a certificate issued by a person authorized to issue such certificates by the veterinary services of the national government of the country of origin, stating:

(1) That all the provisions of this section have been complied with, including paragraphs (i) and (m) of this section;

(2) The paragraph of this section under which the dry-cured ham, pork shoulder, or pork loin was processed; and stating further that, if the product covered by the certificate:

(i) Is an Italian-type ham processed under paragraph (i)(1) of this section, it was processed for a minimum of 400 days;

(ii) Is a Serrano ham processed under paragraph (i)(2) of this section, it was:

(A) Processed for a minimum of 190 days in a country free of swine vesicular disease, in a facility authorized by the veterinary services of the national government of that country to process only meat from countries free of swine vesicular disease; or,

(B) Processed for a minimum of 560 days in any country, in a facility that may also process meat from countries where swine vesicular disease exists;

(iii) Is an Iberian ham processed under paragraph (i)(3) of this section, it was:

(A) Processed for a minimum of 365 days in a country free of swine vesicular disease, in a facility authorized by the veterinary services of the national government of that country to process only meat from countries free of swine vesicular disease; or,

(B) Processed for a minimum of 560 days in any country, in a facility that may also process meat from countries where swine vesicular disease exists;

(iv) Is a dry-cured pork shoulder, it was processed in accordance with paragraph (i)(4) of this section for a minimum of 240 days; or

(v) Is a dry-cured pork loin, it was processed in accordance with paragraph (i)(5) of this section for a minimum of 130 days.

Done in Washington, DC, this 27th day of October 1994.

Terry L. Medley,

Acting Administrator, Animal and Plant Health Inspection Service.

[FR Doc. 94–27274; Filed 11–2–94; 8:45 am]

BILLING CODE 3410–34–P

FEDERAL RESERVE SYSTEM

12 CFR Part 211

[Regulation K; Docket No. R–0793]

International Banking Operations

AGENCY: Board of Governors of the Federal Reserve System.

ACTION: Final rule.

SUMMARY: The Board of Governors of the Federal Reserve System (Board or Federal Reserve) amends its Regulation K concerning the permissible activities of state-licensed branches and agencies of foreign banks. Section 202(a) of the Federal Deposit Insurance Corporation Improvement Act of 1991 (FDICIA or Act) provides that after December 19, 1992, a state-licensed branch or agency of a foreign bank may not engage in any activity that is not permissible for a federal branch of a foreign bank unless the Board has determined that the activity is consistent with sound banking practice, and in the case of an insured branch, the Federal Deposit Insurance Corporation (FDIC) has determined that the activity would pose no significant risk to the affected deposit insurance fund. This amendment to Regulation K sets forth the application procedures which state-licensed branches and agencies of foreign banks will be required to follow in order to request the Board's permission to engage in or continue to engage in an activity which is not permissible for a federal branch of a foreign bank and the requirements of divestiture and cessation plans. Insured branches are also required to seek the approval of the FDIC to engage in or to continue to engage in such an activity. The final rule also amends Regulation K to clarify that no application will be required in connection with the conversion by a foreign bank of its federally-licensed branch or agency into a state-licensed branch or agency.

EFFECTIVE DATE: This regulation is effective on January 1, 1995, except for § 211.21(e) which is effective December 5, 1994.

FOR FURTHER INFORMATION CONTACT: Kathleen M. O'Day, Associate General Counsel (202/452–3786), Ann E. Misback, Managing Senior Counsel (202/452–3788), John W. Rogers, Attorney (202/452–2798); Michael G. Martinson, Assistant Director (202/452–3640), Division of Banking Supervision and Regulation, Board of Governors of the Federal Reserve System. For the hearing impaired only, Telecommunication Device for the Deaf [TDD], Dorothea Thompson (202/452–3544), Board of Governors of the Federal Reserve System, 20th and C Streets, N.W., Washington, D.C. 20551.

SUPPLEMENTARY INFORMATION: Section 202 of the Act amended section 7 of the International Banking Act (IBA) by adding several new subsections concerning the establishment and termination of foreign bank branches in the United States. New subsection 7(h) of the IBA provides that:

(1) IN GENERAL.— After the end of the 1-year period beginning on the date of enactment of the [Act] a State branch or State agency may not engage in any type of activity that is not permissible for a Federal branch unless—

(A) the [Federal Reserve] Board has determined that such activity is consistent with sound banking practice; and

(B) in the case of an insured branch, the Federal Deposit Insurance Corporation has determined that the activity would pose no significant risk to the deposit insurance fund.

12 U.S.C. 3105(h)(1).

In order to implement this provision, the Board issued a proposed rule on January 6, 1993, with a request for public comment. (58 FR 513). In taking this action, the Board stated that it would consider revisions to the proposed rule as appropriate and on the basis of the comments received. The comment period ended on March 5, 1993. The Board indicated that it would accept and process applications under the statute during the pendency of the rulemaking. No applications have been received.

The proposed rule required a foreign bank operating a state-licensed branch or agency in the United States, which desires to engage in or continue to engage in an activity that is not permissible for a federal branch, pursuant to statute, regulation or order or interpretation issued by the Office of the Comptroller of the Currency (OCC), to file an application in letter form to the Board for permission to conduct or to continue to conduct such activity. The proposed regulation set forth the required contents of the application and a procedure for divestiture or cessation of impermissible activities not approved by the Board.

The Board specifically requested comment on several items, including the contents of the application, whether prior notice rather than an application might be appropriate for certain classes of activities, and whether the conduct of activities permitted by the OCC pursuant to informal rather than formal interpretation, opinion or advice should require the filing of an application.

In addition, the Board requested comment on another provision of Regulation K which requires that a

foreign bank wishing to convert from a federal branch or agency license to a state branch or agency license file for approval to do so with the Board.

The Board received four public comments on the regulation. Comments were submitted by a state banking supervisor, an association of state banking supervisors, a trade association and a law firm. The commenters generally were supportive of the approach taken in the proposed rule. The comments focused on whether an activity-based approach rather than a bank-based approach would be preferable, whether the conduct of activities permitted by the OCC pursuant to informal rather than formal interpretation, opinion or advice should require an application and whether an application would be required to conduct an activity that the OCC permitted but only subject to quantitative restrictions. The commenters uniformly stated that no application should be required to convert from a federal branch or agency license to a state branch or agency license.

On March 2, 1993, the FDIC issued its own proposed regulation implementing section 7(h) of the IBA. See 58 FR 11992. The Board has consulted with the FDIC concerning the response to its proposed rule. Both the Board and the FDIC have attempted to make their final rules as consistent with one another as possible and thereby to reduce the burden that might be imposed on applicants. A description of the final rule and an analysis of the relevant comments follows.

Determining if an Activity is Permissible for a Federal Branch

The commenters generally stated that no application should be required from a state-licensed branch or agency for the conduct of an activity that is permitted for a federal branch pursuant to interpretation, opinion or advice issued in writing by the OCC or its staff, as well as by statute, regulation official bulletin, circular or order. The commenters argued that a stricter requirement would result in a competitive disadvantage to state licensed offices and thereby would be inconsistent with the intent of the statute. The Board agrees with that argument. Accordingly, the conduct of activities permitted for a federal branch pursuant to interpretation, opinion or advice issued in writing by the OCC or its staff would not require an application, so long as such interpretation, opinion or advice is still considered valid, *i.e.*, it has not been overruled by the OCC or found invalid by a court of competent jurisdiction. In addition, because national banks and federal branches may rely on a written opinion of counsel that an activity is permissible under the National Bank Act or other applicable statutes, in the Board's view, it would be appropriate to permit state-licensed branches and agencies also to rely on such opinions, provided the opinion of counsel is based on a reasoned analysis of applicable statutes, regulations, official bulletins, circular, orders, or interpretations, opinions or advice of the OCC or its staff. The Board plans to consult with the OCC when questions arise as to the permissibility of any particular activity. Insured branches of foreign banks also should consult with the FDIC as to the permissibility of particular activities.

Bank Approach Versus Activity Approach

The Board's proposed rule took a bank-based approach to implementing the statute; that is, an application was required from each bank wishing to conduct or continue to conduct an activity not permissible for a national bank. The comments suggested that the Board instead take an activity based approach, at least with respect to activities which the commenters believed presented minimal risk. One commenter suggested that the Board entertain applications from industry trade groups with respect to the conduct of such activities.

The Board has determined that a combination of the two approaches is the appropriate way to proceed and has modified the proposed rule accordingly. As described in further detail below, the final rule provides that certain categories of activities are consistent with sound banking practice and that no application should be required to conduct such activities. The fact that the Board's prior consent is not required does not preclude the Board from taking any appropriate action within its authority with respect to such activities if the facts and circumstances warrant such action.

Application Not Required in Certain Instances

The first category of activities exempted from the application requirement are certain activities already determined by the FDIC not to pose a significant risk to the Bank Insurance Fund pursuant to § 362.4(c)(3) of the FDIC's regulations (12 CFR part 362). The Board has determined not to require an application under this part for the conduct of any such activity that the FDIC would permit an insured state bank to conduct directly, provided the activity is permissible for the branch or agency under applicable state law and any other applicable federal law or regulation. The Board believes the conduct of these activities, with proper controls, is consistent with safe and sound banking. As set forth in 12 CFR 362.4(c)(3)(i)–(ii)(A), the exempted activities include guarantee activities and activities found by the Board by regulation or order to be closely related to banking. In addition, the Board has determined to exempt from the application requirement any activity conducted as agent rather than as principal, provided that the activity is one that could be conducted by a state-chartered bank headquartered in the same state as the branch or agency is licensed. Of course, all activities of the branches and agencies remain subject to examination. If any particular activity is found to be improperly conducted, the Board retains enforcement authority to require conformance to safety and soundness requirements.

Finally, like the proposed rule, the final rule provides that an application under this section normally shall not be required where an activity is permissible to a federal branch but the OCC imposes a quantitative restriction on the conduct of such activity by the federal branch. The commenters were supportive of this exemption. The Board believes appropriate quantitative restrictions can be addressed on a case-by-case basis as part of the ongoing supervisory process.

Contents of Application

Section 211.29(b) of the proposed regulation provided that the application shall be in letter form and shall contain certain information, including among other things, a description of the activity in which the branch or agency desires to engage or in which it is already engaged, the foreign bank's financial condition, the assets and liabilities of the branch or agency, the projected effect of the proposed activity on the financial condition of the foreign bank and the branch or agency, and in the case of an application by a state-licensed insured branch, a statement of why the proposed activity will pose no significant risk to the deposit insurance fund.

The commenters suggested that applicants not be required to provide information already available to the Federal Reserve through its general examination and supervisory process. Accordingly, the Board has deleted from the final rule the requirement to provide certain financial information. The Board may request such information in individual cases if the information in its

possession is either out of date or otherwise deemed insufficient.

The Board and the FDIC have consulted concerning the type of information which each agency will need in order to make an informed judgment and have agreed on a common list of information in order that applicants will need to prepare only one application which, in the case of insured branches, may be submitted to both agencies. It is contemplated that the Board and the FDIC will review such applications simultaneously.

Standards To Be Examined

Section 211.29(d) of the final rule sets forth the standards that the Board will examine in order to determine whether a particular activity is consistent with sound banking practice. These factors are:

- What types of risks, if any, the activity poses to the U.S. operations of the foreign banking organization;
- If the activity poses any such risks, the magnitude of each risk; and
- If a risk is not *de minimis*, the actual or proposed procedures to control and minimize such risk.

Each of these factors shall be evaluated in light of the ability of the foreign bank to provide financial and managerial support to the branch or agency, the performance record of the foreign bank in general and the branch or agency in particular, and the volume of the proposed activity. The Board may also determine that a particular activity, after consideration of the above factors and subject to any conditions or limits imposed by the Board, may be conducted by any other state-licensed branch or agency without further application to the Board.

This section remains unchanged from the proposed rule.

Cessation or Divestiture

In the event that a state branch or agency is required to cease conducting an activity pursuant to the final regulation, § 211.29(f) sets forth the guidelines that must be followed to divest or cease the impermissible activity. Generally, this section provides that the state branch or agency shall submit a written plan of divestiture or cessation within 60 days of (1) being notified by the Board or the FDIC that an application to continue to conduct the activity has been denied, (2) the effective date of the regulation in the event that the foreign bank elects not to apply for permission to continue to conduct the activity, and (3) any change in statute, regulation, order or OCC interpretation that renders the activity impermissible. Divestiture or cessation shall be completed within one year, or sooner if the Board so directs. The Board requested comment on whether or not this period of time should be longer or shorter.

No comments were received on this portion of the proposed rule. Accordingly, no substantive changes were made.

Conversion From Federal to State License

As suggested by the commenters, the Board has determined not to require an application under the Foreign Bank Supervision Enhancement Act in connection with the conversion of: (1) a federally-licensed branch to a state licensed-branch; or (2) a federally licensed-agency to a state-licensed agency. Applications are not considered necessary in light of the fact that state-licensed branches and agencies must restrict their activities to those permissible for a federal branch or receive the Board's approval to engage in the activity. Section 24 of Regulation K will be amended accordingly.

Regulatory Flexibility Act

Pursuant to section 605(b) of the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), it is certified that this final rule will not have a significant impact on a substantial number of small entities.

List of Subjects in 12 CFR Part 211

Exports, Federal Reserve System, Foreign banking, Holding companies, Investments, Reporting and record-keeping requirements.

For the reasons set forth in the preamble, the Board amends 12 CFR part 211 as set forth below:

PART 211—INTERNATIONAL BANKING OPERATIONS (REGULATION K)

1. The authority citation for Part 211 is revised to read as follows:

Authority: 12 U.S.C. 221 *et seq.*, 1818, 1841 *et seq.*, 1843 *et seq.*, 3101 *et seq.*, 3901 *et seq.*

2. In § 211.21, paragraph (e) is revised to read as follows:

§ 211.21 Definitions.

* * * * *

(e) *Change the status* of an office means convert a representative office into a branch or agency, or an agency into a branch, but does not include renewal of the license of an existing office.

* * * * *

3. In § 211.29, the text is added to read as follows:

§ 211.29 Applications by state-licensed branches and agencies to conduct activities not permissible for federal branches.

(a) *Scope.* A state-licensed branch or agency shall file with the Board a prior written application for permission to engage in or continue to engage in any type of activity that:

(1) Is not permissible for a federal branch, pursuant to statute, regulation, official bulletin or circular, or order or interpretation issued in writing by the Office of the Comptroller of the Currency; or

(2) Is rendered impermissible due to a subsequent change in statute, regulation, official bulletin or circular, written order or interpretation, or decision of a court of competent jurisdiction.

(b) *Exceptions.* No application shall be required by a state-licensed branch or agency to conduct any activity that is otherwise permissible under applicable state and federal law or regulation and that:

(1) Has been determined by the FDIC pursuant to 12 CFR 362.4(c)(3)(i)–(c)(3)(ii)(A) not to present a significant risk to the affected deposit insurance fund;

(2) Is permissible for a federally-licensed branch but the OCC imposes a quantitative limitation on the conduct of such activity by the federal branch;

(3) Is conducted as agent rather than as principal, provided that the activity is one that could be conducted by a state-chartered bank headquartered in the same state in which the branch or agency is licensed; or

(4) Any other activity that the Board has determined may be conducted by any state-licensed branch or agency of a foreign bank without further application to the Board.

(c) *Contents of application.* An application submitted pursuant to paragraph (a) of this section shall be in letter form and shall contain the following information:

(1) A brief description of the activity, including the manner in which it will be conducted and an estimate of the expected dollar volume associated with the activity;

(2) An analysis of the impact of the proposed activity on the condition of the U.S. operations of the foreign bank in general and of the branch or agency in particular, including a copy, if available, of any feasibility study, management plan, financial projections, business plan, or similar document concerning the conduct of the activity;

(3) A resolution by the applicant's board of directors or, if a resolution is not required pursuant to the applicant's organizational documents, evidence of

approval by senior management, authorizing the conduct of such activity and the filing of this application;

(4) If the activity is to be conducted by a state-licensed insured branch, a statement by the applicant of whether or not it is in compliance with 12 CFR 346.19 and 346.20, Pledge of Assets and Asset Maintenance, respectively;

(5) If the activity is to be conducted by a state-licensed insured branch, statements by the applicant:

(i) That it has complied with all requirements of the Federal Deposit Insurance Corporation concerning an application to conduct the activity and the status of the application, including a copy of the FDIC's disposition of such application, if available; and

(ii) Explaining why the activity will pose no significant risk to the deposit insurance fund; and

(6) Any other information that the Reserve Bank deems appropriate.

(d) *Factors considered in determination.* (1) The Board shall consider the following factors in determining whether a proposed activity is consistent with sound banking practice:

(i) The types of risks, if any, the activity poses to the U.S. operations of the foreign banking organization in general and the branch or agency in particular;

(ii) If the activity poses any such risks, the magnitude of each risk; and

(iii) If a risk is not de minimis, the actual or proposed procedures to control and minimize the risk.

(2) Each of the factors set forth in paragraph (d)(1) of this section, shall be evaluated in light of the financial condition of the foreign bank in general and the branch or agency in particular and the volume of the activity.

(e) *Application procedures.* Applications pursuant to this section shall be filed with the responsible Reserve Bank for the foreign bank. An application shall not be deemed complete until it contains all the information requested by the Reserve Bank and has been accepted. Approval of such an application may be conditioned on the applicant's agreement to conduct the activity subject to specific conditions or limitations.

(f) *Divestiture or cessation.* (1) In the event that an applicant's application for permission to continue to conduct an activity is not approved by the Board or, if applicable, the FDIC, the applicant shall submit a detailed written plan of divestiture or cessation of the activity to the responsible Reserve Bank within 60 days of the disapproval. The divestiture or cessation plan shall describe in detail the manner in which the applicant will divest itself of or cease the activity and shall include a projected timetable describing how long the divestiture or cessation is expected to take. Divestitures or cessation shall be complete within one year from the date of the disapproval, or within such shorter period of time as the Board shall direct.

(2) In the event that a foreign bank operating a state branch or agency chooses not to apply to the Board for permission to continue to conduct an activity that is not permissible for a federal branch or which is rendered impermissible due to a subsequent change in statute, regulation, official bulletin or circular, written order or interpretation, or decision of a court of competent jurisdiction, the foreign bank shall submit a written plan of divestiture or cessation, in conformance with paragraph (f)(1), of this section within 60 days of January 1, 1995 or of such change or decision.

By order of the Board of Governors of the Federal Reserve System, October 27, 1994.

William W. Wiles,

Secretary of the Board.

[FR Doc. 94–27121 Filed 11–2–94; 8:45 am]

BILLING CODE 6210–01–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. 27297; Amendment No. 71–25]

Amendment to the South Florida Low Offshore Airspace Area

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Technical amendment.

SUMMARY: This action amends the description of the South Florida Low airspace area to exclude the airspace within the Grand Bahama terminal control area (TCA) and the Nassau TCA. At the present time, the South Florida Low airspace area is correctly depicted on aeronautical charts as excluding the airspace of the underlying Grand Bahama and Nassau TCAs. However, the current airspace description of this airspace area is erroneous in that it inadvertently includes the Grand Bahamas and the Nassau TCAs as part of the South Florida Low airspace area. This action corrects this error.

EFFECTIVE DATE: November 3, 1994.

FOR FURTHER INFORMATION CONTACT: Reginald C. Matthews, ATP–230, Air Traffic Rules Branch, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, DC 20591, telephone (202) 267–8783.

SUPPLEMENTARY INFORMATION:

Background

The Offshore Airspace Reconfiguration Final Rule published March 2, 1993 (58 FR 12128), amended the Federal Aviation Regulations (FAR), in pertinent part, by designating additional control areas as offshore airspace areas or en route domestic airspace areas. The offshore areas were divided into high and low areas and an effort was made to establish a uniform floor of controlled airspace for certain air traffic operations. Through that rule, the South Florida control area was revised and redesignated as the South Florida Low offshore airspace area. The rule also extended the airspace of the South Florida Low airspace area from 2,700 feet mean sea level (MSL) up to, but not including, 18,000 feet MSL.

The lateral boundaries of the South Florida Low were further revised, by amendment (58 FR 33907; June 22, 1993), to extend from latitude 28°00'00" North to latitude 34°00'00" North. However, both amendments to the South Florida Low airspace area inadvertently included the underlying airspace within the Grand Bahama TCA and the Nassau TCA, both of which have airspace segments extending above 2,700 feet MSL. The South Florida Low is correctly depicted on aeronautical charts as excluding the airspace of the underlying TCAs. However, the airspace description does not reflect this exclusion as was intended.

The Amendment

This amendment to part 71 of the Federal Aviation Regulations (14 CFR part 71) revises the airspace description of the South Florida Low airspace area by excluding the Grand Bahama TCA and the Nassau TCA.

The FAA has determined that this regulation is not a "significant regulatory action" under Executive Order 12866; is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

The Amendment

In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR part 71 as follows:

PART 71—[AMENDED]

1. The authority citation for 14 CFR part 71 continues to read as follows:

Authority: 49 U.S.C. app. 1348(a), 1354(a), 1510; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389; 49 U.S.C. 106(g); 14 CFR 11.69.

§ 71.1 [Amended]

2. The incorporation by reference in 14 CFR 71.1 of Federal Aviation Administration Order 7400.9B, Airspace Designations and Reporting Points, dated July 18, 1994, and effective September 16, 1994, is amended as follows:

Paragraph 6007—Offshore Airspace Areas

* * * * *

South Florida Low, FL [Revised]

That airspace extending upward from 2,700 feet MSL bounded on the west by the Houston Oceanic CTA/FIR; bounded on the north from west to east by the Jacksonville Air Route Traffic Control Center boundary, a line 12 miles from and parallel to the U.S. shoreline and lat. 34°00'00"N., bounded on the east by the New York Oceanic CTA/FIR and the San Juan Oceanic CTA/FIR; bounded on the south from east to west by the Santo Domingo FIR, the Port-Au-Prince CTA/FIR and the Havana CTA/FIR; excluding the Grand Bahama TCA and the Nassau TCA.

* * * * *

Issued in Washington, DC, on October 28, 1994.

Harold W. Becker,

Manager, Airspace-Rules and Aeronautical Information Division.

[FR Doc. 94–27288 Filed 11–2–94; 8:45 am]

BILLING CODE 4910–13–M

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14 CFR Part 73

[Airspace Docket No. 94–ASW–12]

Change Time of Designation for Restricted Areas R–5103A, B, C, and D; McGregor, NM

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action amends the time of designation for Restricted Areas R–5103A, B, C, and D, McGregor, NM. The U.S. Army has determined that the present published time of designation for the restricted areas does not accurately reflect their actual times of use. This action lessens the burden on the public by amending the published time of designation to reflect limited weekend activity in these areas by the military.

EFFECTIVE DATE: 0901 UTC, February 2, 1995.

FOR FURTHER INFORMATION CONTACT: Steve Riley, Military Operations Program Office (ATM–420), Office of Air Traffic System Management, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, DC 20591; telephone: (202) 267–7130.

SUPPLEMENTARY INFORMATION:

The Rule

This amendment to part 73 of the Federal Aviation Regulations amends the time of designation for Restricted Areas R–5103A, B, C, and D, McGregor, NM, from "0700–2000 local time; other times by NOTAM" to "0700–2000 local time Monday-Friday; other times by NOTAM." Following a review of its special use airspace the U.S. Army, Fort Bliss, TX, determined that it has a continuing requirement for the restricted areas; however, the current published time of designation does not accurately reflect the time the airspace is required for military use. This action amends the published time of the restricted areas but does not change the existing boundaries or the types of activities currently conducted within R–5103A, B, C, or D. Because this action is a minor technical amendment in which the public is not particularly interested, I find that notice and public procedure under 5 U.S.C. 553(b) are unnecessary. § 73.51 of part 73 of the Federal Aviation Regulations was republished in FAA Order 7400.8B dated March 9, 1994.

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore—(1) is not a "significant regulatory action" under Executive Order 12866; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

Environmental Review

This action reduces the time of designation of the restricted areas. Accordingly, this action is not subject to environmental assessments and procedures as set forth in FAA Order 1050.1D, "Policies and Procedures for Considering Environmental Impacts."

List of Subjects in 14 CFR Part 73

Airspace, Navigation (air).

Adoption of the Amendment

In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR part 73 as follows:

PART 73—[AMENDED]

1. The authority citation for part 73 continues to read as follows:

Authority: 49 U.S.C. app. 1348(a), 1354(a), 1510, 1522; E.O. 10854; 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389; 49 U.S.C. 106(g); 14 CFR 11.69.

§ 73.51 [Amended]

2. Section 73.51 is amended as follows:

R–5103A McGregor, NM—[Amended]

By removing the current "Time of designation. 0700–2000 local time; other times by NOTAM." and substituting the following: "Time of designation. 0700–2000 local time, Monday-Friday, other times by NOTAM."

R–5103B McGregor, NM—[Amended]

By removing the current "Time of designation. 0700–2000 local time; other times by NOTAM." and substituting the following: "Time of designation. 0700–2000 local time, Monday-Friday, other times by NOTAM."

R–5103C McGregor, NM—[Amended]

By removing the current "Time of designation. 0700–2000 local time; other times by NOTAM." and substituting the following: "Time of designation. 0700–2000 local time, Monday-Friday, other times by NOTAM."

R–5103D McGregor, NM—[Amended]

By removing the current "Time of designation. 0700–2000 local time; other times by NOTAM." and substituting the following: "Time of designation. 0700–2000 local time, Monday-Friday, other times by NOTAM."

Issued in Washington, DC, on October 25, 1994.

Harold W. Becker,

Manager, Airspace-Rules and Aeronautical Information Division.

[FR Doc. 94–27289 Filed 11–2–94; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 2

[Docket No. RM93–19–000]

Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement

Issued: October 26, 1994.

AGENCY: Department of Energy, Federal Energy Regulatory Commission.

ACTION: Final rule; policy statement.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing this policy statement to announce a general policy regarding the pricing of transmission services provided by public utilities and transmitting utilities under the Federal Power Act.

The new policy is designed to allow much greater transmission pricing flexibility than was allowed under previous Commission policies.

EFFECTIVE DATE: This policy statement is effective as of October 26, 1994.

FOR FURTHER INFORMATION CONTACT:

James H. Douglass, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, Telephone: (202) 208–2143 (legal issues)

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SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the **Federal Register**, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in Room 3104, at 941 North Capitol Street, NE., Washington, DC 20426.

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Policy Statement

Issued: October 26, 1994.

The Federal Energy Regulatory Commission (Commission) announces a new policy regarding the pricing of transmission services provided by public utilities and transmitting utilities under the Federal Power Act (FPA).[1] The new policy is designed to allow much greater transmission pricing flexibility than was allowed under previous Commission policies.

Greater pricing flexibility is appropriate in light of the significant competitive changes occurring in wholesale generation markets, and in light of our expanded wheeling authority under the Energy Policy Act of 1992 (EPAct).[2] These recent events underscore the importance of ensuring that our transmission pricing policies promote economic efficiency, fairly compensate utilities for providing transmission services, reflect a reasonable allocation of transmission costs among transmission users, and maintain the reliability of the transmission grid. The Commission also recognizes that advances in computer modeling techniques have made possible certain transmission pricing methods that once would have been impractical.

Based on the record developed in this proceeding, the Commission concludes that there appears to be a variety of workable, non-traditional transmission pricing methods that offer potential improvements in fairness, practicality and economic efficiency. For instance, the Commission believes that distance-sensitive rates using contract path or flow-based methods will be acceptable if properly supported.

Accordingly, the Commission will permit more flexibility to utilities to file innovative pricing proposals that meet the traditional revenue requirement and will allow such proposals to become effective 60 days after filing,[3] as long as they satisfy certain pricing principles discussed below. We refer to this category of proposals as conforming proposals. We will also permit utilities to file pricing proposals that deviate from the traditional revenue requirement, as long as they meet certain requirements discussed below. We refer to these filings as non-conforming proposals. Non-conforming proposals will be permitted to go into effect only prospectively from the date the Commission determines that such a pricing proposal meets the statutory requirements of the FPA, *i.e.*, is just and reasonable and not unduly discriminatory or preferential.

In addition to the guidance in this Policy Statement regarding conforming and non-conforming transmission pricing proposals, there are two specific subject areas for which we have instituted separate proceedings, and which may require transmission pricing flexibility. *See* Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking, IV FERC Stats. & Regs. ¶ 32,507, 59 FR 35274 (July 11, 1994); Alternative Power Pooling Institutions under the Federal Power Act, Notice of Inquiry, FERC Stats. & Regs. ¶ _____ (1994). In those proceedings, we are examining what type of pricing policy is appropriate. We intend to examine whether any special procedural mechanisms are necessary to coordinate our pricing policy and filings proposing alternative power pooling institutions.

I. Introduction

The Commission will consider a broad range of rate design methods, within a utility's embedded original cost revenue requirement, as discussed in Section IV. We will also consider proposals that deviate from a utility's embedded original cost revenue requirement (subject to certain filing procedures and evaluation criteria), as discussed in Section V. The U.S. Supreme Court has recognized the Commission's broad latitude to fix rates. There is no single valid theory of ratemaking. Under the statutory standard of "just and reasonable" it is the result reached, not the method employed, which is controlling. *Duquesne Light Co.* v. *Barasch*, 488 U.S. 299, 316 (1989) (*Duquesne*); *Federal Power Commission* v. *Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944) (*Hope*). As the Court observed in *Duquesne*:

> The designation of a single theory of ratemaking as a constitutional requirement would unnecessarily foreclose alternatives which could benefit both consumers and investors.

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[1] 16 U.S.C. 824(e), 796(23).

[2] *See* 16 U.S.C. 824j, 824k.

[3] Whether to suspend such a filing and impose a refund condition will be decided on a case-by-case basis. *See* West Texas Utilities Company, 18 FERC ¶ 61,189 (1982).

488 U.S. at 316. Consistent with our broad ratemaking authority, in this Policy Statement we announce that we will consider various ratemaking methods to encourage proposals that will produce consumer benefits.

The Commission's traditional transmission pricing policy has permitted a public utility providing firm transmission service to charge rates designed to yield annual revenues equal to the rolled-in embedded cost [4] of the utility's integrated transmission grid on a postage stamp basis (*i.e.*, not distance sensitive), including the rolled-in costs of any new facilities or upgrades that become part of the integrated system. For non-firm transmission service, the Commission has permitted rates to reflect, in addition to the variable costs of providing the service, a charge up to a 100 percent contribution to the fixed costs of providing the service, with the proviso that pricing must reflect the characteristics of the service provided, *e.g.*, the degree of interruptibility. Traditionally, transmission rates have been based on a "contract path" model, *i.e.*, an assumed transmission path from point A to point B, that may or may not represent the actual flows of power on the grid.

In recent years, the Commission attempted to address the industry's changing needs by modifying its historical transmission pricing policy [5] to allow a type of incremental cost pricing.[6] In order to provide new or expanded transmission service, a utility may be required to add expensive transmission assets, which can result in an increase in rolled-in embedded cost rates. To address this possibility, the Commission has allowed a utility to charge transmission-only customers the higher of embedded costs (for the system as expanded) or incremental expansion costs, but not the sum of the two.[7] When the transmission grid is constrained and the utility chooses not to expand its system, the Commission has allowed a utility to charge the higher of embedded costs or legitimate and verifiable opportunity costs, but not the sum of the two. The opportunity costs, in turn, are capped by incremental expansion costs. This type of pricing has been referred to as "or" pricing or *Northeast Utilities* pricing.[8] While "or" pricing will continue to be allowed under the Commission's pricing policy, the Commission is prepared to move beyond "or" pricing to consider other pricing alternatives.

II. Request for Comments

On June 30, 1993, the Commission issued a notice of technical conference and request for comments concerning these policies and other transmission pricing issues. *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, IV FERC Stats. & Regs., Notices ¶ 35,024 (1993) (Pricing Inquiry). The Commission received comments and reply comments from 165 entities, representing a broad cross-section of parties that participate in, or are affected by, the electric utility industry. The Commission also held technical conferences on April 8 and 15, 1994, that provided further opportunity for public comment and discussion. A summary of the comments received in this proceeding that included proposals for change is presented in Appendix A.[9]

Those commenting expressed a variety of opinions on many transmission pricing issues, including whether transmission rates should reflect distance sensitivity and whether and how to compensate for flows over parallel paths. The commenters were nearly unanimous in their call for the Commission to provide further guidance concerning acceptable pricing methods. Some commenters indicated that such guidance would assist the formation of regional transmission groups (RTGs) by indicating what pricing policies will be acceptable to the Commission.

While many of the comments expressed dissatisfaction with the Commission's current pricing policy, the comments indicated no consensus for any one alternative pricing method. However, the commenters expressed general agreement that some type of transmission pricing reform by the Commission is needed. There was a strong consensus that such reform should: (1) Allow greater pricing flexibility; (2) provide pricing that is "transparent" [10] and easy to administer; (3) promote economic efficiency, that is, allow transmission customers to make informed decisions as to the economic consequences of their choices, and encourage transmission owners to make efficient use of, and investment in, the transmission grid; (4) ensure equity and fairness; and (5) facilitate the development of RTGs.[11]

However, there was disagreement regarding the degree to which reform of transmission pricing should stress administrative simplicity versus accuracy. Some commenters advocated the continued use of traditional contract path and postage stamp rates, in part because these rates are simple to administer. Other commenters proposed methods, such as distance sensitive and flow-based rates, that may give better price signals but involve more complexity.

In response to the comments received, the Commission has decided to revise its policies to permit utilities much greater flexibility. We are prepared to accept a variety of pricing methods in addition to *Northeast Utilities* pricing. *Northeast Utilities* pricing will still be acceptable because it fully comports with the pricing principles we adopt today. However, based on the record developed herein, a variety of other pricing methods will also be acceptable.

The Commission concludes that greater pricing flexibility is now required for several reasons. First, exclusive use of methods that worked reasonably well in the past does not provide sufficient flexibility to accommodate the evolving needs of transmission owners and users in a more competitive era.[12] It is important

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[4] Embedded cost is generally viewed as including a fair rate of return on the original cost of facilities, less depreciation, plus operation and maintenance expenses, and taxes. Embedded costs are those costs reflected in the utility's books of account.

[5] *See* Northeast Utilities Service Company (Re: Public Service Company of New Hampshire), Opinion No. 364–A, 58 FERC ¶ 61,070, *reh'g denied*, Opinion No. 364–B, 59 FERC ¶ 61,042, *order granting motion to vacate and dismissing request for rehearing*, 59 FERC ¶ 61,089 (1992), *affirmed in part and remanded in part sub nom.* Northeast Utilities Service Company v. FERC, Nos. 92–1165, *et al.*, 993 F.2d 937 (1st Cir. 1993), *order on remand*, 66 FERC ¶ 61,332, *reh'g denied*, 68 FERC ¶ 61,041 (1994), *appeal pending* No. 94–1949 (1st Cir. Sept. 6, 1994); Pennsylvania Electric Company, 58 FERC ¶ 61,278, *reh'g denied and pricing policy clarified*, 60 FERC ¶ 61,034, *reh'g denied*, 60 FERC ¶ 61,244 (1992), *affirmed sub nom.* Pennsylvania Electric Co. v. FERC, 11 F.3d 207 (D.C. Cir. 1993) (*Penelec*).

[6] Incremental cost is the cost of increasing the level of service provided. In practice, it typically refers to the cost of additional facilities needed to provide the requested service.

[7] This current pricing policy is based on three goals that the Commission adopted in the *Northeast Utilities* case: (1) to hold native load customers harmless, (2) to provide the lowest reasonable cost-based price to third-party firm transmission customers, and (3) to prevent the collection of monopoly rents by transmission owners and promote efficient transmission decisions.

[8] *See supra* note 5.

[9] Appendix A will not appear in the Code of Federal Regulations.

[10] We interpret the commenters to mean that transmission pricing would be identified separately from generation pricing, that transmission pricing would identify all cost components of the transmission service (*e.g.*, identify ancillary service costs) and that pricing information would be readily available to all bulk power participants.

[11] Two RTG agreements recently filed with the Commission postpone dealing with the transmission pricing issue by simply providing that pricing shall be consistent with the Commission's transmission pricing policy. *See* Pacificorp *et al.* (on behalf of Western Regional Transmission Association), 69 FERC ¶_____ (1994); Southwest Regional Transmission Association, 69 FERC ¶_____) (1994).

[12] *See* American Electric Power Service Corporation, 67 FERC ¶ 61,168 at 61,490 (1994).

to gain practical experience with alternative transmission pricing approaches in order to assess how best to accommodate the current and future needs of the industry in providing efficient and reliable power supply as the industry becomes increasingly competitive. Second, our existing "or" pricing policy may not always encourage the most efficient investments in and use of the transmission grid. Third, regional differences (*e.g.*, power flow patterns and population densities) justify a more flexible policy that can account for such differences. Fourth, a more flexible pricing policy may be necessary to implement effectively our RTG policy, which encourages RTGs to deal with a broad range of issues, including pricing, and which suggests that the Commission, in appropriate circumstances, will defer to RTG decision-making.[13] The Commission is convinced that a more flexible pricing policy can help to achieve broader policy goals and be implemented in a manner that is just and reasonable and not unduly discriminatory or preferential.

In developing a more flexible transmission pricing policy, the Commission's basic premise is that comparable access to efficiently priced transmission services is critical to the continued development of a competitive wholesale power market. With this fundamental underpinning in mind, the Commission has developed several pricing principles that new pricing proposals should follow. Some of these principles reflect existing pricing requirements that any new proposal must continue to follow. Other principles, while important, may have to be balanced against one another.

Before discussing the pricing principles and specific new methodologies that may be acceptable, there are several points we would like to make. First, the Commission believes that improving price signals is an important goal, but recognizes that trade-offs between improved price signals and simplicity are inevitable. On one hand, transmission service is typically a small component of the total cost of electric service and, therefore, arguably does not merit overly complex pricing methods.[14] On the other hand, in many cases transmission capacity is a scarce and valuable resource, and its pricing can send signals that promote the efficient siting of generation facilities and efficient decisions as to the dispatch of generation. In addition, new technological advances, particularly in computer technology, have made certain innovative pricing methodologies workable in practice. We therefore must balance the sometimes competing goals of better price signals and simplicity when evaluating any new pricing methodologies.

Second, the Commission also recognizes that it must move beyond certain precedent in order to entertain alternative pricing proposals. For example, instead of requiring a single postage stamp rate for transmission over the integrated transmission system of a corporation, such as a holding company system with several affiliated operating companies,[15] we will now entertain proposals such as zonal rates [16] that take distance within the corporation into account, provided that such proposals are consistent with the pricing principles that we adopt today.[17] Having analyzed new methodologies presented in the record, we believe that some departures from our traditional integrated system pricing requirement will be supportable under the FPA if appropriately developed.

Third, as previously noted, several commenters urged the Commission to provide a framework for reforming pricing that would supplement the Commission's RTG Policy Statement. The Commission continues to believe that it would be appropriate for RTGs to address transmission pricing. We anticipate that the pricing flexibility provided herein, and our willingness to give appropriate deference to RTG decisions, will not only encourage the development of RTGs, but will also encourage RTGs to address transmission pricing, including regional issues affecting such pricing.

Finally, we do not want our policy to be so rigid that utilities will be prohibited from proposing pricing alternatives that may deviate from the traditional revenue requirement. Because transmission remains a natural monopoly, we believe it will be difficult for transmission owners to support such pricing under the FPA, particularly market-based transmission rates. However, we believe that it would be shortsighted to foreclose completely consideration of such non-conforming proposals. The electric utility industry of today is very different from the electric utility industry that existed only 20 years ago and even five years ago. Just as we today change our policies to reflect recent changes, we must remain flexible if we are to respond to future changes. Accordingly, we detail procedures and standards below that will be used in evaluating transmission pricing proposals that do not conform to the traditional revenue requirement.

We now turn to the requirements of the FPA and the pricing principles that we have developed consistent with those requirements.

III. Transmission Pricing Principles

Transmission pricing must adhere to the FPA requirement that transmission rates be just and reasonable and not unduly discriminatory or preferential. This requirement is found in sections 205, 206, and 212. In addition, section 212(a) requires that wholesale transmission rates for services ordered under section 211 must:

- Permit the recovery of all costs incurred in connection with the transmission services and necessary associated services, including, but not limited to, an appropriate share, if any, of legitimate, verifiable and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, and the costs of any enlargement of transmission facilities;
- Promote the economically efficient transmission and generation of electricity; and
- To the extent practicable, ensure that costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the applicant for the 211 order and not from a transmitting utility's existing

[13] Policy Statement Regarding Regional Transmission Groups, 58 FR 41626 (Aug. 5, 1993) III FERC Stats. & Regs. ¶30, 976 (July 30, 1993) (RTG Policy Statement).

[14] Historically, transmission plant has represented less than 12 percent of total electric plant in service for major investor-owned Electric Utilities and generally less than 6 percent of the cost of electricity to end users. (Derived from cost data in *1992 Energy Information Administration Financial Statistics of Major Investor-Owned Electric Utilities.*)

[15] *See, e.g.*, Southern Company Services, 55 FERC ¶61,173 (1991), *order on reh'g*, 58 FERC ¶61,093 (1991), *aff'd, Alabama Power Company* v. *FERC*, 993 F.2d 1557 (D.C. Cir. 1993).

[16] Under zonal rates, a utility's facilities are divided (disaggregated) into a number of zones. The total cost assigned to any request for transmission service would depend on the number of zones traversed and the rate for each zone.

[17] If a utility, or public utility holding company system, proposes to disaggregate its integrated transmission system into distinct components (or zones) for purposes of developing transmission rates for third parties, it must apply the same approach consistently and uniformly across the entire system for all uses of the system, including its own uses.

We caution that any such zonal approach or other disaggregated approach would also need to appropriately recognize all flows on the system. For example, if flows are used to allocate costs on some lines, flows should be used to allocate costs for all remaining lines in the same way; *e.g.*, it would not be acceptable to presume that each transmission customer proportionally uses and relies upon all remaining lines of the integrated system.

wholesale, retail, and transmission customers.

Consistent with these statutory requirements, which give the Commission discretion in setting rates within the zone of reasonableness, and in light of the comments received in response to the Pricing Inquiry, we have formulated five principles that will guide our approval of pricing for both firm and non-firm transmission services in the future. The Commission believes these principles comport with the statutory requirements of sections 205, 206 and 212 of the FPA, and, in the interest of developing a uniform transmission pricing policy, we will apply these same principles to the pricing of transmission service whether that service is provided under section 205, 206, or 211 of the FPA.

The first two principles reflect fundamental requirements previously established by the Commission. A conforming proposal is one that meets the first principle, *i.e.*, it proposes pricing that meets the traditional revenue requirement. A conforming proposal must also meet the second principle, *i.e.*, it must reflect comparability. As to the other three principles, however, these reflect goals that an applicant with a conforming proposal must try to meet, but that ultimately may need to be balanced against one another in the Commission's determination of whether the proposed rates are just and reasonable.

A non-conforming proposal is one that does not meet the first principle, *i.e.*, it does not propose pricing that meets the traditional revenue requirement. However, a non-conforming proposal must meet the second principle, *i.e.*, it must reflect comparability. If a non-conforming proposal does not clearly demonstrate that the comparability requirement is met, it will be rejected. As to the remaining three principles, these reflect goals that an applicant with a non-conforming proposal must try to meet, but that may need to be balanced against one another. In addition, as part of its balancing, the Commission will consider the extent to which the first principle is not met.[18]

We discuss these principles in detail below.

1. Transmission Pricing Must Meet the Traditional Revenue Requirement

For conforming proposals, transmission prices must be based on the costs of the transmission service provided. The process of determining transmission prices involves three distinct steps. First, a utility must determine its total company revenue requirement, the capital component of which traditionally has been measured by embedded (depreciated original) cost. Second, a utility must allocate among individual customers or classes of customers that portion of the total revenue requirement that is attributable to providing transmission services, in a manner which appropriately reflects the costs of providing transmission service to such customers or classes of customers. Finally, the utility must design rates to recover those allocated costs from each customer class.

Different customers may pay different rates if they use the system in different ways. In the aggregate, however, rates are designed so that a transmission owner meets, but does not exceed, its revenue requirement. That is, it should be able to collect revenues from all its customers equal to the sum of its prudently incurred embedded costs, including return on capital.

There are two reasons for requiring transmission pricing to meet the traditional revenue requirement. First, it appears that transmission will remain a natural monopoly for the foreseeable future. It is unlikely that market-based prices for monopoly services, especially for firm transmission service, could be justified under the FPA at the present time, under the current industry structure. However, it is clear that there is no single appropriate ratemaking method under the FPA. The end result is the appropriate yardstick against which to measure the legality of a rate order, not the ratemaking method. Thus, although no single ratemaking method is necessarily favored by the FPA, this pricing principle will ensure that transmission users pay a just and reasonable price for transmission services and that transmission owners, while being appropriately and adequately compensated,[19] will not be able to exercise their market power to collect exorbitant rates.

Second, we believe that pricing within an embedded cost revenue requirement provides adequate incentives for transmission owners to provide comparable transmission services, as long as the transmission owner has the opportunity for full cost recovery. When upgrades are required, the transmission owner may incur significant expenses related to planning and siting new facilities. For example, a utility may be required to pay for environmental mitigation associated with the construction of new transmission facilities. Such costs will be recoverable by the transmission owner if they are prudently incurred.

In addition, under the traditional revenue requirement principle, transmission owners clearly may, with appropriate support,[20] recover the legitimate and verifiable costs of services they provide that are ancillary to transmission services, such as load following, reactive power compensation, and backup power services. However, transmission customers should also be permitted to provide these services themselves or to obtain them from someone else if this is feasible.

Finally, as discussed in Section IV below, we intend to allow significant latitude and a wide variety of non-traditional rate design proposals, within a cost cap based on the total company revenue requirement.

2. Transmission Pricing Must Reflect Comparability

Any new transmission pricing proposal, conforming or non-conforming, must meet the Commission's recently announced comparability standard. In *American Electric Power Service Corporation (AEP)*, 67 FERC ¶ 61,168 (1994), the Commission articulated a new standard for judging whether access to transmission services is unduly discriminatory, or anticompetitive. The Commission noted that "[a]n open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system."[21] This principle has been applied to all open access tariffs filed since *AEP*, as well as to transmission services provided by RTGs.[22]

There is a relationship between price and quality of service (*i.e.*, in general, higher quality service costs more). In Florida Municipal Power Agency v. Florida Power & Light Co., 67 FERC ¶ 61,167 at 61,482 (1994) (*FMPA*), the Commission stated, "[s]ince FMPA

[18] A pricing proposal that deviates from cost only slightly may be easier to justify than one that results in prices several times cost.

[19] *Duquesne*, 488 U.S. at 316; Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia, 262 U.S. 679 (1923); *Hope*, 320 U.S. at 602.

[20] *See* Northern States Power Company (Minnesota and Wisconsin) Opinion No. 383, 64 FERC ¶ 61,324 (1993), *reh'g pending* (reactive power).

[21] 67 FERC at 61,490.

[22] *See* PacifiCorp, *et al.* (on behalf of Western Regional Transmission Association), 69 FERC _____; Southwest Regional Transmission Association, 69 FERC at _____.

wants to be able to use the transmission system as freely as does Florida Power, it must pay a rate that reflects that equality." As a result of the relationship between quality of service and price discussed most recently in *FMPA*, and the growing importance of service comparability, we will require that pricing be comparable. Comparability of service applies to price as well as to terms and conditions. Comparability of transmission pricing involves a "golden rule of pricing"—a transmission owner should charge itself on the same or comparable basis that it charges others for the same service.[23]

This golden rule has several implications. First, for purposes of setting FERC-jurisdictional rates, costs must be allocated between jurisdictional and non-jurisdictional customers in a consistent way, to determine the cost responsibility of the two sets of customers.[24]

Second, when a utility uses its own transmission system to make off-system sales, it should "pay" for transmission service at the same price that third-party customers pay for the same service, and credit the transmission revenues to its native load customers. This treatment restricts the transmission owner's ability to gain an unfair advantage in the bulk power market by selling itself transmission service at a discount that would be subsidized by native load and transmission-only customers.[25]

Pricing comparability does not mean that the Commission is endorsing an end result in which there are no differences in prices paid by various customers. For example, the Commission is not suggesting that prices must be based on highly aggregated costs so that all customers face a uniform rate per kWh of service. Rather, we are receptive to pricing proposals that disaggregate costs in order to give better price signals to all users of the system—third parties and the transmission owner itself. Such disaggregation still permits different customers to pay different prices. Pricing comparability does not rule out such a result.

Finally, comparability of pricing includes certainty of pricing. A transmission customer should have pricing certainty comparable to that of the transmitting utility, *e.g.*, the same transmission pricing certainty for long-term power contracts as the transmitting utility has.

3. Transmission Pricing Should Promote Economic Efficiency

Section 212(a) of the FPA, as amended by EPAct, states that transmission pricing should promote economically efficient generation and transmission of electricity.[26] In our view, this means that transmission pricing should promote good decision-making and foster:

- Efficient expansion of transmission capacity;
- Efficient location of new generators and new load;
- Efficient use of existing transmission facilities, including the efficient allocation of constrained capacity through appropriate market clearing mechanisms; and
- Efficient dispatch of existing generating resources.

To the extent practicable, transmission rates should be designed to reflect marginal costs,[27] rather than embedded costs, in a manner consistent with the remaining principles. We favor marginal cost prices in order to promote efficient decision-making by both transmission owners and users.[28] In the short-run, marginal transmission costs are primarily line losses and, when lines are congested, opportunity costs. In the long-run, marginal transmission costs include all the costs of the transmission system and support services. The Commission recognizes the complexity of estimating marginal cost on the transmission grid and of implementing pricing that follows marginal transmission costs, but we encourage experimentation in this area.[29] On a case-by-case basis, we will balance the desirability of more economically efficient price signals against the additional complexity of implementing such pricing.

4. Transmission Pricing Should Promote Fairness

As a general matter, transmission pricing should be fair and equitable. This has two important implications. First, the EPAct requires that, to the extent practicable, existing wholesale, retail and transmission customers should not pay for the costs incurred in providing wholesale transmission services ordered under section 211. Similarly, we do not believe that third-party transmission customers should subsidize existing customers. We believe this principle should apply equally to transmission services under both section 211 and sections 205 and 206.

A second implication of the fairness principle is that economic harm that could be created during a period of transition from one pricing approach to another should be mitigated to the extent practicable. Solutions to any transition problems arising from pricing reform should balance fairness considerations associated with any reform against the potential efficiency improvements, and should mitigate the hardships arising from any reform. The major purpose of transmission pricing reform should be to provide more efficient price signals, particularly for new transmission uses, and not simply to reallocate sunk costs.

5. Transmission Pricing Should Be Practical

Transmission pricing should be practical and as easy to administer as appropriate given the other pricing principles. A user should be able to calculate how much it will be charged for transmission service. Some pricing proposals may be so complex that they are difficult to understand and analyze. Such complexity, while not fatal, should be balanced by efficiency gains or other advantages produced by such complexity.

IV. Guidance Regarding Pricing Proposals That Conform to the Traditional Revenue Requirement

In addition to the five general principles above, the Commission provides guidance on specific pricing proposals, including examples of acceptable pricing approaches and clarification of limitations on pricing flexibility.

It is important for those involved in transmission pricing discussions and negotiations to have a common understanding of the attributes of

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[23] There is a similar "golden rule or access"—provide the same or comparable services to others as you provide yourself.

[24] The Commission is not in any way suggesting any interference with state authority to determine the appropriate ratemaking methodology for bundled retail sales.

[25] In *PSI*, for example, the Commission required that PSI take transmission service under its own transmission tariff when making market-based power sales. The Commission adopted this approach to prevent PSI from using its transmission ownership to exercise an unfair competitive advantage in wholesale power markets. Public Service Company of Indiana, Inc., Opinion No. 349, 51 FERC ¶ 61,367 at 62,201 (1990), *order on rehearing*, PSI Energy, Inc., 52 FERC ¶ 61,260, *order granting clarification*, 53 FERC ¶ 61,131 (1990), *appeal dismissed sub nom.* Northern Indiana Public Service Co. v. FERC, 954 F.2d 736 (D.C. Cir. 1992).

[26] 16 U.S.C. 824k(a).

[27] Alfred Kahn, *infra* n.28, defines marginal cost as "[t]he cost of producing one more unit; it can equally be envisioned as the cost that would be saved by producing one less unit."

[28] *See* 1 Alfred E. Kahn, The Economics of Regulation 63–86.

[29] Such proposals should be fully supported, with as much detail as possible. *See* New England Power Company, Opinion No. 352, 52 FERC ¶ 61,090 (1990), *reh'g denied*, Opinion No. 352–A, 54 FERC ¶ 61,055 (1991), *aff'd sub nom.* Town of Norwood, Massachusetts v. FERC, 962 F.2d 20 (D.C. Cir. 1992).

various pricing proposals. For example, various parties advocate the use of "megawatt mile" pricing. Several distinct pricing proposals carry the same "megawatt mile" label. Therefore, those proposing transmission pricing reform must provide a clear explanation of their proposal.

As the industry considers possible pricing reform, the following three attributes of any transmission pricing method should be specified to provide a common framework for analysis:

- The method for measuring cost for purposes of rate design: embedded cost, incremental cost, the Commission's current "or" policy, long-run marginal cost, or short-run marginal cost;
- The method for treating power flows: contract path or flow-based approach; and,
- The method for grouping transmission facilities: corporate postage stamp versus more disaggregated approaches, such as zones, or line-by-line methods.[30]

We anticipate that a wide variety of pricing proposals may be reconciled with the traditional revenue requirement. In theory, acceptable cost-based pricing that satisfies our principles could be designed for many combinations of these possible attributes. For example, prices could reflect incremental cost (the first attribute), be based on flow (the second attribute), and be allocated on a line-by-line basis (the third attribute). A different approach is taken by changing any one of the attributes, *e.g.*, zones instead of lines. Therefore, many varieties of cost-based pricing are possible.

We fully intend to be flexible and to consider innovative, conforming pricing approaches that accommodate the changing needs of the competitive bulk power market. This applies to pricing for firm as well as non-firm transmission services. The pricing principles set out in the prior section are intended to guide RTGs and individual utilities in their consideration of new approaches. To provide further guidance, we discuss below examples of new cost-based pricing methods that we believe can be made consistent with our principles. These examples are intended to be illustrative. Other approaches also may be consistent with the principles. In all cases, we emphasize that pricing reform must have a purpose consistent with the principles. We want transmission pricing that supports good and consistent decisionmaking by transmission system users and owners.

A. Examples of Specific Pricing Methods That Conform to the Traditional Revenue Requirement

The following pricing approaches are examples of methods that the Commission would find acceptable, assuming an adequate showing by the utility. In this context, a conforming method is one that clearly meets the first two fundamental requirements and demonstrates that it is capable of satisfying the other three pricing principles (which ultimately may need to be balanced against one another in the Commission's determination of whether the proposed rates are just and reasonable). Of course, the rates resulting from its use must be shown to be just, reasonable and not unduly discriminatory or preferential.

(1) Examples of Acceptable Transmission Pricing by an Individual Utility

A variety of pricing proposals from an individual utility could be acceptable under the five pricing principles. The range of possible approaches includes various combinations of: (1) a traditional contract path approach or a flow-based approach; (2) costs aggregated at the utility level, at a zonal level, or at the line-by-line level; and (3) various cost concepts for rate design, such as embedded cost, "or" cost, incremental cost, or short-run marginal cost. Not all of these possible combinations, however, would necessarily satisfy our principles.

Examples of pricing reform that the Commission would approve if proposed by an individual utility and if they satisfy our principles include:

- Zonal "or" pricing based on power flows from zone to zone within a utility, or within the members of a holding company system. Zonal rates should be supported by showing the use made of separate zones by an individual transaction. Such rates should be supported by an explanation of the data base required and the computer modeling needed to implement it.
- Flow-based line-by-line rates, based on embedded costs "or" pricing. Such rates should be supported by an explanation of the data base required and the computer modeling needed to implement it.
- "Or" pricing, at the corporate level using the traditional contract path approach. This is the current Commission standard and remains an acceptable pricing policy that satisfies our pricing principles.

(2) Examples of Acceptable Transmission Pricing by an RTG

The Commission will provide substantial latitude for innovative, conforming pricing proposals by a regional transmission group that meets the requirements of our RTG Policy Statement.[31] We will give more latitude to RTGs than to individual utilities. This is for two reasons. First, an RTG represents the combined interests of both transmission owners and transmission users, as well as the appropriate participation of state authorities, so pricing proposals are likely to represent an appropriate balancing of those interests. Second, the more attractive proposals for treating regional loop flow problems work better if all the utilities in the region use the same method.

An RTG could propose any pricing reform that is open to an individual utility and also other reforms that address the loop flow issue. Many approaches to reforming transmission pricing that were suggested in the record of the Pricing Inquiry address the loop flow issue and appear to require a regional approach. From the comments, the Commission discerns two major alternatives to traditional contract path pricing that RTGs could choose for dealing with loop flow:

- "Enhanced" contract path pricing, which improves the contractual institutions underlying traditional contract path trading;[32] and
- Flow-based pricing, which refers to pricing designed to reflect the actual or projected power flows associated with a transaction.

Cost-based pricing could be designed to accommodate either of these alternatives. Examples of pricing reform based on a flow-based approach that the Commission would look approvingly on if proposed by an RTG and if consistent with our principles include:

- A MW-mile method, which could be implemented in one of several ways. For example, it could be based on "or" pricing and line-by-line power flows. Alternatively, a MW-mile approach could be based on embedded cost for the whole company, allocated as the ratio of transaction-specific megawatt-miles to total megawatt-miles.

[30] Under a line-by-line pricing method, the costs of each transmission line, or segment, are allocated to individual transmission transactions, based on the usage each transaction makes of each line or segment.

[31] Policy Statement Regarding Regional Transmission Groups, 58 FR 41626 (Aug. 5, 1993), III FERC Stats. & Regs. ¶30,976 (July 30, 1993); *See also* PacifiCorp, *et al.* (on behalf of Western Regional Transmission Association), 69 FERC at _____; Southwest Regional Transmission Association, 69 FERC at _____.

[32] "Enhanced contract path" refers to any approach intended to reconcile capacity rights between points of receipt and delivery and actual power flows on a network of lines.

• Postage-stamp "or" ratemaking at the utility level that is combined with power flow analysis to determine the compensation due to all transmission owners on the parallel paths. This would be a departure from the current contract path approach.

• Zonal "or" pricing based on power flow analysis to determine the use a transaction makes of the facilities in each zone.

• Short-run marginal cost pricing with transmission prices based on line-by-line losses and opportunity costs caused by power flow constraints.

RTGs may be able to design a pricing approach that combines elements of flow-based pricing with elements of contract path pricing. An example might be contract-path pricing for capacity rights to engage in long-term firm transactions combined with flow-based pricing for short-term, nonfirm transactions that are not covered by such rights. As can be seen from these examples, the Commission will provide RTGs substantial flexibility in choosing among a wide range of pricing approaches.

(3) Examples of Unacceptable Transmission Pricing

As discussed above, any pricing proposal, even a proposal that does not conform to the traditional revenue requirement, must meet the just and reasonable standard of the FPA. Below we list two types of pricing proposals which we find unacceptable.

• Postage-Stamp "And" Pricing: Some utilities have proposed so-called "and" pricing, which would add an embedded cost rate to an incremental cost rate for the same service over the same facilities. The proposals have been based on traditional postage stamp ratemaking for which costs are aggregated at the utility level. This type of pricing has been found by the Commission to be unjust and unreasonable.[33] We cannot see how such an approach is consistent with either our fairness principle or our efficiency principle.[34]

• Pricing by Individual Utilities to Account for Loop Flow: While individual utilities may propose new and innovative pricing methods that seek to apportion transmission costs on the basis of scheduled flows (*e.g.*, zonal or line-by-line methods), we also believe that it would be inappropriate for individual utilities to reform their own approach to transmission pricing in a way that is inconsistent with regional practices regarding unscheduled or inadvertent flows (loop flow).[35] We are concerned that individual public utilities may propose approaches to loop flow pricing that lead to a patchwork of mutually inconsistent loop flow pricing methods within a region. Accordingly, a utility's proposal to use flow-based pricing generically to recover the costs of unscheduled inter-utility power flows will be treated as a non-conforming proposal if it is inconsistent with regional loop flow practices, such as use of a contract path convention.[36]

V. Pricing Proposals That Do Not Conform to the Traditional Revenue Requirement

The Commission clearly prefers pricing proposals that are designed not to exceed the traditional revenue requirement. As noted, we believe that given the current industry structure it will be difficult to justify non-conforming proposals. In addition, we believe that the flexibility permitted under this revised transmission pricing policy should be adequate to satisfy the needs of today's electric utility industry, particularly given the current structure of the industry. Nevertheless, the electric utility industry is continuing to evolve[37] and we must ensure that our policies do not impede the continued development of competitive bulk power markets, or the development of new market structures and transmission arrangements. The Commission will consider pricing proposals necessary to accommodate such developments. Some of the proposals discussed in this proceeding may exceed the traditional embedded cost revenue requirement. Such proposals will be considered *provided* they meet certain filing procedures and evaluative criteria. We will provide two procedural avenues for considering non-conforming proposals. We will also provide guidance on the type of evidentiary showing necessary to support such proposals.

A. Procedures for Proposals That Do Not Conform to the Traditional Revenue Requirement

Any public utility that seeks non-conforming pricing must have on file with the Commission an open access transmission tariff offering comparable services. Such comparability tariff must have been accepted for filing by the Commission before a non-conforming pricing proposal will be considered. Moreover, utilities proposing non-conforming transmission pricing must submit such pricing proposals either: (a) in conjunction with a section 205 conforming transmission pricing proposal (the non-conforming proposal would be reflected as alternative "pro forma" rate sheets to the conforming proposal); or (b) in a petition for declaratory order.

(1) Alternative "Pro Forma" Rate Sheets

Under this procedure, the Commission and interested parties would review the non-conforming proposal in conjunction with review of a companion conforming pricing proposal.[38] The conforming proposal would be subject to the notice and suspension procedures of section 205. The non-conforming proposal would not. The non-conforming proposal would be litigated at the same time as the conforming proposal, but could not take effect, if at all, until the end of the proceeding. If, at the end of the proceeding, the Commission determines that the alternative, non-conforming rate proposal is acceptable under the FPA, the Commission will allow the utility to make a compliance rate filing, and the rates will be put into effect prospectively.

This procedure will permit the Commission to determine the extent to which the proposal deviates from the traditional revenue requirement, which may be necessary in determining whether the other features of the proposal are sufficient to offset this. It

[33] *See* Penelec, *supra* n.5.

[34] The flexibility that we endorse in this Policy Statement regarding cost disaggregation, among other things, addresses the industry's underlying concerns regarding "or" pricing. That is, while we cannot justify pricing that purports to recover two measures of a single cost, allowing the entity to account for costs on a disaggregated basis would permit separate pricing for separate facilities or small groupings of facilities. Hence, we would entertain proposals for flow-based line-by-line "or" pricing. This would permit the use of embedded costs for some lines when this is the higher of embedded or incremental costs, and the use of incremental cost for other lines when this is the higher of embedded or incremental costs.

[35] Of course, such individual utility pricing may be appropriate if there are no objections to the loop flow solution from any affected neighboring utilities or transmission customers.

[36] However, a public utility may seek on a case-by-case basis relief from the Commission, including appropriate compensation, in situations in which it is experiencing severe unscheduled loop flows on its system because of specific power transactions by other neighboring utilities and it has been unable to resolve the problem through existing industry mechanisms. *See American Electric Power Service Corp., et al.*, 49 FERC ¶61,377 at 62,381 (1989).

[37] In recent months, the pace of change in the electric industry has increased dramatically. Certain state proceedings on industry restructuring, as well as proceedings before this Commission, have contributed to the development of innovative proposals by both industry participants and academicians. These evolutionary changes support the need for flexibility and the need to permit non-conforming pricing proposals.

[38] *See* Pacific Gas Transmission, 66 FERC ¶61,384, *reh'g denied*, 67 FERC ¶61,247 (1994), *reh'g pending*.

will also permit an examination of how risk, and hence cost of capital, will vary under the conforming and non-conforming proposals. Another benefit of the alternative "pro forma" rate sheets procedure is that the utility would be able to implement the non-conforming pricing, assuming it was just and reasonable, immediately following the Commission's final order.

(2) Declaratory Order Petition

A utility that wishes to have the Commission consider a non-conforming pricing proposal separate from a rate proceeding may bring the matter to the Commission via a petition for declaratory order. Of course, if the Commission found that the utility's proposal met the statutory criteria, the utility would still need to file a rate reflecting the proposal pursuant to FPA section 205. Presumably the section 205 proceeding would be straightforward (*i.e.* akin to a compliance filing), however, since the Commission would have already addressed the merits of the proposal in the declaratory order.

B. Criteria for Evaluating Proposals That Do Not Conform to the Traditional Revenue Requirement

Utilities proposing non-conforming transmission pricing must fully support such proposals. The utility must supply a complete discussion of how the proposal is intended to take account of the pricing principles. The Commission will consider the relative weight of each pricing principle as applied to the facts of each case. We will hold the comparability principle inviolate, however. Absent such support, the Commission will summarily reject the non-conforming proposal even if the utility has agreed to the procedural requirements set forth above.

We will also summarily reject non-conforming proposals that do not submit information showing that the proposal can be expected to:

(a) Produce greater overall consumer benefits than a conforming proposal; and

(b) Promote competitive bulk power markets.[39]

At a minimum, utilities proposing non-conforming transmission pricing must make a showing of benefits to a broad cross-section of consumers which achieve the following:

(i) Greater access and customer choice;

(ii) Projected price decreases to customers of delivered power; and

(iii) Service flexibility and available products to meet customer needs.

As noted, utilities should also explain how the non-conforming proposal promotes competitive bulk power markets.

C. Guidance Regarding Proposals That Do Not Conform to the Traditional Revenue Requirement

We believe that a non-conforming proposal that results from a diverse group such as an RTG, with fair and nondiscriminatory governance and decisionmaking procedures, would more easily be found just and reasonable than a non-conforming proposal from an individual utility, for the same reason we would afford more deference to a conforming RTG transmission pricing proposal than an individual utility conforming proposal.

Although the Commission has been willing, under appropriate circumstances, to permit market-based pricing for sales of generation, the Commission intends to treat market-based transmission rate proposals as non-conforming. Such rates obviously are not cost-based and the Commission does not believe market-based transmission pricing is appropriate at this time. Although the transmission system has multiple owners, the basic provision of firm transmission service is not competitive in most, if not all, circumstances. Rather, each owner can exert considerable market power by controlling the access, pricing and expansion of its portion of the grid. In addition, regulatory approval for new transmission lines is increasingly difficult to obtain and franchised owners are typically the only entities that possess rights of eminent domain. In these circumstances, unlike for sales of generation, the Commission cannot rely on competitive market forces to discipline prices for firm transmission service. Accordingly, any transmission owner advocating a market-based transmission pricing method must demonstrate how it has alleviated these serious concerns.

Some cost-based pricing approaches adhere to a traditional embedded (depreciated original) cost revenue requirement more closely than others. Replacement cost methods and long-run marginal cost methods of pricing, for example, may result in revenue levels that would exceed the traditional revenue requirement. Pricing methods designed to allow a transmission owner to recover more than its traditional revenue requirement (depreciated original cost) are non-conforming and would need to satisfy the procedures and criteria for non-conforming proposals.

VI. Alternative Institutions and Associated Pricing

The Commission is aware that industry participants have begun to discuss alternative institutional arrangements, such as "pool companies" and "transmission companies." Some of these institutions apparently are intended to facilitate efficient wholesale power trading, and may require alternative approaches for the pricing of transmission services. We believe that these alternative institutions hold great potential. They may assist in the resolution of some difficult federal-state jurisdictional issues and in developing mechanisms for resolving or minimizing stranded cost issues. While we are encouraged that such ideas are under discussion, and are open to considering the particular pricing needs of alternative institutions, these concepts are currently in an early, formative stage. The concepts associated with these ideas have not been adequately explored in this pricing docket or in any other Commission forum. Therefore, concurrent with issuing this Policy Statement, we are opening a separate docket to initiate an inquiry regarding alternative power pooling institutions and their particular pricing needs.[40]

VII. Conclusion

The transition to a competitive wholesale bulk power market depends on the availability of comparable transmission services. Comparable transmission service, in turn, must have appropriate prices, terms and conditions. To that end, the Pricing Inquiry has provided the basis for a productive dialogue among the various entities affected by and participating in the transition to a post-EPAct competitive bulk power market, including transmission owners, transmission users, and Federal and state regulators.

It is critical that transmission services be priced in a manner that appropriately compensates transmission owners and creates adequate incentives for system expansion when such expansion is efficient. Of course, any transmission pricing proposal will have to be evaluated under the standards of the FPA. The Commission must ensure that

[39] The reason we are providing flexibility to consider non-conforming transmission pricing proposals is because we do not want to reject out of hand innovative proposals that could benefit ratepayers. However, we do not intend to waste resources considering proposals whose *sole* purpose is to provide more revenue to the transmitting utilities. We will summarily reject such proposals.

[40] *See* Alternative Power Pooling Institutions under the Federal Power Act, Notice of Inquiry, FERC Stats. and Regs. ¶ _____.

any such proposal is just, reasonable, and not unduly discriminatory or preferential. A great many of the approaches discussed in this proceeding have the potential to provide better (*i.e.*, more efficient) price signals. But they also have the potential to complicate and prolong the process of determining appropriate rates for transmission services.

This Policy Statement provides a framework for understanding these competing interests, as well as a basis for continuing the transmission pricing dialogue. The Commission has consciously avoided endorsing any particular commenter's specific pricing methodology. Instead, the Policy Statement attempts to provide guidance while still encouraging industry efforts at innovation. Indeed, a great many of the proposals that were submitted during the Pricing Inquiry are highly theoretical and would need to be tested and evaluated in the context of individual cases.

The commenters in the Pricing Inquiry almost unanimously requested that the Commission allow flexibility. To that end, the Commission has attempted to provide pricing principles and general guidance that allow broad experimentation consistent with federal law and the physics of transmission. Certain experiments, particularly pricing methods that attempt to recognize loop flow, clearly require regional involvement and cooperation if they are to be effective. RTGs are encouraged to address such issues as pricing reform and loop flow.

The Commission encourages filing utilities and new groups that may form, such as RTGs and pool companies, to work closely with state regulatory authorities in developing transmission pricing policy. The Commission is committed to cooperating with all affected parties, especially state regulatory authorities, to ensure that any such pricing reform is implemented in an equitable manner and facilitates an orderly transition to a fully competitive bulk power market. Our pricing principles are expected to provide the foundation for the industry to continue its exploration of transmission pricing reform.

Finally, the Commission in this Policy Statement has proposed procedures under which non-conforming pricing proposals will be considered. We believe these procedures are flexible enough to permit utilities to propose non-conforming pricing innovations which they believe will benefit ratepayers and promote the development of a competitive bulk power market.

The Commission is making this Policy Statement effective immediately. It is based on the voluminous record developed to date in the Pricing Inquiry. We will accept motions for reconsideration submitted within 30 days in order to help us refine the principles established herein and to provide an opportunity to respond to any questions or clarify any ambiguity. We will apply the Policy Statement to transmission pricing proposals submitted in individual cases filed after the date of this Policy Statement.

List of Subjects in 18 CFR Part 2

Administrative practice and procedure, Electric power, Natural gas, Pipelines, Reporting and recordkeeping requirements.

By the Commission.

Lois D. Cashell,

Secretary.

In consideration of the foregoing, the Commission amends Part 2, Chapter I, Title 18 of the Code of Federal Regulations as set forth below.

PART 2—GENERAL POLICY AND INTERPRETATIONS

1. The authority citation for Part 2 continues to read as follows:

Authority: 15 U.S.C. 717–717w, 3301–3432; 16 U.S.C. 792–825y, 2601–2645; 42 U.S.C. 4321–4361, 7101–7352.

2. Part 2 is amended by adding § 2.22, to read as follows:

§ 2.22 Pricing Policy for Transmission Services Provided Under the Federal Power Act.

(a) The Commission has adopted a Policy Statement on its pricing policy for transmission services provided under the Federal Power Act. That Policy Statement can be found at 69 FERC 61,086. The Policy Statement constitutes a complete description of the Commission's guidelines for assessing the pricing proposals. Paragraph (b) of this section is only a brief summary of the Policy Statement.

(b) The Commission endorses transmission pricing flexibility, consistent with the principles and procedures set forth in the Policy Statement. It will entertain transmission pricing proposals that do not conform to the traditional revenue requirement as well as proposals that conform to the traditional revenue requirement. The Commission will evaluate "conforming" transmission pricing proposals using the following five principles, described more fully in the Policy Statement.

(1) Transmission pricing must meet the traditional revenue requirement.

(2) Transmission pricing must reflect comparability.

(3) Transmission pricing should promote economic efficiency.

(4) Transmission pricing should promote fairness.

(5) Transmission pricing should be practical.

(c) Under these principles, the Commission will also evaluate "non-conforming" proposals which do not meet the traditional revenue requirement, and will require such proposals to conform to the comparability principle. Non-conforming proposals must include an open access comparability tariff and will not be allowed to go into effect prior to review and approval by the Commission under procedures described in the Policy Statement.

Note: This Appendix will not appear in the Code of Federal Regulations

Appendix A—Summary of Comments on the Inquiry Concerning the Commission's Pricing Policy for Transmission Services in Docket No. RM93–19–000

The request for comments for the inquiry concerning the Commission's pricing policy for transmission services in Docket No. RM93–19–000 was issued on June 30, 1993. The date for filing responses was extended to November 8, 1993 and reply comments to January 24, 1994. Technical conferences were held on April 8 and 15, 1994. The first day of the conference covered current policy issues. The second day was devoted to advanced pricing concepts and implementation issues.

Comments were received from 165 individual commenters. Five categories of commenters are investor-owned utilities (IOUs, 67 commenters), municipal and cooperative utilities (Muni/Coop, 39 commenters), non-utility generators and independent power producers (NUGs/IPPs, 15 commenters), Regulatory/Government entities (25 commenters), and Others (19 commenters). A list of the commenters is at the end of this appendix; it shows the categories under which their comments are summarized and the acronyms used in this appendix.

A summary of the comments is provided here. The summary is organized in the same manner as the two-day conference (current policy and advanced pricing concepts). The current policy issues are subdivided into eight comment areas and advanced pricing into four comment areas as follows:

Current Policy Issues

(1) General Criteria for Transmission Service Pricing
(2) "And" Versus "Or" Pricing and Related Incentives
(3) Incremental Pricing
(4) Network Service
(5) Ancillary Services
(6) Direction Aspects of Power Flows
(7) Non-Firm Transmission Pricing
(8) Regional Transmission Groups

Advanced Pricing Concepts/Implementation Issues

(1) Alternative Pricing Concepts
(2) Distance/Flow-Based Rates
(3) Contract Path versus Measured Power Flows
(4) Spot Market Pricing

The Commission also received comments on stranded costs in the course of this Inquiry, but these are not addressed in this Pricing Policy Statement because stranded cost is the subject of a proposed rule.[41]

Current Policy Issues

1. General Criteria for Transmission Service Pricing

The first comment area deals with the proposed criteria for assessing transmission pricing reform. Commenters generally find the criteria proposed in Staff's Discussion Paper[42] acceptable. However, certain criteria are more readily agreed upon than others. Most commenters uniformly agree that the proposed criteria should: (1) Be simple to carry out and to administer; (2) promote efficient use of and investment in the transmission grid; (3) provide appropriate price signals to transmission customers; and (4) ensure equity and fairness during and beyond the transition period.

Other proposed criteria by commenters include that transmission pricing policy should:

- Ensure system reliability;
- Be flexible (*i.e.*, no "one size fits all" pricing methodology) and specifically recognize regional differences;
- Encourage the formation of Regional Transmission Groups (RTGs) and give substantial deference to pricing methodologies developed by RTGs;
- Provide for coordination between state and Federal pricing policies and encourage collaborative policy development;
- Provide for grandfathering of existing contracts and arrangements when implementing any new policies;
- Promote competition in *generation;*
- Unbundle rates for transmission services;
- Ensure nondiscriminatory rates, terms, and conditions;
- Not allow native load customers to subsidize firm wheeling;
- Give deference to negotiated agreements (with some commenters adding, where equal bargaining power is involved);
- Ensure rate predictability and transparency of rate derivation; and,
- Allow customers an option to have stable prices over time (although this would not limit parties to fixed rate contracts).

One criterion emphasized by most commenters is that the Commission should exercise maximum flexibility in pricing transmission service. Specifically, many commenters stress that the Commission should not attempt to rigidly apply a single transmission pricing methodology in all cases, to all entities, or to all regions. A general concern raised is that the Commission must recognize the substantial differences present between customer groups, utilities, state and local regulatory bodies, and regional differences. Accordingly, the Commission must resist the temptation to apply one pricing methodology in all cases.

One common view expressed by many Muni/Coops commenters is that the industry must move from a structure where multiple transmission system pricing occurs to a structure where transmission is viewed on a regional basis in conjunction with the development of large, regional power markets. Many commenters advocate the regional transmission grid approach but differ in how the industry and the Commission should advance toward this goal. Some appear to take a more cautious approach. For example, some commenters note that the Commission can only obtain meaningful answers to the questions posed in its transmission pricing inquiry if it first determines the shape of the industry it envisions (such as the regional transmission grid approach or the traditional model based on individually owned and operated transmission systems). APPA[43] contends that before considering changes in traditional transmission pricing, the Commission should develop and articulate a clear statement of its "vision" for the electric industry and specify "where the industry is going, how it will get there, likely impediments, and what steps are necessary for that vision to be fulfilled." Many Muni/Coops commenters also argue that the Commission must first determine if the benefits of transmission pricing reform will outweigh the costs of such reform.

Several Regulatory/Government entities commenters recommend that the following general principles be included in addition to the Commission's proposed criteria:

- The Commission's pricing policies should reflect differences between the rights and responsibilities of native load customers (including retail and wholesale requirements customers) and other users of the transmission system; any transmission pricing policy must ensure that native load customers will be held harmless; and,
- The Commission should seek to promote voluntary resolution of case-specific pricing issues by giving appropriate deference to consensual agreements produced through arms-length negotiations involving all affected parties.

NARUC proposes a consultative process to develop complimentary policies that truly coordinate and render coherent regulation of transmission service. The general goals include coherence of public policy, economic efficiency and reliability in electricity markets, efficiency of processes and decision-making, dialogue between federal and state decision-makers and appropriate input from constituent groups and affected parties as necessary. The Pennsylvania Commission concludes that without careful consideration of the role of state agencies and their interest in economic and environmental impacts, bulk power wheeling as envisioned by the Commission is, and will remain, a theoretical, economic model.

2. "And" Versus "Or" Pricing and Related Incentives

The "and" versus "or" issue dominated the pricing comments. While arguments on all sides of the issue were expressed, the commenters generally opposed the Commission's current corporate "or" policy and alternatively advocated either some form of the "and" pricing method or corporate-average embedded cost-based rates. The positions of the commenters are described below:

The "And" Method: Most IOUs, most Regulatory/Government entities and some Other entities support the "and" methodology. These commenters state that the Commission's "or" pricing policy does not hold the native load customers harmless and violates FPA section 212(a) (because native load customers and shareholders subsidize third party wheeling customers). When additional facilities are needed to serve third party wheeling load, and incremental (or opportunity) costs are greater than average embedded cost, native load customers subsidize that service (because no cost recognition is given to the third party's use of the existing transmission system, without which the transmission service could not be provided). Additionally, if incremental expansion cost related to third party transmission requests are not allowed by state regulators in retail rates, the transmitting utility will not be made whole. Finally, the Commission's policy on opportunity cost which applies the "higher of" test over the entire transaction period instead of an hourly basis precludes opportunity cost recovery in most cases, sends the wrong hourly price signals to transmission customers, and is overly burdensome administratively.

The "Or" Method: Most NUGs/IPPs commenters agree that the Commission's current corporate "or" policy sends the correct price signal for third-party transmission (as long as opportunity costs are "legitimate and verifiable" and continue to be capped at incremental expansion costs). However several commenters oppose pricing based on opportunity costs (as monopoly rents for a constrained system).

The Average Embedded Cost Method: Most of the Muni/Coops, some NUGs/IPPs, and some Other entities generally support the return to traditional corporate-average embedded cost-based rates. The majority of the Muni/Coops commenters and some of the Other commenters oppose both the "or" and the "and" transmission pricing methods (as yielding excessive rates and impeding the competitive generation market that EPAct permits). Such commenters recommend the traditional policy of charging average embedded cost-based transmission rates. Many of these commenters argue that a transmission-dependent utility (TDU) cannot be considered a "marginal" customer, subject to incremental and opportunity cost pricing, because the transmission system was designed to accommodate the TDU's use and has been paid for proportionally by the TDU.

[41] Docket No. RM94–7–000, Notice of Proposed Rulemaking, June 29, 1994.

[42] Staff appendix to *Inquiry Concerning the Commission's Pricing Policy for Transmission Service Provided by Public Utilities Under the Federal Power Act,* FERC States. & Regs. ¶ 35,024 (1993).

[43] Commenters are referred to by acronym here; acronyms are defined in a list at the end of this appendix.

Furthermore, these commenters argue that applying incremental pricing to TDUs is anticompetitive and inconsistent with the EPAct because (1) it forces TDUs to favor power purchases from the host utility over those from a competing power supplier, and (2) TDUs compete with the host utility for requirements customers (who are charged an average embedded cost rate by the host utility).

Commenters views regarding the incentives and disincentives inherent in corporate "or" pricing primarily fall into three basic positions:

(1) Although groups disagreed among themselves on how to calculate various cost-based transmission rates, most Muni/Coops, most Regulatory/Government entities, most NUGs/IPPs, and some others do not believe in allowing any incentives, or premiums above cost-based rates, properly calculated. Most of these commenters agreed that, when a monopoly resource is involved, such incentives amount to allowing "monopoly rents." Transmission is and will remain a natural monopoly, therefore, no incentive is needed beyond recovery of the transmitting utility's prudently-incurred costs and a fair return on its invested capital. Premiums allow the transmission monopolist a competitive advantage in the generation market. Furthermore, there is no need for incentives with the passage of the transmission provisions of the Energy Policy Act; the legal requirement to provide transmission service is sufficient incentive.

(2) Most NUGs/IPPs believe the current incentives provided by the incremental pricing part of the "or" policy are appropriate. However, many of these commenters oppose pricing based on opportunity costs (as monopoly rents for a constrained system).

(3) Those advocating "and" pricing, such as most IOUs and some Others, believe that further incentives are needed. The current "or" policy does not sufficiently compensate utilities for all costs of providing service, thus effectively requiring native load customers to subsidize transmission customers. If utilities are forced to absorb potential cost underrecovery and the risk associated with the "or" pricing methodology, then the rate of return should be adjusted to reflect greater risks assumed by engaging in third party wheeling transactions.

3. Incremental Cost Pricing

Under the Commission's current corporate "or" policy, third-party transmission users may be required to pay the incremental cost of a grid expansion if the incremental cost of the expansion is greater than corporate-average embedded cost. Such incremental pricing can be structured in one of two ways—a *contract* approach in which each user pays the incremental cost of the upgrade it occasions, and an *average* incremental price based on the average cost of all upgrades to the transmission system for a group of users.

Most, though not all, commenters believe that contract pricing is the preferred pricing model. IOUs in particular favor contract pricing because it provides more certainty that a utility's revenue requirements are fully recovered. If incremental pricing increases the risk of less than full revenue recovery, either shareholders or residual customers will bear the extra risks. Most wholesale customers also appear to favor contract pricing, though some have concerns that contract pricing, with different prices for each user, may result in price discrimination. These commenters suggest that similarly situated customers should have the same price, but have different notions of what this would mean.

For many of the difficult practical issues associated with incremental pricing, there is no consistent position taken by all or even most members of any interest group that supports incremental cost pricing. For example, many commenters believe that average incremental cost pricing gives the wrong price signal to both the transmission owner and user. These commenters are concerned that the average incremental cost price does not signal the true cost of the transmission service. A few commenters argue that this will result in underbuilding of the transmission system. Others suggest that this may result in overbuilding, although IOUs in particular doubt this result, given the difficulties inherent in siting, certification and construction of new transmission facilities.

Additionally, commenters are split on the issue of administrative costs and other implementation problems that may result under each pricing model. Some commenters argue that contract pricing entails maintaining separate contracting provisions for each user, with attendant high costs. Other commenters suggest that average incremental cost pricing is more difficult, given the need to estimate incremental costs, and the problems associated with changing average incremental rates as a result of incremental cost changes. One commenter suggests that it is simply not possible to reconcile average incremental pricing with an embedded cost transmission revenue requirement.

Several commenters suggested that it would be appropriate to allow utilities some flexibility to adopt either incremental cost pricing approach. The challenge for the Commission would be to determine under what conditions such flexibility would be warranted, in order to protect both the third-party transmission users and the remaining wholesale and retail customers from being charged for inappropriate costs. Other commenters suggest that some experimentation may be in order. If the Commission chooses to allow such experimentation, it may learn a great deal about the magnitude of the practical problems, as well as potential solutions for those problems.

4. Network Service

The Staff Discussion Paper defined network service as allowing the user to vary its schedule and points of delivery and receipt without paying additional charges for each change. Commenters were asked to discuss the reasonableness of this definition and to provide recommendations on pricing network service. Most IOUs assert that utilities cannot provide third party transmission users with unlimited flexibility in choosing and switching points of receipt and delivery. Unless the transmission customer specifies the points of receipt and delivery, the nature of the generation, and the loads to be served, the transmitting utility will have no way to determine the impact of the proposed network arrangement on its system in terms of either reliability or cost. Unlimited flexibility could require transmission upgrades and make long term planning more difficult (with the potential for overbuilding). If network service is to include unlimited scheduling flexibility, it should be considered a premium service (priced higher than point-to-point service) since it requires higher transmission capacity margins to ensure reliability.

Most Muni/Coops, Regulatory/Government entities, NUGs/IPPs and some Other commenters agree with the Commission's definition of network service. Most Muni/Coops, NUGs/IPPs and some Other commenters insist that network service should be priced on an average embedded cost basis (with no non-cost-based network rate premiums or percentage adders). These commenters argue that such premiums would place network customers at a permanent competitive disadvantage in obtaining economical generation sources and in generation sales, compared to the transmitting utility. Many commenters agree that network access should not be totally flexible, nor be unduly rigid with reservation requirements and excessively advanced scheduling requirements; rather, they believe it should be subject to the same conditions faced by the transmitting utility, and provide access to transmission on an "as if owned" basis.

APPA asserts that it is not aware of any party that is seeking network access without regard to the control area utility's own transmission needs, or that is requesting network service with total flexibility, *i.e.*, no scheduling or backup requirements. APPA adds that it agrees with EEI on two points concerning utilities receiving network service: "they should state in *planning models* the sources of power that most probably will be used to serve loads, and they should schedule generation to serve load with the transmitting utility."

Regulatory/Government entities generally agree that accurate pricing of network service will depend on the nature of the network and any revenue pooling between transmission providers. Therefore, Regulatory/Government entities urge the Commission to be flexible and not mandate any particular method for pricing network service.

5. Ancillary Services

The Staff Discussion Paper gave examples of ancillary services and requested comments on other examples (including how such services should be priced). Most IOUs recommend that unless third party customers obtain ancillary services elsewhere, they should compensate the wheeling utility for the services provided to prevent the native load customers from subsidizing these services. IOUs note that as bulk power markets are becoming more competitive and

independent power producers are supplying ever increasing amounts of generation, these support type services that were once provided on a reciprocal basis among utilities are not being provided by many suppliers because they are either unwilling or unable to provide such service.

One of the main concerns of the Muni/Coops commenters is that costs associated with ancillary services should not already be included in the average cost-based transmission rate. Additionally, several commenters insist that transmission customers should be given the option to provide such services themselves, or obtain them from other utilities, and receive full credit. These commenters also express concern regarding discriminatory pricing. Such commenters urge that any charges for ancillary services assessed to a transmission customer should be the same as the costs faced by the transmitting utility for the same service.

NUGs/IPPs, Regulatory/Government entities and Others generally did not address this issue.

Other claimed ancillary services include: Backup and Standby Service; Loss Service; Redispatch Costs; Control Center Service; Emergency Services; fast starts, "BlackStart" capability (starting up a generating station with no external power supply), regulation, and stability.

Graves, *et al.* proposed that ancillary services could be provided by an independent entity, which they call a "Poolco" (*e.g.*, an existing power pool, an RTG, NERC subregion, or consortium of independent generators). Their version of a Poolco would not participate directly in real power MW brokerage or energy supply; rather, it would own and operate a relatively small collection of generation and flow control assets sufficient to assure the integrity of the system, relying on tieline flows, voltage measurements at a few key load centers, and forecast control-area load changes (over the next few hours).

6. Direction Aspects of Power Flows

The power flows caused by a transmission transaction may be either with, or counter to, the prevailing flows. The incremental effects of transmission transactions may also raise issues with respect to the use of multiple parallel paths and the incremental effects on transmission losses.

A. Directional Flows

Most commenters (most IOUs, some Muni/Coops, and some Regulatory/Government entities) suggest that charges should be applied for all power flows on a system (regardless of direction). Several commenters indicate that reverse flows exist only under some system conditions and that changes in transmission system configuration (due to line outages) and changes in generating unit dispatch, may eliminate any reverse flows. Such commenters also claim that all transmission elements support all power flows. Accordingly, reverse flows should only be credited if they provide a direct economic benefit to the utility.

Other commenters (some Muni/Coops, some Regulatory/Government entities, and most Others) argue that it is important for the Commission to adopt a transmission pricing method which recognizes flow direction and discounts transmission service which "unloads" the system and helps to relieve constrained transmission lines. These commenters suggest that this type of pricing signal encourages the most efficient use of the transmission system.

B. Loop Flows

Few comments on this issue were received from Muni/Coops, NUGs/IPPs, Regulatory/Government entities and Others. There did not appear to be any consensus among the IOUs on the best method to address loop flow problems.

Southern Companies indicates that loop flows were often short-lived and were viewed as part of the normal interconnected operations among utilities. It was once commonly viewed that loop flows on one utility's system would most likely be offset by loop flows on its neighboring systems. In instances where the flows were a problem, negotiated solutions were reached. LG&E notes that bulk power transactions were once predominantly multi-directional and covered shorter distances so that transactions evened out over time.

However, in today's marketplace transactions are more numerous, over longer distances, and unidirectional. As a result, loop flows do not even out over time. In the new competitive environment, Southern Companies, AEP and Northern States claim the situation has changed. In the emerging bulk power market, many more long term firm transactions in a single direction are contemplated which will more adversely impact flows over interconnected systems. These commenters state that it also may be more difficult in a competitive environment to negotiate solutions to parallel flow problems. Consumers believes that uncertainty about loop-flow compensation may be a significant potential barrier to the more rapid development of competition among new generators.

C. Losses

Many commenters (some IOUs, most Muni/Coops, some Others) argue that losses vary in proportion to the distance over which the energy is moved, and accordingly, contend that incremental losses send a more appropriate price signal to the customer (by more closely linking cost causation and cost recovery). Tabors claims that efficiency requires pricing losses at the margin, which can be accomplished using load flow calculations and Optimal Power Flow modeling techniques. On the other hand, many commenters recommend average system line losses. Several of these commenters insist that they should be charged for line losses on the same cost basis that the transmitting owners use for their own dispatch and charge their native load customers.

7. Non-Firm Transmission Pricing

A fundamental issue of non-firm transmission service pricing is whether or not a contribution to capital costs over and above the variable cost of transmission (losses and opportunity costs) should be made for non-firm service. One view is that users of non-firm service should not pay for capacity costs since capacity is not built for them and their service can always be interrupted. On the other end of the spectrum are those that advocate a contribution of up to 100 percent of fixed costs, since firm customers need to be compensated for the use of the transmission system that they support in its entirety.

Most IOUs indicate that non-firm users of the transmission system should contribute to the capital costs of the system. They believe the Commission should rely on its historical precedent, which allows a contribution of up to 100 percent of fixed costs for non-firm service with the revenues being credited to native load customers. Some believe the shareholders should receive some of the revenues from non-firm transactions. Other commenters suggest minimal regulation of non-firm transactions as long as the price does not exceed a cap equal to its fully allocated transmission costs.

Many of the Muni/Coops commenters state that there are no fixed costs associated with providing non-firm transmission services and note that groups in different parts of the country (*e.g.*, PJM, NEPOOL, MAPP and ERCOT) do not include contributions to fixed costs in non-firm transmission pricing. Many commenters believe that no demand charges for non-firm transmission are necessary and argue that such demand charges may have a negative impact on the efficiencies of the economy energy market for short term transactions. For example, Consumer Working Group recommends:

Limiting non-firm rates to real costs (*i.e.* losses) would eliminate the artificial dead zone created by the incentive transmission rates now allowed. By granting all market participants (and not just transmission owners) access at cost to non-firm transactions, all consumers would benefit from increased coordination. Such nondiscriminatory, cost-based pricing of non-firm transmission would serve the EPAct's purpose of stimulating competition in bulk power markets and would promote economically efficient generation of electricity as expressly mandated by Section 212(a). (Consumer Working Group Reply at 21)

8. Regional Transmission Groups

All segments of the industry supported the Commission's encouragement of the development of such groups. Many commenters believe that RTGs represent the best method available to deal with the difficult transmission pricing issues presented in Staff's Discussion Paper. Some commenters cautioned that to be successful, RTGs must be certified by the Commission to ensure proper representation of all groups within the electric utility industry. Many commenters anticipate RTGs will facilitate coordinated regional planning, regional measurement of power flows and regional methodologies to determine the price of any firm wheeling transaction within the region. The information available on a regional basis will allow planning to alleviate current and future transmission constraints within the region as well as send a clear price signal to third party customers requesting service.

RTG's will also provide information as to what transmission capacity is available and the need for any transmission enhancements within the region to accommodate the requested transaction.

Advanced Pricing Concepts/Implementation Issues

1. Alternative Pricing Concepts

Numerous commenters proposed alternative pricing methods, other than those pricing methods normally permitted by this Commission. The methodologies advanced by these commenters varied from conceptual ideas to detailed formulas. Certain concepts and methods were advocated by more than one and in some cases several commenters, including:

- Combinations of, or hybrids between, the "or" and the "and" policies, many of which advocated recovery of all incremental costs and *some* contribution (but not necessarily 100%) to average embedded system costs.
- Variations of recovering strictly incremental or marginal cost pricing; *i.e.*, rates based on long-run incremental cost pricing for long-term firm transmission service and short-run marginal costs for other transactions. Another commenter proposed short-run marginal costs for transactions not requiring upgrades.
- Numerous proposals for a single transmission owner and for regional pricing, planning and operating approaches; for example: (1) The forced divestiture of all utilities' transmission assets and formation of a single transmission owning national grid company or "gridco"; (2) joint ownership, operation and pricing of all transmission within an established region with all transmission users obtaining load ratio shares of the regional grid and paying on an average embedded load ratio basis; (3) a proposal simply to price transmission in a region as if there were a single transmission owner; and (4) many suggestions for the Commission to further examine the companies formed in Norway, Sweden, New Zealand, Victoria (Australia), India, Argentina, England and Wales.
- Establishing a secondary market in transmission rights—transmission purchasers having the capacity to contractually broker, resell, trade, partially assign, or assign firm purchase entitlements as they choose. Capacity trading will provide for the repackaging of capacity rights to fit market needs, thereby creating a market mechanism to "price" and "clear" transmission services as a commodity.
- Numerous proposals advocating that the Commission require the unbundling of rates for transmission and sales services. Unbundling would require transmission owners to include a separate (transparent) transmission charge in any use of the utility's transmission system for the delivery of power in the wholesale market, including that utility's own wholesale sales. Transmission terms and conditions should be the same for all wholesale transactions, regardless of whether the seller is the owner of the transmission facilities used for the transaction.

2. Distance/Flow-Based Rates

Alternatives to postage stamp rates would make rates sensitive to the transmission distance involved in providing the service. Alternatives suggested include various "MW-mile" approaches and other methods based on load flows (such load flow methods can also treat issues involving multiple parallel paths and transmission losses associated with particular transmission transactions). Commenters' support is split between distance-based pricing and postage stamp rates.

Regulatory/Government commenters express a clear preference for distance-sensitive rates (over postage stamp rates). Most Regulatory/Government entities, some IOUs, some NUGs/IPPs, and some Others argue that distance-based rates would compensate the transmitter for increased transmission costs as more of its system is used. This encourages more efficient use of the transmission system. Where more miles of the transmission system are utilized, distance-sensitive rates reflect the proper cost causation. Several commenters believe that simplified distance-sensitive pricing methods, such as some MW-mile methods, used in conjunction with approaches such as zonal pricing that reflects system constraints, would be appropriate. Numerous commenters advocating distance-based rates recommend zonal pricing as a compromise between the administrative simplicity of postage stamp rates and more appropriate price signals of certain distance-based rate methods.

Most Muni/Coops, some IOUs, and some NUGs/IPPs support postage stamp rates and criticize distance-sensitive pricing due to its dependence upon power flow studies involving a base and a change case. Many commenters note that power flows on a transmission system are in constant change, thereby creating a very large number of possible system parameters that could be included in load flow analyses and therefore requiring many simplifying assumptions. Consequently, any attempt to derive a normal base case power flow on which to model an incremental power flow would be flawed and unreliable, particularly for individual utilities located in heavily interconnected networks. Therefore, these commenters prefer the administrative convenience of postage stamp rates over the complexity and questionable accuracy of distance-sensitive rates based on power flow studies.

3. Contract Path Versus Measured Power Flows

The mismatch between the contract path for a transaction and the actual flows creates pricing and equity concerns. Utilities are split regionally on whether to adopt loop flow, or parallel path, pricing reform or retain contract path pricing. Most Western utilities favor retaining contract path pricing. Western utilities maintain that the topology of the WSCC makes it well suited to the use of phase shifters to control the loop flow problem. In addition, the development of Flexible AC Transmission technology may provide additional devices to augment existing control strategies.

Many utilities in the Midwest and the East favor adopting loop flow pricing because over time contract path pricing has left many systems uncompensated for parallel flows. These utilities argue that contract path pricing is outmoded because (1) transmission services have become long-term single direction transactions, (2) many new market entities do not own transmission so that reciprocity is not possible, and (3) negotiated solutions are less possible as competition expands.

Many utilities in favor of loop flow pricing are concerned that the associated transition costs are formidable. Parallel flows constantly change with changes in the dispatch of generation. In addition, some utilities urge the development of RTGs first before implementing loop flow pricing. In fact, there is general agreement that RTGs are an appropriate institution for addressing many of the industry's problems including pricing issues and the siting and construction of transmission facilities.

While there is widespread dissatisfaction with contract path pricing outside of the West, there is considerable uncertainty about how to address the parallel flow problem effectively. Many parties believe that contract path pricing and loop flow pricing can be combined to address the problem, while other parties believe that these two methods are incompatible. Still other parties offer an array of variations on the contract path pricing and loop flow pricing methods. For example, Hogan's "contract network" approach and PacifiCorp's proposal are variations on the contract path pricing method. The GAPP experiment, which the Interregional Transmission Coordination Forum stresses as the way to identify the pricing method to compensate for parallel flows, is a preliminary type of loop flow pricing. The Texas Planned Capacity Wheeling Service and Southern Company's Transmission Cost Actual Path Pricing are also examples of loop flow pricing. Finally, many parties argue that alternatives to contract path pricing should be pursued on a voluntary basis.

4. Spot Pricing for Non-firm Transmission

Few commenters express outright opposition to spot pricing, but most advocate a cautious approach to implementation. Those in the latter category comprise a diverse group of IOUs (including EEI), coops, state commissions and industrial groups. Many suggest that spot pricing schemes should continue to be studied, but not considered for implementation at this time. Some encourage the Commission to conduct experiments similar to the Southwest Bulk Power Experiment and the WSPP

Those opposed to spot pricing generally believe that the benefits are not worth the costs. Some argue that the successful implementation of spot pricing for transmission requires a competitive market in generation that does not now exist. However, some commenters that see promise in spot pricing argue that the necessary market institutions and technology exist today. They cite the operation of tight power pools, electronic bulletin boards, and the WSCC experiment as evidence of this fact.

Some commenters argue that the "up to" transmission rates that many utilities now

use for non-firm transmission service effectively approximate spot transmission pricing. However, others believe that rate design for spot transmission pricing raises a number of difficult issues, such as the use of one-part versus two-part rates, and the appropriate definition of the cost of transmission service.

Several commenters offer highly developed policy proposals or technical models for use in implementing spot pricing. In particular, Hogan and Putnam believe that all participants in the power market should have access to economic dispatch with marginal cost pricing. Hogan argues that transmission rights cannot be built on the traditional wheeling model that assumes that specific power moves to specific customers. He claims that only by stepping away from such misleading assumptions can the Commission design a set of pricing and access reforms that are consistent with the underlying economics and will support an efficient competitive electricity market.

List of Commenters in the Transmission Pricing Policy Inquiry

The following parities filed either initial or reply comments. Acronyms used in this appendix are defined here.

Investor-Owned Electric Utilities and Associations

1. Allegheny Power Service Corporation
2. American Electric Power System Companies (AEP)
3. Arizona Public Service Company
4. Association of Electric Companies of Texas
5. Atlantic City Electric Company
6. Bangor Hydro-Electric Company
7. Carolina Power and Light Company
8. Centerior Energy Corporation
9. Central and South West Services, Inc.
10. Central Illinois Public Service Company
11. Central Louisiana Electric Company
12. Commonwealth Edison Company
13. Consumers Power Company/CMS Energy (Consumers)
14. Dayton Power and Light Company
15. Detroit Edison Company
16. Dominion Resources, Inc.
17. Duke Power Company
18. Duquesne Light Company
19. Edison Electric Institute (EEI)
20. Entergy Services, Inc.
21. Florida Power Corporation
22. Florida Power Corporation, Wisconsin Electric Power Company, and Wisconsin Public Service Corporation
23. Houston Lighting & Power Company
24. Idaho Power Company
25. Indianapolis Power & Light Company
26. Iowa-Illinois Gas and Electric Company
27. LG&E Energy Corp.
28. Long Island Lighting Company
29. Louisville Gas and Electric Company
30. Midwest Power Systems, Inc.
31. Montana Power Company
32. New England Power Service
33. New York State Electric & Gas Corporation
34. Niagara Mohawk Power Corporation (Niagara Mohawk)
35. Northeast Utilities System Companies
36. Northern States Power Company (Northern States)
37. Ohio Edison Company
38. Otter Tail Power Company
39. PacifiCorp
40. Pacific Gas and Electric Company
41. Pennsylvania-New Jersey-Maryland Interconnection
42. Pennsylvania Power & Light Company
43. Philadelphia Electric Company
44. Portland General Electric Company
45. PSI Energy Inc. and Cincinnati Gas & Electric Company
46. Public Service Company of Colorado
47. Public Service Company of New Mexico
48. Public Service Electric and Gas Company
49. Puget Sound Power & Light Company
50. San Diego Gas & Electric Company
51. Sierra Pacific Power Company
52. South Carolina Electric & Gas Company
53. Southern California Edison Company
54. Southern California Gas Company
55. Southern Companies
56. Southwestern Public Service Company
57. Tampa Electric Company
58. Texas Utilities Electric Company
59. Tucson Electric Power Company
60. Union Electric Company
61. United Illuminating Company
62. Unitil Power Corporation
63. Utility Working Group
64. Washington Water Power Company
65. Western Resources, Inc. and Kansas Gas and Electric Company
66. Wisconsin Electric Power Company
67. Wisconsin Public Service Corporation

Municipals, Cooperatives and Government-Owned Electric Utilities and Related Associations

1. Alabama Electric Cooperative, Inc. and South Mississippi Electric Power Association
2. Allegheny Electric Cooperative, Inc.
3. American Public Power Association (APPA)
4. Arizona Power Authority
5. Associated Electric Cooperative, Inc.
6. Basin Electric Power Cooperative
7. Bonneville Power Administration
8. California Department of Water Resources
9. City of Anaheim, California
10. City of Vernon, California
11. Colorado Association of Municipal Utilities
12. Colorado Joint Transmission Principles Participants
13. Consumer Working Group
14. East Kentucky Power Cooperative, Inc., Saluda River Electric Cooperative, Inc., and Wolverine Power Supply Cooperative
15. East Texas Cooperatives
16. Florida Municipal Power Agency, Michigan Municipal Cooperative Group and Wolverine Power Supply Cooperative
17. Indiana Municipal Power Agency
18. Irrigation and Electrical Districts Association of Arizona
19. Large Public Power Council
20. Lincoln Electric System
21. Massachusetts Municipal Power Systems
22. Missouri Basin Municipal Power Agency
23. Municipal Electric Authority of Georgia
24. National Rural Electric Cooperative Association
25. Northern California Power Agency
26. Oglethorpe Power Corporation
27. Old Dominion Electric Cooperative, Inc.
28. Public Generating Pool
29. Sacramento Municipal Utility District
30. South Texas Electric Cooperative, Inc. and Medina Electric Cooperative, Inc.
31. Tennessee Valley Authority
32. Transmission Access Policy Study Group
33. Transmission Agency of Northern California
34. Transmission Dependent Systems
35. Turlock Irrigation District
36. Utah Associated Municipal Power Systems
37. Wabash Valley Power Association, Inc.
38. Wisconsin Public Power, Inc. SYSTEM
39. Wisconsin Wholesale Customers

Non-Traditional Utility Generators (NUGs, IPPs, EWGs and Qfs), Power Marketers Foreign Entities and Related Associations

1. American Wind Energy Association
2. British Columbia Power Exchange Corporation (POWEREX)
3. California Independent Energy Producers Association
4. Electric Generation Association
5. Enron Power Marketing, Inc.
6. Fuel Managers Association
7. Geothermal Resources Association
8. Hydro-Quebec
9. InterCoast Power Marketing Company
10. Kvaener Energy Development Inc. and Citizens Power & Light Co.
11. LG&E Power, Inc.
12. National Independent Energy Producers
13. National Power Plc
14. Ontario Hydro
15. Torco Energy Marketing, Inc.

State Regulatory Commissions and Other Government Agencies

1. Alabama Public Service Commission
2. California Energy Commission
3. California Public Utilities Commission
4. Florida Public Service Commission
5. Georgia Public Service Commission
6. Idaho Public Utilities Commission
7. Illinois Commerce Commission
8. Indiana Utility Regulatory Commission
9. Kansas Corporation Commission
10. Maine Public Utilities Commission and the Vermont Department of Public Service
11. Massachusetts Department of Public Utilities
12. Michigan Public Service Commission
13. National Association of Regulatory Utility Commissioners (NARUC)
14. Nevada Public Service Commission
15. New York State Department of Public Service
16. Ohio Public Utilities Commission the Ohio Sitting Board
17. Pennsylvania Public Utility Commission
18. Sharp, The Hon. Philip R., Chairman, Subcommittee on Energy and Power
19. Texas Public Utility Commission
20. United States Department of Energy
21. United States Department of Justice
22. Virginia State Corporation Commission
23. Wallop, The Hon. Malcolm, Senate Committee on Energy and Natural Resources
24. Washington State Energy Office
25. Wisconsin Public Service Commission

Others

1. American Forest and Paper Association (American Forest & Paper)
2. Burns, Robert E.
3. Committee on Regional Electric Power Cooperation
4. Direct Electric Inc. (Direct Electric)
5. Drazen-Brubaker & Associates, Inc.
6. Electricity Consumers Resource Council, the American Iron and Steel Institute and the Chemical Manufacturers Association
7. Electric Power Research Institute
8. Ernst & Young Utilities Consulting/ Frederick L. McCoy
9. Hogan, William W. (Hogan)
10. Incentives Research, Inc., and Massachusetts Institute of Technology (Graves, *et al.*)
11. Institute of Electrical and Electronic Engineers
12. Interregional Transmission Coordination Forum
13. Joint Consumer Advocates
14. Lively, Mark B.
15. New York Mercantile Exchange
16. Ohio Office of the Consumers' Counsel
17. Putnam, Hayes & Bartlett, Inc. (Putnam)
18. SASY Inc.
19. Tabors Caramanis & Associates (Tabors)

[FR Doc. 94–27091 Filed 11–2–94; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF STATE

Bureau of Consular Affairs

22 CFR Part 40

[Public Notice 2110]

Refusal of Diversity Immigrants

AGENCY: Bureau of Consular Affairs, Department of State.

ACTION: Final rule.

SUMMARY: On March 31, 1994, the Department published a final rule to implement the provisions of sections 201(a)(3), 201(e), 203(c) and 204(a)(1)(G) of the Immigration and Nationality Act, as amended, relating to Diversity Immigrants. There was an inadvertent omission in that publication. This final rule rectifies that omission by promulgating a new section 40.105.

EFFECTIVE DATE: December 5, 1994.

FOR FURTHER INFORMATION CONTACT: Cornelius D. Scully, III, Director, Office of Legislation, Regulations, and Advisory Assistance, Bureau of Consular Affairs, (202) 663–1184.

SUPPLEMENTARY INFORMATION: Public Notice 1925 at 58 FR 68791, December 29, 1993, proposed amendments to 22 CFR Parts 40 and 42 to implement section 201(a)(3), 201(e), 203(c), 203(e)(2), and 204(a)(1)(G) of the Immigration and Nationality Act, as amended, relating to Diversity Immigrants. Public Notice 1973 at 59 FR 15298, March 31, 1994, published the final rule. The Department has belatedly realized that one proposed amendment was not included in the final rule.

In the proposed amendments the Department included a proposal to establish a new § 40.104 incorporating into regulation the statory authority to refuse an application for a diversity immigrant visa under section 203(c) if the applicant does not meet either the education or work experience requirement. Section 203(c)(2) specifies that an alien is not eligible to receive a visa under section 203(c) unless he or she has either at least a high school education or its equivalent or, within the last five years, has had at least two years work experience in an occupation requiring at least two years of training or experience.

There is thus a clear statutory mandate to refuse an application for a diversity immigrant visa if the applicant does not meet that requirement, even though this is couched in terms of eligibility requirements that must be met, rather than in terms of a refusal ground. For this reason, the Department proposed to add a new section 40.104 for this purpose. None of the commenters on the proposed regulations commented on this proposed new section, presumably because it was correctly understood to be merely a technical refinement without substantive effect on the interpretation and application of the underlying statutory provisions.

For reasons not now clear, proposed section 40.104 was not included in the final rule. Since then the Department has recently promulgated a different new section 40.104 in connection with the implementation of section 506 of Public Law 103–317, an unrelated provision. As a result, the Department is now publishing the text of what was originally proposed to be section 40.104 as section 40.105.

List of Subjects in 22 CFR Part 40

Aliens, Documentation, Immigrants, Refusals, Visas.

Accordingly, 22 CFR Part 40 is amended as follows:

PART 40—[AMENDED]

1. The authority citation for part 40 continues to read:

Authority: Sec. 104, 66 Stat. 174, 8 U.S.C. 1104; Sec 109(b)(1), Sec. 131 of Public Law 101–649, 104 Stat. 4997.

2. Part 40 is amended by adding a new § 40.105 to subpart K to read as follows:

§ 40.105 Applicant for immigrant visa under INA 203(c).

An alien shall be ineligible to receive a visa under INA 203(c) if the alien does not have a high school education or its equivalent, as defined in 22 CFR 42.33(a)(2), or does not have, within the five years preceding the date of application for such visa, at least two years of work experience in an occupation which requires at least two years of training or experience.

Dated: October 25, 1994.

Mary A. Ryan,

Assistant Secretary for Consular Affairs.

[FR Doc. 94–27118 Filed 11–2–94; 8:45 am]

BILLING CODE 4710–06–M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[ME13–1–6645; A–1–FRL–5076–6]

Approval and Promulgation of Air Quality Implementation Plans; Maine; Enhanced Inspection and Maintenance in Androscoggin, Cumberland, Kennebec, Knox, Lincoln, Sagadahoc, and York Counties

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In this action, EPA is conditionally approving a revision to the Maine Department of Environmental Protection (DEP) State Implementation Plan (SIP) for Inspection and Maintenance (I/M). This SIP revision was originally submitted to EPA for approval on November 1, 1993. This submittal was supplemented by a letter from the Commissioner of DEP dated May 26, 1994 describing additional changes Maine is making to the I/M program, and a commitment to provide additional material by July 22, 1994 and to address issues relating to the low mileage waiver by specified dates. On July 21, 1994, the State of Maine submitted a revised SIP submittal. The SIP revision includes Chapter 128 of an amended State rule entitled "Motor Vehicle Emission Inspection Program," and additional supporting material including authorizing legislation, administrative items, and a description of the program being implemented.

EPA is conditionally approving the SIP revision on I/M, under section 110(k)(4) of the CAA, based on commitments made by Maine in its May 26, 1994 letter and reiterated in the July 21, 1994 submittal. Maine's commitments pertain to the "low