DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM06–4–000; Order No. 679]

Promoting Transmission Investment Through Pricing Reform

Issued July 20, 2006.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: In this Final Rule, pursuant to the requirements of the Transmission Infrastructure Investment provisions in section 1241 of the Energy Policy Act of 2005, which adds a new section 219 to the Federal Power Act, the Federal Energy Regulatory Commission (Commission) is amending its regulations to establish incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. This Final Rule is intended to encourage transmission infrastructure investment.

DATES: *Effective Date:* This Final Rule will become effective September 29, 2006.

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SUPPLEMENTARY INFORMATION:

Before Commissioners: Joseph T. Kelliher, Chairman; Nora Mead Brownell, and Suedeen G. Kelly.

I. Introduction

1. Pursuant to the directives in section 1241 of the Energy Policy Act of 2005 (EPAct 2005) [1] which added a new section 219 to the Federal Power Act (FPA), in this Final Rule the Commission provides incentives for transmission infrastructure investment that will help ensure the reliability of the bulk power transmission system in the United States and reduce the cost of delivered power to customers by reducing transmission congestion. The Rule does not grant outright any incentives to any public utility, but rather identifies specific incentives that the Commission will allow when justified in the context of individual declaratory orders or section 205 filings by public utilities under the FPA. A number of these incentives reflect departures from what the Commission has permitted in the past and a willingness to consider much greater flexibility with respect to the nature and timing of rate recovery for needed transmission infrastructure. While the Commission in recent years has permitted higher rates of return and deviations from past ratemaking practices in a few individual transmission infrastructure cases,[2] we here determine generically that these types of ratemaking options and others should be considered on a broader basis for those applicants that can demonstrate that their infrastructure proposals meet section 219 requirements.

2. In reaching our determinations in this Final Rule, we have considered comments that reflect widely divergent views with respect to whether and when utilities should receive incentives and what they must demonstrate in order to receive particular incentives. As noted, the Rule does not grant incentives to any public utility but instead permits an applicant to tailor its proposed incentives to the type of transmission investments being made and to demonstrate that its proposal meets the requirements of section 219. Further, under the Rule, the Commission will permit incentives only if the incentive package as a whole results in a just and reasonable rate. For example, an incentive rate of return sought by an applicant must be within a range of reasonable returns and the rate proposal as a whole must be within the zone of reasonableness before it will be approved.

3. An important component of this Rule is the willingness to provide procedural flexibility, including the use of expedited declaratory orders on permitted ratemaking treatments, to help with financing and up-front regulatory certainty for project investments. We are particularly attuned to the need for flexibility to support long-distance interstate projects that significantly reduce the cost of delivered power by reducing transmission congestion on the interstate grid.

4. The Final Rule provides incentive-based rate treatments to any public utility transmitting electric energy in interstate commerce that meets the requirements of section 219 and this Final Rule. The Commission will not limit an applicant's ability to seek incentive-based rate treatments based on corporate structure or ownership. In addition, the Final Rule provides additional incentives, to the extent within our jurisdiction,[3] to any transmitting utility or electric utility transmitting electric energy in interstate commerce that joins a Transmission Organization.[4] Finally, as explained below, to the extent our jurisdiction allows, we encourage public power entities to take advantage of the incentive-based rate treatments outlined in the Final Rule.

5. Some commenters have argued that few or no incentives are needed to encourage new transmission investment. We reject these comments as fundamentally inconsistent with section 219. Section 219 reflects Congress' determination that the Commission's traditional ratemaking policies may not be sufficient to encourage new transmission infrastructure. Although section 219 does not permit approval of rates that are inconsistent with section 205 or 206, section 219 nonetheless constitutes a clear directive that ''the Commission *shall* establish, by rule, incentive-based * * * rate treatments * * * for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion'' (emphasis added). We therefore cannot simply rely on existing ratemaking policy to faithfully implement section 219. This Final Rule therefore identifies a non-exclusive list of ratemaking reforms and requires applicants to tailor their proposals to fit the facts of their particular case.

6. We do agree, however, with the position of certain wholesale customers and state commissions that the Commission should not provide incentives that only serve to increase rates without providing any real incentives to construct new transmission infrastructure. Section 219(a) states that transmission incentives should be ''*benefiting consumers* by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion'' (emphasis added). The purpose of our Rule is to benefit customers by providing real incentives to encourage new infrastructure, not simply increasing rates in a manner that has no correlation to encouraging new investment. The Final Rule, therefore, makes clear that not every incentive identified herein will be necessary or appropriate for every new transmission investment. To provide guidance in this regard to potential applicants, we discuss below why certain incentives may, as a general matter, be better tailored to certain types of investments than others.

II. Background

7. Section 219 of the FPA requires the Commission to establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. Section 219(b) requires that the rule:

[1] Energy Policy Act of 2005, Pub. L. No. 109–58, 119 Stat. 594, 315 and 1283 (2005).

[2] *See Western Area Power,* 99 FERC ¶ 61,306, *reh'g denied,* 100 FERC ¶ 61,331 (2002) (*Western*), *aff'd sub nom. Public Utilities Commission of the State of California* v. *FERC,* 367 F.3d 925 (D.C. Cir. 2004); *Michigan Electric Transmission Co., LLC,* 105 FERC ¶ 61,214 (2003) (*METC*); *American Transmission Company, L.L.C.,* 105 FERC ¶ 61,388 (2003) (*American Transmission*); *ITC Holdings Corp.,* 102 FERC ¶ 61,182, *reh'g denied,* 104 FERC ¶ 61,033 (2003) (*ITC Holdings*).

[3] With regard to non-public utilities, although the Commission's regulatory authority is bound by statute, such entities could be covered by a public utility's incentive rate proposal by a separate agreement between the public utility and a non-public utility. *See Bonneville Power Administration, et al.* v. *FERC,* 422 F.3d 408 (9th Cir. 2005).

[4] Transmission Organization is defined in 18 CFR 35.35(a)(2) of this Final Rule as ''a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities.'' Electric Utility is defined in section 3(22) of the FPA as ''any person or State agency (including any municipality) which sells electric energy; such term includes the Tennessee Valley Authority, but does not include any Federal power marketing agency.'' 16 U.S.C. 796(22). Transmitting Utility is defined in section 3(23) of the FPA as ''any electric utility, qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.'' 16 U.S.C. 796(23).

1. Promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities;

2. Provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies);

3. Encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and

4. Allow the recovery of all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215 of the FPA, and all prudently incurred costs related to transmission infrastructure development, pursuant to section 216 of the FPA (transmission national interest corridors).

8. Section 219(c) requires that the Rule provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization and to ensure that any recoverable costs associated with joining may be recovered through transmission rates charged by the utility or through the transmission rates charged by the Transmission Organization that provides transmission service to the utility. Finally, section 219(d) provides that all rates approved under the Rule are subject to the requirements of sections 205 and 206 of the FPA,[5] which require that all rates, charges, terms and conditions be just and reasonable and not unduly discriminatory or preferential.

9. Congress directed the Commission to issue a Final Rule establishing incentive-based rate treatments for transmission construction within one year of enactment of EPAct 2005, or by August 8, 2006. The Commission issued a Notice of Proposed Rulemaking (NOPR) on November 18, 2005 seeking comment on the Commission's proposal to comply with section 219.[6] In the NOPR, the Commission proposed to amend Part 35 of Chapter I, Title 18 of the *Code of Federal Regulations* by eliminating paragraph 35.34(e) under Subpart F and adding paragraph 35.35 under Subpart G. The Commission received several hundred pages of comments. A list of the commenters appears in Appendix B. As explained below, based on the comments filed, the Commission clarifies and adopts the proposed regulations in the NOPR.

III. Overview

A. The Need for New Transmission Facilities

1. Background

10. As indicated in the NOPR, investment in transmission facilities in real dollar terms declined significantly between 1975 and 1998. Although the amount of investment has increased somewhat in the past few years, data for the most recent year available, 2003, shows investment levels still below the 1975 level in real dollars.[7] This decline in transmission investment in real dollars has occurred while the electric load using the nation's grid more than doubled.[8] Further, the record shows that the growth rate in transmission mileage since 1999 is not sufficient to meet the expected 50 percent growth in consumer demand for electricity over the next two decades.[9]

2. Comments

11. Many commenters agree that there is a significant need for new investment in transmission facilities. EEI states that, although increases in transmission investment are predicted over the 2004 to 2008 period, the industry still has not reached the optimal level of investment.[10] International Transmission notes that growth in transmission capacity has lagged behind the growth in peak demand over the last three decades and this trend is projected to continue through at least 2012.[11] International Transmission cites to studies estimating the cost of power interruptions and fluctuations to range from between $29 billion and $135 billion annually,[12] the cost of the August 2003 Northeast-Midwest blackout to be between $4 billion and $10 billion,[13] congestion costs of $4.8 billion in the ISO/RTO markets of California, New York, New England, the Midwest and PJM for 1999 to 2002,[14] and increases in PJM congestion costs, from $499 million in 2003 to $808 million in 2004.[15]

12. Many transmission users and state commissions also agree that there is a need for additional investment in transmission infrastructure.[16]

13. However, some commenters dispute the need for new transmission investment. They assert the Commission has overlooked that investment in transmission has increased in recent years.[17] They also contend that investment in transmission by utilities in RTOs and ISOs has been significant, citing to the approximately $2 billion of approved spending in PJM since 2000. E.ON U.S. asserts that wide-spread system shortages have rarely occurred during the past 40 or more years, and that there does not appear to be any trend line that would suggest that it is becoming a serious problem now.

3. Commission Determination

14. The issue of whether there is a need for new transmission investment that is sufficient to justify transmission incentives was put to rest by section 219. Section 219 mandates that the Commission "establish, by rule, incentive-based (including performance-based) rate treatments" and, in doing so, "promote reliable and economically efficient transmission and generation of electricity by *promoting capital investment* in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce" (emphasis added). If this were not enough, the legislative

[5] 16 U.S.C. 824(d) and 824(e) (2000).

[6] *Promoting Transmission Investment Through Pricing Reform,* 70 FR 71409 (Nov. 29, 2005), FERC Stats. & Regs., Proposed Regs. ¶ 32,593 (2005).

[7] EEI Survey of Transmission Investment: Historical and Planned Capital Expenditures (1999–2008) at 3 (2005).

[8] Barriers to Transmission Investment, Presentation by Brendan Kirby (U.S. Department of Energy, Oak Ridge National Laboratory), April 22, 2005 Technical Conference, Transmission Independence and Investment, Docket No. AD05–5–000 (April 22, 2005 Technical Conference).

[9] Energy Policy Act of 2005: Hearings before the House Subcommittee on Energy and Commerce, 109th Congress, First Sess. (2005) (Prepared statement of Thomas R. Kuhn, President of EEI).

[10] 2004 State of the Markets Report, Federal Energy Regulatory Commission, Staff Report by the Office of Market Oversight and Investigations, June 2005, at p 27.

[11] *See* Eric Hirst, U.S. Transmission Capacity: Present Status and Future Prospects, a study prepared for EEI and the U.S. Department of Energy Office of Electric Transmission and Distribution, June 2004 (Hirst) and Keeping Energy Flowing: Ensuring a Strong Transmission System to Support Consumer Needs for Cost-Effectiveness, Security and Reliability, a report of the Consumer Energy Council of America, Transmission Infrastructure Forum, January 2005. *See also* Affidavit of Jon E. Jipping, Exhibit A to the Reply Comments of International Transmission (the transmission system purchased in Michigan was 2.5 to 7 years behind schedule in maintenance on key transmission facilities).

[12] Kristina LaCommare and Joseph Eto, Understanding the Cost of Power Interruptions to U.S. Electricity Consumers, Lawrence Berkeley National Laboratory (September 2004) at xiv.

[13] *See* Final Report on the August 14, 2003 Blackout in the United States and Canada by the U.S.-Canada Power System Outage Task Force (April 2004) at 1.

[14] *See* Hirst at 8.

[15] *See* 2004 PJM State of the Market Report at 37 (March 8, 2005).

[16] *E.g.,* TDU Systems, APPA, and Maryland Commission.

[17] *E.g.,* NASUCA and Connecticut DPUC.

mandate of section 219 is supported by abundant evidence, as discussed above, including the fact that transmission investment in real dollars terms is lower today than it was in 1975 when the load was significantly smaller and that, even with the transmission additions of recent years, the industry still incurs significant congestion costs due to inadequate transmission.

B. The Need for Incentives

1. Background

15. In section 219(a) of the FPA, Congress directed the Commission to establish incentive-based rate treatments to foster investment in transmission facilities.

2. Comments

16. Several commenters argue that incentive-based rates are not necessary to encourage transmission construction or that incentives will not accomplish the intended goal.[18] Others assert that reliance on incentives may increase the price of electricity without any real benefit.[19]

17. Commenters urge the Commission to limit the scope of any incentive-based treatments or to adopt mechanisms to ensure that they have their intended effect. For example, the New Mexico AG and TAPS assert that the Commission may implement an incentive-based mechanism by penalizing utilities or RTOs that fail to make investments necessary to ensure the reliability of the transmission grid. The Delaware Commission contends that providing incentives without assessing penalties for failure to meet obligations violates the just and reasonable standard. NASUCA states that it is unfair to provide incentives that increase utility profits but do not hold applicants accountable for performance. The Missouri Commission proposes that the Commission implement a process that determines performance-based return on equity. Other commenters recommend that the Commission make approval of any incentives conditional on the applicant showing a need for the incentive or that the facility would not have been built absent the incentive.

18. In contrast, a number of commenters, including EEI and a large number of utility and Transco commenters, argue that incentives are needed to foster investment in transmission facilities. EEI asserts that incentives are needed to stimulate planning and investment in national interest electric transmission corridors. NU states that the many risk factors associated with transmission investments, such as considerable time delays, negative public opinion of transmission construction, state siting uncertainties and recovery of project costs, justify incentives.

3. Commission Determination

19. Here again, the fundamental issue raised by certain commenters—whether transmission incentives are necessary to encourage new infrastructure—was put to rest by the plain language of section 219(a), which requires the Commission issue a rule that adopts ''incentive-based * * * rate treatments.'' Certain commenters urge the Commission to adopt ''penalties'' in this rulemaking for entities that do not build sufficient transmission. We decline to do so here.

20. Other commenters do not oppose incentives outright, but rather are concerned with the extent to which incentives may increase rates to consumers. Those concerns are premature. The Final Rule does not grant incentive-based rate treatments or authorize any entity to recover incentives in its rates. Rather, it informs potential applicants of incentives that the Commission is willing to allow when justified. Before adopting any incentive-based rate treatments for a particular company, the Commission will need to determine that the applicant has justified its specific incentive request. In addition, although the Commission intends to provide flexible procedural mechanisms by which an applicant may obtain an early determination of which incentives it may receive (*e.g.*, through an expedited declaratory order proceeding), before recovering any incentives in its rates, specific rates must be approved under section 205 of the FPA.

C. Summary of the Nature and Applicability of Incentives Adopted by the Final Rule

21. The incentives adopted by this Final Rule are properly understood only in the context of the traditional regulatory principles they seek to further. The longstanding rule is that utility rate regulation must adequately balance both consumer and investor interests. It is not enough to ensure that investors are properly compensated, and it is not enough to ensure that consumers are protected against excessive rates. Our policies must ensure both outcomes and, in doing so, strike the appropriate balance between these twin objectives. In striking that balance, the courts have recognized that there is no single formula for establishing a just and reasonable rate. Rather, the test is whether the ''end result'' is just and reasonable.[20]

22. The traditional policies that we re-examine here reflect both fundamental precepts: the need to balance investor and consumer interests and the recognition that there is no single formula for doing so. For example, in ensuring that rates produce adequate returns for investors, we do not set a single return on equity for all public utilities, nor do we presume that there is only one return on equity that is appropriate for any individual utility. Rather, our precedents require the establishment of a range of returns and we select an ROE within that range that reflects the facts and circumstances of a particular case. Similarly, our policies regarding the recovery of Construction Work in Progress (CWIP) seek to balance investor and consumer interests by allowing, in the typical case, 50 percent of CWIP in rate base. This policy balances investor and consumer interests in the ordinary case by permitting investors recovery of some construction costs on a current basis while also protecting consumers against full rate recovery before a particular facility is placed into service.

23. Our procedural regulations respecting rate recovery also seek to balance investor and consumer interests. For example, we allow public utilities to determine, as a general matter, the timing and frequency of when to seek a rate increase, which ensures that investors can file a rate increase when current rates are no longer adequate (*e.g.*, when the utility is undergoing a large construction program). However, we also typically require a utility seeking a rate increase to expose all of its costs to review and therefore do not generally permit ''single issue'' rate filings (selective rate adjustment).

24. Section 219 requires the Commission to re-examine these and other policies to determine whether they continue to strike the appropriate balance in encouraging new transmission investment given the significant need for new transmission infrastructure in the Nation. We do so in recognition of the unique and substantial challenges faced by large new transmission projects. Siting major new transmission lines is extraordinarily difficult, given the environmental and land use concerns associated with obtaining and permitting new rights-of-way. The

[18] *E.g.,* APPA, TAPS, NECOE, E.ON U.S., NARUC, and New Jersey Board.

[19] *E.g.,* Connecticut DPUC, NASUCA, NECPUC, Delaware Commission, Missouri Commission, and New Mexico AG.

[20] *See FPC* v. *Hope Natural Gas Co.,* 320 U.S. 591, 602–03 (1944).

experience of American Electric Power Corp. in taking 16 years to complete construction of a new high-voltage transmission line from Wyoming County, West Virginia to Jackson Ferry, Virginia represents an extreme example, but it is illustrative of the significant risks and challenges associated with siting large new transmission projects.[21]

25. These challenges and risks are underscored by the fact that, in many instances, new transmission projects will not be financed and constructed in the traditional manner. New transmission is needed to connect new generation sources and to reduce congestion. However, because there is a competitive market for new generation facilities, these new generation resources may be constructed anywhere in a region that is economic with respect to fuel sources or other siting considerations (*e.g.*, proximity to wind currents), not simply on a ''local'' basis within each utility's service territory. To integrate this new generation into the regional power grid, new regional high voltage transmission facilities will often be necessary and, importantly, no single utility will be ''obligated'' to build such facilities. Indeed, many of these projects may be too large for a single load serving entity to finance. Thus, for the Nation to be able to integrate the next generation of resources, we must encourage investors to take the risks associated with constructing large new transmission projects that can integrate new generation and otherwise reduce congestion and increase reliability. Our policies also must encourage all other needed transmission investments, whether they are regional or local, designed to improve reliability or to lower the delivered cost of power.

26. To address the substantial challenges and risks in constructing new transmission, the Final Rule identifies instances where our regulatory policies may no longer strike the appropriate balance in encouraging new investment. The Final Rule identifies several policies that should be adjusted, where appropriate on the facts of a particular case, to encourage new transmission investment or otherwise remove impediments to such investment. Although each reform adopted by the Final Rule constitutes an ''incentive'' as that term is used by section 219, this label has caused some confusion in the comments. It is true that our reforms adopted in the Final Rule provide ''incentives'' to construct new transmission, but they do not constitute an ''incentive'' in the sense of a ''bonus'' for good behavior. Rather, as we explain below, each will be applied in a manner that is rationally tailored to the risks and challenges faced in constructing new transmission. Not every incentive will be available for every new investment. Rather, each applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. Our reforms therefore continue to meet the just and reasonable standard by achieving the proper balance between consumer and investor interests on the facts of a particular case and considering the fact that our traditional policies have not adequately encouraged the construction of new transmission.

27. A few examples will illustrate this point. The Final Rule permits higher returns on equity for certain transmission investments. This may be appropriate in several contexts, such as where the risks of a particular project exceed the normal risks undertaken by a utility (and hence are not reflected in a traditional discounted cash flow (DCF) analysis) and where necessary to encourage creation of a Transco or participation in a Transmission Organization. However, this does not mean that every new transmission investment should receive a higher return than otherwise would be the case. For example, routine investments to meet existing reliability standards may not always, for the reasons discussed below, qualify for an incentive-based ROE.

28. The Final Rule also adopts incentives that are designed to reduce the risks of new investments. For example, the Final Rule provides that the Commission will provide assurance of recovery of abandoned plant costs if the project is abandoned for reasons outside the control of the public utility. Although this qualifies as an ''incentive'' under section 219, it is perhaps more properly characterized as reducing a regulatory barrier—the potential lack of recovery of costs— to infrastructure development. Moreover, this reform adequately balances consumer and investor interests because it is available only when a project is abandoned for reasons beyond the control of the public utility.

29. Our Final Rule also adopts certain reforms that affect the timing of recovery of new transmission investments. Given the long lead time required to construct new transmission, and the associated cash flow difficulties faced by many entities wishing to invest in new transmission, the Final Rule provides that, where appropriate, the Commission will allow for the recovery of 100 percent of CWIP in rate base. Here again, we seek to remove an impediment—inadequate cash flow— that our current regulations can present to those investing in new transmission. We also will permit, where appropriate, the recovery of the costs of new transmission through a single issue rate filing without requiring the public utility to re-open all its transmission rates to review. We do not, however, suggest that such selective rate adjustments will be appropriate in all cases, as discussed in more detail below. Rather, as with each incentive adopted by the Final Rule, an applicant must show that there is a nexus between its proposal to make a single issue rate adjustment and the facts of its particular case.

D. Effective Date and Duration of Effectiveness For Incentives

1. Background

30. Congress directed the Commission to issue a rule establishing incentive-based rate treatments no later than one year after enactment of EPAct 2005, or by August 8, 2006.

2. Comments

31. Certain commenters urge the Commission to apply the rule to investments made before August 8, 2005 while others ask the Commission to apply the rule to investments made after August 8, 2005.[22] Certain commenters argue that the Commission should not approve incentives for facilities that are pending at the time the Final Rule becomes effective, while others request that the Commission not allow incentives for investment in facilities that an applicant already has committed to build or for Transcos that already exist.[23]

32. Several commenters argue that, once the incentives have been granted, the Commission should not eliminate them, or should do so only under very limited circumstances.[24] In contrast, others argue that the Commission should grant incentives for a specific time period or retain the flexibility to change or review any incentives if it is found the incentives provide no customer benefit.[25] The California Oversight Board requests that any

[21] Although new section 216 of the FPA improves the siting process for certain new projects, it does not eliminate all risks faced by such projects nor does it address the risks faced by other projects that do not reside in a national interest transmission corridor.

[22] *E.g.*, Progress, NEMA, and PG&E.

[23] *E.g.*, PG&E, Connecticut DPUC, NASUCA, TDU Systems and TANC.

[24] *E.g.*, Progress, NEMA, EEI, Trans-Elect, and National Grid.

[25] *E.g.*, TANC, Snohomish, Municipal Commenters, and TDU Systems.

authorized incentives be subject to refund.

33. KKR explains that, under certain circumstances, investors in transmission assets may need favorable rate treatment for a sufficient period of time to ensure an appropriate return on their capital, *i.e.*, for a 15 to 30-year period.[26] KKR recommends that public utilities requesting incentive treatment for an extended period into the future propose criteria that can be used to evaluate that entity's performance during periodic evaluations. KKR notes that applicants may not always be able to meet certain proposed metrics due to circumstances beyond their control. For example, a transmission owner should not lose its incentive rate treatments if it does not succeed in meeting desired reductions in congestion because the applicant may not have complete control of the factors affecting congestion, such as generation additions, changes in load location and operation of neighboring systems, and RTO policies. KKR emphasizes that the Commission should retain the flexibility to assess an applicant's proposal as the facts and circumstances will vary case-by-case. Finally, KKR recommends that applicants be required to file a report on their performance every several years and that the Commission may initiate a proceeding to review incentives only if the criteria are not met. KKR explains that frequent reviews run the risk of distorting results due to the ''lumpiness'' of capital investment and the long time periods to make capital additions and for capital additions to have effects. Further, KKR states that frequent reviews will make long-term investments more uncertain and, hence, less likely. In supplemental comments, KKR asserts that higher ROEs are of material value for Transcos only when long-term. KKR cites International Transmission as an example, noting that it is only able to invest in excess of every dollar it earns back into its system due to the certainty afforded it by its rate compact, which is long-term, formula-based, and includes a reasonable ROE. The certainty and long-term horizon of International Transmission's rates give debt and equity investors in International Transmission comfort that they will ultimately receive an adequate return on their capital.

3. Commission Determination

34. Section 219 of the FPA became effective on August 8, 2005. Codification of section 219 on that date and the requirement for a rule authorizing investment incentives provided notice to the industry that Congress intended that the Commission provide incentive-based rate treatments promptly. Thus, the Final Rule will become effective 60 days after publication in the **Federal Register**. However, we clarify that any investment made in, or costs incurred for, transmission infrastructure after August 8, 2005 that ensures reliability or lowers the cost of delivered power by reducing transmission congestion will be eligible for incentive-based rate treatments under this Rule. Applicants seeking incentive-based rate treatments for investments made or costs incurred after August 8, 2005 will need to satisfy the requirements of this Rule to obtain and recover any incentives and will need to make an appropriate filing under section 205.

35. The fact that a proposed expansion was in a utility's expansion plan as of August 8, 2005 does not disqualify the project for incentive treatment. Inclusion of a facility in a plan does not mean that a project can or will get built. Even where a project already has been planned or announced, the granting of incentives may help in securing financing for the project or may bring the project to completion sooner than originally anticipated. Congress's directive that the Commission issue a rule within one year of enactment of EPAct 2005 shows that Congress intended for the Commission to take steps to bring new transmission on line expeditiously.

36. With respect to the issue of how long an incentive-based proposal should remain in effect, the Commission recognizes that it may be necessary to authorize incentives that may extend over several years in order to support investment in long-term transmission. It can be important to investors making long-term investments in long-lived facilities to be assured that a ratemaking proposal adopted prior to construction of those facilities will not later be altered in a manner that undermines the basis for the financing of those facilities. The Commission will therefore allow applicants to propose specific time periods by which their incentive-based proposals will not be ''re-opened'' in a manner incompatible with the nature of the initial approvals. However, to ensure that ratepayers are also adequately protected, we will require any applicants seeking such a fixed term for its plan to explain how ratepayers can be assured that such a plan is delivering the benefits that formed the basis for the Commission's initial approval of it. For example, an applicant may propose periodic progress assessments with appropriate metrics to measure how well the project is progressing and whether the proposed investment in new transmission is improving reliability or reducing congestion. Such metrics would provide the Commission a means to determine whether and how the applicant is providing the anticipated benefits and thus that the approved incentives need not be revisited. Because the scope and size of each project will differ, any applicant seeking incentive-based rate treatments may propose metrics for its project as well as the frequency for review of those metrics.[27] An applicant may include its proposed metrics and any timetable for review in its section 205 rate filing seeking recovery of incentives.[28] Where such metrics are found to be needed and are approved by the Commission, an applicant would be required to submit information filings to the Commission consistent with the approved metrics and timetable. We clarify, however, that the metrics reviews will not be opportunities to re-argue the issues addressed in proceedings granting the incentive-based rates; they are for the purpose of measuring whether the plan is being implemented as initially approved.

IV. Discussion

A. Standard for Approval of Incentive-Based Rate Treatments

1. The Final Rule Applies to the Recovery of Costs Incurred to Ensure Reliability or to Reduce Transmission Congestion, or Both.

a. Background

37. Proposed § 35.35(d)(1) specifies that the Commission will authorize incentive-based rate treatments for investment by public utilities, including Transcos, in new transmission capacity that reduces the cost of delivered power by reducing congestion or promotes reliability, as demonstrated in an application to the Commission.

b. Comments

38. Many commenters urge the Commission to be flexible in applying the incentives.[29] Southern and the Nevada Companies assert the Commission should not require that facilities both improve regional reliability and reduce congestion to be eligible for an incentive ROE. They

[26] *See also* National Grid and EEI.

[27] The information may include, as well as supplement, information provided in FERC–730, discussed in section V below.

[28] An applicant has the option to include metrics proposals in a declaratory order proceeding, but would also need to include them in the subsequent section 205 rate filing.

[29] *E.g.*, FirstEnergy, Southern, Nevada Companies, AEP.

argue that the guiding factor should be to provide incentives that improve regional reliability and/or reduce transmission congestion. AEP urges the Commission to adopt a functional approach to determine whether a project qualifies for incentives. For example, AEP suggests that projects that connect newer technology generation or renewables be eligible for incentives. Upper Great Plains contends that incentives should be available for projects that support the development of new electric generation in recognition of the expected growth in electric consumption and the need for additional investment to keep pace.

39. Several commenters urge the Commission to establish criteria for transmission projects to demonstrate that they achieve Congress' goals before projects receive an incentive.[30] The New York Commission asks the Commission to convene a technical conference to develop the criteria.

40. The Maryland Commission supports incentives that are forward-looking and targeted to support electric reliability, competitive markets and diversity in fuel sources, including renewable resources, in the short and long term.

c. Commission Determination

41. The purpose of section 219 of the FPA is to benefit consumers by promoting transmission capital investments that result in reliable and economically efficient transmission and generation. Congress did not enact section 219 in isolation. Section 219 is a part of a larger statutory framework in which Congress directed the Commission to take steps to address reliability of the bulk power system as well as to remedy the adverse effects of transmission congestion. For example, in new section 215 of the FPA Congress enacted a regulatory regime under which the Commission will, for the first time in its history, approve and enforce mandatory reliability standards for the nation's power grid.[31] In new section 216, Congress directed the Secretary of Energy to identify areas of the nation in which transmission congestion adversely affects consumers (national interest electric transmission corridors) and gave the Commission certain permitting authority to ensure timely construction of transmission facilities to remedy transmission congestion in those corridors. In section 1223 of EPAct 2005, Congress directed the Commission to encourage the deployment of advanced transmission technologies that increase the capacity, efficiency and reliability of an existing or new transmission facility. In enacting these provisions of EPAct, Congress made clear that it was equally concerned with reliability as well as the adverse impacts of transmission congestion and that the Commission should take steps to address both issues. New FPA section 219, which is complementary to these other EPAct provisions, directs the Commission to provide rate incentives for the purpose of ensuring reliability and reducing transmission congestion. However, nowhere in section 219 does the language say that the Commission may provide incentives only to applicants that propose to both improve reliability and reduce congestion. In fact, we believe it would be contrary to the intent of the new provisions, taken together, to limit incentives this way.

42. Consistent with the overall goals of Congress in EPAct 2005, and in particular its focus on reliability improvements and relief of transmission congestion, we interpret section 219 to promote capital investment in a wide range of infrastructure investments that can have either reliability or congestion benefits rather than investments that have both reliability and congestion benefits. The alternative to this reading would be to apply section 219 in a manner that would deny incentive-based rate treatments to a transmission facility that significantly enhances reliability but does not reduce the cost of delivered power by reducing transmission congestion. This would be contrary to a fundamental goal of EPAct 2005 to improve reliability of the interstate transmission grid. We do not consider such an interpretation to be reasonable. In any event, we expect there will be few transmission projects that provide one type of benefit but not the other.

43. Commenters seeking a narrow reading of section 219 are primarily concerned with the impact of any incentive-based rate treatment on an applicant's rates. These concerns are premature. Before the Commission will permit any applicant to recover incentives in its rates, the Commission will evaluate the rate impact under section 205 or 206 of the FPA. Interested parties may raise any rate concerns at that time. Further, our case-by-case approach ensures that the incentives granted will be tailored to particular circumstances. Finally, except for the rebuttable presumptions addressed below, we will not at this time establish more detailed criteria an applicant must meet to be eligible for incentive-based rate treatments. Establishing criteria now would limit the flexibility of the Rule or improperly pre-judge which projects are acceptable for incentives. The Commission will, on a case-by-case basis, require each applicant to justify the incentives it requests. Because these proceedings will provide ample opportunity for parties to comment on any incentive proposal, we do not see the need for a technical conference or detailed criteria now. This notwithstanding, we provide certain guidance, as described below, regarding the types of projects that may be particularly well suited to certain incentives and others that may not.

2. Other Criteria For Approval of Incentives

a. Comments

44. Numerous commenters seek additional conditions to be considered in the grant of incentives. Some argue that the number of incentives should be limited while others recommend additional criteria that an applicant must satisfy[32] or that the incentives be limited to certain types of facilities. For example, TDU Systems assert that the Final Rule should specifically identify other incentives that will be considered under § 35.35(d)(viii) and specify the parameters for eligibility for the incentives. EEI, however, contends the Commission should allow individual companies to propose any incentives on a case-by-case basis because the individual companies are in a better position to understand the efficacy of particular incentive mechanisms. Similarly, National Grid requests clarification that the incentives are not mutually exclusive and transmission owners should be free to propose customized rate packages that include one or more of the incentives in combination.

45. With regard to additional conditions, some commenters argue, for example, that the Commission should authorize incentives only for proposals that recognize regional differences, that are the product of an open and inclusive regional transmission planning process, increase network capacity, or that respond to specific reliability or congestion concerns. TANC argues that the Commission should limit qualification for the incentives to those transmission projects that are 200 kV and above. NECOE argues that incentives should be provided to

[30] *E.g.*, AEP and New York Commission.

[31] *See* Order No. 672, Rules Concerning Certification of the Electric Reliability Organization; and Procedures or the Establishment, Approval, and Enforcement of Electric Reliability Standards, 71 FR 8662 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204 (2006).

[32] *E.g.*, East Texas, TANC, and TAPS.

utilities that conform to good utility practice and minimize total costs. Also, NECOE asserts that, when more than one incentive is requested, the Commission should require the applicant to demonstrate why a single, appropriately targeted incentive is insufficient. Several commenters urge the Commission to grant incentives for existing facilities and for maintenance of existing facilities.[33] The Southern Companies state that the Commission should grant incentives to proposals that resolve a significant inter or intra-regional constraint, or preclude or mitigate anticipated constraints that may or may not arise. Progress asserts that incentives should be granted to encourage installation of new software to better manage flowgates and calculate Available Transfer Capability values on existing transmission facilities. The Steel Manufacturers state that a utility does not deserve special rate treatment to maintain or upgrade its facility to comply with mandated reliability standards.

46. Several commenters urge the Commission to condition any incentive-based rate treatment on the applicant, among other things, divesting the subject facility to a Transco, demonstrating that the subject facility solves congestion constraints on a regional basis or results in significant new transfer capacity, complying with the 1992 and 1994 Policy Statements, showing that the facilities would not have been built absent the incentives, or showing that the facilities were not already necessary to meet NERC reliability criteria or normal load growth.[34] PJM proposes a tiered procedure to determine whether incentives are warranted. TDU Systems recommend that incentives should be denied to public utilities that have refused to provide requested relief from transmission congestion in the form of transmission upgrades or otherwise, until such congestion is remedied without the incentive rates.

47. Several commenters request that the Commission allow states to play a role in the approval or recovery of incentives because states may hinder recovery of incentives in bundled rates.[35] National Grid asserts that the Commission and states should have an alignment of interests on transmission investment and, therefore, there is no basis to believe that the rule will warrant shifts in states' roles.

b. Commission Determination

48. Congress has determined that there is a need for incentives, and has directed the Commission to issue a rule to provide them. Most of the prerequisites and preconditions raised in the comments reflect a desire to limit or circumscribe the nature or applicability of incentives that may be granted under the rule. We have considered these comments and do not believe that any of them should be adopted at this time. Some of them are consistent with our overall policy goals (such as the emphasis on regional planning) and, to that extent, we explain how we will factor those considerations into an analysis of a proposed incentive. However, some are inconsistent with the policy goals of section 219 because they will only serve to discourage transmission investment. Therefore, unless adopted in other sections of this rule, we will not require applicants to satisfy the requirements proposed in the comments. For example, we reject arguments that an applicant must show that, but for the incentives, the expansion would not occur. Those arguments are based on commenters' conclusions that the Commission's prior issuances (*i.e., Removing Obstacles* order, the 1992 Policy Statement, or the innovative rate proposal in Order No. 2000) required an applicant to show need prior to receiving incentives. However, the Final Rule is based on a clear directive from Congress that does not require an applicant to show that it would not build the facilities but for the incentives. This notwithstanding, we do require applicants to show some nexus between the incentives being requested and the investment being made, *i.e.*, to demonstrate that the incentives are rationally related to the investments being proposed.

49. We also consider our procedures for the approval of incentives to be comprehensive and, therefore, will not attempt to establish gradations regarding either approval requirements or the amount of incentive approved, as recommended by TANC, PJM, Industrial Consumers and others. Section 219 does not mandate higher returns for projects that are part of independent regional planning processes, nor does it require higher standards of review for projects that do not result from independent planning processes. As long as the project ensures reliability or reduces the cost of delivered power by reducing congestion, regardless of where it is located on the nationwide transmission grid, the project is eligible for incentive ratemaking.

50. We will not impose size limits on eligible transmission projects. Projects below 200 kV can have a significant impact on reliability or reduce congestion, and therefore would qualify for incentive treatment. We will also not condition approval of incentives on market power findings. Our regulations and penalties on market power and market behavior are sufficient inducements to ensure markets are not manipulated and, therefore, additional provisions are not necessary.

51. We will not deny incentives to public utilities that have not built transmission upgrades requested by transmission customers. The scope of this Rule is restricted to implementing the requirements of section 219; the appropriate means to address this issue is to file a complaint in a separate proceeding.

52. While the promotion of renewable energy projects supports other policy and regulatory objectives, we will not adopt separate rate-based incentives for renewable energy projects. Congress directed the Commission to issue a rule to ensure reliability or to reduce the cost of delivered power by reducing transmission congestion regardless of the nature of the energy carried over the new transmission facilities. We believe that, by providing incentives applicable to all transmission facilities, the Final Rule provides incentives for transmission to serve renewable resources and, therefore, additional incentives are not necessary.

53. Because section 219 provides a new directive to the Commission to permit greater incentives and does not on its face require an individual showing of need by incentive applicants, we will not require compliance with the 1992 or 1994 Transmission Policy Statements as a precondition for approval of incentives.

54. With regard to state review, the Commission recognizes that incentives for many utilities are incorporated into rates that must receive state commission approval and that many decisions on siting and permitting of new facilities are under the jurisdiction of state and local government authorities. Because of this, we will carefully consider the views of any state bodies having jurisdiction over these matters. We also will, as discussed below, adopt a rebuttable presumption that projects approved by an appropriate state commission or siting authority are eligible for incentives under section 219. We believe that, in these ways, we will appropriately coordinate our consideration of incentives with the

[33] *E.g.*, FirstEnergy, PSEG, AEP, EEI, Duquesne and MidAmerican.

[34] *E.g.*, TDU Systems, APPA, TAPS, NRECA, NARUC, NASUCA, Connecticut DPUC, New Jersey Board, WPS.

[35] *E.g.*, CREPC, KCPL, Steel Manufacturers, Montana-Dakota, MidAmerican, and EEI.

views of responsible state agencies. We will not, however, adopt any further requirements regarding state approval, such as the requirement that an applicant receive state approval of any proposed incentives. While state approval is desirable it is not required by section 219. However, if state approval of a particular plan is required, we expect that any applicant will seek that approval in due course.

55. Finally, we reiterate that an applicant may request any combination of the incentives listed in the Final Rule. Applicants also may request incentives that are not listed in the Final Rule. The Commission will not use the Final Rule to identify each and every incentive an applicant may request. However, this in no way relieves the applicant of fully supporting its rate request and demonstrating that its request for incentives satisfies section 219 and the requirements of this Final Rule. If an interested party believes a particular incentive is not warranted, it may raise its concerns when an applicant proposes that incentive in a declaratory order or in a section 205 rate application.

56. Because section 219 makes clear that the Final Rule should promote capital investment in the operation and maintenance of all facilities for the transmission of electric energy in interstate commerce, new investment in existing facilities will be eligible for incentive-based rate treatments.[36] The reliability benefits of operation and maintenance capital spending are obvious, and we expect applicants incurring this type of capital spending will be able to demonstrate reliability benefits and thereby be eligible for incentive treatment.

3. Rebuttable Presumptions

57. As we discussed above, we will not adopt the variety of preconditions recommended by the commenters. However, we are nonetheless required to make findings that a particular investment falls within the scope of section 219. In making that finding, we have chosen to rely on existing processes to the extent practicable in determining whether a particular facility is needed to maintain reliability or reduce congestion. We describe these processes below and find that, if an applicant satisfies them, its project will be afforded a rebuttable presumption that it qualifies for transmission incentives. Other applicants not meeting these criteria may nonetheless demonstrate that their project is needed to maintain reliability or reduce congestion by presenting us a factual record that would support such findings. Once we determine that the project is eligible for incentives, we would, as described below, consider whether the particular incentives being proposed are appropriate for the particular investments being made.

58. The first rebuttable presumption we will adopt relates to regional planning. Although we will not require participation in regional planning processes as a precondition for obtaining incentives, as section 219 does not require such a precondition, we believe that regional planning processes can provide an efficient and comprehensive forum through which those seeking to make transmission investments can have their projects evaluated to see if they meet the requirements of section 219. Regional planning processes can help determine whether a given project is needed, whether it is the better solution, and whether it is the most cost-effective option in light of other alternatives (*e.g.*, generation, transmission and demand response). It does so by looking at a variety of options across a large geographic footprint; thus, regional planning can allow for a broad assessment of loop flows and impacts on neighboring systems. Regional Planning also can serve as a forum in which states can readily participate.[37] This benefit of a regional planning process is difficult to duplicate on a utility-by-utility basis. It may prove difficult for applicants, on an individual basis, to timely gain access to all the information that might be required to make a showing that the project ensures reliability and/or reduces the cost of delivered power by reducing congestion. The Commission expressly recognized the value of regional planning when it proposed to amend the pro forma Open Access Transmission Tariff of jurisdictional public utilities to require regional planning to ensure that transmission is planned and constructed on a nondiscriminatory basis to support reliable and economic service to all eligible customers in a region.[38] Consistent with our actions in that NOPR and our belief that power markets are regional in nature and that the transmission systems supporting those markets must be supported by regional planning, we will create a rebuttable presumption for projects that result from regional planning. Thus, the Commission will rebuttably presume that transmission projects that result from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission satisfy the requirements of this Rule.[39] In addition, the Commission will adopt the following other rebuttable presumptions. We will also attach a rebuttable presumption that an applicant has met the requirements of section 219 if a proposed project is located in a National Interest Electric Transmission Corridor or where a project has received construction approval from an appropriate state commission or state siting authority.

4. Applicants Seeking Incentive-Based Rates Will Not Be Required To File a Cost-Benefit Analysis

a. Background

59. The NOPR explained that no cost-benefit analysis would be required to obtain incentives because customers will be protected by the Commission's review of applications pursuant to sections 205, 206 and 219 of the FPA, which require that all rates be just and reasonable and not unduly discriminatory or preferential.[40]

b. Comments

60. Certain commenters argue that judicial precedent requires that incentive rates be supported by a showing of a quantifiable relationship between the incentive and the result the incentive is intended to achieve[41] They also argue that the level of the incentive must be calibrated to a level that it is no more than needed to achieve the outcome that the incentive is supposed to produce.[42] They further argue that

[36] In addition, the Final Rule makes available incentives for joining a Transmission Organization.

[37] State representation in stakeholder committee is a feature of the Midwest ISO, *i.e.*, the Organization of MISO States (MISO States or OMS).

[38] *Preventing Undue Discrimination and Preference in Transmission Service,* Notice of Proposed Rulemaking, 71 FR 32,636 (June 6, 2006), FERC Stats. & Regs., Regs. Preambles ¶ 32,603 at P 36 (2006) (OATT Reform NOPR):

We conclude that the inadequacy of the existing obligation to conduct joint and regional transmission system planning, coupled with the lack of transparency surrounding system planning generally, require reform of the *pro forma* OATT to ensure that transmission infrastructure is constructed on a nondiscriminatory basis and is otherwise sufficient to support reliable and economic service to all eligible customers.

[39] An applicant may wish to file a request for incentive treatment for a project which is undergoing consideration in a regional planning process. The Commission will consider such requests, but may make any requested rate treatment contingent upon the project being approved under the regional planning process. As discussed elsewhere in this Final Rule, different types of projects and the circumstances under which they are undertaken may warrant different rate treatments and incentives.

[40] NOPR at P 16.

[41] *E.g.,* NECOE, PSE&G, and WPC Companies.

[42] *E.g.,* NECOE.

section 219 does not require significant changes to the Commission's existing rules and ratemaking policies governing incentive rates, such as its 1992 Policy Statement[43] and Order No. 2000,[44] in which the Commission required that applications for incentives be supported with cost-benefit analyses. They contend that the Commission's existing rules and policies already satisfy the Commission's obligations under the FPA, even as amended by section 219, and should be retained.[45]

61. Several commenters state that, without a cost-benefit analysis, the Commission has no basis for concluding that a particular incentive provides customers with a net benefit or will be just and reasonable.[46] The New York Commission suggests that criteria for a cost-benefit analysis be established through a separate technical conference or rulemaking.

62. PJM argues that the Commission should provide incentives for transmission owners' participation in robust regional transmission planning that identifies both the costs and economic benefits of a given project. PJM proposes that such a process should support a rebuttable presumption that the decision to build is prudent and warrants an ROE incentive.

63. East Texas states that utilities engaged in meeting reliability standards, constructing projects across designated corridors and joining qualified Transmission Organizations should be allowed the incentive rates on the simple showing that they seek to recover no more than their prudently incurred costs. SMUD states that, under section 219, an incentive is appropriate only when it results in lower power costs to consumers. The Oklahoma Commission states that the Commission should give direction as to the showing by applicants that is acceptable in lieu of the cost-benefit analysis.

64. Other commenters argue that a cost-benefit analysis is unnecessary.[47] National Grid states that the Commission already recognized generically the benefits of using ROE adders as an incentive for needed transmission investment in the *Removing Obstacles* order.[48] FirstEnergy asserts that consumers benefit by strengthening the transmission grid and by encouraging new investment in transmission and that the benefits of these factors potentially far exceed the costs. International Transmission asserts that requiring a cost-benefit analysis could delay needed transmission upgrades.

c. Commission Determination

65. We reaffirm the NOPR's determination not to require applicants for incentive-based rate treatments to provide cost-benefit analyses. The courts have long recognized that a primary purpose of the FPA, and its counterpart the Natural Gas Act, is to encourage the orderly development of plentiful supplies of electricity and natural gas at reasonable prices.[49] To carry out this purpose, the Commission may consider non-cost factors as well as cost factors.[50] Moreover, Congress's enactment of section 219 reflects its determination that incentives generally can spur transmission investment which will, in turn, provide the benefits of a robust transmission system identified by the commenters. The Commission will consider the justness and reasonableness of any proposal for incentive rate treatment in individual proceedings.

5. Procedural Requirements for Obtaining Incentive-Based Rate Treatments

a. Background

66. Section 35.35(c) in the NOPR proposed that all rates approved under the rule would be subject to sections 205 and 206 of the FPA. Section 35.35(d) in the NOPR proposed certain options by which an applicant may seek incentive-based rate treatments. The NOPR proposed that applicants must explain whether the proposed facilities are part of an independent regional planning process. The Commission also sought comment on whether the Final Rule should establish a definition of ''independent regional planning process'' or if the Commission should consider this issue on a case-by-case basis.

b. Comments

67. Most transmission owners request that the Commission implement a streamlined process to review and approve incentive-based rate treatments. For example, some suggest that the Commission adopt a pre-approval procedure that provides a preliminary determination of a project's rate treatment, similar to the expedited pre-approval in the Path 15 upgrade in California,[51] to promote timely construction of additional needed transmission facilities.[52]

68. A number of commenters urge the Commission not to require transmission owners to make section 205 filings to implement incentive-based rates. They argue that such proceedings may result in unreasonable delay and uncertainty and thereby discourage, if not preclude, incentive-based rate proposals.[53] Many of these parties urge the Commission automatically to approve incentives once the facilities or investment have been shown to ensure reliability or reduce congestion.[54] Other commenters suggest that the Commission create a category of incentives that would not require any review under section 205 and then hold paper hearings only for those incentives that do not fall within the designated category of incentives.[55] Other commenters request that the Commission establish a rebuttable presumption that each incentive is just and reasonable or allow transmission owners to self-certify that they meet the criteria of section 219.[56] Others similarly ask that there be a presumption that facilities included in a regional planning process are eligible for incentives.[57] Another group of commenters argue that projects need not be part of an independent regional planning process to receive an incentive

[43] *Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities: Policy Statement on Incentive Regulation,* 61 FERC ¶ 61,168 at 61,590 (1992).

[44] *Regional Transmission Organizations,* Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs., Regulations Preambles July 1996–December 2000 ¶31,089 (1999), *order on reh'g,* Order No. 2000–A, 65 FR 12,088 (Mar. 8, 2000), FERC Stats. & Regs., Regulations Preambles July 1996–December 2000 ¶31,092 (2000), *aff'd sub nom. Public Utility District. No. 1 of Snohomish County, Washington v. FERC,* 272 F.3d 607 (D.C. Cir. 2001).

[45] *E.g.,* TDU Systems, NRECA, NECOE, and SMUD.

[46] *E.g.,* NRECA, NARUC, TAPS, East Texas, Connecticut AG, Industrial Customers, NECPUC, California Oversight Board, MISO States, DTE Energy, Wyoming Consumer Advocate, and New York Commission.

[47] *E.g.,* National Grid.

[48] *Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States,* 94 FERC ¶ 61,272, *reh'g denied,* 95 FERC ¶ 61,225, *order on reh'g,* 96 FERC ¶ 61,155, *further order on reh'g,* 97 FERC ¶ 61,024 (2001).

[49] *See, e.g., Pub. Utilities Comm'n of the State of California* v. *FERC,* 367 F.3d 925, 929 (D.C. Cir. 2004) (*CPUC* v. *FERC*), *citing NAACP* v. *FPC,* 425 U.S. 662, 670 (1976).

[50] *Id., citing Permian Basin Area Rate Cases,* 390 U.S. 747, 791, 815 (1968); *Maine Public Utilities Commission* v. *FERC,* No. 05–1001, slip op. at 19 (D.C. Cir., June 30, 2006).

[51] *See Western supra* note 2.

[52] *E.g.,* Mid-American, Nevada Companies, PacifiCorp, and Northwestern.

[53] *E.g.,* United Illuminating, Vectren, NSTAR, and EEI.

[54] *E.g.,* Nevada Companies and MidAmerican.

[55] *E.g.,* EEI, NU, New England TOs, NYSEG, and RGE.

[56] *E.g.,* Southern and FirstEnergy.

[57] *E.g.,* BG&E, PEPCO, KCPL, National Grid, PJM, PJM TOs, United Illuminating and Vectren.

because other regional processes will also provide the same benefits.[58]

69. EEI argues that public utilities should be permitted to make limited section 205 filings to specifically address recovery of incentives in rates, regardless of the form of rate.

70. National Grid requests clarification that the Commission will continue to accept incentive and rate reforms that are tailored to the specific needs of the transmission owner, so that transmission owners can be allowed more traditional rate treatment, such as accruing the allowance for funds used during construction, capitalization of pre-commercial costs and a 30-year depreciation.

71. BG&E requests clarification that, once the Commission approves an incentive-based ROE for a particular regional planning process, any entity within that planning process will be authorized to receive the approved incentive-based ROE without being required to individually apply for, or rejustify, the incentive.

72. Some commenters argue that the Commission must review all elements of an applicant's cost of service before authorizing any incentives.[59] The Steel Manufacturers assert that applicants must justify each incentive they request under sections 205, 206, and 219 and that those applications seeking more than one incentive must demonstrate that the overall package results in rates that satisfy the same criteria.

73. TAPS asserts that, when an applicant files a facility-specific incentive filing the load divisor and depreciation reserve should be updated, in the circumstance that existing rate inputs are known; and, if they are not known because they are part of a ''black box'' settlement, they should be imputed. TAPS suggests ways in which this can be done.

74. Snohomish argues that applicants should be required to submit a schedule of lower-cost alternatives, including potential non-wires solutions, and to explain why these alternatives were not chosen. The Oklahoma Commission recommends that state commissions make the determination as to whether the cost of the project, including the cost of the incentive, is more beneficial for ratepayers than if a generation facility were built closer to avoid the cost of transmission.

75. Finally, several commenters urge the Commission to adopt a generic definition of independent regional planning as well as guidelines and minimum criteria for acceptable independent regional planning processes.[60] Other commenters ask the Commission to be flexible in determining what constitutes a satisfactory ''regional planning process,'' and to take into consideration any differences among regions on a case-by-case basis.[61]

c. Commission Determination

76. Our goal is to provide procedural options that offer applicants flexibility to address their construction and investment opportunities while at the same time ensuring that the resulting rates are just and reasonable and not unduly discriminatory or preferential. The Commission offers two ways to accomplish this. An applicant may obtain these rulings: (1) Through a combination of a petition for a declaratory order and a subsequent section 205 filing or (2) by filing only a section 205 filing. For both of these options, the applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219, that there is a nexus between the incentive sought and the investment being made, and that the resulting rates are just and reasonable.

77. The Commission has found that the first option—petition for declaratory order followed by a section 205 filing—to be a valuable tool. In certain instances, it is valuable for an applicant to obtain an order indicating it qualifies for incentive-based rates prior to making a formal section 205 filing and prior to commencing siting, permitting and construction activities because such orders facilitate financing and investment in new facilities.[62] To provide applicants with as much flexibility as possible, the Commission will permit applicants to seek a declaratory order prior to construction of the facilities to request a finding that the facilities qualify for incentive-based rate treatments. The petitioner would have to demonstrate that its proposal will either ensure reliability or reduce the cost of delivered power by reducing transmission congestion. The petitioner may rely on one of the rebuttable presumptions outlined above or make an independent demonstration. The applicant may also use the petition to justify which incentives it seeks to implement. We clarify that any declaratory order will only rule on whether the applicant's proposal qualifies for incentive-based rate treatment and, if requested, which incentives the applicant may adopt. The applicant must seek to put the rates into effect through a separate single-issue or comprehensive section 205 filing. The Commission's expectation is that, based on past practice, a declaratory order finding that the applicant is eligible for incentive-based rate treatments would be sufficient for the applicant to obtain funding or otherwise acquire financing for the project. The Commission will seek to process petitions for declaratory order quickly. While we cannot guarantee Commission action within 60 days of the request (as is statutorily required for section 205 filings), we will strive to meet that standard.

78. If an applicant obtains a declaratory order finding that the proposal qualifies for incentive-based rate treatment, the subsequent section 205 proceeding would be limited to a review of the applicant's rates and would not include a review of whether the applicant's facility qualifies to receive incentive-based rate treatments. If the petition addresses the applicant's incentives or finds that the required nexus has been demonstrated, the applicant would not be required to re-justify those findings in the section 205 filing. Therefore, if an interested party believes a petitioner's proposal does not qualify for incentive-based rate treatments or that the incentives requested are not justified, the party must raise its objections when the petition is filed and not wait to raise them in the subsequent section 205 proceeding. If an applicant obtains a declaratory order and the proposal changes from the facts on which the declaratory order was issued, the applicant may seek another declaratory order or wait to seek approval of the changes in the subsequent section 205 filing. In that event, interested parties may challenge the changes in the section 205 proceeding.

79. The second option involves filing only a section 205 filing (either ''single-issue'' or comprehensive) to request all of the required approvals. Prior to recovering any incentive-based rate treatments in rates, an applicant must demonstrate that the rates in which the applicant seeks to recover any incentives are just and reasonable and not unduly discriminatory. However, the applicant will have the option of filing a comprehensive section 205 rate case in which all of the utility's rates

[58] *E.g.*, EEI, Progress, Nevada Companies and FirstEnergy.

[59] *E.g.*, Dairyland, TDU Systems, and NASUCA.

[60] *E.g.*, PJM TOs, APPA, International Transmission, MidAmerican, Pacificorp, National Grid, Kentucky Commission, PJM, OMS, NRECA and Semantic.

[61] *E.g.*, Consumer Energy Council, Ameren, SDG&E, Southern Companies, NorthWestern and PEPCO, Dairyland, and Vectren.

[62] *See Western supra* note 2.

would be reviewed in conjunction with the proposed recovery of the incentive-based rate treatments or filing a single-issue section 205 rate filing in which only the impact of the incentive-based rate treatment for the facility granted the incentive will be addressed. As explained below in section IV.B.7 (the discussion of single-issue section 205 proceedings), the Commission believes there is a sufficient need for timely investment in transmission infrastructure to justify, in certain circumstances, a departure from our past practice by allowing an applicant to seek to recover any incentive in a single-issue section 205 rate proceeding. Single issue section 205 proceedings, as well as the declaratory order procedural option discussed above, can remove obstacles to new investments by allowing for timely cost recovery. Single issue filings also can support new investment by allowing applicants to compare the returns of such investments with the risks of the project itself, as opposed to having to compare those returns to both the risks of the project being pursued and the risks associated with re-opening all their rates, which is ordinarily a time-consuming, expensive, litigious and uncertain process. Additionally, in further facilitating these goals, the Commission does not intend to routinely convene trial-type, evidentiary hearings to review either a comprehensive or a single-issue section 205 filing but will attempt to render a decision based on the paper submissions whenever possible.

80. We clarify that no incentives will be granted on a final basis without a section 205 filing. Therefore, an RTO member will not automatically receive incentives granted to another RTO member. However, when evaluating applications for incentive-based rate treatments filed by an RTO member, the Commission will take into account incentives granted to other RTO members, particularly in cases where investments being made by that other RTO member pursuant to a regional plan also lead to the need for expansions by the applicant in its own footprint.

81. We will not specify the rate calculations for section 205 proceedings, as requested by TAPS. These issues are appropriately addressed in individual section 205 proceedings.

82. The Commission will require applicants to justify each of the incentive-based rate treatments it proposes by showing how the proposed incentive satisfies section 219.[63] For example, an applicant will be required to show how the granting of the incentive will promote reliable and economically efficient transmission and generation of electricity, attract new investment, or increase capacity and efficiency of existing transmission facilities or improve their operation. The Commission, as set forth above, provides several vehicles for making this showing, including reliance on a Commission accepted regional planning process. We also will require the applicant to show that there is a nexus between the incentives being proposed and the investment being made.

83. With respect to procedures applicable to joining Transmission Organizations in § 35.35(e), we clarify that applicants also may file a petition for declaratory order as to whether the applicant qualifies for incentives under section 219(c) and then submit a comprehensive or single-issue section 205 filing to obtain approval of the rates, or simply file a comprehensive or single-issue section 205 case to obtain all necessary approvals.

B. Incentives Available To All Jurisdictional Public Utilities

84. In the NOPR, the Commission proposed eight incentive-based rate treatments for transmission infrastructure investments for all public utilities, including Transcos. As discussed below, the Commission will adopt these in the Final Rule.

1. ROE Sufficient To Attract Capital

a. ROE

i. Background

85. The Commission proposed to consider granting an incentive-based ROE to all public utilities (*i.e.*, traditional public utilities and Transcos) that build new transmission facilities that benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion thereby fulfilling the requirements of section 219. As proposed, to receive an incentive-based ROE, a public utility must submit a request in an application under section 205 of the FPA and must support the ROE request by demonstrating how the new facilities will improve regional reliability and reduce transmission congestion. In addition, the application must explain whether the facilities are part of an independent regional planning process, such as that administered by an RTO or ISO or another independent regional planning process recognized by the Commission and how the proposed ROE was derived and why it is appropriate to encourage new investment. (NOPR at P 22) Recognizing that the Commission had approved higher ROEs (referred to in the NOPR as an ''adder'') for certain projects that were designed to increase transfer capability or reduce congestion, the Commission sought comments on the appropriateness of a higher ROE as a mechanism for increasing investment in new capacity.

ii. Comments

86. Numerous Commenters[64] express general support for the proposal to grant incentive-based ROEs to encourage transmission investment stating that it is the most direct and effective means of attracting needed capital to improve the nation's transmission infrastructure. Southern Companies assert that allowing an incentive ROE only ''within the zone of reasonableness'' is inconsistent with Congress's mandate in section 219 that the Commission provide incentive ROEs for transmission investment. NSTAR and Vectren state that an incentive need not be cost-based; an incentive is justified under the statute as just and reasonable if it serves the statutory purpose of improving reliability or reducing the overall cost of delivered power.

87. Other commenters oppose the Commission's proposal to grant incentive-based ROEs for investment in new transmission facilities. For example, APPA states that an ROE adder is basically a bonus payment to reward transmission providers for doing the job for which they are already getting paid an adequate ROE under current Commission standards and relevant FPA requirements. Connecticut DPUC argues ROE adders are not a useful policy tool for improving transmission and the Commission's standard rate review process of assessing the firm's risk-adjusted cost of capital assures a completely adequate ROE without any adders. TDU Systems and New Mexico AG contend that ROE adders will fail the judicial mandate that rates be just and reasonable. CREPC maintains that a blanket ROE increase generally runs counter to the Commission's goal of encouraging transmission investment because it will either unnecessarily increase the cost of electricity to end-users or render an otherwise economic transmission

[63] An applicant would not be required to demonstrate that, but for the incentive, the project would not be completed. Section 219 does not require such a condition.

[64] *E.g.*, National Grid, FirstEnergy, EEI, KCPL, Xcel, Kentucky Commission, Nevada Companies, Progress, and Southern Companies.

project uneconomic in comparison to its alternatives. The California Commission states that the Commission's reliance on incentives granted to Trans-Elect with respect to financing the critical Path 15 upgrade in California several years ago is misleading since the special consideration accorded to Trans-Elect was a direct consequence of the unique, emergency energy crisis facing California and the Western United States in 2001.

88. Some commenters [65] assert that the Commission must consider the certainty of rate recovery for investment in new transmission facilities and associated lower risk—providing the basis for a lower ROE—before granting incentive-based ROEs. Others, however, such as MidAmerican and PacifiCorp, state that the Commission should consider ROE adders or other forms of enhanced returns if a project investment entails levels of risk to investors and consumers that a traditional rate of return would not cover or otherwise lacks the economic or commercial incentives necessary to attract needed capital. PJM recommends the Commission establish an equity return range based on a generic analysis of investor expectations concerning transmission investment as opposed to an analysis of a vertically integrated company or, as an alternative, recognize the overall risk of each project, such as the risk of delayed recovery at the state level.

89. TAPS states that any incentive-based adjustment to transmission returns should take the form of an equivalent adjustment to total return (*i.e.*, return on both debt and equity), rather than making the value of the adjustment vary with the transmitter's capital structure. TDU Systems state that if the Commission allows ROE adders, it should consider applying the adders to the overall rate of return as an alternative to estimating equity returns using public utility returns as a proxy.

90. MISO States argues that the Commission should make clear that proposed ROE incentives are on investments in new transmission, as contrasted with all of a public utility's transmission investment. TAPS claims that increasing the ROE for existing facilities does nothing to encourage investment in new transmission facilities. TDU Systems recommends limiting ROE adders to the portion of rate base related to the new investment.

iii. Commission Determination

91. Consistent with the proposal in the NOPR, the Commission will allow, when justified, an incentive-based ROE to all public utilities (*i.e.*, traditional public utilities and Transcos) for new investments in transmission facilities that benefit consumers by ensuring reliability or reducing the cost of delivered power by reducing transmission congestion. By including this provision in the Final Rule, we meet the requirement of section 219 to provide an ROE that attracts new investment in transmission facilities (including related transmission technologies). Public utilities making investments in transmission infrastructure have made clear, both in their applications for new projects and in their comments on this Rule, that the ROE incentives encourage investment. We expect that an incentive ROE will make transmission projects more attractive, and therefore more likely, when transmission projects must compete for capital in vertically-integrated utilities as well as in transmission and delivery utilities. Accordingly, the Commission will approve an ROE at the upper end of the zone of reasonableness for new infrastructure investments that meet the requirements of section 219 as discussed elsewhere in this Final Rule.

92. Concerns of blanket ROE increases and ROEs that exceed the DCF determined ROE are misplaced. The NOPR's use of the term ''adder'' may have contributed some confusion regarding the Commission's proposal. The Commission, as discussed later in this section, will continue to use the DCF analysis for ROE determinations. That analysis can result in a range of returns (*e.g.*, 9 percent to 13 percent), any of which falling within the range are just and reasonable. This analysis, undertaken in individual rate applications, assesses representative proxy companies and the impact of other factors, including risk, on the zone of reasonableness for ROE. Thus, contrary to certain comments, our justification for a higher ROE is not based on a risk assessment; the risk assessment is part of the traditional DCF analysis.

93. Under the Rule adopted herein, the Commission will provide ROEs at the upper end of the zone of reasonableness for transmission investments that meet the requirements of section 219 as discussed elsewhere in this Final Rule. Incentive-based ROEs, like other incentives offered in this Rule, are to be filed with the Commission for approval before rates that reflect such incentives can be charged. Accordingly, because the approved ROE, including the impact of an incentive, will be within the zone of reasonableness, we consider this provision consistent with section 205 of the FPA. We will not create specific ROE adders (*e.g.*, 100 basis points); the Commission has always considered a range of returns in determining the appropriate ROE and we see no reason to depart from this practice. Though some commenters assert that the incentive need not be cost-based and therefore can justifiably be above the upper-end of the zone of reasonableness, we believe a return within the zone will be adequate to attract new investment and consistent with the intent of Congress in section 219. The Commission will determine the level of the ROE on a case-by-case basis when an application for an incentive-based ROE is filed with the Commission. This is consistent with the approach the Commission has employed to date, which has been found to be just and reasonable.[66]

94. The foregoing does not mean, however, that we will grant incentive-based ROEs to every new investment that increases reliability or reduces congestion. The purpose of section 219 was, as described above, to require the Commission to re-examine whether its current policies are adequate to encourage new investment and strike the appropriate balance between the investor and consumer interests. In many instances, an incentive-based ROE is appropriate because our traditional policies are not sufficient to encourage new investment. For example, a large new interstate transmission project that reduces congestion or increases reliability can face substantial risks that the ordinary transmission investment does not. Further, such projects will often be undertaken only at the election of investors, given that no single entity is ''required'' to undertake them, and thus an incentive-based ROE is appropriate to encourage proactive behavior. Other projects also may present special risks or considerations that merit an incentive-based ROE. By contrast, there are certain projects that may not merit such an incentive. For example, routine investments made to comply with existing reliability standards may not always qualify for an incentive-based ROE. These are the types of investments that have, as a general matter, been adequately addressed through traditional ratemaking because there is an

[65] *E.g.*, NRECA, CREPC, AWEA, the Delaware Commission, New Mexico AG, NY Association, the New York Commission, the California Commission and SMUD.

[66] *Public Utilities Commission of the State of California* v. *FERC*, 367 F.3d 925 (D.C. Cir. 2004).

obligation to construct them and high assurance of recovery of the related costs. For these and other reasons, traditional ROE determinations may continue to be appropriate for these investments. This does not mean that other incentives may not be appropriate for such investments (such as 100 percent CWIP recovery) or that other reliability investments (*e.g.*, substantial new investments to meet new standards) would not qualify for incentive-based ROE determinations.

95. We decline to apply incentives to total return, including debt, as requested by TAPS. Section 219 directs the Commission to focus on ROE, not total return; and this focus is proper. In a competitive market for debt financing, any incentives added to the actual costs of debt will flow to equity investors without actually increasing the returns of debt capital providers. Unlike debt investors who do not propose new investment or make direct investment decisions, equity investors make investment decisions directly or by giving management their proxy. Thus the opportunity for a higher ROE will directly and more transparently influence the actions of those in the position to make initial investment decisions.

96. With regard to questions about whether the opportunity to earn an incentive-based ROE applies to all of a public utility's transmission investment, we clarify that it applies to new transmission investment including investment that results in the enlargement of or improved operation and maintenance of all facilities, consistent with section 219 as discussed elsewhere in this Final Rule.

b. Alternatives to DCF Analysis

i. Background

97. While the Commission has typically utilized a DCF analysis, the NOPR (at P 20) sought comment on whether it should consider alternatives to the DCF analysis as a way to provide incentives for investment in new transmission capacity.

ii. Comments

98. A number of commenters [67] do not support a departure from the DCF method that the Commission currently uses to determine allowed ROE. APPA, for example, states that the DCF approach is generally analytically sound and has produced consistent, predictable results over time, eliminating some of the subjectivity and randomness in equity forecasts that might occur if the Commission were to change methods on a case-by-case basis. The New York Commission supports the use of a DCF analysis as an appropriate means to determine an ROE that reflects commensurate risks and thus would attract new investments.

99. A number of commenters,[68] request that the Commission adopt additional methodologies, such as risk premium, comparable earnings, Fama-French, and/or capital asset pricing, to use along with the current DCF analysis because a multiple model approach will result in a more representative ROE range. These commenters contend that the Commission should make clear that it will consider and use alternative methods of calculating ROEs. They argue that the Commission's final determination of a just and reasonable ROE should be based on a combination of the results from those alternative methods of calculating ROEs, not on the result from any single method, because each method has its own set of theoretical deficiencies and a range of methods ensures all applicable variables are considered.

100. Other Commenters [69] ask that the Commission consider changes to how it determines proxy groups in the DCF analysis, by permitting adjustments for leveraging effects, or adopting modified or expanded proxy groups, as appropriate on a case-by-case basis, and by looking more to companies in the primary or sole business of providing electric delivery service or by isolating those activities from the other activities of public utilities included in proxy groups. EEI recommends that the Commission should use after-tax weighted average cost of capital to adjust for leverage differences among sample companies and recommends applying DCF results to the market value of equity rather than to the book value of equity.

101. NSTAR and New England TOs assert that any changes to the Commission's ROE methodology should not be considered an incentive because updating the ROE methodology including appropriate recognition of risk is not an incentive, but rather is necessary to assure that the ROEs received by transmission-owning utilities are compensatory and fair under current market conditions and recover their cost of capital.

iii. Commission Determination

102. While commenters note that every alternative method has a theoretical deficiency and there is a benefit to introducing more information into the analysis process, we do not see any basis to conclude that the alternative methods would encourage more transmission investment than continued reliance on the DCF analysis. Our past practice of using the DCF approach has yielded just and reasonable results and is consistent with long-standing ratemaking principles. Therefore, at this time, we will not make broadly applicable changes to how the Commission has traditionally performed its DCF analysis on companies in the electric industry. However, we will consider on a case-by-case basis whether the application of the traditional DCF analysis should be modified and entertain proposals to use different proxy groups as a way of capturing different business models.

2. Construction Work in Progress (CWIP) and Pre-Commercial Expenses

a. Background

103. In the NOPR, the Commission noted that the long lead times required to plan and construct new transmission can impact utility cash flow, in turn affecting the overall financial health of a company and its ability to attract capital at reasonable prices. The Commission proposed including 100 percent of CWIP in rate base; [70] and expensing rather than capitalizing pre-commercial operations costs associated with new transmission investment in order to relieve the pressures on utility cash flows associated with transmission investment programs.

104. In 2004, the Commission accepted a proposal by American Transmission Company (American Transmission) to include 100 percent of CWIP in the calculation of transmission rates and to expense pre-commercial operations costs for new transmission investment, instead of capitalizing those costs and earning a return.[71] American

[67] *E.g.*, APPA, the Kentucky Commission, New Mexico AG, NY Association, New York Commission, TDU Systems and TAPS.

[68] *E.g.*, AEP, Ameren, EEI, California Commission, KCPL, PacifiCorp, PEPCO, PJM TOs, Progress Energy, NSTAR, SDG&E, SCE, Southern Companies, Trans-Elect, Vectren and WPS.

[69] *E.g.*, PEPCO, APPA, PJM, AEP, FirstEnergy, and Ameren.

[70] CWIP is a return on capital. Since 1987, the Commission's general policy has been to allow only 50 percent of the non-pollution control/fuel conversion construction costs as CWIP in rate base. The remaining construction costs, including an allowance for funds used during construction (AFUDC) which provides a return on those expenditures, generally would have been capitalized and included in rate base only when the plant went into commercial operation, *i.e.*, when the plant became used and useful. Allowing some portion of the costs in rate base prior to commercial operation provides utilities with additional cash flow in the form of an immediate earned return. *See* 18 CFR 35.25(c)(3).

[71] *See American Transmission, supra* note 2.

Transmission stated that these incentives would help maintain adequate cash flow during the construction process and that without these incentives it could face a downgrade of its fixed income rating over the next several years due to inadequate cash flow, thereby increasing its capital costs by $176 million over a twenty-year horizon.

105. The Commission stated in the NOPR that allowing public utilities, on a case-by-case basis, to include up to 100 percent of prudently incurred transmission-related CWIP in rate base and permitting them to expense prudently incurred pre-commercial operations costs will further the goals of section 219 by relieving the pressures on utility cash flows associated with their transmission investment programs and providing up-front regulatory certainty. The Commission specifically requested comment on (1) the types of costs that should be considered ''pre-commercial'' operation costs; and (2) whether there should be a presumption that these incentives meet the requirements of FPA section 219 that investments ensure reliability and reduce the cost of delivered power.

b. Comments

106. Most of the commenters,[72] support including 100 percent of prudently-incurred CWIP in rate base and expensing all pre-commercial operation costs, stating that these incentives will encourage transmission investment through improved cash flow, greater rate stability and lower rates to future customers. Additionally, SDG&E notes that this incentive will balance short-term rates and long-term rates by increasing the rates during construction but lowering the rates during operation of a facility.

107. Opponents, such as the New Mexico AG and California Commission, state that maintaining the status quo would be in keeping with the long-standing ratemaking doctrine that recovery of utility plant costs should be based on utility plant that is ''used and useful.'' They also oppose expensing pre-commercial costs instead of capitalizing such costs because there will be no opportunity for a comprehensive review of project costs before those costs are passed on to ratepayers.

108. Snohomish argues that the Commission must implement a procedure to handle refunds where the project is never ultimately completed, and must condition inclusion of CWIP and other pre-operation costs in rates on adherence to the construction schedule submitted with the application.

109. In its supplemental comments, EEI recommends the Commission waive the requirement that a utility requesting CWIP must provide a forward-looking allocation that estimates the average use a wholesale customer will make of the utility system over the life of a project, as currently required by 18 CFR 35.25(c)(4). EEI states the purpose of the required forward-looking allocation is to protect wholesale customers against a double whammy (*i.e.*, being required to pay for the construction of new generation facilities if the customer switched supplier). EEI states that the double whammy concern is not present with transmission facilities because the customer will almost certainly not switch transmission suppliers.

110. TDU Systems assert that CWIP should not be allowed for projects for which the public utility receives upfront interconnection payments, nor for any project for which the funds have been provided by a third party, except in tandem with crediting-back of such prepayments or investments on a schedule to which the transmission customer agrees. TDU Systems assert that if formula rates are in place for the public utility seeking to expense the cost of capital assets, inter-generational inequity is even more egregious since the public utility may well receive a one-year amortization of that expense although future rate payers will benefit from the use of those facilities for years to come.

111. Other commenters state that pre-commercial costs should be defined and the Commission should provide guidance.[73] Commenters' proposals for pre-commercial costs definitions include all costs associated with pre-construction activities, such as planning, related studies, and siting costs, including (1) costs of routing studies for placement of transmission lines, (2) costs of certification associated with regulatory approvals including legal and consulting costs, (3) costs of public hearings and informational hearings, (4) costs for design, planning, drafting, surveying services, material procurement and labor in support of project construction, and (5) costs associated with development and implementation of interim measures to maintain adequate reliability level due to the delayed completion of the proposed project.

112. Additionally, EEI argues the Commission should also include as pre-commercial costs other costs that have been traditionally expensed such as costs of resetting relays, using a mobile transformer, making payments to other transmission owners for upgrades to their lines, and the write-offs of the undepreciated cost of facilities that are being replaced with new transmission investment.

113. NRECA states that these costs should be limited to prudently incurred direct transmission investment costs. TDU Systems states that in no event should the Commission allow public utilities to expense costs associated with transmission facilities such as land, towers, transformers, lines, and substations.

114. PJM recommends that costs of developing a transmission proposal through a planning process should be considered a pre-commercial cost.

c. Commission Determination

115. After considering all the comments, we adopt in this Final Rule the proposal from the NOPR to give public utilities, where appropriate, the ability to include 100 percent of prudently incurred transmission-related CWIP in rate base and to expense prudently incurred ''pre-commercial'' costs. These rate treatments will further the goals of section 219 by providing up-front regulatory certainty, rate stability and improved cash flow for applicants thereby easing the pressures on their finances caused by transmission development programs. As noted by many commenters, these proved effective for American Transmission by easing the pressures on American Transmission's finances caused by its transmission development program allowing American Transmission to, among other things, stay on schedule with its development program. For American Transmission, this also meant a higher credit rating and lower cost of capital, thus benefiting customers. Similar results can be expected for other transmission developers availing themselves of such opportunities.

116. We appreciate the concerns, as expressed by the California Commission and others, that the proposal is a departure from existing ratemaking doctrine that rates should be based on plant that is ''used and useful.'' However, as times and circumstances warrant, the Commission has revised its ratemaking policies. In fact in Order No. 298,[74] the Commission did just that

[72] *E.g.*, EEI, American Transmission, AWEA, PG&E, AEP, NSTAR, WPS and TDU Systems.

[73] *E.g.*, EEI, SCE, AEP, NSTAR, WPS, NU, FirstEnergy, the Nevada Companies, KCPL, NRECA and Ameren.

[74] *Construction Work in Progress for Public Utilities; Inclusion of Costs in Rate Base*, Order No.

when it decided to allow any public utility engaged in the sale of electric power for resale to file to include in rate base up to 50 percent of CWIP, subject to limitations. Thus, the Commission already allows inclusion of some CWIP in rate base. The Commission also departed from existing principles in the *American Transmission* and *Southern California Edison* cases.[75] The nation has suffered a decline in transmission investment and it is time that the Commission revisit ratemaking policies that may serve as a barrier to investment and revise them accordingly while ensuring that customers are protected and rates remain just and reasonable. Finally, we note that 100 percent recovery of CWIP costs is already provided for pollution control facilities of public utilities.[76]

117. Allowing public utilities the opportunity, in appropriate situations, to include 100 percent of CWIP in the calculation of transmission rates and to expense pre-commercial operations costs for new transmission investment (instead of capitalizing these costs and earning a return) removes a disincentive to construction of transmission, which can involve very long lead times and considerable risk to the utility that the project may not go forward. The fact that public utilities have the opportunity to recover these costs in rates in a different manner than in the past does not mean that the rates are not subject to review under FPA sections 205 and 206. Even for rates that are formulaic, it may be necessary for the utility to revise the rate formula under section 205 to capture the recovery of these types of costs to the extent that they are not provided for in the formula. Moreover, as the D.C. Circuit has found, the Commission can depart from the norm as long as it reasonably balances consumers' interest in fair rates against investors' interest in ''maintaining financial integrity and access to capital markets.'' [77] Finally, if the transmission facility never enters service (*i.e.*, is never used or useful), the transmission owner may still seek recovery of the expenses associated with the construction work in progress (*i.e.*, the return on capital) under our abandoned plant incentive, as discussed below. Accordingly, we find that the ''used and useful'' ratemaking principle is not a sufficient basis to deny adoption of the NOPR's proposal. However, as explained above, we will require each applicant to demonstrate that there is a nexus between its request for 100 percent CWIP recovery and the investments being made. Ordinarily, such an incentive would be appropriate for large new investments or in situations, as occurred with ATC, where denying such an incentive would adversely affect the utility's ratings. There may be other situations as well where such an incentive is appropriate and we will consider each proposal on the basis of the particular facts of the case.

118. With regard to requests that the Commission condition inclusion of CWIP and pre-operation costs on adherence to the construction schedule submitted with the application and that we implement a procedure to handle refunds in the event the facility is not put into service, we find them to be unnecessary and/or inconsistent with the other measures we adopt in this Final Rule. As discussed further below, the Commission is proposing to provide a public utility with the opportunity to file for abandoned plant costs. Thus, requiring a refund procedure that raises perceived risks of proposing new transmission at this time would be inconsistent. We also do not see the need to condition inclusion of CWIP on adherence to a construction schedule. Because the actual recovery of CWIP will occur either under a rate on file or a rate to be filed under FPA section 205, parties will have an opportunity to raise any concerns with regard to actual expenditures vis-a-vis construction progress at that time. Accordingly, we see no reason to condition inclusion of CWIP on adherence to a construction schedule.

119. The Commission's current CWIP regulations were developed in an era of bundled wholesale services and apply to any rate schedule. Since that time, most wholesale transmission service subject to the Commission's jurisdiction is provided at unbundled rates under open access transmission tariffs. EEI points out that the requirement for a forward looking allocation that estimates the average use a wholesale customer will make of the utility system over the life of the project is not necessary with transmission facilities. We agree. The forward looking allocation ratio was to prevent a customer that was switching power plant suppliers from having to share in the cost of CWIP of a particular plant if the customer had no responsibility in the decision of the utility to build the plant. We believe it highly unlikely that transmission customers will be faced with such an opportunity. Accordingly, because we do not view the ''double whammy'' to be a concern in the transmission context, we grant EEI's request and waive the requirement in 18 CFR 35.25(c)(4) as it pertains to preventing double whammy with regard to CWIP associated with new investment in transmission.[78] Further, we clarify § 35.35(d)(1)(ii) to state that other provisions of § 35.25 apply, unless waived by the Commission on a case-by-case basis. We believe that these clarifications to the regulatory text will avoid uncertainty expressed by commenters regarding the procedures for obtaining the CWIP incentive.

120. In response to comments, we clarify that pre-payments, *i.e.*, payments prior to the start of construction, for project costs by third-parties should not be included in CWIP. If a customer is making contributions in aid of construction, these amounts should not be included in rate base. Similarly, in the instance of generator interconnect, the up-front amount paid by the customer should not be included in rate base; rather it is included in rate base over time as the transmission provider provides credits to the customer.

121. The Commission has previously determined that recovery of CWIP on a formulary basis is not permitted without prior Commission review to ensure that the Commission's CWIP standards are met.[79] The Commission in *Maine Yankee* allowed Maine Yankee to propose a method to limit its filing obligation to once a year so that Maine Yankee did not have to file each month that it changed the CWIP balances in its monthly formula charges.[80] Likewise, we will allow public utilities to propose a method to limit their filing requirement related to CWIP to an annual filing. These annual filings may be limited to CWIP and will not subject

298, FERC Stats. & Regs. ¶ 30,455 (1983), *order on reh'g*, 25 FERC ¶ 61,023 (1983).

[75] *See American Transmission, supra* note 2; Southern California Edison Co., 112 FERC ¶ 61,014, at P 61, *reh'g denied*, 113 FERC ¶ 61,143 (2005) (SCE).

[76] *See* 18 CFR 35.25(c)(1).

[77] *Jersey Central Power & Light Co.* v. *FERC*, 810 F.2d 1168, 1178 (D.C. Cir. 1987) (*Jersey Central*). ''Although a utility's rate base normally consists only of items presently 'used and useful' (*see New England Power Co. Mun. Rate Comm.* v. *FERC*, 668 F.2d 1327, 1333 (D.C. Cir. 1981), *cert. denied*, 457 U.S. 1117 (1982)), a utility may include 'prudent but canceled investments' in its rate base as long as the Commission reasonably balances consumers' interest in fair rates against investors' interest in 'maintaining financial integrity and access to capital markets.' '' *Jersey Central*, 810 F.2d 1168, 1178 (D.C. Cir. 1987).

[78] However, this waiver does not relieve transmission owners from supplying the necessary information required in § 35.25(c)(4) that pertains to CWIP-induced price squeeze. The Commission will evaluate CWIP-induced price squeeze concerns on a case-by-case basis.

[79] *Maine Yankee Atomic Power Co.*, 66 FERC ¶ 61,375, at 62,252–53 & n. 10 (1994) (*Maine Yankee*).

[80] *Id.*, at 62,252.

public utilities to a comprehensive rate review.[81]

122. With respect to the types of pre-commercial operations costs that we will allow to be expensed rather than capitalized, we will allow, on a generic basis, the same types of costs that we approved in the American Transmission settlement.[82] Further, we will entertain proposals by public utilities to expense other types of costs for consideration on a case-by-case basis.

3. Hypothetical Capital Structure

a. Background

123. The Commission stated in the NOPR (at P 29) that it has largely relied on the actual capitalization of a utility in setting its rate of return, but recognized that an overly rigid approach to evaluating a proposed capital structure could be a disincentive to investment in new transmission projects and Transco formation. Each project or company may have unique financial and cash flow requirements, and a rigid approach to acceptable capital structures could threaten the viability of some projects. Accordingly, the Commission proposed allowing applicants to file an overall rate of return based on a hypothetical capital structure, and giving them the flexibility to refinance or employ different capitalizations as may be needed to maintain the viability of new capacity additions. The Commission stated that it expected applicants to develop their proposals based on the specific requirements and circumstances of their projects, and that the Commission would evaluate proposals for this incentive on a case-by-case basis. The Commission required public utilities to provide support in their application for why the hypothetical capital structure incentive is needed to promote investment consistent with the goals of section 219. The Commission required the applicant to provide its transmission investment plan and explain the specific projects to which the proposed return will apply.

b. Comments

124. Many commenters support the hypothetical capital structure as an incentive.[83] Both American Transmission and Trans-Elect note that they received approval to use a hypothetical capital structure and that they had been able to stay on schedule for extensive transmission construction programs.[84]

125. Several parties, including EEI, NSTAR and NU argue in a similar vein that hypothetical capital structures can aid investments by companies that are entering a large capital expenditure program or are emerging from financial distress and may be aiming for a capital structure they have not yet realized. Semantic suggests a 75 percent equity and 25 percent debt capital structure be used to reflect the higher risks of early adoption of advanced technologies.

126. PJM and NSTAR state that hypothetical capital structures are particularly useful for projects involving consortia. PJM cites its proposed consortium approach to building transmission, where a capital structure could be based on the project as a whole rather than piecemeal based on the individual capital structures of each participant in individual rate cases.[85]

127. A number of commenters oppose hypothetical capital structures.[86] APPA and CREPC argue hypothetical capital structures could result in a windfall to public utilities by increasing actual return far in excess of the Commission's allowed return on equity. Commenters also express concern that the proposed incentive represents a departure from Commission precedent and could result in unjust and unreasonable rates.

128. Other commenters, such as the Kentucky Commission, Dairyland and MISO States, assert that the Commission should preclude a public utility from receiving both hypothetical capital structure and the ROE incentive because combining the incentives could result in adopting a cost of equity well in excess of the DCF range of reasonableness.

129. Because of concerns about the criteria to be used in evaluating proposals for hypothetical capital structures, many parties, including CREPC, California Commission, NRECA and California Oversight Board, recommend evaluating the proposal on a case-by-case basis, with California Oversight Board arguing for standard of proof much higher than merely having to support the proposal as the NOPR proposes.

130. NECOE states that the Commission should categorically prohibit vertically-integrated utilities from using a hypothetical capital structure. MISO States argues that this incentive is not reasonable, especially if applied to a company's entire rate base, instead of just its new transmission. APPA states that if a specific transmission project is financed separately from other projects within a transmission network (*e.g.*, merchant transmission line), it may be appropriate to evaluate its capitalization separately from other affiliates; however, the evaluation should be based on actual capitalization instead of hypothetical capitalization. In contrast, Ameren asserts that hypothetical capital structures beyond project-financed investments can be supported and should be considered on a case-by-case basis.[87]

c. Commission Determination

131. The Commission finds that hypothetical capital structures can be an effective tool available to public utilities to foster transmission investment in appropriate circumstances. As some commenters point out, use of a hypothetical capital structure is not new. For example, the Commission has allowed independent transmission companies to use a hypothetical capital structure to recognize the significant benefits of independent ownership and operation of transmission including, among other things, improved access to capital markets for transmission investment[88] and the Commission has allowed its use for specific projects when shown to be necessary for project financing, among other things.[89] Further, as PJM argues in its comments, hypothetical capital structures may be

[81] We deny the request to limit recovery of these incentives to the amount originally budgeted. We note that, as a practical matter, it would be difficult to hold electric transmission projects to the original budget estimate when it can be 10 to 15 years between the time the project is proposed and lines are actually built. Also, if public utilities are held to recovering only originally estimated budgets, they would either have incentives to overestimate costs or to avoid the risky projects which the policy is intended to facilitate.

[82] American Transmission, in its application approved in American Transmission defined pre-certification costs as preliminary survey and investigation costs in Account 183. These costs include all expenditures for, preliminary surveys, plans and investigations, made for the purpose of determining the feasibility of utility projects and costs of studies and analyses mandated by regulatory bodies related to plant in service.

[83] American Transmission, EEI, First Energy, KCPL, Nevada Companies, NSTAR, NU, NYSEG and RGE, PJM, PG&E, Progress, Semantic, Trans-Elect, United Illuminating and Xcel support the proposal.

[84] Trans-Elect cites *Western*, 99 FERC ¶ 61,306 at 62,280, *reh'g denied*, 100 FERC ¶ 61,331 at P 7, 9 (stating that rate treatments including hypothetical capital structure were necessary for the Path 15 project to be built). *See also, METC*, 105 FERC ¶ 61,214 at P 20 (Commission recognized the need to encourage, through regulatory rate-making policy, the independent business model).

[85] PJM TOs concur that the incentive could be helpful in project-specific rates.

[86] *E.g.*, California Commission, TDU Systems, APPA, CREPC, Steel Manufacturers, New Mexico AG, the Oklahoma Commission, PPC, NECOE, Connecticut AG, and the Delaware Commission.

[87] Ameren states that the Commission has approved the use of a hypothetical capital structure to better reflect the risk profile of a regulated enterprise. *See High Island Offshore Systems, L.L.C.*, 110 FERC ¶ 61,043, at P 143, *order on reh'g*, 112 FERC ¶ 61,050 (2005) (*High Island*).

[88] *METC*, 105 FERC ¶ 61,214 at P 20.

[89] *Western, supra* note 2.

effective for development of consortium projects. This can be especially important for projects with a diverse set of sponsors, some of which have different capital structures, (*e.g.*, a power marketing agency that contributes access but no equity compared to a project sponsor that brings only equity to a proposed investment). We note the rise in interest in these types of projects, including such large-scale, multiple-developer projects as the Frontier Line and TransWest proposals. Thus, the Commission finds that, in certain contexts, this incentive is appropriate for consideration under section 219 because it has been demonstrated to foster the development of transmission investment, as indicated by the experience of American Transmission and Trans-Elect.

132. The Commission continues to believe that an overly rigid approach to evaluating proposed capital structures may discourage the development of new transmission projects. Therefore, the Commission will evaluate each proposal on a case-by-case basis but will not prescribe specific criteria or set target debt/equity ratios for evaluating hypothetical capital structures, as requested by some commenters.[90]

133. We will not categorically deny the incentive to vertically-integrated utilities, as recommended by NECOE. We agree with Ameren that there may be circumstances in which a hypothetical capital structure may be appropriate for a transmission investment by a vertically-integrated utility. However, we are not suggesting that hypothetical capital structures will become the norm. As with the other incentives, we will require that the applicant demonstrate a nexus between its proposed incentive and the facts of its particular case.

134. In this regard, we note that many of the instances in which hypothetical capital structures are used and can be used reflect unique circumstances, such as a project or consortium that requires a special capital structure where the capital structure may change significantly with new investments. We disagree with TDU Systems that the Commission has (or should adopt) a general policy on when to use hypothetical capital structures. Moreover, we do not believe that the Commission's recent approvals of hypothetical capital structures for electric transmission companies have resulted in abnormally high equity ratios or over-compensation for the equity holder at the expense of the ratepayer.

4. Accelerated Depreciation

a. Background

135. In the NOPR (at P 30), the Commission proposed accelerated depreciation as another way to increase cash flow to utilities, thereby removing a potential disincentive to investing. The Commission has determined that in some circumstances allowing accelerated depreciation is warranted to encourage investment in transmission infrastructure because it provides improved cash flow and better positions public utilities for longer-term transmission investments.[91] The Commission stated that permitting accelerated depreciation more broadly than just for emergency conditions or special projects may further the goals of section 219 by providing incentives to undertake transmission projects that have the potential to reduce the cost of delivered power and ensure reliability, and, therefore, proposed to allow transmission facilities to be depreciated over a period of 15 years, in place of the typical Commission practice to allow depreciation over the useful life of the facilities.[92]

136. The Commission also sought comment on two issues. The Commission asked whether 15 years is an appropriate time period for cost recovery or whether the Commission should establish a presumption of a shorter or longer depreciable life for new transmission facilities.[93] The Commission also requested comment on whether accelerated depreciation has any longer-term negative impacts that would undermine the goals of section 219.

b. Comments

137. A number of commenters support the proposal to allow accelerated depreciation of 15 years for the reasons set forth in the NOPR.[94] Some of the supporters, such as the Delaware Commission, KCPL, International Transmission, NYSEG and RGE, Progress, Siemens, Upper Great Plains, and United Illuminating recommend that the incentive should be optional.

138. Other commenters oppose the proposal to allow accelerated depreciation of transmission facilities.[95] For example, Connecticut AG, NECOE and TANC assert the accelerated depreciation incentive will increase costs and rates and result in gold-plating and over-building of transmission infrastructure. APPA claims that after new transmission facilities have been depreciated over the shorter time period proposed by the Commission, the transmission owners will essentially be providing transmission service for free. APPA is concerned that when this happens the transmission owners will propose to ''recalibrate'' (*i.e.*, increase) the transmission rate base to depreciate the same facilities yet another time at ratepayer expense.

139. Additionally, TAPS opposes accelerated depreciation because transmitting utilities will no longer earn a return on their investments after the facility has been depreciated and would potentially seek to recover a management fee which would deny ratepayers of the supposed benefits of accelerated depreciation.[96] TAPS claims that given the likelihood of this management fee, the Commission cannot refer to accelerated depreciation as a timing difference. Ameren, on the other hand, states the one drawback to accelerated depreciation is that once the asset has been fully depreciated, the public utility can not earn a return.[97] Ameren states the Commission should consider generic procedures for the establishment of compensatory management fees for fully depreciated transmission assets.

140. TAPS also argues that accelerated depreciation would skew investments towards depreciable plant and away from non-depreciable land even if acquisition of rights-of-way was the cheaper alternative. TAPS states that, if the Commission is intent on permitting accelerated depreciation, the Commission should require the utility to auction off the fully depreciated facilities at full market value with the proceeds credited to ratepayers.

[90] We note that many commenters support case-by-case review and recognize the merits of evaluating the specific circumstances of hypothetical capital structure proposals.

[91] *See Removing Obstacles* and *Western, supra* note 2.

[92] *Removing Obstacles*, 94 FERC ¶ 61,272, at 61,968–69.

[93] For example, in *Removing Obstacles*, the Commission permitted a 10-year depreciable life for facilities that will increase transmission capacity to relieve existing constraints and could be in service within a few months.

[94] *E.g.*, Ameren, EEI, BG&E, FirstEnergy, NSTAR, PG&E, PJM, PJM TOs, SCE and WPS. Ameren, MidAmerican and Nevada Companies assert that the Commission should be receptive to a shorter depreciable life or that a different life may be appropriate, possibly tied to the term of a service agreement.

[95] *E.g.*, TDU Systems, the California Commission, APPA, the Connecticut AG, NY Association, NECOE, TAPS, the New York Commission and TANC.

[96] TAPS cites *High Island*, 110 FERC ¶ 61,043, at P 105–115.

[97] AEP and International Transmission also note this concern.

141. California Commission opposes accelerated depreciation because when a facility is placed into service, the value of the undepreciated plant is at its highest; therefore, the company earns a high return on the plant. As a result, the company has immediate cash flow that does not need to be enhanced. California Commission, TAPS and TDU Systems express concern that accelerated depreciation may cause generational inequities between those who pay for the facilities now and those who do not have to pay later.

142. EEI states that this incentive should not be dependent on corporate structure, should not be limited to 15 years when it may be appropriate to use a shorter depreciable life for certain facilities, and when 15 years is used by a public utility, the company should be able to match the tax law depreciation methodology, which weights the tax depreciation more heavily toward the beginning of the life of the project rather than spreading it evenly over 15 years.

143. APPA cites to a number of concerns including the effect of such accelerated depreciation on book-tax timing differences, and the associated deferred tax accounts, and complications in calculating inter-period income tax allocations. APPA also contends that, if the Commission allows rate recovery over a 15 year life for transmission assets, then there should be no provision for deferred income taxes allowed with respect to such assets in any rate case (and no deduction from rate base), because such book and taxable income with respect to such assets would then be matched.

144. International Transmission asserts that in Order No. 618, the Commission correctly determined that the choice of depreciation method should be left to industry.[98] International Transmission argues that flexibility in determining depreciation methods is particularly important when new technologies are deployed that may not be proven, may cost more or have uncertain useful lives, and may be needed to accommodate ongoing industry restructuring or regulatory innovation.

145. International Transmission states that accelerated depreciation does not increase cash flow for companies with formula rates as it would for companies with stated rates, because the formula rates reset every year. International Transmission urges the Commission to clarify that any changes to depreciation rates for a company using a formula rate will be accepted as a ministerial filing with issues limited only to estimation of the depreciation life and salvage parameters; and that an added bonus of this approach would permit companies with formula rates to remove from their formula rates, in ministerial filings, accumulated deferred income tax balances from rate base. International Transmission argues that to do so would increase cash coverage ratios and the return on equity during the early years of an asset's life and thereby create a tax-related incentive that furthers the Congressional intent to encourage transmission investment.[99] International Transmission states that if it allows companies to use accelerated depreciation, the Commission will need to revisit its Accounting Directive in Order No. 618, in which the Commission stated that recovery over the useful life generally best matches benefits with costs. International Transmission offer that accelerated depreciation could lead to the following problems: (1) Depreciation would no longer be representative of the useful life of assets, (2) the representation of net fixed asset value in financial statements could be distorted; (3) there would be a divergence between Generally Accepted Accounting Principles and Commission reporting and (4) efforts by FASB, the Commission and others to clarify financial reporting could be frustrated.

c. Commission Determination

146. After considering all comments, we will adopt the NOPR proposal to allow, as an option, accelerated depreciation for new transmission facilities that meet the goals of section 219. Accelerated depreciation increases the cash flow of public utilities thereby providing an incentive to undertake transmission investment. However, we are not proposing to grant accelerated depreciation on a generic basis; rather, as with the other incentives, the applicant must demonstrate a nexus between its proposal and the facts of its particular case (*e.g.*, the need for additional cash flow produced by accelerated depreciation in order to fund new transmission investment).

147. We do not share the commenters' concerns that this incentive will result in intergenerational inequity. Most transmission customers are dependent upon the transmission system serving them and are likely to continue to receive transmission service over the long-term. Thus, unlike in power supply situations where there are greater options to change suppliers, there is little likelihood of intergenerational impact through the use of accelerated depreciation for transmission investment. In the event accelerated depreciation results in higher rates in the near-term, most of the same customers paying the higher rates will benefit from lower transmission rates in the longer-term. We clarify that the use of accelerated depreciation may be proposed for new transmission facilities including additions to capacity on existing facilities.

148. Given the long-term under-investment in transmission, we disagree with the comments of the California Commission that existing policy is sufficient to encourage transmission investment in all situations. As the California Commission is aware, Trans-Elect stated that accelerated depreciation was a necessary component for its participation in the Path 15 project. In response to the mandate of section 219, we believe it is appropriate to offer this rate treatment more broadly to encourage the same successful outcome that was achieved with Path 15. This does not mean that accelerated depreciation is necessary or will be granted for every project. Instead, the applicant will be required to demonstrate that there is a need for the additional cash flow produced by the accelerated depreciation or that the incentive is appropriate for other reasons. Likewise, at this juncture, concerns expressed by some commenters about the potential for overbuilding of transmission facilities as a result of this rate treatment are unsupported and highly speculative.

149. We concur with the comments that suggest the need for flexibility in the length of the depreciable life. Therefore, public utilities may propose using accelerated depreciation for rate purposes over a period of time as short as 15 years. Moreover, we will consider, on a case-by-case basis, depreciable lives of less than 15 years because shorter depreciable lives may be appropriate in certain cases, such as advanced technologies for which the useful life is not necessarily known.

150. Based on the comments, we are mindful of the potential consequences of this rate treatment when the facilities are fully depreciated. Commenters

[98] *Depreciation Accounting*, Order No. 618, FERC Stats. and Regs. ¶ 31,104, at 31,694 (2000) (Order No. 618). According to International Transmission, in Order No. 618, the Commission modified its initial proposal to require straight-line depreciation to permit other methods of depreciation that allocated the cost of utility property over its useful life in a systematic and rational manner. The Commission recognized that this approach would ''[allow] flexibility in a changing business environment.''

[99] International Transmission notes that Congress reduced the tax depreciable life on transmission investments from 20 years to 15 years to encourage transmission investment. EPAct 2005, section 1308.

express concern that the Commission will allow public utilities to recalibrate the amount of depreciation, or institute a management fee. Other commenters state the Commission should require certain rules for sale of the facilities because of complications that will arise from selling fully depreciated assets. We will not address those issues here but will address such issues if and when they occur.

151. Commenters raise various accounting issues. With respect to the effect of this rate treatment on ADIT (accumulated deferred incomes taxes), we disagree that this proposal will necessarily require that no provision for deferred incomes taxes be allowed with respect to such assets (and no deduction from rate base). As stated previously, we are going to be flexible with respect to the depreciable lives of qualifying assets; therefore, public utilities may choose 30 years as Trans-Elect did with Path 15 and as a result deferred income taxes may still be necessary. Moreover, even if public utilities choose 15 years, depreciation expense for rate recovery purposes will likely be calculated using the straight-line method over those 15 years,[100] while accelerated depreciation for tax purposes may be calculated using a different method (*e.g.*, double declining balance) over 15 years. Therefore, despite the use of the same 15 year life, method differences could continue to create timing differences for which deferred income taxes would be required.

152. With respect to APPA's concern about potential difficulties in applying SFAS 71,[101] the Commission and other rate regulatory authorities often include amounts in allowable costs for ratemaking purposes in periods other than the period in which those amounts would ordinarily be charged to expense or included in income for financial accounting purposes. In those instances, the rate actions of regulators have economic consequences that must be recognized in financial statements. Under both SFAS 71 and the Commission's Uniform System of Accounts, if regulation provides reasonable assurance that incurred costs will be recovered in future periods, companies must capitalize the costs. If current recovery is provided for costs that are expected to be incurred in the future, companies must recognize the current receipts as a credit amount on the balance sheet. Therefore, because the accounting requirements for accelerated depreciation are no different than accounting for the economic consequences of other rate actions, we do not see an impediment to implementing accelerated rate recovery of transmission assets.

153. We are not persuaded that we need to revisit Order No. 618 in this proceeding as some commenters suggest. In Order No. 618, the Commission established standards for determining depreciation expense for book purposes. Here we are establishing a standard for determining depreciation expense allowable for rate purposes. Although accounting and cost-based rate setting generally share common standards, there are instances, and this is one, where different standards should be used by each discipline and the difference bridged by recognition of regulatory assets or liabilities as provided for in our Uniform System of Accounts.[102] Therefore, companies will continue to depreciate transmission assets over their economic service life in a systematic and rational manner for accounting purposes and separately recognize as a regulatory liability any difference between depreciation expense recognized for accounting purposes and accelerated depreciation expense included in the development of rates. In order to clarify this distinction the Commission shall revise § 35.35(d)(1)(v) of the regulatory text proposed in the NOPR which read ''(v) accelerated regulatory book depreciation.'' The revised regulatory text shall read ''(v) accelerated depreciation used for rate recovery.''

154. We deny International Transmission's request to alter our section 205 filing requirements for public utilities operating under formula rates. In Order No. 618, the Commission permitted utilities to not make a filing to change depreciation rates for accounting purposes but maintained the filing requirement for changes in depreciation rates for rate purposes.[103] The Commission said it would monitor changes in depreciation rates for accounting purposes when companies filed for rate changes. We decline in this Final Rule to adopt International Transmission's requested changes to formula rates. International Transmission is free to petition the Commission to revise its formula rate to allow flexibility going forward, but we decline to make such a generic determination here because to do so would presume that all formula rates worked in the same manner.

5. Recovery of Costs of Abandoned Facilities

a. Background

155. The Commission noted that public utilities, in considering investments that fulfill the requirements of FPA section 219, may encounter investment opportunities with significant risk associated with factors beyond their control, such as generation developers' decisions to develop or terminate the development of potential resources or difficulty obtaining state or local siting approvals. In these circumstances, the Commission stated that it may be appropriate to consider ways to reduce the risk associated with potential upgrades or other improvements to the transmission system. To reduce the uncertainty associated with higher risk projects, thereby facilitating investment in these projects, the Commission proposed allowing recovery of 100 percent of the prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors beyond the control of the public utility.

156. The Commission's proposal was an extension of a recent Commission decision to allow Southern California Edison Company[104] to recover all prudently incurred costs related to certain proposed transmission facilities if those facilities were later cancelled or abandoned.[105] The Commission noted that the company's management did not control the decision to develop or cancel the wind farm generation project and that the company's shareholders did not share in the earnings associated with the generation project. The

[100] The straight-line method is typically used by utilities and will likely continue to be used for most utility property. However, consistent with Order No. 618 we will not require its universal use, as they may be overly prescriptive. Order No. 618 at 31,694.

[101] SFAS 71 applies to general-purpose external financial statements of an enterprise that has regulated operations. The Commission's Uniform System of Accounts for Public Utilities and Licensees (18 CFR Part 101) contains provisions similar to SFAS 71 that apply to financial statements public utilities must file with the Commission.

[102] 18 CFR part 101.

[103] Order No. 618 at 31,695.

[104] *SCE*, 112 FERC ¶ 61,014 at P 58–61, *reh'g denied*, 113 FERC ¶ 61,143 at P 9–15.

[105] Prior to *SCE*, the Commission's policy with respect to recovery of cancelled plant costs provided that 50 percent of the prudently incurred costs of a cancelled generating plant should be amortized as an expense over a period reflecting the life of the plant if it had been completed and that the remaining 50 percent of the prudently incurred costs of the cancelled plant should be written off as a loss. Under this policy, ratepayers are entitled to the income tax deduction associated with that portion of the loss for which they are paying. In addition, they are entitled to a rate base reduction to reflect the accumulated deferred income tax amounts associated with 50 percent of the abandonment loss. *See New England Power Co.*, Opinion No. 295, 42 FERC ¶ 61,016 at 61,068, 61,081–83, *order on reh'g*, 43 FERC ¶ 61,285 (1988). *See also*, *Public Service Company of New Mexico*, 75 FERC ¶ 61,266 at 61,859 (1996) (*PSNew Mexico*).

Commission further determined that the company might be at a higher risk in developing the project because of factors beyond its control. It also noted that SCE was not a wind farm developer and therefore would not directly benefit from the facilities. Thus, the Commission concluded that SCE should not shoulder the risk of the project.[106]

b. Comments

157. A number of commenters support the 100 percent recovery of prudently incurred costs of transmission projects that must be abandoned for reasons beyond the transmission provider's control as a way to reduce the up-front risk associated with important regional projects.[107] Some, like the Kentucky Commission,[108] advocate that the Commission should adopt a case-by-case approach to recovery of costs related to cancelled plant.[109] Kentucky Commission agrees that this incentive should be evaluated on a case-by-case basis to ensure that the decision to abandon the facility was truly beyond the utility's control. California Commission and CADWR do not oppose the recovery of 100 percent of the recovery of prudently incurred costs as long as the determination is made on a case-by-case basis. International Transmission states that preliminary surveys and investigations should also be included in the costs that can be recovered.

158. SCE supports the recovery of abandoned plant and recommends specific standards to facilitate the recovery. SCE states that 100 percent of prudently incurred costs should be approved for recovery if the facility was initially proposed and sited through a process involving stakeholder input and the subsequent decision to abandon is not under the control of management. Additionally, SCE states that utilities should be able to recover the costs of abandoned plant even when they have some control over the decision to abandon but the project was cancelled or abandoned due to problems in obtaining regulatory or other approvals. SCE also supports recovery where economic circumstances have changed, causing there to be no demonstrable net benefits.

159. Others [110] oppose the incentive. For example, CREPC states that guaranteeing the cost recovery of cancelled plant allows investors to ignore risk and places the risk on parties who are unable to manage the risk. ESAI argues that allowing recovery of 100% of prudently incurred development costs runs the risk of producing a proliferation of white elephants.

160. TANC argues that the Commission has upheld and enforced its existing cancelled plant policy and rejected the utility's arguments that it be allowed full recovery of the cancelled plant because it could not get state regulatory approvals; and that the Commission should not adopt a separate policy now.[111] TANC argues the proposal violates the intent of Opinion 295-A which is to encourage investors to make efficient production and consumption decisions.

161. Commenters [112] offer numerous instances where they believe it would be inappropriate to allow a utility to recover abandoned plant costs. For example, the Commission should not permit recovery: where the nature of the project was speculative; and where the project was abandoned for reasons within the control of the utility; or where there is an unexpected turn in the economy. TAPS questions whether project abandonment is really beyond a utility's control if a state siting authority does not outright reject a proposal but instead conditions its acceptance in a way that the utility finds objectionable.

162. Snohomish asserts applicants must make showings of why the project failed and recoverable costs should be limited to the original budget. New Mexico AG, TDU Systems and TAPS assert that if utilities are guaranteed their investment in abandoned facilities they need a lower ROE to represent the reduced risk of recovery.

c. Commission Determination

163. We find that an applicant may request 100 percent of prudently-incurred costs associated with abandoned transmission projects can be included in transmission rates if such abandonment is outside the control of management. This incentive will be an effective means to encourage transmission development by reducing the risk of non-recovery of costs.

164. Many commenters request that we evaluate proposals on a case-by-case basis and we affirm that we intend to do so. The case-by-case approach and the limitation to prudently-incurred costs should adequately discipline investment decisions. However, we will not prescribe specific rules to govern our evaluation but offer limited guidance below.

165. We agree with many commenters that when local, state and federal (as applicable) siting authorities reject an application outright, we would view those circumstances, generally, as abandonment beyond the control of management. As TAPS points out, the situation is less clear when siting authorities do not reject the application outright but add conditions to the application that make it uneconomical or otherwise objectionable. In these instances we would expect the utility to file with the Commission and support the decision to abandon. The Commission will evaluate, in these instances, the change in circumstances from those originally planned on a case-by-case basis.

166. We see no need to specify unique application procedures for this incentive. We will require a section 205 filing for recovery of abandoned plant costs in rates at the time the project is abandoned. We disagree with CREPC that this incentive shifts risk from those who can manage the risk to those who cannot because this incentive is limited by definition to abandonment that is beyond the control of the utility. We will not by rule limit the recovery of costs associated with abandoned plant to the costs included in the original budget estimate. The Commission will evaluate the public utility's cost recovery to ensure no double recovery of costs. For example, if a utility already recovered survey costs by expensing these costs as a pre-commercial cost, it would be unjust and unreasonable for the utility to recover those costs again if the facility was subsequently abandoned.[113]

167. We will not mandate a reduction in ROE for utilities that receive approval for this rate treatment. As stated in the ROE incentive discussion, determinations of a just and reasonable ROE include risk evaluations made in individual rate proceedings and are based on the facts pertinent to the utility and its proxy group. We note, however, that a utility that receives approval to recover abandoned plant in rate base would likely face lower risk and thus may warrant a lower ROE than would

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[106] *SCE.* at P 61.

[107] *E.g.*, AWEA, Ameren, AEP, EEI, KCPL, NSTAR, Vectren, International Transmission, WPS, APPA, NYSEG–RGE, NorthWestern, National Grid, New York Commission, NY Association, Progress, PNM and TNMP, SDG&E, and Upper Great Plains.

[108] *E.g.*, California Commission and CADWR.

[109] Trans-Elect supports the case-by-case approach and cites *San Diego Gas & Elec. Co.*, 98 FERC ¶ 61,332 at 62,408, *reh'g denied*, 100 FERC ¶ 61,073 (2002) (''claims for full recovery of any infrastructure projects that are ultimately cancelled will be addressed by the Commission on a case-specific basis'').

[110] *E.g.*, CREPC, the New Mexico AG, Steel Manufacturers and TANC.

[111] TANC cites *PSNew Mexico.*

[112] *E.g.*, Industrial Consumers, Oklahoma Commission, PPC, MISO States, and TAPS.

[113] We also clarify that we maintain the timing of recovery as set forth in Opinion No. 295 which required recovery over the life of the asset as if it had gone into service.

otherwise be the case without this assurance.[114] This does not mean that the Commission would reject an incentive-based ROE for a project that also receives assurance of abandoned plant costs that are beyond the utility's control. We would consider any such request on a case-by-case basis. The risk of a failed project is only one criteria that would be evaluated in determining whether an incentive-based ROE would be appropriate in a given case.

6. Deferred Cost Recovery

a. Background

168. In the NOPR, the Commission stated that public utilities with a retail rate moratorium may have less incentive to build transmission facilities that could reduce congestion or ensure reliability because of concerns about cost recovery for those facilities. Accordingly, the NOPR proposed to permit such utilities to use a deferred cost recovery mechanism which allows them to commence recovery of new facility costs in FERC-jurisdictional rates at the end of a retail rate moratorium. By providing a mechanism to facilitate cost recovery by public utilities that build transmission facilities during a retail rate moratorium, the Commission believed that it would meet the goals of section 219 by providing certainty to investors that costs can be recovered as quickly as possible.[115]

b. Comments

169. Many commenters support the deferred recovery proposal.[116] International Transmission states that deferred cost recovery should be used to facilitate the divestiture of transmission assets to Transcos. Of those that support the proposal, several urge cooperation between federal and state regulatory authorities.[117] In particular, NSTAR and AEP urge the FERC to collaborate with states and regional state committees to develop solutions for full and timely cost recovery and/or be prepared to intervene in state and court proceedings to the extent state regulators attempt to trap wholesale costs and prevent recovery of those costs in retail rates. EEI urges the Commission to ensure that the necessary regulatory mechanisms are in place to allow cost recovery and should cooperate with the states to develop these recovery mechanisms including transmission cost recovery tracker mechanisms.[118] In EEI's supplemental comments, EEI states that any utility that constructs new transmission facilities should automatically be entitled to deferred cost recovery.

170. Trans-Elect argues that the Commission should allow recovery of all costs approved for deferred recovery for Michigan Electric Transmission Company (METC)[119] and International Transmission.[120]

171. TAPS agrees that deferred cost recovery is reasonable in the case cited in the NOPR in which all connected retail customers pay the same rates and see the same deferral. However, TAPS asserts that allowing utilities with stated rates based on old test years to defer the collection of additional revenues associated with costs related to new facilities would constitute an unreasonable double-dip and would be inconsistent with section 219(d). Moreover, because the rates of bundled retail customers are set elsewhere based on different test years, this double-dip would be paid only by wholesale customers and unbundled retail customers and would be unreasonable and unduly discriminatory.

172. Several commenters opposing deferred cost recovery cite to concerns about the effect on state regulation.[121] Some argue that the proposal may undermine or impinge on areas exclusively under state jurisdiction (Pennsylvania Commission cites 16 U.S.C. 824 (a)(b)). Others allege that the unrestricted ability of a public utility to defer cost recovery until the end of the rate moratorium may not be consistent with the spirit of settlements struck as part of rate freezes.[122] Pennsylvania Commission adds that all the rate caps in its state are time-limited and any incremental benefit from a federal incentive would be more than offset by the legal uncertainty that would be attached to such incentives and the eventual federal/state conflict that would ensue.

173. MISO States argues that the Commission would do better to work with state authorities on retail rate recovery issues (*e.g.*, ensure rate recovery at wholesale and retail) than to adopt a policy unilaterally.[123] MISO States comments that Commission statements and accusations that state-statutory retail rate reviews undermine incentive ratemaking at the federal level are unwarranted. If the Commission proceeds with its proposed incentive of allowing deferred cost recovery, the Commission should consider granting deference to objections from state-level officials, according to MISO States.

174. Other commenters[124] seek assurance that the Commission will ensure the company does not over-recover its actual costs; offer that the Commission should adopt a case-by-case approach to allowing deferred cost recovery until the end of a moratorium and requiring agreement by wholesale and retail customers as to the nature, amount and duration over which the costs are to be deferred and synchronization of wholesale and retail ratemaking practices to avoid regulatory price squeeze;[125] and, argue that the Commission should place limits on the amount that can be deferred, and initial deferral period and subsequent recovery period.

c. Commission Determination

175. We find that permitting public utilities under retail rate freezes to defer recovery of new transmission investment costs undertaken consistent with section 219 will help facilitate investment. Increased certainty of cost recovery of new transmission investment will encourage development of more transmission infrastructure thereby fulfilling the goals of section 219 of the FPA.

176. To date, the Commission has approved deferred cost recovery mechanisms during the formation of Transcos which permitted the new Transcos to defer recovery of other costs such as the ADIT adjustment associated with the acquisition of the transmission system and to defer recovery of the rate differential between the frozen rates and the rate it would have received. As discussed more fully below, we believe that Transcos offer significant benefits and the deferred cost recovery

[114] SCE, *supra* note 104.

[115] The Commission has approved a deferred cost recovery provision that allowed for the recovery of the cost of new facilities upon the end of a retail rate moratorium. *See Trans Elect, Inc.*, 98 FERC ¶ 61,142, *reh'g denied*, 98 FERC ¶ 61,368 (2002).

[116] In addition to commenters mentioned below, AEP, Ameren, KCPL, National Grid, Nevada Companies, NSTAR, NYSEG and RGE, and Upper Great Plains also support the proposal.

[117] *E.g.*, PJM TOs, NSTAR, EEI, and AEP.

[118] NU and PEPCO support EEI's comments.

[119] *See Michigan Electric Transmission Company*, 107 FERC ¶ 61,206 at P12 (2004).

[120] *See ITC Holdings*, 102 FERC ¶ 61,182 at P 74.

[121] *E.g.*, Kentucky Commission, MISO States, Pennsylvania Commission, and Wyoming Advocate.

[122] Similarly, New Mexico AG, California Commission, PPC and Steel Manufacturers oppose the deferred cost recovery proposal because of the potential effect on state regulation.

[123] Steel Manufacturers contends that the Commission should instead work cooperatively with states on transmission planning matters, particularly in regional forums, in order to reduce possible areas for dispute, cost recovery gaps, or duplicative cost recovery.

[124] *E.g.*, Municipal Commenters, and APPA.

[125] APPA notes that new transmission facility costs that would be eligible for inclusion as CWIP in rate base should similarly be eligible for deferred cost recovery to address mismatches in cost recovery created by retail rate freezes.

mechanisms that we approved for METC and International Transmission were helpful to establish those Transcos. We also believe that deferred cost recovery mechanisms should be available to all public utilities, not just Transcos and recognize the importance of ensuring that federal and state ratemaking policies align so that we not only reduce regulatory lag but facilitate transmission development.

177. Most of the comments opposing this proposal cite potential conflicts with state regulation to be a critical issue. We believe that deferred cost recovery mechanisms generally will not hinder retail ratemaking. However, if a situation arises where a state regulator believes that a federal deferred cost mechanism conflicts with a state goal or undermines a state settlement with the applicant, we will consider objections by state regulators on a case-by-case basis, and seek to avoid inconsistencies between state and federal regulation. In this regard, we note that the approval by the Commission of regional state committees provides one vehicle for discussing Federal and state ratemaking issues on a cooperative and regional basis. With respect to TAPS' concern that the cost of the incentive would be recovered from only wholesale customers and unbundled retail customers, the Commission may approve a rate design such that wholesale customers and unbundled retail customers pick up only a proportionate share of the costs of the incentive.

178. With respect to commenters' specific proposals for trackers, limits, and deferral periods, we decline to adopt such proposals here. The justness and reasonableness of any deferred cost recovery proposal will be considered as part of the section 205 filing and there is no basis to arbitrarily place limits on recovery through this rule. The intent of the deferred recovery mechanism is to increase the certainty of cost recovery to encourage more transmission investment. It may also facilitate the creation of Transcos in states where retail rate freezes are in place. The deferred recovery mechanism is an option available for any public utility to propose; a public utility may also propose the use of a regulatory asset, as suggested by APPA.[126] We believe that a public utility must propose a set of incentives that is tailored to the facts of its particular case and the Commission must review those proposals to ensure they are just and reasonable.

7. Other Incentives—Single-Issue Ratemaking

a. Background

179. In the NOPR (at 54), the Commission recognized that transmission pricing issues are some of the most difficult issues facing the industry and that the Commission's policy of not allowing selective adjustments to a cost-of-service may serve as a disincentive to transmission investment.[127] Certain applicants may consider the time requirements and the uncertainties associated with rate proceedings that encompass their entire transmission systems to be disincentives to making incentive filings, as specified in the NOPR. To ensure that the approval process for incentive treatment is as streamlined as possible, thereby ensuring timely infrastructure investments, the Commission stated it was willing to consider incentive filings, applicable to both Transcos and traditional public utilities, that propose rates applicable only to the new transmission project.[128]

b. Comments

180. Numerous commenters[129] support single issue ratemaking for the reasons set forth in the NOPR. Additionally, Ameren states that single-issue ratemaking can be useful in obtaining advance approvals of specific rate treatments that may be required by investors as a condition to financing new construction.[130] Moreover, Kentucky Commission states that as long as single issue rate cases relate only to new transmission and comply with the filing requirements set forth elsewhere in the NOPR, it does not object to this proposal.

181. FirstEnergy states this proceeding is analogous to the *Removing Obstacles* orders where, in order to facilitate development of transmission investment the Commission permitted limited section 205 rate applications. FirstEnergy states that in this proceeding, Congress has realized there is a pressing need for transmission investment and the Commission should permit limited section 205 rate applications to facilitate the needed development. FirstEnergy asserts single issue ratemaking is particularly important for companies using formula rates.

182. AEP states that the Commission should be flexible with ratemaking conventions and that single-issue ratemaking could be a powerful incentive to encourage more transmission investment. AEP also states that single-issue ratemaking along with transmission cost trackers at the state level would be productive measures especially with integrated utilities.

183. TDU Systems notes that where the Commission has accepted single issue ratemaking, the Commission required the implementation of a mechanism that would harmonize the rate increase from that surcharge with adjustments to rates for existing facilities to reflect the offsetting decreases in depreciation costs associated with those existing facilities. EEI agrees that it is important to establish a crediting mechanism in some cases to harmonize the rate treatment for new and existing transmission facilities.[131] PJM, Progress, TAPS and TDU Systems state that Schedule 12 of the PJM tariff provides an example of how concerns with single issue ratemaking can be addressed to implement a $/KW/month adder to network or point-to-point transmission rates.[132]

184. TAPS proposes an alternative approach in which the Commission could harmonize the existing rates and new facility rates, when the inputs to the existing rate are known (*i.e.*, not hidden in a ''black box'' settlement), by updating the load divisor and depreciation reserve, and all other rate components would remain the same (other than the new facility charge). Where the existing rate was black box, a load divisor and depreciation reserve would have to be imputed for these purposes by assuming that the difference between the filed-for and settled rate represented an adjustment to the rate divisor and depreciation reserve.

185. Additionally, if the Commission proceeds with single issue ratemaking, APPA, TAPS and SCE suggest having the public utility file a full rate case at some point in the future which would roll-in the existing rate and the separate

[126] Regardless of whether it proposes to use a regulatory asset, the public utility should explain its proposed accounting for the deferred recovery mechanism.

[127] See, *e.g., City of Westerville, Ohio* v. *Columbus Southern Power Co.*, 111 FERC ¶ 61,307 at P 18 & n.11 (2005).

[128] The NOPR cited *Removing Obstacles* as an example of one type of approach utilizing a limited section 205 filing.

[129] *E.g.,* Ameren, EEI, PJM, Trans-Elect, FirstEnergy, NorthWestern, MidAmerican, Nevada Companies, AEP, KCP&L, Semantic and Xcel.

[130] *See, e.g., Western, supra* note 2 (issuing advance approvals of certain rate treatments for proposed California transmission Path 15 upgrades).

[131] EEI cites *Allegheny Power,* 111 FERC ¶ 61,308 at P 54; *see also* Request for Rehearing of the PJM Transmission Owners, Docket No. ER05–513–001, filed on June 30, 2005.

[132] PJM and TAPS also cite *Allegheny Power* (accepting cost recovery provisions of Schedule 12).

surcharge for the new transmission investment. APPA and TAPS recommend a full rate case after three years while SCE does not state a specific deadline for a full rate case.

186. APPA, NASUCA and TDU Systems oppose single issue ratemaking for transmission service claiming that public utilities are likely earning returns on their existing transmission facilities in excess of previously allowed rates of return (due to load growth, continuing depreciation of existing transmission facilities, and stale rates). They argue that single issue ratemaking fails to determine if the entire transmission rate is just and reasonable. APPA states that to allow a rate increase for a new facility to be added to the transmission rates charged for existing facilities improperly mixes costs from different periods for the same functional class of facilities. In addition, NASUCA and TDU Systems state that single issue ratemaking violates section 205 because one rate determinant may often be accompanied by an associated decrease in other portions of the rate and failure to consider all rate components together can lead to overstatements that produce unjust and unreasonable rates.[133] Further, NASUCA states that waivers of the general rule for a full blown rate case are found only in limited circumstances, for example where the utility is merely an accounting conduit for rate changes made by another utility from which the first utility purchases services.[134]

187. Municipal Commenters oppose single issue ratemaking because it represents a departure from cost-of-service ratemaking in that it fails to demonstrate any nexus between the awarding of proposed incentives and the owner's overall cost of service, need, financing cost, capital structure or performance.

188. TAPS suggests an alternative approach of having companies file their incentive rate proposals, individually tailored to that utility where appropriate, but generally applicable to that utility's qualifying transmission investments. Subsequent facility-specific filings, as necessary, would merely apply the existing approved plan. With this approach, single issue ratemaking is unnecessary according to TAPS.

189. In the event that the Commission decides to proceed with allowing single issue ratemaking for new transmission investment projects, commenters have suggested methodologies for implementing single issue ratemaking and ways to mitigate any potential problems with it.

190. EEI explains that public utilities should be permitted to file with the Commission to establish a revenue requirement to recover the costs of constructing a specific new transmission facility pursuant to section 205. Under this approach, the transmission owner determines whether to establish a new ROE or use its current Commission-approved ROE.

c. Commission Determination

191. We believe that single-issue ratemaking can provide a significant incentive for achieving the infrastructure investment goals of section 219 because it can provide assurance that the decision to construct new infrastructure is evaluated on the basis of the risks and returns of that decision, rather than the additional uncertainty associated with re-opening the applicant's entire base rates to review and litigation. We agree with FirstEnergy that there is a pressing need for transmission investment and therefore the Commission should allow for limited section 205 filings as a way to facilitate needed development, as was approved for the Path 15 project. The Commission's approval of limited section 205 procedures in *Removing Obstacles* showed how useful and appropriate single-issue ratemaking can be for needed investment in existing facilities, as Trans-Elect attests in their comments.

192. We will not require harmonization of rates, roll-in of new and existing rates or reopening of existing rates in this rule, as recommended by some commenters. Nor will we specify in this rule the rate calculations associated with developing a transmission rate for a particular new facility. Our concern in this rule is to ensure new investments are not impeded because of existing-system rate issues. Accordingly, applicants filing for single-issue ratemaking for a particular project are only required to address cost and rate issues associated with the new investment in the section 205 proceeding to approve rates. However, the applicant will be required to fully develop and support any transmission rate designed to recover the costs of a particular transmission system facility or upgrade—including cost allocation and rate design. The Commission will consider the potential need to combine or reconcile the new rate with any existing transmission rate when an applicant submits a request for incentives. In some instances, the Commission may find that single-issue ratemaking is appropriate without any determination as to when that rate will be harmonized with existing rates; in other cases, the Commission may, if appropriate, adopt certain of the mechanisms suggested by the commenters, such as a requirement to file a full rate case at a date certain in the future. In each instance, the Commission will balance the need for new infrastructure, and the importance of permitting single issue ratemaking in support of that infrastructure, with the concerns over whether a specific mechanism is required to re-open existing rates or whether the traditional complaint processes are sufficient for that purpose.

193. We find the claims of some commenters that public utilities are currently earning excessive returns on their existing rates to be speculative. We have no basis to conclude earned returns are excessive since these commenters have not submitted section 206 filings alleging such excessive returns nor do they provide evidence in their pleadings identifying the companies that are realizing excessive returns.

C. Incentives Available to Transcos

1. Definition of Transco

a. Background

194. The NOPR (at P 37) proposed to define a Transco as a stand-alone transmission company, approved by the Commission, which sells transmission service at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility. The Commission invited comments on this proposed definition of Transcos.

b. Comments

195. AEP and PEPCO support the proposed definition because it allows a Transco to be affiliated with another public utility. AEP states that eligible entities should include integrated utility companies or their affiliates, and PEPCO that the definition of a Transco should allow for ownership by a single affiliate.

196. Other commenters support a definition that includes affiliated Transcos, but only those with passive ownership. Commenters differed on the level and nature of independence requirements, if any, that should apply to affiliated Transcos. PJM TOs, for example, argued only for the same governance requirements otherwise

[133] NASUCA cites *Arkansas Power & Light Co.* v. *Missouri Public Service Commission,* 829 F.2d 1444, 1451–52 (8th Cir. 1987) (A state may determine whether the company has experienced savings in other areas which might offset the increased price resulting from the pass-through of the increased wholesale rate).

[134] NASUCA cites *Panhandle Eastern Pipe Line.* v. *FERC,* 613 F. 2d 1120, 1127 (D.C. Cir. 1979).

applicable to Transcos. TAPS, on the other hand, advocates more specific definitions of affiliated Transcos that would need to meet all of the standards of the *Policy Statement Regarding Evaluation of Independent Ownership and Operation of Transmission* (Policy Statement Regarding Evaluation of Independent Ownership).[135] Several commenters, including APPA and ITC, argue for the benefits of independence. Vectren opposes the proposed definition of Transco in the NOPR because by permitting inclusion of transmission owners with affiliates that own generation and/or distribution, it allows a Transco to be substantially identical to a vertically-integrated utility. Vectren questions whether the Commission's policy initiatives would have more impact on an FPA jurisdictional Transco with generation and distribution affiliates than on a traditional integrated transmission owner due to the Transco's parent company's common equity ownership of transmission and distribution as well as its role in making critical Transco business decisions. Vectren also argues that holding companies with Transcos will utilize shared service companies to fulfill common managerial and administrative functions for Transcos and affiliates.

197. Commenters differed on whether the level of affiliate ownership should bear on the definition of a Transco. For example, Ameren states that utilities exhibiting comparable levels of independence (and benefits) should be entitled to similar rate treatments, regardless of organizational structure. Ameren focuses on the level of functional separation and operational independence of the Transco—and not the percentage of passive equity ownership. Semantic requests that the Commission define the maximum permitted traditional utility ownership allowed in a Transco.

198. Some commenters, including TransCanada and American Transmission, advocate flexibility regarding ownership in the proposed definition. NSTAR, National Grid, and OMS contend that the Commission's proposed definition of Transco is overly restrictive in applying only to companies that are solely transmission providers. They argue that transmission and distribution companies that have taken significant steps toward independence by divesting of generation and marketing activities be similarly rewarded.

199. Due to concerns about competition for capital within Transcos, TDU Systems states only Transcos with strict limits on investments in other industries should receive incentive rates. APPA states that Transcos must have access to sources of equity capital other than their affiliates, such as through issuance of new equity or through capital contributions from a diverse base of Load Serving Entity owners.

200. Semantic states that the definition of Transco should be broadened to include entities that deliver services using advanced transmission technologies recognized in section 1223(a) of EPAct 2005, such that a Transco need not directly participate in the flow of energy. A Transco could be an ''Advanced Technology Transco'' that delivers enhanced grid state data processed by analytical software.

c. Commission Determination

201. We will adopt in the Final Rule the definition from the NOPR that a Transco is a stand-alone transmission company that has been approved by the Commission and that sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility. This definition includes the flexibility advocated by some commenters and allows the Commission to consider various business models and arrangements.

202. The definition we adopt here does not exclude affiliated Transcos with active ownership by market participants, or stand-alone transmission companies that own transmission and distribution facilities. However, we expect applicants to demonstrate the value of their particular affiliated Transco proposal. We will consider the eligibility of such arrangements based on a showing of how the specific characteristics of a proposed Transco affect its ability and propensity to increase transmission investment and lead to increased transmission investment similar to the Transcos we have already approved. We note that the three Transcos established thus far—which have all demonstrated their willingness and ability to invest in new transmission—are either not affiliated with any market participant (*e.g.*, International Transmission and METC) or have joint ownership and board membership by a number of market participants and independent members (*e.g.*, American Transmission). Concerns regarding affiliated Transcos, such as those voiced by Vectren, or support for companies that own transmission and distribution or other business structures, will be considered in the context of specific applications for incentive treatment.

203. In addition, because we do not wish to preclude entities that may help foster investment in needed transmission infrastructure simply because they have not yet been proposed or evaluated, we will not establish specific limits on Transcos regarding, for example, business investments in other industries, sources of equity, or levels of active and passive ownership.

204. We also clarify that an entity's status as a Transco will not be conditioned on membership in an ISO or RTO. As the Commission explained in the NOPR, just as the need for investment is a national need, we believe that the expansion and investment objectives of new FPA section 219 are best met by a definition of Transcos that does not restrict the formation of Transcos to only certain organized markets. Similarly, we clarify that an applicant that receives an incentive related to its status as a Transco may also request and be eligible for other generally applicable incentives discussed in the Final Rule, such as those for joining an RTO or ISO. The Commission will consider the suitability of multiple incentives at the time of an application.

205. We will not create a new Transco category that includes entities that do not own transmission facilities, as requested by Semantic. Consistent with section 219 the Final Rule applies to rate treatments for transmission of electric energy in interstate commerce by public utilities. To the extent Semantic meets this requirement, it may file an application for incentive treatment and the Commission will then make its determination of whether the Semantic proposal meets the requirements of section 219.

2. Transco ROE Incentive

a. ROE Incentive

i. Background

206. As part of the encouragement of Transco formation, the Commission stated that it will permit suitably structured Transcos to receive an ROE that both encourages Transco formation and is sufficient to attract investment. For example, the Commission approved equity returns for METC and International Transmission that reflect the significant benefits that their status as Transcos provide, and these returns are higher than those approved for integrated entities. Continuing to allow a higher ROE (that falls within a zone of reasonableness) in recognition of the benefits Transcos provide is an appropriate way to ensure the achievement of section 219's objectives.

[135] ¶ 111 FERC 61,473 (2005).

Therefore, the Commission stated that it will consider the positive impact Transcos have on transmission investment and in turn on the reliable or economically efficient transmission and generation of electricity when it evaluates ROEs proposed by properly structured Transcos. (NOPR at P 40, footnote omitted)

ii. Comments

207. Several commenters,[136] oppose the Commission's proposal to grant an ROE incentive to Transcos outright. Other commenters[137] oppose giving Transcos an incentive that is not available to other business models.

208. Those opposing the outright grant of ROE incentives to Transcos[138] contend, among other things, that: There should be no equity incentive adders without direct demonstration of customer benefits; such incentives would unfairly divert capital to Transcos; and that enhanced Transco ROEs do nothing to solve the problem of building needed transmission.

209. Commenters opposing[139] treatment based on corporate form or business model suggest that the Commission focus on the purpose and effect of the proposed investments, not the type of entity that proposes them. They argue that there is a lack of evidence of how Transcos encourage transmission infrastructure expansion and the track record for Transcos is incomplete.

210. Other commenters raise concerns about the signals the Commission is sending regarding RTOs and independence of operations, planning and expansion that can be ensured through other types of regional transmission groups or through traditional utilities, particularly those in a RTO with a regional planning process.[140] EEI, for example, opposes the Commission managing business models and argues the Commission should not (even unintentionally) give the impression through incentives that it seeks to restructure the transmission sector.

211. Other commenters offer suggestions as to how to distinguish incentives. For example, NU and PJM suggest targeting incentives at companies that are investing in transmission and/or involved in regional planning, regardless of corporate structure. PJM suggests the Commission proceed on a case-by-case basis.

212. Finally, commenters argue that higher ROEs for only some transmission owners are discriminatory and not just and reasonable, and have no basis in section 219. Alternatively, some suggest that Transcos have lower risk than integrated companies and should receive lower ROEs. Others argue that incentives should cover only new investments and behavior,[141] not existing infrastructure. For example, California Commission opposes providing higher ROEs to Transcos, arguing that Transco and traditional integrated utility shareholders bear the same (and only significant) risk as transmission project owners—during the initial stage of project permitting and developing. SCE offers that Transco-specific ROEs might actually provide a disincentive for future Commission-jurisdictional transmission investments by traditional utilities if they can earn higher ROEs on state-jurisdictional facilities. TANC offers that a for-profit Transco has no incentive to make, and, in fact, is discouraged from making, economically efficient and/or energy efficient investments. Dairyland points out that American Transmission's plans for substantial investment were made in the context of a settlement agreement in which American Transmission agreed to a lower ROE than that approved for Midwest ISO transmission owners and that the settlement improved American Transmission's cash flow and reduced its risk, providing a sufficient financial package to enable its investments even with the lower ROE. Dairyland states that American Transmission shows that substantial investment by Transcos is likely to occur even if ROEs are reduced.

213. Some commenters take issue with the representations in the NOPR regarding state and federal jurisdiction.[142] For example, Community Power Alliance opposes rewarding changes in ownership structure resulting in transfer of jurisdiction from state to federal regulators. PEPCO believes the NOPR suggests that traditional utilities may be treated less well by federal regulators merely because they are subject to state as well as federal jurisdiction. New Mexico AG states Transco incentives are nothing more than an attempt by the Commission to override state regulatory jurisdiction. Nevada Companies state that the Commission must work with state regulatory authorities to foster Transco formation.

214. TDU Systems opposes incentive rates for new investment by Transcos after those Transcos form. If any such award is granted, TDU Systems argues it be done only upon demonstration of need, and apply only to system expansions, not existing facilities.

215. Other commenters,[143] generally support incentive-based ROEs to encourage Transco formation. For example, International Transmission supports incentives for Transco formation and investment not merely to reward a particular transmission ownership structure but to encourage a type of transmission ownership that has produced the results that Congress sought when it enacted section 219. International Transmission states that both its own specific experience and the track record of Transcos generally illustrate the benefits of Transco ownership of transmission.[144] International Transmission states that if other forms of transmission ownership invest in transmission in a manner comparable to Transcos, those other entities should be eligible for equal incentives, but that until they do, Transco-specific incentives are fully appropriate.

216. KKR offers the following potential investment advantages of Transcos: elimination of competition for capital between generation and

[136] *E.g.*, APPA, Community Power Alliance, Municipal Commenters, NASUCA, NECPUC, New Mexico AG, NRECA, NU, Pennsylvania Commission, Snohomish, and TANC.

[137] *E.g.*, AEP, BG&E, EEI, First Energy, KCPL, MidAmerican and PacifiCorp, Midwest ISO, NECPUC, Northwestern, PEPCO, PJM, PJM TOs, PPC, Progress Energy, SCE, Southern Companies, and Vectren.

[138] *E.g.*, Municipal Commenters, NECPUC, Progress Energy, Snohomish, PPC.

[139] *E.g.*, APPA, Community Power Alliance, FirstEnergy, Pennsylvania Commission and NASUCA.

[140] *E.g.*, American Wind, Mid American, PacifiCorp, and EEI.

[141] *E.g.*, New Mexico AG, NRECA, Pennsylvania Commission, PG&E, Vectren, Southern Companies, California Commission, SCE, and TANC.

[142] *E.g.*, Community Power Alliance, PEPCO, NSTAR, and PJMTOs.

[143] *E.g.*, International Transmission, KKR, Nevada Companies, TDU Systems, Trans-Elect and Upper Great Plains.

[144] International Transmission states that in the last decade of Detroit Edison's ownership of the facilities now owned by International Transmission, Detroit Edison invested about $10 million a year in those transmission facilities that International Transmission states it invested $41 million on in 2003; $82 million on in 2004; and over $118 million on in 2005. At the end of 2005, the net asset value of International Transmission's facilities has nearly doubled while its CWIP balance remained roughly flat. International Transmission states that this substantially increased investment is producing benefits for consumers in enhanced reliability and increased access to competitively priced generation. International Transmission states that in the latest Midwest ISO Transmission System Expansion Plan, the three Transcos in the Midwest ISO account for 54 percent of the approximately $2.9 billion in projected investment through 2009. Comparing the level of projected investment across Transcos and non-Transcos, the average Transco in the Midwest ISO is investing at over *seven times* the rate of the average non-Transco in the Midwest ISO.

transmission functions; a singular focus on transmission investment which allows more rapid and precise response to market signals indicating when and where transmission investment is needed; a lack of incentive to maintain congestion in order to protect generation market share; and an enhanced ability to manage assets and access to capital markets. As stand-alone entities lacking incentive to favor a particular market participant's generation, Transcos are likely to attract a variety of new generators, including solar and wind renewable generation.

217. KKR states that enhanced ROE can both drive capital investment and support Transco formation. An enhanced ROE in excess of that sufficient to support new investment will be factored into the purchase price of the Transco assets or company and be delivered in whole or in part to the seller.

218. Additional comments in support of higher ROEs for Transcos,[145] note that Transco formation and investment will occur when actual Transco returns are equal to or greater than returns for investments with comparable risk and that these returns must be earned on a consistent basis.

219. Trans-Elect offers suggestions on the manner in which the incentive could be tied specifically (and exclusively) to the acquired facilities. In addition, Trans-Elect states that whatever methodology is used to develop a range of equity cost estimates, use of the mid-point (or average) of that range would be contrary to the notion of stimulating new transmission investment. Particularly in the context of the inherently higher-risk Transco business model, Trans-Elect supports ROEs toward (or at) the high end of the range.

220. Upper Great Plains supports Transco incentives but argues they be limited to what is necessary to put Transcos on an equal footing with other transmission developers. According to Upper Great Plains, leveling the playing field will encourage Transcos to more fully develop the advantages made possible by their business structure.

iii. Commission Determination

221. After considering all the comments, we adopt in this Final Rule the proposal from the NOPR to provide to Transcos a ROE that both encourages Transco formation and is sufficient to attract investment after the Transco is formed. The incentive ROE does not preclude a Transco from applying for any other incentive adopted in this rule, including hypothetical capital structures, ADIT, acquisition premiums, formula rates or deferred cost recovery. We note that such additional incentives could aid the formation of Transcos as well as bolster their ability to add transmission infrastructure. We note, in addition, that application of the ROE incentive or applicable other incentives will likely be more efficiently translated into rates for those applicants that operate under or concurrently propose formula rates.

222. This decision is based on the proven and encouraging track record of Transco investment in transmission infrastructure. For example, International Transmission states that its investment was more than ten times higher in 2005 than the annual investment by DTE during the last decade of DTE's ownership of the same transmission system.[146] Trans-Elect states that it expended $112 million in capital on its system from May 2002 through 2005.[147] Since January 1, 2001, American Transmission states that it has invested approximately $1 billion in strengthening its system, essentially tripling its investment in transmission infrastructure in five years.

223. The expansion plans of existing Transcos are also encouraging. International Transmission notes that in the latest Midwest ISO Transmission System Expansion Plan, the three Transcos in the Midwest ISO account for 54 percent of the Plan's approximately $2.9 billion in projected investment through 2009. It also states that comparing the level of projected investment across Transcos and non-Transcos, the average Transco in the Midwest ISO is investing at a rate that is over *seven times* that of the average non-Transco in the Midwest ISO.[148]

224. As stated in the NOPR, the Commission believes that this positive record of Transco investment in transmission facilities is related to the stand-alone nature of these entities.[149] In particular, we agree with the comments submitted by KKR explaining the benefits of the Transco model. By eliminating competition for capital between generation and transmission functions and thereby maintaining a singular focus on transmission investment, the Transco model responds more rapidly and precisely to market signals indicating when and where transmission investment is needed. We agree that Transcos have no incentive to maintain congestion in order to protect their owned generation. Moreover, Transcos' for-profit nature, combined with a transmission-only business model, enhances asset management and access to capital markets and provides greater incentives to develop innovative services. By virtue of their stand-alone nature, Transcos also provide non-discriminatory access to all grid users.

225. Numerous commenters state that the Commission should not favor one corporate structure (*i.e.*, Transcos) over another. We agree in part. In the context of the goal to increase investment in needed transmission infrastructure, it is inappropriate to favor one corporate structure over another to the extent both business structures have similar transmission investment records. To date, however, no other business structure has a transmission investment record similar to that of a Transco and therefore our incentives that focus on Transcos are justified. While this rule provides incentives for all public utilities, the additional incentives for Transcos, in light of their superior record of adding infrastructure, are neither unduly discriminatory nor contrary to the goals of section 219.

226. We believe an incentive ROE for Transcos is justified because Transcos are spending their additional return on capital spending, as demonstrated by the negative cash flow profiles of the current Transcos and their future capital spending plans, as discussed in the comments of the Transcos and KKR. Though Transcos have demonstrated that they will build transmission, and plan to build more in the future, we agree with commenters that state that our focus should be on actual results—*i.e.*, getting transmission built. Currently, Transcos are spending capital aggressively, reinvesting any earned returns and spending a significant amount more than they are earning. However, continuing to allow a Transco, over the long-term, to receive an incentive ROE for all its facilities that recognizes its increased transmission investment only makes sense if the Transco continues to provide the benefits which we are trying to incentive. Therefore, as discussed earlier, we encourage Transco applicants to submit proposals to measure performance and thereby justify continuation of ROEs (as well as other rate treatments) that were provided for the purpose of attracting and sustaining transmission investments.

227. We disagree with AWEA's statement that single-system Transcos do nothing for regional goals. Even a single-system Transco can build

[145] *E.g.*, Nevada Companies and Trans-Elect.

[146] International Transmission comments at 21.

[147] METC comments at 3.

[148] International Transmission Reply Comments at 6.

[149] NOPR at P 39.

infrastructure that significantly aids a broad region. Moreover, to the extent Transcos belong to transmission organizations, their expansion plans must be approved by transmission organizations and therefore they support regional planning goals.

228. We disagree with Municipal Commenters' contention that the Transco incentive is misguided as transmission prices have increased dramatically in regions where the transmission systems were spun off from investor owned utilities. We have no evidence that Transcos have increased prices, nor did Municipal Commenters provide supporting evidence. Nor do we agree Transco formation would simply increase earnings without any direct demonstration of customer benefits from such formation. The amount of infrastructure likely to be added by Transcos will directly benefit customers in the region. Responding to the Pennsylvania Commission, we have no basis to conclude Transcos may introduce undesirable biases in grid investment and operations. Furthermore, like any public utility, their rates remain subject to review to ensure justness and reasonableness. We therefore have no basis to change our conclusion that Transcos are appropriate structures for investment in infrastructure and accomplishment of the objectives of section 219.

229. In response to concerns of commenters such as NRECA and the California Commission that the incentive return for Transcos is not based on a risk evaluation of Transcos, we believe those concerns are premature. Such an evaluation is more appropriately part of the section 205 process in individual rate applications of assessing representative proxy companies and the impact of other factors, including risk.

230. We expect that providing for deferred cost recovery for Transcos, such as has been approved for Trans-Elect and International Transmission, will address Nevada Companies' concern that state-level rate freezes could preclude recovery of costs associated with divesting transmission assets to Transcos.

231. We believe PEPCO and the New Mexico AG have misinterpreted our statements in the NOPR regarding benefits of federal jurisdiction for Transcos. The NOPR does not state that a state's jurisdiction over some of the activities and assets of traditional utilities hinders investment, as PEPCO maintains. Rather, the NOPR indicated that Transcos would benefit from having incentive approvals determined in a single jurisdiction, by eliminating delay and uncertainty. The purpose of our policy of incentives for Transcos is to build much needed transmission infrastructure. States continue to have jurisdiction over the siting of new transmission infrastructure and many of the high voltage interstate projects will require extraordinary cooperation and collaboration between state and Federal regulators.

b. Transco Level of Independence

i. Background

232. The Commission proposed to clarify and broaden the definition of Transcos to be stand-alone transmission companies approved by the Commission, without a condition of membership in a RTO or ISO, and requested comment on how to factor the level of independence into any request for ROE-based incentives for Transcos. The Commission sought comment on whether it should specify additional incentive levels within the zone of reasonableness to correspond to certain levels of independence and if so, what those amounts should be. The Commission also sought comments concerning whether membership in an RTO or ISO should be considered in setting incentive-based ROEs approved by the Commission for a Transco.[150]

ii. Comments

233. Numerous commenters [151] generally support tying the level of incentives to the level of independence of the Transco. For example, Ameren proposes a tiered approach to ROE incentives, with Transcos that are members of an RTO or ISO entitled to the highest ROE incentive. International Transmission states that it is appropriate to award the highest ROE-based incentives to Transcos that are truly independent. KKR states that Transcos that have achieved total structural independence should receive the most generous set of incentives. MISO States state that the level of Transco independence is an important consideration and, accordingly, the Commission could apply a graduated ROE incentive depending upon the degree of independence between the Transco and market participants, affiliates or generation.

234. National Grid states that the Commission should establish the level of ROE-based incentives based on a sliding scale keyed to various levels of independence for all forms of Transmission Organizations, with one end of the sliding scale being ''total structural independence,'' which would be entitled to full incentives.

235. Trans-Elect states that only entities that establish independence as to operation, planning, construction and investment decisions should qualify for ROE-based incentives for Transcos. Rather than recognizing a ''range'' or ''levels'' of independence that would justify ''additional incentive levels,'' the Commission should confirm that entities that meet the definition of Transco would qualify for the full ROE-based incentive, while those that do not would not be eligible for the incentive. According to Trans-Elect, it is critical that Transco ownership arrangements that reflect truly passive ownership qualify for the full ROE-based incentive and that the independence standard should be deemed satisfied when passive ownership is structured to ensure that the Transco will ''operate free of market participant control or influence.''

236. TDU Systems supports a policy to prevent a Transco with passive ownership interests from earning Transco incentives. TDU Systems assert that should the Commission authorize passive ownership interests by market participants in Transcos, those relationships should be rigorously scrutinized. Passive ownership interests by market participants in Transcos should only be authorized upon a showing that the option of investment in the Transco is open to all LSEs in the region up to their load ratio shares, according to TDU Systems, with governance based on equal and/or equally-weighted votes, if any, for all passive owners. TDU Systems recommend that the Commission commit to monitor these relationships in order to deter the potential for abuse.

237. Some commenters also address whether membership in an RTO or ISO should be considered in setting incentive-based ROEs approved by the Commission for a Transco. For example, PEPCO states that the Commission should not provide additional incentive levels for certain levels of Transco ''independence'' unless it also provides the same incentive levels for participants in other models, such as RTOs. MISO States and PJM believe that the Commission should reverse its proposed policy of not taking into account if the Transco is a member of an RTO and instead recognize the positive benefits of Transco membership in RTOs. AWEA states that incentives for regionalizing the grid through RTO participation should be an additional incentive.

[150] NOPR at P 42.

[151] *E.g.*, Ameren, AWEA, Connecticut DPUC, International Transmission, KKR, MISO States, and National Grid.

238. Others, such as APPA, NRECA, and PG&E support the Commission's proposal that membership in an RTO or ISO should not be a factor in setting incentive-based ROEs for Transcos. WPS states that the proposed incentive for Transcos may be appropriate, but also could be duplicative if the Transco is an RTO member and also receives an incentive for that membership.

iii. Commission Determination

239. We will not establish a specific methodology to factor the level of independence into any request for ROE-based incentives for Transcos. We will also not specify additional incentive levels that remain within the zone of reasonableness, to correspond to certain levels of independence. While not quantifying a precise formula or method, we will consider the level of independence of a Transco as part of our analysis when we determine the proper ROE for the Transco, and evaluate the specific attributes of a particular proposal, including the level of independence, to determine appropriate incentives.

240. Though we are not establishing a range of incentives based on independence, we note that the three existing Transcos, which have significantly increased their transmission investment post-formation, are either totally independent of market participants or can meet the independence standards in the Policy Statement Regarding Evaluation of Independent Ownership. Independence is an important component of the positive contribution of Transcos on investment in needed transmission infrastructure. A Transco with active ownership by a market participant or other new business arrangements is also eligible for Transco incentives to the extent it can show, for example, why active ownership by an affiliate does not affect the integrity of its investment planning, capital formation, and investment processes or how its business structure provides support for transmission investments in a way similar to the structure of non-affiliated Transcos or Transcos with only passive ownership by market participants.

241. In addition, while a Transco need not be a member of an RTO, ISO, or other Transmission Organization, we will also consider such membership as part of our evaluation process on the level of Transco incentives that might be appropriate. We also note that a Transco is eligible for incentives if it is a member in an RTO, ISO, or other Transmission Organization.

3. Accumulated Deferred Income Taxes (ADIT)

a. Background

242. To remove any disincentives that might prevent the sale or purchase of transmission assets to form Transcos, such as capital gains taxes on sales of assets,[152] the Commission (NOPR at P 43) proposed to include in the rates of Transcos an adjustment to recover ADIT. This incentive would provide the assurance of recovery in rate base of adjustments for taxes associated with asset sales, thereby reducing uncertainty.

b. Comments

243. Several Commenters[153] submitted comments that generally support the Commission continuing to consider proposals to include adjustments for ADIT in rates when a Transco is purchasing transmission facilities. For example, Trans-Elect states that continuing to allow adjustments for ADIT will eliminate this tax-related disincentive and, in the process, demonstrate to potential sellers, purchasers and the investment community the Commission's commitment to promoting independent stand-alone transmission businesses. National Grid states that allowing recovery of ADIT is designed to ensure that there is no financial or tax penalty associated with undertaking the transactions necessary to form Transcos and therefore the Commission should allow such recovery to eliminate an obstacle to Transco formation. OMS states that allowing the ADIT cost recovery adjustment appears more reasonable than simply authorizing filings to recover acquisition premiums because the ADIT adjustment premium would be specifically quantifiable and tied to a specified purpose. International Transmission and Trans-Elect also specifically support the Commission's clarification that a stand-alone transmission company that requests an incentive ROE would not be precluded from also requesting the ADIT adjustment.

244. Some commenters raise specific concerns regarding how an ADIT adjustment will be calculated. TAPS states that after the seller is held harmless for its book-based gain-on-sale tax consequences (if any) any remaining tax balance should flow back to ratepayers. TDU Systems state that the ADIT adjustment should be reduced by the seller's ADIT and investment tax credits associated with the transferred property. APPA is concerned about the difficulty a buyer of facilities will have in correctly calculating the ADIT, which is based on the seller's capital gains tax liability. NRECA states that the Commission needs to create sufficient safeguards to prevent double recovery. TAPS and APPA also cite the American Jobs Creation Act of 2004 as substantially mitigating, and potentially eliminating the ADIT concern.

245. APPA, PPC and Snohomish state that, in order to get the ADIT adjustment, buyers of transmission facilities should need to demonstrate concomitant customer benefits to offset increased transmission rates resulting from measures to recover capital gains tax-related acquisition premiums.

246. PPC and Snohomish state that allowing recovery of ADIT goes beyond the stated goal of promoting investment in new transmission capacity, and instead would promote the sale of existing transmission assets. They contend that allowing purchasers to amortize ADIT in rates will increase ratepayer costs and allow Transcos to benefit from the time-value of money without offsetting any actual expenditure. The value of ADIT should be passed through to customers only if the Transco is actually making tax payments, and then only in an amount equal to those payments.

c. Commission Determination

247. We find that it is appropriate for the Commission to continue to consider proposals to make an adjustment to the book value of transmission assets being sold to a Transco to remove the disincentive associated with the impact of accelerated depreciation on federal capital gains tax liabilities. This adjustment is simply intended to remove a disincentive to Transco formation. As explained in the NOPR, transmission owners are unlikely to sell transmission assets at book value if they are not held harmless from capital gains taxes on such sales by including an adjustment for taxes associated with those sales. Buyers of transmission assets may be unwilling to pay such an adjustment without some assurance of recovery of the adjustment in their rate base, as the Commission has addressed in previous Transco-related orders. In addition, we find appropriate the clarification proposed in the NOPR that a Transco requesting an incentive ROE not be precluded from also requesting the ADIT adjustment.

[152] *See, e.g., International Transmission Co.*, 92 FERC ¶ 61,276 at 61,915–16 (2000) (explaining potential disincentives to sellers and buyers of transmission assets if the ADIT adjustment is not granted).

[153] *E.g.*, International Transmission, KKR, National Grid, NorthWestern, OMS, PJM TOs, TAPS, and Trans-Elect.

248. While the Commission will continue to consider proposals to include adjustments for ADIT in rates when a Transco is purchasing transmission facilities, we emphasize that we will review such proposals on a case-by-case basis to ensure that the ADIT adjustment is just and reasonable and not unduly discriminatory or preferential under the particular circumstances of the proposal.[154] Specific concerns about how the ADIT adjustment is calculated, such as those raised by TAPS, TDU Systems, APPA and NRECA, can be raised when a proposal is filed with the Commission. In addition, TAPS' and APPA's concern that the American Jobs Creation Act of 2004 may eliminate the need for an ADIT adjustment can be raised as an issue concerning an applicant's proposed ADIT adjustment in a specific proceeding. We note that, as there is no sunset date for the incentives, applications could be made after the potential tax benefits of the American Jobs Creation Act have lapsed, as the tax law only affects transactions that close by January 1, 2007.

249. We will not require, as requested by APPA, PPC and Snohomish, that our approval of any ADIT adjustment be conditioned on an analysis of costs and benefits related to such an adjustment, as discussed elsewhere in this Rule. We disagree with the implication of PPC that the Transco purchaser is receiving the benefit for ADIT costs that it is not really paying. ADIT is part of the purchase price of the transmission assets sold to the Transco, and hence represents actual costs to the purchaser.

250. However, as described more fully in the Performance Test section, we clarify that continuation of the ADIT adjustment, like continuation of other incentives, is conditional on the applicant achieving benchmarks for its own proposed Commission-approved metrics.

4. Acquisition Premiums for Transco Formation

a. Background

251. The NOPR (at P 55) requested comments on whether the Commission should make a generic determination that general benefits would accrue to ratepayers as a result of Transco formation. It also sought comment on whether any change in the acquisition premium/ratepayer benefits review at the federal level would risk increased resistance to such acquisitions at the state level. The NOPR sought comment on whether there are other mechanisms that the Commission could institute to provide regulatory certainty of the recovery of the acquisition premium both through retail as well as wholesale rates. It also sought comment on what measure the Commission might use in evaluating the appropriateness of such premiums as measured against, for example, the size of the premium, the location of the assets, the level of independence of the Transco, and other relevant factors.

b. Comments

252. Several Commenters[155] support a generic Commission determination that Transco formation benefits consumers and that fair value paid for transmission assets by a Transco will be recoverable, even if that fair value exceeds the book value of those assets by a significant amount. Trans-Elect argues for a case-by-case consideration, *i.e.*, that a Transco should be entitled to make a showing that the benefits of a particular transaction justify allowing a specific acquisition adjustment and that the level of proposed adjustment is appropriate. KKR supports allowing a Transco Applicant to recover an acquisition premium in rates for all or a portion of any premium paid above net book value for purchases of transmission facilities. PNM encourages the Commission to eliminate its historical prohibition against recovery of acquisition adjustments for transmission assets.

253. Several commenters[156] oppose a generic determination regarding the allowance of acquisition premiums for Transcos, and generally support the continuation of current Commission policy which, according to commenters, is case-by-case. They also oppose the Commission making a general determination that Transco formation results in general benefits to customers for purposes of determining whether to allow recovery of an acquisition premium in rates.

254. In response to our request for comment on what measure to use to evaluate the appropriateness of such premiums, Pennsylvania Commission states that if the Commission determines that approval of acquisition adjustments is necessary to encourage acquisition and mergers of transmission systems in a business-neutral way, the Commission should require applicant(s) to demonstrate that such costs were both reasonable and negotiated at arms' length. According to the Pennsylvania Commission, the applicant should be required to offer proof that the purchase price of assets had a reasonable relationship to the market valuation of the assets transferred, that the buyer and seller were financially separate and unrelated, and that directors and officers of, and advisors to, the buyer and seller had a financial and legal ''arm's-length'' relationship before and after consummation of the acquisition. International Transmission suggests that recovery of the difference between book value and fair value, as represented in a proposed purchase price, be limited to no more than 50 percent of any amount paid above the book value of the assets, in order to provide market discipline with respect to the purchase price of the assets. Snohomish states that there must be a means to independently verify the purchase price, such as requiring submission of two or more independent appraisals.

255. Dairyland supports limiting acquisition adjustments to situations where the seller of the facilities to a Transco does not have (or does not simultaneously obtain) an ownership in the Transco. AEP, PJM TOs and SCE state that if the Commission allows recovery of acquisition premiums, it should allow all business models to recover them, including traditional investor-owned utilities.

256. TAPS and TDU systems argue that entities allowed to recover acquisition premium for the formation of Transcos should not also be authorized to receive an enhanced ROE.

257. Nevada Companies state that the Commission must work with state regulatory authorities to foster Transco formation since transmission owners' incentives are reduced if they must give a large portion of an acquisition premium back to customers.

c. Commission Determination

258. We will not in this Final Rule change the Commission's policy of allowing acquisition adjustments in rates only upon a specific showing of ratepayer benefit.[157] However, given the positive contributions of Transcos on transmission investment discussed above, we find that a Transco may propose an acquisition premium as an incentive under the Final Rule, as provided under § 35.35(d)(1)(viii). We

[154] As discussed elsewhere in the Final Rule, an applicant may propose a number of incentives. Thus, a stand-alone transmission company is not precluded from requesting ROE and ADIT.

[155] *E.g.*, International Transmission, KKR, and Trans-Elect.

[156] *E.g.*, Ameren, APPA, MISO States, Northwestern, NRECA, Pennsylvania Commission, PEPCO, PJM TOs, Snohomish, TDU Systems, and WPS.

[157] While the proposed ADIT incentive discussed above would adjust book value and therefore may be considered a premium on net book value, we note that unlike the acquisition premium discussed here, the proposed ADIT incentive addresses tax-related issues outside of the applicant's control.

will continue to evaluate proposals made by Transcos to recover acquisition premiums associated with the purchase of transmission facilities on a case-by-case basis. We appreciate the comments on how the Commission should evaluate the level of acquisition premiums, such as those from Pennsylvania Commission, International Transmission, and Snohomish, and we will take such factors into account in evaluating whether to allow recovery of particular acquisition premiums. While this discussion is limited to providing an incentive for Transco formation, entities other than Transcos can apply for the incentive and the Commission will evaluate those applications on a case-by-case basis.

5. Merchant Transmission

a. Comments

259. LIPA states that because of the NOPR's focus on cost-of-service ratemaking, it has less impact on merchant transmission developers, whose rates are defined by contract (and thus market benefit), and not by Commission cost-of-service ratemaking standards. Merchant transmission developers are generally required to rely on market rates for transmission service negotiated directly with purchasers of their capacity, and to assume (along with the purchasers of their capacity) all of the market risk for their facilities. Merchant transmission developers will base their decisions on other factors, particularly their ability to efficiently attain the market benefits that their investments create.

260. TransCanada believes that a two-tier subscription process would provide merchant developers with some initial regulatory and business certainty by addressing the initial up-front siting and permitting risk (because of the ability to secure meaningful commitments from the first tier subscribers). It would also allow for a full open season for the remainder of the capacity (the second tier) consistent with current Commission policy.

261. National Grid states that the key issues raised in this rulemaking (ensuring adequate returns on equity for investment and independence, facilitating timely and complete cost recovery, etc.) are regulated rate issues, which should be of no concern to merchant transmission developers.

b. Commission Determination

262. With respect to comments on merchant transmission, we agree with comments that this issue is beyond the scope of this Final Rule. Merchant projects are market driven while this final rule deals fundamentally with regulated transmission rates. True merchant transmission projects may play an important role in the future of transmission infrastructure development, but incentives related to, for example, ROE and cost recovery, do not apply to merchant transmission.

D. Performance-Based Ratemaking

1. General Comments

a. Background

263. In the NOPR, the Commission sought comments on ways performance-based ratemaking (PBR) might apply to for-profit Transcos and traditional public utilities, and not-for-profit Transcos and public utility ISOs and RTOs. In the case of for-profit entities, the Commission sought comment on whether there should be mechanisms for sharing gains with ratepayers and, if so, what those mechanisms should be. In the case of not-for-profit public utility ISOs and RTOs, the Commission sought comment on whether and how PBR developed for for-profit entities might be applied to not-for-profit entities. Finally, the Commission sought comment on whether performance-based benchmarks for transmission costs would provide incentives for the deployment of advanced technologies.[158]

b. Comments

264. Commenters generally support the concept of PBR, especially as it was defined in the Commission's 1992 Policy Statement on Incentive Regulation and in Order No. 2000, which emphasize that PBR should be voluntary, have both an upside and downside, that gains should be shared with ratepayers, that benefits should be quantifiable, and that costs to consumers under PBR should not exceed what they would have been under traditional regulation. They urge the Commission to retain these principles.[159]

265. However, citing to current market structure, most commenters expressed a general lack of enthusiasm for PBR, and none held out any expectation that PBR would have a significant role to play in providing consumer benefits. Chief among the obstacles cited to implementing PBR is a difficulty in determining appropriate performance measures or benchmarks. For example, KCP&L emphasized that experts, such as EPRI, are researching appropriate performance measures but have not yet determined how to account for various factors such as system age and configuration, geography and customer density, a point of view shared by many.[160] Moreover, APPA cautions that poorly designed performance measures could lead to unintended and undesirable consequences, and it recommends that the Commission conduct a series of technical conferences and workshops on PBR before considering any implementation. The Kentucky Commission states that performance-based benchmarks for transmission costs are not necessary because any technology that is beneficial will have an economic reward, thereby providing its own incentive. The transmission tariff should reflect prudent operation and maintenance so that, if there is improvement, a greater profit will be realized. For proven technologies, a sharing of both benefits and the risks would be appropriate for deployment of new technologies. Thus, many conclude that the value of PBR seems remote, although voluntary programs could be worth considering.

266. Some commenters oppose PBR because they believe it could deter investment in transmission facilities, contrary to the main objective of the proposed rulemaking. For example, International Transmission concludes that PBR might play a limited role in some circumstances, but warns that some PBR approaches, such as price cap regulation, could actually discourage investment. Others, such as FirstEnergy and Nevada Companies are concerned that PBR could increase risk and, thus, reduce investment. Some commenters believe that PBR might have a limited role in inducing utilities to adopt certain innovative practices and advanced technologies,[161] while other commenters were more concerned that PBR would discourage reliability and provide unwarranted benefits to utilities.[162]

267. Few commenters see any realistic role for PBR as a means of inducing cost saving behavior on the part of non-profit entities, although some, such as Ameren, believe that the Commission's oversight is inadequate. Industrial Consumers, in particular, express the view that PBR has no role to play in the non-profit area and, furthermore, that PBR should not be applied to the profit area unless a proven model would make pricing under PBR as transparent as pricing under conventional ratemaking.

[158] NOPR at P 58.

[159] *E.g.*, NASUCA, TDU Systems, Missouri Commission, and SMUD.

[160] *E.g.*, Comments of KCPL, SCE, and EEI.

[161] *E.g.*, Comments of AEP and UTC Power.

[162] *E.g.*, Comments of NSTAR and the New Mexico AG.

Some commenters [163] stress that safeguards already exist to insure that ISOs/RTOs are efficient and accountable, and they argue that there is no urgency to adopt PBR for RTOs/ISOs. Although they could consider PBR on a limited, case-by-case basis, PJM TOs also emphasize that RTOs with regional planning processes and requirements outside the transmission owners' control are poor candidates for PBR.

268. Among those commenting most favorably on implementing some form of PBR were Progress Energy, Southern Company, and National Grid. Although they see limited immediate applicability of PBR, both Progress Energy and Southern Company recommend specific types of PBR—Progress Energy favors loop flow pricing, and Southern Company favors revenue or rate caps that would reward utilities for increasing throughput. In contrast, National Grid emphasizes that it has had success with PBR mechanisms different from those mentioned in the NOPR outside the U.S. However, until the U.S. industry is more independent and there is greater consolidation of ownership and operation, it does not believe that PBR is an immediate attractive option.

269. Connecticut DPUC, along with testimony submitted by two of its witnesses, Thomas P. Lyon and Pete Landrieu, support the view that PBR is either inappropriate or unlikely to provide important benefits. Lyon's affidavit emphasizes that critical principles for PBR include not only incentives to enhance efficiency and performance, but also should promote an efficient mix of infrastructure investment. He cautions against the use of price caps because they may induce firms to degrade quality, and he would favor some type of profit-sharing plan, perhaps a PBR that links a firm's financial performance to network congestion.[164] Landrieu's affidavit emphasizes that PBR is unnecessary, because system standards and performance are better managed directly by various regional reliability organizations. He also is pessimistic that PBR focused only on transmission will be able to account for important and complex tradeoffs between generation and transmission. He agrees with other comments that note that establishing appropriate benchmarks is an extremely complicated task and for that reason regards benchmark type PBR as unworkable.[165]

c. Commission Determination

270. We interpret ''incentive-based (including performance-based) rate treatments'' in section 219 to require the Commission to consider PBR as an option among incentive ratemaking treatments. To that end, the NOPR invited comments on how performance-based regulation might be used to motivate transmission entities to maintain and operate their systems reliably and efficiently. Consistent with Congress' directive to encourage PBR, we signaled our intention to reevaluate previous Commission policies on PBR. We did not intend that the NOPR be viewed as a rejection of our previous statements or as a comprehensive overview of all possible approaches to PBR. Our objective was to consider whether PBR can play a useful role in transmission pricing reforms in light of the many changes in electric markets that have occurred since our earlier statements.

271. The overwhelming view on PBR from all segments of the industry is ''not at this time'' and ''not given the current industry structure.'' Although there is general support for our earlier principles, we acknowledge, as commenters stress, that our voluntary program has not resulted in any PBR proposals being filed with the Commission. The consensus appears to be that the current state of the industry structure—a multitude of transmission-owning entities, many that do not directly control their transmission assets and operate in diverse geographical regions with very different customer densities, system ages and configurations—makes the determination of generally applicable performance benchmarks unworkable. Some suggest further study of PBR, express general support for the concept, and urge the Commission to remain open to considering voluntary proposals on a case-by-case basis.

272. We share the view of most commenters that it would be premature to adopt generic PBR measures at this time. However, the development of PBR measures may represent a long-term goal for the industry and the Commission to pursue. Among the goals of section 219 is to promote capital investment ''in the enlargement, improvement, maintenance, and operation'' of transmission facilities. Accordingly, we intend to continue to work with the industry to encourage development of PBR proposals.

2. Comments Proposing Performance Tests and Competitive Bidding

a. Comments

273. The New Mexico AG asserts that another way to implement an incentive-based mechanism is to penalize companies or RTOs that do not perform adequately and do not make the investments necessary to ensure the reliability of the transmission grid. The Delaware Commission contends that providing incentives without assessing penalties for failure to meet obligations violates the just and reasonable standard because it rewards monopoly power. Furthermore, the Delaware Commission claims that the plain meaning of incentive requires both rewards and penalties. NASUCA states that it is one-sided and inherently unfair to provide incentives that only increase utility profits with no performance accountability.

274. The Delaware Commission recommends that the Commission implement performance penalties by first defining the utility obligation, then determining whether there are transmission incentive projects which the transmission owner has failed to carry out, and in such situations impose a penalty in the form of a prospective reduction in return on equity or prudence disallowance that can be lifted when the project is complete.

275. TAPS argues that transmission providers should have their returns reduced to the low end of the zone of reasonableness if they fail to achieve and maintain a robust transmission infrastructure. TAPS recommends the Commission consider a number of factors in its determination of system reliability, including congestion, proration of financial transmission rights (FTRs), lack of available transfer capacity (American Transmission), failure to meet customer needs and denial of reasonable access. TAPS also asserts that the capital requirements of major projects should be put out to bid if a vertically-integrated transmission owner is unwilling to permit transmission dependent utility (TDU) participation but refuses to build without receiving above-cost rate treatments.

276. The Missouri Commission proposes that the Commission implement a process that determines performance-based ROEs. The process, according to the Missouri Commission, would require transmission owners to bid out projects, thereby providing an incentive for keeping implementation

[163] *E.g.*, NYISO, CAISO, PJM TOs and NECOE.

[164] Comments of Connecticut DPUC, Affidavit of Thomas P. Lyon at 16–19.

[165] Comments of Connecticut DPUC, Affidavit of Pete Landrieu at 27–28.

costs as low as possible and minimizing the regulatory concern with cost overruns. Projects based on actual costs would receive an ROE below the median of ROEs from the proxy group while projects proposing fixed costs would receive higher ROEs, explains the Missouri Commission. The Missouri Commission also recommends that the bids include an assessment and quantification of specific risks associated with the project. E.ON U.S. would support a competitive bidding process for transmission additions required to enhance reliability or to meet native load requirements.

b. Commission Determination

277. As discussed in the preceding section, the Commission will continue to support industry in the development of PBR but will not in the Final Rule impose it. Accordingly, we will not pursue performance treatments and competitive bidding. Moreover to the extent these proposals consist of penalties (which would not provide incentives to expand transmission infrastructure and would likely limit the investment in infrastructure by reducing the return—and therefore funds for capital expansions), they do not implement the requirements of section 219.

278. We note that the Commission has other regulations to address concerns over access and discrimination raised by commenters, including rules promulgated under Order No. 888, the anti-manipulation provisions of Order No. 672 [166] and market behavior rules. We believe those regulations provide adequate protections. Further, all rates that include incentives will remain in the zone of reasonableness, and, therefore, we disagree with the Delaware Commission that rates without penalties are not just and reasonable.

279. While the requirements of section 219 and the Final Rule do not encompass bidding processes, as recommended by the Missouri Commission and TAPS, we are sympathetic to the objective of the Missouri Commission to reduce the costs of expansions to consumers. We expect that regional planning processes that evaluate and compare the costs and benefits of expansion proposals, as well as state commission reviews and requirement that costs be prudently incurred will serve to provide the screening function desired by the Missouri Commission, and therefore additional processes are not necessary. We agree with NASUCA that there is merit in holding utilities receiving incentives accountable for investing the capital and building the capacity for which the incentives are provided, as we discuss further in section IV.A (Standard for Approval) and section III.D (Effective Date and Duration Of Effectiveness For Incentives). As we discuss further below in section IV.H (Public Power), we will not make TDU participation in the project a precondition for receiving incentives.

E. Advanced Technologies

1. General

a. Background

280. Pursuant to section 219(b)(3) of the FPA, the NOPR proposed to encourage the use of advanced technology in new transmission projects. Advanced transmission technologies are defined in section 1223 of EPAct 2005 to be technologies that increase the capacity, efficiency, or reliability of an existing or new transmission facility.[167] The Commission stated that it expected that the NOPR's proposed incentives, including the ROE-based incentives, will stimulate investment in new transmission facilities, which will, in turn, provide opportunities for the deployment of innovative technologies for those new transmission facilities.

281. The NOPR also asked for comments on: (1) Whether the Commission should require that applications for incentive-based treatment include a technology statement; (2) whether other incentives could fulfill the goals of section 219(b)(3); and (3) whether performance-based benchmarks for transmission costs (*i.e.*, a risk-sharing approach) would provide incentives for the deployment of advanced technologies.[168]

b. Comments

282. NRECA and others support the incentives proposed in the NOPR and do not support additional separate incentives for advanced technology. They believe that technologies will be developed when they are cost effective.

283. NEMA believes the technology list from section 1223 of EPAct 2005 should be incorporated into the Final Rule to ensure that the Commission's regulations express the intent of Congress. But, EEI argues that a predetermined list of advanced technologies would soon become outdated, which may discourage the use of other worthwhile technologies. Bonneville states that the list in the NOPR is incomplete and includes items that range from measures in common use today to very speculative items. AEP believes that any list of advanced technology should be illustrative and non-exclusive.

284. AEP and others want the Commission to encourage additional measures related to reliability and infrastructure development, including control center upgrades, national security-related infrastructure facilities vital to the electric system and operation, the refurbishment of aging transmission assets, advanced grid control technologies for real-time measurement, communications and control, ''non-wires'' alternatives to control or dispatch loads and resources for optimum use of the transmission and distribution infrastructure, inventories of transformers and other critical equipment, and substation upgrades.

285. Some commenters seek incentives for technologies that could indirectly mitigate congestion and enhance grid reliability. UTC Power believes the Commission should provide incentives for distributed generation, such as fuel cells. Sabey believes that advanced technology usage on the distribution system may provide transmission congestion relief. FirstEnergy suggests incentives for pumped storage hydro and compressed air energy storage.

286. NSTAR and Vectren urge the Commission to recognize the higher risk caused by accelerated obsolescence of transmission facilities. Obsolescence may be the result of the changing transmission technology. Accelerated depreciation could be relevant to a specific facility that may have a useful life less than its physical life due to obsolescence.

287. Some commenters, such as International Transmission, state that it is imperative that new technology installed on the grid be reliable and durable for decades. They express concern that new technologies may carry significant risks and may ultimately not be low cost and reliable.

c. Commission Determination

288. We agree with comments that new technologies will be adopted when they are cost effective. Incentives will be considered for advanced technologies through the same evaluation process as

[166] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 71 FR 8662 (Feb. 17, 2006), FERC Stats. & Regs., ¶ 31,204 (2006), *order on reh'g*, Order No. 672–A, 71 FR 19814 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006).

[167] Section 1223 identifies 18 such technologies and further provides that advanced transmission technologies include any other technologies that the Commission considers appropriate.

[168] NOPR at P 64–66.

other technologies, as discussed in this Final Rule.

289. We will not provide a unique incentive designed for a specific technology. To the extent that applicants seek additional incentives for advanced technologies, the Commission will consider the propriety of such incentives on a case-by-case basis.

290. Section 1223 of EPAct 2005 lists 18 advanced transmission technologies. We interpret this list as being illustrative of the kinds of technologies that Congress sought to encourage and not exclusive of advanced technologies that may be employed and considered for incentive ratemaking treatment. We expect new technologies to continually evolve. Moreover, as noted above, section 1223 of EPAct 2005 also provides that advanced transmission technologies include any other advanced transmission technologies that the Commission considers appropriate. Thus, we decline to adopt in the regulatory text a specific list of technologies eligible for incentive ratemaking, and will entertain proposals for incentives rate treatments for advance technologies on a case-by-case basis.

291. This includes technologies that may indirectly mitigate congestion and enhance grid reliability, if such technologies can be shown to increase the capacity, efficiency, or reliability of an existing or new transmission facility.

292. The Commission does not have sufficient information to make generic judgments about what barriers exist, if any, to the introduction of particular technologies based on the record. To the extent applicants believe additional incentives for advanced transmission technologies are needed, they must support such requests in individual cases.

293. In addition, we note that those applicants that do not want to use accelerated depreciation for all their facilities may elect to utilize this incentive for advanced technologies since the useful life of such technologies may not be sufficiently known. The Commission will also consider requests to recover the costs of obsolescent plant, thereby facilitating the addition of new, more technically advanced transmission infrastructure.

2. Case-by-Case Review

a. Comments

294. Ameren and others suggest the Commission should determine whether technology applications are just and reasonable on a case-by case basis, which would allow applicants flexibility to determine which technologies are best suited for a particular project.

295. National Grid believes the Commission should encourage the development of the best technology for particular needs identified in transmission owners' planning processes. This avoids putting the Commission in a position of picking winners and losers, but would allow transmission owners to make appropriate decisions relative to costs, benefits and risks associated with advanced technologies.

296. International Transmission suggests the Commission should determine what incentives are necessary to overcome barriers to deployment of the technologies defined in section 1223 of EPAct 2005, and then authorize those incentives on a case-by-case basis.

297. As an alternative to the case-by-case consideration of incentives, AEP recommends establishment of criteria for transmission investment to receive full incentive treatment. Such criteria might include: reducing congestion, advancing growth and security of the interstate grid, and providing an opportunity to site fuel diverse, newer technology, and environmentally friendly generation.

b. Commission Determination

298. The Commission will consider incentives for advanced technologies on a case-by-case basis. As discussed above, we are not making generic determinations regarding the applicability of incentives to particular technologies. Consistent with this case-by-case approach, we will not adopt AEP's suggestion to establish generic criteria for evaluating which transmission investments will receive full incentives. As discussed by Ameren and others, case-by-case review also provides flexibility to transmission providers in identifying the technologies that are most appropriate for their project applications and business models. It also avoids putting the Commission in a position of picking winners and losers, but allows transmission owners to make appropriate business decisions, as discussed by National Grid. The Commission in its reviews will provide incentives to technologies that increase the capacity, efficiency, or reliability of an existing or new transmission facility.

299. With regard to International Transmission's concerns, the Commission is not in a position to make generic judgments about what barriers exist, if any, to the introduction of particular technologies. To the extent applicants believe additional incentives for their advanced technology applications are needed, they can make a case for advanced technology incentives in their individual proceedings and the Commission will make a case-by-case determination.

3. Whether To Require A Technology Statement

a. Comments

300. TAPS and others believe the Commission should not require that a particular technology or the most advanced technology be used in order to qualify for incentives. They believe that a technology statement would add an unnecessary burden to applications and would likely result in Commission approval of imprudent and routine transmission investment. They also argue that statements made by an applicant would tend to be self-serving, and not detailed enough for proper Commission evaluation. Instead, the Pennsylvania Commission suggests that the Commission develop in-house technology expertise, or alternatively establish a peer review board of nationally recognized independent experts.

301. UTC Power believes the technology statement should also include a list of the advanced technologies capable of meeting the project goals for reducing congestion and increasing reliability, and reasons they were not employed. Duquesne supports a technology statement but does not believe that it should have to be specific as to describe all technologies that were considered and not used.

b. Commission Determination

302. In as much as EPAct 2005 requires the Commission to encourage the deployment of transmission technologies, we will require applicants for incentive rate-treatment to provide a technology statement that describes what advanced technologies have been considered and, if those technologies are not to be employed or have not been employed, an explanation of why they were not deployed.

4. Risk Sharing

a. Comments

303. CCAS suggests that the Commission offer a framework of cost sharing among entrepreneurs, ratepayers, utility shareholders and taxpayers, peer review and competitive solicitation to share and recover qualified research development and demonstration project costs through transmission rates. NEMA supports performance-based ratemaking as a means of enabling advanced technology

implementation for the sharing of benefits and risks between utilities and customers.

304. CAISO suggests that the Department of Energy and the Commission cooperate with the industry and reliability organizations on programs to identify, test, and disseminate information on new technology. APPA also suggests a process for the Commission to work with each region to develop a technology plan and a research and development budget, with costs to be recovered through regional transmission rates. Sabey encourages the Commission to provide incentives for technology demonstrations on small-to-medium scale projects.

305. NU and others suggests the Commission consider incentive ratemaking treatment of research and development dollars spent by utilities, which benefit the advancement of new technology. The Kentucky Commission believes in federal funding for research and that the Department of Energy is an appropriate sponsor for research in new transmission technology.

306. EPRI supports efforts to enhance grid infrastructure, and offers a list of advanced transmission technologies that are near term or commercially available, those that may be available for demonstration within four months with commercial availability in three to five years, and longer-term technologies still in the research and development stage with possible demonstration in three to five years.

b. Commission Determination

307. The Department of Energy is a more appropriate federal agency to promote research and development. Accordingly, research and development are beyond the scope of this proceeding, and we will not include incentive ratemaking for research and development costs in the Final Rule.

5. Other Technology-Related Issues

a. Comments

308. Semantic states that the Final Rule needs to define ''prudently-incurred'' costs that are to be recoverable and proposes that ''prudently-incurred'' be defined to include a substitution test such that expenditures are not made in excess of that which is required. By way of example, Semantic offer that an open RFP process for congestion relief should provide for separate pricing for the avoided cost value of each separable reliability benefit for which the reliability standards require action. This separate pricing of strategies for achieving the reliability and congestion goals must be compared to the summed cost of the advanced technology that can achieve the goals when determining prudence and just and reasonable rates. Semantic believes that such an approach results in greater efficiency in the use of the existing grid and the Final Rule should provide incentives other than ROE adders to foster such efficiency through the use of Advanced Transmission Technologies for time of day congested segments of the grid.

309. American Superconductor states that the Commission should revisit and clarify its Seven Factor Test for distinguishing between transmission and distribution facilities, to reflect technology advances made since the Commission adopted the Seven Factor Test. For example, American Superconductor states that it has developed dynamic VAR technologies that can effectively support transmission grids while connected to distribution facilities. Classification of such advanced technologies as transmission facilities would make them eligible for recovery under Commission-jurisdictional tariffs.

b. Commission Determination

310. We deny Semantic's request to define ''prudently-incurred'' as requiring an open RFP process to consider alternative technologies and to provide additional incentives to address time of day congestion. As previously stated, we expect that new development programs will include, or at least consider, advanced technologies, but we will not mandate it. We agree that improvements in the operation of the grid, perhaps through advanced technologies addressing time of day congestion, could result in efficiency benefits and encourage such proposals on a case-by-case basis.

311. We also deny American Superconductor's request to revisit our Seven Factor Test because it is beyond the scope of this proceeding.[169]

F. Transmission Organization Incentive

1. Background

312. The NOPR (at P 45) proposed that the Commission will continue to consider requests for ROE-based incentives for utilities that join an RTO, in recognition of the benefits such organizations bring to customers, as outlined in detail in Order No. 2000. In addition, it proposed that the Commission will consider similar requests by utilities that join an ISO for an incentive ROE that, while still in the zone of reasonableness, is higher than the ROE the Commission might otherwise allow if the utility did not join.

313. The NOPR (at P 46) also sought comment on whether the Commission should consider incentive-based ROE requests for public utilities that are not in an RTO but that join a Commission-approved regional planning organization.

2. Comments

314. Comments span a wide range of views on proposed incentive for utilities that join an RTO. Several commenters[170] support the proposal to continue to consider requests for ROE-based incentives for utilities that join a Transmission Organization. Most of these commenters also request that the incentive apply equally to both new members and existing members. They contend that denying an incentive to existing Transmission Organization members while awarding it to new members who join these organizations unfairly discriminates against those entities that should be rewarded for taking the initial step of establishing and joining an independent Transmission Organization and would therefore be contrary to good public policy, unjust, unreasonable, and unduly discriminatory. In addition, this discrimination could create an incentive for a transmission owner to depart from an existing RTO and to join a new RTO, simply to obtain the NOPR incentives ''for public utilities that join a Transmission Organization.'' PEPCO states that an adder should apply generally to all facilities for utilities in the RTO, not just to new investment after a new company joins an RTO.

315. Other commenters[171] contend that, if the Commission does allow an incentive for joining a Transmission Organization, the incentive should only apply going forward for new members, not for those who already joined. They argue that incentives should incite or spur a desired future action, and thus it makes no sense to provide incentives to transmission owners for past behavior or for actions that are likely to occur

[169] We note that if these technologies truly perform a transmission function, a more productive approach than modifying the Seven Factor Test may be to propose modification of the Uniform System of Accounts to reflect such plant in a new transmission-related plant account. But that is beyond the scope of this proceeding.

[170] *E.g.*, Ameren, EEI, Electric Power Supply, FirstEnergy, KCPL, MidAmerican, National Grid, NYSEG, NorthWestern, New England TOs, NSTAR, PEPCO, PacifiCorp, PG&E, PJM, PJM TOs, TransCanada, Trans-Elect, Vectren, and WPS.

[171] *E.g.*, Connecticut DPUC, Dairyland, Delaware Commission, NRECA, NECOE, NECPUC, New York Commission, SMUD, TANC, MISO States and TDU Systems.

under other normal business circumstances. Incentives for existing members would represent an unjustified windfall for utilities, at the expense of the transmission customers. In addition, the FPA does not permit the Commission to reward a utility ''in recognition'' of benefits for actions already taken by the utilities.

316. Some of these commenters also assert that the incentive should not apply where a transmission owner is ordered to join a RTO/ISO by statute or has agreed to join an RTO/ISO as a condition of receiving approval for a merger, market-based rates, or because of other regulatory actions. Also, possible incentives for joining an RTO, and the procedures for requesting such incentives, are already addressed in Order No. 2000.

317. Certain commenters [172] contend that the Commission should consider giving ROE incentives only to companies joining a newly forming Transmission Organization, rather than existing ones, and then only for a limited period of time; and if a public utility withdraws from an RTO or ISO for which it obtained an ROE adder for joining, the Commission should issue an order immediately eliminating such ROE adders.

318. Others request that the Commission make a generic finding that entities that join an ISO or RTO automatically qualify for the incentive. For example, Trans-Elect submits that the Commission can and should use the record developed in this proceeding to find, on a generic basis, that RTO/ISO membership produces sufficient customer benefits to qualify for the 50 basis-point ROE adder.

319. Some commenters [173] state that this incentive should not be limited to public utilities. It should apply to all transmitting utilities and electric utilities, including municipal utilities. Another view, that of Northwestern's, would have the Commission consider granting such incentives to transmission owners that are actively engaged in the development of an RTO or ISO, and permit transmission owners to recover prudently incurred costs of developing an RTO or ISO as they are incurred, in regions that do not currently have such an independent entity. American Wind strongly supports the objective to regionalize the grid, but believes that it would not serve the Commission's or Congress' goal to allow incentives to any type of Transmission Organization that is approved by the Commission for the operation of facilities. For example, American Wind states that single-system Transcos do nothing for regional goals.

320. Some commenters raise issues concerning the definition of a Transmission Organization. For example, Bonneville and PNM believe that incentives should be available to utilities that enter agreements or form transmission associations outside the specific models of RTOs or ISOs. MISO States contend that the Commission should not grant ROE incentives to utilities joining Transmission Organizations until these entities are more clearly defined. MISO States assert that the Commission currently has inadequately specified standards and requirements for ''independent transmission providers'' and no established standards or requirements for ''other transmission organizations.''

321. Some commenters seek some type of conditions/criteria for receiving the Transmission Organization incentive, including: Ongoing participation in an ISO that provides open access on the basis of competitive bids and that allocates the costs of grid access to users based on LMP; participation in the relevant ISO or RTO planning process such that the ISO or RTO will make a determination of need; or tying the incentives to whether the Transmission Organization has an effective regional planning process that results in the construction, not merely the identification, of transmission. Others suggest tying the level of the incentive to meeting certain criteria, including: A single sliding scale ROE adder mechanism which is tied to levels of independence; or a graduated incentive tied to important features of the Transmission Organization like degree of independence, range of functions, transparency of operations, openness of stakeholder forums, and geographic scope of the transmission planning area.[174]

322. Some commenters state that there should be penalties associated with a lack of participation in Transmission Organizations.[175] For example, they contend that: The ROE should be reflecting that service not provided by an ISO or RTO is less optimal; there should be a negative 50 basis point penalty on those public utilities that seek to withdraw from RTOs within the first 5 to 10 years of participation to recognize the costs paid by consumers to fund the public utility's participation; and there should be penalties for incumbent transmission owners that continue to frustrate RTO formation.

323. Some commenters oppose ROE-based incentives for joining an RTO or ISO.[176] Among other reasons, they state that: It has not been determined whether the benefits of participation in RTOs outweigh the costs, and, therefore, there is no justification for an incentive to encourage participation in RTOs; that the incentive is unwarranted because RTOs and similar organizations have a poor track record for getting new transmission built; that return incentives for RTO participation raise the already heavy RTO cost burden and add fuel to the concerns of state commissions and customers about RTO costs, thus undermining RTOs; that the risk of joining an RTO/ISO will already be reflected in the utility's return allowance; that joining an RTO/ISO is already lucrative, a fact that can be illustrated by the sound business conditions of the existing transmission owners' businesses in an RTO/ISO area in which transmission businesses will have guaranteed returns as a monopoly business; and that the incentive is not tied to actual new investments, and allowing an increased ROE on all transmission investment (including existing facilities) would merely drive up transmission rates.

324. According to PPC, EPAct 2005 is conspicuously silent regarding whether Transmission Organizations are desirable, and section 219(c) cannot fairly be read to authorize the Commission to provide incentives to the utilities that join such organizations that are greater than those incentives that are available to other, non-member utilities.

325. Several commenters support incentives for participation in a regional planning process that is not necessarily an RTO.[177] For example, PJM supports incentives for transmission owners' participation in robust regional transmission planning processes as an effective, collaborative and transparent means to ensure the development of economically efficient transmission projects that truly benefit customers. MidAmerican states that a strict requirement for public utility participation in an RTO or ISO could discourage certain transmission owners, particularly nonjurisdictional transmission owners, from regional participation under any structure. Bonneville states that modest financial incentives linked to construction of new facilities advocated by an independent

[172] *E.g.*, MISO States, NRECA, and TDU Systems.

[173] *E.g.*, CAISO, APPA, and NRECA.

[174] *E.g.*, SDG&E, CAISO, International Transmission, National Grid, and MISO States.

[175] *E.g.*, California Oversight Board, TDU Systems, and TransCanada.

[176] *E.g.*, APPA, NRECA, and TDU Systems.

[177] *E.g.*, Ameren, Southern Companies, SCE, PJM, and MidAmerican.

regional planning process may be sensible, but incentives must be tied to implementation of the regional plan, not just for mere participation in the organization.

3. Commission Determination

326. To the extent within our jurisdiction, we will approve, when justified, requests for ROE-based incentives for public utilities that join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization. However, we are not persuaded that we should create a generic adder for such membership, but instead will consider the appropriate ROE incentive when public utilities request this incentive. The decision in this rule to consider specific incentives on a case-by-case basis fulfills the Congressional mandate to the Commission.[178] Thus, issues concerning risk such as those raised by SMUD are more appropriately addressed in the proceedings that evaluate proxy companies and set a zone of reasonableness.

327. We will not make a generic finding on the duration of incentives that will be permitted for public utilities that join Transmission Organizations. An entity will be presumed to be eligible for the incentive if it can demonstrate that it has joined an RTO, ISO, or other Commission-approved Transmission Organization, and that its membership is ongoing. Any public utility receiving an incentive ROE for joining a Transmission Organization but that withdraws from such organization is no longer eligible for the ROE incentive.

328. We will not broaden or restrict the definition of Transmission Organization. For purposes of this Final Rule, and as defined in section 3(29) of the FPA, a Transmission Organization means a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities. We note that all RTOs and ISOs are already covered by this definition, and we will consider, on a case-by-case basis, applications for other types of entities to be classified as Transmission Organizations for purposes of whether membership warrants incentives under these provisions.

329. With respect to NorthWestern's argument that the Commission should consider incentives for the development of a Transmission Organization and permit recovery of prudently incurred costs of such development as they are incurred, the Commission will review applications for incentives in the context of filings for the creation of Transmission Organizations and determine the appropriate methods for recovery of costs on a case-by-case basis. With respect to comments suggesting specific criteria to qualify for the incentive (*e.g.*, participation in a planning process) or that the level of the incentive be tied to meeting certain criteria, we will not specify such criteria in this Final Rule.

330. Several comments urge that eligibility for these incentives not be limited to public utilities. However, the fact is that section 219(a) directs that this rulemaking provide incentives for ''public utilities'' and public utilities are the only entities whose rates are jurisdictional under sections 205 and 206 of the FPA. Further, although section 219(c) refers to incentives for ''transmitting utilities'' and ''electric utilities'' that join Transmission Organizations, it also contains the provision ''to the extent within its jurisdiction.'' Accordingly, the rule will apply to jurisdictional public utilities.[179] We clarify that this does not mean that public utilities are precluded from proposing incentive plans under section 205 whereby incentives would be given to public utilities as well as nonpublic utilities. Indeed, we encourage such plans. However, we would generally not have authority under sections 205 and 206 to enforce such incentives for the nonpublic utilities.

331. We also clarify that, as explained earlier, entities that have already joined, and that remain members of, an RTO, ISO, or other Commission-approved Transmission Organization, are eligible to receive this incentive. The basis for the incentive is a recognition of the benefits that flow from membership in such organizations and the fact continuing membership is generally voluntary.[180] Our interpretation of the statute is that eligibility for this incentive flows to an entity that ''joins'' a Transmission Organization and is not tied to when the entity joined. As some commenters note, to do otherwise could create perverse incentives for an entity to actually leave Transmission Organizations and then join another one. It would also be unduly discriminatory for the Commission to consider the benefits of membership in determining the appropriate ROE for new members but not for similarly situated entities that are already members.

332. We will not at this time establish a specific incentive for joining a Commission-approved regional planning organization. A regional planning process is very important to meeting regional transmission needs, and, we believe it will produce benefits for customers. For this reason, we have initiated a proposed rulemaking to require transmission providers to coordinate with interconnected systems when planning transmission system additions.[181] This increased coordination in regional planning proposed in the OATT Reform NOPR would be mandatory, not optional, and therefore we will not offer at this time an incentive for such coordination. However, if a region develops a planning processes that is superior to that required by the OATT reform rulemaking (such as by using an independent entity to perform system planning), nothing in this final rule would preclude entities in the region from requesting appropriate incentives under FPA section 219.

333. As stated earlier in this Final Rule, we will not adopt performance-based ROEs that reduce ROEs for transmitting utilities that do not join Transmission Organizations, as recommended by several commenters. The purpose of this rule is to provide incentives, per the requirements of section 219.

G. Recovery of Prudently Incurred Costs To Comply With Reliability Standards and Recovery of Prudently Incurred Costs Associated With Transmission Infrastructure Development

1. Background

a. Prudently Incurred Costs To Meet Mandatory Reliability Standards

334. Under FPA section 215 (Electric Reliability), an Electric Reliability

[178] We believe that the Commission's accounting and reporting procedures for RTOs, as required by Order No. 668, address commenters' concerns about the management of RTO costs. *See Accounting and Financial Reporting for Public Utilities Including RTOs*, Order No. 668, FERC Stats. & Regs. ¶ 31,199 (2005).

[179] We note that new section 211A gives the Commission authority to order transmission services by otherwise nonjurisdictional transmitting utilities. The Commission has never exercised authority under the new provision and the new provision provides limited rate authority. However, we leave open the possibility that incentives for otherwise nonjurisdictional transmitting utilities could be permitted in an order under section 211A.

[180] Our clarification also applies to utilities that joined RTOs or ISOs because of merger conditions or market-based rate requirements.

[181] *See* OATT Reform NOPR at 214.

Organization may propose, and the Commission may approve by rule or order, reliability standards.[182] Pursuant to section 219(b)(4)(A) of the FPA, the NOPR (at P 47) proposed to allow recovery of all prudently incurred costs necessary to comply with these mandatory reliability standards. Proposed new § 35.35(f) would allow for such recovery.

b. Prudently Incurred Costs Associated With Transmission Infrastructure Development

335. Under FPA section 216 (siting of interstate electric transmission facilities), the Commission has certain backstop siting authority for transmission facilities when the Secretary of Energy designates a geographic area experiencing electric transmission capacity constraints or congestion that adversely affects consumers as a National Interest Electric Transmission Corridor. Pursuant to section 219(b)(4)(B) of the FPA, the NOPR (at P 48) proposed to allow recovery of all prudently incurred costs related to infrastructure development pursuant to section 216. Proposed new § 35.35(g) would allow for recovery of such prudently incurred costs.

2. Comments

336. Several commenters raise issues applicable to both the mandatory reliability standard-related incentive and the infrastructure development-related incentive. For example, PJM TOs argue that the Commission should require that recovery of such prudently incurred costs be through stand-alone section 205 filings.

337. FirstEnergy and National Grid seek clarification that the NOPR is not revising existing policy on the recovery of prudently incurred costs and that there continues to be a presumption that investment is prudently made, with the burden of the challenging party to prove otherwise.

338. NRECA requests guidance from the Commission on what it considers to be prudently incurred costs. NRECA suggests the addition of a test to determine if the costs to comply with mandatory reliability standards and infrastructure development are just, reasonable and not unduly discriminatory, and that the Commission require participation in a regional planning process, with LSE participation.

[182] An Electric Reliability Organization is the organization certified by the Commission to establish and enforce reliability standards for the bulk power system, subject to Commission review. *See* Order Nos. 672 and 672–A.

339. Some commenters proffer specific examples they believe should be considered as prudently incurred reliability or infrastructure development costs. For example, AEP recommends the cost of control centers and national security infrastructure, and Semantic recommends substation tests as reliability costs.

340. East Texas and others caution the Commission to approve only the costs that are necessary to comply with mandatory reliability standards and for transmission infrastructure development. They express concern about the potential for rising costs to customers that may result from additional transmission investment.

341. APPA and others raise issues specific to recovery of prudently incurred costs to comply with mandatory reliability standards. APPA and other commenters agree that it is appropriate for the Commission to allow recovery of all prudently incurred costs to comply with mandatory reliability standards, and recommend the Commission clarify standards for determining that such costs are prudently incurred. TDU Systems suggest the Commission approve only prudently incurred costs to comply with mandatory reliability standards that are approved by a regional entity and in the context of a full FPA section 205 rate hearing or under a formula rate.

342. East Texas raises an issue specific to recovery of prudently incurred costs associated with infrastructure development. It requests that the Commission make explicit provisions in its transmission incentives rules for any actions that it may undertake under the new siting authority provided to it under section 216.

3. Commission Determination

343. The Commission will allow recovery of all prudently incurred costs necessary to comply with the mandatory reliability standards under section 215 and all prudently incurred costs associated with infrastructure development under section 216. In response to commenters, we further clarify that the Commission will review applications for the recovery of such prudently incurred costs under its section 205 procedures.

344. Some confusion may have been caused because the NOPR is more broadly related to transmission pricing reform and expresses the Commission's willingness to consider a variety of transmission pricing ''incentives'' to encourage the construction of new transmission. In many instances new investment in transmission may both improve reliability and reduce congestion. However, the NOPR specifically referred to recovery of ''prudently incurred costs'' in the context of the section 215 and 216-related expenses and investment. We take this opportunity to clarify that we are simply codifying our long standing regulatory policy that allows utilities the opportunity to recover all prudently incurred costs associated with the provision of transmission service in interstate commerce.

345. We deny NRECA's request that the Commission require participation in a regional planning process as part of the prudence review. As we have stated earlier in this rule, we will not make regional planning a precondition of receiving incentive ratemaking treatment. However, we expect and encourage participation in regional planning processes for all major transmission additions, including those within a designated national interest corridor.

346. In regard to commenters' specific examples of what they believe should be considered as prudently-incurred reliability or infrastructure development costs, we find it premature to develop such a list of pre-approved costs without proper consideration of the equipment involved and its application to the transmission system. This type of case-specific justification would be required from the applicant in its section 205 filing.

347. Similarly, we deny APPA's request to establish standards for determining that reliability standards compliance costs are prudently incurred. The Commission is making no change in the long-standing regulatory presumption in a section 205 proceeding that costs are prudently incurred, but parties are free to provide evidence to the contrary; and, ultimately, the burden is on the applicant to demonstrate that its proposal is just and reasonable.

348. We deny the request of East Texas that the Final Rule include explicit provisions for any actions the Commission may take with respect to the Commission's backstop siting authority under FPA section 216. This is beyond the scope of this rulemaking, which addresses only the recovery of prudently-incurred costs related to transmission infrastructure development pursuant to FPA section 216, not the Commission's backstop siting authority under that section. This issue is best addressed in the National Interest Electric Transmission Corridors proceeding in Docket No. RM06–12–000.

H. Public Power

1. Background

349. Given the importance of public power participation and the requirements of section 219, the NOPR (at P 63) requested comments on what actions the Commission should take in this rulemaking to encourage public power participation in new transmission projects. The NOPR asked, for example, whether the consortium approach would help to promote expansion of the transmission grid, and, if so, what types of incentives the Commission could provide to encourage such consortia.

2. Comments

350. Commenters express diverse views. Several commenters [183] express support for the consortium approach. For example, Connecticut DPUC states that the approach has appeal especially for very large transmission projects involving multiple states and that where there is agreement on the project, a sharing of the benefit incentives might be applicable. Similarly, Ameren and PJM state that public power involvement can be valuable and that the Consortium should receive the same incentives available to public utilities developing such projects. PJM supports a case-by-case approach for incentive rate treatment for these types of projects. EEI and MidAmerican offer that regardless of whether public power is involved, any member of the consortium should receive the same incentives that public utilities receive for building new projects. Upper Great Plains states that incentives should be available to all forms of joint projects, not just those arising from an RTO-led consortium.

351. Certain commenters [184] state that public power participation should not be mandated. New England TOs warn that requiring that utilities offer participation in transmission projects to certain pre-specified parties will be counter-productive. New England TOs state that there are other entities (*e.g.*, private equity, merchant transmission) who might have an interest in investing in a particular project and that the Commission has no basis for discriminating in favor of public power by giving it special investment rights and that doing so will create controversy.

352. Some of these same commenters that support the consortia [185] also support the Commission offering to public power entities the same incentives it is offering to jurisdictional public utilities, including Transcos. For example, AMP-Ohio states that the Commission should encourage arrangements that allow public power entities to obtain direct ownership. Wyoming Infrastructure Authority states that public power participation has demonstrably aided grid expansion projects to increase reliability and efficiency of the transmission grid.

353. Others propose limitations, including limiting incentives to those applicants offering third-party participation in projects.[186] Citizens Energy, for example, states that the Commission should require Transmission Organizations to adopt rules which ensure non-discrimination against merchant transmission. TransCanada proposes a specific process for merchant transmission. FirstEnergy states that public power participation should be permitted only when such entities have an OATT on file with the Commission. Still other commenters [187] state public power already enjoys various benefits over investor-owned utilities (*e.g.*, access to low-cost borrowing funds, ability to set own rates, tax advantages) and that the Commission should not further the rate advantages.

3. Commission Determination

354. We agree with comments that public power participation can play an important role in the expansion of the transmission system. We want to encourage public power participation in new transmission projects, but the ratemaking incentives we discuss in the Final Rule are generally not directly available to non-jurisdictional entities such as most public power entities, because they do not file their rates with the Commission. However, to the extent our jurisdiction allows, the Commission will entertain appropriate requests for incentive ratemaking for investment in new transmission projects when public power participates with jurisdictional entities as part of a proposal for incentives for a particular joint project.[188] Encouraging public power participation in such projects is consistent with the goals of section 219 by encouraging a deep pool of participants.

355. We will not specify which incentives might be most appropriate for encouraging participation by public power entities but instead will allow the applicants to make proposals that best suit their circumstances. We also clarify that the Commission's approval of an incentive plan proposed by a public utility that also pertains to an entity that is not otherwise jurisdictional under sections 205 and 206 (*e.g.*, public power), does not affect the non-jurisdictional status of the entity.

356. We will not, however, require public power or other joint participation in a transmission project in order for investment in a project to be eligible for incentives. While participation by a diverse group of investors might be the best structure for an individual project, it is inappropriate to mandate a particular joint-structure be used in all cases. However, we clarify that, to the extent allowed under our jurisdiction, a public power entity should have the same opportunity afforded to jurisdictional entities to recover costs related to new transmission investment.

357. We believe a consortium approach that includes public power and other entities for new investment has value and we encourage participation by public power in meeting the transmission infrastructure provisions of section 219. However, we will not require a consortium approach. We believe it is more appropriate for applicants to fashion proposals for new transmission infrastructure projects that are tailored to the specific circumstances and needs of a particular project. In addition, we believe a consortium-led proposal that is the result of an open, collaborative, regional process and that includes a diverse group of participants may face less resistance from parties when a filing is made here, because competing interests will have already been addressed before the proposal is filed with the Commission.

V. Reporting Requirement

A. Background

358. Section 35.35(h) of the proposed rule would require jurisdictional public utilities to report annually to the Commission no later than April 18, 2007, and, in succeeding years, on the date on which FERC Form No. 1 information is due the following data

[183] *E.g.*, Connecticut DPUC, PJM, Municipal Commenters, Semantic, Progress Energy, and Ameren Services.

[184] *E.g.*, KCPL, National Grid, International Transmission, New England TOs, NU, NYSEG, and SMUD.

[185] *E.g.*, AMP-Ohio, Ameren, CAISO, Municipal Commenters, Nevada Companies, Upper Great Plains, Powder River, Wyoming Infrastructure Authority and Snohomish.

[186] *E.g.*, TAPS, TANC, NECOE, Citizens Energy, TDU Systems, and Municipal Commenters..

[187] *E.g.*, KCPL and EEI.

[188] This is not to say that the Commission would not consider incentive ratemaking treatment for a consortium project that did not include public power participation. Nothing in this rule prevents jurisdictional entities from combining their resources on a project.

and projections: (subsection i) in dollar terms, actual investment for the most recent calendar year, and planned investments for the next five years; and (subsection ii) for all current and planned investments over the next five years, a project by project listing that specifies for each project the expected completion date, percentage completion as of the date of filing and reasons for delay. A draft Form X was provided in the Appendix.

359. In the NOPR (at P 49), the Commission stated that the purpose of the reporting requirement is to determine the effectiveness of the proposed rules and to provide the Commission with an accurate assessment of the state of the industry with respect to transmission investment.

B. Comments

360. A number of commenters [189] support the proposed Form X reporting requirement. For example, International Transmission states that such reports are important to determine if the investment incentives adopted by the Commission are actually working to elicit investment in transmission that benefits consumers. Some of these commenters make a number of recommendations, including the following: Define transmission investment for reporting; include separate categories for new generation interconnection versus other types of system upgrades; classify investments by voltage level to distinguish facilities that have little or nothing to do with the interstate transmission grid; exclude small, miscellaneous upgrades; provide instructions that Transmission Facilities in the table ''Capital Spending On Electric Transmission Facilities'' are defined as transmission assets under the Uniform System of Accounts in accounts 350 through 359; like the report with FERC Form No. 1; provide a list of categories for the ''Reasons for Delay'' column, such as siting, delayed completion of a new generator; report the consumer benefits of the project (*e.g.*, congestion relief, enhanced reliability); require the posting of the information on RTO, ISO, Transco or public utility Web sites or OASIS; require that all the reports be aggregated in one report that is made public, thereby providing manufacturers with a better basis to plan for industry needs.

361. Commenters also contend that the report does not go far enough. [190] Some [191] state that such reports should extend to all transmission providers, including those subject to new section 211A of the FPA and government-owned entities. Semantic asserts that the reporting requirements proposal is incomplete and does not adequately secure the comprehensive state of the grid information required by the regulators and market participants. Semantics would require that power systems state data must be made available in real-time to identify parallel flows and to avoid under-investment, over-investment or bad investments; that the report should provide for the filing of data that enables the Commission to fulfill its oversight responsibility for RTOs under § 35.34(k)(4) and to promote compliance with § 35.34(k)(1). Semantics further recommends that time of day rate schedules should be reported into a web-accessible national repository. Semantic explains that capital investment in advanced technologies will relieve congestion if this information is made known to technology vendors and entrepreneurial entities.

362. Certain commenters [192] that support the reporting also express concerns. For example, National Grid states the Commission should clarify that the forward-looking projections in Form X, rendered in good faith and upon a reasonable basis, would not subject the reporting transmission owners to claims of fraud, detrimental reliance or other liabilities arising from the fact that actual capital spending may vary from reported projections.[193] Ameren requests that the Commission clarify that the reported information is to be provided for informational purposes only and should not be allowed to form the basis of a review by the Commission or other entities regarding the reasonableness or prudence of the amounts reported. PG&E and the Nevada Companies assert that a disclaimer should be added to footnote 1 explaining that much of the information reported here may change over time and may be subject to correction. Trans-Elect asserts that the reporting requirement, alone, should not be allowed to form a basis for a section 206 investigation.

363. Some commenters raise confidentiality concerns.[194] EEI and KCP&L urge that the Commission afford Critical Energy Infrastructure Information (CEII) [195] status to this information since it clearly relates to the production, generation, transmission or distribution of energy, could be useful to a person planning an attack and gives strategic information beyond the location of critical infrastructure. EEI encourages the Commission to perform an evaluation as to the need for confidentiality of selected company information due to the commercially sensitive nature of the information. Similarly, Ameren and TransElect request that the Commission clarify that the required information may be submitted pursuant to the Commission's confidential filing procedures.[196]

364. A number of commenters oppose the reporting requirement for a variety of reasons. Several [197] claim that the Commission has not provided adequate justification for the Form X data collection, as required by the Paperwork Reduction Act, given that the Commission already collects information on utility transmission investment and planning in existing FERC Form Nos. 1, 714 and 715 and that the Commission has not demonstrated the need to make the information collection mandatory. Ameren, AEP and PJM TOs state that the requested information duplicates information already being compiled by RTOs in their planning process; and MISO States suggest that the Commission obtain an aggregate report from the RTO. PJM TOs recommend that Form No. 1 requirements be modified prospectively, instead of requiring a new form. EEI is concerned that the Commission, state commissions and the public may inappropriately rely on the information, expecting the plans to be implemented without regard to the regulatory approvals and applicant and market decisions involved. EEI further states that reporting information on planned future facilities can lead to unnecessary opposition that might not occur with a proper public siting process, lead to speculation in land use fees that can harm the applicant's customers.

365. EEI, arguing that the only accurate measure of the effectiveness of

[189] *E.g.*, International Transmission, NRECA, APPA, National Grid, AEP and TAPS, Siemans, and NEMA.

[190] *E.g.*, International Transmission, Northwestern, Siemans, NEMA, and Semantic.

[191] *E.g.*, International Transmission, EEI, Northwestern, and KCP&L.

[192] *E.g.*, National Grid, Ameren, PG&E, and Nevada Companies.

[193] *See* Section 27A of the Securities Act of 1933, as amended; Section 21E of the Securities Exchange Act of 1934, as amended; 15 U.S.C. 77z–2 and 78u–5; 17 CFR 240.3b–6.

[194] *E.g.*, TransElect, EEI, KCP&L, and Ameren.

[195] They cite *Critical Infrastructure* Information, Order No. 630, 68 FR 9857 (March 3, 2003), FERC Stats. & Regs. ¶ 31,140 (2003), *order on reh'g*, Order No. 630–A, 68 FR 46,456 (Aug. 6, 2003), FERC Stats. & Regs. ¶ 31,147 (2003).

[196] *See* 18 CFR 388.112.

[197] *E.g.*, EEI, Southern, SCE, KCP&L, Nevada Companies, Progress Energy, Mid-American and PG&E.

the incentives is the number of applications filed for incentives, encourages the Commission to simply monitor the number of applications for new transmission facilities, the magnitude of the facilities involved and the incentives sought and thereby obtain the most accurate measure of the effectiveness of the proposed incentives. EEI also encourages the Commission to rely on annual aggregate transmission investment information that EEI has provided to the Commission and can continue collecting for the Commission's benefit. Nevada Companies assert this information should not be required since it is inaccurate and incomplete.

366. Southern, SCE and Ameren propose limitations on the information to be provided as follows: Only aggregate information should be required, and project-specific information should not be required since it is extremely burdensome, entails security and confidentiality issues, and is subject to change; if project-level information is required, that it be limited to major transmission projects, *i.e.*, 345 kv and above; and limit project-specific reporting requirements to only projects costing $20 million or more and that are subject to a Transmission Organization's or a regional planning organization's planning and approval process.

C. Commission Determination

367. To ensure that these rules are successfully meeting the objectives of section 219, the Commission needs industry data, projections and related information that detail the level of investment. The rule's purpose is to both provide new investment as well as ensure that customers benefit. Thus, information regarding projected investments as well as information about completed projects will help the Commission to monitor the success of the ratemaking reforms announced in this rule. Thus, the Commission will adopt the proposed reporting requirement Form X and designate it as the FERC–730. Further, the Commission will make certain modifications to clarify when reports must be filed and what data must be submitted in FERC–730 reports.[198] The information required in FERC–730 is not available from Form Nos. 1, 714 or 715, nor is it available from other federal agencies. For instance, FERC Form No. 1 requires the reporting of historical financial data but does not contain forward looking projections of expected transmission investments.[199] Thus, the information sought is not already readily available and will be required only from public utilities that have been granted incentive rate treatment for specific transmission projects under the provisions of § 35.35.

368. We agree with commenters that, for some utilities, the information requested is similar to information submitted to RTOs. However, the Commission does not receive that information, and the information provided to RTOs may not be identical to the information requested here. Therefore, to ease the administrative burden, those utilities providing information to RTOs can submit the same information to the Commission. We strongly encourage utilities that submit FERC–730 reports to do so in an electronic format via eFiling.[200] To rely on information collected by EEI, as recommended, would not provide the Commission with the accurate information we need to assess the effectiveness of our regulations under section 219. The Commission would not have available to it the survey instruments or the analysis behind the reported information. Thus, reliance on second-hand gathered survey information for the purposes of rate setting would not provide the independent, factual basis to allow the Commission to make a determination that continuing incentives is appropriate. Likewise, the summary investment information available in existing reports does not provide information on projected investment or reasons for delays in projects, thereby limiting its value for determining the effectiveness of the rules.

369. We do not believe a CEII designation is required for this information since it is expected to only include information on capital spending and a general designation of the project name, without requiring data on facility location. With respect to confidential treatment of FERC–730, as a general matter we do not believe that this type of general planning information involves commercially sensitive information. However, while we will require applicants to provide capital spending projections and other information in their applications, we also recognize that applicants may have legitimate reasons to maintain confidentiality of certain information. For this reason, applicants can request protection of information under § 388.112.

370. With respect to project-level information, this information is needed to determine the status of critical projects and reasons for delay, and will play a role in the Commission's evaluation of continuing incentives. To facilitate this review, we will require that filers specify which projects are currently receiving incentives in the project detail table and that they group together those facilities receiving the same incentive. We will not limit the information to projects above a certain voltage, since lower-voltage projects can have significant impacts on reliability and congestion relief, nor will we limit the information to projects subject to a Transmission Organization's or a regional planning organization's planning and approval process since we are addressing a national problem and complete coverage is therefore necessary. As discussed earlier in this rule, projects eligible for incentives—and hence required to submit data—are not restricted to projects or investments that result from regional planning processes. We agree with SCE that a minimum dollar threshold of $20 million is a reasonable level for reporting of significant projects.

371. We agree with many of the recommendations for modifications to the tables as shown in the revised FERC–730 in the Appendix. We will not require the reporting of consumer benefits of projects. In order for these projects to have received an incentive, the project must have met the requirements of this rule, which includes that it benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. We will not require the addition of operating data to the table since the sole purposes of the information collection is to determine the level of capital spending, the status of significant and critical projects and reasons for delay. We will not require a Proposed Operating Date, as recommended by Ameren, since our sole concern with this information is that the planned projects are completed on time; operational start-up issues such as synchronization with the grid and testing introduce additional issues not directly relevant to tracking the progress of investments in new infrastructure.

372. Further, we will not require year-by-year capital spending estimates for

[198] FERC–730 filers are reminded that each FERC–730 filing must be accompanied by a Subscription consistent with the requirements of 18 CFR 385.2005(a).

[199] *See e.g.*, FERC Form No. 1 schedule pp. 204–7, ''Electric Plant in Service (Accounts 101, 102, 103 and 106)'' which requires the reporting of the original cost of electric plant in service and p. 216, ''Construction Work in Progress—Electric (Account 107)'' which requires the reporting of expenditures for certain construction projects at December 31 of the reporting year.

[200] The Commission will issue a separate notice on how to submit this data electronically via eFiling.

the project detail table as recommended by TAPS since the goal of the rule is not to ensure the achievement of annual capital spending targets but rather to ensure the overall project is completed, and if not, the reasons for the delay. We will not require the inclusion of cost allocation or pricing information as recommended by TAPS since that information is beyond the scope of our requirements. We do not see the need for a disclaimer that information is subject to change, since the required information is clearly labeled ''projected'' and ''expected'' and therefore assumed to be subject to change. Since this rulemaking applies to public utilities and incentives are being permitted pursuant to sections 219 and 205, which pertain to public utilities, we will not require information from entities that are not jurisdictional under section 205, although such entities are encouraged to voluntarily provide this information. We clarify that the meaning of ''On Schedule'' in the Project Detail table is the most up-to-date, expected project completion date.

373. We clarify that the reported information is to be provided for informational purposes only, and its purpose is not to establish the prudence of the amounts spent. As we specified earlier in the rule, we expect applicants will propose metrics and provide a nexus between the incentive and the investment, and therefore the information in this report will not be the sole basis for a section 206 investigation. We further clarify that the projections in FERC–730, rendered in good faith and upon a reasonable basis, would not subject the reporting transmission owners to claims of fraud, detrimental reliance or other liabilities arising from the fact that actual capital spending may vary from reported projections.

374. Rather than requiring all public utilities to submit FERC–730, we clarify that only those public utilities that have been granted incentive-based rate treatment for specific transmission projects under the provisions of § 35.35 must file FERC–730 in the manner prescribed in Appendix A. A public utility is subject to the FERC–730 reporting requirement beginning with the year the Commission issues an order in response to a filing made pursuant to section 205 of the Federal Power Act, or in a petition for a declaratory order that precedes a filing pursuant to section 205. The initial FERC–730 filing is due by April 18 of the following calendar year and subsequent filings are due each April 18 thereafter.

375. In addition, we will add a new provision to § 35.35(h) and delegate to the Chief Accountant or the Chief Accountant's designee authority to act on requests for extension of time to file FERC–730 or to waive the requirements applicable to any FERC–730 filing.

376. Finally, we find the data issues raised by Semantic to be beyond the scope of this rulemaking. While the data requested by Semantic could provide a useful purpose for the operations and management of electric facilities and may have applicability to the Commission's regulations for RTOs, this rulemaking is limited to an evaluation of incentives for investment in electric transmission facilities. Therefore, the reporting requirements of the rulemaking are appropriately limited to data on industry investment.

VI. Other Issues

A. Rate Related Issues

1. Rate Related Issues

377. Commenters also raised other rate issues such as formula rates, rate design, the five-month suspension policy and recovery of other costs. The Commission addresses these issues below.

a. Comments on Formula Rates

378. As an alternative to single-issue ratemaking, certain commenters urge the Commission to require recovery of incentives through various forms of formula rates.[201] Certain MISO TOs state that the Commission should facilitate recovery from wholesale and retail customers including bundled and unbundled retail load through a formula rate for new investments. Certain MISO TOs cite section 219 of the FPA to argue that Congress required the Commission to ensure the recovery of *all* prudently incurred costs necessary to comply with mandatory reliability requirements and related to transmission infrastructure development.[202]

379. EEI argues that the section 205 filing for a public utility with a formula rate should be limited to including appropriate language in the formula rate allowing the utility to get the incentives and not be the basis to challenge any other aspect of the formula rate.

b. Comments on Rate Design

380. Several commenters urge the Commission to require applicants to seek rolled-in treatment, rather than participant funding, to recover any costs incurred under the rule.[203] Those commenters assert that participant funding is inequitable because it imposes too much of a system burden on limited customers and that participant funding may actually discourage investment.

381. Other commenters support participant funding for projects.[204] They argue that socialization unfairly requires others to pay for facilities that they do not need and may deter new investment. Xcel requests that the Commission provide clear guidance on the issue of ''rolled in'' versus ''incremental'' pricing. Xcel states that the Commission should allow phased roll-in of transmission facilities as it does for natural gas pipelines because rolled-in pricing would encourage proper siting of generation.

382. EEI states that the Commission should be open to proposals that deviate from the ''higher of'' policy where justified.

383. Other commenters express support for regional or zonal rates.[205] They argue that regional rates would foster new projects because the rates would match cost recovery to the broad regional benefits obtained and reduce opposition from local consumers and state regulators and litigation.

c. Comments on Five-Month Suspension

384. EEI, SCE and Xcel argue that the Commission's current suspension policy hinders transmission investment because delaying the effective date of rates forces a utility to absorb the costs associated with the new facilities during the suspension period, thereby effectively reducing that utility's return on equity. Additionally, EEI argues that, because any rate increase authorized by the Commission could be made subject to refund, with interest, customers could be made whole even without a five-month suspension. SCE suggests that the Commission should either change the threshold for determining when rates are excessive or use a sliding scale that would impose a longer suspension the larger the excessive revenues.

d. Other Comments on Rate Design

385. Commenters raised a variety of rate design issues. Energy Capital states that the Commission must modify traditional ratemaking practices to recognize the risks and structures required to fund a single line transmission project. SCE states that an

[201] *E.g.*, APPA, AWEA, KKR, MDU, PG&E, Certain MISO TOs, and TAPS.

[202] Certain MISO TOs state that all costs of new investment should include the costs of facilities built by the company as well as the costs of facilities allocated to the company through a RTO transmission cost allocation process.

[203] *E.g.*, East Texas, TDU Systems, and TAPS.

[204] *E.g.*, NorthWestern, Progress, Southern Companies, PSEG, and E.ON US.

[205] *E.g.*, TAPS and Upper Great Plains.

additional disincentive to transmission investment is the imputation of revenues from grandfathered agreements that are greater than the actual revenues under the agreements, thereby reducing the earned return for transmission tariff service. TAPS faults the Commission's policy of excluding EPRI dues from transmission rates because wholesale customers may make their own direct contributions. Trans-Elect requests the Commission to confirm that all financing costs, including prepaid liquidity reserve and working capital costs required by the lender as a condition to financing, are recoverable in rates.

e. Commission Determination

386. We agree with several commenters that formula rates can provide the certainty of recovery that is conducive to large transmission expansion programs.[206] Moreover, formula rates alleviate the need for other relief sought by commenters. For example, public utilities with formula rates will generally be able to flow through increased transmission investment without concern as to the Commission's five-month suspension policy with the exception of the suspension period for approval of initial rates. While we continue to encourage public utilities to explore the benefits of filing transmission-related formula rates,[207] we will not require public utilities to use formula rates to recover incentives.

387. We disagree with the interpretation that section 219 requires the Commission to claim jurisdiction over the transmission component of bundled retail load. While MISO TOs are correct that section 219 requires the Commission to ensure the recovery of all costs prudently incurred for section 215 reliability compliance and section 216 national interest corridor investments, we do not believe it is necessary to assert jurisdiction over bundled retail transmission to fulfill this statutory requirement.[208]

388. The rate design issues raised in the comments are beyond the scope of this proceeding.[209] While rate designs can impact infrastructure investment, this rule is limited to addressing incentive treatments that foster infrastructure investment. Interested parties may raise issues associated with rate design policies in the associated section 205 filings in which applicants are seeking rate recovery of transmission incentives.

389. We will not revise our five-month suspension policy in this proceeding. To the extent that public utilities are concerned that the Commission's suspension policy unnecessarily delays recovery of prudent costs, there are alternative means to ensure such recovery. As mentioned previously, formula rates enhance cost recovery certainty. Further, public utilities that are concerned that a particular rate increase may be deemed ''excessive'' under our suspension policy may use our pre-filing process for discussing those concerns.

390. We will not make the determination on Energy Capital's proposal that the Commission modify its traditional ratemaking practices to recognize unique aspects of non-traditional transmission owners because the issues raised are novel and we would be better informed with an actual proposal before us. Regarding SCE's concern about imputing the transmission revenues under grandfathered agreements using the OATT rate, this issue is beyond the scope of this proceeding.

391. We shall deny TAPS proposal to reconsider our policy on recovery of EPRI research and development costs when the unbundled retail load takes service under the same transmission rate as wholesale customers.[210] That is beyond the scope of this proceeding.

392. The Commission will remain flexible with respect to rate treatments proposals that applicants or interested parties can demonstrate to be just and reasonable.

393. We will deny the request to confirm in this proceeding that prepaid liquidity reserve and working capital costs required by project lenders as a condition to financing are recoverable. Those issues were the subject of an Administrative Law Judge's Initial Decision in Docket No. ER05–17–002 and are pending Commission review. Those issues are better addressed in that proceeding because that proceeding has a complete litigated record.

394. We also find that EEI's request that the Commission use this rule to revisit ''and'' pricing to be beyond the scope of this rule.

B. Section 35.34

1. The Proposal To Eliminate Section 35.34(e)

a. Background

395. The NOPR proposed that applicants for incentive ratemaking treatment under section 35.35 would not be required to support their applications with cost-benefit analyses. The NOPR also proposed to eliminate § 35.34(e), which requires cost-benefit analyses by RTO applicants in order to avoid potential conflict between or overlap of the pre-existing regulations and the new § 35.35.

b. Comments

396. Several comments specifically addressed the NOPR's proposal to eliminate § 35.34(e). TDU Systems do not oppose elimination of § 35.34(e), so long as the consumer protections embodied in that section are incorporated into a new rule adopted to replace it. TDU Systems argues that adoption of the conditions and criteria it recommends (*i.e.*, public power participation in planning, financing and construction, and rolled-in rate treatment for expansions of network facilities) would ensure that these protections remain in place. TAPS, APPA and Industrial Consumers support retention of the cost-benefit provision for reasons given in their comments on the cost-benefit issue.

397. NRECA supports the Commission's proposal. Public utilities have had the opportunity for five years now to form RTOs and obtain transmission rate incentives for RTO membership. In light of the fact that it is yet to be demonstrated that the benefits of RTOs outweigh their cost, elimination of this provision is appropriate.

398. MISO supports the elimination of § 35.34(e), because it will be superfluous and unnecessary if the NOPR is adopted. Moreover, MISO points out that the authorization for RTOs to

[206] We will not rule on PG&E's proposed rate base tracking mechanism here because we do not have an actual proposal with supporting documents before us.

[207] *Allegheny Power System Operating Companies*, 111 FERC ¶ 61,308 at P 51 (2005). *See also Allegheny Power System Operating Companies*, 106 FERC ¶ 61,003 at P 32 (2004) (''The parties may explore whether adopting formula rates for recovery of the costs of both the TOs' existing transmission facilities and new transmission facilities would be best. Specifically, we note that other TOs that we have approved incentive rates for also have formula rates.'').

[208] We will not add the term ''all'' to the regulatory text in 18 CFR 35.35(f) and (g) as recommended by Certain MISO TOs. The text in those sections reflects the language in section 219 of the FPA and therefore meets the Commission's compliance requirements.

[209] We will not retain 18 CFR 35.34(e) in the new regulations as requested by MISO States. However, the new regulations allow RTOs to propose alternative incentives in 18 CFR 35.35(d)(1)(iii) and under these new regulations, RTOs may propose the incremental pricing provisions previously included in 18 CFR 35.34(e).

[210] The Commission has explained that, when the basis for calculating the amount of the voluntary contribution to EPRI for research and development is based on the amount of retail sales, recovery from wholesale customers is unreasonable. *See Public Service Company of New Mexico*, Opinion 133, 17 FERC ¶ 61,123 at 61,249 (1981), *order on rehr'g*, Opinion No. 133–A, 18 FERC ¶ 61,036 (1982).

include innovative rate treatments in their rates found in § 35.34(e) expired after January 1, 2005, with respect to transmission rate moratoriums and rates of return that do not vary with capital structure.

399. Ameren Services does not oppose the Commission's proposal to remove existing section 18 CFR 35.34(e) from its regulation. This is consistent with the mandate of new FPA section 219 to provide incentives for qualifying entities. Ameren Services contends that removal of § 35.34(e) will avoid confusion that could arise from potential conflicts between innovative rate treatments available under existing § 35.34(e) and the additional incentives proposed to be adopted in new § 35.35.

400. MISO States generally support the elimination of § 35.34(e). However, MISO States point out that § 35.34(e) appears to contain a provision that permits RTOs to apply for incremental pricing for new transmission facilities in association with an embedded-cost access fee for existing transmission facilities. Such a provision does not appear to be encompassed in the language of the Commission's proposed new § 35.35 rule. MISO States believe that such a provision could prove useful in certain circumstances and urges the Commission not to drop this provision in the transition process of deleting the elements in § 35.34(e) and replacing them with the new elements in § 35.35.

401. NorthWestern opposes preferential treatment based on corporate structure. It argues that if the Commission does remove § 35.34(e) as proposed, it should make certain that its resulting policies provide the appropriate non-preferential treatment.

c. Commission Determination

402. Comments opposing the elimination of the cost-benefit analysis requirement are addressed above in our determination to affirm the NOPR on the cost-benefit issue.

403. MISO States expresses concern that the proposed new § 35.35 does not appear to encompass the provision in pre-existing § 35.34(e)(v) allowing RTOs to apply for incremental pricing for new transmission facilities in association with an embedded-cost access fee for existing transmission facilities. The deletion of § 35.34(e) is intended to eliminate potentially conflicting or overlapping regulations concerning requests for incentive rate treatment. Thus, for example, the deletion of § 35.34(e) eliminates potential confusion over whether a proposal would be an ''innovative'' rate treatment (and require a cost-benefit analysis) under the pre-existing rules or be an incentive rate treatment requirement (with no cost-benefit analysis) under the new rules.

404. In Section IV.D. of this preamble in our determination segment, we find that we do not have a sufficient basis to adopt rules for PBR in this rule. Notwithstanding that determination not to enumerate PBR in the list of incentive rate treatments, we also state that we remain open to consider PBR proposals as an incentive rate treatment pursuant to section 219. Given that determination, and to avoid potential conflict or overlap with the rules adopted herein, we believe that removal of the pre-existing PBR provisions—§§ 35.34(e)(2)(v) and 35.34(e)(3)—is appropriate.

405. We address NorthWestern's comment that the Commission should not favor any particular corporate structure in the discussion of the Transco incentives, *supra* Section IV.

VII. Information Collection Statement

406. The Office of Management and Budget (OMB) regulations require approval of certain information collection requirements imposed by agency rules.[211] The Commission is submitting these reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[212] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502–8415, fax: (202) 273–0873, e-mail: *michael.miller@ferc.gov*].

407. Public Reporting Burden: The Commission did not receive specific comments concerning its burden estimates and uses the same estimate here. Comments on the proposed reporting requirement (proposed in the NOPR as Form X) are addressed above in Section V, Reporting Requirements, where we adopt the FERC–730 information collection requirement. The comments received and our adoption of FERC–730 do not lead us to revise the NOPR's estimates of the public reporting burden.

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
FERC–516:				
Transcos	30	1	296	8,880
Traditional Public Utilities	200	1	181	36,200
FERC–730	200	1	30	6,000
Totals	230	1	222	51,080

Total Annual Hours for Collection: (Reporting + Recordkeeping, (if appropriate)) = 51,080 hours.

Information Collection Costs: The Commission sought comments about the time and corresponding costs needed to comply with these requirements. No comments were received. Costs for FERC–516 and FERC–730 = $6,129,600 (51,080 hours at $120 an hour). (The hourly rate was determined by taking the median annual salary from Bureau of Labor Statistics, Department of Labor Occupational Outlook Handbook. The figures reported by BLS are for 2002 and added to them was an inflation factor of 4.73 percent for the period January 2003 through December 2004.)

Title: FERC–516 ''Electric Rate Schedule Filings'', FERC–730 ''Report of Transmission Investment Activity''.

Action: Proposed Collections.

OMB Control No.: 1902–0096; and to be determined.

Respondents: Business or other for profit.

[211] 5 CFR 1320.13 (2005).

[212] 44 U.S.C. 3507(d) (2000).

Frequency of Responses: On occasion for applicants and annually for transmission investment report.

Necessity of the Information: The Final Rule amends the Commission's regulations to implement the statutory provisions of section 1241 of EPAct 2005. The Act directs the Commission to establish incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities in order to benefit consumers by ensuring reliability and reducing the cost of delivered power by relieving transmission congestion. This mandate addresses an identified need to encourage construction of transmission infrastructure and encourage investment. Sufficient supplies of energy and a reliable way to transport those supplies are necessary to assure reliable energy availability and to enable competitive markets. Without sufficient delivery infrastructure, some suppliers will not be able to enter the market, customer choices will be limited, and prices may be needlessly higher or volatile. The implementation of incentive and performance-based rate treatments supports the Commission's mandate to support investments in transmission capacity to reduce the cost of delivered power by reducing congestion.

408. Entities seeking incentives to build new transmission facilities must file under Part 35 of the Commission's regulations, an application describing how the entity will bring benefits to the grid. The information provided for under Part 35 is identified as FERC–516. The information for actual and planned investments as proposed in an annual report is identified as FERC–730 and the information is provided for under § 35.35(h) of the Commission's regulations.

409. Comments on the final rule may also be sent to the Office of Management and Budget. For information on the requirements, submitting comments on the collection of information and the associated burden estimates including suggestions for reducing this burden, please send your comments to the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 (Attention: Michael Miller, Office of the Executive Director, (202–502–8415) or send comment to the Office of Management and Budget (Attention: Desk Officer for the Federal Energy Regulatory Commission, fax: 202–395–7285, e-mail: *oria_submission@omb.eop.gov.*, and please reference this rulemaking docket no. in your submission.

VIII. Environmental Statement

410. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[213] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[214] Thus, we affirm the finding we made in the NOPR that this Final Rule is procedural in nature and therefore falls under this exception; consequently, no environmental consideration would be necessary.

IX. Regulatory Flexibility Act Certification

411. The Regulatory Flexibility Act (RFA) [215] requires that a rulemaking contain either a description and analysis of the effect that the Final Rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities. However, the RFA does not define ''significant'' or ''substantial'' instead leaving it up to any agency to determine the impacts of its regulations on small entities. The Final Rule will not have a significant adverse impact on a substantial number of small entities. The Final Rule applies only to entities that own, control, or operate facilities for transmitting electric energy in interstate commerce and not to electric utilities per se. Small entities that believe this Final Rule will have a significant impact on them may apply to the Commission for waivers.

X. Document Availability

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

413. From the Commission's Home Page on the Internet, this information is available in the eLibrary. The full text of this document is available on eLibrary both in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

414. User assistance is available for eLibrary and the Commission's Web site during normal business hours. For assistance, please contact Online Support at 1–866–208–3676 (toll free) or 202–502–6652 (e-mail at *FERCOnlineSupport@FERC.gov*), or the Public Reference Room at 202–502–8371, TTY 202–502–8659 (e-mail at *public.referenceroom@ferc.gov*).

XI. Effective Date and Congressional Notification

415. This Final Rule will take effect September 29, 2006. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of the Office of Management and Budget, that this rule is not a major rule within the meaning of section 251 of the Small Business Regulatory Enforcement Fairness Act of 1996.[216] The Commission will submit the Final Rule to both houses of Congress and the Government Accountability Office.[217]

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission.

Magalie R. Salas,

Secretary.

■ In consideration of the foregoing, the Commission amends part 35 of Chapter I, Title 18, *Code of Federal Regulations*, as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

Subpart F—Procedures and Requirements Regarding Regional Transmission Organizations

§ 35.34 [Amended]

■ 2. In § 35.34, remove and reserve paragraph (e).

■ 3. A new subpart G is added to read as follows:

[213] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47897 (1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[214] 18 CFR 380.4(a)(2)(ii).

[215] 5 U.S.C. 601–612 (2000).

[216] 5 U.S.C. 804(2) (2000).

[217] 5 U.S.C. 801(a)(1)(A) (2000).

Subpart G—Transmission Infrastructure Investment Provisions

§ 35.35 Transmission infrastructure investment.

(a) *Purpose.* This section establishes rules for incentive-based (including performance-based) rate treatments for transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.

(b) *Definitions.* (1) *Transco* means a stand-alone transmission company that has been approved by the Commission and that sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility.

(2) *Transmission Organization* means a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities.

(c) *General rule.* All rates approved under the rules of this section, including any revisions to the rules, are subject to the filing requirements of sections 205 and 206 of the Federal Power Act and to the substantive requirements of sections 205 and 206 of the Federal Power Act that all rates, charges, terms and conditions be just and reasonable and not unduly discriminatory or preferential.

(d) *Incentive-based rate treatments for transmission infrastructure investment.* The Commission will authorize any incentive-based rate treatment, as discussed in this paragraph (d), for transmission infrastructure investment, provided that the proposed incentive-based rate treatment is just and reasonable and not unduly discriminatory or preferential. A public utility's request for one or more incentive-based rate treatments, to be made in a filing pursuant to section 205 of the Federal Power Act, or in a petition for a declaratory order that precedes a filing pursuant to section 205, must include a detailed explanation of how the proposed rate treatment complies with the requirements of section 219 of the Federal Power Act and a demonstration that the proposed rate treatment is just, reasonable, and not unduly discriminatory or preferential. The applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219, that there is a nexus between the incentive sought and the investment being made, and that resulting rates are just and reasonable. For purposes of this paragraph (d), incentive-based rate treatment means any of the following:

(1) The Commission will authorize the following incentive-based rate treatments for investment by public utilities, including Transcos, in new transmission capacity that reduces the cost of delivered power by reducing transmission congestion or ensures reliability, and is otherwise just, reasonable and not unduly discriminatory or preferential, as demonstrated in an application to the Commission:

(i) A rate of return on equity sufficient to attract new investment in transmission facilities;

(ii) 100 percent of prudently incurred Construction Work in Progress (CWIP) in rate base;

(iii) Recovery of prudently incurred pre-commercial operations costs;

(iv) Hypothetical capital structure;

(v) Accelerated depreciation used for rate recovery;

(vi) Recovery of 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors beyond the control of the public utility;

(vii) Deferred cost recovery; and

(viii) Any other incentives approved by the Commission, pursuant to the requirements of this paragraph, that are determined to be just and reasonable and not unduly discriminatory or preferential.

(2) In addition to the incentives in § 35.35(d)(1), the Commission will authorize the following incentive-based rate treatments for Transcos, provided that the proposed incentive-based rate treatment is just and reasonable and not unduly discriminatory or preferential:

(i) A return on equity that both encourages Transco formation and is sufficient to attract investment; and

(ii) An adjustment to the book value of transmission assets being sold to a Transco to remove the disincentive associated with the impact of accelerated depreciation on federal capital gains tax liabilities.

(e) *Incentives for joining a Transmission Organization.* The Commission will authorize an incentive-based rate treatment, as discussed in this paragraph (e), for public utilities that join a Transmission Organization, if the applicant demonstrates that the proposed incentive-based rate treatment is just and reasonable and not unduly discriminatory or preferential. Applicants for the incentive-based rate treatment must make a filing with the Commission under section 205 of the Federal Power Act. For purposes of this paragraph (e), an incentive-based rate treatment means a return on equity that is higher than the return on equity the Commission might otherwise allow if the public utility did not join a Transmission Organization. The Commission will also permit transmitting utilities or electric utilities that join a Transmission Organization the ability to recover prudently incurred costs associated with joining the Transmission Organization, either through transmission rates charged by transmitting utilities or electric utilities or through transmission rates charged by the Transmission Organization that provides services to such utilities.

(f) *Approval of prudently-incurred costs.* The Commission will approve recovery of prudently-incurred costs necessary to comply with the mandatory reliability standards pursuant to section 215 of the Federal Power Act, provided that the proposed rates are just and reasonable and not unduly discriminatory or preferential.

(g) *Approval of prudently incurred costs related to transmission infrastructure development.* The Commission will approve recovery of prudently-incurred costs related to transmission infrastructure development pursuant to section 216 of the Federal Power Act, provided that the proposed rates are just and reasonable and not unduly discriminatory or preferential.

(h) *FERC–730, Report of transmission investment activity.* Public utilities that have been granted incentive rate treatment for specific transmission projects must file FERC–730 on an annual basis beginning with the calendar year incentive rate treatment is granted by the Commission. Such filings are due by April 18 of the following calendar year and are due April 18 each year thereafter. The following information must be filed:

(1) In dollar terms, actual transmission investment for the most recent calendar year, and projected, incremental investments for the next five calendar years;

(2) For all current and projected investments over the next five calendar years, a project by project listing that specifies for each project the most up-to-date, expected completion date, percentage completion as of the date of filing, and reasons for delays. Exclude from this listing projects with projected costs less than $20 million; and

(3) For good cause shown, the Commission may extend the time within which any FERC–730 filing is to

be filed or waive the requirements applicable to any such filing. The authority to act on motions for extensions of time to file FERC–730 or to waive the requirements applicable to any FERC–730 filing, including granting or denying such motions, in whole or in part, is delegated to the Chief Accountant or the Chief Accountant's designee.

(i) *Rebuttable presumption.* The Commission will apply a rebuttable presumption that an applicant has met the requirements of section 219 for:

(1) A transmission project that results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission;

(2) A project that has received construction approval from an appropriate state commission or state siting authority; or

(3) A proposed project that is located in a National Interest Electric Transmission Corridor pursuant to section 216 of the Federal Power Act.

Note: The following appendices will not be published in the *Code of Federal Regulations*.

Appendix A—FERC–730, Report of Transmission Investment Activity

Company Name: ____

TABLE 1.—ACTUAL AND PROJECTED ELECTRIC TRANSMISSION CAPITAL SPENDING

Capital spending on electric transmission facilities [1] ($ thousands)	Actual at December 31,	Projected investment (incremental investment by year for each of the succeeding five calendar years)				
	20__	20__	20__	20__	20__	20__
.						

[1] Transmission facilities are defined to be transmission assets as specified in the Uniform System of Accounts in account numbers 350 through 359 (*see*, 18 CFR Part 101).

TABLE 2.—PROJECT DETAIL [1]

Project description [2]	Project type [3]	Expected project completion date (month/year)	Completion status [4]	Is project on schedule? ′(Y/N)	If project not on schedule, indicate reasons for delay [5]
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[1] Respondents must list all projects included in the actual and projected electric transmission capital spending table, excluding those projects with projected costs less than $20 million.
[2] Project description should include voltage level.
[3] Project types are New Build, Upgrade of Existing, Refurbishment/Replacement, or Generator Direct Connection.
[4] Completion status designations are Complete, Under Construction, Pre-Engineering, Planned, Proposed, and Conceptual.
[5] Reasons for delay designations are Siting, Permitting, Construction, Delayed Completion of New Generator, or Other (specify).

Appendix B—Commenters on the NOPR

Public Utilities and Trade Associations

Ameren Service Company (Ameren)
American Electric Power System Corporation (AEP)
American Transmission Companies (American Transmission)
WestConnect Public Utilities (WestConnect)
Baltimore Gas and Electric Company (BG&E)
California Independent System Operator Corporation (California ISO)
Certain Midwest ISO Transmission Owners (Certain MISO TOs)
Citizens Energy Corporation (Citizens Energy)
Consumers Energy Company (Consumers Energy)
DTE Energy Company (DTE Energy)
Duquesne Light Company (Duquesne)
E.ON U.S. LLC (E.ON US)
Edison Electric Institute (EEI)
Electric Power Supply Association (EPSA)
FirstEnergy Service Company (FirstEnergy)
Gridwise Alliance (Gridwise)
International Transmission Company (International Transmission)
ISO New England (ISO-NE)
Kansas City Power & Light Company (KCPL)
MidAmerican Energy Company (MidAmerican)
Midwest Independent Transmission System Operator, Inc. (Midwest ISO)
Montana-Dakota Utilities (Montana-Dakota)
National Grid USA (National Grid)
Nevada Power Company and Sierra Pacific Power Company (Nevada Companies)
New England Transmission Owners (New England TOs)
New York Independent System Operator, Inc. (New York ISO)
New York Electric & Gas Corporation and Rochester Gas & Electric Corporation (NYSEG and RGE)
Northeast Utilities (NU)
NorthWestern Corporation (NorthWestern)
NSTAR Electric & Gas Corporation (NSTAR)
Pacific Gas and Electric Company (PG&E)
PacifiCorp
Pepco Holdings, Inc., et al. (Pepco)
PJM Interconnection, LLC (PJM)
PJM Transmission Owners (PJM TOs)
Progress Energy, Inc. (Progress Energy)
PSEG Companies (PSEG)
Public Service Company of New Mexico and Texas-New Mexico Power Company (PNM and TNMP)
San Diego Gas & Electric Company (SDG&E)
Southern California Edison Company (SCE)
Southern Company Services, Inc. (Southern Companies)
Trans-Elect, Inc. (Trans-Elect)
United Illuminating Company (United Illuminating)
WPC Companies (WPS)
Xcel Energy Services, Inc. (Xcel)

Public Power Entities and Associations

American Municipal Power-Ohio, Inc. (AMP-Ohio)
American Public Power Association (APPA)
Bonneville Power Administration (Bonneville)
California Department of Water Resources State Water Project (CADWR)
CAPX Utilities (CAPX Utilities)
Community Power Alliance
Dairyland Power Cooperative (Dairyland)
East Texas Cooperatives (East Texas)
Hamilton, Ohio, et al. (Municipal Commenters)
Imperial Irrigation District (Imperial)
Los Angeles Department of Water and Power (LADWP)
National Rural Electric Cooperative Association (NRECA)
New England Consumer-Owned Entities (NECOE)
New York Association of Public Power (NY Association)
Public Power Council (PPC)
Public Utility District No. 1 of Snohomish County, Washington (Snohomish)
Sacramento Municipal Utility District (SMUD)
Transmission Access Policy Study Group (TAPS)
Transmission Agency of Northern California (TANC)

Transmission Dependent Utility Systems (TDU Systems)
Upper Great Plains Transmission Coalition (Upper Great Plains)
Wyoming Infrastructure Authority

State Commissions and Other State Entities

California Electricity Oversight Board (California Oversight Board)
Public Utilities Commission of the State of California (California Commission)
Committee on Regional Electric Power Cooperation (CREPC)
Connecticut Attorney General (Connecticut AG)
Connecticut Department of Public Utility Control (Connecticut DPUC)
Delaware Public Service Commission (Delaware Commission)
Kentucky Public Service Commission (Kentucky Commission)
Long Island Power Authority and Long Island Lighting Company (LIPA)
Maryland Public Service Commission (Maryland Commission)
Missouri Public Service Commission (Missouri Commission)
National Association of Regulatory Commissioners (NARUC)
National Association of State Regulatory Consumer Advocates (NASUCA)
New England Conference of Public Utility Commissioners (NECPUC)
New Jersey Board of Public Utilities (New Jersey Board)
New Mexico Attorney General (New Mexico AG)
New York Public Service Commission (New York Commission)
North Dakota Industrial Commission (North Dakota Commission)
Oklahoma Corporation Commission (Oklahoma Commission)
Organization of MISO States (MISO States or OMS)
Pennsylvania Public Utility Commission (Pennsylvania Commission)
Wyoming Office of Consumer Advocate (Wyoming Consumer Advocate)

Others

American Superconductor Corporation (American Superconductor)
American Wind Energy Association (AWEA)
Babcock & Brown, L.P. (Babcock & Brown)
Coalition for the Commercial Application of Superconductors (CCAS)
Consumer Energy Policy of America (CECA)
Electric Power Research Institute (EPRI)
Energy Capital
Energy Financing, Inc. (Energy Financing)
Industrial Consumers [ELCON, et al.] (Industrial Consumers)
JH2 Risk Advisors (JH2)
Kohlberg Kravis Roberts & Co. (KKR)
National Electrical Manufacturers Association (NEMA)
Norton Energy Storage (Norton)
Powder River Energy Corporation (Powder River)
Sabey Corporation (Sabey)
Semantic Applications, Inc. (Semantic)
Siemens Power Transmission & Distribution (Siemens)
Steel Manufacturers Association (Steel Manufacturers)
TransCanada Pipelines Limited (TransCanada)
UTC Power
Vectren Corporation (Vectren)

Reply and Supplemental Comments

EEI
International Transmission
KKR
National Grid

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