respectively; and a new paragraph (e)(5) is added, to read as follows:

§ 157.22 Collaborative procedures for applications for certificates of public convenience and necessity and for orders permitting and approving abandonment.

* * * * *

(e) * * *

(1) The Commission will publish notice of its authorization to use the pre-filing process in the **Federal Register**; the applicant will publish notice of the Commission's authorization to use the pre-filing process in a local newspaper of general circulation in the county or counties in which the proposed project is to be located. To the extent feasible, the applicants' notice will specify the time and place of the initial information meeting(s) and the scoping of environmental issues and will be sent to a mailing list approved by the Commission that includes the names and addresses of landowners affected by the project.

* * * * *

(5) Every three months, the applicant shall file with the Commission a report summarizing the progress made in the pre-filing collaborative process, referencing the public file maintained by the applicant as provided in paragraph (e)(4), of this section where additional information on that process can be obtained. Summaries or minutes of meetings held as part of the collaborative process may be used to satisfy this filing requirement.

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 382

[Docket No. RM00–7–000; Order No. 641]

Revision of Annual Charges Assessed to Public Utilities Issued October 26, 2000

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: In an effort to reflect changes in the electric industry and in the way the Federal Energy Regulatory Commission (Commission) regulates the electric industry, the Commission is amending its regulations to establish a new methodology for the assessment of annual charges to public utilities. The regulation provides that annual charges will be assessed to public utilities that provide transmission service based on the volume of electricity transmitted by those public utilities. The regulation thus will result in the Commission's now assessing annual charges on transmission rather than, as previously, assessing annual charges on both power sales and transmission.

EFFECTIVE DATE: This Final Rule will become effective January 1, 2001.

FOR FURTHER INFORMATION CONTACT:
Herman Dalgetty (Technical Information), Office of the Executive Director and Chief Financial Officer, 888 First Street, N.E., Washington, D.C. 20426, (202) 219–2918.
Jennifer Lokenvitz Schwitzer (Legal Information), Office of the General Counsel, 888 First Street, N.E., Washington, D.C. 20426, (202) 219–4471

SUPPLEMENTARY INFORMATION: Before Commissioners: James J. Hoecker, Chairman; William L. Massey, Linda Breathitt, and Curt Hebert, Jr.

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I. Introduction

In an effort to reflect changes in the electric industry and in the way the Federal Energy Regulatory Commission (Commission) regulates the electric industry, the Commission is amending its regulations to establish a new methodology for the assessment of annual charges to public utilities. The regulation provides that annual charges will be assessed to public utilities that provide transmission service based on the volume of electricity transmitted by those public utilities. The regulation thus will result in the Commission's now assessing annual charges on transmission rather than, as previously, assessing annual charges on both power sales and transmission.

II. Background

A. Commission Authority

The Commission is required by section 3401 of the Omnibus Budget Reconciliation Act of 1986 (Budget Act) [1] to ''assess and collect fees and annual charges in any fiscal year in amounts equal to all of the costs incurred * * * in that fiscal year.'' [2] The annual charges must be computed based on methods which the Commission determines to be ''fair and equitable.'' [3] The Conference Report accompanying the Budget Act provides the Commission with the following guidance as to this phrase's meaning:

> [A]nnual charges assessed during a fiscal year on any person may be reasonably based on the following factors: (1) The type of Commission regulation which applies to such person such as a gas pipeline or electric utility regulation; (2) the total direct and indirect costs of that type of Commission regulation incurred during such year; [4] (3) the amount of energy—electricity, natural gas, or oil—transported or sold subject to Commission regulation by such person during such year; and (4) the total volume of all energy transported or sold subject to Commission regulation by all similarly situated persons during such year.[5]

The Commission may assess these charges by making estimates based upon data available to it at the time of the assessment.[6]

The annual charges do not enable the Commission to collect amounts in excess of its expenses, but merely serve as a vehicle to reimburse the United

[1] 42 U.S.C. 7178.

[2] This authority is in addition to that granted to the Commission in sections 10(e) and 30(e) of the Federal Power Act (FPA). 16 U.S.C. 803(e), 823a(e).

[3] 42 U.S.C. 7178(b).

[4] The Commission is required to collect not only all its direct costs but also all its indirect expenses such as hearing costs and indirect personnel costs. *See* H.R. Conf. Rep. No. 99–1012 at 238 (1986), *reprinted in* 1986 U.S.C.C.A.N. 3868, 3883 (Conference Report); *see also* S. Rep. No. 99–348 at 56, 66 and 68 (1986).

[5] *See* Conference Report at 238.

[6] 42 U.S.C. 7178(c).

States Treasury for the Commission's expenses.[7]

B. Current Annual Charge Billing Procedure

As required by the Budget Act, the Commission's regulations provide for the payment of annual charges by public utilities.[8] The Commission intends that these electric annual charges in any fiscal year will recover the Commission's estimated electric regulatory program costs (other than the costs of regulating Federal Power Marketing Agencies (PMAs) and electric regulatory program costs recovered through electric filing fees) for that fiscal year. In the next fiscal year, the Commission adjusts its annual charges up or down, as appropriate, both to eliminate any over-or under-recovery of the Commission's actual costs and to eliminate any over-or under-charging of any particular person.[9]

In calculating annual charges, the Commission first determines the total costs of its electric regulatory program and subtracts all PMA-related costs and electric filing fee collections to determine total collectible electric regulatory program costs. It then uses the data submitted under FERC Reporting Requirement No. 582 (FERC–582) to determine the total volumes of long-term firm wholesale sales and transmission, and short-term sales and transmission and exchanges for all assessable public utilities. The Commission divides those transaction volumes into its collectible electric regulatory program costs to determine the unit charge per megawatt-hour for each category of long-term and short-term transactions. Finally, the Commission multiplies the transaction volume in each category for each public utility by the relevant unit charge per megawatt-hour to determine the annual charges for all assessable public utilities.[10]

Public utilities subject to these annual charges must submit FERC–582 to the Office of the Secretary by April 30 of each year.[11] The Commission issues bills for annual charges, and public utilities then must pay the charges within 45 days of the date on which the Commission issues the bills.[12]

C. Reasons for This Rule

Since the issuance of Order No. 472, in 1987, the industry has undergone sweeping changes, including: the Commission's establishment of open access transmission as a foundation for competitive wholesale power markets;[13] a movement by many states to develop retail competition; the growing divestiture of generation assets by traditional public utilities; the entry of new market participants into the industry in the form of independent and affiliated power marketers and stand-alone merchant plant generators; and the establishment of Independent System Operators (ISOs), the expected establishment of Regional Transmission Organizations (RTOs), and also the establishment of transmission companies (transcos) and power exchanges as managers of transmission systems and power markets respectively.

As the landscape of the industry has changed and continues to change, the nature of the work of the Commission likewise has changed. This rule, as described below, reflects these changes—changing the way in which the Commission assesses annual charges to recover its electric regulatory program costs to reflect recent industry and Commission changes, by assessing annual charges to public utilities that provide transmission service based on the volumes of electric energy transmitted.

D. Notice of Proposed Rulemaking

On January 28, 2000, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing revisions to the Commission's annual charges regulations.[14] In the NOPR, the Commission proposed a new methodology for the assessment of annual charges to public utilities. The Commission proposed to assess its electric regulatory program costs solely on the MWh of electric energy transmitted in interstate commerce by public utilities, rather than, as the Commission had done in the past, on both jurisdictional power sales and transmission volumes. Specifically, the Commission proposed to assess annual charges to public utilities based on their transmission of electric energy in interstate commerce, as measured by (1) unbundled wholesale transmission, (2) unbundled retail transmission, and (3) bundled wholesale power sales, which for this purpose, by definition, include a transmission component.[15]

As to ISOs, and potential RTOs, that have members that retain ownership of transmission facilities, the Commission stated in the NOPR that it was concerned that the assessment of annual charges to ISOs and RTOs could result in a "double counting" of transactions—by counting a single transaction both to the transmission-owning public utility and to the ISO or RTO. In the NOPR, the Commission proposed two solutions to prevent "double counting": (1) Not charge the ISO or RTO annual charges, but instead charge each individual transmission-owning public utility based on the MWh of transmission service provided on their lines; or (2) allow the ISO or RTO to act as an agent for all of the individual transmission owners and have the ISO or RTO pay the annual charges rather than the individual transmission owners.[16] The Commission, noting that either of these approaches may be acceptable, solicited comments on these two approaches, as well as any other approach that would allow the Commission to collect annual charges on MWh of transmission service in the most administratively efficient manner.

Comments on the NOPR were due on April 3, 2000.[17] The Commission received 35 initial and reply comments in response to the NOPR. Based on consideration of the comments submitted in response to the NOPR, as discussed below, the Commission

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[7] *Id.* at 7178(f). Congress approves the Commission's budget through annual and supplemental appropriations.

[8] 18 CFR Part 382; *see* Annual Charges Under the Omnibus Budget Reconciliation Act of 1986, Order No. 472, 52 FR 21263 and 24153 (June 5 and 29, 1987), FERC Stats. & Regs., Regulations Preambles 1986–1990 ¶ 30,746 (1987), *clarified*, Order No. 472–A, 52 FR 23650 (June 24, 1987), FERC Stats. & Regs., Regulations Preambles 1986–1990 ¶ 30,750, *order on reh'g,* Order No. 472–B, 52 FR 36013 (Sept. 25, 1987), FERC Stats. & Regs., Regulations Preambles 1986–1990 ¶ 30,767 (1987), *order on reh'g,* Order No. 472–C, 53 FR 1728 (Jan. 22, 1988), 42 FERC ¶ 61,013 (1988).

[9] 18 CFR 382.201; *see* Order No. 472, 52 FR at 21263 and 24153, FERC Stats. & Regs., Regulations Preambles 1986–1990 at 30,612–18; *accord* Annual Charges Under the Omnibus Budget Reconciliation Act of 1986, Order No. 507, 53 FR 46445 (Nov. 17, 1985), FERC Stats. & Regs. , Regulations Preambles 1986–1990 ¶ 30,839 at 31,263–64 (1988); Texas Utilities Electric Company, 45 FERC ¶ 61,007 at 61,027 (1988) (*Texas Utilities*).

[10] 18 CFR 382.201; *see* Annual Charges Under the Omnibus Budget Reconciliation Act of 1986 (Phibro Inc.), 81 FERC ¶ 61,308 at 62,424–25 (1997).

[11] 18 CFR 382.201(b)(4).

[12] See *Texas Utilities,* 45 FERC at 61,026.

[13] *See* Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888–A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g,* Order No. 888–B, 62 FR 64688 (Mar. 14, 1997), 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom,* Transmission Access Policy Study Group, *et al.* v. FERC, No. 97–1715 *et al.* (D.C. Cir. June 30, 2000) (*TAPSG*) (Order No. 888).

[14] Revision of Annual Charges Assessed to Public Utilities, Notice of Proposed Rulemaking, 65 FR 5289 (Jan. 28, 2000), FERC Stats. & Regs. ¶ 32,550 (2000).

[15] FERC Stats. & Regs. ¶ 32,550 at 33,921.

[16] *Id.*

[17] The commenters, and the abbreviations for them used herein, are listed in an appendix to this Final Rule.

adopts a Final Rule that follows the approach of the NOPR.

III. Discussion

In Order No. 472, to implement the Budget Act, the Commission formulated an annual charge billing procedure. To do this, the Commission had to determine: (1) The types of companies which the Commission should bill; (2) how to estimate and then allocate the Commission's costs among its different regulatory programs; and (3) how to allocate each program's costs among the companies under each program. After the annual charge billing procedure was formulated, the Commission then had to determine (1) how to adjust the annual charges at the end of a fiscal year ''to eliminate any over-recovery or under-recovery of [the Commission's] total costs, and any overcharging or undercharging of any person'' pursuant to section 3401(e) of the Budget Act; and (2) the standards for waiving all or part of an annual charge pursuant to section 3401(g) of the Budget Act.

We note at the outset that this Final Rule is only for the determination of annual charges to recover the costs of the Commission's electric regulatory program. Therefore, how to apportion the Commission's total costs among the Commission's different regulatory programs is not before the Commission.

Below, we will discuss the types of companies to be billed, the apportionment of our electric regulatory program costs among such companies, and other matters related to the changes to the Commission's regulations on annual charges.

A. The Types of Companies to Be Billed

The Commission's electric regulatory program includes: administering the provisions of Parts II and III of the Federal Power Act (FPA) [18] as they apply to the activities of public utilities (traditionally, principally investor-owned utilities); [19] discharging its responsibilities under various statutes involving the PMAs; and implementing various provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA) [20] involving qualifying cogenerators and small power producers (QFs).

1. Public Utilities

Pursuant to section 205 of the FPA,[21] the Commission regulates the rates, terms and conditions of service of public utilities making sales for resale or transmitting electric energy in interstate commerce. All jurisdictional rates, terms and conditions must be on file with the Commission, and may be approved by the Commission only if they are just and reasonable and not unduly discriminatory or preferential. Under section 206 of the FPA,[22] the Commission may change any rates, terms or conditions that it finds to be unjust, unreasonable, or unduly discriminatory or preferential.

The Commission also regulates certain accounting and corporate activities of public utilities pursuant to the FPA. Examples include the following: Under section 203,[23] the Commission reviews applications filed by public utilities seeking to merge or to dispose of jurisdictional facilities. Pursuant to section 204,[24] the Commission reviews the proposed securities issuances of public utilities whose securities issuances are not regulated by a state commission within the meaning of section 204(f). Under sections 301 and 302,[25] the Commission has authority over a public utility's accounting and its depreciation. Section 304 outlines the Commission's authority to direct public utilities (and also licensees) to report information, including information on transmission of electric energy to the Commission.[26]

2. Federal Power Marketing Agencies

The Commission reviews the rates established by the Department of Energy for the PMAs (Bonneville Power Administration (BPA), Southeastern Power Administration, Southwestern Power Administration, and Western Area Power Administration). While regulation of public utility rates is guided by the FPA, regulation of the PMAs' rates is subject to the standards enumerated in a number of other statutes.[27] Essentially, the statutes require that the rates established by the PMAs must be devised with regard for the recovery of the cost of generation and transmission of electric energy, the encouragement of the most widespread use of the power, the provision of the lowest possible rates to customers consistent with sound business principles, and the protection of the interests of the United States in amortizing its investment in the projects within a reasonable period of time. The Commission is also authorized, pursuant to the Northwest Power Act, to review the Average System Cost methodology used to determine rates for exchange sales by utilities to BPA.

3. Qualifying Facilities

Section 210 of PURPA [28] requires the Commission to prescribe rules to encourage cogeneration and small power production of electricity. In particular, the section directs the Commission to adopt rules requiring utilities to purchase power from and sell power to qualifying cogeneration and small power production facilities. The Commission reviews applications filed by cogenerators and small power producers requesting QF certification, and either grants or rejects such applications based on criteria set forth in the Commission's regulations.[29]

4. Discussion

a. *Proposed New Methodology.* In the NOPR, the Commission proposed to assess annual charges only to public utilities involved in the transmission of electric energy in interstate commerce.

b. *Comments.* Avista argues that the Commission should ensure that filings by PMAs and QFs carry an appropriate filing fee so that the majority of the cost of regulating those entities is paid for by those entities directly.[30] Avista and AEP argue that all costs will be borne by regulated transmission-owning public utilities, while other transmitting entities (non-jurisdictional) will not bear a comparable burden.

c. *Commission Conclusion.* The Commission will adopt the approach taken in the NOPR. That is, it will assess annual charges only to public utilities that provide transmission service.

The Commission is not persuaded that any change is warranted with respect to the Commission's existing policy as to assessment of annual charges to PMAs; the costs associated with the Commission's regulation of

[18] 16 U.S.C. 824–825r.

[19] Under sections 211, 212 and 213 of the FPA, 16 U.S.C. 824j–l, the Commission also has authority over transmitting utilities that are not public utilities. Compare 16 U.S.C. 796(23) *with* 16 U.S.C. 824(b), (e).

[20] 16 U.S.C. 2601–2645.

[21] 16 U.S.C. 824d.

[22] 16 U.S.C. 824e.

[23] 16 U.S.C. 824b.

[24] 16 U.S.C. 824c.

[25] 16 U.S.C. 825, 825a.

[26] 16 U.S.C. 825c.

[27] Flood Control Act of 1944, 16 U.S.C. 825s; Federal Columbia River Transmission System Act, 16 U.S.C. 838g; Pacific Northwest Power Preference Act, 16 U.S.C. 837; Pacific Northwest Electric Power Planning and Conservation Act of 1980, 16 U.S.C. 839; Bonneville Project Act, 16 U.S.C. 832f (Northwest Power Act); Reclamation Act of 1939, 43 U.S.C. 485h; Department of Energy Organization Act, 42 U.S.C. 7101; *see also* DOE Delegation Order No. 0204–108, 48 FR 55664 (Dec. 14, 1983); 18 CFR Parts 300 and 301.

[28] 16 U.S.C. 824a–3.

[29] 18 CFR Part 292.

[30] The issue of filing fees is not before the Commission. In fact, however, QFs are assessed filing fees. 18 CFR 381.505.

PMAs are separately identified and separately recovered.[31]

The Commission will continue to excuse qualifying cogenerators and small power producers from the direct assessment of annual charges.[32] We already have exempted them from regulation under most sections of the FPA, including sections 205 and 206 of the FPA.[33] While these entities could be transmitting utilities subject to our authority under sections 211, 212, and 213 of the FPA, in fact, we have not exercised this limited authority as to any such entities.

The Commission will continue its existing policy that municipal utility systems and rural electric cooperative utility systems that are financed by the Rural Utilities Service will not be required to pay annual charges.[34] While these entities may be transmitting utilities subject to our authority under sections 211, 212 and 213 of the FPA, they are not public utilities under the FPA.[35] In addition, the number of such entities that we, in fact, regulate under this limited authority is very small, as is the amount of transmission they provide under section 211 of the FPA.[36] The Commission also will continue its practice of not assessing annual charges to utilities operating in Alaska or Hawaii. They are not public utilities under the FPA because they do not make wholesale sales or transmit electric energy in interstate commerce.

Lastly, the Commission will not assess annual charges to foreign electric utilities to the extent that their transactions are in foreign commerce or wholly within another country.[37]

[31] *See* 18 CFR 382.201(c).

[32] 18 CFR 382.102(b); *see* Order No. 472, FERC Stats. & Regs., Regulations Preambles 1986–1990 at 30,637. As transmission customers they may, of course, be charged rates by the transmission provider that reflect annual charges assessed to the transmission provider.

[33] *See* 18 CFR 292.601.

[34] *See* supra note 32. As transmission customers they may, of course, be charged rates by the transmission provider that reflect annual charges assessed to the transmission provider.

[35] 18 CFR 382.102(b); *see* 16 U.S.C. 284; South Carolina Public Service Authority, 75 FERC ¶ 61,209 at 61,696 (1996); Dairyland Power Corporation, 37 FPC 12, 15 (1967); *accord,* Salt River Project Agricultural Improvement and Power District v. FPC, 391 F.2d 470, 474 (D.C. Cir.), *cert. denied,* 393 U.S. 857 (1968).

[36] Based upon a review of our records, it appears that we have only twice issued final orders directing such entities to provide transmission service under section 211. *See* Minnesota Municipal Power Agency v. Southern Minnesota Municipal Power Agency, 68 FERC ¶ 61,060 (1994); City of College Station, Texas, 86 FERC ¶ 61,165 (1999).

[37] *E.g.,* British Columbia Power Exchange Corporation, 80 FERC ¶ 61,343 at 62,137, 62,141 (1997) (sales in foreign commerce or within another country are excluded from annual charges calculations).

B. New Apportionment

1. Proposed New Methodology

The Commission, given the changes in the electric industry and in the Commission's regulation of the electric industry, proposed that annual charges be assessed based solely on volumes of electric energy transmitted, rather than, as in the past, based on volumes of electric energy both sold and transmitted.

2. Comments

Many comments received in support of the NOPR stated that the proposal properly recognizes that the Commission's regulatory efforts in electricity are now predominately focused on ensuring non-discriminatory, open access transmission service.[38] APX states that targeting annual charges to power sales and exchanges cannot be justified in relation to the Commission's current workload. PNGC supports the Commission's proposal, stating that it will eliminate a disparity in costs faced by power sellers depending upon their jurisdictional status, eliminate problems faced by power sellers in recovering these costs as part of market prices for power, more accurately assess costs to those services, *i.e.,* transmission, which require much more of its resources, and eliminate multiple assessments currently faced by power sellers.

The Commission notes that the instant rulemaking on annual charges moots the petition for rulemaking and the petition can therefore be terminated.

NYMEX and MLCS support the proposed revisions, stating that for a competitive wholesale power market to continue to develop, electricity must be considered a fungible commodity that can be bought and sold in a competitive open market without incurring excessive transaction costs. They urge that the proposed rule be adopted, as it promotes, rather than stymies, competitive electric wholesale transactions. The rules proposed will reduce transaction costs, better enable the wholesale electric market to respond efficiently to market-driven forces, and promote liquidity and price transparency in the industry.

A number of commenters cautioned that the proposed method is not clear and does not allow public utilities to make a proper analysis as to how the method proposed will impact their companies. These commenters request that the Commission defer final action, provide additional detail and analysis, and allow another opportunity to comment.

[38] Williams EM&T states that it strongly supports the Commission's proposal and notes that that proposal substantially addresses the issues previously raised by Williams EM&T and other power marketers in a petition for rulemaking in Docket No. RM98–14–000, to initiate a rulemaking to modify the methodology for assessing annual charges.

EEI states that, at best, it and its members can only guess at three possible Form No. 1 data line items that may qualify under the proposed method of assessing annual charges.[39] EEI argues that the Commission's clarification regarding the exact line items required to make the proposed annual assessment calculation is needed in order for those entities subject to the rule to evaluate its impact and be in a position to comment other than on the concept. Otherwise, EEI argues, the proposed method cannot be considered "fair and equitable," as required.[40]

Some commenters argue that because the Commission regulates a certain sector of the industry, *i.e.,* transmission, that does not necessarily imply that it is fair or equitable to burden only that sector with all costs associated with the Commission's regulatory activity. They assert that Commission's open access regulations also benefit generators and consumers. Avista argues that more costs of FERC's electric regulatory program are associated with transmission does not mean that all costs associated with all aspects of electric regulation should be recovered only from transmission providers. Avista argues that the Commission should ensure that filings by power marketers and generators carry an appropriate filing fee so that the majority of the cost of regulating those entities is paid for by those entities directly.[41] NEP asserts that the Commission's principle of cost causation provides that entities whose actions give rise to costs should bear the responsibility for those costs. NEP asserts that when the party that causes costs to be incurred is no longer responsible for paying them, there is no incentive for that party to control or reduce those costs; there is no incentive for that party to act efficiently.

A number of commenters state that they generally support the

[39] These include: (1) MWh Delivered/Transfer of Energy-Page 329, Column J; (2) MWh Delivered/Power Exchanges-Page 327, Column I; and (3) MWh Sold-Page 311, Column G. EEI points out that only a part of Column G on page 311 would pick up transmission, and would act as a "catch all" for what is not captured from the line items on pages 327 and 329.

[40] 42 U.S.C. 7178(b).

[41] The issue of filing fees is not before the Commission. In fact, power marketers and generators seeking exempt wholesale generator status are assessed filing fees. 18 CFR 381.801.

Commission's approach, but assert that because the NOPR seeks to assess annual charge cost responsibility to unbundled retail transmission, but not bundled retail transmission, the NOPR methodology could be unfairly prejudicial to the public utilities that have unbundled their retail transmission service to date because it would force these utilities to absorb a disproportionately large percentage of the FERC's electric regulatory program costs. These commenters add that the proposed methodology may serve as a disincentive for additional utilities to unbundle their retail transmission services. Thus, they request that the Commission clearly define and provide the industry with clear criteria for what constitutes unbundled retail transmission services for the purposes of the annual charge calculation.

EEI and ComEd, in this regard, recommend that the Commission clarify that ''unbundled retail transmission,'' as a category of transactions qualifying for annual assessment, does not include bundled retail transmission service in states that have adopted retail competition. EEI notes that some states have adopted retail competition but permit retail customers to elect to continue to receive bundled service.

EPSA and APX urge the Commission to include bundled retail service in its measurement of annual charges, otherwise the NOPR will result in the Commission's costs being spread only to a small fraction of transmission service. EPSA argues that bundled retail customers, like wholesale customers, benefit from the Commission's regulation of open access transmission service.

Cal ISO and FirstEnergy request that the Commission consider exempting unbundled retail transmission from the annual charge assessments, at least on an interim basis until a greater proportion of the country has undergone restructuring. The Midwest ISO states that it does not want to see assignment of cost responsibility to bundled retail customers in states that have not unbundled their retail customers through state customer choice legislation.

SoCal Edison proposes that the unbundled transmission component of the annual charge assessment be phased-in over a five year period. NUSCO asserts that the Commission should recognize that industry restructuring is in different stages throughout the country, and argues that the Commission should provide for a gradual transition to the new methodology. Specifically, NUSCO argues that the Commission should consider adopting a five-year transition to account for transitioning retail markets.

Avista argues that the Commission's proposal is likely to result in other forms of double counting.[42] Avista asserts that a better method would be to assess the charge either at the point of generation or the point of consumption, and argues that a charge on generation would be administratively simpler.

FirstEnergy and NEP argue that the NOPR ignores the occurrence of cost shifting that results because annual charges will not be imposed on other sellers of power. FirstEnergy, APS and GPU Energy assert that cost shifting results in an additional burden in that it will be necessary for the utility to revise its OATT on an annual basis—which is overly burdensome for the public utility, interested parties and the regulatory review process. Member Systems argue that the Commission should allow jurisdictional public utilities to defer collection of any increased assessment until their next section 205 rate increase proceeding.

Avista urges the Commission to consider whether a transmission-owning utility should be assessed annual charges based on the transmission of power generated by a PMA to serve the PMA's load, asserting that a jurisdictional, transmission-owning public utility should not be required to pay annual charges that it cannot recover from its transmission customers or recover such charges from its native load customers. Avista also asserts that the presence of PMAs in some areas of the country raises the possibility that the proposal will have uneven regional impacts noting that PMAs do not operate in all regions of the country.

APS and NEP argue that the Commission's contention that annual charges are ultimately charged to customers through transmission rates, albeit indirectly, is erroneous and flawed.[43] NEM expresses reservations that the proposed methodology could increase costs to power marketers significantly and cautions the Commission on the potentially negative impact on power marketers of blending short- and long-term transactions and effectively increasing the assessments' impact on power marketers that primarily engage in short-term contracts. Thus, NEM requests that the Commission clarify that the proposed methodology is applicable only to transmission facility owners and that only such entities will receive annual bills. NEM asserts that the rulemaking needs to explicitly address the applicability of annual charges to other entities, such as power marketers. NEM expects that it is not the Commission's intention to treat power marketers that do not provide transmission services but engage in power sales, which include a transmission component, like public utilities that own transmission facilities. NEM also asserts that it is critical that the charge be on a per unit basis, not on a per transaction basis since power marketers will be impacted when the transmission owners pass along the assessment charges.

SDG&E argues that the proposed rule should clarify that the ''transmission of electric energy'' for purposes of assessing annual charges should not include its retail load (SDG&E notes that it is obligated to bid all of its retail customers' demand into the California power exchange). SDG&E asserts that such an interpretation would result in its retail customers experiencing a substantial increase in the annual charge over that which they currently bear.

3. Commission Conclusion

The Commission is persuaded that it should change the way in which it apportions annual charges among the entities it regulates, and as a consequence, it will adopt the approach proposed in the NOPR.

As previously stated, at present, the Commission first determines the total costs of its electric regulatory program and subtracts all PMA-related costs and electric filing fee collections to determine the total collectible electric regulatory program costs. It then uses the data submitted under FERC–582 to determine the total volumes of long-term firm sales and transmission, and short-term sales and transmission and exchanges for all assessable public

[42] Avista gives three examples of how double counting may occur. First, the proposal appears vulnerable to double counting with respect to multiple transactions in the same unit of energy, where the transactions include a transmission component. This issue is resolved in our discussion of reassignment. *See infra* note 50. Second, the Commission identified the possibility that the same transaction could be attributed to both an RTO and a transmission-owning member of the RTO. We address this argument below in our discussion of RTOs. Third, a transaction may call for energy to flow over the transmission lines of two or more transmitting utilities or entities, which could result in an assessment of a charge for each entity. We resolve this argument below by assessing annual charges based on transmission tariffs and rate schedules.

[43] APS and NEP cite two examples: (1) Where marketers and EWGs sell their power at the bus bar of a switchyard adjacent to a power plant where different utility systems are interconnected, and (2) where a marketer secures power that is wheeled over a non-jurisdictional entity's system to a jointly owned switchyard where a number of different entities are interconnected.

utilities.[44] The Commission next divides into its collectible electric regulatory program costs those transaction volumes to determine the unit charge per megawatt-hour for each category of transactions. Finally, the Commission multiplies the transaction volume in each category for each public utility by the relevant unit charge per megawatt-hour to determine the annual charges for each assessable public utility.[45] This methodology for assessing annual charges worked well given the industry structure that existed at the time it was adopted. However, because there have been such dramatic changes in the industry, and the Commission's regulation of the industry, this approach is no longer appropriate.

With open-access transmission, functional unbundling and the rapid movement to market-based power sales rates brought about by, *inter alia,* Order No. 888,[46] state retail unbundling efforts, and the recently issued Order No. 2000,[47] the time and effort of our electric regulatory program is now increasingly devoted to assuring open and equal access to public utilities' transmission systems. Wholesale power sales rates are now increasingly being disciplined by competitive market forces and less by the Commission directly. As a consequence, we believe it appropriate to now assess our electric regulatory program costs solely on the MWh of electric energy transmitted in interstate commerce by public utilities providing transmission service,[48] rather than, as in the past, on both jurisdictional power sales and transmission volumes.[49]

As stated above, the Commission will now assess annual charges to all jurisdictional public utilities, as defined by the FPA, that provide transmission service. Such annual charges will be based on the MWh of unbundled transmission service (both wholesale [50] as well as retail [51]) and on bundled wholesale power sales (which, by definition, include a transmission component, assuming that the public utility is not separately reporting the transmission component as unbundled transmission).[52]

We believe that public utilities know the MWh of transmission they are providing (and that need to be reported on their FERC–582), as they do so pursuant to tariffs and rate schedules on file at the Commission and they bill their customers under these tariffs and rate schedules accordingly.[53] Nevertheless, to aid them in completing their FERC–582s, we will identify specific pages and columns where data may be found that, for the purposes of annual charge calculations, corresponds to the transmission services identified in the above narrative description. The classifications of transactions can be obtained from the FERC Annual Report Form No. 1. They include:

(1) Transmission of Electricity for Others, Transfer of Energy, MWh Delivered (Form No. 1, Pg. 328–329, Col. (j)); [54]

(2) Purchased Power, Power Exchanges, MWh Delivered (Form No. 1, Pg. 326–327, Col. (i)); [55] and

(3) Sales for Resale, MWh Sold (Form No. 1, Pg. 310–311, Col. (g)).[56]

For those public utilities, if any, that do not file a Form 1, our narrative description of how, and on what, the annual charges are to be assessed is sufficiently clear to allow them to complete their FERC–582s on a a timely basis.

The Commission also believes that the new assessment methodology is ''fair and equitable,'' as required by the Budget Act. The Commission believes that it is appropriate that annual charge assessments be exclusively based on transmission volumes as regulation of transmission is increasingly the work the Commission is doing and will be doing in the future. This trend, moreover, will only accelerate as the industry moves forward with the formation of RTOs. Given that the annual charge assessment methodology being adopted here will first be effective for annual charge bills to be paid in calendar year 2002, we believe it appropriate to recover our costs based solely on transmission and solely from transmission providers. In addition, as noted above, the Commission believes that power sellers will continue to contribute to the Commission's recovery of its electric regulatory program costs, albeit indirectly, through the cost-based transmission rates (and annual charges are, we find, a legitimate cost of providing transmission service) they pay for the transmission service they may take.[57]

[44] Long-term firm sales and transmission activities, and short-term sales and transmission and exchange activities were defined in 18 CFR 382.102.

[45] The Commission also carries over any over- or under-charge from the prior year as a credit or debit on the current year's annual charge bill.

[46] *See supra* note 13.

[47] Regional Transmission Organizations, Order No. 2000, 65 FR 810 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g,* Order No. 2000–A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000).

[48] This approach is essentially the same as how annual charges are, in practice, assessed against gas pipelines.

[49] The Commission believes that this approach of directly charging only those public utilities that provide transmission service is both fair and equitable. All parties involved in the generation and sale of electric energy rely on the transmission system to move their product. Thus, power sellers will be contributing to the Commission's recovery of its electric regulatory program costs in that they will be using the transmission system and, in any cost-based rates that they pay for transmission service that they may take, will pay, albeit indirectly, their share of the Commission's costs.

[50] With respect to the issue of reassignment of transmission service, we would anticipate that the original provider of the service would report the MWh of transmission service and would therefore be assessed the annual charges associated with that transmission. This approach is, we believe, the only workable approach.

[51] See supra note 13, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,780–85, Order No. 888-A, FERC Stats. & Regs. ¶ 31,043 at 30,334–46; TAPSG, slip op. at 24–35.

[52] Annual charges will be assessed based on all transmission by public utilities, with no distinction made between so-called unbundled retail and unbundled wholesale transmission. See New York State Electric & Gas Corp., 77 FERC ¶ 61,044 (1996), reh'g denied, 83 FERC ¶ 61,203 (1998); New England Power Co., et al., 75 FERC ¶ 61,207 (1996), 76 FERC ¶ 61,008 (1996), reh'g denied, 85 FERC ¶ 61,181 (1998); supra note 13, Order No. 888-A at 30,214–16. This transmission would include all unbundled retail transmission in states with retail choice, even when the retail customer purchases retail power service from its original power supplier. This transmission would also include MWh delivered in wheeling transactions and the MWh delivered in exchange transactions.

If the bundled wholesale power sale involves the use of non-affiliated, third-party transmission systems, any transmission by such systems would be picked up through the non-affiliated, third-party transmission providers' reporting of the MWhs of transmission service they provided. If the bundled wholesale power sale involves the use of the power seller's or its affiliate's transmission system, the transmission component might conceivably be separately reported as unbundled transmission. If, however, this is not the case, the MWhs would need to be reported as a bundled wholesale power sale.

The annual charge will be on a per unit basis, MWh, and not on a per transaction basis.

[53] Insofar as utilities currently bill for the transmission services they provide, these utilities would know how much transmission they are providing and should have little difficulty reporting transmission volumes to the Commission.

We recognize that in some instances public utilities may arrange for agents to act on their behalf in, for example, scheduling transmission service or billing for transmission service. We would anticipate that the public utility itself, rather than the agent, would report the transaction and therefore be responsible for the annual charge assessment. This would be due to the fact that it is the public utility itself that is providing the transmission service, and has the transmission tariff and rate schedules on file with the Commission.

[54] These data include all transmission of power for other entities.

[55] :These data include power delivered by the utility to others in power exchange transactions.

[56] These data include all sales for resale. The data reported on pages 310–311 and the data reported on pages 328–329 may double count MWh since these MWh might be reported first as sales for resale and secondly as energy transmission transactions. This double counting can be overcome by adjusting the volumes on either pages 310–311 or pages 328–329. See supra note 52 and accompanying text.

[57] The Commission notes that public utilities will only need to file FERC–582 and pay annual charges if they provide transmission of electric energy in interstate commerce. In other words, if, for

The new methodology adopted here addresses concerns over potential ''double-counting.'' Because only the entity that is providing the transmission service pursuant to its transmission tariff or rate schedule would report the transmission volumes and accordingly be assessed an annual charge, the risk of charging more than one entity for the same transmission volume disappears. This eliminates the concern that if a transaction, in fact, involves energy flowing over the transmission lines of two or more transmitting entities (even though the contract that calls for the transmission service calls for that service to be provided by only one entity) both entities could be assessed an annual charge for the same transmission volumes.

A number of commenters assert that the Commission needs to clarify that ''unbundled retail transmission'' does not include bundled retail service, while EPSA and APX urge the Commission to include bundled retail service in its calculation of annual charges. In Order No. 888, the Commission held that bundled retail service is not subject to Commission regulation.[58] With this Final Rule we continue the approach taken in Order No. 888 and, in the absence of transmission in an ISO or RTO context (which we discuss below, *see infra* note 68) we will not include bundled retail service in the annual charges calculation.

A few commenters argue that the Commission should consider exempting unbundled retail transmission from the annual charge assessments, at least on an interim basis until a greater proportion of the country has undergone restructuring. These commenters assert that the NOPR methodology could be unfairly prejudicial to public utilities that have unbundled their retail transmission service to date. The Commission notes, however, that more than half of the states are already moving, or have moved to, unbundle transmission.[59] SoCal Edison comments that the proposed methodology may serve as a disincentive for individual utilities to unbundle their retail services. The Commission recognizes that this may increase costs to some public utilities, but nonetheless, the new methodology should not act as a disincentive because of the small magnitude of these costs[60] as compared to the revenues currently being collected for unbundled retail transmission itself.[61] The amount of money covered by this rule, the cost of the Commission's electric regulatory program minus PMA costs and filing fee collections, is also not a large sum[62] in comparison to the revenues being collected for other, wholesale transmission services,[63] and it also will be spread across all public utilities providing transmission service, thus resulting in only a small addition to transmission rates (with, unlike as in the past, no addition to power sales rates). In addition, in the past the regulation of transmission associated with retail power sales was done by the states, and any costs associated with that regulation would have been incurred by state regulatory commissions and would have been subject to whatever regulatory assessments were imposed by those commissions.[64] Now, with the regulation of transmission associated with unbundled retail power sales being done by this Commission, the costs associated with this regulation are incurred by this Commission and are appropriately reflected in our annual charge assessments. In short, what is occurring is more a shifting of costs and assessments, rather than an absolute increase.

Some commenters argue that the NOPR ignores the occurrence of cost shifting that results because annual charges are imposed solely on public utilities providing transmission service and not on other sellers of power. In response, the Commission notes that the current system for assessing annual charges places a heavy emphasis on power sales—reflecting the Commission's traditional focus. As stated earlier, the Commission has been reducing its regulation of the power sale business and that trend is continuing and even accelerating. We thus believe that it is appropriate that the annual charges be borne by the entities and services on which we are now increasingly focusing.

FirstEnergy and NEP argue that cost shifting will result in public utilities having to revise their OATTs on an annual basis. The Commission notes that public utilities make amendments to their OATTs routinely and many public utilities typically made rate change filings in the past. Thus, the Commission does not see the Final Rule as imposing any new burden on public utilities. Member Systems argue that the Commission should allow jurisdictional utilities to defer collection of any increased assessment until their next section 205 rate increase proceeding. The Commission does not agree with the commenters that such deferment is necessary. The Commission believes that the effective date for this Final Rule, as discussed below, provides sufficient notice for utilities to put rates into place for the utilities to be able to collect sufficient monies to pay their annual charge bills in 2002. In fact, some utilities' rates may already be recovering sufficient funds to meet their new annual charge obligations.

SoCal Edison proposes that the unbundled transmission component of the annual charge assessment be phased-in over a five year period while NUSCO seeks a similar phase-in. In response, the Commission believes that a phase-in approach is unnecessary. The Commission believes that the new approach reflects the new realities of the industry and of Commission regulation, is straightforward and easy to apply, and gives public utilities enough time to prepare for the bills that will be paid in 2002.

SDG&E argues that the rule should clarify that the ''transmission of electric energy'' for purposes of assessing annual charges should not include its retail load (SDG&E notes that it is obligated to bid all of its retail customers' demand into the California power exchange). The Commission does not believe that rates will rise dramatically, because, as discussed above, the collectible costs of the Commission's electric regulatory program are not a large sum of money, and will be spread out over a large

example, power marketers are not providing transmission service, they will not need to file FERC–582 or pay annual charges.

[58] *E.g., supra* note 13, Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,217.

[59] For more specific information on the status of state electric industry restructuring activity *see, e.g.,* <*http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html*> (August 2000).

[60] The Commission's total collectible electric regulatory program costs collected in annual charges in 1999 (based on data reported for calendar year 1998) were $54,596,000.

[61] The data reported to us on Form No. 1 do not allow us to estimate what percentage of total retail revenues reflect transmission-related costs. However, the Energy Information Administration of the Department of Energy estimates that transmission accounts for 7 percent of the total cost of delivered power. *See* Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities, A Preliminary Analysis Through 2015, ''Pricing Electricity in a Competitive Market,'' EIA/DOE–0614, p. 11 (August 1997). Thus, the transmission-related revenues would be substantially higher than our total collectible electric regulatory program costs.

[62] *See supra* note 60.

[63] Based on a review of Form No. 1 data for 1998, the total revenues collected just for ''transmission for others'' were approximately 2 billion dollars. Based on a review of the same data, the total revenues collected for ''sales for resale'' (which would include a transmission component) were in excess of 29 billion dollars.

[64] Based on a review of Form No. 1 data for 1999, it appears that 36 of the lower 48 states, or ¾ of the lower 48 states, collect such regulatory assessments.

number of MWhs (all of the MWhs of all transmission providers). In addition, in the past the regulation of transmission associated with retail power sales was done by the states, and any costs associated with that regulation would have been incurred by state regulatory commissions and would have been subject to whatever regulatory assessments were imposed by those commissions.[65] Now, with the regulation of transmission associated with unbundled retail power sales being done by this Commission, the costs associated with this regulation are incurred by this Commission and are appropriately reflected in our annual charge assessments. In short, what is occurring is more a shifting of costs and assessments, rather than an absolute increase.

Based on the foregoing discussion, commencing with the annual charges billed and paid in calendar year 2002, based on data reported for calendar year 2001, the Commission will now assess annual charges to public utilities that provide transmission service based on their transmission of electric energy in interstate commerce, as measured by: (1) Unbundled wholesale transmission, (2) unbundled retail transmission, and (3) bundled wholesale power sales which, by definition, include a transmission component, where the transmission component is not separately reported as unbundled transmission.[66]

4. *Independent System Operators and Regional Transmission Organizations*

a. *Proposed New Methodology.* As to ISOs and potential RTOs that have members that retain ownership of transmission facilities, the Commission stated in the NOPR that it was concerned that the assessment of annual charges could result in a ''double counting'' of transactions—by counting a single transaction both to the transmission-owning public utility and to the ISO or RTO public utility. The NOPR suggested that there were at least two ways to address this issue, and invited comments on these and any other solutions to this problem. One proposed method was not to charge the ISO or RTO itself, but instead charge each transmission-owning public utility based on the MWh of transmission service provided on their lines. The transmission-owning public utility would include the annual charges, as a cost element, in its revenue requirement, which, in turn, is recovered by the ISO or RTO through the ISO's or RTO's open access transmission tariff rates. The other proposed method was to allow the ISO or RTO to act as an agent for all of the individual transmission owners and have the ISO or RTO pay the annual charges rather than the individual transmission owners. The Commission stated that either of these approaches may be acceptable and solicited comments on the two approaches, as well as comments on any other approach that would allow the Commission to collect annual charges on these MWh of transmission service, in the most administratively efficient manner.

b. *Comments.* The Commission received a number of comments on this issue. Williams EM&T states that although it has no specific suggestion regarding which approach would be preferable, it urges the Commission to defer to the comments of the ISOs, RTOs, and transmission-owning entities. TXU Electric believes that either approach would be acceptable, as long as there are adequate measures in place to ensure that there would be no double counting of transactions between the individual utility and the ISO/RTO.

The commenters are generally split, with many on each side. A number of commenters believe that the most equitable method to assess the annual charge is directly to the ISO or RTO, because they are the transmission providers in their respective territories. Consumers supports assessing annual charges to the RTOs, where there is an RTO in place. FirstEnergy states that the only situation where transmission owners should be charged annual charges and allowed to collect the corresponding revenue requirements is where the Commission has not approved an RTO. EEI adds that because the RTO would actually be collecting annual charge costs from transmission customers, through the transmission rates, it makes sense to have the RTOs make the annual charge payments to the Commission. GPU Energy asserts that this will allow the Commission to collect annual charges in the most administratively efficient manner.

SoCal Edison states that, specifically in the California market, the individual transmission owners are no longer the transmission providers and do not have access to information about the transmitted MWh associated with wheeling and existing transmission contracts because such transactions are, for the most part, scheduled directly with the ISO, and only the ISO obtains this data. Therefore, SoCal Edison argues that, as a matter of common sense, the ISOs and RTOs should file the Form 582 and be billed for annual charges. GPU Energy adds that an agency structure much like that proposed in the NOPR is already in place in PJM and that the Commission should not make any findings in the Final Rule that could undo this agreement.

SoCal Edison asserts that there are other advantages to making the ISOs and RTOs the parties responsible for complying with the Commission's annual charge reporting and payment requirements. First, because the ISOs and RTOs are also public utilities, this approach is consistent with the Commission's desire to impose the initial responsibility for annual charges on public utilities. Second, the various ISOs and RTOs are in the best position to pass on annual charge expenses to transmission users. Third, consistent with the Commission's directive that ''all parties involved in the generation and sale of electric energy'' should ultimately bear the cost of annual charges, the ISOs and RTOs will be able to assure that annual charges become the responsibility of transmission consumers by directly billing scheduling coordinators for their proportionate share of the annual charge assessment under the ISOs' and RTOs' respective transmission tariffs.

Avista states that it is impossible to determine exactly how the Commission's proposal would work in an RTO environment, because the RTO environment has yet to exist in most areas and is only newly formed in others. Avista argues that it is fundamentally premature to impose a rulemaking that depends so heavily on RTO formation and the Commission should defer action on the annual charge proposal until more is known about how RTOs will work.

Several commenters state that the NOPR would place a hurdle in the path of RTO formation. APX Companies state that by exempting MWh of transmission usage that is bundled with retail sales from the allocation of the annual charge, the NOPR tells transmission owning utilities that they can still benefit from uniform rules and practices that the Commission adopts in its electric regulatory program, but escape financial responsibility for that program. Member Systems assert that the proposed allocation between utilities that have or have not joined ISOs/RTOs would be unfair and inequitable because a much larger percentage of the Commission's costs would be assessed to utilities that have joined ISOs/RTOs. Member Systems thus submit that the Commission should solicit additional

[65] Based on a review of Form No. 1 data for 1999, it appears that 36 of the lower 48 states, or 3⁄4 of the lower 48 states, collect such regulatory assessments.

[66] *See supra* note 52.

comments to address this problem. SPP requests that the Commission detail the mechanics as to how the assessments against transmission owners will be determined when an RTO is providing the service over their facilities as part of a regional tariff arguing that most transactions will involve the use of facilities from multiple transmission owners and the RTO will not be able to easily identify a particular transmission owner whose facilities were used for a specific transmission transaction.

FirstEnergy adds that to eliminate the potential conflict between Order No. 2000 and the NOPR, and to maintain RTO open architecture, the Commission should give RTOs the flexibility to propose to the Commission other methods for assessing annual charges on a case-by-case basis.

PECO asserts that the regulatory text should be revised to make it clear that the ISO or RTO should pay the resulting assessments and that the ISO or RTO should collect the funds to make those payments from its customers under the tariff.

A number of commenters, on the other hand, believe that transmission owners should be assessed annual charges for transactions over their facilities. Cal ISO argues that this approach is fair and equitable because the transmission owners that own the transmission facilities operated by an ISO are traditionally the entities that have been assessed annual charges for transmission transactions occurring on those facilities, and they have mechanisms in place for accounting for annual charge costs and for passing through the costs to the appropriate parties. Cal ISO adds that this approach would also avoid the need, when new ISOs and RTOs are formed, to develop mechanisms to transfer the responsibility of payment of FERC annual charges to the new organization, and for that organization to recover those costs. Cal ISO states that while procedures and mechanisms for paying annual charges (and for their recovery in rates) could certainly be developed, it would be simpler to allow transmission owners to utilize the pass-through mechanisms that are already in place.

Cal ISO and the Midwest ISO state that, insofar as ISOs or RTOs will not own the transmission systems that are the focus of the Commission's revised annual charge methodology, it seems more appropriate to assess the annual charges against the transmission owners themselves. The Midwest ISO adds that shifting the cost responsibility to the ISO under the guise of the ISO acting as agent is inappropriate because the ISO does not in essence ''make sales for resale or transmit electric energy in interstate commerce'' using its own transmission assets.

Several commenters state that an ISO/RTO will have no shareholders that can absorb revenue shortfalls that arise, either due to the inability to collect fees from all loads or the refusal of some members to remit what is owed. These commenters point out that an ISO/RTO has limited enforcement powers to compel its members to remit FERC fees.

Cal ISO raises other concerns that would complicate the efforts ISOs or RTOs would need to undertake if they were assessed annual charges. In Order No. 2000, the Commission expressed a preference that RTOs include transmission systems owned by municipalities and other utilities that are not ''public utilities'' under the FPA. Under the NOPR, such entities are not subject to FERC annual charges, therefore, the ISO or RTO would be required to take steps to distinguish the MWh transmitted over purely non-jurisdictional transmission systems for purposes of reporting transactions subject to FERC annual charges. LIPA and NYPA assert that the Commission should find that annual charges should not be assessed with respect to transactions involving loads interconnected to non-public utility transmission facilities.

SPP requests that the Commission clarify the treatment of non-FERC regulated transmission owners who have committed their facilities to RTOs, such as municipals and cooperative utility systems.

Under either approach proposed by the Commission, PJM asserts that the Commission should clarify the rule to provide that the ISO/RTO is not subject to annual charges as a public utility. When acting as an agent for the transmission-owning public utilities, the annual charges still should be treated as a cost of the transmission-owning public utilities and should be collected on their behalf from ISO/RTO customers (and paid to the Commission) in a manner similar to the collection of the transmission-owning utilities' revenue requirements.

The Midwest ISO offers a third alternative: The ISO/RTO would provide an accounting of transactions within its region, which would eliminate ''double counting,'' but actual billings and collections would be between the Commission and the transmission-owning public utilities. That is, the ISO/RTO would provide the data (act as an ''information clearinghouse'') but that the obligation to pay annual charges would remain with the individual public utilities.

One commenter suggests that annual charges be assessed to both an ISO or RTO and the individual transmission owner. APS believes that any resulting double counting of transactions should not be a consideration if both entities each contribute to the Commission's electric regulatory program costs. APS asserts that a multitude of ISO and RTO issues occupy the Commission's resources and attention and contribute to the Commission's electric regulatory program costs and those costs should be recovered from those entities.

c. *Commission Conclusion.* After giving consideration to all of the comments received on this issue, the Commission finds that the best approach is to assess the costs of the Commission's electric regulatory program to each public utility [67] that provides transmission service. In other words, whoever is providing the transmission service (*i.e.*, has a tariff or rate schedule on file with the Commission to provide transmission service and thus would have rates on file for that transmission service) is the appropriate entity to be assessed annual charges. If an ISO or RTO public utility has taken over from individual public utilities the function of providing transmission service and has, accordingly, a tariff or rate schedule (and thus rates) on file for such service,[68] then it is the ISO or RTO public utility that will be responsible for paying annual charges, and it will be assessed annual charges based on all transmission that it provides pursuant to its tariff or rate schedule.[69] If an individual public utility continues to provide transmission service, however, and still has, accordingly, a tariff or rate schedule (and thus rates) on file for such service, then that individual public utility will continue to be responsible for paying annual charges. In those cases where, for a particular transmission transaction, transmission service is being provided both by an ISO or RTO public utility and by an individual public utility, then both the ISO or RTO public utility and the individual public utility will be

[67] 18 CFR 382.102(b); *see* 16 U.S.C. 824(e).

[68] It is our expectation that all individual public utilities (and others, as well) will join RTOs and therefore there should be no unfairness as between some individual public utilities and others in terms of assessment of annual charges.

[69] We do not intend to parse an ISO's or RTO's transmission based on whether the facilities that it is providing service over were previously non-jurisdictional. The ISO or RTO public utility is a public utility and is providing jurisdictional transmission service pursuant to tariffs or rate schedules on file with (and regulated by) the Commission. Thus, it is appropriate that annual charges be assessed based on the transmission that the ISO or RTO public utility provides.

assessed annual charges based on the respective services provided.[70]

As discussed previously, the transmission on which annual charges are assessed includes unbundled retail transmission. In the ISO or RTO context, however, where regional transmission services are provided over the system of more than one public utility, all retail transactions involve an unbundled retail transmission component. For example, when PEPCO takes service under the PJM tariff to serve its native load, it makes use of the entire PJM system and, as such, obtains unbundled retail transmission service from other transmission-providing members of PJM. Those transmission volumes, essentially the entire intra-ISO or RTO load, will need to be reported to the Commission in FERC–582 (along with the other transmission provided by the ISO or RTO, *i.e.*, essentially so-called through or export transactions) and annual charges will be assessed accordingly.

As discussed earlier, Avista argues that it is premature to adopt a requirement that, it claims, depends so heavily on RTO formation and requests that the Commission defer action on the annual charge proposal until more is known about how the RTOs will work. The Commission believes that it is appropriate to proceed with this Final Rule at this time for the reasons given earlier, and here we are only creating the mechanism by which annual charges will be assessed (and not how these charges are, in turn, to be recovered by the public utilities in their rates). The Commission believes that there are benefits that can come from the participants in the RTO development process knowing earlier rather than later as to how the Commission intends on assessing annual charges. We believe that proceeding with the Final Rule at this time will aid those who are currently in the process of developing RTOs.

FirstEnergy states that to eliminate the potential conflict between Order No. 2000 and the NOPR, and to maintain RTO open architecture, the Commission should give the RTO flexibility to propose to the Commission other methods for assessing annual charges on a case-by-case basis. On this issue, the Commission believes that this Final Rule does not detract from the RTO participants' flexibility to decide how to structure the new entity. Rather, it simply identifies who will be assessed annual charges (and how those charges will be calculated). The Commission believes that this new approach to annual charges will avoid the occurrence of double counting, which should, in fact, aid the development of RTOs.

Finally, the Commission believes that this approach is both fair and equitable, as required by the Budget Act, as it places the requirement to pay annual charges on the particular entities that will be providing the transmission services on which the annual charges will be assessed.

C. Other Matters

1. Rate Recovery

A number of commenters raise concern about their ability to recover their annual charges in their rates. Some commenters request that the Commission expressly provide that public utilities can fully recover the annual charge assessments from their customers through surcharges to the transmission rates and pass through or balancing account mechanisms. Avista requests that the Commission specify precisely how and under what circumstances annual charges may be passed through to transmission owners.

EEI recommends that the Commission adopt an Annual Charge Adjustment (ACA) surcharge, together with a ''limited Section 205'' rate filing. SoCal Edison requests, that in its case, the Commission declare that the annual charge assessment can be included as a component of the Transmission Revenue Balancing Account Adjustment (TRBAA). APS proposes that a jurisdictional public utility would file annually, by a specific date, an Annual Surcharge Factor reflecting the adjusted annual charge assessed to the utility, divided by the MWH included in Form 582 used to develop the assessed annual charge. Several commenters raise similar concerns regarding cost recovery if an ISO or RTO is the entity assessed annual charges.

We note at the outset that the purpose of this Final Rule is to change the methodology for the assessment of annual charges to public utilities. The issue of rate recovery of annual charges is not within the scope of this Final Rule. The Commission has other regulations already in place that address the recovery of costs in rates, *i.e.*, Part 35, which governs rate change filings.[71] Public utilities thus are not without mechanisms whereby they can come to the Commission for a change in their rates.

However, to allay the concerns of public utilities as to rate recovery, we will state here that we find that the annual charge assessments are costs that can be recovered in transmission rates as a legitimate cost of providing transmission service. We will otherwise leave this issue to be resolved in future rate change filings, as they may come before the Commission from time to time on a case-by-case basis; different public utilities may require different rate revisions to address this matter.

2. Reporting Requirements

The Commission is changing its reporting requirements for annual charges. Currently, a public utility has to submit the total long-term firm sales for resale and transmission megawatt-hours and the total short-term sales, transmission, and exchange megawatt-hours. With the elimination of the distinction between long-term and short-term transactions, such distinctions in the reporting requirements are likewise no longer needed. Similarly, with changing the focus from power to transmission, only those public utilities that provide transmission service will need to comply with the Commission's reporting requirement.

The Commission thus will now require that public utilities that provide transmission service must report total volumes of electric energy transmitted in interstate commerce (as defined above, to include all unbundled transmission and all bundled wholesale power sales), in MWh, by April 30th of each year.[72]

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[70] Likewise, if two or more different public utilities such as two or more RTO public utilities or two or more individual public utilities transmit electric energy sequentially one after the other (as in, for example, the case of electric energy being transmitted over comparatively long distances, and thus by multiple public utilities over their respective transmission systems one after the other), they will each be assessed an annual charge based on their respective transmission of such electric energy.

For example, if the power seller must move power through two different RTOs to reach the power buyer, then each RTO would be assessed annual charges based on its respective transmission of that power. Likewise, in another example, if the power seller must move its power through two different individual public utilities that are not members of an RTO, then each public utility would be assessed annual charges based on its respective transmission of that power. In yet another example, if the power seller must move its power through an individual public utility that is not a member of an RTO, and through an RTO, then, again, the individual public utility and the RTO would each be assessed annual charges based on their respective transmission volumes.

Finally, of course, if an RTO was providing transmission service pursuant to its tariff wholly within the RTO, then only that RTO would be assessed annual charges for that transmission (even if the transmission nominally involved the use of the transmission facilities of two or more members of the RTO).

[71] 18 CFR Part 35; *see* 16 U.S.C. 824d (allowing utilities to seek to change their rates).

[72] Williams EM&T commented that it believed that as a public utility under the FPA, it would still

Finally, as we proposed in the NOPR, any corrections to FERC–582 will need to be made by the end of the calendar year in which the FERC–582 was filed.

3. Standards for Waiving All or Part of an Annual Charge

The Commission did not propose to change and is not changing the standards applicable for waiving all or part of an annual charge. Thus, the Commission will continue to apply to annual charges the stringent standards for waiver currently applicable to filing fees, with a filing period for waiver petitions of 15 days after the issuance of the annual charges bill.

IV. Environmental Statement

The Commission excludes certain actions not having a significant effect on the human environment from the requirement to prepare an environmental assessment or an environmental impact statement.[73] The promulgation of a rule that is procedural or that does not substantially change the effect of legislation or regulations amended raises no environmental considerations.[74] This Final Rule amends Part 382 of the Commission's regulations to establish a new methodology for the assessment of annual charges to public utilities and does not substantially change the effect of the underlying legislation or the regulations being revised. Accordingly, no environmental consideration is necessary.

V. Regulatory Flexibility Act Certification

The Regulatory Flexibility Act (RFA), 5 U.S.C. 601–612, requires rulemakings to contain either a description and analysis of the effect that the proposed rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities.

In *Mid-Tex Elec. Coop.* v. *FERC*, 773 F.2d 327 (D.C. Cir. 1985), the court found that Congress, in passing the RFA, intended agencies to limit their consideration ‘‘to small entities that would be directly regulated'' by proposed rules. *Id.* at 342. The court further concluded that ‘‘the relevant ‘‘economic impact'' was the impact of compliance with the proposed rule on regulated small entities.'' *Id.* at 342.

The Commission does not believe that this Final Rule will have a significant direct impact on small entities. Most, if not all, public utilities that would be assessed annual charges under this Final Rule do not fall within the RFA's definition of a small entity because most public utilities subject to this Final Rule are too large to be considered ‘‘small entities.'' [75] Therefore, the Commission certifies that this Final Rule will not have a ‘‘significant economic impact on a substantial number of small entities.''

VI. Public Reporting Burden and Information Collection Statement

The OMB regulations require OMB to approve certain reporting and recordkeeping (collections of information) requirements imposed by agency rule.[76] The NOPR was submitted to OMB at the time of issuance. OMB did not comment on nor did it take any action on the proposed rule.

No comments from the public on the burden estimate were received. The filing requirements remain essentially the same as those in the NOPR so, therefore, the estimated annual filing burden remains the same. The burden estimate for complying with this final rule is as follows:

Public Reporting Burden: Estimated Annual Burden:

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
FERC–582	242	1	4	968

Total Annual Hours for Collection (reporting + recordkeeping, (if appropriate)) = 968

Information Collection Costs: The Commission sought comments on the costs to comply with these requirements, and no comments were received. The Commission projected the average annualized cost for all respondents to be:

- Annualized Capital/Startup Costs ($0) + Annualized Operations & Maintenance Costs ($53,687).
- (968 hours ÷ 2080 hours per year) × $115,357 = $53,687.
- The cost per respondent is equal to $222 ($53,687 ÷ 242 = $222).

The OMB regulations require OMB to approve certain information collection requirements imposed by agency rule.[77] Accordingly, the Commission provided notice of its proposed information collection to OMB. Again, the Commission received no comments from OMB.

Title: FERC–582, Electric Fees and Annual Charges.

Action: Proposed Data Collection.

OMB Control No.: 1902–0132.

The applicant shall not be penalized for failure to respond to this collection of information unless the collection of information displays a valid OMB control number.

Respondents: Business or other for profit, including small businesses.

Frequency of Responses: Annually.

Necessity of Information: The Final Rule revises the requirements contained in 18 CFR Part 382 to revise the method for determining the assessment of annual charges. The Commission is making its assessment for annual charges more compatible with the current industry and regulatory environment, including and the creation of competitive bulk power markets.

The Commission has the authority under the Omnibus Budget Reconciliation Act of 1986 (42 U.S.C. 7178) to ‘‘assess and collect fees and annual charges in any fiscal year in amounts equal to all of the costs incurred * * * in that fiscal year.'' The Act gives the Commission the flexibility to arrive at a reasonable approximation of its program costs. The costs are determined by a summation of all electric regulatory program costs and then subtracting PMA-related costs and electric regulatory program filing fee collections in order to determine the total collectible costs for the electric regulatory program.

Information submitted under FERC–582 is the basis for the calculation of annual charges, and presently includes total volumes of long-term firm sales and transmission and short-term sales and transmission plus exchanges for all

be required to file a FERC–582, although such report will contain no transmission information and Williams EM&T will be assessed no annual charge. Williams EM&T is mistaken. As noted above, only those public utilities that provide transmission service will need to report volumes of electric energy transmitted in interstate commerce. If Williams EM&T does not provide such service, it will not be required to file FERC–582.

[73] 18 CFR 380.4.

[74] 18 CFR 380.4(a)(2)(ii).

[75] 5 U.S.C. 601(6).

[76] 5 CFR 1320.11; *see* 44 U.S.C. 3507(d).

[77] 5 CFR 1320.11.

public utilities, including power marketers. The Final Rule changes the basis for the calculation of annual charges to the total volumes of electricity transmitted by public utilities that provide transmission service.

Internal Review: The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements. The Commission's Office of the Executive Director will use the data submitted under FERC–582 in order to serve as a billing determinant to recover costs for administering its electric regulatory program, including administering the provisions of Parts II and III of the Federal Power Act and the provisions of the Public Utility Regulatory Policies Act of 1987.

The Commission received approximately 35 comments and reply comments on this NOPR but none on its reporting burden. The Commission's responses to the comments are addressed in the preamble of this Final Rule. The Commission is submitting a copy of the Final Rule, along with information collection submissions for the data collection identified above, to OMB for its review and approval.

Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [Attention: Michael Miller, Office of the Chief Information Officer, Phone: (202) 208–1415, Fax: (202) 208–2425, E-Mail: *mike.miller@ferc.fed.us]*.

For comments concerning the collection of information(s) and associated burden estimate(s), please send your comments to the contact listed above and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, Phone: (202) 395–7318, Fax: (202) 395–7285].

VII. Effective Date and Congressional Notification

This rule will take effect on January 1, 2001. We will begin assessing annual charges under this new methodology starting with bills to be paid in calendar year 2002, based on data reported on FERC–582 in calendar year 2002 (for transactions that occurred in calendar year 2001, the first full year after adoption of changes in the regulations).[78]

Likewise we will make the change discussed above with respect to corrections to FERC–582 effective beginning with the data reported in FERC–582 in calendar year 2002 (for transactions that occurred in calendar year 2001); thus such corrections will need to be submitted on or before December 31, 2002.

The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of the Office of Management and Budget, that this Rule is not a ''major rule'' within the meaning of section 251 of the Small Business Regulatory Fairness Act of 1996.[79] The Commission will submit the Final Rule to both houses of Congress and to the General Accounting Office.[80]

VIII. Document Availability

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://ferc.fed.us) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

From FERC's Home Page on the Internet, this information is available in both the Commission Issuance Posting System (CIPS) and the Records and Information Management System (RIMS).

- CIPS provides access to the texts of formal documents issued by the Commission since November 14, 1994. CIPS can be accessed using the CIPS link or the Energy Information Online icon. The full text of this document will be available on CIPS in ASCII and WordPerfect 8.0 format for viewing, printing and/or downloading.
- RIMS contains images of documents submitted to and issued by the Commission after November 16, 1981. Documents from November 1995 to the present can be viewed and printed from FERC's Home Page using the RIMS link or the Energy Information Online icon. Descriptions of documents back to November 16, 1981, are also available from RIMS-on-the-Web; requests for copies of these and other older documents should be submitted to the Public Reference Room.

User assistance is available for RIMS, CIPS and the Website during normal business hours from our Help Line at (202) 208–2222 (E-mail to WebMaster@ferc.fed.us) or the Public Reference Room at (202) 208–1371 (E-mail to public.referenceroom@ferc.fed.us).

During normal business hours, documents can also be viewed and/or printed in FERC's Public Reference Room, where RIMS, CIPS and the FERC Website are available. User assistance is also available.

List of Subjects in 18 CFR Part 382

Administrative practice and procedure, Electric utilities, Pipelines, Reporting and recordkeeping requirements.

By the Commission.

David P. Boergers,

Secretary.

In consideration of the foregoing, the Commission amends Part 382, Chapter I, Title 18 of the *Code of Federal Regulations,* as follows:

PART 382—ANNUAL CHARGES

1. The authority citation for Part 382 continues to read as follows:

Authority: 5 U.S.C. 551–557; 15 U.S.C. 717–717w, 3301–3432; 16 U.S.C. 791a–825r, 2601–2645; 42 U.S.C. 7101–7352; 49 U.S.C. 60502; 49 App. U.S.C. 1–85.

2. In § 382.102 paragraphs (h), (i), (j) and (k) are removed and paragraphs (l), (m), (n), (o) and (p) are redesignated as (h), (i), (j), (k) and (l), respectively.

3. Section 382.201 is revised to read as follows:

§ 382.201 Annual charges under Parts II and III of the Federal Power Act and related statutes.

(a) *Determination of costs to be assessed to public utilities.* The adjusted costs of administration of the electric regulatory program, excluding the costs of regulating the Power Marketing Agencies, will be assessed to public utilities that provide transmission service (measured, as discussed in paragraph (c) of this section, by the sum of the megawatt-hours of all unbundled transmission and the megawatt-hours of all bundled wholesale power sales (to the extent these latter megawatt-hours were not separately reported as unbundled transmission)).

(b) *Determination of annual charges to be assessed to public utilities.* The costs determined under paragraph (a) of this section will be assessed as annual charges to each public utility providing transmission service based on the proportion of the megawatt-hours of transmission of electric energy in

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[78] Our existing regulations will remain effective for prior submissions and annual charges assessments (*i.e.,* for annual charge bills to be paid in calendar year 2001 based on data reported on FERC–582 in calendar year 2001 (for transactions that occurred in calendar year 2000)).

[79] 5 U.S.C. 804(2).

[80] 5 U.S.C. 801(a)(1)(A).

interstate commerce of each such public utility in the immediately preceding reporting year (either a calendar year or fiscal year, depending on which accounting convention is used by the public utility to be charged) to the sum of the megawatt-hours of transmission of electric energy in interstate commerce in the immediately preceding reporting year of all such public utilities.

(c) *Reporting requirement.* (1) For purposes of computing annual charges, as of January 1, 2002, a public utility, as defined in § 382.102(b), that provides transmission service must submit under oath to the Office of the Secretary by April 30 of each year an original and conformed copies of the following information (designated as FERC Reporting Requirement No. 582 (FERC–582)): The total megawatt-hours of transmission of electric energy in interstate commerce, which for purposes of computing the annual charges and for purposes of this reporting requirement, will be measured by the sum of the megawatt-hours of all unbundled transmission (including MWh delivered in wheeling transactions and MWh delivered in exchange transactions) and the megawatt-hours of all bundled wholesale power sales (to the extent these latter megawatt-hours were not separately reported as unbundled transmission). This information must be reported to 3 decimal places; *e.g.,* 3,105 KWh will be reported as 3.105 MWh.

(2) Corrections to the information reported on FERC–582, as of January 1, 2002, must be submitted under oath to the Office of the Secretary on or before the end of each calendar year in which the information was originally reported (i.e., on or before the last day of the year that the Commission is open to accept such filings).

(d) *Determination of annual charges to be assessed to power marketing agencies.* The adjusted costs of administration of the electric regulatory program as it applies to Power Marketing Agencies will be assessed against each power marketing agency based on the proportion of the megawatt-hours of sales of each power marketing agency in the immediately preceding reporting year (either a calendar year or fiscal year, depending on which accounting convention is used by the power marketing agency to be charged) to the sum of the megawatt-hours of sales in the immediately preceding reporting year of all power marketing agencies being assessed annual charges.

Note: The following appendix will not appear in the Code of Federal Regulations.

Appendix to Preamble—List of Commenters

Abbreviation—Commenter

1. AEP—Operating Companies of the American Electric Power System
2. Allegheny Power—Monongahela Power Company, Potomac Edison Company, and West Penn Power Company
3. APS—Arizona Public Service Company
4. APX—Automated Power Exchange
5. APX Companies—Automated Power Exchange (APX), Coral Power, L.L.C. (Coral), Dynegy Power Marketing, Inc. (Dynegy), Enron Power Marketing, Inc. (EPMI), Koch Energy Trading, Inc. (Koch) and Merchant Energy Group of the Americas (MEGA)
6. Atlantic City—Atlantic City Electric Company, Delmarva Power & Light Company, Potomac Electric Power Company, PPL Electric Utilities Corporation, and Public Service Electric & Gas
7. Avista—Avista Corporation
8. Cal ISO—California Independent System Operator Corporation
9. ComEd—Commonwealth Edison Company
10. Consumers—Consumers Energy Company
11. EEI—Edison Electric Institute
12. EPSA—Electric Power Supply Association
13. FirstEnergy—FirstEnergy Corp.
14. GPU Energy—Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company
15. ISO–NE—ISO New England Inc.
16. LIPA and NYPA—Long Island Power Authority and the Power Authority of the State of New York
17. Member Systems— Members of the Transmission Owners Committee of the Energy Association of New York State (formerly known as the Member Systems of the New York Power Pool)
18. Midwest ISO—Midwest Independent Transmission System Operator, Inc.
19. Midwest ISO Participants—Alliant Utilities, Ameren (on behalf of Central Illinois Public Service Company and Union Electric Company), Central Illinois Light Company, Cinergy Corp. (on behalf of Cincinnati Gas & Electric Company, PSI Energy Inc., and Union Light, Heat & Power), Commonwealth Edison Company (including Commonwealth Edison Company of Indiana), Hoosier Energy Rural Electric Cooperative, Inc., Illinois Power Company, Kentucky Utilities Company, Louisville Gas & Electric Company, Northern States Power Company, Southern Illinois Power Cooperative, Southern Indiana Gas & Electric Corp., Wabash Valley Power Association, Inc., and Wisconsin Electric Power Company.
20. MLCS—Merrill Lynch Capital Services, Inc.
21. NEM—National Energy Marketers Association
22. NEP—New England Power Company
23. NUSCO—Northeast Utilities Service Company
24. NYISO—New York Independent System Operator, Inc.
25. NYMEX—New York Mercantile Exchange
26. PECO—PECO Energy Company
27. PJM—PJM Interconnection, L.L.C.
28. PNGC—Pacific Northwest Generating Cooperative
29. SDG&E—San Diego Gas & Electric Company
30. SoCal Edison—Southern California Edison Company
31. SPP—Southwest Power Pool, Inc.
32. TXU Electric—TXU Electric Company
33. Williams EM&T—Williams Energy Marketing & Trading Company

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DEPARTMENT OF THE TREASURY

Customs Service

19 CFR 10, 12, 18, 24, 111, 113, 114, 125, 134, 145, 162, 171, and 172

[T.D. 00–57]

RIN 1515–AC01

Petitions for Relief: Seizures, Penalties, and Liquidated Damages; Correction

AGENCY: Customs Service, Treasury.

ACTION: Final rule; correction.

SUMMARY: Customs published in the **Federal Register** of September 5, 2000, a document that revised the Customs Regulations relating to the filing of petitions in penalty, liquidated damages, and seizure cases. Inadvertently, Appendix C to Part 171 was incorrectly amended. This document corrects the amendment of that Appendix.

EFFECTIVE DATE: November 2, 2000.

FOR FURTHER INFORMATION CONTACT: Jeremy Baskin, Penalties Branch, Office of Regulations and Rulings, (202) 927–2344.

SUPPLEMENTARY INFORMATION:

Background

On September 5, 2000, Customs published in the **Federal Register** (65 FR 53565) T.D. 00–57 that revised the Customs Regulations relating to the filing of petitions in penalty, liquidated damages, and seizure cases. Parts 171 and 172 of the Customs Regulations were recrafted in that document to include petition processing in seizure and unsecured penalty cases under part 171 and liquidated damages and secured penalty petition processing under part 172. It has come to Customs attention that the amendatory instructions regarding appendix C to part 171 set forth in that document inadvertently failed to remove a section and a note in the Appendix which were