Adoption of the Amendment

PART 75—[AMENDED]

Accordingly, pursuant to the authority delegated to me, Part 75 of the Federal Aviation Regulations (14 CFR Part 75) is amended, as follows:

1. The authority citation for Part 75 continues to read as follows:

Authority: 49 U.S.C. 1348(a), 1354(a), 1510; Executive Order 10854; 49 U.S.C. 106(g) (Revised Pub. L. 97–449, January 12, 1983); 14 CFR 11.69.

§ 75.100 [Amended]

2. Section 75.100 is amended as follows:

J–67 [Revised]

From Linden, CA, via Lakeview, OR, to Portland, OR.

Issued in Washington, DC, on May 28, 1987.

Daniel J. Peterson,

Manager, Airspace-Rules and Aeronautical Information Division.

[FR Doc. 87–12780 Filed 6–4–87; 8:45 am]

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SECURITIES AND EXCHANGE COMMISSION

17 CFR Parts 229, 230, 239, and 240

[Release Nos. 33–6714, IC–15752]

Elimination of Certain Pricing Amendments and Revision of Prospectus Filing Procedures

AGENCY: Securities and Exchange Commission.

ACTION: Final Rule.

SUMMARY: The Securities and Exchange Commission ("Commission") today announced adoption of a new rule and amendments to existing rules intended to simplify the filing requirements applicable to a registration statement at the time of effectiveness. New Rule 430A allows registrants, if specified conditions are satisfied, to omit information concerning the public offering price, price-related information and the underwriting syndicate from a prospectus contained in a registration statement at the time that it is declared effective. The information omitted in reliance upon Rule 430A would be included either in the final prospectus and deemed to be part of the registration statement or in a post-effective amendment to the registration statement. In addition, the Commission has adopted related amendments to Rules 424(b) and 497 to require more immediate filing of a prospectus where Rule 430A has been used. Finally, the Commission has adopted other changes to Rule 424 to provide for a similarly shortened filing period for certain other prospectuses, to eliminate unnecessary filings, and to classify prospectuses according to the nature of the information being modified or added.

EFFECTIVE DATE: July 6, 1987. The amendments to § 230.424 (Rule 424) are effective with respect to all registration statements July 6, 1987. All other amendments are effective July 6, 1987 for registration statements filed or amended on or after that date.

FOR FURTHER INFORMATION CONTACT: Prior to the effective date, Alexander G. Shtofman, (202) 272–2589, Office of Disclosure Policy, Division of Corporation Finance, or for questions regarding applicability to investment companies, Robert Plaze, (202) 272–2107, Office of Disclosure and Adviser Regulation, Division of Investment Management, Securities and Exchange Commission, 450 Fifth Street NW., Washington, DC 20549. After the effective date, contact Mauri L. Osheroff, Deputy Chief Counsel, or Abigail Arms, at (202) 272–2573, Office of Chief Counsel, Division of Corporation Finance or, with respect to investment companies, Robert Plaze, Division of Investment Management.

SUPPLEMENTARY INFORMATION: The Commission today announced the adoption of Rule 430A, related amendments to Items 501, 502, 512 and 601 of Regulations S–K[1] and related amendments to Rules 423,[2] 424,[3] 481,[4] 482,[5] and 497 [6] of Regulation C.[7] Technical amendments have been made to other rules, regulations and forms to conform references to Rule 424 and to adapt requirements to amend Rule 424.

I. Executive Summary

In October 1986, the Commission proposed a new rule and related amendments intended to simplify and reduce registrants' filing obligations under the federal securities laws, while permitting more immediate identification of and access to information filed with the Commission.[8] The Commission is adopting, with modifications, the new Rule, Rule 430A, under the Securities Act of 1933 (the "Securities Act") [9] to eliminate the need for pre-effective amendments to most registration statements filed solely to provide pricing information, price-related information, the names of the underwriting syndicate and respective amounts underwritten, underwriter compensation, material relationships with underwriters and dealer allowances. As adopted, the Rule is available to any registrant that is offering securities for cash pursuant to a registration statement that is declared effective. The Rule 430A information [10] will be disclosed in a prospectus filed under Rule 424 or 497 [11] and deemed to be part of the registration statement as of the time it was declared effective. A post-effective amendment will be necessary, however, where the final prospectus is not filed within five business days after the effectiveness of the registration statement or transmitted by a means reasonably calculated to result in filing with the Commission by that date.

Rule 430A does not change registrants' disclosure obligations to investors. The Rule does not change the information required to be disclosed in either a preliminary prospectus used before effectiveness of the registration statement or a prospectus meeting the requirements of Section 10(a) of the Act (the latter being a "final prospectus").[12]

The Commission has adopted, with modifications, a number of amendments to Rule 424. One of these requires that the prospectus that contains the Rule 430A information be filed not later than the second business day following the earlier of the date of the determination of the public offering price or the date the prospectus containing the Rule 430A information is first used in connection

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[1] 17 CFR 229.501; 17 CFR 229.502; 17 CFR 229.512; 17 CFR 229.601.

[2] 17 CFR 230.423.

[3] 17 CFR 230.424.

[4] 17 CFR 230.481.

[5] 17 CFR 230.482.

[6] 17 CFR 230.497.

[7] 17 CFR 230.400 *et seq.*

[8] Release No. 33–6672 (October 27, 1986) [51 FR 39868]. The proposals generated 17 comment letters. The letters of comment, as well as a copy of the summary of the comment letters prepared by the staff, are available for public inspection and copying at the Commission's Public Reference Room (File No. S7–28–86).

[9] 15 U.S.C. 77a *et seq.* (1982).

[10] In this Release, the information omitted from the form of prospectus contained in a registration statement at effectiveness in reliance upon Rule 430A is sometimes referred to as "Rule 430A information."

[11] Rule 424 governs the filing of prospectuses under the Securities Act. Rule 497 governs the filing of prospectuses by investment companies registered under the Investment Company Act of 1040 (15 U.S.C. 80a–1 *et seq.*). In Securities Act Release No. 33–6660 (Sept. 17, 1986) [51 FR 43384 (Sept. 26, 1986)] the Commission proposed to make Rule 497 the exclusive prospectus filing rule for investment companies. If that proposal is adopted, Rule 424 would no longer be available to investment companies.

[12] 15 U.S.C. 77j a.

In the usual case, a prospectus that omits the Rule 430A information may be used after effectiveness and prior to determination of the public offering price. *See* Part II.A.12 *infra*, "Use of Prospectus After Effectiveness."

with the public offering or sales or transmitted by a means reasonably calculated to result in filing with the Commission on that date. A comparable amendment to Rule 497 provides the same shortened filing period for investment companies relying on Rule 430A. Other changes to Rule 424 shorten the filing period for certain other prospectuses used after effectiveness pursuant to Rule 415,[13] eliminate unnecessary filings and classify Rule 424 prospectuses more systematically.

II. Final Rule and Amendments

A. Rule 430A.

1. Introduction

Rule 430A contemplates that, subject to the satisfaction of specified conditions, a prospectus contained in a registration statement at the time it is declared effective may omit information concerning the public offering price, price-related information and the underwriting syndicate. This information ordinarily is filed in a pre-effective "pricing" amendment to the registration statement.

The elimination of the requirement that such information be filed prior to effectiveness is intended to simplify and reduce filing obligations without reducing investor protection.[14] The change should minimize the risk of disruption of a registrant's marketing schedule caused by the need to file a pricing amendment and wait until the registration statement is declared effective by the Commission or its staff pursuant to delegated authority.[15] At the same time, Rule 430A and the related amendments should not affect the adequacy and timeliness of disclosure of information to investors or investor rights of action under the federal securities laws. There is no change in the information required to be provided to the public by means of either the preliminary prospectus[16] or the final prospectus.

[13] 17 CFR 230.415.

[14] The information will be disclosed in a prospectus filed under Rule 424 or 497. A post-effective amendment will be necessary, however, where the final prospectus is not filed within five business days after the effectiveness of the registration statement or a post-effective amendment thereto. *See* Part II.A.11 *infra*, "Relationship to Rule 415."

[15] *See* section 8(a) of the Securities Act [15 U.S.C. 77h(a)] and 17 CFR 200.30–1(a).

[16] *See* Rule 430 [17 CFR 230.430], which specifies the requirements for a preliminary prospectus for purposes of section 5(b)(1) of the Securities Act [15 U.S.C. 77e(b)(1)], and the discussion of Rule 430A(b) in Part II.A.12 *infra*, "Use of Prospectus After Effectiveness," addressing the use of prospectuses after effectiveness when Rule 430A is utilized.

2. Information That May Be Omitted Under Rule 430A[17]

Rule 430A permits a registration statement to be declared effective that contains a prospectus that omits information on the public offering price (including interest and dividend rates on the securities being offered), underwriting syndicate (including material relationships with any underwriter not named therein), underwriting discounts or commissions, discounts or commissions to dealers, amount of proceeds, conversion rates, call prices and other items dependent upon the public offering price, delivery dates, and terms of the securities dependent upon the offering date.[18] This range of information substantially parallels that in Rule 430.

Questions have been raised about whether "information with respect to . . . the underwriting syndicate", which may be excluded pursuant to Rule 430A, also was intended to address information concerning the managing underwriter(s). The identity of the management underwriter(s) is known prior to effectiveness and Rule 430 does not allow such information to be omitted from a preliminary prospectus. Nor may the information concerning managing underwriters be omitted in reliance upon Rule 430A, which was not intended to change the disclosure required in the preliminary prospectus.

In contrast, Rule 430A specifically permits a registrant to omit the names of other underwriting syndicate members and related information.[19] Prior to the registrant requesting acceleration of effectiveness, the registration statement should include all of the other required information on the plan of distribution [20] but need not include the names of the syndicate members other than the managing underwriter(s), material relationships with any underwriter not named therein, the amounts underwritten and the discounts and commissions.[21] If, however, a registrant chooses to include the names of syndicate members, information concerning material relationships between such named underwriters and the registrant must also be included.

With respect to underwriter compensation, the registration statement should continue to disclose any compensation that is not easily reducible to a dollar per unit basis, such as options or warrants to purchase equity securities, fees for other services to be provided, and right of first refusal on future financings.[22] The underwriting agreement or the final form thereof should continue to be filed as part of the registration statement prior to effectiveness.[23]

Finally, a registrant requesting acceleration of effectiveness of a registration statement for other than a delayed offering pursuant to Rule 415 must have a present intent to offer. The registrant thus must provide all required information other than that omitted in reliance upon Rule 430A, including the information regarding distribution of the preliminary prospectus called for pursuant to Rule 418(a)(7).[24]

3. Eligibility and Conditions for Use of Rule 430A [25]

As proposed, Rule 430A is available to any registrant[26] but is limited to offerings of securities for cash.[27] Thus,

[17] *See* Rule 430A(a).

[18] Terms of the securities dependent upon the offering date include information such as amounts and dates of sinking fund or similar payments, interest or dividend payments, record dates, date from which interest or dividends will accure and redemption dates.

[19] The underwriters, respective amounts underwritten and material relationships with the registrant may be known at the time of effectiveness and disclosure would be required under Item 508(a) of Regulation S–K without a specific exclusion. 17 CFR 229.508(a).

[20] *See* Item 508 of Regulations S–K [17 CFR 229.508].

[21] Rule 430A does not affect the requirement of Rule 415(a)(4)(iv) [17 CFR 230.415(a)(4)(iv)] that the underwriter(s) for an at the market offering of equity securities by or on behalf of the registrant must be named in the prospectus which is part of the registration statement.

[22] *See* Item 508(e) of Regulation S–K [17 CFR 229.508(e)], which requires disclosure of all items that would be deemed by the National Association of Securities Dealers to constitute underwriting compensation for purposes of the Association's Rules of Fair Practice.

[23] *See* part II.A.8 *infra*, "Exhibits."

[24] 17 CFR 230.418(a)(7).

[25] In addition to the criteria for use of the Rule discussed in this section, the Rule contains two further conditions: (1) That the registration statement contain the new undertakings specified in Item 512(j) of Regulation S–K (*see* Rule 430A(a)(2)); and (2) that the information omitted from the prospectus filed as part of the effective registration statement be in the prospectus filed with the Commission under Rule 424(b), Rule 497(h), or in an effective post-effective amendment (*See* Rule 430A(a)(3)). These conditions are discussed *infra* in Parts II.A.10, "Section 11 Liability Issues", II.A.11, "Relationship to Rule 415," and II.B, "Amendments to Rule 424."

[26] *See* Part II.A.7 *infra*, "Bona Fide Estimate Based on Offering Price," concerning non-reporting companies whose public offering price does not fall within the bona fide estimate of the range of the maximum offering price contained in the registration statement.

[27] *See* Rule 430A(a)(1). This requirement should be interpreted in the same manner as the "for cash" requirement for certain primary offerings of securities on Form S–3 [17 CFR 239.13]. *See* General Instruction I.B.1 thereof. For example, notes evidencing promises to pay installments in cash are considered to be cash within the meaning of the proposed Rule.

the Rule is not applicable to a registration statement covering securities to be issued in connection with a business combination, whether effective by a merger or exchange offer, recapitalization, reorganization or other similar transaction.

Rule 430A also is limited to registration statements that are declared effective—*i.e.*, where effectiveness is accelerated by the Commission or its staff acting pursuant to delegated authority, rather than by lapse of time pursuant to section 8(a) of the Securities Act. Accordingly, the Rule is not available for filings that lack a Rule 473 delaying amendment.[28] To permit otherwise would provide a mechanism to avoid the review process. While certain types of filings always become effective automatically and are not permitted to use delaying amendments,[29] the Commission believes these filings need not come within the scope of Rule 430A because such filings characteristically do not contain market-sensitive pricing information determined shortly before commencement of the offering.

4. Pre-effective Amendments: Recirculation

Rule 430A does not alter traditional considerations regarding the need, in light of events or facts that are known prior to effectiveness, to file a pre-effective amendment to assure that the registration statement is not misleading when declared effective.[30] Registrants also should consider whether material changes from the disclosure contained in the latest prospectus distributed to underwriters, dealers and others,[31] either before or after effectiveness,[32] necessitate recirculation of an amended prospectus.[33] Changes that previously were not required to be provided in a pre-effective amendment to the registration statement but were permitted to be made in a prospectus filed after effectiveness can continue to be made in the final prospectus.[34]

5. Post-effective Amendments

Rule 430A also does not alter traditional considerations regarding whether events or facts require post-effective amendment of the registration statement. A registrant that has relied on Rule 430A and files a correcting or updating post-effective amendment to the registration statement may either include the Rule 430A information in the amendment, or omit it from the amendment but include it in a prospectus filed within five business days after the amendment is declared effective. The same alternatives are available when a post-effective amendment is required to be filed because the prospectus containing the Rule 430A information was not filed within five business days after effectiveness of the registration statement.[35] In either case, whether a post-effective amendment contains the Rule 430A information or is used to recommence the five business day period during which the Rule 430A information may be filed in a Rule 424 or Rule 497 prospectus in reliance upon Rule 430A, the amendment must contain a prospectus that is current in all respects.

6. Age of Financial Statements

Rule 430A does not change requirements concerning the age of financial statements contained in a registration statement at the time of effectiveness.[36] Accordingly, use of the Rule does not eliminate the need to file a post-effective amendment if the financial statements are required to be updated at the time of effectiveness, and a registrant whose financial statements are not current should not request acceleration of effectiveness.[37] If a registrant does not file a Rule 424 or Rule 497 prospectus to provide the Rule 430A information within five days of effectiveness, a post-effective amendment filed either to include the Rule 430A information or to recommence the five business day period for Rule 430A [38] must be current in all respects. Thus, to assure the currency of financial information, such a post-effective amendment must contain updated financial statements if the previously filed financial statements are no longer current.[39]

7. Bona Fide Estimate Based on Offering Price

Rule 430A does not change procedures requiring disclosure in the preliminary prospectus of information based on a bona fide estimate of the public offering price. For example, pro forma financial information on such matters as the ratio of earnings to fixed charges [40] should be set forth, accompanied by a clear statement that the information is based on an assumed public offering price and that the pro forma information will vary in a specified manner as the assumed price changes. Disclosure also should continue to be provided on the estimated dollar amount and allocation of proceeds to be received from the offering [41] and on dilution,[42] if applicable.

A registration statement for a registrant not subject to the reporting provisions of the Exchange Act immediately prior to the filing of the registration statement must contain a bona fide estimate of the range of the

[28] 17 CFR 230.473.

[29] The registration statements are: (1) Forms S-3 and F-3 [17 CFR 239.33] for dividend or interest reinvestment plans; (2) Forms S-4 [17 CFR 239.25] for bank or savings and loan holding company formations; and (3) Forms S-8 [17 CFR 239.16b], which are used for employee benefit plans. *See also* Part II.A.9 *infra*, "Applicability of Rule 430A to Investment Companies," with respect to automatically effective investment company registration statements.

[30] For example, a change in the estimated public offering price may materially affect disclosure on the use of proceeds and, if applicable, the adequancy of the proceeds to accomplish one or more stated purposes. *See* Items 504 and 101(a)(2)(iii)(A)(1) of Regulation S-K [17 CFR 229.504; 17 CFR 229.101(a)(2)(iii)(A)(1)], respectively. Other areas of disclosure that may require updating include the business and plan of operation, management's discussion and analysis of financial condition and results of operations, and certain pro forma financial information. *See* Items 101, 303 and 503(d)(9) of Regulation S-K [17 CFR 229.101; 17 CFR 229.303; 17 CFR 229.503(d)(9)], respectively.

[31] *See* Rule 15c2-8 under the Securities Exchange Act of 1934 as amended ("the Exchange Act") [17 CFR 240.15c2-8], 15 U.S.C. 78a-kk.

[32] *See* Rule 430A(c) and Part II.A.12 *infra*, "Use of Prospectus After Effectiveness."

[33] Pursuant to Rule 460 [17 CFR 230.460], the adequacy and availability of information to the public, including information regarding distribution of the preliminary prospectus provided pursuant to Rule 418(a)(7), may be considered in acting upon requests for acceleration of the effectiveness of a registration statement.

[34] Information concerning the amount of securities to be offered is not information that may be omitted pursuant to Rule 430A and changes in such information should be reflected in a pre-effective amendment. If a registrant requests effectiveness in the good faith belief that Rule 430A is available, but determines, after effectiveness, that the amount of securities to be offered must be changed, and increase in amount would require a new registration statement to register the additional securities; a decrease in amount generally would require a post-effective amendment.

[35] *See* Rule 430A(a)(3) and discussion in Part II.A.10 *infra*, "Section 11 Liability Issues."

[36] *See* Rule 3-12 of Regulation S-X [17 CFR 210.3-12].

[37] A registrant requesting acceleration of the effective date shortly before the date as of which financial statement disclosures would be required to be updated should consider whether such statements will fail to reflect any facts or events that have had or may have a material effect on the Company's financial condition not otherwise disclosed in the registration statement. *See* Item 303 of Regulation S-K.

[38] *See* Part II.A.11 *infra*, "Relationship to Rule 415." *See also* Part II.A.5 *supra*, "Post-effective Amendments."

[39] The financial statements would have to be current as of the date of effectivensss of such post-effective amendment.

[40] *See* Item 503(d)(9) of Regulation S-K.

[41] *See* Item 504 of Regulation S-K.

[42] *See* Item 506 of Regulation S-K [17 CFR 299.506].

maximum offering price.[43] If such a registrant requests acceleration of effectiveness in reliance upon Rule 430A and subsequently determines that the public offering price will not fall within the bona fide estimate of the range of the maximum offering price set forth in the prospectus included in the registration statement at the effective date, because changes in such information are of the type that necessitate post-effective amendments, the registrant must file a post-effective amendment to include the Rule 430A information (and update other information) or to update the estimate (and other information).[44]

8. Exhibits

The Rule does not change the filing requirements applicable to exhibits.[45] A registrant choosing not to file a pricing amendment must file all required exhibits with the initial registration statement or a pre-effective amendment. Thus, any required opinion, report or other document prepared by an accountant, other expert or counsel and applicable consents must be filed as part of the registration statement prior to effectiveness.[46] While the public offering price may not be determined until shortly after the registration statement is declared effective, in most cases requisite opinions, consents and reports, including legality opinions, can be issued prior to the specific pricing. Where issuance is not possible prior to effectiveness, the Commission has determined, after consideration of alternative approaches, that the Rule ordinarily will be unavailable.[47]

Certain exhibits, unlike opinions and consents, are not required to be filed in executed form at the time of effectiveness (*e.g.*, trust indentures and underwriting agreements). The filing requirement may be satisfied by submission of the final form of the document to be used; the form must be complete, except that prices, signatures and similar matters may be omitted.[48]

A technical amendment to Instruction 1 to Item 601 of Regulation S–K has been adopted substantially as proposed to provide that information on price and similar matters omitted from an exhibit that is not refiled to provide the information may be provided in a prospectus filed with the Commission pursuant to Rule 424(b) after effectiveness of the registration statement, rather than being included in an amendment to the registration statement.[49] The prior requirement to state in any amendment to the registration statement the basis provided by this Instruction for not refiling such exhibit has been deleted because it is not essential.

9. Applicability of Rule 430A to Investment Companies

As explained in the proposing release, Rule 430A will be used primarily by closed-end investment companies because the pricing amendment typically is not the last event, or is only part of the last event, preceding effectiveness of the registration statements of other investment companies under the Investment Company Act of 1940. One commentator urged the Commission to expand the availability of Rule 430A to unit investment trust whose registration statements become effective automatically under Rule 487.[50] The Commission asked for comment on similar possibilities for streamlining unit investment trust filing procedures in connection with the reproposal of Form N–7[51] and will consider this comment, as well as others received, in connection with the adoption of Form N–7.[52]

10. Section 11 Liability Issues

Section 11 of the Securities Act[53] imposes liability on the issuer, directors, signers, experts and other designated persons for material misstatements in or omissions from a registration statement at the time of effectiveness. Rule 430A as adopted does not alter such liability. Accordingly, paragraph (b) of Rule 430A provides that information omitted from a prospectus filed as part of a registration statement at the time of effectiveness in reliance upon paragraph (a), and subsequently filed in a prospectus pursuant to Rule 424(b) or 497(h),[54] is deemed to be part of the registration statement at the time of effectiveness. Further, one condition to the use of the Rule is inclusion in the registration statement of the new undertaking specified by paragraph (j)(1) to Item 512 of Regulation S–K. The effect of paragraph (b) of the Rule and the Item 512(j)(1) undertaking is to maintain section 11 liability on the information omitted from the prospectus contained in the effective registration statement in reliance on paragraph (a) of Rule 430A and subsequently filed with the Commission.[55] In addition, paragraph (a) of Rule 430A specifies that the information that may be omitted pursuant to the Rule need not be contained in the prospectus in a registration statement at effectiveness in order for the registration statement to meet the requirements of section 7 of the Securities Act for the purposes of section 5[56] thereof. Thus, the fact that such information is not physically contained in the registration statement at the time of effectiveness would not result in liability under these provisions of the Securities Act.

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[43] *See* Item 501(c)(6) of Regulation S–K [17 CFR 229.501(c)(6)].

[44] If the estimate is updated by a post-effective amendment that is current in all respects, Rule 430A may continue to be utilized. *See* Rule 430A(a)(3) and Part II.A.5 *supra*, "Post-effective Amendments."

[45] *See* Item 601 of Regulation S–K.

[46] *See* section 7 and Schedule A(29) of the Securities Act [15 U.S.C. 77g and 77aa Schedule A(29), respectively]; Item 601(b)(5), (6), (7), (8), and (24) of Regulation S–K [17 CFR 229.601(b)(5), (6), (7) (8), and (24)]; and Rules 436–439 [17 CFR 230.436–439]. An amendment to a registration statement that is filed solely for the purpose of adding exhibits and does not change the prospectus need include only the cover page to the registration statement, the exhibit index, the new or revised exhibits and the signature page.

[47] This position, however, is not intended to change the current practice with respect to delayed offerings under Rule 415(a) (1) (x) [17 CFR 230.415(a)(1)(x)]. Although certain qualified legality opinions may be filed as an exhibit to such a registration statement that is declared effective, after pricing and prior to sales an unqualified opinion (and consent) must be filed on Form 8–K [17 CFR 249.308] and thus incorporated by reference into the registration statement or must be contained in a post-effective amendment.

[48] Such exhibits may not be incorporated by reference into any subsequent filing made with the Commission. The completed exhibit, however, even if not part of the registration statement as declared effective, still may be incorporated by reference into other Commission documents if it is previously filed, *e.g.*, as part of a cost-effective amendment or Form 8–K. *See* Instruction 1 to Item 601 of Regulation S–K. These procedures are not affected by Rule 430A.

[49] Although the proposed Instruction only provided for information in a prospectus filed pursuant to Rule 424(b)(1) and (4), the Instruction as adopted allows such information to be contained in any prospectus filed pursuant to Rule 424(b) [17 CFR 230.424(b)].

[50] 17 CFR 230.487. *See* Part II.A.3 *supra*, "Eligibility and Conditions for Use of Rule 430A," concerning the requirement that Rule 430A is only available for registration statements that are declared effective.

[51] Investment Company Act Rel. No. 15612 (March 9, 1987) [52 FR 8286 (March 17, 1987)].

[52] The Commission has, however, adopted paragraph (h) of Rule 497 with modifications to conform to the timing changes made to Rule 424 for the filing of prospectuses containing Rule 430A information. *See* Part II.B *infra*, "Amendments to Rule 424." To accommodate the adoption of Rule 430A, the Commission has also adopted technical amendments to Rules 481 (*see* part II.A.15 *infra*, "Item 502 of Regulation S–K and Rule 481") and Rule 482.

[53] 15 U.S.C. 77k.

[54] *See* Part II.B.1 *infra*, "Types of Prospectuses to be Filed and Classification of Prospectuses," and Part II.A.9 *supra*, "Applicability of Rule 430A to Investment Companies."

[55] As other changes in the prospectus would not be deemed to be part of the registration statement, such changes would not be taken into account in determining the adequacy of the registration statement for section 11 liability purposes.

[56] 15 U.S.C. 77e.

Because of the close proximity in time between effectiveness of the registration statement, the filing of the final prospectus under Rule 424 or 497 and the initial bona fide offering of the securities (as used in sections 4(3) and 13 of the Securities Act), [57] the Commission has determined that it is not necessary for paragraph (j) of Item 512 to contain any undertaking updating the registration statement for statute of limitations and section 11 reliance purposes. However, in the event the Rule 424 or 497 filing is not made within the specified five business day period, Rule 430A requires the filing of a post-effective amendment. Since there is no prescribed time period by which the post-effective amendment must be filed, the Commission has determined after consideration of comments solicited to require an undertaking updating the registration statement for liability and statute of limitations purposes upon the effectiveness of any post-effective amendment containing a prospectus. Accordingly, registrants that intend to utilize Rule 430A as adopted must provide the new undertaking required by Item 512(j)(2) of Regulation S–K.

Section 11 liability continues to extend to exhibits, including opinions of counsel and consents of counsel and accountants, which must be filed as part of the registration statement at the time of effectiveness, as discussed above.[58] In addition, underwriter liability under section 11 is not affected by the omission of underwriters' names from the registration statement; anyone with the status of an underwriter is potentially liable under section 11 whether or not named in the registration statement.[59]

11. Relationship to Rule 415

The new Rule does not affect the existing eligibility requirements for filing a registration statement for a continuous or delayed offering under Rule 415. Accordingly, the securities being offered pursuant to a registration statement declared effective as permitted by Rule 430A must be priced before or shortly after the registration statement is declared effective, and the offering must commence promptly, unless a post-effective amendment is filed or the registration statement meets the criteria for a delayed offering under Rule 415.[60]

Paragraph (a)(3) of the Rule as adopted requires that the Rule 430A information be contained in a post-effective amendment (which must be declared effective before sales are made) if a prospectus containing that information is not filed within five business days after effectiveness of the registration statement or of a post-effective amendment containing a form of prospectus or transmitted by a means reasonably calculated to result in filing with the Commission by that date.[61] The five business day period is not intended as a definition of what constitutes a delayed offering for purposes of Rule 415, but serves to ensure that delays in pricing and marketing securities will not result in offerings inconsistent with the Rule 415 criteria.

Securities offerings that meet the criteria for delayed offerings under Rule 415 do not have to rely upon Rule 430A. Such registration statements may become effective without price, underwriting syndicate and other information, because the information is not known at the time of effectiveness.

However, in order to provide additional market flexibility and to avoid an artificial election between the two rules prior to effectiveness, a registrant eligible to engage in a delayed offering pursuant to Rule 415 may retain the option to proceed under either rule as long as it includes the undertakings called for by both Items 512(a) [62] and 512(j) of Regulation S–K. Such a registrant may choose to include both sets of undertakings (at the time of initial filing or in a pre-effective amendment) either if it plans to offer one tranche of securities immediately and the remainder on a delayed basis, or if it is uncertain at the time it files whether or not the securities will be offered on a delayed basis.[63] At the time it requests acceleration of effectiveness, a registrant that has no present intent to make the first offering of securities under the registration statement promptly, and therefore will be making the offering on a delayed basis rather than in reliance on Rule 430A, should so state in its request for acceleration. It may then continue to omit, in addition to Rule 430A information, other information not known at the time of effectiveness. When the delayed offering is ultimately made, the prospectus containing the required information will be filed pursuant to Rule 424(b)(2) or (5).

On the other hand, a registrant requesting acceleration that plans to offer securities promptly must provide all required information, except that which may be omitted in reliance on Rule 430A. In the event that both sets of undertakings are included and only Rule 430A information is omitted at the time of effectiveness, the registrant will be presumed to be relying upon Rule 430A for the first offering under the registration statement and will file the prospectus containing the Rule 430A information pursuant to Rule 424(b)(1) or (4) within five business days of effectiveness.[64] Nonetheless, registrants eligible to engage in delayed offerings need not file a post-effective amendment to provide the Rule 430A information if the Rule 424(b) prospectus is not filed within five business days; instead, the information may be included in a prospectus filed pursuant to Rule 424(b)(2) or (5).[65] The Item 512(a) undertakings will apply in this fact situation.

This approach will alleviate continuing interpretive and administrative questions concerning whether a registration statement otherwise eligible to be filed as a delayed offering under Rule 415 is a "convenience shelf," *i.e.*, a registration statement for which the offering of some or all the securities is intended at the time of effectiveness to commence promptly. The Commission has stated previously that the securities to be offered promptly cannot be considered part of a delayed offering; therefore, a pricing amendment has been required for such filings.[66] Under Rule 430A, such filings will be able to be declared effective without pricing amendments, provided the terms and conditions of the Rule are met.

[57] 15 U.S.C. 77d(3) and 77m, respectively.

[58] *See* Part II.A 8 *supra*, "Exhibits".

[59] *See generally* section 11(a)(5), (b)(3), (d), (e) and (f) of the Securities Act [15 U.S.C. 77k (a)(5), (b)(3), (d), (e), and (f)].

[60] Such criteria are set forth in Rule 415(a)(1)[17 CFR 230.415(a)(1)]; *see* particularly Rule 415 (a)(1)(x) [17 CFR 230.415(a)(1)((x)].

[61] The business day after the date the registration statement is declared effective, regardless of the time of day effectiveness occurs, is considered the first business day. The prospectus containing the Rule 430A information must be filed by the Commission's close of business on the fifth business day following effectiveness. *See* Rule 110 [17 CFR 230.110].

[62] 17 CFR 229.512(a).

[63] The registrant need not file a pre-effective amendment to remove the Rule 415 undertaking or the checking of the "Rule 415 box" on the cover page in the event that it decides to offer all of the securities promptly.

[64] *See* discussion in Part II.B.1 *infra*, "Types of Prospectuses Required to be Filed and Classification of Prospectuses."

[65] In contrast, registrants making continuous offerings under Rule 415, which are required to commence promptly, may make use of Rule 430A to omit information that would otherwise be required, but a post-effective amendment must be filed if the Rule 424(b) prospectus is not filed within 5 business days. *See* Rule 415(a)(1)(ix) [17 CFR 230.415(a)(1)(ix)].

[66] *See* Securities Act Release No. 6499 (November 17, 1983) [48 FR 52889].

12. Use of Prospectus After Effectiveness

As proposed, then-paragraph (b) of Rule 403A provided that the rule would not "limit the information required to be contained in a form of prospectus meeting the requirements of section 10 [67] of the Act for purposes of section 5(b) thereof used after effectiveness of the registration statement." One commentator believed that an unintended consequence of proposed paragraph (b), when read in conjunction with Rule 430 (which relates only to preliminary prospectuses used prior to the effective date), would have been to prohibit the use of any form of prospectus after the effective date and prior to pricing. As adopted, this paragraph, redesignated paragraph (c) of Rule 430A, has been clarified to reflect that a prospectus that omits Rule 430A information may be used after effectiveness and prior to pricing.[68] However, use of such a prospectus is not permitted for purposes of satisfying the requirements of section 5(b)(2) in connection with delivery of a security for sale or for delivery after a sale or the requirements of section 2(10)(a) in connection with delivery of other written communications (*e.g.*, confirmations) to investors.[69]

Such pre-pricing prospectus must be clearly marked on the cover page to indicate that it is subject to completion or amendment. In lieu of requiring registrants to reprint or sticker to so indicate, the Commission has amended the statement required by Item 501(c)(8) of Regulation S-K and Rule 481(b)(2) so that it may be used after effectiveness and prior to pricing.[70] Rule 423 has also been amended so that a prospectus used after effectiveness and prior to pricing would not have to be re-dated.

13. Formula Pricing

Previously, companies that intended to price an offering according to a formula related to the market price filed alternative prospectus cover pages as part of the registration statement. One cover page described the formula and was used to meet the requirements of paragraph (16) of Schedule A of the Securities Act and Item 501 of Regulation S-K.[71] The other, used in the final prospectus, omitted the formula cover page and included the pricing table that was completed after the securities were priced. The adoption of Rule 430A makes these procedures no longer necessary.

14. Competitive Bidding

The Commission has not changed the procedures applicable to securities to be offered by competitive bidding. Therefore, companies that offer and sell securities by that procedure may not use Rule 430A.[72] Such companies should continue to comply with the current rules and staff interpretations applicable to competitive bidding.[73]

15. Item 502 of Regulation S-K and Rule 481 (Pre-Pricing Stabilization)

Where the registrant or any underwriter knows or has reason to believe that the price of any security may be stabilized to facilitate the offering of registered securities, the prospectus must include the stabilization legend prescribed by Item 502(d)(1) [74] of Regulation S-K or Rule 481(d)(1).[75] Item 502(d)(2) [76] and Rule 481(d)(2) [77] further provide that if such stabilizing began prior to the effective date, the prospectus must set forth the amount of securities bought, the prices at which they were bought and the period within which they were bought. Except where formula pricing was used, previously the offering price was normally determined after the close of the market on the day before the effective date and, accordingly, the effect of Item 502(d)(2) and Rule 481(d)(2) was to require disclosure regarding stabilizing transactions effected prior to pricing.

Where Rule 430A is used, stabilizing transactions may be effected after the effective date but prior to determination of the initial public offering price. To assure that investors receive substantially the same disclosure regarding pre-pricing stabilizing as was previously required, the Commission has amended item 502(d)(2) and Rule 481(d)(2) to provide that, where Rule 430A is used, the prospectus filed pursuant to Rule 424 or Rule 497 (or a post-effective amendment if a Rule 424 or Rule 497 prospectus is not filed) must include information as to stabilizing transactions effected prior to the determination of the initial public offering price.

B. Amendments to Rule 424 [78]

1. Types of Prospectuses Required to be Filed and Classification of Prospectuses

Because the previous requirement of Rule 424 to file with the Commission prospectuses in the exact form furnished to investors [79] resulted in nonessential filings, the Commission has removed the word "exact" and restricted the filing requirement to prospectuses that contain substantive modifications of additions.[80] The term "substantive" refers to additions or modifications that supplement, update or correct the content and substance of the information contained in a prospectus, excluding such matters as those typographical, grammatical, format and clarifying changes that do not affect investors' understanding of the information.[81]

In addition, to facilitate access to and use of the information, the prospectuses are classified according to the nature of the information being added or modified. Because of the new classification scheme, restructured from the proposal, the distinction between the first prospectus filed after effectiveness

[67] 15 U.S.C. 77j.

[68] *See* Part II.A.4 *Supra*, "Pre-Effective Amendments; Recirculation," discussing material changes from the disclosure contained in the lastest prospectus distributed.

[69] 15 U.S.C. 77e(b)(2); 15 U.S.C. 77b(10)(a).

[70] 17 CFR 229.501(c)(8); 17 CFR 230.481(b)(2).

[71] 15 U.S.C. 77aa Schedule A(16) and 17 CFR 229.501, respectively. *See* Instruction 2 to Item 501 of Regulation S-K.

[72] *See* Rule 430A(d).

[73] Rule 445 [17 CFR 230.445] requires the filing of a post-effective amendment to reflect the results of the competitive amendment to reflect the results of the competitive bidding. The post-effective amendment to the registration statement becomes effective automatically at the time it is filed unless the registrant has been notified that proceedings under section 8 of the Securities Act [15 U.S.C. 77h] have been commenced. The staff, however, will permit registrants to file prospectuses pursuant to Rule 424(b) [17 CFR 230.424(b)] to reflect the results of the competitive bidding for securities offered on a delayed or continuous basis under Rule 415.

[74] 17 CFR 229.502(d)(1).

[75] 17 CFR 230.481(d)(1).

[76] 17 CFR 229.502(d)(2).

[77] 17 CFR 230.481(d)(2).

[78] *See* Part II.A.9 *supra*, "Applicability of Rule 430A to Investment Companies," for a discussion of the more limited changes to Rule 497, the rule applicable to filing of investment company prospectuses.

[79] Temporary Rule 499(c)(7) [17 CFR 230.499(c)(7)] permits registrants participating in the Edgar pilot to file Rule 424 prospectuses electronically, rather than in the exact form furnished to investors; the filing contains a narrative explanation of variations in form.

[80] The changes to Rule 424 only affect the filing requirements, not the legal determination as to whether information must be provided to investors, and if so, whether such information may be provided in a prospectus or prospectus supplement without being included in a post-effective amendment. *See, e.g.*, Item 512(a) of Regulation S-K, which specifies certain filings that must be made by post-effective amendment.

The prospectus need not be filed in the exact format in which it is used. Thus, registrants may use available methods to have the prospectus transmitted to Washington and filed by an agent. For example, the prospectus could be telecopied to a service bureau in Washington for filing.

[81] As a result of this change to Rule 424, most registrants that choose to follow traditional procedures and therefore file pricing amendments will not also have to file a Rule 424(b) prospectus, as that prospectus ordinarily would not contain substantive changes from the prospectus contained in the pricing amendment.

and subsequently filed prospectuses has been eliminated. Accordingly, paragraphs (b) and (c) of Rule 424, which maintained such a distinction and specified different times for filing, have been merged.

New paragraphs (b) (1) and (2) apply to prospectuses disclosing "transaction-specific" information, *i.e.*, information relating primarily to the securities offering. If a registrant relies upon Rule 430A, a prospectus used after effectiveness of the registration statement will ordinarily be filed under Rule 424(b)(1).[82] Prospectuses filed under that paragraph will disclose the price, price-related information and underwriter-related information that was omitted from the registration statement at the time of effectiveness.[83]

Any prospectus that discloses transaction-specific information about the offering of securities on a delayed shelf basis under Rule 415(a)(1) (vii), (viii), and (x) ordinarily will be filed under new paragraph (b)(2).[84]

The transaction information will include the price, specific description of the securities, and specific method of distribution. Typically, such a prospectus will be filed every time another series or "tranche" of securities is offered.

Prospectuses reflecting other substantive changes or additions not covered in the first two categories will be filed under new paragraph (b)(3).[85] Finally, prospectuses reflecting information that falls within more than one paragraph of proposed Rule 424(b) will be filed under new paragraph (b)(4) or (5), as applicable.[86] In order to make the classification system useful, paragraph (e) of Rule 424 has been amended to require that the filing specify the applicable paragraph or subparagraph (*i.e.*, "(a)," "(d)" or "(b)(1)"–"(b)(5)") pursuant to which it is being made.[87] The rule as adopted has been reformatted from the proposal in order to simplify these designations.

2. Filing Period

The Commission has shortened the time within which certain prospectuses used after effectiveness of the registration statement must be filed. Such filings warrant a short time period in order that the information may be promptly available to the investing public and the Commission.

Under the proposed amendments, the filing date would have been tied to the first use after effectiveness of the prospectus that contains modified or additional information. Commentators expressed concern that the proposed requirements to file on the date of first use removed too much of the flexibility intended by the proposal, particularly as they would have applied to delayed offerings under Rule 415 that occur late in the business day. The Commission appreciates this desire for flexibility. Nonetheless, it is important for this highly significant information to be on file with the Commission in a timely fashion.

The amendments as adopted balance both concerns, requiring that a prospectus disclosing transaction-specific information specified in either paragraph (b)(1) or (2) be filed not later than the second business day following the earlier of the date of the determination of the offering price or the date that it is first used after effectiveness in connection with the public offering or sales or transmitted by a means reasonably calculated to result in filing with the Commission by that date.[88] The concept of "first use" is not limited to provision of the prospectus to purchasers with their confirmations. Rather, it refers to availability of the prospectus to the managing underwriter, syndicate members or offerees.

In recognition of the possiblity that the Rule 424 filing may not reach the Commission for filing due to circumstances beyond the registrant's control, paragraphs (b)(1) and (b)(2) of Rule 424 provide for transmission by a means reasonably calculated to result in filing with the Commission by the second business day deadline.[89] In order to meet the requirements of Rule 430A, however, it will be necessary for a registrant to ascertain promptly whether a form of prospectus that contains Rule 430A information that has been transmitted for filing under Rule 424(b) or Rule 497(h) actually was received by the Commission. Further, in the event that it was not received, Rule 430A requires that the registrant promptly file such prospectus.

As prospectuses filed under paragraphs (b)(4) and (b)(5) also will contain information subject to the timing requirement provided for in paragraphs (b) (1), and (2), respectively, they are required to be filed no later than the second business day following the date of the earlier of pricing or first use. Paragraphs (b) (4) and (5) also provide for transmission by a means reasonably calculated to result in filing with the Commission by that date.

Unlike prospectuses filed pursuant to paragraphs (b) (1) and (2), prospectuses filed under paragraph (b)(3), which only reflect other substantive changes, will have to be filed no later than the fifth business day after first use; like prospectuses filed pursuant to paragraphs (b) (1) and (2), they may be transmitted by a means reasonably calculated to result in filing with the Commission by that date.[90] In the usual case, mailing of Rule 424(b)(3) prospectuses on the date of first use would suffice even if overnight mail service or similar means were not used.

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[82] As discussed in Part II.A.II *supra*, "Relationship to Rule 415," Rule 430A(a)(3) requires that a post-effective amendment be filed if the prospectus is not filed within five business days after effectiveness.

[83] This prospectus also will include updated information required by various items of Regulation S-K to be provided "as of the latest practicable date" (*see, e.g.*, Item 201(a)(1)(v) [17 CFR 229.201(a)(1)(v)] and Instruction 2 to Item 501 of Regulation S-K).

[84] The prospectuses required to be filed pursuant to paragraph (b)(2) have been limited to those concerning primary offerings on a delayed basis under Rule 415(a)(1)(vii), (viii) and (x) [17 CFR 230.415(a)(1) (vii), (viii) and (x)]. Accordingly, prospectuses relating to all other offerings pursuant to Rule 415, including secondary offerings made on a delayed basis, are to be filed under paragraph (b)(3) unless they contain information omitted pursuant to Rule 430A.

[85] A prospectus containing Rule 430A information with respect to a continuous offering under Rule 415 would be filed pursuant to new paragraph (b)(1); subsequent prospectuses relating to such offerings would be filed pursuant to new paragraph (b)(3). *See* n.65 *supra*.

[86] These two categories represent a combination of (1) and (3), and (2) and (3), respectively. No combination of (1) and (2) is needed.

Category (4) would be used when a prospectus includes both information previously omitted pursuant to Rule 430A and other substantive changes that customarily are permitted to be made in a Rule 424 filing. As noted in n.80 *supra*, the proposed revisions to Rule 424 are not intended to alter traditional considerations determining when information must be included in a post-effective amendment. Accordingly, if a registrant relying on Rule 430A determines after effectiveness that the prospectus will contain information required to be set forth in a post-effective amendment, filing a Rule 424(b) prospectus under category (4) would not substitute for a post-effective amendment. *See* n.55 *supra*.

[87] [17 CFR 230.414(e)]. For example, a prospectus filed pursuant to paragraph (b)(1) of Rule 424 should be designated "424(b)(1)."

[88] *See* Rule 456 [17 CFR 230.456].

[89] The means that may be used is dependent upon the date of transmission; a means ulitized on the first business day following the date of pricing or first use may not suffice if used on the second business day. Unlike prior-Rule 424(c), in the usual case first class mail would not result in compliance.

[90] In the proposing Release, the Commission requested comment as to whether prospectuses that do no more than reflect a change in the "price and certain other narrowly specified terms" of the security should be provided a longer filing period than the proposed two business day period. Extension of the Rule 424(b)(3) filing period to five business days sufficiently responds to these concerns.

3. Filing Format

In the usual case, revised Rule 424(c) explicitly permits the filing of a prospectus supplement or "sticker" only, rather than requiring that a registrant using a supplement refile the entire prospectus with the supplement attached.[91] The prospectus supplement distributed to investors, however, ordinarily is still required to be attached to the prospectus to which the supplement relates.[92] The Rule requires that a supplement smaller than a prospectus page filed separately be attached to a sheet of 8½"×11" paper for ease in processing.

A related amendment requires that the first page of each prospectus supplement include a cross reference to the date(s) of the related prospectus and/or prospectus supplement(s). This will permit the Commission and persons obtaining this information to determine which documents comprise the complete prospectus.[93]

4. Amendments to Rule 424(a) [94]

The Commission has amended paragraph (a) of Rule 424 to eliminate the filing requirement for prospectuses used prior to effectiveness containing non-substantive changes from a previously filed prospectus. This change conforms Rule 424(a) to new Rule 424(b).

III. Cost-Benefit Analysis

To evaluate fully the benefits and costs associated with proposed Rule 430A and the amendments to Rules 424 and 497 and Items 512 and 601 of Regulation S-K, the Commission requested commentators to provide views and data as to the costs and benefits associated with the rules to eliminate pricing amendments and non-substantive Rule 424 filings, to permit the filing of a supplement without the rest of the prospectus, and to require more immediate filing of the prospectus. In this regard, the Commission noted that the amendments would reduce the filing burden borne by registrants, and associated costs such as printing and travel expenses, but that the reduction of these expenses might be offset in part by an increase in the costs associated with filing a Rule 424(b) or Rule 497(h) prospectus at an earlier time. In response to commentator concerns that the offset might reduce the cost savings from Rule 430A rather substantially, the time for filing was lengthened.

IV. Final Regulatory Flexibility Analysis

This final regulatory flexibility analysis concerns new Rule 430A and amendments to Rules 424 and 497 of Regulation C and Items 512 and 601 of Regulation S-K and has been prepared by the Commission in accordance with 5 U.S.C. 604. The corresponding Initial Regulatory Flexibility Analysis is contained in the proposing release.

Objectives of the New Rule and Amendments

The objectives of Rule 430A and the related amendments to Items 512 and 601 of Regulation S-K are to simplify and to reduce filing procedures and to minimize possible disruptions to a registrant's marketing schedule as the result of having to file a pre-effective pricing amendment. The amendments to Rules 424 and 497 governing the prospectus classification system, filing format and time requirements are intended to provide a more useful and effective system for filing post-effective prospectuses. The changes achieve these purposes without affecting the adequacy of disclosure of information to investors or investor protection under the federal securities laws.

Public Comment

No commentators responded to the Commission's request for comments on the Initial Regulatory Flexibility Analysis.

Significant Alternatives

Pursuant to section 604 of the Regulatory Flexibility Act, the following types of alternatives were considered:

(1) The establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities;

(2) The clarification, consolidation or simplification of compliance and reporting requirements under the rules for such small entities;

(3) The use of performance rather than design standards; and

(4) An exemption from coverage of the rules, or any part thereof, for small entities.

Specifically, the Commission considered whether or not Rule 430A should be available to registrants not subject to the reporting provisions of sections 13(a) or 15(d) of the Exchange Act immediately prior to filing a registration statement. The Commission decided to extend the rule to such registrants, thus enabling small issuers to take advantage of the benefits of Rule 430A.

With respect to the amendments to Rule 424 the Commission considered used after effectiveness by small issuers to file such prospectuses any earlier than currently required. The Commission does not believe, however, that such alternative proposals would be consistent with the Commission's mandate of investor protection. Similarly, the Commission does not consider the use of performance standards to be a significant alternative because such standards would be inconsistent with the Commission's statutory mandate.

V. Statutory Basis

Rule 430A is being adopted by the Commission and Rules 423, 424, 481, 482 and 497 and Items 501, 502, 512 and 601 of Regulation S-K are being amended by the Commission pursuant to Sections 7, 10 and 19(a) of the Securities Act.

List of Subjects in 17 CFR Parts 229, 230, 239, and 240.

Reporting and recordkeeping requirements, Securities.

VI. Text of Rules

In accordance with the foregoing, Title 17, Chapter II of the Code of Federal Regulations is to be amended as follows:

PART 229—STANDARD INSTRUCTIONS FOR FILING FORMS UNDER THE SECURITIES ACT OF 1933 AND SECURITIES EXCHANGE ACT OF 1934 AND ENERGY POLICY CONSERVATION ACT OF 1975—REGULATION S-K

1. The authority citation for Part 229 continues to read, in part, as follows:

Authority: Secs. 6, 7, 8, 10, 19(a), 48 Stat. 78, 79, 81, 85; secs. 12, 13, 14, 15(d), 23(a), 48 Stat. 892, 894, 901; secs. 205, 209, 48 Stat. 906, 908; sec. 203(a), 49 Stat. 704; secs. 1, 3, 8, 49 Stat. 1375, 1377, 1379; sec. 301, 54 Stat. 857; secs. 8, 202, 68 Stat. 685, 686; secs. 3, 4, 5, 6, 78 Stat. 565–568, 569, 570–574; sec. 1, 79 Stat. 1051; secs. 1, 2, 3, 82 Stat. 454, 455; secs. 1, 2, 3–5, 28(c), 84 Stat. 1435, 1497; sec. 105(b), 68 Stat.

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[91] Rule 424(c), however, requires registrants filing the Rule 430A information pursuant to Rule 424(b)(1) or (4) to file either a complete prospectus containing the information or a supplement that is attached to the prospectus. Any subsequently filed prospectus supplement need not be attached to the prospectus.

[92] The Commission staff previously has permitted registrants to send prospectus supplements not attached to the prospectus (often called an "appendix" in the employee benefit plan context) to participants if an employee benefit plan or dividend or interest reinvestment plan, provided that the supplement is understandable without reference to the prospectus and that the participants have previously received a complete copy of the prospectus to which the supplement relates and are advised that they may receive another copy on request. *See* Securities Act Release No. 6281 (January 15, 1981) (46 FR 8446) and, *e.g.*, letter re Illinois Power Company (available October 11, 1982). This will continue to be permitted.

[93] The cross reference would not necessarily refer to all previous supplements filed in connection with the prospectus, but only to those supplements that constitute part of the statutory prospectus with respect to the securities currently being offered.

[94] 17 CFR 230.424(a).

1503; secs. 8, 9, 10, 11, 16, 69 Stat. 117, 118, 119, 155; 15 U.S.C. 77f, 77g, 77h, 77j, 77s(a), 78*l*, 78m, 78n, 78*l*(d), 78w(a). * * *

§ 229.10 [Amended]

2. In § 229.10, paragraph (c)(1)(iii) is amended by removing the reference to "Rule 424(c)" and replacing it with a reference to "Rule 424(b)" and by removing the accompanying citation "(§ 230.424(c) of this chapter)" and replacing it with "(§ 230.424(b) of this chapter)".

3. In § 229.501, paragraph (c)(8) is revised to read as follows:

§ 229.501 (Item 501) Forepart of registration statement and outside front cover page of prospectus.

* * * * *

(c) * * *

(8) In the case of any prospectus to be used before the effective date of the registration statement (or, in the case of any prospectus that omits information as permitted by Rule 430A under the Securities Act [§ 230.430A of this chapter], prior to the determination of the initial public offering price), in red ink, the caption "Subject to Completion," the date of its issuance, and the following statement printed in type as large as that generally used in the body of the prospectus:

Information contained herein is subject to completion or amendment. A registration statement relating to these securities has been filed with the Securities and Exchange Commission. These securities may not be sold nor may offers to buy be accepted prior to the time the registration statement becomes effective. This prospectus shall not constitute an offer to sell or the solicitation of an offer to buy nor shall there be any sale of these securities in any State in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any State.

* * * * *

4. By revising paragraph (d)(2) of § 229.502 to read as follows:

§ 229.502 (Item 502) Inside front and outside back cover pages of prospectus.

* * * * *

(d) * * *

(2) If the stabilizing began prior to the effective date of the registration statement, set forth the amount of securities bought, the prices at which they were bought and the period within which they were bought. In the event that Rule 430A under the Securities Act [§ 230.430A of this chapter] is used, the prospectus is filed pursuant to Rule 424(b) [§ 230.424(b) of this chapter] or included in a post-effective amendment must include information as to stabilizing transactions effected prior to the determination of the public offering price set forth in such prospectus.

* * * * *

5. By adding new paragraph (j) of § 229.512 to read as follows:

§ 229.512 (Item 512) Undertakings.

* * * * *

(j) Include the following in a registration statement permitted by Rule 430A under the Securities Act of 1933 [§ 230.430A of this chapter]:

The undersigned registrant hereby undertakes that:

(1) For purposes of determining any liability under the Securities Act of 1933, the information omitted from the form of prospectus filed as part of a registration statement in reliance upon Rule 430A and contained in the form of prospectus filed by the registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of the registration statement as of the time it was declared effective.

(2) For the purpose of determining any liability under the Securities Act of 1933, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

6. By revising Instruction 1 to § 229.601 to read as follows:

§ 229.601 (Item 601) Exhibits.

* * * * *

Instructions to Item 601. 1. If an exhibit to a registration statement (other than an opinion or consent), filed in preliminary form, has been changed only (A) to insert information as to interest, dividend or conversion rates, redemption or conversion prices, purchase or offering prices, underwriters' or dealers' commissions, names, addresses or participation of underwriters or similar matters, which information appears elsewhere in an amendment to the registration statement or a prospectus filed pursuant to Rule 424(b) under the Securities Act [§ 230.424(b) of this chapter], or (B) to correct typographical errors, insert signatures or make other similar immaterial changes, then, notwithstanding any contrary requirement of any rule or form, the registrant need not refile such exhibit as so amended. Any such incomplete exhibit may not, however, be incorporated by reference in any subsequent filing under any Act administered by the Commission.

* * * * *

PART 230—GENERAL RULES AND REGULATIONS, SECURITIES ACT OF 1933

1. The authority citation of Part 230 continues to read, in part, as follows:

Authority: Secs. 230.400 to 230.499 issued under secs. 6, 8, 10, 19, 48 Stat. 78, 79, 81 and 85, as amended (15 U.S.C. 77f, 77h, 77i, 77s);

2. The introductory phrase in the first sentence of § 230.423 is amended to read as follows:

§ 230.423 Date of prospectus.

Except for a form of prospectus used after the effective date of the registration statement and before the determination of the offering price as permitted by Rule 430A(c) under the Securities Act (§ 230.430A(c) of this chapter) or before the opening of bids as permitted by Rule 445(c) under the Securities Act (§ 230.445(c) of this chapter), each * * *

* * * * *

3. By revising paragraphs (a), (b), (c), and (e), and adding a "Note" after paragraph (c) of § 230.424 to read as follows:

§ 230.424 Filing of prospectuses, number of copies.

(a) Five copies of every form of prospectus sent or given to any person prior to the effective date of the registration statement which varies from the form or forms of prospectus included in the registration statement as filed pursuant to § 230.402(a) of this chapter shall be filed as a part of the registration statement not later than the date such form of prospectus is first sent or given to any person: *Provided, however,* that only a form of prospectus that contains substantive changes from or additions to a prospectus previously filed with the Commission as part of a registration statement need be filed pursuant to this paragraph (a); *Provided, further,* that an investment company advertisement which is deemed to be a prospectus pursuant to § 230.482 of this chapter and which is required to be filed pursuant to this paragraph shall not be filed as part of the registration statement.

(b) Ten copies of each form of prospectus purporting to comply with section 10 of the Securities Act [15 U.S.C. 77j] shall be filed with the Commission in the form in which it is used after the effectiveness of the registration statement and identified as required by paragraph (e); *Provided, however,* that only a form of prospectus that contains substantive changes from or additions to a previously filed prospectus is required to be filed; *Provided, further,* that this paragraph (b) shall not apply in respect of a form of prospectus contained in a registration statement and relating solely to securities offered at competitive bidding, which prospectus is intended for use prior to the opening of bids. The ten copies shall be filed or transmitted for filing as follows:

(1) A form of prospectus that discloses information previously omitted from the prospectus filed as part of an effective registration statement in reliance upon Rule 430A under the Securities Act [§ 230.430A of this chapter] shall be filed with the commission no later than the second business day following the earlier of the date of determination of the offering price or the date it is first used after effectiveness in connection with a public offering or sales, or transmitted by a means reasonably calculated to result in filing with the Commission by that date.

(2) A form of prospectus used in connection with a primary offering of securities on a delayed basis pursuant to Rule 415(a)(1)(vii), (viii) or (x) under the Securities Act [§ 230.415(a)(1)(vii), (viii) or (x) of this chapter] that discloses the public offering price, description of securities, specific method of distribution or similar matters shall be filed with the Commission no later than the second business day following the earlier of the date of the determination of the offering price or the date it is first used after effectiveness in connection with a public offering or sales, or transmitted by a means reasonably calculated to result in filing with the Commission by that date.

(3) A form of prospectus that reflects facts or events other than those covered in paragraphs (b)(1) and (2) of this rule that constitute a substantive change from or addition to the information set forth in the last form of prospectus filed with the Commission under this rule or as part of a registration statement under the Securities Act shall be filed with the Commission no later than the fifth business day after the date it is first used after effectiveness in connection with a public offering or sales, or transmitted by a means reasonably calculated to result in filing with the Commission by that date.

(4) A form of prospectus that discloses information, facts or events covered in both paragraphs (b)(1) and (3) shall be filed with the Commission no later than the second business day following the earlier of the date of the determination of the offering price or the date it is first used after effectiveness in connection with a public offering or sales, or transmitted by a means reasonably calculated to result in filing with the Commission by that date.

(5) A form of prospectus that discloses information, facts or events covered in both paragraphs (b)(2) and (3) shall be filed with the Commission no later than the second business day following the earlier of the date of the determination of the offering price or the date it is first used after effectiveness in connection with a public offering or sales, or transmitted by a means reasonably calculated to result in filing with the Commission by that date.

(c) If a form of prospectus, other than one filed pursuant to paragraph (b)(1) or (b)(4) of this Rule, consists of a prospectus supplement attached to a form of prospectus that (1) previously has been filed or (2) was not required to be filed pursuant to paragraph (b) because it did no contain substantive changes from a prospectus that previously was filed, only the prospectus supplement need be filed under paragraph (b) of this rule, provided that the first page of each prospectus supplement includes a cross reference to the date(s) of the related prospectus and any prospectus supplements thereto that together constitute the prospectus required to be delivered by Section 5(b) of the Securities Act [15 U.S.C. 77e(b)] with respect to the securities currently being offered or sold. The cross reference may be set forth in longhand, provided it is legible.

Note.—Any prospectus supplement being filed separately that is smaller than a prospectus page should be attached to an 8½" × 11" sheet of paper.

(d) * * *

(e) Each copy of a form of prospectus filed under this rule shall contain in the upper right corner of the cover page the paragraph of this rule, including the subparagraph if applicable, under which the filing is made, and the file number of the registration statement to which the prospectus relates. The information required by this paragraph may be set forth in longhand, provided it is legible.

4. By adding new § 230.439A to read as follows:

§ 230.430A Prospectus in a registration statement at the time of effectiveness.

(a) The form of prospectus filed as part of a registration statement that is declared effective may omit information with respect to the public offering price, underwriting syndicate (including any material relationships between the registrant and underwriters not named therein), underwriting discounts or commissions, discounts or commissions to dealers, amount of proceeds, conversion rates, call prices and other items dependent upon the offering price, delivery dates, and terms of the securities dependent upon the offering date; and such form of prospectus need not contain such information in order for the registration statement to meet the requirements of Section 7 of the Securities Act [15 U.S.C. 77g] for the purposes of Section 5 thereof [15 U.S.C. 77e]. *Provided that,*

(1) The securities to be registered are offered for cash;

(2) The registrant furnishes the undertakings required by Item 512(j) of Regulation S-K [§ 229.512(j) of this chapter]; and

(3) The information ommitted in reliance upon paragraph (a) from the form of prospectus filed as part of a registration statement that is declared effective is contained in a form of prospectus filed with the Commission pursuant to Rule 424(b) or Rule 497(h) under the Securities Act [§§ 230.424(b) or 230.497(h) of this chapter]; except that if such form of prospectus is not so filed by the later of five business days after the effective date of the registration statement or five business days after the effectiveness of a post-effective amendment thereto that contains a form of prospectus, or transmitted by a means reasonably calculated to result in filing with the Commission by that date, the information omitted in reliance upon paragraph (a) must be contained in an effective post-effective amendment to the registration statement.

(b) The information omitted in reliance upon paragraph (a) from the form of prospectus filed as part of an effective registration statement, and contained in the form of prospectus filed with the Commission pursuant to Rule 424(b) or Rule 497(h) under the Securities Act [§§ 230.424(b) or 230.497(h) of this chapter], shall be deemed to be a part of the registration statement as of the time it was declared effective.

(c) When used prior to determination of the offering price of the securities, a form of prospectus relating to the securities offered pursuant to a registration statement that is declared effective with information omitted from the form of prospectus filed as part of such effective registration statement in reliance upon this Rule 430A need not contain information omitted pursuant to paragraph (a), in order to meet the requirements of Section 10 of the Securities Act [15 U.S.C. 77j] for the purpose of section 5(b)(1) [15 U.S.C. 77e(b)(1)] thereof. This provision shall not limit the information required to be contained in a form of prospectus meeting the requirements of section 10(a) of the Act for the purposes of section 5(b)(2) thereof or exception (a) of Section 2(10) [15 U.S.C. 77b(10)] thereof.

(d) this rule shall not apply to registration statements for securities to be offered by competitive bidding.

Note.—If information is omitted in reliance upon paragraph (a) from the form of prospectus filed as part of an effective registration statement, or effective post-effective amendment thereto, the registrant must ascertain promptly whether a form of prospectus transmitted for filing under Rule 424(b) of Rule 497(h) under the Securities Act actually was received for filing by the Commission and, in the event that it was not, promptly file such prospectus.

5. In § 230.481, paragraphs (b)(2) and (d)(2) are revised to read as follows:

§ 230.481 Information required in prospectus.

* * * * *

(b) * * *

(2) In the case of any prospectus to be used before the effective date of the registration statement (or, in the case of any prospectus that omits information as permitted by Rule 430A under the Securities Act [§ 230.430A of this chapter], prior to the determination of the initial public offering price), in red ink, the capiton "Subject to Completion," the date of its issuance, and the following statement printed in type as large as that generally used in the body of the prospectus:

Information contained herein is subject to completion or amendment. A registration statement relating to these securities has been filed with the Securities and Exchange Commission. These securities may not be sold nor may offers to buy be accepted prior to the time the registration statement becomes effective. This prospectus shall not constitute an offer to sell or the solicitation of an offer to buy nor shall there be any sale of these securities in any State in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any state.

* * * * *

(d) * * *

(2) If the stabilizing began prior to the effective date of the registration statement, disclosure of the amount of securities bought, the prices at which they were bought and the period within which they were bought. In the event that Rule 430A (§ 230.430A of this chapter) is used, the prospectus filed pursuant to Rule 497(h) (§ 230.497(h) of this chapter) or included in a post-effective amendment must include information as to stabilizing transactions effected prior to the determination of the public offering price set forth in such prospectus.

* * * * *

6. Paragraph (a)(4) of § 230.482 is added to read as follows:

§ 230.482 Advertising by an investment company as satisfying requirements of section 10.

* * * * *

(a) * * *

(4) It contains the statement required by Rule 481(b)(2) under the Securities Act [§ 230.481(b)(2) of this chapter] when used prior to effectiveness of the company's registration statement or, in the case of a registration statement that becomes effective omitting certain information from the prospectus contained in the registration statement in reliance upon Rule 430A under the Securities Act [§ 230.430A of this chapter], when used prior to the determination of the public offering price.

* * * * *

7. By adding new paragraph (h) of § 230.497 to read as follows:

§ 230.497 Filing of prospectus—number of copies.

* * * * *

(h) No later than the second business day following the earlier of the date of the determination of the offering price or the date it is first used after effectiveness in connection with a public offering or sales, ten copies of every form of prospectus and Statement of Additional Information, where applicable, that discloses the information previously omitted from the prospectus filed as part of an effective registration statement in reliance upon Rule 430A under the Securities Act [§ 230.430A of this chapter] shall be filed with the Commission in the exact form in which it is used, or transmitted by a means reasonably calculated to result in filing with the Commission by that date.

8. In paragraph (c)(7) of § 230.499, removing the reference to paragraph (c) of Rule 424 as follows:

§ 230.499 EDGAR temporary rule.

* * * * *

(c) * * *

(7) *Rule 424 of Regulation C, "Filing of prospectus—number of copies."* The copies required to be filed by paragraphs (a) and (b) of Rule 424 under the Securities Act (§ 230.424 of this chapter) shall consist * * *

* * * * *

PART 239—FORMS PRESCRIBED UNDER THE SECURITIES ACT OF 1933

1. The authority citation for Part 239 continues to read, in part, as follows:

Authority: The Securities Act of 1933, 15 U.S.C. 77a, *et seq.*, * * *

2. The introductory language of paragraph (b) of Item 11 of Form S–3 (§ 239.13) is revised to read as follows:

Note: The text of Form S–3 does not appear in the Code of Federal Regulations.

§ 239.13 Form S-3, for registration under the Securities Act of 1933 of securities of certain issuers offered pursuant to certain types of transactions.

* * * * *

Form S–3

* * * * *

Part I. Information Required in Prospectus.

* * * * *

Item 11. Material Changes.

(b) Include in the prospectus, if not incorporated by reference therein from the reports filed under the Exchange Act specified in Item 12(a), a proxy or information statement filed pursuant to Section 14 of the Exchange Act, a prospectus previously filed pursuant to Rule 424(b) or (c) under the Securities Act (§ 230.424(b) or (c) of this chapter) or, where no prospectus is required to be filed pursuant to Rule 424(b), the prospectus included in the registration statement at effectiveness, or a Form 8–K filed during either of the two preceeding years: (i) * * *

* * * * *

3. The introductory language of paragraph (b) of Item 10 of Form S–4 (§ 239.25) is revised to read as follows [note that the text of Form S–4 does not appear in the Code of Federal Regulations]:

§ 239.25 Form S-4, for the registration of securities issued in business combination transactions.

* * * * *

Form S–4

* * * * *

Part I. Information Required in the Prospectus.

* * * * *

B. Information About the Registrant

* * * * *

Item 10. Information with Respect to S–3 Registrants.

* * * * *

(b) Include in the prospectus, if not incorporated by reference from the reports filed under the Exchange Act specified in Item 11 of this Form, a proxy or information statement filed pursuant to section 14 of the Exchange Act, a prospectus previously filed pursuant to Rule 424 under the Securities Act (§ 230.424 of this chapter) or, where no prospectus is required to be filed pursuant to Rule 424(b), the prospectus included in the registration statement at effectiveness, or a Form 8–K filed during either of the two preceeding fiscal years:

(1) * * *

* * * * *

4. In Note 1 to General Instruction C, Unavailability of the Form S–8 (Prospectus for Reoffers or Resales), of Form S–8 (§ 239.16b), the reference to "Rule 424(c)" is changed to refer to "Rule 424(b)" and the corresponding citation is changed from "(§ 230.424(c) of this chapter)" to "(§ 230.424(b) of this chapter)".

Note: The text of Form S-8 does not appear in the Code of Federal Regulations.

5. The introductory language of paragraph (b)(1) of Item 11 of Form F-3 (§ 229.33) is revised to read as follows:

Note: The text of Form F-3 does not appear in the Code of Federal Regulations.

§ 239.33 Form F-3, for registration under the Securities Act of 1933 of securities of certain foreign private issuers pursuant to certain types of transactions.

* * * * *

Form F-3

* * * * *

Part I. Information Required in Prospectus.

* * * * *

Item 11. Material Changes.

(b)(1) Include in the prospectus, if not included in the reports filed under the Exchange Act which are incorporated by reference into the prospectus pursuant to Item 12 or a prospectus previously filed pursuant Rule 424(b) or (c) under the Securities Act [§ 230.424(b) or (c) under this chapter] or, where no prospectus is required to be filed pursuant to Rule 424(b), the prospectus included in the registration statement at effectiveness: (i) * * *

* * * * *

6. The introductory language of paragraph (c) of Item 10 of Form F-4 (§ 239.34) is revised to read as follows:

Note: The text of Form F-4 does not appear in the Code of Federal Regulations.

§ 239.34 Form F-4, for registration of securities of certain foreign private issuers issued in certain business combination transactions.

* * * * *

Form F-4

* * * * *

Part I. Information Required in the Prospectus.

* * * * *

B. Information About the Registrant.

* * * * *

Item 10. Information with Respect to F-3 Companies.

* * * * *

(c) Include in the prospectus, if not incorporated by reference from the reports filed under the Exchange Act specified in Item 11 of this Form, from a prospectus previously filed pursuant to Rule 424 under the Securities Act (§ 230.424 of this chapter) or, where no prospectus is required to be filed pursuant to Rule 424(b), the prospectus included in the registration statement at effectiveness, or from a Form 6-K filed during either of the two preceding fiscal years:

(1) * * *

* * * * *

PART 240—GENERAL RULES AND REGULATIONS, SECURITIES EXCHANGE ACT OF 1934

1. The authority citation for Part 240 continues to read, in part as follows:

Authority: Sec. 23, 48 Stat. 901, as amended, 15 U.S.C. 78w. * * *

2. Item 14(b)(1)(ii) introductory text of § 240.14a-101 is revised to read as follows:

§ 240.14a-101 Schedule 14A. Information required in proxy statement.

* * * * *

Item 14. Mergers, Consolidations, Acquisitions and Similar Matters.

* * * * *

b. Information about the registrant and the other person.

* * * * *

(i) Information with respect to S-3 registrants.

* * * * *

(ii) Include in the proxy statement, if not incorporated by reference from the reports filed under the Exchange Act specified in paragraph (b)(1)(iii) of this Item, from a proxy or information statement filed pursuant to section 14 of the Exchange Act, from a prospectus previously filed pursuant to Rule 424 under the Securities Act (§ 230.424 of this chapter) or, where no prospectus is required to be filed pursuant to Rule 424(b), the prospectus included in the registration statement at effectiveness, or from a Form 8-K filed during either of the two preceding fiscal years: * * *

* * * * *

Dated: May 27, 1987.

By the Commission.

Jonathan G. Katz,

Secretary.

[FR Doc. 87-12707 Filed 6-4-87; 8:45 am]

BILLING CODE 8010-01-M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 154, 375, and 382

[Docket No. RM87-3-000; Order No. 472]

Annual Charges Under the Omnibus Budget Reconciliation Act of 1986

Issued: May 29, 1987.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Commission is amending its regulations to establish annual charges as required by section 3401 of the Omnibus Budget Reconciliation Act of 1986. The Commission will assess these charges against gas and oil pipelines, investor-owned utilities (IOUs), Federal power marketing agencies (PMAS), and one electric cooperative. The charges will be based on volumes of energy transported and sold by gas pipelines, PMAs, IOUs and the electric cooperative, and on the revenues received by the oil pipelines.

EFFECTIVE DATE: Section 382.201(b)(4) of the Commission's regulations will be effective May 29, 1987. All other amendments made by this final rule will be effective on July 6, 1987.

FOR FURTHER INFORMATION CONTACT:

For Legal Matters: Roland M. Frye, Jr., Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, DC 20426, (202) 357-8315.

For Technical Matters: Jewel C. Poore, Office of Management Systems Analysis, Management Systems Division, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, DC 20426, (202) 357-5362.

SUPPLEMENTARY INFORMATION:

Before Commissioners: Martha O. Hesse, Chairman; Anthony G. Sousa, Charles G. Stalon, Charles A. Trabandt and C.M. Naeve.

I. Introduction

The Federal Energy Regulatory Commission (Commission) is amending its regulations to establish annual charges as required by section 3401 of the Omnibus Budget Reconciliation Act of 1986 (Budget Act).[1] The Commission will assess these charges against gas and oil pipelines, electric utilities, power marketing agencies, and one electric cooperative. The charges will be based on the volumes of energy transported and sold by the gas pipelines, electric utilities, power marketing agencies, and the electric cooperative, and on the operating revenues received by the oil pipelines.

II. Background

A. The Budget Act

Section 3401(a)(1) of the Budget Act requires the Commission to "assess and collect fees and annual charges in any fiscal year in amounts equal to all of the costs incurred by the Commission in that fiscal year." This authority is in addition to that granted to the Commission in sections 10(e) and 30(e)

[1] Act of October 21, 1986, Pub. L. No. 99-509, Title III, Subtitle E, section 3401, 1986 U.S. Code Cong. & Ad. News (100 Stat.) 1874, 1890-91 (to be codified at 42 U.S.C. 7178), I FERC Statutes & Regulations ¶ 6253.

of the Federal Power Act (FPA).[2] The annual charges must be computed based on methods which the Commission determines to be "fair and equitable." [3] The Conference Report 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 gas pipeline or electric utility regulation; (2) the total direct and indirect costs of that type of Commission regulation incurred during such year; (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.[4]

The Commission may assess these charges by making estimates based upon data available to it at the time of assessment.[5] 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.[6]

Congress will continue to approve the Commission's budget through annual and supplemental appropriations. 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 States Treasury for the Commission's expenses.[7]

B. Existing Fees and Annual Charges Schedules

The Commission currently assesses filing fees and annual charges under several statutes. Title V of the Independent Offices Appropriations Act of 1952 (IOAA) [8] permits the Commission to charge filing fees for special benefits provided to identifiable persons. Such fees are based on the cost to the agency of the agency's services.[9] Section 10(e) of the FPA requires that entities licensed under section 4 of that Act pay "reasonable annual charges" in order to, among other things, reimburse the United States for the costs of administering Title I of the FPA. Section 30(e) of the FPA instructs the Commission to establish fees "adequate to reimburse . . . reasonable costs incurred in connection with any studies or other reviews carried out . . . for purposes of compliance with" section 30 of the FPA.

The existing filing fee regulations implement the IOAA and recover part of the Commission's costs for certain services to gas, oil and electric companies which file with the Commission.[10] Under existing annual charges regulations promulgated pursuant to section 10 of the FPA, the Commission recovers costs from licensees for certain services provided to the hydroelectric industry.[11] On March 11, 1987, the Commission issued a Notice of Proposed Rulemaking [12] which set forth a proposal to implement the recent amendment to section 30 of the FPA.[13]

The Budget Act's billing authority is more comprehensive than the existing billing authority under either the IOAA or the FPA. Unlike FPA sections 10(e) and 30(e) which permit recovery of only those costs incurred in administering Part I and incurred in connection with studies and reviews performed pursuant to section 30 of the FPA respectively, and unlike the IOAA which permits recovery of only those costs incurred in providing special benefits to identifiable persons,[14] the Budget Act *requires* the Commission to recover *all* of its costs.

On January 28, 1987, the Commission issued a Notice of Proposed Rulemaking (NOPR) in which it proposed to recover through annual charges all costs not recouped through existing IOAA filing fees and FPA assessments.[15] The Commission proposed to assess annual charges against gas pipelines and electric utilities based upon volumes of energy transported and sold, and against oil pipelines based upon operating revenues.

The Commission received 90 comments on the proposed rule—19 from gas pipelines, 5 from gas trade associations, 2 from gas producers, 1 from a gas storage facility, 10 from local gas distribution companies (LDCs), 40 from investor-owned utilities (IOUs), 1 from a generating company, 1 from an electric trade association, 1 from a cooperative utility system, 10 from oil pipelines, 1 from an oil pipeline trade association, 5 from state public utility commissions, and 1 from a non-energy trade association.[16]

III. General Discussion of Annual Charges Formula

To implement the Budget Act, the Commission must first formulate an annual charge billing procedure. To do this, the Commission must determine:

- The types of companies which the Commission should bill.
- How to estimate and then allocate the Commission's costs among its regulatory programs.
- How to allocate each program's costs among the companies regulated under each program.

After formulating an annual charge billing procedure, the Commission must then determine:

- How to adjust the annual charges at the end of a fiscal year "to eliminate any overrecovery or underrecovery of [the Commission's] total costs, and any overcharging or undercharging of any person" pursuant to section 3401(e) of the Budget Act.
- The standards for waiving all or part of an annual charge pursuant to section 3401(g) of the Budget Act.

In this Part, the Commission addresses these five steps as they apply to all three programs. Parts IV, V, and VI will specifically address the types of

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[2] Budget Act section 3401(a)(2), *citing* 16 U.S.C. 803(e) (1982) and Act of October 16, 1986, Pub. L. No. 99-495, section 7(c), 1986 U.S. Code Cong. & Ad. News (100 Stat.) 1243, 1248–1249 (to be codified at 16 U.S.C. 823a(e)), I FERC Statutes & Regulations ¶ 6253.

[3] Budget Act section 3401(b).

[4] Conference Report to Accompany H.R. 5300 (Conference Report), H.R. Rep. No. 1012, 99th Cong., 2d Sess. 239, *reprinted in* 1986 U.S. Code Cong. & Ad. News 3868, 3884.

[5] Budget Act section 3401(c).

[6] See Conference Report at 238, 1986 U.S. Code Cong. & Ad. News at 3883; *see also* Report of the Committee on the Budget of the United States Senate, to Accompany S. 2706 (Senate Budget Report), S. Rep. No. 348, 99th Cong., 2d Sess. 56, 66 and 68.

[7] Budget Act section 3401(f).

[8] 31 U.S.C. 9701 (1982).

[9] *See* New England Power Co. v. FPC, 151 U.S. App. D.C. 371, 374–375, 467 F.2d 425, 428–429 (1972), *aff'd*, *415 U.S. 345 (1974)*.

[10] 18 CFR Parts 346 and 381 (1986); *see also* 52 FR 10366 (April 1, 1987), 51 FR 43599 (Dec. 3, 1986), and 51 FR 35347 (Oct. 3, 1986) (all to be codified at 18 CFR Part 381).

[11] 51 FR 24308 (July 3, 1986) (to be codified at 18 CFR Part 11). Also, pursuant to section 10(f) of the FPA, the Commission assesses charges to recover the cost of its headwater benefit investigations. *Id.*

[12] 52 FR 8463 (March 18, 1987) and 10898 (April 6, 1987), IV FERC Statutes & Regulations ¶ 32,436.

[13] Act of October 16, 1986, Pub. L. No. 99-495, section 7(c), 1986 U.S. Code Cong. & Ad. News (100 Stat.) 1243, 1248–1249 (to be codified at 16 U.S.C. 823a(e)).

[14] The legislative history indicates Congress intended the authority of its mandate in the Budget Act to go beyond that contained in Title V of the IOAA. *See* Report of the Committee on the Budget, House of Representatives, to Accompany H.R. 5300 (House Budget Report), H.R. Rep. No. 727, 99th Cong., 2d Sess. 44, *reprinted in* 1986 U.S. Code Cong. & Ad. News 3607, 3640 ("FERC does not currently have authority to assess charges on regulated companies for the remainder of the work performed by FERC in regulating oil pipelines, natural gas pipelines and public utilities. [This] leqislation gives that authority to FERC.")

[15] 52 FR 3128 (Feb. 2, 1987), IV FERC Statutes & Regulations ¶ 32,434.

[16] Some commenters fall into more than one category. A list of commenters is attached as Appendix A.

companies to be billed and the method for allocating the costs within each of the three regulatory areas. The Commission is adopting as a final rule most aspects of its proposed rule regarding each of these five steps. The major differences between the proposed and final rules are that the Commission (1) will assess annual charges against power marketing agencies; (2) will include short-term, limited-term and unit sales of electricity in the "coordination sales" category if such sales are for less than five years; (3) will include long-term firm transmission sales in the "sales for resale" category; (4) will not assess annual charges against gas pipelines with NGA section 7(f) declarations; (5) will assess natural gas pipelines based on only jurisdictional gas; (6) will establish a tracking mechanism for automatic passthrough of the natural gas pipelines' annual charges; (7) will assess oil pipelines based on only their revenues reported in Account Nos. 200, 210, and 220; (8) will impose a maximum level which an oil pipeline's annual charges may not exceed; and (9) will recompute each company's annual charges bill at the end of each fiscal year based on actual year-end data and adjust each company's bill for the following year by the difference between the annual charge payment received and the amount of the recomputed bill.

A. The Annual Charges Formula.

1. The Types of Companies To Be Billed

The Conference Report indicates that Congress intentionally did not specify the classes of companies subject to annual charges.[17] Congress instead granted the Commission discretion to identify the companies to be assessed annual charges. In the NOPR, the Commission proposed that fairness and equity (as required in section 3401(b) of the Budget Act) as well as administrative efficiency [18] justify the assessment of annual charges against only three types of companies: public utilities, interstate oil pipelines and interstate natural gas pipelines.

One commenter argues that while the Commission has certain limited discretion to establish an annual charges system and to allocate amounts to various groups, "it would be wrong to characterize such discretion as authority to create exemptions when Congress—the one body with such power—has chosen not to exercise it." [19] The Commission disagrees with this conclusion. The fact that Congress did not choose to address this issue does not preclude the Commission from doing so. Indeed, by failing to specify what classes of companies are subject to annual charges, Congress left that issue to be resolved by the Commission. Congress may (and generally does) leave the details of legislative implementation to the agencies charged with such implementation.[20]

The Commission therefore adopts the proposal to assess these three types of companies, as set forth in the NOPR. The reasons justifying the Commission's decision to assess annual charges against these three types of companies are discussed in the gas, oil and electric sections of this Preamble (Parts IV, V and VI below). In general, the Commission remains convinced that this approach is consistent with the legislative history, which indicates that the primary focus of Congress was on public utilities, interstate oil pipelines and interstate natural gas pipelines.[21] However, for the reasons set forth in Part VI, the Commission will also assess annual charges against the Federal power marketing agencies.

2. The Method for Estimating and Then Allocating The Commission's Costs Among Its Regulatory Programs

a. *Estimation of Costs.* The Commission is required to "assess and collect fees and annual charges in any fiscal year in amounts equal to all of the costs incurred by the Commission in that fiscal year." [22] The Commission's cost estimates may be based on data available to it at the time of assessment.[23] Because the annual charges must be paid by the end of the fiscal year for which they are assessed,[24] the Commission, when it assesses the annual charges, will not yet have available to it the actual cost data for that year. The Commission must therefore estimate its year-end expenses.

In the NOPR the Commission proposed that the most accurate available data on which to base such estimates would be the prior fiscal year's expenses. The Commission also proposed to adjust this cost figure upward or downward at the time bills are calculated to account for any actual or expected major changes in fiscal expenditures from the previous fiscal year, such as a supplemental budget increase.

The two commenters addressing the merits of this approach both support it.[25] The approach set forth in the NOPR is consistent with the manner in which the Commission develops its operating budget, *i.e.*, the Commission uses the prior fiscal year's expenditures as a guide for developing the next year's budget. For the above reasons, the Commission will use this approach.

b. *Allocation of Costs.* The Conference Report indicates that Congress intended the Commission to recover the costs of each program from those entities directly affected by the activities of the Commission in that program area:

> For example, public utilities subject to the Federal Power Act should be required to pay for the Commission's activities under the Federal Power Act and related statutes, including a proportionate share of the Commission's overhead. They should not be expected to pay for the Commission's activities under the Natural Gas Act or the Natural Gas Policy Act.[26]

The Budget Act does not require the Commission to create a new data base for billing purposes, and it is therefore free to use the most reliable data available to arrive at a reasonable approximation of its program costs.[27]

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[17] Conference Report at 239, U.S. Code Cong. & Ad. News at 3884.

[18] *See generally* House Budget Report at 55, 1986 U.S. Code Cong. & Ad. News at 3651 ("Any billing method that reasonably minimizes FERC and industry administrative costs is acceptable"); *cf. Capital Cities Communications v. Federal Communications Comm'n*, 180 U.S. App. D.C. 276, 279, 554 F.2d 1135, 1138 (1976) ("the statutory requirement that fees should be 'fair and equitable' does leave some room for consideration of administrative convenience"); *National Cable Television Ass'n v. Federal Communications Comm'n (National Cable)*, 180 U.S. App. D.C. 233, 249, 554 F.2d 1094, 1108 (1976) ("considerations of administrative convenience may certainly be taken into account as one factor in the calculation" of fees).

[19] Comments of American Electric Power Service Corp. at 22–23.

[20] *See, e.g.*, *Yakus* v. *United States*, 321 U.S. 414, 424–426 (1944).

[21] The Commission notes that the bill reported out of the House Budget Committee would have assessed annual charges against only these three types of companies. *See* Conference Report at 239, 1986 U.S. Code Cong. & Ad. News at 3884.

[22] Budget Act section 3401(a)(1).

[23] Id. at section 3401(c).

[24] Id. at section 3401(d).

[25] Comments of Detroit Edison Co. at 1; New England Power Co. at 3.

[26] Conference Report at 238–239, 1986 U.S. Code Cong. & Ad. News at 3883–3884.

[27] *See* Budget Act section 3401(c); *see generally* Yosemite Park and Curry Co. v. United States, 686 F.2d 925, 931–932 (Ct. Cl. 1982) and authority cited in nn. 32–34 therein (IOAA fees need only have a reasonable, not exact, relationship to agency cost); *National Cable*, 250 U.S. App. D.C. at 246–247, 554 F.2d at 1105–1106 (FCC need not calculate the exact cost of servicing each regulated entity, but can base its fee computations on approximations); National Ass'n of Broadcasters v. Federal Communications Comm'n, 250 U.S. App. D.C. 259, 271 n. 28,554 F.2d 1118, 1130 n. 28 (1976) (FCC fee calculations need not be exact; reasonable approximations are sufficient.)

Moreover, the Commission's use of currently available data minimizes the administrative burden on the agency and, in the long run, the administrative burden on jurisdictional companies that are billed.[28]

The Commission currently uses a computerized management information system, the Time Distribution Reporting System (TDRS), which accounts for staff time by program area. In the NOPR, the Commission proposed that the TDRS data for the prior fiscal year would provide the most reliable basis for distributing direct and indirect costs among the Commission's gas, oil, and electric programs.

The four companies commenting on this methodology all approve of it.[29] The Commission adopts this approach. The Commission now uses the TDRS as the basis for calculating its IOAA filing fees and for allocating FPA hydroelectric annual charges. This system has proven to be effective and accurate.[30]

The Commission will allocate its costs among the three programs as follows. Costs that are directly related to a particular program (such as the cost of the Commission's contract for a gas pipeline flow analysis computer model) will be charged against only that program, while indirect expenses (such as Commission-wide computer support contracts) will be distributed pro rata among all programs based on direct staff time as reflected in the TDRS data.[31]

The Commission also proposed in the NOPR to distribute on a *pro rata* basis the net expenses (after subtracting filing fees collected) of administering appeals from Department of Energy remedial orders and adjustment request denials. Commenters addressing this issue unanimously oppose proration of DOE appeal expenses.[32] The commenters criticize the proposal as an inter-industry subsidy of the kind the Conference Committee indicated that the Commission should try to avoid:

> [T]he Commission shall endeavor to assess and collect amounts necessary to cover the cost of each regulatory program area from those directly affected by the activities of the Commission in each area.[33]
>
> * * * * *
>
> [P]ublic utilities subject to the Federal Power Act . . . should not be expected to pay for the Commission's activities under the Natural Gas Act or the Natural Gas Policy Act.[34]

Commenters also point out that the NOPR's rationale for excusing the oil pipeline industry from paying all such DOE appeal costs, i.e., that the appeals are unrelated to the Commission's oil pipeline regulatory program, applies equally to the gas and electric industries.[35] They generally suggest that the Commission increase its filing fees for such appeals,[36] and one commenter recommends that the Commission assess appeal costs against the losing parties.[37]

These commenters raise serious issues which are not easily resolved. While the Commission already has in place a fee schedule for DOE appeals, the Commission may propose in a separate docket to increase the IOAA fees for DOE appeals to the maximum extent allowed by law, thereby leaving only a small amount of such costs to be assessed in annual charges. However, as numerous commenters point out, the Commission may assess IOAA fees only for the cost of providing special benefits provided to identifiable persons rather than for all the Commission's costs.[38] To the extent that the Commission's DOE appeal expenses exceed such fee receipts, the Budget Act requires the Commission to recover the entire shortfall.[39] The Commission is aware of no statutory or other authority by which it could assess appeal costs against the losing party in a DOE appeal, and commenters have cited no such authority. Nor does the Commission believe that it would be practical and fair to assess annual charges against such appellants, which generally are small companies that appear before the Commission only once. Roughly 87 percent of these appellants have filed only one appeal with the Commission, and another 10 percent have filed only two appeals. They thus do not take regular advantage of the Commission's expertise and facilities, as do oil and gas pipelines, electric utilities, and Federal power marketing agencies.

The Commission therefore concludes that it has no choice but to recover through annual charges DOE appeal costs not already recouped through filing fees. This approach does not contravene the language of the Conference Report quoted above, which only instructs the Commission to "endeavor" to collect each program's costs from those affected by the program. More important, failure to include DOE costs in the annual charges would contravene the mandate of the statute itself to recover *all* Commission expenses. To the extent that the Conference Report and the statute provide divergent guidance, the Commission must follow the statutory language. Finally, the Commission notes that, even if the DOE appeal filing fees are not increased, the estimated unrecovered costs (based on fiscal year 1986 data) which would be included in annual charges would amount to only $590,000, or a 0.8 percent increase for each category of annual charge recipient. The impact on any particular company would thus be very small. For these reasons, the Commission has decided that each program's total cost will include all its direct costs and a *pro*

[28] *See generally* House Budget Report at 55, 1986 U.S. Code Cong. & Ad. News at 3651 ("Any billing method that reasonably minimizes FERC and industry administrative costs is acceptable"); *cf.* Capital Cities Communications v. Federal Communications Comm'n, 180 U.S. App. D.C. 276, 279, 554 F.2d 1135, 1138 (1976) ("the statutory requirement that fees should be 'fair and equitable' does leave some room for consideration of administrative convenience"); *National Cable*, 180 U.S. App. D.C. at 249, 554 F.2d at 1108 (1976) ("considerations of administrative convenience may certainly be taken into account as one factor in the calculation" of fees).

[29] Comments of New England Power Co. at 9–11; Public Service Co. of Colorado at 3; Detroit Edison Co. at 1; Consolidated Edison Co. at N.Y. at 1–2.

[30] A detailed description of TDRS, including a discussion of its accuracy-control measures, was attached as Appendix A of the NOPR. The United States Court of Appeals for the Tenth Circuit upheld the Commission's filing fee schedules which were based upon the same TDRS system which the Commission will use in establishing annual charges. Phillips Petroleum Co. v. Federal Energy Regulatory Comm'n, 786 F.2d 370, *cert. denied*, ____ U.S. ____, 107 S. Ct. 92, 93 L. Ed. 2d 44, 55 U.S.L.W. 3232 (1986).

[31] The commenters do not object to this approach. *See, e.g.*, Comments of NEPCO at 3 and 10.

The United States Court of Appeals for the Fifth Circuit upheld a similar *pro rata* inclusion of indirect costs in the Nuclear Regulatory Commission's IOAA fees. Mississippi Power & Light Co. v. Nuclear Regulatory Comm'n, 601 F.2d 223, 231 (1979), *cert. denied*, 444 U.S. 1102 (1980); *see also* Central & Southern Motor Freight Tariff Ass'n v. United States, 250 U.S. App. D.C. 63, 77–78, 777 F.2d 722, 736–37 (1985); *National Cable*, 250 U.S. App. D.C. at 242, 554 F.2d at 1101 ("The costs assessed may include a pro rata share of any expenses for regulatory activities which are necessary in order to grant [an FCC certificate of compliance].")

[32] Comments of New England Power Co. at 3 and 10–11; Edison Electric Institute (EEI) at 31–33 and 34; American Electric Power Service Corp. at 27; Boston Edison Co. at 10; Williams Pipe Line Co. at 4; Texas Eastern Transmission Corp. at 12; Williams Natural Gas Co. at 3 and 9; American Gas Ass'n (AGA) at 8; Interstate Natural Gas Ass'n of America (INGAA) at 9–10.

[33] Conference Report at 238, 1986 U.S. Code Cong. & Ad. News at 3883, *quoted in* Comments of EEI at 31.

[34] *Id.* at 238–239, 1986 U.S. Code Cong. & Ad. News at 3883–3884, *quoted in* Comments of EEI at 32.

[35] Comments of Boston Edison Co. at 10; NEPCO at 11.

[36] Comments of American Electric Power Service Corp. at 27; Williams Pipe Line Co. at 4; Texas Eastern Transmission Corp. at 12; AGA at 8.

[37] Comments of Williams Pipe Line Co. at 4.

[38] *See* Federal Power Comm'n v. New England Power Co., 415 U.S. 345 (1974); National Cable Television Ass'n v. United States, 415 U.S. 336 (1974).

[39] *See* Budget Act section 3401(a).

rata share of indirect and DOE appeal costs less DOE appeal fees collected.

In the NOPR, the Commission proposed to reduce each program's costs by the amount of filing fees collected during the prior fiscal year from entities regulated under that program. The Commission also sought comments on whether each company's annual charges should be reduced by the amount of filing fees it paid. Eleven commenters favor a credit to the program,[40] while nine commenters support company-specific credits.[41] One commenter offers observations regarding this issue but takes no position.[42]

The commenters that support crediting the fees to the individual programs argue that company-specific credits would be inconsistent with the premise that filing fees are intended to compensate the Commission for costs incurred in providing a benefit or service,[43] that such credits would in effect relieve companies from paying filing fees,[44] that, because most companies' annual charges would be about the same under either approach, the administrative burden of implementing a company-specific credit would not be justified,[45] that such an approach would work to the disadvantage of companies selling or transporting large volumes of energy but filing relatively few applications at the Commission,[46] that some pipelines are already reimbursed for their filing fees, thus raising the possibility that such pipelines would recover their filing fees twice,[47] and that the additional administrative expense of crediting each company's filing fees would increase the annual charges of all companies.[48]

The commenters that favor company-specific credits argue that companies actively seeking new sales and transportation services would be penalized by the approach proposed in the NOPR, whereas individual credits would encourage more sales and transportation activity consistent with the spirit and intent of Order No. 436,[49] that pipelines with multiple filings should not subsidize the annual charges of companies with few filings,[50] and that company-specific credits would help rectify the disproportionate effect that the Commission's filing fees have on small companies.[51]

The Commission recognizes that, under either approach, some companies will, in varying degrees, subsidize other companies' shares of this agency's expenses. However, the Commission agrees with the arguments of the commenters opposing company-specific credits that such credits would undermine the Commission's filing fee system and would contravene the Commission's policy that those who use the Commission's services should pay more than those who do not. Given these persuasive arguments in favor of crediting the programs, the Commission cannot justify the additional administrative burden and expense which would result from crediting individual companies. The Commission also notes that the approach of crediting fees to the programs as a whole rather than to each company finds support in the House Budget Report:

> FERC is then to allocate and determine the costs incurred in administering its jurisdictional statutes, broken down into the following areas of responsibility: the administration of the Natural Gas Act and the Natural Gas Policy Act; the regulation of interstate oil pipelines under Title 49 U.S.C.; and, the regulation of public utilities under Parts II and III of the Federal Power Act.
>
> From these three subtotals, FERC is to subtract the fees collected (if any) under the Natural Gas Policy Act that are paid in connection with activities which pertain to each of the programs.
>
> The remaining costs of administering its jurisdictional statutes in each of the three areas are those costs which are to be assessed as annual charges.[52]

For these reasons, the Commission will reduce the assessable cost of each program by the amount of filing fees collected during the prior fiscal year from entities regulated under that program, but may adjust this figure if the Commission believes that the number does not accurately estimate the current year's fee receipts. However, the Commission expects that the prior year's filing fee receipts will generally serve as an accurate estimate of the current year's filing fee receipts.

c. *Sufficiency of Data in the NOPR.* Several commenters contend that the Commission did not provide sufficient data for companies to comment meaningfully regarding the estimation and allocation of costs.[53] Specifically, the commenters argue that the NOPR did not provide such data as a breakdown of fiscal year 1988 anticipated costs,[54] the cost of the gas regulatory program in years prior to fiscal year 1986,[55] the projected costs of the gas regulatory program in future fiscal years,[56] the amounts of revenue collected in past fiscal years from each of the Commission's existing filing fees,[57] the total filing fees collected in fiscal year 1986,[58] the estimated annual charges for each company,[59] a breakdown of the Commission's expenses within each of the three regulatory programs,[60] the cost of regulating electric entities other than IOUs,[61] the amounts expended to review PMA rates,[62] the amounts expended to implement the requirements of section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) [63] as they pertain to cogenerators and small power producers,[64] a breakdown of all product categories used in the TDRS,[65] expenditures by each product cagetory,[66] all expenses for the electric

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[40] Comments of New England Power Co. at 3, 10 and 12; Public Service Co. of Colorado at 3; San Diego Gas and Electric Co. at 1; Southern California Edison Co. at 2–3; Texaco USA at 2; Northwest Pipeline Corp. at 8–9; INGAA at 4–5 n.4; Florida Power & Light Co. at 3; Kansas Gas and Electric Co. at 7–8; South Carolina Generating Co. at 4; American Electric Power Service Co. at 36.

[41] Comments of Enron at 8–9; Texas Eastern Transmission Corp. at 11–12; Iowa-Illinois Gas and Electric Co. at 3; Southwestern Public Service Co. at 9; Texas-New Mexico Power Co. at 2; Southern Company Services, Inc. at 24–26; Eastern Shore Natural Gas Co. at 3; Lawrenceburg Gas Transmission Corp. at 5–6; AGA at 8.

[42] Comments of Granite State Gas Transmission, Inc. at 2–3.

[43] Comments of New England Power Co. at 12; Texaco USA at 2.

[44] Comments of Northwest Pipeline Corp. at 9; Kansas Gas and Electric Co. at 7–8.

[45] Comments of New England Power Co. at 12 n. 5.

[46] Comments of San Diego Gas and Electric Co. at 1; Southern California Edison Co. at 3.

[47] Comments of Granite State Gas Transmission, Inc. at 2–3.

[48] Comments of Southern California Edison Co. at 3; *cf.* Florida Power and Light Co. at 3 (concluding that company-specific credits would require "undue refinement of record keeping at FERC").

[49] Comments of Enron at 8–9.

[50] Comments of Texas Eastern Transmission Corp. at 11–12; Iowa-Illinois Gas and Electric Co. at 3; Southern Company Services, Inc. at 24–26.

[51] Comments of Eastern Shore Natural Gas Co. at 2–3.

[52] House Budget Report at 56, 1986 U.S. Code Cong. & Ad. News at 3652.

[53] Comments of West Texas Gas, Inc. at 2, AGA at 4–5 and 6; Southern Company Services, Inc. at 2; Southwestern Public Service Co. at 9 and 11; Cincinnati Gas and Electric Co. at 8–9; Iowa Power and Light Co. at 2; Iowa Southern Utilities Co. at 1–2; Potomac Electric Power Co. at 3; EEI at 10–15.

[54] Comments of West Texas Gas, Inc. at 2.

[55] Comments of AGA at 4.

[56] *Id.*

[57] *Id.*

[58] Comments of EEI at 11.

[59] Comments of AGA at 4; Southwestern Public Service Co. at 11; EEI at 11–12.

[60] Comments of EEI at 11.

[61] Comments of Cincinnati Gas & Electric Co. at 9.

[62] Comments of Iowa Southern Utilities Co. at 2; EEI at 11.

[63] 16 U.S.C. 824a–3 (1982).

[64] Comments of Iowa Southern Utilities Co. at 2; EEI at 11.

[65] Comments of Iowa Southern Utilities Co. at 2; EEI at 11.

[66] Comments of Iowa Southern Utilities Co. at 2.

regulatory program,[67] all filing fees receipts for the electric program,[68] the internal allocation of Commission resources for the electric program which breaks down expenditures between coordination sales and sales for resale,[69] the sources of "interchange out" and "transmission delivered" data for companies filing Annual Report FERC Form No. 1-F,[70] and a breakdown of filing fee receipts by fee category with a comparison of regulatory expenditures by those categories.[71]

The Commission does not believe that the commenters need such specific data in order to make relevant comments about the NOPR. If the NOPR is conceptually flawed, then the absence of additional data would not place commenters at a disadvantage. If the NOPR is conceptually valid, then such data would be irrelevant. The purpose of a notice of proposed rulemaking is to provide an accurate picture of the reasoning that has led the agency to the proposed rule, so that interested parties can contest that reasoning if they wish.[72] To provide such a picture, the Commission need only describe the subjects and issues involved.[73]

Moreover, many of the requests do not appear at all relevant to the issue of cost allocation, *e.g.*, the revenue amounts in past years from each different type of filing fee, the breakdown of all TDRS product categories, and the cost of the gas regulatory program in years prior to fiscal year 1986.

Moreover, it was not necessary to provide pre-1986 program costs or 1988 costs because the 1986 costs figures which the NOPR did provide are more relevant to the estimation of fiscal year 1987 costs. The Commission notes that the commenters could have obtained more detailed breakdowns of program costs from the Commission's annual budget submission to the Office of Management and Budget and the Commission's budget testimony before Congress, both of which are matters of public record and are available in the Public Reference Branch of the Commission's Public and Legal Reference Division, Office of Administrative Services.

[67] *Id.*

[68] *Id.*

[69] *Id.*; EEI at 11.

[70] Comments of Iowa Southern Utilities Co. at 2.

[71] Comments of EEI at 11.

[72] National Cable Television Ass'n v. Federal Communications Comm'n, 241 U.S. App. D.C. 389, 393, 747 F.2d 1503, 1507 (1984).

[73] *See, e.g.*, California Citizens Band Ass'n v. United States, 375 F.2d 43, 49 (9th Cir.), *cert. denied*, 389 U.S. 844 (1967); *see also* B. Schwartz, *Administrative Law* 173 (2d ed. 1984).

3. Allocation of Each Program's Costs Among the Companies Regulated Under Each Program

After the Commission's costs are allocated among the three regulatory programs, the Commission must further allocate each program's costs among the regulated companies. In the NOPR, the Commission proposed that the amount of each natural gas pipeline's and public utility's bill would be directly related to the volume of gas or electricity which it sells or transports, and that the amount of each oil pipeline's bill would be directly related to the operating revenues it receives from the transportation of oil and petroleum products.

The Commission also sought comments on a sampling method which would require the Commission to set up categories of companies based on generalized sales and transportation data, assign companies to various categories, and assess each company within a category the same annual charge. Of the nine commenters addressing the option of a sampling method,[74] only two support it.[75] Those opposing the alternative contend that it would become an administrative nightmare resulting in endless controversies over the proper categories to which companies should be assigned,[76] that its selection in lieu of the proposed method would add needless imprecision to the calculation of annual charges,[77] and that it would add unnecessary expense to the Commission's operations.[78] New England Power Company supports the use of a sampling method because it would be more administratively convenient, would give companies a degree of certainty regarding the amount of their annual charges, and would lend itself to minimum and maximum charge categories.[79] Lawrenceburg Gas Transmission Corporation urges the Commission to establish special categories for short pipelines and for pipelines rendering service solely to their affiliated distribution companies.[80]

The Commission is adopting the method proposed in the NOPR (to base companies' annual charges on volumes of gas or electricity sold or transported and on amounts of oil pipeline revenues) because this method is more precise than the sampling method. Also, it will impose no greater expense or burden on the Commission than the sampling method, and will provide the same degree of certainty to the companies as would the sampling method. Finally, this approach is more closely in accord with the expectation reflected in the Conference Report that the Commission will "assess annual charges proportionately on the basis of annual sales or volumes transported." [81]

4. Adjustment of Charges for a Fiscal Year so as to Eliminate Any Overrecovery or Underrecovery of the Commission's Total Costs and any Overcharging or Undercharging of any Company

In the NOPR, the Commission proposed to correct overrecovery or underrecovery of costs by comparing at the end of the fiscal year the actual amounts collected with the actual fiscal year costs, and adjusting the subsequent fiscal year's estimated program costs by the difference.

Section 3401(e) of the Budget Act requires such an adjustment in order to eliminate any overrecovery or underrecovery of the Commission's costs as well as any overcharging or undercharging of any person being assessed annual charges. In the NOPR, the Commission set forth three approaches for satisfying these two statutory requirements. Under the approach proposed in the NOPR, the Commission would compare at the end of the fiscal year the actual amounts collected with the actual fiscal year costs, and would adjust the subsequent fiscal year's estimated program costs by the difference. The Commission would accordingly increase or decrease each annual charge bill for the next fiscal year, but would not adjust the bills for the recently completed fiscal year. Under the second approach, the Commission would issue refund checks and supplemental charges, once it had the actual fiscal-year-end data with which to compute how much each

[74] Comments of Lone Star Gas Co. at 5; Pacific Gas Transmission Co. at 5; AGA at 8; INGAA at 5; Southwestern Public Service Co. at 10; Southwestern Electric Power Co. at 5; Lawrenceburg Gas Transmission Corp. at 6; New England Power Co. at 3; Southern California Edison Co. at 3.

[75] Comments of Lawrenceburg Gas Transmission Corp. at 6; New England Power Co. at 3.

[76] Comments of AGA at 8.

[77] Comments of Lone Star Gas Co. at 5; Pacific Gas Transmission Co. at 5; Southwestern Public Service Co. at 10; Southwestern Electric Power Co. at 5.

[78] Comments of Southern California Edison Co. at 3.

[79] Comments of New England Power Co. at 3 and 12–16.

[80] Comments of Lawrenceburg Gas Transmission Corp. at 6.

[81] Conference Report at 239, 1986 U.S. Code Cong. & Ad. News at 3884; *see also* House Budget Report at 54–55, 1986 U.S. Code Cong. & Ad. News at 3650–3651; H.R. 5300, 99th Cong., 2d Sess. section 4101(b) (1986).

company was overassessed or underassessed in the Commission's annual charges bill. Under the third approach, the Commission would recalculate each bill based on the Commission's year-end financial data, compare the actual collection from each individual company to the recalculated bill for that company, and carry over any differences as a debit or credit on each company's annual charges bill for the following year.

All five commenters addressing this issue support the approach proposed in the NOPR.[82] They all contend in various ways that the alternatives to the proposal would be too administratively burdensome on the Commission, resulting in unnecessary modifications in the Commission's recordkeeping [83] and perhaps even the need to supplement the Commission staff.[84]

The Commission has decided not to adopt the proposed approach. The NOPR's proposal of adjusting the next year's program cost overrecoveries or underrecoveries at the end of the fiscal year has the advantage of being administratively simple, requiring assessment and collection of only one set of annual charge bills each fiscal year. However, while it may satisfy section 3401(e)'s first requirement of eliminating overrecovery or underrecovery of the Commission's costs, it fails to meet the section's second requirement of eliminating overcharging or undercharging of any person. The advantage of the second approach (recomputing each bill and issuing refund checks and supplemental bills) is that it would satisfy both of section 3401(e)'s requirements. However, the disadvantage is that the approach would impose a major administrative burden on the Commission's Office of Management Systems Analysis to calculate, assess and collect two sets of annual charge bills each year. The third option (recomputing each bill and crediting or debiting each company's bill for the following year) has the combined advantages of the first two options, but none of their disadvantages. It would satisfy both requirements of section 3401(e), would be simple to administer, requiring assessment and collection of only one set of annual charges bills each year,[85] and would impose little more of an administrative burden on the companies than would the method proposed in the NOPR.

The Commission therefore chooses the third option. The entire billing computation is illustrated in the following example, which calculates hypothetical costs for the natural gas program.[86]

Line		(Dollars in thousands) 1987
	Billing Basis	
1	Prior Fiscal Year's Program Cost	49,300
2	Adjustment Based on Current Year Program Changes	
3	Filing Fees Adjustment (Subtract estimated filing fees collected for gas program)	−12,000
4	Billing Basis	37,300
5	Waivers	−100
6	Amount Collected (from annual charges)	37,200
	Actual Costs (Calculated after end of Fiscal Year)	
7	Actual Costs for Program	49,000
8	Filing Fees Adjustment (using actual filing fee receipts)	−12,200
9	Actual Net Costs	36,800
10	Overcollection or Undercollection—Difference between Amount Collected (Line 6) and Actual Net Costs (Line 10)	+400

In the above example, to arrive at the billing basis for FY 1987, the Commission will start with the prior year's actual costs for the natural gas program, hypothetically $49.3 million (line 1). Next, the Commission will adjust for current year program changes (line 2). While there is no adjustment in this example, an adjustment could be expected if there were a significant change, such as the need to request a supplemental budget appropriation from Congress.

Next, the Commission will deduct estimated filing fee collections. The estimate will be based on the prior year's collections, with possible adjustments to take into account the changes in the amount of filing fees published each year.[87] In the above example, the adjustment is $12 million (line 3). The billing basis of $37.3 million (line 4) will be divided among the pipeline companies in annual charges by the proposed method described in Part IV of this Notice.

The Commission may grant waivers of annual charges after billing. In this example, the Commission granted $100,000 in waivers (line 5), and thus would collect $37.2 million in annual charges from pipelines during the fiscal year (line 6).

After the end of the fiscal year, the Commission will calculate actual costs and compare them to the amount collected. In the example, actual costs for the program were $49.0 million (line 7) and actual filing fees received were $12.2 million (line 8). Therefore, actual net costs (line 7 less line 8) were $36.8 million (line 9). In this example, the amount collected from annual charges (line 6) exceeded actual net costs (line 9) by $400,000 (line 10). This difference will be credited or debited in the following year to individual companies, based on the following procedure. The Commission will first recalculate the bills, using actual net costs (line 9) plus the amount lost to waivers during the billing year (line 5). The Commission will then compare actual collections from individual companies to the recalculated bills for those companies, and carry over any differences as debits and credits onto each company's bill for the next year.

5. Standards for Waiving all or Part of an Annual Charge

In the NOPR, the Commission proposed to apply to annual charges the standards for waiver currently applicable to filing fees. The Commission's regulations permit a company to seek a waiver of a filing fee if it can show that it is economically unable to pay all or part of the fee or that such payment would place it in financial distress or emergency.[88] The Commission further proposed that any requests for waiver of annual charges must be received before the bill is due (*i.e.*, within 45 days after the billing date) and must be based upon sufficient financial data for the Commission to make its decision. Finally, the Commission proposed that the Director of the Office of Pipeline and Producer Regulation, the Oil Pipeline Board, and the Director of the Office of Electric Power Regulation would be delegated the authority to rule on waiver requests in the gas, oil and electric areas, respectively.

New England Power Company supports a strict standard as proposed in the NOPR because an annual charge waived for one company would have to be borne by others.[89] However, it also recommends that waivers above an unspecified amount be granted by the full Commission rather than by the office directors and only after other companies are given an opportunity to comment on such waiver requests.[90]

[82] Comments of New England Power Co. at 10 and 18–19; Texaco USA at 11; Pacific Gas Transmission Co. at 5–6; Florida Power and Light Co. at 4; American Electric Power Service Corp. at 36.

[83] Comments of Florida Power and Light Co. at 4.

[84] Comments of New England Power Co. at 19.

[85] The burden of calculating, assessing and collecting two sets of bills (second option) is far greater than that of merely calculating two sets of bills (third option).

[86] This example is a modified version of the one presented in the NOPR.

[87] *See* 18 CFR 381.104 (1986).

[88] 18 CFR 381.106 (1986).

[89] Comments of New England Power Co. at 19.

[90] *Id.*

Lawrenceburg Gas Transmission Corporation supports the proposal that the Director of the Office of Pipeline and Producer Regulation rule on petitions for waiver, arguing that the Director is responsive to the individual financial posture of jurisdictional pipelines.[91] National Fuel Gas Distribution Corporation urges the Commission to permit waivers where an applicant's jurisdictional status is incidental and imposes no significant costs on the Commission.[92] Finally, Detroit Edison Company suggests that any waived charges be recovered at a future date with interest.[93]

The Commission concludes that the stringent standard applicable to filing fees should also apply to annual charges because any charges waived for one company must be paid in the following year by all the program's regulated companies, due to the Budget Act's requirement that the Commission recover *all* its costs. The Commission therefore declines to expand the standards as suggested by National Fuel. The Commission (like Lawrenceburg Gas) is satisfied with the way in which its delegated fee waiver authority has been exercised. The Commission therefore adopts the proposal to delegate its authority to waive annual charges. The Commission sees no advantage to opening up waiver petitions for public comment. Such comments would perforce be limited to statements of general support or opposition based on the commenters' own financial interests (which are irrelevant under the Commission's waiver standards). The Commission also declines to adopt Detroit Edison's suggestion of recovering waived charges with interest. Such an approach would in effect substitute an indefinite loan in lieu of a waiver. This would contravene the Congressional intent that the Commission provide for waivers of annual charges.[94] Finally, the Commission concludes that, given the considerable advance notice to the companies that they would be assessed annual charges, a reduction of the filing period for waiver petitions from 45 to 15 days after issuance of the annual charges bill will not unduly prejudice the companies, and will assure that all payments are due to the Commission prior to the end of each fiscal year (as required by section 3401(a) of the Budget Act).

[91] Comments of Lawrenceburg Gas Transmission Corp. at 8–9.

[92] Comments of National Fuel Gas Distribution Corp. at 4.

[93] Comments of Detroit Edison Co. at 2.

[94] Budget Act section 3401(g).

B. Other Matters

The Commission proposed in the NOPR to provide a 45-day period for payment of annual charges, and to assess interest on overdue annual charges. Such interest will be computed in accordance with § 154.67(c)(2)(iii) of the Commission's regulations.[95]

The Commission also proposed that it may refuse to process any application or consider any other filing of a company which has annual charges or interest amounts in arrears, unless a petition for waiver is pending, and that it may take any other appropriate action permitted by law.

The Commission received one comment addressing the interest issue. Southwestern Public Service Company recommends that the Commission pay the companies interest on any money it overrecovers.[96] Because the Commission will not assess interest against the companies on year-end underrecoveries (but only against companies which do not provide full payment of their bills), the Commission does not believe it would be equitable for it to pay interest on year-end overrecoveries.

The Commission also received one comment concerning the possible refusal to consider filings of companies with annual charges or interest in arrears. The American Paper Institute (API) points out that such filings could include requests regarding new gas or electric service which cannot proceed without prior Commission approval.[97] According to API, if a pipeline or utility is in arrears on payment of annual charges, its customers could suffer the consequences by being denied access to gas supplies or electric power.

API raises a valid equitable concern of the type the Commission contemplated when it proposed that it "may" refuse to process pleadings of a company in arrears. The Commission will consider this and other equitable factors before deciding whether to exercise this enforcement mechanism. The Commission expects that the vast majority of companies will pay their annual charges promptly and that the interest provision will serve as a sufficient enforcement tool in all but the most unusual situations.

The Commission therefore adopts its proposals concerning both interest, the potential refusal to process filings, and also the taking of any other appropriate action permitted by law.

Many commenters took the opportunity to address the Commission's filing fee system. Five commenters suggest that the Commission review the fee amounts to ensure that fee-payers are paying their fair share of the Commission's costs.[98] The Commission in fact reviews each fee amount every year on the basis of the prior year's data. One of these commenters also recommends that the Commission annually review the types of companies to be assessed.[99] The Commission plans to review periodically the types of companies to be assessed annual charges, but will base the frequency of such reviews on its experience with the annual charges program as it evolves.

Another company urges the Commission to recoup at least half its budget from filing fees in order to ensure that companies with few filings at the Commission pay substantially less than those companies with many filings at the Commission.[100] The Commission will continue to review its fees annually to ensure that the filers are paying their fair share of Commission expenses. However, the amount of money which the Commission may lawfully collect in IOAA filing fees is limited by the Supreme Court's narrow construction of the IOAA.[101]

Various commenters also recommend that the Commission revise its fee regulations to give it the discretion to apply direct billing to all proceedings,[102] to increase producer fees,[103] to eliminate producer fees,[104] to

[95] 18 CFR 154.67(c)(2)(iii) (1986):

(2) Interest shall be computed * * *

(iii)(A) At an average prime rate for each calendar quarter on all excessive rates or charges held (including all interest applicable to such rates and charges) on or after October 1, 1979. The applicable average prime rate for each calendar quarter shall be the arithmetic mean, to the nearest one-hundredth of one percent, of the prime rate values published in the Federal Reserve Bulletin, or in the Federal Reserve's "Selected Interest Rates" (Statistical Release G. 13), for the fourth, third, and second months preceding the first month of the calendar quarter.

(B) The interest required to be paid under paragraph (d)(2)(iii)(A) of this section shall be compounded quarterly.

[96] Comments of Southwestern Public Service Co. at 11–12.

[97] Comments of American Paper Institute at 1–2.

[98] Comments of Enron at 8; Pacific Gas Transmission Co. at 4; Virginia Electric and Power Co. at 2; EEI at 37–39; Carolina Power & Light Co. at 12–13.

[99] Comment of Enron at 7.

[100] Comments of San Diego Gas and Electric Co. at 1.

[101] *See* Federal Power Comm'n v. New England Power Co., 415 U.S. 345 (1974); National Cable Television Ass'n v. United States, 415 U.S. 336 (1974).

[102] Comments of Central Illinois Public Service Co. at 6; Public Service Electric and Gas Co. at 3.

[103] Comments of Pacific Gas & Electric Co. at 8.

[104] Comments of Independent Petroleum Ass'n of America at 4.

waive filing fees for any company which pays in excess of a certain amount in annual charges,[105] to assess new filing fees against applicants for preliminary permits and exemptions,[106] intervenors,[107] complainants and protesters,[108] to modify the fees of cogenerators and small power producers,[109] to investigate whether fees assessed for filings under 18 CFR 381.502 overrecover the Commission's costs of addressing such filings,[110] and to fund the PURPA programs and general corporate regulatory program completely from filing or other fees.[111] Such recommendations are beyond the scope of this rulemaking, the only purpose of which is to promulgate regulations concerning annual charges. Moreover, the Commission evaluates its fees annually, will continue to do so in the future, and will change the fees as appropriate.

Four companies express concern that the annual charges regulations could lead to an unwarranted increase in the Commission's expenditures, and recommend various means of capping such costs.[112] These commenters' concern is unnecessary. As indicated in the NOPR and in section II A of this Preamble, Congress will continue to approve the Commission's budget through annual and supplemental appropriations. The annual charges thus do not constitute a "blank check" to the Commission but merely serve as a vehicle to reimburse the United States Treasury for the Commission's expenses approved by Congress.[113]

One commenter argues that the Commission's services are for the public welfare and that the federal tax base should therefore finance the Commission's programs.[114] Such an approach is precluded by the Budget Act, which requires the Commission to recoup all its expenses through filing fees and annual charges rather than through the federal tax base.

Numerous commenters argue that Congress in section 3401 unconstitutionally delegated its taxing authority to the Commission.[115] The Commission of course accepts the constitutionality of a statute enacted by Congress,[116] and is therefore implementing the authority delegated to the Commission by Congress.

Finally, in the NOPR, the Commission proposed to accept payment of annual charges by check, draft, money order, or Electric Funds Transfer System (EFTS). The Commission has decided not to accept EFTS as a valid means of payment of annual charges. The Commission currently does not have such a system and does not believe that the system would be used with sufficient frequency to justify the expense and administrative burden required for its establishment.

IV. Cost Basis for the Natural Gas Regulatory Program

A. The Types of Companies To Be Billed

In the NOPR, the Commission proposed to assess annual charges only against interstate natural gas pipelines, and to continue to collect all the IOAA filing fees it currently collects from natural gas producers, and interstate and intrastate pipelines.[117]

The Commission has the authority to assess annual charges against the approximately 110 intrastate natural gas pipelines that receive authority to transport natural gas across state lines pursuant to section 311 of the NGPA.[118] Section 311 gives the Commission limited jurisdiction over intrastate natural gas pipelines. The Commission believes that such jurisdiction is sufficient to permit the inclusion of these pipelines within the group of companies subject to annual charges under the Budget Act. However, in the NOPR, the Commission proposed not to assess annual charges against these companies because the intrastate pipelines already pay in filing fees almost all the Commission's expenses attributable to the implementation of section 311, because the collection of the difference would be administratively burdensome, and because the Commission does not wish to discourage intrastate pipelines from voluntarily seeking section 311 authorization.

Four commenters support the NOPR's proposal to exempt intrastate pipelines from the assessment of annual charges [119] and two oppose that proposal.[120] Those favoring exemption of intrastate pipelines argue that the intrastates are already paying their own way at the Commission,[121] that such assessment would discourage them from seeking NGPA section 311 authorizations,[122] and that the companies are nonjurisdictional.[123] Those opposing argue that such an exemption requires interstate pipelines to subsidize intrastate pipelines.[124] One commenter also suggests that, if the Commission concludes that collection of the unrecovered section 311 program costs is too burdensome, the Commission should at least include a provision permitting it to assess intrastate pipelines in the event that the amount of unreimbursed costs rises to the level where it is no longer too burdensome to recoup.[125]

The Commission concludes that it should not at this time exercise its authority to assess annual charges against intrastate pipelines. The Commission estimates that such companies already pay in filing fees $1.7 million of the approximately $1.8 million in the gas program costs attributable to the implementation of section 311 with respect to intrastate pipelines. These

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[105] Comments of Texas Eastern Transmission Corp. at 6 n. 6 and 11.

[106] Comments of EEI at 44; American Electric Power Service Corp. at 34–35.

[107] Comments of INGAA at 9; Texas Eastern Transmission Corp. at 9; Northwest Pipeline Corp. at 10; Central Illinois Public Service Co. at 7; Utah Power & Light Co. at 6–7; Pacific Power & Light Co. at 2–3.

[108] Comments of Northwest Pipeline Corp. at 10.

[109] Comments of Carolina Power & Light Co. at 12–13; Kansas Gas & Electric Co. at 5–6; New England Power Co. at 7–8; San Diego Gas & Electric Co. at 2.

[110] Comments of EEI at 37–39.

[111] Comments of American Electric Power Service Corp. at 35–36.

[112] Comments of Pacific Gas and Electric Co. at 3; Public Service Electric and Gas Co. at 2; Central Illinois Public Service Co. at 9 n. 3; Washington Water Power Co. at 2.

[113] Budget Act section 3401(f).

[114] Comments of Texaco USA at 1–2; *cf.* Comments of Williams Natural Gas Co. at 8–9 (arguing that, from the standpoint of commodity marketability, gas is not suitable for assignment of agency costs).

[115] Comments of American Electric Power Service Corp. at 16–19; Boston Edison Co. at 1–7 and 11–12; New England Power Co. at 1 n. 2; Southern Company Services, Inc. at 2–12; EEI at 15–31; Association of Oil Pipelines at 1; Consolidated Gas Transmission Corp. at 9–10; Eastern Shore Natural Gas Co. at 2–3; Enron at 2–3; Northern Border Pipeline Co. at 2; Texas Eastern Transmission Corp. at 3–4 and 14; Connecticut Natural Gas Corp. at 3; Washington Gas Light Co. at 9; INGAA at 5–11; United Distribution Cos. at 4–6.

[116] *See, e.g.,* McDonald v. Board of Election Comm'rs, 394 U.S. 802, 808–809 (1969).

[117] For purposes of this rulemaking, an interstate natural gas pipeline is defined as any person (1) engaged in natural gas sales for resale or natural gas transportation that are subject to the Commission's jurisdiction under the Natural Gas Act (NGA), 15 U.S.C. 717–717w (1982), (2) not engaged solely in "first sales" of natural gas as that term is defined in section 2(21) of the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. 3302(21) (1982), and (3) to whom the Commission has not issued a Natural Gas Act section 7(f) declaration. Based on FY 1986 data, the Commission would expect to collect $11,914,202 in filing fees and $37,625,798 in annual charges in 1987.

[118] 15 U.S.C. 3371 (1982).

[119] Comments of Lone Star Gas Co. at 5–6; Transok, Inc. at 2–3; Association of Texas Intrastate Natural Gas Pipelines at 3; Texaco U.S.A. at 2.

[120] Comments of Texas Eastern Transmission Corp. at 7–8; Iowa State Utilities Board at 3.

[121] Comments of Lone Star Gas Co. at 5–6; Transok, Inc. at 2; Association of Texas Intrastate Natural Gas Pipelines at 3.

[122] Comments of Transok, Inc. at 3; Association of Texas Intrastate Natural Gas Pipelines at 3.

[123] Comments of Lone Star Gas Co. at 5–6.

[124] Comments of Texas Eastern Transmission Corp. at 7–8.

[125] *Id.* at 5, 7–8.

companies have therefore already reimbursed the Commission for nearly all of their share of the regulatory expenses. To the extent that this exemption requires the interstate pipelines to subsidize the intrastate pipelines, such a subsidy is minimal (0.2 percent of gas program costs). The Commission must balance conflicting goals in this rulemaking, and the statute requires only that methods used to compute annual charges be fair and equitable. Also, the collection of the remaining $100,000 in costs from over 100 pipelines would be administratively burdensome.[126] Moreover, the Commission does not wish to discourage intrastate pipelines from voluntarily seeking section 311 authorization. For these reasons, the Commission will not assess annual charges against section 311 intrastate pipelines. However, the Commission will periodically review the categories of companies being assessed annual charges, and if it concludes that the above considerations no longer justify the exemption of intrastate pipelines, the Commission will revise the annual charges regulations accordingly.

Similarly, the Commission proposed in the NOPR not to assess annual charges against producers. Five commenters support this proposal,[127] five oppose it,[128] and two offer additional observations and suggestions.[129] Those supporting the exemption of producers from annual charges argue that the thrust of the Commission's regulatory scheme is to protect the public from potentially abusive pricing practices of those interstate gas pipelines which have developed *de facto* monopolies,[130] that the additional revenue from producers' annual charges would not justify the administrative burden of collecting such charges,[131] and that the increase in producer costs which would result from annual charges would give producers an additional reason to favor intrastate gas sales, contrary to the objectives of the NGPA.[132]

Those opposing the producer exemption contend that it would require pipelines to subsidize producers,[133] that it would place pipelines at a disadvantage when competing with producers in the marketplace,[134] and that the Commission should assess annual charges against at least those producers which it can identify (such as those filing for abandonment under NGA section 7).[135]

The Commission concludes that it should not assess annual charges against producers. Although the Conference Report indicates that Congress intended to give the Commission the discretion to assess charges against any natural gas company it regulates, the legislative history also indicates that its primary focus was on natural gas pipelines.[136] In fact, the House Budget Report expressly placed on the gas pipelines the burden of the Commission's "cost of administering all aspects of the Natural Gas Policy Act of 1978." [137] Therefore, while the Budget Act may authorize the Commission to collect charges from producers, the Commission clearly has the discretion to exclude producers for good cause.

Collection of the approximately $10 million from nearly 10,000 producers would be nearly impossible, and the administrative burden of attempting such a collection would be severe and disproportionate to any countervailing benefits. The Commission does not presently maintain a list of all producers and does not collect a complete body of data by which it could identify such producers. While the Commission is provided some volumetric data by pipelines in their purchased gas adjustment filings, such data only reflects the volumes sold to the pipelines, but not the increasingly large volumes sold to local distribution companies and end users under limited-term abandonments [138] and Order Nos. 436 [139] and 451.[140] While some producers inform the Commission of the sales volumes when they file reports required by the Commission's orders granting limited-term abandonments, the data provided does not distinguish between jurisdictional and nonjurisdictional gas sold. Thus, in order to assess accurately annual charges against producers, the Commission would need to collect additional data from them. The Commission is reluctant to impose this burden on such a large group of small entities.

In addition, the Commission rejects for two reasons the suggestion to assess at least some of the producers, such as those filing for abandonment. First, such an assesment would contravene the goal of the NGPA to create a unified national wellhead market for gas without regard to whether the gas was subject to the Commission's NGA jurisdiction. If the Commission were to assess annual charges against producers, the sale of jurisdictional gas would be less attractive due to the annual charge burden which it would entail—especially the reporting and accounting burdens which would be associated with such charge.[141] Second, it would discriminate against the small minority of producers who still file applications with the Commission.[142] For all the above reasons, the Commission will not assess annual charges against gas producers.

Another alternative which the Commission has considered is to require interstate pipelines to serve as agents for assessing and collecting annual charges from their producer-sellers. Under this alternative, the Commission would inform each pipeline of those costs it would be entitled to recover from producers, and each natural gas pipeline would then have to collect these charges from its producer-sellers. The Commission's calculations of recoverable costs would be based on the

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[126] *See generally* House Budget Report at 55, 1986 U.S. Code Cong. & Ad. News at 3651 ("Any billing method that reasonably minimizes FERC and industry administrative costs is acceptable"); *cf.* Capital Cities Communications v. Federal Communications Comm'n, 180 U.S. App. D.C. 276, 279, 554 F.2d 1135, 1138 (1976) ("the statutory requirement that fees should be 'fair and equitable' does leave some room for consideration of administrative convenience"); *National Cable*, 180 U.S. App. D.C. at 249, 554 F.2d at 1108 (1976) ("considerations of administrative convenience may certainly be taken into account as one factor in the calculation" of fees).

[127] Comments of Champlin Petroleum Co. at 2; Cities Services Oil & Gas Corp. at 2; Independent Petroleum Ass'n of America at 2–3; Natural Gas Supply Ass'n at 3–4; Texaco U.S.A. at 2.

[128] Comments of Lawrenceburg Gas Transmission Corp. at 6–7; Texas Eastern Transmission Corp. at 7; Pacific Gas & Electric Co. at 8; AGA at 6–7; Iowa State Utilities Board at 3–4.

[129] Comments of Lone Star Gas Co. at 6; Pacific Gas & Electric Co. at 8.

[130] Comments of Cities Services Oil & Gas Co. at 2.

[131] Comments of Independent Petroleum Ass'n of America at 2–3.

[132] Comments of Natural Gas Supply Ass'n at 3–4.

[133] Comments of Lawrenceburg Gas Transmission Corp. at 6–7; Pacific Gas & Electric Co. at 8.

[134] Comments of Texas Eastern Transmission Corp. at 7.

[135] Comments of AGA at 6–7; Lawrenceburg Gas Transmission Corp. at 6–7; Iowa State Utilities Board at 3–4.

[136] Conference Report at 239, 1986 U.S. Code Cong. & Ad. News at 3884.

[137] House Budget Report at 54, 1986 U.S. Code Cong. & Ad. News at 3650 (emphasis added).

[138] *See* Felmont Oil Corp. and Essex Offshore, Inc., 33 FERC ¶ 61,333 (1985), *reh'g denied*, 34 FERC ¶ 61,296 (1986).

[139] 50 FR 42408 (Oct. 18, 1985), FERC Statutes & Regulations (Regulations Preambles 1982–1985) ¶ 30,665.

[140] 51 FR 22166 (June 18, 1986), III FERC Statutes & Regulations (Regulations Preambles) ¶ 30,701.

[141] *See* Comments of Independent Petroleum Ass'n of America at 2–3.

[142] In fiscal year 1986, 792 producers filed for abandonment. During the first half of fiscal year 1987, 396 producers have filed for abandonment.

volumetric data currently reported in Annual Report FERC Form No. 2 at page 520, column c (gas receipts by type of source, such as purchases, exchanges, transportation, storage, *etc.*), and page 327, lines 1, 3 and 4, column b (gas purchases by type of source, such as wellhead, processing plant, field line, another pipeline, and city gate). Similar data requirements would have to be added for Annual Report FERC Form Nos. 2-A and 14.

The four commenters addressing this alternative all oppose it,[143] arguing that it would impose severe additional reporting burdens [144] and would bifurcate the wellhead market by increasing the price of interstate gas over that of intrastate gas.[145]

The Commission concludes that, for the reasons already stated, the billing of only interstate pipelines is the most equitable and efficient method of assessing annual charges. Moreover, the Commission is reluctant to impose additional reporting burdens on the pipelines which file Form Nos. 2-A and 14, and does not wish to bifurcate the wellhead market.

As of April 30, 1987, the Commission requlated 148 pipelines under section 7 of the NGA. Of these pipelines, the Commission proposed in the NOPR to assess annual charges against the following groups (which, based on the latest figures, total 135 pipelines):

(a) Interstate natural gas pipelines that have certificates of public convenience and necessity under section 7 of the NGA, that are subject to Commission NGA section 4 authority, and that sell and transport volumes in excess of 200,000 Mcf annually for any of the three calendar years immediately preceding the billing year (currently 114 pipelines);

(b) Interstate natural gas pipelines that have certificate authority under section 7 of the NGA but no tariff on file for jurisdictional or nonjurisdictional sales and that sell and transport volumes in excess of 200,000 Mcf annually for any of the three calendar years immediately preceding the billing year (currently 12 pipelines);

(c) LNG importers that fall within the Commission's jurisdiction pursuant to both sections 3 and 7 of the NGA and that sell and transport volumes in excess of 200,000 Mcf annually for any of the three calendar years immediately preceding the billing year (currently 5 pipelines); and

(d) Regulated interstate natural gas pipelines that have NGA section 7(f) declarations and that sell and transport volumes in excess of 200,000 Mcf annually for any of the three calendar years immediately preceding the billing year (currently 4 pipelines).

The Commission proposed to exempt any interstate natural gas pipeline with annual sales and transportation volumes of 200,000 Mcf or less in each of the three calendar years immediately preceding the billing year (currently 13 pipelines).[146]

1. Interstate Pipeline Companies To Be Billed

Consistent with the Conference Report,[147] the Commission will assess annual charges against those companies over which it has jurisdiction under section 7 of the NGA, exempting only pipelines with NGA section 7(f) declarations (a reversal of the proposal set forth in the NOPR) and pipelines with throughputs of 200,000 Mcf or less annually in each of the three calendar years immediately preceding the billing year.

(a) Interstate natural gas pipelines apply for certificates for the transportation and sale of natural gas for resale in interstate commerce under section 7 of the NGA. One-hundred twenty-two companies, excluding LNG importers but including gatherer-type pipelines, currently have certificates under NGA section 7 and are also subject to the Commission's NGA section 4 rate regulatory authority. In the NOPR, the Commission proposed to assess annual charges against the companies in this group with sales and transportation volumes exceeding 200,000 Mcf annually for any of the three calendar years immediately preceding the billing year. This group currently numbers 114 pipelines.

Each of the three commenters addressing this category of pipelines argues that it was incorrectly included in this category. Lone Star Gas Company contends that its status has changed because it makes no sales for resale in interstate commerce and has no sales tariff on file with the Commission, and that it transports its own and others' gas as an interstate pipeline but makes sales only through its nonjurisdictional local distribution facilities. It requests to be moved to category (b).[148] Lone Star is correct, and the Commission will therefore delete its name from the list of companies in category (a) and add it to the list of companies in category (b). The Commission notes, however, that a shift from category (a) to category (b) will not affect the amount of the company's annual charge.

The second commenter, Cincinnati Gas & Electric Company, argues that its affiliate, Union Light, Heat & Power Company, will be assessed not only for the gas it transports as an interstate pipeline but also for the gas it sells as an LDC. Cincinnati therefore asks that the Commission amend its formula to base the assessment only on transmission system sales and on deliveries for other interstate pipeline companies. Such a sweeping change in its proposed assessment methodology would exclude gas transported for producers, end-users and LDCs (and would apparently relieve Union of any annual charge obligation under the natural gas program). The Commission is unwilling to remove such a large volume of gas from the volumetric basis for annual charges. However, it is not the Commission's intent to assess annual charges based upon any distribution sales volumes which were reported on Form Nos. 2 and 2-A, but which were delivered to the LDC portion of the reporting pipeline by another jurisdictional pipeline and which were not transported through any portion of the reporting pipeline's interstate facilities. (Such volumes would be included in Form No. 2 or 2-A of that other jurisdictional pipeline.) If a company wishes to provide the Commission with a statement made under oath identifying the LDC volumes which it received through a pipeline other than its own, then the Commission will reduce the volumetric total (on page 521 of Form No. 2 or page 18 of Form No. 2-A) by that amount. Such statements are strictly voluntary, but will be subject to the normal audit procedures of the Commission's Office of the Chief Accountant and Office of Pipeline and Producer Regulation. To be considered in the fiscal year 1987 annual charge calculations, such statements must be filed with the Commission within 15 calendar days from the day this rule is issued.[149] In future fiscal years, each pipeline will be required to provide such information as part of the company's Form No. 2 (as a footnote on page

[143] Comments of Lone Star Gas Co. at 6; Lawrenceburg Gas Transmission Corp. at 7; Pacific Gas & Electric Co. at 8; Independent Petroleum Ass'n of America at 2-3.

[144] Comments of Lone Star Gas Co. at 6; Pacific Gas & Electric Co. at 8.

[145] Comments of Independent Petroleum Ass'n of America at 2-3.

[146] In Appendix B, the Commission separates the companies into the above categories based on the most current information in the Commission's files.

[147] Conference Report at 239, 1986 U.S. Code Cong. & Ad. News at 3884.

[148] Comments of Lone Star Gas Co. at 6-7.

[149] To facilitate such natural gas pipelines' timely filing of this data, the Commission is serving a copy of this rule on each pipeline listed in Appendix B. This service is by United States Mail, first class, on the date of issuance of this order.

520)[150] or Form No. 2–A (as a footnote on page 21).[151]

The third commenter, Washington Natural Gas Company, argues that it is a project operator which neither purchases gas, sells gas, takes title to gas, nor transports gas for a charge in the conventional sense. It therefore reports no sales or transportation volumes in its Form No. 2. It merely stores the gas of its three owners and releases the gas into the pipeline as needed. For these reasons, Washington Natural requests removal from the list of entities to be assessed annual charges.[152] The Commission is not exempting Washington Natural or any other company engaged in jurisdictional storage activities. Such a company files storage rates and a Form No. 2 or 2–A with the Commission, and its storage services are considered to be transportation for jurisdictional purposes.

Therefore, the Commission will assess annual charges against all interstate natural gas pipelines that have NGA section 7 certificates, that are subject to NGA section 4 authority, and that sell and transport volumes in excess of 200,000 Mcf annually for any of the three calendar years immediately preceding the billing year.[153]

(b) Section 1(b) of the NGA provides, in part, that the sale in interstate commerce for resale of natural gas for ultimate public consumption is jurisdictional. This usually involves the sale of natural gas to a local distribution company (LDC) the facilities and services of which are under state or local jurisdiction. The Commission has authority to set rates for sales to LDCs pursuant to section 4 of the NGA. However, some natural gas pipeline companies make sales to companies that use the natural gas for their own consumption. These sales are referred to as direct sales. The Commission does not set rates for direct sales because they are not regulated under section 4 of the NGA. However, the construction and operation of service facilities and the interstate transportation of natural gas for direct sale are subject to the Commission's jurisdiction under section 7 of the NGA. Consistent with the scope of the Commission's NGA jurisdiction, the Commission in the NOPR proposed to assess annual charges on all sales volumes, *i.e.*, both the volumes sold for resale and the volumes transported in interstate commerce for direct sale. Sixteen such interstate pipeline companies currently have certificate authority but no sales tariff on file. If the Commission were using the latest data to assess annual charges, it would exempt four pipelines on a volumetric basis (200,000 Mcf or less per year for each of the three immediately preceding calendar years) and assess the remaining twelve pipelines an annual charge. The Commission proposed to calculate the charges based upon total (interstate and intrastate) transportation and sales volumes.

Five commenters argue that the Commission should modify its proposal and determine its annual charge assessment solely on interstate gas sales and transportation volumes. Currently, some pipelines do not separate in their Form Nos. 2 and 2–A their interstate from their intrastate volumes. Likewise, many pipelines that also perform a distribution function do not separate in their Form Nos. 2 and 2–A the volumes sold or transported in interstate commerce from nonjurisdictional volumes sold to end-users. To assess annual charges based on the combined volumes would greatly inflate the volume on which these two types of companies are assessed.[154] The commenters' concern is valid. As noted in Part IV A 1(a) above, the Commission's intent is to base its annual charges on only interstate natural gas volumes. Within 15 calendar days of the day this rule is issued, any interstate pipeline which also performs local distribution or intrastate functions may provide the Commission with a sworn statement that shows (1) the 1986 volumes which the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities, and which it received through gathering facilities, distribution facilities, or intrastate facilities; and (2) the 1986 volumes which the reporting pipeline received, sold or transported through any interstate portion of its pipeline facilities. The Commission will reduce the company's volumetric total by the first amount.[155] In response to the above five comments, the Commission is also amending its instructions to Form Nos. 2 and 2–A to require that every pipeline provide this same data as a footnote on page 520 of its Form No. 2 or on page 21 of Form No. 2–A.

In a related matter, two commenters recommend that the Commission exclude from its computations the gathering volumes currently booked to Account No. 489.[156] These commenters contend that gathering services "arguably" do not require any Commission processing time because gathering is exempted from Commission jurisdiction under NGA section 1(b), and that inclusion of gathering volumes would frequently result in double-counting because most gathering volumes are subsequently transported.

Because the Commission does not have jurisdiction over the function of gathering, any company that reported gathering volumes in its 1986 Form No. 2 or 2–A may file, within 15 calendar days of the day this rule is issued, a sworn statement indicating the amount of gas that represents its gathering volumes.[157] The Commission will reduce the company's volumetric total by that amount, except that the Commission will not reduce the volumetric totals by any gathering volumes of gas if they are destined for the interstate market or if they are transported through any interstate portion of the reporting pipeline.[158] As with LDCs and intrastate piplines, these companies with gathering lines must report such information next year as a footnote on page 520 of Form No. 2 or page 21 of Form No. 2–A.

[150] A revised page 520 of Form No. 2 is attached to this rule as Appendix C.

[151] A revised page 21 of Form No. 2–A is attached to this rule as Appendix D. The new instructions added to both page 520 of Form No. 2 (referred to *supra* note 150) and page 21 of Form No. 2–A are:

Also indicate by footnote the volumes of nonjurisdictional gas which did not incur FERC regulatory costs by showing (1) the local distribution volumes delivered to the local-distribution-company portion of the reporting pipeline by another jurisdictional pipeline; (2) the volumes which the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities, and which the reporting pipeline received through gathering facilities, distribution facilities or intrastate facilities, but not through any of the interstate portion of the reporting pipeline; and (3) the gathering line volumes which were not destined for the interstate market or which were not transported through any interstate portion of the reporting pipeline.

[152] Comments of Washington Natural Gas Co. at 2–4.

[153] Raton Gas Transmission Company correctly informs the Commission that it had been misnamed in the NOPR's Appendix B as Raton Natural Gas Company. Comments of Raton Gas Transmission Co. at 1. The error has been corrected in Appendix B to this rule.

[154] Comments of Lone Star Gas Co. at 7–8; Northwest Pipeline Corp. at 8; Iowa State Utilities Board at 4–5; National Fuel Gas Distribution Corp. at 5; Connecticut Natural Gas Corp. at 2 n. 1.

[155] To facilitate such natural gas pipelines' timely filing of this data, the Commission is serving a copy of this rule on each pipeline listed in Appendix B. This service is by United States Mail, first class, on the date of issuance of this order.

[156] Comments of Northwest Pipeline Corp. at 7–8; Williams Natural Gas Co. at 6–7.

[157] To facilitate such natural gas pipelines' timely filing of this data, the Commission is serving a copy of this rule on each pipeline listed in Appendix B. This service is by United States Mail, first class, on the date of issuance of this order.

[158] *See* Public Service Comm'n of Kentucky v. FERC, 610 F.2d 439 (6th Cir. 1979) (holding that direct sale deliveries from gathering facilities are subject to the Commission's jurisdiction).

(c) In the NOPR, the Commission proposed to assess annual charges against importers that are subject to the Commission's NGA section 3 [159] jurisdiction and that file a Form No. 14, only if the companies are also subject to the Commission's NGA section 7 jurisdiction.[160] In addition, the Commission proposed to assess annual charges against only those importers which sell or transport more than 200,000 Mcf per year in any of the three calendar years immediately preceding the billing year. Based on the latest data, there are currently five companies in this category. No commenters addressed the proposal to assess annual charges against this category of company.

Under the DOE Organization Act,[161] regulatory authority involving natural gas imports and exports is vested in the Secretary of Energy. The Secretary has delegated to the Commission the authority to regulate the use of domestic facilities for the sale or transportation of imported natural gas.[162] One source of natural gas used to supplement national supplies is imported liquefied natural gas (LNG). An LNG importer is subject to the Commission's jurisdiction under section 3 of the NGA and files with the Commission a Form No. 14 indicating the total LNG volumes transported. Because the Commission has jurisdiction over these natural gas companies and has sufficient volumetric data with which to assess annual charges against them, it will include this type of company among the groups to be assessed annual charges.

2. Interstate Pipeline Companies To Be Exempted

(a) In the NOPR, the Commission proposed to exempt natural gas pipelines with annual sales and transportation volumes of 200,000 Mcf or less in each of the three years immediately preceding the billing year. Only one commenter addresses this category of company. Pacific Gas Transmission Company opposes exempting small pipelines, proposing instead that every interstate pipeline be required to pay at least a minimum annual charge.[163]

The Commission has decided to exempt from annual charges all natural gas pipelines with annual sales and transportation volumes of 200,000 Mcf or less in each of the three calendar years immediately preceding the billing year. The Commission does not currently collect the volumetric data necessary to assess accurately annual charges against these smaller pipelines. Collection of such data would impose significant new reporting burdens on these small pipelines and would also increase the Commission's costs of computing, billing and collecting annual charges. The Commission does not believe that the financial benefits to be derived from collecting such data justify the resulting administrative burden on the agency and the small pipelines. For instance, even if the Commission ignored its current absence of data and assumed (to these small pipelines' disadvantage) that each one sold and transported the maximum exempt yearly volume of 200,000 Mcf, the small pipelines would still each be assessed only a $351 annual charge.[164] The maximum annual amount that could be collected from all thirteen companies would thus be only $4,563 (13×$351).[165] The Commission believes that the benefit of collecting this minimal amount of money from so few companies is outweighed by the disadvantages associated with changing the existing reporting requirements.

The Commission rejects Pacific Gas Transmission Company's argument to impose a "minimum charge." The Commission believes that a minimum charge that is greater than $351 would be unfair to such small companies because the annual charge paid by a small pipeline would be based on a higher rate per Mcf than the annual charge paid by a larger pipeline.

Another commenter seeks to expand this "small exemption" to include pipelines of 25 miles or less in length, regardless of the volume sold and transported,[166] and pipelines for which the transportation and sales volumes of natural gas to affiliated LDCs account for 100% of total annual volumes.[167] The Commission declines to add these exemptions. The length of a pipeline and the relationship between pipeline and purchaser are irrelevant to the volumetric approach which Congress indicated that the Commission should adopt.

(b) Under section 7(f) of the NGA, a natural gas pipeline may enlarge or extend its facilities to satisfy increased market demands without prior Commission authorization. Six regulated pipelines, not already included in Parts IV A 1(a) and 1(b) above, currently have section 7(f) declarations. These are natural gas companies under the NGA that perform a distribution function across state lines. For example, under section 7(f) of the NGA, Washington Gas Light Company (which serves the Washington, DC, metropolitan area in Virginia, Maryland and the District of Columbia) can change its facilities and services for the purpose of supplying market demand in its service area without prior Commission authorization.

If the Commission assessed annual charges using the latest data, it would exempt two of these pipelines because they have not sold and transported more than 200,000 Mcf annually for any of the last three calendar years. Under the

[159] 15 U.S.C. 717b (1982).

[160] Persons required to file for authority to import or export natural gas under section 3 of the NGA may or may not be natural gas companies within the meaning of the Natural Gas Act. Natural gas company status is determined by whether a person transports or sells gas subject to section 7 requirements. Under the Department of Energy Organization Act and the Secretary of Energy's Delegation Orders Nos. 0204–111 (49 FR 6684, 6690 (Feb. 22, 1984), 5 Fed. Energy Guidelines (CCH) ¶ 70,033, I FERC Statutes & Regulations ¶ 9912) and 0204–112 (49 FR 6684, 6690–6691 (Feb. 22, 1984), 5 Fed. Energy Guidelines (CCH) ¶ 70,034, I FERC Statutes & Regulations ¶ 9913), the primary jurisdiction under section 3 lies with Department of Energy's Economic Regulatory Administration (ERA). The Commission has the authority only to approve or disapprove the siting and construction of new facilities, and to issue Presidential Permits under Executive Order No. 10,485 for facilities on an international boundary. 3 CFR Part 970 (1949–1953 compilation), 18 FR 5397 (Sept. 9, 1953), *reprinted in* 15 U.S.C. 717b note (1982), *amended by* 3 CFR Part 136 (1979), 43 FR 4957 (Feb. 7, 1978), *reprinted in* 42 U.S.C. 7151 note (1982). Because of this joint authority for section 3 filings and the fact that import authority can be authorized by ERA without the necessity for a filing with the Commission, the Commission will not assess annual charges against companies which fall under the Commission's jurisdiction solely due to section 3 of the NGA and the filing requirements of Part 153 of the Commission's regulations. 18 CFR Part 153 (1986). Based on the latest data, there are currently twelve such companies. No commenters addressed the exclusion of this category of company.

[161] 42 U.S.C. 7101–7352 (1982).

[162] DOE Delegation Order No. 0204–112, 49 FR 6684 (Feb. 22, 1984), 5 Fed. Energy Guidelines (CCH) ¶ 70,034, I FERC Statutes & Regulations ¶ 9913.

[163] Comments of Pacific Gas Transmission Co. at 6; *cf.* Comments of New England Power Co. at 12–16 (advocating minimum annual charges for electric utilities).

[164] This estimated annual charge figure is calculated by multiplying 200,000 Mcf by $.0017539 per Mcf. This latter number is obtained by dividing the annual cost of the natural gas program less filing fees in fiscal year 1986 ($37,625,798) by the total sales and transportation volumes of jurisdictional gas reported for calendar year 1985 (21,464,897 MMcf).

[165] This $4,563, when allocated among the 131 assessed pipelines, increases the average annual charge bill by only $34.83, or 0.01 percent.

[166] Comments of Lawrenceburg Gas Transmission Corp. at 8; *cf.* Comments of Raton Gas Transmission Co. at 1–2 (arguing (like Lawrenceburg) that the proposed rule unfairly assesses short pipelines the same charge per Mcf as long pipelines, but recommending that this problem be avoided by changing the basis of the assessment from Mcf to operating revenues.) Lawrenceburg's Comments at 3–5 makes a similar proposal to change the basis to Mcf-miles. These are discussed below in Part IV B 5.

[167] Comments of Lawrenceburg Gas Transmission Corp. at 5.

proposed rule set forth in the NOPR, the remaining four pipelines would be required to pay an annual charge.

All three comments addressing this category oppose the assessment of annual charges against section 7(f) LDCs in general and against Washington Gas Light Company and Shenandoah Gas Company in particular.[168] Commenters argue that such assessment results in double counting because the gas is assessed when in the pipeline's possession and again when in the LDC's possession,[169] that the Commission's oversight of section 7(f) LDC's is *de minimis*,[170] that inclusion of such LDCs is inequitable when the Commission is at the same time excluding from annual charges the producers and intrastate pipelines both of which types of company cost the Commission far more in regulatory expense than do the two LDCs (Washington Gas Light and Shenandoah Gas),[171] and that the section 7(f) LDCs can only recover annual charges in rate proceedings before state public utility commissions, resulting in a delay in recovery which would place them at a disadvantage as compared to other LDCs.[172] The Commission agrees that the degree of regulation over section 7(f) LDCs is so minimal that assessment of annual charges would be inappropriate. The Commission therefore will exempt all section 7(f) LDCs from paying annual charges.[173]

(c) Iowa-Illinois Gas & Electric Company requests that the Commission exempt three more groups of companies: (1) Any company or portion thereof for which the company has been issued a declaration of exemption ("Hinshaw exemption") from the provisions of the NGA; (2) any company making no sales for resale; and (3) any company fully regulated by state regulatory agencies.[174] The first group will not be assessed annual charges based on any nonjurisdictional gas. According to Iowa-Illinois, the filing fees paid by the second group reimburse the Commission for the expenses which the Commission incurs in regulating such companies. Nevertheless, this group is subject to the Commission's gas transportation rate jurisdiction even though not subject to its sales rate jurisdiction,[175] does cause the Commission to incur expenses (exceeding IOAA fee receipts) in regulating the group's numbers,[176] and will therefore be assessed annual charges. The third group is not regulated by the Commission, was not included as an assessed category in the NOPR, and will not be assessed annual charges.

(d) Finally, Connecticut Natural Gas Corporation seeks confirmation that the Commission does not intend to assess annual charges against companies holding limited jurisdiction certificates.[177] The Commission has no such intention, as evidenced by the fact that no companies with only limited jurisdiction certificates appeared on the NOPR's list of prospective companies to be assessed.

B. Overview of the Annual Charges Formula

In keeping with the Conference Report,[178] the Commission proposed to assess annual charges based on the pipelines' annual sales and transportation volumes. The Commission believes that the most representative sales and transportation volumes can be found in FERC Form No. 2 from the sum of Line 42, *Total Sales* Line 46, *Total, Gas Transported or Compressed for Others*, Line 50, *Natural Gas Delivered to Underground Storage*, and Line 51, *Natural Gas Delivered to LNG Storage*, page 521 (Line 11 plus applicable transportation volumes in Lines 13–15, Page 18 of Form No. 2–A). For importers, FERC Form No. 14, Line 13 of Schedule I, Natural Gas, and Line 13 of Schedule II, LNG, provide this information. As noted above, within fifteen calendar days, pipelines should notify the Commission of any volumes which were not subject to Commission regulation but which were nevertheless included on these lines.

In the NOPR, the Commission proposed to apportion its gas program costs among the assessed natural gas pipeline companies based upon the relationship of each company's total sales and transportation volume subject to Commission's regulation to the total sales and transportation volume subject to Commission regulation of all natural gas pipeline companies being assessed annual charges. Specifically, the Commission proposed to:

(1) Subtract all producer and pipeline filing fee collections from total gas program costs, to yield collectible gas program costs.

(2) Divide collectible gas program costs by the amount of jurisdictional gas sold and transported by all billable gas pipelines,[179] to yield the charge per Mcf.

(3) Multiply the charge per Mcf by the amount of jurisdictional gas sold and transported by each individual gas pipeline, to yield each individual pipeline's annual charge.

Commenters suggest numerous modifications to the proposed formula for calculating gas pipelines' annual charges. Several commenters suggest that the annual charges be based on Mcf-miles (to take into account the difference in size and capital investment of companies),[180] miles of pipelines (to provide a more equitable basis for annual charges),[181] operating revenue (to take into account the differences in size of various companies),[182] the value of the company's certificated facilities (to prevent unusually heavy assessments against companies which are small or do not impose significant regulatory burdens on the Commission),[183] and a two-year or three-year rolling average of sales and transportation volumes (to allow for the possibility of abnormal weather conditions which may alter pipelines' gas loads from year to year).[184] The Commission lacks the data necessary to base an assessment on Mcf-miles, and believes that such an approach would be extremely difficult to administer. Also, the Commission does not believe that the pipeline-miles and facility-value approaches are consistent with the Congressional guidance to assess annual charges on a volumetric basis.

[168] Comments of Washington Gas Light Co. and Shenandoah Gas Co. at 7–10; D.C. Public Service Comm'n at 2, 5 and 6; State Corporation Comm'n of Virginia at 2.

[169] Comments of Washington Gas Light Co. at 8; D.C. Public Service Comm'n at 5; State Corporation Comm'n of Virginia at 2.

[170] Comments of Washington Gas Light Co. at 7; D.C. Public Service Comm'n at 6.

[171] Comments of Washington Gas Light Co. at 9–10; D.C. Public Service Comm'n at 6.

[172] Comments of Washington Gas Light Co. at 10.

[173] Pursuant to our decision in *Iowa-Illinois Gas and Electric Co.*, Docket No. CP86–688–000, 39 FERC ¶ 61,016 at 61,043 (April 3, 1987), we include Iowa-Illinois Gas and Electric Company in this exemption.

[174] Comments of Iowa-Illinois Gas & Electric Co. at 2–3.

[175] *See* Panhandle Eastern Pipe Line Co. v. Public Service Comm'n, 332 U.S. 507, 516 (1947).

[176] IOAA fees in fiscal year 1986 recouped only $5,944,629 of the Commission's $14,575,000 in expenses for the pipeline certificate program.

[177] Comments of Connecticut Natural Gas Corp. at 4–7; *see also* Comments of National Fuel Gas Distribution Corp. at 3–4.

[178] Conference Report at 239, 1986 U.S. Code Cong. & Ad. News at 3884.

[179] If a company does not timely provide the Mcf data, the Commission will calculate the company's annual charge based upon the Commission's estimate of the Mcf amount using other data provided on Form Nos. 2, 2A, or 14 by the company in that year or, if necessary, in a prior year.

[180] Comments of Texaco USA at 2; West Texas Gas, Inc. at 4; Lawrenceburg Gas Transmission Corp. at 4; Raton Gas Transmission Co. at 1–2.

[181] Comments of Texaco USA at 2.

[182] Comments of Raton Gas Transmission Co. at 2; West Texas Gas, Inc. at 4.

[183] Comments of West Texas Gas, Inc. at 4; Iowa State Utilities Board at 4.

[184] Comments of Pacific Gas Electric Co. at 9.

While the operating revenue approach comes closer to the Congressional guidance and is in fact the approach the Commission is using to assess oil pipelines, the strictly volumetric basis for calculating charges more closely conforms to Congressional guidance. Moreover, the unusual equitable consideration present in the oil industry which justifies the Commission's use of operating revenue, *i.e.*, that certain small companies would otherwise be assessed grossly disproportionate annual charges, simply does not exist in the gas industry.[185]

The Commission sees no need to use two or three years of data in computing annual charges. Using the most recent year's figures will provide a more up-to-date picture of a company's fair share of the Commission's expenses. Moreover, using a multi-year data approach could result in the Commission assessing companies no longer within its jurisdiction (such as pipelines which sell their jurisdictional facilities or companies all of whose certificated pipelines qualify for Hinshaw exemptions), a result clearly at odds with Congressional intent that the Commission base its annual charge assessments on the volumes of regulated gas.[186]

Two pipelines purchasing almost all of their gas from Canada argue that they should not be required to pay any share of the Commission's expense to regulate domestic producers, and that such a payment would constitute a subsidy by Canadian producers to domestic producers.[187] This argument fails to recognize that, unlike IOAA fees, the annual charges under the Budget Act need not be based on the benefit accorded the regulated entity.

One common objection to the annual charges formula concerns the potential for multiple assessment against a given volume of gas. Commenters argue that gas sold and transported by one interstate pipeline to another would be subject to multiple annual charge assessments. They also argue that this would place pipelines which buy gas from other pipelines at a disadvantage when competing against producers or brokers who pay no annual charges or against interstate pipelines which buy gas which has not previously been transported through another company's interstate pipeline,[188] and that this situation could impede the free movement of gas in a competitive environment.[189] Another common objection concerns the cost passthrough mechanism proposed in the NOPR (inclusion of annual charges in Account No. 928). Commenters argue that under the proposed mechanism the pipelines might not recover all of their annual charges [190] and might not be able to recoup even the recoverable charges in a timely manner.[191]

Commenters present a number of solutions to these two common objections. The most frequently recommended solution is for the Commission to adopt a tracking mechanism such as the one that the Gas Research Institute (GRI) uses to recover its Commission-approved budget. Under such a mechanism, annual charges would be assessed against gas only when it leaves the Commission's jurisdiction. The assessed pipelines would recover the annual charges through a per-Mcf surcharge automatically included in the pipeline's sales and transportation rates, and would transfer the annual charge collections to the Commission each month.[192] The companies point out that the House Budget Report indicated that no volumes should be counted twice and alluded specifically to the GRI tracking mechanism:

> It is intended that pipeline-to-pipeline sales or deliveries not be included in the calculation of volumes. In this way, no volumes will be counted twice. Many of the pipelines are familiar with identifying those volumes which should not be counted (to avoid double counting), because they perform this identificati[o]n in determining the volumes which are assessed the funding unit for the Gas Research Institute.
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> The Committee's only intent is that each unit of gas that is transported through the interstate pipeline (with adjustments to assure no double imposition of charges) bear the same charges. . . .[193]

The commenters enumerate many advantages to a GRI-type tracking mechanism, *e.g.*, that it would avoid multiple-billing of gas,[194] would avoid the risk of underrecovery in rate case settlements,[195] would avoid the incurrence of carrying costs [196] and other (presumably administrative) costs associated with annual charges,[197] would be similar to a methodology already well-understood by the industry,[198] would keep the annual charges out of a company's gross receipts, thereby precluding the company being taxed on such receipts in certain jurisdictions,[199] would be simple for the Commission to administer [200] and monitor on an ongoing basis,[201] would be inexpensive to administer,[202] would enhance the flow of funds to the United States Treasury,[203] would

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[185] *See* Part V B below. Similarly, the justification for imposing a maximum assessment on oil pipelines (one pipeline system yielding 40 percent of the industry's revenue) does not exist in the gas industry. Therefore, we decline in the gas program to adopt the suggestion by the Iowa State Utilities Board at 4 to impose such a ceiling on annual charges.

[186] Conference Report at 239, 1986 U.S. Code Cong. & Ad. News at 3884.

[187] Comments of Pacific Gas Transmission Co. at 6–7; Pacific Gas & Electric Co at 8–9.

[188] Comments of ANR Pipe Line Co. at 3–4; Columbia Gas Transmission Corp. at 3; Enron at 5–6; Public Service Electric and Gas Co. at 2; Consolidated Gas Transmission Corp. at 4; Northwest Alaskan Pipeline Co. at 4; Washington Gas Light Co. at 4–5; D.C. Public Service Comm'n at 3–4; *cf.* Raton Gas Transmission Co. at 3–4 (noting that gas travelling through the pipelines of two affiliated companies would be subject to two assessments but the same amount of gas travelling through the same two pipelines would be assessed only once if the two affiliates merged).

[189] Comments of Northwest Alaskan Pipeline Co. at 6.

[190] Comments of INGAA at 13; ANR Pipe Line Co. at 4–5.

[191] Comments of Consolidated Gas Transmission Corp. at 7–9; Enron at 3–4; Texas Eastern Transmission Corp. at 5–6.

[192] Comments of Columbia Gas Transmission Corp. at 3–5; Consolidated Gas Transmission Corp. at 5 and 7–9; Enron at 3–5; Washington Gas Light Co. at 4–5; ANR Pipe Line Co. at 3–5; Northwest Alaskan Pipeline Co. at 6–8; Northwest Pipeline Corp. at 5–7; INGAA at 11–13; Texas Eastern Transmission Corp. at 6.

Two other commenters recommend that the Commission adopt a similar tracking mechanism by permitting the pipelines to include their annual charges in their purchased gas adjustments. Comments of Cincinnati Gas & Electric Co. at 12; Lawrenceburg Gas Transmission Corp. at 9. Two other commenters generally support direct billing of the end-user. Comments of Williams Natural Gas Co. at 8; Granite State Gas Transmission, Inc. at 2. Finally, a commenter recommends that pipelines bill end-users for 50 percent of the annual charges and absorb the other 50 percent. Comments of Texaco USA at 2–3.

[193] House Budget Report at 54, 1986 U.S. Code Cong. & Ad. News at 3650, *quoted in* Comments of Washington Gas Light Co. at 4–5 and in Comments of D.C. Public Service Comm'n at 4.

[194] Comments of Northwest Alaskan Pipeline Co. at 6; Northwest Pipeline Corp. at 10; INGAA at 12; Texas Eastern Transmission Corp. at 10.

[195] Comments of Northwest Alaskan Pipeline Co. at 6; Northwest Pipeline Corp. at 5; ANR Pipe Line Co. at 4–5; Consolidated Gas Transmission Corp at 7; Texas Eastern Transmission Corp. at 10.

[196] Comments of Columbia Gas Transmission Corp. at 4–5; Northwest Alaskan Pipeline Co. at 6; Northwest Pipeline Corp. at 5; Enron at 3–4.

[197] Comments of Columbia Gas Transmission Corp. at 4–5.

[198] Comments of Northwest Alaskan Pipeline Co. at 6.

[199] Comments of Texas Eastern Transmission Corp. at 11; INGAA at 12–13.

[200] Comments of Northwest Alaskan Pipeline Co. at 6; Enron at 5–6; Texas Eastern Transmission Corp. at 10–11; INGAA at 12.

[201] Comments of Northwest Alaskan Pipeline Co. at 6.

[202] *Id.* at 7; Northwest Pipeline Corp. at 6.

[203] Comments of Northwest Alaskan Pipeline Co. at 6; Northwest Pipeline Corp. at 5

increase the likelihood of full recovery from program beneficiaries,[204] would spread the charges uniformly [205] over the broadest base of consumers,[206] would avoid an increase in rate filings,[207] and would inform consumers of what share of their gas bill is attributable to the Commission's annual charge.[208]

Commenters also suggest that, if the Commission is unwilling to adopt a tracking mechanism such as used to collect GRI's budget, the Commission should, at the very least, guarantee that the companies will recover these annual charges (along with associated carrying costs) in their rate cases.[209]

The Commission declines to adopt any of the suggestions regarding multiple assessment. While the House Budget Report may be said to prohibit double counting, the Conference Report does not prohibit it. That report indicates Congress' intent that the Commission base its annual charges computations on the "amount of energy . . . transported or sold . . . by *such* person" compared with "the total volume of all energy transported or sold . . . by all similarly situated persons." [210] Because the same gas is frequently transported or sold by several pipelines before leaving the Commission's jurisdiction, a failure to assess every such pipeline would directly contravene Congressional intent that the Commission consider the amount of energy transported or sold by each "such person." Multiple assessment of gas is thus inherent in the approach specified in the Conference Report. The Commission therefore concludes that the assessment methodology it is adopting is consistent with Congressional intent.

Although, as a matter of policy, the Commission generally does not favor use of tracking mechanisms,[211] it has approved such mechanisms in unusual circumstances. The purchased gas adjustment (and the Fuel Adjustment Clause in the electric regulation [212]) were necessitated by rapid increases in gas costs.[213] The GRI tracking mechanism was approved in order to provide gas pipelines an incentive to support voluntarily GRI's research, development and demonstration budget.[214] The Commission's regulations applicable to gas pipelines also permit shippers on the Alaska Natural Gas Transportation System (ANGTS) to pass through transportation costs,[215] due to the unprecedented scale and cost of ANGTS and its unique international character and legal framework.[216]

The Commission concludes that, due to the fact that the annual charges will reduce the net income (before preferred dividends) of the gas pipeline industry by 2.5 percent,[217] the pipelines should be permitted to pass through the charges directly to their customers. While the Commission will establish a tracking mechanism to accomplish this, the mechanism (described below) will not be based upon the GRI mechanism recommended by many of the commenters. (The Commission is not establishing a tracking mechanism for the electric and oil industries because their net income would be reduced only 0.16 percent [218] and 0.53 percent [219] respectively.)

The Commission will therefore amend 18 CFR 154.38 to provide natural gas pipelines the option of passing along the annual charges to their customers through an annual charges adjustment clause (ACA clause) that the pipelines may include in their FERC Gas Tariffs. Alternatively (and as proposed in the NOPR), the pipelines may include their annual charge expenses in Account No. 928 (Regulatory commission expenses) for consideration in their general rate filings made pursuant to 18 CFR 154.63 of the Commission's regulations.

Natural gas pipelines choosing the ACA clause option will be required to include in each of the sales and transportation schedules of their tariffs the unit rate used to determine the annual charge assessment for the previous fiscal year (adjusted as appropriate to a thermal basis, different pressure base, *etc.*) The Commission will give notice of this unit rate each year at the time it calculates the annual charges. Pipelines electing the ACA clause option will then be required to file tariff sheets reflecting the new annual charge unit rate, to be effective on the first day of the next fiscal year. However, only those pipelines the annual charges of which are not in arrears will be permitted to collect the fiscal year's unit rate through ACA clauses.

The ACA clause will authorize the pipeline to collect a per unit surcharge, applicable to each sales and transportation unit delivered by the pipeline. (The surcharge is not applicable to exchange units because annual charge assessments are not based on such units.) While an ACA clause will give pipelines the ability to include the Commission's annual charge unit surcharges in their rates without filing a general rate case to reflect such costs, recovery of the annual charge expenses will lag behind the pipelines' payment of annual charges because annual charges will be assessed and paid near the end of one fiscal year but recouped in rates during the subsequent fiscal year.

Due to the difference between the throughput used to calculate the annual charges and the throughput assessed the per unit surcharge, a pipeline may overrecover or underrecover its prior year's annual charge expenses in any fiscal year. Such disparities will be generally offset during the following year because that year's annual charge assessment will be based on the same

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[204] Comments of Northwest Pipeline Corp. at 10; INGAA at 12; Texas Eastern Transmission Corp. at 10.

[205] Comments of Northwest Alaskan Pipeline Co. at 6; Northwest Pipeline Corp. at 5.

[206] Comments of Texas Eastern Transmission Corp. at 10; INGAA at 12.

[207] Comments of Texas Eastern Transmission Corp. at 11.

[208] Comments of Northwest Pipeline Corp. at 10.

[209] Comments of Columbia Gas Transmission Corp. at 4–5; Texas Eastern Transmission Corp. at 13; INGAA at 13; ANR Pipe Line Co. at 4–5. *See also* producer comments of Cities Service Oil & Gas Co. at 3–4; Independent Petroleum Ass'n of America at 3; Natural Gas Supply Ass'n at 3–4 (supporting guaranteed passthrough in order to preclude pipelines from shifting the annual charges burden to the producers through net-back provisions).

[210] Conference Report at 239, 1986 U.S. Code Cong. & Ad. News at 3884 (emphasis added).

[211] *See* 18 CFR 154.38(d)(3) (1986).

[212] 18 CFR 35.14 (1986).

[213] 18 CFR 154.38(d)(4) (1986).

[214] 18 CFR 154.38(d)(5) (1986).

[215] 18 CFR 154.201–154.213 (1986).

[216] Order No. 320, 48 FR 34,442 (July 29, 1983) and 49,656 (October 27, 1983), FERC Statutes & Regulations (Regulations Preambles 1982–1985) ¶ 30,475 at 30,573.

[217] The Commission arrives at this percentage by dividing the estimated annual charge receipts from the natural gas pipelines ($37,625,798) by 86 percent of the industry's most recent (FY 1986) net income before preferred dividends ($1,512,740,000). The estimated annual charge figure is derived by subtracting the actual 1986 fee receipts ($11,914,202) from the actual 1986 gas pipeline regulatory costs ($49,540,000). The 86-percent figure represents the proportion of the pipelines' net income attributable to gas over which the Commission has jurisdiction.

[218] The Commission arrives at this percentage by dividing the estimated annual charge receipts from electric companies ($19,650,145) by 20 percent of the industry's FY 1985 net income before preferred dividends ($3,740,983,000). The estimated annual charge figure is derived by subtracting the actual 1986 fee receipts ($2,403,855) from the actual 1986 electric regulatory costs ($22,054,000). The 20-percent figure represents the proportion of the electric industry's net income attributable to sales over which the Commission has jurisdiction.

[219] The Commission arrives at this percentage by dividing the estimated annual charge receipts from oil pipelines ($3,944,000) by the industry's 1985 net income ($2,430,845,000). Because the Commission refunded more fees than it received in 1985, the Commission uses a $0 estimation of its filing fee receipts for this calculation and therefore does not reduce the actual 1985 oil pipeline regulatory costs by any estimated filing fee receipts.

throughput data on which the prior year's per unit surcharge was based.

The Commission will permit pipelines to change methods of annual charges cost recovery. However, once a pipeline chooses one method, it can change to the other method only in the context of a general rate change filing under 18 CFR 154.63. A company may not operate under both options at the same time.

C. Other Matters

Under §§ 381.107 and 381.206 of its regulations,[220] the Commission annually bills the Gas Research Institute (GRI) for processing its research, demonstration and development budget.[221] In the NOPR, the Commission proposed to continue billing GRI, with the amounts collected from GRI to be subtracted from the overall costs of the natural gas program. No commenter objects to this approach and the Commission adopts it as proposed.

V. Cost Basis for the Oil Pipeline Regulatory Program

A. The Types of Companies To Be Billed

In the NOPR, the Commission proposed to assess annual charges against all oil pipelines required to file an Annual Report FERC Form No. 6 with the Commission pursuant to section 20 of the Interstate Commerce Act (ICA) [222] and § 357.2 of the Commission's regulations.[223] The Commission did not propose to exempt any oil pipelines from the payment of annual charges. Instead, the Oil Pipeline Board would be authorized to rule on petitions for waiver of the annual charges, and would grant waivers to those companies which meet the standards currently applicable to fees.[224]

Only one commenter addresses the issue of the types of companies to be billed. Phillips Pipeline Company suggests that the Commission exempt any oil pipeline company which transports less than 100,000 barrel-miles of oil per year for each of the last three years.[225] Phillips in essence urges the Commission to establish an oil pipeline exemption similar to that proposed for small gas pipelines. However, the Commission proposed to exempt gas pipelines with throughputs not exceeding 200,000 Mcf for each of the three years immediately preceding the billing year in large part because the Commission lacks the data necessary to compute such companies' annual charges on a volumetric basis.[226] That problem does not exist regarding oil pipelines. Moreover, no jurisdictional pipeline has transported less than 100,000 barrel-miles for *any* of the last three years, much less *all* three years. The Commission therefore rejects Phillips' argument.

B. Overview of the Annual Charges Formula

The Commission has decided to apportion its oil program costs among the oil pipelines based on the ratio of each company's operating revenue to all companies' operating revenue. In the NOPR, the Commission noted that each oil pipeline reports to the Commission in its Annual Report FERC Form No. 6 the amount of barrels delivered, barrel-miles transported,[227] and operating revenue received each year. The Commission is not apportioning the program's expenses based on the number of barrels delivered by the pipelines, even though such an approach would be most closely in accord with the volumetric approaches used to compute annual charges for natural gas pipelines and electric utilities. Such an approach would result in disproportionately high annual charges assessed against companies with short pipelines because it would not take into account the distance which the pipelines transported the delivered oil. A company moving a specific volume of oil one mile through a short pipeline would be assessed the same annual charge as another company moving the same volume of oil 100 miles through a longer pipeline. The Commission therefore concludes that, in the oil pipeline industry, the appointment of annual charges based on barrels delivered would result in inequitable assessments of annual charges.

The Commission also is not apportioning the program's expenses based on the number of barrel-miles transported. In its Form No. 6 (Line 33a of page 600), each company currently provides the Commission with the number of trunkline barrel-miles. However, Form No. 6 currently does not require reporting of gathering-line barrel-miles.[228] The Commission's data for calculating annual charges based upon barrel-miles would thus be incomplete unless the Commission imposed additional filing requirements on the oil pipelines, a step which the Commission is reluctant to take given that most pipelines do not currently have in place a mechanism for determining gathering-line barrel-miles. Moreover, the assessment of annual charges based on trunkline barrel-miles would lead to an inequitable assessment of annual charges.[229]

Given the problems with assessing annual charges based on either barrels-delivered or barrel-miles, the Commission has decided to apportion costs among oil pipelines based on each company's operating revenues. While not strictly a volumetric approach, this methodology is nevertheless consistent with the Conference Report which provides that the annual charges should be assessed on the basis of "annual sales or volumes transported" [230] because annual operating revenues are directly related to the annual transportation services which generate those revenues.

Two commenters argue that, regardless of which method is adopted, the Commission should establish minimum and maximum annual charges for oil pipelines.[231] The suggested ranges for annual charges are $5,000 to $250,000 [232] and $1,000 to $250,000.[233] A

[220] 18 CFR 381.107 and 381.206 (1986).

[221] *See generally* Gas Research Institute, 36 FERC ¶ 61,395 (1986).

[222] 49 U.S.C. 20 (1976).

[223] 18 CFR 357.2 (1986). Based on FY 1986 data, the Commission expects to collect $3,944,000 in filing fees and annual charges from oil pipelines in 1987. The 137 oil pipelines which the Commission currently regulates are listed in Appendix E.

[224] *See supra* Part III A 5.

[225] Comments of Phillips Pipeline Co. at 3–4.

[226] See *supra* Part IV A 2(a).

[227] A barrel-mile is one barrel of oil or petroleum product moving one mile. Oil pipelines do not own the commodity they transport, but provide only a transportation service.

[228] Unlike gathering-line gas, gathering-line oil is subject to the Commission's transportation jurisdiction.

[229] The incomplete data regarding barrel-miles would cause an inequitable distribution of annual charges between companies with and without gathering lines. The most recently compiled mileage figures which include gathering miles (not to be confused with barrel-mile data, which is not available) show that gathering lines make up approximately 20 percent of all oil pipeline mileage. Even though the volumes through these lines are generally small compared with those of trunklines, the impact of excluding gathering barrel-miles from the annual charge computation would yield inequitable results. The mileage figures also indicate that five companies which own only gathering lines would be exempted from paying any annual charges at all (Clarco Pipeline Company, Ohio Oil Gathering Corporation II, National Transit Company, White Shoal Pipeline Corporation, and Crown-Rancho Pipe Line Corporation).

[230] Conference Report at 239, 1986 U.S. Code Cong. & Ad. News at 3884.

[231] Comments of Sohio Alaska Pipeline Co. at 4–5; ARCO Pipeline Co. at 2; *see also* Comments of Iowa State Utilities Board at 4 (generally suggesting a maximum annual charge but not recommending a specific figure).

[232] Comments of Sohio Alaska Pipeline Co. at 1–2.

[233] Comments of ARCO Pipeline Co. at 2.

third company suggests a minimum charge of $20,000.[234] Two companies argue that, without such a ceiling, the owners of the Trans-Alaska Pipeline System (TAPS) will be required to pay 40 percent of the Commission's oil program expenses.[235] One of these companies points out that such a payment is grossly disproportionate, especially given the minimal attention the Commission will need to devote to TAPS as a result of the settlement resolving all interstate TAPS rate case issues and establishing a methodology for determining maximum tariffs through the year 2011.[236]

The Commission sees no need to establish a minimum charge. The $1,000 proposed minimum charge would affect adversely 22 small companies and would reduce each of the other pipeline's bills by a maximum of only $191.[237] Given this *de minimis* effect, the Commission declines to impose a minimum charge. However, the Commission agrees with the commenters' recommendation to establish a maximum charge of $250,000 in order to avoid assessing disproportionate annual charges on the TAPS owners. The amount of undercollection which could be caused by the use of a maximum charge will be recovered by adding proportionate shares of the undercollection to the annual charges of the companies with annual charges less than the maximum. This reapportioning will result in charges that more accurately reflect the Commission's per company burden. Finally, the Commission will adjust annually this maximum figure by raising or lowering it in proportion to the increase or decrease in the oil program budget.[238]

This adjusted figure will be rounded to the nearest $1,000.[239]

Several commenters oppose the operating revenue methodology proposed in the NOPR. Champlin Petroleum Company argues that the proposed method is unfair because a new pipeline would pay no charges during its first year due to the absence of any base period.[240] Champlin also contends that, under the methodology proposed in the NOPR, a newer pipeline would pay a higher portion of the total costs because its rate of return would be based on a more expensive capital base.[241] While this first result may seem inequitable, the Commission notes that, under all three methods, a new pipeline would pay no annual charges during its first fiscal year. Moreover, as discussed above, the operating revenue method is less inequitable than the barrels-delivered or the barrel-miles methods. Concerning the second argument, the Commission sees no inequity in a company with greater revenue paying a greater portion of the Commission's regulatory expenses.

Champlin further contends that the proposed method would penalize rate-filers, because a company that increases its tariffs (and thus its revenues) will pay a proportionately higher annual charge the following year than the company that ignores cost passthrough.[242] The Commission does not believe that a company would decline to seek to raise its rates because it would have to pay a small percentage (currently approximating less than 0.1 percent) of that rate increase to the Commission the following year.

Phillips Pipeline Company contends that the smaller pipelines would be required to subsidize the larger pipelines. According to Phillips, larger pipelines tend to file more often with the Commission because they have more origin and destination points, and the Commission therefore incurs more expense servicing such pipelines.[243] However, the company supports this argument with no data. The Commission also notes that filings involving origin and destination points are seldom contested and therefore involve very little regulatory expense. Finally, this argument ignores the fact that Congress has told the Commission to base its allocation of annual charges on some volumetric standard (or its equivalent), not on the cost to the Commission.

Phillips also argues that the proposed method penalizes short-haul pipelines which "may well" have more revenues for fewer barrel-miles traveled.[244] Phillips' argument is admittedly hypothetical and the company supports it with no data.

Sohio Alaska Pipeline Company contends that low-revenue oil pipelines (such as Williams Pipe Line Company) can draw enormously on the Commission's resources.[245] While Sohio is correct, it is also true that high-revenue oil pipelines can do the same.

Finally, Williams Pipe Line Company opposes the operating revenue methodology on the ground that the level of pipelines' revenues is unrelated to the level of regulatory oversight required.[246] This is true, as noted just above. However, to the extent that the proposed methodology would impose an inequity on larger pipelines, the maximum annual charge should afford them some protection. To the extent that it works an inequity on smaller oil pipelines, the Commission believes that such an inequity is outweighed by other inequities previously noted which would result from the barrels-transported and barrel-mile methods.

A number of companies also suggest modifications to the operating revenue methodology. Two commenters suggest that the Commission should limit the revenue base to the operating revenue from Commission-regulated tariffs, *i.e.*, only the revenue reported in Account Nos. 200, 210, and 220.[247] The Commission agrees.[248] The revenue

[234] Comments of Williams Pipe Line Co. at 3.

[235] Comments of ARCO Pipeline Co. at 1–2; Exxon Pipeline Co. at 2.

[236] Comments of Exxon Pipeline Co. at 2. While this is Exxon's characterization of the Commission's future burden related to TAPS rates, a recent Commission order approving a two-owner TAPS settlement stated that nonparties to the settlement "may file at any time in the future for an adjudicated rate." Trans-Alaska Pipeline System, 35 FERC ¶ 61,425 at 61,982 (1986).

[237] This maximum estimated difference is calculated as follows. Assuming that the 22 small pipelines would otherwise pay no annual charges, the minimum charge of $1000 would reduce the collective annual charges of the remaining 115 oil pipelines by $22,000 (22×$1000), or $191 per pipeline ($22,000÷115).

[238] This maximum figure is currently 6.339 percent of the estimated costs of administering the oil regulatory program ($250,000÷$3,944,000).

[239] The Commission believes the unique nature of the oil pipeline industry justifies treating its annual charges differently from those of the gas and electric industries. Neither of those industries receives nearly half its operating revenue from a single energy transportation system such as TAPS. Moreover, as noted in the Comments of Sohio Alaska Pipeline Co. at 3, "whether the barrels-delivered, barrel-miles or revenue approach is employed, inequities are present." The imposition of a maximum charge at least reduces these inequities. Finally, the Commission notes that it does not currently spend more than $250,000 regulating any single oil pipeline.

This decision to establish a maximum charge renders moot two arguments by Exxon Pipeline Company. Comments of Exxon Pipeline Co. at 2 (contending that, under the proposed method, TAPS and other frontier pipelines would pay more than their fair share simply because their operating revenue was higher due to the cost of service requirements associated with their massive investment and operating costs); and 4 (suggesting that the Commission weight-average several measures of company activity (such as number of barrels transported and number of pipelines owned) in order to avoid overcharging TAPS owners).

[240] Comments of Champlin Petroleum Co. at 2.

[241] Comments of Champlin Petroleum Co. at 2; *see also* Comments of Sohio Alaska Pipeline Co. at 3 and 5 (arguing that the proposed method penalizes large-diameter pipelines because of their greater revenue).

[242] Comments of Champlin Petroleum Co. at 2.

[243] Comments of Phillips Pipe Line Co. at 2.

[244] *Id.*

[245] Comments of Sohio Alaska Pipeline Co. at 3.

[246] Comments of Williams Pipe Line Co. at 2.

[247] Comments of ARCO Pipe Line Co. at 1–2; American Petrofina Pipe Line Co. at 1–2.

[248] Because of this decision, the Commission concludes that it is unnecessary to address the suggested modification of Williams Pipe Line Co. at 3, to reduce the operating revenue figure by the

Continued

assigned to other accounts is not directly related to the transportation tariffs regulated by the Commission, *i.e.*, while related to the transportation of oil, the services which result in such revenue are not required by such transportation. Account No. 230 includes only "allowance oil" revenues from the sale of oil collected for use as replacement oil in the event of an oil loss. Account No. 240 includes only demurrage and storage revenues. Demurrage charges are in essence a fee for late delivery or late receipt of oil. Storage revenue derives from fees assessed to store excess oil. Moreover, the Commission does not have complete storage volume data. Some storage facilities are owned by pipelines (*e.g.*, Williams Pipe Line Company) which report storage volumes to the Commission, while other storage facilities are owned by pipelines' affiliates (*e.g.*, affiliates of Chase Transportation Company) which do not report storage volumes to the Commission. Account No. 250 includes only rental revenues, *i.e.*, funds received by a pipeline company renting a pipeline to another company. (Any transportation revenues from such a rented pipeline would appear on the renter's Form No. 6.) Finally, Account No. 260 includes incidental revenues not directly related to the transportation of oil.

Three pipelines express a preference for the barrel-mile method.[249] Phillips Pipe Line Company contends that the Commission could obtain barrel-mile information from the Association of Oil Pipelines and thereby avoid imposing any new filing requirements on oil pipeline companies.[250] However, Phillips has not indicated that its trade association has data on gathering-line volumes, the only data the Commission does not already have for use in the barrel-mile method. Even if the association does have and is willing to provide such information,[251] the data would still not be certified as correct by the gathering-line company and could not be directly audited by the Commission.

Williams Pipe Line Company contends that the barrel-miles method is the most reliable indicator of pipelines' levels of business activity and regulatory exposure, that the barrel-miles method is most closely in accord with Congressional intent, and that the failure to include gathering-line data in the allocation formula would cause no significant disparities because of the short distances involved.[252] Williams supplies no support for its first (reliable indicator) argument. Nor does Williams explain why operating revenue is not at least as good an indicator of business activity and regulatory exposure as barrel-miles. Regarding its second (Congressional intent) argument, the Commission believes that, while the barrels-delivered methodology may be closer to the literal language of the Conference Committee's guidance that the Commission base its computations on "the amount of energy—electricity, gas, or oil—transported or sold," [253] the operating revenues standard is also consistent with Congressional intent. Moreover, for the reasons already stated, the Commission concludes that the barrels-delivered and the barrel-miles methods are less satisfactory than the operating revenues standard in meeting the "fair and equitable" standard set forth in section 3401(b). Williams provides no data to support its third argument that omission of gathering-line volumes will cause no significant disparities. The Commission notes that several oil pipeline companies own nothing but gathering lines.[254]

Only one pipeline, Exxon Pipeline Company, supports the barrels-delivered methodology. Exxon argues that under this method, TAPS owners would pay a more equitable 6.1 percent of the Commission's oil program costs, an amount which Exxon claims will more accurately match the level of service to be provided by the Commission to TAPS.[255] The Commission notes that the maximum charge of $250,000 will protect the TAPS owners from paying more than their fair share of the oil program expenses. Exxon also points out that the barrels-delivered approach is consistent with the approach used to assess gas pipelines and electric utilities and with the language of both the Budget Act and the Conference Report.[256] Because the barrels-delivered approach results in certain small pipelines being assessed disproportionately high annual charges, the Commission believes that fairness and equity (required by the statute) mandate the use of a standard in assessing oil pipelines which differs from that used in assessing gas pipelines or electric utilities.

Finally, one pipeline suggests an approach entirely different from those in the NOPR. Exxon Pipeline Company proposes that the Commission assess user fees against pipelines.[257] While filing fees are not within the scope of this rulemaking, the Commission notes that it currently does assess filing fees against oil pipelines [258] and that it will reduce the amount of annual charges imposed on the oil pipeline industry by the amount of fees received.

For all the reasons discussed above, the Commission believes that apportioning the annual charges based on operating revenue would most fairly and equitably distribute the oil program costs. The Commission will therefore apportion its oil program costs among the oil pipeline companies based upon the relation each company's annual operating revenue bears to the total annual operating revenue for all oil pipeline companies being assessed annual charges, with a 1987 maximum annual charge of $250,000 (adjusted annually to reflect changes in the oil program budget). Specifically, an individual company's annual charge will be calculated as follows:

(1) Subtract all oil pipeline fee collections (from total oil program costs, to yield collectable oil program costs.

(2) Divide the collectable oil program costs by the total of all oil companies' operating revenue in Account Nos. 200, 210 and 220 (FERC Form No,. 6, page 301, lines 1, 2 and 3, column d),[259] to yield the charge per dollar of operating revenue.

(3) Multiply the charge per dollar of operating revenue by each company's operating revenue, to yield each individual company's annual charge.

(4) For every company with an annual charge determined to be above the maximum charge, set that company's annual charge equal to maximum charge and reapportion the overage amounts (those above the maximum) to the remaining companies. This

amount of terminalling charges and loss allowances. These are not included in Accounts 200, 210, and 220. The decision also would make it extremely difficult to base annual charges assessments on net income, as suggested by Texaco USA at 3. The net income would include earnings from activities other than the jurisdictional transportation of oil. Moreover, the Commission notes that companies could easily manipulate their net income by simply assuming greater debt, and that a parent company of a pipeline could easily assign more of the parent's debt to the subsidiary.

[249] Comments of Champlin Petroleum Co. at 2; Phillips Pipe Line Co. at 2; Williams Pipe Line Co. at 2.

[250] Comments of Phillips Pipe Line Co. at 2.

[251] The association in its comments does not indicate that it has such gathering line volumetric data.

[252] Comments of Williams Pipe Line Co. at 2.

[253] Conference Report at 239, 1986 U.S. Code Cong. & Ad. News at 3884.

[254] *See supra* note 229.

[255] Comments of Exxon Pipeline Co. at 6.

[256] *Id.*

[257] Comments of Exxon Pipeline Co. at 4.

[258] *See* 18 CFR Part 346 (1986).

[259] If a company does not timely provide the operating revenue data, the Commission will calculate the company's annual charge based on the Commission's estimate of the operating revenue using other data provided on FERC Form No. 6 by the company in that year, or, if necessary, information provided in a prior year.

reapportioning is to be done using the same method outlined in steps 1 through 3 above but with the exclusion of those companies whose annual charge is already set at the maximum amount, and is to be repeated until no company's annual charge exceeds the maximum charge.

C. Other Matters

In the NOPR, the Commission proposed that the oil pipelines be allowed to include annual charges in their Operating Expense Account No. 510, Supplies and Expenses, of the Commission's Uniform System of Accounts.[260] The Commission indicated that it considers annual charges to be a cost of doing business for the oil pipelines.

Three commenters address this issue. Enterprise Pipeline Company seeks confirmation that the oil pipelines can pass through the annual charges to their shippers.[261] They can, as long as such passthroughs are consistent with Commission-approved rates.

Enterprise also suggests that the oil pipelines be permitted to bill the annual charges directly to the shippers.[262] Santa Fe Pacific Pipelines, Inc. presents a similar suggestion, that the Commission establish an annual fee percentage (similar to the GRI approach suggested by many gas pipelines). Santa Fe contends that this is the most equitable method because (1) the shipper ultimately pays, and (2) during periods in which oil pipeline companies do not file for rate increases, no other method would permit the companies to recover annual charges from their customers.[263] The Commission declines to adopt either of these suggestions. Unlike the natural gas program's annual charges, which reduce the gas pipelines' profits by 2.5 percent and which may therefore be passed through automatically to the pipelines' customers through a tracking mechanism, the oil program's annual charges will reduce the profits of the oil pipelines by only 0.53 percent, a figure too small to justify the establishment of a tracking mechanism.[264] Moreover, regarding Santa Fe's second point, if the pipelines do not take advantage of their right to seek rate increases from the Commission, that is their own business decision and is irrelevant to the appropriateness of the method for assessing annual charges. Finally, unlike the Commission's natural gas program, the oil program currently has in place no tracking mechanism by which to implement such a direct charge. Given the time constraints placed on the Commission by Congress, there is not sufficient time in this rulemaking proceeding to establish such a mechanism.

Finally, Williams Pipe Line Company suggests that the pipelines be permitted to choose each year whether to expense or to accrue and amortize the annual charges.[265] This is, in essence, a proposal that the pipelines be permitted to "bank" whatever annual charges they cannot pass through to their customers (presumably due to market conditions). The Commission declines to adopt Williams' suggestion because such an approach would permit companies to circumvent the tariffs approved by the Commission.

VI. Cost Basis for the Electric Regulatory Program

A. The Types of Companies To Be Billed

The Commission currently regulates 186 IOUs (including parent, subsidiary, and affiliated utilities), one cooperative,[266] and five Federal Power Marketing Agencies (PMAs).[267] In the NOPR, the Commission proposed to assess annual charges against those IOUs which (a) have rate schedules on file for sales for resale and coordination (interchange out and transmission delivered) sales [268] to municipal or cooperative electric utility systems, PMAs or other IOUs, and (b) are required to file an Annual Report FERC Form No. 1 (Major Utilities) or Form No. 1–F (Non-Major Utilities).

1. Power Marketing Agencies

In the NOPR, the Commission proposed to exempt the PMAs from the payment of annual charges. The Commission proposed to exempt the PMAs because it believed that Congress intended the Commission to recover the costs of the entire electric program from "public utilities" as defined in section 201(e) of the FPA [269] and limited by section 201(f) of the FPA.[270] Commenters addressing this issue unanimously oppose the NOPR's interpretation of congressional intent.[271] Those commenters raise two major issues: (1) Whether the Commission should exempt PMAs from paying annual charges, and (2) if the PMAs are exempted from the assessment of annual charges, whether the IOUs should be assessed the costs of PMA regulation.

The Commission proposed to exempt PMAs because it does not regulate them under the FPA, the House bill's basis for determining which entities are to be assessed charges. In response, one commenter argues that the Commission's jurisdiction under the Budget Act is not intended to be as narrow as the Commission's jurisdiction under the FPA.[272]

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[260] 18 CFR Part 352 (1986). *See generally* Senate Budget Report at 74.

[261] Comments of Enterprise Pipeline Co. at 1.

[262] Id. at 1–2.

[263] Comments of Santa Fe Pacific Pipelines, Inc. at 1–2.

[264] *See supra* notes 217 and 219.

[265] Comments of Williams Pipe Line Co. at 4.

[266] Golden Spread Electric Cooperative, Inc. (GSEC) filed on April 21, 1987, a rate schedule for the sale of firm requirements service to all of its members. Docket No. ER87-396-000.

[267] These entities are listed in Appendix F. Based on FY 1986 data, the Commission expects to collect $19,650,145 in annual charges and $2,403,855 in filing fees during FY 1987.

[268] The NOPR defined sales for resale as delivered energy reported on page 401 of the Form No. 1, line 22; on page 16 of the Form No. 1-F, line 7, column (C); and in Schedule II, Part 6 of EIA Form No. 861. Interchange out sales were defined as delivered energy reported on page 401 of Form No. 1, line 13. Transmission delivered was defined as energy listed at page 401 of Form No. 1, line 17.

[269] 16 U.S.C. 824(e) (1982). Section 201(e) states:

(e) "Public utility" defined.

The term "public utility" when used in this subchapter and subchapter III of this chapter means any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter (other than facilities subject to such jurisdiction solely by reason of section 824i, 824j, or 824k of this title).

[270] 16 U.S.C. 824(f) (1982). Section 201(f) states:

(f) United States, State, political subdivision of State, or agency or instrumentality thereof exempt.

No provision in this subchapter shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto.

[271] American Electric Power Service Corporation, Boston Edison Company, Carolina Power & Light Company, Central Illinois Public Service Company, Cincinnati Gas & Electric Company, Consolidated Edison Company of New York, Inc., Cleveland Electric Illuminating Company, Duke Power Company, Edison Electric Institute, Electric Utilities, Florida Power & Light Company, Golden Spread Electric Cooperative, Inc., Interstate Power Company, Iowa-Illinois Gas and Electric Company, Iowa Power and Light Company, Iowa Southern Utilities Company, Iowa State Utilities Board, Kansas Gas and Electric Company, Middle South Utilities, Inc., Montana Power Company, New England Power Service, Potomac Electric Power Company, Pacific Gas and Electric Company, Pacific Power & Light Company, Public Service Commission of Nevada, Public Service Electric and Gas Company, Puget Sound Power & Light Company, South Carolina Electric & Gas Company, Southern California Edison Company, Southern Company Services, Inc., Southwestern Electric Power Company, Southwestern Public Service Company, Texas-New Mexico Power Company, Texas Utilities Electric Company, Upper Peninsula Power Company, Utah Power & Light Company, Virginia Electric and Power Company, Washington Water Power Company.

[272] Comments of Montana Power Company (MPCo) at 4.

Another commenter points out that PMAs do not pay fees under the FPA and the IOAA because of statutory exemptions. A similar statutory exemption is absent from the Budget Act. Consequently, the commenter concludes that the Commission cannot assume that Congress intended to exempt PMAs from being assessed annual charges because the statute is silent on that issue.[273]

The commenters are persuasive in their arguments that the Budget Act does not make the assessment of annual charges contingent upon whether the Commission has jurisdiction over and collects fees from an entity regulated under the FPA. The Budget Act gives the Commission the authority to assess annual charges against any entity involved in the transfer or sale of energy under its jurisdiction. The Budget Act contains no explicit exemption for PMAs and the Commission has therefore decided not to infer one.

According to some commenters, neither the wording of the Budget Act nor its legislative history supports the conclusion that Congress intended to excuse the PMAs from financial responsibility for the administrative costs they generate at the Commission.[274] Some commenters point out that Congress intended the charges imposed under the Budget Act to be levied against entities "directly affected" by the Commission's regulatory program, without regard to the type of entity.[275] They argue that since PMAs are "directly affected" by the Commission's regulatory program they should be subject to annual charges.

The Commission agrees with the commenters that Congress may not have directed the Commission to use the rejected House bill as a guide to determine every type of entity that should be assessed an annual charge.[276] The Commission recognizes that neither the express language of the statute nor its legislative history addresses Commission treatment of PMAs. Furthermore, since Congress deleted from the enacted legislation the definition of the entities to be assessed annual charges (which would have exempted PMAs), the Commission concludes that it may assess PMAs annual charges as long as such an assessment is fair and equitable.

The Commission agrees with the commenters that Congress intended the annual charges imposed under the Budget Act to be levied against entities "directly affected" by the regulatory programs. This congressional intent, however, does not give the Commission such broad authority as to impose annual charges on every entity conceivably "directly affected" by the regulatory programs. For example, the Budget Act does not give the Commission jurisdictional authority over previously nonjurisdictional entities. Rather, the Budget Act gives the Commission authority to assess annual charges against entities already within the Commission's jurisdiction because of some other statute or administrative delegation.

The Commission's jurisdictional authority over the PMAs is limited to the regulation of PMA rates.[277] The Commission agrees with the commenters that its rate authority which imposes costs on the Commission likewise justifies the assessment of annual charges. For example, the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) gives the Commission the authority to finalize the rates that the Bonneville Power Administration (BPA) establishes. It provides that "(r)ates . . . shall become effective only . . . upon confirmation and approval by the Federal Energy Regulatory Commission upon a finding by the Commission that such rates . . . are based upon the Administrator's total system costs. . . ." [278] The Budget Act requires that the Commission's entire costs be recovered and that the recovery be accomplished in a "fair and equitable manner."[279] The Budget Act, combined with section 7 of the Northwest Power Act, gives the Commission sufficient authority to assess BPA annual charges.[280]

There are four other PMAs, the Alaska Power Administration (APA), the Southeastern Power Administration (SEPA), the Southwestern Power Administration (SWPA), and the Western Area Power Administration (WAPA). Several statutes vested rate confirmation authority for these PMAs to the Department of Interior.[281] Section 302 of the Department of Energy Organization Act transferred this oversight authority to the Department of Energy (DOE).[282] DOE Delegation Order No. 0204–108 transferred final rate oversight authority over APA, SEPA, SWPA, and WAPA from DOE to the Commission.[283] The delegation order provided, in part, that any rate developed by these PMAs "shall not become effective on a final basis unless and until such rate is confirmed and approved by the . . . Commission." [284]

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[273] Comments of Puget Sound Power & Light Company (PSP&L) at 6–7.

[274] Comments of Southern Company Services, Inc. (SCSI) at 14; Comments of Southern California Edison Company (SC Edison) at 1–2.

[275] Comments of Boston Edison Company, Central Vermont Public Service Corporation, El Paso Electric Company, Florida Power Corporation, Montaup Electric Company, Northern States Power Company, Public Service Company of New Hampshire, and Wisconsin Electric Power Company (Utilities Group I) at 8.

[276] Congress suggested the House bill as a guide only for establishing the classes to be assessed charges in connection with cogenerators and small power producers. The Conference Report said:

The House provision excluded the cost of regulating small power production and cogeneration, and exempted such power producers from annual charges. The Senate had no comparable provision. However, the Senate provision permitted the Commission to waive fees and charges. The Senate provision also did not specify the specific classes of entities subject to annual charges or fees, as the House provision did. The substitute follows the Senate provision in not specifying classes of entities subject to charges and fees and permitting the Commission to waive fees and charges. No specific exemption for cogenerators and small power producers is included. The conferees did not include the specific exemption, because the substitute provides sufficient authority for the Commission to achieve a similar result. The House included the specific exemption, and the Commission requested such language because of a concern that the imposition of fees could frustrate the purpose of encouraging small power production and cogeneration. The conferees expect the Commission to take into account this concern, as well as other appropriate concerns, in determining whether to assess fees or charges upon such power producers.

Conference Report at 239, 1986 U.S. Code Cong. & Ad. News at 3884.

[277] However, the Commission cannot establish rates for a PMA. The Commission can only approve or disapprove a PMA rate proposal.

[278] Northwest Power Act section 7(a)(2)(B), 16 U.S.C. 839e(a)(2)(B) (1982).

[279] The Conference Report states:

In defining the "fair and equitable" method of computing the fees and charges, the Commission shall endeavor to assess and collect amounts necessary to cover the cost of each of its program areas from those directly affected by the activities of the Commission in each area.

Conference Report at 238, 1986 U.S. Code Cong. & Ad. News at 3883.

[280] Furthermore, a court has held that BPA rate filings under section 7(k) of the Northwest Power Act (nonfirm, nonregional sales of energy), 16 U.S.C. 839e(k) (1982), are subject to FPA procedural and filing requirements. Southern California Edison Company v. FERC, 770 F.2d 779 (9th Cir. 1985). Consequently, the Commission regulates the BPA under the FPA, albeit to a limited extent. This authority provides the Commission with yet another basis on which it can assess the BPA annual charges.

[281] The Flood Control Act of 1944, 16 U.S.C. 825s (1982); the Federal Columbia River Transmission System Act, 16 U.S.C. 838g (1982); the Pacific Northwest Power Preference Act, 16 U.S.C. 837 (1982); the Pacific Northwest Electric Power Planning and Conservation Act of 1980, 16 U.S.C. 839 (1982); the Reclamation Act of 1939, 43 U.S.C. 485h (1982).

[282] 42 U.S.C. 7152 (1982).

[283] 48 FR 55664 (Dec. 14, 1983), I FERC Statutes & Regulations ¶ 9910, *amending* DOE Delegation Order No. 0204–33, 43 FR 60636 (Dec. 28, 1978).

[284] I FERC Statutes & Regulations ¶ 9910 at 9926. *See also* DOE Delegation Order No. 0204–33, giving the Commission similar approval authority over BPA rates. I FERC Statutes & Regulations ¶ 9907.

One of the Commission's review criteria is "whether the . . . rates are sufficient to recover the costs of producing and transmitting electric energy. . . ." [285]

One commenter asserts that while the Commission has discretionary power to waive annual charges for PMAs, such discretion must be tempered with fairness and equity.[286]

The Commission agrees that its discretionary power to waive annual charges for any entity must be tempered with fairness and equity. As argued by the commenters, the Commission incurs significant costs regulating PMAs. Furthermore, no commenter has argued that public policy supports the exemption of PMAs from annual charge assessment and the Commission is aware of none. In consideration of the filed comments and after examination of related statutes, the Commission concludes that it would not be fair or equitable to exempt PMAs from the assessment of annual charges.[287]

The second issue raised in connection with the proposed exemption for PMAs is whether the IOUs should be assessed the cost of Commission regulation of exempted PMAs. Many commenters oppose this allocation of costs.[288] Some challenge the Commission's assertion that the PMA enabling statutes are related to the FPA [289]—a finding which, if valid, could justify assessing the costs against the IOUs.[290] In light of the Commission's decision to assess annual charges against PMAs and to exclude the costs of regulating the PMAs from the category of costs to be assessed against IOUs, it is not necessary to decide the issue of the "relatedness" of the PMA enabling statutes and the FPA.[291]

2. Municipals and Rural Electric Cooperative Utility Systems

In the NOPR, the Commission proposed to exempt municipals and rural cooperative utility systems (cooperatives) from the assessment of annual charges. Some commenters argue that these entities should not be exempt, pointing out that municipals and cooperatives frequently compete with IOUs in the markets of sales for resale and coordination sales of electric power.[292] Thus, one commenter argues that IOUs should not be required to subsidize their municipal and cooperative competitors.[293]

According to one commenter, the appropriate criteria for assessing annual charges to municipals and cooperatives is cost causation.[294] In other words, the Commission should endeavor to charge those "directly affected" by particular regulatory programs.[295] Some commenters believe that nonjurisdictional entities can be directly affected by Commission regulation and therefore must be assessed annual charges under the Budget Act.[296] Two commenters point out that when municipals and cooperatives appear before the Commission seeking redress, they generate regulatory costs for which they should compensate the Commission.[297]

The Commission will exempt municipals and cooperatives because, with one exception, it does not have direct jurisdiction over these entities under the FPA or any other statute.[298] In the Commission's view, the argument that it should assess annual charges against municipals and cooperatives so as to be fair and equitable is misplaced. Unlike PMAs over which the Commission has limited rate jurisdiction, the Commission has no jurisdiction over municipals and cooperatives that have no rates on file at the Commission. The Commission sees no more basis for assessing annual charges against such municipals and cooperatives than against any other nonjurisdictional group.[299] The Commission recognizes that these entities do affect the costs of regulating the sale or exchange of jurisdictional energy by intervening in rate cases, independently seeking redress through complaint procedures, utilizing Commission research resources, and by being customers whose characteristics influence the determination of the just and reasonable rate. The Commission believes that municipals and cooperatives will ultimately pay for most or all of these activities since most or all of the annual charges paid by the utilities will be passed through to their customers.

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[285] I FERC Statutes & Regulations at 9926.

[286] Comments of SCSI at 15.

[287] The Commission notes that the Northwest Power Act provides that the BPA shall "establish and, as appropriate, revise [rates] to recover . . . the costs associated with the acquisition, conservation, and transmission of electric power. . . ." Northwest Power Act section 7(a)(1), 16 U.S.C. 838e(a)(1) (1982). Thus, the assessment of annual charges will not merely transfer funds from one government agency to another. BPA and the other PMAs, through similar enabling statutory provisions, will be able to recover these charges from their customers. *See supra* note 281.

[288] Comments of Interstate Power Company (IPC) at 5–7; Iowa-Illinois Gas and Electric Company (IIG&E) at 3–4; Kansas Gas & Electric Company (KG&E) at 2–5; Potomac Electric Power Company (PEPCo) at 3; Southwestern Electric Power Company (SWEPCo) at 4–5; Florida Power & Light Company (FP&L) at 5.

[289] Comments of American Electric Power Service Corporation (AEP) at 24–27; Utilities Group I at 9–10; FP&L at 4–6; IPC at 5.

[290] The Conference Report indicates that the Commission must recover the costs of its regulatory activities under the FPA and "related" statutes. Conference Report at 238–239, 1986 U.S. Code Cong. & Ad. News at 3883–3884.

[291] The Commission does note in passing that it is arguable that these PMA enabling statutes are related to the FPA. In Southern California Edison Company v. FERC, 770 F.2d 779 (9th Cir. 1985), the Court held that certain BPA rate filings are subject to FPA procedural and filing requirements. Furthermore section 303 of the FPA requires federal agencies to follow FPA sections 301 and 302 accounting and depreciation standards. *See* 16 U.S.C. 826b (1982). Finally, section 311 of the FPA gives the Commission broad investigatory authority relating to electric energy, however produced, whether or not otherwise subject to the Commission's jurisdiction. *See* 16 U.S.C. 825j (1982).

[292] Comments of Carolina Power & Light Company, Cleveland Electric Illuminating Company, Upper Peninsula Power Company (Utilities Group II) at 11–12; Public Service Commission of Nevada (PSC Nevada) at 1–2.

[293] Comments of PSC Nevada at 2.

[294] Comments of Texas-New Mexico Power Company (TNMP) at 1.

[295] Comments of Utilities Group I at 2; MPCo at 8.

[296] Comments of MPCo at 4–5; Edison Electric Institute (EEI) at 31–33; Utilities Group I at 8–9.

[297] Comments of New England Power Company (NEPCo) at 6–7; TNMP at 1.

[298] The Conference Report clearly intended that the Commission assess annual charges only against entities that were under its jurisdiction pursuant to a statute other than the Budget Act:

The conferees intend that annual 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 gas pipeline or electric utility regulation;* (2) the total direct and indirect costs of that type of Commission regulation incurred during such year; (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.

Conference Report at 239, 1986 U.S. Code Cong. & Ad. News at 3884 (emphasis added).

One commenter asserts that, if municipals or cooperatives have Commission-approved tariffs or exchange agreements on file, they should be assessed annual charges. Comments of PSC Nevada at 1–2. The Commission agrees that municipals or cooperatives which file rates with the Commission could then be assessed annual charges. To date, however, no municipals or cooperatives other than GSEC have filed any rate schedules. *See supra* note 266 and *infra* note 299.

[299] Under tne NOPR, two criteria were proposed which would identify the recipients of bills for annual charges, *i.e.*, entities that file Form No. 1s (or Form No. 1–Fs for nonmajor utilities, or Energy Information Administration (EIA) Form No. 412 for the PMAs) and that have rate schedules on file with the Commission. The rate schedules are the instruments required to be filed by the providers of services, which are subject to the Commission's regulation. The municipals and cooperatives do not meet this criterion in most instances. However, GSEC, an electric cooperative, recently filed a rate schedule for the sale of firm requirements power it purchases from an IOU and that it intends to sell to its members. *See supra* note 266. As a result, the Commission will have direct authority over GSEC pursuant to the FPA once the Commission accepts its rate filing, and therefore will assess it annual charges.

3. Cogenerators and Small Power Producers

In the NOPR, the Commission proposed to exempt cogenerators and small power producers from annual charge assessments. Commenters argue that cogenerators and small power producers should be assessed annual charges.[300] They point out that congressional rejection of the House bill (which exempted these entities from the annual charges) requires the Commission to weigh other concerns against any possible exemption. They allege that the Commission did not do this.[301] A group of commenters asserts that the Commission must consider factors other than the cost of annual charges to cogenerators and small power producers if it exempts these entities because, if cost were the only relevant factor, Congress would have exempted these entities in the Budget Act.[302] This group argues that, before an exemption can be granted, the Commission must demonstrate that the charges would adversely affect the cogeneration and small power production programs.[303] One commenter argues that it is unrealistic to believe that cogeneration and small power production programs would be discouraged if annual charges were imposed.[304]

The Commission continues to believe that it is appropriate to exempt cogenerators and small power producers from annual charges. The Commission believes that the amount which would be assessed against these entities as an annual charge does not justify the risk of discouraging the fullest development of cogeneration and small power production by these small entities.[305] Furthermore, an additional problem arises in assessing annual charges to these entities because of the ephemeral nature of the constituency. The pool of applicant cogenerators and small power producers changes from year to year, thereby precluding the use of "makewhole" annual charge mechanisms.

Several commenters argue that IOUs should not be assessed (and in effect subsidize) the costs of regulating cogenerators and small power producers.[306] Two commenters argue that, even under section 210 of PURPA, which was designed to encourage cogeneration and small power production, IOUs and their customers are not required to subsidize cogenerators and small power producers.[307]

A group of commenters state that, if the House bill is to serve as justification for the exemption of cogenerators and small power producers, then the cost of regulating the cogenerators and small power producers cannot be recovered from IOUs. They point out that the House bill exempted cogenerators and small power producers from annual charges *and* removed the cost of these programs from the annual charges to be assessed.[308]

The Commission disagrees with the commenters. Even if PURPA specifically prohibits subsidizing these entities, the Commission believes that Congress clearly envisioned the possibility that IOUs would absorb the unrecovered costs of regulating cogenerators and small power producers.

While Congress did not adopt the explicit exemption for cogenerators and small power producers that was in the House bill, the conferees explicitly stated that the Commission retained the discretion to grant the exemption if it wished to do so to encourage the development of cogeneration and small power production. Significantly, the portion of the House bill which excluded the cost of regulating cogenerators and small power producers from the charges to be assessed to non-exempt entities, was not adopted or even referred to by the conferees. Thus, the Commission is left with the requirement that all of its costs (including the cost of regulating small power producers and cogenerators) be recovered *and* the congressional guidance favoring exemption of these entities.[309] The conclusion is inescapable that Congress was aware that, if the Commission exempts cogenerators and small power producers from annual fees, as it clearly has the discretion to do, then other entities (namely IOUs) must absorb those costs.

4. Electric Utilities of Alaska and Hawaii

The NOPR proposed to exempt intrastate utilities from the assessment of annual charges. Only one commenter addresses this proposed exemption. NEPCo opposes the proposed exemption alleging it is unfair. NEPCo argues that "there is a threshold level of costs incurred by the Commission from many utilities who have no or very small levels of FERC jurisdictional sales. This fact mitigates toward a minimum fee assessment. . . ." [310]

The Budget Act's legislative history limits annual charges to the cost of regulating energy which is transferred between entities pursuant to Commission jurisdiction.[311] IOUs in Hawaii and Alaska do not sell jurisdictional energy. Consequently, the Commission does not have the power to assess them annual charges.[312]

5. Other Entities

Because of the type of sales involved, several commenters request that they be exempt from annual charges even though they are subject to the jurisdiction of the Commission. They argue that jurisdictional sales and exchanges between subsidiaries, parents,[313] affiliated companies,[314] power pool members,[315] and members

[300] Comments of Utilities Group I at 10–11; MPCo at 6; Utah Power and Light Company (UP&L) at 4–6.

[301] Comments of Utilities Group I at 10–11; MPCo at 6.

[302] Comments of Utilities Group I at 5–8.

[303] *Id* at 10–11.

[304] Comments of UP&L at 4–6.

[305] Indeed, the cost of regulating cogenerators and small power producers which is not recovered by filing fees is so substantial that it could very well inhibit development of these alternative energy sources. In FY 1986, the Commission recovered in filing fees only $442,900 of its $1,526,696 in cogeneration and small power production program costs.

[306] Comments of KG&E at 5–6; NEPCo at 7–8; San Diego Gas and Electric Company (San Diego) at 2; South Carolina Electric and Gas Company (SCE&G) at 3.

[307] Comments of Southwestern Public Service Company (SPSCo) at 5–7; Virginia Electric Power Company (VEPCo) at 1–2.

[308] Comments of Utilities Group II at 14–16.

[309] Conference Report at 239, 1986 U.S. Cong. Code & Ad. News at 3884.

[310] Comments of NEPCo at 9.

[311] *See* Conference Report at 238–239, 1986 U.S. Code Cong. & Ad. News at 3883–3884.

[312] *See* Part VI A 2 for discussion of the effect of an entity making jurisdictional sales on the Commission's power to assess annual charges. *See* Part VI C 3 for a discussion of individual requests for exemption by two Texas IOUs. However, these Texas utilities are subject to the Commission's jurisdiction due to their interstate transmission activities. Therefore, the Commission will assess them annual charges based on only these transmission activities. (All remaining Texas utilities engage in interstate sales for resale or coordination transactions).

[313] Comments of Ohio Valley Electric Corporation (OVEC) at 1–7; Allegheny Power Systems Inc. (Allegheny) at 2; Cincinnati Gas & Electric Company (CG&E) at 6–8; *See also* Comments of Commonwealth Edison Company (CEC) at 2 (suggesting, as a compromise, that the Commission reflect no more than 10% of jurisdictional sales between parent and wholly-owned subsidiaries in the annual assessment).

[314] Comments of Middle South Utilities (MSU) at 2–3; SCSI at 17–24.

[315] Comments of AEP at 33; Pacific Power and Light Company (PP&L) at 1; Connecticut Light & Power Company, Western Massachusetts Electric Company, Holyoke Water Power Company, Northeast Utilities Service Company, Northeast Nuclear Energy Company (Northeast Utilities) at 2–3; MSU at 2; GSEC at 7; Washington Water Power Company (WWP) at 2.

of cooperatives [316] should be exempt from the assessment of charges. Some of the commenters reason that these types of transactions should not be considered for purposes of allocating annual charges because they are not intended to generate a profit.[317] Similarly, they argue that separate corporate identities within the same company are often mandated by state law, not economic necessity.[318] Some commenters assert that annual charges assessed for these transactions constitute discriminatory, multiple-billing for the same amount of electricity.[319]

The Commission does not agree that transactions among subsidiaries, parents, affiliates, power pool members, or cooperatives should be exempt from annual charges. It does not matter if the transaction which is subject to Commission oversight generates, or is intended to generate, a profit. An annual charge is not intended to represent an assessment on total energy delivered to the ultimate end-user of that energy. Rather, it is designed to allocate the cost of regulating each wholesale transaction. Consequently, while there may be a multiple assessment on some kilowatt-hours, such assessment is justified because *each* wholesale transaction is governed by a rate schedule on file with the Commission which causes the Commission to incur separate and distinct costs.[320] Furthermore, the Commission is unaware of any public policy which would justify exempting these cost-generating activities because of the relationship of the parties involved.

Some commenters argue that, even if the Commission incurs costs to regulate the entities involved in these transactions, the cost is minimal because these types of transactions generate little dispute among the parties before the Commission.[321] Thus, they assert that these affilated company transactions are less expensive to regulate. The Commission does not believe that it is appropriate to treat affiliated companies differently from nonaffiliated companies. In fact, because affiliated companies may have mutual interests, the Commission must take a more active role in investigating the justness and reasonableness of the rates which they charge one another.[322]

Two commenters propose that the Commission assess annual charges against intervenors in rate cases. Alternatively, they propose that the Commission charge intervenors fees.[323] Another commenter believes that intervenors should be billed directly so that they can be made to "understand that use of the Commission's time and other resources are not free of charge."[324]

The Commission is not persuaded that intervenors should be assessed annual charges or fees for participating in dockets where the Commission must evaluate a rate filing. First, the Commission has no authority to assess annual charges against nonjurisdictional entities, as noted earlier, and many intervenors, which have no rates on file, are nonjurisdictional entities. Furthermore, the Commission believes that assessment of a fee or charge will have an unnecessary and undesirable "chilling effect" on intervenors, such as state authorities, who exercise their right to be heard and who have no customers to whom they can pass the assessed charge or fee. The Commission believes that, on the whole, intervenors' activities contribute positively to its oversight authority. The Commission therefore declines to assess fees or charges which may inhibit this contribution. Moreover, the administrative disadvantages of annual charge assessment to intervenors would outweigh any perceived advantage. Assessment of annual charges to intervenors would require estimates of the potential costs of intervention by jurisdictional and nonjurisdictional entities who may or may not be customers of the entity which filed the rate and whose intervention in a single case may be the only contact they ever have with the Commission. Finally, intervenors, who are customers of an entity against which charges are assessed, will indirectly absorb most or all of the cost of this activity through their rates.

Still another commenter proposes that the Commission modify the basic proposal by reducing the bills to IOUs that negotiate their rates before filing.[325] The Commission believes that it would be administratively costly and unduly burdensome to attempt to assign all regulatory costs directly to specific proceedings. Furthermore, given the form in which Commission staff time is reported, it is not possible for the Commission to separate out the time spent on particular rate cases. Since the Budget Act does not require that the Commission change its method of data collection, the Commission will not do so here.

B. Overview of the Annual Charges Formula

The NOPR proposed to apportion costs among the IOUs on the basis of sales for resale and coordination sales (interchange out and transmission kilowatt-hour deliveries). These energy sales are reported to the Commission in Form Nos. 1 and 1-F and the Annual Electric Utility Report Form No. 861 filed with the EIA.[326]

The final rule will apportion costs among IOUs and certain other entities with rates on file at the Commission on the basis of adjusted sales for resale and adjusted coordination sales [327] minus the costs of regulating PMAs. The costs of regulating PMAs will be apportioned among the five PMAs.[328]

1. Proposed Apportionment.

In the NOPR, the Commission proposed to apportion its electric program costs among investor-owned utilities (currently 186) based upon each IOU's total jurisdictional sales for resale and coordination sales. Specifically, the Commission proposed to:

(1) Subtract all electric program filing fee collections from total electric program costs, to yield the collectable electric program costs.

[316] Comments of SCSI at 18; GSEC at 6-7.

[317] Comments of OVEC at 4-7.

[318] Comments of OVEC at 6.

[319] Comments of Northeast Utilities at 2-3; AEP at 33; SCG&E at 4; CSEC at 7. These commenters believe that instances where there is no multiple assessment constitute an unfair advantage because the cost per kilowatt-hour is correspondingly lower.

[320] *See also* discussion of multiple billing issue in Part IV B.

[321] Comments of Baltimore Gas & Electric Company (BC&E) at 5-6; CEC at 2.

[322] Many times these transactions between affiliated companies involve the total passthrough of costs which are not objectively scrutinized until they reach the Commission. *See, e.g.,* Tucson Electric Power Company, 7 FERC ¶ 61,298 (1979), *reh'g denied sub nom.* Alamito Company, 33 FERC ¶ 61,286 (1985). In this case the customer complained of excessive purchased coal costs which were the result of the passthrough of the costs of coal that the utility purchased from one of its affiliates. *See also* Nantahala Power & Light Company v. FERC, 727 F.2d 1342, 1345 (4th Cir. 1984), where the court recognized that the Commission has an additional burden when it scrutinizes affiliate transactions which affect rates.

[323] Comments of UP&L at 6-7; PP&L at 2-3.

[324] Comments of Central Illinois Public Service Co. (CIPSCo) at 7.

[325] Comments of CIPSCo at 6-7.

[326] The classifications of delivered energy are listed at page 401 of Form No. 1 under "Electric Energy Account" as (1) Interchange out (line 13), (2) Transmission delivered (line 17), and (3) Sales for resale (line 22). Sales for resale information is similarly identified in Form No. 1-F on page 16, line 7, column c. Comparable information on all companies is available at Schedule II, Part 8, Energy Services and Disposition, in EIA Form No. 861.

[327] *See infra* Part VI B 1 for the discussion of how short-term, limited-term, and unit sales of less than five years duration have been shifted from the sales for resale category, as defined in the NOPR, to the coordination sales category, thereby rendering both categories "adjusted" in the final rule.

[328] *See supra* Part VI A 1.

(2)(a) Multiply the collectable electric program costs by the proportion of time devoted to sales for resale activities, to yield the sales for resale costs.

(b) Multiply the collectable electric program cost by the proportion of time devoted to coordination sales activities, to yield the coordination sales costs.

(3)(a) Divide the sales for resale costs by the total IOU sales for resale kilowatt-hours, to yield the sales for resale charge per kilowatt-hour.

(b) Divide the coordination sales costs by the total IOU coordination sales kilowatt-hours, to yield the coordination sales charge per kilowatt-hour.

(4)(a) Multiply the sales for resale charge per kilowatt-hour by each IOU's sales for resale kilowatt-hours, to yield each IOU's sales for resale charge.

(b) Multiply the coordination sales charge per kilowatt-hour by each IOU's coordination sales kilowatt-hours, to yield each IOU's coordination sales charge.

(5) Add each IOU's sales for resale charge and coordination sales charge, to yield each IOU's total annual charge.

Several commenters favor the proposal to apportion costs between sales for resale and coordination sales. One commenter argues that such an apportionment would be more balanced than focusing only on sales for resale or on a formula which does not differentiate data or apportion the Commission's work load by categories.[329] Another commenter concurs with this allocation of costs between resale and interchange out and transmission, as the costs of regulating sales for resale are significantly higher than the cost of regulating coordination sales.[330] One IOU favors the proposed allocation, which distinguishes between the different types of sales, because it is reasonable from an accounting perspective.[331]

Some commenters, while favoring the basic proposal for apportionment, propose to refine the allocation. One commenter wants the Commission to exclude all short-term, limited-term, and unit sales from the sales for resale category, and instead to include them in the coordination sales category. The commenter believes that these types of sales are similar to coordination sales because they are limited in the amount of energy contracted for and duration of delivery.[332]

The Commission agrees that short-term, limited-term, and unit sales of less than five years duration should be included in the definition of coordination sales. However, the Commission does not believe that unit sales for a duration of five years or more should be included in that definition. Longer-term unit sales and long-term firm transmission sales are similar to sales for resale because they have similar administrative and regulatory costs. By contrast, coordination sales do not share the same types of administrative costs because they are usually opportunity sales negotiated between buyer and seller that do not typically require intensive regulatory review.

One commenter proposes that the Commission assess these costs "based on electric revenues—similar to the method proposed in allocating charges to oil pipeline companies." [333] Another commenter questions the validity of assessing the Commission's costs on the basis of the volume of sales because sales volumes do not directly correlate to the causation of regulatory costs.[334] Another commenter also points out the perceived irrelevance of the volume of sales to the regulatory costs generated.[335]

The Commission believes that annual charges based on the deliveries of volumes of energy under these two service classifications is in accord with the Conference Report's requirement that the annual charges be assessed on the basis of the "annual sales or volumes transported." [336] The electric annual charges will therefore be based upon kilowatt-hours sold in each category.

One commenter is concerned that the proposed assessment methodology would act "as a disincentive for sales for resale and even more so for coordination transactions since such transactions typically carry little, if any, associated charges." [337] The Commission is not persuaded that the assessment of charges based upon coordination transactions will discourage these sales. First, the charge will be known at the time the transaction takes place. Second, the charge will apply to all such transactions. Third, the charge is so small (on the order of 1/100 mill per kilowatt-hour) that it is not likely to affect the economics of a transaction.

In an effort to ensure that all IOUs are actually assessed annual charges, NEPCo proposes that the Commission set up a fee schedule with three categories of IOUs. The schedule would contain minimum and maximum fees. According to NEPCo, the division of IOUs into these categories reflects the fact that all utilities impose costs upon the Commission. NEPCo believes that utilities with substantial jurisdictional sales impose approximately the same level of costs on the Commission even though there may be variations in the magnitude of sales in that category.[338] NEPCo proposes assessing a flat fee to each utility category—major and non-major utilities, as used in the Uniform System of Accounts, as well as a "nominal" category.

The Commission disagrees with NEPCo. A minimum and maximum fee schedule is not practical, necessary, or equitable. Such a fee schedule, which could be administratively simple, could have undesirable results. For example, a single flat fee assessed to each "major" utility would be unduly burdensome to smaller utilities in this "major" category as compared to the larger utilities. Furthermore, unlike in the oil area, there is no great disparity between a potential annual charge and the actual cost of regulation of an IOU.[339]

The Commission's proposed assessment is fairer and more accurate than the use of general categories because it does not give equal weight to all wholesale energy transactions which clearly impose differing burdens on the Commission. For example, a review of the TDRS data indicates that approximately 30 percent of all of the Commission's resources used to regulate the electric program are dedicated to the processing and review of coordination sales, a category representing approximately 60 percent of the total kilowatt-hours regulated by the Commission. The assignment of actual TDRS man-hours to the categories of sales for resale and coordination sales is a more equitable approximation of the total regulatory costs and how they should be apportioned than an assessment system which classifies IOUs as NEPCo proposes and which does not use actual TDRS data.

2. Alternative Apportionment Formulae

In the NOPR, the Commission requested comments on two alternatives for allocating costs to the IOUs. Under the first alternative, the Commission would apportion costs solely on the

[329] Comments of AEP at 31.

[330] Comments of SC Edison at 2.

[331] Comments of MSU at 4. *See also* KG&E at 6–7 (favoring the proposed apportionment on the ground that the amount of Commission resources dedicated to sales for resale transactions far exceeds the resources dedicated to coordination sales).

[332] Comments of Utilities Group II at 10.

[333] Comments of WWP at 2.

[334] Comments of PP&L at 2.

[335] Comments of NEPCo at 14.

[336] Conference Report at 239, 1986 U.S. Code Cong. & Ad. News at 3884.

[337] Comments of PP&L at 2.

[338] Comments of NEPCo at 14–15.

[339] *See supra* Part V B.

basis of sales for resale. It would not consider the effect of interchange out or transmission deliveries. Under the second alternative, the Commission would assess costs on the basis of total Commission-regulated energy deliveries but would not attempt to distinguish coordination-type services, *i.e.*, interchange out and transmission deliveries, from sales for resale.

Few commenters support these alternatives. One commenter favors Alternative No. 1 which allocates costs solely to sales for resale because the commenter argues that the filing fees for coordination sales compensate the Commission for the costs it incurs regulating those sales. Consequently, that commenter believes that no annual charge should be assessed for coordination sales. The commenter also believes that sales for resale filings are the most likely to be litigated and, as such, are responsible for the costs that the annual charges are designed to recover.[340] Similarly, another commenter argues that most IOUs do not engage in coordination sales, and that the allocation of program costs based on interchange out and transmission deliveries may inhibit these sales.[341]

One commenter points out compelling reasons for rejecting this alternative. It argues that the allocation of all costs to one type of service would be unfair and inequitable because the Commission spends more time reviewing and deciding sales for resale rate schedules than coordination rate schedules. Furthermore, it claims that in the future there will be a significant increase in coordination sales and a corresponding increase in Commission regulation of these sales.[342]

A few commenters support Alternative No. 2, which allocates costs on the basis of an IOU's total jurisdictional energy sales without distinguishing between sales for resale and coordination sales. Two commenters prefer this alternative because it would be administratively easy to implement.[343] One commenter also argues that there is occasional difficulty categorizing a type of service at issue in a particular case which, in turn, would compromise the validity of the assignment of costs to the two types of sales.[344]

[340] Comments of BG&E at 5–6.

[341] Comments of Northeast Utilities at 2.

[342] Comments of NEPCo at 17.

[343] *Id.* at 17–18; Iowa State Utilities Board (ISUB) at 3.

[344] Comments of NEPCo at 17–18.

Another commenter favors this alternative because all kilowatt-hours would bear an equal share; no particular transaction type would subsidize another type of transaction; and the process of determining annual charges would be simpler than the Commission's original proposal.[345] Alternatively, this commenter proposes to allocate costs among at least three categories—coordination sales, bulk power sales, and wholesale sales.[346] The commenter believes that additional differentiation of sales types would diminish the possibility of group cross-subsidization because of imperfectly allocated annual charges.[347]

For the reasons previously set forth in Part VI B 1, the Commission does not believe that any of the alternatives are more desirable than the original proposal. After consideration, the Commission adopts the apportionment methodology proposed in the NOPR, and will apply the methodology to all entities being assessed annual charges other than PMAs. The Commission believes that apportionment yields a fair and equitable distribution of regulatory costs incurred. The respective costs associated with the two classes of service will be determined by dividing these costs by the total kilowatt-hours delivered under each class. The figures so derived will be multiplied by each assessed entity's kilowatt-hours delivered under each class to determine that entity's total annual assessment. Specifically, an individual entity's annual charge will be calculated as follows:

(1) All electric filing fee collections and all costs of regulating PMAs will be subtracted from the total electric program costs, to yield collectable electric program costs.

(2)(a) Collectable electric program costs will be multiplied by the proportion of time devoted to adjusted sales for resale activities, to yield the adjusted sales for resale costs.

(b) Collectable electric program costs will be multiplied by the proportion of time devoted to adjusted coordination sales activities, to yield the adjusted coordination sales costs.

(3)(a) The adjusted sales for resale costs will be divided by the entity's total adjusted sales for resale kilowatt-hours, to yield the adjusted sales for resale charge per kilowatt-hour.

(b) The adjusted coordination sales costs will be divided by the entity's total adjusted coordination sales kilowatt-hours, to yield the adjusted coordination sales charge per kilowatt-hour.

[345] Comments of SCSI at 28.

[346] *Id.*

[347] *Id.* Another commenter supports Alternative No. 2 without specifying the reason. *See* Comments of SWEPCo at 9.

(4)(a) The adjusted sales for resale charge per kilowatt-hour will be multiplied by each entity's adjusted sales for resale kilowatt-hours, to yield each entity's adjusted sales for resale charge.

(b) The adjusted coordination charge per kilowatt-hour will be multiplied by each entity's adjusted coordination sales kilowatt-hours, to yield each entity's adjusted coordination sales charge.

(5) Each entity's adjusted sales for resale charge and adjusted coordination sales charge will be added together, to yield each entity's total annual charge.[348]

3. PMA Costs

The procedures adopted by the Commission for assessing annual charges to the PMAs parallel those adopted for the other entities with rate schedules on file at the Commission except in three respects.

First, since PMAs do not pay filing fees, the Commission will not credit any amount against assigned PMA program costs.

Second, the Commission will determine the PMAs' annual charges based on sales reported by the PMAs in EIA Form No. 412 which they file with the Energy Information Administration. EIA Form No. 412 data, however, is reported on a fiscal year rather than the calendar year basis. Consequently, PMA annual charges will be based on prior fiscal year sales data.

Third, no differentiation between "Sales for Resale" and "Coordination Sales" is necessary for PMAs because the Commission's review of these rates is not of such a nature that distinctions can be drawn between different classes of service.[349] Consistent with this fact, the Commission reports its time and resources incurred in regulating the PMAs as a single category in the TDRS system. Therefore, the Commission believes it appropriate to allocate the costs of regulating the PMAs on the basis of the total kilowatt-hour energy sales of each PMA.

C. Other Matters

1. Passthrough of Charges in Account No. 928

In the NOPR, the Commission proposed that annual charges assessed against IOUs be charged to Account No. 928 (Regulatory Commission Expenses) of the Commission's Uniform System of Accounts. One commenter generally supports the proposal.[350] However, many commenters urge the Commission to modify the proposal.

[348] *See supra* note 327.

[349] *See supra* Part VI A 1.

[350] Comments of NEPCo at 10.

One group of commenters proposes that the Commission authorize an annual adjustment provision in sales for resale rate schedules similar to a fuel cost adjustment clause.[351] For coordination sales, that group of commenters asks the Commission to be flexible and to permit a utility to specify as a component of its existing rate the annual charge incurred in conjunction with the sale without making another rate filing.[352] That group points out that the charge will change from year to year because of changes in the Commission's costs, changes in the volume of jurisdictional sales, and changes in the weather.[353]

Another commenter points out that the annual charges are not a part of current rates and therefore may not be recoverable through the proposed mechanism. It suggests that the Commission "adopt a transition rule to allow collection of the annual charges from wholesale customers until such time when rates are adjusted to include annual charges."[354]

One commenter suggests that the Commission permit IOUs to add the estimated kilowatt-hour charges to bills rendered under currently effective rates for resale and coordination transactions in order to effectuate immediate recovery. Alternatively, this commenter proposes that the Commission allow an IOU to make one filing, that may be subject to a nominal filing fee, in order to revise all of that IOU's effective rates to reflect the newly imposed killowatt-hour charge. The commenter proposes to limit the proceeding to the sole issue of the per kilowatt-hour annual charge.[355] According to that same commenter it would be unfair to require IOUs to file rate changes in order to include these charges in base rates.[356]

One commenter points out that Congress intended "that the Commission implement its new authority through a 'generic decision' so that new rate proceedings would not have to be conducted for each company before the new charges are included in rates."[357] This commenter suggests that the Commission allow the annual charge to be included in an energy-related account, so that the costs could, "at least on a short term basis, be passed through in a fuel adjustment clause to wholesale customers on a kilowatt-hour basis or on a similar basis in formula rates commonly used in interchange sales agreements."[358]

Another commenter requests that the Commission issue a statement that the annual charges in Account No. 928 benefit retail customers, and are not simply a regulatory expense related to sales for resale which would require the entire expense to be allocated to the wholesale customers.[359]

The Commission will not adopt any of the above suggestions regarding automatic and guaranteed passthroughs. The Commission generally does not favor the use of automatic and guaranteed passthroughs.[360] These types of automatic mechanisms have been approved under circumstances very different from those that are present here.[361] For instance, unlike fuel costs which are susceptible to wide fluctuations that may not be reasonably predicted, and where such costs represent a substantial cost of providing service, it is extremely doubtful that an IOU or any other entity with a rate schedule on file with the Commission will face financial hardship if it is not able to recover annual charges until it makes and supports a new rate filing. Furthermore, the Commission believes that these annual charges represent reasonably estimable test period costs that should be recovered as would any other expense in a rate filing.[362] Thus, these costs are not so different in nature from other test period costs as to warrant special rate treatment.

The House version, which contained the suggestion that the Commission implement these annual charges through a general proceeding, was not adopted in the final bill, nor was it mentioned by the conferees. The Commission therefore feels free not to adopt this suggestion, especially in light of Commission policy which would counsel against such a generic proceeding at this time.[363]

2. Form Revisions

The NOPR proposed to base the assessment of the annual charges on information obtained from Form Nos. 1 and 1-F. Some IOUs express concern about this proposal. AEP points out that there may be inconsistencies among companies in the way the information is reported in these forms. In fact, AEP says that its past Form No. ls report overly high total coordination sales figures because it reported data on a metered basis rather than on an accounting or net basis.[364] As a result, AEP requests that the Commission clarify the instructions in the Form No. 1 to ensure that the IOUs file appropriate data in their Form No. 1 reports.[365] Another commenter is concerned that some IOUs have failed and will fail to file the required form or may inconsistently report data.[366]

The Commission has reviewed the Form Nos. 1 and 1-F, in conjunction with the comments to the NOPR, for the purposes of calculating annual charges. It appears that information reported in the Form Nos. 1 and 1-F is not consistent with the categorization of services proposed in the NOPR.

The Commission is therefore instituting a new information requirement (designated as FERC Reporting Requirement No. 582) solely for the purpose of assessing annual charges. The Commission believes that this new requirement should eliminate the concerns of the commenters about the consistency of the data used to assess annual charges. The new requirement obliges entities, other than PMAs, which have rate schedules on file with the Commission to report adjusted sales for resale in kilowatt-hours, as reported in Form No. 1 on page 310-311, Account No. 447; adjusted interchange out in kilowatt-hours as shown in Form No. 1 on page 328, included in Account

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[351] Comments of Utilities Group II at 10. *See also* Comments of KC&E at 8 (suggesting that the Commission require that the annual charge be reflected as a component of all fixed and formula rates without a formal filing).

[352] Comments of Utilities Group II at 10.

[353] *Id.* at 9.

[354] Comments of FP&L at 1.

[355] Comments of SWEPCo at 3-4.

[356] *Id.* at 4.

[357] Comments of EEI at 8, *citing* H.R. Rep. No. 99-727, 99th Cong., 2nd Sess. 54 (1986). *See also* Comments of SCSI at 28-31.

[358] Comments of EEI at 8.

[359] Comments of PEPCo at 3.

[360] *See* 18 C.F.R § 35.4 (1986); Southwestern Electric Power Company, 31 FERC ¶ 61,389 (1985) (in which the Commission rejected a formula rate with an automatically adjusting return on common equity as being contrary to notice and filing requirements of the FPA).

[361] *See* New England Power Company, Opinion No. 633, 48 F.P.C. 899, 905 (1972) (Fuel Adjustment Clauses are a "practical vehicle for preserving the economic integrity of utilities . . . .") *See also* 18 CFR 35.14 (1986), the purpose of which is to provide prompt recovery of costs by utilities with frequent changes in the delivered cost of fossil fuel. The cost of fossil fuel is a major direct cost in the case of every electric utility using such fuel to generate electricity.

The automatic passthrough of natural gas pipelines annual charges is distinguishable in that those annual charges reduce the gas pipeline industry's profits approximately 1,500 percent more than the electric utilities' profits are reduced. *See supra* notes 217 and 218.

[362] Test period costs represent the basis for estimating costs which should be included in base rates. *See* 18 C.F.R. 35.13(d) (1986).

[363] *See supra* note 360.

[364] Comments of AEP at 32.

[365] *Id* at 33.

[366] Comments of SWEPCo at 10.

No. 555; and adjusted transmission delivered as shown in Form No. 1 on page 332, Account No. 456. This information requirement also redefines these three types of energy transactions. The following definitions are to be used for purposes of this information reporting requirement only:

Adjusted Sales for Resale for Annual Charges

This category includes jurisdictional sales of energy under contracts that do not anticipate service interruptions. Such energy must be available to a resale customer at all times during the period covered by a commitment, even under adverse conditions. Transactions to include under this reporting category are firm power sales supplying the full requirements or partial requirements of a customer, and sales of energy from unit or system capacity of a long-term duration (five years or more) under contracts that do not anticipate service interruptions when capacity is operationally available. These transactions include long-term sales of capacity and energy and long-term firm transmission service.

Adjusted Transmission Delivered for Annual Charges

Jurisdictional energy transactions not included in the above Adjusted Sales for Resale category, involving power transmitted for another party over the transmission facilities of the utility providing service.

Adjusted Interchange out for Annual Charges

Jurisdictional energy transactions not included in either the above Adjusted Sales for Resale category or the above Adjusted Transmission Delivered category.

All entities with rate schedules on file at the Commission must file, under oath, the data requested. This 1986 information must be filed with the Office of the Secretary within 15 days of the date of issuance of this rule.[367] In all subsequent years, this information shall be filed with the Office of the Secretary by April 30th of each year. In the absence of this filing, the Commission staff may estimate each entity's adjusted sales for resale and adjusted coordination sales including adjusted interchange out and adjusted transmission delivered for purposes of computing the annual charge.

3. Special Individual Requests

Three IOUs petition the Commission for special relief from assessment of annual charges. Texas Utilities Electric Company (TUECo) requests deletion of its name from the list of IOUs that will be assessed annual charges. According to TUECo, it is not a "public utility" as defined by the FPA and it is "subject to Commission jurisdiction solely under sections 210, 211, and 212 of the Federal Power Act."[368]

The Commission does not believe that TUECo should be exempt from annual charges. TUECo is, to a limited extent, subject to the Commission's jurisdiction. In fact, it has rate schedules on file with the Commission and files a FERC Form No. 1 annually. Since transactions are made under the rate schedules it is only fair that TUECo pay its portion of the Commission's expenses allocable to these transactions.

Houston Lighting & Power Company (HL&PCo), which has a single transmission tariff on file with the Commission, asserts that it should not be assessed an annual charge because it is not a "public utility" within the meaning of the FPA and therefore should not be assessed charges. HL&PCo relies on the NOPR's statement that only public utilities would be assessed annual charges.[369] Alternatively, HL&PCo argues that the filing fee it already paid in conjunction with its sole tariff compensates the Commission for any costs the Commission has incurred on HL&PCo's behalf.[370] Thus HL&PCo believes that assessment of annual charges to it would not constitute the recovery of costs of regulating IOUs.

The Commission is denying HL&PCo's requests for the same reasons it denies TUECo's request. The Commission incurs administrative costs in providing services to IOUs and other entities which have rate schedules on file with the Commission. Every such entity can take advantage of this program. The Commission emphasizes that the IOAA, not the Budget Act, allows a fee to be assessed only for a specific benefit rendered. Under the Budget Act, the assessment of an annual charge against entities with few rate filings is "fair and equitable" because, even if the entity files no requests for specific benefits, it nevertheless may be subject to Commission review of accounting or corporate matters or benefit from a host of Commission services.[371] Annual charge assessments for these two Texas utilities will be limited to and based upon the number of kilowatt-hour transactions taking place under the rate schedules on file with the Commission.

Ohio Valley Electric Corporation (OVEC) requests that the Commission exempt the sales transactions between it and its out-of-state wholly-owned subsidiary Indiana-Kentucky Electric Corporation (IKEC). According to OVEC, it was formed by 15 IOUs for the purpose of supplying the electric power requirements of the United States Department of Energy's gaseous diffusion plant.[372] OVEC claims that IKEC provides no retail service and makes only one sale for resale, the rate schedule for which was filed with the Commission on September 10, 1953.[373] OVEC asserts that IKEC should be exempt from the annual charge because the two companies' separate corporate identities exist only because of statutory requirements of the two states in which they operate. OVEC also asserts that assessing it an annual charge would be taking money out of DOE's coffers to put into the Commission's.

The Commission denies OVEC's request because the reason for its peculiar structure, while dictated by state corporate requirements, still generates costs when the Commission regulates the transactions between the two companies. Indeed, it is that structure which requires that a sale take place. The Commission must in turn regulate these power sales between OVEC and IKEC, thereby incurring the cost of regulation. Since the Commission is aware of no compelling policy reason to exempt them from the annual charges, IKEC will be so assessed.

OVEC's, HL&PCo's and TUECo's requests for exemption from annual charges are more appropriately designated as waivers. They are clearly IOUs which would otherwise be subject to annual charge assessment. None of them have alleged that the criteria necessary for waiver are applicable to their situations.[374] Thus, the

[367] To facilitate the timely filing of the requested information, the Commission is serving a copy of this rule on each entity listed in Appendix F. This service is by United States Mail, first class, on the date of issuance of this rule.

[368] Comments of TUECo at 2.

[369] Comments of HL&PCo at 5–6.

[370] *Id.* at 4.

[371] These may include access to the Commission's library and public docket room; availability of Commission filings, notices and decisions through the RIMS system of document retrieval; the publication and indexing of Commission decisions, regulations, underlying statutes, notices of proposed rulemakings, regulatory preambles, *etc.* in *FERC Reports* and *FERC Statutes & Regulations;* the opportunity to participate in proceedings in which the company's competitors seek benefits; the availability of Commission staff to discuss informally regulatory questions, either over the telephone or in person; plus the more general advantages which regulation provides to the members of any regulated industry.

[372] Comments at OVEC at 2.

[373] As modified by letter filed December 1, 1977 in Docket No. ER77–632. Comments of OVEC at 5.

[374] As noted in Part III B 5 above, the Commission will apply the same waiver standards as now apply to a petition for waiver of all or part of a filing fee. A company requesting waiver of a filing fee must show that it is economically unable to pay all or part of the fee or that such payment would place it in financial distress or emergency. 18 CFR 381.106 (1986). The Commission will impose the same stringent standard to requests for waiver of annual charges because any charges waived for one

Continued

Commission concludes that these IOUs should be assessed annual charges. Finally, the Commission does not believe that any of the three petitioners will suffer a significant monetary drain on their financial resources because of these annual charges. Annual charges will be assessed against those entities which (1) have rate schedules on file for sales for resale and coordination (interchange out and transmission delivered) sales, and (2) are required to file FERC Form No. 1 or 1–F. If an entity has few or no sales under these rate schedules, it will be assessed little or no annual charges.

VII. Regulatory Flexibility Act

When the Commission is required by section 553 of the Administrative Procedure Act [375] to publish a notice of proposed rulemaking, it is also required by section 603 of the Regulatory Flexibility Act (RFA) [376] to prepare and make available for public comment an initial regulatory flexibility analysis, unless the Commission certifies pursuant to the RFA that the proposed rule would not have a "significant economic impact on a substantial number of small entities." [377] The RFA is intended to ensure careful and informed agency consideration of rules that may significantly affect small entities and to encourage consideration of alternative approaches to minimize harm to or burdens on small entities.

In this case, the RFA requires the Commission to analyze only the impacts on small entities that would be subject to this rule. As discussed before, this rule would only apply to four distinct classes of entities—interstate natural gas pipeline companies regulated under the NGA and the NGPA, public utilities, electric cooperatives and Federal Power Marketing Agencies regulated under the FPA and related statutes, and interstate oil pipeline companies regulated under the ICA. However, the Commission has proposed not to assess annual charges against specific small entities, such as natural gas pipelines with annual sales and transportation volumes not exceeding 200,000 Mcf in each of the three years immediately preceding the billing year; electric cooperatives without rates on file with the Commission; those entities that apply for qualifying facility status under PURPA; and those entities that seek review of DOE adjustment denials and remedial orders.

One commenter contends that multiple assessment of annual charges on the same kilowatt-hours will have a "significant economic impact" on the small entities which comprise electric cooperatives.[378] The Commission does not believe that the sale-for-resale assessment on the order of only $.001 per kilowatt-hour constitutes a "significant" economic impact under the Regulatory Flexibility Act.

Overall, the Commission does not believe that this rule will have a significant direct impact on small entities. Specifically, most, if not all, jurisdictional natural gas pipeline companies, public utilities, power marketing agencies, and oil pipeline companies that would be assessed annual charges under this rule do not fall within the RFA's definition of small entity because most jurisdictional natural gas pipeline companies, public utilities, power marketing agencies, and oil pipeline companies subject to this rule are too large to be considered "small entities." [379] Therefore, the Commission certifies that this rule will not have a "significant economic impact on a substantial number of small entities."

VIII. Paperwork Reduction Act Statement

The Paperwork Reduction Act [380] and the Office of Management and Budget (OMB) regulations [381] require that OMB approve certain information collection requirements imposed by agency rule. On May 28, 1987, the OMB approved for 90 days information collection requirements in 18 CFR 382.105 and 382.201(b)(4) under OMB Control Number 1902–0132, supplemental reporting requirements and revisions to FERC Form Nos. 2 and 2–A under OMB Control Numbers 1902–0028 and 1902–0030 respectively, and the natural gas rate annual charge adjustment clause filing requirement in 18 CFR 154.38(d)(6)(i) under OMB Control Number 1902–0070.

IX. Notice and Comment

The Commission finds good cause for making § 382.201(b)(4) of the Commission's regulations effective upon less than 30 days' notice. That regulation requires a public utility to file certain sales-for-resale and coordination sales data with the Commission within fifteen days from the issuance of this rule.

Notice and comment procedures are not required under the Administrative Procedure Act when the agency for good cause finds that notice and comment is impracticable, unnecessary, or contrary to the public interest.[382] The legislative history of the Administrative Procedure Act indicates that notice and comment is impracticable "when the de and required execution of the agency functions would be unavoidably prevented by its undertaking public rule-making proceedings." [383]

The Commission finds that, in this instance, providing for notice and comment before the issuance of this portion of the final rule is impractical and unnecessary. Congress required the Commission to issue a rule requiring payment of the first annual charge bills by the end of fiscal year 1987.[384] To meet this deadline, the Commission must have the sales-for-resale and coordination-sales data by mid-June 1987. The Commission thus does not have sufficient time to allow for notice and comment prior to the effective date of § 382.201(b)(4). Therefore, the Commission is making that regulation effective immediately.[385]

X. Effective Date

Section 382.201(b)(4) of the Commission's regulations will be effective May 29, 1987. All other amendments made by this final rule will be effective on July 6, 1987.

List of Subjects

18 CFR Part 154

Alaska, Natural gas, Pipelines, Reporting and recordkeeping requirements.

18 CFR Part 375

Authority delegations (government agencies), Seals and insignia, Sunshine Act.

18 CFR Part 382

Annual charges.

In consideration of the foregoing, the Commission amends Parts 154 and 375 of, and adds Part 382 to, Chapter I, Title 18, Code of Federal Regulations, as set forth below.

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company must be paid the following year by all of the program's regulated companies, due to the Budget Act's requirement that the Commission recover *all* its costs.

[375] 5 U.S.C. 553 (1982).

[376] 5 U.S.C. 601–612 (1982).

[377] 5 U.S.C. 605(b) (1982).

[378] Comments of GSEC at 8–9.

[379] 5 U.S.C. 601(6) (1982).

[380] 44 U.S.C. 3501–3520 (1982).

[381] 5 CFR Part 1320 (1986).

[382] 5 U.S.C. 553(b)(B) (1982).

[383] Senate Rep. No. 752, 79th Cong., 1st Sess. 16 (1945).

[384] *See* Budget Act section 3401(d).

[385] As noted in Part VI C 2 above, to facilitate the electric entities' timely filing of this data, the Commission is serving a copy of this rule on each such entity listed in Appendix F. This service is by United States Mail, first class, on the date of issuance of this rule.

By direction of the Commission.

Kenneth F. Plumb,

Secretary.

PART 154—[AMENDED]

1. The authority citation of Part 154 is revised to read as follows:

Authority: Omnibus Budget Reconciliation Act of 1986, Pub. L. No. 99-509, Title III, Subtitle E, Sec. 3401 (Oct. 21, 1986); Natural Gas Act, 15 U.S.C. 717-717w (1982); Natural Gas Policy Act, 15 U.S.C. 3301-3432 (1982); Administrative Procedure Act, 5 U.S.C. 551-557 (1982); Interstate Commerce Act, 49 U.S.C. 1-27 (1976); Department of Energy Organization Act, 42 U.S.C 7102-7352 (1982); E.O. 12009, 3 CFR 1978 Comp., p. 142; Federal Power Act, 16 U.S.C. 791a-828c (1982); Public Utility Regulatory Policies Act, 16 U.S.C. 2601-2645 (1982).

2. In § 154.38, a new paragraph (d)(6) is added to read as follows:

§ 154.38 Composition of rate schedule.

* * * * *

(d) *Statement of rate.*

* * * * *

(6)(i) A natural gas pipeline company may adjust its rates annually to recover from its customers annual charges assessed it by the Commission under Part 382 of this chapter pursuant to an annual charge adjustment clause (ACA clause). The ACA clause: (A) Must be filed with the Commission; (B) must indicate the amount of annual charges to be flowed through per unit of energy sold or transported (ACA unit charge); and (C) can only be effective if approved by the Commission. A natural gas pipeline choosing to recover its annual charges pursuant to an ACA clause must use the ACA unit charge specified by the Commission at the time the Commission calculates the annual charge bills.

(ii) A company must reflect the ACA unit charge in each of its rate schedules applicable to sales or transportation deliveries. The company must apply the ACA unit charge to the commodity component of rate schedules with two-part rates.

(iii) Changes to the ACA unit charge must be filed annually to reflect the annual charge unit rate, as authorized by the Commission each fiscal year. Any tariff filings made by the company to change its ACA unit charge must meet the notice requirements of § 154.22 of this part.

(iv) Only if the company has paid the applicable annual charge in compliance with § 382.103 of this chapter, its ACA unit charge can go into effect.

(v) A company may recover annual charges through an ACA unit charge only if its rates do not otherwise reflect the costs of annual charges assessed by the Commission under § 382.106(a)(i) of this chapter.

* * * * *

PART 375—[AMENDED]

3. The authority citation of Part 375 is revised to read as follows:

Authority: Omnibus Budget Reconcilation Act of 1986, Pub. L. No. 99-509, Title III, Subtitle E, Sec. 3401 (Oct. 21, 1986); Department of Energy Organization Act, 42 U.S.C. 7101-7352 (1982); E.O. 12009, 3 CFR 1978 Comp., p.142; Administrative Procedure Act, 5 U.S.C. 551-557 (1982).

4. In § 375.306, a new paragraph (j) is added to read as follows:

§ 375.306 Delegations to the Oil Pipeline Board.

* * * * *

(j) Deny or accept, in whole or part, petitions for waiver of annual charges prescribed in § 382.203 of this chapter in accordance with the standard set forth in § 382.105 of this chapter.

5. In § 375.307, a new paragraph (w) is added to read as follows:

§ 375.307 Delegations to the Director of the Office of Pipeline and Producer Regulation.

* * * * *

(w) Deny or accept, in whole or part, petitions for waiver of annual charges prescribed in § 382.202 of this chapter in accordance with the standard set forth in § 382.105 of this chapter.

6. In § 375.308, a new paragraph (v) is added to read as follows:

§ 375.308 Delegations to the Director of the Office of Electric Power Regulation.

* * * * *

(v) Deny or accept, in whole or part, petitions for waiver of annual charges prescribed in § 382.201 of this chapter in accordance with the standard set forth in § 382.105 of this chapter.

7. A new Part 382 is added to read as follows:

PART 382—ANNUAL CHARGES

Subpart A—General Provisions

Sec.

382.101 Purpose.
382.102 Definitions.
382.103 Payment.
382.104 Enforcement.
382.105 Waiver.
382.106 Accounting for annual charges paid under Part 382.

Subpart B—Assessment of Annual Charges

382.201 Annual charges under Parts II and III of the Federal Power Act and related statutes.
382.202 Annual charges under the Natural Gas Act, Natural Gas Policy Act and related statutes.
382.203 Annual charges under the Interstate Commerce Act.

Authority: Omnibus Budget Reconciliation Act of 1986, Pub. L. No. 99-509, Title III, Subtitle E, sec. 3401 (Oct. 21, 1986); Department of Energy Organization Act, 42 U.S.C. 7101-7352 (1982); E.O. 12009, 3 CFR 1978 Comp., p.142 Administrative Procedure Act, 5 U.S.C. 551-557 (1982); Natural Gas Act 15 U.S.C. 717-717w (1982); Federal Power Act, 16 U.S.C. 791a-828c (1982); Natural Gas Policy Act, 15 U.S.C. 3301-3432 (1982); Public Utility Regulatory Policies Act, 16 U.S.C. 2601-2645 (1982); Interstate Commerce Act, 49 U.S.C. 1-27 (1976).

Subpart A—General Provisions

§ 382.101 Purpose.

The purpose of this part is to establish procedures for calculating and assessing annual charges to reimburse the United States for all of the costs incurred by the Commission, other than costs incurred in administering Part I of the Federal Power Act and costs recovered through the Commission's filing fees.

§ 382.102 Definitions.

For the purpose of this part:

(a) "Natural gas pipeline company" means any person:

(1) Engaged in natural gas sales for resale or natural gas transportation subject to the jurisdiction of the Commission under the Natural Gas Act whose sales for resale and transportation exceed 200,000 Mcf at 14.73 psi (60 °F) in any of the three calendar years immediately preceding the fiscal year for which the Commission is assessing annual charges; and

(2) Not engaged soley in "first sales" of natural gas as that term is defined in section 2(21) of the Natural Gas Policy Act of 1978; and

(3) To whom the Commission has not issued a Natural Gas Act section 7(f) declaration.

(b) "Public utility" means any person who owns or operates facilities subject to the jurisdiction of the Commission under Parts II and III of the Federal Power Act, and who has rate schedule(s) on file with the Commission and who is not a "qualifying small power producer" or a "qualifying cogenerator", as those terms are defined in section 3 of the Federal Power Act, or the United States or a state, or any political subdivision of the United States or a state, or any agency, authority, or instrumentality of the United States, a state, political subdivision of the United States, or political subdivision of a state.

(c) "Oil pipeline company" means any person engaged in the transportation of crude oil and petroleum products subject to the Commission's jurisdiction under the Interstate Commerce Act.

(d) "Natural gas regulatory program" is the Commission's regulation of the natural gas industry under the Natural Gas Act; Natural Gas Policy Act of 1978; Alaska Natural Gas Transportation Act; Public Utility Regulatory Policies Act; Department of Energy Organization Act; Outer Continental Shelf Lands Act; Energy Security Act; Regulatory Flexibility Act; Crude Oil Windfall Profit Tax Act; National Environmental Policy Act; National Historic Preservation Act.

(e) "Electric regulatory program" is the Commission's regulation of the electric industry under Parts II and III of the Federal Power Act; Public Utility Regulatory Policies Act; Powerplant and Industrial Fuel Use Act; Department of Energy Organization Act; Energy Security Act; Regulatory Flexibility Act; Pacific Northwest Electric Power Planning and Conservation Act; Flood Control and River and Harbor Acts; Bonneville Project Act; Federal Columbia River Transmission Act; Reclamation Project Act; Nuclear Waste Policy Act; National Environmental Policy Act; and the Public Utility Holding Company Act.

(f) "Oil regulatory program" is the Commission's regulation of the oil pipeline industry under the Interstate Commerce Act; Department of Energy Organization Act; Regulatory Flexibility Act; Outer Continental Shelf Lands Act; and the Crude Oil Windfall Profit Tax Act.

(g) "Person" means an individual, partnership, corporation, association, joint stock company, public trust, or organized group of persons, whether incorporated or not.

(h) "Adjusted sales for resale activities" means the portion of the Commission's electric regulatory program devoted to the regulation of sales for resale.

(i) "Adjusted sales for resale" are the jurisdictional sales of energy under contracts that do not anticipate service interruptions Such energy must be available to a resale customer at all times during the period covered by a commitment, even under adverse conditions. Transactions to include under this reporting category are firm power sales supplying the full requirements or partial requirements of a customer, and sales of energy from unit or system capacity of a long-term duration (five years or more) under contracts that do not anticipate service interruptions when capacity is operationally available. These transactions include long-term sales of capacity and energy and long-term firm transmission service.

(j) "Adjusted transmission delivered" are jurisdictional energy transactions not included in the above "Adjusted sales for resale" category, involving power transmitted for another party over the transmission facilities of the utility providing service.

(k) "Adjusted interchange out" are jurisdictional energy transactions not included in either the above "Adjusted sales for resale" category or the above "Adjusted transmission delivered" category.

(l) "Adjusted coordination sales activities" means the portion of the Commission's electric regulatory program consisting of the regulation of all jurisdictional sales of energy except adjusted sales for resale activities.

(m) "Adjusted sales for resale kilowatt-hours" means the number of kilowatt-hours of electrical energy (1) sold under contracts that do not anticipate service interruptions, (2) reported as adjusted sales for resale under section 382.201(b)(4) of this Part, and (3) the rates, charges, terms and conditions of which are regulated by the Commission.

(n) "Adjusted coordination sales kilowatt-hours" means the number of kilowatt-hours of electrical energy that are (1) not adjusted sales for resale kilowatt-hours, (2) reported as adjusted interchange out and adjusted transmission delivered under section 382.201(b)(4) of this Part, and (3) the rates, charges, terms and conditions of which are regulated by the Commission.

(o) "Operating revenues" means the monies (1) received by an oil pipeline company for providing common carrier services regulated by the Commission, and (2) included in FERC Account No. 200, 210 or 220 in FERC Annual Report Form No. 6, page 301, lines 1, 2, and 3, column d, under Part 352 of the Commission's regulations.

(p) "Fiscal year" means the twelve-month period that begins on the first day of October and ends on the last day of September.

(q) "Preceding calendar year" means the twelve-month period that begins on the first day of January and ends the last day of December and immediately precedes the end of the fiscal year for which the Commission is assessing annual charges.

(r) "Adjusted costs of administration" means the difference between the estimated costs of administering a regulatory program for each fiscal year adjusted to reflect any overcollection or undercollection of cost attributable to that regulatory program in the annual charge assessment for the preceding fiscal year, and the estimated amount of filing fees collected during that fiscal year under the provisions of Parts 346 and 381 of the Commission's regulations for activities that relate to that regulatory program.

(s) "Power Marketing Agencies" means the Bonneville Power Administration, the Alaska Power Administration, the Southeastern Power Administration, the Southwestern Power Administration, and the Western Area Power Administration.

§ 382.103 Payment.

(a) Annual charges assessed under this part must be paid within 45 days of the issuance of the bill by the Commission, unless a petition for waiver has been filed under § 382.105 of this part.

(b) Payment must be made by check, draft, or money order, payable to the United States Treasury.

(c) If payment is not made within 45 days of issuance of a bill, interest will be assessed. Interest will be computed in accordance with § 154.67(c)(2)(iii) of this chapter, from the date on which the bill becomes delinquent.

§ 382.104 Enforcement.

The Commission may refuse to process any petition, application, or other filing submitted by or on the behalf of any person that does not pay the annual charge assessed when due, or may take any other appropriate action permitted by law.

§ 382.105 Waiver.

(a) *Filing of petition.* Any annual charges bill recipient may submit a petition for waiver of the regulations in this part. An original and two copies of a petition for waiver must include evidence, such as a financial statement, clearly showing either that the petitioner does not have the money to pay all or part of the annual charge, or, if the petitioner does pay the annual charge, that the petitioner will be placed in financial distress or emergency. Petitions for waiver must be filed with the Office of the Secretary of the Commission within 15 days of issuance of the bill.

(b) *Decision on petition.* The Commission or its designee will review the petition for waiver and then will notify the applicant of its grant or denial, in whole or in part. If the petition is denied in whole or in part, the annual charge becomes due 30 days from the date of notification of the denial.

§ 382.106 Accounting for annual charges paid under Part 382.

(a) Any natural gas pipeline company subject to the provisions of this part must account for annual charges paid by charging the amount to either Account No. 928, Regulatory Commission Expenses, of the Commission's Uniform System of Accounts, or the natural gas pipeline company's annual charge adjustment clause prescribed in § 154.38(d)(6) of this chapter.

(b) Any public utility subject to the provisions of this Part must account for annual charges paid by charging the amount to Account No. 928, Regulatory Commission Expenses, of the Commission's Uniform System Accounts.

(c) Any oil pipeline company subject to the provisions of this Part must account for annual charges paid by charging the amount to Account No. 510, Supplies and Expenses, of the Commission's Uniform System of Accounts.

Subpart B—Annual Charges

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

(a) *Determination of costs to be assessed against public utilities.* The adjusted costs of administration of the electric regulatory program, excluding the costs of regulating the Power Marketing Agencies, will be apportioned between adjusted sales for resale activities and adjusted coordination sales activities in proportion to the total staff time dedicated to each. The amount apportioned to adjusted sales for resale activities will constitute "adjusted sales for resale costs," and the amount apportioned to adjusted coordination sales activities will constitute "adjusted coordination sales costs."

(b) *Determination of annual charges to be assessed against public utilities.* (1) The adjusted sales for resale costs determined under paragraph (a) of this section will be assessed against each public utility based on the proportion of the adjusted sales for resale kilowatt-hours of each 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 adjusted sales for resale kilowatt-hours in the immediately preceding reporting year of all public utilities being assessed annual charges.

(2) The adjusted coordination sales costs determined under paragraph (a) of this section will be assessed against each public utility based on the proportion of the adjusted coordination sales kilowatt-hours of each 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 adjusted coordination sales kilowatt-hours in the immediately preceding reporting year of all public utilities being assessed annual charges.

(3) The annual charges assessed against each public utility will be the sum of the amounts determined in paragraphs (b)(1) and (b)(2) of this section.

(4) Reporting requirement. (i) For purposes of computing annual charges, a public utility, as defined in § 382.102(b) of this part, subject to the provisions of this part, must submit under oath to the Office of the Secretary of the Commission, by June 13, 1987, and by April 30 of each year thereafter, an original and conformed copies of the following information (designated as FERC Reporting Requirement No. 582):

(A) The total annual adjusted sales for resale kilowatt-hours, as defined in § 382.102(m) of this part; and

(B) The total annual adjusted coordination sales kilowatt-hours, as defined in § 382.102(n) of this part.

(ii) The data required in paragraphs (4)(a) (i) and (ii) of this section will be derived from information reported to the Commission annually in the FERC Form Nos. 1 and 1–F. For purposes of computing annual charges, the definitions in § 382.102(i)–(1) of this part will be used in conjunction with the following worksheet to determine data reported in paragraphs (4)(a) (i) and (ii) of this section.

WORKSHEET.—AS REPORTED ON THE FERC FORM NO. 1

[Amounts in kilowatt-hours]

Annual charge categories	Form 1 sales for resale	Form 1 inter-change out	Form 1 transmis-sion delivered	Kwh totals
Totals from form 1	([1])	([2])	([3])	([4])
(A) Adjusted sales for resale for A/C purposes				
(B) Coordination sales including transmission delivered and interchange out for A/C purposes				

[1] Must agree with totals shown in Form No. 1, on pages 310–311, included in Account No. 447.

[2] Must agree with total interchange out shown in Form No. 1, on page 328, included in Account No. 555.

[3] Must agree with total transmission delivered shown in Form No. 1, on page 332, included in Account No. 456.

[4] Total A+B=Total [1]+[2]+[3].

(c) *Determination of annual charges to be assessed against 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 kilowatt-hours of sales of each power marketing agency in the immediately preceding fiscal year to the sum of the kilowatt-hours of sales in the immediately preceding fiscal year of all power marketing agencies being assessed annual charges.

§ 382.202 Annual charges under the Natural Gas Act and Natural Gas Policy Act of 1978 and related statutes.

The adjusted costs of administration of the natural gas regulatory program will be assessed against each natural gas pipeline company based on the proportion of the total jurisdictional gas subject to Commission regulation which was sold and transported by each company in the immediately preceding calendar year to the sum of the jurisdictional gas subject to Commission regulation which was sold and transported in the immediately preceding calendar year by all natural gas companies being assessed annual charges.

§ 382.203 Annual charges under the Interstate Commerce Act.

(a) The adjusted costs of administration of the oil regulatory program will be assessed against each oil pipeline company based on the proportion of the total operation revenues of each oil pipeline company for the immediately preceding calendar year to the sum of the operating revenues for the immediately preceding calendar year of all oil pipeline companies being assessed annual charges.

(b) No oil pipeline company's annual charge may exceed a maximum charge established each year by the Commission to equal 6.339 percent of the adjusted costs of administration of the oil regulatory program. The maximum charge will be rounded to the nearest $1000. For every company with an annual charge determined to be above the maximum charge, that company's annual charge will be set at the maximum charge, and any amount above the maximum charge will be reapportioned to the remaining companies. The reapportionment will be computed using the method outlined in paragraph (a) of this section (but excluding any company whose annual charge is already set at the maximum amount). This procedure will be repeated until no company's annual charge exceeds the maximum charge.

Note.—Appendices A through F will not appear in the Code of Federal Regulations.

Appendix A—List of 90 Commenters

Allegheny Power System, Inc.
American Electric Power Service Corporation
American Gas Association
American Paper Institute, Inc.
American Petrofina Pipe Line Company
ANR Pipe Line Company
ARCO Pipe Line Company
Association of Oil Pipe Lines
Association of Texas Intrastate Natural Gas Pipelines
Baltimore Gas and Electric Company
Boston Edison Company *et al.*
Central Illinois Public Service Company
Champlin Petroleum Company
Cincinnati Gas & Electric Company *et al.*
Cities Services Oil & Gas Company
Columbia Gas Transmission Corporation
Commonwealth Edison
Connecticut Natural Gas Corporation
Consolidated Edison Company of New York
Consolidated Gas Transmission Corporation
Detroit Edison Company
Duke Power Company
Eastern Shore Natural Gas Company
Edison Electric Institute
Electric Utilities
Enterprise Pipeline Company
Exxon Pipeline Company
Florida Power & Light Company
Florida Public Utilities Company
Georgia Power Company
Golden Spread Electric Cooperative, Inc.
Granite State Gas Transmission, Inc.
Houston Lighting & Power Company
Independent Petroleum Association of America
Interstate Natural Gas Association of America
Interstate Power Company
Iowa-Illinois Gas and Electric Company
Iowa Power and Light Company
Iowa Southern Utilities Company
Iowa State Utilities Board
Kansas Gas and Electric Company
Lawrenceberg Gas Transmission Corporation
Lone Star Gas Company
Middle South Utilities, Inc.
Montana Power Company
National Fuel Gas Distribution Corporation
Natural Gas Supply Association
New England Power Service
Northeast Utilities
Northern Border Pipeline Company
Northern Natural Gas Company
Northwest Alaskan Pipeline Company
Northwest Pipeline Corporation
Ohio Valley Electric Corporation
Pacific Gas and Electric Company
Pacific Gas Transmission Company
Pacific Power & Light Company
Panhandle Eastern Pipe Line Company
Phillips Pipe Line Company
Potomac Electric Power Company
Public Service Commission of the District of Columbia
Public Service Commission of Nevada
Public Service Company of Colorado
Public Service Electric and Gas Company
Puget Sound Power & Light Company
Raton Gas Transmission Company
San Diego Gas and Electric Company
Santa Fe Pacific Pipelines, Inc.
Sohio Alaska Pipeline Company
South Carolina Electric & Gas Company
South Carolina Generating Company
Southern California Edison Company
Southern Company Services, Inc.
Southwestern Electric Power Company
Southwestern Public Service Company
State Corporation Commission of Virginia
Texaco USA
Texas Eastern Transmission Corporation
Texas-New Mexico Power Company
Texas Utilities Electric Company
Transok, Inc.
United Distribution Companies
Utah Power & Light Company
Virginia Electric and Power Company
Washington Gas Light Company
Washington Natural Gas Company
Washington Water Power
West Texas Gas, Inc.
Williams Natural Gas Company
Williams Pipe Line Company

Appendix B

1. List of 131 Natural Gas Companies which would be Assessed Annual Charges based upon April 1987 Data.

(a) Interstate natural gas pipelines that have certificates of public convenience and necessity under section 7 of the NGA, that are subject to Commission NGA section 4 authority, and that sell and transport volumes in excess of 200,000 Mcf annually for any of the three calendar years immediately preceding the billing year (currently 114 pipelines):

Alabama-Tennessee Natural Gas Company
Algonquin Gas Transmission Company
Algonquin LNG Inc.
ANR Pipeline Company
ANR Storage Company
Arkla Energy Resources, a division of Arkla, Inc.
Associated Natural Gas Company
Bayou Interstate Pipeline System
Bear Creek Storage Company
Black Marlin Pipeline Company
Blue Dolphin Pipe Line Company
Bluefield Gas Company
Border Gas, Inc.
Boundary Gas, Inc.
Canyon Creek Compression Company
Caprock Pipeline Company
Carnegie Natural Gas Company
Chandeleur Pipe Line Company
Cimarron Transmission Company
Colorado Interstate Gas Company
Columbia Gas Transmission Corporation
Columbia Gulf Transmission Company
Commercial Pipeline Company, Inc.
Consolidated Gas Transmission Corporation
Distrigas of Massachusetts Corporation
East Tennessee Natural Gas Company
Eastern Shore Natural Gas Company
El Paso Natural Gas Company
Equitable Gas Company, a division of Equitable Resources, Inc.
Florida Gas Transmission Company
Freeport Interstate Pipeline Company
Gas Gathering Corporation
Gas Transport, Inc.
Gasdel Pipeline System Inc.
Granite State Gas Transmission, Inc.
Great Lakes Gas Transmission Company
Hampshire Gas Company
High Island Offshore System
Honeoye Storage Corporation
Inland Gas Company, Inc.
Jackson Prairie Underground Storage Project, Washington Natural Gas Company, Operator
Jupiter Energy Corporation
KN Energy, Inc.
Kentucky West Virginia Gas Company
Lawrenceburg Gas Transmission Corporation
Locust Ridge Gas Company
Lone Star Gathering Company
Louisiana-Nevada Transit Company
MIGC, Inc.
Marengo Corporation
Michigan Consolidated Gas Company
Michigan Gas Storage Company
Mid Louisiana Gas Company
Midwestern Gas Transmission Company
Mississippi River Transmission Corporation
Mountain Fuel Resources, Inc.
National Fuel Gas Supply Corporation
Natural Gas Pipeline Company of America
North Penn Gas Company
Northern Border Pipeline Company
Northern Natural Gas Company, a Division of Enron Corp.

Northwest Alaskan Pipeline Company
Northwest Pipeline Corporation
Ohio River Pipeline Corporation
Orange and Rockland Utilities, Inc.
Overthrust Pipeline Company
Ozark Gas Transmission System
Pacific Gas Transmission Company
Pacific Interstate Offshore Company
Pacific Interstate Transmission Company
Pacific Offshore Pipeline Company
Panhandle Eastern Pipe Line Company
Pelican Interstate Gas System
Penn-Jersey Pipe Line Company
Penn-York Energy Corporation
Point Arguello Natural Gas Line Company
Raton Gas Transmission Company
Ringwood Gathering Company
Sabine Pipe Line Company
Seagull Interstate Corporation
Sea Robin Pipeline Company
South County Gas Company
South Georgia Natural Gas Company
Southern Natural Gas Company
Southwest Gas Corporation
Southwest Gas Storage Company
Southwest Gas Transmission Company
Stingray Pipeline Company
Superior Offshore Pipeline Company
Tarpon Transmission Company
TCP Gathering Company
Tennessee Gas Pipeline Company, a Division of Tenneco, Inc.
Texas Eastern Transmission Corporation
Texas Gas Pipe Line Corporation
Texas Gas Transmission Corporation
Texas Sea Rim Pipeline, Inc.
Trailblazer Pipeline Company
Transco Gas Supply Company
Transcontinental Gas Pipe Line Corporation
Transwestern Pipeline Company
Trunkline Gas Company
Union Light, Heat and Power Company
United Gas Pipe Line Company
U-T Offshore System
Valero Interstate Transmission Company
Valley Gas Transmission, Inc
West Texas Gas, Inc.
West Texas Gathering Company
Western Gas Interstate Company
Western Transmission Corporation
Williams Natural Gas Company
Williston Basin Interstate Pipeline Company
Wyoming Interstate Company, Ltd.
Zenith Natural Gas Company

(b) Interstate natural gas pipelines that have certificate authority under section 7 of the NGA but no tariff on file for jurisdictional and nonjurisdictional sales and that sell and transport volumes in excess of 200,000 Mcf annually for any of the three calendar years immediately preceding the billable year (currently 12 pipelines):

American Distribution Company (Alabama Division)
Glacier Gas Company
Great Plains Natural Gas Company
Indiana Utilities Corporation
Interstate Power Company
Iowa Public Service Company
Lone Star Gas Company, a Division of Enserch Corporation
Michigan Power Company
Pennsylvania and Southern Gas Company
Phillips Gas Pipeline Company
South Penn Gas Company
Union Gas System, Inc.

(c) LNG importers that fall within the Commission's jurisdiction pursuant to both sections 3 and 7 of the NGA and that sell and transport volumes in excess of 200,000 Mcf annually for any of the three calendar years immediately preceding the billable year (currently 5 pipelines):

Columbia LNG Corporation
Consolidated System LNG Company
Distrigas Corporation
Southern Energy Company
Trunkline LNG Company

2. List of 29 Natural Gas Companies which would be Exempted from Annual Charges based upon April 1987 Data.

(a) Companies the sales and transportation transactions of which do not exceed 200,000 Mcf per year for each of the three calendar years immediately preceding the billable year (currently 13 companies):

Blacksville Oil and Gas Co., Inc.
C.B. Gas Gathering, Inc.
Frontier Gas Storage Company
Gaylord Container Corporation
Georgia-Pacific Corporation
Great River Gas Company
International Paper Company
Mid-Continent Gas Storage Company
Mitco Pipeline Company
Northern States Power Company
RMNG Gathering Company
Urbana Corporation
Wheeler Gas, Inc.

(b) Importers with NGA section 3 and Presidential Permit authority only (currently 12 importers):

City of Roma, Texas
Del Norte Natural Gas Company
Entex, Inc.
Gas Service, Inc.
Inter-City Minnesota Pipelines Ltd., Inc.
Manchester Gas Company
Marathon Oil Company
Montana Power Company
Phillips Petroleum Company
St. Lawrence Gas Company
Valero Transmission Company
Vermont Gas Systems, Inc.

(c) Regulated interstate natural gas pipelines that have NGA section 7(f) declarations and that sell and transport volumes in excess of 200,000 Mcf annually for any of the three calendar years immediately preceding the billable year (currently 4 pipelines):

Arkansas Oklahoma Gas Corporation
Iowa-Illinois Gas and Electric Company
Shenandoah Gas Company
Washington Gas Light Company

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APPENDIX C

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 19__

GAS ACCOUNT — NATURAL GAS

1. The purpose of this page is to account for the quantity of natural gas received and delivered by the respondent, taking into consideration differences in pressure bases used in measuring Mcf of natural gas received and delivered.

2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.

3. Enter in column (c) the Mcf as reported in the schedules indicated for the items of receipts and deliveries.

01 NAME OF SYSTEM

Line No.	Item (a)	Ref. Page No. (b)	Amount of Mcf (14.73 psia at 60°F) (c)
2	GAS RECEIVED		
3	Natural Gas Produced	506	
4	LPG Gas Produced and Mixed with Natural Gas	515	
5	Manufactured Gas Produced and Mixed with Natural Gas		
6	Purchased Gas		
7	Wellhead	327	
8	Field Lines	327	
9	Gasoline Plants	327	
10	Transmission Line	327	
11	City Gate Under FERC Rate Schedules	327	
12	LNG	327	
13	Other	327	
14	TOTAL, Gas Purchased *(Enter Total of lines 7 thru 13)*	327	
15	Gas of Others Received for Transportation	312	
16	Receipts of Respondents' Gas Transported or Compressed by Others	332	
17	Exchange Gas Received	328	
18	Gas Withdrawn from Underground Storage	512	
19	Gas Received from LNG Storage		
20	Gas Received from LNG Processing		
21	Other Receipts *(Specify):*		
22	TOTAL Receipts *(Enter Total of lines 3 thru 5, 14, and 15 thru 21)*		

Add: (Instruction 4, page 521)

4. *** Also indicate by footnote the volumes of nonjurisdictional gas which did not incur FERC regulatory costs by showing (1) the local distribution volumes delivered to the local-distribution-company portion of the reporting pipeline by another jurisdictional pipeline; (2) the volumes which the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities, and which the reporting pipeline received through gathering facilities, distribution facilities or intrastate facilities, but not through any of the interstate portion of the reporting pipeline; and (3) the gathering line volumes which were not destined for the interstate market or which were not transported through any interstate portion of the reporting pipeline.

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 19__

GAS ACCOUNT — NATURAL GAS (Continued)

4. In a footnote report the volumes of gas from respondent's own production delivered to respondent's transmission system and included in natural gas sale.

5. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose. Use copies of pages 520 and 521.

01 NAME OF SYSTEM

Line No.	Item (a)	Ref. Page No. (b)	Amount of Mcf (14.73 psia at 60°F) (c)
23	GAS DELIVERED		
24	Natural Gas Sales		
25	Field Sales		
26	To Interstate Pipeline Companies for Resale Pursuant to FERC Rate Schedules	310	
27	Retail Industrial Sales	306	
28	Other Field Sales	310	
29	TOTAL, Field Sales *(Enter Total of lines 26 thru 28)*		
30	Transmission Systems Sales		
31	To Interstate Pipeline Co. for Resale Under FERC Rate Sched.	310	
32	To Intrastate Pipeline Co. and Gas Utilities for Resale Under FERC Rate Schedules	310	
33	Mainline Industrial Sales Under FERC Certification	306	
34	Other Mainline Industrial Sales	306	
35	Other Transmission System Sales	310	
36	TOTAL, Transmission System Sales *(Enter Total of lines 31 thru 35)*		
37	Local Distribution by Respondent		
38	Retail Industrial Sales	303	
39	Other Distribution System Sales	303	
40	TOTAL, Distribution System Sales *(Lines 38 + 39)*		
41	Interdepartmental Sales		
42	TOTAL SALES *(Enter Total of lines 29, 36, 40 and 41)*		
43	Deliveries of Gas Transported or Compressed for:		
44	Other Interstate Pipeline Companies	312	
45	Others	312	
46	TOTAL, Gas Transported or Compressed for Others *(Enter Total of lines 44 and 45)*	312	
47	Deliveries of Respondent's Gas for Trans. or Compression by Others	332	
48	Exchange Gas Delivered	328	
49	Natural Gas Used by Respondent	330	
50	Natural Gas Delivered to Underground Storage	512	
51	Natural Gas Delivered to LNG Storage		
52	Natural Gas Delivered to LNG Processing		
53	Natural Gas for Franchise Requirements		
54	Other Deliveries *(Specify)*:		
55	TOTAL SALES & OTHER DELIVERIES *(Lines 42, 46, 47 thru 54)*		
56	UNACCOUNTED FOR		
57	Production System Losses		
58	Storage Losses		
59	Transmission System Losses		
60	Distribution System Losses		
61	Other Losses *(Specify in so far as possible)*:		
62	TOTAL Unaccounted for *(Enter Total of lines 57 thru 61)*		
63	TOTAL SALES, OTHER DELIVERIES, AND UNACCOUNTED FOR *(Enter Total of lines 55 and 62)*		

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APPENDIX D

Add: (Instruction 2, Part XVII, page 18)

2. *** Also indicate by footnote the volumes of nonjurisdictional gas which did not incur FERC regulatory costs by showing (1) the local distribution volumes delivered to the local-distribution-company portion of the reporting pipeline by another jurisdictional pipeline; (2) the volumes which the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities, and which the reporting pipeline received through gathering facilities, distribution facilities or intrastate facilities, but not through any of the interstate portion of the reporting pipeline; and (3) the gathering line volumes which were not destined for the interstate market or which were not transported through any interstate portion of the reporting pipeline.

PART XVII: GAS ACCOUNT—NATURAL GAS

1. The purpose of this part is to account for the quantity of natural gas received and delivered by the respondent. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
2. Enter in column (b) the Mcf as reported in parts indicated for the respective items of receipts and deliveries.
3. If the respondent operates two or more systems which are not interconnected, separate pages should be submitted for each system.

01 Name of System:

Line No.	Item (a)	Amount of Mcf (14.73 psia at 60° F) (b)
02	GAS RECEIVED	
03	Natural Gas Produced	
04	Purchased Gas *(Enter total of above column b, line 05, Part XVI, Gas Purchases)*	
05	Other Receipts *(Specify):*	
06		
07		
08		
09	TOTAL RECEIPTS *(Enter total of lines 03 thru 08)*	
10	GAS DELIVERED	
11	Natural Gas Sales *(Transcribe entry from page 16, line 12, column c, Part XIII, Gas Sales Data)*	
12	Other Deliveries *(Specify):*	
13		
14		
15		
16	TOTAL DELIVERIES *(Enter total of lines 11 thru 15)*	
17	Unaccounted for	
18	TOTAL DELIVERIES AND UNACCOUNTED FOR *(Enter total of lines 16 and 17)*	

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Appendix E

List of Interstate Oil Pipeline Companies which would be Assessed Annual Charges Based on 1985 Data (currently 137 pipelines):

Acorn Pipeline Company
Air Force Pipeline, Inc.
Algonquin Pipeline Company
Allegheny Pipeline Company
Amerada Hess Pipeline Corporation
American Petrofina Pipe Line Company
Amoco Pipeline Company
ARCO Pipe Line Company
Asamera Pipeline, Inc.
Ashland Pipe Line Company
Atlantic Pipeline Corporation
Badger Pipe Line Company
Belle Fourche Pipeline Company
Black Lake Pipe Line Company
BP Pipelines, Inc.
Buccaneer Pipe Line Company
Buckeye Pipe Line Company, L.P.
Buckeye Pipe Line Company of Michigan, L.P.
Butte Pipe Line Company
C & T Pipeline, Inc.
Calnev Pipe Line Company
Cenergy Transmission Company
Chase Transportation Company
Chevron Pipe Line Company
Chicap Pipe Line Company
Chisholm Pipeline Company
Ciniza Pipe Line, Inc.
Citgo Pipeline Company
Cities Service NGL Pipeline Company
CKB Petroleum, Inc.
Clarco Pipe Line Company
CNG Pipeline Company
Coastal Pipeline Company
Cochin Pipeline System
Collins Pipeline Company
Colonial Pipeline Company
Conoco Pipeline Company
Cook Inlet Pipe Line Company
Crown-Rancho Pipe Line Corporation
Diamond Shamrock Refining and Marketing Company
Dixie Pipeline Company
Dome Pipeline Corporation
El Paso Frontera Corporation
Emerald Pipe Line Corporation
Enron Liquids Pipeline Company
Enterprise Pipeline Company
Enterprise Products Company of Mississippi
Eureka Pipe Line Company
Explorer Pipeline Company
Exxon Pipeline Company
Farmland Industries, Inc.
Four Corners Pipe Line Company
Frontier Pipeline Company
G & T Pipeline Company
Gulf Central Pipeline Company
Hess Pipeline Company
Howell Crude Oil Company
Husky Pipeline Company
Interstate Storage & Pipe Line Corporation
Jayhawk Pipeline Corporation
Kaneb Pipe Line Company
Kaw Pipe Line Company
Kerr-McGee Pipeline Corporation
Kiantone Pipeline Corporation
Koch Pipelines, Inc.
Kuparuk Transportation Company
Lake Charles Pipe Line Company
Lakehead Pipe Line Company, Inc.
Largo Company
Laurel Pipe Line Company
Locap, Inc.
Marathon Pipe Line Company
Mark Oil Pipeline Company
McMoran Pipeline Company
Mesa Transmission Company
Mid-America Pipeline Company
Mid-Valley Pipeline Company
Midland-Lea, Inc.
Milne Point Pipe Line Company
Minnesota Pipe Line Company
Mitco Pipeline Company
Mobil Alaska Pipeline Company
Mobil Eugene Island Pipeline Company
Mobil Pipe Line Company
National Transit Company
Navajo Pipeline Company
Northern Rockies Pipe Line Company
NW Pipeline Inc.
Ohio Oil Gathering Corporation II
Ohio River Pipe Line Company
Oiltanking of Texas Pipeline Company
Olympic Pipe Line Company
Osage Pipe Line Company
Owensboro-Ashland Company
Paloma Pipeline Company
Pennzoil Offshore Pipeline Company
Phillips Alaska Pipeline Corporation
Phillips Pipe Line Company
Pioneer Pipe Line Company
PL Pipeline Company
Plantation Pipe Line Company
Platte Pipe Line Company
Pogo Offshore Pipeline Company
Point Pedernales Pipeline Company
Portal Pipe Line Company
Portland Pipe Line Corporation
Samedan Pipeline Corporation
Santa Fe Pipeline Company
Seminole Pipeline Company
Shamrock Pipe Line Corporation
Shell Pipe Line Corporation
Sohio Alaska Pipeline Company
Sohio Pipe Line Company
Sonat Oil Transmission, Inc.
Southcap Pipe Line Company
Southern Pacific Pipe Lines, Inc.
Sun Oil Line Company of Michigan
Sun Pipe Line Company
Tecumseh Pipe Line Company
Texaco Pipeline Inc.
Texas Eastern Transmission Corporation
Texas-New Mexico Pipe Line Company
Total Pipeline Corporation
Trans Mountain Oil Pipe Line Corporation
Trans-Ohio Pipeline Company
Transco Terminal Company
Unocal Pipeline Company
Wascana Pipe Line, Inc.
West Emerald Pipe Line Corporation
West Shore Pipe Line Company
West Texas Gulf Pipe Line Company
Western Oil Transportation Company, Inc.
White Shoal Pipeline Corporation
Williams Pipe Line Company
Wolverine Pipe Line Company
Wyco Pipe Line Company
Yellowstone Pipe Line Company

Appendix F

1. List of Investor-Owned Utilities which would be Assessed Annual Charges Based on 1986 Data (currently 186 IOUs):

AEP Generating Co.
Alabama Power Co.
Alamito Co.
Alcoa Generating Corp.
Allegheny Generating Co.
Appalachian Power Co.
Arizona Public Service Co.
Arkansas Power & Light Co.
Atlantic City Electric Co.
Baltimore Gas & Electric Co.
Bangor Hydro-Electric Co.
Black Hills Power and Light Co.
Blackstone Valley Electric Co.
Boston Edison Co.
Cambridge Electric Light Co.
Canal Electric Co.
Carolina Power & Light Co.
Centel Corp.
Central Hudson Gas & Electric Corp.
Central Illinois Light Co.
Central Illinois Public Service Co.
Central Louisiana Electric Co., Inc.
Central Maine Power Co.
Central Power & Light Co.
Central Vermont Public Service Corp.
Cincinnati Gas & Electric Co., The
Citizens Utilities Co.
Cleveland Electric Illuminating Co.
Columbus & Southern Ohio Electric Co.
Commonwealth Edison Co.
Commonwealth Edison Co. of Ind., Inc.
Commonwealth Electric Co.
Connecticut Light & Power Co.
Connecticut Valley Electric Co., Inc.
Connecticut Yankee Atomic Power Co.
Consolidated Edison Co. of New York, Inc.
Consolidated Water Power Co.
Consumers Power Co.
Dayton Power & Light Co., The
Delmarva Power & Light Co.
Detroit Edison Co., The
Duke Power Co.
Duquesne Light Co.
Eastern Edison Co.
Edison Sault Electric Co.
Electric Energy, Inc.
Empire District Electric Co., The
EUA Power Corporation
Fitchburg Gas & Electric Light Co.
Florida Power & Light Co.
Florida Power Corp.
Georgia Power Co.
Green Mountain Power Corp.
Gulf Power Co.
Gulf States Utilities Co.
Holyoke Power & Electric Co.
Holyoke Water Power Co.
Houston Lighting & Power Co.[1]
Idaho Power Co.
Illinois Power Co.
Indiana & Michigan Electric Co.
Indiana-Kentucky Electric Corp.
Indianapolis Power & Light Co.
Interstate Power Co.
Iowa Electric Light & Power Co.
Iowa-Illinois Gas & Electric Co.
Iowa Power & Light Co.
Iowa Public Service Co.
Iowa Southern Utilities Co.
James River-New Hampshire Electric Co.
Jersey Central Power & Light Co.
Kansas City Power & Light Co.
Kansas Gas & Electric Co.

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[1] Annual charges are to be assessed based only on those sales under rate schedules on file with the Commission. For FERC purposes of Reporting Requirement No. 582, this company should identify the jurisdictional nature of the kilowatt-hour transactions taking place.

Kansas Power & Light Co.
Kentucky Power Co.
Kentucky Utilities Co.
Kingsport Power Co.
Lake Superior District Power Co.
Lockhart Power Co.
Long Island Lighting Co.
Louisiana Power & Light Co.
Louisville Gas & Electric Co.
Madison Gas & Electric Co.
Maine Electric Power Co.
Maine Public Service Co.
Maine Yankee Atomic Power Co.
Massachusetts Electric Co.
Metropolitan Edison Co.
Michigan Power Co.
Minnesota Power & Light Co.
Mississippi Power & Light Co.
Mississippi Power Co.
Missouri Power & Light Co.
Missouri Public Service Co.
Missouri Utilities Co.
Monongahela Power Co.
Montana Dakota Utilities Co.
Montana Power Co.
Montaup Electric Co.
Mt. Carmel Public Utility Co.
Nantahala Power & Light Co.
Narragansett Electric Co.
Nevada Power Co.
New England Electric Trans. Corp.
New England Power Co.
New Orleans Public Service, Inc.
New York State Electric & Gas Corp.
Niagara Mohawk Power Corp.
North Central Power Company, Inc.
Northeast Nuclear Energy Co.
Northern Indiana Public Service Co.
Northern States Power Co. (Minn)
Northern States Power Co. (Wis)
Northwestern Public Service Co.
Ohio Edison Co.
Ohio Power Co.
Ohio Valley Transmission Corp.
Oklahoma Gas & Electric Co.
Orange & Rockland Utilities, Inc.
Otter Tail Power Co.
Pacific Gas & Electric Co.
Pacific Power & Light Co.
Pennsylvania Electric Co.
Pennsylvania Power & Light Co.
Pennsylvania Power Co.
Philadelphia Electric Co.
Philadelphia Electric Power Co.
Portland General Electric Co.
Potomac Edison Co.
Potomac Electric Power Co.
Public Service Co. of Colorado
Public Service Co. of Indiana
Public Service Co. of New Hampshire
Public Service Co. of New Mexico
Public Service Co. of Oklahoma
Public Service Electric & Gas Co.
Puget Sound Power & Light Co.
Rochester Gas & Electric Co.
Rockland Electric Co.
Safe Harbor Water Power Corp.
San Diego Gas & Electric Co.
Savannah Electric & Power Co.
Sierra Pacific Power Co.
South Beloit Water, Gas & Electric Co.
South Carolina Electric & Gas Co.
South Carolina Generating Co.
Southern California Edison Co.
Southern Company Services, Inc.
Southern Electric Generating Co.
Southern Indiana Gas & Electric Co.
Southwestern Electric Power Co.
Southwestern Public Service Co.
St. Joseph Light & Power Co.
Superior Water, Light & Power Co.
Systems Energy Resources, Inc.
Tampa Electric Co.
Tapoco, Inc.
Texas Utilities Electric Co.[2]
Texas-New Mexico Power Co.
Toledo Edison Co.
Tucson Electric Power Co.
UGI Corp.
Union Electric Co.
Union Light, Heat & Power Co.
United Illuminating Co.
Unitil Power Corp.
Upper Peninsula Generating Co.
Upper Peninsula Power Co.
Utah Power & Light Co.
Utilicorp United Inc.
Vermont Electric Power Co., Inc.
Vermont Yankee Nuclear Power Corp.
Virginia Electric & Power Co.
Warm Springs Power Enterprises
Washington Water Power Co.
West Penn Power Co.
West Texas Utilities Co.
Western Massachusetts Electric Co.
Wisconsin Electric Power Co.
Wisconsin Power & Light Co.
Wisconsin Public Service Corp.
Wisconsin River Power Co.
Yadkin, Inc.
Yankee Atomic Electric Co.
York Haven Power Co.

2. List of Cooperatives to be Assessed Annual Charges: Golden Spread Electric Cooperative, Inc.

3. List of the five Power Marketing Agencies to be Assessed Annual Charges:

Alaska Power Administration
Bonneville Power Administration
Southeastern Power Administration
Southwestern Power Administration
Western Area Power Administration

[FR Doc. 87-12550 Filed 6-4-87; 8:45 am]

BILLING CODE 6717-01-M

[2] *See supra* note 1.

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Parts 74 and 81

[Docket No. 83C-0127]

D&C Red No. 8 and D&C Red No. 9; Permanent Listing for Use in Ingested Drug and Cosmetic Lip Products and Externally Applied Drugs and Cosmetics; Confirmation of Effective Date and Further Treatment

AGENCY: Food and Drug Administration.

ACTION: Final rule; confirmation of effective date and further amendment.

SUMMARY: The Food and Drug Administration (FDA) is announcing that it has completed its evaluation of objections it received to the permanent listing of D&C Red No. 8 and D&C Red No. 9 as color additives for use in ingested drug and cosmetic lip products and externally applied drugs and cosmetics. In response to the objections, FDA is modifying several aspects of the manufacturing process specified in the permanent listing regulation. This document incorporates those modifications and confirms the effective date of January 6, 1987, for the regulation listing D&C Red No. 8 and D&C Red No. 9. This document also amends the color additive regulations by removing D&C Red No. 8 and D&C Red No. 9 from the color additive provisional list.

DATES: Effective date confirmed for the December 5, 1986, final rule (51 FR 43877): January 6, 1987; effective date of the amendment in this document is July 7, 1987, except as to any provisions that may be stayed by the filing of proper objections; objections by July 6, 1987.

ADDRESS: Written objections to the Dockets Management Branch (HFA-305), Food and Drug Administration, Rm. 4-62, 5600 Fishers Lane, Rockville, MD 20857.

FOR FURTHER INFORMATION CONTACT: Gerad L. McCowin, Center for Food Safety and Applied Nutrition (HFF-330), Food and Drug Administration, 200 C St. SW., Washington, DC 20204, 202-472-5676.

SUPPLEMENTARY INFORMATION:

1. Background

In the **Federal Register** of December 5, 1986 (51 FR 43877), FDA permanently listed D&C Red No. 8 and D&C Red No. 9 for use in ingested drug and cosmetic lip products in amounts not exceeding 0.1 percent by weight of the finished product and externally applied drugs and cosmetics in amounts consistent with current good manufacturing practice. That action responded to a petition filed by the Cosmetic, Toiletry and Fragrance Association, Inc. The final rule also amended 21 CFR 81.1(b), 81.25, and 81.27 by removing the entries for D&C Red No. 8 and D&C Red No. 9. The final rule revised 21 CFR 81.10 and 81.30 by adding new paragraphs (t) and (s), respectively, which terminated the provisional listings and cancelled the certificates issued for D&C Red No. 8 and D&C Red No. 9 for use in mouthwash, dentifrices, and ingested drugs, except ingested drug lip products. The final rule also revised 21 CFR 82.1308 to state that: (1) D&C Red No. 8 must conform in identity and specifications to the requirements of 21

CFR 74.1308 (a)(1) and (b) and (2) the lakes of D&C Red No. 8 must be made only from certified batches of D&C Red No. 8. The final rule also revised 21 CFR 82.1309 to state that (1) D&C Red No. 9 must conform in identity and specifications to the requirements of § 74.1309 (a)(1) and (b) and (2) the lakes of D&C Red No. 9 must be made only from certified batches of D&C Red No. 8 or D&C Red No. 9. The final rule (51 FR 43877), corrected January 9, 1987 (52 FR 902), FDA gave interested persons until January 6, 1987, to file objections.

In a separate final rule published in the Federal Register of December 5, 1986 (51 FR 43899), FDA extended the closing date for the provisional listing of D&C Red No. 8 and D&C Red No. 9 until February 3, 1987, to provide time for the receipt and evaluation of any objections submitted in response to the final rule for these color additives. Six objections were submitted in response to the listing order. The agency extended the closing date on February 3, 1987 (52 FR 3224) to April 6, 1987, and again on April 6, 1987 (52 FR 10882) to June 5, 1987, to provide time to properly respond to these objections.

The objections are on file in the Dockets Management Branch (address above) under the docket number found in the heading of this document. FDA also received one comment in support of its regulation from the Cosmetic, Toiletry and Fragrance Association that has also been placed on file under the same docket number. No requests for a hearing were received in response to the listing regulation. The objections and the agency's responses to them are summarized below.

II. Objections and the Agency's Response

A. Interpretation of the Delaney Clause

1. Public Citizen Litigation Group (PCLG) objected to the final rule permanently listing D&C Red No. 8 and D&C Red No. 9 on the ground that, because D&C Red No. 8 and D&C Red No. 9 are animal carcinogens, the Delaney Clause (21 U.S.C. 376(b)(5)(B)) prohibits the agency from approving their use in drugs and cosmetics. PCLG stated, "that, as the agency has also admitted, if the Delaney Clause is interpreted to prohibit the approval of color additives which are animal carcinogens, then the agency may not approve D&C Red Nos. 8 and 9." PCLG incorporated by reference the basis for its interpretation of the Delaney Clause discussed in the legal memoranda filed in *Public Citizen* v. *Department of Health and Human Services*, and *Public Citizen* v. *Young*, No. 1548 (D.C. Cir.).

In the judicial proceedings noted above, the agency has opposed PCLG's interpretation of the Delaney Clause. In response to PCLG's objection, the agency incorporates in this document the legal memoranda filed on behalf of FDA in the same proceedings. The agency also incorporates in this document the notices that appeared in the Federal Register of February 19, 1987 (51 FR 5081 and 5083), and that clarified the agency's explanation of its interpretation of the Delaney Clause. As discussed in the final rule permanently listing D&C Red No. 8 and D&C Red No. 9, it remains the agency's position that, under any reasonable standard, D&C Red No. 8 and D&C Red No. 9 are safe for use in ingested drug and cosmetic lip products and externally applied drugs and cosmetics and that the Delaney Clause does not bar the permanent listings of these color additives. All scientific, legal, and policy discussions set forth in the preamble to the December 5, 1986 (51 FR 43877), final rule for these two color additives are applicable in this document.

B. Lakes of D&C Red No. 8 and D&C Red No. 9

1. Manufacture of Lakes From Previously Certified Straight Color Additives

Several objections complained that the requirement that lakes of D&C Red No. 8 and D&C Red No. 9 be manufactured from certified straight color additives unnecessarily imposes a technically infeasible burden upon the manufacturer. The objections contended that analytical methodologies currently employed for enforcement of chemical specifications in the straight color additives were equally applicable for determining compliance with chemical specifications for lakes of the color additives. The objections were not supported or accompanied by any data.

As discussed in the preamble to the final listing regulations, the agency was concerned about the possible role of unsulfonated subsidiary colors in producing the carcinogenic effects observed in the National Cancer Institute study of D&C Red No. 9. The preamble also discussed possible variation in the amount of this type of impurity that may be present in a given batch of the color additive. Thus, to the extent that this type of impurity may contribute to the observed effect, the level of risk presented by any given batch of D&C Red No. 8 or D&C Red No. 9 could vary depending upon the concentration of unsulfonated subsidiary colors in the batch. For these and other reasons, the agency set specifications restricting the permissible levels of unsulfonated subsidiary colors and other impurities in batches of D&C Red No. 8 or D&C Red No. 9 to levels below or comparable to those found in the animal-tested batch, as discussed in the final rule. See 51 FR 43891–43892.

The analytical methodologies available for enforcing all of these specifications during certification are reliable and accurate only for the straight color additives, not for the lakes of the color additives. The agency is unaware of data or information that establishes the propriety of using any methodology to enforce all of the chemical specifications for impurities in all of the permitted forms of lakes of the straight color additives. The objections to the final rule failed to submit any information or analytical data on this issue. Accordingly, the final rule has not been changed and continues to require that lakes of either D&C Red No. 8 or D&C Red No. 9 be manufactured from a certified straight color additive.

The contention that it is technically infeasible to manufacture the lakes in the manner required by the listing regulation is, in the agency's view, not substantiated. Although this requirement is new, it does not appear infeasible. To manufacture a straight color additive, one must combine certain chemical intermediates. This results in a relatively insoluble color additive. When it forms, the color additive precipitates immediately in the reaction vat. Isolation of the precipitated color additive as the sodium salt yields D&C Red No. 8 straight color additive. Soluble barium is used primarily to treat the precipitated color additive after the reaction to form the barium salt of the color additive. When isolated, this salt yields D&C Red No. 9.

As discussed in the preamble to the final rule, intermediates, subsidiary colors, and other impurities present in the reaction vat will also be precipitated at this time. The agency has set specifications for some of these components. If the color additive is allowed to precipitate in the presence of a laking substratum, the components for which specifications have been established could be present in the lakes of the color additives at higher levels than permitted by the specifications. The agency, however, does not have adequate methods for the detection of these components in lakes. Accordingly, the final rule requires that D&C Red No. 8 or D&C Red No. 9 be isolated and certified after formation of the straight color additive before the laking process can be continued (normally, the laking process is essentially a one-step, in situ process). Other than this one intervention, the final rule does not specify a particular method of manufacture for the lakes. While admittedly difficult, this process is not infeasible and it is the least burdensome process that the agency is aware of that will ensure the manufacture of a color additive that meets the specifications set forth in the final rule.

2. Two objections to the final rule stated that § 82.1051 *Lakes (D&C)* of the color additive regulations and the definition of lakes in § 70.31(e) are confusing and need revision.

In the final rule, the agency discussed the advance notice of proposed rulemaking concerning lakes and its intention to propose general regulations concerning the definition of lakes and the safety and chemical specifications for lakes. As discussed also in the final rule, the agency finds that these actions on lakes should be discussed separately in a future **Federal Register** document. FDA finds that these issues need not be resolved first before FDA takes the action discussed in the December 5, 1986, final rule on D&C Red No. 8 and D&C Red No. 9.

2. Technical Objections Concerning the Laking Process

3. One manufacturer declared that the final rule requires an impossibility: The manufacture of D&C Red No. 9 barium lake from dry straight D&C Red No. 9. In addition, the manufacturer pointed out that a precipitant is used to remove excess soluble barium during the manufacture of D&C Red No. 9 and that, in fact, this straight color additive is isolated as a lake or, at least, laked on the precipitant used.

The agency agrees that it would be difficult to manufacture D&C Red No. 9 barium lake from dry straight D&C Red No. 9. The agency notes, however, that the final rule does not restrict manufacture of D&C Red No. 9 lakes to dry certified straight D&C Red No. 9. There are ways to overcome the dry state of the straight color additive and successfully manufacture the lake. For example, the new regulation permits the processing of certified D&C Red No. 8 straight color additive into D&C Red No. 9 lake by returning the certified straight color additive D&C Red No. 8 to a solution suitable for processing into a lake of D&C Red No. 9. The objection contained no data to show why other potential ways could not be used to make the lake.

The agency points out that neither the presence of small amounts of excess soluble barium in D&C Red No. 9 as a result of the manufacturing process nor the isolation of D&C Ped No. 9 in the presence of a precipitant prevents the agency from certifying D&C Red No. 9 as a straight color additive. Straight color additives are those color additives that meet the specifications as prescribed by the final rule, and D&C Red No. 9 has a specification for excess barium. This, in combination with the other specifications, helps to define D&C Red No. 9 straight color additive. The agency, therefore, intends to certify as straight color additives any batches of color additives that meet the new identity description and chemical specifications regarding subsidiary colors, chemical intermediates, and other impurities.

4. Two objections questioned the general description of the manufacturing process for D&C Red No. 9 straight color additive contained in § 74.1309(a) (identity). The objections noted it is necessary during manufacture to treat the color additive to reduce soluble barium in D&C Red No. 9 to levels that meet the chemical specification for soluble barium described in § 74.1309(b).

The agency finds that these objections have merit and has decided to amend the identity section of the final rule to clarify the use of barium chloride and sulfate ion in the manufacture of the straight color additive. Barium chloride is added during the manufacture of the color additive to produce the color additive as a barium salt. Gross removal of the excess of barium chloride will help to reduce the levels of soluble barium and subsequent levels of barium sulfate that may form in the color additive when it is treated with sulfate ion. The reagent typically used to reduce soluble barium during manufacture of the color additive is sodium sulfate. The use of this reagent causes excess soluble barium to be converted to insoluble barium sulfate.

The agency is amending the identity section to provide for the removal of gross excess soluble barium (usually in the form of barium chloride) and then to allow for the use of sulfate ion for the removal of the final residues of soluble barium to the specification level or below.

The agency finds that precipitation of soluble barium as barium sulfate occurs as part of the manufacturing process for D&C Red No. 9 and that this color additive is isolated with residual barium sulfate, which is a lake substratum. However, the agency does not consider the isolation of D&C Red No. 9 in this manner to be a lake.

While agreeing that this use of sulfate ion, to the extent necessary to reduce soluble barium levels, is consistent with the appropriate manufacturing process for a straight color additive, the agency is concerned that the manufacturing process not result in the formation of excessive levels of precipitated barium sulfate. This concern is based primarily on the potential interference of excess barium sulfate with agency analytical methods used to enforce other specification levels for this straight color additive. Thus, the agency recommends that residual levels of barium sulfate be kept to a minimum, consistent with appropriate manufacturing practice.

The agency lacks the analytical methodology and sufficient data on the straight color additive to set a specification for barium sulfate in D&C Red No. 9. This may be considered in a **Federal Register** document when data on the levels of barium sulfate in straight D&C Red No. 9 become available. The agency has amended § 74.1309(a), however, to indicate that barium chloride should be removed to the fullest extent possible and that sulfate ion may be added during manufacture of D&C Red No. 9 to further reduce levels of soluble barium after gross removal of barium chloride to attain a straight color additive in its final form.

5. Two objections stated that setting the level of use of D&C Red No. 8 and D&C Red No. 9 at 0.1 percent rendered these color additives no longer useful as straight color additives.

The agency explained in its final rule (51 FR 43890 and 43891) that establishing a level of use for these color additives at 0.1 percent was appropriate from a risk estimate and safety standpoint and that, at the 0.1 percent concentration, the additive remained useful in imparting color to some products. The agency recognizes that this level is much lower than originally requested, and that at the lower level, the color additives may no longer be capable of imparting sufficient color for many former uses. Regardless, the agency continues to believe that the reduction is appropriate, and the comments submitted no new data or information on this issue.

6. One objection concerned the listing of two previously unspecified impurities, chloroform extractable unsulfonated subsidiary colors and the sodium or barium (1:2) salts of 5-chloro-2-[4-hydroxy-1-naphthalenyl)azo]-4-methylbenzene sulfonic acid, on the grounds that FDA did not provide written, validated test methods for their determination. The objection requested that a 180-day extension of the provisional list be granted to test the methods to determine what problems if any it will have with standard products, and to take appropriate remedial technical action.

The final rule listing D&C Red No. 8 and D&C Red No. 9 published on December 5, 1986 (51 FR 43877). The objector has thus, in effect, had the necessary time requested to test the methods in question. Accordingly, the agency is denying the objections. However, the agency recognizes the manufacturers' concerns with the new methodologies, and will work closely with any manufacturer that experiences difficulties in this area.

7. One objection asked that the agency reconsider the level set for the 50 parts per million (ppm) specification for chloroform extractable unsulfonated subsidiary colors because data available to the agency showed its level to be much higher in the toxicology samples.

The agency gave an extensive discussion as to why it selected this low value for the chloroform extractable colors. In brief, although the agency has data on the levels of combined unsulfonated subsidiary colors present in D&C Red No. 9, it does not have reliable data on the levels of all of the individual subsidiary colors present in the toxicology sample. The levels of these individual colors may vary significantly from batch to batch. The agency, therefore, reasoned that the combined levels of these unsulfonated colors should not be permitted above FDA's ability to detect their presence in D&C Red No. 8 and D&C Red No. 9. This level is 50 ppm and it represents a tenfold to fifteenfold reduction in the levels found in the toxicology samples. This across-the-board decrease in the level of unsulfonated subsidiary colors would not be selective but would reduce the presence of each subsidiary color. This requirement is technically achievable for manufacturers and would ensure that the levels of unsulfonated subsidiary colors present in future certified batches of these color additives would not be greater than the levels in the toxicology sample. The objection failed to substantially address the agency's concerns on this issue. The agency has no basis upon which to rule that the 50 ppm specification for chloroform extractable colors should be changed. Accordingly, the agency rejects the objection.

III. Conclusion

The agency has completed its evaluation of the objections and concludes that a continuation of the stay of the regulations is not warranted in response to the objections. FDA also concludes that the objection concerning the manufacturing process is correct and the agency is modifying § 74.1309 accordingly. Additionally, there was no request for a hearing in conjunction with the objections that were submitted. Therefore, this document confirms the effective date of January 6, 1987, for all portions of the final rule except the description of the manufacturing process modified in this final rule for D&C Red No. 9.

Objections to or requests for a public hearing on the modifications in § 74.1309(a) as set forth in this document may be submitted under 21 CFR 12.20 through 12.22. The amended portions of § 74.1309(a) shall become effective on July 7, 1987, except as to any provisions that may be stayed by the filing of proper objections. Until that time, the identity prescribed by the listing regulation of December 5, 1986 (51 FR 43877), is in effect. This document also amends the color additive regulations by removing D&C Red No. 8 and D&C Red No. 9 from the color additives provisional list on June 5, 1987.

IV. Objections

Any person who will be adversely affected by the amendment to § 74.1309 regarding the manufacturing process may at any time on or before July 6, 1987 file with the Dockets Management Branch (address above) written objections thereto. Each objection shall be separately numbered, and each numbered objection shall specify with particularity the provisions of the regulation to which objection is made and the grounds for the objection. Each numbered objection on which a hearing is requested shall specifically so state. Failure to request a hearing for any particular objection shall constitute a waiver of the right to a hearing on that objection. Each numbered objection for which a hearing is requested shall include a detailed description and analysis of the specific factual information intended to be presented in support of the objection in the event that a hearing is held. Failure to include such a description and analysis for any particular objection shall constitute a waiver of the right to a hearing on the objection. Three copies of all documents shall be submitted and shall be identified with the docket number found in brackets in the heading of this document. Any objections received in response to the regulation may be seen in the Dockets Management Branch between 9 a.m. and 4 p.m., Monday through Friday. FDA will publish notice of the objections that the agency has received or lack thereof in the **Federal Register.**

List of Subjects

21 CFR Part 74

Color additives, Cosmetics, Drugs, Medical devices.

21 CFR Part 81

Color additives, Cosmetics, Drugs.

Therefore, under the Federal Food, Drug, and Cosmetic Act, the transitional provisions of the Color Additive Amendments of 1960, and under authority delegated to the Commissioner of Food and Drugs, Parts 74 and 81 are amended as follows:

PART 74—LISTING OF COLOR ADDITIVES SUBJECT TO CERTIFICATION

1. The authority citation for 21 CFR Part 74 continues to read as follows:

Authority: Secs. 701, 706, 52 Stat. 1055–1056 as amended, 74 Stat. 399–407 as amended (21 U.S.C. 371, 376); 21 CFR 5.10.

2. In § 74.1309 by revising paragraph (a)(1) to read as follows:

§ 74.1309 D&C Red No. 9.

(a) *Identity.* (1) The color additive D&C Red No. 9 is principally the barium salt (1:2) of 5-chloro-2-[(2-hydroxy-1-naphthalenyl)azo]-4-methylbenzenesulfonic acid (CAS Reg. No. 5160–2–1). To manufacture the additive, 2-amino-5-chloro-4-methylbenzenesulfonic acid is diazotized using sodium nitrite and hydrochloric acid and coupled with 2-naphthalenol. The resultant color additive is converted to the barium salt with barium chloride acting as a precipitant and excess barium chloride is removed to the fullest extent possible. Sulfate ion may then be added for the purpose of further removing excess soluble barium. The color additive is isolated as the barium salt.

* * * * *

PART 81—GENERAL SPECIFICATIONS AND GENERAL RESTRICTIONS FOR PROVISIONAL COLOR ADDITIVES FOR USE IN FOODS, DRUGS, AND COSMETICS

3. The authority citation for 21 CFR Part 81 continues to read as follows:

Authority: Secs. 701, 706, 52 Stat. 1055–1056 as amended, 74 Stat. 399–407 as amended (21 U.S.C. 371, 376); Title II, Pub. L. 86–618, sec. 203, 74 Stat. 404–407 as amended (21 U.S.C. 376, note); 21 CFR 5.10.

§ 81.1 [Amended]

4. Part 81 is amended in § 81.1 *Provisional lists of color additives* by removing the entries for "D&C Red No.

8" and "D&C Red No 9" in paragraph (b).

§ 81.27 [Amended]

5. In § 81.27 *Conditions of provisional listing* by removing the entries for "D&C Red No. 8" and "D&C Red No. 9" in paragraph (d).

Dated: May 31, 1987.

Frank E. Young,

Commissioner of Food and Drugs.

[FR Doc. 87-12798 Filed 6-4-87; 8:45 am]

BILLING CODE 4160-01-M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 261 and 266

[SW FRL-3213-6]

Hazardous Waste Management System; Definition of Solid Waste; Technical Corrections

AGENCY: Environmental Protection Agency.

ACTION: Technical corrections to definition of solid waste rulemaking.

SUMMARY: On January 4, 1985, EPA promulgated final rules defining the statutory term "solid waste" and adopting regulations for hazardous wastes that are recycled. EPA has since identified two provisions that require correction or clarification. This notice makes those changes.

EFFECTIVE DATE: June 5, 1987.

FOR FURTHER INFORMATION CONTACT: RCRA Hotline, toll free, at (800) 424-9436 or (202) 382-3000. For technical information contact Michael Petruska, U.S. Environmental Protection Agency, 401 M Street SW., Washington, DC. 20460, (202) 382-4761.

SUPPLEMENTARY INFORMATION:

I. Technical Corrections to Rule

1. On January 4, 1985, as part of the final rule defining "solid waste", EPA amended § 261.33 to state that commercial chemical products are solid wastes when they are "discarded" as defined in § 261.2(a)(2)(i) (*i.e.* by being abandoned), or when recycled by burning, use in fuel production, or placement on the land when this is not the material's normal manner of use. See 50 FR at 665. This provision correctly reflected the Agency's intent. The provision was amended in the course of codifying certain of the 1984 RCRA amendments, however, and this amendment (51 FR at 28744, July 15, 1985) inadvertently changed the meaning of the provision to say that these materials are wastes when recycled in any manner (because, under the July 15 amendment, the term "discarded" was no longer limited to its meaning of § 261.2(a)(2)(i)). EPA did not intend this change, 50 FR at 618, nor did the Congress (see, e.g. RCRA section 3004(q)(1), final sentence). Accordingly, we are correcting the rule by restoring the regulatory language that was inadvertently deleted from the January 4, 1985 rule.

2. Subpart C of Part 266 applies to hazardous wastes that are recycled by being placed on or applied to the land, a practice termed 'used in a manner constituting disposal.' The rules apply when hazardous wastes are applied directly to the land, and when hazardous wastes are first mixed or otherwise combined with any other substance (or substances) before being applied to the land. See § 266.20(a). The rules further indicate that certain waste-derived products that are placed on the land are not presently subject to regulation, namely those that are produced for the general public's use and that undergo a chemical reaction in the course of production so that the hazardous waste component is inseparable by physical means. See § 266.20(b). (Waste-derived fertilizers produced for the general public's use also are exempt. *Id.*)

These rules contain an unintended redundancy. Language in § 266.20(b), exempting certain waste-derived products from regulation, is also cited in § 266.20(a) which states the overall applicability of the section, and so applies not only to waste-derived products but also to the hazardous wastes themselves before being incorporated into the products. We are correcting the redundancy by removing the langauge exempting products from § 266.20(a), so that § 266.20(a) (as intended) sets out the jurisdictional applicability of Subpart C of Part 266, and § 266.20(b) sets forth exemptions from regulation (again, as intended). This change will not only remove redundant regulatory language but indicate more clearly that hazardous wastes are *always* subject to regulation prior to being used in a manner that constitutes disposal (*i.e.*, in the transportation and storage phases of management, even if a waste-derived products' actual application is presently exempt.) The Agency, in the preamble to the final rule, stated explicitly that such wastes are regulated before being incorporated into waste-derived products. See 50 FR 629/1 (Jan. 4, 1985).

II. Regulatory Impact

Under Executive Order 12291, EPA must judge whether a regulation is "major" and therefore subject to the requirements of a Regulatory Impact Analysis. Since this notice makes technical corrections and does not change the previously approved final rule, this rule is not major and no Regulatory Impact Analysis is required.

List of Subjects in 40 CFR Parts 261 and 266

Hazardous material, Waste treatment and disposal, Recycling.

Dated: May 29, 1987.

J.W. McGraw,

Acting Assistant Administrator for Solid Waste and Emergency Response.

For the reasons set out in the Preamble, Title 40 of the Code of Federal Regulations is amended as follows:

PART 261—IDENTIFICATION AND LISTING OF HAZARDOUS WASTE

1. The authority citation for Part 261 continues to read as follows:

Authority: Sections 1006, 2002(a), 3001, and 3002 of the Solid Waste Disposal Act as amended by the Resource Conservation and Recovery Act of 1976, as amended [42 U.S.C. 6905, 6912(a), 6921, and 6922].

2. Section 261.33 is amended by revising the introductory paragraph to read as follows:

§ 261.33 Discarded commercial chemical products, off-specification species, container residues, and spill residues thereof.

The following materials or items are hazardous wastes if and when they are discarded or intended to be discarded as described in § 261.2(a)(2)(i), when they are mixed with waste oil or used oil or other material and applied to the land for dust suppression or road treatment, when they are otherwise applied to the land in lieu of their original intended use or when they are contained in products that are applied to the land in lieu of their original intended use, or when, in lieu of their original intended use, they are produced for use as (or as a component of) a fuel, distributed for use as a fuel, or burned as a fuel.

* * * * *

PART 266—STANDARDS FOR THE MANAGEMENT OF SPECIFIC WASTES AND SPECIFIC TYPES OF WASTE MANAGEMENT FACILITIES

3. The authority citation for Part 266 continues to read as follows:

Authority: Sec. 1006, 2002(a), 3008, and 3014 of the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, as amended [42 U.S.C. 6095, 6912(a), 6925, and 6934].