

required by Congress through the Omnibus Budget Reconciliation Act of 1986 (“Budget Act”).³ The IRC believes the time has come for the Commission to reexamine its prior holdings⁴ concerning its assessment methodology. Additions to the Commission’s mission, as prescribed by Congress in the Energy Policy Act of 2005 (“EPAAct 2005”),⁵ as well as changes in the fundamental assumptions which gave rise to the Commission’s prior rulings, support a reexamination of the assessment methodology and rule change at this time in order to satisfy Congress’ “fair and equitable” mandate and end the discriminatory allocation methodology presently in use. The IRC respectfully submits that, with the benefit of an additional four years of experience since the last time the Commission examined its assessment program, it is now clear that the assumptions underlying the current program have not materialized, and circumstances in the industry have sufficiently changed to require a new and different approach to the Commission’s assessment methodology to remedy the discriminatory impact of the present fee assessment structure. Moreover, immediate reform is needed to remedy a clear disincentive to RTO participation in contravention of Congress’ directive to provide incentives to continued RTO participation.⁶

³ 42 U.S.C. § 7178 (2000).

⁴ *E.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 103 FERC ¶ 61,048, *order denying reh’g*, 104 FERC ¶ 61,060 (2003), *aff’d* 388 F.3d 903 (D.C. Cir. 2004); *Revision of Annual Charges to Public Utilities (California Independent System Operator)*, 101 FERC ¶ 61,043, *order dismissing reh’g*, 101 FERC ¶ 61,326 (2002).

⁵ Energy Policy Act of 2005, Pub. L. No. 109-58, Title XII, 119 Stat. 594, 941-986 (2005) (codified in relevant part at 16 U.S.C. §§ 824 *et seq.*).

⁶ 16 U.S.C. § 824s(c).

Specifically, as the electric power markets have continued to evolve since the adoption of Order No. 641,⁷ and particularly with respect to developments over the last several years (including passage of EAct 2005), the Commission's method of allocating the costs of its electric regulatory program has become increasingly unfair and inequitable to members of RTOs and ISOs and as a result is discriminatory in its application.⁸ Two features of the current methodology lie at the heart of the problem. First, the Commission's current assessment methodology includes the bundled retail load of both jurisdictional and non-jurisdictional public utilities taking service over transmission lines under the functional control of RTOs and ISOs. In contrast, for public utilities operating outside of RTOs and ISOs, the bundled retail loads for these entities are excluded under the current methodology. This results in an unduly discriminatory, unfair and inequitable distribution of Commission regulatory costs to RTO and ISO members.

Second, the added scope of the Commission's authority granted in EPACT 2005 – in particular, the Commission's new authority and considerable increase in responsibility over reliability matters under new Federal Power Act Section 215,⁹ along with the

⁷ *Revision of Annual Charges Assessed to Public Utilities*, Order No. 641, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,109 (2000), *order on reh'g*, Order No. 641-A, 94 FERC ¶ 61,290 (2001).

⁸ FERC fees, although assessed to RTOs, are ultimately paid by market participants including load serving entities. Through these comments, the IRC raises these concerns in recognition of the burden that the present allocation methodology has placed on the individual members of the constituent RTOs and ISOs.

⁹ 16 U.S.C. § 824o.

resulting costs – has significantly exacerbated the discriminatory impact of the present allocation methodology on RTOs and ISOs.

As a result, RTOs and ISOs bear a disproportionate, and ever-growing, share of the Commission’s annual charges. Indeed, based on 2006 figures, RTOs and ISOs accounted for roughly 54% of U.S. peak load, but were assessed nearly 83% of FERC’s total annual charges. For example, as discussed in greater detail below, members of Southwest Power Pool (“SPP”) were assessed over \$9.0 million in 2005 annual charges; the same entities would have incurred, cumulatively, only \$1.4 million in charges had they operated independently of the RTO. The cause of this disparity is the inclusion of bundled retail load for members of RTOs and ISOs under the current methodology. The disparity and resulting inequity, already impacting two-thirds of the United States population, will continue to grow as regulatory program costs increase. Consequently, the time has come for the Commission to change the manner in which its regulatory fees are allocated to ensure a more fair, equitable and non-discriminatory allocation between entities operating within an RTO or ISO and those operating outside of such organizations.

The IRC therefore urges the Commission to consider alternative methodologies that will eliminate the disparate assessments currently borne by ISOs and RTOs. One possible approach would capture, within the scope of assessable volumes, all reportable energy transmitted across the electric grid, either by using volumes reported on Form 582 (subject to amending the Form 582 reporting requirements to include bundled retail load for non-RTO/ISO transmission providers) or by using peak load data, as reported in FERC Form 1. However, whichever methodology is adopted should separately account

for costs incurred by the Commission in connection with the implementation of mandatory reliability standards, per Section 215 of EPAct. Such reliability-related costs should be identified and assessed to *all* users, owners and operators of the bulk-power system. The IRC provides specific comments below on alternative approaches that would address these concerns and otherwise satisfy the Congressional mandate for “fair and equitable” fee assessments.

Background

The Commission’s authority to assess annual charges arises under the Budget Act, enacted in 1986. Section 3401(a)(1) of the Budget Act requires the Commission to assess and collect amounts equal to all of the costs incurred by the Commission in the relevant fiscal year using a methodology that is “fair and equitable.”¹⁰ Following enactment of the Budget Act, the Commission adopted Order No. 472,¹¹ under which annual charges

¹⁰ 42 U.S.C. § 7178(b) (2000). The Conference Report accompanying passage of the Budget Act provided the following guidance on the “fair and equitable” standard:

- (1) the type of Commission regulation which applies to such person such as a gas pipeline or electric utility regulation; (2) the total direct and indirect costs of that type of Commission regulation incurred during such year; (3) the amount of energy – electricity, natural gas, or oil – transported or sold subject to Commission regulation by such person during such year; and (4) the total volume of all energy transported or sold subject to Commission regulation by all similarly situated persons during such year.

Conf. Rep. No. 99-1012 at 238 (1986), *reprinted in* 1986 U.S.C.C.A.N. 3868, 3883.

¹¹ *Annual Charges under the Omnibus Budget Reconciliation Act of 1986*, Order No. 472, 1986-1990 FERC Stats. & Regs., Regs. Preambles ¶ 30,746, *clarified*, Order No. 472-A, 1986-1990 FERC Stats. & Regs., Regs. Preambles ¶ 30,750, (continued)

were assessed based on each jurisdictional utility's total wholesale volume of long-term firm sales and transmission and short-term sales and transmission and exchanges.

In 2000, the Commission proposed to change its annual charge regulations to account for "sweeping changes" within the industry – most notably, the implementation of open-access transmission and functional unbundling, as well as the accelerated trend toward market-based rate power sales following the promulgation of Order Nos. 888 and 2000. The Commission found that "the time and effort of our electric regulatory program is now increasingly devoted to assuring open and equal access to public utilities' transmission systems,"¹² and on that basis adopted Order No. 641 to change to an assessment methodology which calculates charges based solely on transmission volumes.¹³ Under Order No. 641, transmission associated with bundled retail sales was exempt from annual charge assessments; however, within the RTO/ISO context, Order No. 641 included the entire load, including bundled retail load, in the total transmission volume subject to annual charge assessments. The same disparity is true for load served by non-jurisdictional entities operating within an RTO or ISO versus those who operate independently of a regional organization.

order on reh'g, Order No. 472-B, 1986-1990 FERC Stats. & Regs., Regs. Preambles ¶ 30,767; *order on reh'g*, Order No. 472-C, 42 FERC ¶ 61,013 (1988).

¹² *Revision of Annual Charges Assessed to Public Utilities*, Notice of Proposed Rulemaking, IV FERC Stats. & Regs., Proposed Regs. ¶ 32,550, at 33,920 (2000) ("Order No. 641 NOPR").

¹³ The Commission's assessments for its electric program are based on the total volume of a utility's (1) unbundled wholesale transmission; (2) unbundled retail transmission; and (3) bundled wholesale power sales which have embedded a jurisdictional transmission component.

In the course of the Order No. 641 rulemaking, several parties, including members of the IRC, pointed out the disproportionate impact of the new assessments on RTOs and ISOs. These parties argued that the Commission’s proposed allocation of program costs between utilities that have or have not joined RTOs or ISOs – and, in particular, the bundled retail load exemption for non-RTO/ISO utilities – unfairly imposed a much larger percentage of Commission costs on RTO/ISO members. The Commission rejected these arguments, stating that “it is our expectation that *all* individual public utilities (and others, as well) will join RTOs...”¹⁴ On this assumption, the Commission concluded that there was “no unfairness as between some individual public utilities and others in terms of assessment of annual charges.”¹⁵ On rehearing, the Commission again declined to modify its assessment methodology.¹⁶

Upon the Commission’s first application of its new assessment methodology in 2002, RTO and ISO members expected their assessments to increase; however, many RTOs and ISOs observed that their annual charges were far higher than anticipated – in some cases, by over 400%.¹⁷ Accordingly, upon receipt of the 2002 invoices, and following the Commission’s decision not to grant rehearing of these invoiced charges, the Midwest ISO, the New York ISO, and PJM petitioned the Commission to initiate a new rulemaking for the purpose of reexamining the annual charge assessments. The joint

¹⁴ Order No. 641 at 31,855 n.68 (emphasis added).

¹⁵ *Id.* at 31,855.

¹⁶ Order No. 641-A, 94 FERC ¶ 61,290 (2001).

¹⁷ *See* Request for Rehearing of New York Independent System Operator, Inc., Docket No. RM00-7-003, at 1, 9 (Aug. 14, 2002).

petitioners argued that, as RTOs, their annual charge assessments should, if anything, be lower than non-RTOs. The petition requested that the Commission return to the Order No. 472 approach of assessing electric regulatory program costs to power sales as well as to transmission.

The Commission denied the joint petition for rulemaking,¹⁸ finding that petitioners were effectively seeking untimely rehearing of Order No. 641. The Commission also indicated that its regulatory focus was continuing to trend increasingly toward transmission and that assessing annual charges to power sales was no longer compatible with the agency's resource and workload allocation. On rehearing, the Commission again declined to revisit its assessment charge methodology, stating that its focus "has not to date substantially changed since we prescribed our current method of assessing electric annual charges."¹⁹ The D.C. Circuit Court of Appeals affirmed the Commission,²⁰ finding that it owed heightened deference to the agency on decisions involving rulemaking requests, but reminding the Commission of its promise to reconsider the annual charge regulations "***if the resource-allocation assumptions underlying Order No. 641 prove false.***"²¹

Since the Court issued its opinion in *Midwest ISO v. FERC*, RTO development and expansion has virtually ceased and states have slowed and even retreated on their

¹⁸ *Midwest Indep. Transmission Sys. Operator, Inc.*, 103 FERC ¶ 61,048 (2003).

¹⁹ *Midwest Indep. Transmission Sys. Operator, Inc.*, 104 FERC ¶ 61,060 (2003).

²⁰ *Midwest ISO v. FERC*, 388 F.3d at 906.

²¹ *Id.* at 913 (emphasis added).

retail deregulation processes.²² This represents a major change in the basic assumptions underlying the Commission’s rationale for adopting the Order No. 641 methodology. In apparent recognition of these developments, the Commission issued the instant NOI on April 21, 2008 and invited public comments on each of the following questions:

- 1) Whether the current electric annual charges assessment methodology remains a fair and equitable method for recovering FERC’s electric regulatory program costs;
- 2) If the current electric annual charges assessment methodology is no longer a fair and equitable method, what alternative methodology is fair and equitable; and
- 3) For any such alternative methodology, what entities should be assessed electric annual charges and how such an alternative methodology would work.

The following comments address each of these questions.

IRC Comments

A. The Current Methodology Does Not Constitute A Fair and Equitable Approach To Allocating Recovery of the Commission’s Electric Regulatory Program Costs and is Discriminatory In Its Application.

In adopting Order No. 641, the Commission based its assessment methodology on several assumptions regarding the evolution of the electric power industry, including an increased focus on open access transmission, functional unbundling, increases in market-based rate sales of electric power and continued retail unbundling efforts at the state level.²³ In addition, and of particular significance, was the anticipated growth in RTO

²² See, e.g., Energy Information Administration, “Status of Electric Restructuring by State,” (Data as of Apr. 2007), http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html (indicating that 8 states have suspended programs to restructure retail electric markets and only 15 states have restructured their retail electric markets as of April 2007).

²³ NOI at P 7.

and ISO participation and the mitigative effect of such growth on the allocation of annual charge assessments.²⁴

These assumptions have not survived the test of time. To the contrary, the expectation of substantial RTO growth and accelerated retail unbundling – two factors that would have tempered the disproportionality problem and spread the burden of annual assessments more equitably – have not come to pass. Thus, the actual implementation of the Commission’s current fee assessment structure has operated in a manner that was neither anticipated nor intended by the Commission, particularly when viewed in the context of the reforms mandated by the EAct 2005 and related regulatory initiatives.

1. The Commission’s Rationales and Justifications for the Order No. 641 Methodology Have Not Materialized

Many of the foregoing facts were presented to the Commission (and the Court) in the prior proceedings but were found to have been raised too soon after implementation of Order No. 641 to warrant initiation of a new rulemaking. However, these facts are now firmly established. Indeed, there is no anticipation that significant additional load will be coming under the operational control of existing RTOs and ISOs in the near future, and efforts in non-RTO/ISO areas to create such organizations (*i.e.* the Southeast, Southwest and Northwest), have completely ceased as the courts have ruled compliance with Order No. 2000 to be strictly voluntary.²⁵ Similarly, the Commission’s predictions regarding state level unbundling have largely failed to materialize, with several states abandoning – and in some cases reversing – their retail unbundling initiatives since the

²⁴ See *supra* note 14.

²⁵ *Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607, 616 (D.C. Cir. 2001).

issuance of Order No. 641.²⁶ The Commission itself has also abandoned its standard market design proposal.²⁷

Today, roughly half of the nation's electricity flows occur within an RTO footprint – hardly the outcome of 100% RTO participation that the Commission anticipated and assumed when it decided to impose the bulk of its regulatory costs on RTOs and ISOs. These changed circumstances, or rather the lack of progress in the development in regional organizations that the Commission predicted, have rendered Order No. 641's assessment methodology discriminatory to RTO and ISO participants and, more generally, non-compliant with the Budget Act's "fair and equitable" requirement.

2. *The Commission's Current Assessment Structure is Unduly Discriminatory and Inequitable Because It Places a Disproportionate Burden on RTOs and ISOs*

As discussed above, the discriminatory impact of the present methodology is magnified for RTOs and ISOs by the fact that transmission associated with bundled retail load served within their footprint is included in the transmission volume against which Commission assessments are levied while bundled retail load served by non-RTO/ISO utilities is not.²⁸ In addition, volumes attributable to the retail load of non-jurisdictional

²⁶ See *supra* note 22.

²⁷ *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, 112 FERC ¶ 61,073 (2005).

²⁸ Notably, the Commission includes retail load volumes when allocating its fees to RTOs and ISOs irrespective of whether the retail load has been unbundled under state law. As a result, the Commission has gone far beyond its holding in Order 888, which only extended its jurisdictional reach over a finite subset of retail load – *i.e.*, retail load unbundled under state retail choice laws.

entities within RTOs and ISOs are subject to annual charge assessments, while corresponding volumes outside of RTOs and ISOs are not. The practical effect of these disparities is to increase the burden for transmission-owning members of RTOs and ISOs unfairly and without any economic or cost-causation justification. This result is neither “fair” nor “equitable” and therefore contravenes the Budget Act’s statutory mandate.

The conversion of SPP to an RTO in 2004 provides a telling example of how the bundled retail load disparity contributes to the inherent inequities of the current methodology. In fiscal year 2005, approximately 185 million MWh in the SPP footprint were subject to Commission assessments under Order No. 641. By contrast, if the transmission-owning members of SPP operated outside of an RTO, the total energy volume subject to Commission assessment would be less than 29 million MWh. This translates to a difference of almost \$8 million – an increase of over 600% – of additional assessments levied against SPP’s members than would have occurred had they not participated in an RTO.²⁹

Because RTOs and ISOs are assessed the vast majority of the costs of the regulatory program, and in turn pass along those charges to their customers and/or transmission-owning members, the current assessment methodology hardly promotes voluntary RTO participation and is at odds with Congress’ directive to the Commission to provide incentives for RTO development.³⁰ In particular, the disparity undermines

²⁹ See Attachment A.

³⁰ 16 U.S.C. § 824s(c).

Order No. 2000 and the Commission's specific objective³¹ of promoting nation-wide participation in RTOs through "favorable ratemaking treatments . . . which should, at a minimum, eliminate any rate disincentives to RTO formation."³² The magnitude of the problem is borne out by recent data: in 2006, for example, RTOs and ISOs were responsible for approximately 83%³³ of the Commission's electric regulatory assessments despite serving only roughly 54% of the peak load volume during that time.³⁴

3. *As Directed by the Court of Appeals, the Time Has Come for Reassessment of the Order No. 641 Methodology.*

What has resulted from Order No. 641 is an unbalanced and discriminatory cost allocation methodology. The Commission's annual fees continue to be allocated based on numerical calculations that bear no relationship to the activities giving rise to the underlying costs or the manner in which those costs are allocated to those entities on whose behalf the Commission's services are provided.

Given the divergence between Commissions' assumptions underlying its decision in Order No. 641 and actual experience, the time to reconsider the Order No. 641

³¹ *Regional Transmission Organizations*, Order No. 2000, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,089, at 30,993 (1999) ("***Our objective*** is for all transmission-owning entities in the nation, including non-public utility entities, to place their transmission facilities under the control of appropriate RTOs in a timely manner.") (emphasis added), *order on reh'g*, Order No. 2000-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,092 (2000), *petitions for review dismissed sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

³² Order No. 2000 at 31,034.

³³ See Attachment B.

³⁴ The 54% figure was calculated by including ERCOT peak load and non-jurisdictional peak load in the denominator, but excluding ERCOT and non-jurisdictional, non-RTO/ISO load from the numerator.

methodology has come. In fact, in rejecting an RTO attempt to revisit Order No. 641 charges in 2004, the Court of Appeals for the D.C. Circuit upheld the Commission's assessment methodology, but mandated that the Commission "reconsider its system of charges if the resource-allocation assumptions underlying Order No. 641 prove false."³⁵ Three and one-half years hence, it has become clear that many of the forward-looking assumptions underlying the Order No. 641 charge allocation methodology have not come to pass, thereby rendering the program unfair and inequitable, as well as unduly discriminatory. Additionally, the passage of EAct 2005 – and in particular the expansive applicability of new FPA Section 215 – has created Commission regulatory costs which cannot be disproportionately allocated to RTO and ISO regulation within the strictures of the "fair and equitable" standard.

The notion that the Commission would become increasingly focused on transmission-related regulation versus regulation of wholesale sales, although somewhat accurate, does not tell the whole story as to the scope of the Commission's activities, particularly given Congress' recent assignments to the Commission in EAct 2005 related to the repeal of the Public Utility Holding Company Act ("PUHCA"), authority over transmission siting and reliability. In addition, the Commission has devoted substantial resources to designing and redesigning its approval and review process for requests to sell wholesale power at market-based rates.³⁶ Likewise, as the NOI

³⁵ *Midwest ISO v. FERC*, 388 F.3d at 913.

³⁶ *See, e.g., Market-Based Rates for Wholesale Sales of Electric Energy, Capacity, and Ancillary Services by Public Utilities*, Order No. 697, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, 123 FERC ¶ 61,055 (2008); *AEP Power Marketing Inc.*, 107 FERC ¶ 61,018, *order on reh'g*, 108 FERC ¶ 61,026 (2004); *see also* NOI at P 20.

recognizes,³⁷ the Commission has expended significant effort to establish market rules and mitigation rules for wholesale power sales, create enforcement and investigation mechanisms for ensuring compliance with market rules, and implement new EAct 2005 authority over mergers and sanctioning power against market manipulation. These efforts are more closely tied to wholesale power sale activities, rather than solely transmission-related activities, suggesting that the Commission’s regulatory efforts, although still emphasizing transmission, may not be as singularly focused on the strict provision of transmission service as the Order No. 641 fee allocation methodology would imply.

As the Commission moves forward in implementing the mandates of the EAct 2005, the Order No. 641 assessment methodology, if unchanged, will continue to burden RTO and ISO participants in an unduly discriminatory fashion. Enactment of the EAct has imposed upon the Commission new nationwide reliability and planning responsibilities, the regulatory costs of which will fall disproportionately on RTOs and ISOs under the current methodology, notwithstanding that such activities and programs apply to and serve to benefit all regions, not just RTO and ISO regions.

For instance, Section 215 of the EAct³⁸ requires the Commission to certify and oversee an Electric Reliability Organization (“ERO”) and implement a system of mandatory, enforceable, reliability standards applicable to the entire bulk-power system, including organized RTO/ISO regions, non-RTO public utilities, and non-jurisdictional entities. To date, the Commission has certified the North American Electric Reliability

³⁷ NOI at PP 20-21.

³⁸ 16 U.S.C. § 824o.

Corporation (“NERC”) as its ERO, approved NERC’s creation of several “Regional Entities” and reviewed over 100 NERC-proposed reliability standards – efforts that benefit all users of the bulk-power system and not just RTO and ISO members. However, despite the fact that the Commission’s reliability program under Section 215 is applicable to “all users, owners and operators of the bulk-power system,”³⁹ the regulatory costs associated with these new Commission responsibilities are being assessed to bundled retail load within RTOs and ISOs but not to bundled retail load outside of RTOs and ISOs. Again, the impact to RTOs and ISOs is disproportionate because the current assessment methodology excludes the bundled retail load of public utilities that are not part of an RTO or ISO.

As the Commission’s focus in the area of reliability increases, so will its regulatory costs. While RTOs and ISOs understand that they must be responsible for their fair share of the Commission’s reliability oversight costs, the current allocation methodology and the impact of the bundled retail load disparity discriminatorily allocates the vast majority of such costs to RTO and ISO members while enabling public utilities that are not part of an RTO or ISO to avoid paying an appropriate share of costs associated with the Commission’s increased reliability responsibilities under EAct 2005. The same is true for the implementation of Order No. 890⁴⁰ and its nine planning

³⁹ *Id.* § 824o(b)(1).

⁴⁰ *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,241, *order on reh’g*, Order No. 890-A, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,261 (2007).

principles,⁴¹ which presumably will demand more Commission time and effort in both RTO and non-RTO regions.⁴² The skewing of annual charge assessments will also continue to grow given that the Commission’s new planning mandates apply across the transmission grid to all market participants.⁴³ Because RTOs and ISOs pay the bulk of the Commission’s electric regulatory costs, their members are paying a disproportionate share of the Commission’s costs to enforce compliance with planning requirements by both non-RTO participants and non-jurisdictional utilities.

B. Alternative Methods for Recovery of the Commission’s Electric Regulatory Program Costs Exist and Should Be Considered

As invited in the NOI, the IRC respectfully presents several potential alternative methods to replace the Order No. 641 methodology. For organizational purposes, the IRC presents its answers to both questions (B) and (C) of the Commission’s NOI in this section – namely, identifying what alternative proposals exist (B), and explaining how such proposals would work (C).⁴⁴

⁴¹ The nine planning principles include coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation. Order No. 890 at PP 444-561.

⁴² The Commission recognized in adopting Order No. 890 that some of its changes to the *pro forma* Open Access Transmission Tariff (“OATT”) are not relevant to RTOs and ISOs. Order No. 890 at P 158 (“[S]ome of the changes adopted in the Final Rule may not be as relevant to ISO/RTO transmission providers as they are to non-independent transmission providers.”).

⁴³ Order No. 890 at P 441.

⁴⁴ NOI at P 23.

1. *As a Threshold Matter, the Commission Must Track and Separately Assess Reliability-Related Costs to All Users of the Transmission Grid*

At the outset, it is important to note that Congress has established new and separate reliability obligations giving rise to costs that, per EAct, are properly assessed to all “users, owners and operators of the bulk-power system.”⁴⁵ For this reason, the IRC believes that the Commission should develop a methodology for recovering its costs that recognizes its broader jurisdiction for reliability purposes and avoids simply layering those costs on top of the costs of other regulatory activities it recovers through its annual assessment charges. To this end, the Commission should track and separately account for the costs associated with reliability activities independently from the Commission’s more traditional regulatory program costs and activities in order to recognize the Commission’s broader jurisdictional reach in the area of development and enforcement of reliability standards. For identified reliability program costs, in order to abide by EAct’s mandate for assessments to all owners and users of the grid, the Commission could use the approach currently used by NERC to fund its reliability activities – *i.e.*, the “net energy for load” (“NEL”) approach.⁴⁶ Under the NERC method, net energy for load is calculated as “[b]alancing authority area generation (less station use), plus energy received from other balancing authority areas, less energy delivered to balancing

⁴⁵ 16 U.S.C. § 824s(b)(1).

⁴⁶ The Commission approved the NEL methodology as a “fair, reasonable and uncomplicated method [for ERO cost recovery] that minimizes the possibility of ‘double counting.’” *Rules Concerning Certification of the Electric Reliability Organization: Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,204, at P 35, *order on reh’g*, Order No. 672-A, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,212 (2006), *appeal docketed sub nom. New York Indep. Sys. Op. v. FERC*, No. 06-1185 (D.C. Cir. May 30, 2006).

authority areas through interchange . . . include[ing] balancing authority area losses, but exclud[ing] energy required for storage at electric energy storage facilities, such as pumped storage.”⁴⁷ The Commission could utilize the same calculation to assess charges for its reliability program across users, owners and operators of the transmission system, thereby avoiding the anomalous situation of forcing the RTOs and ISOs to bear a disproportionate burden of this far larger regulatory program that applies to more entities than just the public utilities that the Commission has historically regulated.

Costs associated with conventional regulatory activities should be recovered under a different assessment methodology. For such non-reliability costs, the IRC believes that several of the following suggested approaches would achieve the Commission’s goal of recovering its costs in a fair and equitable manner while removing the discriminatory aspects of the current methodology as discussed above.

2. *Alternative Assessment Methodologies That Would Result in Fair and Equitable Distribution of Commission Costs*

a. *Allocation of Traditional (Non-Reliability) Program Costs Should Be Assessed To All Reportable Electric Energy*

One approach that would yield a fair and equitable distribution of Commission annual charges is to assess such charges on a “Reportable Energy” basis, using FERC Form No. 582 as the source for volume data. However, in order to properly implement this approach, and to ensure annual charges are spread across all properly-assessable energy volumes in a non-discriminatory manner, the Commission must amend its FERC 582 reporting regulations to require reporting of the transmission component associated with all bundled retail load by utilities operating outside of RTOs and ISOs. Such data is

⁴⁷ Order No. 672 at P 35 n.7.

already included in the Form 1 filings of non-RTO/ISO transmission providers and requiring its inclusion as part of Form 582 would put such utilities on equal footing with RTO and ISO members.⁴⁸

The Reportable Energy approach would have the added benefit of using an allocator that better reflects the use of the transmission system. This approach will also eliminate the retail load discrepancy, resulting in a more fair and equitable approach to Commission assessments and eliminating today's FERC fee disincentive to RTO participation.

The Reportable Energy approach is also better suited to the operational realities within today's electric industry. For instance, in RTOs and ISOs with organized markets, transmission providers cannot separately "paint" and track the electrons associated with a native load sale versus a wholesale sale and thus cannot separate out native load volumes. Likewise, on non-RTO/ISO systems, it is increasingly difficult to do so given the growing use of spot sales, swaps, sales in, out and through RTO/ISO markets (both on a contract path and flow basis) and other complex transactions.⁴⁹ The Reportable Energy

⁴⁸ Obviously, any change to FERC 582 reporting requirements would have to be broad enough to ensure that *all* transmission associated with serving bundled retail load would be included in the total transmission volumes reported by *all* reporting utilities regardless of participation in an RTO or ISO.

⁴⁹ In fact, the use of a contract path methodology for reserving transmission service versus a network approach is not based on whether an entity is in an RTO/ISO or not. Some RTOs and ISOs continue to utilize the contract path methodology, many still provide point to point service and all are subjected to flows through their system from contract paths. As a result, attempting to separate sales as between sales to native load versus sales for resale is increasingly difficult. For this reason, the IRC proposes use of an allocator based on total use of the transmission system, noting that the choice of a reasonable allocator does not pre-determine issues concerned with specific jurisdictional uses of the grid.

approach avoids having to differentiate between energy sold at retail versus energy sold for resale because it simply assesses costs based on reportable and clearly verifiable transmission volumes.⁵⁰

The Reportable Energy approach suggested by the IRC would entail the following steps:

- Determine the Commission's total electric regulatory program costs and back out the costs associated with reliability oversight. Reliability costs can be allocated on the NEL basis as discussed above or using some other methodology which distributes such charges to all users, owners and operators of the transmission grid. The remaining costs can be assessed to transmission providers on a Reportable Energy basis;
- Determine the total MWh of energy transmitted on the grid over a given year from all reporting transmission providers;
- Calculate the total MWh reported by RTOs/ISOs to the total MWh reported by all reporting transmission providers. This forms the RTO/ISO allocation of FERC fees with the balance going to the other entities filing FERC 582 reports.

The allocation of costs under this approach would not constitute an exercise of jurisdiction over retail sales, but would merely recognize the existence of an interstate

⁵⁰ The IRC is *not* suggesting that the Commission redefine service to native load for purposes of this docket. Rather, the difficulty in assessing how native load is served demonstrates that the continued use of the present allocation methodology which treats retail load within an RTO or ISO differently than retail load outside of such regions is patently discriminatory and should no longer be utilized.

transmission component associated with retail sales transactions to which annual charges can be fairly imposed, especially given that such charges are already being imposed on comparable volumes being transmitted on the systems of RTOs and ISOs. The Commission's goal should be to develop a fair, just and reasonable allocation approach that is compatible with fundamental tenets of sound rate design. The Commission need not become embroiled in revisiting jurisdictional issues to remedy the obvious discrimination occurring today. In short, utilizing a reasonable, Reportable Energy allocator and resulting rate design is separate and apart from, and does not control, broader jurisdictional determinations. Finally, this approach is consistent with the Commission's traditional approach to ratemaking where costs are allocated based on energy volumes.⁵¹

b. Allocation Based on Peak Transmission Load

Under this approach, the Commission would assess annual charges on the basis of each transmission provider's reported peak load.⁵² This approach is similar to the Reportable Energy approach above and would be calculated on a similar basis, using peak load figures rather than total energy volume figures. Each reporting transmission provider's peak load would be divided by the total peak load of the transmission system to obtain each transmission provider's percentage share of the Commission's regulatory charges. Again, reliability-related costs would be recovered under a separate methodology as discussed above. The IRC's preliminary analysis indicates that an

⁵¹ Additionally, the Commission would not need to be concerned about whether and how to allocate costs between transmission and wholesale sales. *See* NOI at n.35.

⁵² The Commission has also suggested this alternative methodology. *Id.* at P 22.

allocation methodology based on peak load would provide a more equitable, non-discriminatory means of assessing cost responsibility among all entities, both members of RTOs/ISOs and market participants in non-RTO/ISO bilateral market regions. This approach also has the advantage of using readily-available data to calculate annual charges utilizing a straightforward formula.⁵³ Accordingly, the IRC believes that this approach would serve to remedy the arbitrary and discriminatory impact of the present allocation methodology.

c. Allocation Based on a Two-Part Fee Designed to Mitigate and Account for Current Disproportionate Allocation to RTOs and ISOs

Under this hybrid approach, a two-tier fee structure for non-reliability related program costs could be developed to mitigate the impact of the disparity inherent in the current methodology, to ensure that the “fair and equitable” standard is met, particularly given that the Commission’s new responsibilities in areas such as planning and siting are not limited to RTOs and ISOs.⁵⁴ By adopting a two-tier assessment methodology, the Commission could both eliminate the inequity brought about by the current methodological discrepancies and also ensure that all entities pay annual assessment charges associated with the costs they cause.

⁵³ For example, annual, non-coincident peak load data is provided in Form 1 and could be used as the basis for assessing annual charges for general (non-reliability related) FERC program costs to jurisdictional entities.

⁵⁴ This approach, as with the others presented herein, would be applied to collect the FERC’s program costs after the costs of the reliability program are backed out for collection through a separate NEL-based rider as discussed above. *See supra* section B.1.

A two-tiered rate would also reflect the very different way that transmission service and native load sales are handled in RTO regions (*i.e.* mostly through network service without distinction between native load and other service with market transactions settled financially on a day-ahead basis) versus non-RTO regions (where native load transactions are generally treated differently under contract path service provided under physical transmission reservations). This approach has the further advantage of providing, in effect, a mathematical smoothing-out of annual charge assessments, producing at a nondiscriminatory result whether an entity participates in an RTO or ISO or not.

Any two-tier assessment methodology must include objective measures to address the discriminatory features of the current methodology, as described above, and mitigate the disproportionate assessments to RTOs and ISOs through the reallocation of regulatory costs. The disparity can be measured by applying the various allocators proposed herein – *e.g.* total transmission volumes or peak load. This method would preserve the existing “reach” of the present allocation methodology but would, through rate design, correct for the otherwise discriminatory impact of today’s methodology.

d. Allocation Based on Functional Considerations That Classify and Assign Commission Program Costs Consistent with the Nature of the Costs and the Entities on Whose Behalf These Costs Are Incurred

Under this approach, the various functional activities giving rise to the Commission’s program costs would be identified (*e.g.* reliability, generation, transmission, siting, PURPA, review of affiliate transactions, enforcement, merger reviews, technology innovation and demand side management activities) along with the beneficiaries of these functional activities (*i.e.* retail customers, for-profit load serving

entities, for-profit generators, and for-profit transmission entities). An examination would then be made to determine which constituent-beneficiary category benefits for each functional activity, and in what proportion, followed by an intra-category breakdown of benefits by geographic region. Of course, under this approach it should be recognized that RTOs and ISOs enhance reliability and assist in price discovery and transparency, not just in their footprint but also in neighboring control areas. For example, all entities take advantage of the greater flexibility and larger set of tools which RTOs have to manage reliability issues occurring at the borders and throughout the interconnection. Functionalization of costs is a standard practice in ratemaking and would provide a rational basis for the Commission fee assessment based on sound principles of cost-causation and assessment of beneficiaries.

While this approach would likely require the Commission to engage in more detailed record-keeping of its efforts, it also arguably would yield the most fair and equitable result. The Commission would be required to categorize its efforts and determine which “beneficiaries” were involved in each category of efforts. All categories of jurisdictional entities would share in the cost responsibility for the Commission’s regulatory program, in shares that roughly equate to their cost causation. Moreover, the Commission could separately track its costs associated with reliability and other new post-EPA 2005 responsibilities and assign those costs accordingly to the entities that benefit.

3. *IRC Comments on Other Suggested Alternative Approaches*

The IRC offers commentary on other proposed alternatives that the IRC believes would either be impractical or would not result in a fair and equitable distribution of Commission costs.

a. *Assessing Annual Charges Based on Jurisdictional Wholesale Power Sales as Well as Transmission Services*⁵⁵

The specific import of this alternative approach is not clear from the NOI. To the extent that this approach would simply revert to the pre-Order No. 641 assessment methodology, the IRC submits that it is not a practical alternative in organized markets and/or on systems that provide primarily network service. *See* discussion *supra* at note 49 and accompanying text.

b. *Determining Annual Charges Using Factors Other Than the Volume of MWh Transmitted in Interstate Commerce, Such as Peak Load or Transmission Investment*⁵⁶

Although the IRC believes that an allocation based on book value of transmission investment would have the effect of reducing the percentage of annual costs currently allocated to RTOs and ISOs, the IRC believes that such an approach could be challenged on grounds that it unfairly discriminates against owners of newer vintage assets, without a cost-causation justification. In addition, the IRC believes that such an approach could be viewed as undermining ongoing regulatory initiatives to promote new infrastructure investment. Accordingly, the IRC would not advocate this alternative approach. On the

⁵⁵ NOI at P 22.

⁵⁶ *Id.*

other hand, as noted above, IRC supports an assessment approach based on reported transmission system peak load or total annual transmission volumes.⁵⁷

Conclusion

The IRC appreciates the Commission's invitation to offer comments regarding its annual assessment charges. For the foregoing reasons, the IRC respectfully requests that the Commission reevaluate its annual charge regulations and adopt a methodology that mitigates the patently discriminatory impacts associated with the current methodology. The IRC stands ready to work with the Commission and all stakeholders in the development of a NOPR designed to institute much needed and long overdue reforms in this area.

Respectfully submitted,

/s/ Craig Glazer
Craig Glazer
Vice President – Federal Government
Policy
PJM Interconnection, L.L.C.
1200 G Street, NW, Suite 600
Washington, D.C. 20005
glazec@pjm.com
(202) 423-4743

/s/ Stephen G. Kozey
Stephen G. Kozey
Vice President and General Counsel
**Midwest Independent Transmission
System Operator, Inc.**
P.O. Box 4202
Carmel, Indiana 46082-4202
skozey@midwestiso.org
(317) 249-5431

⁵⁷ See *supra* sections B.2.a & b.

/s/ Robert E. Fernandez
Robert E. Fernandez
Vice President and General Counsel
Elaine Robinson
Director of Regulatory Affairs
**New York Independent System
Operator, Inc.**
290 Washington Avenue Extension
Albany, N.Y. 12203
rfernandez@nyiso.com
(518) 356-7504
erobinson@nyiso.com
(518) 356-6178

/s/ Anthony J. Ivancovich
Nancy Saracino
Vice President, General Counsel &
Corporate Secretary
Anthony J. Ivancovich
Assistant General Counsel
**California Independent System
Operator Corporation**
151 Blue Ravine Road
Folsom, CA 95630
aivancovich@caiso.com
(916) 608-7135

/s/ Stacy Duckett
Stacy Duckett
Vice President, General Counsel & Corporate Secretary
Southwest Power Pool, Inc.
415 North McKinley
#140, Plaza West
Little Rock, AR 72205-3020
sduckett@spp.org
(501) 614-3296

May 28, 2008

ATTACHMENT A

Southwest Power Pool RTO
Analysis of FERC Assessment Costs for FY 2005 for SPP and its Members

SPP Entity	BEFORE ACTUAL		Notes	PROFORMA AFTER - Under SPP RTO	
	Assessable MWH Energy (1)	Unadjusted 2005 FERC Assessment		Total Assessable MWH Energy (2)	FERC Assessment under SPP
American Electric Power					
Public Service Company of Oklahoma	1,394,500	\$71,103		18,826,884	\$959,953
Southwestern Electric Power Company	6,265,895	\$319,488		23,596,890	\$1,203,168
Texas North Company (SPP portion)	97,304	\$4,961	(a)	153,023	\$7,802
TDUs					
East Texas Electric Cooperative	614,898	\$31,353	(b)	356,687	\$18,187
Arkansas Electric Cooperative Corporation	n/a	n/a	(c)	3,186,591	\$162,479
Oklahoma Municipal Power Authority	n/a	n/a	(c)	598,373	\$30,510
Northeast Texas Electric Cooperative	n/a	n/a	(c)	3,008,284	\$153,388
Tex-La Cooperative of Texas	n/a	n/a	(c)	454,913	\$23,195
Greenbelt	n/a	n/a	(c)	28,748	\$1,466
Lighthouse	n/a	n/a	(c)	9,908	\$505
Aquila - Missouri PS, St. Joseph L&P, WestPlains Energy	5,421,260	\$276,422		9,931,246	\$506,379
The Empire District Electric Company	810,808	\$41,342		5,271,309	\$268,776
Kansas City Power & Light Company	512,031	\$26,108		15,638,457	\$797,380
Oklahoma Gas and Electric Company	3,054,994	\$155,769		27,638,457	\$1,409,242
Westar Energy, Inc.	6,743,049	\$343,817		21,931,139	\$1,118,234
Midwest Energy, Inc.	379,209	\$19,335		1,486,080	\$75,773
Xcel Energy - Southwestern Public Service	3,468,175	\$176,837		25,538,078	\$1,302,147
Grand River Dam Authority	n/a	n/a	(c)	5,010,757	\$255,491
Western Farmers Electric Cooperative	n/a	n/a	(c)	6,449,953	\$328,873
City Utilities of Springfield (Missouri)	n/a	n/a	(c)	3,481,756	\$177,529
Subtotal	28,762,123	\$1,466,535		172,597,533	\$8,800,477
PTP Customers				12,392,914	\$631,895
Total		\$1,466,535		184,990,447	\$9,432,372

\$0.050988430 /MWH - 2005 FERC Assessment Rate

Notes:

- (1) MWH data from the FERC Electric Assessment Table for FY 2005
- (2) MWH data provided by SPP in Annotated – Schedule 12 Summary

- (a) Only a small portion of Texas North Company is in SPP, the majority is in ERCOT - Assumed 5% of load in SPP to determine the 2005 FERC Assessment portion
- (b) East Texas Electric Cooperative paid a 2005 FERC Assessment as the Commission determined them to be a FERC jurisdictional entity
- (c) Munis and coops not assessed directly by FERC - Joining an RTO/ISO creates an indirect assessment of FERC fees

ATTACHMENT B

Attachment B

FERC Fee Summary by ISO/RTO

Current Fiscal Year Charge (including effect of prior year adjustments) - as billed by FERC:

	<u>2002</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>
California ISO	9,094,334	11,348,976	7,822,812	12,346,819	10,832,507	11,286,820
Midwest ISO	-	1,376,391	29,998,527	30,010,722	29,245,822	28,862,184
ISO New England	-	-	-	-	6,327,692	6,352,693
New York ISO	6,234,908	7,862,930	5,311,674	8,572,309	7,754,555	7,797,837
PJM	1,744,908	25,160,264	14,099,102	21,383,377	32,671,167	33,341,384
Southwest Power Pool	-	-	-	-	8,333,076	8,688,040
Total to ISOs - in \$\$	17,074,150	45,748,561	57,232,115	72,313,227	95,164,819	96,328,958
Total to ISOs - as %	23%	54%	66%	65%	83%	84%
Total to non-ISOs - in \$\$	57,019,996	39,669,119	29,963,561	39,258,297	19,069,134	18,994,867
Total to non-ISOs - as %	77%	46%	34%	35%	17%	16%

Current Fiscal Year Charge (not including effect of prior year adjustments):

	<u>2002</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>
California ISO	9,361,025	9,038,198	10,576,809	11,571,568	10,882,024	11,302,644
Midwest ISO	-	13,459,037	19,182,528	28,582,679	29,364,517	28,904,885
ISO New England	-	-	-	-	6,318,504	6,361,881
New York ISO	6,406,923	6,272,354	7,214,466	7,893,166	7,676,814	7,920,148
PJM	11,091,204	12,897,139	15,422,743	22,847,553	32,752,552	33,389,011
Southwest Power Pool	-	-	-	-	8,320,976	8,700,140
Total to ISOs - in \$\$	26,859,152	41,666,728	52,396,546	70,894,966	95,315,387	96,578,709
Total to ISOs - as %	41%	54%	59%	65%	82%	83%
Total to non-ISOs - in \$\$	38,753,850	36,100,275	36,902,454	37,718,031	20,374,150	19,103,286
Total to non-ISOs - as %	59%	46%	41%	35%	18%	17%