loss of power supply or control signal to the valve. In support of the change, both petitioners contend that a fail-safe design to account for a component failure as the present definition states is not possible. Also, they argue that a component can only assume a preplanned condition and that the definition would require all components to have fail-safe designs. Additionally, INGAA asserts that internal parts of valves cannot be designed or made "fail-safe," and feels that MTB does not intend that "every" component be designed to be fail-safe.

In response to the petitions, FERC comments that since the only substantive requirement for fail-safe design applies to automatic shutoff valves (§ 193.2125), the inclusion of "component" in the fail-safe definition is appropriate.

MTB adopted the present definition of "fail-safe" in response to comments on the NPRM. The broader term "component or component part" in the NPRM was changed to "component or control device" in the final rule. This change was precisely in accordance with the wording recommended by AGA and the TPSSC. INGAA made no recommendation in response to the NPRM.

Concern expressed by the petitioners that all components are required to be fail-safe because of the word "component" in the definition is not warranted. The Part 193 definitions do not by themselves impose any requirements. Rather, they are used to assist in applying the substantive rules of Part 193. The definition of "fail-safe" applies only where fail-safe designs are prescribed for specific components by substantive rules in Part 193 (e.g., § 193.2125). More important, the concept of "fail-safe" in the context of long scientific and engineering understanding is more broadly applicable than to loss of power or control signals. It applies to any malfunction of a part or system for which corrective action is needed in order to maintain a safe operation. In the case of a valve subject to § 193.2125, some internal parts would have to have a fail-safe design. For example, a diaphragm actuator may be designed to open or close a valve, as desired, in the event of diaphragm failure. Similarly, the inner valve designs may provide for the valve to close or open in the event of shaft failure from erosion or uncoupling, and instrument controls may be selected to perform appropriately in the event of loss of power, plugged bleed orifices, or linkage failure. A reaction only to loss of power or control signal does not adequately cover the intended fail-safe concept. Therefore, in accordance with the above discussion and FERC's position, the present wording of the definition of "fail-safe" is retained without change.

*Section 193.2015 Petitions for finding or approval.*

This section sets forth procedures that an operator must follow in requesting the Director of MTB to make findings or grant approvals as authorized by Part 193. To ensure that MTB has adequate time to respond to individual requests, the procedures require that they be submitted at least 90 days before the finding or approval is needed. AGA and INGAA argue that this provision does not commit MTB to act within a definite time frame, and that operators need to know when action will be taken on requests. Although implied by the current rule, MTB agrees that its policy to respond within 90 days should be clearly stated. At the same time, under some circumstances a period longer than 90 days may be needed. Therefore, § 193.2015 is revised to provide that within 90 days after requests are received, operators will be notified either of the action taken on requests or, in cases where the request requires more extensive consideration or where additional data or comments are requested and delay is expected, the date by which MTB anticipates action will be taken.

*Section 193.2057(a)(1) Thermal Exclusion Zone (targets).*

This section requires safe separation distances between impounding systems and certain targets for purpose of thermal radiation protection, not including targets that an operator uses as LNG facilities. In its petition, INGAA sought to except from the rule, all operator's facilities by changing the term "LNG facility" to "facility." INGAA asserted that pipe storage, maintenance yards, and other non-LNG pipeline facilities should not be subject to the separation distances.

In opposing INGAA's proposal, FERC considered the present wording to be sufficiently flexible, and argues that housing provided by an operator might not be protected from thermal radiation under the suggested change.

MTB feels the term "facility" as proposed by INGAA would open a door for broad exclusions. Concern expressed by FERC regarding operator-owned housing is in general accord with MTB's view. Housing, general office buildings, recreational facilities, or other targets not considered "pipeline facilities" should clearly not be excepted from thermal radiation protection. However, as presently written, the final rule excepts only pipeline facilities that are "LNG facilities." The MTB believes that other pipeline facilities of the operator, since they are of similar risk and purpose, should be excepted. Also, to not except them would create an undue compliance burden in situations where an operator uses common grounds for its LNG and non-LNG pipeline facility operations.

Accordingly, MTB has modified this section to except "pipeline facilities." Thus, a thermal radiation exclusion zone of an LNG facility does not apply with respect to other pipeline facilities of the operator.

*Section 193.2057(a)(2) Thermal Exclusion Zone (drainage channels).*

Proposals to provide a different method than required by § 193.2057(c)(1) to determine exclusion distances for elongated drainage channels were submitted by each of the petitioners. The proposals suggested that a modified method be used when the length to width ratio of a channel exceeds 4 to more realistically approximate the thermal zone from a burning elongated pool of liquid.

Each of the petitioners proposed a different method and asserted that the results of its proposed method would be conservative and either technically correct or more representative. None provide substantiation, either in the form of a logically derived detailed derivation or supportive test data. Each method generally produces different results for a given set of conditions.

In determining an exclusion distance "d" under § 193.2057 (b) and (c), INGAA recommended that an impoundment area (A) be calculated using an assumed length(l) of 4 times the width(w). This assumed value would be used to determine "d" from the formula $d=(f)(A)^{0.5}$ and to determine flame length (L) under paragraph (b)(4), in the formula $(L)=6(A/\pi)^{0.5}$.

AGA also recommends that "d" and (L) would be determined from an assumed value (A). However, AGA would calculate the assumed (A) using an assumed diameter of 4 times surface area divided by the surface perimeter.

While Western recommends use of the same formula proposed by AGA to determine an assumed (A), Western advocates using the assumed (A) to determine only the flame length (L).

In response to the petitions, FERC essentially supported the method recommended by AGA but proposed an additional provision to assure that impounding spaces associated with such drainage channels meet all other requirements of this section. In argument, FERC expressed only the view that a reduction (in the resulting exclusion distance) would be appropriate for drainage channels.

Using a 10-foot wide channel with varying lengths for comparing results under the § 193.2057 method for calculating exclusion distance ("d") to results under the proposed methods shows the following:

1. For a 40' x 10' channel, all methods would result in "d" equaling f(20). In the case of public streets, for example where § 193.2057(d) provides for (f)=(1.1), "d" would be 22 feet.

2. For a 41' x 10' channel, "d" would be—

- 22.2 feet under § 193.2057
- 22 feet under INGAA's proposed method
- 29 feet under AGA's proposed method

3. For a 1000' x 10' channel "d" would be—

- 110' under § 193.2057
- 22 feet under INGAA's proposed method
- 35 feet under AGA's proposed method

As can be seen, the INGAA method results in a constant 22-foot exclusion distance no matter what the channel length. While the sudden 7-foot increase in exclusion distance for only a one-foot increase in channel length under the AGA method is not believed to be warranted for safety reasons, MTB seriously questions the adequacy of a 35-foot exclusion distance for a 1000-foot channel length.

The proposed methods of determining an assumed (A) would reduce flame length (L) in amounts proportionate to changes effected in "d." Reductions in (L) would tend to further reduce the safe separation distance between an impoundment system and targets. Whether this reduction would be significant is dependent on other parameters, such as topography, impoundment dimensions, and type of targets.

Incident thermal radiation from any unshielded source point in a flame pattern diminishes with the square of the distance from the source. Energy absorption by the atmosphere further reduces intensity with increasing distance. Therefore, MTB agrees with the implicit view of petitioners that a formula different from the one in § 193.2057(c)(1) would probably be appropriate for an elongated fire field, because incident thermal flux from its more distant source points could be considerably less than incident flux from source points of an equidimensional fire field. This problem was addressed by MTB in the NPRM. However, the proposed point source equation that was to have been applied to the problem received much inconsistent but adverse comment. An alternate methodology was not promulgated in the final rule because (a) response to the NPRM proposal regarding elongated impoundment was generally negative; (b) corroborative test data for elongated impoundment was not known to be available; (c) current thermal radiation data and analysis is imprecise; (d) a need for a specific rule for elongated impoundment was not demonstrated, in that unreasonable exclusion distances resulting from the general method prescribed would be infrequent; and (e) the final rule included in paragraph (c)(2), provisions for the use of new test methods.

The methods recommended by petitioners are not substantiated by either corroborative data or analytical derivation and cannot be logically supported. Also, the methods do not consider the changing intensity of incident flux at equidistant locations along the major and minor axes of a fire field.

The apparent source of the AGA and Western proposal is equation (F-15) in the AGA report IS-3-1. The author, Welker, does not provide either supportive data or derivation for (F-15). Moreover, the formula is proposed only for use in determining flame height by

Thomas' correlation, not for use with the incident flux equation for distance $(d)=(f)(A)^{0.5}$. Of greatest importance, the equation (F-15), is clearly proposed for use only if impoundment is "reasonably regular," that is, the ratio is "not more than" 4 to 1. An irregular flame base is discussed on Page C-69 of IS-3-1. Here a 2 to 1 ratio is suggested as the limit for equating areas. Clearly, application of the formula recommended by AGA and Western and supported by FERC does not appear to have a valid basis for use with elongated impoundment having a ratio greater than 4 to 1.

INGAA's proposal appears to be an effort to simplify. Its evident basis is an assumption that two separate fires, in a channel, separated by a space that is 4 channel widths in length, would not emit thermal radiation to a target on an orthogonal line passing 2 widths away from the end of each fire. Clearly, this is not valid and is the antithesis of safety, particularly in view of the downwind spread of vapor before ignition occurs, potential for multiple fires once a major fire occurs, and the high levels of incident flux permitted under the rule.

Section 193.2057(c)(2) provides for the use of new methods, if adequately substantiated, to determine thermal protective distance. As mentioned above, emissive flux from a channel was a factor in adopting this provision. In view of this feature and the foregoing discussion, a change in the rule is unjustified without appropriate substantiation. Present wording, therefore, is retained as written.

*Section 193.2057(b)(4)(i) Measurement of flame length "L".*

Only INGAA proposed a change to this section: It would delete the clause defining impoundment area (A) by measurement at the "lowest point along the top inside edge of the dike" and replace it with a clause prescribing that (A) be based only on the volume spilled before spilling is shut off by automatic systems (INGAA uses the term "maximum potential spill" to describe this volume). Such a change results in (A) being the area of a sump, rather than the total area of impounding space available to contain a spill. In this section, area (A) is used to determine (L), a length to account for flame height in the equation $(L)=6(A/\pi)^{0.5}$. INGAA's only support for its proposal is that use of the larger value for (A), as set forth in the final rule, would tend to discourage "drain-to-sump impoundment design" and that this design "should provide the most favorable safety aspects in case of an LNG spill."

In responding to the INGAA proposal, FERC expresses the view that MTB's use of design spills under § 193.2059 for vapor dispersion appears inconsistent with use of "full tank spills" for the thermal radiation protection. The MTB approach was said to be valid, however, given the greater potential for destruction from a fire close to storage tanks. Commenting that a significant reduction in thermal exclusion zone would result if an exclusion distance were based on sump design, FERC disagreed with INGAA's proposal.

The latest edition (1979) of NFPA 59A provides that thermal radiation protection be based on impoundment of a total spill for targets such as outdoor assembly of 50 or more persons, residences and certain buildings such as penal and educational structures, and "a property line which can be built upon." In the case of such property lines, protective distance would be further increased if a lower level of incident flux (3000 instead of 10,000 BTU/ft.$^2$-hr.) could result from a design spill. Each of these NFPA 59A design spill provisions is more stringent than INGAA's proposal.

Foremost for public safety, the paramount safeguard is containment of a spill. If a spill is not confined, it will spread. Vapor dispersion distance will increase and leakage into underground systems may occur, with results similar to those experienced in Cleveland, Ohio.

The Part 193 standards are designed to minimize the possibility of catastrophic failure. However, the possibility cannot be completely eliminated. Because of this possibility, some provisions to mitigate the otherwise very severe consequences of such an event must be retained. For example, standards relating to impoundment design and capacity are predicated on the premise that a catastrophic failure resulting in a full pool of LNG could occur.

Ignition and fire have greater expectancy than vapor dispersion with a large spill. On-site ignition sources are common. A spill that results in vapor dispersion may subsequently be ignited, whereas the opposite is not expectable. Therefore, fire and consequent thermal radiation is more likely to occur as the result of a spill than extensive vapor dispersion.

Sump basins to contain a small spill of flammable liquid or LNG were proposed respectively in the ANPRM and NPRM. In response to comments, this proposed requirement was dropped in the final rules. However, sumps are most effective in controlling fires from small spills and thereby serve to protect the operator's equipment. They are required in impounding systems for water collection purposes under § 193.2171. Capacity for holding small LNG spills can be provided at little or no additional cost. Therefore, the MTB disagrees with INGAA's assertion that prudent operators will be dissuaded from installing sumps unless the prescribed thermal exclusion zone is reduced by permitting a shortened flame length.

Moreover, even given an absolute assurance that a spill size would be small, much of the impoundment space surface area may be wetted from a postulated discharge and flow to a sump basin. This aspect would clearly affect thermal radiation because of fire size in the same way it affects vapor dispersion due to contact surface area and resulting vaporization rate. Thus, even if thermal radiation were to be based on a less-than-catastrophic-failure design spill, use of the sump area, as suggested by INGAA, in determining a safe exclusion distance would produce an inadequate thermal exclusion zone.

The prescribed thermal exclusion zone is not based on a full tank spill, as stated by FERC, since a spill large enough to cover the impounding space floor would result in essentially the same level of thermal radiation as a total spill. Therefore, considering: (a) The likelihood of a fire in the event of a spill; (b) the need to provide for a major or catastrophic spill since it cannot be ruled out; (c) that maximum harm is most likely during the first moments after ignition; and (d) that thermal radiation hazard would be nearly alike for various sizes of spills, § 193.2057(b)(4)(i) is retained in its present form.

*Section 193.2057(d)(6) Limiting values for incident radiant flux on offsite targets.*

This section establishes a protective distance between the impounding system for each LNG container or LNG transfer line and the operator's "property line," based on a maximum allowable incident radiant flux at the property line of 10,000 BTU/ft$^2$ hour. The rule is intended to provide a minimum level of protection against thermal radiation for persons who may be near an LNG facility outside its property line, such as on trails or in small recreation areas, for which safe separation distances are not otherwise required by § 195.2057(d).

AGA, INGAA, and Western argue that this requirement is impossible to meet for marine cargo transfer systems, since they must approach and cross an operator's property line at the shoreline. Western is also concerned that sea water vaporizers would have to be located further away from an unfrequented beach area than necessary for safety.

As stated in the preamble to the NPRM, MTB adopted the "property line" requirement with some modification from an existing NFPA 59A provision. this requirement and the NFPA provision can be interpreted, however, to refer to the right-of-way for a facility. The term "right-of-way" and not "property line" is used in the definition of "pipeline facility," and, in turn, "LNG facility". Although MTB agrees with the petitioners that a safe distance from a "property line"—using the term in its ordinary sense—cannot be provided for transfer lines that must cross a property line, this impossibility does not exist for distances between such a facility and its right-of-way. For these reasons, § 193.2057(d)(6) is amended by substituting "right-of-way" for "property line."

MTB does not agree with Western that § 193.2057(d)(6) should be further amended to exclude sea water vaporizers. Although some additional piping and pumping costs might result when such vaporizers are located further away from the shoreline (reduced cost for LNG and gas piping could be more than offsetting), there are no overriding compliance considerations as in the case of marine cargo transfer systems, and persons who may be near the facilities should be afforded every reasonable protection.

*Section 193.2059(d)(1)(i) Flammable vapor-gas dispersion protection (design spill time criteria).*

This paragraph prescribes a design vaporization rate for a spill into an impounding system serving an LNG container or LNG transfer system. The design rate is based on a presumed failure of LNG transfer piping, with additional time for piping that penetrates an LNG storage tank either above or below the liquid level. This vaporization rate is used in determining the design combustible gas dispersion distance.

Each of the petitioners requests that the minimum spill time of 10 minutes not be required for attended cargo transfer operations (transfers between a storage tank and a tank vehicle or marine vessel), arguing that a minimum time is unreasonable on top of the existing requirement in § 193.2439 that transfer piping have an automatic shutdown control system, and the proposed requirement in § 193.1117 (Notice 5; Docket No. OPSO-46) that cargo transfer operations be continuously monitored by personnel. In addition, for penetrations below the liquid level, all petitioners would eliminate the prescribed additional time for liquid head to equilibrate with that in impoundment (or otherwise reach the penetration level). This additional time for side or bottom penetrations of LNG storage tanks is viewed as unreasonable since § 193.2195(c) requires an internal shut-off valve that would have to have a fail-safe design under § 193.2125, making a prolonged spill from a tank unreasonable to assume. AGA also argues that as a maximum, the spill time should not be longer than the time required by NFPA-59A.

FERC disagrees with the petitions regarding the 10-minute minimum, stating that in actual practice, a time lapse between emergency notification and shutdown has been demonstrated. Also, FERC points out that § 193.2439(c) permits a reasonable delay in automatic shutdown time between alarm and shutdown to provide for a manual response and adds that any delay in leak detection would further increase shutdown time.

MTB disagrees with petitions to eliminate the 10-minute minimum for cargo transfer systems that are monitored or constantly attended and equipped for shutdown as required by § 193.2439. In furtherance of the concerns raised by FERC that delays in emergency response can occur, the attention of an attendant may be diverted due to other events, he may be slow to respond due to the normally quiescent nature of plant operation, or he may fail to respond effectively because of unfamiliarity with the problem or the trauma of a first time real life LNG emergency. Also, the requirements of § 193.2439 are not a satisfactory safety substitute for the 10-minute minimum design spill, because each sensor or component part would have to function properly in a possibly adverse environment during an emergency to assure a lesser shutdown period. Functional failure of any part of a control system or by an attendant would probably result in dispersion distance extending far beyond the design exclusion zone boundaries, with the attendant potential for severe consequences.

Thus, MTB believes the 10-minute spill time is necessary to account for any variety of conditions that can result in delay of shutdown. Further, the 10-minute time was adopted for consistency with the long standing NFPA 59A requirement for containers with top penetrations, perhaps an even safer situation than presented by cargo transfers.

Similar to the above discussion about § 193.2439, control of vapor dispersion from a tank impoundment should not be dependent on the operation of an internal valve required by § 193.2195, even though a fail-safe design is prescribed. Unlike top penetrations, where LNG spillage will passively terminate when power is cut off since the boiling liquid will not siphon, the internal valve is not a passive device. It clearly is part of an active control system which requires transmission of a control signal, correct response to the signal, and liquid tight closure of the valve. An active system is inherently less safe, since some positive action is required. If the petitions for removal of equilibration time were granted, the level of stringency would be the same for top, side, and bottom penetrations, yet safe control of vapor dispersion would rely on the operation of an internal valve that cannot be readily inspected or tested. The MTB believes this active system is not an adequate substitute for the current spill provision. Accordingly, the petitions to reduce the level of stringency for side and bottom penetrations to the same level required for top penetrations are denied.

Paragraph 2-2.3.3(c) of 59A provides for a one hour design spill limit for penetrations in storage tanks below the liquid level that are fitted with internal valves when surveillance and shutdown provisions are acceptable to the authority having jurisdiction. AGA argued that adopting this provision would encourage sub-diking. MTB believes this conditional one hour limit would have little effect, since in those cases where sub-diking could limit the design dispersion distance, appropriate design with a sub-diking arrangement probably could provide for about the same distances whether or not the spill time is limited to one hour. Also, where sub-diking may be encouraged, top penetrations would be discouraged.

MTB believes that encouragement of sub-diking to reduce dispersion distance does not justify an increased risk to the public from the potential dispersion of combustible vapor beyond exclusion zone boundaries if the internal valve fails to operate when needed within a one-hour time period. Therefore this alternate petition is denied, also.

However, some potential for misinterpretation of this requirement in the final rule has become apparent to MTB. Therefore, wording has been changed to clarify that the design spill is considered to continue under the condition of a failed shutoff valve until either liquid equilibration occurs, or until the liquid level in the tank falls below the tank penetration.

*Section 193.2061(f) Seismic investigation and design forces (prohibitions).*

This section prohibits locating LNG storage tanks where a site investigation shows that very high seismic activity could occur. By precluding the construction of facilities in areas where seismic predictability and design accommodation may be beyond the state of the art, the rule precludes the likelihood of a catastrophic or uncontained spill. If an operator believes that state-of-the-art capability can be demonstrated, an operator may apply to the Director for a waiver of the prohibition. Under this section, highly seismic areas are identified as those:

(1) Within one mile of an estimated differential displacement exceeding 60 inches on a Quaternary fault;

(2) Where estimated design acceleration exceeds 0.8g; or

(3) Where the potential for soil liquefaction cannot be accommodated.

*The Issues*

There are two basic issues addressed in the petitions for reconsideration. One is the appropriateness of adopting an absolute exclusionary rule like § 193.2061(f) for locating LNG storage tanks. The other is the validity of the fault-at-one-mile criteria to identify a highly seismic area where special government attention is required before a facility may be built.

*First Issue; Petitions and Comments*

With respect to the first issue, each of the three petitioners argues that outright prohibition should be eliminated in favor of a case-by-case government approval process for siting LNG facilities in identified highly seismic areas. The petitioners argue that prohibition is unreasonble and not in the public interest, considering energy supply and the availability of acceptable sites. AGA and INGAA contend that the regulations should require either compliance with specific conditions, or a demonstration to MTB of design safety by the operator. Knowledge of specific characteristics of the fault is necessary to justify prohibition according to Western. It cites the testimony at the April 1979 conference of Devine, Newmark, Jahns, and Hanson for support. The petitioners do not view the opportunity to seek a waiver from the prohibition as a favorable regulatory framework within which to plan and seek financing for new facilities.

In its remarks filed in support of Western, Alaska says the "prohibition" is an "aberational and inconsistent" provision in Part 193, since all other provisions have flexibility for balancing construction costs against the hazards of a location. In view of Alaska's special interest in LNG production and consequently in the availability of marketing terminals, it argues that States should be permitted to balance public health and safety with energy supply and economics.

Stevens and Johnson also advocated reconsideration favoring the petitioner's position against exclusionary seismic standards. Stevens thought that, otherwise, Alaska would be impaired in helping to offset the energy shortage. He also expressed support for Alaska's position on the matter.

Johnson expressed concern that exclusionary seismic provisions might block an LNG plant in California and plant expansion at Western's Point conception site. He concluded that design which could accommodate the seismic conditions should be available, and that the standards should provide for such judgment, but not reduce safety.

Western further argues against MTB's statement that commenters failed to substantiate that design can accommodate severe earthquakes by referring to testimony by Newmark and Jahns that dams and other structures have withstood seismic events according to design. Western also says that, according to Newmark, any probable earthquake could be accommodated by design, if there were no cost constraints. Also, Western contends that tests performed in connection with construction of facilities have demonstrated tolerance of severe seismic forces. Regarding MTB's reasoning that prohibition in highly seismic areas is in the public interest because consequences of a severe earthquake are so significant, Western again argues that experts say proper design will preclude adverse consequences, that other redundant safety standards in Part 193 (impoundment and exclusion zones) will protect the public, and that a spill at a remote site would not endanger the public even with total tank failure from an earthquake.

FERC expressed unqualified support of all of MTB's reasons for prohibition. More critically, FERC observed that no experience (even with dams) or testing has shown that LNG storage tanks have tolerance for faulting.

Comments in support of the exclusionary approach were received from Sierra, Bixby, Hollister and Citizens. In commenting on seismic features of the petitions, Sierra urged rejection, saying such changes would emasculate the final rule and are contrary to the public interest. Support of the MTB rationale as well as the content of § 193.2061(f) is expressed. The prohibition is considered to be necessary by Sierra because of the unpredictability of both the faulting, itself, as well as the effects of faulting in a geologically active area. Bixby, Hollister, and Citizens point out that the petitioners continue to ignore the opportunity for seeking a waiver. Since this administrative procedure is readily available, they say modification of the rule is unwarranted. These commenters also underscore Western's admission that the issues are repetitious. Since the rules have been extensively reviewed, they argue, the petitions should be dismissed.

*MTB's Disposition of First Issue*

Contrary to allegations by Western, other provisions in Part 193, such as requirements for vapor dispersion, thermal radiation, and diking, will not assure public protection if a design seismic event is exceeded. For vapor dispersion, the exclusion zone is sized to accommodate only a piping failure, rather than a catastrophic tank failure. And if diking fails, resulting in an uncontained spill, none of the basic safeguards would be sufficient. Thus, provisions exceeding the requirements of Part 193 would be necessary to assure public safety if seismic overload resulted in catastrophic failure.

Construction tests that demonstrate tolerance for severe seismic forces, as alleged by Western, are not prescribed in the final rules. FERC states there are no such tests. Higher pneumatic and full hydrostatic tests of tanks, proposed in the NPRM, could have demonstrated tolerance for some level of dynamic loading from earthquakes and wind. Other proposed requirements in the ANPRM could have provided information for post evaluation of seismic loads and stress levels. However, these proposed requirements were vigorously opposed by commenters on the ANPRM and were not adopted in the final rules. Nevertheless, there are tests and instrumentation which could demonstrate certain levels of tolerance to earthquake forces. Any reliance on such forms of demonstration should be made as part of a governmental review process.

The statement, attributed by Western to Newmark, that without cost constraint, any probable earthquake could be accommodated by design, appears to contradict Newmark's comment that designs for differential displacements larger than 2 or 3 feet require extensive study and research. Even if accommodation by design for extreme seismic events is possible, the principal concern is the uncertainty in predicting the nature and magnitude of the event to be accommodated.

MTB imposed the prohibition under § 193.2061(f) because of the high degree of inherent uncertainty in determining the features of a causative geology and predicting seismic effects, particularly near-field activity; and the dearth of reliable technology for structural designs to accommodate very high seismic action. Comments by Devine and FERC, expert testimony referenced by Bixby and others, and extensive technical literature bear out MTB's concerns relating to geologic and seismic uncertainties. Seismic evaluations done at Point Conception, that show a difference in earthquake energy release of about 30 to 1, emphasize this concern. Newmark; comments by Bixby, Hollister and Citizens on expert testimony; research sponsored by the National Science Foundation; and technical literature point out that more extensive study and research are needed for structural designs to accommodate large differential surface displacements.

Accordingly, in adopting § 193.2061(f), MTB took the view that little could be gained by review and approval by the Director, where adequate technology is likely to be unavailable for making sound technical judgments. However, with respect to the issue of whether outright prohibition is an appropriate regulatory approach, MTB upon reconsideration has determined that modification of the opening clause of § 193.2061(f) to provide for a case-by-case approval would be more appropriate for the following reasons: First, although an approval process is basically only a procedural variation of the prohibition/waiver approach, it provides a more favorable atmosphere within which to seek authority to build a new LNG storage tank. The safety and technical issues and background information to be considered would be the same as in a waiver proceeding, and the matters to be considered can be specified by regulation. Secondly, lead time can be controlled, permitting more timely go/no-go decisions. Thirdly, the specter of the prohibition/waiver process could reflect unfavorably on an otherwise desirable site having compensating safety features. Finally, considering the nation's energy demands, a case-by-case approval approach would establish a procedural route within the regulations for siting a high risk energy facility without foreclosing in advance any particular site. Thus, § 193.2061(f) has been revised to adopt, in part, the petitioners' request by eliminating the outright prohibition. Rejection or approval of a site relative to the risk created by high seismic activity is made subject to evaluation by the Director, as requested by petitioners.

In responding to a request for approval made under § 193.2061(f), MTB contemplates that the decision process would include submitting the request and supporting data to an ad hoc panel for evaluation and recommendations. This DOT chaired panel would, at a minimum, be composed of individuals representing the State(s) and localities most directly concerned with the proposed site and private and Federal government experts on seismic investigation and design force matters. The panel's report and recommendations would be part of the record of proceedings on the approval application and made available for public comment in advance of the Director's decision.

*Second Issue; Petitions and Comments (Exclusion Distance)*

With respect to the second issue—whether a one mile distance from a Quaternary fault with 60 or more inches of displacement is an appropriate indicator of a highly seismic area—AGA and INGAA proposed identical changes in § 193.2061(f)(1). Addressing the "one mile separation" aspect of this issue, the word "beneath" would replace the words "within one mile" so as to restrict the identifying criteria to a 60-inch Quaternary differential fault displacement beneath the tank foundation. Elimination of the one mile separation was also proposed by Western. However, Western seeks to modify the language describing the triggering criteria to "60 inches of differential surface displacement of a seismogenic Quaternary fault beneath the tank foundation."

AGA and INGAA contend that the only effect from a fault on a tank that is separated by one mile or any other distance will be from acceleration. Therefore, they assert, only differential fault displacement beneath the tank is applicable to identifying a high seismic risk. Also, AGA together with Western urge deletion of the one mile criterion on the basis that at shoreline sites, proof that faulting is within precribed limits is very difficult. They say that present geophysical methods necessary for offshore investigation cannot provide the required accuracy. Western goes on to comment that the 60 inches of displacement, which it proposed in response to the NPRM, was to have applied at tank location rather than at a one mile distance. Therefore, they assert use of the 60-inch criteria in conjunction with a one mile exclusion distance is unjustified.

In rebuttal to MTB's rationale in the preamble that uncertainties about future faulting and fault splays justify the one mile zone, Western argues that it is invalid to conclude that the area within one mile of a Quaternary fault is unsafe without considering whether the fault is "seismogenic" (could it produce an earthquake). Western contends that further seismic examination and design by experts is a more appropriate regulatory approach. Western also rebuts MTB's statement in the preamble that the final rule was developed with the assistance of Devine and his testimony. With reference to the public hearing in April 1979, they quote Devine as saying that one mile could not cover all unsafe situations and may be either over or under conservative, and that a determination of fault size, ongoing displacement, or surrounding faults and relative displacement on each are necessary. Western concludes that MTB cannot say that Devine is supportive of the final rule and contends that there is no evidence in the record to support the one mile criterion.

Commenting on the issues, Newmark supports the position of the petitioners regarding deletion of the one mile criterion. He proposes language that, except for the amount of displacement, is identical with the language used by AGA and INGAA. The location of the fault displacement is proposed to be changed from "within one mile" to "beneath" the tank foundation. However, no explanation is given for this proposal, or about the uncertainties associated with predicting near-field seismic activity. Newmark merely asserts that "an arbitrary distance to faults regardless of their size and probability of slip is unrealistic and arbitrary."

Misgivings about the one mile criterion were also indicated by Devine in his comments as well as his testimony. However, he points out that a fault trace is not likely to be known with the certainty necessary to assure that the next movement on the fault will not result in differential ground displacement at some distance from the known fault trace, or trace of last movement. Devine feels this factor supports exclusion zones. This factor is not acknowledged by the petitioners.

FERC disagrees with assertion by AGA and INGAA that a fault not directly beneath a component presents only an acceleration problem. FERC cites a number of features that must be acknowledged in earthquake design: (1) Liquefaction, subsidence, and tilting are potential problems regardless of distance from a fault; (2) faulting on a single continuous fault surface is rare; (3) new faulting, particularly when close to existing faults, cannot be ruled out; (4) the effects of shaking, when close to a fault, cannot be reasonably predicted, even when directional effects are ignored; and (5) directional effects, as shown by the 1979 Santa Barbara event, can be substantial.

FERC also takes exception to comments by AGA and Western that lack of accuracy in data on offshore faults would preclude shoreline locations. This, they say, is an invalid reason to eliminate an otherwise valuable restriction because if faults could not be discovered by state-of-the-art geotechnical investigation, the site would be acceptable.

Sierra, Bixby, Hollister and Citizens generally support the one-mile exclusionary zone, but indicate that, if anything, a more stringent standard is called for.

Considering the unpredictability of both the potential for faulting and its effects, Sierra feels that the one mile criterion is inadequate. In support of this view, the testimony of Hanson given at the April 1979 MTB conference is referenced. In the testimony he stated that one mile separation from significant faults would not be enough to prevent tanks from being located over a serious fault, and claimed that two or three miles would be a better standard. To exemplify, Sierra alleges that an ever increasing number of faults have been discovered over several square miles at Point Conception, California, as a result of ongoing investigations. The USGS Open File Report No. 80-229 (March 1979, at 16) is referenced for substantiation. The Report is said to conclude that the faults found so far are "structurally inseparable elements of a regional system of severe faults."

Bixby also refers to Hanson's testimony. He is quoted as recommending an exclusionary zone of two to three miles for thrust faults and one mile as a national basis, but adds that this limit may not be adequate for California.

Testimony by Newmark at the April 1979 meeting supporting the exclusionary approach is also quoted by Bixby. Newmark states, "I would support an exclusion principle that barred a facility like this within about a mile of the San Andreas fault." Bixby also relates that Newmark's testimony before FERC in June 1976 states that LNG facilities can be reliably designed within a mile or so of a fault on which earthquake motions of one or two feet might be expected. This testimony, according to Bixby, shows that Newmark, while opposing an exclusion zone in his letter supporting the petitioners, has endorsed the concept in testimony.

As a corollary, Bixby, Hollister, and Citizens all point out that the expert sworn testimony and comments in the docket contradict Western's allegation that there is no evidence in the record to support the one mile criterion.

*Petitions and Comments; (Differential Displacement)*

The magnitude of estimated differential Quaternary displacement is the other aspect of the second issue that must be considered. Although petitioners did not request a change in the 60 inches or more magnitude, it becomes a matter for reconsideration because of the petitions to establish displacement criteria for faults at a point beneath the tank, the associated comments on the appropriate magnitude of a fault displacement beneath the tank, and the need for changes recognized by MTB as a result of the comments.

Western asserts that the prescribed 60 inches of differential displacement over two million years is not valid criteria for discriminating against an area one mile around a fault without evaluating the potential effects at the tank site. As mentioned, Western acknowledges that this magnitude of displacement was its own proposal for a final rule made in response to the NPRM. However, Western states correctly that it was to be applied in connection with a fault location beneath the tank. This criteria, it alleges, is in accordance with testimony by Newmark and Jahns. Both men are said to be recognized experts who believe that "varying seismic conditions simply require varying design conditions." However, Western acknowledges that while Newmark speculated that "innovative" design could accommodate displacements in excess of 36 inches, he also stated that current state-of-the-art design, with innovation, can accommodate displacements of only 2 to 3 feet.

Western recalls Jahns' statement that facilities have been designed for 30 feet of displacement. The Palmsdale Dam in Southern California was cited as the example. The criteria of 60 inches of displacement located directly under a tank was therefore viewed by Western as appropriate for triggering special consideration in the installation of large LNG tanks.

Newmark's own comments also address the matter of appropriate limits for displacement directly under an LNG tank. He quotes an excerpt from his testimony at the April 1979 meeting. In part, it says that special designs, not beyond the state-of-the-art, can handle two or three feet. But, it continues, "I would not want to generalize, however, and say that one should permit relative surface motions larger than that under an important structure, or one that is essential to safety." At a following point, he asserts that design for larger displacement is possible, but would require great and extensive study and research.

In his comment, Newmark says that § 193.2061(f)(1) does not accurately reflect his testimony at the April 1979 conference. He proposes revisions in § 193.2061(f)(1) identical with that of the petitioners AGA and INGAA, except that the limit of differential displacement would be 30 inches, rather than 60 inches proposed by the petitioners.

Newmark's position, that motions exceeding 2 or 3 feet are beyond the state-of-the-art, is also referenced by Bixby to show that Newmark, who testified as Western's expert, now disagrees with Western's position that up to 60 inches is within the state-of-the-art. In addition, Bixby points out that Newmark earlier testified (El Paso, Alaska LNG Co. Case, Tr. Vol. 157, P. 25946) that LNG facilities could not be reliably designed at, over, or within a mile or so of a fault with one or two feet of expected motion.

With respect to Jahns' statement about the magnitude of displacement allowable for design purposes (30 feet), FERC argues that "no experience, even with dams (which are not comparable with LNG facilities) or tests have shown that facilities have tolerance for faulting." Also, use of the word "seismogenic," proposed by Western to describe the Quaternary fault at issue, while appearing inocuous, is considered to be a potentially serious problem by FERC. FERC contends that a fault probably could not be proven to be nonseismogenic. As a result, FERC feels that litigation could be extensive and unresolvable, yet impose excessive burdens on opposing parties. Accordingly, FERC recommends that the term not be used in the standard.

*MTB's Disposition of Second Issue*

Experts in the field do not uniformly agree on geologic and seismologic terms or their meanings. From the comments and related testimony, conflict about the nature and effects of earthquakes also becomes evident. This is not an unreasonable circumstance, since rapid development is being experienced in these fields. Also, these fields are not precise disciplines and must rely on deductive reasoning as much or more than on direct observation and measurement.

The term "differential Quaternary fault displacement" used by AGA, INGAA, and Newmark, in describing the type of displacement located beneath a tank, clearly is intended to mean differential surface displacement, (i.e., differential displacement of the ground at its interface with the tank foundation). This is made evident by Newmark's interchangable use of the term "relative surface motions." As used in the final rule, this same term means historic differential movement at the face of a Quaternary fault whether evident by measurement or estimate. Western, in an apparent effort to clarify, uses the term "differential surface displacement of a seismogenic Quaternary fault." Rather than adding clarity, this would introduce possible ambiguity, since unless a fault that is immediately beneath the tank is classified as "seismogenic," construction could apparently proceed without regard to the magnitude of surface displacement that is predicted to occur beneath the tank.

Assertions by AGA and INGAA that ground acceleration will be the only effect from a remote fault are not considered valid. Near-field seismic effects from major events, such as differential surface displacement, subsidence, tilting, vibratory motion, and liquefaction are not well known, as stated by FERC. Also, as Devine explains, differential surface displacement may occur at some unpredictable distance from a known fault, or trace of last movement.

The uncertainties in both the faulting and potential effects were also recognized by Sierra, Bixby, Hollister, and Citizens as a justification for the separation. The discussion by Sierra about the results of ongoing, detailed investigation at Point Conception lends weight to Devine's argument.

Hanson's testimony, cited by Bixby, supports the need for separation. And although Newmark expresses opposition to separation (but does not give justification for this view), he has testified in favor of separation as recently as 1976, according to Bixby.

The specter of the uncertainties associated with near-field seismic effects of an earthquake is the principal reason MTB included provisions for separation in the final rule. The San Fernando, California, Earthquake of 1971 (USGS and NOAA preliminary report, 1971) is a good example of some of these uncertainties: Acceleration and other seismic effects far exceeded anticipations for an event of only such moderate size. Rated at 6.6 Richter (the San Francisco 1906 and Alaska 1964 events, in the range of 8.3 Richter radiated a few hundred times more energy), accelerations were the highest ever recorded, measuring 1.0g horizontal and 0.7g vertical with local responses even more dramatic. Evidence suggests that buildings were accelerated vertically at 1.0g (minimum) for about 0.1 seconds. A 20 ton fire truck was moved 6 to 8 feet without showing tire marks, and wine glass stems were broken without lateral movement. Both of these occurrences would require over 1.0g vertical acceleration. A "shattered earth" effect was exhibited in some locations, and at one point a rock roadcut appeared to have exploded. The Van Norman Dam (overlooking heavily populated San Fernando Valley) was severely damaged and at the brink of catastrophic failure. Perhaps of greatest significance, some areas of great disturbance were delineated by narrow bands, with only minor damage just beyond, exemplifying the degree of uncertainty in the translation of seismic motions, as discussed by Devine.

MTB agrees with FERC that the argument by AGA and Western about the possible preclusion of shoreline facilities due to offshore investigative limitations is invalid. Investigative measures beyond state-of-the-art techniques are not presumed under the separation provision.

MTB acknowledges that the final rule adopted Western's suggested magnitude of displacement (60 inches) in conjunction with a separation provision. However, this decision is not a valid rationale for deleting the separation provision. The 60-inch criterion clearly exceeds state-of-the-art design for displacement under LNG tanks, and is more appropriate when used in conjunction with a provision for separation from a fault of such magnitude. Western's argument that MTB cannot cite Devine as authority for the final rule is contradicted by Devine's comments on the petitions. MTB together with Devine agree that the criteria are appropriate as used in the final rule.

The criterion of one mile for the separation distance in the final rule is to provide for the unpredictable lateral offset in translation of movement along new faulting (or along a splay or swarm of faults of unknown dimension or location) to a point at the surface under an LNG tank. MTB recognized that a fixed distance could not apply to all conditions. As Devine stated, it could be underconservative in some cases—overconservative in others. (The relevant comments of Devine, and others in this respect, applied to the NPRM criteria which did not prescribe a fixed limit of movement). However, basing the distance on a prescribed amount of differential Quaternary displacement clearly restricted the conditions to a limited range.

As previously stated, the one mile criterion, as used in the final rule, is supported by FERC, Sierra, and Bixby. Although Sierra, Bixby, Hollister, and Citizens indicated that an even greater distance is needed, and expert witness, Hanson, testified (with respect to the NPRM) that 2 or 3 miles would be a better standard, MTB selected one mile as the appropriate distance for a national standard, since in most areas of application, seismic data would not be well known and uncertainties in prediction would be greatest. In such areas, one mile would likely be sufficient to provide suitable attenuation and reduce the likelihood of excessive differential surface displacement occurring under the tank.

Notwithstanding Hanson's view that a distance of 2 or 3 miles would be more appropriate near a significant fault, MTB considers an exclusion distance based on such active locations to be inappropriate for a national standard. However, where more information about the seismic features of such active locations are available, or can be obtained from appropriate investigation by the prudent operator, such information may be sufficient for accurately predicting ground displacement at a tank site. If so, MTB believes the final rule should be changed to permit operators to use this information in judging the safety of a site.

In his testimony, Hanson supported the one mile criterion as a national standard, and according to comments, even Newmark, in other testimony, advocates a one mile distance under certain conditions. Contrary to Western's allegations, response to the NPRM as well as testimony at the April 1979 conference provide ample basis in the record for the one mile criteria, as stated by commenters opposing the petitions. MTB believes the one-mile criteria, when applied in conjunction with specified differential displacement on a Quaternary fault, is appropriate for locations where there is insufficient information to assure a reliable level of predictability about faulting at the tank site. Accordingly, after reconsideration, the one mile zone is retained, but the final rule is revised to narrow its application to areas where reliable prediction of site specific displacement cannot be made. The decision is consistent with petitioner's arguments that a prohibition against construction should not apply without first allowing an opportunity for more detailed investigation of projected effects at a tank site.

MTB has not adopted as a final rule Western's proposal in response to the NPRM (and restated by petitioners in this proceeding) to allow siting of a tank where no more than 60 inches of differential surface displacement is predicted to occur under the tank. Clearly this amount exceeds state-of-the-art design capabilities by a factor of about 2. Even Newmark, Western's expert, made a point of commenting on the petitions in this respect. He argues that the final rules do not reflect his testimony, and follows with an excerpt from his testimony that one should not permit designs for relative surface motions of more than 2 or 3 feet under an important structure. As FERC noted, Western's concept of acceptable displacement derives from a combination of Newmark's 2 or 3 feet for LNG tanks, and Jahns' 30 feet for the Palmsdale, California, dam. This is a contrived view that is not shared by MTB.

Opposing comments extensively debate the 60-inch value, citing expert witness testimony to show that it exceeds limits for accommodation by state-of-the-art designs. Newmark, himself, Western's expert, makes a point of commenting to show that he considers 30 inches to be the appropriate limit. He explains that design for greater displacement requires extensive study and research. And Bixby, citing Newmark's testimony in 1976 before FERC, points out that 30 inches is a quantum step from the one or two feet, within a mile, that he then favored.

Based on comments and testimony, and in consideration of the critical nature of LNG tanks and impoundment, MTB concludes that 30 inches is the outer limit of credible state-of-the-art design, and is including this value in the revised final rule in connection with the allowance made for predictions of displacements at tank sites based on historic data or field examinations.

Use of the term "seismogenic" to describe the character of Quaternary faults to be considered, as recommended by Western, is not adopted for reasons discussed by FERC.

Under the revised rule, where local geologic and seismic conditions are sufficiently well known to predict seismic response immediately beneath a tank, or impoundment for a tank, the need for government review would be dependent on whether differential surface displacement can be reliably predicted to be no more than 30 inches. Construction could proceed on decision by the operator if 30 inches or less of such displacement can be assured.

On the other hand, a differential Quaternary fault displacement exceeding 60 inches within one mile, as currently prescribed, would be the applicable criteria to determine the need for government review if local conditions are not sufficiently well known to reliably predict surface displacement beneath the tank or dike.

Thus, where reliable predictability is possible, surface displacement under the tank or dike becomes the governing criteria. This is important because in areas having the highest seismic activity, a data base for prediction is more likely. Therefore, it serves to help fill the 60.1 inch/1 mile–60-inch/0 mile gap of the current rule, as well as to minimize the likelihood that excessive displacement would occur beneath a tank or dike that has not been accommodated by design. For example, under the revised rule, review for sites more than 1 mile from the San Andreas fault may be required if there is sufficient data base for prediction of displacement at the site, but less than 30 inches relative movement under the tank and dike cannot be reliably assured. Conversely, siting a tank at distances less than a mile from a differential Quaternary fault displacement of 60 inches, or more, may be permissible without review, depending on the nature of intervening seismological conditions and data base for predicting displacement at the site.

The prohibition due to soil liquefaction has also been made subject to a petition for approval by the Director, since some of the same overriding benefits of a site, such as remoteness, might apply equally to such conditions.

The revised final rule also sets out the information that an applicant for approval must submit with a petition filed under § 193.2015. This information would include an analysis of the geologic and seismic conditions, design plans with a report showing that the design standards of § 193.2061 would be met under the predicted extreme conditions, and if applicable, any other safety-related siting or design features of the facility not required by Part 193.

*Section 193.2063(b)(2) Flooding.*

Both AGA and INGAA acknowledge that this section on its own merit is acceptable, as it requires that access to a facility site by offsite personnel be "reasonably assured" in a 100 year flooding event. However, they feel this section when read with the general siting requirements of § 193.2055 implies that access to the site must also be assured for fire fighting equipment along public roads. If this is the case, the petitioners say that in the Gulf Coast area, many access roads would have to be raised 20 feet or more for a distance of about 25 miles.

Section 193.2055 provides as a general requirement that a site must have "ease of access" for handling emergency situations. This general requirement covers many aspects of the means of access to an LNG facility. Section 193.2063(b)(2) deals specifically with access during flooding, and, as such, is governing under those conditions to the extent that access need only be reasonably assured. Therefore, in the example cited by the petitioners, access roads need not be raised where alternative means of access for offsite emergency personnel and equipment are available, such as by boat or helicopter. Hence, this paragraph remains unchanged.

*Section 193.2067(a)(3) Wind Forces (penetration by missiles).*

Design of containers and other LNG facilities listed in § 193.2051 to withstand penetration by wind borne missiles is required under this paragraph. Its purpose is to assure the integrity of the facility when impacted by objects carried by the wind (particularly a tornado).

Petitions to make only the dikes of impounding systems for LNG storage tanks subject to this requirement were submitted by AGA and INGAA. Western, who proposed a rule on wind borne missiles in response to the NPRM, did not comment. The petitioners argue that the required design is infeasible in most cases, and since all but very large spills would disperse in high winds, only LNG storage tank dikes should be subject to the requirement.

Commenting on the petitions, FERC feels the requirement is vague and design determinations are impossible where missile size and velocity is unknown.

MTB does not agree with petitioners that all damage causing winds would quickly disperse spills and associated vapor, since in the case of tornadoes, high winds quickly move away. Spillage and dispersion would continue.

With respect to the dilemma suggested by FERC, missile size would be a site specific determination. Missile velocity would be calculated using wind forces from wind velocities determined under paragraph (b). Impact loading could be calculated from this information.

However, MTB agrees that design for all of the prescribed facilities to meet this requirement is impractical, if not impossible. A large portion of the facilities would require shielding by protective walls. Also, while an event of this type involves the potential penetration of an LNG storage tank, MTB believes that the continued integrity of the storage tank impoundment is the appropriate safeguard for public protection.

In reconsideration, therefore, the final rule has been revised to reflect the views of petitioners. Only the impoundment systems for LNG storage tanks must be capable of withstanding impact from wind borne missiles.

*Section 193.2067(b)(2) Wind Forces (design speed).*

This section prescribes the bases to be used in determining design wind forces. Its purpose is to assure that containers and other LNG facilities listed in § 193.2051 are designed to withstand the highest wind velocities that can be reasonably expected at the site.

Both AGA and INGAA have petitioned for changes, arguing that a wind design under paragraph (b)(2)(i) based on the prescribed $10^{-4}$ probability of exceedence of the "most critical combination of wind velocity and duration" would result in unrealistically high wind loads. AGA suggests that where probability of tornado occurrence exceeds $10^{-4}$, the design wind be 200 MPH, the wind speed currently prescribed under paragraph (b)(2)(ii) for use when adequate wind data are unavailable. Where probability of tornado occurrence is less than $10^{-4}$, the LNG facility would be subject to ANSI-A 58.1, currently prescribed for only small shop fabricated tanks. AGA implies that determining the probability of tornado occurrence is far easier than probability of wind velocity.

AGA would also limit the required wind design to containers and storage tank dikes, but since no explanation for the proposed change was given, this aspect of the petition was not considered. MTB considers the risk of wind damage other than missile penetration to be a serious matter for all the facilities listed in § 193.2051.

INGAA recommends that the 200 MPH wind speed, now permitted for design where adequate local data are not available to predict some other value, be adopted as an upper limit design standard for all situations.

As a principal argument, both petitioners cite NBS Technical Note 868, "Statistical Analysis of Extreme Winds" to show that a probabilistic determination of wind speed is unrealistic. In providing examples of one probabilistic approach, this report shows wind speeds for various return periods. Based on one type of distribution (Type II, Frechet), and only thirty-seven sample observations, the extreme wind at Corpus Christi, Texas, with an extrapolated return period of 10,000 years is given as 970 MPH.

AGA contends a wind speed this high is physically impossible. INGAA asserts that the 970 MPH speed is unrealistic and would preclude LNG facilities at most coastal locations. It argues that the recommended 200 MPH speed is a reasonable upper limit.

In support of its proposal to use ANSI-A 58.1 for the wind design of containers, AGA states that it contains reasonable steady wind criteria and is referenced by NFPA 59A. As an alternative to referencing ANSI, AGA suggests referencing NFPA 59A which also references ANSI-A 58.1, since experts continuously evaluate NFPA standards.

In commenting on the petitions, FERC states that a change in wording of the final rule is warranted, stating that the 970 MPH wind far exceeds the 200 MPH criteria for sites lacking adequate data.

MTB believes that ANSI-A 58.1 does not provide an adequate wind design level for facilities critical to public safety, such as large LNG facilities. According to NBS 868, ANSI uses only twenty years for a data base which gives unreliable predictability. Also, a mean return period of only fifty years is used (compared to the 10,000 year period) which would result in a high risk level, not consistent with other risk criteria in Part 193. Further, the Frechet (Type II) distribution, which is disclaimed by petitioners, is the basis for ANSI criteria. In this case, however, for the ANSI fifty-year return period, predicted extreme wind velocity for Corpus Christi is reduced by one magnitude to 97 MPH.

Therefore, MTB is not persuaded to adopt AGA's proposed use of ANSI-A 58.1 or NFPA 59A as a wind design basis for areas with a low probability of tornado occurrence.

The proposed requirements for wind force design in the NPRM essentially paralleled AGA's petition to use the probability of tornado occurrence as a threshold for applying a design wind speed. Basically, AGA would only change the design wind from the NPRM speed of 250 MPH to 200 MPH, which was adopted in the final rules for use where adequate local wind data is unavailable. In response to the NPRM, many commenters argued that setting a high design wind speed based on the probability of tornado occurrence would be unreasonable since the frequency of that speed would not be considered. They advocated a site specific wind speed based on probability of nonexceedence. AGA was one of these commenters.

In addition to this reason, MTB dropped the NPRM approach because locations not subject to tornadoes might have a relatively high probability of wind speeds caused by other types of storms that greatly exceed wind speeds that produce design loads of building standards. A major gap in design for wind forces and consequent nonuniform levels of protection dependent solely on the likelihood of tornadoes occurring in the area could have resulted.

Accordingly, MTB rejects AGA's recommendation to base design wind forces on a 0.5 percent probability of a tornado occurring within fifty years at a given site.

Section 193.2067 does not require the use of NBS Technical Note 868, "Statistical Analysis of Extreme Winds," for determining the probabilistic wind speed having a return period of 10,000 years. In extrapolating for return periods of 50, 10,000, and 1,000,000 years, the respective velocities with Type II distribution for Corpus Christi are 97, 970, and 9,426 MPH. The corresponding values for Type I distribution are 78, 128 and 172 MPH. These features alone show that either or both the wind data is inadequate or the technique is inappropriate.

Moreover, the NBS report is not intended to provide a standard method for determining extreme winds at any location. Its purpose, clearly stated, is part of an effort to evaluate wind provisions in existing building codes with particular emphasis on the twenty year data base and the Gumbel and Frechet types of data distribution for modeling. In essence, the NBS report concludes:

1. The twenty year data base (using only extreme velocities) is inadequate varying up to several hundred percent for a 1000 year recurrence interval at the same station using different twenty year data sets;

2. Type I and Type II distributions with small tail lengths were both found to fit extratropical as well as tropical storm data; and

3. No single distribution was universally applicable to all data sets.

The citation by petitioners of a single datum in the NBS report to demonstrate the unreliability of one predictive technique does not reflect on the reliability of other techniques that are available. Therefore, the use of this datum by petitioners is not a valid reason to delete the present requirement. There are several techniques that might be appropriate on a site specific basis. The number of years in the data base might be expanded. Alternatively, with a more classical approach, the data base could be expanded by using a broader wind range to correlate speed with return periods by applying the method of least squares to establish best fit equations that are consistent with cycles of natural phenomena. Several analytical techniques can be used to statistically test the degree of reliability of the correlation. Nevertheless, as discussed in the preambles of both the NPRM and the final rule, such techniques are only of value where adequate wind data are available at a potential LNG site. Where they are not, the final rule sets the design wind speed at 200 MPH.

Based on a review of tornado and other wind data, MTB expects that probabilistic speeds established by using appropriate methods and data will normally fall under 200 MPH. Therefore the 200 MPH wind speed is considered to be a safe upper limit for design wind forces whether or not adequate wind data are available for reliable probabilistic prediction. Consequently, § 193.2067(b)(2) is revised, consistent with INGAA's recommendation, to allow use of the 200 MPH design wind speed without having to make a data search and evaluation to determine if adequate data are available to predict a design wind speed. Still, the predictive alternative is retained for optional use where adequate data are available and reliable predictive techniques are used.

*Section 193.2109(c) Insulation.*

AGA and INGAA objected to the use of the term "noncombustible" to describe insulation cover. INGAA felt "self-extinguishing" should be used in the final rule, as proposed in the NPRM. AGA preferred "will not support combustion." Both petitioners note that the final rule seems to defy the FTC decision prohibiting "* * * such terms as 'non-burning', 'self-extinguishing', or 'noncombustible' or any term of the like meaning * * *" to describe the burning characteristics of cellular plastics, but, at the same time, recommend similar terminology.

The two different suggestions suppport the MTB contention, as fully and clearly stated in the preamble, that insulation and the terminology associated with it are presently in a state of flux. As stated in the preamble, MTB will use the term "noncombustible" (NFPA 59A–1979 uses this term in 4–1.5.1) until such time as other agencies or industry develops new criteria. Under the "noncombustible" term in the final rule, material other than cellular plastics must be used as insulation cover.

INGAA also recommended that "where practical" be added to modify the requirement that insulation covering not be subject to "ultraviolet decay." MTB agrees with the contention that there are instances, as on pumps, where it is impractical to use covering materials that are not subject to even a minute degree of decay. However, MTB is adding the word "detrimental" before "ultraviolet" rather than adopting the term "where practical," as the latter term is too indefinite.

*Section 193.2123(d) Valves.*

INGAA requested that this section be rewritten to apply only to valves that are intended for use during a controllable emergency. Since this suggestion is consistent with the intent of the rule, MTB has made a clarifying change to eliminate any possible inference that a broader application was intended.

*Section 193.2151 General design characteristics (impounding systems).*

AGA and INGAA recommended that the words "to the maximum extent possible, will prevent" be deleted and replaced by "will minimize the possibility of" in describing the degree to which impoundment design must prevent liquid from escaping. It was claimed the present wording is an absolute design requirement, and one nearly impossible to achieve. MTB feels the suggested wording, "minimize the possibility," could unduly weaken the rule and would be subject to broad interpretation, and, therefore, has not adopted the INGAA suggestion. The final rule provides sufficient design flexibility but requires that design provide for foreseeable events, considering the design spill specified by § 193.2155.

Both petitioners stated the present wording was adopted without the benefit of review and comment by industry, the public, or the TPSSC. This is a curious argument since the questioned wording derives directly from the NPRM.

*Section 193.2153(a) Classes of Impounding Systems.*

The final rule was changed from the NPRM to allow as much as 24 inches between a dike and the component impounded in a Class 1 impounding system. AGA and INGAA stated the 24-inch space is inadequate to provide a safe working environment for the operator's employees. INGAA recommended a change to 60 inches, whereas AGA proposed more generalized wording to permit distance adequate for maintenance provided the top of the dike is at or above the maximum liquid level of the component served.

FERC felt it would be reasonable to relax the 24-inch limit because of the limited space for personnel and equipment, commenting that only in-tank pumps would be possible.

Misunderstanding about the background, features, and effects of the different classes of impounding systems in Part 193 is made apparent by the comments. The classification of impounding systems derives from NFPA 59A, § 210, 1975 edition. Beginning in the ANPRM and NPRM, two separate classes were proposed for impoundment surrounding a container: A Class 1 configuration (inner face of dike in contact with container) and a Class 2 configuration (dike separated from container). The physical distinction between these two systems results in different safety benefits for each system, and an associated design standard may vary according to the inherent level of safety provided by the class of impoundment.

For example, for low distant diking (Class 2), additional impounding capacity above the required for Class 1 is considered necessary to provide for vapor borne, low friction kinetic flow from a major tank failure, since design configurations of the dike's inner face that will reliably prevent overflow have not yet been developed. With smaller spills, added capacity serves to protect against overflow from splash, jetting, and wave action. When dikes are high, and close-in (Class 2), the addded capacity provides a factor of safety for uncertainties about formation of vapor bubbles from heat transfer and super heat and their residence time with resulting expansion and reduced density of the mix, coupled with an upward surge of the column of impounded LNG above the level of equilibration due to the kinetics of a rapid release (U-tube effect).

With Class 1 systems, a dike located against the wall of a tank would serve to mitigate the potential of overflow from these causes even in the event of a major tank failure, since contact surface temperature would be lower, and rapid discharge would be restricted. Also, such a configuration, in providing some added support to a tank, would tend to limit the extent of tank failure and resulting size of opening. Accordingly, the required Class 1 impounding capacity is only 110 percent of storage capacity.

In developing the final rules, the NPRM version of Class 1 was modified to permit under Class 1 impoundment up to 24 inches of spacing between a dike's inner face and the tank impounded. This provision was intended for use with specific designs now in use, including protective dikes required under § 193.2155(a)(5)(ii). The purpose of the spacing is to provide a buffer to cushion or prevent excessive loads or shock due to foundation settlement, earthquakes, windloading or other forces from being transmitted between dikes and tanks. Also, it could provide for eccentricities in the configuration of a tank. Certain kinds of infrequent inspection or maintenance could, by design, be accomplished remotely without entry into the annulus by personnel. In addition, the spacing would permit insulation of the inner face of the dike, outer tank surface, or both in order to further minimize vapor dispersion from an impounding system with high close-in dikes that do not have the 150 percent of storage capacity required for Class 2 systems.

Installation of equipment and entry of personnel into the annular space for maintenance duties (except for infrequent occasions when the container is purged out of service) were not considered relevant in prescribing a maximum of 24 inches of separation. The paramount consideration was to balance construction needs against the desire to maintain the benefits intended for a Class 1 system. Also, with this dimension, during operation the effects of natural phenomena, such as ice build up by the migration of moisture in accordance with the laws of natural distribution, together with meterological effects, would mandate either that the annulus be filled with insulation, inert gas or other materials and sealed or covered. Thus, while providing additional safety benefits, this design would restrict spillage to essentially the same degree as a Class 1 system having the dike in contact with the container. Accordingly, MTB concluded that classification under Class 1 impoundment was appropriate.

The INGAA and AGA petitions to reclassify a Class 2 system with more than 24 inches of separation as a Class 1 system would serve only to reduce the minimum impounding capacity for a system with a great uncertainty in overflow potential. Such a change would destroy the principle of prescribing safety factors that are proportionate to the potential for overflow. Considering spacing above 60 inches in small increments, it is evident that logical justification of a Class 2 category and related provisions would be eliminated. Accordingly, the petitions are denied.

*Section 193.2161(a) Dikes, general.*

Western objects to the prohibition under this section of penetrations in dikes to accommodate piping or any other purposes, and argues that penetrations in LNG storage tank dikes should be permitted to accommodate transfer piping provided the penetrations meet the same structural standards required for dikes (§§ 193.2129 and 193.2155). Western claims that the prohibition imposes high construction costs at a baseload liquefaction plant, since at a multi-tank plant, a single set of pumps can serve all tanks at a plant from a position outside the impoundment area by running LNG transfer piping through the dikes. Western points out the final rule forces the operator to have a separate pumping system for each tank and to either put the loading pumps inside the tank or impoundment. In addition to costs, such placement, Western argues, presents maintenance and handling difficulties especially if high close-in dikes are used to reduce the exclusion zone. Providing additional space for pumps and maintenance within the impoundment, Western argues, might result in more impoundment capacity than necessary under the standards. In addition, Western expressed concern that as a result of increased wetted surface area, the required exclusion distance for thermal radiation and vapor dispersion might have to be increased.

While FERC supports the prohibition of dike penetrations at peak shaving and satellite facilities so as to assure dike integrity, it opposes the prohibition of dike penetrations for transfer lines at multiple tank plants because of the advantages of a central pumping system.

Assured containment of a major LNG spill inside an impounding space is the most crucial consideration in LNG safety. Safety features that rely on impoundment integrity, such as exclusion zones for thermal radiation and vapor dispersion, would not be effective unless a spill is contained. A major spill may result from a variety of causes, and such potential forms a basis for several safety standards, other than § 193.2161. For example, thermal exclusion zones are intended to provide safe distances from burning of a spill that could range in size from one that only covers the floor of the impounding system up to a total tank failure. Also, other standards such as § 193.215(a), § 193.2155(a) thru (c), and § 193.2181, concerning impoundment design and capacity, are clearly intended to assure dike integrity in the event of major tank failure.

Moreover, impoundment is one feature in LNG plant design whose performance capability will usually remain untested after construction unless an event requiring its complete integrity occurs. Since it is the last "line of defense" against potentially very serious consequences, the benefit of impoundment integrity weighs heavily against the low possibilities of events occurring that could result in a loss of containment.

The prohibition against penetrations is founded on the premise that where dikes are penetrated, a potential avenue is created for a spill of LNG to escape impoundment. There are two basic failure modes to be considered in assessing the acceptability of penetrations: First, there is failure of the penetrating piping in a way that would provide an open conduit for liquid to escape. Second, there is failure of the diking at the point of penetration, or at the point of discontinuity in the dike structure where the sealing structure for the penetration joins the basic diking. These two hypothetical failure modes are "either/or" possibilities, and are, therefore, additive in considering the probability of loss in dike integrity.

Considering the first failure mode in light of Western's petition, an environmental event, such as seismic or wind loads that exceed design, could result in tank failure and would be likely to result in failure inside impoundment of the transfer line as well, since by their design, transfer lines have equivalent or greater susceptability to failure from such events. Also, failure of a tank that results in its collapse (e.g., toe overload or tilt from other causes with subsequent spillage from the cryogenic shell causing embrittlement and fracture of the overstressed noncryogenic outer shell) will almost certainly rupture the transfer line inside impoundment. The point of penetration through the dike would be the most likely failure location because of the physical constraint and resulting stress. Thus, for safety considerations, it must be presumed that a tank failure would be accompanied by failure of the transfer line within the impounding system.

In the event of such failure, prevention of uncontrollable flow from impoundment would rely on the transfer line and valve located beyond the diking being unimpaired with the valve closed. Such reliance is not justified in view of the susceptability to damage of transfer lines when subjected to a tank-damaging environmental event. Also, even if loss of integrity of the external transfer system does not result from the environmental event, simultaneous thermal and mechanical shock from the sudden impact of LNG could cause the external cryogenic value, if initially at ambient temperature, to rupture. An incident of this type is reported to have occurred at the LNG plant in Arzew, Algeria, on March 30, 1977. As reported, an aluminum valve on the transfer line of an inground tank shattered when impacted by LNG without precooling. Spillage was estimated at 37,500 to 150,000 gallons, and superheat explosions from LNG contact with water continued for 12 hours. Windows 15km away were claimed to have been broken. One fatality at the plant resulted.

The second failure mode—loss of dike integrity—is of equal or greater concern. Where maximum stress levels are expected to be relatively high by design, logical engineering principles require a configuration that is regular and free of discontinuities in order to minimize uncertainties in stress analysis. The importance of this principle is recognized in the gas pipeline safety standards (49 CFR Part 192) where stress levels in pipelines must be reduced at locations near valve assemblies, fabricated assemblies, and certain fittings and connections, even though stresses are relatively controllable (e.g., fluid pressure is controlled by relief or other devices). It becomes more significant when the stress producing forces are not controllable, as the case would be in extreme environmental events coupled with loading from the collapsing transfer line and thermal contraction stress from impinging LNG, along with hydrodynamic action of the spilling fluid. Penetration by transfer lines in dikes would be subject to both uncertainties in stress analysis and indeterminate loading forces, and Western has offered no substantiation that the design standards it propose to apply to penetrations can be met. Even under normal operation, the point of penetration could be subject to frequent thermal cycling with the associated possibility of time-dependent deterioration of the dike's mechanical properties. Also, the seal structure for penetration could be subject to thermal shock and high thermal gradients from an LNG spill, with resulting mechanical distortions and seal failure.

The petition and partial supporting comment by FERC are primarily based on economic grounds. While MTB believes that added costs are likely, it is important to note that the Final Evaluation did not show § 193.2161 to be a high cost section requiring a detailed probability analysis of costs and benefits.

As to the alleged maintenance and handling difficulties, MTB believes that additional pumps should increase service life as well as reduce routine preventive maintenance.

Neither additional impounding capacity or increased exclusion distance would automatically follow from the penetration prohibition. Rather, it would be a design decision of the operator, since large capacity in-tank pumps; with high discharge pressure and complete systems for removal are currently available.

Considering the broad economic picture, most existing LNG plants have elected over-the-dike transfer. Even the petitioner has incorporated tank-top transfer in its plant planned for Point Conception, California, which would presumably include transfer over the dikes as a combined feature of safety and economics. Accordingly, the petition is denied.

*Section 193.2165 Dike dimensions.*

INGAA finds the phrase "inside edge of the top of the dike" confusing as it applies the second time in § 193.2165. However, the recommended change for clarity does not properly define the dimensions involved. We believe the term "liquid level impounded" may be the source of confusion, because it does not necessarily mean liquid level of the component served by impoundment as intended. MTB has revised the wording for clarity.

*Section 193.2175 Shared impoundment.*

AGA and INGAA argue that this rule could easily be interpreted to require each component inside an impounding system to be separately impounded, which would be impractical and unreasonable. The petitioners' suggested wording would require protection in accordance with § 193.2107, dealing with high and low temperature protection.

Section 193.2175 was intended as a more stringent requirement than § 193.2107. The original intent was that if items to be impounded as required by § 193.2149 are included within a single impounding system (shared impoundment), leakage from one item should not cause another to leak and possibly overwhelm the system. MTB now recognizes the unreasonableness in applying this policy to, say, a storage tank and its transfer line or other component combinations. As by far, the greatest hazard would be a leak from an LNG storage tank causing a leak in another storage tank. MTB believes protection can be reasonably provided in these cases and is revising the section to apply only to LNG storage tanks. Other components mentioned by INGAA, such as piping, valves, compressors, etc. would be covered by § 193.2107.

*Section 193 2181(a) Impoundment capacity, LNG storage tanks.*

AGA recommends that the required impoundment capacity for Class 2 and 3 impounding systems be changed from 150 percent to 110 percent, arguing that a 50 percent safety factor is unreasonable in light of the vapor dispersion zone required by § 193.2059 and the allowable use of vapor barriers under § 193.2163. Western recommends 100 percent for all classes of impoundment, plus any additional volume needed to meet the requirements of § 193.2151 and 193.2165, concerning dike design, and § 193.2179, impoundment capacity in general. Western argues that these sections will require varying degrees of capacity above 100 percent in amounts sufficient to keep a liquid impounded.

FERC argues that while it may be possible to design a dike to withstand phenomena such as wetting, splash, and wave action, the lack of acceptable hydrodynamic models justifies the 150 percent capacity.

As indicated by the FERC comment, dike designs which can assure containment of a spill from a major tank failure are unproven. In the case of low distant diking, configurations which can counteract horizontal components of motion in a rising wave of LNG impacting a dike face are only theoretical. Even with more testing, a question of scaling effects may remain, since large scale tests may not be practical.

With high close-in dikes, the question about formation and residence time of vapor bubbles from vaporization, with resulting expansion which could cause the column of LNG to overflow a dike, has not been fully resolved. Also, the rise in the impounded LNG column above the level of equilibration due to the kinetics of a rapid release (U-tube effect) could add to this problem.

Since designs that will reliably prevent overflow in the event of a major spill from an LNG storage tank have not yet been established, MTB believes that excess capacity is necessary to provide a factor of safety for Class 2 and 3 systems serving LNG storage tanks. Accordingly, MTB stands by its original position stated in the preamble of the NPRM and the final rules and leaves § 193.2181(a) unchanged.

*Clarifying amendments.* The scope of Part 193, as stated in § 193.2001, now exempts marine cargo transfer systems from any of the requirements in Part 193. Under the MTB/USCG memorandum of understanding (MOU) on the regulation of waterfront LNG facilities (published in the NPRM), the siting of these facilities, except with respect to vessel traffic management, is to be subject to MTB regulatory authority. Thus, as currently stated, the scope of Part 193 conflicts with the MOU regarding the siting of marine cargo transfer systems and associated facilities. Section 193.2001(b)(3) is, therefore, amended to make it clear that the Part 193 siting requirements apply to marine cargo transfer systems (not including those portions in navigable water excluded from jurisdiction under § 193.2001(b)(4)).

So that there is no doubt about which of the safety standards in Part 193 govern "siting," the title and scope of Subpart B are amended to refer to the Subpart B requirements as "siting requirements," rather than site-related design requirements. The "site-related design" term was used in the ANPRM and NPRM since the Act at that time did not specifically authorize regulations for siting LNG facilities. The siting provisions were proposed, therefore, as an aspect of facility design, which it is in a generic sense of design.

The current definition of "LNG facility" refers to pipeline facilities that are "used in the process of" activities related to producing, transferring, or storing LNG or changing LNG to gas. MTB believes the words "in the process of" restrict the meaning of "LNG facility" in a way not intended by the Act. To be more consistent with the Act's definition, the term "LNG facility" under § 193.2007 is amended by replacing the words "in the process of" with the word "for." This change more correctly classifies pipeline facilities as LNG facilities that are associated with the various LNG processes, even though they may not directly be a part of a particular process.

*Recordkeeping.* The effective date of the recordkeeping requirements of §§ 193.2119 and 193.2329 and other provisions incorporated by reference in Part 193 was postponed in the final rules document published at 45 FR 9184 pending coordination with the Office of Management and Budget under the Federal Reports Act. MTB has since determined that such coordination is not required by that Act and, consequently, an effective date for those recordkeeping requirements is established by this document as set forth above.

In view of the foregoing, 49 CFR Part 193 is amended as follows:

1. In § 193.2001, paragraph (b)(3) is revised to read as follows:

§ 193.2001 Scope of part.

* * * * *

(b) * * *

(3) In the case of a marine cargo transfer system and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before a storage tank.

* * * * *

2. In § 193.2005, paragraph (b)(1) is revised to read as follows:

§ 193.2005 Applicability.

* * * * *

(b) * * *

(1) The siting requirements apply only to LNG storage tanks that are significantly altered by increasing the original storage capacity or relocated, not pursuant to an application for approval filed as provided by paragraph (a)(2) of this section before March 1, 1978; and

* * * * *

3. In § 193.2007, the definition of "LNG facility" is amended to read as follows:

§ 193.2007 Definitions.

* * * * *

"LNG facility" means a pipeline facility that is used for liquefying or solidifying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas.

* * * * *

4. Section 193.2015 is revised to read as follows:

§ 193.2015 Petitions for finding or approval.

Where a rule in this part authorizes the Director to make a finding or approval, any operator may petition the Director to make such finding or approval. Petitions must be sent to the Director, Materials Transportation Bureau, 400 7th Street, SW., Washington, D.C. 20590, and be received at least 90 days before the operator requests that the finding or approval be made. Each petition must refer to the rule authorizing the action sought and contain information or arguments that justify the action. Unless otherwise specified, no public proceeding is held on a petition before it is granted or denied. Within 90 days after a petition is received, the Director notifies the petitioner of the disposition of the petition or, if the request requires more extensive consideration or additional information or comments are requested and delay is expected, of the date by which action will be taken.

5. Section 193.2051 is revised to read as follows:

§ 193.2051 Scope.

This subpart prescribes siting requirements for the following LNG facilities: Containers and their impounding systems, transfer systems and their impounding systems, emergency shutdown control systems, fire control systems, and associated foundations, support systems, and normal or auxiliary power facilities necessary to maintain safety.

* * * * *

6. In § 193.2057, paragraph (a)(1) is revised to read as follows, and item (6) of the table under paragraph (d) is amended by deleting the words "property line" and inserting the words "right-of-way" in lieu thereof:

§ 193.2057 Thermal radiation protection.

(a) * * *

(1) Within the thermal exclusion zone, the impounding system may not be located closer to targets listed in paragraph (d) of this section than the exclusion distance "d" determined according to this section, unless the target is a pipeline facility of the operator.

* * * * *

7. In § 193.2059, paragraph (d)(1)(i) is revised to read as follows:

§ 193.2059 Flammable vapor-gas dispersion protection.

* * * * *

(d) * * *

(1) * * *

(i) The rate of vaporization is not less than the sum of flash vaporization and vaporization from boiling by heat transfer from contact surfaces during the time necessary for spill detection, instrument response, and automatic shutdown by the emergency shutdown system but, not less than 10 minutes, plus, in the case of impounding systems for LNG storage tanks with side or bottom penetrations, the time necessary for the liquid level in the tank to reach the level of the penetration or equilibrate with the liquid impounded assuming failure of the internal shutoff valve.

* * * * *

8. In § 193.2061, paragraph (f) is revised, paragraph (g) is redesignated as (h), and a new paragraph (g) is added to read as follows:

§ 193.2061 Seismic investigation and design forces.

* * * * *

(f) An LNG storage tank or its impounding system may not be located at a site where an investigation under paragraph (c) of this section shows that any of the following conditions exists unless the Director grants an approval for the site:

(1) The estimated design horizontal acceleration exceeds 0.8g at the tank or dike foundation.

(2) The specific local geologic and seismic data base is sufficient to predict future differential surface displacement beneath the tank and dike area, but displacement not exceeding 30 inches cannot be assured with a high level of confidence.

(3) The specific local geologic and seismic data base is not sufficient to predict future differential surface displacement beneath the tank and dike area, and the estimated cumulative displacement of a Quaternary fault within one mile of the tank foundation exceeds 60 inches.

(4) The potential for soil liquefaction cannot be accommodated by design and construction in accordance with paragraph (b)(1) of this section.

(g) An application for approval of a site under paragraph (f) of this section must provide at least the following:

(1) A detailed analysis and evaluation of the geologic and seismic characteristics of the site based on the geotechnical investigation performed under paragraph (c) of this section, with emphasis on prediction of near-field seismic response.

(2) The design plans and structural analysis for the tank, its impounding system, and related foundations, with a report demonstrating that the design requirements of this section are satisfied, including any test results or other documentation as appropriate.

(3) A description of safety-related features of the site or designs, in addition to those required by this part, if applicable, that would mitigate the potential effects of a catastrophic spill (e.g., remoteness or topographic features of the site, additional exclusion distances, or multiple barriers for containing or impounding LNG).

(h) * * *

9. In § 193.2067, paragraphs (a)(3) and (b)(2) are revised to read as follows:

### § 193.2067 Wind forces.

(a) * * *

(3) In the case of impounding systems for LNG storage tanks, impact forces and potential penetrations by wind borne missiles.

(b) * * *

(2) For all other LNG facilities—

(i) An assumed sustained wind velocity of not less than 200 miles per hour, unless the Director finds a lower velocity is justified by adequate supportive data; or

(ii) The most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

### § 193.2109 [Amended]

10. In § 193.2109, paragraph (c) is amended by inserting the word "detrimental" between the words "to" and "ultraviolet."

11. In § 193.2123 paragraph (d) is revised to read as follows:

### § 193.2123 Valves.

* * * * *

(d) Powered local and remote operation must be provided for valves intended for use during a controllable emergency that would be difficult or excessively time-consuming to operate manually during such an emergency.

* * * * *

### § 193.2165 [Amended]

12. Section 193.2165 is amended by inserting the word "horizontal" between the words "the" and "distance" and by deleting the word "impounded" and inserting the words "in the component or vessel" in lieu thereof.

13. Section 193.2175 is revised to read as follows:

### § 193.2175 Shared impoundment.

When an impounding system serves more than one LNG storage tank, a means must be provided to prevent low temperature or fire resulting from leakage from any one of the storage tanks served causing any other storage tank to leak. The means must not result in a vapor dispersion distance which exceeds the exclusion zone required by § 193.2059.

## Subpart B [Title Amended]

14. In the table of sections and the text of the rules, the title of Subpart B is amended by deleting "Site Related Design Requirements" and inserting "Siting Requirements" in lieu thereof.

(49 U.S.C. 1674a; 49 CFR 1.53 and Appendix A of Part 1)

Issued in Washington, D.C., on August 21, 1980.

L. D. Santman,

*Director, Materials Transportation Bureau*

[FR Doc. 80-26213 Filed 8-27-80; 8:45 am]

BILLING CODE 4910-60-M

## INTERSTATE COMMERCE COMMISSION

## 49 CFR Part 1033

[Seventh Revised Service Order No. 1473]

## Various Railroads Authorized To Use Tracks and/or Facilities of the Chicago, Rock Island & Pacific Railroad Co., Debtor (William M. Gibbons, Trustee)

**AGENCY:** Interstate Commerce Commission.

**ACTION:** Seventh Revised Service Order No. 1473.

**SUMMARY:** Pursuant to Section 122 of the Rock Island Transition and Employee Assistance Act, Pub. L. 96-254, this order authorizes various railroads to provide interim service over Chicago, Rock Island and Pacific Railroad Company, Debtor (William M. Gibbons, Trustee), and to use such tracks and facilities as are necessary for operations. This order permits carriers to continue to provide service to shippers which would otherwise be deprived of essential rail transportation. In particular, Seventh Revised Service Order No. 1473, revises Appendix A, Item 12 of Sixth Revised Service Order No. 1473, by rescinding the authority for the Southwestern Oklahoma Railroad Company to operate between Mangum and Anadarko, Oklahoma, due to an apparent inability of the carrier to provide rail service as authorized.

**EFFECTIVE DATE:** 11:59 p.m., August 31, 1980, and continuing in effect until 11:59 p.m., November 30, 1980, unless otherwise modified, amended or vacated by order of this Commission.

**FOR FURTHER INFORMATION CONTACT:** M. F. Clemens, Jr. (202) 275-7840.

Decided: August 22, 1980.

Pursuant to Section 122 of the Rock Island Transition and Employee Assistance Act, Pub. L. 96-254, the Commission is authorizing various railroads to provide interim service over Chicago, Rock Island and Pacific Railroad Company, Debtor (William M. Gibbons, Trustee), (RI) and to use such tracks and facilities as are necessary for that operation.

In view of the urgent need for continued service over RI's lines pending the implementation of long-range solutions, this order permits carriers to continue to provide service to shippers which would otherwise be deprived of essential rail transportation.

Seventh Revised Service Order No. 1473, revises Appendix A, Item 12 of Sixth Revised Service Order No. 1473, by rescinding the authority for the